Facts 2005

FACTS

THE NORWEGIAN PETROLEUM SECTOR

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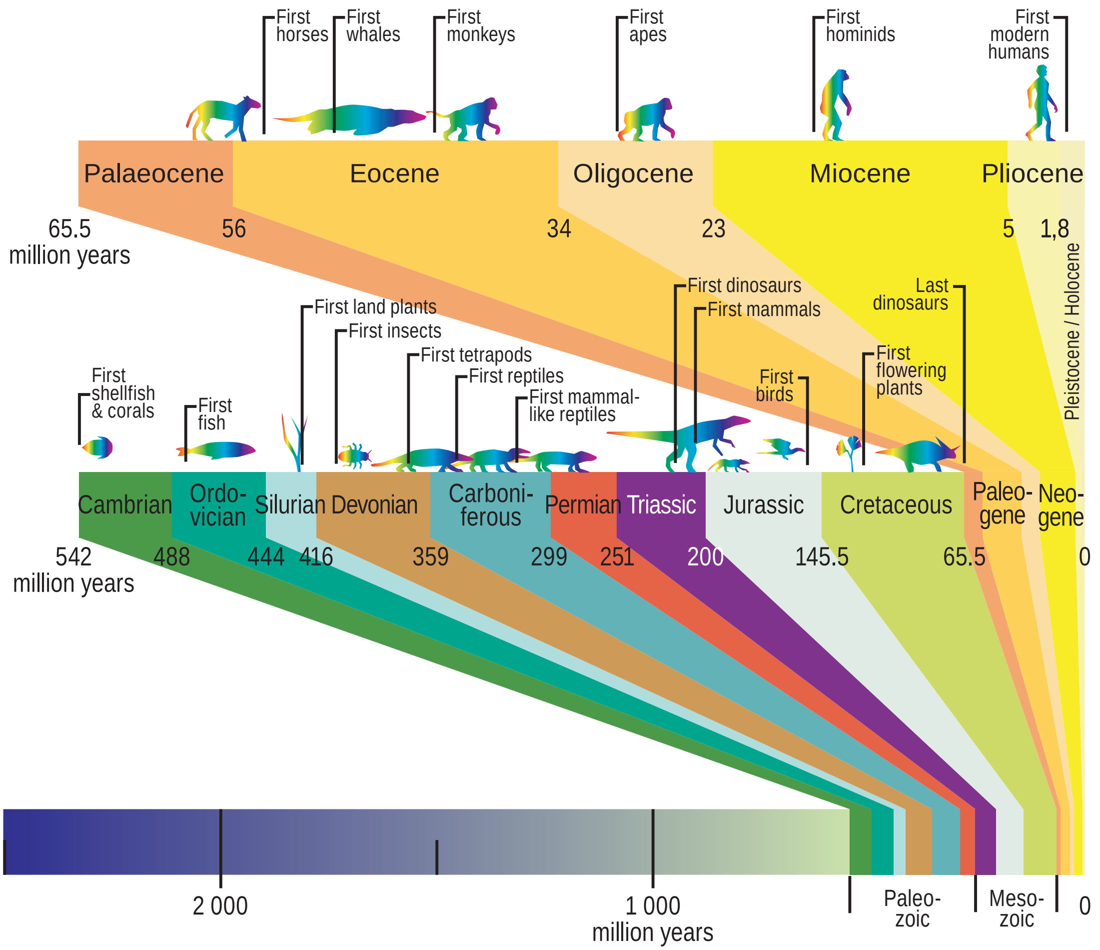

The Geological Timescale

Foreword by the Minister of Petroleum and Energy, Thorhild Widvey

The petroleum sector is now Norway's largest industry and it has made an important contribution to economic growth and to financing the Norwegian welfare state. In more than 30 years of operations, the business has created value in excess of NOK 4,000 billion in current terms.

Norway's oil and gas resources belong to the Norwegian society and must be managed for the maximum benefit of present and future generations. The aim of the Government's oil and gas policy is therefore to assist in the best possible stewardship of the resources, in order to maximise their value to the benefit of both companies and society at large – within a framework of sustainable development.

Record production levels in 2004

In 2004, production derived from 48 fields, 42 in the North Sea and 6 in the Norwegian Sea, and this was a record year for petroleum production on the Norwegian Continental Shelf (NCS). Output amounted to 3.2 million barrels of oil (including NGL and condensate) per day and 78 billion standard cubic metres of gas. This makes Norway the world's third largest oil exporter and seventh largest oil producer.

2004 saw the world's strongest growth in oil demand for many years. To find similar growth, we would have to go back 30 years. Over the year, the price of oil varied from 29 to 52 US dollars a barrel (Brent).

In 2004, the Government submitted a white paper on oil and gas activities, in which one of the most important topics was the cost level on the NCS. Reducing costs is a robust strategy for sustaining future activity. The authorities share a responsibility for the cost level in their regulation of activities. Accordingly, I am in dialogue with my colleagues in other ministries to ensure that the governmental processes and regulations are designed cost-effectively.

Research and development (R&D)

It is important for the state, in its capacity as owner of the resources, to ensure that they are exploited optimally. Cooperation between the oil companies, the supply industry and research institutions has been important in the development of activities and will continue to be so in the future. Extensive R&D activities on the part of both the companies and the authorities, have been, and will remain, essential.

In 2004, the Government gave petroleum research a major boost and increased funding for it by more than 60 percent in the 2005 budget. Experience shows that long-term, targeted R&D measures are a necessary contributory factor in developing oil and gas activities. Notably, R&D has been crucial for the development of a competitive Norwegian supply industry.

I am also committed to seeing the Norwegian oil and gas industry succeed internationally. Considering the extensive experience that the Norwegian petroleum industry has now accumulated, there should be excellent opportunities for further expansion in other markets. The industry's vision of substantially increasing the Norwegian supply industry's turnover beyond the NCS is ambitious, but should be perfectly achievable.

Mature fields

Significant portions of the NCS are now in a mature phase, with declining output and increasing operating costs in existing fields, as well as lower expectations for the sizes of future discoveries. In spite of this, there remain considerable resources in the mature areas of the NCS and the authorities' greatest challenge in the mid to long term is to help ensure that any decline in output is minimised and that the fields' lifetimes are extended. In order to realise the residual value, I would especially like to emphasise the importance of measures for improved oil recovery and efficient operations. Such measures will provide increased revenues and a longer lifetimes. We are now seeing the industry taking these opportunities seriously and activity levels are rising.

Considerable volumes of oil will remain unexploited after the planned abandonment of the major fields in the mature areas. It is thus extremely important to focus on increasing the level of recovery, in order to extract the greatest possible value from the fields. In 2004, the average recovery rate for oil from the NCS was 46 percent. With productive cooperation with the companies and a commitment to this on the part of the industry, I firmly believe that the recovery rate can be stepped up further.

As for the immature areas, we are now seeing much interest in the Barents Sea. Three promising exploration wells is planned to be drilled in the Barents Sea in the winter of 2005. The potential is huge, but there is also a considerable risk. The oil companies' access to new, prospective exploration areas and licences is essential for the future development of the continental shelf. At this time last year, much of the debate revolved around the low level of activity and what could be done to increase the number of exploration wells. For its part, the Government responded by improving access to exploration acreage, attracting more players, increasing competition and adjusting the licensing terms. I would note that the awards in predefined exploration areas in 2004 (APA 2004) were the largest in mature areas of the NCS since the authorities introduced the system of annual award rounds in 1999. 28 production licences were awarded, against 19 in the previous round, while the number of awarded companies increased.

Most of the indicators are now positive. We expect a high activity level, stable production, and many new development projects to be processed by the authorities. 2005 also seems to be a record year for investment on the NCS, while cooperation with other petroleum-producing nations is good. In other words – great potential lies ahead of us, which will be important for Norway's future as a petroleum-producing nation.

Minister of Petroleum and Energy

Foreword by Director general, Norwegian Petroleum Directorate, Gunnar Berge

The Norwegian state is the property owner of the Norwegian Continental Shelf (NCS), and in this capacity the authorities have substantial interests to manage. The paramount objective of the Norwegian Petroleum Directorate (NPD) is to contribute to creating the greatest possible value to society from the petroleum activities by means of prudent resource management, safety, contingency planning and the external environment. To perform this task, the authorities must be committed and possess competences similar to those in the petroleum companies – plus a little more. The companies are experts in the fields and the areas on the NCS where they have a particular interest. The authorities need to have expertise on the entire NCS. The NPD is the technical body of the Ministry of Petroleum and Energy (MPE), with competence in geology, geophysics, reservoir technology, finance and other specialist disciplines. This is a prerequisite for being in a position to manage the ownership interests in a way that benefits the whole society. The NPD advises and defines terms and conditions in respect of both the ministry and other decision-making authorities.

From knowledge to value

One absolute precondition for contributing to value-creation is knowledge and overview. The optimal exploitation of oil and gas resources on the NCS requires that we keep up-to-date on how substantial the resources are and where they are located. Every year, the NPD prepares a resource account, which shows what has been produced and sold, what has been discovered and what remains to be found. The NPD's experts regularly update the estimates of the total volume of resources on the NCS, based on the best methods available at any time. In addition to its own calculations, the NPD has the authority to require the companies to supply all necessary and relevant information. Amongst other things, our data provide a basis for making forecasts of future production and investment. The NPD's unique databases are also highly valuable to other stakeholders. The Norwegian authorities have a policy of making data available to interested parties – at the lowest possible cost. Such openness is globally unique, and represents an important contribution to making the NCS more attractive.

Activity levels on the NCS are on the rise

In 2004, 17 exploration wells were drilled on the NCS: 9 wildcat and 8 appraisal wells. This is all too few. We estimate that a third of the resources on the shelf are yet to be found. The NPD believes that at least 30 exploration wells should be drilled on the NCS each year in order to maintain activity at the required level. To step up exploration activity, over recent years, the authorities have given the industry access to large new exploration areas, and we are expecting a vigorous increase in activity. The companies have reported that they will drill 30–40 exploration wells in 2005. Access to drilling facilities may now be a limiting factor, and this is a major challenge for the authorities and industry alike.

But increased activity related to discoveries and fields in production is also anticipated. At present, there are plans for developing 17 discoveries. There are 44 additional discoveries that may be developed in the longer term. There are also plans for improved oil recovery, which gives grounds for optimism. The average recovery target for oil on the NCS is 50 percent. The NPD has been charged by the MPE with assessing whether it can be justified to raise this target further. Even if not all of the 100-plus improved recovery projects reported by the companies are realised, this still indicates that the industry has a strong will to make an extra effort to increase the levels of recovery. The NPD considers this work to be so important that we are awarding a special annual prize, the IOR (Improved Oil Recovery) prize, to the licence, company or person who has made an extraordinary effort in this direction.

Unit costs must fall

Cost levels on the NCS are a major challenge. As the fields mature and production falls, costs per produced unit of oil and gas will increase. If we are unable to manage costs better, we risk leaving considerable resources will be left behind in the underground. E-operations may be a solution to help make operations on the NCS more efficient. In Report to the Storting no. 38, on petroleum activities, the NPD was assigned the task of becoming a driving force for increased use of e-operations on the NCS. E-operations involve employing real-time data to co-ordinate the work between organisations and specialist involvement to achieve better and quicker decision-making in both the exploration and operation phases. E-operations may contribute to improve recovery, reduce costs and improve safety. In the autumn of 2004, the NPD set up an e-operations forum, with representation from oil companies, suppliers, trade unions, the authorities and research institutions. The aim of the e-operations forum is to be a driving force for the sharing of knowledge and experience and to discuss the opportunities and challenges.

Director general, NPD

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1 The petroleum sector – Norway's largest industry

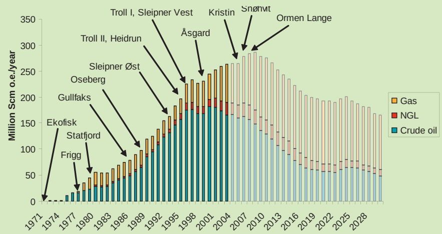


Figure 1.1 Production level and start-up dates for important fields
(Source: NPD/MPE)

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

With the Ekofisk discovery in 1969, the Norwegian oil adventure began to earnest. Production from the field began on 9 June 1971, and in the following years a number of major discoveries were made. Today, there are 48 fields in production on the NCS. Production from these fields corresponds to around 20 times the domestic consumption of petroleum and has established Norway as a key supplier to the global oil market and the European gas market. In connection with the development of the Snøhvit field, for the first time agreements have been signed for the sale of gas to markets outside Europe.

2004 was a record year for petroleum production on the NCS. Production amounted to 3.2 million barrels of oil (including NGL and condensate) per day and 78 billion standard cubic metres of gas, making a total of saleable petroleum of 263 million standard cubic metres of oil equivalents (scm oe).

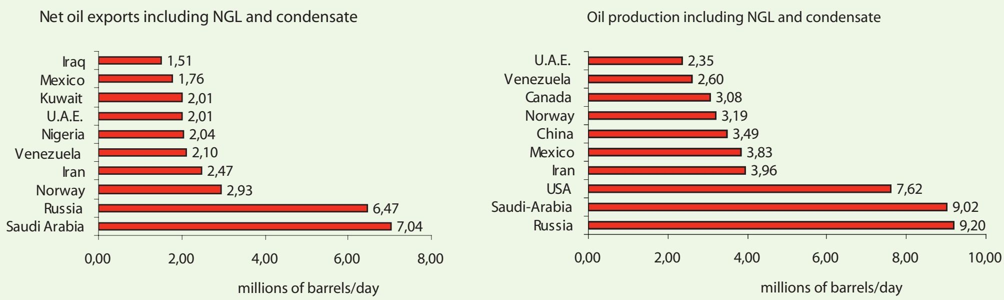
Norway ranks as the world's third largest oil exporter and the seventh largest oil producer. In 2003, Norway was the world's third largest gas exporter and the eighth largest gas producer[1].

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 more than 30 years of operation, the industry has created values in excess of NOK 4,000 billion in current terms; it is today Norway's largest industry. In 2004, the petroleum sector accounted for 21 percent of the value creation in the country. This equates to twice the value creation of the manufacturing industry and around 15 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 2004, the state's net cash flow from the petroleum sector

[1] Source: IEA: Key World Energy Statistics 2004 (based on 2003 figures).



Figur 1.2 The largest oil producers and exporters in 2004 (incl. NGL/condensate)
(Source: Petroleum Economics Ltd)

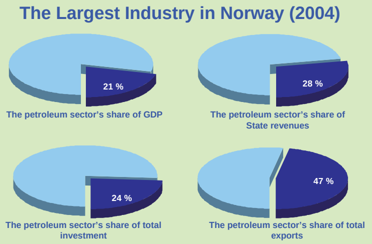


Figure 1.3 Macroeconomic indicators for the petroleum sector *(Source: Statistics Norway, Ministry of Finance)*

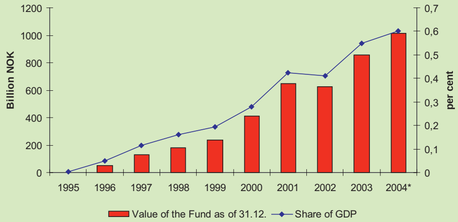


Figure 1.4 The size of the Petroleum Fund at 31.12.2004 and as a share of GDP *(Source: Norwegian Public Accounts, Statistics Norway)*

amounted to 28 percent of total revenues. After more than 30 years of production, the business has generated net revenues to the state in the order of NOK 2,000 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 Petroleum Fund. By the end of 2004, the value of this fund was NOK 1,016 billion.

In 2004, crude oil, natural gas and pipeline services accounted for 47 percent of the value of Norway's exports. This share increases to nearly 50 percent if refined products and goods and services from the supply industry are included. In 2004, the total NOK value of petroleum exports was 346 billion, 36 times higher than the export value of fish.

Since the petroleum industry started its activities on the NCS, huge sums have been invested in exploration, field development, transport infrastructure and onshore installations; at the end of 2004 around NOK 1,800 billion in current terms. Investment for 2004 was NOK 71 billion, or 24 percent of the country's total real investments.

Norwegian petroleum industry

The development of Norwegian and Norwegian-based petroleum expertise has been an important factor in Norwegian petroleum policy. Initially, there was a strong element of knowledge transfer from foreign oil companies and supply/service companies, but today Norway has a highly developed and internationally competitive petroleum industry. This applies to oil companies, the supply industry and research institutions alike. The industry provides a powerful boost for innovation and technology development to other sectors of the Norwegian economy.

Supply companies in Norway are active along most of the supply chain – from exploration and development to production and disposal. In a number of areas, Norwegian suppliers are among the world leaders, in particular in seismic surveying, subsea installations and floating production systems. They are present in all of the country's counties. Local and regional economic trickle-down from petroleum activities extends to a relatively high degree even to areas of the country not normally associated with petroleum activities. The Norwegian Directorate of Labour's latest survey, from 2003, showed that more than 75,000 people are employed in the petroleum industry in Norway.

Future trends

In spite of more than 30 years of production, only about 30 percent of the expected total resources on the NCS have been produced. There is thus huge potential for further value creation.

Figure 1.5 shows a forecast for future production from the NCS. It is based on the Norwegian Petroleum Directorate's (NPD) estimate of recoverable petroleum resources on the NCS and assumes that the authorities and the industry take the requisite decisions for recovering the remaining volumes.

Oil production is expected to remain relatively constant until 2007, and then to fall gradually. Gas production is expected to increase until 2010 and to plateau at a level of 120 billion scm. From representing around 30 percent of Norwegian petroleum production in 2005, gas production is likely to continue to increase and may come to represent a share of more than 50 percent by 2014. In the longer term, the number and size of new discoveries will be a critical factor for the production level.

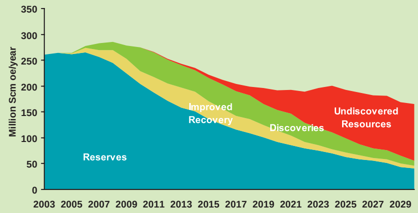


Figure 1.5 Production forecast (breakdown of oil/gas in figure 1.1)
(Source: NPD/MPE)

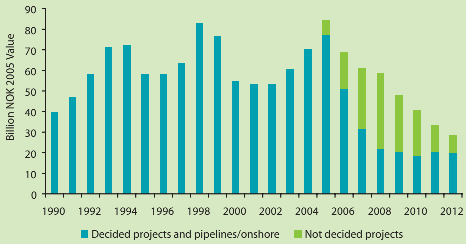


Figure 1.6 Historic investments and forecasted future investments
(Source: NPD/MPE)

The level of activity on the NCS remains high. In 2004, investments of NOK 71 billion were made, while investments in exploration activity amounted to NOK 4 billion. In 2005, an investment level of NOK 88 billion is anticipated and between 30 and 40 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 Snøhvit, Ormen Lange and Kristin. Investments are expected to fall after 2005, but forecasts indicate that activity in the industry will remain high over the long term, see fig. 1.6. In the years ahead, investment will relate primarily to modification and drilling activities. There is considerable uncertainty in the investment forecasts, in both the longer and the shorter terms. In addition to the investments, the forecasts also show a market for operations and maintenance of NOK 30–35 billion annually for years to come.

The oil companies' investments in development, operations and maintenance on the NCS generate considerable demand for products and services from the supply industry in Norway and elsewhere. However continued growth depends on success internationally. International experience and participation in international development projects are extremely important for the further growth of the supply industry. In addition, international experience of this kind has the potential to contribute to further cost savings on the NCS.

Ekofisk

2 The Norwegian resource management model

The Norwegian Parliament

A crusial step in securing Norway the rights to any oil and gas off the Norwegian coast was to claim jurisdiction and proprietary right ot the area now known as the Norwegian Continental Shelf (NCS). This prosess was not finalised until May 1963. At that time, there were no Norwegian oil companies and very few institutions that could involve themselves in petroleum activities.

Right from the start, it has been fundamental that the oil and gas resources belong to the whole of Norwegian society, and that they must be administered for the benefit of present and coming generations.

National administration and control were an early prerequisite for the Norwegian government, as was the building up of governmental institutions and a Norwegian oil community. The NCS was opened up gradually, with only a limited number of blocks being offered in each licensing round, in order to maintain a moderate rate of development.

To begin with, the Norwegian government selected a model in which foreign companies carried out all petroleum activities on the NCS. Over time, the Norwegian involvement was strengthened by the creation of a wholly owned state oil company, Statoil.

"We understand that you are interested in exploring for oil in the North Sea. We hold the rights to this and we do not intend to grant any licences before we know what we are doing. We are quite simply giving you a challenge: Educate us!" These were the words of Jens Evensen, the chairman of the newly created Norwegian Petroleum Council, when meeting representatives of international oil companies, who had been invited to the Ministry of Foreign Affairs for one of the first meetings about petroleum activities in Norway.

Source: Kindingstad & Hagemann (2002), "Norges oljehistorie" (freely translated)

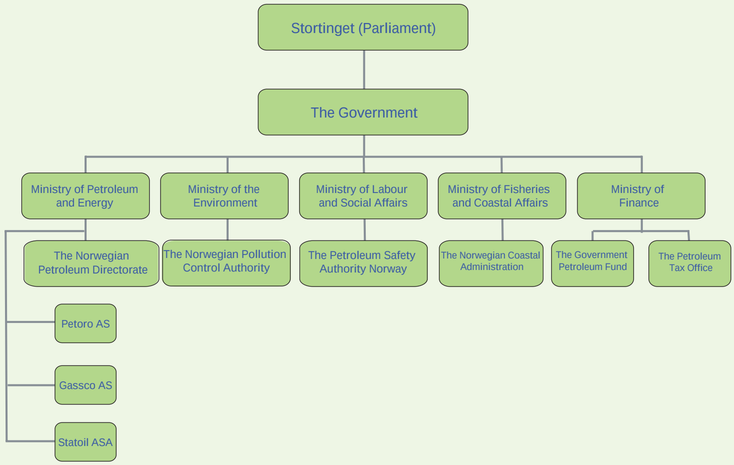


Figure 2.1 National organisation of the petroleum sector

Additionaly, Norsk Hydro took part in the petroleum activities. A private Norwegian company, Saga Petroleum, was also established. The cooperation and competition between the various companies on the NCS have been crucial, as they have all possessed different technical, organisational and commercial expertise. This policy has played its part in Norway having today its own oil companies and a competitive supply industry, and in the nation having secured high revenues from the sector.

The present division of labour and responsibility

The organisation of petroleum activities reflects Norwegian attitudes to ownership of natural resources and organisation of the civil service and business activities. Respect for the environment, health, the working environment and safety plays an important role. All of the current players in the Norwegian petroleum industry have a common interest in creating the greatest possible value from the recovery of Norwegian petroleum resources. The organisation of the business today, as well as the division of labour and responsibility, aim to ensure that important social interests are protected, and that the value created will benefit the society.

The Storting

The Storting, the Norwegian parliament, creates the framework for Norwegian petroleum activities. The methods used include passing legislation and adopting propositions, as well as discussing and responding to white papers about the petroleum activities. Major development projects or matters of great principle must be discussed and approved by the Storting. The Storting also has a duty to control the government and the civil service.

The government

The government holds the executive power over petroleum policy and is responsible to the Storting for this policy. In applying the policy, the government and the ministries are supported by their subordinate directorates and agencies. The responsibility for the various parts of the petroleum policy is distributed as follows:

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

The oil companies

National and multinational companies are responsible for petroleum activities on the NCS. These activities include many complicated decisions of a commercial and technical nature, and, as elsewhere in society, coordination and competition between commercial players often yields the best results. In order to protect the interests of society, the authorities seek as far as possible to influence the companies' decisions through clear-cut and predetermined frameworks for their activities. In this way, decisions made by the oil companies also yield the most benefit for society.

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 NCS. This includes ensuring that the petroleum activities are carried out in accordance with the guidelines drawn up 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 special responsibility for monitoring the state-owned corporations, Petoro AS and Gassco AS, and the partly state-owned Statoil ASA.

The Norwegian Petroleum Directorate

The most important tasks for the Petroleum Directorate are to maintain the administrative and financial control of exploration and recovery of the petroleum resources, in order to ensure that they are 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 corporation which is responsible for the State's Direct Financial Interest (SDFI) on behalf of the state.

Gassco AS

Gassco AS is a state-owned corporation responsible for the transport of natural gas from the NCS.

Statoil ASA

Statoil ASA is listed on the Oslo and New York stock exchange. As of 1 March 2005, the state owned a 70.9 percent stake in the company.

THE MINISTRY OF LABOUR AND SOCIAL AFFAIRS

The Ministry of Labour and Social Affairs holds the overall responsibility for the working environment and for safety and contingency measures in relation to the petroleum sector.

The Petroleum Safety Authority Norway

The Petroleum Safety Authority holds responsibility for safety, contingency measures and the working environment in the petroleum sector.

THE MINISTRY OF FINANCE

The Ministry of Finance has the overall responsibility for ensuring that the state collects taxes, fees and other revenue 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 correct assessment and collection of the taxes and fees that have been decided on by the political authorities.

The Government Petroleum Fund

The Ministry of Finance is responsible for administrating the Government Petroleum Fund. Responsibility for operational administration has been delegated to Norges Bank.

THE MINISTRY OF FISHERIES AND COASTAL AFFAIRS

The Ministry of Fisheries and Coastal Affairs is responsible for maintaining adequate contingency measures against acute pollution in Norwegian waters.

The Norwegian Coastal Administration

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

THE MINISTRY OF THE ENVIRONMENT

The Ministry of the Environment holds the overall responsibility for management of the Norwegian environment.

The Norwegian Pollution Control Authority

The responsibilities of the Norwegian Pollution Control Authority include to follow up the Pollution Control Act. A second key task is to provide the Ministry of the Environment with advice, guidelines and technical documentation.

Coordination within the industry

There exist today a number of arenas and meeting places in order to promote coordination in the petroleum industry, and to improve the players' wider understanding of the range of challenges that the industry faces – be they organisational, technological or commercial. The Ministry of Petroleum and Energy sees it as important to support and participate actively in them.

1 Industry and industrial cooperation linked to the petroleum industry, domestically and abroad

Topplederforum (senior management forum)

A new forum for senior management in the petroleum industry was introduced in 2000, under the leadership of the Minister for Petroleum and Energy, with the aim of promoting efficiency and activity on the NCS. Today, the Topplederforum is made up of around 30 senior managers from oil companies, the supply industry, labour organisations and the authorities. Its mandate is to reinforce the international competationess of the NCS, as well as the competitive strength of the Norwegian supply industry, both at home and abroad. Initiatives originating from this forum include projects and working processes related to the cost level on the NCS, as well as improvement of cooperation within in the sector.

INTSOK

INTSOK – Norwegian Oil and Gas Partners – is a foundation that was established by the authorities in 1997, in partnership with the Norwegian petroleum industry. It is regarded by the Norwegian authorities as an important partner. In excess of 150 companies are members of the foundation. INTSOK aims to help and promote Norwegian petroleum industry internationally. The goal is for the Norwegian petroleum industry to increase it´s annual turnover significantly from the current level of around NOK 35 billion.

Petrad

As part of its international activities, the MPE also supports the Petrad foundation. Petrad is a Norwegian aid agency, which offers various types of knowledge transfer programms to management of national oil companies and petroleum authorities in developing countries.

2 The significance of technological developments in value creation and competetiveness in the oil and gas industry

OG21 – Oil and gas in the 21st century

In order to be able to face the major challenges of value creation and environmental protection that are linked both to the development of the NCS and to reinforcing Norwegian industry's competetiveness, a broad-ranging partnership within the oil and gas industry was implemented in 2001, with the aim of establishing a national strategy for research and development. This partnership is known as OG21 – Oil and gas in the 21^{st} century.

One important goal for this initiative is to ensure a unified and more efficient partnership within the oil and gas industry in the fields of research, demonstration and commercialisation of technology. Attention has been directed at achieving efficiency gains throughout the value/research chain and between oil companies, the supply industry and research institutions.

Based on the most important challenges faced by the petroleum industry, the following five main priorities have been identified in the OG21 partnership: 1) Environmental issues 2) Increased recovery 3) Deep-water production, 4) Industrial use of gas and 5) Development of small fields.

DEMO 2000

Another important initiative for the promotion of new technological solutions within the petroleum industry is the Demo 2000 partnership. This is a technological initiative directed at three main goals:

- New field developments on the NCS through new and cost-effective technology and new implementation models
- Increased certainty of implementation within budget and according to plan
- New Norwegian industrial products for sale in a global marketplace

Demonstrations and pilot projects will qualify new, cost-effective technology for use. The goal is to create new development projects, products and jobs. The pilot projects involve a close cooperation between supply companies, research institutions and oil companies, a partnership that, in itself, contributes to the development of a forward-looking, market-oriented network. The programme funding is channelled through the Research Council of Norway.

PETROMAKS

In 2004, a new major petroleum research programme, PETROMAKS, was established, coordinated by the Research Council of Norway. The technological goals defined in OG21 form the starting point for PETROMAKS, which is intended to improve recovery from producing fields and increase accessibility to new reserves. The key research tasks within the first phase of this new programme are:

- Exploration: Development of geophysical measurement methods, exploration and reservoir models and improved understanding of basin formation.
- Increased recovery in a wider perspective: Development of methods for stimulated recovery, reservoir monitoring and control, drilling technology, as well as new processes, methods and technology for gas delivery.

Petropol

The Petropol research programme is coordinated by the Research Council of Norway. Its objective is to

maintain and extend the knowledge base of the social science research community in Norway working on petroleum-related issues.

3 Exploration activities

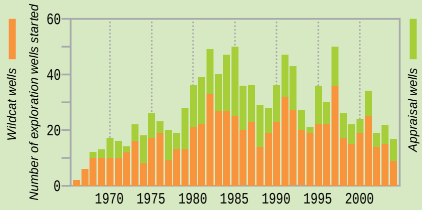


Figure 3.1 Exploration wells started on the NCS, 1966–2004
(Source: NPD)

In order to recover the petroleum resources on the Norwegian Continental Shelf (NCS), undiscovered resources must first be explored for and proven. Exploration activities are an important indicator of future production. Typically, it takes several years from a decision to begin exploring for resources to any discoveries being put into production. The framing of the 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 NCS than was previously the case and hence towards making fewer major discoveries. For the authorities, it is important that the framing of the exploration policy makes for the rapid and efficient identification of new resources. It is the companies which then undertake the exploration itself and the proving of new resources. The exploration policy is therefore designed to increase the attractiveness of the NCS and to help bring in new players to complement the existing ones. The authorities seek to promote a high level of activity on the continental shelf through the structure of the licensing system and through area access and management.

A fundamental precondition for petroleum activities on the NCS 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 the licensing policy, where, in the opening up of new areas, in the announcement of licensing rounds and in the awarding of production licences, much emphasis is accorded to arriving at schemes that cater to the interests of all the users of the marine areas.

The licensing system

The Petroleum Act no. 72 of 29 November 1996 pertaining to petroleum activities provides the overall legal basis for the licensing system which regulates petroleum activities. The Act and its appurtenant regulations authorise the award of licences to explore for, produce and transport petroleum and so forth.

The Petroleum Act establishes that the proprietary right to subsea petroleum deposits on the NCS 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 (MPE) puts together a group of companies for each licence or can make adjustments to a group which has submitted a joint application. The MPE appoints an operator for this partnership, who executes the day to day activities under the terms of the licence.

The production licence regulates the rights and duties 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 production of petroleum within its specified geographical area.

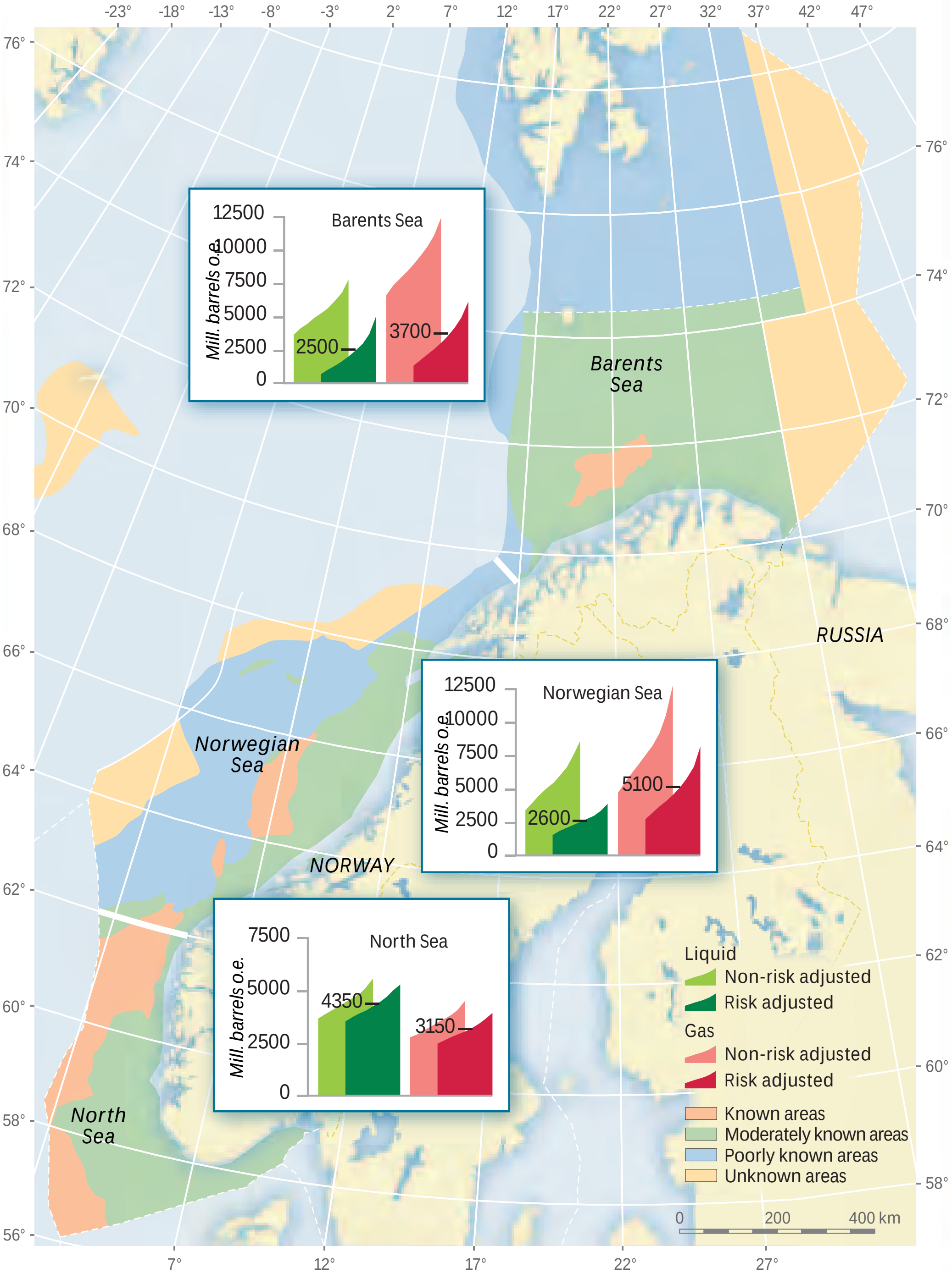


Figure 3.2 Undiscovered resources
(Source: NPD)

Ownership of the petroleum produced rests with the licensees. Each licence is awarded for an initial exploration period, which can last up to 10 years. A specified work obligation must be met during this period, including seismic surveying and/or exploration drilling and so forth. Providing the work obligation has been completed by the end of the period, the licensees are generally entitled to retain up to half the area covered by the licence for a specified period, generally 30 years. An area fee is charged per square kilometre, as set out in detailed rules. Providing all the licensees agree, a licence can be relinquished once the work obligation has been fulfilled.

Mature and frontier areas

The parts of the NCS that the Parliament has opened up for petroleum activities are the bulk of the North Sea, Norwegian Sea and southern Barents Sea. The Norwegian Petroleum Directorate's (NPD) estimate of undiscovered resources in the areas on the continental shelf are a total of 3.4 billion square cubic metre recoverable oil equivalents. This equates roughly to the volumes that have already been produced to date on the NCS and the resources are divided more or less equally between the three regions, with 35 percent in the North Sea, 36 percent in the Norwegian Sea and 29 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 respect of realising the commercial potential of the undiscovered resources on the NCS.

The mature areas are characterised by known geology, only minor technical challenges and well developed or planned infrastructure. This makes the probability of success from drilling prospects relatively high, but, equally, means that there is less likelihood of major new discoveries. In some of the mature areas of the NCS, petroleum activities have been going on for more than 30 years, and as a result the geology is well understood and, in many places, the infrastructure is well developed.

Frontier areas on the other hand are characterised by a scant understanding of the geology, major technical challenges and a lack of infrastructure. Here, the uncertainty linked to exploration activity is greater, but, on the other hand, there is the prospect of major new discoveries. These factors tend to limit the number of actors qualified to search for such resources. In addition to wide experience and technical and geological expertise, those operating in these areas must have solid financial backing.

Exploration policy in mature and frontier areas

Mature areas

Petroleum activities on the NCS began in the North Sea and have over the years, moved northwards. This means that, in terms of exploration, large areas of the North Sea are now considered mature. In addition to this, there has also been considerable exploration of the Halten Bank in the Norwegian Sea and this region, too, is considered mature. The latest area to be considered mature is the area around the Snøhvit field in the Barents Sea. There is currently no production here, but the understanding of the area is good and production and infrastructure are planned through the Snøhvit development now underway.

The probability of success from drilling prospects in mature areas is relatively high, while at the same time the likelihood of making major new discoveries has diminished. The average size of dis-

Mature areas in the North Sea

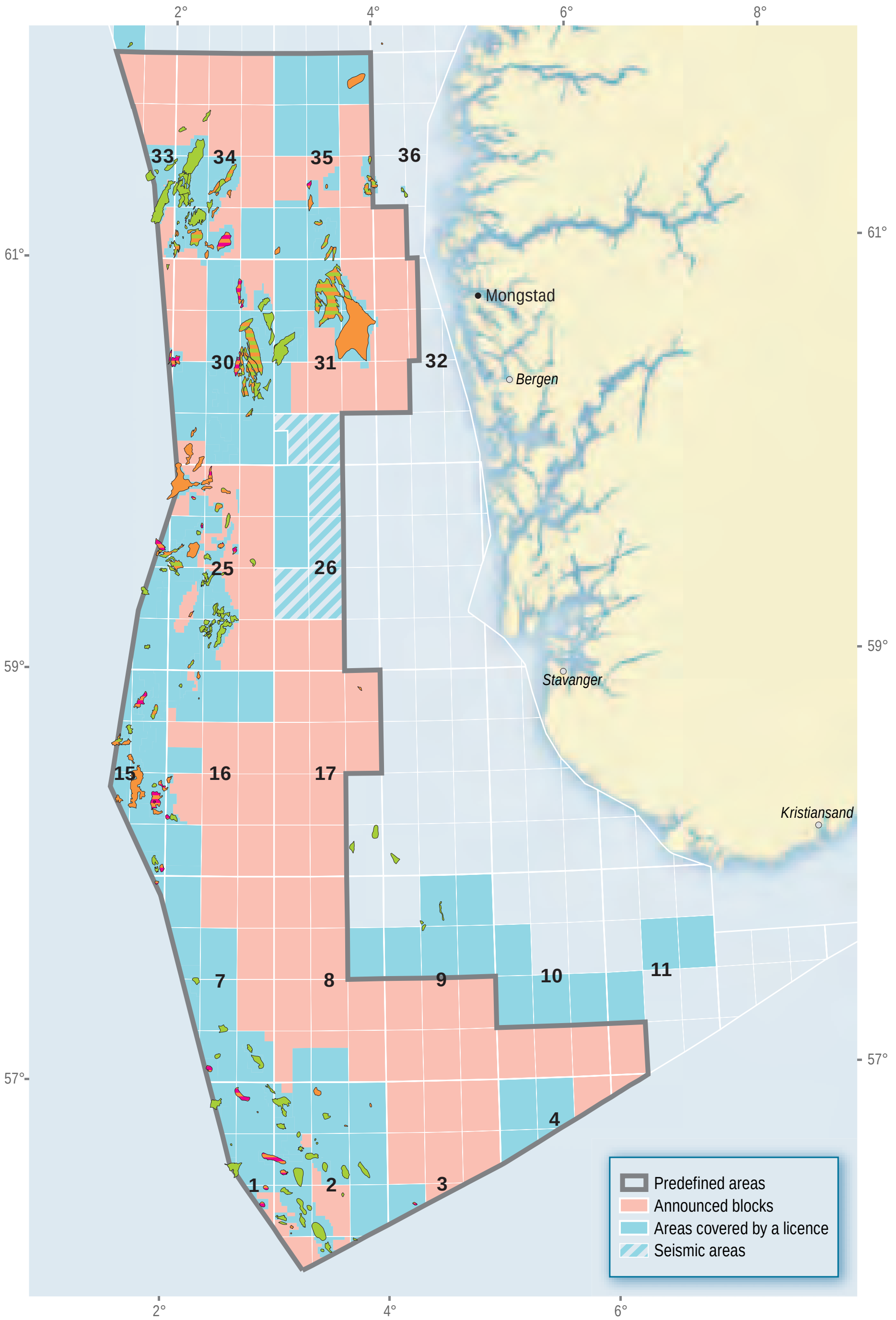


Figure 3.3 Awards in predefined areas – North Sea announcement 2005
(Source: NPD)

Mature areas in the Norwegian Sea

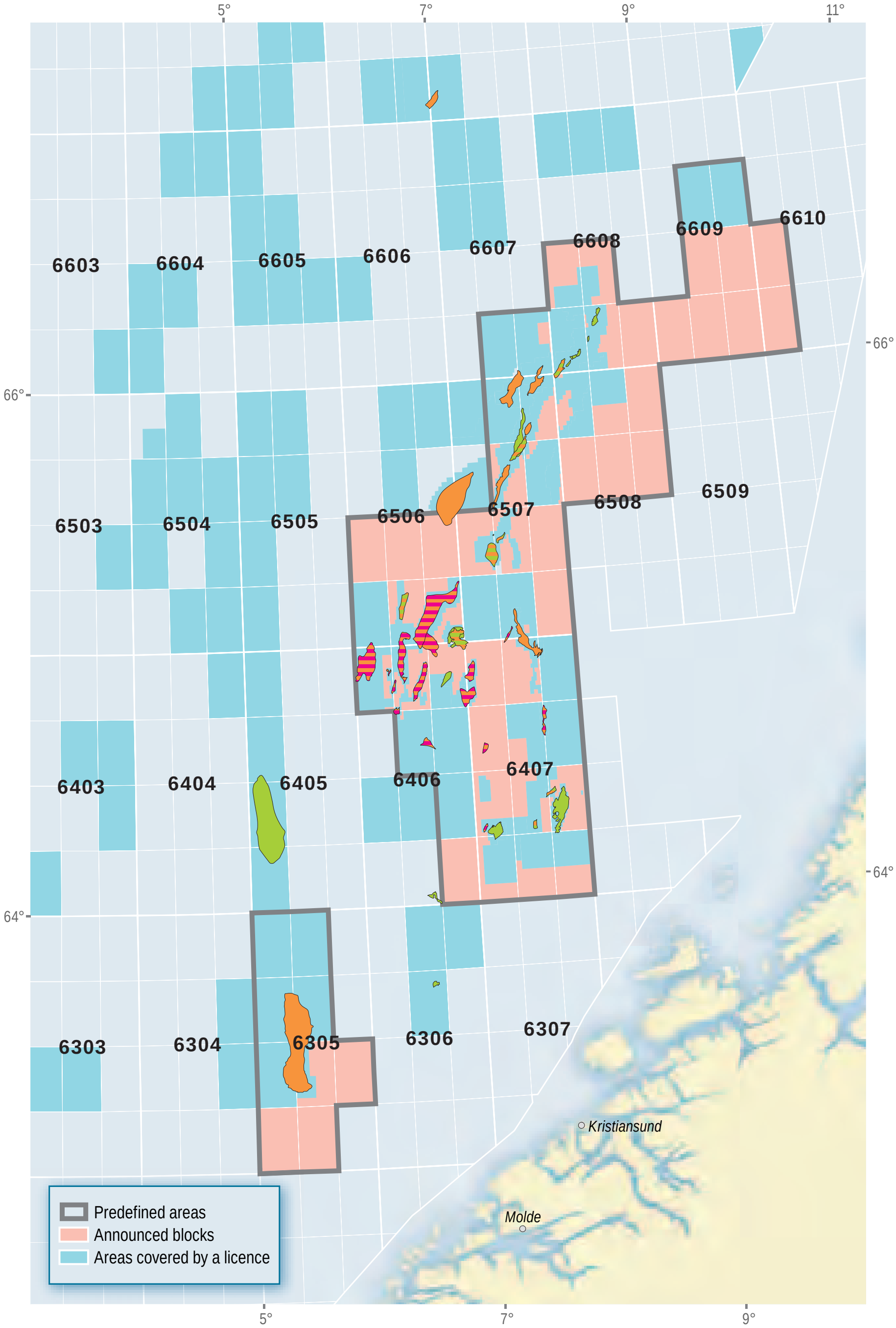


Figure 3.4 Awards in predefined areas – Norwegian Sea announcement 2005
(Source: NPD)

Mature areas in the Barents Sea

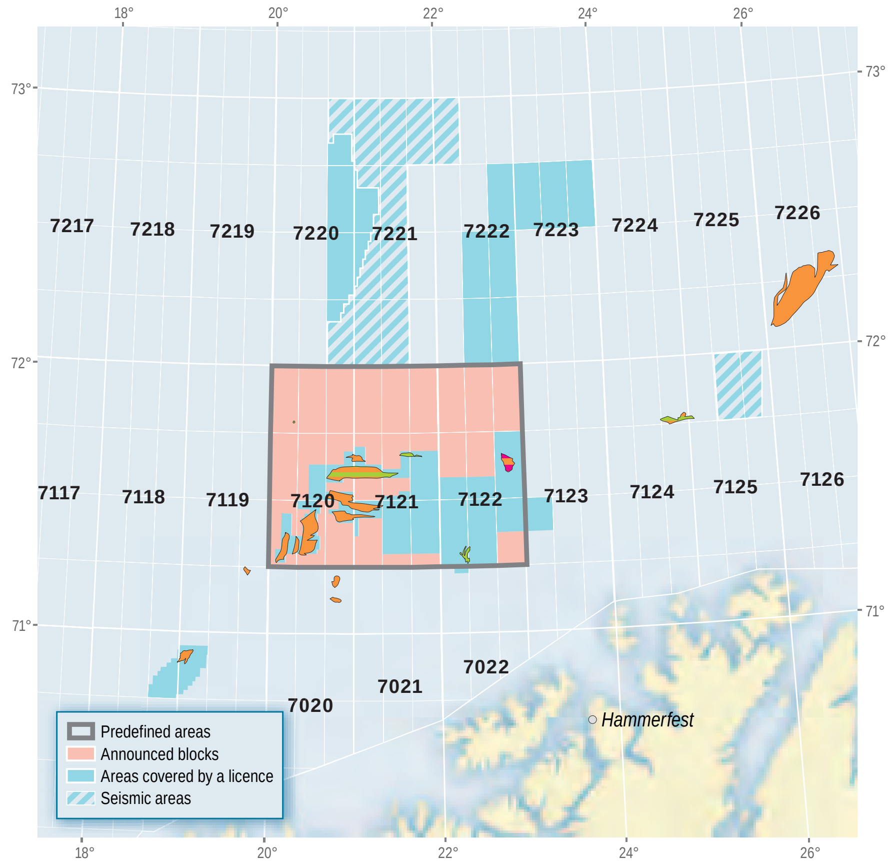


Figure 3.5 Awards in predefined areas – Barents Sea announcement 2005
(Source: NPD)

coveries in mature areas is also expected to fall off. As a result, the value of each discovery to the oil companies is less, and the largest oil producers are therefore showing less interest in these areas. Also, the life expectancy of the existing infrastructure is limited and it is therefore important to prove and recover resources in the area before it is abandoned. If this is not done, profitable resources may remain in the ground, because the discoveries are too small to warrant a separate infrastructure development.

Previously, the authorities conducted licensing rounds on the principle of gradual exploration of areas. There was a gradual shift northwards in step with increased understanding of the areas. The knowledge accumulated through systematically building on expertise from previously awarded production licences has meant that the frequency of discoveries on the NCS has been high.

As the NCS has matured, the need for this form of gradual access has reduced. In mature areas, it is important that the industry has access to larger areas, so that time-critical resources can quickly be developed. It is also important that the areas allocated to the industry are explored quickly and efficiently.

The government has therefore changed its policy on mature areas and, in 2003, introduced a scheme for production licence "Awards in Predefined Areas" (APA) in mature parts of the NCS. This scheme has led to the creation of predefined exploration areas, comprising, mature areas of the NCS. The areas will be extended, but not reduced, as new areas mature. In addition, there is the proposal for a fixed annual cycle of licensing rounds in mature areas. So far, this has lead to two such rounds in mature areas, APA 2003 and APA 2004. Figure 3.3, 3.4 and 3.5 indicate the announced area in APA 2005.

An area within a predefined area that has been relinquished between announcement and the application deadline will be included in the announcement area. This means that all areas relinquished within the predefined area will automatically be considered as announced at the time they are relinquished. In this way, other companies, who may have a different view of prospects in the area, will rapidly be given the opportunity to explore it. This means swifter circulation of areas and more efficient exploration of the mature areas.

More frequent licensing rounds and larger announced areas in each round have brought about an increase in licensed areas. At the beginning of 2005, 16 percent of the area open for petroleum activities on the NCS were covered by a licence – an increase of 9 percent from previous year.

For the authorities, it is important that an area covered by a licence is explored. The framework must therefore seek to encourage companies who have been awarded production licences not to leave the area idle, but to actively explore it.

To meet the challenges resulting from larger sections of the NCS now being designated as mature and from larger sections being covered by licences, the framework has been changed.

In the mature areas, the work obligations that the companies assume on award of new production licences are designed as a set of activity and decision-making junctures, where the companies must decide, at each decision-making juncture whether they wish to undertake new activities under the licence or relinquish the area in its entirety.

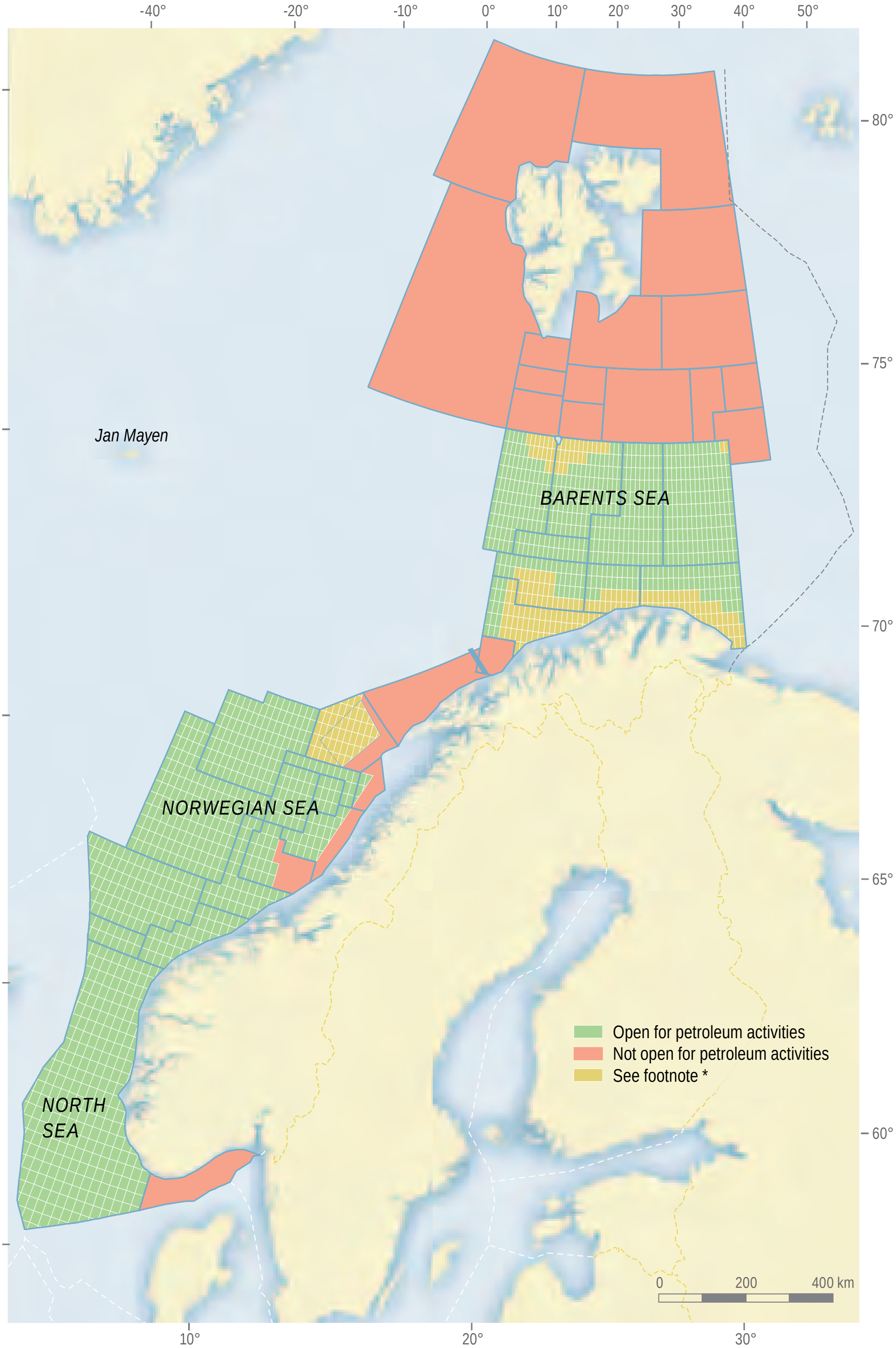
A second important change is that, on award, the production licence areas are more 'tailored' than previously in that the companies are only awarded areas where the companies have concrete plans.

In addition, at the end of the initial period, changes have been made to which areas companies are permitted to hold onto. Previously, at the end of the initial period, companies could retain up to 50 percent of the awarded area with no obligation for any specific further activity. Now, however, the companies may, as a rule, only retain areas in which they plan to commence production.

Frontier areas

The areas which are currently considered to be immature on the NCS are large parts of the Barents Sea and Norwegian Sea. In the Norwegian Sea, this is true in particular of the deep-water areas and the northernmost sections, In addition to this, the coastal areas in the southern section of the NCS are also relatively immature.

In these areas, it is still possible to make major new discoveries. The potential for such discoveries in the frontier areas serves to sustain the competitiveness of the NCS from an international perspective, and the areas retain the potential for attracting interest from the biggest multinational oil companies. More and more of the southern NCS is now mature. This has triggered the need to investigate the conditions for petroleum activities in the large frontier areas that remain in the northern sections of the continental shelf.



* Area excluded from year-round petroleum activities in light of the ULB
(government report on impact on Lofoten - Barents Sea of petroleum activities)

Figure 3.6 Open and not open areas on the NCS
(Source: NPD)

Figure 3.7 Norwegian and Russian part of the Barents Sea
(Source: NPD)

In response to environmental and fisheries concerns, the government initiated an assessment study of the consequences of year-round petroleum activities in the Lofoten – Barents Sea area. On the basis of the results, the government decided that awarded areas in Nordland VI off the Lofoten islands should not be opened up further for petroleum activities. This issue will be considered anew when the overall management plan for the Barents Sea has been prepared. At the same time, the government decided on a general opening up of future year-round petroleum activities in the already-opened areas of the southern Barents Sea, with the exception of certain especially valuable areas.

In the winter of 2003, the Ministry of Petroleum and Energy and the Ministry of Fisheries and Coastal Affairs set up a working group to assess the feasibility of a coexistence between the fisheries and petroleum industries in the area from Lofoten northwards, including the Barents Sea. Institutions participating were: The Ministry of Fisheries and Coastal Affairs, the Ministry of Petroleum and Energy, The Directorate of Fisheries, the Institute of Marine Research, the Norwegian Petroleum Directorate, the Norwegian Fishermen's Association and the Norwegian Oil Industry Association. The working group summarised its work in a report completed in July 2003.

In Report to the Parliament no. 38 (2003–2004) the government stated that it wished to continue the work done in this group to evaluate issues between the petroleum and fisheries sectors. The MPE aims to resume work in this coexistence group in 2005.

With the announcement of the 18th licensing round in 2003, the industry was given access to relatively large areas in frontier areas as well. The announcement was the largest in frontier areas since 1965. With the 18th licensing round, the principles regarding amendments to the rules for relinquishing sections of mature areas were also extended to apply to frontier areas. It is not, however, expedient for the companies with production licence in frontier areas to submit a development plan at the end of the initial period, so the main rule for relinquishments in these areas is confined to resources proven by drilling. As in mature areas, the same amendments have also been made in frontier areas in respect of tailoring the areas that are allocated.

Unopened areas

There are still large parts of the NCS which the Parliament has not opened up for petroleum activities – the whole of the northern Barents Sea, Troms 2, Nordland VII, parts of Nordland VI, coastal regions off the Nordland coast and the Skagerak (see figure 3.6).

A decision by the Parliament on the opening up of these areas for petroleum activities is required before they can be announced in any licensing round. As a basis for the Storting's decision, an impact assessment, covering such aspects as the environmental, economic and social effects of the activities on other industries and adjacent regions, will need to be carried out. The issue must also be put to local authorities and key stakeholding organisations which may be considered to have a particular interest in the matter.

In addition to the above-mentioned areas, the present government has also decided not to allow petroleum activities in especially vulnerable areas in the Barents Sea and Nordland VI. Activities here will be reassessed once the management plan for the Barents Sea is ready.

Area with overlapping claims

The boundary between Norway and Russia has still not been finally drawn and is currently being negotiated by the Russian and Norwegian authorities. The area is outlined in figure 3.7 and covers roughly an area the size of the Norwegian part of the North Sea.

Industry structure

Industry structure here refers to the number and composition of the oil companies involved in petroleum activities on the NCS. The key place occupied on the NCS by the largest multinational players is a natural consequence of the fact that it has been characterised by projects that are few in number, large in size and resource-intensive, and with very substantial assets to be realised. To a large degree therefore, the authorities aimed to limit the players to the biggest multinational companies, since it is these who, from their wide experience and expertise, were best able to exploit the demanding opportunities the NCS offered. As the continental shelf has matured and the challenges it poses have changed and diversified, it is important that the composition of the players involved should in turn reflect this new reality. In recent years therefore, there has been a focus on bringing new competent players onto the NCS, and these have been smaller players who have a particular focus on matures areas and tail-end production.

Prequalification

In order to facilitate the terms for new players, in Report to the Parliament no. 39 (1999–2000) *Oil and gas activities* a scheme for prequalifying new operators and licensees was introduced. From the scheme's inception to January 2005, 25 companies had prequalified for, or become licensees on the NCS. Other companies are currently being evaluated or have indicated a wish to prequalify.

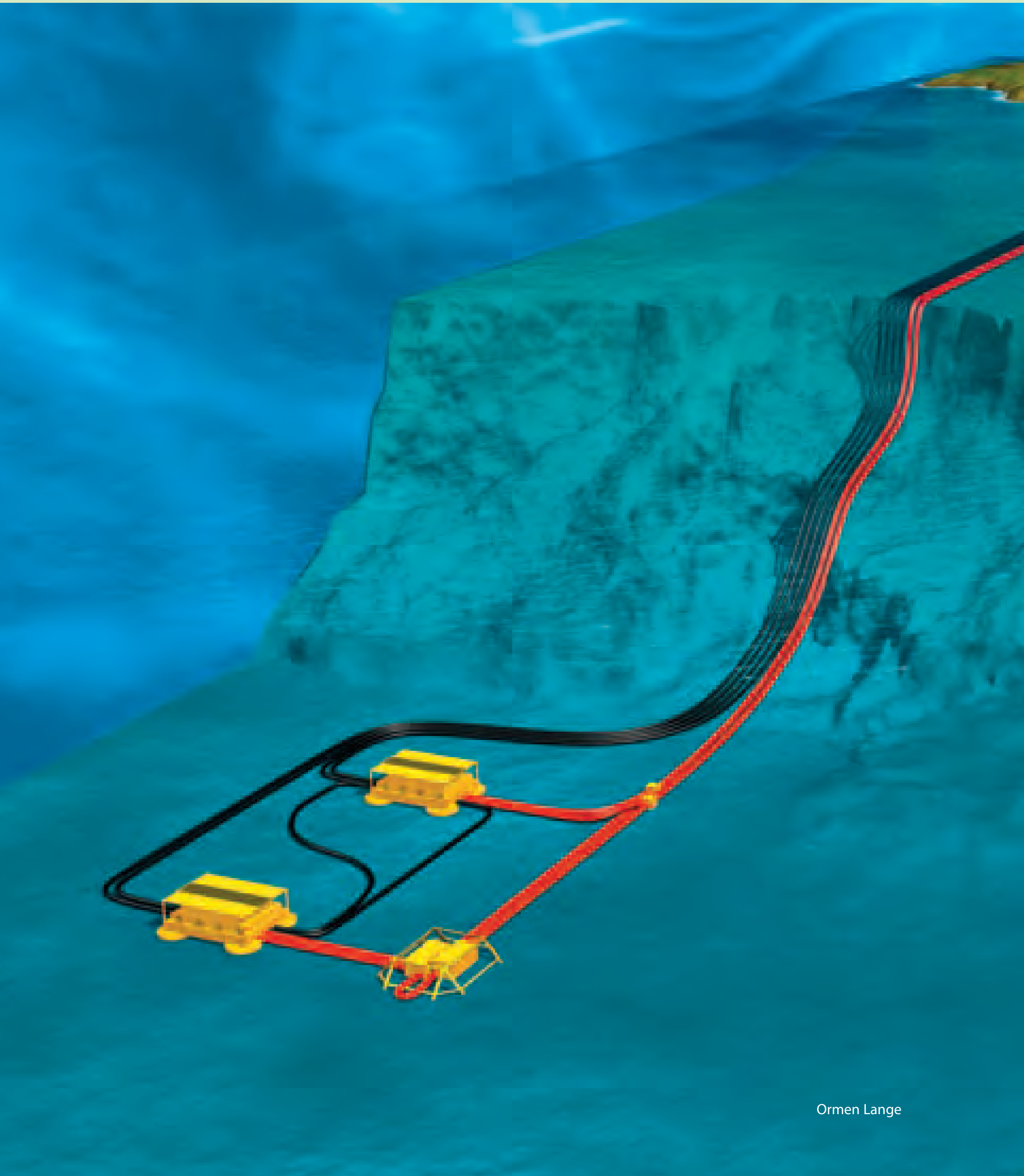
The figure shows prequalified and new companies on the NCS since 2000. Those marked with an asterisk no longer exist today as independent companies.

Prequalified/new companies since 2000

Sumitomo	OER	Petoro
Paladin	Talisman	Mærsk
Aker Energy *	Ruhrgas	Anadarko
Dong	Kerr McGee	CNR
Pelican *	Pertra	Lasmo*
GdF	Oranje Nassau	Revus
Lundin	Endeavour	Centrica
DNO	BG Norge	Wintershall
	Altinex	Noble Energy

* Companies that no longer exists as individual companies

4 Development and operations



Ormen Lange

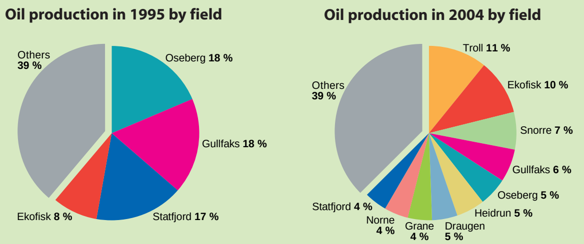


Figure 4.1 Distribution of oil production by field on the NCS
(Source: NPD)

In 2004, Norway produced more oil and gas than ever before, a total of 3.2 million barrels of oil per day (including NGL and condensate) and 78 billion standard cubic metres of gas. Total production of oil and gas is expected to remain at these levels over the next few years, with a slight increase up to the anticipated peak year of 2008. In the future, oil volumes will decrease while gas volumes will increase. 10 years ago, gas made up 15 percent of total production, in 2004 this had increased to 30 percent and it is expected that, by 2014, gas will exceed 50 percent of the total production. Figure 1.1 in chapter 1 shows historical and future trends in petroleum production from the Norwegian Continental Shelf (NCS).

In 2004, before Frigg was shut down, there where 49 fields in production, 43 in the North Sea and 6 in the Norwegian Sea. With the Snøhvit field, coming on stream in 2006, petroleum will also be produced from the Norwegian sector of the Barents Sea.

Production on the NCS has been dominated by some large fields. Several of these are now in decline, while new fields have been added, with the result that current production is distributed over more fields than previously. This is a natural development. 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, under field names such as Ekofisk, Frigg, Statfjord, Oseberg, Gullfaks and Troll. These fields have been, and still are, of great significance for developments on the NCS. The large fields have contributed to the establishment of an infrastructure that subsequent fields have been able to tie themselves into.

Figure 4.1 shows that 60 percent of oil produced in 1995 came from only four fields. In 2004, the equivalent proportion of the production was distributed over 10 fields. In the same period, the number of crude oil fields increased from 29 to 37.

As the Norwegian petroleum industry has moved northwards, it has entered into areas containing huge gas resources. Consequently, a number of gas fields have, been developed and a comprehensive gas transport infrastructure established, which has made it possible to develop additional gas resources. Development of the gas fields, combined with falling production from major oil fields, has meant that gas is becoming an ever more important part of Norway's petroleum production.

The number of fields on the NCS is increasing and they are found in an increasing geographical area. Decreasing
production from the major oil fields, combined with development of new fields, makes production less concentrated than it used to be, at the same time as the gas share is increasing.

Fields and infrastructure – potential for efficient exploitation

To protect society's interests vis-à-vis development and operations, the authorities have established frameworks for these activities, which are intended to ensure that the companies make decisions that are also to the benefit of society at large. It is important for these frameworks to be clear and to create predictability in relation to the companies' decisions. 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.

The petroleum industry frameworks commit the companies to prudent development and operations of the petroleum resources. This means that it is the companies which are responsible for putting forward and executing new projects, while it is the authorities which give the final consent for implementation. In the case of large projects, plans must be submitted for approval by the authorities. As part of the approval process, stakeholders may express their views, ensuring that all relevant factors are taken into account. Project approval is hence contingent upon optimal recovery and acceptable consequences.

Development of proven petroleum resources lays the foundation for current production and value creation from the petroleum industry. Development of 48 fields on the NCS, however, also provides the opportunity for further exploitation of resources in the vicinity of producing fields. Overall, at issue here is a considerable potential, which, sensibly utilised, is capable of generating huge value for society, and which comprises a number of elements. In respect of existing fields and infrastructure, this potential can be divided into essentially two categories:

- further development of producing fields
- tie-in of discoveries and exploration for new deposits

Further development of producing fields

Although the total production of oil and gas has never been higher, many fields are facing declining production. This applies especially to the major oil fields that came on stream in the 1970s and 1980s. Despite decreasing production, there is still a great potential for increased recovery from producing fields. This is illustrated in figure 4.2, which shows resources in fields that are on stream.

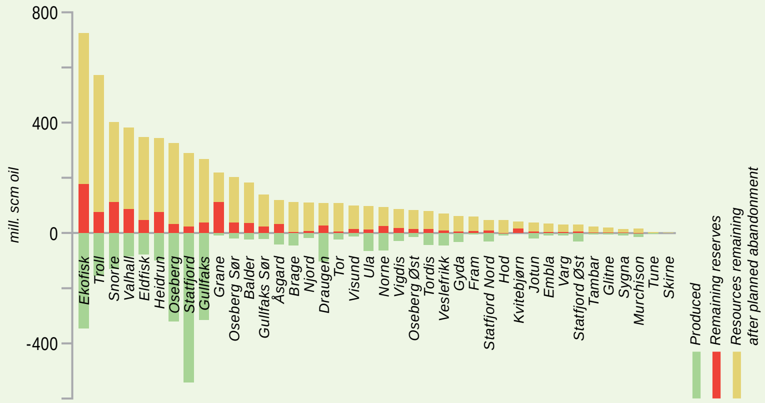


Figure 4.2 Distribution of resources – on-stream fields
(Source: NPD)

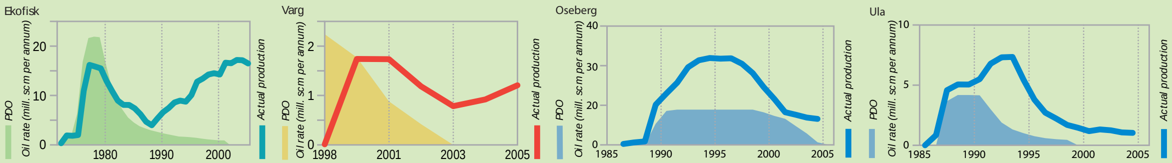


Figure 4.3 Production trends for the Ekofisk, Varg, Ula and Oseberg fields.
(*Source: NPD*)

The figure shows a three-way split of the resources:

- produced volumes
- remaining reserves; i.e. resources for which plans exist for recovery (reserves)
- resources for which plans for development and operations have not been approved, and which will remain unexploited after planned decommissioning

This last category offers a significant potential. Based on figures reported by the companies, projects are being considered that will increase recovery of oil from on-stream fields by around 230 million scm of oil. This is equivalent to 8 new Alvheim fields[1]. In addition, the Norwegian Petroleum Directorate (NPD) has estimated the potential yield from further measures to be in the vicinity of 290 million scm of oil. In all, a potential for increased recovery which exceeds half a billion scm of oil has been identified. This volume has a gross value of around NOK 750 billion[2] and illustrates that increased recovery can create huge values.

A number of measures are necessary if this potential is to be realised. They can be divided into two groups – *efficient operations* and *increased recovery.*

Efficient operations impact upon production costs, and will for this reason affect resource recovery, because it is possible to maintain profitable production longer when production is more efficient. As production falls, many fields face a situation in which costs must be reduced in order to justify profitable production at lower levels. At the same time, communication technology has paved the way for new methodologies. Ways of exploiting these are often referred to as "e-operations" or "smart operations". E-operations involve using information technology to change work processes to achieve better decision-making, to control equipment and processes remotely and to move functions and personnel onshore. The basis for e-operations is computer technology which makes it possible to transfer information over long distances more or less instantaneously. Onshore personnel can thus receive the same information at the same time as offshore personnel, and this offers the potential for changes in working practices. Different technologies and expertise are brought together into a single unit that enables new constellations between offshore and onshore, oil companies and subcontractors. Reduced costs and smart operations are, therefore, elements that will contribute to efficient operations, and consequent increased production.

In addition to efficient operations, it is possible to implement a number of measures that affect revenues more directly in the form of increased recovery. Some examples include infill drilling, injection into the reservoir to enhance recovery, modifications of processing equipment, etc. The development and use of new technology has been, and is, extremely important. Progress in technology makes it possible, for example, to drill wells and develop fields in ways that have previously been technically impossible.

Figure 4.3 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 decommissioned. Due to efficient

[1] Alvheim is a medium-sized field that is currently being developed.
[2] The gross value is based on an oil price of NOK 230 per barrel.

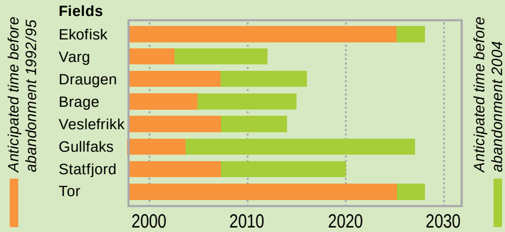


Figure 4.4 Lifetimes for selected fields (Source: NPD)

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 that considerable value can be created by increased recovery. Figure 4.3 also shows that increased recovery extends a field's lifetime, which is beneficial, because it makes room for implementing further development measures, and implies that the infrastructure will remain in place for a longer period.

Figure 4.4 shows that a field's lifespan changes over time. This is because the production period provides increased insight and knowledge – which, in turn, provides the basis for implementing supplementary projects that could not be decided 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.

Tie-in of discoveries and exploration for new resources

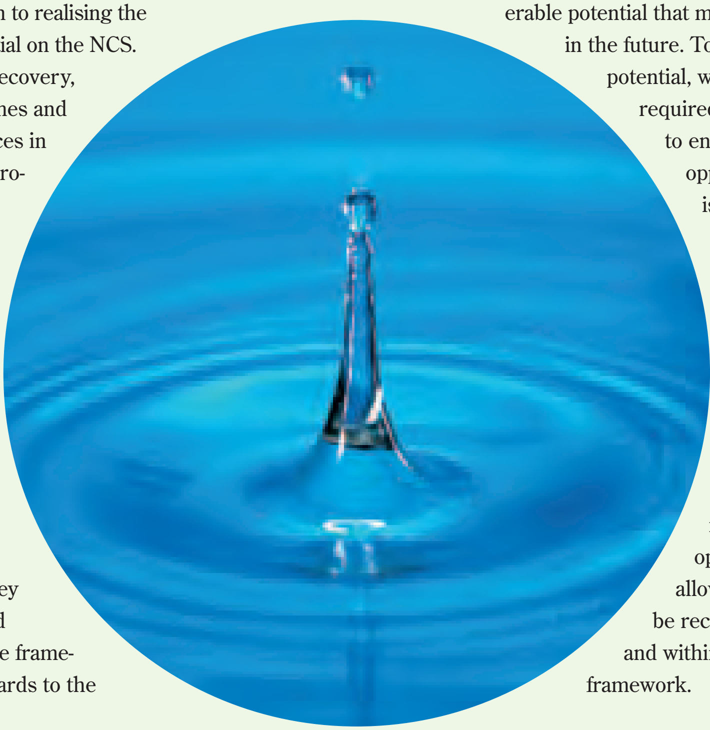
By year-end 2004, just below NOK 1,800 billion in current monetary value has been invested on the NCS. This is equivalent to more than NOK 1 billion each week over the whole period. The investment has led to the establishment of an extensive infrastructure that makes it possible to produce and market petroleum, but also forms a basis for the development of further resources in a cost-efficent manner.

As production falls, spare capacity in the existing infrastructure will often be available. Exploitation of such capacity may provide for an effective utilisation of resources that can be tied back 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 are too small to carry their own infrastructure. It follows from this that the resource potential in the areas around existing infrastructure must be explored thoroughly before such infrastructure is decommissioned. Failure to do so may cause society to miss out on significant value.

Estimates from the NPD indicate that around two thirds of the undiscovered resources on the NCS are likely to be in the North Sea and the Norwegian Sea. These are the areas on the NCS that currently have an extensive infrastructure established. In order to map the prospects in these areas, and to be able to exploit 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 way, while stringent requirements are set for those companies that are awarded exploration acreage. In extension of this policy, and in the light of the fact that a number of fields are approaching decommissioning, it is important that the existing infrastructure is exploited effectively, whether by the owners themselves or by third-party users.

Even though the NCS is populated by many platforms, and an extensive network of pipelines, third-party users of the existing infrastructure often face a monopoly situation, or at least limited competition. If we are to ensure effective exploitation of the petroleum resources, the infrastructure owners must not take advantage of such a market situation. Third-party use is an example of a "win-win" situation. The host field can share fixed costs among more users, and third-party users may benefit from investment that has already been made. This will often prove positive for resource recovery in both the host field and satellite fields.

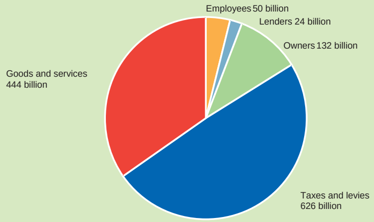
In order to ensure that the potential in and around producing fields is exploited, it is important that the participating interests are vested with the companies which want to make the most of them. This is why the authorities take a positive view of transfers of participating interests. In addition, the authorities have opened up for a broader range of players; cf. 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 area. With this in mind, the Norwegian authorities believe that a diversity of players, making different assessments and priorities, makes for a positive contribution to realising the resource potential on the NCS.



Increased recovery, extended lifetimes and tie-in of resources in the vicinity of producing fields forms the basis for the creation of extensive added value for society. However, increased recovery and extended lifetimes are only acceptable if they can be achieved within justifiable frameworks with regards to the natural environment, health, working environment and safety. Further development of resources in and around existing fields often involves the use of existing infrastructure. This provides less freedom of action compaired to new developments, because companies are not at liberty to choose whichever technical solution they prefer, due to limitations of existing equipment, weight limitations, etc.

Looking ahead 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. To realise this potential, work will be required on many fronts, to ensure that all the opportunities at issue are evaluated. For the long term, where the ambition is to produce oil until 2050 and gas until 2100 or beyond, it is crucial to realise all the opportunities that allow petroleum to be recovered profitably and within a justifiable framework.

Social accounts 1969-2004 for Ekofisk



Total value creation from the Ekofisk sector to the end of 2004 (at 2004 values) was NOK 1 260 billion
(Source: ConocoPhillips)

Ekofisk – an example of a successful partnership between oil companies, the supply industry and research institutions

Half of the world's petroleum resources are to be found in chalk reservoirs, the type present in the Ekofisk area. In general terms, chalk can be said to have relatively poor production qualities and a relatively low recovery rate. This was a very serious problem in the early development phases of the Ekofisk field, and in 1971 the recovery rate, in other words how large a proportion of the total petroleum reserves could actually be recovered, was estimated at 17 percent for the main Ekofisk reservoir. Broad-based research and technological developments have increased this estimate to 46 percent in 2005. The Ekofisk area is currently home to 29 facilities, around 1,100 km of internal pipelines and two export pipelines – one for crude oil and NGL to Teesside in the UK, and one for dry gas to Emden in Germany. After 30 years on stream, Ekofisk is still one of the highest producing fields on the NCS. The aim is to maintain activity in the area until 2050.

In order to achieve this, great emphasis has been placed on a continuous and interactive process between the oil companies' operational and in-house research communities, as well as close cooperation between oil companies, the authorities, research institutions and the sub-contractor industry.

As early as 1980, the Joint Chalk Research project was initiated by Norwegian and Danish authorities, in collaboration with the oil companies who were licensees in the various chalk fields of the North Sea. This research continues in 2005. Since the mid 1980s, the Ekofisk licensees have supported chalk studies at the University of Bergen, in order to gain a detailed understanding of the fundamental mechanisms connected to water injection into fissured chalk. Many Master and PhD students have taken part in this work. The RUTH and SPOR research programmes have been carried out within the framework of the Norwegian Research Council, studying injection of water and gas into the reservoir. Sintef, Rogaland Research, Reslab and IKU have also participated in this. A separate project, ThermicAiroil, has investigated air injection to increase recovery, with both national and multinational research institutions participating. A further project for increasing recovery, Corec, has been financed by the licensees and carried out in collaboration with Rogaland Research and the University of Stavanger. In addition to project financing, the oil companies provide project data, priorities and, not least, practical experience for the research.

At the end of 2004, figures for the Ekofisk area show that a total value of around NOK 1 260 billion had been created. NOK 444 billion was used for products and services, NOK 50 billion for salaries and other employee benefits and NOK 24 billion to loan providers. The licensees were left with NOK 132 billion, while the state received NOK 626 billion in taxes and levies (all in 2004 values).

5 Disposal after operations cease

The Ekofisk Tank before and after operation cease

Figure 5.1 To be removed: the Frigg field drilling and production platform, DP2
(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. When petroleum activity has ceased, everything must be cleared and removed.

To date, the Ministry of Petroleum and Energy (MPE) has approved more than 10 decommissioning plans. In most cases it was decided that abandoned facilities were to be removed and taken ashore. e.g. Odin, Nordøst Frigg, Øst Frigg and Lille-Frigg. The two most recent approvals are those for Ekofisk I and Frigg. Removal of the installations in the Frigg field and parts of the Ekofisk field is planned to start during 2005. Permission was also given, following consideration of the decommissioning plans for Ekofisk I and Frigg, to leave in place the Ekofisk Tank and its protection wall, as well as the concrete substructure TCP2 at the Frigg field.

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 1996 Petroleum Act. Disposal of facilities is governed, in addition to the Petroleum Act, by Norway's obligations under the OSPAR Convention (Convention for the Protection of the Marine Environment of the NorthEast Atlantic). 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 methods 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 strong grounds for disposal at sea.

If derogation from the OSPAR decision concerning disposal ashore 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 an exemption. There are a number of conditions that must be met if permission is granted. Up to now, Norway has granted two exemptions to the OSPAR decision concerning disposal ashore. As mentioned, permission has been granted to leave in place the Ekofisk Tank and its protection wall, as well as the concrete substructure TCP2, at the Frigg field.

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

Decommissioning plans

A principal provision of the legislation requires licensees to submit a decommissioning plan to the Ministry two to five years before a licence expires or is surrendered, 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 disposal plan is assessed by the MPE and the Ministry of Labour and Social Affairs (safety aspects). The MPE coordinates the public hearing of the impact assessment.

The MPE 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 ashore must be put before the Storting.

Liability

If a decision for non-removal is made, the legislation states that the licensees are liable for any damage or hindrance resulting deliberately, or negligently, from the installation remaining in place. 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.

6 Gas Management System

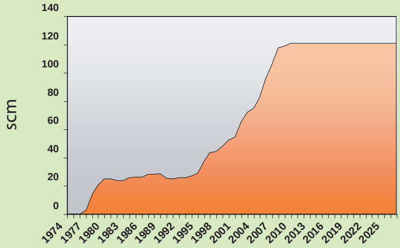


Figure 6.1 Historic and estimated Norwegian gas exports
(Source: NPD/ MPE)

Norwegian gas is important for supply of energy in Europe, and is exported to all of the major consumer countries in western Europe. There are four terminals receiving Norwegian gas on the Continent, two in Germany, one in Belgium and one in France. There will be two terminals receiving Norwegian gas in the United Kingdom when the Langeled pipeline, which will pipe gas from the Ormen Lange field, comes on stream in 2007 (see map). The Norwegian gas transport system is extensive, containing a total of more than 6,600 km of pipeline. Treaties have been drawn up governing the rights and obligations between Norway and the gas recipient countries. In January 2005, Norway and the United Kingdom entered into a framework agreement that governs gas landing pipelines from Norway to the United Kingdom. This will be submitted to the Storting during the first half of 2005.

Norwegian gas exports meet around 14 percent of the European gas needs. Most Norwegian exports go to Germany and France, where Norwegian gas supplies around 30 percent of the total consumption. When the Ormen Lange field comes on stream, Norwegian gas will have a market share of around 15-20 percent in Britain. Producers on the Norwegian continental shelf (NCS) have entered into sales agreements with buyers in Germany, France, the UK, Belgium, the Netherlands, Italy, Spain, the Czech Republic, Austria, Poland and Denmark.

Norwegian pipelines currently have a capacity of 100 billion scm, which will increase to 120 billion scm when Langeled has been completed. This amount is equivalent to six times the total electricity production in Norway.

Achieving the highest possible value for Norwegian petroleum resources is an overall goal. Most of the fields on the NCS 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 lay the ground for efficiency in all stages of the gas chain – exploration, development and transport.

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 high emphasis on consideration of various transport alternatives, so that the selected solution is as robust as possible. Costs involved in constructing pipelines are high, 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 originally thought needed, so that any new gas discoveries can be transported through the existing pipeline system.

Each licensee in the Norwegian sector is responsible for selling its own gas. This policy changed in 2001, in connection with the closure of the Gas Negotiating Committee (GNC) system. In the past, all gas produced in the Norwegian sector was sold under supervision of the authorities through the GNC. Today, Statoil markets the Norwegian state's oil and gas together with its own petroleum, in accordance with the national sales regulations.

Official policy instruments

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.[1] Many fields on the NCS contain both gas and oil. When awarding gas production licences, the authorities take into account optimum recovery of oil. On occasion, the authori-

[1] See chap. 3 Exploration and chap. 4 Development and operation

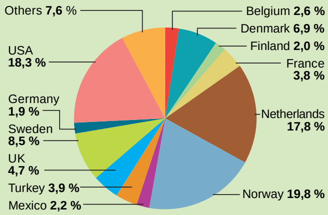


Figure 6.2 Sales of NGL/Condensate 2004* Total 21.1 mill. scm oe
** by country of first destination*
(Source: NPD)

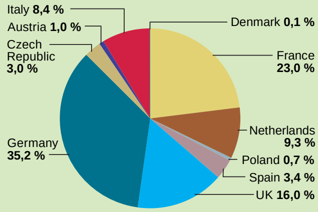


Figure 6.3 Norwegian natural gas exports 2004
Total 77.7 bill. scm oe
(Source: NPD)

ties, with a regard to the need to produce oil, have awarded licences for production of less gas than applied for by the companies.

The authorities play an important part in establishing transport capacity, and increasing system capacity. They 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 (MPE) employs a number of instruments to achieve these. 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 association with development of new infrastructure and when the use of the existing infrastructure is changed. The operator, the ownership and questions of regulated access can be employed independently.

Gassco

Gassco AS is the operating company for Gassled, which comprises most of the transport system on the NCS. Gassco was established out of the partial privatisation of Statoil in 2001. Areas of operational responsibility include operations (planning, monitoring, coordination and administration of transport from the fields to the receiving terminals) and development of the transport system. Gassco is responsible for coordination of development processes for the upstream gas pipeline network, as well as assessing the need to carry out such developments. Gassco recommends solutions, but does not itself invest.

It is important to have a neutral and independent operator of the gas transport system. This ensures that all users of the system are treated equally, in regard both to use of the system and to the consideration of capacity applications. This is necessary to ensure effective exploitation of the resources on the NCS. A neutral company ensures that a holistic view is taken of potential developments of the infrastructure, including exploitation of benefits of scale. Effective exploitation of the existing gas transport system may also contribute to the reduction, or postponement, of the need for new investment.

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 taken into third party use and are 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 is to be used to transport the gas can be avoided.

Regulated access to the transport system

The pipeline system is a natural monopoly, requiring huge initial investments. This is why gas transport tariffs are regulated by a dedicated regulation issued by the ministry. This ensures that 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.

Gassled – total ownership structure for gas transport

The ownership split in Gassled:

Petoro AS*	38.29%
Statoil ASA	20.38%
Norsk Hydro Produksjon AS	11.13%
Total E&P Norge AS	9.04%
ExxonMobil Exploration and Production Norway AS	5.18%
Norske Shell Pipelines AS	4.68%
Mobil Development Norway AS	4.57%
Norsea Gas AS	3.01%
Norske ConocoPhillips AS	2.03%
Eni Norge AS	1.68%

* Petoro AS is the licensee for the state's participation share (State's Direct Financial Interest- SDFI)

Petoro's share in Gassled will be increased by around 9.5 percent with effect from 1 January 2011, and the other licensees' shares will be reduced correspondingly 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 39.5 percent in 2003-2010 and 49 percent from 2011. The licence period for relevant Gassled facilities will run until 31 December 2028.

The coordinated ownership structure for the most significant parts of the gas infrastructure has laid the way for a uniform access regime and will ease administration and daily operation of gas transport in the future.

7 Government petroleum revenues

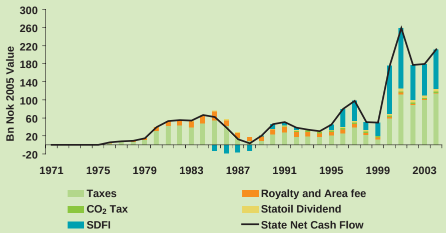


Figure 7.1 The net government cash flow from petroleum activities
(Source: National Accounts and National Budget)

National Budget 2005 estimates:

	NOK Billion
Direct taxes	112,8
Royalty, Co_2-tax,	
Area fee	4,5
SDFI	85,9
Statoil dividend	5,2
Total	**208,3**

Figure 7.2 The net government cash flow from petroleum activities 2004
(Source: National Accounts and National Budget)

The government earns high revenues from the petroleum sector. In 2004, 28 percent of government revenue came from this sector. Figure 7.1 shows income from the sector over time. It has been high over the last years, and revenues in 2004 were especially high. The value of the remaining petroleum reserves on the Norwegian continental shelf (NCS) was estimated to NOK 3050 billion in the National Budget for 2005.

The government gets a high share of the value created through:
- Taxation of oil and gas activities
- Charges/fees
- Direct ownership of fields on the NCS (The State's Direct Financial Interest: SDFI)
- Dividends from ownership of Statoil

Why has Norway 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 common ownership of the resources on the NCS, and that the oil companies are allowed to exploit a valuable, limited resource.

The petroleum tax system

Petroleum taxation builds on the Norwegian rules for ordinary corporation tax, which is charged at 28 per cent both on land and offshore. Owing to the extraordinary profitability of the production of the Norwegian petroleum resources, a special tax of 50 per cent is also levied on income from these activities.
When calculating taxable income for both ordinary and special tax, investment is subject to depreciation on a linear basis over six years from the date it was made. Companies may also deduct all relevant expences, including exploration-, research and development-, net financial-, operating- and decommissioning expenses. Net income is consolidated between fields. 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 investment (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. 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 income to the society with the requirement for sufficient post-tax profitability for the companies.

Taxes

Other important taxes linked to petroleum activities are the royalty, the area fee and the carbon dioxide tax.

The CO_2 tax was introduced in 1991 and is the most important instrument for reducing CO_2 emissions from petroleum activities. CO_2 tax is levied at a rate per standard cubic metre (scm) of gas burnt or directly released and per litre of oil burnt. The rate for 2005 is NOK 0.78 per litre of oil/scm of gas.

The area fee accrues on all production licences after the expiry of an initial period. It is intended to encourage return of acreage that companies do not wish to exploit. Special rules apply for the oldest licences and licences in the Barents Sea.

Operating income (norm price)
– Operating expenses
– Linear depreciation for investments (6 years)
– Exploration expenses
– CO_2-tax and area fee
– Net financial costs (limited by the thin capitalisation rule: 20 % equity)
= Corporation tax base (tax rate: 28 %)
– Uplift (7,5% of investment for 4 years)
= Special tax base (tax rate: 50 %)

Figure 7.3 Calculation of petroleum tax
(Source: MPE)

Royalty is being phased out, and will not be paid after 2005. Currently, royalty is only paid by two fields, Gullfaks and Oseberg.

Norm prices

Most oil companies in the Norwegian sector are parts of corporations with a diversified global business portfolio. Petroleum recovered 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 equate to what two independent parties would have agreed on jointly for each individual sale. In order to avoid this problem, Section 4 of the Petroleum Tax Act states that norm prices may be determined, to be used in the calculation of taxable income, instead of using the actual income from the sale. The method of determining and the use of norm prices is described in regulations.

The norm price is fixed by the Norm Price Board (NPB), and should be equivalent to the price paid for the petroleum had it been traded between independent parties. The norm price is determined each month and for each field. The NPB meets each quarter to determine prices for the previous quarter. The prices are based on sales reported by the field operating companies, and with the monthly average for Brent Blend as an important reference price. The companies are informed of the price in writing, and are invited to submit their views before the final norm price is determined. The decision may be appealed to the Ministry of Petroleum and Energy within 30 days of the price being determined. When the NPB does not find it appropriate to determine a norm price, the actual sales price will be used as the basis for taxation. This applies for certain crude oils, NGL and 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 dividend from its ownership of Statoil and Hydro. The SDFI is an arrangement in which the state owns interests in a number of oil and gas fields, pipelines and onshore facilities. Each interest is decided when production licences are awarded and the size 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. The SDFI was established on 1 January 1985. Before that, only Statoil, at the time a fully state owned company, had been responsible for 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 listed and privatised on 18 June 2001, the administration of the SDFI portfolio was transferred to the state-created trust company, Petoro.

The arrangement with SDFI interests has a neutral effect, as no risk is transferred from the state to the companies. The SDFI arrangement means that the state, when awarding acreage, can decide exactly how much of the value created it shall receive. In the case of production licences where profitability is estimated as being low, the state can decide to take a small, or even no, share, while a larger share would be appropriate for more profitable fields.

Statoil dividend

As of 1 March 2005, the state owns a 70.9 percent stake in Statoil. As an owner of Statoil, the state receives dividends, which form part of the state revenue from the petroleum sector.

8 Environmental considerations in the Norwegian petroleum sector

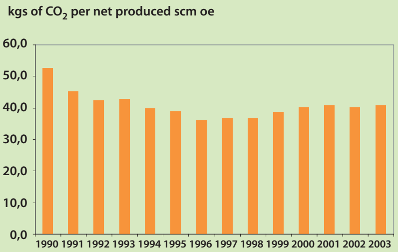


Figure 8.1 Emissions of taxable CO_2 per produced unit
(Source: NPD)

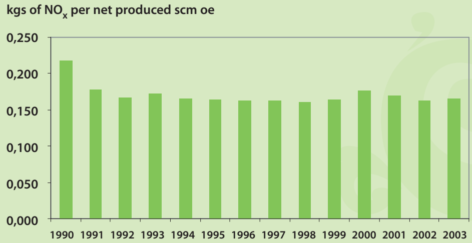


Figure 8.2 Emissions of NO_x per produced unit
(Source: MPE, NPD)

In 1971, the Storting gave the growth of a Norwegian petroleum sector due consideration, and its industry committee drew up a recommendation which contained what would later be known as the “ten oil commandments”. The ten oil commandments became guidelines for Norwegian oil and energy policy and two of these would become significant for the protection of the external environment:

- Development of the oil industry must take other industries into account, as well as nature and protection of the environment.
- Natural gas that could be exploited must not be flared off except during brief test production periods.

Present day goals state that Norway, as an important energy nation, should also be a pioneer in the protection of the environment. Since the early 1970s, legislation and regulations that protect the environment have gradually been established, and today the petroleum industry is thoroughly regulated in order to protect the external environment.

The environment is protected in all phases of the industry. The petroleum legislation requires that impact assessments are carried out before new areas are opened to the petroleum industry, and conditions may be set before an area is opened. Development plans (PDO/PIO) must also be officially approved, and the impact assessments play an important part in these. This ensures that environmental aspects of petroleum activities are taken into account at an early stage.

The authorities also take environmental considerations into account when awarding development licences on the Norwegian Continental Shelf (NCS), and can impose special requirements on the petroleum industry in specific areas. This is an accurate measure that ensures environmentally sound operation of the petroleum industry in potentially vulnerable areas. There may, for example, be seasonal regulation of certain activities, or special limitations on discharges.

Regulation of emissions to the air

The most important emissions to the air from the petroleum industry are CO_2 and NO_x from energy production and flaring, as well as emissions of nmVOCs from loading and storage of oil. Norway has undertaken to reduce these emissions in accordance with such international agreements as the Kyoto and Gothenburg protocols, and in accordance with national targets.

Since its introduction in 1991, the CO_2 tax legislation has been the most important measure for reducing CO_2 emissions. The CO_2 tax gave Norway a stringent regulation which has led to considerable reductions in emissions. CO_2 emissions are also regulated by the flare licences granted by the Ministry of Petroleum and Energy (MPE), which are based on the provisions of the Petroleum Act. Flaring is only permitted if necessary for safety reasons.

Until the present time, NO_x emissions have not been regulated, although this will change when EU Directive 96/61 EC, concerning integrated pollution prevention and control (IPPC), is written into Norwegian legislation. This will lay down specific NO_x emission limits, based on the requirement for best available technology (BAT), before 2007. A number of NO_x-reducing initiatives have been implemented on the NCS, including the installation of several gas turbines employing low-NO_x technology.

nmVOC emissions from oil loading and storage offshore are regulated by the Norwegian Pollution Control Authority (NPCA), and are based on the provisions of the Pollution Act. As a result of the stringent emission requirements, the companies operating on the NCS have formed a joint venture to install recycling equipment for nmVOCs on tankers. This will lead to a noticeable reduction in nmVOC emissions by 2008.

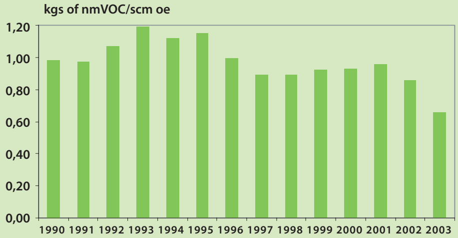


Figure 8.3 nmVOC emissions per produced unit *(Source: MPE, NPD)*

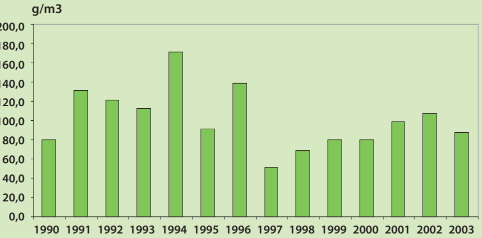


Figure 8.4 Content of production, injection and pipeline chemicals in produced water *(Source: EnvironmentWeb)*

Regulation of offshore discharges

The most significant offshore discharges from the petroleum industry are chemical discharges from wells and well operations, and discharges of oil and naturally occurring chemical substances from discharges of produced water. Sea discharges are regulated by discharge permits from the NPCA, based on the provisions of the Pollution Act.

Active research and development of chemicals with no negative environmental impact is being carried out to reduce chemical discharges. New cleaning technologies to reduce the content of oil and naturally occurring chemical substances in produced water that is discharged to the sea are being developed. At several fields, produced water is reinjected into the reservoirs to avoid discharges.

The authorities have established a strategy that has been defined by the so-called zero discharge targets, to achieve reduction of discharges to the sea. As of now, in principle, no environmentally hazardous substances shall be discharged, nor shall there be any discharge, or discharge shall be minimised, of environmentally harmful substances. The authorities and the industry have established a working group which is considering various discharge-reducing measures, in order to achieve the targets. This dialogue is contributing to the development of new hi-tech solutions within the industry.

It is usually possible to use environmentally sound techniques in new fields, but there are several reasons why this can be difficult in existing fields. Work towards zero discharge targets must therefore include a comprehensive assessment of environmental impact, safety concerns, technical reservoir conditions and costs. The conditions at certain fields may be such that the practically achievable target is to minimise discharges.

In the Lofoten – Barents Sea area the authorities have established special, more stringent requirements concerning discharges to the sea. This involves no discharge to the sea of produced water, drill cuttings or mud under normal operating conditions. In this area, petroleum activities will be subject to even more stringent environmental regulation than on other parts of the NCS.

The work on reducing discharges to the sea is important for several reasons. At present, there is no scientific agreement about any long-term effects of these discharges. In order to improve available knowledge, the Ministry of Petroleum and Energy, the Ministry of the Environment and the petroleum industry are financing a research programme under the Norwegian Research Council into the long-term effects of sea discharges from the petroleum operations (PROOF).

For more detailed information about the petroleum and energy authorities' safeguarding of environmental interests, please see the Ministry of Petroleum and Energy's environmental publication, Environment 2005.

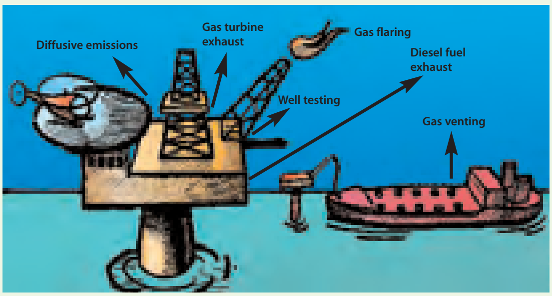


Figure 8.5 Emissions to the air

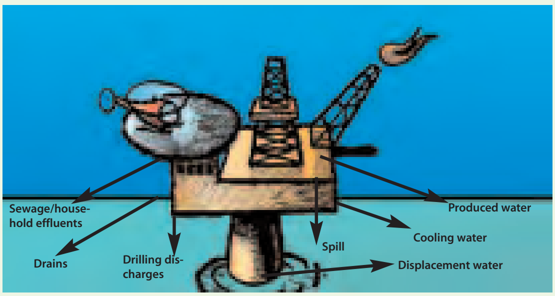


Figure 8.6 Discharges to the sea

9 Petroleum Resources

Drill Bit

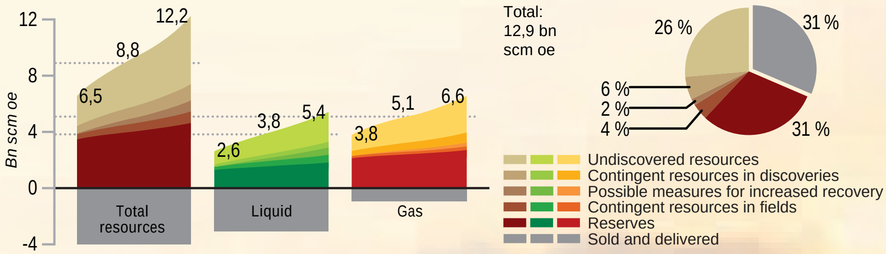


Figure 9.1 Petroleum resources and uncertainty in the estimates

The NPD's estimates of total discovered and undiscovered petroleum resources on the Norwegian continental shelf are 12.9 billion scm oil equivalent (oe). Around 4.0 billion scm oe have been recovered, 31 percent of the total resources. The remaining total recoverable resources amount to 8.8 billion scm oe, 5.2 billion scm of which are proven resources, with an estimated 3.4 billion scm oe undiscovered. It is also estimated that potential future measures for increased recovery may yield a total of 0.225 billion scm oe.

In 2004, exploration led to little resource growth. Four new discoveries have been made, containing total resources of around 17 - 22 mill. scm recoverable oil. Some of the resource estimates have not yet been completely evaluated and must still be regarded as very uncertain.

Since petroleum production began on the Norwegian continental shelf in 1971, 4.0 billion scm oe has been produced from 61 fields. In 2004, the Skirne and Kvitebjørn fields started production. 42 fields in the North Sea and 6 in the Norwegian Sea were on stream at the end of the year. The plans for development and operation (PDO) for the Kristin, Alvheim, Ormen Lange, Snøhvit and Urd fields have been approved, but they are not yet on stream. The PDOs for three new fields, Alvheim, Ormen Lange and Urd, were approved in 2004.

Figure 9.1 shows the total recoverable potential on the Norwegian continental shelf although the estimates are uncertain. The quantities are classified according to the Norwegian Petroleum Directorate's resource classification system for total resources, liquid and gas.

Resources

Resources is a collective term that covers technically recoverable quantities of petroleum. The resources are classified according to the maturity of the project that is necessary to recover them. The main classifications are reserves, contingent resources and undiscovered resources.

The detailed resource accounts as at 31.12.2004 are shown in table 9.1 and in the annex.

Reserves

Reserves cover remaining recoverable, sellable petroleum resources in petroleum deposits that the licensees have decided to develop, and for which the authorities have approved the PDO, or given PDO exemption for. Reserves also include petroleum resources 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 3.9 billion scm oe, and have been reduced by four percent from 4.1 to 3.9 billion scm over the last year. Submission of development plans for Alvheim, Urd, Vilje and Skinfaks and the amended PDO for Rimfaks added 54 million scm oe to the reserves. A number of projects for increased recovery from existing fields were also decided on, adding a total of 66 mill. scm oe. At the same time, 265 mill. scm oe was produced, leading to a net reduction in reserves of 144 mill. scm oe in 2004.

Contingent resources

The term "contingent resources" is used for discovered petroleum for which development has not yet been decided on.

In 2004, there was an increase in contingent resources in fields of 38 mill. scm oe. It is contingent resources in the planning stage that account for around 80 percent of this increase, deriving from improved recovery projects in several fields. The fields that contribute most to this increase are Ekofisk, Gullfaks, Åsgard and Gungne.

The estimate for contingent resources in discoveries has been reduced by 17 mill. scm oe to 746 mill. scm oe. This reduction is due to there being only four new discoveries on the Norwegian continental shelf during the year, to resources having been transferred to lower resource categories, and to a downgrading of the resource potential in discoveries 6405/7-1 and 6406/1-2.

The resource potential from possible future measures for increased recovery has been reduced this year by 175 mill. scm of oil. This year's oil estimate has been calculated at 125 mill. scm, while the gas estimate is 100 billion scm, which is unchanged from last year. Potential measures for increased recovery have been calculated based on the authorities' goal of achieving an average recovery rate for oil from oil fields of 50 percent and for gas from gas fields of 75 percent. The reduction in the oil potential from last year results from the fact that more projects for increased recovery have been realised this year, and have therefore been reported in lower resource categories.

Undiscovered resources

Undiscovered resources are quantities of petroleum that are assumed to be present in defined plays, confirmed and unconfirmed, which have not yet been proven by drilling (resource categories eight and nine). The estimate for the total undiscovered resources is 3.4 billion scm oe, and is unchanged in relation to last year's estimate.

The North Sea

A total of 7.1 billion scm oe has been discovered in the North Sea, and 3.6 billion scm oe has been produced. Remaining reserves amount to 2.7 billion scm oe, 38 percent of which is oil. Last year's production from the North Sea was 211 million scm oe, but because of increases in reserves in the fields that are on stream, and the additional reserves that have resulted from submission of development plans, the remaining reserves in the North Sea have not been reduced by more than 110 mill. scm oe in comparison with the previous years.

There are no major changes in the estimates for contingent resources and for undiscovered resources in the North Sea. Estimates for undiscovered resources indicate around 1.2 billion scm oe.

The Norwegian Sea

A total of 2.0 billion scm oe has been discovered in the Norwegian Sea, 0.4 billion scm oe of which has been produced. The remaining reserves amount to around 1.0 billion scm oe, 63 percent of which is gas. The production in 2004 was 55 mill. scm oe. This led to a reduction in remaining reserves of 33 mill. scm oe compared with last years resource account, despite increased reserves in some of the fields in production and addition of new reserves from Urd after PDO approval of the field. There are no major adjustments in the estimates for contingent resources and for undiscovered resources in the Norwegian Sea.

The Barents Sea

Oil equivalents of 0.2 billion scm oe have been discovered in the Barents Sea. Production will start in 2006, when the Snøhvit field comes on stream. There was little change in the estimates of contingent resources in fields and discoveries here last year.

Table 9.1 Resource accounts at 31.12.2004

Total recoverable potential	Status at 31.12.2004 Oil	Gas	NGL	Cond	Total	Change from 2003 Oil	Gass	NGL	Cond.	Total
Project status category	mill. scm	bn. scm	mill. tonnes	mill. scm	mill. scm oe	mill. scm	bn scm	mill. tonnes	mill. scm	mill. scm oe
Produced	2870	948	81	72	4044	162	78	13	1	265
Remaining reserves’	1225	2386	123	86	3930	-10	-75	-2	-56	-144
Contingent resources in field	278	190	31	13	539	10	23	1	3	38
Contingent resources in discovery	179	483	21	44	746	-50	23	-1	12	-17
Potential from improved recovery*	125	100			225	-175	0	0	0	-175
Undiscovered	1160	1900		340	3400	0	0	0	0	0
Total	**5837**	**6007**	**255**	**556**	**12885**	**-63**	**48**	**12**	**-41**	**-33**
North Sea										
Produced	2546	902	73	60	3647	132	64	9	-3	211
Remaining reserves’	1014	1579	65	6	2723	-27	-65	0	-18	-110
Contingent resources in field	220	137	24	7	409	5	11	1	0	18
Contingent resources in discovery	103	168	8	26	312	-17	14	3	6	9
Undiscovered	615	500		75	1190	0	0	0	0	0
Total	**4498**	**3286**	**170**	**173**	**8281**	**92**	**24**	**13**	**-14**	**128**
Norwegian Sea										
Produced	324	46	8	12	398	31	14	4	3	55
Remaining reserves’	210	646	52	62	1019	16	-9	-2	-38	-33
Contingent resources in field	51	49	7	6	119	8	12	0	2	23
Contingent resources in discovery	66	308	13	18	417	-32	9	-4	5	-25
Undiscovered	235	810		175	1220	0	0	0	0	0
Total	**886**	**1860**	**80**	**274**	**3172**	**24**	**26**	**-2**	**-27**	**19**
Barents Sea										
Produced	0	0	0	0	0	0	0	0	0	0
Remaining reserves’	0	160	5	18	188	0	-1	0	0	-1
Contingent resources in field	7	4	0	1	12	-3	0	0	0	-3
Contingent resources in discovery	10	7	0	0	17	-1	0	0	0	-1
Undiscovered	310	590		90	990	0	0	0	0	0
Total	**327**	**761**	**5**	**109**	**1207**	**-4**	**-1**	**0**	**0**	**-5**

‘ Includes resource categories 1, 2 and 3

* Resources from future measures for improved recovery are calculated only for the total recoverable potential and have not been broken down by area.

10 Fields in production

Keys to tables in chapters 10–12

Interests in fields do not necessarily correspond with interests in the individual production licences (unitised fields or ones for which the sliding scale has been exercised have a different composition of interests than the production licence). Because interests are shown up to two decimal places, licensee holdings in a field may add up to less than 100 percent. Interests are shown at 1 January 2005.

“Recoverable reserves originally present” refers to reserves in resource categories 0, 1, 2 and 3 in the NPD’s classification system (see the definitions below).

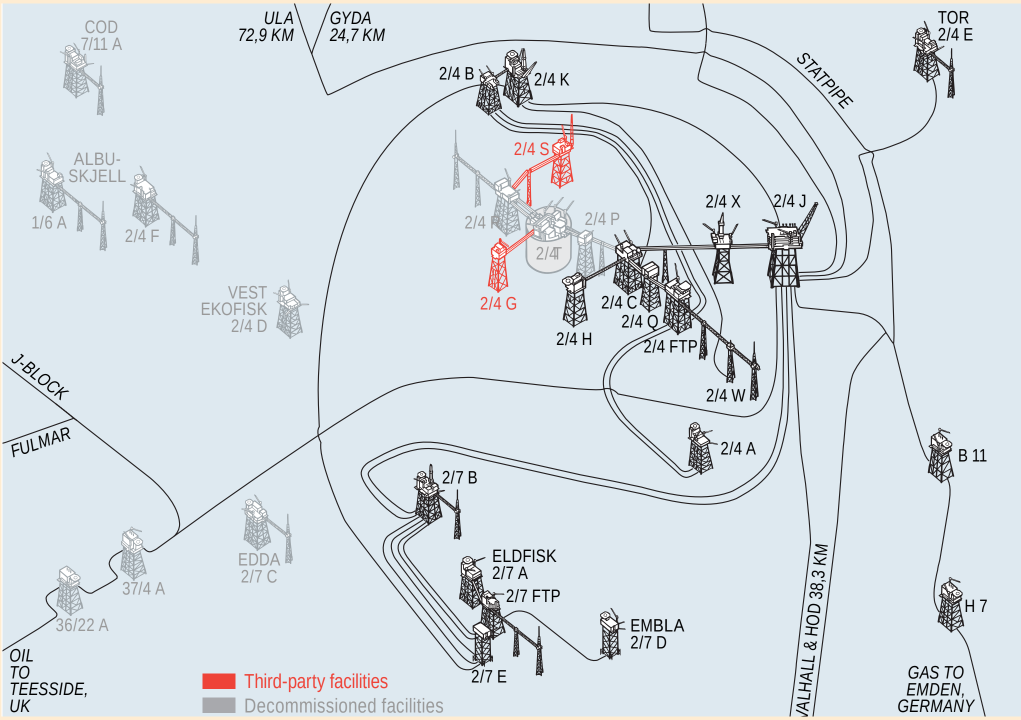
“Recoverable reserves remaining” refers to reserves in resource categories 1, 2 and 3 in the NPD’s classification system (see the definitions below).

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

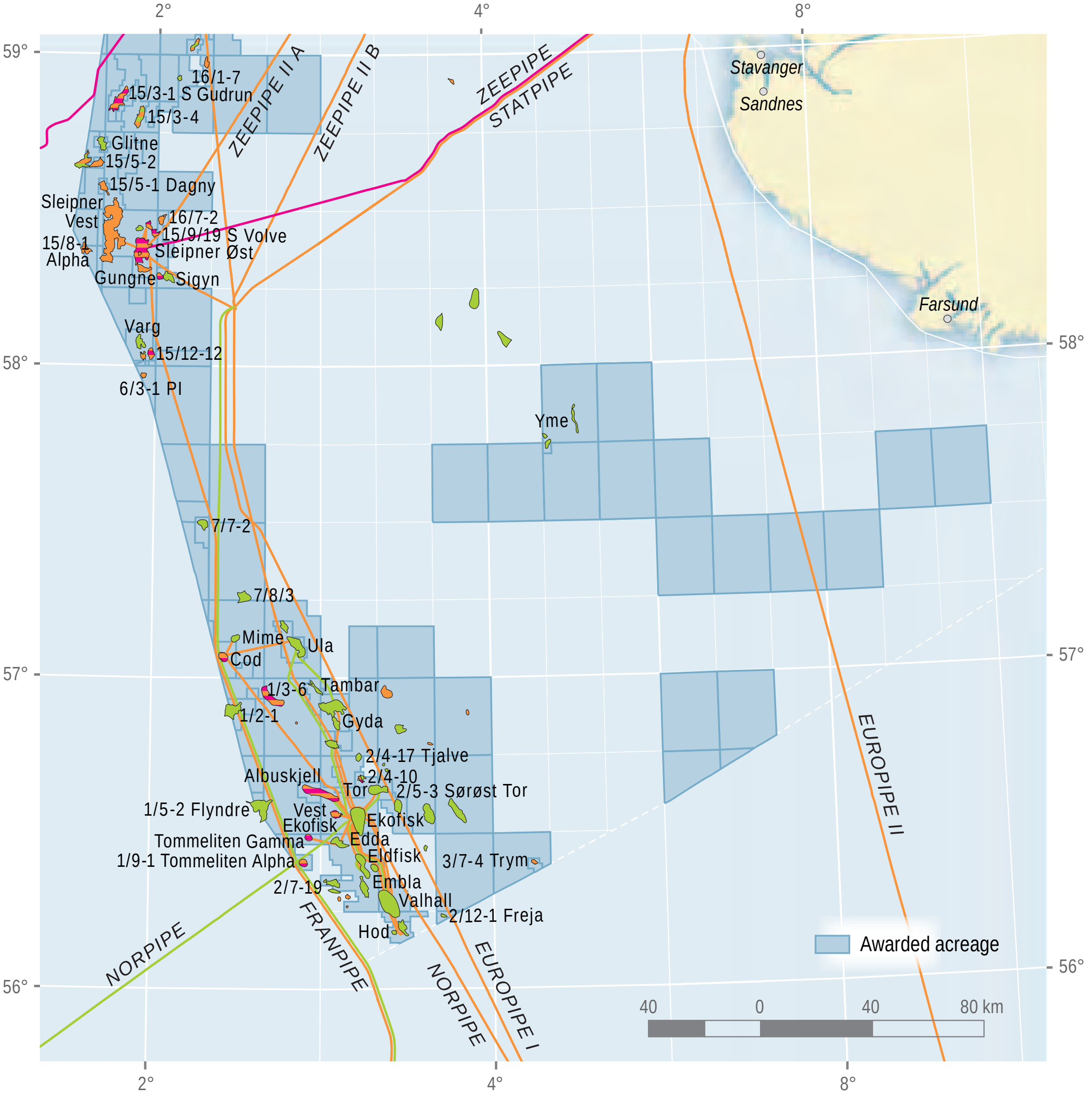
Southern North Sea

The southern part of the North Sea sector became important for the country at an early stage, with Ekofisk as the first Norwegian offshore field to come on stream, more than 30 years ago. Ekofisk serves as a hub for petroleum operations in this area, with surrounding developments utilising the infrastructure which ties it to continental Europe and Britain. Norwegian oil and gas is exported from Ekofisk to Teesside in the UK and Emden in Germany respectively. North of Ekofisk are the Sleipner fields. Sleipner Øst came on stream in 1993, followed by Sleipner Vest in 1996. In addition to producing substantial quantities of gas and condensate, these fields serve as a hub for the gas transport system on the Norwegian Continental Shelf (NCS).

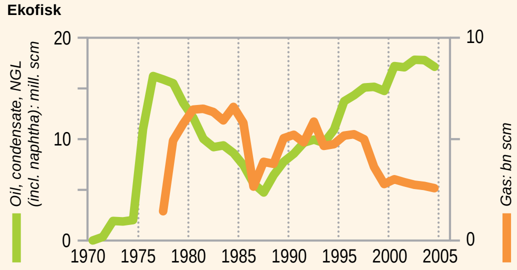
Although there has been production from the Southern North Sea for many years, remaining resources in the region are substantial. Oil and gas output is accordingly expected to continue beyond another three decades.



Facilities in the Ekofisk Area



Southern North Sea



Ekofisk

Block and production licence	Block 2/4 – production licence 018. Awarded 1965.	
Discovery	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 at 31.12.2004**
	524.1 million scm oil	178.3 million scm oil
	184.9 billion scm gas	58.7 billion scm gas
	14.3 million tonnes NGL	3.1 million tonnes NGL
Production	**Estimated production in 2005:**	
	Oil: 281,000 barrels/day Gas: 2.71 billion scm NGL: 0.29 million tonnes	
Investment	Total investment is likely to be NOK 134.2 billion	
	NOK 103.7 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

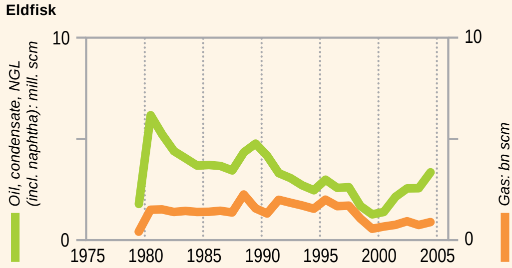
Development:
Production at Ekofisk began in 1971 from the jack-up facility Gulftide. The sea depth in the area is between 70 an 75 metres. During the first years, the field produced to tankers from four wells, until the concrete tank was in place in 1973. Since then, the field has been populated by many 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 facility 2/4-H, the production facility 2/4-C, drilling and production facility 2/4-X and the processing facility 2/4-J. Other facilities at the centre that are still in use are 2/4-FTP and 2/4-W which are a riser facility for production from the wellhead facility 2/4-A in the south and 2/4-B in the north and a wellhead facility for water injection, respectively. In addition, 2/4-K is in use in the north of the field as main facility for water injection. 2/4-K is tied back to 2/4-B by a bridge. Test production from the Ekofisk field was formally started on 09.06.1971. Approval in principle of the technical system for development of the Ekofisk field was given on 01.03.1972. 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.

Recovery strategy:
Ekofisk was originally developed using depletion. 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 to accommodate this. 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 is piped to the export pipelines via the processing facility on 2/4-J at Ekofisk.
Gas from the Ekofisk area is piped to Emden, while the oil, which also contains the NGL fractions, is piped to Teesside.

Status:
Production from Ekofisk is expected to maintain its current high level, and increase to a degree. This is mainly due to increased numbers of wells and increased processing capacity from a new facility coming on stream in 2005. 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 next years. The base of 2/4-M, has been installed and drilling has commenced. Planned completion of the topside is in 2005. A possible transference of production from 2/4-A and 2/4-B is still being considered, and a decision is expected during 2005. Continual drilling is, under the current strategy, the key to high recovery levels. Work on cleaning and disposal of disused facilities is still continuing.



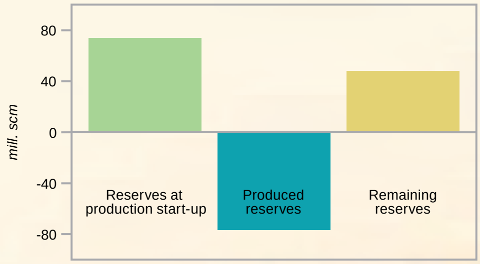
Eldfisk

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 at 31.12.2004**
	124.7 million scm oil	47.6 million scm oil
	50.6 billion scm gas	15.6 billion scm gas
	4.4 million tonnes NGL	1.0 million tonnes NGL
Production	**Estimated production in 2005:**	
	Oil: 52,000 barrels/day Gas: 1.14 billion scm NGL: 0.09 million tonnes	
Investment	Total investment is likely to be NOK 53.6 billion	
	NOK 42.5 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

Development:
The original Eldfisk development consisted of three facilities. The sea depth in the area is between 70 and 75 metres. Eldfisk B is a combined drilling, wellhead and process facilities on the Bravo structure, while Eldfisk A and FTP are wellhead and process facilities tied back by a bridge at the Alpha structure. Eldfisk A has drilling facilities. Oil and gas is transported in two pipelines to the Ekofisk Centre for onward transport to Teesside and Emden. Modifications have been made to Eldfisk and Ekofisk to enable the oil from Eldfisk to be piped directly to the export pumps on 2/4-J. In 1999, a new water injection facility, 2/7-E, was installed on the Alpha structure. The facility also supplies the Ekofisk field with some injection water through a new pipeline from Eldfisk to Ekofisk 2/4-K. Eldfisk was approved as Phase IV of the Ekofisk development in the Royal Decree of 25.04.1975. 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.

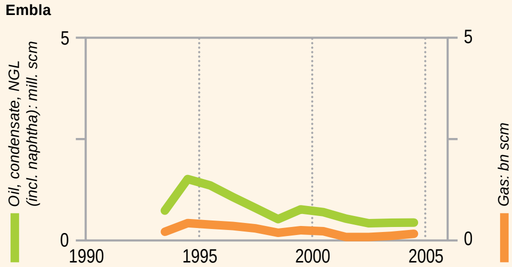
Reservoir:
Production from the Eldfisk field recovers oil from the Ekofisk, Tor and Hod chalk formations. The field consists of three structures: Alpha, Bravo and Øst Eldfisk.

Production strategy:
Eldfisk was originally developed with depletion. In 1999, water injection began at the field, based on horizontal injection wells. Gas is also injected that, for capacity or marketing reasons, has not been sold.



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

Status:
In lack of special measures, Eldfisk production is expected to remain constant in the years to come. In relation to current plans, there exists a great potential for increase in the reserves by increasing the number of wells and by optimising water injection. A study is in progress to determine measures to increase recovery from Eldfisk. The measures may necessitate new facilities at the field. A conclusion is expected in the autumn of 2005. The figure above shows the development of reserves.



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 at 31.12.2004**
	13.3 million scm oil	4.7 million scm oil
	4.1 billion scm gas	1.3 billion scm gas
	0.5 million tonnes NGL	0.2 million tonnes NGL
Production	**Estimated production in 2005:**	
	Oil: 6,000 barrels/day Gas: 0.19 billion scm NGL: 0.02 million tonnes	
Investment	Total investment is likely to be NOK 3.5 billion	
	NOK 3.5 billion had been invested as at 31.12.05 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

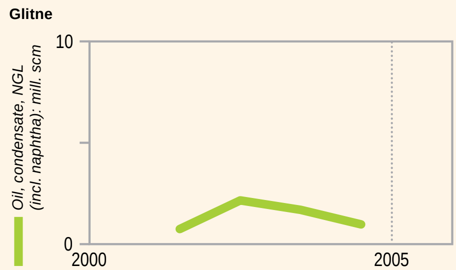
Development:
Embla has been developed with an unmanned wellhead facility that is remotely controlled from Eldfisk. The sea is 70 – 75 metres deep in the area. The PDO for Embla was approved on 14.12.1990. The amended PDO was approved on 25.04.1995.

Reservoir:
The Embla field produces from a segmented sandstone reservoir from the Devonian and Jurassic Ages. The reservoir is over 4,000 m beneath the sea bed.

Recovery strategy:
Embla uses depletion as the drive mechanism.

Transport:
Oil and gas is 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 piped to Teesside.

Status:
Without drilling more wells, or stimulating the existing wells, production from Embla will decrease in the future.



Glitne

Blocks and production licences	Block 15/5 - production licence 048 B. Awarded 2001.	
	Block 15/6 - production licence 029 B. Awarded 2001.	
Discovered	1995	
Development approval	08.09.2000 by the Crown Prince Regent in Council of State	
On stream	29.08.2001	
Operator	Statoil ASA	
Licensees	DONG Norge AS	9.30%
	Det Norske Oljeselskap AS	10.00%
	Statoil ASA	58.90%
	Total E&P Norge AS	21.80%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	7.2 million scm oil	1.7 million scm oil
Production	**Estimated production in 2005:**	
	Oil: 16,000 barrels/day	
Investment	Total investment is likely to be NOK 1.6 billion	
	NOK 1.6 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

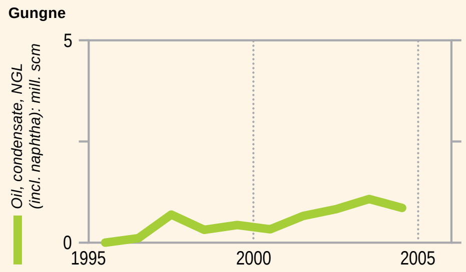
Development:
Glitne is an oilfield that lies 40 km northeast of the Sleipner area in 110 metres of water. The development consists of the floating production, storage and offloading vessel, Petrojarl 1, which is tied back to four production wells and a water injection well.

Reservoir:
The reservoir consists of amalgamated structureless sand sheets of deep-marine fandeposits in the upper Heimdal formation.

Recovery strategy:
Associated gas is used for gas lift, while excess gas is re-injected.

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

Status:
Production from Glitne was originally planned to last for a little more than two years, but is now estimated as lasting twice as long, i.a. due to effeciert placement of wells and good pressure support. Water production is now around 70 percent of fluid processing capacity and is expected to increase to around 90 percent in 2005.



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 of State.	
On stream	21.04.1996	
Operator	Statoil ASA	
Licensees	ExxonMobil Exploration and 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 at 31.12.2004**[1]
	9.9 billion scm gas	9.9 billion scm gas
	1.3 million tonnes NGL	0.3 million tonnes NGL
	3.1 million scm condensates	
Production	**Estimated production in 2005:**	
	Gas: 1.51 billion scm NGL: 0.22 million tonnes Condensate: 0.49 million scm	
Investment	Total investment is likely to be NOK 1.0 billion	
	NOK 1.0 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

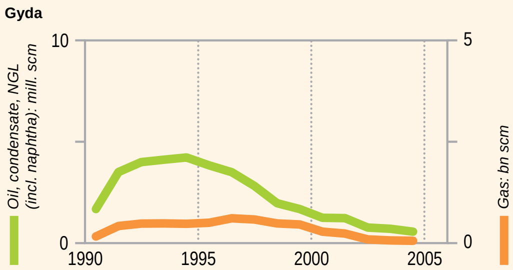
[1] Gas production for Gungne, Sleipner Vest and Sleipner Øst are measured together and therefore the remaining gas reserves are shown equal to the original.

Development:
Gungne is a gas field that lies in 83 metres of water and produces via two wells at Sleipner A.

Reservoir:
Gungne produces gas and condensates mainly from sandstone reservoirs in the Skagerrak formation from the Triassic Age. Reservoir sandstones from the early Jurassic Age overlap the structure in the south, but are not present over the highest parts of the structure in the north. The field has been heavily affected by salt tectonics. The characteristics are generally good, apart from the permeability. The reservoir is faulted and lateral continual slate strata act as barriers.

Recovery strategy:
Gungne produces using depletion.

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



Gyda

Block and production licence	Block 2/1 - production licence 019 B. Awarded 1977.	
Discovered	1980	
Development approval	02.06.1987 in Parliament	
On stream	21.06.1990	
Operator	Talisman Energy Norge AS	
Licensees	DONG Norge AS	34.00%
	Norske AEDC A/S	5.00%
	Talisman Energy Norge AS	61.00%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	36.8 million scm oil	4.6 million scm oil
	5.9 billion scm gas	0.6 billion scm gas
	1.9 million tonnes NGL	0.2 million tonnes NGL
Production	**Estimated production in 2005:**	
	Oil: 14,000 barrels/day Gas: 0.16 billion scm NGL: 0.03 million tonnes	
Investment	Total investment is likely to be NOK 14.2 billion	
	NOK 13.4 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

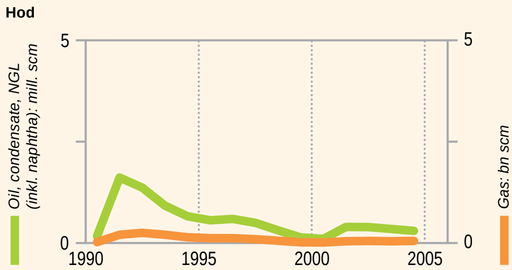
Development:
The Gyda field is in 66 metres of water. The field has been developed with a combined drilling, accommodation and processing facility with a steel jacket.

Reservoir:
The reservoir consists of late Jurassic sandstone.

Recovery strategy:
The field is developed with water injection as drive mechanism.

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

Status:
Water production is increasing and assessment of measures for reduction of water production are ongoing.



Hod

Block and production licence	Block 2/11 - production licence 033. Awarded 1969.
Discovered	1974
Development approval	26.06.1988 in Parliament
On stream	30.09.1990
Operator	BP Norge AS
Licensees	Amerada Hess Norge AS 25.00% BP Norge AS 25.00% Enterprise Oil Norge AS 25.00% Total E&P Norge AS 25.00%
Recoverable reserves	**Original:** 8.3 million scm oil 1.4 billion scm gas 0.2 million tonnes NGL **Remaining as at 31.12.2004** 0.5 million scm oil
Production	**Estimated production in 2005:** Oil: 4,000 barrels/day Gas: 0.04 billion scm NGL: 0.01 million tonnes
Investment	Total investment is likely to be NOK 2.1 billion NOK 2.1 billion had been invested as at 31.12.04 (2005 values)
Operating organisation	Stavanger
Main supply base	Tananger

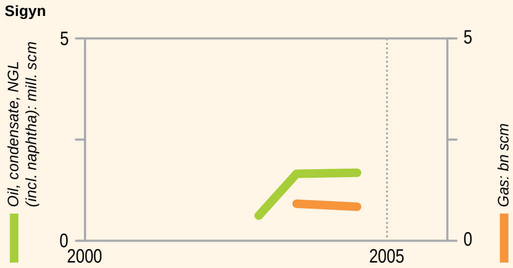
Development:
Hod is an oil field in 72 metres of water. The field is developed with an unmanned production facility, which is controlled remotely from the Valhall field 13 kilometres farther north. The PDO for Hod was approved on 26.06.1988. The PDO for the Hod Sadel area was approved on 20.06.1994.

Reservoir:
The field is producing from chalk rocks 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 depletion. Since 2001, gas lift has been used in the most important well in the field to increase production.

Transport:
Oil and gas are separated using a separation unit on the production facility before being 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 is relatively stable at a low level. The field is in a late phase with the current recovery strategy. At the moment, water injection is being considered to improve the resource exploitation from the Hod Øst structure. A pilot project for water injection in the field may prove appropriate.



Sigyn

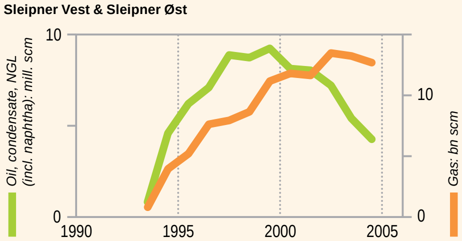
Block and production licence	Block 16/7 - production licence 072. Awarded 1981.	
Discovered	1982	
Development approval	31.08.2001 by the King in Council of State	
On stream	22.12.2002	
Operator	ExxonMobil Exploration and Production Norway AS	
Licensees	ExxonMobil Exploration and Production Norway AS	40.00%
	Norsk Hydro Produksjon AS	10.00%
	Statoil ASA	50.00%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	6.1 billion scm gas	4.4 billion scm gas
	3.0 million tonnes NGL	2.3 million tonnes NGL
	4.6 million scm condensate	2.6 million scm condensate
Production	**Estimated production in 2005:**	
	Gas: 0.96 billion scm NGL: 0.29 million tonnes Condensate: 0.80 million scm	
Investment	Total investment is likely to be NOK 2.2 billion	
	NOK 2.2 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

Development:
Sigyn is located in the Sleipner area in around 70 metres of water. The field has been developed with a subsea template as a satellite of Sleipner Øst. Production is controlled from Sleipner Øst. The wellstream is sent through two pipelines to the Sleipner A facility. The PDO for Sigyn was approved by Royal Decree on 31.08.2001. Test production from the Sigyn Øst field was carried out in December 1997.

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 Skagerrak formation.

Recovery strategy:
The oil is recovered by depletion.

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



Sleipner Vest includes total production from Sleipner Øst and Sleipner Vest

Sleipner Vest

Blocks and production licences	Block 15/6 - production licence 029. Awarded 1969. Block 15/9 - production licence 046. Awarded 1976.	
Discovered	1974	
Development approval	14.12.1992 in Parliament	
On stream	29.08.1996	
Operator	Statoil ASA	
Licensees in Sleipner Vest	ExxonMobil Exploration and Produksjon Norway AS Norsk Hydro Produksjon AS Statoil ASA Total E&P Norge AS	32.24% 8.85% 49.50% 9.41%
Recoverable reserves	**Original:** 108.1 billion scm gas 8.1 million tonnes NGL 28.1 million scm condensate	**Remaining as at 31.12.2004**[1] 65.7 billion scm gas 5.0 million tonnes NGL 6.2 million scm condensate
Production	**Estimated production in 2005:** Gas: 9.23 billion scm NGL: 0.45 million tonnes Condensate: 1.70 million scm	
Investment	Total investment is likely to be NOK 23.3 billion NOK 22.2 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

[1] Gas production for Gungne, Sleipner Vest and Sleipner Øst is measured collectively. The remaining reserves shows Sleipner Øst and Vest collectively.

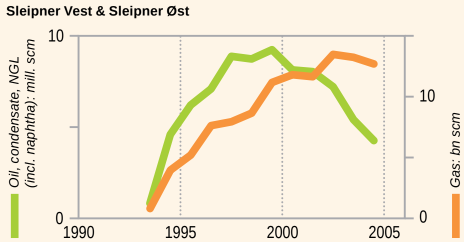
Development:
Sleipner Vest is a gas field in 110 metres of water, which consists of a normally unmanned wellhead facility, Sleipner B and a processing facility, Sleipner T. The Alpha Nord segment has been developed with a subsea template and four production wells. The subsea template is tied back to Sleipner T.

Reservoir:
Sleipner Vest produces from the Mid-Jurassic Sleipner and Hugin formations. Gas and condensate are mainly produced here, but local oil deposits have been observed without being produced. Most of the reserves are found in the Hugin formation, which is divided into an upper and lower section. The Hugin reservoir consists of a series of beach deposits. The Sleipner formation is part of the Hugin formation and consists of a sequence of fluvial deposits. The salt tectonic activity from the Triassic Age further complicates the structure. 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 depletion.

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 is injected into Sleipner Øst. The gas that is not reinjected is piped to Sleipner Øst for export. CO_2 is reinjected from Sleipner A in the Utsira formation via its own injection well. 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:
The field is divided into five segments: Epsilon, Delta, Beta, Alpha Sør and Alpha Nord. Alpha Nord came on stream in October 2004. Gas export capacity amounts to 100 percent of the design basis for both facilities. Sleipner T was modified for low pressure production in 2002, and low pressure production has been implemented on Sleipner B. Well-boring for Delta and Beta Vest at Sleipner Vest will be considered in the light of the new 3D seismic survey.



Sleipner Øst

Block and production licence	Block 15/9 - production licence 046. Awarded 1976.	
Discovered	1981	
Development approval	15.12.1986 in Parliament	
On stream	24.08.1993	
Operator	Statoil ASA	
Licensees in Sleipner Øst	ExxonMobil Exploration and 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 at 31.12.2004**[1]
	65.8 billion scm gas	65.7 billion scm gas
	12.5 million tonnes NGL	5.0 million tonnes NGL
	27.1 million scm condensate	6.2 million scm condensate
Production	**Estimated production in 2005:**	
	Gas: 2.24 billion scm NGL: 0.34 million tonnes Condensate: 0.64 million scm	
Investment	Total investment is likely to be NOK 33.9 billion	
	NOK 32.5 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

[1] Gas production for Gungne, Sleipner Vest and Sleipner Øst is measured collectively. The remaining reserves shows Sleipner Øst and Vest collectively.

Development:

Sleipner Øst is gas condensate field in 82 metres of water. The field has been developed with an integrated processing, drilling and accommodation facility with a concrete casing, Sleipner A. A separate riser facility has also been built, Sleipner R which is tied back to Sleiner A with a bridge. Sleipner R 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.
PDO for Sleipner Øst was approved on 15.12.1986. PDO for Loke was approved in 1991 and production started in 1993. Development of Loke Trias was approved on 29.08.1995 and production started on 19.06.1998.

Reservoir:

The Sleipner Øst and Loke resources are mainly found in sandstone in the Ty formation from the Tertiary Age and sandstones in the Hugin formations from the Mid-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. Below the Hugin formation is the Triassic Skagerrak formation. The Skagerrak formation, which makes up the main reservoir at Loke, consists of alluvial deposits and has moderate to poor reservoir characteristics. The sandy Skagerrak formation is, however, not present in the main Sleipner Øst field. The Late Jurassic Draupne formation occurs over the Hugin formation, and consists mainly of deep marine slate in the Sleipner Øst area, with a sequence of slate and sandstone localised in Loke. Faults segment the Hugin reservoir.

Recovery strategy:

The Hugin reservoir at Sleipner Øst and Loke produces with depletion, while the Ty reservoir receives pressure support from gas injection, in order to accelerate and increase production of condensate. The injectors are positioned on the edges of the reservoirs to avoid breakthrough of dry gas in the producers.

In order to accelerate gas and condensate recovery and extend the individual wells' plateau production, the pressure in the separator B on Sleipner A has been reduced.

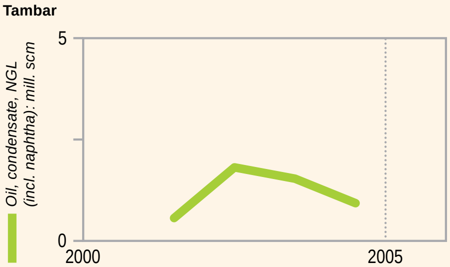
Transport:

Gas and unstable condensate from Sleipner Øst, Loke, Sigyn and Gungne is processed on Sleipner A. Processed gas from Sleipner A and Sleipner T (the process facility Sleipner Vest) is mixed with gas from Troll and exported via Draupner to Zeebrugge. Unstable condensate from Sleipner Vest and Sleipner Øst is mixed at Sleipner A and piped to Kårstø for processing into stable condensate and NGL products.

Status:

There are a total of 17 production wells at Sleipner Øst. At the moment, well capacity is greater than processing capacity. Produced gas that is not exported is injected into the Ty reservoir for pressure support, using five injection wells.

Gas injection into the Ty reservoir will continue until 2005-2006. After this, a massive blowdown of the reservoir will begin. In 2007, gas from Ormen Lange will be exported to the UK via Sleipner A. During 2005, wells are planned to be drilled from Sleipner A to the segments My2 and My3 at Sleipner Øst, as well as to an isolated segment of Gungne.



Tambar

Blocks and production licences	Block 1/3 - production licence 065. Awarded 1981. Block 2/1 - production licence 019 B. Awarded 1977.	
Discovered	1983	
Development approval	03.04.2000 by the King in Council of State	
On stream	15.07.2001	
Operator	BP Norge AS	
Licensees	BP Norge AS DONG Norge AS	55.00% 45.00%
Recoverable reserves	**Original:** 6.7 million scm oil 1.8 billion scm gas 0.2 million tonnes NGL	**Remaining as at 31.12.2004** 2.1 million scm oil 1.8 billion scm gas
Production	**Estimated production in 2005:** Oil: 15,000 barrels/day Gas: 0.28 billion scm NGL: 0.02 million tonnes	
Investment	Total investment is likely to be NOK 1.7 billion NOK 1.5 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

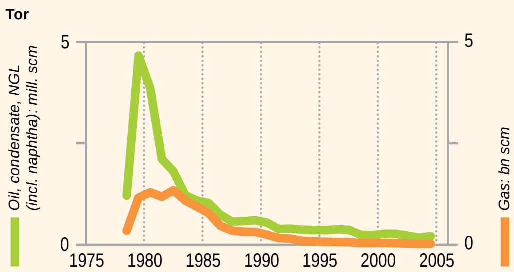
Development:
Tambar is an oilfield that is located around 16 km southeast of the Ula field and around 12 km northwest of the Gyda field. The field has been developed with an unmanned wellhead facility without a processing plant.

Reservoir:
The reservoir consists of Late Jurassic sandstone which was deposited in a shallow marine environment. The hydrocarbon trap is a fault trap with two anticlines that are separated by a structural saddle. The reservoir quality is heterogeneous, and the reservoir is divided into zones according to the quality of the sand.

Recovery strategy:
Three wells have been drilled that produce from the C sand. Oil is recovered from them by depletion. Studies have been carried out to investigate the potential of different ways of increasing oil recovery, but the reservoir's complexity indicates that water or gas injection would not be financially viable.

Transport:
Production is piped to Ula, where the oil is separated and exported in the existing pipeline to Teesside via Ekofisk. The gas is injected into the Ula reservoir to contribute to increased recovery of oil.

Status:
Installation of a multiphase pump for transfer to Ula and drilling supplementary wells are being considered to increase oil recovery. In June 2004, a leak was discovered in the export pipeline to Ula, and Tambar was shut down. Production was resumed in mid-December 2004, using the Ula Gyda Interconnector Pipeline (UGIP) as an export pipeline to Ula. UGIP is a temporary solution until a new pipeline is in place.



Tor

Blocks and production licences	Block 2/4 - production licence 018. Awarded 1965. Block 2/5 - production licence 006. Awarded 1965.
Discovered	1970
Development approval	04.05.1973
On stream	28.06.1978
Operator	ConocoPhillips Skandinavia AS
Licensees in Tor	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:** 26.7 million scm oil; 11.6 billion scm gas; 1.2 million tonnes NGL **Remaining as at 31.12.2004:** 4.7 million scm oil; 0.9 billion scm gas; 0.1 million tonnes NGL
Production	**Estimated production in 2005:** Oil: 3,000 barrels/day Gas: 0.03 billion scm
Investment	Total investment is likely to be NOK 8.1 billion NOK 8.0 billion had been invested as at 31.12.04 (2005 values)
Operating organisation	Stavanger
Main supply base	Tananger

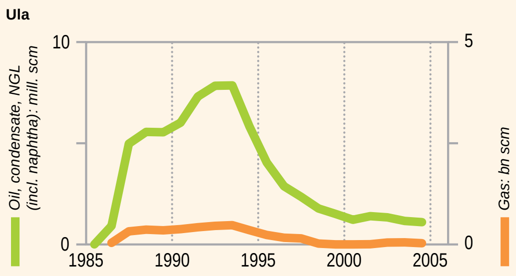
Development:
Tor is an oil field in about 70 metres water that has been developed with a combined wellhead and processing facility with transport by pipelines to the Ekofisk Centre for export. The Tor field won development approval in phase III of the Ekofisk development.

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

Recovery strategy:
Tor was originally produced by depletion. In 1992, limited water injection at Tor commenced. The facility has later been upgraded.

Transport:
Oil and gas are piped to the export pipelines through the 2/4-J processing facility at Ekofisk. Gas from the Ekofisk area is transported by pipeline to Emden, while the oil, which also contains NGL fractions, is piped to Teesside.

Status:
A study is currently considering future prospects for Tor. Seismic surveys, which form part of this work, will be completed in 2005.



Ula

Blocks and production licences	Block 7/12 - production licence 019. Awarded 1965 Block 7/12 - production licence 019 B. Awarded 1977.	
Discovered	1976	
Development approval	30.05.1980 by Parliament	
On stream	06.10.1986	
Operator	BP Norge AS	
Licensees	BP Norge AS DONG Norge AS Svenska Petroleum Exploration AS	80.00% 5.00% 15.00%
Recoverable reserves	**Original:** 78.2 million scm oil 3.8 billion scm gas 2.9 million tonnes NGL	**Remaining as at 31.12.2004** 12.5 million scm oil 0.4 million tonnes NGL
Production	**Estimated production in 2005:** Oil: 28.000 barrels/day NGL: 0.04 million tonnes	
Investment	Total investment is likely to be NOK 19.9 billion NOK 18.9 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

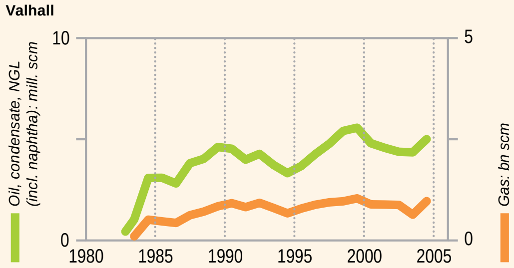
Development:
The Ula oilfield lies in about 70 metres of water. The development consists of three conventional steel facilities for production, drilling and accommodation. The facilities are tied back to each other by bridges.

Reservoir:
The main reservoir is in Late Jurassic Age sandstone. The sand was deposited in a shallow marine environment and is extremely bioturbated. Permeability varies from good to very good, but deteriorates towards the edges.

Recovery strategy:
To begin with, oil was recovered by depletion, but after some years water injection was used 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. The operator considers that WAG has had a very favourable impact on draining the reservoir, and wishes to extend the WAG programme further. At present, there are 15 wells in the field: eight production wells, three water injection wells and four WAG wells. The wells in the WAG programme are positioned so that injection takes place on the edges of the field, while production comes from the top of the reservoir.

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

Status:
Depending on access to injection gas, the extent of the WAG programme will be decided at the end of 2005.



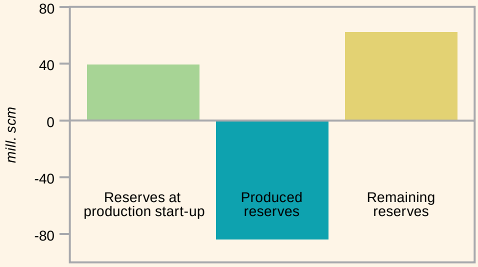
Valhall

Blocks and production licences	Block 2/11 - production licence 033 B. Awarded 2001. Block 2/8 - production licence 006 B. Awarded 2000.	
Discovered	1975	
Development approval	02.06.1977 by Parliament	
On stream	02.10.1982	
Operator	BP Norge AS	
Licensees in Valhall	Amerada Hess Norge AS	28.09%
	BP Norge AS	28.09%
	Enterprise Oil Norge AS	28.09%
	Total E&P Norge AS	15.72%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	171.5 million scm oil	87.6 million scm oil
	29.2 billion scm gas	12.6 billion scm gas
	4.4 million tonnes NGL	1.6 million tonnes NGL
Production	**Estimated production in 2005:** Oil: 110,000 barrels/day Gas: 1.37 billion scm NGL: 0.14 million tonnes	
Investment	Total investment is likely to be NOK 53.6 billion NOK 41.2 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

Development:
Valhall is an oilfield lying in 70 metres of water. The field was originally developed with three facilities, for accommodation, drilling and production. Oil is separated from gas at Valhall using two separation units. The heavier gas fractions, NGL, are separated at Valhall through a fractioning tower and are then mainly transported in the oil stream. In May 1996, a riser facility (WP) with space for 19 wells was installed. The four facilities are tied back to each other with bridges. The water injection facility was installed centrally in the field in the summer of 2003 and tied back with a bridge to WP. The drilling rig on this facility will also be used by WP. The flank development consists of two wellhead facilities positioned in the north and south of the field. The southern facility was installed in October 2002 and came on stream in May 2003. The northern facility was installed in the summer of 2003 and came on stream in January 2004. Valhall processes production from Hod, and delivers gas for gas lift in Hod's wells. The Valhall development was approved by the Norwegian Parliament in 1977. 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.

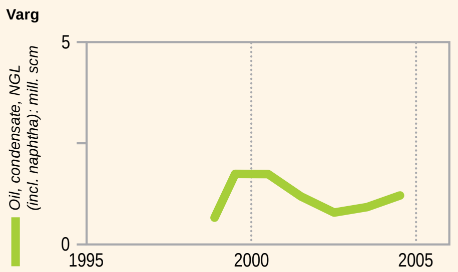
Reservoir:
The Valhall field produces from chalk rock in the Tor and Hod formations.

Recovery strategy:
Recovery originally took place using depletion with compaction. Water injection in the centre of the field was decided on in 2000, and started in January 2004 in a converted production well.



Transport:
Oil and NGL are piped to Ekofisk for onward transport to Teesside. Gas is piped to Norpipe for onward transport to Emden.

Status:
Production from Valhall is expected to increase from current levels. This is mainly due to the increased number of wells and the start 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. The water injection project has suffered delays, but, as at January 2005, drilling from the injection facility has commenced. As the seabed has subsided at the centre of the field, and the original facilities have aged, new development is planned. This will probably involve a new facility with processing plant and accommodation. The licensees have commenced work and a decision is expected in the course of 2005. Fixed cables on the seabed are also used to monitor the reservoir. The figure above shows the development of reserves.



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 of State	
On stream	22.12.1998	
Operator	Pertra AS	
Licensees	Pertra AS	70.00%
	Petoro AS	30.00%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	12.1 million scm oil	4.5 million scm oil
Production	**Estimated production in 2005:**	
	Oil: 21,000 barrels/day	
Investment	Total investment is likely to be NOK 5.8 billion	
	NOK 5.8 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Trondheim	
Main supply base	Tananger	

Development:
Varg is an oilfield to the south of Sleipner Øst in 84 metres of water. The field is being produced from a leased production vessel (Petrojarl Varg) with integrated oil storage that is connected to a wellhead facility called Varg A. In 1999, the production vessel was sold to Petroleum Geo Services (PGS), who also assumed responsibility for the operation of the vessel. The wellhead facility and production vessel are tied back to flexible flowlines for oil production, water and gas injection, as well as power and control cables.

Reservoir:
The field contains oil in Late Jurassic sandstone reservoirs. The structure is faulted and segmented. In 2003, an appraisal well was drilled that showed additional oil in a segment in the western region of the Varg field (Varg Vest segment). Production from this segment started in January 2004, and has increased the chances of extended operations at Varg considerably.

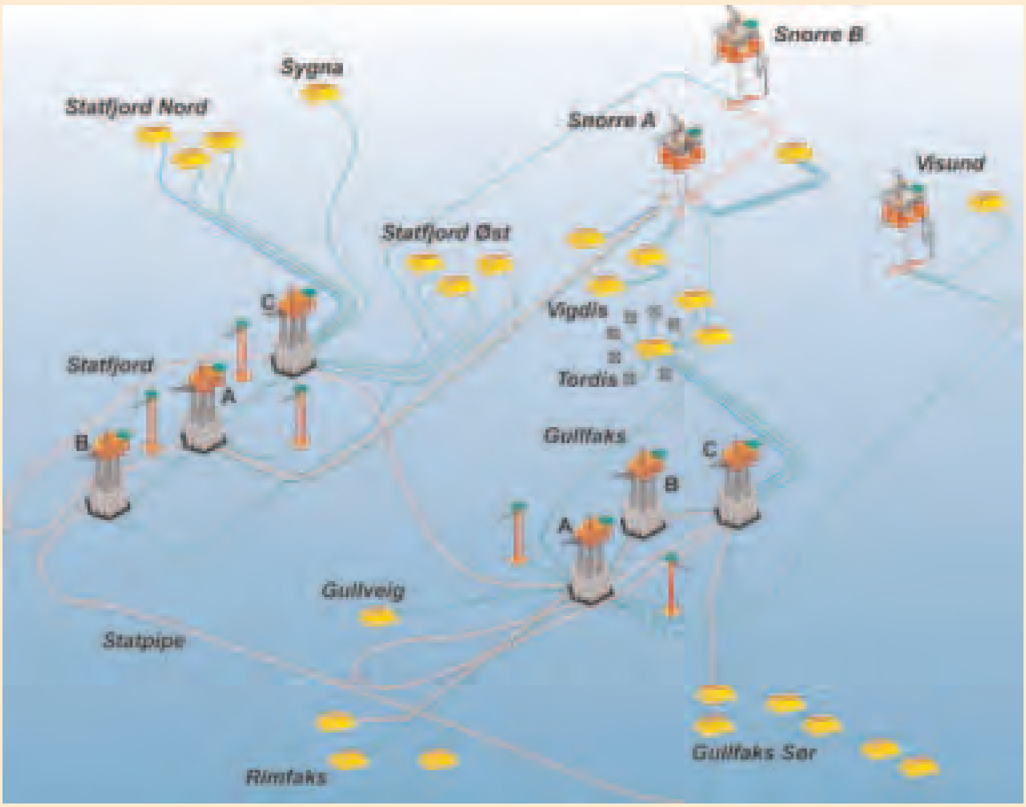
Recovery strategy:
Recovery currently takes place by injection of gas into the reservoir for pressure maintenance, through two injection wells that are located furthest north and south of the field, as well as in the Varg Vest segment.

Transport:
Oil is unloaded from the production vessel into shuttle tankers.

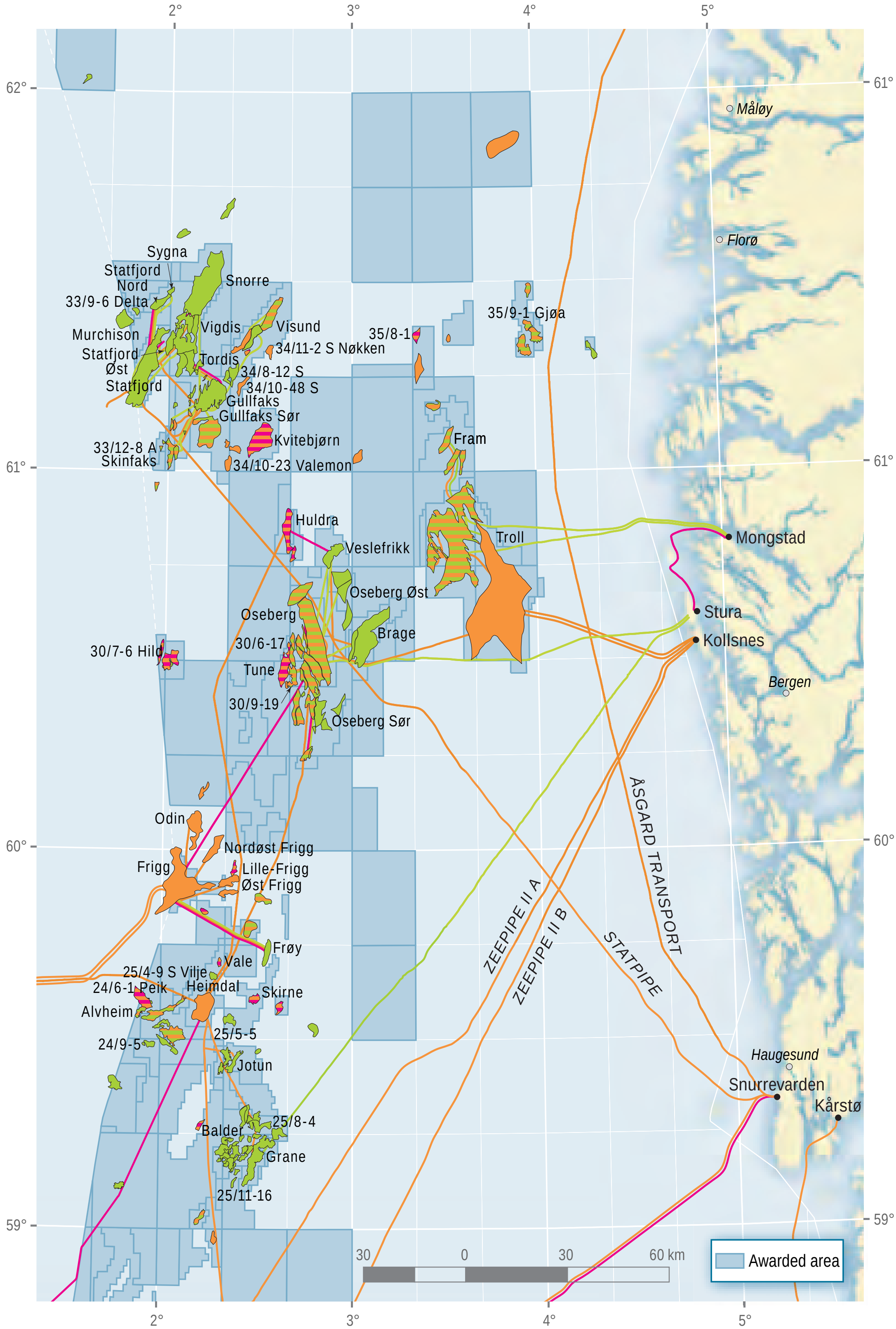
Status:
The decommissioning plan for the field was approved in 2001. The plan was to produce until the summer of 2002. Petra has, however, been successful in its work to increase the reserves in the field, and has also carried out initiatives to prove additional resources. In 2001, oil and gas were proven in the wildcat well 15/12-12 that was drilled into a structure in the south of Varg (Varg Sør). An appraisal well was drilled into the structure in 2003, and this proved gas and small amounts of oil. Plans are being prepared for development of the Varg Sør structure.

Northern North Sea

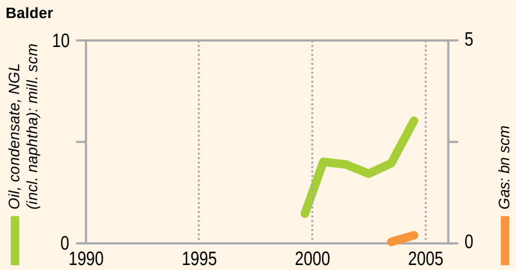
The main areas in the northern part of Norway's North Sea are Tampen, Troll/Oseberg and Frigg/Heimdal.
Tampen contains a number of fields, including Statfjord, Snorre, Gullfaks, Visund, Vigdis and Tordis. Several of these rank among Norway's largest oil fields. Although this is a mature petroleum province, its resource potential remains considerable. Troll has a very important function in gas deliveries from the Norwegian vontinental shelf, but has also become a substantial oil producer. The Oseberg area includes Brage and Veslefrikk as well as Oseberg itself. Oil production from this part of the Norwegian vontinental shelf is declining, but will remain substantial for many years to come. Oseberg is set to increase its gas deliveries. Heimdal has developed into a gas centre which provides processing services for surrounding fields. Production from the Frigg field, one of the first and largest gas fields in the North Sea, was shut down in the autumn 2004.



The Tampen area



Northern North Sea



Balder

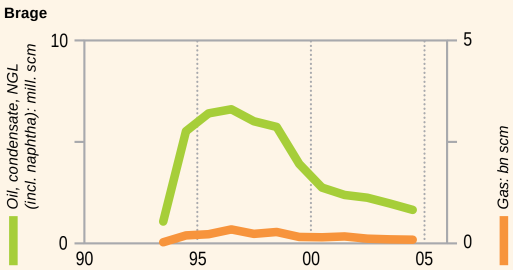
Blocks and production licences	Block 25/10 - production licence 028. Awarded 1969. Block 25/11 - production licence 001. Awarded 1965. Block 25/8 - production licence 027. Awarded 1969. Block 25/8 - production licence 027 C. Awarded 2000. Block 25/8 - production licence 169. Awarded 1991.	
Discovered	1967	
Development approval	02.02.1996 by the King in Council of State	
On stream	02.10.1999	
Operator	ExxonMobil Exploration and Production Norway AS	
Licensees	ExxonMobil Exploration and Production Norway AS	100.00%
Recoverable reserves	**Original:** 58.9 million scm oil 1.6 billion scm gas	**Remaining as at 31.12.2004** 36.5 million scm oil 1.4 billion scm gas
Production	**Estimated production in 2005:** Oil: 119,000 barrels/day Gas: 0.30 billion scm	
Investment	Total investment is likely to be NOK 25.2 billion NOK 22.1 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

Development:
The Balder field is an oil field 190 km west of Stavanger in 125 metres of water. The field has been developed with subsea wells that are tied back to the production and storage vessel, Balder FPSO, from which oil and gas are processed. The Ringhorne discovery has been developed with a combined accommodation, drilling and wellhead facility, which is also tied back to Balder FPSO and a subsea template with an oil production well and a water injection well. The PDO for Balder was approved on 02.02.1996. The PDO for Ringhorne was approved on 11.05.2000 and production started on 21.05.2001. Production from the Ringhorne facility started 11.02.2003. Ringhorne is now integrated as part of Balder. The amended PDO for Ringhorne and PIO for transport of oil from the Jurassic reservoir at Ringhorne to Jotun and gas from Balder to Jotun was approved on 14.02.2003. Exemption from PDO for development of the Ringhorne Vest reservoir in the Ty formation was granted on 14.11.2003.

Reservoir:
The Balder development contains several separated structures of Tertiary sandstones. The Ringhorne development includes several reservoirs of the same type as the original Balder and a reservoir from the Jurassic Age.

Recovery strategy:
Balder is recovered by natural water mechanism, water injection and gas injection.

Transport:
Oil and gas from the Jurassic reservoir at Ringhorne are transported to Jotun for final processing. Excess gas from Balder was originally reinjected into the reservoir.



Brage

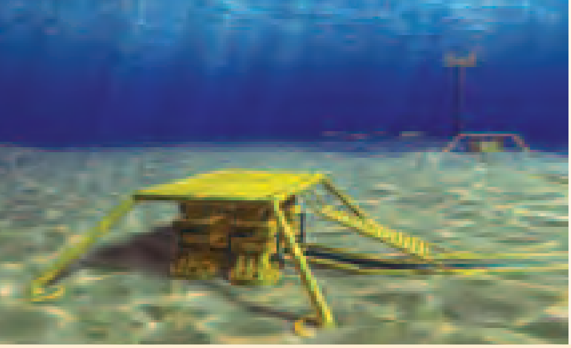
Blocks and production licences	Block 30/6 - production licence 053 B. Awarded 1998. Block 31/4 - production licence 055. Awarded 1979. Block 31/7 - production licence 185. Awarded 1991.
Discovered	1980
Development approval	29.03.1990 by Parliament
On stream	23.09.1993
Operator	Norsk Hydro Produksjon AS
Licensees in Brage	Endeavour Energy Norge AS 4.44% Eni Norge AS 12.26% ExxonMobil Exploration and Production Norway AS 13.84% Norsk Hydro Produksjon AS 20.00% Paladin Resources Norge AS 20.00% Petoro AS 14.26% Revus Energy AS 2.50% Statoil ASA 12.70%
Recoverable reserves	**Original:** 48.5 million scm oil, 2.9 billion scm gas, 0.8 million tonnes NGL **Remaining as at 31.12.2004** 3.8 million scm oil, 0.8 billion scm gas
Production	**Estimated production in 2005:** Oil: 29,000 barrels/day Gas: 0.08 billion scm NGL: 0.02 million tonnes
Investment	Total investment is likely to be NOK 16.8 billion NOK 16.5 billion had been invested as at 31.12.04 (2005 values)
Operating organisation	Bergen
Main supply base	Mongstad

Development:
The Brage field is an oilfield that is in 140 metres of water and has been developed with an integrated production and accommodation facility with a steel casing. The development was approved by Parliament on 29.03.1990 and the field came on stream on 23.09.1993. Trial production from the Sognefjord formation took place in the autumn of 1997, and these deposits were given development approval by the King in Council of State on 20.10.1998.

Reservoir:
The Brage field consists of Jurassic sandstone reservoirs in the Early Jurassic Statfjord formation and the Mid-Jurassic Fensfjord formation. There is also oil and gas in the Late Jurassic Sognefjord formation.

Recovery strategy:
The recovery mechanism in the Statfjord formation is by water injection, in the Fensfjord formation by water and gas injection. The Sognefjord formation is recovered using natural depletion.

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



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 of State	
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 at 31.12.2004**
	11.2 million scm oil	7.6 million scm oil
	4.3 billion scm gas	4.3 billion scm gas
	0.1 million tonnes NGL	0.1 million tonnes NGL
Production	**Estimated production in 2005:**	
	Oil: 29,000 barrels/day	
Investment	Total investment is likely to be NOK 3.9 billion	
	NOK 3.7 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

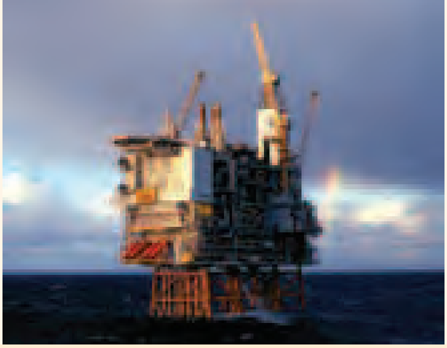
Development:
Fram is an oilfield that is located in the northern part of the North Sea, around 22 km north of Troll. The development so far (Fram Vest) consists of two subsea templates tied back to Troll C. The gas is separated from the fluid on Troll C and reinjected into the Fram Vest reservoir. Development of the Fram Vest deposits was approved by the King in Council of State on 23.03.2001.

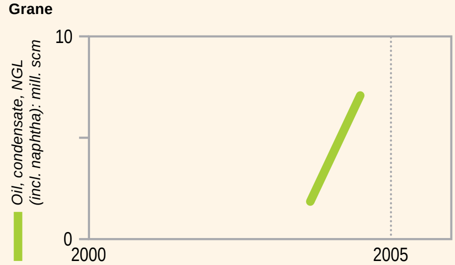
Reservoir:
The reservoir consists of Late Jurassic sandstone and is on a rotated and faulted block.

Recovery strategy:
The recovery mechanism is gas injection.

Transport:
The Fram wellstream is piped to Troll C for processing. The oil is then transported to Mongstad through the Troll II pipeline. When gas injection ceases, the gas will be exported via Troll A to Kollsnes.

Status:
Work is in progress on further development of other structures in the area. A PDO for the eastern sections (Fram Øst), has been submitted to the authorities in february 2005 and will most likely be considered during spring.





Grane

Blocks and production licences	Block 25/11 - production licence 001. Awarded 1965. Block 25/11 - production licence 169 B1. Awarded 2000. Block 25/11 - production licence 169 B2. Awarded 2000.	
Discovered	1991	
Development approval	14.06.2000 by Parliament	
On stream	23.09.2003	
Operator	Norsk Hydro Produksjon AS	
Licensees in Grane	ExxonMobil Exploration and Production Norway AS	25.60%
	Norsk Hydro Produksjon AS	38.00%
	Norske ConocoPhillips AS	6.40%
	Petoro AS	30.00%
Recoverable reserves	**Original:** 120.3 million scm oil	**Remaining as at 31.12.2004** 112.5 million scm oil
Production	**Estimated production in 2005:** Oil: 176,000 barrels/day	
Investment	Total investment is likely to be NOK 18.4 billion NOK 13.4 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

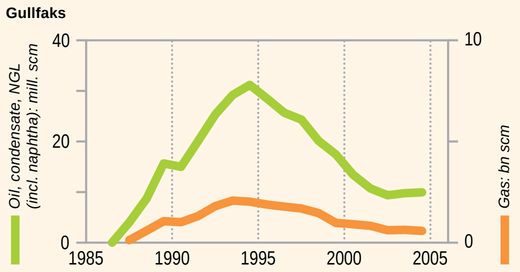
Development:
The Grane oilfield is located to the east of the Balder field in the North Sea, in 127 metres of water, and has been developed with an integrated accommodation, drilling and processing facility with a seabed-standing steel casing. The facility has 40 well slots.

Reservoir:
The field consists of a main structure and some additional structures. The reservoir consists of Tertiary Age sandstones with good reservoir characteristics, containing high viscosity oil.

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.

Transport:
Oil from Grane is piped from the field to the Sture terminal for metering, storage and export. Injection gas will be imported through a pipe from the Heimdal facility.

Status:
Nine oil producers and two gas injection wells were pre-drilled, in addition to a well for injection of cuttings. Drilling of production wells continues.



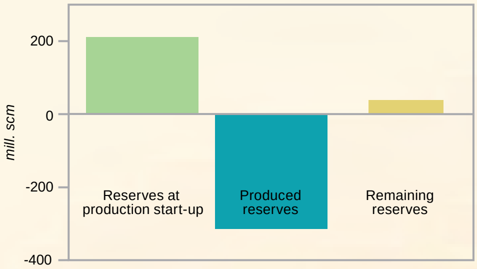
Gullfaks

Blocks and production Licences	Block 34/10 - production licence 050. Awarded 1978. Block 34/10 - production licence 050 B. Awarded 1995.
Discovered	1978
Development approval	09.10.1981 by Parliament
On stream	22.12.1986
Operator	Statoil ASA
Licensees	Norsk Hydro Produksjon AS 9.00% Petoro AS 30.00% Statoil ASA 61.00%
Recoverable reserves	**Original:** 351.9 million scm oil; 22.6 billion scm gas; 2.6 million tonnes NGL **Remaining as at 31.12.2004** 37.5 million scm oil; 1.3 billion scm gas; 0.3 million tonnes NGL
Production	**Estimated production in 2005:** Oil: 151,000 barrels/day Gas: 0.53 billion scm NGL: 0.06 million tonnes
Investment	Total investment is likely to be NOK 107.9 billion NOK 101.7 billion had been invested as at 31.12.04 (2005 values)
Operating organisation	Bergen
Main supply bases	Sotra and Florø

Development:
Gullfaks is an oilfield in from 130 to 220 metres of water. 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. Over the last few years, Gullfaks A and C have been developed in order to receive and process oil and gas from Gullfaks Sør. Gas capacity on Gullfaks A was expanded in the spring of 2003. In addition to processing petroleum from Gullfaks and Gullfaks Sør, the facilities are also involved in production and export 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 and was approved on 09.10.1981. Production started on 22.12.1986. The PDO for the eastern section (Gullfaks C) was approved on 01.06.1985. The development plan for Gullfaks Vest was approved on 15.01.1993, and recovery from the Lunde formation was approved on 03.11.1995.

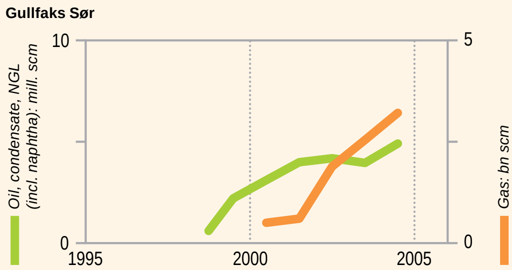
Reservoir:
The Gullfaks reservoirs consist of sandstones in the Brent group from the Mid-Jurassic Age, and Early Jurassic and Late Triassic sandstones in the Cook, Statfjord and Lunde formations. The reservoirs are 2,800 – 3,400 m below the seabed. Gullfaks consists of rotated fault blocks in the west and a structural horst in the east, with an intermediate highly faulted area.

Recovery strategy:
The drive mechanism for recovery from Gullfaks is mainly full 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. Certain minor fault blocks are recovered using depletion.



Transport:
Oil is exported from Gullfaks A and C via loading buoys to tankers. Processed rich gas is sent into the export pipeline directly to Statpipe for further processing at Kårstø and export through Norpipe/Europipe to the Continent. When needed, parts of the gas may also exported via the Statfjord field.

Status:
Production from Gullfaks is in the decline phase. Potential for increased recovery from Gullfaks has been identified, partly by finding and draining pockets of remaining oil in water-flooded areas, and partly through massive water circulation. Comprehensive analysis has also been carried out to calculate the potential for injecting CO_2 into the reservoir. There are a number of small deposits in the flank areas around Gullfaks that can be drilled and recovered using long-rage wells. Some of these have been granted exemption from PDOs and are already on stream. The figure above shows the development of reserves.



Gullfaks Sør

Blocks and production licences	Block 33/12 - production licence 037 B. Awarded 1998. 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 of State	
On stream	10.10.1998	
Operator	Statoil ASA	
Licensees	Norsk Hydro Produksjon AS	9.00%
	Petoro AS	30.00%
	Statoil ASA	61.00%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	43.8 million scm oil	23.4 million scm oil
	39.1 billion scm gas	30.4 billion scm gas
	4.5 million tonnes NGL	3.4 million tonnes NGL
Production	**Estimated production in 2005:** Oil: 75,000 barrels/day Gas: 3.34 billion scm NGL: 0.38 million tonnes	
Investment	Total investment is likely to be NOK 22.7 billion NOK 19.0 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Bergen	
Main supply bases	Sotra and Florø	

Development:
Gullfaks Sør has been developed with subsea templates tied to the Gullfaks A and Gullfaks C facilities. The Gullfaks Sør deposits have been developed with four subsea templates tied to Gullfaks A for phase 1 and two subsea templates tied to Gullfaks C for phase 2. A production well has also been drilled from Gullfaks A to Gullfaks Sør. Rimfaks and Gullveig have been developed with three and one seabed templates, respectively, tied to Gullfaks A. The wellstream from phase 1 is processed on Gullfaks A. The gas from phase 1 is reinjected into Gullfaks Sør and Rimfaks. The wellstream from phase 2 is processed on Gullfaks C.

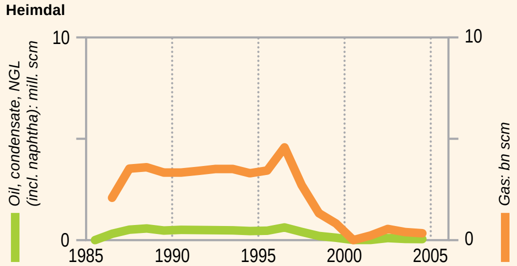
Gulltopp will be developed through an extended reach production well from Gullfaks A. Gullfaks Sør has been developed in two phases. The PDO for phase 1 was approved on 29.03.1996 and includes recovery of oil and condensate from deposits 34/10-2 Gullfaks Sør, 34/10-17 Rimfaks and 34/10-37 Gullveig. The PDO for phase 2 was approved on 08.06.1998 and includes recovery of gas from the Brent group in the Gullfaks Sør deposit. In January 2004, PDO exemption was granted for 34/10-47 Gulltopp, and Gulltopp was included in Gullfaks Sør.

Reservoir:
The Gullfaks Sør reservoirs consist of Mid-Jurassic sandstones in the Brent group and the Early Jurassic and Late Triassic Statfjord formations. The reservoirs are around 2,400 – 3,400 m under the seabed in western rotated fault blocks. Gullveig is the shallowest of the three deposits, with the top reservoir at 2,400 metres. The reservoirs in the Gullfaks Sør deposits are heavily segmented, with many internal faults, and the Statfjord formation has poor flow characteristics. Rimfaks, Gullveig and Gulltopp show good reservoir characteristics.

Recovery strategy:
Recovery of oil and condensate from Gullfaks Sør is partly driven by pressure maintenance, using gas reinjection in the Brent group, and by depletion in the Statfjord formation. Recovery of gas is driven by depletion. Rimfaks is produced using full pressure maintenance using gas reinjection. Recovery of oil from Gullveig is driven by depletion, and production is affected by the production at Tordis and Gullfaks. Gulltopp will be recovered using gas lift in the production well from Gullfaks A.

Transport:
The oil is exported from Gullfaks A via loading buoys to tankers. Rich gas from phase 2 is exported through Statpipe to Kårstø for further processing and export to the Continent. A gas export pipeline ties Gullfaks A and Gullfaks C to Statpipe.

Status:
The Gullfaks Sør reservoirs show different productivity and pressure development. The estimated reserves for the Gullfaks Sør deposit have been adjusted down in relation to the original plans, especially in the Statfjord formation, as a result of lower productivity than originally assumed. Gullveig and Rimfaks have proved to have better production characteristics than estimated in the original plans, and existing facilities at Rimfaks have insufficient capacity to recover the Rimfaks resources. In order to increase well capacity at Rimfaks, installation of an extra subsea template in the Gullfaks Sør area is planned. The amended PDO for Rimfaks was approved by the authorities in February 2005.



Heimdal

Block and production licence	Block 25/4 - production licence 036 BS. Awarded 2003.	
Discovered	1972	
Development approval	10.06.1981 by Parliament	
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 at 31.12.2004**
	7.1 million scm oil	0.8 million scm oil
	42.1 billion scm gas	
Production	**Estimated production in 2005:**	
	Gas: 0.1 billion scm	
Investment	Total investment is likely to be NOK 18.4 billion	
	NOK 18.4 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Bergen	
Main supply base	Dusavik	

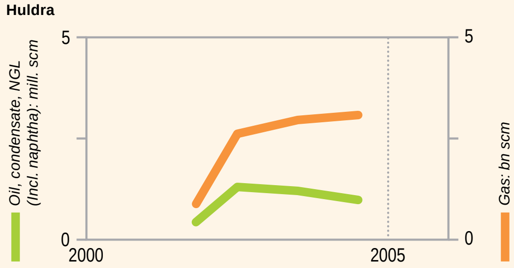
Development:
Heimdal is a gas field in 120 metres of water. The field has been developed with an integrated drilling, production and accommodation facility with a steel base (HMP1). The PDO for Heimdal was approved by the Norwegian Parliament on 10.06.1981. The field came on stream on 13.12.1985. The Heimdal Jura development was approved on 02.10.1992. The PDO for Heimdal Gas Centre (HGS) was approved on 15.01.1999 and the centre came on stream in 2000. The plan involves construction of a new riser facility (HRP) and modification and upgrade of HMP1. HRP is a steel-based facility tied back to HMP1 by a bridge.

Reservoir:
The reservoir consists of Tertiary sandstones in the Heimdal formation laid down as deep-marine turbidites.

Recovery strategy:
Heimdal is developed with natural depletion.

Transport:
Originally, gas was piped from Heimdal to Statpipe, but may also now be transported by other pipelines. Condensates are piped to Brae in the British sector. After HGS was constructed, a new gas pipeline (Vesterled) has been laid up to the existing gas pipeline from Frigg to St. Fergus. A gas pipeline has been laid from HRP to Grane for gas injection. Huldra, Vale and Skirne are tied to a pipeline to Heimdal for processing.

Status:
The production facilities are mainly used for processing from Huldra, Vale and Skirne. If the facility has spare capacity, gas is also produced from the Heimdal reservoir.



Huldra

Blocks and production licences	Block 30/2 - production licence 051. Awarded 1979.	
	Block 30/3 - production licence 052 B. Awarded 2001.	
Discovered	1982	
Development approval	02.02.1999 by Parliament	
On stream	21.11.2001	
Operator	Statoil ASA	
Licensees in Huldra	Norske ConocoPhillips AS	23.34%
	Paladin Resources Norge AS	0.50%
	Petoro AS	31.96%
	Statoil ASA	19.88%
	Total E&P Norge AS	24.33%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	4.3 million scm oil	0.9 million scm oil
	12.9 billion scm gas	4.2 billion scm gas
	0.1 million tonnes NGL	
Production	**Estimated production in 2005:**	
	Oil: 8,000 barrels/day Gas: 1.92 billion scm NGL: 0.01 million tonnes	
Investment	Total investment is likely to be NOK 7.1 billion	
	NOK 7.0 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Bergen	
Main supply bases	Sotra and Florø	

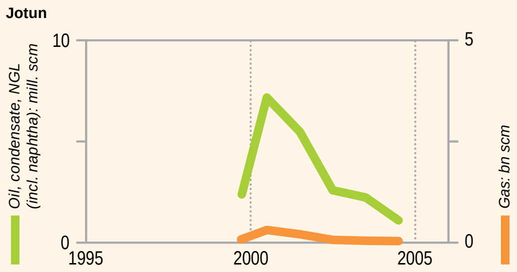
Development:
Huldra is a gas field in 125 metres of water. The field is developed with a wellhead steel facility that separates gas and condensate for transport in separate pipelines. The facility is normally unmanned and is remotely operated from Veslefrikk B, 16 km away.

Reservoir:
The reservoir is in a rotated fault block which inclines to the east, and consists of Jurassic sandstone belonging to the Brent group. The Huldra reservoir has high pressure and high temperature. Communication in the reservoir is uncertain, but the production history indicates two main segments without pressure communication. There are many small faults in the field.

Recovery strategy:
The field's recovery strategy is depletion.

Transport:
Following first stage separation, the wet gas is transported to Heimdal for further processing. Some of the gas is cold ventilated. Condensate is transported to Veslefrikk for processing.

Status:
Drilling has been completed at the field, and it is producing gas and condensate from a total of six production wells. Production at Huldra now exceeds the forecast plateau rate. The field is estimated as remaining at its plateau rate for just less than three years, before the production rate gradually declines.



Jotun

Blocks and production licences	Block 25/7 - production licence 103 B. Awarded 1998. Block 25/8 - production licence 027 B. Awarded 1999.
Discovered	1994
Development approval	10.06.1997 by Parliament
On stream	25.10.1999
Operator	ExxonMobil Exploration and Production Norway AS
Licensees in Jotun	Enterprise Oil Norge AS 45.00% ExxonMobil Exploration and Production Norway AS 45.00% Lundin Norway AS 7.00% Petoro AS 3.00%
Recoverable reserves	**Original:** 25.4 million scm oil, 0.7 billion scm gas **Remaining as at 31.12.2004** 6.0 million scm oil, 0.1 billion scm gas
Production	**Estimated production in 2005:** Oil: 14,000 barrels/day Gas: 0.01 billion scm
Investment	Total investment is likely to be NOK 10.7 billion NOK 10.3 billion had been invested as at 31.12.04 (2005 values)
Operating organisation	Stavanger
Main supply base	Dusavik

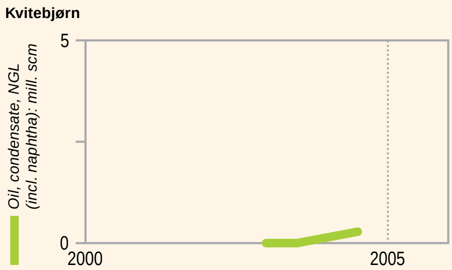
Development:
Jotun is an oil field in 126 m of water located around 25 km north of Balder, 165 km west of Haugesund. It has been developed with a production vessel, Jotun A (FPSO), and a wellhead facility with drilling module and accommodation, Jotun B. Jotun also processes gas from Balder and oil from the Jurassic reservoir in the Ringhorne deposits at Balder.

Reservoir:
The Jotun oilfield consists of three structures. The eastern structure also has a gas cap. The reservoirs are distally located in a submarine fan system. The three structures are relatively flat and only separated by minor depressions. Between the three structures, there is a difference of only a few metres in oil/water contact. To the west the sand is mostly homogenous and has the best reservoir quality, while to the east there is more slate content in the reservoir.

Recovery strategy:
Recovery is driven by reinjection of produced water.

Transport:
The oil is exported via loading buoys to tankers. The processed rich gas is exported via Statpipe to the Kårstø plant. The facility and the ship are tied together by flowlines for oil and gas injection and for water injection, as well as power and control cables.

Status:
Jotun production fell from plateau earlier than estimated, and the drop in production has been larger than previously estimated. Since 2004, Jotun has received oil and gas from Balder for processing and onward transport.



Kvitebjørn

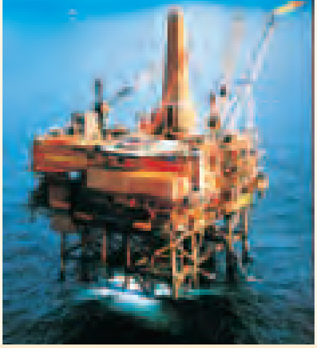
Block and production licence	Block 34/11 - production licence 193. Awarded 1993.	
Discovered	1994	
Development approval	14.06.2000 by Parliament	
On stream	26.09.2004	
Operator	Statoil ASA	
Licensees	Norsk Hydro Produksjon AS	15.00%
	Petoro AS	30.00%
	Statoil ASA	50.00%
	Total E&P Norge AS	5.00%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004.**
	18.0 million scm oil	17.7 million scm oil
	51.8 billion scm gas	51.3 billion scm gas
	2.2 million tonnes NGL	2.2 million tonnes NGL
Production	**Estimated production in 2005:**	
	Oil: 36,000 barrels/day Gas: 4.48 billion scm NGL: 0.21 million tonnes	
Investment	Total investment is likely to be NOK 10.7 billion	
	NOK 8.8 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Bergen	

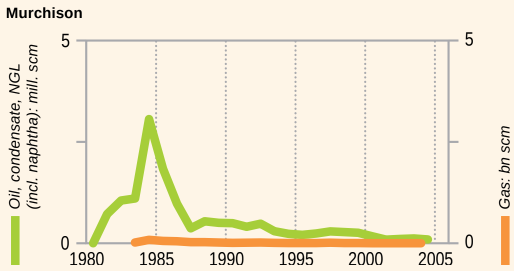
Development:
Kvitebjørn is a gas condensate field that has been developed with an integrated accommodation, drilling and processing facility with a seabed steel jacket. It is in 190 metres of water. 11 production wells are planned to be drilled. The processing plant is dimensioned for a daily production of 20.7 mill. scm rich gas and 10,000 scm condensate. Drill cuttings and polluted water are injected in a dedicated disposal well.

Reservoir:
The reservoir consists of sandstones in the Mid-Jurassic Brent group. The area of the reservoir is around 44 km^2, and it lies at an approx. depth of 4,000 metres, at high temperature and pressure.

Recovery strategy:
Recovery is driven by 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.



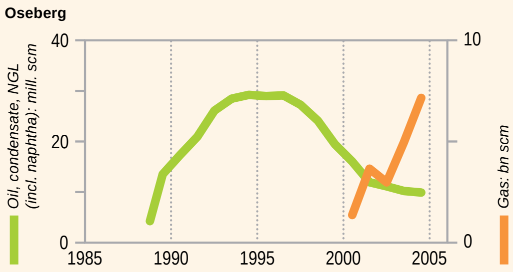


Murchison

Block and production licence	Block 33/9 - production licence 037 C. Awarded 2000. The Norwegian share of the field is 22.2 percent, the British share 77.8 percent.	
Discovered	1975	
Development approval	15.12.1976	
On stream	28.09.1980	
Operator	CNR International (UK) Limited	
Licensees in Murchison	Revus Energy AS	10.68%
	Statoil ASA	11.52%
	CNR International (UK) Limited	68.72%
	Ranger Oil (UK) Ltd	9.08%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
(Norwegian share)	14.0 million scm oil	0.7 million scm oil
	0.4 billion scm gas	0.1 billion scm gas
Production	**Estimated production in 2005:**	
(Norwegian share)	Oil: 2,000 barrels/day	
Investment	Total investment is likely to be NOK 7.1 billion NOK 6.9 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Aberdeen, Scotland	
Main supply base	Peterhead, Scotland	

Development:
Murchison has been developed with a combined drilling, accommodation and production facility with a steel jacket. 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. This is established in the agreement between Norway and the United Kingdom relating to exploitation of the Murchison reservoir and offtake of petroleum therefrom, cf. Parliamentary Bill. no. 15 (1980–1981) and Recommendation no. 57 (1980–1981). Supplementary agreement, cf. Parliamentary Bill no. 68 (1981–82) and Recommendation no. 169 (1981–1982).

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. The gas is piped to St. Fergus in Scotland. In 2002, CNR International (UK) took over as operator from Kerr McGee North Sea (UK) Ltd.



Oseberg

Blocks and production licences	Block 30/6 - production licence 053. Awarded 1979.	
	Block 30/9 - production licence 079. Awarded 1982.	
Discovered	1979	
Development approval	05.06.1984 by Parliament	
On stream	01.12.1988	
Operator	Norsk Hydro Produksjon AS	
Licensees in Oseberg	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 at 31.12.2004**
	353.7 million scm oil	32.7 million scm oil
	102.8 billion scm gas	82.7 billion scm gas
	6.2 million tonnes NGL	3.3 million tonnes NGL
Production	**Estimated production in 2005:**	
	Oil: 126,000 barrels/day Gas: 2.02 billion scm NGL: 0.50 million tonnes	
Investment	Total investment is likely to be NOK 79.3 billion	
	NOK 74.4 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

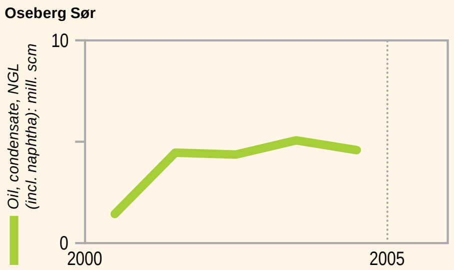
Development:
Oseberg is an oilfield with an overlaying gas cap. Oil recovery from Oseberg was developed in two phases. The first phase of the development included a field centre in the south consisting of two facilities, Oseberg A and B. Oseberg A is a process and accommodation facility with a concrete base structure. Oseberg B is a drilling and water injection facilities with a steel jacket. Phase 2 includes development of the northern part of the field. The Oseberg C facility is an integrated production, drilling and accommodation facility (PDQ). The Oseberg D facility is an facility for gas processing with a steel jacket tied to Oseberg Field Centre. Oseberg Vest flank has been developed with a four-well subsea template that is tied to Oseberg B. The facilities at the field centre will also be used for processing oil and gas from the Oseberg Øst, Oseberg Sør, Oseberg Vest and Tune fields. The PDO for Oseberg Phase 1 was approved on 05.06.1984. The field came on stream on 01.12.1988. Oseberg Phase 2, development of the northern part of the field, was approved on 19.01.1988. Oseberg Phase 3, the gas phase with installation of a facility for gas processing, was approved on 13.12.1996 and began operation in October 1999. The PDO for Oseberg Vestflanke was approved on 19.12.2003.

Reservoir:
The field consists of several reservoirs in the Mid-Jurassic Brent group, and is divided into three main 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, and there is a high recovery factor from the field.

Recovery strategy:
Pressure in the Oseberg field is maintained by gas, water and 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. TOGI was taken off stream in 2002 in accordance with the gas delivery agreement.

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

Status:
Most production wells are now drilled horizontally. Use of horizontal and advanced wells, in conjunction with gas injection and VAG, has contributed to high oil recovery levels from the Oseberg field. The challenge in the future will be to recover the oil that remains between the gas cap and the water zone, and to balance the gas recovered by taking into account the oil production from the field. Oseberg Vestflanke will come on stream in the autumn of 2005.



Oseberg Sør

Blocks and production licences	Block 30/12 - production licence 171 B. Awarded 2000.	
	Block 30/9 - production licence 079. Awarded 1982	
	Block 30/9 - production licence 104. Awarded 1985.	
Discovered	1984	
Development approval	10.06.1997 by Parliament	
On stream	05.02.2000	
Operator	Norsk Hydro Produksjon AS	
Licensees in Oseberg Sør	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 at 31.12.2004**[1]
	57.6 million scm oil	37.7 million scm oil
	8.9 billion scm gas	8.9 billion scm gas
Production	**Estimated production in 2005:**	
	Oil: 81,000 barrels/day Gas: 0.82 billion scm	
Investment	Total investment is likely to be NOK 14.5 billion	
	NOK 12.5 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

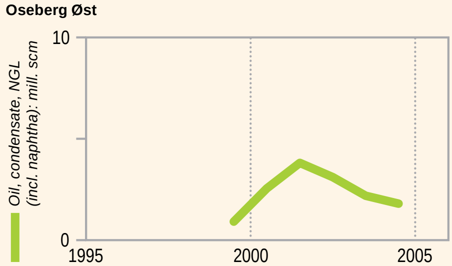
[1] Gas from Oseberg Sør is not reallocated from Oseberg and therefore the remaining gas reserves are equal to the original.

Development:
Oseberg Sør is an oil field and has been developed with an integrated facility with accommodation, drilling module and first stage separation of oil and gas. The jacket and topside are made of steel. There are also several structures in the field that have been produced from subsea templates that are tied back to the Oseberg Sør facility. Final processing of oil and gas takes place on the Oseberg Field Centre. The PDO for Oseberg Sør was approved by the Norwegian Parliament on 10.06.1997. The field came on stream on 05.02.2000. An amended PDO for part of the development, the Oseberg Sør J structure, was approved on 15.05.2003.

Reservoir:
The reservoir consists of Jurassic sandstones and is divided into several separate structures.

Recovery strategy:
Recovery mainly takes place using water injection, but associated gas is also reinjected from the Oseberg Sør facility, so that there is WAG (Water/Alternating Gas) injection in parts of the field.

Transport:
The oil is piped from the Oseberg Sør facility to the Oseberg Field Centre. Following final processing, the oil is piped to the Sture terminal. Gas is transported via Oseberg Gas Transport into Statpipe via the Heimdal 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 of State	
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 at 31.12.2004**[1]
	30.2 million scm oil	15.8 million scm oil
	0.7 billion scm gas	0.7 billion scm gas
Production	**Estimated production in 2005:**	
	Oil: 24,000 barrels/day Gas: 0.06 billion scm	
Investment	Total investment is likely to be NOK 9.4 billion	
	NOK 6.8 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

[1] Gas from Oseberg Øst not allocated separately from Oseberg, remaining reserves therefore equal original reserves.

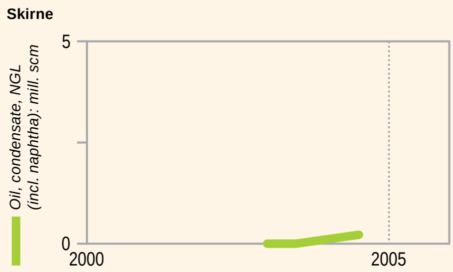
Development:
Oseberg Øst is an oil field and has been developed with a facility with a steel jacket with accommodation, drilling equipment and first stage separation of oil, water and gas. The facility stands in 160 metres of water.

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 Mid-Jurassic Brent group.

Recovery strategy:
Pressure is maintained in the field using both water injection and WAG (Water/Alternating Gas) injection.

Transport:
The oil is piped to the Oseberg Field Centre for further processing and transport through the Oseberg Transport System (OTS) pipeline to Sture terminal. The gas is mainly injected into the field, although a minor amount is extracted at Oseberg Field Centre and exported through Oseberg Gas Transport.

Status:
The field has a relatively low rate of recovery, although various measures for increasing oil recovery are being considered in an ongoing process. A new drilling campaign, comprising up to seven new wells, was decided in autumn 2004. The wells will contribute to increasing the oil reserves to the extent of six million scm.



Skirne

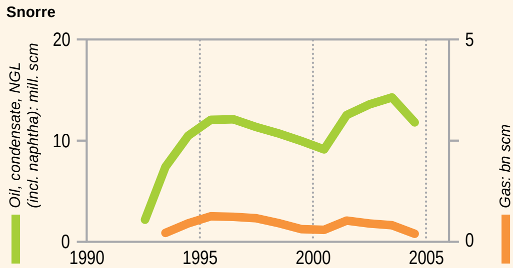
Block and production licence	Block 25/5 - production licence 102. Awarded 1985.	
Discovered	1990	
Development approval	05.07.2002 by the Crown Prince Regent in Council of State	
On stream	03.03.2004	
Operator	Total E&P Norge AS	
Licensees	Marathon Petroleum Norge AS	20.00%
	Norsk Hydro Produksjon AS	10.00%
	Petoro AS	30.00%
	Total E&P Norge AS	40.00%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	1.6 million scm oil	1.4 million scm oil
	6.7 billion scm gas	6.0 billion scm gas
Production	**Estimated production in 2005:**	
	Oil: 6,000 barrels/day Gas: 1.31 billion scm	
Investment	Total investment is likely to be NOK 2.4 billion	
	NOK 2.0 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	

Development:
Skirne has been developed in association with Heimdal. The production wells are tied back with a pipeline to Heimdal for processing. The PDO for the Skirne field, including Byggve, was approved on 05.07.2002. Following an application by the operator, Byggve has been regarded as part of the Skirne field from the autumn of 2003.

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

Recovery strategy:
The recovery mechanism is natural depletion.

Transport:
Gas condensate is piped to the Heimdal facility.



Snorre

Blocks and production licences	Block 34/4 - production licence 057. Awarded 1979.	
	Block 34/7 - production licence 089. Awarded 1984.	
Discovered	1979	
Development approval	27.05.1988 by Parliament	
On stream	03.08.1992	
Operator	Statoil ASA	
Licensees in Snorre	Amerada Hess Norge AS	1.18%
	Enterprise Oil Norge AS	1.18%
	ExxonMobil Exploration and Production Norway AS	11.16%
	Idemitsu Petroleum Norge AS	9.60%
	Norsk Hydro Produksjon AS	17.65%
	Petoro AS	30.00%
	RWE Dea Norge AS	8.88%
	Statoil ASA	14.40%
	Total E&P Norge AS	5.95%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	242.4 million scm oil	113.0 million scm oil
	6.4 billion scm gas	1.3 billion scm gas
	4.7 million tonnes NGL	0.7 million tonnes NGL
Production	**Estimated production in 2005:**	
	Oil: 193,000 barrels/day	
Investment	Total investment is likely to be NOK 76.9 billion	
	NOK 58.4 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Florø	

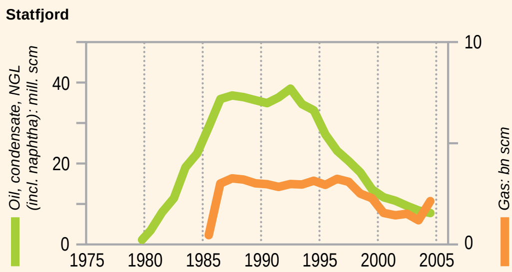
Development:
Snorre is an oil field that has been developed in two phases. Phase 1 includes a floating steel facility for accommodation and processing (Snorre TLP) in the south, and a subsea template with ten well slots (Snorre SPS) centrally in the field, tied back to Snorre TLP. Snorre TLP has also been developed with its own processing facility for production from the Vigdis field. Phase 2 includes a semi-submersible integrated drilling, processing and accommodation facility (Snorre B) in the northern part of the field. The PDO for Snorre phase 1, which covers the southern part of the field with the Snorre A facility, was approved on 27.05.1988. The amended development plan for Snorre, with a new module on Snorre A for production from Vigdis, was approved on 16.12.1994. The PDO for Snorre phase 2, which covers the northern part of Snorre with the Snorre B facility, was approved on 08.06.1998. Snorre B came on stream in June 2001.

Reservoir:
The Snorre field consists of several large fault blocks. The reservoir sandstone belongs to the Early Jurassic and Triassic Statfjord and Lunde formations, and has been deposited on a flood plain. The reservoir has a complex structure with many channels and internal flow barriers.

Recovery strategy:
Pressure in Snorre is maintained fully using water injection, gas injection and water/alternating gas (WAG) 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 TLP before transport to Statfjord A for final processing and export. The oil is loaded onto tankers at Statfjord and the gas is sent through Statpipe to Kårstø. Processed oil from Snorre B is piped to Statfjord B for storage and loading to tankers. All gas from Snorre B is reinjected into the reservoir, but can, if required, also be piped to Snorre TLP.

Status:
There are plans to modify the processing plant at Snorre A in order to increase the capacity for production and injection of water and gas.



Statfjord

Blocks and production licences	Block 33/12 - production licence 037. Awarded 1973.	
	Block 33/9 - production licence 037. Awarded 1973.	
	Norwegian share of the field is 85.47%, British share is 14.53%	
Discovered	1974	
Development approval	16.06.1976 by Parliament	
On stream	24.11.1979	
Operator	Statoil ASA	
Licensees in Statfjord	A/S Norske Shell	8.55%
	Enterprise Oil Norge AS	0.89%
	ExxonMobil Exploration and 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 UK Ltd.	4.84%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
(Norwegian share)	565.8 million scm oil	24.2 million scm oil
	54.3 billion scm gas	4.6 billion scm gas
	14.9 million tonnes NGL	1.6 million tonnes NGL
Production	**Estimated production in 2005:**	
(Norwegian share)	Oil: 99,000 barrels/day Gas: 1.52 billion scm NGL: 0.53 million tonnes	
Investment	Total investment is likely to be NOK 112.5 billion	
	NOK 106.7 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply bases	Sotra and Florø	

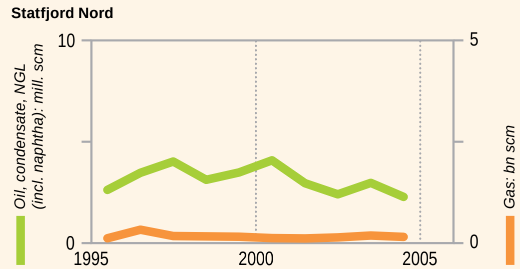
Development:
Statfjord is an oil field that is on the border between the Norwegian and British sectors of the continental shelf, in around 145 metres of water. The field has been developed in three phases with the fully integrated facilities Statfjord A, Statfjord B and Statfjord C. Statfjord A is centrally positioned on the Statfjord field, and came on stream in November 1979. Processing capacity for oil at Statfjord A is approx. 67,000 scm per day, and the facility has a storage capacity of 175,000 scm. Capacity for water injection is approx. 65,000 m^3 per day. Partially processed oil from Snorre TLP has been piped to Statfjord A since August 1992. Statfjord B is located on the southern part of the Statfjord field, and came on stream in November 1982. Production capacity for oil is 16,000 scm per day, and the facility has a storage capacity of 302,000 scm. Water injection capacity is approx.. 65,000 m^3 per day. Statfjord C is positioned on the northern part of the Statfjord field, and came on stream in June 1985. The facility is identically constructed to Statfjord B. Production capacity for oil is 20,000 scm. Capacity for water injection at Statfjord C is approx. 60,000 m^3 per day. Statfjord's satellite fields (Statfjord Øst, Statfjord Nord and Sygna) have a separate inlet separator on Statfjord C with a capacity of approx. 20,000 scm oil. The northern flank of the Statfjord field has been developed with two subsea facilities, one for production and one for injection, tied back to Statfjord C. Production from the northern flank started in the summer of 1999.

Reservoir:
The Statfjord field consists of a large fault block, inclining towards the west, as well as a number of smaller fault blocks along the east flank. The field extends into the British sector. The reservoirs in the Statfjord field consist of sandstones belonging to the Brent group, the Cook formation and the Statfjord formation.

Recovery strategy:
The Brent reservoir was originally developed using pressure support from water injection. In 1998, based on results from a trial with WAG injection in lower Brent, and reservoir studies, it was decided to implement WAG injection as the recovery strategy throughout Brent. Calculations indicate that WAG injection at Brent provides increased oil recovery to the extent of 10.5 million scm by injecting 15 billion scm gas. The Statfjord formation has been developed using pressure support from upflank gas injection. Since 1994, implementation of a new recovery strategy, with upflank water injection and supporting gas injection in the upper part of the Statfjord formation and down flank WAG injection in the lower part of the Statfjord formation, has begun in stages, based on experience from production and reservoir studies. The Cook formation came on stream in 1994. The recovery strategy is based on phasing in wells that already penetrate the reservoir, and possibly deepening existing wells. Pressure in production is supported by water injection. The Northern flank of the field came on stream with its own subsea wells in August 1999.

Transport:
Stabilised oil is stored in storage cells at each facility. Oil is loaded from one of the three oil loading systems at the field. The gas is piped through Statpipe to Karstø, where NGL is separated before dry gas is transported on to Emden. The UK extracts its share of the oil through the Flags pipeline from Statfjord B to St. Fergus in Scotland.

Status:
There is high activity with reboring and reperforation of the wells in order to maintain production levels. Plan for gas blowdown for the Statfjord field (Statfjord Late Phase) was submitted to the authorities in February 2005. The Plan will extend the lifetime of the field by around 10 years and provide significant extra recovery of approx. 41 billion scm and an increase in oil recovery of around four million scm.



Statfjord Nord

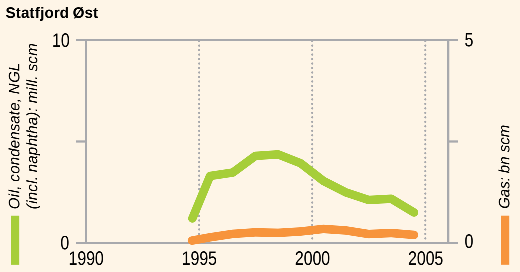
Block and production licence	Block 33/9 - production licence 037. Awarded 1973.	
Discovered	1977	
Development approval	11.12.1990 by Parliament	
On stream	23.01.1995	
Operator	Statoil ASA	
Licensees	A/S Norske Shell	10.00%
	Enterprise Oil Norge AS	1.04%
	ExxonMobil Exploration and Production Norway AS	25.00%
	Norske ConocoPhillips AS	12.08%
	Petoro AS	30.00%
	Statoil ASA	21.88%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	39.3 million scm oil	8.9 million scm oil
	2.6 billion scm gas	0.9 billion scm gas
	0.9 million tonnes NGL	0.3 million tonnes NGL
Production	**Estimated production in 2005:**	
	Oil: 35,000 barrels/day Gas: 0.28 billion scm NGL: 0.10 million tonnes	
Investment	Total investment is likely to be NOK 7.4 billion	
	NOK 7.2 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Sotra	

Development:
Statfjord Nord is an oil field that is located around 17 km north of Statfjord in 250 – 290 metres of water and has been developed with three subsea templates tied back to Statfjord C. Two of the well templates are for production and one is for water injection. Each of the well templates has four well slots. One well slot on the injection well template at Statfjord Nord has been used for an injection well at the Sygna field. The water injection capacity of Statfjord Nord and Sygna together is 28,000 m^3 per day.

Reservoir:
The Statfjord Nord reservoir consists of Mid-Jurassic sandstones belonging to the Brent group and Late Jurassic sandstones (the Munin formation).

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

Transport:
The wellstream is piped through two pipelines to Statfjord C for processing, storage and export. Statfjord Nord and Statfjord Øst use the same equipment on Statfjord C.



Statfjord Øst

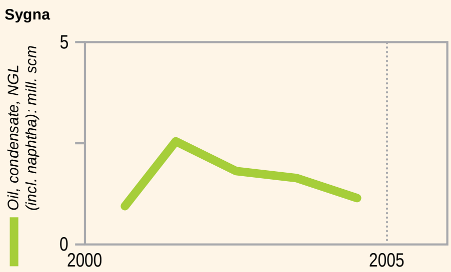
Blocks and production licences	Block 33/9 - production licence 037. Awarded 1973.	
	Block 34/7 - production licence 089. Awarded 1984.	
Discovered	1976	
Development approval	11.12.1990 by Parliament	
On stream	24.09.1994	
Operator	Statoil ASA	
Licensees in Statfjord Øst	A/S Norske Shell	5.00%
	Enterprise Oil Norge AS	0.52%
	ExxonMobil Exploration and 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 at 31.12.2004**
	35.7 million scm oil	6.1 million scm oil
	3.9 billion scm gas	1.4 billion scm gas
	1.4 million tonnes NGL	0.5 million tonnes NGL
Production	**Estimated production in 2005:**	
	Oil: 24,000 barrels/day Gas: 0.42 billion scm NGL: 0.15 million tonnes	
Investment	Total investment is likely to be NOK 6.5 billion	
	NOK 6.2 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Sotra	

Development:
Statfjord Øst is an oil field located around 7 km northeast of the Statfjord field in 150 – 190 metres of water. The field has been developed with three well templates that are tied back to Statfjord C. Two of the templates are for production and one for water injection. Each subsea template has four well slots.

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

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

Transport:
The wellstream is piped through two pipelines to Statfjord C for processing, storage and export. Statfjord Øst and Statfjord Nord use the same processing equipment on Statfjord C.



Sygna

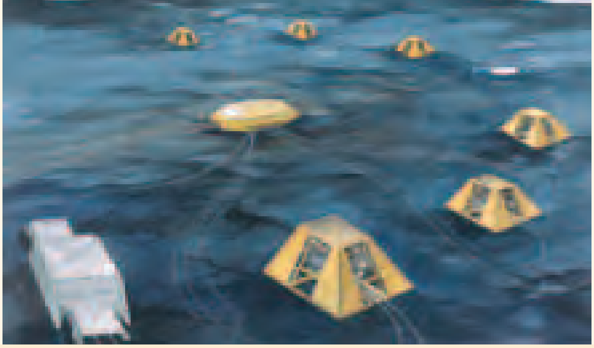
Blocks and production licences	Block 33/9 - production licence 037. Awarded 1973. Block 34/7 - production licence 089. Awarded 1984.	
Discovered	1996	
Development approval	30.04.1999 by the King in Council of State	
On stream	01.08.2000	
Operator	Statoil ASA	
Licensees in Sygna	A/S Norske Shell	5.50%
	Enterprise Oil Norge AS	0.57%
	ExxonMobil Exploration and 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:** 10.9 million scm oil	**Remaining as at 31.12.2004** 3.2 million scm oil
Production	**Estimated production in 2005:** Oil: 11,000 barrels/day	
Investment	Total investment is likely to be NOK 2.3 billion NOK 2.1 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Florø	

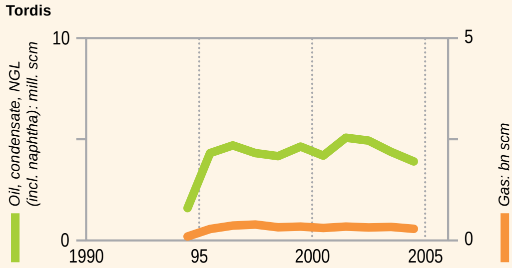
Development:
Sygna is an oil field that straddles the boundary between production licences 037 and 089 between the Snorre and Statfjord fields. The field has been developed with a subsea template, with four well slots, that is tied back to Statfjord C. Three production wells have been drilled at Sygna. An injection well from Statfjord Nord provides water injection.

Reservoir:
The Sygna reservoir consists of Mid-Jurassic sandstones belonging to the Brent group.

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

Transport:
The wellstream is piped to Statfjord C for processing, storage and export. Statfjord Nord, Statfjord Øst and Sygna share processing equipment on Statfjord C.





Tordis

Block and production licence	Block 34/7 - production licence 089. Awarded 1984.	
Discovered	1987	
Development approval	14.05.1991 by Parliament	
On stream	03.06.1994	
Operator	Statoil ASA	
Licensees	ExxonMobil Exploration and 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 at 31.12.2004**
	58.1 million scm oil	14.3 million scm oil
	5.2 billion scm gas	1.9 billion scm gas
	1.7 million tonnes NGL	0.4 million tonnes NGL
Production	Estimated production in 2005: Oil: 58,000 barrels/day Gas: 0.28 billion scm NGL: 0.11 million tonnes	
Investment	Total investment is likely to be NOK 8.9 billion NOK 8.6 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Florø	

Development: Tordis is an oil field located between the Snorre and Gullfaks fields in around 200 metres of water, and 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 piped to Gullfaks C through two pipelines. Injection water is piped from Gullfaks C. Tordis consists of four discoveries: Tordis, Tordis Øst, Borg and 34/7-25 S. The PDO for Tordis was approved on 14.05.1991. The PDO for Tordis Øst was approved on 13.10.1995. Test production were carried out at Borg in 1998 for a period of six months. The PDO for Borg was approved on 29.06.1999. 34/7-25 S was regarded as part of Tordis, and the authorities did not require separate approval for development of this discovery.

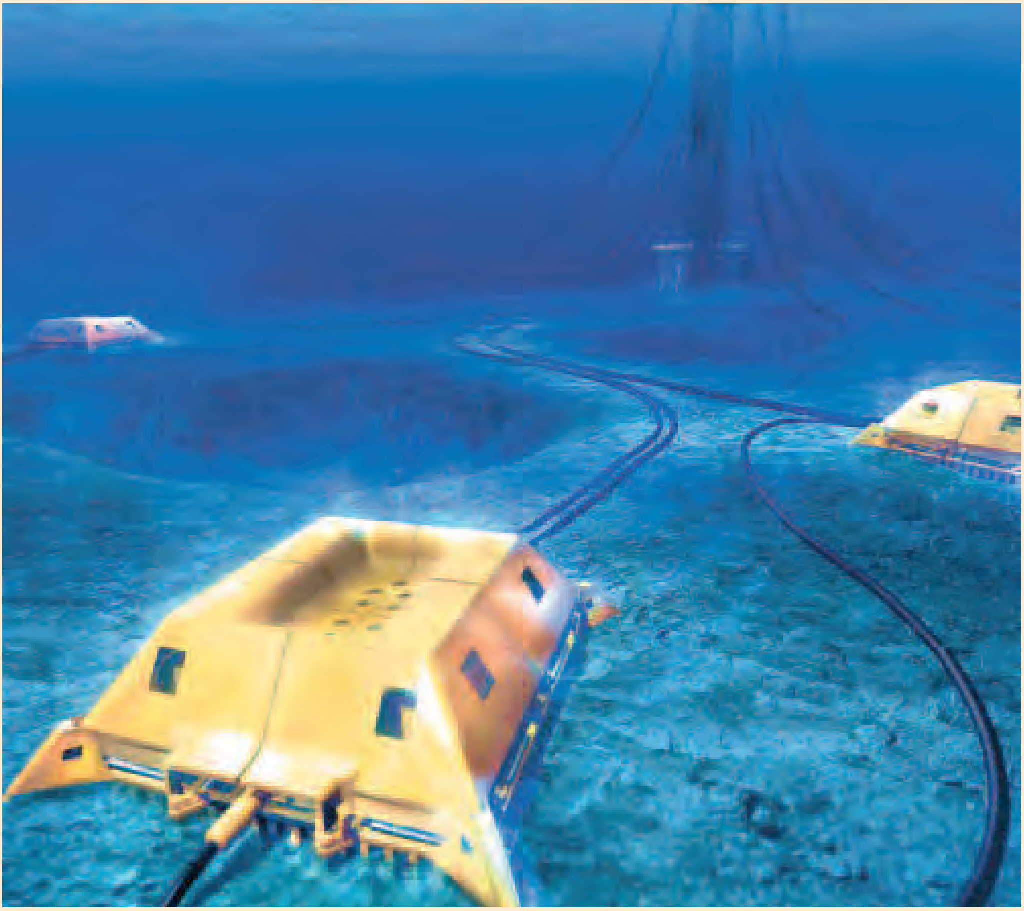
Reservoir: The reservoirs in the Tordis and Tordis Øst discoveries consist of Mid-Jurassic sandstones in the Brent group. The reservoir at Borg consists of sandstones that are equivalent in period with the Late Jurassic Draupne formation. The reservoir in 34/7-25 S consists of fallen sandstones from the Brent group and sandstones that are from the equivalent period to the Draupne formation. The Tordis reservoirs lie at a depth of 2,000 – 2,500 m.

Recovery strategy: Pressure in the Tordis and 34/7-25 S discoveries is partially maintained using water injection and natural water pressure. Pressure at Borg is fully maintained using water injection. Recovery at Tordis Øst takes place with pressure support from natural water pressure.

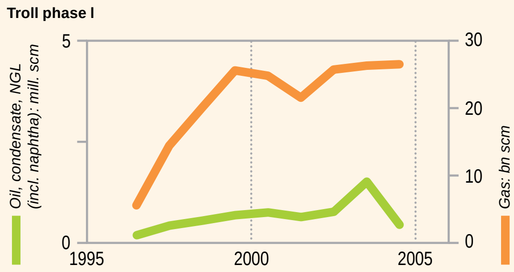
Transport: Oil from Tordis is exported from Gullfaks C. The export gas is piped through Statpipe to Kårstø.

Troll

Troll lies about 65 km off Kollsnes and comprises two main structures: Troll Øst and Troll Vest. The first of these primarily occupies blocks 31/3 and 31/6, while most of Troll Vest is found in block 31/2. Roughly two-thirds of the field's recoverable gas reserves are thought to lie in Troll Øst. A staged development has been pursued, with phase I covering gas reserves in the eastern region and phase II focusing on the oil reserves in Troll Vest. Phase III will cover gas reserves in the latter area. A thin oil layer underlies the whole Troll field, but is only sufficiently thick for commercial recovery in the Troll Vest region. The latter divides into oil and gas provinces, where the thickness of the oil-bearing zones is 22-27 and 11-14 metres respectively. Test production from the two provinces in 1990 and 1991 yielded positive results. The field has huge gas resources and one of the largest oil volumes remaining on the Norwegian continental shelf.



Troll Pilot



Troll Phase I

Blocks and production licences	Block 31/2 - production licence 054. Awarded 1979	
	Block 31/3 - production licence 085. Awarded 1983	
	Block 31/3 - production licence 085C Awarded 2002	
	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 Parliament	
On stream	09.02.1996	
Operator	Statoil ASA	
Licensees in Troll	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 at 31.12.2004**
	1318.0 billion scm gas	1128.6 billion scm gas
	30.8 million tonnes NGL	30.8 million tonnes NGL
	1.6 million scm condensate	
Production	**Estimated production in 2005:**	
	Gas: 27.20 billion scm NGL: 0.51 million tonnes	
Investment	Total investment is likely to be NOK 70.0 billion	
	NOK 47.4 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Bergen	
Main supply base	Ågotnes	

Development:

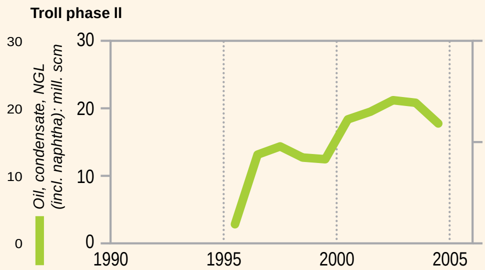
Troll Phase I has been developed with Troll A, in which the gas from Troll Øst has been recovered by Statoil as operator. Troll A is a fixed wellhead facility with a concrete casing. At Troll Øst there also has been installed the TOGI subsea template which has exported gas to Oseberg for gas injection. The sea in the Troll area is more than 300 metres deep. The PDO for Troll phase I, which included Troll A and the gas reserves at Troll Øst, was approved on 15.12.1986. An updated plan, in which processing was moved to a land-based facility (at Kollsnes), was approved in 1990. The PIO for the NGL facility at Kollsnes was approved in 2002.

Reservoir:
The gas and oil at Troll Øst and Vest are mainly found in the Sognefjord formation that consists of Jurassic sandstone. Some of the reservoir is also in the underlying Fensfjord formation. The field consists of three relatively large rotated fault blocks.

Recovery strategy:
The gas in Troll Øst is recovered using 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 piped partly to the Sture terminal, partly to Mongstad. The dry gas is piped in Zeepipe II A and II B. Small gas quantities are supplied to Kollsnes Industrial Estate.

Status:
In 2002 and 2003 Troll was the field that produced most oil and gas from the Norwegian sector of the continental shelf. Increased compression capacity for gas has been under development at Troll A in 2004.



Troll Phase II

Blocks and production licences	Block 31/2 - production licence 054. Awarded 1979. Block 31/3 - production licence 085. Awarded 1983. Block 31/3 - production licence 085C Awarded 2002. 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 Parliament
On stream	19.09.1995
Operator	Norsk Hydro Produksjon AS
Licensees in Troll	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:** 233.2 million scm oil **Remaining as at 31.12.2004** 77.0 million scm oil
Production	**Estimated production in 2005:** Oil: 249,000 barrels/day
Investment	Total investment is likely to be NOK 66.8 billion NOK 62.1 billion had been invested as at 31.12.04 (2005 values)
Operating organisation	Bergen
Main supply base	Mongstad

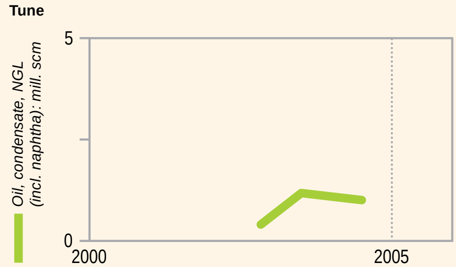
Development:
Troll Phase II has been developed with Troll B and Troll C recovering oil from Troll Vest with Norsk Hydro as operator. Troll B is a floating concrete facility, while Troll C is a semi-submersible steel facility. Oil from Troll Vest is produced from several subsea templates that are tied back to Troll B and C by flowlines. Troll Pilot, which is tied back to one of the subsea templates, is a plant for subsea separation and reinjection of produced water. The sea depth in the Troll area exceeds 300 metres. The Troll C facility is also used for production from the Fram field. The PDO for Troll phase II, which included Troll B and development of the Troll Vest oil province, was approved on 18.05.1992. A further development of Troll Vest, with Troll C, was approved in 1997. There have been several PDO approvals concerning subsea templates at Troll Vest.

Reservoir:
The gas and oil at Troll Øst and Vest is found mainly in the Sognefjord formation, which consists mainly of Jurassic sandstone. Some 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 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.

Recovery strategy:
Oil production at Troll Vest takes place through horizontal wells that are drilled immediately above the oil/water contact in the thin oil zone. There is also depletion here, but there will be simultaneous expansion of the gas cap and the water zone below the oil. There has been reinjection of some of the gas produced to assist in optimising the oil production. One important aspect of the strategy has been to recover the oil quickly. The timing of the recovery has been considered critical because of the risk of reduced oil production when the pressure is reduced 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 piped partly to the Sture terminal, partly to Mongstad. The dry gas is piped in Zeepipe II A and II B. Small amounts of the gas are delivered to Kollsnes Industrial Estate. The oil from Troll B and C is piped in the Troll Oil Pipelines I and II, respectively, to the oil terminal at Mongstad.

Status:
Troll Vest has been drilled with horizontal production wells from subsea templates with up to four drilling facilities at the same time. In all, more than 100 oil production wells have been drilled at Troll Vest. Over the last few years, annual decisions have been in favour of drilling new production wells that contribute to increasing oil reserves from Troll, and there are still a number of wells planned to be drilled. A number of multi-branch wells have been drilled and future plans also include five and six branch wells. Several well templates, which may increase recovery, are under evaluation. Kollsnes was split out of the coordinated Troll field in 2004, so that the Kollsnes terminal is now operated by Gassco as a part of Gassled.



Tune

Blocks and production licences	Block 30/5 - production licence 034. Awarded 1969.	
	Block 30/6 - production licence 053. Awarded 1979.	
	Block 30/8 - production licence 190. Awarded 1993.	
Discovered	1996	
Development approval	17.12.1999 by the King in Council of State	
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:**	**Remaining as at 31.12.2004**[1]
	3.8 million scm oil	1.6 million scm oil
	15.9 billion scm gas	15.9 billion scm gas
Production	**Estimated production in 2005:**	
	Oil: 6,000 barrels/day Gas: 2.16 billion scm	
Investment	Total investment is likely to be NOK 4.7 billion	
	NOK 3.9 billion had been invested as at 31.12.04 (2005 values)	

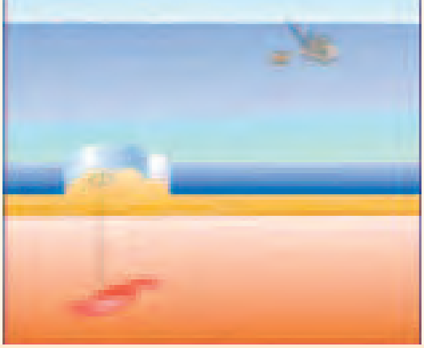
[1] Gas from Tune is not reallocated from Oseberg and therefore the remaining gas reserves are equal to the original

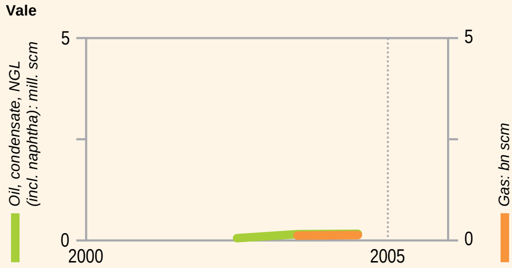
Development:
The Tune field is a gas and gas condensate field that is located around 10 km west of the Oseberg Field Centre. The field has been developed with a subsea facility with four production wells in the centre of the field. A new well template was tied back in 2004 to produce from the Tune Nord area. The PDO for the Tune field was approved on 17.12.1999 and it came on stream in 28.11.2002. In March 2004 PDO exemption for development of the northern part of the field was granted.

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

Recovery strategy:
Recovery is driven by depletion.

Transport:
The Tune subsea facility is tied back to the Oseberg D facility by two flowlines and a service line. A reception module for Tune has been built at Oseberg D. Condensate from Tune is stabilised at the Oseberg Field Centre and is transported to Sture through the Oseberg Transport System (OTS). Gas from Tune is injected into the Oseberg field, while the field’s licensees are returned sales gas from the Oseberg field.





Vale

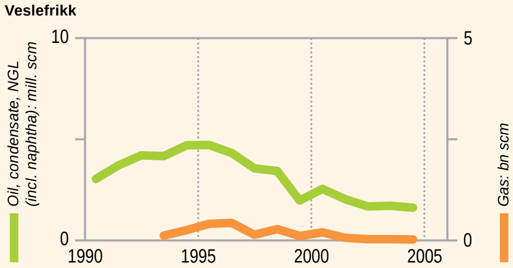
Block and production licence	Block 25/4 - production licence 036. Awarded 1971.
Discovered	1991
Development approval	23.03.2001 by the Crown Prince Regent in Council of State
On stream	31.05.2002
Operator	Norsk Hydro Produksjon AS
Licensees	Marathon Petroleum Norge AS 46.90% Norsk Hydro Produksjon AS 28.85% Total E&P Norge AS 24.24%
Recoverable reserves	**Original:** 1.8 million scm oil, 2.4 billion scm gas **Remaining as at 31.12.2004:** 1.4 million scm oil, 2.2 billion scm gas
Production	**Estimated production in 2005:** Oil: 8,000 barrels/day Gas: 0.53 billion scm
Investment	Total investment is likely to be NOK 2.0 billion NOK 1.6 billion had been invested as at 31.12.04 (2005 values)
Operating organisation	Bergen

Development:
Vale is located 16 km north of Heimdal and has been developed with a subsea facility tied back to Heimdal.

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

Recovery strategy:
Recovery is driven by depletion.

Transport:
Gas condensate is produced at the Heimdal facility.



Veslefrikk

Blocks and production licences	Block 30/3 - production licence 052. Awarded 1979.	
	Block 30/6 - production licence 053. Awarded 1979.	
Discovered	1981	
Development approval	02.06.1987 by Parliament	
On stream	26.12.1989	
Operator	Statoil ASA	
Licensees	Paladin Resources Norge AS	27.00%
	Petoro AS	37.00%
	RWE Dea Norge AS	13.50%
	Statoil ASA	18.00%
	Svenska Petroleum Exploration AS	4.50%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	56.1 million scm oil	10.9 million scm oil
	2.6 billion scm gas	0.5 billion scm gas
	1.1 million tonnes NGL	
Production	**Estimated production in 2005:**	
	Oil: 30,000 barrels/day	
Investment	Total investment is likely to be NOK 16.8 billion	
	NOK 16.0 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Bergen	
Main supply bases	Sotra and Florø	

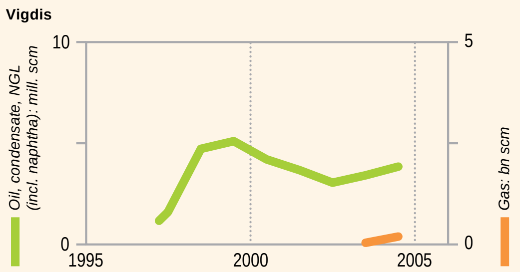
Development:
Veslefrikk is an oil field and is developed with two facilities. Veslefrikk is a steel facility with a drilling plant and bridge connection to Veslefrikk B, which processes the wellstream. Veslefrikk B is a converted drilling facility with processing facility and accommodation. The facility was upgraded in 1999 to receive condensate from the Huldra field. The PDO for the Veslefrikk field was approved on by Parliament on 02.06.1987. Production started 26.12.1989. The PDO for the Statfjord formation was approved on 11.06.1994. The PDO for the reservoir in Upper Brent and I areas was approved on 16.12.1994.

Reservoir:
The main reservoir consists of Jurassic sandstone in the Brent group, and is a raised fault block (horst). There are also reservoirs in the Intra Dunlin Sand and in the Statfjord formation.

Recovery strategy:
Pressure in the reservoir is supported by injection of water and gas.

Transport:
An oil pipeline is tied back to the Oseberg Transport System (OTS) for transport to the Sture terminal. Gas is transported through the Statpipe system.

Status:
Production from Veslefrikk is in the decline phase. Continual work is taking place to increase recovery for the field, including by drilling new wells and by distributing the gas injection optimally in the field. A pilot project to inject polymer gel into the reservoir, in order to reduce water flow into a production well, was carried out at the end of 2004.



Vigdis

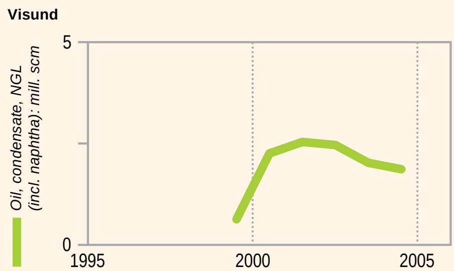
Block and production licence	Block 34/7 - production licence 089. Awarded 1984.	
Discovered	1986	
Development approval	16.12.1994 by the King in Council of State	
On stream	28.01.1997	
Operator	Statoil ASA	
Licensees	ExxonMobil Exploration and Production Norway AS	10.50%
	Idemitsu Petroleum Norge AS	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 at 31.12.2004**
	47.9 million scm oil	18.6 million scm oil
	1.2 billion scm gas	1.0 billion scm gas
	0.8 million tonnes NGL	0.7 million tonnes NGL
Production	**Estimated production in 2005:**	
	Oil: 71,000 barrels/day Gas: 0.21 billion scm NGL: 0.13 million tonnes	
Investment	Total investment is likely to be NOK 10.8 billion	
	NOK 10.1 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Florø	

Development:
Vigdis is an oil field that is located between the Snorre and Gullfaks fields in 280 metres of water. The field has been developed with subsea templates tied back to Snorre TLP. The wellstream is piped to Snorre TLP through two flowlines. Injection water is piped from Snorre TLP. Oil from Vigdis is processed in a dedicated processing module on Snorre TLP. The PDO for parts of Vigdis was approved on 16.12.1994. It came on stream on 28.01.1997. The PDO for the remaining parts of Vigdis, including discoveries 34/7-23 S, 34/7-29 S and 34/7-31, and the adjoining deposits (Vigdis Extension) was approved on 20.12.2002.

Reservoir:
The reservoirs consist of Mid-Jurassic sandstones in the Brent group. The field also contains reservoirs that consist of Early Jurassic and Late Triassic sandstones in the Statfjord formation, and sandstone reservoirs that are equivalent in time to the Late Jurassic Draupne formation. The reservoir in discoveries 34/7-23 S, 34/7-29 S and 34/7-31 consists of sandstones that are equivalent in time to the Draupne formation. The reservoirs are at a depth of 2200 - 2600 metres.

Recovery strategy:
Pressure is partially maintained using water injection.

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



Visund

Block and production licence	Block 34/8 - production licence 120. Awarded 1985.	
Discovered	1986	
Development approval	29.03.1996 by Parliament	
On stream	21.04.1999	
Operator	Statoil ASA	
Licensees at Visund	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 at 31.12.2004**
	27.6 million scm oil	15.8 million scm oil
	52.2 billion scm gas	52.2 billion scm gas
	6.7 million tonnes NGL	6.7 million tonnes NGL
Production	**Estimated production in 2005:**	
	Oil: 33,000 barrels/day Gas: 0.43 billion scm NGL: 0.07 million tonnes	
Investment	Total investment is likely to be NOK 20.1 billion	
	NOK 16.7 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Bergen	
Main supply base	Florø	

Development:
Visund is an oil field to the east of the Snorre field. The development includes a semi-submersible integrated steel accommodation, drilling and processing facility (Visund A). Visund A is in 335 metres of water. The northern section of Visund has also been developed with a subsea facility around 10 km to the north of Visund A. The PDO for the oil deposits at Visund was approved on 29.03.1996. The PDO for the gas deposits and the PIO for gas export were approved on 04.10.2002.

Reservoir:
Visund contains oil and gas in several inclined fault blocks with several separate pressure and fluid systems. Oil and gas are found in Jurassic and Triassic sandstones.

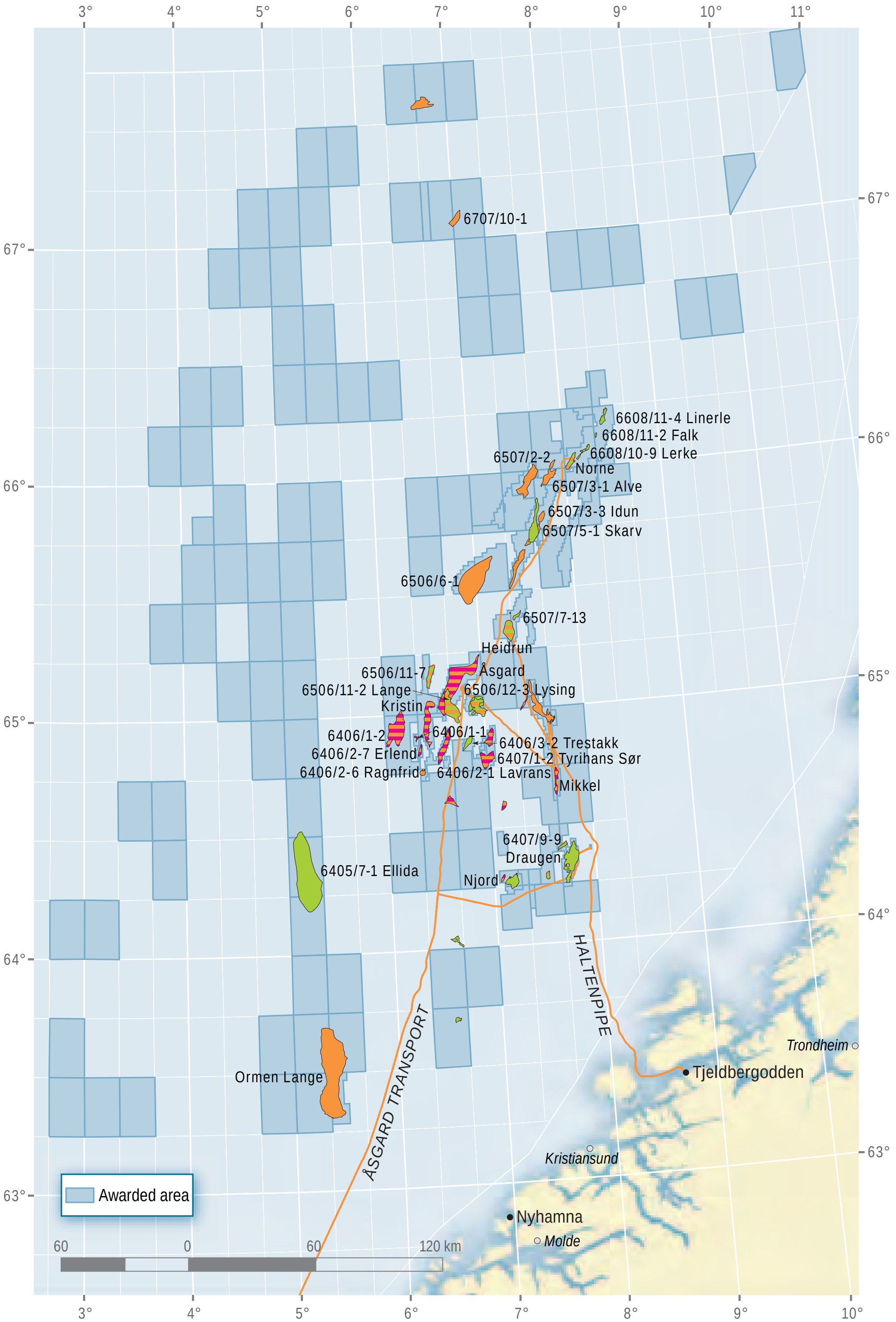
Recovery strategy:
Recovery is driven by gas injection, water is also injected into one of the reservoirs. From the autumn of 2005, some of the gas produced will be exported.

Transport:
The oil is piped to Gullfaks A, for storage and export with the oil from Gullfaks. The gas will be exported in a new pipeline to the Kvitebjørn gas pipeline and transport to Kollsnes. At Kollsnes, NGL is separated for onward transport of gas to the market.

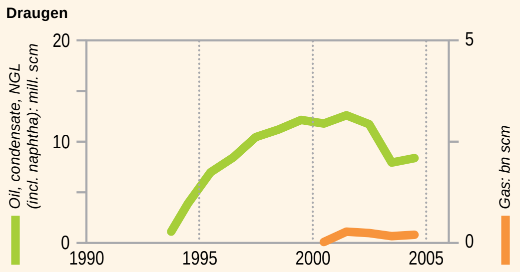
Status:
According to the plans, gas export will commence on 1.10.2005.

Norwegian Sea

The Norwegian Sea was opened for exploration in connection with the fifth licensing round in 1979. In the autumn of 1988, it was decided that the Draugen oil field would be the first Norwegian Sea discovery to be developed, and it came on stream in October 1993. Heidrun, Njord, Norne, Åsgard and Mikkel have since started production, while a plan for development and operation (PDO) for Kristin was approved in 2001. This region also contains substantial gas resources, including the Ormen Lange field, for which development approval was given in 2004.



The Norwegian Sea



Draugen

Block and production licence	Block 6407/9 - production licence 093. Awarded 1984.	
Discovered	1984	
Development approval	19.12.1988 by Parliament	
On stream	19.10.1993	
Operator	A/S Norske Shell	
Licensees	A/S Norske Shell	26.20%
	BP Norge AS	18.36%
	ChevronTexaco Norge AS	7.56%
	Petoro AS	47.88%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	131.4 million scm oil	28.2 million scm oil
	1.5 billion scm gas	0.6 billion scm gas
	2.3 million tonnes NGL	0.9 million tonnes NGL
Production	**Estimated production in 2005:**	
	Oil: 110,000 barrels/day Gas: 0.19 billion scm NGL: 0.24 million tonnes	
Investment	Total investment is likely to be NOK 25.5 billion	
	NOK 24.8 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Kristiansund	
Main supply base	Kristiansund	

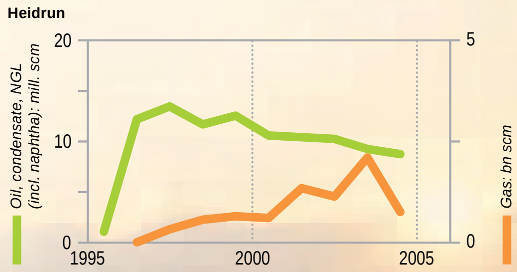
Development:
Draugen is an oil field in 250 metres of water. The field has been developed with a concrete fixed facility (monotower) supporting an integrated topside. The oil is processed at the facility and stabilised oil is stored in tanks in the base of the facility. Two flowlines link the facility to a floating loading buoy. The Garn Vest and Rogn Sør deposits have been developed with a total of five subsea wells and tied back to the main facility at Draugen. The field has six subsea water injection wellheads. The PDO for Draugen was approved on 19.12.1988. The field came on stream on 19.10.1993. 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 Late Jurassic sandstones in the Rogn formation. The Garn formation in the west of the field is also on stream. The reservoir is relatively homogenous, with good reservoir characteristics.

Recovery strategy:
Pressure in the field is maintained using water injection.

Transport:
The oil is exported via a floating loading buoy to tankers. Since November 2000, associated gas has been delivered through the Åsgard Transport pipeline for onward transport to Kårstø.

Status:
It is expected that production will fall from plateau in 2005, and that the quantity of produced water will increase significantly. Various measures to increase recovery are being considered. A pilot project for reinjection of the produced water is underway, and permanent full-scale reinjection will be considered when results are available. 4D-seismics to survey remaining resources and relevant drilling targets are being acquired.



Heidrun

Blocks and production licences	Block 6507/8 - production licence 124. Awarded 1986.	
	Block 6707/7 - production licence 095. Awarded 1984.	
Discovered	1985	
Development approval	14.05.1991 by Parliament	
On stream	18.10.1995	
Operator	Statoil ASA	
Licensees in Heidrun	Eni Norge AS	5.12%
	Norske ConocoPhillips AS	24.31%
	Petoro AS	58.16%
	Statoil ASA	12.41%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	175.0 million scm oil	75.5 million scm oil
	40.7 billion scm gas	33.2 billion scm gas
	2.9 million tonnes NGL	2.6 million tonnes NGL
Production	**Estimated production in 2005:**	
	Oil: 142,000 barrels/day Gas: 0.46 billion scm NGL: 0.08 million tonnes	
Investment	Total investment is likely to be NOK 61.5 billion	
	NOK 52.9 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stjørdal	
Main supply base	Kristiansund	

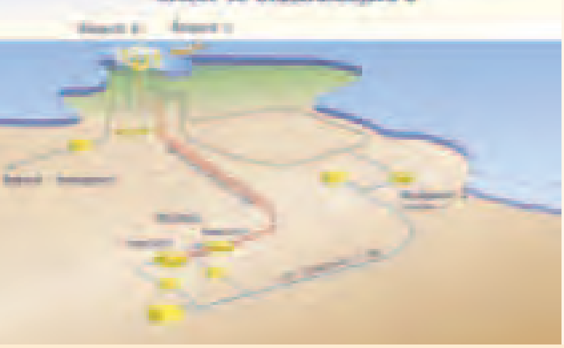
Development:
The Heidrun field is located on the Halten bank off mid-Norway in 350 metres of water, and has been developed with a floating concrete tension leg platform, installed over a subsea template with 56 well slots. The northern part of the field is developed with seabed facilities. The PDO for Heidrun was approved on 14.05.1991. The field came on stream on 18.10.1995. The PDO for the Heidrun northern flank was approved on 12.05.2000.

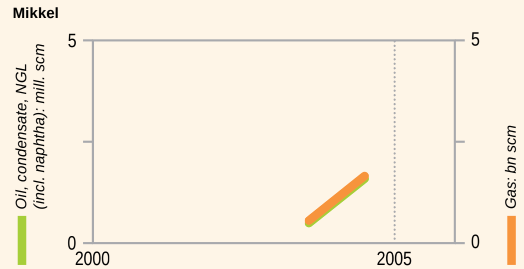
Reservoir:
The reservoir consists of Early and Mid-Jurassic sandstones. The structure is heavily faulted.

Recovery strategy:
Pressure in the field is maintained using water injection, as well as injection of excess gas.

Transport:
Heidrun oil is transferred to tankers at the field. The oil is shipped to Mongstad and Tetney (UK). The gas is piped to Tjeldbergodden and Kårstø.

Status:
The plant for reinjection of produced water has shown good regularity since upstart in 2003.
There is great potential for increased oil recovery and huge prospect possibilities. Active efforts are been made to find methods that can contribute to increasing the degree of recovery, as well as discover new deposits.





Mikkel

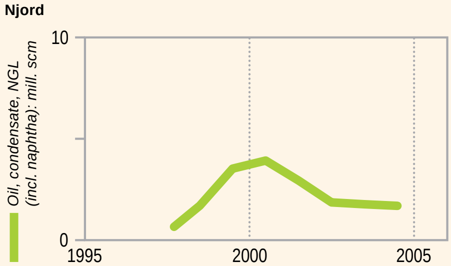
Blocks and production licences	Block 6407/5 - production licence 121. Awarded 1986.	
	Block 6407/6 - production licence 092. Awarded 1984.	
Discovered	1987	
Development approval	14.09.2001 by the King in Council of State	
On stream	01.08.2003	
Operator	Statoil ASA	
Licensees in Mikkel	Eni Norge AS	14.90%
	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 at 31.12.2004**
	24.1 billion scm gas	22.0 billion scm gas
	6.0 million tonnes NGL	5.4 million tonnes NGL
	6.6 million scm condensate	5.7 million scm condensate
Production	**Estimated production in 2005:**	
	Gas: 1.74 billion scm NGL: 0.44 million tonnes Condensate: 0.69 million scm	
Investment	Total investment is likely to be NOK 2.1 billion	
	NOK 1.9 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stjørdal	
Main supply base	Kristiansund	

Development:
Mikkel is a gas field that lies to the east of the Halten bank around 40 km south of Åsgard and 40 km north of Draugen in 220 metres of water. The field consists of a subsea facility with two well templates. The wellstream from the Mikkel field is led through a well template at 6507/11-1 Midgard to Åsgard B, where it is separated and processed.

Reservoir:
The reservoir consists of Mid-Jurassic sandstone in six structures, separated by faults.

Recovery strategy:
Depletion is used for recovery.

Transport:
From Mikkel, the wellstream flows to the Åsgard B facility for processing. Condensate is separated from the gas on Åsgard B. The separated condensate is stabilised on Åsgard B before it is exported from the field together with Åsgard's own condensate. The rich gas is piped through the Åsgard Transport pipeline to Kårstø for separation of the wet gas components. The dry gas is transported on from Kårstø to the Continent through the Europipe II pipeline.



Njord

Blocks and production licences	Block 6407/10 - production licence 132. Awarded 1987. Block 6407/7 - production licence 107. Awarded 1985.
Discovered	1986
Development approval	12.06.1995 by Parliament
On stream	30.09.1997
Operator	Norsk Hydro Produksjon AS
Licensees in Njord	E.ON Ruhrgas Norge AS 15.00% 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% Paladin Resources Norge AS 15.00% Petoro AS 7.50%
Recoverable reserves	**Original:** / **Remaining as at 31.12.2004** 25.6 million scm oil / 7.8 million scm oil 8.7 billion scm gas / 8.7 billion scm gas 1.4 million tonnes NGL / 1.4 million tonnes NGL
Production	**Estimated production in 2005:** Oil: 31,000 barrels/day
Investment	Total investment is likely to be NOK 12.5 billion NOK 10.8 billion had been invested as at 31.12.04 (2005 values)
Operating organisation	Kristiansund
Main supply base	Kristiansund

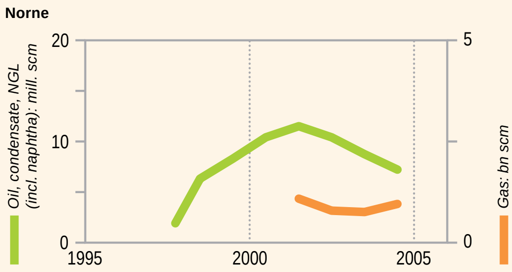
Development:
Njord is an oil field that is located around 30 km west of Draugen in 330 metres of water, which has been developed with a steel semi-submersible drilling, accommodation and production facility. The facility is located over the field's subsea completed wells, which are tied back to the facility through flexible risers. The Plan for Development and Operation (PDO) for the Njord field was approved on 12.06.1995. The PDO and Plan for Installation and Operation (PIO) for Njord gas export were submitted to the authorities on 15.11.2004.

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 that is produced at Nord is reinjected on the east flank for pressure support and increased oil recovery from this part of the field. The western and northern segments produce using depletion.

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

Status:
Production from Njord is in the decline phase. At the end of 2004, a new drilling and intervention campaign to increase oil recovery was initiated. Gas export is planned to begin on 01.10.2007.



Norne

Blocks and production licences	Block 6508/1 - production licence 128 B. Awarded 1998.	
	Block 6608/10 - production licence 128. Awarded 1986.	
Discovered	1992	
Development approval	09.03.1995 by Parliament	
On stream	06.11.1997	
Operator	Statoil ASA	
Licensees in Norne	Eni Norge AS	6.90%
	Enterprise Oil Norge AS	6.00%
	Norsk Hydro Produksjon AS	8.10%
	Petoro AS	54.00%
	Statoil ASA	25.00%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	88.5 million scm oil	25.9 million scm oil
	13.8 billion scm gas	10.2 billion scm gas
	2.5 million tonnes NGL	2.1 million tonnes NGL
Production	**Estimated production in 2005:**	
	Oil: 100,000 barrels/day Gas: 1.21 billion scm NGL: 0.15 million tonnes	
Investment	Total investment is likely to be NOK 19.5 billion	
	NOK 16.4 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Harstad	
Main supply base	Sandnessjøen	

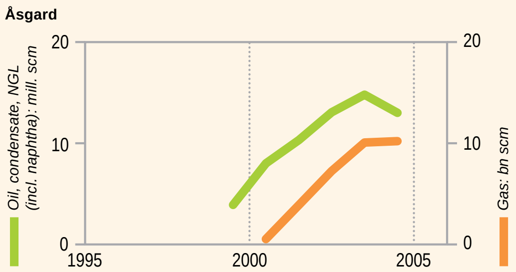
Development:
Norne is an oil field located around 80 km north of the Heidrun field and around 200 km from the Helgeland coast in about 380 metres of water. The field has been developed with a production and storage vessel tied back to five wellhead templates. Flexible risers carry the wellstream up to the vessel. The vessel carries processing facilities and tanks for oil storage before being transferred to shuttle tankers. The Norne vessel does not carry drilling and completion equipment.

Reservoir:
The Norne field consists of two separate segments. The oil and gas at Norne is contained in Jurassic sandstone in the Fangst and Båt groups. Oil is mainly found in the Ile and Tofte formations, gas in the Garn formation. The reservoir is 2,525 metres deep at its shallowest.

Recovery strategy:
The oil is recovered using water and gas injection.

Transport:
The oil is transferred to shuttle tankers for transport. Gas export started in February 2001 through a dedicated pipeline to Åsgard and on through the Åsgard Transport pipeline to Kårstø.

Status:
Around 70 percent of estimated reserves have now been produced, and production has fallen from plateau, mainly because of increased water production. Various measures to increase recovery have been implemented, including Microbial Enhanced Oil Recovery (MEOR). The potential for further increases in recovery will lie in strategies such as efficient well solutions and optimum use of gas at the field.



Åsgard

Blocks and production licences	Block 6406/3 - production licence 094 B. Awarded 2002.	
	Block 6407/2 - production licence 074. Awarded 1982.	
	Block 6407/3 - production licence 237. Awarded 1998.	
	Block 6506/11 - production licence 134. Awarded 1987.	
	Block 6506/12 - production licence 094. Awarded 1984.	
	Block 6507/11 - production licence 062. Awarded 1981.	
Discovered	1981	
Development approval	14.06.1996 by Parliament	
On stream	19.05.1999	
Operator	Statoil ASA	
Licensees in Åsgard	Eni Norge AS	14.90%
	Mobil Development Norway AS	7.35%
	Norsk Hydro Produksjon AS	9.60%
	Petoro AS	35.50%
	Statoil ASA	25.00%
	Total E&P Norge AS	7.65%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	73.6 million scm oil	32.7 million scm oil
	195.3 billion scm gas	163.4 billion scm gas
	38.3 million tonnes NGL	33.0 million tonnes NGL
	46.2 million scm condensate	34.7 million scm condensate
Production	**Estimated production in 2005:**	
	Oil: 102,000 barrels/day Gas: 10.84 billion NGL: 2.0 million tonnes	
	Condensate: 4.06 million scm	
Investment	Total investment is likely to be NOK 59.1 billion	
	NOK 55.7 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stjørdal	
Main supply base	Kristiansund	

Development:
Åsgard is in 240 – 300 metres of water and has been developed with subsea completed wells linked to a production and storage vessel, FPSO (Åsgard A), for production and storage of oil, and a floating, semi-submersible facility (Åsgard B) for gas and condensate processing. The gas centre is tied back to a storage vessel for condensate (Åsgard C). The Åsgard facilities are an important part of the Norwegian Sea infrastructure. In addition to processing their own production, the facilities process gas from Mikkel. The Åsgard field has been developed in two phases. The fluids phase came on stream on 19.05.1999 and the gas export phase from 01.10.2000. The field includes the discoveries 6506/12-1 Smørbukk, 6506/12-3 Smørbukk Sør and 6507/11-1 Midgard.

Reservoir:
6506/12-1 Smørbukk is located on 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 Jurassic and contain gas, condensate and oil with a relatively high gas/oil ratio. The reservoir is at depths down to 4,850 m. 6506/12-3 Smørbukk Sør, with reservoir rocks in the Garn, Ile and Tilje formations, is from the Early to Mid-Jurassic period and contains oil, gas and condensate. The petroleum trap in 6507/11-1 Midgard is a standing fault block (horst). The Midgard discovery is divided into four structural segments with the main reservoir in the Mid-Jurassic Garn and Ile formations.

Recovery strategy:
Recovery from 6506/12-1 Smørbukk and 6506/12-3 Smørbukk Sør uses gas injection. 6507/11-1 Midgard uses depletion. There is a thin oil zone (11.5 m) below the gas cap at 6507/11-1 Midgard, which is not commercially viable to produce.

Transport:
Oil and condensate are temporarily stored at the field and shipped to the mainland by shuttle tankers. The gas is exported through a gas pipeline (Åsgard Transport) from Åsgard to Kårstø.

Status:
Most of the production wells have been drilled, and active efforts are being made to increase recovery from the field.

Fields which have ceased production

The following fields had ceased to produce at 31 December 2004:

Albuskjell

Block	1/6 and 2/4
Development approval	25.04.1975
Cessation plan/Decommissioning	The cessation plan was approved by Royal Decree on 21 December 2001, and in Report no. 47 (1999–2000) to the Parliament
On stream	26.05.1979
Production ceased	26.08.1998
Total production over field lifetime	Oil: 7.4 million scm Gas: 15.5 billion scm NGL: 1.0 million tonnes

Cod

Block	7/11
Development approval	04.05.1973
Cessation plan/Decommissioning	The cessation plan was approved by Royal Decree on 21 December 2001, and in Report no. 47 (1999–2000) to the Parliament
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

Edda

Block	2/7
Development approval	25.04.1975
Cessation plan/Decommissioning	The cessation plan was approved by Royal Decree on 21 December 2001, and in Report no. 47 (1999–2000) to the Parliament
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

Frigg

Block	25/1
Development approval	13.06.1974
Cessation plan/Decommissioning	The cessation plan was approved by Royal Decree on 26 September 2003, and in Parliamentary Bill 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

Frøy

Block	25/2 and 25/5
Development approval	18.05.1992
Cessation plan/Decommissioning	The cessation plan was approved by Royal Decree on 29 May 2001, and in Report no. 47 (1999–2000) to the Parliament
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

Lille-Frigg

Block	25/2
Development approval	06.09.1991
Cessation plan/Decommissioning	Parliamentary Bill no. 53 (1999–2000) and Report no. 47 (1999-2000) to the Parliament
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

Mime

Block	7/11
Development approval	06.11.1992
Cessation plan/Decommissioning	Parliamentary Bill no. 15 (1996–1997) and Report no. 47 (1999–2000) to the Parliament
On stream	25.10.1990
Production ceased	04.11.1993
Total production over field lifetime	Oil: 0.4 million scm Gas: 0.1 billion scm

Nordøst Frigg

Block	25/1 and 30/10
Development approval	12.09.1980
Cessation plan/Decommissioning	Parliamentary Bill no. 36 (1994–1995)
On stream	01.12.1983
Production ceased	08.05.1993
Total production over field lifetime	Gas: 11.6 billion scm

Odin

Block	30/10
Development approval	18.07.1980
Cessation plan/Decommissioning	Parliamentary Bill no. 50 (1995–1996) and Report no. 47 (1999–2000) to the Parliament
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

Tommeliten Gamma

Block	1/9
Development approval	12.06.1986
Cessation plan/Decommissioning	Parliamentary Bill no. 53 (1999–2000) and Report no. 47 (1999–2000) to the Parliament
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: 0.6 million tonnes

Vest Ekofisk

Block	2/4
Development approval	04.05.1973
Cessation plan/Decommissioning	The cessation plan was approved by Royal Decree on 21 December 2001, and Report no. 47 (1999-2000) to the Parliament
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

Yme

Block	9/2 and 9/5
Development approval	06.01.1995
Cessation plan/Decommissioning	The cessation plan was approved by Royal Decree on 4 May 2001.
On stream	27.02.1996
Production ceased	17.04.2001
Total production over field lifetime	Oil: 7.9 million scm

Øst Frigg

Block	25/1 and 25/2
Development approval	14.12.1984
Cessation plan/Decommissioning	Parliamentary Bill no. 8 (1998–1999) and Report no. 47 (1999–2000) to the Parliament
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

11 Fields under development

Approved projects in existing fields are described in Chapter 10

Alvheim

Blocks and production licences	Block 24/6 - production licence 088 BS. Awarded 2003.	
	Block 24/6 - production licence 203. Awarded 1996.	
	Block 25/4 - production licence 036 C. Awarded 2003.	
	Block 25/4 - production licence 203. Awarded 1996.	
Discovered	1998	
Development approval	06.10.2004 by the King in Council of State	
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:**	
	23.5 mill. scm oil	
	5.7 bn scm gas	
Investment	Total investment is likely to be NOK 8.4 bn	
	NOK 0.7 bn had been invested at 31.12.04 (2005 values)	

Development: Alvheim is an oil and gas field comprising the three discoveries 24/6-2, 24/6-4 and 25/4-7. The sea in the area is 120-130 metres deep. The field will be developed using a production ship and subsea wells. The oil will be stabilised and stored for export in the production ship. The development of Alvheim was approved by a Royal Decree of 06.10.2004.

Reservoir: The Alvheim reservoir consists of sandstone laid down as turbidites from the Shetland Platform in the Early Tertiary.

Recovery strategy: Alvheim is planned to be recovered using natural waterdrive.

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

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

Kristin

Blocks and production licences	Block 6406/2 - production licence 199. Awarded 1993. Block 6506/11 - production licence 134 B. Awarded 2000.	
Discovered	1997	
Development approval	17.12.2001 in the Parliament	
Operator	Statoil ASA	
Licensees in Kristin	Eni Norge AS	9.00%
	Mobil Development Norway AS	10.50%
	Norsk Hydro Produksjon AS	14.00%
	Petoro AS	18.90%
	Statoil ASA	41.60%
	Total E&P Norge AS	6.00%
Recoverable reserves	**Original:** 29.9 million scm oil 33.0 billion scm gas 6.9 million tonnes NGL	
Investment	Total investment is likely to be NOK 21.1 bn NOK 15.2 billion had been invested at 31.12.04 (2005 values)	

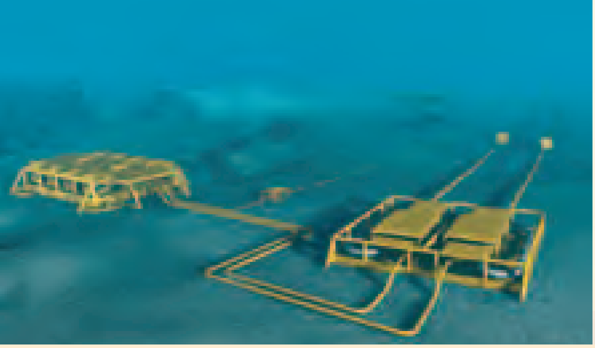
Development: Kristin is a gas field, to be developed using a subsea production facility with well stream transfer to a semi-submersible production facility for processing.

Reservoir: The reservoirs are in Middle Jurassic sandstone and lie some 4,600 metres deep. The two reservoirs are in the Garn and Ile formations and contain gas and condensate at very high pressure and temperature. There may also be recoverable resources in the Tofte formation.

Recovery strategy: Recovery will be assisted by depletion owing to the high pressure and low dewpoint.

Transport: Rich gas from Kristin will be transported in a separate pipeline to Åsgard Transport. The gas will be sent on to the Kårstø installation, where ethane and NGL will be extracted. Sales gas will be transported onwards to the Continent. Light oil will be separated and stabilised at Kristin and transferred to a storage ship tied back to an Åsgard C loading buoy for storage and export.

Status: The progress of drilling and completion has been slower than predicted. Estimates of recoverable resources in the Garn formation have been reduced because of predicted poorer reservoir characteristics. There are proven recoverable resources in the Tofte formation. Kristin is expected to go off plateau early, and it is therefore pertinent to arrange for processing of production from other discoveries in the area.



Ormen Lange

Blocks and production licences	Block 6305/4 - production licence 209. Awarded 1996.	
	Block 6305/5 - production licence 209. Awarded 1996.	
	Block 6305/7 - production licence 208. Awarded 1996.	
	Block 6305/8 - production licence 250. Awarded 1999.	
Discovered	1997	
Development approval	02.04.2004 in the Parliament	
Operator	Norsk Hydro Produksjon AS	
Licensees for Ormen Lange	A/S Norske Shell	17.04%
	DONG Norge AS	10.34%
	ExxonMobil Exploration and Production Norway AS	7.23%
	Norsk Hydro Produksjon AS	18.07%
	Petoro AS	36.48%
	Statoil ASA	10.84%
Recoverable reserves	**Original:**	
	375.2 billion scm gas	
	22.1 million scm condensate	
Investment	Total investment is likely to be NOK 31.8 bn	
	NOK 1.8 billion had been invested at 31.12.04 (2005 values)	

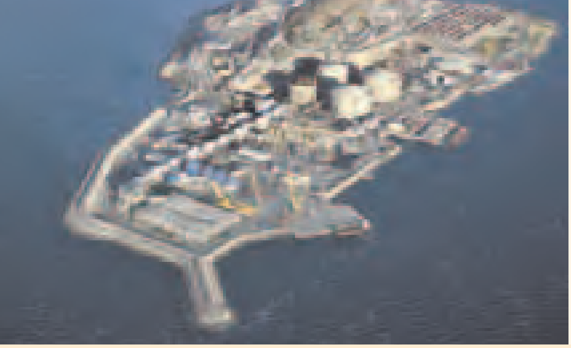
Development: Ormen Lange is planned to be developed using 24 wells drilled from four subsea templates. Water depth in the area where the installations are planned to be located varies from 800 to 1,100 metres. Six predrilled production wells will be ready for production start-up on 01.10,2007. Ormen Lange lies in the Møre basin in the southern part of the Norwegian Sea, approximately 130 km west of Kristiansund. The field contains gas and some condensate. The development area is in the Storegga slide depression, formed some 8,200 years ago.

Reservoir: The main reservoir is in sandstone rocks of the Early Tertiary, about 2,700-2,900 metres deep.

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

Transport: The unprocessed well stream, consisting of gas and condensate, will be piped through two 30” multi-phase pipelines to a land installation at Nyhamna in the municipality of Aukra in Møre og Romsdal county. At the plant at Nyhamna, the gas will be dried and compressed before being transported through a 42” gas export pipe, Langeled, south to Sleipner and onward to the UK.

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



Snøhvit

Blocks and production licences	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 in the Parliament
Operator	Statoil ASA

Licensees in Snøhvit	Amerada Hess Norge AS	3.26%
	Gaz de France Norge AS	12.00%
	Petoro AS	30.00%
	RWE Dea Norge AS	2.81%
	Statoil ASA	33.53%
	Total E&P Norge AS	18.40%

Recoverable reserves	**Original:**
	160.2 billion scm gas
	5.1 million tonnes NGL
	17.9 million scm condensate
Investment	Total investment is likely to be NOK 18.9 bn
	NOK 3.8 billion had been invested at 31.12.04 (2005 values)

Development: Snøhvit is a gas field with condensate and an underlying oil zone. Snøhvit lies in the central section of the Hammerfest basin. The production facility will consist of subsea templates for 19 production wells and a CO_2 injection well. The facility will be positioned on the sea-bed at a depth of between 250 and 345 metres.

Reservoir: The Snøhvit area consists of seven structures containing gas, condensate and oil, in sandstone from the Early and Mid-Jurassic periods.

Recovery strategy: Recovery will be by depletion. The development does not include recovery of the oil zone. The CO_2 content of the gas will be removed at the plant at Melkøya and sent back to the field for injection into a formation below the oil and gas.

Transport: The unprocessed well stream, comprising natural gas incorporating CO_2, NGL and condensate, will be transported through a 160 km long pipe to the Melkøya plant for processing and export. At Melkøya the gas will be processed and cooled to liquefy it (LNG). Transport to the market will be by special ship.

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 of State	
Operator	Statoil ASA	
Licensees	Eni Norge AS	11.50%
	Enterprise Oil Norge AS	10.00%
	Norsk Hydro Produksjon AS	13.50%
	Petoro AS	24.55%
	Statoil ASA	40.45%
Recoverable reserves	Original:	
	10.4 mill. scm oil	
	0.1 billion scm gas	
Investment	Total investment is likely to be NOK 3.5 bn	
	NOK 1.1 billion had been invested at 31.12.04 (2005 values)	

Development: Urd consists of the discoveries 6608/10-6 Svale and 6608/10-8 Stær situated respectively some 5 and 10 km north-east of the Norne production ship. They will be developed using well templates tied back to the Norne ship. Five oil producers and three water injectors are planned in all. The production wells will use gas lift. On the well templates, there will be vacant slots for extra wells or for phasing in additional resources. Planned production start-up is 1.10.2005 and production is predicted to last until 2016.

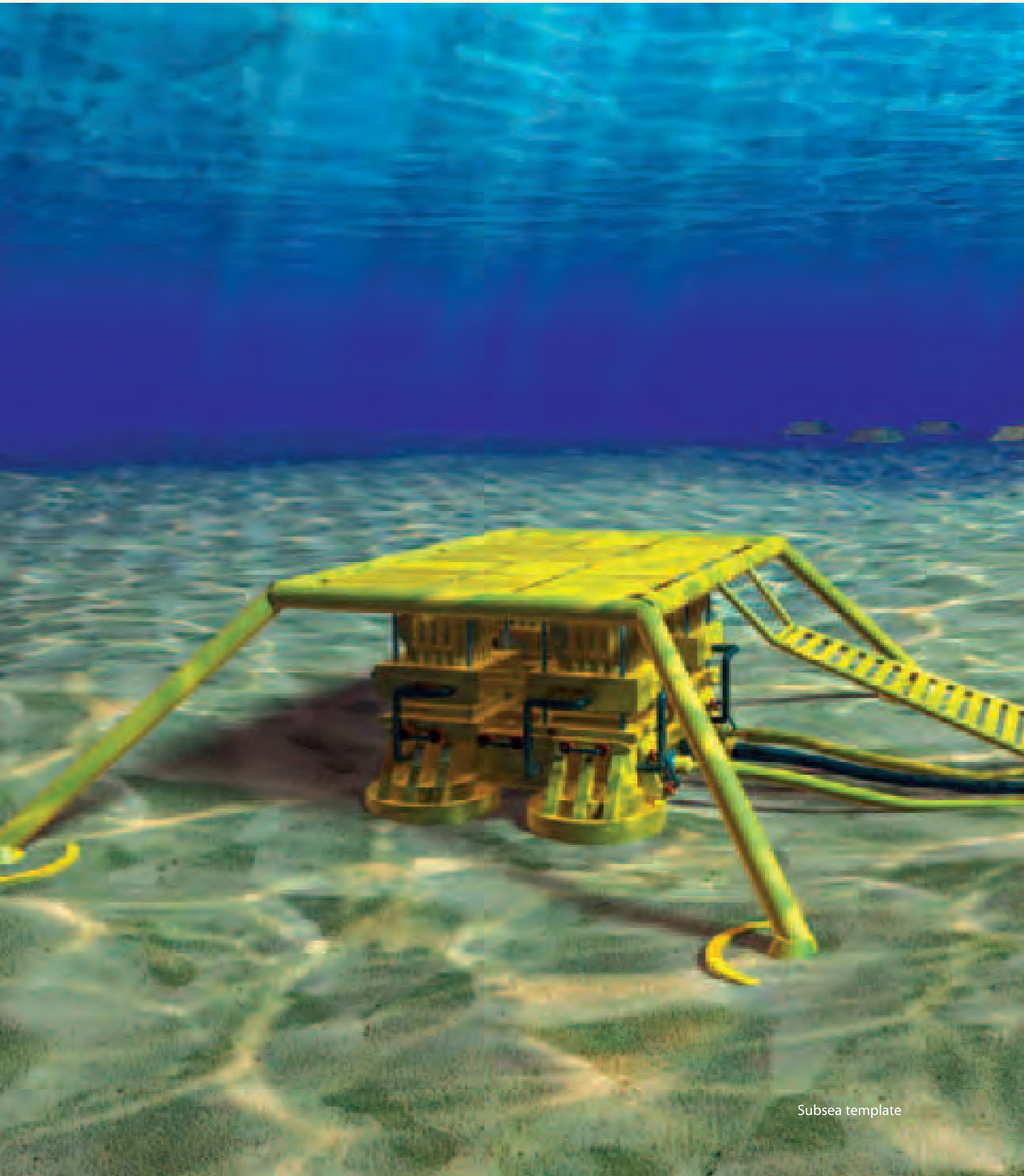
Transport: On the Norne ship, the well stream will be processed and oil/condensate will be stabilised and loaded via buoys along with other oil/condensate from the Norne field. Rich gas will be exported along with gas from the Norne field in Åsgard Transport for further processing at Kårstø.

Reservoir: The discoveries lie in rotated fault blocks in the northern section of the Dønna terrace. The reservoirs are from the Early to Mid-Jurassic periods and consist of sandstones in the Åre, Tilje and Ile formations.

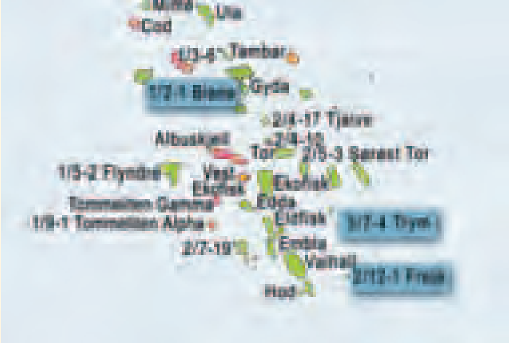
Recovery strategy: Both Svale and Stær are lacking gas caps and both will be produced using seawater injection for pressure maintenance. Oil in the Svale discovery is relatively heavy and the production is especially sensitive to the volume of water injected into the reservoir.

Status: The subsea installations will be put in place before production start-up on 01.10.2005. Five of the eight planned wells will be drilled and completed before production start-up, while the last three will be completed during the first quarter of 2006.

12 Future developments



Subsea template



Discoveries in the planning phase

Excludes discoveries included under new resources in existing fields.

1/2-1 Blane	Production licence 143 BS, Operator: Paladin Resources Norge AS
Resources	Oil: 0.8 million scm Gas: 0.1 billion scm

1/2-1 Blane lies on the boundary between the UK and Norwegian sectors and contains oil. The reservoir is in marine sandstone of the Paleogene period. On the basis of mapping and reservoir studies, it is anticipated that the majority of the resources lie on the UK side of the boundary.

PDO is expected in the spring of 2005. Development will be based on a well head facility with two production wells and one water injection well with a pipeline to the Ula field.

2/12-1 Freja	Production licence 113, Operator: Amerada Hess Norge AS
Resources	Oil: 2.9 million scm Gas: 0.6 billion scm

2/12-1 Freja lies near the boundary between the Danish and Norwegian sectors and contains oil and associated gas. The reservoir is in Late Jurassic sandstone at a depth of some 4,900 metres. 2/12-1 lies in a complex fault region between the Feda graben in the west and the Gertrud graben in the east. The reservoir is presumed to be divided into separate fault blocks. Oil has also been proven in a deposit named Gert on the Danish side of the dividing line.

2/12-1 was declared commercially viable in June 1992. It is most likely that the discovery will be assigned a straightforward development solution based on the use of existing infrastructure in the area.

3/7-4 Trym	Production licence 147, Operator: A/S Norske Shell
Resources	Gas: 3.3 billion scm Condensate: 0.8 million scm

3/7-4 Trym lies near the boundary between the Danish and Norwegian sectors and contains gas and condensate. The reservoir lies in Late and Mid-Jurassic sandstone, in the same salt-induced structure as the Danish Lulita field. It is presumed to be separate from a fault zone on the north side of the dividing line, but there may be pressure communication in the water zone.

It is most likely that the discovery will be assigned a straightforward development solution based on the use of existing infrastructure in the Danish sector. PDO is expected to be submitted to the authorities during 2005.

15/3-1 S Gudrun	Production licence 025, 187, Operator: Statoil ASA
Resources	Oil: 15.2 million scm Gas: 8.4 billion scm NGL: 5.4 million tonnes

15/3-1 Gudrun lies 13 km east of the boundary between the UK and Norwegian sectors and about 50 km north of the Sleipner area and contains both oil and gas. The reservoir is in Late Jurassic sandstone at a depth of some 4,000-4,500 metres. Development will be based on subsea installations tied back through a transport solution to existing infrastructure.

15/5-1 Dagny	Production licence 029, 048, Operator: Statoil ASA
Resources	Gas: 3.8 billion scm NGL: 0.2 million tonnes Condensate: 1.2 million scm

15/5-1 Dagny lies due north-west of the main Sleipner Vest structure and is a small discovery containing gas and condensate; it is divided into two production licences, 048 and 029. The reservoirs consist of Mid-Jurassic sandstone in the Hugin formation.

Development will most likely be based on a subsea facility tied back to existing infrastructure at Sleipner A or to Sleipner T via Alfa Nord. 15/5-1 Dagny may come on stream during 2008-2010 when there is available capacity on the Sleipner field.

15/9-19 S Volve	Production licence 046, Operator: Statoil ASA
Resources	Oil: 11.0 million scm Gas: 1.2 billion scm NGL: 0.2 million tonnes Condensate: 0.1 million scm

15/9-19 Volve lies approx. 8 km north of the Sleipner A facility on Sleipner Øst and approx. 3 km west of Loke. The reservoir is in a combined stratigraphic and structural fault and consists of Jurassic/Triassic rock in the Hugin formation in the Theta Vest structure. The reservoir contains oil. The western section of the structure is heavily faulted and there is uncertainty about communication between the faults. Around 80 percent of the oil present has however been mapped in the eastern section of the structure, where there is less uncertainty about interpretation.

The development concept consists of a jack-up processing and drilling facility and a ship to store stabilised oil. Rich gas will be transported to Sleipner A for onward export. A PDO was submitted to the authorities in February 2005.

15/12-12	Production licence 038, Operator: Pertra AS
Resources	Gas: 4.3 billion scm Condensate: 1.4 million scm

The 15/12-12 discovery lies in the southern North Sea near the boundary between the Norwegian and UK sectors. It lies around a salt structure. The reservoir consists of Late Jurassic sandstone and has a gas-capped oil zone. It has been divided by the operator into three zones, the first two of which have good reservoir characteristics. The top of the reservoir lies at a depth of approx. 2,823 metres. Pressure measurements on 15/12-12 show that it is in pressure communication with the Varg field.

The operator is working on plans to develop the discovery.

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 lies approx. 8 km east of the Heimdal field and the water depth here is some 120 metres. The reservoir is in sandstone of Paleocene age, laid down as turbidite flows from the west. It is about 2,130 metres below sea level. The discovery well proved an oil column of 18 metres.

The discovery is located near existing infrastructure in an area with a number of small new discoveries. Potential development is being assessed, but there are no concrete plans as yet.

25/11-16	Production licence 169, Operator: Norsk Hydro Produksjon AS
Resources	Oil: 3.6 million scm

The 25/11-16 discovery lies due west of the Grane field and contains oil and associated gas. The reservoir is in Paleocene sandstone in the Heimdal formation at a depth of some 1,750 metres. It is in an area with a series of sand structures that are part of a submarine fan system.

There are a number of options available for development, the most likely of which is a subsea tie-back to Grane, or possible long-range wells from Grane.

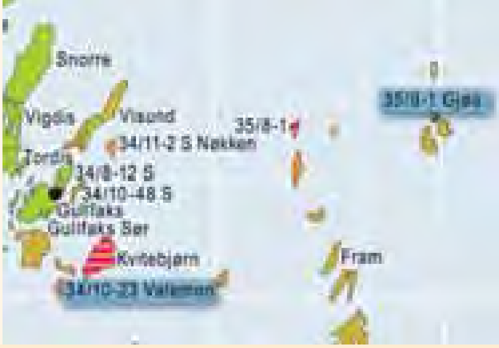
30/6-17	Production licence 053, Operator: Norsk Hydro Produksjon AS
Resources	Gas: 1.5 billion scm

30/6-17 is a small oil and gas discovery in the Oseberg area. The reservoir is in Early Jurassic sandstone of the Cook formation and lies below the main reservoir in the Oseberg field at a depth of 2,200 metres. It contains mainly gas, with a thin oil zone.

A likely development will be using a long-range production well at about 9,500 metres from Oseberg B. Because of planned continuous drilling from Oseberg B to well targets in the Oseberg field, drilling of a production well for the 30/6-17 discovery will probably not take place before 2007.

30/9-19	Production licence 079, 190, Operator: Norsk Hydro Produksjon AS
Resources	Oil: 2.3 million scm Gas: 5.9 billion scm

The 30/9-19 discovery was proven in 1998. The discovery has a 14 metre thick oil column with a gas cap in the delta structure in the Oseberg field. The reservoir is at a depth of 3,200 metres and consists of Mid-Jurassic sandstones (the Tarbert and Ness formations). The PDO for the 30/9-19 discovery is under preparation and is planned to be submitted to the authorities in July 2005.



34/10-23 Valemon	Production licence 050, 193, Operator: Statoil ASA
Resources	Gas: 18.1 billion scm NGL: 0.8 million tonnes Condensate: 5.6 million scm

34/10-23 Valemon lies in blocks 34/11 and 34/10. Four exploration wells have been drilled, three of them proving gas. The discovery has of a complex structure with many faults. The reservoirs are in Mid-Jurassic sandstone in the Brent group and Cook formation. They are some 4,000 metres deep, and at high temperature and pressure.

The plan is to drill an appraisal well in 34/10-23 Valemon from Kvitebjørn in 2005. The discovery is planned to be developed using a subsea template tied back to existing infrastructure, with Kvitebjørn being the most likely tie-back point. The use of long-range production wells from Kvitebjørn will also be assessed.

35/9-1 Gjøa	Production licence 153, Operator: Statoil ASA
Resources	Oil: 7.1 million scm Gas: 30.4 billion scm Condensate: 1.4 million scm

35/9-1 Gjøa was proven in 1989 and lies about 42 km north of the Fram field. The area, consisting of several segments with some uncertain communication, contains a reservoir in sandstone in the Fensfjord formation. The discovery contains gas with a relatively thin oil zone.

Statoil is the operator in the development phase, while Gaz de France will take over operating responsibility when the field comes on stream. A number of different development options have been evaluated, including a production ship (FPSO), fixed facilities and subsea development. The choice of concept will be made in the spring of 2005. The PDO is planned to be submitted to the authorities at year-end 2005.

6407/1-2 Tyrihans Sør	Production licence 073, 091, Operator: Statoil ASA
Resources	Oil: 24.7 million scm Gas: 32.6 billion scm NGL: 5.8 million tonnes

6407/1-2 Tyrihans Sør also includes 6407/1-3 Tyrihans Nord. The two discoveries were proven in 1982 and 1983 respectively and lie approx. 25 km south-east of the Åsgard field. In addition to the wildcat wells, an appraisal well was drilled in each of the two discoveries. 6407/1-2 Tyrihans Sør has an oil column with a condensate-rich gas cap. 6407/1-3 Tyrihans Nord contains gas condensate with an underlying oil column. The main reservoir for both discoveries is the Garn formation.

The licensees have opted for a subsea tie-back with processing at Kristin. The PDO will probably be submitted to the authorities in the summer of 2005. Recovery will be based on gas injection from Åsgard B into 6407/1-2 Tyrihans Sør in the initial years. Underwater pumps will also be used for the injection of seawater to further increase recovery. The licensees have also evaluated other measures to improve fluid recovery, such as an extended period of gas injection and recovery of the oil zone in 6407/1-3 Tyrihans Nord.

In 2004, the licensees made investments in advance in the Kristin facilities, now under construction, to reduce the extent of work at sea on the Kristin field.

6507/3-3 Idun	Production licence 159, Operator: Statoil ASA
Resources	Gas: 13.2 billion scm NGL: 0.9 million tonnes Condensate: 0.3 million scm

6507/3-3 Idun lies between Heidrun and Norne in a faulted area of the Dønna terrace in the Nordland II area. The discovery contains gas. The reservoir consists of Mid-Jurassic sandstones. The top of the reservoir lies at a depth of about 3,330 metres.

Work is being done on various development options for the discoveries in the area. At present, a subsea facility with tie-back to a future field centre at 6507/5-1 Skarv is the most likely. A decision on developing the discoveries in the area and the choice of development concept may be made in 2005.

6507/5-1 Skarv	Production licence 159, 212, 212 B, 262, Operator: BP Norge AS
Resources	Oil: 14.1 million scm Gas: 38.4 billion scm NGL: 6.1 million tonnes Condensate: 3.9 million scm

6507/5-1 Skarv was proven in 1998 and contains oil and gas in Jurassic and Cretaceous sandstone in three fault segments. The discovery lies about 200 km off the Helgeland coast, mainly in production licence 212, but also in 262 and 159, and is in about 400 metres of water.

Skarv is seen as a potential field centre for oil recovery and gas export through a tie-back to existing infrastructure. It is assumed that development will be based on a stand-alone development concept. Both a production ship and a semi-submersible production facility are under evaluation. Development and the timing of a production start-up depend on finding an export solution for the gas.

7122/7-1 Goliat	Production licence 229, Operator: Eni Norge AS
Resources	Oil: 6.9 million scm

The 7122/7-1 Goliat oil discovery lies between the Snøhvit field and Hammerfest. The reservoir is sandstone from the Late Triassic to Mid-Jurassic ages and lies about 1,100 metres below sea level. The discovery consists of a series of structural segments lying up against the Troms-Finnmark fault.

Drilling is planned during 2005 to ascertain whether the discovery can be developed.

Discoveries decided by the licensees

25/4-9 S Vilje	Production licence 036, Operator: Norsk Hydro Produksjon AS
Resources	Oil: 8.9 million scm

25/4-9 S Vilje lies about 11 km NNE of the Heimdal field and 5 km south-west of Vale. The sea in the area is 120 metres deep. The reservoir consists of turbidite sandstone of Paleocene (Early Tertiary) age at around 2,150 metres below sea level. The discovery well proved an approx. 65 metres oil column in sand from the Heimdal subsection of the Lista formation.

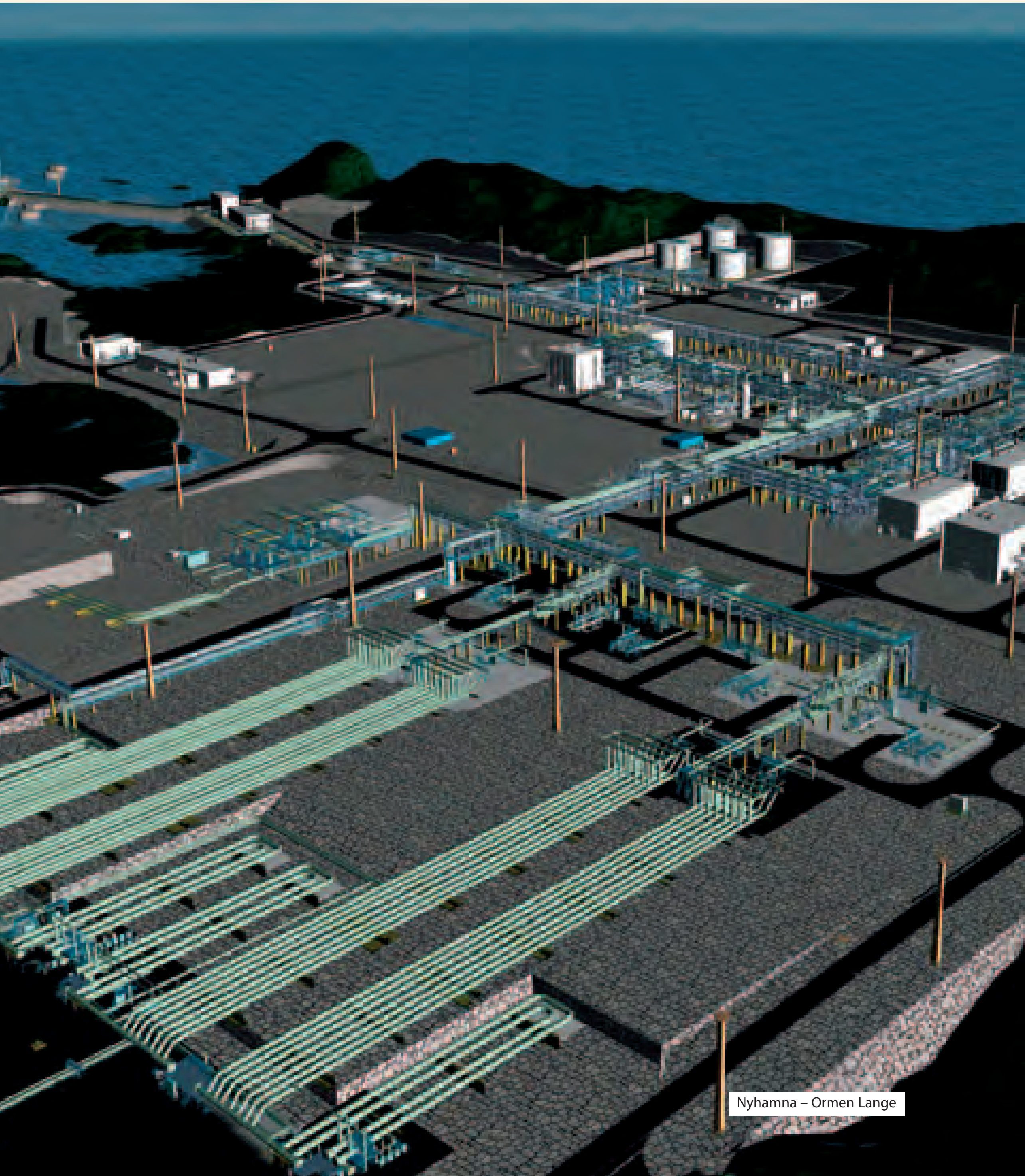
Norsk Hydro Produksjon AS submitted a PDO for Vilje on behalf of the licensees on 23.12.2004 and the plan was approved 18.03.2005. Vilje is planned to be developed using two subsea wells tied to the Alvheim FPSO when in place. Recovery of the resources will be by natural waterdrive. Production start-up is planned for February 2007.

33/12-8 A Skinfaks	Production licence 152, Operator: Statoil ASA
Resources	Oil: 3.0 million scm Gas: 1.5 billion scm NGL: 0.3 million tonnes Condensate: 0.2 million scm

33/12-8 Skinfaks is located in the Gullfaks area, and contains gas in the upper section of the reservoir, with oil in the lower. The reservoir is sandstone in the Mid-Jurassic Brent group and the Early Jurassic Statfjord formation. The Skinfaks discovery consists of several reservoirs in separate, rotated fault blocks. The Brent reservoir is approx. 2,800 metres deep and the Statfjord reservoir is approx. 3,300 metres deep.
The PDO for development was submitted to the authorities in December 2004. The plan is to develop Skinfaks using a subsea template and a satellite well, and with pipelines to Gullfaks Sør for onward transport in an existing pipe to Gullfaks C. The development will be coordinated with additional development of Rimfaks and Gullfaks Sør. Skinfaks will be included in Gullfaks Sør. Production start-up is planned for 2007.

The PDO for Skinfaks was approved by the King in Council of State on 11.02.2005.

13 Pipelines, land facilities and other infrastructure



Nyhamna – Ormen Lange

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

The map shows existing and planned pipelines

Gassled pipelines
Operator: Gassco AS

Licensees:	
Petoro AS[1]	38.29%
Statoil ASA	20.38%
Norsk Hydro Produksjon AS	11.13%
Total E&P Norge AS	9.04%
ExxonMobil Exploration and Production Norway AS	5.18%
Norske Shell Pipelines AS	4.68%
Mobil Development Norway AS	4.58%
Norsea Gas AS	3.02%
Norske ConocoPhillips AS	2.03%
Eni Norge AS	1.67%

[1] In autumn 2005, the completion of the Kårstø gas processing complex extension will lead to a change in the ownership shares. Petoro's holding in Gassled will be increased by around 9.5 percent with effect from 1 January 2011, and the other parties' holdings will be reduced proportionally with effect from the same date.

The Parliament requested in the spring of 2001 that the MPE invite the relevant companies to negotiations on the creation of a unified ownership structure for gas transport. Gassled represents the merger of companies owning nine pipelines between them into a single partnership. The partnership agreement establishing Gassled 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: Zeepipe, Europipe I and II, Franpipe, Statpipe (including the transport-related facilities at Kårstø), Vesterled, Oseberg Gas Transport, Åsgard Transport and Norpipe. The Kollsnes gas processing facility also became part of Gassled on 1 February 2004. Gassled is organised into various zones for access and tariffs. For more detailed information on Gassled and the organisation of Norwegian gas transport operations, see the www.gassco.no web site. Gassco, which serves as operator for Gassled and certain other pipelines, is based at Bygnes in the municipality of Karmøy in Rogaland. From here, it coordinates gas deliveries through the pipeline network from fields in the North and Norwegian Seas to land facilities in Norway and receiving terminals in continental Europe and the UK. Gassco coordinates and controls the flow of gas through a network about 6,600 kilometres long, and manages all transport of Norwegian gas to market. The following presentation describes the pipelines owned by Gassled and operated by Gassco.

Europipe I
This 40-inch pipeline starts at the Draupner E riser facility and runs for 660 km to terminate at Emden in Germany. Europipe I came into service in 1995. It has a capacity of about 46-54 mill. scm/day, depending on operating mode. The pipeline has been built for an operating life of 50 years and total investment is put at NOK 20.7 billion (2005 value).

(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. See Proposition no. 60 (1992-93) and Recom. no. 164 (1992–93) to the Parliament.)

Europipe II

This 42-inch pipeline runs for 650 km from Kårstø to Dornum in Germany, and became operational in 1999. With a capacity of about 71 mill, scm/day, Europipe II has been built for an operating life of 50 years. Total investment at start-up is put at NOK 9.3 billion (2005 value).

(Supplementary agreement of 19 May 1999 to the Europipe agreement (see Proposition no. 60 (1992-93) and Recom. no. 164 (1992–93) to the Parliament) 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 km from the Draupner E riser platform in the North Sea to a receiving terminal at Dunkirk in France. A separate partnership has been established for the terminal, owned 65 per cent by the Gassled group and 35 per cent by Gaz de France. The pipeline became operational in 1998. Franpipe has a capacity of about 52 mill. scm/day. It has been built for an operating life of 50 years, with the total investment put at NOK 9.6 billion (2005 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 Proposition no. 44 (1996–97) and Recom. no. 164 (1996–97) to the Parliament.)

Norpipe Gas pipeline

This 36-inch line starts at Ekofisk and runs for 440 km 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 platforms, 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 around 35 mill. scm/day without using the compressor capacity on the B11 riser platform, and capacity will increase to 42–43 mill. scm/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 about NOK 25.6 billion (2005 value).

(Agreement between Norway and Germany concerning the transmission of petroleum through a pipeline from the Ekofisk field and adjacent areas to Germany. See Proposition no. 88 (1973-74) and Recom. no. 250 (1993–74) to the Parliament.)

Oseberg Gas Transport (OGT)

This 36-inch line starts at Oseberg and runs for roughly 109 km to the riser facility at Heimdal. Becoming operational in 2000, its capacity is about 40 mill. scm/day. OGT has been built for an operating life of 50 years, and total investment is NOK 1.84 billion (2005 value).

Statpipe

This 880-km pipeline system includes a riser facility and a gas processing plant at Kårstø. Becoming operational in 1985, the system's 30-inch rich gas leg begins at Statfjord and runs for 308 km to Kårstø, with a capacity of about 25 mill. scm/day. The dry gas section has three components. One of these comprises a 28-inch pipeline running for about 228 km from Kårstø to the Draupner S riser facility, with a capacity of roughly 20 mill. scm/day, depending on operating mode. The second component is a 36-inch pipeline running for about 155 km from the Heimdal riser facility to Draupner S, with a capacity of about 30 mill. scm/day. The third section is a 36-inch pipeline running for roughly 203 km from Draupner S to Ekofisk, with a capacity of about 30 mill. scm/day. The Heimdal-Draupner S and Kårstø-Draupner S pipelines can also be used for reversed flow. Total investment is put at NOK 44.4 billion (2005 value), excluding the gas processing plant at Kårstø.

Vesterled

This 32-inch pipeline runs for about 350 km from the Heimdal riser facility to St. Fergus in the UK and became operational in 1978. It has a capacity of about 36 mill. scm/day. Total investment in Vesterled is put at NOK 31.4 billion (2005 value).

(Agreement between Norway and the UK concerning amendments to the Frigg treaty of 10 May 1976. See Proposition no. 73 (1998–99) and Recom. no. 219 (1998–99) to the Parliament.)

Zeepipe

Zeepipe I comprises a 40-inch pipeline running for about 814 km from Sleipner riser to Zeebrugge in Belgium. The gas receiving terminal in Zeebrugge belongs to a separate partnership, with the Gassled partners holding 49 per cent and the Belgian Fluxys company 51 per cent. Zeepipe I became operational in 1993 and has a capacity of roughly 41 mill. scm/day. Zeepipe I also includes a 30-inch pipeline between Sleipner and Draupner S with a capacity of 29 mill. scm/day. Zeepipe II A starts at the Kollsnes gas processing plant near Bergen and runs for about 303 km to the Sleipner riser platform. This 40-inch line became operational in 1996 and has a capacity of 57 mill. scm/day. Work has begun to increase capacity in Zeepipe II A to 72 mill. scm/day and to 71 mill. scm/day in Zeepipe II B. This capacity will become available from 1 October 2005 for Zeepipe II B and from 1 October 2006 for Zeepipe II A. Zeepipe II B is 40 inches in diameter and runs for roughly 300 km from the Kollsnes gas processing plant to the Draupner E. Becoming operational in 1997, this line has a capacity of 60 mill. scm/day. The Zeepipe system has been built for an operating life of 50 years. Total investment is put at NOK 23.5 billion (2005 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 Proposition no. 148 (1987–88) and Recom. no. 164 (1988–89) to the Parliament.)

Åsgard Transport

This 42-inch pipeline runs for about 707 km from the Åsgard field to terminate at Kårstø. It became operational in 2000, with a capacity of about 69 mill. scm/day. Åsgard Transport is built for an operating life of 50 years, with total investment at start-up of around NOK 10.2 billion (2005 value).

Gassled land facilities

Kollsnes gas processing plant

The gas processing plant at Kollsnes in the municipality of Øygarden in Hordaland County forms part of Gassled. Construction work began at the site in 1991 and was completed by 1 October 1996, the deadline for starting contractual gas deliveries from Troll. Wellstreams are separated at Kollsnes into gas and condensate. The gas is dried and compressed before being piped to continental Europe. The condensate is piped on to the Vestprosess facility at Mongstad. The facility has been extended with a plant for extraction of NGL from 1 October 2004 to receive gas from Kvitebjørn, and later Visund. The plant's capacity is now 146 mill. scm of gas and 11,000 scm of condensate per day.

Kårstø gas and condensate processing plant

The Kårstø gas processing facilities north of Stavanger separate and fractionate rich gas to methane, ethane, propane, iso-butane, normal butane and naphtha. Methane and some of the ethane is piped away. Unstabilised condensate delivered through a pipeline from Sleipner Øst is stabilised at Kårstø's condensate facility by separating out the lightest components. The rest of the ethane, as well as iso-butane and normal butane, is 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. The complex received 592 vessel calls in 2004 and shipped out more than 8 mill. tonnes of liquids.
Processing facilities at Kårstø comprise four fractionation/distillation lines for methane, ethane, propane, butanes and naphtha, plus a fractionation line for stabilising condensate. The gas processing facilities have a rich-gas capacity of 70 mill. scm per day, while the condensate and ethane plants can process roughly 5.5 mill. and 620,000 tonnes per year respectively. An expansion of the Kårstø gas processing facilities to 88 mill. scm/day has been initiated, and is due to become operational by 1 October 2005.

Other pipelines

Draugen Gas Export

Operator	A/S Norske Shell[1]	
Licensees	Petoro AS[2]	47.8%
	BP Norge AS	18.36%
	A/S Norske Shell	26.20%
	ChevronTexaco Norge AS	7.56%
Investment	Total investment at start-up around NOK 1 billion (2005 value)	
Operating lifetime	The technical operating lifetime is 50 years	
Capacity	About 2 billion scm/year	
Operating organisation	Kristiansund	

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

[2] Petoro's participation in Gassled will be increased by around 9.5 percent with effect from 1 January 2011, and the participation of the other parties will be reduced correspondingly with effect from the same date.

The plan for installation and operation of Draugen Gas Export was approved in April 2000. The 16-inch pipeline from the Draugen field to Åsgard Transport is 78 km long and provides opportunities for possible tie-ins of other fields in the area. The pipeline started up in November 2000.

Grane Gas Pipeline

Operator	Norsk Hydro Produksjon AS
Licensees	As for the Grane field
Investment	Total investment at start-up was around NOK 0.3 bn. (2005 value)
Operating lifetime	The technical operating life is 30 years
Capacity	Around NOK 3.6 billion scm per year

The plan for installation and operation of the Grane Gas Pipeline was approved in June 2000. This 18-inch pipeline from the Heimdal riser facility to the Grane facility is 50 km long and became operational in September 2003. It carries gas to Grane for injection into the reservoir to improve oil recovery from this field.

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 around NOK 1.53 billion (2005 value)	
Operating lifetime	The technical operating lifetime is 30 years	
Capacity	34,000 scm oil per day	

The plan for installation and operation of the Grane Oil Pipeline was approved in June 2000. This 29-inch pipeline from Grane to the Sture terminal is 220 km long. It became operational in September 2003 to coincide with the start of production from Grane.

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 around NOK 2.75 billion (2005 value) in pipelines and the terminal	
Operating lifetime	The licence expires on 31 December 2020	
Capacity	2.2 billion scm/year of gas	

This 16-inch gas pipeline runs for 250 km from Heidrun on the Halten Bank 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. The latter uses Heidrun gas as feedstock. Annual gas supplies to the methanol plant total some 0.7 billion scm.

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 around NOK 0.9 bn. (2005 value)	
Operating lifetime	The technical operating lifetime is 50 years	
Capacity	Around 4.0 billion scm per year	

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

The authorities received a plan for installation and operation of Heidrun Gas Export in 1997, plus a supplement to this in March 1999. Approval of the proposals was given by the MPE in the spring of 2000. This 16-inch pipeline runs roughly 37 km from Heidrun to tie into the Åsgard Transport system. It became operational in February 2001.

Kvitebjørn Oil Pipeline

Operator	Statoil ASA	
Licensees	Statoil ASA	50.00%
	Petoro AS	30.00%
	Norsk Hydro Produksjon AS	15.00%
	Total E&P Norge AS	5.00%
Investment	Total investment at start-up was around NOK 0.51 bn. (2005 value)	
Operating lifetime	The technical operating lifetime is 25 years	
Capacity	About 10,000 scm per year	
Operating organisation	Bygnes, Karmøy	

Kvitebjørn Oil Pipeline will transport condensate from Kvitebjørn to the Mongstad oil terminal; this 16-inch line runs for about 90 km to tie in to an existing connection point on Troll Oil Pipeline II. The pipeline became operational in the second half of 2004.

Langeled

Operator	Norsk Hydro Produksjon AS	
Licensees	Petoro AS	32.95%
	Norsk Hydro Produksjon AS	17.61%
	A/S Norske Shell	16.50%
	Statoil ASA	14.99%
	DONG Norge AS	10.22%
	ExxonMobil Exploration and Production Norway AS	6.95%
	Norske ConocoPhillips AS	0.78%

The plan for installation and operation estimates start-up costs at around NOK 20.3 billion (2005 value). Interests in Langeled will be determined before the line becomes operational on the basis of updated cost estimates.

The Langeled system will transport gas from the land facilities for Ormen Lange at Nyhamna in mid-Norway via a tie-in at the Sleipner riser facility to a new receiving terminal at Easington on the UK East coast. This system will comprise a 42-inch pipeline from Nyhamna to Sleipner (the northern leg) and a 44-inch line from Sleipner to Easington (southern leg). Capacity will be just over 80 mill. scm/day in the northern leg and about 70 mill. scm/day in the southern. The system will have an overall length of roughly 1,200 km. The southern leg is due to become operational in October 2006, with the northern following in October 2007. Norsk Hydro will be the operator for the development phase. Gassco AS will be the operator for the operating phase.

Norne Gas Transport System (NGTS)

Operator	Gassco AS	
Licensees	Petoro AS	54.00%
	Statoil ASA	25.00%
	Norsk Hydro Produksjon AS	8.10%
	Eni Norge AS	6.90%
	Enterprise Oil Norge AS	6.00%
Investment	Total investment at start-up was around NOK 1.1 bn. (2005 value).	
Operating lifetime	Technical operating lifetime is 50 years	
Capacity	About 3.6 billion scm per year	

The authorities received a plan for installation and operation of the NGTS in 1997, plus a supplement to this in April 1999. Licence to install and operate the NGTS was given by the MPE in the spring of 2000. This 16-inch pipeline runs roughly 126 km from Norne to tie in to the Åsgard Transport system. It became operational in February 2001.

Norpipe

Owner	Norpipe Oil AS[1]	
Operator	ConocoPhillips Skandinavia AS	
Ownership in Norpipe Oil AS	ConocoPhillips Skandinavia AS	35.05%
	Total E&P Norge AS	34.93%
	Statoil ASA	20.00%
	Eni Norge AS	6.52%
	Norsk Hydro Produksjon AS	3.50%
Investment	Total investment at start-up was around NOK 15.8 billion (2005 value)	
Operating lifetime	The pipeline has been designed for an operating lifetime of at least 30 years Extending its technical life is under constant review	
Capacity	Design capacity is about 53 mill. scm/year (900,000 b/day), – including the use of friction-inhibiting chemicals. The receiving facilities restrict capacity to about 810,000 b/day.	
Operating organisation	Stavanger	

[1] The SDFI will receive a five per cent interest in Norpipe Oil AS on 15 October 2005 through a similar reduction in the equity interest held by Statoil ASA in the company.

Owned by Norpipe Oil AS, the 34-inch Norpipe oil pipeline is about 354 km long and starts at the Ekofisk Centre, where three pumps have been placed. It crosses the UK continental shelf to come ashore at Teesside. A tie-in point for UK fields is located about 50 km 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, and are operated by ConocoPhillips. The oil 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 Proposition no. 110 (1972–73) and Recom. no. 262 (1972–73) to the Parliament.)

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 AS	4.33%
	Norske ConocoPhillips AS	2.40%
Investment	Total investment at start-up was around NOK 9.5 bn. (2005 value)	
Capacity	121,000 scm/day (technical), 990,000 scm (storage)	
Operating lifetime	The pipeline is designed for a lifetime of 40 years	
Operating organisation	Bergen	

Oseberg oil is piped for 115 km through a 28-inch line from the field's A facility to the crude oil terminal at Stura in Øygarden municipality. The Oseberg group has established a separate partnership to operate the line. This partnership has concluded agreements with the licensees for Veslefrikk, Brage, Oseberg Sør, Oseberg Øst, Tune and Huldra to transport oil and condensate from these fields via Oseberg A and the OTS to the Sture terminal at Stura. Oil and NGL from Frøy were piped from the TCP2 facility on Frigg to Oseberg A through Frostpipe. After Frøy was shut down in March 2001, Frostpipe was filled with seawater and preserved for reuse by 2005. The OTS partnership has concluded an agreement with the Grane shippers to receive, store and export oil from this field.

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 about NOK 1.53 bn. (2005 value)	
Capacity	200,000 b/d	
Operating organisation	Bygnes, Karmøy and Kårstø, Tysvær	

The decision to land condensate from Sleipner Øst at Kårstø in Norway rather than at Teesside in the UK meant that the field's licensees had to lay a 20-inch pipeline from Sleipner A and organise the required expansion of the Kårstø complex. The Storting approved the construction of this line in December 1989. Unprocessed condensate from Sleipner Øst began to flow through the 245 km pipeline in 1993. At Kårstø, it is fractionated into NGL and stabilised condensate for the market. This line also began carrying condensate from Sleipner Vest, Loke, Sigyn and Gungne in 1997.

Troll Oil Pipeline I

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	3.70%
	Norske ConocoPhillips AS	1.66%
Investment	Total investment at start-up was about NOK 1.12 bn. (2005 value)	
Operating lifetime	Troll Oil Pipeline I is designed to operate for 35 years	
Capacity	42,500 scm/day of oil with use of friction inhibitors	
Operating organisation	Bygnes, Karmøy and Kårstø, Tysvær	

This 85 km facility transports oil from the Troll B facility to the terminal at Mongstad. With its plan for installation and operation approved in December 1993, the 16-inch line was ready when Troll B came on stream with oil in September 1995 and is licensed to 2023. The Troll licensees have established a separate partnership to handle operation of the line.

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	3.70%
	Norske ConocoPhillips AS	1.66%
Investment	Total investment at start up was about NOK 1.02 bn.(2005 value)	
Operating lifetime	Troll Oil Pipeline II is designed for a lifetime of 35 years	
Capacity	Current oil capacity is 40,000 scm/day. The hydraulic capacity of the line is 47,500 scm/day (without use of friction inhibitors)	
Operating organisation	Bygnes, Karmøy and Kårstø, Tysvær	

This 20-inch pipeline has been built to carry oil over the 80 km from Troll C to the terminal at Mongstad. The plan for installation and operation received government approval 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 piped through Troll Oil Pipeline II, which is licensed 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 accept vessels up to 440,000 tonnes, as well as six caverns excavated from the bedrock 50 metres below ground. These caverns have a total storage capacity of 1.5 mill. m^3 of crude oil. About 500 calls by oil carriers are handled annually.
This facility was constructed to support the marketing of crude oil loaded offshore on Gullfaks, Draugen, Norne, Åsgard, Heidrun and other fields. These consignments are loaded into shuttle tankers, which have a steaming range confined to north-west Europe. By storing and transhipping 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 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 store and transfer system to ships) and Vestprosess DA (the transfer system to the Vestprosess pipeline).

The Sture oil terminal at Stura near Bergen receives oil and condensate via the OTS pipeline from the Oseberg A facility as well as from the Oseberg, Veslefrikk, Brage, Oseberg Sør, Oseberg Øst, Tune and Huldra fields. Since the autumn of 2003, the terminal has also received 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 cavern stores for crude oil with a combined capacity of 1 million scm, a 60,000 m^3 rock cavern store for LPG and a 200,000 m^3 ballast water cavern. A separate unit for recovering volatile organic compounds given off from tankers has been installed.

The MPE 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 mix. The latter can be either exported by ship or piped through the Vestprosess line 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 Parliament 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 mill. scm.

Norferm AS, owned by Statoil ASA and DuPont, produces bioproteins at Tjeldbergodden. With an annual design capacity of 10,000 tonnes of bioproteins, this plant can consume up to 25 mill. m^3 of methane per year. That corresponds to three per cent of the gas received from Heidrun.

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 km pipeline carries unprocessed 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. The latter are stored in rock caverns before export. The Vestprosess plant utilises waste energy and utilities from the refinery.

The map shows the optical fibre cables on the Norwegian continental shelf

E-operations on the Norwegian continental shelf

Within the petroleum industry, e-operations involve using (near) real-time data to integrate work between organisations and between specialist areas in order to make faster and better decisions in all phases of petroleum activities. Modern technology, connecting fields to the shore by broadband links, allows onshore personnel to access information at the same time as those offshore. When field data is available in real time for relevant specialist groups, more efficient support, monitoring and control can take place from shore-based organisations.

E-operations can contribute to increasing the resources that are recovered, reducing costs and increasing safety. This assessment is based on e-operations providing improved use of the information that is gathered and higher levels of automation. They will also reduce offshore manning, which will both reduce costs and improve the risk scenario.

The current situation

Optical fibre cables have been laid over much of the Norwegian continental shelf and they provide a excellent starting point for e-operations, and many installations are already hooked up to broadband communication. This is a prerequisite for transferring large volumes of data. To exploit the digital infrastructure to the full, there need to be access solutions for third parties, with appropriate cost sharing and sufficient data security. The map shows the optical fibre cable network on the Norwegian continental shelf.

Most inroads into the new operational methods have been made within drilling. Real-time data has begun to be integrated between the operations rooms on and offshore, making these simultaneously available for technical personnel, drilling engineers and reservoir geologists. Similar progress has not been achieved within operations and maintenance, although some companies have implemented the technology and work processes in production management. Several operators have already established onshore operations centres that are linked to operations rooms on the installations. It is also possible to connect to operations rooms in other parts of the world.

Future progress

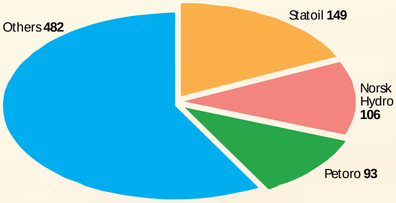
E-operations will be an important element in future developments, as can be seen already in the Kristin, Snøhvit and Ormen Lange fields, now under development. Where profitable, existing fields will be able to link into the digital infrastructure in order to use the new technology.

Changes in working methods and distribution of labour between offshore and onshore, and between operators and suppliers, will be able to create new organisational structures, which link staff and organisations regardless of physical position.

To realise the potential offered by e-operations, coordination between fields, operators and suppliers is necessary, making standardisation vital. For older fields, the challenge is to adapt the ambition levels and progress schedules to get the solutions accepted and deployed in good time before they are decommissioned.

Research and development is taking place among suppliers, oil companies and research institutions. Technical solutions exist, but more research and development is needed to transform data into useful information and knowledge, and to develop advanced sensors that are reliable over time, as well as wireless communication on the installations themselves. Organisational solutions must also be found so that the necessary integration is achieved across specialist boundaries and geographical location, as well as between different suppliers and oil companies.

14 Operators and licensees



Production licences

The table below lists the operators and participants in production licences and fields on the Norwegian continental shelf, as at 8 February 2005. There are 249 active recovery licences with 251 operatorships. Both Statoil ASA and Norsk Hydro Produksjon AS are the operators in licences 085 and 085B. In addition, Gassco AS is the operator for the gas pipeline network. For further information about production licences, please visit the NPDs Fact Pages: www.npd.no

	Operator	Production licence	Field
Amerada Hess Norge AS	1	9	4
A/S Norske Shell	10	19	7
BG Norge AS	2	6	
BP Norge AS	14	20	5
ChevronTexaco Norge AS	2	9	1
CNR International (Norway) AS	1	1	1
ConocoPhillips Skandinavia AS	10	13	9
Det Norske Oljeselskap AS	3	9	1
DONG Norge AS	4	29	6
Eni Norge AS	11	48	16
Enterprise Oil Norge AS	1	17	10
ExxonMobil Exploration and Production Norway AS	17	34	16
Kerr-McGee Norway AS	1	1	
Lundin Norway AS	5	13	2
Marathon Petroleum Norge AS	10	19	4
Mobil Development Norway AS	1	24	8
Norske ConocoPhillips AS	1	22	13
Norsk Hydro Produksjon AS	53	106	40
Paladin Resources Norge AS	4	26	5
Pertra AS	4	8	2
RWE Dea Norge AS	3	23	7
Statoil ASA	77	149	45
Talisman Energy Norge AS	7	11	2
Total E&P Norge AS	9	62	36
Endeavour Energy Norge AS		10	2
E.ON Ruhrgas Norge AS		5	1
Gaz de France Norge AS		21	3
Idemitsu Petroleum Norge AS		4	6
Mærsk Oil Norway AS		1	
Noble Energy (Europe) Limited		1	
Norske AEDC A/S		1	1
Petoro AS		93	40
Revus Energy AS		11	3
Svenska Petroleum Exploration AS		5	2

15 List of addresses – government bodies and licensees

All in Norway except where stated. The international dialling code for Norway is 47.

GOVERNMENT BODIES

The Ministry of Petroleum and Energy
Postboks 8148 Dep, 0033 Oslo
Tel. 22 24 90 90, fax 22 24 95 65

The Norwegian Petroleum Directorate (NPD)
Postboks 600, 4003 Stavanger
Tel. 51 87 60 00, fax 51 55 15 71

The Norwegian Petroleum Directorate 's office in Harstad
Postboks 787, 9488 Harstad
Tel. 77 01 83 50, fax 77 06 38 95

The Ministry of Labour and Social Affairs
Postboks 8019 Dep, 0030 Oslo
Tel. 22 24 90 90, fax 22 24 87 11

The Petroleum Safety Authority Norway
Postboks 599, 4003 Stavanger
Tel. 51 87 60 50, fax 51 87 60 80

The Ministry of Finance
Postboks 8008 Dep, 0030 Oslo
Tel. 22 24 90 90, fax 22 24 95 10

The Ministry of the Environment
Postboks 8013 Dep, 0030 Oslo
Tel. 22 24 90 90, fax 22 24 95 60

OPERATORS

Amerada Hess Norge AS
C. J. Hambros plass 2C, 0164 Oslo
Tel. 22 94 00 00, fax 22 42 63 27

A/S Norske Shell
Postboks 40, 4098 Tananger
Tel. 51 69 30 00, fax 51 69 30 30

BG Norge AS
Postboks 780 Sentrum
4004 Stavanger
Tel. 51 20 59 00, fax 51 20 59 90

BP Norge AS
Postboks 197 Forus, 4065 Stavanger
Tel. 52 01 30 00, fax 52 01 30 01

ChevronTexaco Norge AS
Postboks 97 Skøyen, 0212 Oslo
Tel. 22 13 56 60, fax 22 13 56 90

CNR International (Norway) AS
c/o Wikborg, Rein & Co.
Postboks 1513 Vika, 0117 Oslo
Tel. 22 82 75 00, fax 22 82 75 01

ConocoPhillips Skandinavia AS
Postboks 220, 4098 Tananger
Tel. 52 02 00 00, fax 52 02 66 00

Det Norske Oljeselskap AS
Postboks 1345 Vika, 0113 Oslo
Tel. 23 23 84 80, fax 23 23 84 81

DONG Norge AS
Postboks 450 Sentrum,
4002 Stavanger
Tel. 51 50 62 50, fax 51 50 62 51

Eni Norge AS
Postboks 101 Forus, 4064 Stavanger
Tel. 51 57 48 00, fax 51 57 49 30

Enterprise Oil Norge AS
c/o A/S Norske Shell
Postboks 40, 4098 Tananger
Tel. 51 69 30 00, fax 51 69 30 30

ExxonMobil Exploration and Production Norway AS
Postboks 60 Forus, 4064 Stavanger
Tel. 51 60 60 60, fax 51 60 66 60

Gassco AS
Postboks 93, 5501 Haugesund
Tel. 52 81 25 00, fax 52 81 29 46

Kerr-McGee Norway AS
Postboks 1233
5811 Bergen
Tel. 55 21 52 00, fax 55 21 52 01

Lundin Norway AS
Strandveien 50 D
1366 Lysaker
Tel. 67 10 72 50, fax 67 10 72 51

Marathon Petroleum Norge AS
Postboks 480 Sentrum, 4002 Stavanger
Tel. 51 50 63 00, fax 51 50 63 01

Mobil Development Norway AS
c/o Esso Norge AS
Postboks 60 Forus, 4064 Stavanger
Tel. 51 60 60 60, fax 51 60 66 60

Norsk Hydro Produksjon AS
Drammensveien 264
0246 Oslo
Tel. 22 53 81 00, fax 22 53 22 34

Norske ConocoPhillips AS
Postboks 220
4098 Tananger
Tel. 52 02 00 00, fax 52 02 66 00

Paladin Resources Norge AS
Postboks 530 Sentrum, 4003 Stavanger
Tel. 51 50 62 00, fax 51 50 62 26

Pertra AS
Postboks 482, 7405 Trondheim
Tel. 73 98 30 00, fax 73 98 30 10

RWE Dea Norge AS
Postboks 243 Skøyen, 0213 Oslo
Tel. 21 30 30 00, fax 21 30 30 99

Statoil ASA
4035 Stavanger
Tel. 51 99 00 00, fax 51 99 00 50

Talisman Energy Norge AS
Postboks 649 Sentrum, 4003 Stavanger
Tel. 52 00 20 00, fax 52 00 15 00

Total E&P Norge AS
Postboks 168 Sentrum, 4001 Stavanger
Tel. 51 50 30 00, fax 51 72 66 66

OTHER LICENSEES

E. ON Ruhrgas Norge AS
Postboks 640 Sentrum, 4003 Stavanger
Tel. 51 51 74 00, fax 51 51 74 10

Endeavour Energy Norge AS
Postboks 44
3671 Notodden
Tel. 22 01 04 70, fax 22 01 04 71

Gaz de France Norge AS
Postboks 242 Forus, 4066 Stavanger
Tel. 52 04 46 00, fax 52 04 46 01

Idemitsu Petroleum Norge AS
Postboks 1844 Vika, 0123 Oslo
Tel. 23 23 85 00, fax 23 23 85 01

Mærsk Oil Norway AS
Postboks 244, 1326 Lysaker
Tel. 67 10 76 00, fax 67 10 76 01

Noble Energy (Europe) Limited
Suffolk House, 154 High Street, Sevenoaks,
Kent, TN13 1XE, UK
Tel. +44 01732 741 999, fax +44 01732 464 140

Norske AEDC A/S
Postboks 207 Sentrum, 4001 Stavanger
Tel. 51 91 70 40, fax 51 91 70 41

Petoro AS
Postboks 300 Sentrum, 4002 Stavanger
Tel. 51 50 20 00, fax 51 50 20 01

Revus Energy AS
Postboks 230 Sentrum, 4001 Stavanger
Tel. 51 50 63 50, fax 51 50 63 51

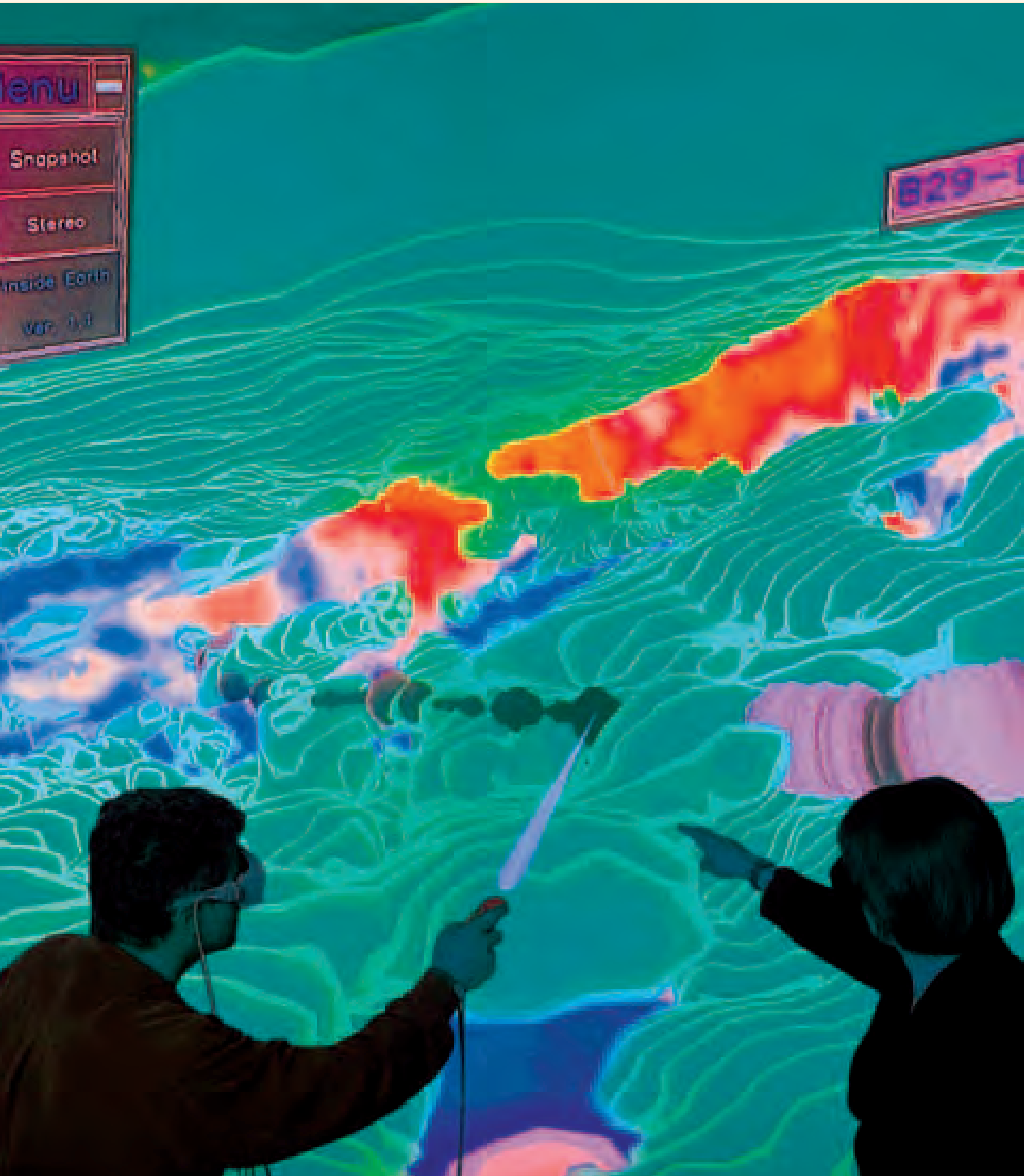
Svenska Petroleum Exploration AS
c/o KPMG AS
Petroleumsveien 6,
4064 Stavanger
Tel. 51 91 47 00, fax 51 81 48 00

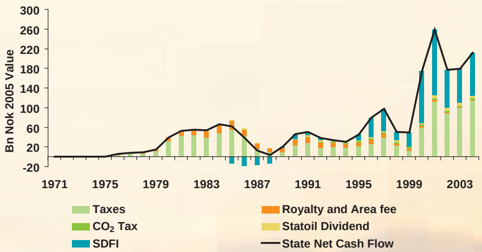
OTHERS

The Norwegian Oil Industry Association
Postboks 8065 Postterminalen, 4068 Stavanger
Tel. 51 84 65 00, fax 51 84 65 01

Oslo office
Postboks 1949 Vika, 0125 Oslo
Tel. 51 84 65 00, fax 51 84 65 91

Appendix





Historical statistics

Table 1: The state's revenues from petroleum activities, NOK millions accumulated:

Year	Ordinary tax	Special tax	Production fee	Area fee	CO_2 tax	Net cash flow SDFI	Statoil dividend	State´s net cash flow*
1971			14					14
1972			42					42
1973			69					69
1974			121					121
1975			208					208
1976	1143	4	712	99				1 958
1977	1694	725	646	57				3 122
1978	1828	727	1213	51				3 819
1979	3399	1492	1608	53				6 552
1980	9912	4955	3639	63				18 569
1981	13804	8062	5308	69			0,057	27 243
1982	15,036	9014	5757	76			368	30 251
1983	14232	8870	7663	75			353	31 193
1984	18333	11078	9718	84			795	40 008
1985	21809	13013	11626	219		-8343	709	39 033
1986	17308	9996	8172	198		-11960	1245	24 959
1987	7137	3184	7517	243		-10711	871	8 241
1988	5129	1072	5481	184		-9133	0	2 733
1989	4832	1547	7288	223		755	0	14 645
1990	12366	4963	8471	258		7344	800	34 202
1991	15021	6739	8940	582	810	5879	1500	39 471
1992	7558	7265	8129	614	1916	3623	1400	30 505
1993	6411	9528	7852	553	2271	159	1250	28 024
1994	6238	8967	6595	139	2557	5	1075	25 576
1995	7854	10789	5884	552	2559	9259	1614	38 511
1996	9940	12890	6301	1159	2787	34959	1850	69 886
1997	15489	19528	6220	617	3043	40404	1600	86 808
1998	9089	11001	3755	527	3229	14572	2940	45 041
1999	5540	6151	3222	561	3261	25769	135	44 623
2000	21921	32901	3463	122	3047	98219	1702	161 372
2001	41464	64316	2481	983	2862	125439	5746	243 236
2002	32512	52410	1320	447	3012	74785	5045	169 233
2003	36819	60280	765	460	3056	67484	5133	173 665
2004**	42900	69900	700	500	3300	85900	5222	208 289

*The state's net cash flow also includes an entry for net other revenues

*(Source: Norwegian Public Accounts/**White Paper no. 31 (2004–2005)*

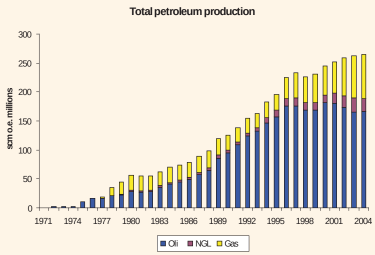


Table 2: Petroleum production on the Norwegian Continental Shelf, millions of standard cubic metres oil equivalent (scm oe millions):

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

(Source: Norwegian Petroleum Directorate)

Table 3: Value creation, exports, employment, investment and exploration costs:

Year	Gross product (NOK millions)	Export value (NOK millions)	Number of employees	Investments incl. exploration costs (NOK mill.)	Exploration costs (NOK millions)
1971	12	36	NA	691	NA
1972	209	244	200	1 192	NA
1973	260	393	300	2 326	NA
1974	1 068	845	900	5 138	NA
1975	4 256	3 622	2 200	7 291	NA
1976	6 957	7 092	2 700	9 270	NA
1977	8 697	8 600	4 000	10 589	NA
1978	14 984	14 838	6 100	9 228	NA
1979	23 738	23 964	7 900	9 061	NA
1980	44 749	43 884	9 700	10 119	NA
1981	55 834	51 139	12 200	14 462	4 133
1982	62 735	56 492	13 100	15 909	5 519
1983	74 334	66 727	13 900	27 028	5 884
1984	91 177	81 173	15 800	32 244	7 491
1985	98 454	88 579	17 700	32 839	7 830
1986	60 936	55 894	18 000	33 155	6 654
1987	60 728	56 653	17 800	35 247	4 951
1988	50 908	50 141	18 700	29 680	4 151
1989	78 088	74 933	18 600	31 957	5 008
1990	96 962	89 894	19 200	32 223	5 137
1991	102 908	98 325	19 700	43 065	8 137
1992	104 212	98 666	20 900	49 512	7 680
1993	109 244	105 731	22 300	57 579	5 433
1994	114 174	108 573	22 500	54 653	5 011
1995	121 602	115 476	21 700	48 583	4 647
1996	167 515	167 200	22 100	47 878	5 455
1997	183 129	177 825	24 100	62 494	8 300
1998	131 630	128 807	24 900	79 216	7 577
1999	178 605	173 428	24 700	69 096	4 993
2000	341 552	325 382	23 600	53 589	5 274
2001	327 778	320 052	26 700	57 144	6 815
2002	283 029	281 158	28 400	54 000	4 476
2003	293 267	290 966	27 800	64 362	4 134
2004	348 523	346 430	27 900	71 069	4 014

(Source: Statistics Norway)

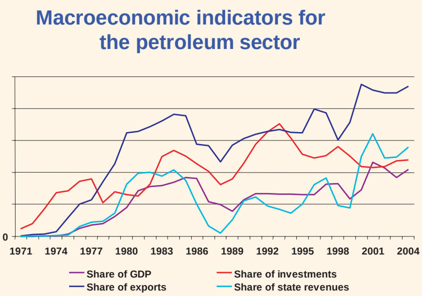


Table 4: The petroleum sector's percentage share of GNP, exports, real investments, and of the state's total revenues:

Year	Share of GNP (%)	Share of exports (%)	Share of real investments (%)	Share of the state's total revenues (%) *
1971	0.01	0.10	2.33	0.05
1972	0.19	0.61	4.03	0.12
1973	0.20	0.81	8.65	0.16
1974	0.72	1.42	13.58	0.25
1975	2.51	5.86	14.18	0.38
1976	3.59	10.09	17.21	3.07
1977	3.98	11.40	17.88	4.38
1978	6.24	16.99	10.49	4.77
1979	8.96	22.79	13.92	7.31
1980	14.23	32.39	13.06	16.27
1981	15.59	32.91	12.60	19.76
1982	15.83	34.31	16.33	19.90
1983	16.83	36.16	25.00	18.86
1984	18.44	38.11	26.88	20.74
1985	17.99	37.69	25.13	17.50
1986	10.85	28.80	22.69	10.13
1987	9.90	28.36	20.43	3.21
1988	7.91	23.45	16.14	1.02
1989	11.38	28.53	17.92	5.20
1990	13.34	30.60	22.87	11.14
1991	13.37	31.92	28.86	12.25
1992	13.19	32.88	32.68	9.49
1993	13.16	33.46	35.22	8.50
1994	13.07	32.59	30.76	7.24
1995	12.97	32.44	25.70	10.06
1996	16.31	39.87	24.59	16.14
1997	16.48	38.59	25.34	18.15
1998	11.63	30.16	28.17	9.56
1999	14.48	35.67	25.09	8.93
2000	23.25	47.44	21.88	25.07
2001	21.48	45.90	21.45	32.07
2002	18.63	45.03	21.60	24.49
2003	18.78	45.11	23.63	24.80
2004	20.68	47.02	23.93	27.70

*2004: Figures from new national budget balance including national insurance 2004

(Source: Statistics Norway, Ministry of Finance, Ministry of Petroleum and Energy)

Table 5: Historical production from fields no longer producing and fields currently in production

Field	Oil mill. scm	Gas bn scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv.[1)] mill. Sm^3	Year of discovery[2)]
Albuskjell	7,4	15,5	1,0	0,0	24,8	1972
Cod	2,9	7,3	0,5	0,0	11,1	1968
Edda	4,8	2,0	0,2	0,0	7,2	1972
Frigg	0,0	116,2	0,0	0,5	116,6	1971
Frøy	5,6	1,6	0,0	0,1	7,3	1987
Lille-Frigg	1,3	2,2	0,0	0,0	3,5	1975
Mime	0,4	0,1	0,0	0,0	0,5	1982
Nordøst Frigg	0,0	11,6	0,0	0,1	11,7	1974
Odin	0,0	27,3	0,0	0,2	27,5	1974
Tommeliten Gamma	3,9	9,7	0,6	0,0	14,6	1978
Vest Ekofisk	12,2	26,0	1,4	0,0	40,8	1970
Yme	7,9	0,0	0,0	0,0	7,9	1987
Øst Frigg	0,0	9,2	0,0	0,1	9,3	1973
Historical production	**46,2**	**228,6**	**3,7**	**0,9**	**282,8**	
Balder[a)]	22,3	0,2	0,0	0,0	22,6	1967
Brage	44,7	2,1	0,8	0,0	48,3	1980
Draugen	103,1	0,9	1,3	0,0	106,5	1984
Ekofisk	345,8	126,2	11,2	0,0	493,2	1969
Eldfisk	77,1	35,0	3,4	0,0	118,6	1970
Embla	8,6	2,8	0,3	0,0	12,0	1988
Fram	3,6	0,0	0,0	0,0	3,6	1987
Glitne	5,6	0,0	0,0	0,0	5,6	1995
Grane	7,8	0,0	0,0	0,0	7,8	1991
Gullfaks[b)]	314,4	21,3	2,3	0,0	339,9	1978
Gullfaks Sør[c)]	20,4	8,7	1,0	0,0	31,1	1978
Gungne[3)]	0,0	0,0	1,0	3,4	5,3	1982
Gyda[d)]	32,2	5,4	1,7	0,0	40,8	1980
Heidrun	99,5	7,5	0,3	0,0	107,7	1985
Heimdal	6,3	44,0	0,0	0,0	50,3	1972
Hod	7,9	1,4	0,2	0,0	9,7	1974
Huldra	3,4	8,7	0,1	0,0	12,3	1982
Jotun	19,4	0,7	0,0	0,0	20,1	1994
Kvitebjørn	0,3	0,6	0,0	0,0	0,8	1994
Mikkel	0,0	2,1	0,5	0,9	4,1	1987

Murchison	13,3	0,3	0,3	0,0	14,2	1975
Njord	17,8	0,0	0,0	0,0	17,8	1986
Norne	62,6	3,6	0,4	0,0	66,9	1992
Oseberg[e)]	321,0	20,1	2,8	0,0	346,5	1979
Oseberg Sør	19,9	0,0	0,0	0,0	19,9	1984
Oseberg Øst	14,4	0,0	0,0	0,0	14,4	1981
Sigyn	0,0	1,7	0,7	2,1	5,1	1982
Skirne	0,2	0,7	0,0	0,0	0,9	1990
Sleipner Vest og Øst[3) f)]	0,0	108,2	15,6	49,0	186,9	1974
Snorre	129,4	5,1	4,0	0,0	142,1	1979
Statfjord	541,6	49,7	13,3	0,1	616,8	1974
Statfjord Nord	30,3	1,7	0,6	0,0	33,0	1977
Statfjord Øst	29,6	2,5	0,9	0,0	33,7	1976
Sygna	7,8	0,0	0,0	0,0	7,8	1996
Tambar	4,6	0,0	0,1	0,0	4,8	1983
Tor	21,9	10,7	1,1	0,0	34,8	1970
Tordis[g)]	43,9	3,4	1,2	0,0	49,5	1987
Troll[h)]	156,2	189,5	0,0	4,3	350,0	1979
Tune	2,1	0,0	0,1	0,0	2,2	1996
Ula	65,7	3,8	2,5	0,0	74,2	1976
Vale	0,4	0,3	0,0	0,0	0,6	1991
Valhall	83,8	16,7	2,7	0,0	105,7	1975
Varg	7,6	0,0	0,0	0,0	7,6	1984
Veslefrikk	45,2	2,1	1,2	0,0	49,5	1981
Vigdis	29,3	0,2	0,2	0,0	29,8	1986
Visund	11,8	0,0	0,0	0,0	11,8	1986
Åsgard	40,9	31,9	5,4	11,6	94,6	1981
Production - fields on stream	**2824**	**720**	**77**	**71**	**3762**	
Total sold and supplied	**2870**	**948**	**81**	**72**	**4044**	

1) The conversion factor for NGL tonnes to scm is 1.9.

2) The year the first discovery well was drilled

3) Measurements of gas production from Gungne, Sleipner Vest and Sleipner Øst are combined

a) Balder includes Ringhorne

b) Gullfaks includes Gullfaks Vest

c) Gullfaks Sør includes Gullveig and Rimfaks

d) Gyda includes Gyda Sør

e) Oseberg includes Oseberg Vest

f) Sleipner Øst includes Loke

g) Tordis includes Tordis Øst and Borg

h) Troll includes TOGI

Table 6: Fields in production or fields with approved plans for development and operation

Field	Reserves mill. scm oe	Year of[5] discovery	Operator at 31.12.2004	Production licence/ Unit area
Alvheim[1]	29,2	1998	Marathon Petroleum Norge AS	036 C, 088 BS, 203
Balder	60,5	1967	ExxonMobil Exploration and Production Norway AS	001
Brage	53,0	1980	Norsk Hydro Produksjon AS	Brage
Draugen	137,2	1984	A/S Norske Shell	093
Ekofisk	736,1	1969	ConocoPhillips Skandinavia AS	018
Eldfisk	183,6	1970	ConocoPhillips Skandinavia AS	018
Embla	18,3	1988	ConocoPhillips Skandinavia AS	018
Fram	15,6	1992	Norsk Hydro Produksjon AS	090
Glitne	7,2	1995	Statoil ASA	048 B
Gullfaks	379,3	1978	Statoil ASA	050
Gullfaks Sør	91,4	1978	Statoil ASA	050
Gungne	15,4	1982	Statoil ASA	046
Gyda	46,3	1980	Talisman Energy Norge AS	019 B
Heidrun	221,2	1985	Statoil ASA	Heidrun
Heimdal	49,3	1972	Norsk Hydro Produksjon AS	036 BS
Hod	10,2	1974	BP Norge AS	033
Huldra	17,4	1982	Statoil ASA	Huldra
Jotun	26,2	1994	ExxonMobil Exploration and Production Norway AS	Jotun
Kristin[1]	76,1	1997	Statoil ASA	Haltenbanken Vest
Kvitebjørn	74,1	1994	Statoil ASA	193
Mikkel	42,1	1987	Statoil ASA	Mikkel
Murchison	14,4	1975	CNR International (UK) Limited	Murchison
Njord	36,9	1986	Norsk Hydro Produksjon AS	Njord
Norne	107,1	1992	Statoil ASA	Norne
Ormen Lange[1]	397,3	1997	Norsk Hydro Produksjon AS	Ormen Lange
Oseberg[2]	468,2	1979	Norsk Hydro Produksjon AS	Oseberg
Oseberg Sør	66,5	1984	Norsk Hydro Produksjon AS	Oseberg Sør
Oseberg Øst	30,9	1981	Norsk Hydro Produksjon AS	053
Sigyn	16,4	1982	ExxonMobil Exploration and Production Norway AS	072

Skirne	8,3	1990	Total E&P Norge AS	102
Sleipner Vest	151,6	1974	Statoil ASA	Sleipner Vest
Sleipner Øst	116,7	1981	Statoil ASA	Sleipner Øst
Snorre	257,8	1979	Statoil ASA	Snorre
Snøhvit[1)]	187,7	1984	Statoil ASA	Snøhvit
Statfjord	648,5	1974	Statoil ASA	Statfjord
Statfjord Nord	43,5	1977	Statoil ASA	037
Statfjord Øst	42,2	1976	Statoil ASA	Statfjord Øst
Sygna	10,9	1996	Statoil ASA	Sygna
Tambar	8,7	1983	BP Norge AS	065
Tor	40,6	1970	ConocoPhillips Skandinavia AS	Tor
Tordis	66,5	1987	Statoil ASA	089
Troll[3)]	1611,3	1979	Norsk Hydro Produksjon AS	Troll
Troll[4)]		1983	Statoil ASA	Troll
Tune	19,7	1996	Norsk Hydro Produksjon AS	190
Ula	87,6	1976	BP Norge AS	019
Urd[1)]	10,6	2000	Statoil ASA	128
Vale	4,2	1991	Norsk Hydro Produksjon AS	036
Valhall	209,0	1975	BP Norge AS	Valhall
Varg	12,1	1984	Pertra AS	038
Veslefrikk	60,7	1981	Statoil ASA	052
Vigdis	50,6	1986	Statoil ASA	089
Visund	92,6	1986	Statoil ASA	Visund
Åsgard	388,0	1981	Statoil ASA	Åsgard

1) Field with approved development plans where production had not commenced at 31.12.2004

2) Resources in Oseberg also include Oseberg Vest

3) Resources include the total resources for Troll, including the section operated by Statoil ASA

4) The resources are included in the row abowe

5) The year the first discovery well was drilled

Table 7: Original recoverable reserves and remaining reserves in fields in production

	Originally saleable[1)]					Remaining reserves[4)]				
	Oil	Gas	NGL	Condensate	Oil equiv.[2)]	Oil	Gas	NGL	Condensate	Oilequiv.[2)]
	mill. scm	bn. scm	mill. tonnes	mill. scm	mill. scm	mill. scm	bn. scm	mill. tonnes	mill. scm	mill. Sm^3
Alvheim[3)]	23,5	5,7	0,0	0,0	29,2	23,5	5,7	0,0	0,0	29,2
Balder[a)]	58,9	1,6	0,0	0,0	60,5	36,5	1,4	0,0	0,0	37,9
Brage	48,5	2,9	0,8	0,0	53,0	3,8	0,8	0,0	0,0	4,7
Draugen	131,4	1,5	2,3	0,0	137,2	28,2	0,6	0,9	0,0	30,7
Ekofisk	524,1	184,9	14,3	0,0	736,1	178,3	58,8	3,1	0,0	242,9
Eldfisk	124,7	50,6	4,4	0,0	183,6	47,6	15,6	1,0	0,0	65,0
Embla	13,3	4,1	0,5	0,0	18,3	4,7	1,3	0,2	0,0	6,3
Fram	11,2	4,3	0,1	0,0	15,6	7,6	4,3	0,1	0,0	12,0
Glitne	7,2	0,0	0,0	0,0	7,2	1,7	0,0	0,0	0,0	1,7
Grane	120,3	0,0	0,0	0,0	120,3	112,5	0,0	0,0	0,0	112,5
Gullfaks[b)]	351,9	22,6	2,6	0,0	379,3	37,5	1,3	0,3	0,0	39,4
Gullfaks Sør[c)]	43,8	39,1	4,5	0,0	91,4	23,4	30,4	3,4	0,0	60,3
Gungne[5]	0,0	9,9	1,3	3,1	15,4	0,0	9,9	0,3	-0,2	10,1
Gyda[d)]	36,8	5,9	1,9	0,0	46,3	4,6	0,6	0,2	0,0	5,5
Heidrun	175,0	40,7	2,9	0,0	221,2	75,5	33,2	2,6	0,0	113,5
Heimdal	7,1	42,1	0,0	0,0	49,3	0,8	0,0	0,0	0,0	0,8
Hod	8,3	1,4	0,2	0,0	10,2	0,5	0,0	0,0	0,0	0,5
Huldra	4,3	12,9	0,1	0,0	17,4	0,9	4,2	0,0	0,0	5,1
Jotun	25,4	0,7	0,0	0,0	26,2	6,0	0,1	0,0	0,0	6,0
Kristin[3)]	29,9	33,0	6,9	0,0	76,1	29,9	33,0	6,9	0,0	76,1
Kvitebjørn	18,0	51,8	2,3	0,0	74,1	17,7	51,3	2,3	0,0	73,3
Mikkel	0,0	24,1	6,0	6,6	42,1	0,0	22,0	5,4	5,7	38,0
Murchison	14,0	0,4	0,0	0,0	14,4	0,7	0,1	-0,3	0,0	0,1
Njord	25,6	8,7	1,4	0,0	36,9	7,8	8,7	1,4	0,0	19,2
Norne	88,5	13,8	2,5	0,0	107,1	25,9	10,2	2,1	0,0	40,1
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	102,8	6,2	0,0	468,2	32,7	82,7	3,3	0,0	121,6
Oseberg Sør	57,6	8,9	0,0	0,0	66,5	37,7	8,9	0,0	0,0	46,6
Oseberg Øst	30,2	0,7	0,0	0,0	30,9	15,8	0,7	0,0	0,0	16,5
Sigyn	0,0	6,1	3,0	4,6	16,4	0,0	4,4	2,3	2,6	11,3
Skirne	1,6	6,7	0,0	0,0	8,3	1,4	6,0	0,0	0,0	7,4
Sleipner Vest	0,0	108,1	8,1	28,1	151,6					

Sleipner Øst[f)]	0,0	65,8	12,5	27,1	116,7					
Sleipner Vest og Øst[5)]						0,0	65,7	5,0	6,2	81,4
Snorre	242,4	6,4	4,7	0,0	257,8	113,0	1,3	0,7	0,0	115,8
Snøhvit[3)]	0,0	160,2	5,1	17,9	187,7	0,0	160,2	5,1	17,9	187,7
Statfjord	565,8	54,3	14,9	0,0	648,5	24,2	4,6	1,6	0,0	31,8
Statfjord Nord	39,3	2,6	0,9	0,0	43,5	8,9	0,9	0,3	0,0	10,5
Statfjord Øst	35,7	3,9	1,4	0,0	42,2	6,1	1,4	0,5	0,0	8,5
Sygna	10,9	0,0	0,0	0,0	10,9	3,2	0,0	0,0	0,0	3,2
Tambar	6,7	1,8	0,2	0,0	8,7	2,1	1,8	0,0	0,0	3,9
Tor	26,7	11,6	1,2	0,0	40,6	4,7	0,9	0,1	0,0	5,8
Tordis[g)]	58,1	5,2	1,7	0,0	66,5	14,3	1,9	0,4	0,0	17,0
Troll[h)]	233,2	1318,0	30,8	1,6	1611,3	77,0	1128,6	30,8	-2,7	1261,3
Tune[6)]	3,8	15,9	0,0	0,0	19,7	1,6	15,9	0,0	0,0	17,5
Ula	78,2	3,8	2,9	0,0	87,6	12,5	0,0	0,4	0,0	13,3
Urd[3)]	10,4	0,1	0,0	0,0	10,6	10,4	0,1	0,0	0,0	10,6
Vale	1,8	2,4	0,0	0,0	4,2	1,4	2,2	0,0	0,0	3,6
Valhall	171,5	29,2	4,4	0,0	209,0	87,6	12,6	1,6	0,0	103,3
Varg	12,1	0,0	0,0	0,0	12,1	4,5	0,0	0,0	0,0	4,5
Veslefrikk	56,1	2,6	1,1	0,0	60,7	10,9	0,5	-0,1	0,0	11,3
Vigdis	47,9	1,2	0,8	0,0	50,6	18,6	1,0	0,7	0,0	20,8
Visund	27,6	52,2	6,7	0,0	92,6	15,8	52,2	6,7	0,0	80,8
Åsgard	73,6	195,3	38,3	46,2	388,0	32,7	163,4	33,0	34,7	293,4
Total	**4036,6**	**3103,9**	**199,6**	**157,4**	**7677,2**	**1212,8**	**2386,2**	**122,3**	**86,1**	**3917,5**

1) The table shows expected value. All 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 31.12.2004

4) A negative remaining reserves figure for a field is the result of the product not being reported under original sellable volumes. This applies to produced NGL and condensate

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

6) Tune gas not reallocated back from Oseberg

a) Balder includes Ringhorne

b) Gullfaks includes Gullfaks Vest

c) Gullfaks Sør includes Gullveig and Rimfaks

d) Gyda includes Gyda Sør

e) Oseberg includes Oseberg Vest

f) Sleipner Øst includes Loke

g) Tordis includes Tordis Øst and Borg

h) Troll includes TOGI

Table 8: Reserves in discoveries decided by the licensees

Discovery	Oil mill. scm	Gas bn. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv.[1] mill. scm oe	Year of discovery[2]
25/4-9 S Vilje	8,9	0,0	0,0	0,0	8,9	2003
33/12-8 A Skinfaks	3,0	1,5	0,3	0,2	5,2	2002
Total	**11,8**	**1,5**	**0,3**	**0,2**	**14,1**	

1) The conversion factor for NGL tonnes to scm is 1.9.

2) The year the first discovery well was drilled.

Table 9: Resources in discoveries in the planning phase

Discovery	Oil mill. scm	Gas bn. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv.[1] mill. scm oe	Year of discovery[2]
1/2-1	0,9	0,1	0,0	0,0	0,9	1989
15/12-12	0,0	4,3	0,0	1,4	5,7	2001
15/3-1 S	15,2	8,4	5,4	0,0	33,9	1975
15/5-1 Dagny	0,0	3,8	0,2	1,2	5,3	1978
15/9-19 S Volve	11,0	1,2	0,2	0,1	12,6	1993
2/12-1 Freja	2,9	0,6	0,0	0,0	3,5	1987
25/11-16	3,60	0,00	0,0	0,0	3,69	1992
25/5-5	3,53	0,09	0,0	0,0	3,70	1995
3/7-4 Trym	0,00	3,32	0,0	0,84	4,25	1990
30/6-17	0,00	1,48	0,0	0,00	1,57	1986
30/9-19	2,26	5,86	0,0	0,00	8,21	1998
34/10-23 Valemon [3]	0,0	18,1	0,8	5,6	25,2	1985
35/9-1 R Gjøa	7,1	30,4	0,0	1,4	38,9	1989
6407/1-2 Tyrihans Sør [4]	24,7	32,6	5,9	0,0	68,4	1983
6507/3-3 Idun	0,0	13,2	0,9	0,3	15,1	1999
6507/5-1 Skarv [5]	14,1	38,4	6,1	3,9	68,0	1998
7122/7-1 Goliat	6,9	0,0	0,0	0,0	6,9	2000
Total	**92,1**	**161,8**	**19,6**	**14,8**	**306,0**	

1) The conversion factor for NGL tonnes to scm is 1.9

2) The year the first discovery well was drilled

3) 34/10-23 Valemon has resources in categories 4 and 5

4) 6407/1-2 Tyrihans Sør has resources in categories 4 and 5

5) 6507/5-1 Skarv has resources in categories 4 and 5

Table 10: Resources in discoveries where development is likely but not yet clarified

Discovery	Oil mill. scm	Gas bn. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv.[1] mill. scm oe	Year of discovery[2]
1/3-6	1,1	1,8	0,0	0,3	3,2	1991
1/5-2 Flyndre	5,1	1,6	0,0	0,0	6,6	1974
1/9-1 Tommeliten Alpha	7,5	12,8	0,0	0,0	20,3	1977
15/3-4	7,6	3,8	0,0	0,0	11,4	1982
15/5-2	0,0	4,9	0,0	0,4	5,3	1978
15/8-1 Alpha	0,0	4,1	0,5	1,0	6,1	1982
16/7-2	0,0	1,8	0,3	0,5	2,9	1982
2/4-10	2,1	0,0	0,0	0,0	2,1	1973
2/4-17 Tjalve	1,0	1,6	0,1	0,0	2,8	1992
2/5-3 Sørøst Tor	1,0	0,0	0,0	0,0	1,0	1972
2/7-19	3,6	3,4	0,0	0,0	7,1	1990
24/6-1 Peik	0,0	2,0	0,0	0,3	2,3	1985
24/9-5	7,1	0,9	0,0	0,0	7,9	1994
25/8-4	1,0	0,0	0,0	0,0	1,0	1992
30/7-6 Hild	4,3	33,2	0,0	7,7	45,2	1978
33/9-6 Delta	2,3	0,2	0,0	0,0	2,4	1976
34/11-2 S	0,0	4,5	0,0	2,9	7,4	1996
34/8-12 S	1,0	0,7	0,0	0,0	1,7	2001
35/8-1	0,0	11,6	0,0	2,4	14,0	1981
6/3-1	0,4	0,9	0,0	0,0	1,3	1985
6405/7-1	1,0	0,0	0,0	0,0	1,0	2003
6406/1-1	0,0	1,1	0,0	0,3	1,4	2001
6406/1-2	0,0	15,0	0,0	4,8	19,8	2003
6406/2-1 Lavrans	0,0	14,4	0,0	3,9	18,3	1995
6406/2-6 Ragnfrid	0,0	2,7	0,0	1,8	4,5	1998
6406/2-7 Erlend	0,0	1,7	0,0	1,3	2,9	1999
6406/3-2 Trestakk	5,3	1,8	0,0	0,0	7,0	1986
6407/9-9	0,2	1,2	0,0	0,2	1,6	1999
6506/11-2 Lange	1,0	0,5	0,0	0,0	1,5	1991
6506/11-7	2,2	1,0	0,0	0,0	3,1	2001
6506/12-3 Lysing	1,5	0,3	0,0	0,0	1,8	1985
6506/6-1	0,0	118,0	0,0	0,0	118,0	2000

6507/2-2	0,0	19,8	0,0	0,0	19,8	1992
6507/3-1 Alve	0,0	8,3	0,0	1,6	9,9	1990
6507/7-13	0,9	0,0	0,0	0,0	1,0	2001
6608/10-9 Lerke	0,6	0,1	0,0	0,0	0,7	2003
6608/11-2 Falk	1,6	0,1	0,0	0,0	1,7	2000
6608/11-4 Linerle	13,5	0,0	0,0	0,0	13,5	2004
6707/10-1	0,0	38,3	0,0	0,0	38,3	1997
7/7-2	2,4	0,1	0,0	0,0	2,5	1992
7/8-3	6,0	0,2	0,1	0,0	6,3	1983
7121/4-2 Snøhvit Nord	0,0	3,5	0,0	0,2	3,7	1985
7121/5-2 Beta	3,1	3,3	0,0	0,2	6,6	1986
Total	**84,1**	**321,0**	**1,0**	**29,6**	**436,6**	

1) The conversion factor for NGL tonnes to scm is 1.9

2) The year the first discovery well was drilled

Table 11: Resources in new, unevaluated discoveries

Discovery	Oil mill. scm	Gas bn. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv.1) mill. scm oe	Year of discovery2)
16/1-7	0,7	0,1	0,0	0,0	0,8	2004
34/10-48 S	2,4	0,0	0,6	0,0	3,5	2004
Total	**3,1**	**0,1**	**0,6**	**0,0**	**4,3**	

1) The conversion factor for NGL tonnes to scm is 1.9

2) The year the first discovery well was drilled

Concepts and conversions

Resources

Petroleum resources are a collective term which embraces technically recoverable volumes of oil, gas, natural gas liquids (NGL) and condensate. They are classified by the maturity of the industrial project required to recover them. The main classes are reserves, contingent resources and undiscovered resources.

Reserves

Reserves are defined in accordance with the NPD's classification system cf figure. Reserves may be regarded as the economically recoverable part of the petroleum in a field or a discovery.

Volumes are given in standard cubic metres (scm) for oil, condensate and gas, and in tonnes for NGL. A measure of total resources can be obtained by summing the energy content in the various types of petroleum. This sum is given in scm of oil equivalent (scm oe).

The conversion from scm to tonnes depends on composition and changes over time.

1 scm oil	=	1.0 scm oe
1 scm condensate	=	1.0 scm oe
1 000 scm gas	=	1.0 scm oe
1 tonne NGL	=	1.9 scm oe

Gas	1 cubic foot	1 000.00	btu
	1 cubic metre	9 000.00	kcal
	1 cubic metre	35.30	cubic feet

Crude oil	1 scm	6.29	barrels
	1 scm	0.84	toe
	1 tonne	7.49	barrels
	1 barrel	159.00	litres
	1 barrel/day	48.80	tonnes/year
	1 barrel/day	58.00	scm/year

	MJ	kWh	TCE	TOE	Scm of natural gas	Barrels of oil
1 MJ, megajoule	1	0.278	0.0000341	0.0000236	0.0281	0.000176
1 kWh, kilowatt hour	3.60	1	0.000123	0.000085	0.0927	0.000635
1 TCE, tonne coal equivalent	29 300	8 140	1	0.69	825	5.18
1 TOE, tonne oil equivalent	42 300	11 788	1.44	1	1 190	7.49
1 scm natural gas	40.00	9.87	0.00121	0.00084	1	0.00629
1 barrel of crude oil (159 litres)	5 650	1 569	0.193	0.134	159	1

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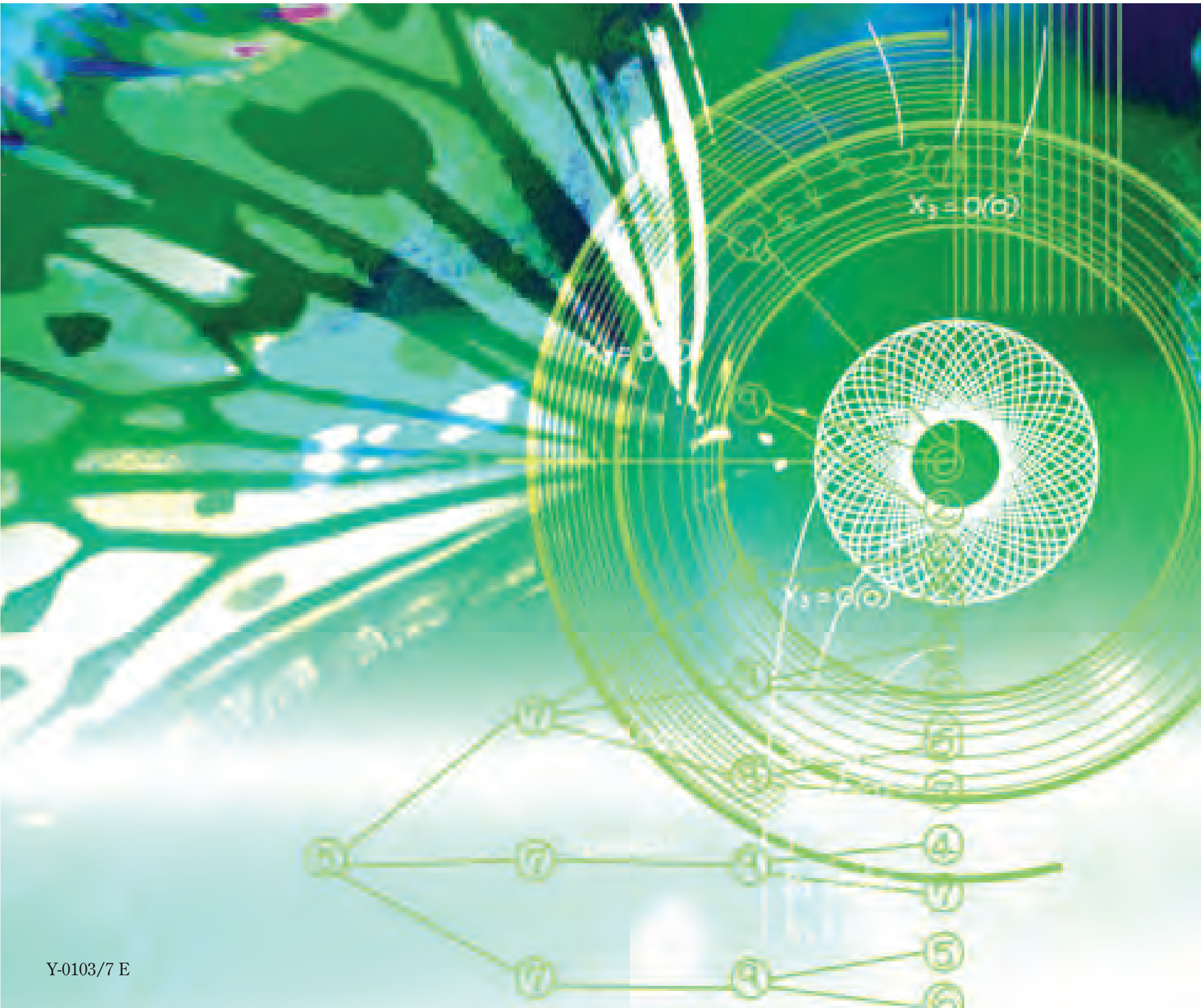

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