FACTS

THE NORWEGIAN PETROLEUM SECTOR

2008

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Foreword by the Minister of Petroleum and Energy, Åslaug Haga

These are interesting and challenging times for Norway's largest industry; the petroleum activities. The oil and gas resources on Norway's continental shelf form the foundation for value creation and substantial revenues to the State, and also constitute a basis for a high-tech industry. At the same time, climate challenges occupy a prominent place on the social agenda, and this will be one of the industry's main challenges in the years to come.

The level of investments and activity is high. Total investments for 2008 are expected to reach more than NOK 100 billion. The revised national budget assumes that state revenues from the petroleum activities will be NOK 356 billion in 2008. Exports from the Norwegian petroleum-related supplier industry are increasing steadily, with foreign sales amounting to about NOK 50 billion. The technology being exported is based on knowledge and expertise developed in the Norwegian petroleum activities.

The petroleum industry is fundamental for Norway as an energy nation. About 130,000 people are employed in the petroleum activities, which also create substantial ripple effects in other industries. The high activity level leads to a tight job market with intense competition for the best-qualified personnel. The interaction between education, research and the industry is important in order to meet the challenge of getting more young people to pursue educations that will prepare them for employment in the petroleum activities.

Based on our petroleum expertise, Norway has an important role to play in the development of technology that can reduce global emissions of greenhouse gases. Power production and other use of fossil energy is the largest source of global greenhouse gas emissions. The world needs energy, and much of the global energy consumption over the short and intermediate term will have to come from fossil sources such as oil, gas and coal. At the same time, CO_2 emissions must be reduced. The petroleum activities account for 29 per cent of Norway's greenhouse gas emissions. As a responsible energy producer, Norway has both an interest in and a responsibility to produce oil and gas in the most environmentally-friendly manner possible. We must be able to accomplish both of these objectives: Provide energy that is produced using the best possible environmentally-friendly technology and reduce emissions of CO_2.

The Climate White Paper presented by the Government in 2007 represents a solid foundation on which we have continued to build through the climate compromise with the three opposition parties the Conservatives, the Christian Democrats and the Liberals. The climate compromise means that Norway's total emissions of CO_2 shall be reduced by 30 per cent by 2020, and that about two-thirds of the emission reductions shall be made on the national level. Reducing greenhouse gas emissions on the shelf is a prioritised task in the years to come. Many measures have already been implemented to cut emissions on the Norwegian shelf. The CO_2 tax, which has been in force since 1991, has been a key element in the work to reduce greenhouse gas emissions. From 1 January 2008, the activities will be incorporated into the Norwegian quota system and must purchase quotas for their emissions. The CO_2 tax has been adjusted downwards so that the quota price and the CO_2 tax together will be at a comparable level to what the CO_2 tax alone was previously. The Government will continue to work on electrification and energy efficiency on the shelf.

The Government is bringing the full force of its commitment to bear on the development of technology for capturing and storing CO_2. We have set ambitious goals for CO_2 handling at Kårstø and Mongstad, and for establishing a value chain for transport and injection of CO_2. There are enormous opportunities here, but the technological challenges are very demanding. The Norwegian efforts to develop technologies to capture CO_2 in connection with energy production are very important in the work to reduce global greenhouse gas emissions. The goal is to make this technology available on a commercial basis, so that it will be cheaper to clean CO_2 than to pollute. This technology is not just important for Norway, but will also be important for capture and storage worldwide.

The merger of Statoil and Hydro in 2007 has given us a new company that will make its mark on the Norwegian economy and the activity on the Norwegian shelf. The State's role as owner in the company and manager for the Norwegian shelf will be an important perspective in the years to come.

2007 has been a year of vigorous exploration activity, and this is expected to continue in 2008. Of the 32 exploration wells spudded, 20 are wildcat wells and 12 are appraisal wells. The Luno discovery in the central North Sea in 2007, which proved 10 - 30 million standard cubic meters of light oil, is an interesting discovery with considerable potential. The plan is to drill an appraisal well on the discovery in 2008. These kinds of discoveries in mature areas are exciting.

There are many new players on the shelf. A total of 13 new companies were prequalified as licensees or operators on the Norwegian shelf in 2007. The latest round in predefined areas (APA 2007) attracted considerable interest and there was tough competition for several of the blocks.

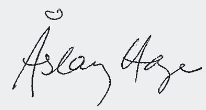
The interest for the nomination of blocks for the 20th licensing round, has also been substantial. As a part of the Government's new line concerning open conduct in the petroleum policy, the licensing rounds will from now on be the object for a broad hearing, before the blocks are announced. Both social and environmental interests may express their view in the hearing process. The government will decide which blocks to be announced based on an overall assessment, emphasising the continued sound coexistence between the petroleum industry and other industries.

Ormen Lange and Snøhvit are large gas fields that commenced operations in 2007, and they will make substantial contributions to gas production. For the first time, we had petroleum production from the Barents Sea and the use of LNG technology opens new markets for Norwegian gas. What many people thought impossible ten years ago has now become possible.

The Government places great emphasis on creating regional and local ripple effects from the petroleum sector, which both Ormen Lange and Snøhvit exemplify. In both of these developments, local and regional businesses have demonstrated that they can make significant contributions. The oil companies are also taking responsibility for this through programs for supplier development. So far, Northern Norwegian industry has delivered goods and services worth more than NOK 3 billion to the Snøhvit project. The land facility is also adapted to allow for establishing outlets for gas for local and regional consumers.

Today, Norway is the world's third largest exporter of gas. In 2013, gas production will exceed oil production. We currently deliver gas in amounts equivalent to the total consumption in Germany. Oil production is somewhat lower than in 2006, while gas production has tripled since the 1990s, reaching 90 billion Sm^3 in 2007. The 2007 decision to hold back the gas on the Troll field in order to extract more oil was an important decision aimed at achieving the best possible management of the resources on the shelf. The Troll gas will still be produced, however at a later time.

Even though large parts of the oil and gas activities have entered a more mature phase, significant petroleum resources remain to be produced. Just 36 per cent of the estimated resources have been produced. For example, technological development makes it possible to drill wells and develop fields in ways that were previously not technically feasible. The oil companies have made great progress in using new technology to increase the recovery rate in producing fields, streamline operations and explore for resources in the proximity of developed infrastructure. Raising the recovery rate for fields is a common long-term goal. In order to reach this goal, many measures have been implemented on the large oil fields in order to extract more from existing wells, to drill more wells and make adjustments to process facilities. Although much has been done, there is still more to do.



Minister of Petroleum and Energy

Foreword by Director General Bente Nyland

Oil production in Norway peaked six-seven years ago, while gas production continues to rise. It is expected to increase from the current level of approximately 90 billion scm per year to 116 billion scm in 2011. Although the Norwegian Petroleum Directorate's (NPD's) forecasts show a continued decline in oil production, we expect the decline over the next five-year period to be lower than for the previous five-year period because new oil fields are coming on stream. The forecasts confirm that Norway will remain a significant producer of oil and gas for many decades to come.

However, oil production is dropping faster than we predicted even just a few years ago, and this is reason for concern. The authorities are closely monitoring the situation, e.g. through the use of PIAF (Performance Indicator Analysis for Fields), a methodical tool that helps identifying challenges on producing fields. The operators are challenged to address these issues including the degree to which the companies follow up their own plans and, if they do not, what is stopping them.

Strategy for increasing oil recovery

With today's plans, 54 per cent of the oil will be left in the fields. This is not good enough. The authorities have set a goal of increasing the oil reserves by five billion barrels during the ten-year period from 2005 to 2015. Analyses in 2007 indicated that 75 per cent of this increase would have to come from fields that are already producing.

To make this possible, we need to see increased oil recovery and disposition of gas in combination. Gas injection is a key factor on many fields to achieve a high recovery rate. On fields that contain both oil and gas, gas production cannot be accelerated without incurring negative consequences for reservoir pressure and long-term resource exploitation. When the Ministry of Petroleum and Energy, following advice from the NPD, chose to say no to accelerated gas production on the Troll field, this was a decision based on a thorough evaluation of reservoir technical factors and consequences, not just for the Troll field, but also for the neighbouring areas. Increased gas production now, could have wasted large volumes of oil, and thus also substantial financial assets for the Norwegian society.

The NPD believes that it is now time to introduce other methods for improving oil recovery than gas and water injection. The high oil prices should allow for testing of more advanced methods in pilot proje cts on some of the fields on the Norwegian shelf.

Much remains to be found

Exploration activity has picked up in recent years. In 2007, 32 exploration wells were spudded and 12 new discoveries were made, making it a good year. On the other hand, these discoveries are considerably smaller than in previous years. This puts more pressure on profitability requirements and emphasises the importance of identifying cost-effective development solutions.

2008 is shaping up to be a year with even higher number of exploration wells. Forecasts indicate that 35-40 exploration wells will be drilled this year.

The NPD estimates that approximately 25 per cent of the recoverable resources on the shelf have yet to be discovered. However, there is great uncertainty associated with these estimates; the resources could be less, but they could also be much larger.

Interest in the shelf remains high. This is evidenced by both the interest shown in APA 2007 (Awards in Predefined Areas) and the interest in nominating blocks for the 20th licensing round. This is also reinforced by the steady stream of new companies applying for prequalification for the Norwegian shelf. More than 50 companies have been prequalified as operators or licensees since 2000.

The oil companies are focussed on exploration acreage, and the authorities have taken this seriously. In fact, the total acreage announced in the past seven years equals the total area in the previous 30 years. Still, the industry continues to press for more.

Coexistence

The faster pace of licence awards and substantial new areas to be mapped also entail increased activity. This is a desirable result of the authorities' policies. However, it also entails a greater risk of conflicts with other users of the sea, such as the fishing fleet. We must work to avoid this. Coexistence between these two industries is the key to positive development on the shelf.

For quite some time, the areas offshore Lofoten and Vesterålen have ranked high on the companies' wish lists. These areas have not been opened up for award of production licences. Towards the year 2010, the NPD will acquire seismic data in Nordland VII and Troms II. This was decided when the Storting considered White Paper No. 8 (2005-2006), (Management plan for the waters off Lofoten and the Barents Sea) in 2006. Data from the NPD's acquisition will be part of the foundation when the Storting reconsider the management plan in 2010. Acquisition of seismic data in this area is challenging due to the significant fishery activity. Therefore, the acquisition will take place in close dialogue with the fishery industry to prevent potential conflicts.

Emissions

CO_2 emissions from petroleum production also constitute a major challenge. Norway has lower emissions per produced unit of oil and gas than any other petroleum-producing country. This is because the authorities have set stringent requirements from the very beginning, and the industry has followed up. Important measures have included the prohibition against flaring - except for safety-related considerations - and the CO_2 tax. Other measures are now needed to achieve further emission reductions.

In 2007, the NPD coordinated the work on a new study on power from land, in cooperation with the Norwegian Pollution Control Authority, the Norwegian Water Resources and Energy Administration and the Petroleum Safety Authority Norway. We also conducted a mapping of the North Sea to find reservoirs that are suitable for depositing large volumes of CO_2, and the preliminary conclusion of this study is that good areas do exist. This work will continue with more thorough investigation of the so-called Johansen formation in the northern part of the North Sea, where the objective is to drill a well during the next one and a half years. This will provide us with even better information about the reservoir.

Scenarios

The NPD conducted a scenario analysis in 2007 for the Norwegian shelf up to 2046. The analysis can be found at *www.npd.no*, and is described in the NPD's resource report for 2007. In summary, the analysis points out that a positive future for the Norwegian shelf and Norwegian petroleum activities requires that new exploration acreage is made available and that we find solutions that contribute to reduction of greenhouse gas emissions. The industry must also work hard and with a long-term perspective on technology development for improved recovery from producing fields.

Bente Nyland

Director General

Content

1

The petroleum sector- Norway's largest industry

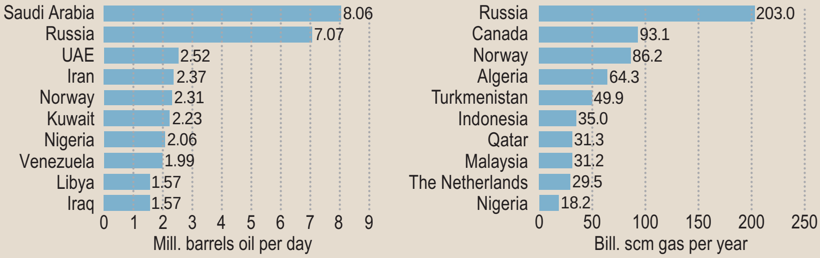


Figure 1.1 The largest oil exporters (including NGL/condensate) in 2007 and gas exporters in 2006

(Source: KBC Market Services)

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

With the Ekofisk discovery in 1969, the Norwegian oil adventure really began. Production from the field started on 15 June 1971, and in the following years a number of major discoveries were made. Today, there are 57 fields in production on the Norwegian continental shelf. In 2007, these fields produced 2.6 million barrels of oil per day (including NGL and condensate) and 90 billion standard cubic metres (scm) gas, for a total production of saleable petroleum of 238 million scm oil equivalents (o.e.). Norway ranks as the world's fifth largest oil exporter and the eleventh largest oil producer. In 2006, Norway was the third largest gas exporter and the sixth largest gas producer in the world.

The significance of the petroleum sector in the Norwegian society

Petroleum activities have contributed significantly to economic growth in Norway and to the financing of the Norwegian welfare state. Through nearly 40 years of operations, the industry has created values in excess of NOK 6000 billion in current terms; and it is currently Norway's largest industry. In 2007, the petroleum sector accounted for 24 per cent of value creation in the country. The value creation of the petroleum industry is almost three times higher than the manufacturing sector and around 18 times the total value creation of the primary industries.

Through direct and indirect taxes and direct ownership, the state is ensured a high proportion of the values created from the petroleum activities. In 2007, the state's net cash flow from the petroleum sector amounted to approximately 31 percent of total revenues. After more than 35 years of production, the sector has generated net revenues to the state in the order of NOK 3000 billion in current terms. The state's net cash flow is transfered to a separate fund, the Government Pension Fund – Global (formerly the Government Petroleum Fund). By the end of 2007, the value of this fund was about NOK 2000 billion. The revenues from the petroleum sector is gradually spend by covering the oil-adjusted budget deficit. The guidlines for fiscal policy entail that the oil-adjusted budget

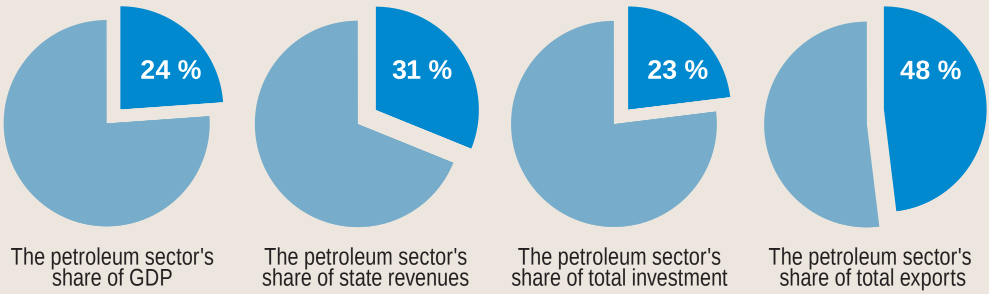


Figure 1.2 Macroeconomic indicators for the petroleum sector

(Source: Statistics Norway, Ministry of Finance)

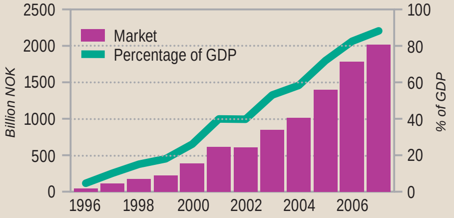


Figure 1.3 The size of the Government Pension Fund - Global at 31.12.2007 and as a share of GDP
(Source: Norwegian Public Accounts, Statistics Norway)

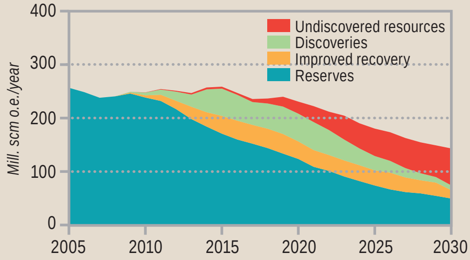


Figure 1.4 Production forecast
(Source: Norwegian Petroleum Directorate/Ministry of Petroleum and Energy)

will over time match the expected real return on the capital in the fund.

In 2007, crude oil, natural gas and pipeline services accounted for 48 per cent of the value of Norway's exports. Measured in NOK, the value of petroleum exports was 509 billion, 14 times higher than the export value of fish.

Since the petroleum industry started its activities on the Norwegian continental shelf, enormous sums have been invested in exploration, field development, transport infrastructure and land facilities. At the end of 2007 this amounted to approximately NOK 2100 billion in current terms. Investments in 2007 amounted to NOK 109 billion, or 23 per cent of the country's total real investments.

Future trends

We have produced approximately 36 per cent of the expected total resources on the Norwegian continental shelf. There is thus potential for further value creation for many years to come.

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

Petroleum production is expected to remain steady over the next few years. The production of oil and other liquids will fall gradually. Gas export on the other hand is expected increase and to reach a level between 125 to 140 bill. scm within the next decade. From representing approximately 40 per cent of the total Norwegian petroleum production in 2007, the share attributed to gas production will increase considerably in the future. In the longer term, the number and size of new discoveries will be a critical factor for the production level.

The level of activity on the Norwegian continental shelf is high. In 2008 an investment level of NOK 106 billion (excluding exploration costs) is anticipated and approximately 35-40 exploration wells are scheduled for drilling. There will be investments both in measures to increase oil recovery and in developing new fields. The individual projects with the largest investments are Troll, Skarv and Gjøa. Investments are expected to increase until 2010 and the activity level in the industry will remain high over the long term, see Figure 1.5. In the years ahead, investments will relate primarily to modification and drilling activities. There is considerable uncertainty tied to the investment forecasts, for both the longer and the shorter terms. In addition to the investments, the forecasts also reveal a market for operations and maintenance of approximately NOK 50 billion annually for many years to come.

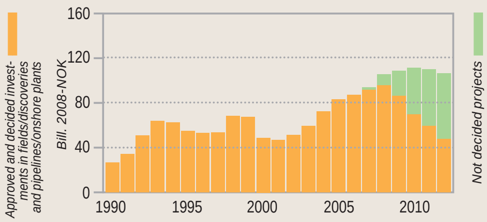


Figure 1.5 Historic investments and forecasted future investments (investments excl. exploration costs)
(Source: Norwegian Petroleum Directorate/ Ministry of Petroleum and Energy)

The oil price is a very important factor as regards the activity level and revenues to the state. The price of oil has increased substantially in recent years, averaging approximately USD 72.5 per barrel in 2007 (Brent quality). At the beginning of 2008, the price exceeded USD 90 per barrel. There are several reasons for the high price level. The world economy has experienced strong growth and although a moderate slowing of this growth is expected in the future, this indicates that the demand for oil will remain high. Available production capacity worldwide is low, with increased vulnerability to interruptions in production. The cost of expanding new capacity has risen considerably. If the world economy continues to grow, there is reason to believe that oil prices will remain at a relatively high level in the years to come.

2 Norwegian resource management

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

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

The current resource management model

In order for oil companies to make rational investment decisions, the framework conditions must be predictable and transparent. This is the general basis for the incentive system Norway has

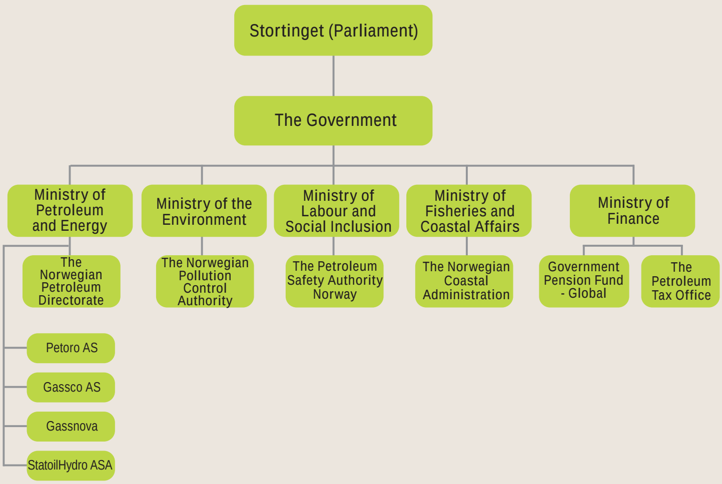


Figure 2.1 State organisation of the petroleum sector
(Source: Ministry of Petroleum and Energy)

established on the Norwegian continental shelf. Organisation of the activities and the division of roles and responsibilities shall ensure that important social considerations are safeguarded and that the value created from the activities benefits the Norwegian society as a whole. At the same time, consideration for the external environment, health, work environment and safety plays an important role.[1]

Norwegian and international oil companies are responsible for the actual conduct of petroleum activities on the Norwegian continental shelf. Competition between oil companies yields the best result when it comes to maximising the value of the petroleum resources. At the same time, it is important that the authorities can understand and evaluate the decisions made by the companies. Therefore, Norway has established a system whereby oil companies have ideas and carry out the technical work required to recover the resources, but their activities also require approval by the authorities. The approval of the authorities is required in all stages of the petroleum activities, in connection with exploration drilling[2], plans for development and operation[3] and decommissioning plans[4] for fields. In this system, the oil companies create the necessary technical solutions to recover the resources, while the Norwegian authorities ensure that these solutions concur with the goal of maximising the values for the Norwegian society as a whole.

For the oil companies to fill the function of maximising the values on the Norwegian continental shelf, a framework must be in place which provides the petroleum industry with incentives to fulfil the state's objectives while at the same time meeting their own goals, which is to maximise their profits. Through the petroleum taxation system and the State's Direct Financial Interest (SDFI), the state receives a substantial portion of the revenues from the petroleum activities.[5] At the same time, however, tax deductions are granted for the costs associated with petroleum activities. In such a tax system, the Norwegian State functions as a passive owner in a production licence on the Norwegian continental shelf. This system implies that, if the oil companies do not make money, the Norwegian State will not collect revenues. In this manner, all players in the Norwegian petroleum sector have a common interest in ensuring that production of the Norwegian petroleum resources creates the greatest possible values.

Cooperation and competition

While competition is desirable, cooperation between the players in the petroleum industry is also beneficial. Therefore, the authorities as a main rule award production licences to a group of companies instead of one company alone. Production licences are normally awarded on the basis of applications from oil companies in connection with licensing rounds.[6] The most important criterias for award include understanding the geology, technical expertise, financial strength and the experience of the oil company. Based on the applications, the Ministry of Petroleum and Energy establishes a licensee group. In this group, the oil companies exchange ideas and experience, and share the costs and revenues associated with the production licence. The companies compete, but must also cooperate to maximise the value in the production licence they have been

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

2 Ref. Chapter 4.

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

4 More on decommissioning after production is concluded in Chapter7.

5 Ref. Chapter 3.

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

awarded. Under this system, expertise and experience from around the world are gathered together in nearly all of the production licences on the Norwegian continental shelf. The licensee group also functions as an internal control system within the production licence, where each licensee is responsible for monitoring the work of the operator.

The petroleum sector is driven by technological innovation. Maximising the values on the Norwegian continental shelf requires that oil companies constantly apply the best available technology, and that they carry out the necessary research and development. Therefore, the Norwegian authorities have established an environment that promotes technological development. Today there is close collaboration between oil companies, research institutes, the supply industry and the authorities when it comes to technology and research.[7]

National organisation of the petroleum sector

The Storting

The Storting, the Norwegian parliament, establishes the framework for Norwegian petroleum activities. The methods used include passing legislation and adopting propositions, as well as discussing and responding to white papers concerning the petroleum activities. Major development projects or matters of great public importance must be discussed by the Storting. The Storting also supervises the government and the public administration.

The government

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

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

The Senior Management Forum (Toppleder-forum) was established in 2000, and is chaired by the Minister of Petroleum and Energy. The Senior Management Forum is an arena where the industry and the authorities can discuss key challenges and proposals for concrete measures. However, no formal decisions on oil and gas policy are made in the Forum. The Forum is composed of 37 senior managers from oil companies, the supply industry, employees' and employers' organisations, research institutes and the authorities.

7 *See Chapter 8.*

More on the national organisation of the petroleum sector

THE MINISTRY OF PETROLEUM AND ENERGY

The Ministry of Petroleum and Energy holds the overall responsibility for management of petroleum resources on the Norwegian continental shelf. This includes ensuring that the petroleum activities are carried out in accordance with the mandates given by the Storting and the government. The Norwegian Petroleum Directorate is administratively subordinate to the Ministry of Petroleum and Energy. In addition, the Ministry holds a particular responsibility for monitoring the state-owned corporations, Petoro AS, Gassco AS and Gassnova, and the partly state-owned StatoilHydro ASA.

The Norwegian Petroleum Directorate

The Norwegian Petroleum Directorate is administratively subordinate to the Ministry of Petroleum and Energy. The Norwegian Petroleum Directorate plays a major role in the management of the petroleum resources, and is an important advisory body for the Ministry of Petroleum and Energy. The Norwegian Petroleum Directorate exercises management authority in connection with exploration for and exploitation of petroleum deposits on the Norwegian continental shelf. This also includes authority to issue regulations and make decisions according to rules and regulations for the petroleum activities.

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 Norwegian continental shelf.

Gassnova

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

StatoilHydro ASA

In 2007, Norsk Hydro's oil and gas activities merged with Statoil, and the new company was named StatoilHydro ASA. StatoilHydro ASA is listed on the Oslo and New York stock exchanges. The state owns a 62.5 per cent share in the company. The state's objective is to increase its ownership share to 67 per cent over time.

More on the national organisation of the petroleum sector

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

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

THE MINISTRY OF FINANCE
The Ministry of Finance holds the overall responsibility for ensuring that the state collects taxes, fees and other revenues from the petroleum sector.

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

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

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

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

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

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

3 Government petroleum revenues

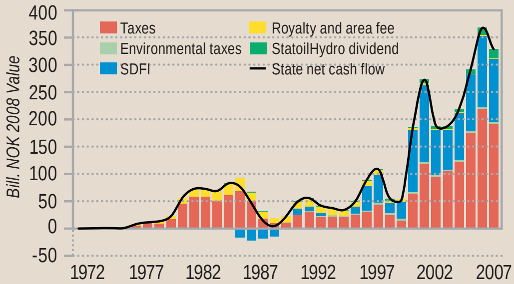


Figure 3.1 The net government cash flow from petroleum activities
(Source: Norwegian Public Accounts and account figures for SDFI)

Direct taxes:	186.5
Environmental taxes and area fee:	4.6
SDFI:	112.3*
StatoilHydro dividend:	16.4**
Total:	319.8

* SDFI annual accounts 2007 (except transfer to SPFF)
** Dividend for 2006 paid in 2007 plus share buyback effects

Figure 3.2 The net government cash flow from petroleum activities 2007 (bill. NOK)
(Source: Norwegian Public Accounts 2007 and account figures for SDFI)

The government receives significant revenues from the petroleum sector. In 2007, 31 percent of government revenues stemmed from this sector. Figure 3.1 shows income from the sector, which has been high in recent years, with 2006 being a year with very high payments to the state. The value of the remaining petroleum reserves on the Norwegian continental shelf was estimated at 3790 billion 2008-NOK in the Revised National Budget for 2008.

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

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

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

The petroleum tax system

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

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

The petroleum tax system has been designed for neutrality, so that an investment project that is profitable for an investor before tax, will also be profitable after tax. It is, therefore, possible to harmonise the requirement for significant revenues to the society with the requirement for sufficient post-tax profitability for the companies.

Other taxes

The most important other taxes linked to petroleum activities are the carbon dioxide tax, the NO_X tax and the area fee.

The CO_2 tax was introduced in 1991 and is an instrument for reducing CO_2 emissions from the petroleum sector. CO_2 tax is levied at a rate per standard cubic metre (scm) of gas burned or directly released and per litre of petroleum burned. The rate for 2008 is NOK 0.45 per litre of petroleum or scm of gas.

Pursuant to the Gothenburg Protocol of 1999, Norway has an obligation to reduce annual emissions of nitrogen oxides (NO_X). In order to fulfil this obligation, a NOx tax was introduced from 1 January 2007. For 2008, the tax is NOK 15.39 per kg of NO_X.

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

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

Norm prices

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

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

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

The State's Direct Financial Interest (SDFI)

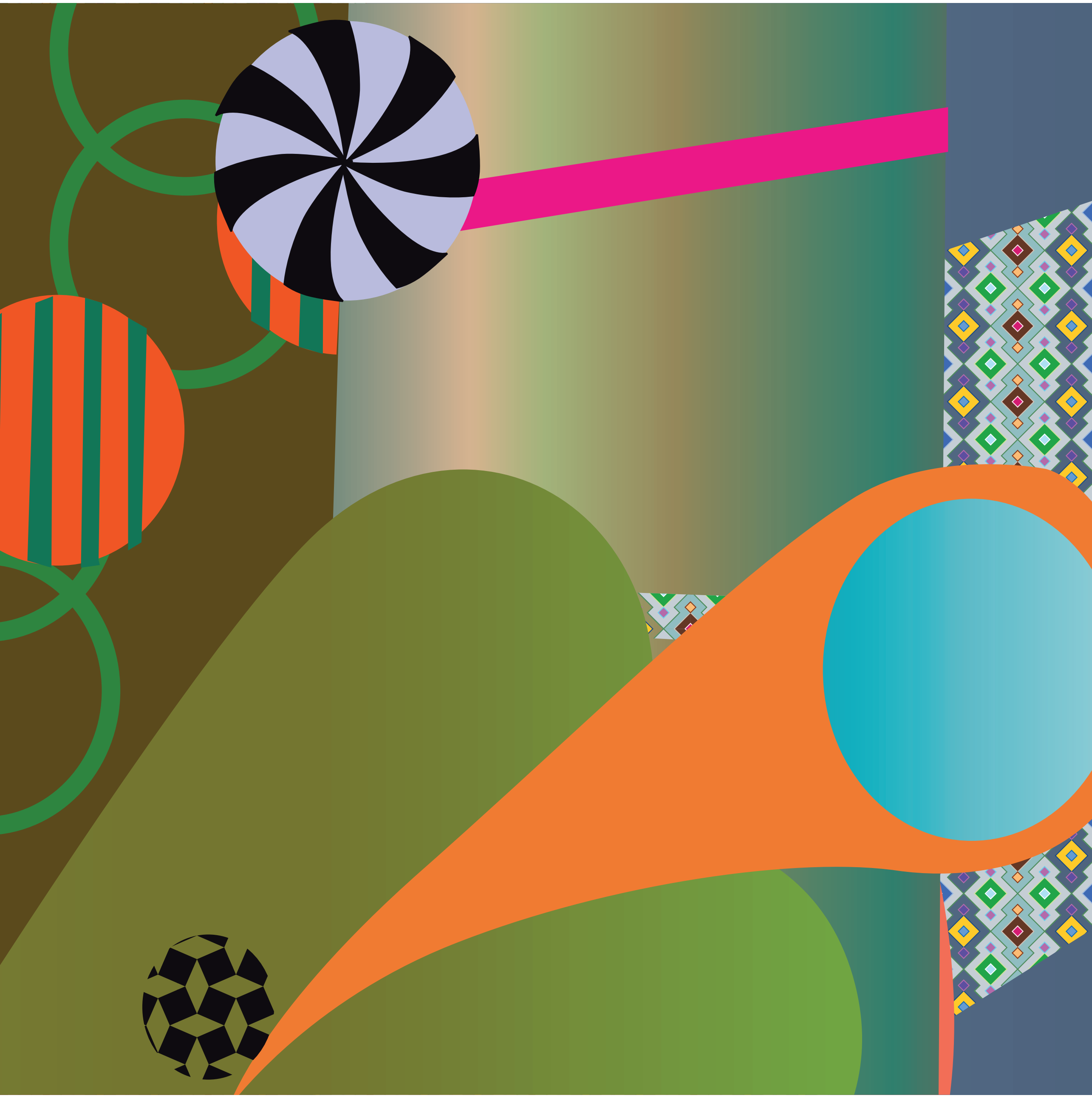
The State's Direct Financial Interest (SDFI) is an important source of state revenues, in addition to taxes, fees and dividends from its ownership in StatoilHydro. SDFI is an arrangement in which the state owns interests in a number of oil and gas fields, pipelines and onshore facilities. Each government take is decided when production licences are awarded and the size of the state interest varies from field to field. As one of several owners, the state pays its share of investments and costs, and receives a corresponding share of the income from the production licence. SDFI was established on 1 January 1985. Prior to this, Statoil alone, at the time a fully state-owned company, was responsible for the state's ownership holdings in production licences. In 1985, Statoil's participation was split into one direct financial share for the state (SDFI) and one for Statoil. When Statoil was privatised and listed on 18 June 2001, the administration of the SDFI portfolio was transferred to the state-created trust company, Petoro. As of 1 January 2008 the state had participating interests in 114 production licences and 14 joint ventures for pipelines and onshore installations.

The SDFI arrangement implies that the state, when awarding acreage, can determine exactly how much of the value creation shall devolve on the state. For production licences with low expected profitability, the state can decide to take a small interest, or even refrain from taking an interest, while a larger share would be appropriate for more profitable areas.

StatoilHydro dividend

As of 1 January 2008, the state owns 62.5 percent of the shares in StatoilHydro. As an owner in StatoilHydro, the state receives dividends, which form part of the state's revenues from the petroleum sector.

4 Exploration activities



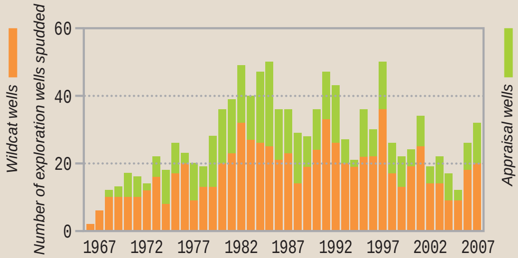


Figure 4.1 Exploration wells spudded on the NCS 1966-2007

(Source: Norwegian Petroleum Directorate)

Exploring for and proving undiscovered resources is a prerequisite for recovering the petroleum resources on the Norwegian continental shelf. Exploration activities are an important indicator of future production. Typically, it takes several years from a decision to begin exploring for resources until any discoveries can be put into production. The framing of exploration policy is hence an important aspect of Norwegian resource management.

For the authorities, it is important that Norwegian exploration policy provides for rapid and efficient identification of new resources. It is the companies that undertake the exploration and the proving of new resources. Exploration policy is therefore designed to increase the attractiveness of the Norwegian continental shelf for established and new players that can contribute to efficient exploration of the shelf. The government will give the companies access to attractive exploration acreage. The exploration acreage should offer possibilities in both mature and new, less explored areas.

The exploration activities have increased substantially in 2006 - 2007 after a period of low activity. A total of 32 exploration wells were spudded in 2007, including 20 wildcats, which yielded 12 discoveries. High exploration activity is expected to continue in 2008. The Norwegian Petroleum Directorate forecast indicates that 35 - 40 exploration wells will be drilled in 2008. Several frontier wells in the Norwegian Sea and the Barents Sea will become important for the mapping and evalwuation of the resource potential in these areas.

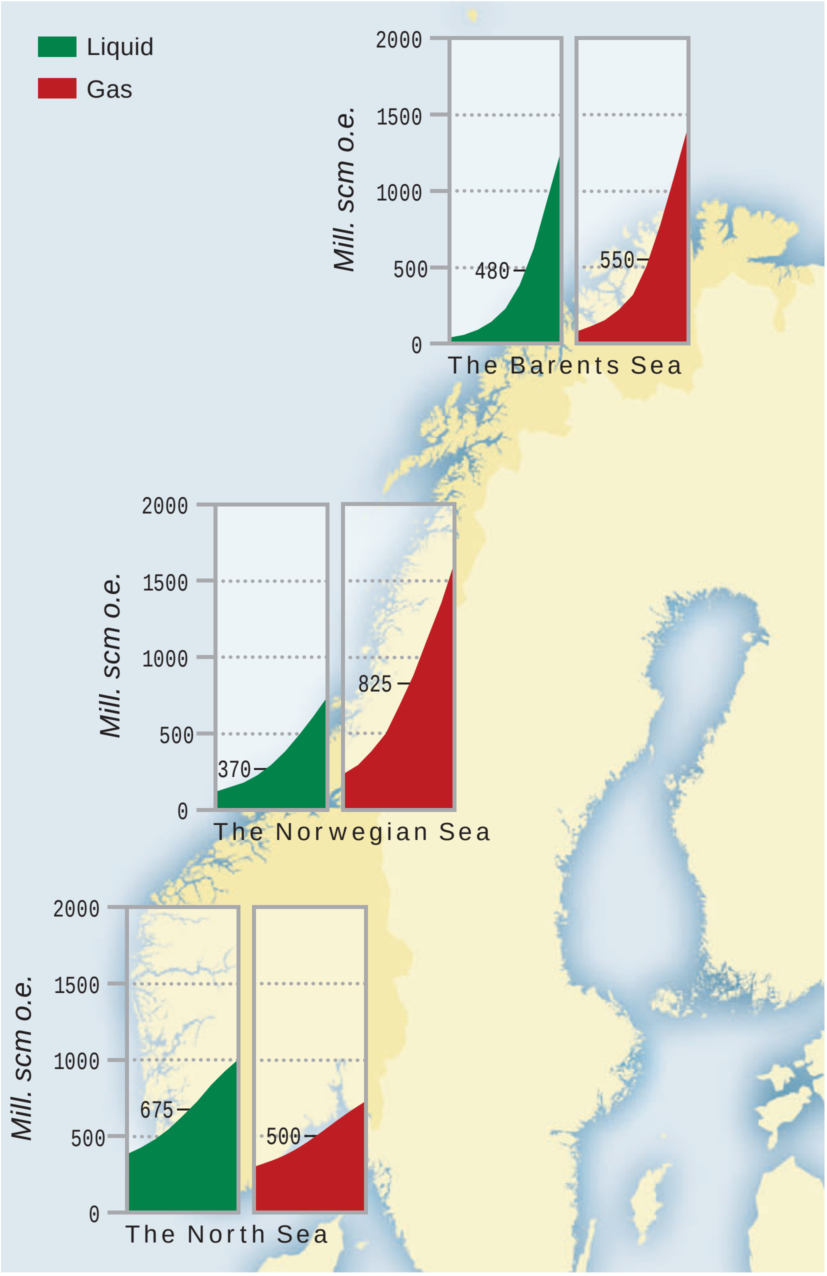
A fundamental precondition for petroleum activities on the Norwegian continental shelf is the coexistence of the oil industry and other users of the sea and land areas affected by such activities. This precondition is also important in licensing policy. This policy places great emphasis on safeguarding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

The licensing system

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

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

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



Figuere 4.2 Undiscovered resources by area. The figure in each bar shows expected recoverable volume while the uncertainty in the estimate is shown by the curved line, low estimate to the left, high estimate to the right

(Source: Norwegian Petroleum Directorate)

out the day-to-day activities under the terms of the licence.

The production licence regulates the rights and obligations of licensees in relation to the state. This document supplements the provisions of the Petroleum Act and specifies detailed terms for each licence. The licence provides an exclusive right for exploration, exploration drilling and the production of petroleum within the geographical area specified in the production licence. Ownership of the petroleum produced rests with the licensees.

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

Mature and frontier areas

The parts of the Norwegian continental shelf that the Norwegian Parliament (Storting) has opened up for petroleum activities are the greater part of the North Sea, the Norwegian Sea and the southern Barents Sea. The Norwegian Petroleum Directorate's estimate of undiscovered resources in the areas on the continental shelf totals 3.4 billion standard cubic metres (scm) of recoverable oil equivalents. This is slightly less than the volumes that have already been produced to date on the Norwegian continental shelf and the resources are divided more or less equally between the three regions, with 35 per cent in the North Sea, 35 per cent in the Norwegian Sea and 30 per cent in the Barents Sea (see Figure 4.2). Depending on the degree of maturity of the different areas, there is some variation in the types of challenges faced in realising the commercial potential of the undiscovered resources on the Norwegian continental shelf.

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

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

Exploration policy in mature and frontier areas

Mature areas

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

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

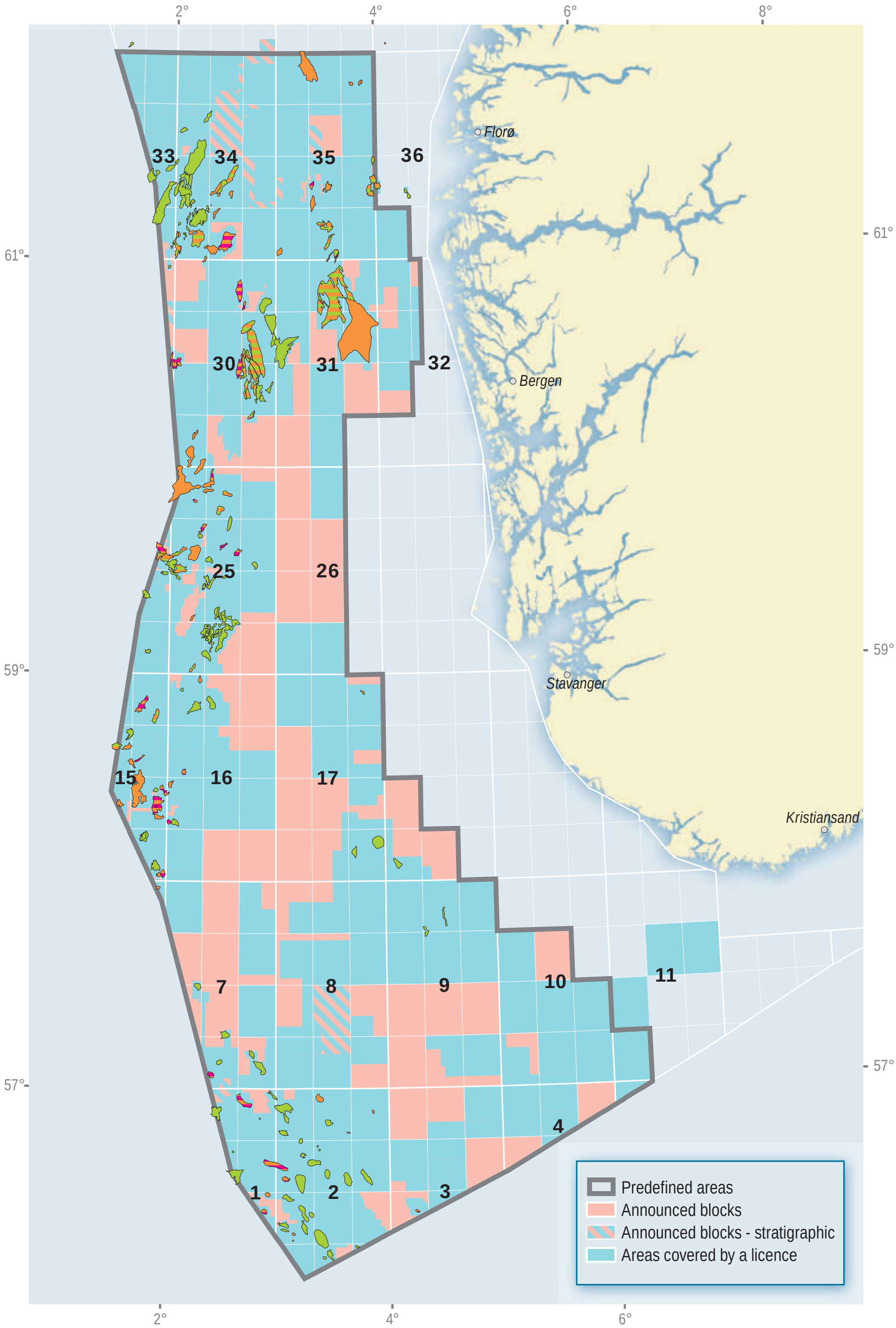
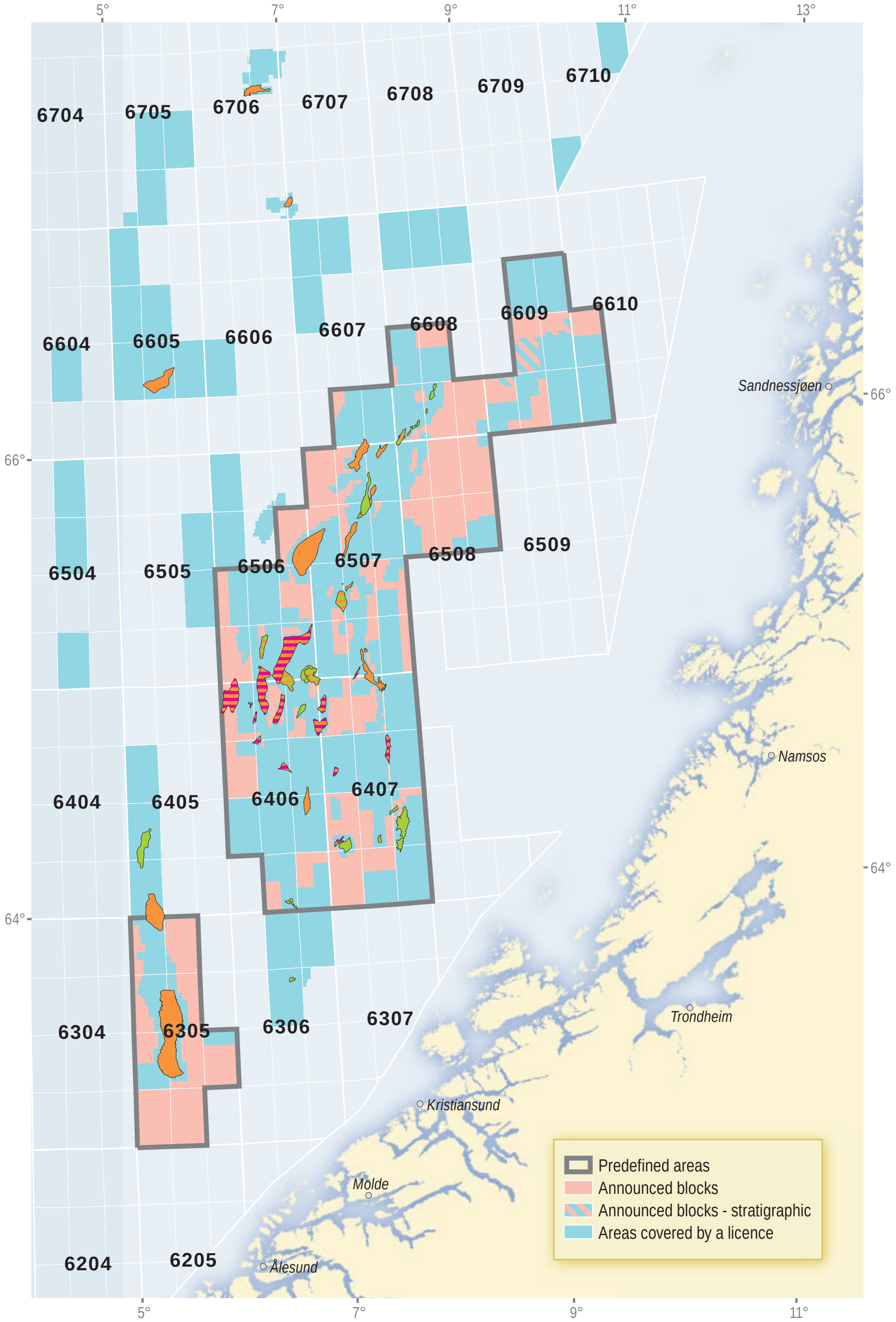


Figure 4.3 Awards in pre-defined areas - North Sea announcement 2008
(Source: Norwegian Petroleum Directorate)



Figur 4.4 Awards in pre-defined areas - Norwegian Sea announcement 2008
(Source: Norwegian Petroleum Directorate)

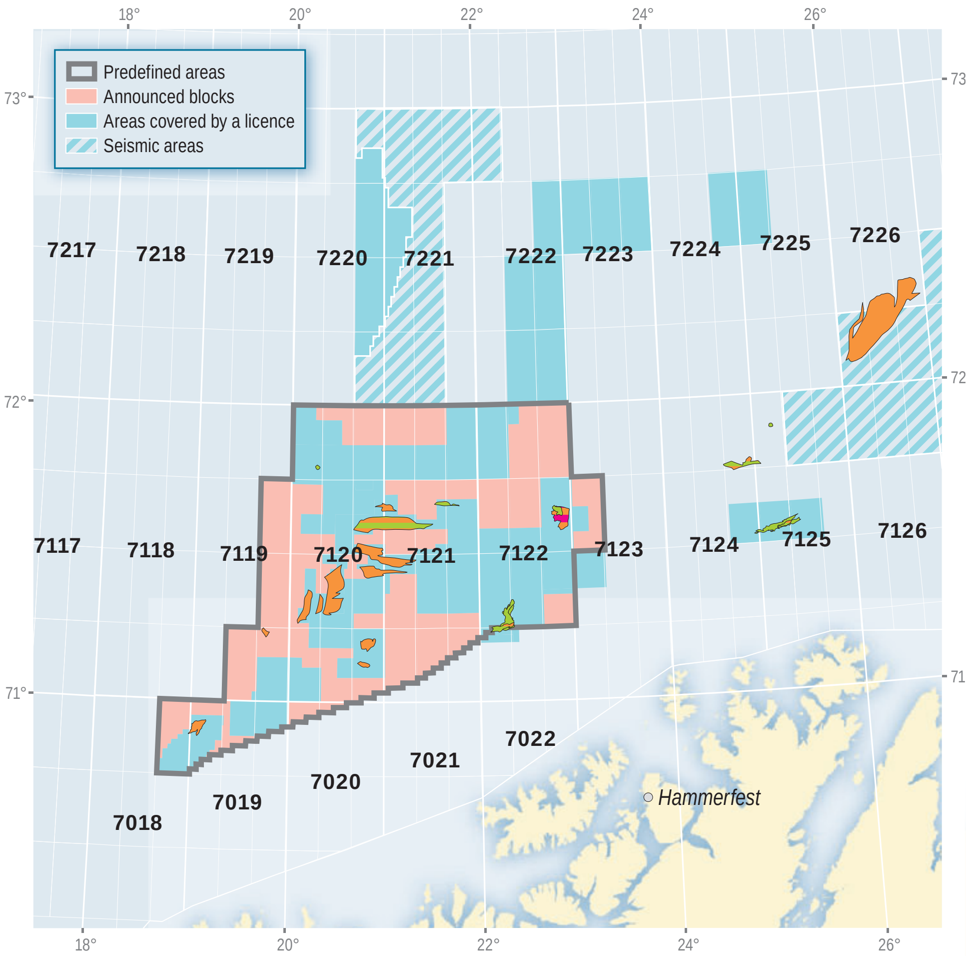


Figure 4.5 Awards in pre-defined areas - Barents Sea announcement 2008

(Source: Norwegian Petroleum Directorate)

too small to warrant a stand-alone development of infrastructure.

The authorities have determined that industry access to larger parts of mature areas is important so that time-critical resources can be produced. It is also important that the areas awarded to the industry are explored quickly and efficiently. For this reason, the Government has implemented a policy shift in mature areas, introducing a scheme in 2003 for award of production licences in predefined areas (APA) in mature areas of the Norwegian continental shelf (Storting White Paper No. 38 (2003 - 2004) *Oil and Gas Activities*). The premise of this system is the designation of large, predefined exploration areas which encompass all mature areas on the Norwegian continental shelf. This area will be expanded, never curtailed, as new areas mature. The system entails a permanent annual cycle for licensing rounds in mature areas. Five such licensing rounds have been carried out in mature areas to date (APA 2003 - 2006). Figures 4.3, 4.4 and 4.5 show the areas announced for award in APA 2008.

Active exploration within licensed areas is important to the authorities. The areas awarded are tailored so that the companies will only get acreage where they have specific plans. The work obligations assumed when companies are awarded new production licences is a set of activities and decisions. At each juncture, the company must

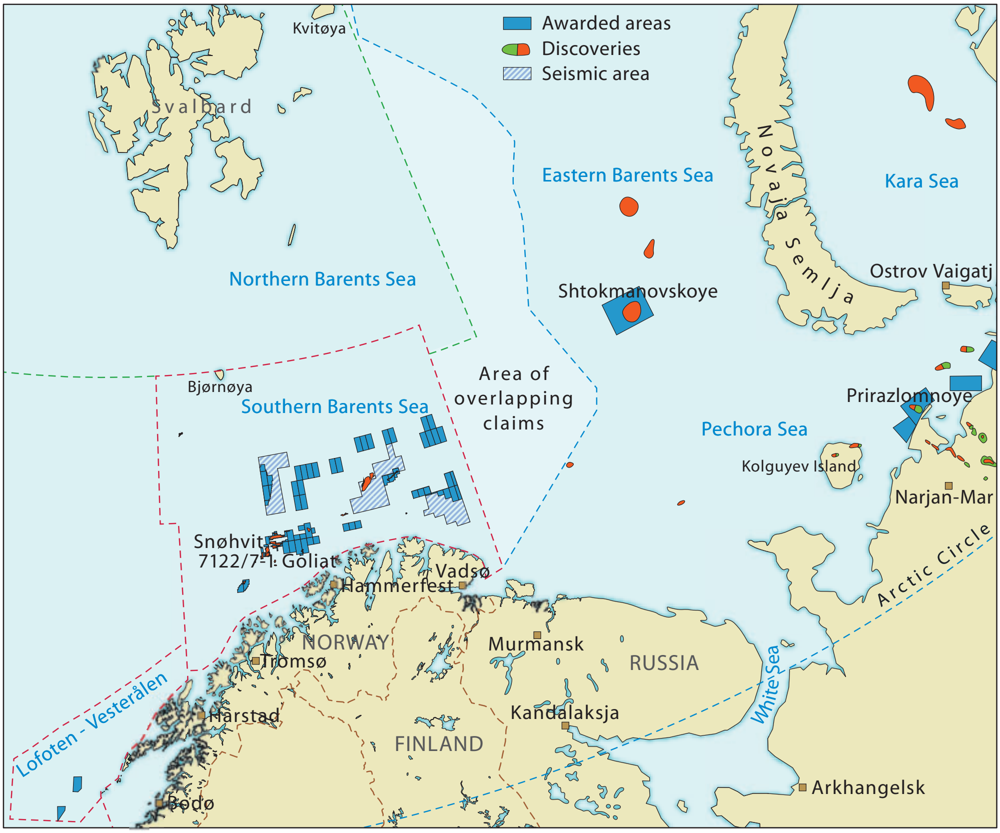


Figure 4.6 Norwegian and Russian part of the Barents Sea
(Source: Norwegian Petroleum Directorate)

decide whether it wants to implement new activities in the licence or relinquish the entire area. Relinquished acreage can be applied for by new companies that may have a different view on the prospectivity. This leads to a more rapid circulation of acreage and more efficient exploration of the mature areas.

At the expiration of the initial period the companies could previously retain as much as 50 per cent of the awarded area without obligation to carry out any specific activity. Today, the basic rule is that companies can only retain areas in which they plan to start production.

The area fee is also a policy instrument intended to help increase activity in the awarded areas. The idea behind the area fee is that no area fee shall be paid for areas where production or active exploration activity is taking place. In the initial period in which exploration activity proceeds according to a compulsory work programme, the licensees pay no fee. After the initial period, the licensees shall pay an annual fee to the state for each square kilometre of the area that is covered under a production licence. As of 1 January 2007, the area fee rules were intensified in order to reinforce the function of the fee in overall resource management. Under the new rules, the companies shall pay NOK 30 000 per square kilometre for the first year, with the rate increasing to NOK 60 000 for the second year. From and including the third year, the companies pay the maximum fee rate, which is NOK 120 000 per square kilometre. The companies

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

*Companies that no longer exist as individual companies

Figure 4.7 Prequalified/new companies since 2000 (As of 1st quarter 2008)
(Source: Ministry of Petroleum and Energy)

can achieve an exemption from the area fee if they submit a Plan for Development and Operation, a so-called PDO, to the Ministry of Petroleum and Energy. However, area fee exemptions are granted only for the areas that comprise the geographic extent of the resources, and for which a PDO has been submitted. The regulations also provide for area fee exemptions for two years if the companies drill a wildcat well.

Frontier areas

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

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

The announcement of the 19th licensing round in 2005 had particular focus on areas in the Barents Sea and the western part of the Norwegian Sea. The 20th licensing round is planned to be announced in the spring of 2008 with award of production licenses in 2009.

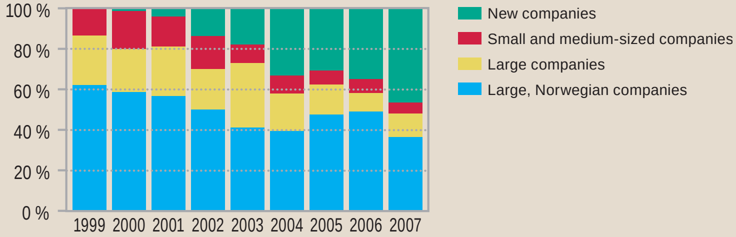
The gradual expansion of petroleum activities towards the vast frontier areas in the northern parts of the Norwegian continental shelf has necessitated a clarification of the terms and conditions for petroleum activities in these areas.

Storting White Paper No. 8 (2005-2006) *Comprehensive management plan for the marine environment in the Barents Sea and the waters of Lofoten* (Integrated Management Plan), was submitted to the Storting in the spring of 2006. The integrated management plan presents the framework for the petroleum activities in these areas. The plan gives guidelines as to where petroleum activites are permitted and on what conditions. Several programs have been initiated to gather more knowledge about the ocean areas in the plan, before the plan is to be revised in 2010. One of these is a three-year program for geological mapping and acquisition of seismic data at Nordland VII and Troms II, executed by the Norwegian Petroleum Directorate. In 2007, NOK 70 million was allocated for this program, and in 2008 the budget is NOK 140 million.

The work on an integrated management plan for the Norwegian Sea commenced in the spring of 2007. The aim is, as for the above-mentioned plan, to establish framework conditions that balance the interests of the fisheries, the petroleum industry and the shipping industry. The plan will consider the compound impact for the environment in these ocean areas and will set up the framework for regulating the different commercial interests in these areas. The integrated management plan for the Norwegian Sea is scheduled to be forwarded in the spring of 2009.

Unopened areas

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



Figur 4.8 Exploration costs in production licences in the North Sea according to the size of the companies *(Source: Norwegian Petroleum Directorate)*

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

Area with overlapping claims

The border between Norway and Russia remains unclear and is currently being negotiated by Russian and Norwegian authorities. This area, approximately equivalent to the Norwegian part of the North Sea, is marked on Figure 4.6.

Industry structure

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

Prequalification

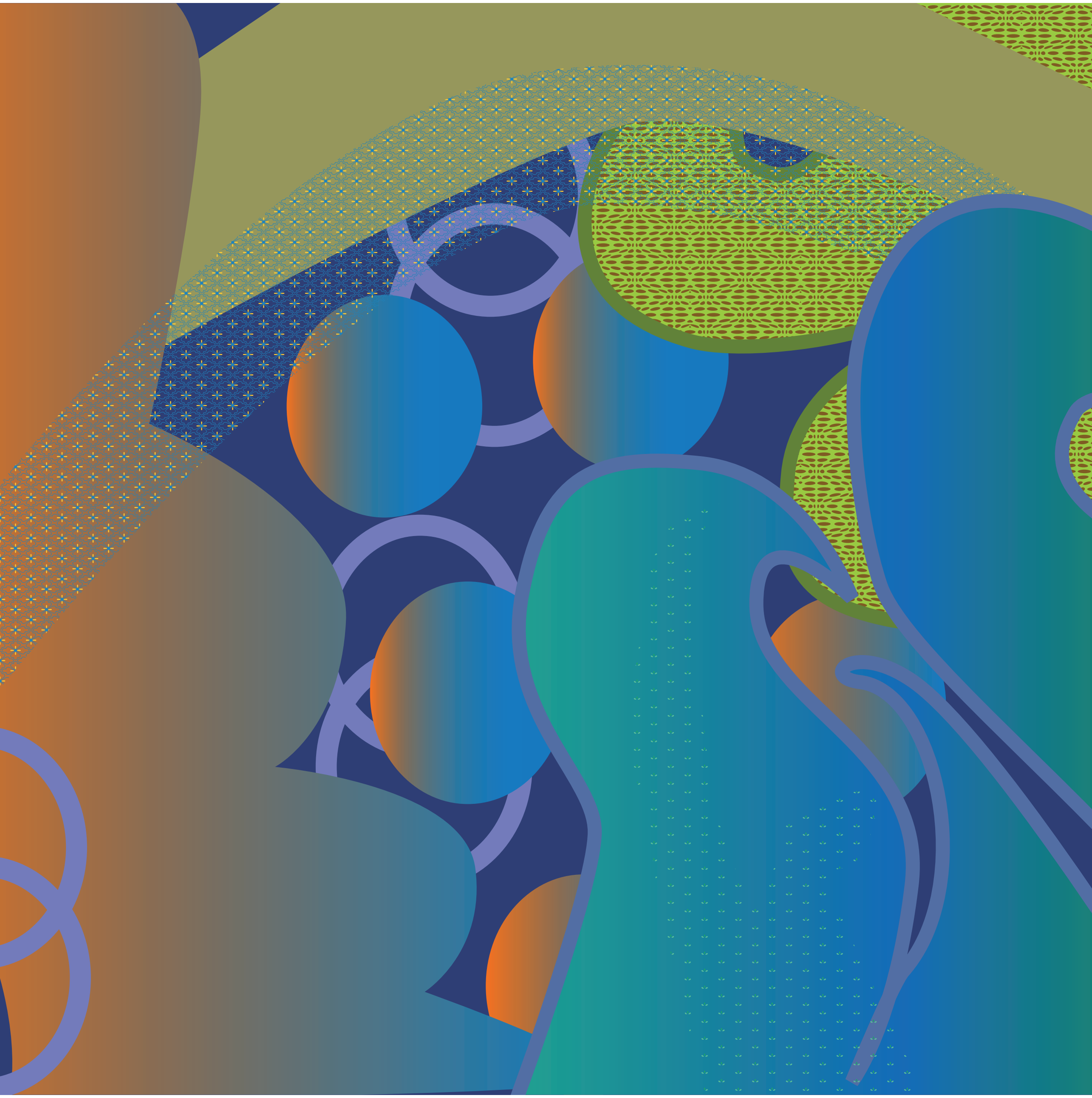
In order to facilitate the entry of new players, Storting White Paper No. 39 (1999–2000) *Oil and Gas Activities* introduced a system for prequalification of new operators and licensees. From the scheme's inception to January 2008, 48 companies have been prequalified for the Norwegian continental shelf (as of 1st quarter 2008). Additional companies are currently being evaluated or have indicated that they wish to become prequalified. Figure 4.7 shows prequalified companies on the Norwegian continental shelf since 2000.

Significant acreage and production licences have been awarded to these new players in the licensing rounds in mature areas. In the period 2004 - 2006, new players have accounted for about 30 per cent of the exploration costs in the North Sea.

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

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

5 Development and operations



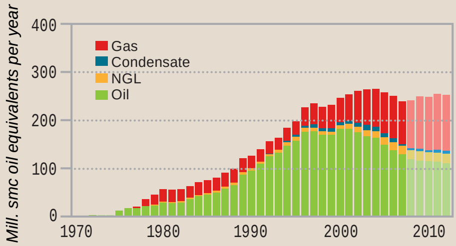


Figure 5.1 Total petroleum production and production forecast for the coming years.
(Source: Norwegian Petroleum Directorate)

In 2007, Norwegian oil and gas production totalled 238 million standard cubic metres (scm). Of this, natural gas production accounted for about 89 million scm, and an augmentation of 2 billion scm compared to the record-breaking year 2006. Natural gas sales are expected to increase further in 2008 to more than 99 million scm, with additional increases expected in the years to come. The natural gas share of total petroleum sales is expected to increase from 38 percent in 2007 to 46 percent in 2012. Figure 5.1 shows historical production of oil and gas, and expected production for the next few years.

At the end of 2007, there were 46 producing fields in the North Sea and nine producing fields in the Norwegian Sea. Four new fields, Blane, Enoch, Ormen Lange and Snøhvit, have come into production in 2007. Volve started producing in February 2008, and it is expected that Alvheim, Rev and Vilje will come on stream this year.

Historic development

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

Effective production of petroleum resources

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

Under petroleum industry framework conditions, companies are obliged to carry out prudent development and operation of proven petroleum resources. This means that the companies are responsible for submitting and executing new projects, whereas the authorities give the final consent for implementation. When a new deposit is to be developed, the company must submit a plan for development and operation (PDO) for approval. An important part of the development plan is an environmental impact assessment which interested parties are given the opportunity to comment upon in a hearing round. The impact assessment is to describe the development's expected impact on the environment, any transboundary environmental effects, natural resources, fisheries and society in

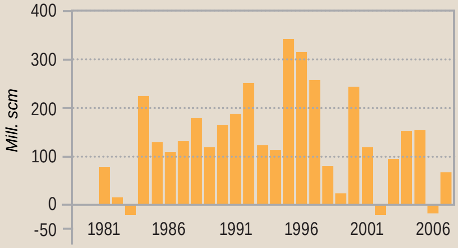


Figure 5.2 Gross reserve growth, oil 1981-2007
(Source: Norwegian Petroleum Directorate)

general. The governmental consideration of this assessment and of the development plan, ensures a prudent project in terms of resources, as well as acceptable consequences for other matters of public interest.

Development of proven petroleum resources i s the basis for production and value creation from the petroleum industry today, but the importance of exploiting the resources in the known areas is increasing. This constitutes an enormous potential that can generate significant values for society if it is exploited prudently. The Norwegian Petroleum Directorate has assessed this potential and has arrived at an objective for reserve growth on the Norwegian continental shelf of 800 million scm (five billion barrels) oil before 2015. This is equivalent to twice the original oil resources in the Gullfaks fields. This objective is a stretch target for both the industry and the authorities. If we are to realise this potential, we must increase recovery from fields in production, develop discoveries in the vicinity of existing infrastructure, prove and develop new resources and constantly operate the fields better and more cost-efficiently. Figure 5.2 shows annual growth of oil reserves in the period 1981–2007. The accounts for 2007 show a growth of 65 million scm of oil, included as new reserves. The largest augmentation in the oil reserves comes from the Skarv, Troll and Oseberg fields.

Increased recovery in mature areas

Parts of the Norwegian continental shelf are currently defined as mature areas. This term refers to areas that are characterised by familiar

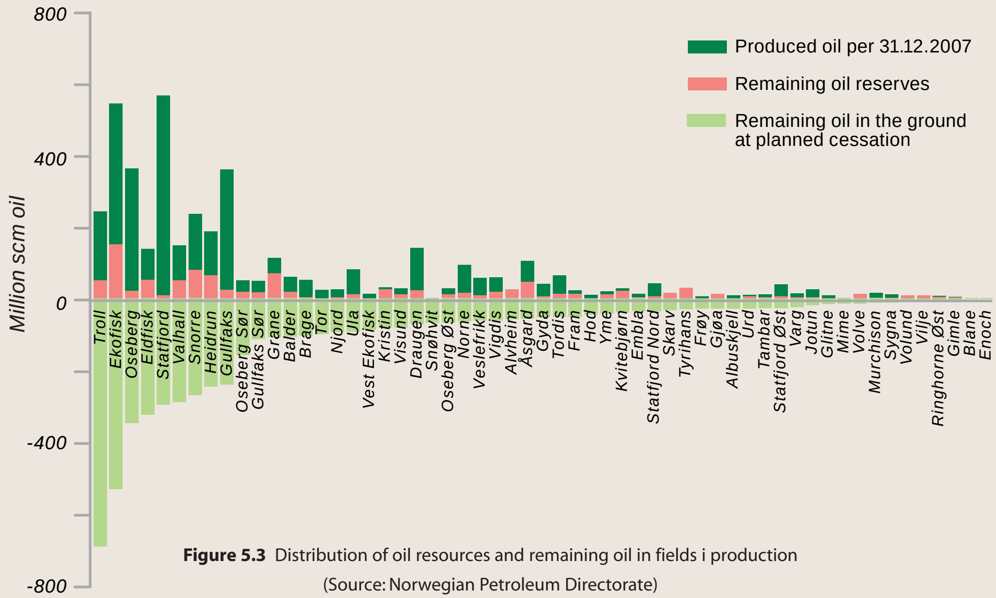


Figure 5.3 Distribution of oil resources and remaining oil in fields i production
(Source: Norwegian Petroleum Directorate)

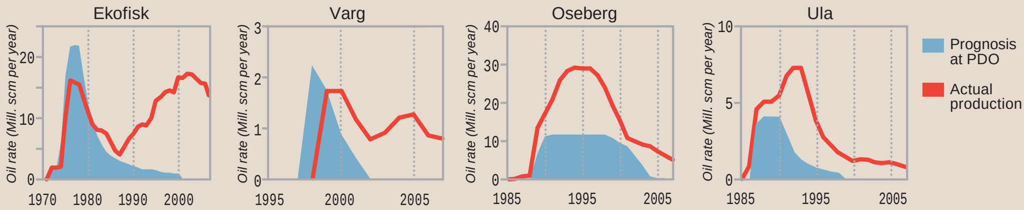


Figure 5.4 Production trends for Ekofisk, Varg, Oseberg and Ula
(Source: Norwegian Petroleum Directorate)

geology, well-developed infrastructure, falling production and increasing unit costs. There is still a considerable potential for value creation in these areas if we are able to increase the recovery rate in producing fields, streamline operations and explore for resources near existing infrastructure.

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

- Produced quantities
- Remaining reserves
- Resources that will be left in the ground after planned shutdown

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

Increased recovery

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

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

Extended lifetime

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

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

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

Efficient operations

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

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

Developments in communications technology have given rise to new working methods. The introduction of integrated operations in the petroleum activity, entail that information technology is used to alter work processes to achieve better decisions, to remote-control equipment and processes, and to move functions and personnel onshore. The goal is reduced costs and more effective operations.

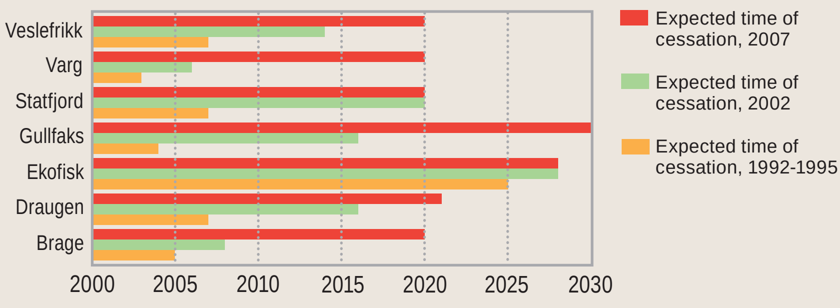


Figure 5.5 Lifetime for selected fields

(Source: Norwegian Petroleum Directorate)

In an international context, today's Norwegian petroleum industry has achieved great advances in the implementation of integrated operations. One of the reasons for this is that broadband (fibre-optic cable) has already been laid to many of the fields on the Norwegian continental shelf. Integrated operations have become an important element in many new developments. The 2007 annual status report from the operators indicates a committed effort towards integrated operations on many mature fields. Wherever profitable, existing fields will be linked to the digital infrastructure for implementation of the new technology.

New discoveries – effective use of infrastructure

In 2006, NOK 100 billion was invested on the Norwegian continental shelf. Total investments on the Norwegian continental shelf have now reached about NOK 2000 billion in current monetary value. This is equivalent to more than NOK 1 billion each week over the whole period. These investments have made it possible to establish extensive infrastructure which is a precondition for producing and marketing petroleum, but it also forms a basis for the development of additional resources in a cost-efficient manner.

As production from a field declines, spare capacity will often be available in the existing infrastructure. Such capacity may provide for an effective exploitation of resources that can be tied in to existing infrastructure. In some cases, the use of existing infrastructure will be a prerequisite for profitable development of new fields, because some of these deposits are too small to justify their own separate infrastructure. Exploration for and development of resources near existing infrastructure can result in significant value for the Norwegian society.

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

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

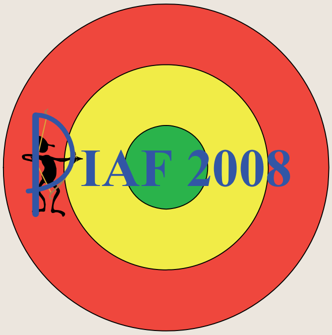
Future trends

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

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

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

PIAF



In 2005, the Ministry of Petroleum and Energy and the Norwegian Petroleum Directorate started the work of developing a new method to follow up the fields in production on the Norwegian continental shelf. The method was first implemented in 2006 and was called PIAF (performance indicator analysis for fields). PIAF will be carried out every year.

The background for this initiative was that the government wanted a more systematic and closer follow up of how the operators and the licensees work to develop the resources in and around fields in production, including increased recovery, phasing in additional resources and increasing the efficiency of operations. The operators in each of the fields work continuously on many different projects for operation and further development of the fields. The objective of PIAF is to ensure that the authorities have a better and more systematic overview over the development of resource growth, recovery operating costs and investments. Problems that obstruct the fields' development and possible improvement areas can be identified through PIAF. PIAF also makes it possible to distinguish between the problems concerning the entire continental shelf and the ones concerning specific fields.

In PIAF, field development is benchmarked in relation to the development in other fields, and the fields are ranked. This ranking is a supplement to the continuous follow-up of the petroleum activity. In total, this lays the foundation for the government's prioritisation of which fields and areas should be followed up. PIAF provides an objective overview of fields that have a better development compared to other fields, and which in certain areas represent a best practice in the petroleum activity.

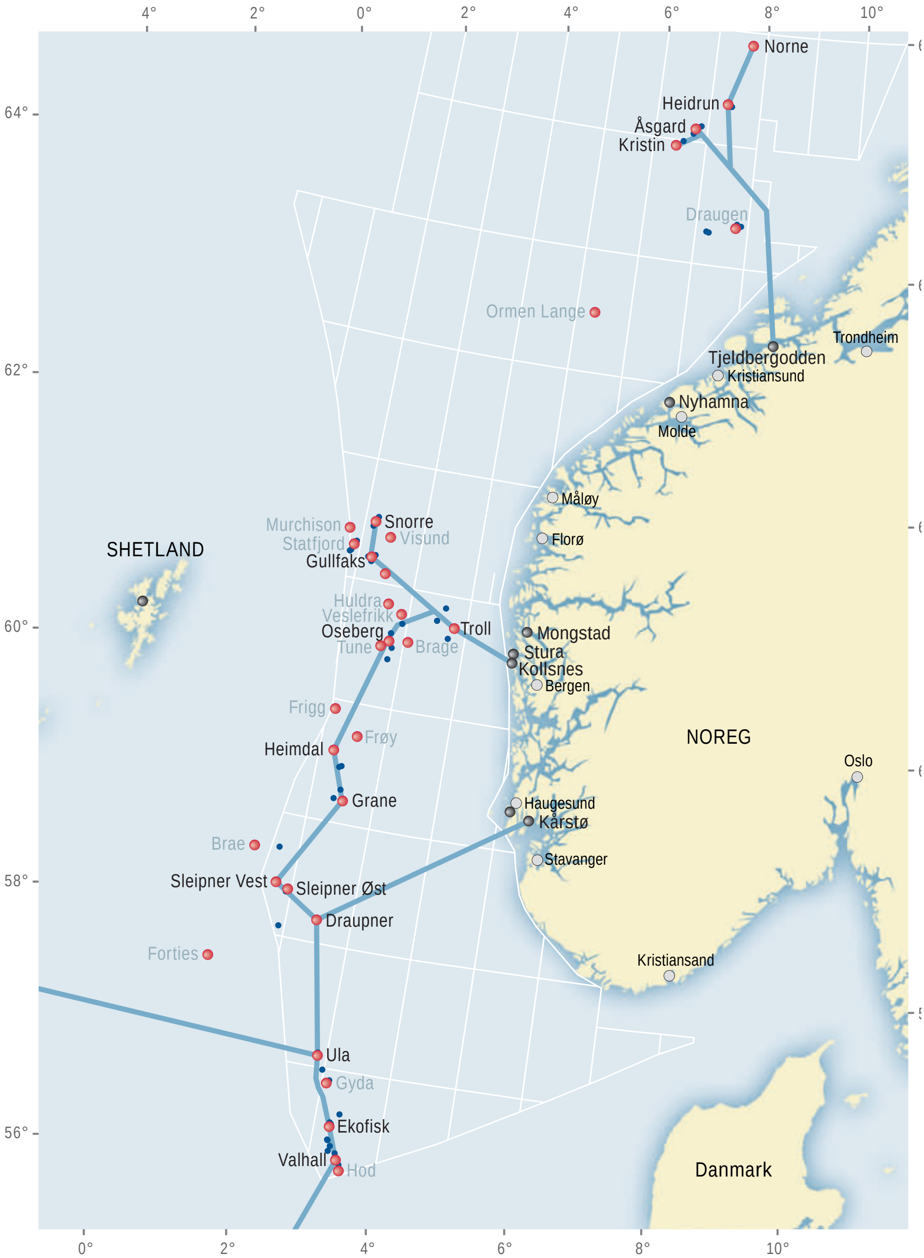


Figure 5.6 Optical fiber cables on the Norwegian continental shelf

(Source: Norwegian Petroleum Directorate)

6 Norwegian gas exports

Gas activities comprise an increasing part of the petroleum sector, and thus bring considerable revenues to the state. Norwegian gas is also important for the supply of energy in Europe, and is exported to all of the major consumer countries in Western Europe. In terms of energy content, gas exports in 2007 were about eight times larger than normal Norwegian power production. Norwegian gas exports supply approximately 16 per cent of the European gas consumption.[1] Most Norwegian exports go to Germany, the UK and France, where Norwegian gas accounts for 20 to 30 per cent of the total consumption. Producers on the Norwegian continental shelf have entered into sales agreements with buyers in Germany, France, the UK, Belgium, the Netherlands, Italy, Spain, the Czech-Republic, Austria and Denmark. With the Snøhvit field will Norway also supplies LNG (Liquefied Natural Gas) to the USA and other customers.

Current capacity in the Norwegian pipeline system is about 120 billion standard cubic metres (scm). There are four receiving terminals for Norwegian gas on the Continent; two in Germany, one in Belgium and one in France. There are also two terminals in the UK (see Figure 5.1). The Norwegian gas transport system consists of a network of 7800 km of pipelines. Treaties have been developed to govern rights and obligations between Norway and the countries that have landing sites for gas.

Achieving the highest possible value for Norwegian petroleum resources is a paramount goal. Most of the fields on the Norwegian continental shelf contain both oil and gas, so that attempts must be made to achieve the optimum balance between oil and gas production. At the same time, the gas management system must facilitate efficiency in all stages of the gas chain – exploration, development and transport.

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

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

Sector organisation

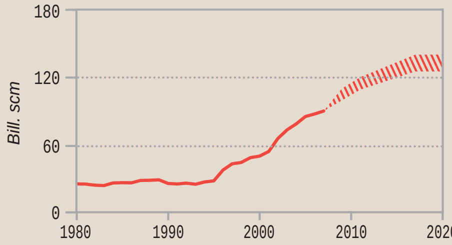
The general policy instruments employed in gas resource management are exploration policy, conditions for approval of development plans and production licences for oil and gas (see Chapters 4 and 5). Many fields on the Norwegian continental shelf contain both gas and oil. When awarding gas production licences, the authorities take into account optimum recovery of oil. On occasion, the authorities have awarded licences for production of less gas than applied for by the companies, out of consideration for the need to produce oil.

The authorities play an important part in establishing transport capacity and increasing system capacity. The authorities are responsible for studying alternative transport methods, in order to ensure efficient system development. At the same time, it is impor-

1 *OECD Europe*

Figure 6.1 Gas pipelines

(Source: Norwegian Petroleum Directorate)



Figur 6.2 Historic and expected Norwegian gas exports. The gas export is expected to reach a level between 125 and 140 bill. scm during the next decade.
(Source: Norwegian Petroleum Directorate/Ministry of Petroleum and Energy)

tant to ensure efficient operation, including achieving economies of scale. The Ministry of Petroleum and Energy employs a number of instruments to achieve this. Three central instruments in the Norwegian gas transport system are: The operator Gassco AS, the coordinated ownership Gassled and regulated conditions for access to the transport system. Use of these instruments is assessed in connection with development of new infrastructure and when the use of the existing infrastructure is changed. Operatorship, ownership and questions regarding regulated access can be employed independently.

Gassco

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

Gassco shall contribute to comprehensive further development of the Norwegian gas infrastructure. Development of the gas infrastructure must take place in a manner that is expedient for the existing gas infrastructure on the Norwegian continental shelf.

A neutral company ensures that consideration is given to the submitted development alternatives for infrastructure, as well as exploitation of economics of scale. Gassco's task is to coordinate the processes for further development of the upstream network of gas pipelines, and to assess the need for such further development. Gassco recommends solutions, but does not itself invest in infrastructure.

A neutral and independent operator of the gas transport system is important to ensure that all users of the system are treated equally, both in regard to making use of the system and to the consideration of capacity increases. This is necessary to ensure efficient exploitation of the resources on the Norwegian continental shelf. Efficient exploitation of the existing gas transport system may also contribute to the reduction, or postponement, of the need for new investments.

Gassled

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

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

Regulated access to the transport system

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

Gassled – overall ownership structure for gas transport

The ownership split in Gassled:

Petoro AS*	37,89 %
StatoilHydro ASA	20,45 %
StatoilHydro Petroleum AS	11,61 %
Total E&P Norge AS	8,00 %
Exxon Mobil Exploration and Production Norway AS	5,44 %
Norske Shell Pipelines AS	4,09 %
Mobil Development Norway AS	4,22 %
Norsea Gas AS	2,81 %
Norske ConocoPhillips AS	2,02 %
Eni Norge AS	1,56 %
A/S Norske Shell	1,24 %
Dong E&P Norge AS	0,68 %

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

Petoro's share in Gassled will be increased by approximately 8.4 per cent with effect from 1 January 2011, and the other licensees' shares will be adjusted correspondingly on the same date. The SDFI share in Norsea Gas AS is 40.0 per cent. When this is taken into account, the state, represented by SDFI, will have a share in Gassled of 39.4 per cent in 2003 - 2010 and 47.5 per cent from 2011. The licence period for most of the Gassled facilities will run until 31 December 2028.

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

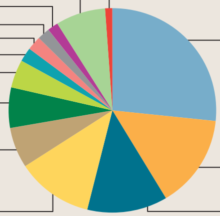
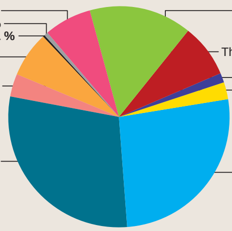


Figure 6.3 Sale of NGL/condensate 2007 in total 18.9 mill. scm o.e., by country of first destination. *(Source: Norwegian Petroleum Directorate)*



Figur 6.4 Norwegian natural gas exports 2007 in total 86.7 bill. scm., by country *(Source: Norwegian Petroleum Directorate)*

7 Decommissioning

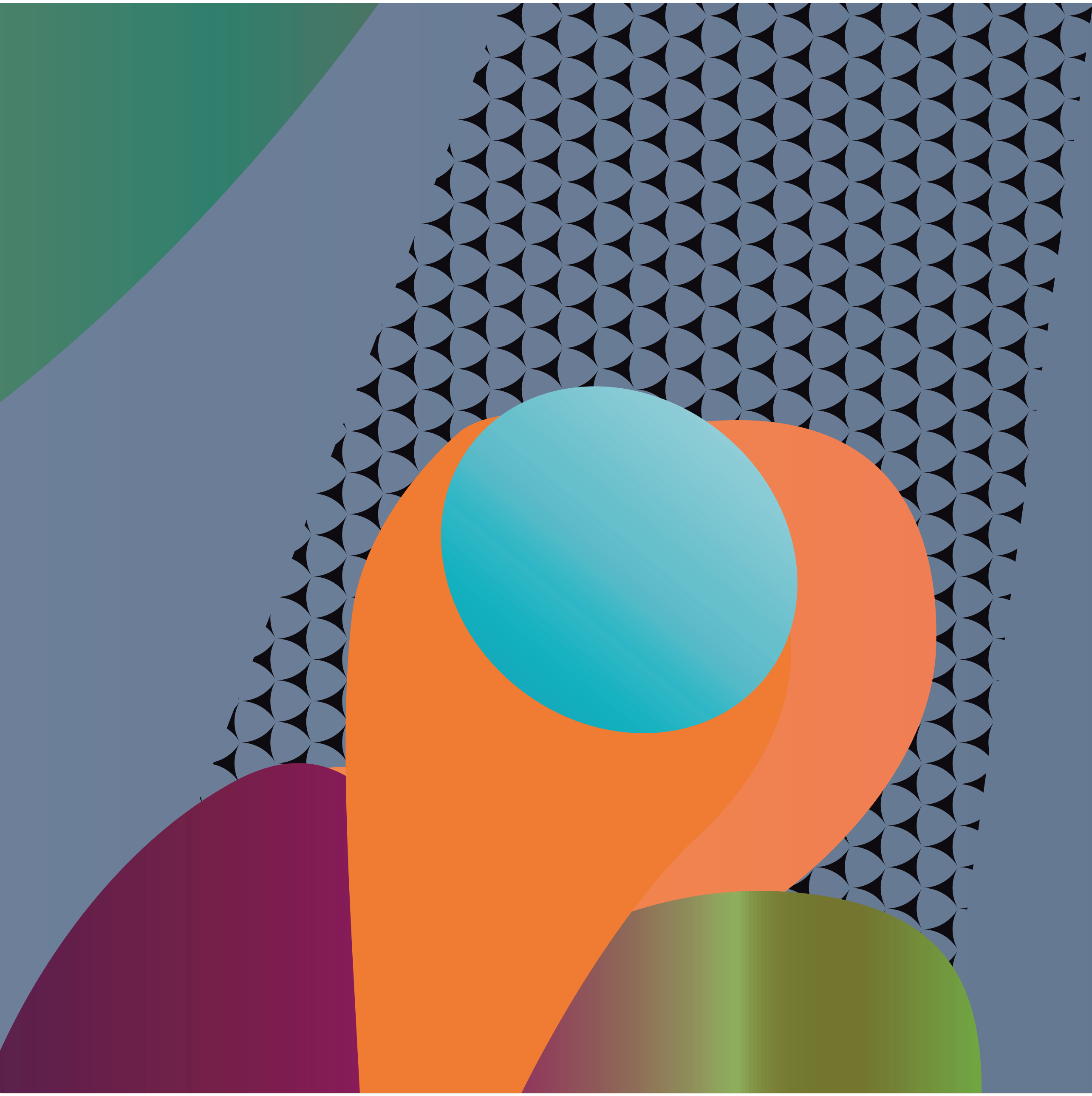


Figure 7.1 Drilling and production installation DP2, to be removed from the Frigg field
(Source: Total E&P Norge AS)

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

To date, the Ministry of Petroleum and Energy has approved more than 10 decommissioning plans. In most cases it has been decided that abandoned facilities are to be removed and taken ashore, e.g. Odin, Nordøst Frigg, Øst Frigg, Lille-Frigg, Frøy and TOGI. Following consideration of the decommissioning plans for Ekofisk I and Frigg, permission was given to leave in place the concrete substructure and protective wall on the Ekofisk Tank, as well as the concrete substructure TCP2 at the Frigg field. The work to remove the facilities on the Frigg field and parts of Ekofisk commenced in 2005. The decommissioning plan for MCP-01 is currently being considered by the Ministry.

The regulations

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

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

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

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

Decommissioning plans

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

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

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

Liability

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

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

(Source: ConocoPhillips)

8

Research, technology and industrial development

Norwegian petroleum industry

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

Supplier firms in Norway are represented in most steps of the value chain, from exploration and development to production and disposal. Norwegian suppliers are among the best in the world in fields such as seismic surveys, drilling equipment, subsea facilities and floating production solutions. These supplier firms are located in every county in Norway and the local and regional ripple effects of the petroleum activities are evident even in parts of the country that would not normally be expected to have a link to this industry. Approximately 100,000 people are employed in the petroleum sector in Norway.

Investments by oil companies in development, operation and maintenance on the Norwegian continental shelf generate a considerable demand for products and services from the supplier industry in Norway and abroad. In order to stimulate the continuation of this growth, the supplier firms must ensure that they continue their expansion into the international arena.

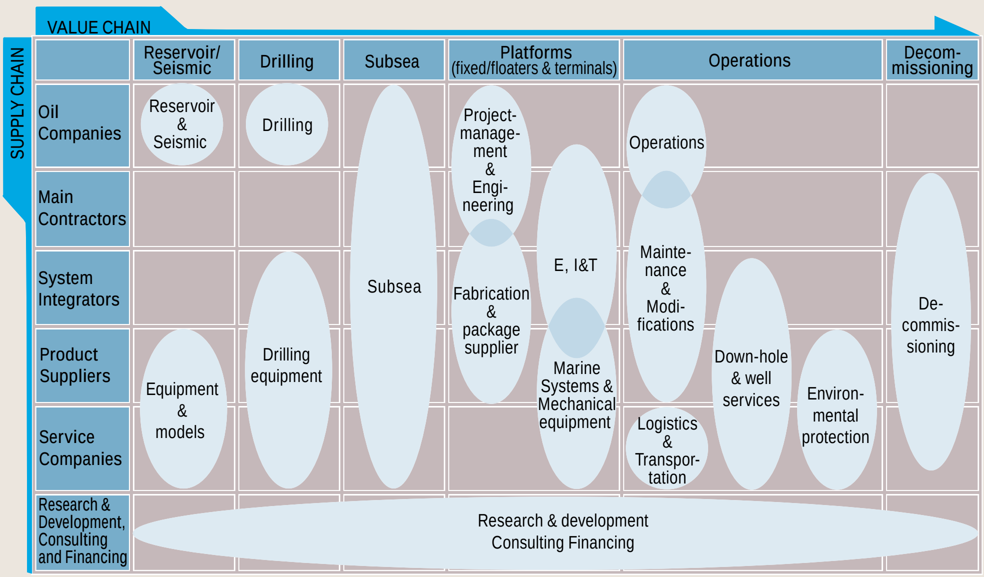


Figure 8.1 Interactive map of the Norwegian Oil & Gas "World-Class" Clusters

(Source: www.Intsok.com)

International experience and participation in international development projects are extremely important for the further development of the supplier industry. This international experience could also help reduce the cost level on the Norwegian continental shelf.

Industry and industrial cooperation linked to the petroleum industry

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

INTSOK

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

Petrad

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

Oil for development

The Ministry of Petroleum and Energy cooperates with the Ministry of Foreign Affairs, the Ministry of Finance and the Ministry of the Environment on a joint commitment to assist developing countries when it comes to petroleum administration and good management. This program includes:

- Reinforcing Norwegian bilateral assistance to countries requesting Norwegian petroleum expertise.
- Emphasis on sound governance and insight in petroleum management.

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

EITI

The Extractive Industries Transparency Initiative is an international initiative the purpose of which is to strengthen governance in resource-rich countries through the publication of revenues from oil and mining companies to the state. Publication of revenue streams may contribute to greater accountability on the part of the authorities to the populace. The initiative is supported by governments, non-governmental organisations and companies.

An overriding principle in the Norwegian authorities' petroleum management, as in all parts of the administration, is that it should meet the highest standards with regard to accountability. It is an important principle in Norwegian petroleum management that there should be transparency regarding tax payments to the state. The revenue streams are independently audited through the work of the Office of the Auditor General in Norway.

Norway is well-positioned to demonstrate international leadership regarding the issue of transparency of revenue streams from the petroleum industry. Norway has established the Oil for Development programme, which aims to build capacity and strengthen institutions in resource-rich developing countries. It is an aim of both the EITI and the Norwegian petroleum tax system to secure transparency of revenue streams. While Norway already has in place mechanisms for ensuring transparency of the tax revenue streams, Norway nonetheless decided in the fall of 2007 to implement the EITI in Norway. While Norway already meets the intentions of the EITI, the purpose of Norway's undertaking to implement the EITI is to further the initiative internationally.

The member companies in OLF, the Norwegian Oil Industry Association, share the government's ambition of greater revenue transparency in the extractive industries. On behalf of its members, the association has accepted that tax payments to the Norwegian state from oil companies present on the Norwegian continental shelf may be made public.

Norway also hosts the International Secretariat of the EITI. More information on the EITI may be found at www.eitransparency.org.

Research and technological development in the oil and gas sector

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

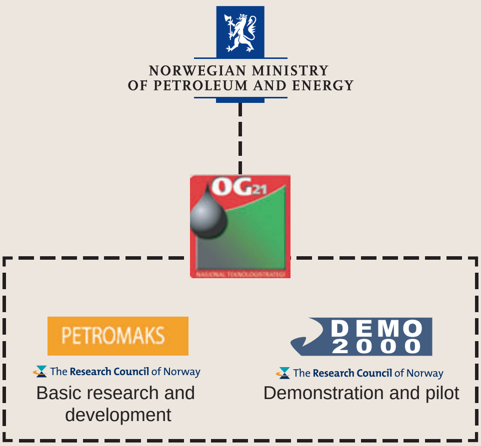


Figure 8.2 Ministry of Petroleum and Energy's involvement in petroleum research.
(Source: Ministry of Petroleum and Energy)

In order to meet the challenges associated with efficient, environmentally sustainable and safe petroleum activities, OG21 – oil and gas in the 21st century - was established on the initiative of the Ministry of Petroleum and Energy in 2001. The objective was to align prevailing focus in core competence segments and research efforts in the oil and gas industry within a common national technology strategy (the OG21 strategy). Today, OG21 is organised in a board, whose composition is determined by the Ministry of Petroleum and Energy, and a secretariat. The vision of OG21 is to develop new technology to maximise value creation on the Norwegian continental shelf, as well as increase the export of technology. The OG21 Forum is a meeting place where all parties with interest in petroleum research can participate in the OG21 strategy process and represents an important platform for outreach with the industry regarding the ongoing strategy work.

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

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

The authorities' contribution to petroleum research is largely organised in the PETROMAKS and DEMO 2000 research programs. These programs are intended to contribute to attaining the goals identified in the national technology strategy for the petroleum industry. The funds from the authorities are channelled through the Research Council of Norway, which coordinates the programs.

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

1 Environmental technology for the future.
2 Exploration technology and reservoir characterisation.
3 Enhanced recovery.
4 Cost-effective drilling and intervention.
5 Integrated operations and real time reservoir management.
6 Subsea processing and transportation.

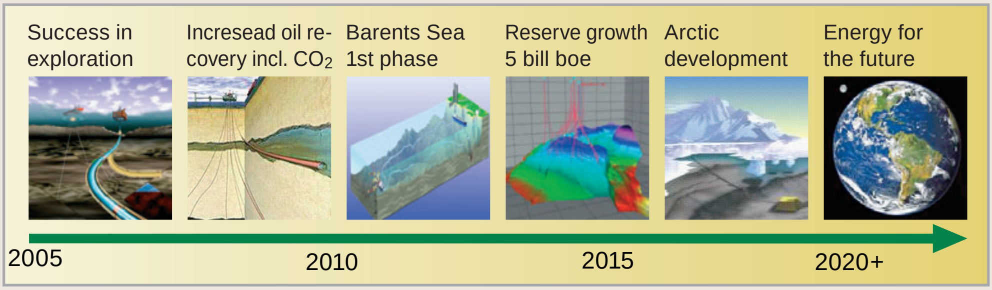


Figure 8.3 OG21's technology road map for value creation on the Norwegian continental shelf

(Source: OG21)

7 Deep water and subsea production technology.
8 Gas technologies.

Members of the new OG21 board were appointed by the Ministry of Petroleum and Energy in October 2007. The new OG21 board is chaired by StatoilHydro. OG21 is to submit an action plan to the Ministry during the first quarter of 2008. The action plan will define the most important actions that will be pursued during the term of the board.

PETROMAKS

PETROMAKS covers strategic fundamental research and development of expertise, research application and technology development. The programme's target groups are Norwegian companies and groups that wish to promote the build-up of knowledge and expertise in Norway, as well as productivity, innovation and exports in the petroleum sector. As the national strategy for petroleum research, OG21 serves to guide PETROMAKS' priorities in their calls for project proposals.

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

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

PETROMAKS also finances research on arctic-related challenges: Many of the obstacles in the far north are identical to those encountered on the Norwegian continental shelf. Exceptions include challenges related to extreme climate, less developed infrastructure, development and production in ice-affected areas, handling of ice and transport over very long distances. The Research Council of Norway (RCN) has not initiated particular programmes for the far north or the Arctic regions. Research on topics relevant to these areas is integrated within the RCN's existing activities, inter alia PETROMAKS.

DEMO 2000

An important initiative in the promotion of new technological solutions within the petroleum industry is the DEMO 2000 programme. DEMO 2000 targets projects where new technology can be demonstrated through pilot projects and field tests, and relates particularly to challenges associated with carrying research-based innovations into the market. New technology is often associated with high costs and high risk. DEMO 2000 aims to reduce such costs and risks by supporting pilot and demonstration projects. The programme contributes to the implementation of the national technology strategy, OG21.

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

The DEMO 2000 programme has supported demonstration of new petroleum technology since 1999. Some of the technologies developed through the programme are already available on a commercial basis, and have resulted in significant cost savings for the industry. DEMO 2000 believes that their ambition is a realistic one - to ensure that a greater number of new solutions can be put to commercial use within the coming years, both in Norway and abroad, including in technical disciplines such as seabed processing, gas compression on the seabed, efficient drilling and integrated operations (remote control). Innovations within these areas carry a substantial potential for increased value creation.

The DEMO 2000 programme, like PETROMAKS, emphasises developing and testing petroleum technology especially relevant to conditions pertinent to the far north and Arctic regions.

PETROSAM

PETROSAM is a social-scientific petroleum research programme. The aim of the programme is to increase knowledge and competence regarding social conditions relevant to strategic and policy-making decisions of the government and the petroleum sector. PETROSAM will also focus on international relations, in particular the Middle East and Russia. PETROSAM was established in 2006 and will run for five years.

PROOF

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

Other strategic research

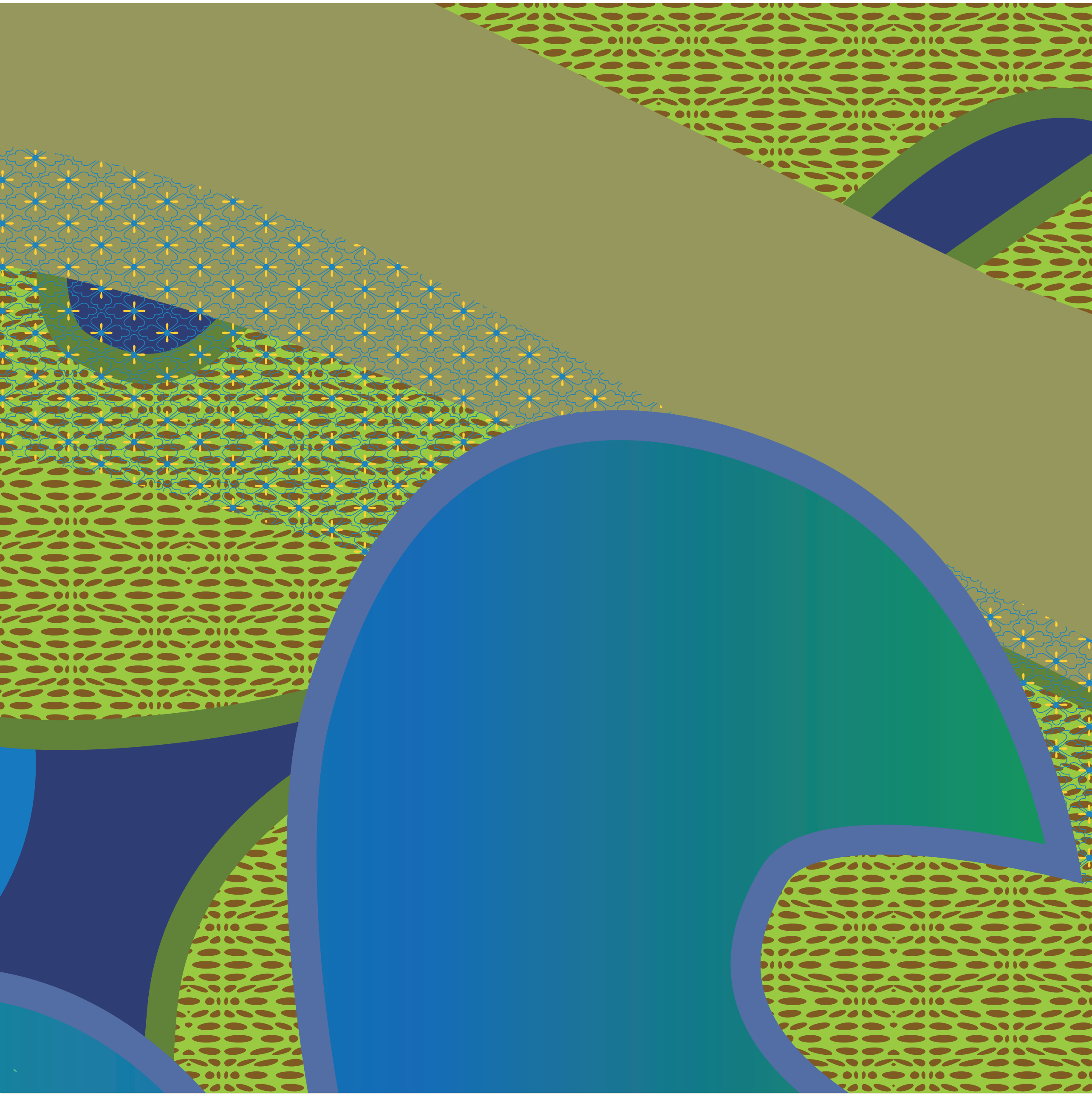
The MPE also finances strategic fundamental research which is conducted within the framework of priorities for petroleum-related disciplines. This research aims to establish world-class R&D expertise in the university and institute sector.

CLIMIT

CLIMIT is a cooperative programme between Gassnova and the Research Council of Norway, and relates to research, development and demonstration of technology associated with environmentally friendly gas-fired power production. The programme is financed partly by the Gas Technology Fund's returns, which are managed by Gassnova, and partly by funds channelled through, and managed by, the Research Council.

CLIMIT's vision is to contribute to profitable CO_2 capture from gas-fired power plants. The programme will cover financial support to the entire development chain, from long-term research for competence building to projects demonstrating CO_2 capture technologies. The project portfolio will mainly focus on technology solutions for cost-effective CO_2 capture. In addition, development of knowledge and solutions for safe and reliable capture of CO_2 in geological formations is being prioritised.

9 Environmental considerations in the Norwegian petroleum sector



Norway as a pioneer in environmental solutions

Consideration for the environment has always been an integrated part of the Norwegian petroleum activities. In order to ensure that Norway can combine its role as a major energy producer with being a pioneer in environmental issues, a comprehensive set of policy instruments has been developed to safeguard consideration for the natural environment in all phases of the activities, from licensing rounds to exploration, development, operations and decommissioning.

Norway was quick to take the climate issue seriously, and in 1991 it was one of the first countries to introduce a substantial CO_2 tax. This taxation has led to development of technology and triggered initiatives that lead to considerable emission reductions. The strict regulation of flaring through the Petroleum Act contributes to a low general level of flaring on the Norwegian continental shelf, compared with other countries. The authorities and the petroleum industry have worked together closely to reach the objective of zero environmentally hazardous discharges to sea from the petroleum activities (zero discharge target). The oil industry has invested over NOK 6 billion to reduce the discharges to sea. As a result, the zero discharge targets are considered to be achieved as regards discharges of environmentally hazardous chemical additives. As a result of the continuous strong emphasis on the environment, the Norwegian petroleum sector maintains very high environmental standards compared with petroleum sectors in other countries.

This chapter provides an overview of policy instruments designed to ensure that the environment is taken into consideration, measures implemented to reduce emissions and discharges, as well as the status of emissions to air and discharges to sea from the petroleum activities.

The various phases of the petroleum activities give different types of emissions and discharges. Exploration activity entails discharge of drill cuttings and emissions to air from energy production. During the operations phase there are discharges to sea and emissions to air, primarily water with residues of oil and chemicals (produced water), carbon dioxide (CO_2) and nitrogen oxides (NO_X) from energy production and flaring and non-methane volatile organic compounds (nmVOC) from storage and loading of crude oil. There is also a risk of acute oil spills both during the exploration and the operations phases.

Acts and legislation that regulate the petroleum sector

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

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

Agreements and obligations

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

In accordance with the Kyoto Protocol, Norway has committed itself to an emissions cap whereby average emissions for the years 2008 – 2012 shall not increase by more than one per cent compared to the emissions level in 1990. Relative to current levels, this implies a reduction of approximately seven per cent. The obligation can be met through reducing domestic emissions here in Norway, and in other countries by the use of the Kyoto mechanisms (international emission trading, the green development mechanism and joint implementation).

In June 2007, the Government presented a new white paper on climate policy. In its white paper, the Government proposes that Norway will improve its commitment under the Kyoto Protocol by 10 per cent. According to the agreement on climate policy of january 2008 between the Government and the opposition parties in the Storting, Norway will become carbon-neutral in 2030. In addition, the agreement on climate policy proposes reductions in Norway's greenhouse gas emissions of 15 -17 million tonnes of CO_2-equivalents by 2020, including forestry. This implies that approximately 2/3 of the total reductions in emissions will be carried out domestically.

With the Greenhouse Emission Trading Act, Norway has established a national quota system for greenhouse gases from 2005, as a follow-up to the Kyoto Protocol. The Greenhouse Emission Trading Act was revised in 2007. There was also a decision to implement the EU's Emission Trading Directive in the EEA Agreement. Thus, the Norwegian Emission Trading Scheme will be part of the EU's Emission Trading Scheme from 2008 to 2012.

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

Discharges of oil and chemicals may have local impacts in the immediate vicinity of the facilities. These discharges are regulated on a national basis

Policy instruments to reduce emissions/discharges from the petroleum activities

CO_2

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

With effect from 1 January 1991, the use of gas, oil and diesel in connection with petroleum operations on the Norwegian continental shelf is subject to CO_2 tax under the CO_2 Tax Act. As of 1 January 2008, the CO_2 tax is NOK 0.45 per litre of oil and standard cubic metre (scm) of burned gas (or approximately NOK 184/tonne CO_2). Under the Petroleum Act, burning of gas through flaring, beyond what is necessary to ensure the safety of normal operations, is not permitted without consent from the Ministry of Petroleum and Energy.

The Greenhouse Gas Emission Trading Act was revised in 2007. The petroleum sector offshore is now included in the Norwegian emission trading scheme from 2008, together with the facilities already subject to quota obligations in the first period from 2005 - 2007. The petroleum sector will have to buy all the quotas it needs in the market, however, the CO_2 tax is decreased so that the price of a quota and the CO_2 tax together amount to a corresponding level as the previous CO_2 tax alone.

NO_X

On November 28, 2006, the Storting (Norwegian Parliament) adopted a tax on emissions of NO_X, in pursuance of changes in the regulations relating to the Act concerning sales tax (1 January 2007). The tax comprises the total emissions from the petroleum sector from turbines with effect over 10 MW and engines over 750 hp. In addition, the tax applies to emissions from flaring. The tax is NOK 15/kg NO_X.

The objective of the tax is to reduce the annual emissions of NO_X in Norway to 156,000 tonnes before 2010, in accordance with Norway's commitment under the Gothenburg Protocol from 1999 (ratified by Norway 30 January, 2002). The tax mainly targets emissions from domestic activity, and includes emissions from large plants from the maritime, aviation, and land-based sectors, as well as emissions from the Norwegian continental shelf. Shipping companies, shipowners, proprietors of land-based activities, as well as operators on the Norwegian continental shelf are obliged to pay the NO_X tax.

In the operations phase, emissions of NO_X on the Norwegian continental shelf are regulated by means of terms stipulated in the PDO/PIO approval process. Emission permits covering NO_X can also be granted under the Pollution Control Act. The Norwegian Pollution Control Authority is currently working on updating the process for granting emission permits.

When the Storting considered the NO_X tax, it was decided that emission sources covered by an agreement with the Ministry of the Enviroment to create a fund to reduce nitrogen oxide (NO_X) emissions, would not be obliged to pay the NOx tax in addition. These agreements mandate implementation of NO_X reducing measures according to a fixed environmental goal.

The Norwegian State, represented by the Ministry of Environment has entered into an agreement on NO_X reducing measures with Norwegian business and industry organisations. Emissions from these organisations shall not exceed 98,000 tonnes in the geographical area prescribed by the Gothenburg Protocol. The organisations will establish a NOx fund that will help the organisations fulfil their obligations under the agreement.

nmVOC

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

Oil, organic compounds and chemicals

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

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

Zero environmentally hazardous discharges to sea

The objective of zero environmentally hazardous discharges to sea from the petroleum activities was established in Storting White Paper No. 58 (1996 –1997) *Environmental Policy for Sustainable Development* . Since then, the authorities and the industry have worked together in a dedicated group to precisely define the objective and identify methods for achieving this goal. This objective has also been discussed in several subsequent white papers such as White Paper No. 12 (2001 – 2002) *Pure and* abundant ocean and White Paper No. 38 (2003 – 3004) *About the petroleum activity.*

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

When selecting measures to reduce discharges from the individual fields, an overall assessment of the consequences for the environment, costs, safety and reservoir aspects must be carried out in the early work towards developing fields. It is therefore possible that the achievable target in practical terms on an existing field, based on such field-specific overall assessments, is minimising discharges. Operating companies on the Norwegian continental shelf were expected to be ambitious in their endeavours to achieve this goal, and they were also expected to work actively to develop and put to use new techniques that can contribute to achieving this goal. The oil industry has invested about NOK 6 billion in efforts to reduce discharges to sea since 2002.

Definitions of zero discharges and zero discharges targets

Definitions

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

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

Zero discharge targets

Environmentally hazardous substances:

- Zero discharges, or minimisation of discharges of naturally occurring environmental toxins encompassed by end objective No. 1 for chemicals hazardous to health and the environment, ref. the priorities list in Storting White Paper No. 25 (2002–2003).
- Zero discharges of chemical additives in the Norwegian Pollution Control Authority's black category (general prohibition on use and discharge) and the red category (high priority for phasing out via substitution)*.

Other chemical substances:

Zero discharges or minimisation of discharges of the following substances that can lead to harm to the environment:

- Oil (components that are not hazardous to the environment)*.
- Substances in the Norwegian Pollution Control Authority's yellow and green categories.
- Cuttings.
- Other substances that can lead to harm to the environment.

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

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

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

- No discharge of produced water. Injection of produced water is the assumed basis, or use of other technology that prevents discharge of produced water. In case of operation deviation, maximum 5 per cent of the produced water can be released to sea if it is cleaned (before discharge to sea).
- No discharge of drilling mud or drilling fluids. Drilling mud and drilling fluids will be reinjected or taken to land for disposal. Drilling mud from the top hole section may normally be discharged under the condition that the discharge does not contain substances with unacceptable environmental effects and only in areas where the potential for damage to vulnerable environmental components is considered to be low.
- No discharge to sea from well testing.

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

The goal for naturally occurring substances in produced water has not been accomplished to the same extent as for chemicals additives. Produced water contains residues of oil and chemical substances, both chemicals added in the process and naturally occurring chemical substances. With regard to oil and naturally occurring substances in produced water, process optimisations, reinjection of produced water and cleaning measures appear to contribute most to reducing the risk of harm to the environment, within an acceptable cost frame.

Reports from the companies show that many measures have been implemented. Several of the planned measures have been more time-consuming than expected. Thus, full effect from the measures can not be expected until in 2008/2009. In 2009, the government will assess goal achievement and the need for further measures to ensure that the goal of zero discharges to sea will be met.

The petroleum activity's per centage contribution to the national discharges to sea in 2004 was less than three per cent for all the environmentally hazardous substances in the Norwegian Pollution Control Authority's priority list.

Emissions and discharges from the petroleum activities

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

Measuring and reporting discharges and emissions

In most cases, emissions to air are calculated on the basis of the volume of fuel gas and diesel consumed on the facility. The emission factors are based on measurements from suppliers or standard figures developed by the industry itself, through the Norwegian Oil Industry Association, or using field-specific measurements.

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

The Norwegian Pollution Control Authority, the Norwegian Petroleum Directorate and the Norwegian Oil Industry Association have established a joint database to report discharges to sea and emissions to air from the petroleum activities. Since 2004, all operators on the Norwegian continental shelf report emission/discharge data directly in this database. This allows both the operating companies themselves and the authorities to more easily analyse historical emissions to air and discharges to sea in a more complete and consistent manner.

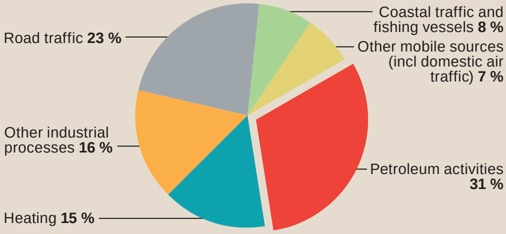


Figure 9.1 Sources of Norwegian emissions of CO_2 2007

(Source: Statistics Norway)

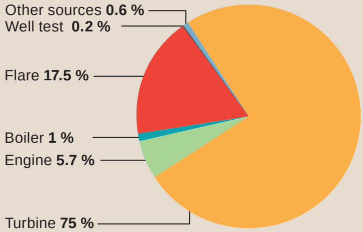


Figure 9.2 CO_2 emissions from petroleum activities 2007, by source

(Source: Norwegian Petroleum Directorate)

Emission status for CO_2

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

The environmental effects of CO_2 emissions include the following:

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

In a national context, petroleum activities are responsible for 31 per cent of CO_2 emissions (see Figure 9.1). This per centage is expected to fall in the years to come. Other major emission sources in Norway include road traffic and other mobile sources, heating and emissions from industrial processes.

The Norwegian continental shelf has reached a historic production level. In the years to come, CO_2 emissions from the petroleum sector will be approximately 14 million tonnes CO_2 annually. The emissions will peak around 2012, and towards 2020 the emissions will gradually decline due to decreasing production, improvement in technology and focus on environment.

Emissions from the petroleum sector are mainly linked to emission from power generation at the offshore facilities (see Figure 9.2). After the CO_2 tax was introduced in 1991, improved energy efficiency and reduced flaring led to a reduction in CO_2 emissions per produced oil equivalent from 1991 to 1997 (see Figure 9.3). The emissions are about to increase as a consequence of more energy demanding operations, more fields have entered into a mature phase with greater water production, as well as longer distances for gas transportation.

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

Measures for reducing CO_2 emissions

Development of combined solutions for energy production offshore (combined cycle power

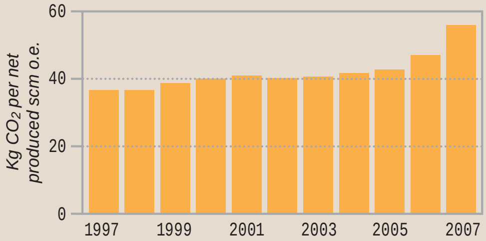


Figure 9.3 Emissions of taxable CO_2 per produced unit

(Source: Norwegian Petroleum Directorate)

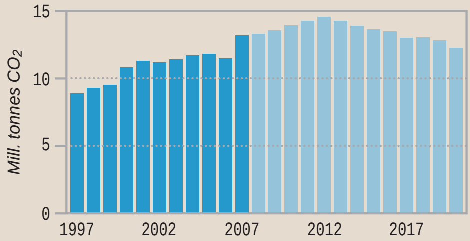


Figure 9.4 Emissions of CO_2 from the Norwegian petroleum sector

(Source: Norwegian Petroleum Directorate)

CO_2 emissions from production in Norway compared to the international average

Emissions on the Norwegian continental shelf are low compared to most other producing countries in the world. The figure shows Norway's emissions compared to the world average.

The figure shows emissions of CO_2 per produced unit of petroleum, and shows the development in emissions for Norway and for the world. Norway's emissions per produced unit in 2006 were approximately 47 kg per scm oil equivalent. The international average for the same year was approximately 120 kg per scm per oil equivalent.[1]

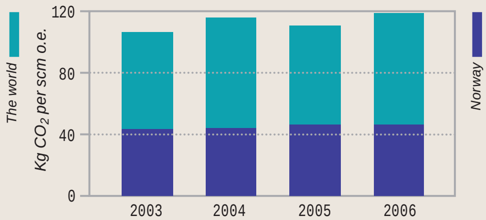


Figure 9.5 Emissions of CO_2 per produced unit in Norway compared to the world average (2003-2006) (Source: Norwegian Petroleum Directorate)

1 Source: International Association of Oil and Gas Producers, www. ogp.org.uk

plants), recirculation of flare gas and injection of CO_2 from produced gas at Sleipner Vest are examples of the Norwegian continental shelf 's leading-edge position in terms of implementing efficient environmental solutions.

Combined power solutions

A combined cycle power plant is a solution where heat from turbine exhaust gas is used to produce steam, which in turn is used to generate electric power. Combined cycle power increases energy efficiency, and is currently in use on the Oseberg, Snorre and Eldfisk fields. These facilities are unique in a global offshore context.

Storage of CO_2

CO_2 can be injected and stored in depleted oil and gas reservoirs, or in geological formations under water or on land. Since 1996, one million tonnes of CO_2 have been stored annually in the Utsira formation in connection with processing of gas from the Sleipner field. Storing CO_2 in the Utsira formation is unique. This is the only facility in the world where large quantities of CO_2 are stored in a geological formation under the seabed. On the Snøhvit field, separation and storage of CO_2 commenced in April this year. At the onshore LNG-plant on Melkøya, CO_2 is separated from the natural gas and piped back to the field, where the CO_2 is reinjected into the ground and stored in the Tubåen formation, 2600 metres beneath the seabed. At full capacity on Snøhvit, 700,000 tonnes of CO_2 will be stored per year.

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

The Norwegian authorities work actively to ensure that such storage of CO_2 can be achieved in a safe and secure manner. Work is therefore being undertaken under the auspices of the OSPAR and London Conventions to ensure that sound international regulations for CO_2 storage are established. In the autumn of 2006, it was agreed under the London Convention that injection and storage of CO_2 in geological formations under the seabed would be allowed. This change entered into force on 10 February 2007. Similar changes were made to the OSPAR Convention in the summer of 2007. The changes will enter into force when at least seven of the parties to the convention have ratified the changes in the resolution.

The Ministry of Petroleum and Energy has given Gassco, Gassnova, the Norwegian Petroleum Directorate and the Norwegian Water Resources and Energy Directorate the task of evaluating different solutions for transport and storage of CO_2 from the CO_2 capture plants, including Kårstø and Mongstad. The group is to make a recommendation on solutions for transport and storage of CO_2, taking into consideration cost evaluations, reservoir conditions and technological risk. The initial recommendation was submitted in the summer of 2007. According to the plans, an investment decision will be made in 2009.

On assignment from the Ministry of Petroleum and Energy, Gassco has followed up the work and evaluated temporary transportation and storage solutions from the Mongstad Test Centre for CO_2 capture and storage. The costs involved in the different alternatives have turned out to be very high, and the Government has decided to finalize the project related to a temporary transportation and storage solution for the testing period. To help compensate for the release of captured CO_2 from the Mongstad Test Centre for a period of time, the Government consider to purchase additional quotas for the emissions.

A new state-owned enterprise, Gassnova SF, was established in July 2007. The enterprise has been given responsibility for the state's interests in the test centre at Mongstad, the work on CO_2 capture and storage at Kårstø, as well as the projects to study transportation and storage of CO_2.

Use of CO_2 to enhance oil recovery

The Norwegian Petroleum Directorate has estimated that there is a significant technical potential for improved oil recovery through the use of CO_2 in oil fields on the Norwegian continental shelf. New studies, among others the Draugen CO_2-chain, have shown negative profitability using assumptions that take into account current costs and oil prices. The great potential, as well as focus on emissions, implies that the Norwegian Petroleum Directorate still will have a special focus on use of CO_2 to enhance oil recovery.

Power plants and energy efficiency

CO_2 emissions from power production account for approximately 90 per cent of the total emissions from offshore activities. In 2004, the authorities and the industry worked together to carry out a study of the potential for more efficient power supply on the Norwegian continental shelf. The study concluded that a realistic, although ambitious, estimate of potential emission reductions was between five and ten per cent over a period of ten years. This improvement has already been included in the forecast for CO_2 emissions from

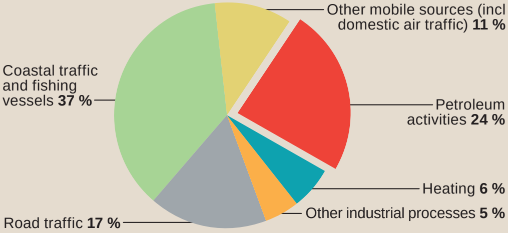


Figure 9.6 Sources of NO_x emissions in Norway, 2007

(Source: Statistics Norway)

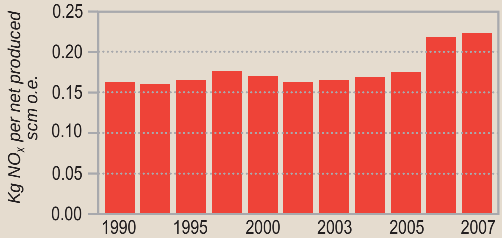


Figure 9.7 NO_x emissions per produced unit

(Source: Norwegian Petroleum Directorate)

the sector. This can be achieved if the industry systematically implements energy management in all aspects of the operations. The industry will follow up the authorities' study. The Norwegian Oil Industry Association is working on developing common guidelines for establishing and implementing energy management.

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

Flaring

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

Emission status for NO_X

Emissions of CO_2 and NO_X are closely connected. As for CO_2, gas combustion in turbines, flaring of gas and diesel consumption on the facilities are key emission sources also for NO_X. The volume of emissions depends both on the combustion technology and the quantity of fuel used.

The environmental effects of NO_X emissions include the following:

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

Mobile sources account for the majority of the Norwegian NO_X emissions (see Figure 9.6). The petroleum sector contributes 24 per cent. Emissions of NO_X per produced oil equivalent have slightly increased since 1997 (see Figure 9.7). The total emissions of NO_X from the sector have also increased compared with 1991 (see Figure 9.8). The main cause of the growth so far is increased activity, which has entailed a need for more energy, and in turn, more emissions.

Measures for reducing NO_X emissions

Most of the measures designed to reduce CO_2 emissions also contribute to reducing NO_X emissions from the petroleum sector. Other measures that can help reduce NO_X emissions include introducing low-NO_X burners as standard on gas turbines on new facilities.

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

Injection of steam or water in the combustion chamber can reduce NO_X emissions. However, this technology is not in use today because steam or water injection is not qualified to be used offshore. Among other things, there are great challenges related to the fact that the technology requires great amounts of clean water. However, in the future, this technology could contribute to

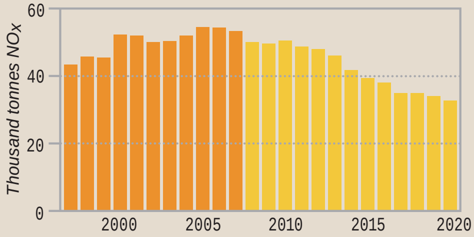
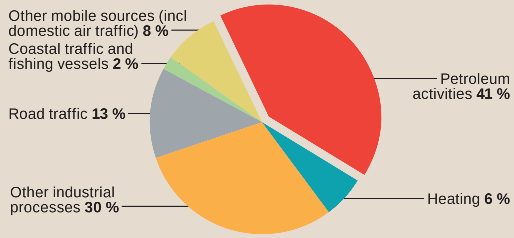


Figure 9.8 Emissions of NO_x from the petroleum sector
(Source: Norwegian Petroleum Directorate)



Figur 9.9 Sources of Norwegian emissions of nmVOC, 2007
(Source: Statistics Norway)

reducing NO_X emissions from the petroleum sector even more.

NOx from flaring
The emission forecast for NO_X is lower this year than previous years because one of the factors used to estimate NO_X emissions from flaring has been reduced.[2]

Emission status for nmVOC

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

- Formation of ground-level ozone, which can damage health, crops and buildings.
- Direct exposure to nmVOC can cause respiratory tract damage.
- NmVOC contributes indirectly to the greenhouse effect in that CO_2 and ozone are formed when nmVOC reacts with air in the atmosphere.

The petroleum sector is the main source of nmVOC emissions in Norway (see Figure 9.9), accounting for approximately 41 per cent of total emissions. Emissions of nmVOC largely originate from storage and loading of crude oil offshore. Minor emissions also occur at the gas terminals and in connection with small leaks. Other industrial processes and road traffic are also important sources of nmVOC emissions in Norway. The petroleum sector's share of this is shrinking due to the phase-in of emission-reducing technology. Emissions of nmVOC per produced unit of oil have also declined in recent years (see Figure 9.10).

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

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

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

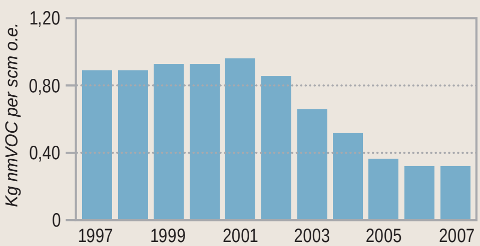


Figure 9.10 Sources of nmVOC emissions per produced unit
(Source: Norwegian Petroleum Directorate)

2 A factor of 12 g NO_x per scm gas flared been used previously. As a result of work under the auspices of Sintef, this factor has been downgraded to 1.2 g NO_x per scm gas flared as a basis for estimation. The factor has also been used in the emission forecasts. The consequence of the changed factor is between 4000 – 5000 tonnes NO_x annually.

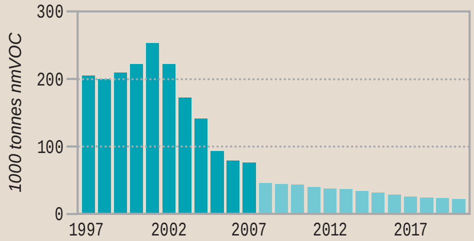


Figure 9.11 Emissions of nmVOC from petroleum activities
(Source: Norwegian Petroleum Directorate)

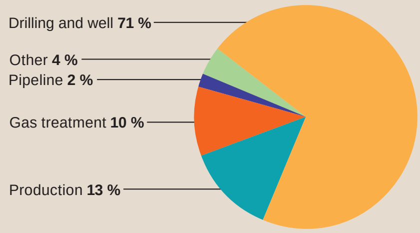


Figure 9.12 Discharges of chemicals from petroleum activities, by sources, 2007
(Source: Norwegian Petroleum Directorate)

Measures for reducing nmVOC emissions

For a number of years, the oil companies have worked to make technology for recovering nmVOC available to storage vessels and shuttle tankers. Today, tested technology exists that can reduce emissions from loading by approximately 70 per cent. Several vessels have now installed technology to reduce emissions. The operators of fields with buoy loading on the Norwegian continental shelf have formed a joint venture (see text box page 79).

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

Discharge status for chemicals, oil and other organic compounds

Discharges of chemicals

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

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

Some of the environmental effects caused by chemicals:

- They have a certain local toxic effect, but are diluted in the water column so that the acute impact on the environment is not very significant other than in the immediate vicinity of the discharge.
- A small per centage of chemical discharges may have very serious environmental consequences, including hormone disruption or bioaccumulation.

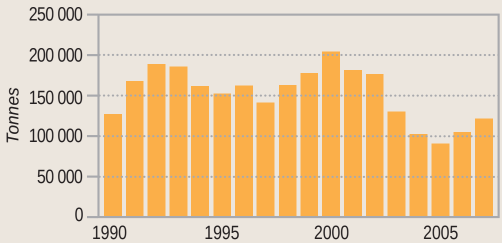


Figure 9.13 Total discharges of chemicals from petroleum activities
(Source: Norwegian Petroleum Directorate)

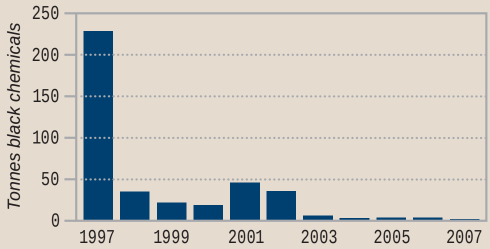


Figure 9.14 Discharges of black chemicals from petroleum activities *(Source: Norwegian Petroleum Directorate)*

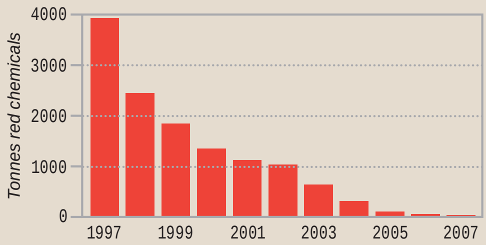


Figure 9.15 Discharges of red chemicals from petroleum activities *(Source: Norwegian Petroleum Directorate)*

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

Most chemical discharges are associated with drilling activity (see Figure 9.12), and discharge volumes vary according to the level of activity taking place. Figure 9.13 shows the development in total discharges of chemicals from the petroleum activities. Discharges of added environmentally hazardous production chemicals (black and red chemicals, ref. Norwegian Pollution Control Authority's classification) have been reduced by 94 per cent for black chemicals and 98 per cent for red chemicals since 2000. Figures 9.14 and 9.15 illustrate the development in discharges of environmentally hazardous chemicals.

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

Discharges of oil and other naturally occurring chemical substances

Total discharges of oil from the Norwegian petroleum activities account for a small portion of the total discharges into the North Sea. The majority of oil discharged into the North Sea is considered to come from shipping and from the mainland via rivers. Figure 9.16 provides an overview of acute oil discharges greater than one cubic meter (m^3). All acute discharges from the facilities on the Norwegian continental shelf are reported to the National Coastal Administration, and the causes of the discharges are investigated.

During 40 years of oil and gas activities the operations have not caused major acute oil spills that have reached land – and the number of discharges greater than one cubic meter are few. In 2006, the total volume of acute discharges to sea was 122 m^3. Unfortunately, in December 2007, there was an incident at the Statfjord field in the North Sea involving discharge of approximately 4408 m^3 of oil – the second largest discharge of oil on the Norwegian continental shelf. This oil discharge was a serious reminder that there are risks involved in all offshore operations. As a consequense, the total volume of acute discharges to sea for 2007 was 4488 m^3. The objective for the industry and the authorities is to continue to reduce the risk of oil spills from future operations on the Norwegian continental shelf.

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

Oil discharges from the petroleum sector largely occur in connection with ordinary operations. Water that is produced with oil and gas contains remnants of oil in the form of droplets (dispersed oil), other organic components (including dissolved oil fractions), inorganic components (heavy metals, naturally low-radioactive compounds, etc.) and residues of chemical

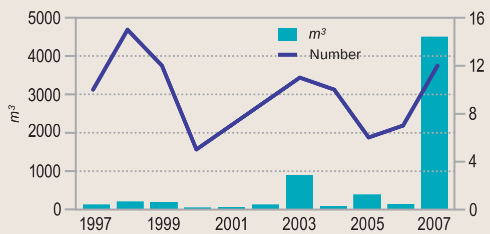


Figure 9.16 Acute oil discharges of more than one cubic meter *(Source:Norwegian Petroleum Directorate)*

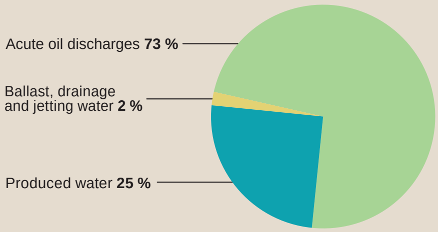


Figure 9.17 Discharges of oil from petroleum activities, by activity, 2007 *(Source: Norwegian Petroleum Directorate)*

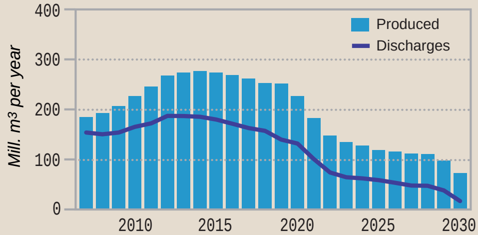


Figure 9.18 Forecast for produced water and discharges of produced water *(Source: Norwegian Petroleum Directorate)*

additives. The produced water is reinjected into the subsurface or cleaned to the extent possible before it is discharged to sea. Oily cuttings and drilling fluid that previously accounted for a large share of the oil discharged from the petroleum activity, is now reinjected into suitable reservoirs or. taken to land for further treatment. Figure 9.17 shows oil discharges distributed by activities, while Figure 9.18 illustrates the predicted development in the volume of produced water and discharges of produced water. Implemented actions have led to considerable reductions in the discharge of oil per unit of produced water. Due to maturing fields, the implemented actions do not exceed the increase in discharges, although the discharges have been stabilized at the current level. Figure 9.19 shows the total oil discharges and the average concentration of dispersed oil in water (mg/litre).

New research results indicate that alkyl phenol in produced water does not entail a risk to the fish populations in the North Sea. However, potential long-term effects are uncertain. To increase this knowledge, the Ministry of Petroleum and Energy, the Ministry of the Environment and the petroleum industry have cooperated to finance the research program "Long-term effects of discharges to sea from the petroleum activity (PROOF)", which was initiated in the autumn of 2002 under the Research Council of Norway. The program has now been continued as a subsidiary program (PROOFNy) under the research program "Sea and Coast".

The main areas included in PROOFNy are effects in the water column, special research assignments in the Arctic region, the link between research and monitoring, long-term effects of acute spills and the discharge of cuttings. The program also hopes to focus on projects in the area of synergetic effects on the ecosystem.

Industry joint venture

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

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

The joint venture agreement was signed in 2002, and 27 companies take part in this collaboration which covers buoy loading of oil from Varg, Glitne, Jotun, Balder, Gullfaks, Statfjord, Draugen, Njord, Åsgard and Norne.

At the end of 2005, nmVOC-reducing technology had been installed on 13 buoy loaders, as well as on two ships transporting oil from Heidrun. The nmVOC-emissions was reduced by approximately 40.000 tonnes. Focus in the future will be on measures to achieve high operational regularity on existing facilities.

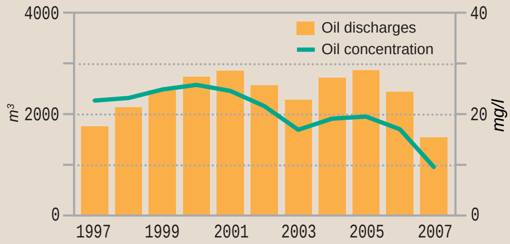


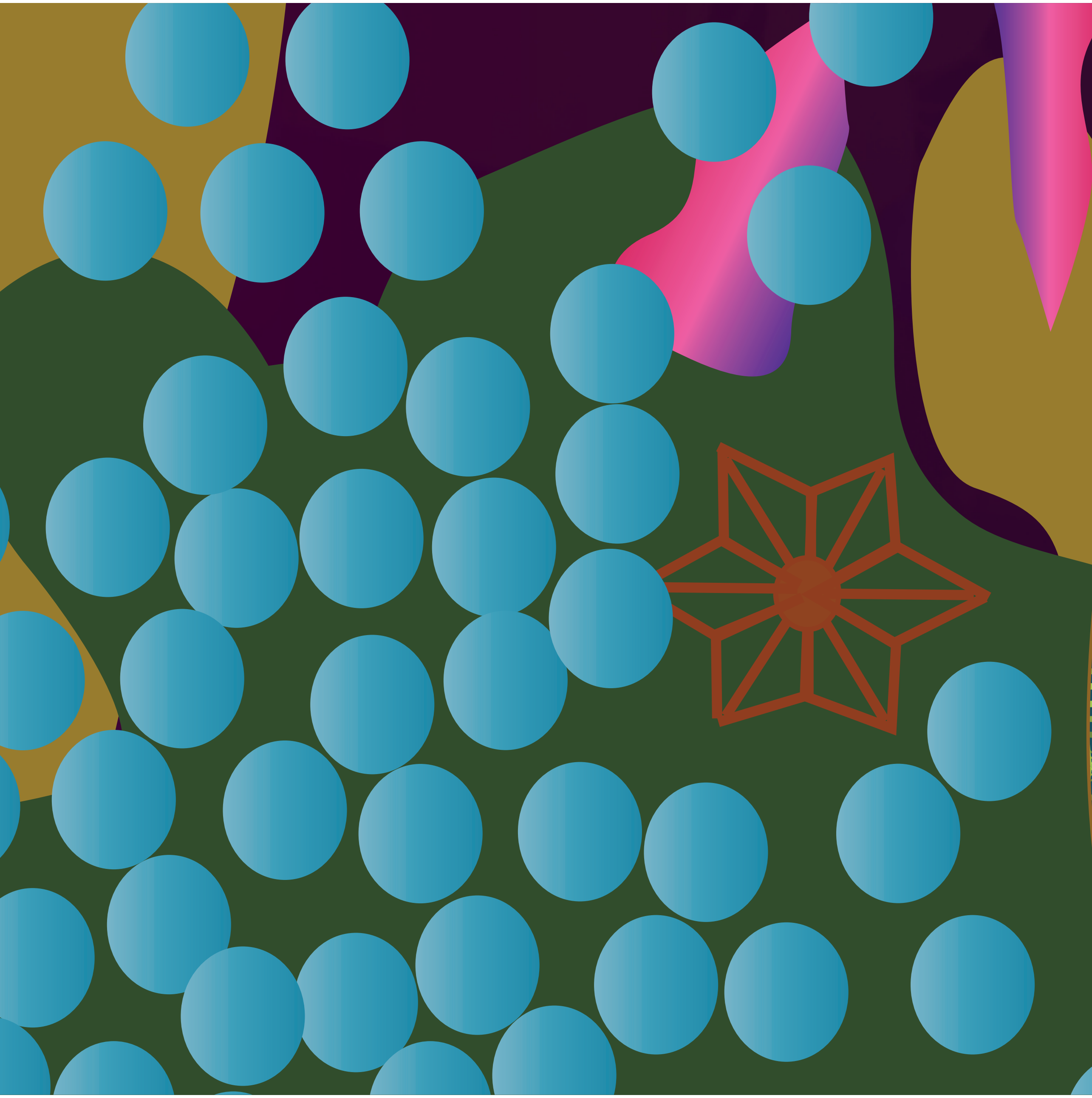
Figure 9.19 Discharge of oil in produced water and corresponding oil concentration (Source: Norwegian Petroleum Directorate)

Oil spill preparedness

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

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

10 Petroleum resources



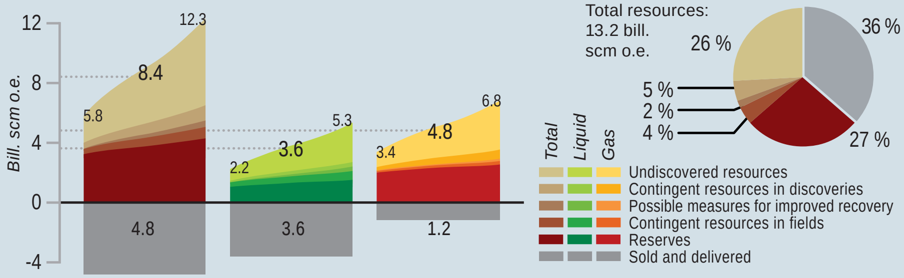


Figure 10.1 Petroleum resources and uncertainty in the estimates at 31.12.2007
(Source: Norwegian Petroleum Directorate)

The Norwegian Petroleum Directorate (NPD) estimates that the total discovered and undiscovered petroleum resources on the Norwegian continental shelf (NCS) amount to approximately 13 billion standard cubic meters of oil equivalents (scm o.e.). Of this, a total of 4.8 billion scm o.e., or 36 per cent of the total resources, have been produced. The total remaining recoverable resources amount to 8.4 billion scm o.e. Of this volume, 5.0 billion scm o.e. are proven resources, while the estimate for undiscovered resources is 3.4 billion scm o.e.

Resource growth from exploration activity in 2007 was relatively good. 12 new discoveries were made. The total recoverable resources from exploration activity are 49 million scm oil and 17 billion scm gas. Some of the discoveries are still being evaluated and the estimates are thus very uncertain.

Since petroleum production began on the Norwegian continental shelf in 1971, a total of 4.8 billion scm o.e. have been produced from 69 fields. In 2007, the Blane, Enoch, Ormen Lange and Snøhvit fields commenced production. At the end of 2007, 46 of the producing fields are in the North Sea, nine in the Norwegian Sea and one in the Barents Sea. PDOs for seven new fields were approved in 2007; Alve, Gjøa, Rev, Skarv, Volund, Vega and Vega Sør. In addition, a new development of the remaining resources in Yme, further development of Valhall as well as an amended PDO for Ringhorne, were approved.

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

Resources

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

The detailed resource accounts as of 31 December 2007 are shown in Table 10.1 and in tables in Appendix 2.

Reserves

Reserves include remaining recoverable petroleum resources in deposits for which the authorities have approved the PDO or granted a PDO exemption. Reserves also include petroleum resources in deposits that the licensees have decided to develop, but for which the plan has not been processed by the authorities in the form of a PDO approval or a PDO exemption.

The reserves on the Norwegian continental shelf are estimated at 3.6 billion scm o.e. Gross gas and liquid reserves increased by 190 million scm o.e. in 2007. Gross reserves on several fields increased and contingent resources matured to reserves, but the reserves decreased in total. Since 238 million scm o.e. were produced in 2007 (cf. footnote 1, table 10.1), the resource accounts show a net reduction in remaining reserves of 48 million scm o.e.

As regards the authorities' goal of maturing 800 million scm of oil to reserves before 2015, 154 million scm of oil were booked as reserves in 2005. In the 2006 accounts, the achieved reserve growth was reduced to 136 million scm oil, while the accounts for 2007 show a gross increase of 65 million scm to a total of 201 million scm oil reserves growth.

Contingent resources

Contingent resources include discovered quantities of petroleum for which a development decision has yet to be made. Contingent resources in fields, not including resources from potential future measures to improve recovery (resource category 7A), decreased by 46 million scm o.e. The reason for this reduction is a general maturing of resources in projects on fields in 2007, from contingent resources to reserves.

The estimate for contingent resources in discoveries has been adjusted downward by only 8 million scm o.e. to 646 million scm o.e, even though resources were matured to reserves for the 6507/5-1 Skarv and 6507/3-3 Idun discoveries. The modest reduction reflects the relatively good resource growth from exploration in 2007..

The resource potential for possible future measures to improve oil recovery (resource category 7A) is now estimated at 145 million scm o.e., up 5 million scm o.e. compared to last year. The estimate for gas is 77 million scm o.e., a reduction of 53 million scm o.e. from last year.

Undiscovered resources

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

The North Sea

A total of 7.3 billion scm o.e. has been proven in the North Sea, of which 4.3 billion scm o.e. have been produced. Remaining reserves are 2.4 billion scm o.e., of which 33 per cent is oil. Production from the North Sea in the past year totalled 181 million scm o.e. Remaining reserves in the North Sea were reduced by 97 million scm o.e, whereas contingent resources in discoveries increased by 76 million scm o.e due to a relatively good resource growth from exploration. Eight new oil discoveries were made in the North Sea in 2007. Undiscovered resources in the North Sea are expected to amount to about 1.2 billion scm o.e.

The Norwegian Sea

A total of 2.0 billion scm o.e. has been proven in the Norwegian Sea, of which 0.6 billion scm o.e. have been produced. Remaining reserves amount to about 1.0 billion scm o.e., of which 66 per cent is gas. Production in 2007 was 57 million scm o.e.(cf. footnote 1, table 10.1). Estimated remaining reserves have increased as a result of reserves upgrades in many of the fields in the Norwegian Sea in addition to the resources in the discoveries 6507/5-1 Skarv and 6507/3-3 Idun having matured to reserves. For the same reason the estimate for contingent resources has been reduced by 114 million scm o.e compared to last years accounts. Three new gas discoveries were made in the Norwegian Sea in 2007. The estimate for undiscovered resources in the Norwegian Sea is unchanged from last year.

The Barents Sea

A total of 0.27 billion scm o.e. has been proven in the Barents Sea. There is a reduction in the estimate for contingent resources in fields and an increase in contingent resources in discoveries in the Barents Sea the last year. The contingent resources in fields have been reduced by 10 million scm o.e i.a. because the oil zone in the Snøhvit field is no longer considered for development. Contingent resources in discoveries have increased i.a. due to a new discovery in the Barents Sea last year. The estimate for undiscovered resources in the Barents Sea is unchanged from last year.

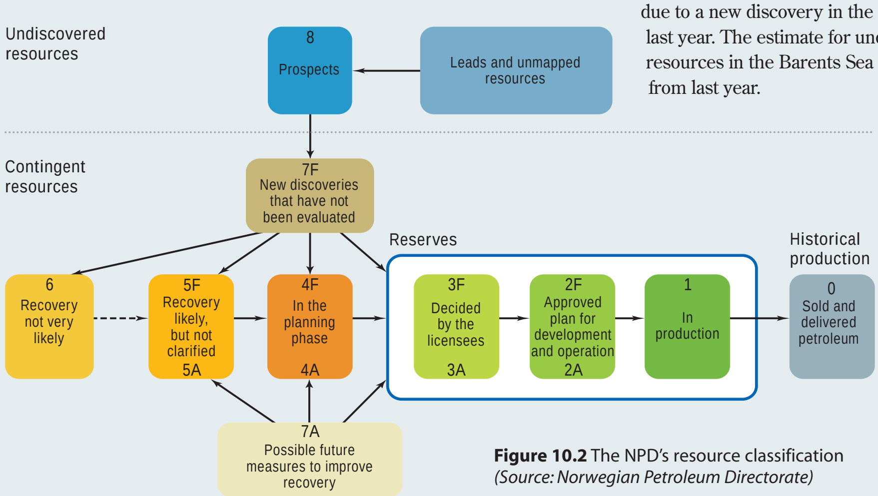


Figure 10.2 The NPD's resource classification
(Source: Norwegian Petroleum Directorate)

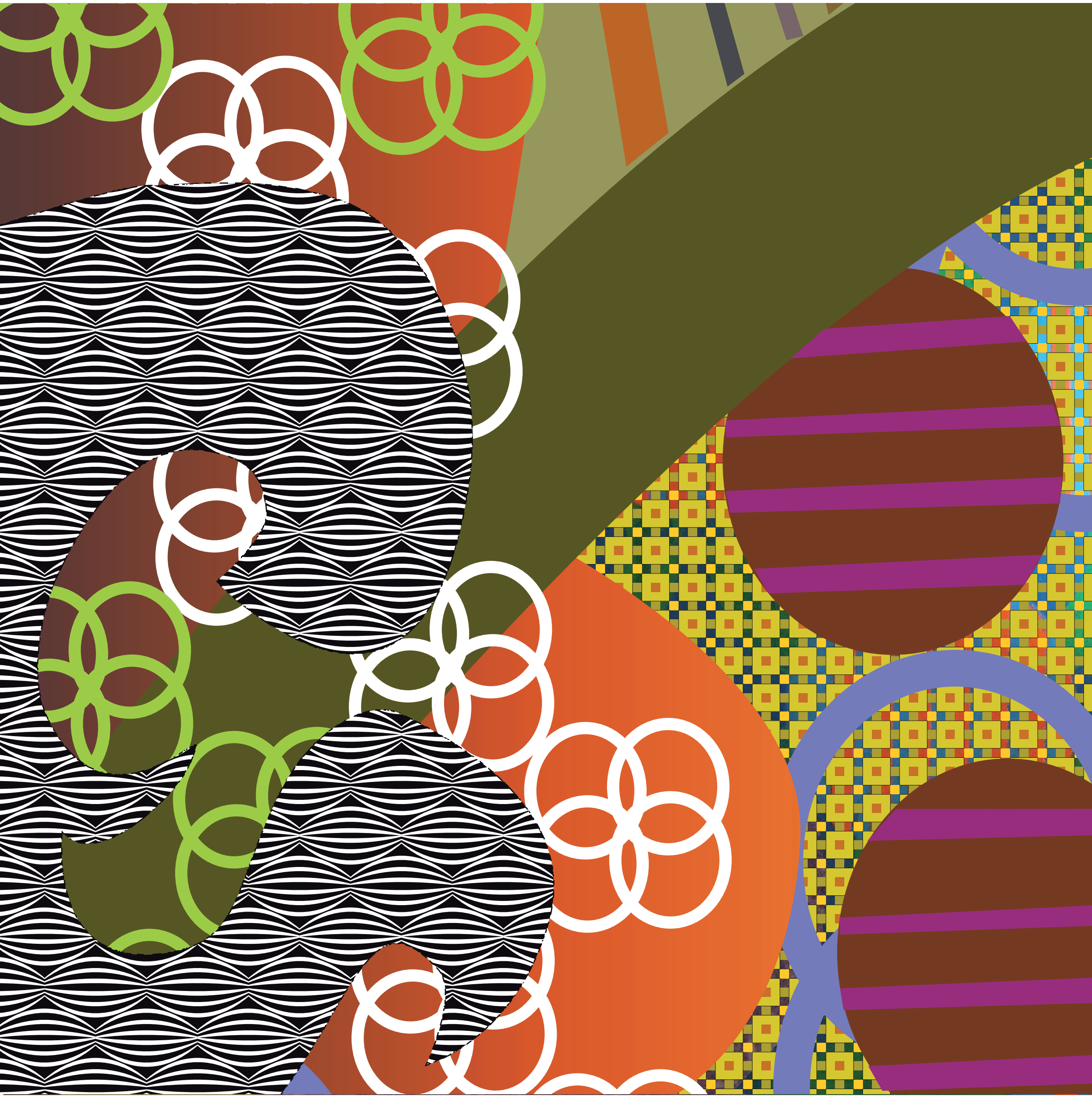
Table 10.1 Resource accounts per 31.12.2007

Total recoverable potential Project status category	Resource accounts per 31.12.2007 Oil mill scm	Gas bill scm	NGL mill tonnes	Cond mill scm	Total mill scm o.e.	Changes from 2006 Oil mill scm	Gas bill scm	NGL mill tonnes	Cond mill scm	Total mill scm o.e.
Produced[1]	3283	1232	107	92	4811	128	90	9	3	238
Remaining reserves[2]	1013	2313	123	51	3611	-63	11	1	2	-48
Contingent resources in fields	318	166	25	7	538	-57	0	5	2	-46
Contingent resources in discoveries	169	405	16	42	646	17	-19	-6	7	-8
Potential from improved recovery[3]	145	77			222	5	-53	0	0	-48
Undiscovered	1260	1875		265	3400	0	0	0	0	0
Total	**6188**	**6068**	**271**	**457**	**13228**	**30**	**28**	**8**	**15**	**88**
North Sea										
Produced	2878	1135	90	70	4254	100	68	5	3	181
Remaining reserves[2]	784	1479	69	3	2397	-58	-30	-2	-6	-97
Contingent resources in fields	263	98	13	5	390	-32	-10	3	1	-35
Contingent resources in discoveries	106	139	9	20	283	40	27	2	6	76
Undiscovered	620	500		55	1175	0	0	0	0	0
Total	**4651**	**3351**	**181**	**153**	**8498**	**50**	**55**	**9**	**4**	**125**
Norwegian Sea										
Produced[1]	405	97	17	22	557	28	22	4	0	57
Remaining reserves[2]	228	673	48	31	1024	-5	41	3	8	49
Contingent resources in fields	55	60	12	1	139	-15	9	1	1	-2
Contingent resources in discoveries	20	242	6	20	294	-38	-59	-9	-1	-114
Undiscovered	220	825		150	1195	0	0	0	0	0
Total	**928**	**1897**	**84**	**224**	**3208**	**-30**	**13**	**-1**	**8**	**-10**
Barents Sea										
Produced	0	0	0	0	0	0	0	0	0	0
Remaining reserves[2]	0	160	6	18	190	0	0	0	0	0
Contingent resources in fields	0	8	0	1	10	-10	0	0	0	-10
Contingent resources in discoveries	44	23	0	2	69	15	13	0	2	30
Undiscovered	420	550		60	1030	0	0	0	0	0
Total	**464**	**742**	**7**	**81**	**1300**	**5**	**13**	**0**	**2**	**21**

[1] Including historic production to Tjeldbergodden
[2] Includes resource categories 1, 2 and 3
[3] Resources from future measures for improved recovery are calculated for the total recoverable potential and have not been broken down by area

(Source: Norwegian Petroleum Directorate)

11 Fields in production



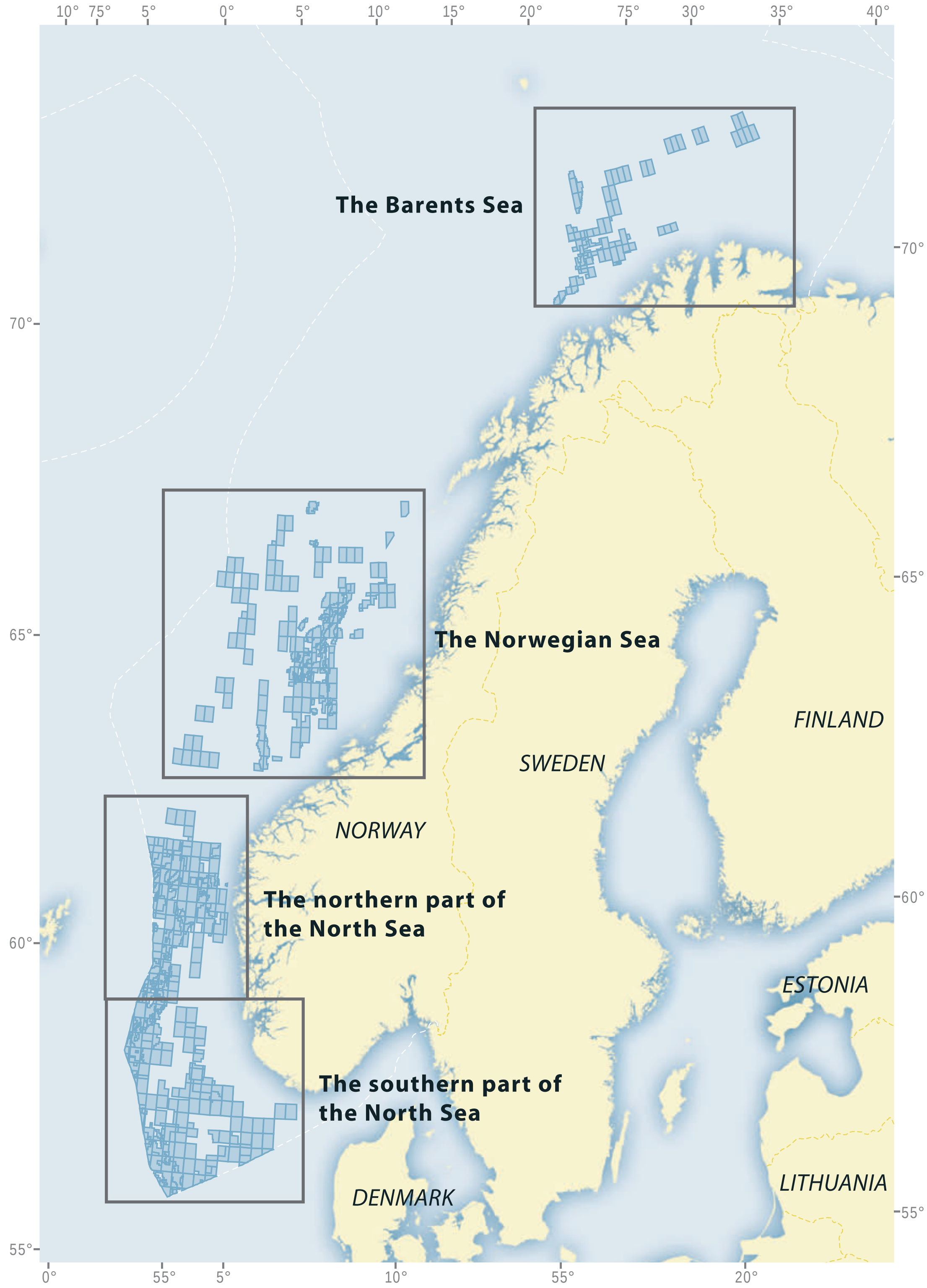


Figure 11.1 Areas on the Norwegian continental shelf

The southern part of the North Sea

The southern part of the North Sea became important for the country when Ekofisk came on stream in 1971 as the first Norwegian offshore field. At present 26 fields are located in the area, 18 of these are now in production. Seven fields have been shut down after production has ceased and some of these are now being prepared for redevelopment. New development of Yme has been initiated. There is also a large activity in the area in connection with disused facilities. Ekofisk serves as a hub for petroleum operations in this area, with several fields utilising the infrastructure for further transport in the Norpipe system. From Ekofisk, oil is exported by pipeline to Teesside in the United Kingdom, while gas is sent by pipeline to Emden in Germany. The Sleipner fields, north of the Ekofisk area, serve as an important hub for the gas transport system on the Norwegian continental shelf.

Although there has been production from the southern part of the North Sea for 35 years, remaining resources in the area are substantial, particularly in the large chalk fields in the very south of the area. Production of oil and gas is expected to continue from this area for at least another three decades.

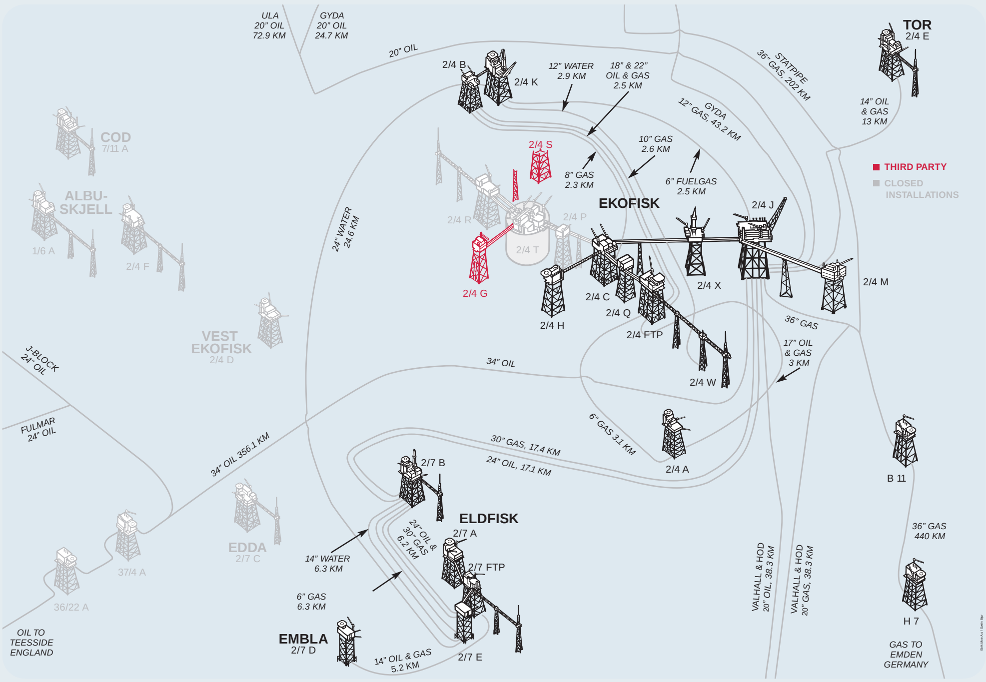


Figure 11.2 Facilities in the Ekofisk area

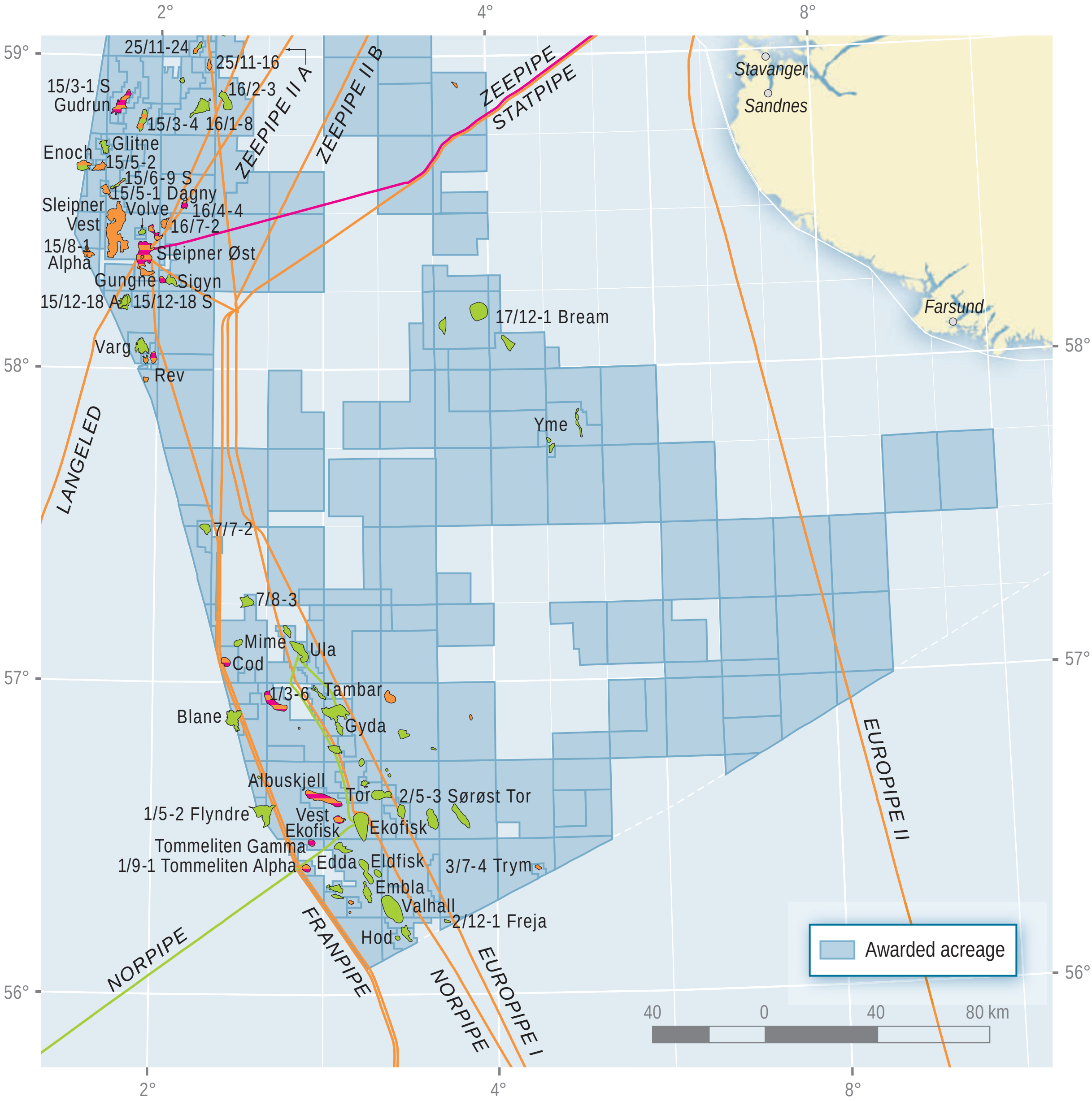


Figure 11.3 The southern part of the North Sea

The northern part of the North Sea

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

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

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

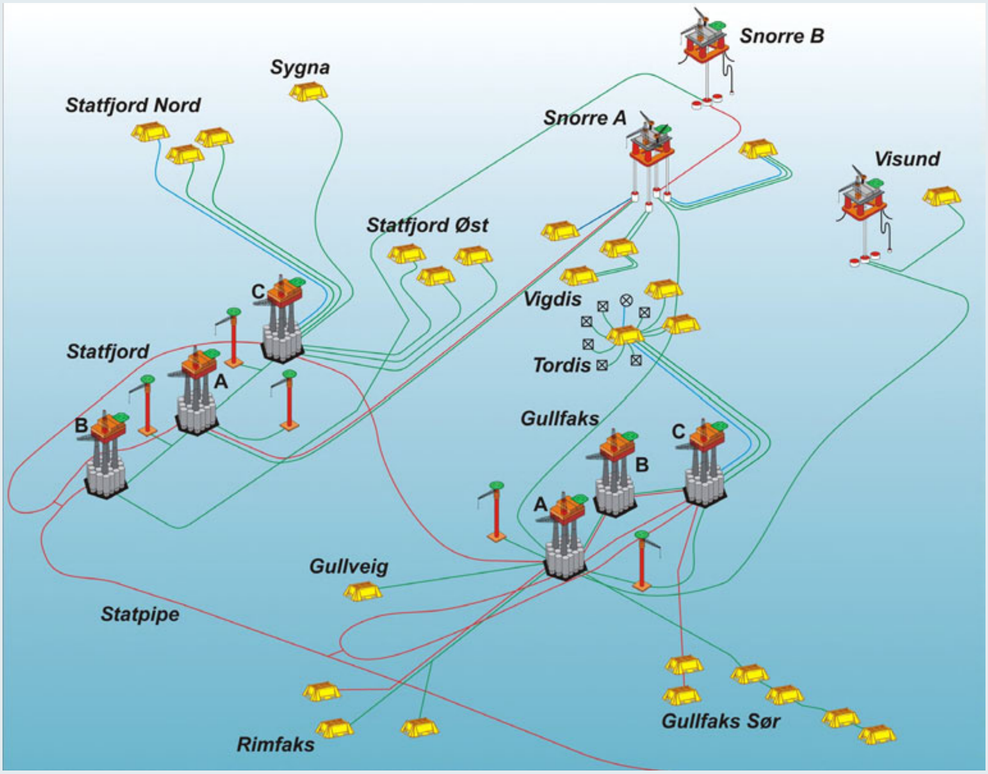


Figure 11.4 Facilities in the Tampen area
(Source: Statoil)

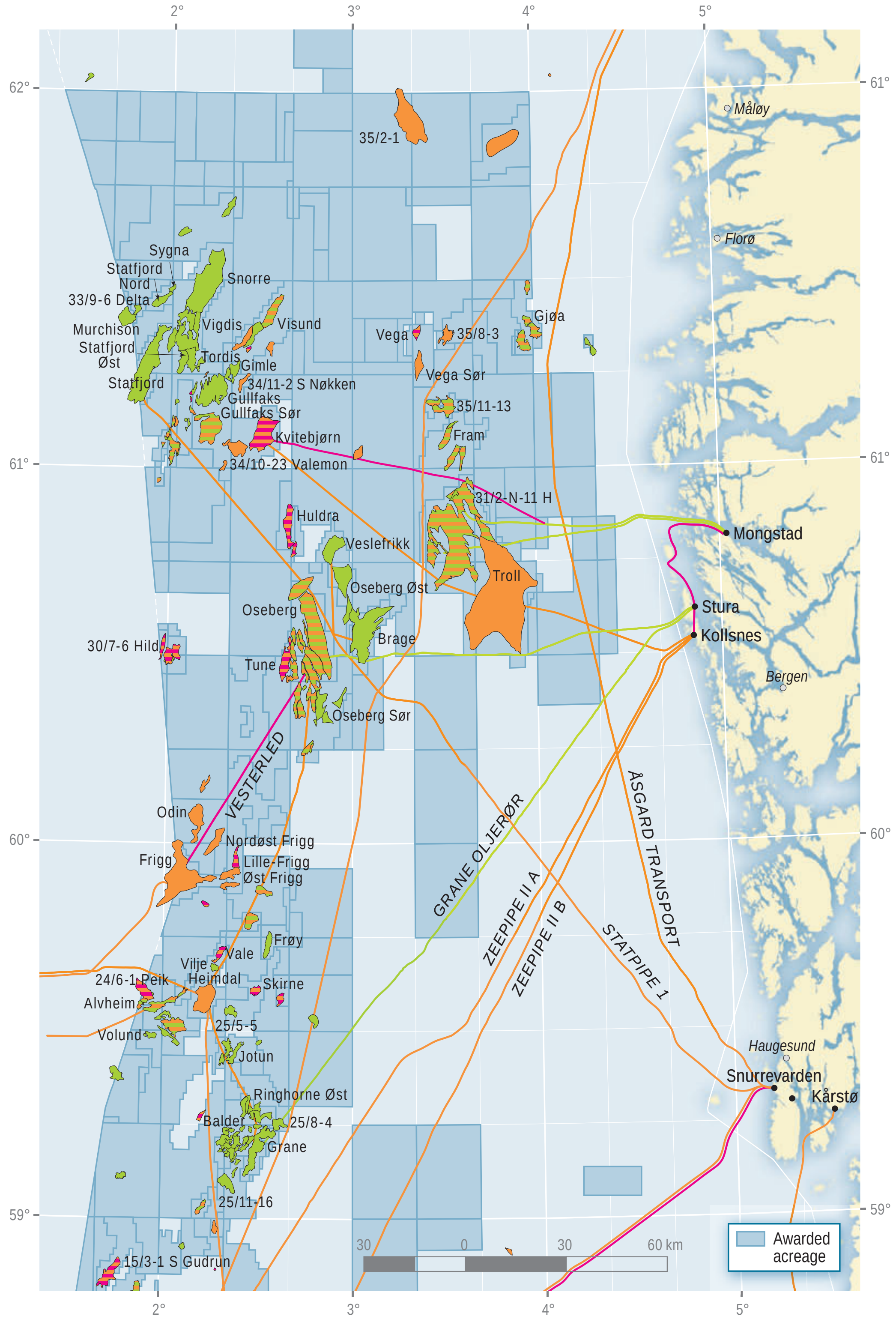


Figure 11.5 The northern part of the North Sea

The Norwegian Sea

The Norwegian Sea is a less mature petroleum province than the North Sea. At present 11 fields are located in the area and more will be developed over the coming years. Development plans for Alve and Skarv were approved by the authorities in 2007. Alve is planned to come on stream towards the end of 2008 while Skarv will come on stream in 2011. No fields have ceased production. Draugen was the first field to come on stream, in 1993. There are significant gas reserves in the Norwegian Sea. The Åsgard field and the Åsgard Transport represent the key processing and gas export infrastructure for the Norwegian Sea. The gas from Åsgard, Kristin, Mikkel, Norne and Draugen is transported in the Åsgard Transport pipeline to Kårstø in Rogaland, and gas from Heidrun is transported in Haltenpipe to Tjeldbergodden in Møre og Romsdal. Gas production from Ormen Lange started in 2007. The gas is transported in a new pipeline to Nyhamna, and from there on to Easington in the United Kingdom. Oil from the fields in the Norwegian Sea is transported by tankers.

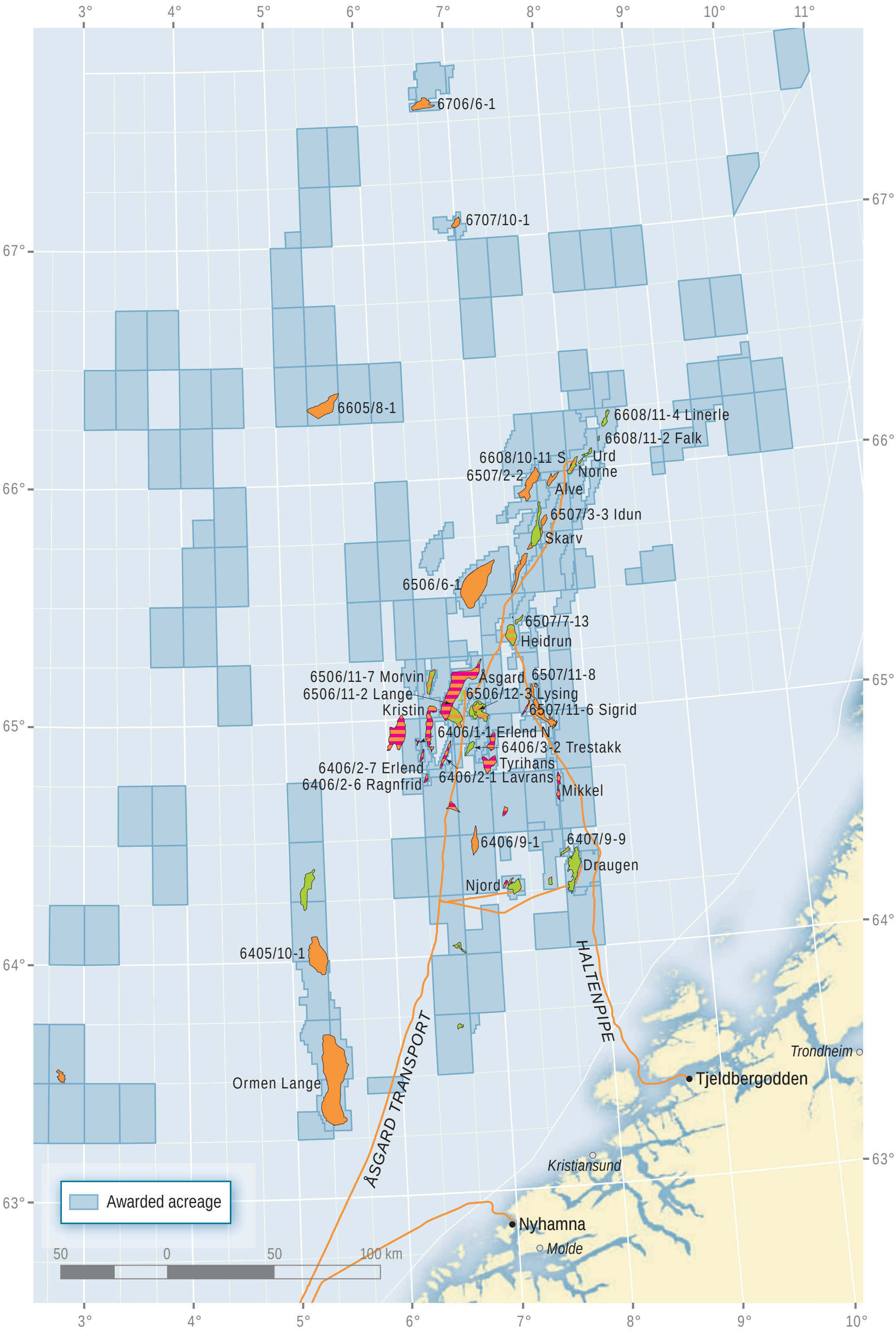


Figure 11.6 The Norwegian Sea

The Barents Sea

The Barents Sea is an immature petroleum province. Snøhvit is the only field developed so far. The field came on stream in 2007. Several discoveries in the area are being considered tied to Snøhvit in connection with a possible further development at Melkøya. There are also plans for development of the discovery 7122/7-1 Goliat where development concepts are being evaluated. The gas from Snøhvit is transported in pipeline to Melkøya and further processed and liquefied to LNG which is transported by tankers to the market.

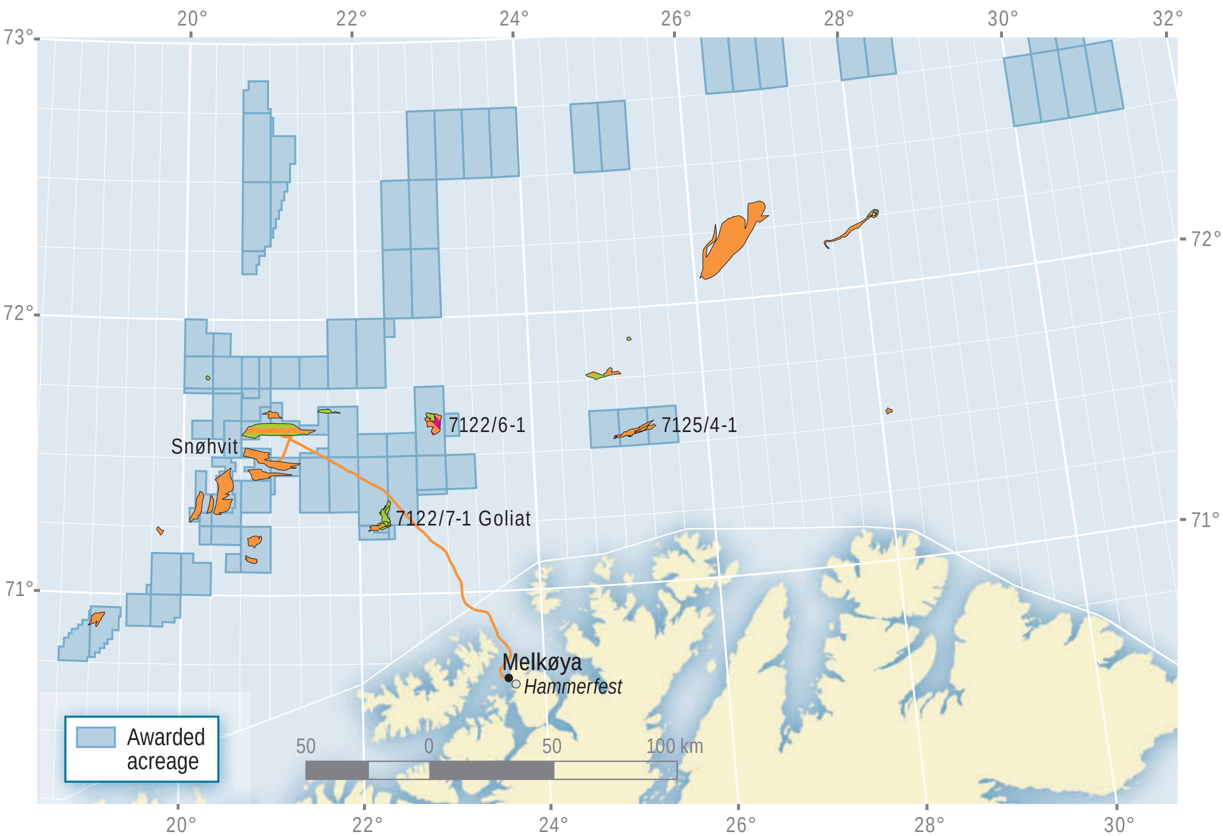


Figure 11.7 The Barents Sea

Keys to tables in Chapters 11–13

Participating interests in fields do not necessarily correspond with interests in the individual production licences since unitised fields or fields for which the sliding scale has been exercised, have a different composition of interests than the production licence.

Because interests are quoted with only two decimal places, licensee holdings in some of the fields may not add up to 100 per cent. Participating interests are shown as of 31 December 2007.

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

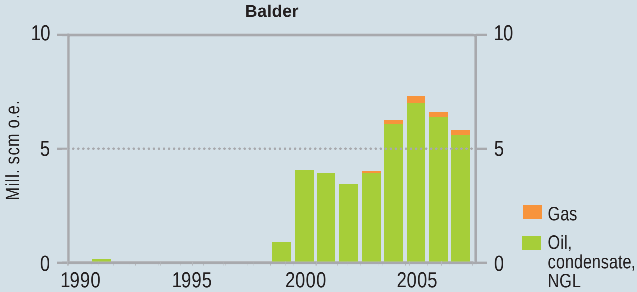
"Recoverable reserves remaining at 31 December 2007" refers to reserves in resource categories 1, 2 and 3 in the Norwegian Petroleum Directorate's resource classification.

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

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

Pictures and illustrations in Chapters 11 – 14:

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



Balder

Block and production licences	Block 25/10 - production licence 028, awarded 1969 Block 25/11 - production licence 001, awarded 1965 Block 25/8 - production licence 027, awarded 1969 Block 25/8 - production licence 027 C, awarded 2000 Block 25/8 - production licence 169, awarded 1991	
Discovered	1967	
Development approval	02.02.1996 by the King in Council	
On stream	02.10.1999	
Operator	ExxonMobil Exploration & Production Norway AS	
Licensees	ExxonMobil Exploration & Production Norway AS	100.00 %
Recoverable reserves	**Original:** 58.7 million scm oil 1.9 billion scm gas	**Remaining as of 31.12.2007** 17.4 million scm oil 1.0 billion scm gas
Production	**Estimated production in 2007:** Oil: 73 000 barrels/day, Gas: 0.22 billion scm	
Investment	Total investment is expected to be NOK 27.3 billion (2008 values) NOK 25.3 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

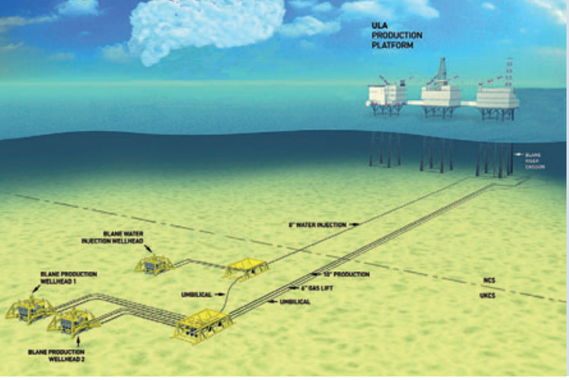
Development:
Balder is an oil field in the northern part of the North Sea. The sea depth in the area is 125 metres. The field has been developed with subsea wells tied back to the accommodation, production and storage vessel, Balder FPSO, where oil and gas are processed. The Ringhorne discovery, included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

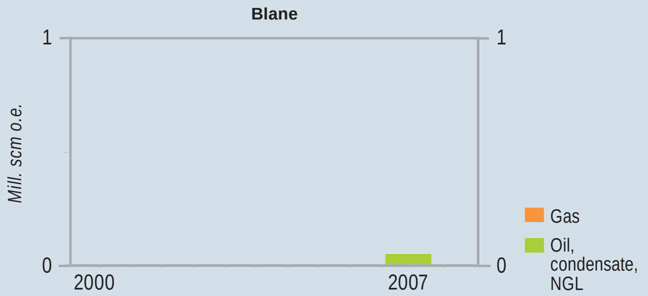
Reservoir:
The field contains several separate oil deposits in Paleocene sandstones. The main reservoirs are in the Rogaland group and belong to the Heimdal, Hermod and Ty formations at a depth of about 1700 metres. The Ringhorne development comprises several reservoirs of the same type as in Balder and a main reservoir of Jurassic age containing oil and associated gas.

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

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

Status
New seismic (4D) analysis will be used to evaluate new well locations





Blane

Block and production licences	Block 1/2 - production licence 143 BS, awarded 2003 The Norwegian part of the field is 18%, the British part is 82%	
Discovered	1989	
Development approval	01.07.2005	
On stream	12.09.2007	
Operator	Talisman Energy Norge AS	
Licensees	Talisman Energy Norge AS	18.00 %
	Bow Valley Petroleum (UK) Limited	12.50 %
	Eni UK Limited	13.90 %
	Eni ULX Limited	4.11 %
	Moc Exploration (U.K.) Limited	13.99 %
	Roc Oil (GB) Limited	12.50 %
	Talisman North Sea Limited	25.00 %
Recoverable reserves (Norwegian part)	**Original:** 0.8 million scm oil	**Remaining as of 31.12.2007** 0.8 million scm oil
Production	**Estimated production in 2008:** Oil: 2 000 barrels/day	
Investment	Total investment is expected to be NOK 0.6 billion (2008 values) NOK 0.5 billion have been invested as of 31.12.2007 (2008 values)	

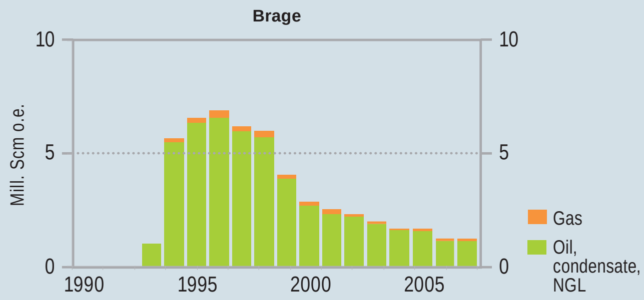
Development:
Blane is an oil field located in the southern part of the North Sea on the border to the British sector southwest of Ula. The water depth in the area is about 70 metres. The field has been developed with a subsea facility tied to the Ula field. The facilities on the seabed are located on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

Reservoir:
The reservoir is in marine Paleocene sandstones in the Forties formation at a depth of about 3 090–3 150 metres.

Recovery strategy:
Produced water from Blane, Tambar and Ula is mixed at Ula and will be used as injection water for pressure support on Blane when the water injection well is completed. Gas lift may also be considered when gas capacity at Ula has been upgraded in 2008.

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

Status
The field came on stream in September 2007.



Brage

Block and production licences	Block 30/6 - production licence 053 B, awarded 1998 Block 31/4 - production licence 055, awarded 1979 Block 31/7 - production licence 185, awarded 1991	
Discovered	1980	
Development approval	29.03.1990 by the Storting	
On stream	23.09.1993	
Operator	StatoilHydro Petroleum AS	
Licensees	Altinex Oil Norway AS	12.26 %
	Endeavour Energy Norge AS	4.44 %
	Petoro AS	14.26 %
	Revus Energy ASA	2.50 %
	StatoilHydro ASA	12.70 %
	StatoilHydro Petroleum AS	20.00 %
	Talisman Energy Norge AS	33.84 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	51.6 million scm oil	3.1 million scm oil
	3.7 billion scm gas	1.2.billion scm gas
	1.2 million tonnes NGL	0.2 million tonnes NGL
Production	**Estimated production in 2008:** Oil: 16 000 barrels/day, Gas: 0.12 billion scm, NGL: 0.04 million tonnes	
Investment	Total investment is expected to be NOK 20.4 billion (2008 values) NOK 19.8 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

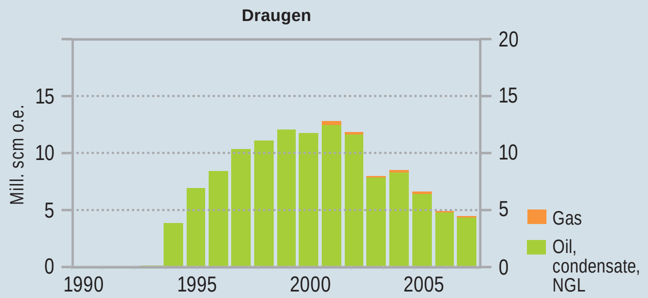
Development:
Brage is an oil field east of Oseberg in the northern part of the North Sea. The sea depth in the area is 140 metres. Brage has been developed with a fixed integrated production, drilling and accommodation facility with a steel jacket.

Reservoir:
The reservoir contains oil in sandstones in the Statfjord formation of Early Jurassic age and the Fensfjord formation of Middle Jurassic age. There is also oil and gas in the Sognefjord formation of Late Jurassic age. The reservoirs are at a depth of about 2000–2300 metres. The reservoir quality varies from poor to excellent.

Recovery strategy:
The recovery mechanism in the Statfjord and Fensfjord formations is water injection. The wells in the Fensfjord formation are recovered by gas lift. The Sognefjord formation is recovered with pressure depletion, but gas injection will start in 2008.

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

Status:
Brage is in tail production, and work is proceeding to find new ways of increasing recovery from the field. The water injection capacity is being increased and produced water is reinjected into parts of the field. New wells have been drilled in 2007 and more wells are planned for the coming years. Adding chemicals to the injection water to improve water flow is also being evaluated.



Draugen

Block and production licences	Block 6407/9 - production licence 093, awarded 1984	
Discovered	1984	
Development approval	19.12.1988 by the Storting	
On stream	19.10.1993	
Operator	A/S Norske Shell	
Licensees	A/S Norske Shell	26.20 %
	BP Norge AS	18.36 %
	Chevron Norge AS	7.56 %
	Petoro AS	47.88 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	140.0 million scm oil	22.2 million scm oil
	1.5 billion scm gas	0.3 billion scm gas
	2.5 million tonnes NGL	0.6 million tonnes NGL
Production	**Estimated production in 2008:**	
	Oil: 62 000 barrels/day, Gas: 0.10 billion scm, NGL: 0.14 million tonnes	
Investment	Total investment is expected to be NOK 31.5 billion (2008 values)	
	NOK 28.9 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Kristiansund	
Main supply base	Kristiansund	

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

Reservoir:
The main reservoir is in sandstones belonging to the Rogn formation of Late Jurassic age. The Garn formation of Middle Jurassic age in the western part of the field is also producing. The reservoirs lie at a depth of about 1600 metres and are relatively homogenous, with good reservoir characteristics.

Recovery strategy:
The field is produced with pressure maintenance through water injection, and gas lift is installed in the wells.

Transport:
The oil is exported by tankers via a floating loading buoy. The associated gas is sent through the Åsgard Transport pipeline to Kårstø.

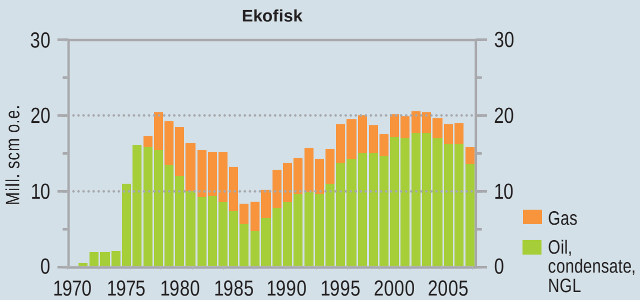
Status:
Various measures to increase oil recovery are being evaluated and two new production wells are being drilled. The licensees are evaluating gas injection and further drilling as possible methods for increased oil recovery. CO_2 injection has been evaluated and rejected.

Ekofisk

Block and production licences	Block 2/4 - production licence 018, awarded 1965	
Discovered	1969	
Development approval	01.03.1972	
On stream	15.06.1971	
Operator	ConocoPhillips Skandinavia AS	
Licensees	ConocoPhillips Skandinavia AS	35.11 %
	Eni Norge AS	12.39 %
	Petoro AS	5.00 %
	StatoilHydro ASA	0.95 %
	StatoilHydro Petroleum AS	6.65 %
	Total E&P Norge AS	39.90 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	540.6 million scm oil	150.0 million scm oil
	160.2 billion scm gas	26.6 billion scm gas
	14.8 million tonnes NGL	2.7 million tonnes NGL
Production	**Estimated production in 2008:**	
	Oil: 232 000 barrels/day, Gas: 2.78 billion scm, NGL: 0.27 million tonnes	
Investment	Total investment is expected to be NOK 171.3 billion (2008 values)	
	NOK 131.5 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

Development:
Ekofisk is an oil field located in the southern part of the North Sea. The sea depth in the area is between 70-75 metres. Production at Ekofisk began in 1971 from the jack-up facility Gulftide. During the first years, the field produced to tankers from four wells, until the concrete tank was in place in 1973. Since then, the field has been further developed with many facilities, including riser facilities for associated fields and export pipelines. Several of these have been decommissioned and are awaiting disposal. Today, the operative parts of the Ekofisk Centre consist of the accommodation facilities, Ekofisk H and Ekofisk Q, the production facility Ekofisk C, the wellhead facility for water injection Ekofisk W, the drilling and production facility Ekofisk X , the processing facility Ekofisk J and the production and processing facility Ekofisk M. From the wellhead facility Ekofisk A south on the field, production goes to the riser facility Ekofisk FTP for processing at the Ekofisk Centre. In 2007 the pipeline from Ekofisk B in the northern part of the field was rerouted to Ekofisk M. Ekofisk B is connected by bridge to Ekofisk K, the main facility for water injection.

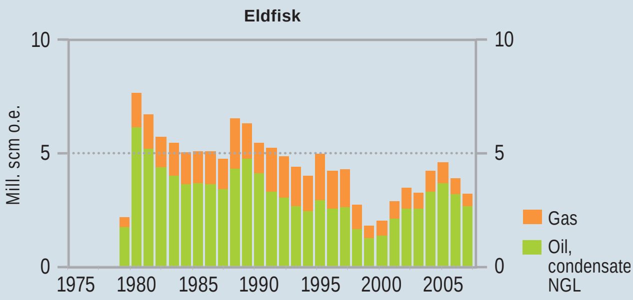
Reservoir:
The Ekofisk field produces from the Ekofisk and Tor chalk formations of Early Paleocene and Late Cretaceous ages. The reservoir rocks are finegrained and dense, but pervasive fractures increase flow. The reservoir lies about 2 900-3 250 metres below sea level.



Recovery strategy:
Ekofisk was originally developed with pressure 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 correspondingly. In addition to the water injection, compaction of the soft chalk provides extra force to drainage of the field. This effect is reinforced because the injected water contributes to weakening the chalk. The reservoir compaction has resulted in subsidence of the seabed, up till now 9 metres, centrally on the field. It is expected that the subsidence will continue for many years, but at a lower rate.

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

Status:
Production from Ekofisk has been maintained at its current high level the past years. This is mainly due to increased number of water injection wells and production from new facilities on the field. High activity is expected to continue at the field over the coming years. Several new facilities may be installed. Concept selection for new facilities is expected summer of 2008. In addition to efforts to optimise short and long-term production, work on cleaning and disposal of disused facilities is in progress. So far, the deck facility on Ekofisk T has been dismantled and cleaning of the tank is planned for in 2008.



Eldfisk

Block and production licences	Block 2/7 - production licence 018, awarded 1965	
Discovered	1970	
Development approval	25.04.1975	
On stream	08.08.1979	
Operator	ConocoPhillips Skandinavia AS	
Licensees	ConocoPhillips Skandinavia AS	35.11 %
	Eni Norge AS	12.39 %
	Petoro AS	5.00 %
	StatoilHydro ASA	0.95 %
	StatoilHydro Petroleum AS	6.65 %
	Total E&P Norge AS	39.90 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	136.7 million scm oil	50.4 million scm oil
	44.3 billion scm gas	7.2 billion scm gas
	4.2 million tonnes NGL	0.6 million tonnes NGL
Production	**Estimated production in 2008:**	
	Oil: 37 000 barrels/day, Gas: 0.47 billion scm, NGL: 0.05 million tonnes	
Investment	Total investment is expected to be NOK 96.2 billion (2008 values)	
	NOK 52.0 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

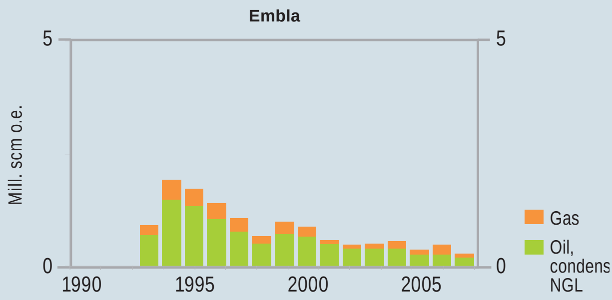
Development:
Eldfisk is an oil field located near of Ekofisk in the southern part of the North Sea. The sea depth in the area is 70-75 metres. The original Eldfisk development consisted of three facilities. Eldfisk B is a combined drilling, wellhead and process facility, while Eldfisk A and FTP are wellhead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

Reservoir:
The Eldfisk field produces from the Ekofisk, Tor and Hod chalk formations from the Early Paleocene and Late Cretaceous ages. The reservoir rock is finegrained and dense, but pervasive fractures increase flow. The field consists of three structures: Alpha, Bravo and Øst Eldfisk.

Recovery strategy:
Eldfisk was originally developed with pressure depletion. In 1999, water injection began at the field, based on horizontal injection wells. Gas is also injected in periods. Pressure depletion has caused compaction in the reservoir, which has resulted in several metres of seabed subsidence.

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

Status:
The original facilities, Eldfisk A, B and FTP have a short remaining operating lifetime and must be upgraded or replaced if production from Eldfisk shall continue in the future. A major project has been initiated to find the best solution for a long-term development of the field. A concept selection is expected in the summer of 2008.



Embla

Block and production licences	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 %
	Petoro AS	5.00 %
	StatoilHydro ASA	0.95 %
	StatoilHydro Petroleum AS	6.65 %
	Total E&P Norge AS	39.90 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	12.0 million scm oil	2.6 million scm oil
	5.2 billion scm gas	2.0 billion scm gas
	1.4 million tonnes NGL	1.0 million tonnes NGL
Production	**Estimated production in 2008:**	
	Oil: 3 000 barrels/day, Gas: 0.10 billion scm, NGL: 0.01 million tonnes	
Investment	Total investment is expected to be NOK 5.1 billion (2008 values)	
	NOK 4.3 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

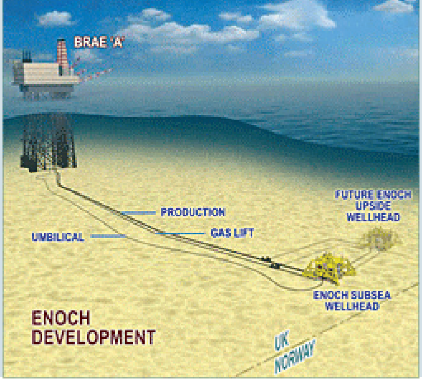
Development:
Embla is located close to Eldfisk in the southern part of the North Sea. The field has been developed with an unmanned wellhead facility which is remotely controlled from Eldfisk. The sea depth in the area is 70-75 metres. The amended PDO for Embla was approved on 25.04.1995.

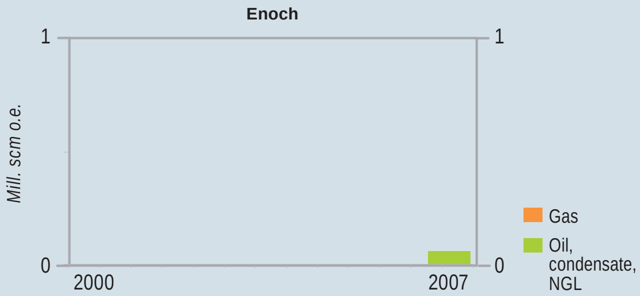
Reservoir:
The Embla field produces from a segmented sandstone reservoir of Devonian and Permian ages. The reservoir is complex and lies at more than 4 000 metres. Embla is the first field with high pressure and high temperature developed in the area.

Recovery strategy:
Embla is produced with pressure depletion.

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

Status:
In the long-term, new wells may be drilled if Eldfisk is developed with new facilities.





Enoch

Block and production licences	Block 15/5 - production licence 048 B, awarded 2001 The Norwegian part of the field is 20%, the British part is 80%.	
Discovered	1991	
Development approval	01.07.2005	
On stream	31.05.2007	
Operator	Talisman North Sea Limited	
Licensees	Altinex Oil Norway AS	4.36 %
	DONG E&P Norge AS	1.86 %
	Noil Energy ASA	2.00 %
	StatoilHydro ASA	11.78 %
	Bow Valley Petroleum (UK) Limited	12.00 %
	Dana Petroleum (E & P) Limited	8.80 %
	Dyas UK Limited	14.00 %
	Endeavour Energy (UK) Limited	8.00 %
	Roc Oil (GB) Limited	12.00 %
	Talisman LNS Limited	1.20 %
	Talisman North Sea Limited	24.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
(Norwegian part)	0.3 million scm oil	0.2 million scm oil
	0.1 billion scm gas	0.1 billion scm gas
Production	**Estimated production in 2008:** Oil: 1 000 barrels/day, Gas: 0.03 billion scm	
Investment	Total investment is expected to be NOK 0.2 billion (2008 values) NOK 0.2 billion have been invested as of 31.12.2007 (2008 values)	

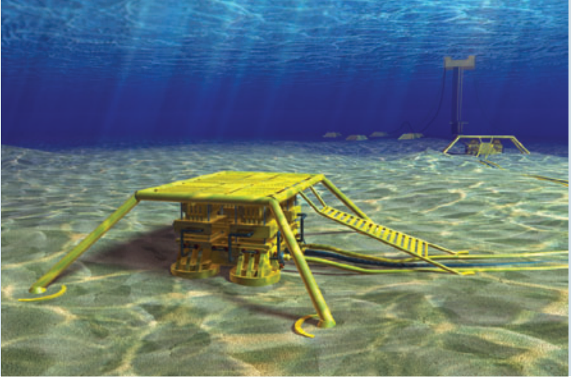
Development:
Enoch is located in the southern part of the North Sea on the border to the British sector, northwest of Sleipner. The field has been developed with a subsea facility on the UK continental shelf and is tied to the British field Brae.

Reservoir:
The reservoir is sandstones in a submarine fan system of Paleocene age at a depth of about 2 100 metres. The reservoir quality is varying.

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

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

Status
Enoch came on stream in May 2007.



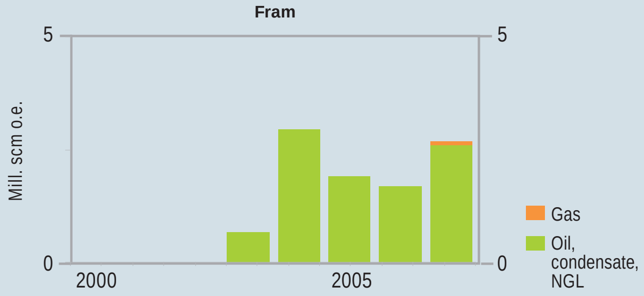
Fram

Block and production licences	Block 35/11 - production licence 090, awarded 1984	
Discovered	1992	
Development approval	23.03.2001 by the King in Council	
On stream	02.10.2003	
Operator	StatoilHydro Petroleum AS	
Licensees	Gaz de France Norge AS	15.00 %
	Idemitsu Petroleum Norge AS	15.00 %
	Mobil Development Norway AS	25.00 %
	StatoilHydro ASA	20.00 %
	StatoilHydro Petroleum AS	25.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	22.1 million scm oil	12.3 million scm oil
	8.8 billion scm gas	8.7 billion scm gas
	0.1 million tonnes NGL	0.1 million tonnes NGL
Production	**Estimated production in 2008:**	
	Oil: 44 000 barrels/day, Gas: 0.29 billion scm	
Investment	Total investment is expected to be NOK 10.5 billion (2008 values)	
	NOK 8.6 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

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

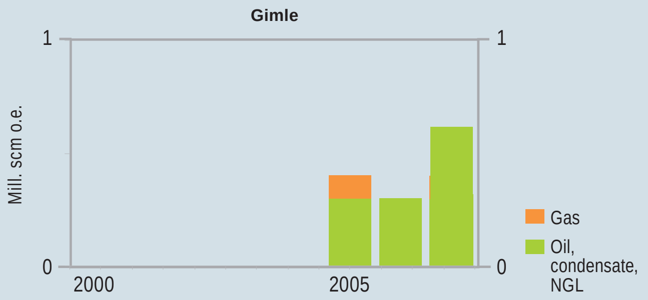
Reservoir:
The reservoirs in Fram Vest and Fram Øst consist partly of Upper Jurassic turbidity sandstones in the Draupne formation and shallow marine sandstones in the Sognefjord formation, and partly sandstones in the Etive formation of Middle Jurassic age. The reservoirs are in several isolated rotated fault blocks and contain oil with an overlying gas cap. The reservoir depth is about 2300-2500 metres. The reservoir in the Fram Vest deposit is complex while the reservoirs in the Fram Øst deposit are generally of good quality.

Recovery strategy:
Production from the Fram Vest deposit takes place with gas injection as pressure support. Injected gas is party produced from Fram and partly supplied from Troll the first years. Early gas breakthrough has resulted in reduced gas injection. Gas export from Fram started in autumn 2007. The Fram Øst deposit in the Sognefjord formation will be produced with injection of produced water as pressure support from the autumn 2008. The Fram Øst deposit in the Etive formation will be recovered by gas expansion drive.



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

Status:
Fram Vest has a more heterogeneous reservoir than expected. Several production wells will be drilled on the Fram Øst deposit the coming years. Additional resources which may be tied back to Fram Vest were proven in the H-Nord structure in 2007.



Gimle

Block and production licences	Block 34/10 - production licence 050 DS, awarded 2006	
Discovered	2004	
Development approval	18.05.2006	
On stream	19.05.2006	
Operator	StatoilHydro ASA	
Licensees	ConocoPhillips Skandinavia AS	5.79 %
	Petoro AS	24.19 %
	StatoilHydro ASA	47.23 %
	StatoilHydro Petroleum AS	17.90 %
	Total E&P Norge AS	4.90 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	4.1 million scm oil	2.9 million scm oil
	0.9 billion scm gas	0.9 billion scm gas
	0.1 million tonnes NGL	0.1 million tonnes NGL
Production	**Estimated production in 2008:**	
	Oil: 10 000 barrels/day	
Investment	Total investment is expected to be NOK 0.9 billion (2008 values)	
	NOK 0.5 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Bergen	

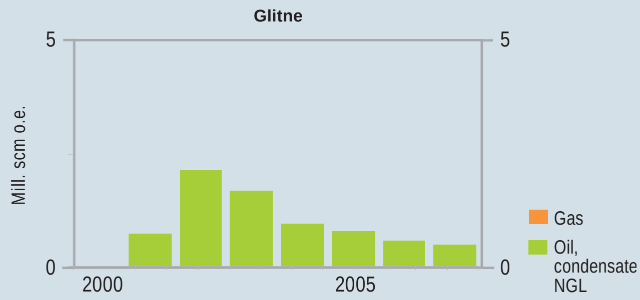
Development:
Gimle is a small oil field in the northern part of the North Sea. The sea depth in the area is about 220 metres. The field is tied to the Gullfaks C facility by two wells.

Reservoir:
The reservoir consists of sandstones in the Tarbert formation of Middle Jurassic age, in a downfaulted structure northeast of Gullfaks. The reservoir depth is about 2 900 metres. The reservoir characteristics are very good with only a few minor faults.

Recovery strategy:
The field is recovered by water injection.

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

Status:
A water injection well was drilled and started injection in autumn 2007. Drilling of a third production well started in November 2007. This well also has exploration targets in two prospects.



Glitne

Block and production licences	Block 15/5 - production licence 048 B, awarded 2001 Block 15/6 - production licence 029 B, awarded 2001
Discovered	1995
Development approval	08.09.2000 by the Crown Prince Regent in Council
On stream	29.08.2001
Operator	StatoilHydro ASA

Licensees	DONG E&P Norge AS	9.30 %
	Noil Energy ASA	10.00 %
	StatoilHydro ASA	58.90 %
	Total E&P Norge AS	21.80 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	8.1 million scm oil	0.7 million scm oil
Production	**Estimated production in 2008:**	
	Oil: 8 000 barrels/day	
Investment	Total investment is expected to be NOK 2.9 billion (2008 values) NOK 2.9 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

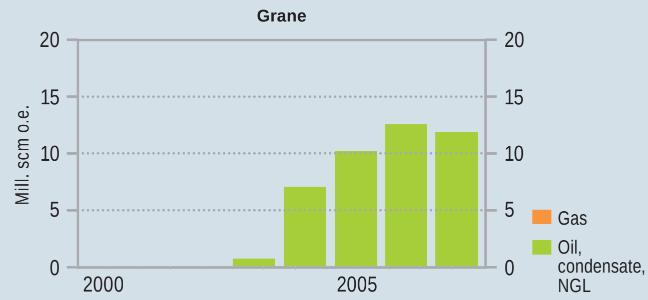
Development:
Glitne is an oil field in the southern part of the North Sea, 40 kilometres north of the Sleipner area. The sea depth in the area is about 110 metres. The development consists of four production wells and a water injection well tied back to the floating production, storage and offloading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

Reservoir:
The reservoir consists of several separate sand sheets of deepmarine fan deposits in the upper part of the Heimdal formation of Paleocene age.

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

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

Status:
One well was drilled in 2007 and various measures to increase the lifetime of the field are being considered.



Grane

Block and production licences	Block 25/11 - production licence 001, awarded 1965 Block 25/11 - production licence 169 B1, awarded 2000	
Discovered	1991	
Development approval	14.06.2000 by the Storting	
On stream	23.09.2003	
Operator	StatoilHydro Petroleum AS	
Licensees	ConocoPhillips Skandinavia AS	6.40 %
	ExxonMobil Exploration & Production Norway AS	25.60 %
	Petoro AS	30.00 %
	StatoilHydro Petroleum AS	38.00 %
Recoverable reserves	**Original:** 112.4 million scm oil	**Remaining as of 31.12.2007** 69.6 million scm oil
Production	**Estimated production in 2008:** Oil: 176 000 barrels/day	
Investment	Total investment is expected to be NOK 25.4 billion (2008 values) NOK 17.8 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

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

Reservoir:
The field consists of one main reservoir structure and some additional segments. The reservoir depth is about 1 700 metres and consists of sandstones in the Heimdal formation of Paleocene age with good reservoir characteristics. The oil has high viscosity. Some oil is also present above the main structure in the Lista formation.

Recovery strategy:
The recovery mechanism is gas injection at the top of the structure, and longrange horizontal production wells at the bottom of the oil zone. The oil in the Lista formation will probably be recovered with support from the gas injection in the Heimdal formation.

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

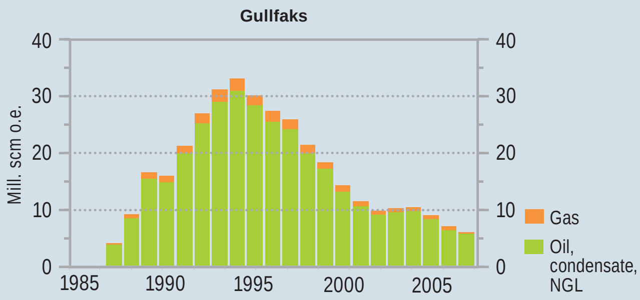
Status:
Several new wells are being planned, most of them as multilateral wells. Water injection in the reservoir is now planned to start in 2009.

Gullfaks

Block and production licence	Block 34/10 - production licence 050, awarded 1978 Block 34/10 - production licence 050 B, awarded 1995	
Discovered	1978	
Development approval	09.10.1981 by the Storting	
On stream	22.12.1986	
Operator	StatoilHydro ASA	
Licensees	Petoro AS StatoilHydro ASA StatoilHydro Petroleum AS	30.00 % 61.00 % 9.00 %
Recoverable reserves	**Original:** 358.4 million scm oil 24.3 billion scm gas 2.7 million tonnes NGL	**Remaining as of 31.12.2007** 23.6 million scm oil 1.8 billion scm gas 0.1 million tonnes NGL
Production	**Estimated production in 2008:** Oil: 78 000 barrels/day, Gas: 0.42 billion scm, NGL: 0.05 million tonnes	
Investment	Total investment is expected to be NOK 129.5 billion (2008 values) NOK 117.7 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Bergen	
Main supply base	Sotra and Florø	

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

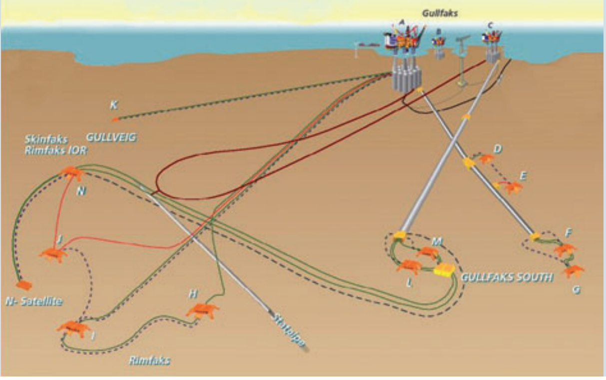
Reservoir:
The Gullfaks reservoirs consist of Middle Jurassic sandstones in the Brent group, and Lower Jurassic and Upper Triassic sandstones in the Cook, Statfjord and Lunde formations. The reservoirs are 1 700-2 000 metres below the sea level. The Gullfaks reservoirs are located in rotated fault blocks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



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

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

Status:
Production from Gullfaks is in the decline phase. Efforts are being made to increase recovery, partly by locating and draining pockets of remaining oil in waterflooded areas, and partly through continued massive water circulation.
A new project has also been initiated to evaluate necessary facility upgrades for lifetime extension towards 2030.
Concept selection is planned for in the spring of 2008, while decision on implementation is expected in 2009.

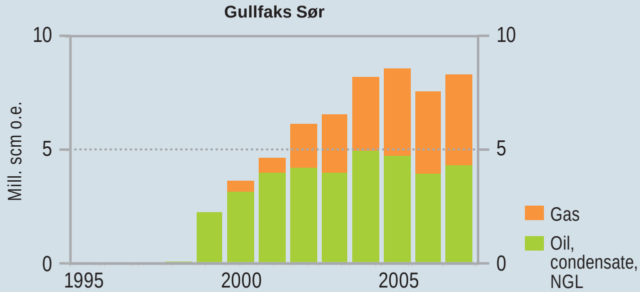


Gullfaks Sør

Block and production licences	Block 32/12 - production licence 152, awarded 1988 Block 33/12 - production licence 037 B, awarded 1998 Block 33/12 - production licence 037 E, awarded 2004 Block 34/10 - production licence 050, awarded 1978 Block 34/10 - production licence 050 B, awarded 1995	
Discovered	1978	
Development approval	29.03.1996 by the King in Council	
On stream	10.10.1998	
Operator	StatoilHydro ASA	
Licensees	Petoro AS StatoilHydro ASA StatoilHydro Petroleum AS	30.00 % 61.00 % 9.00 %
Recoverable reserves	**Original:** 48.1 million scm oil 42.5 billion scm gas 5.1 million tonnes NGL	**Remaining as of 31.12.2007** 17.6 million scm oil 22.3 billion scm gas 2.7 million tonnes NGL
Production	**Estimated production in 2008:** Oil: 52 000 barrels/day, Gas: 3.50 billion scm, NGL: 0.44 million tonnes	
Investment	Total investment is expected to be NOK 38.2 billion (2008 values) NOK 31.9 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Bergen	
Main supply base	Sotra and Florø	

Development:
Gullfaks Sør is located to the south of Gullfaks in the northern part of the North Sea. It has been developed with a total of eleven subsea templates tied back to the Gullfaks A and Gullfaks C facilities. The Gullfaks Sør deposits have been developed in two phases. The PDO for Phase 1 included production of oil and condensate from the 34/10-2 Gullfaks Sør, 34/10-17 Rimfaks and 34/10-37 Gullveig deposits. The PDO for Phase 2 was approved on 08.06.1998 and covered production of gas from the Brent group in the Gullfaks Sør deposit. 34/10-47 Gulltopp was discovered in 2002 and included in Gullfaks Sør in 2004. Gulltopp is produced through an extended reach production well from Gullfaks A.
A PDO for Rimfaks IOR and the 33/12-8 A Skinfaks discovery was approved on 11.02.2005. This project includes a new subsea template and a satellite well. The Skinfaks discovery is now included in Gullfaks Sør and production started in January 2007.

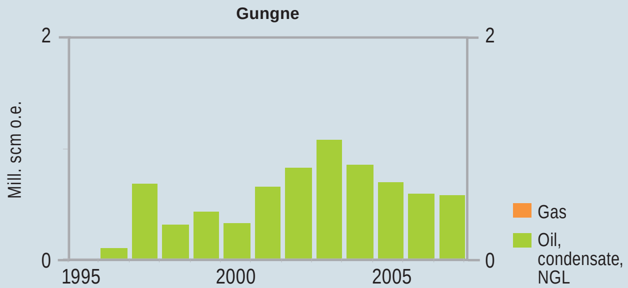
Reservoir:
The Gullfaks Sør reservoirs consist of Middle Jurassic sandstones in the Brent group and Lower Jurassic and Upper Triassic sandstones in the Cook, Statfjord and Lunde formations. Only the Brent and Statfjord reservoirs are currently developed. The reservoirs lie 2 400-3 400 metres below the sea level, in rotated fault blocks. The reservoirs in the Gullfaks Sør deposit are heavily segmented, with many internal faults, and the Statfjord formation has poor flow characteristics. The Skinfaks, Rimfaks, Gullveig and Gulltopp deposits however show good reservoir characteristics.



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

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

Status:
New development wells in recent years have proven increased resources in the Gullfaks Sør deposits. Production from the Gulltopp deposit will start in May 2008. As part of the project, Gullfaks Satellite Late Phase, plans are being made for a future gas phase for the deposits now mainly recovering oil.



Gungne

Block and production licences	Block 15/9 - production licence 046, awarded 1976	
Discovered	1982	
Development approval	29.08.1995 by the King in Council	
On stream	21.04.1996	
Operator	StatoilHydro ASA	
Licensees	ExxonMobil Exploration & Production Norway AS	28.00 %
	StatoilHydro ASA	52.60 %
	StatoilHydro Petroleum AS	9.40 %
	Total E&P Norge AS	10.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007***
	14.1 billion scm gas	14.1 billion scm gas
	1.4 million tonnes NGL	
	4.0 million scm condensate	
Production	**Estimated production in 2008:**	
	Gas: 1.14 billion scm	
Investment	Total investment is expected to be NOK 1.8 billion (2008 values)	
	NOK 1.8 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

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

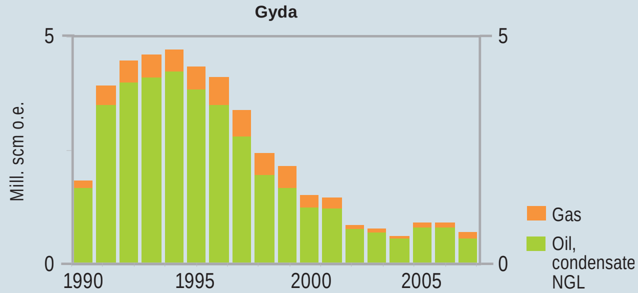
Development:
Gungne is a gas condensate field located in the Sleipner area in the southern part of the North Sea. The sea depth in the area is 83 metres. Gungne produces via two wells drilled from Sleipner A.

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

Recovery strategy:
Gungne is recovered by pressure depletion.

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

Status:
New wells are being considered.



Gyda

Block and production licences	Block 2/1 - production licence 019 B, awarded 1977	
Discovered	1980	
Development approval	02.06.1987 by the Storting	
On stream	21.06.1990	
Operator	Talisman Energy Norge AS	
Licensees	DONG E&P Norge AS	34.00 %
	Norske AEDC A/S	5.00 %
	Talisman Energy Norge AS	61.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	39.2 million scm oil	5.1 million scm oil
	6.0 billion scm gas	0.2 billion scm gas
	1.9 million tonnes NGL	0.1 million tonnes NGL
Production	**Estimated production in 2008:**	
	Oil: 13 000 barrels/day, Gas: 0.14 billion scm, NGL: 0.02 million tonnes	
Investment	Total investment is expected to be NOK 18.2 billion (2008 values)	
	NOK 16.1 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

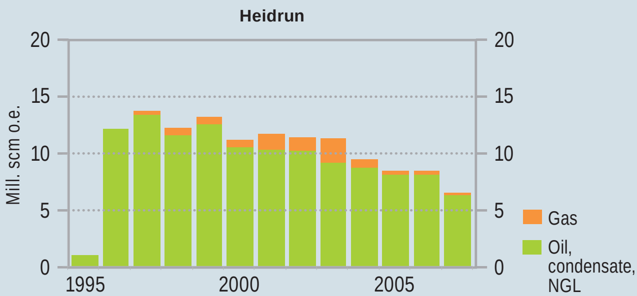
Development:
The Gyda field is located between Ula and Ekofisk in the southern part of the North Sea. It has been developed with a combined drilling, accommodation and processing facility with a steel jacket. The sea depth in the area is 66 metres.

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

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

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

Status:
Gyda is in its tail phase and experiences increasing water production and challenges in maintaining the oil production. The production licence period has been extended to 2018 and work is ongoing to extend the lifetime of the field correspondingly. Several new wells are being drilled on the field. A compressor was installed in 2007 for a gas lift pilot. This has resulted in improved production from the wells. It is considered to tie-in other deposits in the area to Gyda.



Heidrun

Block and production licences	Block 6507/8 - production licence 124, awarded 1986 Block 6707/7 - production licence 095, awarded 1986	
Discovered	1985	
Development approval	14.05.1991 by the Storting	
On stream	18.10.1995	
Operator	StatoilHydro ASA	
Licensees	ConocoPhillips Skandinavia AS	24.31 %
	Eni Norge AS	5.12 %
	Petoro AS	58.16 %
	StatoilHydro ASA	12.41 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	186.0 million scm oil	64.1 million scm oil
	41.6 billion scm gas	30.7 billion scm gas
	2.0 million tonnes NGL	1.5 million tonnes NGL
Production	**Estimated production in 2008:** Oil: 96 000 barrels/day, Gas: 0.12 billion scm, NGL: 0.02 million tonnes	
Investment	Total investment is expected to be NOK 81.6 billion (2008 values) NOK 63.6 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Stjørdal	
Main supply base	Kristiansund	

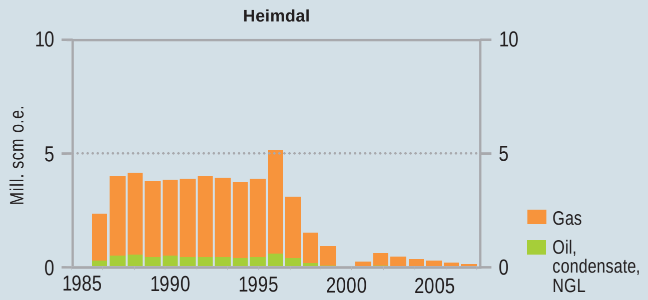
Development:
The Heidrun field is located on Haltenbanken in the Norwegian Sea. The sea depth in the area is 350 metres. The field has been developed with a floating concrete tension leg platform, installed over a subsea template with 56 well slots. The northern part of the field is developed with subsea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

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

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

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

Status:
Continuous efforts are being made to find new methods to increase oil recovery. Several wells have been drilled over the past years. CO_2 injection and increase of gas processing capacity, are being considered.



Heimdal

Block and production licences	Block 25/4 - production licence 036 BS, awarded 2003	
Discovered	1972	
Development approval	10.06.1981 by the Storting	
On stream	13.12.1985	
Operator	StatoilHydro Petroleum AS	
Licensees	Marathon Petroleum Norge AS	23.80 %
	Petoro AS	20.00 %
	StatoilHydro ASA	20.00 %
	StatoilHydro Petroleum AS	19.44 %
	Total E&P Norge AS	16.76 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	7.2 million scm oil	0.8 million scm oil
	42.8 billion scm gas	0.4 billion scm gas
Production	**Estimated production in 2008:**	
	Gas: 0.15 billion scm	
Investment	Total investment is expected to be NOK 21.6 billion (2008 values) NOK 21.0 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

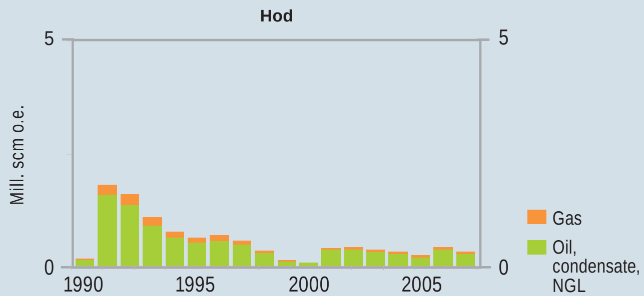
Development:
Heimdal is a gas condensate field located in the northern part of the North Sea. The sea depth in the area is 120 metres. The field has been developed with an integrated drilling, production and accommodation facility with a steel jacket (HMP1). The Heimdal Jurassic development was approved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

Reservoir:
The reservoir consists of sandstones in the Heimdal formation of Paleocene age, deposited as deepmarine turbidity currents. The reservoir depth is about 2 100 metres.

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

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

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



Hod

Block and production licences	Block 2/11 - production licence 033, awarded 1969	
Discovered	1974	
Development approval	26.06.1988 by the Storting	
On stream	30.09.1990	
Operator	BP Norge AS	
Licensees	BP Norge AS	25.00 %
	Enterprise Oil Norge AS	25.00 %
	Hess Norge AS	25.00 %
	Total E&P Norge AS	25.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	9.3 million scm oil	0.5 million scm oil
	1.7 billion scm gas	0.1 billion scm gas
	0.4 million tonnes NGL	0.1 million tonnes NGL
Production	**Estimated production in 2008:**	
	Oil: 4 000 barrels/day, Gas: 0.04 billion scm, NGL: 0.01 million tonnes	
Investment	Total investment is expected to be NOK 2.9 billion (2008 values)	
	NOK 2.7 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

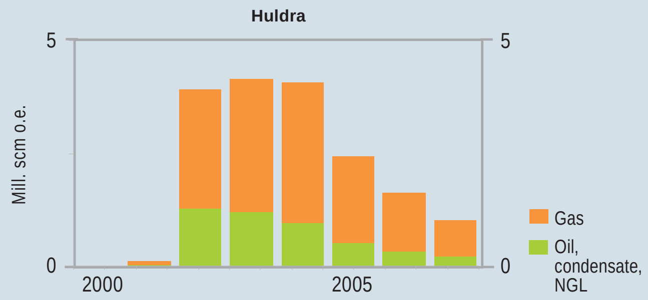
Development:
Hod is an oil field located 13 kilometres south of the Valhall field in the sourthern part of the North Sea. The sea depth is 72 metres. The field is developed with an unmanned production facility, which is remotely controlled from the Valhall field. The PDO for the Hod Sadel area was approved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

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

Recovery strategy:
Recovery takes place through pressure depletion. Five wells are in production and gas lift is used in in two wells to increase production. In 2006 a pilot for water injection was implemented, but only minor volumes of water were injected and the well is now shut in.

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

Status:
Production from Hod Øst and Hod Vest is stable at a low level. The field is in a late phase with the current recovery strategy. An injection pump will be installed in 2009 to restart the water injection pilot.



Huldra

Block and production licences	Block 30/2 - production licence 051, awarded 1979 Block 30/3 - production licence 052 B, awarded 2001	
Discovered	1982	
Development approval	02.02.1999 by the Storting	
On stream	21.11.2001	
Operator	StatoilHydro ASA	
Licensees	ConocoPhillips Skandinavia AS	23.34 %
	Petoro AS	31.96 %
	StatoilHydro ASA	19.88 %
	Talisman Energy Norge AS	0.50 %
	Total E&P Norge AS	24.33 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	4.9 million scm oil	0.6 million scm oil
	15.9 billion scm gas	3.2 billion scm gas
	0.1 million tonnes NGL	
Production	**Estimated production in 2008:** Oil: 4 000 barrels/day, Gas: 1.09 billion scm	
Investment	Total investment is expected to be NOK 8.8 billion (2008 values) NOK 8.6 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Bergen	
Main supply base	Sotra and Florø	

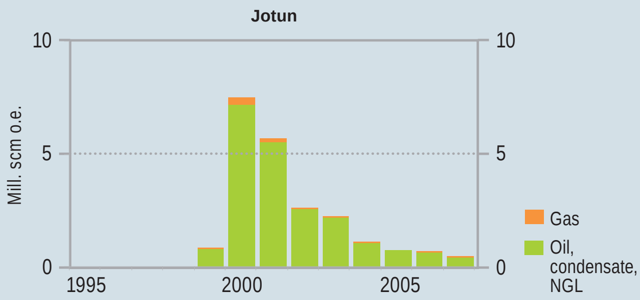
Development:
Huldra is a gas condensate field located north of Oseberg in the northern part of the North Sea. The field is developed with a steel wellhead facility with a simple process plant. The facility is remotely operated from Veslefrikk B, 16 kilometres away. The sea depth in the area is 125 metres.

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

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

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

Status:
After installation of a gas compressor on the field, the low pressure production started in June 2007. The compressor will increase the recovery at reduced wellhead pressure and extend the lifetime of the field with five years. A new well will be drilled in 2008 to prove resources in deeper layers which may extend the lifetime of the field.



Jotun

Block and production licences	Block 25/7 - production licence 103 B, awarded 1998 Block 25/8 - production licence 027 B, awarded 1999	
Discovered	1994	
Development approval	10.06.1997 by the Storting	
On stream	25.10.1999	
Operator	ExxonMobil Exploration & Production Norway AS	
Licensees	Dana Petroleum Norway AS	45.00 %
	ExxonMobil Exploration & Production Norway AS	45.00 %
	Lundin Norway AS	7.00 %
	Petoro AS	3.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	24.0 million scm oil	2.7 million scm oil
	0.9 billion scm gas	0.1 billion scm gas
Production	**Estimated production in 2008:**	
	Oil: 7 000 barrels/day, Gas: 0.03 billion scm	
Investment	Total investment is expected to be NOK 12.1 billion (2008 values) NOK 12.0 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

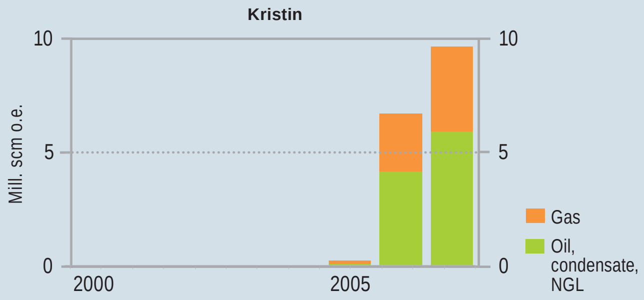
Development:
Jotun is an oil field located 25 kilometres north of Balder in the northern part of the North Sea. The sea depth in the area is 126 metres. The field has been developed with a combined accommodation, production and storage vessel (FPSO), Jotun A, and a wellhead facility, Jotun B. Jotun is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

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

Recovery strategy:
The field is recovered by pressure support from the aquifer combined with partial reinjection of produced water.

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

Status:
New well targets will be considered in 2008.



Kristin

Block and production licences	Block 6406/2 - production licence 199, awarded 1993 Block 6506/11 - production licence 134 B, awarded 2000	
Discovered	1997	
Development approval	17.12.2001 by the Storting	
On stream	03.11.2005	
Operator	StatoilHydro ASA	
Licensees	Eni Norge AS	8.25 %
	Mobil Development Norway AS	10.88 %
	Petoro AS	19.58 %
	StatoilHydro ASA	41.30 %
	StatoilHydro Petroleum AS	14.00 %
	Total E&P Norge AS	6.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	30.2 million scm oil	24.9 million scm oil
	29.5 billion scm gas	23.0 billion scm gas
	6.6 million tonnes NGL	5.2 million tonnes NGL
	2.1 million scm condensate	
Production	**Estimated production in 2008:** Oil: 70 000 barrels/day, Gas: 3.61 billion scm, NGL: 0.80 million tonnes	
Investment	Total investment is expected to be NOK 25.9 billion (2008 values) NOK 24.7 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Stjørdal	
Main supply base	Kristiansund	

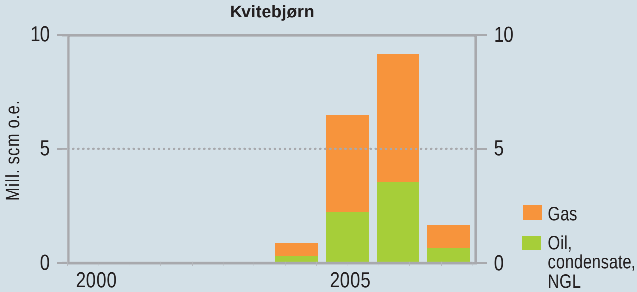
Development:
Kristin is a gas condensate field in the Norwegian Sea. The field is developed with a subsea facility and a semi-submersible production facility for processing. The sea depth in the area is about 370 metres. Provision has been made for tie-in and processing of other deposits in the area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

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

Recovery strategy:
Kristin is recovered by pressure depletion.

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

Status:
Drilling of production wells has taken longer than planned, and production so far is therefore lower than expected. Work is ongoing to find solutions to production and drilling challenges related to pressure depletion and water breakthrough in wells.



Kvitebjørn

Block and production licences	Block 34/11 - production licence 193, awarded 1993	
Discovered	1994	
Development approval	14.06.2000 by the Storting	
On stream	26.09.2004	
Operator	StatoilHydro ASA	
Licensees	Enterprise Oil Norge AS	6.45 %
	Petoro AS	30.00 %
	StatoilHydro ASA	43.55 %
	StatoilHydro Petroleum AS	15.00 %
	Total E&P Norge AS	5.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	27.4 million scm oil	21.6 million scm oil
	74.9 billion scm gas	63.3 billion scm gas
	3.1 million tonnes NGL	2.0 million tonnes NGL
Production	**Estimated production in 2008:**	
	Oil: 23 000 barrels/day, Gas: 6.08 billion scm, NGL: 0.25 million tonnes	
Investment	Total investment is expected to be NOK 14.5 billion (2008 values) NOK 12.1 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Bergen	
Main supply base	Florø	

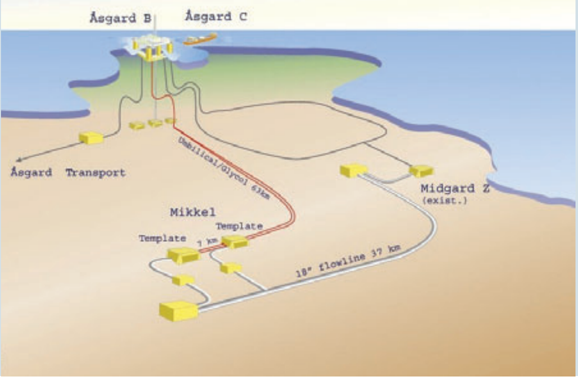
Development:
Kvitebjørn is a gas condensate field located east in the Tampen area in the northern part of the North Sea. The field is developed with an integrated accommodation, drilling and processing facility with a steel jacket. Sea depth in the area is about 190 metres. 10 production wells have been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

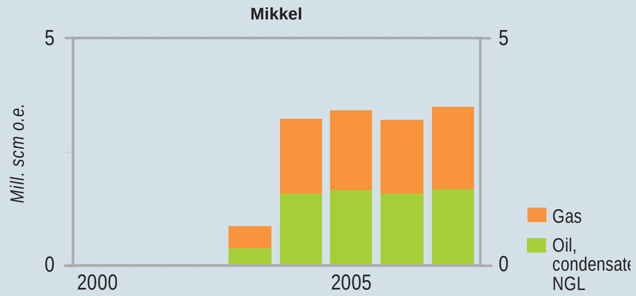
Reservoir:
The reservoir consists of sandstones in the Middle Jurassic Brent group. The reservoir lies at approximately 4 000 metres depth, and has high temperature and high pressure. The reservoir quality is good.

Recovery strategy:
The field is recovered by pressure depletion.

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

Status:
The production from Kvitebjørn has been temporarily reduced in 2007. The reduction will make it possible to drill additional wells to obtain higher production at a later stage and increased recovery in total.





Mikkel

Block and production licences	Block 6407/5 - production licence 121, awarded 1986 Block 6407/6 - production licence 092, awarded 1984	
Discovered	1987	
Development approval	14.09.2001 by the King in Council	
On stream	01.08.2003	
Operator	StatoilHydro ASA	
Licensees	Eni Norge AS	14.90 %
	Mobil Development Norway AS	33.48 %
	StatoilHydro ASA	33.97 %
	StatoilHydro Petroleum AS	10.00 %
	Total E&P Norge AS	7.65 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	4.4 million scm oil	3.5 million scm oil
	22.9 billion scm gas	15.6 billion scm gas
	5.8 million tonnes NGL	3.8 million tonnes NGL
	2.3 million scm condensate	
Production	**Estimated production in 2008:** Oil: 9 000 barrels/day, Gas: 1.57 billion scm, NGL: 0.42 million tonnes	
Investment	Total investment is expected to be NOK 2.3 billion (2008 values) NOK 2.1 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Stjørdal	
Main supply base	Kristiansund	

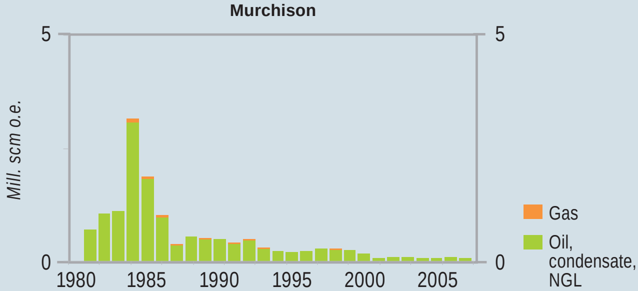
Development:
Mikkel is a gas condensate field located east in the Norwegian Sea, about 30 kilometres north of Draugen. The sea depth in the area is 220 metres. The field has been developed with a subsea facility with two templates tied back to Åsgard B.

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

Recovery strategy:
Mikkel is recovered by pressure depletion.

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

Status:
An additional well was planned to be drilled in 2007, but positive production experience showed that there was no need for a new well.



Murchison

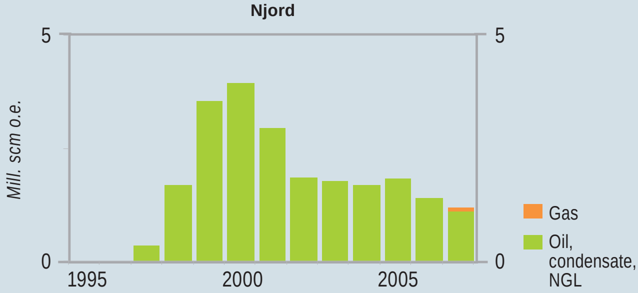
Block and production licences	Block 33/9 - production licence 037 C, awarded 2000 The Norwegian part of the field is 22.2%, the British part is 77.8%	
Discovered	1975	
Development approval	15.12.1976	
On stream	28.09.1980	
Operator	CNR International (UK) Limited	
Licensees	Revus Energy ASA CNR International (UK) Limited	22.20 % 77.80 %
Recoverable reserves (Norwegian part)	**Original:** 14.2 million scm oil 0.4 billion scm gas	**Remaining as of 31.12.2007** 0.7 million scm oil 0.1 billion scm gas
Production	**Estimated production in 2008:** Oil: 1 000 barrels/day	
Investment	Total investment is expected to be NOK 8.1 billion (2008 values) NOK 7.9 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Aberdeen, Scotland	
Main supply base	Peterhead, Scotland	

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

Reservoir:
The reservoirs are in Jurassic sandstones.

Recovery strategy:
The field is recovered by pressure support from water injection. Murchison is in tail production.

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



Njord

Block and production licences	Block 6407/10 - production licence 132, awarded 1987 Block 6407/7 - production licence 107, awarded 1985	
Discovered	1986	
Development approval	12.06.1995 by the Storting	
On stream	30.09.1997	
Operator	StatoilHydro Petroleum AS	
Licensees	E.ON Ruhrgas Norge AS	30.00 %
	Endeavour Energy Norge AS	2.50 %
	Gaz de France Norge AS	20.00 %
	Mobil Development Norway AS	20.00 %
	Petoro AS	7.50 %
	StatoilHydro Petroleum AS	20.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	24.0 million scm oil	2.0 million scm oil
	10.7 billion scm gas	10.6 billion scm gas
	1.7 million tonnes NGL	1.7 million tonnes NGL
Production	**Estimated production in 2008:** Oil: 13 000 barrels/day, Gas: 1.8 billion scm, NGL: 0.29 million tonnes	
Investment	Total investment is expected to be NOK 15.5 billion (2008 values) NOK 14.0 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Kristiansund	
Main supply base	Kristiansund	

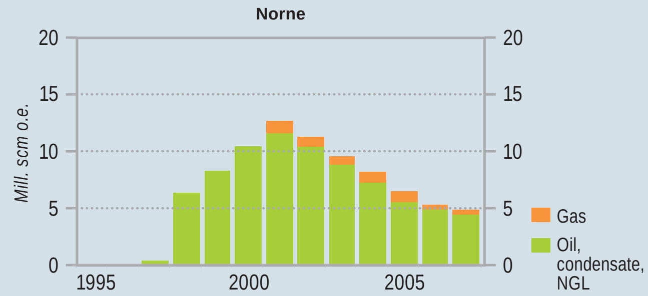
Development:
Njord is an oil field located around 30 kilometres west of Draugen in the Norwegian Sea. The sea depth in the area is 330 metres. The field has been developed with a steel semi-submersible drilling, accommodation and production facility and a storage vessel, Njord B. The facility is located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

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

Recovery strategy:
Most of the gas produced at Njord has been reinjected for pressure support and increased oil recovery from parts of the field. Gas export from the field started in the autumn of 2007, and only minor volumes of gas are now being reinjected.

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

Status:
Gas export from the field started in December 2007. A new drilling campaign to improve oil recovery will start in the summer of 2008. Two wells were drilled to the northwestern flank of the field in 2007. These segments will be tied in to Njord, with expected production start in 2010.



Norne

Block and production licences	Block 6508/1 - production licence 128 B, awarded 1998. Block 6608/10 - production licence 128, awarded 1986.	
Discovered	1992	
Development approval	09.03.1995 by the Storting	
On stream	06.11.1997	
Operator	StatoilHydro ASA	
Licensees	Eni Norge AS	6.90 %
	Petoro AS	54.00 %
	StatoilHydro ASA	31.00 %
	StatoilHydro Petroleum AS	8.10 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	93.0 million scm oil	16.0 million scm oil
	11.6 billion scm gas	6.2 billion scm gas
	1.4 million tonnes NGL	0.7 million tonnes NGL
Production	**Estimated production in 2008:**	
	Oil: 45 000 barrels/day, Gas: 0.19 billion scm, NGL: 0.02 million tonnes	
Investment	Total investment is expected to be NOK 30.9 billion (2008 values) NOK 22.6 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Harstad	
Main supply base	Sandnessjøen	

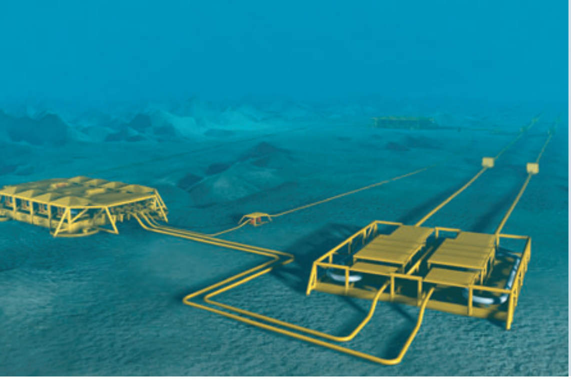
Development:
Norne is an oil field located around 80 kilometres north of the Heidrun field in the Norwegian Sea. The sea depth in the area is 380 metres. The field has been developed with a production and storage vessel, connected to six subsea wellhead templates. Flexible risers carry the wellstream up to the vessel.

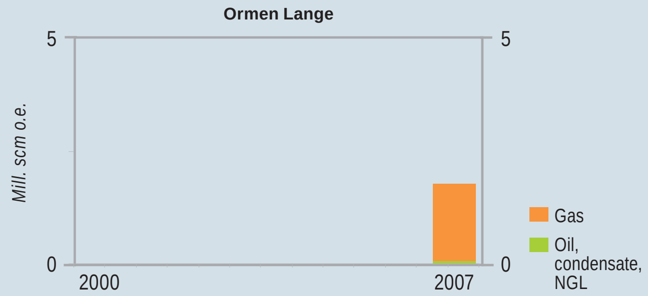
Reservoir:
The reservoir is in Jurassic sandstones. Oil is mainly found in the Ile and Tofte formations, and gas in the Garn formation. The reservoir depth is about 2500 metres. The reservoir quality is good.

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

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

Status:
Various measures to increase recovery have been implemented on Norne, including use of new well technology. A multilateral well was drilled in 2007 and will be completed in 2008.





Ormen Lange

Block and production licences	Block 6305/4 - production licence 209, awarded 1996 Block 6305/5 - production licence 209, awarded 1996 Block 6305/7 - production licence 208, awarded 1996 Block 6305/8 - production licence 250, awarded 1999	
Discovered	1997	
Development approval	02.04.2004 by the Storting	
On stream	13.09.2007	
Operator	A/S Norske Shell	
Licensees	A/S Norske Shell	17.04 %
	DONG E&P Norge AS	10.34 %
	ExxonMobil Exploration & Production Norway AS	7.23 %
	Petoro AS	36.48 %
	StatoilHydro ASA	10.84 %
	StatoilHydro Petroleum AS	18.07 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	393.7 billion scm gas	392.1 billion scm gas
	28.5 million scm condensate	28.4 million scm condensate
Production	**Estimated production in 2008:** Gas: 10.82 billion scm, Condensate: 0.99 million scm	
Investment	Total investment is expected to be NOK 53.3 billion (2008 values)* NOK 15.8 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Kristiansund	

**Total investment, including the land facilities, is expected to be 75.1 billion (2008 values)*

Development:
Ormen Lange is a gas field located in the Møre Basin in the southern part of the Norwegian Sea. The sea depth in the area varies from 800-1 100 metres. The large sea depth has made the development very chal-lenging and has resulted in development of new technology. The field will be developed with 24 wells from three subsea templates.

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

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

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

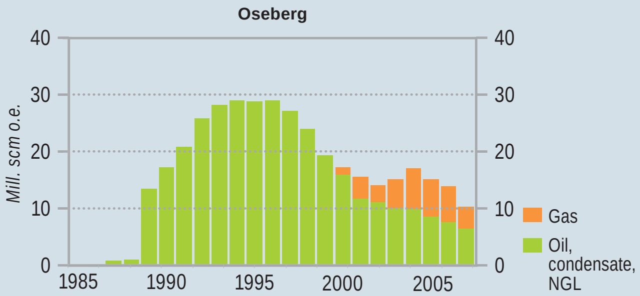
Status
The gas production started officially in October 2007. A/S Norske Shell took over the operatorship from StatoilHydro 1 November 2007. Three wells are now in production. Five new wells will be completed in 3rd quarter 2008 and the on-shore facility will then produce at its maximum.

Oseberg

Block and production licences	Block 30/6 - production licence 053, awarded 1979 Block 30/9 - production licence 079, awarded 1982	
Discovered	1979	
Development approval	05.06.1984 by the Storting	
On stream	01.12.1988	
Operator	StatoilHydro Petroleum AS	
Licensees	ConocoPhillips Skandinavia AS	2.40 %
	Mobil Development Norway AS	4.70 %
	Petoro AS	33.60 %
	StatoilHydro ASA	15.30 %
	StatoilHydro Petroleum AS	34.00 %
	Total E&P Norge AS	10.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	361.1 million scm oil	21.2 million scm oil
	109.2 billion scm gas	91.0 billion scm gas
	8.7 million tonnes NGL	3.7 million tonnes NGL
Production	**Estimated production in 2008:** Oil: 91 000 barrels/day, Gas: 3.49 billion scm, NGL: 0.57 million tonnes	
Investment	Total investment is expected to be NOK 99.1 billion (2008 values) NOK 89.1 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

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

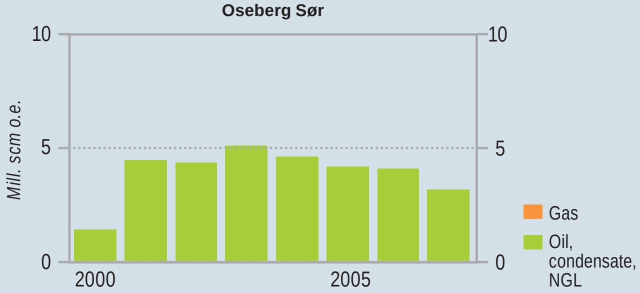
Reservoir:
The field consists of several sandstone reservoirs in the Middle Jurassic Brent group, and is divided into several structures. The main reservoir is located in the Oseberg and Tarbert formations, but production also takes place from the Etive and Ness formations. The field has generally good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



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

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

Status:
Additional resources were proven in the Gamma Main Statfjord structure in 2007. The production from this structure is planned to start in the spring of 2008 with two wells drilled from Oseberg field centre. The challenge on Oseberg will be to produce the oil that remains under the gas cap, and to balance the gas and oil production from the field. A later start of the gas blowdown is considered. A module for low pressure production has been decided for the Oseberg Field Centre. Test production has started from an overlying chalk reservoir in the Shetland group on the Oseberg field to evaluate the flow characteristics. Oseberg Delta will commence production in 2008.



Oseberg Sør

Block and production licences	Block 30/12 - production licence 171 B, awarded 2000 Block 30/9 - production licence 079, awarded 1982 Block 30/9 - production licence 104, awarded 1985	
Discovered	1984	
Development approval	10.06.1997 by the Storting	
On stream	05.02.2000	
Operator	StatoilHydro Petroleum AS	
Licensees	ConocoPhillips Skandinavia AS	2.40 %
	Mobil Development Norway AS	4.70 %
	Petoro AS	33.60 %
	StatoilHydro ASA	15.30 %
	StatoilHydro Petroleum AS	34.00 %
	Total E&P Norge AS	10.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	49.9 million scm oil	18.6 million scm oil
	11.6 billion scm gas	6.8 billion scm gas
Production	**Estimated production in 2008:** Oil: 43 000 barrels/day, Gas: 0.64 billion scm	
Investment	Total investment is expected to be NOK 22.5 billion (2008 values) NOK 18.5 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

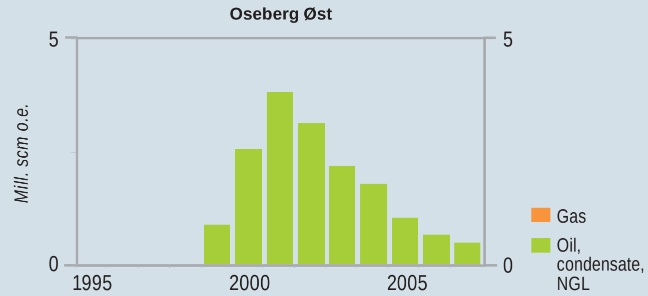
Development:
Oseberg Sør is an oil field located south of Oseberg in the northern part of the North Sea. The sea depth in the area is approximately 100 metres. The field has been developed with an integrated steel facility with accommodation, drilling module and first stage separation of oil and gas.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

Reservoir:
Oseberg Sør consists of ten deposits with Jurassic sandstone reservoirs in separate structures. The reservoir depth is between 2 200-2 800 metres. The main reservoir is in the Tarbert and Heather formations of Jurassic age. The reservoir quality is moderate.

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

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

Status:
The Oseberg Sør G Sentral deposit will be developed by wells drilled from the Oseberg Sør facility in late 2008.



Oseberg Øst

Block and production licences	Block 30/6 - production licence 053, awarded 1979	
Discovered	1981	
Development approval	11.10.1996 by the King in Council	
On stream	03.05.1999	
Operator	StatoilHydro Petroleum AS	
Licensees	ConocoPhillips Skandinavia AS	2.40 %
	Mobil Development Norway AS	4.70 %
	Petoro AS	33.60 %
	StatoilHydro ASA	15.30 %
	StatoilHydro Petroleum AS	34.00 %
	Total E&P Norge AS	10.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	27.4 million scm oil	10.8 million scm oil
	0.4 billion scm gas	0.2 billion scm gas
Production	**Estimated production in 2008:**	
	Oil: 15 000 barrels/day, Gas: 0.02 billion scm	
Investment	Total investment is expected to be NOK 11.7 billion (2008 values)	
	NOK 9.1 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

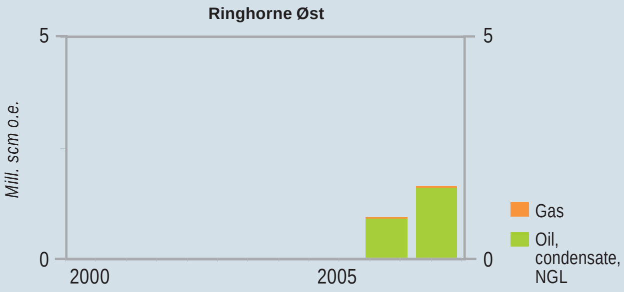
Development:
Oseberg Øst is an oil field located east of Oseberg in the northern part of the North Sea. The field has been developed with an integrated fixed facility with accommodation, drilling equipment and first stage separation of oil, water and gas. The sea depth in the area is about 160 metres.

Reservoir:
The main reservoir consists of two structures, separated by a sealing fault. The structures contain several oilbearing layers in the Middle Jurassic Brent group with varying reservoir characteristics.

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

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

Status:
Measures for increased oil recovery are continuously being evaluated. The drilling equipment on the Oseberg Øst facility has been upgraded and a new drilling campaign of seven wells has started. The first well in the drilling campaign is planned to start production in June 2008. Increased gas injection by importing gas to the field is also being evaluated.



Ringhorne Øst

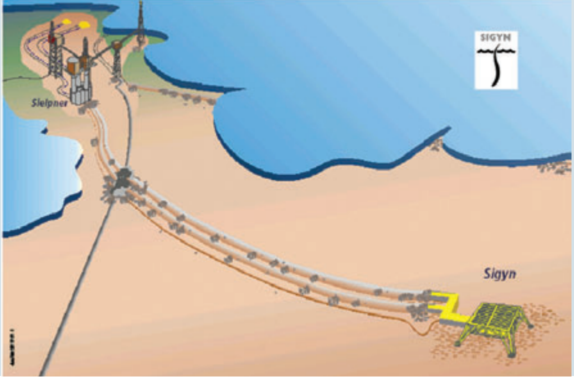
Block and production licences	Block 25/8 - production licence 027, awarded 1969 Block 25/8 - production licence 169, awarded 1991	
Discovered	2003	
Development approval	25.11.2005 by the King in Council	
On stream	19.03.2006	
Operator	ExxonMobil Exploration & Production Norway AS	
Licensees	ExxonMobil Exploration & Production Norway AS	77.38 %
	Petoro AS	7.80 %
	StatoilHydro ASA	3.12 %
	StatoilHydro Petroleum AS	11.70 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	6.4 million scm oil	3.9 million scm oil
	0.1 billion scm gas	0.1 billion scm gas
Production	**Estimated production in 2008:**	
	Oil: 18 000 barrels/day, Gas: 0.03 billion scm	
Investment	Total investment is expected to be NOK 0.5 billion (2008 values) NOK 0.5 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Stavanger	

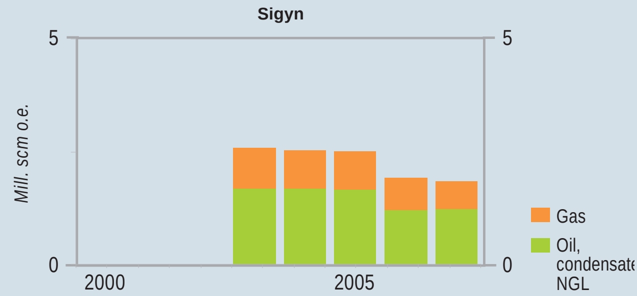
Development:
Ringhorne Øst is an oil field located north of Balder in the northern part of the North Sea. The sea depth in the area is about 130 meters. The field is developed by three production wells drilled from the Ringhorne facility on the Balder field.

Reservoir:
The field contains oil with associated gas at about 1 900 metres depth. The reservoir is in Jurassic sandstones in the Statfjord formation. The reservoir quality is good.

Recovery strategy:
The field is recovered with natural water drive from a regional aquifer to the north and east of the structure.

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





Sigyn

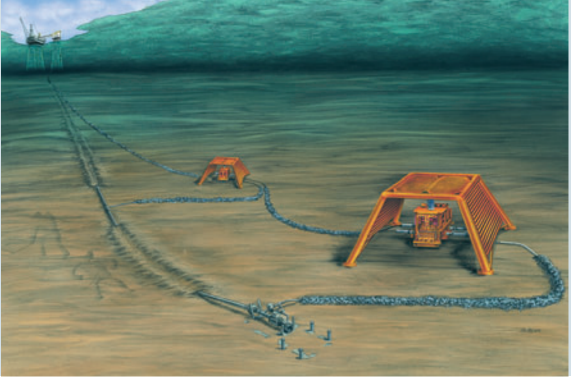
Block and production licences	Block 16/7 - production licence 072, awarded 1981	
Discovered	1982	
Development approval	31.08.2001 by the King in Council	
On stream	22.12.2002	
Operator	ExxonMobil Exploration & Production Norway AS	
Licensees	ExxonMobil Exploration & Production Norway AS	40.00 %
	StatoilHydro ASA	50.00 %
	StatoilHydro Petroleum AS	10.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	6.0 billion scm gas	2.0 billion scm gas
	2.4 million tonnes NGL	0.8 million tonnes NGL
	4.5 million scm condensate	
Production	**Estimated production in 2008:**	
	Gas: 0.49 billion scm, NGL: 0.21 million tonnes	
Investment	Total investment is expected to be NOK 2.4 billion (2008 values)	
	NOK 2.4 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

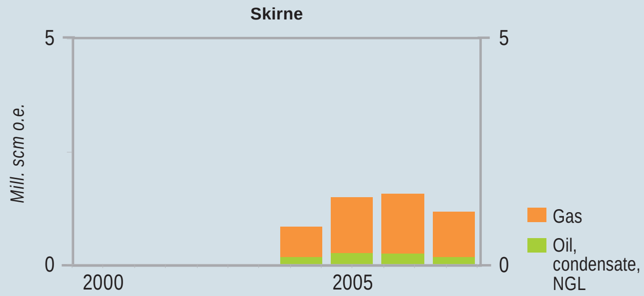
Development:
Sigyn is located in the Sleipner area in the southern part of the North Sea. The sea depth in the area is around 70 metres. The field comprises the deposits Sigyn Vest, which contains gas and condensate, and Sigyn Øst, which contains light oil. The field has been developed with a subsea template as a satellite of Sleipner Øst. The wellstream is controlled from Sleipner Øst and is sent through two 12 kilometres long pipelines to the Sleipner A facility.

Reservoir:
The main reservoir lies in the Triassic Skagerrak formation at a depth of about 2 700 metres.

Recovery strategy:
The field is produced with pressure depletion.

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





Skirne

Block and production licences	Blokk 25/5 - production licence 102, awarded 1985	
Discovered	1990	
Development approval	05.07.2002 by the Crown Prince Regent in Council	
On stream	03.03.2004	
Operator	Total E&P Norge AS	
Licensees	Marathon Petroleum Norge AS	20.00 %
	Petoro AS	30.00 %
	StatoilHydro Petroleum AS	10.00 %
	Total E&P Norge AS	40.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	2.0 million scm oil	1.0 million scm oil
	8.9 billion scm gas	4.7 billion scm gas
Production	**Estimated production in 2008:**	
	Oil: 4 000 barrels/day, Gas: 1.19 billion scm	
Investment	Total investment is expected to be NOK 2.9 billion (2008 values)	
	NOK 2.7 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Stavanger	

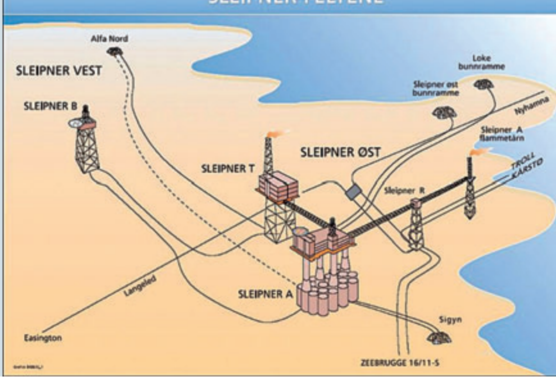
Development:
Skirne which includes the Byggve deposit, contains gas and condensate and is located east of Heimdal in the northern part of the North Sea. The sea depth in the area is about 120 metres. The field has been developed with two subsea facilities tied to Heimdal by pipeline.

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

Recovery strategy:
The field is recovered by pressure depletion.

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

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



Sleipner Vest

Block and production licences	Block 15/6 - production licence 029, awarded 1969 Block 15/9 - production licence 046, awarded 1976	
Discovered	1974	
Development approval	14.12.1992 by the Storting	
On stream	29.08.1996	
Operator	StatoilHydro ASA	
Licensees	ExxonMobil Exploration & Production Norway AS	32.24 %
	StatoilHydro ASA	49.50 %
	StatoilHydro Petroleum AS	8.85 %
	Total E&P Norge AS	9.41 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007***
	120.6 billion scm gas	39.7 billion scm gas
	8.3 million tonnes NGL	3.3 million tonnes NGL
	29.2 million scm condensate	0.8 million scm condensate
Production	**Estimated production in 2008:** Gas: 7.41 billion scm, NGL: 0.42 million tonnes, Condensate: 1.29 million scm	
Investment	Total investment is expected to be NOK 27.7 billion (2008 values) NOK 25.6 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

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

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

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

Recovery strategy:
Sleipner Vest is recovered by pressure 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 goes to Sleipner A for further export. CO_2 is injected into the Utsira formation via a dedicated injection well from Sleipner A. Unstable condensate from Sleipner Vest and Sleipner Øst is mixed at Sleipner A and sent to Kårstø for processing to stable condensate and NGL products.

Status:
To maintain production when the field comes off plateau, a new compressor on Sleipner B will be started during 2008. Drilling and development of several nearby deposits will also be evaluated in the coming years, and a drilling rig will be installed on Sleipner B in 2008.

Sleipner Øst

Block and production licences	Block 15/9 - production licence 046, awarded 1976	
Discovered	1981	
Development approval	15.12.1986 by the Storting	
On stream	24.08.1993	
Operator	StatoilHydro ASA	
Licensees	ExxonMobil Exploration & Production Norway AS	30.40 %
	StatoilHydro ASA	49.60 %
	StatoilHydro Petroleum AS	10.00 %
	Total E&P Norge AS	10.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007***
	68.3 billion scm gas	39.7 billion scm gas
	13.1 million tonnes NGL	3.3 million tonnes NGL
	27.9 million scm condensate	0.8 million scm condensate
Production	**Estimated production in 2008:**	
	Gas: 1.9 billion scm, NGL: 0.27 million tonnes, Condensate: 0.36 million scm	
Investment	Total investment is expected to be NOK 41.1 billion (2008 values)	
	NOK 38.6 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

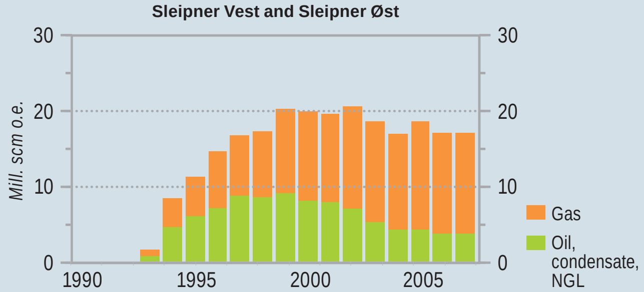
** Gas production from Gungne, Sleipner Vest and Sleipner Øst is measured collectively. The remaining reserves show Sleipner Øst and Sleipner Vest in total.*

Development:
Sleipner Øst is a gas condensate field in the southern part of the North Sea. The sea depth in the area is 82 metres. The field has been developed with an integrated processing, drilling and accommodation facility with a concrete jacket, Sleipner A. A riser facility, Sleipner R, connects Sleipner A to the pipelines for gas transport and to the flare stack Sleipner F. Two subsea templates have also been installed, one for production from the northern part of Sleipner Øst and one for production of the Loke deposit. Three Sigyn wells are also tied back to Sleipner A.

The PDO for Loke was approved in 1991 and production started in 1993. Development of Loke Triassic was approved on 29.08.1995 and production started on 19.06.1998.

Reservoir:
The Sleipner Øst and Loke reservoirs are mainly in sandstones in the Ty formation of Paleocene age and sandstones in the Hugin formation of Middle Jurassic age. The reservoir depth is about 2 300 metres. There is no pressure communication between the two reservoir zones. The underlying Triassic Skagerrak formation is the main reservoir at Loke with moderate to poor reservoir characteristics.

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



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

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

Status:
Two new wells were drilled in 2007. There are plans to increase recovery by reducing the inlet pressure at Sleipner A.

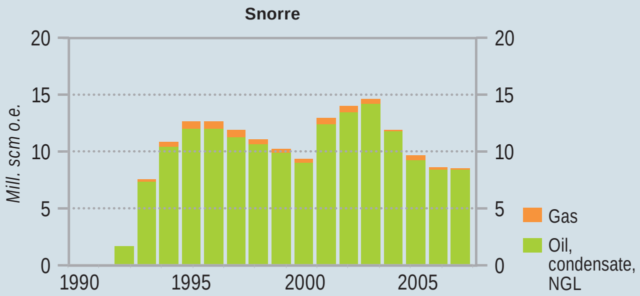
Snorre

Block and production licences	Block 34/4 - production licence 057, awarded 1979 Block 34/7 - production licence 089, awarded 1984	
Discovered	1979	
Development approval	27.05.1988 by the Storting	
On stream	03.08.1992	
Operator	StatoilHydro ASA	
Licensees	ExxonMobil Exploration & Production Norway AS	11.58 %
	Hess Norge AS	1.04 %
	Idemitsu Petroleum Norge AS	9.60 %
	Petoro AS	30.00 %
	RWE Dea Norge AS	8.28 %
	StatoilHydro ASA	15.55 %
	StatoilHydro Petroleum AS	17.77 %
	Total E&P Norge AS	6.18 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	234.2 million scm oil	79.2 million scm oil
	6.5 billion scm gas	0.9 billion scm gas
	4.8 million tonnes NGL	0.4 million tonnes NGL
Production	**Estimated production in 2008:** Oil: 133 000 barrels/day	
Investment	Total investment is expected to be NOK 96.6 billion (2008 values) NOK 71.8 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Stavanger	
Main supply base	Florø	

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

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

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



Transport:
Oil and gas are separated in two stages on Snorre A before transport in separate pipelines to Statfjord A for final processing and export. The oil is loaded onto shuttle tankers at Statfjord and the gas is sent through the Statpipe pipeline to Kårstø. Processed oil from Snorre B is routed by pipeline to Statfjord B for storage and loading to shuttle tankers. All gas from Snorre B is reinjected into the reservoir, but may, when required, also be sent by pipeline to Snorre A.

Status:
In 2007 it was decided to increase the processing capacities for production and injection of water. Several measures are being evaluated to increase recovery on Snorre, i.a. increased gas injection by gas import to the field. Concept selection is expected in 2008 for Snorre Future Development which constitutes a long-term solution for Snorre when the oil export via Statfjord has ceased.

Snøhvit

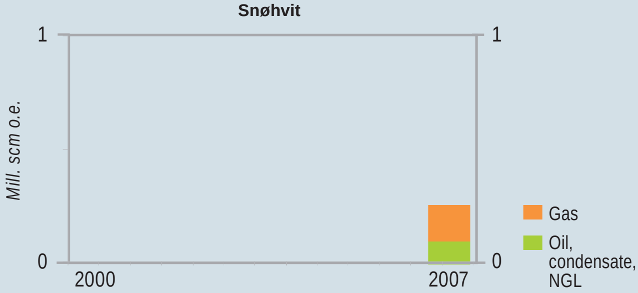
Block and production licences	Block 7120/6 - production licence 097, awarded 1984	
	Block 7120/7 - production licence 077, awarded 1982	
	Block 7120/8 - production licence 064, awarded 1981	
	Block 7120/9 - production licence 078, awarded 1982	
	Block 7121/4 - production licence 099, awarded 1984	
	Block 7121/5 - production licence 110, awarded 1985	
	Block 7121/7 - production licence 100, awarded 1984	
Discovered	1984	
Development approval	07.03.2002 by the Storting	
On stream	21.08.2007	
Operator	StatoilHydro ASA	
Licensees	Gaz de France Norge AS	12.00 %
	Hess Norge AS	3.26 %
	Petoro AS	30.00 %
	RWE Dea Norge AS	2.81 %
	StatoilHydro ASA	33.53 %
	Total E&P Norge AS	18.40 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	160.6 billion scm gas	160.4 billion scm gas
	6.3 million tonnes NGL	6.3 million tonnes NGL
	18.1 million scm condensate	18.0 million scm condensate
Production	**Estimated production in 2008:**	
	Gas: 5.03 billion scm, NGL: 0.30 million tonnes, Condensate: 0.79 million scm	
Investment	Total investment is expected to be NOK 17.4 billion (2008 values)*	
	NOK 8.8 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Harstad and Stjørdal	

** Total investment, including the land facilities, is expected to be 64.5 billion (2008 values)*

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

Reservoir:
The reservoirs contain gas, condensate and oil in Lower and Middle Jurassic sandstones belonging to the Stø and Nordmela formations. The reservoir depth is about 2 300 meters.

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



Transport:
The unprocessed wellstream, containing natural gas inclusive CO_2, NGL and condensate, is trans-ported through a 160 kilometres long pipeline to the facility at Melkøya for processing and export. The gas is processed and cooled down to liquid form (LNG) at Melkøya. The CO_2 content in the gas is separated at Melkøya and sent back to the field and reinjected in a deeper formation. LNG is shipped to the market.

Status:
In the summer of 2007, an appraisal well was drilled in the western part of the field in order to collect more information from the oil zone. The well results showed that there was no basis for development of the oil zone. The LNG facility has been closed down for a longer period due to technical problems.

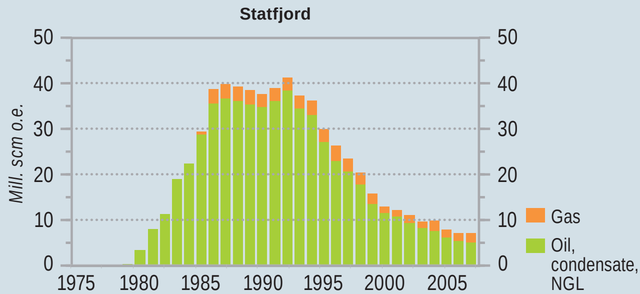
Statfjord

Block and production licences	Block 33/12 - production licence 037, awarded 1973 Block 33/9 - production licence 037, awarded 1973 The Norwegian part of the field is 85.47%, the British part is 14.53%	
Discovered	1974	
Development approval	16.06.1976 by the Storting	
On stream	24.11.1979	
Operator	StatoilHydro ASA	
Licensees	A/S Norske Shell	8.55 %
	ConocoPhillips Skandinavia AS	10.33 %
	Enterprise Oil Norge AS	0.89 %
	ExxonMobil Exploration & Production Norway AS	21.37 %
	StatoilHydro ASA	44.34 %
	Centrica Resources Limited	9.69 %
	ConocoPhillips (U.K.) Limited.	4.84 %
Recoverable reserves (Norwegian part)	**Original:**	**Remaining as of 31.12.2007**
	564.6 million scm oil	9.1 million scm oil
	78.8 billion scm gas	23.2 billion scm gas
	24.8 million tonnes NGL	10.0 million tonnes NGL
Production	**Estimated production in 2008:** Oil: 47 000 barrels/day, Gas: 2.37 billion scm, NGL: 1.33 million tonnes	
Investment	Total investment is expected to be NOK 138.1 billion (2008 values) NOK 126.7 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Stavanger	
Main supply base	Sotra and Florø	

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

Reservoir:
The Statfjord reservoirs lie at a depth between 2 500-3 000 meters in a large fault block tilted towards the west, and in a number of smaller fault compartments along the east flank. The reservoirs are in Jurassic sandstones belonging to the Brent group and the Cook and Statfjord formations. The Brent group and Statfjord formation have excellent reservoir quality.

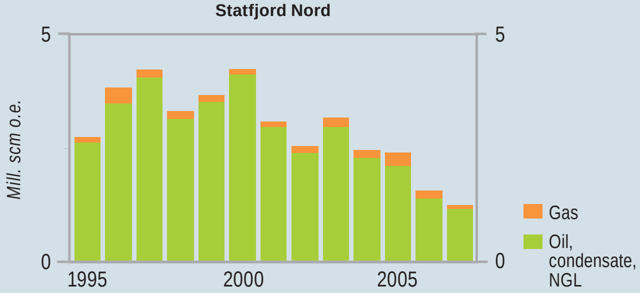
Recovery strategy:
The Brent reservoir produces with pressure support from water alternating gas injection (WAG). The Statfjord formation produces with pressure support from water injection and supplemental gas injection in the upper part, and WAG injection in the lower part. The oil in the Cook formation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



and the injection wells will be converted to water producers. This will extend the lifetime of the field by ten years and improve the recovery of both oil and gas.

Transport:
Stabilised oil is stored in storage cells at each facility. Oil is loaded to tankers from one of the three oil loading systems at the field. The gas is sent through the Statpipe pipeline to Kårstø, where NGL is separated before dry gas is transported on to Emden. The UK licensees route their share of the gas through the Far North Liquids and Gas System (FLAGS) pipeline from Statfjord B to St. Fergus in Scotland. Tampen Link is a new pipeline for export of the gas from Statfjord Late Life to the UK via FLAGS. The gas export through Tampen Link started in October 2007.

Status:
The facilities are being modified as part of the Statfjord Late Life, and 11 wells were drilled in 2007. The lifetime of Statfjord A and the Snorre tie-in to Statfjord A are now being evaluated in cooperation with the licensees in the Snorre field.



Statfjord Nord

Block and production licences	Block 33/9 - production licence 037, awarded 1973	
Discovered	1977	
Development approval	11.12.1990 by the Storting	
On stream	23.01.1995	
Operator	StatoilHydro ASA	
Licensees	A/S Norske Shell	10.00 %
	ConocoPhillips Skandinavia AS	12.08 %
	Enterprise Oil Norge AS	1.04 %
	ExxonMobil Exploration & Production Norway AS	25.00 %
	Petoro AS	30.00 %
	StatoilHydro ASA	21.88 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	40.9 million scm oil	6.2 million scm oil
	2.6 billion scm gas	0.4 billion scm gas
	0.9 million tonnes NGL	0.2 million tonnes NGL
Production	**Estimated production in 2008:**	
	Oil: 14 000 barrels/day, Gas: 0.04 billion scm, NGL: 0.02 million tonnes	
Investment	Total investment is expected to be NOK 8.5 billion (2008 values)	
	NOK 8.1 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Stavanger	
Main supply base	Sotra	

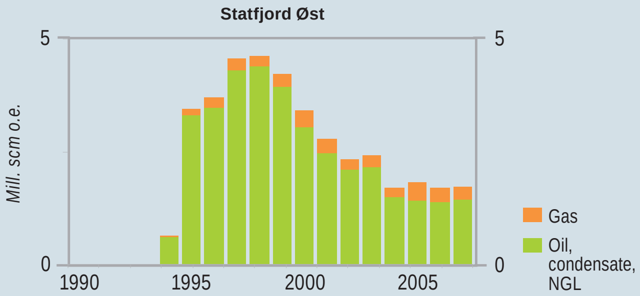
Development:
Statfjord Nord is an oil field located approximately 17 kilometres north of Statfjord in the Tampen area. The sea depth in the area is 250-290 metres. The field has been developed with three subsea templates tied back to Statfjord C. Two templates are for production and one is for water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

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

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

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

Status:
It is being considered if water alternating gas injection (WAG) can be a method for improved oil recovery on Statfjord Nord. Final decision is expected in 2009.



Statfjord Øst

Block and production licences	Block 33/9 - production licence 037, awarded 1973 Block 34/7 - production licence 089, awarded 1984	
Discovered	1976	
Development approval	11.12.1990 by the Storting	
On stream	24.09.1994	
Operator	StatoilHydro ASA	
Licensees	A/S Norske Shell	5.00 %
	ConocoPhillips Skandinavia AS	6.04 %
	Enterprise Oil Norge AS	0.52 %
	ExxonMobil Exploration & Production Norway AS	17.75 %
	Idemitsu Petroleum Norge AS	4.80 %
	Petoro AS	30.00 %
	RWE Dea Norge AS	1.40 %
	StatoilHydro ASA	25.05 %
	StatoilHydro Petroleum AS	6.64 %
	Total E&P Norge AS	2.80 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	37.9 million scm oil	4.8 million scm oil
	4.2 billion scm gas	0.7 billion scm gas
	1.6 million tonnes NGL	0.3 million tonnes NGL
Production	**Estimated production in 2008:** Oil: 16 000 barrels/day, Gas: 0.12 billion scm, NGL: 0.07 million tonnes	
Investment	Total investment is expected to be NOK 8.2 billion (2008 values) NOK 7.7 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Stavanger	
Main supply base	Sotra	

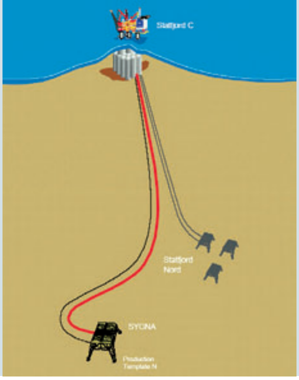
Development:
Statfjord Øst is an oil field located approximately 7 kilometres northeast of the Statfjord field in the Tampen area. The sea depth in the area is 150-190 metres. The field has been developed with three subsea templates tied back to Statfjord C. Two of the templates are for production and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

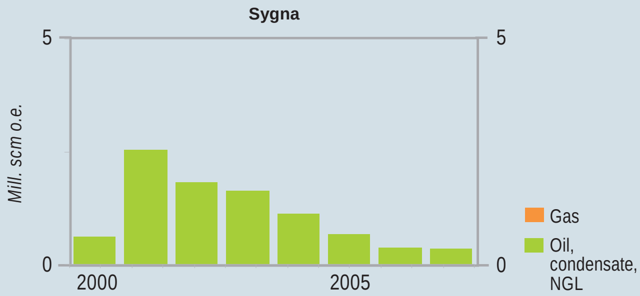
Reservoir:
The Statfjord Øst reservoir consists of Middle Jurassic sandstones in the Brent group. The reservoir depth is about 2 400 metres.

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

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

Status:
Through Tubing Rotary Drilling (TTRD) is being evaluated as a method for improved oil recovery on Statfjord Øst. Gas lift in the wells may also be implemented.





Sygna

Block and production licences	Block 33/9 - production licence 037, awarded 1973 Block 34/7 - production licence 089, awarded 1984	
Discovered	1996	
Development approval	30.04.1999 by the King in Council	
On stream	01.08.2000	
Operator	StatoilHydro ASA	
Licensees	A/S Norske Shell	5.50 %
	ConocoPhillips Skandinavia AS	6.65 %
	Enterprise Oil Norge AS	0.57 %
	ExxonMobil Exploration & Production Norway AS	18.48 %
	Idemitsu Petroleum Norge AS	4.32 %
	Petoro AS	30.00 %
	RWE Dea Norge AS	1.26 %
	StatoilHydro ASA	24.73 %
	StatoilHydro Petroleum AS	5.98 %
	Total E&P Norge AS	2.52 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	10.6 million scm oil	1.4 million scm oil
Production	**Estimated production in 2008:** Oil: 4 000 barrels/day	
Investment	Total investment is expected to be NOK 2.5 billion (2008 values) NOK 2.4 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Stavanger	
Main supply base	Florø	

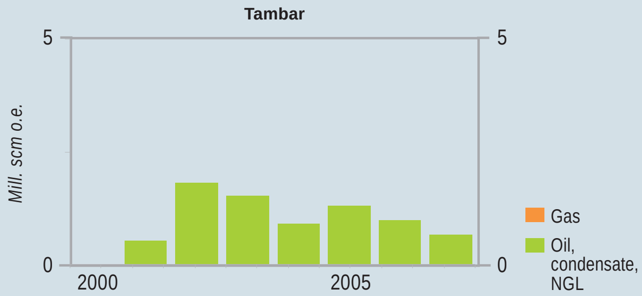
Development:
Sygna is an oil field located just north of the Statfjord Nord field in the Tampen area. The sea depth in the area is about 300 metres. The field has been developed with one subsea template with four well slots, connected to Statfjord C.

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

Recovery strategy:
The field is produced by water injection with water supplied from Statfjord Nord.

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

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



Tambar

Block and production licences	Block 1/3 - production licence 065, awarded 1981 Block 2/1 - production licence 019 B, awarded 1977	
Discovered	1983	
Development approval	03.04.2000 by the King in Council	
On stream	15.07.2001	
Operator	BP Norge AS	
Licensees	BP Norge AS	55.00 %
	DONG E&P Norge AS	45.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	10.3 million scm oil	2.8 million scm oil
	3.1 billion scm gas	3.1 billion scm gas
	0.3 million tonnes NGL	0.1 million tonnes NGL
Production	**Estimated production in 2008:** Oil: 11 000 barrels/day, Gas: 0.15 billion scm, NGL: 0.02 million tonnes	
Investment	Total investment is expected to be NOK 3.5 billion (2008 values) NOK 3.3 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

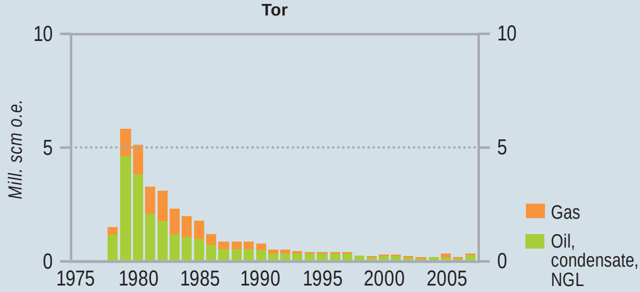
Development:
Tambar is an oil field located southeast of the Ula field in the southern part of the North Sea. The sea depth in the area is 68 metres. The field has been developed with a remotely controlled wellhead facility without processing facility. The Tambar Øst deposit has been developed with a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

Reservoir:
The reservoir consists of Upper Jurassic sandstones in the Ula formation, deposited in a shallow marine environment. The reservoir lies between 4 000-4 200 metres and the characteristics are generally very good. The reservoir in Tambar Øst lies between 4 050-4 200 metres and consists of Upper Jurassic sandstones deposited in a shallow marine environment. The reservoir quality is varying.

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

Transport:
The oil is transported to Ula through a new pipeline which was installed in 2007. After processing at Ula, the oil is exported in the existing pipeline system to Teesside via Ekofisk. The gas is used for gas injection on Ula to improve the oil recovery.

Status:
A multiphase pump which is being installed will reduce the wellhead pressure and increase oil recovery from Tambar. One of the well slots at Tambar was in 2007 used to drill a well to the Tambar Øst deposit. The oil from this deposit is now produced with the wellstream from Tambar to Ula.



Tor

Block and production licences	Block 2/4 - production licence 018, awarded 1965 Block 2/5 - production licence 006, awarded 1965	
Discovered	1970	
Development approval	04.05.1973	
On stream	28.06.1978	
Operator	ConocoPhillips Skandinavia AS	
Licensees	ConocoPhillips Skandinavia AS	30.66 %
	Eni Norge AS	10.82 %
	Petoro AS	3.69 %
	StatoilHydro ASA	0.83 %
	StatoilHydro Petroleum AS	5.81 %
	Total E&P Norge AS	48.20 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	23.6 million scm oil	1.0 million scm oil
	11.0 billion scm gas	0.2 billion scm gas
	1.2 million tonnes NGL	
Production	**Estimated production in 2008:** Oil: 3 000 barrels/day, Gas: 0.03 billion scm	
Investment	Total investment is expected to be NOK 9.7 billion (2008 values) NOK 9.4 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

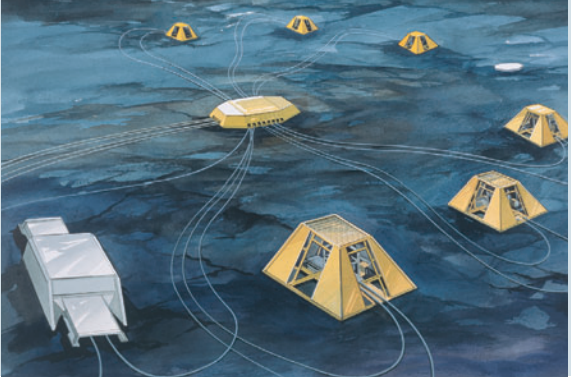
Development:
Tor is an oil field in the Ekofisk area in the southern part of the North Sea. The field has been developed with a combined wellhead and processing facility with transport through pipelines to the Ekofisk Center and further export. The sea depth in the area is about 70 metres.

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

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

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

Status:
A study will be initiated to evaluate the future of the Tor field.



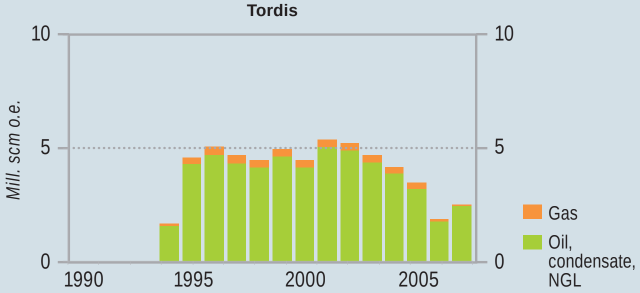
Tordis

Block and production licences	Block 34/7 - production licence 089, awarded 1984	
Discovered	1987	
Development approval	14.05.1991 by the Storting	
On stream	03.06.1994	
Operator	StatoilHydro ASA	
Licensees	ExxonMobil Exploration & Production Norway AS	10.50 %
	Idemitsu Petroleum Norge AS	9.60 %
	Petoro AS	30.00 %
	RWE Dea Norge AS	2.80 %
	StatoilHydro ASA	28.22 %
	StatoilHydro Petroleum AS	13.28 %
	Total E&P Norge AS	5.60 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	63.5 million scm oil	12.4 million scm oil
	5.4 billion scm gas	1.6 billion scm gas
	1.8 million tonnes NGL	0.4 million tonnes NGL
Production	**Estimated production in 2008:**	
	Oil: 46 000 barrels/day, Gas: 0.05 billion scm, NGL: 0.02 million tonnes	
Investment	Total investment is expected to be NOK 13.0 billion (2008 values)	
	NOK 12.5 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Stavanger	
Main supply base	Florø	

Development:
Tordis is an oil field located between the Snorre and Gullfaks fields in the Tampen area. The sea depth in the area is approximately 200 metres. The field has been developed with a central subsea manifold tied back to Gullfaks C. Seven separate satellite wells and two subsea templates are tied back to the subsea manifold. The wellstream is transferred to Gullfaks C through two pipelines. Injection water is piped to Tordis from Gullfaks C. Tordis consists of four deposits: Tordis, Tordis Øst, Borg and 34/7-25 S. The PDO for Tordis Øst was approved on 13.10.1995. The PDO for Borg was approved on 29.06.1999. An amended PDO for Tordis (Tordis IOR) was approved on 16.12.2005.

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

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



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

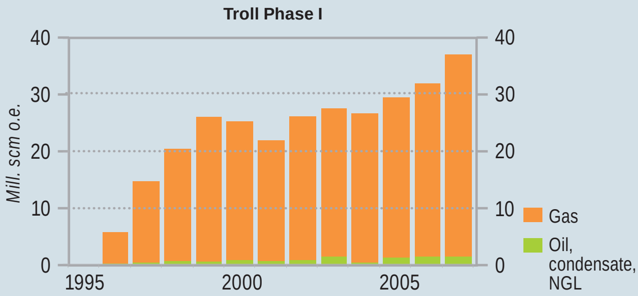
Status:
The water injection in Tordis has been at a low level in 2007 due to well problems. The project Tordis IOR was completed in 2007 when a subsea separator was installed on the field and a well for injection of produced water into the Utsira formation was drilled. The project also included modifications on Gullfaks C for low pressure production.

Troll

The Troll field lies in the northern part of the North Sea about 65 kilometres west of Kollsnes. The water depth in the area is more than 300 metres. The field has huge gas resources and one of the largest oil volumes remaining on the Norwegian continental shelf. Troll comprises two main structures: Troll Øst and Troll Vest, and roughly two-thirds of the recoverable gas reserves lie in Troll Øst. A thin oil rim underlies the gas throughout the Troll field, but so far only in Troll Vest is this oil zone of sufficient thickness to be commercial, 11 to 27 metres. In 2007, an oil column of 6-9 metres was proven in the northern part of Troll Øst and test production is planned to start during 2008. A phased development has been pursued, with Phase I recovering gas reserves in Troll Øst and Phase II focused on the oil reserves in Troll Vest. The gas reserves in Troll Vest will be developed in a future phase 3. The Troll licensees are conducting studies to plan for further development of the field. Troll was the largest producer of both oil and gas on the Norwegian continental shelf in the period 2000 – 2004.

Troll I

Block and production licences	Block 31/2 - production licence 054, awarded 1979 Block 31/3 - production licence 085, awarded 1983 Block 31/3 - production licence 085 C, awarded 2002 Block 31/3 - production licence 085 D, awarded 2006 Block 31/5 - production licence 085, awarded 1983 Block 31/6 - production licence 085, awarded 1983 Block 31/6 - production licence 085 C, awarded 2002	
Discovered	1983	
Development approval	15.12.1986 by the Storting	
On stream	09.02.1996	
Operator	StatoilHydro ASA	
Licensees	A/S Norske Shell	8.10 %
	ConocoPhillips Skandinavia AS	1.62 %
	Petoro AS	56.00 %
	StatoilHydro ASA	20.80 %
	StatoilHydro Petroleum AS	9.78 %
	Total E&P Norge AS	3.69 %
Recoverable reserves*	**Original:**	**Remaining as of 31.12.2007**
	1330.7 billion scm gas	1024.7 billion scm gas
	25.7 million tonnes NGL	22.8 million tonnes NGL
	1.6 million scm condensate	
Production	**Estimated production in 2008:** Gas: 28.26 billion scm, NGL: 1.28 million tonnes	
Investment	Total investment is expected to be NOK 89.8 billion (2008 values) NOK 58.8 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Bergen	
Main supply base	Ågotnes	



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

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

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

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

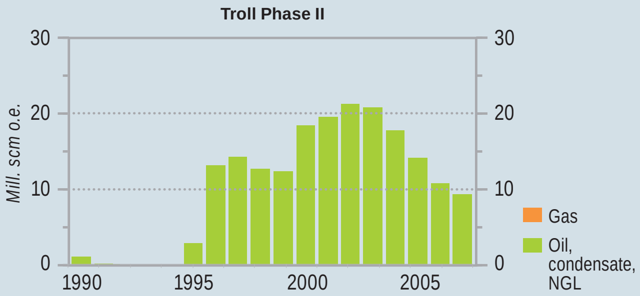
Status:
The licensees are planning test production of oil from the northern part of Troll Øst.

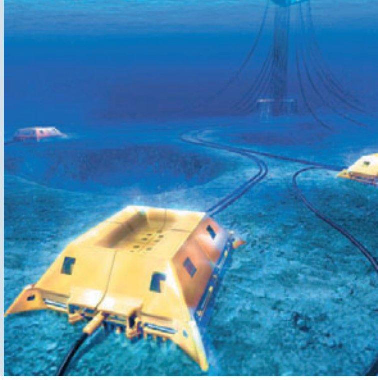

Troll II

Block and production licences	Block 31/2 - production licence 054. Awarded 1979	
	Block 31/3 - production licence 085. Awarded 1983	
	Block 31/3 - production licence 085 C. Awarded 2002	
	Block 31/3 - production licence 085 D. Awarded 2006	
	Block 31/5 - production licence 085. Awarded 1983	
	Block 31/6 - production licence 085. Awarded 1983	
	Block 31/6 - production licence 085 C. Awarded 2002	
Discovered	1979	
Development approval	18.05.1992 by the Storting	
On stream	19.09.1995	
Operator	StatoilHydro Petroleum AS	
Licensees	A/S Norske Shell	8.10 %
	ConocoPhillips Skandinavia AS	1.62 %
	Petoro AS	56.00 %
	StatoilHydro ASA	20.80 %
	StatoilHydro Petroleum AS	9.78 %
	Total E&P Norge AS	3.69 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	240.8 million scm oil	50.3 million scm oil
Production	**Estimated production in 2008:**	
	Oil: 138 000 barrels/day	
Investment	Total investment is expected to be NOK 94.8 billion (2008 values)	
	NOK 78.9 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

Development:
Troll Phase II has been developed with Troll B, a floating accommodation and process facility with concrete hull, and Troll C, a semi-submersible accommodation and process facility with steel hull. Oil from Troll Vest is produced from several subsea templates tied back to Troll B and Troll C by flowlines. Troll Pilot, which was installed in 2000 at a depth of 340 meters, is a subsea plant for separation and reinjection of produced water. Development of Troll C was approved in 1997. There have been several PDO approvals concerning subsea templates at Troll Vest.

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

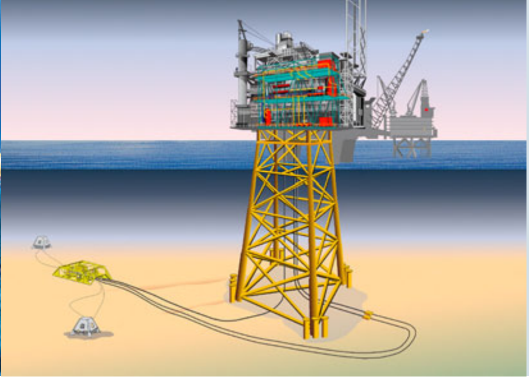


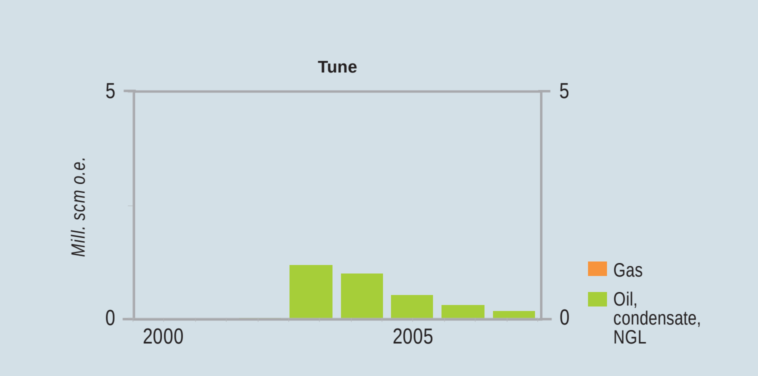


Recovery strategy:
Oil production at Troll Vest takes place through long horizontal wells drilled right above the oil/water contact in the thin oil zone. The main recovery strategy is pressure depletion, but there will be simultaneous expansion of the gas cap above and the water zone below the oil. In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

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

Status:
Drilling on Troll Vest with horizontal production wells from subsea templates continues with three mobile drilling facilities in activity. In total, more than 120 oil production wells have now been drilled at Troll Vest. Over the last few years, decisions have been made each year in favour of drilling new production wells that contribute to increasing oil reserves from Troll, and there are still a number of wells in the drilling plan. Several multibranch wells have been drilled, with up to six branches in one well. The licensees are evaluating plans for gas and water injection in Troll Vest to maintain oil production.





Tune

Block and production licences	Block 30/5 - production licence 034, awarded 1969 Block 30/6 - production licence 053, awarded 1979 Block 30/8 - production licence 190, awarded 1993	
Discovered	1996	
Development approval	17.12.1999 by the King in Council	
On stream	28.11.2002	
Operator	StatoilHydro Petroleum AS	
Licensees	Petoro AS	40.00 %
	StatoilHydro ASA	10.00 %
	StatoilHydro Petroleum AS	40.00 %
	Total E&P Norge AS	10.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	3.5 million scm oil	0.5 million scm oil
	18.8 billion scm gas	4.9 billion scm gas
	0.1 million tonnes NGL	
Production	**Estimated production in 2008:**	
	Oil: 1 000 barrels/day, Gas: 0.56 billion scm	
Investment	Total investment is expected to be NOK 5.3 billion (2008 values) NOK 4.7 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

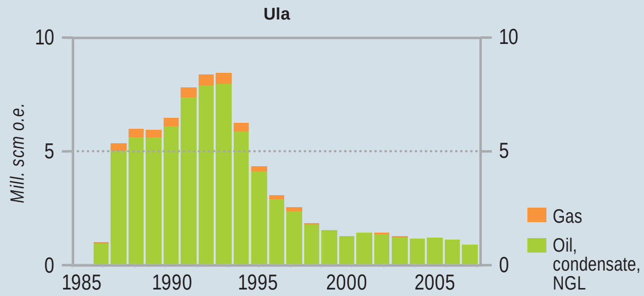
Development:
The Tune field is a gas condensate field located around 10 kilometres west of the Oseberg Field Centre in the northern part of the North Sea. The sea depth in the area is approximately 95 metres. The field has been developed with a subsea template with four production wells in the centre of the field. In March 2004, a PDO exemption was granted for development of the northern part of the field, while a similar exemption was granted for the southern part of the field in May 2005 (Tune Phase III). There are prospects in the area which may be tied to the Tune template.

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

Recovery strategy:
The field is recovered by pressure depletion.

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

Status:
There are plans to drill a new well in the southern part of Tune. The purpose of the well is to produce proven hydrocarbons and the well also has an exploration target in a prospect further south.



Ula

Block and production licences	Block 7/12 - production licence 019, awarded 1965 Block 7/12 - production licence 019 B, awarded 1977	
Discovered	1976	
Development approval	30.05.1980 by the Storting	
On stream	06.10.1986	
Operator	BP Norge AS	
Licensees	BP Norge AS	80.00 %
	DONG E&P Norge AS	5.00 %
	Svenska Petroleum Exploration AS	15.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	80.5 million scm oil	11.9 million scm oil
	3.9 billion scm gas	0.6 million tonnes NGL
	3.1 million tonnes NGL	
Production	**Estimated production in 2008:**	
	Oil: 13 000 barrels/day, NGL: 0.02 million tonnes	
Investment	Total investment is expected to be NOK 26.1 billion (2008 values) NOK 22.6 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

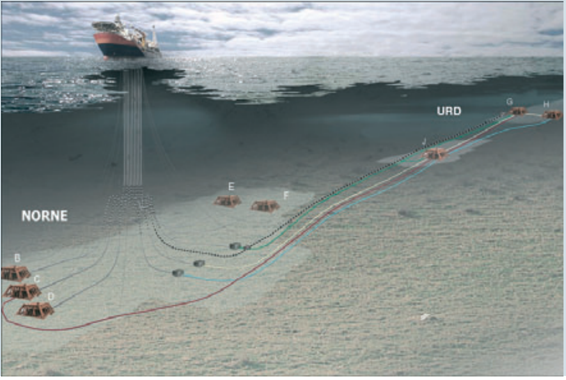
Development:
Ula is an oil field in the southern part of the North Sea. The sea depth in the area is 70 metres. The development consists of three conventional steel facilities for production, drilling and accommodation. The facilities are connected by bridges.

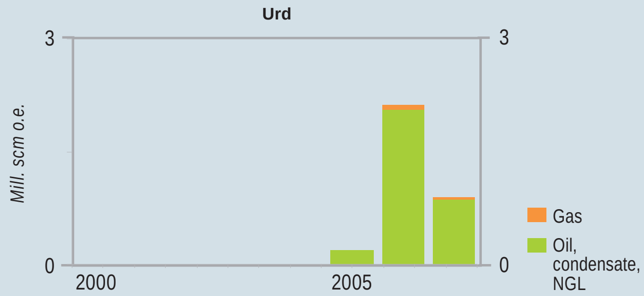
Reservoir:
The main reservoir is at a depth of 3 345 metres in the Upper Jurassic Ula formation. The reservoir consists of three layers and two of them are producing well.

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

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

Status:
From September 2007, Blane is tied to the Ula field for processing. The production from Ula has been lower than expected the last year due to technical problems in several wells. Ula gas capacity is being upgraded with a new gas process and gas injection module (UGU) which will be in operation from the summer of 2008. Based on the positive effect on oil recovery, evaluation is ongoing to expand the WAG program by drilling additional wells from 2009 and importing more gas for injection.





Urd

Block and production licences	Block 6608/10 - production licence 128, awarded 1986	
Discovered	2000	
Development approval	02.07.2004 by the Crown Prince Regent in Council	
On stream	08.11.2005	
Operator	StatoilHydro ASA	
Licensees	Eni Norge AS	11.50 %
	Petoro AS	24.55 %
	StatoilHydro ASA	50.45 %
	StatoilHydro Petroleum AS	13.50 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	9.5 million scm oil	6.4 million scm oil
	0.3 billion scm gas	0.2 billion scm gas
Production	**Estimated production in 2008:**	
	Oil: 10 000 barrels/day, Gas: 0.02 billion scm	
Investment	Total investment is expected to be NOK 5.6 billion (2008 values)	
	NOK 4.4 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Harstad	

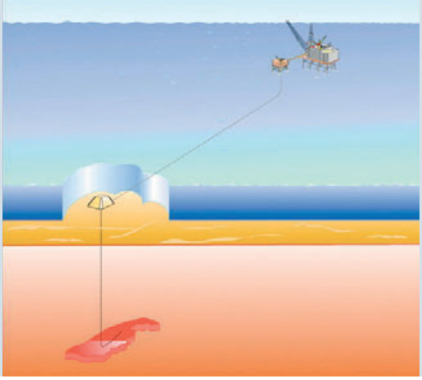
Development:
Urd is located northeast of Norne in the Norwegian Sea. The sea depth in the area is approximately 380 metres. The field includes two oil filled deposits 6608/10-6 Svale and 6608/10-8 Stær. Urd has been developed with subsea templates tied back to the Norne vessel.

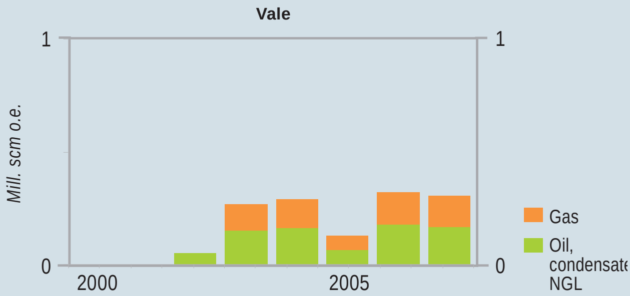
Reservoir:
The reservoir consists of Lower to Middle Jurassic sandstones belonging to the Åre, Tilje and Ile formations at a depth of 1 800-2 300 metres.

Recovery strategy:
Urd is recovered by water injection. The wells are also equipped with gas lift to handle low pressure and high water cut.

Transport:
The wellstream is processed on the Norne vessel, and oil is stabilised and offloaded together with oil from the Norne field. The gas is exported to the Norne field and further in Åsgard Transport to Kårstø.

Status:
The production in 2007 has been lower than expected from the Svale deposit while production from the Stær deposit has been as expected.





Vale

Block and production licences	Block 25/4 - production licence 036, awarded 1971	
Discovered	1991	
Development approval	23.03.2001 by the Crown Prince Regent in Council	
On stream	31.05.2002	
Operator	StatoilHydro Petroleum AS	
Licensees	Marathon Petroleum Norge AS	46.90 %
	StatoilHydro Petroleum AS	28.85 %
	Total E&P Norge AS	24.24 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	1.7 million scm oil	0.9 million scm oil
	2.2 billion scm gas	1.6 billion scm gas
Production	**Estimated production in 2008:**	
	Oil: 2 000 barrels/day, Gas: 0.13 billion scm	
Investment	Total investment is expected to be NOK 2.2 billion (2008 values)	
	NOK 2.1 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Bergen	

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

Reservoir:
The reservoir consists of Middle Jurassic sandstones in the Brent group. The reservoir depth is about 3 700 metres. The reservoir quality varies from good to moderate.

Recovery strategy:
The field is recovered by pressure depletion.

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

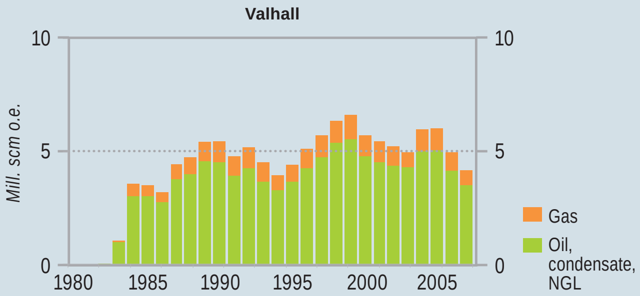
Valhall

Block and production licences	Block 2/11 - production licence 033 B, awarded 2001 Block 2/8 - production licence 006 B, awarded 2000	
Discovered	1975	
Development approval	02.06.1977 by the Storting	
On stream	02.10.1982	
Operator	BP Norge AS	
Licensees	BP Norge AS	28.09 %
	Enterprise Oil Norge AS	28.09 %
	Hess Norge AS	28.09 %
	Total E&P Norge AS	15.72 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	147.0 million scm oil	50.9 million scm oil
	26.7 billion scm gas	7.7 billion scm gas
	5.4 million tonnes NGL	2.4 million tonnes NGL
Production	**Estimated production in 2008:**	
	Oil: 49 000 barrels/day, Gas: 0.54 billion scm, NGL: 0.07 million tonnes	
Investment	Total investment is expected to be NOK 72.2 billion (2008 values) NOK 53.2 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

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

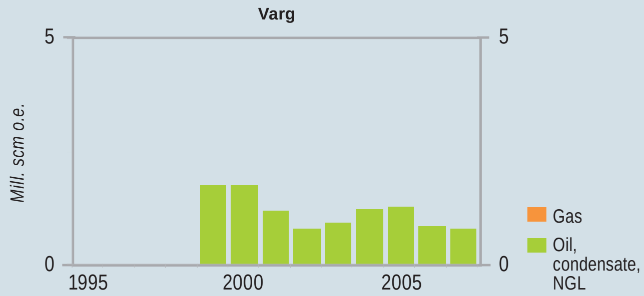
Reservoir:
The Valhall field produces from chalk in the Tor and Hod formations of Late Cretaceous age. The reservoir depth is about 2 400 metres. The chalk in the Tor formation is finegrained and soft, with pervasive fractures allowing oil and water to flow more easily. As a result of pressure depletion from production, the chalk has compacted, causing subsidence of the seabed at Valhall.

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



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

Status:
In relation to current plans, there are significant possibilities for further increases in reserves by using all well slots and optimizing water injection. As the seabed has subsided, and the original facilities have aged, a new facility with processing plant and accommodation is being built. A decision has been made to supply electric power to this facility from land.



Varg

Block and production licences	Block 15/12 - production licence 038, awarded 1975	
Discovered	1984	
Development approval	03.05.1996 by the King in Council	
On stream	22.12.1998	
Operator	Talisman Energy Norge AS	
Licensees	Det norske oljeselskap ASA	5.00 %
	Petoro AS	30.00 %
	Talisman Energy Norge AS	65.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	13.6 million scm oil	3.1 million scm oil
Production	**Estimated production in 2008:**	
	Oil: 12 000 barrels/day	
Investment	Total investment is expected to be NOK 7.9 billion (2008 values)	
	NOK 7.6 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

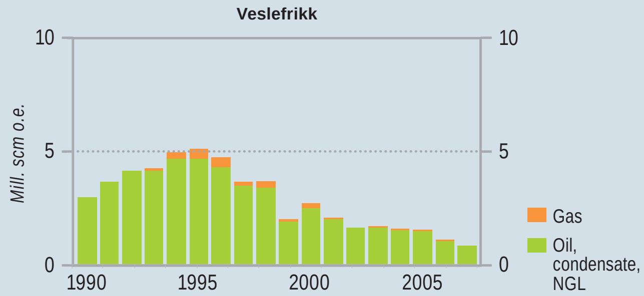
Development:
Varg is an oil field to the south of Sleipner Øst in the southern part of the North Sea. The sea depth in the area is 84 metres. The field has been developed with a production vessel (Petrojarl Varg) with integrated oil storage, and a connected wellhead facility (Varg A). The decommissioning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

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

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

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

Status:
The operator is continuously evaluating means to increase the resources at Varg. Several prospects in the area are being evaluated. The Grevling prospect, approximately 18 kilometres north of Varg, is expected to be drilled in 2008. Measures to optimize the recovery are being considered, i.a. water alternating gas injection (WAG).



Veslefrikk

Block and production licences	Block 30/3 - production licence 052, awarded 1979 Block 30/6 - production licence 053, awarded 1979	
Discovered	1981	
Development approval	02.06.1987 by the Storting	
On stream	26.12.1989	
Operator	StatoilHydro ASA	
Licensees	Petoro AS	37.00 %
	RWE Dea Norge AS	13.50 %
	Revus Energy ASA	4.50 %
	StatoilHydro ASA	18.00 %
	Talisman Energy Norge AS	27.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	56.5 million scm oil	7.8 million scm oil
	3.8 billion scm gas	1.6 billion scm gas
	1.3 million tonnes NGL	0.1 million tonnes NGL
Production	**Estimated production in 2008:** Oil: 17 000 barrels/day	
Investment	Total investment is expected to be NOK 26.5 billion (2008 values) NOK 19.9 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Bergen	
Main supply base	Sotra and Florø	

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

Reservoir:
The reservoirs consist of Jurassic sandstones in the Brent and Dunlin groups and the Statfjord formation. The main reservoir is in the Brent group and contains about 80 per cent of the reserves. The reservoir depths are between 2 800-3 200 metres.

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

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

Status:
Production from Veslefrikk is in the decline phase. The project Veslefrikk 2020 is evaluating modification and upgrading of the facilities to extend the lifetime of Veslefrikk. Several methods to increase the oil recovery are being evaluated. Prospects in the area will also be considered drilled and tied back to Veslefrikk.

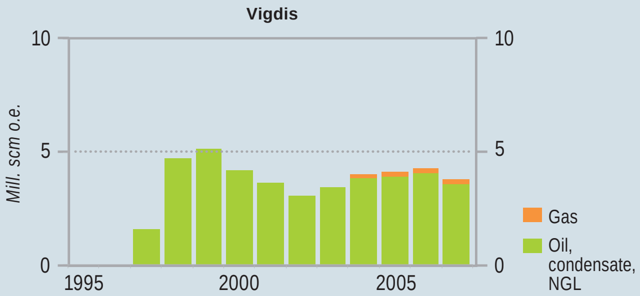
Vigdis

Block and production licences	Block 34/7 - production licence 089, awarded 1984	
Discovered	1986	
Development approval	16.12.1994 by the King in Council	
On stream	28.01.1997	
Operator	StatoilHydro ASA	
Licensees	ExxonMobil Exploration & Production Norway AS	10.50 %
	Idemitsu Petroleum Norge AS	9.60 %
	Petoro AS	30.00 %
	RWE Dea Norge AS	2.80 %
	StatoilHydro ASA	28.22 %
	StatoilHydro Petroleum AS	13.28 %
	Total E&P Norge AS	5.60 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	57.4 million scm oil	17.4 million scm oil
	1.5 billion scm gas	0.7 billion scm gas
	1.4 million tonnes NGL	0.8 million tonnes NGL
Production	**Estimated production in 2008:**	
	Oil: 53 000 barrels/day, Gas: 0.14 billion scm, NGL: 0.16 million tonnes	
Investment	Total investment is expected to be NOK 18.9 billion (2008 values)	
	NOK 13.5 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Stavanger	
Main supply base	Florø	

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

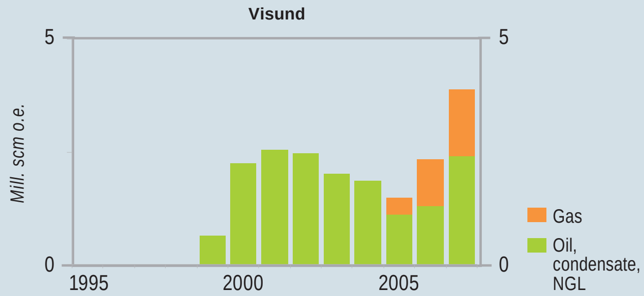
Reservoir:
The reservoirs consist of Middle Jurassic sandstones in the Brent group, Lower Jurassic and Upper Triassic sandstones in the Statfjord formation, and Upper Jurassic intra Draupne sandstones. The reservoirs are at a depth of 2 200-2 600 metres. The quality of the reservoirs are generally good.

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



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

Status:
The operator is evaluating means to increase recovery from Vigdis. Two new wells for production and water injection have been drilled and will start production in 2008. It has been decided to increase the water injection on Vigdis with water supplied from Statfjord C.



Visund

Block and production licences	Block 34/8 - production licence 120, awarded 1985	
Discovered	1986	
Development approval	29.03.1996 by the Storting	
On stream	21.04.1999	
Operator	StatoilHydro ASA	
Licensees	ConocoPhillips Skandinavia AS	9.10 %
	Petoro AS	30.00 %
	StatoilHydro ASA	32.90 %
	StatoilHydro Petroleum AS	20.30 %
	Total E&P Norge AS	7.70 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	27.6 million scm oil	11.3 million scm oil
	50.6 billion scm gas	47.7 billion scm gas
	6.5 million tonnes NGL	6.4 million tonnes NGL
Production	**Estimated production in 2008:**	
	Oil: 27 000 barrels/day, Gas: 1.34 billion scm, NGL: 0.20 million tonnes	
Investment	Total investment is expected to be NOK 27.8 billion (2008 values)	
	NOK 21.7 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Bergen	
Main supply base	Florø	

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

Reservoir:
Visund contains oil and gas in several tilted fault blocks with varying pressure and liquid systems. The reservoirs are in Middle and Lower Jurassic and Upper Triassic sandstones in the Brent group and the Statfjord and Lunde formations.

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

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

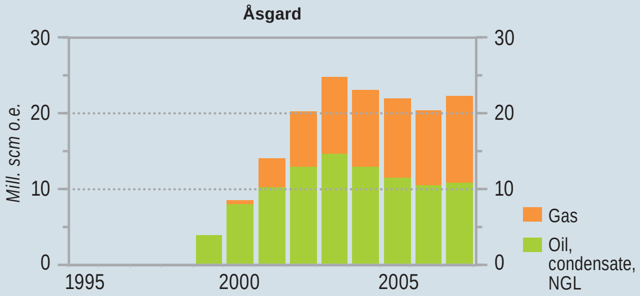
Status:
A challenge for Visund is to maintain reservoir pressure to optimize oil recovery before gas export levels increase. One measure being evaluated is to access more water to increase water injection. Reduced gas export is also being considered. Two exploration targets near Visund are planned to be drilled in 2008 to prove possible additional resources which may be tied in to the field.


Åsgard

Block and production licences	Block 6406/3 - production licence 094 B, awarded 2002 Block 6407/2 - production licence 074, awarded 1982 Block 6407/3 - production licence 237, awarded 1998 Block 6506/11 - production licence 134, awarded 1987 Block 6506/12 - production licence 094, awarded 1984 Block 6507/11 - production licence 062, awarded 1981	
Discovered	1981	
Development approval	14.06.1996 by the Storting	
On stream	19.05.1999	
Operator	StatoilHydro ASA	
Licensees	Eni Norge AS	14.82 %
	Mobil Development Norway AS	7.24 %
	Petoro AS	35.69 %
	StatoilHydro ASA	24.96 %
	StatoilHydro Petroleum AS	9.61 %
	Total E&P Norge AS	7.68 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2007**
	102.9 million scm oil	45.8 million scm oil
	181.9 billion scm gas	118.2 billion scm gas
	33.8 million tonnes NGL	22.7 million tonnes NGL
	16.0 million scm condensate	
Production	**Estimated production in 2008:** Oil: 122 000 barrels/day, Gas: 9.6 billion scm, NGL: 1.86 million tonnes	
Investment	Total investment is expected to be NOK 76.6 billion (2008 values) NOK 67.5 billion have been invested as of 31.12.2007 (2008 values)	
Operating organisation	Stjørdal	
Main supply base	Kristiansund	

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

Reservoir:
6506/12-1 Smørbukk is a rotated fault block, bordered by faults in the west and north and structurally deeper areas to the south and east. The reservoir formations Garn, Ile, Tofte, Tilje and Åre are of Jurassic age and contain gas, condensate and oil. 6506/12-3 Smørbukk Sør, with reservoir rocks in the Garn, Ile and Tilje formations of Early to Middle Jurassic ages, contains oil, gas and condensate. The Midgard discovery is divided into four structural segments with the main reservoir in the Middle Jurassic Garn and Ile formations. The reservoirs lie at depths down to 4 850



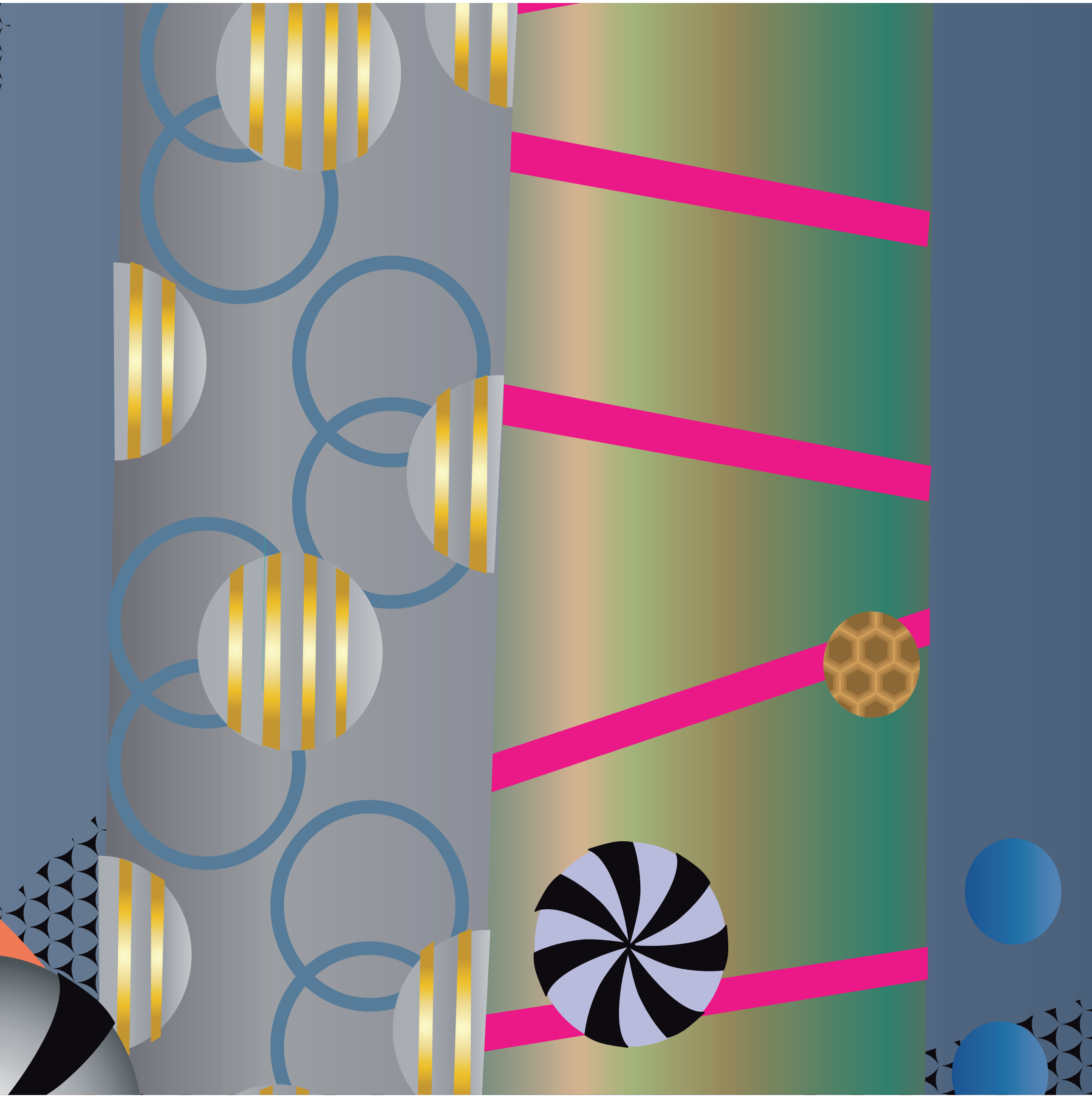
metres. The reservoir quality varies between the formations and there are large differences in porosity and permeability between the three deposits.

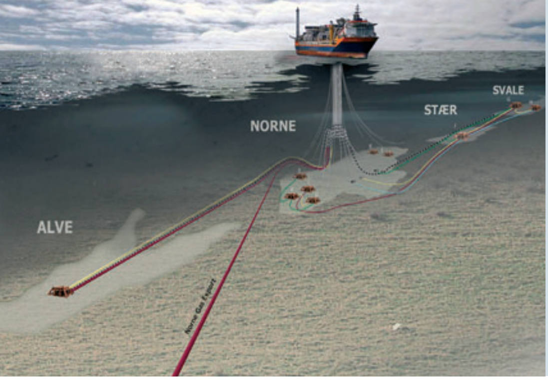
Recovery strategy:
The Smørbukk and Smørbukk Sør deposits are produced with gas injection. The Midgard deposit is produced by pressure depletion. There is a thin oil zone (11.5 m) below the gas cap in Midgard, but at the time there are no plans to produce the oil. Studies are ongoing to maintain an optimal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

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

Status:
Most of the production wells have been drilled, and efforts are being made to increase recovery from the field. There are plans to tie 6506/11-7 Morvin and 6507/11-8 Yttergryta to Åsgard. In addition measures to increase production of low CO_2 gas from Midgard are being considered. Deposits containing low CO_2 gas in the area are being explored.

12 Fields under development





Alve

Block and production licence	Block 6507/3 - production licence 159 B, awarded 2004	
Discovered	1990	
Development approval	16.03.2007 by the King in Council	
Operator	StatoilHydro ASA	
Licensees	DONG E&P Norge AS	15.00 %
	StatoilHydro ASA	75.00 %
	StatoilHydro Petroleum AS	10.00 %
Recoverable reserves	**Original:** 5.9 billion scm gas 1.1 million tonnes NGL 1.3 million scm condensate	
Investment	Total investment is expected to be NOK 2.8 billion (2008 values) NOK 1.0 billion have been invested as of 31.12.2007 (2008 values)	

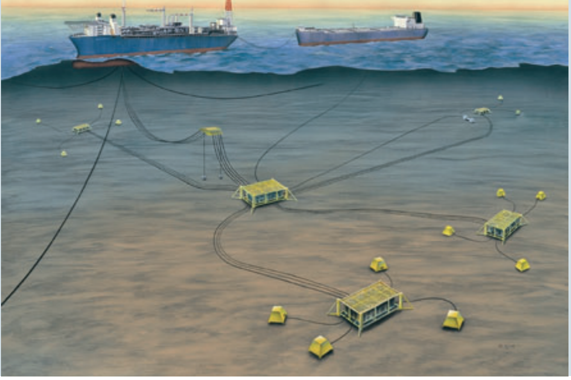
Development:
Alve is a gas and condensate field located about 16 kilometres southwest of Norne. The sea depth in the area is about 370 meters. The development concept is a standard subsea template with four well slots and one production well.

Reservoir:
The reservoir is in Middle Jurassic sandstones in the Garn and Not formations. The reservoir lies at a depth of about 3 600 metres.

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

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

Status:
A combined exploration and production well will be drilled in 2008 to prove possible additional resources in the underlying Ile and Tilje formations. According to the plan, production from the Garn and Not formations in this well will start in December 2008. Possible discoveries in the Ile and Tilje formations may be developed later.



Alvheim

Block and production licence	Block 24/6 - production licence 088 BS, awarded 2003	
	Block 24/6 - production licence 203, awarded 1996	
	Block 25/4 - production licence 036 C, awarded 2003	
	Block 25/4 - production licence 203, awarded 1996	
Discovered	1998	
Development approval	06.10.2004 by the King in Council	
Operator	Marathon Petroleum Norge AS	
Licensees	ConocoPhillips Skandinavia AS	20.00 %
	Lundin Norway AS	15.00 %
	Marathon Petroleum Norge AS	65.00 %
Recoverable reserves	**Original:**	
	24.5 million scm oil	
	5.7 billion scm gas	
Investment	Total investment is expected to be NOK 16.7 billion (2008 values)	
	NOK 12.8 billion have been invested as of 31.12.2007 (2008 values)	

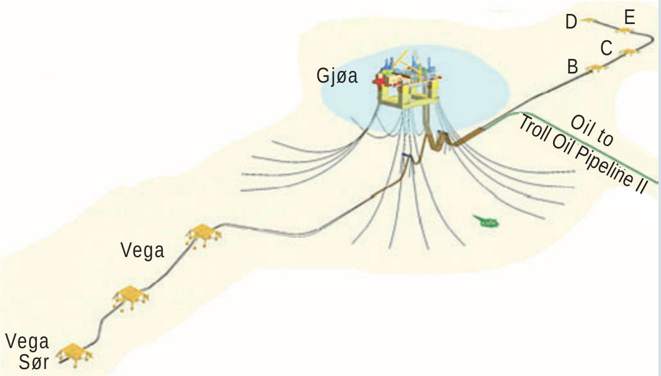
Development:
Alvheim is an oil and gas field in the northern part of the North Sea by the border to the British sector. The field comprises the three deposits 24/6-2, 24/6-4 and 25/4-7. The deposit 24/6-4 Boa lies partly in the British sector. The sea depth in the area is 120-130 metres. The field is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

Reservoir:
The reservoir consists of sandstones deposited as turbidites in the Heimdal formation of Paleocene age. The reservoir depth is about 2 100 metres.

Recovery strategy:
Alvheim will be produced with natural water drive.

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

Status:
Planned production start-up is the spring of 2008.



Gjøa

Block and production licence	Block 35/9 - production licence 153, awarded 1988 Block 36/7 - production licence 153, awarded 1988
Discovered	1989
Development approval	14.06.2007 by the Storting
Operator	StatoilHydro ASA
Licensees	A/S Norske Shell 12.00 % Gaz de France Norge AS 30.00 % Petoro AS 30.00 % RWE Dea Norge AS 8.00 % StatoilHydro ASA 20.00 %
Recoverable reserves	**Original:** 11.1 million scm oil 32.6 billion scm gas 5.6 million tonnes NGL
Investment	Total investment is expected to be NOK 27.1 billion (2008 values) NOK 3.9 billion have been invested as of 31.12.2007 (2008 values)

Development:
Gjøa is located about 40 kilometres north of the Fram field. The sea depth in the area is 360 metres. Statoil is operator for the development phase, while Gaz de France will take over the operatorship when the field goes on stream. The development comprises five subsea templates tied to a semi submersible production and processing facility.

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

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

Transport:
Stabilized oil will be exported in a new 55 kilometres long pipeline which will be connected to Troll Oljerør II, for further transport to Mongstad. The rich gas will be exported in a new 130 kilometers long pipeline to the FLAGS transport system on the UK continental shelf, for further transport to St. Fergus.

Status:
Production is expected to start in 2010.

Rev

Block and production licence	Block 15/12 - production licence 038 C, awarded 2006	
Discovered	2001	
Development approval	15.06.2007 by the King in Council	
Operator	Talisman Energy Norge AS	
Licensees	Petoro AS	30.00 %
	Talisman Energy Norge AS	70.00 %
Recoverable reserves	**Original:**	
	4.7 billion scm gas	
	0.5 million tonnes NGL	
	0.8 million scm condensate	
Investment	Total investment is expected to be NOK 3.7 billion (2008 values)	
	NOK 2.2 billion have been invested as of 31.12.2007 (2008 values)	

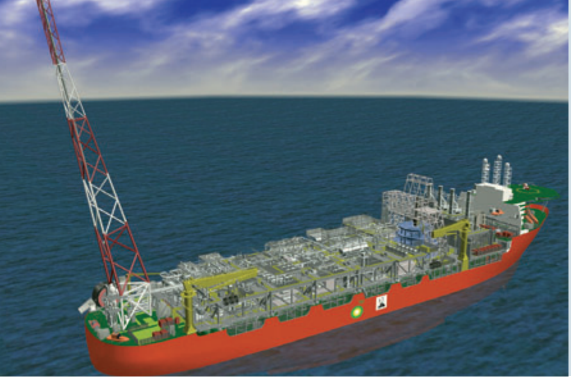
Development:
Rev is located close to the border between Norwegian and British sector, four kilometres south of the Varg field. The development concept is subsea facilities connected to the Armada complex on the UK continental shelf. The sea depth in the area is about 90-110 metres.

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

Recovery strategy:
The recovery will be based on pressure depletion.

Transport:
The wellstream will be routed through a 9 kilometres long pipeline to the Armada complex for processing and further export to the UK.

Status:
An appraisal well drilled on the east flank in 2007 proved additional resources. The well may later be used as a production well. Planned start of production for Rev is late 2008.



Skarv

Block and production licence	Block 6507/2 - production licence 262, awarded 2000	
	Block 6507/3 - production licence 159, awarded 1989	
	Block 6507/3 - production licence 212 B, awarded 2002	
	Block 6507/5 - production licence 212, awarded 1996	
	Block 6507/6 - production licence 212, awarded 1996	
Discovered	1998	
Development approval	18.12.2007 by the Storting	
Operator	BP Norge AS	
Licensees	BP Norge AS	23.84 %
	E.ON Ruhrgas Norge AS	28.08 %
	PGNiG Norway AS	11.92 %
	StatoilHydro ASA	34.11 %
	StatoilHydro Petroleum AS	2.06 %
Recoverable reserves	**Original:**	
	14.5 million scm oil	
	41.5 billion scm gas	
	5.4 million tonnes NGL	
	1.9 million scm condensate	
Investment	Total investment is expected to be NOK 31.9 billion (2008 values)	
	NOK 1.5 billion have been invested as of 31.12.2007 (2008 values)	

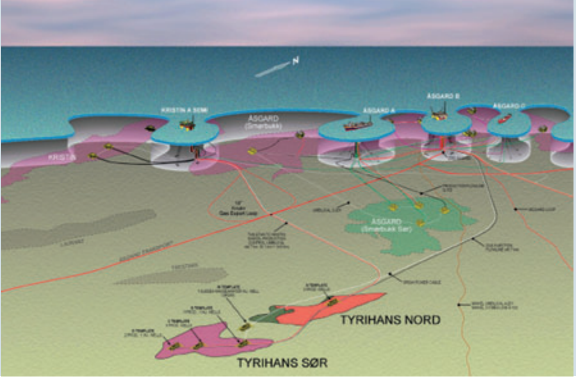
Development:
Skarv is located about 35 kilometres southwest of the Norne field in the northern part of the Norwegian Sea. The development comprises the deposits 6507/5-1 Skarv and 6507/3-3 Idun. The sea depth in the area is between 250-450 metres. The development concept is a floating production facility (FPSO) connected to five subsea templates.

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

Recovery strategy:
In the Garn and Tilje formations, gas reinjection is planned for the first years in order to increase oil recovery.

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

Status:
The production vessel and templates are under construction and are planned to be completed in the autumn of 2010. Drilling is planned to start in the summer of 2009, with production start in 2011.



Tyrihans

Block and production licence	Block 6406/3 - production licence 073 B, awarded 2004	
	Block 6406/3 - production licence 091, awarded 1984	
	Block 6407/1 - production licence 073, awarded 1982	
Discovered	1983	
Development approval	16.02.2006 in the Storting	
Operator	StatoilHydro ASA	
Licensees	Eni Norge AS	6.23 %
	Mobil Development Norway AS	11.75 %
	StatoilHydro ASA	46.84 %
	StatoilHydro Petroleum AS	12.00 %
	Total E&P Norge AS	23.18 %
Recoverable reserves	**Original:**	
	29.0 million scm oil	
	29.3 billion scm gas	
	5.3 million tonnes NGL	
Investment	Total investment is expected to be NOK 15.2 billion (2008 values)	
	NOK 6.1 billion have been invested as of 31.12.2007 (2008 values)	

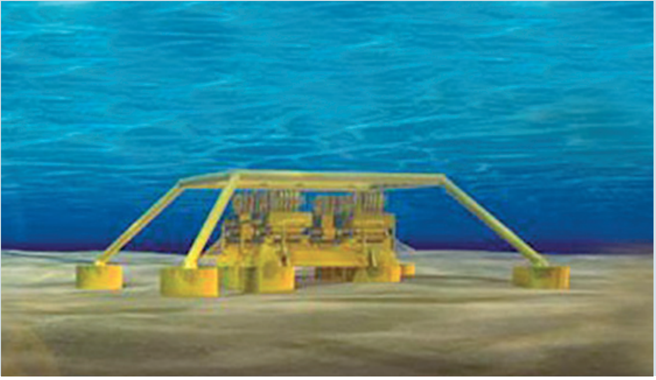
Development
Tyrihans is located in the Norwegian Sea about 25 kilometres southeast of the Åsgard field. The sea depth in the area is about 270 metres. Tyrihans comprises the discoveries 6407/1-2 Tyrihans Sør which was discovered in 1983 and 6407/1-3 Tyrihans Nord discovered in 1984. The development concept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

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

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

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

Status
Start of production is planned for in 2009 when processing capacity becomes available at Kristin.



Vega

Block and production licence	Block 35/11 - production licence 248, awarded 1999 Block 35/8 - production licence 248, awarded 1999	
Discovered	1981	
Development approval	14.06.2007 by the Storting	
Operator	StatoilHydro Petroleum AS	
Licensees	Petoro AS	40.00 %
	StatoilHydro ASA	20.00 %
	StatoilHydro Petroleum AS	40.00 %
Recoverable reserves	**Original:** 9.4 billion scm gas 0.5 million tonnes NGL 1.7 million scm condensate	
Investment	Total investment is expected to be NOK 4.8 billion (2008 values) NOK 0.5 billion have been invested as of 31.12.2007 (2008 values)	

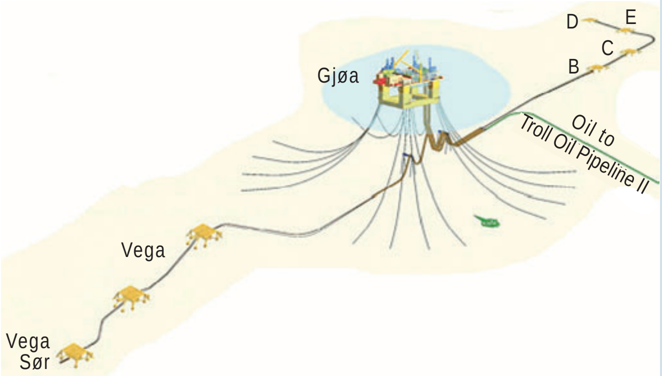
Development:
Vega is located north of the Fram field in the northern part of the North Sea. The sea depth in the area is about 370 metres. The field comprises two separate gas and condensate deposits, proven by 35/8-1 in 1981 and 35/8-2 in 1982. A combined PDO for Vega and Vega Sør was approved by the authorities in June 2007. The field is developed with two subsea templates tied to the process facility at Gjøa.

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

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

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

Status:
The production is planned to start in October 2010.



Vega Sør

Block and production licence	Block 35/11 - production licence 090 C, awarded 2005
Discovered	1987
Development approval	14.06.2007 by the Storting
Operator	StatoilHydro Petroleum AS
Licensees	Bayerngas Norge AS 25.00 % Gaz de France Norge AS 15.00 % Idemitsu Petroleum Norge AS 15.00 % StatoilHydro ASA 20.00 % StatoilHydro Petroleum AS 25.00 %
Recoverable reserves	**Original:** 7.4 billion scm gas 0.4 million tonnes NGL 2.4 million scm condensate
Investment	Total investment is expected to be NOK 2.9 billion (2008 values) NOK 0.3 billion have been invested as of 31.12.2007 (2008 values)

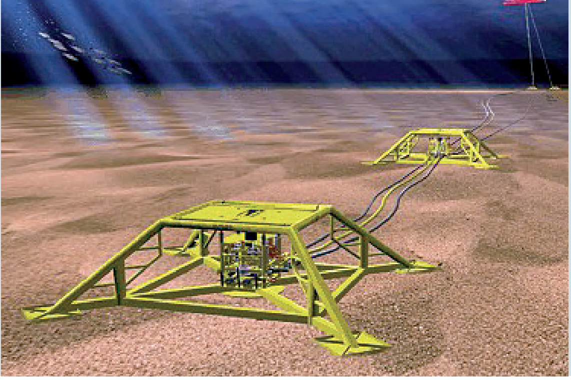
Development:
Vega Sør is a gas and condensate field located near the Fram field. The sea depth in the area is about 370 metres. A combined PDO for Vega and Vega Sør was approved by the authorities in June 2007. The development concept for gas and condensate is a subsea template tied to Vega.

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

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

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

Status:
The production is planned to start in October 2010. Development of the oil zone will be considered in connection with the discovery 35/11-13 located east of Vega Sør.



Vilje

Block and production licence	Block 25/4 - production licence 036, awarded 1971	
Discovered	2003	
Development approval	18.03.2005 by the King in Council	
Operator	StatoilHydro Petroleum AS	
Licensees	Marathon Petroleum Norge AS	46.90 %
	StatoilHydro Petroleum AS	28.85 %
	Total E&P Norge AS	24.24 %
Recoverable reserves	**Original:**	
	8.3 million scm oil	
	0.4 billion scm gas	
Investment	Total investment is expected to be NOK 3.2 billion (2008 values)	
	NOK 2.6 billion have been invested as of 31.12.2007 (2008 values)	

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

Reservoir:
The reservoir consists of turbidity sandstones in the Heimdal formation of Paleocene age and lies approximately 2 150 metres below sea level.

Recovery strategy:
Production will be accomplished by natural water drive.

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

Status:
Production start-up is planned for May 2008, dependent on start-up of Alvheim.

Volund

Block and production licence	Block 24/9 - production licence 150, awarded 1988	
Discovered	1994	
Development approval	18.01.2007 by the King in Council	
Operator	Marathon Petroleum Norge AS	
Licensees	Lundin Norway AS	35.00 %
	Marathon Petroleum Norge AS	65.00 %
Recoverable reserves	**Original:**	
	7.4 million scm oil	
	0.6 billion scm gas	
Investment	Total investment is expected to be NOK 3.4 billion (2008 values)	
	NOK 0.6 billion have been invested as of 31.12.2007 (2008 values)	

Development:
Volund is an oil field located south of Alvheim. The sea depth in the area is 120-130 metres. The field is being developed with three subsea wells connected to Alvheim.

Reservoir:
The reservoir is sandstone intrusions in the Balder formation of Eocene age at a depth of about 2 000 metres.

Recovery strategy:
Volund will be produced with water injection as drive mechanism.

Transport:
The wellstream will be routed in a pipeline to Alvheim for buoy-loading.

Status:
Production start-up is planned for in the spring of 2009.

Volve

Block and production licence	Block 15/9 - production licence 046 BS, awarded 2006	
Discovered	1993	
Development approval	22.04.2005 by the Crown Prince Regent in Council	
Operator	StatoilHydro ASA	
Licensees	ExxonMobil Exploration & Production Norway AS	30.40 %
	PA Resources Norway AS	10.00 %
	StatoilHydro ASA	49.60 %
	StatoilHydro Petroleum AS	10.00 %
Recoverable reserves	**Original:**	
	12.5 million scm oil	
	1.2 billion scm gas	
	0.2 million tonnes NGL	
	0.1 million scm condensate	
Investment	Total investment is expected to be NOK 3.1 billion (2008 values)	
	NOK 2.1 billion have been invested as of 31.12.2007 (2008 values)	

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

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

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

Transport:
The rich gas is transported to Sleipner A for further export.

Status:
The field started production on 12 February 2008. The prospects Volve Sør and Volve Vestflanke which are included in the PDO will be drilled in 2008 by extending new production wells.

Yme

Block and production licence	Block 9/2 - production licence 316, awarded 2004 Block 9/5 - production licence 316, awarded 2004	
Discovered	1987	
Development approval	11.05.2007 by the King in Council	
Operator	Talisman Energy Norge AS	
Licensees	Det norske oljeselskap ASA	10.00 %
	Revus Energy ASA	20.00 %
	Talisman Energy Norge AS	70.00 %
Recoverable reserves*	**Original:**	**Remaining as of 31.12.2007**
	18.8 million scm oil	10.9 million scm oil
Investment*	Total investment is expected to be NOK 8.3 billion (2008 values) NOK 3.7 billion have been invested as of 31.12.2007 (2008 values)	

*Include original and new development

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

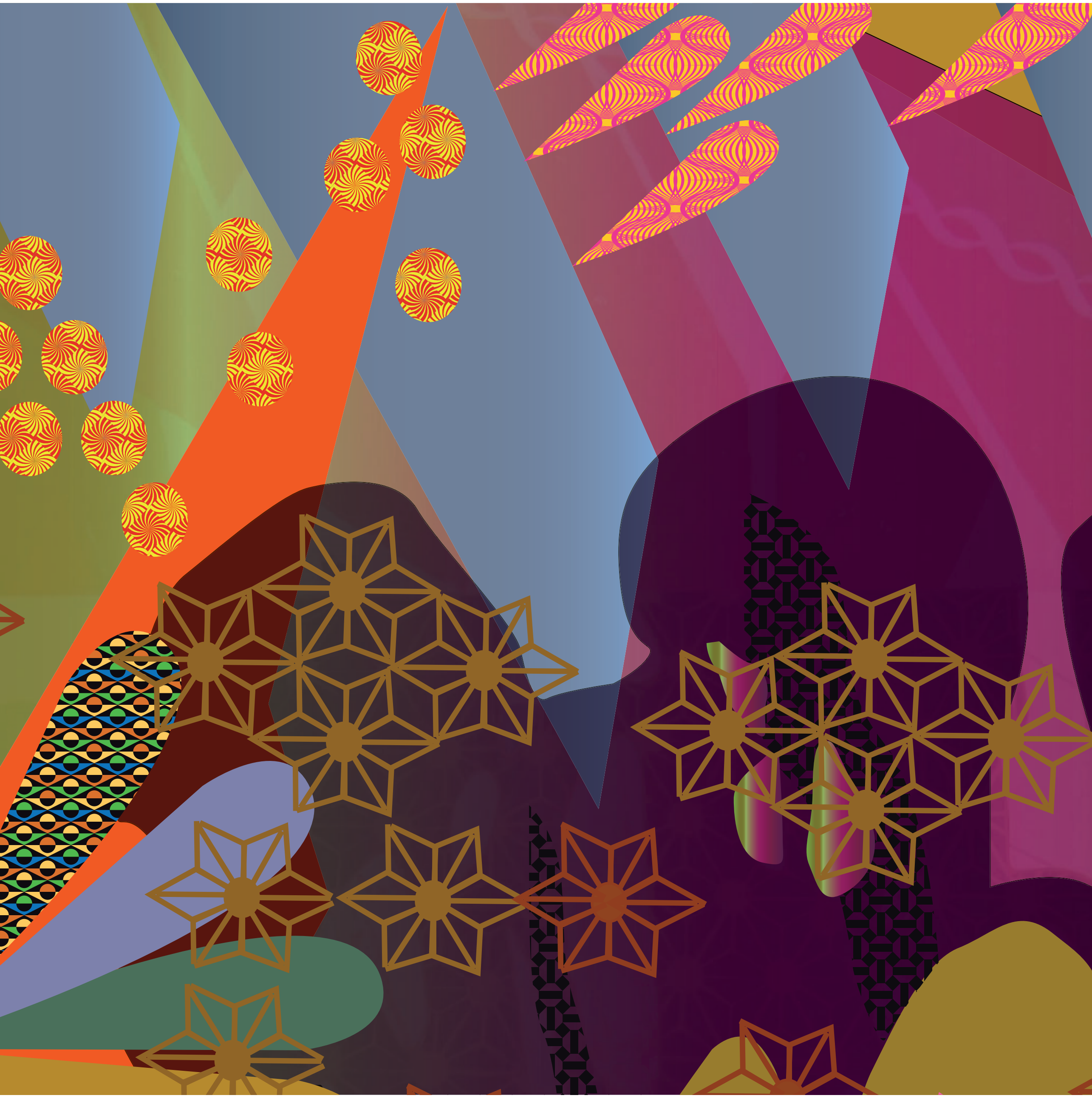
Reservoir:
Yme contains two separate main structures, Gamma and Beta, comprising five discoveries. The reservoir is in Middle Jurassic sandstones in the Sandnes formation at a depth of about 3 150 metres.

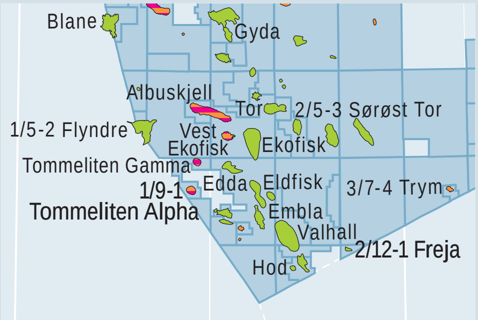
Recovery strategy:
Yme will mainly be produced with water injection as drive mechanism. Excess gas may also be injected together with water in one well.

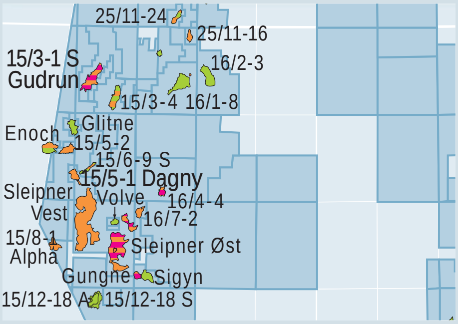
Transport:
The wellstream will be processed at the Yme facility and the oil will be stored in the tank for export via buoy-loading to tankers. Excess gas is planned to be injected.

Status:
Start of production is planned for early 2009. The possibility of using power supply from land at a later stage will be evaluated during 2008.

13 Future developments







Discoveries in the planning phase

This list does not comprise discoveries included in existing fields.

1/9-1 TOMMELITEN ALPHA	Production licence 044, Operator: ConocoPhillips Skandinavia AS
Resources	Oil: 10.3 million scm, Gas: 16.9 billion scm, NGL: 0.3 million tonnes

1/9-1 Tommeliten Alpha was discovered in 1977. The sea depth in the area is approximately 80 metres. The discovery is located about 20 kilometres southwest of the Ekofisk field, near the border to the UK sector. The discovery contains gas and condensate in Upper Cretaceous chalk at a depth of 3 500 metres. Four appraisal wells have been drilled on the discovery, the most recent being 1/9-7 in 2003. The licensees are evaluating the resource base and alternative development concepts. Production may start in 2013 at the earliest.

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

2/12-1 Freja was discovered in 1987, close to the border between the Danish and Norwegian sectors. The sea depth in the area is 70 metres. The reservoir is in Upper Jurassic sandstones. The reservoir lies at a depth of about 4 900 metres, and contains oil and associated gas. 2/12-1 Freja is located in a complex geological area between Fedagraben in the west and Gertrudgraben in the east. It is assumed that the reservoir is divided into separate fault blocks. Oil has also been proven in the neighbouring Gert deposit on the Danish side of the border. The deposit will most likely be developed with a wellhead facility or subsea template connected to existing infrastructure in the Danish sector.

15/3-1 S GUDRUN	Production licence 025, Operator: StatoilHydro ASA
Resources	Oil: 13.6 million scm, Gas: 12.6 billion scm, NGL: 7.7 million tonnes

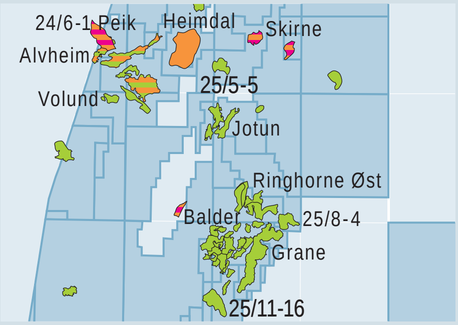
15/3-1 S Gudrun was discovered in 1975 about 40 kilometres north of the Sleipner area. The sea depth in the area is approximately 110 metres. The discovery contains oil and gas in Upper Jurassic sandstones, at a depth of 4 000–4 500 metres. The appraisal well 15/3-8 which was drilled in 2006, resulted in a reduced resource estimate. According to the plan, 15/3-1 S Gudrun will be developed together with the 15/3-4 discovery, which is located ten kilometres further to the southeast.

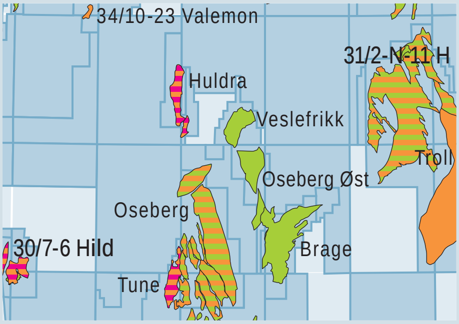
Several development solutions are being evaluated and concept selection is planned for in the autumn of 2008. A PDO is planned to be submitted to the authorities in the autumn of 2009. Production may start in 2013.

15/5-1 DAGNY	Production licence 029, 048, Operator: StatoilHydro ASA
Resources	Gas: 5.2 billion scm, NGL: 0.7 million tonnes, Condensate: 1.7 million scm.

15/5-1 Dagny is located northwest of Sleipner Vest. This small gas and condensate discovery was made in 1978. The discovery is divided between two production licences, 048 and 029. The reservoir consists of Middle Jurassic sandstones in the Hugin formation.

The development will most likely be a subsea facility connected to existing infrastructure in the Sleipner area. Several prospects and discoveries in the area will be considered in connection with this development. Concept selection is planned for in the autumn of 2009. The production may start in 2012/2013.





25/5-5	Production licence 102, Operator: Total E&P Norge AS
Resources	Oil: 3.5 million scm, Gas: 0.1 billion scm.

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

The discovery is located close to existing infrastructure. The operator is currently remapping the discovery.

25/11-16	Production licence 169, Operator: StatoilHydro Petroleum AS
Resources	Oil: 5.5 million scm, Gas: 0.1 billion scm.

The 25/11-16 discovery was made in 1992 west of the Grane field. The sea depth in the area is 120 metres. The well proved oil and associated gas at a depth of about 1 750 metres in Paleocene sandstones in the Heimdal formation. The sandstone is deposited as turbidites from the west.

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

30/7-6 HILD	Production licence 040, 043, Operator: Total E&P Norge AS
Resources	Gas: 14.7 billion scm, Condensate: 1.9 million scm.

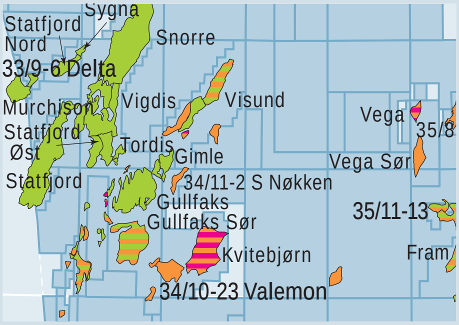
30/7-6 Hild was discovered in 1978, near the border to the UK continental shelf. The sea depth in the area is 100–120 metres. The reservoir is structurally complex, with gas at high temperatures and high pressure. The reservoir is in Middle Jurassic sandstones in the Brent group. Oil has also been proven in a more shallow reservoir.

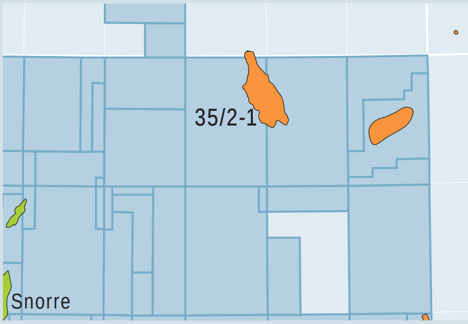
The licensees are evaluating a phased development.

31/2-N-11 H	Production licence 054, Operator: StatoilHydro Petroleum AS
Resources	Oil: 0.4 million scm.

31/2-N-11 H was discovered in 2005 in the northern part of Troll Vest, in Middle Jurassic sandstones in the Brent group. This is the first time oil has been proven in layers stratigraphically below the Upper Jurassic sandstones in Troll. The reservoir depth is about 1 900 metres.

The oil will be produced by a subsea template connected to Troll C.





33/9-6 DELTA	Production licence 037 D, Operator: Revus Energy ASA
Resources	Oil: 0.1 million Sm³

33/9-6 Delta is located between Murchison and Statfjord Nord. The discovery was made in 1976. The reservoir is in Middle Jurassic sandstones in the Brent group.

The development concept will be a production well drilled from the Murchison facility in the UK sector, possibly in 2008.

34/10-23 VALEMON	Production licence 050, 193, Operator: StatoilHydro ASA
Resources	Gas: 40.0 billion scm, Condensate: 7.1 million scm.

34/10-23 Valemon is located in blocks 34/11 and 34/10, west of the Kvitebjørn field. The sea depth in the area is about 135 metres. Five exploration wells have been drilled on the discovery, the first in 1985, and gas has been proven in four of them. The discovery has a complex structure with many faults. The reservoirs consist of Middle Jurassic sandstones in the Brent group and Lower Jurassic sandstones in the Cook formation at a depth of approximately 4 000 metres, with high pressures and high temperatures.

The operator has remapped the discovery. The NPD has in 2007 increased the resource estimate based on the preliminary results of the remapping of the area which is planned to be included in the development. The licensees will evaluate various development solutions and tie-in possibilities based on updated resource estimates. Development with a fixed facility seems most likely.

35/2-1	Production licence 318, Operator: StatoilHydro Petroleum AS
Resources	Gas: 17.7 billion scm.

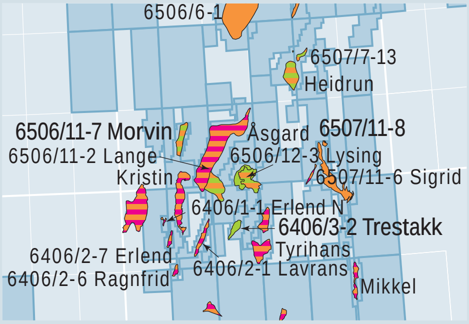
35/2-1 was discovered in 2005 and is located west of Florø, about 100 kilometres northeast of the Gullfaks field. The sea depth in the area is about 380 metres. The discovery contains methane. The reservoir is unconsolidated Pleistocene sandstones in the Nordland group, 580 metres below the sea level. The shallow reservoir implies low pressure and drilling is challenging.

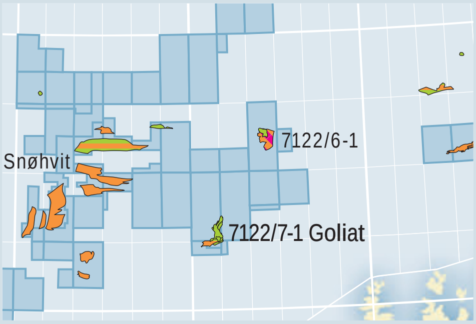
The licensees are considering drilling an appraisal well in 2009 and are evaluating possible development concepts. Earliest expected production start is 2013.

35/11-13	Production licence 090 B, Operator: StatoilHydro Petroleum AS
Resources	Oil: 6.5 million scm, Gas: 2.1 billion scm.

35/11-13 was discovered in 2005 north of the Fram field. The sea depth in the area is approximately 360 metres. The reservoir contains oil with a gas cap in Upper Jurassic sandstones. The appraisal well 35/11-14 S, drilled in the autumn of 2006, proved oil and gas in a new fault segment and gave important additional information about the discovery.

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





6406/3-2 TRESTAKK	Production licence 091, 091 B, Operator: StatoilHydro ASA
Resources	Oil: 8.9 million scm, Gas: 2.0 billion scm, NGL: 0.8 million tonnes

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

The operator is preparing a PDO for the Trestakk deposit. Possible development concepts are a FPSO, tied to Åsgard A, Åsgard B or Kristin. Gas for injection can be supplied from Åsgard A.

6506/11-7 MORVIN	Production licence 134 B, Operator: StatoilHydro ASA
Resources	Oil: 7.7 million scm, Gas: 3.2 billion scm, NGL: 0.7 million tonnes

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

A PDO was submitted to the authorities in February 2008. The development concept is a subsea development with tie-in to Åsgard B.

6507/11-8 YTTERGRYTA	Production licence 062, Operator: StatoilHydro ASA
Resources	Gas: 1.5 billion scm, NGL: 0.2 million tonnes, Condensate: 0.1 million scm.

6507/11-8 Yttergryta was discovered in 2007 and is located about 5 kilometres north of Midgard. The reservoir contains gas in Middle Jurassic sandstones in the Fangst group.

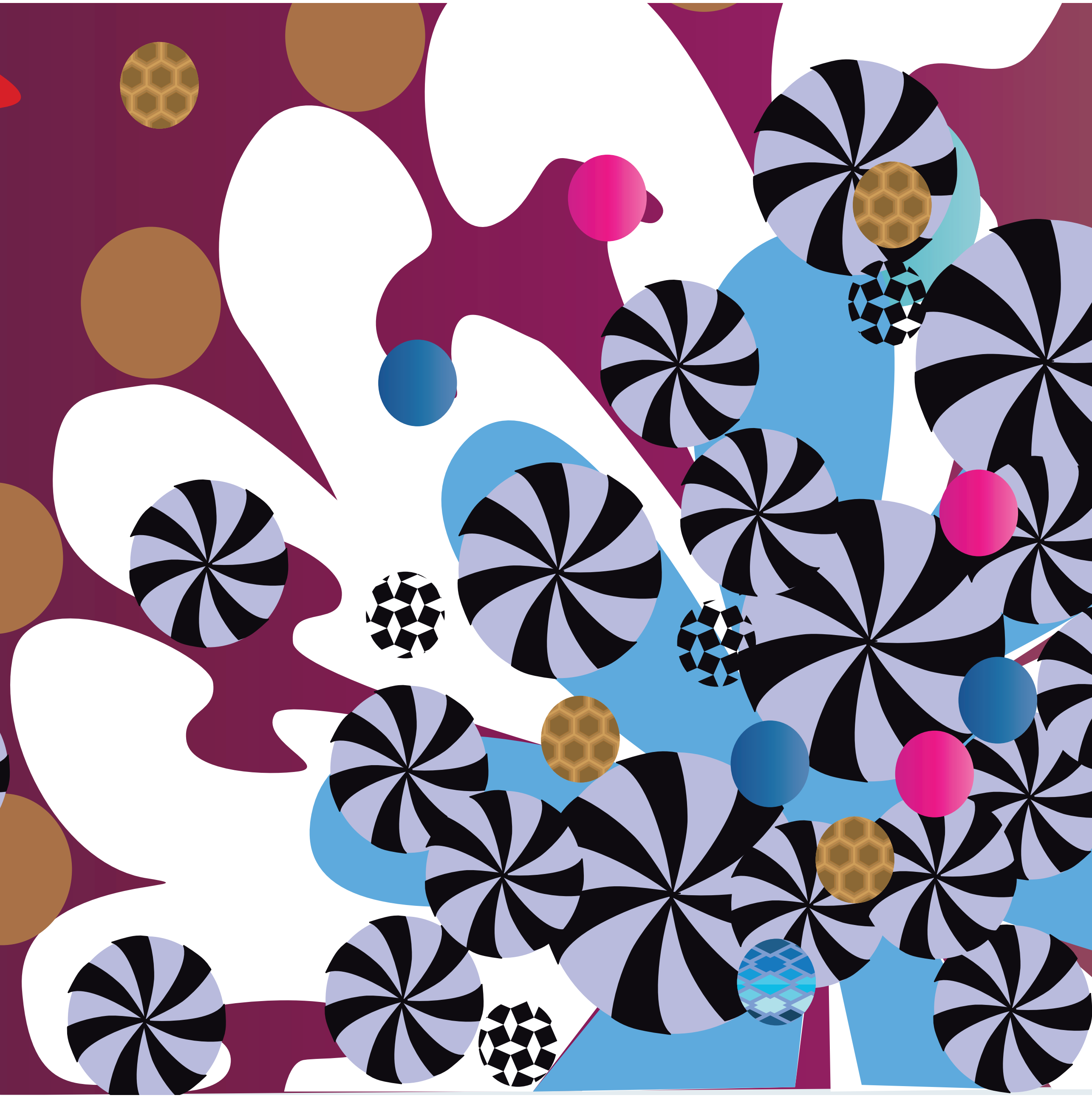
The gas will be produced using a subsea well and transported in a new pipeline to the Midgard X template and further through existing pipeline to Åsgard B for processing. The operator submitted a PDO to the authorities in January 2008.

7122/7-1 GOLIAT	Production licence 229, 229 B, Operator: Eni Norge AS
Resources	Oil: 27.5 million scm, Gas: 3.1 billion scm, NGL: 0.2 million tonnes

7122/7-1 Goliat was discovered in 2000 and is located 50 kilometres southeast of Snøhvit and 85 kilometres northwest of Hammerfest. The sea depth in the area is about 370 metres. The first exploration well proved oil in sandstones in the Realgrunnen subgroup of the Late Triassic to Early Jurassic ages, about 1 100 metres below sea level. Appraisal well 7122/7-3 proved hydrocarbons in three different levels. In addition to oil and gas in the Realgrunnen subgroup, oil was proven in the Snadd formation and oil and gas in the Kobbe formation, both of Middle Triassic age. Further appraisal drilling was carried out with wells 7122/7-4 S and 7122/7-5 A. These wells also proved hydrocarbons in the Kobbe formation.

The lisencees have decided to proceed with a development concept based on a floating production and storage facility tied to subsea wells.

14 Fields where production has ceased



Fields where production has ceased

The fields in this summary are shut down as of 31 December 2007. Plans for new development are however in progress for some of these fields. Yme is being redeveloped, see chapter 12 Fields under development.

Albuskjell

Block	1/6 and 2/4
Development approval	25.04.1975
Cessation plan/ decommissioning	The cessation plan was approved by Royal Decree 21 December 2001 and in Storting White Paper No. 47 (1999–2000)
On stream	26.05.1979
Production ceased	26.08.1998
Operator at time of cessation	Phillips Petroleum Company Norway
Total production over field lifetime	Oil: 7.4 million scm, Gas: 15.6 billion scm, NGL: 1.0 million tonnes.

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

Cod

Block	7/11
Development approval	04.05.1973
Cessation plan/ decommissioning	The cessation plan was approved by Royal Decree 21 December 2001 and in Storting White Paper No. 47 (1999–2000)
On stream	26.12.1977
Production ceased	05.08.1998
Operator at time of cessation	Phillips Petroleum Company Norway
Total production over field lifetime	Oil: 2.9 million scm, Gas: 7.3 billion scm, NGL: 0.5 million tonnes.

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

Edda

Block	2/7
Development approval	25.04.1975
Cessation plan/ decommissioning	The cessation plan was approved by Royal Decree 21 December 2001 and in Storting White Paper No. 47 (1999–2000)
On stream	02.12.1979
Production ceased	05.08.1998
Operator at time of cessation	Phillips Petroleum Company Norway
Total production over field lifetime	Oil: 4.8 million scm, Gas: 2.0 billion scm, NGL: 0.2 million tonnes.

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

Frigg

Block	25/1
Development approval	13.06.1974
Cessation plan/ decommissioning	The cessation plan was approved by Royal Decree 26 September 2003 and Storting White Paper No. 38 (2003–2004)
On stream	13.09.1977
Production ceased	26.10.2004
Operator at time of cessation	Total E & P Norge AS
Total production over field lifetime	Gas: 116.2 billion scm, Condensate: 0.5 million scm.

Status: Final disposal of the facilities is ongoing.

Frøy

Block	25/2 and 25/5
Development approval	18.05.1992
Cessation plan/ decommissioning	The cessation plan was approved by Royal Decree 29 May 2001 and in Storting White Paper No. 47 (1999–2000)
On stream	15.05.1995
Production ceased	05.03.2001
Operator at time of cessation	TotalFinaElf Exploration AS
Total production over field lifetime	Oil: 5.6 million scm., Gas: 1.6 billion scm, Condensate: 0.1 million scm.

Status: The acreage was re-awarded in 2006 as production licence 364. The present operator is Det norske oljeselskap ASA.

Lille-Frigg

Block	25/2
Development approval	06.09.1991
Cessation plan/ decommissioning	Storting Proposition No. 53 (1999–2000) and in Storting White Paper No. 47 (1999–2000)
On stream	13.05.1994
Production ceased	25.03.1999
Operator at time of cessation	Elf Petroleum Norge AS
Total production over field lifetime	Oil: 1.3 million scm, Gas: 2.2 billion scm.

Status: The acreage was re-awarded in 2006 as production licence 362. The present operator is StatoilHydro Petroleum AS. An exploration well is planned to be drilled in a down-faulted structure next to the field.

Mime

Block	7/11
Development approval	06.11.1992
Cessation plan/ decommissioning	Storting Proposition No. 15 (1996–1997) and in Storting White Paper No. 47 (1999–2000)
On stream	01.01.2003
Production ceased	04.11.1993
Operator at time of cessation	Norsk Hydro Produksjon AS
Total production over field lifetime	Oil: 0.4 million scm, Gas: 0.1 billion scm

Status: The acreage was re-awarded in 2003 as production licence 301. The present operator is Talisman Energy Norge AS. An appraisal well was drilled in 2007, but the well was dry. A decision on re-development or relinquishment is expected in June 2008.

Nordøst Frigg

Block	25/1 and 30/10
Development approval	12.09.1980
Cessation plan/ decommissioning	Storting Proposition No. 36 (1994–1995)
On stream	01.12.1983
Production ceased	08.05.1993
Operator at time of cessation	Elf Petroleum Norge AS
Total production over field lifetime	Gas: 11.6 billion scm, Condensate: 0.1 million scm.

Status: The acreage was re-awarded in 2007 as production licence 415. The present operator is StatoilHydro Petroleum AS. A decision on re-development of remaining gas resources or relinquishment is expected in 2009.

Odin

Block	30/10
Development approval	18.07.1980
Cessation plan/ decommissioning	Storting Proposition No. 50 (1995–1996) and in Storting White Paper No. 47 (1999–2000)
On stream	01.04.1984
Production ceased	01.08.1994
Operator at time of cessation	Esso Exploration and Production Norway AS
Total production over field lifetime	Gas: 27.3 billion scm, Condensate: 0.2 million scm.

Status: The acreage was re-awarded in 2007 as production licence 415. The present operator is StatoilHydro Petroleum AS. A decision on re-development of remaining gas resources or relinquishment is expected in 2009.

Tommeliten Gamma

Block	1/9
Development approval	12.06.1986
Cessation plan/ decommissioning	Storting Proposition No. 53 (1999-2000) and in Storting White Paper No. 47 (1999–2000)
On stream	03.10.1988
Production ceased	05.08.1998
Operator at time of cessation	Den norske stats oljeselskap a.s.
Total production over field lifetime	Oil: 3.9 million scm, Gas: 9.7 billion scm, NGL: 0.5 million tonnes.

Status: There are no specific plans to recover the remaining resources.

Vest Ekofisk

Block	2/4
Development approval	04.05.1973
Cessation plan/ decommissioning	The cessation plan was approved by Royal Decree 21 December 2001 and in Storting White Paper No. 47 (1999–2000)
On stream	31.05.1977
Production ceased	25.08.1998
Operator at time of cessation	Phillips Petroleum Company Norway
Total production over field lifetime	Oil: 12.2 million scm, Gas: 26.0 billion scm, NGL: 1.4 million tonnes.

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

Øst Frigg

Block	25/1 and 25/2
Development approval	14.12.1984
Cessation plan/decommissioning	Storting Proposition No. 8 (1998–1999) and in Storting White Paper No. 47 (1999–2000)
On stream	01.10.1988
Production ceased	22.12.1997
Operator at time of cessation	Elf Petroleum Norge AS
Total production over field lifetime	Gas: 9.2 billion scm, Condensate: 0.1 million scm.

Status: No activity.

15 Pipelines and onshore facilities

Figure 15.1 Existing and projected pipelines
(Source: Norwegian Petroleum Directorate)

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

Gassled pipelines

Operator: Gassco AS

Licensees:

Petoro AS[1]	37.892 %
StatoilHydro ASA	20.448 %
StatoilHydro Petroleum AS	11.607 %
Total E&P Norge AS	7.995 %
ExxonMobil Exploration and Production Norway AS	5.444 %
Mobil Development Norway AS	4.219 %
Norske Shell Pipelines AS	4.093 %
Norsea Gas AS	2.807 %
Norske ConocoPhillips AS	2.017 %
Eni Norge AS	1.556 %
A/S Norske Shell	1.240 %
DONG E&P Norge AS	0.682 %

[1] Petoro is the licensee for the State's Direct Financial Interest (SDFI). Petoro's participating interest in Gassled will be increased by approximately 8.4 per cent with effect from 1 January 2011, and the other parties' participating interests will be adjusted with effect from the same date.

In the spring of 2001, the government asked the relevant companies to establish a unified ownership structure for gas export. Gassled represents the merger of nine gas transport facilities into a single partnership. The Gassled ownership agreement was signed on 20 December 2002, and came into effect on 1 January 2003. Gassled's licence runs to 2028 Gassled encompasses: Europipe I, Europipe II, Franpipe, Norpipe, Oseberg Gas transport, Statpipe, Tampen Link, Vesterled, Zeepipe, Åsgard Transport, Langeled, Kollsnes gas processing plant and Kårstø gas and condensate processing plant. Gassled is organised into various zones for access and tariffs. Gassco coordinates and controls the flow of gas through a network of pipelines about 7 800 kilometres long, and handles all transport of Norwegian gas to the markets.

Europipe I

This 40-inch pipeline starts at the Draupner E riser facility and runs for 660 kilometres, ending at Emden in Germany. Europipe I came into operation in 1995. It has a capacity of about 46-54 million scm per day, depending on operating mode. The pipeline has been built for an operating life of 50 years and total investment at star-tup was approximately NOK 22.1 billion (2008 value). In addition to the pipeline, investments also include the terminal at Dornum and the Europipe Metering Station (EMS) in Emden.

(Agreement between Norway and Germany concerning the transmission of gas from the Norwegian continental shelf and other areas through a pipeline to the Federal Republic of Germany. (The Europipe Agreement), ref. Storting Proposition No. 60 (1992-1993) and Recommendation No. 164 (1992–1993).)

Europipe II

This 42-inch pipeline runs for 650 kilometres from Kårstø to Dornum in Germany, Europipe Receiving Facilities (ERF), and became operational in 1999. With a capacity of about 71 million scm per day, Europipe II has been built for an operating life of 50 years. Total investment at start-up was approximately NOK 9.98 billion (2008 value).

(Supplementary agreement of 19 May 1999 to the Europipe agreement (see Storting Proposition No. 60 (1992-1993) and Recommendation No. 164 (1992–1993)) concerning the transmission of gas from Norway through a new pipeline (Europipe II) to Germany, ratified in accordance with Royal Decree of 14 September 2001).

Franpipe

This 42-inch gas pipeline runs for 840 kilometres from the Draupner E riser facility in the North Sea to a receiving terminal at Dunkerque in France. The Gassled partnership owns 65 per cent of the terminal, while Gaz de France owns 35 per cent. The pipeline became operational in 1998. Franpipe has a capacity of about 52 million scm per day. It has been built for an operating life of 50 years. The total investment at start-up was approximately NOK 10.3 billion (2008 value).

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

Norpipe Gas pipeline

This 36-inch line starts at Ekofisk and runs for 440 kilometres to the Norsea Gas terminal in Emden, Germany. Also owned by Gassled, the Emden terminal cleans and meters the gas prior to onward distribution. The line became operational in 1977. Two riser facilities, H7 and B11, each with three compressors, are positioned on the German continental shelf. In 2007 a bypass was installed at H7, and H7 has now been shut down. The transport capacity is approximately 32 million scm per day without using the compressor capacity on the B11 riser facility. Capacity will increase to 42–43 million scm per day if the B11 compressors are used. Norpipe has been built for an operating life of at least 30 years. An application for extension of the lifetime of both Norpipe Gas pipeline and B11 is being considered by the authorities. Total investment at start-up was approximately NOK 27.5 billion (2008 value).

(Agreement between Norway and Germany concerning the transmission of petroleum through a pipeline from the Ekofisk field and adjacent areas to Germany. See Storting Proposition No. 88 (1973-1974) and Recommendation No. 250 (1973-1974).)

Oseberg Gas Transport (OGT)

This 36-inch line starts at Oseberg and runs for roughly 109 kilometres to the riser facility at Heimdal (HRP). The pipeline became operational in 2000 and has a capacity of approximately 40 million scm per day. OGT has been built for an operating life of 50 years, and total investment at start-up was approximately NOK 2.04 billion (2008 value).

Statpipe

This 880-kilometres pipeline system includes a riser facility and a gas processing plant at Kårstø. The system became operational in 1985. Statpipe Rich Gas, with a diameter of 30 inches, starts at Statfjord and runs for 308 kilometres to Kårstø, with a capacity of about 25 million scm per day. Statpipe Dry Gas has three components. One of these comprises a 28-inch pipeline running for about 228 kilometres from Kårstø to the Draupner S riser facility, with a capacity of roughly 20 million scm per day, depending on operating mode. The second component is a 36-inch pipeline running for about 155 kilometres from the the main facility at Heimdal (HMP) to Draupner S, with a capacity of about 30 million scm per day. The third s is a 36-inch pipeline running for roughly 203 kilometres from Draupner S to Ekofisk, with a capacity of about 30 million scm per day. The Heimdal-Draupner S and Kårstø-Draupner S pipelines can also be used for reversed flow. Total investment at start-up was approximately NOK 47.5 billion (2008 value), excluding the gas processing plant at Kårstø.

Tampen Link

The pipeline Tampen Link starts at the Statfjord field and ends at the FLAGS pipeline, 1.4 kilometres south of the Brent Alpha facility. About 15.5 kilometres of the new gas export pipeline lie on the British side of the border. Tampen Link was included in Gassled in 2007. The pipeline has a diametre of 32 inches, runs for 23 kilometres and has an initial capacity of approximately 25 million scm per day. The capacity is dependent upon inlet conditions at the connection points in the Statfjord area. Total investment at start-up was approximately 2.04 billion 2008-NOK. The investments include, in addition to the pipeline, necessary modifications on Statfjord B. Tampen Link has been built for an operating life of 30 years. (See plan for installation and operation referred to in St.prp. No. 53 (2004-2005).

Vesterled

This 32-inch pipeline runs for about 350 kilometres from the Heimdal riser facility (HRP) to the receiving terminal at St. Fergus in the UK and became operational in 1978. It has a capacity of about 38.6 million scm/day. Total investment in Vesterled at start-up was approximately NOK 33.6 billion (2008 value). In addition to the pipeline, this total investment includes investments associated with construction of the St. Fergus terminal.

(Agreement between Norway and the UK concerning amendments to the Frigg treaty of 10 May 1976. Referred to in St.prp. No. 73 (1998–1999) and Recommendation No. 219 (1998–1999)).

Zeepipe

Zeepipe I comprises a 40-inch pipeline running for about 814 kilometres from Sleipner (SLR) to the receiving terminal in Zeebrugge, Belgium. The terminal in Zeebrugge belongs to a separate partnership, with the Gassled partners holding 49 per cent and the Belgian Fluxys company holding 51 per cent. Zeepipe I became operational in 1993 and has a capacity of roughly 41 million scm per day. Zeepipe I also includes a 30-inch pipeline between Sleipner (SLR) and Draupner S.

Zeepipe II A starts at the Kollsnes gas processing plant and ends at the Sleipner riser facility. This pipeline became operational in 1996. Zeepipe II A is a 40-inch pipeline which is 303 kilometres long and has a capacity of 72 million scm per day.

Zeepipe II B starts at the Kollsnes gas treatment plant and ends at Draupner E. The pipeline became operational in 1997. Zeepipe II B has a 40-inch diameter, runs for about 300 kilometres and has a capacity of 71 million scm per day. The Zeepipe system has been built for an operating life of 50 years. Total investment at start-up is approximately NOK 25.1 billion (2008 value).

(Agreement between Norway and Belgium concerning the transmission of gas from the Norwegian continental shelf and other areas through a pipeline to Belgium. See Storting Proposition No. 148 (1987–1988) and Recommendation No. 21 (1988–1989).)

Åsgard Transport

This 42-inch pipeline runs for about 707 kilometres from the Åsgard field to Kårstø. It became operational in 2000, with a capacity of about 69 million scm/day. Åsgard Transport is built for an operating life of 50 years. Total investment at start-up was approximately NOK 10.9 billion (2007 value).

Langeled

The Langeled gas transport system runs from the onshore facilities for Ormen Lange at Nyhamna, via a tie-in point at the Sleipner riser facility to a new receiving terminal at Easington on the eastern coast of the UK. The system comprises a 42-inch pipeline from Nyhamna to the Sleipner riser (northern leg) and a 44-inch line from Sleipner to Easington (southern leg). Capacity is about 80 million scm/day in the northern leg and about 70 million scm/day in the southern leg. The system has an overall length of roughly 1 200 kilometres. The southern pipeline became operational in October 2006, with the northern pipeline following in October 2007. Norsk Hydro was the operator for the development phase of the southern leg, while Gassco AS is the operator for the development phase of the northern leg and the operating phase of the whole transport system. Langeled was included in Gassled in the autumn of 2006. Total investment at start-up was approximately NOK 17.7 billion (2008 values).

Kollsnes gas processing plant

The gas processing plant at Kollsnes forms part of Gassled. Wellstreams are separated at Kollsnes into gas and condensate. The gas is dried and compressed before being sent to the Continent via a pipeline to Sleipner and Draupner.

Kollsnes also delivers a small amount of gas to the LNG plant at the Gasnor-Kollsnes Industrial Park. Following a stabilisation process, the condensate is sent on to the Vestprosess plant at Mongstad. This plant was upgraded in 2004 with an NGL extraction plant to treat gas from Kvitebjørn and Visund. After the upgrade, the capacity is 143 million scm dry gas per day and 9 780 scm condensate per day. In order to ensure that the plant can deliver 143 million scm dry gas per day, a new export compressor was put into operation from 1 October 2006.

Kårstø gas and condensate processing plant

Rich gas is processed at the Kårstø gas processing facility and the products, which are dry gas, ethane, propane, iso-butane, normal butane and naphtha, are separated. The dry gas, which largely contains methane and ethane, is transported by two pipelines from Kårstø, Europipe II to Germany and Statpipe to Draupner. The Kårstø condensate facility receives unstabilised condensate from the Sleipner fields. The condensate is stabilised by separating out the lightest components. Ethane, iso-butane and normal butane are stored in refrigerated tanks, while naphtha and condensate are held in tanks at ambient temperature. Propane is stored in large refrigerated rock caverns. These products are exported from Kårstø in liquid form by ship.

Processing facilities at Kårstø comprise four extraction/fractionation lines for methane, ethane, propane, butanes and naphtha, plus a fractionation line for stabilising condensate. The condensate plant has a capacity of approximately 5.5 million tonnes of unstabilised condensate per year. After the last expansion, the KEP-2005 project, the capacity for recovering ethane at Kårstø has increased to 950,000 tonnes per year. At the same time, the gas processing facility was upgraded to handle 88 million scm rich gas per day.

Other pipelines

Draugen Gas Export

Operator	A/S Norske Shell	
Licensees	Petoro AS	47.88%
	BP Norge AS	18.36%
	A/S Norske Shell	26.20%
	Chevron Norge AS	7.56%
Investment	Total investment at start-up was approximately NOK 1.17 billion (2008 value)	
Operating lifetime	The technical operating lifetime is 50 years	
Capacity	Approximately 2 billion scm per year	

This 16-inch pipeline links the Draugen field to Åsgard Transport, and provides opportunities for possible tie-ins of other fields in the area. The pipeline is 78 kilometres long and commenced operation in November 2000.

Grane Gas Pipeline

Operator	StatoilHydro Petroleum AS
Licensees	As for the Grane field
Investment	Total investment at start-up was approximately NOK 0.32 billion (2008 value)
Operating lifetime	The technical operating life is 30 years
Capacity	Approximately 3.6 billion scm per year

The pipeline commenced operation in September 2003. Gas injection is required in order to produce the oil from the Grane field. This gas is transported to the field through the Grane Gas Pipeline. The 50 kilometres long pipeline runs from the Heimdal riser facility to Grane. The diameter of the pipeline is 18 inches.

Grane Oil Pipeline

Operator	StatoilHydro Petroleum AS	
Licensees	Petoro AS	43.60%
	ExxonMobil Exploration and Production Norway AS	25.60%
	StatoilHydro Petroleum AS	24.40%
	ConocoPhillips Skandinavia AS	6.40%
Investment	Total investment at start-up was approximately NOK 1.68 billion (2008 value)	
Operating lifetime	The technical operating lifetime is 30 years	
Capacity	34 000 scm oil per day	

This pipeline became operational at the same time as the Grane field, in September 2003. The pipeline links the Grane field to the Sture terminal. It is 220 kilometres long and has a diameter of 29 inches.

Haltenpipe

Operator	Gassco AS	
Licensees	Petoro AS	57.81%
	StatoilHydro ASA	19.06%
	ConocoPhillips Skandinavia AS	18.13%
	Eni Norge AS	5.00%
Investment	Total investment at start-up was approximately NOK 3.0 billion (2008 value) in pipelines and the terminal	
Operating lifetime	The licence expires on 31 December 2020	
Capacity	2.2 billion scm gas per year	

This 16-inch gas pipeline runs for 250 kilometres from the Heidrun field in the Norwegian Sea to Tjeldbergodden, where StatoilHydro ASA and ConocoPhillips Skandinavia AS have built a methanol plant close to the receiving terminal. This plant uses Heidrun gas to produce methanol. Gas deliveries to the methanol plant are approximately 0.7 billion scm per year.

Heidrun Gas Export

Operator	StatoilHydro ASA[1]	
Licensees	Petoro AS	58.16%
	ConocoPhillips Skandinavia AS	24.31%
	StatoilHydro ASA	12.41%
	Eni Norge AS	5.12%
Investment	Total investment at start-up was approximately NOK 0.97 billion (2008 value)	
Operating lifetime	The technical operating lifetime is 50 years	
Capacity	Approximately 4.0 billion scm per year	

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

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

Kvitebjørn Oil Pipeline (KOR)

Operator	StatoilHydro ASA	
Licensees	StatoilHydro ASA	43.55 %
	Petoro AS	30.00 %
	StatoilHydro Petroleum AS	15.00 %
	Total E&P Norge AS	5.00 %
	Enterprise Oil Norge AS	6.45 %
Investment	Total investment at start-up was approximately NOK 0.53 billion (2008 value)	
Operating lifetime	The technical operating lifetime is 25 years	
Capacity	Approximately 10 000 scm per day	

Kvitebjørn Oil Pipeline (KOR) transports condensate from Kvitebjørn to the Mongstad oil terminal. This 16-inch line runs for about 90 kilometres to tie in to the Y-connection on Troll Oil Pipeline II. The pipeline became operational in the second half of 2004.

Norne Gas Transport System (NGTS)

Operator	Gassco AS	
Licensees	Petoro AS	54.00%
	StatoilHydro ASA	31.00%
	Norsk Hydro Produksjon AS	8.10%
	Eni Norge AS	6.90%
Investment	Total investment at start-up was approximately NOK 1.27 billion. (2008 value).	
Operating lifetime	Technical operating lifetime is 50 years	
Capacity	Approximately 3.6 billion scm per year	

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

Norpipe Oil Pipeline

Owner	Norpipe Oil AS	
Operator	ConocoPhillips Skandinavia AS	
Ownership in Norpipe Oil AS	ConocoPhillips Skandinavia AS	35.05%
	Total E&P Norge AS	34.93%
	StatoilHydro ASA	15.00%
	Eni Norge AS	6.52%
	StatoilHydro Petroleum AS	3.50%
	Petoro AS	5.00%
Investment	Total investment at start-up was approximately NOK 17.0 billion (2008 value)	
Operating lifetime	The pipeline has been designed for an operating life of at least 30 years. The technical lifetime is under constant review.	
Capacity	Design capacity for the oil pipeline is about 53 million scm per year (900.000 bbls/day), including the use of friction-inhibiting chemicals. The receiving facilities restrict capacity to 128 776 scm per day.	

The Norpipe Oil Pipeline crosses the British continental shelf, with landfall at Teesside in the UK. The 34-inch Norpipe oil pipeline is about 354 kilometres long and starts at the Ekofisk Centre, where three pumps have been placed. A tie-in point for UK fields is located about 50 kilometres downstream of Ekofisk. Two riser facilities, each with three pumps, were previously tied to the pipeline, but were bypassed in 1991 and 1994 respectively.

Two British-registered companies, Norsea Pipeline Ltd and Norpipe Petroleum UK Ltd, own the oil export port and fractionation plant for extracting NGL in Teesside. The pipeline carries crude from the four Ekofisk fields (Ekofisk, Eldfisk, Embla and Tor) as well as from Valhall, Hod, Ula, Gyda and Tambar, and from several British fields.

(Agreement between Norway and the UK concerning the transmission of petroleum through a pipeline from the Ekofisk field and adjacent areas to the UK. See Storting Proposition No. 110 (1972–1973) and Recommendation No. 262 (1972–1973).)

Oseberg Transport System (OTS)

Operator	StatoilHydro Petroleum AS	
Licensees	Petoro AS	48.38%
	StatoilHydro Petroleum AS	22.24%
	StatoilHydro ASA	14.00%
	Total E&P Norge AS	8.65%
	Mobil Development Norway AS	4.33%
	ConocoPhillips Skandinavia AS	2.40%
Investment	Total investment at start-up was approximately NOK 10.1 billion. (2008 value)	
Operating lifetime	The pipeline is designed for a lifetime of 40 years	
Capacity	121.000 scm per day (technical), 990.000 scm (storage)	

Oil from the Oseberg field is transported in a 115 kilometres long, 28-inch line from the Oseberg A facility to the crude oil terminal at Stura in Øygarden municipality. The Oseberg licensees have established a separate partnership to operate this pipeline.

Sleipner Øst Condensate pipeline

Operator	StatoilHydro ASA	
Licensees	StatoilHydro ASA	49.60%
	ExxonMobil Exploration and Production Norway AS	30.40%
	StatoilHydro Petroleum AS	10.00%
	Total E&P Norge AS	10.00%
Investment	Total investment at start-up was approximately NOK 1.68 billion. (2008 value)	
Capacity	32 000 scm oil per day	

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

Troll Oil Pipeline I

Operator	StatoilHydro ASA	
Licensees	Petoro AS	55.77%
	StatoilHydro ASA	20.85%
	StatoilHydro Petroleum AS	9.73%
	A/S Norske Shell	8.29%
	Total E&P Norge AS	3.71%
	ConocoPhillips Skandinavia AS	1.66%
Investment	Total investment at start-up was approximately NOK 1.27 billion. (2008 value)	
Operating lifetime	Troll Oil Pipeline I is designed to operate for 35 years	
Capacity	42 500 scm per day of oil with use of friction inhibitors	

Troll Oil Pipeline I was built to transport oil from Troll B to the oil terminal at Mongstad. The pipeline has a diameter of 16 inches and a length of 85 kilometres. The Troll licensees have established a separate partnership to handle operation of the line. Troll Oil Pipeline I was in place and ready to receive oil production from Troll B, which started in September 1995.

Troll Oil Pipeline II

Operator	StatoilHydro ASA	
Licensees	Petoro AS	55.77%
	StatoilHydro ASA	20.85 %
	StatoilHydro Petroleum AS	9.73%
	A/S Norske Shell	8.29%
	Total E&P Norge AS	3.71%
	ConocoPhillips Skandinavia AS	1.66%
Investment	Total investment at start up was approximately NOK 1.12 billion.(2008 value)	
Operating lifetime	Troll Oil Pipeline II is designed for a lifetime of 35 years	
Capacity	Current capacity is 40.000 scm per day. The hydraulic capacity is 47 500 scm per day (without use of friction inhibitors)	

This 20-inch pipeline has been built to carry oil over the 80 kilometres from Troll C to the terminal at Mongstad. The plan for installation and operation was approved in March 1998, and Troll Oil Pipeline II was ready to begin operation when Troll C started production on 1 November 1999. Oil from Fram and Kvitebjørn is transported through Troll Oil Pipeline II. The licence period for the pipeline lasts to 2023.

Onshore facilities

Mongstad crude oil terminal

Owner	StatoilHydro ASA	65.00%
	Petoro AS	35.00%

The terminal at Mongstad incorporates three jetties able to receive vessels up to 440.000 tonnes, as well as six caverns blasted in the bedrock 50 metres below ground. These caverns have a total storage capacity of 1.5 million m^3 of crude oil.

This facility was constructed to support the marketing of crude oil loaded offshore. Crude oil from fields with buoy loading (including Gullfaks, Statfjord, Draugen, Norne, Åsgard and Heidrun) is loaded offshore onto buoy loader shuttle tankers, which have a sailing range confined to northwest Europe. By storing and transshipping crude at Mongstad, however, Statoil can sell the oil to more distant destinations. Mongstad is also the receiving terminal for the oil pipelines from Troll B, Troll C, Troll Blend (Fram) and Kvitebjørn fields, as well as shuttle tankers from Heidrun.

Ormen Lange onshore facility

Owner	As for the Ormen Lange field.

The process plant for Ormen Lange at Nyhamna is a conventional plant for gas drying, compression, gas export, condensate separation/stabilisation/storage and fiscal measurement of gas and condensate. The condensate is being exported by ship from Nyhamna. The plant became operational in September 2007. The land facility has been designed for an operating life of 30 years, while part of the main infrastructure has been designed for 50 years. The plant has a capacity of 70 million scm dry gas per day gas at a receiving pressure of 90 bar.

Snøhvit onshore facility

Owner:	As for the Snøhvit field.

The unprocessed well stream from the Snøhvit field is transported through a 160 kilometres long pipeline to the facility at Melkøya for processing and export. Condensate, water and CO_2 are separated from the well stream on the onshore facility before the natural gas is being cooled down to liquid form (LNG) and stored in dedicated tanks. Power is normally supplied by five gas turbines at the facility. Condensate and LPG products are stored in tanks for export. Separated CO_2 is sent in return to the Snøhvit field and injected into a separate formation below the oil and gas.

Sture terminal

Owner	The Sture terminal forms part of the joint venture for the Oseberg Transport System (OTS), with the same ownership interests. The exception is the LPG export facilities, which are owned by StatoilHydro Petroleum AS (the refrigerated LPG storage and transfer system to ships) and Vestprosess DA (export facility to Vestprosess).

The Sture oil terminal receives oil and condensate via the pipeline from the Oseberg A facility from the Oseberg, Veslefrikk, Brage, Oseberg Sør, Oseberg Øst, Tune and Huldra fields. The terminal also receives Grane oil through the Grane Oil Pipeline. The terminal began operating in December 1988. It incorporates two jet-ties able to berth oil tankers up to 300.000 tonnes, five rock caverns for storing crude oil with a combined capacity of 1 million scm, a 60.000 m^3 rock cavern storage for LPG and a 200.000 m^3 ballast water cavern. A separate unit for recovering volatile organic compounds (VOC) has been installed.

A fractionation plant which came in operation in December 1999 processes unstabilised crude from Oseberg into stabilised oil and an LPG blend. The produced LPG blend can either be exported by ship from the terminal or sent through the Vestprosess pipeline between Kollsnes, Stura and Mongstad.

Tjeldbergodden

Owner	Statoil Metanol ANS:	
Owners in Statoil Metanol ANS:	StatoilHydro ASA	81.70%
	ConocoPhillips Skandinavia AS	18.30%

The methanol plant at Tjeldbergodden began production on 5 June 1997. Gas deliveries through the Haltenpipe total 0.7 billion scm annually, which yield 830.000 tonnes of methanol.

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

Vestprosess

Owner	Petoro AS	41.00%
	StatoilHydro ASA	17.00%
	StatoilHydro Petroleum AS	17.00%
	Mobil Exploration Norway Inc.	10.00%
	A/S Norske Shell	8.00%
	Total E&P Norge AS	5.00%
	ConocoPhillips Skandinavia AS	2.00%

The Vestprosess DA partnership owns and operates a gas transport system and a gas separation facility for NGL. These facilities came on stream in December 1999. A 56 kilometres pipeline carries unstabilised NGL from the Kollsnes gas terminal, via the oil terminal at Stura, to Mongstad.

At Mongstad, processing starts by separating out naphtha and LPG. The naphtha serves as refinery feedstock, while the LPG is fractionated in a dedicated process into propane and butane. These products are stored in rock caverns before export.

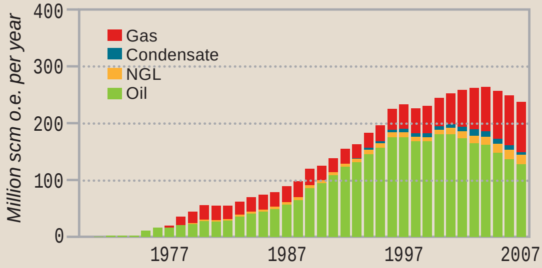
Appendix

Appendix 1 Historical statistics

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

Year	Ordinary tax	Special tax	Production fee	Area fee	Environ-mental taxes	Net cash flow SDFI	Dividend StatoilHydro
1971			14				
1972			42				
1973			69				
1974			121				
1975			208				
1976	1143	4	712	99			
1977	1694	725	646	57			
1978	1828	727	1213	51			
1979	3399	1492	1608	53			
1980	9912	4955	3639	63			
1981	13804	8062	5308	69			0.057
1982	15036	9014	5757	76			368
1983	14232	8870	7663	75			353
1984	18333	11078	9718	84			795
1985	21809	13013	11626	219		-8343	709
1986	17308	9996	8172	198		-11960	1245
1987	7137	3184	7517	243		-10711	871
1988	5129	1072	5481	184		-9133	0
1989	4832	1547	7288	223		755	0
1990	12366	4963	8471	258		7344	800
1991	15021	6739	8940	582	810	5879	1500
1992	7558	7265	8129	614	1916	3623	1400
1993	6411	9528	7852	553	2271	159	1250
1994	6238	8967	6595	139	2557	5	1075
1995	7854	10789	5884	552	2559	9259	1614
1996	9940	12890	6301	1159	2787	34959	1850
1997	15489	19582	6220	617	3043	40404	1600
1998	9089	11001	3755	527	3229	14572	2940
1999	5540	6151	3222	561	3261	25769	135
2000	21921	32901	3463	122	3047	98219	1702
2001	41465	64316	2481	983	2862	125439	5746
2002	32512	52410	1320	447	3012	74785	5045
2003	36819	60280	766	460	3056	67482	5133
2004	43177	70443	717	496	3309	80166	5222
2005	61589	103294	360	224	3351	98602	8139
2006	78015	133492	42	2308	3405	125523	12593
2007	70281	116233	0	764	3876	112336	16448

(Source: Norwegian Public Accounts and account figures for SDFI)



Total petroleum production

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

Table 1.2 Petroleum production on the Norwegian continental shelf, million standard cubic meter oil equivalents

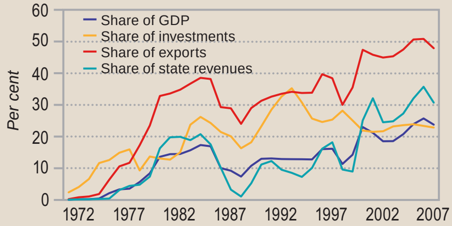
Year	Oil	Gas	Condensate	NGL	Total production
1970					
1971	0.4	0.0	0.0	0.0	0.4
1972	1.9	0.0	0.0	0.0	1.9
1973	1.9	0.0	0.0	0.0	1.9
1974	2.0	0.0	0.0	0.0	2.0
1975	11.0	0.0	0.0	0.0	11.0
1976	16.2	0.0	0.0	0.0	16.2
1977	16.6	2.7	0.0	0.0	19.3
1978	20.6	14.2	0.0	0.0	34.9
1979	22.5	20.7	0.0	1.1	44.3
1980	28.2	25.1	0.0	2.4	55.8
1981	27.5	25.0	0.0	2.2	54.7
1982	28.5	24.0	0.0	2.3	54.8
1983	35.6	23.6	0.0	2.7	62.0
1984	41.1	26.0	0.1	2.6	69.8
1985	44.8	26.2	0.1	3.0	74.0
1986	48.8	26.1	0.1	3.8	78.8
1987	57.0	28.2	0.1	4.1	89.3
1988	64.7	28.3	0.0	4.8	97.9
1989	86.0	28.7	0.1	4.9	119.7
1990	94.5	25.5	0.0	5.0	125.1
1991	108.5	25.0	0.1	4.9	138.5
1992	124.0	25.8	0.1	5.0	154.8
1993	131.8	24.8	0.6	5.5	162.7
1994	146.3	26.8	2.8	7.1	183.1
1995	156.8	27.8	3.7	7.9	196.3
1996	175.4	37.4	4.4	8.2	225.5
1997	175.9	43.0	6.4	8.1	233.3
1998	168.7	44.2	6.0	7.4	226.3
1999	168.7	48.5	6.5	7.0	230.7
2000	181.2	49.7	6.3	7.2	244.4
2001	180.9	53.9	6.6	10.9	252.3
2002	173.6	65.5	8.0	11.8	259.0
2003	165.5	73.1	11.1	12.9	262.5
2004	162.8	78.5	9.1	13.6	264.0
2005	148.1	85.0	8.4	15.7	257.2
2006	136.6	87.6	8.0	16.7	248.8
2007	128.3	89.7	3.5	16.6	238.0

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

Table 1.3 Value creation, exports, employment, investment and exploration costs

Year	Gross product (MNOK)	Export value (MNOK)	Numbers of employees	Investment incl. exploration costs (MNOK)	Exploration costs (MNOK)
1971	12	75	NA	691	
1972	207	314	200	1 192	
1973	258	504	300	2 326	
1974	1 056	1 089	900	5 138	
1975	4 218	3 943	2 200	7 291	
1976	6 896	7 438	2 700	9 270	
1977	8 617	8 852	4 000	10 589	
1978	14 835	15 117	6 100	9 228	
1979	23 494	24 788	7 900	9 061	
1980	44 285	44 638	9 700	10 119	
1981	55 189	52 432	12 200	14 462	4 133
1982	61 891	57 623	13 100	15 909	5 519
1983	73 298	68 082	13 900	27 028	5 884
1984	90 092	82 504	15 800	32 244	7 491
1985	97 347	90 098	17 700	32 839	7 830
1986	59 988	57 239	18 000	33 155	6 654
1987	59 574	58 301	17 800	35 247	4 951
1988	49 966	51 720	18 700	29 680	4 151
1989	76 768	76 681	18 600	31 957	5 008
1990	95 400	92 451	19 200	32 223	5 137
1991	101 346	101 015	19 700	43 065	8 137
1992	102 578	101 187	20 900	49 512	7 680
1993	107 542	108 463	22 300	57 579	5 433
1994	112 623	113 099	22 500	54 653	5 011
1995	120 198	121 169	21 700	48 583	4 647
1996	165 444	167 200	23 000	47 878	5 455
1997	180 594	177 825	24 000	62 494	8 300
1998	129 098	128 807	28 000	79 216	7 577
1999	176 591	173 428	27 000	69 096	4 993
2000	340 640	326 658	29 000	53 589	5 274
2001	325 333	322 291	32 000	57 144	6 815
2002	283 462	283 343	31 000	54 000	4 476
2003	295 356	291 220	29 000	64 362	4 134
2004	361 262	347 926	30 000	71 473	4 010
2005	465 341	439 881	32 000	88 478	7 537
2006	555 628	511 352	31 000	95 740	11 718
2007	543 409	508 954	35 000	109 298	17 921

(Source: Statistics Norway)



Macroeconomic indicators for the petroleum sector

(Source: Statistics Norway, Ministry of Finance)

Table 1.4 The petroleum sector's percentage share of the gross national product, exports, real investments and the state's total revenues

Year	Share of gross national product	Share of exports	Share of real investment	Share of state's total revenues
1971	0.01	0.21	2.33	0.05
1972	0.18	0.79	4.03	0.12
1973	0.19	1.04	6.56	0.16
1974	0.40	1.82	11.61	0.25
1975	2.09	6.36	12.56	0.38
1976	3.28	10.54	14.86	3.07
1977	3.52	11.68	15.92	4.38
1978	5.63	17.23	9.27	4.77
1979	8.35	23.47	13.68	7.31
1980	13.58	32.80	13.03	16.27
1981	14.41	33.58	12.69	19.76
1982	14.48	34.80	15.00	19.90
1983	15.66	36.69	23.71	18.86
1984	17.31	38.55	26.18	20.74
1985	16.90	38.16	24.26	17.50
1986	10.01	29.29	21.43	10.13
1987	9.17	28.91	20.04	3.21
1988	7.33	23.99	16.27	1.02
1989	10.74	28.99	18.15	5.20
1990	12.96	31.28	23.20	11.14
1991	13.06	32.60	28.49	12.25
1992	12.87	33.51	32.65	9.49
1993	12.83	34.12	35.23	8.50
1994	12.82	33.76	30.76	7.24
1995	12.74	33.83	25.67	10.06
1996	16.02	39.69	24.58	16.14
1997	16.14	38.42	25.33	18.15
1998	11.32	30.00	28.17	9.56
1999	14.24	35.49	25.07	8.93
2000	23.00	47.39	21.88	25.07
2001	21.17	45.82	21.46	32.07
2002	18.50	44.96	21.65	24.50
2003	18.53	45.35	23.17	24.80
2004	20.73	47.49	23.58	27.25
2005	23.92	50.66	23.87	32.01
2006	25.70	50.86	23.35	35.72
2007	23.74	47.89	22.82	30.70

(Source: Statistics Norway, Ministry of Finance)

Appendix 2 The petroleum resources
(per 31.12.2007)

Table 2.1 Historical production from fields in production and fields with ceased production

Field	Oil mill. scm	Gas bill. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv.[1)] mill scm o.e.	Year of discovery[2)]
Albuskjell	7.4	15.5	1.0		24.8	1972
Cod	2.9	7.3	0.5		11.2	1968
Edda	4.8	2.0	0.2		7.2	1972
Frigg		116.2		0.5	116.6	1971
Frøy	5.6	1.6		0.1	7.3	1987
Lille-Frigg	1.3	2.2		0.0	3.5	1975
Mime	0.4	0.1	0.0		0.5	1982
Nordøst Frigg		11.6		0.1	11.7	1974
Odin		27.3		0.2	27.5	1974
Tommeliten Gamma	3.9	9.7	0.6		14.6	1978
Vest Ekofisk	12.2	26.0	1.4		40.8	1970
Øst Frigg		9.2		0.1	9.3	1973
Historical production	**38.3**	**228.6**	**3.7**	**0.9**	**274.9**	
Balder[a)]	41.3	0.9	0.0	0.0	42.2	1967
Blane	0.0	0.0	0.0	0.0	0.1	1989
Brage	48.5	2.5	1.0	0.0	52.8	1980
Draugen	117.8	1.3	1.9	0.0	122.7	1984
Ekofisk	390.6	133.6	12.0	0.0	547.1	1969
Eldfisk	86.2	37.1	3.6	0.0	130.2	1970
Embla	9.4	3.2	0.4	0.0	13.3	1988
Enoch	0.1	0.0	0.0	0.0	0.1	1991
Fram	9.8	0.1	0.0	0.0	9.9	1992
Gimle	1.1	0.1	0.0	0.0	1.2	2004
Glitne	7.4	0.0	0.0	0.0	7.4	1995
Grane	42.8	0.0	0.0	0.0	42.8	1991
Gullfaks[b]	334.7	22.5	2.6	0.0	362.1	1978
Gullfaks Sør[c]	30.5	20.2	2.4	0.0	55.3	1978
Gungne[3]	0.0	0.0	1.5	4.3	7.1	1982
Gyda[d)]	34.1	5.7	1.8	0.0	43.3	1980
Heidrun[e)]	121.9	11.0	0.5	0.0	133.7	1985
Heimdal	6.4	42.4	0.0	0.0	48.9	1972
Hod	8.8	1.5	0.2	0.0	10.8	1974
Huldra	4.4	12.8	0.1	0.0	17.3	1982
Jotun	21.4	0.8	0.0	0.0	22.2	1994
Kristin	5.3	6.5	1.4	2.1	16.6	1997
Kvitebjørn	5.9	11.6	1.0	0.0	19.4	1994
Mikkel	0.9	7.3	2.0	2.2	14.2	1987
Murchison	13.5	0.3	0.3	0.0	14.5	1975
Njord	22.0	0.1	0.0	0.0	22.1	1986

Field	Oil mill. scm	Gas bill. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv. mill scm o.e.	Year of discovery[2)]
Norne	77.0	5.5	0.6	0.0	83.6	1992
Ormen Lange	0.0	1.7	0.0	0.1	1.8	1997
Oseberg[f)]	339.9	18.2	5.0		367.6	1979
Oseberg Sør	31.3	4.8			36.1	1984
Oseberg Øst	16.6	0.3			16.9	1981
Ringhorne Øst	2.6	0.1	0.0	0.0	2.6	2003
Sigyn	0.0	4.0	1.5	4.4	11.3	1982
Skirne	1.0	4.2	0.0	0.0	5.1	1990
Sleipner Vest and Sleipner Øst[3)g)]	0.0	149.2	18.1	56.3	239.8	1974
Snorre	155.0	5.7	4.4	0.0	169.0	1979
Snøhvit	0.0	0.2	0.0	0.1	0.3	1984
Statfjord	555.4	55.7	14.7	0.2	639.3	1974
Statfjord Nord	34.7	2.2	0.7	0.0	38.3	1977
Statfjord Øst	33.1	3.5	1.2	0.0	38.9	1976
Sygna	9.3	0.0	0.0	0.0	9.3	1996
Tambar	7.4	0.0	0.2	0.0	7.8	1983
Tor	22.6	10.8	1.2	0.0	35.6	1970
Tordis[h]	51.0	3.8	1.4	0.0	57.4	1987
Troll[i)]	190.5	306.0	2.8	4.3	506.2	1979
Tune	3.1	14.0	0.1	0.0	17.3	1996
Ula	68.6	3.9	2.6	0.0	77.3	1976
Urd	3.1	0.1	0.0	0.0	3.2	2000
Vale	0.8	0.6	0.0	0.0	1.4	1991
Valhall	96.1	19.0	3.0	0.0	120.9	1975
Varg	10.5	0.0	0.0	0.0	10.5	1984
Veslefrikk	48.7	2.2	1.2	0.0	53.2	1981
Vigdis	40.0	0.8	0.6	0.0	42.0	1986
Visund	16.3	2.9	0.2	0.0	19.6	1986
Yme	7.9	0.0	0.0	0.0	7.9	1987
Åsgard	57.2	63.7	11.1	17.1	159.0	1981
Producing fields	**3244.7**	**1003.9**	**103.5**	**91.2**	**4536.4**	
Total sold and delivered	**3283.0**	**1232.5**	**107.2**	**92.2**	**4811.4**	

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

(Source: Norwegian Petroleum Directorate)

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

Field	Reserves mill. scm o.e.	Year of discovery[5]	Operator at 31.12.2007	Production licence/ unit area
Alve[1]	9.2	1990	Statoil Hydro ASA	159 B
Alvheim[1]	30.2	1998	Marathon Petroleum Norge AS	036 C, 088 BS, 203
Balder	60.6	1967	ExxonMobil Exploration & Production Norway AS	001
Blane	0.9	1989	Talisman Energy Norge AS	Blane
Brage	57.6	1980	Statoil Hydro Petroleum AS	Brage
Draugen	146.3	1984	A/S Norske Shell	093
Ekofisk	728.9	1969	ConocoPhillips Skandinavia AS	018
Eldfisk	188.9	1970	ConocoPhillips Skandinavia AS	018
Embla	19.8	1988	ConocoPhillips Skandinavia AS	018
Enoch	0.4	1991	Talisman North Sea Limited	Enoch
Fram	31.1	1992	Statoil Hydro Petroleum AS	090
Gimle	5.2	2004	Statoil Hydro ASA	Gimle
Gjøa[1]	54.5	1989	Statoil Hydro ASA	153
Glitne	8.1	1995	Statoil Hydro ASA	048 B
Grane	112.4	1991	Statoil Hydro Petroleum AS	Grane
Gullfaks	387.8	1978	Statoil Hydro ASA	050
Gullfaks Sør	100.2	1978	Statoil Hydro ASA	050
Gungne	20.8	1982	Statoil Hydro ASA	046
Gyda	48.8	1980	Talisman Energy Norge AS	019 B
Heidrun	231.5	1985	Statoil Hydro ASA	Heidrun
Heimdal	50.0	1972	Statoil Hydro Petroleum AS	036 BS
Hod	11.7	1974	BP Norge As	033
Huldra	21.1	1982	Statoil Hydro ASA	Huldra
Jotun	25.0	1994	ExxonMobil Exploration & Production Norway AS	Jotun
Kristin	74.3	1997	Statoil Hydro ASA	Haltenbanken Vest
Kvitebjørn	108.1	1994	Statoil Hydro ASA	193
Mikkel	40.5	1987	Statoil Hydro ASA	Mikkel
Murchison	14.7	1975	CNR International (UK) Limited	Murchison
Njord	37.9	1986	Statoil Hydro Petroleum AS	Njord
Norne	107.2	1992	Statoil Hydro ASA	Norne
Ormen Lange	422.2	1997	A/S Norske Shell	Ormen Lange
Oseberg[2]	486.9	1979	Statoil Hydro Petroleum AS	Oseberg
Oseberg Sør	61.5	1984	Statoil Hydro Petroleum AS	Oseberg Sør
Oseberg Øst	27.8	1981	Statoil Hydro Petroleum AS	053
Rev[1]	6.5	2001	Talisman Energy Norge AS	038 C
Ringhorne Øst	6.5	2003	ExxonMobil Exploration & Production Norway AS	Ringhorne Øst

Field	Reserves mill. scm o.e.	Year of discovery[5)]	Operator at 31.12.2007	Production licence/ unit area
Sigyn	14.9	1982	ExxonMobil Exploration & Production Norway AS	072
Skarv[1)]	68.3	1998	BP Norge As	Skarv
Skirne	10.9	1990	Total E&P Norge AS	102
Sleipner Vest	165.6	1974	Statoil Hydro ASA	Sleipner Vest
Sleipner Øst	121.0	1981	Statoil Hydro ASA	Sleipner Øst
Snorre	249.9	1979	Statoil Hydro ASA	Snorre
Snøhvit	190.7	1984	Statoil Hydro ASA	Snøhvit
Statfjord	690.5	1974	Statoil Hydro ASA	Statfjord
Statfjord Nord	45.2	1977	Statoil Hydro ASA	037
Statfjord Øst	45.1	1976	Statoil Hydro ASA	Statfjord Øst
Sygna	10.6	1996	Statoil Hydro ASA	Sygna
Tambar	13.9	1983	BP Norge As	065
Tor	36.8	1970	ConocoPhillips Skandinavia AS	Tor
Tordis	72.3	1987	Statoil Hydro ASA	089
Troll[3)]	1621.8	1979	Statoil Hydro Petroleum AS	Troll
Troll[4)]		1983	Statoil Hydro ASA	Troll
Tune	22.6	1996	Statoil Hydro Petroleum AS	190
Tyrihans[1)]	68.4	1983	Statoil Hydro ASA	Tyrihans
Ula	90.3	1976	BP Norge As	019
Urd	9.9	2000	Statoil Hydro ASA	128
Vale	3.8	1991	Statoil Hydro Petroleum AS	036
Valhall	184.0	1975	BP Norge As	Valhall
Varg	13.6	1984	Talisman Energy Norge AS	038
Vega[1)]	12.1	1981	Statoil Hydro Petroleum AS	248
Vega Sør[1)]	10.6	1987	Statoil Hydro Petroleum AS	090 C
Veslefrikk	62.7	1981	Statoil Hydro ASA	052
Vigdis	61.6	1986	Statoil Hydro ASA	089
Vilje[1)]	8.7	2003	Statoil Hydro Petroleum AS	36
Visund	90.6	1986	Statoil Hydro ASA	Visund
Volund	8.0	1994	Marathon Petroleum Norge AS	150
Volve[1)]	14.2	1993	Statoil Hydro ASA	046 BS
Yme	18.8	1987	Talisman Energy Norge AS	316
Åsgard	365.0	1981	Statoil Hydro ASA	Åsgard

1) Fields with approved development plans where production had not commenced at 31.12.2007
2) Resources in Oseberg also include Oseberg Vest
3) The resources include the total resources for Troll.
4) The resources are included in the row above
5) The year the discovery well was drilled

(Source: Norwegian Petroleum Directorate)

Table 2.3 Original recoverable reserves and remaining reserves in fields

	Original reserves[1]					Remaining reserves[4]				
	Oil mill. scm	Gas bill. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv.[2] mill scm o.e.	Oil mill. scm	Gas bill.scm	NGL mill. tonnes	Condensate mill.scm	Oil equiv.[2] mill.scm o.e.
Alve[3]	0	5.85	1.08	1.3	9.2	0.0	5.9	1.1	1.3	9.2
Alvheim[3]	24.5	5.7	0.0	0.0	30.2	24.5	5.7	0.0	0.0	30.2
Balder[a]	58.7	1.9	0.0	0.0	60.6	17.4	1.0	0.0	0.0	18.4
Blane	0.8	0.0	0.0	0.0	0.9	0.8	0.0	0.0	0.0	0.8
Brage	51.6	3.7	1.2	0.0	57.6	3.1	1.2	0.2	0.0	4.8
Draugen	140.0	1.5	2.5	0.0	146.3	22.2	0.3	0.6	0.0	23.6
Ekofisk	540.6	160.2	14.8	0.0	728.9	150.0	26.6	2.7	0.0	181.8
Eldfisk	136.7	44.3	4.2	0.0	188.9	50.4	7.2	0.6	0.0	58.7
Embla	12.0	5.2	1.4	0.0	19.8	2.6	2.0	1.0	0.0	6.4
Enoch	0.3	0.1	0.0	0.0	0.4	0.2	0.1	0.0	0.0	0.3
Fram	22.1	8.8	0.1	0.0	31.1	12.3	8.7	0.1	0.0	21.2
Gimle	4.1	0.9	0.1	0.0	5.2	2.9	0.9	0.1	0.0	4.0
Gjøa[3]	11.1	32.6	5.6	0.0	54.5	11.1	32.6	5.6	0.0	54.5
Glitne	8.1	0.0	0.0	0.0	8.1	0.7	0.0	0.0	0.0	0.7
Grane	112.4	0.0	0.0	0.0	112.4	69.6	0.0	0.0	0.0	69.6
Gullfaks[b]	358.4	24.3	2.7	0.0	387.8	23.6	1.8	0.1	0.0	25.7
Gullfaks Sør[c]	48.1	42.5	5.1	0.0	100.2	17.6	22.3	2.7	0.0	44.9
Gungne[5]	0.0	14.1	1.4	4.0	20.8	0.0	14.1	0.0	0.0	14.1
Gyda[d]	39.2	6.0	1.9	0.0	48.8	5.1	0.2	0.1	0.0	5.5
Heidrun[e]	186.0	41.6	2.0	0.0	231.5	64.1	30.7	1.5	0.0	97.7
Heimdal	7.2	42.8	0.0	0.0	50.0	0.8	0.4	0.0	0.0	1.1
Hod	9.3	1.7	0.4	0.0	11.7	0.5	0.1	0.1	0.0	0.9
Huldra	4.9	15.9	0.1	0.0	21.1	0.6	3.2	0.0	0.0	3.8
Jotun	24.0	0.9	0.0	0.0	25.0	2.7	0.1	0.0	0.0	2.8
Kristin	30.2	29.5	6.6	2.1	74.3	24.9	23.0	5.2	0.0	57.7
Kvitebjørn	27.4	74.9	3.1	0.0	108.1	21.6	63.3	2.0	0.0	88.7
Mikkel	4.4	22.9	5.8	2.3	40.493	3.5	15.6	3.8	0.0	26.3
Murchison	14.2	0.4	0.0	0.0	14.7	0.7	0.1	0.0	0.0	0.8
Njord	24.0	10.7	1.7	0.0	37.9	2.0	10.6	1.7	0.0	15.8
Norne	93.0	11.6	1.4	0.0	107.2	16.0	6.2	0.7	0.0	23.6
Ormen Lange	0.0	393.7	0.0	28.5	422.2	0.0	392.1	0.0	28.4	420.4
Oseberg[f]	361.1	109.2	8.7	0.0	486.9	21.2	91.0	3.7	0.0	119.2
Oseberg Sør	49.9	11.6	0.0	0.0	61.5	18.6	6.8	0.0	0.0	25.4
Oseberg Øst	27.4	0.4	0.0	0.0	27.8	10.8	0.2	0.0	0.0	10.9
Rev[3]	0.0	4.7	0.5	0.8	6.5	0.0	4.7	0.5	0.8	6.5
Ringhorne Øst	6.4	0.1	0.0	0.0	6.5	3.9	0.1	0.0	0.0	3.9
Sigyn	0.0	6.0	2.4	4.5	14.9	0.0	2.0	0.8	0.0	3.6
Skarv[3]	14.5	41.5	5.4	1.9	68.3	14.5	41.5	5.4	1.9	68.3

	Original reserves[1]					Remaining reserves[4]				
	Oil mill. scm	Gas bill. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv.[2] mill scm o.e.	Oil mill. scm	Gas bill.scm	NGL mill. tonnes	Condensate mill.scm	Oil equiv.[2] mill.scm o.e.
Skirne	2.0	8.9	0.0	0.0	10.9	1.0	4.7	0.0	0.0	5.7
Sleipner Vest	0.0	120.6	8.3	29.2	165.6					0.0
Sleipner Øst[g]	0.0	68.3	13.1	27.9	121.0					0.0
Sleipner Vest and Sleipner Øst[5]					0.0	0.0	39.7	3.3	0.8	46.8
Snorre	234.2	6.5	4.8	0.0	249.9	79.2	0.9	0.4	0.0	80.9
Snøhvit	0.0	160.6	6.3	18.1	190.7	0.0	160.4	6.3	18.0	190.5
Statfjord	564.6	78.8	24.8	0.0	690.5	9.1	23.2	10.0	0.0	51.4
Statfjord Nord	40.9	2.6	0.9	0.0	45.2	6.2	0.4	0.2	0.0	6.9
Statfjord Øst	37.9	4.2	1.6	0.0	45.1	4.8	0.7	0.3	0.0	6.1
Sygna	10.6	0.0	0.0	0.0	10.6	1.4	0.0	0.0	0.0	1.4
Tambar	10.3	3.1	0.3	0.0	13.9	2.8	3.1	0.1	0.0	6.1
Tor	23.6	11.0	1.2	0.0	36.8	1.0	0.2	0.0	0.0	1.2
Tordis[h]	63.5	5.4	1.8	0.0	72.3	12.4	1.6	0.4	0.0	14.9
Troll[4] [i]	240.8	1330.7	25.7	1.6	1621.8	50.3	1024.7	22.8	-2.7	1115.7
Tune[6]	3.5	18.8	0.1	0.0	22.6	0.5	4.9	0.0	0.0	5.4
Tyrihans[3]	29.0	29.3	5.3	0.0	68.4	29.0	29.3	5.3	0.0	68.4
Ula	80.5	3.9	3.1	0.0	90.3	11.9	0.0	0.6	0.0	13.0
Urd	9.5	0.3	0.0	0.0	9.9	6.4	0.2	0.0	0.0	6.6
Vale	1.7	2.2	0.0	0.0	3.8	0.9	1.6	0.0	0.0	2.5
Valhall	147.0	26.7	5.4	0.0	184.0	50.9	7.7	2.4	0.0	63.1
Varg	13.6	0.0	0.0	0.0	13.6	3.1	0.0	0.0	0.0	3.1
Vega	0.0	9.4	0.5	1.7	12.1	0.0	9.4	0.5	1.7	12.1
Vega Sør	0.0	7.4	0.4	2.4	10.6	0.0	7.4	0.4	2.4	10.6
Veslefrikk	56.5	3.8	1.3	0.0	62.7	7.8	1.6	0.1	0.0	9.5
Vigdis	57.4	1.5	1.4	0.0	61.6	17.4	0.7	0.8	0.0	19.6
Vilje[3]	8.3	0.4	0.0	0.0	8.7	8.3	0.4	0.0	0.0	8.7
Visund	27.6	50.6	6.5	0.0	90.6	11.3	47.7	6.4	0.0	71.0
Volund[3]	7.4	0.6	0.0	0.0	8.0	7.4	0.6	0.0	0.0	8.0
Volve[3]	12.5	1.2	0.2	0.1	14.2	12.5	1.2	0.2	0.1	14.2
Yme[3]	18.8				18.8	10.9	0.0	0.0	0.0	10.9
Åsgard	102.9	181.9	33.8	16.0	365.0	45.8	118.2	22.7	-1.1	206.0
Sum	**4257.2**	**3316.4**	**227.0**	**142.4**	**8147.2**	**1012.5**	**2312.5**	**123.9**	**51.7**	**3612.0**

1) The table shows expected value. The estimates are subject to uncertainty
2) The conversion factor for NGL tonnes to scm is 1.9
3) Fields with approved development plans where production had not commenced at 31.12.2007
4) A negative remaining reserve figure is a result of the product not being reported under original saleable volumes. This applies to produced NGL and condensate
5) Gas production for Gungne, Sleipner Vest and Sleipner Øst are metered in total

a) Balder also includes Ringhorne
b) Gullfaks also includes Gullfaks Vest
c) Gullfaks Sør includes Gulltopp,Gullveig, Rimfaks and Skinfaks
d) Gyda also includes Gyda Sør
e) Heidrun also includes Tjeldbergodden
f) Oseberg also includes Oseberg Vest
g) Sleipner Øst also includes Loke
h) Tordis also includes Tordis Øst and Borg
i) Troll also includes TOGI

(Source: Norwegian Petroleum Directorate)

Table 2.4 Resources in discoveries in the planning phase

Discovery	Oil mill. scm	Gas mill. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv.[1] mill.scm o.e.	Year of discovery[2]
1/9-1 Tommeliten Alpha	10.3	16.9	0.3	0.0	27.8	1977
15/3-1 S Gudrun	13.6	8.9	5.3	0.0	32.6	1975
15/5-1 Dagny	0.0	5.2	0.7	1.7	8.1	1978
2/12-1 Freja	2.9	0.6	0.0	0.0	3.5	1987
25/11-16	5.5	0.1	0.0	0.0	5.7	1992
25/5-5	3.5	0.1	0.0	0.0	3.6	1995
30/7-6 Hild[3]	0.0	14.7	0.0	1.9	16.6	1978
31/2-N-11 H	0.4	0.0	0.0	0.0	0.4	2005
33/9-6 Delta	0.1	0.0	0.0	0.00	0.1	1976
34/10-23 Valemon[4]	0.0	40.0	0.0	7.08	47.1	1985
35/11-13	6.5	2.1	0.0	0.00	8.6	2005
35/2-1	0.0	17.7	0.0	0.00	17.7	2005
6406/3-2 Trestakk	8.9	2.0	0.8	0.0	12.5	1986
6506/11-7 Morvin	7.7	3.2	0.7	0.0	12.2	2001
6507/11-8	0.0	1.5	0.2	0.1	1.9	2007
7122/7-1 Goliat	27.5	3.1	0.2	0.0	30.9	2000
Total	**87.0**	**116.0**	**8.2**	**10.7**	**229.3**	

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

(Source: Norwegian Petroleum Directorate)

Table 2.5 Resources in discoveries where recovery is likely but not clarified

Discovery	Oil mill. scm	Gas mill. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv.[1] mill.scm o.e.	Year of discovery[2]
1/3-6	4.9	3.6	0.0	0.0	8.5	1991
1/5-2 Flyndre	0.2	0.0	0.0	0.0	0.2	1974
15/3-1 S Gudrun	0.0	3.7	2.4	0.0	8.3	1975
15/3-4	2.9	1.3	0.7	0.0	5.5	1982
15/5-2	0.0	4.9	0.0	0.4	5.3	1978
15/8-1 Alpha	0.0	2.2	0.0	1.8	4.0	1982
16/7-2	0.0	1.6	0.0	0.7	2.3	1982
17/12-1 Bream	9.5	0.0	0.0	0.0	9.5	1972
2/5-3 Sørøst Tor	3.1	0.9	0.0	0.0	3.9	1972
24/6-1 Peik	0.0	1.7	0.0	0.5	2.2	1985
25/8-4	1.0	0.0	0.0	0.0	1.0	1992
3/7-4 Trym	0.0	3.4	0.0	0.7	4.2	1990
34/11-2 S Nøkken	0.0	2.7	0.0	1.2	3.9	1996
35/8-3	0.0	2.7	0.0	0.6	3.2	1988
6406/1-1 Erlend N.	0.0	1.1	0.0	0.3	1.4	2001
6406/2-1 Lavrans	0.0	11.7	0.0	3.3	15.0	1995
6406/2-6 Ragnfrid	0.0	2.1	0.0	1.7	3.8	1998
6406/2-7 Erlend	0.0	1.7	0.4	0.9	3.4	1999
6406/9-1	0.0	40.8	0.0	1.4	42.2	2005
6407/9-9	0.2	1.2	0.0	0.2	1.5	1999
6506/11-2 Lange	0.4	0.2	0.0	0.0	0.6	1991
6506/12-3 Lysing	1.5	0.3	0.0	0.0	1.8	1985
6506/6-1	0.0	89.3	2.8	5.0	99.6	2000
6507/11-6 Sigrid	0.0	1.9	0.3	0.4	2.9	2001
6507/2-2	0.0	6.0	1.0	0.4	8.3	1992
6507/7-13	0.9	0.0	0.0	0.0	1.0	2001
6605/8-1	0.0	26.0	0.0	2.6	28.6	2005
6608/10-11 S	0.0	0.2	0.0	0.0	0.2	2006
6706/6-1	0.0	13.1	0.0	1.3	14.4	2003
6707/10-1	0.0	35.5	0.0	1.3	36.8	1997
7/7-2	3.4	0.1	0.0	0.0	3.5	1992
7/8-3	2.4	0.1	0.0	0.2	2.7	1983
7122/6-1	5.5	14.4	0.0	1.8	21.7	1987
Sum	**35.9**	**274.3**	**7.6**	**26.7**	**351.4**	

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

2) The year the discovery well was drilled

(Source: Norwegian Petroleum Directorate)

Table 2.6 Resources in discoveries that have not been evaluated

Discovery	Oil mill. scm	Gas mill. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv.[1] mill.scm o.e.	Year of discovery[2]
15/12-18 S	4	0	0	0	4	2007
15/6-9 S	3.39	3.9	0.0	1.8	9.0	2007
16/1-8	12	0.0	0.0	0.0	12.0	2007
16/2-3	5	0.0	0.0	0.0	5.0	2007
16/4-4	0	0.5	0.0	1.4	1.9	2007
25/11-24	10.9	0.0	0.0	0.0	10.9	2007
6405/10-1	0	4.0	0.0	1.5	5.5	2007
7125/4-1	10.9	5.9	0.0	0.0	16.8	2007
Total	**46.19**	**14.2**	**0.0**	**4.6**	**65.1**	

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

(Source: Norwegian Petroleum Directorate)

Appendix 3 Operators and licensees

The table below lists the operators and licensees in production licences and fields on the Norwegian continental shelf. There are 393 active production licences and 396 operatorships. Both StatoilHydro ASA and StatoilHydro Petroleum AS are operators in production licences 085 and 085 B while Maersk Oil Norway AS and StatoilHydro Petroleum AS are operators in production licence 296. In addition. Gassco AS is the operator for large parts of the gas pipeline network. For more facts about the petroleum activities. please visit the Norwegian Petroleum Directorate's web site: www.npd.no. Various reports relating to production licences and licensees can be downloaded from www.npd.no/reports.

Table 3.1 Operators and licensees per March 2008

	Operatorship	Production licence	Field
A/S Norske Shell	9	23	8
Aker Exploration AS	1	12	
BG Norge AS	15	23	
BP Norge AS	10	13	6
Centrica Resources Norge AS	8	13	
Chevron Norge AS	1	7	1
ConocoPhillips Skandinavia AS	12	37	23
DONG E & P Norge AS	6	33	8
Dana Petroleum Norway AS	1	9	1
Det norske oljeselskap ASA	11	28	3
Discover Petroleum AS	1	7	
E.ON Ruhrgas Norge AS	5	21	2
Endeavour Energy Norge AS	4	18	2
Eni Norge AS	15	51	16
ExxonMobil Exploration and Production Norway A/S	9	24	17
Gaz de France Norge AS	2	30	5
Hess Norge AS	1	15	4
Idemitsu Petroleum Norge AS	1	14	7
Lundin Norway AS	18	32	3
Maersk Oil Norway AS	1	7	
Maersk Oil PL 018C Norway AS	1	1	
Marathon Petroleum Norge AS	8	16	6
Nexen Exploration Norge AS	8	9	
Noil Energy ASA	15	32	4
Norwegian Energy Company ASA	5	31	
OMV Norge AS	4	5	

	Operatorship	Production licence	Field
Petro-Canada Norge AS	5	17	
Premier Oil Norge AS	1	10	1
RWE Dea Norge AS	4	44	8
Revus Energy ASA	11	38	4
Rocksource ASA	1	5	
StatoilHydro ASA	105	180	54
StatoilHydro Petroleum AS	64	124	53
Talisman Energy Norge AS	17	39	9
Total E&P Norge AS	13	74	39
Wintershall Norge AS	3	12	

Other licensees	Production licence	Field
Altinex Oil Norway AS	10	2
Bayerngas Norge AS	6	1
Brigde Energy AS	7	
Concedo ASA	3	
Discover Petroleum AS	3	
Edison International Spa	5	
Enterprise Oil Norge AS	6	7
Faroe Petroleum Norge AS	12	
Genesis Petroleum Norway AS	5	
Mobil Development Norway AS	26	9
Noble Energy Norge AS	3	
Norske AEDC A/S	1	1
PA Resources Norway AS	13	1
PGNiG Norway AS	3	1
Petoro AS	125	45
Sagex Petroleum Norge AS	3	
Serica Energy (UK) Ltd	2	
Skagen 44 AS	2	
Skeie Energy AS	1	
Svenska Petroleum Exploration AS	5	3
VNG Norge As	4	

(Source: Norwegian Petroleum Directorate)

Appendix 4 List of addresses

GOVERNMENT BODIES

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

The Norwegian Petroleum Directorate
P.O. Box 600, 4003 Stavanger
Tel. +47 51 87 60 00. Fax +47 51 55 15 71
www.npd.no

The Harstad office
P.O. Box 787, 9488 Harstad
Tel. +47 77 01 83 50. Fax +47 77 06 38 95

The Ministry of Labour and Social Inclusion
P.O. Box 8019 Dep, 0030 Oslo
Tel. +47 22 24 90 90. Fax +47 22 24 95 76
www. regjeringen.no/aid

The Petroleum Safety Authority Norway
P.O. Box 599, 4003 Stavanger
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Appendix 5 Conversion factors

Oil. condensate and gas volumes are stated in standard cubic metres (scm) and NGL volumes in tonnes.
A measure of total resources can be obtained by adding up the energy content in the various types of petroleum. The total is calculated in standard cubic metre oil equivalents (scm o.e.).

1 scm oil	=	1.0 scm o.e.
1 scm condensate	=	1.0 scm o.e.
1000 scm gas	=	1.0 scm o.e.
1 tonne NGL	=	1.9 scm o.e.

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

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

Approximate energy content

		MJ
1	scm natural gas	40
1	scm crude oil	35 500
1	tonne coal equivalent	29 300

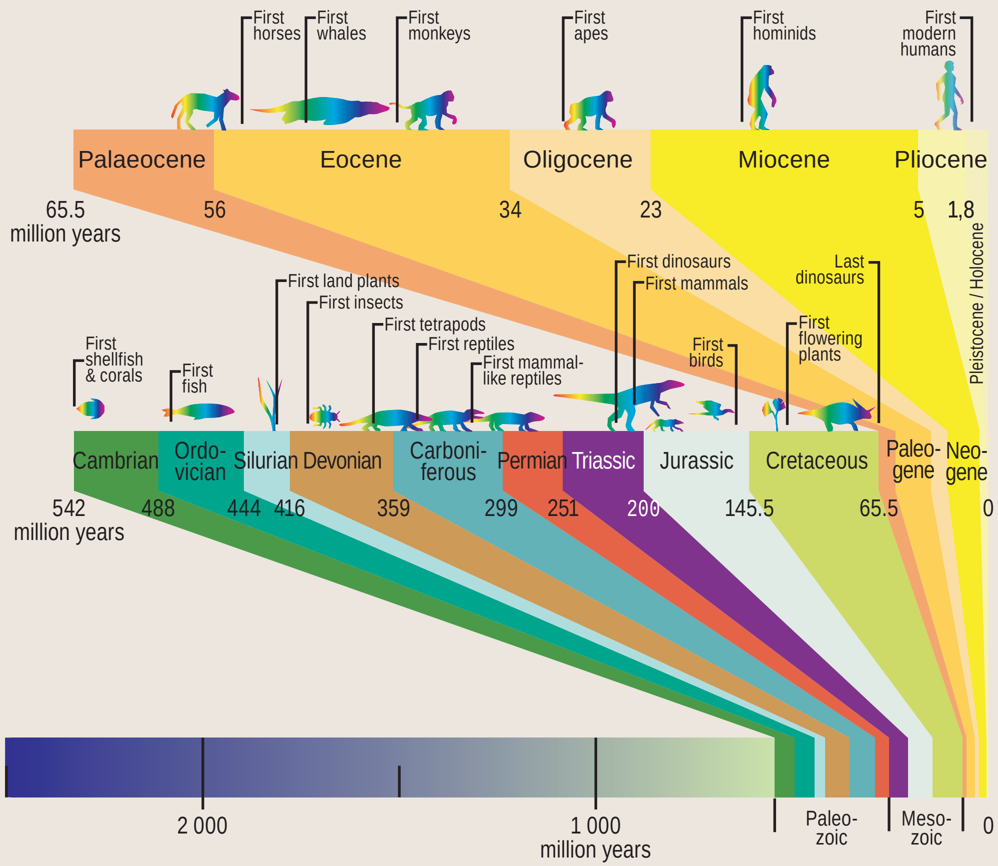
Conversion factors for volume

1	scm crude oil	=	6.29 barrels
1	scm crude oil	=	0.84 tonnes crude oil (average for oil from the Norwegian continental shelf)
1	scm gas	=	35.314 cubic feet

Conversion factors between various units of energy

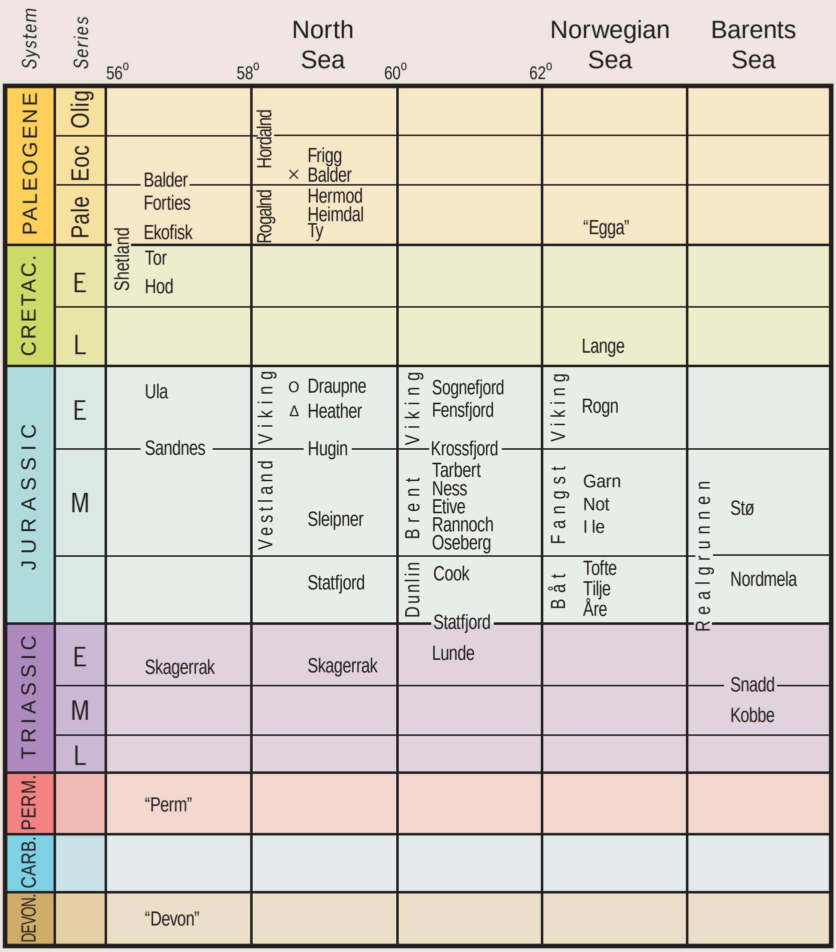
			MJ	kWh	BTU
1	MJ	Megajoule	1	0.2778	947.80
1	kWh	kilowatt hour	3.6	1	3412.10
1	BTU	British thermal unit	0.001055	0.000293	1

Appendix 6 The Geological Timescale



Appendix 7 Reservoir and Lithostratigraphy

Reservoir type
Age and lithostratigraphy



× Balder - intra Balder sandstone
o Draupne - intra Draupne sandstone
Δ Heather - intra Heather sandstone
"Egga" - informal unit