FACTS 2012

THE NORWEGIAN PETROLEUM SECTOR

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Cover: Exploration activity in the Barents Sea January 2012
(Photo: Harald Pettersen, Statoil)

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Coccoliths which build up to form chalk. Layers of this rock are found in the the Ekofisk area's Tor formation in the North Sea. (Illustration: Robert W. Williams, NPD)

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PREFACE

Ola Borten Moe

The Minister of Petroleum and Energy

The Minister of Petroleum and Energy

2011 was a very good year for the oil and gas activities in Norway, with many new discoveries. I had been a member of the cabinet for barely a month when we received news of the discovery in the wildcat well on Skrugard northwest of Hammerfest. We also received confirmation of the Havis prospect in the same licence in early 2012. Together, these discoveries amount to 400-600 million barrels of oil equivalents. Johan Sverdrup could become one of our largest oil discoveries; made in an area that we thought we already knew quite well. This shows that exploration in these areas is important in order to find and exploit the full value of our natural resource assets.

There is a lot of activity on the shelf. Last year, we processed ten development plans, ranging from minor, time-critical projects to revitalisation of the Ekofisk field to the tune of NOK 65 billion. Overall investments in the projects will exceed NOK 100 billion. Norway also grew in size in 2011. The demarcation agreement with Russia gave us 87,000 square kilometres of new shelf.

However, despite an abundance of good news and many important discoveries, the fact is that Norwegian oil production is declining. Oil production has decreased by 1.3 million barrels per day since the peak. Without more positive investment decisions, oil production could be cut in half as we approach the end of the decade. My goal and our shared task is to curb this decline as much as we possibly can. The fantastic year of discoveries now behind us does not change this goal. It is no more than a good initial contribution to solving this task.

It is crucial that the licensees in the various fields extract all profitable resources in order to limit the production decline. The importance of what takes place on existing fields cannot be exaggerated. It is important to exploit the infrastructure and avoid a situation where too many resources are left in the ground because we cannot produce them in time. New discoveries and new acreage cannot replace a lack of results on existing fields. On the other hand, we need new discoveries and new acreage to maintain activity over time. In other words, we must have a parallel commitment across the entire chain.

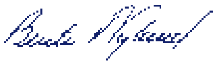
Our petroleum activity is moving further north. It has taken time to develop the Barents Sea into our third petroleum province. Thirty-two years have passed since the area was opened, and 30 years since the first gas was proven – in Snøhvit. Geological mapping and impact assessments are well underway in the southeastern Barents Sea, our new ocean territory bordering Russia. The same is true of the waters around the island of Jan Mayen. I am working towards presenting the question of opening these two areas to the Storting (Norwegian Parliament) in 2013. The fact that we now see the possibility of significant, long-term petroleum activity in the Barents Sea can mean great opportunities for Finnmark County and Northern Norway. Development of new discoveries will create the greatest possible values for society, and can contribute to regional ripple effects. The petroleum activity is moving north, and the dialogue and interaction between authorities, industry and regional businesses is important in order to find the good solutions. In this way we will ensure maximum value creation and optimal resource management in the best interests of Norway as a nation.

In the Petroleum White Paper, we confirmed that our strategy for developing the petroleum sector entails a proactive, parallel commitment to:

- increasing recovery from producing fields,
- developing commercial/profitable discoveries,
- exploring in open acreage and
- opening new areas

I believe that the Government and the Storting, through the Petroleum White Paper and the surrounding process, have laid a very good foundation for such development. It confirmed broad political agreement as regards the basic principles of petroleum policy I laid out in the White Paper. The primary goal of our petroleum policy – facilitating profitable production of oil and gas in a long-term perspective – remains firm. This is extremely important for an industry with such a long-term perspective – like the Norwegian petroleum activities.

PREFACE
Bente Nyland
Director General



Director Generral

Storting White Paper No. 28 (2010-2011) *An industry for the future – Norway's petroleum activities* highlights efforts within four specific areas. Firstly: We must increase recovery from producing fields. Today, less than half of the resources in the fields are produced. A stronger commitment and smarter measures can yield significant added value for the companies and the Norwegian society.

A review shows that the big, old fields in the North Sea stand out: Ekofisk, Statfjord, Snorre, Heidrun, Gullfaks and Oseberg are the fields that have the most remaining oil. Extracting just one or two per cent more from these large fields will be more valuable than extracting more from smaller fields – although everything helps. Implementing measures on many of the large fields is becoming urgent; otherwise we risk losing this opportunity.

Secondly: We must develop commercial discoveries. Many discoveries have been made in recent years. In fact, discoveries have been made in almost every second well. A common feature, though, is that they are small. In many cases, development can be warranted because the discoveries can be tied-in to existing infrastructure. Access to infrastructure will not last forever; therefore it is important that we approve development of these discoveries.

Ten plans for development and operation (PDOs) were approved in 2011. This, along with an increasing number of discoveries that appear to be on track for development, leads us to expect a high rate of development activity in the next few years.

Thirdly: We have to explore more in the areas that have been opened for petroleum activity. We have to explore to make discoveries. A lot of exploration activity is taking place on the Norwegian shelf, and it has yielded results. In 2011, 54 exploration wells were completed and 22 new oil and gas discoveries were made. Sixteen of the discoveries were made in the North Sea, three in Norwegian Sea and three in the Barents Sea. In addition to the major Johan Sverdrup discovery in the North Sea, proven in the fall of 2010 (well 16/2-6) and confirmed in 2011 (well 16/2-8), the exploration success in the Barents Sea is also worthy of mention. Two important discoveries were made there last year, and one discovery was confirmed early this year. Read more about the Norwegian Petroleum Directorate's annual summary, the Shelf in 2011, at *www.npd.no*.

We are approaching 100 exploration wells drilled in the Barents Sea. Perhaps we are finally nearing a breakthrough here, and we can look forward to more good news from the Barents Sea in the next few years. The NPD has always believed in the Barents Sea, even when many dismissed the possibility of large, new discoveries and abandoned the area in the late 1990s.

We are working on the 22nd regular licensing round on the Norwegian shelf, 47 years after the first licensing round was announced. We note that the companies are still very interested, also in the north.

The fourth point made in the Petroleum White Paper is that we must open new areas for petroleum activity. The last time new acreage was opened was in 1994. The Storting has tasked the NPD with mapping the geology in the new area to improve knowledge about where new discoveries would be most likely, as well as to complete data coverage in the unopened area.

Such survey activities are taking place in the southeastern Barents Sea, in the new area that borders Russia. After years of waiting, the new demarcation line was finally clarified in 2011. The NPD immediately began acquiring seismic data, and these surveys will be concluded during the course of this year.

In addition to the southeastern Barents Sea, the NPD is also mapping the geology in the Norwegian waters near Jan Mayen. The Storting has also asked us to map the unopened parts of the continental shelf off Nordland county (Nordland IV and V).

The Norwegian Petroleum Directorate will continue – in its 40th year – to function as a national shelf library, spreading facts and knowledge. We shall provide relevant data and analyses, and communicate potential and consequences. This publication – *Facts 2012* – is one such contribution.

CONTENT

1 NORWEGIAN PETROLEUM HISTORY

Pouring concrete for the foundations of the large concrete platforms from the 1980s was hard, physical work. (Photo: Leif Berge, Statoil)

At the end of the 1950s, very few people believed that the Norwegian continental shelf concealed a wealth of oil and gas. But the gas discovery in Groningen in the Netherlands in 1959 led to newfound optimism surrounding the North Sea's petroleum potential.

In October 1962, Philips Petroleum sent a letter to the Norwegian authorities requesting permission to conduct exploration in the North Sea. The company wanted a licence for the parts of the North Sea on the Norwegian continental shelf. The offer was USD 160 000 per month and was regarded as an attempt to acquire exclusive rights. For the authorities, it was out of the question to surrender the entire shelf to one company. If the areas were to be opened for exploration, more companies were needed.

In May 1963, the government proclaimed sovereignty over the Norwegian continental shelf. A new act stipulated that the State was the landowner and that only the King (Government) could grant licences for exploration and production. But even though Norway had proclaimed sovereignty over vast ocean areas, a few important clarifications were still needed regarding delineation of the continental shelf, primarily in relation to Denmark and the UK. Agreements regarding delineation of the continental shelf on the basis of the median line principle were signed in March 1965 and the first licensing round was announced on 13 April 1965. 22 production licences were awarded, covering 78 blocks. The first exploration well was drilled during the summer of 1966, but turned out to be dry.

With the discovery of Ekofisk in 1969, the Norwegian oil adventure started in earnest. Production from the field started on 15 June 1971 and during the following years, several large discoveries were made. In the 1970s, the exploration activity was concentrated in the North Sea, but the shelf was also gradually opened northwards. Only a limited number of blocks were announced for each licensing round and the most promising areas were explored first. This led to world-class discoveries and the production from the Norwegian continental shelf has been dominated by these large fields that were given names such as Ekofisk, Statfjord, Oseberg, Gullfaks and Troll. These fields have been and still are very important for the development of the petroleum activities in Norway. The development of the large fields has led to the establishment of infrastructure, enabling tie-in of a number of other fields. The production from several of the major fields is declining now, as new, smaller fields have established themselves. Therefore, Norwegian petroleum production is currently divided among more fields than before.

In the beginning, the authorities chose to start with a model where foreign companies operated the petroleum activities. This meant that foreign companies initially dominated the exploration activities and developed the first oil and gas fields. Eventually, the Norwegian involvement increased with Norsk Hydro joining in, and in 1972, Statoil was established with the State as sole owner. A policy was also established mandating 50 per cent State participation in each production licence. In 1993, this principle was changed so that an assessment is made in each individual case as to whether there will be State participation and whether the ownership interest will be higher or lower. Another private Norwegian company, Saga Petroleum, also established itself. In 1999, Saga was acquired by Norsk Hydro while Statoil was partly privatized in 2001 which led to the establishment of Petoro. Petoro then took over the handling of the State's direct financial interest (SDFI) established in 1985, from Statoil. In 2007, Statoil merged with Norsk Hydro's oil and gas activities. Today, about 50 Norwegian and foreign companies are active on the shelf. The current oil production and its importance for the Norwegian economy are discussed in Chapter 3 – The petroleum sector – Norway's largest industry.

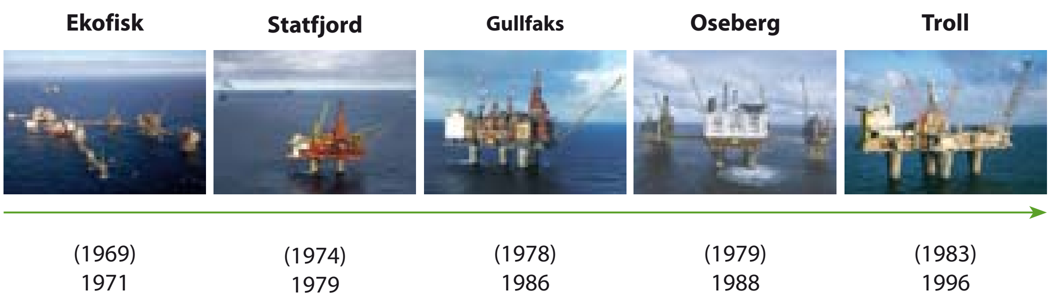


Figure 1.1 Historical timebase. Year of discovery in brackets.

Fact box 1.1 What is petroleum?

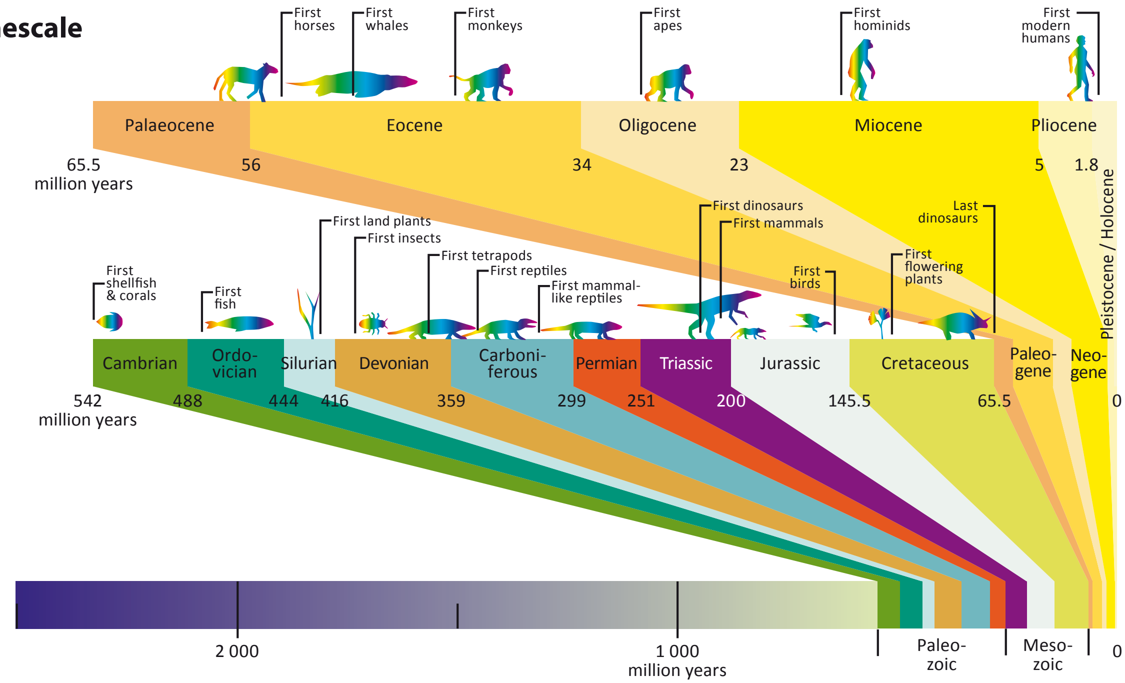
Oil and gas are formed over several million years through decomposition and conversion of organic matter deposited in ocean areas. Most of the oil and gas deposits on the Norwegian continental shelf originate from a thick layer of black clay that is currently several thousand metres under the seabed. The black clay is a source rock, which means a deposit that contains significant organic residue. The clay was deposited around 150 million years ago at the bottom of a sea that covered much of present-day northwestern Europe. This sea was unique in that the seabed was dead and stagnating at the same time as the upper water masses were teeming with life. Large amounts of microscopic phytoplankton accumulated in the oxygen-free bottom sediments. Over time, they were buried deeper, and after a long chemical conversion through bacterial decomposition and subsequent thermal effects, liquid hydrocarbons and gas were formed in the source rock.

During oxygen-free decomposition of organic matter, substances such as kerogen are formed, which in turn creates oil and gas at increased temperatures and pressures. On the Norwegian continental shelf, the temperature increases by 25 degrees per kilometre of depth. After more than one hundred million years of erosion and depositing, there can be several kilometres of clay and sand over the source rock. Oil is formed when the kerogen's temperature reaches 60 - 120 degrees; at higher temperatures, mainly gas is formed.

As the oil and gas are formed, they seep out of the source rock and follow the path of least resistance, determined by pressure and the rock's permeability. Because hydrocarbons are lighter than water, they will migrate upward in porous, water-bearing rocks. The oil and gas migration takes place over thousands of years and can extend over tens of kilometres until it is stopped by denser layers. Reservoir rocks are porous and always saturated with various compositions of water, oil and gas. Most of Norway's petroleum resources are trapped in reservoir rocks deposited in large deltas formed by rivers that ran into the sea during the Jurassic Age. The main reservoirs on e.g. the Gullfaks, Oseberg and Statfjord fields are in the large Brent delta from the Jurassic Age. Large reserves are also found in sand deposited on alluvial plains from the Triassic Age (the Snorre field), in shallow seas from the Late Jurassic Age (the Troll field) and as subsea fans from the Paleogene Age (the Balder field). In the southern North Sea, thick layers of chalk, consisting of microscopic calcareous algae, are an important reservoir rock.

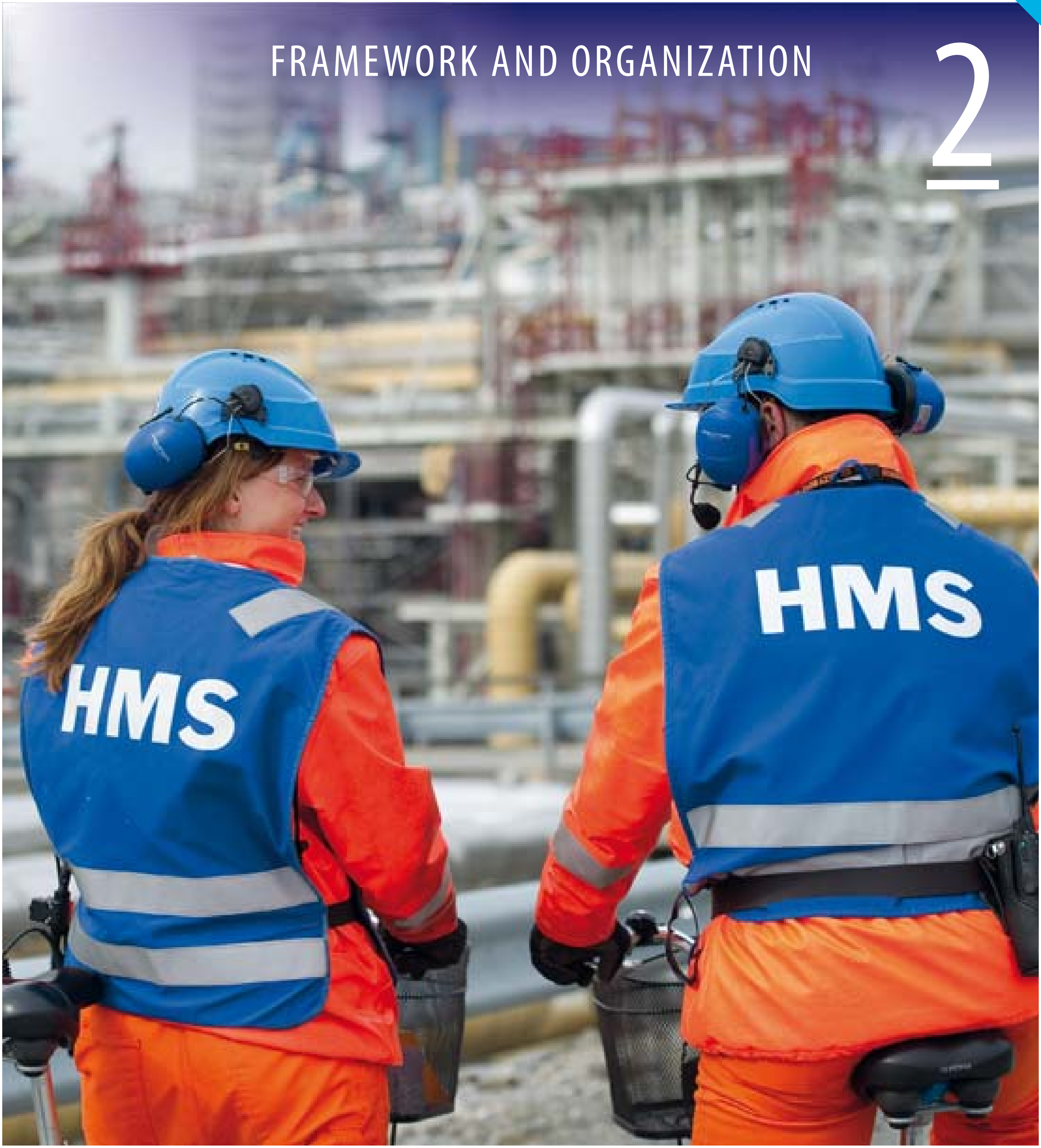
Clay stone and argillaceous sandstone form dense deposits that affect the migration routes from the source rock to the reservoir. They are also essential for keeping petroleum in place in the reservoir over an extended period of time. Dense deposits that form a cap over the reservoir rocks are called cap rocks. In addition, the reservoir rocks must have a shape that collects the oil: a trap. When an area contains source rocks, reservoir rocks, cap rocks and a trap, the preconditions are present for discovering oil and gas deposits.

The Geological Timescale



FRAMEWORK AND ORGANIZATION

2



Workers at the gas treatment facility at Kårstø. (Photo:-Øyvind Hagen, Statoil)

A predictable and transparent framework must be in place in order for the oil companies to make good decisions. The organization of the activities, as well as how roles and responsibilities are defined, must ensure proper attention to all important considerations and make sure that the value created benefits society as a whole. This includes consideration for the external environment, health, working environment and safety[1]. We all benefit from a framework that provides the petroleum industry with incentives to meet the State's objectives, while also fulfilling their own goals of maximising company profit.

The Petroleum Act (Act of 29 November 1996 No. 72 relating to petroleum activities) contains the general legal basis for the licensing system governing Norwegian petroleum activities. According to the Act and appurtenant regulations (Regulations of 27 June 1997 No. 653), licences can be awarded for exploration for, and production and transport of, petroleum. The Petroleum Act confirms that the property right to the petroleum deposits on the Norwegian continental shelf is vested in the State. Official approvals and permits are necessary in all phases of the petroleum activities, from award of exploration and production licences, in connection with acquisition of seismic data and exploration drilling[2], to plans for development and operation[3], and plans for field cessation[4].

Impact assessments and opening of new areas

Before a production licence is awarded for exploration or production, the area where the activity will occur must be opened for petroleum activities. In this respect an impact assessment must be carried out to evaluate factors such as the economic and social effects and the environmental impact the activity could have for other industries and the adjacent districts. The impact assessment and opening of new areas are governed by Chapter 3 of the Petroleum Act and Chapter 2a of the Petroleum Regulations.

Announcement

Production licences are normally awarded through licensing rounds. The government announces a certain number of blocks that are available for award of production licences. The announcement is made in the Official Journal of Norway (Norsk Lysningsblad), the Official Journal of the European Communities, and on the Norwegian Petroleum Directorate's (NPD's) website. The announcement is governed in more detail in Chapter 3 of the Petroleum Act, and Chapter 3 of the Petroleum Regulations.

Award

Applicants can apply individually or as a group. The content of the application and the procedure for applying for production licences is governed by Chapter 3 of the Petroleum Act and Chapter 3 of the Petroleum Regulations. The Norwegian Petroleum Directorate has prepared guidelines for how to formulate the application, available on the NPD's website.

Based on the applications submitted, the Ministry of Petroleum and Energy (MPE) awards production licenses to a group of companies. Relevant, objective, non-discriminatory and announced criteria form the basis for these awards. The Ministry designates an operator for the joint venture, which will be responsible for the operational activities authorised by the licence. The licensee group also functions as an internal control system in the production licence, where each licensee's role is to monitor the work done by the operator.

Awards are governed by Chapter 3 of the Petroleum Act and Chapter 3 of the Petroleum Regulations.

The production licence

The production licence regulates the rights and obligations of the licencee vis-à-vis the Norwegian State. The document supplements the requirements in the Petroleum Act and provides detailed conditions. It grants companies exclusive rights to surveys, exploration drilling and production of petroleum within the geographical area covered by the licence. The licensees become the owners of the petroleum that is produced. A standard production licence with appendices is available on the MPE's website. More detailed provisions concerning the production licence can be found in Chapter 3 of the Petroleum Act and Chapter 3 of the Petroleum Regulations.

Exploration

The production licence applies for an initial period (exploration period) that can last for up to ten years. During this period, a set work commitment must be carried out in the form of e.g. geological/geophysical preliminary work and/or exploration drilling. If all the licensees agree, the production licence can be relinquished when the work commitment has been fulfilled. If the licensees want to continue the work in the production licence, the license will enter the extension period, which is the period for development and operation. The exploration period is governed in more detail in Chapter 3 of the Petroleum Act and Chapter 3 of the Petroleum Regulations.

Development and operation

Based on the framework for the petroleum activities, companies are required to carry out prudent development and operation of proven petroleum deposits. This means that the companies are responsible for working towards and implementing new projects, while the authorities grant the final consent to start the process. When a new deposit is to be developed, the company must submit a Plan for Development and Operation to the Ministry for approval. An important part of the development plan is an impact assessment which is submitted for consultation to various bodies that could be affected by the specific development. The impact assessment shows how the development is expected to affect the environment, fishe-

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

2 Cf. Chapter 5.

3 Chapter 6 discusses development and operations. Gas resource management is discussed in Chapter 7.

4 More on decommissioning after end of production, see Chapter 6.

ries, and society in general. The processing of this assessment and all the development plan itself ensures projects that are prudent in terms of resource management, and that have acceptable consequences for other general public interests. The impact assessment is compulsory unless the licensees document that the development is comprised by an existing relevant impact assessment. The Ministry has drawn up a guide for plans for development and operation and for plans for installation and operation. The main objective of the guide is to clarify the regulations and the authorities' expectations for developers on the Norwegian shelf. This guide is available on the NPD's and MPE's websites.

Development and operation is governed in more detail by Chapter 4 of the Petroleum Act and the Petroleum Regulations.

Cessation of petroleum activities

As a main rule, the Petroleum Act requires licensees to submit a cessation plan to the Ministry two to five years before the licence expires or is relinquished, or use of a facility ceases. The cessation plan must have two main parts; an impact assessment and a disposal section. The impact assessment provides an overview of the expected consequences of the disposal for the environment and other factors. The disposal part must include proposals for how cessation of petroleum activities on a field can be accomplished.

Chapter 5 of the Petroleum Act and Chapter 6 of the Petroleum Regulations govern disposal or cessation of facilities. In addition to the Petroleum Act, the OSPAR convention (Convention for the protection of the marine environment of the North-East Atlantic) governs disposal of our facilities. Under this Convention, only a few facilities can be abandoned on site.

Liability for pollution damage

Liability for pollution damage is governed by Chapter 7 of the Petroleum Act. The licensees are responsible for pollution damage without regard for fault, in other words, a so-called strict liability occurs.

Safety

Safety aspects associated with the petroleum activities are governed by Chapters 9 and 10 with appurtenant regulations. The petroleum activities shall be conducted in a prudent manner to ensure a high level of HSE throughout all phases of the activities.

State organisation of the petroleum activities

Stortinget (Norwegian Parliament)
The Storting sets the framework for the petroleum activities in Norway, in part by adopting legislation. Major development projects and issues of fundamental importance must be deliberated in the Storting. The Storting also controls the Government and public administration.

The Government
The Government exercises executive authority over petroleum policy, and answers to the Storting as regards policies. To carry out its policies, the Government is assisted by the ministries, underlying directorates and supervisory authorities. The responsibility for filling the various roles in Norwegian petroleum policy is distributed as follows:

- Ministry of Petroleum and Energy – responsible for resource management and the sector as a whole
- Ministry of Labour – responsible for safety and working environment
- Ministry of Finance – responsible for petroleum taxation
- Ministry of Fisheries and Coastal Affairs – responsible for oil spill preparedness
- Ministry of Health and Care Services - responsible for health issues
- Ministry of the Environment – responsible for the external environment

More on the organisation of the petroleum activities

MINISTRY OF PETROLEUM AND ENERGY
The Ministry of Petroleum and Energy (MPE) has the overall responsibility for managing the petroleum resources on the Norwegian continental shelf. The Ministry must ensure that the petroleum activities are carried out in accordance with the guidelines set by the Storting and the Government. The Ministry also has an owner's responsibility for the State-owned companies Petoro AS and Gassco AS, and the partly state-owned oil company, Statoil ASA.

The Norwegian Petroleum Directorate
The Norwegian Petroleum Directorate (NPD) sorts under the Ministry of Petroleum and Energy. The NPD plays a key role in petroleum management, and is an important advisory body for the MPE. The NPD exercises administrative authority in connection with exploration for and production of petroleum deposits on the Norwegian continental shelf. This also includes the authority to stipulate regulations and make decisions under the petroleum activities regulations.

Petoro AS
Petoro AS is a State-owned enterprise which handles the State's direct financial interest (SDFI), on behalf of the Norwegian State.

Gassco AS
Gassco AS is a State-owned enterprise responsible for transport of gas from the Norwegian continental shelf. The company is the operator of Gassled. Gassco has no ownership interest in Gassled, but carries out its operatorship in a neutral, efficient manner in relation to both owners and users.

Statoil ASA
Statoil ASA is an international company with activities in 41 countries. The company is listed on the Oslo and New York stock exchanges. As of 31 December 2010, the Norwegian State owns 67 per cent of the company's shares.

More on the State organisation of the petroleum activities

THE MINISTRY OF LABOUR
The Ministry of Labour has overall responsibility for regulating and supervising the working environment and safety and emergency preparedness in connection with the petroleum activities.

The Petroleum Safety Authority Norway
The Petroleum Safety Authority Norway (PSA) has regulatory responsibility for technical and operational safety, including emergency preparedness and working environment in the petroleum activities.

THE MINISTRY OF FINANCE
The Ministry of Finance has the overall responsibility for ensuring that the State collects taxes and fees (corporate tax, special tax, CO_2 tax and NO_x tax) from the petroleum activities.

The Petroleum Tax Office
The Petroleum Tax Office is part of the Norwegian Tax Administration, which reports to the Ministry of Finance. The primary task of the Petroleum Tax Office is to ensure correct levying and payment of taxes and fees adopted by the political authorities.

The Directorate of Customs and Excise
The primary task of the Directorate of Customs and Excise concerning the petroleum activity is to ensure correct levying and payment of NO_x tax adopted by the political authorities.

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

THE MINISTRY OF FISHERIES AND COASTAL AFFAIRS
The Ministry of Fisheries and Coastal Affairs is responsible for ensuring proper preparedness against acute pollution in Norwegian waters.

The Norwegian Coastal Administration
The Norwegian Coastal Administration is responsible for the State's oil spill preparedness.

THE MINISTRY OF THE ENVIRONMENT
The Ministry of the Environment has the overall responsibility for managing environmental protection and the external environment in Norway.

The Climate and Pollution Agency
The responsibilities of the Climate and Pollution Agency include following up the Pollution Control Act. Another key task is to provide advice and technical basis material to the Ministry of the Environment.

The State's revenues from the petroleum activities

Norway has a special system for State revenues from the petroleum activities. The main reason for this system is the extraordinary return associated with producing these resources. The petroleum resources belong to the Norwegian society and the State secures a large portion of the values created. This is mainly done through taxation and direct ownership through SDFI.

The petroleum taxiation system
The petroleum taxation system is based on the rules for ordinary corporate taxation, but specified in the Petroleum Taxation Act (Act of 13 June 1975 No. 35 relating to the taxation of subsea petroleum deposits). Due to the extraordinary profit associated with recovering the petroleum resources, an additional special tax is levied on this type of commercial activity. The ordinary tax rate is the same as on land, 28 per cent. The special tax rate is 50 per cent. When one calculates the basis for ordinary tax and special tax, investments are subject to straight-line depreciation over six years from the year they are incurred. Deductions are allowed for all relevant costs, including costs associated with exploration, research and development, financing, operations and removal (see Figure 3.3). Consolidation between fields is allowed. To shield normal return from special tax, an extra deduction is allowed in the basis for special tax, called uplift. This amounts to 30 per cent of the investments (7.5 per cent per year for four years, from and including the investment year).

Companies that are not in a tax position can carry forward deficits and uplift with interest. These rights follow the participating interest and can be transferred. Companies can also apply for a refund of the tax value of exploration expenses in connection with the tax assessment.

The petroleum taxation system is designed to be neutral, so that an investment project that is profitable for an investor before tax will also be profitable after tax. This makes it possible to safeguard the consideration both for substantial income for society as a whole, as well as the fact that companies want to implement profitable projects.

Norm price

The produced petroleum from the Norwegian continental shelf is largely sold to affiliated companies. To assess whether the prices set between affiliated companies are comparable to what would have been agreed between two independent parties, the Petroleum Taxation Act states that norm prices can be stipulated for use when calculating taxable income for the purpose of the tax assessment. The Petroleum Price Board (PPR) sets the norm price, which aims to reflect what the petroleum could have been sold for between independent parties. The Board receives information from and meets with companies before setting the final norm price. This system applies to certain grades of crude oil and NGL. For gas, the actual sales price is used as the basis.

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

= Corporation tax base (tax rate: 28 %)
– Uplift (7.5 % of investment for 4 years)

= Special tax base (tax rate: 50 %)

Figure 2.1 Calculating petroleum tax
(Source: Ministry of Petroleum and Energy)

Area fee

The area fee is intended to help ensure that awarded acreage is explored efficiently, so that potential resources come on stream as soon as possible, within a prudent financial framework, and such that existing fields achieve longer lifetimes.

Environmental taxes

Important environmental taxes for the petroleum activities are the CO_2 tax and the NO_x tax. The petroleum activities are also subject to a quota obligation, which means that licencees must purchase emission quotas for each tonne of CO_2 they emit from activities on the Norwegian continental shelf.

The CO_2 tax was introduced in 1991 and is a policy instrument designed to reduce emissions of CO_2 from the petroleum activities. The CO_2 tax is paid per standard cubic metre (scm) of gas that is burned or released directly, and per litre of petroleum burned. For 2012, the tax is set at NOK 0.49 per litre of petroleum or standard cubic metre of gas.

Under the Gothenburg protocol of 1999, Norway is obligated to reduce its annual emissions of nitrogen oxide (NO_x), which led to the introduction of an NO_x tax from 1 January 2007. For 2012, the tax rate is set at NOK 16.69 per kg NO_x.

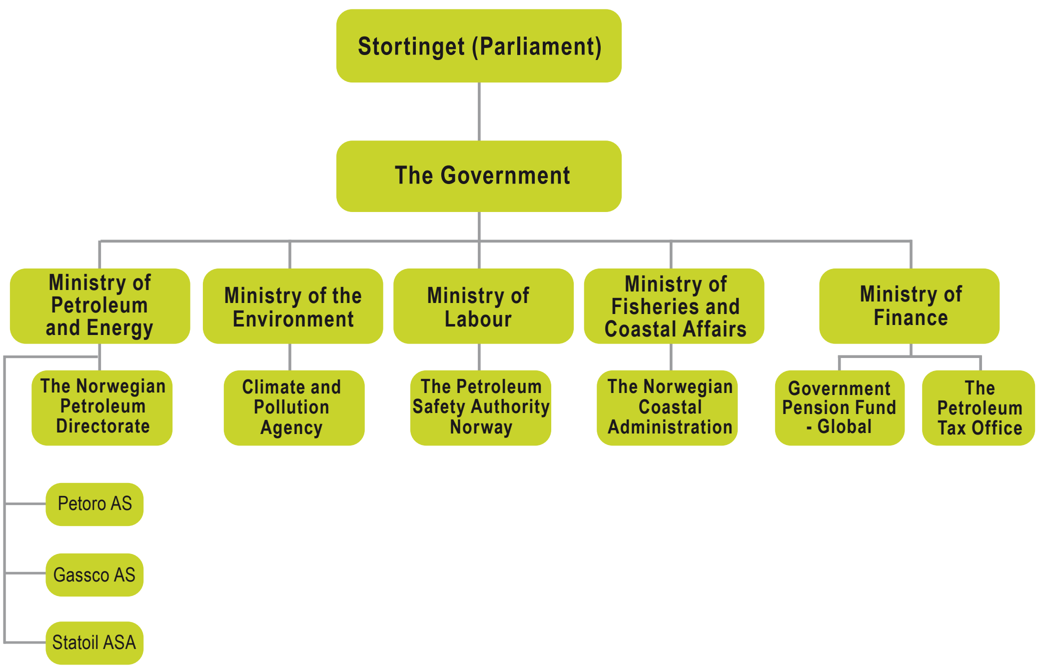


Figure 2.2 State organisation of the petroleum activities *(Source: State budget)*

SDFI

The State's direct financial interest (SDFI) is a system whereby the State owns a share of many oil and gas fields, pipelines and land facilities. The ownership interest in the oil and gas fields is set in connection with award of the production licences, and the size of the interest varies from field to field. As one of multiple owners, the State covers part of the investments and costs, and receives a corresponding portion of the income from the production licence. SDFI was established with effect from 1 January 1985. Until then, the State only had ownership in production licences through the company Statoil, where the State then was the sole owner. In 1985, Statoil's participating interest was split into a direct financial interest to the State (SDFI) and an interest for Statoil. When Statoil was listed on the stock exchange in 2001, management of the SDFI portfolio was transferred to the State-owned management company Petoro. As of 1 January 2012, the State had direct financial interests in 146 production licences, as well as interests in 14 joint ventures in pipelines and land facilities.

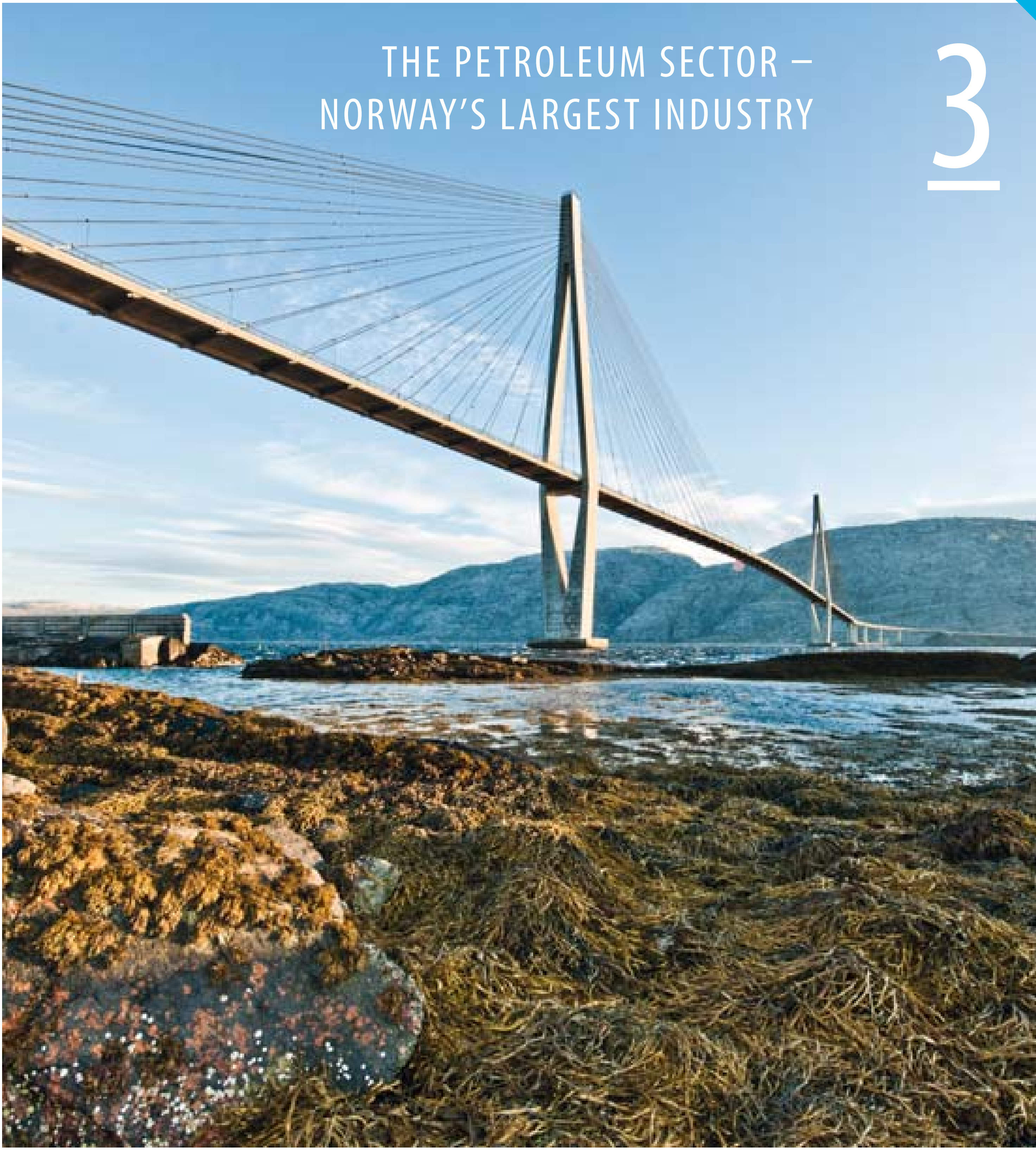
Dividend from Statoil

The State owns 67 per cent of the shares in Statoil. As an owner of Statoil, the State receives dividends which are part of the revenues from the petroleum activities. The dividend paid to the Norwegian State in 2011 was NOK 13.35 billion.

EITI

Extractive Industries Transparency Initiative (EITI) is an international initiative with the purpose of reinforcing sound management principles by disclosing and reconciling revenue flows to the State from oil, gas and mining companies in countries that are rich in natural resources. Greater transparency surrounding cash flows will contribute to better management, and help allow citizens to hold their governments accountable for how these revenues are used. As the only OECD nation so far, Norway has implemented EITI. A stakeholder group has been established with participants from the authorities, companies and the general population. The group takes active part in the process of implementing EITI in Norway. Norway was approved as a compliant EITI country in March 2011, and was the sixth country to secure approval. 12 other countries are approved and around 20 other countries arein the process of implementing EITI.

3 THE PETROLEUM SECTOR – NORWAY'S LARGEST INDUSTRY



The Helgeland Bridge is a landmark and plays an important role in the development of the Helgeland coast. (Photo: Monica Larsen, NPD)

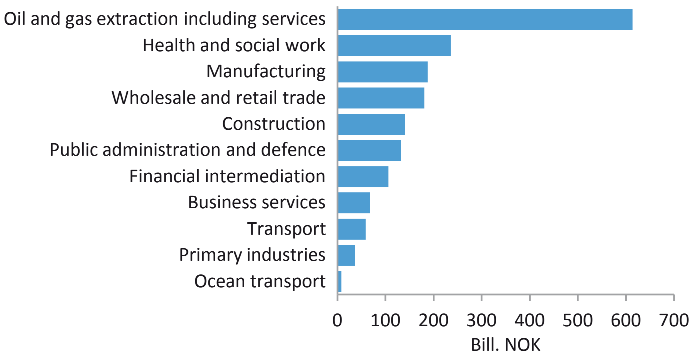


Figure 3.1 Value creation in selected industries 2011
(Kjelde: National accounts, Statistics Norway)

The petroleum activities in the Norwegian society

The petroleum activities have been crucial for Norway's financial growth and in financing the Norwegian welfare state. Over more than 40 years, petroleum production on the shelf has added more than NOK 9000 billion to the country's GDP. In 2010, the petroleum sector represented 21 per cent of the country's total value creation. Value creation in the petroleum industry is more than double that of the landbased industry, and about 15 times the total value creation in the primary industries.

Currently, 70 fields are in production on the Norwegian continental shelf. In 2011, these fields produced more than 2.0 million barrels of oil (including NGL and condensate) per day and a total of about 100 billion standard cubic metres (Sm^3) of gas, a marketable petroleum production totalling 229.7 million Sm^3 of oil equivalents (o.e.). Norway is ranked as the seventh largest oil exporter and the fourteenth largest oil producer in the world. In 2010, Norway was the world's second largest gas exporter, and the world's sixth largest gas producer.

The State receives substantial income from the petroleum activities. Tax from the production companies and direct ownership (SDFI) ensures that the State receives a large share of the values created by the petroleum activities. The State's income from the sector amounted to about one-fourth of its total revenues in 2010. Figure 3.4 shows the payments from the industry. In the 2011 national budget, the value of the petroleum resources remaining on the continental shelf is estimated at NOK 4 124 billion.

The State's income from the petroleum activities is transferred to a separate fund, the Government Pension Fund – Global. In 2011, transfers to the Government Pension Fund – Global totalled approx. NOK 271 billion. At the end of 2011, the fund was valued at NOK 3 312 billion. This corresponds to more than NOK 650 000 for every Norwegian.
In 2011, crude oil, natural gas and pipeline services represented nearly half of Norway's export value. The export of petroleum products amounted to almost NOK 500 billion in 2010. This is nearly ten times the export value of fish.

Since the start of the petroleum activities on the Norwegian continental shelf, vast amounts have been invested in exploration, field development, transport infrastructure and onshore facilities. The investments in 2010 amounted to as much as 26 per cent of the country's total fixed capital investments.

The road ahead

It is expected that petroleum production will remain relatively stable over the next few years. The production of oil and other liquids will gradually be reduced. However, gas sales will increase to between 105 and 130 billion Sm^3 over the next decade. Over the longer term, the number of new discoveries and their size will be decisive for the production level. So far, about 43 per cent of what are considered to be the total recoverable resources on the Norwegian continental shelf have been produced. The remaining recoverable resources on the shelf constitute a significant potential for value creation for years to come.

The investment level on the Norwegian shelf has been very high in recent years. In 2011, more than NOK 125 billion was invested,

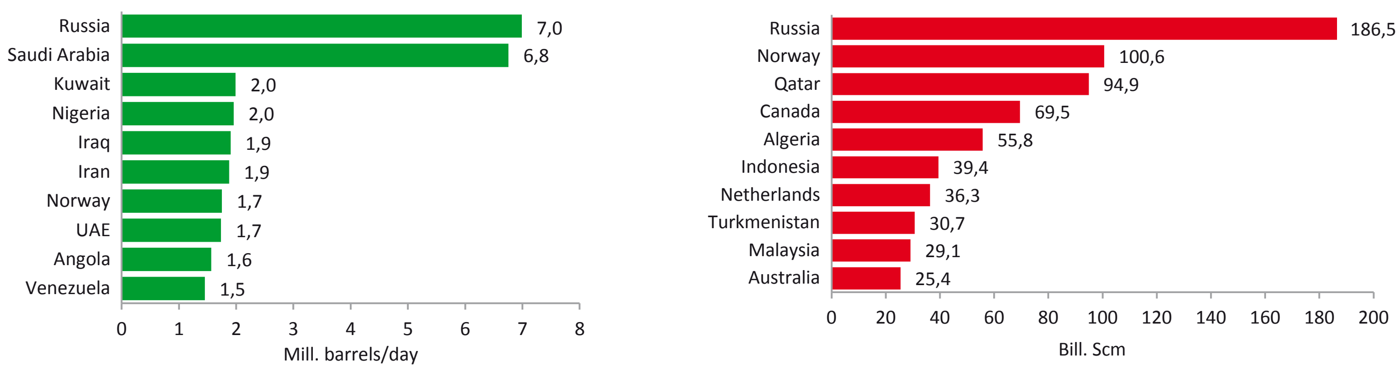


Figure 3.2 The largest oil exporters (oil includes NGL and condensate) in 2011 and gas exporters in 2010
(Source: KBC Market Services)

Fact box 3.1 An industry for the future

A key precondition for further developing the petroleum resources is that we have a resource base to exploit. During the past 40 years, we have extracted around 40 per cent of the expected recoverable resources. We have produced a larger percentage of oil than of gas. Sixty per cent of our resources remain in the subsurface. In addition come parts of the previously disputed area to the west of the demarcation line in the Barents Sea and the areas around the island of Jan Mayen. The Government presented the oil and gas white paper, *An industry for the future – Norway's petroleum activities* in the spring of 2011. An abitious and feasable long-term prouction plan is presented in the white paper.

A steady activity level must be maintained in order to achieve the goal of long-term management and value creation from the petroleum resources. This can best be facilitated through a parallel and active commitment in three areas:

– Increase recovery from existing fields and development of commercial discoveries.
– Continue active exploration of opened acreage, both in mature and frontier areas.
– Implement the opening processes for Jan Mayen and the part of the previously disputed area to the west of the demarcation line in the Barents Sea South, which can provide a basis for new economic activity in Northern Norway.

including exploration. The operating costs in 2011 amounted to almost NOK 60 billion. Both the investments and the operating costs are expected to remain high in the years to come. In particular, investments will increase considerably. The activity volume on the shelf will represent a significant market for the supplier industry for many years.

Nationwide employment

The demand from the petroleum industry has been and is very important for the activity in several industries around the country. Statistics Norway has analysed the effects of this demand, for example on employment in Norway. On the basis of direct and indirect deliveries to the petroleum industry, the agency has prepared an estimate of the scope of employment that can be related to the direct and indirect deliveries to the petroleum industry. For 2009, the estimate is 206 000 employed. The deliveries to the petroleum industry come from various parts of Norwegian industry and commerce. The employment effects therefore cover a broad range of industries.

Ripple effects of the petroleum activities

The development of new discoveries must create the largest possible values for the nation. It will also provide local and regional ripple effects.

When developing discoveries, it is important to find good development and operation solutions. The experiences from developments such as Skarv, Ormen Lange, Snøhvit and Goliat show that new, larger developments provide ripple effects locally and regionally, regardless of development solution. One important condition for achieving good ripple effects is for local and regional industry and commerce to utilise the business opportunities offered by a development in the vicinity.

The Norwegian supplier industry

The petroleum resources on the Norwegian shelf have laid the foundation for a highly competent and internationally competitive oil and gas industry. Today, the supplier industry delivers advanced technology, products and services for the Norwegian shelf and international markets. The industry is active within exploration acti-

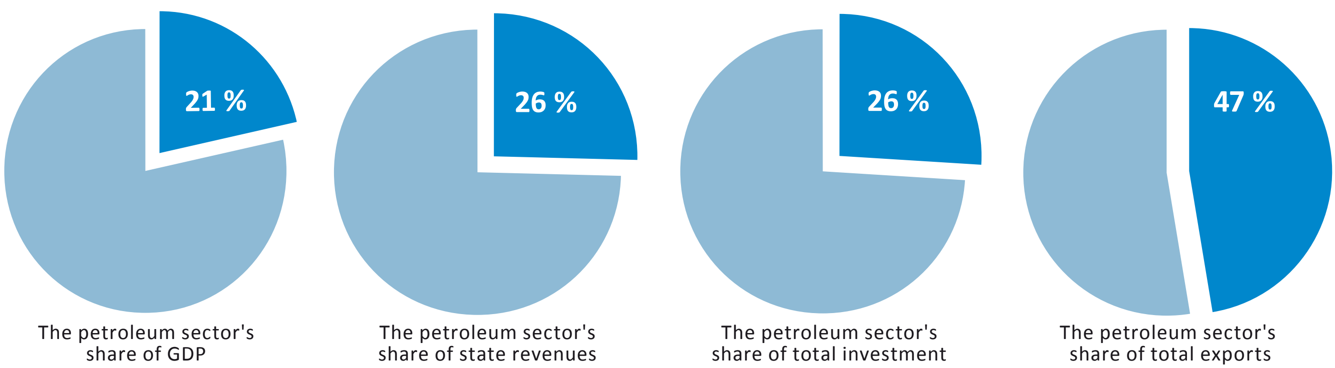


Figure 3.3 Macroeconomic indicators for the petroleum sector 2010
(Source: Statistics Norway, Ministry of Finance)

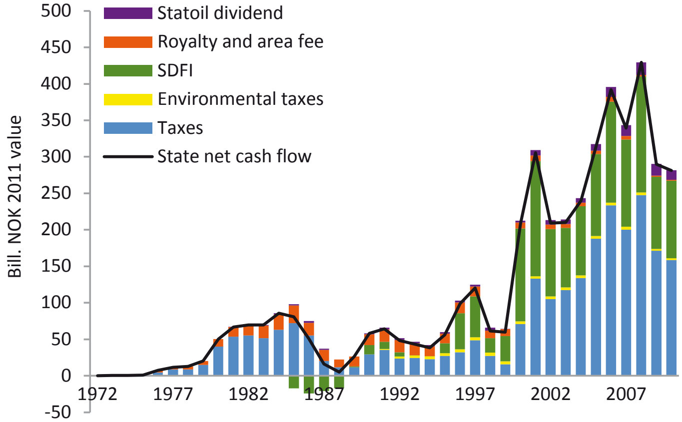


Figure 3.4 The net government cash flow from petroleum activities *(Source: Norwegian Public Accounts)*

Direct taxes	155.6
Environmental taxes, area fee and other	3.6
SDFI	104.1
Statoil dividend	12.8*
Total:	**276.0**

* Dividend for 2009 paid in 2010

Figure 3.5 The net government cash flow from petroleum activities in 2010 (bill. NOK) *(Source: Norwegian Public Accounts)*

vity, new developments, operations, maintenance, modifications and abandonment of fields. Some companies concentrate on one of these markets, while others have activities in several parts of the value chain. The Norwegian service and supply industry increased its turnover from NOK 195 to 248 billion from 2007 to 2009. This corresponds to a growth of 25 per cent. The petroleum industry also provides a strong impetus to innovation and technological development within other Norwegian industries.

Successful international industry

Over the last decade, several Norwegian suppliers have gained a strong international position. This is a direct result of the will to develop and use new technology on the Norwegian shelf. The interaction between the oil companies on the shelf, the supplier industry and the research environments has yielded good results.

From 1995 to 2009, the Norwegian supplier industry has increased its international sales more than fivefold. In later years, the growth has been greatest in China, Southeast Asia and Australia. Figures from Menon Business Economics indicate that, in 2009, Norwegian petroleumrelated companies had sales totalling NOK 118 billion abroad, compared with NOK 15.5 billion in 1995.

To strengthen the Norwegian petroleum industry internationally, the INTSOK foundation was established by the authorities and the industry in 1997. Together, they work to ensure that Norwegian suppliers win assignments in international markets.

The energy market

Secure access to energy is important for all countries. Through increased use of energy, manpower can be released from low-productive manual labour. The most important driving forces behind the increased energy demand are economic and population growth. In the future, the increased demand will mostly come from countries outside the OECD.

Fact box 3.2 The Government Pension Fund - Global

The Government Pension Fund - Global (SPU) was established in 1990 for the purpose of ensuring a long-term perspective when using the Government's petroleum income. The first transfer to the SPU took place in 1996. The State's total net cash flow from the petroleum activities is transferred to the Government Pension Fund - Global. In addition, the fund receives income through return, including interest and yield on the fund's investments. The petroleum revenues are gradually phased into the economy by covering the structural non-oil deficit in the national budget. It is phased in approximately in line with the development in the fund's expected real return.

Net cash flow from the petroleum activities
– Non-oil deficit in the national budget
\+ Return on the fund's investments
= Revenues for the Government Pension Fund - Global

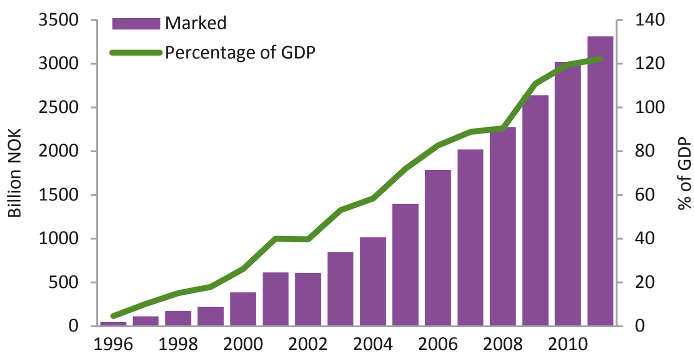


Figure 3.6 The size of the Government Pension Fund – Global at 31.12.2011 and as a share of GDP
(Source: Statistics Norway, Norges Bank)

Oil accounts for about one-third of the world's total energy consumption and more than half of the oil consumption takes place in the transportation sector as fuel for various types of motor vehicles. Oil is also used as a raw material in industry and to a lesser extent for combined heat and power production. The demand for oil is rising, particularly in the developing countries, such as China, India and countries in the Middle East. The world's largest oil producers are Saudi Arabia, Russia and the US. Much of the remaining oil resources are located in the Middle East, where the largest producers have joined forces with some other producing countries in a production cartel, OPEC. The price of oil is determined by supply and demand on the world market. To a certain degree, OPEC can influence the prices by increasing or decreasing supply. We also see that oil prices are now increasingly affected by the development in the international financial markets.

Natural gas accounts for more than 20 per cent of the world's total energy demand. The most important markets for natural gas are in Europe, Asia and North America. Solutions for transporting gas as LNG (liquefied natural gas – refrigerated gas) on ships have made the market for natural gas more globalised. Natural gas is generally used in the household sector for heating and cooking, in industry and for production of electricity. Over the last ten years, the gas market has undergone significant changes. The possibilities for recovering unconventional gas have considerably increased the world's gas reserves, and the growth in LNG supply has made gas available in new markets.

Fact box 3.3 Subsea technology

Development and use of new subsea technology is an important focus area on the Norwegian shelf and internationally. Using subsea facilities, small fields can be tied into larger facilities and field centres. The useful life of existing platforms and infrastructure is extended, and in such cases, subsea technology will contribute to recovering more resources from the field areas. The advances within subsea technology also facilitate development in very deep waters. The subsea segment has been a business area where the Norwegian supplier industry is an international leader in technology.

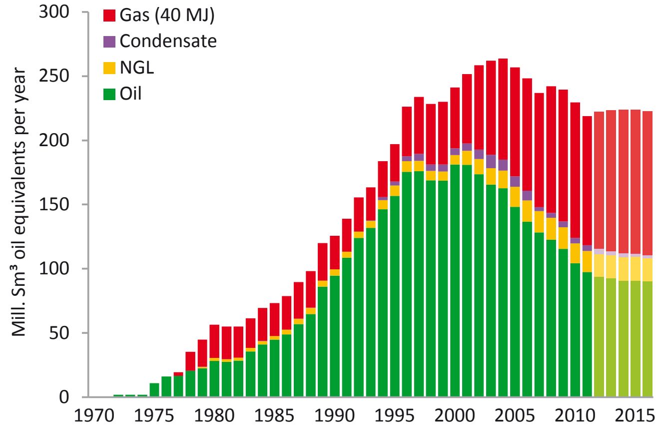


Figure 3.7 Historical production of oil and gas and production forecast for the coming years
(Source: Norwegian Petroleum Directorate)

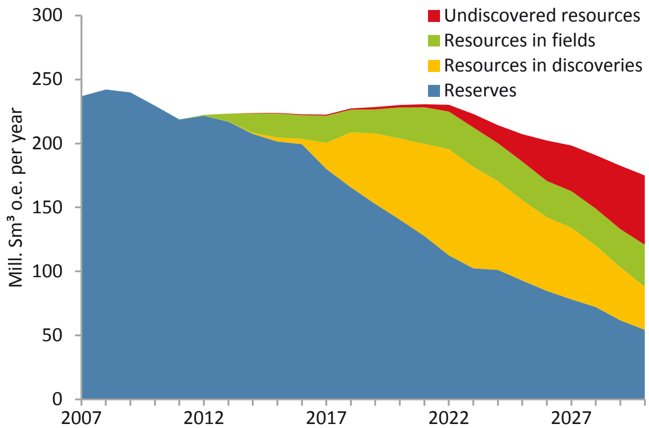


Figure 3.8 Production forecast *(Source: Norwegian Petroleum Directorate/Ministry of Petroleum and Energy)*

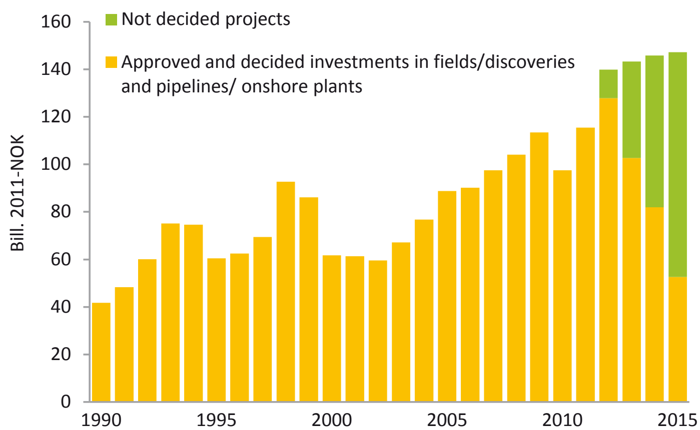
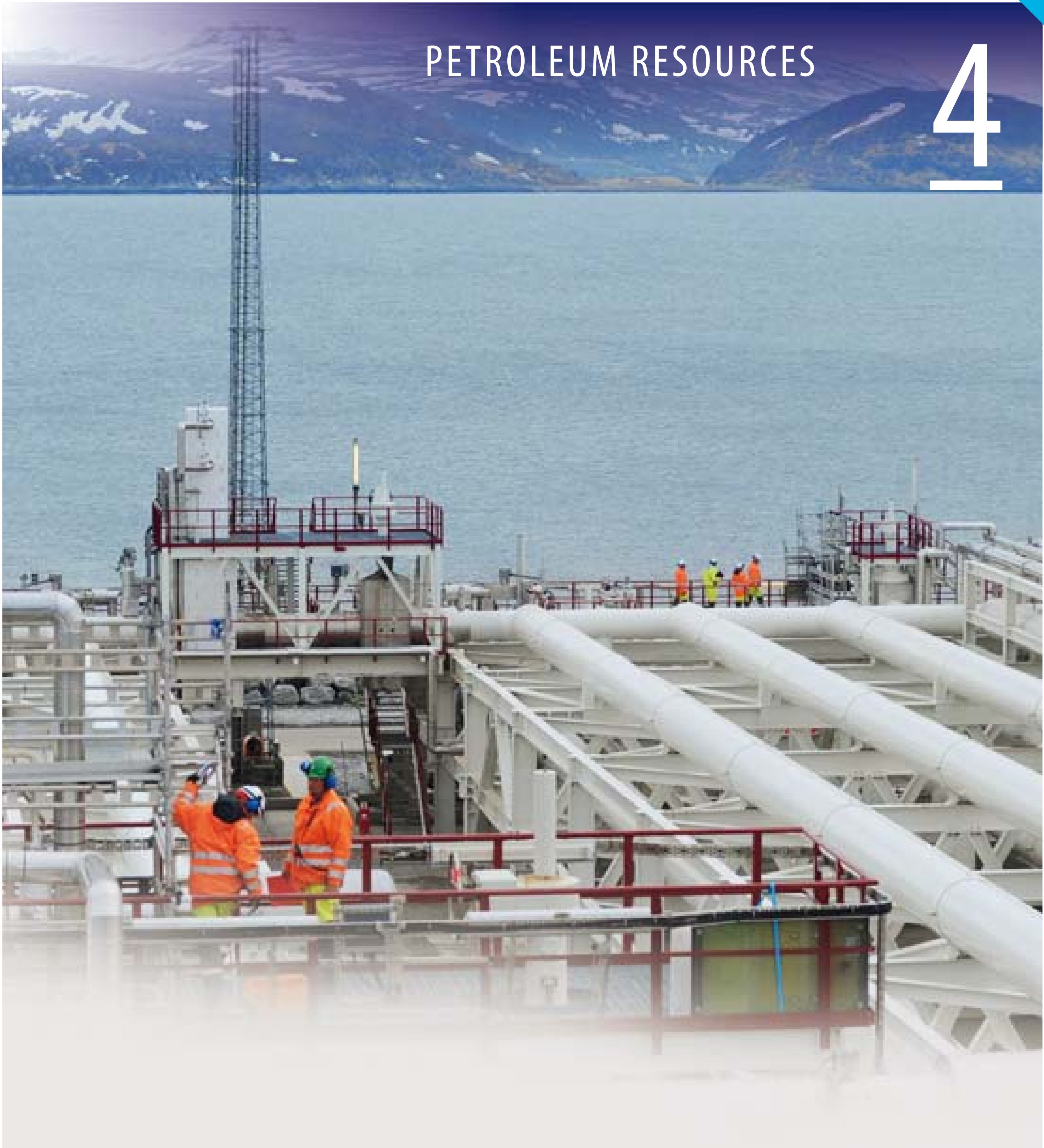


Figure 3.9 Historical investments (exploration costs not included) *(Source: Norwegian Petroleum Directorate/Ministry of Petroleum and Energy)*

PETROLEUM RESOURCES

4



Resources from the Snøhvit field on the way in to the Melkøy facility in Hammerfest. (Photo: Harald Pettersen, Statoil)

Resources

Resources is a collective term for recoverable petroleum volumes. The resources are classified according to their maturity, see Figure 4.2. The classification includes the following categories: decided by the licensees 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 categories are thus reserves, contingent resources and undiscovered resources.

The Norwegian Petroleum Directorate's base estimates for discovered and undiscovered petroleum resources on the Norwegian continental shelf amount to about 13.1 billion standard cubic metres of oil equivalents (billion Sm^3 o.e.). Of this, a total of 5.7 billion Sm^3 o.e. have been sold and delivered, which corresponds to 44 per cent of the total resources. The total remaining recoverable resources thus amount to 7.4 billion Sm^3 o.e. Of this, 4.9 billion Sm^3 o.e. have been discovered, while the estimate for undiscovered resources is 2.5 billion Sm^3 o.e.

The overall growth of discovered resources from exploration activities in 2011 is estimated at 61 million Sm^3 oil and 53 billion Sm^3 gas. Twenty-two new discoveries were made in 54 exploration wells. Many of the discoveries have not been evaluated, and the estimates are therefore very uncertain.

Since production started on the Norwegian continental shelf in 1971, petroleum has been produced from a total of 82 fields. In 2011, production started from the Trym field in the North Sea. Of the fields that were producing at the end of 2011, 56 are located in the North Sea, 13 in the Norwegian Sea and one in the Barents Sea.

Figure 4.1 shows the estimates for recoverable resources on the Norwegian continental shelf. The volumes are divided according to the Norwegian Petroleum Directorate's resource classification and shows total resources, liquid and gas.

The detailed resource accounts as of 31 December 2011 are presented in Table 4.1 and in tables in Appendix 2.

Reserves

Reserves include remaining recoverable petroleum resources in deposits for which the authorities have approved PDOs or granted PDO exemptions, and in deposits the licensees have decided to produce, but where the authorities have not yet processed the plan.

In 2011, the reserve growth was 260 million Sm^3 o.e. At the same time, 222 million Sm^3 o.e. (including historical gas production from Tambar, which was not included last year) were sold and delivered. The resource accounts show, therefore, an increase of 38 million Sm^3 o.e. in remaining reserves, which is about one per cent.

As regards the authorities' goal of maturing 800 million Sm^3 of oil to reserves by 2015, 93 million Sm^3 of oil were recorded as new reserves in 2011. During the period from 2005 to 2011, the overall reserve growth totals 452 million Sm^3 of oil.

Contingent resources

Contingent resources include proven petroleum volumes for which a decision to produce has not yet been made. Contingent resources in fields, not including resources from possible future measures for improved recovery (resource category 7A), decreased by 189 million Sm^3 o.e. The reason for this is that in 2011 there has been a good maturing of resources on the fields to reserves.

The volume of contingent resources in discoveries has increased by 356 million Sm^3 o.e., to 1006 million Sm^3 o.e. The increase can be explained by factors such as the positive growth of resources from new discoveries, and that the resource estimate for the 16/2-6 Johan Sverdrup discovery increased by 270 million Sm^3 o.e. after drilling several delineation wells in 2011.

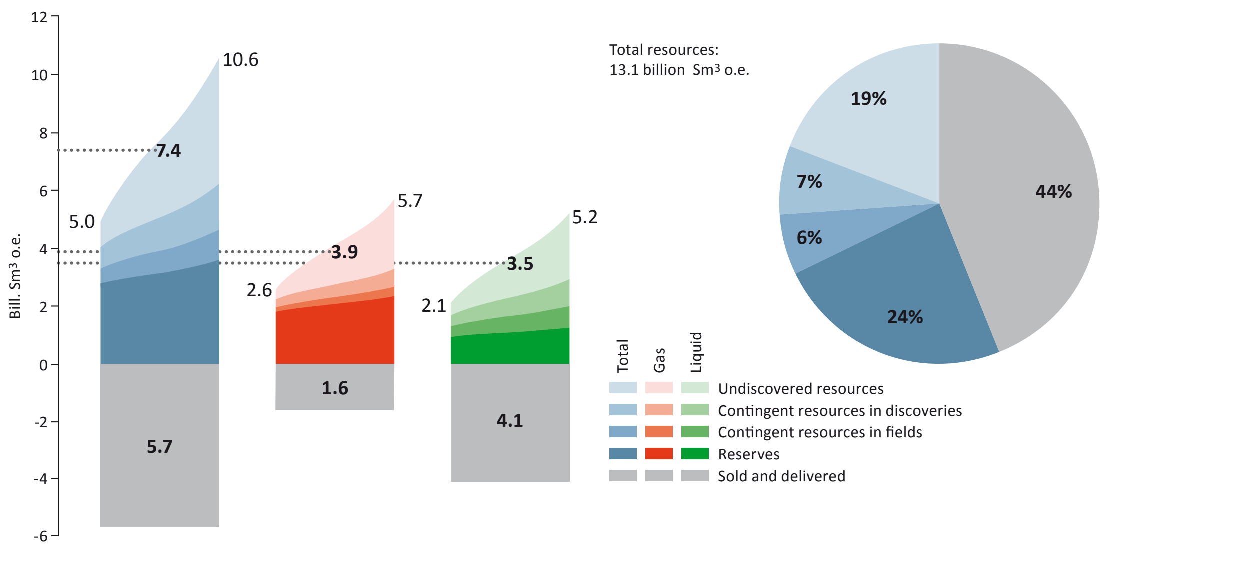


Figure 4.1 Petroleum resources and uncertainty in the estimates per 31.12.2011 *(Source: Norwegian Petroleum Directorate)*

Undiscovered resources

Undiscovered resources include petroleum volumes that are assumed to exist, but which have not yet been proven through drilling (resource categories 8 and 9).

The Norwegian Petroleum Directorate has, as a result of the new discoveries made in 2011, reduced its estimate of total undiscovered resources by the year's discoveries.
The estimate was reduced by 0.1 billion Sm³ o.e. to 2.5 billion Sm³ o.e.

The North Sea

The changes in the accounts for what has been sold and delivered from the North Sea over the past year totalled 145 million Sm³ o.e. (including the historical gas production from Tambar, which was not included last year). The growth of gross reserves was 184 million Sm³ o.e. This increase is partly due to the approved PDOs for the 25/5-7 Atla og 7/7-2 Brynhild discoveries, and because the licensees submitted a PDO for 25/8-17 Jette*. In addition, there has been an increase in reserves for fields in operation. This led to an increase in the remaining reserves in the North Sea by 39 million Sm³ o.e. Contingent resources in fields were reduced by 170 million Sm³ o.e. This is partly because projects on several fields were decided, and contingent resources therefore matured to reserves. Sixteen new discoveries were made in the North Sea in 2011, and the contingent resources in discoveries increased by 302 million Sm³ o.e. The reason is that the resource estimate for the 16/2-6 Johan Sverdrup discovery proven in 2010 was updated.

** PDO for Jette was approved in February 2012.*

The Norwegian Sea

Changes in the accounts for what has been sold and delivered from the Norwegian Sea in 2011 totalled 72 million Sm³ o.e. The growth in gross reserves was 58 million Sm³ o.e., due in part to approval of the PDO for 6407/8-5 S Hyme and submission of the PDO for 6608/10-12 Skuld*. Gas reserves in fields such as Åsgard and Njord have increased. Still, remaining reserves in the Norwegian Sea are reduced by 14 million Sm³ o.e. Contingent resources in fields are reduced by 49 million Sm³ o.e., primarily due to the PDO for Åsgard compression being submitted and resources maturing to reserves. Three new discoveries were made in the Norwegian Sea in 2011. Still, the estimate for contingent resources in discoveries was reduced by 21 million Sm³ o.e. compared with last year's accounts. This is partly due to resources maturing to reserves for 6407/8-5 S Hyme and 6608/10-12 Skuld.

** PDO for Skuld was approved in January 2012.*

The Barents Sea

Changes in what has been sold and delivered from the Barents Sea in 2011 totalled 5 million Sm³ o.e. Gross reserves on the Snøhvit field have increased by 20 million Sm³ o.e., and therefore the remaining reserves in the Barents Sea have increased by 15 million Sm³ o.e. Contingent resources in fields have increased by 31 million Sm³ o.e., partly because two new projects for improved recovery on the Snøhvit field were formalised. Three new discoveries have been made in the Barents Sea in 2011. This resulted in contingent resources in discoveries increasing by 73 million Sm³ o.e.

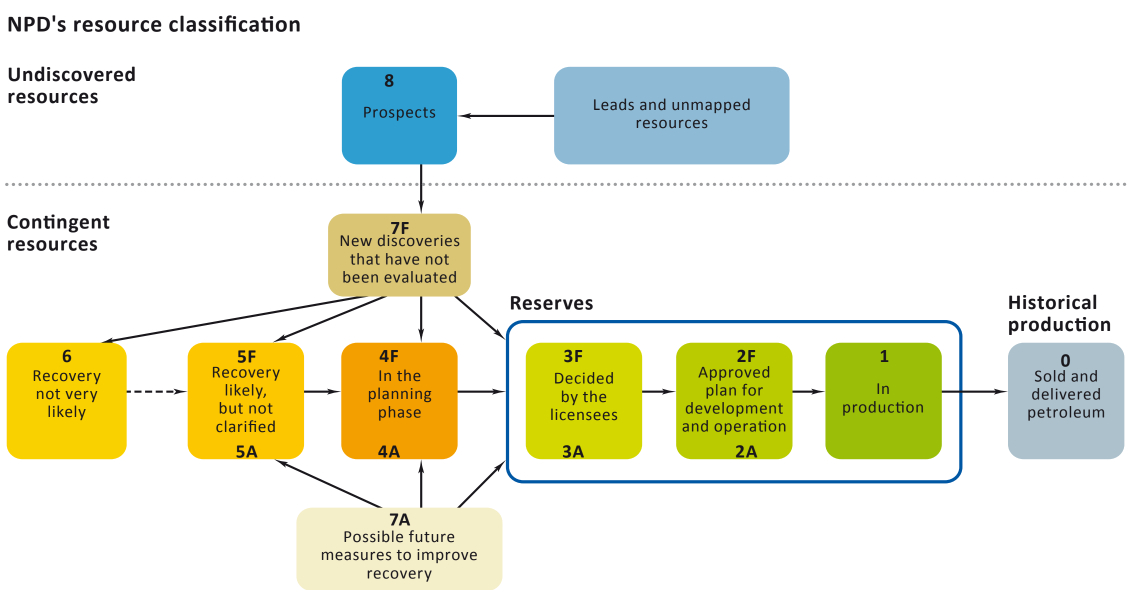


Figure 4.2 The NPD's resource classification *(Source: Norwegian Petroleum Directorate)*

Table 4.1 Resource accounts per 31.12.2011

Total recoverable potential Project status category	Resource accounts per 31.12.2011					Changes from 2010				
	Oil mill Sm³	Gas bill Sm³	NGL mill tonnes	Cond mill Sm³	Total mill Sm³ o.e.	Oil mill Sm³	Gas bill Sm³	NGL mill tonnes	Cond mill Sm³	Total mill Sm³ o.e.
Produced*	3723	1651	142	100	5743	98	104	8	5	222
Remaining reserves**	823	2070	125	30	3161	-5	27	11	-5	38
Contingent resources in fields	356	179	18	3	572	-54	-114	-9	-3	-189
Contingent resources in discoveries	574	386	14	19	1006	319	29	3	3	356
Potential from improved recovery***	140	50			190	0	-20			-20
Undiscovered	1140	1205		110	2455	-60	-50		-5	-115
Total	**6756**	**5540**	**299**	**262**	**13127**	**298**	**-25**	**13**	**-5**	**293**
North Sea										
Produced	3228	1383	107	69	4884	76	58	5	2	145
Remaining reserves**	636	1433	70	2	2203	-9	45	3	-4	39
Contingent resources in fields	314	118	11	1	454	-56	-105	-4	-1	-170
Contingent resources in discoveries	488	162	10	15	684	286	9	2	4	302
Undiscovered	520	270		20	810	-20	-10	0	-5	-35
Total	**5187**	**3365**	**198**	**107**	**9036**	**277**	**-4**	**6**	**-4**	**281**
Norwegian Sea										
Produced	495	253	33	27	839	21	42	3	2	72
Remaining reserves**	156	472	48	9	728	4	-26	6	-4	-14
Contingent resources in fields	42	30	5	0	82	2	-35	-7	-4	-49
Contingent resources in discoveries	47	171	4	4	230	-5	-16	0	-1	-21
Undiscovered	280	450		40	770	-5	-5	0	0	-10
Total	**1020**	**1377**	**90**	**81**	**2650**	**18**	**-40**	**3**	**-7**	**-23**
Barents Sea										
Produced	0	15	1	3	19	0	4	0	1	5
Remaining reserves**	31	165	8	19	230	0	8	2	3	15
Contingent resources in fields	0	30	2	2	36	0	27	1	2	31
Contingent resources in discoveries	38	53	0	0	92	38	35	0	0	73
Undiscovered	340	485		50	875	-35	-35	0	0	-70
Total	**409**	**748**	**11**	**75**	**1252**	**3**	**39**	**4**	**6**	**55**

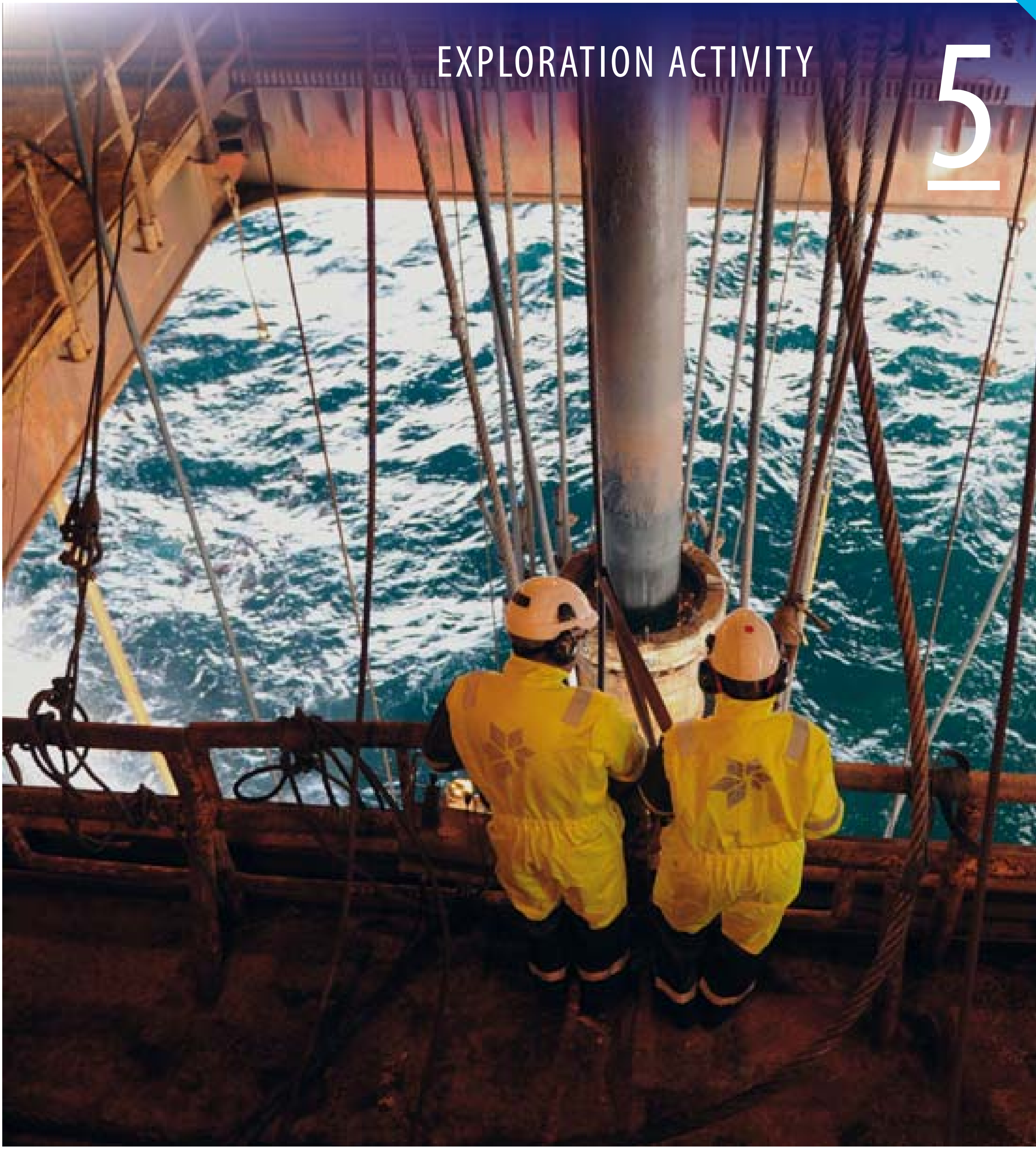
* Includes historical production of gas from Tambar, not included last year.

** Includes resource categories 1, 2 and 3.

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

EXPLORATION ACTIVITY

5



From Transocean Leader, while drilling to delineate the Johan Sverdrup discovery in the North Sea in 2011. (Photo: Harald Pettersen, Statoil)

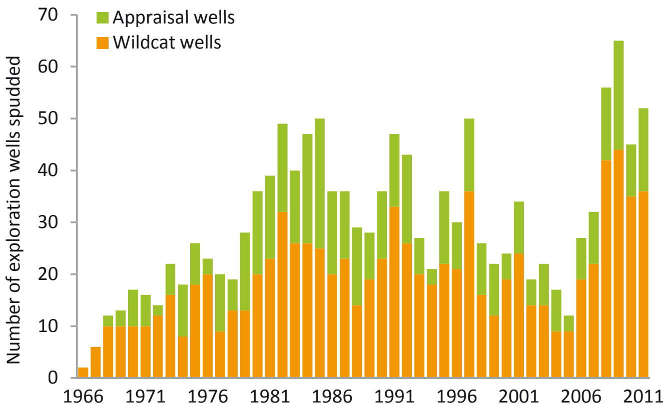


Figure 5.1 Exploration wells spudded on the NCS 1966–2011 *(Source: Norwegian Petroleum Directorate)*

In order to produce the petroleum resources found on the Norwegian continental shelf, we must first explore for and prove these resources. Exploration activity is an important indicator of future production. Generally, it takes several years from when a decision is made to explore for resources until potential discoveries can come on stream. 10-15 years is not uncommon in frontier areas. Formulation of exploration policies is therefore an important part of long-term Norwegian resource management, and these policies have been designed with a view towards making the Norwegian continental shelf attractive to both established and new players who can contribute to efficient exploration. The Government will provide companies with access to attractive exploration acreage, which should include a mix of mature and less explored areas.

On the Norwegian continental shelf, the Norwegian Parliament (Storting) has opened most of the North Sea, the Norwegian Sea and the southern Barents Sea for petroleum activities. Estimates prepared by the Norwegian Petroleum Directorate of undiscovered resources in areas on the shelf total around 2.5 billion Sm^3 of recoverable oil equivalents. The resources are fairly evenly distributed between the three regions, with about 33 per cent in the North Sea, about 31 per cent in the Norwegian Sea and about 36 per cent in the Barents Sea (see Figure 5.2). There are varying challenges as regards realising the economic potential of the undiscovered resources, depending on the maturity of the area.

Fact box 5.1 The licensing system

The Norwegian licensing system consists of two types of licensing rounds. The first is the numbered licensing rounds which comprise less mature parts of the shelf. These rounds have been used since 1965, and in recent years have been held every second year. The oil companies are invited to nominate blocks they would like to see announced and, on this basis, the Government determines a certain number of blocks for which companies can apply for production licences.

The other licensing round system entails award of production licences in predefined areas (APA) in mature parts of the continental shelf introduced by the Government in 2003. This system entails the establishment of large, pre-defined exploration areas comprising all of the mature acreage on the shelf. Companies can apply for acreage within this defined area. The area will be expanded, never reduced, as new areas are matured. A regular, fixed cycle is planned for licensing rounds in mature areas. So far, nine annual rounds have been carried out (APA 2003–2011).

Under both types of licensing rounds, applicants can apply individually or in groups. Impartial, objective, non-discriminatory and announced criteria form the basis for the award of production licences. Based on the applications received, the Ministry of Petroleum and Energy awards production licences to a group of companies. The Ministry designates an operator for the joint venture, to be responsible for the operational activities authorised under the licence.

The production licence applies for an initial period (exploration period) that can last up to ten years.

Fact box 5.2 Area fee

The area fee is a policy instrument with the aim of increasing activity in the awarded area. The idea behind the fee is that no area fee will be paid for areas where production or active exploration is in progress. During the initial period, wherein the exploration activity follows a mandatory work programme, the licensees do not pay a fee. After the initial period, licensees must pay an annual fee to the Norwegian State for each square kilometre of the area covered by the production licence. Effective 1 January 2007, the area fee rules were intensified to reinforce the function of the fee. According to the new rules, companies must pay NOK 30 000 per square kilometre during the first year, and the rate increases to NOK 60 000 in the second year. From and including the third year, companies pay the maximum fee rate of NOK 120 000 kroner per square kilometre. Companies can be exempted from the area fee if they submit a plan for development and operation (PDO) to the Ministry of Petroleum and Energy. The area fee exemption is only granted for the area that comprises the geographical extent of the deposits, and for which a PDO has been submitted. The regulations also provide for an exemption from the area fee for two years if the company drills an additional wildcat well beyond the mandatory work commitment.

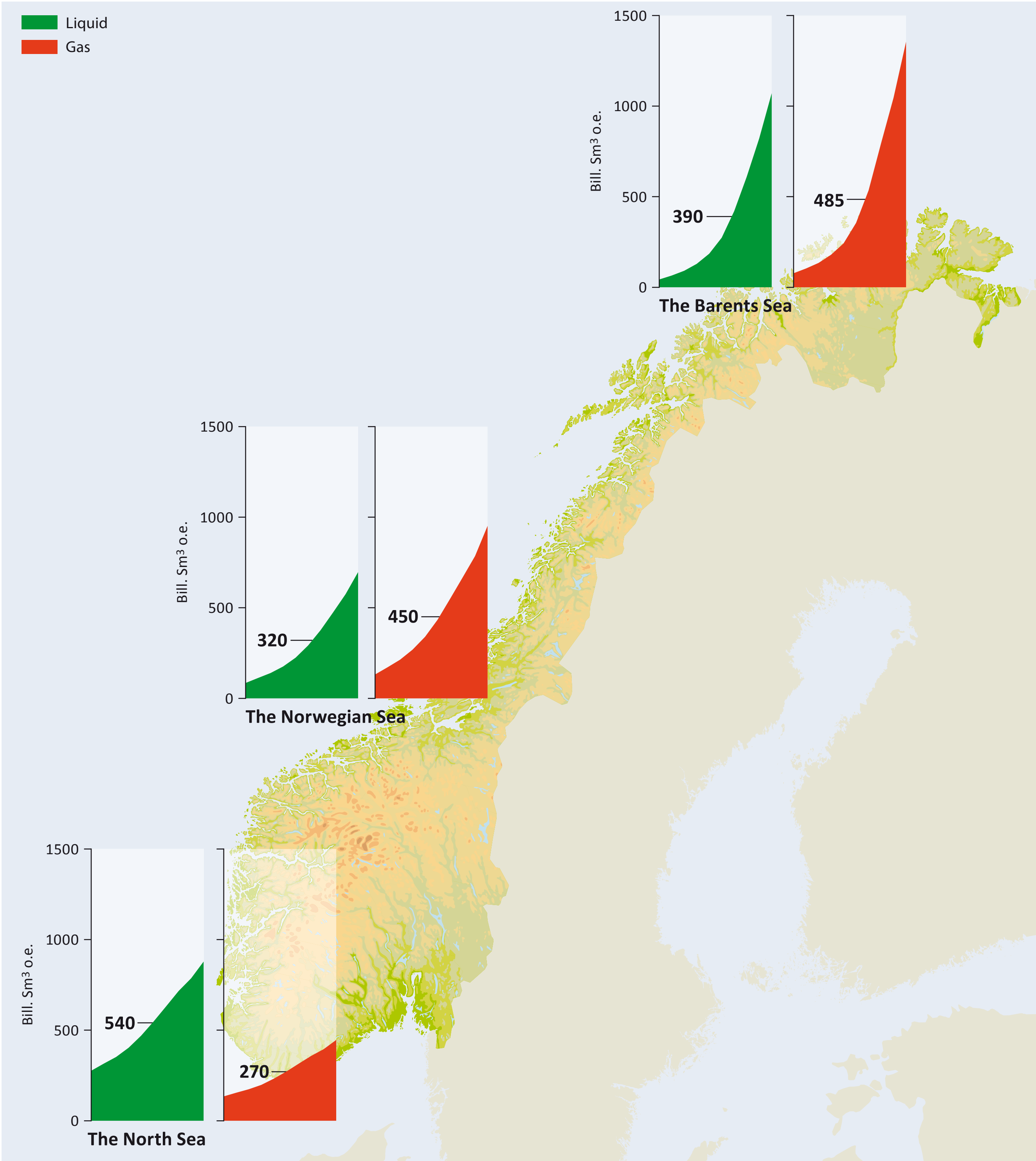


Figure 5.2 Undiscovered resources distributed by area. The number in each column indicates expected recoverable volume while the uncertainty in the estimate is shown by the slanted line, low estimate on the left, high estimate on the right. *(Source: Norwegian Petroleum Directorate)*

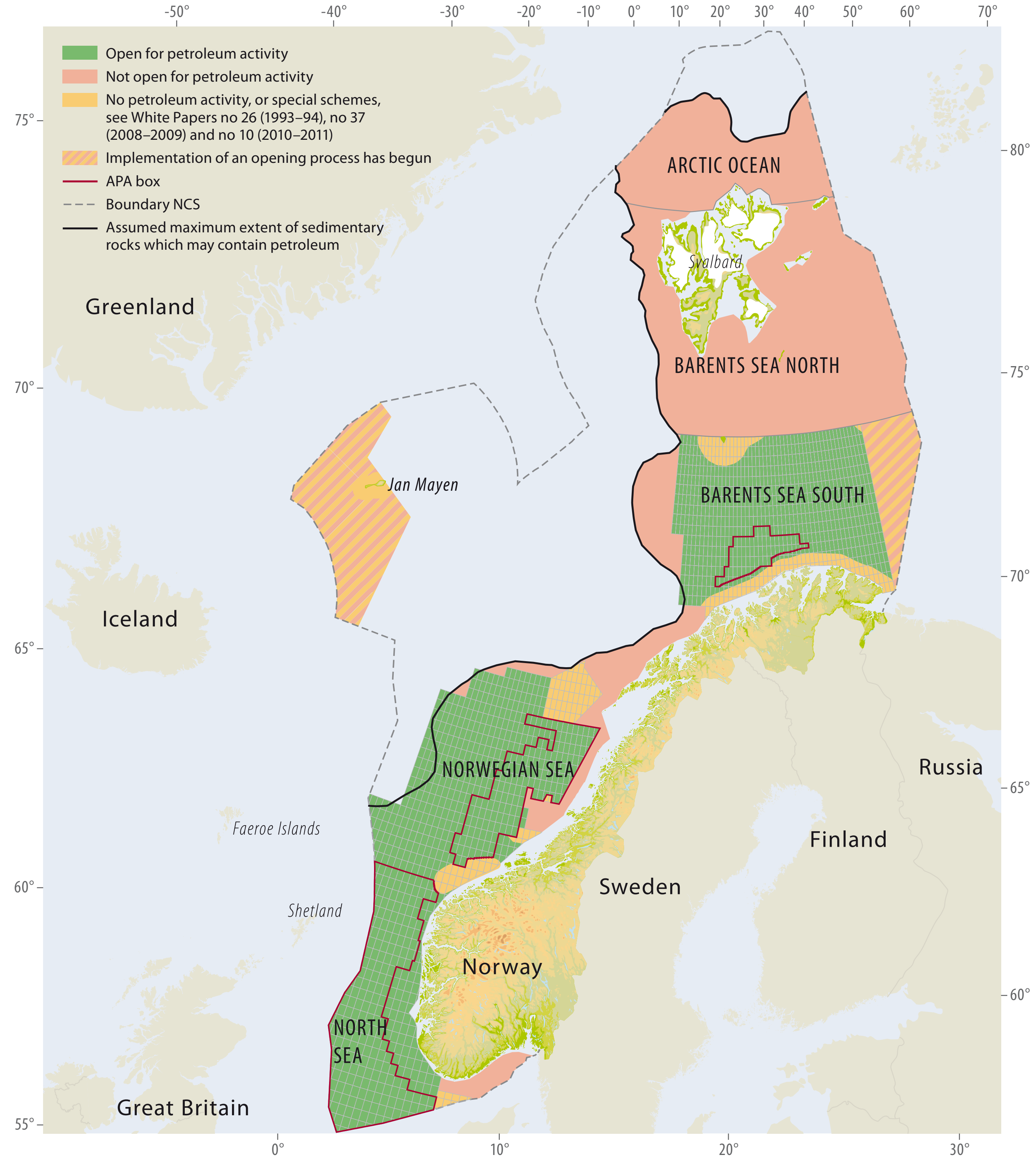


Figure 5.3 Area status on the Norwegian continental shelf per March 2012 *(Source: Norwegian Petroleum Directorate)*

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 northward, based on the principle of stepwise exploration. This means that large parts of the North Sea are now considered to be mature from an exploration perspective. The same applies to Haltenbanken and the area around the Ormen Lange field in the Norwegian Sea, as well as the area surrounding Snøhvit in the Barents Sea.

Mature areas are characterised by known geology and well-developed or planned infrastructure. It is very likely that discoveries will be made, but less likely that large new discoveries will be made. It is therefore important to prove and produce the resources in an area before existing infrastructure is shut down. If this cannot be done, profitable resources could be left behind because the discoveries are too small to justify independent development of infrastructure.

In these areas, the authorities have deemed it important that the industry receives access to a larger area, so that resources that are time-critical can be produced in a timely manner. It is also important that area awarded to the industry is explored rapidly and efficiently. In this connection, the Government introduced the awards in pre-defined areas (APA) scheme in 2003. Figure 5.3 shows the area available for award in APA 2011.

For the authorities, it is important that licensed area is actively worked. The area comprised by the production licence to be awarded is tailored so that companies are awarded only those areas where they have concrete plans. Relinquished acreage can be applied for by new companies that may have a different view as regards prospectivity. This leads to faster circulation of acreage and more efficient exploration of the mature areas. After expiration of the initial period, companies could previously retain up to 50 per cent of the awarded area without committing to specific activity. Today, the main rule is that they can only retain the area for which they have plans to start production. .

Frontier areas

The areas currently regarded as frontier areas on the Norwegian continental shelf include large parts of the Barents Sea and the Norwegian Sea, as well as smaller areas in the North Sea. As regards the Norwegian Sea, this applies particularly to deepwater areas and the northernmost areas. The coastal areas in the southern part of the shelf are also relatively unexplored.

Characteristics of frontier areas include little knowledge of the geology, significant technical challenges and lack of infrastructure. Uncertainty surrounding exploration activity is greater here, but there is also the possibility of making major new discoveries. Players that are to explore in frontier areas must have broad-based experience, technical and geological expertise, as well as a solid financial foundation.

Through the 18th licensing round, the principles in the changed rules for relinquishing licences in mature areas were also applied to frontier areas. But it is not expedient for all companies that have been awarded production licences in frontier areas to submit a development plan at the end of the initial period, so the main rule for relinquishment in these areas is linked to delineation of resources proven through drilling. Otherwise, the same changes have been made in frontier areas as in mature areas as regards customising the area to be awarded.

The 21th licensing round was awarded in the spring of 2011, covering 24 blocks in the Barents Sea and the Norwegian Sea. 29 oil and gas companies were granted licenses.

Unopened areas and opening processes

There are still large areas of the Norwegian continental shelf that the Storting has not opened for petroleum activities. This applies to all of the Barents Sea North, eastern part of the Barents Sea South, the north-eastern part of the Norwegian Sea (Troms II, Nordland VII and parts of Nordland IV, V and VI), coastal areas off Nordland County, Skagerrak and the area around Jan Mayen. The general rule for unopened areas is that the Storting must resolve to open an area for petroleum activities before a licensing round can be announced. The basis for such decisions must include preparation of an impact assessment to consider factors such as economic and social effects, as well as environmental effects the activities could have for other industries and the surrounding district.

At present, there are two ongoing opening processes; one for the areas near Jan Mayen and a second for the southeastern Barents Sea area. (See Fact box 5.4)

The integrated management plan for the Barents Sea – Lofoten area was updated in March 2011. The government decided that during this parliamentary period, no environmental impact assessment will be carried out under the Petroleum Act for Troms II, Nordland VII, or the parts of Nordland IV, V and VI that have not been opened for petroleum activities. The Norwegian Ministry of Petroleum and Energy has been requested to carry out a process aimed at increasing knowledge regarding the unopened areas of the northeastern North Sea. Acquired knowledge will be used to update the integrated management plan. Acquired knowledge will also be fundamental for a potential impact assessment later on. Topics to be included in the knowledge acquisition programme were determined in the autumn of 2011, in close cooperation between the Ministry, local and regional parties, as well as organisations representing various interests and areas. Input meetings have been held in Harstad, Stokmarknes, Svolvær, Bodø and Oslo. Extensive knowledge about the unopened areas already exists; therefore, the focus is to bridge the knowledge gaps. Several studies will be carried out in 2012. The Norwegian Petroleum Directorate has been responsible for a three-year programme for geological mapping and acquisition of seismic data in this process. In total, the Norwegian Petroleum Directorate estimates that there are 202 million standard cubic metres of undiscovered oil equivalents in the evaluated area, which includes Troms II, Nordland VII and Nordland VI.

Player scenario and activity

The number and composition of the oil companies that conduct petroleum activities on the Norwegian continental shelf is called the player scenario. The largest international players have achieved a central role, a natural consequence of the large, demanding tasks on the shelf. As the area has matured and the challenges have changed in character and become more diversified, it has been important to adapt the player scenario to this altered situation. Therefore, in

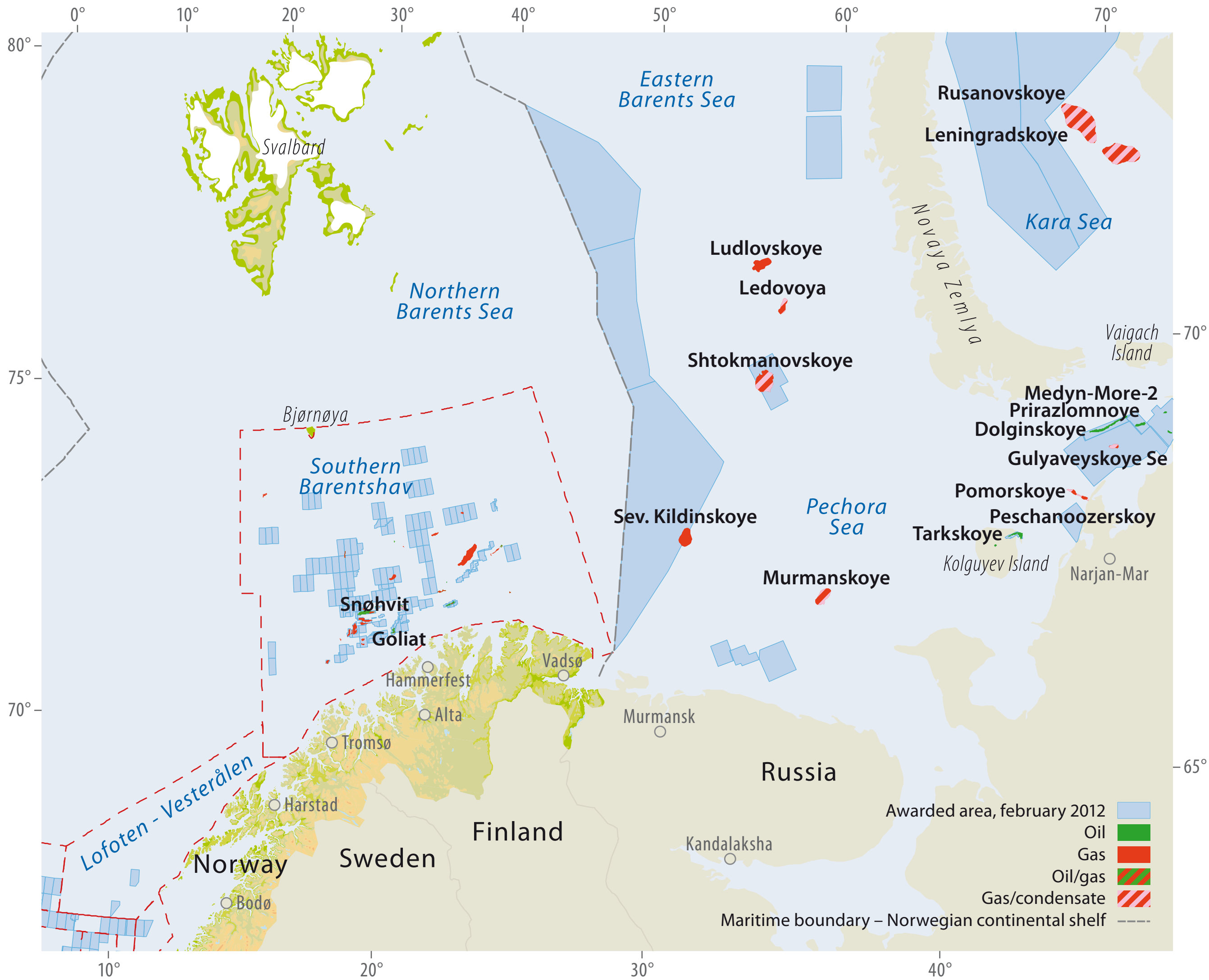


Figure 5.4 Norwegian and Russian part of the Barents Sea per March 2012 *(Source: Norwegian Petroleum Directorate/OGRI RAS)*

recent years, the focus has been on bringing in new players, in part through establishing the APA system in 2003 and introduction of the exploration reimbursement scheme in 2005 (see Figure 5.7).

This has yielded results. Following a period of low exploration activity, the situation rebounded in 2006, see Figure 5.6. Figure 5.5 also clearly shows that the new companies are responsible for the increase in drilling costs as exploration activity has recovered and the new players now account for over 40 percent of the exploration costs on the shelf. A new record was set in 2009 with 65 exploration wells spudded. Of these, 44 were wildcat wells and 28 discoveries were made, the highest number so far. A total of 45 exploration wells were spudded in 2010, of which 35 were wildcat wells. Sixteen discoveries were made. In 2011, a total of 54 exploration wells were spudded, of which 22 were discoveries. 2011 will be remembered especially because of the "Skrugard" discovery in the Barents Sea and the "Johan Sverdrup" discovery in the North Sea.

To better pave the way for new players, Storting White Paper No. 39 (1999–2000) Oil and gas activities, introduced a system for prequalifying new operators and licensees. As regards the annual licensing rounds in mature areas, the new players have been awarded significant acreage and production licences. So far, most of the new companies have concentrated on mature areas in the North Sea and Norwegian Sea. In the most recent rounds, these companies have also shown increasing interest in the Barents Sea. More new companies are expected to take part in the licensing rounds in frontier areas as they gain sound knowledge of the shelf and establish larger organisations in Norway. A list of all licensees on the Norwegian continental shelf is provided in Appendix 3.

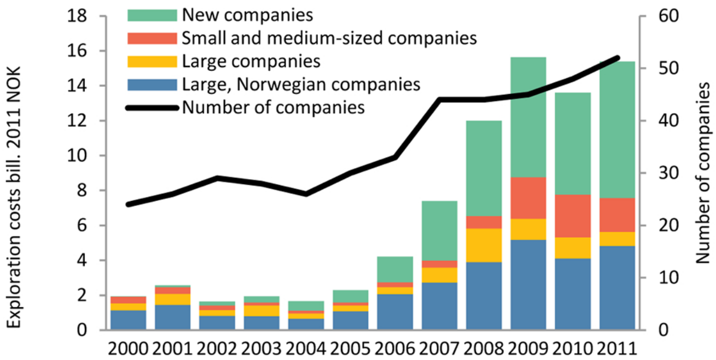


Figure 5.5 Exploration costs in production licences in the North Sea according to the size of the companies
(Source: Norwegian Petroleum Directorate)

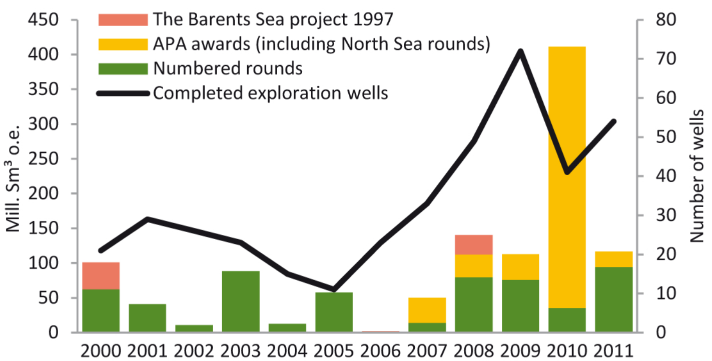


Figure 5.6 Resource growth
(Source: Norwegian Petroleum Directorate)

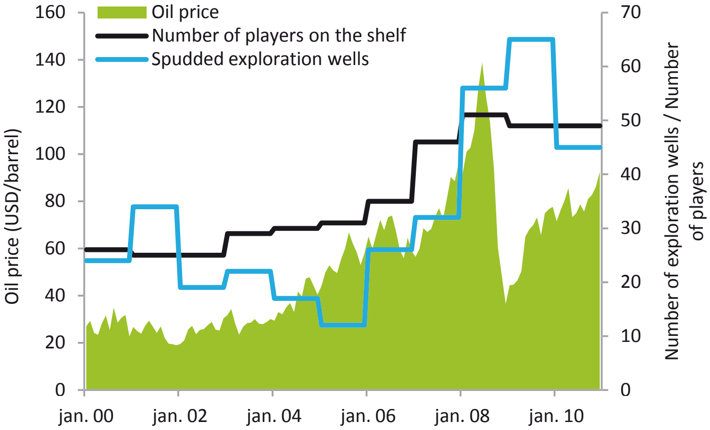


Figure 5.7 Rising oil prices and a diverse company picture have contributed to high exploration activity *(Source: Norwegian Petroleum Directorate)*

Fact box 5.3 Management plans

The management plans highlight the Government's guidelines for carrying out comprehensive management of the Norwegian maritime areas. The objective of the management plans is thus to facilitate value creation through sustainable use of resources and ecosystem services in the relevant maritime areas.

A fundamental precondition for the petroleum activities is coexistence between the oil industry and other users of the sea and land areas which the petroleum activities will impact. The management plans thus establish framework conditions that balance the interests of the fishery industry, the petroleum industry and the shipping industry, while simultaneously ensuring consideration for the environment.

The first management plan, Storting White Paper No. 8 (2005–2006) Integrated management of the marine environment in the Barents Sea and the waters off Lofoten (HFB) was submitted to the Storting in the spring of 2006. A number of programmes in recent years have gathered more knowledge about the maritime area in advance of the scheduled update of HFB in 2011. The work on a comprehensive management plan for the Norwegian Sea (HFNH) started in the spring of 2007 and was submitted to the Storting in the spring of 2009 as Storting White Paper No. 37 (2008-2009) Integrated management plan for the marine environment in the Norwegian Sea (management plan), while a management plan for the North Sea-Skagerak (HFNS) will be completed in 2013.

Fact box 5.4: Opening processes for unopened areas

Parts of the Norwegian continental shelf are not opened to petroleum activities. These include parts of Nordland IV, V, and Nordland VI, VII and Troms II, areas near Jan Mayen, the southeast Barents Sea, northern Barents Sea and Skagerak. In addition, there are restrictions or special requirements related to some areas within the opened areas.

Two opening processes for new areas on the Norwegian continental shelf are now ongoing.These processes are governed by the Petroleum Act.

As regards Jan Mayen, the Government decided in 2009 to initiate an opening process for petroleum activities near Jan Mayen, with a view towards awarding production licences. A draft impact assessment programme has been out for consultation and was set autumn 2011. In the time to come, several studies will be undertaken to analyse consequences of petroleum activities on other business, society and the environment. Field studies of flora and fauna on the Jan Mayen island have also been conducted. In addition, the Norwegian Petroleum Directorate will continue its seismic acquisition activities to be able to assess potential petroleum resources in the areas subject to opening processes. If the analyses based on the impact assessment are promising, the Government will recommend an opening of the areas in the autumn of 2013.

On 7 June 2011, the agreement between the Norwegian and Russian authorities on the marine demarcation line between Norway and Russia in the Barents Sea and the Arctic Ocean entered into force . The new area to the west of the demarcation line seems promising regarding hydrocarbon prospectivity. Hydrocarbons are found both east and west of the previous disputed area, where the Norwegian Petroleum Directory started its seismic activity in the summer of 2011. The new area will also be subject to seismic surveys in the summer of 2012. The Norwegian Government has initiated an impact assessment under the Petroleum Act, with a view to granting production licences. A draft impact assessment programme was sent out for public consultation of 2011, and will be finalised during spring 2012. The Storting will receive a recommendation to open the new area for petroleum activities, given that the impact assessment forms a solid foundation for doing so.

DEVELOPMENT AND OPERATIONS

6

The welding seams must be extremely precise when laying pipeline on the Norwegian shelf. (Photo: Anette Westgaard, Statoil)

In 2011, the authorities approved the plans for development and operation (PDOs) for Hyme, Knarr, Visund Sør, Vigdis Nordøst, Valemon, Stjerne, Vilje Sør (PDO exemption), Atla, Brynhild, Ekofisk Sør and Eldfisk II. The Skuld PDO was approved in January 2012, and PDOs for Åsgard, Jette, Hild and Luno are awaiting approval by the authorities. Additionally, development plans may be submitted for Bøyla, Svalin, Dagny, Draupne and Mikkel Sør.

Efficient production of petroleum resources

In consideration of the public interest in connection with development and operation of oil and gas fields, the authorities have established a framework for these activities. The authorities have organised a model that is characterised by both competition and cooperation between the players. The purpose of this is to create a climate for good decisions that serve the companies as well as the greater community. See Chapter 2 for more information regarding organisation and framework.

The development of discovered petroleum resources is the basis for production and value creation from the petroleum industry today. It is becoming increasingly important to better utilise the resources in the known areas. Briefly stated, this is a significant potential that can generate substantial values for society if it is utilised in a prudent manner.

The Norwegian Petroleum Directorate has assessed this potential and arrived at a goal for reserve growth on the Norwegian continental shelf of 800 million Sm^3 of oil before 2015. This corresponds to about twice the original oil resources in the entire Gullfaks field. This is a stretch goal for the industry and the authorities. At the end of 2011, the reserve growth has been 451 million Sm^3 of oil while the goal was 480 million Sm^3 of oil. Figure 6.1 shows the annual growth in oil reserves during the period 1981–2011. The 2011 accounts showed a growth of 93 million Sm^3 of oil, recorded as new reserves. In 2010, 64 million Sm^3 of oil was recorded. The largest increase in oil reserves comes from the Ekofisk, Snorre, Heidrun and Troll fields. Additionally, the resources in Skuld, Hyme and Brynhild have matured to reserves.

Improved recovery in mature areas

There is still a considerable potential for value creation if the recovery rate is improved in producing fields, operations are made more efficient and exploration for resources takes place close to the developed infrastructure.

Figure 6.2 shows an overview of the total oil resources in producing fields. The resources can be divided into:

- Produced volumes
- Remaining reserves
- Resources that will remain in the ground after the planned shutdown.

The figure shows that, based on the current plans, large amounts of oil resources will remain after the planned shutdown of these fields. Several measures are necessary if more of these resources are to be produced. The measures can be divided into two main groups; one covers measures for improved recovery, and the other involves improving the efficiency of operations.

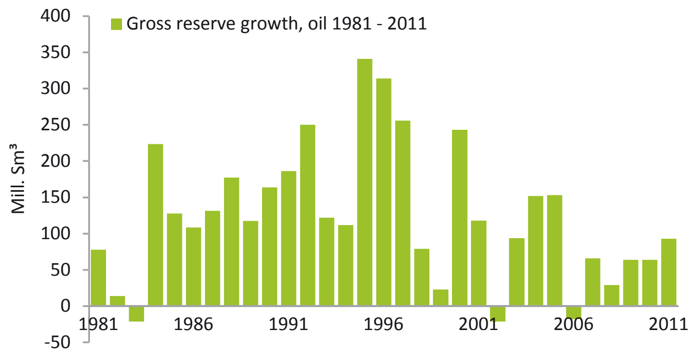


Figure 6.1 Figure 6.1 Gross reserve growth, oil 1981–2011 *(Source: Norwegian Petroleum Directorate))*

Improved recovery

Primarily, the licensees must invest in projects that can improve recovery. Examples include drilling more wells, measures for extracting more from existing wells, injection in reservoirs to recover more petroleum, and adaptations in process facilities. Such measures contribute to improve the average recovery rate. In 1995, the expected average recovery rate for oil for producing fields at the expected time for shutdown, was about 40 per cent – today it is 46 per cent. Development and use of new technology has been very important to improve recovery, and still is. The

Fact box 6.1 The development selection

In February 2010, the Ministry established a committee (also called the Åm committee), with a mandate of studying measures for improved recovery from existing fields on the Norwegian continental shelf. The committee delivered its report in September 2010 and it has been subject to public consultation.

The committee's task was to explore and identify any obstacles related to technology, expertise, regulations, finances, etc. that cause socio-economically profitable resources in and around existing fields, not to be recovered.

The committee points out that measures to improve recovery from fields on the Norwegian shelf will require considerable effort from the various players. The committee has therefore challenged both authorities and the industry with several recommendations and measures for realising the significant value potential associated with improved recovery from remaining resources.

The committee identified three key areas for improved recovery: access to drilling rigs, cost level and new technology. The report can be downloaded from the Ministry's website.

technological development makes it possible to e.g. drill wells and develop fields in ways that were previously technically impossible.

Figure 6.3 shows the production development for the Ekofisk, Varg, Oseberg and Ula fields. We see that the actual production from these fields has been very different from what was stated in the original development plans.

In Figure 6.3, we also see that improved recovery means a longer lifetime. Longer lifetime is positive because it facilitates implementation of more recovery measures, and entails that the infrastructure will remain in place for a longer period. This also increases the chances of other discoveries being connected to this infrastructure. Figure 6.4 also shows that fields' lifetime will be longer than previously assumed.

Efficient operations

The most important factor for extending the useful life of a field is that the production is profitable. Efficient operations contribute to reducing production costs. The resource recovery is affected because profitable production can be maintained longer than if the operation was less efficient. This contributes to production of resources that are currently not profitable. Many fields are facing a situation where the cost level must be reduced to defend profitable operation at a lower production level. Efficient operations are also crucial to reduce emissions to air and discharges to sea from the activities on the Norwegian continental shelf.

New discoveries – efficient utilisation of infrastructure

In 2011, more than NOK 115 billion* was invested on the Norwegian continental shelf. In total, about NOK 2300 billion* has been invested there, measured in current value. A lot of infrastructure has been established through these investments. This infrastructure makes it possible to produce and market petroleum, but also lays the foundation for developing additional resources in a cost-effective manner.

When the production from a field declines, capacity will be available in the infrastructure. Such capacity can provide very efficient exploitation of resources that can be tied into this infrastructure. In some cases, using the existing infrastructure is a precondition for profitable development of new fields, because the fields are too small for profitable development of separate infrastructure. Exploration for and development of resources in the vicinity of existing infrastructure can provide significant values for the Norwegian society. Read more about exploration in mature areas in Chapter 5.

In 2005, to contribute to efficient use of existing infrastructure, including existing platforms and pipelines, the Ministry of Petroleum and Energy prepared separate Regulations in this area, the Regulations relating to the use of facilities by others, effective 1 January 2006. The objective of the Regulations is to ensure efficient use of the infrastructure and thus provide licensees with good incentives for carrying out exploration and production activities. The purpose will be fulfilled through providing a framework for the negotiation process and the design of tariffs and general terms in agreements regarding the use of facilities by others. The Regulations entail no changes in the principle that the commercial players must negotiate good solutions for both parties.

To ensure that the potential in and around producing fields is exploited, it is important that the ownership interests rest with the companies that want to make the most of this. A wider spectrum of players is encouraged; cf. the discussion of the player picture

** Exploration costs excluded - no reporting on exploration costs prior to 1985.*

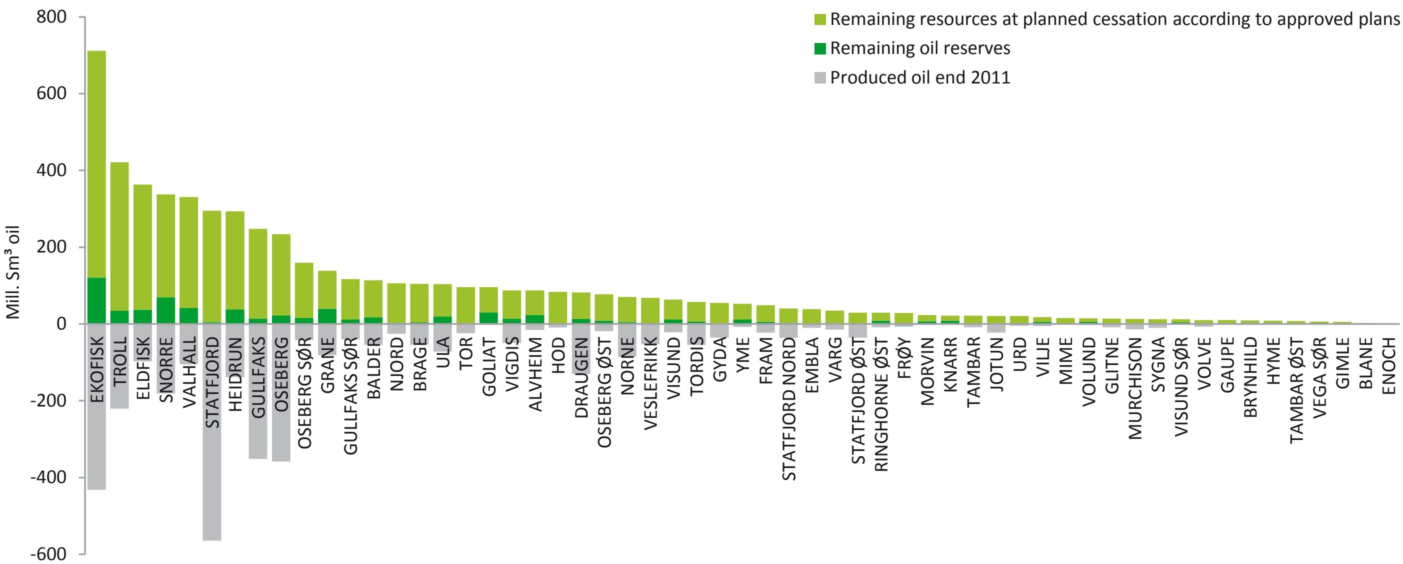


Figure 6.2 Distribution of oil resources and oil reserves in fields *(Source: Norwegian Petroleum Directorate)*

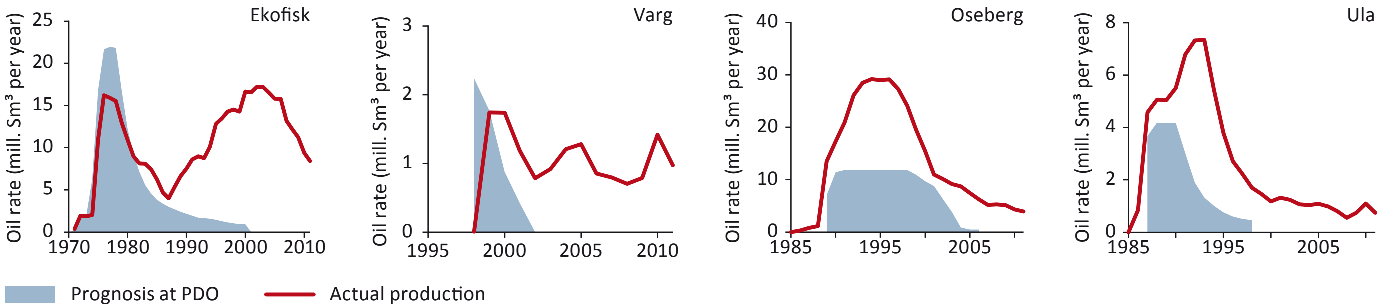


Figure 6.3 Production development for Ekofisk, Varg, Oseberg and Ula
(Source: Norwegian Petroleum Directorate)

in Chapter 5. The Norwegian authorities believe that a diversity of players that make different assessments and prioritisations is positive as regards realising the resource potential on the Norwegian continental shelf.

Improved recovery, longer useful life and phasing in resources near producing fields, lays the foundation for creating significant added value for the society. In order to further develop the resources in and around existing fields, infrastructure in place must be used. Thus the companies have less freedom than in new developments, and can, for example, not choose just any technical solution due to limitations in existing equipment, weight limits, etc.

Decommissioning

The petroleum activities merely lease the ocean, and all phases of the oil and gas activities must consider the environment and other users of the ocean. As a point of departure, when the activities end, everything must be cleaned and removed.

So far, the Ministry of Petroleum and Energy has processed more than ten cessation plans. It has been decided that abandoned facilities will be removed and transported to land, with examples of such facilities including Odin, Nordøst Frigg, Øst Frigg, Lille Frigg, Frøy and TOGI. During processing of the cessation plans for Ekofisk I and Frigg, permission was given to leave in place the concrete substructure and protective wall on the Ekofisk tank and the TCP2 concrete substructure on the Frigg field.

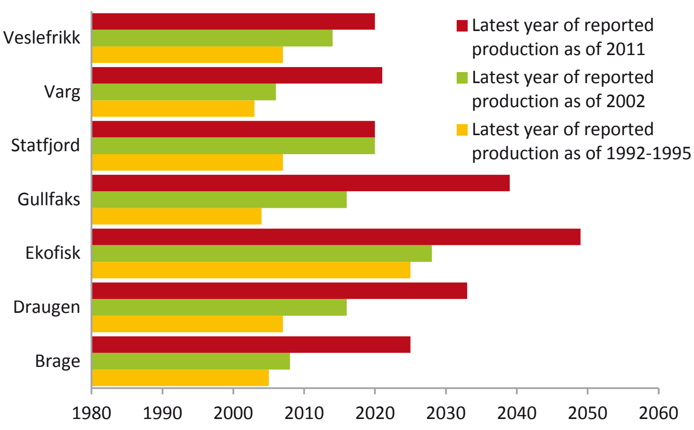


Figure 6.4 Lifetime for selected fields
(Source: Norwegian Petroleum Directorate))

Regulations

When the authorities make decisions regarding how a facility on the Norwegian continental shelf must be disposed of, both national and international regulations are applied. The Petroleum Act of 1996 governs disposal or decommissioning of facilities. In addition to the Petroleum Act, the OSPAR convention (Convention for the Protection of the Marine Environment of the North-East Atlantic) governs disposal of facilities. OSPAR decision 98/3 on the Disposal of Disused Offshore Installations entered into force on 9 February 1999, and lays down guidelines for disposal alternatives that are acceptable for various types of offshore facilities. The decision does not include pipelines, parts of facilities that are below the seabed, and concrete anchor foundations that are not a hindrance for fisheries.

The decision entails that it is prohibited to dump or to abandon all or parts of scrapped facilities in the ocean area. Exceptions from the prohibition can be made for some facilities or parts of facilities if a comprehensive assessment shows that there are strong reasons for disposal at sea.

For pipelines and cables, the guidelines in Storting White Paper No. 47 (1999–2000) Disposal of scrapped pipelines and cables, shall apply. As a general rule, pipelines and cables can be abandoned when they are not an inconvenience or constitute a risk for demersal fishing, assessed based on the costs associated with trenching, covering or removal.

As a main rule, the Petroleum Act requires licensees to present a cessation plan to the Ministry two to five years before the licence expires or is relinquished, or the use of a facility ends.

The cessation plan must have two main sections; an impact assessment and a disposal section. The impact assessment provides an overview of consequences that are expected from the disposal, e.g. for the environment. The disposal section must include a proposal for a final disposal solution.

A disposal decision will be made on the basis of the impact assessment and the consultation opinions, as well as the disposal section and evaluations of this section.

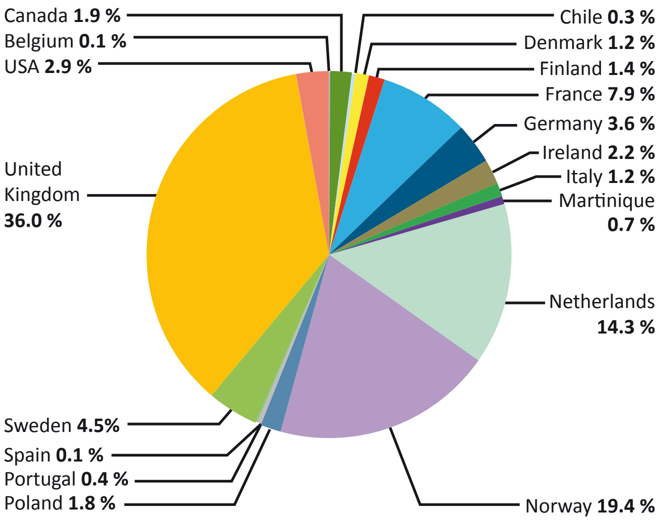


Figure 6.5 Deliveries of Norwegian crude oil distributed by receiving country, 2011 *(Source: Statistics Norway)*

Figure 6.6 The pumping facility 37/4A whose substructure was removed during the summer *(Source: ConocoPhillips)*

Figure 6.7 Illustration of the Ekofisk tank before and after removal of the topside *(Source: ConocoPhillips)*

The licensees at the time the disposal decision is made are responsible for carrying out the disposal. In 2009, the Petroleum Act was amended so that the party that sells part of a production licence has an alternative liability for removal costs related to the sold share.

When a decision is made regarding abandonment, the Regulations stipulate that the licensees are still responsible for wilful or negligent damage, injury or inconvenience in connection with the abandoned facility. However, the licensees and the State can agree that future maintenance and responsibilities will be transferred to the State for an agreed financial compensation.

GAS EXPORT FROM THE NORWEGIAN SHELF 7

Norwegian export gas arriving at the terminal in Emden, Germany. The Norwegian Petroleum Directorate makes sure that the measuring instruments work precisely. (Photo: Emilie Ashley, NPD)

Gas activities make up a growing share of the petroleum sector, and provide the State with considerable revenues. Norwegian gas is important for the European energy supply and is exported to all the major consumer countries in Western Europe. In energy content, the gas export in 2011 was about eight times that of the normal Norwegian production of electricity. Norwegian gas export covers close to 20 per cent of European gas consumption. Most of the exports go to Germany, the UK, Belgium and France, where Norwegian gas accounts for between 20 and 40 per cent of the total gas consumption.

Producing companies on the Norwegian continental shelf have gas sales agreements with buyers in Germany, France, the UK, Belgium, the Netherlands, Italy, Spain, the Czech Republic, Austria and Denmark. The Snøhvit facility delivers LNG (liquefied natural gas) to countries including the US, Japan, South Korea and several countries in the EU area. Figure 7.1 shows historical and expected Norwegian gas sales. The gas sales are expected to peak at a level between 105 and 130 billion Sm^3 in 2020, while sales are expected to be between 80 and 120 billion Sm^3 in 2025.

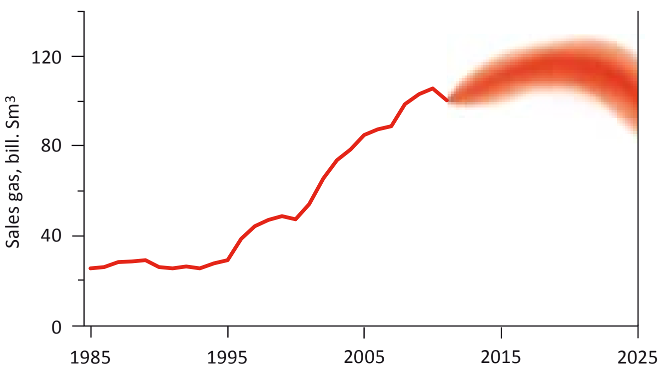


Figure 7.1 Sales gas from Norwegian fields *(Source: Norwegian Petroleum Directorate / Ministry of Petroleum and Energy)*

The transport capacity in the Norwegian pipeline system is currently about 120 billion Sm^3 per year. There are four receiving terminals for Norwegian gas on the Continent; two in Germany, one in Belgium and one in France. In addition, there are two receiving terminals in the UK (see map). The Norwegian gas transport system includes a network of pipelines with a length totalling more than 7975 km. This roughly corresponds to the distance from Oslo to Beijing. Treaties have been drawn up that govern rights and obligations between Norway and countries with landing points for gas.

All licensees on the Norwegian continental shelf are responsible for selling their own gas. Statoil sells oil and gas owned by the State, together with its own petroleum, in accordance with special instructions.

Gas production requires substantial investments in transport solutions. Most of the Norwegian gas is transported via pipelines from the fields to the gas consumers. In new developments, the authorities put considerable emphasis on exploring various transport solutions, so that the most robust solution can be selected. In many cases, it is prudent to construct the pipelines somewhat larger than is initially needed, so that gas from potential new gas fields can be transported in the existing pipeline system.

Organisation of the gas transport system

It is a paramount goal to achieve the greatest possible value for the Norwegian petroleum resources. Most fields contain both oil and gas, and it is a question of securing an optimal balance between oil and gas production. When the authorities grant production licences for gas, optimal recovery of oil is considered. The authorities play an important role in ensuring that the processing and transport capacity is adapted to various scenarios for new production in the intermediate and long term.

At the same time, it is important to ensure efficient operations in the Norwegian gas transport system, e.g. in the form of economies of scale. The authorities' tools in this regard are the operating company Gassco, the joint ownership of the Gassled system and regulated access to the transport system

Gassco

Gassco AS was established in 2001, and the State owns 100 per cent of the company. Gassco is the operator of the gas transport system with both special and public operator responsibility. The special operator responsibility entails the development of infrastructure and the operation and management of capacity in the gas transport system. Public operatorship means carrying out facility management in pursuance of the Petroleum Act and the health, safety and environment (HSE) legislation. This activity is also regulated in the operator agreement with Gassled[1].

Gassco studies transport solutions, and advises the authorities. Gassco will contribute to a comprehensive further development of Norwegian gas infrastructure. In cases where major developments are considered, this entails that other Norwegian gas beyond fields that trigger a gas transport need, must also be included in the assessments. Further development of the gas infrastructure must take place in a manner that is beneficial for the existing gas infrastructure.

Gassled

Gassled was established on 1 January 2003 and is a joint venture. The company has no employees, and is organised through various committees with specific tasks.

The joint venture owns a majority of the transport system for Norwegian gas, which is to say the pipelines and the terminals. Gassled includes all rich and dry gas facilities that are either used or planned to be used by both the owners and others. When a third party uses a pipeline or transport-related facility, the plan is for these to be included in Gassled, and become part of the central upstream gas transport system.

Regulated access to the transport system

The pipeline system is a natural monopoly, with significant infrastructure investments. Therefore, the tariffs for gas transport are regulated through separate regulations stipulated by the Ministry of Petroleum and Energy. This ensures that profits are extracted in the fields and not in the transport system. The oil companies have

1 Chapter 14 provides a more detailed description of the special and public operatorship.

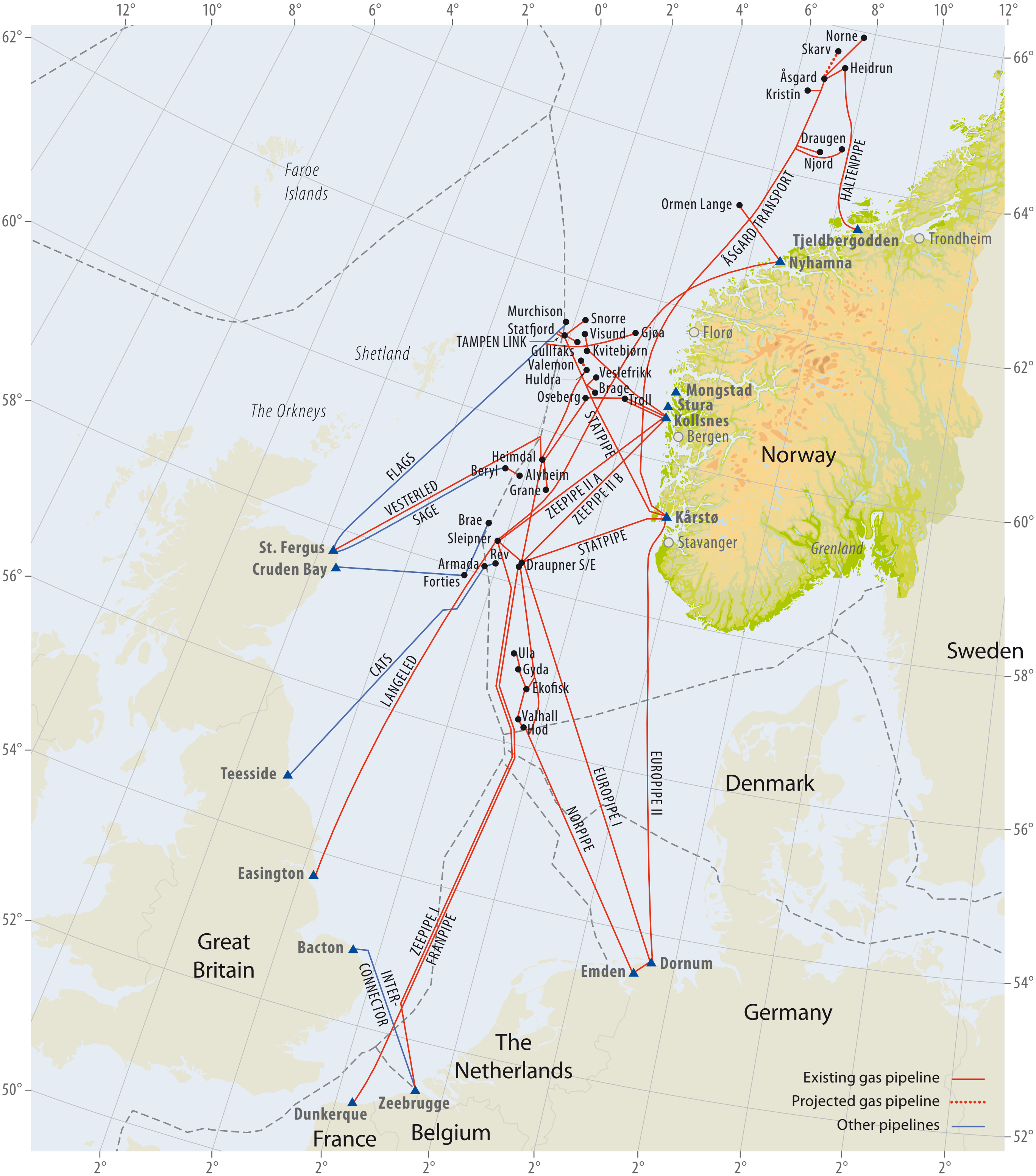


Figure 7.2 Gas pipelines *(Source: Norwegian Petroleum Directorate)*

access to capacity in the system based on the need for gas transport. To ensure good resource management, transport rights can be transferred between users when capacity needs change.

Joint ownership of the transport system ensures that the gas is transported as efficiently as possible and provides the greatest value creation, in part by avoiding conflicts of interest regarding what pipeline the gas will be transported through. Gassco is the operator of Gassled, by agreement with the owners. Gassco also manages the consideration for efficient transport of gas in the day-to-day operation of the facilities, as part of the special operatorship. See more detailed discussion in Chapter 14.

Norwegian gas production 2010, mill. Sm^3		
Pipeline exports	97 326	92.5 %
Sales to Norway	1 645	1.6 %
Sales to re-injection	1 347	1.3 %
LNG	4 953	4.7 %
Total	105 271	100.0 %
Source: Gassco/Norwegian Petroleum Directorate		

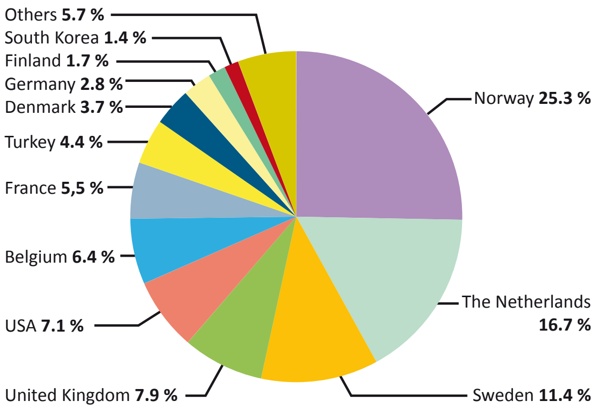


Figure 7.3 Sale of NGL/condensate in 2011 by country of first destination, about 20.2 mill. Sm^3 o.e. *(Source: Norwegian Petroleum Directorate)*

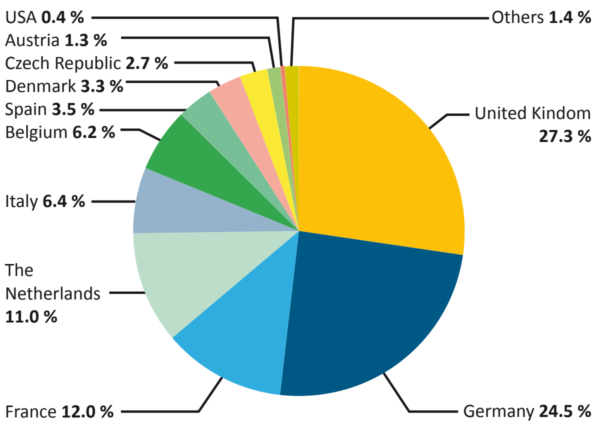


Figure 7.4 Norwegian natural gas exports 2011, based on buyer company's nationality *(Source: Norwegian Petroleum Directorate)*

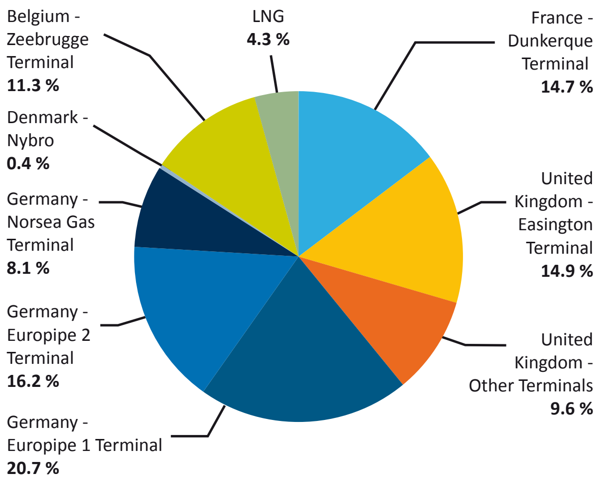


Figure 7.5 Norwegian natural gas exports, about 100,2 billion Sm^3 distributed by receiving terminal *(Source: Gassco/Norwegian Petroleum Directorate)*

8

RESEARCH IN THE OIL AND GAS ACTIVITIES

Each year, large amounts of money are used for research in the oil and gas industry. (Photo: Øyvind Hagen, Statoil)

New technology has played an important role in achieving an optimal and environmentally friendly exploitation of the resources on the Norwegian shelf. Favourable framework conditions from the authorities have given the companies incentives to carry out research and technology development. Close collaboration between oil companies, the supplier industry and research institutions has been a precondition for this development. Through technology developed on the Norwegian shelf, the Norwegian supplier industry has also gained a competitive advantage internationally.

The Norwegian shelf is facing several new challenges. There are fewer large discoveries and developments than before. Production of the remaining resources in the fields is more demanding than those resources that have been produced. The opportunities available to individual projects for financing technological development are smaller. To meet these challenges, a continued focus on research and development is needed from the players on the Norwegian shelf and the State as resource owner. Figure 8.2 shows how the Ministry of Petroleum and Energy is involved in petroleum research in Norway.

To meet the challenges associated with efficient and prudent petroleum activities, the Oil and Gas in the 21st Century (OG21) strategy was established in 2001, on the initiative of the Ministry of Petroleum and Energy. OG21 has helped oil companies, universities, research institutions, the supplier industry and the authorities agree on a joint national technology strategy for oil and gas.

The State provides the incentives for research and technological development mainly through the regulatory framework and direct allocations to the Research Council.

The allocations to the Research Council are mainly directed at the research programs PETROMAKS and DEMO 2000. These programs will contribute to reaching the goals that are set through the OG21 strategy.

PETROMAKS

PETROMAKS supports a wide range of projects from basic research to innovation projects in the industry. The purpose of the program is to mature more reserves, both from producing fields and through discoveries. Since 2003, about NOK 2 billion has been allocated to 360 projects. This has triggered NOK 2.1 billion in additional financing, mainly from business and industry. PETROMAKS is an important policy instrument for promoting long-term research and evelopment of capabilities. Since its start in 2003, the program has financed 291 research fellows and 136 post doctoral students. This is a very high figure compared with what the oil companies support of similar positions, and illustrates the importance of public funding for long-term and basic research.

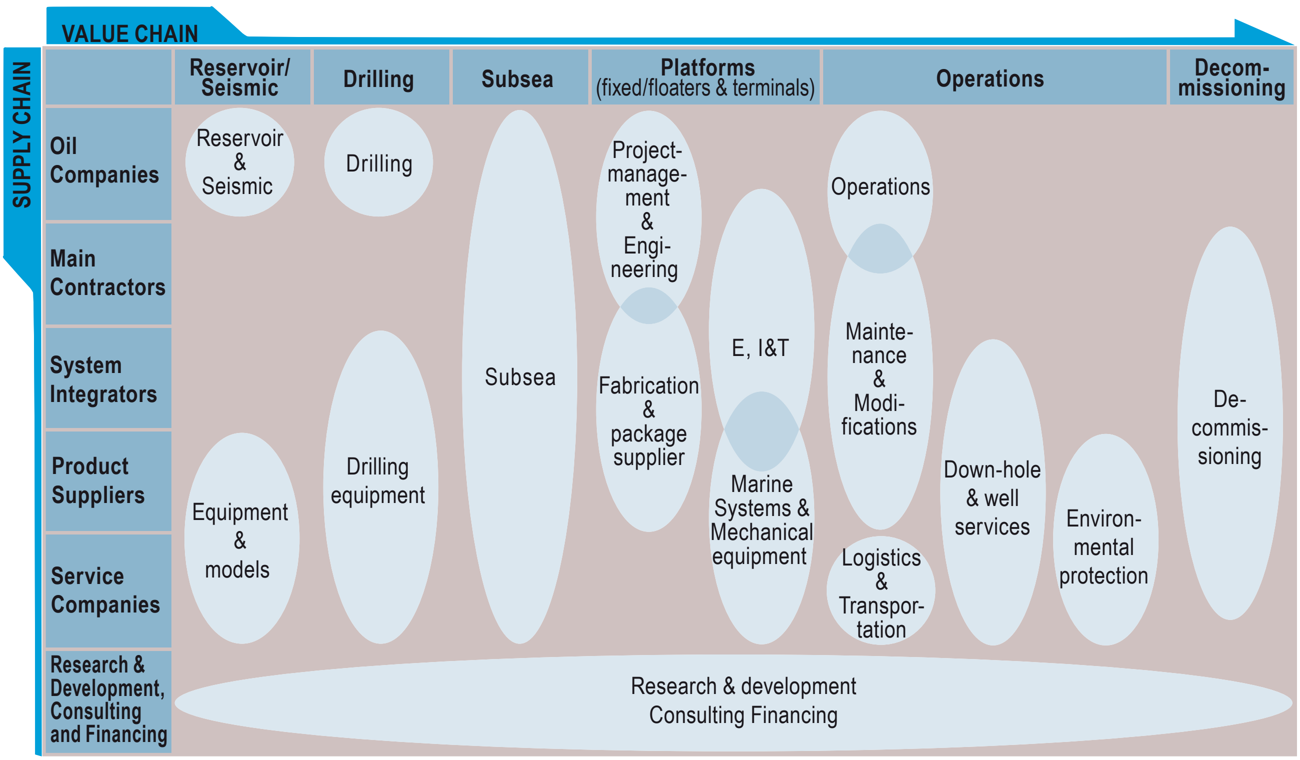


Figure 8.1 Map of the Norwegian Oil & Gas "World-Class" Clusters *(Source: www.Intsok.com)*

DEMO 2000

DEMO 2000 is an important policy instrument for testing new technology solutions in the petroleum industry. The purpose of the program is to reduce costs and risk for the industry by supporting pilot projects and demonstrations. DEMO 2000 functions as a collaborative arena in the oil and gas sector, and is particularly important for the supplier industry. The contractors and the research community do not benefit from the same incentives for developing technology as the oil companies investing in the technology. On the basis of legal frameworks, the oil companies benefit from targetted tax incentives pertaining to their research-related licence expenditures.

Since its start in 1999, DEMO 2000 has supported 241 pilot projects. The total costs associated with these projects amount to NOK 2.7 billion, and the authorities have contributed close to NOK 700 million through the national budget.

Other research programs

Several other petroleum-relevant research programs receive public support. ProofNy, a sub-program under The Ocean and Coast, targets research on the long-term effects on the ocean as a result of the petroleum activities. PETROSAM supports petroleum research related to the social sciences. The Research Council of Norway has also established several Centres of Excellence (SFF) and Centres for Research-driven Innovation (SFI). Several of these centres are relevant for the petroleum industry, such as CIPR (Centre for Integrated Petroleum Research) at the University of Bergen, FACE within multiphase research at Sintef/IFE, the Center for Integrated Operations in the Petroleum Industry at the Norwegian -University of Science and Technology (NTNU), the Center for Drilling and Well for Improved Recovery (CDWR) at IRIS (in cooperation with Sintef) and the Centre for Sustainable Arctic Coastal and Marine Technology at NTNU. The centres for research-driven innovation can receive support for up to eight years, and the centres for distinguished research can receive support for up to ten years.

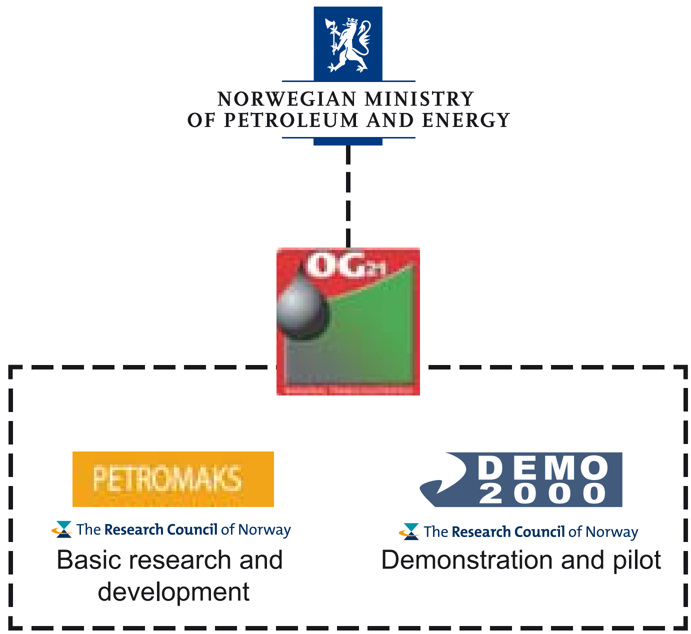


Figure 8.2 Ministry of Petroleum and Energy's involvement in petroleum research *(Source: Ministry of Petroleum and Energy)*

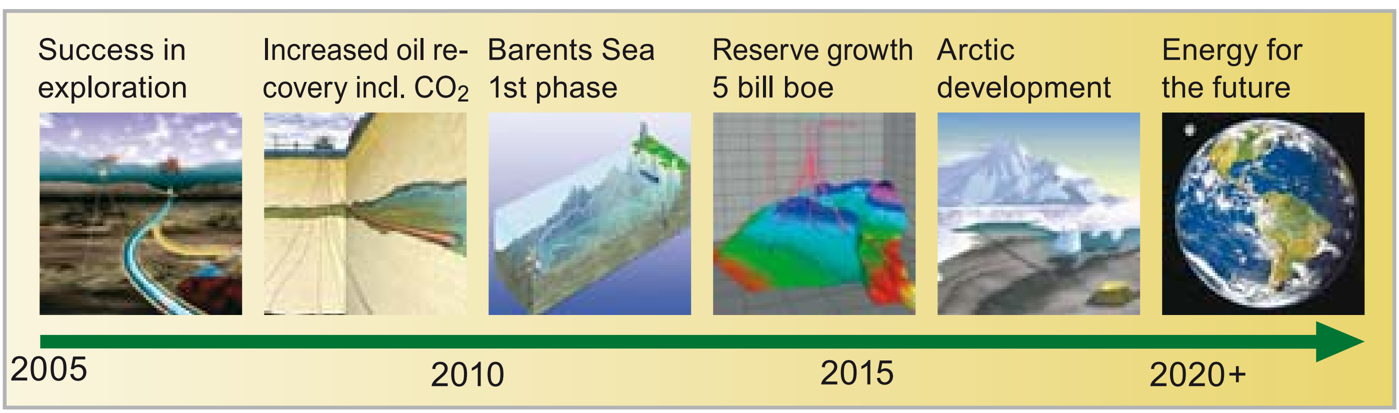
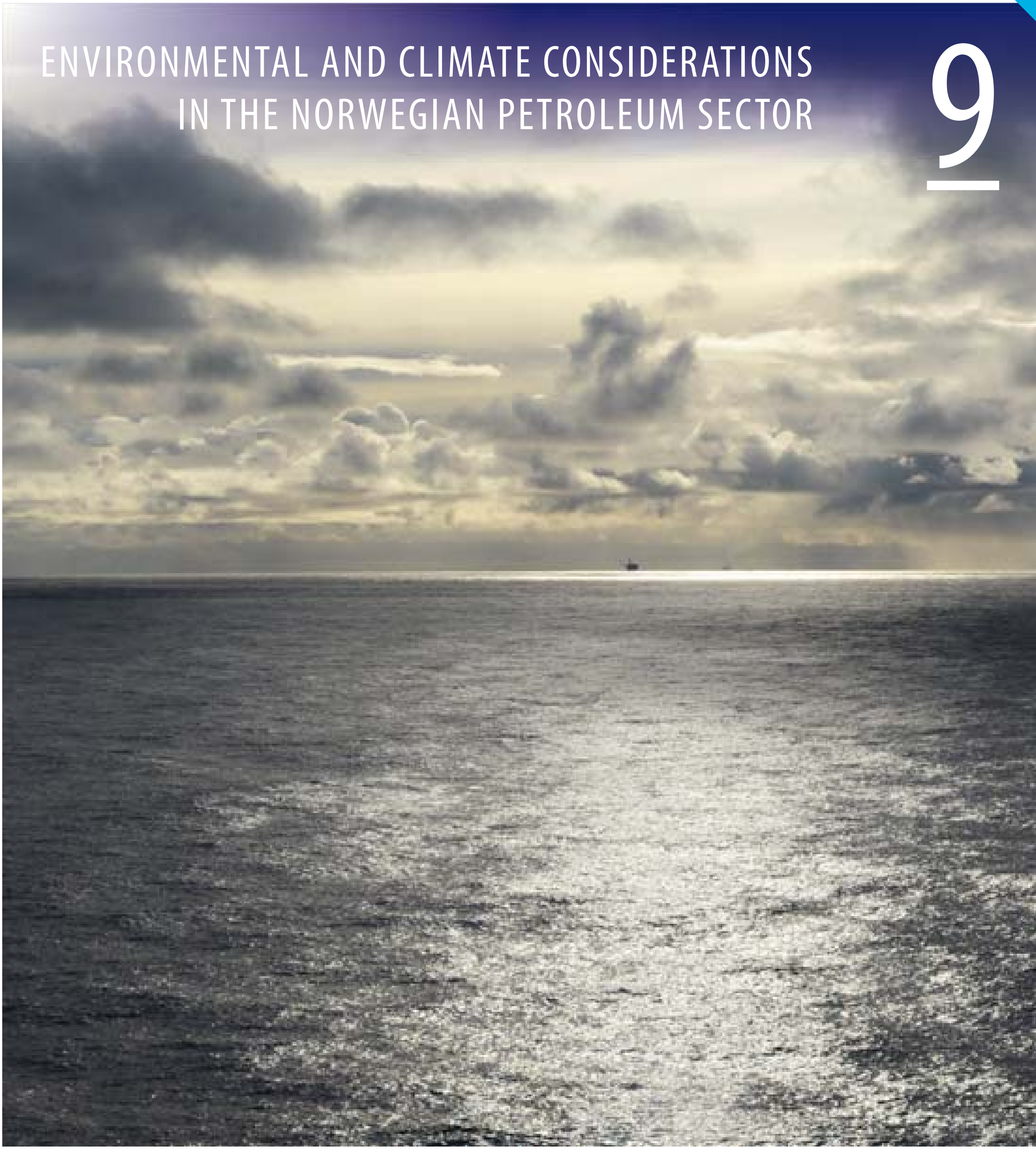


Figure 8.3 OG21's technology road map for value creation on the Norwegian continental shelf *(Source: OG21)*

ENVIRONMENTAL AND CLIMATE CONSIDERATIONS IN THE NORWEGIAN PETROLEUM SECTOR

9



The petroleum industry operates in somewhat harsh environments year-round. (Photo: Harald Pettersen, Statoil)

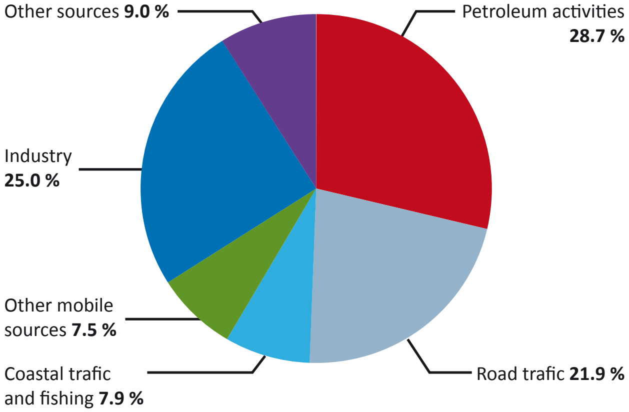
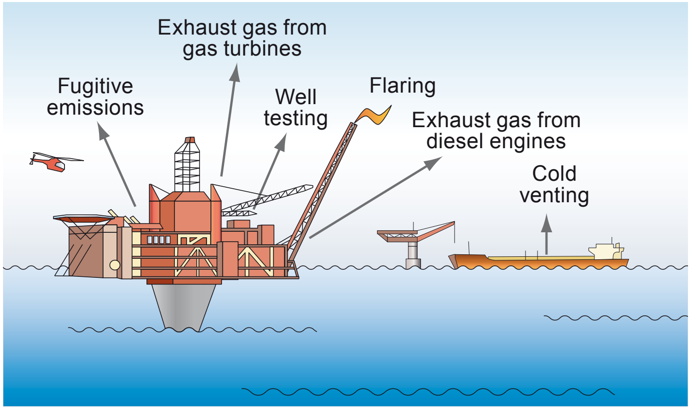


Figure 9.1 Sources of Norwegian emissions of CO_2, 2009
(Source: Statistics Norway)



Overview emission/discharge sources

Environmental and climate considerations have always been an integral part of the Norwegian petroleum activities. A comprehensive policy instrument scheme has been developed, which safeguards environmental and climate considerations in all phases of the petroleum activities, from licensing rounds to exploration, development, operation and cessation. The strict restrictions on flaring under the Petroleum Act contribute to keeping the general flaring level on the Norwegian shelf low, compared with the international level.

Norway, as one of the first countries in the world, introduced a CO_2 tax in 1991. The tax has led to technological development and triggered measures that have yielded considerable emission reductions. The authorities and the petroleum industry have worked together to reach the goal of zero harmful discharges to sea (the zero emissions goal). The goal of zero discharges is considered to have been achieved for added chemicals.

As a result of a continuing strong emphasis on the environment, the Norwegian petroleum sector maintains a very high environmental standard compared with petroleum activities in other countries.

This chapter provides an overview of emissions to air and discharges to sea from the petroleum activities, as well as policy instruments and measures that safeguard environmental and climate considerations.

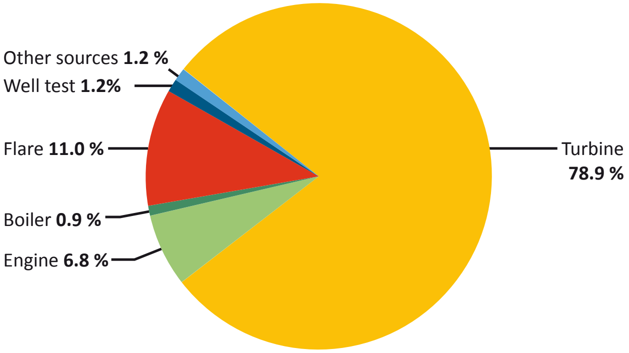


Figure 9.2 CO_2 emissions from petroleum activities 2010, by source
(Source: Norwegian Petroleum Directorate)

Emissions and discharges from the petroleum activities

Emissions to air from the petroleum sector are generally flue gas from combustion of natural gas in turbines, flaring of natural gas and combustion of diesel (see Figure 9.2). The flue gas contains e.g. CO_2 and NO_x. Other emissions include nmVOC, methane (CH4) and sulphur dioxide (SO_2). Discharges to sea from the petroleum sector contain remnants of oil and chemicals used in the production processes. There are also discharges to sea of drill cuttings with remnants of water-based drilling fluids.

Statutes and framework agreements that regulate emissions and discharges from the petroleum activities

Emissions and discharges from the Norwegian petroleum activities are regulated through several acts, including the Petroleum Act, the CO_2 Tax Act, the Sales Tax Act, the Greenhouse Gas Emission Trading Act and the Pollution Control Act. The onshore petroleum facilities face the same policy instruments as other land-based industry. In the petroleum legislation, the processes related to impact studies and approval of new development plans (PDOs/PIOs) are important. Onshore facilities or facilities within the baseline are also subject to the requirements of the Planning and Building Act (see Chapter 5).

Norway has also committed to limiting some emissions and discharges through international agreements.

Measurement and reporting of emissions and discharges

The Climate and Pollution Agency, the Norwegian Petroleum Directorate and the Norwegian Oil Industry Association have established a joint database for reporting emissions to air and discharges to sea from the petroleum activities, «Environmental Web» (EW). All operators on the Norwegian continental shelf report emission and discharge data directly into the database.

The method for estimating emissions of greenhouse gases has recently been revised, and thus the prognoses are somewhat different compared with last year's facts.

Fact box 9.1 Emissions to air

The agreements regarding emissions to air normally specify an emission limit for each country. The wording of the agreements is crucial for whether the mandatory limitations must be carried out fully within the borders of each country, or whether reductions can also be carried out in other countries where the reduction costs could be lower. The costs associated with reducing emissions from the various emission sources, both national and international, affect which measures to implement in the petroleum sector.

According to the Kyoto Protocol, Norway has an emissions target which entails that the country's average emissions of greenhouse gases for the years 2008–2012 shall not increase more than one per cent compared with the emissions level in 1990. Norway is well on the way to meeting its obligations. The requirement is fulfilled by reducing emissions nationally and in other countries using the Kyoto mechanisms «The Clean Development Mechanism» (CDM) and «Joint implementation» (JI). In Storting White Paper No. 34 (2006-2007) *Norwegian climate policy*, the Government suggested that Norway exceed the Kyoto goal by ten percentage points.

With the Greenhouse Gas Emission Trading Act of 2005 (revised several times since), Norway established a national quota system for greenhouse gases. In the autumn of 2007, Norway implemented the EU's Emission Trading Directive, and the Norwegian quota system is linked to the EU's quota system during the period 2008–2012. In December 2008, the EU agreed on an emissions trading directive for the period 2013–2020. This directive is now under assessment by the EEA/EFTA countries.

Emissions with regional environmental consequences are regulated through the protocols under the Convention on Long-Range Transboundary Air Pollution (the LRTAP Convention). In 1999, together with the USA, Canada and other European countries, Norway signed the Gothenburg Protocol. The protocol seeks to resolve the environmental issues of acidification, over-fertilisation and ground-level ozone. The Gothenburg Protocol came into force in 2005. According to this protocol, Norway shall reduce NO_x emissions to 156 000 tonnes by 2010. This entails a 29 per cent reduction compared with the 1990 emissions levels. The nmVOC obligation is approximately equivalent to what Norway has agreed to under the current Geneva Protocol. This requires the annual nmVOC emissions from the entire mainland and Norwegian economical zone south of the 62nd parallel to be reduced as soon as possible by 30 per cent compared with the 1989 levels. According to the Gothenburg Protocol, the total national emissions must not exceed 195 000 tonnes per year by 2010. Due to reduction measures on tankers that carry out offshore loading on the Norwegian shelf, as well as lower oil production, these requirements have been fulfilled.

In the autumn of 2009, the EU directive on national emission ceilings for certain atmospheric pollutants («the NEC Directive») was included in the EEA Agreement. Starting in 2010, the Directive stipulates annual emission ceilings for the individual countries of the same substances included in the Gothenburg Protocol. Norway is committed through the EEA Agreement to carry out the same emission reductions as those defined in the Gothenburg Protocol.

CO_2 emission status

Nationally, the petroleum activities accounted for about 29 per cent of the CO_2 emissions in 2010 (see Figure 9.1). The other large sources of CO_2 emissions in Norway are emissions from industrial processes and road traffic.

The development on the Norwegian continental shelf is heading towards more mature fields and longer distances for gas transport. Processing and transport of produced gas is more energy-intensive than production and transport of liquids. Gas production accounts for an increasing share on the Norwegian continental shelf. In addition, the fields' reservoir pressure is decreasing.

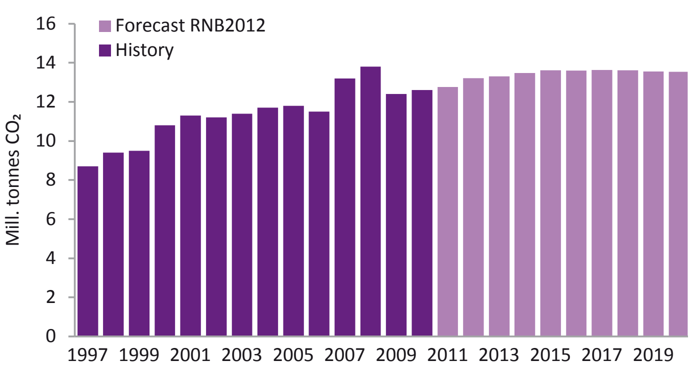


Figure 9.3 Emissions of CO_2 from the Norwegian petroleum sector *(Source: Norwegian Petroleum Directorate)*

Policy instruments for reducing CO_2 emissions

Norway is well in the forefront when it comes to utilising environmentally efficient solutions, and policy instruments are used and measures are implemented in the work to reduce CO_2 emissions. The CO_2 Tax Act and the Greenhouse Gas Emission Trading Act are the key instruments for reducing these emissions. The authorities can also use other instruments, such as conditions in PDOs/PIOs, emission/discharge permits and production licences, which for example include flaring.

The CO_2 tax

Pursuant to the CO_2 Tax Act, the use of gas, oil and diesel in connection with petroleum activities on the continental shelf is subject to a CO_2 tax as of 1 January 1991. As of 1 January 2012, the CO_2 tax is NOK 0.49 per litre of oil or per standard cubic metre (Sm^3) of gas.

The Greenhouse Gas Emission Trading Act

The Greenhouse Gas Emission Trading Act was enacted in 2005 and was most recently revised in 2011. The offshore petroleum facilities

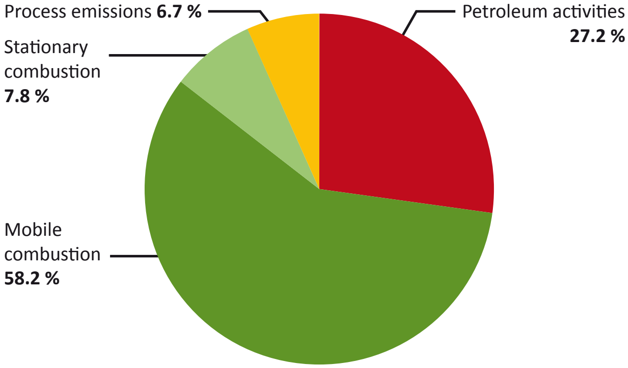


Figure 9.4 Sources of NO_x emissions in Norway in 2009
(Sources: Statistics Norway)

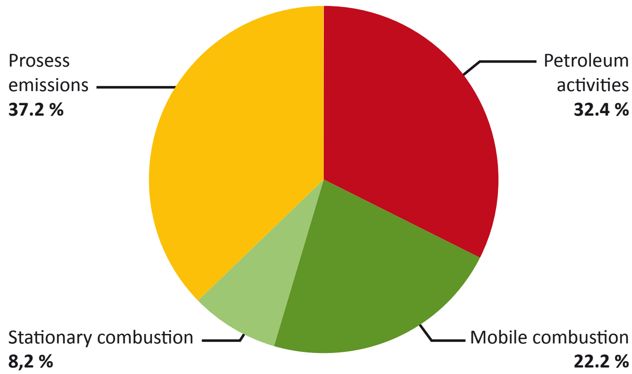


Figure 9.6 Sources of Norwegian emissions of nmVOC in 2009
(Source: Statistics Norway)

are included in the Norwegian quota system as of 2008, together with the companies that had a quota duty during the first period of the quota system (2005–2007). As of today, the petroleum facilities must purchase emission quotas for all their emissions. Purchases of emission quotas are in addition to the CO_2 tax, and yield an expected total CO_2 cost of close to NOK 300 per tonne of CO_2.

Conditions and permits

According to the Petroleum Act, burning of gas in flares beyond what is necessary to ensure normal operations is not permitted without approval from the Ministry of Petroleum and Energy. Flaring accounts for about 11 per cent of the CO_2 emissions from the petroleum activities. A number of emission reduction measures put Norway in the forefront in this area.

All Plans for Development and Operation of oil and gas fields (PDOs/PIOs) must contain a good and efficient energy solution, including an analysis of possible power supply from shore. This applies to both new field developments and major modifications on existing facilities.

Examples of measures for reducing CO_2 emissions from fields

The authorities and the oil companies maintain a strong focus on research and technological development to find good technical solutions that can contribute to reducing harmful emissions. Considerable efforts are devoted to developing environmental expertise and technology, and the Norwegian petroleum industry is in the forefront when it comes to utilising both environmentally and climate friendly solutions. This has yielded results, and many of the solutions used in Norway have become export commodities.

Combined cycle power

Combined cycle power is a solution in which the exhaust gas from turbines is used to produce steam, which is then used to generate electricity. Combined cycle power increases energy exploitation and is currently in use on the Oseberg, Snorre and Eldfisk fields. These facilities are unique in a global offshore perspective.

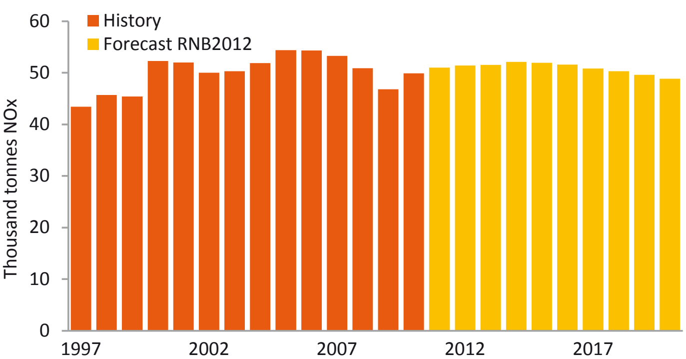


Figure 9.5 Emissions of NO_x from the petroleum activities
(Source: Norwegian Petroleum Directorate)

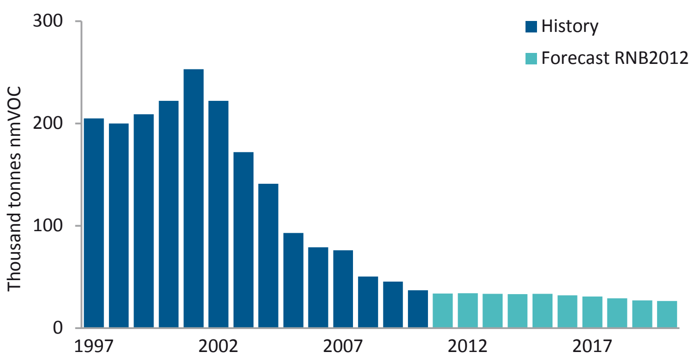


Figure 9.7 Emissions of nmVOC from the petroleum activities
(Source: Norwegian Petroleum Directorate)

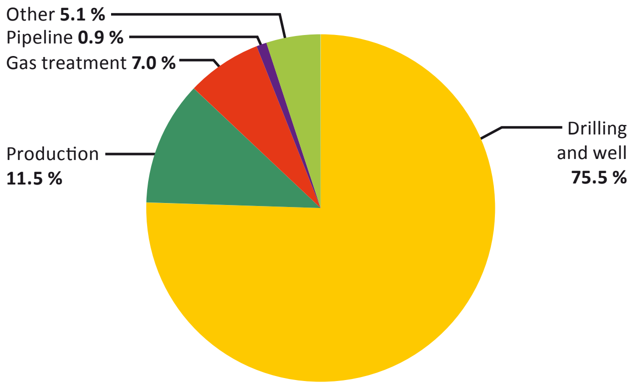


Figure 9.8 Discharges of chemicals from Norwegian petroleum activities, by sources, 2010 *(Source: Norwegian Petroleum Directorate)*

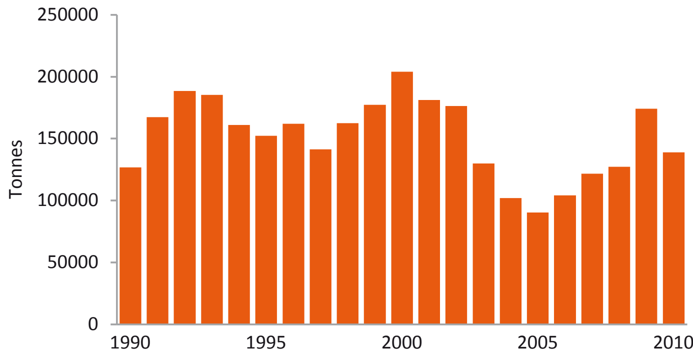


Figure 9.9 Total discharges of chemicals from Norwegian petroleum activities *(Source: Norwegian Petroleum Directorate)*

Storage of CO_2

CO_2 can be injected and stored in depleted oil or gas reservoirs, or in geological formations under water or on shore. Since 1996, about one million tonnes of CO_2 has been stored annually in the Utsira formation in connection with processing the gas from the Sleipner Vest field. With the Sleipner project, Norway was the first country in the world to store large amounts of CO_2 in a geological formation under the seabed in the Utsira formation. In April 2008, the Snøhvit field started separating and storing CO_2 before the natural gas is cooled to liquid gas (LNG). The CO_2 gas runs through pipes from the LNG plant on Melkøya and back to the field where it is injected and stored in the Tubåen formation. During normal operation on Snøhvit, up to 700 000 tonnes of CO_2 can be stored per year.

Energy conservation

Several energy conservation measures have been carried out after the CO_2 tax came into effect in 1991. Energy efficiency and energy management systems are important measures in the work to reduce emissions. This work requires continuous follow-up. The choice of measure depends e.g. on the facility's age, operations pattern, installed equipment and processes, as well as available execution capacity. Examples of measures include modifications to power-intensive equipment (i.e. compressors and pumps), and optimisation of the process for improved energy utilisation.

Power from shore

Power from shore must be viewed in light of the fact that there are considerable differences between the facilities when it comes to technical properties, costs and the effect they have on other power users through the connection to the general power supply.

As of today, several fields receive all or some of their power supply from shore. For instance, the facilities on Troll A, Ormen Lange and Gjøa use power from the electrical grid, while Valhall Redevelopment and Goliat will be provided with power from shore when production starts. In 2010, about 42 per cent of Norwegian gas exports came from fields with power supply from shore.

NO_x emission status

The emissions of CO_2 and NO_x are closely related. As for CO_2, gas combustion in turbines, flaring of gas and diesel consumption on the facilities are the main emission sources also for NO_x. The volume of emissions depends both on the combustion technology and how much fuel is used. For example, combustion in gas turbines results in lower emissions of NO_x than combustion in diesel engines.

NO_x consists of several nitrogen compounds that contribute to acidification. The environmental effects of NO_x include harm to fish and animal life through acidification of river systems and soil, as well as damage to health, crops and buildings due to the formation of ground-level ozone.

Mobile sources account for the majority of the Norwegian NO_x emissions (see Figure 9.4). The petroleum sector contributes approximately 27 per cent. The sector's total emissions of NO_x have increased since 1991 (see Figure 9.5) but have stabilised over the last ten years. The primary cause of the growth is increased level of activity contributing to more emissions.

Policy instruments for reducing NO_x emissions

Conditions and permits

During the operations phase, emissions of NO_x on the continental shelf are regulated by conditions that might be set in connection with consideration of the PDOs/PIOs. Emission permits can also be granted pursuant to the Pollution Control Act, which includes NO_x.

The NO_x tax

On 28 November 2006, the Storting approved a tax on emissions of NO_x. The tax is directed towards emissions from mainland activities, and includes emissions from large units within shipping, aviation, land-based activity and the continental shelf. Within the petroleum sector, the tax covers total emissions from larger gas turbines and machines and from flaring. In 2012, the tax is set at NOK 16.69 per kilogram of NO_x.

In connection with the Storting's consideration of the NO_x tax, a decision was made to provide an exemption for emission sources

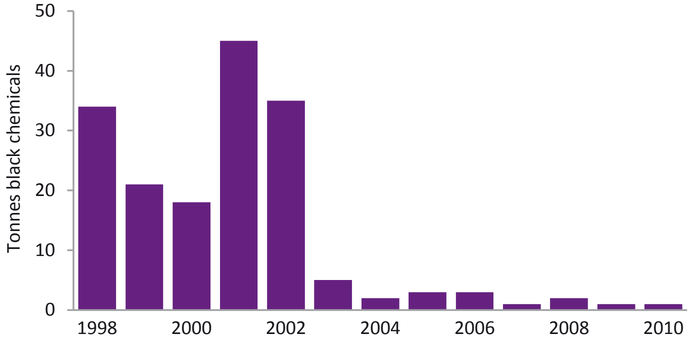


Figure 9.10 Discharges of black chemicals from petroleum activities *(Source: Norwegian Petroleum Directorate)*

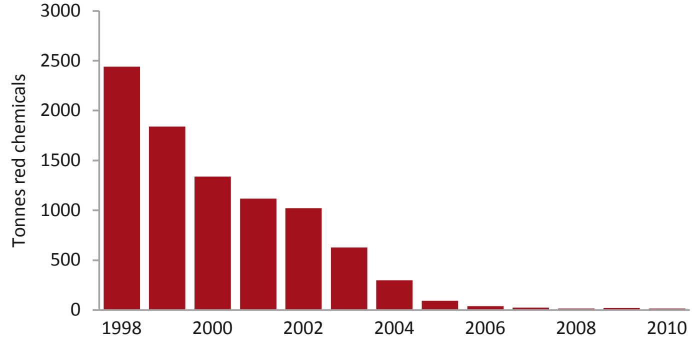


Figure 9.11 Discharges of red chemicals from petroleum activities *(Source: Norwegian Petroleum Directorate)*

covered by environmental agreements with the State regarding implementation of NO_x-reducing measures. An environmental agreement has been signed by the Norwegian State and industry organisations regarding reduction of NO_x emissions.

The industry organisations have established a separate NO_x fund that will be used to fulfil their commitments under this agreement. On behalf of the industry organisations, the fund collects payments per kilogram of NO_x emissions from enterprises that have endorsed the agreement, and the fund provides contributions to cost-effective NO_x-reducing measures. As of 14 December 2011, 656 enterprises had endorsed the new environmental NO_x agreement for 2011-2017. Most of the oil and gas industry's activities have endorsed the agreement.

Example of a measure for reducing NO_x emissions

Low NO_x burners

One measure is low-NO_x burners, which can be retrofitted on existing turbines. Studies show that the general cost level of retrofitting such burners is considerably higher than previously assumed. In general, low NO_x technology installed on machines running with a high utilisation factor will result in considerable reductions in NO_x emissions.

NmVOC emissions status

NmVOC is a designation for volatile organic compounds, with the exception of methane, which evaporate from subtances such as crude oil. The environmental effects of nmVOCs include the formation of ground-level ozone, which can result in health hazards and damage to crops and buildings. NmVOCs can also cause respiratory tract damage in the event of direct exposure, and contributes indirectly to the greenhouse effect through formation of CO_2 and ozone when nmVOCs react with air in the atmosphere.

The petroleum sector has traditionally been one of the main sources of nmVOC emissions in Norway. The emissions of nmVOCs from the petroleum activities are mainly from storage and loading of crude oil offshore. Minor emissions also occur at the gas terminals. Other industrial processes and road traffic are also important sources of nmVOC emissions in Norway (see Figure 9.6). The emissions from the petroleum sector have, however, been substantially reduced since 2001 and the prognosis indicates a strong decline in the years ahead (see Figure 9.7). The primary cause of the emission reductions is the implementation of emission reducing technology.

After a substantial decline in Norwegian emissions of nmVOC since 2001, emissions increased by 1 per cent in 2010, amounting to a total of 141 000 tonnes nmVOC. Improved loading technology in the petroleum sector has contributed to the overall nmVOC reductions, and the decline for this source continued in 2010. Solvent emissions from products, however, increased in 2010, outweighing the emission reductions in the petroleum sector. Nevertheless, Norway's total nmVOC emissions were 28 per cent below the Gothenburg protocol requirements.

Policy instruments and measures for reducing nmVOC emissions

For several years, the oil companies have worked on making technology for recovery of nmVOC available for storage ships and shuttle tankers. Today, tested technology exists that can reduce emissions from loading by about 70 per cent. The agreement regarding industrial cooperation was signed in 2002. It will contribute to coordinate the phase-in of technology that meets the requirements for best available emission-reducing technology (BAT) in a suitable and cost-effective manner. At the end of 2009, 19 shuttle tankers had installed nmVOC-reducing technology, as well as the storage ships Norne, Åsgard A and C, Jotun, Balder, Varg and Volve. The Alvheim field's facility came on stream in July 2010.

A recovery facility for nmVOC was put to use at the crude oil terminal at Sture in 1996. The facility is the first of its kind at a crude oil terminal. Loading tankers must have connection equipment installed in order to use the facility. As of 1 January 2003, all ships have been required to install equipment for recovery of nmVOC, and the ships can normally not approach the facility without the necessary equipment.

Discharges to sea

Discharges to sea mainly include produced water, drill cuttings and remnants of chemicals and cement from drilling operations.

Produced water

Oil and chemical discharges from produced water can have local effects close to the facilities, and are regulated nationally through discharge permits pursuant to the Pollution Control Act. The discharges are also regulated internationally through the Oslo-Paris Convention for discharges to sea (the OSPAR Convention). The internationally stipulated maximum level for oil content in water was reduced for discharges to sea to 30 mg per litre as of 2007.

The goal of zero environmentally harmful discharges to sea from the petroleum activities was established in 1997. After the goal of zero discharges to sea was stipulated, the authorities and the industry have worked together to specify the goal and arrive at solutions for reaching the goal. The goal has been achieved.

Chemical discharge status

Chemicals is a collective term for all additives and excipients used in drilling and well operations, and in production of oil and gas. The main rule is that environmentally harmful substances must not be discharged, whether they are added or naturally occurring.

The contribution from the petroleum sector to the national discharges to sea is less than three per cent of the environmental toxins on the Climate and Pollution Agency's (Klif's) priority list.

About 99 per cent of the chemicals used in the Norwegian petroleum activities are chemicals that are believed to have little or no environmental effects (green and yellow chemicals). A large share of them are substances that occur naturally in seawater. The rest are environmentally harmful chemicals or chemicals where potential effects are not sufficiently documented.

Most of the chemical discharges are related to the drilling activities (see Figure 9.8), and the discharge amounts vary according to the activity level. Figure 9.9 shows the development in the total discharges of chemicals from the petroleum activities.

The chemicals that are not discharged either dissolve in the oil, are deposited underground or are treated as hazardous waste.

Policy instruments for reducing discharges of chemicals

The companies must apply for a discharge permit in order to discharge chemicals to sea. The Climate and Pollution Agency (Klif) grants discharge permits pursuant to the provisions of the Pollution Control Act. Pursuant to the Pollution Control Act, operators themselves are responsibile for and have a duty to establish necessary emergency preparedness to respond to acute pollution. In addition, there is municipal and State emergency preparedness.

Discharges of oil

The total discharges of oil from the Norwegian petroleum activities account for a small share of the total discharges to the North Sea. The primary discharges of oil to the North Sea are from shipping and from the mainland through rivers. It is assumed that about 5 per cent of the total discharges of oil to the North Sea are from the Norwegian petroleum activities.

Acute discharges

All acute discharges from the facilities on the continental shelf are reported to the Norwegian Coastal Administration, and the causes are investigated.

The petroleum activities have not caused large acute discharges of oil that have led to environmental damage. In 2009, the total acute discharges to sea amounted to 104 m^3. In 2007, the total acute discharges to sea amounted to 4488 m^3, as a result of the incident on the Statfjord field in the North Sea.

The environmental effects of any acute oil discharges depend on more factors than just the size of the discharge. Among other things, the discharge site, the season, wind speed, currents and the efficiency of the emergency preparedness are crucial for the extent of the damage. Acute oil discharges can harm fish, sea mammals, seabirds and beach zones. In Norway, the most serious acute discharges are from ships near the coast.

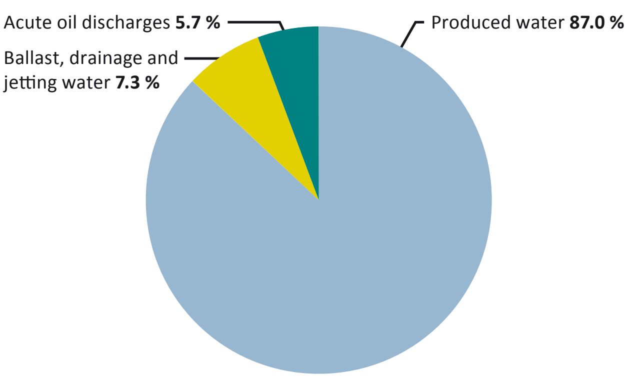


Figure 9.12 Discharges of oil from the petroleum activities, distributed by activity, 2010
(Source: Norwegian Petroleum Directorate)

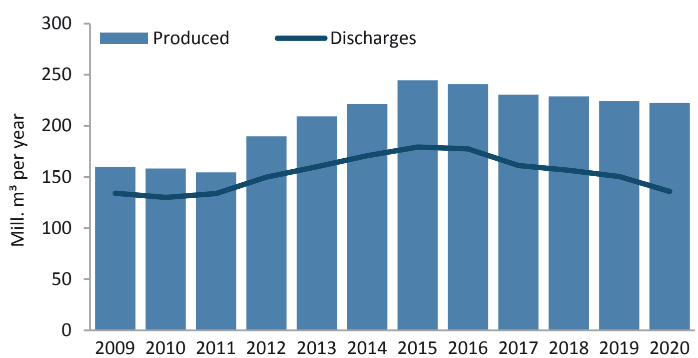


Figure 9.13 Forecast for produced water and discharges of produced water
(Source: Norwegian Petroleum Directorate)

Discharges from operations

Water produced together with oil and gas contains remnants of oil in droplet form (dispersed oil) and other organic components (including loose oil fractions). The produced water is reinjected underground or treated before it is discharged to sea. Oil-contaminated drill cuttings and drilling fluid, which previously accounted for a significant share of the oil discharges from the activities, are now injected in separate reservoirs or transported onshore for further processing. Figure 9.12 shows oil discharges distributed by activities, while Figure 9.13 shows the projected development in the volume of produced water and discharges of produced water. Implemented measures have led to considerable reductions in discharges of oil per unit of produced water.

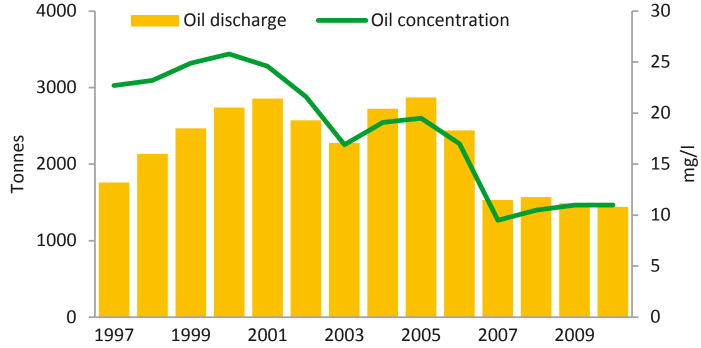


Figure 9.14 Discharge of oil in produced water and corresponding oil concentration *(Source: Norwegian Petroleum Directorate)*

Policy instruments for reducing discharges of oil

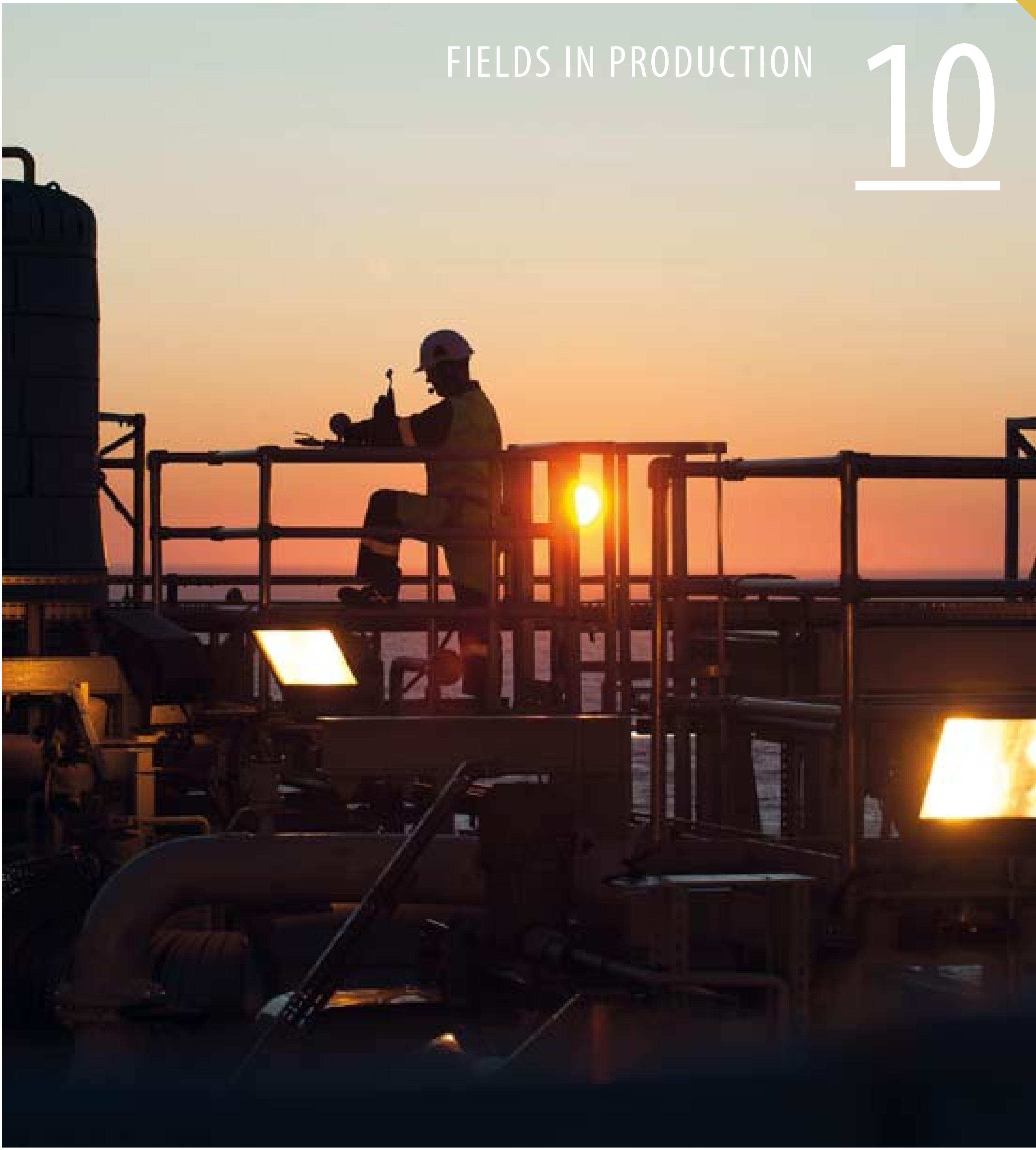
In the same manner as for chemicals, companies must apply for a discharge permit to discharge oil to sea. The Climate and Pollution Agency grants discharge permits pursuant to the provisions of the Pollution Control Act. Pursuant to the Pollution Control Act, operators themselves have responsibility for and a duty to establish necessary emergency preparedness to respond to acute pollution. In addition, there is municipal and State emergency preparedness.

Fact box 9.2 Oil spill preparedness

In Norway, the emergency preparedness against acute pollution is made up of private preparedness, municipal preparedness and government preparedness. The Ministry of Fisheries and Coastal Affairs, through the Norwegian Coastal Administration, is responsible for coordinating the collective national oil spill preparedness, and the State's preparedness against acute pollution. The Ministry of the Environment is responsible for stipulating requirements for emergency preparedness against acute pollution in municipal and private enterprises. The Climate and Pollution Agency approves emergency preparedness plans and verifies that the requirements are followed.

The oil companies, represented by the operator, are responsible for handling acute incidents resulting from own activities, with appropriately dimensioned emergency preparedness. The Norwegian Clean Seas Association for Operating Companies (NOFO), where the owners are several companies that are licensees on the Norwegian shelf, has also established regional plans that take into account reinforcement of seagoing emergency preparedness and preparedness along the coast and in the beach zone. NOFO administers and maintains a preparedness that includes personnel, equipment and vessels. NOFO has five bases along the coast: Stavanger, Mongstad, Kristiansund, Træna and Hammerfest. In addition, some fields have permanently placed NOFO equipment. NOFO has a total of 16 oil spill response systems and carries out joint exercises every year.

FIELDS IN PRODUCTION 10



Operator on assignment on the Åsgard B facility in the Norwegian Sea. (Photo: Marit Hommedal, Statoil)

Keys to tables in Chapters 10 – 12

Participating interests in fields do not necessarily correspond with interests in the individual production licences, since unitised fields or fields for which the sliding scale has been exercised have a different composition of interests than the production licence. Interests are quoted with only two decimal places, so licensee holdings in some of the fields may not add up to 100 per cent. Participating interests are shown as of February 2012.

"Original recoverable reserves" refers to reserves in resource categories 0, 1, 2 and 3 in the Norwegian Petroleum Directorate's resource classification, see figure 4.2. "Recoverable reserves remaining as of 31 December 2011" refers to reserves in resource categories 1, 2 and 3 in the Norwegian Petroleum Directorate's resource classification.

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

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

Maps in Chapters 10 – 13

- Oil
- Gas
- Oil/gas
- Gas/condensate
- Discoveries not yet delimited

Graphs in Chapter10

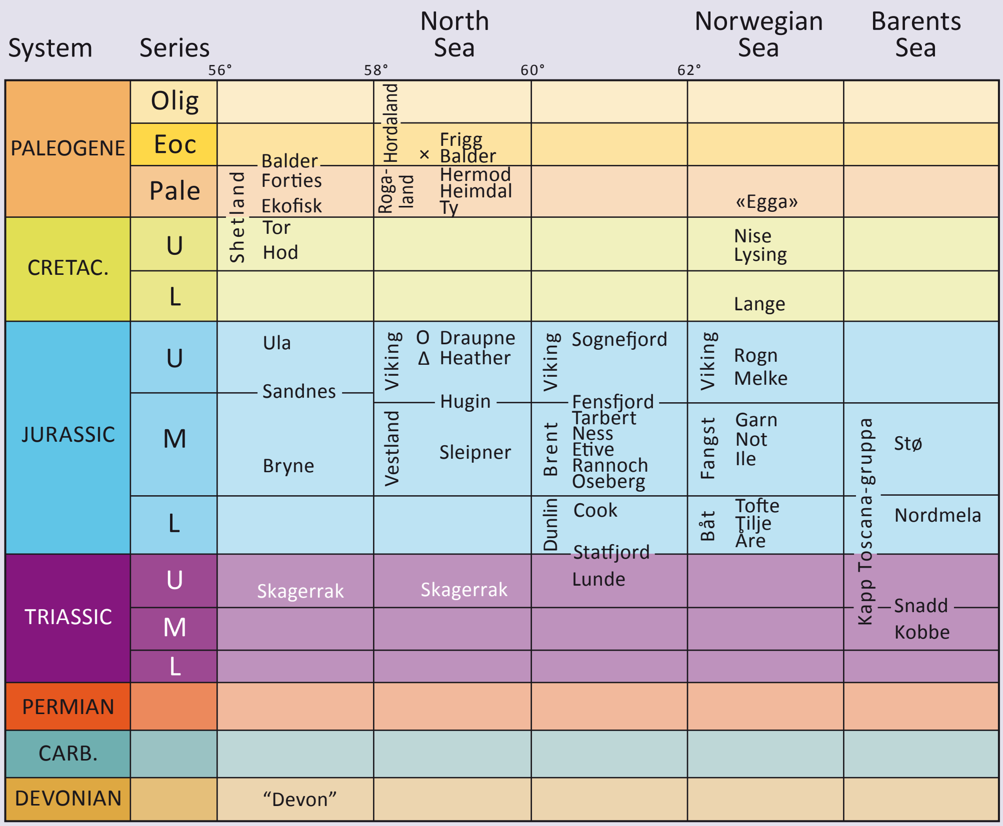
- Oil, condensate, NGL
- Gas

Pictures and illustrations in Chapters 10 – 14

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

Reservoir type

Chrono- and lithostratigraphy



× Balder – intra Balder sandstone
O Draupne – intra Draupne sandstone
Δ Heather – intra Heather sandstone
"Egga" – informal unit

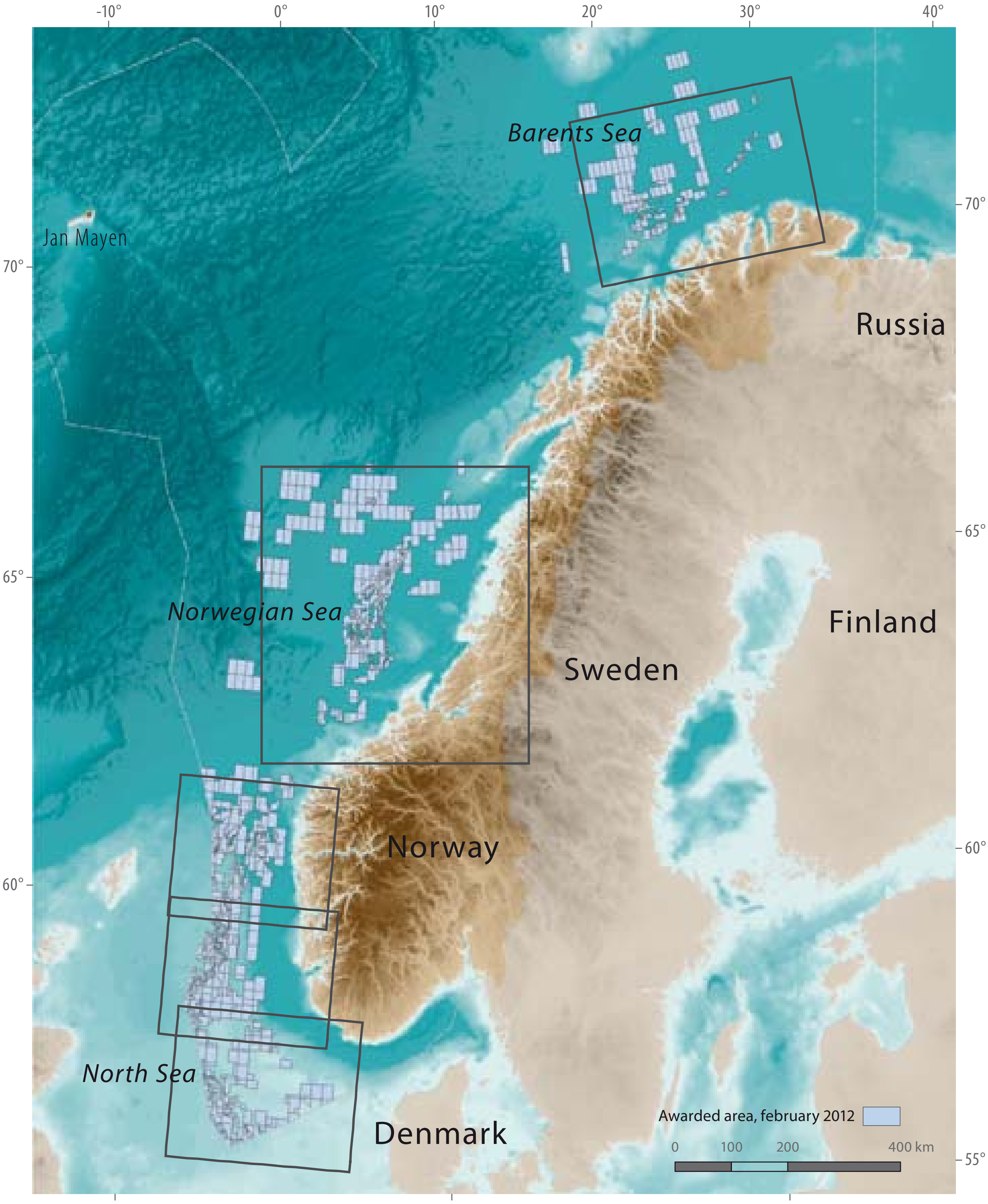


Figure 10.1 Areas on the Norwegian continental shelf *(Source: Norwegian Petroleum Directorate)*

The southern part of the North Sea

The southern part of the North Sea is still an important petroleum province for Norway 40 years after Ekofisk came on stream. Ekofisk is now the largest field on the Norwegian continental shelf, measured in daily oil production. There are 12 fields in production in the southern part of the North Sea after Trym came on stream in February 2011. Oselvar is expected to start production in 2012. Seven fields are shut down and facilities are being removed. Ekofisk serves as a hub for petroleum operations in this area, with several fields utilising the infrastructure of Ekofisk for further transport in the Norpipe system. There are substantial remaining resources in the southern part of the North Sea, particularly in the large chalk fields in the very south of the area. Production of oil and gas is expected to continue in this area for as many as 40 more years.

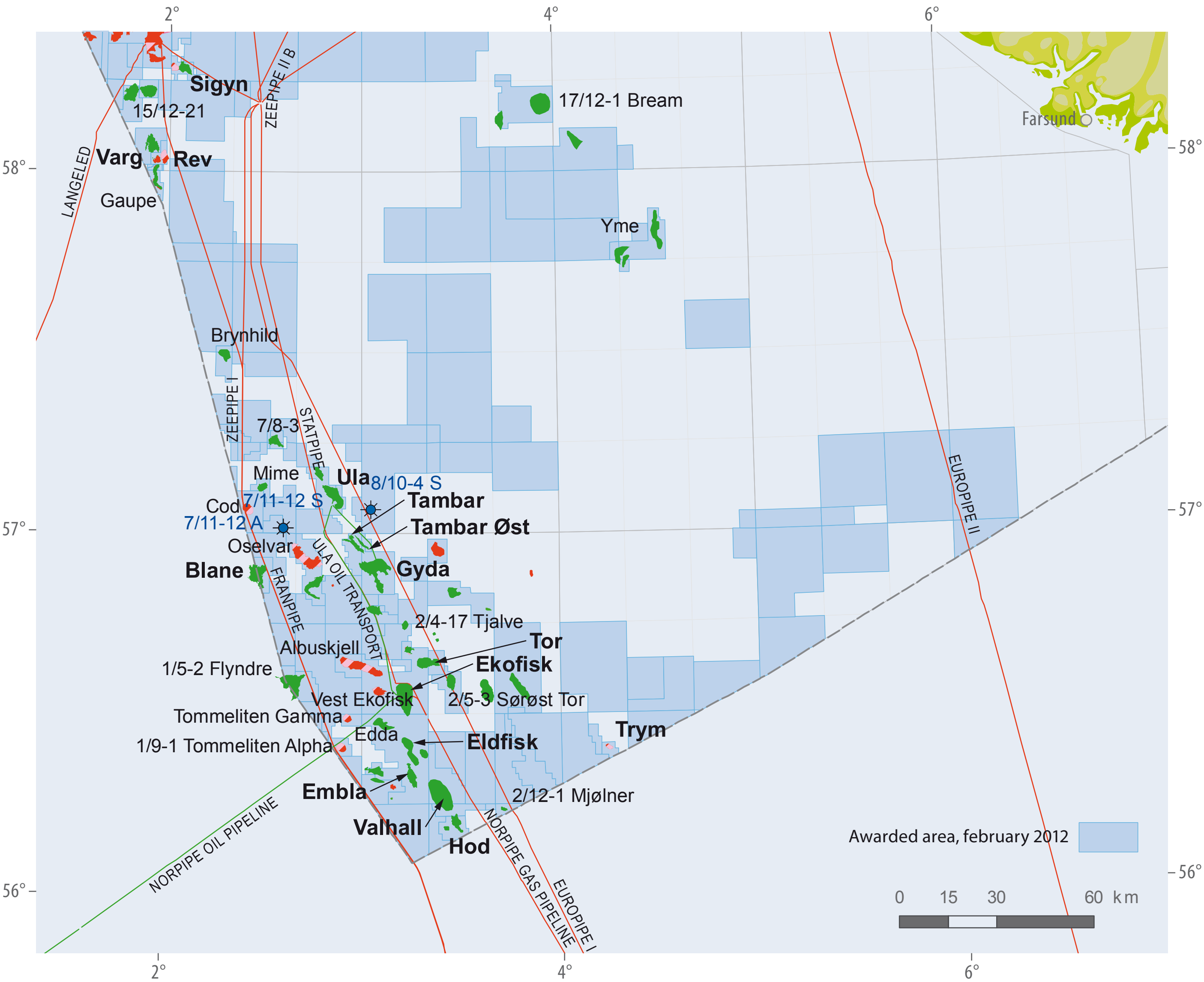


Figure 10.2 Fields and discoveries in the southern part of the North Sea *(Source: Norwegian Petroleum Directorate)*

The central part of the North Sea

The central part of the North Sea has a long petroleum history. Balder, discovered in 1967, was the first oil discovery on the Norwegian continental shelf, but was developed 30 years later. The first development was the Frigg gas field, which was in production for almost 30 years, until it was shut down in 2004. At present, 19 fields are in production in the central part of the North Sea and three fields, Gaupe, Gudrun and Atla are being developed. Several discoveries are in the planning phase, including the significant Johan Sverdrup oil discovery on Utsirahøgda Sør. Six fields in the Frigg area have been shut down, and the facilities have been removed. Some of these fields may be redeveloped later. Heimdal has produced gas since 1985, and is now primarily a gas centre which performs processing services for other fields. Heimdal and the Sleipner fields represent important hubs for the gas transportation system on the Norwegian continental shelf. Oil and gas from fields in the central part of the North Sea are transported by tankers or by pipelines to onshore facilities in Norway and the United Kingdom.

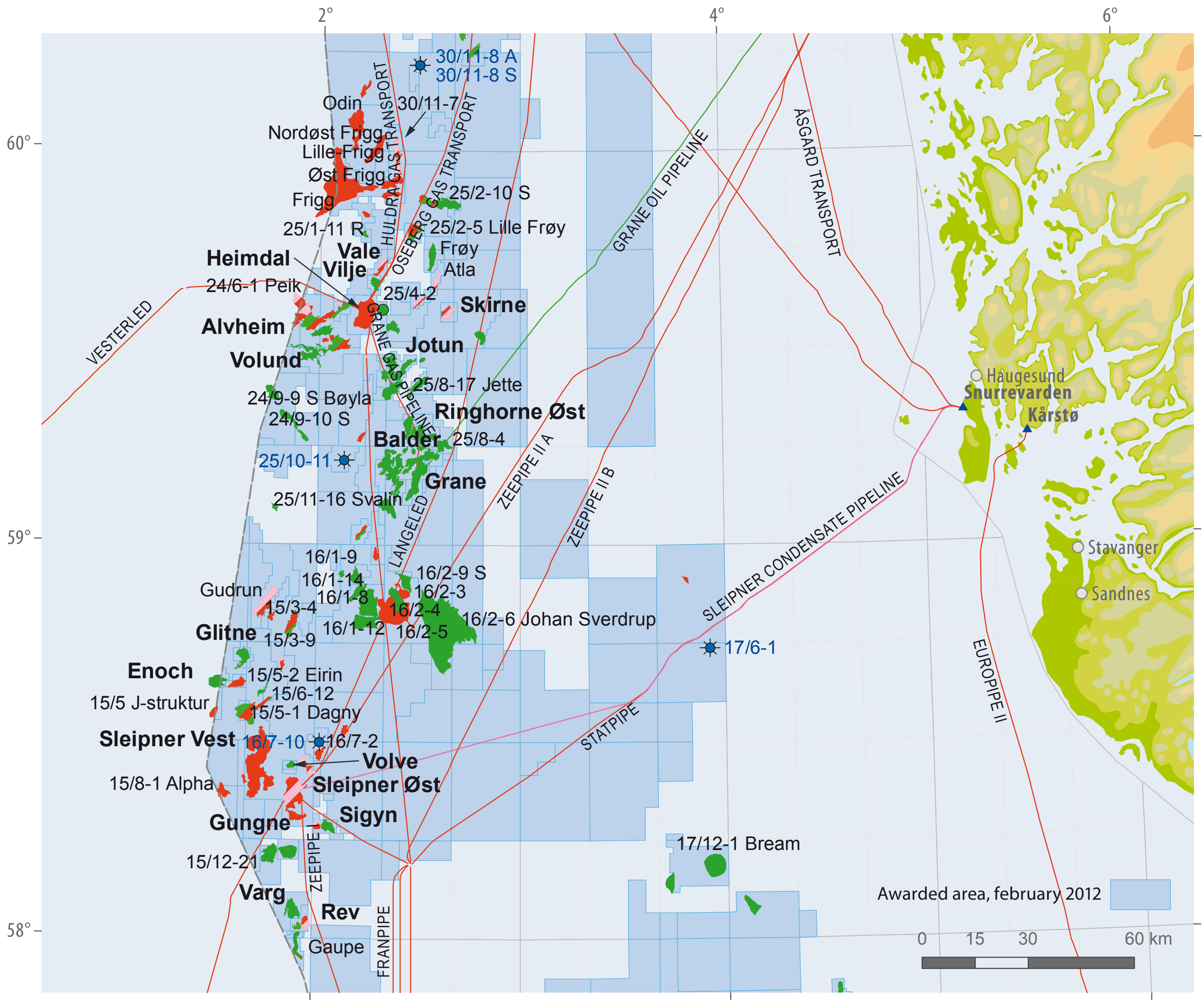


Figure 10.3 Fields and discoveries in the middle part of the North Sea *(Source: Norwegian Petroleum Directorate)*

The northern part of the North Sea

The northern part of the North Sea encompasses two main areas, the Tampen area and the Oseberg/Troll area. At present 26 fields are in production in this part of the North Sea. One field, Visund Sør, is being developed. After 30 years of production from the area there is still a substantial resource potential remaining. Production is expected to continue for at least another 30 years. The Troll field plays a major role regarding gas supplies from the Norwegian continental shelf and will remain the main source of Norwegian gas exports throughout this century. As the major oil fields reach the end of production, substantial gas volumes will be produced in the gas blow-down period/low pressure production period. Oil and gas from the fields in the northern part of the North Sea is transported by tankers or by pipelines to onshore facilities in Norway and the United Kingdom.

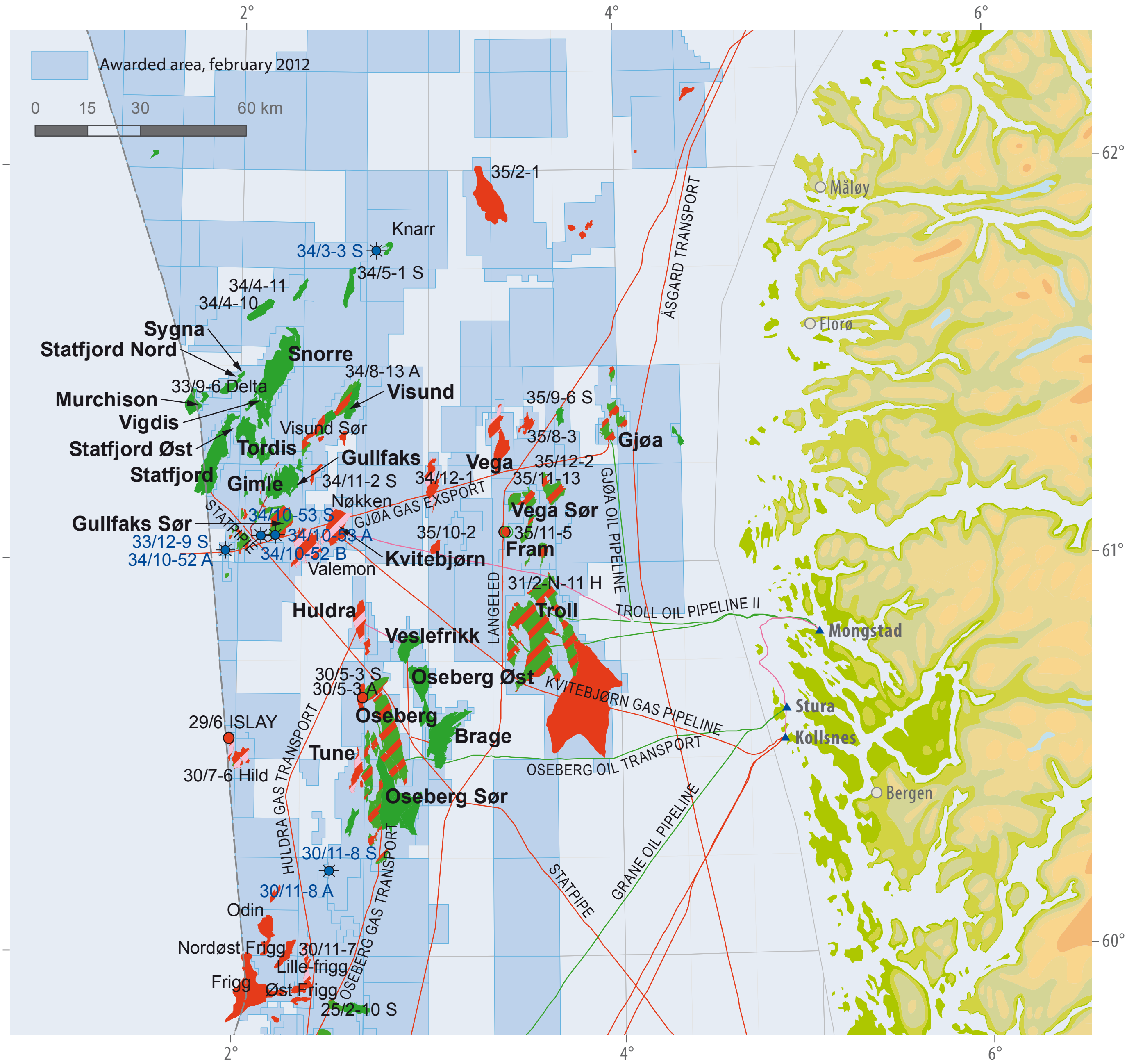


Figure 10.4 Fields and discoveries in the northern part of the North Sea *(Source: Norwegian Petroleum Directorate)*

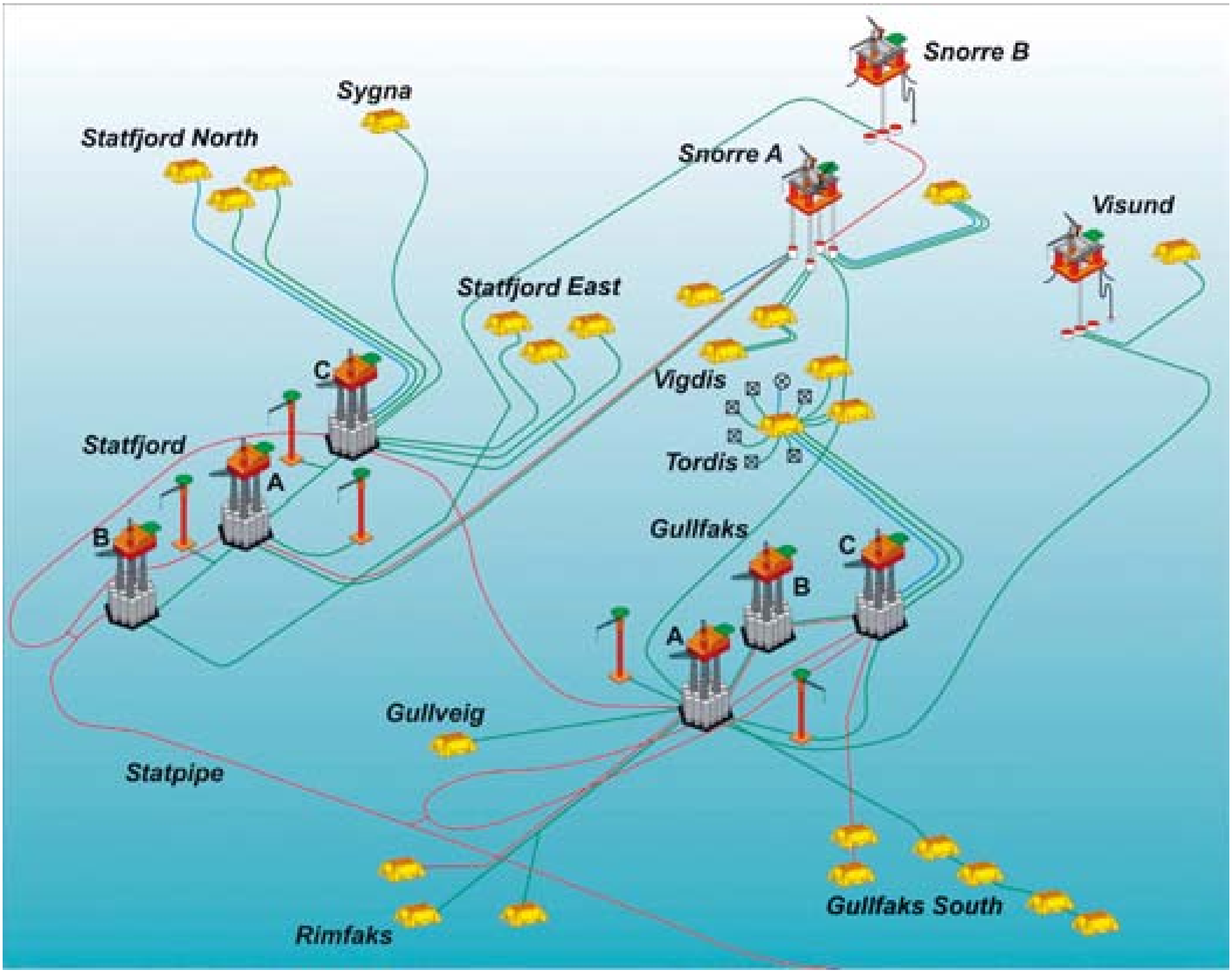


Figure 10.5 Facilities in the Tampen area *(Source: Statoil)*

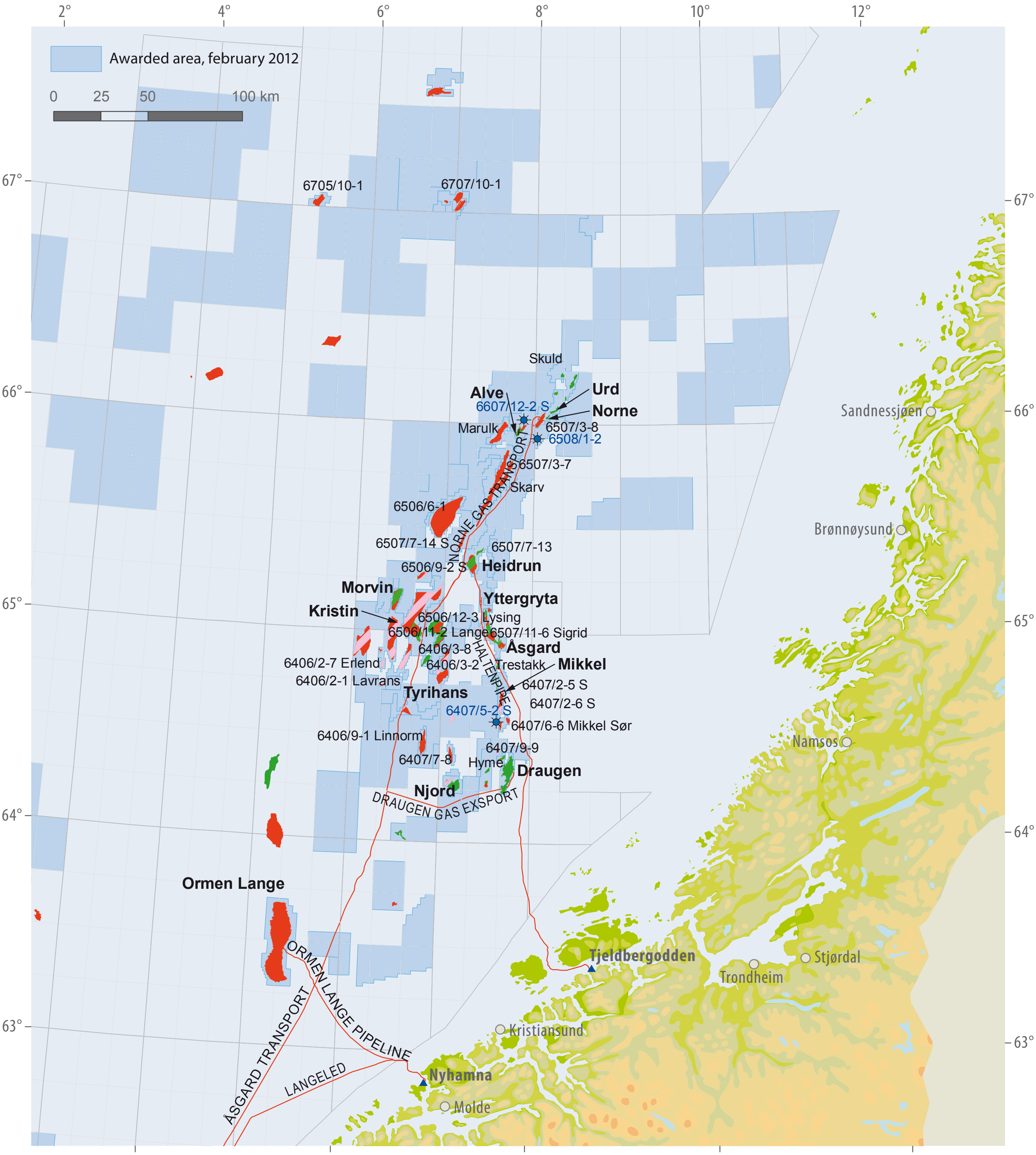


Figure 10.6 Fields and discoveries in the Norwegian Sea *(Source: Norwegian Petroleum Directorate)*

The Norwegian Sea

The Norwegian Sea is a less mature petroleum province than the North Sea. Draugen was the first field to come on stream, in 1993, and now 13 fields are producing in the Norwegian Sea after the development of Morvin. Four fields, Skarv, Marulk, Hyme and Skuld, are being developed. Yttergryta have ceased production. There are significant gas reserves in the Norwegian Sea. The gas produced from the fields is transported in the Åsgard Transport pipeline to Kårstø in Rogaland and in Haltenpipe to Tjeldbergodden in Møre og Romsdal. Gas production from Ormen Lange is transported by pipeline to Nyhamna, and from there on to Easington in the United Kingdom. Oil from the fields in the Norwegian Sea is transported by tankers.

The Barents Sea

The Barents Sea is considered an immature petroleum province. Snøhvit is the only field developed so far, and came on stream in 2007. The gas from Snøhvit is transported by pipeline to Melkøya and further processed and liquefied to LNG, which is transported by special tankers to market. The Goliat field is being developed, with planned production start late in 2013.

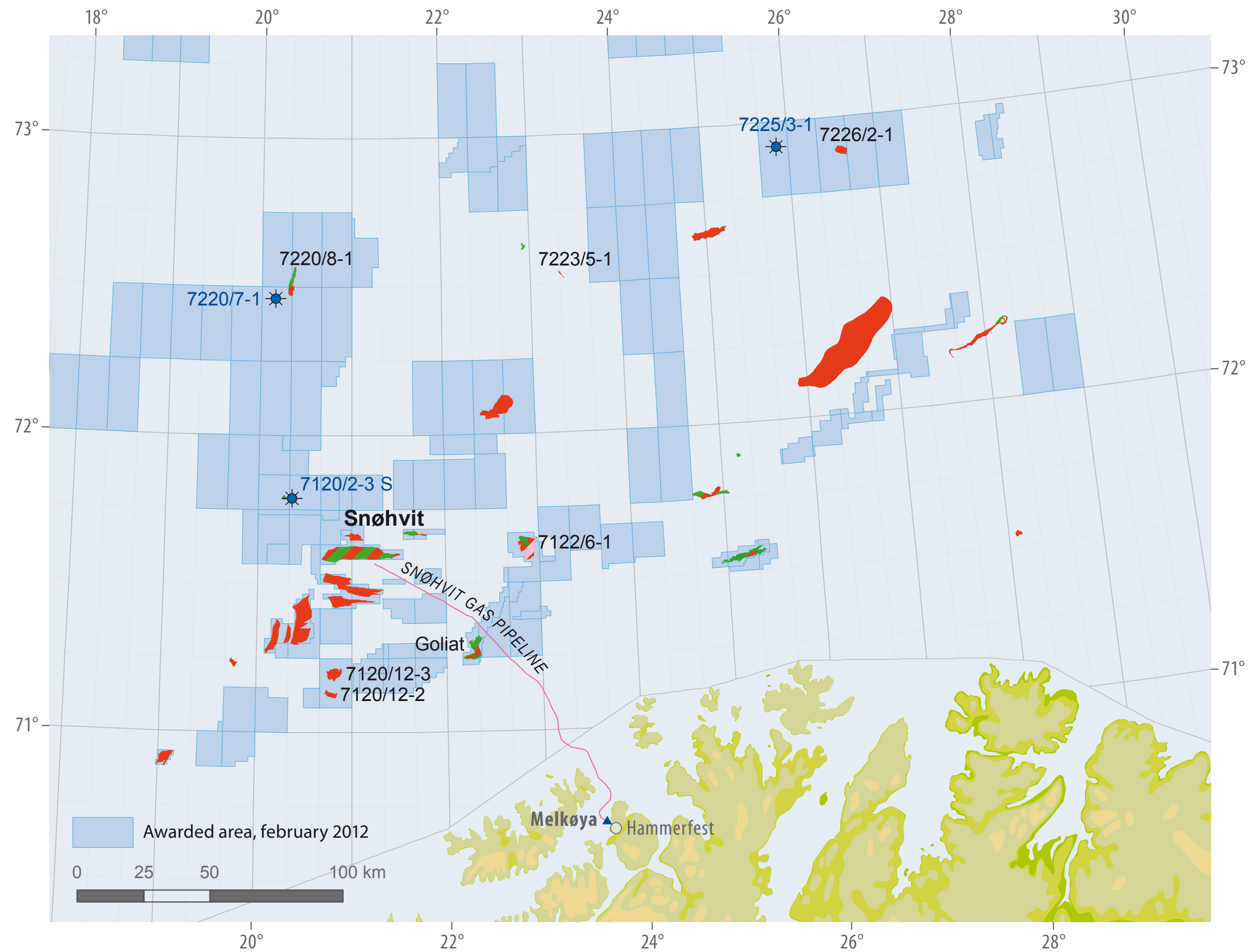
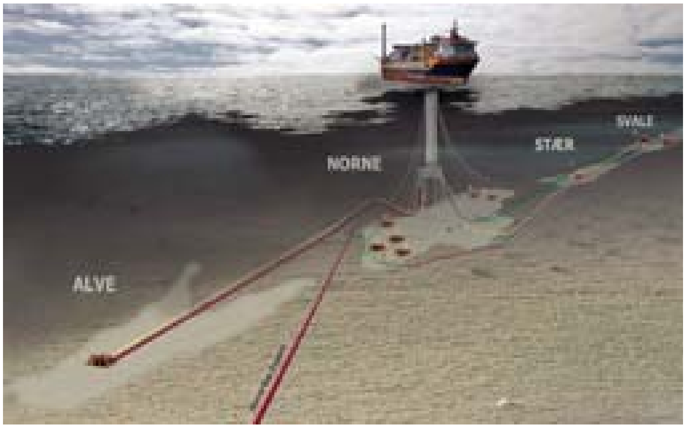


Figure 10.7 Fields and discoveries in the Barents Sea *(Source: Norwegian Petroleum Directorate)*

Alve

Blocks and production licences	Block 6507/3 - production licence 159 B, awarded 2004.		
Development approval	16.03.2007 by the King in Council	**Discovered** 1990	
On stream	19.03.2009		
Operator	Statoil Petroleum AS		
Licensees	DONG E&P Norge AS		15.00 %
	Statoil Petroleum AS		85.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	1.4 million Sm^3 oil	0.6 million Sm^3 oil	
	5.1 billion Sm^3 gas	2.6 billion Sm^3 gas	
	1.1 million tonnes NGL	0.6 million tonnes NGL	
Estimated production in 2012	Oil: 3 000 barrels/day, Gas: 0.61 billion Sm^3, NGL: 0.13 million tonnes		
Expected investment from 2011	0.4 billion 2011 values		
Total investment as of 31.12.2010	3.5 billion nominal values		



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

Reservoir: The reservoir is in Jurassic sandstones of the Garn, Not, Ile and Tilje Formations. The reservoir lies at a depth of about 3 600 metres.

Recovery strategy: The reservoir is produced by pressure depletion.

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

Status: The second production well was started in April 2011, and is producing oil and gas from the Ile and Tilje Formations.

Alve

Mill. Sm³ o.e.

Alvheim

Blocks and production licences	Block 24/6 - production licence 088 BS, awarded 2003 Block 24/6 - production licence 203, awarded 1996. Block 25/4 - production licence 036 C, awarded 2003 Block 25/4 - production licence 203, awarded 1996.		
Development approval	06.10.2004 by the King in Council	**Discovered** 1998	
On stream	08.06.2008		
Operator	Marathon Oil Norge AS		
Licensees	ConocoPhillips Skandinavia AS		20.00 %
	Lundin Norway AS		15.00 %
	Marathon Oil Norge AS		65.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	38.9 million Sm^3 oil	23.2 million Sm^3 oil	
	6.8 billion Sm^3 gas	5.3 billion Sm^3 gas	
Estimated production in 2012	Oil: 70 000 barrels/day, Gas: 0.57 billion Sm^3		
Expected investment from 2011	4.9 billion 2011 values		
Total investment as of 31.12.2010	16.4 billion nominal values		

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

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

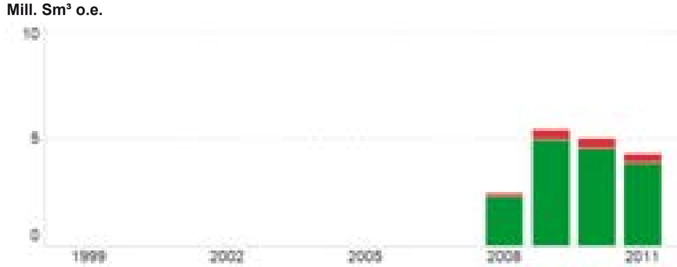
Recovery strategy: Alvheim is produced by natural water drive from an active underlying aquifer.

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

Status: Alvheim is producing beyond expectations and there has been a gradual increase in the resources as a result of development drilling. A new development well is planned in 2012. The field can be an oil hub for new discoveries in the area.

Alvheim

Mill. Sm³ o.e.



Balder

Blocks and production licences	Block 25/10 - production licence 028, awarded 1969. Block 25/11 - production licence 001, awarded 1965. Block 25/8 - production licence 027, awarded 1969 Block 25/8 - production licence 027 C, awarded 2000 Block 25/8 - production licence 169, awarded 1991.		
Development approval	02.02.1996 by the King in Council	**Discovered** 1967	
On stream	02.10.1999		
Operator	ExxonMobil Exploration & Production Norway AS		
Licensees	ExxonMobil Exploration & Production Norway AS		100.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	71.3 million Sm^3 oil	17.3 million Sm^3 oil	
	1.6 billion Sm^3 gas	0.3 billion Sm^3 gas	
Estimated production in 2012	Oil: 42 000 barrels/day, Gas: 0.05 billion Sm^3		
Expected investment from 2011	7.9 billion 2011 values		
Total investment as of 31.12.2010	21.7 billion nominal values		
Main supply base	Dusavik		

Development: Balder is an oil field in the central part of the North Sea, at a water depth of 125 metres. The field has been developed with subsea wells tied back to the accommodation, production and storage vessel, «Balder FPSO», where oil and gas are processed. The Ringhorne discovery, included in the Balder field, is developed with a combined accommodation, drilling and wellhead facility, tied back to the «Balder FPSO». The PDO for Ringhorne was approved in May 2000 and production started in May 2001. An amended PDO for Ringhorne was approved in 2007.

Reservoir: The field contains several separate oil deposits in Eocene, Paleocene and Jurassic sandstones. The reservoirs in the Rogaland Group belong to the Heimdal, Hermod and Ty Formations, and the reservoirs in the Brent Group belong to the Statfjord Formation. Top reservoirs are at a depth of about 1 700 metres.

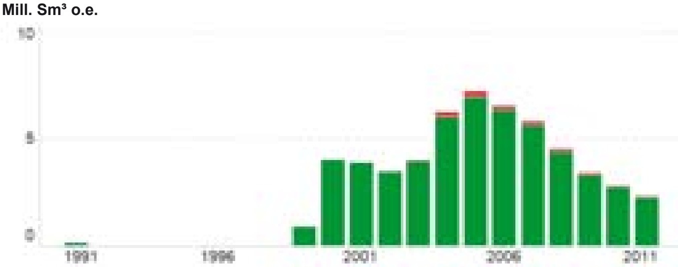
Recovery strategy: Balder and Ringhorne produce primarily by natural aquifer drive, but some water injection for pressure support is utilised, especially as regards the Ringhorne Jurassic reservoir. Gas is also injected if the gas export system is down.

Transport: The Ringhorne facility is tied to the *Balder* and *Jotun FPSOs* for processing, crude oil storage and gas export. The oil is transported by tankers. Excess gas from Balder is routed to Jotun for gas export. Jotun exports Ringhorne and Balder gas to Statpipe. In periods with reduced gas export, excess gas may be injected into the Balder reservoir.

Status: The field is in the decline phase, but it is assumed that it will continue producing until 2025. Studies have been started to evaluate possible means to improve recovery. A 4D seismic survey completed in 2009 has been analysed to evaluate new well locations. A drilling campaign started on Ringhorne in 2011, and new campaigns will continue on both Balder and Ringhorne over the next years. New production wells are being planned at both Ringhorne and Balder. These can start production from 2012-2016.

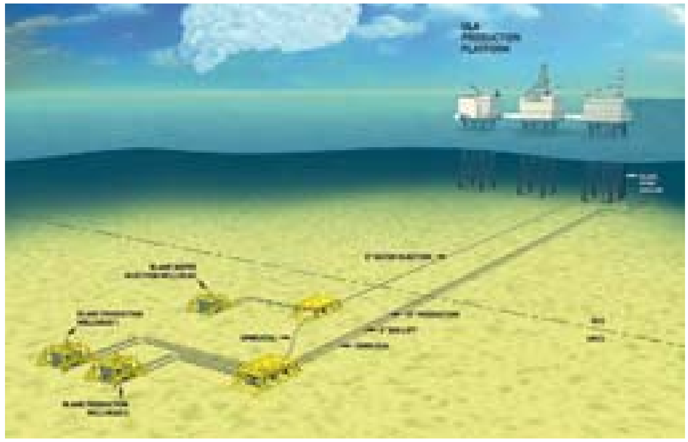
Balder

Mill. Sm^3 o.e.



Blane

Blocks and production licences	Block 1/2 - production licence 143 BS, awarded 2003. The Norwegian part of the field is 18 %, the British part is 82 %		
Development approval	01.07.2005	**Discovered** 1989	
On stream	12.09.2007		
Operator	Talisman Energy Norge AS		
Licensees	Talisman Energy Norge AS		18.00 %
	Dana Petroleum (BVUK) Limited		12.50 %
	Faroe Petroleum (UK)Limited		18.01 %
	JX Nippon Exploration and Production (UK) Limited		13.99 %
	Roc Oil (GB) Limited		12.50 %
	Talisman Energy (UK) Limited		25.00 %
Recoverable reserves (Norwegian part)	**Original**	**Remaining as of 31.12.2011**	
	0.9 million Sm^3 oil	0.4 million Sm^3 oil	
Estimated production in 2012	Oil: 1 000 barrels/day		
Total investment as of 31.12.2010	0.5 billion nominal values		



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

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

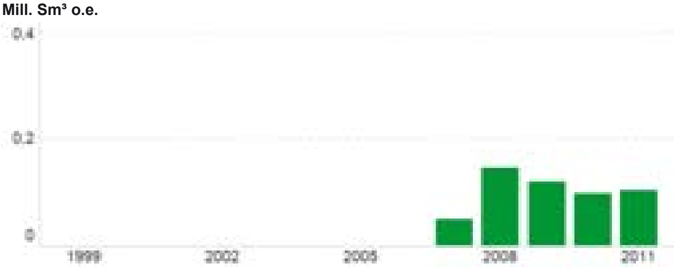
Recovery strategy: Blane is produced by pressure support from injection of produced water from Blane, Tambar and Ula. In addition, gas lift is used in the wells.

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

Status: Gas lift started in February 2009, but poor regularity of the gas lift supply has been experienced in 2011 due to operational problems. The overall field performance has been good. Water breakthrough was experienced in one well in 2011.

Blane

Mill. Sm^3 o.e.



Brage

Blocks and production licences	Block 30/6 - production licence 053 B, awarded 1998. Block 31/4 - production licence 055, awarded 1979. Block 31/7 - production licence 185, awarded 1991.		
Development approval	29.03.1990 by the Storting	**Discovered** 1980	
On stream	23.09.1993		
Operator	Statoil Petroleum AS		
Licensees	Core Energy AS		12.26 %
	Faroe Petroleum Norge AS		14.26 %
	Spring Energy Norway AS		2.50 %
	Statoil Petroleum AS		32.70 %
	Talisman Energy Norge AS		33.84 %
	VNG Norge AS		4.44 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	58.6 million Sm^3 oil	4.1 million Sm^3 oil	
	4.3 billion Sm^3 gas	1.2 billion Sm^3 gas	
	1.5 million tonnes NGL	0.3 million tonnes NGL	
Estimated production in 2012	Oil: 14 000 barrels/day, Gas: 0.09 billion Sm^3, NGL: 0.04 million tonnes		
Expected investment from 2011	3.5 billion 2011 values		
Total investment as of 31.12.2010	16.4 billion nominal values		
Main supply base	Mongstad		

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

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

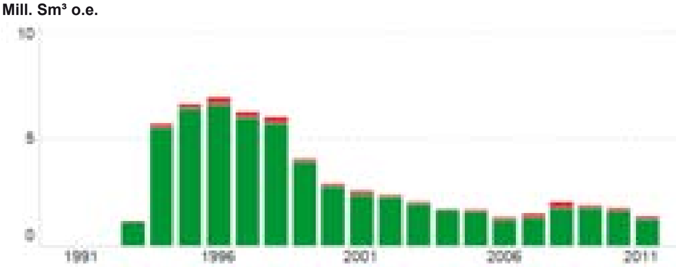
Recovery strategy: The recovery mechanism in the Statfjord and Fensfjord Formations is water injection. Gas injection in the Sognefjord Formation started in March 2009. The first oil producers in the Brent Group started production in 2008, supported by water injection.

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

Status: Brage has been producing for a long time, and work is still ongoing to find new ways of increasing recovery from the field. New wells have been drilled in recent years, and more wells are planned for the coming years. Brage is also evaluating several technologies for enhanced oil recovery. A pilot project for microbiological injection (MEOR) is planned.

Brage

Mill. Sm^3 o.e.



Draugen

Blocks and production licences	Block 6407/9 - production licence 093, awarded 1984.		
Development approval	19.12.1988 by the Storting	**Discovered** 1984	
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 31.12.2011**	
	143.0 million Sm^3 oil	13.2 million Sm^3 oil	
	1.5 billion Sm^3 gas	0.3 million tonnes NGL	
	2.6 million tonnes NGL		
Estimated production in 2012	Oil: 34 000 barrels/day, Gas: 0.02 billion Sm^3, NGL: 0.06 million tonnes		
Expected investment from 2011	3.4 billion 2011 values		
Total investment as of 31.12.2010	22.2 billion nominal values		
Main supply base	Kristiansund		

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

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

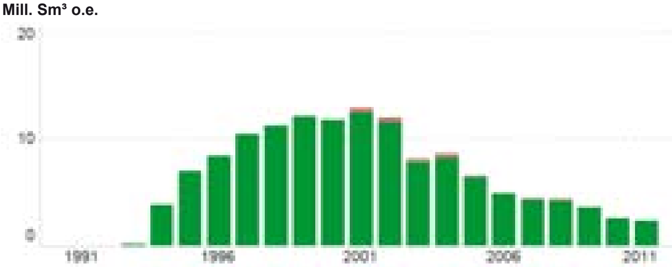
Recovery strategy: The field is produced by pressure maintenance from water injection and aquifer support.

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

Status: Several measures to increase oil recovery have been evaluated. Based on a 4D seismic survey carried out in 2009, an infill drilling campaign was sanctioned in 2011 .The project includes four production wells and a subsea pump. The first oil from the project is scheduled in 2013. During 2011, significant work was completed in order to bring 3rd party tie-ins to Draugen. In June 2011, the 6406/9-1 Linnorm discovery selected Draugen as its tie-in host. Because of this, development of the Hasselmus discovery for fuel gas has been put on hold and development for gas export will be evaluated.

Draugen

Mill. Sm^3 o.e.



Ekofisk

Blocks and production licences	Block 2/4 - production licence 018, awarded 1965.	
Development approval	01.03.1972	**Discovered** 1969
On stream	15.06.1971	
Operator	ConocoPhillips Skandinavia AS	
Licensees	ConocoPhillips Skandinavia AS	35.11 %
	Eni Norge AS	12.39 %
	Petoro AS	5.00 %
	Statoil Petroleum AS	7.60 %
	Total E&P Norge AS	39.90 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**
	552.7 million Sm^3 oil	120.9 million Sm^3 oil
	162.1 billion Sm^3 gas	21.5 billion Sm^3 gas
	14.9 million tonnes NGL	2.1 million tonnes NGL
Estimated production in 2012	Oil: 127 000 barrels/day, Gas: 1.29 billion Sm^3, NGL: 0.15 million tonnes	
Expected investment from 2011	84.8 billion 2011 values	
Total investment as of 31.12.2010	84.0 billion nominal values	
Main supply base	Tananger	

Development: Ekofisk is an oil field located in the southern part of the North Sea. The water depth in the area is 70 - 75 metres. The field was initially produced to tankers until a concrete storage tank was installed in 1973. Since then, the field has been further developed with many facilities, including riser facilities for associated fields and export pipelines. Several of these have been decommissioned and are awaiting disposal. Today, the operative parts of the Ekofisk Centre consist of the accommodation facilities, Ekofisk H and Ekofisk Q, the production facility Ekofisk C, the drilling and production facility Ekofisk X, the processing facility Ekofisk J and the production and processing facility Ekofisk M. From the wellhead facility Ekofisk A, located in the southern part of the field, production goes to the riser facility Ekofisk FTP for processing at the Ekofisk Centre. The pipeline from Ekofisk B in the northern part of the field is routed to Ekofisk M. Ekofisk K is a facility for water injection. A plan for water injection at Ekofisk was approved in December 1983, a PDO for Ekofisk II was approved in November 1994 and a PDO for Ekofisk Growth was approved in June 2003. In June 2008 a subsea template for water injection wells was approved. These have replaced the water injection at Ekofisk W, which is no longer in use. In March 2010, the new accommodation facility, Ekofisk L, was approved. This will replace Ekofisk H and Ekofisk Q. Ekofisk L will be in operation from autumn 2013. Permanent cables have been installed on the seabed over the Ekofisk reservoir for acquisition of seismic data.

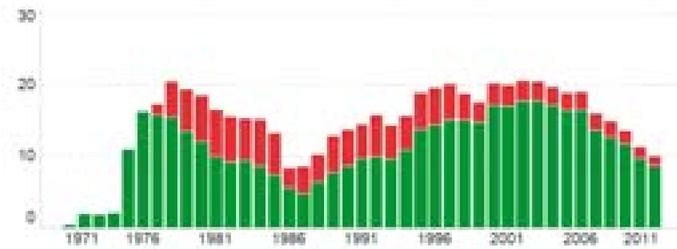
Reservoir: The Ekofisk field produces from naturally fractured chalk of the Ekofisk and Tor Formations of Early Paleocene and Late Cretaceous ages. The reservoir rocks have high porosity, but low permeability. The reservoir has an oil column of more than 300 metres and lies 2 900 - 3 250 metres below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

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

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

Status: Production from Ekofisk is maintained at a high level through continuous drilling of water injection and production wells from several facilities. A PDO for Ekofisk Sør was approved in June 2011. The project includes two new installations; Ekofisk Z, a production facility, and Ekofisk VB, a subsea template for water injection wells. Ekofisk Z is expected to start production in 2013.

Ekofisk
Mill. Sm³ o.e.



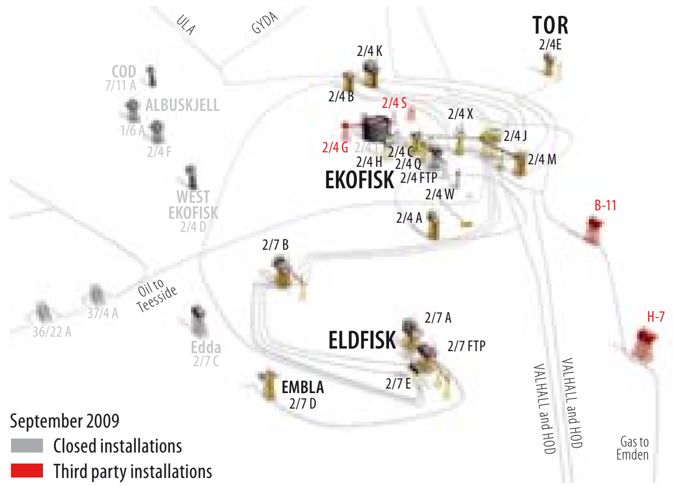


Figure 10.8 Facilities in the Ekofisk area *(Source: ConocoPhillips)*

Eldfisk

Blocks and production licences	Block 2/7 - production licence 018, awarded 1965.		
Development approval	25.04.1975	**Discovered** 1970	
On stream	08.08.1979		
Operator	ConocoPhillips Skandinavia AS		
Licensees	ConocoPhillips Skandinavia AS		35.11 %
	Eni Norge AS		12.39 %
	Petoro AS		5.00 %
	Statoil Petroleum AS		7.60 %
	Total E&P Norge AS		39.90 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	134.8 million Sm^3 oil	36.9 million Sm^3 oil	
	44.1 billion Sm^3 gas	4.9 billion Sm^3 gas	
	4.1 million tonnes NGL	0.2 million tonnes NGL	
Estimated production in 2012	Oil: 50 000 barrels/day, Gas: 0.47 billion Sm^3, NGL: 0.07 million tonnes		
Expected investment from 2011	39.8 billion 2011 values		
Total investment as of 31.12.2010	31.2 billion nominal values		
Main supply base	Tananger		

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

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

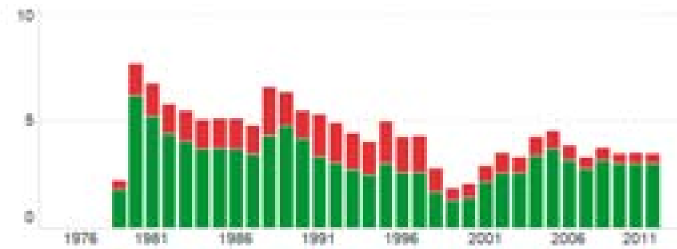
Recovery strategy: Eldfisk was originally developed by pressure depletion. In 1999, water injection began at the field, based on horizontal injection wells. Gas is also injected in periods when export is not possible. Pressure depletion has caused compaction in the reservoir, which has resulted in a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

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

Status: A PDO for Eldfisk II was approved in June 2011. This plan includes a new combined accommodation, wellhead and process facility, Eldfisk S, bridge-connected to Eldfisk E. The new facility will replace several functions of Eldfisk A and Eldfisk FTP. Modifications to the existing facilities are also a part of the scope. The Embla field will be tied back to Eldfisk S. About 40 new production and injection wells will be drilled from Eldfisk S with start-up in 2015.

Eldfisk

Mill. Sm^3 o.e.



Embla

Blocks and production licences	Block 2/7 - production licence 018, awarded 1965.		
Development approval	14.12.1990 by the King in Council	**Discovered** 1988	
On stream	12.05.1993		
Operator	ConocoPhillips Skandinavia AS		
Licensees	ConocoPhillips Skandinavia AS		35.11 %
	Eni Norge AS		12.39 %
	Petoro AS		5.00 %
	Statoil Petroleum AS		7.60 %
	Total E&P Norge AS		39.90 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	11.3 million Sm^3 oil	1.2 million Sm^3 oil	
	5.9 billion Sm^3 gas	2.2 billion Sm^3 gas	
	0.6 million tonnes NGL	0.2 million tonnes NGL	
Estimated production in 2012	Oil: 3 000 barrels/day, Gas: 0.16 billion Sm^3, NGL: 0.02 million tonnes		
Expected investment from 2011	0.7 billion 2011 values		
Total investment as of 31.12.2010	3.1 billion nominal values		
Main supply base	Tananger		

Development: Embla is an oil field located near 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 water depth in the area is 70 – 75 metres. An amended PDO for Embla was approved in April 1995.

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

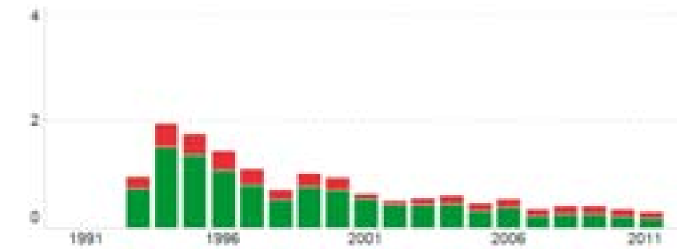
Recovery strategy: Embla is produced by pressure depletion.

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

Status: As a part of the Eldfisk II project, Embla will be tied to the new Eldfisk S facility. This enables an extended lifetime for Embla.

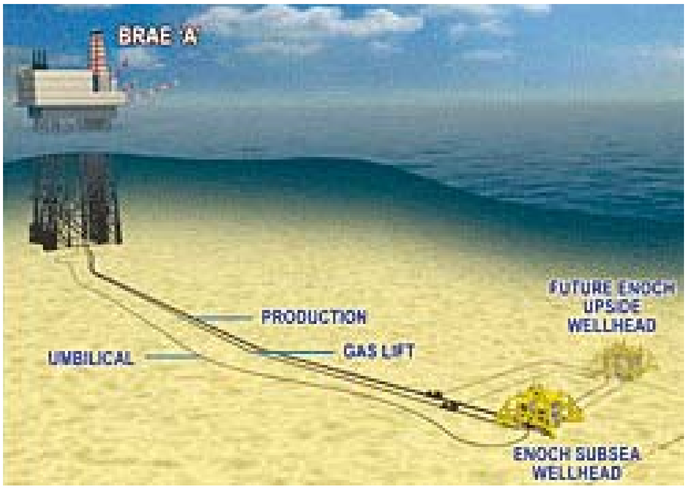
Embla

Mill. Sm^3 o.e.



Enoch

Blocks and production licences	Block 15/5 - production licence 048 D, awarded 2005. The Norwegian part of the field is 20 %, the British part is 80%	
Development approval	01.07.2005	**Discovered** 1991
On stream	31.05.2007	
Operator	Talisman North Sea Limited	
Licensees	Altinex Oil Norway AS	4.36 %
	Det norske oljeselskap ASA	2.00 %
	Faroe Petroleum Norge AS	1.86 %
	Statoil Petroleum AS	11.78 %
	Dana Petroleum (BVUK) Limited	20.80 %
	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 (Norwegian Part)	**Original**	**Remaining as of 31.12.2011**
	0.4 million Sm^3 oil	0.1 million Sm^3 oil
Estimated production in 2012	Oil: 400 barrels/day	
Total investment as of 31.12.2010	0.2 billion nominal values	



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

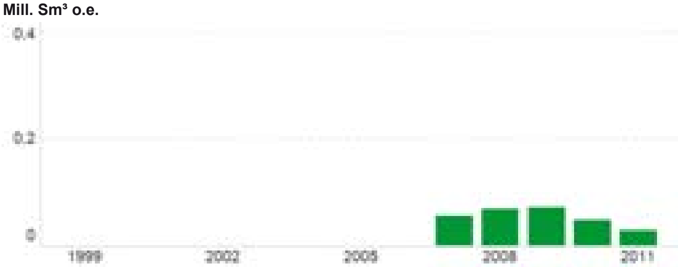
Reservoir: The reservoir, containing oil, is in Paleocene sandstones at a depth of approximately 2 100 metres. The reservoir quality is variable.

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

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

Enoch

Mill. Sm³ o.e.



Fram

Blocks and production licences	Block 31/2 - production licence 090 E, awarded 2010. Block 35/11 - production licence 090, awarded 1984.	
Development approval	23.03.2001 by the King in Council	**Discovered** 1992
On stream	02.10.2003	
Operator	Statoil Petroleum AS	
Licensees	ExxonMobil Exploration & Production Norway AS	25.00 %
	GDF SUEZ E&P Norge AS	15.00 %
	Idemitsu Petroleum Norge AS	15.00 %
	Statoil Petroleum AS	45.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**
	28.0 million Sm^3 oil	5.7 million Sm^3 oil
	8.5 billion Sm^3 gas	6.6 billion Sm^3 gas
	0.5 million tonnes NGL	0.4 million tonnes NGL
Estimated production in 2012	Oil: 36 000 barrels/day, Gas: 0.57 billion Sm^3, NGL: 0.04 million tonnes	
Expected investment from 2011	0.1 billion 2011 values	
Total investment as of 31.12.2010	9.9 billion nominal values	
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 water depth in the area is approximately 350 metres. The field comprises two deposits, Fram Vest and Fram Øst. The Fram Vest deposit is developed by two subsea templates tied back to Troll C. The gas is separated from the liquid on Troll C and re-injected into the Fram Vest reservoir. The development of the Fram Øst deposit was approved on 22.04.2005. This development includes two subsea templates tied back to Troll C. Production from Fram Øst started in October 2006.

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

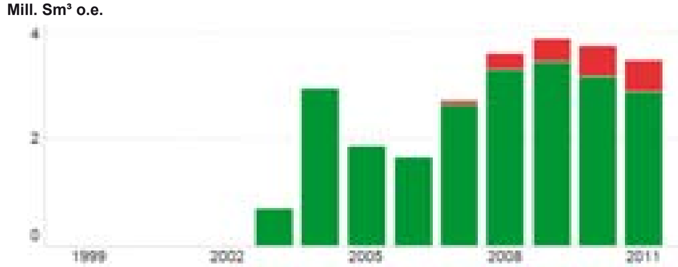
Recovery strategy: The Fram Øst deposit in the Sognefjord Formation is produced by injection of produced water as pressure support, in addition to natural aquifer drive. The Brent reservoir in the Fram Øst deposit is recovered by pressure support from natural aquifer drive.Gas lift is used in the wells.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

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 is exported via Troll A to Kollsnes.

Status: Additional resources have been proven in new deposits near the field. These are being considered in connection with the further development of Fram. Several prospects have been identified within the PL090 licence.

Fram

Mill. Sm³ o.e.



Gimle

Blocks and production licences	Block 34/10 - production licence 050 DS, awarded 2006. Block 34/7 - production licence. Block 34/8 - production licence 120 B, awarded 2006.		
Development approval	18.05.2006	**Discovered** 2004	
On stream	19.05.2006		
Operator	Statoil Petroleum AS		
Licensees	ConocoPhillips Skandinavia AS		5.79 %
	Petoro AS		24.19 %
	Statoil Petroleum AS		65.13 %
	Total E&P Norge AS		4.90 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	2.7 million Sm³ oil	0.2 million Sm³ oil	
	0.7 billion Sm³ gas	0.6 billion Sm³ gas	
	0.1 million tonnes NGL	0.1 million tonnes NGL	
Estimated production in 2012	Oil: 2 000 barrels/day, Gas: 0.30 billion Sm³, NGL: 0.06 million tonnes		
Total investment as of 31.12.2010	0.8 billion nominal values		

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

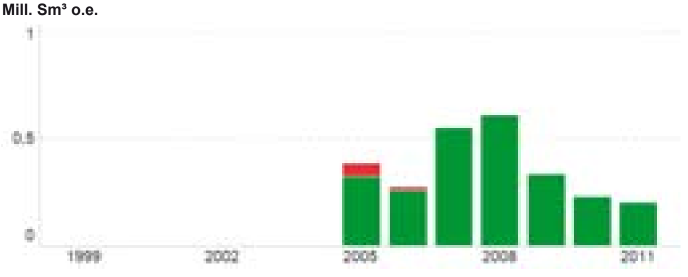
Reservoir: The reservoir consists of sandstones of the Tarbert Formation of Middle Jurassic age, in a downfaulted structure northeast of the Gullfaks field. There are also slumped sands of Late Jurassic age. The reservoir depth is about 2 900 metres, and the reservoir has good quality.

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

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

Status: Drilling of a new well northeast of Gimle is being considered. The aim is to drill an exploration pilot in combination with a new production well in 2012.

Gimle



Gjøa

Blocks and production licences	Block 35/9 - production licence 153, awarded 1988. Block 36/7 - production licence 153, awarded 1988.		
Development approval	14.06.2007 by the Storting	**Discovered**	
On stream	07.11.2010		
Operator	GDF SUEZ E&P Norge AS		
Licensees	A/S Norske Shell		12.00 %
	GDF SUEZ E&P Norge AS		30.00 %
	Petoro AS		30.00 %
	RWE Dea Norge AS		8.00 %
	Statoil Petroleum AS		20.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	10.3 million Sm³ oil	7.9 million Sm³ oil	
	30.6 billion Sm³ gas	28.7 billion Sm³ gas	
	8.1 million tonnes NGL	7.8 million tonnes NGL	
Estimated production in 2012	Oil: 42 000 barrels/day, Gas: 2.57 billion Sm³, NGL: 0.68 million tonnes		
Expected investment from 2011	3.9 billion 2011 values		
Total investment as of 31.12.2010	25.6 billion nominal values		
Main supply base	Florø		

Development: Gjøa is located about 40 kilometres north of the Fram field. The water depth in the area is 360 metres. The development comprises five subsea templates tied to a semi-submersible production and processing facility. The Gjøa facility is partly supplied with power from shore. Vega and Vega Sør are tied to the Gjøa facility.

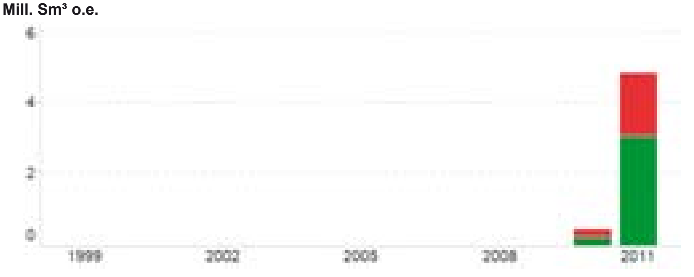
Reservoir: The reservoir contains gas above a relatively thin oil zone in Jurassic sandstones in the Viking, Brent and Dunlin Groups. The field comprises several tilted fault segments with partly uncertain communication and variable reservoir quality. The reservoir depth is about 2 200 metres.

Recovery strategy: The reservoir is produced by pressure depletion.

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

Status: Gjøa is being evaluated as host for additional resources in the area.

Gjøa



Glitne

Blocks and production licences	Block 15/5 - production licence 048 B, awarded 2001. Block 15/6 - production licence 029 B, awarded 2001.		
Development approval	08.09.2000 by the Crown Prince Regent in Council	**Discovered** 1995	
On stream	29.08.2001		
Operator	Statoil Petroleum AS		
Licensees	Det norske oljeselskap ASA		10.00 %
	Faroe Petroleum Norge AS		9.30 %
	Statoil Petroleum AS		58.90 %
	Total E&P Norge AS		21.80 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	9.2 million Sm³ oil	0.5 million Sm³ oil	
Estimated production in 2012	Oil: 2 000 barrels/day		
Expected investment from 2011	0.2 billion 2011 values		
Total investment as of 31.12.2010	2.5 billion nominal values		
Main supply base	Dusavik		

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

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

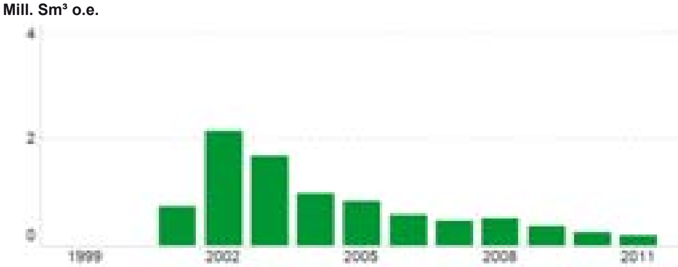
Recovery strategy: Glitne is recovered by pressure support from a large natural aquifer in the Heimdal Formation. Associated gas is used for gas lift in the horizontal wells.

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

Status: Glitne is a mature field with limited remaining reserves. A new well is planned in 2012. It is expected that production from the field will cease in late 2014.

Glitne

Mill. Sm³ o.e.



Grane

Blocks and production licences	Block 25/11 - production licence 001, awarded 1965 Block 25/11 - production licence 169 B1, awarded 2000.		
Development approval	14.06.2000 by the Storting	**Discovered** 1991	
On stream	23.09.2003		
Operator	Statoil Petroleum AS		
Licensees in Grane	ConocoPhillips Skandinavia AS		6.17 %
	ExxonMobil Exploration & Production Norway AS		28.22 %
	Petoro AS		28.94 %
	Statoil Petroleum AS		36.66 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	120.9 million Sm³ oil	39.5 million Sm³ oil	
Estimated production in 2012	Oil: 110 000 barrels/day		
Expected investment from 2011	9.0 billion 2011 values		
Total investment as of 31.12.2010	18.6 billion nominal values		
Main supply base	Mongstad		

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

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

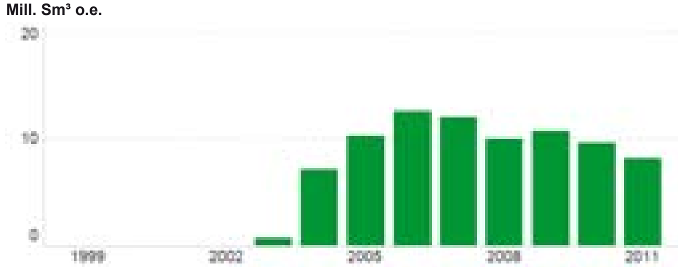
Recovery strategy: The recovery mechanism is gas injection at the top of the structure, and horizontal production wells at the bottom of the oil zone. From December 2010 Grane terminated gas import from the Heimdal gas centre, and only the produced gas is being re-injected into the reservoir. Oil recovery will be maintained by expansion of the gas cap and water injection.

Transport: Oil from Grane is transported by pipeline to the Sture terminal for storage and export.

Status: Several new wells are being planned, most of them as multi-lateral wells. In February 2011, the first water injector started up.

Grane

Mill. Sm³ o.e.



Gullfaks

Blocks and production licences	Block 34/10 - production licence 050, awarded 1978 Block 34/10 - production licence 050 B, awarded 1995.	
Development approval	09.10.1981 by the Storting	**Discovered** 1978
On stream	22.12.1986	
Operator	Statoil Petroleum AS	
Licensees	Petoro AS	30.00 %
	Statoil Petroleum AS	70.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**
	365.4 million Sm³ oil	14.0 million Sm³ oil
	23.1 billion Sm³ gas	
	2.7 million tonnes NGL	
Estimated production in 2012	Oil: 40 000 barrels/day	
Expected investment from 2011	14,4 billion 2011 values	
Total investment as of 31.12.2010	72.0 billion nominal values	
Main supply base	Sotra and Florø	

Development: Gullfaks is an oil field located in the Tampen area in the northern part of the North Sea. The water depth in the area is 130 – 220 metres. The field has been developed with three integrated processing, drilling and accommodation facilities with concrete bases and steel topsides (Gullfaks A, B and C). Gullfaks B has a simplified processing plant with only first stage separation. Gullfaks A and C receive and process oil and gas from Gullfaks Sør and Gimle. The facilities are also involved in production and transport from the Tordis, Vigdis and Visund fields. The Tordis production is processed in a separate facility on Gullfaks C. A PDO for Gullfaks C was approved on 1 June 1985, a PDO for Gullfaks Vest was approved on 15 January 1993, and recovery from the Lunde Formation was approved on 3 November 1995. In December 2005, an amended PDO for the Gullfaks field was approved, covering prospects and small discoveries which can be drilled and produced from existing facilities.

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

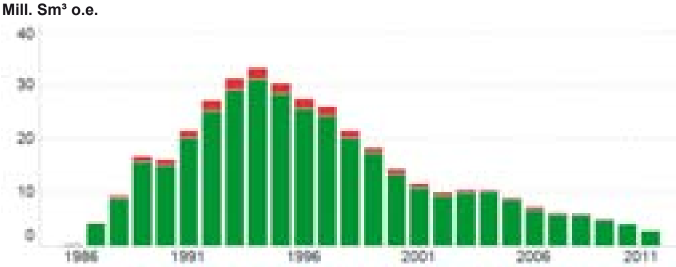
Recovery strategy: The drive mechanisms are water injection, gas injection and water/alternating gas injection (WAG). The drive mechanisms vary between drainage areas in the field, with water injection as the main strategy.

Transport: Oil is exported from Gullfaks A and Gullfaks C via loading buoys to shuttle tankers. Rich gas is sent through the export pipeline to Statpipe for further processing at Kårstø and export to the Continent as dry gas.

Status: Evaluations for extending the lifetime of Gullfaks are ongoing. This includes upgrades of the drilling facilities at Gullfaks A, B and C.

Gullfaks

Mill. Sm³ o.e.



Gullfaks Sør

Blocks and production licences	Block 32/12 - production licence 152, awarded 1988. Block 33/12 - production licence 037 B, awarded 1998 Block 33/12 - production licence 037 E, awarded 2004. Block 34/10 - production licence 050, awarded 1978 Block 34/10 - production licence 050 B, awarded 1995.	
Development approval	29.03.1996 by the King in Council	**Discovered** 1978
On stream	10.10.1998	
Operator	Statoil Petroleum AS	
Licensees	Petoro AS	30.00 %
	Statoil Petroleum AS	70.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**
	52.1 million Sm³ oil	11.8 million Sm³ oil
	64.4 billion Sm³ gas	33.9 billion Sm³ gas
	8.0 million tonnes NGL	4.2 million tonnes NGL
Estimated production in 2012	Oil: 30 000 barrels/day, Gas: 2.3 billion Sm³, NGL: 0.26 million tonnes	
Expected investment from 2011	20.0 billion 2011 values	
Total investment as of 31.12.2010	26.7 billion nominal values	
Main supply base	Sotra and Florø	

Development: Gullfaks Sør is located to the south of Gullfaks in the northern part of the North Sea. It has been developed with a total of 12 subsea templates tied back to the Gullfaks A and Gullfaks C facilities. Gullfaks Sør has been developed in two phases. The PDO for Phase 1 included production of oil and condensate from the 34/10-2 Gullfaks Sør, 34/10-17 Rimfaks and 34/10-37 Gullveig deposits. The PDO for Phase 2 was approved on 8 June 1998 and covered production of gas from the Brent Group in the Gullfaks Sør deposit. In 2004, the 34/10-47 Gulltopp discovery was included in Gullfaks Sør. Gulltopp is produced through an extended reach production well from Gullfaks A. A PDO for the 33/12-8 A Skinfaks discovery and Rimfaks IOR was approved on 11 February 2005. The development included a new subsea template and a satellite well.

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

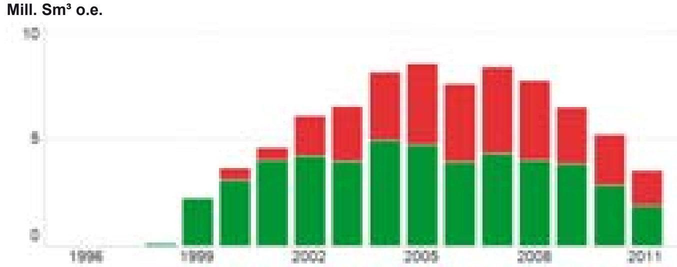
Recovery strategy: Recovery from the Brent reservoir in Gullfaks Sør is driven by pressure depletion after gas injection ceased in 2009. The Brent reservoir in Rimfaks is produced by full pressure maintenance by gas injection, whereas the Statfjord Formation has partial pressure support from gas injection.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

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: A project to evaluate the redevelopment of the Gullfaks Sør Statfjord Formation is ongoing. In order to increase gas production from Gullfaks Sør, a subsea gas compressor will be installed on the field.

Gullfaks Sør

Mill. Sm³ o.e.



Gungne

Blocks and production licences	Block 15/9 - production licence 046, awarded 1976.	
Development approval	29.08.1995 by the King in Council	**Discovered** 1982
On stream	21.04.1996	
Operator	Statoil Petroleum AS	
Licensees	ExxonMobil Exploration & Production Norway AS	28.00 %
	Statoil Petroleum AS	62.00 %
	Total E&P Norge AS	10.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**
	14.4 billion Sm^3 gas	0.9 billion Sm^3 gas
	2.1 million tonnes NGL	0.2 million tonnes NGL
	4.6 million Sm^3 condensate	0.3 million Sm^3 condensate
Estimated production in 2012	Gas: 0.36 billion Sm^3, NGL: 0.06 million tones, Condensate: 0.09 million Sm^3	
Total investment as of 31.12.2010	1.9 billion nominal values	
Main supply base	Dusavik	

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

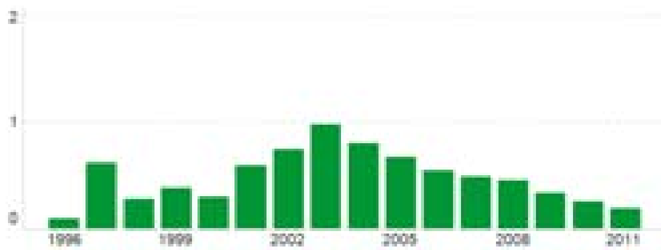
Reservoir: The reservoir consists of sandstones of the Skagerrak Formation of the Triassic age. The reservoir depth is about 2 800 metres. The reservoir quality is generally good, but the reservoir is segmented, and lateral shale layers act as internal barriers.

Recovery strategy: Gungne is recovered by pressure depletion.

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

Gungne

Mill. Sm³ o.e.



Gyda

Blocks and production licences	Block 2/1 - production licence 019 B, awarded 1977.	
Development approval	02.06.1987 by the Storting	**Discovered** 1980
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 31.12.2011**
	35.9 million Sm^3 oil	0.3 million Sm^3 oil
	6.3 billion Sm^3 gas	0.2 billion Sm^3 gas
	1.9 million tonnes NGL	
Estimated production in 2012	Oil: 4 000 barrels/day, Gas: 0.05 billion Sm^3, NGL: 0.01 million tonnes	
Expected investment from 2011	0.8 billion 2011 values	
Total investment as of 31.12.2010	11.8 billion nominal values	
Main supply base	Tananger	

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

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

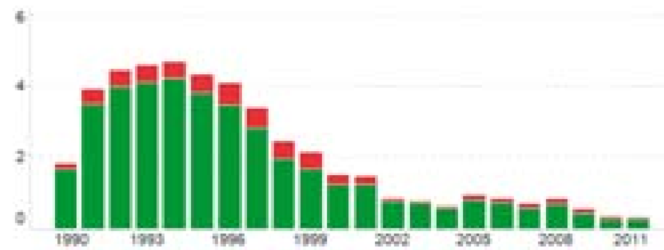
Recovery strategy: The field produces with water injection as the drive mechanism for the main part of the field. Pressure support from the gas cap and the aquifer are drive mechanisms for other parts of the field.

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

Status: Gyda is a mature field in tail phase and experiences increasing water production and challenges in maintaining the oil production. Work is ongoing to prolong the lifetime of the field. This includes further infill drilling and plans for installation of artificial lift in some wells. Gas lift has increased well production.

Gyda

Mill. Sm³ o.e.



Heidrun

Blocks and production licences	Block 6507/8 - production licence 124, awarded 1986. Block 6707/7 - production licence 095, awarded 1984.		
Development approval	14.05.1991 by the Storting	**Discovered** 1985	
On stream	18.10.1995		
Operator	Statoil Petroleum AS		
Licensees	ConocoPhillips Skandinavia AS		24.31 %
	Eni Norge AS		5.12 %
	Petoro AS		58.16 %
	Statoil Petroleum AS		12.41 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	177.1 million Sm³ oil	38.3 million Sm³ oil	
	44.0 billion Sm³ gas	29.4 billion Sm³ gas	
	2.0 million tonnes NGL	1.5 million tonnes NGL	
Estimated production in 2012	Oil: 52 000 barrels/day, Gas: 0.71 billion Sm³		
Expected investment from 2011	22.0 billion 2011 values		
Total investment as of 31.12.2010	50.9 billion nominal values		
Main supply base	Kristiansund		

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

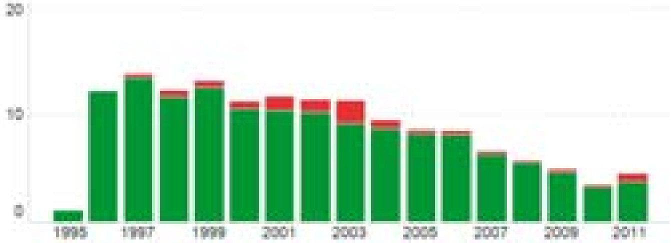
Reservoir: The reservoir consists of sandstones of the Garn, Ile, Tilje and Åre Formations of Early and Middle Jurassic age. The reservoir is heavily faulted. The Garn and Ile Formations have good reservoir quality, while the Tilje and Åre Formations are more complex. The reservoir depth is about 2 300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

Recovery strategy: The recovery strategy for the field is pressure maintenance using water and gas injection in the Garn and Ile Formations. In the more complex part of the reservoir, in the Tilje and Åre Formations, the main recovery strategy is water injection. Some segments are also produced by pressure depletion. Optimisation of the drainage strategy is under evaluation and was reported to the NPD in 2011. Several methods to improve the recovery and prolong the lifetime of the field are evaluated, including increased number of wells, possible implementation of new drilling technology and EOR methods.

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

Status: New well targets are continuously assessed in an effort to increase oil recovery. Different pilots to improve recovery are being assessed, and some are implemented.

Heidrun
Mill. Sm³ o.e.



Heimdal

Blocks and production licences	Block 25/4 - production licence 036 BS, awarded 2003.		
Development approval	10.06.1981 by the Storting	**Discovered** 1972	
On stream	13.12.1985		
Operator	Statoil Petroleum AS		
Licensees	Centrica Resources (Norge) AS		23.80 %
	Petoro AS		20.00 %
	Statoil Petroleum AS		39.44 %
	Total E&P Norge AS		16.76 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	8.2 million Sm³ oil	1.6 million Sm³ oil	
	47.0 billion Sm³ gas	1.7 billion Sm³ gas	
Estimated production in 2012	Oil: 400 barrels/day, Gas: 0.14 billion Sm³		
Expected investment from 2011	0.2 billion 2011 values		
Total investment as of 31.12.2010	10.0 billion nominal values		
Main supply base	Mongstad		

Development: Heimdal is a gas field located in the central part of the North Sea. The water 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 2 October 1992. A PDO for Heimdal Gas Centre (HGS) was approved on 15 January 1999. This included a new riser facility (HRP), connected by a bridge to HMP1. Heimdal is now mainly a processing centre for other fields. Huldra, Skirne and Vale deliver gas to Heimdal. In addition, gas from Oseberg is transported via Heimdal.

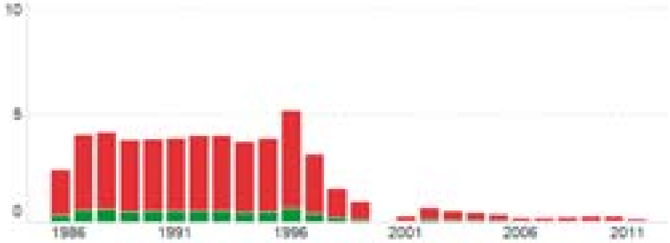
Reservoir: The reservoir consists of sandstones of the Heimdal Formation of Paleocene age, deposited as sub-marine fan systems. The reservoir depth is about 2 100 metres.

Recovery strategy: The field has been recovered by pressure depletion. Heimdal will continue to produce small amounts until 2014.

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

Status: The licensees are searching for new gas resources that can be tied to Heimdal to prolong the lifetime of the gas centre. Valemon is a new candidate with gas which can be transported/processed via Heimda, with planned start-up in 2014.

Heimdal
Mill. Sm³ o.e.



Hod

Blocks and production licences	Block 2/11 - production licence 033, awarded 1969.	
Development approval	26.06.1988 by the Storting	**Discovered** 1974
On stream	30.09.1990	
Operator	BP Norge AS	
Licensees	BP Norge AS	37.50 %
	Hess Norge AS	62.50 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**
	10.4 million Sm³ oil	1.0 million Sm³ oil
	1.8 billion Sm³ gas	0.2 billion Sm³ gas
	0.4 million tonnes NGL	0.1 million tonnes NGL
Estimated production in 2012	Oil: 1 000 barrels/day, Gas: 0.01 billion Sm³	
Expected investment from 2011	0.1 billion 2011 values	
Total investment as of 31.12.2010	2.1 billion nominal values	
Main supply base	Tananger	

Development: Hod is an oil field located 13 kilometres south of the Valhall field in the southern part of the North Sea. The water depth is 72 metres. The field is developed with an unmanned production facility, which is remotely controlled from the Valhall field. In addition, the field produces through wells drilled from Valhall. The PDO for the Hod Sadel area was approved in June 1994.

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

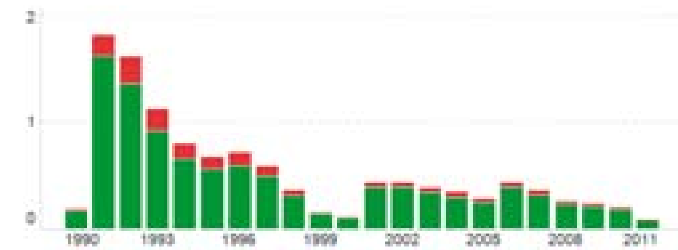
Recovery strategy: The field has been produced by pressure depletion. Gas lift is used in two wells to increase production. A water injection pilot was started in 2011 and full field water injection is also being considered in connection with a further development of the field.

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

Status: Production from Hod Øst and Hod Vest is stable at a low level. The field is in the tail phase with the current recovery strategy. There are plans for redevelopment which can extend the lifetime of the field. The operator has applied for licence extension from 2015.

Hod

Mill. Sm³ o.e.



Huldra

Blocks and production licences	Block 30/2 - production licence 051, awarded 1979. Block 30/3 - production licence 052 B, awarded 2001.	
Development approval	02.02.1999 by the Storting	**Discovered** 1982
On stream	21.11.2001	
Operator	Statoil Petroleum AS	
Licensees	ConocoPhillips Skandinavia AS	23.34 %
	Petoro AS	31.96 %
	Statoil Petroleum AS	19.88 %
	Talisman Energy Norge AS	0.50 %
	Total E&P Norge AS	24.33 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**
	5.2 million Sm³ oil	0.2 million Sm³ oil
	17.5 billion Sm³ gas	1.2 billion Sm³ gas
	0.1 million tonnes NGL	
Estimated production in 2012	Oil: 1 000 barrels/day, Gas: 0.39 billion Sm³	
Expected investment from 2011	0.1 billion 2011 values	
Total investment as of 31.12.2010	7.4 billion nominal values	
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 water depth in the area is 125 metres. The field is developed with a steel wellhead facility with a simple process plant. The facility is normally not manned and is remotely operated from Veslefrikk B, 16 kilometres away.

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

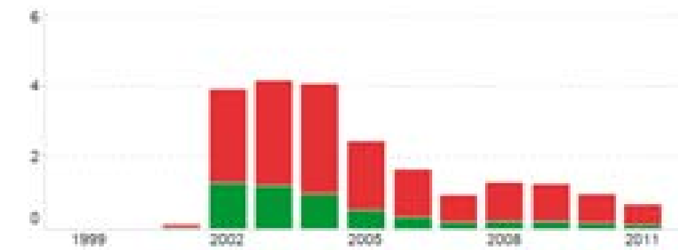
Recovery strategy: Huldra is recovered by pressure depletion. Low pressure production began in 2007 after a gas compressor was installed on the field. The compressor has prolonged the lifetime of the field by several years.

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

Status: Huldra is in the tail production phase and it is expected that the field will cease production in a few years. The partnership has decided to further reduce the pressure and this will extend the lifetime of the field.

Huldra

Mill. Sm³ o.e.



Jotun

Blocks and production licences	Block 25/7 - production licence 103 B, awarded 1998. Block 25/8 - production licence 027 B, awarded 1999.		
Development approval	10.06.1997 by the Storting	**Discovered** 1994	
On stream	25.10.1999		
Operator	ExxonMobil Exploration & Production Norway AS		
Licensees	Dana Petroleum Norway AS		45.00 %
	Det norske oljeselskap ASA		7.00 %
	ExxonMobil Exploration & Production Norway AS		45.00 %
	Faroe Petroleum Norge AS		3.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	23.6 million Sm^3 oil	1.0 million Sm^3 oil	
	0.9 billion Sm^3 gas		
Estimated production in 2012	Oil: 3 000 barrels/day		
Expected investment from 2011	0.1 billion 2011 values		
Total investment as of 31.12.2010	9.5 billion nominal values		
Main supply base	Dusavik		

Development: Jotun is an oil field located 25 kilometres north of Balder in the central part of the North Sea. The water 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. The easternmost structure has a small gas cap. The reservoirs consist of sandstones of the Heimdal Formation of Paleocene age. The reservoirs are deposited in a sub-marine fan system and lie at a depth of about 2 000 metres. To the west the sand has good reservoir quality, while the shale content increases towards the east.

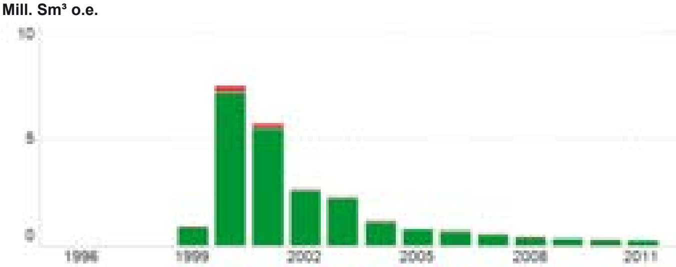
Recovery strategy: The field is recovered by pressure support from the aquifer. Produced water is now injected in the Utsira Formation, and is no longer used for pressure support. Gas lift is used in all the producing wells.

Transport: The Jotun FPSO is an integrated part of the Balder and Ringhorne fields. Ringhorne delivers gas and oil to the Jotun FPSO. Excess gas from Balder is routed to Jotun for gas export. Jotun processes and exports the rich gas via Statpipe to Kårstø. The oil is exported via the production vessel at Jotun to tankers on the field.

Status: The field is in the tail production phase. Water cut has continued to rise, and is now about 96 per cent of the wellstream. Jette, a small oilfield nearby, will be tied-in during 2012 and will start oil production via Jotun early in 2013. The production on Jotun is expected to last until 2021.

Jotun

Mill. Sm^3 o.e.



Kristin

Blocks and production licences	Block 6406/2 - production licence 199, awarded 1993. Block 6506/11 - production licence 134 B, awarded 2000.		
Development approval	17.12.2001 by the Storting	**Discovered** 1997	
On stream	03.11.2005		
Operator	Statoil Petroleum AS		
Licensees	Eni Norge AS		8.25 %
	ExxonMobil Exploration & Production Norway AS		10.88 %
	Petoro AS		19.58 %
	Statoil Petroleum AS		55.30 %
	Total E&P Norge AS		6.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	22.2 million Sm^3 oil	6.4 million Sm^3 oil	
	28.6 billion Sm^3 gas	11.2 billion Sm^3 gas	
	6.4 million tonnes NGL	2.8 million tonnes NGL	
	2.1 million Sm^3 condensate		
Estimated production in 2012	Oil: 17 000 barrels/day, Gas: 1.45 billion Sm^3, NGL: 0.32 million tonnes		
Expected investment from 2011	2.4 billion 2011 values		
Total investment as of 31.12.2010	24.2 billion nominal values		
Main supply base	Kristiansund		

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

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

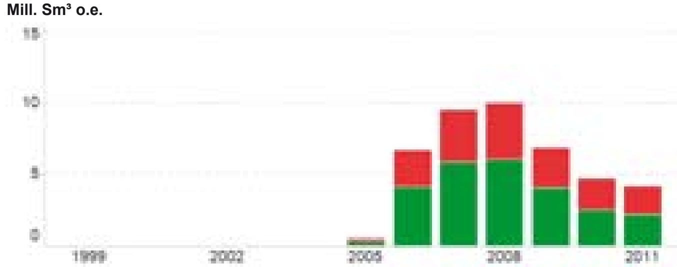
Recovery strategy: Kristin is recovered by pressure depletion.

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

Status: The reservoir pressure at Kristin is decreasing faster than expected, leading to challenges such as production of water and sand. Work is ongoing to find technical solutions to production and drilling challenges related to pressure decrease and water breakthrough in wells. Low pressure production (LPP) from the reservoir will be implemented starting in 2014. This will contribute to improved recovery. Work is being done on the development of additional resources in nearby segments. Kristin is also evaluated as a possible processing centre for other discoveries in the area.

Kristin

Mill. Sm^3 o.e.



Kvitebjørn

Blocks and production licences	Block 34/11 - production licence 193, awarded 1993.		
Development approval	14.06.2000 by the Storting	**Discovered** 1994	
On stream	26.09.2004		
Operator	Statoil Petroleum AS		
Licensees	Enterprise Oil Norge AS		6.45 %
	Petoro AS		30.00 %
	Statoil Petroleum AS		58.55 %
	Total E&P Norge AS		5.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	26.4 million Sm³ oil	11.4 million Sm³ oil	
	91.8 billion Sm³ gas	59.5 billion Sm³ gas	
	5.1 million tonnes NGL	2.2 million tonnes NGL	
Estimated production in 2012	Oil: 39 000 barrels/day, Gas: 6.27 billion Sm³, NGL: 0.33 million tonnes		
Expected investment from 2011	7.1 billion 2011 values		
Total investment as of 31.12.2010	13.0 billion nominal values		
Main supply base	Florø		

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

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

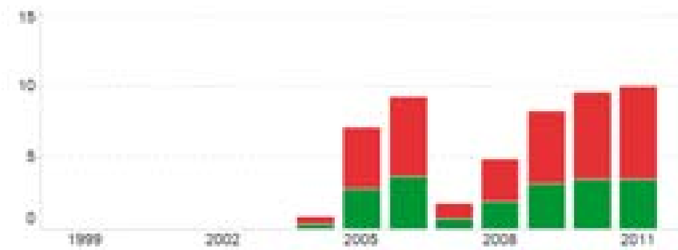
Recovery strategy: The field is recovered by pressure depletion.

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

Status: There are plans to continue to drill infill wells, mature new drilling targets on the flanks of the field and install a gas compressor on the platform, with start-up in late 2013.

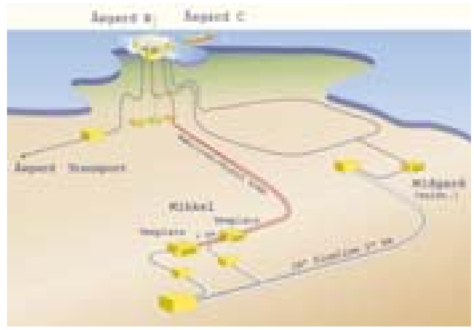
Kvitebjørn

Mill. Sm³ o.e.



Mikkel

Blocks and production licences	Block 6407/5 - production licence 121, awarded 1986. Block 6407/6 - production licence 092, awarded 1984.		
Development approval	14.09.2001 by the King in Council	**Discovered** 1987	
On stream	01.08.2003		
Operator	Statoil Petroleum AS		
Licensees	Eni Norge AS		14.90 %
	ExxonMobil Exploration & Production Norway AS		33.48 %
	Statoil Petroleum AS		43.97 %
	Total E&P Norge AS		7.65 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	4.6 million Sm³ oil	1.7 million Sm³ oil	
	24.1 billion Sm³ gas	10.1 billion Sm³ gas	
	6.6 million tonnes NGL	2.8 million tonnes NGL	
	2.3 million Sm³ condensate		
Estimated production in 2012	Oil: 6 000 barrels/day, Gas: 1.56 billion Sm³, NGL: 0.42 million tonnes		
Expected investment from 2011	3.1 billion 2011 values		
Total investment as of 31.12.2010	1.9 billion nominal values		
Main supply base	Kristiansund		



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

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

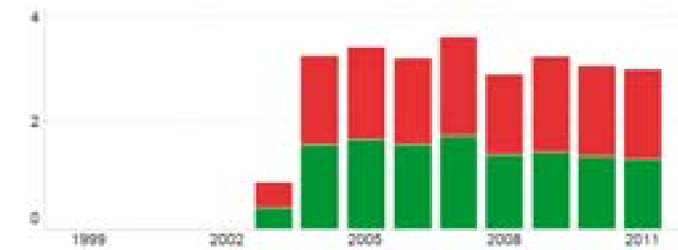
Recovery strategy: Mikkel is recovered by pressure depletion.

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

Status: Establishment of a gas compression facility at Midgard was sanctioned in July 2011. It is expected that the project will be processed by the Storting in 2012. The gas compression project is planned for start-up in 2015 to maintain pressure in the pipelines from Mikkel and Midgard to Åsgard B. A stable supply of low CO_2 gas from Mikkel and Midgard is also important for dilution of the high CO_2 gas from Kristin in the Åsgard Transport pipeline to Kårstø. Work is being done to realise proven gas resources in the area via Mikkel and Midgard to Åsgard B.

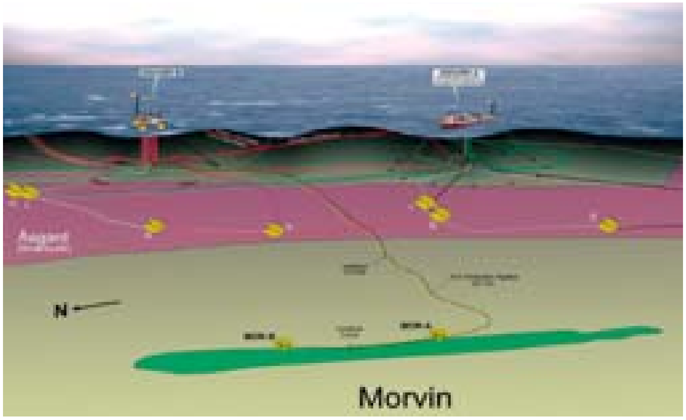
Mikkel

Mill. Sm³ o.e.



Morvin

Blocks and production licences	Block 6506/11 - production licence 134 B, awarded 2000 Block 6506/11 - production licence 134 C, awarded 2006.		
Development approval	25.04.2008 by the King in Council	**Discovered** 2001	
On stream	01.08.2010		
Operator	Statoil Petroleum AS		
Licensees	Eni Norge AS		30.00 %
	Statoil Petroleum AS		64.00 %
	Total E&P Norge AS		6.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	9.2 million Sm^3 oil	7.2 million Sm^3 oil	
	3.1 billion Sm^3 gas	3.1 billion Sm^3 gas	
	0.7 million tonnes NGL	0.7 million tonnes NGL	
Estimated production in 2012	Oil: 30 000 barrels/day, Gas: 0.22 billion Sm^3, NGL: 0.04 million tonnes		
Expected investment from 2011	0.6 billion 2011 values		
Total investment as of 31.12.2010	7.4 billion nominal values		



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

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

Recovery strategy: Morvin will be produced by pressure depletion.

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

Status: The field came on stream in August 2010.

Morvin

Mill. Sm³ o.e.

Murchison

Blocks and production licences	Block 33/9 - production licence 037 C, awarded 2000. The Norwegian part of the field is 22.2 %, the British part is 77.8 %		
Development approval	15.12.1976	**Discovered** 1975	
On stream	28.09.1980		
Operator	CNR International (UK) Limited		
Licensees	Wintershall Norge ASA		22.20 %
	CNR International (UK) Limited		77.80 %
Recoverable reserves (Norwegian part)	**Original**	**Remaining as of 31.12.2011**	
	13.9 million Sm^3 oil	0.1 million Sm^3 oil	
	0.3 billion Sm^3 gas		
Estimated production in 2012	Oil: 1 000 barrels/day		
Expected investment from 2011	0.1 billion 2011 values		
Total investment as of 31.12.2010	2.6 billion nominal values		
Main supply base	Peterhead, Scotland		

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

Reservoir: The reservoirs are in Jurassic sandstones.

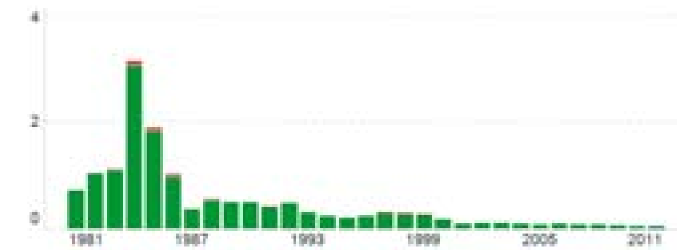
Recovery strategy: The field is recovered by pressure support from water injection.

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

Status: Murchison is in the tail phase, and production may end within a few years.

Murchison

Mill. Sm³ o.e.



Njord

Blocks and production licences	Block 6407/10 - production licence 132, awarded 1987. Block 6407/7 - production licence 107, awarded 1985.	
Development approval	12.06.1995 by the Storting	**Discovered** 1986
On stream	30.09.1997	
Operator	Statoil Petroleum AS	
Licensees	E.ON Ruhrgas Norge AS	30.00 %
	Faroe Petroleum Norge AS	7.50 %
	GDF SUEZ E&P Norge AS	40.00 %
	Statoil Petroleum AS	20.00 %
	VNG Norge AS	2.50 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**
	28.0 million Sm^3 oil	2.8 million Sm^3 oil
	16.2 billion Sm^3 gas	9.1 billion Sm^3 gas
	3.4 million tonnes NGL	1.7 million tonnes NGL
Estimated production in 2012	Oil: 15 000 barrels/day, Gas: 1,55 billion Sm^3, NGL: 0.31 million tonnes	
Expected investment from 2011	6.0 billion 2011 values	
Total investment as of 31.12.2010	13.6 billion nominal values	
Main supply base	Kristiansund	

Development: Njord is an oil field located about 30 kilometres west of Draugen in the Norwegian Sea. The water depth in the area is 330 metres. The field has been developed with a semi-submersible drilling, accommodation and production facility and a storage vessel, Njord B. The facility is located over subsea completed wells connected through flexible risers. The PDO for Njord gas export was approved on 21 January 2005.

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

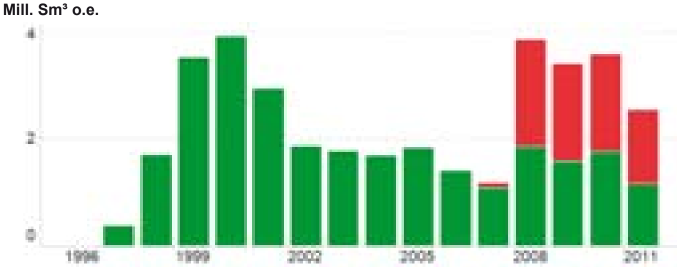
Recovery strategy: Initial production strategy was gas injection for pressure support in parts of the reservoir and pressure depletion in the rest of the reservoir. After gas export started in 2007, only minor volumes of gas have been injected. Due to the complex reservoir with many faults, the field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

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

Status: In the coming period, a number of key activities are planned for the Njord field. Subsurface activities include the drilling and completion of the first production well on the northwest flank and infill drilling on the main field. Key topside activities include the Hyme field riser tie-in and repairs pending from the riser incident during 2011, the installation of the low pressure production upgrade and topside modifications and upgrades to handle production from the northwest flank.

Njord

Mill. Sm^3 o.e.



Norne

Blocks and production licences	Block 6508/1 - production licence 128 B, awarded 1998. Block 6608/10 - production licence 128, awarded 1986.	
Development approval	09.03.1995 by the Storting	**Discovered** 1992
On stream	06.11.1997	
Operator	Statoil Petroleum AS	
Licensees	Eni Norge AS	6.90 %
	Petoro AS	54.00 %
	Statoil Petroleum AS	39.10 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**
	90.8 million Sm^3 oil	4.6 million Sm^3 oil
	11.8 billion Sm^3 gas	5.4 billion Sm^3 gas
	1.8 million tonnes NGL	1.0 million tonnes NGL
Estimated production in 2012	Oil: 18 000 barrels/day, Gas: 0,16 billion Sm^3, NGL: 0.02 million tonnes	
Expected investment from 2011	3.3 billion 2011 values	
Total investment as of 31.12.2010	22.8 billion nominal values	
Main supply base	Sandnessjøen	

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

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

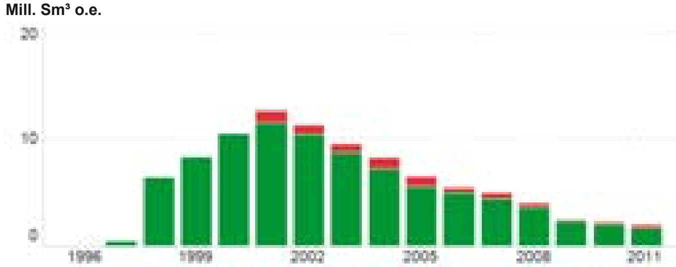
Recovery strategy: The oil is produced by water injection as drive mechanism. Gas injection ceased in 2005 and all gas is now being exported.

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

Status: Various measures to improve recovery are being considered, including the use of new well technology. Several light well interventions and new production wells are planned in 2012 to maintain the oil production.

Norne

Mill. Sm^3 o.e.



Ormen Lange

Blocks and production licences	Block 6305/4 - production licence 209, awarded 1996. Block 6305/5 - production licence 209, awarded 1996. Block 6305/7 - production licence 208, awarded 1996. Block 6305/8 - production licence 250, awarded 1999.		
Development approval	02.04.2004 by the Storting	**Discovered** 1997	
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 %
	Statoil Petroleum AS		28.92 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	297.0 billion Sm^3 gas	220.5 billion Sm^3 gas	
	16.3 million Sm^3 condensate	10.3 million Sm^3 condensate	
Estimated production in 2012	Gas: 21.23 billion Sm^3, Condensate: 1.69 million Sm^3		
Expected investment from 2011	30.6 billion 2011 values		
Total investment as of 31.12.2010	31.1 billion nominal values		
Main supply base	Kristiansund		

Development: Ormen Lange is a gas field located in the Møre Basin in the southern part of the Norwegian Sea. The water depth in the area varies from 800 to in excess of 1 100 metres. The deep water and the seabed conditions have made the development very challenging and have triggered development of new technology. The field is being developed in several phases. The plans for development of Ormen Lange call for 24 deepwater wells. In 2007 two subsea templates were located in the central area of the field. In 2009 the third template was installed in the southern part of the field. The fourth template was installed in the northern part of the field in 2011.

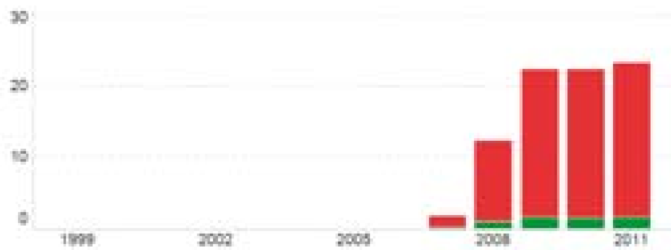
Reservoir: The main reservoir consists of sandstones of Paleocene age in the "Egga" Formation, about 2 700 - 2 900 metres below sea level.

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

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

Status: The field is producing at plateau with 15 wells. Reserve estimates were reduced considerably in 2011. During 2011, the licence changed its base case for future gas compression to a combination of onshore compression from 2016 together with an infield compression solution from 2021.

Ormen Lange
Mill. Sm³ o.e.

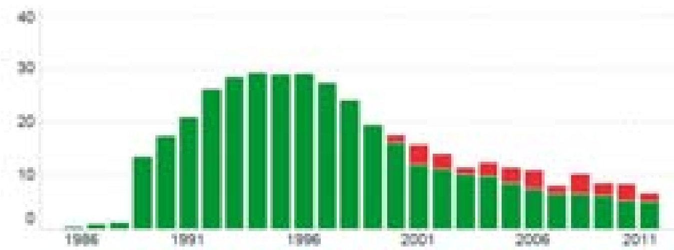


Oseberg

Blocks and production licences	Block 30/6 - production licence 053, awarded 1979. Block 30/9 - production licence 079, awarded 1982.		
Development approval	05.06.1984 by the Storting	**Discovered** 1979	
On stream	01.12.1988		
Operator	Statoil Petroleum AS		
Licensees	ConocoPhillips Skandinavia AS		2.40 %
	ExxonMobil Exploration & Production Norway AS		4.70 %
	Petoro AS		33.60 %
	Statoil Petroleum AS		49.30 %
	Total E&P Norge AS		10.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	381.0 million Sm^3 oil	22.4 million Sm^3 oil	
	105.4 billion Sm^3 gas	75.1 billion Sm^3 gas	
	12.0 million tonnes NGL	4.4 million tonnes NGL	
Estimated production in 2012	Oil: 55 000 barrels/day, Gas: 3.12 billion Sm^3, NGL: 0.43 million tonnes		
Expected investment from 2011	19.0 billion 2011 values		
Total investment as of 31.12.2010	63.8 billion nominal values		
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 water depth in the area is about 100 metres. Oseberg is developed in multiple phases. The Oseberg Field Centre in the south consists of two facilities, the process and accommodation facility Oseberg A and the drilling and water injection facility Oseberg B. Oseberg C is an integrated production, drilling and quarters facility (PDQ) in the northern part of the field. Oseberg D is a facility for gas processing tied to the Oseberg Field Centre. Oseberg Vestflanke has been developed with a subsea template tied back to Oseberg B. Oseberg Delta has been developed with a subsea template tied back to Oseberg D. Production from the Statfjord Formation of the Gamma Main structure started in 2008 with two wells from the Oseberg Field Centre. The facilities at the Field Centre process oil and gas from the fields Oseberg Øst, Oseberg Sør and Tune. The PDO for the northern part of the field was approved on 19 January 1988. The PDO for Oseberg D was approved on 13

Oseberg
Mill. Sm³ o.e.



December 1996. The PDO for Oseberg Vestflanke was approved on 19 December 2003, and the PDO for Oseberg Delta was approved on 23 September 2005.

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

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

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

Status: The challenge on the main Oseberg reservoir will be to produce the remaining oil below the gas cap, and to balance the gas offtake with regard to oil recovery from the field. A module for low pressure production has been installed at the Oseberg Field Centre and the compressor has been upgraded. In addition, upgrades of the drilling facilities on Oseberg B and C are ongoing. Test production is ongoing from an overlying chalk reservoir in the Shetland Group on the Oseberg field to evaluate the flow characteristics. A further development of the satellite structures is under evaluation.

Oseberg Sør

Blocks and production licences	Block 30/12 - production licence 171 B, awarded 2000. Block 30/9 - production licence 079, awarded 1982 Block 30/9 - production licence 104, awarded 1985.		
Development approval	10.06.1997 by the Storting	**Discovered** 1984	
On stream	05.02.2000		
Operator	Statoil Petroleum AS		
Licensees	ConocoPhillips Skandinavia AS		2.40 %
	ExxonMobil Exploration & Production Norway AS		4.70 %
	Petoro AS		33.60 %
	Statoil Petroleum AS		49.30 %
	Total E&P Norge AS		10.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	56.9 million Sm^3 oil	15.3 million Sm^3 oil	
	14.5 billion Sm^3 gas	7.7 billion Sm^3 gas	
	1.5 million tonnes NGL	1.5 million tonnes NGL	
Estimated production in 2012	Oil: 31 000 barrels/day, Gas: 0.31 billion Sm^3, NGL: 0.14 million tonnes		
Expected investment from 2011	9.8 billion 2011 values		
Total investment as of 31.12.2010	18.7 billion nominal values		
Main supply base	Mongstad		

Development: Oseberg Sør is an oil field located south of Oseberg in the northern part of the North Sea. The water depth in the area is approximately 100 metres. The field has been developed with an integrated steel facility with accommodation, drilling module and first-stage separation of oil and gas. In addition, several deposits included in the Oseberg Sør field have been developed with subsea templates tied back to the Oseberg Sør facility. Final processing of oil and gas takes place on the Oseberg Field Centre. The development of the Oseberg Sør J structure was approved in 2003 and production started in November 2006. The development of the 30/9 -22 Stjerne structure with a subsea template was approved on 12 October 2011.

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

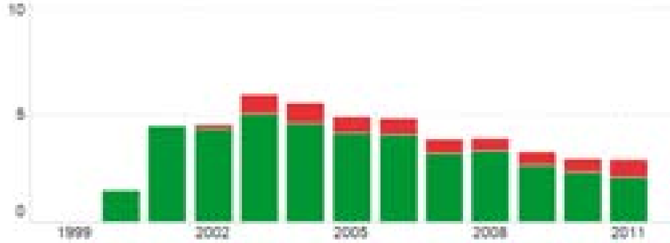
Recovery strategy: Recovery mainly takes place by water and gas injection. In parts of the field, water alternating gas injection (WAG) is being used. Water used for injection is produced from the Utsira Formation.

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

Status: Optimal use of available gas for re-injection and a strategy for blowdown of the Oseberg Sør reservoirs have been evaluated. A strategy to combine smaller prospects and discoveries into clusters large enough to trigger new infrastructure has been established.

Oseberg Sør

Mill. Sm^3 o.e.



Oseberg Øst

Blocks and production licences	Block 30/6 - production licence 053, awarded 1979.		
Development approval	11.10.1996 by the King in Council	**Discovered** 1981	
On stream	03.05.1999		
Operator	Statoil Petroleum AS		
Licensees	ConocoPhillips Skandinavia AS		2.40 %
	ExxonMobil Exploration & Production Norway AS		4.70 %
	Petoro AS		33.60 %
	Statoil Petroleum AS		49.30 %
	Total E&P Norge AS		10.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	27.2 million Sm^3 oil	8.9 million Sm^3 oil	
	0.4 billion Sm^3 gas	0.1 billion Sm^3 gas	
	0.1 million tonnes NGL	0.1 million tonnes NGL	
Estimated production in 2012	Oil: 12 000 barrels/day, Gas: 0.01 billion Sm^3, NGL: 0.01 million tonnes		
Expected investment from 2011	4.4 billion 2011 values		
Total investment as of 31.12.2010	8.1 billion nominal values		
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 water depth in the area is about 160 metres.

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

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

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

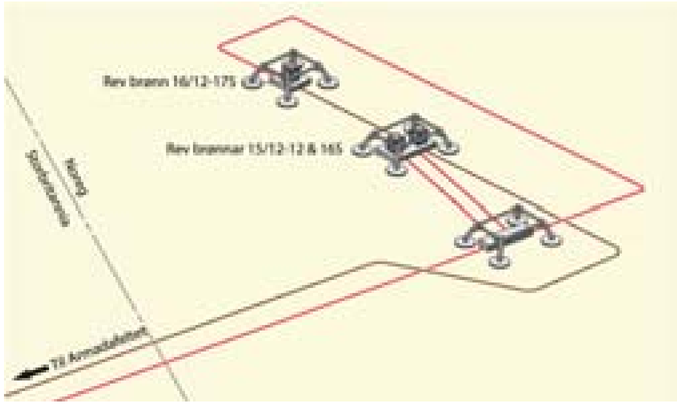
Status: One challenge is to balance production with a limited availability of gas for injection. In addition, focus has been on improving the performance of the drilling facility.

Oseberg Øst

Mill. Sm^3 o.e.

Rev

Blocks and production licences	Block 15/12 - production licence 038 C, awarded 2006.		
Development approval	15.06.2007 by the King in Council	**Discovered** 2001	
On stream	24.01.2009		
Operator	Talisman Energy Norge AS		
Licensees	Petoro AS		30.00 %
	Talisman Energy Norge AS		70.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	1.2 million Sm^3 oil	0.5 million Sm^3 oil	
	4.4 billion Sm^3 gas	2.2 billion Sm^3 gas	
	0.3 million tonnes NGL	0.3 million tonnes NGL	
Estimated production in 2012	Oil: 3 000 barrels/day, Gas: 0.72 billion Sm^3, NGL: 0.06 million tonnes		
Expected investment from 2011	0.5 billion 2011 values		
Total investment as of 31.12.2010	3.8 billion nominal values		



Development: Rev is a gas-condensate field located close to the border between the Norwegian and British sectors, four kilometres south of the Varg field. The field is developed with three subsea gas producers connected to the Armada field on the British continental shelf. The water depth in the area is 90 - 110 metres.

Reservoir: The reservoir consists of Upper Jurassic sandstones of good quality surrounding a salt structure at about 3 000 metres depth. Pressure measurements show that the reservoir is in communication with the Varg field.

Recovery strategy: The field is produced by pressure depletion/gas expansion.

Transport: The wellstream is routed through a pipeline to the Armada field in the British sector, for processing at the CATS terminal and further export to the UK. The condensate is sold as stabilised crude oil.

Rev

Mill. Sm^3 o.e.

Ringhorne Øst

Blocks and production licences	Block 25/8 - production licence 027, awarded 1969 Block 25/8 - production licence 169, awarded 1991.		
Development approval	10.11.2005 by the King in Council	**Discovered** 2003	
On stream	19.03.2006		
Operator	ExxonMobil Exploration & Production Norway AS		
Licensees	ExxonMobil Exploration & Production Norway AS		77.38 %
	Faroe Petroleum Norge AS		7.80 %
	Statoil Petroleum AS		14.82 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	16.6 million Sm³ oil	8.4 million Sm³ oil	
	0.4 billion Sm³ gas	0.2 billion Sm³ gas	
Estimated production in 2012	Oil: 19 000 barrels/day, Gas: 0.03 billion Sm³		
Expected investment from 2011	1.3 billion 2011 values		
Total investment as of 31.12.2010	0.7 billion nominal values		

Development: Ringhorne Øst is an oil field located northeast of Balder in the central part of the North Sea. The water depth in the area is about 130 metres. The field is developed with three production wells drilled from the Ringhorne facility on the Balder field.

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

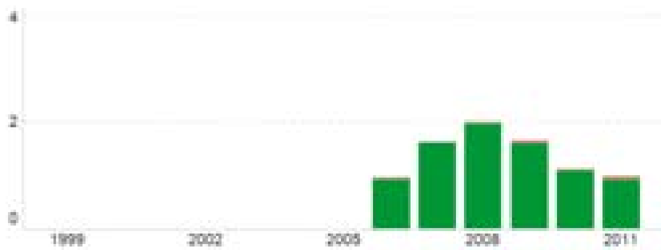
Recovery strategy: The field is recovered by natural water drive from a regional aquifer to the north and east of the structure. All the wells have gas lift to optimise production, and this will be expanded due to increasing water production.

Transport: Production from Ringhorne Øst is routed via the Ringhorne wellhead platform and then further to the Balder and Jotun facilities for processing, storage and export.

Status: The field is in the tail phase, but is expected to produce until 2023. One production well was drilled and brought online in 2011. Another well was spudded in late 2011 and is scheduled to start producing in early 2012. Two or three new wells are on the 2012 - 2016 drilling schedule.

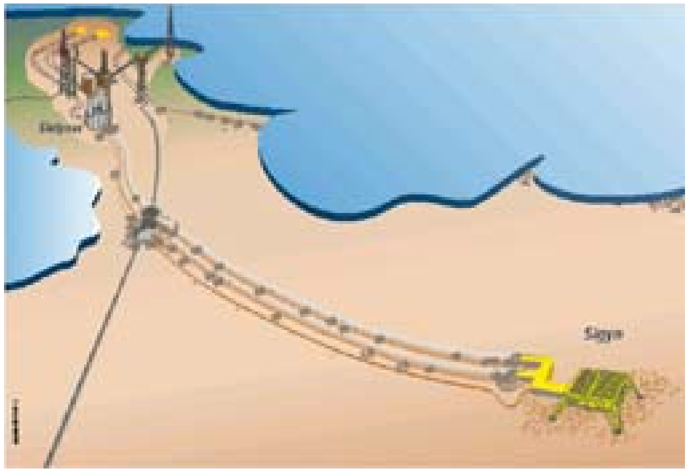
Ringhorne Øst

Mill. Sm³ o.e.



Sigyn

Blocks and production licences	Block 16/7 - production licence 072, awarded 1981.		
Development approval	31.08.2001 by the King in Council	**Discovered** 1982	
On stream	22.12.2002		
Operator	ExxonMobil Exploration & Production Norway AS		
Licensees	ExxonMobil Exploration & Production Norway AS		40.00 %
	Statoil Petroleum AS		60.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	7.0 billion Sm³ gas	1.2 billion Sm³ gas	
	2.9 million tonnes NGL	0.7 million tonnes NGL	
	5.3 million Sm³ condensate		
Estimated production in 2012	Gas: 0.28 billion Sm³, NGL: 0.07 million tonnes		
Total investment as of 31.12.2010	2.0 billion nominal values		
Main supply base	Dusavik		



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

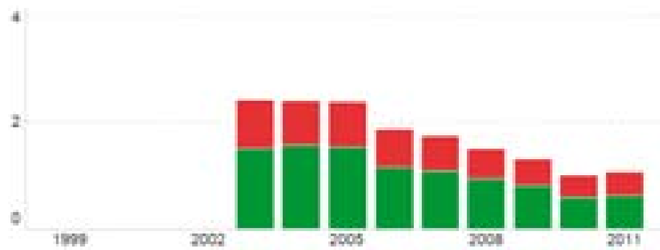
Reservoir: The main reservoir lies in the Triassic Skagerrak Formation at a depth of approximately 2 700 metres and the reservoir quality is good.

Recovery strategy: The field is recovered by pressure depletion.

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

Sigyn

Mill. Sm³ o.e.



Skirne

Blocks and production licences	Block 25/5 - production licence 102, awarded 1985.		
Development approval	05.07.2002 by the Crown Prince Regent in Council	**Discovered** 1990	
On stream	03.03.2004		
Operator	Total E&P Norge AS		
Licensees	Centrica Resources (Norge) AS		20.00 %
	Petoro AS		30.00 %
	Statoil Petroleum AS		10.00 %
	Total E&P Norge AS		40.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	2.2 million Sm^3 oil	0.5 million Sm^3 oil	
	10.1 billion Sm^3 gas	1.8 billion Sm^3 gas	
Estimated production in 2012	Oil: 2 000 barrels/day, Gas: 0.48 billion Sm^3		
Expected investment from 2011	0.1 billion 2011 values		
Total investment as of 31.12.2010	2.7 billion nominal values		

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

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

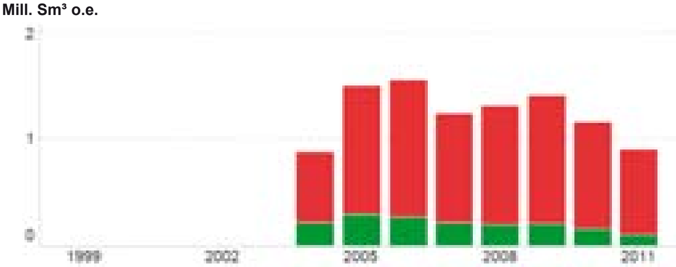
Recovery strategy: The field is recovered by pressure depletion.

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

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

Skirne

Mill. Sm^3 o.e.



Sleipner Vest

Blocks and production licences	Block 15/6 - production licence 029, awarded 1969. Block 15/9 - production licence 046, awarded 1976.		
Development approval	14.12.1992 by the Storting	**Discovered** 1974	
On stream	29.08.1996		
Operator	Statoil Petroleum AS		
Licensees	ExxonMobil Exploration & Production Norway AS		32.24 %
	Statoil Petroleum AS		58.35 %
	Total E&P Norge AS		9.41 %
Recoverable reserves*	**Original**	**Remaining as of 31.12.2011**	
	128.7 billion Sm^3 gas	21.7 billion Sm^3 gas	
	9.2 million tonnes NGL	1.8 million tonnes NGL	
	31.4 million Sm^3 condensate	4.5 million Sm^3 condensate	
Estimated production in 2012	Gas: 5.75 billion Sm^3, NGL: 0.42 million tonnes, Condensate: 1.19 million Sm^3		
Expected investment from 2011	2.1 billion 2011 values		
Total investment as of 31.12.2010	22.7 billion nominal values		
Main supply base	Dusavik		

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

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

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

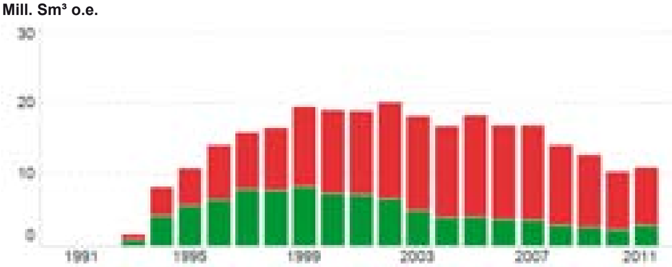
Recovery strategy: Sleipner Vest is recovered by pressure depletion.

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

Status: Two wells were drilled and completed in 2011, and a new drilling campaign is scheduled from 2015.

Sleipner Vest & Sleipner Øst

Mill. Sm^3 o.e.



Sleipner Øst

Blocks and production licences	Block 15/9 - production licence 046, awarded 1976.		
Development approval	15.12.1986 by the Storting	**Discovered** 1981	
On stream	24.08.1993		
Operator	Statoil Petroleum AS		
Licensees	ExxonMobil Exploration & Production Norway AS		30.40 %
	Statoil Petroleum AS		59.60 %
	Total E&P Norge AS		10.00 %
Recoverable reserves*	**Original**	**Remaining as of 31.12.2011**	
	66.3 billion Sm^3 gas	21.7 billion Sm^3 gas	
	13.2 million tonnes NGL	1.8 million tonnes NGL	
	26.8 million Sm^3 condensate	4.5 million Sm^3 condensate	
Estimated production in 2012	Gas: 0.29 billion Sm^3, NGL: 0.06 million tonnes, Condensate: 0.07 million Sm^3		
Expected investment from 2011	2.7 billion 2011 values		
Total investment as of 31.12.2010	26.6 billion nominal values		
Main supply base	Dusavik		

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

Development: Sleipner Øst is a gas condensate field in the central part of the North Sea. The water depth in the area is 82 metres. The field has been developed with an integrated processing, drilling and accommodation facility with a concrete gravity base structure, Sleipner A. In addition, a riser facility, Sleipner R, which connects Sleipner A to the pipelines for gas transport and a flare stack Sleipner F, have been installed. Two subsea templates have also been installed, one for production from the northern part of Sleipner Øst and one for production of the Loke deposit. The Sigyn and Gungne fields 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 August 1995 and production started in 1998.

Reservoir: The Sleipner Øst and Loke reservoirs are mainly in sandstones of the Ty Formation of Paleocene age and the Hugin Formation of Middle Jurassic age. In addition, gas has been proven in the Heimdal Formation, overlying the Ty Formation. The reservoir depth is approximately 2 300 metres. .

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

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

Status: Improved recovery through further reduced inlet pressure was started in 2010. An agreement for tie-in and processing of oil and rich gas from Gudrun at the Sleipner facilities was made in 2010 and production will start from Gudrun in 2014.

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

Snorre

Blocks and production licences	Block 34/4 - production licence 057, awarded 1979. Block 34/7 - production licence 089, awarded 1984.		
Development approval	27.05.1988 by the Storting	**Discovered** 1979	
On stream	03.08.1992		
Operator	Statoil Petroleum AS		
Licensees	Core Energy AS		1.04 %
	ExxonMobil Exploration & Production Norway AS		11.58 %
	Idemitsu Petroleum Norge AS		9.60 %
	Petoro AS		30.00 %
	RWE Dea Norge AS		8.28 %
	Statoil Petroleum AS		33.32 %
	Total E&P Norge AS		6.18 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	251.0 million Sm^3 oil	69.7 million Sm^3 oil	
	6.7 billion Sm^3 gas	0.4 billion Sm^3 gas	
	4.8 million tonnes NGL	0.2 million tonnes NGL	
Estimated production in 2012	Oil: 99 000 barrels/day, Gas: 0.03 billion Sm^3, NGL: 0.01 million tonnes		
Expected investment from 2011	42.4 billion 2011 values		
Total investment as of 31.12.2010	62.5 billion nominal values		
Main supply base	Florø		

Development: Snorre is an oil field in the Tampen area in the northern part of the North Sea. The water depth in the area is 300 - 350 metres. Snorre A in the south is a floating steel facility (TLP) for accommodation, drilling and processing. Snorre A also has a separate process module for production from the Vigdis field. A subsea template with ten well slots, Snorre UPA, is located centrally on the field and connected to Snorre A. Snorre B is located in the northern part of the field and is a semi-submersible integrated drilling, processing and accommodation facility. . An amended PDO for Snorre, including a new processing module on Snorre A for processing oil from Vigdis, was approved on 16 December 1994. The PDO for Snorre B was approved on 8 June 1998. Snorre B came on stream in June 2001.

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

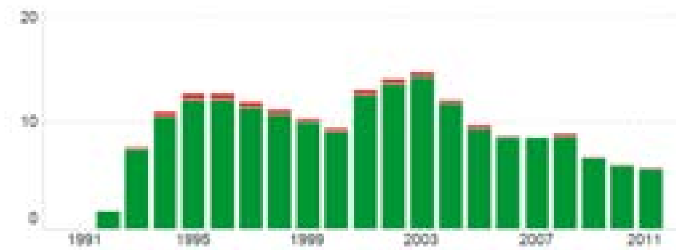
Recovery strategy: Snorre is by pressure maintenance by water injection, gas injection and water alternating gas injection (WAG). Lack of injection capacity and wells has over time led to lower than desired pressure in parts of the field.

Transport: Oil and gas are separated in two stages at Snorre A before transport in separate pipelines to Statfjord A for final processing and export. The oil is loaded onto shuttle tankers at Statfjord and excess gas is sent through the Statpipe pipeline to Kårstø. Processed oil from Snorre B is routed by pipeline to Statfjord B for storage and loading to shuttle tankers. All gas from Snorre B is normally re-injected, but may also be sent to Snorre A for injection or export.

Status: The licensees are working on development plans for extended production from the field (Snorre 2040 project). Infill drilling, modification of facilities, new infrastructure and long-term transport solution are key elements in the studies.

Snorre

Mill. Sm³ o.e.



Snøhvit

Blocks and production licences	Block 7120/5 - production licence 110, awarded 1985. Block 7120/6 - production licence 097, awarded 1984. Block 7120/7 - production licence 077, awarded 1982. Block 7120/8 - production licence 064, awarded 1981. Block 7120/9 - production licence 078, awarded 1982. Block 7121/4 - production licence 099, awarded 1984. Block 7121/5 - production licence 110, awarded 1985. Block 7121/7 - production licence 100, awarded 1984.		
Development approval	07.03.2002 by the Storting	**Discovered** 1984	
On stream	21.08.2007		
Operator	Statoil Petroleum AS		
Licensees	GDF SUEZ E&P Norge AS		12.00 %
	Petoro AS		30.00 %
	RWE Dea Norge AS		2.81 %
	Statoil Petroleum AS		36.79 %
	Total E&P Norge AS		18.40 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	172.8 billion Sm³ gas	157.6 billion Sm³ gas	
	8.7 million tonnes NGL	7.9 million tonnes NGL	
	21.8 million Sm³ condensate	19.0 million Sm³ condensate	
Estimated production in 2012	Gas: 5.85 billion Sm³, NGL: 0.29 million tonnes, Condensate: 0.98 million Sm³		
Expected investment from 2011	20.1 billion 2011 values		
Total investment as of 31.12.2010	8.1 billion nominal values		

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

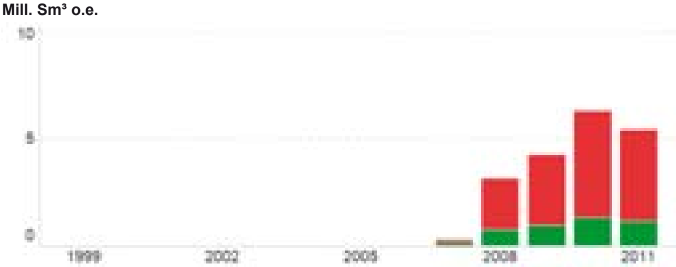
Reservoir: The reservoirs contain gas, condensate and oil in Lower and Middle Jurassic sandstones of the Stø and Nordmela Formations. The reservoir depth is approximately 2 300 metres.

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

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

Status: Evaluation of expansion of the Melkøya plant with a second processing train is ongoing.

Snøhvit
Mill. Sm³ o.e.

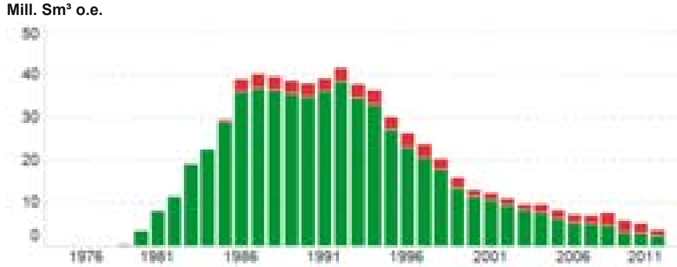


Statfjord

Blocks and production licences	Block 33/12 - production licence 037, awarded 1973. Block 33/9 - production licence 037, awarded 1973. The Norwegian part of the field is 85.47 %, the British part is 14.53 %		
Development approval	16.06.1976 by the Storting	**Discovered** 1974	
On stream	24.11.1979		
Operator	Statoil Petroleum AS		
Licensees	Centrica Resources (Norge) AS		9.44 %
	ConocoPhillips Skandinavia AS		10.33 %
	ExxonMobil Exploration & Production Norway AS		21.37 %
	Statoil Petroleum AS		44.34 %
	Centrica Resources Limited		9.69 %
	ConocoPhillips (U.K.) Limited.		4.84 %
Recoverable reserves (Norwegian part)	**Original**	**Remaining as of 31.12.2011**	
	569.4 million Sm³ oil	4.8 million Sm³ oil	
	75.2 billion Sm³ gas	10.5 billion Sm³ gas	
	19.8 million tonnes NGL	3.2 million tonnes NGL	
	0.6 million Sm³ condensate	0.1million Sm³ condensate	
Estimated production in 2012	Oil: 21 000 barrels/day, Gas: 1.18 billion Sm³, NGL: 0.31 million tonnes. Condensate: 0.01 million Sm³		
Expected investment from 2011	9.3 billion 2011 values		
Total investment as of 31.12.2010	63.4 billion nominal values		
Main supply base	Sotra and Florø		

Development: Statfjord is an oil field straddling the border between the Norwegian and British sectors in the Tampen area. The water 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 8 June 2005.

Statfjord
Mill. Sm³ o.e.



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

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

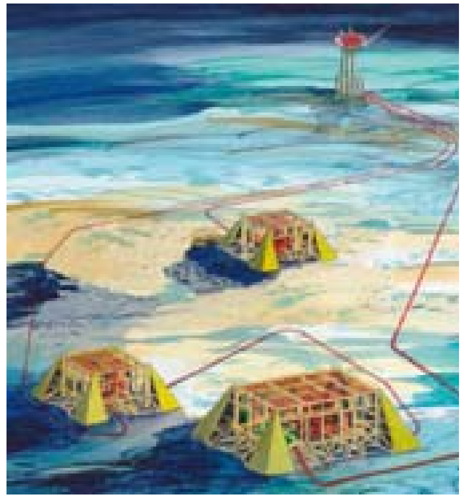
Transport: Stabilised oil is stored in storage cells at each facility. Oil is loaded to tankers from one of the two oil loading systems at the field. From 2007, gas is exported through Tampen Link, which is routed via the Far North Liquids and Gas System (FLAGS) pipeline to the United Kingdom. The UK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

Status: The facilities are being modified as part of Statfjord Late Life, and wells were drilled and repaired in 2010 and 2011. There are plans to drill 64 new oil, water and gas wells during Statfjord Late Life. At the end of September 2011, 43 of these wells were completed. The first 4 wells were recompleted with artificial lift (ESP) in 2011.

Statfjord Nord

Blocks and production licences	Block 33/9 - production licence 037, awarded 1973.		
Development approval	11.12.1990 by the Storting	**Discovered** 1977	
On stream	23.01.1995		
Operator	Statoil Petroleum AS		
Licensees	Centrica Resources (Norge) AS		11.04 %
	ConocoPhillips Skandinavia AS		12.08 %
	ExxonMobil Exploration & Production Norway AS		25.00 %
	Petoro AS		30.00 %
	Statoil Petroleum AS		21.88 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	39.2 million Sm^3 oil	2.8 million Sm^3 oil	
	2.0 billion Sm^3 gas	0.3 million tonnes NGL	
	1.1 million tonnes NGL		
Estimated production in 2012	Oil: 5 000 barrels/day, Gas: 0.02 billion Sm^3, NGL: 0.01 million tonnes.		
Total investment as of 31.12.2010	5.7 billion nominal values		
Main supply base	Sotra		

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



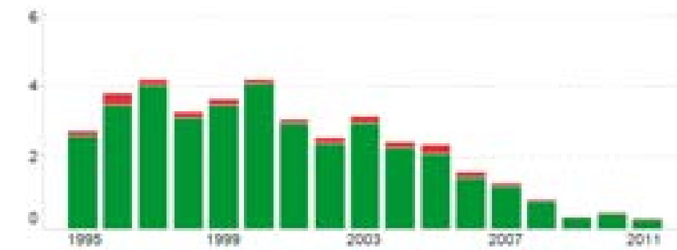
Reservoir: The Statfjord Nord reservoirs consist of Middle Jurassic sandstones of the Brent Group (Tarbert, Etive and Rannoch Formations), and Upper Jurassic sandstones. The reservoirs lie at a depth of approximately 2 600 metres and are of good quality.

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

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

Status: The current key challenge is to restore pressure maintenance. The plan is to repair the second water injector by the second half of 2013. Water alternating gas injection (WAG) has been evaluated and rejected.

Statfjord Nord
Mill. Sm^3 o.e.



Statfjord Øst

Blocks and production licences	Block 33/9 - production licence 037, awarded 1973. Block 34/7 - production licence 089, awarded 1984.		
Development approval	11.12.1990 by the Storting	**Discovered** 1976	
On stream	24.09.1994		
Operator	Statoil Petroleum AS		
Licensees	Centrica Resources (Norge) AS		5.52 %
	ConocoPhillips Skandinavia AS		6.04 %
	ExxonMobil Exploration & Production Norway AS		17.75 %
	Idemitsu Petroleum Norge AS		4.80 %
	Petoro AS		30.00 %
	RWE Dea Norge AS		1.40 %
	Statoil Petroleum AS		31.69 %
	Total E&P Norge AS		2.80 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	36.6 million Sm^3 oil	0.9 million Sm^3 oil	
	3.9 billion Sm^3 gas	0.1 billion Sm^3 gas	
	2.1 million tonnes NGL	0.7 million tonnes NGL	
Estimated production in 2012	Oil: 8 000 barrels/day, Gas: 0.04 billion Sm^3, NGL: 0.02 million tonnes.		
Expected investment from 2011	0.1 billion 2011 values		
Total investment as of 31.12.2010	5.9 billion nominal values		
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 water depth in the area is 150 - 190 metres. The field has been developed with three subsea templates tied back to Statfjord C. Two of the templates are for production and one for water injection. In addition, one production well has been drilled from Statfjord C.

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

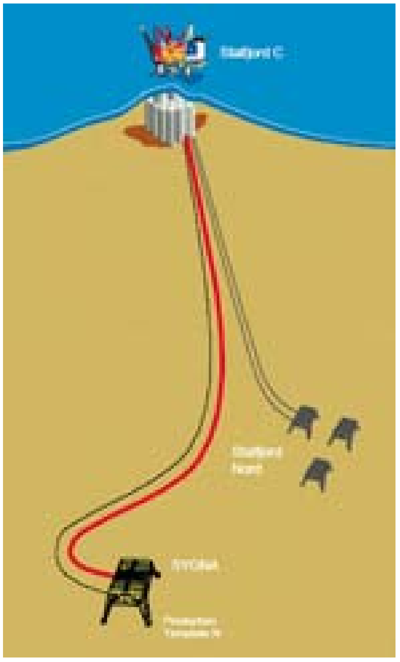
Recovery strategy: The field is currently being produced by pressure depletion.

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

Status: The field is affected by pressure depletion from blow down of Statfjord. The Light Well Intervention (LWI) program was completed in 2010 and boosted production significantly. The water injectors are shut down, and the re-evaluated drainage strategy involves no more water injection for the remaining lifetime of the field. The drilling of a new production well from Statfjord C to Statfjord Øst is being considered. Alternatively, water injection may be re-established by drilling a new water injection well.

Sygna

Blocks and production licences	Block 33/9 - production licence 037, awarded 1973. Block 34/7 - production licence 089, awarded 1984.		
Development approval	30.04.1999 by the King in Council	**Discovered** 1996	
On stream	01.08.2000		
Operator	Statoil Petroleum AS		
Licensees	Centrica Resources (Norge) AS		6.07 %
	ConocoPhillips Skandinavia AS		6.65 %
	ExxonMobil Exploration & Production Norway AS		18.48 %
	Idemitsu Petroleum Norge AS		4.32 %
	Petoro AS		30.00 %
	RWE Dea Norge AS		1.26 %
	Statoil Petroleum AS		30.71 %
	Total E&P Norge AS		2.52 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	10.6 million Sm^3 oil	0.8 million Sm^3 oil	
Estimated production in 2012	Oil: 1 000 barrels/day		
Total investment as of 31.12.2010	2.0 billion nominal values		
Main supply base	Florø		



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

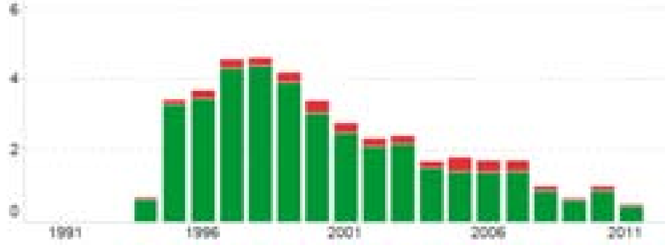
Reservoir: The Sygna reservoir consists of Middle Jurassic sandstones of the Brent Group. The reservoir depth is approximately 2 650 metres. The reservoir quality is good.

Recovery strategy: The field is currently being produced by pressure depletion.

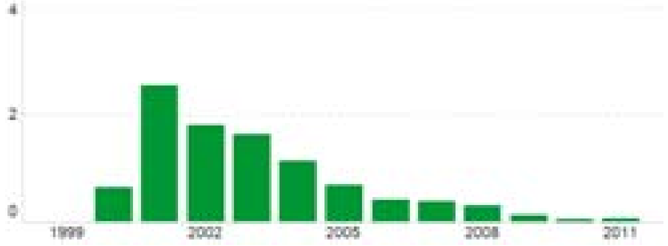
Transport: The wellstream is sent by pipeline to Statfjord C for processing, storage and export. Statfjord Nord, Statfjord Øst and Sygna have a shared process module on Statfjord C.

Status: The water injection well is shut down. Until injection is restored by 2013, production will be limited and there will be periods of no production. Water alternating gas (WAG) has been evaluated and found uneconomical.

Statfjord Øst
Mill. Sm^3 o.e.



Sygna
Mill. Sm^3 o.e.



Tambar

Blocks and production licences	Block 1/3 - production licence 065, awarded 1981. Block 2/1 - production licence 019 B, awarded 1977.		
Development approval	03.04.2000 by the King in Council	**Discovered** 1983	
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 31.12.2011**	
	9.0 million Sm^3 oil	0.3 million Sm^3 oil	
	2.0 billion Sm^3 gas	0.1 billion Sm^3 gas	
Estimated production in 2012	Oil: 2 000 barrels/day, Gas: 0.03 billion Sm^3		
Expected investment from 2011	0.1 billion 2011 values		
Total investment as of 31.12.2010	2.2 billion nominal values		
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 water depth in the area is 68 metres. The field has been developed with a remotely controlled wellhead facility without processing equipment.

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

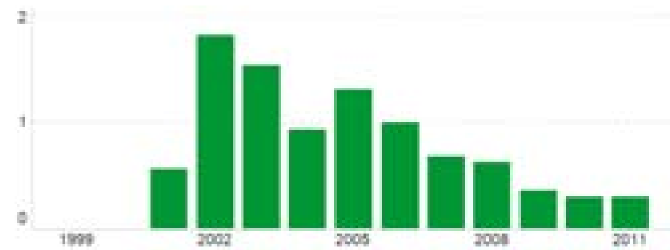
Recovery strategy: The field is recovered by pressure depletion and limited aquifer drive. The production went off plateau in 2002 and is now declining.

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

Status: A multi-phase pump installed in 2008 to reduce the wellhead pressure and increase recovery from Tambar, has failed and is not in use. A major challenge in the future is that high water cut in the wells restricts production. In 2012, the licensees will concentrate on well work and surveillance. Artificial gas lift to increase the oil recovery will be considered.

Tambar

Mill. Sm^3 o.e.



Tambar Øst

Blocks and production licences	Block 1/3 - production licence 065, awarded 1981. Block 2/1 - production licence 019 B, awarded 1977 Block 2/1 - production licence 300, awarded 2003.		
Development approval	28.06.2007	**Discovered** 2007	
On stream	02.10.2007		
Operator	BP Norge AS		
Licensees	BP Norge AS		46.20 %
	DONG E&P Norge AS		43.24 %
	Norske AEDC A/S		0.80 %
	Talisman Energy Norge AS		9.76 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	0.3 million Sm^3 oil		
Estimated production in 2012	Oil: 290 barrels/day		
Total investment as of 31.12.2010	1.0 billion nominal values		

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

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

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

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

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

Tambar inkluderer produksjonen frå Tambar Øst

Tor

Blocks and production licences	Block 2/4 - production licence 018, awarded 1965. Block 2/5 - production licence 006, awarded 1965.		
Development approval	04.05.1973	**Discovered** 1970	
On stream	28.06.1978		
Operator	ConocoPhillips Skandinavia AS		
Licensees	ConocoPhillips Skandinavia AS		30.66 %
	Eni Norge AS		10.82 %
	Petoro AS		3.69 %
	Statoil Petroleum AS		6.64 %
	Total E&P Norge AS		48.20 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	24.4 million Sm^3 oil	0.8 million Sm^3 oil	
	10.9 billion Sm^3 gas	0.1 billion Sm^3 gas	
	1.2 million tonnes NGL		
Estimated production in 2012	Oil: 3 000 barrels/day, Gas: 0.01 billion Sm^3		
Expected investment from 2011	0.7 billion 2011 values		
Total investment as of 31.12.2010	3.5 billion nominal values		
Main supply base	Tananger		

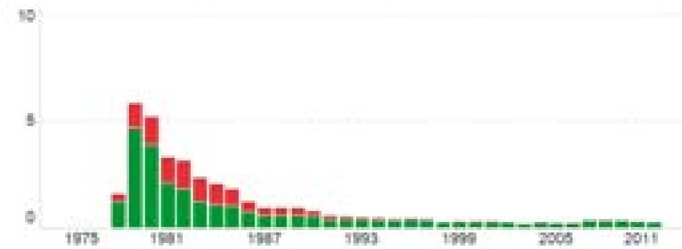
Development: Tor is an oil field in the Ekofisk area in the southern part of the North Sea. The water depth in the area is about 70 metres. The field has been developed with a combined wellhead and processing facility tied to Ekofisk.

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

Recovery strategy: Tor was originally recovered by pressure depletion. In 1992, limited water injection commenced. The facility has subsequently been upgraded and the scope of water injection has been expanded.
Transport: Oil and gas are transported by pipelines to the processing facility at Ekofisk J. Gas from the Ekofisk area is transported by pipeline to Emden, while the oil, also containing NGL fractions, is sent via pipeline to Teesside.

Status: The Tor facility has a limited remaining lifetime. A redevelopment of the field, to recover significant remaining resources in both the Tor and the Ekofisk formations, is being evaluated.

Tor



Tordis

Blocks and production licences	Block 34/7 - production licence 089, awarded 1984.		
Development approval	14.05.1991 by the Storting	**Discovered** 1987	
On stream	03.06.1994		
Operator	Statoil Petroleum AS		
Licensees	ExxonMobil Exploration & Production Norway AS		10.50 %
	Idemitsu Petroleum Norge AS		9.60 %
	Petoro AS		30.00 %
	RWE Dea Norge AS		2.80 %
	Statoil Petroleum AS		41.50 %
	Total E&P Norge AS		5.60 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	61.5 million Sm^3 oil	6.4 million Sm^3 oil	
	4.7 billion Sm^3 gas	0.4 billion Sm^3 gas	
	1.8 million tonnes NGL	0.2 million tonnes NGL	
Estimated production in 2012	Oil: 14 000 barrels/day, Gas: 0.07 billion Sm^3, NGL: 0.03 million tonnes.		
Expected investment from 2011	3.7 billion 2011 values		
Total investment as of 31.12.2010	11.0 billion nominal values		
Main supply base	Florø		

Development: Tordis is an oil field located between the Snorre and Gullfaks fields in the Tampen area in the northern part of the North Sea. The water depth in the area is approximately 200 metres. The field has been developed with a central subsea manifold tied back to Gullfaks C. Seven separate satellite wells and two subsea templates are tied back to the manifold. In addition, a subsea separator was installed at the field in 2007. Injection water is transported by pipeline from Gullfaks C. Tordis comprises four deposits: Tordis, Tordis Øst, Borg and 34/7-25 S. The PDO for Tordis Øst was approved on 13 October 1995. The PDO for Borg was approved on 29 June 1999. An amended PDO for Tordis (Tordis IOR) was approved on 16 December 2005.

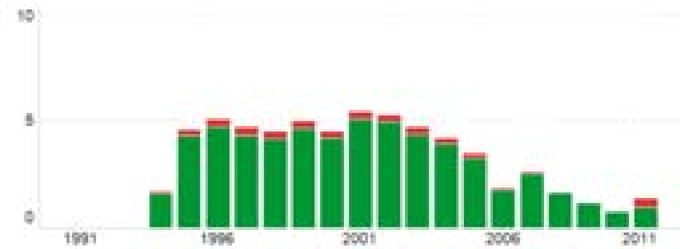
Reservoir: The reservoirs in Tordis and Tordis Øst consist of Middle Jurassic sandstones of the Brent Group. The reservoir in Borg consists of Upper Jurassic sandstones in the intra-Draupne Formation, and the reservoir in 34/7-25 S consists of sandstones of the Brent Group and sandstones of Late Jurassic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

Recovery strategy: Production is accomplished by partial pressure maintenance and by water injection and natural aquifer drive. Pressure at Borg is fully maintained using water injection. Tordis Øst is produced with pressure support from natural aquifer drive.

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

Status: The Tordis subsea separator has been shut down since 2008 and as a result all production is sent to Gullfaks for processing. Production is currently restricted due to ongoing repairs on one of the two pipelines to Gullfaks C.

Tordis



Troll

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

Troll I

Blocks and production licences	Block 31/2 - production licence 054, awarded 1979 Block 31/3 - production licence 085, awarded 1983 Block 31/3 - production licence 085 C, awarded 2002 Block 31/3 - production licence 085 D, awarded 2006 Block 31/5 - production licence 085, awarded 1983 Block 31/6 - production licence 085, awarded 1983 Block 31/6 - production licence 085 C, awarded 2002		
Development approval	15.12.1986 by the Storting	**Discovered** 1983	
On stream	09.02.1996		
Operator	Statoil Petroleum AS		
Licensees	A/S Norske Shell		8.10 %
	ConocoPhillips Skandinavia AS		1.62 %
	Petoro AS		56.00 %
	Statoil Petroleum AS		30.58 %
	Total E&P Norge AS		3.69 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	1410.9 billion Sm^3 gas	1019.1 billion Sm^3 gas	
	27.7 million tonnes NGL	22.2 million tonnes NGL	
	1.6 million Sm^3 condensate		
Estimated production in 2012	Gas: 31.03 billion Sm^3, NGL: 1.08 million tonnes		
Expected investment from 2011	28.4 billion 2011 values		
Total investment as of 31.12.2010	45.3 billion nominal values		
Main supply base	Ågotnes		

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

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

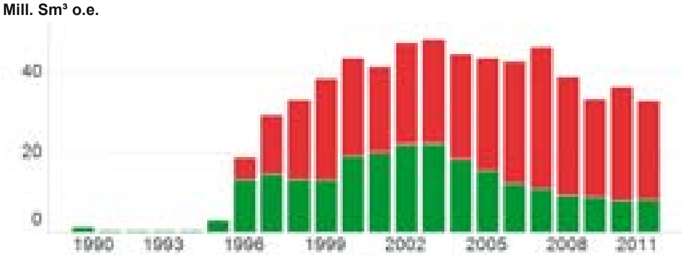
Recovery strategy: The gas in Troll Øst is recovered by pressure depletion through 39 wells drilled from Troll A.

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

Status: Installation of two more gas compressors is ongoing on Troll A. The TOGI decommissioning will be completed during 2012.

Troll II ➡

Troll



The graph shows total production from Troll I and Troll II.

Troll II

Blocks and production licences	B 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		
Development approval	18.05.1992 by the Storting	**Discovered** 1979	
On stream	19.09.1995		
Operator	Statoil Petroleum AS		
Licensees	A/S Norske Shell		8.10 %
	ConocoPhillips Skandinavia AS		1.62 %
	Petoro AS		56.00 %
	Statoil Petroleum AS		30.58 %
	Total E&P Norge AS		3.69 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	255.8 million Sm^3 oil	35.1 million Sm^3 oil	
Estimated production in 2012	Oil: 122 000 barrels/day		
Expected investment from 2011	27.1 billion 2011 values		
Total investment as of 31.12.2010	76.7 billion nominal values		
Main supply base	Mongstad		

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

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

Recovery strategy: The oil in Troll Vest is produced by means of long horizontal wells which penetrate the thin oil zone immediately above the oil-water contact. The recovery strategy is based primarily on pressure depletion, but this is accompanied by a simultaneous expansion of both the gas cap above the oil zone and the underlying water zone. Several multi-branch wells have been drilled, with up to seven branches in the same well. In the Troll Vest oil province, some of the produced gas is re-injected into the reservoir to optimise oil production.

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

Status: Drilling on Troll Vest with horizontal production wells from subsea templates continues. There are presently about 120 active oil production wells at Troll Vest. Over the last few years, decisions have been continuously made to drill new production wells to increase the oil reserves in Troll. A four-rig drilling strategy has been implemented.

Trym

Blocks and production licences	Block 3/7 - production licence 147, awarded 1988.		
Development approval	26.03.2010 by the King in Council	**Discovered** 1990	
On stream	12.02.2011		
Operator	DONG E&P Norge AS		
Licensees	Bayerngas Norge AS		50.00 %
	DONG E&P Norge AS		50.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	1.3 million Sm^3 oil	1.0 million Sm^3 oil	
	4.4 billion Sm^3 gas	4.0 billion Sm^3 gas	
Estimated production in 2012	Oil: 5 000 barrels/day, Gas: 0.53 billion Sm^3		
Expected investment from 2011	0.8 billion 2011 values		
Total investment as of 31.12.2010	2.1 billion nominal values		

Development: Trym is located three kilometres from the border to the Danish continental shelf. The water depth in the area is around 65 metres. The development concept is a subsea template tied to the Harald facility on the Danish side of the border.

Reservoir: The reservoir contains gas and condensate in Upper Jurassic and Middle Jurassic sandstones in the Sandnes and Bryne Formations. The discovery lies on the same salt structure as the Danish field Lulita, at a depth of about 3 400 metres. The deposits are assumed to be separated by a fault zone on the Norwegian side of the border, but there may be pressure communication in the water zone.

Recovery strategy: Trym is produced by natural pressure depletion via two horizontal production wells.

Transport: The wellstream is processed on the Harald facility for further transport.

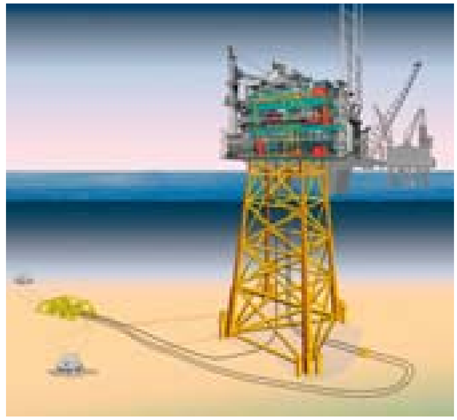
Status: Production started in February 2011.

Trym

Mill. Sm^3 o.e.

Tune

Blocks and production licences	Block 30/5 - production licence 034, awarded 1969. Block 30/6 - production licence 053, awarded 1979. Block 30/8 - production licence 190, awarded 1993.		
Development approval	17.12.1999 by the King in Council	**Discovered** 1996	
On stream	28.11.2002		
Operator	Statoil Petroleum AS		
Licensees	Petoro AS		40.00 %
	Statoil Petroleum AS		50.00 %
	Total E&P Norge AS		10.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	3.3 million Sm^3 oil		
	18.2 billion Sm^3 gas		
	0.2 million tonnes NGL		
Estimated production in 2012	Gas: 0.49 billion Sm^3		
Total investment as of 31.12.2010	4.7 billion nominal values		
Main supply base	Mongstad		



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

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

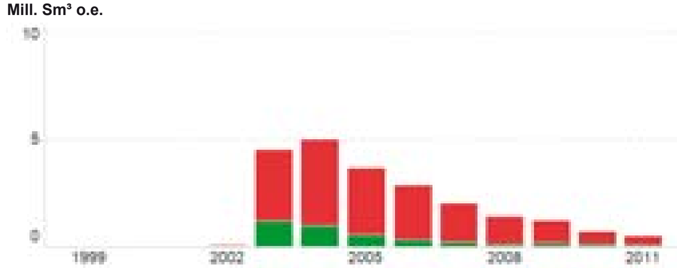
Recovery strategy: The field is recovered by pressure depletion. Low pressure production has been started.

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

Status: Tune is in the tail phase. Implementation of low pressure production has been implemented and this will increase the production.

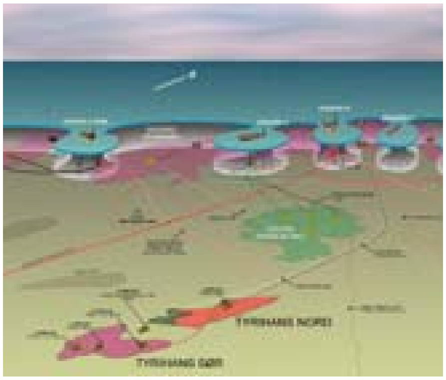
Tune

Mill. Sm^3 o.e.



Tyrihans

Blocks and production licences	Block 6406/3 - production licence 073 B, awarded 2004 Block 6406/3 - production licence 091, awarded 1984. Block 6407/1 - production licence 073, awarded 1982.		
Development approval	16.02.2006 by the Storting	**Discovered** 1983	
On stream	08.07.2009		
Operator	Statoil Petroleum AS		
Licensees	Eni Norge AS		6.23 %
	ExxonMobil Exploration & Production Norway AS		11.75 %
	Statoil Petroleum AS		58.84 %
	Total E&P Norge AS		23.18 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	31.9 million Sm³ oil	21.1 million Sm³ oil	
	37.2 billion Sm³ gas	36.5 billion Sm³ gas	
	9.9 million tonnes NGL	9.8 million tonnes NGL	
Estimated production in 2012	Oil: 85 000 barrels/day		
Expected investment from 2011	4.4 billion 2011 values		
Total investment as of 31.12.2010	13.4 billion nominal values		



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

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

Recovery strategy: During the first years, recovery is based on gas injection from Åsgard B into Tyrihans Sør. In addition, subsea pumps will be used for injection of seawater to increase recovery. It has also been decided to produce the oil zone in Tyrihans Nord. LPP (Low Pressure Production) will be relevant for Kristin from 2014. Tyrihans will also benefit from this drainage strategy.

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

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

Tyrihans
Mill. Sm³ o.e.

Ula

Blocks and production licences	Block 7/12 - production licence 019, awarded 1965 Block 7/12 - production licence 019 B, awarded 1977.		
Development approval	30.05.1980 by the Storting	**Discovered** 1976	
On stream	06.10.1986		
Operator	BP Norge AS		
Licensees	BP Norge AS		80.00 %
	DONG E&P Norge AS		20.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	91.4 million Sm³ oil	19.7 million Sm³ oil	
	3.9 billion Sm³ gas	0.8 million tonnes NGL	
	3.4 million tonnes NGL		
Estimated production in 2012	Oil: 11 000 barrels/day, NGL: 0.02 million tonnes		
Expected investment from 2011	6.6 billion 2011 values		
Total investment as of 31.12.2010	14.5 billion nominal values		
Main supply base	Tananger		

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

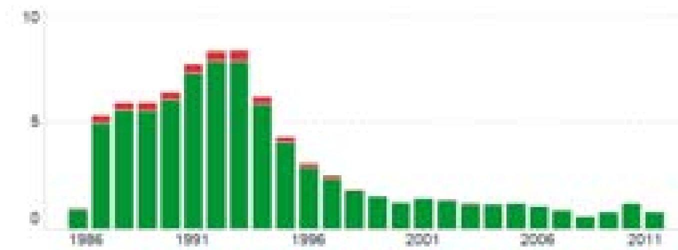
Reservoir: The main reservoir is at a depth of 3 345 metres in the Upper Jurassic Ula Formation. The reservoir consists of three layers, and two of them are producing well.

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

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

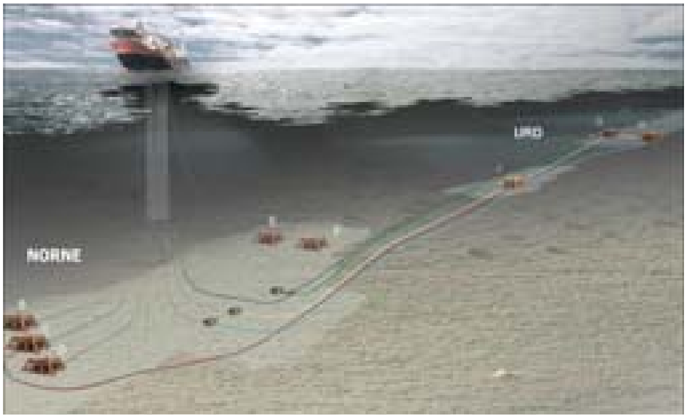
Status: Based on the positive effect the WAG programme has on oil recovery, it has been expanded by drilling several additional wells. The Oselvar field is expected to start production in April 2012. The Oselvar wellstream will be processed on Ula, and the gas from the field will be injected in the Ula reservoir for increased recovery. An evaluation of possible development of the underlying Triassic reservoir is ongoing, and test production has been carried out as part of this evaluation.

Ula
Mill. Sm³ o.e.



Urd

Blocks and production licences	Block 6608/10 - production licence 128, awarded 1986.		
Development approval	02.07.2004 by the Crown Prince Regent in Council	**Discovered** 2000	
On stream	08.11.2005		
Operator	Statoil Petroleum AS		
Licensees	Eni Norge AS		11.50 %
	Petoro AS		24.55 %
	Statoil Petroleum AS		63.95 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	6.6 million Sm^3 oil	1.9 million Sm^3 oil	
	0.1 billion Sm^3 gas		
Estimated production in 2012	Oil: 5 000 barrels/day.		
Expected investment from 2011	1.0 billion 2011 values		
Total investment as of 31.12.2010	4.3 billion nominal values		



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

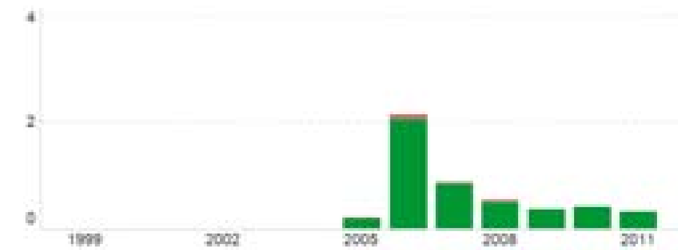
Reservoir: The reservoirs consist of Lower to Middle Jurassic sandstones of the Åre, Tilje and Ile Formations at a depth of 1 800 – 2 300 metres.

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

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

Status: Production performance has been almost as expected in 2011. Proven resources in the Melke Formation, overlying the Svale and Stær deposits, are presently not considered profitable for production.

Urd
Mill. Sm³ o.e.



Vale

Blocks and production licences	Block 25/4 - production licence 036, awarded 1971.		
Development approval	23.03.2001 by the Crown Prince Regent in Council	**Discovered** 1991	
On stream	31.05.2002		
Operator	Statoil Petroleum AS		
Licensees	Centrica Resources (Norge) AS		46.90 %
	Statoil Petroleum AS		28.85 %
	Total E&P Norge AS		24.24 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	2.4 million Sm^3 oil	1.2 million Sm^3 oil	
	2.3 billion Sm^3 gas	1.3 billion Sm^3 gas	
Estimated production in 2012	Oil: 4 000 barrels/day, Gas: 0.19 billion Sm^3		
Expected investment from 2011	0.1 billion 2011 values		
Total investment as of 31.12.2010	2.4 billion nominal values		

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

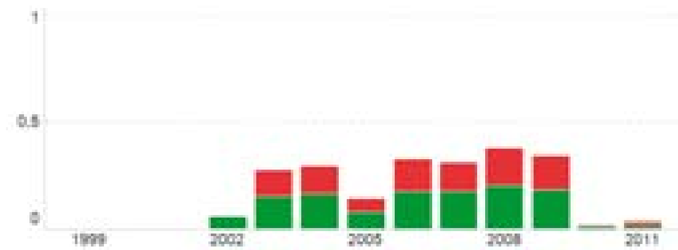
Reservoir: The reservoir consists of Middle Jurassic sandstones of the Brent Group. The reservoir depth is approximately 3 700 metres. The reservoir has low permeability.

Recovery strategy: The field is recovered by pressure depletion.

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

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

Vale
Mill. Sm³ o.e.



Valhall

Blocks and production licences	Block 2/11 - production licence 033 B, awarded 2001. Block 2/8 - production licence 006 B, awarded 2000.		
Development approval	02.06.1977 by the Storting	**Discovered** 1975	
On stream	02.10.1982		
Operator	BP Norge AS		
Licensees	BP Norge AS		35.95 %
	Hess Norge AS		64.05 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	146.7 million Sm^3 oil	41.8 million Sm^3 oil	
	27.2 billion Sm^3 gas	6.8 billion Sm^3 gas	
	5.5 million tonnes NGL	2.2 million tonnes NGL	
Estimated production in 2012	Oil: 33 000 barrels/day, Gas: 0.28 billion Sm^3, NGL: 0.04 million tonnes.		
Expected investment from 2011	17.6 billion 2011 values		
Total investment as of 31.12.2010	56.7 billion nominal values		
Main supply base	Tananger		

Development: Valhall is an oil field located in the southern part of the North Sea. The water 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. 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 in June 1995. The PDO for Valhall water injection was approved in November 2000. The PDO for Valhall flank development was approved in November 2001. A PDO for Valhall redevelopment was approved inJune 2007.

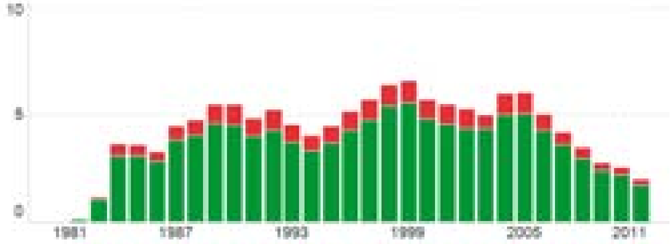
Reservoir: The Valhall field produces from chalk in the Tor and Hod Formations of Late Cretaceous age. The reservoir depth is approximately 2 400 metres. The chalk in the Tor Formation is fine-grained and soft, with considerable fracturing allowing oil and water to flow more easily than in the Hod formation.

Recovery strategy: Recovery originally took place by pressure depletion with compaction drive. As a result of pressure depletion from production, compaction of the chalk has caused subsidence of the seabed, presently six metres at the central part of the field. Water injection in the centre of the field started in January 2004 and is expanding. Gas lift will also be important to optimise production and will be implemented in most of the production wells.

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

Status: In 2010, a project was approved to establish gas lift in the wells on the flanks of the field in 2012. A new field centre with processing and accommodation facilities is installed and will be completed and come on production autumn 2012. The new facility will be supplied with power from shore. Drilling of new production and injection wells will continue to increase production and recovery from the field. Permanent seismic cables on the seabed are being utilised to identify new well targets for remaining oil in the reservoir.

Valhall
Mill. Sm³ o.e.



Varg

Blocks and production licences	Block 15/12 - production licence 038, awarded 1975.		
Development approval	03.05.1996 by the King in Council	**Discovered** 1984	
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 31.12.2011**	
	15.1 million Sm^3 oil	0.7 million Sm^3 oil	
Estimated production in 2012	Oil: 7 000 barrels/day		
Expected investment from 2011	0.5 billion 2011 values		
Total investment as of 31.12.2010	7.5 billion nominal values		
Main supply base	Tananger		

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

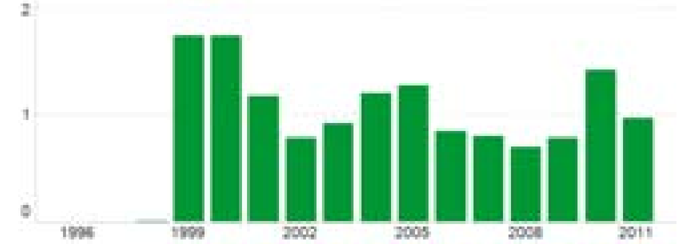
Reservoir: The reservoir is in Upper Jurassic sandstones at a depth of approximately 2 700 metres. The structure is segmented and includes several isolated compartments with varying reservoir properties.

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

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

Status: Varg is in the tail phase, but the field is expected to produce until 2021 if the lifetime of the facilities can be extended. Measures to optimise recovery are being considered. In 2011 water alternating gas injection (WAG) was started, and the first gas cycle has given very positive effects. Two infill producers are planned in the next couple of years, and several are planned for the coming years. The 15/12-21 (Grevling) discovery, proven in 2009, may be connected to Varg, which can prolong the lifetime of the Varg field.

Varg
Mill. Sm³ o.e.



Vega

Blocks and production licences	Block 35/11 - production licence 248, awarded 1999. Block 35/7 - production licence 248 B, awarded 2006. Block 35/8 - production licence 248, awarded 1999.		
Development approval	14.06.2007 by the Storting	**Discovered** 1981	
On stream	02.12.2010		
Operator	Statoil Petroleum AS		
Licensees	Bayerngas Norge AS		10.00 %
	GDF SUEZ E&P Norge AS		6.00 %
	Idemitsu Petroleum Norge AS		6.00 %
	Petoro AS		24.00 %
	Statoil Petroleum AS		54.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	2.8 million Sm^3 oil	2.2 million Sm^3 oil	
	8.2 billion Sm^3 gas	8.1 billion Sm^3 gas	
	1.7 million tonnes NGL	1.7 million tonnes NGL	
Estimated production in 2012	Oil: 12 000 barrels/day, Gas: 1.01 billion Sm^3, NGL: 0.20 million tonnes.		
Expected investment from 2011	1.2 billion 2011 values		
Total investment as of 31.12.2010	4.0 billion nominal values		
Main supply base	Florø		

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

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

Recovery strategy: The field is produced by pressure depletion.

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

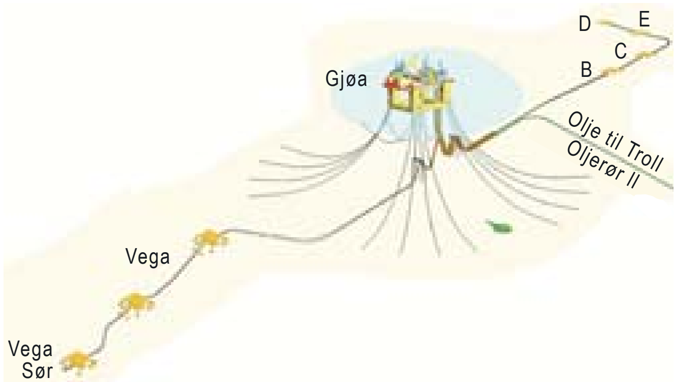
Status: All producers have been drilled and completed during 2010 and 2011.

Vega

Mill. Sm³ o.e.

Vega Sør

Blocks and production licences	Block 35/11 - production licence 090 C, awarded 2005.		
Development approval	14.06.2007 by the Storting	**Discovered** 1987	
On stream	02.12.2010		
Operator	Statoil Petroleum AS		
Licensees	Bayerngas Norge AS		10.00 %
	GDF SUEZ E&P Norge AS		6.00 %
	Idemitsu Petroleum Norge AS		6.00 %
	Petoro AS		24.00 %
	Statoil Petroleum AS		54.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	2.6 million Sm^3 oil	2.6 million Sm^3 oil	
	4.6 billion Sm^3 gas	4.0 billion Sm^3 gas	
	0.9 million tonnes NGL	0.8 million tonnes NGL	
Estimated production in 2012	Oil: 1 000 barrels/day, Gas: 0.05 billion Sm^3, NGL: 0.01 million tonnes		
Expected investment from 2011	0.7 billion 2011 values		
Total investment as of 31.12.2010	3.1 billion nominal values		
Main supply base	Florø		



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

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

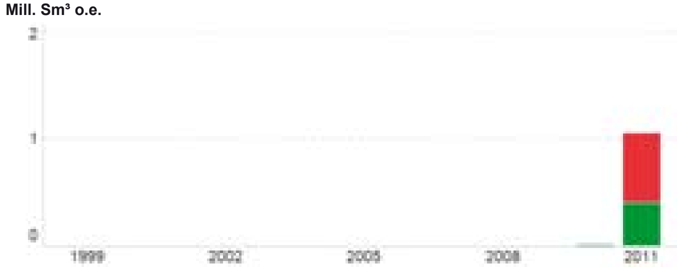
Recovery strategy: The field is produced by pressure depletion.

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

Status: Production from Vega Sør is currently shut-in. Sidetrack drilling of one producer is planned in 2012. The field is expected to start producing in late 2012 / early 2013.

Vega Sør

Mill. Sm³ o.e.



Veslefrikk

Blocks and production licences	Block 30/3 - production licence 052, awarded 1979. Block 30/6 - production licence 053, awarded 1979.		
Development approval	02.06.1987 by the Storting	**Discovered** 1981	
On stream	26.12.1989		
Operator	Statoil Petroleum AS		
Licensees	Petoro AS		37.00 %
	RWE Dea Norge AS		13.50 %
	Statoil Petroleum AS		18.00 %
	Talisman Energy Norge AS		27.00 %
	Wintershall Norge ASA		4.50 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	54.0 million Sm³ oil	2.4 million Sm³ oil	
	5.7 billion Sm³ gas	3.5 billion Sm³ gas	
	2.0 million tonnes NGL	0.8 million tonnes NGL	
Estimated production in 2012	Oil: 11 000 barrels/day, Gas: 0.27 billion Sm³, NGL: 0.09 million tonnes		
Expected investment from 2011	4.0 billion 2011 values		
Total investment as of 31.12.2010	15.6 billion nominal values		
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 water 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 June 1994. The PDO for the reservoirs in the Upper Brent and I-areas was approved on 16 December 1994.

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

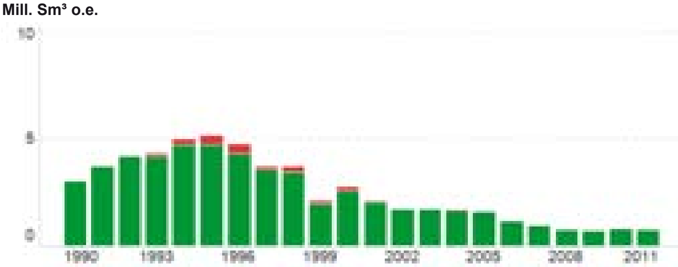
Recovery strategy: Production takes place with pressure support from water injection, and water alternating gas injection (WAG) in the Brent and Dunlin reservoirs, and with gas injection in the Statfjord Formation. Remotely controlled completions (DIACS) are used in WAG wells. Some gas has been exported from November 2011.

Transport: An oil pipeline is connected to the Oseberg Transport System (OTS) for transport to the Sture terminal. Gas for export is transported through the Statpipe system to Kårstø and Emden.

Status: Veslefrikk is in tail production phase. The drilling facilities will be upgraded to secure the possibility for operation throughout the economical lifetime of the field. The licensees are currently working to establish a gas strategy for the field to optimise the development of the remaining oil and gas resources.

Veslefrikk

Mill. Sm³ o.e.



Vigdis

Blocks and production licences	Block 34/7 - production licence 089, awarded 1984.		
Development approval	16.12.1994 by the King in Council	**Discovered** 1986	
On stream	28.01.1997		
Operator	Statoil Petroleum AS		
Licensees	ExxonMobil Exploration & Production Norway AS		10.50 %
	Idemitsu Petroleum Norge AS		9.60 %
	Petoro AS		30.00 %
	RWE Dea Norge AS		2.80 %
	Statoil Petroleum AS		41.50 %
	Total E&P Norge AS		5.60 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	63.4 million Sm³ oil	13.7 million Sm³ oil	
	1.9 billion Sm³ gas	0.4 billion Sm³ gas	
	1.2 million tonnes NGL	0.3 million tonnes NGL	
Estimated production in 2012	Oil: 35 000 barrels/day, Gas: 0.12 billion Sm³, NGL: 0.05 million tonnes		
Expected investment from 2011	7.0 billion 2011 values		
Total investment as of 31.12.2010	13.9 billion nominal values		
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 water depth in the area is 280 metres. The field comprises several discoveries, and has been developed with subsea templates connected to Snorre A. The wellstream is routed to Snorre A through two flowlines. 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 34/7-23 S discovery and adjoining deposits, was approved on 20 December 2002.

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

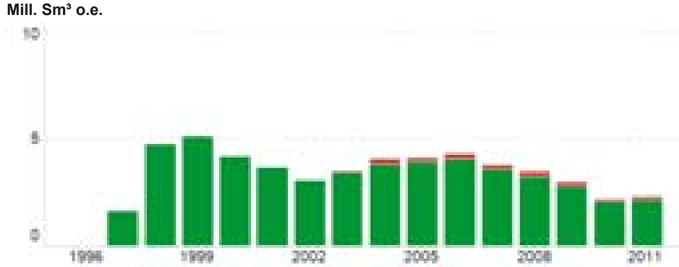
Recovery strategy: Production is based on partial pressure maintenance using water injection. Parts of the reservoirs are affected by the pressure blowdown of the Statfjord field, so water injection is used to counteract the effect.

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

Status: A PDO for Vigdis Nordøst was approved in 2011. The development involves a new subsea template with wells tied-back to the existing Vigdis subsea infrastructure.

Vigdis

Mill. Sm³ o.e.



Vilje

Blocks and production licences	Block 25/4 - production licence 036 D, awarded 2008.		
Development approval	18.03.2005 by the King in Council	**Discovered** 2003	
On stream	01.08.2008		
Operator	Statoil Petroleum AS		
Licensees	Marathon Oil Norge AS		46.90 %
	Statoil Petroleum AS		28.85 %
	Total E&P Norge AS		24.24 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	11.3 million Sm^3 oil	5.6 million Sm^3 oil	
Estimated production in 2012	Oil: 21 000 barrels/day		
Expected investment from 2011	1.1 billion 2011 values		
Total investment as of 31.12.2010	1.9 billion nominal values		

Development: Vilje is an oil field located in the central part of the North Sea, about 20 kilometres northeast of Alvheim and just north of the Heimdal field. It is a subsea development with two horizontal subsea wells connected to the production vessel "Alvheim FPSO". The water depth in the area is approximately 120 metres.

Reservoir: The reservoir is a turbidite deposit, in the Heimdal Formation of the Paleocene age. The reservoir lies approximately 2 150 metres below sea level.

Recovery strategy: The field is recovered by natural water drive from the regional underlying Heimdal aquifer.

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

Status: Production has been above expectations due to better production efficiency. There is a potential for drilling an additional well to drain the southern extension of the field.

Vilje

Mill. Sm³ o.e.

Visund

Blocks and production licences	Block 34/8 - production licence 120, awarded 1985.		
Development approval	29.03.1996 by the Storting	**Discovered** 1986	
On stream	21.04.1999		
Operator	Statoil Petroleum AS		
Licensees	ConocoPhillips Skandinavia AS		9.10 %
	Petoro AS		30.00 %
	Statoil Petroleum AS		53.20 %
	Total E&P Norge AS		7.70 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	33.0 million Sm^3 oil	11.3 million Sm^3 oil	
	49.5 billion Sm^3 gas	43.0 billion Sm^3 gas	
	6.2 million tonnes NGL	5.8 million tonnes NGL	
Estimated production in 2012	Oil: 15 000 barrels/day, Gas: 0.48 billion Sm^3, NGL: 0.06 million tonnes		
Expected investment from 2011	11.1 billion 2011 values		
Total investment as of 31.12.2010	20.7 billion nominal values		
Main supply base	Florø		

Development: Visund is an oil field east of the Snorre field in the northern part of the North Sea. The development includes a semi-submersible integrated accommodation, drilling and processing steel facility (Visund A). The water depth is about 335 metres at Visund A. The PDO for gas export was approved on 4 October 2002. The northern part of the Visund field was developed with a subsea template, about 10 kilometres north of Visund A, but has been shut down since 2006.

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

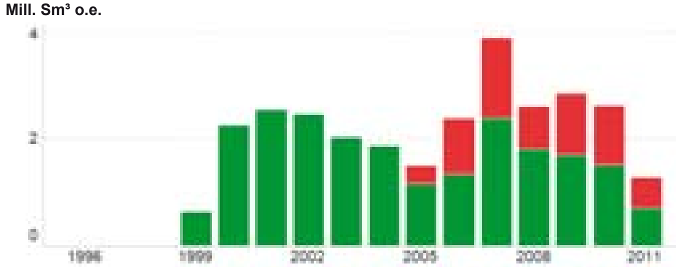
Recovery strategy: Oil production is driven by gas injection and water alternating gas injection (WAG). Produced water is also re-injected into one of the reservoirs. Limited export of produced gas was started autumn of 2005.

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

Status: A challenge for the Visund field is to maintain reservoir pressure to optimise the oil recovery before gas export levels increase. The northern part of the Visund field will be redeveloped with a template, and is expected to start production at the end of 2013. The licencees are currently working to develop the 34/8-13 A (Titan) discovery, and the main plan is to drill one well from Visund A, and one well from the Visund Nord template later on.

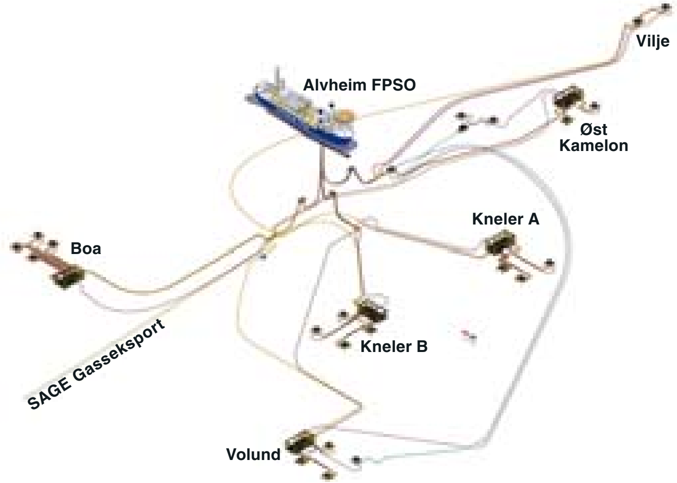
Visund

Mill. Sm³ o.e.



Volund

Blocks and production licences	Block 24/9 - production licence 150, awarded 1988.		
Development approval	18.01.2007 by the King in Council	**Discovered** 1994	
On stream	10.09.2009		
Operator	Marathon Oil Norge AS		
Licensees	Lundin Norway AS		35.00 %
	Marathon Oil Norge AS		65.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	7.8 million Sm^3 oil	5.2 million Sm^3 oil	
	1.0 billion Sm^3 gas	0.8 billion Sm^3 gas	
Estimated production in 2012	Oil: 24 000 barrels/day, Gas: 0.19 billion Sm^3		
Expected investment from 2011	0.6 billion 2011 values		
Total investment as of 31.12.2010	3.2 billion nominal values		



Development: Volund is an oil field located about 10 kilometres south of Alvheim in the central part of the North Sea. The field is developed as a subsea tie-back to the nearby production vessel "Alvheim FPSO" with three horizontal subsea wells. The water depth in the area is about 120-130 metres.

Reservoir: The reservoir is in Paleocene sandstone intrusions in the Hermod Formation, which in the Early Eocene age were remobilised and injected into the overlying Balder formation. The reservoir depth is about 2 000 metres.

Recovery strategy: Volund is produced by pressure support from a single water injection well. Produced water on the "Alvheim FPSO" is used for injection.

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

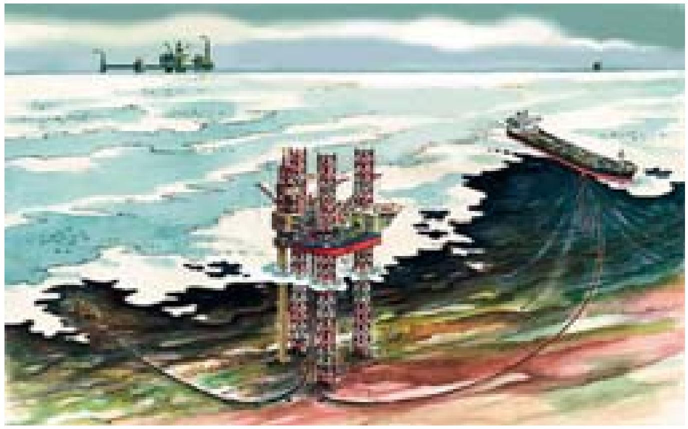
Status: Volund started production in 2009 from one production well, but was then shut in due to insufficient capacity on the "Alvheim FPSO". In August 2010, all producers came online when there was available capacity on the "Alvheim FPSO". During 2011, there has been spare capacity on the "Alvheim FPSO", and Volund has been able to increase the production.

Volund

Mill. Sm^3 o.e.

Volve

Blocks and production licences	Block 15/9 - production licence 046 BS, awarded 2006.		
Development approval	22.04.2005 by the Crown Prince Regent in Council	**Discovered** 1993	
On stream	12.02.2008		
Operator	Statoil Petroleum AS		
Licensees	Bayerngas Norge AS		10.00 %
	ExxonMobil Exploration & Production Norway AS		30.40 %
	Statoil Petroleum AS		59.60 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	8.5 million Sm^3 oil	1.5 million Sm^3 oil	
	0.8 billion Sm^3 gas	0.1 billion Sm^3 gas	
	0.2 million tonnes NGL		
	0.1 million Sm^3 condensate		
Estimated production in 2012	Oil: 10 000 barrels/day, Gas: 0.04 billion Sm^3, NGL: 0.01 million tonnes		
Expected investment from 2011	0.1 billion 2011 values		
Total investment as of 31.12.2010	3.0 billion nominal values		



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

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

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

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

Status: Production on Volve is expected to decline rapidly in the coming years. New drilling targets are being evaluated in order to establish a basis for a new drilling campaign planned for the summer of 2012.

Volve

Mill. Sm^3 o.e.

Yttergryta

Blocks and production licences	Block 6507/11 - production licence 062, awarded 1981 Block 6507/11 - production licence 263 C, awarded 2008.		
Development approval	21.05.2008 by the King in Council	**Discovered** 2007	
On stream	05.01.2009		
Operator	Statoil Petroleum AS		
Licensees	Eni Norge AS		9.80 %
	Petoro AS		19.95 %
	Statoil Petroleum AS		45.75 %
	Total E&P Norge AS		24.50 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	0.3 million Sm³ oil	1.4 billion Sm³ gas	
	2.4 billion Sm³ gas	0.3 million tonnes NGL	
	0.5 million tonnes NGL		
Estimated production in 2012	Gas: 0.30 billion Sm³, NGL: 0.06 million tonnes		
Total investment as of 31.12.2010	1.5 billion nominal values		

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

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

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

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

Status: The field came on stream in January 2009, and was shut down in late 2011 because of water production in the gas production well.

Yttergryta

Mill. Sm³ o.e.

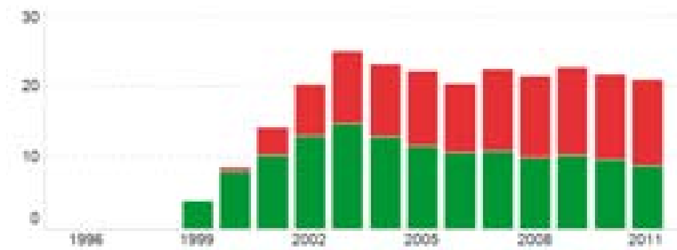
Åsgard

Blocks and production licences	Block 6406/3 - production licence 094 B, awarded 2002. Block 6407/2 - production licence 074, awarded 1982. Block 6407/3 - production licence 237, awarded 1998. Block 6506/11 - production licence 134, awarded 1987. Block 6506/12 - production licence 094, awarded 1984. Block 6507/11 - production licence 062, awarded 1981.		
Development approval	14.06.1996 by the Storting	**Discovered** 1981	
On stream	19.05.1999		
Operator	Statoil Petroleum AS		
Licensees	Eni Norge AS		14.82 %
	ExxonMobil Exploration & Production Norway AS		7.24 %
	Petoro AS		35.69 %
	Statoil Petroleum AS		34.57 %
	Total E&P Norge AS		7.68 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	103.8 million Sm³ oil	25.9 million Sm³ oil	
	200.6 billion Sm³ gas	89.3 billion Sm³ gas	
	38.8 million tonnes NGL	18.7 million tonnes NGL	
	16.1 million Sm³ condensate		
Estimated production in 2012	Oil: 86 000 barrels/day, Gas: 11.83 billion Sm³, NGL: 2.26 million tonnes		
Expected investment from 2011	41.9 billion 2011 values		
Total investment as of 31.12.2010	60.0 billion nominal values		
Main supply base	Kristiansund		

Development: Åsgard is located centrally in the Norwegian Sea. The water depth in the area is 240 – 300 metres. Åsgard includes the discoveries 6506/12-1 Smørbukk, 6506/12-3 Smørbukk Sør and 6507/11-1 Midgard. The field has been developed with subsea completed wells tied back to a production and storage vessel, "Åsgard A", which produces and stores oil, and a floating, semi-submersible facility, Åsgard B, for gas and condensate processing. The gas centre is connected to a storage vessel for condensate, Åsgard C. The Åsgard field has been developed in two phases. The liquid phase came on stream in 1999 and the gas export phase started on 1 October 2000.The Åsgard facilities are an important part of the Norwegian Sea infrastructure where gas from Mikkel and Yttergryta is processed, and injection gas is delivered to Tyrihans. The Morvin field is tied back to Åsgard B.

Åsgard

Mill. Sm³ o.e.



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

Recovery strategy: Smørbukk Sør is produced by pressure support from gas injection. Smørbukk is produced partly by pressure depletion and partly by injection of excess gas from the field. Midgard is produced by pressure depletion. Converting gas injection wells into gas production wells at Smørbukk has started, and the technology makes it possible to switch between injection and production. This will maintain both gas injection in Smørbukk and Smørbukk Sør and gas export volume from Åsgard. I addition, a separate study on optimisation of the drainage strategy on Smørbukk Sør has started and the plan is to mature the project with a phased development with production start-up of the first phase in 2014 and the second phase, depending on the results of the first phase, in 2015/2016. Establishment of a gas compression facility at Midgard was sanctioned by the licensees in July. It is expected that the project will be processed by the Storting in 2012. Start-up of the gas compression project is planned for 2015. This facility is needed to maintain the gas stream in the pipeline from Mikkel and Midgard to Åsgard B and thereby prevent creation of hydrates and water surges in the pipeline, which could lead to production stops. A stable supply of low CO_2 gas from Mikkel and Midgard is also important for dilution of the high CO_2 gas from Kristin in the Åsgard Transport to Kårstø.

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

Status: Most of the production wells have been drilled, and efforts are being made to increase recovery from the field, partly by drilling infill wells and sidetrack wells (TTRD wells). Also, timing of implementing Åsgard A and B low pressure production is being evaluated. Other efforts for increasing recovery from Åsgard A include, for example, upgrading the CO_2 removal facility at Åsgard B and extending the lifetime of Åsgard A. Prolonging the economic lifetime of Åsgard B is also a focus area. An appraisal well in 2009 proved oil and gas in a new segment northeast of Smørbukk. The deposit will be tied-in to Åsgard B, with planned production start in 2013. There are other proven resources in the area with low CO_2 gas. Work is being done to realise these via Mikkel and Midgard to Åsgard B. In addition, technical studies considering third-party discoveries as tie-back candidates to Åsgard are ongoing.

11 FIELDS UNDER DEVELOPMENT

Because of the high level of activity on the Norwegian shelf, tasks are lined up for the supplier industry. (Photo: Harald Pettersen, Statoil)

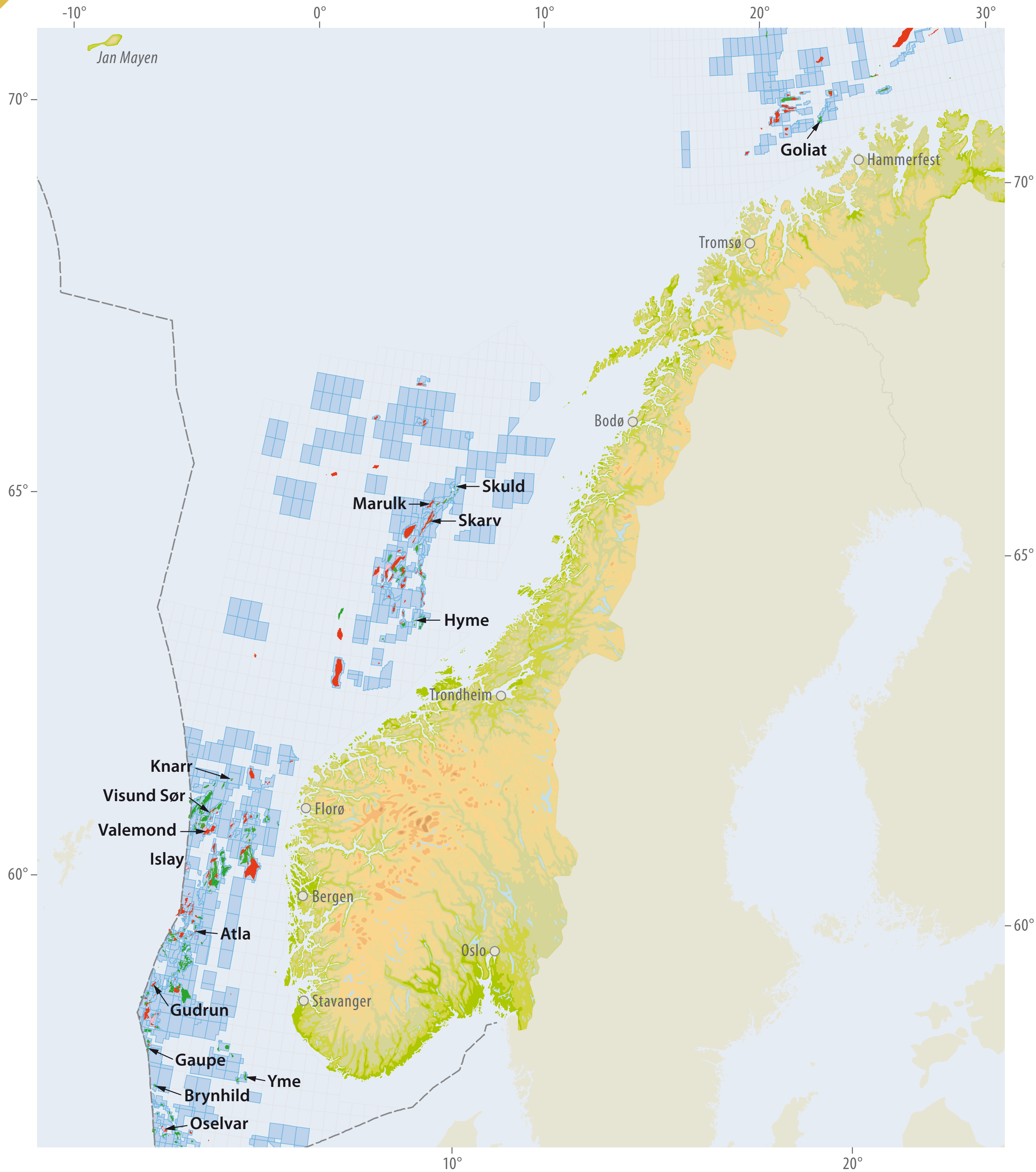
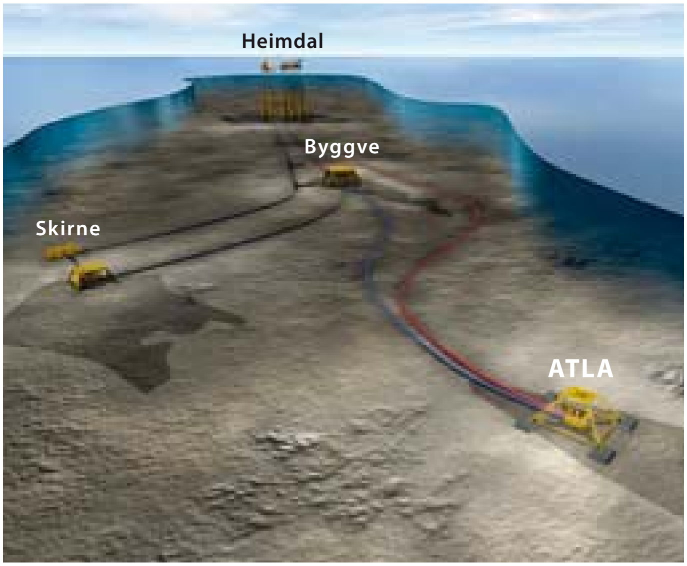


Figure 11.1 Fields under development *(Source: Norwegian Petroleum Directorate)*

Atla

Blocks and production licences	Block 25/5 - production licence 102 C, awarded 2009.		
Development approval	04.11.2011 by the King in Council	**Discovered** 2010	
Operator	Total E&P Norge AS		
Licensees	Centrica Resources (Norge) AS		20.00 %
	Det norske oljeselskap ASA		10.00 %
	Petoro AS		30.00 %
	Total E&P Norge AS		40.00 %
Recoverable reserves	**Original**		
	0.3 million Sm^3 oil		
	1.4 billion Sm^3 gas		
Expected investment from 2011	1.7 billion 2011 values		



Development: 25/5-7 Atla was discovered in the fall of 2010, about 20 kilometres northeast of the Heimdal field. The water depth in the area is 119 metres. Atla will be developed with a subsea template tied back to the Skirne/Byggve subsea template to Heimdal for processing of the fluid.

Reservoir: The reservoir contains gas/condensate in sandstones of the Middle Jurassic Brent Group, at a depth of about 2 700 metres.

Recovery strategy: The recovery strategy is gas depletion with one production well.

Transport: Gas transport to the UK or the Continent via Gasled. For condensate, the plan is to use the same transport solution as Heimdal, the Forties system in the UK (via Brae).

Status: The PDO was approved in 2011 and production is planned to start in October 2012.

Brynhild

Blocks and production licences	Block 7/4 - production licence 148, awarded 1988. Block 7/7 - production licence 148, awarded 1988.		
Development approval	11.11.2011 by the King in Council	**Discovered** 1992	
Operator	Lundin Norway AS		
Licensees	Lundin Norway AS		70.00 %
	Talisman Petroleum Norge AS		30.00 %
Recoverable reserves	**Original**		
	3.2 million Sm^3 oil		
Expected investment from 2011	4.1 billion 2011 values		

Development: Brynhild is located about 10 kilometres from the UK border, about 55 kilometres northwest of the Ula field and 38 kilometres north of the UK field Pierce. The water depth in the area is about 80 metres. The development concept is a subsea development with tie-in to the Hæwene Brim FPSO located at the Pierce field in the UK.

Reservoir: The reservoir lies at a depth of about 3 300 metres in Late Jurassic sandstones belonging to the Ula Formation. The reservoir contains strongly under-saturated oil at reservoir conditions closely bordering high pressure – high temperature (HPHT) conditions.

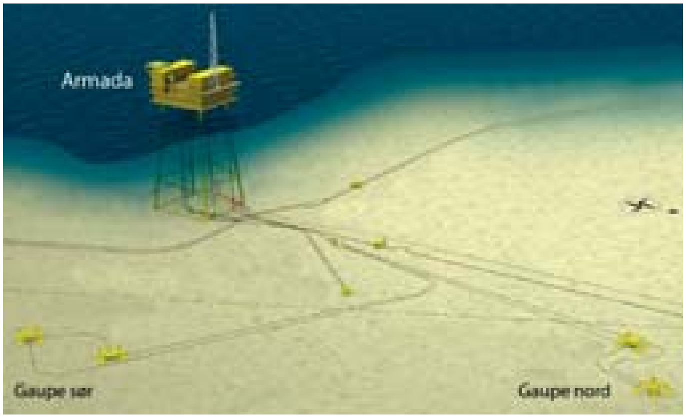
Recovery strategy: The Brynhild oil will be produced by water injection.

Transport: The wellstream will be transported by pipeline to the FPSO located at the Pierce field for processing. The processed oil will be exported by shuttle tankers to market, while gas is re-injected into the Pierce field.

Status: The PDO was approved in November 2011. Production is planned to start in October 2013.

Gaupe

Blocks and production licences	Block 15/12 - production licence 292, awarded 2003 Block 15/12 - production licence 292 B, awarded 2009. Block 6/3 - production licence 292, awarded 2003.	
Development approval	25.06.2010 by the King in Council	**Discovered** 1985
Operator	BG Norge AS	
Licensees	BG Norge AS	60.00 %
	Lundin Norway AS	40.00 %
Recoverable reserves	**Original**	
	1.3 million Sm^3 oil	
	3.3 billion Sm^3 gas	
	0.2 million tonnes NGL	
	0.1 million Sm^3 condensate	
Expected investment from 2011	2.1 billion 2011 values	
Total investment as of 31.12.2010	0.4 billion nominal values	



Development: Gaupe is located close to the border between the Norwegian and UK sectors, about 12 kilometres south of the Varg field. The water depth in the area is approximately 90 metres. The development concept is two single horizontal subsea wells tied to the Armada installation on the UK shelf.

Reservoir: The Gaupe reservoirs are in two structures, Gaupe South and Gaupe North, at a depth of approximately 3 000 metres. Most of the resources are in Triassic sandstones, while some are in Middle Jurassic sandstones. The two structures have a free gas cap overlying an oil zone, with different hydrocarbon contacts.

Recovery strategy: Gaupe will be produced by pressure depletion. Initial production will be from the oil zone, followed by combined production from the oil and gas zones.

Transport: The wellstream will be processed at the Armada installation for export to the UK. The rich gas will be transported via the CATS pipeline to Teesside, and condensate and oil will be transported via the Forties pipeline.

Status: Production is planned to start in March 2012.

Goliat

Blocks and production licences	Block 7122/7 - production licence 229, awarded 1997. Block 7122/8 - production licence 229, awarded 1997.	
Development approval	18.06.2009 by the Storting	**Discovered** 2000
Operator	Eni Norge AS	
Licensees	Eni Norge AS	65.00 %
	Statoil Petroleum AS	35.00 %
Recoverable reserves	**Original**	
	30.6 million Sm^3 oil	
	7.3 billion Sm^3 gas	
	0.3 million tonnes NGL	
Expected investment from 2011	27.5 billion 2011 values	
Total investment as of 31.12.2010	3.5 billion nominal values	

Development: Goliat was discovered in 2000 and is located about 50 kilometres southeast of the Snøhvit field in the Barents Sea. The water depth in the area is 360 – 420 metres. Goliat will be developed with a circular FPSO (Sevan 1000) including eight subsea templates with a total of 32 well slots. The subsea templates will be tied back to the FPSO with an integrated storage and loading system.

Reservoir: The Goliat reservoirs contain oil and thin gas caps in Triassic sandstones of the Kapp Toscana Group (Realgrunnen subgroup) and the Kobbe Formation. The reservoirs lie at a depth of 1 100 – 1 800 metres in a complex and segmented structure.

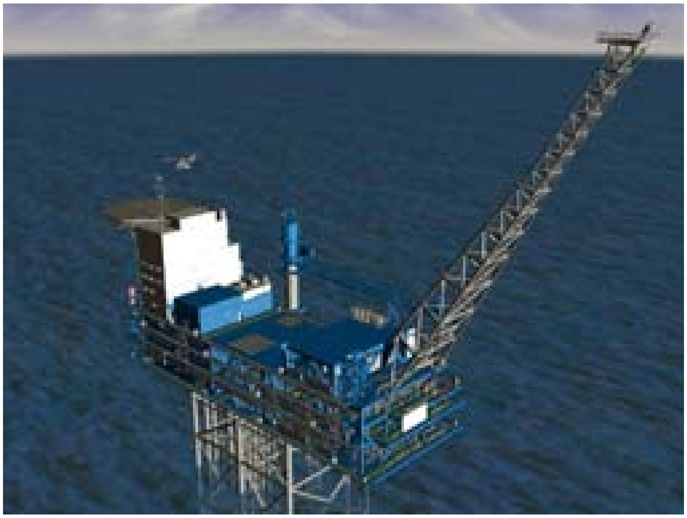
Recovery strategy: Goliat will be produced using water injection as pressure support. Associated gas will be re-injected until a possible export solution for gas through the Snøhvit pipeline to Melkøya is in place.

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

Status: Production is planned to start in late 2013

Gudrun

Blocks and production licences	Block 15/3 - production licence 025, awarded 1969.		
Development approval	16.06.2010 by the Storting	**Discovered** 1975	
Operator	Statoil Petroleum AS		
Licensees	GDF SUEZ E&P Norge AS		25.00 %
	Statoil Petroleum AS		75.00 %
Recoverable reserves	**Original**		
	11.2 million Sm^3 oil		
	6.0 billion Sm^3 gas		
	1.2 million tonnes NGL		
Expected investment from 2011	17.6 billion 2011 values		
Total investment as of 31.12.2010	1.1 billion nominal values		



Development: Gudrun is located about 50 kilometres north of the Sleipner fields. The water depth is approximately 110 metres. Gudrun is being developed with a steel jacket, one stage processing facility with oil and rich gas tied back to Sleipner A through two dedicated pipelines.

Reservoir: The reservoirs contain oil and gas in Upper Jurassic sandstones in the Draupne Formation and gas in the Middle Jurassic Hugin Formation. The reservoirs lie at a depth of 4 000 - 4 760 metres.

Recovery strategy: Gudrun will be produced by natural pressure depletion through seven production wells.

Transport: Oil and gas will be transported to the Sleipner A facility for further processing and export.

Status: Production is planned to start in 2014.

Hyme

Blocks and production licences	Block 6407/8 - production licence 348, awarded 2004.		
Development approval	24.06.2011 by the King in Council	**Discovered** 2009	
Operator	Statoil Petroleum AS		
Licensees	Core Energy AS		17.50 %
	E.ON Ruhrgas Norge AS		17.50 %
	Faroe Petroleum Norge AS		7.50 %
	GDF SUEZ E&P Norge AS		20.00 %
	Statoil Petroleum AS		35.00 %
	VNG Norge AS		2.50 %
Recoverable reserves	**Original**		
	3.2 million Sm^3 oil		
	0.5 billion Sm^3 gas		
	0.2 million tonnes NGL		
Expected investment from 2011	4.5 billion 2011 values		

Development: Hyme is located about 19 kilometres northeast of the Njord field and about 10 kilometres west of Draugen. The water depth in the area is about 260 metres. Hyme will be developed with a standard subsea template with four well slots. Hyme is connected to the Njord facility with an umbilical and a production pipe, a water injection pipe, and a pipe for gas lift. The development plan includes one subsea production well and one subsea water injection well tied to Njord.

Reservoir: The reservoir contains oil and gas in the Lower Jurassic Tilje Formation. The main reservoir at Hyme includes the Tilje 2.2 and Tilje 3 Formations. The reservoirs are located at a depth of about 2 150 metres. The quality of the reservoir is good.

Recovery strategy: The drainage strategy is a two-branched well in the Tilje Formation. The well is placed on the top of the structure to avoid early water break through. The drainage strategy is seawater injection for pressure support.

Transport: Oil and gas will be transported via the Njord facility

Status: Production is planned to start in the first quarter of 2013.

Islay

Blocks and production licences	Block 29/6 - production licence 043 CS, awarded 2010 Block 29/6 - production licence 043 DS, awarded 2010. The Norwegian part of the field is 5.51 %, the British part is 94.49 %		
Development approval	05.07.2010	**Discovered** 2008	
Operator	TOTAL E&P UK PLC		
Licensees	Total E&P Norge AS		100.00 %
(Norwegian part) Recoverable reserves (Norwegian part)	**Original**		
	0.1 billion Sm^3 gas		

Development: Islay straddles the border between the UK and Norwegian continental shelves. The water depth is 122 metres. Islay will be developed with one well tied to the existing Forvie manifolds.

Reservoir: The reservoir lies at a depth of between 3 700 and 3 900 metres and contains gas condensate in Middle Jurassic sandstones of the Brent Formation.

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

Transport: Production from the Forvie Manifold will be routed via the Forvie-Alwyn pipeline to the Alwyn North NAB platform where the fluids are separated. The gas will be exported via the FUKA pipeline to St Fergus in Scotland, whereas the liquids will be exported to the Sullom Voe Terminal via the Cormorant Alpha platform and the Brent system.

Status: Production is planned to start in March 2012.

Knarr

Blocks and production licences	Block 34/3 - production licence 373 S, awarded 2006.		
Development approval	09.06.2011 by the Storting	**Discovered** 2008	
Operator	BG Norge AS		
Licensees	BG Norge AS		45.00 %
	Idemitsu Petroleum Norge AS		25.00 %
	RWE Dea Norge AS		10.00 %
	Wintershall Norge ASA		20.00 %
Recoverable reserves	**Original**		
	8.3 million Sm^3 oil		
	0.2 billion Sm^3 gas		
	0.4 million tonnes NGL		
Expected investment from 2011	6.5 billion 2011 values		

Development: Knarr is located approximately 50 kilometres northeast of Snorre. The water depth is 410 metres. Knarr will be developed with an FPSO.

Reservoir: The reservoir lies at a depth of about 3 800 metres and contains oil in Lower Jurassic sandstones of the Cook Formation.

Recovery strategy: The production strategy will include pressure maintenance by water injection.

Transport: Oil will be offloaded from the Knarr FPSO to tankers, and the gas will be exported via Far North Liquids and Associated Gas System (FLAGS) to St Fergus in Scotland.

Status: Production is planned to start in early 2014.

Marulk

Blocks and production licences	Block 6507/2 - production licence 122, awarded 1986. Block 6507/3 - production licence 122 B, awarded 2002. Block 6607/11 - production licence 122 D, awarded 2006. Block 6607/12 - production licence 122 C, awarded 2004.	
Development approval	15.07.2010 by the King in Council	**Discovered** 1992
Operator	Eni Norge AS	
Licensees	DONG E&P Norge AS	30.00 %
	Eni Norge AS	20.00 %
	Statoil Petroleum AS	50.00 %
Recoverable reserves	**Original**	
	0.7 million Sm^3 oil	
	8.4 billion Sm^3 gas	
	1.4 million tonnes NGL	
Expected investment from 2011	2.4 billion 2011 values	
Total investment as of 31.12.2010	0.4 billion nominal values	

Development: Marulk is a gas and condensate field located about 25 kilometres southwest of the Norne field. The water depth in the area is about 370 metres. Marulk will be developed with a subsea template tied back to the Norne vessel.

Reservoir: The reservoir contains gas and condensate in Cretaceous sandstones in the Lysing and Lange Formations at a depth of about 2 800 metres.

Recovery strategy: Marulk will be produced by pressure depletion.

Transport: The wellstream will be sent to the Norne vessel for processing. The gas will then be transported to Åsgard Transport and further to Kårstø for export.

Status: Drilling and completion of the two production wells started in autumn 2011. Production is planned to start spring 2012.

Oselvar

Blocks and production licences	Block 1/2 - production licence 274 CS, awarded 2008. Block 1/3 - production licence 274, awarded 2002.	
Development approval	19.06.2009 by the King in Council	**Discovered** 1991
Operator	DONG E&P Norge AS	
Licensees	Altinex Oil Norway AS	15.00 %
	Bayerngas Norge AS	30.00 %
	DONG E&P Norge AS	55.00 %
Recoverable reserves	**Original**	
	4.0 million Sm^3 oil	
	4.4 billion Sm^3 gas	
Expected investment from 2011	2.8 billion 2011 values	
Total investment as of 31.12.2010	1.7 billion nominal values	

Development: Oselvar is located 21 kilometres southwest of the Ula field, in the southern part of the North Sea. The water depth in the area is about 70 metres. The development concept is a subsea template with production wells tied to Ula by pipeline.

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

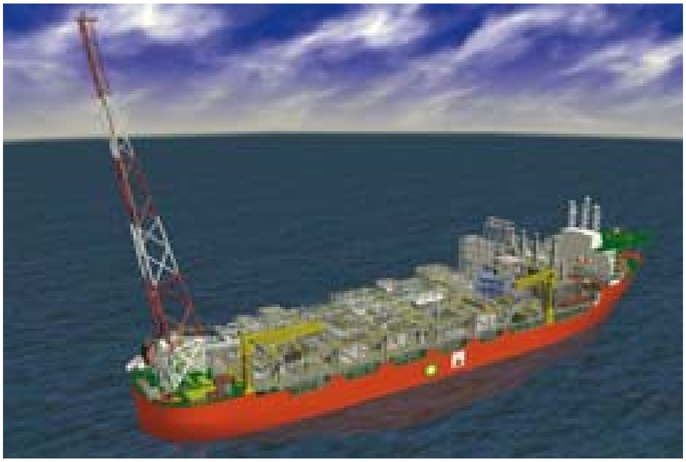
Recovery strategy: Oselvar will be produced by natural pressure depletion via three horizontal production wells.

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

Status: Production is planned to start in April 2012.

Skarv

Blocks and production licences	Block 6507/2 - production licence 262, awarded 2000. Block 6507/3 - production licence 159, awarded 1989 Block 6507/3 - production licence 212 B, awarded 2002. Block 6507/5 - production licence 212, awarded 1996. Block 6507/6 - production licence 212, awarded 1996.		
Development approval	18.12.2007 by the Storting	**Discovered** 1998	
Operator	BP Norge AS		
Licensees	BP Norge AS		23.84 %
	E.ON Ruhrgas Norge AS		28.08 %
	PGNiG Norway AS		11.92 %
	Statoil Petroleum AS		36.16 %
Recoverable reserves	**Original**		
	15.3 million Sm^3 oil		
	43.4 billion Sm^3 gas		
	5.7 million tonnes NGL		
Expected investment from 2011	16.3 billion 2011 values		
Total investment as of 31.12.2010	28.2 billion nominal values		



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

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

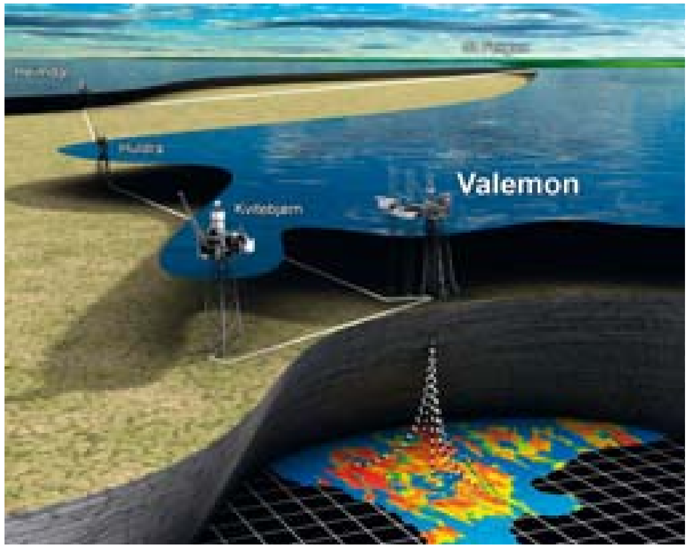
Recovery strategy: In the Garn and Tilje Formations, re-injection of gas is planned for the first years in order to increase oil recovery.

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

Status: The FPSO was completed and towed to the field in August 2011. Templates are being installed at the field. Drilling started in 2010, and production is planned to start in May/June 2012.

Valemon

Blocks and production licences	Block 30/1 - production licence 050 C, awarded 1999. Block 34/10 - production licence 050, awarded 1978 Block 34/10 - production licence 050 B, awarded 1995 Block 34/10 - production licence 050 D, awarded 2007. Block 34/11 - production licence 193 B, awarded 2009 Block 34/11 - production licence 193 D, awarded 2011.		
Development approval	09.06.2011 by the Storting	**Discovered** 1985	
Operator	Statoil Petroleum AS		
Licensees	Enterprise Oil Norge AS		3.23 %
	Petoro AS		30.00 %
	Statoil Petroleum AS		66.78 %
Recoverable reserves	**Original**		
	4.9 million Sm^3 oil		
	26.1 billion Sm^3 gas		
	1.3 million tonnes NGL		
Expected investment from 2011	19.0 billion 2011 values		
Total investment as of 31.12.2010	0.1 billion nominal values		



Development: 34/10-23 Valemon is located in blocks 34/11 and 34/10, just west of the Kvitebjørn field. The water depth is about 135 metres. Several appraisal wells have been drilled on the discovery. The development concept is a production platform with a simplified separation process.

Reservoir: The deposit has a complex structure with several faults. The reservoirs consist of Middle Jurassic sandstones in the Brent Group and Lower Jurassic sandstones in the Cook Formation. The reservoirs lie at a depth of approximately 4 000 metres, with high pressure and temperature.

Recovery strategy: Valemon will be produced by pressure depletion.

Transport: The condensate will be transported to Kvitebjørn, and via the Kvitebjørn oil pipeline to Mongstad. The plan is to transport rich gas in a pipeline to Heimdal for further export to the United Kingdom or the Continent.

Status: The plan is to start drilling wells in 2012 with production planned to start in 2014.

Visund Sør

Blocks and production licences	Block 34/8 - production licence 120, awarded 1985.		
Development approval	10.06.2011 by the King in Council	**Discovered** 2008	
Operator	Statoil Petroleum AS		
Licensees	ConocoPhillips Skandinavia AS		9.10 %
	Petoro AS		30.00 %
	Statoil Petroleum AS		53.20 %
	Total E&P Norge AS		7.70 %
Recoverable reserves	**Original**		
	3.7 million Sm^3 oil		
	9.6 billion Sm^3 gas		
	1.2 million tonnes NGL		
Expected investment from 2011	4.6 billion 2011 values		

Development: Visund Sør is located 10 kilometres southwest of the Visund platform and approximately 10 kilometres northeast of Gullfaks C. The water depth in the area is around 290 metres. Visund Sør will be developed with a subsea template tied to Gullfaks C.

Reservoir: The reservoirs lie at a depth of 2 800 - 2 900 metres and contain oil and gas in Middle Jurassic sandstones of the Brent Group.

Recovery strategy: The oil from Visund Sør will be produced by expansion of the gas cap, followed by depletion for gas production.

Transport: Oil and gas will be routed to Gullfaks C for processing and export.

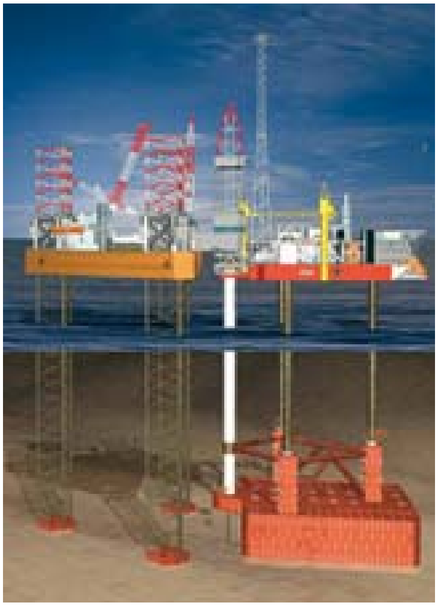
Status: Production is planned to start in autumn 2012.

Yme

Blocks and production licences	Block 9/2 - production licence 316, awarded 2004. Block 9/5 - production licence 316, awarded 2004.		
Development approval	11.05.2007 by the King in Council	**Discovered** 1987	
On stream	27.02.1996		
Operator	Talisman Energy Norge AS		
Licensees	Lotos Exploration and Production Norge AS		20.00 %
	Norske AEDC A/S		10.00 %
	Talisman Energy Norge AS		60.00 %
	Wintershall Norge ASA		10.00 %
Recoverable reserves*	**Original**	**Remaining as of 31.12.2011**	
	19.9 million Sm^3 oil	12.0 million Sm^3 oil	
Expected investment from 2011	3.1 billion 2011 values		
Total investment as of* 31.12.2010	9.6 billion nominal values		

* Include original and new development

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



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

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

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

Status: It is uncertain when production can start.

12 FUTURE DEVELOPMENTS

More and more fields are being developed with underwater installations, here showing the installation on Vigdis Øst. (Photo: A. Osmundsen, Statoil)

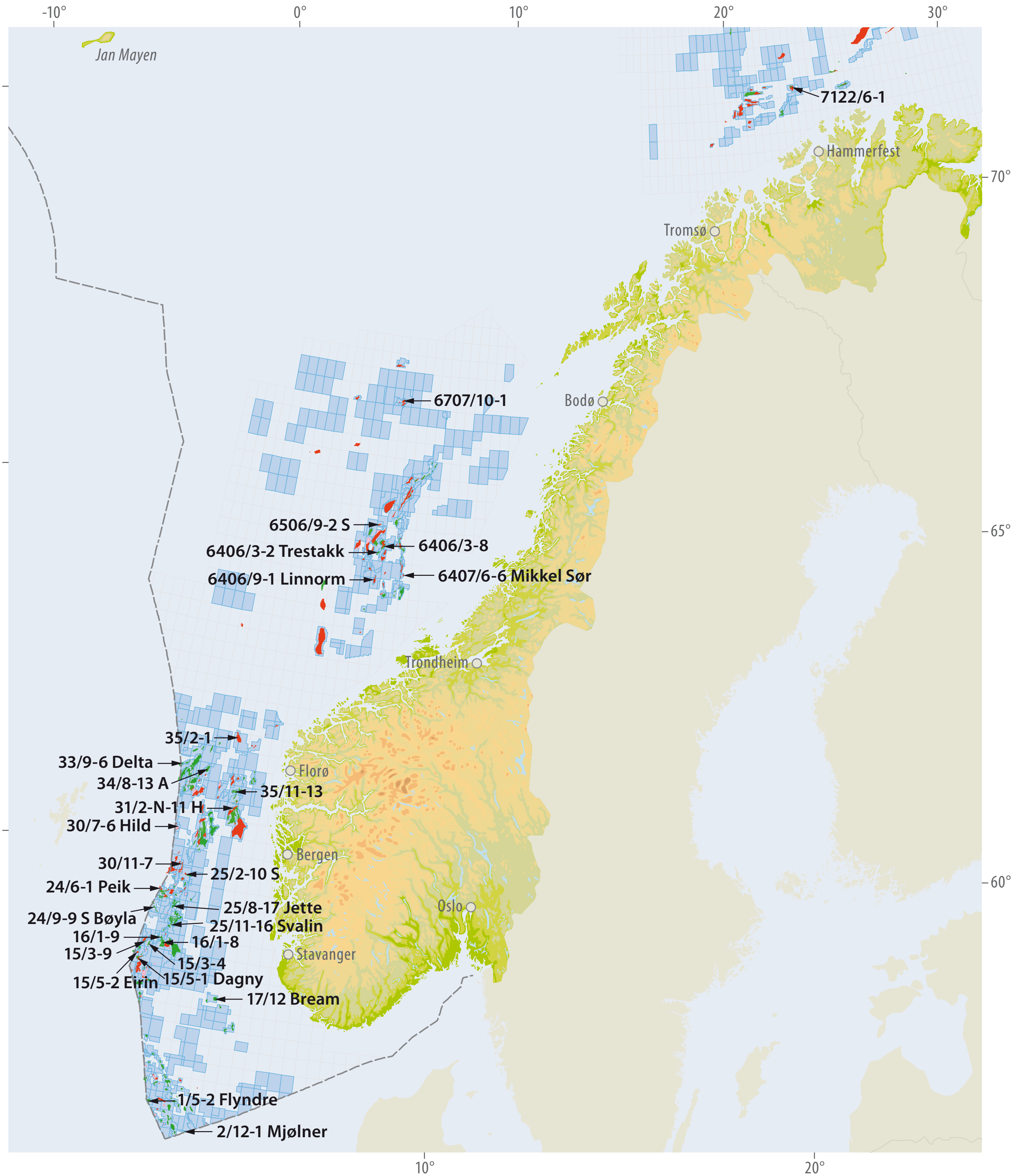


Figure 12.1 Future developments *(Source: Norwegian Petroleum Directorate)*

This list does not comprise discoveries included in existing fields as of 31 December 2011.

Development decided by the licensees

25/8-17 Jette

Production licence : 027 D, 169 C, 504. Operator: Det norske oljeselskap ASA

Resources: Oil: 1.6 million Sm^3. Gas: 0.4 billion Sm^3

Jette consists of the 25/8-17 oil discovery which was drilled in 2009. It is located approximately six kilometres south of the Jotun field, at about 127 metres water depth. The reservoir is at a depth of a little more than 2 000 metres in the Heimdal Formation of Paleocene age. Jette will be developed with a subsea template tied to the Jotun platform. The PDO was approved on 17 February 2012, and production is planned to start in the first quarter of 2013.

33/9-6 Delta

Production licence: 037 D. Operator: Wintershall Norge ASA

Resources: Oil: 0.1 million Sm^3

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

6608/10-12 and 6608/10-14 S Skuld

Production licence: 128. Operator: Statoil Petroleum AS

Resources: Oil: 13.4 million Sm^3. Gas: 0.9 billion Sm^3. NGL: 0.1 million tonnes

Skuld is located in the Norwegian Sea, north of Norne, at a water depth of about 340 metres and consists of the two oil deposits 6608/10-12 Dompap and 6608/10-14 S Fosskall, which are located 26 and 16 kilometres, respectively, north of the Norne vessel. Skuld is being developed with subsea templates tied back to the "Norne FPSO". The reservoirs consist of Lower to Middle Jurassic sandstones of the Åre, Tofte and Ile Formations at a depth of 2 400–2 600 metres.

Skuld will be recovered by water injection. In addition, some of the wells will be supplied with gas lift to be able to produce at low reservoir pressure with high water cut.

The wellstream will be processed on the Norne vessel, and the oil will be buoy-loaded together with the oil from the Norne field. The gas will be transported by pipeline from the Norne vessel to Åsgard, then exported via Åsgard Transport System to Kårstø.

The PDO was approved on 20 January 2012. Drilling of the development wells is planned to start in March 2012, and production is planned to start in December 2012.

Discoveries in the planning phase

1/5-2 Flyndre

Production licence: 018 DS, 297. Operator: Maersk Oil Norway AS

Resources: Oil: 0.4 million Sm^3

1/5-2 Flyndre was discovered in 1974 and straddles the border between the Norwegian and the UK sectors in the Ekofisk area. The water depth in the area is 70 metres. The discovery contains oil and associated gas in Paleocene sandstones and Upper Cretaceous chalk. Four wells have been drilled on the discovery, one on the Norwegian side and three on the UK side. Most of the resources are in the Paleocene reservoir on the UK continental shelf. The plan is to submit an FDP (Field Development Plan) the UK and Norwegian authorities early in 2012. The chalk reservoir is not included in the development plan. The planned development concept is a subsea template on the UK side tied to the Clyde platform on the UK continental shelf. Production is planned to start in September 2013.

15/3-4

Production licence: 025, 187. Operator: Statoil Petroleum AS

Resources: Oil: 1.9 million Sm^3. Gas: 1.6 billion Sm^3. NGL: 0.2 million tonnes

15/3-4 (Sigrun) was discovered in 1981 and is located about 10 kilometres southeast of the Gudrun field. The water depth in the area is about 110 metres. The discovery contains oil in the Hugin Formation of Middle Jurassic age at a depth of about 3 800 metres. The discovery will be further evaluated in 2012. A possible development concept is a subsea template tied back to the Gudrun facility.

15/3-9

Production licence: 025, 187. Operator: Statoil Petroleum AS

Resources: Oil: 0.6 million Sm^3. Gas: 0.3 billion Sm^3. NGL: 0.1 million tonnes

15/3-9 (Gudrun Øst) is an oil discovery located about 4 kilometres southeast of Gudrun. The plan is to produce the resources using a long-reach well from the Gudrun facility. The production strategy is pressure depletion.

15/5-1 Dagny

Production licence: 029, 029 B, 048, 303. Operator: Statoil Petroleum AS

Resources: Oil: 8.6 million Sm^3. Gas: 16.6 billion Sm^3.
NGL: 2.4 million tonnes. Condensate: 3.0 million Sm^3

15/5-1 Dagny is an oil and gas discovery located 250 kilometres west of Stavanger and 30 kilometres northwest of the Sleipner A installation. The water depth is 116 metres. The field was discovered in 1974 and the reservoir contains oil and gas in the Upper Jurassic Hugin Formation at a depth of about 3 700 metres below sea level. The development solution is a new steel platform. Drilling is planned using a mobile jack-up rig. Oil is exported via offshore loading (FSU). The rich gas is exported to Sleipner for processing and further export of sales gas to Gassled, and condensate/NGL to Kårstø. A phased gas injection approach is selected as drainage strategy. Injection will start with gas from the Eirin discovery located 9 kilometres northwest of Dagny. Implementation of full gas injection and import from Gassled will be a separate decision in 2017, based on new information from production drilling and early experience gained from production and injection. The concept was selected in December 2011. The licensees plan to submit a PDO in December 2012, and production is expected to start in December 2016.

15/5-2 Eirin

Production licence: 048 E, Operator: Statoil Petroleum AS

Resources: Gas: 10.2 billion Sm^3. NGL: 0.1 million tonnes.
Condensate: 0.7 million Sm^3

15/5-2 Eirin was discovered in 1978, and is located approximately 40 kilometres northwest of Sleipner A and 9 kilometres northwest of the 15/5-1 Dagny discovery. About 80 % of the gas resources are in the Upper Triassic Skagerak Formation, and about 20 % in the Jurassic Sleipner Formation. The Skagerak Formation is at a depth of about 4 100 metres below sea level. The development solution is a four-slot template with two gas wells tied back to the planned Dagny platform, where the wellstream is partly processed and the gas is used for injection in Dagny to increase recovery. The water depth at the proposed Eirin template location is 118 metres.

Eirin will be developed parallel with Dagny. The concept was selected in December 2011. The licensees plan to submit a PDO in December 2012, and start production in December 2016.

16/1-8

Production licence: 338. Operator: Lundin Norway AS

Resources: Oil: 25.6 million Sm^3. Gas: 1.9 billion Sm^3. NGL: 0.8 million tonnes

** Resources in 16/1-12 (Luno Extension), RC7F, are not included*

16/1-8 (Luno) was discovered in 2007, about 35 kilometres south of Grane and Balder. Two appraisal wells, 16/1-10 and 16/1-13, were drilled in 2009 and 2010. The water depth is about 110 metres. The reservoir contains gas and oil in Jurassic and Upper Triassic sandstones and conglomerates, at a depth of 1 900 – 1 990 metres. A PDO was submitted to the authorities in January 2012. The licensees recommend a stand-alone development with a fixed production facility. The production facility will have the flexibility to accommodate a tie-back to the Draupne discovery. The production strategy will be pressure maintenance by water injection. Produced gas will be exported to Sleipner or to the UK gas transportation system. Estimated production start-up is late 2015.

16/1-9

Production licence: 001 B. Operator: Det norske oljeselskap ASA

Resources: Oil: 17.2 million Sm^3. Gas: 3.6 billion Sm^3. NGL: 0.7 million tonnes.

16/1-9 (Draupne) was discovered in 2008, about 30 kilometres south of Grane and Balder. An appraisal well and a sidetrack, 16/1-11 and 16/1-11A, were drilled on the discovery in 2010. The water depth in the area is about 110 metres. The reservoir contains oil and gas in the Middle Jurassic Sleipner Formation and the Upper Triassic Skagerrak Formation. The reservoir lies at a depth of about 2 400 metres. The licensees are considering a stand-alone development with a fixed production facility with tie-back to the Luno facility. Two additional oil discoveries, 25/10-8 Hanz and 16/1-7 West Cable, are planned to be produced through the Draupne production facilities. According to plan, a PDO will be submitted to the authorities in 2012.

17/12-1 Bream

Production licence: 407. Operator: BG Norge AS

Resources: Oil: 7.2 million Sm^3

17/12-1 Bream was discovered in 1972 in production licence 016. The discovery is located at a water depth of about 110 metres in the southeastern part of the North Sea, approximately 50 kilometres northwest of the Yme field. The reservoir is in Middle Jurassic sandstones of the Sandnes Formation, at a depth of about 2 300 metres. The discovery was relinquished in 1994 and then awarded to production licence 407 in 2007. An appraisal well, 17/12-4, including two horizontal sidetracks, was drilled in 2009. The most probable development solution is a leased FPSO. Water injection is recommended as drainage strategy and, according to plan, associated gas will be re-injected. Possible production start up is 2015/2016.

24/6-1 Peik

Production licence: 088. Operator: Centrica Resources (Norge)

Resources: Gas: 2.5 billion Sm^3. Condensate: 0.7 million Sm^3

24/6-1 Peik was discovered in 1985, and was delineated by well 9/15a-1 drilled in the UK sector in 1987. The discovery straddles the border between the Norwegian and UK sectors, about 18 kilometres west of Heimdal and just northwest of the Alvheim field. The water depth is about 120 metres. The reservoir contains Middle Jurassic sandstones in the Vestland Group. The reservoir lies at a depth of approximately 4 500 metres and contains gas and condensate under high pressure. The planned development concept is a subsea facility tied to a Norwegian hub in the area, or to a field in the UK sector.

24/9-9 S Bøyla

Production licence: 340. Operator: Marathon Oil Norge AS

Resources: Oil: 3.2 million Sm^3. Gas: 0.3 billion Sm^3

24/9-9 S Bøyla, previously called "Marihøne", was discovered in 2009. The discovery is located about 28 kilometres south of the Alvheim field. The water depth in the area is about 120 metres. The reservoir contains oil in sandstones of the Paleocene Hermod Formation and lies at a depth of about 2 100 metres. Development of the discovery is planned with a subsea facility tied back to Alvheim. The plan is to submit a PDO to the MPE in July 2012, with expected production start at the end of 2013 or the beginning of 2014.

Frøy

Production licence: 364. Operator: Det norske oljeselskap ASA

Resources: Oil: 11.1 million Sm^3

Frøy is an oilfield located in blocks 25/2 and 25/5, about 32 kilometres southeast of the Frigg field and 25 kilometres northeast of the Heimdal field. The water depth is 117 metres. Frøy was originally part of production licences 026 and 102, which were awarded in 1976 and 1995. The field was discovered in 1987 and production started in May 1995, with Elf Petroleum Norge AS as operator. When production was shut down in March 2001, a total of 5.6 million Sm^3 oil and 1.6 billion Sm^3 associated gas had been produced. The Frøy field was granted to production licence 364 in January 2006. In September 2008, the operator submitted a PDO for redevelopment to the authorities. Subsequently, the licensees have withdrawn the PDO as a result of uncertainty related to profitability.

25/2-10 S

Production licence: 442. Operator: Statoil Petroleum AS

Resources: Oil: 10.0 million Sm^3. Gas: 2.0 billion Sm^3

Well 25/2-10 S was drilled on the Frigg Gamma structure, where oil/gas was discovered in 1986. The discovery is located about 20 kilometres east of the Frigg field. The water depth in the area is about 120 metres. The reservoir contains oil and gas in sandstones of the Eocene Frigg Formation and lies at a depth of about 1 900 metres. The resources also include the Frigg Delta structure, where well 25/2-17 was drilled in 2009, resulting in an oil discovery in the same reservoir.

25/11-16 Svalin

Production licence: 169. Operator: Statoil Petroleum AS

Resources: Oil: 12.2 million Sm^3

25/11-16 Svalin was discovered in 1992, 8 kilometres southwest of the Grane field, and includes the 25/11-25 S discovery made in 2008. The water depth in the area is approximately 120 metres. The wells proved oil and associated gas in Paleocene to Lower Eocene sandstones in the Heimdal and Balder Formations at a depth of approximately 1 750 metres. The sandstones are deposited as sub-marine fans. The 25/11-25 S discovery will be developed by a platform MLT well from the Grane platform, and the 25/11-16 discovery will be developed with a subsea tie-in to Grane. According to plan, a PDO will be submitted to the authorities in 2012, with expected production start in 2014.

30/7-6 Hild

Production licence: 040. 043, Operator: Total E&P Norge AS

Resources: Oil: 5.8 million Sm^3. Gas: 20.0 billion Sm^3. NGL: 0.9 million tonnes. Condensate: 3.5 million Sm^3

30/7-6 Hild was discovered in 1978 and is located near the border to the UK sector, about 42 kilometres west of Oseberg. The water depth is 100 – 120 metres. The reservoir is structurally complex, and contains gas at high temperatures and pressure. There are three reservoirs in Middle Jurassic sandstones in the Brent Group at a depth of 3 700–4 400 metres. Oil has also been proven in a reservoir of Eocene age at approximately 1 750 metres.

A PDO was submitted by the licensees in January 2012. The oil and gas reservoirs will be developed with a fixed production facility. The wells will be drilled by a mobile jack-up rig. Production is expected to start at the end of 2016.

30/11-7

Production licence: 035 B. Operator: Statoil Petroleum AS

Resources: Oil: 0.6 million Sm^3. Gas: 4.3 billion Sm^3

Well 30/11-7 was drilled on the Fulla structure, where a gas/condensate discovery was made in 2009. The discovery is located about 10 kilometres northeast of the Frigg field. The water depth in the area is about 111 metres. The reservoir contains gas and condensate in sandstones of the Middle Jurassic Ness Formation and lies at a depth of about 4 000 metres.

31/2-N-11 H

Production licence: 054. Operator: Statoil Petroleum AS

Resources: Oil: 0.6 million Sm^3

31/2-N-11 H was discovered in 2005 in the northern part of Troll Vest. The reservoir is in Middle Jurassic sandstones in the Brent Group underlying the reservoirs at Troll. The Brent reservoir lies at a depth of approximately 1 900 metres. The oil will be produced by a subsea facility connected to Troll C.

34/8-13 A

Production licence: 120. Operator: Statoil Petroleum AS

Resources: Oil: 1.3 million Sm^3. Gas: 0.4 billion Sm^3

34/8-13 A (Titan) was discovered in 2009 just east of the Visund field, inside the Visund Unit (PL 120), at about 380 metres water depth. A possible development solution for the discovery is being considered. The northern part of Visund is being redeveloped after the subsea facility was closed down in 2006. 34/8-13 A Titan may be developed by a well drilled from the Visund A platform and later by an additional well from the Visund Nord template.

35/2-1

Production licence: 269, 318, 318 C. Operator: Statoil Petroleum AS

Resources: Gas: 19.5 billion Sm^3

35/2-1 (Peon) was discovered in 2005 and is located west of Florø, about 75 kilometres northeast of Snorre and Visund. The water depth is about 380 metres. The reservoir contains methane in unconsolidated sandstones in the Nordland Group of Pleistocene age, and lies at a depth of 580 metres below sea level. The shallow reservoir implies low pressure and well drilling challenges. The licensees drilled an appraisal well in 2009, and are now evaluating possible development concepts.

35/11-13

Production licence: 090 B. Operator: Statoil Petroleum AS

Resources: Oil: 5.0 million Sm^3. Gas: 2.0 billion Sm^3

35/11-13 (Astero) was discovered in 2005, and is located north of the Fram field. The water depth is 360 metres. The reservoir contains oil with a gas cap in Upper Jurassic sandstones at a depth of approximately 3 100 metres. Several development concepts are being evaluated, e.g. subsea templates tied to Troll B or Gjøa.

6406/3-2 Trestakk

Production licence: 091. Operator: Statoil Petroleum AS

Resources: Oil: 7.7 million Sm^3. Gas: 1.9 billion Sm^3. NGL: 0.5 million tonnes

6406/3-2 Trestakk was discovered in 1986 and proved oil. The discovery was delineated by well 6406/3-4 in 1987. The discovery is located in the Norwegian Sea, just south of Åsgard. The water depth is 300 metres. The reservoir consists of Middle Jurassic sandstones of the Garn Formation. The sandstones were deposited in a shallow marine environment and are relatively homogeneous, with calcite cemented intervals. The top of the reservoir lies at a depth of 3 885 metres.

6406/3-8

Production licence: 475 BS. Operator: Wintershall Norge ASA

Resources: Oil: 21.0 million Sm^3. Gas: 1.4 billion Sm^3

6406/3-8 (Maria) was discovered in 2010 and is located on Haltenbanken in the Norwegian Sea. The water depth is 290 – 315 metres. The structure is divided into two parts, Maria South and Maria North. The discovery well was drilled in Maria South, and oil was found in the Middle Jurassic Garn Formation. The depth is 3 700–3 800 meters. An appraisal well will be drilled during the first quarter of 2012 to test the Maria North structure. In 1988, 6406/3-5 was drilled in the middle to lowest part of the structure and was dry with shows.

6406/9-1 Linnorm

Production licence: 255, Operator: A/S Norske Shell

Resources: Gas: 23.7 billion Sm^3. Condensate: 0.6 million Sm^3

Linnorm consists of the 6406/9-1 Linnorm discovery, made in 2005. The discovery is located on Haltenbanken, about 40 kilometres northwest of Draugen and 20 kilometres west of Njord. The discovery was delineated in 2007 by the 6406/9-2 appraisal well. The water depth is about 308 metres. The Linnorm discovery consists of gas with high (about 7 mol %) CO_2 content. The gas was proven in separated, stacked sandstone reservoirs at depths from about 4 500 to about 5 200 metres in the Tilje, Tofte and Ile Formations of Early to Middle Jurassic age. The quality of the sandstone reservoirs in the formations is highly variable. Linnorm will be developed with subsea templates tied to Draugen. The gas from Linnorm will be exported to Nyhamna by pipeline from Draugen to the planned Norwegian Sea Gas Infrastructure (NSGI, gas export pipeline from "Luva"). The operator is expected to submit a PDO to the MPE in 2013, with expected production start in the fourth quarter of 2016.

6407/6-6 Mikkel Sør

Production licence: 312. Operator: Statoil Petroleum AS

Resources: Oil: 0.6 million Sm^3. Gas: 2.2 billion Sm^3. NGL: 0.5 million tonnes

6407/6-6 Mikkel Sør consists of the discoveries 6407/6-6 (Gamma), discovered in 2008, and 6407/6-7 S (Harepus), discovered in 2009. The discoveries are located on Haltenbanken, about 8 kilometres south of the Mikkel field. The water depth at the discovery wells is 226–247metres. The 6406/6-6 well proved gas and condensate in sandstones in the Middle Jurassic Garn and Ile Formations. The reservoirs in the Garn and Ile Formations are present from 2 110 to 2 233 metres. The discovery well 6407/6-7S proved gas and condensate in sandstones in the Upper Jurassic Garn Formation. The reservoir in the Garn Formation is present from 2 777 to 2 811 metres. The most likely development solution is subsea templates tied to the infrastructure on Mikkel, and further transport of the wellstream to Åsgard B for export. The operator is expected to submit a PDO to the MPE in 2013.

6506/9-2 S

Production licence: 433. Operator: Centrica Resources (Norge)

Resources: Oil: 1.7 million Sm^3. Gas: 9.7 billion Sm^3

The 6406/9-2 S (Fogelberg) discovery was made in 2010. The discovery is located on Haltenbanken, about 10 kilometres north of the Smørbukk deposit. The water depth at the discovery well is about 280 metres. The discovery well proved gas and condensate in sandstones in the Garn and Ile Formations of Upper to Middle Jurassic age. The reservoirs in the Garn and Ile Formations are present from about 4 300–4 374 metres. The discovery will be developed with subsea templates tied to existing infrastructure in the area. The operator is expected to submit a PDO to the MPE in 2017, with production start-up in 2020.

6707/10-1

Production licence: 218 Operator: Statoil Petroleum AS

Resources: Gas: 46.3 billion Sm^3. Condensate: 0.8 million Sm^3

6707/10-1 (Luva) was discovered in 1997, and is located about 320 kilometres west of Bodø. The water depth in the area is about 1 270 metres. The reservoir contains gas in Cretaceous sandstones in the Nise Formation at a depth of about 3 000 metres. Two wells drilled nearby in 2008, 6707/10-2 S and 6706/12-1, proved additional gas resources which can be tied to a joint development. In January 2011, the licensees chose a floating field centre, the first Spar in Norway, as the field centre. The size of the discoveries, the water depth and the distance to other fields and to shore were important criteria for the concept selection. The field centre is prepared for use as a future field centre for other discoveries in the area. The development depends on new solutions for gas transportation from the Norwegian Sea. The plan is to transport the gas from "Luva" and discovery 6406/9-1 Linnorm in a new pipeline to Nyhamna (NSGI). Therefore, the development schedules for the discoveries and the new transport system (NSGI project) are co-ordinated. All three projects have decided on concepts. Earliest PDO submission for "Luva" is late 2012. Deep water represents technical challenges, and the project will develop technology that can be useful for future developments in Norway.

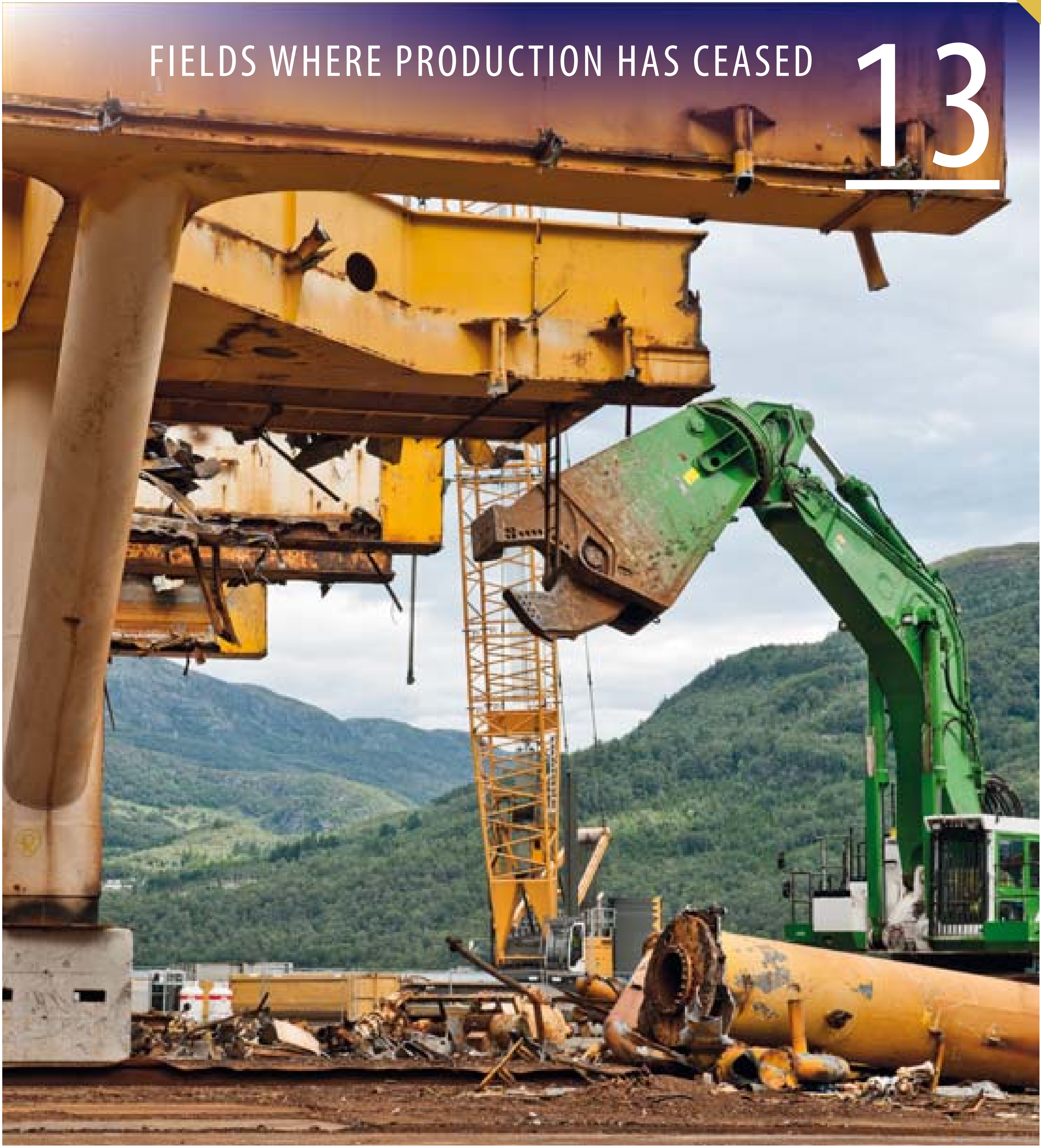
7122/6-1

Produksjonsløyve: 110 B. Operator: Statoil Petroleum AS

Resources: Gas: 3.7 billion Sm^3. Condensate: 0.2 million Sm^3

7122/6-1 (Tornerose) was discovered in 1987, and is situated about 110 kilometres northwest of Hammerfest. The water depth in the area is about 400 metres. The reservoir is from the Late Triassic age. The plan is to develop the discovery with subsea templates tied back to the Snøhvit facility. The development is linked to the start-up of a new process plant (Train 2) on Melkøya.

FIELDS WHERE PRODUCTION HAS CEASED 13



The Norwegian shelf has matured, and the first installations are being removed and scrapped on land. (Photo: Monica Larsen, NPD)

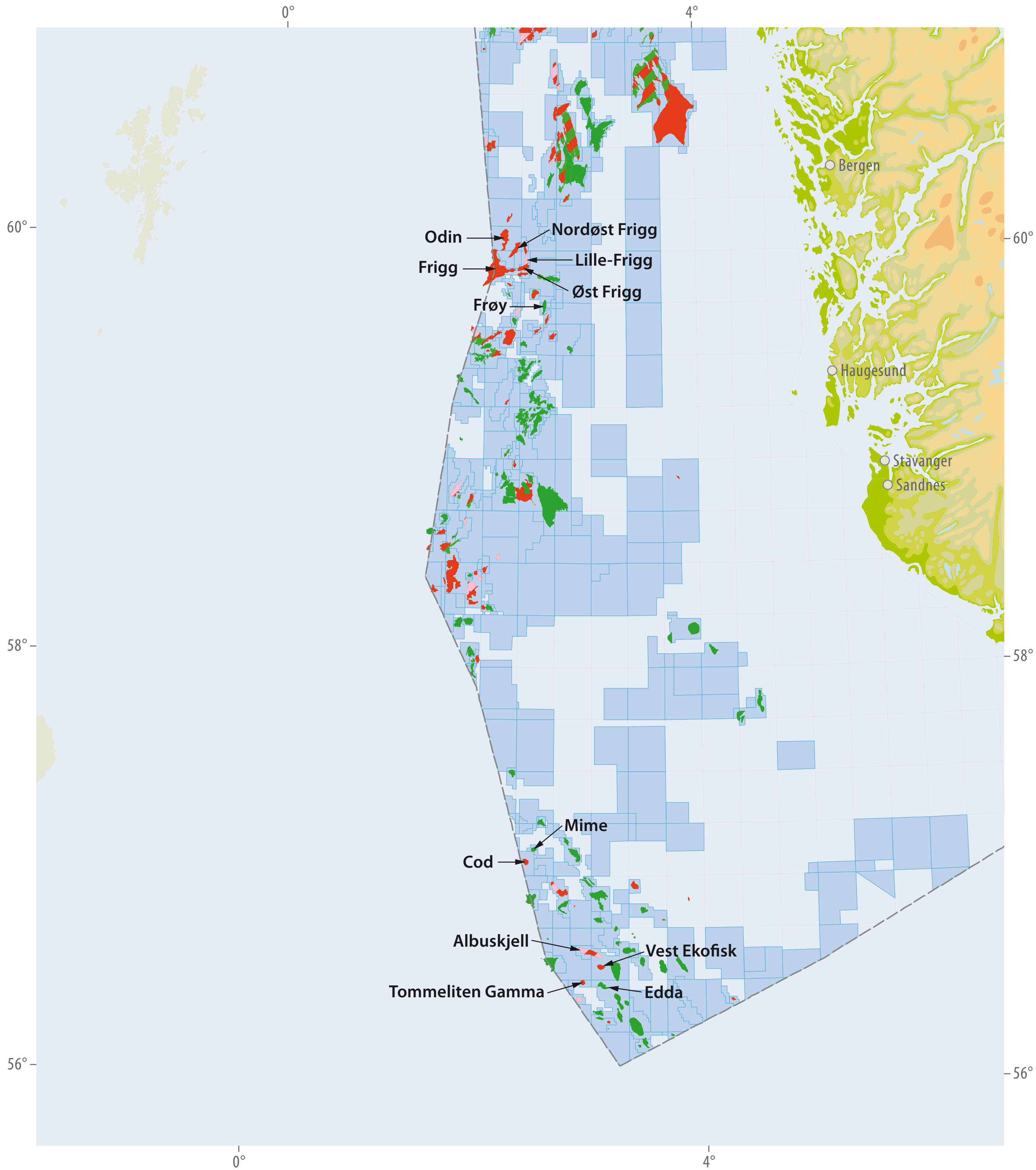


Figure 13.1 Fields where production has ceased *(Source: Norwegian Petroleum Directorate)*

The fields in this summary are not in production as of 31 December 2011. However, there are re-development plans for some of these fields. Yme is being re-developed, see chapter 11; Fields under development. Frøy is also described in chapter 12; Future developments.

Albuskjell	
Block	1/6 and 2/4
Development approval	25.04.1975
Cessation plan/ decommissioning	The cessation plan was approved by Royal Decree 21 December 2001, and in the Storting White Paper No. 47 (1999–2000)
On stream	26.05.1979
Production ceased	26.08.1998
Operator at time of cessation	Phillips Petroleum Company Norway
Total production over field lifetime	Oil: 7.4 million Sm^3, Gas: 15.6 billion Sm^3, NGL: 1.0 million tonnes

Frigg	
Block	25/1
Development approval	13.06.1974
Cessation plan/ decommissioning	The cessation plan was approved by Royal Decree 26 September 2003, and in the Storting White Paper No. 38 (2003–2004)
On stream	13.09.1977
Production ceased	26.10.2004
Operator at time of cessation	Total E&P Norge AS
Total production over field lifetime	Gas: 116.2 billion Sm^3, Condensate: 0.5 million Sm^3

Cod	
Block	7/11
Development approval	04.05.1973
Cessation plan/ decommissioning	The cessation plan was approved by Royal Decree 21 December 2001, and in the Storting White Paper No. 47 (1999–2000)
On stream	26.12.1977
Production ceased	05.08.1998
Operator at time of cessation	Phillips Petroleum Company Norway
Total production over field lifetime	Oil: 2.9 million Sm^3, Gas: 7.3 billion Sm^3, NGL: 0.5 million tonnes

Frøy	
Block	25/2 og 25/5
Development approval	18.05.1992
Cessation plan/ decommissioning	The cessation plan was approved by Royal Decree 29 May 2001, and in the Storting White Paper No. 47 (1999–2000)
On stream	15.05.1995
Production ceased	05.03.2001
Operator at time of cessation	TotalFinaElf Exploration AS
Total production over field lifetime	Oil: 5.6 million Sm^3, Gas: 1.6 billion Sm^3, Condensate: 0.1 million Sm^3

Edda	
Block	2/7
Development approval	25.04.1975
Cessation plan/ decommissioning	The cessation plan was approved by Royal Decree 21 December 2001, and in the Storting White Paper No. 47 (1999–2000)
On stream	02.12.1979
Production ceased	05.08.1998
Operator at time of cessation	Phillips Petroleum Company Norway
Total production over field lifetime	Oil: 4.8 million Sm^3, Gas: 2.0 billion Sm^3, NGL: 0.2 million tonnes

Lille-Frigg	
Block	25/2
Development approval	06.09.1991
Cessation plan/ decommissioning	Storting Proposition No. 53 (1999–2000) and Storting White Paper No. 47 (1999–2000)
On stream	13.05.1994
Production ceased	25.03.1999
Operator at time of cessation	Elf Petroleum Norge AS
Total production over field lifetime	Oil: 1.3 million Sm^3, Gas: 2.2 billion Sm^3

Mime	
Block	7/11
Development approval	06.11.1992
Cessation plan/ decommissioning	Storting Proposition No. 15 (1996–1997) and Storting White Paper No. 47 (1999–2000)
On stream	01.01.1993
Production ceased	04.11.1993
Operator at time of cessation	Norsk Hydro Produksjon AS
Total production over field lifetime	Oil: 0.4 million Sm^3, Gas: 0.1 billion Sm^3

Tommeliten Gamma	
Block	1/9
Development approval	12.06.1986
Cessation plan/ decommissioning	Storting Proposition No. 53 (1999-2000) and Storting White Paper No. 47 (1999–2000)
On stream	03.10.1988
Production ceased	05.08.1998
Operator at time of cessation	Den norske stats oljeselskap a.s.
Total production over field lifetime	Oil: 3.9 million Sm^3, Gas: 9.7 billion Sm^3, NGL: 0.5 million tonnes

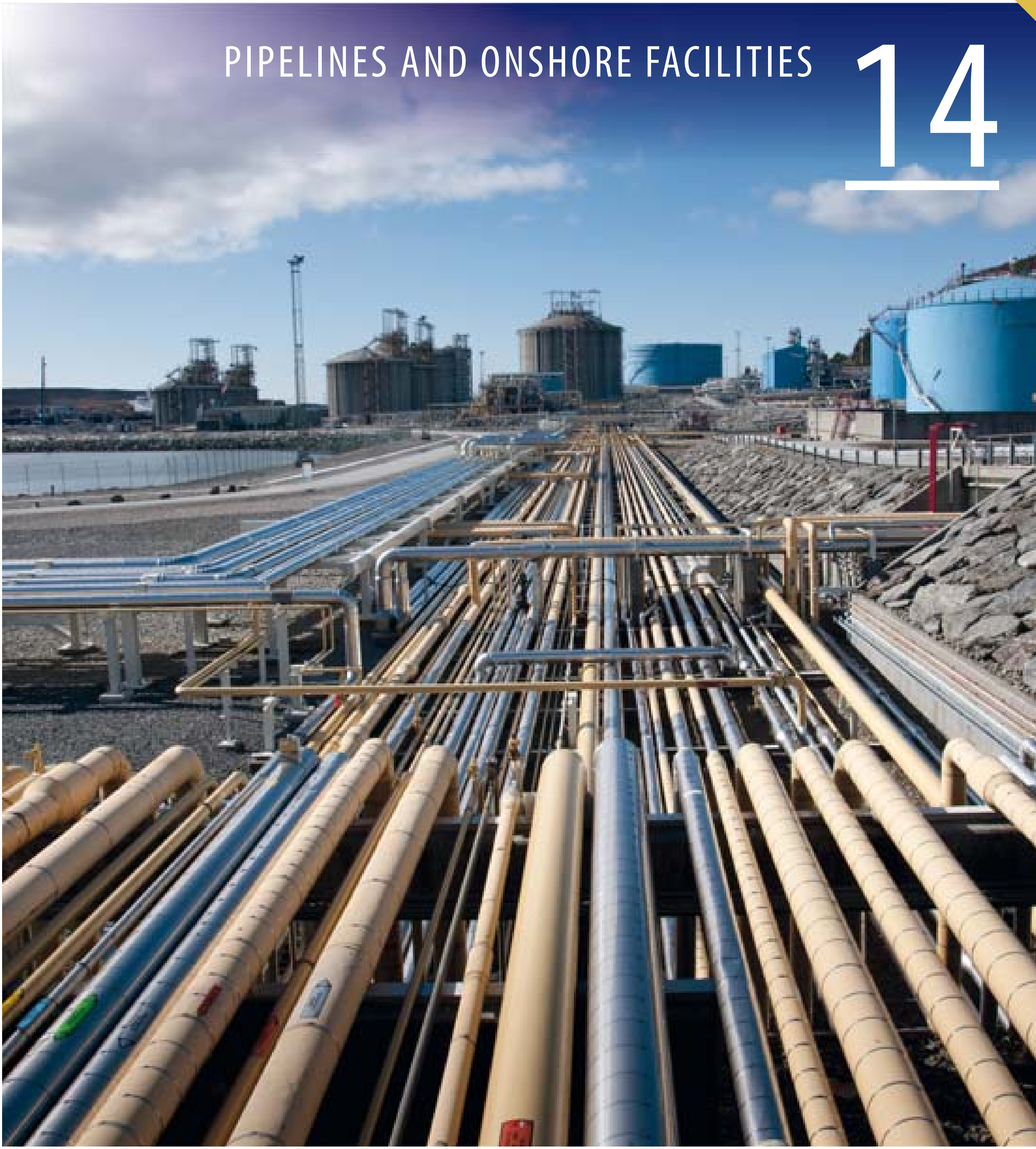
Nordøst Frigg	
Block	25/1 og 30/10
Development approval	12.09.1980
Cessation plan/ decommissioning	Storting Proposition No. 36 (1994–1995)
On stream	01.12.1983
Production ceased	08.05.1993
Operator at time of cessation	Elf Petroleum Norge AS
Total production over field lifetime	Gas: 11.6 billion Sm^3, Condensate: 0.1 million Sm^3

Vest Ekofisk	
Block	2/4
Development approval	04.05.1973
Cessation plan/ decommissioning	The cessation plan was approved by Royal Decree 21 December 2001 and in the Storting White Paper No. 47 (1999–2000)
On stream	31.05.1977
Production ceased	25.08.1998
Operator at time of cessation	Phillips Petroleum Company Norway
Total production over field lifetime	Oil: 12.2 million Sm^3, Gas: 26.0 billion Sm^3, NGL: 1.4 million tonnes

Odin	
Block	30/10
Development approval	18.07.1980
Cessation plan/ decommissioning	Storting Proposition No. 50 (1995–1996) and Storting White Paper No. 47 (1999–2000)
On stream	01.04.1984
Production ceased	01.08.1994
Operator at time of cessation	Esso Exploration and Production Norway A/S
Total production over field lifetime	Gas: 27.3 billion Sm^3, Condensate: 0.2 million Sm^3

Øst Frigg	
Block	25/1 and 25/2
Development approval	14.12.1984
Cessation plan/ decommissioning	Storting Proposition No. 8 (1998–1999) and Storting White Paper No. 47 (1999–2000)
On stream	01.10.1988
Production ceased	22.12.1997
Operator at time of cessation	Elf Petroleum Norge AS
Total production over field lifetime	Gas: 9.2 billion Sm^3, Condensate: 0.1 million Sm^3

PIPELINES AND ONSHORE FACILITIES 14



Gassco's gas treatment facility at Kårstø is a hub for Norwegian gas export. (Photo: Øyvind Hagen, Statoil)

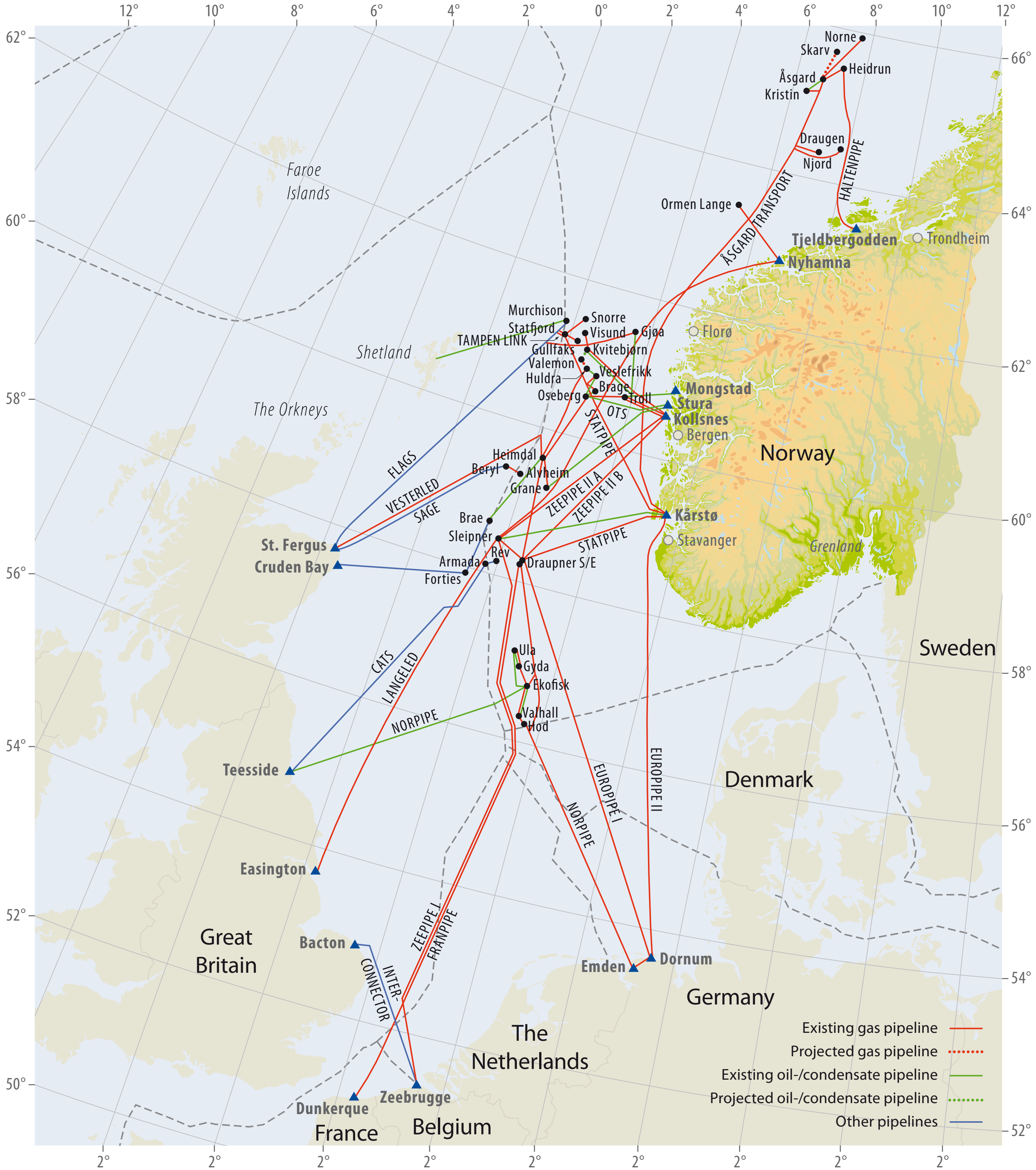


Figure 14.1 Existing and projected pipelines *(Source: The Norwegian Petroleum Directorate)*

Gassled

Gassled is a joint venture for the owners of the gas transport system linked to the Norwegian continental shelf. The gas transport system consists of pipelines, platforms and onshore process facilities and gas terminals abroad. The system is used by all parties needing to transport Norwegian gas. The receiving terminals for Norwegian gas in Germany, Belgium, France and the UK are wholly or partially owned by Gassled. Gassled is organised in different access zones with different tariff levels.

Gassco's role as neutral operator

Gassco's role as a neutral and independent operator of the gas transport system is important for ensuring that all users are treated equally, both as regards utilisation of the transport system and considerations for increasing capacity. This is necessary to ensure efficient utilisation of the resources on the continental shelf. Efficient utilisation of the existing gas transport system can also contribute to reducing or post-poning the need for new investments. Gassco has the operatorship and coordinates and manages the gas streams through the pipeline network to the markets (system operation). In addition, Gassco is responsible for administration of the gas transport capacity (capacity administration) and development of infrastructure.

System operation

System operation entails planning, monitoring, coordination and management of the product streams from the fields, through the transport network to gas terminals abroad. The users of the systems receive an agreed volume and quality of gas in accordance with requirements stipulated in the sales contracts between gas seller and buyer. Another important part of the system operation is coordination of maintenance of pipelines and facilities on the Norwegian continental shelf. The system operation also entails preparing new transportation systems for operation, metering and audits (monitoring volumes for the tax authorities), as well as planning all shipping of the liquid products from the Kårstø process facility.

Capacity administration

Capacity administration consists of allocation and distribution of capacity in the transport system pursuant to regulations and agreements signed between the players. The gas shippers reserve transport capacity in the first-hand market based on a daily need within a time period. These periods can be either several years, one year or one day.

Gassco invoices the shippers for the reserved capacity as part of the capacity administration. The Gassled tariffs are based on tariffs at entry and exit points in the various areas and are stipulated by the Ministry of Petroleum and Energy in the Tariff Regulations. In addition, tariffs are stipulated for processing services. The tariffs contain an element for capital tariff that will provide the investors a reasonable return on the originally invested capital, an element for investments to maintain the system and an operation cost element to cover operating expenses and certain minor investments.

Capacity can also be acquired in the second-hand market. Through the second-hand market, the shippers can sell previously acquired capacity amongst themselves. All sales of transport capacity take place through a website, a virtual marketplace where the companies can bid on each other's available transport capacity.

Facility management

Facility management ensures that current gas transport facilities are continually optimised and modified. In addition, facility management handles construction of new facilities or equipment, if necessary. In connection with establishing Gassco, it was decided that the original players, in certain cases, would continue the day-to-day work of operating the facilities. One of Gassco's important tasks is to check that those that deliver technical services, do so in accordance with current statutes, rules and agreements.

Infrastructure development

Gassco is responsible for developing the infrastructure of the Norwegian gas transport system and must ensure efficient use of the gas transport network. Gassco recommends necessary capacity changes, which may result in further development and investment in infrastructure for transport and processing of gas from the Norwegian shelf. This ensures the consideration for the totality of the development alternatives for the infrastructure and utilisation of economies of scale.

Pipeline system facts

The table below shows gas pipelines and facilities covered by Gassled. The transport capacities are based on standard assumptions for the pressure conditions and energy content of the gas, maintenance days and flexibility in operation.

Pipeline	From – to	Start-up (year)	Capacity (million Sm^3/d)	Dimensions (inches)	Length (km)	Investment cost (billion NOK 2011)
Europipe	Draupner E*–Emden in Germany	1995	45–54	40	620	23.6
Europipe II	Kårstø–Dornum in Germany	1999	74	42	658	10.6
Franpipe	Draupner E*–Dunkerque in France	1998	54	42	840	11.0
Norpipe	Ekofisk–Norsea Gas Terminal in Germany	1977	32–44	36	440	29.3
Oseberg Gas Transport (OGT)	Oseberg–Heimdal*	2000	40	36	109	2.2
Statpipe (rich gas)	Statfjord–Kårstø		24	30	308	
Statpipe (dry gas)	Kårstø–Draupner S*		20	28	228	
Statpipe (dry gas)	Heimdal*–Draupner S*		30	36	155	
Statpipe (dry gas)	Draupner S*–Ekofisk Y		30	36	203	
Statpipe (all pipelines)		1985				50.5
Tampen Link	Statfjord–FLAGS pipeline in the UK	2007	9–25	32	23	2.2
Vesterled	Heimdal*–St. Fergus in Scotland	1978	38	32	360	35.7
Zeepipe	Sleipner*–Draupner S*		55	30	30	
Zeepipe	Sleipner*–Zeebrugge in Belgium	1993	42	40	813	
Zeepipe IIA	Kollsnes–Sleipner*	1996	72	40	299	
Zeepipe IIB	Kollsnes–Draupner E*	1997	71	40	301	
Zeepipe (all pipelines)						26.6
Åsgard Transport	Åsgard–Kårstø	2000	69	42	707	11.6
Langeled (northern pipeline)	Nyhamna–Sleipner*	2007	80	42	627	
Langeled (southern pipeline)	Sleipner*–Easington in England	2006	72	44	543	
Langeled (both pipelines)						18.8
Norne Gas Transport System (NGTS)	Norne–Åsgard Transport	2001	4	16	128	1.3
Kvitebjørn gas pipeline	Kvitebjørn–Kollsnes	2004	27	30	147	1.2
Gjøa gas pipeline	Gjøa–FLAGS in the UK	2010	17	29	131	1.9
Riser facility						

Gassled onshore facilities in Norway

There are two onshore facilities in the Gassled system.

Kollsnes gas treatment facility

The gas treatment plant at Kollsnes is part of Gassled. At Kollsnes, the wellstream is separated into gas and condensate. The gas is dried and compressed before it is shipped to the Continent through two pipelines to Sleipner and Draupner.

Kollsnes also delivers a lesser quantity of gas to the LNG facility at the Kollsnes industrial estate. Following a stabilisation process, the condensate is routed on to the Vestprosess facility at Mongstad. In 2004, the Kollsnes facility was upgraded with an NGL extraction facility for treatment of gas from Kvitebjørn and Visund. After the upgrade, the capacity is 143 million Sm^3 of dry gas per day and 9780 Sm^3 of condensate per day. A new export compressor came on stream in 2006.

Kårstø gas processing and condensate facility

Rich gas and unstabilised condensate arrive at Kårstø. In the process facility, these raw materials are separated into dry gas as well as six different liquid products. In addition to methane, rich gas contains the components ethane, propane, normal butane, methyl propane and naphtha. These are separated and stored for ship transport. The dry gas, which mainly contains methane and ethane, is transported in two pipelines from Kårstø, Europipe II to Germany and Statpipe to Draupner. The Kårstø condensate facility receives unstabilised condensate from Sleipner and stabilises the condensate by extracting the lightest components. Ethane, methyl propane and normal butane are cooled and stored in tanks, while naphtha and condensate are stored in tanks with ambient temperatures. Propane is cooled and stored in large cavern halls. Ships transport these products in liquid form from Kårstø.

The facilities at Kårstø include four extraction and fractionation lines for methane, ethane, propane, butane and naphtha, and one fractionation line for stabilisation of condensate. The condensate facility has a capacity of about 5.5 million tonnes of non-stabilised condensate per year. After the last expansion (Kårstø Expansion Project 2005), the capacity for recovering ethane at Kårstø was increased to 950 000 tonnes per year. At the same time, the gas treatment facility was upgraded to handle 88 million Sm³ of rich gas per day.

Onshore facilities	Location	Capacity gas	Capacity other products
Kollsnes gas treatment facility	Øygarden municipality in Hordaland	143 million Sm³/d dry gas	1.3 million tonnes/year condensate
Kårstø gas processing and condensate facility	Tysvær municipality in Rogaland	77 million Sm³/d dry gas	6.3 million tonnes/year NGL and condensate

Pipelines outside Gassled

Gas pipelines

Pipeline	Operator	From – to	Start-up (year)	Capacity	Dimensions (Inches)	Length (km)	Investment cost (billion NOK 2011)
Draugen Gas Export	AS Norske Shell	Draugen–Åsgard Transport	2000	2 billion Sm³/year	16	78	1.2
Grane Gas Pipeline	Statoil Petroleum AS	Heimdal–Grane	2003	3.6 billion Sm³/year	18	50	0.3
Haltenpipe	Gassco AS	Heidrun–Tjeldbergodden	1996	2 billion Sm³/year	16	250	3.2
Heidrun Gas Export	Statoil Petroleum AS	Heidrun–Åsgard Transport	2001	4 billion Sm³/year	16	37	1.0

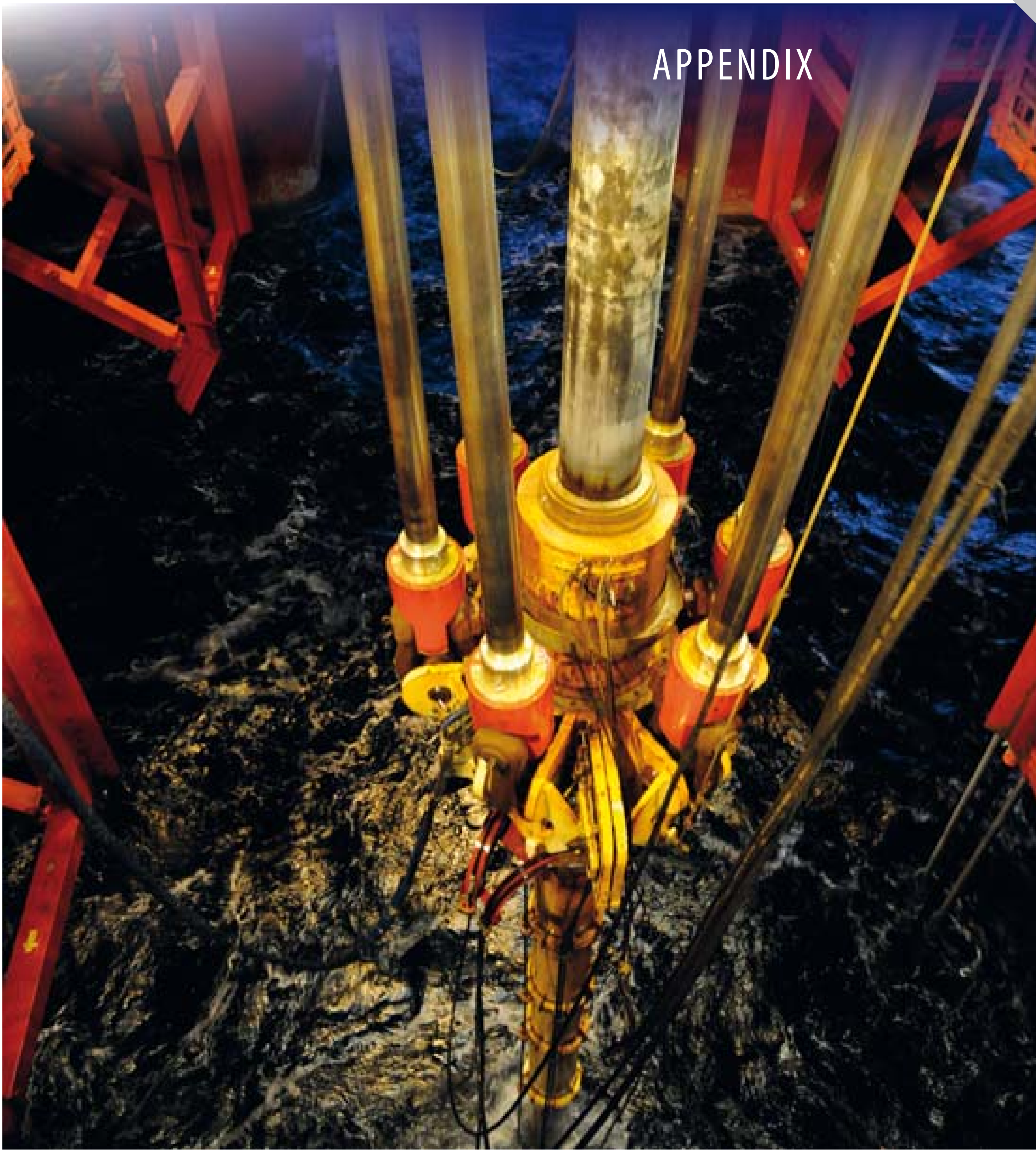
Oil and condensate pipelines

Pipeline	Operator	From – to	Start-up (year)	Capacity	Dimensions (Inches)	Length (km)	Investment cost (billion NOK 2011)
Grane Oil Pipeline	Statoil Petroleum AS	Grane–Sture Terminal	2003	34 000 Sm³/d oil	29	220	1.7
Kvitebjørn Oil Pipeline	Statoil Petroleum AS	Kvitebjørn–Mongstad (connected to the Y-connection on Troll Oil Pipeline II)	2004	10 000 Sm³/d oil	16	90	0.5
Norpipe Oil Pipeline	Norpipe Oil AS	Ekofisk–Teeside in the UK	1975	53 million Sm³/year oil	34	354	18.0
Oseberg Transport System	Statoil Petroleum AS	Oseberg A–Sture Terminalen	1988	121 000 Sm³/d oil	28	115	10.6
Sleipner Øst condensate pipeline	Statoil Petroleum AS	Sleipner A–Kårstø	1993	32 000 Sm³/d oil	20	245	1.7
Troll Oil Pipeline I	Statoil Petroleum AS	Troll B–Mongstad	1995	42 500 Sm³/d oil	16	86	1.3
Troll Oil Pipeline II	Statoil Petroleum AS	Troll C–Mongstad	1999	40 000 Sm³/d oil	20	80	1.2
Huldra condensate	Statoil Petroleum AS	Huldra-Veslefrikk	2001	7900 Sm³/d	8	16	0.4
Gjøa Oil Pipeline	GDF SUEZ E&P Norway AS	Gjøa – TOR (Troll Oil Pipeline) II (Mongstad)	2010	5.4 million Sm³/year oil	16	55 km	

Other onshore facilities

Onshore facility	Location	Description and products
The Mongstad terminal	Hordaland	Three quay facilities for ships up to 400 000 tonnes. 3 mountain caverns totalling 1.5 million m^3 of crude oil. Receives crude oil by ship from e.g. Gullfaks, Statfjord, Draugen, Norne, Åsgard and Heidrun and is the landing terminal for the oil pipelines from Troll B, Troll C, Fram, Kvitebjørn, Gjøa, Vega and Vega Sør.
Nyhamna onshore facility	Aukra municipality in Møre og Romsdal	The process facility for Ormen Lange at Nyhamna is a conventional facility for gas dehydration, compression, gas export, condensate separation/stabilisation/storage as well as fiscal metering of gas and condensate. The facility has a capacity of 70 million Sm^3 of dry gas per day at a receiving pressure of 90 bar.
Melkøya onshore facility	Off Hammerfest in Finnmark County	The untreated wellstream from the Snøhvit field is routed through a 143-kilometre long pipeline to the facility on Melkøya for processing and ship transport. At the onshore facility, condensate, water and CO_2 are separated from the wellstream before the natural gas is cooled to liquid form (LNG) and stored in dedicated tanks. The pipeline has an accessible technical capacity of 7.7 million scm per year. The CO_2 that is separated from the natural gas is returned to the Snøhvit field where it is injected into a separate formation under the oil and gas.
The Sture terminal	Øygarden municipality in Hordaland	The Sture terminal receives oil and condensate through the pipeline from Oseberg A, from the Oseberg, Veslefrikk, Brage, Oseberg Sør, Oseberg Øst, Tune and Huldra fields. The terminal also receives oil from the Grane field through the Grane oil pipeline. The Sture facility includes two quay facilities that can receive oil tankers up to 300 000 tonnes, five crude caverns with a capacity of 1 million scm, an LPG cavern holding 60 000 scm and a ballast water cavern holding 200 000 m^3. A fractionation plant processes unstabilised crude from the Oseberg field into stable crude oil and LPG blends.
Tjeldbergodden	Aure municipality in Nordmøre in Møre og Romsdal	Methanol plant. The gas deliveries through Haltenpipe amount to about 0.7 billion scm per year, which yields 830 000 tonnes of methanol. An air gas plant has been built in connection with the methanol plant. Tjeldbergodden Luftgassfabrikk DA also has a smaller fractionation and LNG facility with a capacity of 35 million scm per year.
Vestprosess	Lindås municipality in Hordaland	The Vestprosess DA company owns and operates a transport system and separation facility for wet gas (NGL). Through a 56-kilometre long pipeline, unstabilised NGL is shipped from the gas terminal at Kollsnes via the oil terminal at Sture and on to Mongstad. At Mongstad, naphtha and LPG are separated first. The naphtha is used as a raw material in the refinery, while the LPG is fractionated in a separate process facility. The fractionation products, propane and butane, are stored in caverns for subsequent export.

APPENDIX



New discoveries give renewed optimism in the Barents Sea. From drilling in January 2012. (Photo: Harald Pettersen, Statoil)

APPENDIX 1
Historical statistics

Table 1.1 Sold and delivered volumes from fields in production and fields where production has ceased

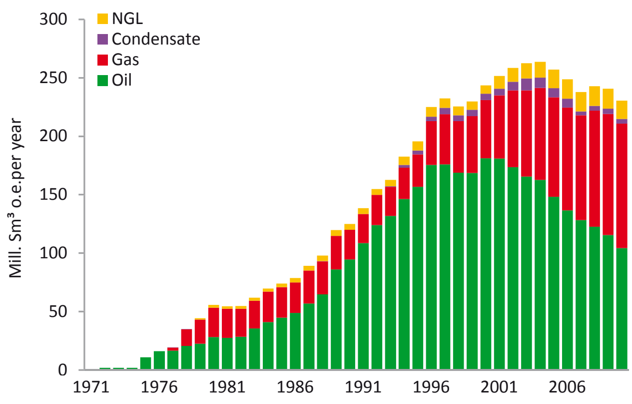
Year	Ordinary tax	Special tax	Production fee	Area fee	Environmental taxes	Net cash flow SDFI	Dividend StatoilHydro
1971			14				
1972			42				
1973			69				
1974			121				
1975			208				
1976	1 143	4	712	99			
1977	1694	725	646	57			
1978	1 828	727	1 213	51			
1979	3 399	1 492	1 608	53			
1980	9 912	4 955	3 639	63			
1981	13 804	8 062	5 308	69			0.057
1982	15 036	9 014	5 757	76			368
1983	14 232	8 870	7 663	75			353
1984	18 333	11 078	9 718	84			795
1985	21 809	13 013	11 626	219		-8 343	709
1986	17 308	9 996	8 172	198		-11 960	1 245
1987	7 137	3 184	7 517	243		-10 711	871
1988	5 129	1 072	5 481	184		-9 133	0
1989	4 832	1 547	7 288	223		755	0
1990	12 366	4 963	8 471	258		7 344	800
1991	15021	6 739	8 940	582	810	5 879	1 500
1992	7 558	7 265	8 129	614	1 916	3 623	1 400
1993	6 411	9 528	7 852	553	2 271	159	1 250
1994	6 238	8 967	6 595	139	2 557	5	1 075
1995	7 854	10 789	5 884	552	2 559	9 259	1 614
1996	9 940	12 890	6 301	1 159	2 787	34 959	1 850
1997	15 489	19 582	6 220	617	3 043	40 404	1 600
1998	9 089	11 001	3 755	527	3 229	14 572	2 940
1999	5 540	6 151	3 222	561	3 261	25 769	135
2000	21 921	32 901	3 463	122	3 047	98 219	1 702
2001	41 465	64 316	2 481	983	2 862	125 439	5 746
2002	32 512	52 410	1 320	447	3 012	74 785	5 045
2003	36 819	60 280	766	460	3 056	67 482	5 133
2004	43 177	70 443	717	496	3 309	80 166	5 222
2005	61 589	103 294	360	224	3 351	98 602	8 139
2006	78 015	133 492	42	2 308	3 405	125 523	12 593
2007	70 281	116 233	0	764	3 876	111 235	14 006
2008	88 802	150 839	0	1 842	3 684	153 759	16 940
2009	61 501	103 733	0	1 470	2 262	95 339	15 489
2010	58 830	96 779		1 373	2 186	104 053	12 818

(Source: Norwegian Public Accounts)

Table 1.2 Petroleum production on the Norwegian continental shelf, millions standard cubic meter oil equivelents

Year	Oil	Gas	Condensate	NGL	Total production
1971	0.4	-	0.0	0.0	0.4
1972	1.9	-	0.0	0.0	1.9
1973	1.9	-	0.0	0.0	1.9
1974	2.0	-	0.0	0.0	2.0
1975	11.0	-	0.0	0.0	11.0
1976	16.2	-	0.0	0.0	16.2
1977	16.6	2.65	0.0	0.0	19.3
1978	20.6	14.20	0.0	0.0	34.9
1979	22.5	20.67	0.0	1.1	44.3
1980	28.2	25.09	0.0	2.4	55.8
1981	27.5	24.95	0.0	2.2	54.7
1982	28.5	23.96	0.0	2.3	54.8
1983	35.6	23.61	0.0	2.7	62.0
1984	41.1	25.96	0.1	2.6	69.8
1985	44.8	26.19	0.1	3.0	74.0
1986	48.8	26.09	0.1	3.8	78.8
1987	57.0	28.15	0.1	4.1	89.3
1988	64.7	28.33	0.0	4.8	97.9
1989	86.0	28.74	0.1	4.9	119.7
1990	94.5	25.48	0.0	5.0	125.1
1991	108.5	25.03	0.1	4.9	138.5
1992	124.0	25.83	0.1	5.0	154.8
1993	131.8	24.80	0.5	5.5	162.6
1994	146.3	26.84	2.4	7.1	182.6
1995	156.8	27.81	3.2	7.9	195.7
1996	175.4	37.41	3.8	8.2	224.9
1997	175.9	42.85	5.4	8.1	232.3
1998	168.7	44.19	5.0	7.4	225.4
1999	168.7	48.48	5.5	7.0	229.7
2000	181.2	49.75	5.4	7.2	243.6
2001	180.9	53.89	5.7	10.9	251.4
2002	173.6	65.50	7.3	11.8	258.3
2003	165.5	73.12	10.3	12.9	261.8
2004	162.8	78.33	8.7	13.6	263.4
2005	148.1	84.96	8.0	15.7	256.8
2006	136.6	87.61	7.6	16.7	248.5
2007	128.3	89.66	3.1	16.6	237.6
2008	122.7	99.33	3.9	16.9	242.8
2009	115.5	103.75	4.4	16.9	240.6
2010	104.4	106.4	4.1	15.5	230.4

(Source: Norwegian Petroleum Directorate)

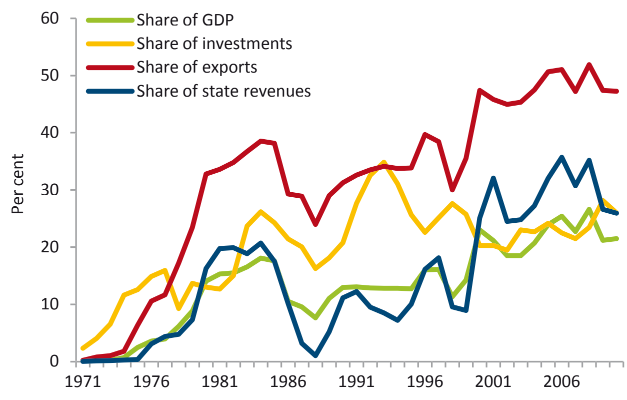


Total petroleum production
(Source: Norwegian Petroleum Directorate)

Table 1.3 Value creation, exports, employment, investments and exploration costs

Year	Gross product (MNOK)	Export value (MNOK)	Numbers of employees	Investment incl. exploration costs (MNOK)	Exploration costs (MNOK)
1971	12	75		704	
1972	207	314	200	1 274	
1973	258	504	300	2 457	
1974	1 056	1 089	1000	5 313	
1975	4 218	3 943	2 400	7 227	
1976	6 896	7 438	3 000	10 421	
1977	8 617	8 852	4 400	12 621	
1978	14 835	15 117	6 900	6 912	
1979	23 494	24 788	8 800	10 792	
1980	44 285	44 638	10 900	11 000	
1981	55 189	52 432	13 700	12 262	4 133
1982	61 891	57 623	14 600	16 148	5 519
1983	73 298	68 082	15 500	28 883	5 884
1984	90 092	82 504	17 700	34 029	7 491
1985	97 347	90 098	19 900	32 730	7 830
1986	59 988	57 239	20 200	33 302	6 654
1987	59 574	58 301	20 100	34 247	4 951
1988	49 966	51 720	21 000	29 522	4 151
1989	76 768	76 681	21 100	31 777	5 008
1990	95 400	92 451	21 600	31 976	5 137
1991	101 346	101 015	22 100	42 634	8 137
1992	102 578	101 187	23 500	49 196	7 680
1993	107 542	108 463	25 200	57 168	5 433
1994	112 623	113 099	25 400	54 189	5 011
1995	120 198	121 169	24 400	47 890	4 647
1996	165 444	167 200	24 800	47 158	5 456
1997	180 594	177 825	27 100	61 774	8 300
1998	129 098	128 807	27 800	78 683	7 577
1999	176 591	173 428	27 600	70 041	4 992
2000	340 640	326 658	26 500	55 406	5 272
2001	325 333	322 291	30 000	56 548	6 815
2002	283 462	283 343	33 000	53 398	4 476
2003	295 356	291 220	32 700	63 597	4 134
2004	361 262	347 926	32 600	71 285	4 010
2005	465 341	439 881	34 600	88 256	7 537
2006	548 837	511 354	36 400	95 477	11 728
2007	516 218	490 930	38 900	108 252	17 929
2008	669 223	635 026	40 300	122 237	24 411
2009	505 008	477 937	42 300	134 399	27 889
2010	537 773	496 358	43 300	126 604	25 493

(Source: Statistics Norway)



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

APPENDIX 2
The petroleum resources
(per 31.12.2011)

Table 2.1 Sold and delivered volumes from fields in production and fields where production has ceased

Field	Oil mill. Sm^3	Gas bill. Sm^3	NGL mill. tonnes	Condensate mill. Sm^3	Oil equiv.[1)] mill Sm^3 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
Sold and delivered from fields where production has ceased	**38.3**	**228.6**	**3.7**	**0.9**	**274.9**	
33/9-6 Delta[3)]	0.1		0.0		0.1	1976
Alve	0.8	2.5	0.4		4.1	1990
Alvheim	15.7	1.5			17.2	1998
Balder	54.0	1.3			55.3	1967
Blane	0.5		0.0		0.5	1989
Brage	54.5	3.1	1.2		59.9	1980
Draugen	129.8	1.5	2.3		135.8	1984
Ekofisk	431.8	140.6	12.8		596.8	1969
Eldfisk	97.9	39.1	3.9		144.3	1970
Embla	10.2	3.7	0.4		14.7	1988
Enoch	0.3	0.0			0.3	1991
Fram	22.3	1.9	0.2		24.6	1992
Gimle	2.5	0.1	0.0		2.6	2004
Gjøa	2.4	2.0	0.4	0.1	5.1	1989
Glitne	8.8				8.8	1995
Grane	81.4				81.4	1991
Gullfaks	351.4	23.1	2.8		379.8	1978
Gullfaks Sør	40.3	30.5	3.8		78.1	1978
Gungne		13.5	1.9	4.2	21.3	1982
Gyda	35.5	6.2	1.9		45.3	1980
Heidrun[5)]	138.8	14.6	0.6		154.4	1985
Heimdal	6.5	45.2			51.8	1972
Hod	9.4	1.6	0.3		11.6	1974
Huldra	5.0	16.3	0.1		21.5	1982
Jotun	22.5	0.9			23.4	1994
Kristin	15.8	17.4	3.6	2.1	42.1	1997
Kvitebjørn	15.0	32.3	2.8		52.6	1994
Mikkel	2.9	14.0	3.7	2.2	26.2	1987
Morvin	2.0				2.0	2001
Murchison	13.8	0.3	0.3	0.0	14.7	1975
Njord	25.2	7.1	1.6		35.4	1986
Norne	86.2	6.4	0.8		94.1	1992

Field	Oil mill. Sm³	Gas bill. Sm³	NGL mill. tonnes	Condensate mill. Sm³	Oil equiv.[1)] mill Sm³ o.e.	Year of discovery[2)]
Ormen lange		76.5		5.9	82.4	1997
Oseberg	358.6	30.3	7.6		403.3	1979
Oseberg Sør	41.6	6.8			48.5	1984
Oseberg Øst	18.3	0.3			18.6	1981
Rev	0.6	2.3	0.0		3.0	2001
Ringhorne Øst	8.2	0.2			8.4	2003
Sigyn		5.8	2.3	5.5	15.7	1982
Skirne	1.7	8.3			9.9	1990
Sleipner Vest og Øst[4)]		173.3	20.5	53.7	266.0	1974
Snorre	181.3	6.3	4.6		196.4	1979
Snøhvit		15.1	0.8	2.8	19.4	1984
Statfjord	564.6	64.7	16.6	0.5	661.4	1974
Statfjord Nord	36.4	2.3	0.8		40.1	1977
Statfjord Øst	35.6	3.8	1.3		42.0	1976
Sygna	9.8				9.8	1996
Tambar	8.7	2.0	0.2		11.1	1983
Tambar Øst	0.2	0.0	0.0		0.3	2007
Tor	23.7	10.8	1.2		36.7	1970
Tordis	55.0	4.2	1.6		62.2	1987
Troll[6)]	220.7	413.5	5.5	4.3	648.9	1979
Trym	0.3	0.5			0.8	1990
Tune	3.4	18.2	0.1		21.8	1996
Tyrihans	10.8	0.7	0.2		11.7	1983
Ula	71.7	3.9	2.6		80.5	1976
Urd	4.7	0.1	0.0		4.9	2000
Vale	1.2	0.9			2.2	1991
Valhall	104.9	20.4	3.3		131.6	1975
Varg	14.4				14.4	1984
Vega	0.6	0.1	0.0	0.0	0.8	1981
Vega Sør	0.0	0.6	0.1	0.0	1.0	1987
Veslefrikk	51.6	2.2	1.2		56.1	1981
Vigdis	49.7	1.5	0.9		52.9	1986
Vilje	5.6	0.3			5.9	2003
Visund	21.7	6.5	0.4		29.0	1986
Volund	2.6	0.3			2.9	1994
Volve	7.0	0.7	0.1	0.1	8.1	1993
Yme	7.9				7.9	1987
Yttergryta	0.3	0.9	0.2		1.5	2007
Åsgard	77.9	111.4	20.1	17.1	244.5	1981
Producing fields	**3684.8**	**1422.4**	**138.0**	**98.7**	**5468.1**	
Total sold and delivered	**3723.1**	**1651.0**	**141.7**	**99.6**	**5743.0**	

1) The conversion factor for NGL tonnes to Sm³ is 1.9.
2) The year the first discovery well was drilled.
3) 33/9-6 Delta has test production.
4) Gas production from Sleipner Vest and Sleipner Øst are metered collectively.
5) Heidrun also includes Tjeldbergodden.
6) Troll also includes TOGI.

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

Field	Original reserves mill. Sm^3 o.e.	Year of discovery[2)]	Operator per 31.12.2011	Production licence/ unit area
Alve	8.5	1990	Statoil Petroleum AS	159 B
Alvheim	45.7	1998	Marathon Oil Norge AS	036C, 088 BS, 203
Atla[1)]	1.7	2010	Total E&P Norge AS	102 C
Balder	72.9	1967	ExxonMobil Exploration & Production Norway AS	001
Blane	0.9	1989	Talisman Energy Norge AS	Blane
Brage	65.6	1980	Statoil Petroleum AS	Brage
Brynhild[1)]	3.2	1992	Lundin Norway AS	148
Draugen	149.6	1984	A/S Norske Shell	093
Ekofisk	743.1	1969	ConocoPhillips Skandinavia AS	018
Eldfisk	186.6	1970	ConocoPhillips Skandinavia AS	018
Embla	18.5	1988	ConocoPhillips Skandinavia AS	018
Enoch	0.4	1991	Talisman North Sea Limited	Enoch
Fram	37.6	1992	Statoil Petroleum AS	090
Gaupe[1)]	5.0	1985	BG Norge AS	292
Gimle	3.6	2004	Statoil Petroleum AS	Gimle
Gjøa	56.4	1989	GDF SUEZ E&P Norge AS	153
Glitne	9.2	1995	Statoil Petroleum AS	048 B
Goliat[1)]	38.5	2000	Eni Norge AS	229
Grane	120.9	1991	Statoil Petroleum AS	Grane
Gudrun[1)]	19.5	1975	Statoil Petroleum AS	025
Gullfaks	393.6	1978	Statoil Petroleum AS	050
Gullfaks Sør	131.8	1978	Statoil Petroleum AS	050
Gungne	23.0	1982	Statoil Petroleum AS	046
Gyda	45.9	1980	Talisman Energy Norge AS	019 B
Heidrun	224.9	1985	Statoil Petroleum AS	Heidrun
Heimdal	55.1	1972	Statoil Petroleum AS	036 BS
Hod	13.0	1974	BP Norge AS	033
Huldra	22.9	1982	Statoil Petroleum AS	Huldra
Hyme[1)]	4.0	2009	Statoil Petroleum AS	348
Islay[1)]	0.1	2008	Total E&P UK PLC	043 CS, 043 DS
Jotun	24.5	1994	ExxonMobil Exploration & Production Norway AS	Jotun
Knarr[1)]	9.3	2008	BG Norge AS	373 S
Kristin	65.0	1997	Statoil Petroleum AS	Haltenbanken Vest
Kvitebjørn	127.8	1994	Statoil Petroleum AS	193
Marulk[1)]	11.8	1992	Eni Norge AS	122
Mikkel	43.4	1987	Statoil Petroleum AS	Mikkel
Morvin	13.6	2001	Statoil Petroleum AS	134 B
Murchison	14.2	1975	CNR International (UK) Limited	Murchison
Njord	50.6	1986	Statoil Petroleum AS	Njord
Norne	106.0	1992	Statoil Petroleum AS	Norne
Ormen Lange	313.2	1997	A/S Norske Shell	Ormen Lange
Oseberg	509.1	1979	Statoil Petroleum AS	Oseberg
Oseberg Sør	74.3	1984	Statoil Petroleum AS	Oseberg
Oseberg Øst	27.8	1981	Statoil Petroleum AS	Oseberg
Oselvar[1)]	8.5	1991	DONG E&P Norge AS	274
Rev	6.3	2001	Talisman Energy Norge AS	038 C
Ringhorne Øst	17.0	2003	ExxonMobil Exploration & Production Norway AS	Ringhorne Øst

Field	Original reserves mill. Sm^3 o.e.	Year of discovery[2)]	Operator per 31.12.2011	Production licence/ unit area
Sigyn	17.8	1982	ExxonMobil Exploration & Production Norway AS	072
Skarv[1)]	69.4	1998	BP Norge AS	SKARV
Skirne	12.3	1990	Total E&P Norge AS	102
Sleipner Vest	177.5	1974	Statoil Petroleum AS	Sleipner Vest
Sleipner Øst	118.1	1981	Statoil Petroleum AS	Sleipner Øst
Snorre	266.8	1979	Statoil Petroleum AS	Snorre
Snøhvit	211.0	1984	Statoil Petroleum AS	Snøhvit
Statfjord	682.8	1974	Statoil Petroleum AS	Statfjord
Statfjord Nord	43.2	1977	Statoil Petroleum AS	037
Statfjord Øst	44.4	1976	Statoil Petroleum AS	Statfjord Øst
Sygna	10.6	1996	Statoil Petroleum AS	Sygna
Tambar	11.0	1983	BP Norge AS	065
Tambar Øst	0.3	2007	BP Norge AS	Tambar Øst
Tor	37.6	1970	ConocoPhillips Skandinavia AS	Tor
Tordis	69.5	1987	Statoil Petroleum AS	089
Troll	1742.6	1983	Statoil Petroleum AS	Troll
Trym	5.8	1990	DONG E&P Norge AS	147
Tune	21.9	1996	Statoil Petroleum AS	190
Tyrihans	88.0	1983	Statoil Petroleum AS	Tyrihans
Ula	101.8	1976	BP Norge AS	019
Urd	6.8	2000	Statoil Petroleum AS	128
Vale	4.7	1991	Statoil Petroleum AS	036
Valemon[1)]	33.5	1985	Statoil Petroleum AS	Valemon
Valhall	184.3	1975	BP Norge AS	Valhall
Varg	15.1	1984	Talisman Energy Norge AS	038
Vega	14.3	1981	Statoil Petroleum AS	248
Vega Sør	9.0	1987	Statoil Petroleum AS	090 C
Veslefrikk	63.5	1981	Statoil Petroleum AS	052
Vigdis	67.5	1986	Statoil Petroleum AS	089
Vilje	11.3	2003	Statoil Petroleum AS	036 D
Visund	94.2	1986	Statoil Petroleum AS	Visund
Visund Sør[1)]	15.6	2008	Statoil Petroleum AS	Visund Inside
Volund	8.9	1994	Marathon Petroleum Norge AS	150
Volve	9.7	1993	Statoil Petroleum AS	046 BS
Yme[1)]	19.9	1987	Talisman Energy Norge AS	316
Yttergryta	3.5	2007	Statoil Petroleum AS	062
Åsgard	394.2	1981	Statoil Petroleum AS	Åsgard

[1)] Fields with approved development plans where production had not started per 31.12.2011.
[2)] The year the first discovery well was drilled.

Table 2.3 Original and remaining reserves in fields

Field	Original reserves[1] Oil mill. Sm³	Gas bill. Sm³	NGL mill. tonnes	Condensate mill. Sm³	Oil equiv. 2) mill Sm³ o.e.	Remaining reserves [4] Oil mill. Sm³	Gas bill. Sm³	NGL mill. tonnes	Condensate mill. Sm³	Oil equiv. [2] mill. Sm³ o.e.
Alve	1.4	5.1	1.1	0.0	8.5	0.6	2.6	0.6	0.0	4.4
Alvheim	38.9	6.8	0.0	0.0	45.7	23.2	5.3	0.0	0.0	28.5
Atla[3]	0.3	1.4	0.0	0.0	1.7	0.3	1.4	0.0	0.0	1.7
Balder	71.3	1.6	0.0	0.0	72.9	17.3	0.3	0.0	0.0	17.6
Blane	0.9	0.0	0.0	0.0	0.9	0.4	0.0	0.0	0.0	0.4
Brage	58.6	4.3	1.5	0.0	65.6	4.1	1.2	0.3	0.0	5.8
Brynhild[3]	3.2	0.0	0.0	0.0	3.2	3.2	0.0	0.0	0.0	3.2
Draugen	143.0	1.5	2.6	0.0	149.6	13.2	0.0	0.3	0.0	13.8
Ekofisk	552.7	162.1	14.9	0.0	743.1	120.9	21.5	2.1	0.0	146.4
Eldfisk	134.8	44.1	4.1	0.0	186.6	36.9	4.9	0.2	0.0	42.3
Embla	11.3	5.9	0.6	0.0	18.5	1.2	2.2	0.2	0.0	3.7
Enoch	0.4	0.0	0.0	0.0	0.4	0.1	0.0	0.0	0.0	0.1
Fram	28.0	8.5	0.5	0.0	37.6	5.7	6.6	0.4	0.0	13.0
Gaupe[3]	1.3	3.3	0.2	0.1	5.0	1.3	3.3	0.2	0.1	5.0
Gimle	2.7	0.7	0.1	0.0	3.6	0.2	0.6	0.1	0.0	1.1
Gjøa	10.3	30.6	8.1	0.0	56.4	7.9	28.7	7.8	0.0	51.3
Glitne	9.2	0.0	0.0	0.0	9.2	0.5	0.0	0.0	0.0	0.5
Goliat[3]	30.6	7.3	0.3	0.0	38.5	30.6	7.3	0.3	0.0	38.5
Grane	120.9	0.0	0.0	0.0	120.9	39.5	0.0	0.0	0.0	39.5
Gudrun[3]	11.2	6.0	1.2	0.0	19.5	11.2	6.0	1.2	0.0	19.5
Gullfaks	365.4	23.1	2.7	0.0	393.6	14.0	0.0	0.0	0.0	14.0
Gullfaks Sør	52.1	64.4	8.0	0.0	131.8	11.8	33.9	4.2	0.0	53.7
Gungne	0.0	14.4	2.1	4.6	23.0	0.0	0.9	0.2	0.3	1.7
Gyda	35.9	6.3	1.9	0.0	45.9	0.3	0.2	0.0	0.0	0.6
Heidrun	177.1	44.0	2.0	0.0	224.9	38.3	29.4	1.5	0.0	70.5
Heimdal	8.2	47.0	0.0	0.0	55.1	1.6	1.7	0.0	0.0	3.4
Hod	10.4	1.8	0.4	0.0	13.0	1.0	0.2	0.1	0.0	1.4
Huldra	5.2	17.5	0.1	0.0	22.9	0.2	1.2	0.0	0.0	1.4
Hyme[3]	3.2	0.5	0.2	0.0	4.0	3.2	0.5	0.2	0.0	4.0
Islay[3]	0.0	0.1	0.0	0.0	0.1	0.0	0.1	0.0	0.0	0.1
Jotun	23.6	0.9	0.0	0.0	24.5	1.0	0.0	0.0	0.0	1.1
Knarr[3]	8.3	0.2	0.4	0.0	9.3	8.3	0.2	0.4	0.0	9.3
Kristin	22.2	28.6	6.4	2.1	65.0	6.4	11.2	2.8	0.0	22.9
Kvitebjørn	26.4	91.8	5.1	0.0	127.8	11.4	59.5	2.2	0.0	75.2
Marulk[3]	0.7	8.4	1.4	0.0	11.8	0.7	8.4	1.4	0.0	11.8
Mikkel	4.6	24.1	6.6	2.3	43.4	1.7	10.1	2.8	0.0	17.2
Morvin	9.2	3.1	0.7	0.0	13.6	7.2	3.1	0.7	0.0	11.6
Murchison	13.9	0.4	0.0	0.0	14.2	0.1	0.0	0.0	0.0	0.1
Njord	28.0	16.2	3.4	0.0	50.6	2.8	9.1	1.7	0.0	15.2
Norne	90.8	11.8	1.8	0.0	106.0	4.6	5.4	1.0	0.0	11.9
Ormen Lange	0.0	297.0	0.0	16.3	313.2	0.0	220.5	0.0	10.3	230.8
Oseberg	381.0	105.4	12.0	0.0	509.1	22.4	75.1	4.4	0.0	105.8
Oseberg Sør	56.9	14.5	1.5	0.0	74.3	15.3	7.7	1.5	0.0	25.8
Oseberg Øst	27.2	0.4	0.1	0.0	27.8	8.9	0.1	0.1	0.0	9.2
Oselvar[3]	4.0	4.4	0.0	0.0	8.5	4.0	4.4	0.0	0.0	8.5
Rev	1.2	4.4	0.3	0.0	6.3	0.5	2.2	0.3	0.0	3.3
Ringhorne Øst	16.6	0.4	0.0	0.0	17.0	8.4	0.2	0.0	0.0	8.6
Sigyn	0.0	7.0	2.9	5.3	17.8	0.0	1.2	0.7	0.0	2.5

Field	Original reserves[1]					Remaining reserves[4]				
	Oil mill. Sm^3	Gas bill. Sm^3	NGL mill. tonnes	Condensate mill. Sm^3	Oil equiv. 2) mill Sm^3 o.e.	Oil mill. Sm^3	Gas bill. Sm^3	NGL mill. tonnes	Condensate mill. Sm^3	Oil equiv. [2] mill. Sm^3 o.e.
Skarv[3]	15.3	43.4	5.7	0.0	69.4	15.3	43.4	5.7	0.0	69.4
Skirne	2.2	10.1	0.0	0.0	12.3	0.5	1.8	0.0	0.0	2.4
Sleipner Vest	0.0	128.7	9.2	31.4	177.5					
Sleipner Øst	0.0	66.3	13.2	26.8	118.1					
Sleipner Vest og Øst[5]						0.0	21.7	1.8	4.4	29.5
Snorre	251.0	6.7	4.8	0.0	266.8	69.7	0.4	0.2	0.0	70.4
Snøhvit	0.0	172.8	8.7	21.8	211.0	0.0	157.6	7.9	19.0	191.6
Statfjord	569.4	75.2	19.8	0.6	682.8	4.8	10.5	3.2	0.1	21.4
Statfjord Nord	39.2	2.0	1.1	0.0	43.2	2.8	0.0	0.3	0.0	3.4
Statfjord Øst	36.6	3.9	2.1	0.0	44.4	0.9	0.1	0.7	0.0	2.4
Sygna	10.6	0.0	0.0	0.0	10.6	0.8	0.0	0.0	0.0	0.8
Tambar	9.0	2.0	0.0	0.0	11.0	0.3	0.1	0.0	0.0	0.3
Tambar Øst	0.3	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.0
Tor	24.4	10.9	1.2	0.0	37.6	0.8	0.1	0.0	0.0	0.9
Tordis	61.5	4.7	1.8	0.0	69.5	6.4	0.4	0.2	0.0	7.3
Troll	255.8	1432.6	27.7	1.6	1742.6	35.1	1019.1	22.2	-2.7	1093.7
Trym	1.3	4.4	0.0	0.0	5.8	1.0	4.0	0.0	0.0	5.0
Tune	3.3	18.2	0.2	0.0	21.9	0.0	0.0	0.0	0.0	0.1
Tyrihans	31.9	37.2	9.9	0.0	88.0	21.1	36.5	9.8	0.0	76.3
Ula	91.4	3.9	3.4	0.0	101.8	19.7	0.0	0.8	0.0	21.3
Urd	6.6	0.1	0.0	0.0	6.8	1.9	0.0	0.0	0.0	1.9
Vale	2.4	2.3	0.0	0.0	4.7	1.2	1.3	0.0	0.0	2.5
Valemon[3]	4.9	26.1	1.3	0.0	33.5	4.9	26.1	1.3	0.0	33.5
Valhall	146.7	27.2	5.5	0.0	184.3	41.8	6.8	2.2	0.0	52.8
Varg	15.1	0.0	0.0	0.0	15.1	0.7	0.0	0.0	0.0	0.7
Vega	2.8	8.2	1.7	0.0	14.3	2.2	8.1	1.7	0.0	13.5
Vega Sør	2.6	4.6	0.9	0.0	9.0	2.6	4.0	0.8	0.0	8.0
Veslefrikk	54.0	5.7	2.0	0.0	63.5	2.4	3.5	0.8	0.0	7.5
Vigdis	63.4	1.9	1.2	0.0	67.5	13.7	0.4	0.3	0.0	14.6
Vilje	11.3	0.0	0.0	0.0	11.3	5.6	0.0	0.0	0.0	5.6
Visund	33.0	49.5	6.2	0.0	94.2	11.3	43.0	5.8	0.0	65.2
Visund Sør[3]	3.7	9.6	1.2	0.0	15.6	3.7	9.6	1.2	0.0	15.6
Volund	7.8	1.0	0.0	0.0	8.9	5.2	0.8	0.0	0.0	6.0
Volve	8.5	0.8	0.2	0.1	9.7	1.5	0.1	0.0	0.0	1.6
Yme[3]	19.9	0.0	0.0	0.0	19.9	12.0	0.0	0.0	0.0	12.0
Yttergryta	0.3	2.4	0.5	0.0	3.5	0.0	1.4	0.3	0.0	2.0
Åsgard	103.8	200.6	38.8	16.1	394.2	25.9	89.3	18.7	-1.1	149.7
Total	**4492.9**	**3490.5**	**263.3**	**128.8**	**8612.5**	**808.3**	**2068.6**	**126.0**	**30.5**	**3146.6**

[1] The table shows expected value, the estimates are subject to uncertainty.
[2] The conversion factor for NGL tonnes to Sm^3 is 1.9.
[3] Fields with approved development plans where production had not started per 31.12.2011.
[4] A negative remaining reserves figure for a field is a result of the product not being reported under original reserves. This applies to produced NGL and condensate.
[5] Gas production from Sleipner Vest and Øst are metered collectively.

Table 2.4 Reserves in discoveries the licensees have decided to develop

Discovery	Oil mill. Sm^3	Gas bill. Sm^3	NGL mill. tonnes	Condensate mill. Sm^3	Oil equiv.[1] mill. Sm^3 o.e.	Year of discovery[2]
25/8-17 Jette	1.6	0.4	0.0	0.0	2.0	2009
33/9-6 Delta	0.1	0.0	0.0	0.0	0.1	1976
6608/10-12 Skuld[3]	13.4	0.9	0.1	0.0	14.6	2008
Total	**15.1**	**1.3**	**0.1**	**0.0**	**16.6**	

[1] The conversion factor for NGL tonnes to Sm^3 is 1.9.
[2] The year the first discovery well was drilled.
[3] 6608/10-12 Skuld has resources in RC 5A and 5F. The volumes are included in contingent resources for discoveries.

Table 2.5 Resources in fields and discoveries in the planning phase

Discovery	Oil mill. Sm^3	Gas bill. Sm^3	NGL mill. tonnes	Condensate mill. Sm^3	Oil equiv.[1] mill. Sm^3 o.e.	Year of discovery[2]
Frøy[3]	8.7	0.0	0.0	0.0	8.7	1987
1/5-2 Flyndre	0.4	0.1	0.0	0.0	0.5	1974
15/3-4	1.9	1.6	0.2	0.0	4.0	1982
15/3-9	0.6	0.3	0.1	0.0	1.0	2010
15/5-1 Dagny	8.6	16.6	2.4	3.0	32.6	1978
15/5-2 Eirin	0.0	10.2	0.1	0.7	11.0	1978
16/1-8	25.6	1.9	0.8	0.0	29.0	2007
16/1-9[4]	17.2	3.6	0.7	0.0	22.2	2008
17/12-1 Bream	7.2	0.0	0.0	0.0	7.2	1972
24/6-1 Peik	0.0	2.5	0.0	0.7	3.1	1985
24/9-9 S Bøyla	3.2	0.3	0.0	0.0	3.4	2009
25/11-16 Svalin[5]	12.2	0.0	0.0	0.0	12.2	1992
25/2-10 S[6]	10.0	2.0	0.0	0.0	12.0	1986
30/11-7	0.6	4.3	0.0	0.0	4.9	2009
30/7-6 Hild[7]	5.8	20.0	0.9	3.5	31.1	1978
31/2-N-11 H	0.6	0.0	0.0	0.0	0.6	2005
34/8-13A[8]	1.3	0.4	0.0	0.0	1.7	2009
35/11-13	5.0	2.0	0.0	0.0	7.0	2005
35/2-1	0.0	19.5	0.0	0.0	19.5	2005
6406/3-2 Trestakk	7.7	1.9	0.5	0.0	10.6	1986
6406/3-8	21.0	1.4	0.0	0.0	22.4	2010
6406/9-1 Linnorm	0.0	23.7	0.0	0.6	24.3	2005
6407/6-6[9] Mikkel Sør	0.6	2.2	0.5	0.0	3.8	2008
6506/9-2 S	1.7	9.7	0.0	0.0	11.4	2010
6707/10-1[10]	0.0	46.3	0.0	0.8	47.1	1997
7122/6-1	0.0	3.7	0.0	0.2	3.9	1987
Total	**131.2**	**174.0**	**6.3**	**9.4**	**326.5**	

[1] The conversion factor for NGL tonnes to Sm^3 is 1.9.
[2] The year the first discovery well was drilled.
[3] The licensees look at a re-development of the field. The volume is included in category 4A for fields.
[4] 16/1-9 includes resources in 16/1-7 and 25/10-8 Hanz.
[5] 25/11-16 Svalin includes resources in 25/11-25 S Svalin - discovery year 2008.
[6] 25/2-10 S includes resources in 25/2-17 - discovery year 2009.
[7] 30/7-6 Hild includes resources in 29/6-1 and 30/7-2.
[8] 34/8-13 A includes resources in 34/8-13 S - discovery year 2009.
[9] 6407/6-6 includes resources in 6407/6-7 S - discovery year 2009.
[10] 6707/10-1 includes resources in 6707/10-2 S and 6706/12-1.

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

Discovery	Oil mill. Sm^3	Gas bill. Sm^3	NGL mill. tonnes	Condensate mill. Sm^3	Oil equiv.[1] mill. Sm^3 o.e.	Year of discovery[2]
1/9-1 Tommeliten Alpha[3]	6.5	14.6	0.5	0.0	22.0	1977
15/12-21	7.7	0.0	0.0	0.0	7.7	2009
15/8-1 Alpha	0.0	2.2	0.5	1.6	4.7	1982
16/2-6	280.0	5.0	0.0	0.0	285.0	2010
16/7-2	0.0	0.6	0.1	0.4	1.2	1982
2/5-3 Sørøst Tor	3.1	0.9	0.0	0.0	3.9	1972
2/4-17 Tjalve	0.6	1.0	0.2	0.0	1.9	1992
2/12-1 Mjølner	3.0	0.8	0.1	0.0	4.0	1987
24/9-10 S	0.9	0.1	0.0	0.0	1.0	2011
25/1-11 R	1.5	0.0	0.0	0.0	1.5	2010
25/2-5 Lille Frøy	3.0	1.6	0.0	0.0	4.6	1976
25/8-4	1.0	0.0	0.0	0.0	1.0	1992
34/10-53 A	0.1	0.4	0.1	0.0	0.6	2011
34/10-53 S	0.3	5.4	0.7	0.0	7.0	2011
34/11-2 S Nøkken	1.8	4.0	0.5	0.0	6.7	1996
35/8-3	0.0	2.7	0.0	0.6	3.2	1988
35/9-6 S	4.2	3.3	0.3	0.0	8.1	2010
6406/2-1 Lavrans	2.7	8.8	1.5	0.0	14.4	1995
6406/2-7 Erlend	2.2	2.9	0.7	0.0	6.4	1999
6407/7-8	0.0	4.9	0.0	0.9	5.8	2008
6407/9-9	0.0	1.6	0.0	0.1	1.7	1999
6506/11-2 Lange	0.5	0.5	0.1	0.0	1.1	1991
6506/12-3 Lysing	1.2	0.2	0.0	0.0	1.4	1985
6506/6-1	0.0	26.8	0.0	0.0	26.8	2000
6507/11-6 Sigrid	0.4	1.9	0.3	0.0	2.9	2001
6507/3-8	0.0	1.4	0.2	0.1	1.9	2009
6507/7-13	0.9	0.0	0.0	0.0	1.0	2001
6507/7-14 S	0.2	10.0	0.1	0.0	10.4	2010
6705/10-1	0.0	17.6	0.0	0.3	17.9	2009
7/8-3	3.8	0.0	0.0	0.0	3.8	1983
7220/8-1 Skrugard[4]	38.4	3.0	0.0	0.0	41.4	2011
Total	**363.9**	**122.1**	**5.8**	**3.9**	**501.0**	

[1] The conversion factor for NGL tonnes to Sm^3 is 1.9.
[2] The year the first discovery well was drilled.
[3] 1/9-1 Tommeliten Alpha has resources in category 5A and 5F.
[4] 7220/8-1 Skrugard has resources in resource category 5F and 7F.

Table 2.7 Resources in discoveries that have not been evaluated

Discovery	Oil mill. Sm³	Gas bill. Sm³	NGL mill. tonnes	Condensate mill. Sm³	Oil equiv.[1] mill. Sm³ o.e.	Year of discovery[2]
15/6-12	0.4	0.1	0.0	0.0	0.5	2011
16/1-12	5.0	0.6	0.0	0.0	5.6	2009
16/1-14	5.3	0.2	0.0	0.0	5.6	2010
16/2-3	2.9	0.4	0.0	0.0	3.3	2007
16/2-4	0.0	1.9	0.0	0.3	2.2	2007
16/2-5	0.0	1.9	0.0	0.2	2.1	2009
16/2-9 S	1.2	0.0	0.0	0.0	1.2	2011
25/4-2	0.8	0.1	0.0	0.0	0.9	1973
30/11-8 A	0.5	2.2	0.0	0.8	3.5	2011
30/11-8 S	5.3	0.8	0.0	0.2	6.2	2011
30/5-3 S	0.0	4.1	0.0	0.4	4.6	2009
34/10-52 A	0.0	0.5	0.0	0.0	0.5	2011
34/10-52 B	0.0	0.1	0.0	0.0	0.2	2011
34/12-1	0.0	11.3	1.4	2.1	16.1	2008
34/3-3 S	3.2	0.0	0.0	0.0	3.2	2011
34/4-10	4.8	0.7	0.0	0.0	5.5	2000
34/4-11	24.0	2.9	0.0	0.0	26.9	2010
34/5-1 S	2.1	0.2	0.0	0.0	2.3	2010
35/10-2	0.0	2.8	0.3	0.5	3.9	1996
35/12-2	8.6	0.0	0.0	0.0	8.7	2009
6407/2-5 S	2.9	1.3	0.0	0.1	4.3	2009
6407/2-6 S	0.0	1.9	0.0	0.5	2.4	2010
6507/3-7	0.0	0.8	0.0	0.0	0.8	2009
6508/1-2	0.3	0.1	0.0	0.0	0.4	2011
6607/12-2 S	2.8	3.6	0.0	0.6	7.0	2011
7120/12-2	0.0	8.0	0.0	0.1	8.1	1981
7120/12-3	0.0	1.8	0.0	0.0	1.8	1983
7120/2-3 S	0.0	5.0	0.0	0.0	5.0	2011
7225/3-1	0.0	28.0	0.0	0.0	28.0	2011
7226/2-1	0.0	3.3	0.0	0.1	3.4	2008
8/10-4 S	6.8	0.7	0.0	0.0	7.5	2011
7/11-12A		2.5			2.5	2011
Total	**76.9**	**88.1**	**1.7**	**6.0**	**174.2**	

[1] The conversion factor for NGL tonnes to Sm³ is 1.9.

[2] The year the first discovery well was drilled.

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 495 active production licences and 495 operatorships. In addition, Gassco AS is the operator for large parts of the gas pipeline network. For more information, please visit the Norwegian Petroleum Directorate's web site: *www.npd.no*

Table 3.1 Operators and licensees per March 2012

Operator/licensee	Operatorship in production licence	Licensee in production licence	Licensee in field
A/S Norske Shell	7	18	4
Bayerngas Norge AS	1	35	5
BG Norge AS	9	13	2
BP Norge AS	11	15	7
Bridge Energy Norge AS	1	17	
Centrica Resources (Norge) AS	8	29	8
Chevron Norge AS	2	6	1
ConocoPhillips Skandinavia AS	10	41	24
DONG E & P Norge AS	9	28	9
Dana Petroleum Norway AS	5	31	3
Det norske oljeselskap ASA	27	70	9
E.ON Ruhrgas Norge AS	10	32	3
Edison International Norway Branch	3	14	
Eni Norge AS	13	51	21
ExxonMobil Exploration and Production Norway AS	10	58	25
Faroe Petroleum Norge AS	4	37	7
Front Exploration AS	1	11	
GDF SUEZ E&P Norge AS	8	41	8
Hess Norge AS	2	6	2
Idemitsu Petroleum Norge AS	3	27	9
Lotos Exploration and Production Norge AS	4	11	1
Lundin Norway AS	28	55	5
Maersk Oil Norway AS	6	19	
Marathon Oil Norge AS	9	16	3
North Energy ASA	2	21	
Norwegian Energy Company ASA	4	33	
OMV (Norge) AS	8	16	
PGNiG Norway AS	1	12	1
Premier Oil Norge AS	6	15	1
RWE Dea Norge AS	6	39	9
Repsol Exploration Norge AS	3	14	
Rocksource ASA	7	18	
Spring Energy Norway AS	3	33	1
Statoil Petroleum AS	182	241	70
Suncor Energy Norge AS	8	16	
Talisman Energy Norge AS	16	90	9
Total E&P Norge AS	22	78	42
Valiant Petroleum Norge AS	1	5	
VNG Norge AS	8	29	3
Wintershall Norge ASA	26	45	4

Other licensees	Operatorship in production licence	Licensee in production licence	Licensee in field
4Sea Energy AS		3	
Agora Oil & Gas AS		6	
Altinex Oil Norway AS		4	2
Concedo ASA		10	
Core Energy AS		6	3
Enterprise Oil Norge AS		5	2
Fortis Petroleum Norway AS		5	
Nexen Exploration Norge AS		1	
Norske AEDC AS		5	3
Petoro AS		158	48
Skagen 44 AS		15	
Skeie Energy AS		5	1
Spring Energy Exploration AS		2	
Svenska Petroleum Exploration AS		14	2
Talisman Petroleum Norge AS		1	1

APPENDIX 4
Conversion factors

Oil equivalents (abbreviated o.e.) is a term used to sum up volumes of oil, gas, NGL and condensate. Such a total can be arrived at by applying a common property, such as energy, mass, volume or sales value. The Norwegian Petroleum Directorate uses a volumetric conversion of NGL to liquid and an energy conversion factor for gas, based on typical properties (*) on the Norwegian continental shelf.

** The properties of oil, gas and NGL vary from field to field and over time, but a common and constant conversion factor is used in the resource accounts for all discoveries and fields.*

1 Sm^3 oil	=	1.0 Sm^3 o.e.
1 Sm^3 condensate	=	1.0 Sm^3 o.e..
1000 Sm^3 gas	=	1.0 Sm^3 o.e.
1 tonne NGL	=	1.9 Sm^3 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 Sm^3	6.29 barrels
	1 Sm^3	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 Sm^3 per year

Approximate energy content

	MJ
1 Sm^3 natural gas	40
1 Sm^3 crude oil	35 500
1 tonne coal equivalent	29 300

Conversion factors for volume

1 Sm^3 crude oil	=	6.29 barrels
1 Sm^3 crude oil	=	0.84 tonnes crude oil
	=	(average for oil from the Norwegian continental shelf)
1 Sm^3 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

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