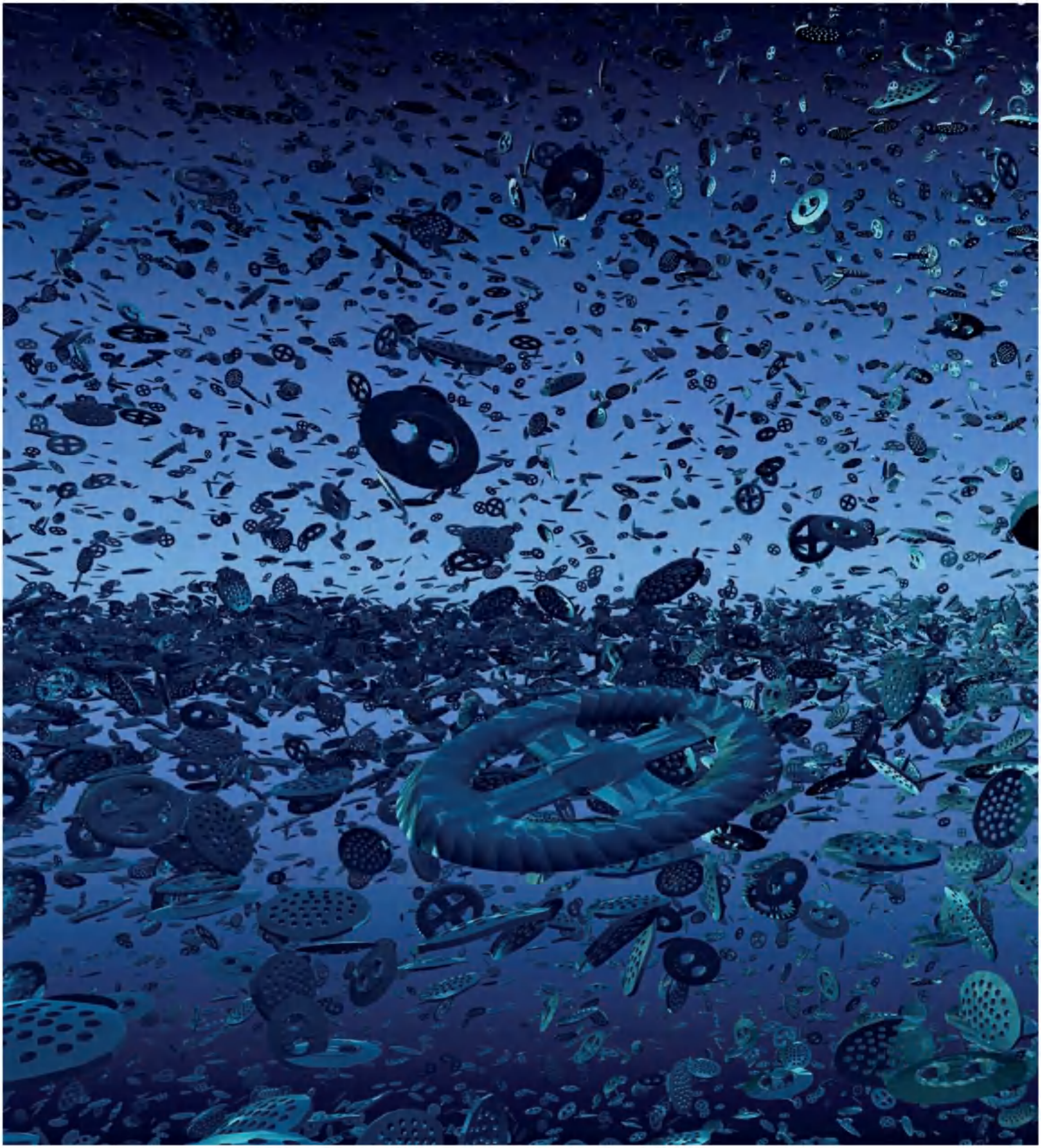
FACTS 2013

THE NORWEGIAN PETROLEUM SECTOR



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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Cover: The Jotun Field in the North Sea.
(Photo: Odd Furenes/ExxonMobil)

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PREFACE

Ola Borten Moe

Minister of Petroleum and Energy

Minister of Petroleum and Energy

The Norwegian petroleum sector is characterised by a high activity level and a strong sense of optimism. Many years with favourable oil and gas prices have presented us with significant opportunities. We have seized these opportunities by taking the first steps towards delivering on the high ambitions presented in the Government White Paper on petroleum activities. These steps include active and parallel efforts on improved recovery from producing fields, development of commercial discoveries, exploration activity in open acreage and the opening of new areas.

Curbing decline in production from existing fields is extremely important for short and medium-term value creation. A broad approach at a sufficiently early stage on the various fields is required. It is positive that significant efforts have been made in this area – but more can be done. As a part of our effort, the Ministry has initiated the establishment of a dedicated research centre for improved recovery. This will contribute to the development of progressive technological solutions which can subsequently be applied by the industry.

We have approved a number of developments in recent years. Most of these are smaller discoveries that will be tied in to existing fields. They have become profitable as a result of standardisation, rapid project implementation and favourable product prices. I hope this positive trend will continue. We have also seen a number of new, standalone developments in the last couple of years. This comes just a few years after predictions by many that the Goliat development would be the last standalone project on the Norwegian shelf. This illustrates just how quckly prospects change.

We are in the process of delivering on our ambitions, yet much still remains. The active, parallel efforts described in the White Paper are just as relevant today. Individual discoveries such as Johan Sverdrup and Skrugard/Havis have not changed this. We need more significant discoveries – fairly quickly – in order to maintain value creation towards 2020 and beyond.

Access to prospective acreage is a precondition for maintaining profitable activity over time, as it takes time to develop a new area. A new area opened today will not yield significant contribution to production until around 2030. That is why we are working diligently on new areas, including the south-eastern Barents Sea.

The Government has laid the foundation for the greatest possible value creation from our petroleum resources. This will benefit the entire Norwegian people. Through continued active long-term policies, we can ensure that this will continue for the foreseeable future. This will be the primary task for the Ministry and for the Norwegian Petroleum Directorate in the years to come.

CONTENT

1 NORWEGIAN PETROLEUM HISTORY

From the jacking up of the Ekofisk platforms in 1987. Here a piece is being put in place to extend one of the legs on the Ekofisk 2/4 hotel facility. (Photo: Husmo, ConocoPhillips/Norwegian Petroleum Museum)

At the end of the 1950s, few people imagined that the Norwegian continental shelf concealed wealth consisting of vast volumes of oil and gas. However, 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 situated 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 than one company was 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, some 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.

The Norwegian oil adventure begun with the discovery of Ekofisk in 1969. Production from the field started on 15. June 1971, and several large discoveries were made during the following years. In the 1970s, the exploration activity was concentrated on 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 production from the Norwegian continental shelf has since been dominated by these large fields, which were given names such as Ekofisk, Statfjord, Oseberg, Gullfaks and Troll. These fields have been, and still are, very important for the development of petroleum activities in Norway. The development of these large fields has also led to the establishment of infrastructure, enabling tie-in of a number of other fields. Production from several of the major fields is now in declinine, and the trend is now development of and production from new, smaller fields. Therefore, Norwegian petroleum production is currently divided among a larger number of 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. The Norwegian involvement increased with the entry of Norsk Hydro, and in 1972, Statoil was established with the State as sole owner. A policy was also established to give the State a mandate for 50 per cent 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, was also established. In 1999, Saga was acquired by Norsk Hydro. Statoil was listed in 2001, something that led to the establishment of Petoro. Petoro took over administration of the State's Direct Financial Interest (SDFI), established in 1985, from Statoil. In 2007, Statoil merged with Norsk Hydro's oil and gas division. 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.

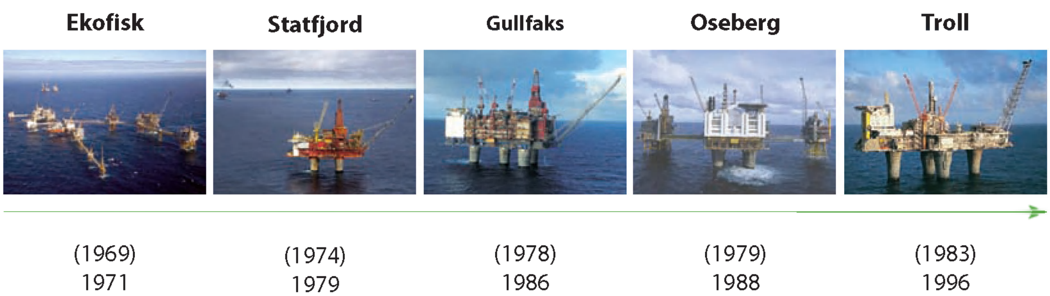


Figure 1.1 Historical timeline. Year of discovery in parenthesis.

Fact box 1.1 What is petroleum?

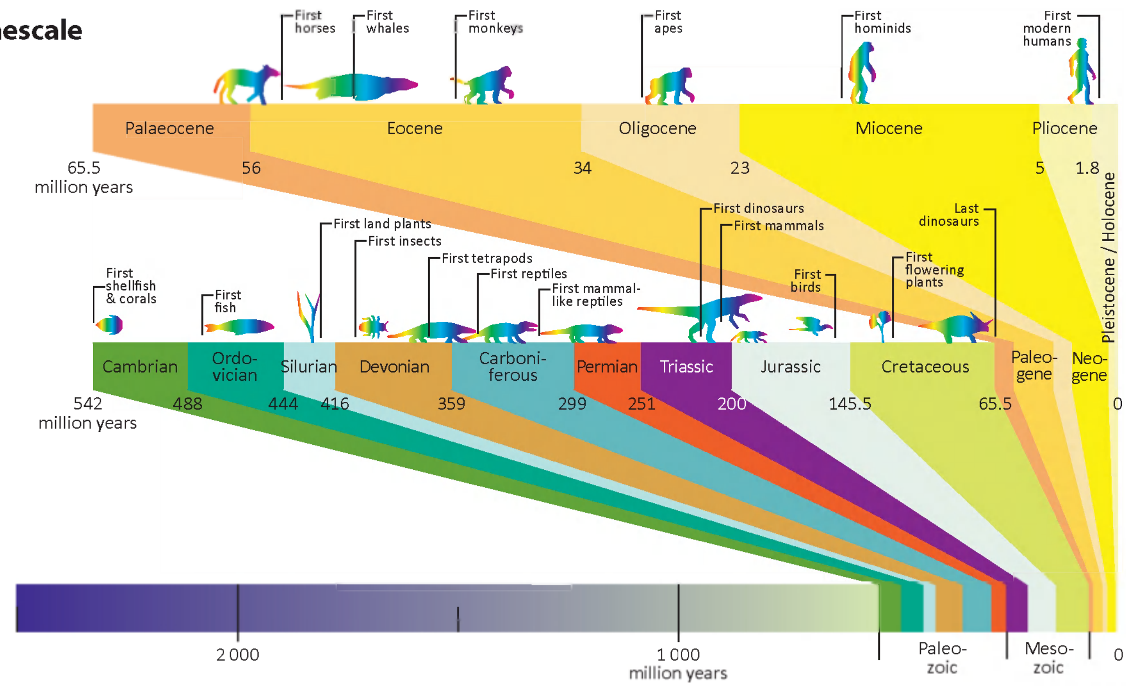
Oil and gas are formed over several million years through decomposition and conversion of organic matter deposited in ocean areas. Most of the oil and gas deposits on the Norwegian continental shelf originate from a thick layer of black clay that is currently located several thousand metres under the 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 stagnant at the same time as the upper water masses were teeming with life. Large amounts of microscopic phytoplankton was 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 Palaeocene Age (the Balder field). In the southern North Sea, thick layers of chalk, consisting of microscopic calcareous algae, constitute an important reservoir rock.

Clay stone and argillaceous sandstone form dense deposits that affect 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 in a so-called trap. When an area contains source rocks, reservoir rocks, cap rocks and a trap, the preconditions are present for discovering oil and gas.

The Geological Timescale



2 FRAMEWORK AND ORGANIZATION

Proper protective equipment is required for work offshore.
(Photo: Odd Furenes, ExxonMobil)

A predictable and transparent framework is a prerequisite for good decisions to be made by the oil companies. The organisation of the activities, as well as how roles and responsibilities are defined, must ensure adequate 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]. Everyone benefits 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 to the Act (Regulations of 27 June 1997 No. 653), licences can be awarded for exploration, 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 the 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 acreage

Before a production licence is awarded for exploration or production, the relevant area 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. Each year, the government announces a certain number of blocks that may be included in applications for production licences. The announcement is made in the Official Journal of Norway (Norsk Lysingsblad), the Official Journal of the European Communities, and on the Norwegian Petroleum Directorate's (NPD's) website. The announcement is governed in more detail by 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 on how to formulate the application, and these are 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.

The production licence

The production licence regulates the rights and obligations of the companies vis-à-vis the Norwegian State. The document supplements the requirements in the Petroleum Act and stipulates detailed terms and 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 is valid for an initial period (exploration period) that can last for up to ten years. During this period, a work commitment programme 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 by Chapter 3 of the Petroleum Act and Chapter 3 of the Petroleum Regulations.

Development and operation

If the companies find that it is commercially viable to develop a field, they are required to carry out prudent development and operation of proven petroleum deposits. This means that the companies are responsible for the development of 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, fisheries, and society in general. The processing of this assessment and the development plan itself, ensures that the projects are prudent in terms of resource management, and that the consequences for other general

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 *See Chapter 6 for more on decommissioning after end of production.*

public interests are acceptable. The impact asessment is compulsory unless the licensee can document that the development is covered by a relevant existing impact asessment. 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 decommissioning plan to the Ministry two to five years before the licence expires or is relinquished, or before the 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 (Oslo Paris Convention for the protection of the marine environment of the North-East Atlantic) also governs disposal of our facilities. Under this Convention, only a small number of 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. This is referred to as strict liability.

Safety

Safety aspects associated with the petroleum activities are governed by Chapters 9 and 10 of the Petroleum Act, with appurtenant regulations. The petroleum activities shall be conducted in a prudent manner to ensure that a high level of HSE can be maintained and developed throughout all phases, in line with the continuous technological and organisational development.

State organisation of the petroleum activities

The Storting (Norwegian Parliament) 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 supervises the Government and public administration.

The Government exercises executive authority over the petroleum policy, and answers to the Storting. 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 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 ownership 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) reports to 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 35 countries. The company is listed on the Oslo and New York stock exchanges. As of 31 December 2012, 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, as well as safety and emergency preparedness in connection with the petroleum activities.

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

THE MINISTRY OF FINANCE
The Ministry of Finance has 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 Directorate of Customs and Excise ensures correct levying and payment of NO_x tax.

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 sound emergency 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 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 basic technical materials 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 returns associated with producing these resources. The petroleum resources belong to the Norwegian society and the State secures a large portion of the value created through taxation and direct ownership through the SDFI.

The petroleum taxation system
The petroleum taxation system is based on the rules for ordinary corporate taxation, but specified in a separate 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, while the special tax rate is 50 per cent. When the basis for ordinary tax and special tax is calculated, 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 for the fact that companies want to implement profitable projects.

Norm price

Petroleum produced 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, norm prices can be stipulated for use when calculating taxable income for the purpose of the tax assessment. The Petroleum Price Council (PPR) sets the norm price. The Council 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 Calculation of petroleum tax
(Source: The Ministry of Petroleum and Energy)

Area fee

The area fee[5] 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 licensees 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 (Sm_3) of gas that is burned or released directly, and per litre of petroleum burned. For 2013, the tax is set at NOK 0.96 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 a NO_x tax from 1 January 2007. For 2013, the tax rate is set at NOK 17.01 per kg NO_x.

5 More about the area fee in fact box 5.2.

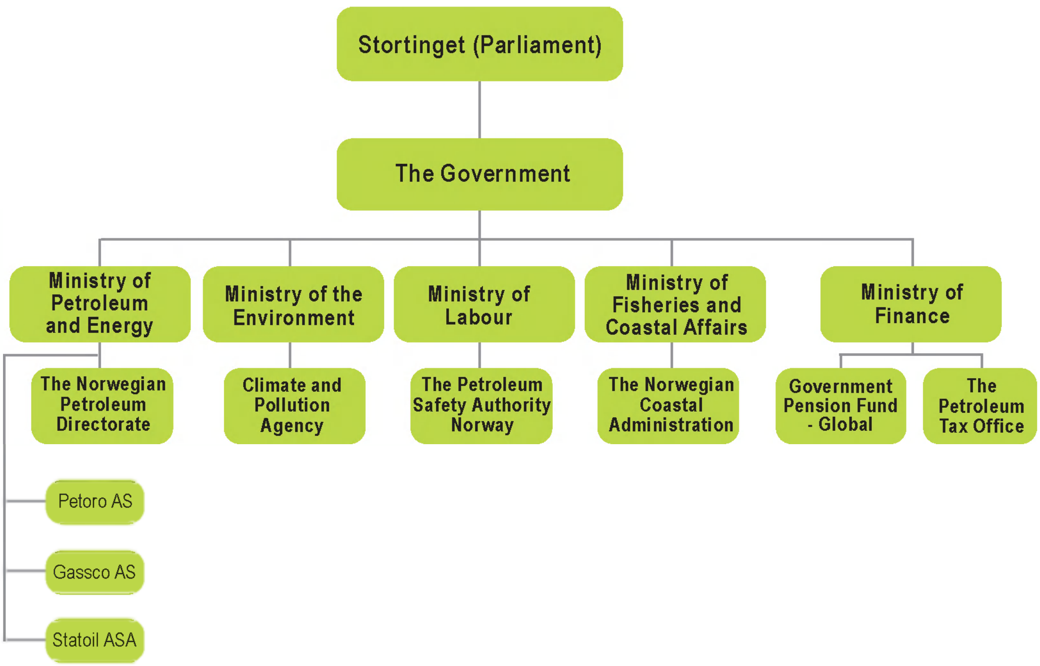


Figure 2.2 State organisation of the petroleum activities *(Source: The National Budget)*

SDFI

The State's direct financial interest (SDFI) is a system in which the State owns a share of many oil and gas fields, pipelines and onshore 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 its share of the investments and costs, and receives a corresponding portion of the income from the production licence. The SDFI was established with effect from 1 January 1985. Until then, the State only had ownership in production licences through the company Statoil, in which the State was the sole owner. In 1985, Statoil's participating interest was split into one direct financial interest for the State (SDFI) and one 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 2013, the State had direct financial interests in 158 production licences, as well as interests in 15 joint ventures in pipelines and onshore facilities.

Dividend from Statoil

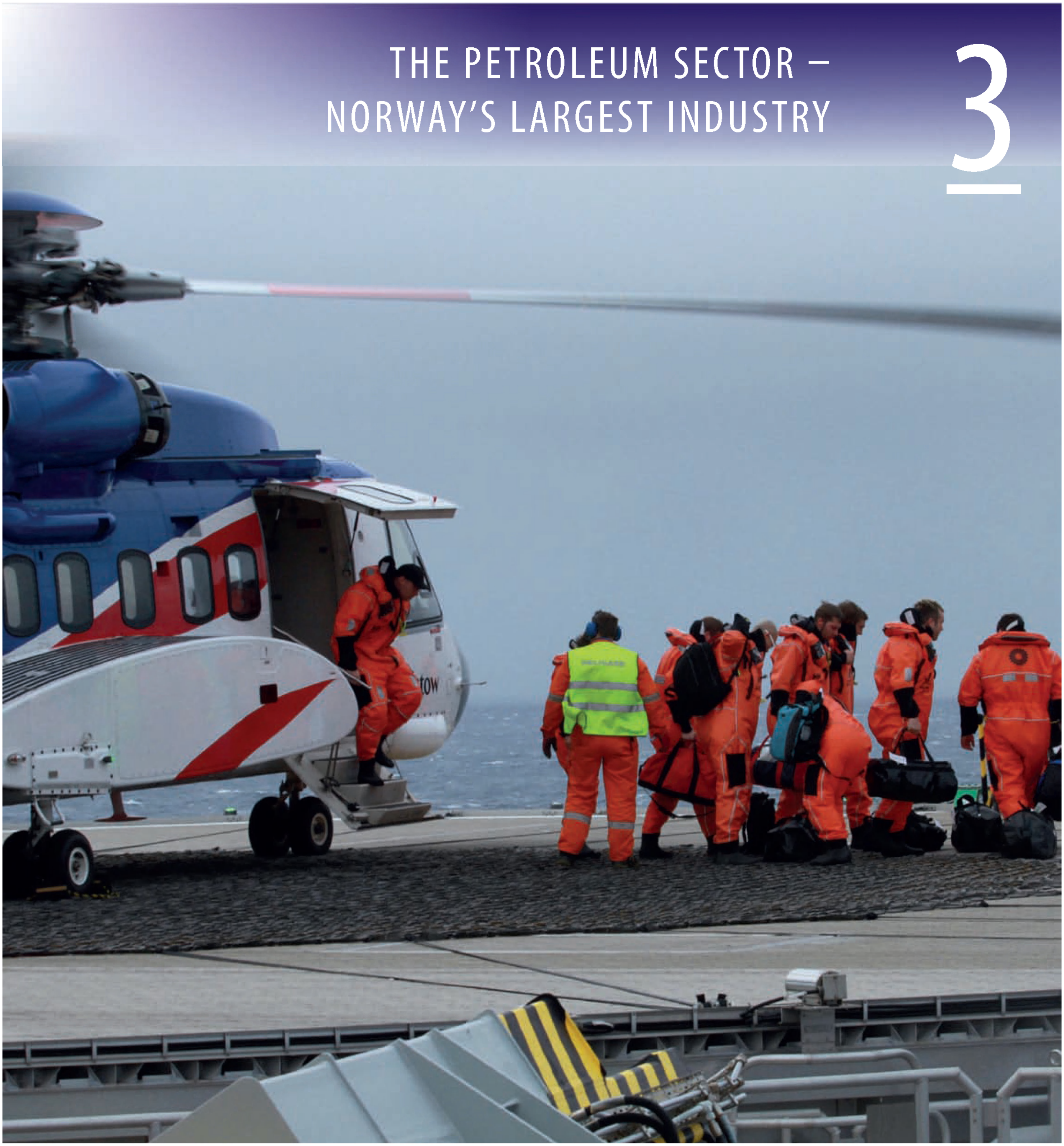
The State owns 67 per cent of the shares in Statoil. As an owner of Statoil, the State receives dividends which are part of the revenues from the petroleum activities. The dividend paid to the Norwegian State in 2012 was NOK 13.88 billion.

EITI

The 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 enable 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 is actively involved 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. 19 other countries have been approved and around 20 other countries are in the process of implementing EITI.

3

THE PETROLEUM SECTOR – NORWAY'S LARGEST INDUSTRY



A milestone was reached for the petroleum industry on the Helgeland coast when the Skarv field came on stream in 2012/2013. A new shift lands at Skarv.
(Photo: Kjetil Alsvik, BP)

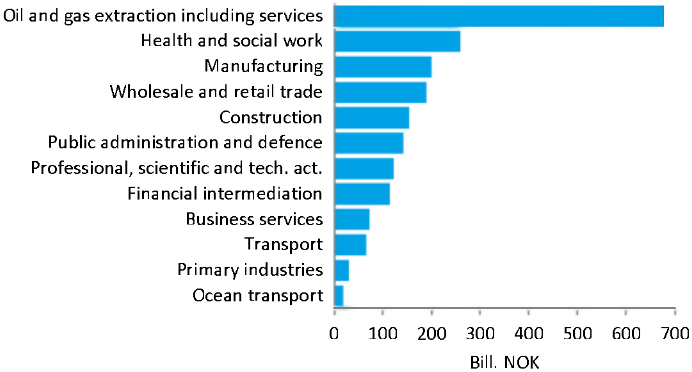


Figure 3.1 Value creation in selected industries 2012 *(Source: National Accounts, Statistics Norway)*

The petroleum activities in 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 2012, the petroleum sector represented more than 23 per cent of the country's total value creation.

Currently, 76 fields are in production on the Norwegian continental shelf. In 2012, these fields produced about 1.9 million barrels of oil (including NGL and condensate) per day, and about 111 billion standard cubic metres (Sm_3) of gas, giving Norway a marketable petroleum production totalling 225.14 million Sm_3 of oil equivalents (o.e.). In 2011, Norway was the seventh largest oil exporter and the fourteenth largest oil producer in the world. In 2011, Norway was the world's third 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 value created by the petroleum activities. The State's income from the sector amounted to about 30 per cent of total State revenue in 2012. Figure 3.4 shows the payments from the industry.

The State's income from the petroleum activities is transferred to a separate fund, the Government Pension Fund – Global. In 2012, transfers to this fund totaled more than NOK 270 billion. At the end of 2012, the fund was valued at NOK 3 816 billion. This corresponds to more than NOK 750 00 for every Norwegian citizen.

In 2012, crude oil, natural gas and pipeline services represented slightly more than half of Norway's export value. The export of petroleum products amounted to more than NOK 600 billion in 2012.

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 2012 amounted to nearly 29 per cent of the country's total fixed capital investments.

The road ahead

Following several years of decline in total petroleum production, it is now expected that production will increase slightly in the coming years, before ebbing off again in a more long-term perspective. The relationship between production of gas and oil, including NGL and condensate, is expected to remain relatively stable in the future. Over the longer term, the number of new discoveries and their size will be decisive for the production level. So far, about 44 per cent of the estimated 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 high in recent years. In 2012, more than NOK 175 billion was invested, including investments related to exploration. The operating costs in 2012 amounted to about NOK 60 billion. Both investments and operating costs are expected to remain high in the years to come. The activity level on the shelf will represent a significant market for the supplier industry for many years.

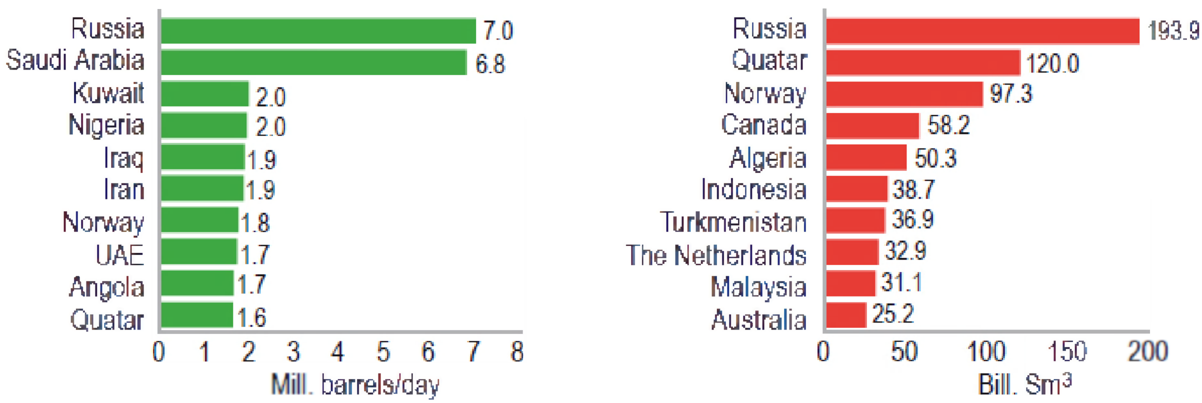


Figure 3.2 The largest oil exporters (oil includes condensate) and gas exporters in 2011 (Updated August 2013) *(Source: KBC Market Services)*

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. After 40 years of production, about 60 per cent of the expected recoverable resources still remain in the ground. This is in addition to resources in Norway's part of the previously disputed area, and the areas around 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. The paper describes a production course that can be made possible through a broad range of efforts on the Norwegian shelf. 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 develop of commercial discoveries.
- Continue active exploration of opened acreage, both in mature and frontier areas.
- Implement the opening processes for Jan Mayen and Norway's part of the previously disputed area to the west of the demarcation line in the Barents Sea South.

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 this demand has had on among other things, 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 petroleum industry. For 2009, the estimate was 206 000 jobs. 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 value for society as a whole, as well as provide local and regional ripple effects.

When developing discoveries, it is important to find good socioeconomic development- and operation solutions. The experiences from developments such as Skarv, Ormen Lange, Snøhvit and Goliat show that new, major developments provide ripple effects locally and regionally regardless of development solution. One important condition for achieving good ripple effects is that local and regional industry and commerce are able 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 to the Norwegian shelf and to international markets. The industry is active within exploration activity, 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 offshore industry increased its turnover from 248 to 361 billion NOK from 2009 to 2011. This constitutes a

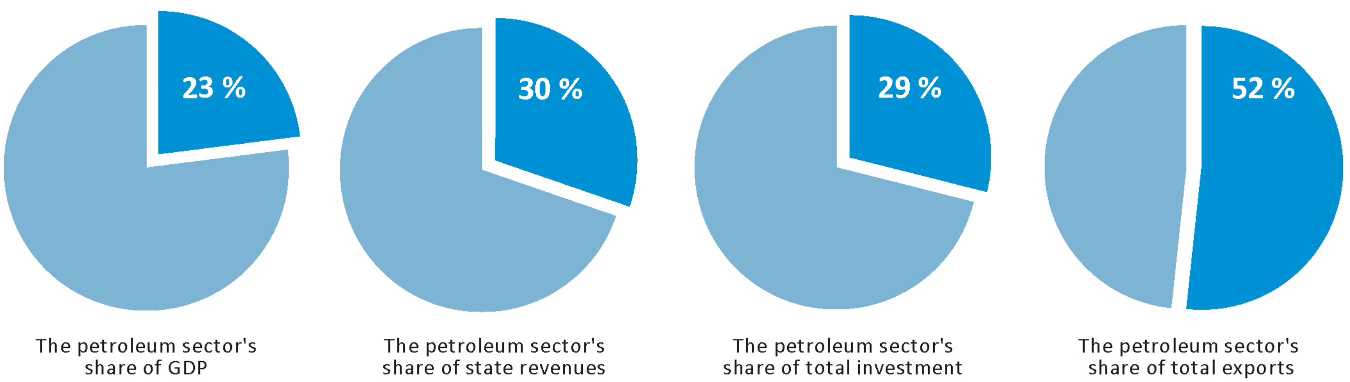


Figure 3.3 Macroeconomic indicators for the petroleum sector 2012
(Source: Statistics Norway, Ministry of Finance)

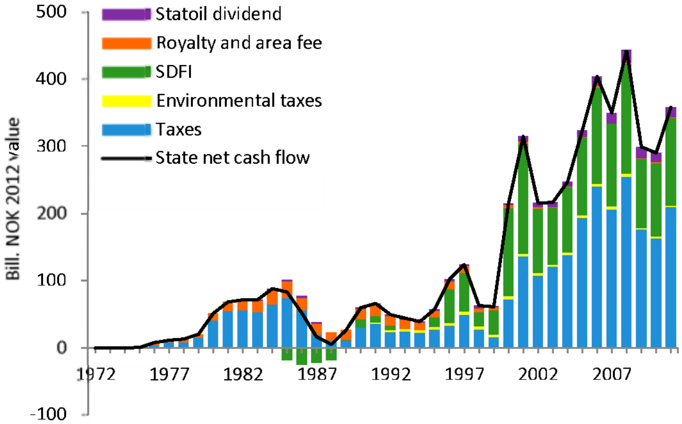


Figure 3.4 Net cash flow to the State from the petroleum activities *(Source: State Accounts)*

Direct taxes	214.7
Environmental taxes, area fee and other	3.8
SDFI	122.7
Statoil dividend	13.9
Total:	**355.1**

Figure 3.5 Net cash flow to the State from the petroleum activities 2011 (billion NOK) *(Source: Norwegian Public Accounts)*

growth of about 48 per cent. The petroleum industry also provides a strong impetus to innovation and technological development within other Norwegian industries.

A 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 oil companies on the shelf, the supplier industry and the research environments has yielded good results.

Figures from Rystad Energy indicate that in 2011, Norwegian petroleum-related companies had sales totalling NOK 152 billion abroad, compared with NOK 118 billion in 2009.

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

The energy market

Securing access to energy is important to 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 growth and population growth. In the future, the increased demand will mostly come from countries outside the OECD.

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. Oil is also used as a raw material in industry and, to some extent, in combined heat and power production. The demand for oil is rising, particularly in countries

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 State'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 returns, 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

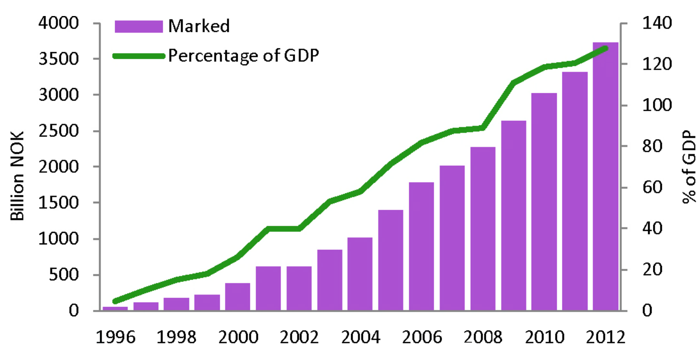


Figure 3.6 Size of the Government Pension Fund - Global as at 31 December 2012 and as part of GDP
(Source: Statistics Norway, the Central Bank of Norway)

such as China, India and countries in the Middle East. The world's largest oil producers are Saudi Arabia, Russia and the USA. 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 the OPEC production cartel. The price of oil is determined by supply and demand in the world market. To a certain degree, OPEC can influence the price by increasing or decreasing supply.

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 global. 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 possibility of recovering unconventional gas has increased the world's gas reserves considerably, and the growth in LNG supply has made gas available in new markets.

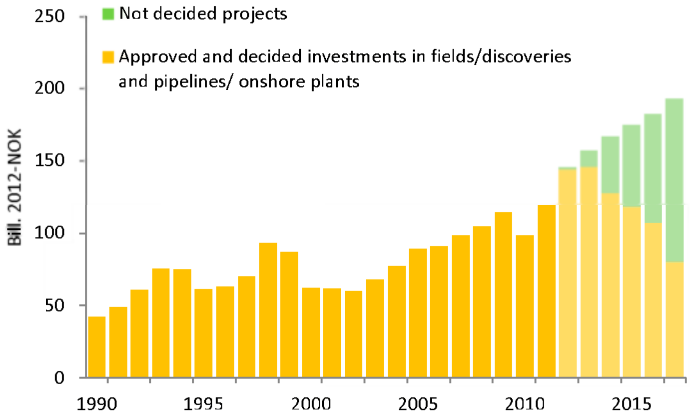


Figure 3.9 Historical investments (excluding investment in exploration) *(Source: The Norwegian Petroleum Directorate/ Ministry of Petroleum and Energy)*

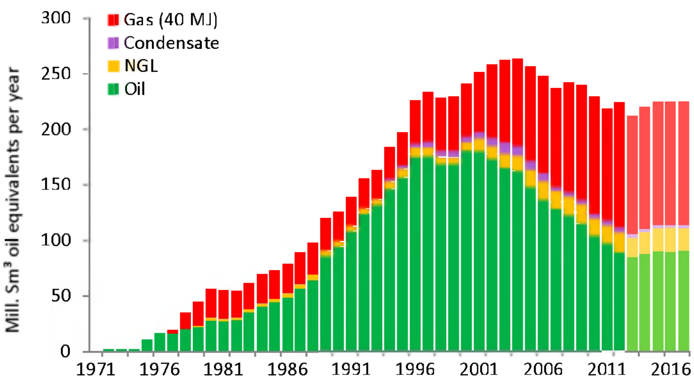


Figure 3.7 Historical production of oil and gas, and prognosis for production in coming years
(Source: The Norwegian Petroleum Directorate)

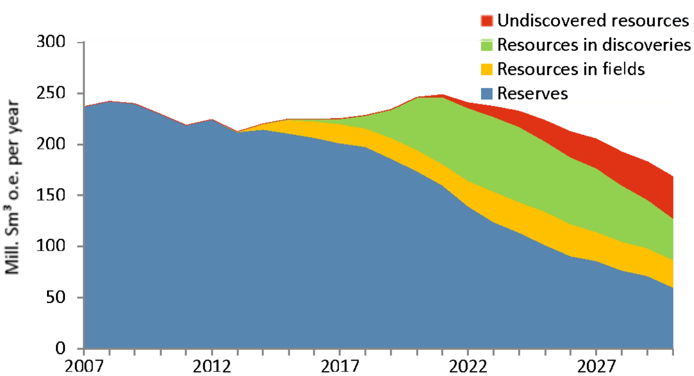
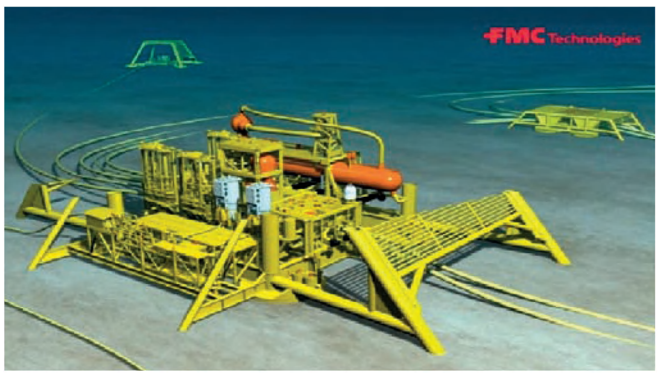


Figure 3.8 Production prognosis for oil and gas *(Source: The Norwegian Petroleum Directorate/Ministry of Petroleum and Energy)*

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 additional 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 in which the Norwegian supplier industry is an international technology leader.



4 PETROLEUM RESOURCES

Pipelaying on the Ekofisk field, the first field on the Norwegian shelf. The field is expected to produce for another 40 years. (Photo: Kjetil Alsvik, ConocoPhillips)

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 approx. 13.6 billion standard cubic metres of oil equivalents (billion Sm^3 o.e.). Of this, a total of 6 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 amount to 7.6 billion Sm^3 o.e. Of this, 5 billion Sm^3 o.e. have been discovered, while the estimate for undiscovered resources is 2.6 billion Sm^3 o.e.

The total growth of discovered resources from exploration activities in 2012 is estimated at 132 million Sm^3 o.e. Thirteen new discoveries were made in 26 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 88 fields. In 2012, production started from the Atla, Gaupe, Islay, Oselvar and Visund Sør fields in the North Sea and from the Marulk field in the Norwegian Sea. Of the fields that were producing at the end of 2012/beginning of 2013, 61 are located in the North Sea, 14 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 show total resources; liquid and gas.

Detailed resource accounts as of 31 December 2012 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 are still processing the plan.

In 2012, the reserve growth was 344 million Sm^3 o.e. At the same time, 226 million Sm^3 o.e. were sold and delivered. The resource accounts show an increase of 118 million Sm^3 o.e. in remaining reserves, which is about four per cent.

As regards the authorities' goal of maturing 800 million Sm^3 of oil to reserves by 2015, 155 million Sm^3 of oil were recorded as new reserves in 2012. During the period from 2005 to 2012, the overall reserve growth totals 607 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), increased by only 1 million Sm^3 o.e. The reason for the low growth is that decisions have been made and resources in fields have matured to reserves, and that some projects on fields are reduced in scope and volume.

The volume of contingent resources in discoveries has decreased by 25 million Sm^3 o.e., to 980 million Sm^3 o.e. The reduction can be explained by factors such as resources maturing to reserves in the 15/5-1 Gina Krog, 16/1-8 Edvard Grieg, 16/1-9 Ivar Aasen, 24/9-9 S Bøyla, 25/11-16 Svalin, 30/7-6 Martin Linge and 6707/10-1 Aasta Hansteen discoveries.

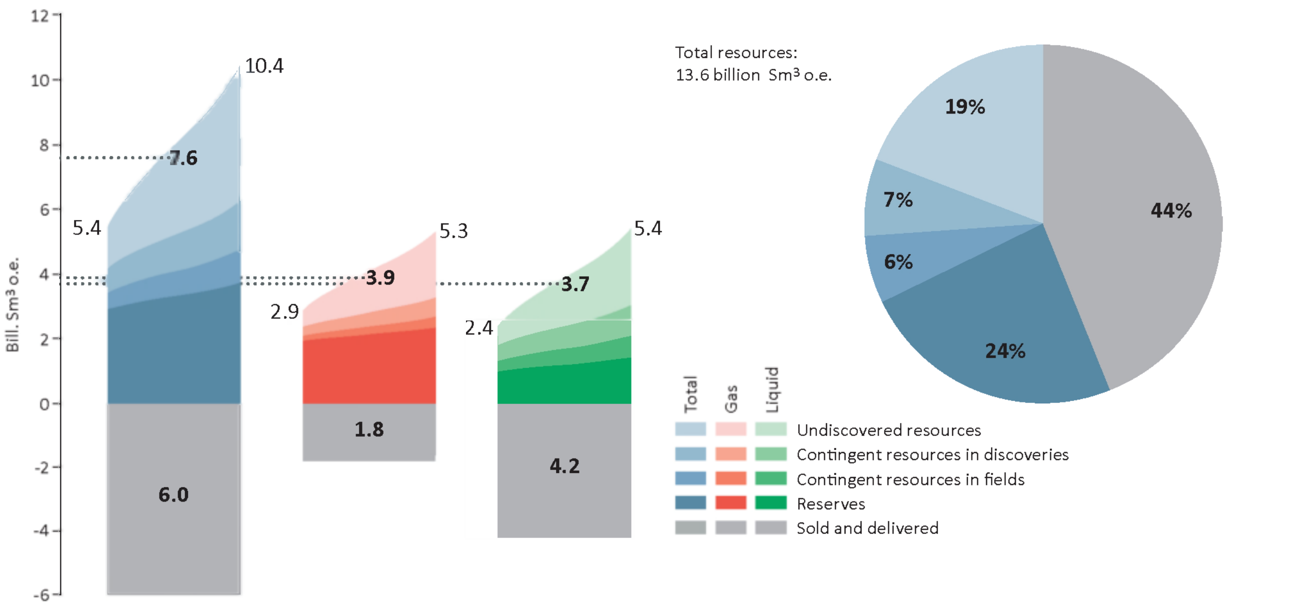


Figure 4.1 Petroleum resources and uncertainty in the estimates per 31.12.2012 *(Source: Norwegian Petroleum Directorate)*

Undiscovered resources

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

A complete update of the resource estimates on the Norwegian continental shelf was carried out in 2012. The volume of undiscovered resources is now estimated at 2 590 million Sm^3 o.e., an increase of 135 million Sm^3 o.e. compared with last year's accounts. This volume does not include volumes from the new areas in the south-eastern Barents Sea and around Jan Mayen. It is believed that there are greater deposits of undiscovered oil, and less gas, on the Norwegian shelf than previously estimated. It is especially the undiscovered oil resources in the North Sea and Barents Sea that are believed to be greater than previously estimated, and gas resources in the North Sea and Barents Sea are adjusted downward. Estimates for the Norwegian Sea have only been marginally adjusted.

The North Sea

Changes in the accounts show that 151 million Sm^3 o.e. have been sold and delivered from the North Sea over the past year. The growth of gross reserves was 244 million Sm^3 o.e. The increase is partly due to the approved PDOs for the 16/1-8 Edvard Grieg, 24/4-9 S Bøyla, 2/11-16 Svalin and 30/7-6 Martin Linge discoveries, and because the licensees submitted a PDO for 15/5-1 Gina Krog and 16/1-9 Ivar Aasen. 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 93 million Sm^3 o.e. Contingent resources in fields were reduced by 37 million Sm^3 o.e., partly because projects on fields were decided and contingent resources therefore matured to reserves, and partly because some projects on fields are reduced in size and volume. Five new discoveries were made in the North Sea in 2012. Contingent resources in discoveries were reduced by 48 million Sm^3 o.e. The reason is that resources in the 15/5-1 Gina Krog, 16/1-8 Edvard Grieg, 16/1-6 Ivar Aasen, 24/4-9 S Bøyla, 2/11-16 Svalin and 30/7-6 Martin Linge discoveries matured to reserves.

The Norwegian Sea

Changes in the accounts for what has been sold and delivered from the Norwegian Sea in 2012 totalled 69 million Sm^3 o.e. The growth in gross reserves was 100 million Sm^3 o.e., partly because the PDO for 6707/10-1 Aasta Hansteen was submitted. In addition, gas reserves in several fields in the Norwegian Sea increased. Remaining reserves in the Norwegian Sea have therefore increased by 31 million Sm^3 o.e. Contingent resources in fields increased by 13 million Sm^3 o.e., because new projects to improve recovery on fields were approved. Five new discoveries were made in the Norwegian Sea in 2012. Still, the estimate for contingent resources in discoveries was reduced by 47 million Sm^3 o.e. compared with last year's accounts. This is partly due to resources maturing to reserves for 6707/10-1 Aasta Hansteen.

The Barents Sea

Changes in the accounts show that 6 million Sm^3 o.e. have been sold and delivered from the Barents Sea in 2012. Increase in gross reserves was minimal. Remaining reserves are therefore reduced by 6 million Sm^3 o.e. Contingent resources in fields have increased by 26 million Sm^3 o.e., partly because two projects for improved recovery on the Snøhvit field have matured further and increased in volume. Three new discoveries were made in the Barents Sea in 2012. Contingent resources in discoveries thus increased by 70 million Sm^3 o.e.

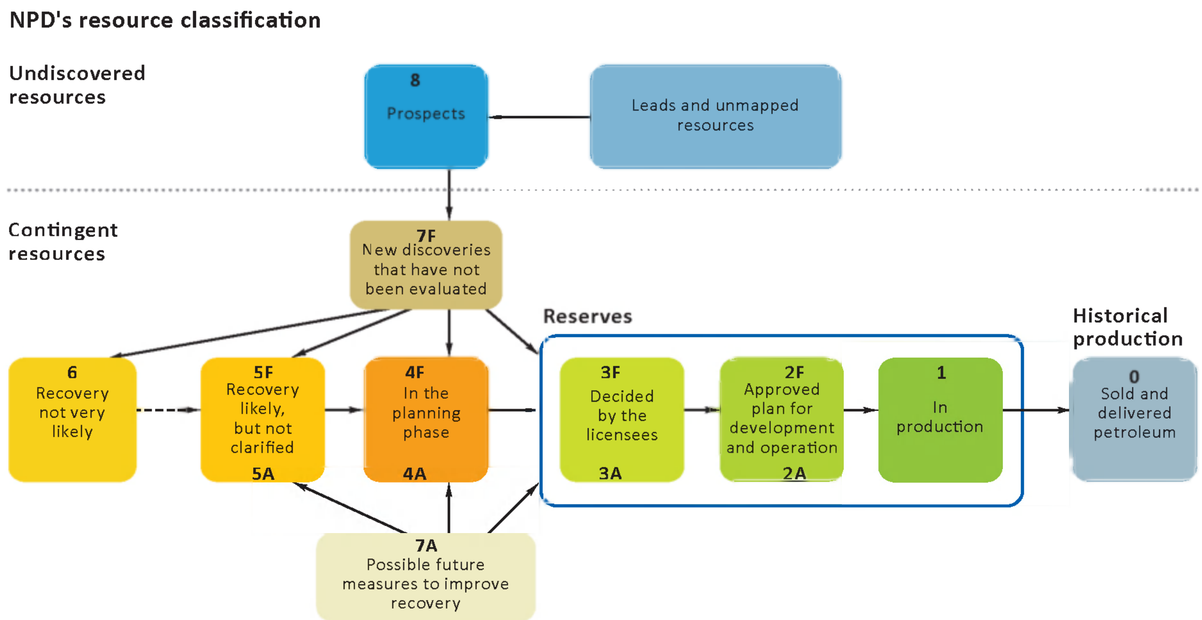


Figure 4.2 The Norwegian Petroleum Directorate's resource classification *(Source: Norwegian Petroleum Directorate)*

Table 4.1 Resource accounts per 31.12.2012

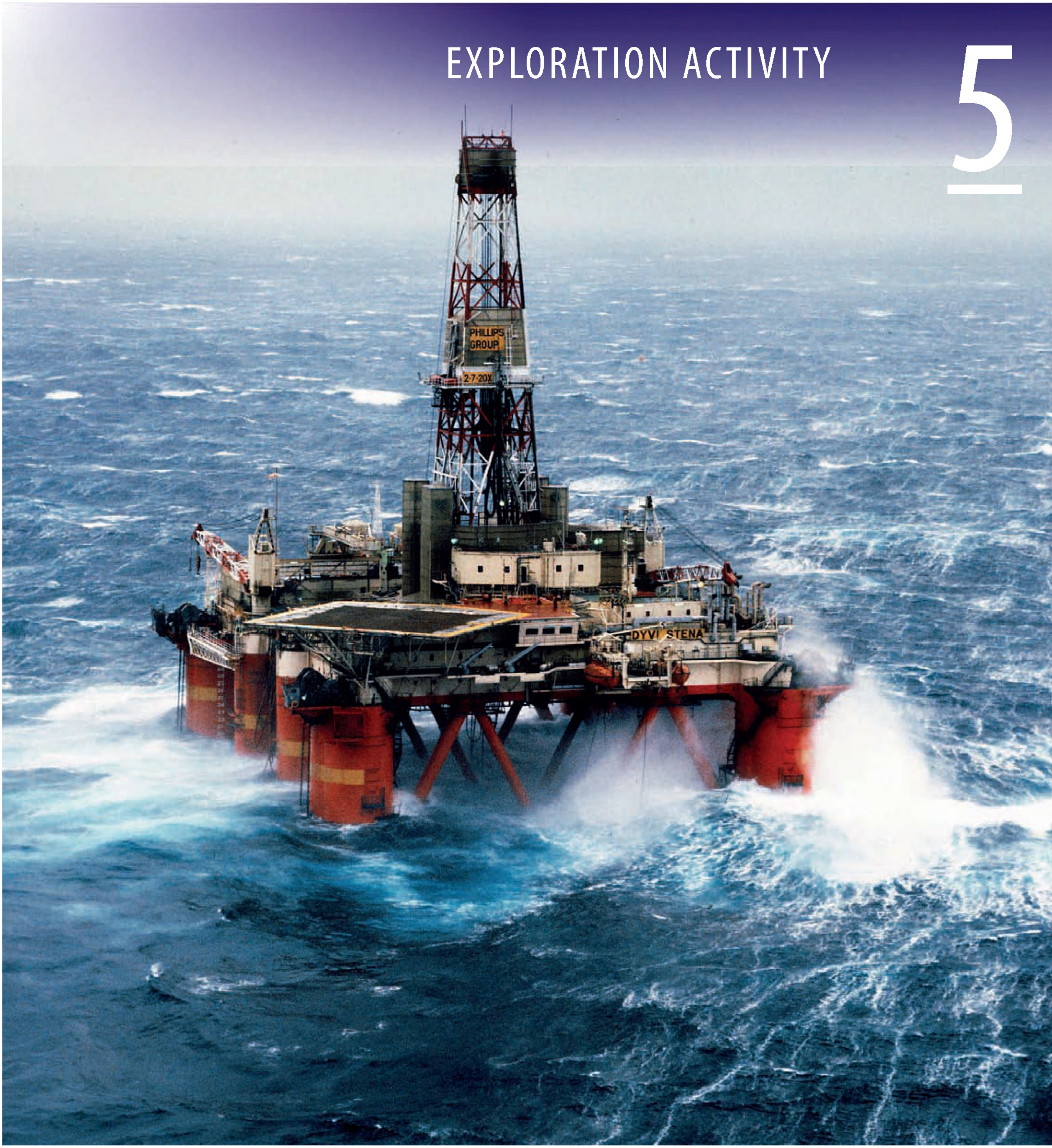
Total recoverable potential	Resource accounts per 31.12.2012					Changes from 2011				
Project status category	Oil mill Sm^3	Gas bill Sm^3	NGL mill tonnes	Cond mill Sm^3	Total mill Sm^3 o.e.	Oil mill Sm^3	Gas bill Sm^3	NGL mill tonnes	Cond mill Sm^3	Total mill Sm^3 o.e.
Produced	3812	1766	151	104	5969	89	115	9	5	226
Remaining reserves*	889	2090	138	37	3279	66	20	13	7	118
Contingent resources in fields	332	203	17	6	574	-24	25	-1	3	1
Contingent resources in discoveries	589	344	14	19	980	15	-42	0	0	-25
Potential from improved recovery**	130	50			180	-10	0			-10
Undiscovered	1295	1190		105	2590	155	-15		-5	135
Total	**7048**	**5643**	**321**	**271**	**13572**	**291**	**103**	**22**	**9**	**445**
North Sea										
Produced	3298	1452	113	72	5036	70	69	5	2	151
Remaining reserves*	712	1415	85	8	2296	76	-17	15	6	93
Contingent resources in fields	292	105	10	1	417	-23	-12	-1	0	-37
Contingent resources in discoveries	457	145	10	14	636	-32	-17	1	-1	-48
Undiscovered	595	235		20	850	75	-35	0	0	40
Total	**5353**	**3353**	**218**	**114**	**9234**	**166**	**-12**	**20**	**7**	**199**
Norwegian Sea										
Produced	514	294	37	29	908	19	41	4	2	69
Remaining reserves*	147	510	48	10	759	-9	38	0	1	31
Contingent resources in fields	40	43	6	0	95	-2	12	1	0	13
Contingent resources in discoveries	46	127	3	3	183	-1	-44	-1	-1	-47
Undiscovered	300	445		35	780	20	-5	0	-5	10
Total	**1048**	**1419**	**94**	**78**	**2724**	**27**	**43**	**4**	**-3**	**75**
Barents Sea										
Produced	0	20	1	4	25	0	5	0	1	6
Remaining reserves*	30	164	6	19	224	0	-1	-2	0	-6
Contingent resources in fields	0	55	1	5	62	0	24	0	2	26
Contingent resources in discoveries	86	72	1	2	162	48	19	1	2	70
Undiscovered	400	510		50	960	60	25	0	0	85
Total	**517**	**821**	**9**	**79**	**1433**	**108**	**73**	**-2**	**5**	**181**

* 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

5

EXPLORATION ACTIVITY



Dyvi Stena drilling on the Ekofisk field.
(Photo: Husmo, ConocoPhillips/Norwegian Petroleum Museum)

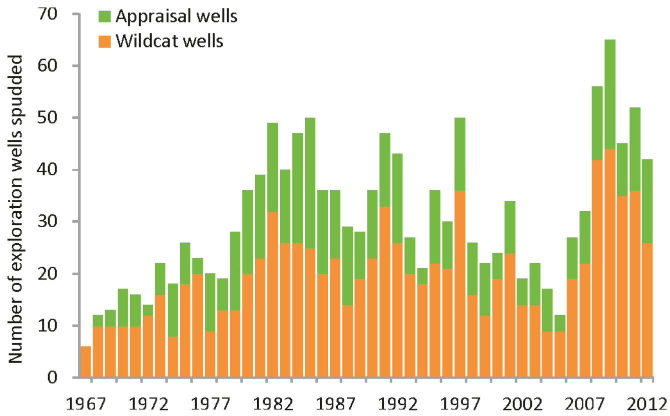


Figure 5.1 Spudded exploration wells on the Norwegian continental shelf 1966-2012 *(Source: The Norwegian Petroleum Directorate)*

In order to produce the petroleum resources found on the Norwegian continental shelf, one must first explore for and prove these resources. The level of exploration activity is an important indicator of future production. It generally takes several years from a decision is made to explore for resources until potential discoveries can come on stream. 10-15 years is not uncommon in frontier areas. The design of exploration policies is therefore an important part of long-term Norwegian resource management. These policies have been designed to make 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 30 per cent in the Norwegian Sea and about 37 per cent in the Barents Sea (see Figure 5.2). The figure does not include Jan Mayen and the southeastern Barents Sea.

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, they 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, and was introduced by the Government in 2003. This system entails the establishment of 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, but never reduced, within the framework set by the management plans, as new areas are matured. A regular, fixed cycle is planned for licensing rounds in mature areas. So far, ten annual rounds have been carried out (APA 2003–2012).

Under both types of licensing rounds, applicants can apply individually or in groups. Impartial, objective, non-discriminatory and pre-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 as 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 NOK 60 000 during the second year. As of the third year, companies pay the maximum rate of NOK 120 000 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. The companies can also apply for an exemption if there is deficient infrastructure in the area, or if extensive work is being carried out in a production licence.

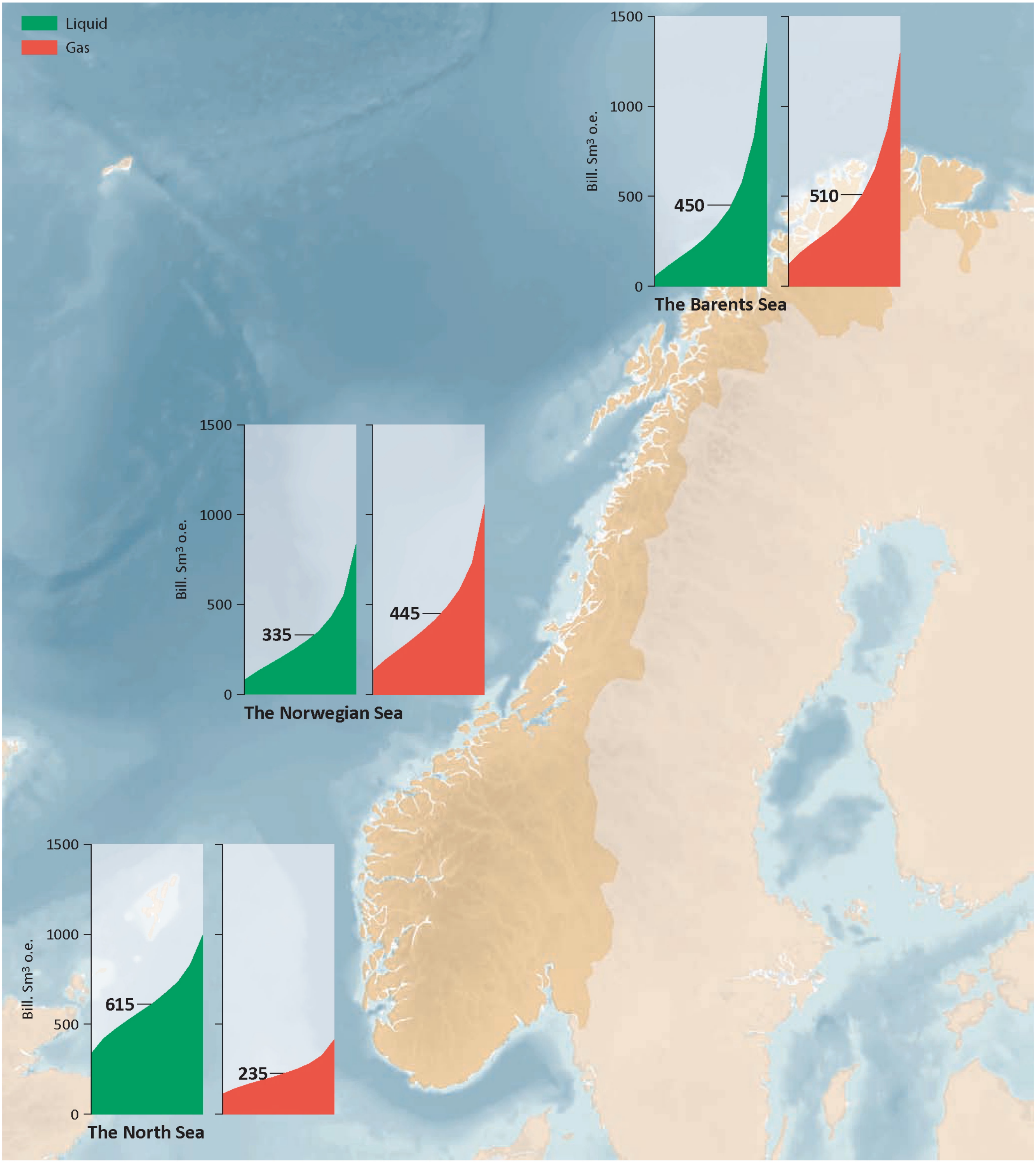


Figure 5.2 Undiscovered resources distributed by area. The figure in each column shows expected recoverable volumes and the uncertainty in the estimate is shown in the sloping line, low estimate on the left, high estimate on the right
(Source: The Norwegian Petroleum Directorate)

Figure 5.3 Area status for the Norwegian continental shelf as at March 2012 *(Source: The 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 north, 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 the Halten Bank and the area around the Ormen Lange field in the Norwegian Sea, as well as the area surrounding Snøhvit and Goliat in the Barents Sea.

Mature areas are characterised by known geology and well-developed or planned infrastructure. It is likely that discoveries will be made, but less likely that these new discoveries will be large. 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 potentially be left behind because the discoveries are too small to justify independent development of infrastructure.

The additional resources from the area surrounding a producing or planned field can also increase the fields' profitability through, for example, a better area solution, and by extending the lifetime of the main fields so more of the present resources can be produced.

In mature areas, the authorities have deemed it important that the industry is given 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. Therefore, the Government introduced the Awards in Pre-defined Areas (APA) scheme in 2003. Figure 5.3 shows the area made available for award in APA 2011.

For the authorities, it is important that an active effort is undertaken in the licensed area. The area covered by the production licence is tailored so that companies are awarded only those areas for which they have tangible plans. Relinquished acreage can be applied for by new companies that may have a different view on its 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 want to explore frontier areas must have broad-based experience, technical and geological expertise, as well as a solid financial foundation.

As of the 18th licensing round, the principles in the changed rules for relinquishing licences in mature areas were also applied to frontier areas. It is not necessary for all companies that have been awarded production licences in frontier areas to submit a development plan at the end of the initial period. 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 and work programmes to be awarded.

The 21th licensing round was awarded in the spring of 2011, covering 24 licences in the Barents Sea and the Norwegian Sea. Ownership interest were offered to 29 oil and gas companies. The plan is to finalise the 22nd licensing round on the shelf during the first half of 2013.

Unopened areas and opening processes

There are still large areas of the Norwegian continental shelf that have not been opened for petroleum activities by the Storting. This applies to all of the northern Barents Sea, the eastern part of the southern Barents Sea, the north-eastern 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 the environmental impact the activities could have for other industries and the surrounding districts.

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

The Integrated Management Plan for the Barents Sea – Lofoten area was published in March 2011. The Government decided that, during the current parliamentary period, no environmental impact assessment will be carried out 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 north-eastern 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 stakeholders, 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 were 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.

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

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 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 recent years, the focus has been on bringing in new players, in part through establishing prequalification process 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 make significant contributions to exploration on the Norwegian 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. In 2012, 42 exploration wells were spudded, which resulted in 13 discoveries.

To better pave the way for new players, a system for prequalifying new operators and licensees has been introduced. As regards the annual licensing rounds in mature areas, the new players have been awarded several 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.

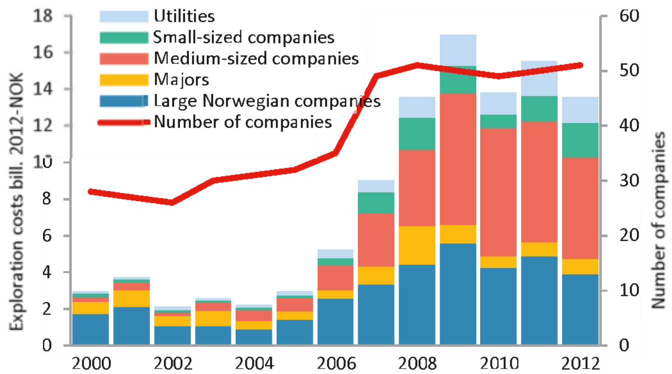


Figure 5.5 Exploration costs in production licences in the North Sea according to the size of the companies
(Source: The Norwegian Petroleum Directorate)

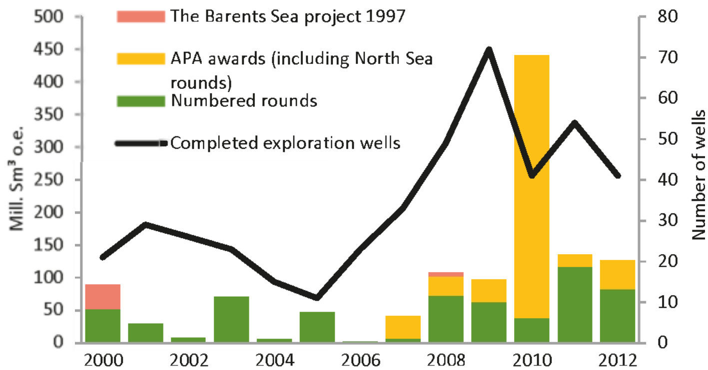


Figure 5.6 Resource growth
(Source: The Norwegian Petroleum Directorate)

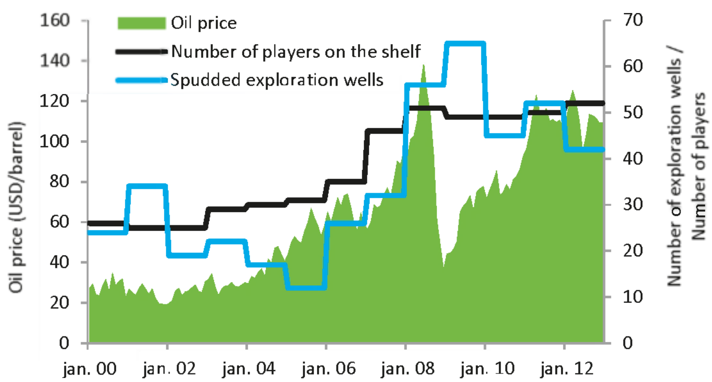


Figure 5.7 Rising oil price and a more diverse player scenario has contributed to high exploration activity
(Source: The Norwegian Petroleum Directorate)

Fact box 5.3 Management plans

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

A fundamental precondition for petroleum activities on the Norwegian shelf is coexistence between the oil industry and other users of the sea and land areas which the petroleum activities may 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 of the Barents Sea and the Waters off Lofoten (HFB)* was submitted to the Storting in the spring of 2006. A number of programmes have in recent years gathered more knowledge about the sea area in advance of the scheduled update of HFB in 2011. The work on an integrated management plan for the Norwegian Sea started in the spring of 2007, and White Paper No. 37 (2008-2009) *Integrated management plan for the marine environment in the Norwegian Sea (management plan)* was submitted to the Storting in the spring of 2009. An integrated management plan for the North Sea-Skagerrak (HFNS) will be submitted to the Storting in 2013.

Fact box 5.4 Opening processes for unopened areas

Parts of the Norwegian continental shelf are not opened for petroleum activities. Unopened areas include parts of Nordland IV, V, and VI, Nordland VII and Troms II, Trøndelag I East, areas around Jan Mayen as well as the southeastern Barents Sea and the northern Barents Sea. In addition, there are restrictions or special requirements related to activities in certain areas within the opened areas.

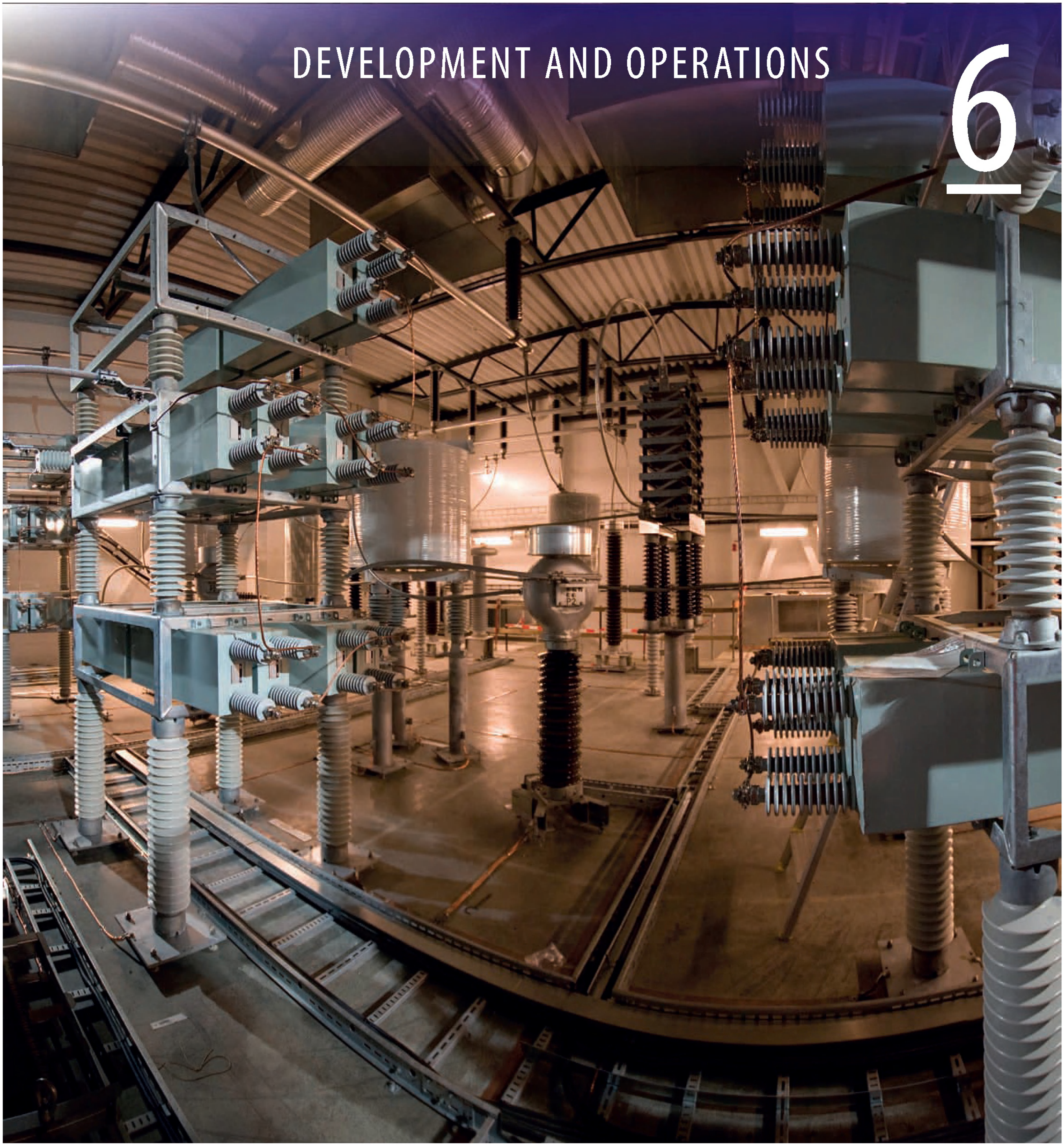
Two opening processes are currently ongoing; one for Norwegian waters off Jan Mayen and one for the Barents South East Area.

In 2009, the Government decided to initiate an opening process for petroleum activities around Jan Mayen, with a view to grant production licences. An impact assessment consisting of a number of studies has been carried out to shed light on consequences for other industry and commerce activities, society and the environment. Field studies of flora and fauna in the sea areas off Jan Mayen, as well as on the island itself, have also been conducted. In addition, the Norwegian Petroleum Directorate will continue its seismic acquisition activities to assess potential petroleum resources in the surrounding waters. Based on, among other things, the results from the impact assessment, the Government will decide on a recommendation to open the areas for petroleum activities. Iceland has implemented two licensing rounds in Icelandic waters bordering Jan Mayen.

On 7 July 2011, the agreement on maritime delimitation in the Barents Sea between Norway and Russia came into effect. Hence, the Norwegian Government commenced a process to open the Barents South East Area for petroleum activities. The area is promising, and petroleum discoveries have been made both east and west of the area. In 2011 and 2012, the NPD conducted seismic surveys in the area. An impact assessment has been completed to evaluate the impact of petroleum activities on other industries, on society and on the environment. A recommendation to open the area for petrolum activities will be sendt to the Storting if the impact assessment provides the grounds for doing so. Russia has currently awarded three exploration licences in new areas east of the demarcation line.

DEVELOPMENT AND OPERATIONS

6



Lista converter station. The Valhall field receives 100 per cent of its electricity from shore via a 295-km power cable from Lista. (Photo: BP)

In 2012, the authorities approved the plans for development and operation (PDOs) for Skuld, Jette, Åsgard subsea compression, Martin Linge, Edvard Grieg, Bøyla and Svalin. The PDOs for Gina Krog, Ivar Aasen and Aasta Hansteen are awaiting approval by the authorities. In 2013, development plans are expected for Zidane, Flyndre and Oseberg Delta 2.

Efficient production of petroleum resources

Given society's large vested interests in the development and operation of oil and gas fields, the authorities have established a framework for these activities. The authorities have created 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 society as a whole. Chapter 2 contains more information about organisation and framework.

Development of discovered petroleum resources is the basis for production and value creation from the petroleum industry today. It is becoming increasingly important to improve utilisation of the resources in familiar areas. This constitutes a significant potential that can generate substantial value for society, if it is utilised efficiently. 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 in the decade leading up to 2015. This corresponds to about twice the original oil resource estimate for the entire Gullfaks field. This is a stretch goal for the industry and for the authorities. At the end of 2012, the reserve growth has been 607 million Sm^3 of oil. In 2012 alone, the reserves increased by 155 million Sm^3. The average increase of 80 million Sm^3 per year that is needed to achieve the goal has not yet been reached.

Figure 6.1 shows the annual growth in oil reserves during the period 1993–2012. The 2012 accounts show a growth of 155 million Sm^3 of oil, recorded as new reserves. The largest increase in oil reserves comes from the Ekofisk, Troll and Gullfaks Sør fields and from the Edward Grieg, Svalin, Martin Linge, Gina Krog and Ivar Aasen resources.

Improved recovery in mature areas

There is still a considerable potential for value creation in improving the recovery rate in producing fields, making operations more efficient and exploring for resources close to developed infrastructure.
Figure 6.2 shows an overview of oil resources in the 25 largest producing fields. The resources can be divided into three groups:

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

The figure shows that under the current plans, vast resources will remain after the planned shutdown of these fields alone. Several measures are necessary if more resources are to be produced on the Norwegian shelf. The measures can be divided into two main groups; measures for improved recovery, and improving the efficiency of operations.

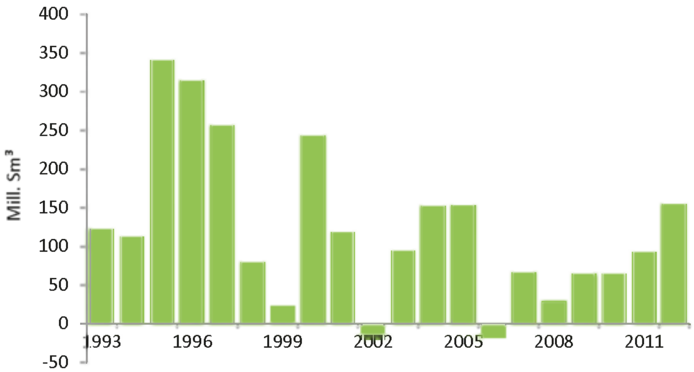


Figure 6.1 Gross reserve growth, oil 1993–2012
(Source: Norwegian Petroleum Directorate)

Improved recovery

First and foremost, 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 oil recovery rate for producing fields was about 40 per cent – today it is about 46 per cent. Development and use of new technology has been and continues to be very important in order to improve recovery.

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

Figure 6.3 also shows that improved recovery means a longer field lifetime. A longer lifetime is positive. It makes implementation of additional recovery measures possible, 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 field lifetimes will be longer than previously assumed.

Efficient operations

The most important factor for extending the useful life of a field is profitable production. Efficient operations contribute to the reduction of production costs. Furthermore, efficient operations enable profitable production over the long term. This enables to production of resources that are currently unprofitable. Many fields are facing a situation where the cost level must be reduced for operations to be profitable at a lower production level. Efficient operations are also crucial for reducing emissions to air and discharges to sea from the activities on the Norwegian continental shelf.

New discoveries – efficient utilisation of infrastructure

In 2012, approximately NOK 146 billion* was invested on the Norwegian continental shelf. In total, about NOK 2400 billion* has been invested on the shelf, measured in current value. A lot of infrastructure has been established through these investments. This infrastructure makes it possible to produce and market petroleum, and also lays the foundation for the development of additional resources in a cost-effective manner.

Declining production from a field releases infrastructure capacity. Such capacity can provide efficient exploitation of resources that can be tied into this infrastructure. In some cases, the use of existing infrastructure is a precondition for the development of production from new deposits that are too small for profitable standalone development. Exploration for and development of resources in the vicinity of existing infrastructure can provide significant value for the Norwegian society. Read more about exploration in mature areas in Chapter 5.

In 2005, in an effort to contribute to efficient use of existing infrastructure, including existing platforms and pipelines, the Ministry of Petroleum and Energy prepared separate regulations, *the Regulations relating to the use of facilities by others*, with effect from 1. January 2006. The objective of these Regulations is to ensure efficient use of infrastructure and thus provide licensees with good incentives to carry out exploration and production activities. The purpose will be fulfilled through the provision of 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 it is the commercial players who 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 range of players is encouraged; cf. the discussion of the player scenario in Chapter 5. The Norwegian authorities believe that a diversity of players that make different assessments and priorities is positive for realising the resource potential on the Norwegian continental shelf.

Improved recovery, longer useful life and the phasing in of resources near producing fields lay the foundation for realising significant added value for society. Existing infrastructure must be utilised in order to further develop the resources in and around existing fields. Thus, the companies have less freedom here than in new developments, and are not free to choose any technical solution due to limitations in existing equipment, weight limits etc.

Clean-up after production ends

The petroleum activities merely borrow the ocean, and all phases of the oil and gas activities must consider the environment and other users of the ocean. The rule of thumb is that all equipment must be cleaned and/or removed when petroleum activities end.

So far, the Ministry of Petroleum and Energy has processed more than ten decomissioning plans. In most cases, it has been decided that abandoned facilities must be removed and transported to shore, as was done with facilities such as Odin, Nordøst Frigg, Øst Frigg, Lille Frigg, Frøy and TOGI. During processing of the decomissioning 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.

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 (Oslo-Paris Convention for the

** Exploration costs excluded.*

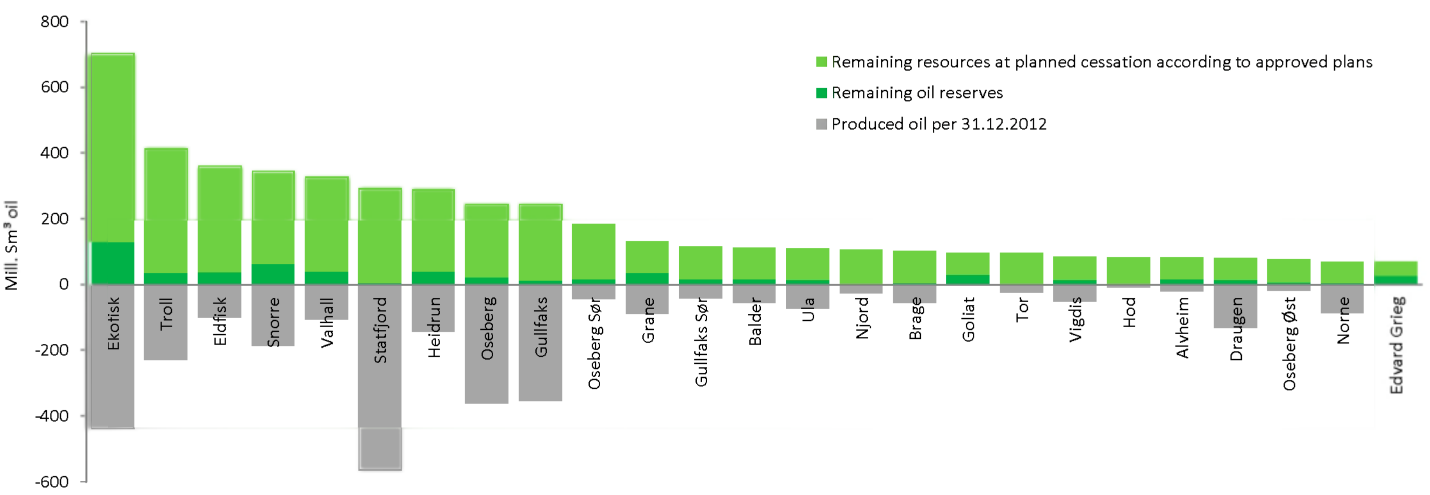


Figure 6.2 Distribution of oil resources and oil reserves in fields *(Source: Norwegian Petroleum Directorate)*

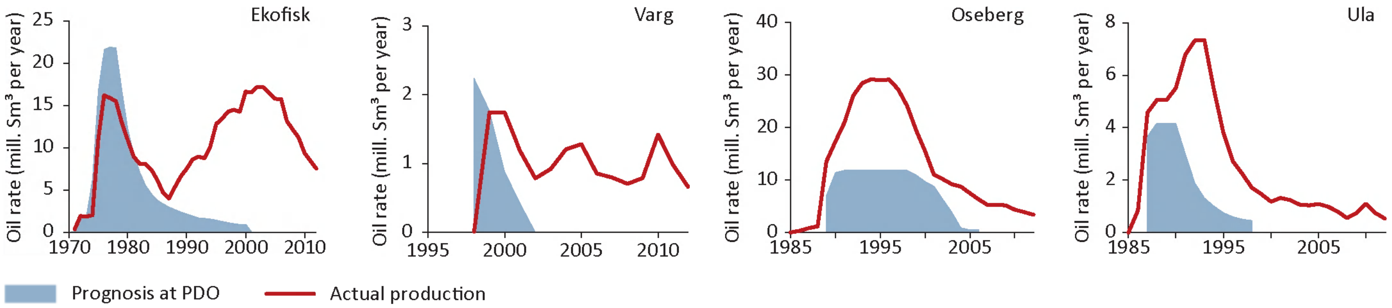


Figure 6.3 Production development for Ekofisk, Varg, Oseberg and Ula *(Source: Norwegian Petroleum Directorate)*

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 in 1999, and lays down guidelines for what is acceptable for various types of offshore facilities. The decision does not include pipelines, parts of facilities that are below the seabed, or concrete anchor foundations that do not obstruct fishing.

The decision means that it is prohibited to dump or to abandon all or parts of scrapped facilities at sea. Exceptions can be made for some facilities, or parts of facilities, if a comprehensive assessment shows that there are strong reasons for disposal at sea.

As regards 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, based on an assessment of the costs associated with trenching, covering or removal.

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

The decomissioning plan must have two main sections; one impact assessment and one disposal section. The impact assessment provides an overview of consequences, 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, the consultation opinions, the disposal section and evaluations of this section.

The licensees at the time of the disposal decision 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 liable for wilful or negligent damage, harm or inconvenience in connection with the abandoned facility. The licensees and the State can agree that future maintenance and responsibilities will be transferred to the State for an agreed financial compensation.

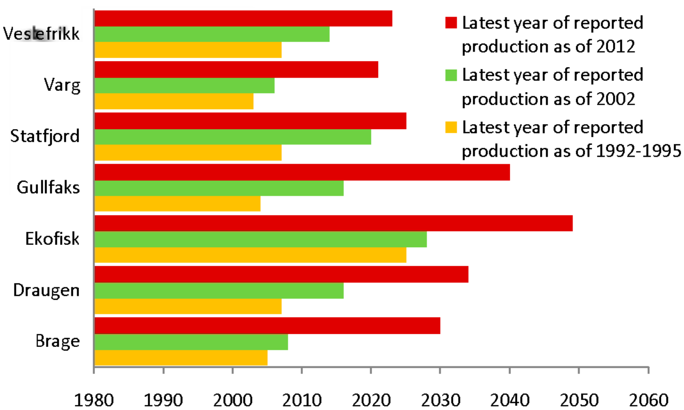


Figure 6.4 Lifetime for selected fields *(Source: Norwegian Petroleum Directorate))*

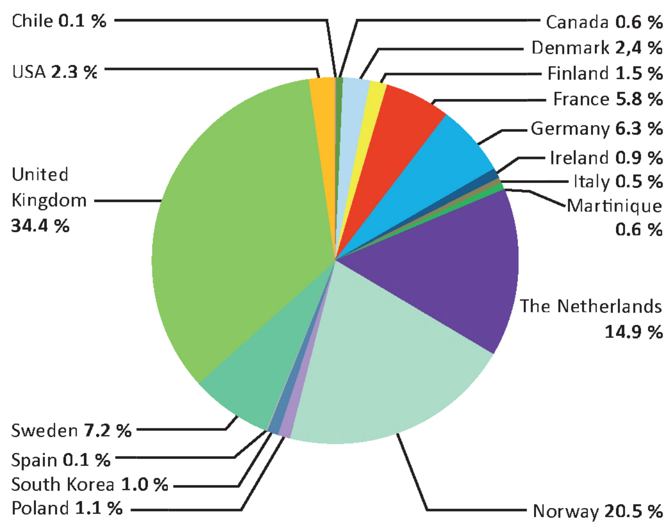


Figure 6.5 Deliveries of Norwegian crude oil distributed by receiving country, 2012 *(Source: Statistics Norway)*

Figure 6.6 Illustration of the Ekofisk tank before and after removal of the topside *(Source: ConocoPhillips)*

Figure 6.7 The Balder heavy lift vessel prepares removal of the Edda topside frame *(Photo: Kjetil Alsvik, ConocoPhillips)*

GAS EXPORT FROM THE NORWEGIAN SHELF

7

Norwegian gas is transported to the market in Europe from Kårstø in Rogaland.
(Photo: Morten Berentsen, Petroleum Safety Authority Norway)

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 2012 was about ten 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 Spain, the UK, Japan 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.

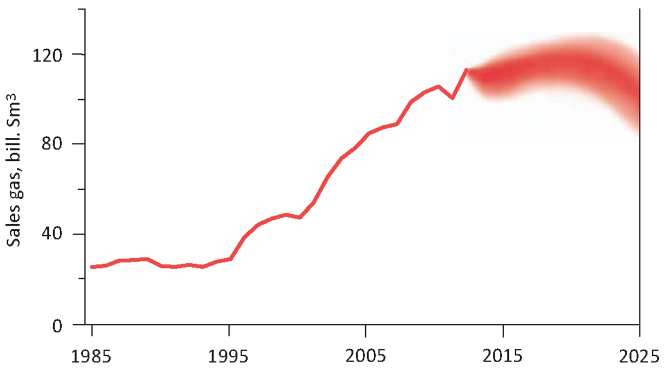


Figure 7.1 Sales gas from Norwegian fields *(Source: Norwegian Petroleum Directorate / Ministry of Petroleum and Energy)*

The transport capacity in the Norwegian pipeline system is currently about 120 billion Sm3 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 from the Norwegian shelf.

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.

A unique feature of gas production is that it 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 what 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 award 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 development of infrastructure and 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 holistic 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 terminals. Gassled includes all rich and dry gas facilities that are either used by both the owners and others, or are planned for such use. 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.

1 *See Chapter 14 for a discussion on the special and general operator responsibility.*

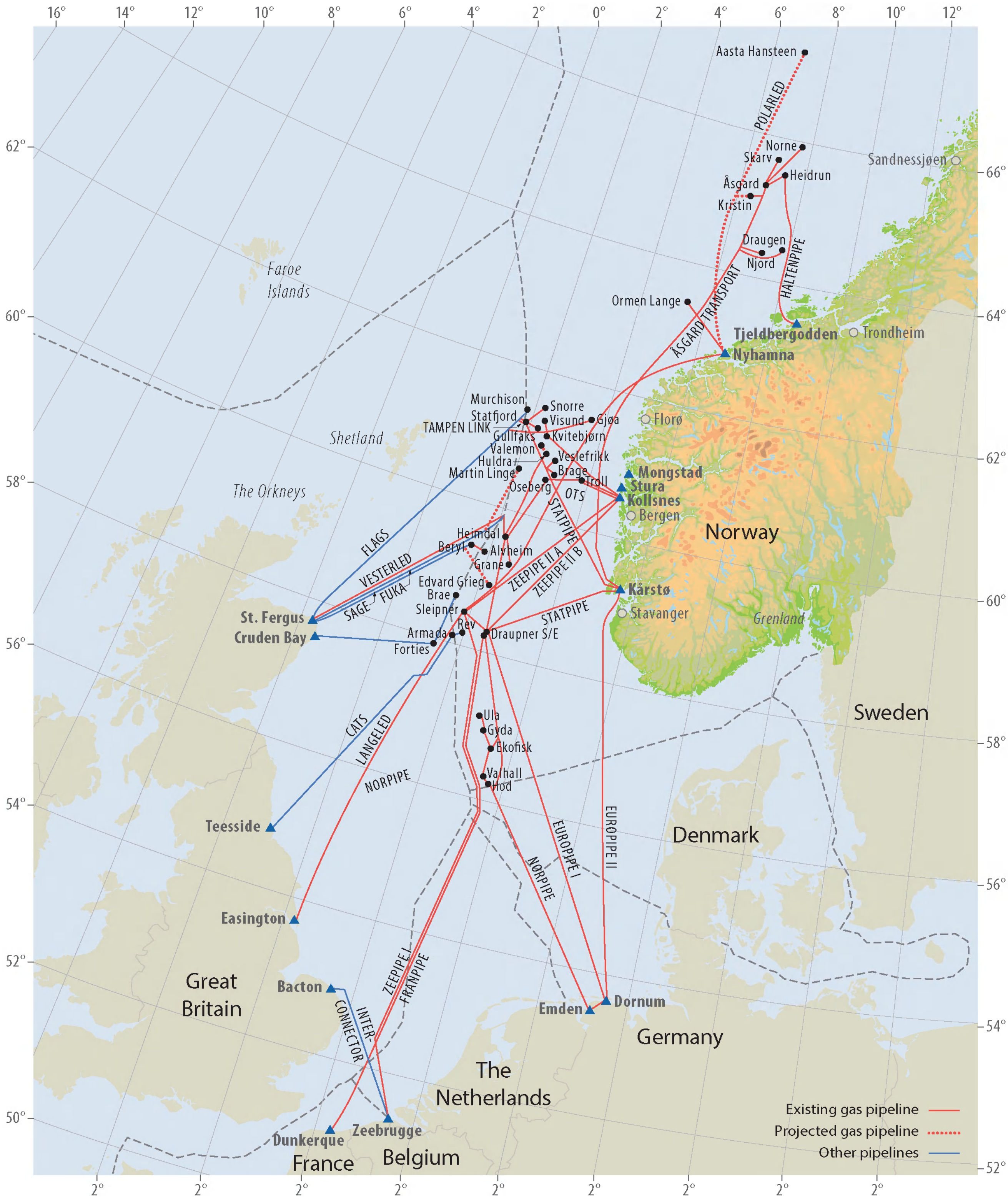


Figure 7.2 Gas pipelines *(Source: Norwegian Petroleum Directorate)*

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 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 operator responsibility. See Chapter 14 for a more detailed discussion of capacity administration.

Norwegian gas production 2012, mill. Sm^3		
Pipeline exports	109	94.7 %
Sales to Norway	1.4	1.2 %
Sales to re-injection	0	0.0 %
LNG	4.7	4.1 %
Total	115.1	100.0 %
Source: Gassco/Norwegian Petroleum Directorate		

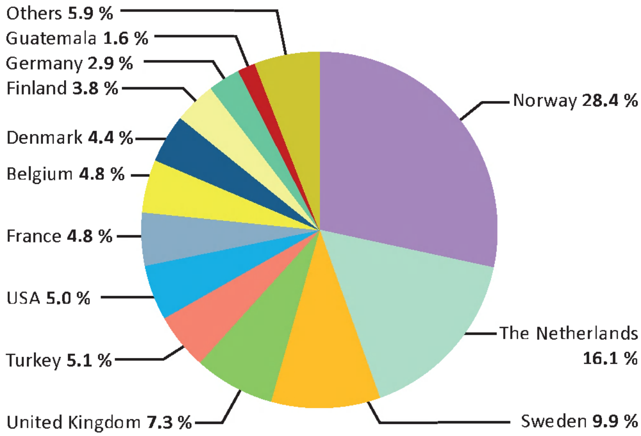


Figure 7.3 Sale of NGL/condensate in 2012 by country of first destination, about 20.8 mill. Sm^3 o.e. *(Source: Norwegian Petroleum Directorate)*

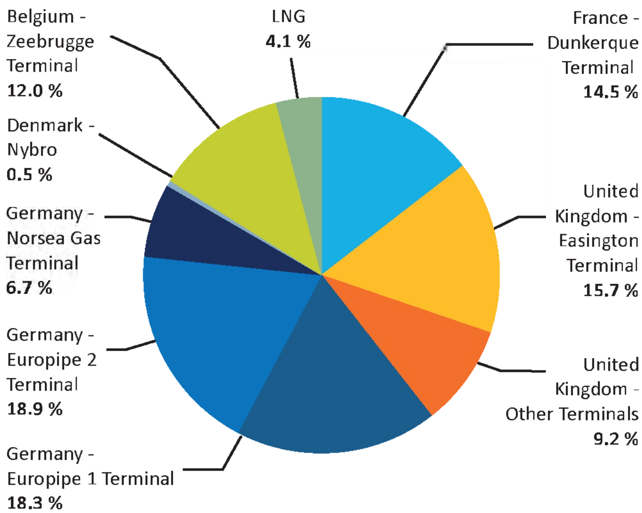
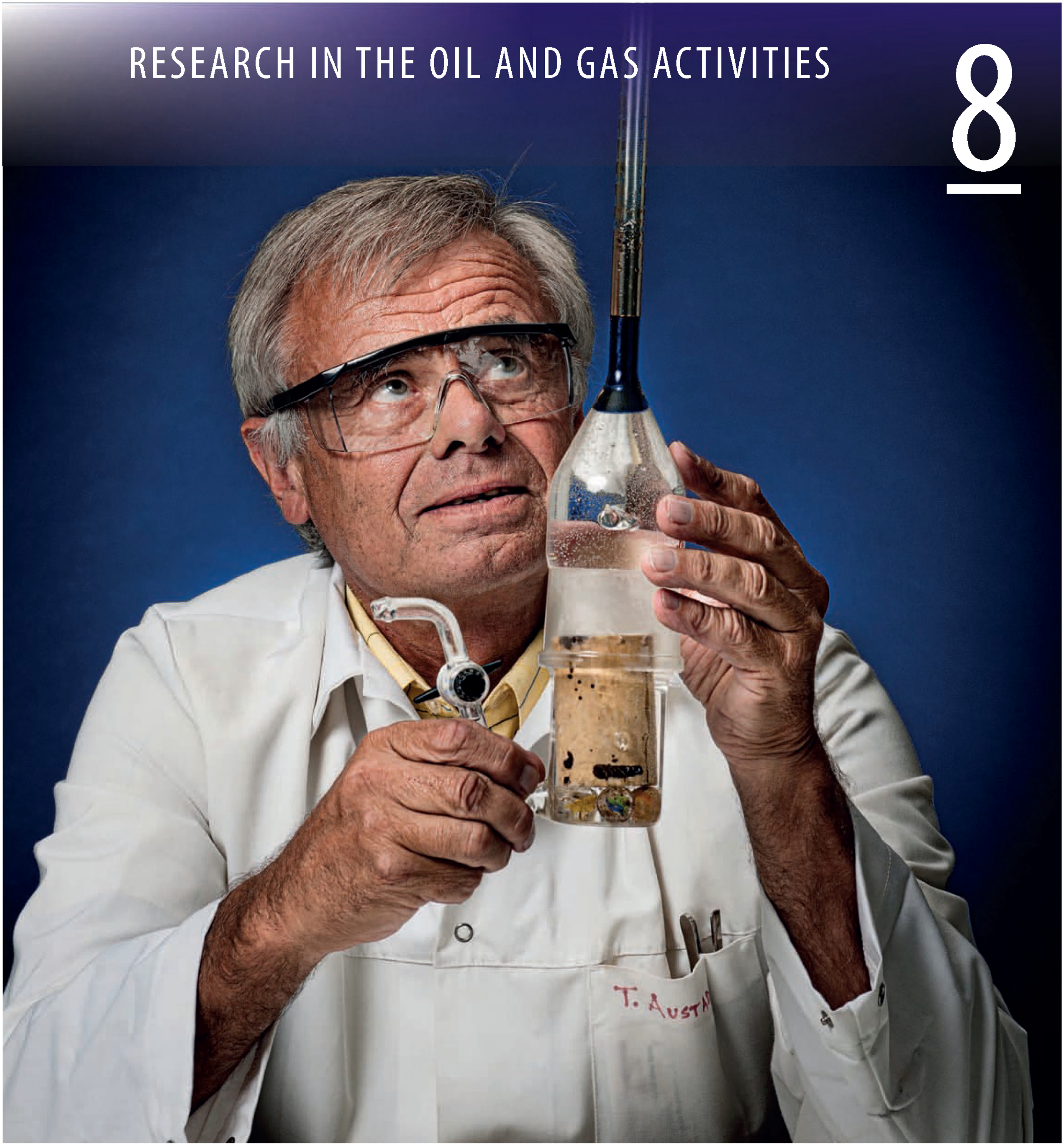


Figure 7.4 Norwegian natural gas exports, about 113.7 billion Sm^3 distributed by receiving terminal *(Source: Gassco/Norwegian Petroleum Directorate)*

RESEARCH IN THE OIL AND GAS ACTIVITIES

8



Professor Tor Austad at the University of Stavanger has received the NPD's IOR award for improved recovery for his research. Austad's work has provided important contributions to knowledge which has resulted in improved oil recovery from chalk fields on the Norwegian shelf. (Photo: Monika Larsen, Norwegian Petroleum Directorate)

New technology has played an important role in achieving an optimal and environmentally friendly exploitation of the resources on the Norwegian continental shelf. Favourable framework conditions from the authorities have given the companies incentives to carry out research and technology development. Close collaboration between oil companies, suppliers and research institutions has been a precondition for this development. Technology developed on the Norwegian shelf has also given the Norwegian supplier industry 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 is more demanding than those resources that have been produced. It is thus more difficult for individual projects to finance technological development. 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, cf. www.OG21.no.

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

The allocations to the Research Council are mainly directed at the research programmes PETROMAKS 2 and DEMO 2000. These programs will contribute to reaching the goals that are set through the OG21 strategy.

PETROMAKS 2

PETROMAKS 2 will replace PETROMAKS, which will end in 2013. The programme supports a wide range of projects from basic research to innovation projects in the industry. PETROMAKS 2 will have overall responsibility for the best possible management of the Norwegian petroleum resources and future-oriented industrial development in the sector. Since 2003, about NOK 2 billion has been allocated to 341 projects and 84 pre-projects. This has triggered NOK 2.1 billion in additional financing, mainly from business and industry. PETROMAKS 2 is an important policy instrument for promoting long-term research and expertise development. Since its start in 2003, PETROMAKS and PETROMAKS 2 have financed 430 research fellows (doctorates and post-doctoral work). 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.

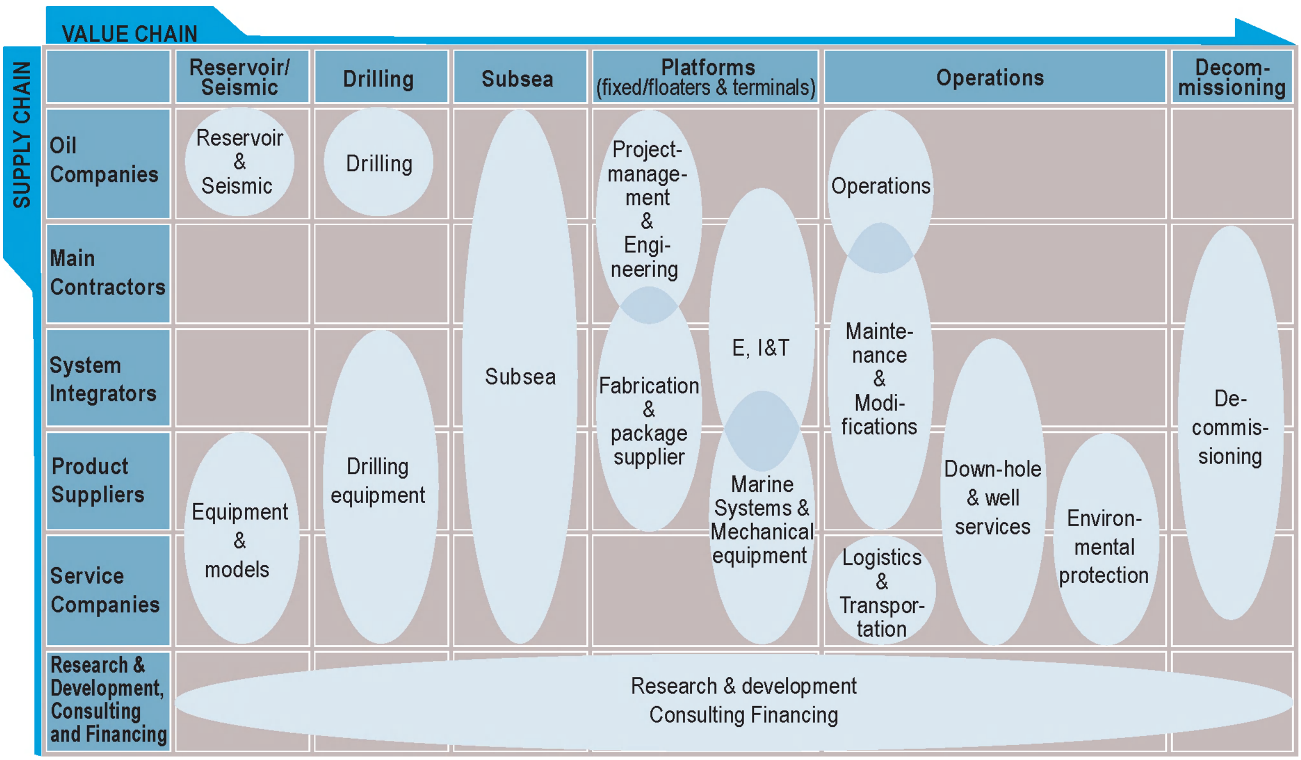


Figure 8.1 Map of Norwegian oil and gas clusters *(Source: www.Intsok.com)*

DEMO 2000

DEMO 2000 is an important policy instrument for testing new technology solutions in the petroleum industry. The purpose of the programme is to reduce costs and risk for the industry by supporting pilot projects and demonstrations. DEMO 2000 also functions as a collaborative arena between the oil companies and supplier companies, and is particularly important for the suppliers. The suppliers 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 framework, the oil companies benefit from targeted tax incentives pertaining to their research-related licence expenditures in the production licences.

Since its start in 1999, DEMO 2000 has supported 260 pilot projects. The total costs associated with these projects amount to NOK 3.2 billion, and the authorities have contributed close to NOK 800 million through the National Budget.

Other research programmes

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 (SFFs) and Centres for Research-based Innovation (SFIs). Several of these centres are relevant for the petroleum industry, such as FACE within multi-phase 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 at IRIS (in cooperation with Sintef), the Centre for Sustainable Arctic Marine and Coastal Technology at NTNU, AMOS within regulation and marine technology at NTNU and CAGE within gas hydrates in Arctic regions at the University of Tromsø. The Centres for Research-based Innovation can receive support for up to eight years, and the Centres of Excellence can receive support for up to ten years.

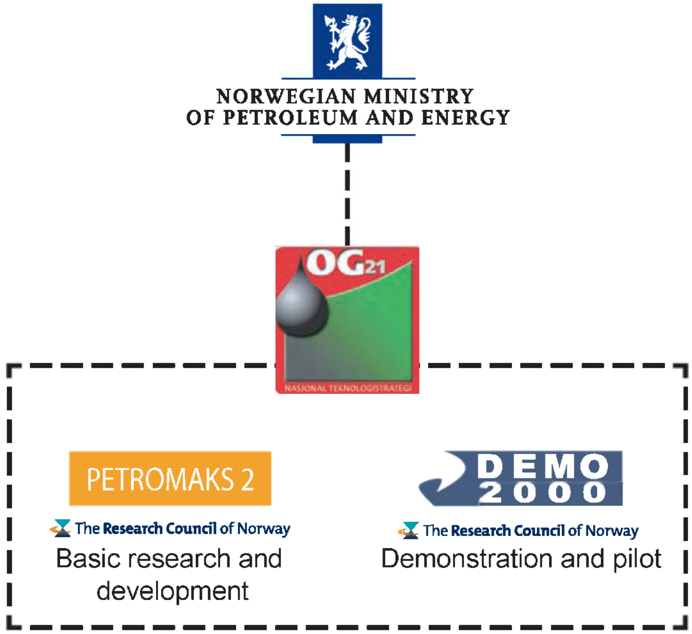


Figure 8.2 The Ministry of Petroleum and Energy's involvement in petroleum research *(Source: The Ministry of Petroleum and Energy)*

The Norwegian Ministry of Petroleum and Energy has taken the initiative to establish a new cooperation on gas and oil technology, GOT, within the International Energy Agency (IEA). The initiative builds on the OG21 model, and will be implemented in 2013. The aim is to bring the petroleum industry, research institutions and governments together to co-operate in identifying common technological challenges in this important area.

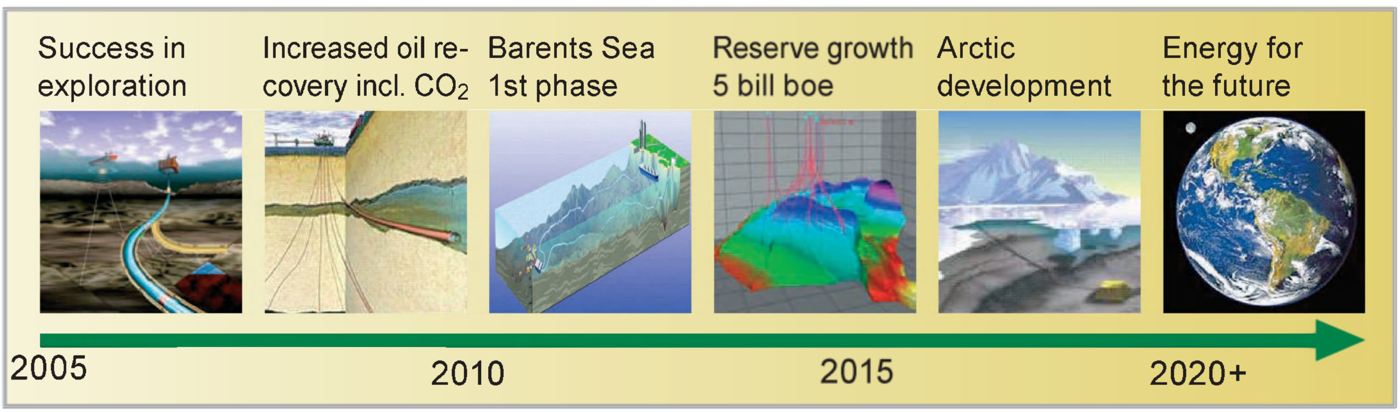


Figure 8.3 OG21's technology roadmap for value creation on the Norwegian continental shelf *(Source: OG21)*

ENVIRONMENTAL AND CLIMATE CONSIDERATIONS IN THE NORWEGIAN PETROLEUM SECTOR

9

In the autum of 2012, Eni Norge joined with Statoil and NOFO in organising a comprehensive exercise to test oil spill preparedness in the Barents Sea. (Photo: Eni Norge, News on request)

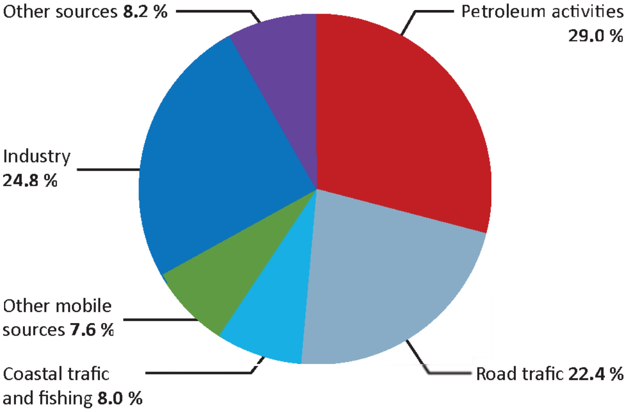
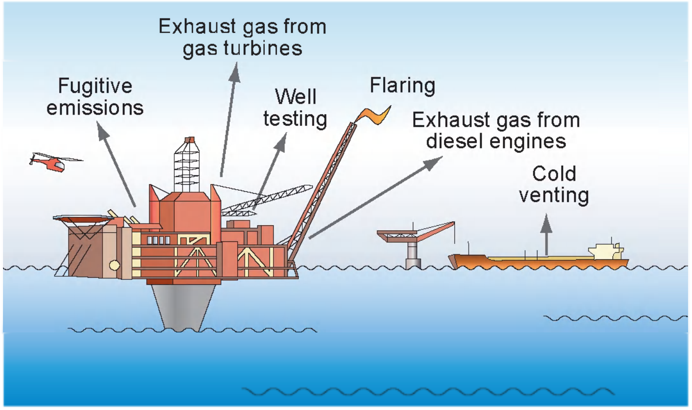


Figure 9.1 Sources of Norwegian emissions of CO_2, 2011
(Source: Statistics Norway)



Overview emission/discharge sources

Environmental and climate considerations have always been an integral part of Norwegian petroleum activities. A comprehensive policy instrument scheme 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.

As one of the first countries in the world, Norway 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 discharge goal). The goal 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.

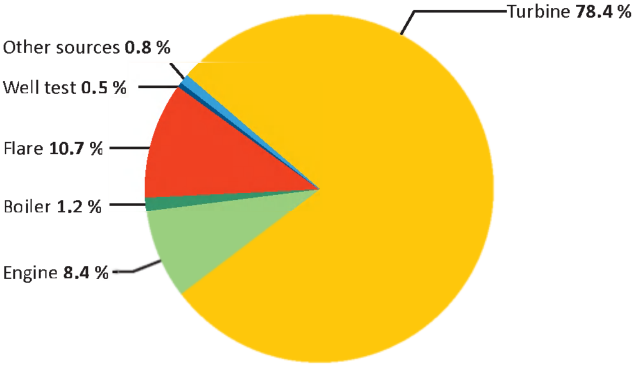


Figure 9.2 CO_2 emissions from petroleum activities 2011 – distributed by source
(Source: The Norwegian Petroleum Directorate)

Emissions and discharges from the petroleum activities

Emissions to air from the petroleum sector are generally exhaust gases 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. The processes related to impact asessments and approval of new development plans (PDOs/PIOs) are cornerstones of the petroleum legislation. 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 certain emissions and discharges through international agreements.

Measurement and reporting of emissions and discharges

The Climate and Pollution Agency, the Norwegian Petroleum Directorate and Norwegian Oil and Gas (formerly 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.

Fact box 9.1 A proactive climate report

In spring 2012, the Government submitted Report No. 21 to the Storting (2011-2012) *Norwegian Climate Policy*. In the report, the Government proposes implementing a number of measures to reduce greenhouse gas emissions and spur technology development. Some of the most important measures include a new climate and energy fund and increasing the CO_2 tax on the shelf.

The climate policy should contribute to develop and transform the industry in a climate-friendly direction. The Government wants to establish a climate and energy fund with a basis in Enova for technology development in the industry. The goal is technology development that reduces greenhouse gas emissions.

The Government's goal is to increase the offshore supply of electric power from the mainland. This presupposes, at the same time, that development of sufficient new power supply is ensured, or that an adequate new grid is put in place to prevent regional market imbalances. At the same time, biological diversity and consideration for the costs of these measures must be safeguarded. To provide the companies with increased incentives for electrification, the Government increased the CO_2 tax for petroleum activities by NOK 200 per tonne.

CO_2 emission status

Nationally, the petroleum activities accounted for about 29 per cent of CO_2 emissions in 2011 (see Figure 9.1). The other large sources of CO_2 emissions in Norway are emissions from industrial processes and road traffic. Updated information on production and emissions in the petroleum sector indicates that emissions from the petroleum sector are estimated to increase until about 2017, and then gradually decrease. The development must be seen in context with the expected production of oil and gas on the Norwegian shelf. Recent developments on the Norwegian continental shelf have headed 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 has accounted for an increasing share of emissions on the Norwegian continental shelf. In addition, the gas fields' reservoir pressure is decreasing. Several major oil fields have been discovered in recent years and have been scheduled for development.

Policy instruments to reduce CO_2 emissions

Norway is a front runner 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 include e.g. flaring.

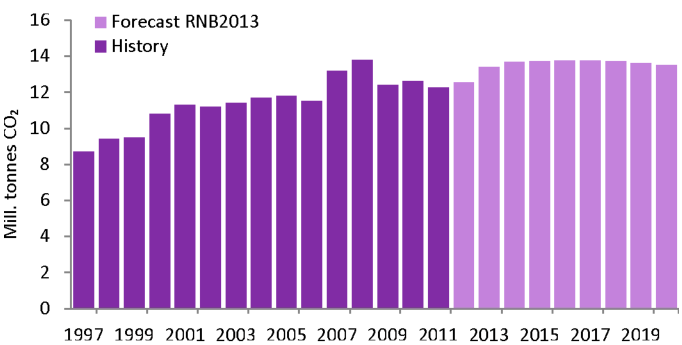


Figure 9.3 CO_2 emissions from the petroleum sector in Norway *(Source: The Norwegian Petroleum Directorate)*

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. In line with Report No. 21 to the Storting (2011-2012) Norwegian climate policy, the CO_2 tax for the petroleum activities has increased by NOK 200 per tonne CO_2 effective 1 January 2013. The fee is NOK 0.96 per Sm3 of gas and litre of oil or condensate.

The Greenhouse Gas Emission Trading Act

Norway is part of the EU's emissions trading (EU ETS) system. This entails that the EU's Emission Trading Directive with associated decisions applies for Norwegian activities that are subject to mandatory allowances in line with the activities subject to mandatory allowances in the EU. The Greenhouse Gas Emission Trading Act was enacted in 2005 and was most recently amended in April of 2011. The third emissions trading period started on 1 January 2013, and will run until 2020. As of 1 January 2008, the petroleum activities are subject to both a CO_2 tax and mandatory emissions allowances.

With a price of allowances in the EU ETS of about NOK 50 per tonne of CO_2, and a CO_2 tax for the petroleum activities at a fixed price of NOK 400, the total price for greenhouse gas emissions in the petroleum activities will be about NOK 450 per tonne of CO_2. If the price of allowances in the EU ETS increases over time, it provides a basis for reducing the CO_2 tax so that the overall carbon price remains at about the same level.

Conditions and permits

Flaring of gas necessary to ensure safe operations is permitted following approval from the Ministry of Petroleum and Energy. Flaring accounted for about 11 per cent of the CO_2 emissions from the petroleum activities in 2011. A number of emission reduction measures put Norway in the forefront in this area.

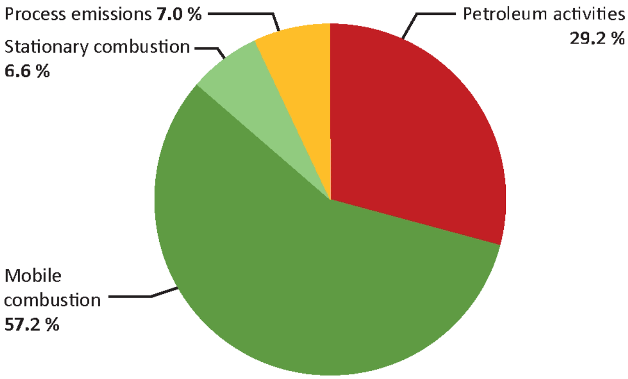


Figure 9.4 Sources of NO_x emissions in Norway in 2011
(Sources: Statistics Norway)

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 to reduce CO_2 emissions from fields

The authorities and the oil companies maintain a strong focus on research and technological development in order to find good technical solutions that can contribute to reduce harmful emissions. Considerable efforts are devoted to the development of 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

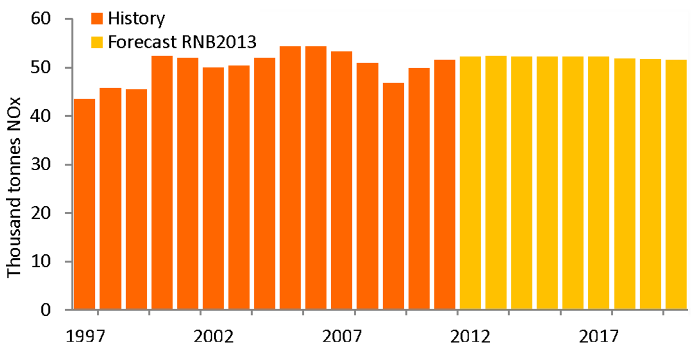


Figure 9.5 NO_x emissions from the petroleum activities
(Source: The Norwegian Petroleum Directorate)

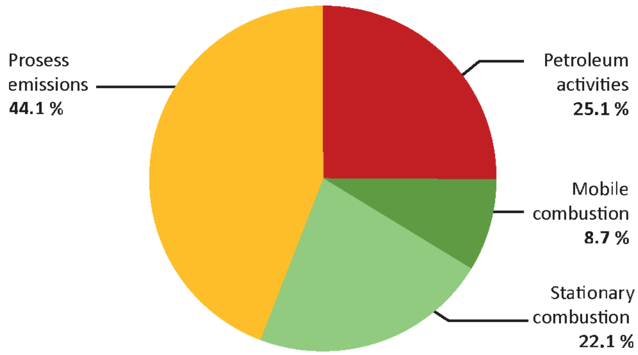


Figure 9.6 Sources of Norwegian nmVOC emissions in 2011
(Source: Statistics Norway)

is currently in use on the Oseberg, Snorre and Eldfisk fields. These facilities are unique in a global offshore perspective.

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 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 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. During normal operation on Snøhvit, up to 700 000 tonnes of CO_2 is stored each 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

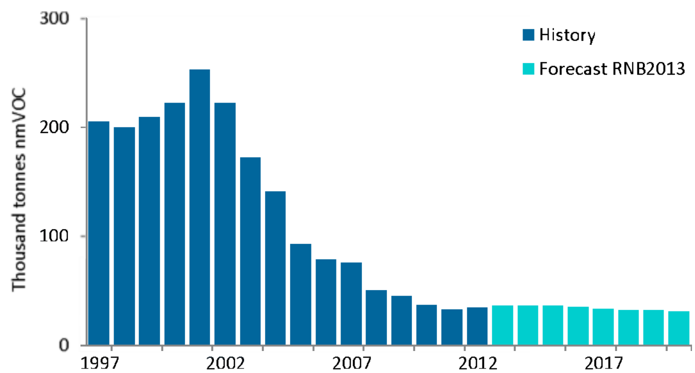


Figure 9.7 nmVOC emissions from the petroleum activities
(Source: The Norwegian Petroleum Directorate)

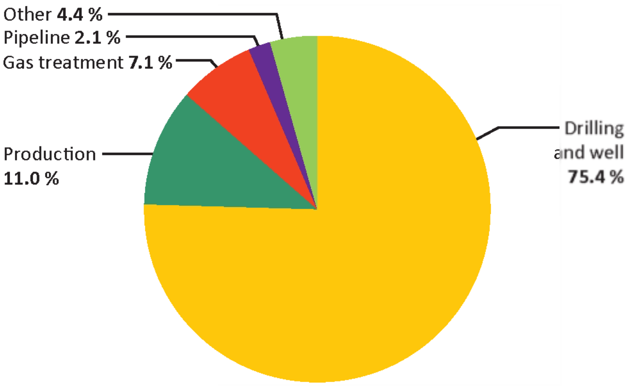


Figure 9.8 Discharge of chemicals from the Norwegian petroleum activities, distributed by source, 2011 *(Source: The Norwegian Petroleum Directorate)*

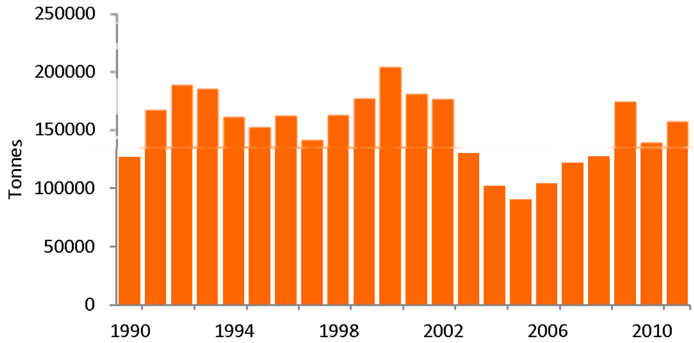


Figure 9.9 Total discharges of chemicals from Norwegian petroleum activities *(Source: The Norwegian Petroleum Directorate)*

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 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. Valhall came on stream in January 2013 with its new production platform. The new processing facility runs on power from shore via a cable from Lista. Goliat will be provided with power from shore when production starts. In 2012, about 48 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 wildlife 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 29 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 was an increased level of activity contributing to more emissions.

Policy instruments to reduce 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 covers 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 domestic activities, and covers 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 2013, the tax is set at NOK 17.01 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 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 are covered by the agreement.

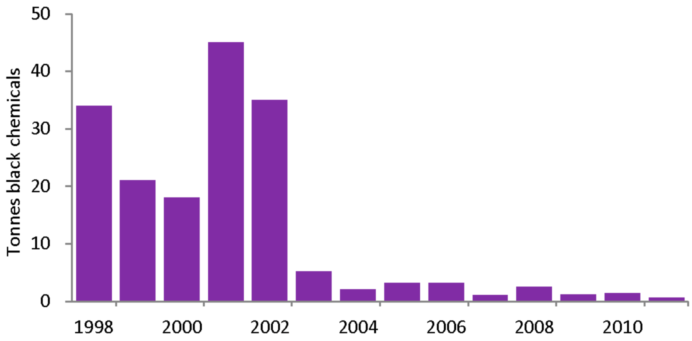


Figure 9.10 Discharge of black chemicals from the petroleum activities *(Source: The Norwegian Petroleum Directorate)*

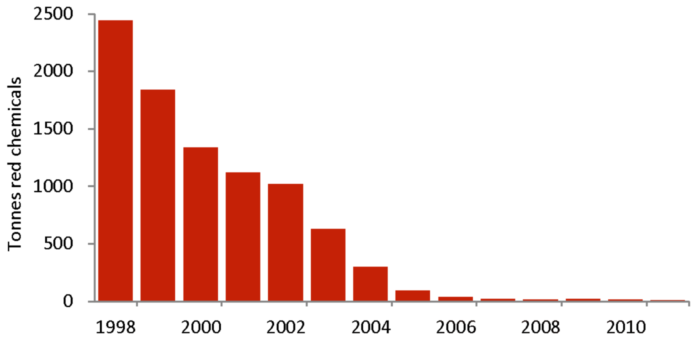


Figure 9.11 Discharge of red chemicals from the petroleum activities *(Source: The Norwegian Petroleum Directorate)*

Example of a measure to reduce NO_x emissions

Low NO_x burners

Low-NO_x burners 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 efficiency 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 evaporates from substances 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 damage the airways 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. In 2011, Norwegian nmVOC emissions totalled 138 800 tonnes.

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 been substantially reduced since 2001 and the prognosis indicates a continued low level in the years ahead (see Figure 9.7). Measures to limit emissions have resulted in a decline in excess of 90 per cent from 2001 to 2011, which is the main reason why the Norwegian nmVOC emissions are well below the targets in the Gothenburg Protocol. The primary cause of the emission reductions is the implementation of emission-reducing technology.

Fact box 9.2 The Business Sector's NO_x Fund

Reduced NO_x emissions are the primary goal of the Environmental Agreement on NO_x and the Business Sector's NO_x Fund. The fund is a cooperative effort where the member companies can apply for support for emission-reducing measures. Payments to the fund will replace the NO_x tax for participating companies. The NO_x Fund was established by 15 cooperating business associations. All companies subject to NO_x emission tax can join the Environmental Agreement on NO_x 2011-2017.

Policy instruments and measures to reduce 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 industrial cooperation agreement was signed in 2002 and 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. In 2011, 21 buoy loading vessels had installed nmVOC-reducing technology. In addition, all production vessels (FPSOs) and storage vessels (FSOs) had implemented nmVOC-reducing measures through installation of an emission-reduction facility or quota agreements.

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 call at 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.

Fact box 9.3 Oil spill preparedness

In Norway, the emergency preparedness against acute pollution is made up of private preparedness, municipal preparedness and State 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), which is owned by 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.

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 Convention for the Protection of the Marine Environment of the North-East Atlantic (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 clarify the goal and arrive at solutions for reaching the goal. The goal has been partially 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). Many 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 drilling activities (see Figure 9.8), and the discharge amounts vary according to the activity level. Figure 9.9 shows the development in 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.

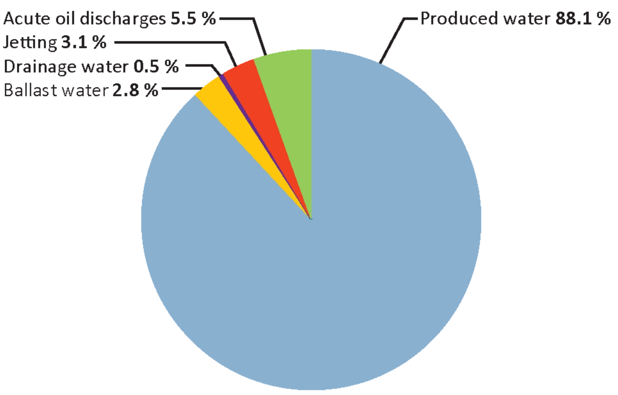


Figure 9.12 Discharges/emissions from the petroleum activities, distributed by activities, 2011
(Source: The Norwegian Petroleum Directorate)

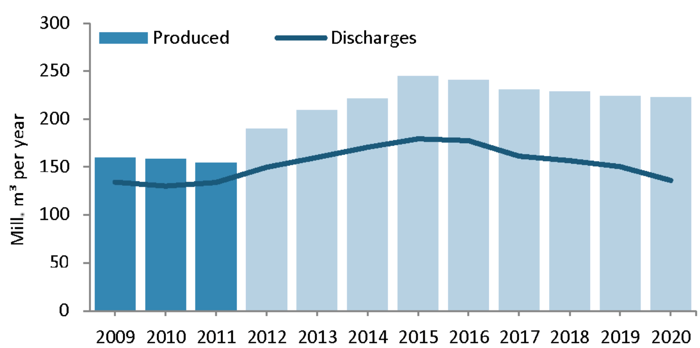


Figure 9.13 Prognosis for produced water and for discharge of produced water
(Source: The Norwegian Petroleum Directorate)

Policy instruments to reduce 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 responsible 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 on the Norwegian shelf. The primary discharges of oil on the Norwegian shelf are from shipping and from the mainland through rivers. It is assumed that about 5 per cent of the total discharges of oil on the Norwegian shelf are from the Norwegian petroleum activities.

Acute discharges

All acute discharges from 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 the 40 years with petroleum production, discharges from the activities have never reached shore. In 2011, the total acute oil discharges to sea amounted to 19 m^3.

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 scope of damage. Acute oil discharges can harm fish, sea mammals, seabirds and beach zones. In Norway, the most serious acute discharges are from ships along the coast.

Discharges from operations

Water produced along 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.

Policy instruments to reduce 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. This is in addition to municipal and State emergency preparedness.

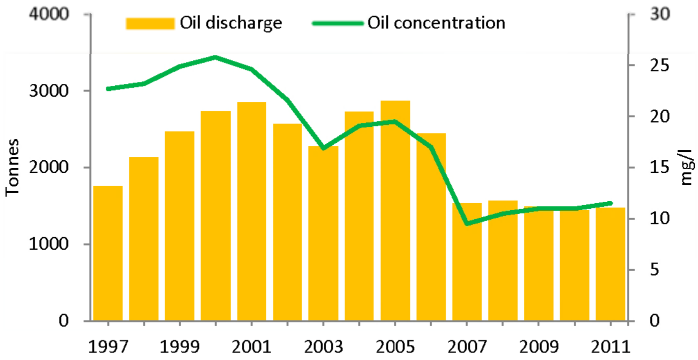
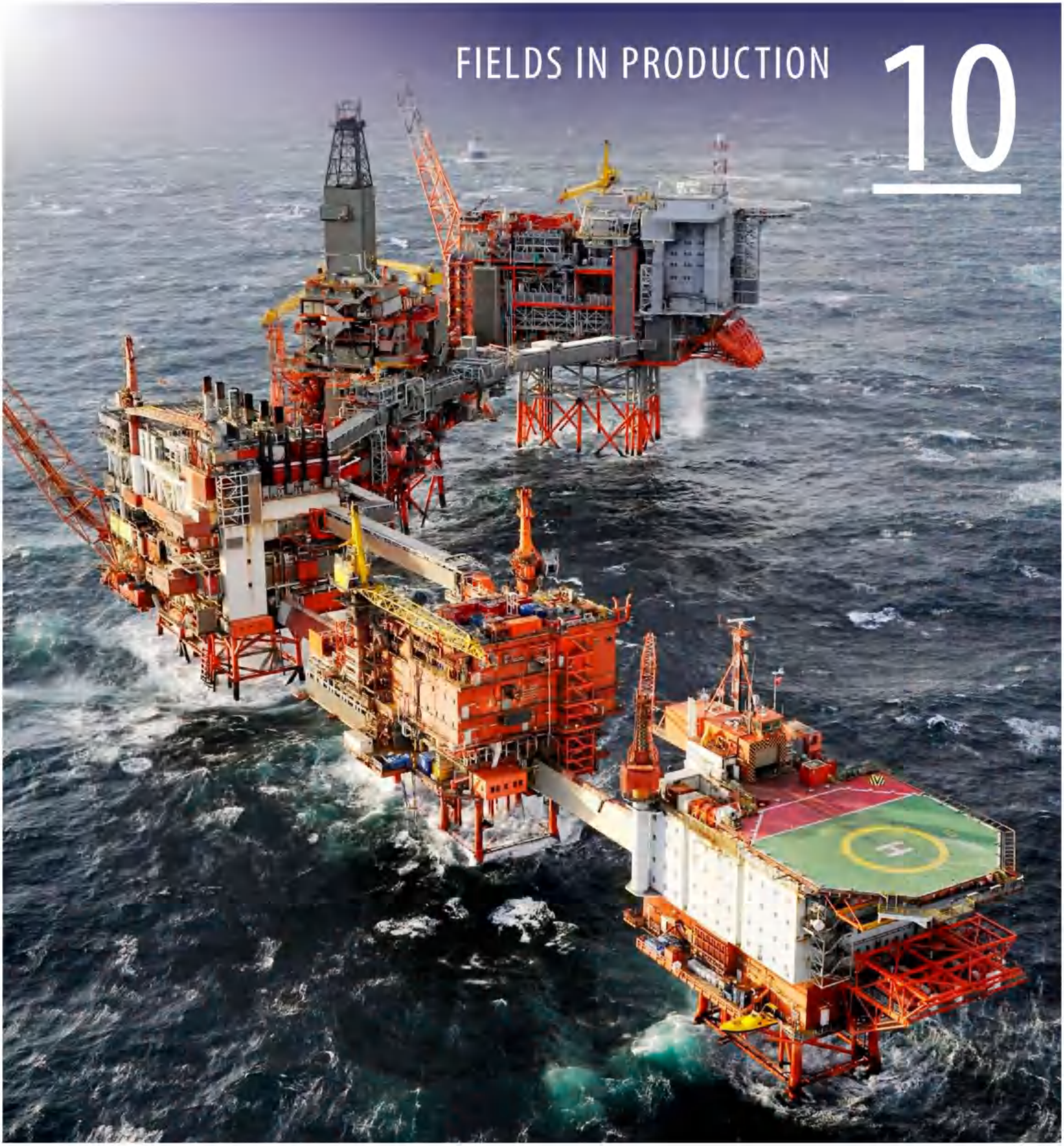


Figure 9.14 Discharge of oil in produced water and associated oil concentration *(Source: The Norwegian Petroleum Directorate)*

10 FIELDS IN PRODUCTION



The Valhall field in the southern North Sea.
(Photo: Kjetil Alsvik, BP)

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

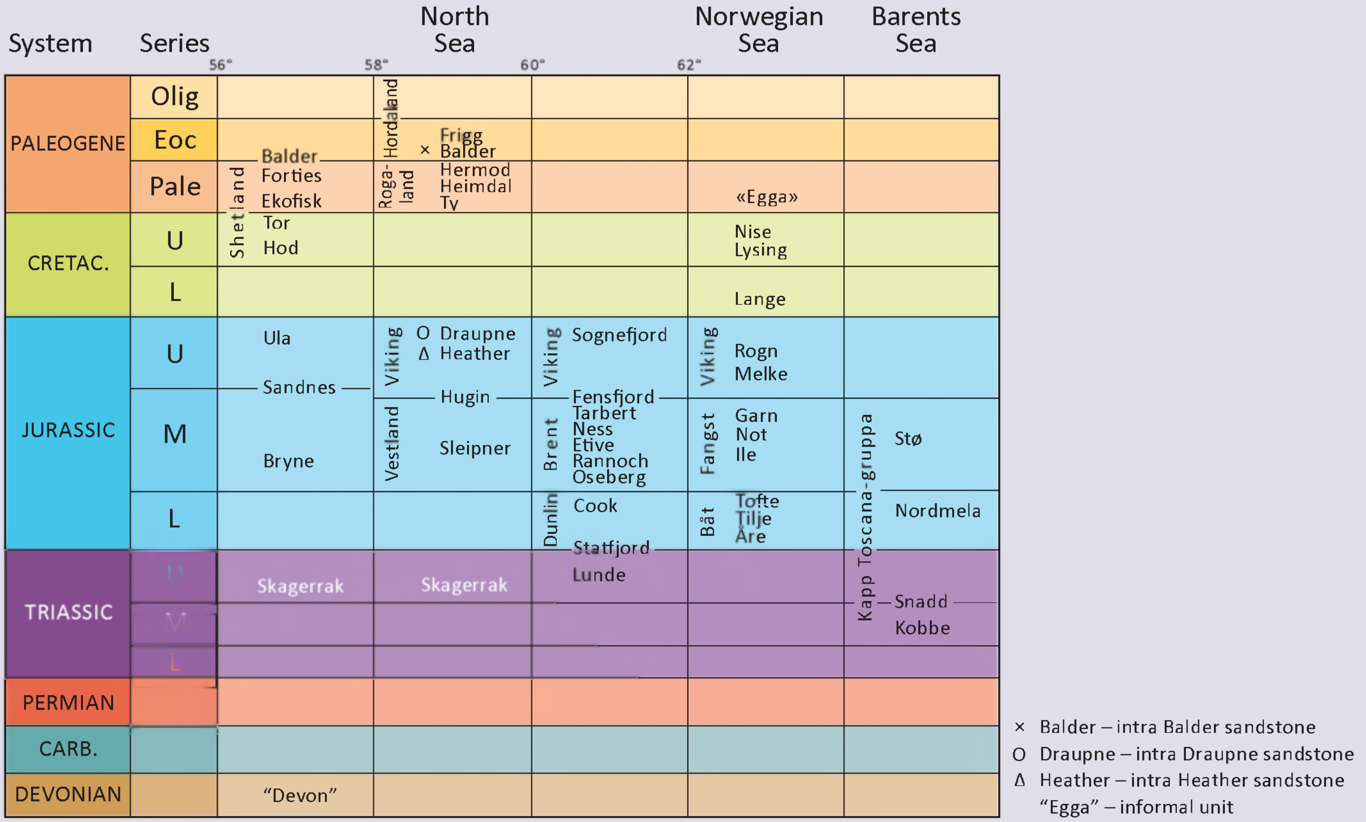
- Oil, condensate, NGL
- Gas

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



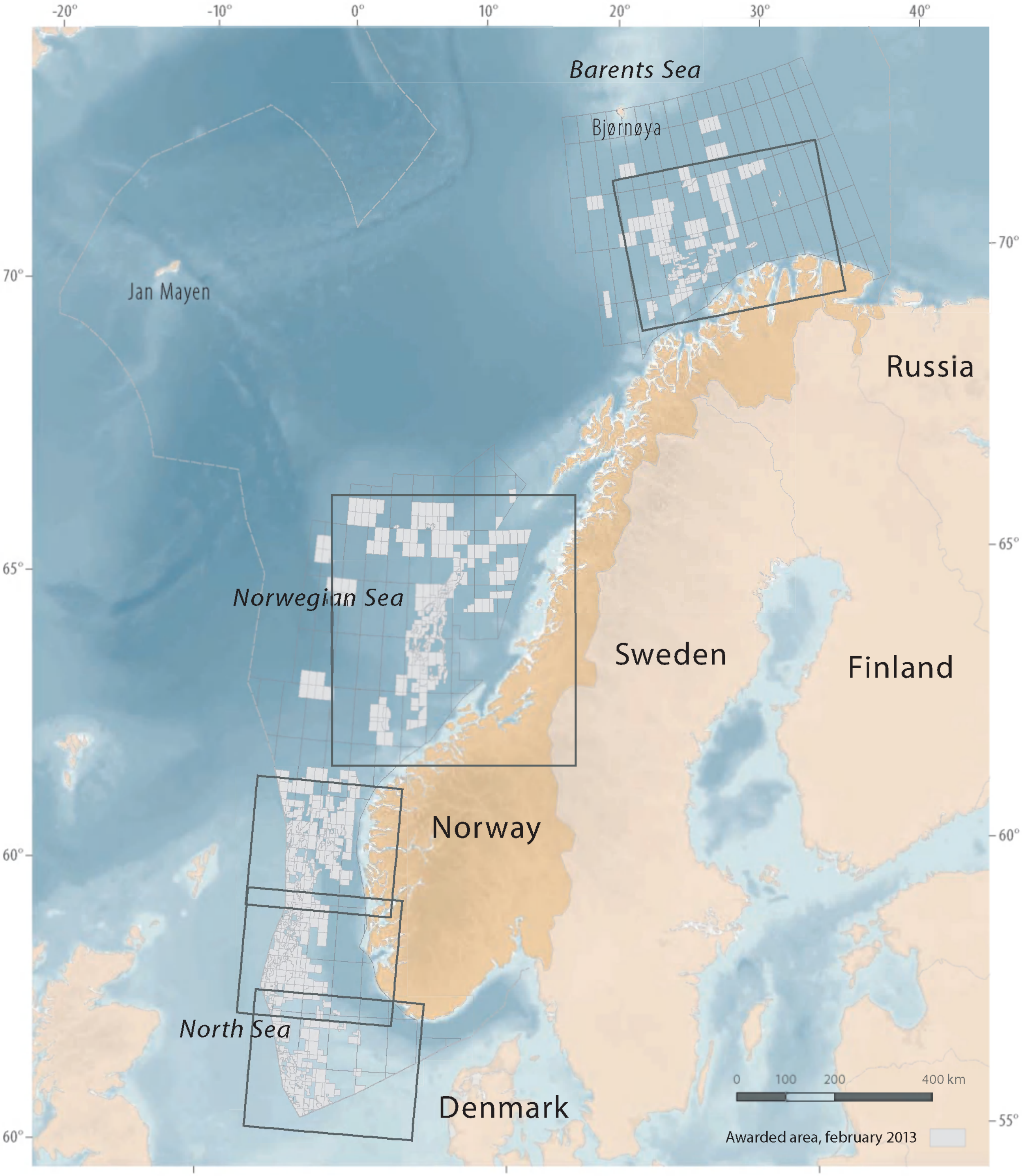


Figure 10.1 Areas on the Norwegian continental shelf *(Source: Norwegian Petroleum Directorate)*

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 the largest field on the Norwegian continental shelf, measured in daily oil production. There are 13 fields in production in the southern part of the North Sea, after Oselvar came on stream in April 2012. Two fields, Yme and Brynhild are being developed. 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 at 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.

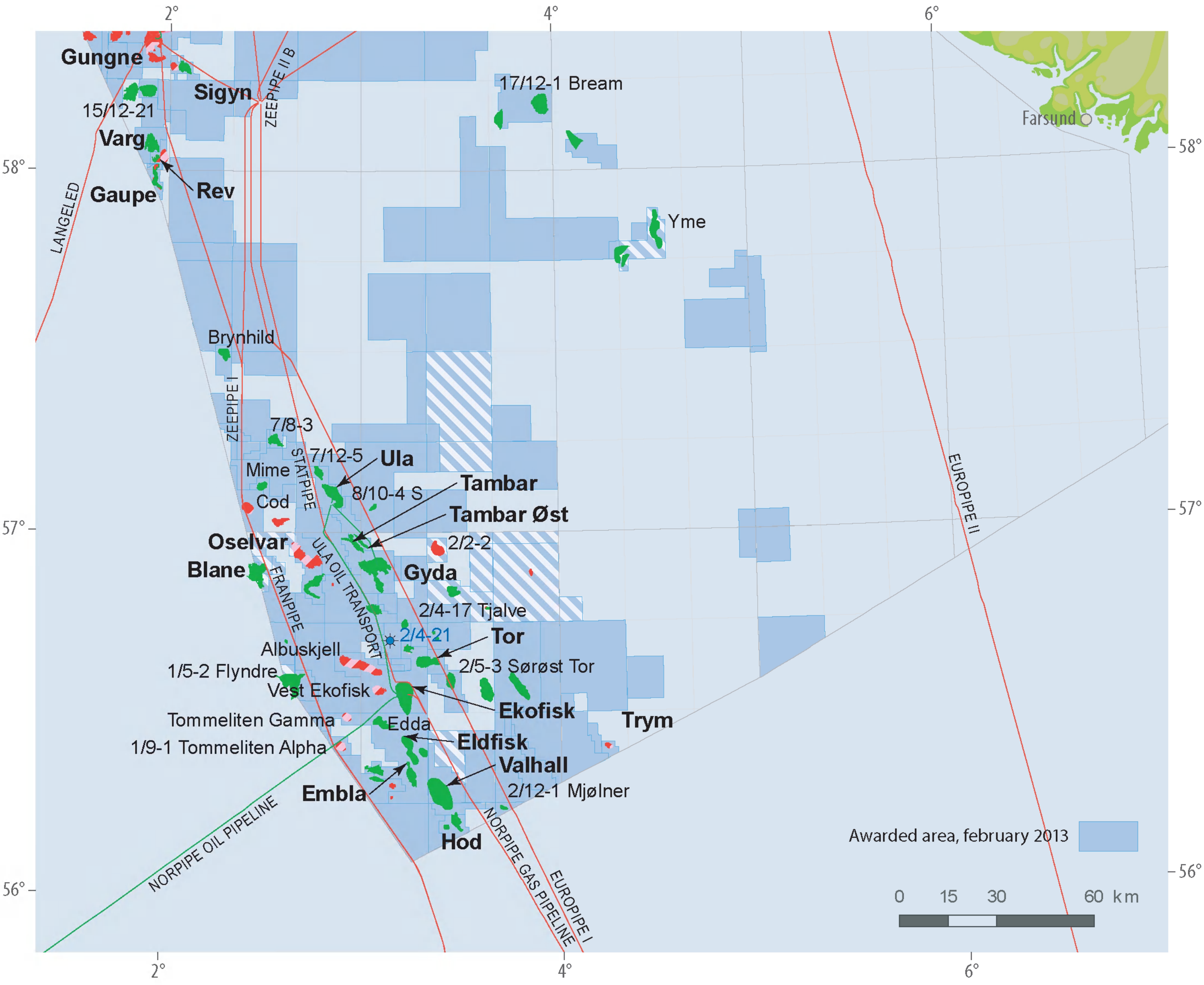


Figure 10.2 Fields and discoveries in the southern part of the North Sea *(Source: Norwegian Petroleum Directorate)*

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. It was in production for almost 30 years, until it was shut-down in 2004. At present, 21 fields are in production in the central part of the North Sea, after Atla and Gaupe came on stream in 2012. Five fields, Bøyla, Edvard Grieg, Gudrun, Jette and Svalin are being developed, and development plans have been submitted for the two discoveries, Ivar Aasen and Gina Krog. Several discoveries are also in the planning phase, including the significant Johan Sverdrup oil discovery. Heimdal, which has produced gas since 1985, is now primarily a gas centre providing processing services for other fields in the North Sea. The Sleipner fields also 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 in pipelines to onshore facilities in Norway and the United Kingdom.

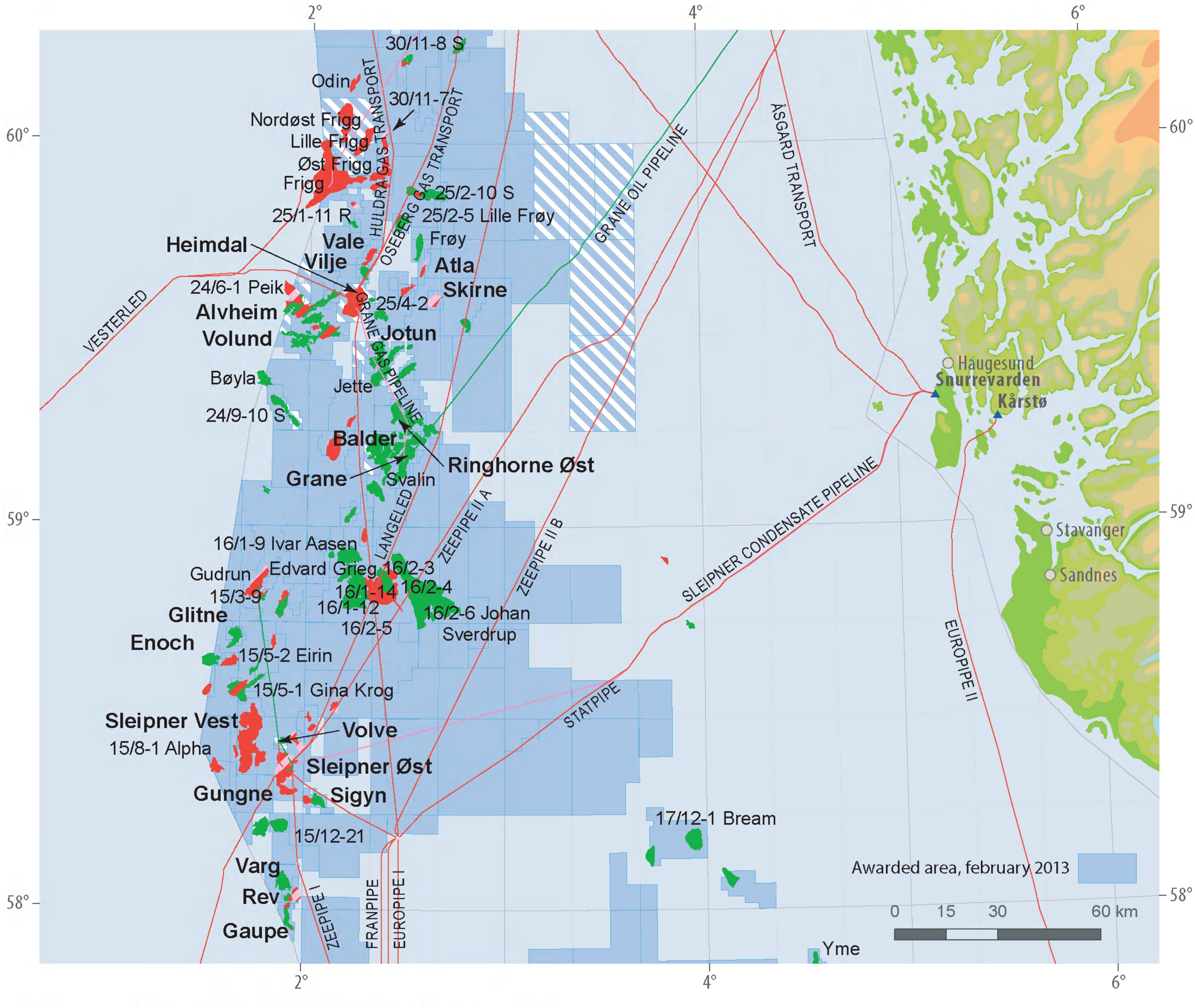


Figure 10.3 Fields and discoveries in the middle part of the North Sea *(Source: Norwegian Petroleum Directorate)*

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. Three fields, Martin Linge, Knarr and Valemon are being developed, and several discoveries are in the planning phase for future development. 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

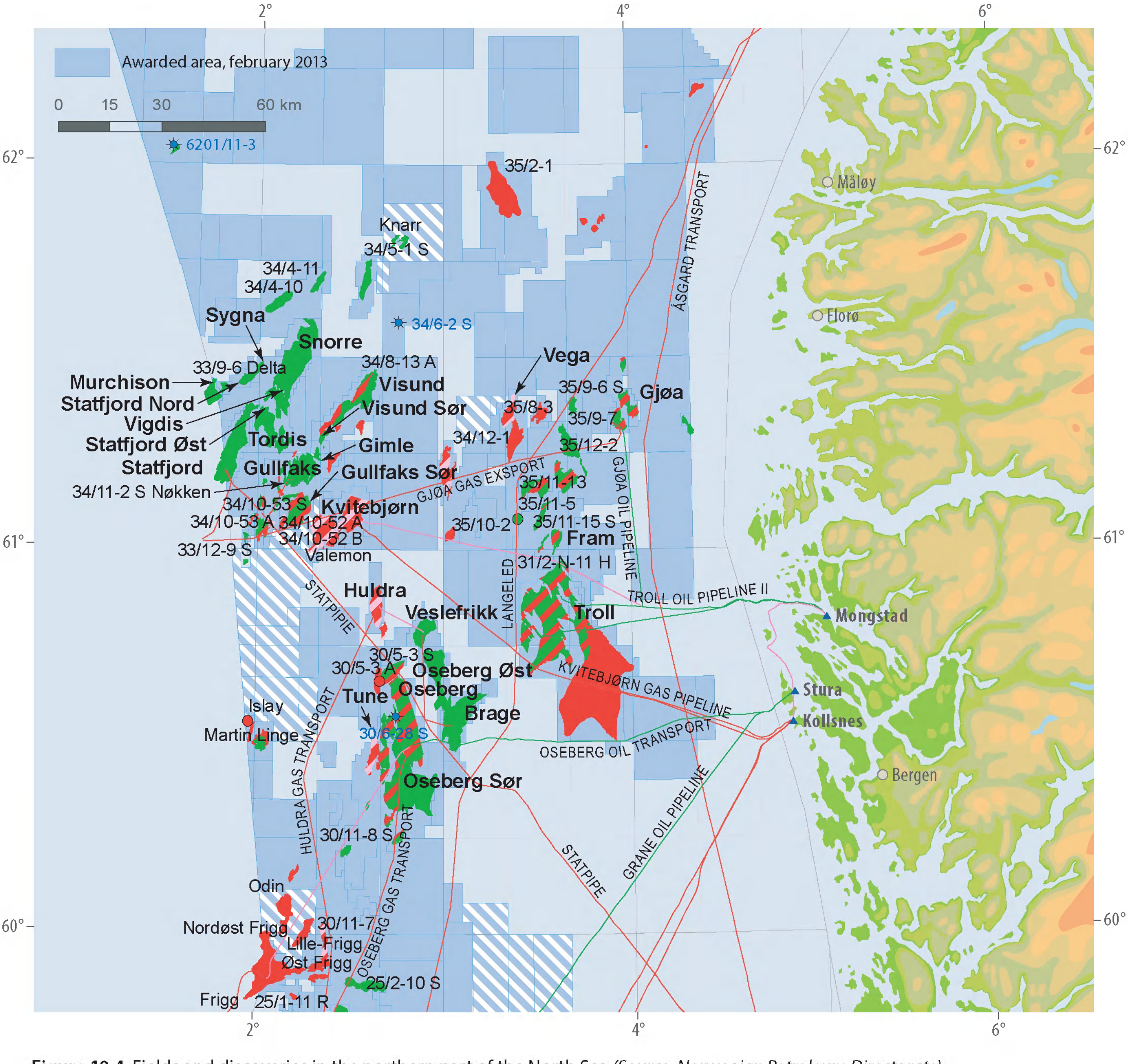


Figure 10.4 Fields and discoveries in the northern part of the North Sea *(Source: Norwegian Petroleum Directorate)*

fields reach the end of production, substantial gas volumes may be produced in a gas blow-down and low pressure production period. Oil and gas from the fields in the northern part of the North Sea is transported by tankers or in pipelines to onshore facilities in Norway and the United Kingdom.

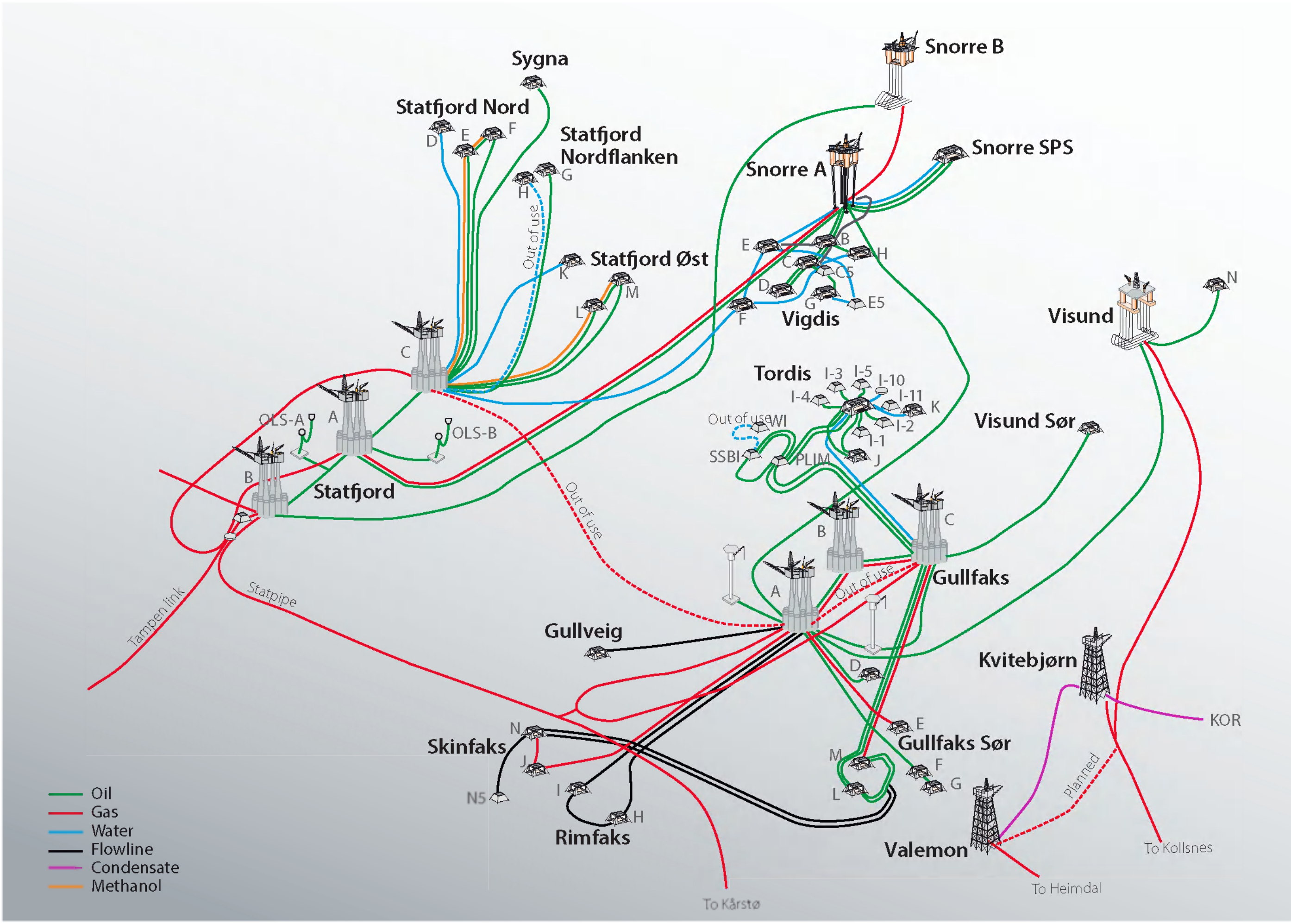


Figure 10.5 Facilities in the Tampen area *(Source: Statoil)*

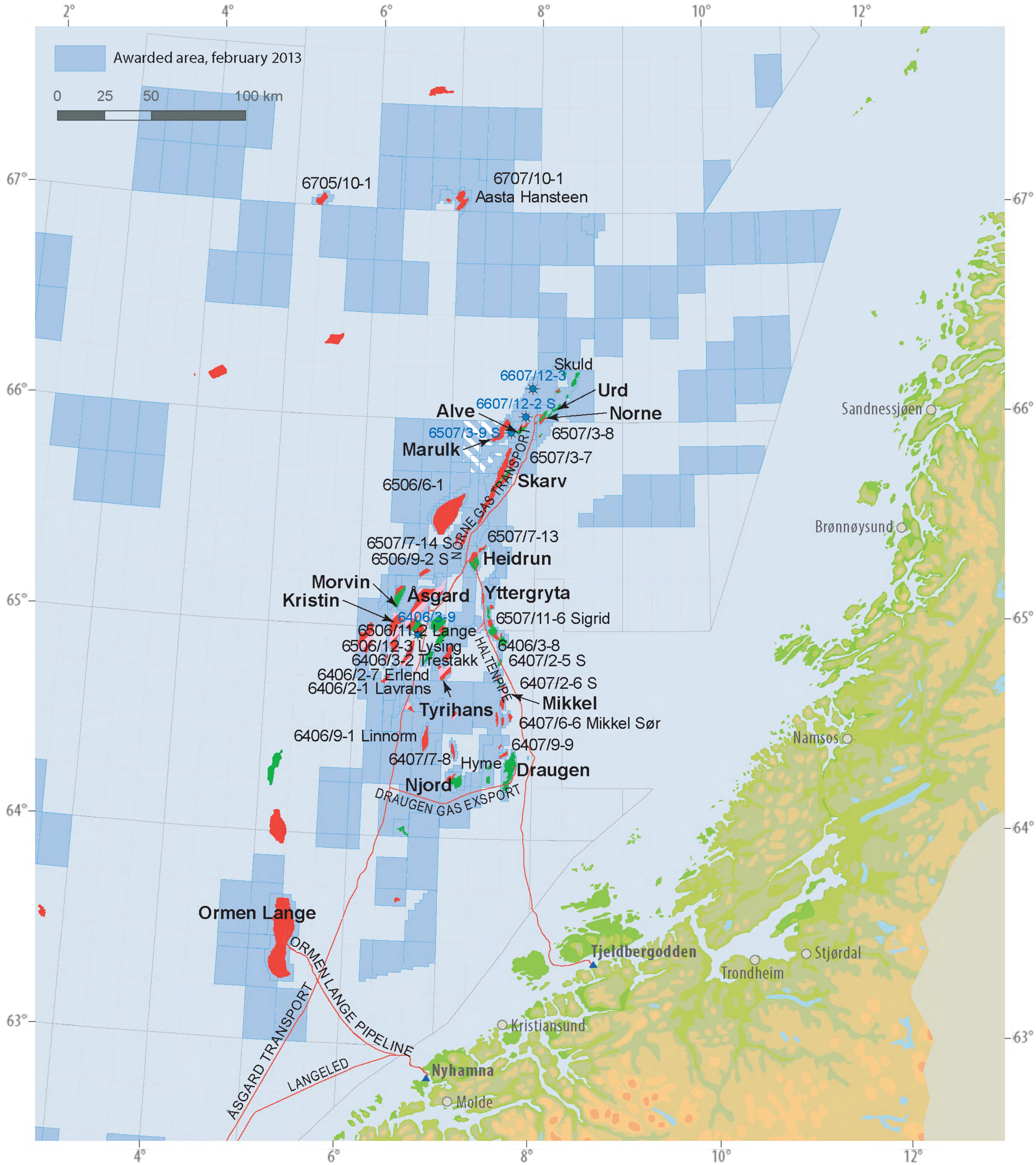


Figure 10.6 Fields and discoveries in the Norwegian Sea *(Source: Norwegian Petroleum Directorate)*

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. Sixteen fields are now producing in the Norwegian Sea, after Hyme, Marulk and Skarv started production. One field, Skuld, is being developed and a development plan for the 6707/10-1 Aasta Hansteen gas discovery has been submitted. 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 and 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.

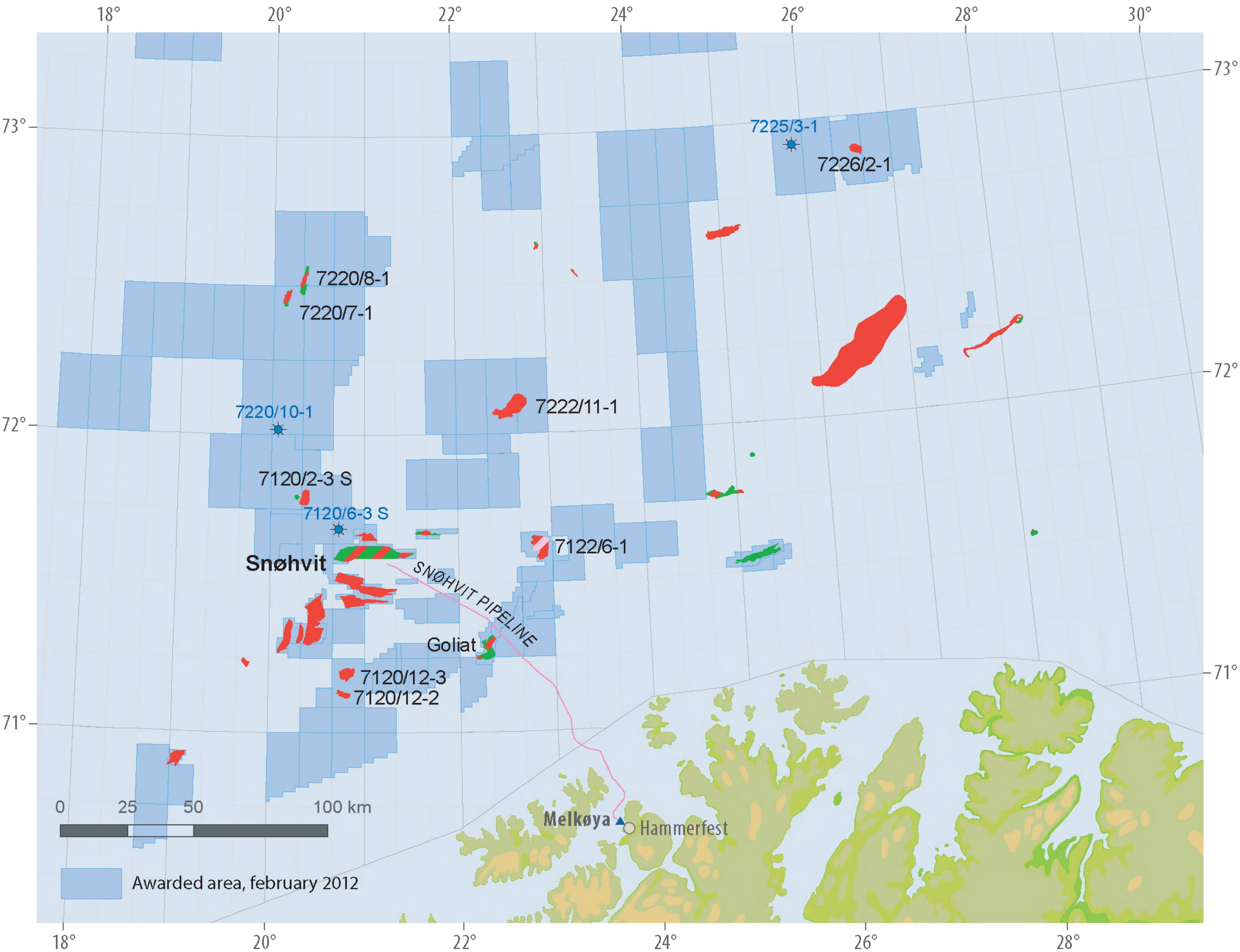
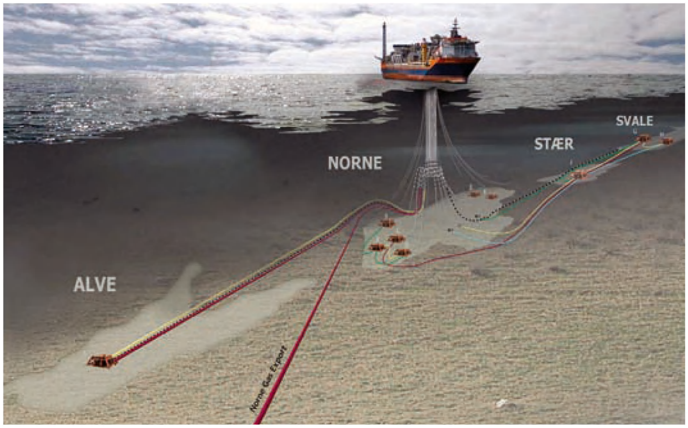


Figure 10.7 Fields and discoveries in the Barents Sea *(Source: Norwegian Petroleum Directorate)*

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 31.12.2012**
	1.9 million Sm^3 oil	0.8 million Sm^3 oil
	5.7 billion Sm^3 gas	2.7 billion Sm^3 gas
	1.1 million tonnes NGL	0.6 million tonnes NGL
Estimated production in 2013	Oil: 3 000 barrels/day, Gas: 0.51 billion Sm^3, NGL: 0.10 million tonnes	
Expected investment from 2012	0.1 billion 2012 values	
Total investment as of 31.12.2011	3.9 billion nominal values	



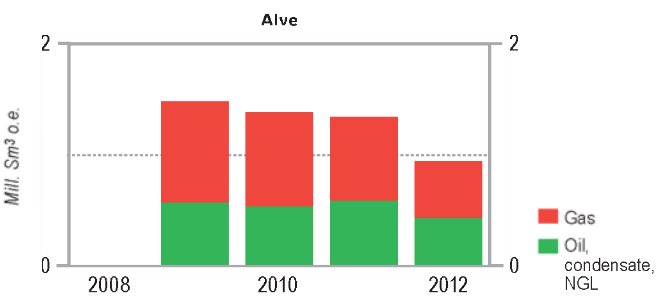
Development: Alve is a gas, condensate and oil field located about 16 kilometres southwest of Norne in the Norwegian Sea. The water depth in the area is about 370 metres. The development concept is a standard subsea template with four well slots and two production wells.

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.

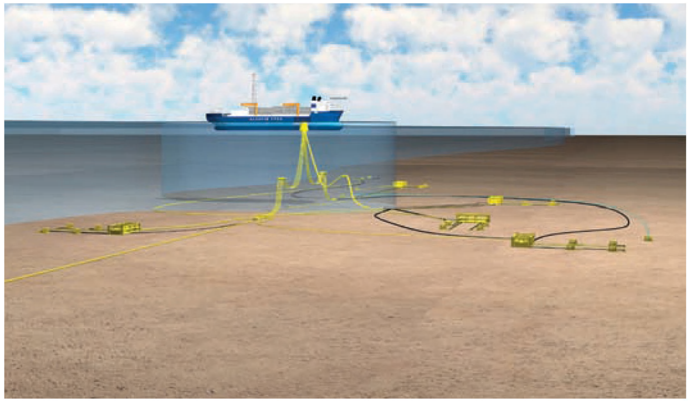
Transport: Alve is tied to the Norne vessel by a pipeline. The gas is transported via the Norne pipeline to Åsgard Transport and further to Kårstø for export.

Status: Two wells are producing oil and gas from the Ile and Tilje Formations.



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 31.12.2012**
	37.2 million Sm^3 oil	17.5 million Sm^3 oil
	6.8 billion Sm^3 gas	4.7 billion Sm^3 gas
Estimated production in 2013	Oil: 59 000 barrels/day, Gas: 0.58 billion Sm^3	
Expected investment from 2012	1.8 billion 2012 values	
Total investment as of 31.12.2011	17.7 billion nominal values	



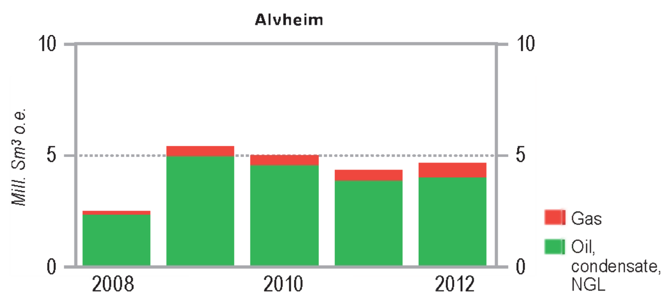
Development: Alvheim is an oil and gas field located in the central part of the North Sea, west of Heimdal and near the border to the British sector. The field includes three discoveries, 24/6-2 (Kamelon), 24/6-4 (Boa) and 25/4-7 (Kneler). 24/6-4 (Boa) lies partly in the British sector. The water depth 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 on the production vessel. The Vilje and Volund fields 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. Several new wells are planned for 2014/2015. The field can be an oil hub for future discoveries in the area. A PDO for Bøyla, a third party tie-in, was approved in 2012.



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
On stream	07.10.2012	
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**	**Remaining as of 31.12.2012**
	0.3 million Sm³ oil	0.3 million Sm³ oil
	1.4 billion Sm³ gas	1.3 billion Sm³ gas
Estimated production in 2013	Oil: 2 000 barrels/day, Gas: 0.6 billion Sm³	
Expected investment from 2012	1.2 billion 2012 values	
Total investment as of 31.12.2011	0.3 billion nominal values	

Development: Atla is located about 20 kilometres northeast of the Heimdal field. The water depth in the area is about 119 metres. Atla is developed with one production well from a subsea template tied back via the Skirne/Byggve subsea facility to Heimdal for processing.

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

Recovery strategy: The recovery strategy is gas depletion.

Transport: The wellstream is transported to Heimdal for processing and export.

Status: Production started in October 2012.

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 31.12.2012**
	72.1 million Sm³ oil	16.2 million Sm³ oil
	2.0 billion Sm³ gas	0.6 billion Sm³ gas
Estimated production in 2013	Oil: 32 000 barrels/day, Gas: 0.04 billion Sm³	
Expected investment from 2012	9.6 billion 2012 values	
Total investment as of 31.12.2011	23.2 billion nominal values	
Main supply base	Dusavik	

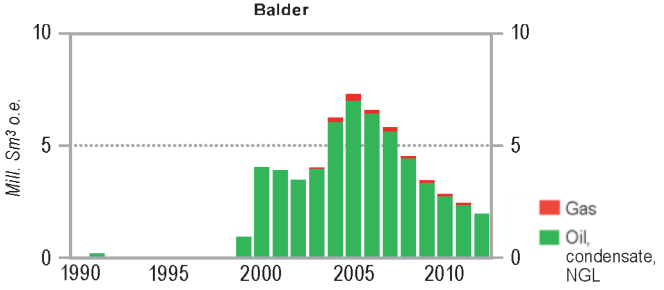
Development: Balder is an oil field in the central part of the North Sea, at a water depth of 125 metres. The field has been developed with subsea wells tied back to the accommodation, production and storage vessel, "Balder FPSO", where oil and gas are processed. The Ringhorne discovery, included in 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: Balder and Ringhorne contain several separate oil deposits in Eocene, Paleocene and Jurassic sandstones. Top reservoirs are at a depth of about 1 700 metres.

Recovery strategy: Balder and Ringhorne produce primarily by natural aquifer drive, but re-injection of produced water is used for pressure support, especially into the Ringhorne Jurassic reservoir. Excess water is injected into the Utsira formation. Gas is also injected if the gas export system is down.

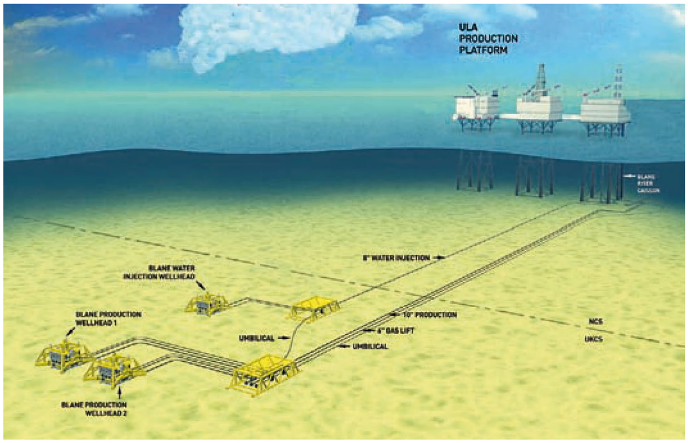
Transport: The Ringhorne facility is tied to the "Balder FPSO" and "Jotun FPSO" for processing, crude oil storage and gas export. The oil is transported by tankers. Excess gas from Balder is routed to Jotun for export. Jotun exports Ringhorne and Balder gas via Statpipe.

Status: The field is in the decline phase, but production is likely to continue until 2025. Ongoing studies are evaluating possible means to improve recovery. 4D seismic acquired in 2006, 2009 and 2012 is being used as a basis for reservoir monitoring and to evaluate drilling targets for more wells. A new drilling campaign started on Ringhorne in 2010 and several new wells will be drilled on Balder over the next years.



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		18.00 %
	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 31.12.2012**	
	0.8 million Sm^3 oil	0.3 million Sm^3 oil	
Estimated production in 2013	Oil: 1 000 barrels/day		
Total investment as of 31.12.2011	0.5 billion nominal values		



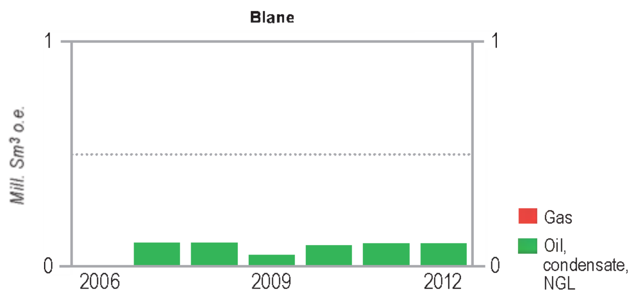
Development: Blane is an oil field located southwest of Ula in the southern part of the North Sea, on the border to the British sector. The water depth in the area is about 70 metres. The field has been developed with a subsea facility tied to the Ula field. The subsea templates are located on the British 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: The overall field performance has been good. Water breakthrough was experienced in the production wells. Gaslift is now required to keep the field producing. A new reservoir model will be used to evaluate whether more wells can be justified to improve recovery.



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 %
	Tullow Oil Norge 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 31.12.2012**	
	59.3 million Sm^3 oil	4.0 million Sm^3 oil	
	4.5 billion Sm^3 gas	1.2 billion Sm^3 gas	
	1.5 million tonnes NGL	0.3 million tonnes NGL	
Estimated production in 2013	Oil: 12 000 barrels/day, Gas: 0.05 billion Sm^3, NGL: 0.02 million tonnes		
Expected investment from 2012	4.4 billion 2012 values		
Total investment as of 31.12.2011	17.1 billion nominal values		
Main supply base	Mongstad		

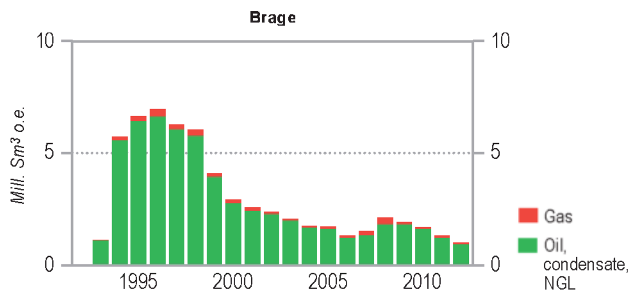
Development: Brage is an oil field east of Oseberg in the northern part of the North Sea. The water depth in the area is 140 metres. Brage has been developed with a fixed integrated production, drilling and accommodation facility with a steel jacket.

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 lie at a depth of 2 000 – 2 300 metres. The reservoir quality varies from poor to excellent.

Recovery strategy: The recovery strategy in the Statfjord and Fensfjord Formations is water injection. Gas injection started in March 2009 in the Sognefjord Formation. 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. WAG injection will start in a part of the Brent reservoir in 2013. A pilot project for microbiological injection (MEOR) is planned.



Draugen

Blocks and production licences	Block 6407/12 - production licence 176, awarded 1991. 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	44.56 %
	Chevron Norge AS	7.56 %
	Petoro AS	47.88 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**
	146.7 million Sm³ oil	14.9 million Sm³ oil
	1.6 billion Sm³ gas	0.1 billion Sm³ gas
	2.8 million tonnes NGL	0.4 million tonnes NGL
Estimated production in 2013	Oil: 29 000 barrels/day, Gas: 0.01 billion Sm³, NGL: 0.05 million tonnes	
Expected investment from 2012	12.3 billion 2012 values	
Total investment as of 31.12.2011	23.3 billion nominal values	
Main supply base	Kristiansund	

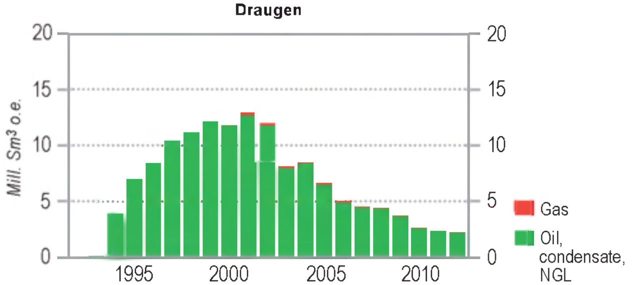
Development: Draugen is an oil field in the Norwegian Sea at a water depth of 250 metres. The field has been developed with a concrete fixed facility and integrated topside. Stabilised oil is stored in tanks in the base of the facility. Two pipelines transport the oil from the facility to a floating 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 which only three are being used.

Reservoir: The main reservoir is in sandstones in 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.

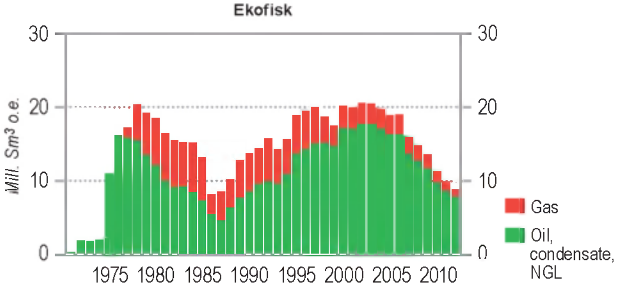
Status: Several measures to increase oil recovery have been evaluated. Based on a 4D seismic survey from 2009, an infill drilling campaign was sanctioned in 2011.The project includes four production wells and a subsea pump. The first oil from the project is scheduled in 2013. In December 2012, the planned tie-in of the 6406/9-1 Linnorm discovery to Draugen was put on hold. Because of this, supply of fuel gas to Draugen will be a challenge from 2016.



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 31.12.2012**	
	569.2 million Sm³ oil	129.8 million Sm³ oil	
	164.5 billion Sm³ gas	22.8 billion Sm³ gas	
	15.2 million tonnes NGL	2.2 million tonnes NGL	
Estimated production in 2013	Oil: 102 000 barrels/day, Gas: 0.88 billion Sm³, NGL: 0.12 million tonnes		
Expected investment from 2012	84.3 billion 2012 values		
Total investment as of 31.12.2011	94.2 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 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 production facility 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. 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.

Reservoir: The Ekofisk field produces from naturally fractured chalk in 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 area for water injection 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 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 wells and production wells from several facilities. Production from Ekofisk Z and injection from Ekofisk VB are planned to start in 2013.

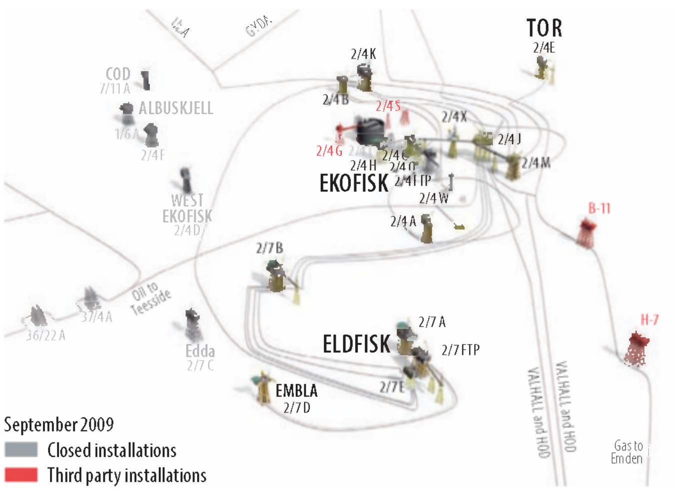


Figure 10.8 Facilities in the Ekofisk area *(Source: ConocoPhillips)*

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 31.12.2012**	
	137.9 million Sm^3 oil	37.3 million Sm^3 oil	
	44.8 billion Sm^3 gas	5.4 billion Sm^3 gas	
	4.1 million tonnes NGL	0.2 million tonnes NGL	
Estimated production in 2013	Oil: 34 000 barrels/day, Gas: 0.20 billion Sm^3, NGL: 0.04 million tonnes		
Expected investment from 2012	38.8 billion 2012 values		
Total investment as of 31.12.2011	35.0 billion nominal values		
Main supply base	Tananger		

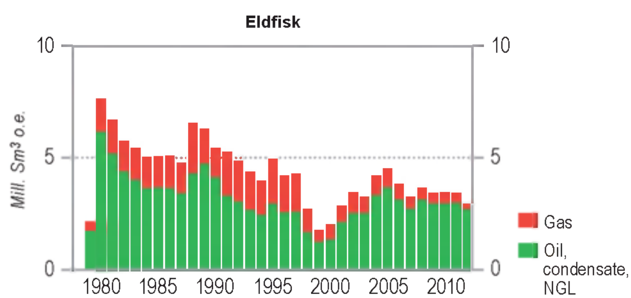
Development: Eldfisk is an oil field located south of Ekofisk, in the southern part of the North Sea. The water depth in the area is 70 - 75 metres. The original Eldfisk development consisted of three facilities. Eldfisk B is a combined drilling, wellhead and process facility, while Eldfisk A and Eldfisk 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. A PDO for Eldfisk II was approved in June 2011. The plan includes a new combined accommodation, wellhead and process facility, Eldfisk S, connected by bridge to Eldfisk E. The new facility will replace several functions of Eldfisk A and Eldfisk FTP. The Embla field will be tied back to Eldfisk S.

Reservoir: The Eldfisk field produces from chalk in the Ekofisk, Tor and Hod Formations of the Early Paleocene and Late Cretaceous ages. The reservoir rock is fine-grained and dense, but has 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 via 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: The new facility, Eldfisk S, is under construction. Ongoing modifications to the existing facilities are part of the Eldfisk II project. About 40 new production and injection wells will be drilled from Eldfisk S with start-up in 2015.



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 31.12.2012**	
	11.9 million Sm³ oil	1.5 million Sm³ oil	
	7.5 billion Sm³ gas	3.6 billion Sm³ gas	
	0.7 million tonnes NGL	0.3 million tonnes NGL	
Estimated production in 2013	Oil: 2 000 barrels/day, Gas: 0.09 billion Sm³, NGL: 0.01 million tonnes		
Expected investment from 2012	0.6 billion 2012 values		
Total investment as of 31.12.2011	3.1 billion nominal values		
Main supply base	Tananger		

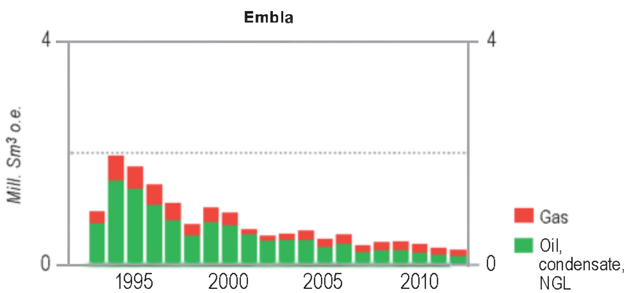
Development: Embla is an oil field located near Eldfisk in the southern part of the North Sea. The field has been developed with an unmanned wellhead facility which is remotely controlled from Eldfisk. The water depth in the area is 70 – 75 metres. An amended PDO for Embla was approved in April 1995.

Reservoir: The Embla field produces from a segmented sandstone and conglomerate reservoir of Devonian and Permian 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.

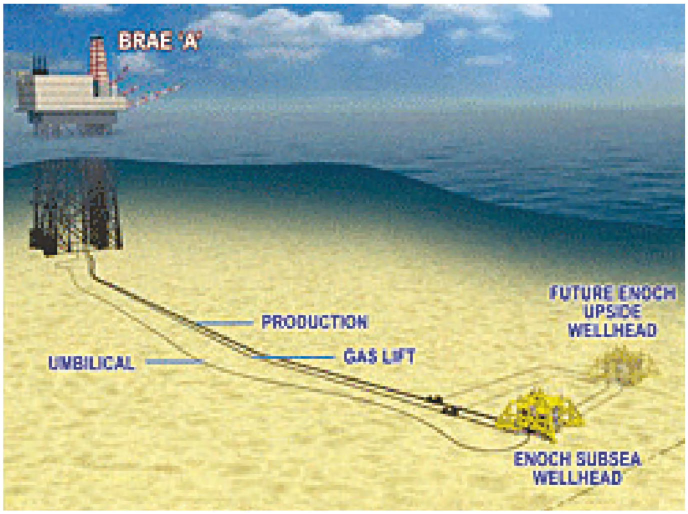
Transport: Oil and gas are transported to Eldfisk for processing and on to the Ekofisk Centre for export. Gas from the Ekofisk area is transported by pipeline to Emden, while the oil, which also contains NGL fractions, is routed by pipeline to Teesside.

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.



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	Det norske oljeselskap ASA		2.00 %
	Faroe Petroleum Norge AS		1.86 %
	Noreco Norway AS		4.36 %
	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 31.12.2012**	
	0.4 million Sm³ oil	0.1 million Sm³ oil	
Total investment as of 31.12.2011	0.2 billion nominal values		

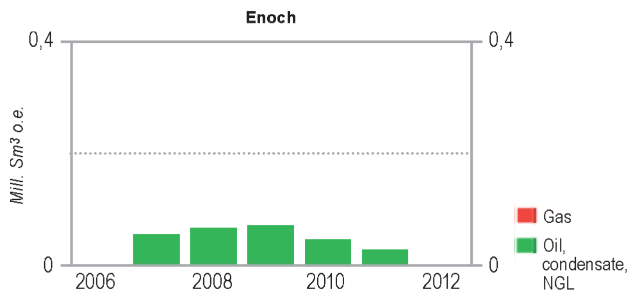


Development: Enoch is located in the central part of the North Sea on the border to the British sector, just northwest of Sleipner. The field has been developed with a subsea facility on the British continental shelf and is tied to the British field Brae.

Reservoir: The reservoir contains oil 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.



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 31.12.2012**	
	30.7 million Sm^3 oil	5.9 million Sm^3 oil	
	8.8 billion Sm^3 gas	6.3 billion Sm^3 gas	
	0.6 million tonnes NGL	0.4 million tonnes NGL	
Estimated production in 2013	Oil: 35 000 barrels/day, Gas: 0.62 billion Sm^3, NGL: 0.04 million tonnes		
Expected investment from 2012	0.1 billion 2012 values		
Total investment as of 31.12.2011	9.9 billion nominal values		
Main supply base	Mongstad		

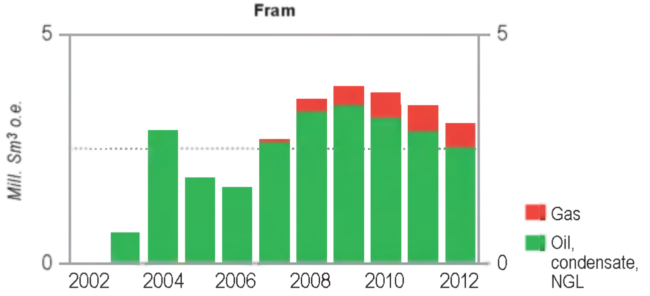
Development: Fram is an oil field located in the northern part of the North Sea, about 20 kilometres north of Troll. The water depth in the area is approximately 350 metres. The field comprises two deposits, Fram Vest and Fram Øst. The Fram Vest deposit is developed by two subsea templates tied back 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 in April 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 sandstones in a sub-marine fan system in the Draupne Formation and shallow marine sandstones in the Sognefjord Formation of Late Jurassic age and partly of sandstones in 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 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 in the area. A PDO exemption for development of Fram H-Nord has been sent the authorities. Development plans include a two branch multilateral (MLT) well with gas lift, which will be produced by pressure depletion. Production will be routed through a subsea template tied in to Fram Vest and on to Troll C for processing.



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	
On stream	31.03.2012		
Operator	BG Norge AS		
Licensees	BG Norge AS		60.00 %
	Lundin Norway AS		40.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2012**	
	0.2 million Sm^3 oil	0.1 million Sm^3 oil	
	0.5 billion Sm^3 gas	0.3 billion Sm^3 gas	
Estimated production in 2013	Oil: 1 000 barrels/day, Gas: 0.12 billion Sm^3, NGL: 0.01 million tonnes		
Expected investment from 2012	0.2 billion 2012 values		
Total investment as of 31.12.2011	2.1 billion nominal values		

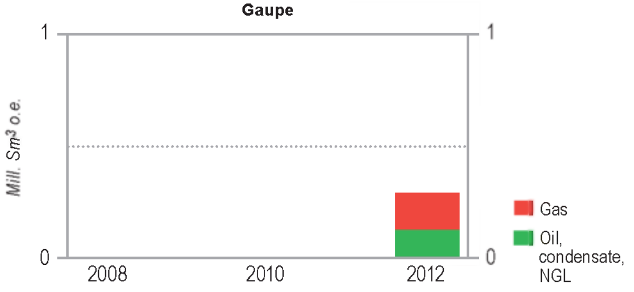
Development: Gaupe is located close to the border between the Norwegian and UK sectors, about 12 kilometres south of the Varg field. The water depth in the area is approximately 90 metres. The development concept is two single horizontal subsea wells tied to the Armada installation on the UK shelf.

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 is produced by pressure depletion. Initial production is from the oil zone, followed by combined production from the oil and gas zones.

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

Status: Production started in March 2012. The two development wells came in with low production rates, and the field is now expected to produce for only two to four years.



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 31.12.2012**
	3.0 million Sm^3 oil	0.4 million Sm^3 oil
	1.4 billion Sm^3 gas	1.0 billion Sm^3 gas
	0.3 million tonnes NGL	0.2 million tonnes NGL
Estimated production in 2013	Oil: 2 000 barrels/day, Gas: 0.35 billion Sm^3, NGL: 0.07 million tonnes	
Expected investment from 2012	0.5 billion 2012 values	
Total investment as of 31.12.2011	0.8 billion nominal values	

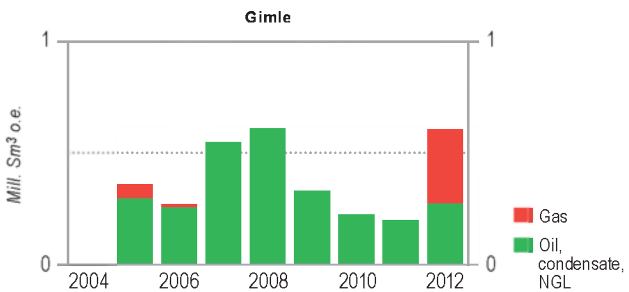
Development: Gimle is an oil field in the northern part of the North Sea. The water depth in the area is about 220 metres. The field is tied to the Gullfaks C facility by two production wells and one water injection well drilled from Gullfaks C.

Reservoir: The reservoir consists of sandstones in 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: A production well combined with an exploration pilot is currently being drilled. Findings in the new well will be important input for further evaluation of additional wells on the field.



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** 1989
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 31.12.2012**
	11.6 million Sm^3 oil	6.4 million Sm^3 oil
	32.7 billion Sm^3 gas	27.8 billion Sm^3 gas
	8.7 million tonnes NGL	7.6 million tonnes NGL
Estimated production in 2013	Oil: 24 000 barrels/day, Gas: 2.71 billion Sm^3, NGL: 0.72 million tonnes	
Expected investment from 2012	2.4 billion 2012 values	
Total investment as of 31.12.2011	28.0 billion nominal values	
Main supply base	Florø	

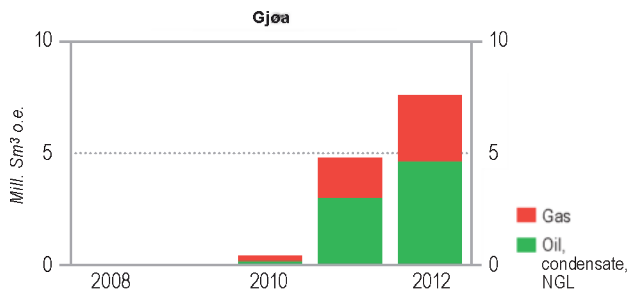
Development: Gjøa is located about 40 kilometres north of the Fram field. The water depth in the area is 360 metres. The development comprises five subsea templates tied to a semi-submersible production and processing facility. The Gjøa facility is partly supplied with power from shore. Vega and Vega 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 through a pipeline connected to Troll Oljerør II, for further transport to Mongstad. Rich gas is exported by 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.



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 31.12.2012**	
	8.9 million Sm^3 oil		
Estimated production in 2013	Oil: 230 barrels/day		
Expected investment from 2012	0.5 billion 2012 values		
Total investment as of 31.12.2011	2.5 billion nominal values		
Main supply base	Dusavik		

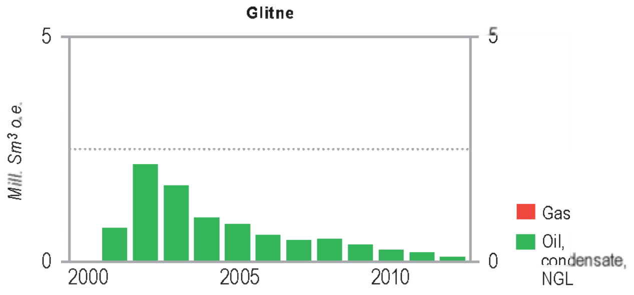
Development: Glitne is an oil field in the central part of the North Sea, 40 kilometres north of the Sleipner area. The water depth in the area is about 110 metres. The field is developed with six horizontal production wells and one water injection well, tied back to the production and storage vessel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

Reservoir: The reservoir consists of several separate sandlobes 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 was used for gas lift in the horizontal wells until August 2012.

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 was drilled in 2012, but was abandoned. A disposal plan was submitted in August 2012, and it is expected that production from the field will cease during the first quarter of 2014.



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	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 31.12.2012**	
	124.6 million Sm^3 oil	36.1 million Sm^3 oil	
Estimated production in 2013	Oil: 98 000 barrels/day		
Expected investment from 2012	10.0 billion 2012 values		
Total investment as of 31.12.2011	19.7 billion nominal values		
Main supply base	Mongstad		

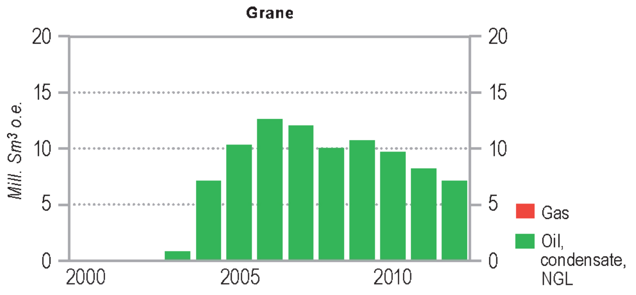
Development: Grane is an oil field located east of the Balder field in the central part of the North Sea. The water depth is 128 metres. The field has been developed with an integrated accommodation, drilling and processing facility with a fixed steel jacket. The facility has 40 well slots.

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. Only the produced gas is being re-injected into the reservoir. Water injection started in February 2011. Oil recovery will be maintained by expansion of the gas cap, water injection and drilling of deep side-tracks from existing producers.

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. It has been decided to install a permanent reservoir monitoring system on the seabed to increase recovery with improved seismic.



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 31.12.2012
	365.5 million Sm^3 oil	11.6 million Sm^3 oil
	23.1 billion Sm^3 gas	
	2.8 million tonnes NGL	
Estimated production in 2013	Oil: 39 000 barrels/day	
Expected investment from 2012	39.6 billion 2012 values	
Total investment as of 31.12.2011	74.9 billion nominal values	
Main supply base	Sotra and Florø	

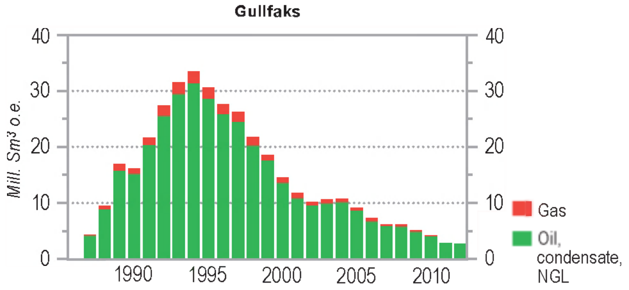
Development: Gullfaks is an oil field located in the Tampen area in the northern part of the North Sea. The water depth in the area is 130 – 220 metres. The field has been developed with three integrated processing, drilling and accommodation facilities with concrete bases and steel topsides (Gullfaks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

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 at a depth of 1 700 – 2 000 metres. 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 recovery strategy varies between the drainage areas on the field, with water injection as the main strategy.

Transport: Oil is exported from Gullfaks A and Gullfaks C via loading buoys onto tankers. Rich gas is transported through Statpipe for further processing at Kårstø.

Status: Evaluation of lifetime extension of Gullfaks is ongoing. This includes upgrades to the drilling facilities. Increased oil recovery through optimized distribution of gas and water injection in the various areas of the field is a major challenge. The licensees are also evaluating injection of silica gel as a method to increase oil recovery from Gullfaks. Studies are ongoing on future tie-in of Snorre oil export. Future tie-in of export oil from Snorre is being studied.



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 31.12.2012
	58.8 million Sm^3 oil	16.6 million Sm^3 oil
	65.1 billion Sm^3 gas	32.1 billion Sm^3 gas
	9.2 million tonnes NGL	5.0 million tonnes NGL
Estimated production in 2013	Oil: 37 000 barrels/day, Gas: 2.18 billion Sm^3, NGL: 0.27 million tonnes	
Expected investment from 2012	31.0 billion 2012 values	
Total investment as of 31.12.2011	28.3 billion nominal values	
Main supply base	Sotra and Florø	

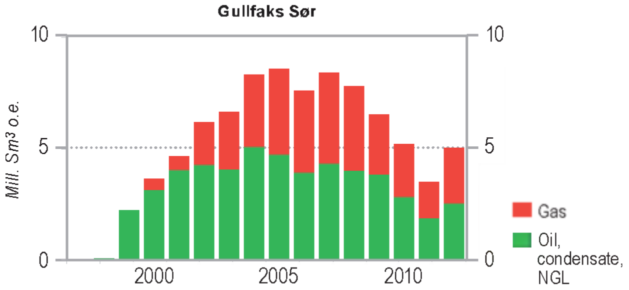
Development: Gullfaks Sør is located to the south of Gullfaks in the northern part of the North Sea. It has been developed with a total of 12 subsea templates tied back to the Gullfaks A and Gullfaks C facilities. Gullfaks Sør has been developed in two phases. The PDO for Phase 1 included production 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 in 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 in February 2005. The development included a new subsea template and a satellite well. An amended PDO for the redevelopment of Gullfaks Sør Statfjord Formation was approved in October 2012.

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.

Status: A project to develop resources in the western parts of the area is ongoing. Prolonged gas injection to increase oil recovery from some of the Gullfaks Sør reservoirs is being evaluated. A subsea gas compressor will be installed on the field in order to boost gas production.



Gungne

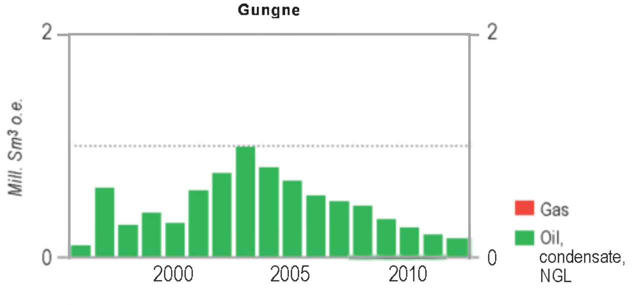
Blocks and production licences	Block 15/9 - production licence 046, awarded 1976.		
Development approval	29.08.1995 by the King in Council	**Discovered** 1982	
On stream	21.04.1996		
Operator	Statoil Petroleum AS		
Licensees	ExxonMobil Exploration & Production Norway AS		28.00 %
	Statoil Petroleum AS		62.00 %
	Total E&P Norge AS		10.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2012**	
	15.2 billion Sm^3 gas	1.3 billion Sm^3 gas	
	2.2 million tonnes NGL	0.3 million tonnes NGL	
	4.7 million Sm^3 condensate	0.4 million Sm^3 condensate	
Estimated production in 2013	Gas: 0.32 billion Sm^3, NGL: 0.06 million tones, Condensate: 0.06 million Sm^3		
Total investment as of 31.12.2011	1.9 billion nominal values		
Main supply base	Dusavik		

Development: Gungne is a 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.



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 31.12.2012**	
	36.5 million Sm^3 oil	0.9 million Sm^3 oil	
	6.7 billion Sm^3 gas	0.5 billion Sm^3 gas	
	2.0 million tonnes NGL	0.1 million tonnes NGL	
Estimated production in 2013	Oil: 3 000 barrels/day, Gas: 0.06 billion Sm^3, NGL: 0.01 million tonnes		
Expected investment from 2012	0.9 billion 2012 values		
Total investment as of 31.12.2011	12.4 billion nominal values		
Main supply base	Tananger		

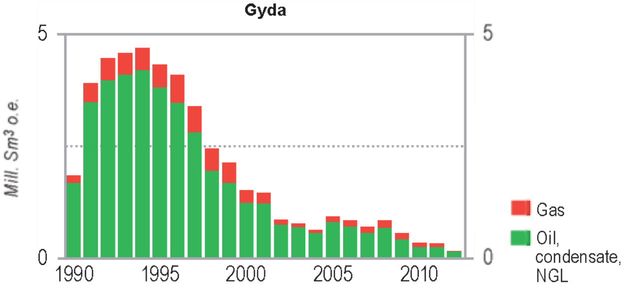
Development: Gyda is an oil field located between Ula and Ekofisk in the southern part of the North Sea. The water depth in the area is 66 metres. The field has been developed with a combined drilling, accommodation and processing facility with a steel jacket.

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 is produced by 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 the 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 development of the Gyda South area which still has a good reserve potential. In 2013 a new producer will be drilled on Gyda South and an existing producer in the area will be converted to water injection. Opportunities to prolong the lifetime of the field include evaluations of potential third party tie-ins.



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 31.12.2012**	
	182.1 million Sm^3 oil	40.1 million Sm^3 oil	
	46.5 billion Sm^3 gas	31.3 billion Sm^3 gas	
	2.2 million tonnes NGL	1.7 million tonnes NGL	
Estimated production in 2013	Oil: 65 000 barrels/day, Gas: 0.76 billion Sm^3		
Expected investment from 2012	23.2 billion 2012 values		
Total investment as of 31.12.2011	52.9 billion nominal values		
Main supply base	Kristiansund		

Development: The Heidrun field is located on Haltenbanken in the Norwegian Sea. The water depth is about 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 in May 2000.

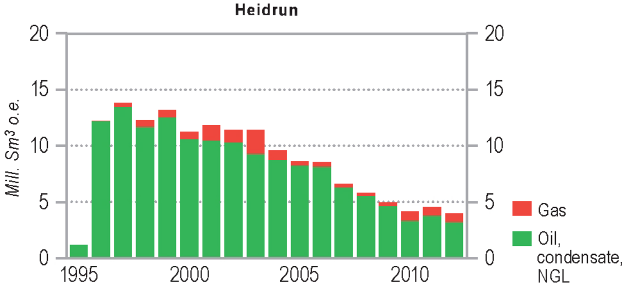
Reservoir: The reservoir consists of sandstones in the Garn, Ile, Tilje and Åre Formations of Early and Middle Jurassic age. The reservoir is heavily faulted. The Garn and Ile Formations have good reservoir quality, while the Tilje and Åre Formations are more complex. The reservoir depth is about 2 300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

Recovery strategy: The recovery strategy for the field is pressure maintenance using water 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 evaluated in an effort to increase oil recovery. Light Well Interventions have resulted in increased oil recovery. Pilots to improve recovery are being assessed, and some have been implemented. In addition, there are ongoing technical studies to identify potential third-party tie-back candidates to Heidrun.

Heidrun



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		33.80 %
	Petoro AS		20.00 %
	Statoil Petroleum AS		29.44 %
	Total E&P Norge AS		16.76 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2012**	
	8.2 million Sm^3 oil	1.6 million Sm^3 oil	
	46.9 billion Sm^3 gas	1.7 billion Sm^3 gas	
Estimated production in 2013	Oil: 330 barrels/day, Gas: 0.11 billion Sm^3		
Expected investment from 2012	0.2 billion 2012 values		
Total investment as of 31.12.2011	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 in October 1992. A PDO for Heimdal Gas Centre (HGS) was approved in 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. Atla, Huldra, Skirne and Vale deliver gas to Heimdal. In addition, gas from Oseberg is transported via Heimdal.

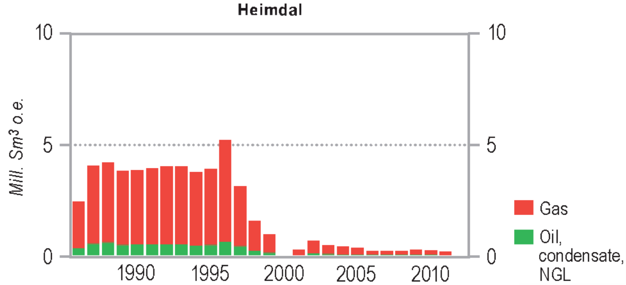
Reservoir: The reservoir consists of sandstones of the Heimdal Formation of Paleocene age, deposited as sub-marine fan systems. The reservoir depth is about 2 100 metres.

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

Transport: Originally, gas from Heimdal was sent in Statpipe to Kårstø and on to the Continent, but now can 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 working to identify new gas resources that can be tied to Heimdal to prolong the lifetime of the gas centre. Valemon is a new candidate that can transport gas via Heimdal when Huldra gas export via Heimdal is ended, probably in 2014.

Heimdal



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 31.12.2012**	
	10.4 million Sm^3 oil	0.9 million Sm^3 oil	
	1.8 billion Sm^3 gas	0.2 billion Sm^3 gas	
	0.4 million tonnes NGL	0.1 million tonnes NGL	
Estimated production in 2013	Oil: 1 000 barrels/day, Gas: 0.01 billion Sm^3		
Expected investment from 2012	0.1 billion 2012 values		
Total investment as of 31.12.2011	2.3 billion nominal values		
Main supply base	Tananger		

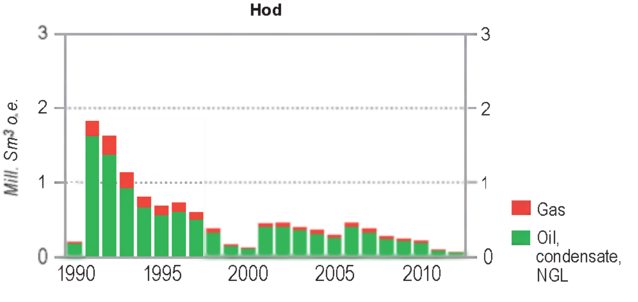
Development: Hod is an oil field located 13 kilometres south of the Valhall field in the southern part of the North Sea. The water depth is 72 metres. The field is developed with an unmanned production facility, which is remotely controlled from the Valhall field. The PDO for the Hod Sadel area was approved 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 produces 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: The field is in the tail phase and the production from Hod Øst and Hod Vest was closed down in 2012. There are plans for redevelopment which can extend the lifetime of the field. The operator has applied for licence extension from 2015.



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 31.12.2012**	
	5.1 million Sm^3 oil	0.7 billion Sm^3 gas	
	17.5 billion Sm^3 gas		
	0.1 million tonnes NGL		
Estimated production in 2013	Oil: 950 barrels/day, Gas: 0.36 billion Sm^3		
Total investment as of 31.12.2011	7.5 billion nominal values		
Main supply base	Sotra and Florø		

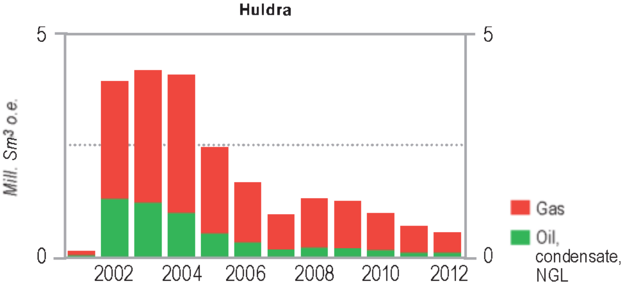
Development: Huldra is a gas condensate field located north of Oseberg in the northern part of the North Sea. The water depth in the area is 125 metres. The field is developed with a wellhead facility with a simple process plant. The facility is remotely operated from Veslefrikk B, 16 kilometres away.

Reservoir: The reservoir is in Middle Jurassic sandstones of the Brent Group in a rotated fault block. The reservoir initially had 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 produced by pressure depletion. Low pressure production began in 2007, after a gas compressor was installed on the field.

Transport: Following first stage separation, the wet gas is transported to Heimdal for further processing and export. The condensate is transported to Veslefrikk for processing and export. The Huldrapipe to Heimdal is planned to be utilized by Valemon from 2014.

Status: Huldra is in the tail production phase, but maintains the well potential, and the decline has been less than expected.



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
On stream	10.04.2012	
Operator	TOTAL E&P UK PLC	
Licensees	Total E&P Norge AS	100.00 %
Recoverable reserves (Norwegian part)	**Original**	**Remaining as of 31.12.2012**
	0.1 billion Sm^3 gas	0.1 billion Sm^3 gas
Estimated production in 2013	Gas: 0.04 billion Sm^3	
Expected investment from 2012	0.2 billion 2012 values	
Total investment as of 31.12.2011	0.6 billion nominal values	

Development: Islay straddles the border between the UK and Norwegian sectors in the northern North Sea. The water depth is 122 metres. Islay is developed with one well tied to the Forvie manifold on UK side.

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

Recovery strategy: The field is produced by pressure depletion.

Transport: Production is routed via the Forvie-Alwyn pipeline to the British Alwyn field for separation. The gas is exported via the FUKA pipeline to St Fergus in Scotland, whereas the liquids are exported to the Sullom Voe terminal in the Shetland Islands.

Status: Production started in April 2012.

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 31.12.2012**
	23.4 million Sm^3 oil	0.7 million Sm^3 oil
	1.1 billion Sm^3 gas	0.2 billion Sm^3 gas
Estimated production in 2013	Oil: 2 000 barrels/day	
Expected investment from 2012	0.2 billion 2012 values	
Total investment as of 31.12.2011	9.5 billion nominal values	
Main supply base	Dusavik	

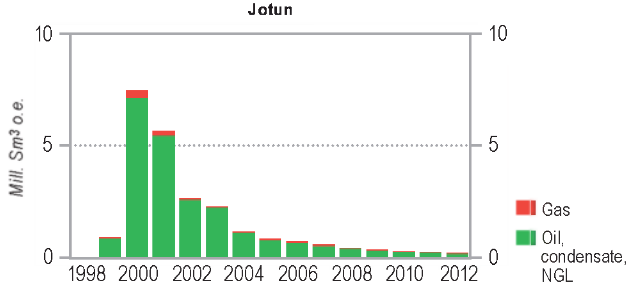
Development: Jotun is an oil field located 25 kilometres north of Balder in the central part of the North Sea. The water depth in the area is 126 metres. The field has been developed with a combined accommodation, production and storage vessel (FPSO), "Jotun A", and a wellhead facility, Jotun B. Jotun 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 in 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 reservoir quaility is good, while the shale content increases towards the east.

Recovery strategy: The field is recovered by pressure support from the aquifer. Produced water is 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 facilities. 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 97 per cent of the wellstream. Jette, a small oilfield nearby, will be tied-in and production via Jotun is planned to start in the second quarter of 2013. Jotun is expected to produce until 2021.



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 31.12.2012**
	22.9 million Sm^3 oil	6.0 million Sm^3 oil
	28.7 billion Sm^3 gas	9.7 billion Sm^3 gas
	6.3 million tonnes NGL	2.3 million tonnes NGL
	2.1 million Sm^3 condensate	
Estimated production in 2013	Oil: 15 000 barrels/day, Gas: 1.18 billion Sm^3, NGL: 0.25 million tonnes	
Expected investment from 2012	2.2 billion 2012 values	
Total investment as of 31.12.2011	24.5 billion nominal values	
Main supply base	Kristiansund	

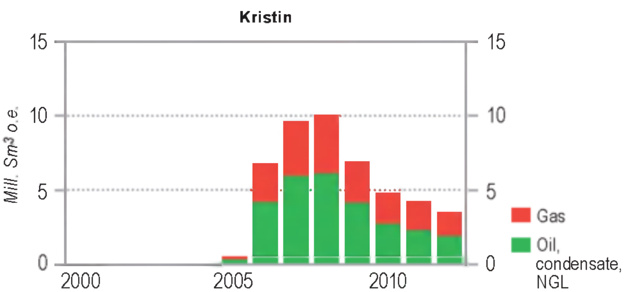
Development: Kristin is a gas condensate field in the Norwegian Sea. The field is developed with four subsea templates tied back to a semi-submersible facility for processing, Kristin Semi. The water depth in the area is about 370 metres. Provision has been made for tie-in and processing of other deposits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

Reservoir: The reservoirs are in Jurassic sandstones in the Garn, Ile and Tofte Formations and contain gas and condensate that were initially under high pressure and temperatures. The reservoirs lie at a depth of 4 600 metres. The reservoir quality is generally 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 evaluated as a possible processing centre for other discoveries in the area. Kristin is planned to host the cross-over between Polarled and Åsgard Transport.



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	Centrica Resources (Norge) AS	19.00 %
	Enterprise Oil Norge AS	6.45 %
	Petoro AS	30.00 %
	Statoil Petroleum AS	39.55 %
	Total E&P Norge AS	5.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2012**
	27.3 million Sm^3 oil	9.8 million Sm^3 oil
	89.1 billion Sm^3 gas	49.8 billion Sm^3 gas
	11.5 million tonnes NGL	8.1 million tonnes NGL
Estimated production in 2013	Oil: 34 000 barrels/day, Gas: 7.03 billion Sm^3, NGL: 0.34 million tonnes	
Expected investment from 2012	8.2 billion 2012 values	
Total investment as of 31.12.2011	13.7 billion nominal values	
Main supply base	Florø	

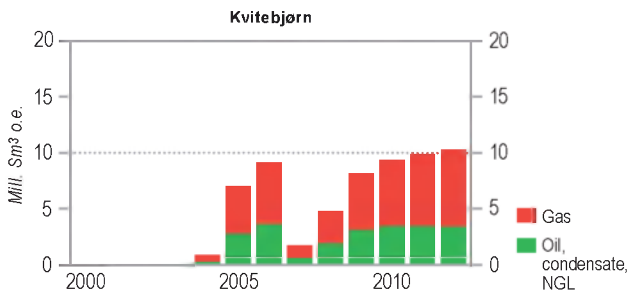
Development: Kvitebjørn is a gas condensate field located in the eastern part of the Tampen area, in the northern part of the North Sea. Water depth in the area is about 190 metres. The field is developed with an integrated accommodation, drilling and processing facility with a steel jacket. An amended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

Reservoir: The main reservoir consists of Middle Jurassic sandstones of the Brent Group. Discoveries have also been made in the Cook- and Statfjord Formations. The reservoir lies at a depth of approximately 4 000 metres and initially had high temperature and high pressure. The reservoir quality is good.

Recovery strategy: The field is recovered by pressure depletion.

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

Status: Drilling on Kvitebjørn is challenging due to depleted reservoir pressure. A new infill well was drilled in 2012 and a second is being drilled in 2013. Development of the east flank of the field is being considered. Gas pre-compression will be installed on the platform, with start-up in December 2013. Modifications are being made to prepare for tie-in of the Valemon field in 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
On stream	02.04.2012	
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**	**Remaining as of 31.12.2012**
	0.7 million Sm^3 oil	0.6 million Sm^3 oil
	8.4 billion Sm^3 gas	7.8 billion Sm^3 gas
	0.9 million tonnes NGL	0.9 million tonnes NGL
Estimated production in 2013	Oil: 290 barrels/day, Gas: 0.16 billion Sm^3, NGL: 0.02 million tonnes	
Expected investment from 2012	1.5 billion 2012 values	
Total investment as of 31.12.2011	2.2 billion nominal values	

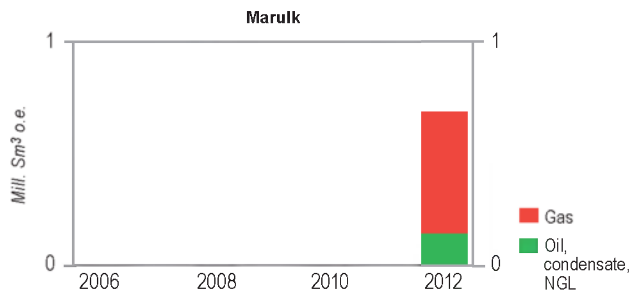
Development: Marulk is a gas and condensate field located about 25 kilometres southwest of the Norne field. The water depth in the area is about 370 metres. Marulk is developed with a subsea template tied back to the Norne vessel.

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 is produced by pressure depletion.

Transport: The wellstream is sent to the Norne vessel for processing. The gas is then transported to Åsgard Transport and further to Kårstø.

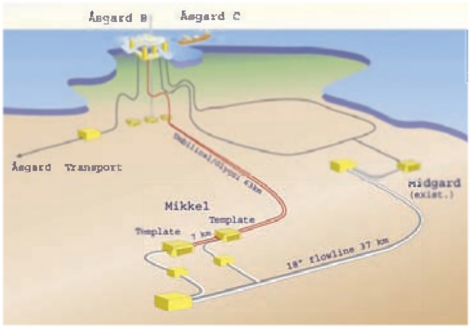
Status: Gas production started in April 2012. This is the first Eni operated field in Norway.



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 31.12.2012**	
	6.6 million Sm^3 oil	3.3 million Sm^3 oil	
	31.4 billion Sm^3 gas	15.8 billion Sm^3 gas	
	8.6 million tonnes NGL	4.4 million tonnes NGL	
	2.2 million Sm^3 condensate		
Estimated production in 2013	Oil: 5 000 barrels/day, Gas: 1.40 billion Sm^3, NGL: 0.40 million tonnes		
Expected investment from 2012	3.6 billion 2012 values		
Total investment as of 31.12.2011	2.2 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. A gas compression facility at Midgard was approved in 2012.

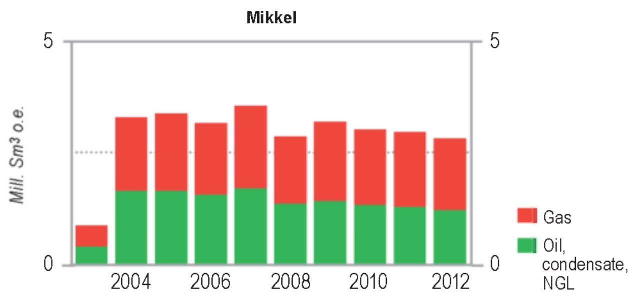


Reservoir: The field has a 300-metre thick gas condensate column and a thin underlying oil zone. The reservoir consists of Jurassic sandstones in the Garn, Ile and Tofte Formations in six structures separated by faults, all with good reservoir quality. The reservoir depth is approximately 2 500 metres.

Recovery strategy: Mikkel is recovered by pressure depletion.

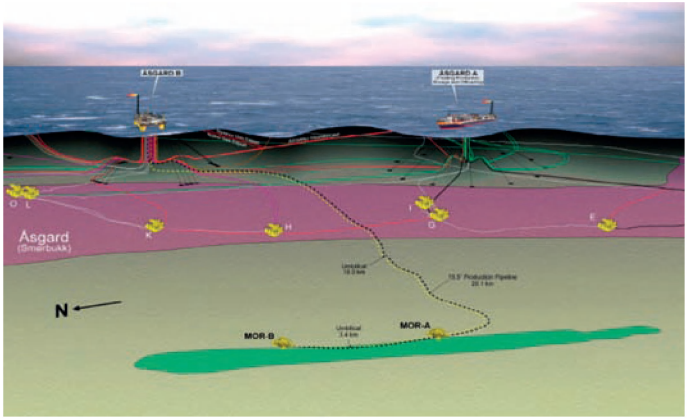
Transport: The wellstream from Mikkel is combined with the wellstream from the Midgard deposit and routed to Åsgard B for processing. The condensate is separated from the gas and stabilised before it is shipped together with condensate from Åsgard. The condensate is sold as oil (Halten Blend). The rich 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: The pressure decline in the reservoir has been less than anticipated and has resulted in an increased gas estimate for the field. The gas compression planned to start in 2015 will accelerate and prolong gas production from Mikkel. 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. Work is being done to develop proven gas resources in the area via Mikkel and Midgard to Åsgard B.



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 31.12.2012**
	9.3 million Sm^3 oil	5.6 million Sm^3 oil
	4.5 billion Sm^3 gas	4.5 billion Sm^3 gas
	1.1 million tonnes NGL	1.1 million tonnes NGL
Estimated production in 2013	Oil: 19 000 barrels/day, Gas: 0.49 billion Sm^3, NGL: 0.12 million tonnes	
Total investment as of 31.12.2011	8.0 billion nominal values	



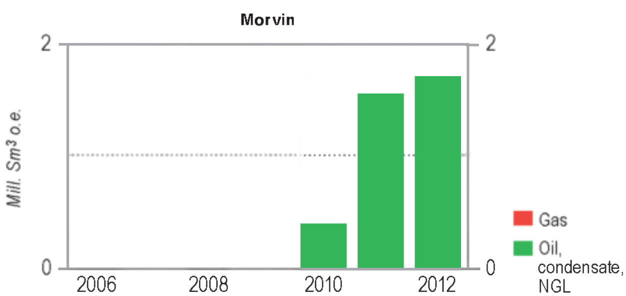
Development: Morvin is located approximately 20 kilometres north of Kristin and 15 kilometres west of Åsgard. The water depth in the area is about 350 metres. The field is developed with two subsea templates tied back to Åsgard B.

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 is 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.



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 AS	22.20 %
	CNR International (UK) Limited	77.80 %
Recoverable reserves (Norwegian part)	**Original**	**Remaining as of 31.12.2012**
	13.9 million Sm^3 oil	
	0.3 billion Sm^3 gas	
Estimated production in 2013	Oil: 640 barrels/day	
Expected investment from 2012	0.1 billion 2012 values	
Total investment as of 31.12.2011	2.6 billion nominal values	
Main supply base	Peterhead, Scotland	

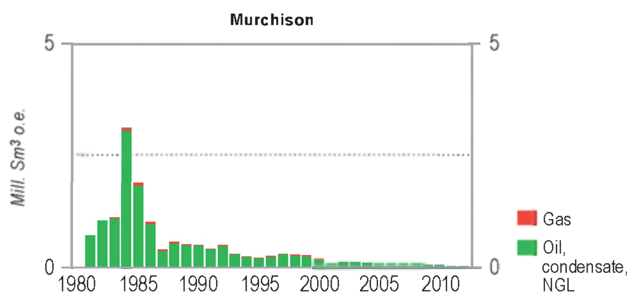
Development: Murchison straddles the border between the Norwegian and British sectors in the Tampen area, in the northern part of the North Sea. The field has been developed with a combined drilling, accommodation and production facility with a steel jacket situated in the British sector. The British 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 cessation of production is expected in 2014.



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 31.12.2012**
	28.5 million Sm³ oil	3.0 million Sm³ oil
	17.2 billion Sm³ gas	9.4 billion Sm³ gas
	3.9 million tonnes NGL	2.1 million tonnes NGL
Estimated production in 2013	Oil: 10 000 barrels/day, Gas: 0.98 billion Sm³, NGL: 0.23 million tonnes	
Expected investment from 2012	6.0 billion 2012 values	
Total investment as of 31.12.2011	14.9 billion nominal values	
Main supply base	Kristiansund	

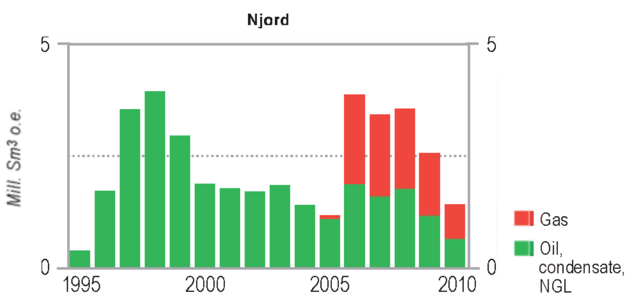
Development: Njord is an oil field located about 30 kilometres west of Draugen in the Norwegian Sea. The water depth in the area is 330 metres. The field has been developed with a semi-submersible drilling, accommodation and production facility and a storage vessel, "Njord B". The facility is placed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

Reservoir: The reservoir consists of Jurassic sandstones in the Tilje and Ile Formations. The field has a complicated fault pattern with only partial communication between the segments. The reservoir depth is 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. Production is expected to be significantly below production potential. This is due to a continued need for topside work requiring production stops. In addition, some existing wells will be shut down to allow for planned drilling operations. Hyme, a tie-into Njord, is planned to come on stream in the first quarter of 2013.



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 31.12.2012**
	90.8 million Sm³ oil	3.8 million Sm³ oil
	12.0 billion Sm³ gas	5.4 billion Sm³ gas
	1.6 million tonnes NGL	0.8 million tonnes NGL
Estimated production in 2013	Oil: 11 000 barrels/day, Gas: 0,17 billion Sm³, NGL: 0.03 million tonnes	
Expected investment from 2012	2.4 billion 2012 values	
Total investment as of 31.12.2011	23.8 billion nominal values	
Main supply base	Sandnessjøen	

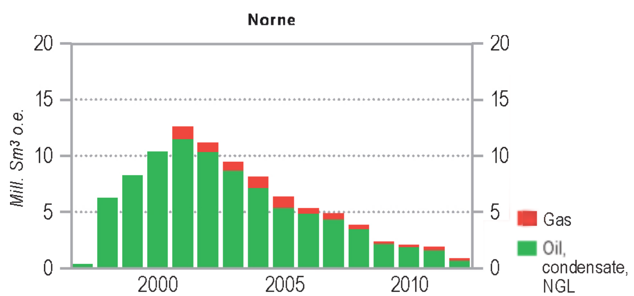
Development: Norne is an oil field located about 80 kilometres north of the Heidrun field in the Norwegian Sea. The water depth in the area is 380 metres. The field has been developed with a production and storage vessel, "Norne FPSO", connected to seven subsea templates. Flexible risers carry the wellstream up to the production vessel. In April 2008, an amended PDO for Norne and Urd was approved. The Alve and Marulk fields are connected as satellites to the "Norne FPSO". The Skuld field, where production is planned to start in March 2013, is also a satellite to the "Norne FPSO". Two heavy oil discoveries and several prospects in the area around Norne and Urd are being evaluated.

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.

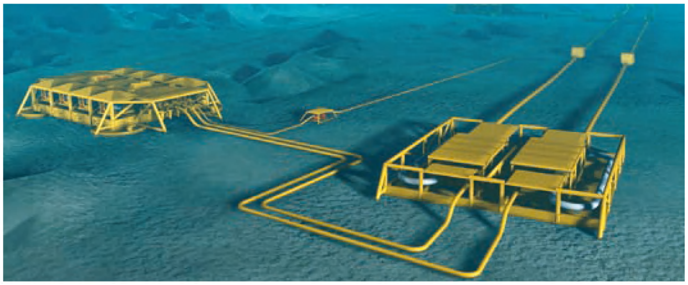
Transport: The oil is loaded onto tankers for export. Gas export started in 2001, and the gas is transported through a dedicated pipeline to Åsgard and on through the Åsgard Transport pipeline to Kårstø.

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 2013 to maintain the oil production.



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 31.12.2012**	
	306.3 billion Sm³ gas	207.7 billion Sm³ gas	
	16.7 million Sm³ condensate	9.1 million Sm³ condensate	
Estimated production in 2013	Gas: 21.39 billion Sm³, Condensate: 1.38 million Sm³		
Expected investment from 2012	24.8 billion 2012 values		
Total investment as of 31.12.2011	36.0 billion nominal values		
Main supply base	Kristiansund		



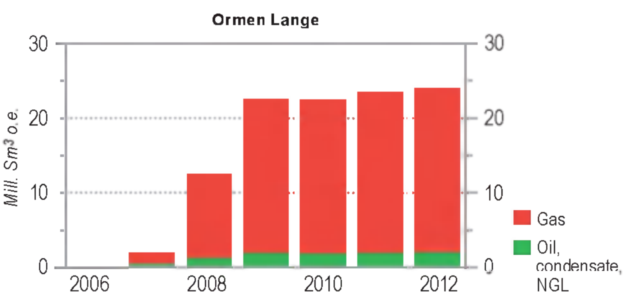
Development: Ormen Lange is a gas field located in the Møre Basin in the southern part of the Norwegian Sea. The water depth in the area varies from 800 to in excess of 1 100 metres. The deep water and the seabed conditions have made the development very challenging and have triggered development of new technology. The field is being developed in several phases. Ormen Lange was planned with 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 later, 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.

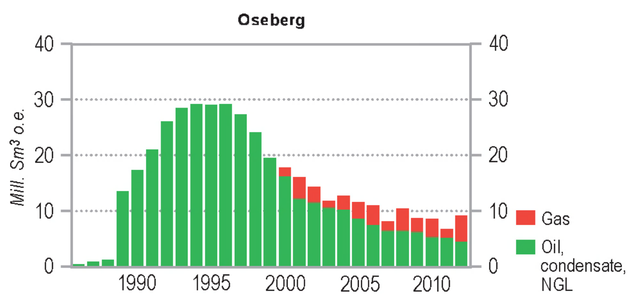
Status: The field is producing at plateau. Reserve estimates were reduced considerably in 2011. Base case for future gas compression is changed to a combination of onshore compression from 2016 and an in-field compression solution from 2021.



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 %
	Petoro AS		33.60 %
	Statoil Petroleum AS		49.30 %
	Total E&P Norge AS		14.70 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**	
	384.6 million Sm³ oil	22.7 million Sm³ oil	
	104.1 billion Sm³ gas	69.2 billion Sm³ gas	
	12.1 million tonnes NGL	3.8 million tonnes NGL	
Estimated production in 2013	Oil: 59 000 barrels/day, Gas: 2.96 billion Sm³, NGL: 0.40 million tonnes		
Expected investment from 2012	21.5 billion 2012 values		
Total investment as of 31.12.2011	66.6 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 in January 1988. The PDO for Oseberg D was approved in December 1996. The PDO for Oseberg Vestflanke was approved in December 2003, and the PDO for Oseberg Delta was approved in September 2005.



Reservoir: The field consists of several Middle Jurassic sandstone reservoirs in 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 have generally 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 are produced 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 with the main Oseberg reservoir is to balance the oil production below the gas cap with the gas offtake. Upgrades of the drilling facilities on Oseberg B and C were completed during 2012. Test production to evaluate flow characteristics from an overlying chalk reservoir in the Shetland Group on the Oseberg field is ongoing. Further development of the Delta structure west of the main field is planned.

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 %
	Petoro AS		33.60 %
	Statoil Petroleum AS		49.30 %
	Total E&P Norge AS		14.70 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2012**	
	61.0 million Sm^3 oil	17.2 million Sm^3 oil	
	16.0 billion Sm^3 gas	8.0 billion Sm^3 gas	
	1.6 million tonnes NGL	1.6 million tonnes NGL	
Estimated production in 2013	Oil: 46 000 barrels/day, Gas: 0.49 billion Sm^3, NGL: 0.09 million tonnes		
Expected investment from 2012	12.0 billion 2012 values		
Total investment as of 31.12.2011	20.1 billion nominal values		
Main supply base	Mongstad		

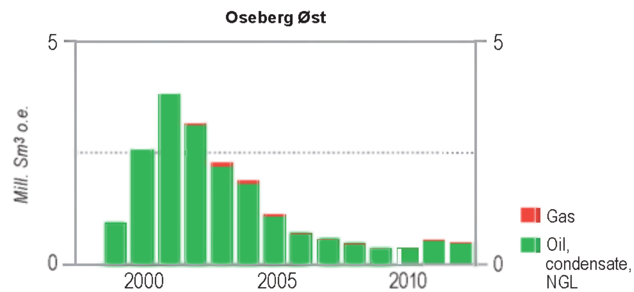
Development: Oseberg Sør is an oil field located south of Oseberg in the northern part of the North Sea. The water depth in the area is approximately 100 metres. The field has been developed with an integrated steel facility with accommodation, drilling module and first-stage separation of oil and gas. In addition, several deposits on the 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 in 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 future blowdown of the Oseberg Sør reservoirs are being evaluated. A strategy to combine smaller prospects and discoveries into clusters large enough to trigger new infrastructure has been established. Drilling of the wells on the 30/9-22 Stjerne structure is ongoing.



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 %
	Petoro AS		33.60 %
	Statoil Petroleum AS		49.30 %
	Total E&P Norge AS		14.70 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2012**	
	26.7 million Sm^3 oil	7.9 million Sm^3 oil	
	0.4 billion Sm^3 gas	0.1 billion Sm^3 gas	
	0.3 million tonnes NGL	0.3 million tonnes NGL	
Estimated production in 2013	Oil: 7 000 barrels/day		
Expected investment from 2012	8.1 billion 2012 values		
Total investment as of 31.12.2011	8.8 billion nominal values		
Main supply base	Mongstad		

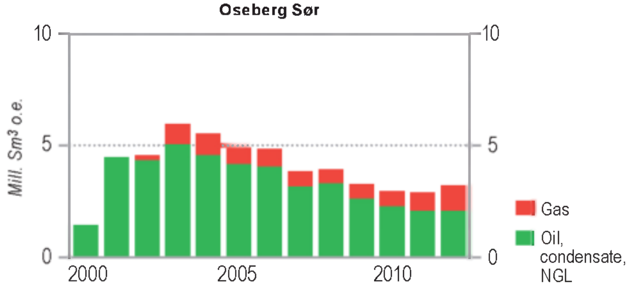
Development: Oseberg Øst is an oil field located east of Oseberg in the northern part of the North Sea. The field has been developed with an integrated fixed facility with accommodation, drilling equipment and first stage separation of oil, water and gas. The water depth in the area is about 160 metres.

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: Limited availability of produced gas for power generation is a challenge. In addition, there is focus on improving the drilling performance.



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	Bayerngas Norge AS		30.00 %
	DONG E&P Norge AS		55.00 %
	Noreco Norway AS		15.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2012**	
	4.6 million Sm^3 oil	4.5 million Sm^3 oil	
	3.9 billion Sm^3 gas	3.9 billion Sm^3 gas	
Estimated production in 2013	Oil: 5 000 barrels/day, Gas: 0.14 billion Sm^3		
Expected investment from 2012	2.0 billion 2012 values		
Total investment as of 31.12.2011	3.5 billion nominal values		

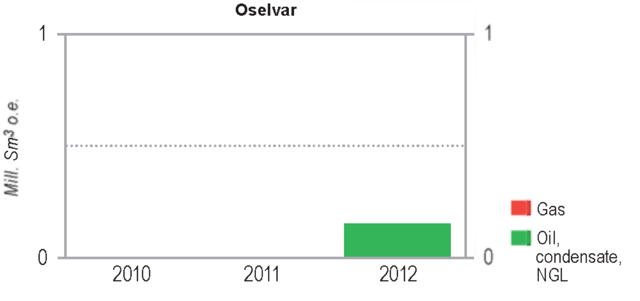
Development: Oselvar is located 21 kilometres southwest of the Ula field, in the southern part of the North Sea. The water depth in the area is about 70 metres. The development concept is a subsea template with production wells tied to Ula by pipeline.

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 is produced by natural pressure depletion via three horizontal production wells.

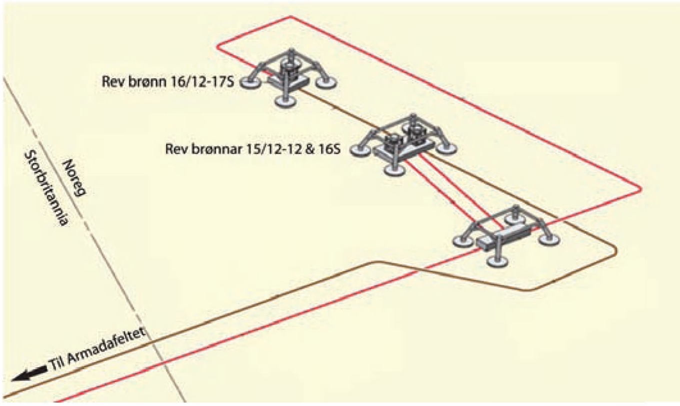
Transport: The wellstream is transported by pipeline to Ula for processing. The gas is used for injection in Ula for improved recovery, while the oil is transported by pipeline to Ekofisk for further export.

Status: Production started from the first two wells in April 2012 and from the third well in July 2012. Production in 2012 was lower than expected due to technical problems in one well. Possible intervention or side-track operations are being evaluated for this well.



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 31.12.2012**
	0.7 million Sm^3 oil	
	2.7 billion Sm^3 gas	
	0.1 million tonnes NGL	
Estimated production in 2013	Oil: 200 barrels/day, Gas: 0.6 billion Sm^3	
Expected investment from 2012	0.6 billion 2012 values	
Total investment as of 31.12.2011	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 well stream 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.

Status: The pressure development indicates that Rev may cease production in the near future. Since gas from the Varg field will be transported via the Rev infrastructure from late 2013, it may be possible to periodically produce the wells on Rev.

Ringhorne Øst

Blocks and production licences	Block 25/8 - production licence 027, awarded 1969 Block 25/8 - production licence 169 E, awarded 2011.		
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 31.12.2012**	
	15.4 million Sm^3 oil	6.3 million Sm^3 oil	
	0.4 billion Sm^3 gas	0.1 billion Sm^3 gas	
Estimated production in 2013	Oil: 14 000 barrels/day, Gas: 0.02 billion Sm^3		
Expected investment from 2012	0.8 billion 2012 values		
Total investment as of 31.12.2011	0.7 billion nominal values		

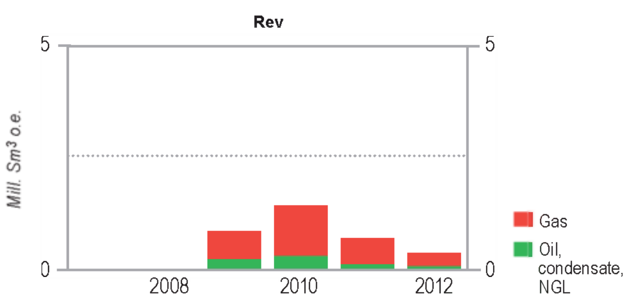
Development: Ringhorne Øst is an oil field located northeast of Balder in the central part of the North Sea. The water depth in the area is about 130 metres. The field is developed with four production wells drilled from the Ringhorne facility on the Balder field.

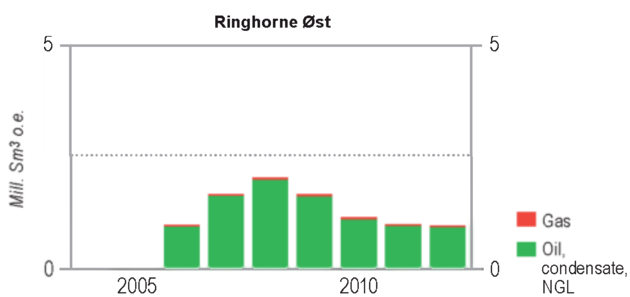
Reservoir: The reservoir contains oil with associated gas in Jurassic sandstones in the Statfjord Formation. The reservoir lies at a depth of approximately 1 940 metres and has very good quality.

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

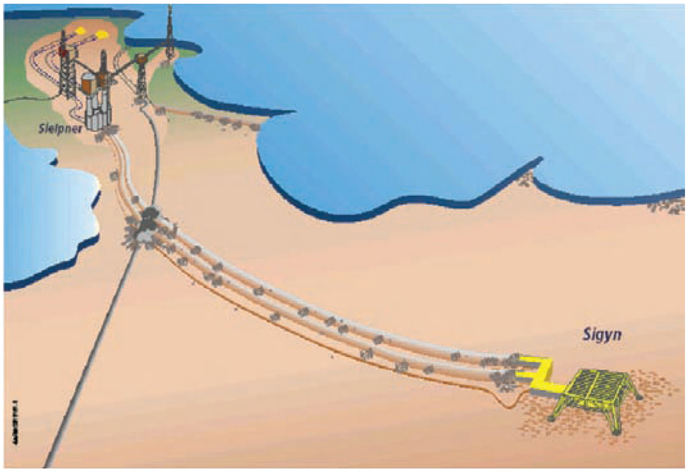
Status: The field is in the tail phase, but is expected to produce until 2025. A new production well was drilled and brought online in 2012. Two new wells are on the 2013 - 2015 drilling schedule.





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 31.12.2012**	
	6.9 billion Sm^3 gas	0.7 billion Sm^3 gas	
	2.6 million tonnes NGL	0.2 million tonnes NGL	
	6.4 million Sm^3 condensate	0.6 million Sm^3 condensate	
Estimated production in 2013	Gas: 0.25 billion Sm^3, NGL: 0.09 million tonnes, Condensate: 0.21 million Sm^3		
Total investment as of 31.12.2011	2.0 billion nominal values		
Main supply base	Dusavik		

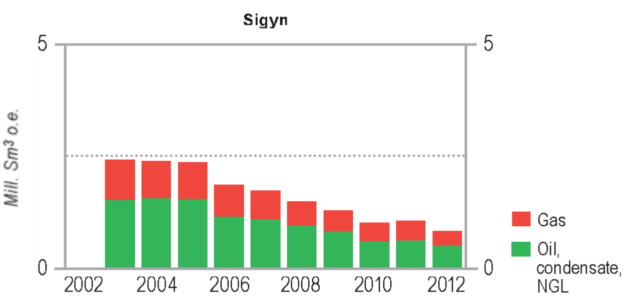


Development: Sigyn is located in the Sleipner area in the central part of the North Sea. The water depth in the area is around 70 metres. The field comprises the deposits Sigyn Vest, which contains gas and condensate, and Sigyn Øst, which contains light oil. The field has been developed with a subsea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



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	
On stream	01.01.2013		
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**	**Remaining as of 31.12.2012**	
	15.3 million Sm^3 oil	15.5 million Sm^3 oil	
	43.4 billion Sm^3 gas	43.4 billion Sm^3 gas	
	5.6 million tonnes NGL	5.6 million tonnes NGL	
Estimated production in 2013	Oil: 51 000 barrels/day, Gas: 2.88 billion Sm^3 ,NGL: 0.38 million tonnes		
Expected investment from 2012	11.2 billion 2012 values		
Total investment as of 31.12.2011	37.1 billion nominal values		
Main supply base	Sandnessjøen		

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. Skarv is 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.

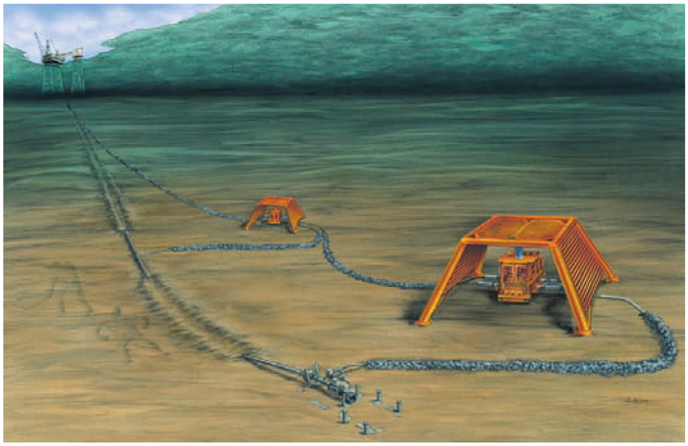
Recovery strategy: In the Garn and Tilje Formations, re-injection of gas is planned for the first years in order to increase oil recovery.

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

Status: The FPSO was completed and installed at the field in August 2011. Drilling of production wells started in 2010, and production started in late December 2012.

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		30.00 %
	Petoro AS		30.00 %
	Total E&P Norge AS		40.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2012**	
	2.2 million Sm^3 oil	0.5 million Sm^3 oil	
	10.2 billion Sm^3 gas	1.3 billion Sm^3 gas	
Estimated production in 2013	Oil: 1 000 barrels/day, Gas: 0.25 billion Sm^3		
Expected investment from 2012	0.1 billion 2012 values		
Total investment as of 31.12.2011	2.7 billion nominal values		



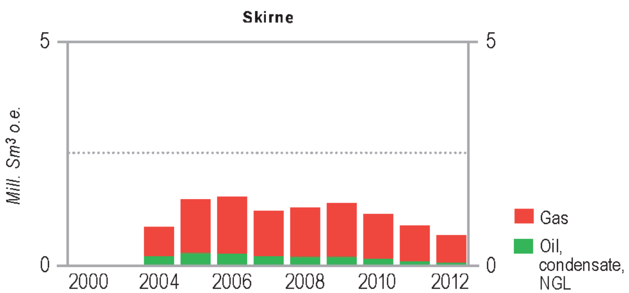
Development: Skirne, which includes the Byggve deposit, contains gas and condensate and is located east of Heimdal in the central part of the North Sea. The water depth in the area is about 120 metres. The field has been developed with two subsea templates tied to Heimdal by a pipeline. The Atla field was tied back to the Skirne/Byggve subsea template in 2012.

Reservoir: The reservoir consists of Middle Jurassic sandstones in 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: Skirne is expected to produce until 2017.



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 31.12.2012**	
	133.3 billion Sm^3 gas	19.8 billion Sm^3 gas	
	9.5 million tonnes NGL	1.5 million tonnes NGL	
	32.9 million Sm^3 condensate	4.5 million Sm^3 condensate	
Estimated production in 2013	Gas: 5.15 billion Sm^3, NGL: 0.34 million tonnes, Condensate: 1.04 million Sm^3		
Expected investment from 2012	0.7 billion 2012 values		
Total investment as of 31.12.2011	23.2 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.

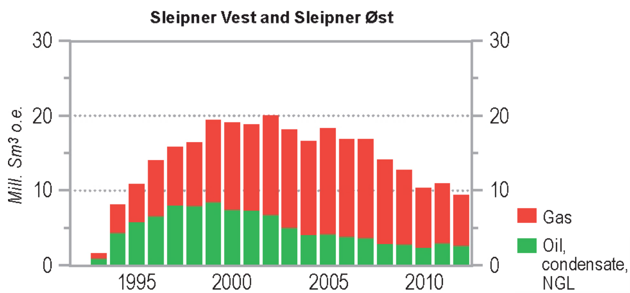
Development: Sleipner Vest is a gas field in the central part of the North Sea. The water depth in the area is about 110 metres. The field is developed with the wellhead facility Sleipner B, which is remotely operated from the Sleipner A facility on the Sleipner Øst field, and the processing facility 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: There was a drilling campaign from July 2009 to June 2011. A new drilling campaign is scheduled from 2015.



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 31.12.2012**	
	67.8 billion Sm^3 gas	1.5 billion Sm^3 gas	
	13.5 million tonnes NGL	0.4 million tonnes NGL	
	27.0 million Sm^3 condensate	0.2 million Sm^3 condensate	
Estimated production in 2013	Gas: 0.49 billion Sm^3, NGL: 0.08 million tonnes, Condensate: 0.09 million Sm^3		
Expected investment from 2012	2.3 billion 2012 values		
Total investment as of 31.12.2011	26.8 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 in August 1995 and production started in 1998.

Reservoir: The Sleipner Øst and Loke reservoirs are mainly in sandstones in 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: An agreement for tie-in and processing of oil and rich gas from Gudrun at the Sleipner facilities was made in 2010, and production is planned to start from Gudrun in 2014. Rich gas from Gina Krog is planned to be tied-in and processed at the Sleipner facilities from 2017.

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		17.76 %
	Idemitsu Petroleum Norge AS		9.60 %
	Petoro AS		30.00 %
	RWE Dea Norge AS		8.28 %
	Statoil Petroleum AS		33.32 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2012**	
	249.9 million Sm^3 oil	64.1 million Sm^3 oil	
	6.6 billion Sm^3 gas	0.3 billion Sm^3 gas	
	4.7 million tonnes NGL	0.1 million tonnes NGL	
Estimated production in 2013	Oil: 85 000 barrels/day		
Expected investment from 2012	53.2 billion 2012 values		
Total investment as of 31.12.2011	65.5 billion nominal values		
Main supply base	Florø		

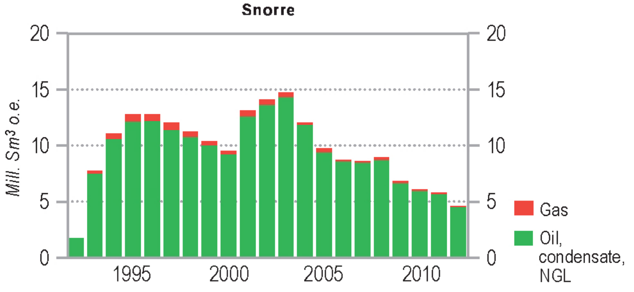
Development: Snorre is an oil field in the Tampen area in the northern part of the North Sea. The water depth in the area is 300 - 350 metres. Snorre A in the south is a floating steel facility (TLP) for accommodation, drilling and processing. Snorre A also has a separate process module for production 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 in December 1994. The PDO for Snorre B was approved in 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 in the Statfjord and Lunde Formations. The reservoir depth is 2 000 - 2 700 metres. The reservoir has a complex structure with many alluvial channels and internal flow barriers.

Recovery strategy: Snorre is produced with pressure support from water injection, gas injection and water alternating gas injection (WAG).

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, or through Tampen Link to St Fergus. 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. It has been decided to install a permanent reservoir monitoring system on the seabed to increase recovery through improved seismic quality. The licensees have also decided to implement an Enhanced Oil Recovery pilot on water diversion using silica gel.



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 31.12.2012**
	176.7 billion Sm^3 gas	156.9 billion Sm^3 gas
	6.4 million tonnes NGL	5.4 million tonnes NGL
	22.6 million Sm^3 condensate	19.0 million Sm^3 condensate
Estimated production in 2013	Gas: 5.36 billion Sm^3, NGL: 0.27 million tones, Condensate: 0.86 million Sm^3	
Expected investment from 2012	29.2 billion 2012 values	
Total investment as of 31.12.2011	8.2 billion nominal values	

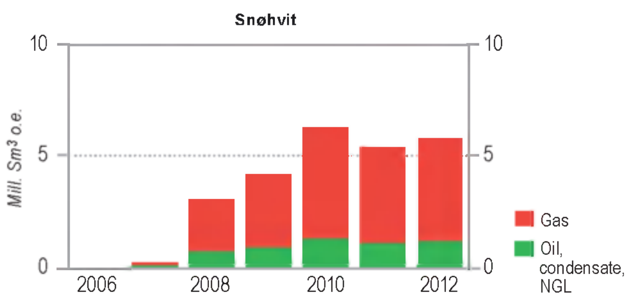
Development: Snøhvit is located in the Barents Sea in the central part of the Hammerfest basin, at a water depth of 310 - 340 metres, and is a gas field with condensate and an underlying thin oil zone. Snøhvit unit includes the Snøhvit, Albatross and Askeladd structures. The approved PDO for the gas 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 in 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.

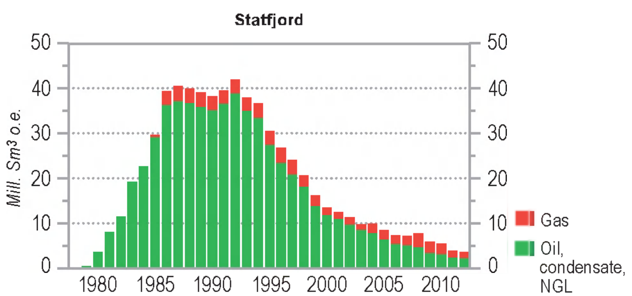
Status:
Snøhvit is being developed in multiple phases. In the current phase, additional wells and a possible tie-in of Snøhvit Nord are being evaluated. An evaluation of a second CO_2 injection well is on-going. Increased robustness of the LNG plant at Melkøya is being evaluated.



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	19.76 %
	ExxonMobil Exploration & Production Norway AS	21.37 %
	Statoil Petroleum AS	44.34 %
	Centrica Resources Limited	14.53 %
Recoverable reserves (Norwegian part)	**Original**	**Remaining as of 31.12.2012**
	570.4 million Sm^3 oil	4.3 million Sm^3 oil
	77.4 billion Sm^3 gas	11.4 billion Sm^3 gas
	23.0 million tonnes NGL	6.1 million tonnes NGL
	1.1 million Sm^3 condensate	0.6 million Sm^3 condensate
Estimated production in 2013	Oil: 23 000 barrels/day, Gas: 1.05 billion Sm^3, NGL: 0.47 million tonnes. Condensate: 0.05 million Sm^3	
Expected investment from 2012	9.7 billion 2012 values	
Total investment as of 31.12.2011	65.3 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 located 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 in June 2005.



Reservoir: The Statfjord reservoirs lie at a depth of 2 500 - 3 000 metres in a large fault block tilted towards the west, and in a number of smaller fault compartments along the east flank. The reservoirs are in Jurassic sandstones in 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 onto 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 have been modified as part of the Statfjord Late Life Project. There are plans to drill about 70 new oil, water and gas wells during Statfjord Late Life. At the end of 2012, about 50 of these wells were completed.

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		23.13 %
	ExxonMobil Exploration & Production Norway AS		25.00 %
	Petoro AS		30.00 %
	Statoil Petroleum AS		21.88 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2012**	
	39.5 million Sm^3 oil	3.0 million Sm^3 oil	
	2.1 billion Sm^3 gas	0.3 million tonnes NGL	
	1.1 million tonnes NGL		
Estimated production in 2013	Oil: 2 000 barrels/day		
Total investment as of 31.12.2011	5.7 billion nominal values		
Main supply base	Sotra		

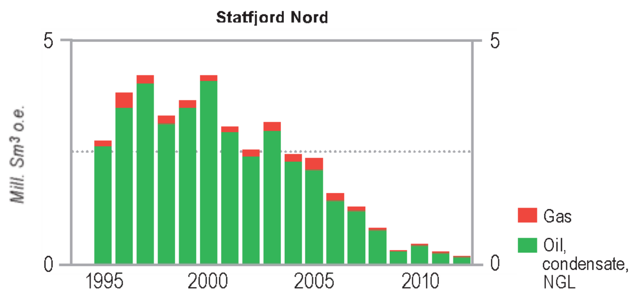
Development: Statfjord Nord is an oil field located approximately 17 kilometres north of the Statfjord field in the Tampen area. The water depth in the area is 250 - 290 metres. The field has been developed with three subsea templates tied back to Statfjord C. Two of the templates are for production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

Reservoir: The Statfjord Nord reservoirs consist of Middle Jurassic sandstones in the Brent Group, 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 one of the two water injectors in the second half of 2013 and to resume production.



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		11.56 %
	ExxonMobil Exploration & Production Norway AS		20.55 %
	Idemitsu Petroleum Norge AS		4.80 %
	Petoro AS		30.00 %
	RWE Dea Norge AS		1.40 %
	Statoil Petroleum AS		31.69 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2012**	
	36.8 million Sm^3 oil	0.7 million Sm^3 oil	
	4.0 billion Sm^3 gas	0.1 billion Sm^3 gas	
	2.1 million tonnes NGL	0.8 million tonnes NGL	
Estimated production in 2013	Oil: 3 000 barrels/day, Gas: 0.02 billion Sm^3, NGL: 0.01 million tonnes.		
Expected investment from 2012	0.1 billion 2011 values		
Total investment as of 31.12.2011	6.0 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 in the Brent Group. The reservoir depth is approximately 2 400 metres.

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

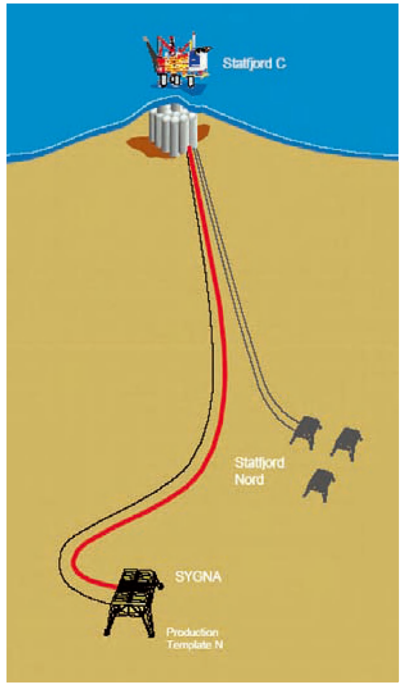
Transport: The wellstream is routed through two pipelines to Statfjord C for processing, storage and export. Statfjord Øst, Sygna and Statfjord Nord have a shared process module on Statfjord C.

Status: The field is affected by pressure depletion from the 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.

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		12.72 %
	ExxonMobil Exploration & Production Norway AS		21.00 %
	Idemitsu Petroleum Norge AS		4.32 %
	Petoro AS		30.00 %
	RWE Dea Norge AS		1.26 %
	Statoil Petroleum AS		30.71 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2012**	
	11.0 million Sm^3 oil	1.1 million Sm^3 oil	
Estimated production in 2013	Oil: 1 000 barrels/day		
Total investment as of 31.12.2011	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.

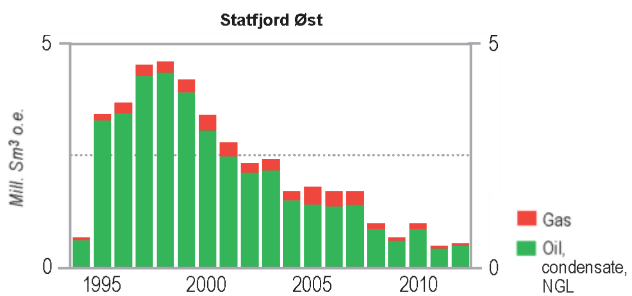


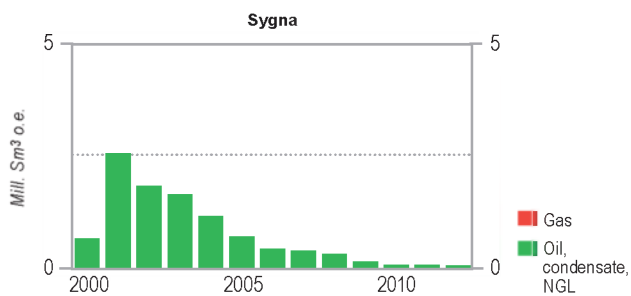
Reservoir: The Sygna reservoir consists of Middle Jurassic sandstones in the Brent Group. The reservoir depth is approximately 2 650 metres. The reservoir quality is good.

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

Transport: The wellstream is transported 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, production will be limited and there will be periods of no production.





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 31.12.2012**	
	9.5 million Sm^3 oil	0.6 million Sm^3 oil	
	2.0 billion Sm^3 gas	0.2 million tonnes NGL	
	0.5 million tonnes NGL		
Estimated production in 2013	Oil: 2 000 barrels/day		
Expected investment from 2012	0.1 billion 2012 values		
Total investment as of 31.12.2011	2.2 billion nominal values		
Main supply base	Tananger		

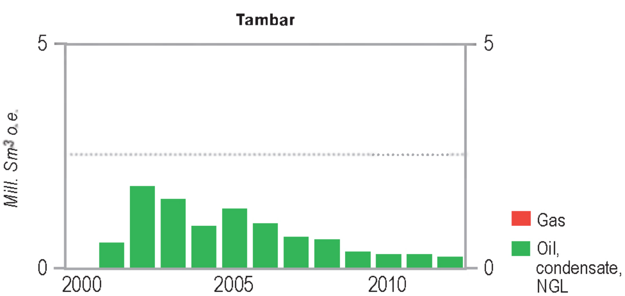
Development: Tambar is an oil field located southeast of the Ula field in the southern part of the North Sea. The water depth in the area is 68 metres. The field has been developed with a remotely controlled wellhead facility without processing equipment.

Reservoir: The reservoir consists of Upper Jurassic sandstones in 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 failed and is out of order. The plan for 2013 is to restart the multi-phase pump. Major challenges are wells that die and high water cut in the wells, which restricts production. In 2013, the licensees will concentrate on well work and surveillance. Gas lift to increase the oil recovery will be considered. Infill drilling is also evaluated.



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 31.12.2012**	
	0.3 million Sm^3 oil		
Estimated production in 2013	Oil: 340 barrels/day		
Total investment as of 31.12.2011	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 in 2012 was stable and above expectation. Infill options are evaluated.

Tambar includes production from 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 31.12.2012**	
	24.3 million Sm^3 oil	0.4 million Sm^3 oil	
	10.9 billion Sm^3 gas	0.1 billion Sm^3 gas	
	1.2 million tonnes NGL		
Estimated production in 2013	Oil: 3 000 barrels/day, Gas: 0.01 billion Sm^3		
Expected investment from 2012	0.2 billion 2012 values		
Total investment as of 31.12.2011	3.9 billion nominal values		
Main supply base	Tananger		

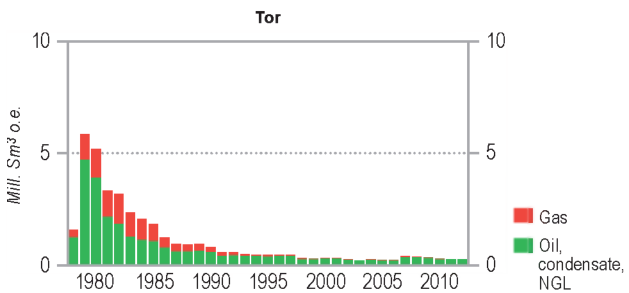
Development: Tor is an oil field in the Ekofisk area in the southern part of the North Sea. The water depth in the area is about 70 metres. The field has been developed with a combined wellhead and processing facility tied to Ekofisk.

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

Recovery strategy: Tor was originally 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.



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		16.10 %
	Idemitsu Petroleum Norge AS		9.60 %
	Petoro AS		30.00 %
	RWE Dea Norge AS		2.80 %
	Statoil Petroleum AS		41.50 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2012**	
	61.2 million Sm^3 oil	6.0 million Sm^3 oil	
	4.6 billion Sm^3 gas	0.4 billion Sm^3 gas	
	1.8 million tonnes NGL	0.2 million tonnes NGL	
Estimated production in 2013	Oil: 13 000 barrels/day, Gas: 0.05 billion Sm^3, NGL: 0.03 million tonnes.		
Expected investment from 2012	3.8 billion 2012 values		
Total investment as of 31.12.2011	12.2 billion nominal values		
Main supply base	Florø		

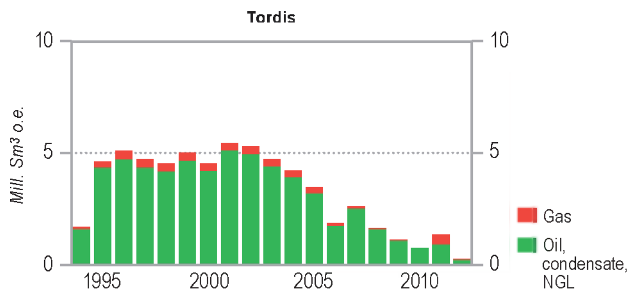
Development: Tordis is an oil field located between the Snorre and Gullfaks fields in the Tampen area in the northern part of the North Sea. The water depth in the area is approximately 200 metres. The field has been developed with a central subsea manifold tied back to Gullfaks C. Eight separate satellite wells and two subsea templates are tied back to the manifold. A subsea separator was installed at the field in 2007. Injection water is supplied from Gullfaks C. Tordis comprises four deposits: Tordis, Tordis Øst, Borg and 34/7-25 S. The PDO for Tordis Øst was approved in October 1995. The PDO for Borg was approved in June 1999. An amended PDO for Tordis (Tordis IOR) was approved in 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 partly accomplished by pressure support from water injection and partly by 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 separated in the subsea facility and transported through two pipelines to Gullfaks C for further processing. The oil is exported by tankers, while the gas is exported via Gassled to Kårstø.

Status: Production and water injection at Tordis was reduced in 2012 due to corrosion and replacement of production pipelines to Gullfaks C. A main challenge is to optimize oil production while limiting water and sand production.



Troll

The Troll field lies in the northern part of the North Sea, about 65 kilometres west of Kollsnes. The water depth in the area is more than 300 metres. The field has huge gas resources and one of the largest oil volumes remaining on the Norwegian continental shelf. Troll 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 in the Fensfjord Formation 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 31.12.2012**
	1432.8 billion Sm^3 gas	984.9 billion Sm^3 gas
	27.5 million tonnes NGL	21.1 million tonnes NGL
	1.5 million Sm^3 condensate	
Estimated production in 2013	Gas: 30.43 billion Sm^3, NGL: 1.12 million tonnes	
Expected investment from 2012	24.6 billion 2012 values	
Total investment as of 31.12.2011	47.9 billion nominal values	
Main supply base	Ågotnes	

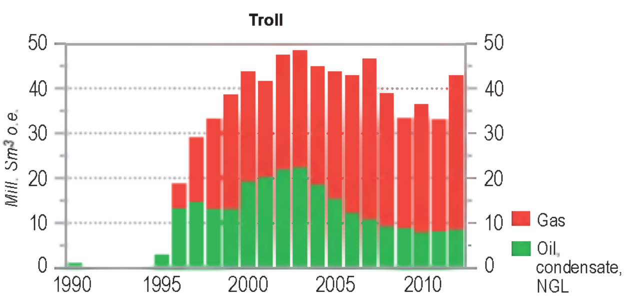
Development: Troll Phase I has been developed with Troll A which is a fixed wellhead and compression facility with a concrete substructure. Troll A is powered by electricity from shore. An updated development plan involving the transfer of gas processing to Kollsnes was approved in 1990. Kollsnes was 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. Decommissioning and removal of the Troll Oseberg Gas Injection (TOGI) subsea template was completed in 2012.

Reservoir: The gas and oil reservoirs in the Troll Øst and Troll Vest structures consist primarily of shallow marine sandstones in the Sognefjord Formation of Late Jurassic age. Part of the reservoir is also in the Fensfjord Formation of Middle Jurassic age 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 on Troll A is expected to be finished during 2015.



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

Troll II

Blocks and production licences	Block 31/2 - production licence 054, awarded 1979 Block 31/3 - production licence 085, awarded 1983 Block 31/3 - production licence 085 C, awarded 2002 Block 31/3 - production licence 085 D, awarded 2006 Block 31/5 - production licence 085, awarded 1983 Block 31/6 - production licence 085, awarded 1983 Block 31/6 - production licence 085 C, awarded 2002		
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 31.12.2012**	
	263.8 million Sm^3 oil	36.0 million Sm^3 oil	
Estimated production in 2013	Oil: 126 000 barrels/day		
Expected investment from 2012	34.2 billion 2012 values		
Total investment as of 31.12.2011	82.7 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 made continuously to drill new production wells to increase the oil reserves in Troll. A four-rig drilling strategy has been decided.

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 31.12.2012**	
	1.5 million Sm^3 oil	0.8 million Sm^3 oil	
	4.3 billion Sm^3 gas	3.2 billion Sm^3 gas	
Estimated production in 2013	Oil: 4 000 barrels/day, Gas: 0.60 billion Sm^3		
Total investment as of 31.12.2011	3.0 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 trend 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.

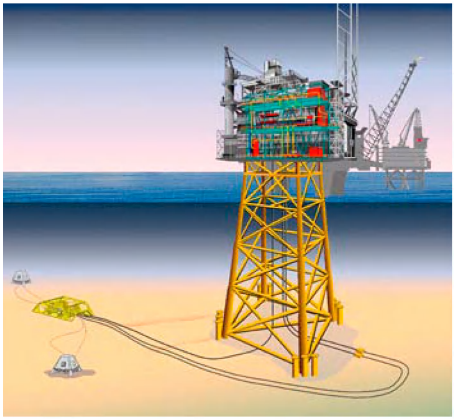
Recovery strategy: Trym is produced by natural pressure depletion via two horizontal production wells.

Transport: The wellstream is processed on the Harald facility for further transport through the Danish pipeline network.

Status: Production started in February 2011. Both producers are performing as expected. An exploration well was drilled on the Trym South prospect near the Trym field in the first quarter of 2013.

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 31.12.2012**	
	3.3 million Sm^3 oil		
	18.2 billion Sm^3 gas		
	0.2 million tonnes NGL		
Estimated production in 2013	Oil: 530 barrels/day, Gas: 0.34 billion Sm^3		
Total investment as of 31.12.2011	4.7 billion nominal values		
Main supply base	Mongstad		



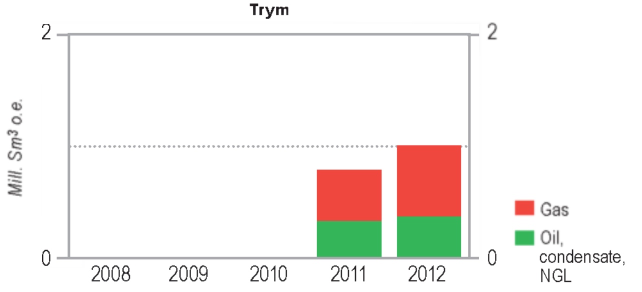
Development: Tune is a gas-condensate field located about 10 kilometres west of the Oseberg Field Centre in the northern part of the North Sea. The water depth in the area is approximately 95 metres. The field has been developed with a subsea template and a satellite well tied to Oseberg. In March 2004,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

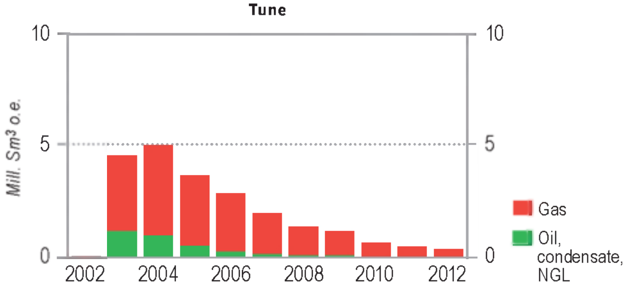
Reservoir: The reservoir consists of Middle Jurassic sandstones in the Brent Group and is divided into several inclined fault blocks. The reservoir depth is approximately 3 400 metres.

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 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.

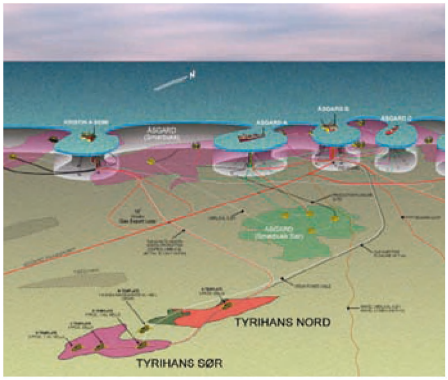
Status: Tune is in the tail phase. Implementation of low pressure production was completed in 2012. This will increase and prolong the production.





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	11.79 %
	Statoil Petroleum AS	58.84 %
	Total E&P Norge AS	23.15 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2012**
	32.4 million Sm^3 oil	16.5 million Sm^3 oil
	41.7 billion Sm^3 gas	40.9 billion Sm^3 gas
	10.9 million tonnes NGL	10.7 million tonnes NGL
Estimated production in 2013	Oil: 57 000 barrels/day, Gas: 0.13 billion Sm^3, NGL: 0.03 million tonnes	
Expected investment from 2012	4.9 billion 2012 values	
Total investment as of 31.12.2011	15.2 billion nominal values	
Main supply base	Kristiansund	



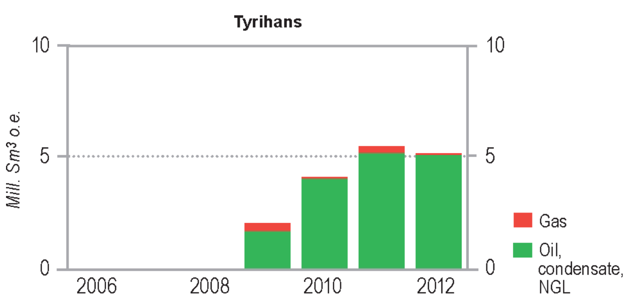
Development: Tyrihans is located in the Norwegian Sea about 25 kilometres southeast of the Åsgard field. The water depth in the area is about 270 metres. Tyrihans consists of the discoveries 6407/1-2 Tyrihans Sør, which was discovered in 1983, and 6407/1-3 Tyrihans Nord, discovered in 1984. The development 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.



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 31.12.2012**
	87.9 million Sm^3 oil	15.7 million Sm^3 oil
	3.9 billion Sm^3 gas	1.4 million tonnes NGL
	4.0 million tonnes NGL	
Estimated production in 2013	Oil: 11 000 barrels/day, NGL: 0.01 million tonnes	
Expected investment from 2012	8.2 billion 2012 values	
Total investment as of 31.12.2011	14.7 billion nominal values	
Main supply base	Tananger	

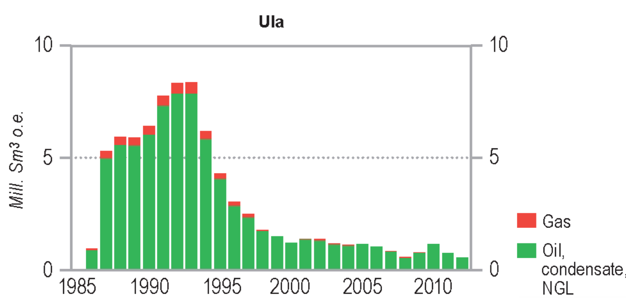
Development: Ula is an oil field in the southern part of the North Sea. The water depth in the area is about 70 metres. The development consists of three conventional steel facilities for production, drilling and accommodation. The facilities are connected by bridges. The wellstream from Blane was tied 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 (2001), Blane (2007) and Oselvar (2012). Gas lift is used in some of the wells.

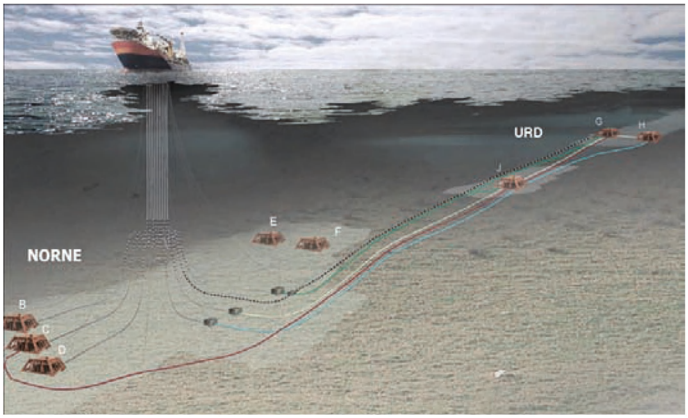
Transport: The oil is transported by pipeline via Ekofisk to Teesside. All gas is re-injected into the reservoir to increase oil recovery.

Status: Based on the positive effect the WAG programme has on oil recovery, it has been expanded by drilling additional WAG wells. More wells are planned for 2013-2016 An evaluation of possible development of the underlying Triassic reservoir is ongoing, and test production is part of this evaluation.



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 31.12.2012**	
	7.0 million Sm^3 oil	2.0 million Sm^3 oil	
	0.2 billion Sm^3 gas		
Estimated production in 2013	Oil: 7 000 barrels/day, Gas: 0.01 billion Sm^3		
Expected investment from 2012	0.9 billion 2012 values		
Total investment as of 31.12.2011	5.1 billion nominal values		



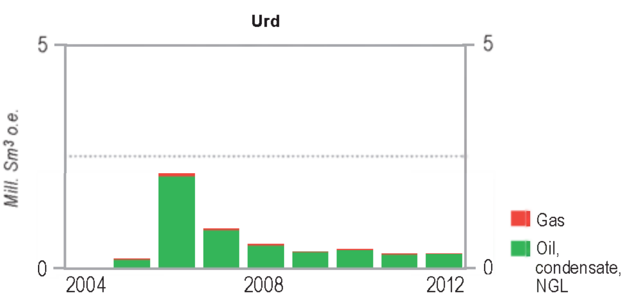
Development: Urd is located northeast of Norne in the Norwegian Sea. The water depth in the area is approximately 380 metres. The field comprises two oil deposits, 6608/10-6 Svale and 6608/10-8 Stær. Urd has been developed with subsea templates tied back to the Norne vessel. In April 2008, an amended 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 in 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 2012. Proven resources in the Melke Formation, overlying the Svale and Stær deposits, are being evaluated for possible production.



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	Centrica Resources (Norge) AS		
Licensees	Centrica Resources (Norge) AS		75.76 %
	Total E&P Norge AS		24.24 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2012**	
	2.4 million Sm^3 oil	1.1 million Sm^3 oil	
	2.3 billion Sm^3 gas	1.3 billion Sm^3 gas	
Estimated production in 2013	Oil: 4 000 barrels/day, Gas: 0.20 billion Sm^3		
Expected investment from 2012	0.1 billion 2012 values		
Total investment as of 31.12.2011	2.5 billion nominal values		

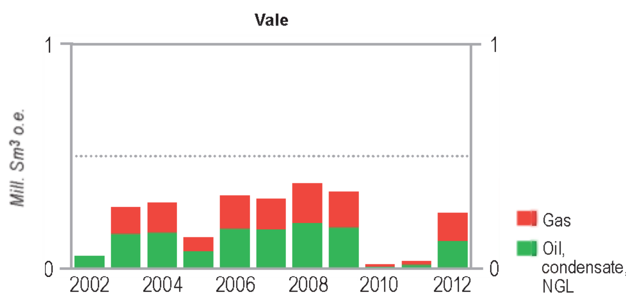
Development: Vale is a gas and condensate field located 16 kilometres north of Heimdal in the central part of the North Sea. The field has been developed with a subsea template tied back to Heimdal. The water depth in the area is approximately 115 metres.

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

Recovery strategy: The field is recovered by pressure depletion.

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

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



Valhall

Blocks and production licences	Block 2/11 - production licence 033 B, awarded 2001. Block 2/8 - production licence 006 B, awarded 2000.	
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 31.12.2012**
	147.4 million Sm^3 oil	41.5 million Sm^3 oil
	27.5 billion Sm^3 gas	6.9 billion Sm^3 gas
	5.5 million tonnes NGL	2.2 million tonnes NGL
Estimated production in 2013	Oil: 45 000 barrels/day, Gas: 0.49 billion Sm^3, NGL: 0.07 million tonnes.	
Expected investment from 2012	16.5 billion 2012 values	
Total investment as of 31.12.2011	61.5 billion nominal values	
Main supply base	Tananger	

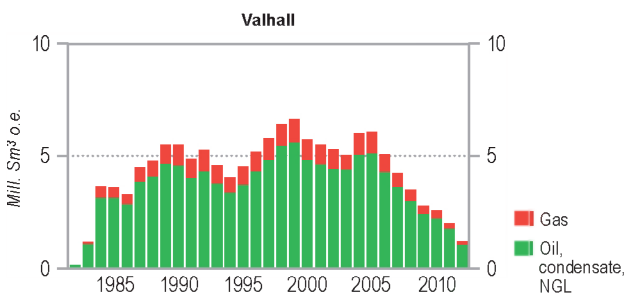
Development: Valhall is an oil field located in the southern part of the North Sea. The water depth in the area is about 70 metres. The field was originally developed with three facilities for accommodation, drilling and production. In 1996, a wellhead facility, Valhall WP, with 19 slots for additional 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 on 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 in June 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: Work to establish gas lift in the wells on the flanks of the field is ongoing. A new field centre (PH) with processing and accommodation facilities is installed and will be completed and start production early in 2013. 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 utilised to identify new well targets for remaining oil in the reservoir.



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 31.12.2012**
	16.4 million Sm^3 oil	1.4 million Sm^3 oil
	1.1 billion Sm^3 gas	1.1 billion Sm^3 gas
	1.0 million tonnes NGL	1.0 million tonnes NGL
Estimated production in 2013	Oil: 9 000 barrels/day, Gas: 0.02 billion Sm^3, NGL: 0.02 million tonnes.	
Expected investment from 2012	1.3 billion 2012 values	
Total investment as of 31.12.2011	7.9 billion nominal values	
Main supply base	Tananger	

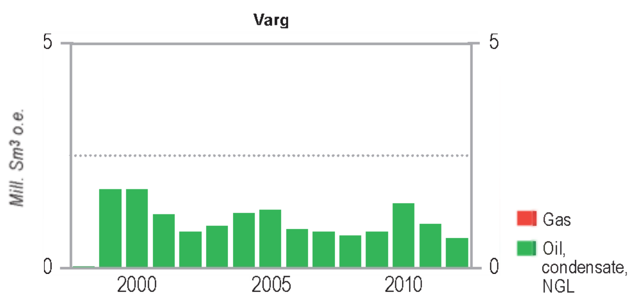
Development: Varg is an oil field to the south of Sleipner Øst in the central part of the North Sea. The water depth in the area is 84 metres. The field has been developed with the production vessel, "Petrojarl Varg", which has integrated oil storage connected to the wellhead facility Varg A. The decommissioning 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.

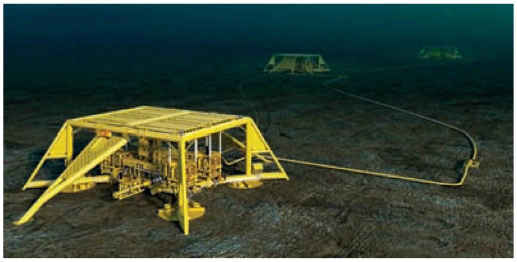
Transport: Oil is off-loaded from the production vessel onto tankers. All the gas is injected, but a solution for possible gas export in the future is being considered.

Status: Varg is in the tail phase, but the field is expected to produce until 2021. A gas pipeline will be installed between Varg and Rev, in order to export the gas via the CATS pipeline system to the UK. Measures to optimise recovery are being considered. In 2011 water alternating gas injection (WAG) started, and the first gas cycles had positive effects. A new drilling campaign with two infill producers has started, 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.



Vega

Blocks and production licences	Block 35/11 - production licence 090 C, awarded 2005 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 31.12.2012**	
	6.6 million Sm^3 oil	5.1 million Sm^3 oil	
	14.0 billion Sm^3 gas	12.2 billion Sm^3 gas	
	2.4 million tonnes NGL	2.0 million tonnes NGL	
Estimated production in 2013	Oil: 17 000 barrels/day, Gas: 1.37 billion Sm^3, NGL: 0.24 million tonnes.		
Expected investment from 2012	1.9 billion 2012 values		
Total investment as of 31.12.2011	8.5 billion nominal values		
Main supply base	Florø		



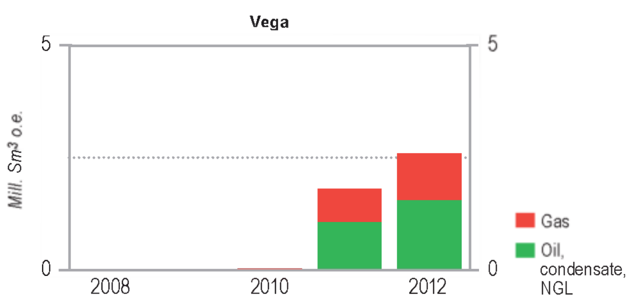
Development: Vega is located directly north of the Fram field in the northern part of the North Sea. The water depth in the area is about 370 metres. The field comprises three separate gas and condensate deposits, 35/8-1, 35/8-2 Vega and 35/11-2 Vega Sør. A combined PDO for Vega and Vega Sør was approved by the authorities in June 2007. The field is being developed with three subsea templates tied to the processing facility at Gjøa.

Reservoir: The Vega reservoirs are in Middle Jurassic sandstones in the Brent Group, with high temperature and pressure initially, and relatively low permeability. The reservoir depth is about 3 500 metres. Vega Sør contains gas and condensate with an oil zone in the upper part of the Middle Jurassic Brent Group, at a depth of 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 planned producers have been drilled and completed on the Vega field. Production from the Vega Sør subsea template is closed down. Sidetrack drilling of a production well on Vega Sør was carried out in 2013 and production is expected to start in late 2013.



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 31.12.2012**	
	54.1 million Sm^3 oil	1.8 million Sm^3 oil	
	5.7 billion Sm^3 gas	3.3 billion Sm^3 gas	
	2.0 million tonnes NGL	0.7 million tonnes NGL	
Estimated production in 2013	Oil: 11 000 barrels/day, Gas: 0.33 billion Sm^3, NGL: 0.11 million tonnes		
Expected investment from 2012	2.4 billion 2011 values		
Total investment as of 31.12.2011	16.7 billion nominal values		
Main supply base	Sotra and Florø		

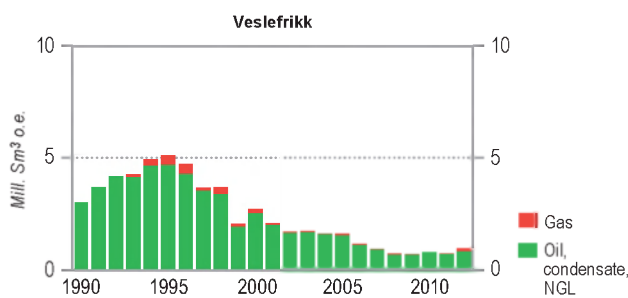
Development: Veslefrikk is an oil field located about 30 kilometres north of Oseberg in the northern part of the North Sea. The water depth is about 185 metres. The field is developed with two facilities, Veslefrikk A and Veslefrikk B. Veslefrikk A is a fixed steel wellhead facility with bridge connection 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 in June 1994. The PDO for the reservoirs in the Upper Brent and I-areas was approved in December 1994.

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

Recovery strategy: Production takes place with pressure support from water alternating gas injection (WAG) in the Brent and Dunlin reservoirs, and with gas injection in the Statfjord Formation. Gas export from Veslefrikk started in late 2011 and the recovery strategy now is to balance gas export and gas injection to optimise drainage of remaining oil and gas resources.

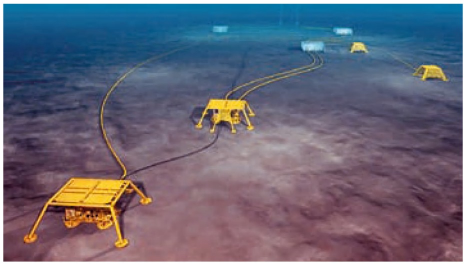
Transport: An oil pipeline is connected to the Oseberg Transport System (OTS) for transport to the Sture terminal. Gas for export is transported through the Gassled system to Kårstø.

Status: Veslefrikk oil production is declining and gas export will increase in the future. The drilling rig has been upgraded and new development wells are being planned.



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		16.10 %
	Idemitsu Petroleum Norge AS		9.60 %
	Petoro AS		30.00 %
	RWE Dea Norge AS		2.80 %
	Statoil Petroleum AS		41.50 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2012**	
	66.6 million Sm^3 oil	15.0 million Sm^3 oil	
	1.9 billion Sm^3 gas	0.2 billion Sm^3 gas	
	1.2 million tonnes NGL	0.3 million tonnes NGL	
Estimated production in 2013	Oil: 39 000 barrels/day, Gas: 0.13 billion Sm^3, NGL: 0.05 million tonnes		
Expected investment from 2012	8.2 billion 2012 values		
Total investment as of 31.12.2011	14.8 billion nominal values		
Main supply base	Florø		



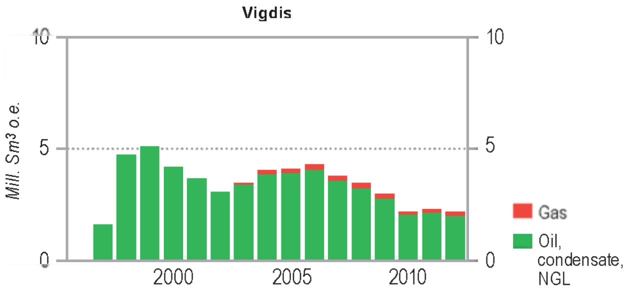
Development: Vigdis is an oil field located between the Snorre and Gullfaks fields in the Tampen area in the northern part of the North Sea. The water depth in the area is 280 metres. The field comprises several discoveries, and has been developed with six subsea templates and two satellite wells connected to Snorre A. Oil from Vigdis is processed in a dedicated processing module on Snorre A. Injection water is supplied from Snorre A and Statfjord C. The PDO for Vigdis Extension, including the 34/7-23 S discovery and adjoining deposits, was approved in December 2002. The PDO for Vigdis Nordøst was approved in September 2011.

Reservoir: The reservoir in the Vigdis Brent deposit consists of Middle Jurassic sandstones in the Brent Group, while the Vigdis Øst and Vigdis Nordøst deposits have reservoirs in Lower Jurassic and Upper Triassic sandstones in 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 support using water injection. Some of the reservoirs are affected by the pressure depletion of the Statfjord field.

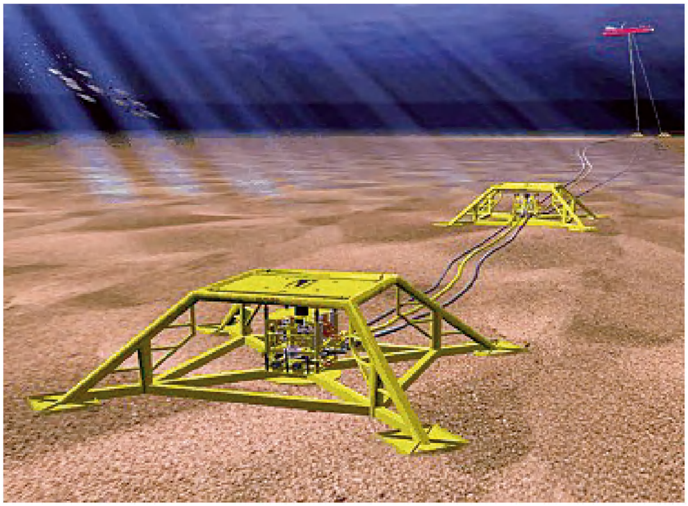
Transport: The wellstream from Vigdis is routed to Snorre A through two flowlines. Stabilised oil is transported by pipeline from Snorre A to Gullfaks A for storage and export. The gas from Vigdis is partly used for injection at Snorre and partly exported through Tampen Link to St Fergus.

Status: The Vigdis Nordøst subsea template for production and water injection was installed and tied back to existing Vigdis templates in 2012. Production started in March 2013. A main challenge at Vigdis is to optimise oil production while limiting water and sand production.



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	Marathon Oil Norge 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 31.12.2012**	
	13.6 million Sm^3 oil	6.2 million Sm^3 oil	
Estimated production in 2013	Oil: 19 000 barrels/day		
Expected investment from 2012	1.2 billion 2011 values		
Total investment as of 31.12.2011	1.9 billion nominal values		



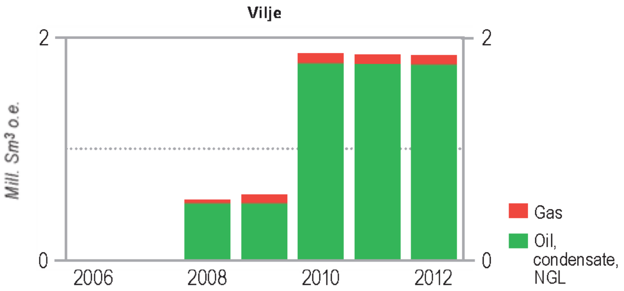
Development: Vilje is an oil field located in the central part of the North Sea, about 20 kilometres northeast of Alvheim and just north of the Heimdal field. It is a subsea development with two horizontal subsea wells connected to the production vessel "Alvheim FPSO". The water depth in the area is 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: As of 1 October 2012, the operatorship for Vilje has been transferred from Statoil to Marathon Oil Norge AS. Production has been above expectations due to better production efficiency and delayed water cut. Future development plans for the field entail the drilling of a new well, Vilje Sør, in the southern extension of the field, in 2013.



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 31.12.2012**	
	33.9 million Sm³ oil	11.5 million Sm³ oil	
	51.3 billion Sm³ gas	44.3 billion Sm³ gas	
	6.4 million tonnes NGL	6.0 million tonnes NGL	
Estimated production in 2013	Oil: 16 000 barrels/day, Gas: 0.45 billion Sm³, NGL: 0.06 million tonnes		
Expected investment from 2012	14.5 billion 2012 values		
Total investment as of 31.12.2011	22.1 billion nominal values		
Main supply base	Florø		

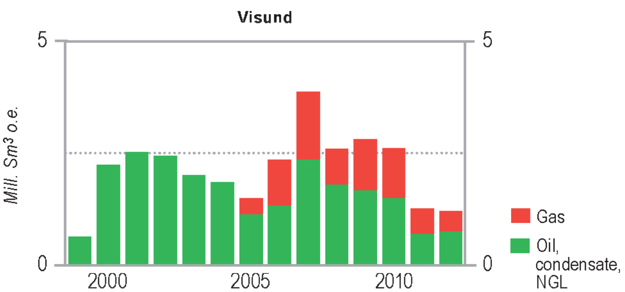
Development: Visund is an oil field east of the Snorre field in the northern part of the North Sea. The development includes a semi-submersible integrated accommodation, drilling and processing steel facility (Visund A). The water depth is about 335 metres at Visund A. The PDO for gas export was approved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

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 gas export started in 2005.

Transport: The oil is sent by pipeline to Gullfaks A for storage and export via tankers. 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 is redeveloped with a new template, and will start production in 2013. The 34/8-13 A (Titan) discovery, east of Visund is planned to be developed by wells drilled from Visund.



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	
On stream	22.11.2012		
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 31.12.2012**	
	2.7 million Sm³ oil	2.7 million Sm³ oil	
	7.3 billion Sm³ gas	7.3 billion Sm³ gas	
	0.9 million tonnes NGL	0.9 million tonnes NGL	
Estimated production in 2013	Oil: 11 000 barrels/day, Gas: 0.54 billion Sm³, NGL: 0.07 million tonnes		
Expected investment from 2012	4.1 billion 2012 values		
Total investment as of 31.12.2011	0.8 billion nominal 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 about 290 metres. Visund Sør is 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 in the Brent Group.

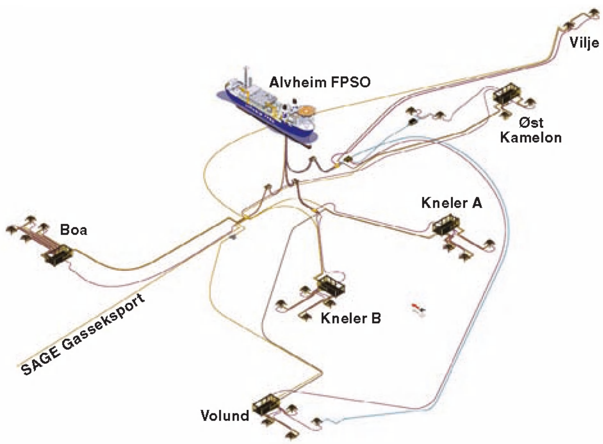
Recovery strategy: The oil from Visund Sør is produced by expansion of the gas cap, followed by depletion for gas production.

Transport: The wellstream is routed to Gullfaks C for processing and export.

Status: Production started in November 2012.

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 31.12.2012**	
	8.6 million Sm^3 oil	4.0 million Sm^3 oil	
	0.9 billion Sm^3 gas	0.5 billion Sm^3 gas	
Estimated production in 2013	Oil: 21 000 barrels/day, Gas: 0.13 billion Sm^3		
Expected investment from 2012	0.7 billion 2012 values		
Total investment as of 31.12.2011	3.2 billion nominal values		



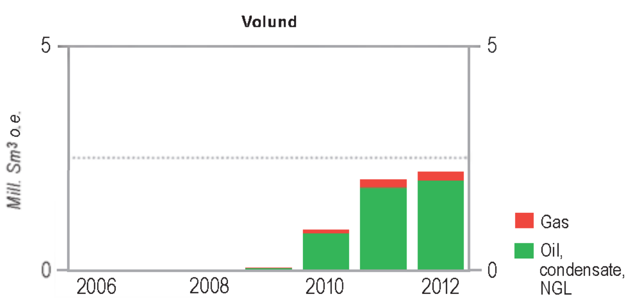
Development: Volund is an oil field located about 10 kilometres south of Alvheim in the central part of the North Sea. The field is developed as a subsea tie-back to the nearby production vessel, "Alvheim FPSO", with three horizontal subsea wells. The water depth in the area is about 120-130 metres.

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 the Hermod aquifer and a single water injection well. Produced water on the "Alvheim FPSO" is used for injection.

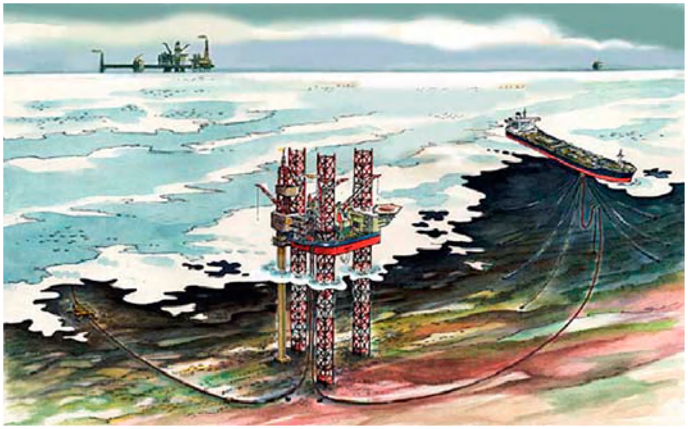
Transport: The wellstream is routed by pipeline to Alvheim for buoy-loading. Associated gas is transported via Alvheim to the Scottish Area Gas Evacuation pipeline system to St Fergus in the United Kingdom.

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". A new well targeting the northwest flank of the injection complex was drilled in 2012 and will come on stream during the first quarter of 2013. Volund has had two years of successful production, which has increased predicted recovery from the field.



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 31.12.2012**	
	8.7 million Sm^3 oil	1.0 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 2013	Oil: 9 000 barrels/day, Gas: 0.03 billion Sm^3		
Expected investment from 2012	0.8 billion 2012 values		
Total investment as of 31.12.2011	3.0 billion nominal values		



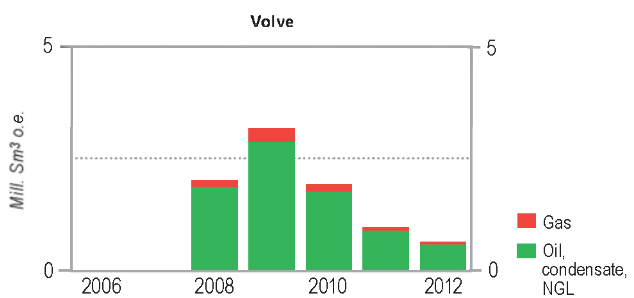
Development: Volve is an oil field located in the central part of the North Sea, approximately eight kilometres north of Sleipner Øst. The water depth in the area is about 80 metres. The development concept is a jack-up processing and drilling facility and the vessel "Navion Saga" for storing stabilised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

Reservoir: The reservoir contains oil in a combined stratigraphic and structural trap in Jurassic sandstones in 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.

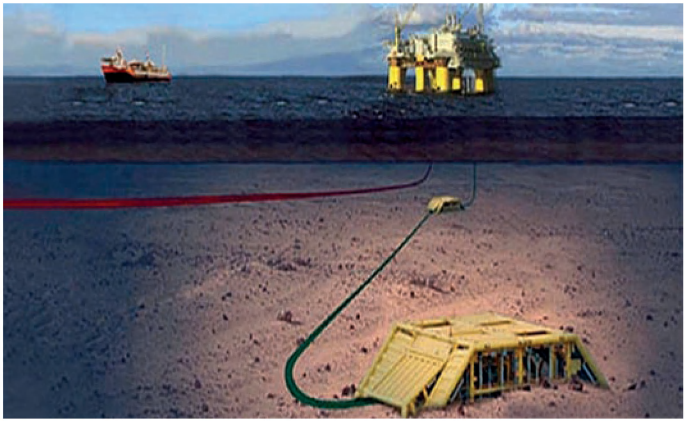
Transport: The rich gas is transported to Sleipner A for further export. The oil is exported by tankers.

Status: Production on Volve is expected to decline rapidly in the coming years. New drilling targets have been evaluated in order to establish a basis for a new drilling campaign planned for the first half of 2013.



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 31.12.2012**
	0.3 million Sm^3 oil	1.0 billion Sm^3 gas
	2.2 billion Sm^3 gas	0.2 million tonnes NGL
	0.4 million tonnes NGL	
Estimated production in 2013	Gas: 0.49 billion Sm^3, NGL: 0.09 million tonnes	
Total investment as of 31.12.2011	1.5 billion nominal values	



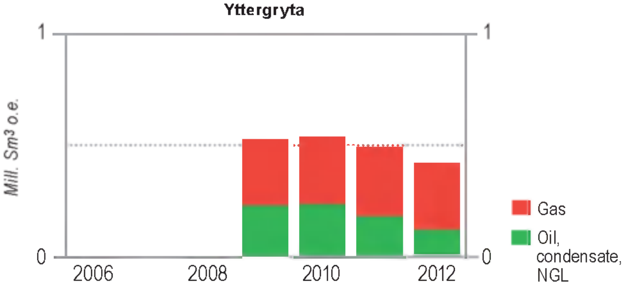
Development: The field is located in the Norwegian Sea, approximately 5 kilometres north of the Midgard deposit. The water depth in the area is about 300 metres. The field has been developed with a subsea template tied to Midgard, and the gas is produced from one well.

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

Recovery strategy: The field has been produced by pressure depletion.

Transport: The gas was 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 breakthrough in the gas production well. An attempt to restart production in 2012 failed. Due to an agreement with Åsgard, gas is still sold from the field.

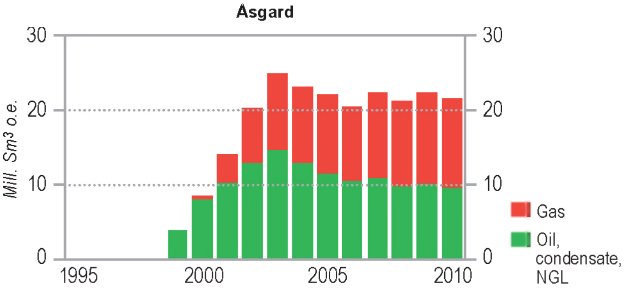


Åsgard

Blocks and production licences	Block 6406/3 - production licence 094 B, awarded 2002. Block 6407/2 - production licence 074, awarded 1982. Block 6407/3 - production licence 237, awarded 1998. Block 6506/11 - production licence 134, awarded 1987. Block 6506/12 - production licence 094, awarded 1984. Block 6507/11 - production licence 062, awarded 1981.	
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 31.12.2012**
	100.4 million Sm^3 oil	18.6 million Sm^3 oil
	207.7 billion Sm^3 gas	84.1 billion Sm^3 gas
	39.4 million tonnes NGL	16.8 million tonnes NGL
	17.1 million Sm^3 condensate	
Estimated production in 2013	Oil: 55 000 barrels/day, Gas: 9.23 billion Sm^3, NGL: 1.86 million tonnes	
Expected investment from 2012	38.6 billion 2012 values	
Total investment as of 31.12.2011	65.3 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 October 2000.The Åsgard facilities are an important part of the Norwegian Sea infrastructure where gas from Mikkel is processed, and injection gas is delivered to Tyrihans. The Morvin field is tied back to Åsgard B.

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 project on optimisation of the drainage strategy on Smørbukk Sør has started. The plan is to mature the project with a phased development with production start-up of the first phase in 2015 and the second phase, depending on the results of the first phase, a few years later. Establishment of a gas compression facility at Midgard was approved in 2012 and start-up of the facility is planned for 2015. This facility is needed to maintain the gas stream in the pipeline 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 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). Implementing Åsgard A and B low pressure production is also being evaluated. Phase I is a planned to start operation in 2013, and phase II in 2015. Other efforts for increasing recovery from Åsgard include prolonging 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.

The living quarter is lifted into place on the Goliat facility, which is currently under construction at the Hyundai yard in South Korea.
(Photo: Eni Norge, News on request)

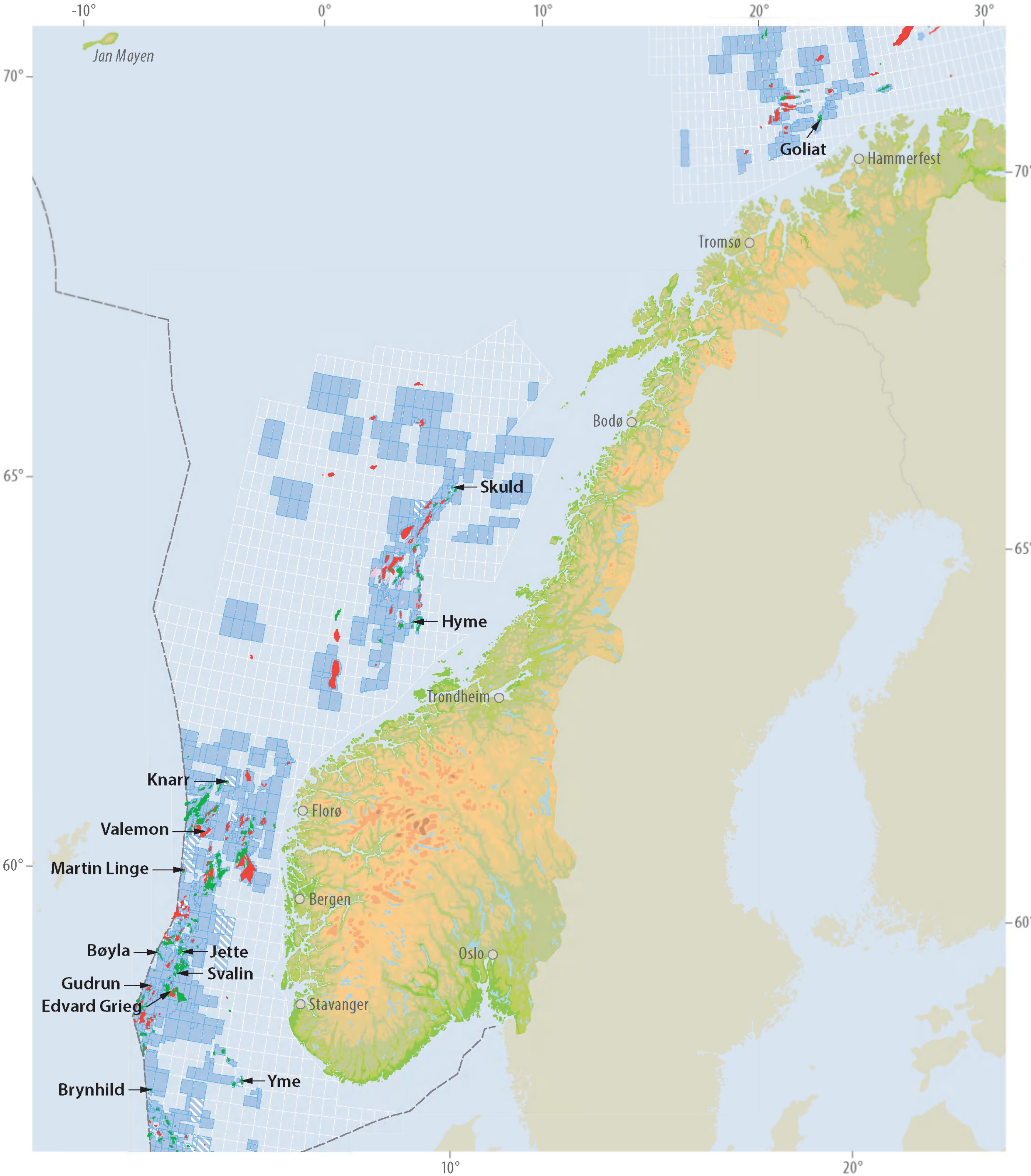


Figure 11.1 Fields under development *(Source: Norwegian Petroleum Directorate)*

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		90.00 %
	Talisman Energy Norge AS		10.00 %
Recoverable reserves	**Original**		
	3.6 million Sm^3 oil		
Expected investment from 2012	5.0 billion 2012 values		
Total investment as of 31.12.2011	0.2 billion nominal values		

Development: Brynhild is located about 10 kilometres from the UK border, about 55 kilometres northwest of the Ula field and 38 kilometres from the UK Pierce field. The water depth in the area is about 80 metres. The development concept is a subsea template and manifold, tied-in to the Hæwene Brim FPSO located on the Pierce field in the UK. Water for injection will be supplied from Pierce.

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

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

Transport: The wellstream will be transported by pipeline to the Hæwene Brim FPSO for metering and processing. The processed oil will be exported by shuttle tankers to the 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.

Bøyla

Blocks and production licences	Block 24/9 - production licence 340, awarded 2004.		
Development approval	26.10.2012 by the King in Council	**Discovered** 2009	
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**		
	3.4 million Sm^3 oil		
	0.3 billion Sm^3 gas		
Expected investment from 2012	4.8 billion 2012 values		
Total investment as of 31.12.2011	0.1 billion nominal values		

Development: The oil discovery Bøyla is situated about 28 kilometres south of the Alvheim field. Water depth is about 120 metres. The development solution for Bøyla is a subsea template tied back to the Alvheim FPSO.

Reservoir: The Bøyla reservoir is within the Hermod Sandstone Member, which is a channelised sub-marine fan system of Late Paleocene to Early Eocene age, and lies at a depth of about 2 100 metres.

Recovery strategy: Water injection is required for pressure support due to limited connected aquifer volume. Gas lift will also be required to support flow, once production wells start producing water.

Transport: The oil and gas from Bøyla will be transported to Alvheim for processing and export.

Status: The PDO was submitted in June 2012. Production is planned to start in October 2014.

Edvard Grieg

Blocks and production licences	Block 16/1 - production licence 338, awarded 2004.		
Development approval	11.06.2012 by the Storting	**Discovered** 2007	
Operator	Lundin Norway AS		
Licensees	Lundin Norway AS		50.00 %
	OMV (Norge) AS		20.00 %
	Wintershall Norge AS		30.00 %
Recoverable reserves	**Original**		
	26.2 million Sm^3 oil		
	1.8 billion Sm^3 gas		
	0.6 million tonnes NGL		
Expected investment from 2012	21.7 billion 2012 values		

Development: Edvard Grieg is located about 35 kilometres south of Grane and Balder. The water depth is about 110 metres. The development comprises a PdQ jacket solution using a separate jack-up for drilling and completion. The PdQ platform will have sufficient spare well slots for possible additional wells, together with the possible development of nearby discoveries and prospects.

Reservoir: The reservoir contains oil at a depth of 1 900 – 1 940 metres. The reservoir consists of Upper Triassic to Lower Cretaceous alluvial, aeolian and shallow marine conglomerates and sandstones. Oil is also proven in the underlying basement.

Recovery strategy: Edvard Grieg will be produced by pressure support from water injection.

Transport: The oil will be exported by pipeline to the Grane Oil Pipeline, which is connected to the Sture terminal. The gas is planned to be exported in a separate pipeline to the Scottish Area Gas Evacuation (SAGE) System.

Status: The platform is under construction. Production is planned to start in late 2015.

Goliat

Blocks and production licences	Block 7122/10 - production licence 229, awarded 1997. Block 7122/11 - production licence 229 B, awarded 2007. 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**		
	30.2 million Sm^3 oil		
	7.3 billion Sm^3 gas		
	0.3 million tonnes NGL		
Expected investment from 2012	26.7 billion 2012 values		
Total investment as of 31.12.2011	10.2 billion nominal values		

Development: Goliat is an oilfield 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.

Status: Production is planned to start late in 2014.

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**		
	11.7 million Sm^3 oil		
	6.4 billion Sm^3 gas		
	1.3 million tonnes NGL		
Expected investment from 2012	12.9 billion 2012 values		
Total investment as of 31.12.2011	5.9 billion nominal values		

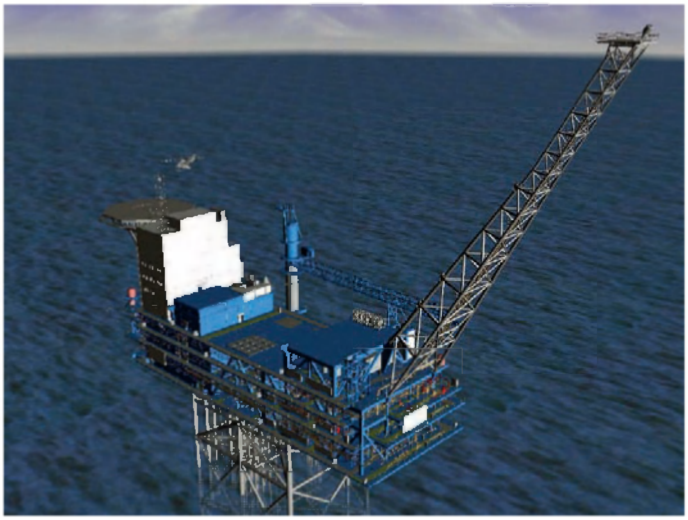
Development: Gudrun is located 50 kilometres north of Sleipner. The water depth is approximately 110 metres. Gudrun is being developed with a fixed facility with a steel jacket and first-stage processing, tied back to Sleipner A through two dedicated pipelines; one for oil and one for rich gas.

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.

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 E&P 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 2012	3.9 billion 2012 values		
Total investment as of 31.12.2011	0.9 billion nominal 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 a production pipeline, a water injection pipeline, and a pipeline for gas lift. The development plan includes one production well and one water injection well.

Reservoir: The reservoir contains oil and gas in the Lower Jurassic Tilje Formation. The reservoir is 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 on the top of the structure and water injection for pressure support.

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

Status: The field came on stream in February 2013.

Jette

Blocks and production licences	Block 25/7 - production licence 504, awarded 2009. Block 25/8 - production licence 027 D, awarded 2007. Block 25/8 - production licence 169 C, awarded 2009.		
Development approval	17.02.2012 by the King in Council	**Discovered** 2009	
Operator	Det norske oljeselskap ASA		
Licensees	Det norske oljeselskap ASA		70.00 %
	Petoro AS		30.00 %
Recoverable reserves	**Original**		
	1.5 million Sm^3 oil		
	0.1 billion Sm^3 gas		
Expected investment from 2012	3.9 billion 2012 values		
Total investment as of 31.12.2011	0.3 billion nominal values		

Development: Jette is located about six kilometres south of the Jotun Field. Water depth is about 127 metres. Jette will be developed with a subsea template tied to the Jotun A facility.

Reservoir: The reservoir is in the Heimdal Formation, which is a sub-marine fan system of the Late Paleocene age and lies at a depth of approximately 2 200 metres.

Recovery strategy: Jette will be produced with natural pressure support from aquifer.

Transport: The wellstream will go to Jotun A and further to Jotun B for processing and loading.

Status: The PDO was approved in February 2012. Production is planned to start in the second quarter of 2013.

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 AS		20.00 %
Recoverable reserves	**Original**		
	11.9 million Sm^3 oil		
	0.3 billion Sm^3 gas		
	0.8 million tonnes NGL		
Expected investment from 2012	10.0 billion 2012 values		
Total investment as of 31.12.2011	0.5 billion nominal values		

Development: Knarr is located approximately 50 kilometres northeast of Snorre. The water depth is 410 metres. Knarr is being developed with an FPSO and two subsea templates for production and injection, connected to a subsea manifold.

Reservoir: The reservoir lies at a depth of about 3 800 metres and contains oil in Lower Jurassic sandstones in 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 routed in a new gas pipeline to the Far North Liquids and Associated Gas System (FLAGS) and exported to St Fergus in the UK.

Status: The FPSO and subsea facilities are under construction. Drilling of development wells will start in summer 2013 and production is planned to start in May 2014.

Martin Linge

Blocks and production licences	Block 29/6 - production licence 043, awarded 1976. Block 29/6 - production licence 043 BS, awarded 2006. Block 29/9 - production licence 040, awarded 1975. Block 30/4 - production licence 043, awarded 1976. Block 30/4 - production licence 043 BS, awarded 2006. Block 30/7 - production licence 040, awarded 1975.	
Development approval	11.06.2012 by the Storting	**Discovered** 1978
Operator	Total E&P Norge AS	
Licensees	Petoro AS	30.00 %
	Statoil Petroleum AS	19.00 %
	Total E&P Norge AS	51.00 %
Recoverable reserves	**Original**	
	6.0 million Sm^3 oil	
	19.7 billion Sm^3 gas	
	0.7 million tonnes NGL	
	3.0 million Sm^3 condensate	
Expected investment from 2012	23.9 billion 2012 values	
Total investment as of 31.12.2011	0.4 billion nominal values	

Development: Martin Linge is located near the border to the British sector, about 42 kilometres west of Oseberg. The water depth in the area is 100 – 120 metres. Martin Linge will be developed with a fully integrated fixed production platform with an FSO for oil and condensate storage. The wells will be drilled by a mobile jack-up rig. The installation will be supplied with power from shore.

Reservoir: The main reservoir is structurally complex, and contains gas and condensate 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. In addition, the field contains oil in the Frigg Formation of Eocene age at approximately 1 750 metres. The Frigg Formation has good reservoir quality.

Recovery strategy: The gas reservoir will be produced by pressure depletion, whereas the oil production from the Eocene reservoir will be supported by natural aquifer drive and gas lift. Produced water will be re-injected into a disposal reservoir.

Transport: Rich gas will be transported through a pipeline to the FUKA gas transport system on the UK sector, and oil and condensate will be exported via tankers from the FSO.

Status: Production is planned to start by the end of 2016.

Skuld

Blocks and production licences	Block 6608/10 - production licence 128, awarded 1986.	
Development approval	20.01.2012 by the King in Council	**Discovered** 2008
Operator	Statoil Petroleum AS	
Licensees	Eni Norge AS	11.50 %
	Petoro AS	24.55 %
	Statoil Petroleum AS	63.95 %
Recoverable reserves	**Original**	
	13.4 million Sm^3 oil	
	0.6 billion Sm^3 gas	
	0.1 million tonnes NGL	
Expected investment from 2012	8.8 billion 2012 values	
Total investment as of 31.12.2011	1.4 billion nominal values	

Development: Skuld is located in the Norwegian Sea, north of the Norne Field, at a water depth of about 340 metres. The field consists of the two oil deposits, 6608/10-12 Dompap and 6608/10-14 S Fossekall, 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.

Reservoir: The reservoirs consist of Lower to Middle Jurassic sandstones in the Åre, Tofte and Ile Formations at a depth of 2 400–2 600 metres. The reservoirs contain oil.

Recovery strategy: Skuld will be recovered with pressure support by water injection. In addition, some of the wells will be supplied with gas lift to be able to produce at low reservoir pressure and high water cut.

Transport: 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 further via Åsgard Transport System to Kårstø.

Status: The PDO was approved in January 2012. Drilling of the development wells started in March 2012, and production is planned to start in the first half of 2013.

Svalin

Blocks and production licences	Block 25/11 - production licence 169, awarded 1991.		
Development approval	23.11.2012 by the King in Council	**Discovered** 1992	
Operator	Statoil Petroleum AS		
Licensees	ExxonMobil Exploration & Production Norway AS		13.00 %
	Petoro AS		30.00 %
	Statoil Petroleum AS		57.00 %
Recoverable reserves	**Original**		
	12.1 million Sm³ oil		
Expected investment from 2012	4.2 billion 2012 values		

Development: Svalin is located 8 kilometres southwest of the Grane field. The water depth in the area is approximately 120 metres. Svalin will be developed by a multilateral well drilled from the Grane platform, and with a subsea facility tied in to Grane.

Reservoir: There is 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.

Recovery strategy: Svalin will be recovered by pressure depletion.

Transport: The wellstream will be processed on Grane and transported by pipeline to the Sture terminal for storage and export.

Status: The PDO was approved in 2012. Production from Svalin is planned to start in two phases, in November 2013 and in June 2014.

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	Centrica Resources (Norge) AS		13.00 %
	Enterprise Oil Norge AS		3.23 %
	Petoro AS		30.00 %
	Statoil Petroleum AS		53.78 %
Recoverable reserves	**Original**		
	4.9 million Sm³ oil		
	26.1 billion Sm³ gas		
	1.3 million tonnes NGL		
Expected investment from 2012	16.8 billion 2012 values		
Total investment as of 31.12.2011	1.5 billion nominal values		

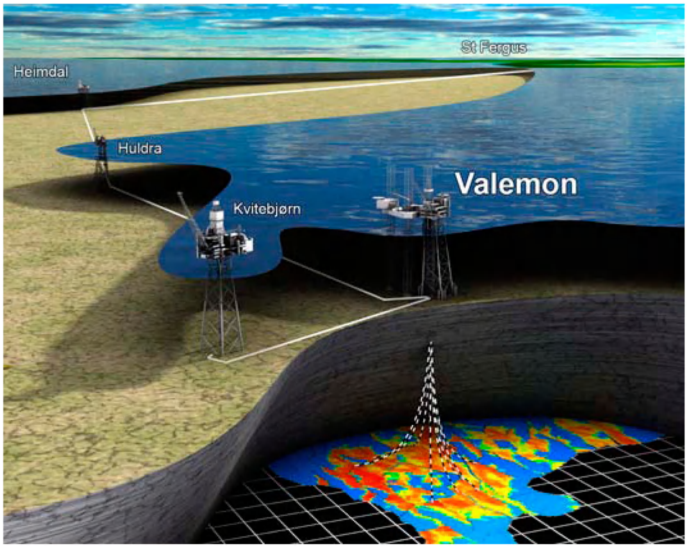
Development: Valemon is located in blocks 34/11 and 34/10, just west of the Kvitebjørn field. The water depth is 135 metres. Several appraisal wells have been drilled on the discovery. The development concept is a fixed steel production platform with a simplified separation process. The platform will be remotely controlled from the Kvitebjørn field or from shore.

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 by pipeline to Kvitebjørn, and via the Kvitebjørn oil pipeline to Mongstad. The rich gas is planned to be exported in the Huldra pipeline to Heimdal for further export to the United Kingdom or the Continent.

Status: The platform is under construction. Drilling of wells started in 2012 and production start is scheduled for October 2014.



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 AS	10.00 %
Recoverable reserves*	**Original**	**Remaining as of 31.12.2012**
	22.0 million Sm³ oil	14.1 million Sm³ oil
Expected investment from 2012	4.2 billion 2012 values	
Total investment as of* 31.12.2011	11.7 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.

Status: Due to technical difficulties, the licensees have decided to remove most of the existing installation from the field. The licensees are currently working on new development plans for the field.

12 FUTURE DEVELOPMENTS

Many fields are developed with subsea facilities. This one rests on the seabed at the Atla field, where production started in 2012. (Photo: Total, Woldcam)

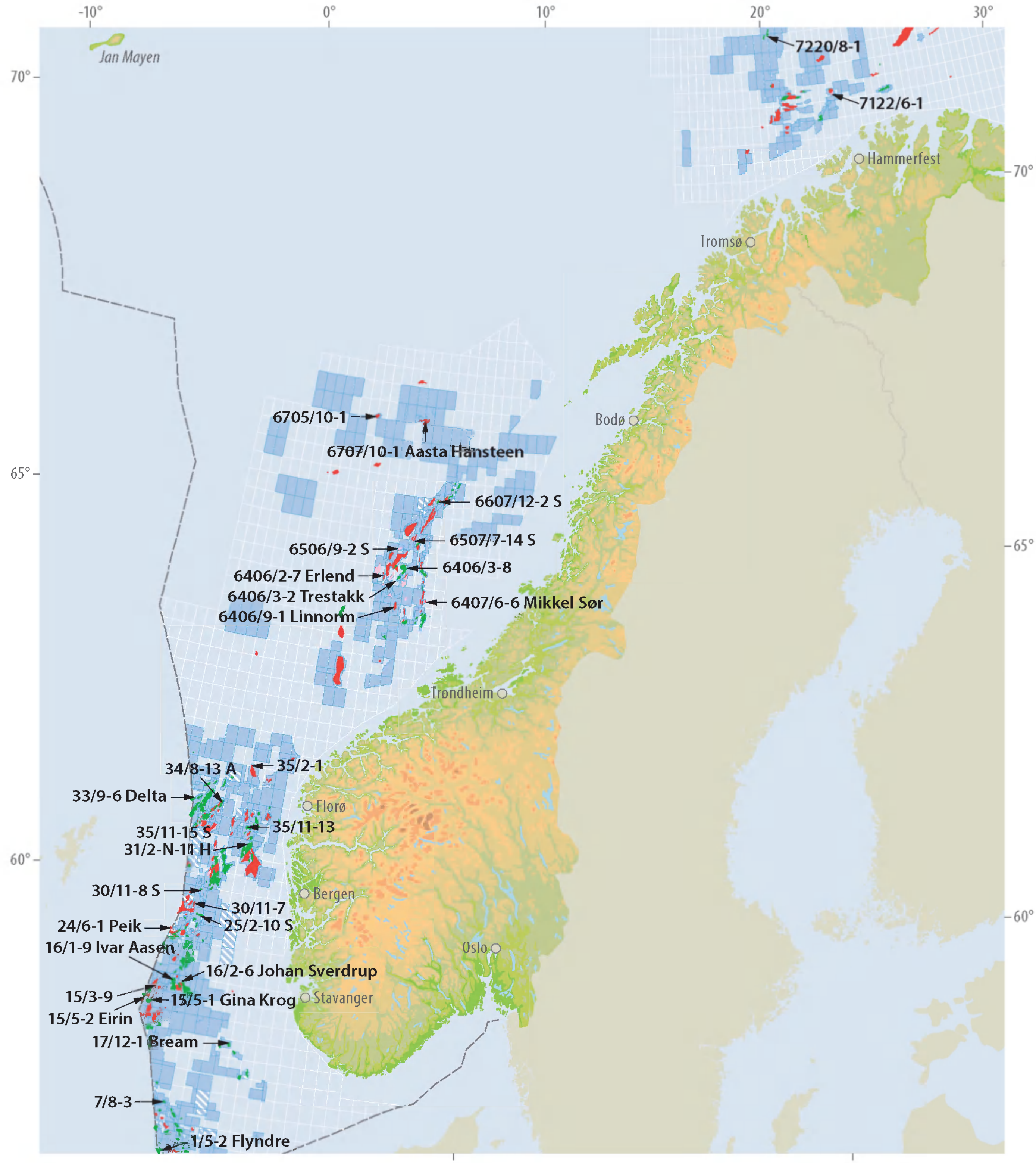


Figure 12.1 Future developments *(Source: Norwegian Petroleum Directorate)*

Developments decided by the licensees

15/5-1 Gina Krog

Production licence:	029 B, 029 C, 048, 303, Operator: Statoil Petroleum AS
Resources:	Oil: 16.8 million Sm^3, Gas: 12.5 billion Sm^3, NGL: 3.3 million tonnes, Condensate: 1.6 million Sm^3

15/5-1 Gina Krog 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 jack-up rig. Oil will be transported by tankers via offshore loading (FSU). The rich gas will be transported to Sleipner for processing and onto Gassled for export. Condensate and NGL will be exported to Kårstø. The drainage strategy is gas injection. The licensees submitted the PDO in December 2012, and production start is expected in 2017.

16/1-9 Ivar Aasen

Production licence:	001 B, 028 B, 242, Operator: Det norske oljeselskap ASA
Resources:	Oil: 18.3 million Sm^3, Gas: 4.7 billion Sm^3, NGL: 1.1 million tonnes

16/1-9 Ivar Aasen 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 sandstones in the Middle Jurassic Sleipner Formation and the Upper Triassic Skagerrak Formation. The reservoir lies at a depth of about 2 400 metres. Ivar Aasen is planned as a stand-alone development with a fixed production facility tied back to the Edvard Grieg facility. Two additional oil discoveries, 25/10-8 Hanz and 16/1-7 West Cable, are planned to be produced through the Ivar Aasen production facilities. The licensees submitted a PDO in December 2012, and production start is planned for late 2016.

33/9-6 Delta

Production licence:	037 D, Operator: Wintershall Norge AS
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, which will continue until Murchison is shut down in 2013 or 2014.

35/11-15 S

Production licence:	090, 248, Operator: Statoil Petroleum AS
Resources:	Oil: 1.7 million Sm^3

35/11-15 S (Fram H-Nord) is an oil discovery located just north of the Fram field, at a water depth of 360 metres. The discovery well was drilled in 2007, and a decision to develop was made in June 2012. A PDO exemption was submitted to the authorities in April 2012. Fram H-Nord is planned to be developed with a two branch multilateral (MLT) well with gas lift, which will be produced by pressure depletion. The production will be routed through a 4-slot template tied in to existing A2-template on the Fram Vest field and processed on Troll C. Fram H-Nord contains oil in turbidity sandstones in the Heather Formation of Late Jurassic age, at a reservoir depth of approximately 2 950 metres.

6707/10-1 Aasta Hansteen

Production licence:	218, Operator: Statoil Petroleum AS
Resources:	Gas: 45.4 billion Sm^3, Condensate: 0.9 million Sm^3

6707/10-1 Aasta Hansteen 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. In 2008, two nearby wells, 6707/10-2 S and 6706/12-1, were drilled and proved additional gas resources that can be tied to a joint development. Aasta Hansteen will be developed with a floating field centre, the first Spar platform in Norway. The facility will be 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 Aasta Hansteen and other discoveries in the planned Polarled pipeline to Nyhamna. Therefore, the development schedules for Aasta Hansteen and Polarled have been coordinated. Deep water represents technical challenges, and Aasta Hansteen will develop technology that can be useful for future developments in Norway. The PDO was submitted 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, Gas: 0.1 billion 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 a Field Development Plan to the UK and Norwegian authorities in 2013. 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.

7/8-3

Production licence:	301, Operator: Lundin Norway AS
Resources:	Oil: 3.8 million Sm^3

7/8-3 is an oil discovery from 1983 that was appraised in 2006. It is located about 27 kilometres northwest of Ula. Ula or Pierce (UK) are potential host platforms.

15/3-9

Production licence:	025, 187, Operator: Statoil Petroleum AS
Resources:	Oil: 0.9 million Sm^3, Gas: 0.5 billion Sm^3, NGL: 0.1 million tonnes, Condensate: 0.0 million Sm^3

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.

15/5-2 Eirin

Production licence:	048 E, Operator: Statoil Petroleum AS
Resources:	Gas: 7.9 billion Sm^3, NGL: 0.1 million tonnes, Condensate: 0.3 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 Gina Krog 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 planned development solution is a four-slot template with two gas wells tied back to the planned Gina Krog platform, where the wellstream will be partly processed and the gas will be used for injection on Gina Krog to increase recovery. The water depth at the proposed Eirin template location is 118 metres. The licensees plan to submit a PDO late in 2013, and start production in 2017.

16/2-6 Johan Sverdrup

Production licence:	265, 501, Operator: Lundin Norway AS
Resources:	Oil: 300.0 million Sm^3, Gas: 7.8 billion Sm^3, NGL: 3.8 million tonnes

16/2-6 Johan Sverdrup was discovered in 2010 approximately 40 kilometres south of Grane and Balder. Five appraisal wells and two sidetracks were drilled on the discovery in 2011, and six appraisal wells and two sidetracks were drilled in 2012. Water depth in the area is approximately 115 metres. The reservoir contains oil in Jurassic sandstones at a depth of 1 900 metres. The licensees are considering development solutions with several installations and plan to make a concept decision in October 2013.

17/12-1 Bream

Production licence:	407, Operator: BG Norge AS
Resources:	Oil: 6.8 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 in 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 in 2017.

24/6-1 Peik

Production licence:	088, Operator: Centrica Resources (Norge) AS
Resources:	Oil: 0.6 million Sm^3, Gas: 2.0 billion Sm^3

24/6-1 Peik was discovered in 1985, and was delineated by the 9/15a-1 well 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.

25/2-10 S

Production licence:	442, Operator: Centrica Resources (Norge) AS
Resources:	Oil: 11.2 million Sm^3, Gas: 3.4 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.

30/11-7

Production licence:	035 B, 362, Operator: Centrica Resources (Norge) AS
Resources:	Oil: 0.6 million Sm^3, Gas: 4.1 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 110 metres. The reservoir contains gas and condensate in sandstones in the Middle Jurassic Ness Formation and lies at a depth of about 4 000 metres.

30/11-8 S

Production licence:	035, Operator: Statoil Petroleum AS
Resources:	Oil: 6.6 million Sm^3, Gas: 3.2 billion Sm^3, NGL: 0.2 million tonnes

30/11-8 S (Krafla) and sidetrack 30/11-8-A were drilled in 2011. Oil and gas were discovered in two nearby structures, Krafla Main and Krafla West. The reservoirs are in the Middle Jurassic sandstones in the Brent Group at a depth of 3 200 – 3 650 metres. The water depth in the area is 108 metres. The discovery is located about 35 kilometres south of the Oseberg field centre. In this early phase, the evaluation of various development solutions and tie-back alternatives is ongoing.

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 one well connected to Troll C. Production is expected to start in 2014.

34/8-13 A

Production licence:	120, Operator: Statoil Petroleum AS
Resources:	Oil: 2.6 million Sm^3, Gas: 1.1 billion Sm^3, NGL: 0.1 million tonnes

34/8-13 A (Titan) was discovered in 2009 just east of the Visund field, inside the Visund Unit (PL 120), at a water depth of about 380 metres. The discovery well proved oil in Intra-Draupne sandstone of Late Jurassic age, at a depth of 2 900 metres. Titan may be developed by a well drilled from the Visund A platform and later by an additional well from the Visund Nord subsea template. Production start is expected in early 2015, and recovery strategy will be pressure depletion.

35/11-13

Production licence:	090 B, 090 C, 248, Operator: Statoil Petroleum AS
Resources:	Oil: 3.4 million Sm^3, Gas: 0.6 billion Sm^3, NGL: 0.0 million tonnes

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 Gjøa.

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 evaluating possible development concepts.

6406/2-7 Erlend

Production licence:	199, 257, Operator: Statoil Petroleum AS
Resources:	Oil: 0.9 million Sm^3, Gas: 1.0 billion Sm^3, NGL: 0.2 million tonnes

6406/2-7 Erlend was discovered in 1999. The western part of the discovery lies in production licence 257. The discovery is located southwest of the Kristin field and northwest of the 6406/2-6 Ragnfrid discovery on Haltenbanken in the Norwegian Sea. The water depth is 293 metres. The reservoir consists of Middle Jurassic sandstones in the Garn and Ile Formations. The top of the reservoir lies at a depth of 4 560 metres. In addition, there are good indications of petroleum in sandstones in the lower part of the Cretaceous Lange Formation. The most likely development solution is a subsea template tied to the Kristin infrastructure.

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 in 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. The most likely development solution is subsea templates tied to a joint infrastructure with Maria.

6406/3-8

Production licence:	475 BS, Operator: Wintershall Norge AS
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 discovery is located about 20 kilometres southeast of Åsgard. The water depth is 290 – 315 metres. The structure is divided into two parts, Maria South and Maria North. The discovery well was drilled on Maria South, and oil was found in sandstones in the Middle Jurassic Garn Formation. The reservoir depth is 3 700 – 3 800 meters. An appraisal well was drilled in 2012 and confirmed the northern part of the discovery. Two development solutions are being evaluated. The plan is to submit a PDO in 2016, with expected production start in 2017.

6406/9-1 Linnorm

Production licence:	255, Operator: A/S Norske Shell
Resources:	Gas: 23.9 billion Sm^3, Condensate: 0.5 million Sm^3

6406/9-1 Linnorm was discovered 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 310 metres. The Linnorm discovery consists of gas with high (about 7 mol %) CO2 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. The future of the Linnorm project is being evaluated by the licensees.

6407/6-6 Mikkel Sør

Production licence:	312, 312 B, 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 226–247 metres. 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 lie at a depth of 2 110–2 233 metres. The discovery well 6407/6-7 S proved gas and condensate in sandstones in the Upper Jurassic Garn Formation. The reservoir in the Garn Formation lies at a depth of approximately 2 800 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. A PDO is expected to be submitted in 2013.

6506/9-2 S

Production licence:	433, Operator: Centrica Resources (Norge) AS
Resources:	Oil: 1.7 million Sm^3, Gas: 9.7 billion Sm^3

6506/9-2 S (Fogelberg) was discovered 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 4 300–4 380 metres. The discovery will be developed with subsea templates tied to existing infrastructure in the area. The operator is expected to submit a PDO in 2016, with production expected to start in 2020.

6507/7-14 S

Production licence:	435, Operator: RWE Dea Norge AS
Resources:	Gas: 17.4 billion Sm^3, NGL: 0.2 million tonnes, Condensate: 0.5 million Sm^3

6507/7-14 S (Zidane) consists of two separate structures, Zidane east and Zidane west. Zidane east was proven in 2010. The discovery is located about 15 kilometres northwest of the Heidrun field in the Norwegian Sea. The reservoir consists of sandstones in the Middle Jurassic Garn and Ile Formations. The water depth is 344 metres. Zidane west was proven about 3.5 kilometres west of Zidane east in sandstones in the Middle Jurassic Garn and Ile Formations. The reservoir lies at a depth of about 4 530 metres, and the water depth is about 400 metres. Subsea templates tied to the Heidrun platform is the most likely development solution. A PDO is planned to be submitted in 2014, and production is expected to start in 2017.

6607/12-2 S

Production licence:	127, Operator: Total E&P Norge AS
Resources:	Oil: 0.9 million Sm^3, Gas: 4.7 billion Sm^3, Condensate: 1.3 million Sm^3

6607/12-2 S (Alve Nord) was proven in 2011. The oil and gas discovery is located about eight kilometres west of Norne in the Norwegian Sea. The water depth is about 370 metres. The reservoirs consist of Cretaceous and Lower Jurassic sandstones. The discovery may be developed in connection with existing fields in the area.

6705/10-1

Production licence:	327, 327 B, Operator: Statoil Petroleum AS
Resources:	Gas: 17.8 billion Sm^3, Condensate: 0.3 million Sm^3

6705/10-1 (Asterix) was discovered in 2009. The discovery is located in the

Vøring Basin in the Norwegian Sea. The water depth is 1 335 metres. The reservoir consists of Upper Cretaceous sandstones in the Springar Formation. The sandstones were deposited from turbiditic massflows. The reservoir depth is about 3 200 metres. The most likely development solution is subsea templates tied to the future infrastructure on Aasta Hansteen.

7122/6-1

Production licence 110 B, Operator: Statoil Petroleum AS	
Resources Gas: 3.7 billion Sm^3, Condensate: 0.2 million Sm^3	

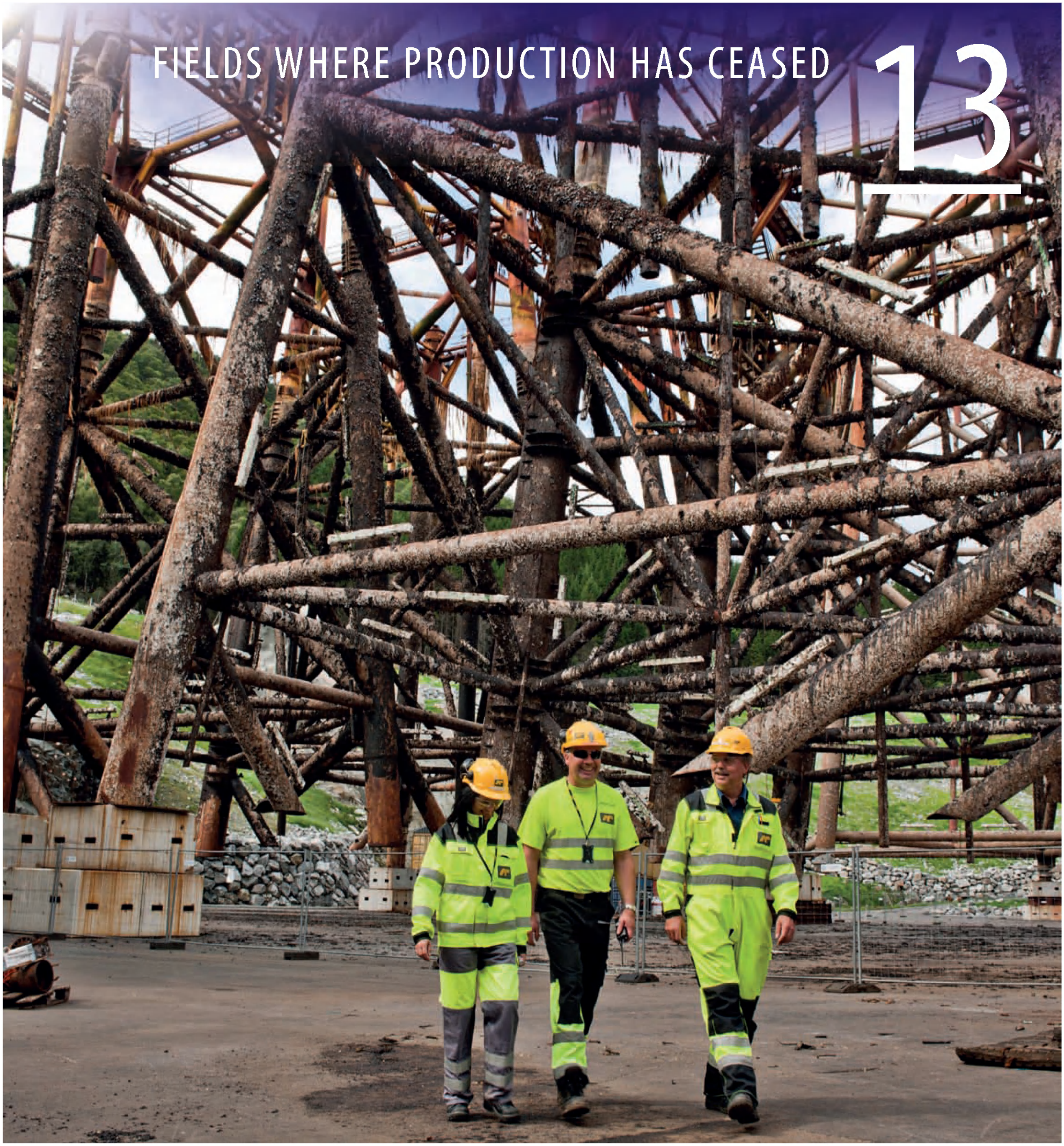
7122/6-1 (Tornerose) was discovered in 1987, and is situated about 110 kilometres northwest of Hammerfest. The water depth in the area is about 400 metres. The reservoir is from the Late Triassic age. The plan is to develop the discovery with subsea templates tied back to the Snøhvit facility.

7220/8-1

Production licence:	532, Operator: Statoil Petroleum AS
Resources:	Oil: 40.9 million Sm^3

7220/8-1 (Skrugard) was discovered in 2011 and proved oil and gas. The discovery is located in the Barents Sea about 110 kilometres north of the Snøhvit field. The water depth is about 370 metres. The reservoir consists of Middle to Lower Jurassic sandstones. A joint development of Skrugard and 7220/7-1 (Havis) with a floating facility and a pipeline to an onshore terminal is planned.

13 FIELDS WHERE PRODUCTION HAS CEASED



The Norwegian continental shelf has matured, and the first early facilities have been removed and scrapped on shore.
(Photo: Monika Larsen, Norwegian Petroleum Directorate)

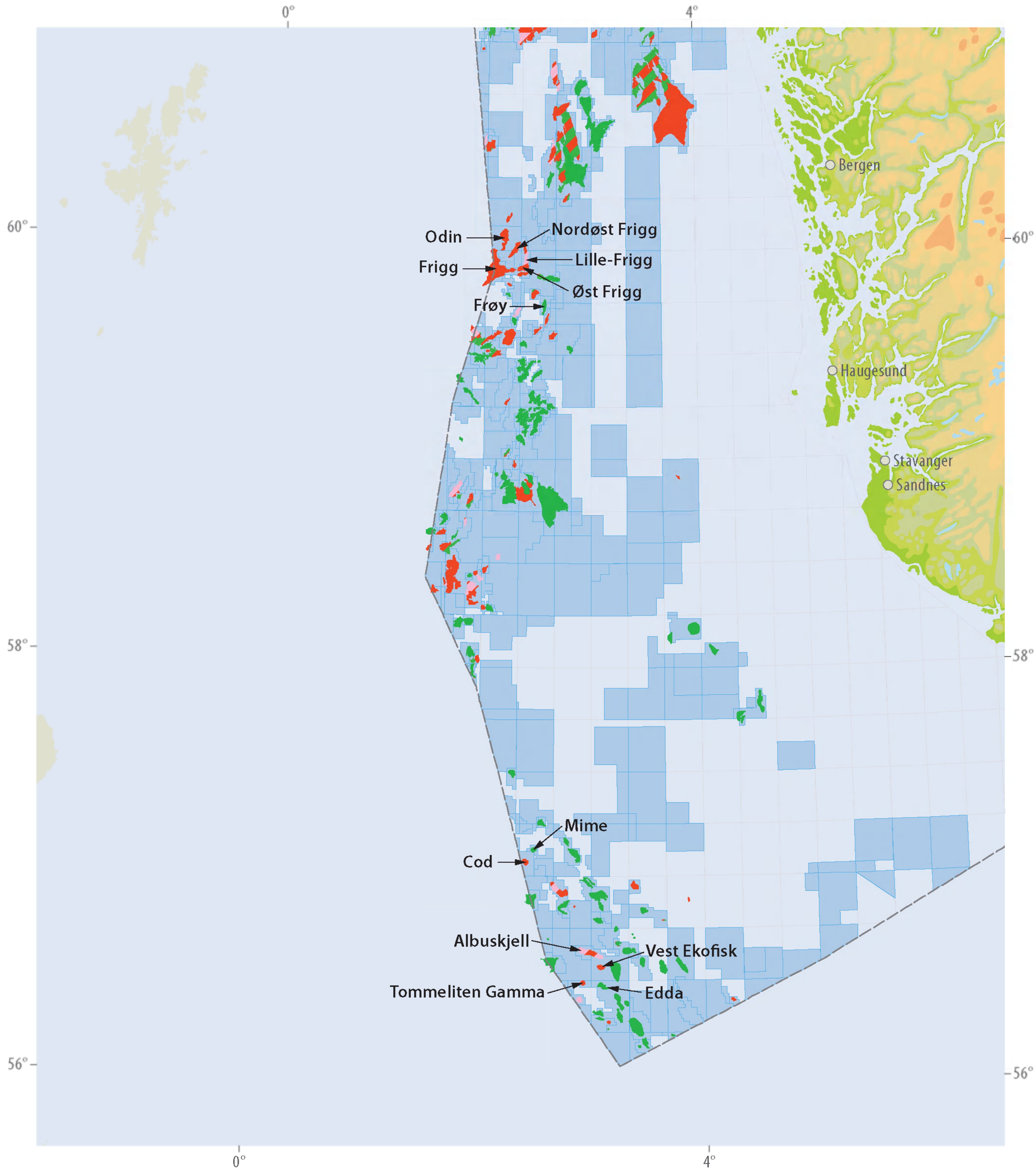


Figure 13.1 Fields where production has ceased *(Source: Norwegian Petroleum Directorate)*

The fields in this summary are not in production as of 31 December 2012.

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

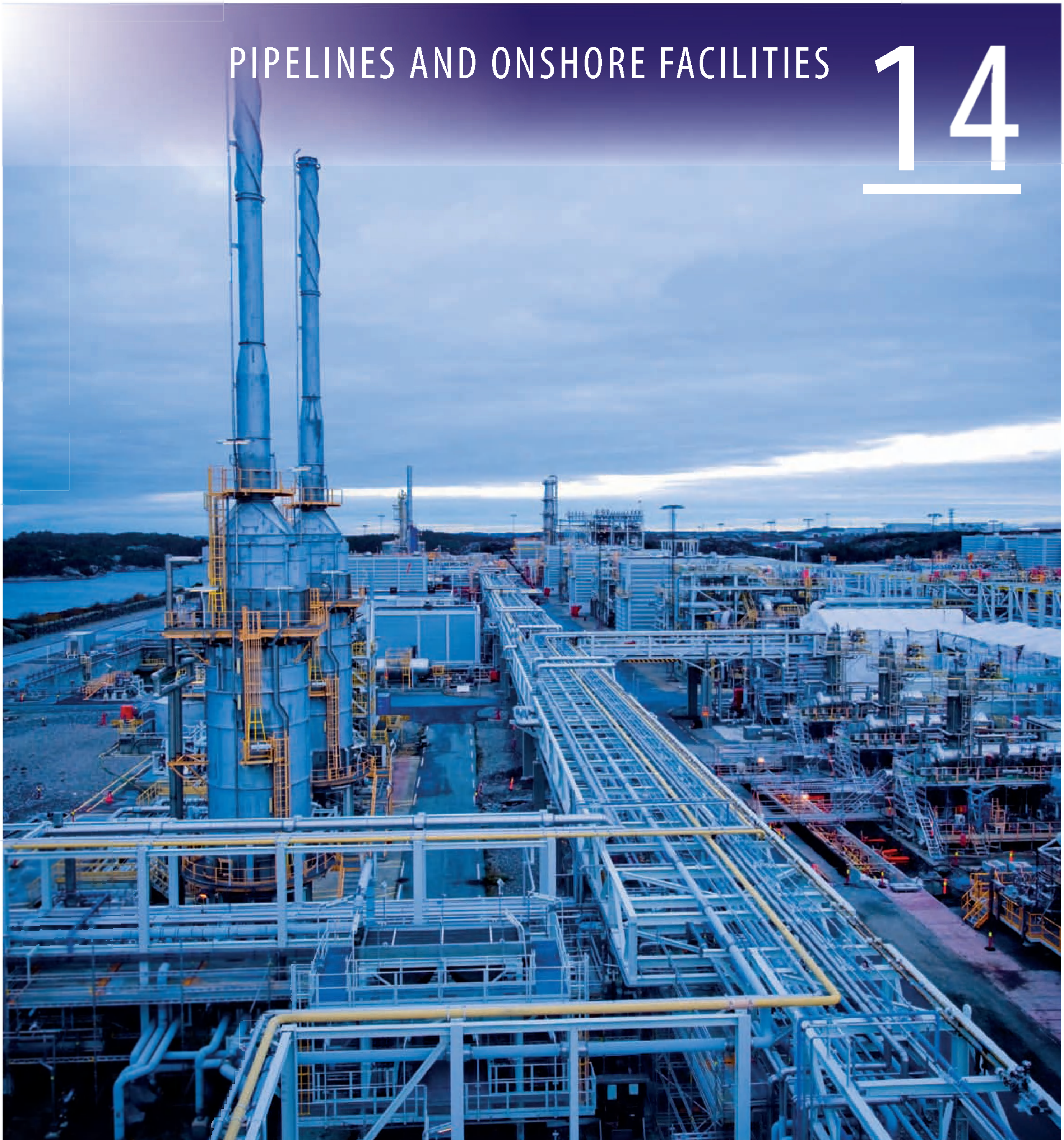
Odin

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



The facility at Kollsnes in Hordaland is part of the Troll development. From here, the gas is transported to the UK and the rest of Europe. (Photo: Gassco)

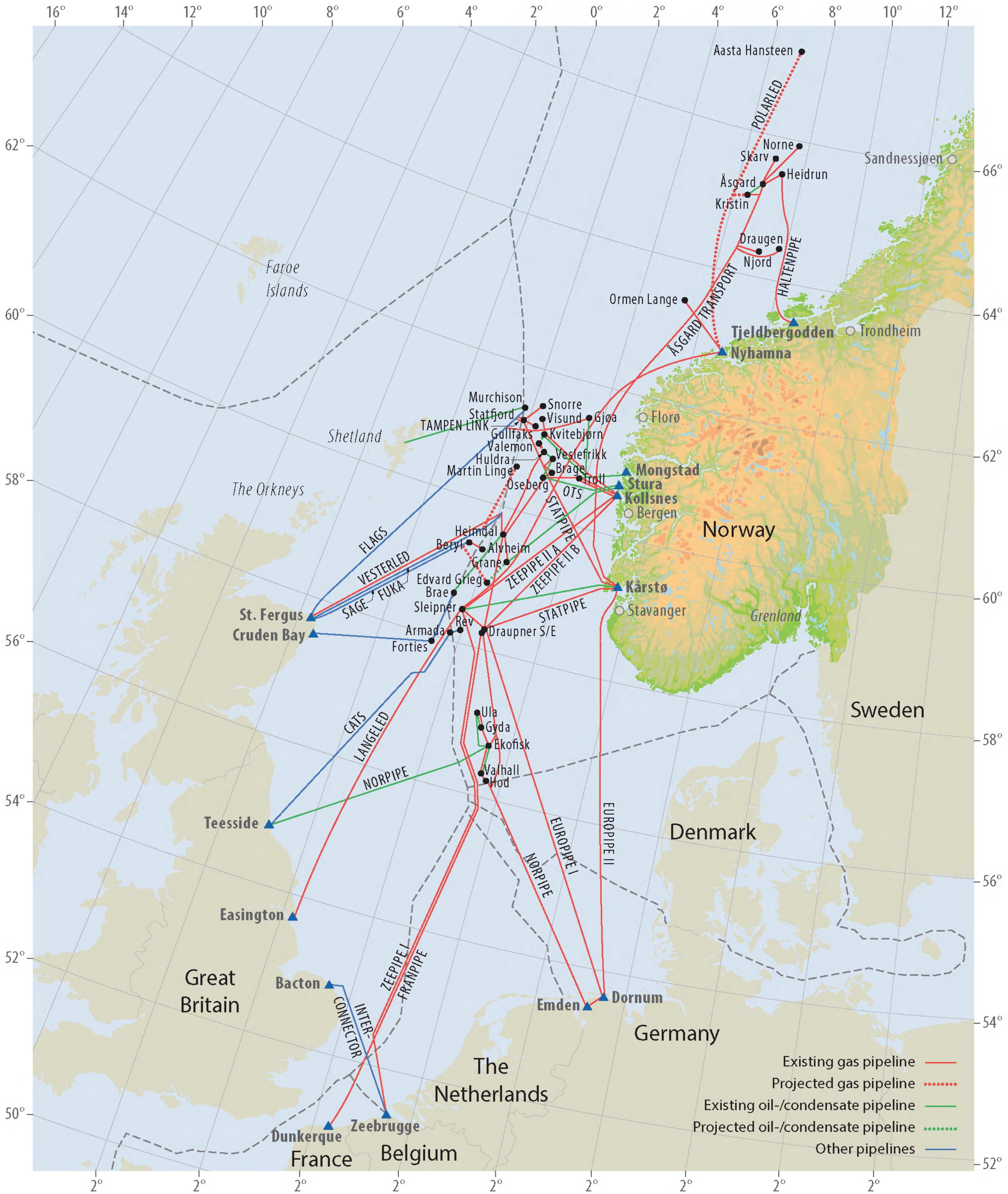


Figure 14.1 Existing and projected pipelines *(Source: The Norwegian Petroleum Directorate)*

Gassled

Gassled is a joint venture for the owners of the gas transport system on 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's activities are regulated by the Petroleum Regulations and tariffs for the individual services stipulated by the Ministry of Petroleum and Energy. At the end of 2012, the owners of Gassled were Petoro AS, Solveig Gas Norway AS, Njord Gas Infrastructure AS, Silex Gas Norway AS, Infragas Norge AS, Statoil Petroleum AS, Norsea Gas AS, ConocoPhillips Skandinavia AS, DONG E&P Norge AS, GDF SUEZ E&P Norge AS and RWE Dea Norge AS.

Gassco's role as neutral operator

Gassco's role as a neutral and independent operator of the gas transport system is important in order to ensure 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 postponing the need for new investments. Gassco has the operatorship and coordinates and manages the gas streams flowing 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 sellers and buyers. 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 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. As of September 2011, interruptible capacity was introduced, i.e. capacity that is not used by the shippers that have reserved capacity in the first hand market. 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. Gassco has established so-called technical service agreements with Statoil (for operation of pipelines and the Kårstø and Kollsnes facilities), ConocoPhillips for the Norpipe gas pipeline and TOTAL UK plc. for the Vesterled gas pipeline and receiving terminal in St. Fergus in Scotland.

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 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 administered by Gassled. The capacities provided in the below table are technical available capacity rounded off to the nearest whole number. The transport capacity can be influenced by pressure conditions, temperature, gas quality and other operational conditions.

Pipeline	From – to	Start-up (year)	Capacity (million Sm³/d)	Dimension (inches)	Length (km)	Investment Billion 2010-NOK
Europipe	Draupner E*–Emden in Germany	1995	46	40	620	23.3
Europipe II	Kårstø–Dornum in Germany	1999	71	42	658	10.5
Franpipe	Draupner E*–Dunkerque in France	1998	55	42	840	10.9
Norpipe	Ekofisk–Norsea Gas Terminal in Germany	1977	32	36	440	28.9
Oseberg Gas Transport (OGT)	Oseberg–Heimdal*	2000	35	36	109	2.2
Statpipe (rich gas)	Statfjord–Kårstø		25	30	308	
Statpipe (dry gas)	Kårstø–Draupner S*		21	28	228	
Statpipe (dry gas)	Heimdal*–Draupner S*		31	36	155	
Statpipe (dry gas)	Draupner S*–Ekofisk Y		30	36	203	
Statpipe (all pipelines)		1985				49.9
Tampen Link	Statfjord–FLAGS pipeline in the UK	2007	10–27	32	23	2.2
Vesterled	Heimdal*–St. Fergus in Scotland	1978	39	32	360	35.3
Zeepipe	Sleipner*–Draupner S*		55	30	30	
Zeepipe	Sleipner*–Zeebrugge in Belgium	1993	42	40	813	
Zeepipe IIA	Kollsnes–Sleipner*	1996	74	40	299	
Zeepipe IIB	Kollsnes–Draupner E*	1997	73	40	301	
Zeepipe (all pipelines)						26.3
Åsgard Transport	Åsgard–Kårstø	2000	70	42	707	11.5
Langeled (northern pipeline)	Nyhamna–Sleipner*	2007	75	42	627	
Langeled (southern pipeline)	Sleipner*–Easington in the UK	2006	72	44	543	
Langeled (both pipelines)						18,6
Norne Gas Transport system (NGTS)	Norne–Åsgard Transport	2001	7	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 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 dehydrated 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 onward 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 Sm3 of dry gas per day and 9780 Sm3 of condensate per day. A new export compressor came on line 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, isobutane and naphtha. These are separated and stored for ship transport. The dry gas, which mainly contains methane and ethane, is transported via 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, isobutane 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 Sm3of rich gas per day.

Onshore facilities	Location	Capacity for gas	Capacity for other products
Kollsnes gas treatment facility	Øygarden municipality in Hordaland	143 million Sm^3/d dry gas	1.3 million tonnes/year condensate
Kårstø gas processing and condensate facility	Tysvær municipality in Rogaland	79 million Sm^3/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 2010-NOK)
Draugen Gas Export	AS Norske Shell	Draugen–Åsgard Transport	2000	2 billion Sm^3/year	16	78	1.2
Grane Gas Pipeline	Statoil Petroleum AS	Heimdal–Grane	2003	3.6 billion Sm^3/year	18	50	0.3
Haltenpipe	Gassco AS	Heidrun–Tjeldbergodden	1996	2 billion Sm^3/year	16	250	3.2
Heidrun Gas Export	Statoil Petroleum AS	Heidrun–Åsgard Transport	2001	4 billion Sm^3/year	16	37	1.0

Oil and condensate pipelines

Pipeline	Operator	From – to	Start-up (year)	Capacity	Dimension (inches)	Length (km)	Investment cost (billion 2010-NOK)
Grane Oil Pipeline	Statoil Petroleum AS	Grane–Sture Terminal	2003	34 000 Sm^3/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 Sm^3/d oil	16	90	0.5
Norpipe Oil Pipeline	Norpipe Oil AS	Ekofisk–Teeside in the UK	1975	53 million Sm^3/year oil	34	354	17.8
Oseberg Transport System	Statoil Petroleum AS	Oseberg A–Sture Terminalen	1988	121 000 Sm^3/d oil	28	115	10.5
Sleipner Øst condensate pipeline	Statoil Petroleum AS	Sleipner A–Kårstø	1993	32 000 Sm^3/d oil	20	245	1.7
Troll Oil Pipeline I	Statoil Petroleum AS	Troll B–Mongstad	1995	42 500 Sm^3/d oil	16	86	1.3
Troll Oil Pipeline II	Statoil Petroleum AS	Troll C–Mongstad	1999	40 000 Sm^3/d oil	20	80	1.2
Huldra condensate	Statoil	Huldra–Veslefrikk	2001	7900 Sm^3/d	8	16	0.35
Gjøa Oil Export	GDF SUEZ E&P Norway AS	Gjøa – TOR (Troll Oil Pipeline) II (Mongstad)	2010	Approx.5.4 million Sm^3/year	16	55 km (to connection with TOR II)	

Other onshore facilities

Onshore facility	Location	Description and products
Mongstad Terminal	Lindås and Austrheim municipalities in Hordaland County	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 County	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	Hammerfest municipality 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 available technical capacity of 7.7 million Sm^3 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 Sm^3, an LPG cavern holding 60 000 Sm^3 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 Møre og Romsdal	Methanol plant. The gas deliveries through Haltenpipe amount to about 0.7 billion Sm^3 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 Sm^3 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

From the Sleipner facility.
(Photo: Morten Berentsen, Petroleum Safety Authority Norway)

APPENDIX 1
Historical statistics

Table 1.1 Sold and delivered volumes from fields in production and fields where production has ceased

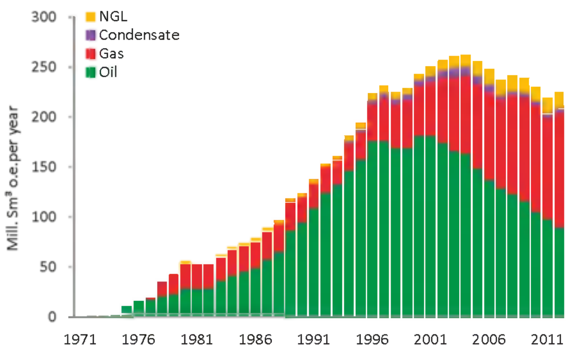
Year	Ordinary tax	Special tax	Production fee	Area fee	Environmental taxes	Net cash flow SDFI	Dividend StatoilHydro
1971			14				
1972			42				
1973			69				
1974			121				
1975			208				
1976	1 143	4	712	99			
1977	1694	725	646	57			
1978	1 828	727	1 213	51			
1979	3 399	1 492	1 608	53			
1980	9 912	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
2011	78 243	127 693		1 517	2 225	127 775	13 350

(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
2011	97,5	100,4	4,6	16,3	218.8
2012	89	112,8	4,5	17,5	223.8

(Source: Norwegian Petroleum Directorate)



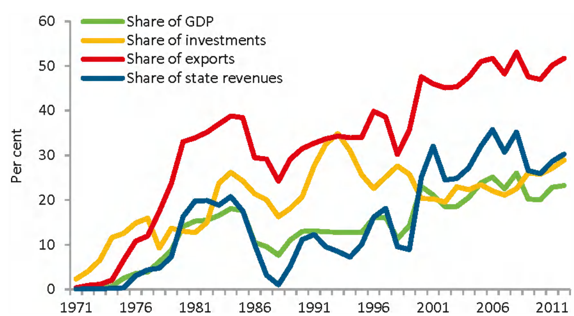
Total petroleum production
(Source: Norwegian Petroleum Directorate)

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	511 584	36 400	95 477	11 728
2007	519 174	491 194	38 900	108 252	17 929
2008	666 391	635 385	40 300	124 242	24 411
2009	481 380	453 674	42 300	135 825	27 889
2010	528 968	483 849	64 817 *	125 421	25 493
2011	643 096	572 269	69 306	146 290	27 399
2012	691 545	614 832	-	172 465	26 990

(Source: Statistics Norway)

* Employment figures from 2010 onwards are based on a new standard, and cannot be directly compared with numbers from previous years. The increased number of employees is due to the fact that Statistics Norway's definition of petroleum related sectors has been expanded.



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

APPENDIX 2
The petroleum resources
(per 31.12.2012)

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	0.0	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	1.1	3.0	0.5		5.1	1990
Alvheim	19.7	2.1			21.8	1998
Atla	0.0	0.0			0.1	2010
Balder	55.9	1.3			57.2	1967
Blane	0.6		0.0		0.6	1989
Brage	55.2	3.3	1.2		60.8	1980
Draugen	131.9	1.6	2.4		138.0	1984
Ekofisk	439.4	141.7	13.0		605.7	1969
Eldfisk	100.5	39.4	3.9		147.3	1970
Embla	10.3	3.8	0.4		15.0	1988
Enoch	0.3	0.0			0.3	1991
Fram	24.8	2.5	0.2		27.7	1992
Gaupe	0.1	0.2	0.0	0.0	0.3	1985
Gimle	2.6	0.4	0.1		3.2	2004
Gjøa	5.2	4.9	1.1	0.2	12.4	1989
Glitne	8.9				8.9	1995
Grane	88.5				88.5	1991
Gullfaks	353.9	23.1	2.8		382.3	1978
Gullfaks Sør	42.2	33.0	4.1		83.0	1978
Gungne		13.9	1.9	4.3	21.8	1982
Gyda	35.7	6.2	1.9		45.4	1980
Heidrun[4]	142.0	15.3	0.6		158.3	1985
Heimdal	6.5	45.2			51.8	1972
Hod	9.5	1.6	0.3		11.6	1974
Huldra	5.1	16.7	0.1		22.0	1982
Islay	0.0	0.0	0.0		0.0	2008
Jotun	22.7	0.9			23.6	1994
Kristin	16.9	19.0	4.0	2.1	45.6	1997
Kvitebjørn	17.5	39.3	3.4		63.2	1994
Marulk	0.0	0.5	0.0		0.7	1992
Mikkel	3.3	15.6	4.2	2.2	29.0	1987
Morvin	3.7				3.7	2001

Field	Oil mill. Sm³	Gas bill. Sm³	NGL mill. tonnes	Condensate mill. Sm³	Oil equiv.[1] mill Sm³ o.e.	Year of discovery[2]
Murchison	13.8	0.3	0.3	0.0	14.8	1975
Njord	25.5	7.8	1.8		36.7	1986
Norne	87.0	6.6	0.8		95.0	1992
Ormen Lange		98.7		7.7	106.3	1997
Oseberg	361.9	34.9	8.3		412.6	1979
Oseberg Sør	43.7	8.0			51.7	1984
Oseberg Øst	18.7	0.3			19.0	1981
Oselvar	0.2		0.0		0.2	1991
Rev	0.7	2.6	0.0		3.4	2001
Ringhorne Øst	9.1	0.2			9.3	2003
Sigyn		6.2	2.4	5.8	16.5	1982
Skirne	1.7	8.9			10.6	1990
Sleipner Vest		113.5	8.1	28.4	157.2	1974
Sleipner Øst		66.3	13.0	26.8	117.8	1981
Snorre	185.8	6.3	4.6		200.9	1979
Snøhvit		19.8	1.0	3.5	25.3	1984
Statfjord	566.1	66.0	16.9	0.5	664.8	1974
Statfjord Nord	36.5	2.3	0.8		40.3	1977
Statfjord Øst	36.1	3.9	1.3		42.5	1976
Sygna	9.9				9.9	1996
Tambar	8.9	2.0	0.2		11.3	1983
Tambar Øst	0.3	0.0	0.0		0.3	2007
Tor	23.9	10.8	1.2		37.0	1970
Tordis	55.3	4.2	1.6		62.5	1987
Troll[5]	227.8	447.9	6.4	4.3	692.1	1979
Trym	0.7	1.1			1.8	1990
Tune	3.4	18.5	0.1		22.2	1996
Tyrihans	15.9	0.7	0.2		17.0	1983
Ula	72.2	3.9	2.6		81.1	1976
Urd	5.0	0.1	0.0		5.2	2000
Vale	1.3	1.1			2.4	1991
Valhall	105.9	20.6	3.3		132.7	1975
Varg	15.1				15.1	1984
Vega	1.5	1.8	0.4	0.1	4.2	1981
Veslefrikk	52.3	2.3	1.3		57.0	1987
Vigdis	51.6	1.7	0.9		55.1	1981
Vilje	7.4	0.3			7.7	1986
Visund	22.4	7.0	0.5		30.2	2003
Visund Sør	0.0	0.0	0.0		0.1	1986
Volund	4.6	0.4			5.1	1994
Volve	7.6	0.7	0.1	0.1	8.7	1993
Yme	7.9				7.9	1987
Yttergryta	0.3	1.2	0.2		2.0	2007
Åsgard	81.8	123.7	22.5	17.1	265.4	1981
Producing fields	**3773.9**	**1537.1**	**147.1**	**103.2**	**5693.8**	
Total sold and delivered	**3812.2**	**1765.7**	**150.9**	**104.2**	**5968.8**	

[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] Heidrun also includes Tjeldbergodden
[5] 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 31.12.2012	Production licence/ unit area
Alve	9.7	1990	Statoil Petroleum AS	159 B
Alvheim	44.0	1998	Marathon Oil Norge AS	203
Atla	1.7	2010	Total E&P Norge AS	102 C
Balder	74.0	1967	ExxonMobil Exploration & Production Norway AS	001
Blane	0.9	1989	Talisman Energy Norge AS	Blane
Brage	66.7	1980	Statoil Petroleum AS	Brage
Brynhild[1)]	3.6	1992	Lundin Norway AS	148
Bøyla[1)]	3.7	2009	Marathon Oil Norge AS	340
Draugen	153.6	1984	A/S Norske Shell	093
Edvard Grieg[1)]	29.2	2007	Lundin Norway AS	338
Ekofisk	762.5	1969	ConocoPhillips Skandinavia AS	018
Eldfisk	190.4	1970	ConocoPhillips Skandinavia AS	018
Embla	20.7	1988	ConocoPhillips Skandinavia AS	018
Enoch	0.4	1991	Talisman North Sea Limited	Enoch
Fram	40.6	1992	Statoil Petroleum AS	090
Gaupe	0.7	1985	BG Norge AS	292
Gimle	5.0	2004	Statoil Petroleum AS	Gimle
Gjøa	60.7	1989	GDF SUEZ E&P Norge AS	153
Glitne	8.9	1995	Statoil Petroleum AS	048 B
Goliat[1)]	38.1	2000	Eni Norge AS	229
Grane	124.6	1991	Statoil Petroleum AS	Grane
Gudrun[1)]	20.6	1975	Statoil Petroleum AS	025
Gullfaks	394.0	1978	Statoil Petroleum AS	050
Gullfaks Sør	141.3	1978	Statoil Petroleum AS	050
Gungne	24.1	1982	Statoil Petroleum AS	046
Gyda	47.0	1980	Talisman Energy Norge AS	019 B
Heidrun	232.8	1985	Statoil Petroleum AS	Heidrun
Heimdal	55.1	1972	Statoil Petroleum AS	036 BS
Hod	13.0	1974	BP Norge AS	033
Huldra	22.8	1982	Statoil Petroleum AS	Huldra
Hyme[1)]	4.0	2009	Statoil Petroleum AS	348
Islay	0.1	2008	Total E&P UK PLC	043 CS, 043 DS
Jette[1)]	1.7	2009	Det norske oljeselskap ASA	Jette
Jotun	24.5	1994	ExxonMobil Exploration & Production Norway AS	Jotun
Knarr[1)]	13.6	2008	BG Norge AS	373 S
Kristin	65.7	1997	Statoil Petroleum AS	Haltenbanken Vest
Kvitebjørn	138.3	1994	Statoil Petroleum AS	193
Martin Linge[1)]	30.0	1978	TOTAL E & P Norge AS	Martin Linge
Marulk	10.8	1992	Eni Norge AS	122
Mikkel	56.5	1987	Statoil Petroleum AS	Mikkel
Morvin	16.0	2001	Statoil Petroleum AS	134 B
Murchison	14.2	1975	CNR International (UK) Limited	Murchison
Njord	53.1	1986	Statoil Petroleum AS	Njord
Norne	105.8	1992	Statoil Petroleum AS	Norne
Ormen Lange	323.1	1997	A/S Norske Shell	Ormen Lange
Oseberg	511.6	1979	Statoil Petroleum AS	Oseberg
Oseberg Sør	80.1	1984	Statoil Petroleum AS	Oseberg
Oseberg Øst	27.6	1981	Statoil Petroleum AS	Oseberg
Oselvar	8.6	1991	DONG E&P Norge AS	274
Rev	3.5	2001	Talisman Energy Norge AS	038 C
Ringhorne Øst	15.8	2003	ExxonMobil Exploration & Production Norway AS	Ringhorne Øst

Field	Original reserves mill. Sm^3 o.e.	Year of discovery[2)]	Operator per 31.12.2012	Production licence/ unit area
Sigyn	18.2	1982	ExxonMobil Exploration & Production Norway AS	072
Skarv[1)]	69.6	1998	BP Norge AS	Skarv
Skirne	12.4	1990	Total E&P Norge AS	102
Skuld[1)]	14.2	2008	Statoil Petroleum AS	128
Sleipner Vest	184.3	1974	Statoil Petroleum AS	Sleipner Vest
Sleipner Øst	120.4	1981	Statoil Petroleum AS	Sleipner Øst
Snorre	265.5	1979	Statoil Petroleum AS	Snorre
Snøhvit	211.5	1984	Statoil Petroleum AS	Snøhvit
Statfjord	692.7	1974	Statoil Petroleum AS	Statfjord
Statfjord Nord	43.6	1977	Statoil Petroleum AS	037
Statfjord Øst	44.9	1976	Statoil Petroleum AS	Statfjord Øst
Svalin[1)]	12.1	1992	Statoil Petroleum AS	169
Sygna	11.0	1996	Statoil Petroleum AS	Sygna
Tambar	12.4	1983	BP Norge AS	065
Tambar Øst	0.3	2007	BP Norge AS	Tambar Øst
Tor	37.5	1970	ConocoPhillips Skandinavia AS	Tor
Tordis	69.2	1987	Statoil Petroleum AS	089
Troll	1750.2	1983	Statoil Petroleum AS	Troll
Trym	5.8	1990	DONG E&P Norge AS	147
Tune	21.9	1996	Statoil Petroleum AS	190
Tyrihans	94.8	1983	Statoil Petroleum AS	Tyrihans
Ula	99.3	1976	BP Norge AS	019
Urd	7.2	2000	Statoil Petroleum AS	128
Vale	4.7	1991	Centrica Resources (Norge) AS	036
Valemon[1)]	33.5	1985	Statoil Petroleum AS	Valemon
Valhall	185.4	1975	BP Norge AS	Valhall
Varg	19.4	1984	Talisman Energy Norge AS	038
Vega	25.2	1981	Statoil Petroleum AS	Vega
Veslefrikk	63.5	1981	Statoil Petroleum AS	052
Vigdis	70.8	1986	Statoil Petroleum AS	089
Vilje	13.6	2003	Marathon Oil Norge AS	036 D
Visund	97.4	1986	Statoil Petroleum AS	Visund Inside
Visund Sør	11.8	2008	Statoil Petroleum AS	Visund Inside
Volund	9.5	1994	Marathon Petroleum Norge AS	150
Volve	9.9	1993	Statoil Petroleum AS	046 BS
Yme[1)]	22.0	1987	Talisman Energy Norge AS	316
Yttergryta	3.3	2007	Statoil Petroleum AS	062
Åsgard	400.1	1981	Statoil Petroleum AS	Åsgard

[1)] Fields with approved development plans where production had not started per 31.12.2012
[2)] The year the first discovery well was drilled

Table 2.3 Original and remaining reserves in fields

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.
Alve	1.9	5.7	1.1	0.0	9.7	0.8	2.7	0.6	0.0	4.6
Alvheim	37.2	6.8	0.0	0.0	44.0	17.5	4.7	0.0	0.0	22.2
Atla	0.3	1.4	0.0	0.0	1.7	0.3	1.3	0.0	0.0	1.6
Balder	72.1	2.0	0.0	0.0	74.0	16.2	0.6	0.0	0.0	16.8
Blane	0.8	0.0	0.0	0.0	0.9	0.3	0.0	0.0	0.0	0.3
Brage	59.3	4.5	1.5	0.0	66.7	4.0	1.2	0.3	0.0	5.9
Brynhild[3)]	3.6	0.0	0.0	0.0	3.6	3.6	0.0	0.0	0.0	3.6
Bøyla[3)]	3.4	0.3	0.0	0.0	3.7	3.4	0.3	0.0	0.0	3.7
Draugen	146.7	1.6	2.8	0.0	153.6	14.9	0.1	0.4	0.0	15.6
Edvard Grieg[3)]	26.2	1.8	0.6	0.0	29.2	26.2	1.8	0.6	0.0	29.2
Ekofisk	569.2	164.5	15.2	0.0	762.5	129.8	22.8	2.2	0.0	156.8
Eldfisk	137.9	44.8	4.1	0.0	190.4	37.3	5.4	0.2	0.0	43.1
Embla	11.9	7.5	0.7	0.0	20.7	1.5	3.6	0.3	0.0	5.7
Enoch	0.4	0.0	0.0	0.0	0.4	0.1	0.0	0.0	0.0	0.1
Fram	30.7	8.8	0.6	0.0	40.6	5.9	6.3	0.4	0.0	12.9
Gaupe	0.2	0.5	0.0	0.0	0.7	0.1	0.3	0.0	0.0	0.4
Gimle	3.0	1.4	0.3	0.0	5.0	0.4	1.0	0.2	0.0	1.8
Gjøa	11.6	32.7	8.7	0.0	60.7	6.4	27.8	7.6	0.0	48.6
Glitne	8.9	0.0	0.0	0.0	8.9	0.0	0.0	0.0	0.0	0.0
Goliat[3)]	30.2	7.3	0.3	0.0	38.1	30.2	7.3	0.3	0.0	38.1
Grane	124.6	0.0	0.0	0.0	124.6	36.1	0.0	0.0	0.0	36.1
Gudrun[3)]	11.7	6.4	1.3	0.0	20.6	11.7	6.4	1.3	0.0	20.6
Gullfaks	365.5	23.1	2.8	0.0	394.0	11.6	0.0	0.0	0.0	11.6
Gullfaks Sør	58.8	65.1	9.2	0.0	141.3	16.6	32.1	5.0	0.0	58.2
Gungne	0.0	15.2	2.2	4.7	24.1	0.0	1.3	0.3	0.4	2.3
Gyda	36.5	6.7	2.0	0.0	47.0	0.9	0.5	0.1	0.0	1.5
Heidrun	182.1	46.5	2.2	0.0	232.8	40.1	31.3	1.7	0.0	74.5
Heimdal	8.2	46.9	0.0	0.0	55.1	1.6	1.7	0.0	0.0	3.3
Hod	10.4	1.8	0.4	0.0	13.0	0.9	0.2	0.1	0.0	1.4
Huldra	5.1	17.5	0.1	0.0	22.8	0.0	0.7	0.0	0.0	0.8
Hyme[3)]	3.2	0.5	0.2	0.0	4.0	3.2	0.5	0.2	0.0	4.0
Islay	0.0	0.1	0.0	0.0	0.1	0.0	0.1	0.0	0.0	0.1
Jette[3)]	1.5	0.1	0.0	0.0	1.7	1.5	0.1	0.0	0.0	1.7
Jotun	23.4	1.1	0.0	0.0	24.5	0.7	0.2	0.0	0.0	0.9
Knarr[3)]	11.9	0.3	0.8	0.0	13.6	11.9	0.3	0.8	0.0	13.6
Kristin	22.9	28.7	6.3	2.1	65.7	6.0	9.7	2.3	0.0	20.1
Kvitebjørn	27.3	89.1	11.5	0.0	138.3	9.8	49.8	8.1	0.0	75.1
Martin Linge[3)]	6.0	19.7	0.7	3.0	30.0	6.0	19.7	0.7	3.0	30.0
Marulk	0.7	8.4	0.9	0.0	10.8	0.6	7.8	0.9	0.0	10.2
Mikkel	6.6	31.4	8.6	2.2	56.5	3.3	15.8	4.4	0.0	27.5
Morvin	9.3	4.5	1.1	0.0	16.0	5.6	4.5	1.1	0.0	12.3
Murchison	13.9	0.4	0.0	0.0	14.2	0.0	0.0	0.0	0.0	0.0
Njord	28.5	17.2	3.9	0.0	53.1	3.0	9.4	2.1	0.0	16.4
Norne	90.8	12.0	1.6	0.0	105.8	3.8	5.4	0.8	0.0	10.8
Ormen Lange	0.0	306.3	0.0	16.7	323.1	0.0	207.7	0.0	9.1	216.7
Oseberg	384.6	104.1	12.1	0.0	511.6	22.7	69.2	3.8	0.0	99.0
Oseberg Sør	61.0	16.0	1.6	0.0	80.1	17.2	8.0	1.6	0.0	28.4
Oseberg Øst	26.7	0.4	0.3	0.0	27.6	7.9	0.1	0.3	0.0	8.5

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.
Oselvar	4.6	3.9	0.0	0.0	8.6	4.5	3.9	0.0	0.0	8.4
Rev	0.7	2.7	0.1	0.0	3.5	0.0	0.0	0.0	0.0	0.1
Ringhorne Øst	15.5	0.4	0.0	0.0	15.8	6.3	0.1	0.0	0.0	6.5
Sigyn	0.0	6.9	2.6	6.4	18.2	0.0	0.7	0.2	0.6	1.7
Skarv[3]	15.5	43.4	5.6	0.0	69.6	15.5	43.4	5.6	0.0	69.6
Skirne	2.2	10.2	0.0	0.0	12.4	0.5	1.3	0.0	0.0	1.8
Skuld[3]	13.4	0.6	0.1	0.0	14.2	13.4	0.6	0.1	0.0	14.2
Sleipner Vest	0.0	133.3	9.5	32.9	184.3	0.0	19.8	1.5	4.5	27.1
Sleipner Øst	0.0	67.8	13.5	27.0	120.4	0.0	1.5	0.4	0.2	2.6
Snorre	249.9	6.6	4.7	0.0	265.5	64.1	0.3	0.1	0.0	64.6
Snøhvit	0.0	176.7	6.4	22.6	211.5	0.0	156.9	5.4	19.0	186.2
Statfjord	570.4	77.4	23.0	1.1	692.7	4.3	11.4	6.1	0.6	27.9
Statfjord Nord	39.5	2.1	1.1	0.0	43.6	3.0	0.0	0.3	0.0	3.6
Statfjord Øst	36.8	4.0	2.1	0.0	44.9	0.7	0.1	0.8	0.0	2.3
Svalin[3]	12.1	0.0	0.0	0.0	12.1	12.1	0.0	0.0	0.0	12.1
Sygna	11.0	0.0	0.0	0.0	11.0	1.1	0.0	0.0	0.0	1.1
Tambar	9.5	2.0	0.5	0.0	12.4	0.6	0.0	0.3	0.0	1.1
Tambar Øst	0.3	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.0
Tor	24.3	10.9	1.2	0.0	37.5	0.4	0.1	0.0	0.0	0.5
Tordis	61.2	4.6	1.8	0.0	69.2	6.0	0.4	0.2	0.0	6.8
Troll	263.8	1432.8	27.5	1.5	1750.2	36.0	984.9	21.1	-2.8	1058.2
Trym	1.5	4.3	0.0	0.0	5.8	0.8	3.2	0.0	0.0	4.0
Tune	3.3	18.3	0.2	0.0	21.9	0.0	0.0	0.0	0.0	0.1
Tyrihans	32.4	41.7	10.9	0.0	94.8	16.5	40.9	10.7	0.0	77.8
Ula	87.9	3.9	4.0	0.0	99.3	15.7	0.0	1.4	0.0	18.3
Urd	7.0	0.2	0.0	0.0	7.2	2.0	0.0	0.0	0.0	2.0
Vale	2.4	2.3	0.0	0.0	4.7	1.1	1.3	0.0	0.0	2.3
Valemon[3]	4.9	26.1	1.3	0.0	33.5	4.9	26.1	1.3	0.0	33.5
Valhall	147.4	27.5	5.5	0.0	185.4	41.5	6.9	2.2	0.0	52.7
Varg	16.4	1.1	1.0	0.0	19.4	1.4	1.1	1.0	0.0	4.4
Vega	6.6	14.0	2.4	0.0	25.2	5.1	12.2	2.0	0.0	21.1
Veslefrikk	54.1	5.7	2.0	0.0	63.5	1.8	3.3	0.7	0.0	6.5
Vigdis	66.6	1.9	1.2	0.0	70.8	15.0	0.2	0.3	0.0	15.7
Vilje	13.6	0.0	0.0	0.0	13.6	6.2	0.0	0.0	0.0	6.2
Visund	33.9	51.3	6.4	0.0	97.4	11.5	44.3	6.0	0.0	67.1
Visund Sør	2.7	7.3	0.9	0.0	11.8	2.7	7.3	0.9	0.0	11.7
Volund	8.6	0.9	0.0	0.0	9.5	4.0	0.5	0.0	0.0	4.5
Volve	8.7	0.8	0.2	0.1	9.9	1.0	0.1	0.0	0.0	1.1
Yme[3]	22.0	0.0	0.0	0.0	22.0	14.1	0.0	0.0	0.0	14.1
Yttergryta	0.3	2.2	0.4	0.0	3.3	0.0	1.0	0.2	0.0	1.3
Åsgard	100.4	207.7	39.4	17.1	400.1	18.6	84.1	16.8	0.0	134.7
Total	**4627.9**	**3564.1**	**281.3**	**137.4**	**8863.8**	**854.2**	**2027.8**	**134.5**	**34.6**	**3172.0**

[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 31.12.2012.
[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.

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]
15/5-1 Gina Krog[3]	15.4	12.5	3.3	1.6	35.8	2009
16/1-9 Ivar Aasen[4]	18.3	4.7	1.1	0.0	25.0	2008
33/9-6 Delta	0.1	0.0	0.0	0.0	0.1	1976
35/11-15 S	1.7	0.0	0.0	0.0	1.7	2007
6707/10-1 Aasta Hansteen[5]	0.0	45.4	0.0	0.9	46.3	2008
Total	**35.4**	**62.6**	**4.4**	**2.5**	**108.8**	

[1] The conversion factor for NGL tonnes to Sm^3 is 1.9.
[2] The year the first discovery well was drilled.
[3] 15/5-1 Gina Krog has also resources in RC 5A. The volume is included in RC 5 in contingent resources for discoveries.
[4] 16/1-9 Ivar Aasen includes 16/1-7 and 25/10-8 Hanz.
[5] 6707/10-1 Aasta Hansteen includes 6706/12-1 and 6707/10-2 S.

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
15/3-9	0.8	0.4	0.1	0.0	1.3	2010
15/5-2 Eirin	0.0	7.9	0.1	0.3	8.4	1978
16/2-6 Johan Sverdrup[4]	300.0	7.8	3.8	0.0	315.0	2010
17/12-1 Bream	6.8	0.0	0.0	0.0	6.8	1972
24/6-1 Peik	0.6	2.0	0.0	0.0	2.5	1985
25/2-10 S[5]	11.2	3.4	0.0	0.0	14.5	1986
30/11-7	0.6	4.1	0.0	0.0	4.7	2009
30/11-8 S[6]	6.6	3.3	0.2	0.0	10.4	2011
31/2-N-11 H	0.6	0.0	0.0	0.0	0.6	2005
34/8-13A[7]	2.6	1.1	0.1	0.0	4.0	2009
35/11-13	3.4	0.6	0.0	0.0	4.1	2005
35/2-1	0.0	19.5	0.0	0.0	19.5	2005
6406/2-7 Erlend	0.9	1.0	0.2	0.0	2.3	1999
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	22.6	0.0	0.5	23.2	2005
6407/6-6[8] 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
6507/7-14 S[9]	0.0	17.4	0.2	0.5	18.2	2010
6607/12-2 S	0.9	4.7	0.0	1.3	6.8	1997
6705/10-1	0.0	17.8	0.0	0.3	18.1	2009
7/8-3	3.8	0.0	0.0	0.0	3.8	1983
7122/6-1	0.0	3.7	0.0	0.2	3.9	1987
7220/8-1[10]	40.9	0.0	0.0	0.0	40.9	2011
Total	**411.1**	**132.6**	**5.8**	**3.1**	**557.9**	

[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 consider a re-development of the field. The volume is included in category 4A for fields.
[4] 16/2-6 JOHAN SVERDRUP includes 16/2-12 Geitungen.
[5] 25/2-10 S includes 25/2-17 discovery year 2009.
[6] 30/11-8 S includes 30/11-8 A - discovery year 2011. resources in RC 4F and RC 7F.
[7] 34/8-13 A includes 34/8-13 S - discovery year 2009.
[8] 6407/6-6 MIKKEL SØR includes 6407/6-7 S - discovery year 2009.
[9] 6507/7-14 S includes 6507/7-15 S - discovery year 2012.
[10] 7220/8-1 has gas resources in RC 7A .

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	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
16/1-12	5.1	0.5	0.2	0.0	5.9	2009
16/1-14	5.2	0.2	0.1	0.0	5.5	2010
2/12-1 Mjølner	3.0	0.8	0.1	0.0	4.0	1987
2/2-2	0.0	2.0	0.0	0.0	2.0	1982
2/4-17 Tjalve	0.5	0.7	0.1	0.0	1.4	1992
2/5-3 Sørøst Tor	3.1	0.9	0.0	0.0	3.9	1972
8/10-4 S	9.4	0.9	0.0	0.0	10.3	2011
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
30/5-3 S	0.5	4.5	0.0	0.0	5.0	2009
33/12-9 S	0.5	0.5	0.1	0.0	1.2	2012
34/10-53 A	0.1	0.4	0.1	0.0	0.6	2011
34/10-53 S	0.8	8.6	1.5	0.0	12.2	2011
34/11-2 S Nøkken	1.8	4.0	0.5	0.0	6.7	1996
34/4-11	15.8	1.8	0.5	0.0	18.5	2010
35/8-3	0.6	2.7	0.0	0.0	3.2	1988
35/9-6 S	5.4	4.0	0.0	2.5	12.0	2010
6406/2-1 Lavrans	2.2	8.3	0.7	0.0	11.8	1995
6407/7-8	0.5	2.0	0.3	0.0	3.0	2008
6407/9-9	0.0	1.6	0.0	0.1	1.7	1999
6506/11-2 Lange	0.5	0.2	0.1	0.0	0.9	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
7220/7-1[3]	45.4	0.0	0.0	0.0	45.4	2012
7225/3-1	0.0	41.6	0.7	1.5	44.4	2011
Total	**122.4**	**134.8**	**6.3**	**5.8**	**275.1**	

1) The conversion factor for NGL tonnes to Sm^3 is 1.9
2) The year the first discovery well was drilled
3) 7220/7-1 has gas resources in resource category 7A

Table 2.7 Resources in discoveries that have not been evaluated

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]
7/12-5	0.8	0.2	0.0	0.0	1.0	1981
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
2/4-21	0.0	14.1	0.0	6.4	20.6	2012
25/4-2	0.8	0.1	0.0	0.0	0.9	1973
30/6-28 S	1.8	0.0	0.3	0.0	2.4	2012
34/10-52 A	0.0	0.5	0.0	0.1	0.6	2011
34/10-52 B	0.2	0.4	0.0	0.0	0.6	2011
34/12-1	0.0	11.3	1.4	2.1	16.1	2008
34/4-10	4.8	0.7	0.0	0.0	5.5	2000
34/5-1 S	1.6	0.2	0.0	0.0	1.7	2010
34/6-2 S	6.8	0.6	0.0	0.0	7.4	1996
35/10-2	0.0	2.8	0.3	0.5	3.9	1996
35/12-2	4.8	0.7	0.0	0.0	5.5	2009
35/9-7	22.2	8.1	0.0	0.0	30.3	2012
6201/11-3	4.5	0.0	0.0	0.0	4.5	2012
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	2009
6507/3-7	0.0	0.8	0.0	0.0	0.8	2009
6507/3-9 S	0.2	2.1	0.3	0.0	2.7	2012
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
7220/10-1	0.0	5.8	0.0	0.3	6.0	2012
7222/11-1	0.0	6.0	0.0	0.0	6.0	2008
7226/2-1	0.0	0.2	0.0	0.0	0.2	2008
Total	**54.2**	**76.8**	**2.3**	**10.5**	**145.8**	

1) The conversion factor for NGL tonnes to Sm^3 is 1.9.
2) The year the first discovery well was drilled.

APPENDIX 3
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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