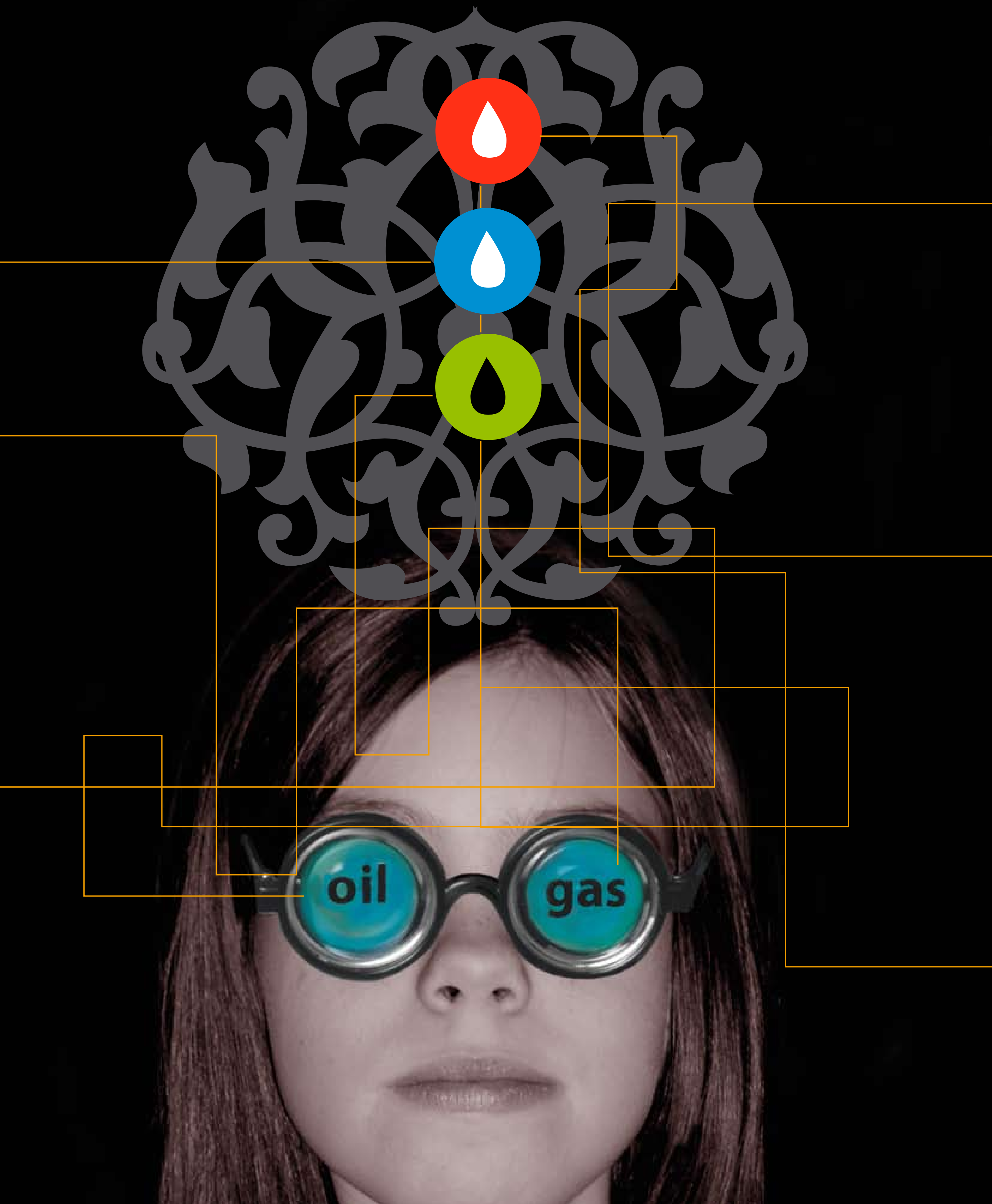
THE PETROLEUM RESOURCES ON THE NORWEGIAN CONTINENTAL SHELF 2007



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NORWEGIAN PETROLEUM
DIRECTORATE

Preface

The Norwegian Petroleum Directorate shall contribute to creating the greatest possible values for society from the oil and gas activities by means of prudent resource management based on safety, emergency preparedness and safeguarding of external environment.

It is therefore vital that the Directorate maintains an overview of and evaluates the petroleum activities and resources on the Norwegian continental shelf. This work forms an important basis for assessing the most efficient means of exploring for, developing and recovering the oil and gas resources.

The Norwegian Petroleum Directorate has unique access to facts on the petroleum activities. When this information is compiled in a coherent, lucid manner, it helps to ensure that decisions may be taken at the appropriate time and give the best possible result.

This report presents an updated survey of the petroleum resources on the Norwegian continental shelf.

Stavanger, August 2007

Bente Nyland

Bente Nyland
Director General

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1 The challenges on the continental shelf

The petroleum resources will not last for ever. It is therefore important for Norway to look ahead so as to be prepared for the changes that will come. In this report, the Norwegian Petroleum Directorate presents the current status of the petroleum resources on the Norwegian continental shelf. This is the basis on which the authorities can lay plans for the future.

Since no-one can predict the future with certainty, on this occasion the Directorate is presenting four alternative scenarios for the future of Norwegian petroleum activities if the basic scenario proves incorrect. This will enable us to prepare ourselves for changes that may come, and to view the consequences of the various choices we can make.

In this report, the Directorate also describes the various plays on the continental shelf, and explains the techniques used and the evaluations made when it estimates the undiscovered resources. This information is important for exploration work, particularly for new companies which need to get acquainted with the geology and the possibilities for finding oil and gas in Norway.

Significant volumes remain to be produced and found on the Norwegian continental shelf. Only a third of the total resources have so far been produced, and a quarter of them have still not been discovered. Oil and gas prices are high at the moment, giving the industry and society in general good incentives to produce at a maximum rate. Oil production reached its peak a couple of years ago, but gas production is still increasing. However, the industry is finding less than it produces, which places demands on both it and the authorities. The industry must actively explore the acreage it has been allocated. The Petroleum Directorate believes that substantial resources can still be discovered in areas where production licences have been awarded. At the same time, the industry must gain access to new areas for exploration. The authorities must find an appropriate balance between concern for the resources and concern for the environment and other social factors so that as much as possible of the Norwegian continental shelf (Figure 1.1) can be made available to the industry in a sound manner.

For several years, the Norwegian authorities have been seeking to make the continental shelf attractive to new companies which can bring know-how, capital and enthusiasm into Norwegian petroleum exploration. There are now obvious signs that this has led to great activity with regard to applications for awards and trading of shares in the licences. Both the industry and the authorities face a challenge to ensure that this also leads to the drilling of more exploration wells and more discoveries being made.

Large volumes of oil and gas also remain in fields that are in production. Based on current plans, the average recovery factor for oil is expected to be 46 per cent. Continuous research and development of technology are required to raise this further. The authorities expect the companies on the Norwegian continental shelf to make a determined effort to ensure the highest possible recovery. Two years ago, the Directorate set the aim of increasing the oil reserves by five billion barrels in ten years. This target is ambitious, but in view of the current trend and the plans made by the industry for recovery from the fields, it is within reach.

Great attention is centred on environmental issues, both nationally and internationally. The world is engaged on climate change and reducing the emissions of CO_2 and other greenhouse gases. Focus is also being placed on the reliability of energy supplies and developing alternative sources of fuel and electricity. This places great demands on Norway as a supplier of traditional energy in the form of oil and gas.

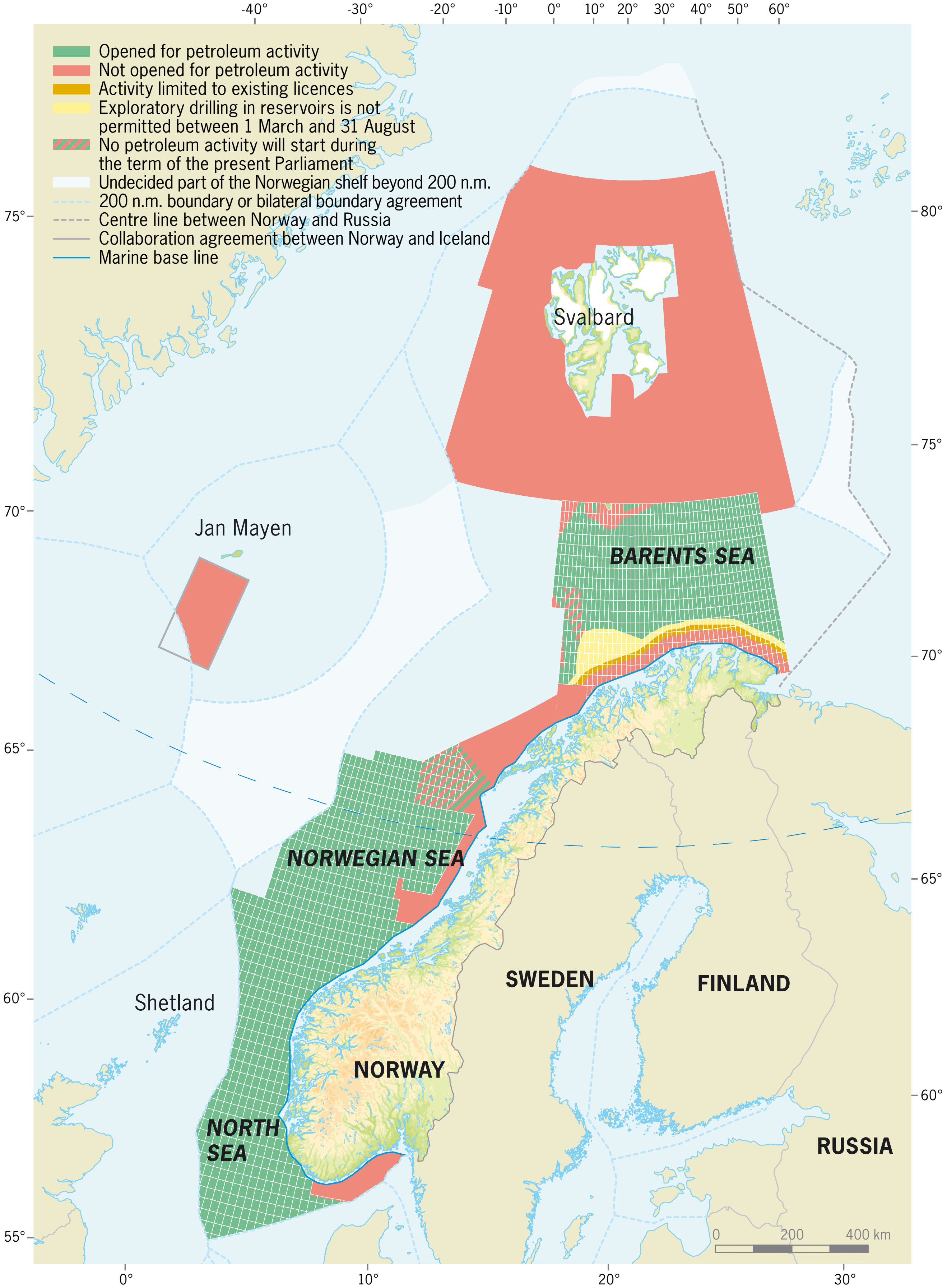


Figure 1.1 Status of petroleum activity areas on the Norwegian continental shelf

2 The resources

Each year, the Norwegian Petroleum Directorate draws up a survey of the petroleum resources on the Norwegian continental shelf, called a resource account. This shows the volumes produced, the remaining, proven, recoverable volumes and an estimate of the undiscovered petroleum resources. The figures in the resource account represent what will be produced under given preconditions.

The account covers all the resources on the Norwegian continental shelf, including those in areas that have still not been opened for petroleum activity. Area of overlapping claims with Russia in the Barents Sea and the continental shelf around Jan Mayen are not included. Since only about 50 per cent of the Norwegian continental shelf has been opened for exploration, large areas are still unexplored (Figure 2.1).

It is impossible to judge precisely how much oil and gas will be produced from the Norwegian continental shelf. The estimate is based on assumptions regarding profitability, geology, technical aspects in the reservoirs, costs and developments in technology and know-how.

The total recoverable resources are calculated to be between 10.6 and 16.9 billion standard cubic metre oil equivalents (Sm³ o.e.), with a mean value (base estimate) of 13.1 billion Sm³ o.e., 4.6 billion Sm³ o.e. of which have been produced (Figure 2.2). The resource account as of 31 December 2006 is shown in Table 2.1.

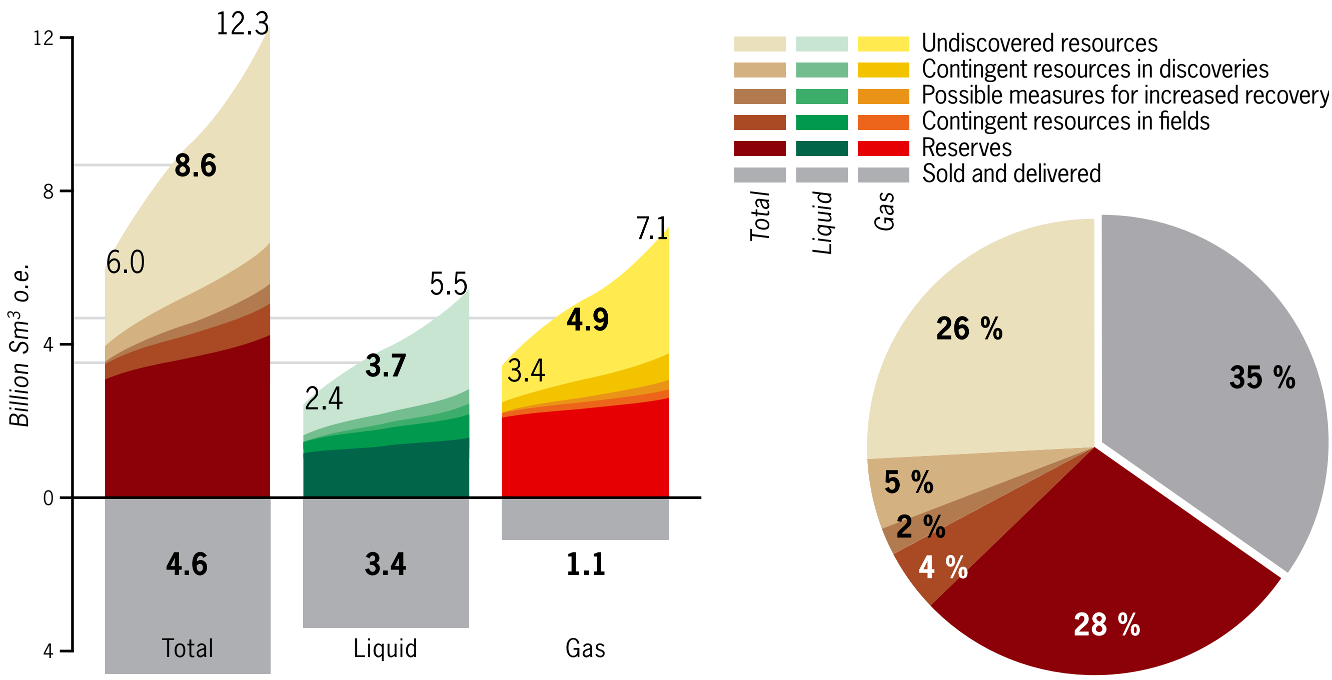
Resource classification

The resource account is based on the resource classification drawn up by the Petroleum Directorate. The classification covers the total, recoverable volumes of petroleum, both discovered and undiscovered. They are divided into categories according to maturity in relation to production (Figure 2.2).

Resources is a collective term for technically recoverable petroleum volumes. The resource classification divides them into the principal categories of reserves, contingent resources and undiscovered resources.

Reserves are remaining, recoverable petroleum resources in deposits which the licensees have decided to develop. They are divided into various categories according to the maturity of the projects: whether they are in production, being developed or the licensees have decided to develop them.

Contingent resources are discovered volumes of petroleum for which decisions to develop have still not been made. They are also divided into various categories according to the maturity of the projects.



Remaining resources with range of uncertainty

Total resources: 13.1 billion Sm³ o.e

Figure 2.2 Recoverable petroleum resources on the Norwegian continental shelf as of 31 December 2006

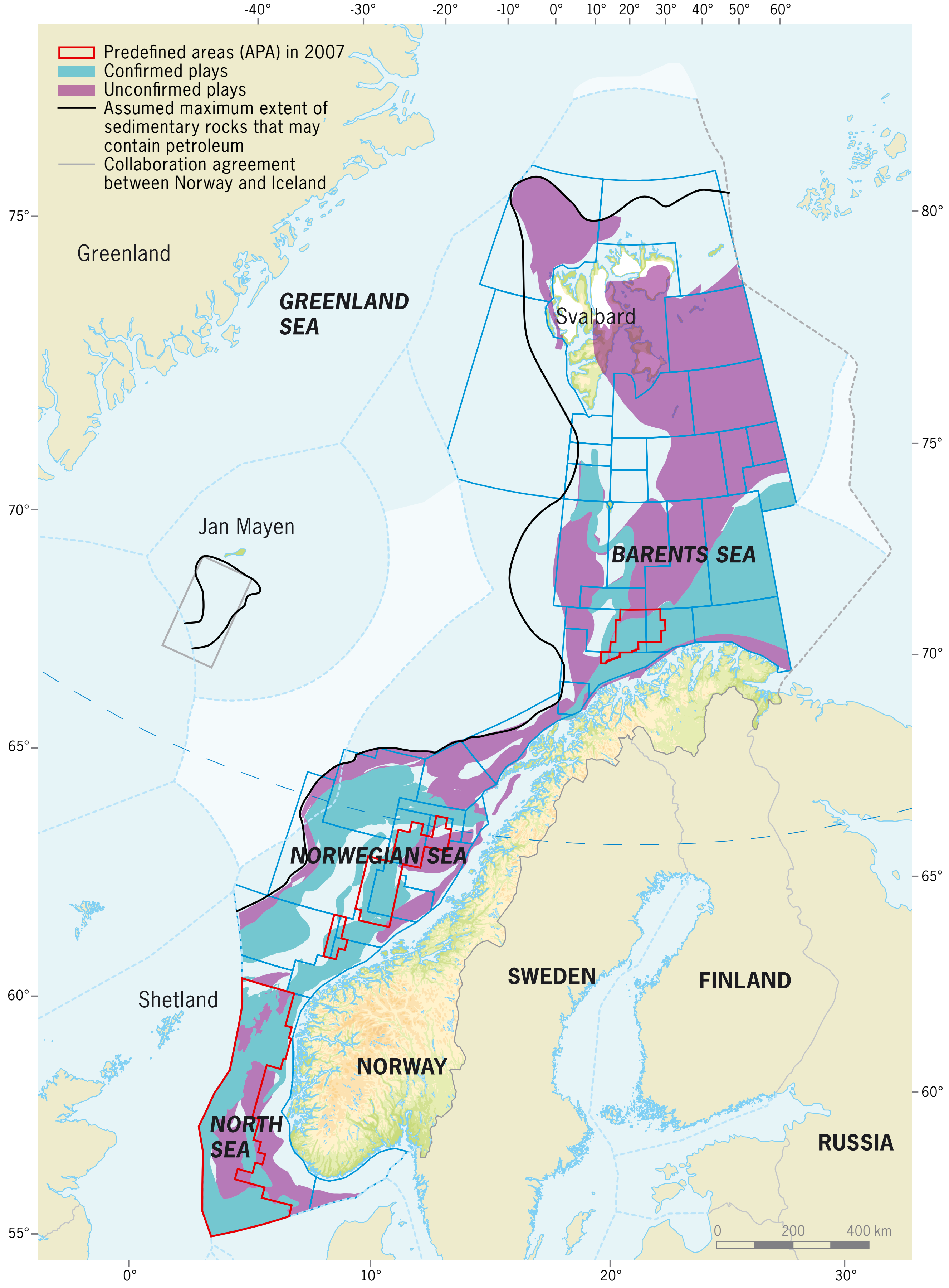


Figure 2.1 Areas where the Norwegian Petroleum Directorate has defined plays

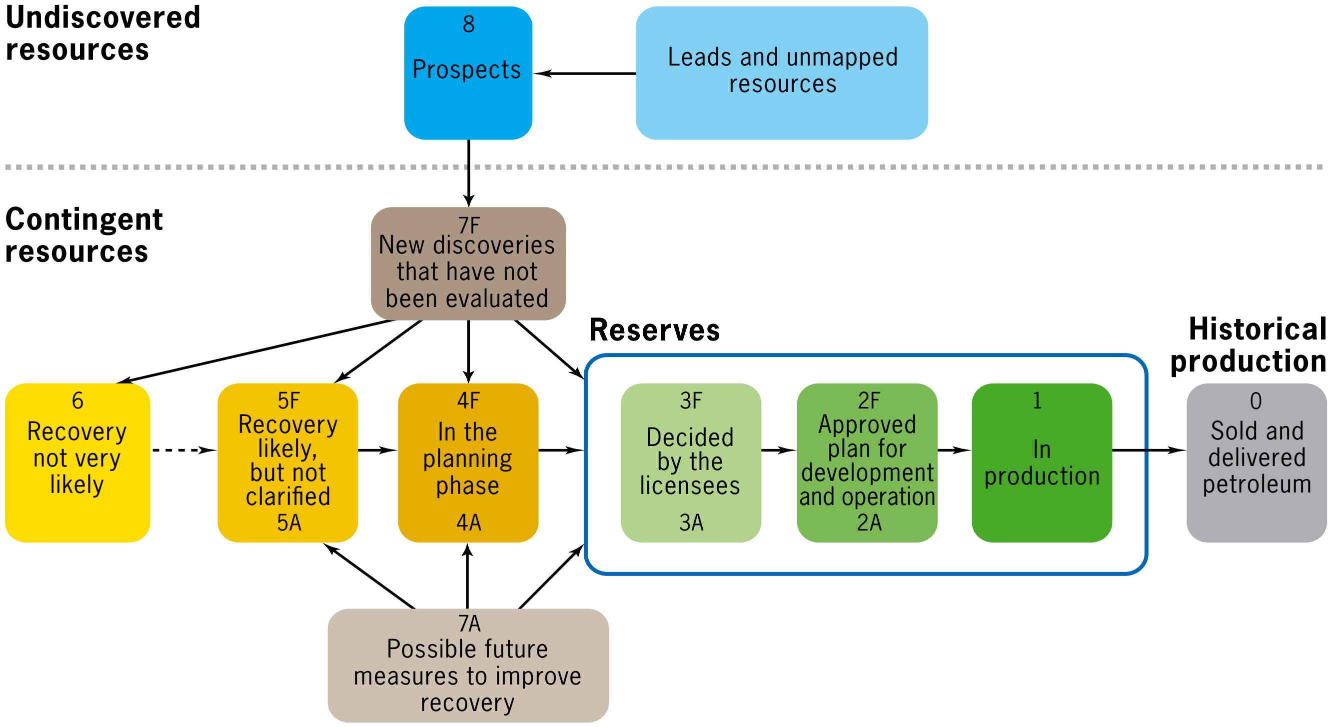


Figure 2.3 The Norwegian Petroleum Directorate's classification of the petroleum resources

Status		Resource class	Category	Project status	Oil mill. Sm³	Gas mrd. Sm³	NGL** mill. t.	Cond. mill. Sm³	Sum o.e. mill. Sm³
Discov-ered	**Field**	**Historic production**	0	Sold and delivered	3 155	1 142	99	89	4 573
		Reserves	1	In production	944	1 371	96	-0	2 497
			2	Approved plan	105	607	14	42	781
			3*	Decided by the licensees	26	324	13	7	381
			Sum reserves		*1 075*	*2 302*	*123*	*49*	*3 659*
		Contingent resources	4	In the planning phase	187	79	12	3	291
			5	Recovery likely, but not clarified	177	87	8	2	282
			7F	New discoveries tied to fields being evaluated	12	1	0	0	13
			7A	Possible future measures for increased recovery	140	130			270
			Sum contingent resources in fields		*515*	*296*	*20*	*5*	*855*
		Sum reserves and contingent resources in fields			*1 591*	*2 599*	*143*	*53*	*4 514*
	Dis-cov-ery	Contingent resources	4F	In the planning phase	102	104	14	12	243
			5F	Recovery likely, but not clarified	48	318	9	23	405
			7F	New discoveries being evaluated	2	2	0	0	5
		Sum contingent resources in fields			*152*	*424*	*22*	*35*	*654*
Undiscovered		**Undiscovered resources**	8 and 9	Prospects and unmapped resources	1 260	1 875		265	3 400
Total resources				*Sum total resources*	*6 158*	*6 040*	*263*	*442*	*13 141*
				Sum remaining resources	*3 003*	*4 897*	*165*	*354*	*8 568*

* Includes reserves from discoveries
** 1 tonne of NGL = 1,9 Sm³ o.e.

Table 2.1 Resource account as of 31 December 2006

Undiscovered resources are volumes of petroleum which are expected to be found in defined plays, confirmed or unconfirmed, but still not proven by drilling.

Produced volumes

About a third (4.6 billion Sm³ o.e.) of the expected, recoverable petroleum resources have already been produced. More than three-quarters of the total production since the start in 1971 have been oil, condensate or NGL (Natural Gas Liquids). The sale of gas, which began in 1977, is steadily increasing and in 2006 it accounted for 35 per cent of the total production.

3.2 million Sm³ of oil have been produced from 57 fields. Production from nine of these fields has now ceased. The four large fields, Statfjord, Ekofisk, Oseberg and

Gullfaks in the North Sea, account for half of the oil that is produced. Since 1994, these fields have stood for an increasingly smaller percentage of the total oil production (Figure 2.4).

Nine oil fields have begun production in the last five years. As of 31 December 2006, 48 fields were producing oil on the continental shelf. Eight of these produce more than 100 000 barrels per day and account for more than half of the oil production (Figure 2.5).

Since 1977, 51 fields have contributed to the delivery of more than 1.1 billion Sm^3 of gas. Four of these have now closed down. The Troll, Ekofisk, Sleipner Øst, Sleipner Vest and Frigg fields in the North Sea have provided more than half the gas supplies. Gas came from 38 fields in 2006, and Troll, Sleipner Øst and Sleipner Vest contributed more than half the volume.

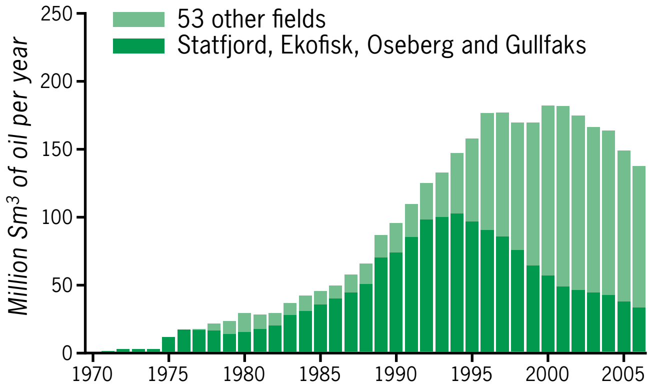
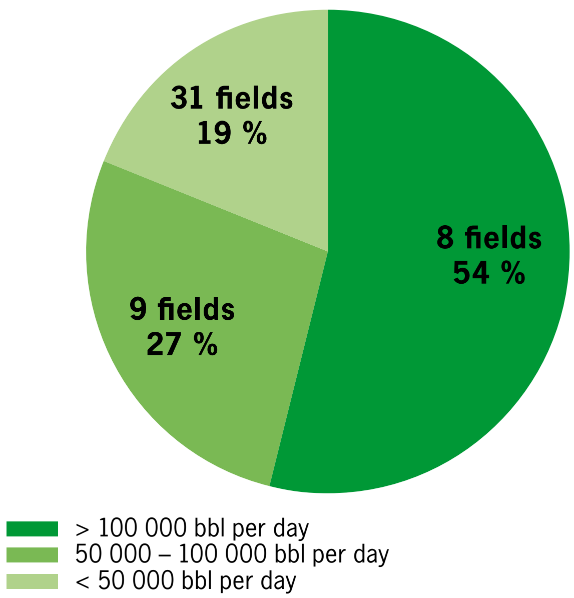


Figure 2.4 Oil production on various fields



8 fields: *Balder, Ekofisk, Grane, Gullfaks, Heidrun, Oseberg, Snorre and Troll*
9 fields: *Draugen, Eldfisk, Gullfaks Sør, Norne, Oseberg Sør, Statfjord, Valhall, Vigdis, and Åsgard*
31 fields: *Brage, Embla, Fram, Gimle, Glitne, Gyda, Heimdal, Hod, Huldra, Jotun, Kristin, Kvitebjørn, Mikkel, Murchison, Njord, Oseberg Øst, Ringhorne Øst, Skirne, Statfjord Nord, Statfjord Øst, Sygna, Tambar, Tor, Tordis, Tune, Vale, Ula, Urd, Varg, Veslefrikk and Visund*

Figure 2.5 Oil fields arranged according to the oil production rate in 2006

Remaining, proven resources

The total recoverable resources (including reserves) that have been proven and remain to be produced are estimated at 5.2 billion Sm^3 o.e. The liquid resources (oil, NGL and condensate) are estimated at 2.1 billion Sm^3 o.e. Oil alone accounts for 1.7 billion Sm^3. This estimate varies from year to year depending on how much is proven by exploration, how much is expected to be obtained from the existing fields and how much has been produced. The estimate has declined in the past ten years because the growth from exploration has been low and production high (Figure 2.6).

The largest remaining resources are in the North Sea (Figure 2.7), and it is here, too, that production has

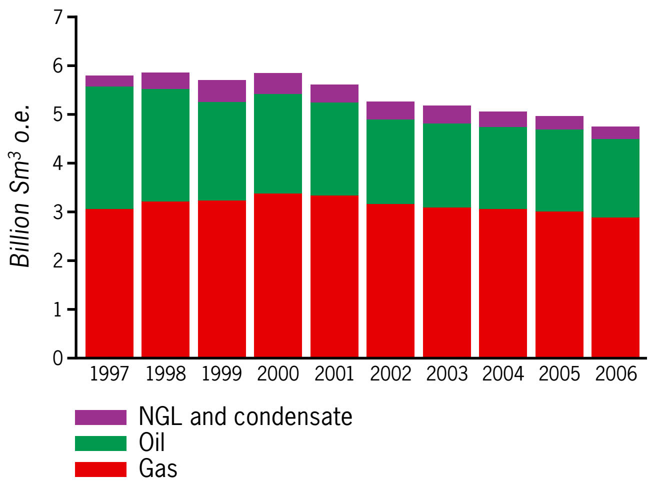


Figure 2.6 Annual estimates of the remaining, proven and recoverable resources in 1997-2006

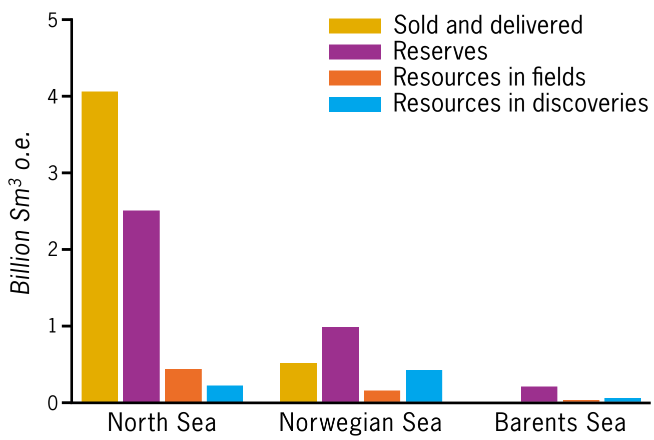


Figure 2.7 Remaining, proven and recoverable resources arranged geographically and compared with sold and delivered volumes

been highest. More than half of the proven resources here have already been produced. The North Sea also has some resources in fields that have still not been put into production. The reserves in the Norwegian Sea are less than half those in the North Sea, but it has fairly substantial resources in discoveries for which a decision on development has still not been made. The proven resources in the Barents Sea are less than in the other two areas, but there is a considerable potential for finding more (see Chapter 5). The sum of the remaining, proven resources breaks down as 3.1 billion Sm³ o.e. in the North Sea, 1.5 billion Sm³ o.e. in the Norwegian Sea and 0.2 billion Sm³ o.e. in the Barents Sea.

Reserves

Reserves are remaining, recoverable petroleum volumes in projects that have been approved for development or are already in production. As of 31 December 2006, 52 fields were in production on the Norwegian continental shelf, 44 in the North Sea and eight in the Norwegian Sea. Nine more fields were approved for development. Production had ceased on 13 fields. The Norwegian gas reserves are larger than the oil reserves (Figure 2.8). Nearly 70 per cent of the total reserves are in the North Sea, 25 per cent in the Norwegian Sea and five per cent in the Barents Sea.

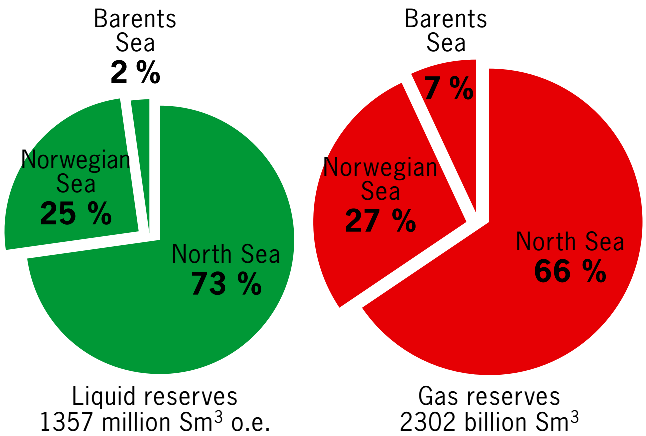


Figure 2.8 Liquid and gas reserves arranged geographically

Growth in reserves in oil fields

The reserves in a field increase when decisions on new projects for development or enhanced recovery are made. New studies of reservoirs on the field may also lead to increases or decreases in estimates of the reserves. A study of 36 oil-producing fields on the Norwegian continental shelf showed that only seven had a negative trend in their oil reserves compared with their original Plan for Development and Operation (PDO). Most of them had a significant growth in their reserves (Figure 2.9). The growth in the volume of oil relative to the original plans is 1.5 billion Sm³.

There has been a gross increase in the oil reserves (that is, the annual increase in the reserves before production is subtracted) on the Norwegian continental shelf every year except three (Figure 2.10). A major development of large and medium-sized fields took place in the 1980s. The estimates for the reserves in the same fields grew strongly in the 1990s, when new drilling technology, particularly for drilling horizontal and multi-branch wells, began to be used. The Directorate is keen to have flexibility on the installations to give sufficient capacity to implement various measures for enhanced recovery. The high price of oil in recent years has made it more profitable to implement such measures. Figure 2.10 shows a reduction or only a slight increase in the estimates in years when few fields were developed. Experience gained from

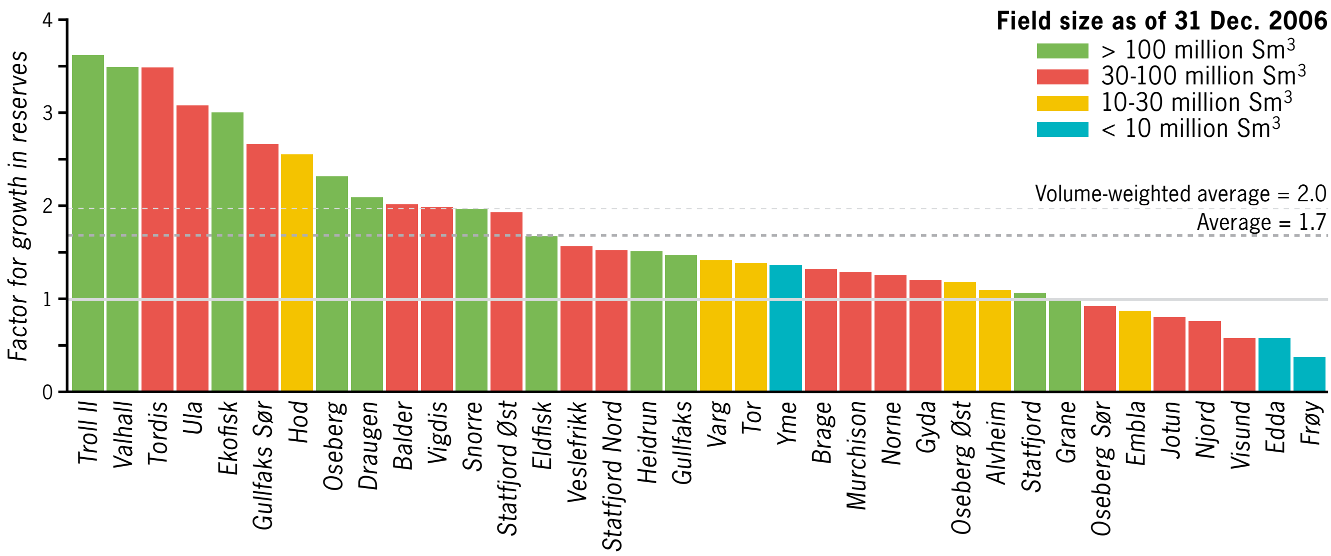


Figure 2.9 Factor for the growth in the oil reserves compared with the original Plan for Development and Operation (The reserves have declined in fields with a factor of less than 1)

Residual oil: As oil is produced from the reservoir, it is replaced by water. Usually only water flows when the oil content in the pores in the reservoir approaches 20 per cent. The oil that remains is called residual oil. Zones containing residual oil also occur where the oil originally present has leaked out and been displaced by water. In some fields, there are therefore large volumes of residual oil beneath the actual oil reservoir. All together, large volumes of oil remain in the ground in this manner. In some cases, injecting CO_2 into the oil reservoirs can enhance recovery, since CO_2 dissolves in the residual oil, causing it to increase in volume and become more fluid.

Fact Box 2.1

production, or new reservoir models, have led to the reserve estimates for some fields being reduced.

There are many ways of increasing recovery from the fields. Injection of water is a well-known example. Drilling of long, horizontal wells and multi-branch wells has also enabled a substantial increase in the reserves in many fields, as has injection of natural gas and the use of WAG (alternating water and gas injection). In the last few years, research has been carried out on methods of reducing the volume of residual oil in the fields. This is oil that cannot be obtained from the reservoirs using ordinary production methods, and can therefore not be produced (see Fact Box 2.1). Residual oil is a substantial potential resource on the Norwegian continental shelf.

The net change in the oil reserves (the annual change in the reserves after subtracting the production) is shown in Figure 2.11. The remaining reserves have been significantly reduced in recent years owing to high oil production, the smaller size of fields that have been developed and fewer major projects for improved recovery.

In the last ten years, the total gross increase in the oil reserves has been 1 079 million Sm^3, and in the same period 1 662 million Sm^3 of oil have been produced.

In 2005, the Petroleum Directorate set a target of achieving a gross growth of 800 million Sm^3 (five billion barrels) in the oil reserves by 2015. During the first two years, the reserves have increased by 135 million Sm^3. Figure 2.12 shows the actual growth in the reserves in the fields relative to the target. There was a small reduction in the reserves from 2005 to 2006 due to re-assessments of the reserves in some of the larger fields. The sum of the forecasts made by the operators nevertheless shows that the target is within reach.

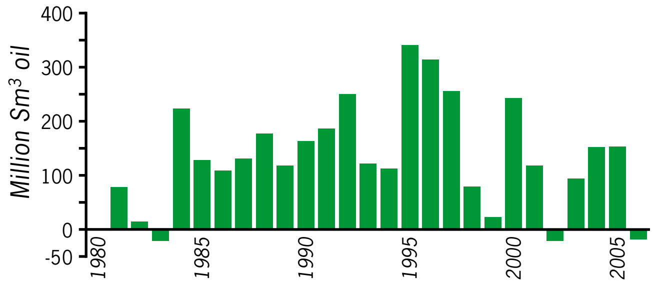


Figure 2.10 Annual gross increases in the oil reserves

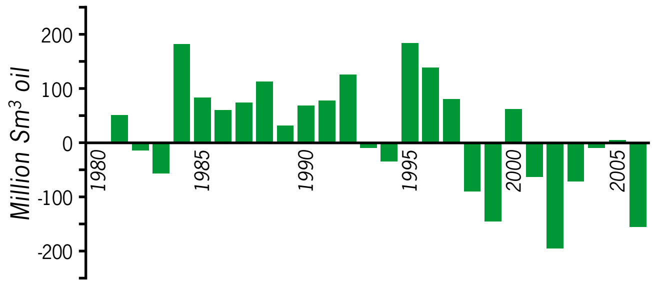


Figure 2.11 Annual net increases in the oil reserves

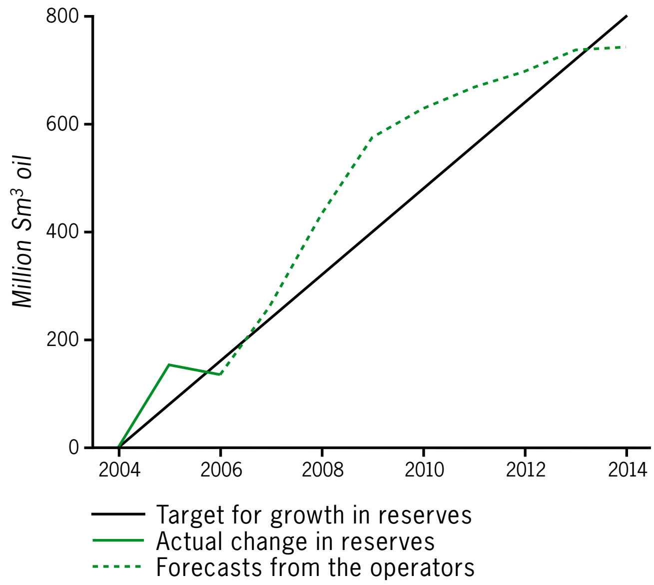


Figure 2.12 Trend in the growth of oil reserves

Contingent resources in fields

Contingent resources in fields are resources that can be converted into reserves if the licensees decide to do so. They include resources in the planning phase, resources that are likely to be recovered but are still not clarified, and resources from future measures for improved recovery (resource classes 4, 5 and 7A).

Contingent liquid resources in the resource account comprise 375 million Sm^3, half of which are in planned projects for increased recovery. The Directorate expects decisions to recover these resources in the next few years. An additional 140 million Sm^3 of liquid are defined as resources from possible measures for increased recovery.

Contingent gas resources in the fields comprise 166 billion Sm^3, nearly half of which is in fields that are in the planning phase. In addition, other possible measures for increased gas recovery will give 130 billion Sm^3.

Ten years ago, the contingent resources in fields comprised nearly 11 per cent of the recoverable resources. Today they amount to just over 4 per cent. The NPD estimates that most of what is now classified as contingent resources will be classified as reserves in the course of the next ten years.

Discoveries

There has been considerable maturation and development of discoveries in recent years. Ten years ago, the discovery portfolio consisted of approximately 95 discoveries which the NPD believed were possible to develop. These represented about 20 per cent of the remaining, proven resources on the continental shelf. 53 of these have now been developed. As of 31 December 2006, the portfolio held 50 discoveries, representing 654 million Sm^3 o.e. two-thirds of which are gas. This is only 13 per cent of the remaining, proven resources.

It is uncertain whether all these discoveries can be developed. Since many of the remaining discoveries are small, the availability of infrastructure is the most critical factor. This particularly applies to small gas discoveries which have to await vacant capacity in existing or planned pipelines. The complexity of reservoirs and the composition of oil and gas in the discovery may also mean that some discoveries are difficult to develop.

As of 31 December 2006, the Petroleum Directorate's resource class 4, that is, fields in the planning phase, holds 15 discoveries. If current plans are implemented, decisions to develop these will be made in the course of the next five years. Resource class 5, that is, discoveries where recovery is probable but not clarified, contains 32 discoveries. In addition, three discoveries have still not been evaluated.

Undiscovered resources

A substantial proportion of the petroleum resources on the continental shelf have still not been discovered. The Norwegian Petroleum Directorate estimates that about as much is left to be found in all the three areas, the North Sea, the Norwegian Sea and the Barents Sea. The gas volumes are highest in the Norwegian Sea, whereas the North Sea has most oil (Table 2.2).

Considerable uncertainty is attached to the calculations of the undiscovered petroleum resources. The estimates are based on a number of preconditions. In addition to the mean value (base estimate), low (P90) and high (P10) estimates are also stated (Chapter 5) to indicate the uncertainty in the estimates. The Directorate estimates that the undiscovered resources on the continental shelf amount to between 1.6 and 5.8 billion Sm^3 o.e., with a mean value of 3.4 billion Sm^3 o.e.

Area	Liquid			Gas			Total		
	P90	Mean	P10	P90	Mean	P10	P90	Mean	P10
North Sea	380	675	1000	300	500	730	750	1175	1650
Norwegian Sea	120	370	740	230	825	1620	370	1195	2340
Barents Sea	40	480	1270	80	550	1430	160	1030	2620
Total	***640***	***1525***	***2640***	***750***	***1875***	***3330***	***1550***	***3400***	***5800***

Table 2.2 Undiscovered petroleum resources (million Sm^3 o.e.)

3 Exploration

Introduction

Large parts of the Norwegian continental shelf are well explored, and mostly small discoveries are now made in those areas. However, since the infrastructure is well developed there, even these may be profitable to develop. Challenges relating to technology and costs influence profitability most in the less well-known areas.

More knowledge and continual improvements in technology, such as that used to gather, process and interpret geophysical data, are essential to achieve profitable exploration in both mature and immature areas. Here, new companies can contribute new ideas, and have the ability and willingness to make an effort. They may therefore make an important contribution to further profitable exploration and recovery.

In 1999, the authorities introduced a new scheme for allocating production licences in mature areas in the North Sea (the North Sea Awards - NSA). One reason for this was to stimulate more efficient exploration and utilisation of additional resources in areas close to existing fields. These allocations were made annually until 2002. This scheme was followed up by annual Awards in Predefined Areas (APA), which also included parts of the Norwegian Sea and the Barents Sea. The first awards under this scheme were made in 2003.

A number of changes in the taxation system were introduced in 2006 to make it easier for new companies to participate in the activity on the Norwegian continental shelf. The Government, for instance, pays the tax value of losses from the exploration activity. From 2007, changes have also been introduced in the provisions regarding the area fee. The intention with this change is that the fee will prove a better incentive to ensure activity in the licences, and result in acreage where no activity is taking place being relinquished so that it can be allocated to companies wishing to explore in these areas.

The introduction of these new schemes has helped to increase the number of new companies operating on the Norwegian continental shelf. More licences have been awarded to new companies, which now have a greater share of the exploration activity. It is too early to say whether this will lead to better profitability in exploration and production, but this report nevertheless presents some trends that show possible links between the activity of the new companies and changes in the framework conditions.

In addition to the annual awards in predefined areas, ordinary licensing rounds have been announced about every other year in recent years. On these occasions, blocks are announced in immature areas where little or no exploration has taken place. The strategy for announcing and allocating acreage in immature parts has largely followed the principle of sequential exploration. This entails that results from wells in an area should be available, and time should be given to evaluate the results, before new blocks in the same area are announced. This means that available information will be used when further exploration takes place, and the drilling of unnecessary and dry wells can be avoided.

Access to exploration acreage

The companies mainly gain access to acreage through allocations in the licensing rounds and the annual awards in predefined areas, but they can also acquire acreage by purchasing or exchanging shares in production licences.

Access to announced acreage has increased following the introduction of annual awards. The acreage made available in the 2006 APA was almost six times larger than that announced in the first NSA in 1999 (Figure 3.1). The number of allocations in 2007 (the 2006 APA) is the highest since the first licensing round in 1965 (Figure 3.2).

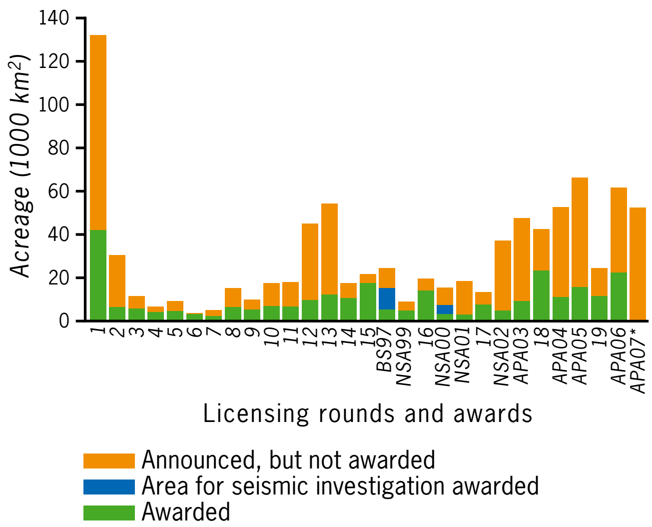


Figure 3.1 Announced and awarded acreage on the Norwegian continental shelf (The predefined areas (APA) for 2007 had not been awarded when this report went into print)

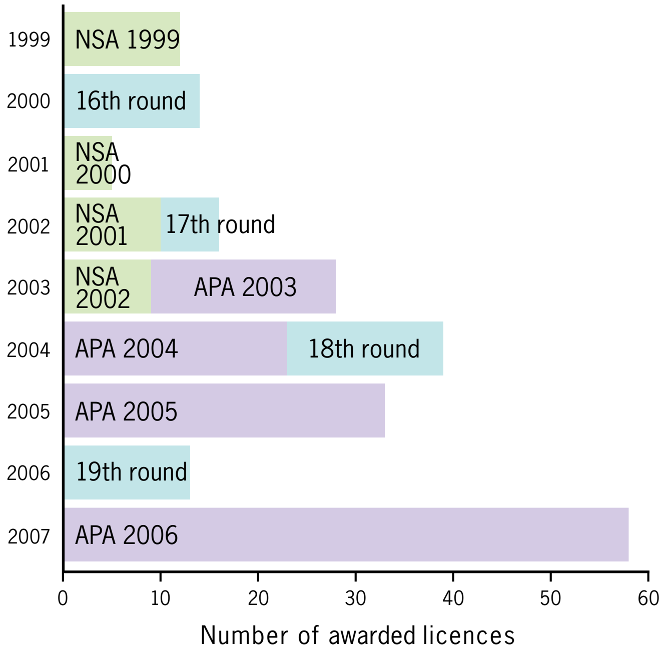


Figure 3.2 Annual awards since 1999

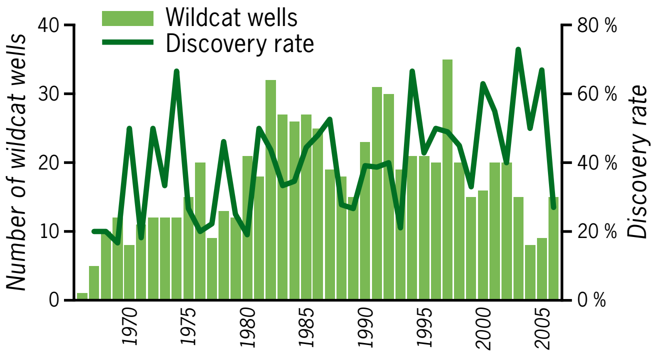


Figure 3.3 Number of wildcat wells and the discovery rate per year

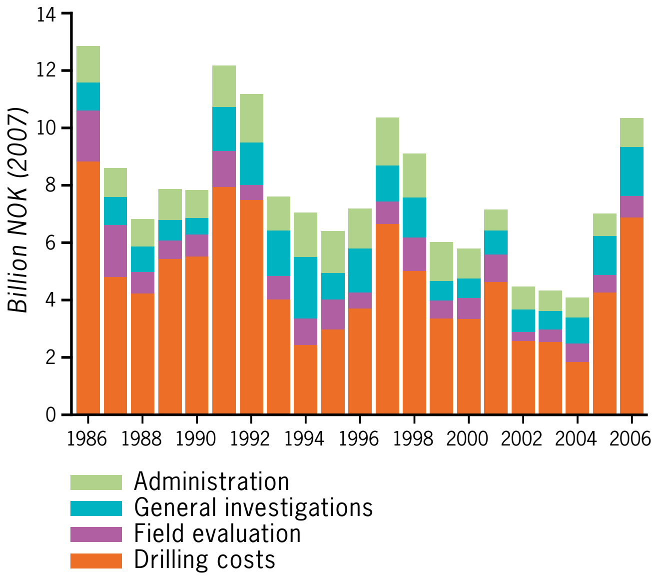


Figure 3.4 Total exploration costs per year

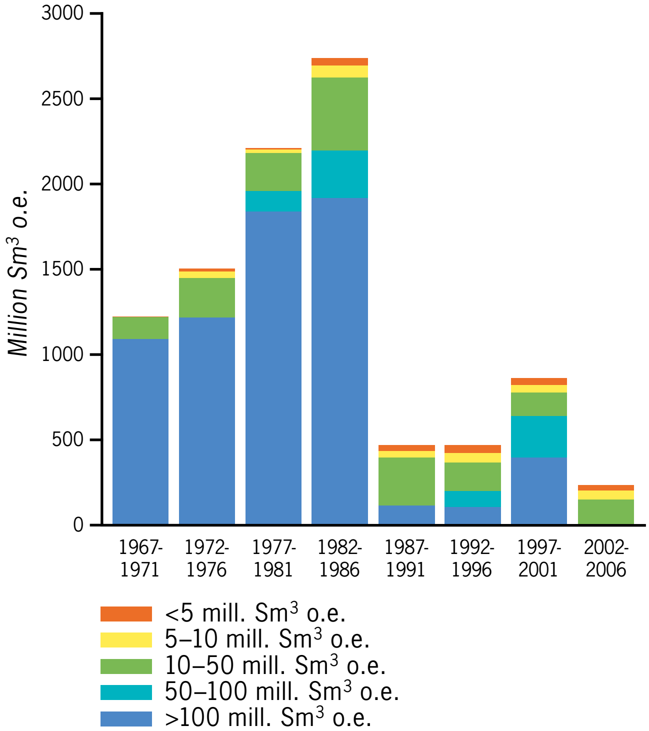


Figure 3.5 Resources in discoveries made in five-year periods arranged according to the size of the discovery

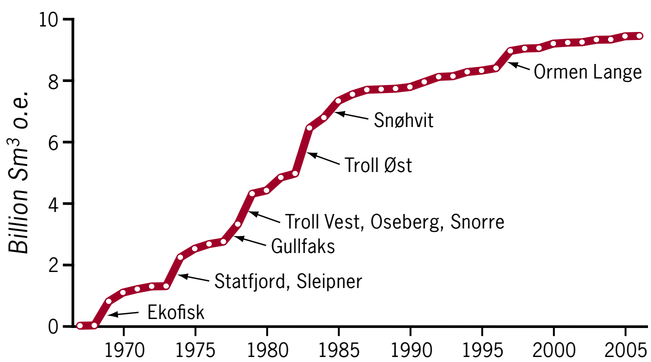


Figure 3.6 Total growth in resources (Later changes in the resource estimates for the individual discoveries are backdated to the year they were discovered. Resource categories 6 and 7A are not included.)

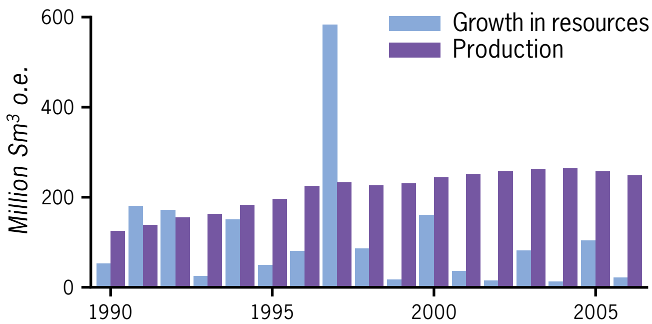


Figure 3.7 Production and annual growth in resources

Results and trends in the exploration activity

The number of wildcat wells that are drilled is a good measure of the exploration activity. The level of exploration activity has been low in the last three or four years, but the number of exploration wells has risen in the last two years (Figure 3.3). Fifteen wildcat wells were completed in 2006 against nine in 2005. The exploration costs have also risen in the past two years, and in 2006 they reached their highest figure since 1992. The drilling costs account for the largest part of the exploration costs (Figure 3.4). Drilling 15 wildcat wells in 2006 cost just as much as 35 in 1997.

The discovery rate has been high in the last ten years (Figure 3.3), but the discoveries have mostly been small (Figure 3.5). Consequently, the growth in resources has been low in the last 20 years (Figure 3.6). The largest discovery (about 400 million Sm^3 o.e.) made in this period was Ormen Lange in the Norwegian Sea in 1997, but the growth in resources from 1997 to 2006 does not equal the production in the same period (Figure 3.7).

The effect of new schemes in mature areas

It is still important to prove resources in mature areas. The authorities therefore want to make it more attractive for new companies to operate on the Norwegian continental shelf. The annual North Sea Awards from 1999 to 2002 and the annual Awards in Predefined Areas since 2003 (inclusive) were introduced to further this aim, as were the recently introduced changes in the taxation system and the area fee. The full effect of these schemes cannot yet be seen, but some possible links may nevertheless be mentioned.

The number of allocations to new companies has risen considerably, from one in the NSA in 1999 to 99 in the APA in 2006 (Figure 3.8). This shows that the authorities have been successful in attracting new companies to the Norwegian continental shelf. Table 3.1 shows which companies are classified as new in this context.

Licences awarded in recent years account for a large proportion of the mandatory drill or relinquish the licence arrangement (also called "drill or drop obligation") as distinct from firm obligations to drill one or more wells. Approximately two-thirds (120) of the licences from 1999 to 2006 have an obligation to drill or return the licence (Figure 3.9). So far, such decisions have been made in half of the licences, and in about half of these it has been decided to return all the allocated acreage. The scheme thus helps to ensure a more rapid circulation of acreage.

The proportion of the exploration costs for which the new companies are responsible has increased (Figure 3.10). In the past three years, such companies have stood for more than 30 per cent of the exploration costs in the North Sea. However, it is too early to say whether

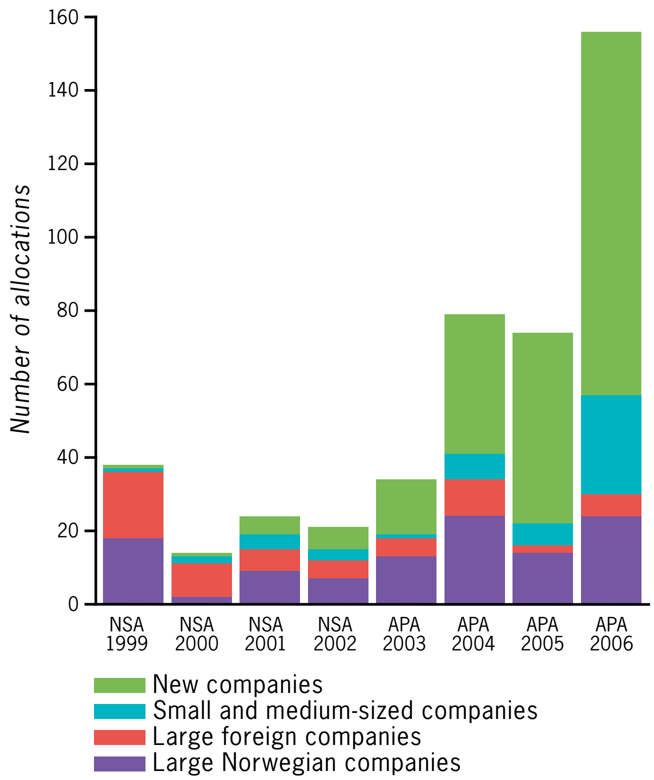


Figure 3.8 Number of allocations in mature areas apportioned according to the various types of companies

New companies	Aker Exploration, Altinex, BG Norge, Bridge Energy, Centrica, DONG, E.ON Ruhrgas, Edison, Endeavour, Ener, Fareo Petroleum, Gaz de France, Genesis, Kerr-McGee, Lundin, Marathon, Maersk, Nexen, Noble, Noreco, PA Resources, Pertra, Premier, Revus, Rocksource, Serica Energy, Talisman, Wintershall
Small and medium-sized companies	AEDC, Amerada Hess, DNO, Idemitsu, OMV Norge, Pelican, Petro-Canada, RWE Dea, Svenska Petroleum Exploration, Ugland Construction Company
Large, foreign companies	BP, Eni, ExxonMobil, ChevronTexaco, ConocoPhillips, Shell, Total
Large, Norwegian companies	Petoro, Statoil, Hydro

Table 3.1. Companies which have been awarded production licences since 1999 (Those which were active in Norway before 1999 are grouped according to size. Companies which were awarded their first production licence after 1999 are called "new companies". The table is up-to-date as of April 2007.)

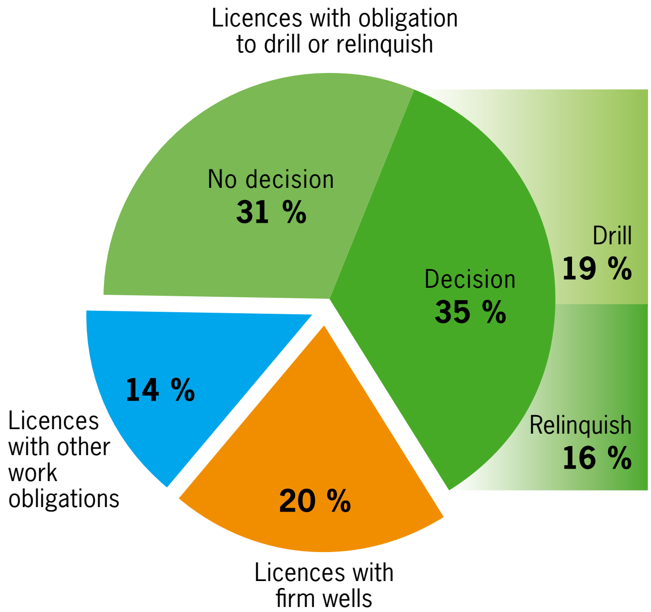


Figure 3.9 Types of work obligations in production licences allocated from 1999 to 2006 (Licences allocated in the predefined areas (APA) in 2006 are not included)

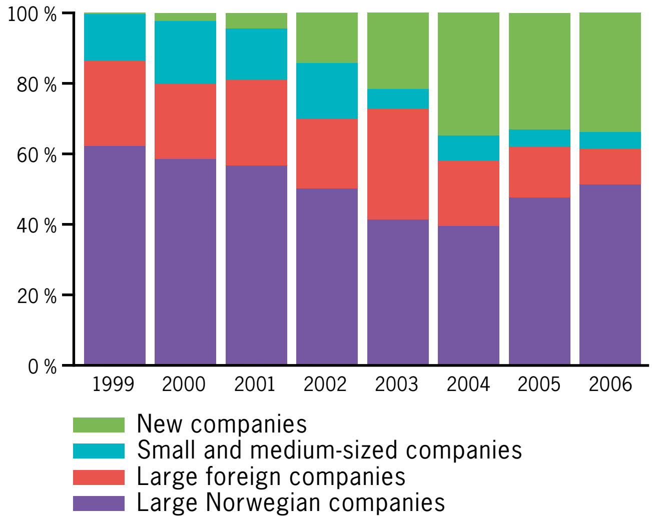


Figure 3.10 Proportion of the total exploration costs in the North Sea apportioned according to the various types of companies

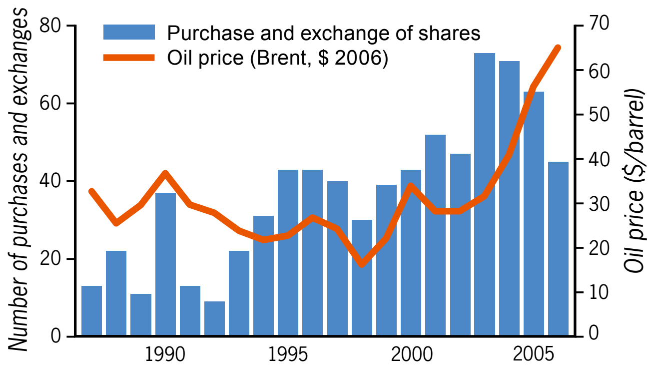


Figure 3.11 Purchase and exchange of ownership shares on the Norwegian continental shelf

this has led to more discoveries that can be profitably developed. The process from exploration to production usually takes several years.

The number of purchased or exchanged shares has increased since 1999, when the new schemes were be introduced (Figure 3.11). More availability of new acreage and more companies operating as licensees on the Norwegian continental shelf may have brought more circulation in the shares' market. The number has declined somewhat in the last three years, perhaps because of the rise in the oil price, which seems to influence the interest of companies to exchange or sell. Since 1999, the new companies have stood for a steadily increasing share in the purchasing or exchanging of shares (Figure 3.12).

It is reasonable to assume that more circulation results in more value creation. New owners may bring new ideas and motivation to explore and develop the resources. The Norwegian Petroleum Directorate has examined whether the purchase or exchange of shares has actually helped to increase the value of the licences. Changes in the discovery rate may be an indicator of this. It transpires that the discovery rate has risen from 9 to 30 per cent following the purchase or exchange of shares in production licences with few discoveries (Figure 3.13).

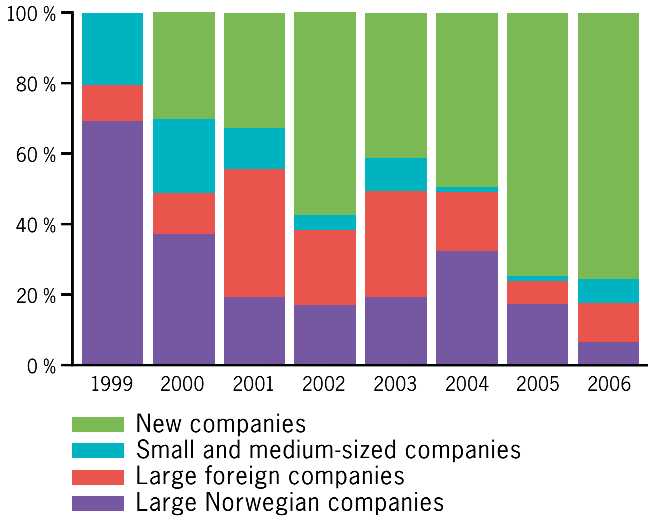


Figure 3.12 Proportion of purchases and exchange of ownership shares on the Norwegian continental shelf apportioned according to the various types of companies

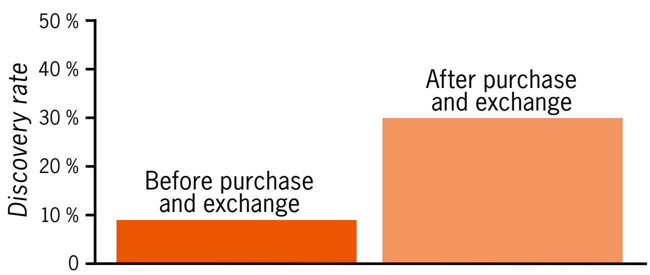


Figure 3.13 Discovery rates before and after purchase or exchange in licences with a lower than average discovery rate

4 Forecasts

Each year, the Norwegian Petroleum Directorate prepares short-term and long-term forecasts for production, costs, investments, and discharges and emissions. These are based on data obtained from the operators. It also undertakes its own evaluations, particularly in relation to fluctuations in the rig market, capacity in the industry, expected gas sales and the probable onset dates for projects.

Short-term forecast (2007-2011)

The Norwegian Petroleum Directorate expects that nearly 1.3 billion Sm³ o.e. of oil and gas will be produced and sold in 2007-2011. This is about the same as in the previous five years. This forecast is based on production taking place on 80 fields during this period. Only one field is planned to be closed down in this period.

The production of liquid in this period is estimated at 735 million Sm³ o.e., which is nearly 20 per cent less than in the previous five-year period. The Directorate assumes that virtually all the oil production will come from fields that are already in production or are currently being developed, and from projects for improved recovery (Figure 4.1). The production level is expected to be between 380 000 and 415 000 Sm³ o.e. (2.4 and 2.6 million barrels o.e.) per day, with oil accounting for 320 000 to 350 000 Sm³ of this. The decline in production in the coming years is estimated to be approximately six per cent per year.

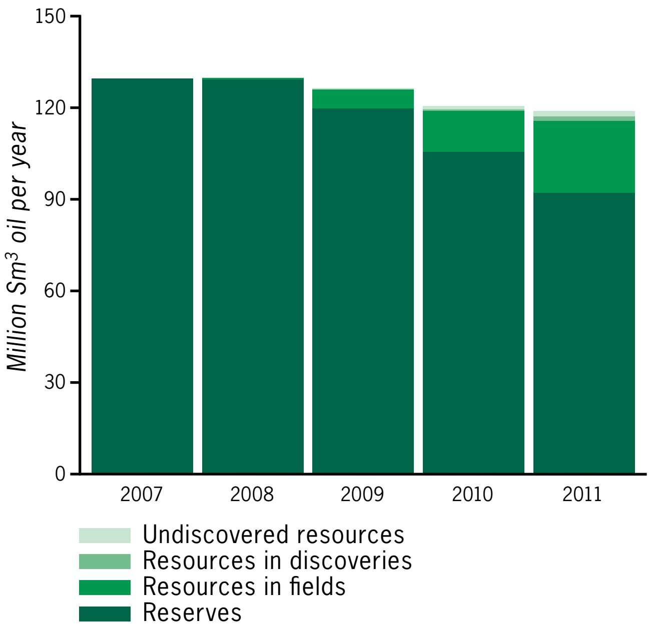


Figure 4.1 Five-year forecast for the oil production

The forecasts are uncertain. There is even considerable uncertainty in the short-term forecast for oil production, as regards both the total volume that can be produced and the annual production (Figure 4.2). The uncertainty (see also the description of uncertainty in Chapter 5) is particularly attached to the reservoir properties, the onset date for new projects and the regularity of fields that are in production. A lengthy shutdown of a field will, of course, lead to lower production that particular year, but not necessarily in succeeding years.

Experience shows that actual production is generally lower than companies forecast for the coming five years. In 2000-2006, oil production proved to be, on average, about five per cent lower than the companies forecasted for the succeeding year. In its forecast, the NPD has allowed for this by reducing the estimate for production in the next six years and adding the reduced volume to the succeeding six years to achieve a balance in the course of 12 years.

Gas production will rise gradually during the period. The Directorate estimates that the sale of gas from the continental shelf will increase from the present level of less than 90 billion Sm³ per year to nearly 120 billion Sm³ per year in 2011 (Figure 4.3).

It expects that 550 billion Sm³ of gas will be sold in 2007-2011, which is 160 billion Sm³ (42 per cent) more than in the previous five years. A further 175 billion Sm³ will be used for injection projects to enhance recovery. Much of this gas will be produced for sale later. The main sources for gas sales in this period will be fields that are already in production, together with the Ormen Lange and Snøhvit fields, which are expected to go on stream in 2007. Thirty per cent of the gas sold in this period will come from fields in the Norwegian Sea, nearly half of it from Ormen

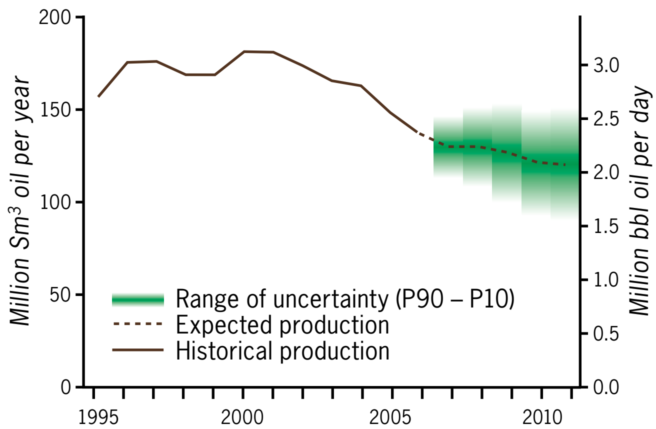


Figure 4.2 Historical oil production and the uncertainty in the forecast

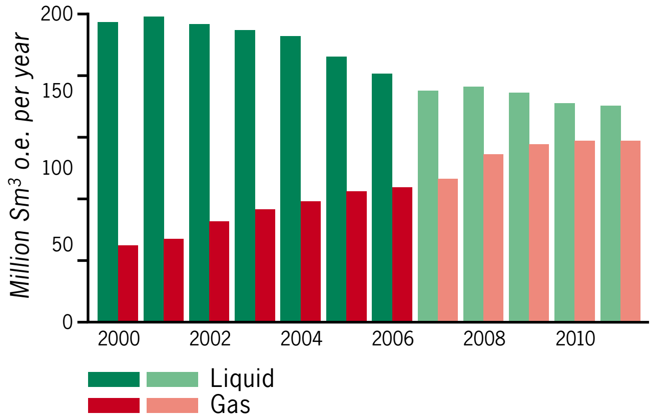


Figure 4.3 Historical production and five-year production forecasts for liquid and gas

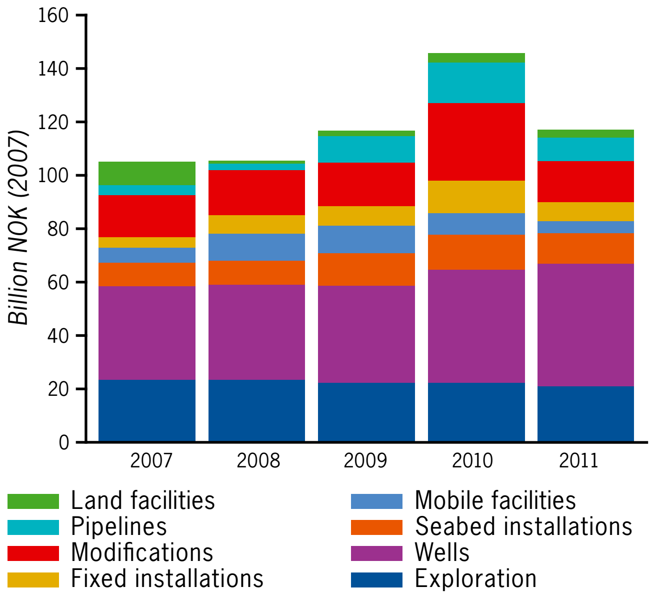


Figure 4.4 Five-year forecasts for investments

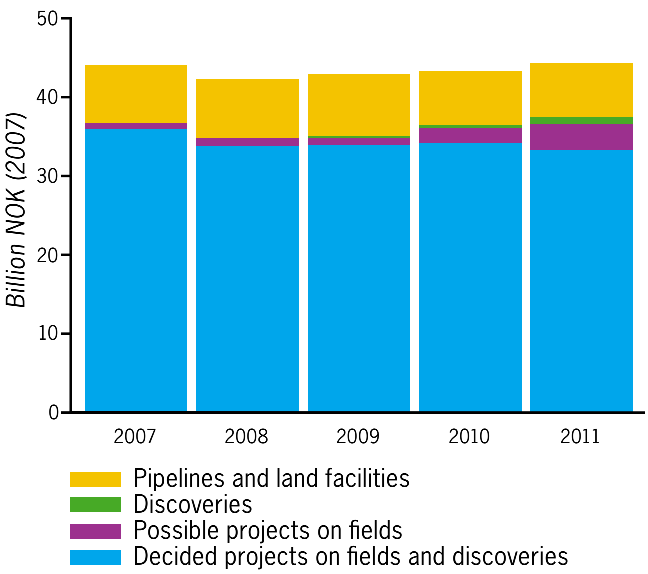


Figure 4.5 Five-year forecasts for operating costs

Lange. The Barents Sea, that is Snøhvit, will contribute four per cent of the total sale. Uncertainty in the gas sale forecasts is particularly linked to just when the new fields will go on stream.

Investments on the Norwegian continental shelf are at a record high level. About NOK 82 billion are expected to be invested on installations, wells, pipelines and terminals in 2007. Added to this are exploration costs of NOK 23 billion. More than NOK 590 billion are expected to be invested between now and 2012, half of which will be linked to exploration and drilling of new development wells (Figure 4.4), and about a quarter to construction of new facilities. Several fields and discoveries are planned to be developed in this period: Gjøa in the North Sea, 6507/5-1 Skarv in the Norwegian Sea and 7122/7-1 Goliat in the Barents Sea are among the largest. In addition, several new facilities will be installed on existing fields, Ekofisk, Eldfisk and Valhall, in the North Sea. In the course of the next five years, these projects will account for half of the investments in new facilities.

Great uncertainty is attached to the level of annual investments in both the short and the long term. This is related to, for instance, the price of oil and gas, whether the reservoirs will require new technical solutions, whether the level of costs will change, new resource estimates, availability of rigs, and changes in production capacity. Lower investments than assumed may result from fewer decisions being taken to implement projects than initially assumed, or that discoveries are developed later than assumed.

The operating costs are estimated at between NOK 42 and 45 billion in the period up to and including 2011 (Figure 4.5).

Forecasts for discharges and emissions

Oil and gas production results in varying volumes of emissions to the atmosphere and discharges to the sea, which vary per produced unit from field to field and through the lifetime of the fields, partly depending upon the production level, the type of installation, the reservoir properties and the length of transport to the gas market.

Emissions consist mainly of carbon dioxide (CO_2), nitrogen oxides (NOx), volatile organic compounds (nmVOC) and methane (CH_4). CO_2 and NOx mainly result from energy production on the installations and flaring, whereas nmVOC and CH_4 stem from evaporation of crude oil during storage and loading.

Discharges chiefly derive from produced water that contains residues of oil and chemicals from the reservoir, and chemicals from drilling and well activities.

Provisional estimates indicate that petroleum activity was responsible for 27 per cent of the total CO_2 emissions in Norway in 2006. Figure 4.6 shows the distribution of CO_2 emissions in 2005. In 2006, 90 per cent of the CO_2 emissions derived from stationary sources offshore (Figure 4.7). The remainder came from emissions in connection with processing, exploration drilling, development drilling and gas terminals.

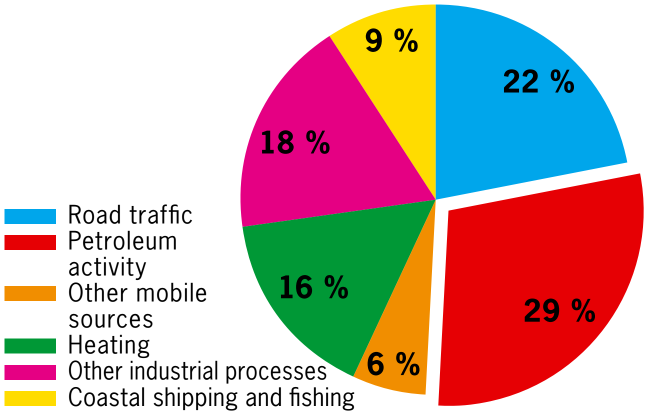


Figure 4.6 Sources of Norwegian CO_2 emissions in 2005 (source: Statistics Norway)

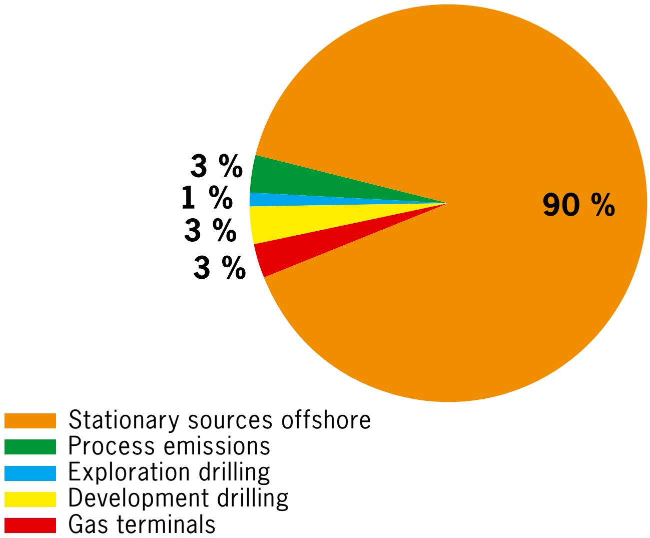


Figure 4.7 Sources of CO_2 emissions from the petroleum activity in 2006

The total CO_2 emissions have increased in recent years, but dropped slightly in 2006 (Figure 4.8). Per produced unit, they are lower than in 1990, before the CO_2 tax was introduced in 1991, but a slight increase has been recorded in the last ten years (Figure 4.9), mainly because production on the Norwegian continental shelf chiefly comes from fields that are in their late phase, which usually requires more energy than earlier phases.

CO_2 emissions are expected to continue to rise in the next five years due to more activity on the Norwegian continental shelf and because more fields will enter their late phase. In the long term, the decline in the total production will result in the total CO_2 emissions from the shelf being about the same level around 2030 as in 1990 (Figure 4.8).

The introduction of the CO_2 tax in 1991 was an effective means of achieving a reduction in the CO_2 emissions from the petroleum industry. Measures to further reduce CO_2 emissions may, for example, be combined solutions for energy production offshore, recirculation of flare gas and injection of CO_2 into the ground to improve recovery or for storage.

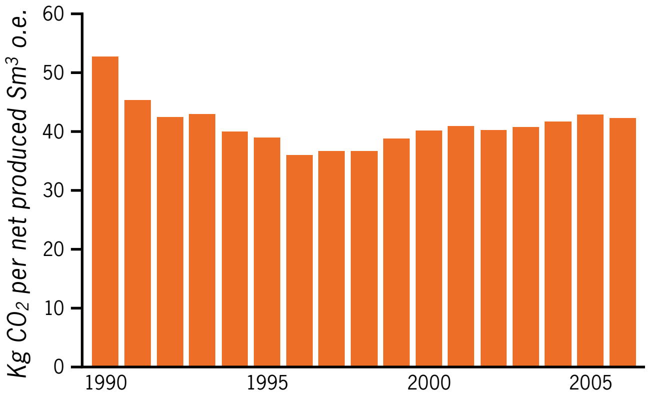


Figure 4.9 CO_2 emissions from the Norwegian petroleum sector per unit produced

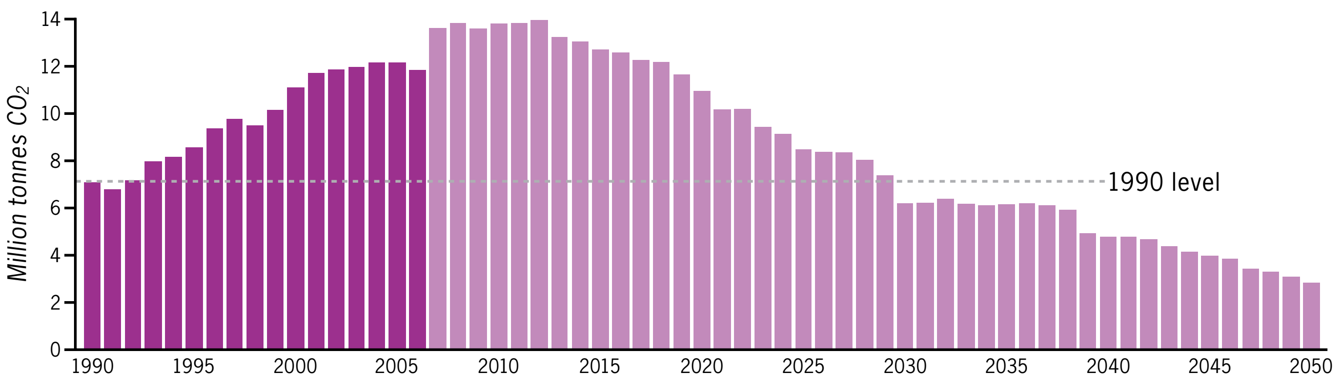


Figure 4.8 CO_2 emissions from the Norwegian petroleum sector

The petroleum activities are responsible for 28 per cent of the total NOx emissions in Norway. These emissions have risen in step with increased production in recent years (Figure 4.10). Improved technology has nevertheless given lower emissions per unit produced (Figure 4.11). The forecast shows that NOx emissions will decline from 2008.

Most measures to reduce CO_2 emissions also reduce NOx emissions. In addition, low-NOx burners are installed in gas turbines on new installations and these will, in time, help to reduce the NOx emissions per unit produced. About 25 per cent of the gas turbines on the Norwegian shelf have low-NOx technology.

The petroleum sector is the principal source for nmVOC emissions and was responsible for 40 per cent of the total emissions in Norway in 2006. The sources are mainly storage and loading of crude oil at sea and at land facilities. Such emissions have decreased in recent years, measured in terms of both the total figure (Figure 4.12) and per unit produced (Figure 4.13). This trend seems to be continuing, even though more fields with floating storage facilities are being developed. One reason for the trend is that the industry has been obliged to reduce the nmVOC emissions during loading and storage.

Most discharges of chemicals are related to drilling and well activity (Figure 4.14), and should therefore vary in pace with the level of activity. However, despite an increase in activity, this kind of discharge has been reduced in recent years (Figure 4.15), and is expected to be further reduced in the years to come. In principle, no toxic substances are to be discharged, whether they have been introduced or occur naturally. Environmentally hazardous chemicals are replaced by chemicals with little or no detrimental effect, and 99 per cent of the chemicals now used are thought to be of this kind.

The petroleum activity in Norway has not occasioned major, acute oil spills that have reached land. Oil spills from the petroleum sector mainly derive from regular operations (Figure 4.16). Water that is produced together with oil and gas contains residues of oil, other organic elements, inorganic components and remains of added chemicals. Measures to reduce the discharges have been inadequate to reverse the trend of an increasing discharge of produced water, which is mainly a consequence of more and more of the production taking place from old fields where production of water increases. The measures have, however, helped to reduce the discharge of oil per produced unit of water (Figure 4.17).

Long-term forecast (2007-2026)

The Norwegian Petroleum Directorate estimates that 4.7 billion Sm^3 o.e will be produced over the next 20 years, about the same as the total production to date.

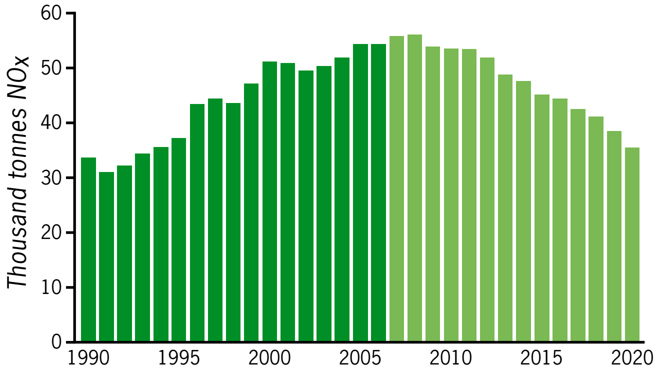


Figure 4.10 NOx emissions from the Norwegian petroleum sector

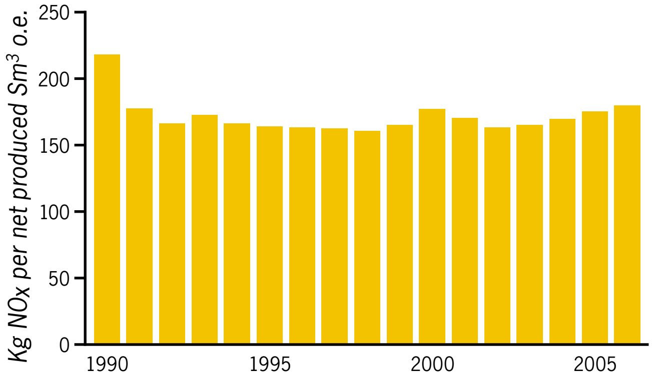


Figure 4.11 NOx emissions from the Norwegian petroleum sector per unit produced

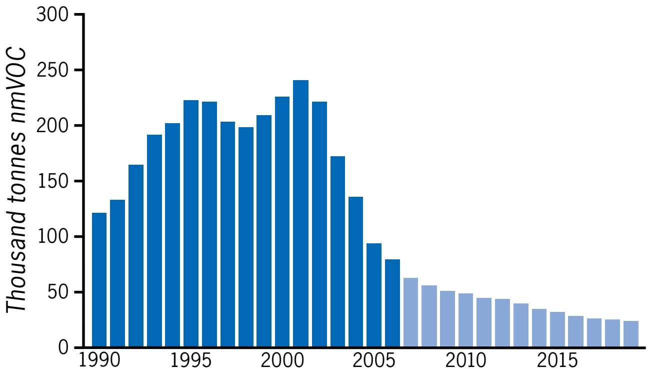


Figure 4.12 nmVOC emissions from the Norwegian petroleum sector

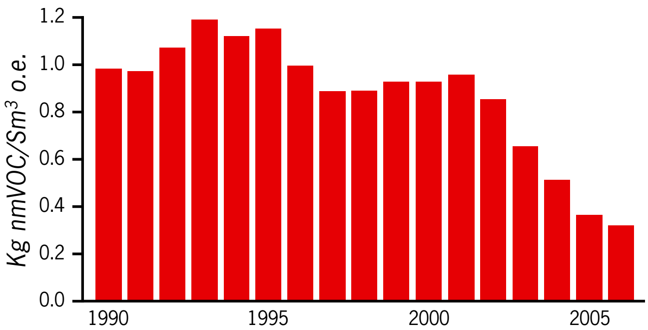


Figure 4.13 nmVOC emissions from the Norwegian petroleum sector per unit produced

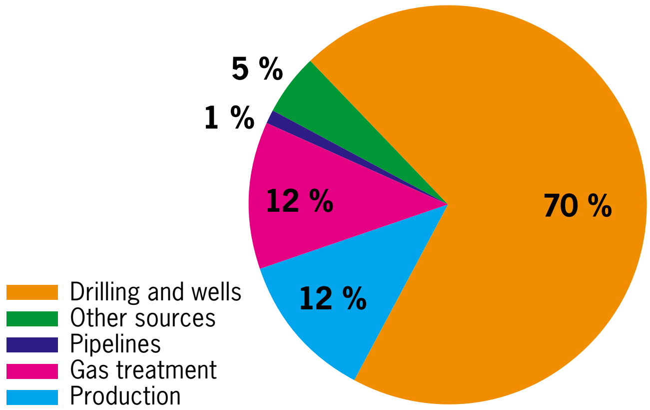


Figure 4.14 Sources of chemical discharges from the Norwegian petroleum sector in 2005

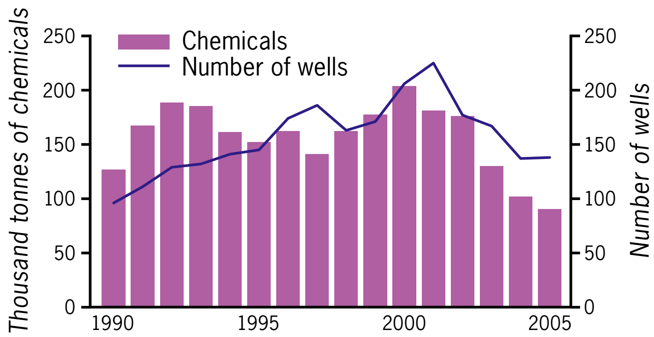


Figure 4.15 Number of wells and discharges of chemicals from the Norwegian petroleum sector

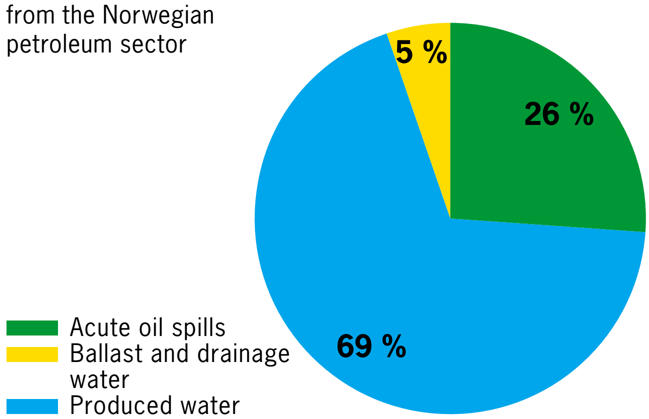


Figure 4.16 Oil spills from the Norwegian petroleum sector in 2005

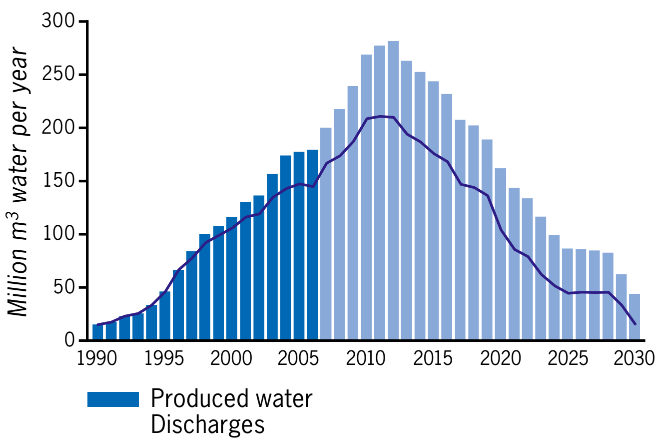


Figure 4.17 Forecast for production of water and discharge of produced water

This forecast is uncertain. It is based on current plans for fields and discoveries, adjusted in keeping with the Directorate's own evaluations. For instance, based on experience from earlier years, the start-up date for some projects has been put back somewhat. Two-thirds of the production is expected to come from fields that are now in production and or have been approved for development and a further 14 per cent from the same fields as improved recovery. Twelve per cent is expected to derive from the development of proven discoveries and 10 per cent from future discoveries (Figure 4.18). Approximately half of the production in 2026 will come from fields that have still not been discovered.

Considerable activity is expected in the long-term period. In connection with the yearly submission of data for the National Budget, the Directorate has been informed of more than 300 projects for improved recovery on fields that are in production, and the long-term forecast presumes that most of these will be realised. It also assumes that the majority of discoveries will be developed. The forecast is based on the fact that about 30 exploration wells are drilled each year. Ten years usually elapses between a discovery is made and the start-up of production. This gives a 65 million Sm^3 o.e. per year growth in resources from exploration for the next 20 years.

The Directorate estimates that 1.8 billion Sm^3 of oil will be produced by 2026. This is 35 per cent less than in the previous 20-year period. Oil production peaked in 2000 when there was an average production rate of 3.1 million barrels per day. About 60 per cent of the production up to 2026 will come from what are now classified as reserves. The remainder will come from measures for increased recovery on fields that are already in production, development of proven discoveries and undiscovered resources. The sale of gas from the continental shelf is expected to rise appreciably so that production in the next 20 years will be substantially higher than in the previous 20 years.

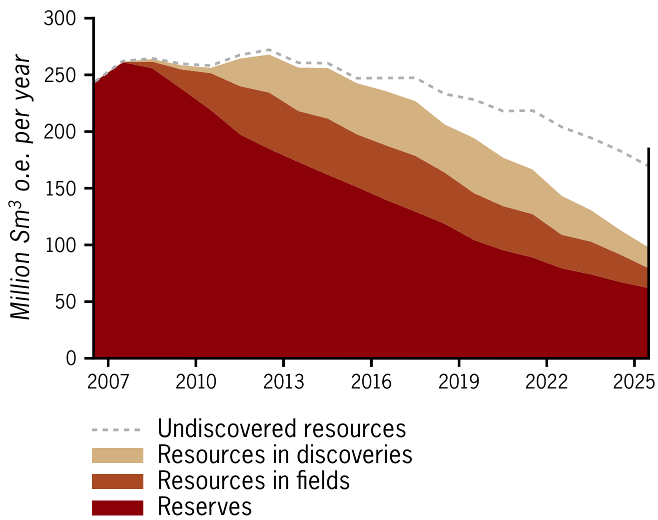


Figure 4.18 Forecast for the total production in 2007-2026, apportioned according to the maturity of the resources

5 Undiscovered resources

Introduction

Preparing estimates of the undiscovered resources forms an important part of the work performed by the Norwegian Petroleum Directorate. These estimates, along with knowledge about the various plays, are important for the choices the authorities have to make regarding the exploration of the Norwegian continental shelf, such as choosing areas that are to be announced for allocation.

The estimates of the undiscovered resources are based on the full breadth of expertise found in the Directorate. Geological mapping of the continental shelf, in areas that are opened for exploration and in areas not opened, forms the basis of the estimates. Knowledge about reservoirs that have already been proven is also valuable, as, too, is an understanding of how much of the proven resources can be recovered. The Directorate's comprehensive data bases, containing information on wells, discoveries, fields, prospects and plays (see Fact Box 5.1), form the foundation for the work.

The undiscovered resources

The Norwegian Petroleum Directorate estimates that between 1.6 and 5.8 billion Sm^3 o.e. of oil, gas, condensate and NGL remain to be found on the Norwegian continental shelf. Their mean value is 3.4 billion Sm^3 o.e. About 45 per cent is liquids and 55 per cent gas. Thirty per cent of the total petroleum volume will probably be located in the Barents Sea (outside the area with overlapping claims), 35 per cent in the Norwegian Sea and 35 per cent in the North Sea (Table 5.1, Figure 5.1). Such estimates are uncertain, particularly in areas with least information. The Barents Sea is the least explored area and has the largest range of uncertainty. There is also considerable uncertainty in the Norwegian Sea. Uncertainty is least in the North Sea, where knowledge of the geology and the reservoir properties is best.

The estimate of the total undiscovered resources has not changed since 2003 even though oil and gas have been proven since the last estimate was made. There are several reasons for this. The Directorate's latest review has confirmed a number of the assumptions that lay behind the previous estimate. Since the previous estimate, both the industry and the NPD have carried out a great deal of mapping in connection with the awards in predefined areas and ordinary licensing rounds. This has provided much new information on prospectivity on large parts of the continental shelf and enhanced the Directorate's expectations of how much remains to be discovered. The recent exploration results in the Barents Sea have also raised our expectations of oil discoveries on this part of the shelf, partly at the cost of expectations of gas (Figures 5.2 and 5.3).

All told, this has led the Directorate to maintain its estimate of 3.4 billion Sm^3 o.e. About 225 million Sm^3 o.e. have been found in the past four years. Figure 5.4 compares various estimates made by the NPD over the last ten years.

No new analysis has been made of the possibility of finding oil and gas in the areas off Lofoten and Vesterålen (Nordland VI, VII and Troms II), because the Directorate, at the request of the Storting (Norwegian Parliament),

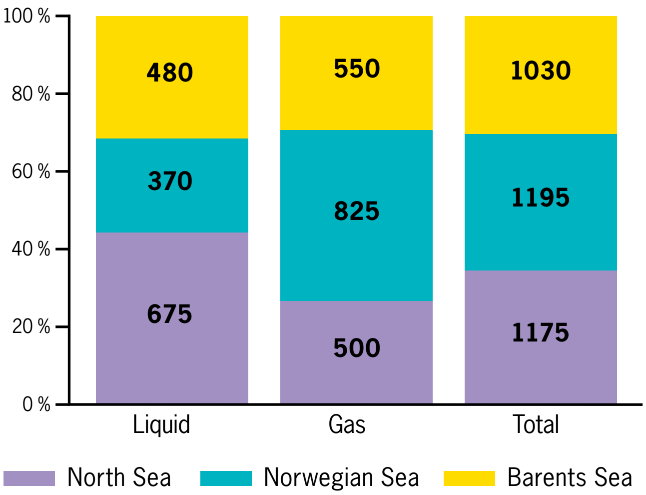


Figure 5.1 Distribution of the undiscovered resources in percentages. The volumes are stated in million Sm^3 o.e.

Area	Liquid			Gas			Total		
	P90	Mean	P10	P90	Mean	P10	P90	Mean	P10
North Sea	380	675	1000	300	500	730	750	1175	1650
Norwegian Sea	120	370	740	230	825	1620	370	1195	2340
Barents Sea	40	480	1270	80	550	1430	160	1030	2620
Total	***640***	***1525***	***2640***	***750***	***1875***	***3330***	***1550***	***3400***	***5800***

Table 5.1 Undiscovered resources (million Sm^3 o.e.) in the various areas, with the range of uncertainty

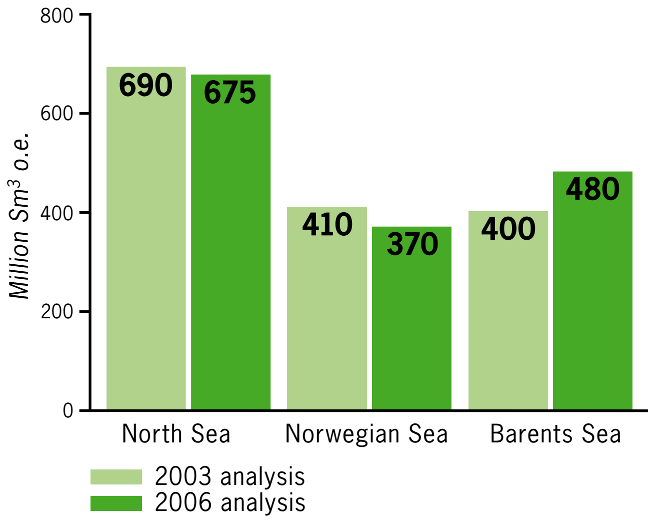


Figure 5.2 Comparison of the estimates for liquids in the 2006 and 2003 analyses

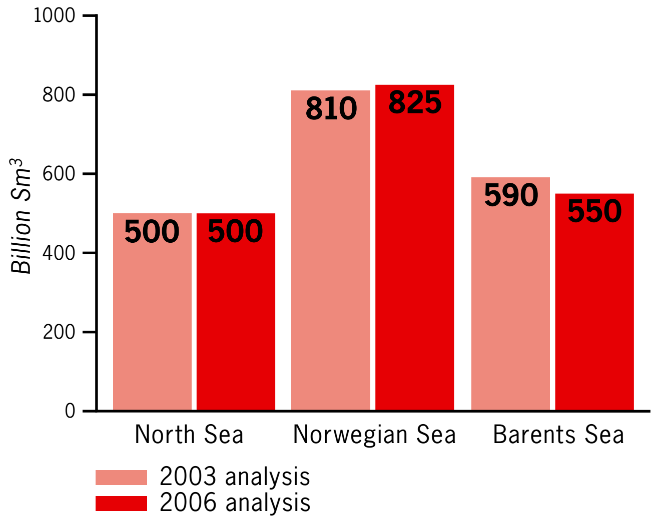


Figure 5.3 Comparison of the estimates for gas in the 2006 and 2003 analyses

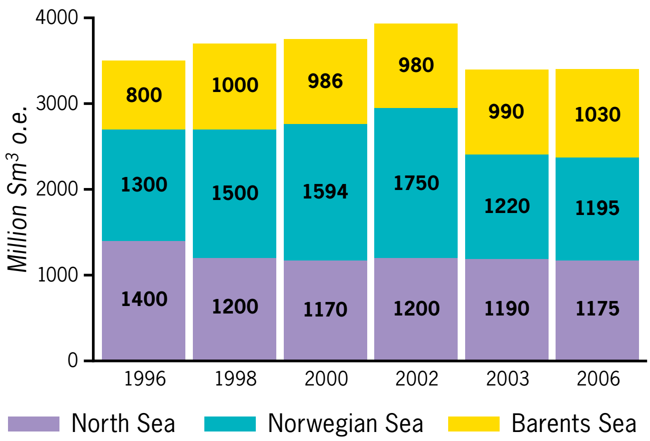


Figure 5.4 Estimates made by the Norwegian Petroleum Directorate of the undiscovered resources in the last 10 years

has begun to acquire geophysical data and carry out new mapping in this area as a follow-up of White Paper No. 8 (2005-2006): Integrated Management of the Marine Environment of the Barents Sea and the Sea Areas off the Lofoten Islands. Any revised estimate of the resources will be published at a later date.

Play analysis

The Norwegian Petroleum Directorate calculates the undiscovered resources with the help of a method called play analysis, which it has used for many years. Both the method and the data tool have been undergoing continuous development. The method is very suitable in an area where the geology is known and where many prospects have been mapped and some wells drilled, as is the case on the Norwegian continental shelf. Other methods also exist.

Play analysis concerns estimating how much petroleum can be proven and produced from each play (Fact Box 5.1). Statistical techniques are used to add these analyses together to produce an overall estimate for a larger area, such as all the Norwegian continental shelf.

A play is a geographically delimited area where several geological factors occur together so that producible petroleum can be proven. These factors are: 1) *Reservoir rock*, which is a porous rock where petroleum can be preserved. Reservoir rocks in a specific play will belong at a given lithostratigraphical level. 2) *Trap*, which is an impermeable rock or a geological structure enveloping the reservoir rock so that the petroleum is retained and accumulates in the reservoir. The trap must be formed before the petroleum stops entering the reservoir. 3) *Source rock*, which is shale, limestone or coal containing organic material that can be converted into petroleum. The source rock must also be mature, that is to say the temperature and pressure must be appropriate for petroleum actually to be formed, and petroleum must be able to move from the source rock to the reservoir rock.

A play is *confirmed* when producible petroleum is found in it. The production does not necessarily have to be profitable. If no producible petroleum has yet been found in a play, it is *unconfirmed*.

A prospect is a possible petroleum deposit that has still not been drilled, but which has been mapped and whose volume can be calculated. The probability of a petroleum deposit being provable in a given prospect is called the *probability of discovery*.

Fact Box 5.1

A number of geological and technical factors have to be evaluated for each play. Estimates have to be made of how many prospects (Fact Box 5.1) may feasibly be mapped, how much petroleum they may contain, the recovery factor, the likelihood of a discovery being made, and whether it will contain gas, liquid, or both. The basis for this work is the large NPD data bases and the Directorate's detailed knowledge of the geological conditions, technological solutions and financial premises on the continental shelf. These factors are processed by employing Monte Carlo simulation. The result is an estimate of how much oil and gas remains to be found and how much of this can be recovered.

Uncertainty and probability are two important concepts for understanding the calculation of the undiscovered resources (Fact Box 5.2). The uncertainty is the range between high and low estimates, and the probability is the likelihood that something will take place.

All resource estimates for plays are stated with a range of uncertainty, and some also state a probability, such as 20 per cent, which means that there is only a 20 per cent probability that producible oil or gas will be found in the play, whereas there is an 80 per cent probability that nothing at all will be found.

When Monte Carlo simulation is used to add the plays together, allowance is made for the play probability by ensuring that each play is only included in the thousands of analyses in the Monte Carlo simulation as many times as the probability attributed to it requires. In the example above, this play is included in 20 per cent of the analyses. This practice is followed for all the plays that are added together. The result is generally presented as a range of uncertainty with a mean value.

The Directorate also makes forecasts for future production from the undiscovered resources (see Chapter 4). The play analysis gives us a chance to estimate how many discoveries need to be made to achieve the resource estimate and how large these will be. Naturally, both the number and size have a range of uncertainty. This is the least precise part of the analysis and the results must be used with caution. The assumptions made there include estimates of future exploration activity, the discovery rate, the lead time from the discovery being made to the development being completed, and the production level. These, in turn, are based on experience of the Norwegian continental shelf and the Petroleum Directorate's expectations for the future development. These forecasts are in part used to calculate future income and expenses in the National Budget.

The plays on the Norwegian continental shelf
The Norwegian Petroleum Directorate has defined 68 plays on the Norwegian continental shelf (Table 5.2), 33 of which have been confirmed by proving hydrocarbons. The area with overlapping claims in the Barents Sea and the continental shelf around Jan Mayen are not included in this analysis. In the North Sea, where exploration has been taking place longer than elsewhere, as many as three-quarters of the plays have been confirmed. Nine of

The **uncertainty** expresses the range of possible outcomes or results. It can be described in many ways, but a low and a high estimate is most frequently used (for example, the Norwegian Petroleum Directorate estimates that between 1.6 and 5.8 billion Sm^3 o.e. of oil, gas, condensate and NGL remain to be found on the Norwegian continental shelf). This uncertainty is generally calculated by statistical methods, such as Monte Carlo simulation. The high and low estimates can then be described using statistical terms. The Directorate generally uses P90 for the low estimate; that is, there is a 90 per cent probability that the result will be equivalent to or greater than the P90 value. P10 is used for the high estimate; that is, there is a 10 per cent probability that the result will be equivalent to or greater than the P10 value. (In the example, 1.6 billion is the P90 value and 5.8 billion the P10 value.)

The **mean value** is the average value. It is generally defined as the arithmetic mean of all the outcomes in the statistical distribution.

The **probability** expresses the possibility of something occurring. It is generally expressed in percentages. 10 per cent probability means that something will occur in one out of ten cases. 100 per cent probability means that it is absolutely certain that something will occur. The *play probability* is the term for the probability that producible petroleum can actually be proven in a play. This is calculated with the help of geological mapping and statistical methods. The probability that a prospect contains the volume of petroleum that has been calculated, given that a play is, or becomes, confirmed may be called the *prospect probability*. The *probability of discovery* is the product of the play probability and the prospect probability. When the play is confirmed, the probability of discovery and the prospect probability are identical.

Fact Box 5.2

20 have been confirmed in the Norwegian Sea, whereas only six of 23 plays in the Barents Sea have been confirmed. 73 per cent of the estimate of the undiscovered resources is in confirmed plays (Figure 5.5). The plays are described in detail in Appendix 1 of this report.

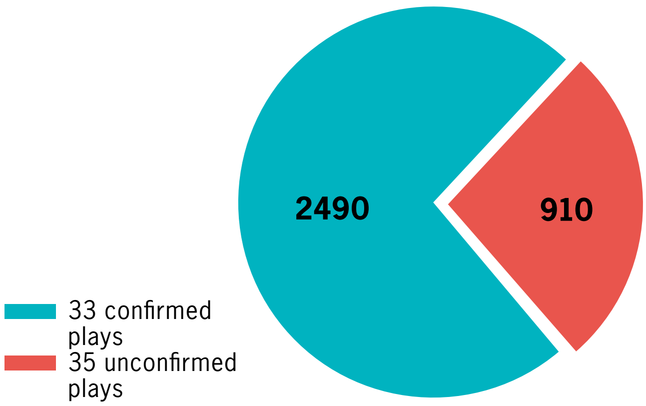


Figure 5.5 Distribution of the resources in confirmed and unconfirmed plays (million Sm^3 o.e.)

The plays are based on the Directorate's assessments. Plays can be defined in various ways. In every case, an assessment has to be made of how large an area and how much of the rock succession is to be included. The oil companies or others can present a different number of plays based on other methods or assessments of the geology. The plays may be of different sizes and have different estimates of resources.

Area	Confirmed	Unconfirmed	Total
North Sea	18	7	25
Norwegian Sea	9	11	20
Barents Sea	6	17	23
Total	*33*	*35*	*68*

Table 5.2 Number of confirmed and unconfirmed plays on the Norwegian continental shelf.

Large parts of the Norwegian continental shelf are covered by plays, that is, areas where oil or gas is known or believed to be found (Figure 2.1). The plays in large areas of the Norwegian Sea and not least the Barents Sea are still unconfirmed. There are also some areas where the Directorate at present does not believe that discoveries can be made. The northern part of the Barents Sea has not been opened for petroleum activity. Our understanding of its geology will most probably change if it is opened for exploration.

Unconventional petroleum resources

Introduction

The conventional oil and gas resources will not last for ever. Fewer large discoveries of conventional oil and gas are being made worldwide now than some years ago. At the same time, production is increasing. If the world is to be able to maintain its present energy consumption, alternative sources of petroleum are required.

Other deposits of oil and gas exist than those recovered in conventional oil and gas fields. These are often called unconventional petroleum resources, which denote petroleum that occurs naturally, independently of a traditional trap. Such resources can occur over large areas and, unlike conventional oil and gas fields, be independent of a geological structure. One example is oil shale, which is a rock that can be worked by ordinary mining. Oil shale has been exploited for oil production for several centuries. Unconventional, as a concept, does not necessarily mean that it is something new or requires new technology; it just differs from conventional oil and gas fields. Unconventional petroleum resources may also cover petroleum that is manufactured industrially, for instance from coal.

Recovering many of the unconventional petroleum resources has substantial environmental consequences; enormous opencast quarries to work coal, oil shale or tar sand, and polluting production methods for working tar sand and extra heavy oil are well-known examples. Handling the environmental consequences when such resources are to be exploited will be a major challenge, and this must be taken into consideration when assessing whether it is in the interest of society to exploit them.

Fact Box 5.3 reviews the most important unconventional petroleum resources. The Norwegian Petroleum Directorate has so far not been engaged in mapping possible resources in Norway, but considerable research has taken place elsewhere in the world regarding both where they can be found and how they can be produced. Various attempts have also been made to assess how much oil and gas can be produced from the unconventional petroleum resources. These estimates vary greatly. Large parts of the resources are at present far too expensive to produce, or the technology to produce them is lacking. Enormous volumes of unconventional petroleum resources exist; probably more than the total volumes of conventional petroleum resources. The largest quantities can be obtained from gas hydrates or oil shales, but how much can be recovered depends on research and technological development, the oil and gas prices, the environmental consequences and political willingness.

Possible unconventional petroleum resources in Norway

Owing to the large, easily available conventional petroleum resources on the Norwegian continental shelf, little focus has so far been placed on unconventional petroleum resources in Norway. As the need for alternative resources increases, there may also be a need to consider these resources. The production of several of these resources can probably be combined with the storage of CO_2, so that the production can also give a significant environmental benefit. The two most relevant sources of unconventional petroleum in Norway at present are gas hydrates and coal.

Gas hydrates have been found in a number of wells all over the Norwegian continental shelf. Research on and testing of methods to produce gas from gas hydrates is in progress in many places. An example is the Mallik field, which is situated on land in the Mackenzie Delta in Canada. This field is being developed as an international research project. The technological challenges and costs are expected to be still greater offshore.

Considerable quantities of coal are found in Svalbard. There are also large coal deposits on every part of the Norwegian continental shelf, but no reliable estimates have been made of the size of these resources, although they are substantial. However, at present there is no relevant method for extracting this offshore coal. Large quantities of coal are cheaply available around the world and the Directorate does not expect profitable coal mining to take place on the Norwegian continental shelf in the foreseeable future. However, the coal is a source of gas. In view of the development taking place elsewhere in the world regarding gas production from coal deposits, it is not improbable that gas can also be produced directly from coal sometime in the future (Fact Box 5.3). The NPD has so far not prepared any estimate of the likely size of the resources.

Large volumes of gas have been found in impermeable sedimentary rocks in several parts of the world (Fact Box 5.3). The presence of such resources on the Norwegian continental shelf, too, cannot be excluded. However, producing them with current technology requires a large number of wells and a considerable effort to increase the permeability of the rock. This is at present only profitable under favourable conditions on land. Compared with other gas resources, a considerable advance in technology is required to make this kind of production profitable offshore.

Bitumen and extra heavy oil: These are oils that are extremely viscous. Bitumen is generally defined as petroleum with a viscosity greater than 10 000 centipoises (cp) at reservoir temperature, or with an API gravity of less than 10 degrees. Extra heavy oil has a viscosity between 10 000 and 100 cp. The natural deposits are called tar sand, oil sand, oil-impregnated sand, natural asphalt or bituminous rock.

Bitumen and extra heavy oil are found in many parts of the world. Canada has the largest occurrences of bitumen. Bitumen is mainly recovered by opencast mining or produced from wells by injecting steam to make the bitumen fluid. The largest occurrences of extra heavy oil are found in the Orinoco belt in Venezuela. The distinction between bitumen and extra heavy oil is not clear, and the expressions are sometimes used interchangeably.

No significant deposits of bitumen and extra heavy oil have been found on land in Norway. Petroleum of this type has been observed in several wells on the Norwegian continental shelf, but it will be difficult to map and produce. Compared with offshore conventional oil and gas, this resource currently has little commercial interest in Norway.

Oil shale: This is a collective term for fine-grained sedimentary rocks that will liberate oil and gas when crushed and distilled. Such rocks are found in many parts of the world and may range from small accumulations to gigantic deposits extending over thousands of square kilometres and many hundreds of metres thick. Oil shales are worked by ordinary mining, mostly opencast.

Oil shales are generally not profitable to work with the current prices of oil, gas and coal. Some production takes place in countries with easily accessible occurrences of oil shales, but which do not have their own oil production. The best-known example is Estonia, where oil shales are the energy source for several power stations. The largest known occurrence in the world is the Green River Formation in the western USA. Other countries with large known deposits are Australia, Brazil, Canada, Israel, Jordan, China and Russia.

Significant quantities of oil shale have not been mapped on land in Norway. It is uncertain whether there may be major deposits offshore. As far as the Norwegian Petroleum Directorate is aware, no attempts have been made to investigate them. There are at present no production methods for offshore oil shale.

Unconventional gas resources: Unconventional gas occurs in a number of rocks, besides coal. These deposits have a variety of names, such as tight gas sandstones, shale gas, basin centre gas and continuous gas plays. Unconventional gas resources consist of the same hydrocarbons as other petroleum gas, mainly methane and other light hydrocarbons, but occur in different ways from the conventional gas deposits. Unconventional gas resources are usually evenly distributed in rocks, including coal, over enormous areas and without structural closures or other traps. They often occur near the surface and the drilling costs, on land, are low. In addition, the discovery rate is generally higher than 90 per cent. There are substantial challenges as regards reservoirs and production technology, which make profitable production from these resources difficult.

The main problem is to find areas where the permeability in the reservoir is adequate to support profitable production. The permeability in unconventional gas reservoirs is usually very low, but can sometimes be improved by mechanically fracturing the rock around the wells. So far, a large number of wells have been required to recover these resources. Consequently, little attention has been given to such resources offshore where it is extremely expensive to drill wells. Innovations in drilling technology and more knowledge on how such resources occur, also offshore, will probably change this in the years to come.

Similarly, large volumes of gas are found in shale. Shale is generally a porous rock, but its permeability is very low. Consequently, the gas can only be produced if the shale is sufficiently fractured. Gas has been produced from shale in the USA for well over 100 years.

There are large volumes of unconventional gas in the world. Estimates of how much can be produced vary from 15 to 50 trillion (10^{12}) m^3 of gas, but some experts think that the figure is very much higher. These deposits are best investigated and understood in the USA, where about a fifth of the gas consumption comes from them.

Such resources have not been mapped in Norway or on the Norwegian continental shelf. At present, there is little to suggest that such gas can be an important resource for Norway.

Gas from gas hydrate: Gas hydrate consists of gas and water molecules which bind themselves to one another in a lattice structure that may resemble ice. The gas is principally methane. One cubic metre (m^3) of hydrate contains 4.3-5.1 m^3 of gas (4.65 m^3 for methane). Gas hydrate occurs in many places. Offshore, along the continental margins, gas hydrate has been found in both oil and gas wells, and in many places around the world when sampling for research purposes. Very large deposits of gas hydrate have been found on land in regions with permafrost, particularly in Alaska, Canada and Siberia. In these regions, it has, moreover, been shown that gas hydrate can function as a cap rock above conventional gas resources, often at a very shallow level. This probably also occurs offshore, and will then sometimes constitute a safety risk during drilling. No reliable estimates exist of the volumes of gas resources that are trapped in gas hydrate, but the highest estimates exceed the total conventional gas resources in the world.

Production of gas from gas hydrate can take place in several ways. If the hydrate is the cap rock for a conventional gas field, it will gradually dissolve as pressure in the conventional reservoir drops during production. This can contribute substantially to the recoverable resources from such a gas field. Gas can be produced directly from gas hydrate by heating the hydrate using steam, for instance. Another method is to add chemicals (for example, methanol) which will loosen the lattice structure so that the gas is liberated and can be produced through wells.

Experiments are in progress where CO_2 is injected into the gas hydrate. CO_2 will replace the methane in the lattice structure so that the methane can be liberated and produced. In the future, this may also be an important mechanism for dealing with the CO_2 problem.

Gas from coal: Coal is found in large quantities throughout the world and is mined in more than 50 countries. It has been known that coal contains gas ever since the first gas explosion in a coal mine several hundred years ago. Coal has been an important source of gas in many coal-producing countries such as China, the USA, Russia, the Ukraine, Australia, New Zealand and many countries in Central Europe and Central Asia.

Gas has traditionally been produced from coal from abandoned coal mines (coal mine methane – CMM), but has increasingly become an exploration target in its own right (coal bed methane – CBM). The production takes place through wells drilled into coal-bearing beds. The gas, which is formed naturally in the coal, then flows to the well, either because the coal is fractured or with the help of various stimulating measures such as mechanical fracturing and water or gas injection. If such production can compete with conventional gas production on the Norwegian continental shelf, it is likely that it will also take place here. There are no reliable estimates of how much gas can be profitably recovered from coal. Some estimates are in the order of 30 trillion (10^{12}) m^3 of gas. This is ten times the world consumption of gas in 2006. Such estimates will become more reliable as the technology is developed and new deposits are mapped.

Research is in progress on methods of using CO_2 as injection gas in coal deposits. This may substantially increase the recovery of petroleum gas from the coal at the same time as it solves an environmental problem.

Gas can also be produced from coal industrially. This can take place by heating the coal under high pressure with a limited input of oxygen or with the help of steam. Gas mixtures are then formed that can be refined into various types of gas. Gas manufactured from coal in this way is also used to produce liquid petroleum (see below).

Oil from coal: Oil can be recovered from coal by various industrial methods. It can be done directly by dissolving the coal in a solvent at high temperature. This is an efficient method, but further refining is required to obtain oil of fuel quality. It can also be done indirectly by converting the coal to gas (see above) and then converting this gas into various petroleum products. Better ways of producing oil from coal are continuously being developed, and industrial plants are operating in several countries. South Africa has advanced furthest and has been producing oil from coal for over 50 years.

Fact Box 5.3

6 Scenarios for development on the Norwegian continental shelf

Background

In 2006, it was 40 years since the drilling rig Ocean Traveler came to Norway and drilled the first exploration well on the Norwegian continental shelf. This was the start of a Norwegian oil and gas fairytale which very few envisaged in 1966. So far, approximately 1200 exploration wells and 2600 development wells have been drilled on the Norwegian continental shelf. 65 fields have been put into production, and 13 of these are now closed down. Seven onshore facilities have also been built. New technology has been developed and adopted to meet the challenges that have arisen as the most easily accessible resources have been produced, and to satisfy increasingly stringent demands on environmentally sound and safe activities.

The trend has gone from building large steel and concrete platforms with processing plants, a permanent crew and many support functions, to developments based on sea-bed installations where the processing and control functions take place entirely from existing installations or on land. This has also brought enhanced safety for the personnel and the environment.

The authorities have accommodated the framework conditions to the challenges posed by the continental shelf at any one time, at the same time as the policy has been predictable and trustworthy. The trend shows that the industry, together with the authorities, is able and willing to solve the challenges which the petroleum activity faces, at the same time as this activity takes place in co-existence with other industries.

Following 40 good and exciting years, it may be timely to think about what the future may bring. Recently, the trend has been marked by high prices for oil and gas, a growing demand for Norwegian gas, increasing interest for exploration in the Barents Sea, record large response regarding allocations and many new companies wanting to get a foothold on the Norwegian continental shelf. At the same time, challenges are present in the shape of declining oil production, rising costs, fewer and smaller discoveries, and poor recruitment of new specialists. How will the industry and the authorities meet these challenges? Will increased environmental awareness in the population lead to the petroleum activity being looked upon as an industry of the past or will new technology make oil and gas part of the solution of the climate problems?

What may the future bring?

We are accustomed to learning by experience, that is, from something we ourselves or others have done or experienced. Experience is always in the past. If we make up stories, scenarios, about what may take place, we can also learn from the future.

Scenarios are stories, postulates, about the future. They assist long-term thinking in a world full of uncertainties. Scenarios are tales of how the Norwegian continental shelf may develop, in this case up to 2046. These stories are intended to increase our understanding of the uncertainty in the estimates of the total resources (described in Chapter 2).

Scenarios are not prophecies. The world and the surroundings change. The changes may be small and invisible from day to day, but over a longer period they can have major and surprising consequences. The scenarios are intended to prepare us so that we can plan and implement measures in time. This report presents four scenarios for the development on the Norwegian continental shelf.

The driving forces

The driving forces are the building blocks for the scenarios. The building blocks that are of greatest significance for production and value creation can have major effects, causing breaks in trends and making the future completely different from what we envisage today. Some of the most crucial driving forces for the development are discussed below, but first we will review some global developmental trends that lie behind all the scenarios and then describe in more detail the driving forces that distinguish the different scenarios that have been chosen, focusing on those that affect conditions on the Norwegian continental shelf.

General developmental trends

Population trend and demand for energy

In 1966, when the first well on the Norwegian continental shelf was drilled, there were just over three billion people on the Earth. Today there are more than six billion. In 20 years, there will be about eight billion, and in 2046 probably around nine billion.

This population trend, coupled with the rising standard of living experienced by large sectors of the Earth's inhabitants, will bring an increasing demand for energy. This will be especially noticeable in countries that have previously had a relatively low growth in the demand for energy, such as Brazil, Russia, India and China.

According to the International Energy Agency (IEA), approximately 80 per cent of the world's energy consumption is now covered by fossil sources (Figure 6.1).

The IEA predicts that the demand for energy will increase by about 50 per cent up to 2030, which is an annual growth of 1.6 per cent. The power sector will account for a third of the expected global growth. The nuclear energy capacity will increase, but the share of nuclear energy used to generate electricity will decline because the consumption of fossil fuels will grow more rapidly. In the foreseeable future, the world will be entirely dependent on fossil sources of energy, like coal, oil and natural gas.

Security of supplies
The global production of oil and gas will to an increasing degree take place in a limited number of countries and be largely under the control of national, state-owned companies The IEA forecasts show that a major portion of the increase in the world's oil supplies in the next 25 years will come from the OPEC countries (Figure 6.2). These nations are dominated by state-owned companies. The same trend is seen in the IEA forecasts for gas supplies (Figure 6.3). This can be looked upon as a challenge for the security of supplies for energy importing nations. The IEA has pointed out that the oil and gas industry must greatly increase its investments in exploration and development to counteract this trend.

Norwegian oil and gas has competitive advantages in a world focused on security of supplies. The Norwegian continental shelf still has large resources and an efficient and flexible network of transportation and processing facilities. In addition, distances are shorter to the major markets in Europe and the USA than from producers in the Middle East.

Rising energy consumption leads to more environmental challenges
The growth in energy consumption gives increased greenhouse gas emissions. If new measures are not implemented to reduce the emissions, the global energy-related CO_2 emissions will increase by more than 50 per cent by 2030, according to estimates from the IEA. The developing nations will be responsible for as much as three-quarters of this increase. According to the UN Climate Panel, a stabilisation of greenhouse gases in the atmosphere will give an increase in the global mean temperature of 2.0-2.4 degrees compared with the pre-industrial level. Such stabilisation will probably require a 50-80 per cent reduction in the global emissions of greenhouse gases from the present level until 2050. This requires

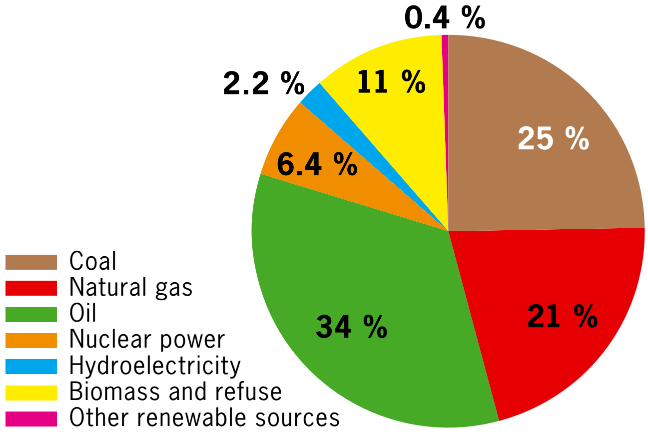


Figure 6.1 World energy consumption apportioned according to energy sources (source: IEA World Energy Outlook 2006)

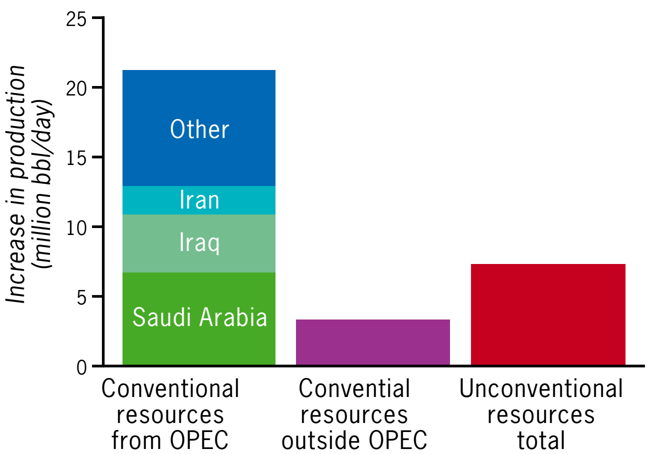


Figure 6.2 Increase in the world oil production over the next 25 years according to the IEA reference scenario (source: IEA World Energy Outlook 2006)

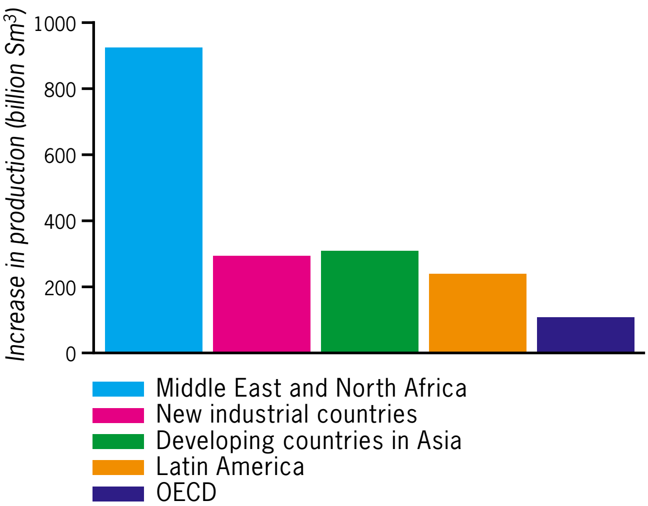


Figure 6.3 Increase in the world gas production over the next 25 years according to the IEA reference scenario (source: IEA World Energy Outlook 2006)

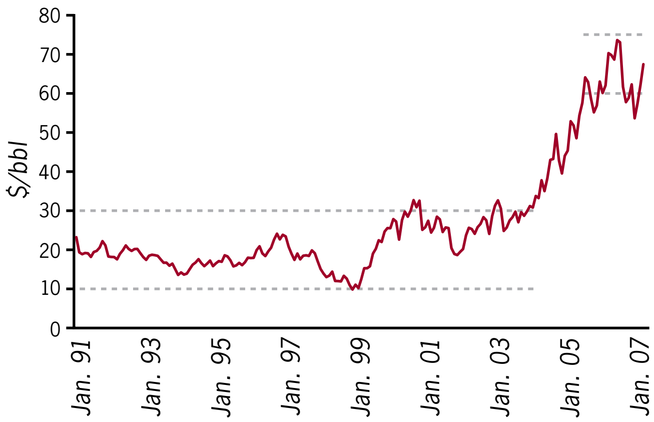


Figure 6.4 Trend in the nominal price of Brent Blend oil (source: BP Statistical Review of World Energy 2006)

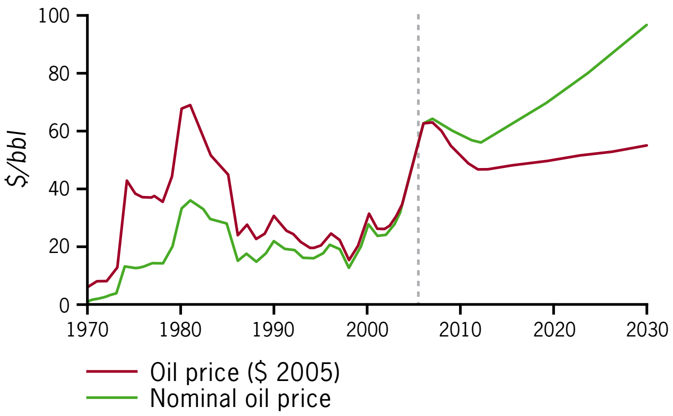


Figure 6.5 Reference scenario for the trend in the price of oil (source: IEA World Energy Outlook 2006)

ambitious international agreements, and the industrial nations must be prepared to take on a substantial responsibility for the global reductions in emissions.

Prices of oil and gas as a driving force

During the 40 years that have passed since petroleum activities started in Norway, the price of oil has swung from less than 3 dollars a barrel to the present level of 60 to 70 dollars a barrel.

The costs on the Norwegian continental shelf are significantly higher than corresponding ones in other oil-producing countries like Saudi Arabia and Iran. For exploration and recovery of oil and gas on the Norwegian continental shelf to be of interest, the prices have to be sufficiently high to more than cover the costs.

The present price of oil is at a historically high level (Figure 6.4). The companies have adjusted their price expectations upwards accordingly. According to the Cambridge Energy Research Association (CERA), the companies now use 40 dollars a barrel as the lower limit to test the robustness of the projects, whereas they recently applied 20 dollars.

The reference scenario presented by the IEA in World Energy Outlook 2006, was based on a slightly rising oil price from 2012 (Figure 6.5). This price trend reflects an expected increase in the market share for a few oil-producing countries and rising production costs outside the OPEC nations. The IEA assumes that in general the gas price will follow the trend in the price of oil since natural gas largely follows the oil price due to the oil-price index in sales contracts and because of considerable competition between different sources of energy in the end-user markets for natural gas. We also base our scenarios on this.

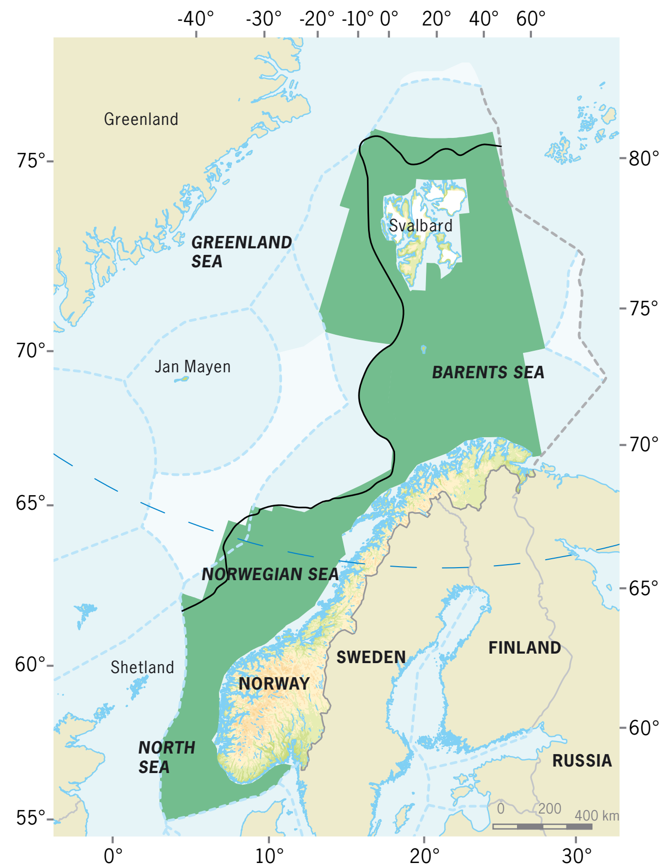
When the price of oil rises, exploration activity usually increases. A high oil price also leads to more developments and the implementation of more measures for improved recovery. At the same time, high prices stimulate more technological development. On the other hand, lower prices will give a reduction in exploration, fewer developments and less effort put into improved recovery and development of technology.

Undiscovered resources as a driving force

The volume of the resources on the Norwegian continental shelf is uncertain. The Petroleum Directorate estimates that between 1.6 and 5.8 billion Sm^3 o.e. of oil, gas, condensate and NGL remain to be found. Their mean value is 3.4 billion Sm^3 o.e. It is also uncertain how much of these resources the industry will gain access to. The NPD estimate presumes that all the green area in figure 6.6 will be opened for oil and gas activity.

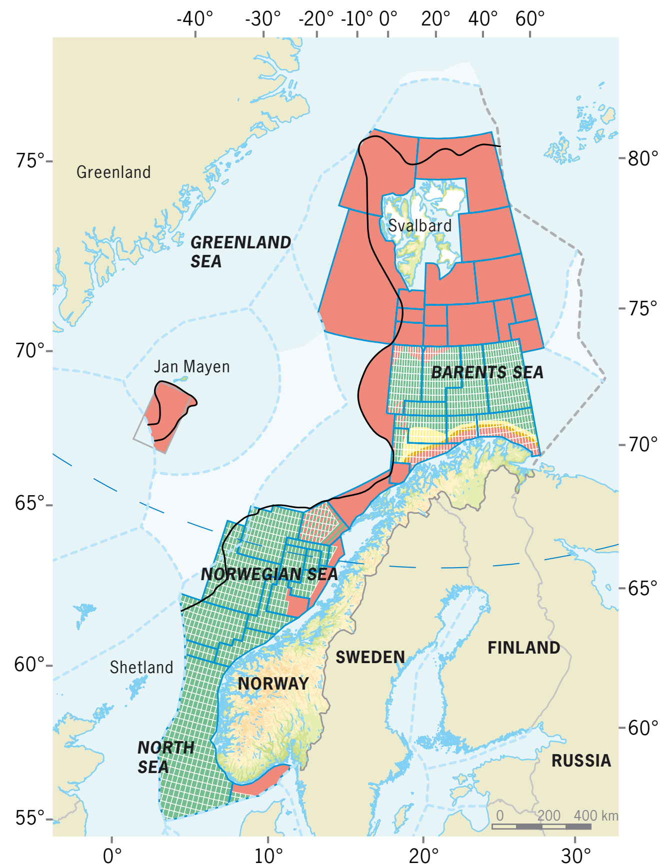
The areas that are now open for exploration are shown in figure 6.7. Large areas have still not been opened; these are shown in red.

The management of the petroleum resources on the Norwegian continental shelf has always been based on knowledge. Norwegian licensing policy has been to open area by area and gradually acquire more knowledge. This exploration strategy is generally called sequential exploration. The largest areas that are still not opened are in the North. The development here will be important for how much acreage will be available for exploration. In addition to concern for the environment and the fisheries, the relationship with Russia will be crucial. Agreement with Russia on the management of the resources in the area with overlapping claims is important for an overall area strategy in the Barents Sea.



Assumed maximum extent of sedimentary rocks that may contain petroleum

Figure 6.6 Areas (in green) which form the basis for the Norwegian Petroleum Directorate's base resource estimate (Some of these areas have not yet been opened for petroleum activity)



Opened for petroleum activity
Not opened for petroleum activity
Activity limited to existing licences
Exploration drilling in reservoirs not permitted between 1 March and 31 August
No petroleum activity will start during the term of the present Parliament
Assumed maximum extent of sedimentary rocks that may contain petroleum

Figure 6.7 Status of petroleum activity on the Norwegian continental shelf

Oil and gas production in the next 40 years – alternative scenarios

Will Norway continue to be a significant exporter of oil and gas in 2046? To cast light on this question, this report describes four possible scenarios for the future. Two key preconditions that have been described earlier are mainly applied here, the trends in the prices of oil and gas and how large a portion of the undiscovered resources will be made accessible for exploration and production (Figure 6.8).

Scenario A: full speed ahead

The first scenario assumes high activity on the Norwegian continental shelf because a large acreage is accessible (Figure 6.9), there is a high discovery rate and environmental concerns place only minor limitations on the activity. The oil and gas prices are lower than in the IEA reference scenario (Figure 6.5). The low prices curb the exploration activity, but the activity level is stimulated again because several large discoveries are made in the Norwegian Sea and the Barents Sea. Production remains high.

Because of a major gas development in the Norwegian Sea, new pipelines are laid to the North Sea. Norway and Russia reach agreement on exploration in the area of overlapping claims in the Barents Sea, and several major gas discoveries are made. In cooperation with Russia, these form the basis for a new LNG terminal on the coast of Finnmark. The northern part of the Barents Sea and the area surrounding Jan Mayen are opened for exploration. A discovery is made off Jan

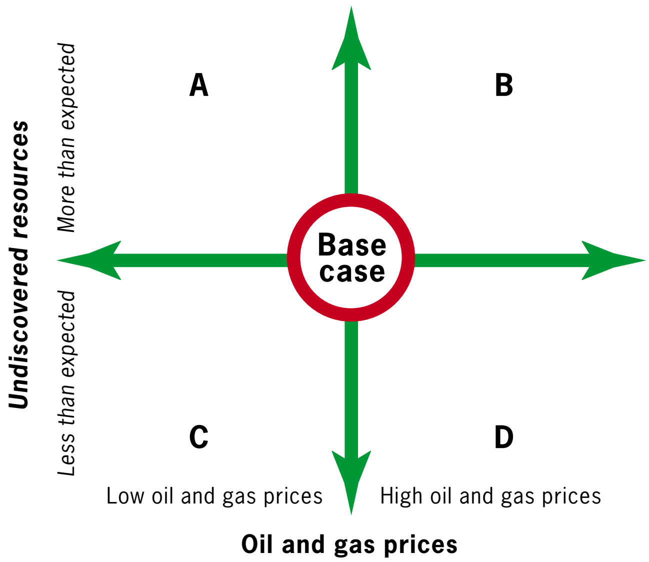
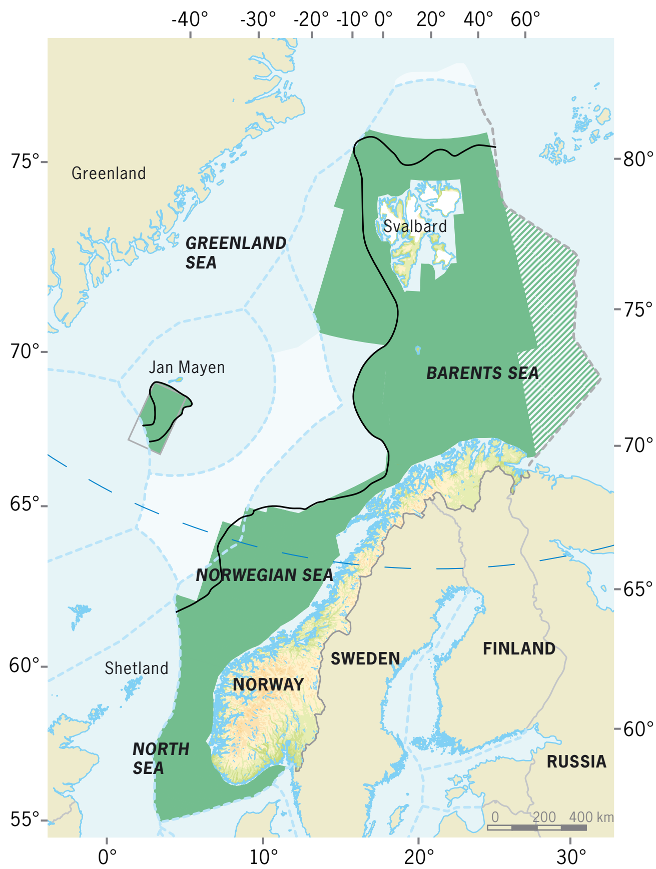


Figure 6.8 The four scenarios compared with variations in the prices of oil and gas and expectations for undiscovered resources



Opened for petroleum activity
Area with overlapping claims
Assumed maximum extent of sedimentary rocks that may contain petroleum

Figure 6.9 Areas (in green) opened for petroleum activity in scenarios A, B and D

Mayen. Late in the period, several large oil and gas discoveries are made in the northern Barents Sea.

Gradually, the northern areas become the pivot for the oil and gas activity, and the Norwegian continental shelf is attractive for the major companies because they gain access to the northern areas. Considerable cooperation is set up between Norway and Russia.

Owing to a relatively low oil price, it is difficult to make CO_2 value chains profitable. The low prices mean that injection for improved oil recovery is not profitable either.

More and larger discoveries than expected mean that production is higher than the extrapolation of the Directorate's long-term forecast (see Chapter 4). Most of the discoveries are gas, and the gas production from the Norwegian continental shelf increases.

Scenario B: technolab

This scenario presumes that much acreage is available (Figure 6.9) and the prices of oil and gas are always higher than the IEA reference scenario (Figure 6.5). The high prices result in high exploration activity and production. Together with stable framework conditions to reduce greenhouse gas emissions, this leads to predictability for investments and accelerated technological development. The Norwegian continental shelf becomes a technological laboratory for dealing with CO_2. This scenario has the highest oil and gas production.

Oil and gas prices are constantly high, leading to increased activity and stimulating technological development. Several major discoveries are made in the Norwegian Sea and the Barents Sea. Because of a major gas development in the Norwegian Sea, new pipelines are laid to the North Sea. Oilfield development takes place in the Barents Sea. Norway and Russia reach agreement on exploration in the area with overlapping claims in the Barents Sea, and several major gas discoveries are made. In cooperation with Russia, these form the basis for a new LNG terminal on the coast of Finnmark. The northern part of the Barents Sea and the area surrounding Jan Mayen are opened for exploration. Discoveries are made off Jan Mayen. Late in the period, several large oil and gas discoveries are made in the northern Barents Sea. The Norwegian continental shelf is very attractive for the major companies because they gain access to the northern regions. Gradually, the northern regions become the pivot for the oil and gas activity in Norway.

The main contributions made by Norway in the struggle against climate change are to supply gas as a replacement for coal, to supply energy generated in an environmentally friendly manner, and to develop and begin to use technology for dealing with CO_2. This makes it possible to continue to focus on and use fossil fuels like coal, oil and gas. High prices for oil and gas, in addition to carbon capture and storage, make injection for enhanced oil recovery profitable.

The Norwegian continental shelf becomes a laboratory for developing technology for the capture, storage and injection of CO_2. Private funding focusing on clean technology invests substantial sums for technological development on the Norwegian continental shelf.

High prices and substantial technological development mean that it eventually becomes profitable to inject CO_2 in coal and gas hydrates to store CO_2 and simultaneously recover gas. A pilot project to produce gas from coal starts in 2025, and in 2035 another one starts to produce gas from gas hydrates from the Norwegian continental shelf. Gas hydrates are attractive for long-term storage of CO_2 because they make the hydrate more stable and result in more natural gas being produced. This offers enormous possibilities. Large quantities of energy are stored in gas hydrates around the world, probably more than the total global resources of oil and gas. There proves to be considerable quantities of gas hydrates on the Norwegian continental shelf.

The petroleum industry becomes attractive to socially minded young people who view the industry as part of the solution to the climate problems and not just one of the causes for them.

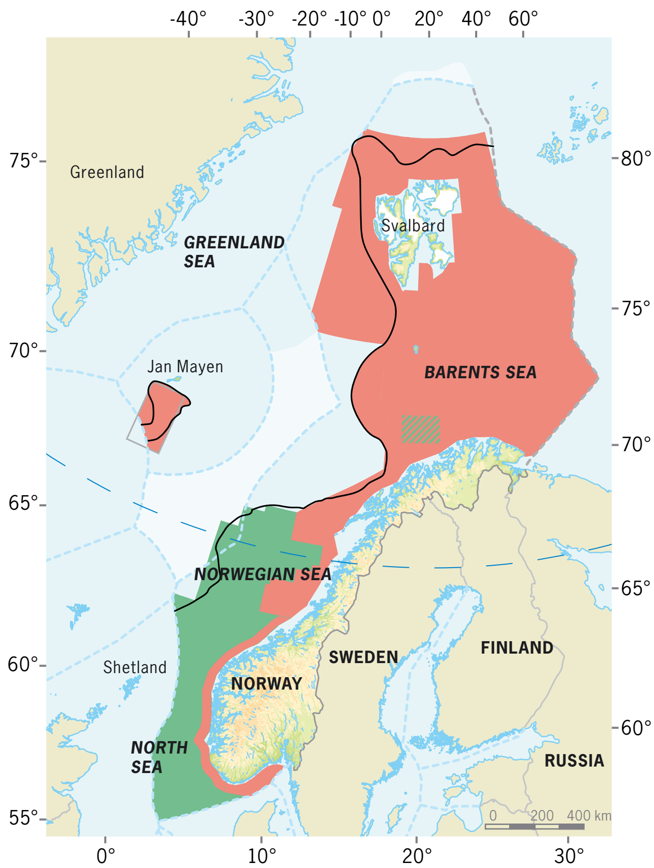
More and larger discoveries than expected, mean that production is higher than the extrapolation of the Directorate's long-term forecast. The use of CO_2 for injection to improve oil recovery results in more oil production on the fields than expected. Injection of CO_2 in coal and gas hydrates towards the end of the period also leads to increased gas production.

Scenario C: sorry, we're closed

This scenario envisages low activity on the Norwegian continental shelf. Norway introduces its own stringent environmental measures because international agreement has not been achieved. This results in reduced access to exploration acreage (Figure 6.10) and stringent demands on emissions. The combined effect is the lowest production of the four scenarios.

Oil and gas prices are comparatively low. Few discoveries are made and exploration declines. Stringent environmental demands mean that no more licensing rounds are announced for the northern areas. The Barents Sea is closed for new activities.

Norway adopts new environmental demands that are significantly stricter than those agreed in other countries. Norway decides to reduce greenhouse gas emissions by 10 per cent from the 1990 level by 2012 and by 30 per cent from the 1990 level by 2020. The majority of this reduction must be implemented within Norway. Some of the production has to be closed down to meet the Kyoto demands for 2008-2012. The companies are not allowed to increase the export of gas either. New sales contracts for gas are not entered into. Stringent demands are placed on carbon capture and storage. It is also required that installations on the Norwegian continental shelf get power from wind power or from land.



Opened for petroleum activity
Not opened for petroleum activity
Assumed maximum extent of sedimentary rocks that may contain petroleum

Figure 6.10 Areas (in green) opened for petroleum activity, and areas (in red) that have not been opened in scenario C

Significantly smaller and fewer discoveries than expected are made because of limitations on available acreage. Moreover, little is achieved in improved oil recovery. The companies gradually begin to leave the Norwegian continental shelf. Production is significantly lower than the extrapolation of the Directorate's long-term forecast.

Scenario D: blood, sweat and tears
In this scenario, the oil and gas prices remain consistently high, giving a great deal of activity. Plenty of acreage is available (Figure 6.9), but the exploration results are disappointing. Higher prices result in more activity, considerable development of technology and efforts to improve oil recovery. The companies find considerably less than expected in the Norwegian Sea and the North Sea, and production on the Norwegian continental shelf is less than expected. Agreement is reached with Russia regarding exploration in the North, but no significant discoveries are made.

The poor exploration results lead to declining interest in the Norwegian continental shelf and many companies decide to pull out, but those which focus on enhanced oil recovery find it worthwhile to remain. The high price of oil gives incentives for development of CO_2 injection technology, creating optimism and a willingness to try out new solutions.

It proves to be very difficult to recover gas from coal. The gas hydrate deposits are considerably smaller than assumed and they will scarcely be commercially viable in the foreseeable future. Further research is postponed indefinitely.

Few and smaller discoveries mean that the production in this scenario is less than the extrapolation of the Directorate's long-term forecast (Chapter 4). Carbon capture and injection raise the recovery factor and help to give higher oil production on several fields.

Summary
The world and the surroundings change. It is impossible to foresee the future with certainty. In this report, the Petroleum Directorate has presented four possible scenarios for future developments which will help to gain an understanding of the uncertainty in the estimates of the total resources.

The scenarios do not cover all the potential courses of events. Clearly, other factors than those described here may influence the development and these may be political, economic or technological. One example would be if new and easily available sources of energy were rapidly developed.

Figure 6.11 shows the production on the Norwegian continental shelf according to these four scenarios. The figure also shows the production according to the Petroleum Directorate's base estimate. In scenarios A and B, the production in 2046 is substantial, approximately as it was in the 1990s, whereas in scenarios C and D, the production in 2046 will be considerably lower, on a par with that in the early 1980s.

The purpose of the scenarios is not to describe every possible course of events, but to help to pave the way for a new manner of thinking, create preparation for action and be able to function as an aid to test measures and strategies. This can hopefully help to ensure that essential and far-sighted actions are taken so that Norway remains an important producer and exporter of oil and gas in 2046 too.

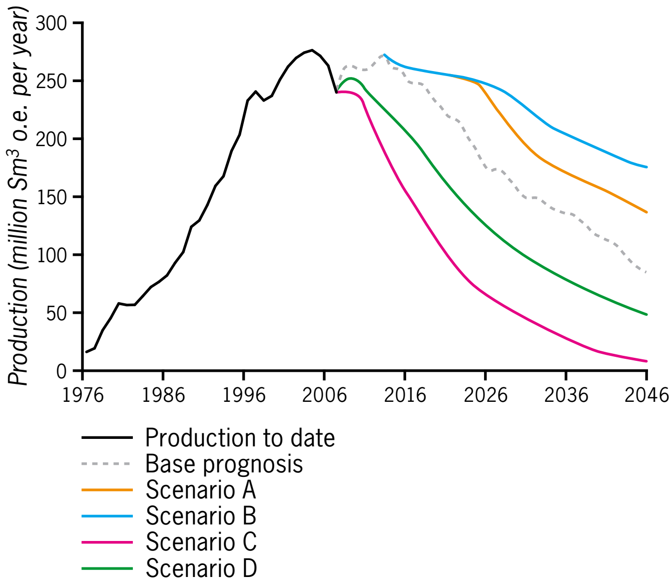


Figure 6.11. Scenarios for the total production of petroleum (liquid and gas) in Norway compared with the Petroleum Directorate's base prognosis

Appendix 1: The plays

Introduction

This appendix describes the various plays in the three areas comprising the Norwegian continental shelf: the North Sea, the Norwegian Sea and the Barents Sea. The plays are grouped according to geological level and their distribution is shown on a number of maps. Some of the plays may stretch into British, Danish or Russian sectors. The descriptions and the resource estimates in this report only apply to the Norwegian sector. The area with overlapping claims in the Barents Sea is not included in this analysis either.

A play is a geographically delimited area where several geological factors occur together so that producible petroleum can be proven. These factors are: 1) Reservoir rock, which is a porous rock where petroleum can be preserved. Reservoir rocks in a specific play will belong at a given lithostratigraphical level. 2) Trap, which is an impermeable rock or a geological structure enveloping the reservoir rock so that the petroleum is retained and accumulates in the reservoir. The trap must be formed before the petroleum stops entering the reservoir. 3) Source rock, which is shale, limestone or coal containing organic material that can be converted into petroleum. The source rock must also be mature, that is to say the temperature and pressure must be appropriate for petroleum actually to be formed, and there must be a migration path enabling the petroleum to move from the source rock to the reservoir rock.

The plays in the North Sea

The North Sea is the area south of 62° N. In this context, the name North Sea is only used for the Norwegian part. The subsidence of the Central Trough and the Viking Graben gave space for large thicknesses of sediment to be deposited from the Carboniferous to the present day.

Exploration has been taking place in the North Sea for over 40 years and most of the large Norwegian fields are situated here. This is a mature part of the continental shelf and most of the plays are confirmed. The Norwegian Petroleum Directorate estimates that 1175 million Sm^3 of liquid and gas remain to be found in the North Sea (Table 5.1). This comprises 35 per cent of the total undiscovered resources. In other words, there is still a great deal left to be found in the North Sea, but future discoveries are expected to be small.

The most important source rocks in the North Sea are shales in the Upper Jurassic. Thick beds of shale rich in organic matter were deposited over most of the North Sea area in late Jurassic time. In the Norwegian sector, these belong in the Draupne Formation in the Viking Group or the Mandal Formation in the Tyne Group. Middle Jurassic coal is another important source rock, mainly for gas. In the southern part of the Norwegian sector, this coal is found in the Bryne Formation in the Vestland Group. In the northern part of the North Sea, these coal seams are found in the Brent Group. Source rocks may possibly be found in Carboniferous or older strata in the southern part of the North Sea, but these have so far not been confirmed.

For long periods prior to the Triassic, the North Sea area was dry land, and sandstones and conglomerates were deposited in rivers, lakes and desert plains. The reservoir in the Embla field consists of such old rocks. A great deal of uncertainty attaches to the prospectivity of these sediments. In many places, they are so deeply buried that little or no porosity is left in the rock. So far, discoveries have only been made where the old reservoir is so situated that oil and gas from much younger source rocks are able to migrate in.

Level	Reservoir rock	Confirmed plays	Uncom-firmed plays	Total
Post-palaeocene	Sandstone	3	1	4
Palaeocene	Limestone and sandstone	4	2	6
Create-ceous	Limestone and sandstone	3	1	4
Upper Jurassic	Sandstone	3		3
Trias to Middle Jurassic	Sandstone	4	2	6
Pre-Triassic	Sandstone	1	1	2
Total		***18***	***7***	***25***

Table A.1 Confirmed and unconfirmed plays in the North Sea

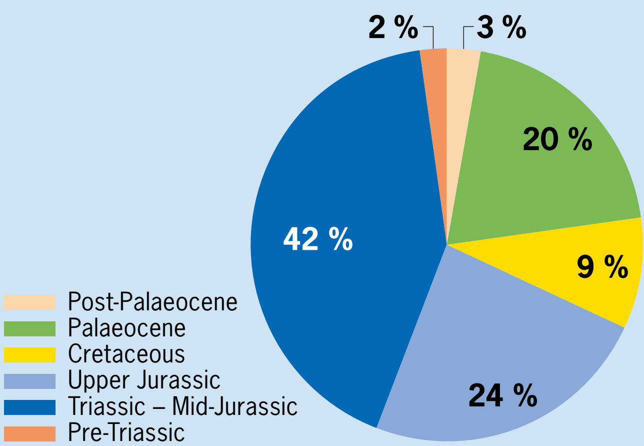


Figure A.1 Stratigraphical distribution of the undiscovered resources in the North Sea

From Triassic to Middle Jurassic time, the North Sea area was gradually inundated by the sea. Thick beds of sandstone were deposited, initially on alluvial plains and later in the delta that prograded northwards. The Brent Group consists mainly of deltaic sediments which are now good reservoirs for oil and gas. The Viking Graben opened at the end of the Jurassic, and large fault blocks formed along it. These rotated along the faults and formed large structural traps. Statfjord, Snorre, Gullfaks and Visund are some of the major fields whose reservoirs lie in such fault blocks.

In Late Jurassic time, marine conditions prevailed over large parts of the North Sea area. Shallow-marine sandstones were initially deposited in many places. The Viking Group and the Vestland Group contain such sandstones that have good reservoir properties. The thickest beds are found near the Norwegian coast and form the reservoir in the Troll field, for example. Shales were deposited above these sandy beds, and they became the predominant source rock for oil in the North Sea.

Throughout the Cretaceous and part way into the Palaeocene, the sea in the North Sea area was dominated by tremendous numbers of microscopic algae with calcareous shells. When the algae died, the shells sank to the bottom and by degrees formed thick beds. These limestone deposits, called chalk, form the reservoirs in large oilfields like Ekofisk and Valhall.

Land uplift and erosion around the North Sea basin led to sand once more being carried into the basin. This sand was transported far into the basin by turbidity currents and was deposited on the seabed as deep-marine fans. The oil in the fields Grane and Balder, including Ringhorne, is in sandstone reservoirs which formed in this manner. Sand was deposited on the seabed in large parts of the North Sea area in the Eocene and Oligocene, too. These deposits form the reservoir in the Frigg field.

Twenty-five plays have been defined in the North Sea, and 18 of these are confirmed (Table A.1). The greatest potential is in plays of Triassic to Middle Jurassic age (Figure A.1). The lithostratigraphy in the North Sea area is illustrated in figure A.2. The most important structural elements are shown in the play maps (Figures A.3 - A.8).

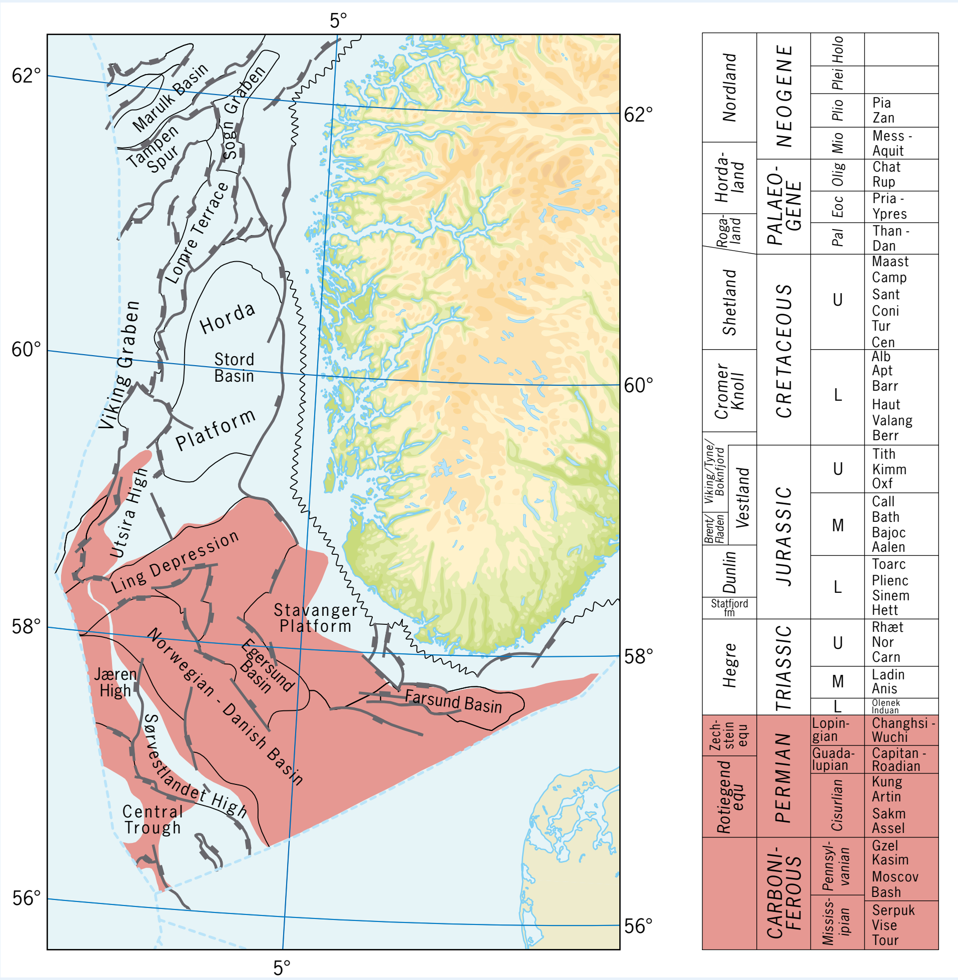
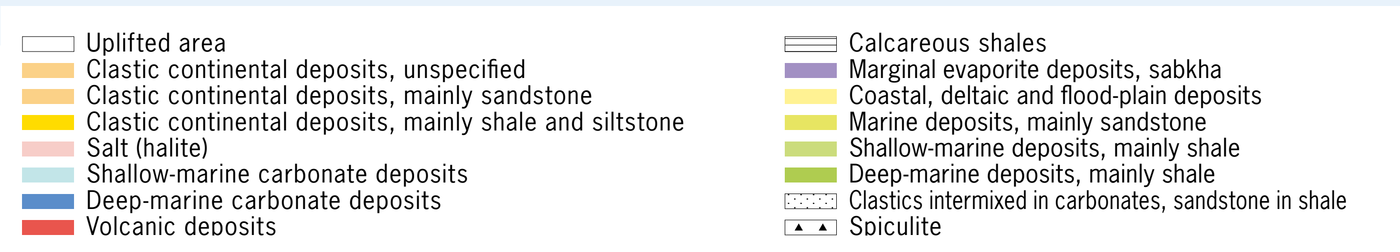


Figure A.3 Pre-Triassic plays in the North Sea



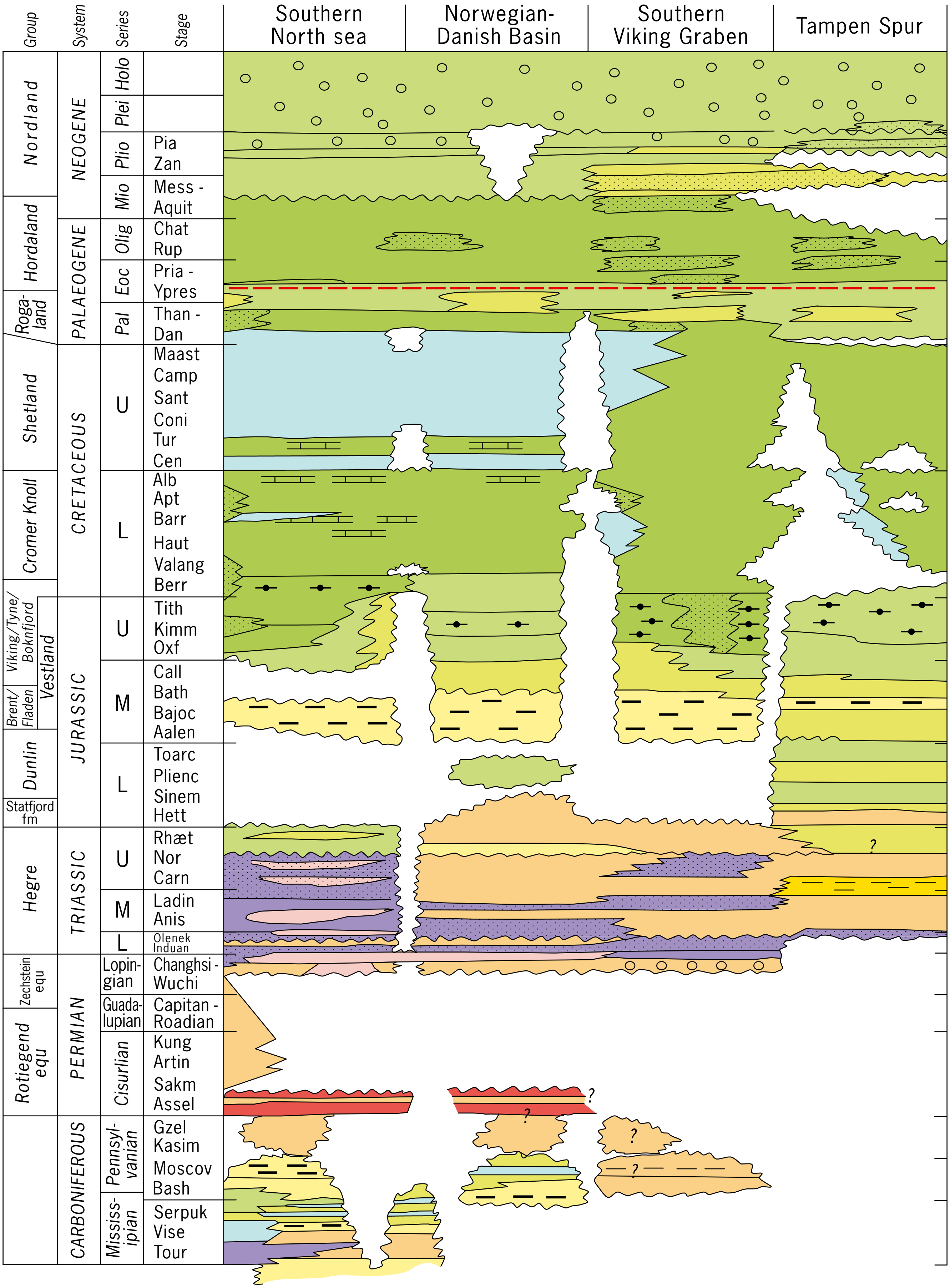


Figure A.2 The lithostratigraphy in the North Sea

Pre-Triassic plays

There is one confirmed and one unconfirmed play with reservoirs from Palaeozoic time in the southernmost part of the North Sea (Figure A.3). The westernmost play lies deepest in the succession in the Central Trough. Because the rocks have been uplifted in several places as a result of the structural development, the old reservoirs have received hydrocarbons from the well-known Upper Jurassic source rocks. The Embla oilfield belongs to this play, and some other smaller discoveries have also been made. The reservoirs consist of sandstones and conglomerates from the Devonian, Carboniferous and Permian.

There are also Palaeozoic sandstones further east, in the Norwegian-Danish Basin, and these belong to the unconfirmed play. If they are to be able to be filled with hydrocarbons, migration must take place from so far unknown, older source rocks. In 2006, the large Kogge prospect, which was in the Egersund Basin and belonged to this play, was drilled, but no discovery was made. The resource estimate for the play was low prior to that, and has now been further reduced. The traps in these plays will be structural traps in rotated fault blocks.

Triassic to Middle Jurassic plays

These plays (Figure A.4) include some of the largest oilfields in the North Sea. The largest play is found over large parts of the northern North Sea, in the Viking Graben, the Sogn Graben, the Møre Basin, the Tampen Spur and the Horda Platform. The large Statfjord, Gullfaks, Oseberg, Snorre and Visund fields are situated here. Sandstones in the large Brent delta constitute the best reservoirs. Older sandstones in the Hegre Group and the Statfjord Formation are also important reservoir rocks. Even after this play has been explored for nearly 40 years, and many large discoveries have been made, the Norwegian Petroleum Directorate believes that more than a quarter of the undiscovered resources in the North Sea can still be found here.

A play has been defined in the southern part of the Viking Graben, above the Utsira and Jæren Highs and in the Ling Depression. The reservoirs are in the Sleipner and Hugin Formations in the Vestland Group and in the Skagerrak Formation in the Hegre Group. Parts of the Statfjord Formation are also present. Sleipner Vest and Sleipner Øst have their reservoirs in this play.

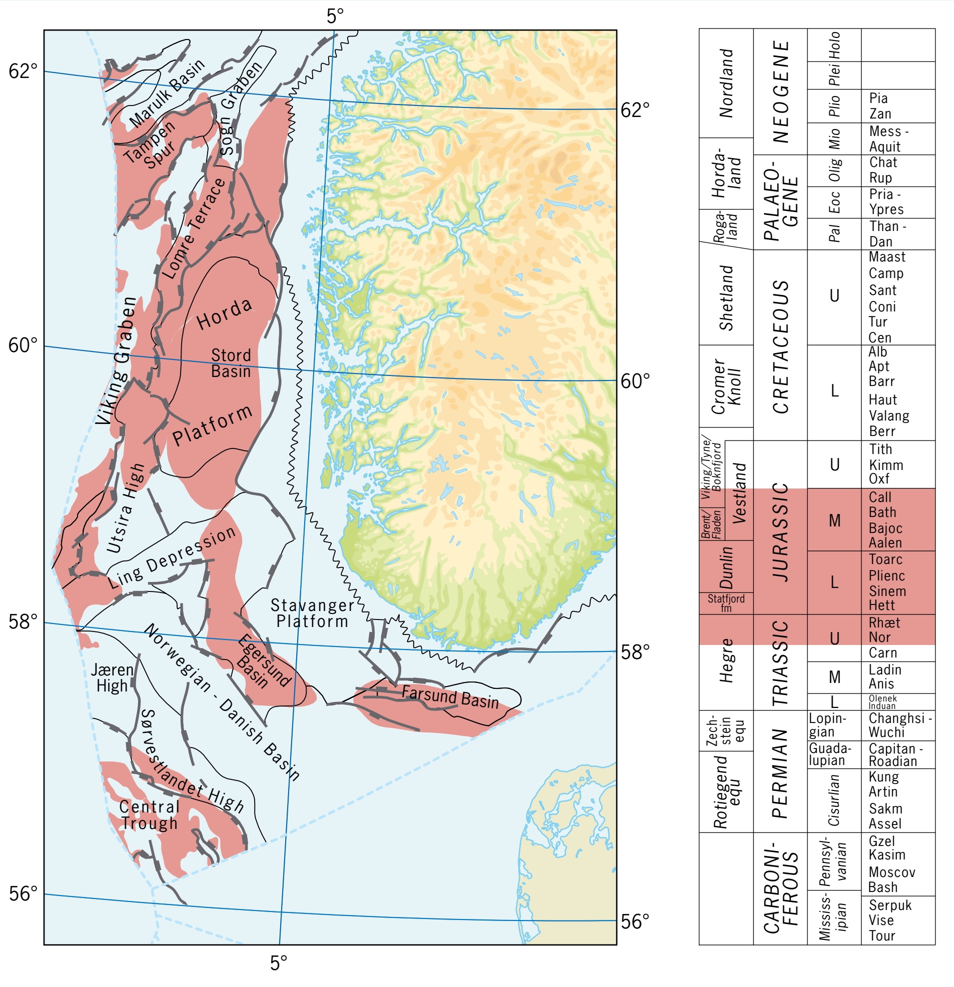


Figure A.4 Triassic to Middle Jurassic plays in the North Sea

The southern part of the North Sea has a play with reservoir rocks belonging to the Gassum and Skagerrak Formations in the Hegre Group and the Bryne Formation in the Vestland Group. The Trym field is in this play. The fourth confirmed play is in the Egersund Basin; it was confirmed by the discovery of the Yme field.

The North Sea also has two unconfirmed plays at this level, one in the Stord Basin and another in the Farsund Basin. No mature source rocks have been proven in these areas. Several dry wells have been drilled in the Stord Basin. No wells have so far been drilled in the Farsund Basin.

The most important type of trap for these plays is structural traps in rotated fault blocks. Future discoveries are expected to be made in this type of trap, but traps that are more dependent on stratigraphical closures are also possible.

Upper Jurassic plays

Sandstones of Late Jurassic age are found in three parts of the North Sea (Figure A.5) and form the basis for three plays, all of which are confirmed. The thickest sandstones are found near the coast on the Horda Platform and further out in the Stord Basin, the Sogn Graben and the northern part of the Viking Graben. These sandstones are the Heather, Krossfjord, Fensfjord and Sognefjord Formations, all of which belong in the Viking Group. They form the reservoir in the large Troll field, for example.

Late Jurassic sandstones are also found further west, on the Tampen Spur. These are often erosion products of older sandstones which were eroded when the Viking Graben opened, and rotated fault blocks formed parallel to the graben. The sandstones belong to the Heather and Draupne Formations in the Viking Group, and several discoveries have been made. The reservoir in the Statfjord Nord field belongs to this play.

In the southern North Sea, the Ula Formation in the Vestland Group, the Eldfisk Formation in the Tyne Group and the sandstones in the Draupne, Heather and Brae Formations in the Viking Group were deposited at this time. This play has been confirmed by a number of discoveries. The Ula, Gyda and Tambar fields have reservoirs in this play. Recent mapping has shown that the prospects are in general smaller than previously assumed, and the resource estimate for this play has been adjusted downwards somewhat.

The traps in these plays are both pure structural traps and combined structural and stratigraphical traps. The source rock for all the plays is Upper Jurassic shale which, in many cases, is in direct contact with the reservoirs.

Cretaceous plays

The Cretaceous plays have limestone and sandstone as reservoir rocks. Four plays are defined (Figure A.6), and three of them are confirmed.

The southernmost part of the North Sea has thick, porous carbonate beds in the Hod, Tor and Ekofisk Formations in the Shetland Group and the Vidar Formation in the Rogaland Group. These form the reservoirs in several important North Sea oilfields, such as Ekofisk and Valhall. Based on the reservoir properties, it is appropriate to divide the area into two plays.

Wells drilled on the Utsira High, somewhat further north, have also shown carbonate beds, but no discoveries were made in these, and this play is regarded as unconfirmed. Adequate reservoir properties have not been proven either, but seismic anomalies indicate that areas that have higher porosity and a possibility for producible hydrocarbons may be found there.

The fourth play is located in the northern part of the North Sea. The reservoir rock is marine sandstone deposited in fans. The play has been confirmed by the discovery, 35/3-2 Agat.

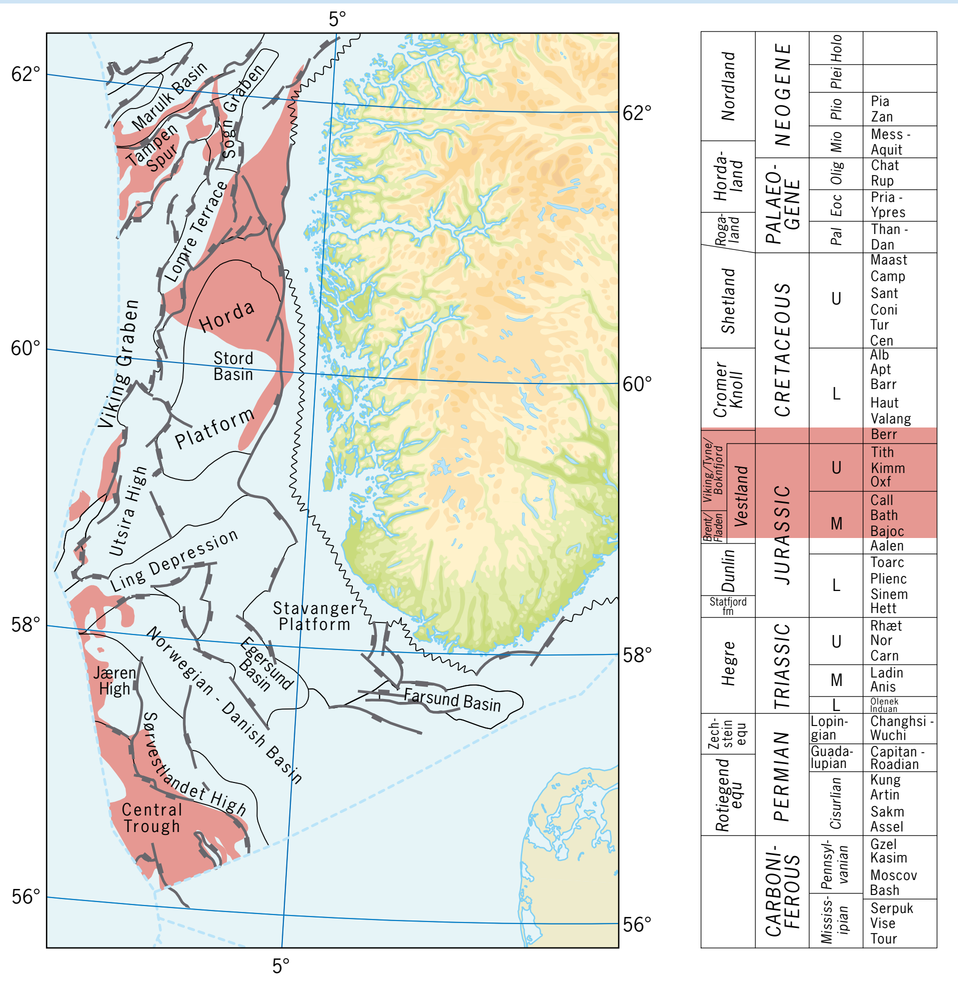


Figure A.5 Upper Jurassic plays in the North Sea

Palaeocene plays

Marine sand was deposited over large parts of the North Sea area in the Palaeocene. Six plays have been defined (Figure A.7), and four are confirmed. The largest play has reservoirs in the Ty, Heimdal, Hermod and intra Balder Formations in the Rogaland Group and has been confirmed in several fields, including Heimdal, Balder, Jotun and Grane. These sandstones were deposited as deep-marine fans of sand from the west and extend onto the Norwegian continental shelf from the British sector. The NPD estimates that about 20 per cent of the undiscovered liquid resources in the North Sea are in this play. Based on the results of recent drilling, the resource figures have been adjusted somewhat since the previous analysis. The volumes of undiscovered liquids have been reduced, and the figures for undiscovered gas have been raised somewhat.

Another play is found in the Central Trough and parts of the Jæren High. It has reservoirs in the Maureen, Andrew, Fiskebank and Forties Formations in the Rogaland Group. The play has been confirmed in the British sector and in some small discoveries in the Norwegian sector in the Central Trough.

Sandstones in the Sele and Lista Formations in the Rogaland Group form a third play on the border to the Danish continental shelf. It has been confirmed in the Siri and Nini fields in Denmark.

Corresponding sandstones are also found somewhat further north, in the Egersund Basin, the Åsta Graben and on the Sørvestlandet High. So far, no discoveries have been made in this play, and it is therefore unconfirmed.

Sandstones in the Lista Formation form two plays in the northern part of the North Sea. Discoveries in the British sector have confirmed a play on the western part of the Tampen Spur. The other play is situated further east, such as on the northern part of the Horda Platform and over the Sogne Graben. No discoveries have been made here, and the play is therefore unconfirmed.

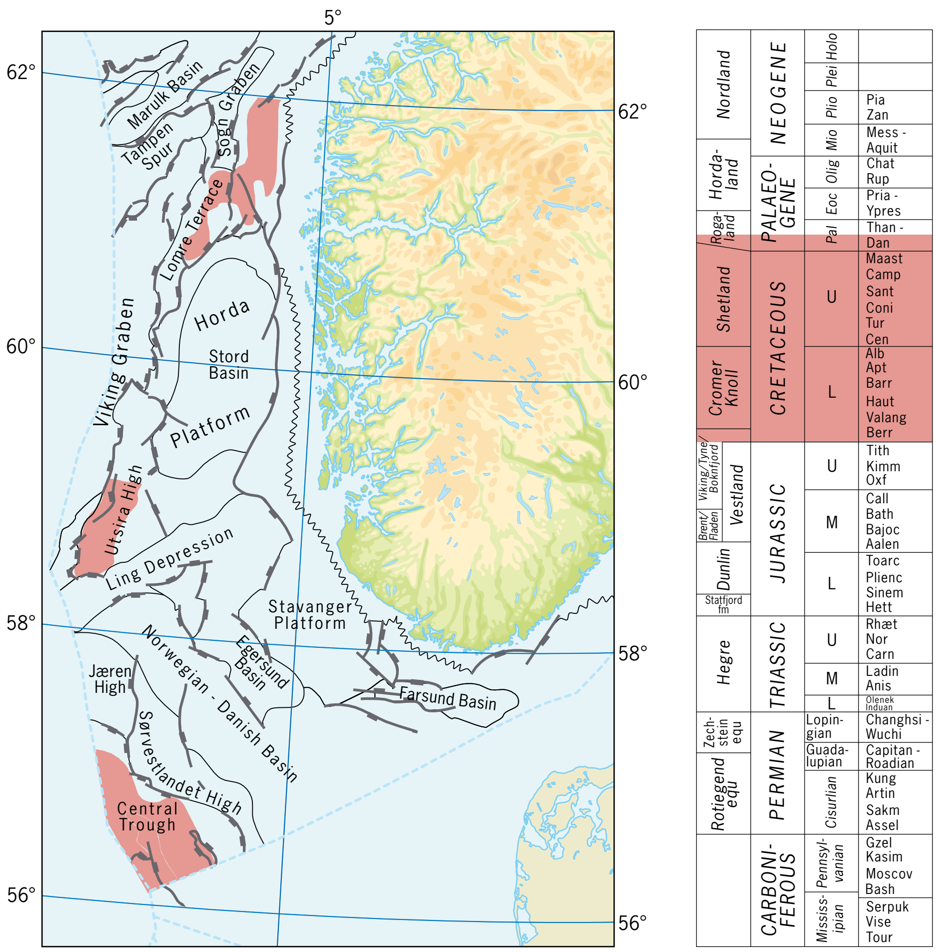


Figure A.6 Cretaceous plays in the North Sea

The youngest plays

Four plays have been defined in the uppermost beds in the North Sea (Figure A.8). These were deposited in the Eocene, Oligocene, and Miocene, and three of them are confirmed.

The Frigg Formation in the Hordaland Group forms one of the plays in the Viking Graben and the western part of the Horda Platform. This play has been confirmed i. a. by the Frigg field.

The Grid Formation, also part of the Hordaland Group, was deposited further south, in the direction of the Utsira High. The play is confirmed by discoveries in both the Norwegian and the British sectors.

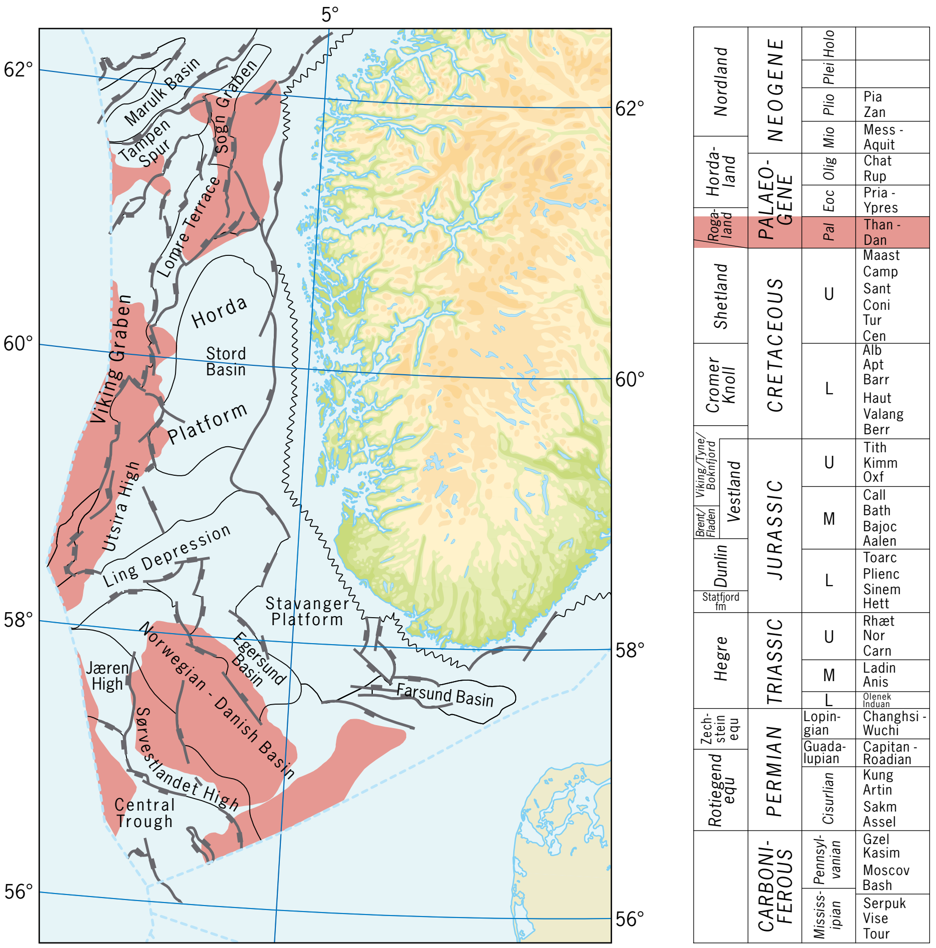


Figure A.7 Palaeocene plays in the North Sea

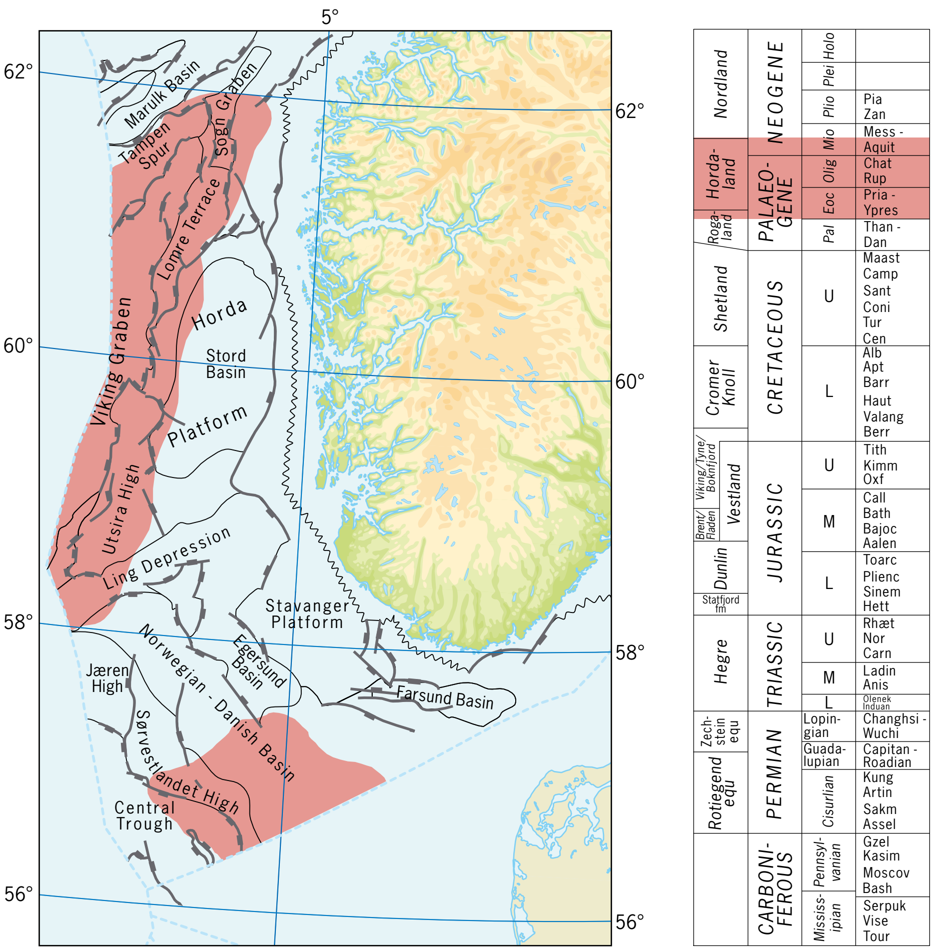


Figure A.8 The youngest plays in the North Sea

The third confirmed play is found in the Norwegian-Danish Basin, the Åsta Graben and on the Sørvest-landet High, and has sand-stone reservoirs in the Grid and Vade Formations in the Hordaland Group. The play is confirmed on the Danish continental shelf.

Sandstones belonging to the Skade and Vade Formations in the Hordaland Group and the Utsira Formation in the Nordland Group are found over large parts of the North Sea. They have been recog-nised in many wells from the Ling Depression in the south to the Sogne Graben in the north. No discoveries have yet been made in these beds. Many of the prospects are dependent upon migra-tion of hydrocarbons over large distances. There is also a considerable risk that the oil in these shallow beds will be of poor quality due to bacteria and other organ-isms (biodegradation).

A gas discovery was made in 2005 in Pliocene sandstones in block 35/2 in the Peon prospect (35/2-1), only 165 metres below the seabed. This new play has still not been fully evaluated and mapped.

Uplifted area
Clastic continental deposits, unspecified
Clastic continental deposits, mainly sandstone
Clastic continental deposits, mainly shale and siltstone
Salt (halite)
Shallow-marine carbonate deposits
Deep-marine carbonate deposits
Volcanic deposits
Calcareous shales
Marginal evaporite deposits, sabkha
Coastal, deltaic and flood-plain deposits
Marine deposits, mainly sandstone
Shallow-marine deposits, mainly shale
Deep-marine deposits, mainly shale
Clastics intermixed in carbonates, sandstone in shale
Spiculite

The plays in the Norwegian Sea

The Norwegian Sea extends from 62˚ N to approximately 69˚ 30′ N, and includes areas with depths of up to several thousand metres. Based on the terms of the Law of the Sea Convention, Norway has handed over its submission of rights to appreciable areas in the deep ocean beyond the 200 nautical mile boundary (Figure 1.1). This documentation is being considered by the UN Continental Shelf Commission. The Norwegian Sea was opened for exploration in 1980, when a limited number of blocks on the Halten Bank were announced in the fifth licensing round.

Apart from the oldest phase, the geological development in the Norwegian Sea differs from that in the North Sea and the Barents Sea. The oldest phase, up to the Cretaceous Period, is marked by extension and subsidence. This led to the break-up of the ancient continent at the end of the Jurassic. Continental and, later, marine sediments were deposited in this phase, building up, in places considerable, thicknesses of sand. Most of the major discoveries have been made in traps formed by fault blocks that contain thick piles of sediment that slid out and were tilted in a basin which slowly became wider and deeper. More fine-grained sediments were deposited above the blocks and sealed these so that the oil and gas, which formed later, are preserved.

As the Cretaceous Period began, the Earth's crust cooled, leading to subsidence of the basin. Thick beds of fine-grained and locally somewhat calcareous sediments were deposited. In some places, the Cretaceous sediments reach a thickness of seven kilometres. Because the North American Plate was moving, the outer part of the Vøring Marginal High was uplifted in mid-Cretaceous time. This phase resulted in the deposition of sandy beds over large parts of the basin (the Lysing Formation). Later subsidence brought further deposition of thick layers of sediment. Well 6302/6-1 (the Tulipan prospect) in the western part of the Møre Basin was drilled in 2005 through chalky limestone in both the Upper Cretaceous and the Palaeocene. This is the same type of rock that forms the reservoirs in the chalk fields in the Ekofisk area in the southern North Sea.

The break-up of the area between Greenland and Norway increased in the Palaeocene. Volcanic rocks forced their way up through the thin crust and formed a new sea floor between the two continents. In the first phase, thick layers of volcanic rocks formed on the western margin of the basin, and they now prevent the signals used to acquire seismic data from penetrating to the underlying strata. It is therefore uncertain what underlies these layers. The plate movements led to parts of the area being uplifted and eroded in the Palaeocene. Sand fans were deposited in the basin from both the west (Greenland) and the east (Norway). It is difficult to map the Cretaceous – Palaeocene boundary in central and western parts of the Vøring Basin because sedimentation was for the most part continuous, with little variation in the type of sediment and without clear

Level	Reservoir rock	Confirmed plays	Unconfirmed plays	Total
Post-Palaeocene	Sandstone, volcanic rocks		2	2
Palaeocene	Sandstone	2	1	3
Upper Cretaceous	Sandstone	4	1	5
Lower Createceous	Sandstone	1	1	2
Upper Jurassic	Sandstone	1	1	2
Upper Triassic to Middle Jurassic	Sandstone	1	2	3
Palaeozoic	Sandstone		3	3
Total		***9***	***11***	***20***

Table A.2 Confirmed and unconfirmed plays in the Norwegian Sea

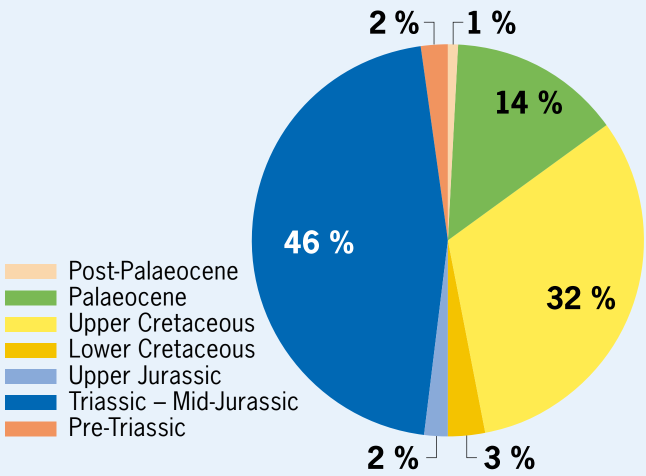


Figure A.9 Stratigraphical distribution of the undiscovered resources in the Norwegian Sea

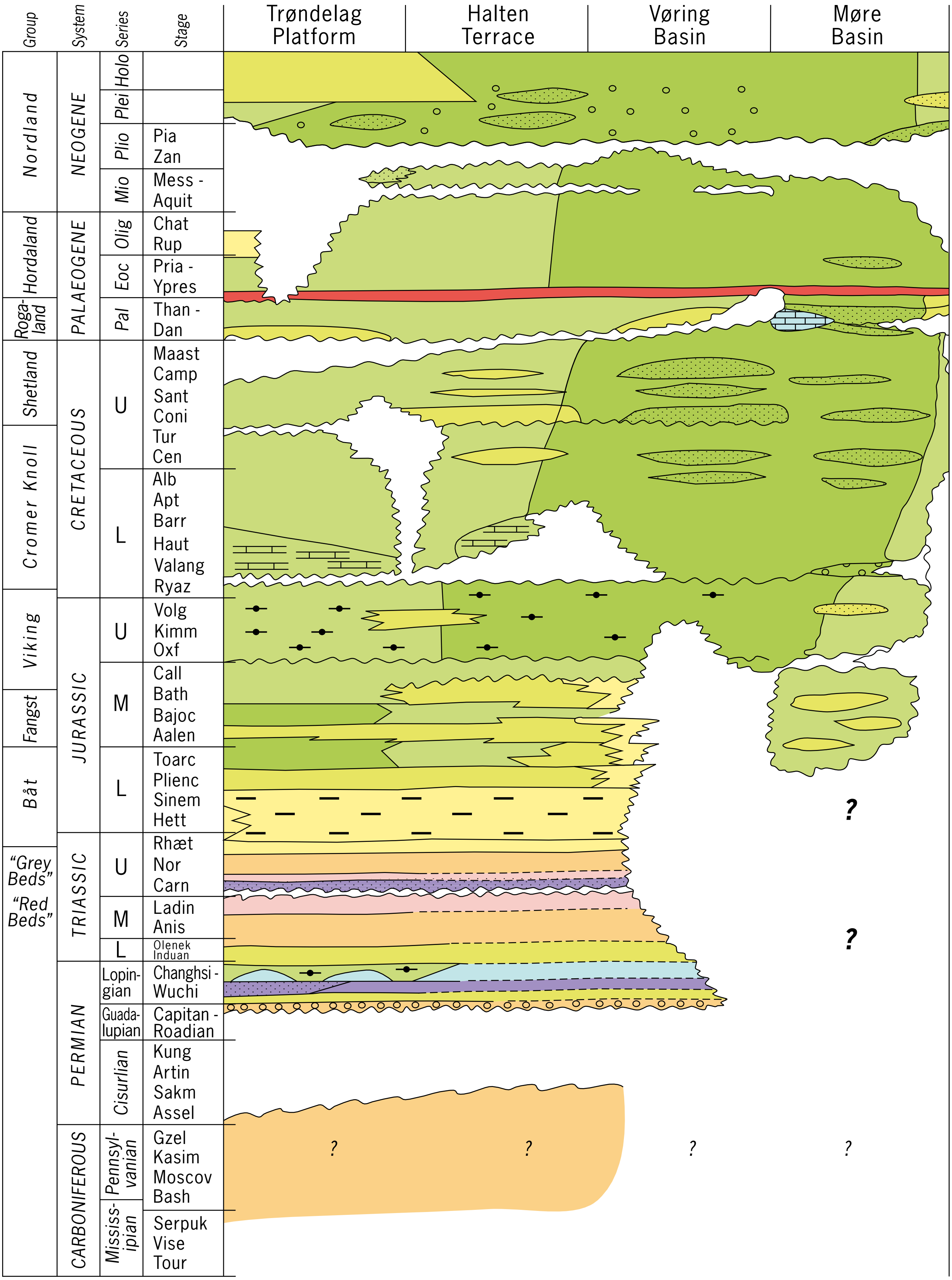


Figure A.10 The lithostratigraphy in the Norwegian Sea breaks in the sequence. There are therefore no obvious seismic indicators to aid the mapping. Precise dating of drill cores is also difficult because erosion of older sediments has led to a mixing of fossils from the Cretaceous and the Cenozoic. Recent investigations, in part performed through the Norwegian Petroleum Directorate, show that the Cretaceous-Palaeocene boundary must be placed considerably deeper in the outer part of the basin than previously assumed.

The Directorate has defined 20 plays in the Norwegian Sea, and 9 are confirmed (Table A.2). The reservoir rocks are sandstones formed in a variety of sedimentary settings in various geological periods. The estimate for the undiscovered resources in the Norwegian Sea is 370 million Sm³ o.e. of liquid and 825 billion Sm³ of gas (Table 5.1). This amounts to 35 per cent of the total undiscovered resources. The greatest potential is found in plays that are defined in Upper Triassic to Upper Jurassic rocks (Figure A.9). Plays in Cretaceous rocks also have a high potential. The lithostratigraphy in the Norwegian Sea is illustrated in figure A.10. The most important structural elements are shown in the play maps (Figures A.11 - A.18).

Palaeozoic plays in the eastern part of the Norwegian Sea

Two plays are defined in Palaeozoic strata in the eastern part of the Norwegian Sea. These lie near land in the Helgeland Basin, the Frøya Basin and the Nordland Ridge off the coast of Trøndelag and southern and central Nordland, and in the Ribban Basin and the Utrøst Ridge off Lofoten and Vesterålen (Figure A.11).

These plays are assumed to have reservoirs in sandstone that was originally deposited on land as alluvial fans and fluvial deposits, and also as deltas and shallow-marine deposits. Shallow-water limestone deposits may also occur.

The plays have not been confirmed, but are defined on the basis of sediments that have been found in shallow wells near land and by seismic studies.

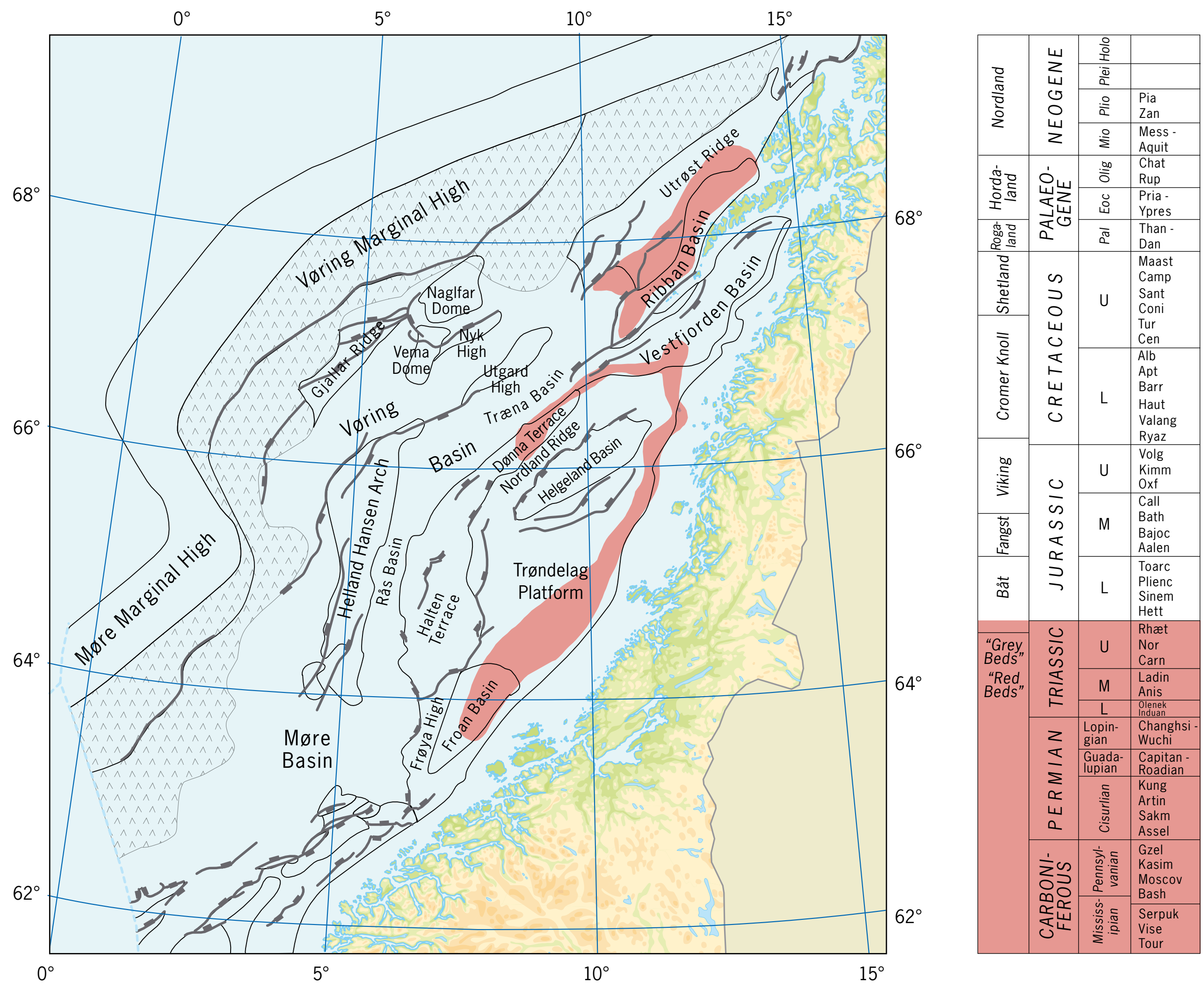


Figure A.11 Palaeozoic plays in the eastern part of the Norwegian Sea

Play beneath the basalt on the Vøring and Møre Marginal Highs

This play is partly defined on the basis of drilling results and deposits that are found in East Greenland. Since Norway and East Greenland comprised the eastern and western margins, respectively, of the same sedimentation basin during the Palaeozoic, it is assumed that the same types of sediment were deposited on both sides.

Basalt, which was emplaced in the Palaeocene, prevents seismic signals from penetrating deeper. It is therefore impossible to map any traps beneath these lavas. Gravity measurements and seismic data from the Møre and Vøring Basins, however, indicate the presence of an underlying ridge of older rocks. It is therefore possible that sediments from any time between the Permian and the Jurassic, inclusive, have been deposited. Research is currently being done to find methods of improving the seismic resolution beneath the lava.

It is also uncertain whether there are source rocks in this area. The Spekk Formation in the Viking Group, which is the source for the discoveries on the Halten Terrace, may not have been deposited here, or it has been eroded from parts of the area due to later tectonic movements in the Cretaceous and the Cenozoic.

The play assumes that the Spekk Formation is present and mature along the eastern part of the Vøring Marginal High and that petroleum can migrate up along this. Other possible source rocks may be coal and organic-rich shales in the Åre Formation in the Båt Group in the Upper Triassic to Lower Jurassic. This has been found on the Halten Terrace. A third possibility is an equivalent unit to the Ravnefjell Formation, which is a source rock in East Greenland. It could also be that source rocks were deposited in the deep Vøring Basin in the Cretaceous. This possibility is supported by analyses of the oil in the Ormen Lange field, which show that one or more Cretaceous source rocks may be present.

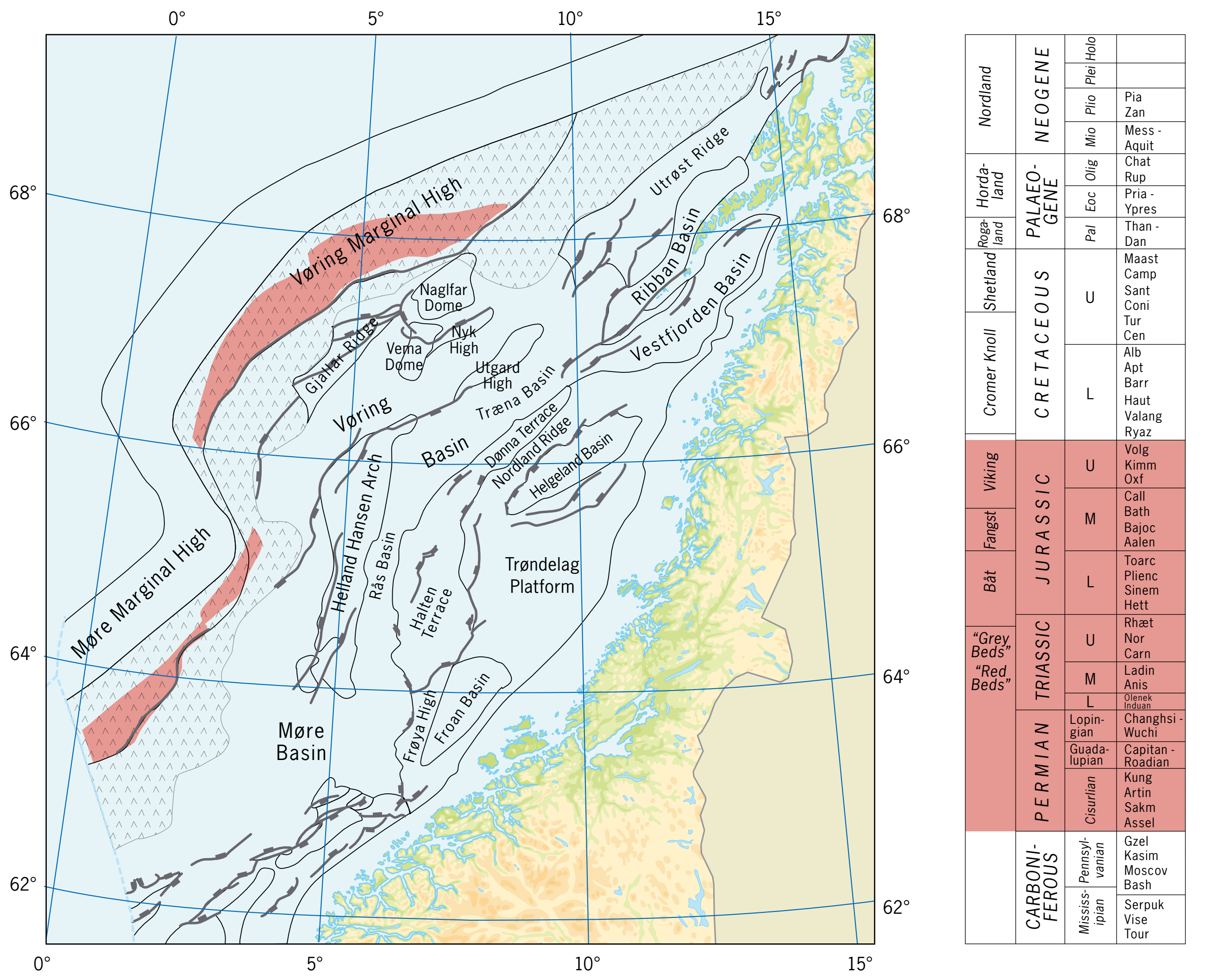


Figure A.12 Play beneath the basalt in the Norwegian Sea

Great uncertainty is attached to this play, but if it is confirmed, it may mean that the same type of play can be defined with greater certainty in other areas, too. The Directorate believes that research drilling through these basalts may reduce several of the major uncertainties.

Plays in the Upper Triassic to Middle Jurassic

These plays are spread over three main areas (Figure A.13). The largest play is confirmed, and is located on the Halten Terrace, the Nordland Ridge, the Dønna Terrace and in the Træna Basin. It also has two branches to the north and south of the main area. The play has reservoirs in coastal and delta-top sandstones (the Åre and Tilje Formations in the Båt Group) in the Upper Triassic and Lower Jurassic, and in shallow-marine and deltaic sandstones (the Fangst Group) in the Middle Jurassic. These have been encountered in all the wells that have been drilled through these stratigraphical levels in this area. The traps are rotated fault blocks formed in the Late Jurassic and Early Cretaceous and draped with Early Cretaceous shales. The source of the hydrocarbons is assumed to be organic-rich shales in the Spekk Formation in the Viking Group.

The northernmost play, which remains unconfirmed, is located west of Lofoten and Vesterålen, and is mainly in the Ribban Basin, along the Utrøst Ridge and in the Træna Basin. The reservoir rocks are assumed to be of the same age and type as in the confirmed play just described. Sandstone has been found in shallow drill cores, and corresponding rocks are known from Andøya and East Greenland. The traps are rotated fault blocks with a cap rock of Upper Jurassic shale. The source rock is most likely the Spekk Formation, but coal in the Åre Formation may also be feasible. It is thought to have formed oil in the deeper parts of the Ribban Basin. The source rock may also be so mature that it has formed gas in the deeper parts of the Træna Basin. No hydrocarbons have been found in shallow wells in the area, but there are indications of hydrocarbons in the seismic

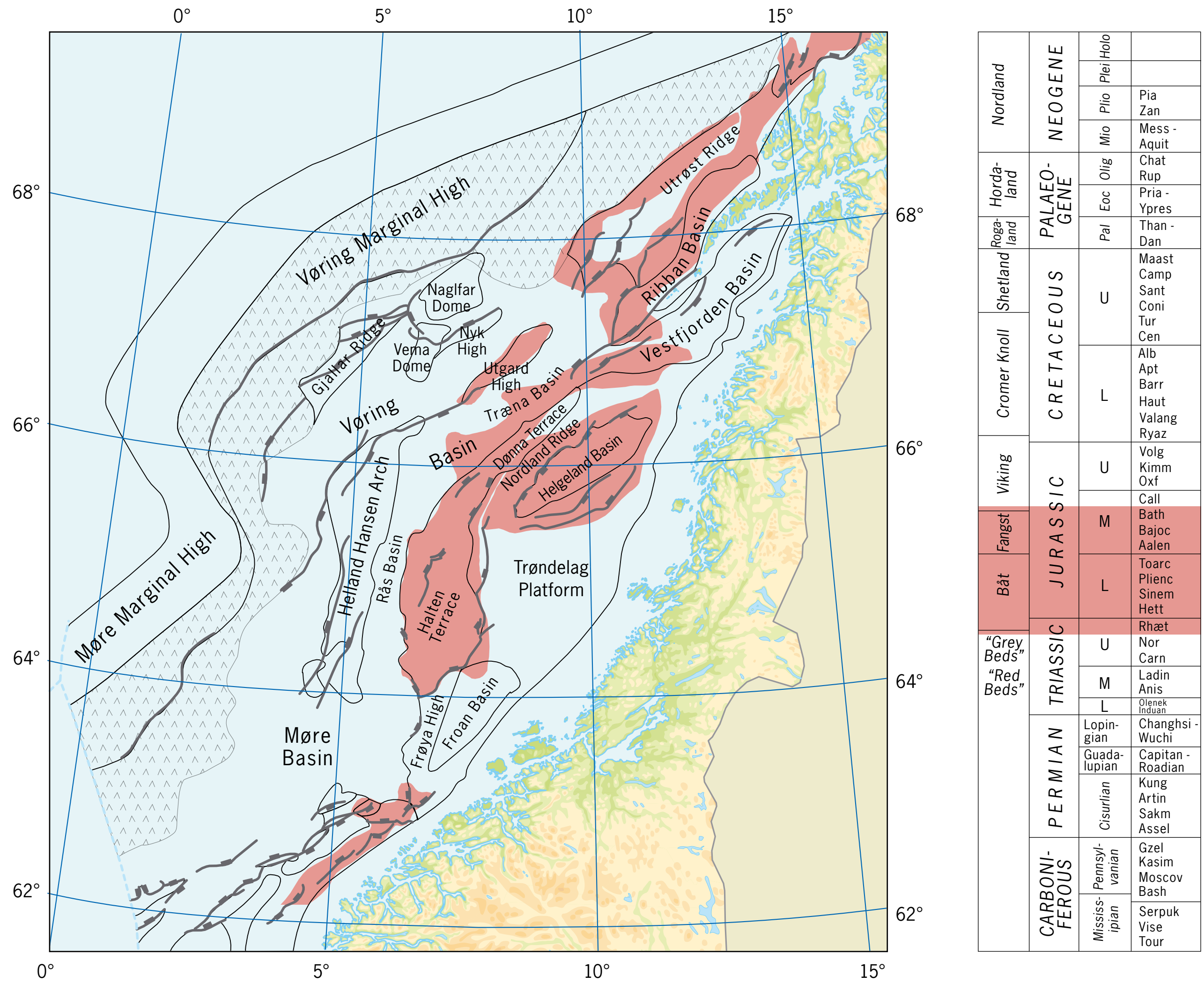


Figure A.13 Upper Triassic to Middle Jurassic plays in the Norwegian Sea data in the western part of the area, towards the Røst High. Uplift and erosion may have reduced the sealing properties and led to leakage. This is considered to be the greatest risk regarding this play.

The third play is unconfirmed and is in the shallower Helgeland Basin, east of the Halten Terrace. It includes coastal and delta-flat sandstones (the Åre Formation) and shallow-marine sandstones (the Tilje Formation) in the Upper Triassic and Lower Jurassic. These have been encountered in several wells. No sandstone has been found in the Middle Jurassic (the Fangst Group). The traps are rotated fault blocks formed in the Late Jurassic and Early Cretaceous and they are draped with Lower Cretaceous shales. The source of the hydrocarbons is assumed to be coal and organic-rich shale in the Åre Formation. The area is thought to be so shallow that the Åre Formation is only marginally mature, and the Upper Jurassic Spekk Formation is immature. It is therefore likely that limited volumes of hydrocarbons have been formed, inadequate to fill all the prospects. A Permian source rock was found in a shallow drilling on the Helgeland coast. If this is found further out in the basin, it may have been a source rock for this area. Late uplift of the eastern part of the play area may have reduced the potential for preservation. The risk in this play is first and foremost attached to whether or not a mature source rock is present.

Plays in the Upper Jurassic

Two plays are defined in the Upper Jurassic (Figure A.14). One is located on the Trøndelag Platform and the Frøya High and is confirmed by the Draugen field. The reservoir rock consists of shallow-marine sandstones. The traps are mainly stratigraphical. The source rock is the Spekk Formation, possibly with some contribution from the Åre Formation. The Spekk Formation is marginally mature in this area and accumulation of petroleum is dependent upon migration from deeper areas west of the play.

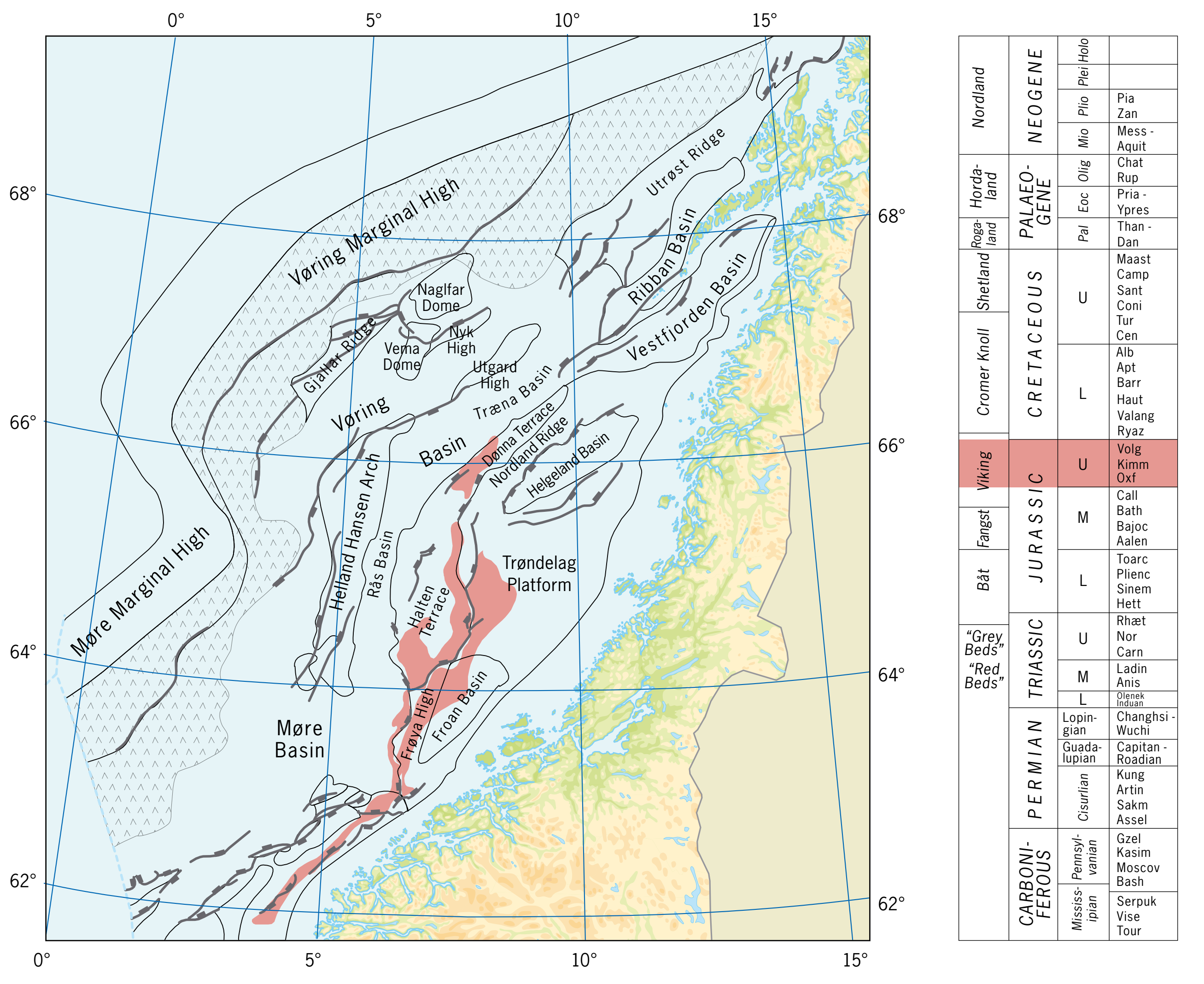


Figure A.14 Upper Jurassic plays in the Norwegian Sea

The second play is located just west of the foregoing one, on the western flank of the Trøndelag Platform, the Frøya High, the Nordland Ridge and along the coast of Møre. The reservoir rock is assumed to be sandstone deposited in submarine fans along the faults. The traps are mainly stratigraphical.

Lower Cretaceous plays

Two Lower Cretaceous plays have been defined (Figure A.15). They are characterised by having reservoir rocks formed of sandstone deposited as fans along the basin margin. The source rocks are the Spekk Formation and/or the Åre Formation. The traps are stratigraphical, with on-lapping beds of sand. One play is confirmed by several discoveries. It stretches along the western flank of the Halten Terrace and the Nordland Ridge, through the Træna Basin and into the Vestfjorden Basin. The other is located furthest south along the Møre coast and has not been confirmed. Its reservoir and source rocks are the same as for the confirmed play.

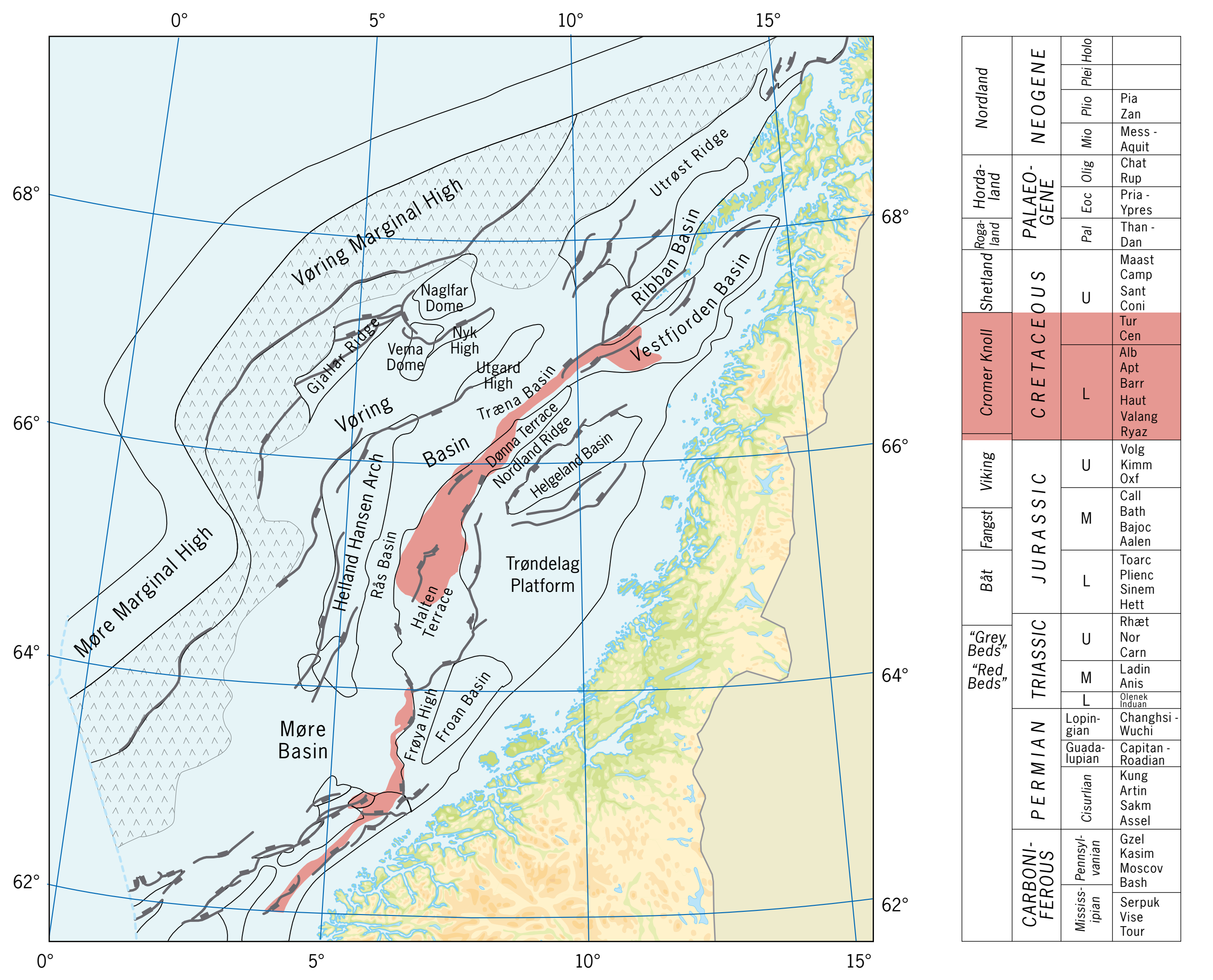


Figure A.15 Lower Cretaceous plays in the Norwegian Sea

Upper Cretaceous plays

Five plays have been defined in the Upper Cretaceous (Figure A.16), and four have been confirmed by discoveries. The play off Lofoten and Vesterålen has not been confirmed. Its reservoir is assumed to be sand fans in the upper part of the Cromer Knoll Group and in the Shetland Group.

The confirmed plays have reservoirs in sand fans of various ages in the Lysing, Kvitnos, Nise and Springar Formations in the upper part of the Cromer Knoll Group and in the Shetland Group. The north-westernmost play has been confirmed by discoveries on the Nyk High and the Vema Dome, where it is difficult to delimit this play from the overlying Palaeocene deposits; hence, the Palaeocene is partly included in this play. New interpretations of the dates from the wells in the area now provide a better basis for separating the plays. Mapping based on these new interpretations is in progress. The original definition of the plays is retained for the moment.

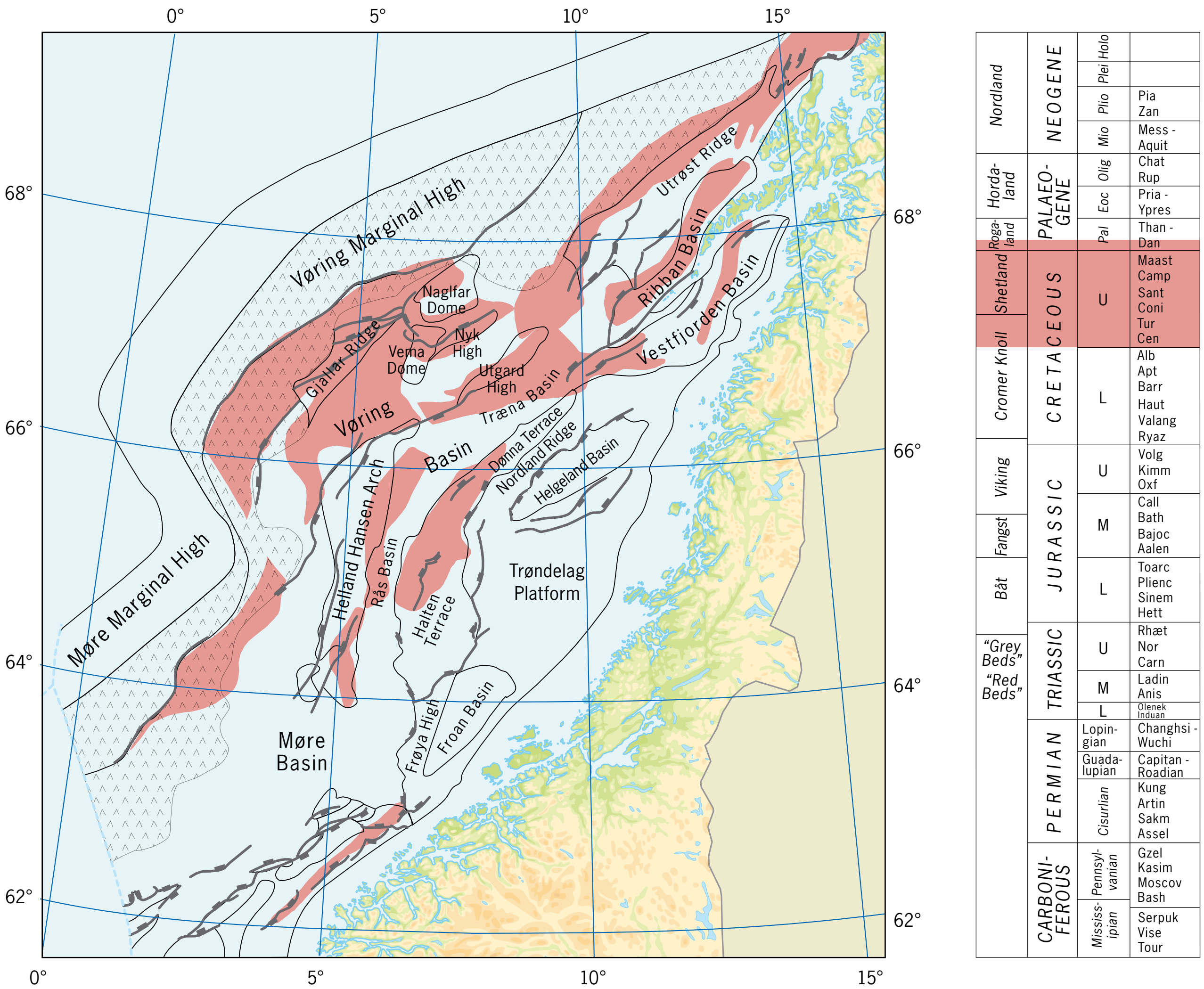


Figure A.16 Upper Cretaceous plays in the Norwegian Sea

Palaeocene plays

Three plays have been defined in the Palaeocene (Figure A.17), and discoveries have confirmed two of them. The Ormen Lange field confirmed a play along the eastern margin of the Møre Basin. Its reservoir consists of sandstone that was deposited in a large fan that developed from the land area in the east. Ormen Lange mainly contains gas, but a thin oil zone has been found in the eastern part of the field. Source rocks for Ormen Lange have not been conclusively determined, but they may be the Spekk Formation or Cretaceous shales.

A very extensive play covers the western parts of the Møre and Vøring Basins. It was confirmed by the discovery in 6706/6-1 (the Hvitveis prospect). The reservoir is marine sandstones which were deposited as fans that built out from the northwest (Greenland). The wells that have been drilled in this play show poorer reservoir quality than has been found in the Cretaceous. Prospects have been mapped in the northern part of the play area, and these have good, direct hydrocarbon indications in the seismic data.

An unconfirmed play is situated in the outer part of the Vestfjorden Basin, along the northern flank of the Nordland Ridge. Its reservoir consists of shallow-marine sandstone fans, and sandstone with very good reservoir quality has been found in the wells. The source rock is expected to be the Spekk Formation.

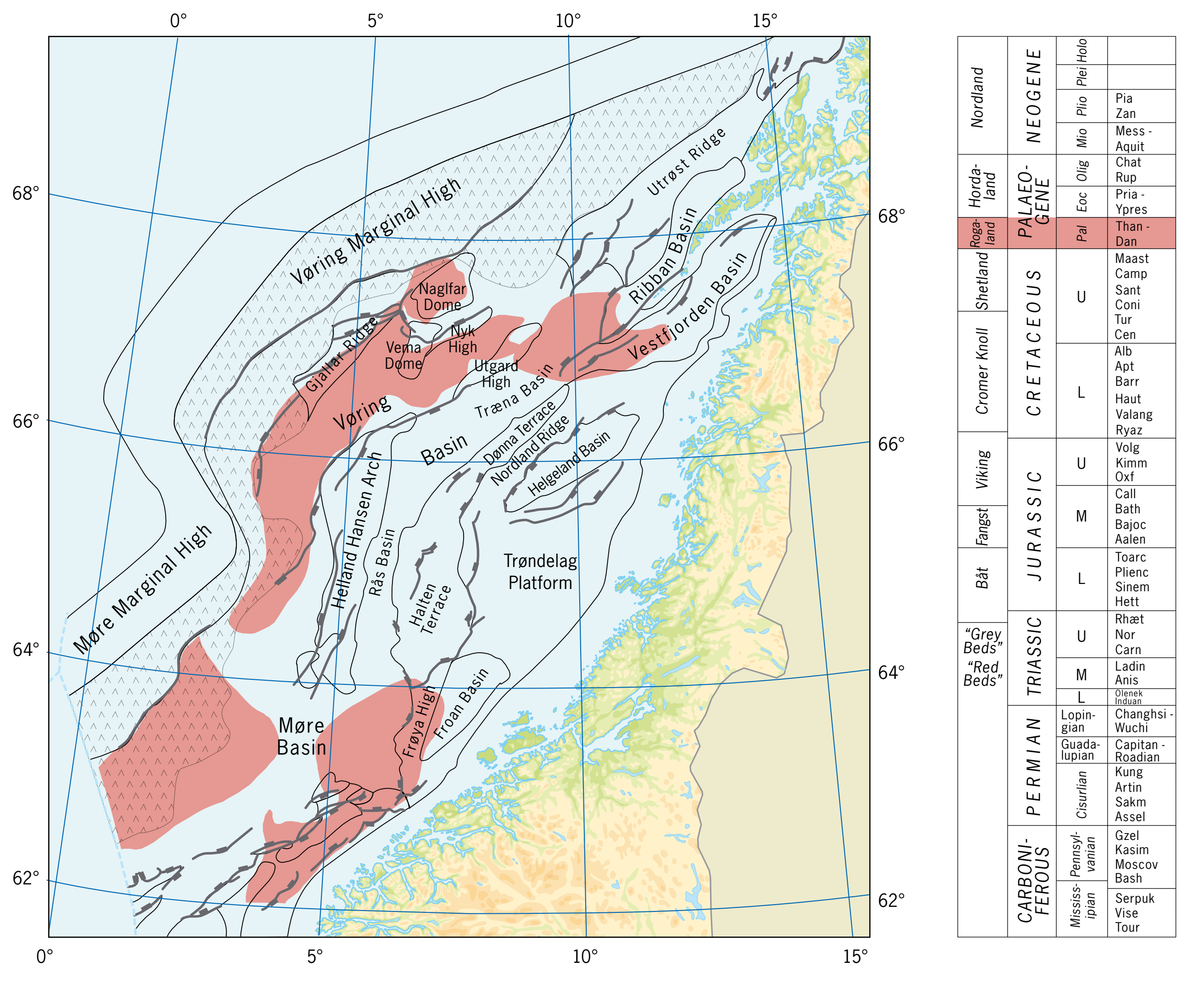


Figure A.17 Palaeocene plays in the Norwegian Sea

Post-Palaeocene plays

Two plays have been defined in the upper part of the Cenozoic (Figure A.18), but both are unconfirmed. It is possible that in one play, along the Vøring and Møre Marginal Highs, volcanic strata of Eocene age may be so heavily fractured that they can have good reservoir properties. Accumulations of this type have been described in several parts of the world. The source rock for this play is uncertain; there are possibilities for source rocks in both the Cretaceous and perhaps the Cenozoic.

There are seismic indications of submarine fans in the Pliocene furthest south in the Møre Basin. This situation can be compared with the Utsira Formation in the North Sea. Shales in the Upper Jurassic (the Spekk Formation) and the Cretaceous may be source rocks for this play.

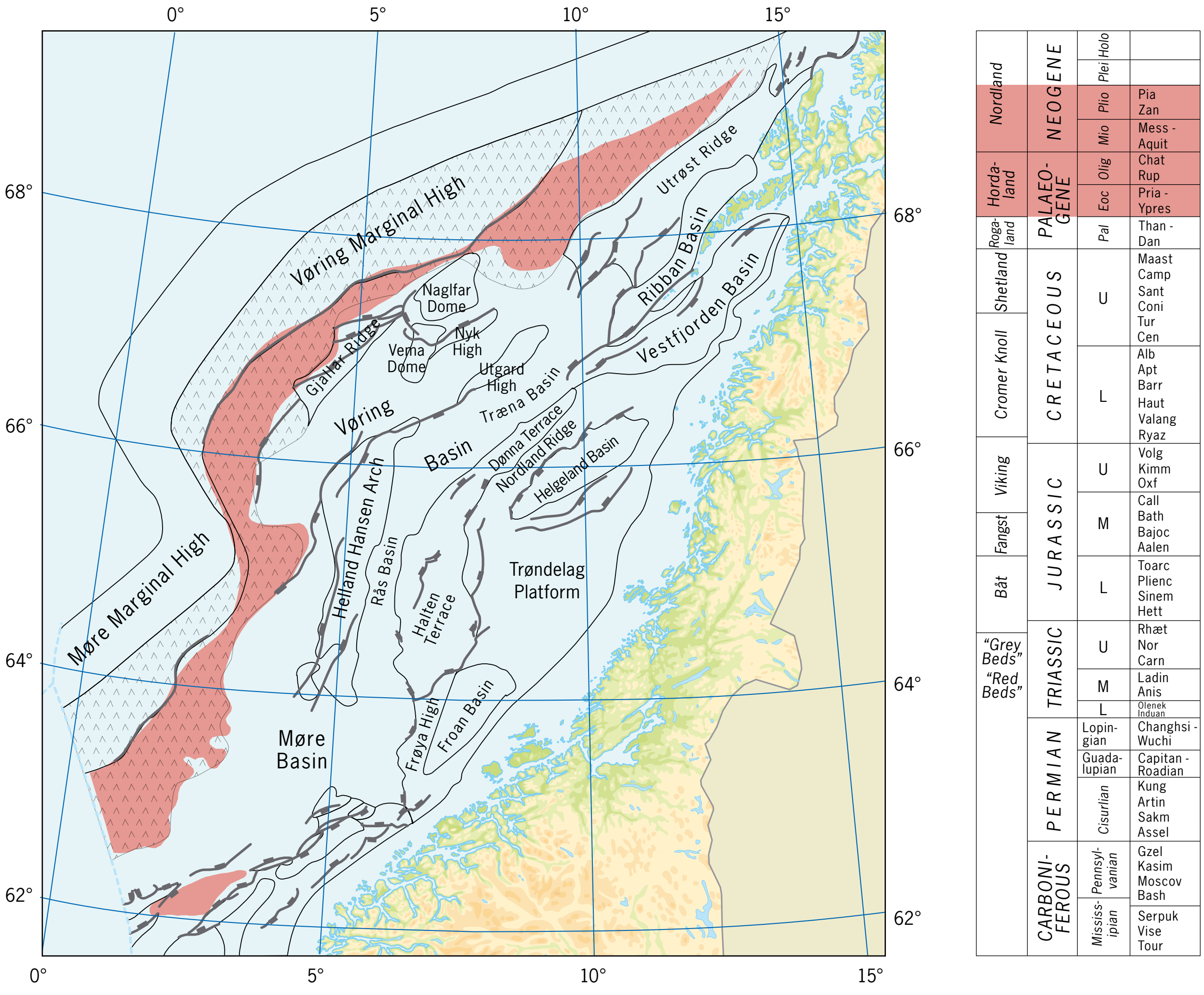


Figure A.18 Post-Palaeocene plays in the Norwegian Sea

Plays in the Barents Sea

The Barents Sea covers the area north of 69˚ 30′ N. The area south of 74˚ 30′ N is generally called the southern Barents Sea, while the area to the north of this is called the northern Barents Sea. Areas in the southern Barents Sea were opened for exploration in 1980. The first discovery, 7120/8-1 Askeladd, was made in 1981. The Norwegian Petroleum Directorate has defined plays as far east as the line demarcating the area with overlapping claims, adjacent to the Russian sector. This area is therefore not covered by this review.

So far, 72 exploration wells have been drilled in the Barents Sea. In addition, 80 scientific boreholes (shallow wells) have been drilled which have provided valuable information about the geology of the Barents Sea. These shallow wells have been drilled in both the northern and southern Barents Sea.

A comparatively complete succession of sediments from the Late Palaeozoic to the Cenozoic has been preserved in the Barents Sea area. In south-western parts, the sedimentary succession is up to 15 kilometres thick in some places. It is dominated by clastic rocks like shales and sandstone, but carbonates and evaporites (rock salt and the like) were also deposited in the Late Carboniferous and Early Permian.

Sediments from the Carboniferous right up to the Palaeogene are found in the platform areas in the east, where tectonic activity has been moderate since the Carboniferous. Younger sediments and ocean-floor basalts dominate along the margin of the deep-water areas in the west and north. This was a very active tectonic area in Mesozoic and Cenozoic times.

High temperatures are essential if the organic material in the rocks is to be converted into hydrocarbons. It is important that the source rocks have been sufficiently deeply buried (are mature) for hydrocarbons to be formed, because the temperature in the Earth's crust rises with increasing depth. Uplift will cause the temperature to sink. This may lead to the source rock not becoming mature. The Barents Sea area has experienced several periods of tilting, uplift and reactivation of faults. Significant uplift and erosion of the succession took place, particularly in the Cenozoic. The strongest erosion occurred in the northern and western parts of the Barents Sea, as well as in the Hammerfest Basin and on the Loppa High, where it has been calculated that 1500-2000 metres of sediments have been eroded. As many as 3000 metres of sediments are assumed to have been removed by erosion in the areas most affected. Uplift of the platform areas in the east and subsidence on the Barents Sea margin in the west may have resulted in previously accumulated petroleum leaking out of the structures in the area. It is important to take this complicated history of uplift and erosion into account when the plays in the Barents Sea are to be defined and evaluated.

Twenty-five discoveries have been made in the Barents Sea, most of them in the Hammerfest Basin where their reservoirs are in sandstone, mainly Jurassic, as in

Level	Reservoir rock	Confirmed plays	Unconfirmed plays	Total
Palaeogene to neogene	Sandstone		2	2
Upper Jurassic to Lower Cretaceous	Sandstone		1	1
Jurassic	Sandstone	3		3
Triassic	Sandstone	2	2	4
Upper Carboniferous to permian	Carbonate and some sandstone	1	8	9
Devonian to Lower Carboniferous	Sandstone and some carbonate		4	4
Total		***6***	***17***	***23***

Table A.3 Confirmed and unconfirmed plays in the Barents Sea

Uplifted area
Clastic continental deposits, unspecified
Clastic continental deposits, mainly sandstone
Clastic continental deposits, mainly shale and siltstone
Salt (halite)
Shallow-marine carbonate deposits
Deep-marine carbonate deposits
Volcanic deposits
Calcareous shales
Marginal evaporite deposits, sabkha
Coastal, deltaic and flood-plain deposits
Marine deposits, mainly sandstone
Shallow-marine deposits, mainly shale
Deep-marine deposits, mainly shale
Clastics intermixed in carbonates, sandstone in shale
Spiculite

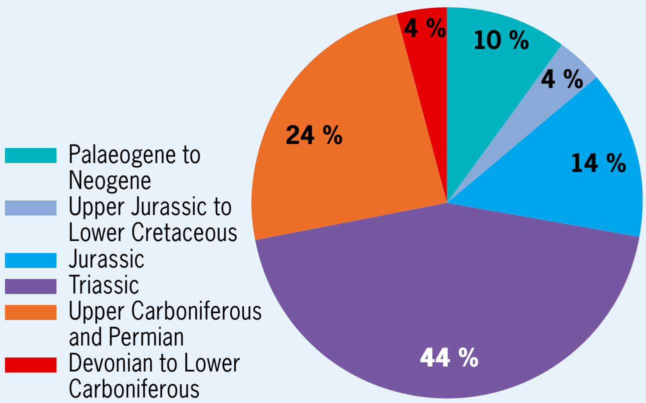


Figure A.19 Stratigraphical distribution of the undiscovered resources in the Barents Sea

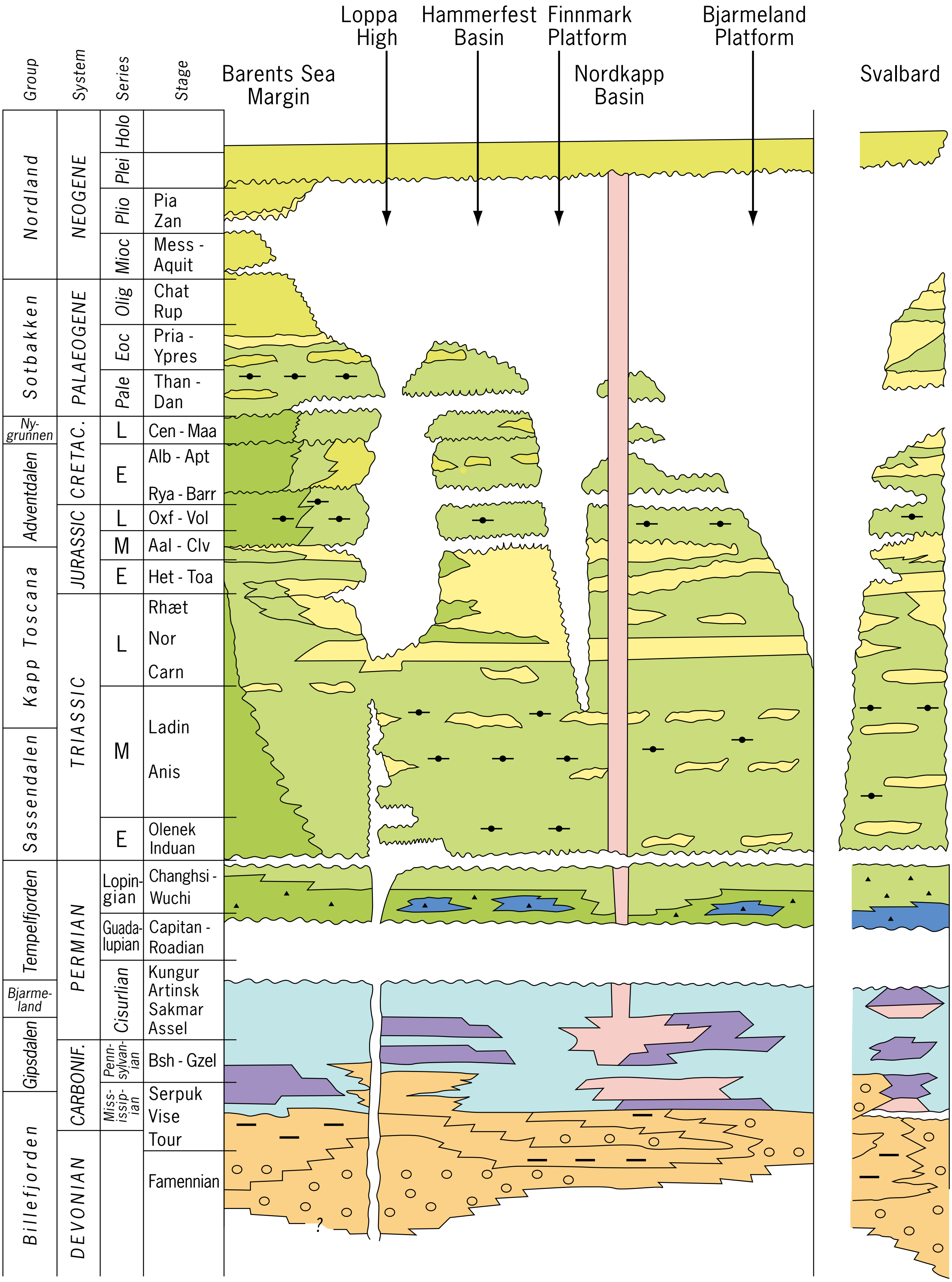


Figure A.20 The lithostratigraphy in the Barents Sea the Snøhvit field. Deeper discoveries have also been made, such as in Triassic sandstones in 7122/7-1 Goliat and 7125/4-1 (The Nucula prospect). Oil and gas have also been found in Triassic sandstones in the Nordkapp Basin, which is dominated by salt tectonics. Gas and oil have been found in carbonates of Carboniferous to Permian age on the Finnmark Platform. The Barents Sea has several important source rocks throughout the succession from the Devonian to the Palaeogene.

The Norwegian Petroleum Directorate has defined 23 plays in the Barents Sea, from the Devonian to the Neogene. Six of these are confirmed (Table A.3). Lack of exploration over large parts of the Barents Sea explains why as many as 17 plays remain unconfirmed. The estimate of the undiscovered resources in the Barents Sea is 480 million Sm³ o.e. of liquid and 550 billion Sm³ of gas (Table 5.1). This amounts to 30 per cent of the total undiscovered resources. The liquid resources have increased by 20 per cent relative to previous estimates, whereas the gas resources have been reduced by seven per cent. The proportion of liquid has increased because several oil discoveries have been made recently. Data from drilled wells have enhanced the belief that more source rocks that have generated oil can be found in the Barents Sea. About half of the undiscovered resources in the Barents Sea are in the unconfirmed plays. The Triassic contains the greatest proportion of the undiscovered resources (Figure A.19). The lithostratigraphy in the Barents Sea is shown in figure A.20. The most important structural elements are shown in the play maps (Figures A.21 - A.26).

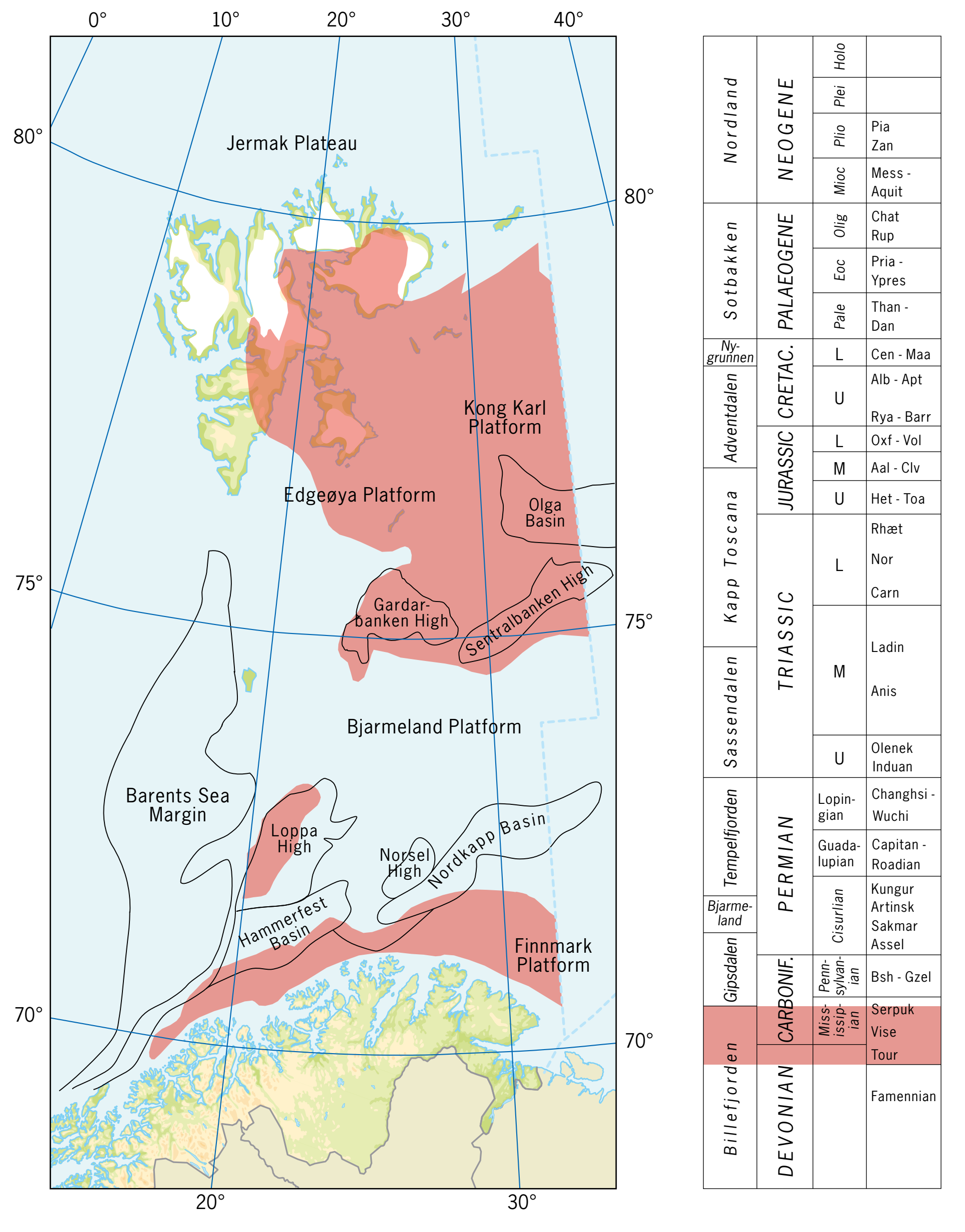


Figure A.21 Devonian to Lower Carboniferous plays in the Barents Sea.

Devonian to Lower Carboniferous plays

Four plays have been defined at this level in the Barents Sea (Figure A.21). Carbonates were deposited as reefs in a narrow belt along the eastern margin of the Finnmark Platform in the Devonian. The climate and the depositional environment changed at the transition to the Carboniferous. A large system of branching and meandering rivers, fans and floodplains deposited sandstones and conglomerates over a large part of the Barents Sea area (the Billefjorden Group). Three plays with reservoirs in the Billefjorden Group have been defined, but no discoveries have yet been made in these plays, even though several of them have been encountered in exploration wells and shallow, scientific wells. Source rocks for these plays may be carbon-rich shales and coal of Late Devonian to Early Carboniferous age.

Upper Carboniferous and Permian plays

As many as nine plays have been defined in the Barents Sea at this level (Figure A.22). The climate changed, bringing tropical conditions to the Barents Sea in Late Carboniferous time. This resulted in the deposition of carbonates on hypersaline platforms with lagoons, tidal flats and shallow evaporite basins (the Gipsdalen Group). At the onset of the Permian, the climate became colder and conditions became more open and marine (the Bjarmeland Group). Carbonate build-ups still formed along the basin margins and in some shallow areas.

In the Late Permian, the Røye Formation in the Tempelfjorden Group, characterised by sponge spicules, was deposited further out in the basin on a continental shelf with a low-energy environment. Diagenetic replacement of the spicules led to extensive formation of flint in the succession in the Upper Permian. One of the nine plays has been confirmed by well 7128/4-1. This was drilled on the Finnmark Platform, and a small gas discovery was made in a reservoir rock composed of sponge spicules, generally called spiculite.

The carbonate shelf became partially exposed towards the end of the Lower Permian. The carbonate rocks were eroded and re-deposited as bioclastic sand. Siliciclastic sand was introduced from the adjacent land areas along the Barents Sea margin in the west and on the Finnmark Platform. Stratigraphical traps associated with karstification, and with diagenetic effects from the carbonates, including dolomitisation, are thought to be the most likely types of traps. A combination of structural and stratigraphical traps may also occur. Knowledge of these plays is limited, especially that in the northern Barents Sea. Wells in the southern Barents Sea have confirmed that the carbonates are present.

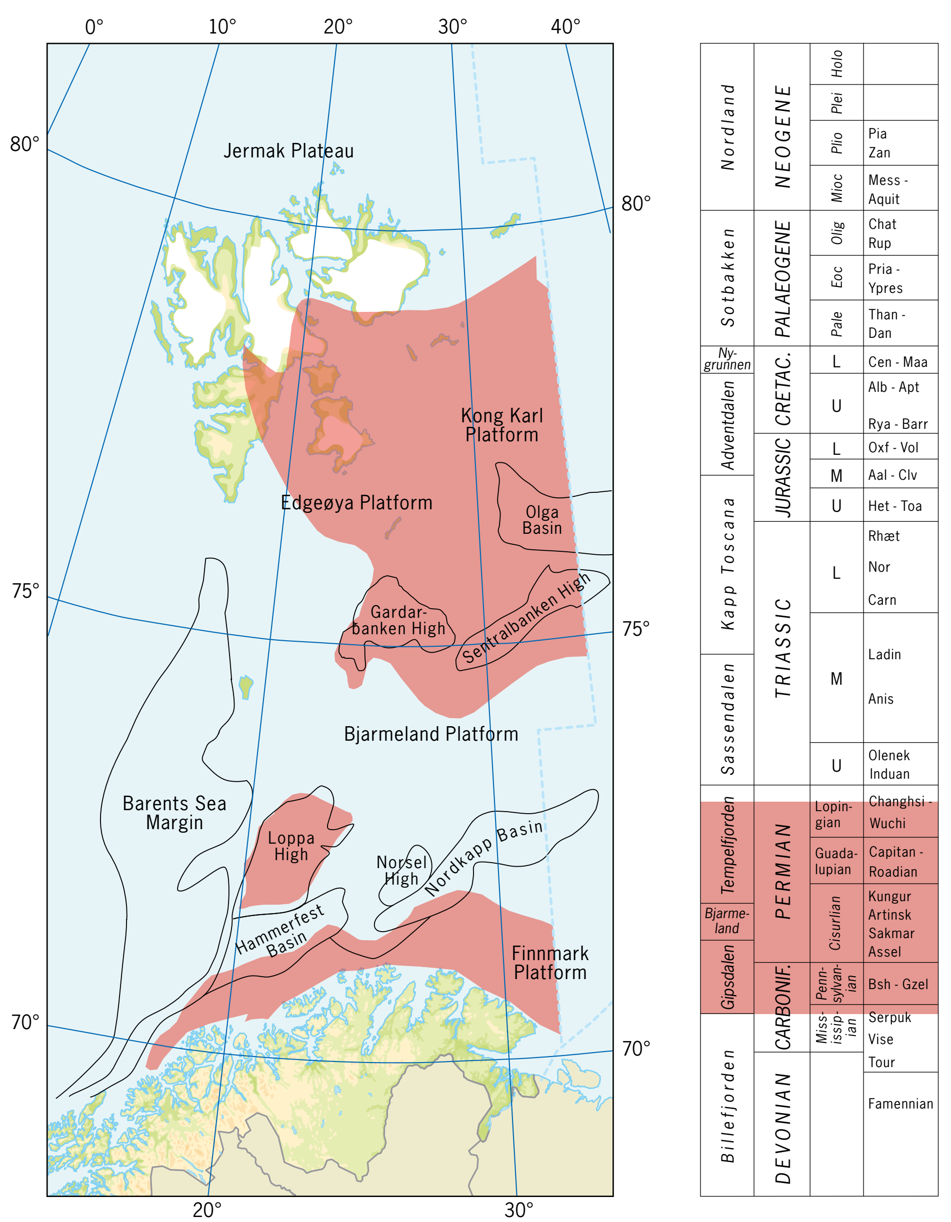


Figure A.22 Upper Carboniferous and Permian plays in the Barents Sea.

Several different source rocks in the Upper Devonian to Lower Carboniferous, Upper Permian or Lower Triassic may have formed hydrocarbons for these plays.

One of the nine plays has been confirmed by well 7128/4-1. This well, drilled on the Finnmark Platform, made a small gas discovery in a reservoir rock composed of sponge spicules, often referred to as spiculite.

Triassic plays

Four Triassic plays have been defined in the Barents Sea (Figure A.23). In the Triassic, the Barents Sea area was dominated by rivers and coastal plains. Marine shales were deposited in the north and west early in the Triassic, off coastal and deltaic areas. These are probably important source rocks. The rivers, which flowed from the east, perhaps also from a mainland area in the south, transported sand which was deposited in prograding coastal and delta-plain sequences. The two Lower Triassic plays have sandstone reservoirs in the Sassendalen Group, and the two Upper Triassic plays have sandstone reservoirs in the Snadd Formation of the Kapp Toscana Group.

Two of the plays have been confirmed by several oil and gas discoveries. Several different types of traps have been recognised through these discoveries, including stratigraphical traps formed by wedging out of sandstone beds, salt-related structural traps, and traps formed by rotating fault blocks. Several source rocks may be feasible in the Upper Devonian to Lower Carboniferous, Upper Permian or Lower Triassic.

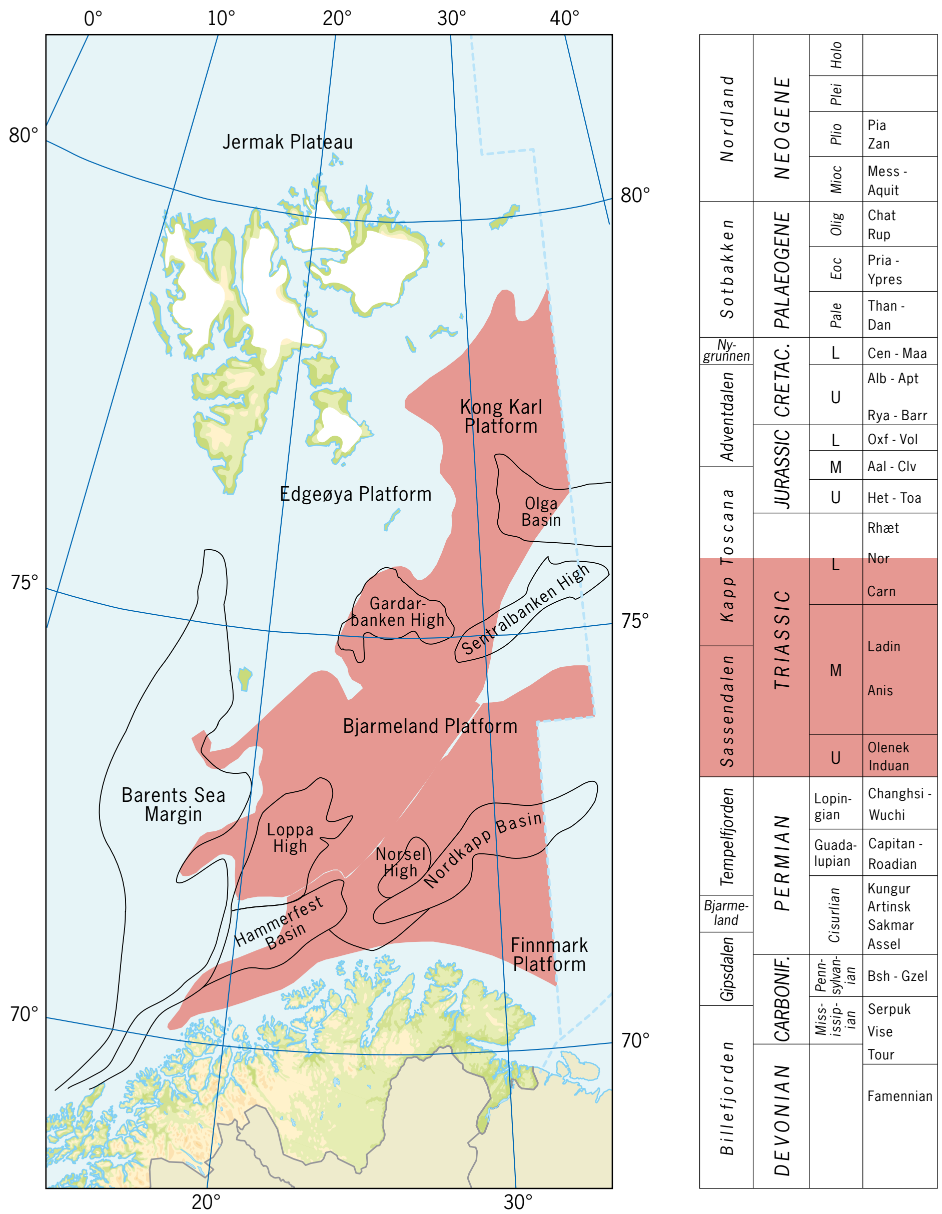


Figure A.23 Triassic plays in the Barents Sea

Jurassic plays

Three Jurassic plays have been defined in the Barents Sea (Figure A.24), and all of them have been confirmed by both oil and gas discoveries, such as those forming the Snøhvit field, 7122/7-1 Goliat, 7125/4-1 and 7019/1-1. Only one of the plays just extends into the northern Barents Sea. In the Jurassic, the Barents Sea area was a shallow-marine and continental environment. Sand was deposited on deltaic plains, flood plains and various shallow-marine settings. The plays have reservoirs of sandstone in the Stø, Nordmela and Fruholmen Formations in the Kapp Toscana Group. The traps in these plays are rotated fault blocks. The main source rock is the Hekkingen Formation in the Adventdalen Group, which consists of shales of Jurassic age. Organic-rich shales in the Lower to Middle Triassic may also be important source rocks.

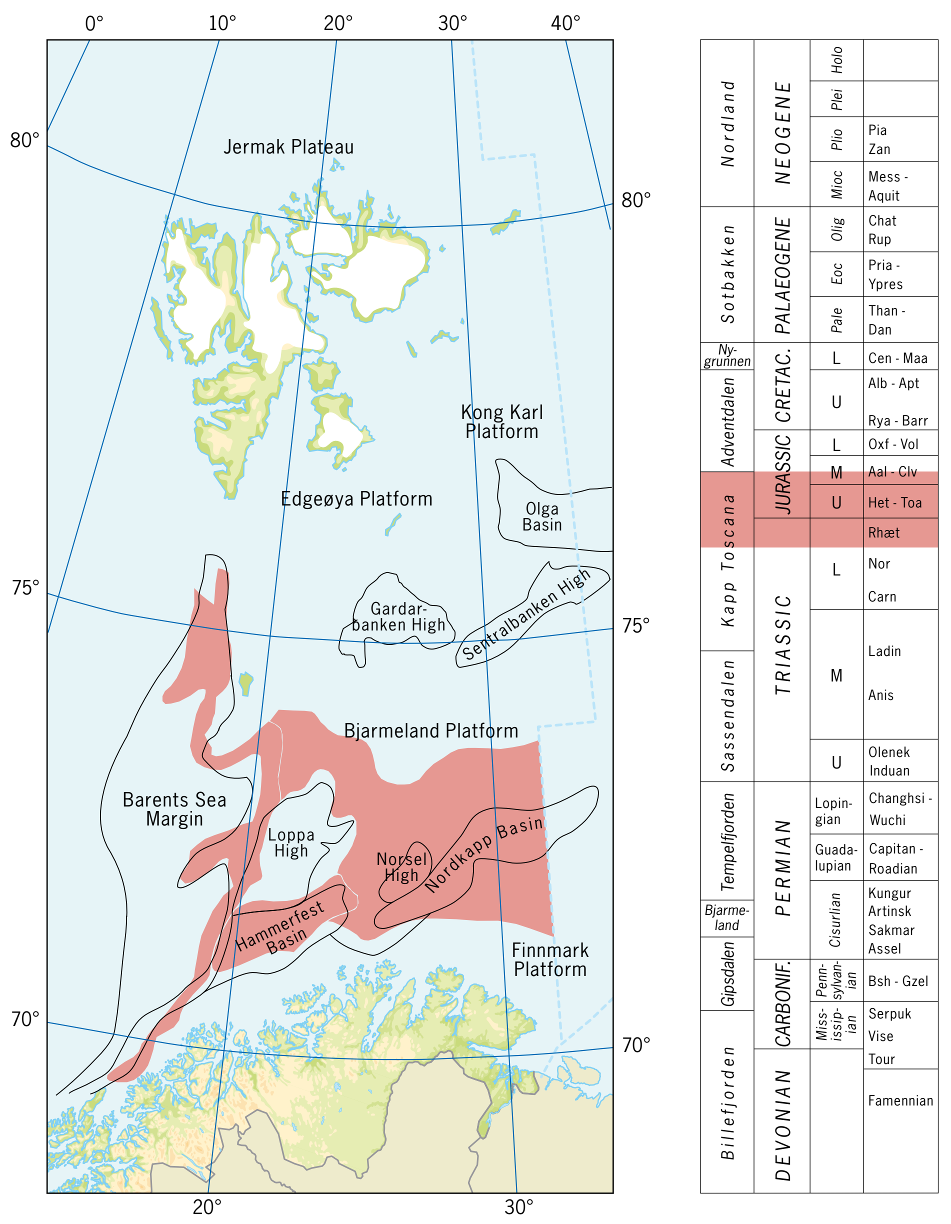


Figure A.24 Jurassic plays in the Barents Sea

Upper Jurassic to Lower Cretaceous plays

One play has been defined in the Upper Jurassic to Lower Cretaceous in the Barents Sea (Figure A.25). It has been defined on the basis of local sandstones in the Knurr and Kolje Formations in the Adventdalen Group. These shallow-marine sandstones are thought to have been deposited along active faults in Late Jurassic to Early Cretaceous time. The most likely type of trap will be stratigraphically wedging out sandstones, often with a structural component. These local sandstones have been encountered in exploration wells, but the play has still not been confirmed. The most likely source rock for this play is the Hekkingen Formation. Other source rocks may also be able to generate hydrocarbons for this play.

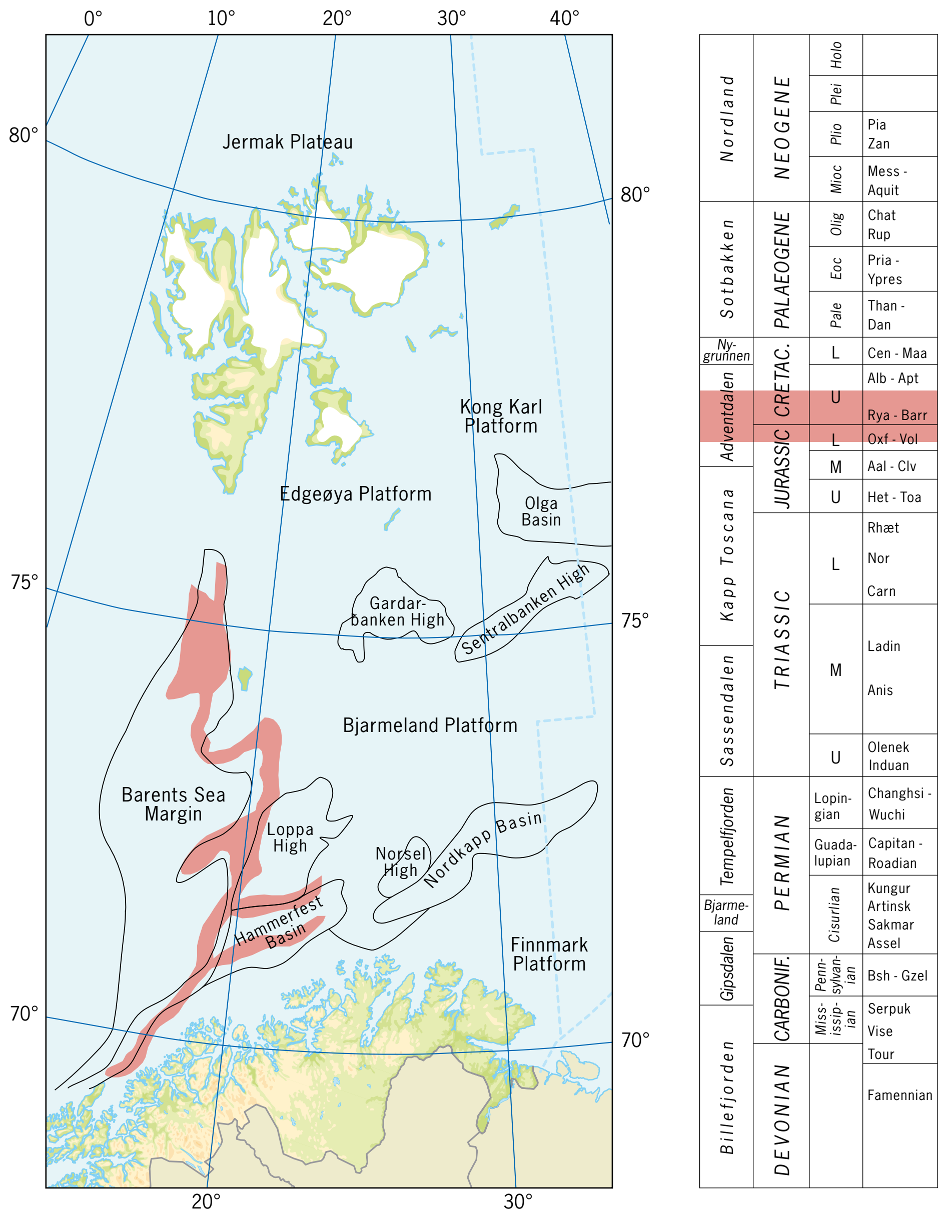


Figure A.25 Upper Jurassic to Lower Cretaceous play in the Barents Sea

Palaeogene to Neogene plays

Two plays have been defined at this level (Figure A.26). One of them is located north of Svalbard. Large quantities of sediments were deposited in deltas and in shallow to deeper marine environments due to the extensive uplift and erosion that took place over large parts of the Barents Sea area during the Cenozoic. The sandstones belong to the Torsk Formation in the Van Mijenfjorden Group. Structural traps and stratigraphical traps formed by wedging out of sandstones are the most likely types of trap. Salt-related stratigraphical traps may also occur. Possible source rocks for these plays may be of Cretaceous and Palaeogene age.

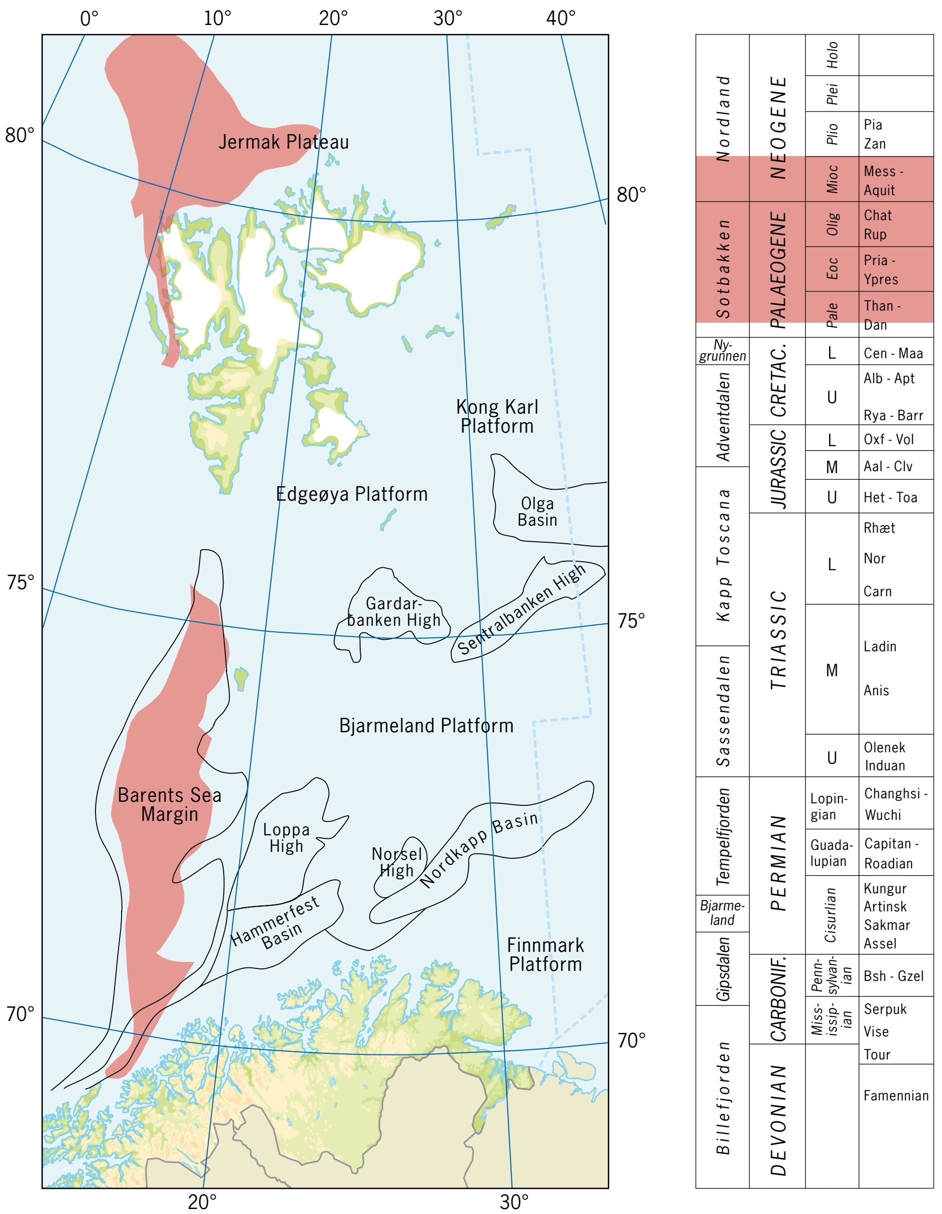


Figure A.26 Palaeogene to Neogene plays in the Barents Sea

Appendix 2: Terms and definitions

Abandoned well: A well that is permanently plugged in the drilling phase, for technical reasons.

Appraisal well: An exploration well drilled to determine the extent and size of a petroleum deposit that has already been discovered by a wildcat well.

Area fee: An annual fee which the licensees on the Norwegian shelf pay the Government for each square kilometre of the acreage covered by a production licence. The fee is not charged for acreage where satisfactory activity that fulfils specific requirements is shown to be taking place.

Associated gas: Natural gas dissolved in oil in the reservoir.

Awards: Companies that are approved as operators or licensees on the Norwegian continental shelf may apply to be awarded production licences. The awards take place through licensing rounds and annual allocations in predefined areas. The authorities decide which areas of the Norwegian continental shelf are to be opened for petroleum activity and which companies are to be awarded production licences.

Barrel of oil: An American volumetric measurement = 159 litres.

Block: A geographical unit of division used in the petroleum activities on the continental shelf. The maritime areas within the outermost limit of the continental shelf are divided into blocks measuring 15 minutes of latitude and 20 minutes of longitude, unless adjacent areas of land, borders with the continental shelves of other nations, or other factors decree otherwise.

Blow-out: Sudden, powerful, uncontrolled discharge of gas, oil, drilling mud and water from a well.

Branch drilling: Drilling from an existing well path towards a new well target.

CNG (Compressed Natural Gas): Dry gas or natural gas under pressure in tanks.

CO2 equivalent: CO_2 and other greenhouse gases recalculated to the volume of CO_2 which gives a corresponding greenhouse effect.

CO_2 tax: A tax paid for emission of CO_2 when burning petroleum and emitting natural gas on platforms used in connection with the production or transportation of petroleum (see the CO_2 Tax Act).

Cold flaring: Controlled emission of cold gas.

Condensate: A mixture of the heaviest components of natural gas. Condensate is fluid at normal pressure and temperature.

Condensed Natural Gas: Natural gas that is condensed into liquid by lowering its temperature.

Continental shelf: The continental shelf is defined both legally and geologically. Legally, it is the sea bed and its substrate in the maritime areas which extend beyond Norwegian territorial waters over the entire natural continuation of the land territory to the outermost extent of the continental margin, but not less than 200 nautical miles from the sea boundaries from which the breadth of the territorial waters is measured, yet not beyond the centre line relative to another nation. Geologically, the continental shelf denotes the fairly flat seabed stretching from land out to the edge of the shelf. In a more informal context, the continental shelf sometimes also includes the slope beyond the edge of the shelf, so that such areas where petroleum activities are taking place are also covered by the term.

Contingent resources: Recoverable petroleum volumes that have been discovered, but for which no decision has been taken, or permission given, to recover.

Core sample: Sample taken from a rock formation by core drilling or the use of a sidewall core.

Crude oil: Liquid petroleum from the reservoir. Most of the water and dissolved natural gas has been removed.

Discovery rate: The technical discovery rate is the relationship between the number of technical discoveries and the number of wildcat wells. The economic or commercial discovery rate is the relationship between the number of discoveries that are developed or are clearly profitable today and the number of wildcat wells.

Discovery: A petroleum deposit, or several petroleum deposits combined, discovered in the same well, and which testing, sampling or logging have shown probably contain mobile petroleum. The definition covers both commercial and technical discoveries. The discovery receives the status of a field, or becomes part of an existing field when a Plan for Development and Operation (PDO) is approved by the authorities (see Field).

Drilling programme: A description that contains specific information about wells and well paths relating to planned drilling and well activities.

Drilling rig: The derrick, essential machinery and ancillary equipment used to drill for oil or gas on land or from an offshore drilling installation.

Dry gas: Almost pure methane gas, lacking water and with few heavy components.

E-operation: E-operation denotes the kind of operation where use is made of the opportunities which new and improved information technology provides by utilising approximately real-time data to achieve better and quicker decisions. Another term for the same is integrated operation.

EOR (Enhanced Oil Recovery): The term used for advanced methods of reducing the residual oil saturation in the reservoir.

Exploration well: A well drilled to prove a possible deposit of petroleum or obtain information to delimit a discovered deposit. The term covers both wildcat and appraisal wells.

Field: One petroleum deposit, or a number of concentrated petroleum deposits, covered by an approved Plan for Development and Operation (PDO), or for which exemption from such a plan has been granted.

Fixed facility: A facility or installation that is permanently located on the field during the lifetime of the field. Production ships are covered by this definition if they are intended to be permanently placed on the field.

Flaring: Controlled burning of gas.

Hydrocarbons: Chemical compounds with molecular chains composed of carbon (C) and hydrogen (H) atoms. Oil and gas consist of hydrocarbons.

Integrated operation: See E-operation.

Kick: Loss of control over a well, resulting in uncontrolled backflow of drilling liquid. It is an indication of a blow-out due to the well taking in gas, oil or water.

Licensed acreage: The acreage awarded in a production licence. Only exploration drilling and production may take place in an area covered by a production licence.

Licensee: A physical or legal person, or several such persons, who, under the terms of the Petroleum Act or earlier jurisdiction, has a licence to search for, recover, transport or utilise petroleum. If a licence is awarded to several such persons together the expression licensee can cover both the licensees combined and the individual participant.

Licensing round: See Awards.

LNG (Liquefied Natural Gas): See Condensed Natural Gas.

LPG (Liquefied Petroleum Gases): Mainly propane (C_3H_8) and butane (C_4H_{10}) transformed into liquid by raising the pressure or cooling.

Moveable facility: A facility or installation not intended to be permanently located on the field during the lifetime of the field; for instance, a drilling platform or a well intervention device (see § 3 of the Directions for the Framework Provisions).

Multi-branch well: A well drilled to produce and/or inject from several well paths simultaneously.

Natural gas: Hydrocarbons in gaseous form. Gas sold under the name natural gas mainly consists of methane (CH_4), some ethane and propane, small amounts of other, heavier hydrocarbons and traces of contaminants like CO_2 and H_2S.

NGL (Natural Gas Liquids): A collective term for the petroleum qualities, ethane, propane, isobutane, normal butane and naphtha. NGL are partially liquid at normal pressure.

nmVOC (non-methane Volatile Organic Compounds): The term for volatile, organic compounds, except methane, that evaporate from, among other things, crude oil.

Oblique drilling: Drilling of a well whose path is not planned to be drilled vertically.

Observation well: Production or test production well used to measure specific well parameters.

Oil equivalents (o.e.): Used when oil, gas, condensate and NGL are to be totalled. The term is either linked to the amount of energy liberated by combustion of the various types of petroleum or to the sales values, so that everything can be compared with oil.

Oil: Collective term for crude oil and other liquid petroleum products.

Operator: The agent who, on behalf of the licensee, is in charge of the day-to-day management of the petroleum activity.

Originally, recoverable petroleum volumes: The total, saleable volumes of petroleum from the start to the end of production, based on the prevailing estimate of the in-place volumes and the recovery factor.

PDO: Plan for Development and Operation of petroleum deposits.

Petroleum: The term for all liquid and gaseous hydrocarbons found in a natural state in the substrate, and also other substances recovered in connection with such hydrocarbons.

Petroleum Act: Act of 29 November 1996 No. 72 concerning Petroleum Activities.

Petroleum activity: All activity linked to subsea petroleum deposits, including investigation, exploratory drilling, recovery, transport, utilisation and termination, and also the planning of such activities, but not the bulk transportation of petroleum by ship.

Petroleum deposit: An accumulation of petroleum in a geological unit, delimited by rock types at structural or stratigraphical boundaries, contact surfaces between petroleum and water in the formation, or a combination of these, such that the petroleum concerned is everywhere in pressure communication through liquid or gas.

Petroleum register: A register of all production licences and licences for the construction and operation of installations for transportation and utilisation of petroleum (see § 6-1 of the Petroleum Act).

PIO: Plan for Installation and Operation.

Play: A play is a geographically demarcated area where several geological factors occur together so that producible petroleum can be proven. These factors are: 1) Reservoir rock, which is a porous rock where petroleum can be preserved. Reservoir rocks to a specific play will belong to a given lithostratigraphical level. 2) Trap, which is an impermeable rock or a geological structure enveloping the reservoir rock so that the petroleum is retained and accumulates in the reservoir. The trap must be formed before the petroleum stops entering the reservoir. 3) Source rock, which is shale, limestone or coal containing organic material that can be converted into petroleum. The source rock must also be mature, that is to say the temperature and pressure must be appropriate for petroleum actually to be formed, and there must be a migration path enabling the petroleum to move from the source rock to the reservoir rock. A play is confirmed when producible petroleum is found in it. The production does not necessarily have to be profitable. If no producible petroleum has yet been found in a play, it is unconfirmed.

Probability of discovery: Describes the feasibility of proving petroleum in a prospect by drilling. The probability of discovery results from multiplying the probabilities of the existence of the play, the presence of a reservoir, a trap, the migration of petroleum into the field and the preservation of petroleum in the field (see Play).

Production licence: This licence gives a monopoly to perform investigations, exploration drilling and recovery of petroleum deposits within the geographical area stated in the licence. The licensees become owners of the petroleum that is produced. A production licence may cover one or more blocks or parts of blocks and regulates the rights and obligations of the participant companies with respect to the Government. The document supplements the provisions of the Petroleum Act and states detailed terms for the individual licences. Exploration period: At the outset, the production licence is awarded for an initial period (exploration period) that may last up to 10 years. In this period, the licensees are obliged to carry out specific tasks, such as seismic surveying and/or exploration drilling. If these mandatory tasks are fulfilled within the exploration period, the licensees may, in principle, demand to retain up to half the area covered by the award for up to 30 years.

Production well: Collective term for wells used to recover petroleum, including injection wells, observation wells and possible combinations of these.

Prospect: A possible petroleum trap with a mappable, delimited volume of rock.

Recovery: The production of petroleum, including the drilling of production wells, injection, assisted recovery, treatment and storage of petroleum for transport, and loading of petroleum for transportation by ship, as well as the construction, location, operation and use of installations used for recovery.

Recovery factor: The relationship between the volume of petroleum that can be recovered from a deposit and the volume of petroleum originally in place in the deposit.

Recovery well: A well used for production of petroleum or water, or for injection purposes.

Refining: The refining of crude oil is really a distillation process. The components with different boiling points are separated in a distillation tower. When heated, the oil is converted to gas, which condenses again at different temperatures to, among others, petrol, paraffin, diesel, heating oils, coke and sulphur.

Reserves: Remaining, recoverable, saleable volumes of petroleum in petroleum deposits which the licensees have decided to recover and the authorities have approved a PDO or granted exemption from a PDO. Reserves also include volumes of petroleum in deposits which the licensees have decided to recover, but whose plans have not yet been approved by the authorities in the form of a PDO or exemption from a PDO.

Rich gas: A mixture of wet and dry gas (methane, ethane, propane, butanes, etc.).

Riser: A pipe that transports liquid up from the well to the production or drilling platform.

Royalty: A fee payable to the Government, calculated on the basis of the volume and the value of produced petroleum, at the shipping point on the production site. The fee is demanded pursuant to § 4-9, paragraph 2 of the Petroleum Act.

Seismic (geophysical) investigations: Seismic profiles are acquired by transmitting sound waves from a source above or in the substratum. The sound waves travel through the rock layers which reflect them up to sensors on the seabed or at the surface, or in a borehole. This enables an image of the geology in the substratum to be formed. Seismic mapping of the Norwegian continental shelf started in 1962.

Shallow borehole: A hole drilled to obtain information about the rock characteristics and/or to perform geotechnical investigations before installations are sited, and which is not drilled to prove or delimit a petroleum deposit, or produce or inject petroleum, water or other medium.

Stratigraphy: The succession of beds of rock that are deposited on one another (= lithostratigraphy) or the age of the various beds of rock relative to geological time periods (= chronostratigraphy).

Termination plan: Plan to be presented to the authorities by the licensees before a production permit or a permit to install and operate installations for transport and utilisation of petroleum expires or is relinquished, or the use of an installation finally ceases. The plan must include proposals for continued production or shutdown of production and how installations are to be disposed of.

Undiscovered resources: The volumes of petroleum that, at a given moment in time, are estimated to be recoverable from deposits that have still not been discovered by drilling.

Well: A hole drilled to find or delimit a petroleum deposit and/or produce petroleum or water for injection purposes, inject gas, water or another medium, or map or monitor well parameters. A well may consist of one or more well paths and may have one or more terminal points.

Well path: Denotes the location of a well from a terminal point to the wellhead. A well path may consist of one or more well tracks.

Well track: The part of a well path that stretches from a drilling out point on an existing well path to a new terminal point for the well.

Wet gas: Collective term for liquid petroleum products, including NGL.

Wildcat well: An exploration well drilled to find out whether petroleum exists in a possible deposit.

Zero emissions and discharges: Means that, in principle, no environmentally hazardous substances, or other substances, are to be emitted or discharged if they can result in damage to the environment (detailed definition in White Paper no. 25 (2002-2003)). Special demands for emissions and discharges in the Barents Sea are that, in principle, no emissions or discharges are to take place during normal operations, irrespective of whether they may result in damage to the environment (detailed definition in White Paper no. 38 (2003-2004)).

Common abbreviations

CO:	carbon monoxide
CO_2:	carbon dioxide
NOx:	nitrogen oxides
VOC:	volatile organic compounds
nmVOC:	non-methane volatile organic compounds
SO_2:	sulphur dioxide
Sm^3:	standard cubic metre
o.e.:	oil equivalents
t:	tonne
mill.:	millions
bill.:	billions
bbl:	barrel (of oil)
boe:	barrels of oil equivalents
Mbbl:	Million bbl [1])
Mboe:	Million boe [1])
Bcf:	Billion cubic feet (10^9)
Tcf:	Trillion cubic feet (10^{12})

[1]) There are many different ways of abbreviating volumetric units and production rates. For instance, "M" is often used as an abbreviation before the volume measurement, but this may mean 1000 or 1 000 000, depending on the context. The Norwegian Petroleum Directorate wants abbreviations to be used as precisely as possible and recommends that the SI system be used as far as possible. According to the SI system, M ("mega") stands for 1 000 000. Where uncertainty may arise regarding the meaning of these abbreviations, the Norwegian Petroleum Directorate recommends that abbreviations are avoided or replaced by figures

Coversion tables:

1 Sm^3 of oil	= 1.0 Sm^3 o.e.
1 Sm^3 of condensate	= 1.0 Sm^3 o.e.
1000 Sm^3 of gas	= 1.0 Sm^3 o.e.
1 tonne of NGL	= 1.9 Sm^3 NGL = 1.9 Sm^3 o.e.

Gas	1 cubic foot	1 000.00	Btu
	1 cubc 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/day	48.80	tonnes/yr
	1 barrel/day	58.00	Sm^3 per yr

	MJ	kWh	TKE	TOE	Sm^3 natural gas	Barrel crude oil
1 MJ, megajoule	1	0.278	0.0000341	0.0000236	0.0281	0.000176
1 kWh, kilowat hour	3.60	1	0.000123	0.000085	0.0927	0.000635
1 TKE, tonne coal equivalent	29 300	8 140	1	0.69	825	5.18
1 TOE, tonne oil equivalent	42 300	11 788	1.44	1	1 190	7.49
1 Sm^3 natural gas	40.00	9.87	0.00121	0.00084	1	0.00629
1 barrel crude oil (159 litres)	5 650	1 569	0.193	0.134	159	1

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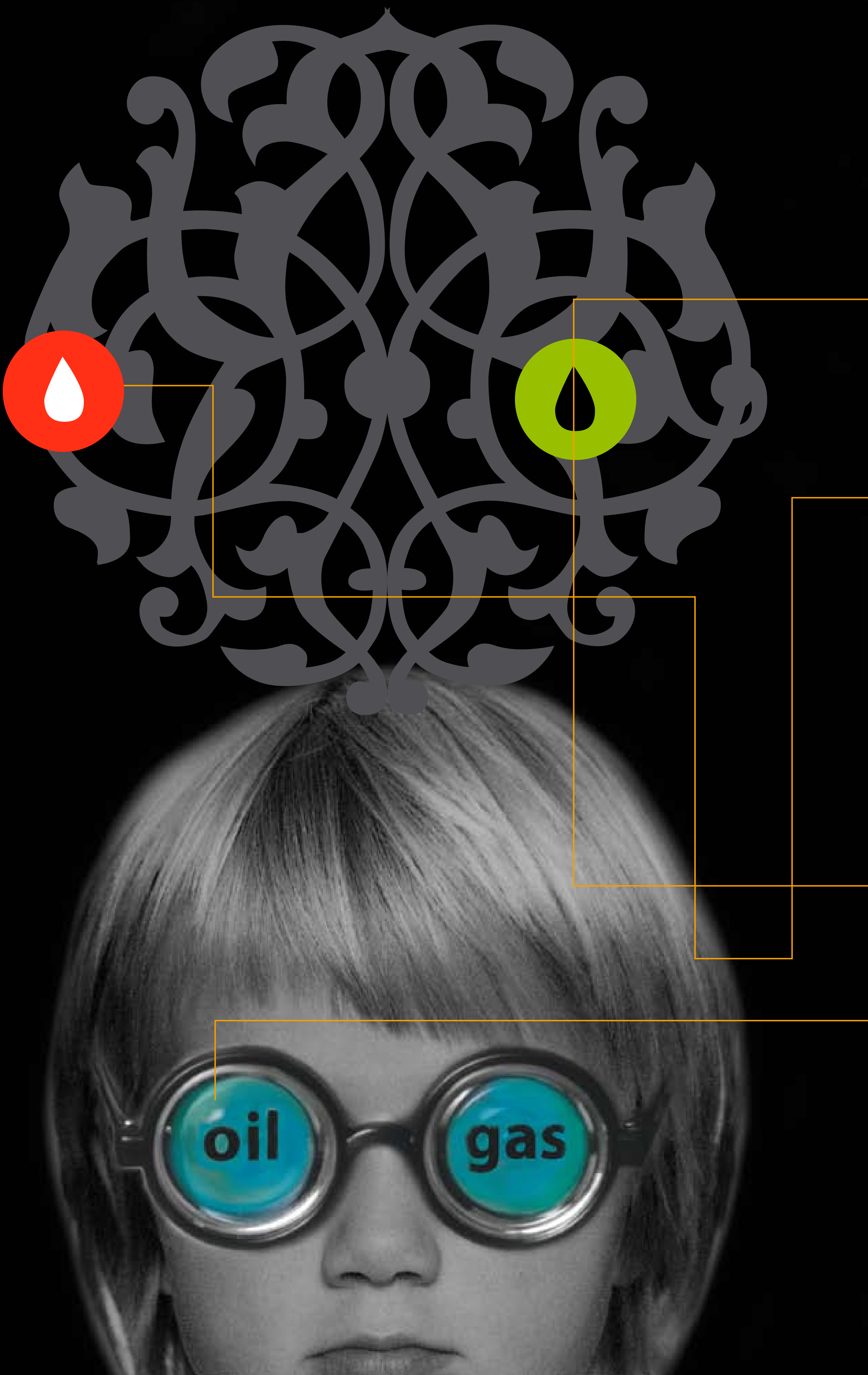

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