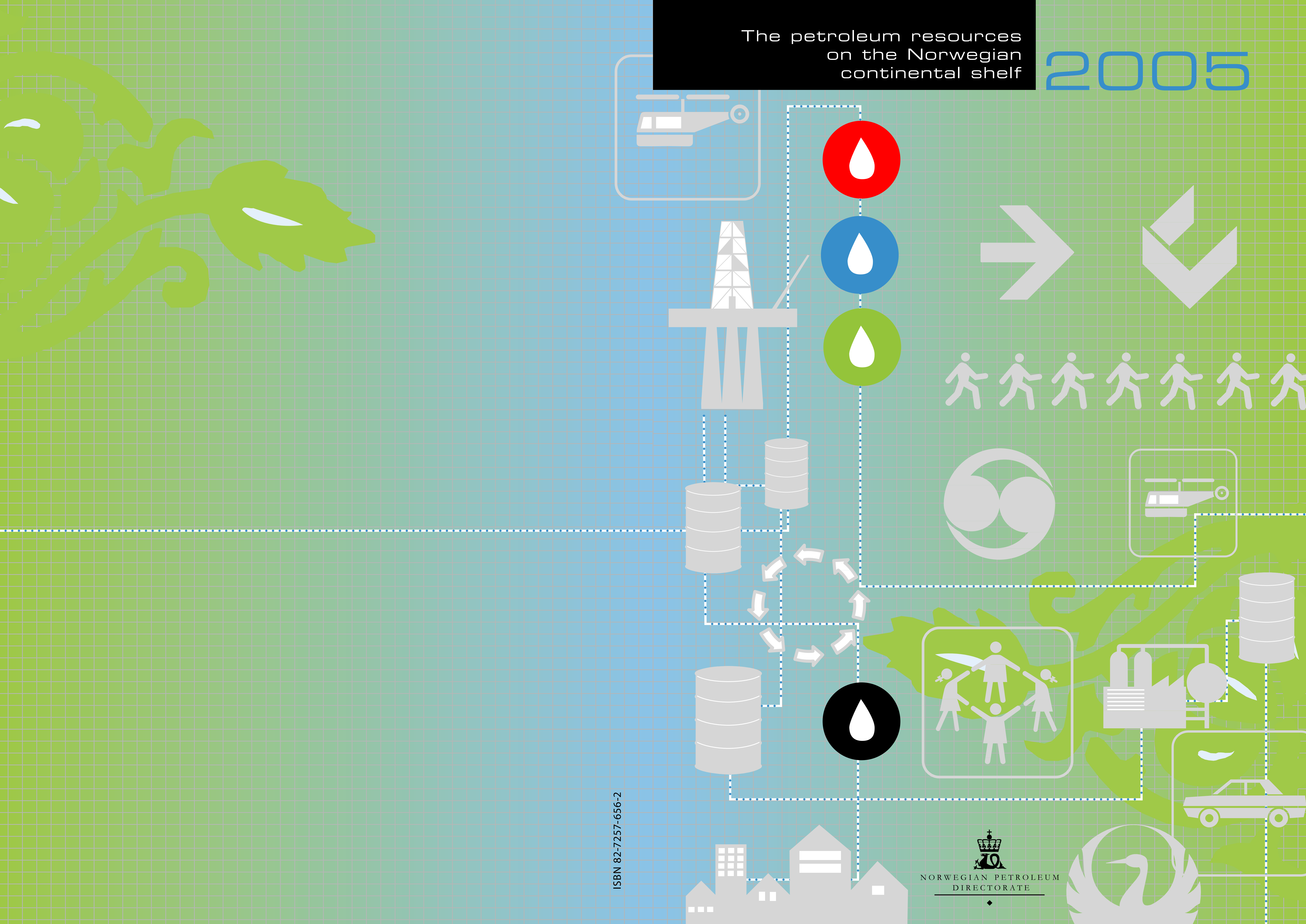
The petroleum resources on the Norwegian continental shelf

2005



ISBN 82-7257-656-2

NORWEGIAN PETROLEUM DIRECTORATE

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Translation: Richard Binns
Printed by: Kai Hansen, Stavanger
Paper: Arctic Volume 200/130 gr

NORWEGIAN PETROLEUM
DIRECTORATE

Preface

The Norwegian Petroleum Directorate shall contribute to creating the highest possible values for society from oil and gas activities, through a sound management of resources founded on safety, readiness and the external environment.

It is therefore vital that the Directorate maintains an overview of and evaluates the petroleum activities and petroleum 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 from the Directorate presents an updated survey of the petroleum resources on the Norwegian continental shelf.

Stavanger, June 2005

Gunnar Berge
Director General

Content

1 Challenges on the continental shelf

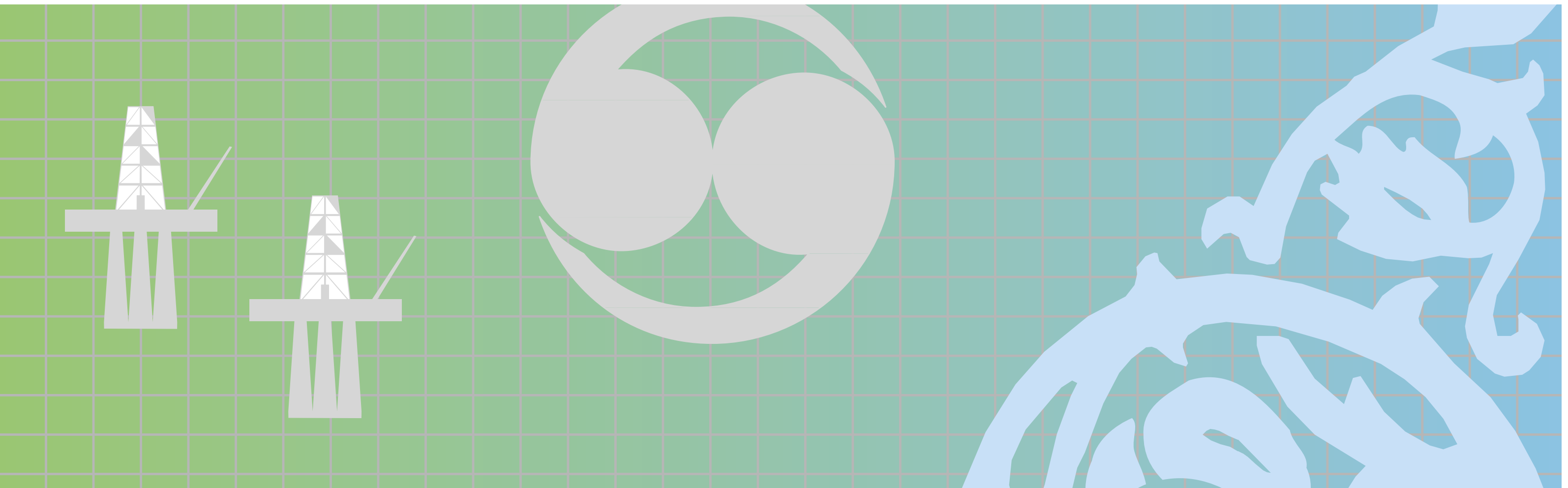
The task of the Norwegian Petroleum Directorate is to help to obtain the best possible value creation from the oil and gas activities. This is partly achieved by directing focus on challenges in the petroleum industry that can give improved utilisation of the resources and higher value creation for society. This report therefore takes up several important challenges. Exploration for oil and gas must take place if high production is to be maintained in the future. The effort to obtain more of the resources on the fields must continue. Measures must be found to enable the fields to be run more efficiently. There must be greater awareness of the effects on the costs and resources imposed by the various demands placed on the industry.

The Norwegian Petroleum Directorate is keen for Norway to have a long-term perspective on the oil and gas activities. The authorities require the petroleum industry to act in such a way that the resources will also benefit society as much as possible. This demands an active dialogue. It requires that the NPD maintains a good overview of the activities, keeps society informed and, at all times, points out the challenges faced by the activities.

Each year, the authorities draw up forecasts for oil and gas production, investments and revenues. These are based on the plans of the oil companies and the authorities' own assessments. In this report, we discuss how reliable these forecasts are and what is required to achieve the goals we set ourselves. The Norwegian Petroleum Directorate points out, here, that the oil remaining in the fields that are in production is decreasing rapidly and that if the targets are to be achieved there is an urgent need for measures to ensure that oil resources are put into production.

A great deal of uncertainty is attached to exploration for oil and gas. How much will be discovered? Will development be profitable? How quickly can the fields be put in production? The targets set by the authorities presuppose active exploration on the Norwegian continental shelf and that many profitable discoveries will be made. We estimate that approximately a quarter of the resources still remain to be found, but at the same time we point out that a huge exploration effort will be needed to find these resources. The authorities have an active exploration policy, giving the companies good possibilities for access to acreage to explore in both mature and immature areas. The oil companies are still showing great interest in the Norwegian continental shelf. It is also vital that more and more medium-sized and small companies take an active part in the activity in Norway, not least in exploration.

It is the recovery of oil and gas that creates the revenues. The task of profitably obtaining as much as possible from the fields is therefore one of the greatest and most important challenges. The Norwegian Petroleum Directorate has always actively supported and assisted the companies to ensure the highest possible recovery, both to utilise the infrastructure optimally and to extract as much of the resources as possible. In this report, we have chosen to focus on the oil recovery. We have also decided to direct attention to the very good effect gas injection has had on oil recovery in Norway. Gas injection still has a great potential. We point out that to exploit this optimally may require co-operation between companies and licensees. The Norwegian Petroleum Directorate believes the industry should enter into such cooperation when it can increase the profitability of this kind of project.



The increase in the recovery factor is often used as a measure for the work done to obtain more oil from a reservoir. The authorities have also set an overall goal for the oil recovery factor on the Norwegian continental shelf as a stretch target for the industry. In this report, the Directorate points out that the increase in the average recovery factor on the Norwegian continental shelf is beginning to flatten out and it is mainly just a few large fields that have ensured an overall increase in recent years. We also point out that many of the fields that will be developed in the future may have a lower recovery factor than some of the older fields. Consequently, it may now be more expedient to start to use an increase in the oil reserves as a measure of whether the reservoirs are being efficiently utilised, rather than an average recovery factor. In this report, the Norwegian Petroleum Directorate has therefore set a new, overall target for oil recovery, namely that the oil reserves in the next ten years must increase by five billion barrels. This is an ambitious goal which will demand a number of measures for improved oil recovery, many new fields in production and a high level of exploration.

Another major challenge on the Norwegian continental shelf is that the unit costs for oil recovery are rising strongly. It is getting more and more expensive to produce a barrel of oil. In this report, we point out that the operating costs for the installations on the Norwegian continental shelf will constitute an increasing share of the total costs. Raising the efficiency of the operations will be the key to both enhancing the recovery and meeting the rising unit costs. Making the operations more efficient does not only have to do with reducing costs viewed in isolation, but also means placing focus on raising the income account. It is about building flexibility into equipment, production strategies, maintenance philosophy and, not least, the production processes.

The Norwegian Petroleum Directorate believes that integrated operation (sometimes called e-operation) has a great potential for making many of the activities in the petroleum industry more efficient. Integrated operation can pave the way for new production processes, more efficient operations, lower costs on the installations and better utilisation of expertise and equipment.

We point out in this report that operating costs can be significantly reduced just by taking the best methods amd equipment into use. If new technology and production methods are developed, the potential for further reductions in costs is appreciable.

Both forecasts and resource inventories depend on the oil and gas resources being recorded and classified. In this report, we provide information about various means of classifying resources and have written a separate chapter that can be used as a reference source for this report or for other work discussing oil and gas resources. In addition, a chapter has been included that deals with terms and definitions that will be useful for both this report and general reference.

2 Resources and forecasts

2.1 Introduction

The Norwegian Petroleum Directorate prepares annual updates of estimates of the petroleum resources on the Norwegian continental shelf. These estimates, which include both discovered and undiscovered resources, are gathered together in an inventory called the resource account. The figures in the resource account represent what will be produced under given premises. The most important premises are that the petroleum industry is given permission to explore where the resources can be found and that the companies thereafter decide to produce what they have discovered.

The account covers all the areas on the Norwegian continental shelf where the Norwegian Petroleum Directorate has evaluated the resource basis. This means that areas not currently open for petroleum activities are also included in the account. The area with overlapping claims in the Barents Sea and the continental shelf surrounding Jan Mayen are not included. About 60 per cent of the Norwegian continental shelf has been opened for exploration, and large areas are still not explored (Figure 2.1).

No-one knows exactly how much oil and gas can be produced from the Norwegian continental shelf. The estimate of how much can be profitably produced is partly based on assumptions regarding the geology, aspects of reservoir technology, future production and costs, and developments in technology and know-how.

The total recoverable resources are now calculated to be between 10.6 and 16.3 billion Sm³ oil equivalents (o.e.), with an expected value of 12.9 billion Sm³ o.e. (Figure 2.2), 4.0 billion Sm³ o.e. of which have been produced. The estimate of how much remains to be found is 3.4 billion Sm³ o.e., with a range of uncertainty spanning 2.1 - 4.9 billion Sm³ o.e.

2.2 Resource classification

The Norwegian Petroleum Directorate employs a resource classification to calculate and show how much of the resources

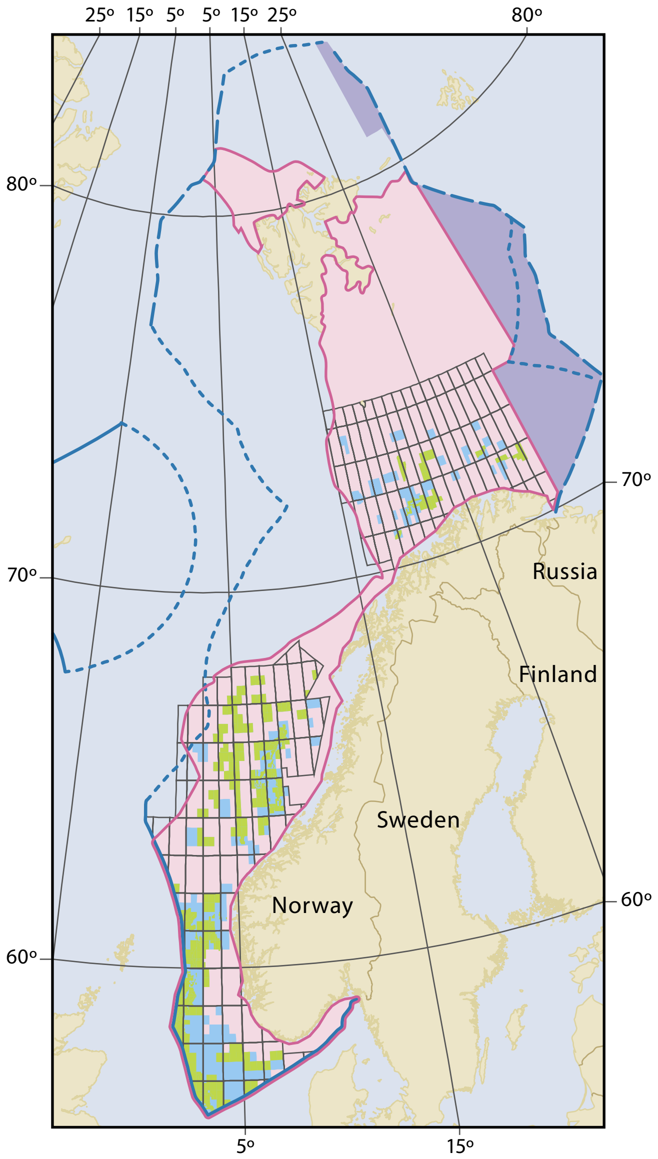


Figure 2.1 Map of the Norwegian continental shelf with adjacent boundaries, showing areas where the Norwegian Petroleum Directorate has evaluated the resource basis.

Resource class		Category		Oil mill. Sm³	Gas bill. Sm³	NGL mill. tonn	Cond. mill. Sm³	Sum o.e. mill. Sm³
Historic production		0	Sold and delivered	2870	948	81	72	4044
Field	Reserves	1	Reserves in production	1084	1459	101	46	2781
		2	Approved plan	126	597	14	40	788
		3*	Decided by the licensees	16	330	8	0	361
		Sum reserves		*1225*	*2386*	*123*	*86*	*3930*
	Contingent resources	4	In the planning phase	176	128	23	7	355
		5	Recovery likely, but not clarified	96	62	8	6	178
		7F	New discoveries tied to fields being evaluated	6	0	0	0	6
		7A	Possible future incr. recovery measures	125	100			225
		Sum contingent resources in fields		*403*	*290*	*31*	*13*	*764*
	Sum reserves and contingent resources in fields			*1627*	*2676*	*153*	*99*	*4694*
Discovery	Contingent resources	4F	In the planning phase	88	159	19	15	299
		5F	Recovery likely, but not clarified	88	324	1	30	443
		7F	New discoveries being evaluated	3	0	1	0	4
	Sum contingent resources in discoveries			*179*	*483*	*21*	*44*	*746*
Undiscovered resources		8 and 9	Prospects and unmapped resources	1160	1900		340	3400
Total resources			*Sum total resources*	*5837*	*6007*	*255*	*556*	*12885*
			Sum remaining resources	*2967*	*5059*	*174*	*484*	*8840*

* Includes reserves from discoveries

Table 2.1 The resource account as of 31 December 2004.

can be produced. This classification shows the volumes of petroleum approved for development (reserves), the volumes requiring clarification and depending on decisions (contingent resources) and the volumes it is assumed will be found (undiscovered resources). In addition, it shows where the resources are situated in the development chain from undiscovered resources via discoveries, development, production, and on to when production ceases. A field may have several projects or plans to recover deposits in different resource categories.

The classification (see Figure 6.1, page 48) draws a clear distinction between resources and reserves. Resources are all the estimated volumes of petroleum. The expression covers both in-place and recoverable volumes, even though only the recoverable resources are classified.

The term reserves is, here, only used for future, recoverable volumes of petroleum in projects that are approved for development or are already in production. This differs from the usual use of the term reserves, which generally refers to remaining, uncertain, and perhaps even undiscovered, resources. Our use of the term, however, covers more than the restricted definition which the petroleum companies use in their reports to the American stock exchange authority (see Chapter 6). The classification forms the basis for the Directorate's resource account.

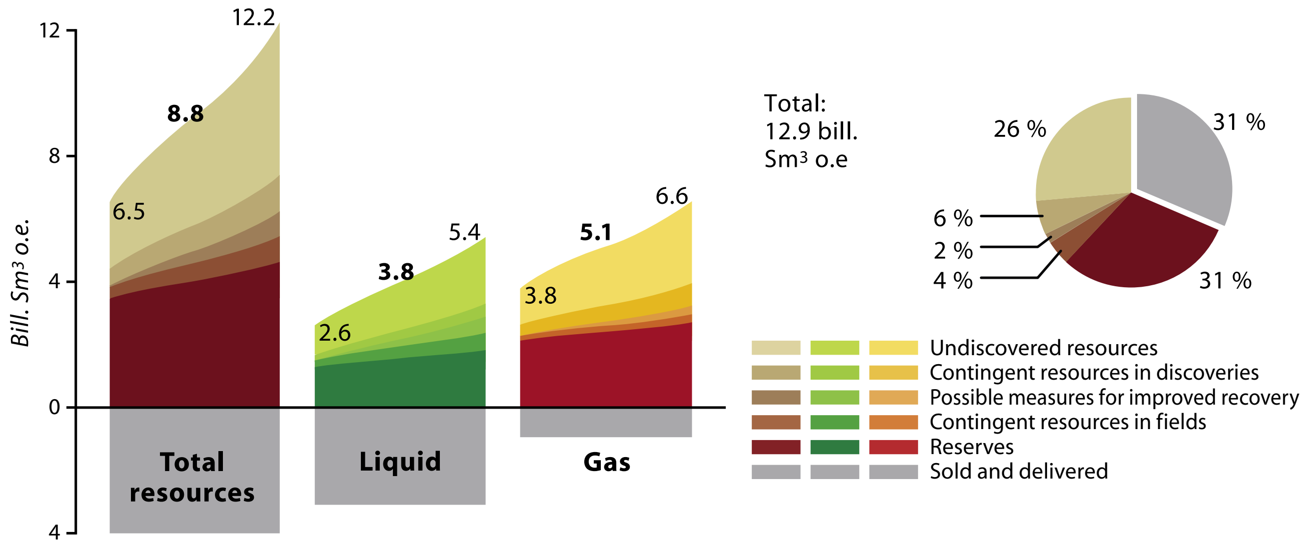


Figure 2.2 Distribution of the total, recoverable petroleum resources on the Norwegian continental shelf as of 31 December 2004.

The resource account (Table 2.1) is based on a number of technical and financial premises. The estimates are based on the development solutions which the petroleum companies choose or consider for the various projects, or on the Directorate's assessments of which development solutions may be relevant. The Directorate bases its assessment of the most mature resources (reserves and resources in specific development projects and projects for improved recovery) on the development solutions which the oil companies consider are relevant. This gives development costs that are accommodated to the prerequisites concerning prices which the companies themselves use as a basis. Today, most projects are assessed on the basis of an oil price of between 20 and 25 dollars a barrel. If the price of oil remains high for a long time, and the companies raise the price prerequisites they use in their economic evaluations of the projects, the volumes in these resource classes will increase. In the same way, lower oil prices will lead to a reduction in the recoverable volumes.

The estimate of the undiscovered resources must be viewed in a longer time perspective. This is an estimate which the Directorate makes without direct regard to the prices of oil and gas. In other words, it is an estimate based chiefly on geological and technical assessments. Nevertheless, general assumptions are added regarding the recovery factor and how small the smallest deposits explored for will be. These assumptions remain unchanged from year to year. However, both the recovery factor and the assessment of the smaller deposits will be affected by the technological development and the prices. The assessment of which areas the authorities make available for new exploration will also be affected by this. It must therefore be assumed that if the oil price stands at a different level for a long time, or major advances in recovery technology are made, future estimates of the undiscovered resources will be affected. The Directorate has not changed its estimate of the undiscovered resources from the Resource Report in 2003.

The Directorate's resource classification is one of several recognised means of categorising resources. Chapter 6 gives a thorough description of this classification, and of two other international classification systems.

2.3 Discovered resources

2.3.1 Discovered, in-place resources

In all, about 18 billion Sm³ o.e. of oil and gas have been proven on the Norwegian continental shelf (Figure 2.3). This quantity is termed the originally-in-place resources and covers all the oil and gas present in all proven deposits, including resources in discoveries which, with present-day technology and economic premises, are most unlikely to be utilised. A large proportion of the oil and gas will remain in the reservoirs when production ceases.

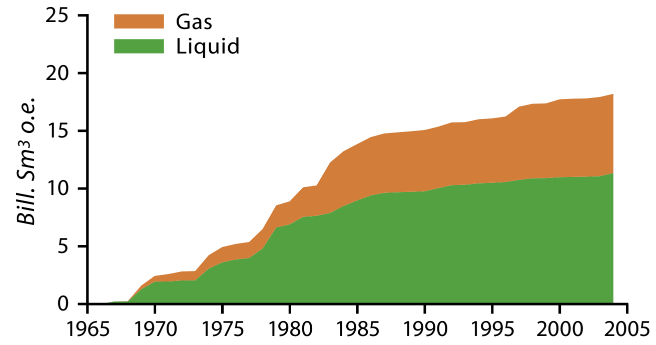


Figure 2.3 Trend in the accumulated, discovered, in-place liquids and gas from 1967 to 2004. The present-day estimates are fed back to the year when each discovery was made.

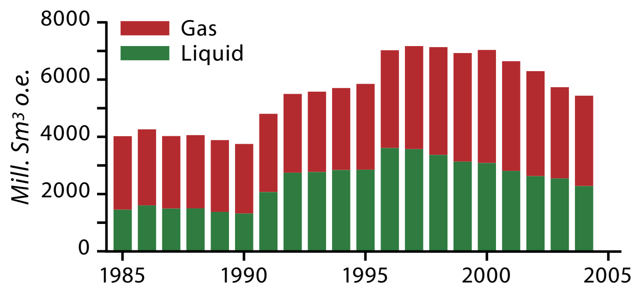


Figure 2.4 Annual estimates of the remaining, discovered resources from 1985 to 2004.

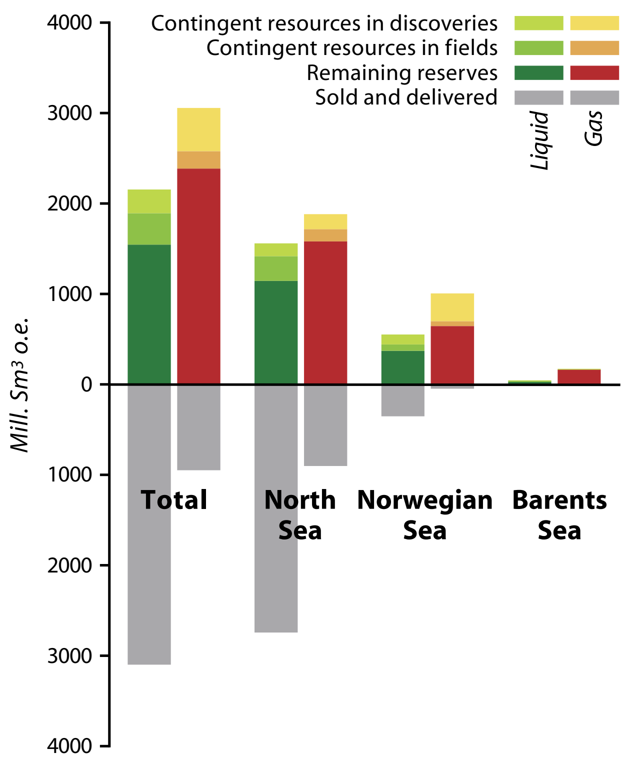


Figure 2.5 Geographical distribution of the discovered, recoverable petroleum resources.

How many of these resources can be recovered depends upon many factors (natural, technical, environmental and economic), which will vary from deposit to deposit.

2.3.2 Discovered, recoverable resources

The discovered, recoverable resources can be divided into a) remaining, discovered, recoverable resources, and b) sold and delivered quantities.

The remaining, discovered, recoverable resources are estimated to be 5.2 billion Sm³ o.e. The remaining, recoverable liquid resources (oil, NGL and condensate) are estimated to be 2.3 billion Sm³ o.e., 1.8 billion Sm³ of which are oil. This estimate varies over time, depending on how much is discovered during exploration, how much is expected to be extracted from the existing fields and how high the production level has been. The estimate is at its lowest level since 1991 (Figure 2.4), at the same time as the production is at a peak level.

The remaining, discovered, recoverable resources comprise 3.4 billion Sm³ o.e. in the North Sea, 1.6 billion Sm³ o.e. in the Norwegian Sea and 0.2 billion Sm³ o.e in the Barents Sea.

2.3.3 Reserves

The portion of the remaining, discovered, recoverable and saleable quantities that it has been decided to develop, or which are already in production, is called reserves. As of 31 December 2004, 48 fields were in production on the Norwegian continental shelf, 42 in the North Sea and six in the Norwegian Sea. Five fields were, in addition, approved for development. Production had ceased on 13 fields. 70 per cent of the reserves are in the North Sea, 25 per cent in the Norwegian Sea and five per cent in the Barents Sea.

As new projects for development or improved recovery are approved, the resources are redefined as reserves. Increases in reserves can be traced on both the individual fields and the continental shelf as a whole.

2.3.4 Growth in reserves

The increase in reserves on individual fields is called the reserves growth. A reserves growth takes place on most fields in all the world's petroleum provinces, and contributes substantially to increased production. Only five of the 34 oil-producing fields studied on the Norwegian continental shelf have had a negative development in their

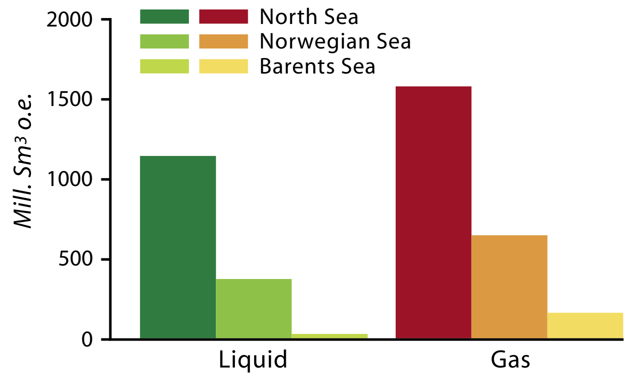


Figure 2.6 Geographical distribution of the liquid and gas reserves.

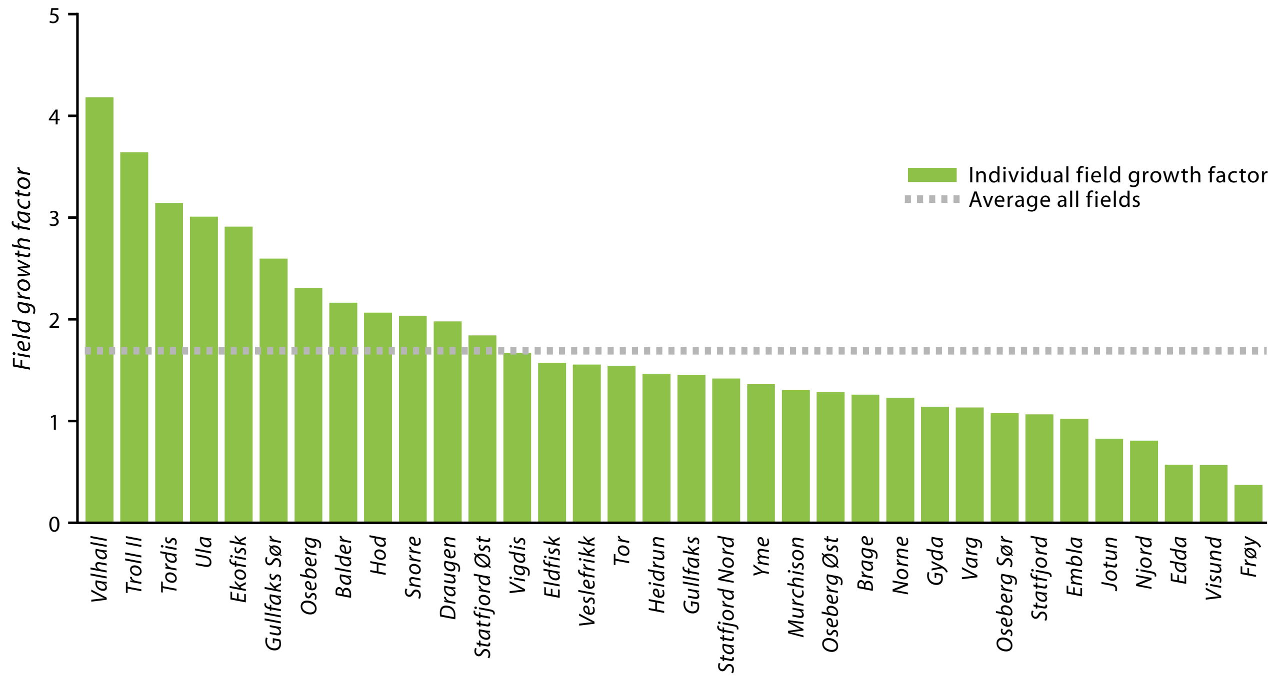


Figure 2.7 Factors for the growth in reserves of oil relative to the volume in their original plans for development and operation.

oil reserves relative to their original plans for development and operation. The majority have had a significant growth in their oil reserves (Figure 2.7). The average growth factor for reserves for all oil fields is now 1.7.

Figure 2.8 shows the growth in reserves for the same fields over time. The estimate of the reserves may often be reduced after the Plan for Development and Operation is approved, when information is acquired from drilling of production wells and how production on the fields behaves. As more knowledge of a field is obtained, the estimate of the reserves will, nevertheless, gradually increase provided projects for improved recovery can be implemented.

There has been a gross increase in the oil reserves (that is, the annual increase in the reserves before subtracting the production) on the Norwegian continental shelf in all except two years (Figure 2.9 and 2.10). This has taken place despite variations in development activity and oil prices. There are two main reasons for this trend. Extensive development of large and medium-sized fields took place in the 1980s, and in the 1990s there was a great increase in the estimates of the reserves on the same fields.

The net change in the reserves, that is the annual change in the reserves with production subtracted, is shown in figure 2.11. The high oil production combined with the fields that are being developed being smaller than previously, and fewer projects for improved recovery, has resulted in a significant reduction in the remaining reserves in recent years.

During the last ten years, the overall increase in the gross oil reserves has been 1600 million Sm³. More than half of this volume stems from projects for improved recovery. A third comes from development of discoveries made prior to this ten-year period. Just less than ten per cent results from new discoveries having been made that have also been approved for development in this period (Figure 2.12). In the course of the same ten years, 1710 million Sm³ of oil have been produced.

2.3.5 Contingent resources in fields

In most of the fields, in addition to the reserves, there are resources that can be redefined as reserves in the near future if the licensees decide to do so. In the resource account, 349 million Sm³ o.e. are defined as contingent liquid resources. Two-thirds of this volume is in projects for improved recovery that are in the planning phase and for which the Norwegian Petroleum Directorate expects a decision on recovery to be made within the next few years. A further 125 million Sm³ o.e. of liquid are defined as resources from possible measures for improved recovery.

Contingent gas resources in the fields comprise 190 billion Sm³. Two-thirds of these are in the planning phase. In

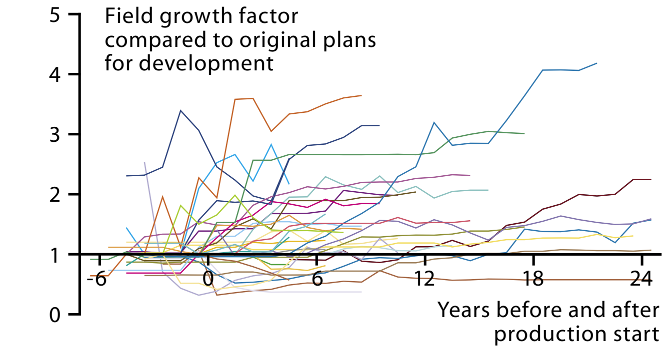


Figure 2.8 Trend in the growth in reserves of oil per field compared with their original plans for development and operation.

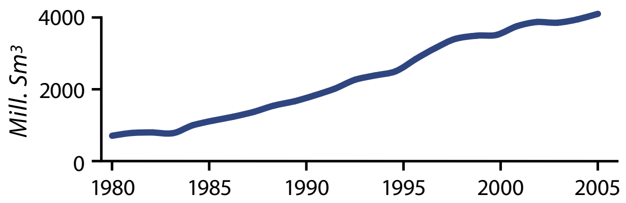


Figure 2.9 Accumulated gross increase in the reserves of oil in 1980-2004.

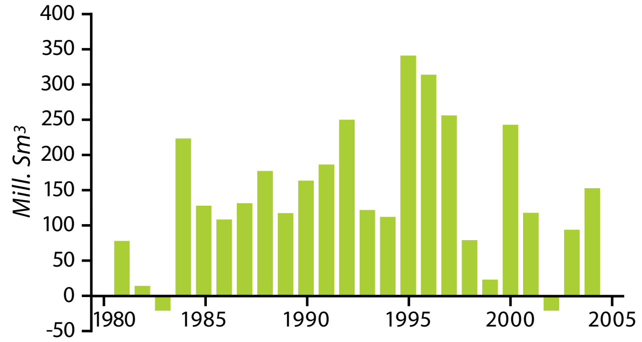


Figure 2.10 Annual gross increase in the reserves of oil in 1980-2004.

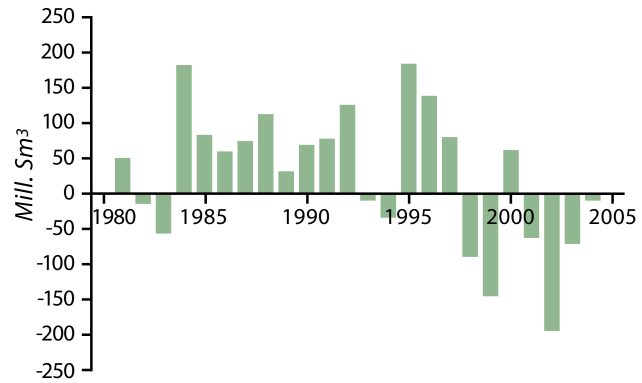


Figure 2.11 Annual net increase in the reserves of oil in 1980-2004.

addition, there are other possible measures for improved gas recovery for 100 billion Sm³.

Ten years ago, the contingent resources in fields amounted to six per cent of the recoverable resources. Today, they comprise four per cent. The Norwegian Petroleum Directorate estimates that more than 90 per cent of the liquid and 85 per cent of the gas now classified as contingent resources will be redefined as reserves by 2014.

2.3.6 Discoveries

The resources in 60 discoveries for which a decision for development has still not been taken comprise eight per cent of the remaining, recoverable resources (Figure 2.13). Ten years ago, the portfolio consisted of 84 discoveries, which comprised 13 per cent of all the recoverable resources on the continental shelf. During the last ten years, it has been decided to develop 24 oil discoveries and 17 gas discoveries.

The resources in these 60 discoveries comprise 742 million Sm³ o.e., 40 per cent of which concerns projects in the planning phase. Two-thirds of the volume is gas resources. The gas discovery, 6506/6-1 ("Victoria"), is the largest, and is responsible for almost 20 per cent of the volume in the discovery portfolio. Six discoveries account for 60 per cent of the volume (Figure 2.14). The largest oil discovery, 15/3-1 S Gudrun, containing 15 million Sm³ of oil, was made in 1975.

It is uncertain whether all discoveries can be developed. Since a large number of the remaining discoveries are small, access to infrastructure (for example, installations with production, processing and transportation capacity) is the most critical factor. This particularly applies to gas discoveries which must either wait for vacant capacity in existing or planned gas transport pipelines, or are too small for a separate means of gas transport to be profitably developed. Moreover, reservoir complexity and the composition of the oil and gas in the discovery may make a few discoveries difficult to develop.

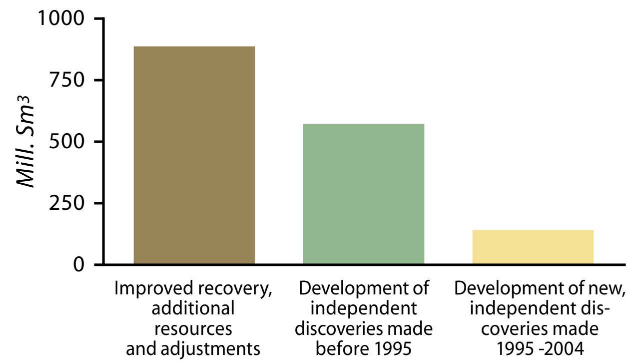


Figure 2.12 Total gross increase in the reserves of oil in 1995-2004.

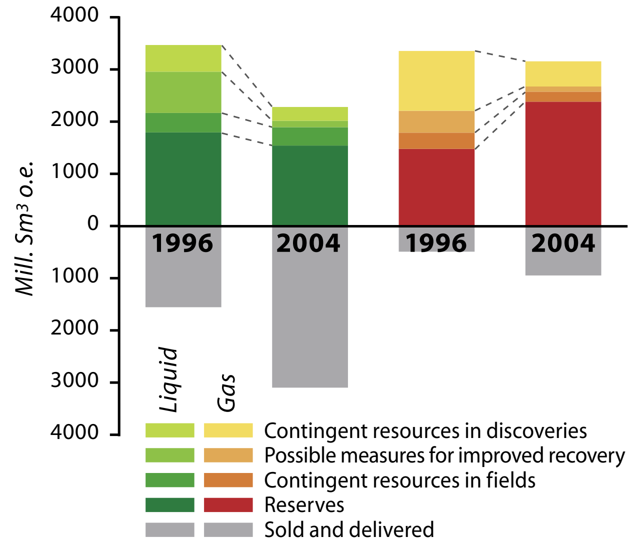


Figure 2.13 Discovered resources in 1996 and 2004.

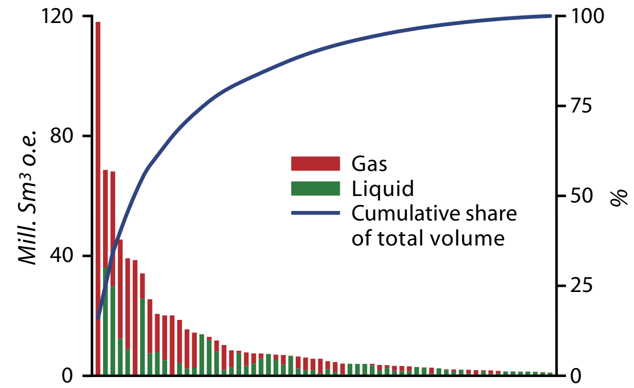


Figure 2.14 Sixty discoveries where development decision has not yet been made, ranked according to the size of the recoverable volumes.

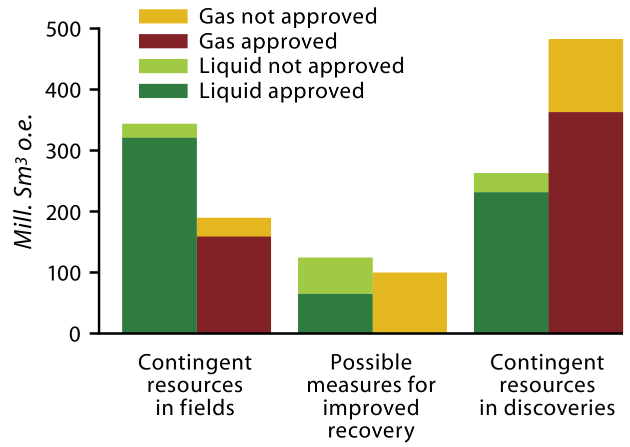


Figure 2.15 Volumes of forecasted decisions on development in the next 10 years, with the remaining volumes relative to the present resource account.

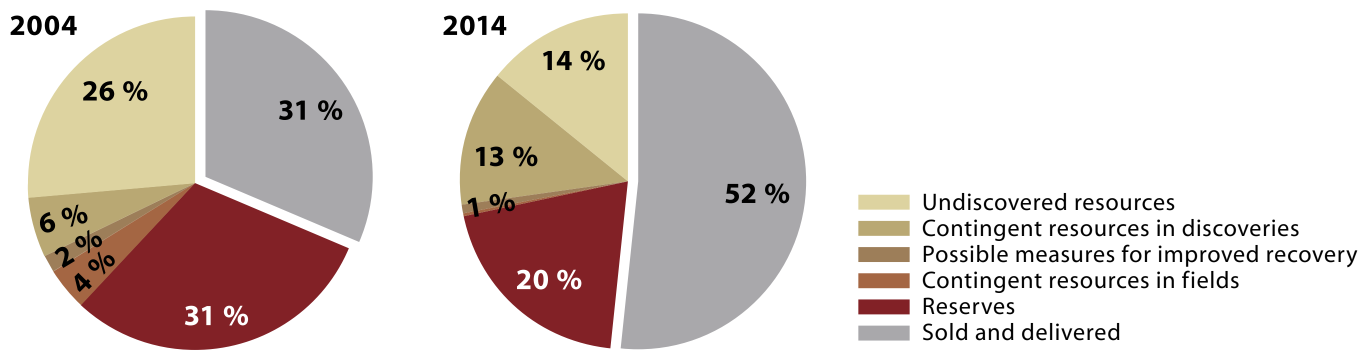


Figure 2.16 State of the resources in 2004 and 2014 according to the present-day forecast.

If present-day plans are carried out, decisions will be taken during the next ten years to develop all the discoveries that are now in the planning phase. In addition, the NPD assumes that decisions will be taken to recover nearly 90 per cent of the liquid and 75 per cent of the gas in discoveries where development is now probable but not clarified (Figure 2.15). With this in mind, it is possible to predict the resources for 2014. Based on the present-day forecast, discoveries will make up 13 per cent of the total resources in 2014 (Figure 2.16). A large part of the discovery portfolio in 2014 will therefore consist of discoveries which will be made during the next 10 years. The forecasts also take into account assumptions regarding future production of undiscovered resources.

2.4 Undiscovered resources

A substantial part of the petroleum resources on the continental shelf have still not been discovered. These resources are found in all three provinces, the North Sea, the Norwegian Sea and the Barents Sea. Calculations of the undiscovered resources made by the Norwegian Petroleum Directorate show that the assumed, recoverable quantities are approximately equally large in all three provinces, although the quantity of gas is likely to be largest in the Norwegian Sea and that of oil in the North Sea (table 2.2).

Uncertainty is always attached to the calculations of the undiscovered petroleum resources. The estimates are based on a great many assumptions. There is usually also a difference in the estimates made by different companies and institutions. To illustrate the uncertainty in the Directorate's estimate, in addition to the statistically expected mean, a low (P90) and a high (P10) estimate is also stated. The estimate for the undiscovered resources on the Norwegian continental shelf has a statistically expected mean of 3.4 billion Sm³ o.e. and is within the range of 2.1 (P90) to 4.9 (P10) billion Sm³ o.e. There is also a small possibility (20 per cent) that the undiscovered volume will be less than 2.1 or more than 4.9 billion Sm³ o.e.

Province	Liquid	Gas	Total		
			P90	Mean	P10
North Sea	690	500		1190	
Norwegian Sea	410	810		1220	
Barents Sea	400	590		990	
Total	1500	1900	2100	3400	4900

Table 2.2 Undiscovered petroleum resources (in millions Sm³ o.e.)

Several different methods exist for calculating the undiscovered petroleum resources. Which method is chosen partly depends upon how much information is available about the areas and how well the areas are investigated. The Norwegian Petroleum Directorate employs a method called play analysis.

Play analysis is based on a set of circumstances that can lead to the formation of recoverable deposits of oil or gas in the substrata. A play is both concrete and abstract. It is concrete with regard to geographical and geological limitations and abstract since it is a calculation model. The circumstances that are evaluated in the analysis are:

- Is a reservoir rock present and does it have adequate quality?
- Are cap rocks present and structures that can form traps for petroleum?
- Is there a source rock that has formed hydrocarbons, and have the hydrocarbons migrated into the reservoir rock after the traps formed?

A play exists when geologists believe that a set of these circumstances is present in an area.

A play may be either unconfirmed or confirmed. It is unconfirmed if it has still not been shown that the play can contain deposits of oil and gas. When at least one discovery of producible hydrocarbons has been made, a play is regarded as confirmed.

The Norwegian Petroleum Directorate has defined 68 plays on the Norwegian continental shelf, and 32 of these have so far been confirmed.

For each play, a calculation is made of how much oil and gas it may contain. Uncertainty is attached to all the parameters that enter into the calculations, and this is made allowance for by inserting probability distributions. The volumes of petroleum are calculated by statistical methods using Monte Carlo simulation. The results for each individual play are then aggregated using statistical methods and presented as a probability distribution for the total volume. In the case of unconfirmed plays, the probability that the play is in fact "true" is also estimated. This figure is included in the statistical calculation of all the undiscovered resources.

The Directorate has based its estimate of the undiscovered resources on a recovery factor of just less than 40 per cent of the oil and just over 60 per cent of the gas. These are average values. There is sometimes a considerable spread in the recovery factor both within a play and between the various areas on the continental shelf.

The estimate for the undiscovered resources represents the potential for what may be discovered and recovered based on geological and technical assessments. For this volume actually to be proven and produced requires geological mapping, drilling of exploration wells, investments in development and production of profitable resources. From the outset, the calculations are not based on any other premises regarding petroleum prices than that the very smallest discoveries are omitted from the estimate.

2.5 Forecasts

The future production of petroleum on the continental shelf depends upon many factors. Some of the most important are the remaining existence of resources and the ability to discover and develop new discoveries. Future activity also depends upon expectations regarding the prices of oil and gas. This means that considerable uncertainty is attached to the forecasts.

The Norwegian Petroleum Directorate prepares both short- and long-term annual forecasts for oil, gas, NGL and condensate production. The short-term forecasts are largely based on data from the operators, including the prices of oil and gas which they use in their economic calculations. The Directorate adjusts the short-term forecasts for fluctuations in the rig market, expected gas sales and probable starting times for projects. The more long term a forecast is, the more important are the evaluations of it made by the authorities. One of the most important premises on which the authorities base their evaluations is the amount of gas that will be sold in the future. The long-term forecast places that at 120 billion Sm³ a year from 2011 onwards. If it rises significantly beyond that, much of the production and many of the investments will be advanced. On the other hand, if it the sales level is significantly lower, much of the production and many of the investments will be postponed.

2.5.1 Short-term forecast (2005-2009)

The Norwegian Petroleum Directorate expects the total production of oil and gas to rise in the next five years. In 2005-2009, nearly 1400 million Sm³ o.e. are expected to be produced and sold. This is approximately ten per cent more than in the last five years.

The production of liquid, which has stood at 185-195 million Sm³ o.e. a year (3.2 million barrels a day) since 1996, is expected to remain at that level until 2006 or 2007. Kristin, a gas and condensate field, contributes greatly to the maintenance of this level. The subsequent decline rate for liquid is calculated to be around five per cent a year. The basis for this forecast is that more than 15 new fields will help to maintain the production during this period at the same time as two fields are expected to be closed down (Figure 2.17). The Directorate expects 130 million Sm³ o.e. of NGL and condensate to be produced during 2005-2009.

At the same time as liquid production falls, gas production will increase. The Directorate assumes that the sale of gas from the continental shelf will increase smoothly from the present figure of less than 80 billion Sm³ a year to 120 billion Sm³ a year in 2011 (Figure 2.18).

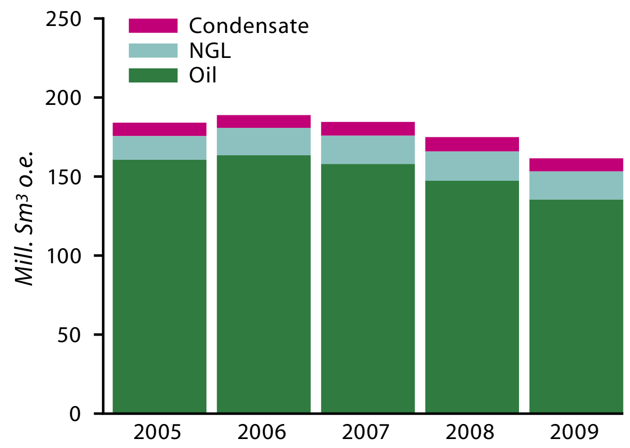


Figure 2.17 Expected production of liquids in 2005-2009.

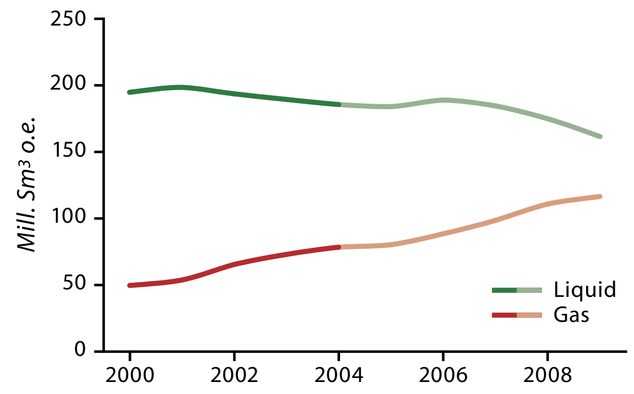


Figure 2.18 Historical and forecasted production of liquids and gas in 2000-2009.

The forecast for the liquid production in the next five years is marked by falling production of what are now reserves in existing fields at the same time as the ambitions are high for new projects in the form of improved recovery from existing fields and development of proven discoveries. It assumes that 97 per cent of the production in this period will come from fields already in operation or currently being developed, along with related projects for improved recovery (Figure 2.19).

There is uncertainty in the short-term forecast for oil production as regards both the total volume that can be produced in the period and the annual rate. A total of 760 million Sm^3 of oil is expected to be produced in 2005-2009 (Figure 2.20), 100 million Sm^3 less than in the previous five-year period. The uncertainty is estimated to be +/- 15 per cent and is chiefly attached to the ability of the reservoirs to supply oil and the date the new projects will start.

Moreover, uncertainty is always attached to the regularity of fields that are in operation. This becomes apparent in the annual uncertainty (Figure 2.21). A relatively long, unplanned, shut down of a field will naturally lead to lower production in the year it occurs, but not necessarily the following year.

The Norwegian Petroleum Directorate expects that 500 billion Sm^3 of gas will be sold in 2005-2009, while 175 billion Sm^3 will be used for injection purposes. Twice as much gas will be sold in 2005-2009 as in the previous five years. Troll, Åsgard, Sleipner Vest and Kvitebjørn contribute to more than half of this. In addition, production from Kristin, Snøhvit and Ormen Lange is expected to start in 2005, 2006 and 2007, respectively. Nearly ten per cent of the sale of gas during the period is expected to come from new developments and projects. Uncertainty is naturally also attached to the forecasts of gas sales, the uncertainty being particularly attached to when the fields go on stream.

Investments on the Norwegian continental shelf are at a record high level. Approximately 83 billion NOK are expected to be invested in platforms, wells, pipelines and onshore facilities in 2005 (Figure 2.22). A further six billion NOK will be spent on exploration. Well over 300 billion NOK will be invested in the period up to 2009. The investments are expected to gradually decrease during the period as the developments of Ormen Lange, Snøhvit and Kristin are completed, because the discovery portfolio does not currently contain any opportunities for major development.

A fifth of the investments forecasted for 2005-2009 are expected to be spent on constructing new installations, a fifth on modifying existing installations, a fifth in connection with pipelines and onshore facilities, and two-fifths on drilling development wells (Figure 2.23). About a fifth of the investments in new installations, representing only four per cent of the total investments, are expected to be spent on constructing fixed subsea installations.

The uncertainty in the forecast for investments for 2005-2009 (Figure 2.24) is based on experience gained with deviations in these forecasts. The investments will be higher than the basic forecast if projects to recover resources in fields and discoveries are phased in earlier than assumed. Later phasing-in of new discoveries, lower investments to recover the reserves in operating fields and the possibility that fewer projects on fields will be agreed will be the most important reasons for lower investments than assumed in the basic forecast.

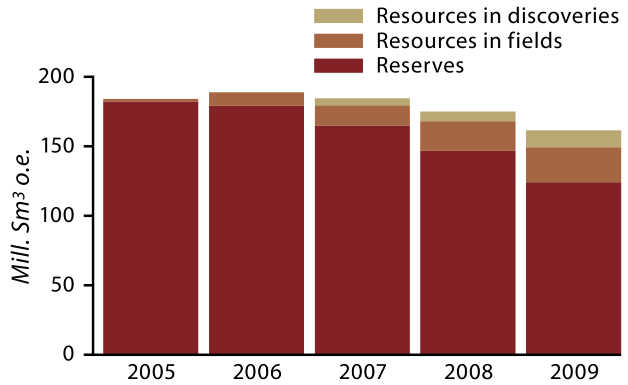


Figure 2.19 Expected production of liquids, distributed according to the maturity of the resources in 2005-2009.

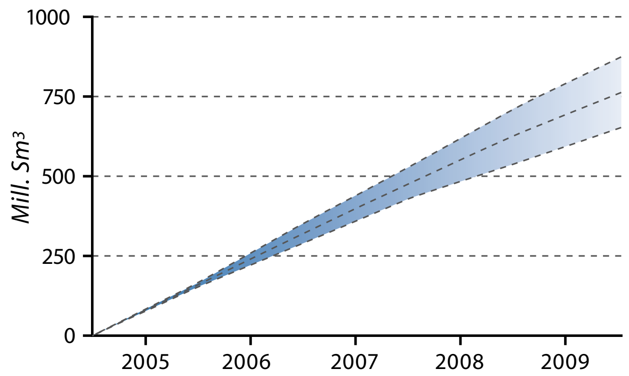


Figure 2.20 Accumulated uncertainty in the oil production up to 2009.

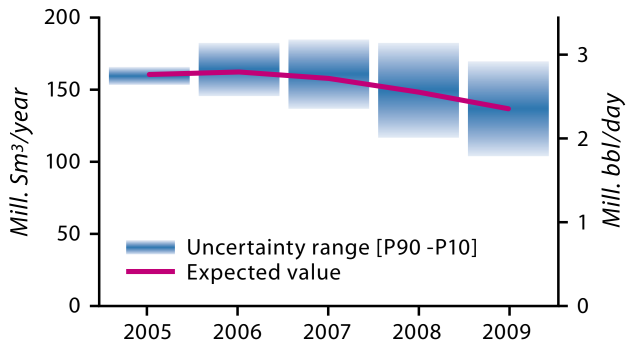


Figure 2.21 Annual uncertainty in the oil production in 2005-2009.

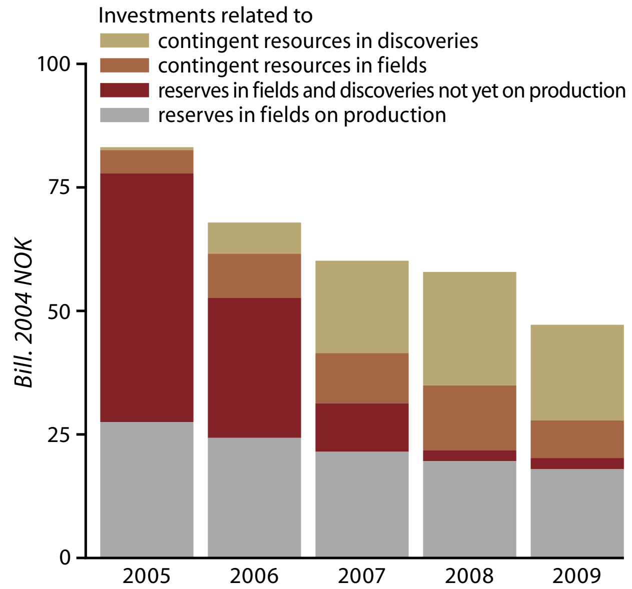


Figure 2.22 Forecast for investments in 2005-2009, distributed according to the maturity of the projects.

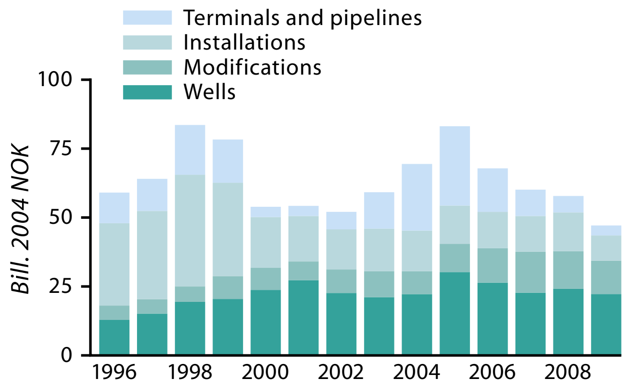


Figure 2.23 Historical and forecasted investments in 1996-2009.

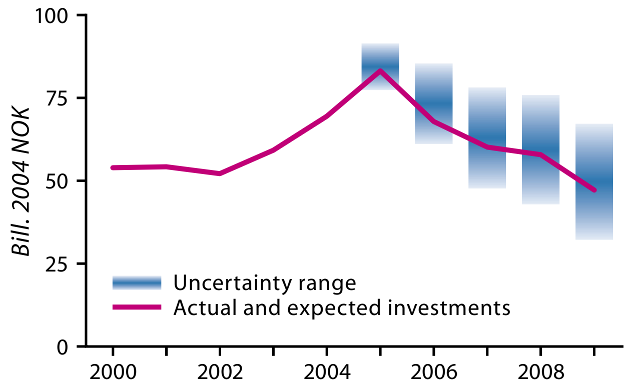


Figure 2.24 Historical and forecasted investments in 2000-2009, with the annual uncertainty.

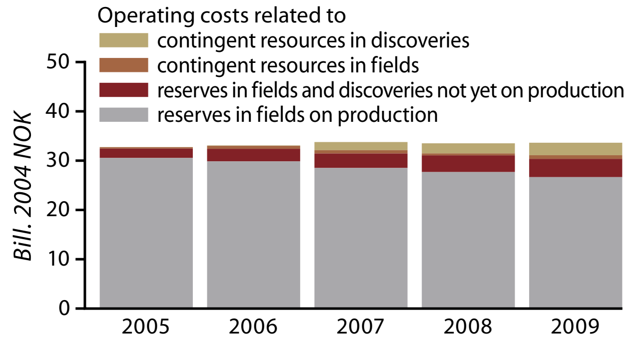


Figure 2.25 Forecast for operating costs in 2005-2009, distributed according to the maturity of the projects.

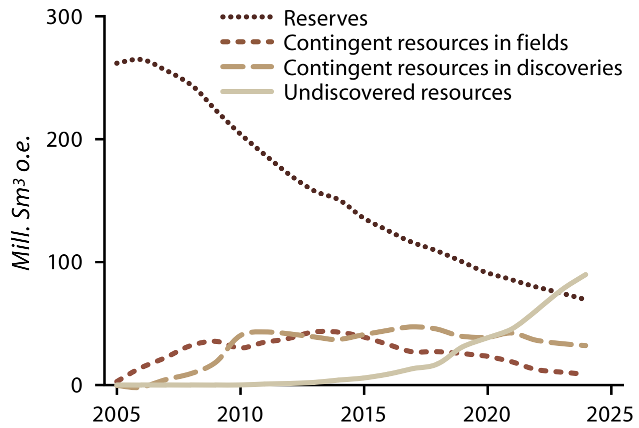


Figure 2.26 Long-term forecast for 2005-2024, distributed according to the maturity of the resources.

The operating costs are estimated to be just less than 35 billion NOK in 2005, and will remain at that level through 2005-2009 (Figure 2.25). The vast majority (95 per cent) of the operating costs are linked with recovering current reserves.

2.5.2 Long-term forecast (2005-2024)

The Norwegian Petroleum Directorate expects 4.7 billion Sm^3 o.e. to be produced from the continental shelf during the next 20 years. This is 15 per cent more than has been produced so far. Two-thirds of the production in this period will come from fields that are already in production or have been approved for development. A further 11 per cent is expected to come as improved recovery from the same fields. During this period, 14 per cent of the production will come from the development of proven discoveries and eight per cent from discoveries that have still not been made. Even in this long-term perspective, there is a modest contribution from undiscovered resources (Figure 2.26).

This is because assumptions regarding moderate exploration activity, gas sales accommodated to the present-day transport capacity (120 billion Sm³ a year) and an average lead time from discovery to development of seven to ten years have been fed into this scenario.

The resources have undergone significant maturing since White Paper no. 38 (2001-2002) introduced the concept of a "decline scenario" based on the production of what were reserves in 2002. The updated forecast for the period up to 2024 is based on a more than 30 per cent rise in the volume of reserves compared with that presented in the White Paper. This comprises a fifth of the remaining, proven resources on the continental shelf. The forecast shows a rise in the total production until 2008, after which there will be an annual fall of approximately three per cent (Figure 2.27). Figure 2.28 shows that liquid production will decrease, whereas gas sales will rise to 120 billion Sm³ a year from 2011 (Figure 2.29).

2.5.3 Forecasts for emissions and discharges

Oil and gas production leads to emissions to the atmosphere and discharges to the sea. The emissions are chiefly carbon dioxide (CO_2) and nitrogen oxides (NO_X) originating from energy generation on the installations, flaring and cold venting. Volatile organic hydrocarbon compounds (nmVOC – non-methane volatile organic compounds) are also emitted in connection with loading and storage of oil. Discharges to the sea mainly concern produced water containing oil and chemical residues, and chemicals from drilling and well activities.

Both the authorities and the oil companies have a goal of zero discharge of hazardous substances to the sea. This means that, in principle, no hazardous substances, neither chemical additives used in connection with drilling and production nor naturally occurring chemical substances, are to be discharged. This goal is to be attained within limits that are acceptable as regards environmental hazards, safety, technology, aspects that are specific to a field and economic premises. Because of this goal, the Norwegian Petroleum Directorate anticipates that discharges to the sea will be further reduced in the next few years, irrespective of the level of activity (Figure 2.30).

Increased gas and oil production requires more energy and, hence, higher CO_2 emissions. However, none of these increases are necessarily proportional to the production level. Many factors that are specific to fields affect the emission level; for instance, the maturity of the field, its location, the recovery strategy, transport solutions, which source of energy is chosen, and the opportunities to use environmentally friendly technology and energy effectiveness. The NPD expects the level of emissions to rise from

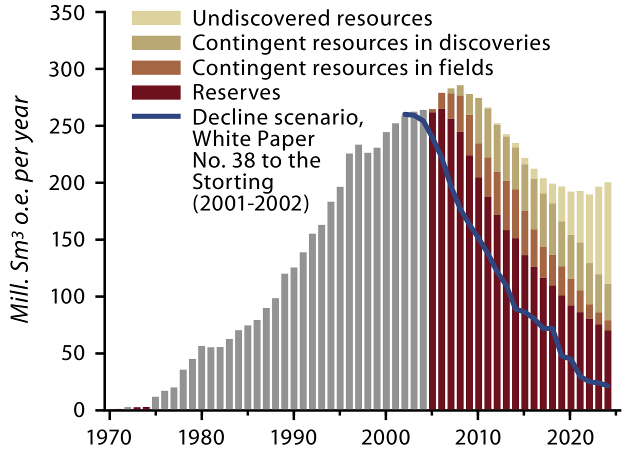


Figure 2.27 Total petroleum production in 1971-2024.

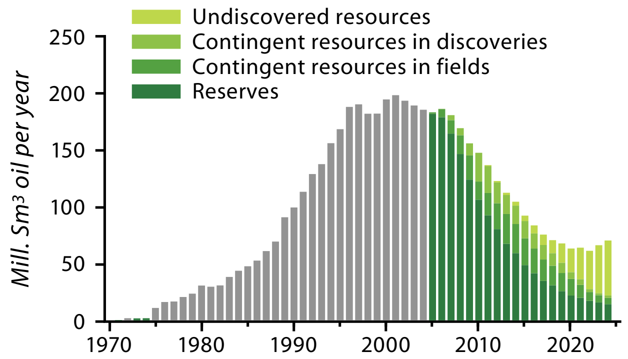


Figure 2.28 Total liquid production in 1971-2024.

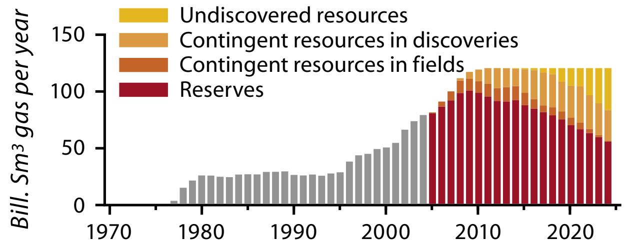


Figure 2.29 Total gas sales in 1971-2024.

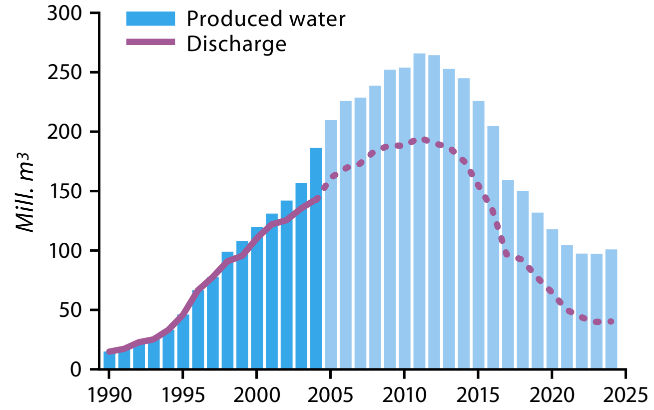


Figure 2.30 Total water production and discharges to the sea in 1990-2024.

around 12.2 million tonnes of CO_2 in 2004 to approximately 14.3 million tonnes in 2009, and then to decline (Figure 2.31).

The NO_X emissions have remained stable at around 50 000 tonnes a year in recent years, and the NPD expects a gradual reduction from 2006 (Figure 2.32). The emissions of NO_X will also to some extent depend on the level of activity, but technology exists that can substantially reduce them. Such technology will normally be fitted to new installations and lead to a reduction in the total emission in the years ahead, even if production does not fall equally fast.

The use of buoy loading affects the emissions of nmVOC most. Tested technology for recycling nmVOC in connection with these operations exists today and can reduce the emissions by approximately 70 per cent. The installation of this equipment on all facilities will be completed by 2006 and will give a significant reduction in the emissions (Figure 2.33).

2.5.4 Flaring

Since the start of the petroleum activity on the Norwegian continental shelf, gas flaring has been looked upon as squandering of resources and reservoir energy. Flaring is in principle not permitted beyond what is essential for safety reasons.

The level of flaring is low in Norway compared with other countries and has remained stable in recent years (Figures 2.34 and 2.35). Following the introduction of the CO_2 tax in 1991, a number of measures have been carried out to limit the quantity of gas flared. The reduction in the need to flare gas is one of the clearest examples of the CO_2 tax having had an effect. Simple, routine changes in everyday operations and optimising of processing plant were implemented following its introduction. More advanced technol-

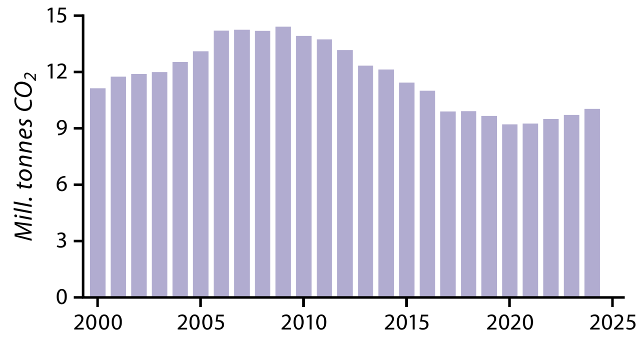


Figure 2.31 Total CO_2 emissions from the petroleum sector in 2000-2024.

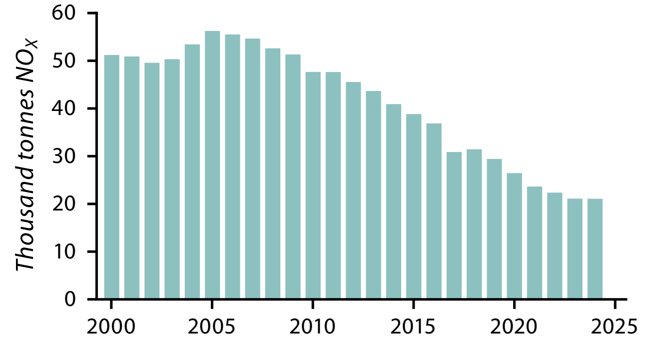


Figure 2.32 Total NO_X emissions from the petroleum sector in 2000-2024.

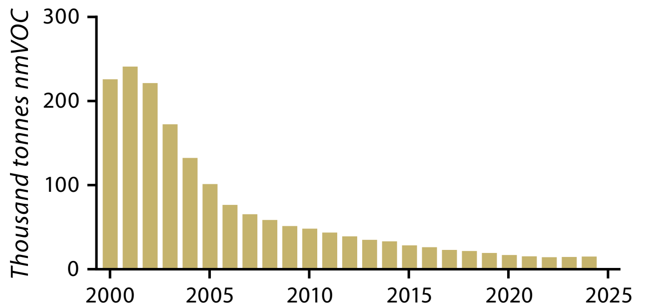


Figure 2.33 Total nmVOC emissions from the petroleum sector in 2000-2024.

ogy has also been developed by Norwegian companies and taken into use to limit the need for flaring. Recently, this technology has become an export product for Norwegian industry and has been taken into use in the petroleum activity in other countries.

One of the most important factors deciding the level of flaring on the individual installation is the regularity of the processing plant (how smoothly and stably it functions). High regularity helps to give less need for flaring. Decisions taken when a field is being designed will have a great deal to say for the future regularity of the plant. In the case of fields that are already on stream, operating practices and procedures will help to determine the flaring level if a way of disposing of gas should cease to be available.

When the authorities annually renew the production permission of a field, in addition to approving a production volume, permission is given to flare gas based on what is essential for safety reasons. The flaring permit also includes a volume of gas which takes into account any unforeseen events that may call for gas flaring over and beyond the need during stable operations. This gives flexibility that makes it possible to avoid frequent plant shutdowns, because re-starting a plant generally gives increased emissions.

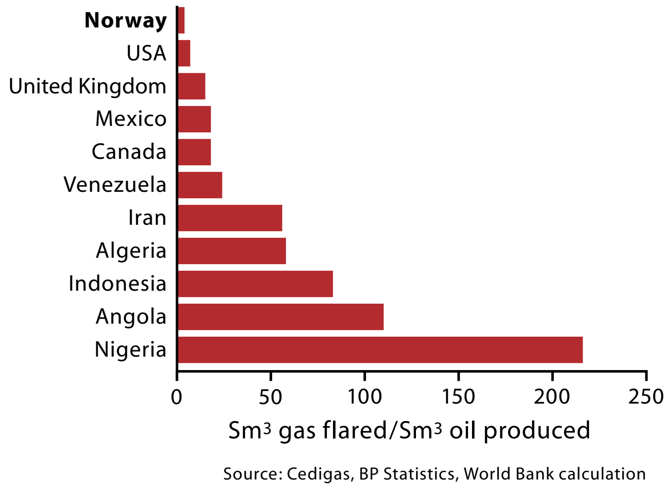


Figure 2.34 Gas flared per unit produced in various countries in 2002.

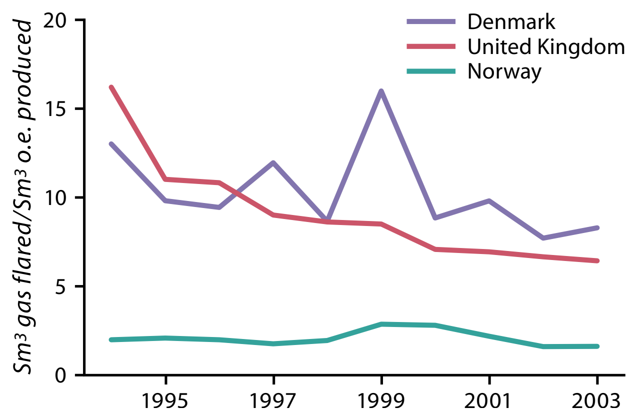


Figure 2.35 Gas flared per unit produced in Denmark, the United Kingdom and Norway in 1994-2003.

3 Exploration

3.1 Introduction

Measured by the number of exploration wells, little exploration has taken place on the Norwegian continental shelf in recent years even though the companies have been awarded more and more acreage and more production licences. The number of awards per year has risen greatly in the last five years. It will take time before this increase gives results in the form of more drilling, but already in 2005 more exploration wells are being planned than for several years.

In the North Sea, more exploration wells have been drilled near fields and fewer in immature areas in recent years. However, plans exist for some interesting exploration wells with a large potential linked with plays that are little explored.

A substantial acreage was awarded in the Norwegian Sea in the 18th licensing round in 2004. This forms a basis for increasing exploration and drilling in the area in the coming years. In particular, the investigation of the deep-water areas in the west will be most important for the future activity on this part of the Norwegian continental shelf.

Large areas in the Norwegian part of the Barents Sea, which may have a potential for significant quantities of gas and oil, still remain to be investigated. The Norwegian Petroleum Directorate expects more exploration in the Barents Sea in the next few years as a result of new awards.

3.2 Access to exploration acreage

The companies mainly gain access to acreage through the awards in the, normally biennial, licensing rounds, and the annual awards in predefined areas (APA). In addition, shares in the production licences are traded through purchase and exchange. In the licensing rounds, the authorities announce blocks in immature areas where little or no investigation has taken place.

The APA were introduced in 2003 as a follow-up of the North Sea Allocations (NSA). The scheme means that large, predefined exploration areas have been selected which cover areas with infrastructure(s) and parts of the continental shelf that are known from earlier exploration. These areas will gradually be extended as new areas mature. APA 2003 covered acreage in the North Sea and the Norwegian Sea, whereas APA 2004 also included acreage in the Barents Sea.

The APA 2005 were announced in January 2005. The largest extensions were in the Norwegian Sea near Ormen Lange and north-east of Norne. In the North Sea, the largest extensions were in the area north of Tampen and in the south-eastern part of the North Sea, in the Norwegian-Danish Basin and towards the Egersund Basin. The acreage in the Barents Sea was not extended. It is expected that the APA 2005 will be awarded at the end of 2005. Awards in the 19th licensing round are expected early 2006.

3.2.1 Awards of production licences in the past five years

The authorities' wish to increase the exploration activity has led to extended access to acreage and a larger number of awards. After the introduction of annual awards, initially through the NSA and subsequently through the APA, the access to acreage has increased substantially, nearly trebling from 2002 to 2004 (Figure 3.1). The number of

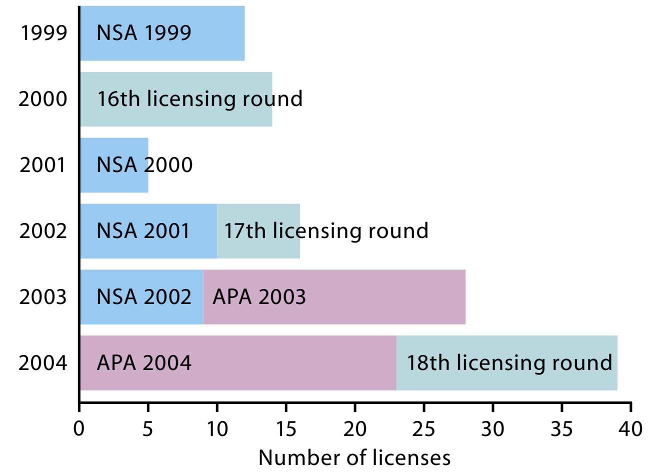


Figure 3.1 Number of production licences (operatorships) awarded per year since 1999.

Large companies		BP, ChevronTexaco, ConocoPillips, Eni, ExxonMobil, Shell, Total
Large, Norwegian companies		Norsk Hydro, Statoil, Petoro
Medium-sized companies		Amerada Hess, Idemitsu, RWE-DEA
Small companies		DNO, Svenska Petroleum
New companies	**Medium-sized companies**	BG Group, Kerr-McGee, Lundin, Marathon, Mærsk, Talisman
	Small companies	Endeavour, Paladin, Revus
	Gas and energy companies	DONG, Gaz de France, Ruhrgas

Table 3.1 Companies that have received awards since 1999, arranged by their size. Takeovers and fusions of companies are shown with their ownership as of February 2005 (for example, the former Enterprise is now listed as Shell).

awards through licensing rounds has remained fairly stable and the increase is chiefly linked to the APAs. So far, 2004 is the year when the largest acreage and the largest number of production licences have been awarded since the first licensing round in 1965. The number of companies that were allocated acreage was also high compared with previous rounds. The NSA and APA have stood for nearly 70 per cent of the production licences awarded since 1999.

In the same period, companies that are new to the Norwegian continental shelf have received a significant, and increasing, number of awards. New companies (Table 3.1) often enter the continental shelf as licensees without having responsibility as an operator. The number of production licences awarded to all the licensees (including operators) is therefore a good illustration of the overall level of activity. Awards to the new companies reached their highest level to date in APA 2004 when new companies received 32 awards, just over 50 per cent of the production licences awarded in that allocation (Figure 3.2).

Gas and energy companies have had steady access to production licences in recent years. The new medium-sized companies have had the most marked increase in the number of awards and received more than 50 per cent of the awards in APA 2004 (Figure 3.3).

Production licences awarded in the licensing rounds show a corresponding, but slightly delayed, trend (Figure 3.4), thus proving that the new companies on the Norwegian continental shelf mainly focus on acreage in mature areas.

Medium-sized and new companies received 50 per cent of the production licences in the 18th licensing round, while new gas and energy companies received two and three production licences, respectively, in the 17th and 18th licensing rounds. No new companies were awarded licences in the 16th round (Figure 3.5). The situation regarding awards in recent years shows that the new companies are steadily being awarded more production licences. The authorities anticipate that these companies will play a larger role on the continental shelf in the years to come.

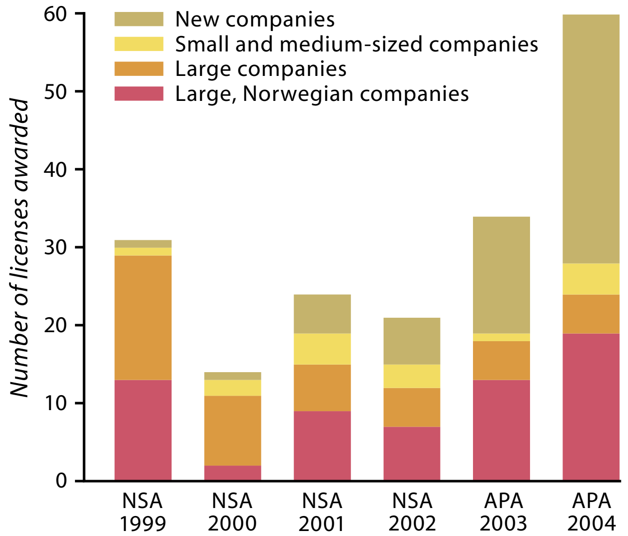


Figure 3.2 Number of production licences (all licensees) awarded in mature areas.

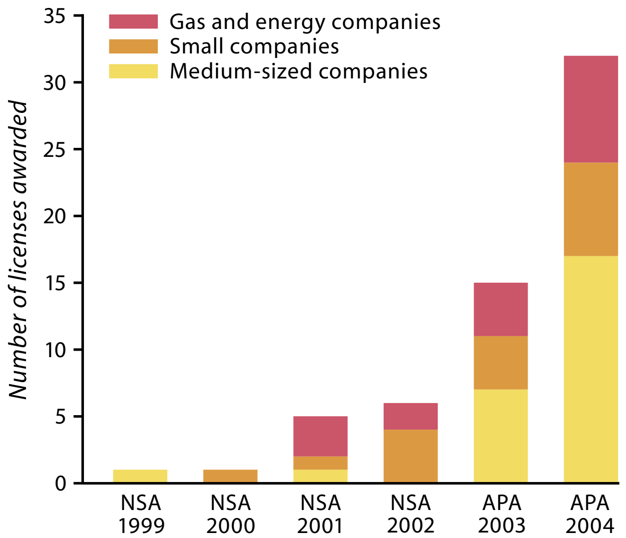


Figure 3.3 Number of production licences (all licensees) awarded to new companies in mature areas.

3.3 Exploration activity

The exploration level has been low recently. 17 exploration wells were spudded in 2004 compared with 22 in 2003 (Figure 3.6). Nine of them were wildcat wells, in contrast to 14 in 2003. Hence, measured by the number of wildcat wells, 2004 is the year with the lowest exploration activity since the beginning of the 1970s. The overall plans of the companies for 2005 will give an increase.

Four new discoveries were made in 2004. So far, one of these, 6608/11-4 Linerle, seems likely to have potential for independent development. Another discovery, 34/10-48 S, has already been put into test production from Gullfaks. Eleven new discoveries were made in 2003 (Figure 3.7).

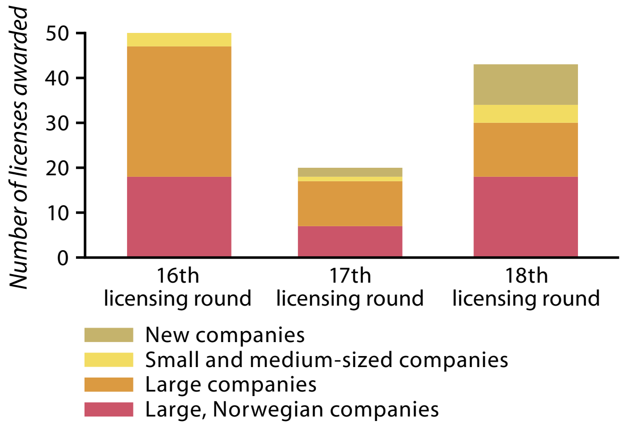


Figure 3.4 Number of production licences (all licensees) awarded in licensing rounds since 1999.

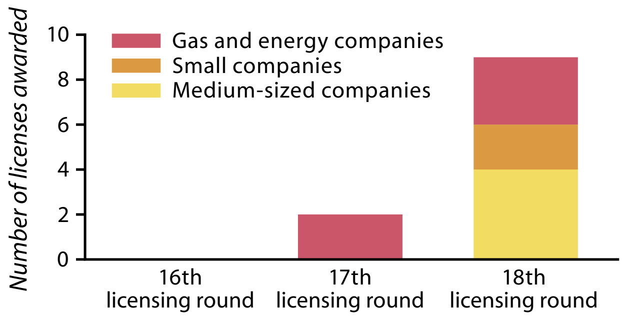


Figure 3.5 Number of production licences (all licensees) awarded to new companies in licensing rounds since 1999.

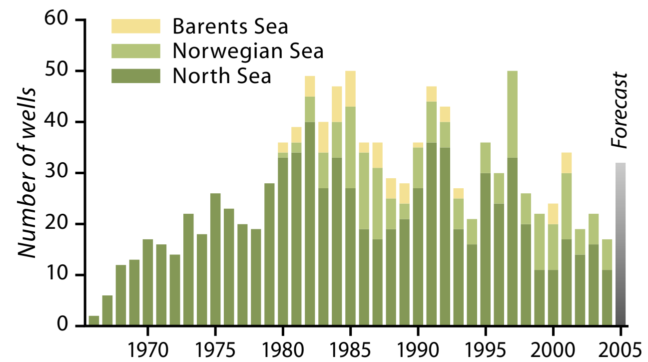


Figure 3.6 Spudded exploration wells on the Norwegian continental shelf in 1966-2005, distributed according to provinces.

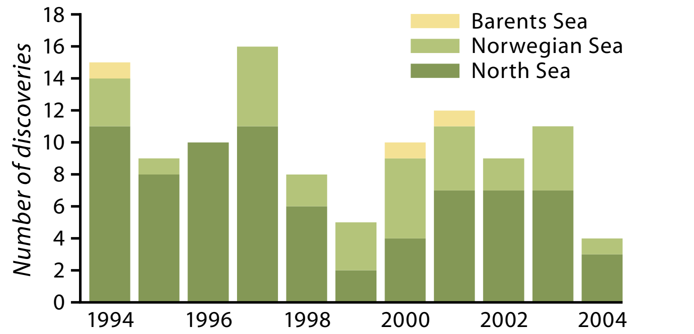


Figure 3.7 Discoveries on the Norwegian continental shelf in 1994-2004, distributed according to provinces.

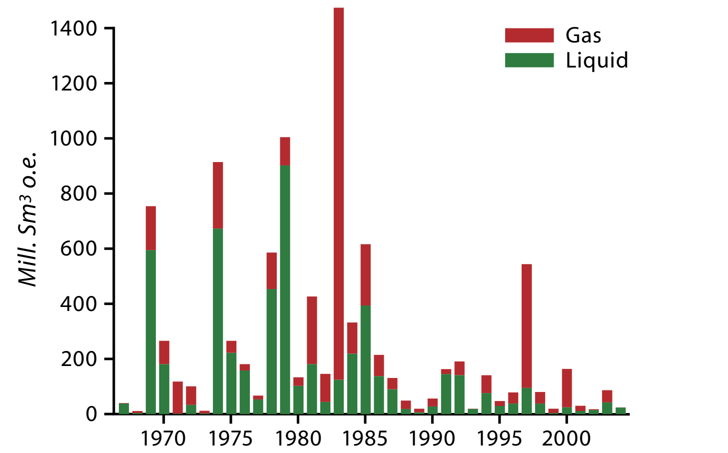


Figure 3.8 Liquid and gas resources discovered per year in 1967-2004.

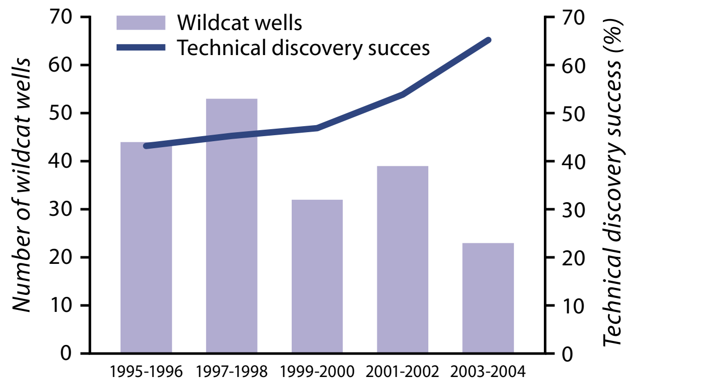


Figure 3.9 Number of wildcat wells and their technical discovery success in 1995-2004.

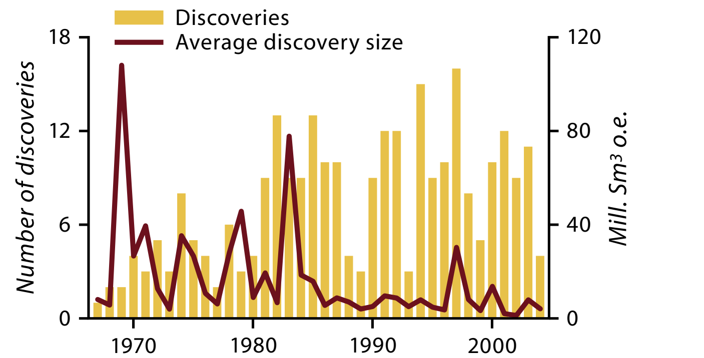


Figure 3.10 Number of discoveries and their average size in 1967-2004.

In the 15 discoveries made in 2003 and 2004, 67 million Sm³ of recoverable liquid and 45 billion Sm³ of recoverable gas were proven. This was more than twice as much as in the two previous years (Figure 3.8).

The average, technical discovery success in the past ten years is in excess of 50 per cent. In other words, at least every other wildcat well has given a discovery. The technical discovery success has increased in recent years (Figure 3.9), with 2003 as the best year, when about 80 per cent of the wildcat wells gave discoveries. However, the number of wildcat wells has declined. Only 23 were drilled in the past two years, against 39 in 2001 and 2002.

The discovery success has grown, but the discoveries have become increasingly smaller in recent years (Figure 3.10). The majority of discoveries are made in mature areas in the North Sea. The declining size of discoveries in mature areas poses a great challenge to the industry. Such discoveries are too small to be interesting for many of the large, traditionally dominating, companies on the Norwegian continental shelf. However, they may represent opportunities for new, small and medium-sized companies which can see a profitable potential in developing them.

3.3.1 The North Sea

Little exploration has taken place in the North Sea in recent years. Only nine wildcat wells were spudded in 2003 and five in 2004. In addition, seven appraisal wells were spudded in 2003 and six in 2004 (Figure 3.11). By the end of 2004, a total of 826 exploration wells had been drilled in the North Sea. The North Sea is a mature petroleum province and this is reflected in the high discovery rate but with only small volumes in the discoveries made. Seven discoveries were made in 2003 and three in 2004 (see Figure 3.7).

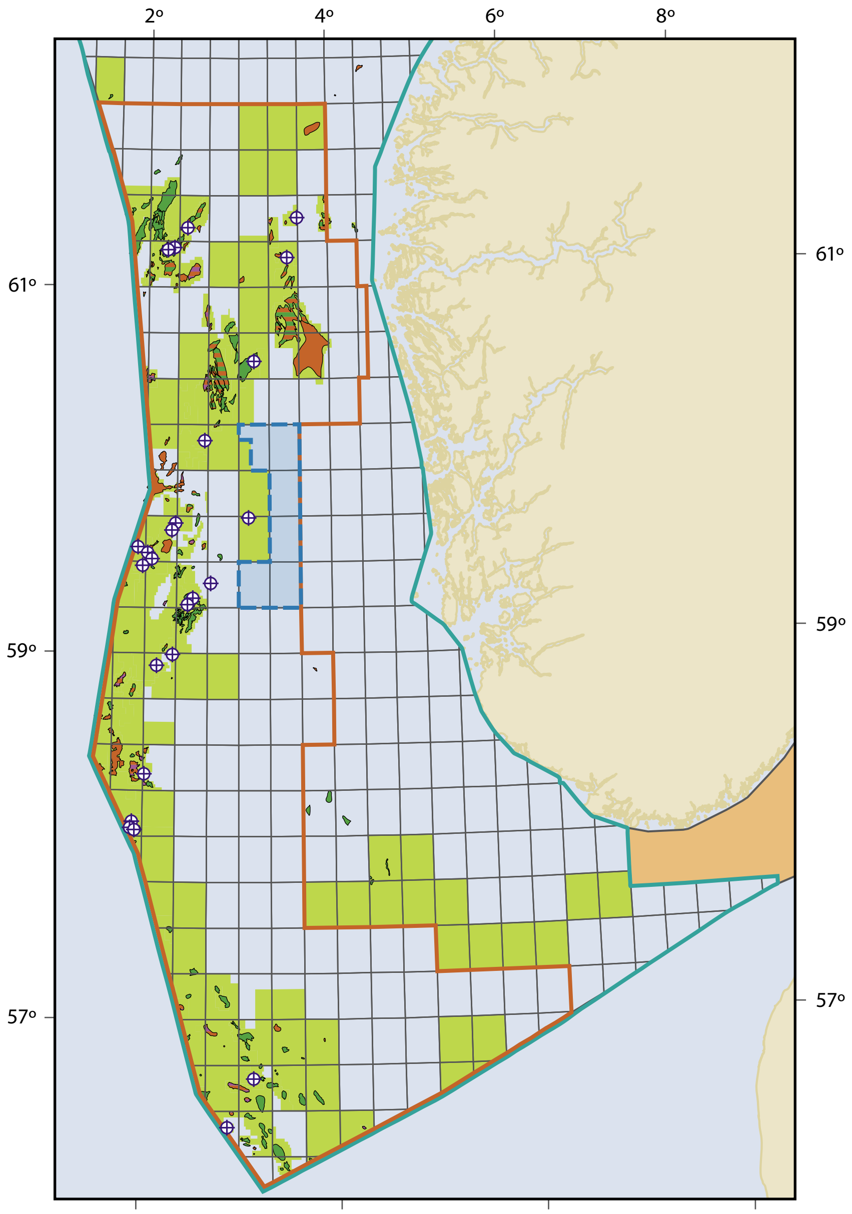


Figure 3.11 Exploration areas in the North Sea.

Most of the exploration wells drilled in the North Sea in the last two years were drilled near producing fields and known discoveries. Two new operators stood for a large part of these investigations.

Considerable work has been done on the Palaeocene plays in the North Sea. It was decided to develop Alvheim after wells 24/6-4, 24/9-7, 25/4-7 and 25/4-9 S were drilled. Additional resources were discovered on Balder through the drilling of wells 25/8-14 S and 25/8-C-20. Small quantities of hydrocarbons were also found in Palaeocene strata in well 16/1-6.

Small additionally resources were discovered in rocks of Cretaceous age while drilling production wells on the Gullfaks field. A new, small discovery was also made on Brage, in strata beneath the main reservoir.

The growth in resources in the North Sea is limited relative to the production, but a large part of the proven volumes can be put into production quite quickly through existing infrastructure.

3.3.2 The Norwegian Sea

The first wildcat well in the Norwegian Sea was spudded in 1980, and the first discovery (6507/11-1 Midgard, now part of Åsgard) was made in 1981. By the end of 2004, 193 exploration wells had been drilled in the Norwegian Sea.

Twelve exploration wells have been drilled in the last two years (see Figure 3.6), ten in or near mature areas, and two in the comparatively little investigated, deep-water areas in the west (Figure 3.12). Hydrocarbons were found in seven wells, three of which were appraisal wells. Considerable exploration has taken place recently around Norne, where four wells have been drilled in the last two years. Two of these, 6608/10-9 Lerke and 6608/11-4 Linerle, gave new discoveries. The latter is the largest and most promising discovery made in 2004. In addition, an appraisal well was drilled on 6507/3-1 Alve, just south-west of Norne. Gas and a small column of oil were discovered here.

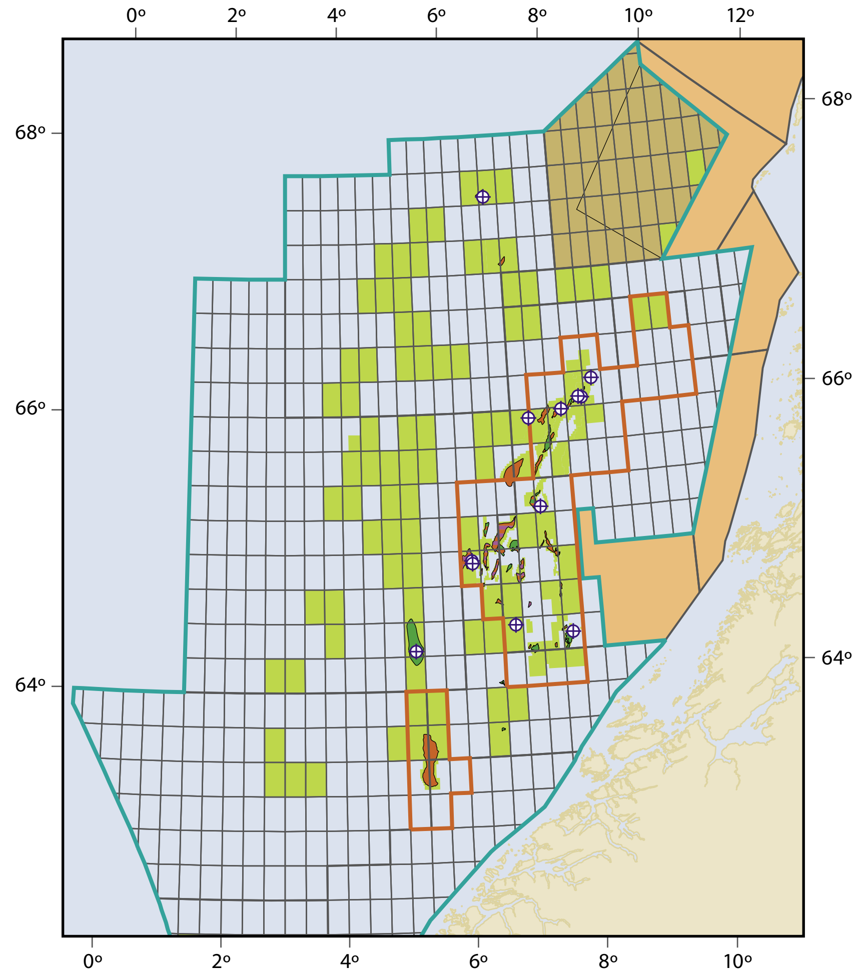


Figure 3.12 Exploration areas in the Norwegian Sea.

Well 6706/6-1 discovered gas in the Naglfar Dome, in the north-western part of the Norwegian Sea. Further activity here is dependent on larger gas resources being discovered before it will be profitable to construct new infrastructure.

A substantial column of oil was discovered north of Ormen Lange in a well in an area where gas was expected to be found. The in-place resources in this discovery, 6405/7-1 Ellida, seem to be large, but the quality of the reservoir in the well is poor. The next well in the production licence will be drilled in another structure to try to find a better reservoir. This oil discovery has, nevertheless, made the area significantly more interesting for further exploration. A large part of the oil was formed in a local source rock of Cretaceous age. This is the first time a substantial potential for oil has been discovered in source rocks of Cretaceous age in the Norwegian Sea. 6406/1-2 discovered hydrocarbons in strata of Cretaceous age near Åsgard.

May 2005
In spring 2005, drilling is also taking place in block 6406/9. This well has discovered gas and condensate at several reservoir levels. This is a promising result with a view to possible development in the area, but delineation of the discovery and drilling of neighbouring structures are required before a final decision on development can be taken. A new appraisal well will probably be drilled in 2006.

3.3.3 The Barents Sea

The first wildcat well in the Norwegian part of the Barents Sea was drilled in 1980, and the first discovery, 7120/8-1 Askeladd, was made the following year. This discovery is now part of Snøhvit, which the authorities approved for development in 2002. It is planned to start production on Snøhvit in 2006. By the end of December 2004, 61 exploration wells had been drilled in the Barents Sea. Figure 3.13 shows the production licences in the Barents Sea.

The Government decided in 2001 that the consequences of year-round petroleum activity in the northern areas should be studied before the activity in these areas could continue. All petroleum activity in the Barents Sea was suspended pending this study, which was called the "Impact assessment of year-round activities in the Lofoten – Barents Sea area" (ULB). In all, 26 specialist background studies on a variety of topics were performed for the ULB report in 2001-2003.

On the basis of the ULB report, the Government decided in 2003 to allow further year-round petroleum activity in the acreage that had already been made available in the southern part of the Barents Sea, with certain exceptions. The exceptions are the coastal areas off Troms and Finnmark and the particularly valuable areas, the Polar Front, the ice margin, Bjørnøya (Bear Island) and the Tromsø Bank. Nor did the Government open for continued petroleum activity in Nordland VI; it was proposed that a detailed evaluation of this question should be made when the overall management plan for the Barents Sea is available, probably in 2006 or 2007. The Government's decision regarding the northern areas was put before the Parliament in White Paper no. 38 (2003-2004). The Parliament endorsed the views of the Government.

There is increasing interest for exploration in the Barents Sea. The development of Snøhvit has shifted attention towards the area once more, as have new discoveries of oil and gas resources in the Hammerfest Basin and the previously little investigated eastern part of the Barents Sea. The large discoveries in the Russian part of the Barents Sea have also contributed to the increased interest for the Norwegian part. The Barents Sea is in general little investigated, even though it is assumed that the Arctic contains a substantial part of the world's undiscovered petroleum resources. Many companies have stressed the importance of developing new infrastructures in eastern Finnmark or on the Kola Peninsula. A development of the enormous Russian discovery, Shtokmanovskoye, is an opportunity to get such infrastructure in place. The Norwegian Petroleum Directorate believes it will be important to obtain a better overview of the resource base in the Barents Sea. This will provide a better opportunity to assess which resources can be linked to possible new infrastructures and to the infrastructure currently being constructed in connection with Snøhvit.

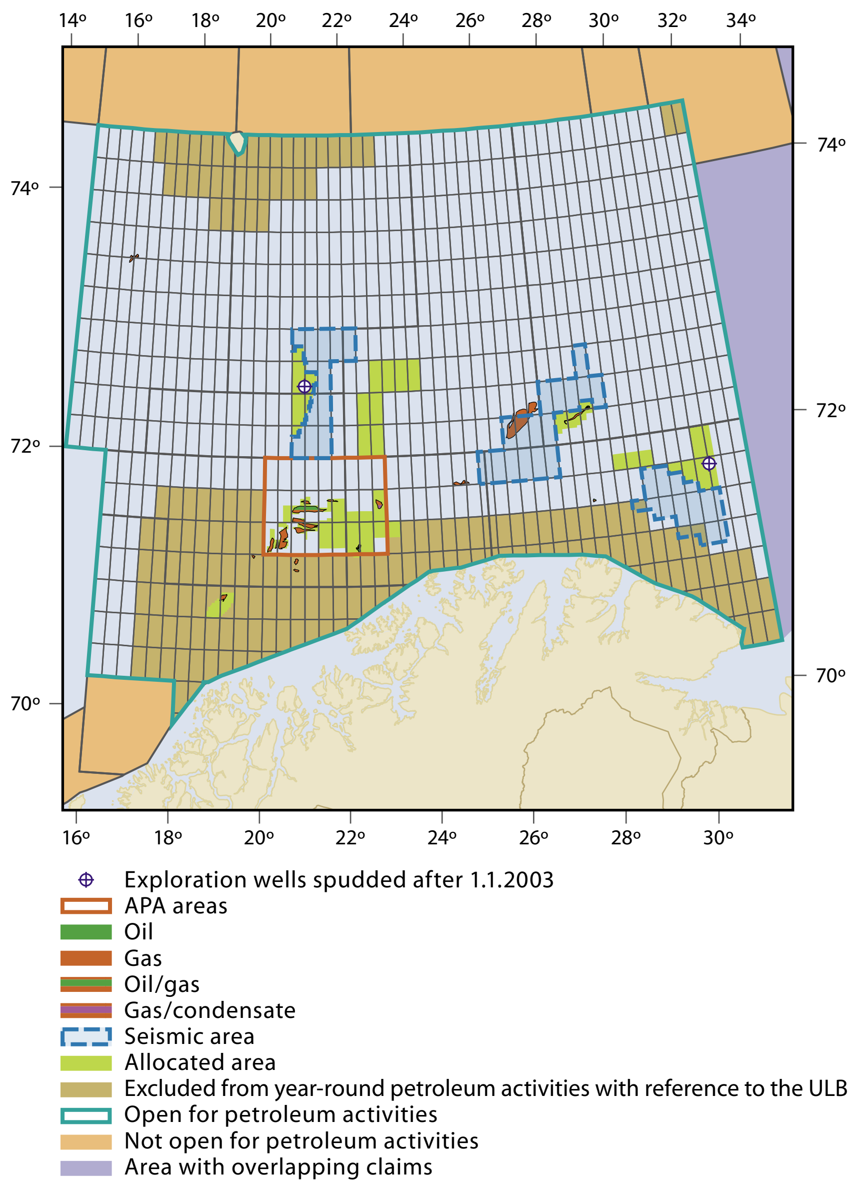


Figure 3.13 Exploration areas in the Barents Sea.

May 2005
There are plans for four wildcat wells in the Norwegian part of the Barents Sea in 2005. The first well, 7220/6-1, was drilled by Norsk Hydro on the Loppa High. The well located good traces of oil in carbonate rocks of Permian age. Analyses indicate that the oil was formed from an older source rock than that which has been discovered in the Hammerfest Basin. This opens for interesting possibilities in large areas in the north and east of the Barents Sea, where Late Jurassic source rocks are located in a position that is too shallow to have formed hydrocarbons.

Another wildcat well, 7131/4-1, was drilled by Statoil. This is the easternmost exploration well drilled in the Norwegian part of the Barents Sea. The well was dry, but the results are nevertheless important for understanding the geology in this area.

It is also planned to drill a well in the North Cape Basin, and another south of the oil discovery, 7122/7-1 Goliat.

3.3.4 Planned exploration

At the end of December 2004, plans existed to drill 25-30 exploration wells from mobile installations and five to ten from permanently placed installations in 2005. Mainly because of a hard pressed rig market, these figures will probably prove to be lower by the end of the year.

About two-thirds of the planned exploration wells are to be drilled in the North Sea and the remainder in the Norwegian Sea and the Barents Sea. Most of them are wildcat wells.

In the North Sea, the exploration is concentrated around fields that are on stream, particularly in the Tampen, Oseberg and Sleipner areas. All the exploration wells that are planned to be drilled from fixed installations are in the North Sea. In addition, interesting wildcat wells are planned that will investigate several prospects with a major potential linked to little investigated plays, some of them in the Egersund and Farsund basins.

Several of the wildcat wells planned in the Norwegian Sea are in the deep-water areas in the west. They will investigate prospects where the probability for discoveries is slight, but which have a large potential as regards both volume and economy. The results of these wells can have a great deal to say for further activity in the Norwegian Sea.

In the Barents Sea, all the planned wildcat wells will investigate prospects where the probability for discoveries is slight, but which have a large potential as regards both volume and economy. The wells are important for further exploration in the area. Even if they should prove to be dry, there is still an appreciable untested potential in the Barents Sea, where the great majority of the Norwegian Petroleum Directorate's 23 plays are still unconfirmed. The wells will therefore provide vital information about the area, even if hydrocarbons are not discovered.

3.4 What influences the exploration activity?

The increase in the exploration activity we are now seeing indications of on the Norwegian continental shelf results from conditions both within and outside Norway. An important reason is the rise in the price of oil, which chiefly results from a higher global demand for oil. One way in which exploration activity can be measured is the number of wildcat wells that are drilled. Figure 3.14 show that there is usually a close link between the nominal price of oil and the number of wildcat wells. On the other hand, few wildcat wells were drilled on the Norwegian continental shelf from 2001 to 2004, even though the price of oil was high. This gap seems to be disappearing when we consider the wildcat wells planned for 2005.

Rising demand for oil and gas has contributed to a stronger exploration effort. As a result, the petroleum industry is investing more money worldwide on exploration than has been usual in recent years. In addition, results of the measures initiated by Norwegian authorities to make exploration for oil and gas more financially attractive are now becoming apparent. More production licences are being awarded and several new companies are participating. The Norwegian Petroleum Directorate expects this to have a positive effect on the future exploration activity.

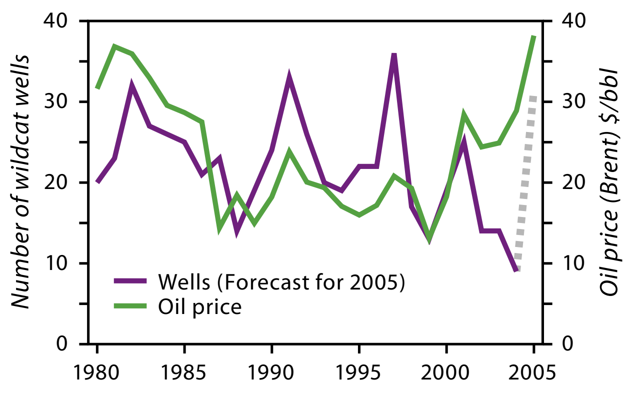


Figure 3.14 Number of wildcat wells on the Norwegian continental shelf per year and the trend in the nominal price of oil in 1980-2005.

To make it easier for new companies to participate in the petroleum activity, the Government, in White Paper no. 38 (2003-2004), proposed adjustments to the petroleum taxation system. They mean, among other things, that the state now pays the fiscal value of loss incurred by the exploration activity the same year as it accrues and the fiscal value of any losses incurred by operating on the continental shelf. The Norwegian Parliament endorsed this adjustment in connection with the debate on the revised National Budget for 2005. The adjustments were made to give greater security for new companies and improved profitability for investments. Partly to increase the exploration activity, the authorities want more companies to be involved.

Increased drilling activity worldwide has given a greater demand for mobile drilling rigs and higher rig rates. The Norwegian market for moveable rigs is no exception and the market is hard pressed now. The majority of rigs that are available for the Norwegian market are chartered until part way into 2006. The Norwegian market differs from other regions chiefly because of the severe climatic conditions and strict demands regarding the working environment. These conditions have led to more stringent demands regarding rigs for the Norwegian continental shelf than in other regions.

If a drilling rig is to operate on the Norwegian continental shelf it must first undergo evaluation to see whether it meets the demands that are placed to enable it to receive an acknowledgement of compliance (AOC). Several rigs are known which, with minor upgrading, can meet these demands in a comparatively short time. However, with a high demand in the regions where they are operating, there is little incentive to move them to Norwegian waters. For this to take place, there probably needs to be an opportunity for long-term contracts.

This situation can make it difficult for the companies to drill the wells that are planned. To tackle this problem, some of the large companies have entered into long-term co-operation on the joint use of drilling platforms.

3.5 Exploration costs

Less and less has been invested on exploration in recent years (Figure 3.15). Costs connected with exploration wells are the most expensive item in exploration, and the most important elements of the drilling costs are the cost of hiring drilling rigs and technical services.

If we just look at the awards connected with NSA and APA, the new companies have not only been awarded acreage and production licences, they have also invested money. In the last four years, these new companies have stood for more than 20 per cent of the exploration costs (Figure 3.16).

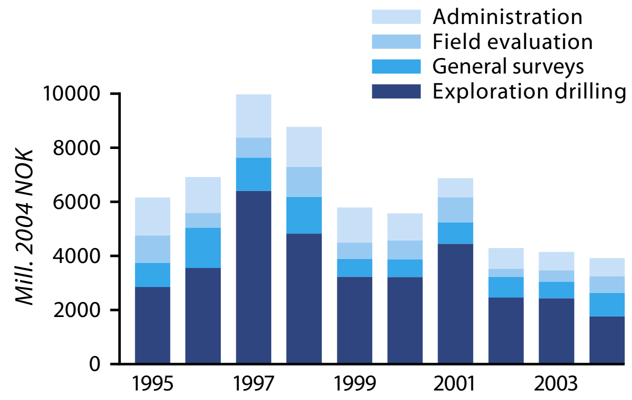


Figure 3.15 Exploration costs in 1995-2004.

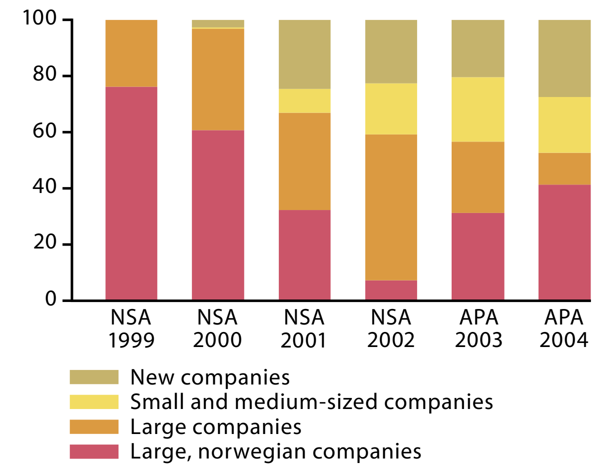


Figure 3.16 Exploration costs in production licences awarded in NST and APA, distributed according to the size of the companies (see table 3.1).

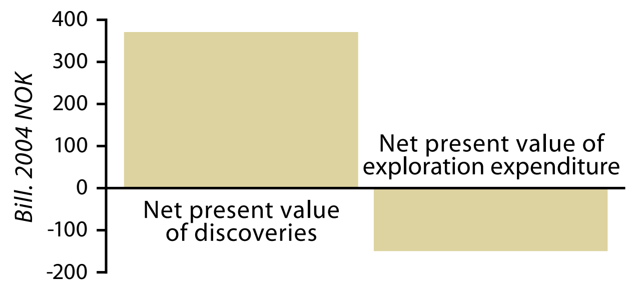


Figure 3.17 Pre-tax profitability of exploration on the Norwegian continental shelf in 1992-2003.

3.6 The attractiveness of the Norwegian continental shelf

So far, the Norwegian continental shelf has been looked upon as an attractive oil and gas province in a global context. Virtually all the largest international oil companies have been involved here. The reasons for this appeal are good prospectiveness, good opportunities to develop technology and expertise, and stable economic and political conditions.

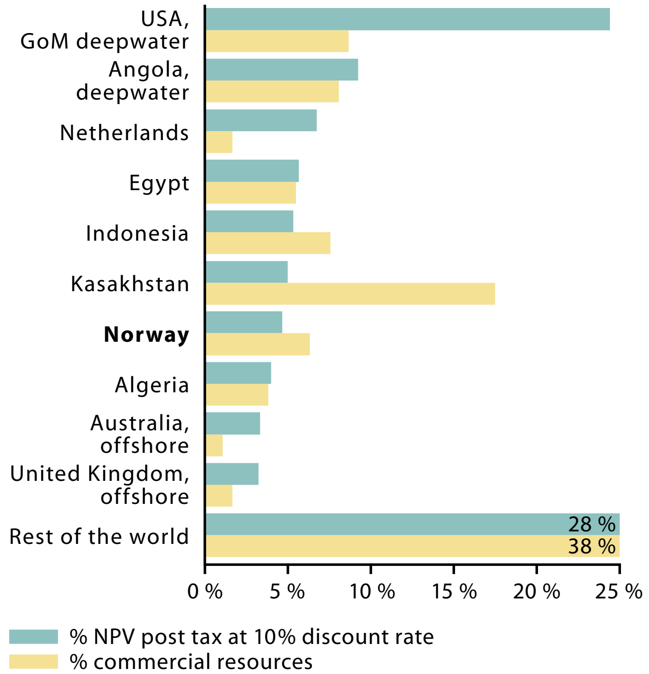
Exploration on the Norwegian continental shelf has been viewed as productive and competitive compared with other petroleum provinces. This has been confirmed in part by earlier analyses carried out by the Norwegian Petroleum Directorate, Wood Mackenzie and IHS Energy.

In 2004, the Directorate undertook an analysis of exploration profitability in 1992 to 2003. This showed that the exploration had generated substantially more value than it cost (Figure 3.17).

Wood Mackenzie has recently performed two analyses that compared value creation from exploration activity in various petroleum provinces. In the first analysis, which examined exploration from 1996 to 2002, Norway was ranked number seven of 22 countries and was placed ahead of several that are normally considered attractive, like Azerbaijan, Brazil and Australia.

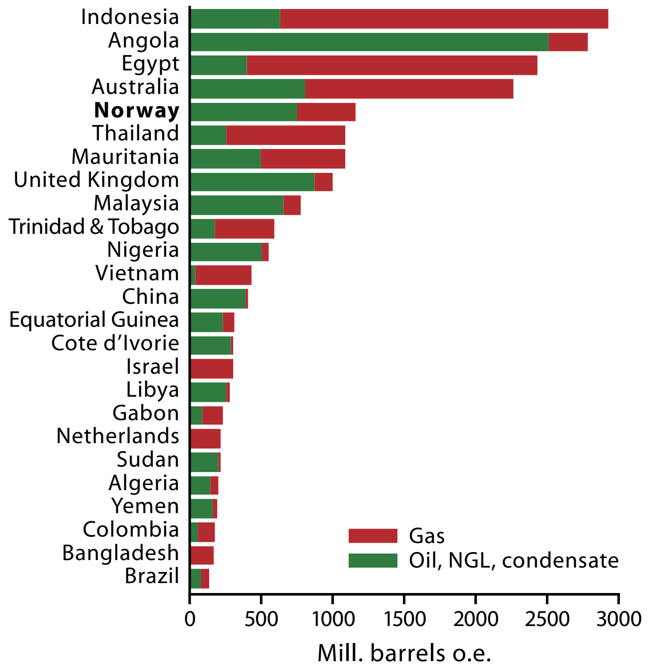
In the second analysis made by Wood Mackenzie, which examined exploration from 1994 to 2003, Norway again came seventh, but now out of 66 countries or regions (Figure 3.18).

In January 2005, IHS Energy presented a study of the exploration success of 25 major, independent oil companies[1] from 1999 to 2003. The analysis showed that Norway came out well, being placed fifth as regards the total resources discovered (Figure 3.19) and fourth for the number of discoveries (Figure 3.20).



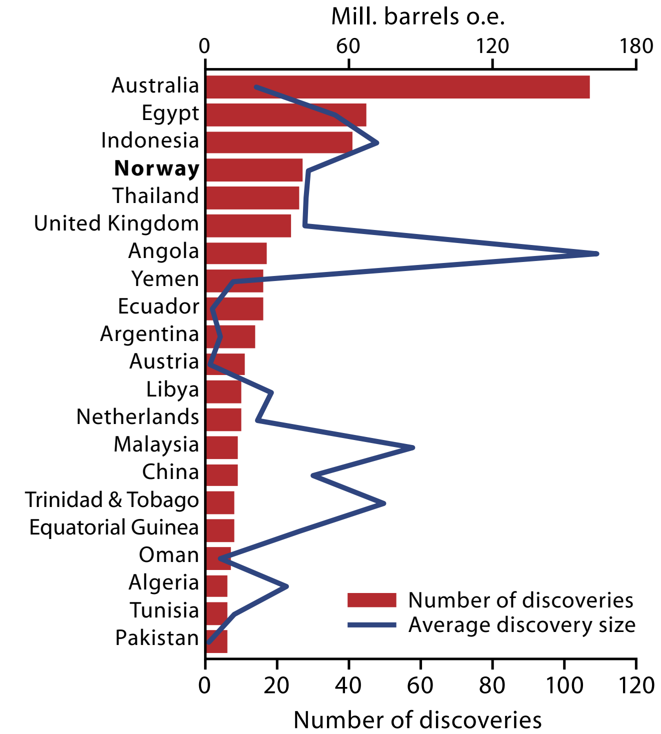
Source: Wood Mackenzie

Figure 3.18 Global distribution of commercial resources and their net present value for 1994-2003.



Source: IHS Energy

Figure 3.19 Gross resources discovered per country by 25 large independent companies in 1999-2003.



Source: IHS Energy

Figure 3.20 Number of discoveries and their average size per country made by 25 large independent companies in 1999-2003.

[1] The companies in the analysis are Amerada Hess, Anadarko, Apache, Wintershall, BG Group, BHP Billiton, Burlington Resources, Canadian Natural Resources, Devon Energy, EnCana, Kerr-McGee, Marathon, Murphy, Nexen, Norsk Hydro, OMV, Occidental, Petro-Canada, Pioneer Natural Resources, Pogo Producing, Santos, Talisman, Unocal, Vintage Petroleum and Woodside.

4 Recovery of oil

4.1 Introduction

The objective of the authorities is that as much as possible of the resources that are proven on the Norwegian continental shelf are recovered in a manner that creates the highest possible value for society. The Norwegian Petroleum Directorate strives to make this feasible, partly by helping the petroleum industry choose the best recovery methods, encouraging the various players to work together to gain benefit from coordination, and putting focus on the framework conditions where it considers this to be necessary. To ensure a high recovery factor, good utilisation of the resources and value creation from the fields, access to appropriate technology, sufficiently qualified personnel and ability to take decisions are essential.

4.2 Why do we not recover 100 per cent of the oil?

The recovery factor for oil is a target for how great a proportion of the oil can be recovered.

$$\text{Recovery factor} = \frac{\text{Estimate of recoverable oil}}{\text{Estimate of in-place oil}}$$

The in-place volumes and the volumes assumed to be recoverable are both used to calculate the recovery factor. Uncertainty is attached to both these quantities, especially in the early phase of a project. The various oil companies, moreover, often calculate the in-place volume differently, thus making it difficult to compare the recovery factor from one field to another. Changes in the recovery factor over time are, nevertheless, an indicator of the effort made by the licensees to enhance recovery.

The oil occupies minute pores in the rock forming the reservoir. In an oil reservoir, between 60 and 90 per cent of the pore volume is filled with oil and the rest with water. To be able to produce the oil, the oil that is in the pores must be displaced by something else. This can take place by natural seepage of water when the pressure drops or a when gas cap expands. Generally, water or gas must be injected to achieve adequate displacement.

Even when good displacement is present, some oil will remain in the pores. How large this residual oil saturation is will depend upon the properties of the rock and the oil, and also the properties of the displacing substance. Displacement with gas generally gives lower residual saturation (5-15 per cent) than displacement with water (10-25 per cent). The fraction of oil recovered where there is efficient displacement is called the microscopic displacement efficiency.

In addition to the oil that remains where efficient displacement is present, there will be areas in the reservoir where displacement will be less efficient and areas where the displacing medium does not reach. The shape and extent of the reservoir, how the quality of the reservoir rock varies and where the production wells are placed determine the efficiency of the displacement. Normally, this is divided into the vertical displacement efficiency, which is mainly

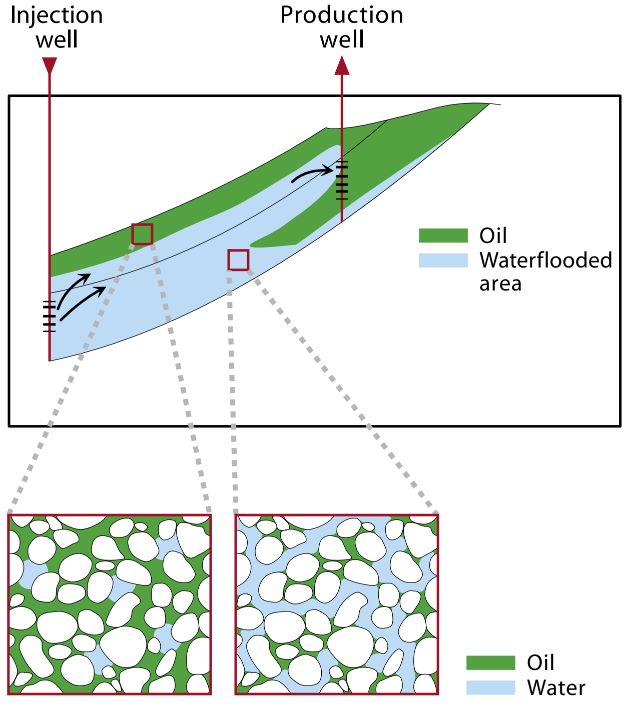
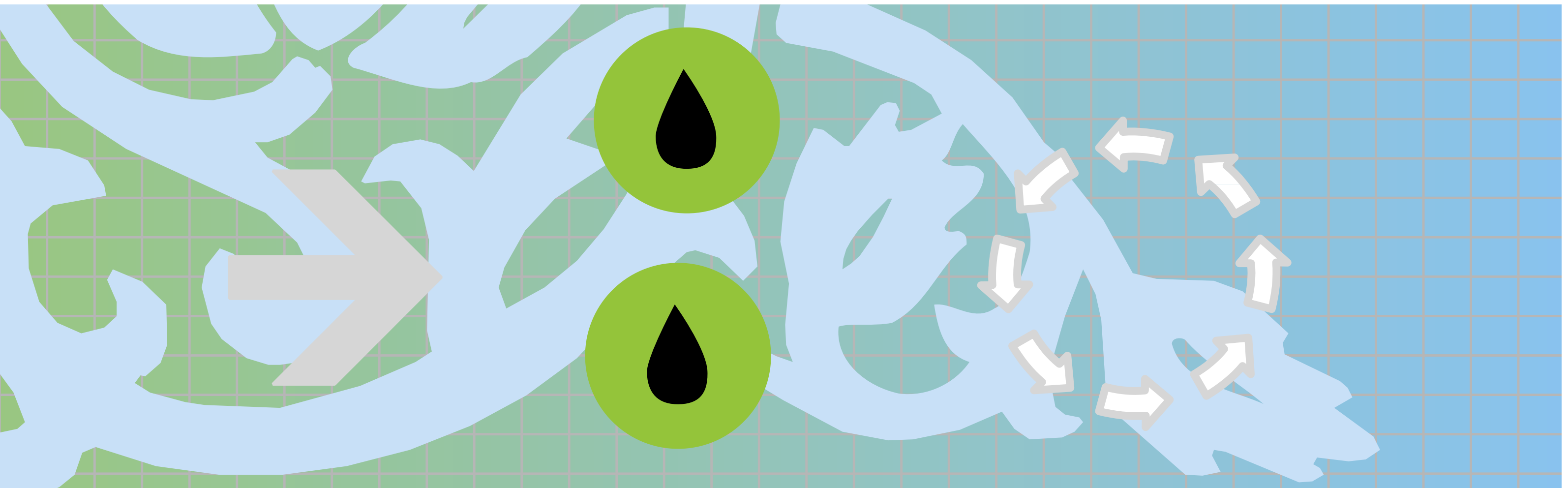


Figure 4.1 Section through a reservoir showing an example of the distribution of oil and water following water flooding, and the distribution of the liquids at the pore level.



The recovery factor can be calculated in the following way

$$R = R_m \cdot R_h \cdot R_v \quad \text{where } R_m = \frac{S_{oi} - S_{or}}{S_{oi}}$$

R = Total recovery factor
R_m = Microscopic displacement efficiency
R_h = Horizontal displacement efficiency
R_v = Vertical displacement efficiency
S_{oi} = Initial oil saturation
S_{or} = Residual oil saturation

Example of the calculation of recovery factors with different values of the component parameters

Initial oil saturation	S_{oi}	0.8	0.8	0.8
Residual oil saturation	S_{or}	0.1	0.3	0.2
Microscopic displacement efficiency	$R_m = (S_{oi}-S_{or})/S_{oi}$	0.875	0.6	0.75
Vertical displacement efficiency	R_v	0.8	0.7	0.9
Horizontal displacement efficiency	R_h	0.8	0.7	0.7
Recovery factor	$R = R_m \cdot R_v \cdot R_h$	0.56	0.306	0.473
Recovery factor in per cent		56 %	31 %	47 %

Table 4.1 Estimation of recovery factor

controlled by the stratification in the reservoir, and the horizontal displacement efficiency, which is controlled by the shape and extent of the reservoir and by faults. Figure 4.1 illustrates how the displacement can act both on the pore level and on the larger scale.

Table 4.1 shows examples of the recovery factor with different values for the various parameters. If the recovery factor (R) is to be changed, at least one of the component factors must be changed. Good knowledge of the reservoir is required, and comprehensive studies will be needed to calculate the effect of a measure and whether it is cost efficient.

4.3 Reservoir complexity and the recovery factor

A review of the reservoirs in the fields on the Norwegian continental shelf shows a large scatter in the calculated recovery factor. This is illustrated in Figure 4.2. The calculation of the recovery factor may change as new information about the reservoir is acquired. Developments in technology and changes in the strategies used for production may also lead to changes in the estimated, recoverable volume and, hence, also the recovery factor. The reservoir quality varies considerably from field to field, and it is natural to have great variations in the recovery factor. The recovery factor may, nevertheless, be a good indicator to use to assess the possibilities and effects of different measures.

A joint project between Statoil, Norsk Hydro and the Norwegian Petroleum Directorate has defined a Reservoir Complexity Index (RCI). The aim of the project has been

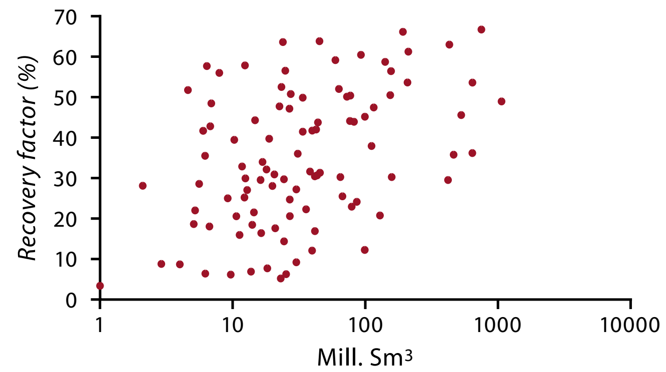


Figure 4.2 Recovery factor for oil from various deposits (reservoirs) in relation to in-place volumes.

to express the complexity of the reservoir and thereby indicate how challenging it may be to achieve a higher recovery factor. A number of parameters that describe the reservoir conditions enter into this. They include general permeability, contrasts in permeability, vertical and horizontal communications in the reservoir (influenced, for example, by faults), impervious strata, density, temperature, tendency for water or gas to be drawn towards the production wells (coning) and the like. The various parameters are given a value based on objective limits and subjective assessments. Weighting factors are used between the parameters, and the overall value is normalised to an index between 0 and 1. A high index indicates a more complex reservoir than a low index.

Figure 4.3 shows the RCI and recovery factor for the reservoirs that have been evaluated. As expected, there is a good relationship between a low RCI and a high recovery

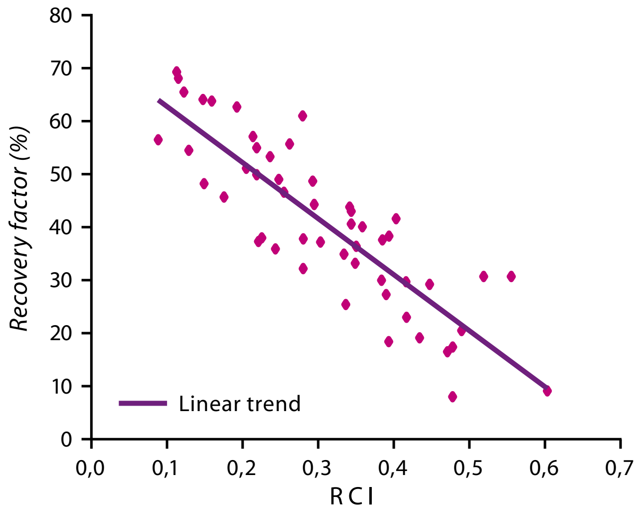


Figure 4.3 Recovery factor for oil from various deposits in relation to the reservoir complexity index (RCI).

factor. This type of tool may be valuable for evaluating the recovery factor in a reservoir and is employed by several companies to compare and assess various reservoirs. The tool will be further developed and will be used to analyse how the recovery from different reservoirs and fields stands in relation to others with corresponding complexity.

4.4 Trend in the recovery factor

The Norwegian Petroleum Directorate has been following the trend over time in the recovery factor for oil from oil fields on the Norwegian continental shelf for a long time. Figure 4.4 shows the trend in the average recovery factor for all oil fields (which were approved for development at the time concerned) and the trend for four large fields on the Norwegian continental shelf compared with the others. The large fields are seen to have the highest recovery factor and the greatest increase in recent years. This is because many of the fields whose development has been agreed in recent years are smaller and/or have more complex reservoirs and, hence, lower estimates of recoverable oil. On the large fields, it has been possible over time to implement many measures that help to enhance the expected recovery factor. The recovery from these fields is focused upon, at the same time as it is possible to implement measures because wells and infrastructure are available and the resources are sufficiently large for new investments. On the large fields, even a small increase in the recovery factor will represent a substantial volume of extra oil. Figure 4.4 shows that there has only been a modest increase in the average recovery factor for the other fields.

The estimates of the recovery factor are often stated for the field as a whole, but the factor usually varies considerably between different reservoirs (deposits) in a field. Figures 4.5 and 4.6 show the current estimates for the in-place oil, recoverable oil and recovery factor for the various deposits in a large and a medium-sized oil field on the Norwegian continental shelf. It is seen that the difference in the recovery factor may be very large for different reservoirs in the same field. When measures to improve the recovery factor are to be evaluated, it is important to study

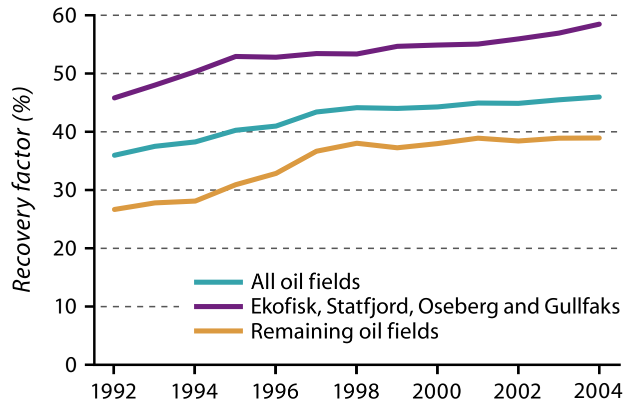


Figure 4.4 Trend in the recovery factor for oil from 1992 to 2004.

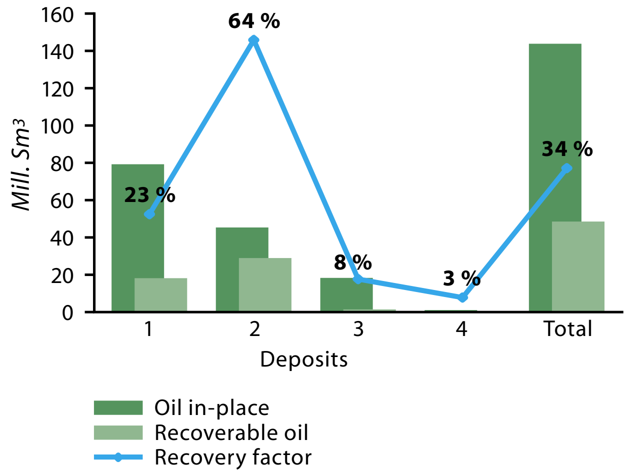


Figure 4.5 In-place oil, recoverable oil and recovery factor for various deposits in a medium-sized field on the Norwegian continental shelf.

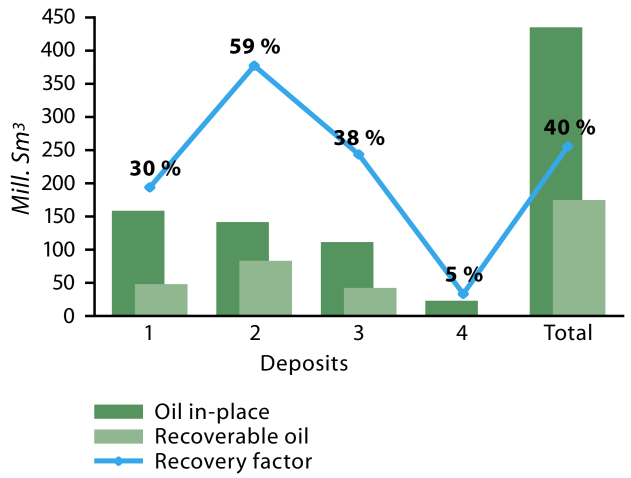


Figure 4.6 In-place oil, recoverable oil and recovery factor for various deposits in a large field on the Norwegian continental shelf.

each reservoir separately because the reservoir properties and the possibilities for enhanced recovery can be very different.

4.5 New goals for the recovery on the Norwegian continental shelf

In the 1997 Resource Report, the Norwegian Petroleum Directorate presented a target for the average recovery factor on the Norwegian continental shelf of 50 per cent for oil and 75 per cent for natural gas. This has been a stretch target and an inspiration for both the companies and the authorities to make efforts to achieve higher and more efficient recovery from the fields. The target for the recovery factor for oil has often been used as a measure for both old and new oil fields.

It has mainly been the large fields that have helped to draw the average recovery factor upwards. For the other oil fields there has, on average, been a flattening out (see Figure 4.4). This is gradually representing a significant challenge. The overall recovery factor for oil fields on the Norwegian continental shelf is now 46 per cent.

The variation in the recovery factor is large, even within a single oil field. The average recovery factor is therefore an indicator which has its weaknesses. For instance, the recovery factor will increase without more oil being taken out if the estimate of the in-place resources is reduced. In the same way, the recovery factor may be reduced even though the reserves increase if the estimate of the in-place resources increases more than the reserves.

Many of the new deposits and fields that are put into production are smaller, have moderate or poor reservoir properties and are developed with installations that have fewer possibilities to implement measures to enhance the recovery. This means that in future we will probably see many oil fields with a lower recovery factor than we now see in the best fields. It is also important to discover more oil in and around the large fields. The reserves will then increase, but the average recovery factor may be reduced.

To be able to follow the trend in the growth of reserves on the continental shelf, the Norwegian Petroleum Directorate believes it will now be useful to shift from an aim for an average recovery factor to focus more strongly on a target for the recovery, that is to say a target for how many extra oil reserves can be produced on the Norwegian continental shelf in relation to present-day plans. This target should be a primary objective and must therefore be kept separate from the resource account and production forecasts. The trend towards achieving this target can be followed successively.

The resource account shows that plans exist for various measures to enhance recovery and for the development of new fields and deposits that, all told, will give approximately 580 million Sm^3 extra oil reserves (see Table 2.1). In addition, deposits will eventually be developed that have still not been discovered. Experience shows that some planned projects will not be implemented, but also that profitable projects may soon emerge that were not included in the earlier planning.

At the end of 2004, the remaining oil reserves on the Norwegian continental shelf amounted to 1225 million Sm^3. The Norwegian Petroleum Directorate believes there should be an aim to increase the reserves by 800 million Sm3 of oil, corresponding to five billion barrels, in the next ten years. The NPD forecasts estimate that Norway will, in the same period, produce approximately 1300 million Sm^3 of oil. Hence, if this target is attained, the oil reserves will amount to approximately 725 million Sm^3 in ten years time. This presupposes that the industry succeeds in releasing the potential seen today for increasing the recovery from the fields, new discoveries are developed and increasingly improved and more cost-effective recovery methods are developed.

The new target can be expressed as follows:

Five billion barrels of extra oil reserves before 2015

This corresponds to one and a half times the original oil reserves in Ekofisk, or six times more oil as in Draugen. The target is also 1.4 billion barrels, or 220 million Sm^3, more than we expect will be added as new reserves with present-day plans and forecasts (Figure 4.7). The Directorate will closely follow the trend towards such a target.

The Norwegian Petroleum Directorate considers that efforts must be made to achieve the highest possible profitable recovery from all fields. Some fields will be able to attain a recovery factor for oil that is well over 70 per cent, whereas others will experience great difficulty attaining 30 per cent. No-one knows with certainty which new possibilities technology will offer in the future. As we have shown, it is uncertain how high the average recovery factor can be in the future. The NPD is nevertheless suggesting a revised

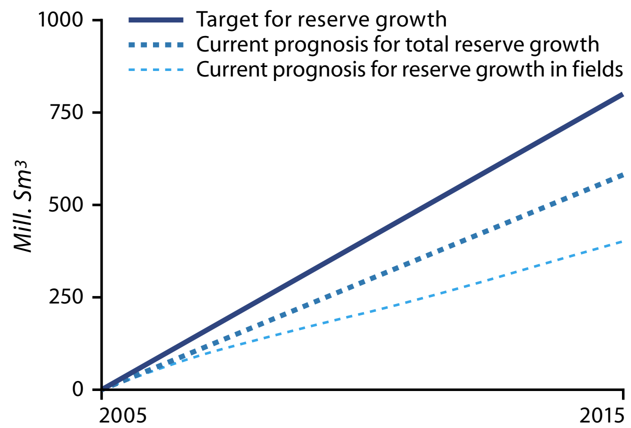


Figure 4.7 Targets and forecasts for the growth in reserves.

target for the recovery factor. This target must reflect the situation that Norway still has an ambition to increase the recovery from the fields over and beyond present-day plans, and it is hoped this, too, will prove an inspiration for further research, development and implementation of new measures for enhanced recovery from the fields on the Norwegian continental shelf. In the long term, it should be possible to raise the average recovery factor for oil on the Norwegian continental shelf to 55 per cent. This is a large increase relative to the current 46 per cent, and if it is to be achieved all the parties in the Norwegian petroleum industry must make a substantial effort. The Norwegian Petroleum Directorate has not stipulated a time by which such an average recovery factor can be attained, and it must therefore be viewed independently of the Directorate's target of five billion extra barrels of oil reserves by 2015.

4.6 Measures that have helped to enhance recovery

Injection of water or gas will often be decisive for achieving a high recovery factor for oil. Factors that are specific to particular fields will decide whether it is water injection, gas injection or a combination of these that is most effective. The number and placing of wells is also important for efficient recovery.

A number of different measures exist to improve the recovery from the fields on the Norwegian continental shelf. A well-known example is water injection on Ekofisk, which was implemented following thorough investigations to find out whether this could be used in chalk fields. Combined with compaction of the reservoir, it has given a large increase in the recovery factor compared with what was originally estimated.

Another important example is advances in drilling. The drilling of long, horizontal wells has now become conventional technology, and wells with several branches are now used on a number of fields. This has contributed significantly towards improving the recovery on the Norwegian shelf. The development of such wells has been decisive for the oil recovery on Troll.

Injection of natural gas and the use of WAG (water-alternating-gas injection) have helped to give a high recovery factor as, too, have better tools for reservoir visualisation and well management. WAG is a technique where the positive effects of injected water and injected gas are combined in the reservoir. This can give very low residual oil saturation, and there is less need for gas, to which there may be limited access.

In addition to natural gas, it is also feasible to use CO_2, nitrogen and air as injection gas. CO_2 injection has been employed for many years in countries, particularly the USA, where reservoirs containing pure CO_2 gas are available.

Injection of CO_2 separated from the exhaust emitted by gas- or coal-fired power stations or other industry could, in addition, give an environmental benefit. The technique has so far not been employed to improve recovery on the Norwegian continental shelf because the cost is too high. Injection of nitrogen and air are not conventional methods and pose great challenges as regards the reservoir and safety.

More untraditional methods, like the use of foam combined with WAG (FAWAG) and of microbes (MIOR) which form chemicals in the reservoir, have also been tested on the Norwegian continental shelf. FAWAG is used in several wells on Snorre, and MIOR have been employed for a long time on Norne. These methods have so far had a limited effect for the overall oil recovery on the Norwegian continental shelf. Research has also been performed on additives to the injection water that may reduce the residual oil saturation, but this method has still not been taken into use.

In the last 10-15 years, when oil prices have been low, most of the resources for research on oil and gas recovery have been directed at technology that can be applied within a short time. This concerns drilling and well management and mapping of oil-rich pockets in the reservoir where infill wells can be placed (seismic methods and visualisation). The effort has given results which, in some cases, have been extremely good, and has helped to maintain the production level for oil from the Norwegian continental shelf in recent years.

Research on methods to reduce the residual oil saturation has a more long-term perspective. The effort in Norway, as in the rest of the world, has varied in pace with the price of oil. From being an area of commitment in the 1980s, the activity was greatly reduced in the early 1990s, both in the companies and at the research institutions.

It is vital that research and development still take place over a broad range of methods. This can give the industry alternative methods to use when conditions are appropriate, or to solve particular problems. If the price of oil stands at a high level for a long time, it is also natural to assume there will be more opportunities to use such advanced methods.

4.7 Effect of gas injection

The justification for choosing gas injection varies from field to field. In some cases, gas injection gives the best recovery, whereas in other cases the absence of opportunities to export natural gas is an important factor. Gas is therefore also injected into fields where the effect is moderate, because this offers a chance to produce the oil without having to burn the gas. The effect of injection, expressed as extra oil per volume of injected gas, varies substantially from field to field.

By the end of 2004, a total of 413 billion Sm³ of gas had been injected on the Norwegian continental shelf (a quantity that can be compared with the gas reserves on Ormen Lange). Most of this gas, approximately 75 per cent, has been injected in the Oseberg, Statfjord, Ekofisk, Åsgard and Sleipner Øst fields. Gas has been injected into a total of 27 fields on the continental shelf. A few fields, like Oseberg, Ekofisk, Grane and Fram, have received, or will receive, gas from other fields, in addition to re-injecting their own gas. However, for the majority of the fields, the injection is based on re-injection of their own natural gas. The same gas can also be produced and injected several times.

Figure 4.8 shows gas injection used on various fields up to 2004. Figure 4.9 shows both the total historical gas injection and the forecast for future injection based on plans prepared by the companies. The figure shows that, in recent years, 35 to 40 billion Sm³ of gas have been injected each year. This level will be maintained for some time. The great majority of the gas that is injected will be produced and sold later.

The Norwegian Petroleum Directorate has undertaken a review of the fields on the Norwegian continental shelf that have injected, and/or have plans to inject, large quantities of natural gas. The average effect so far has been around 0.5-0.6 million Sm³ of extra oil per billion Sm³ of injected gas. The effect varies from field to field by between 0.2 and 1.0.

The NPD estimates that because of gas injection into the fields on the Norwegian continental shelf, 180-220 million Sm³ more oil and condensate have been produced than would have been the case without gas injection. This is more than the total oil reserves in Heidrun. If existing plans for gas injection are added, we assume that a total of 270-310 million Sm³ more oil and condensate will be recovered, that is, an additional approximately 90 million Sm³. In addition, there are increased or accelerated revenues because the gas injection permits continuous oil and condensate production when the production for various reasons would otherwise have fallen or stopped.

Injection of natural gas gives Norway 270-310 million Sm³ of extra oil and condensate

To make this estimate, we have compared the effect of gas injection with what would have been the alternative recovery method. In many cases, this would have been water injection or, in some cases, no injection. This means that if gas injection was to stop, the loss would be significantly greater than 90 million Sm³ of oil and condensate because water injection is not available as an alternative method on several of the fields.

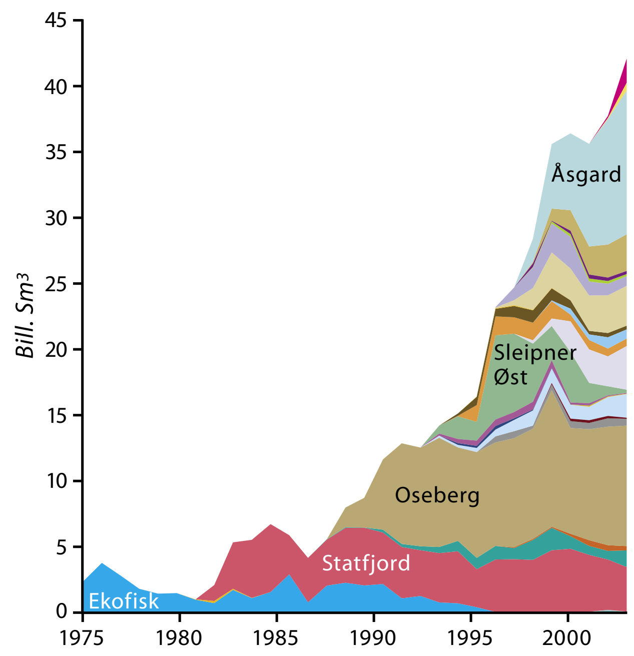


Figure 4.8 Historical gas injection on fields on the Norwegian continental shelf.

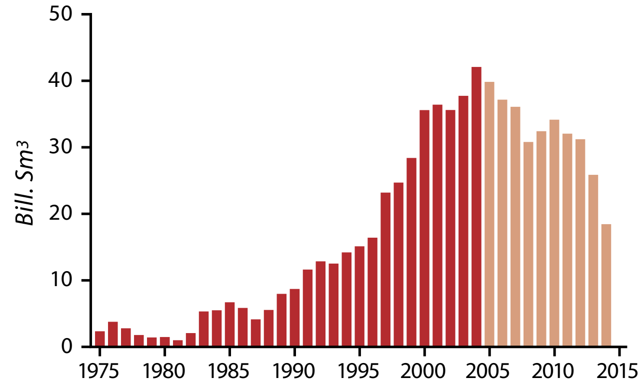


Figure 4.9 Total historical gas injection and the forecast for future injection on the Norwegian continental shelf.

4.8 Challenges with injection and use of natural gas

There are no pure gas fields on the Norwegian shelf. All the fields that mainly contain gas have either an oil zone beneath the gas cap or a high content of condensate in the gas. When a portfolio of such fields is being developed, it is particularly vital that the licensees find a good balance between the recovery of the liquid and the gas resources. Different interests may be present in this weighing of the options. For instance, it may be more profitable for some licensees to sell natural gas early, rather than using it to maintain the pressure in the reservoir, thereby obtaining more of the oil. In any case, the effect of injecting natural gas will decline over time. Sooner or later, it will thus be necessary and desirable to change the production. The timing of this shift from the one phase to the other will be influenced by a number of factors, including expected market conditions for oil and gas.

The most important forms of gas injection on the Norwegian continental shelf are:

Non-miscible gas injection. This method can be used when the pressure and temperature in the reservoir are such that the gas and the oil behave as two separate phases. The gas is lightest and places itself over the oil as a gas cap, and pushes the oil towards the production wells, which are usually placed lowermost in the oil zone. The largest projects which use this method are on Oseberg and Grane.

Miscible gas injection. This method can be used when the pressure and temperature in the reservoir mean that the injected gas dissolves in the oil and the oil becomes more fluid. This is considered a very efficient method (high microscopic displacement efficiency). The largest projects where this method has been, or is being, used are the gas injection in the Statfjord Formation on Statfjord and in the Smørbukk Sør reservoir in Åsgard.

Tertiary gas injection following water flooding. This means that gas is injected into a reservoir following a lengthy period of water injection. In areas where the oil is not displaced by the water, it may be displaced by gas, thus increasing the vertical and horizontal displacement efficiency. The method is used in the Brent Formation on Statfjord.

Water-alternating-gas injection (WAG). Gas and water are injected alternately into the same well. This can take place under miscible conditions in the reservoir, as is the case on Snorre, but in most cases it takes place without miscibility, that is to say that the oil and the gas behave as different phases in the reservoir. The effect is then somewhat similar to that obtained by tertiary gas injection, that water and gas displace the oil from different parts of the reservoir. A number of fields on the Norwegian continental shelf employ this form of injection. Under miscible conditions, the microscopic displacement efficiency will also increase.

Injection in gas-condensate fields to increase the recovery of condensate. In a gas-condensate field, the natural gas contains both light and heavier components. If such a field is produced without injection, the pressure will gradually drop. Some of the heavier hydrocarbons in the gas will then be precipitated in the reservoir (they condense) and cannot be produced. If gas is injected, the pressure will remain high for a longer period and a larger proportion of the condensate content will be produced. The largest projects using this method are on Sleipner Øst and in the Smørbukk reservoirs on Åsgard.

Statfjord is an example of a field where a decision to change the production strategy has recently been taken. "Statfjord late life" is a project that partly concerns re-producing previously injected natural gas. Gas now dissolved in the oil will be liberated by lowering the pressure in the reservoir. This will be achieved by producing free gas and water. Some oil will still be produced, but the total amount will be less than by continued injection of gas and water.

Corresponding challenges will be linked to fields where the oil lies beneath a large gas cap. A key question will be how long it is profitable to keep the natural gas in the reservoir to thereby maintain the pressure and obtain as much as possible of the oil. In many cases, production of gas will lead to an end to the possibility for extra oil recovery. One example is Troll, which contains large quantities of both oil and gas. Studies show that if other factors remain unchanged, the earlier gas is taken out of the Troll Vest reservoir, the less oil it will be possible to obtain. The challenge in the years ahead will therefore be to focus on profitable measures for improved oil recovery, including continued development of technology. At the same time, it will be essential to look into every possibility, quantify them, rate them and clarify them so that they can be weighed up against the value of continuing to develop the gas resources.

Another major challenge is how to arrange for gas injection in new, small field developments, especially where extra gas from outside can help to improve the recovery of oil or condensate. In a few cases, gas-condensate fields may benefit from re-circulating dry natural gas to obtain more condensate. Oil fields contain both oil and natural gas, and injection of their own gas or gas from other fields is a production scenario that must be evaluated. It generally gives appreciably more oil recovery than both pressure depletion and water injection.

In areas lacking processing or transportation capacity for natural gas, re-injection is a good alternative to support oil production on the fields. The natural gas can perhaps be produced later if such capacity becomes available. Sometimes it may be expedient for the licensees of those fields to co-operate on the use of infrastructure for gas. Such solutions demand co-operation between players who often have different shares in fields and infrastructures belonging to them. The Norwegian Petroleum Directorate believes it is important for the licensees to look into the possibilities for this type of collaboration so that the overall profitability in the projects will be as high as possible.

4.9 Other factors that are important for improved recovery

A number of measures have been implemented that have given good results on the Norwegian continental shelf, such as drilling of new wells, multibranch wells and long-reaching wells from existing installations. Some discoveries near the fields have led to new subsea developments which utilise available processing and transportation capacity. This has taken place in a period when the oil prices have been under pressure, and many of the projects have been profitable even when the expected oil price was less than 10 dollars a barrel.

Some measures for improved recovery on existing fields are major projects that require extensive modifications or new installations. Such projects often have high threshold costs. They require large investments, have higher operation costs, and represent a substantial risk in the initial years because the increased revenues come several years later. This has made it extremely difficult to obtain decisions on injecting water, natural gas, CO_2, N_2, air and chemicals as long as there are low expectations regarding the price of oil.

Figure 4.10 illustrates how much oil has been produced from each field on the Norwegian continental shelf, how much is expected to be produced with currently approved plans, and how much of the resources will remain after planned shutdown. A great deal of oil still remains in the large fields, even in those with a high recovery factor, and this represents a large, extra volume of oil if the recovery from these fields can be further improved. A large proportion of these resources have high recovery costs.

Until a few years ago, the price expectations of the companies generally stood far below 20 dollars a barrel. The threshold costs for constructing new infrastructure and modifying installations may be difficult to justify with the value such a price expectation gives. The companies will, moreover, insist on a risk premium (an extra gain because there is a risk of something going wrong and the income not materialising in such projects).

Consequently, in the same period, with the exception of gas injection on Grane, no projects were implemented which required large investments on injection equipment or new infrastructure to transport injection media to new installations.

The petroleum companies have had expectations of long-term oil prices in excess of 20 dollars a barrel since the second half of 2004. The Norwegian Petroleum Directorate sees clear signs of more ambitious objectives for recovery, not only in Norway, but also elsewhere in the world. The economy in most of the methods is relatively good if the oil price expectations rise to above 22-25 dollars a barrel. High oil prices lead to enhanced profitability for energy and recovery projects throughout the world. Large, time-critical projects for improved recovery on the Norwegian continental shelf will have to compete with these projects and will therefore often not be considered equally commercially attractive.

It may be challenging to realise major investment projects to improve the recovery from the fields. The projects may not be considered particularly attractive commercially and will compete internationally for people and capital. However, wide-ranging co-operation between companies and authorities has previously helped to ensure that projects like Ekofisk water injection, Troll gas injected in Oseberg (TOGI) and Troll oil have been realised and have contributed to significantly increased value.

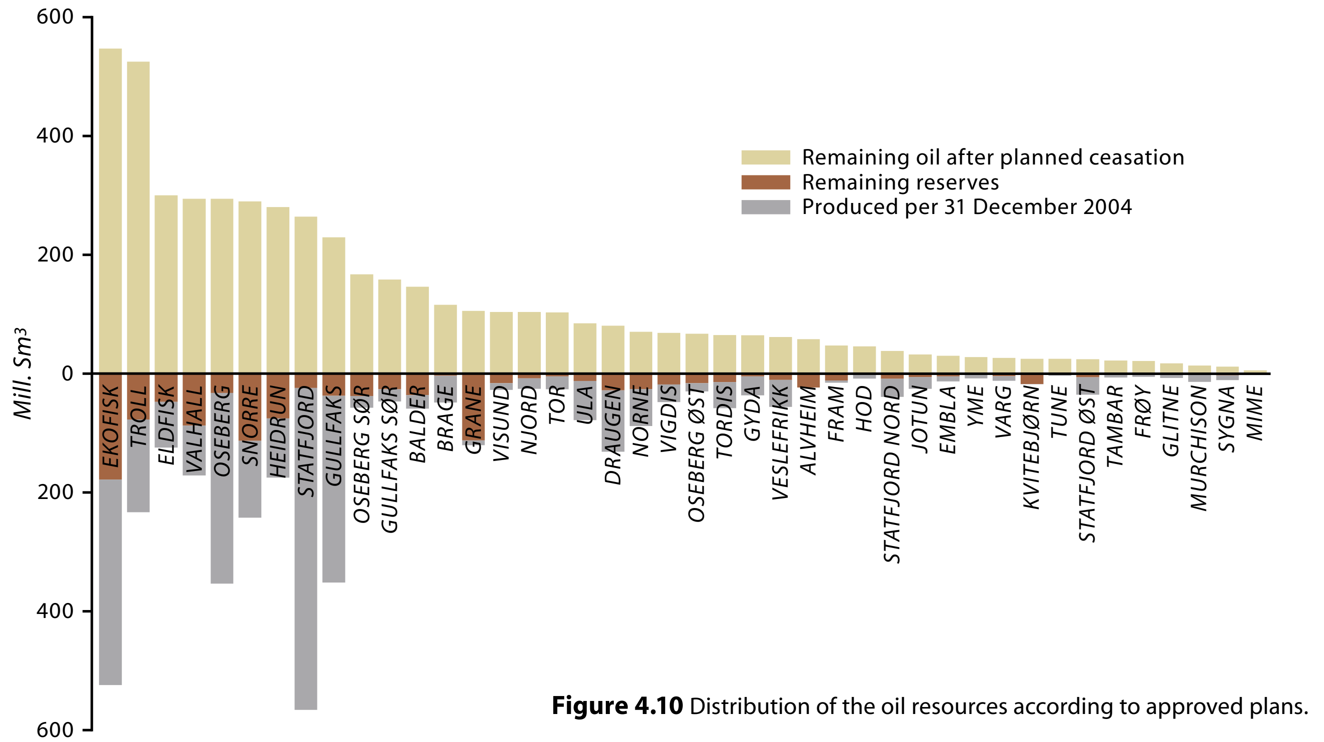


Figure 4.10 Distribution of the oil resources according to approved plans.

5 Efficient operations

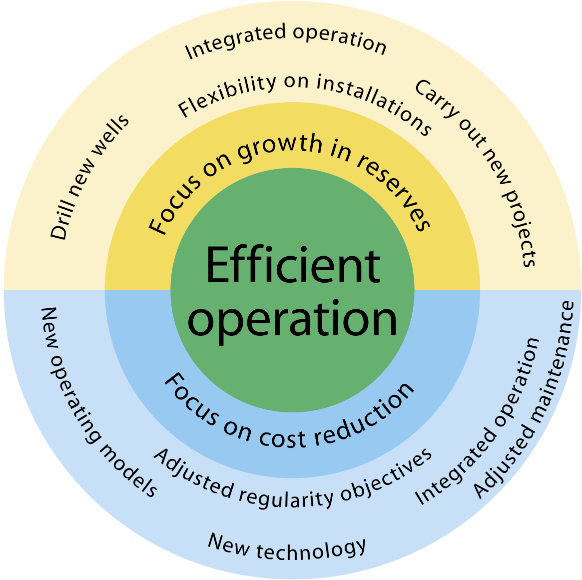


Figure 5.1 Efficient operations.

5.1 Introduction

The Norwegian Petroleum Directorate is keen for increased values to be created by improved efficiency in all phases of the activity. In the years ahead, the costs in the operating phase will make up a rising proportion of the total costs on the Norwegian continental shelf (Figure 5.2). In addition, several fields on the shelf have entered the decline phase. Making the operations more efficient may be a key to enhanced recovery from the fields and surrounding resources. This report, therefore directs focus on efficiency in the operating phase.

With regard to efficient operations, the NPD is placing emphasis on two aspects, facilitating a future growth in reserves and at the same time identifying and exploiting the potential to reduce operating costs.

When the Norwegian continental shelf is viewed as a whole, the unit costs, considered in isolation, are low and will only rise moderately in the future (Figure 5.3). A more marked rise is not envisaged because the installations with the highest unit costs are gradually being shut down. Measures to enhance recovery will generally only contribute to marginal rises in the operating costs. However, the measures do depend upon investments, and it is therefore insufficient to just have low unit costs for the operations.

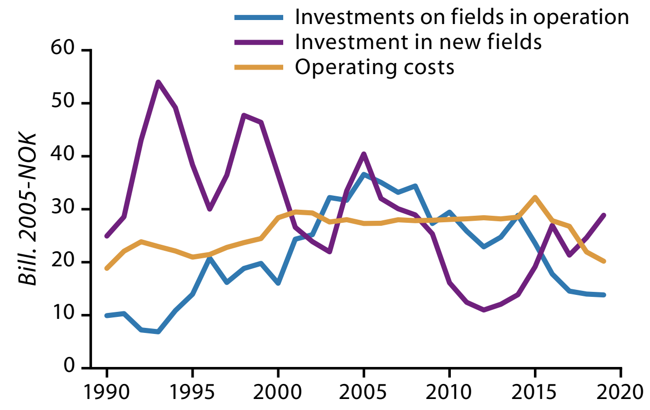


Figure 5.2 History and forecasts for investments and operating costs on the Norwegian continental shelf.

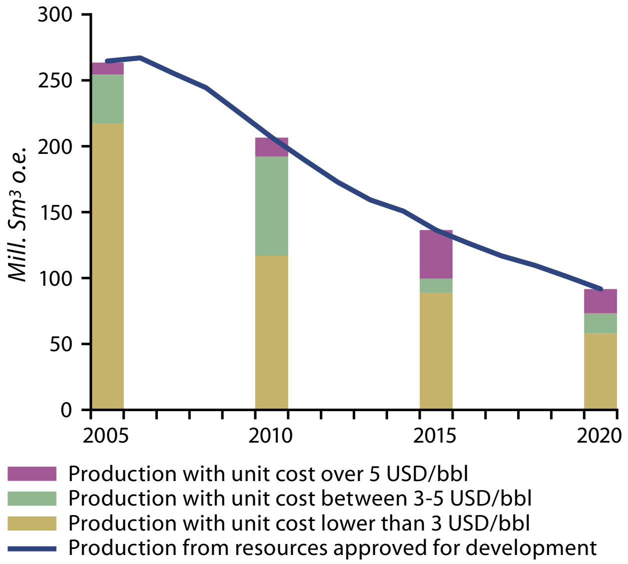
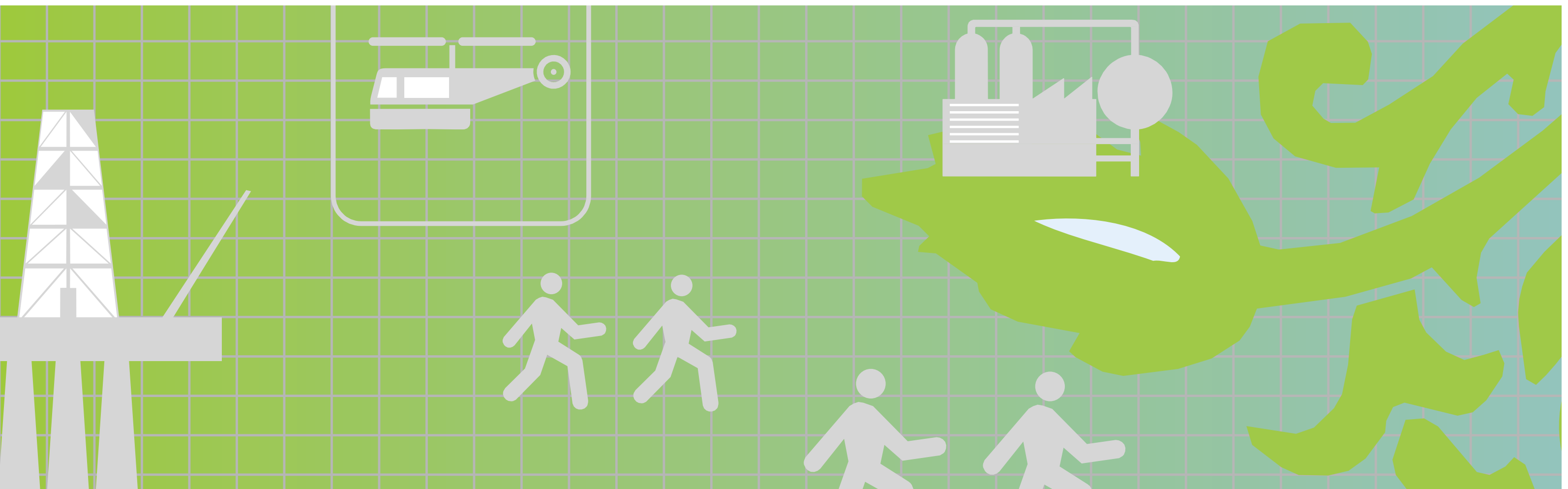


Figure 5.3 Production forecasts and expected unit costs for operations (excluding the CO_2 tax and tariffs).



5.2 Cost-effective requirements from the authorities

To permit the resources to be exploited as efficiently as possible, it is important that requirements made on the industry by the authorities are implemented in a cost-effective, flexible manner. This includes overall assessments of the costs and consequences linked with meeting these requirements. In addition to the investments themselves, such consequences as postponing production, increasing maintenance and reducing regularity must be included in the assessments.

Requirements made by the authorities may demand modifications to the installations and the related cost is made up of several elements, all of which should enter into the basis for the decision (Figure 5.4). Major projects will require a limited halt in production. In addition, the fields will cease production from time to time in connection with a revision stop. In such periods, all projects will be placed in a prioritised order. Requirements from the authorities are given high priority and will thus often be met at the expense of other, income-generating projects. It is, moreover, important that the requirements from different bodies among the authorities are coordinated.

Environmental benefits and related costs – an example

Requirements from the authorities concerning reductions in emissions and discharges are normally dealt with through permits for each individual plant. In practice, it is difficult for the authorities to identify the most cost-effective measures. One way of handling this is to regulate the emissions and discharges by using a flexible instrument, such as tradeable maximum levels of pollutants. The plant owners themselves can then assess whether it is cheaper to reduce the pollution or purchase maximum levels of pollutants. The figure shows that by selecting the most cost-effective measures in this example, substantial reductions in discharges and emissions can be achieved at a limited total cost. The measures that must be implemented to achieve reductions of more than 80 per cent will, however, be extremely expensive to carry out.

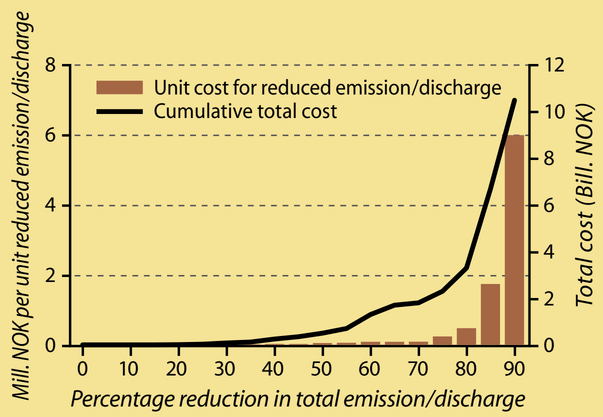


Figure 5.5 Reductions in emissions and discharges, total costs and unit costs for various measures. The measures are arranged by their cost effectiveness.

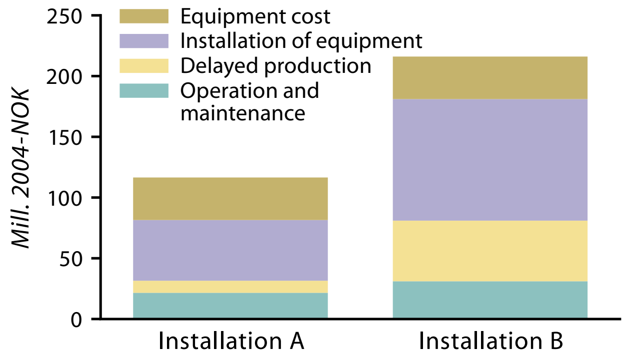


Figure 5.4 Examples from two different installations of the total costs of a measure required by the authorities.

5.3 Paving the way for future growth in resources

The development solution chosen for a field places limitations on opportunities for optimal production in various phases of the lifetime of the field. Normally, a development will be designed to result in the lowest possible investments relative to assumed requirements in the plateau phase. In many cases, the developments are therefore poorly accommodated to changing requirements later in the lifetime of the field. Decisions taken during the design, development and early operating phases will influence the possibility for achieving optimal production following the plateau period. It is therefore important to place emphasis on the need for investments in the operating phase and the value of incorporating flexibility when the installations are being planned. This may be very important for the total utilisation of the resources. Examples of the flexibility may be to prepare for the possibility of drilling from the installation, extra well slots, possibilities for bringing in more risers, and having vacant space and a weight margin to be able to install new equipment.

Experience shows that the development of a field will never be quite in keeping with the original plans. The pro-

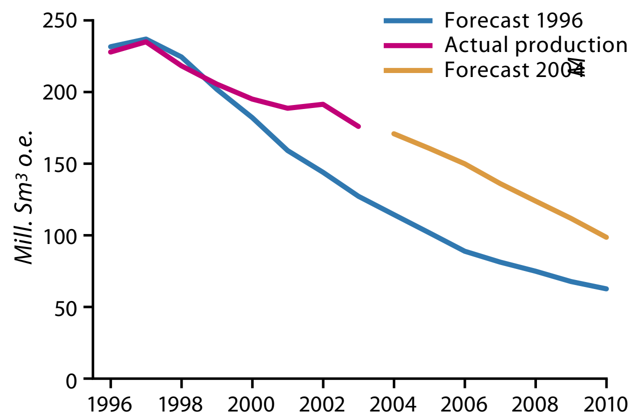


Figure 5.6 Two production forecasts for fields which started production before 1997, actual production up to 2004 for the same fields.

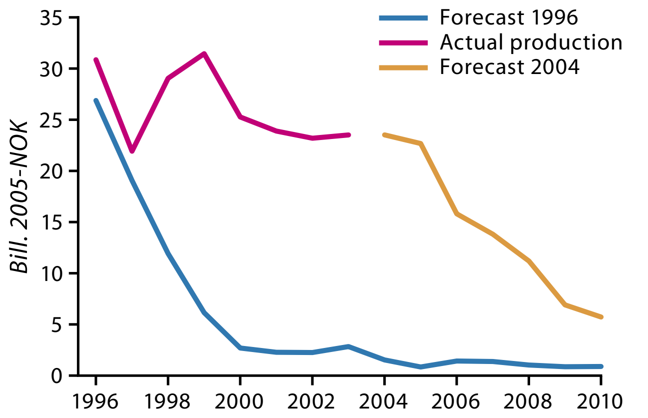


Figure 5.7 Two forecasts for investments in the operating phase for fields which started production before 1997, and the actual investments up to 2004 for the same fields.

duction from fields put on stream prior to 1997 has been up to 50 per cent higher than original forecasts indicated (Figure 5.6). Figure 5.7 shows that this required substantial investments. Field developments which had adequate flexibility for additional investments have benefited by obtaining higher production than that which formed the basis for the original production plans.

5.3.1 Efficient operations improve recovery

The operating costs are vital for the lifetime of the installations and, hence, also for the basis for profitability in new projects on the fields. When a project is initiated, it is important to feel assured that the infrastructure will be available for a sufficiently long time. To obtain efficient utilisation of the infrastructure for such additional resources it is therefore decisive that the level of costs provides a basis for long-term production from the individual field.

A large part of the infrastructure in mature areas of the Norwegian continental shelf will be operative for many years to come. This is illustrated in Figure 5.8, which outlines the lifetime of the installations. The lifetime shown here is based on plans for the production of the reserves on the fields. Large areas lie within a radius of 50 kilometres from installations that have plans for production extending more than 20 years into the future. There are 2.7 billion Sm³ o.e. of oil and gas in the form of additional resources in fields, discoveries and prospects in this area. Cost-cutting measures can give a long lifetime and, even with low prices, thus lay the basis for continuing, long-term value creation.

Reducing operating costs without new measures for improved recovery will have little effect on the resources (Figure 5.9), but will nevertheless be important for the profitability of the field and make it simpler to carry out new projects.

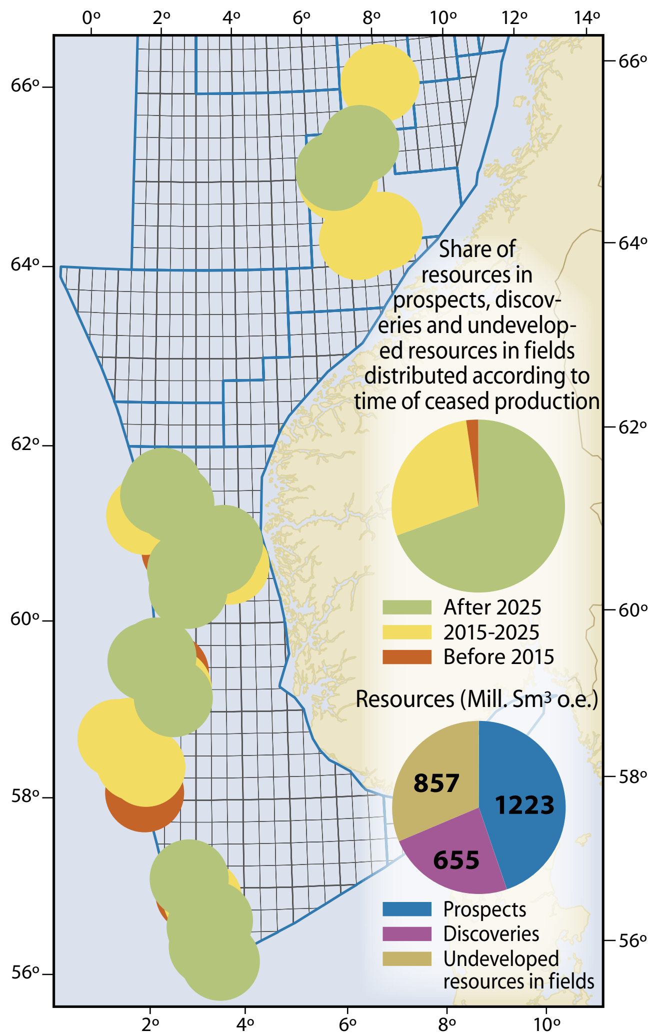


Figure 5.8 Areas (50 kilometre radius) for phasing-in around relevant fields, arranged by the remaining production time for the confirmed reserves on the fields. Fields in red areas will cease production within ten years, those in yellow areas between 10 and 20 years and those in green areas after more than 20 years.

If the lifetime of all the fields is extended by two years, with the same production level as in the last planned production year, the recovery from fields that are already in production will increase by approximately 80 million Sm³ o.e. The phasing-in of new resources will further increase the volume.

A large proportion of the operating costs are difficult to alter in the short term. Even if production declines, it is often difficult to reduce the costs correspondingly. The profitability will thus be poorer and there will be less likelihood of new projects being approved. Measures that improve recovery generally have better profitability when they are initiated early. In the end phase, they often have marginal profitability compared with other projects.

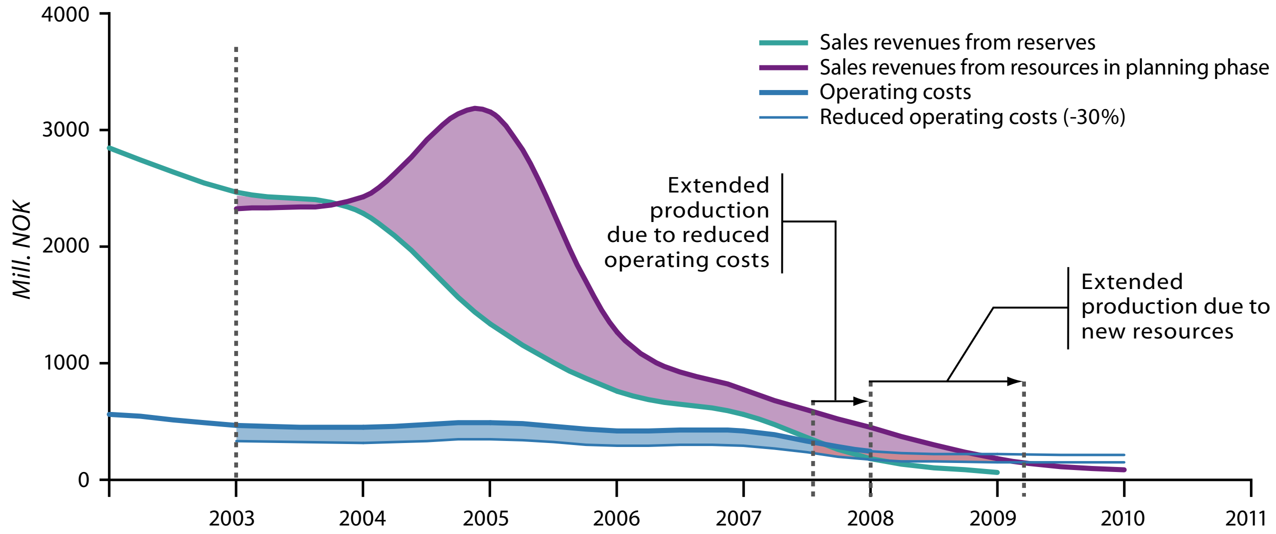


Figure 5.9 An example showing the trend in sales revenues, operating costs and lifetime, with and without reductions in operating costs and with and without developing new reserves.

5.4 Reducing operating costs

The installations on the Norwegian continental shelf are tailored for their field. This makes it difficult to undertake direct comparisons of the operating costs on the various fields. Nonetheless, there are some general conditions and functions that control the operating costs of the installations. The Norwegian Petroleum Directorate has performed a study to identify these on the basis of data reported for 2004 from all the installations on the shelf. The most important cost drivers have been identified and assessed together with technical and production data for the installations. Since this analysis was performed at a high level, there will be other cost drivers that are important for some installations because of equipment on the installation, sea-bed conditions, reservoir conditions and so on. The comparisons made also reveal a substantial scatter in the results and, in isolation, fail to give a complete picture of how close the connection is between the operating costs and the various drivers. The parameters studied and the degree of connection with the level of the operating costs is shown in Figure 5.10.

As expected, the level of offshore manning and production capacities are clearly related to the level of the operating costs. The study also reveals a link between the annual investments on the field in the operating phase and operating costs the same year (Figure 5.11). This indicates that investments lead to more activity generally and more use of supporting activities like management (offshore and onshore), operations offshore, operational support on land, logistic services, catering and so on.

It will be reasonable to assume that new installations have a lower level of operating costs than older ones. However,

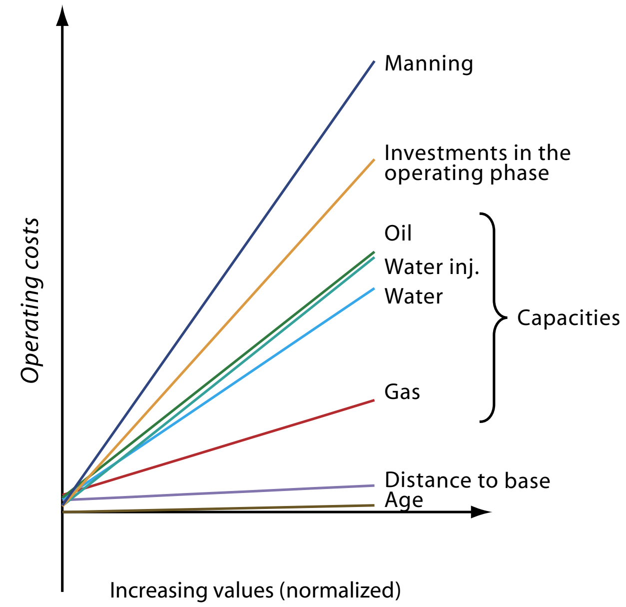


Figure 5.10 Relationship between operating costs and various parameters.

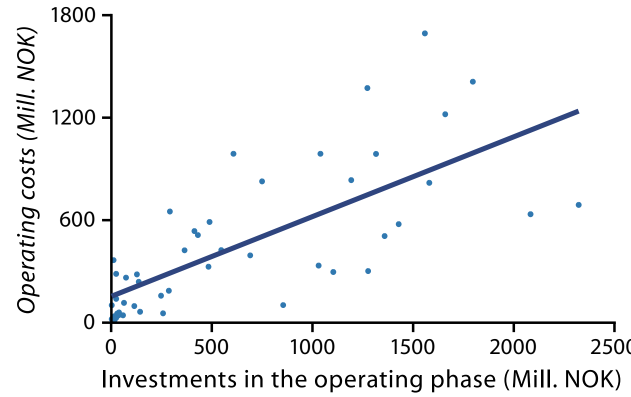
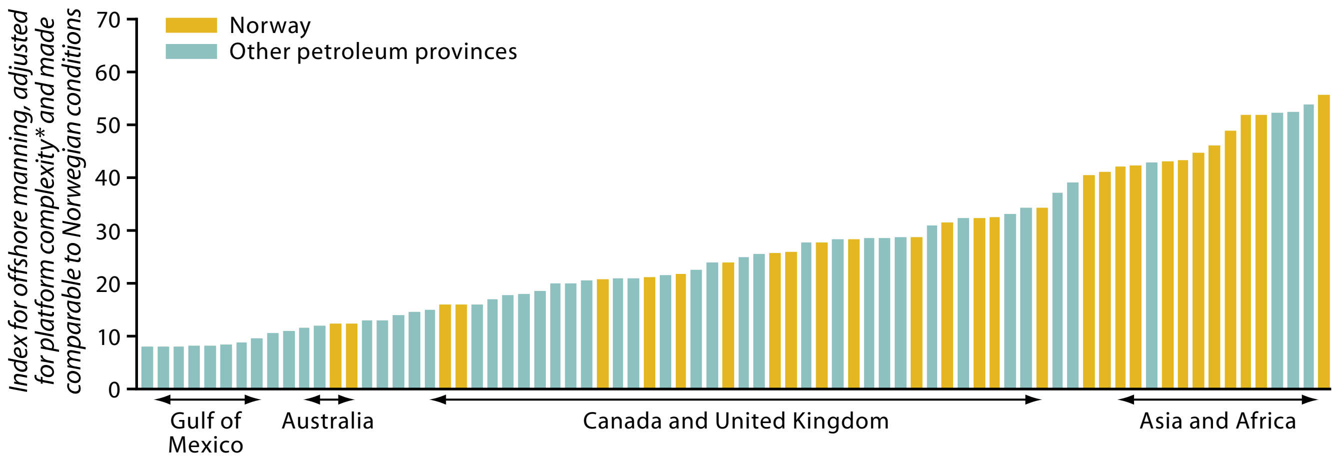


Figure 5.11 Relationship between operating costs and investments in the operating phase.



* Index showing increasing influence from factors affecting manning level, such as age, size, number of wells, etc.
Source: Operating companies on the Norwegian continental shelf; McKinsey: team analysis

Figure 5.12 Manning levels on Norwegian and foreign platforms (Source: Konkraft).

the analysis reveals no clear connection between the age of the installations and the figure for the operating costs, in spite of the fact that the manning level on new installations normally is lower than on old installations. This could perhaps be partly because the oldest ones have been upgraded regularly and the operation philosophy has changed.

The manning levels on Norwegian platforms are on the whole high. In its study, "Mapping the cost situation on the Norwegian continental shelf" (2004): Konkraft writes: "The analysis shows that platforms on the Norwegian continental shelf vary considerably (Fiure 5.12). Some have manning levels that are in line with those on other shelves. Other platforms on the Norwegian continental shelf are, however, more comparable with platforms in low-cost countries in Asia and Africa. British platforms also show a large variation in the manning levels, but on average the levels are somewhat lower than on Norwegian platforms."
The costs attached to operating personnel account for a large proportion of the total operating costs. In the same report, Konkraft estimates this proportion to be 65 per cent. The analysis performed by the Norwegian Petroleum Directorate also shows a clear connection between the manning levels and the level of the operating costs (Figure 5.13)

To reduce operating costs, one of the greatest challenges will therefore be to have adequate flexibility in the operational organisation to enable the workload and manning to be optimised with respect to the requirements on the field. This will be particularly vital when production goes off plateau.

In Figure 5.14, the fields on the Norwegian continental shelf are grouped according to their complexity based on their production capacity and investment level in the

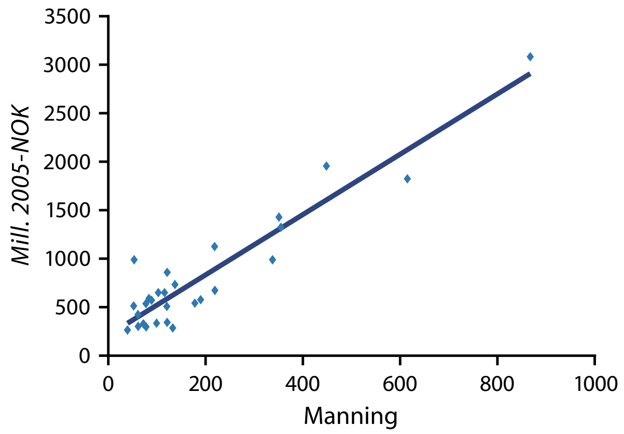


Figure 5.13 Relationship between operating costs and manning on fields on the Norwegian continental shelf.

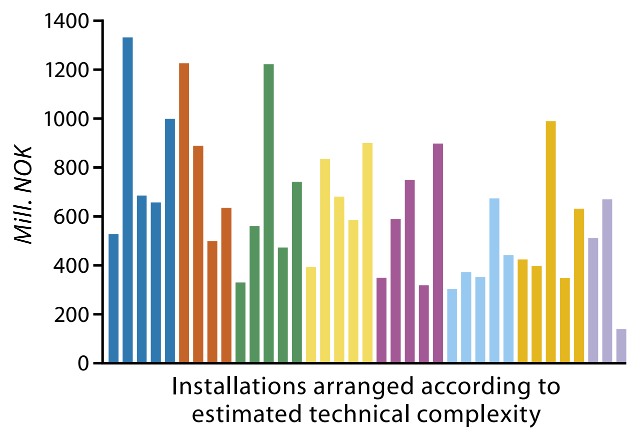


Figure 5.14 Operating costs (2004) for installations, grouped by their technical complexity. The large, most technically complex installations are placed to the left, and smaller, less complex ones further to the right in the figure.

operating phase. There are great differences in the level of the operating costs between the fields, even on fields with similar complexity. Aspects that are specific to a particular field, and hence its tailor-made design, partly explain these differences. The study indicates that possibilities for reducing the costs are applied to differing extents on the fields. To illustrate the potential for reducing operating costs, their level is compared with international "best practice". A "best practice" operating cost has been estimated for a representative selection of eight platforms. Compared with actual operating costs, the study indicates a potential for cost reductions of around 30 per cent, merely by making use of experience from other fields (Figure 5.15).

If the potential for using new types of equipment, new working methods and new communication infrastructure is fully exploited, the overall potential for cost reduction is likely to be significantly higher (Figure 5.15).

A 30 per cent reduction in the operating costs on all fields to the end of their lifetime will save around 115 billion NOK (non-discounted) in the period up to 2020 (Figure 5.16). This does not allow for possible increased revenues from implementing new projects.

The implementation of cost-reducing measures will be influenced by priorities and effort, not least on the part of the operator. The efficiency-enhancing measures may be demanding to implement, especially if they entail major changes in the operating model, moving work operations to land, or possible manning reductions. In some cases, the benefits may seem small if the operator only takes a small share, not least when the tax rate is high.

5.4.1 Measures that may improve the operating efficiency

The operation philosophy for a field includes production, demands on regularity, maintenance, manning and which tasks are to be carried out on the field.

The operation philosophy is affected by a number of factors and is usually established on the basis of the level at plateau production. The procedures for the operation are thus based on a significantly higher production than towards the end of the field's lifetime. It may therefore be natural to assess whether the existing operation philosophy is still optimal.

An accommodation of the operation philosophy may mean everything from minor adjustments in work tasks and maintenance, to entirely new ways of operating the field or installation. Examples of this are the introduction of various elements of integrated operation or transferring operational tasks to equipment suppliers or contractors.

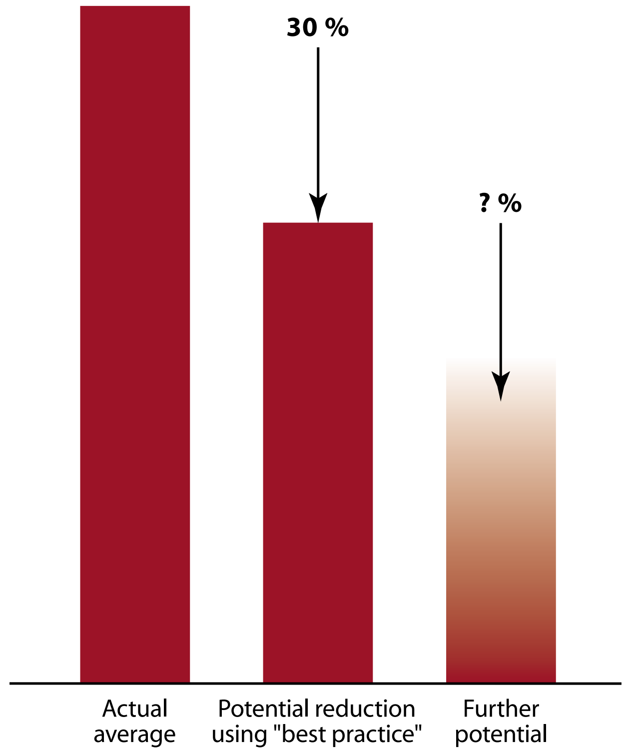


Figure 5.15 Estimated potential for reducing operating costs on the Norwegian continental shelf based on a calculated average of present-day "best practice". A further potential for reduction is also shown.

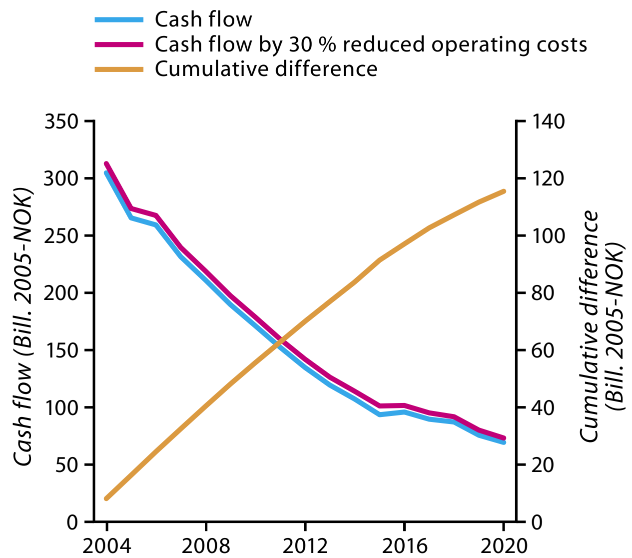


Figure 5.16 Accumulated increase in the cash flow with a 30 per cent reduction in operating costs.

The Frigg example

In autumn 2004, the Frigg field closed down after 27 years' production. This was one of the first fields to be put into production on the Norwegian shelf, and when it was shut down, four platforms were operating.

At the beginning of the 1990s, it was clear that production was declining drastically and the shutdown date lay only a few years away if the cost of operating the field was not reduced.

An extensive re-organisation of both the organisation and the operation philosophy from 1997 onwards meant that the field could continue producing until autumn 2004 and that production was profitable right down to a level of 1 million Sm^3 of gas a day. The operating costs were reduced by about 40 per cent relative to the beginning of the 1990s. In the last year, the average production was 4.6 million Sm^3 a day and the technical cost was 4.1 dollars a barrel.

Some interesting fundamental features of the re-organisation may be worth noting:

- Extensive use of technicians and managers on the platforms directly during the re-organisation
- Low, permanent operational manning with an integrated team and direct responsibility – eliminating the first-line supervisor (changed to a specialist without personnel responsibility)
- Conversion to campaign-based maintenance following a criticality assessment (15-20 per cent improved efficiency)
- Systematic review of all the equipment on the platforms based on their importance for operations. Superfluous equipment was shut down and some was removed.
- Re-organisation of the maintenance philosophy from the principal emphasis being put on preventive measures to a large proportion of condition-based and corrective maintenance based on the importance of the equipment.

In addition, the appointment of contractors to perform the maintenance work in 2001 helped to place focus on:

- Better co-operation with suppliers and development of expertise among the contractors
- Incentive-based contracts with the contractors

Source: Total E&P Norge AS

Many measures may make the operation of the fields more efficient. In some connections, major changes in the infrastructure are required, entailing shutdown, rebuilding or installation of new plant. Good effects may also be achieved with minor adjustments, like closing down or replacing old equipment, or upgrading existing equipment. For some platforms, the solution may be to introduce new operating models by bringing in integrated operation, moving work tasks to land, remote control and automation, or transferring operational tasks to contractors. Simple adjustments in the operation philosophy will also help, such as in relation to maintenance, or requirements regarding regularity.

5.4.1.1 Adjustments in maintenance strategy

Maintenance, which is an important part of the operation of an installation, requires the fulfilment of certain minimum criteria to be able to keep the operation going. The most important is to take care of human safety and the external environment. The technical state of the installation and its equipment, and targets for regularity, determine the level of maintenance demanded.

The need for maintenance increases as equipment ages. However, reduced demands on regularity and removal of superfluous equipment may help to reduce the scale.

Maintenance will mainly be performed on the basis of three different strategies, regular maintenance in accordance with a pre-appointed plan, maintenance based on the monitored condition of the equipment, and maintenance to restore the technical state of faulty equipment. It may be best to have different maintenance strategies for different parts of the plant. By assessing the strategy against the phase the field is in, it may be possible to reduce maintenance costs appreciably.

The maintenance strategy is normally changed when the platform approaches shutdown. The result of less maintenance may be that the platform is in an inadequate technical state to continue operating after the planned shutdown date. This may be a problem if the preconditions for production change or the price of petroleum makes further production profitable.

Different maintenance strategies

Preventive maintenance is usually based on the supplier's general experience with the equipment, and is carried out at fixed intervals determined by the supplier.

Condition-based maintenance means that the condition of the equipment is monitored. Maintenance is carried out before faults arise which lead to the equipment or operations stopping. The monitoring will be able to be performed from land. A shift from preventive to more condition-based maintenance may reduce the cost of transporting maintenance workers and accommodating them at sea, and make it easier to compare similar problems on different platforms.

Corrective maintenance is maintenance undertaken after a fault has arisen. This strategy is normally used for equipment that is not critical for the production.

5.4.1.2 Regularity

Regularity is a measure of how much of the time a plant is in operation. Normally, the goal is the highest possible regularity to ensure high production. High regularity, however, comes with a cost attached, and it may be natural to consider whether it is necessary to have equally high regularity when production is declining. High regularity will often mean that the platform has several identical sets of equipment components (redundant), which need maintaining.

When regularity is optimally adjusted, the need for equipment on the platform can be reduced. There will also be less need for monitoring, maintenance and spare-part stores. The scale of the work can therefore be reduced and the operating costs fall.

5.4.1.3 Operating models

A critical review of the operations on a field should also include a review of the operating model itself. As the example from Frigg shows, a shift from preventive to condition-based and corrective maintenance may reduce the manning needs.

In some cases, a job in an operating company is linked to work on a particular platform, which gives little flexibility in relation to the efficient use of personnel. To increase the flexibility, one possibility may be to use the same strategy as in service and contracting companies where the personnel are not linked to specific platforms. This may help to develop more flexible and accommodating organisations, which will always be in proportion to the volume of work.

Distributing tasks and responsibility between operator and contractor may help to give greater efficiency. The Norwegian continental shelf has what are called "service operators", but on the British side of the North Sea an arrangement called "Duty Holder" is used. In addition to the traditional form of contract where the oil company pays the contractor for work, spare parts and supplying services at fixed rates, an incentive-based model is also used. The service operator and the oil company jointly draw up performance criteria and the service operator is given a free hand to treat them as tools.

5.4.1.4 Integrated operation

By integrated operation we mean, here, new forms of operation where information technology enables real-time data to be employed to achieve better and quicker decisions. Real-time data are information that is updated at the same moment as it is generated. In this way, personnel on land and out on the field gain access to information. When everyone has the same information simultaneously, for instance drilling and well data, process information or information on operating and maintenance parameters, the organisation on land can give platform personnel rapid and efficient support.

The Norwegian Petroleum Directorate believes there is a big potential for increased value creation if the oil industry utilises the data flow better by adapting organisations and ways of working to a more integrated and interdisciplinary work form. Giving different groups of specialists the chance to work in an integrated manner on the basis of up-to-date facts forms a foundation for quicker and better decisions. Several large operating companies on the Norwegian shelf have now defined this as a strategic area of commitment.

The introduction of interaction rooms is part of this development. Different groups of specialists sit there together, both physically in the same room and at different places with the help of technical equipment. The interaction between sea and land, and between operator and supplier, largely takes place with the help of computer systems. Problems can then be discussed and decisions taken quickly, irrespective of geographical location.

An efficient digital infrastructure offers many opportunities for better utilisation of available data. The combination of access to real-time data and historical data, and an ever-increasing capacity for data processing and visualisation, together with new working procedures, offers possibilities for optimising the operation of the fields.

Efficient use of information technology can also provide benefits in connection with maintenance planning. It paves the way for better prioritising of tasks and optimising of the offshore manning level. Remote monitoring of the technical state of offshore equipment, performed, for example, by the supplier, may make it easier to choose preventive measures and give better control of when maintenance must be carried out. This is now used on several sites on the Norwegian continental shelf.

The Norwegian Petroleum Directorate has taken the initiative to speed up the introduction of integrated operation by setting up an E-operation forum to which all relevant players are invited to discuss experience gained, opportunities and challenges.

More information on integrated operation and the E-operation forum can be found at
http://www.npd.no/Norsk/Emner/E-drift/

6 Resource classification

To keep an account of the quantity of petroleum on the continental shelf it is essential to have a good system of classifying it. Simple, good definitions of various types of petroleum are important, and the resources must be capable of being grouped in relation to their degree of maturity as regards investigation, planning and recovery. The Norwegian Petroleum Directorate has employed several different classifications over the years. The systems have gradually become more detailed and focused to be able to be good instruments for keeping a survey of the resources and providing a basis for various analyses.

Many different systems are in use today, both national and international systems, which reflect different traditions. This hampers international communication and comparison of data globally. Only now has a system, the UNFC, been designed that harmonises these various systems (see below). This chapter looks at the NPD classification and two of the most important international classifications, the development of which the Norwegian Petroleum Directorate has contributed to in various ways.

Resources and reserves are the two most key terms used when we speak about quantities of petroleum. However, they are not unambiguous, and their meaning varies in the different national and international classifications .

Resources cover all petroleum volumes. *In-place resources*, also called resources originally-in-place, are the quantity of petroleum calculated to be present in a deposit before production starts. *Contingent resources* are proven, recoverable quantities which it is assumed can be recovered, but where recovery has still not been decided by the licensees. Both technical and commercial assessments may remain before a decision on recovery can be taken.

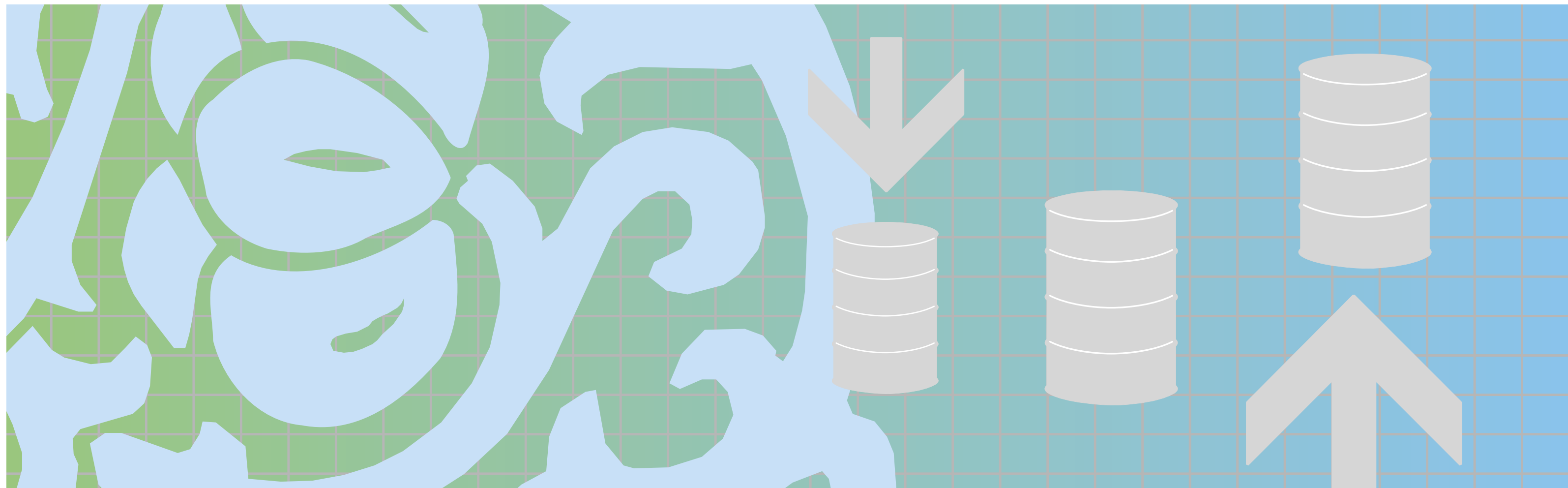
Reserves cover the remaining, recoverable, saleable quantities of petroleum in fields and projects where recovery has been decided. If a decision has been taken, the discovered quantities are not reserves but contingent resources. Hence, reserves are a subgroup of resources.

6.1 The Norwegian Petroleum Directorate's classification

The current NPD classification has been in use since 2001. The system covers all the recoverable petroleum, both discovered and undiscovered. The estimates of the in-place resources are not included in this system. Because the recovery of petroleum takes place by way of industrial projects, emphasis has been placed on the classification being able to follow their development. A field may be developed in several stages and will therefore include a number of projects. These have differing degrees of maturity as regards planning, development and production. The NPD system therefore classifies the quantities of petroleum in the individual projects by their maturity in relation to recovery.

The classification is divided into three classes: reserves, contingent resources and undiscovered resources (Figure 6.1). *Reserves* cover the remaining quantities of petroleum which the licensees have decided to recover and for which the authorities have approved a development plan. In other words, it may also be said that reserves are the remaining quantity in agreed projects that can be recovered with present-day technology and under current economic conditions and terms. *Contingent resources* are the recoverable quantities discovered, but about which a decision has not yet been taken and which have not yet been approved

[1] In the industry, some English terms are also used which, in many cases, have a very specific meaning, and which have not been translated to Norwegian. One example is "Proved reserves", a term devised many years ago in the USA. It is particularly used in connection with the reports made by the companies to the stock exchange authorities (SEC rules). Proved reserves comprise the limited portion of the reserves that can be verified through direct observations in wells and by the use of various methods of testing. Estimates of "Proved reserves" are first and foremost of importance to investors and owners as a basis for determining the value of the companies. In relation to the estimates of reserves which the companies report to the Norwegian Petroleum Directorate, proved reserves constitute a conservative estimate, often around 70-75 per cent of the estimate.



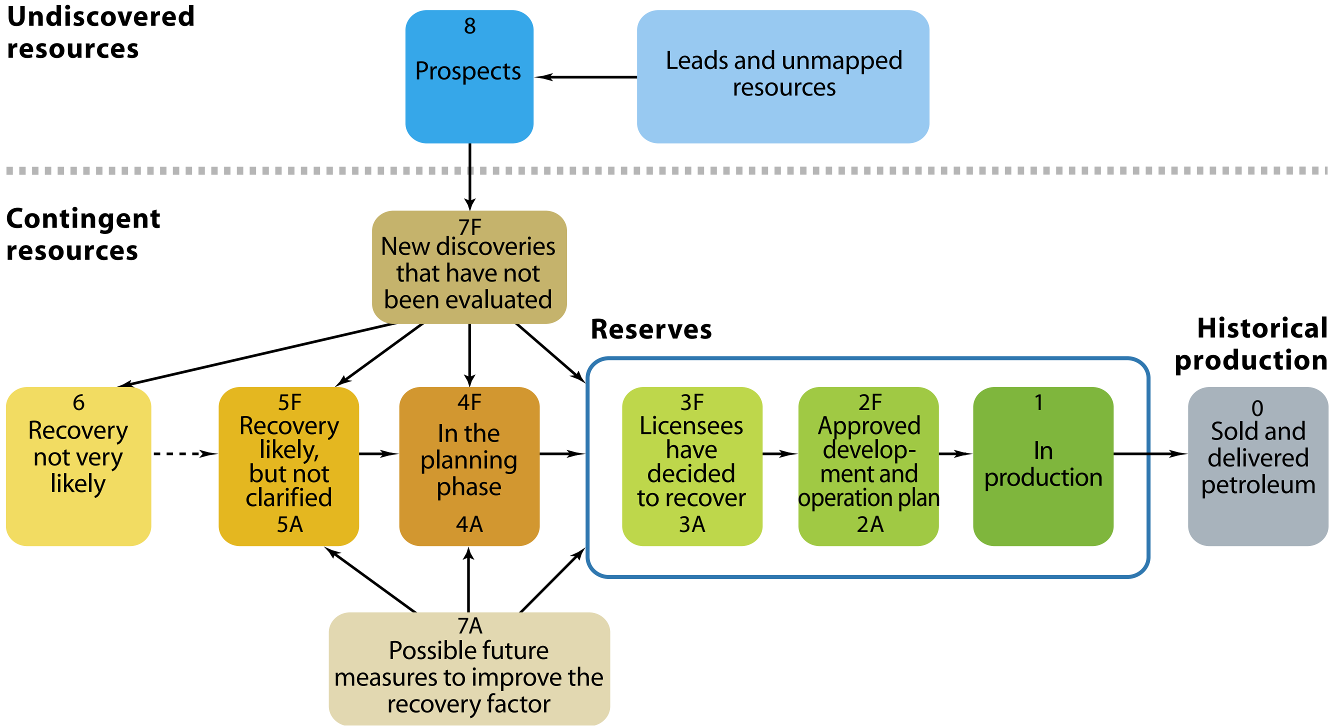


Figure 6.1 The Norwegian Petroleum Directorate's classification of the petroleum resources.

for development. Contingent resources also include resources attached to projects for improved recovery that have not been agreed upon in fields that are in production. *Undiscovered resources* are, as the term implies, the quantities of petroleum which it is assumed can be found if exploration continues and which can then be recovered. What is produced, sold and supplied comprises historical production. This is strictly speaking not a class; nor is it part of the reserves.

Each class is divided into different categories according to the status of the projects, and these are referred to as project status categories. They serve as useful "containers" for projects that have equivalent status as regards planning or development. The categories have also proved useful for evaluating and analysing groups of projects or, for example, to assess the entire Norwegian portfolio of discoveries.

More information about the NPD classification can be found on the home page of the Norwegian Petroleum Directorate:
http://www.npd.no/regelverk/r2002/frame_n.htm.

6.2 The SPE/WPC/AAPG's classification of the petroleum resources

Through the 1980s and 1990s, a number of professional organisations made a considerable effort to develop useful classifications of petroleum. The Society of Petroleum Engineers and the World Petroleum Congress jointly published a classification of reserves in 1997. This effort continued in cooperation with the American Association of Petroleum Geologists, and in 2000 a system for classifying the total petroleum resources was published, known as the SPE/WPC/AAPG classification (Figure 6.2). This system has many features in common with the Norwegian Petroleum Directorate's classification, which was one of the sources referred to in the work, and it is based on the same philosophy regarding maturing of resources up to recovery. The system is based on the in-place volumes, which are divided into discovered and undiscovered volumes. The main classes are the recoverable volumes, which include reserves, contingent resources and prospective resources. In addition to these classes, the system covers produced quantities and quantities that cannot be recovered, that is to say the quantities which, for physical, technical or financial reasons, will remain in the rocks after production has ceased.

The classes along the vertical axis reflect the financial risk, or the maturity, in the same way as the NPD system. In addition, the horizontal axis shows the degree of certainty in the observation of the petroleum quantities. For reserves, this is stated as "proved", "proved plus probable" and "proved plus probable plus possible", where "proved" is the most reliable and most conservative estimate. Contingent resources and prospective resources are divided into low, best and high estimates.

Like the Norwegian Petroleum Directorate's system, the SPE/WPC/AAPG classification can be divided into project status categories and thus be used as an instrument for handling portfolios. The SPE/WPC/AAPG classification is gaining ground and being used by more and more countries. Some oil companies are also starting to use the system. The SPE has prepared comprehensive guidelines for the calculation of petroleum volumes and the use of the classification.

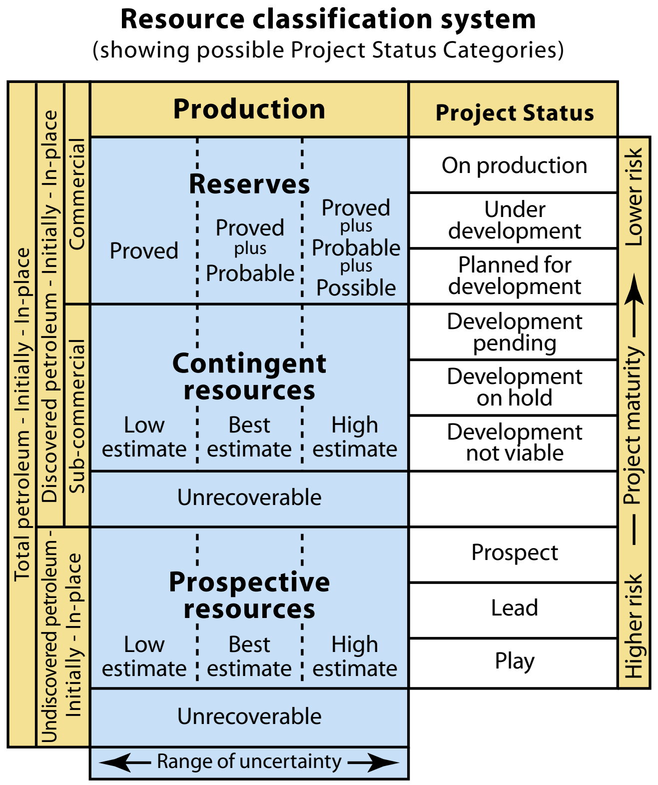


Figure 6.2 The SPE/WPC/AAPG classification of petroleum resources.

More information can be found at:
http://www.spe.org/spe/jsp/basic/0,,1104_1730,00.html

6.3 The UN framework classification for energy and mineral resources (UNFC)

At the beginning of the 1990s, Russia proposed that the United Nations should draw up an international classification for coal and minerals, partly because of the need to disseminate information on the quantities and potentials of resources to international companies and investors. In 1997, the UN Economic and Social Commission (ECOSOC) recommended that UN member countries should start to use this classification, called the *United Nations Framework Classification for Reserves/Resources – Solid Fuels and Mineral Commodities.* More than 60 nations are now using it.

In 2001, work began on harmonising the classifications of petroleum and uranium with that of coal and minerals. In the case of petroleum, special emphasis was placed on the SPE/WPC/AAPG classification and a classification drawn up in Russia. This effort resulted in the drawing up of a new system, the *United Nations Framework Classification for Fossil Energy and Mineral Resources (UNFC).* In July 2004, the ECOSOC recommended that this new system be adopted by the member countries and international organisations, and considerable focus has subsequently been placed on this system as a possible replacement for existing systems, particularly after concern in the media regarding the way certain oil companies have reported information to the stock exchange.

The UNFC employs three criteria as its basis: "Economic and commercial viability" (E), "Field project and feasibility" (F) and "Geological knowledge" (G) (Figure 6.3). This can be illustrated as a three-dimensional system with an E axis, an F axis and a G axis.

Corresponding criteria are used directly or indirectly in other classification systems, too. For example, the "Field project and feasibility" axis in the UNFC can be compared with the set of project status categories in the NPD classification. Many of the most important classifications can thus be compared and harmonised with the UNFC.

Each of these criteria is then divided into principal categories:

E1 Economic
E2 Potentially Economic
E3 Intrinsically Economic

F1 Justified Development and/or Production Project
F2 Contingent Development Project
F3 Project Undefined

G1 Reasonably Assured Geological Conditions
G2 Estimated Geological Conditions
G3 Inferred Geological Conditions
G4 Potential Geological Conditions

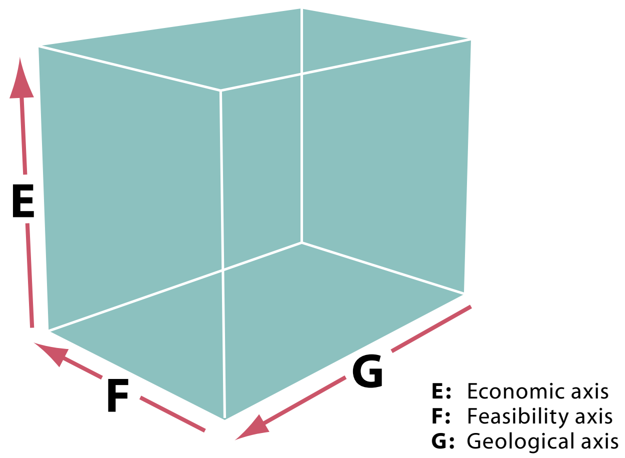


Figure 6.3 The principal criteria in the UN Framework Classification for Energy and Mineral Resources (UNFC).

The quantities of petroleum will be classified as a combination of E, F and G categories. Each category can be divided into subcategories as the need arises, particularly the E and F axes. However, further subdivision increases the complexity and should be applied with care.

The position within the system is uniquely determined when the categories are referred to in alphabetical order: E-F-G. The categories are numbered, where ”1” denotes the best. For instance, the quantities corresponding to E1, F1 and G1 are denoted 111. This can be presented graphically as a collection of cubes which show every possible combination of the E, F and G categories (Figure 6.4).

To avoid problems that might arise due to their different usage and understanding, the UNFC does not use the terms ”reserves” and ”resources” in its definitions, and thus stands out as a global, consistent system. Guidelines are currently being drawn up for the use of the UNFC for petroleum.

The UNFC is now being considered for use in a number of contexts, for instance as a basis for reporting resources to various international organisations. New regulations are now being drawn up for the financial reporting of activities concerned with the extraction of resources, the ”extractive industries”, which include the petroleum industry. The UNFC is one of the classifications being considered for this purpose.

For companies, authorities and the general public, it will be a great advantage to have this based on a common classification. The Norwegian Petroleum Directorate has not decided how this will affect its own reporting practices, but it is actively contributing to the drawing up of the system. Such a system will simplify communication and will also reduce the need to maintain many parallel systems and databases.

More information about the UNFC can be found on the UNECE home page:
http://www.unece.org/ie/se/pdfs/UNFC/UNFCemr.pdf

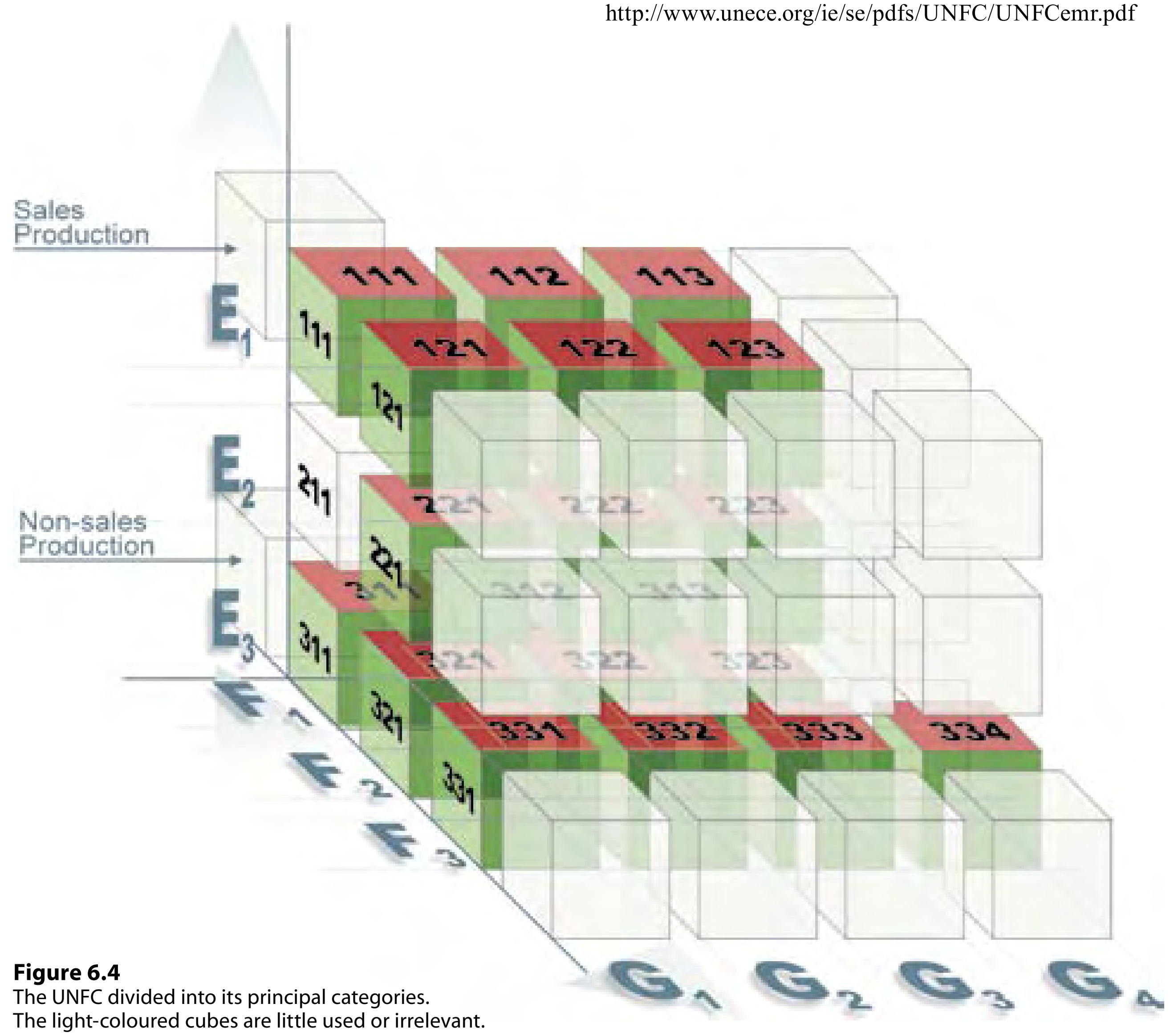


Figure 6.4
The UNFC divided into its principal categories.
The light-coloured cubes are little used or irrelevant.

7 Terms and definitions

Abandoned well: A well 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 demanded pursuant to the provisions in §4-9, paragraph 2 of the Petroleum Act.

Associated gas: Natural gas dissolved in oil.

Awards: Companies that are approved as operators or licensees on the Norwegian 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 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): Natural gas under pressure in tanks.

CO_2 tax: A tax paid for 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.

Continental shelf: The sea bed and its substrata 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.

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 have been removed.

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).

Discovery success: Technical discovery success is the relationship between the number of technical discoveries and the number of wildcat wells. Economic or commercial discovery success is the relationship between the number of discoveries that are developed or are clearly profitable today and the number of wildcat wells.

Drilling programme: Description that contains specific information concerning wells and well paths relating to planned drilling and well activities.

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

E-operation: See 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 discovery, or a number of concentrated discoveries, which the licensees have decided to develop and for which the authorities have approved, or granted exemption for, a Plan for Development and Operation (PDO).

Fixed facility: A facility or installation 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 for safety purposes.

Growth in reserves: Any increase in the reserves on a defined field, whether it concerns improved recovery from the same deposit or results from increasing the reserves by developing new discoveries and linking these to the field.

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

Integrated operation: Integrated operation denotes the kind of operation where use is made of the opportunities which new and improved information technology provide by utilising approximate real-time data to achieve better and quicker decisions.

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): Mainly methane (CH_4) transformed into liquid form by cooling.

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).

Multibranch 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), and 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 an exploration well whose path is not planned to be drilled vertically.

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

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

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.

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: Collective term for hydrocarbons. The term covers 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 transportation of petroleum in bulk 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 geographically and stratigraphically delimited area where a specific set of geological factors is present so that petroleum should be able to be proven in producible volumes. Such geological factors are a reservoir rock, trap, mature source rock, migration routes, and that the trap was formed before the migration of petroleum ceased. All discoveries and prospects in the same play are characterised by the play's specific set of geological factors.

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 or injection.

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 which the licensees have decided to recover and the authorities have given permission to recover.

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

Rig: A derrick, essential machinery and additional equipment used when drilling for oil or gas on land or from a drilling platform at sea.

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 1 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 sea bed or at the surface, or down in a borehole. This enables an image of formations in the substratum to be formed. The 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.

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: Recoverable volumes of petroleum that it is estimated may be discovered with further exploration.

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: A mixture of gas mainly in liquid phase.

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

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
NO_x	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.

Conversion table:

	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 cubic metre	9 000.00	kcal
	1 cubic metre	35.30	cubic feet
Crude oil	1 Sm^3	6.29	barrels
	1 Sm^3	0.84	toe
	1 tonne	7.49	barrels
	1 barrel	159.00	litres
	1 barrel/day	48.80	tonnes/yr
	1 barrel/day	58.00	Sm^3 per yr

	MJ	**kWh**	**TCE**	**TOE**	**Sm^3 Natural gas**	**Barrel Crude oil**
1 MJ, megajoule	1	0.278	0.0000341	0.0000236	0.0281	0.000176
1 kWh, kilowatt hour	3.60	1	0.000123	0.000085	0.0927	0.000635
1 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

NORWEGIAN PETROLEUM DIRECTORATE