Petroleum resources on the Norwegian continental shelf 2003

NORWEGIAN PETROLEUM DIRECTORATE

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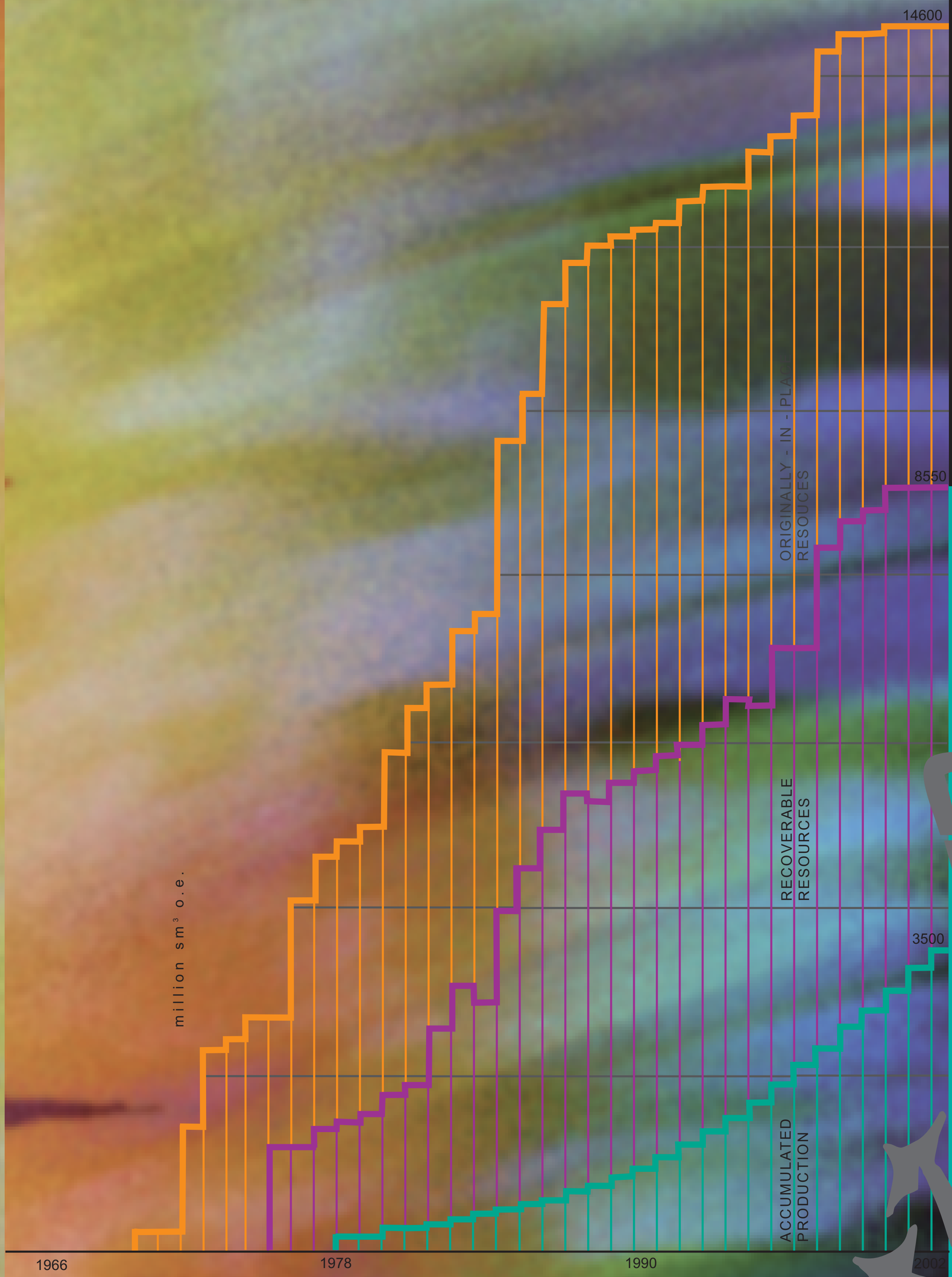

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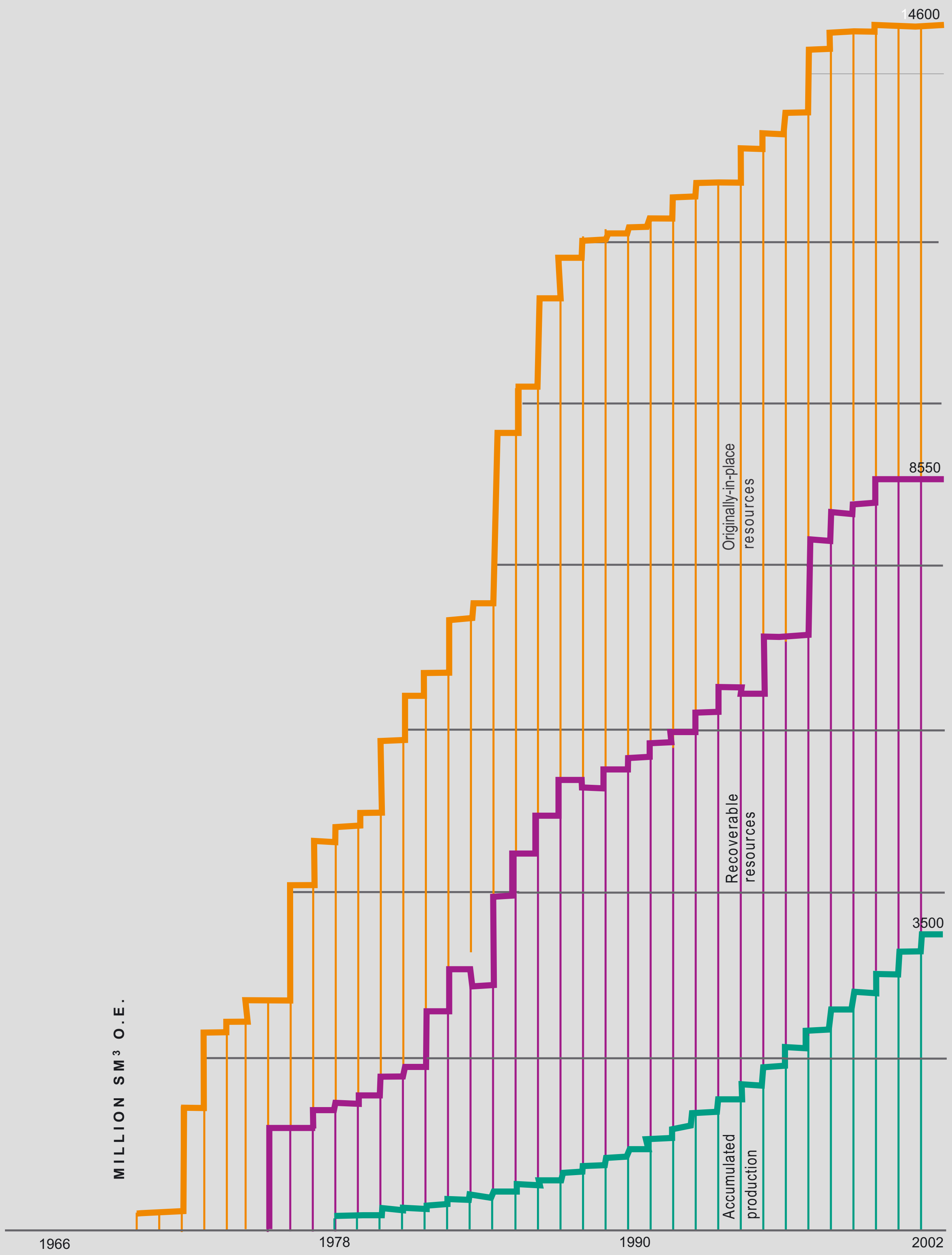

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The petroleum resources on the Norwegian continental shelf 2003

NORWEGIAN PETROLEUM
DIRECTORATE

Preface

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

It is therefore important that the Directorate has the best possible understanding of geological factors, the total petroleum resources and possible technological and environmental limitations on the Norwegian continental shelf. This forms the basis for planning future petroleum activities on the shelf.

The Norwegian Petroleum Directorate has unique access to facts on all the activity. By compiling this information in a coherent, lucid manner, it helps to ensure that major and minor decisions give the best possible overall solution of complicated problems.

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

Stavanger, june 2003

Gunnar Berge
Director General

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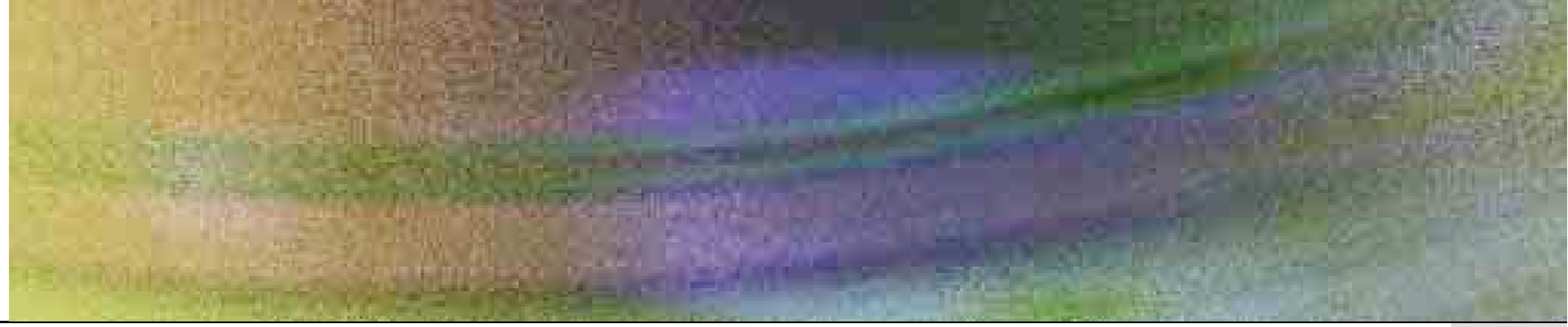

1 Introduction and summary

In this report, the Norwegian Petroleum Directorate (NPD) presents an estimate of the total recoverable resources on the Norwegian continental shelf updated to 31 May 2003. A new calculation of the potential of undiscovered resources has been undertaken. A re-evaluation of the potential that can be realised through improved recovery is also presented.

The Norwegian continental shelf is divided into three petroleum provinces, the North Sea, the Norwegian Sea and the Barents Sea. This report describes the challenges present in these three areas and shows what characterises a mature province like the North Sea in contrast to the Barents Sea, which is less mature. Finally, a summary of forecasts for future trends in petroleum production, related costs and emissions to the environment is presented.

The total recoverable petroleum resources are now calculated to be 12.8 billion Sm^3 oil equivalents (o.e.), about 1 billion Sm^3 o.e. less than was stated in the resource account of 31 December 2002. The change is a consequence of reductions in the estimates for undiscovered resources and improved recovery from existing fields. The uncertainty in the estimated total figure is large, ranging from 10.5 to 14.5 billion Sm^3 o.e.

The total petroleum resources are the sum of discovered and undiscovered recoverable resources, and include volumes that have already been produced. The resources split as 6.1 billion Sm^3 o.e. oil, 6.0 billion Sm^3 o.e. gas, 0.4 billion Sm^3 o.e. NGL and 0.3 billion Sm^3 o.e. condensate. The remaining recoverable resources are calculated to be 9.2 billion Sm^3 o.e.

Despite the reduced estimate for the undiscovered resources, the possibilities for making discoveries on the continental shelf are still good.

The changes in the estimates for the total undiscovered resources in the North Sea and the Barents Sea are insignificant. The estimate for the Norwegian Sea has been reduced by 30 per cent. Enhanced knowledge of the geology in the best investigated area in the Norwegian Sea forms the basis for reducing the expectations regarding both the size and the number of new discoveries. Expectations regarding the areas in the deeper parts of the Vøring Basin in the Norwegian Sea have also been somewhat reduced. Results of mapping during the last year suggest that the areas off Lofoten are more promising than previously thought.

In recent years, oil and gas production volumes have exceeded the volumes of new discoveries. Explanations for this situation are that fewer wildcat wells have been drilled than previously, and that the discoveries made have been smaller.

The authorities raised the predictability for the allocation of new exploration areas through annual awards of licenses for the North Sea from 1999 to 2002. In May 2003, these allocations were replaced by a system of predefined exploration areas in mature parts of the North Sea and the Norwegian Sea. The areas that will now be announced will be available to the industry for several years. New, mature areas will be added gradually.

The practice of awarding licenses every other year will continue in the more immature parts of the continental shelf. The 18th licensing round is expected to be announced in the last quarter of 2003, for allocation in spring 2004. It is planned to announce blocks in both the North Sea and the Norwegian Sea. Areas off Lofoten and Nordland will await consideration of the impact assessment regarding year-round petroleum activities in the Lofoten-Barents Sea region.

Substantial volumes of oil will remain in the reservoirs after the large fields have been shut down. A great deal of effort is being put into the task of identifying and planning measures to enable the profitable recovery of some of these resources.

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A study performed by the NPD on the potential for value creation in fields that are in production has shown that profitability and lack of technological development are the greatest obstacles for implementing such measures. The expected average recovery factor for oil from oil fields is now calculated to be 45 per cent. The authorities still aim to attain a 50 per cent average recovery factor for oil from oil fields and a 75 per cent average recovery factor for gas from gas fields.

After 37 years of exploration drilling and 32 years of production there is still uncertainty regarding how much can be recovered from the resources that have been found. The future production estimates are therefore uncertain. The uncertainty is linked to the exploration activity, which discoveries will be approved for development and decisions regarding projects for improved recovery. Undiscovered resources amount to 40 per cent of the estimated recoverable resources that remain. It will be difficult to realise these resources if the present low exploration activity continues. Increasing exploration activities will be a challenge.

Improved capacity for gas transport is an important prerequisite for encouraging continued high exploration activity and maturing of resources in the Norwegian Sea. With discoveries that are waiting for access to existing gas pipelines, there will be no capacity for transporting additional volumes until after 2020. Exploration in the next few years will therefore probably concern prospects that are large enough to form a basis for a new gas pipeline.

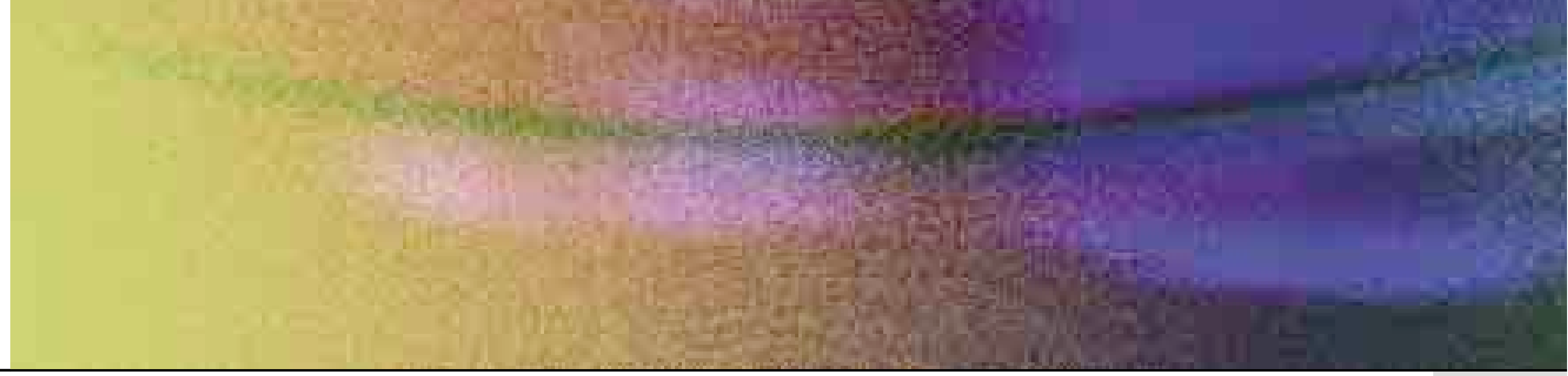
A number of assumptions in addition to those concerning geology and technology need to be made to be able to calculate the economically recoverable resources. The price of oil and gas must be estimated, and consideration must be given to the future level of costs and the availability of highly qualified personnel. Moreover, the players, both the industry and the authorities, must show willingness and ability to invest in the required research and development.

Only a quarter of the estimated recoverable resources on the Norwegian continental shelf has been produced and sold, the quarter that was easiest to find and recover. Much more effort will be needed to recover the remainder.

Report no. 38 to the Storting (2001-2002) pointed out the difference between a long-term scenario and a decline scenario. The former presumes that all the players continue to show aggressive commitment to the sector. A decline scenario means that only already approved production plans will be fulfilled. The long-term scenario also presumes that both present-day and future demands for sustainable development are implemented so that measures can be put in where the effects are greatest relative to the costs. The difference in value amounts to at least NOK 2000 billion, probably more than double that if the price of oil remains as high as it has been in recent years. There should be a basis for transferring these values from ”the ground to the book”, but this calls for willingness to act.

The NPD hopes this report can contribute to the ongoing debate.

2 The petroleum resources on the Norwegian continental shelf



The Norwegian Petroleum Directorate's resource account gives a survey of the recoverable petroleum resources on the Norwegian continental shelf. It covers quantities that have been sold and delivered, discovered remaining recoverable petroleum resources, and undiscovered resources which are assumed to be recoverable.

The total resources are now calculated to be 12.8 billion Sm^3 oil equivalents (o.e.). The resource account shows a reduction of 980 million Sm^3 o.e. relative to the last account (published on 31 December 2002). This results from reductions in the estimates of the undiscovered resources in the Norwegian Sea and the expected volume arising from extraordinary measures to improve recovery from existing fields.

2.1 DISCOVERED RESOURCES

In-place resources

Drilling on the Norwegian continental shelf has proven a total of 14.5 billion Sm^3 o.e. of oil and gas. This quantity is termed resources originally-in-place and includes all the oil and gas present in the reservoirs, both the quantity which is considered recoverable and the quantity which will remain in the reservoirs after production ceases.

Originally recoverable resources

The discovered originally recoverable resources are divided into sold and delivered quantities and remaining discovered resources.

The expectation regarding how much of the discovered originally in-place resources that can be recovered changes over time. The volume that can be recovered depends on natural, technical and financial factors.

Until the last few years, the estimates for both the originally-in-place and the originally recoverable petroleum resources have risen steadily (Figures 2.1 and 2.2). The oil industry will need to make a determined effort if this trend is to continue. In recent years, oil and gas production has exceeded the addition of new resources, resulting in the remaining volumes being reduced each year.

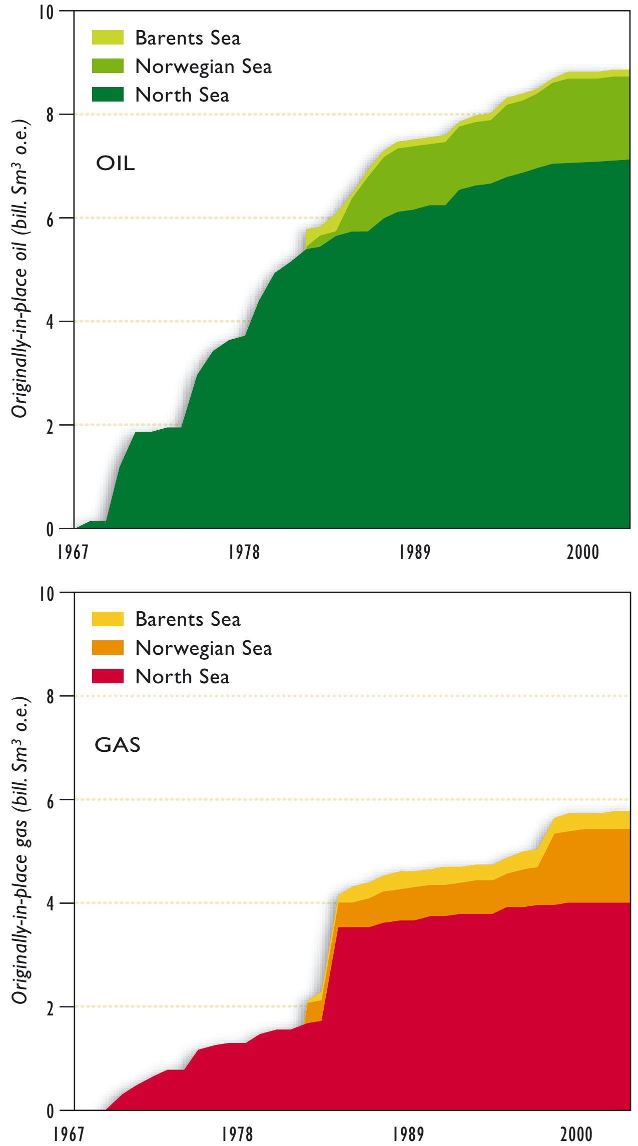


Figure 2.1

The growth of originally-in-place quantities of oil and gas in the North Sea, the Norwegian Sea and the Barents Sea. The estimate of the in-place petroleum in each deposit may change over time as a result of new mapping and understanding, or because an appraisal well shows that the discovery is larger or smaller than initially assumed. The figure shows the present estimate of the in-place resources.

2.2 UNDISCOVERED RESOURCES

The estimate for the undiscovered resources on the Norwegian continental shelf has a volumetric expected value of 3400 million Sm^3 o.e. The changes in the estimates for the total undiscovered resources in the North Sea and the Barents Sea are insignificant, but the corresponding estimate for the Norwegian Sea has been reduced by 30 per cent.

This revised estimate results from an evaluation made by the Norwegian Petroleum Directorate, partly based on new information from discoveries and fields, recent drilling, and the prospects in NPD's database.

Considerable uncertainty is attached to the estimate of the quantities of undiscovered petroleum. It is therefore stated with an area of uncertainty spanning from a low (P90) to a high (P10) estimate, in addition to a statistically expected value. The estimate for the undiscovered resources has been reduced by 530 million Sm^3 o.e. since the last evaluation in 2001. Chapter 3 deals with this in more detail.

2.3 THE RESOURCE ACCOUNT

The resource account provides a survey of the total recoverable petroleum resources. The figures are based on the expected value of each individual discovery and field, and the undiscovered resources. Uncertainty is attached to the calculation of the recoverable resources and the realisation of the potential, that is to say whether the projects that are needed to realise this will be carried out.

Resource classification

To quantify how much of the in-place resources can be produced at a given time, the Directorate uses a resource classification system drawn up in co-operation with the petroleum industry (www.npd.no). This system is harmonised with that which the Society of Petroleum Engineers (SPE), the World Petroleum Congress (WPC) and the American Association of Petroleum Geologists (AAPG) published in 2000. It is based on the maturity of the projects. It shows which resources are approved for production (reserves),

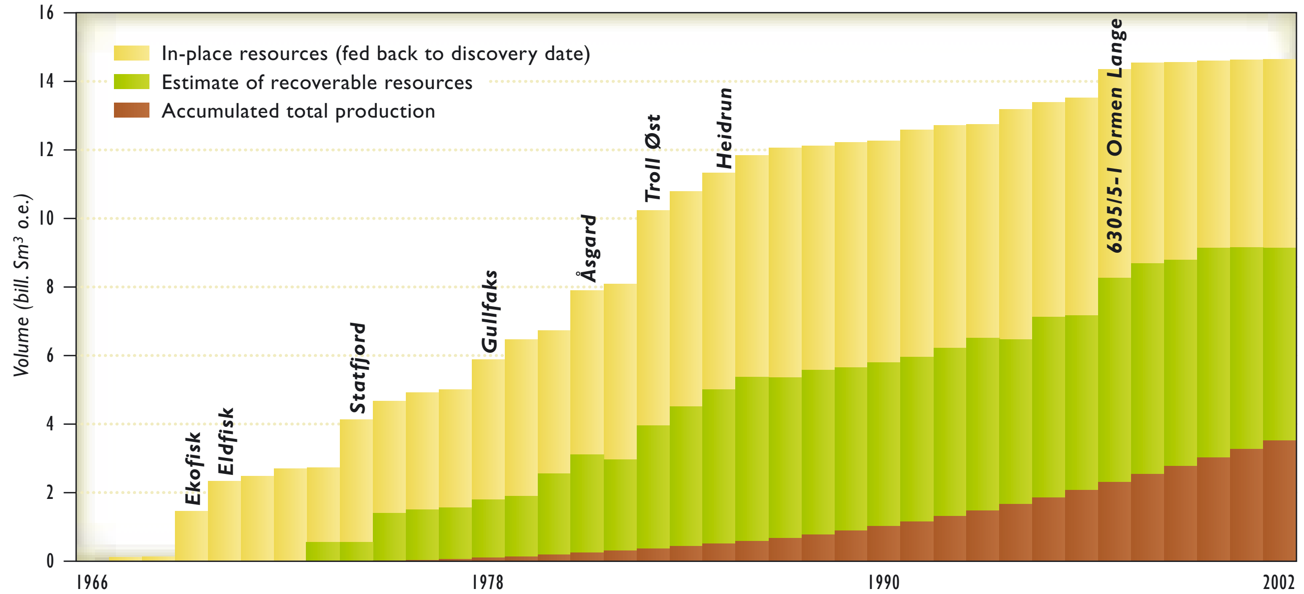


Figure 2.2

Historical production and estimate for the total recoverable volumes relative to the discovered in-place volumes. The figure shows examples of when fields and discoveries were found.

which require clarification and decision-making (contingent resources) and which can be assumed to be found in the future (undiscovered resources). The system shows where the resources are situated in the development chain from an undiscovered resource, via its discovery, its development, the production stage and on to when production ceases (Figure 2.3). A consequence of the system is that a single field can have projects in different resource classes. The system also shows which resources are linked with original recovery projects (F = First) and which are linked to measures to improve recovery (A = Additional).

Total recoverable petroleum resources

The total recoverable resources are calculated to be 12.8 billion Sm^3 o.e., 6.8 billion Sm^3 o.e. of this being liquid and 6.0 billion Sm^3 o.e. gas. Liquid is a collective term for oil, NGL and condensate.

The resource account shows the originally recoverable petroleum resources on the Norwegian continental shelf (Table 2.1). The account for fields and discoveries is based on figures updated to 31 December 2002, whereas the NPD's estimates of the undiscovered petroleum resources and resources linked to possible future measures for improved recovery are updated to 31 May 2003.

Recoverable liquid and gas

The breakdown of the total recoverable resources shows that more than a quarter, 27 per cent, of the total volume of the resources has been produced and 29 per cent fall into approved projects. Estimated undiscovered resources account for 26 per cent (Figures 2.5 - 2.7)

Sold and delivered quantities

So far, 2.7 billion Sm^3 o.e. of liquids (oil, NGL and condensate) and 796 billion Sm^3 of gas have been sold and delivered from the Norwegian shelf. By 31 December 2002, 55 per cent of the recoverable resources of liquid and 25 per cent of the recoverable resources of gas had been sold and delivered (Figure 2.4).

Fields in production and fields approved for development

As of 31 December 2002, 45 fields were in production, 40 in the North Sea and five in the Norwegian Sea. Another eight fields were approved for development, but had not been put into production. Production had ceased in 12 fields.

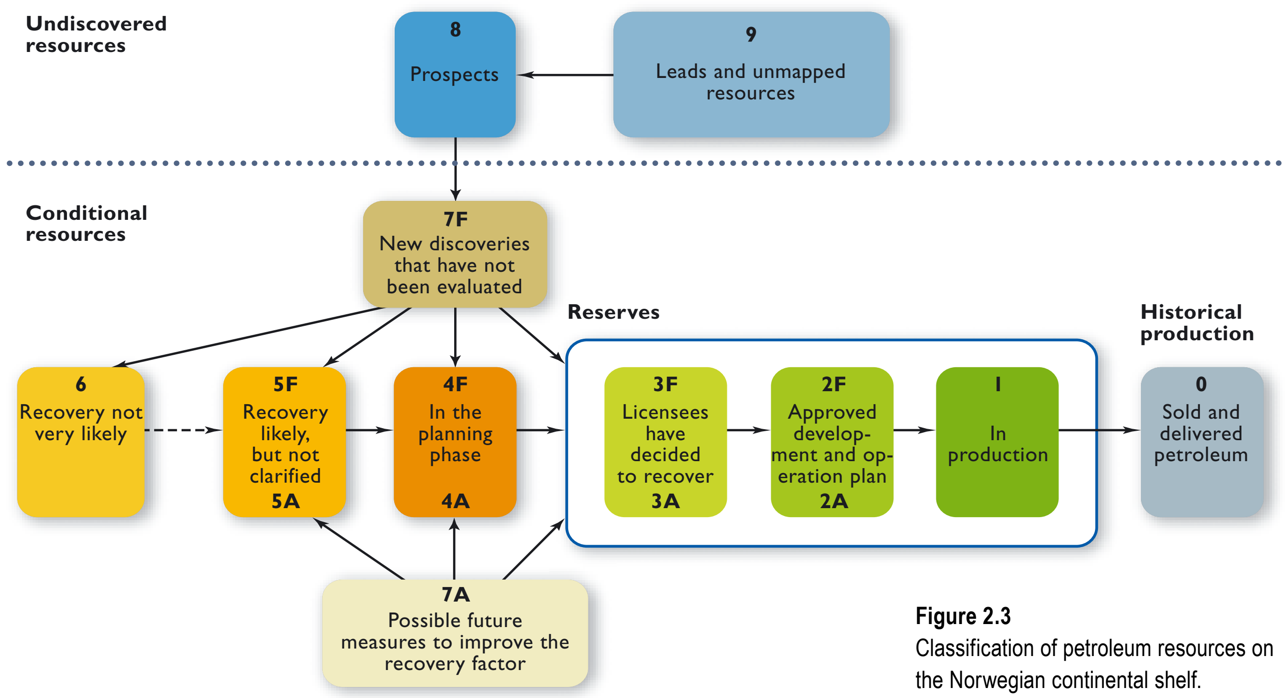


Figure 2.3
Classification of petroleum resources on the Norwegian continental shelf.

Oil equivalents (abbreviated o.e.) are used when oil, NGL, condensate and gas volumes are to be totalled or compared, and precise volume specifications are unnecessary. From 1996 onwards, the NPD has given the total petroleum resources in Sm^3 oil equivalents (Sm^3 o.e.). The following conversion factors are used:

1 tonne NGL corresponds to 1.9 Sm^3 NGL
1 Sm^3 oil, NGL or condensate corresponds to 1 Sm^3 o.e.
1000 Sm^3 gas correspond to 1 Sm^3 o.e.

Improved recovery from fields

In addition to the reserves which it is planned to produce from the fields, it is possible to further improve the recovery of both oil and gas. The companies are working on many potential projects. The most concrete ones are placed in resource categories 4 and 5, which contain more than 50 projects involving a total of 306 million Sm^3 of oil, condensate and NGL, and 198 billion Sm^3 of gas.

The NPD has undertaken a survey which reveals more than 100 specific projects and possible measures for improved recovery. These constitute 750 million Sm^3 o.e. It has determined a volume required to achieve the aim of average recoveries amounting to 50 per cent of the oil and 75 per cent of the gas (category 7 A). The oil and gas resources in category 7 A have been reduced from those stated in the account dated 31 December 2002 (Table 2.1). The reasons for this reduction are that projects for improved recovery have become concretised and that the NPD now only cal-

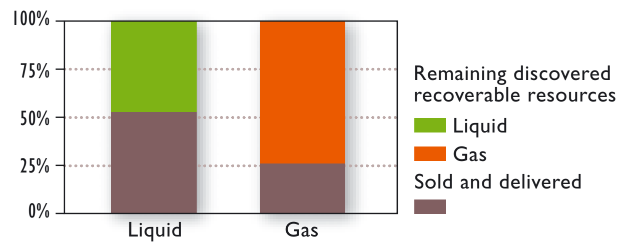


Figure 2.4
Sold and remaining volumes of liquid and gas.

Class	Category	Project status	Oil mill. Sm^3	Gas bill. Sm^3	NGL mill. tonne	Condensate mill. Sm^3	Oil equiv.[1] mill. Sm^3	Change 31 Dec. 2002: *Liquid* mill. Sm^3	*Gas* bill. Sm^3	*Oil equiv.*[1] mill. Sm^3
		FIELDS								
Historical production	0	**Sold and delivered as of 31 Dec. 2002**	**2542**	**796**	**63**	**59**	**3516**			
Reserves	1	Remaining reserves in production	1085	1399	84	53	2697			
	2-3	Reserves with approved / submitted PDO	221	719	34	77	1082			
Contingent resources		**Total reserves**	**1306**	**2117**	**118**	**130**	**3778**			
	4	In the planning phase	192	136	19	5	369			
	5	May be developed in the long term	58	62	4	7	133			
	7F	New discoveries being evaluated	2				2			
		Total contingent resources in fields	**252**	**198**	**22**	**12**	**504**			
		Total reserves in fields and resources	**1558**	**2315**	**141**	**142**	**4283**			
		DISCOVERIES								
	4	In the planning phase	87	529	12	37	676			
	5	May be developed in the long term	80	322	4	25	433			
	7F	New discoveries being evaluated	3	1	0	2	6			
		Total contingent resources in discoveries	**170**	**852**	**16**	**64**	**1115**			
	7A	Poss. future measures for improved recovery	350	100			450	*-50*	*-400*	***-450***
Undiscovered resources	**8-9**	**Undiscovered resources**	**1500**	**1900**			**3400**	*80*	*-610*	***-530***
		Total	**6120**	**5964**	**219**	**265**	**12764**	***30***	***-1010***	***-980***
		Remaining resources	**3578**	**5167**	**156**	**206**	**9248**	***30***	***-1010***	***-980***

1) 1.9 is the conversion factor to Sm^3 for 1 tonne NGL

Table 2.1
Resource account for the Norwegian continental shelf as of 31 May 2003, with changes relative to 31 December 2002.

culates the potential present in the fields and not, in addition, the potential from future developments of discoveries. Oil produced as an associated phase with the gas is not included in the calculation.

Based on the reserves reported by the companies at the end of 2002, the expected average recovery factor for oil from oil fields on the Norwegian continental shelf is calculated to be 45 per cent (Figure 2.8). This is an increase on recent years, when it has remained unchanged at 44 per cent. Some fields on the Norwegian shelf have a recovery factor for oil that is extremely high by international standards; Statfjord, Oseberg and Draugen, for instance, are expected to achieve a factor in excess of 60 per cent before production ceases.

The expected average recovery factor for oil fields rose each year from 1990 to 1998, but the rise has been insignificant since 1998. The increase is mainly ascribed to measures implemented on the largest and most mature fields. Improved knowledge of the fields, developments while production has been taking place and the use of new methods have formed the basis for implementing the measures for improved recovery.

Corresponding calculations have been made for the result of possible future measures for improved gas recovery based on a targeted average recovery factor of 75 per cent for gas from gas fields. Neither gas discoveries nor gas produced as an associated phase along with oil, NGL and condensate are included in the basis for the calculations.

The new, reduced estimates for resource category 7 A are 350 million Sm^3 of oil and 100 billion Sm^3 of gas.

Resources in proven discoveries

Discoveries that have not yet been approved for development account for 11 per cent of the remaining resources. There are 21 discoveries in resource category 4 and 41 in resource category 5, and together they contain more than 1100 million Sm^3 o.e.

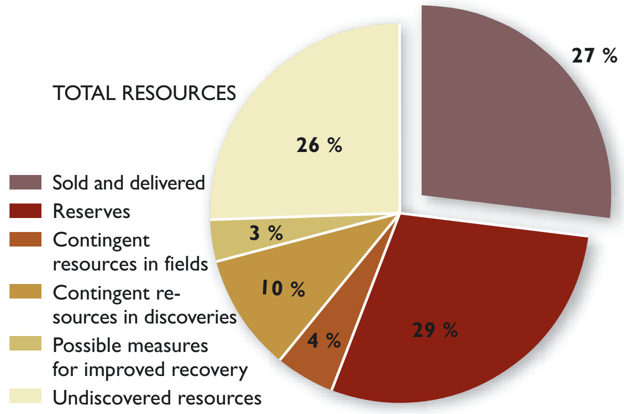


Figure 2.5
Distribution of the total recoverable resources, 12.8 billion Sm^3 o.e.

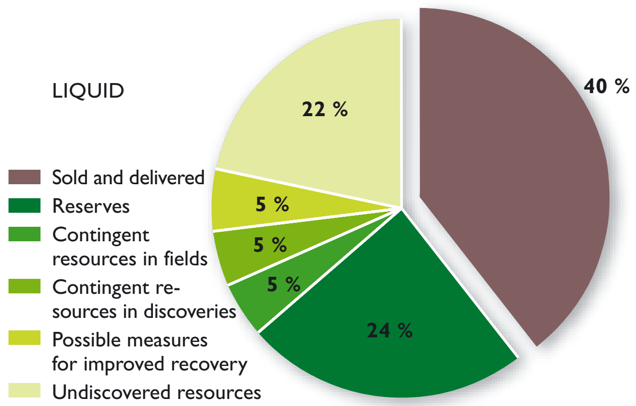


Figure 2.6
Distribution of the recoverable liquid resources, 6.8 billion Sm^3 o.e.

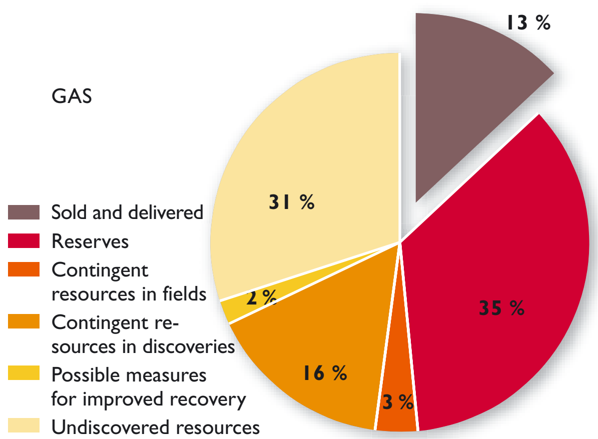


Figure 2.7
Distribution of the recoverable gas resources, 6.0 billion Sm^3 o.e.

The Norwegian shelf has so far been dominated by large oil discoveries, but fewer and smaller ones have been made in recent years. The largest oil discovery that has not been approved for development is 15/9-19 S Volve, which has 11.7 million Sm^3 o.e of recoverable oil resources.

Twenty-six per cent of the remaining, proven gas resources are in discoveries that are in the planning phase, or where recovery is probable but not clarified. These are dominated by a few large discoveries, among them 6305/5-1 Ormen Lange in the Norwegian Sea which contains 375 billion Sm^3 of gas. When the decision to develop 6305/5-1 Ormen Lange is taken, the resource potential for non-approved gas discoveries will be reduced by more than 40 per cent.

The resources in category 4 constitute 677 million Sm^3 o.e., amounting to an average of 31 million Sm^3 o.e. per discovery. Resources in discoveries where development is probable but not clarified (resource category 5) constitute a potential of 433 million Sm^3 o.e., their average size being 11 million Sm^3 o.e. 6506/6-1 ("Victoria") in the Norwegian Sea is the largest discovery in this class, accounting for almost 30 per cent of the portfolio.

Uncertainties in the resource estimates

The estimated volumes present in the individual resource categories are somewhat uncertain and mainly reflect uncertainties regarding the geology and reservoir technology. Stochastic modelling is used to calculate an expected volume and a low and a high estimate for each resource category (Figure 2.9).

The area of uncertainty is greatest for the least mature resources, i.e. those placed in the higher resource categories. For these, the uncertainty is linked with the mapping of the extent of the deposit, the probability of a discovery being made and the reservoir and production properties.

The uncertainty will be less for fields that are in production and will be associated with the behaviour of the reservoir, the effect of the chosen recovery strategy, and which measures are implemented to improve recovery.

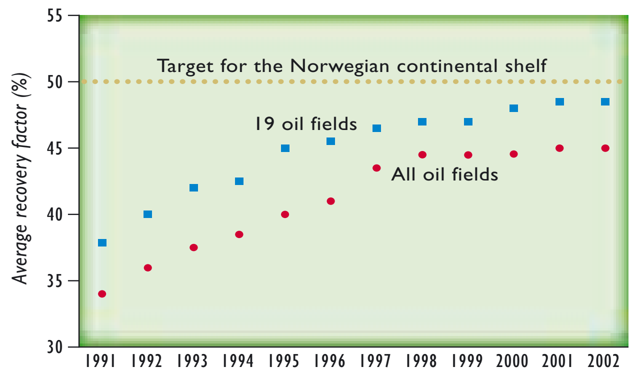


Figure 2.8
Average recovery factor for all oil fields on the Norwegian continental shelf and for 19 fields approved for development in 1991.

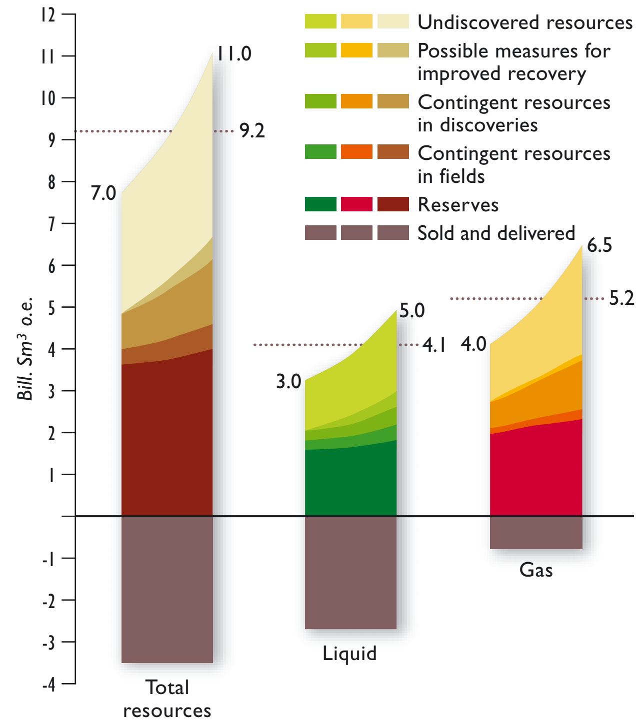


Figure 2.9
Uncertainties in the resource estimates.

3 Undiscovered petroleum resources

3 UNDISCOVERED PETROLEUM RESOURCES

A large part of the petroleum resources on the continental shelf have not been discovered yet. The size of these quantities may be estimated. Resource estimation means calculating the quantity of recoverable petroleum resources it is possible to find in an area. The estimate shows what it is feasible to find and recover if the entire area and all the prospects are explored. It therefore represents a potential of what can be found and recovered based on geological evaluations. How much will actually be found and recovered depends on economic and technical factors.

The estimates are generally given as a figure, the statistically expected value. However, a great deal of uncertainty is often attached to the calculation of the undiscovered petroleum resources. To illustrate this uncertainty, low (P90) and high (P10) estimates are given in addition to the statistically expected value.

The uncertainty in the estimate is least in areas that are well mapped and explored, and highest in areas where we have little or limited knowledge of the geological conditions. Areas where no drilling has taken place are often, in addition, assigned a risk factor for not making any discoveries. These areas may have a significant resource potential that is not clarified. To make this evident, both risk-adjusted and non-risk-adjusted quantities are stated for the individual areas.

A play is a geographically and stratigraphically delimited area where a specific set of geological factors exists in order that petroleum may be provable in commercial quantities. Such geological factors are reservoir rock, trap, mature source rock and migration paths, and the trap must have been formed before termination of the migration of petroleum. All discoveries and prospects within the same play are characterised by the specific set of geological factors of the play model.

Confirmed plays contain at least one discovery of commercial quantities of petroleum. It is thus confirmed that the critical geological factors are simultaneously present for these plays.

Unconfirmed plays are plays in which no petroleum has so far been discovered, either because exploration has still not started, or that only dry wells have been drilled in the play.

A prospect is a possible petroleum trap with a mappable, delimited reservoir rock volume.

The probability of discovery describes the possibility of proving petroleum in a prospect by drilling. The probability of discovery emerges through the product of the probabilities that the play exists, the presence of reservoirs, traps, migration of petroleum into traps and preservation of petroleum in the traps.

3.1 METHODOLOGY FOR CALCULATING UNDISCOVERED RESOURCES

Several methods exist for calculating the undiscovered petroleum resources. The choice depends partly on the amount of data and the knowledge of the areas. The NPD employs a method called play analysis (see Figure 3.1 and the definition of a play). The results have been compared with results from other methods, and this has led to some adjustments of the technique employed.

A play is defined within a basin on the basis of drilling results and interpretations of seismic and geological data. All discoveries and prospects belong to a play. A resource quantity is calculated for each play. The most important basis for this calculation is the number of discoveries that are expected to be made and their size. Geological factors and the technical properties of the reservoir of any discovery that have been made within the play form the basis for calculating the resources in the future discoveries. Uncertainty is attached to all the parameters that enter into the calculation and this is taken care of by inserting

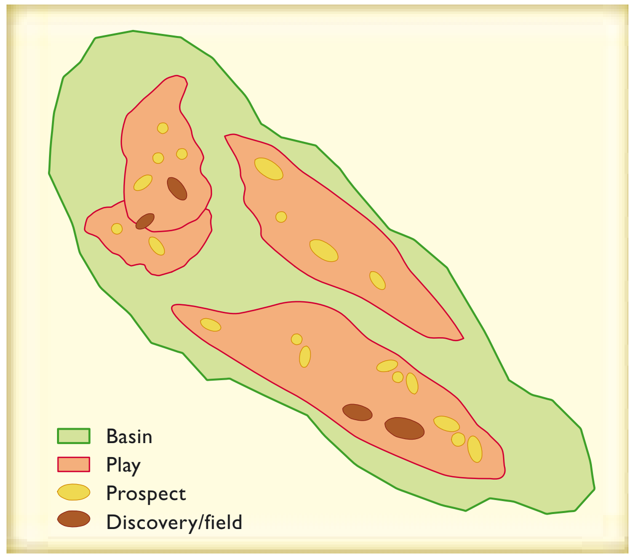


Figure 3.1
Sketch of the relationship between a basin, a play and a prospect.

STATISTICAL TERMS

Expected value – the mean value. Confidence interval – also called interval estimate. An 80 per cent confidence interval means that 80 per cent of all results of the statistical analysis (Monte Carlo simulation) will fall within this interval. In other words, it means that one is 80 per cent certain that the result will lie within the interval chosen. For an 80 per cent confidence interval, it is usual to choose the interval between P90 and P10.

P10 – the value for which there is a 10 per cent probability that the resources will be equal to or larger.

P90 – the value for which there is a 90 per cent probability that the resources will be equal to or larger.

Monte Carlo simulation – a method used to reach a probability distribution of the results from a combination of many variables which have uncertainty attached to them, for instance, when the resources in a play are to be calculated and there is uncertainty attached to the number of prospects, how many prospects will give discoveries, the reservoir properties, and whether there are liquid or gas phases. The Monte Carlo simulation performs a random selection of values for the various variables and calculates a result. This is repeated thousands of times and the results are displayed as a probability distribution.

Stochastic method – statistical calculations based on random choices of known values. A Monte Carlo simulation is an example of a stochastic method.

probability distributions for the various parameters. The quantities are calculated stochastically using Monte Carlo simulation. The results for the individual plays are then aggregated to give a total quantity, and are presented as a probability distribution.

A play is confirmed when at least one discovery of producible hydrocarbons is made. For plays where no discoveries have been made (unconfirmed plays), a probability is calculated for whether the factors that define the play are present simultaneously. In unconfirmed plays, the resources are then risk-weighted by multiplying them by the probability that the play will function. This is referred to as the risk-adjusted quantity. The non-risk-adjusted quantity is then a measure of the potential of the play if it is confirmed.

The investigation and evaluation performed by the NPD has defined a total of 68 plays, 32 of which have so far been confirmed (Table 3.1).

The parameters employed in the play analyses are as far as possible calibrated with actual data. For each play, a size distribution is calculated for the future discoveries that can be expected in the play. This size distribution is partly based on the size of existing discoveries and prospects in the play. Uncertainty is also attached to the size of the discoveries that arise from the analysis (Figure 3.2).

In general, prospects with the greatest potential and the highest probability for making discoveries will be drilled first. After each drilling, the assortment of remaining prospects that have not been drilled is gradually reduced and changed. As time passes, this affects both the number and the composition of the prospects and hence also the basis for estimating the undiscovered resources.

When all the discoveries that have been made on the Norwegian continental shelf are plotted in decreasing order of size it is seen that a few extremely large and very many small discoveries have been made (Figure 3.3). The size distribution

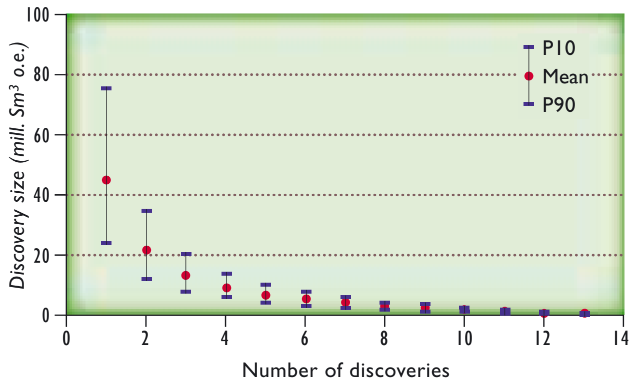


Figure 3.2
Size of future discoveries in a play, including the uncertainties.

Area	Total number of plays	Confirmed		Unconfirmed	
		Number	Proportion of resources	Number	Proportion of resources
North Sea	25	18	97 per cent	7	3 per cent
Norwegian Sea	20	9	65 per cent	11	35 per cent
Barents Sea	23	5	45 per cent	18	55 per cent
Total	68	32	70 per cent	36	30 per cent

Table 3.1
Plays on the Norwegian continental shelf.

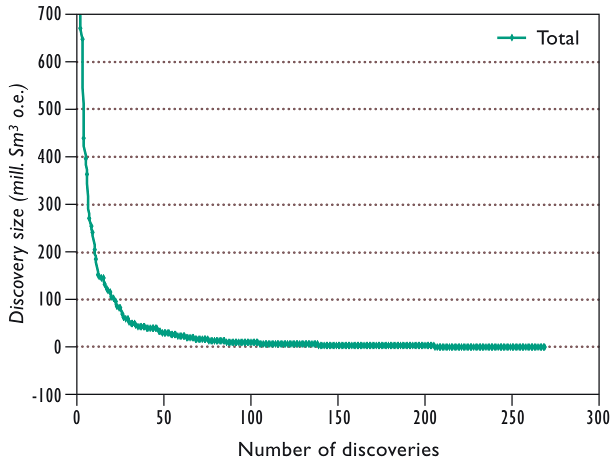


Figure 3.3
Discoveries on the Norwegian continental shelf arranged by size. The Troll field (1611 million Sm^3 o.e.) extends beyond the size axis.

is a steeply decreasing curve. This can be described as a lognormal distribution. A lognormal distribution of discoveries is typical for the majority of basins in the world. Lognormal distributions are employed when calculating the undiscovered resources in the individual plays.

To calibrate the calculations with known data, the NPD has also employed discovery process modelling. This technique has been used for some selected plays which have a long exploration history and many discoveries. The method is based on the assumption that the largest prospects are drilled first and the largest discoveries are made in the first phase of the exploration of an area. The size of the discoveries is plotted in the order in which they are made and an indicator for the change in discovery size is calculated which also provides a basis for estimating the number of future discoveries (Figure 3.4).

In the play analyses, it is important to estimate how many prospects are present in a play, how many of these can become discoveries and the size of the discoveries. In areas where little or no drilling has been undertaken, the prospects are the most important source of information. Their size, number and location relative to geological trends provide a basis for preparing estimates for the whole play. Drilling results will eventually confirm or disprove prospects and plays, and form the basis for adjusting the expectations.

As a basis for estimating the total undiscovered resources, prospect data must nevertheless be used with care. Earlier analyses of prospect data and an updated review of the results of exploration drilling from 1990 to 2002 have shown that pre-drilling estimates of expected in-place resources were far higher than what were actually proved by discoveries (Figure 3.5). This has led to a review of the prospects in the NPD database. One result of this review is that the resource estimate for some of the plays has been reduced.

3.2 RESULTS OF THE RESOURCE ESTIMATION

The estimate of the total undiscovered resources on the Norwegian continental shelf has an expected value of 3400 million Sm^3 o.e., 1500 million Sm^3 o.e. of which are liquid

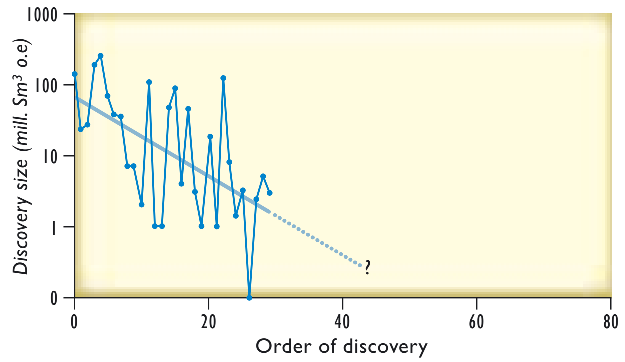


Figure 3.4
Distribution of discoveries in the Early to Middle Jurassic play in the Norwegian Sea. The size of discoveries shows a tendency to decrease. Future discoveries are expected to follow this trend.

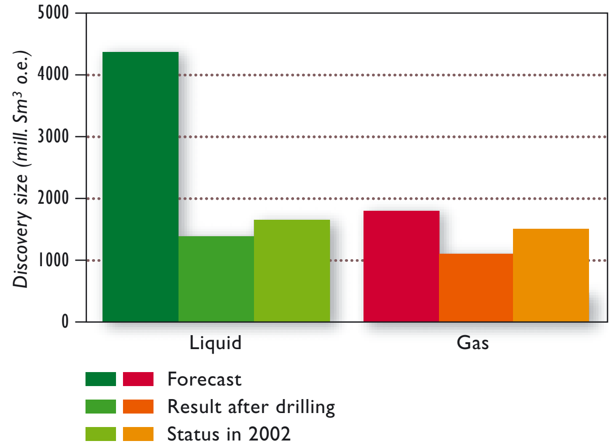


Figure 3.5
Aggregated result of discoveries made from 1990 to 2002. The compilation shows the forecast of the in-place resources prior to drilling, the resources after discovery and the present status of the same discoveries.

Area	Estimate 31 May 2003			Estimate 31 Dec. 2002			Change			
	Liquid	Gas	Total	Liquid	Gas	Total	Liquid	Gas	Total	%
North Sea	690	500	1190	630	570	1200	60	-70	-10	-1
Norwegian Sea	410	810	1220	480	1270	1750	-70	-460	-530	-30
Barents Sea	400	590	990	310	670	980	90	-80	10	1
Total	1500	1900	3400	1420	2510	3930	80	-610	-530	-13

Table 3.2 Changes in the estimates of the undiscovered resources in 2002 - 2003 (in million Sm^3 o.e.).

(oil, condensate and NGL) and 1900 billion Sm^3 gas (free gas and associated gas). This is a reduction of 530 million Sm^3 o.e., i.e. 13 per cent, compared with the previous estimate (Table 3.2). The changes in the estimate for the total undiscovered resources in the North Sea and the Barents Sea are insignificant, but the estimate for the total undiscovered resources in the Norwegian Sea has been reduced by 30 per cent. These estimates are a result of new play analyses performed by the NPD and based on, among other things, new information from discoveries and fields, new wells and information from the NPD prospect database.

The undiscovered resources comprise about 40 per cent of the total, remaining, recoverable resources on the continental shelf. The expected value of these undiscovered resources is 1190 million Sm^3 o.e. in the North Sea, 1220 million Sm^3 o.e. in the Norwegian Sea and 990 million Sm^3 o.e. in the Barents Sea. However, the uncertainty in the estimates is great (Table 3.3 and Figure 3.6).

Assuming that the undiscovered resources are equally distributed within the extent of each play, a calculation shows that more than 90 per cent

The "known areas" on the map are the most mature areas on the shelf, where there has been lengthy and successful exploration, and substantial infrastructure exists or is planned. It is presumed that the major discoveries already have been made in these areas and that any future ones will probably be smaller.

"Moderately known areas" on the map are areas that have regional to semi-regional seismic data coverage and information from scattered wells. Continued exploration in these areas is expected to be low until any new plays are confirmed.

"Little known areas" are areas with limited drilling information, but which are to some extent well mapped with regional seismic data coverage. Exploration there is either in the starting phase or has not yet begun.

"Unknown areas" are areas with negligible seismic data coverage, and no or negligible drilling information.

Area	Liquid			Gas			Total			
	P90	Expected	P10	P90	Expected	P10	P90	Expected	P10	%
North Sea	550	690	850	400	500	600	1020	1190	1390	35
Norwegian Sea	240	410	620	430	810	1050	790	1220	1770	36
Barents Sea	100	400	790	210	590	1120	460	990	1700	29
Total	1100	1500	1960	1300	1900	2660	2640	3400	4300	100

Table 3.3
The undiscovered petroleum resources (in million Sm^3 o.e.) in the various areas. The uncertainty is shown with an 80 per cent confidence interval (P90 - P10).

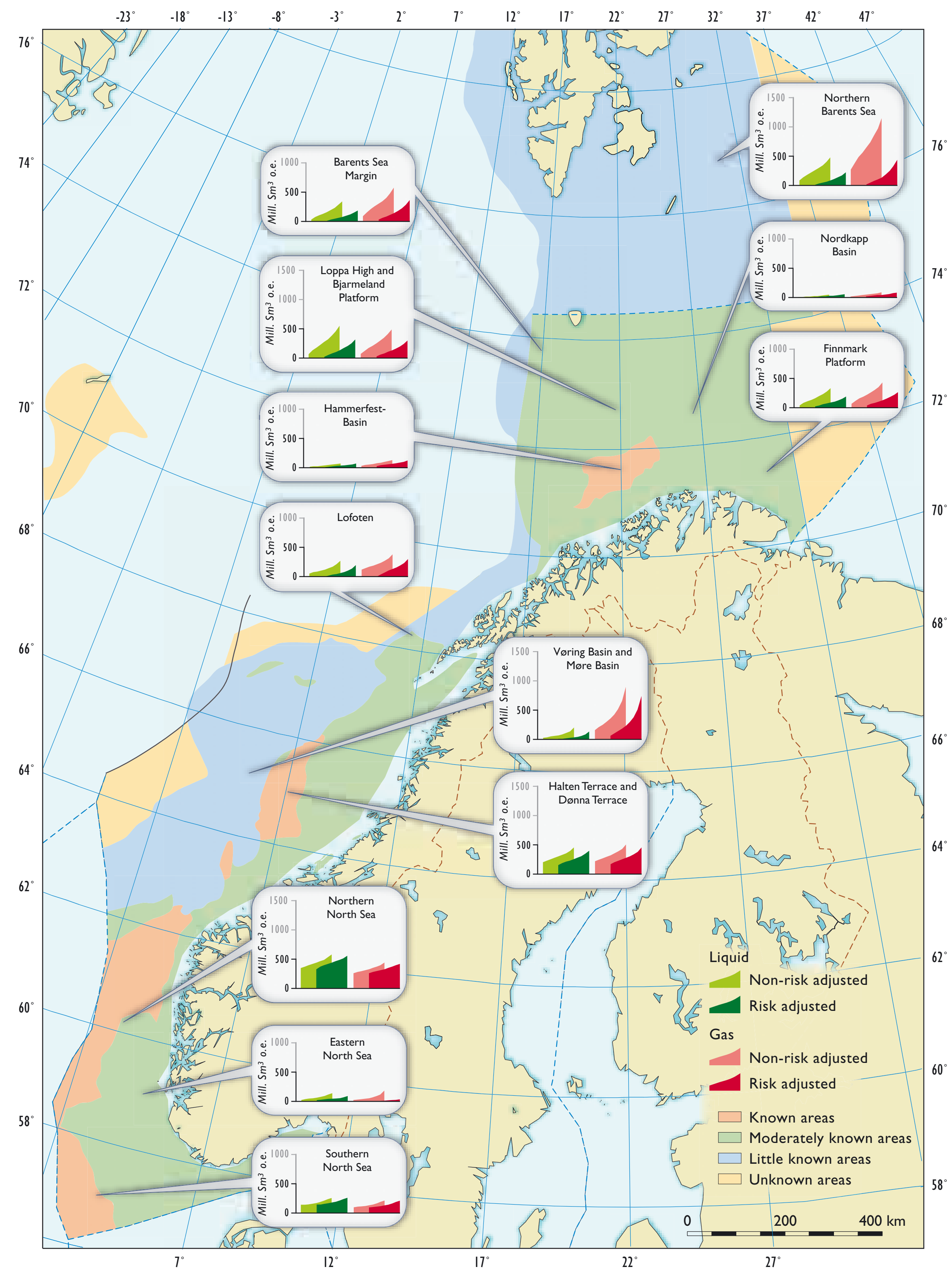


Figure 3.6
Potential for undiscovered resources in areas of varying maturity. The foreground bars show the expected mean quantities of liquid and gas, respectively, and the uncertainties involved. The bars behind these show the theoretical (non-risk adjusted) basis for the estimates on which the means and ranges of uncertainty are based if all the plays in the area are confirmed.

The petroleum resources on the Norwegian continental shelf 2003

of them are in areas that have been opened for exploration and 22 per cent are in awarded areas.

The estimate of the undiscovered resources has changed over time partly because new information and better knowledge lead to new interpretations and more reliable estimates, and partly because discoveries are made that lead to the undiscovered resources being reduced while the discovered ones increase (Figure 3.7).

In 1998, the Norwegian Sea resources were adjusted upwards due to confirmation of the Late Cretaceous plays in the Vøring Basin. These plays were confirmed by two discoveries, 6707/10-1 Nykhøgda and 6305/5-1 Ormen Lange. In 2000, the 6506/6-1 ("Victoria") gas discovery led to a new, more optimistic, evaluation of the Jurassic play on the Halten Terrace and Dønna Terrace. Together with new evaluations of the prospects mapped in the play, this led to an upward adjustment of the undiscovered resources in the Norwegian Sea. The total undiscovered resources were estimated at 3930 million Sm³ o.e. in 2001. This estimate was not changed in 2002. The most important reason for the new estimates being lower is that the expectations have been reduced in several plays, particularly the potential for gas. However, the expectations for some plays in the Norwegian Sea have been adjusted upwards significantly without this having balanced the reduced expectations in other plays.

Undiscovered resources in the North Sea

The estimate of the undiscovered resources in the North Sea has an expected value of 1190 million

Period	Reservoir rock	Confirmed plays	Unconfirmed plays
Pre-Jurassic	Sandstone	1	1
Triassic - Early Jurassic/Mid Jurassic	Sandstone	4	2
Late Jurassic	Sandstone	3	
Early Cretaceous	Sandstone	1	
Late Cretaceous	Chalk	2	1
Tertiary	Sandstone	7	3

Table 3.4 Plays in the North Sea.

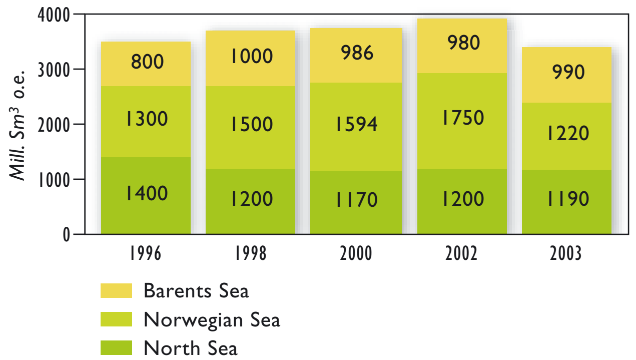


Figure 3.7
Estimates of the total undiscovered resources on the Norwegian continental shelf from 1996 to 2003.

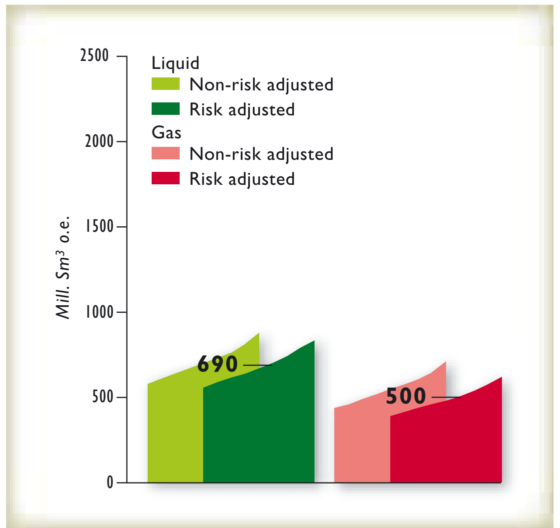


Figure 3.8
Total undiscovered resources in the North Sea distributed between liquid and gas.

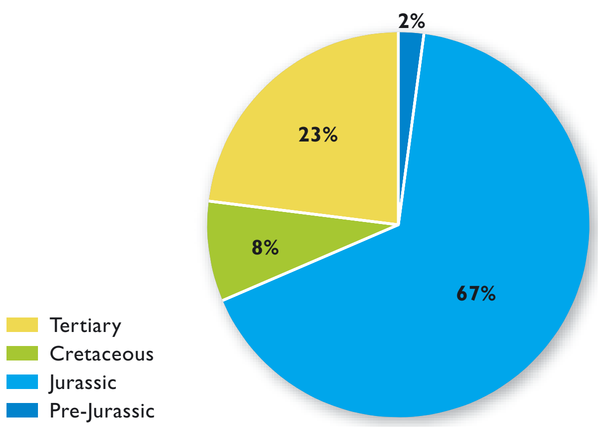


Figure 3.9
Proportions of the total undiscovered resources in the North Sea distributed according to geological periods.

Sm³ o.e., 690 million Sm³ o.e. of which are liquid and 500 billion Sm³ gas (Figure 3.8). The estimate within a confidence interval of P90 to P10 varies from 1000 to 1400 million Sm³ o.e. (Table 3.3).

Twenty-five plays have been defined in the North Sea, 18 of which are confirmed. They are grouped according to geological periods: pre-Jurassic, Jurassic, Cretaceous and Tertiary (Figure 3.9 and Table 3.4).

Most of the North Sea is well known and the uncertainty in the estimates is therefore less here than in the other areas. New well information and mapping have led to some adjustments in the resource estimates for the individual plays. However, the total resource estimate has been only insignificantly changed from analyses made in previous years. The estimate for undiscovered gas resources has been reduced following a closer assessment of the prospects in Jurassic plays. The proportion of liquid in the estimate of the undiscovered resources has increased because two new plays have been defined that mainly contain oil, the view on the possibility of recovering condensate has changed and several plays of Early Tertiary age have been adjusted.

Two-thirds of the undiscovered resources are located in plays of Jurassic age, comprising structural traps of Early and Middle Jurassic age and stratigraphical traps of Late Jurassic age. As much as 73 per cent of the discovered resources derive from these. It is assumed that about 80 per cent of the expected remaining gas resources are located in Jurassic plays, whereas the oil resource potential is prevalent in plays of Cretaceous and Tertiary age. Virtually all the resources are in areas open for exploration and approximately 40 per cent are in awarded areas. This distribution is based on the assumption that the resources are evenly distributed within the extent of the plays (Figures 3.10 and 3.11).

The modelling result shows that mostly small and medium-sized discoveries can be expected in the North Sea. Discoveries containing less than 5 million Sm³ o.e. comprise more than half of the expected discoveries, but owing to their size they make up only a small proportion of the total resources in the area. The play analyses show that 80 per cent of the resources are expected to be found in dis-

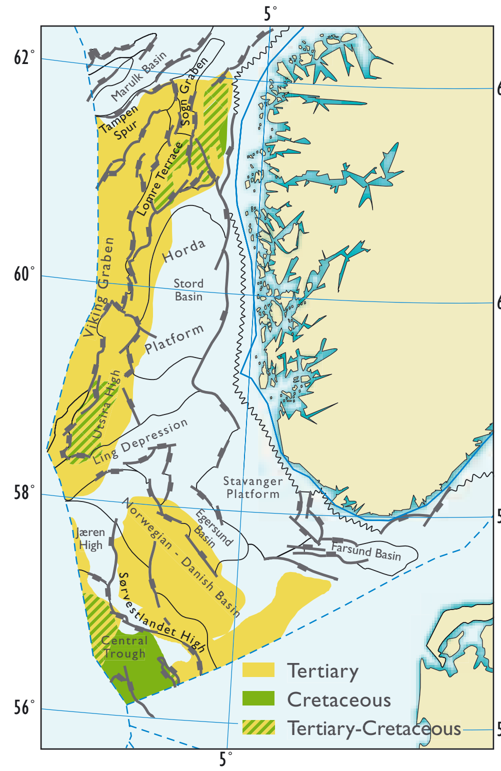


Figure 3.10
Distribution of Tertiary and Cretaceous plays in the North Sea.

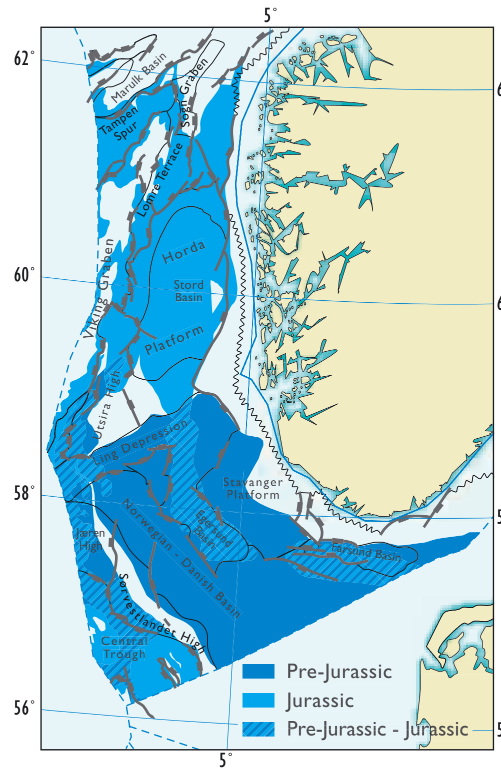


Figure 3.11
Distribution of Jurassic and Pre-Jurassic plays in the North Sea.

coveries larger than 5 million Sm^3 o.e. Calculations based on expected values show that not many large discoveries will be made in the North Sea in the future. However, owing to the uncertainty, relatively large discoveries cannot be excluded, even though they are considered less likely today.

Large parts of the North Sea are looked upon as being a well-known petroleum-geological province (Figure 3.6). It is in this area all the large discoveries have been made, and the potential for new discoveries is greatest here. This area comprises the Central Trough, Viking Graben, Tampen Spur and Horda Platform. An unconfirmed Tertiary play still exists in the northern part.

The south-eastern part of the North Sea is less explored. It has local basins with high-potential, but high-risk, plays that have not been investigated. Local plays of Jurassic age have been mapped in the Stord Basin and Farsund Basin, but they have so far not been investigated by drilling. Uncertainty is attached to the source rock, but both areas have a great potential if some of the plays are confirmed.

Undiscovered resources in the Norwegian Sea

The total undiscovered resources in the Norwegian Sea are estimated at 1220 million Sm^3 o.e., 410 million Sm^3 o.e. of which are liquid and 810 million Sm^3 o.e. gas (Figure 3.12). The uncertainty in the estimate is large, ranging from 790 to 1770 million Sm^3 o.e. within a confidence interval between P90 and P10. This is a reduction of 30 per cent from the previous estimate. 95 per cent of the undiscovered resources are located in areas open for exploration and 20 per cent of these are in awarded areas. This distribution is based on the assumption that the resources are evenly distributed within the extent of the plays.

Twenty plays are defined in the Norwegian Sea, and 11 of these are unconfirmed (Table 3.5). The nine confirmed plays make up as much as 64 per cent of the potential for undiscovered resources.

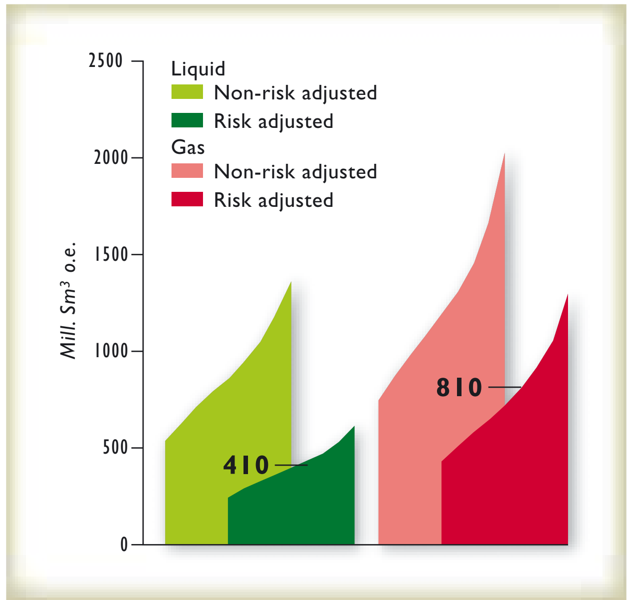


Figure 3.12
Total undiscovered resources in the Norwegian Sea distributed between liquid and gas.

Period	Reservoir rock	Confirmed plays	Unconfirmed plays
Pre-Jurassic	Sandstone		3
Jurassic	Sandstone	2	3
Cretaceous	Sandstone	5	2
Tertiary	Sandstone	2	3

Table 3.5
Plays in the Norwegian Sea.

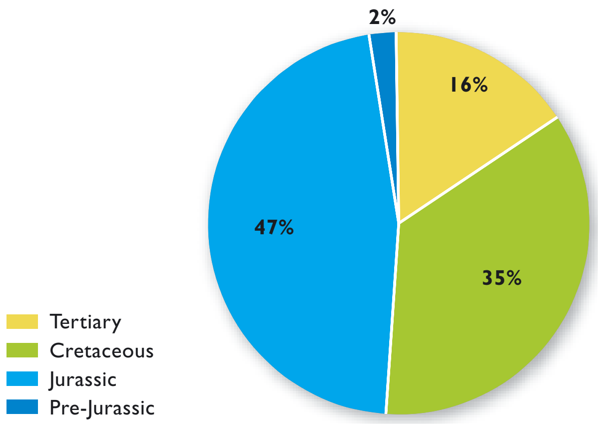


Figure 3.13
Proportions of the total undiscovered resources in the Norwegian Sea distributed according to geological periods.

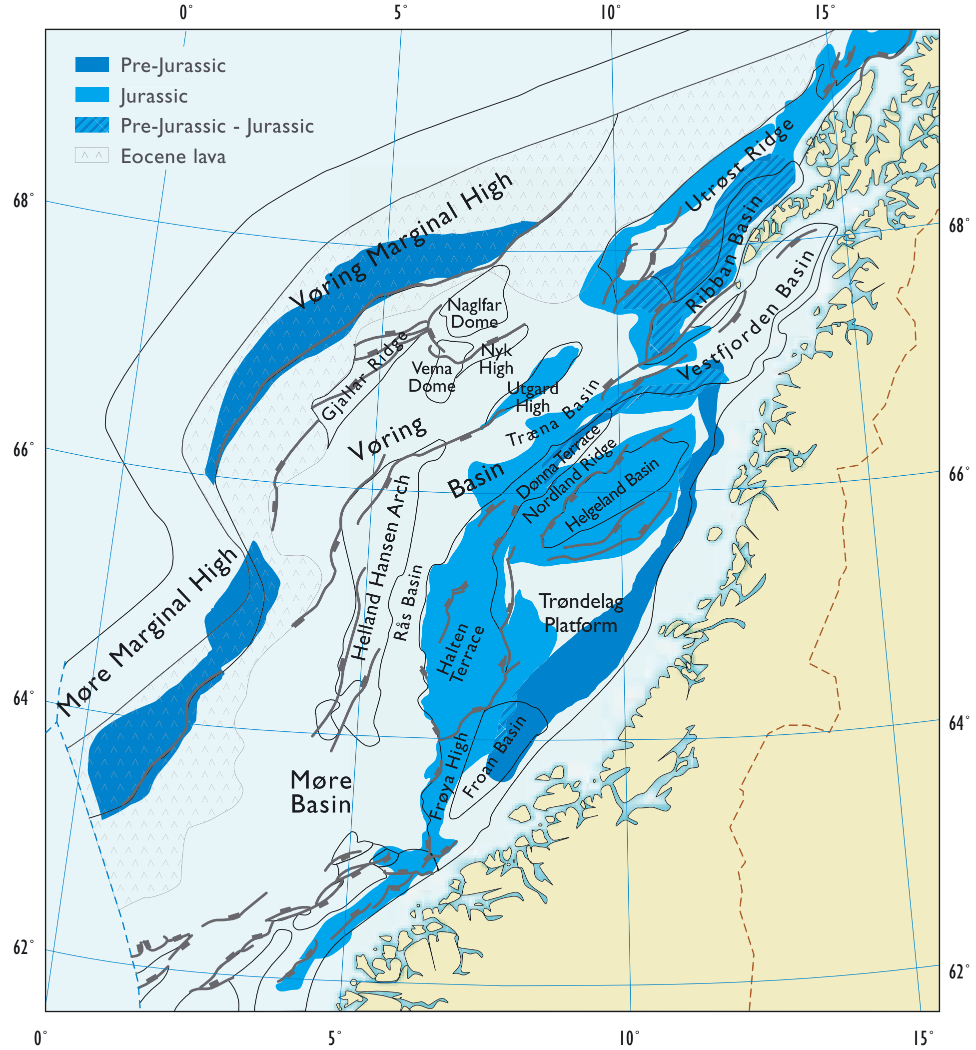


Figure 3.14 Distribution of Pre-Jurassic and Jurassic plays in the Norwegian Sea.

The NPD expects that the majority of future discoveries in the Norwegian Sea will be medium and small. However, it is feasible to make larger ones, particularly in the plays in deep water in the west and off Lofoten. If exploration drilling confirms these plays, it is estimated that a number of discoveries containing up to 50 million Sm^3 o.e. can be made, and some even larger ones.

In the Norwegian Sea, 75 per cent of the discovered resources are in plays of Jurassic age (Figure 3.14). The new calculations show that almost half of the undiscovered resources will be found in Jurassic plays (Figure 3.13). Five Jurassic plays have been defined, but only two of these are confirmed. A considerable potential for undiscovered resources still exists in unconfirmed Jurassic plays. The plays with the largest resource potential are located off Lofoten.

Only 4 per cent of the discovered resources in the Norwegian Sea are located in Cretaceous plays. On the other hand, the undiscovered resources in these plays make up 35 per cent of the total undiscovered resources in the Norwegian Sea and are mainly attached to plays situated in the western part of the Vøring Basin. Two of the seven plays are unconfirmed (Figures 3.13 and 3.15).

Twenty-one per cent of the discovered resources in the Norwegian Sea are located in Tertiary plays. The gas discovery, 6305/5-1 Ormen Lange, contains most of these resources. The undiscovered resources in these plays comprise 16 per cent of the potential for undiscovered resources in the Norwegian Sea (Figure 3.13). Since three of five plays are still unconfirmed, large discoveries can still be made.

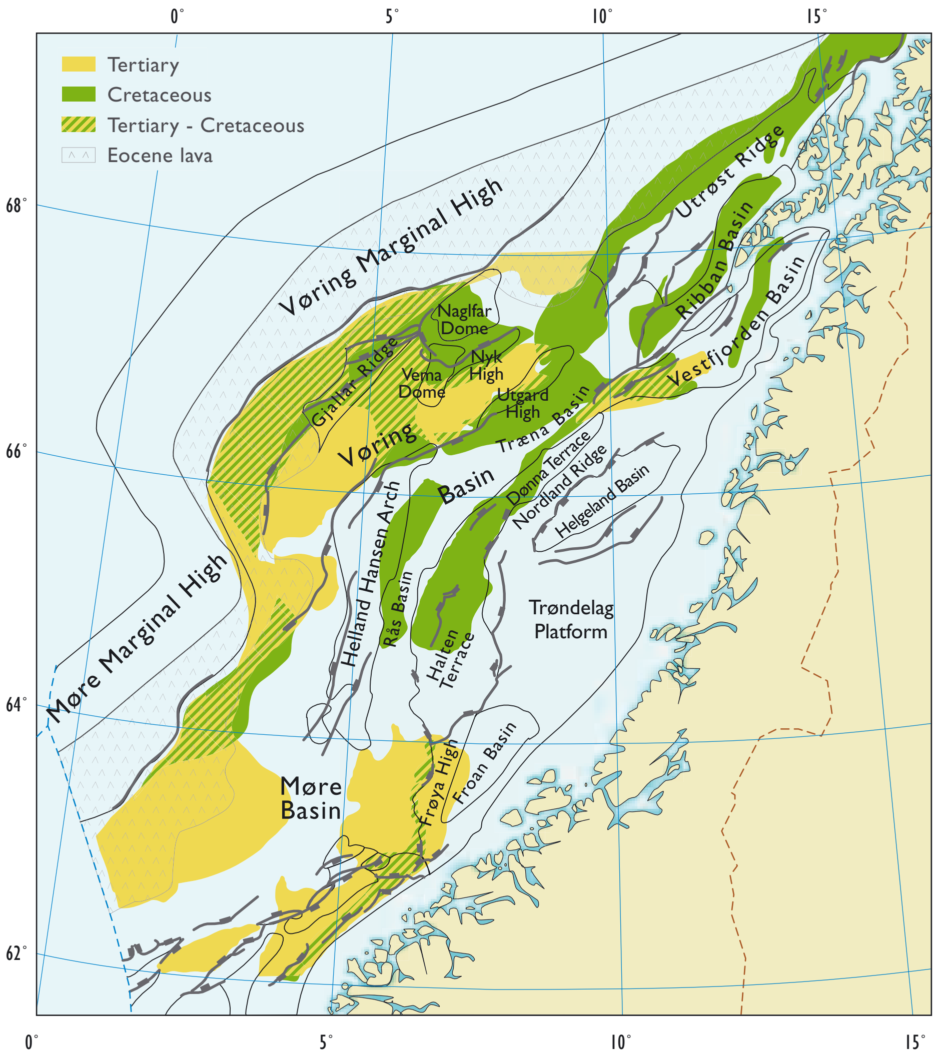


Figure 3.15 Distribution of Cretaceous and Tertiary plays in the Norwegian Sea.

The greatest reduction in the estimate for the unconfirmed resources in the Norwegian Sea has been made in the Early to Middle Jurassic play on the Halten Bank. Considerable analysis has been made of discoveries, drilling results and mapped prospects in this play, and this has resulted in the number of future discoveries and of their average size being reduced. This has led to the estimate for the undiscovered resources in the play being halved relative to the previous estimate. The resources on the Halten Bank make up approximately half of the total undiscovered resources in the Norwegian Sea.

Prospects in the Cretaceous and Tertiary plays in the Vøring Basin and the Møre Basin have been identified, to a great extent, with the help of direct hydrocarbon indicators (DHI) from seismic data. Drilling results show that a prospect with a DHI does not always give a discovery. This, in addition to new assessments of migration and retention of petroleum in the traps, has reduced the probability of discoveries in these plays. The area is still poorly known and future drilling will reduce the uncertainty and may lead to a change in the resource estimates.

Recent mapping of the area off Lofoten shows that Cretaceous and Jurassic plays may contain appreciable undiscovered resources. The play analysis shows that approximately 20 per cent of the undiscovered resources in the Norwegian Sea are located in this area. The plays are unconfirmed and it is uncertain whether discoveries will be made. Any future discoveries will result in an increase in the resource estimate.

Period	Reservoir rock	Confirmed plays	Unconfirmed plays
Late Devonian - Early Carboniferous	Limestone and dolomite		1
Early Carboniferous - Permian	Sandstone		5
Late Carboniferous - Late Permian	Limestone and dolomite	1	6
Triassic	Sandstone	2	2
Jurassic - Cretaceous	Sandstone	2	2
Tertiary	Sandstone		2

Table 3.6
Confirmed and unconfirmed plays in the Barents Sea.

Undiscovered resources in the Barents Sea

The total undiscovered resources in the Barents Sea have an expected value of 990 million Sm^3 o.e., 400 million Sm^3 o.e. of which are liquid and 590 million Sm^3 o.e. gas. The uncertainty in the estimate is large and ranges from 460 to 1700 million Sm^3 o.e. within a confidence interval between P90 and P10. The large area of uncertainty is mainly caused by limited knowledge of the geology of the area, especially north of 74° 30' N (Table 3.3 and Figure 3.16).

Eight wells were drilled in the Barents Sea in 2000–2001. These wells and large quantities of 2D and 3D seismic data acquired in connection with the Barents Sea Project have helped to provide a better understanding of the geology of the area and improve the mapping of potential petroleum traps. New mapping and evaluation have led to adjustments in the resource estimates in the individual plays, but the estimate for the total resources is insignificantly changed. The estimates for gas resources are reduced, but those for liquids have increased because the new estimates allow for larger quantities of condensate from the gas than previously assumed, based on the discoveries that have already been made.

Twenty-three plays have been defined within the geological periods of pre-Triassic (Devonian, Carboniferous, Permian), Triassic, Jurassic, Cretaceous and Tertiary age. Limited knowledge of the geology in large areas means that 18 of the 23 plays remain unconfirmed (Figures 3.18 – 3.20 and Table 3.6). The five confirmed plays make up as much as 45 per cent of the expected total undiscovered resources in the Barents Sea (Figure 3.17). The potential for undiscov-

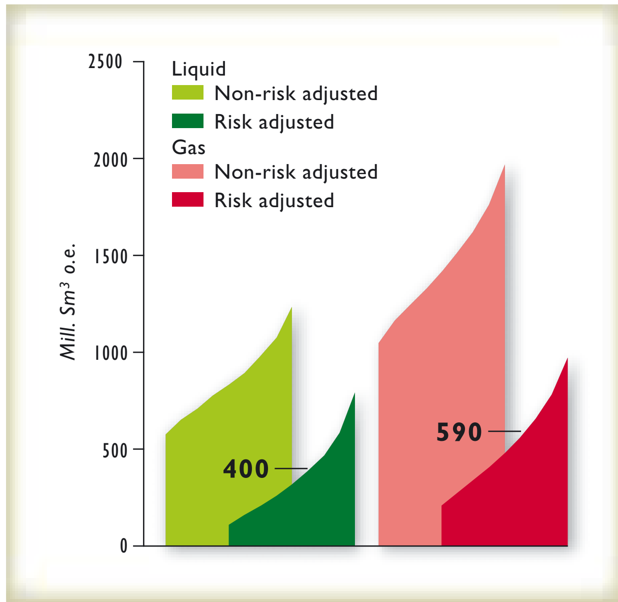


Figure 3.16
Total undiscovered resources in the Barents Sea distributed between liquid and gas.

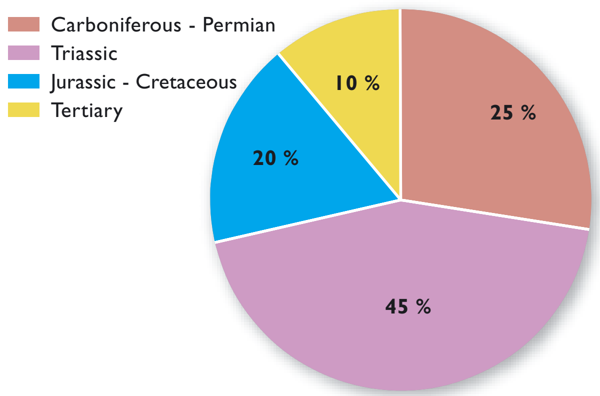


Figure 3.17
Proportions of the total undiscovered resources in the Barents Sea distributed according to geological periods.

ered resources in unconfirmed plays in the Barents Sea is great. If several of the plays are confirmed, the resource estimate will rise significantly.

In addition to these plays, ten possible plays of Devonian to Tertiary age exist. They may mature to plays if more detailed mapping is undertaken, or more exploration wells are drilled.

As most of the plays remain unconfirmed, great uncertainty is attached to the undiscovered resources in the Barents Sea. It is difficult to judge what the sizes of any future discoveries may be in different parts of the area. Large discoveries may be made in areas where no exploration wells have been drilled.

Based on knowledge of the geology and the development of the Snøhvit field, only the Hammerfest Basin may be characterised as a well-known area. The NPD has mapped four plays that occur in the Hammerfest Basin and three of these have been confirmed by discoveries. They are of Triassic and Jurassic age. The most important source rock in the Hammerfest Basin is shale of Late Jurassic age (the Hekkingen Formation). In addition, petroleum has been formed in Cretaceous and Triassic shales. The risk-adjusted, undiscovered quantities are approximately 100 million Sm^3 o.e., 60 per cent of which are gas. It is comparatively unlikely that new, large discoveries will be made.

The Barents Sea south of 74° 30' N, apart from the Hammerfest Basin, is characterised as moderately well known. Most of the plays are located in this area and are mainly of Triassic age or older. The source rocks in the area mainly consist of Late Jurassic shales (the Hekkingen Formation) and Triassic shales. There are also possibilities for source rocks in shales of Devonian, Carboniferous, Permian and Cretaceous age. It is expected that the Barents Sea Margin and the area containing the Loppa High and the Bjarmeland Platform have the greatest potential for undiscovered resources (Figure 3.6).

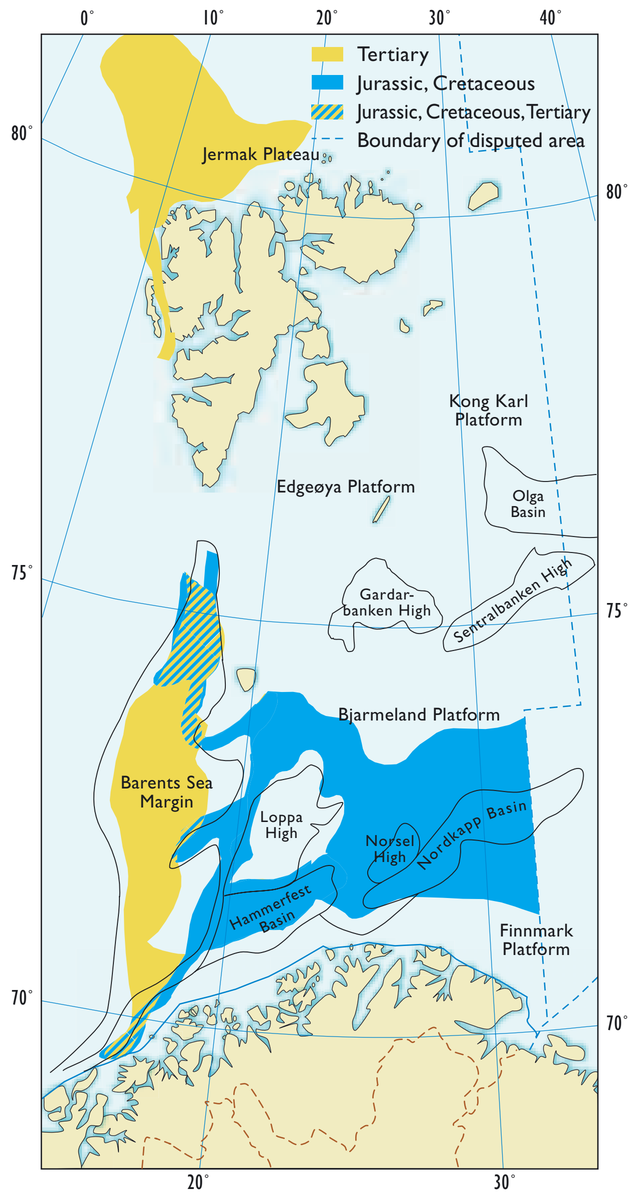


Figure 3.18
Distribution of Jurassic, Cretaceous and Tertiary plays in the Barents Sea.

The Barents Sea north of 74° 30' N must be characterised as poorly known. The risk-adjusted, undiscovered resources are limited compared to the large extent of the area, but the theoretical calculations show that the undiscovered resources, especially gas, are significant.

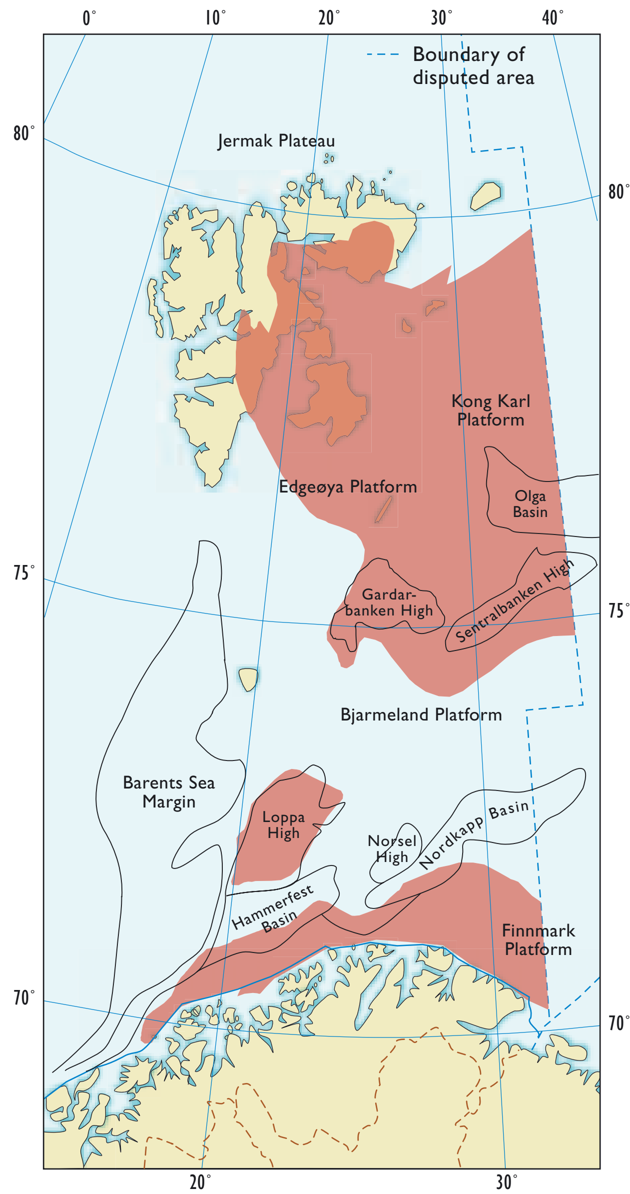


Figure 3.19
Distribution of Carboniferous-Permian plays in the Barents Sea.

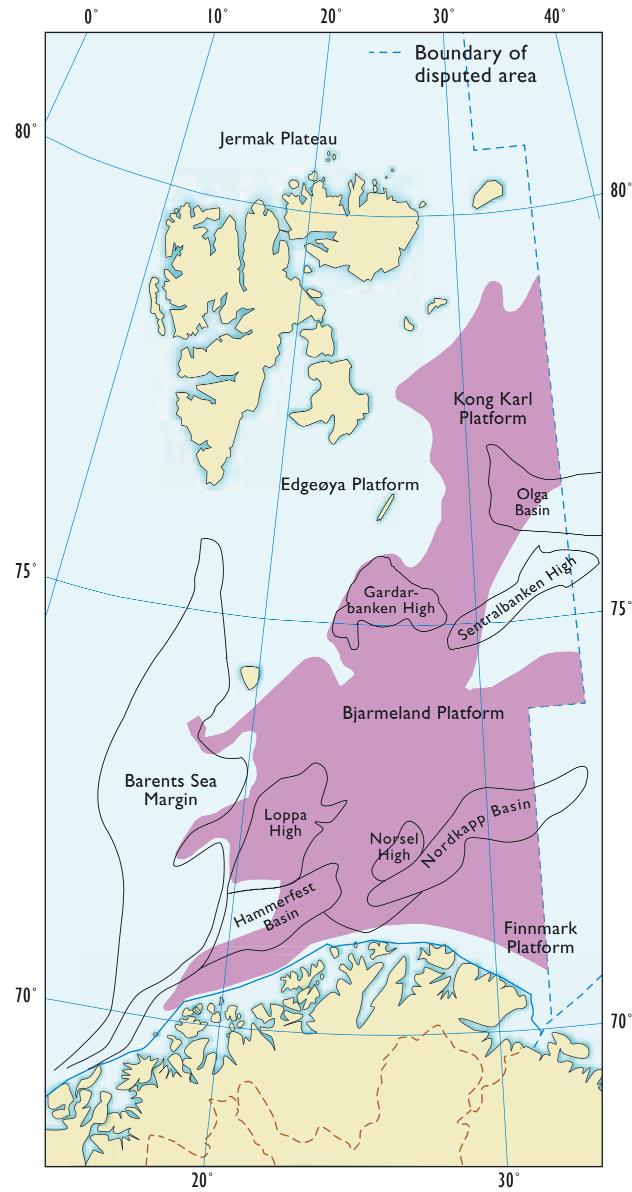
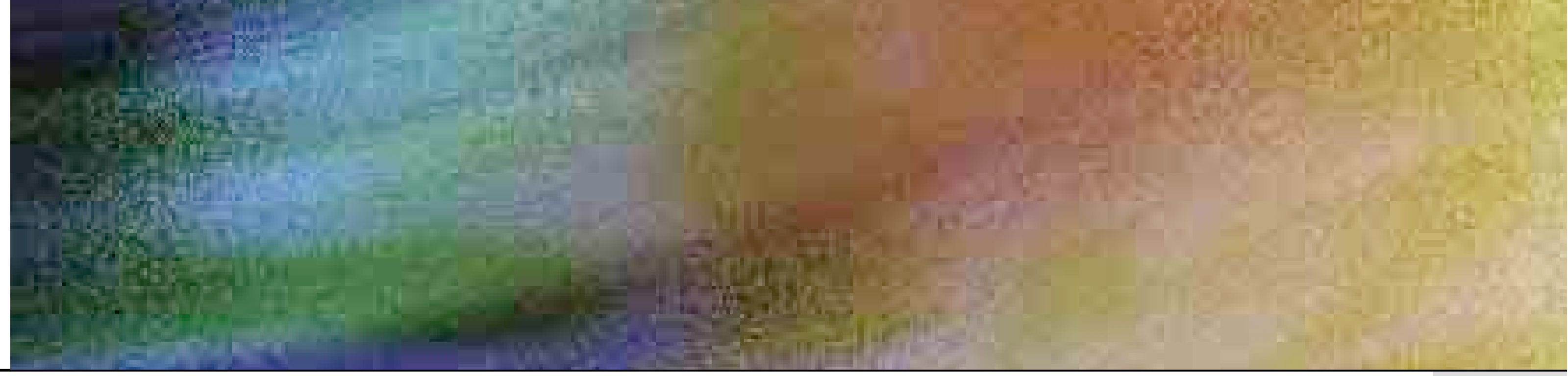


Figure 3.20
Distribution of Triassic plays in the Barents Sea.

4 Exploration on the Norwegian continental shelf



4.1 CHALLENGES AND TRENDS

The chance of making large discoveries on the Norwegian continental shelf still exists, especially in areas characterised as moderately or little known (Figure 3.6).

There has been no petroleum activity in the areas north of Lofoten in 2002 and so far in 2003. Any activity there must await the consideration of a report - Environmental impact assessment of year-round petroleum operations in the Lofoten – Barents Sea area.

The acreage awarded to date comprises approximately 22 per cent of that in which the NPD has mapped plays. To make more discoveries, it is important to drill more wildcat wells in previously awarded acreage and continue to award acreage where it is feasible to make new discoveries. In addition, new technology is expected to be developed which will make new discoveries simpler and cheaper to make. The trend regarding exploration results has been high success in making technical discoveries and declining annual growth in resources.

4.2 ACCESS TO ACREAGE

In recent years, the authorities have increased the degree of predictability as regards the licensing system. From 1999 to 2002, there have been annual awards in mature parts of the North Sea, referred to as the North Sea awards. In addition, there have been biennial licensing rounds in less mature parts of the continental shelf.

In May 2003, a licensing round with predefined exploration areas in mature parts of the shelf was announced for the first time. The acreage concerns mature areas in both the Norwegian Sea and the North Sea, and the system replaces the annual North Sea awards. The acreage announced now will be available to the industry for the next few years.

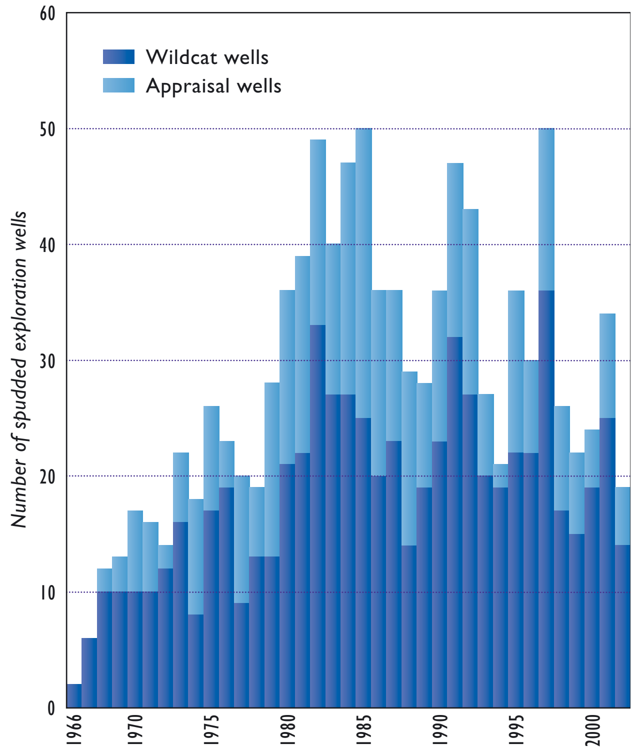


Figure 4.1
Number of spudded exploration wells on the Norwegian continental shelf.

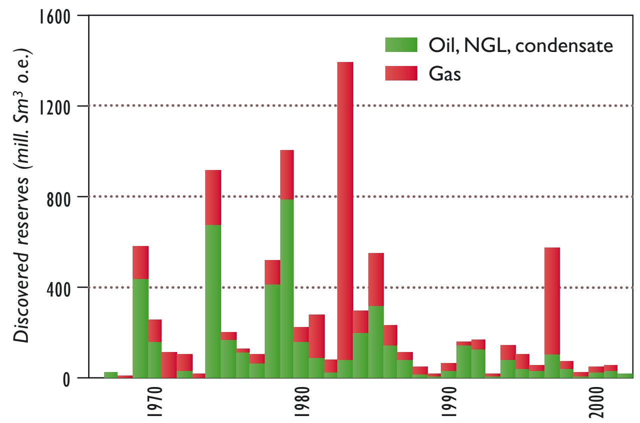


Figure 4.2
Liquid and gas resources discovered in new exploration wells each year.

The Ministry of Petroleum and Energy will continue the practice of biennial awards in immature parts of the continental shelf. For the 18th licensing round, the companies are being invited to nominate blocks which in their opinion should be included in the round. The closing date for nominations is 1 August 2003. They may nominate blocks in all opened acreage south of 68° N, thus including that in the North Sea.

To ensure activity in awarded acreage, the authorities have reviewed production licences where exploration activity has been low or non-existent in recent years. It transpires that approximately 25 production licences fall into this category. Together with the companies, the NPD will look into the reasons for the low activity in these licences and suggest measures to improve it.

4.3 RESOURCE GROWTH, TECHNICAL DISCOVERY SUCCESS AND EXPLORATION EFFICIENCY

The first wildcat well on the Norwegian continental shelf was drilled in 1966, and by 31 December 2002, 680 wildcat wells had been drilled (wells spudded are shown in Figure 4.1). Of these, 499 were in the North Sea, 128 in the Norwegian Sea and 53 in the Barents Sea. In addition, 367 appraisal wells have been drilled, 305 in the North Sea, 54 in the Norwegian Sea and 8 in the Barents Sea. Exploration drilling in the Norwegian Sea and the Barents Sea began in 1980, 14 years later than in the North Sea.

Even though the technical discovery success is still high, the growth in resources has declined. Many discoveries are made, but they are now comparatively small (Figures 4.2 and 4.3).

In the last 30 years, the growth in resources from discoveries with recoverable resources of less than 100 million Sm^3 o.e. has been considerable and approximately constant. The proportion of the resource growth from smaller discoveries has risen. It comprised 55 per cent of the discovered resources in the last ten years, 21 per cent in 1983–1992 and 18 per cent in 1973–1982. Two discoveries in excess of 100 million Sm^3 o.e. have been made since 1993. These are the gas discoveries 6305/5-1 Ormen Lange and 6506/6-1 ("Victoria") in the Norwegian Sea (Figure 4.4).

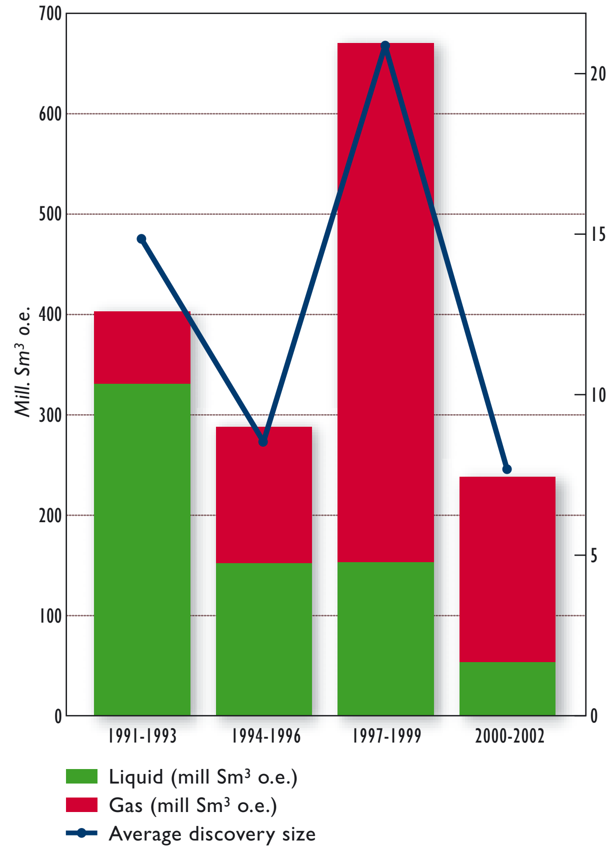


Figure 4.3
Recoverable resources discovered in 1991 - 2002, and the average size of discoveries.

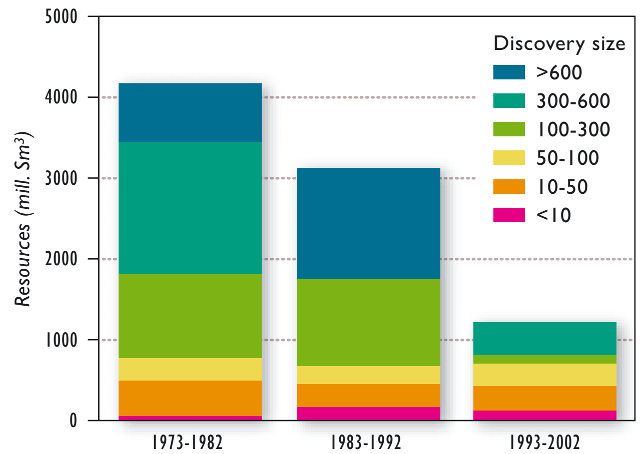


Figure 4.4
Growth in resources and sizes of discoveries during the last 30 years.

Over time, the growth in resources from exploration has decreased while production has increased. During the first few years of Norwegian petroleum operations, growth exceeded production so that the remaining resources increased annually, but in the last 15 years annual production has been higher than the growth in resources. An exception was 1997 when 6305/5-1 Ormen Lange in the Norwegian Sea was discovered (Figure 4.5).

Of the 92 wildcat wells drilled in the last five years, a third were in production licences awarded before 1985 (1st-8th licensing rounds); 21 of the 47 discoveries made in this period are in these licences. This shows there are still good chances of making discoveries in the acreage awarded early. These discoveries are not large, but many are profitable because of available capacity in existing infrastructure, new development concepts and new drilling technology. In addition, new knowledge about both known and new plays is being utilised to define prospects that can give new discoveries (Figures 4.6 and 4.7).

Technical discovery success

The technical discovery success has varied, but is in general high by international standards. In 1974, discoveries were made in 8 of the 11 wildcat wells begun, the highest technical discovery success so far. The poorest year was 1994, when only one discovery was made in a total of 19 wildcat wells. The average success to date is 40 per cent, but in the last three years it has been more than 50 per cent (Figures 4.8 and 4.9).

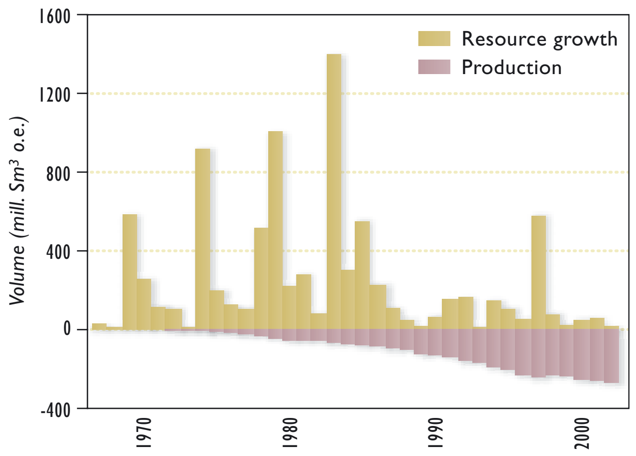


Figure 4.5
Annual growth in resources from exploration compared with annual petroleum production.

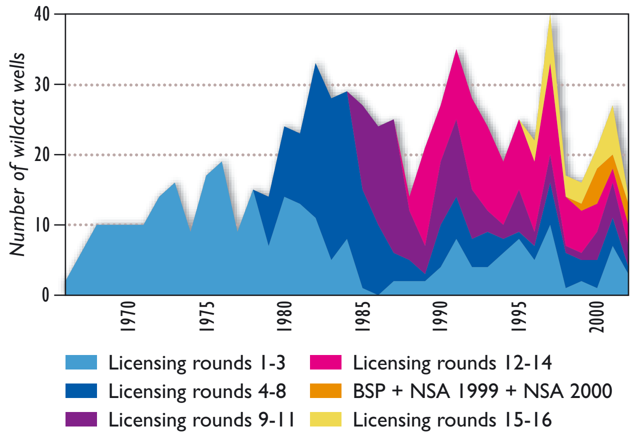


Figure 4.6
Number of wildcat wells drilled a year arranged according to the various licensing rounds. BSP signifies Barents Sea Project, NSA signifies North Sea awards.

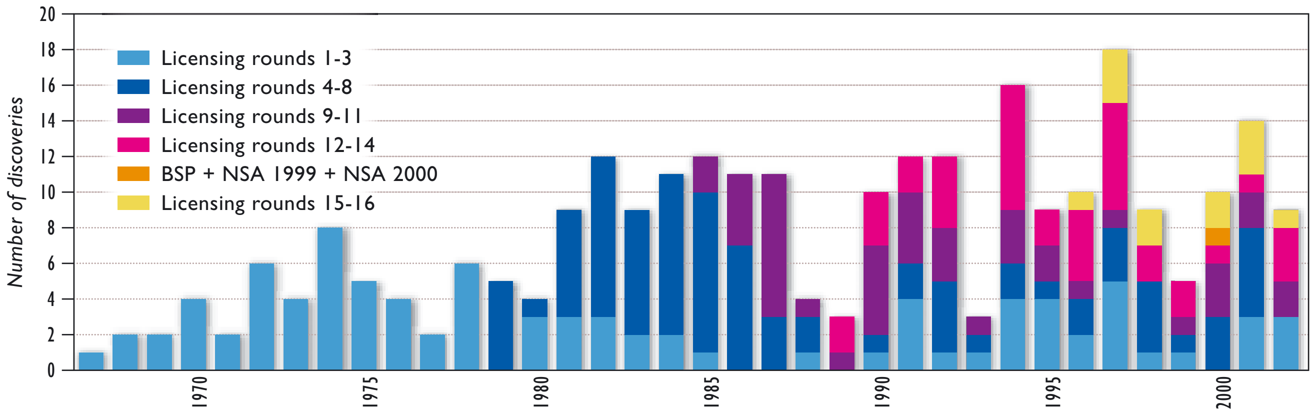


Figure 4.7 Number of discoveries a year arranged according to the various licensing rounds. BSP signifies Barents Sea Project, NSA signifies North Sea awards.

Technical discovery success: The ratio between the number of technical discoveries and the number of wildcat wells.
Economic/commercial discovery success: The ratio between the number of discoveries which are developed or are clearly profitable today and the number of wildcat wells.

Apart from the specially good years in the 1970s, the technical discovery success has shown a slightly rising trend in the 30-year period. The most important reason is that the availability and quality of seismic data have developed significantly, making it possible to improve the mapping and evaluation of prospects that are smaller and more difficult to identify, and which are now drilled.

Exploration efficiency

Exploration efficiency can be measured in the resource growth per wildcat well and cost per volumetric o.e. discovered. It was highest in the 1970s, declined in the 1980s, but rose again at the end of the 1990s until it dropped markedly in 2002 because of lower resource growth per well (Figure 4.10).

4.4 EXPLORATION TECHNOLOGY

The hope is that recently developed technology can make prospect definition still more precise and exploration in general more accurate. One recently developed technique for which there are great hopes is sea-bed logging (SBL). This concept is based on the use of electromagnetic waves which are transmitted from a source on a surface vessel. The reflected signals are received by a radio receiver placed on the sea bed. Accumulations of petroleum should result in a diagnostic profile for the reflected radio signals. There is also increased interest in high-resolution, airborne recording of natural oil leaks, which provide information about where petroleum can be found in the bedrock. The data are collected by flying over relevant areas with an optical spectrometer which records fluorescence from hydrocarbons. Increased use of sea-bed seismic (OBS and OBC) is also expected, which will enhance the quality of the seismic data in areas where particular problems exist. However, problems still need to be solved in connection with acquiring and processing sea-bed seismic data.

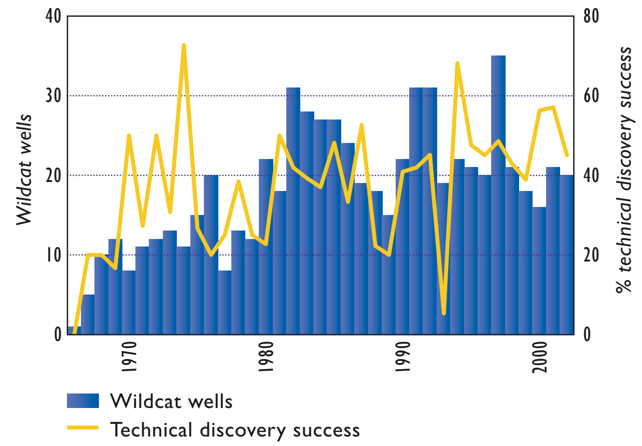


Figure 4.8
Number of wildcat wells a year, and annual technical discovery success.

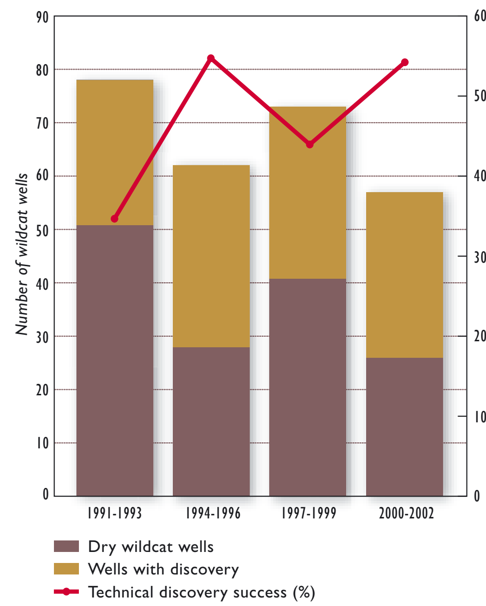


Figure 4.9
Numbers of wildcat wells with discoveries and dry wildcat wells in 1991 - 2002.

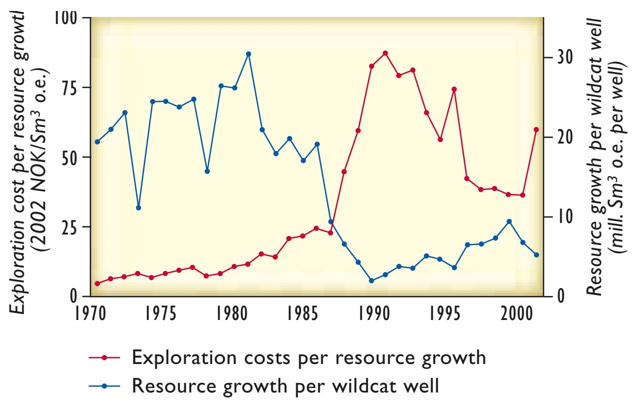


Figure 4.10
Trend in exploration efficiency on the Norwegian continental shelf, 5-year sliding average.

As regards interpretation, a rapid development of software is taking place on new, PC-based visualisation tools. This may mean that more information can be acquired more rapidly from the seismic data with the help of attribute analyses.

4.5 CURRENT SITUATION

In 2002, 14 wildcat wells were spudded on the Norwegian continental shelf, and plans show that 12 to 16 will be spudded in 2003. This may be the fewest wildcat wells spudded since the early 1970s. So far this year, three discoveries have been made, 25/4-7 in the Heimdal area, 6608/10-9 near the Norne field, and 6706/6-1 on the Naglfar Dome in the Norwegian Sea.

Positive results in the form of new discoveries in moderately well known and unknown areas may lead to more wells being drilled. Unfortunately, the results from the wildcat wells drilled on prospects expected to contain sufficient resources to give new, independent developments have been disappointing in recent years. The last significant discovery, 6305/5-1 Ormen Lange, was made in 1997. It is particularly in little known, deep-water areas in the Norwegian Sea the industry hopes to make new, substantial discoveries. In that respect, interest is attached to Esso's well, 6706/6-1, that has been completed, and the Statoil drilling on licence no. 281 (Grip High, awarded in the 17th licensing round), which will be drilled later this year. Well 6706/6-1 encountered small quantities of gas which are not profitable to produce today. However, it has provided important information about the development of the reservoir sand in this production licence and neighbouring areas.

Measured by the number of wildcat wells, the exploration activity shows co-variation with the price of oil. In years when the oil price is high, many wells are drilled, but in the last two years few wildcat wells have been drilled even though the oil price has been high (Figure 4.11).

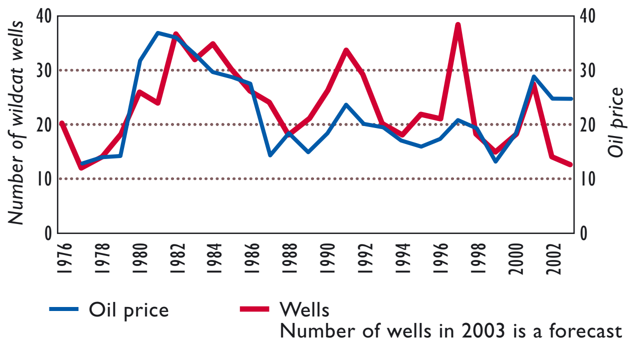
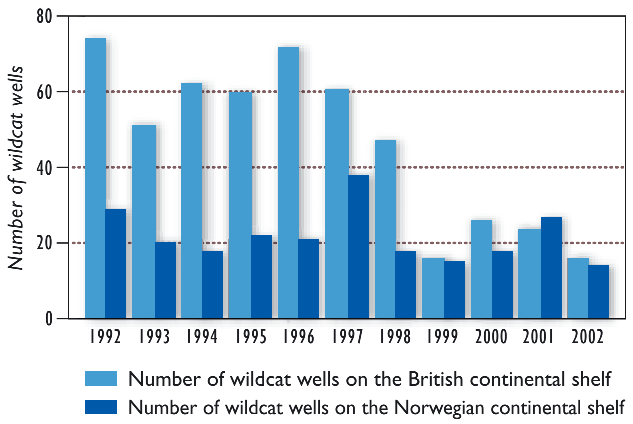


Figure 4.11
Number of wildcat wells a year on the Norwegian continental shelf and the trend in the nominal oil price.



Source:
British data: http://www.og.dti.gov.uk/information/index.htm

Figure 4.12
Number of wildcat wells in the Norwegian and British sectors of the continental shelf in the last ten years.

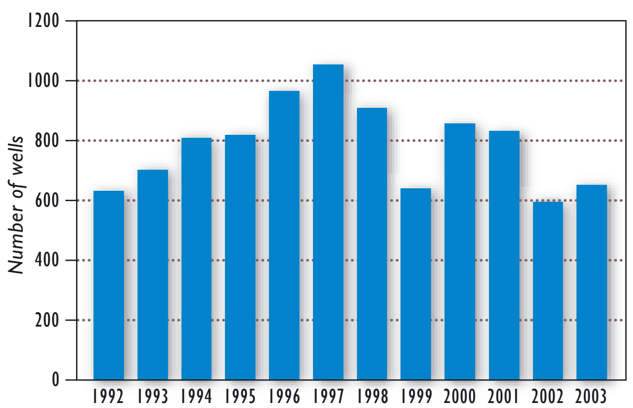


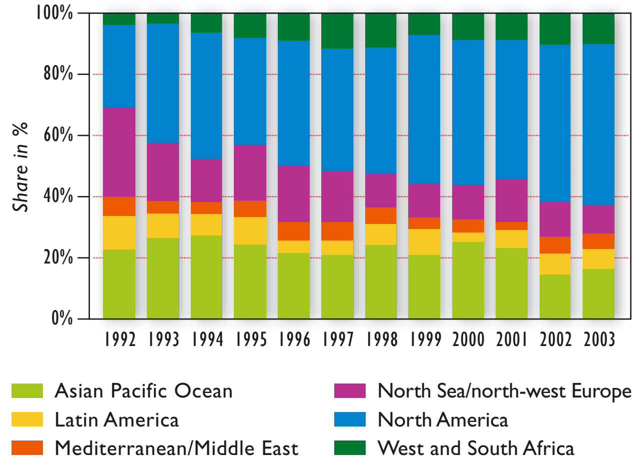
Figure 4.13
Number of wildcat wells drilled from mobile rigs offshore throughout the world.

The trend with a decreasing number of wildcat wells per year is not solely a feature for Norway. It also shows itself on the British continental shelf and offshore throughout the world (Figures 4.12 and 4.13).

The proportion of wildcat wells drilled at sea in North America (Gulf of Mexico) has shown a rising trend in the last ten years. The trend has been declining in the North Sea (Great Britain, Denmark, Norway) and the Asiatic part of the Pacific Ocean (Figure 4.14).

Statoil and Hydro are the dominant operators on the Norwegian continental shelf. Other companies have drilled comparatively few exploration wells. The takeovers and mergers of the last few years have led to fewer operators today than 4-5 years ago (Figure 4.15).

Takeovers and mergers have partly been prompted by the largest oil companies not having increased their recorded reserves by implementing their own projects and exploration. Instead they have achieved their growth targets through takeovers (Figure 4.16).



Source: ODS Petrodata

Figure 4.14
Regional distribution of wildcat wells.

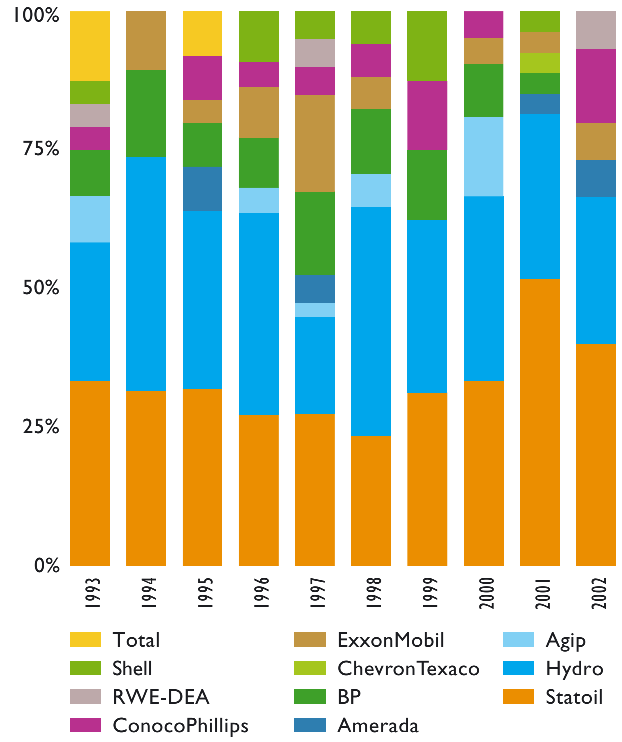
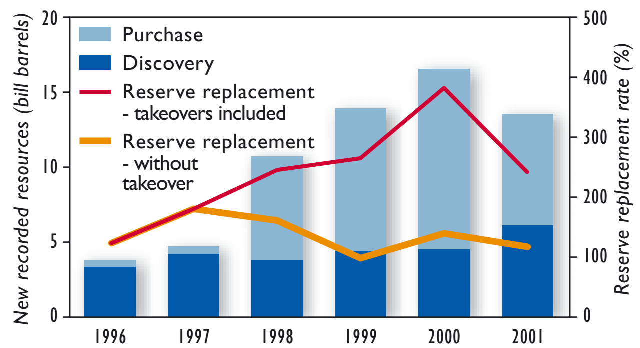
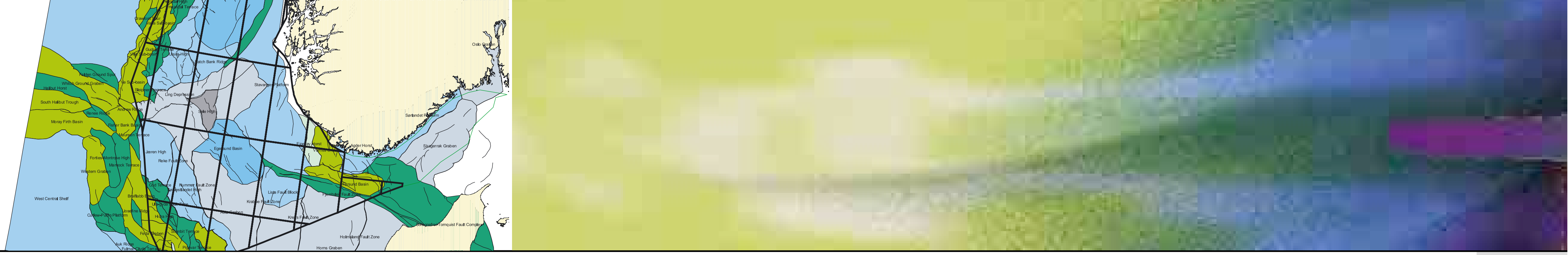


Figure 4.15
Share of spudded wildcat wells per current operator per year. Former operators taken over by, or merged with, other operators are shown as current operators (e.g. wells operated by Saga before 2000 are shown as being operated by Hydro).



Source: Wood MacKenzie

Figure 4.16
New recorded reserves compared with reserve replacement from takeovers. SEC data (Securities and Exchange Commission). Data from: "Super majors", ChevronTexaco, ConocoPhillips, Unocal, Anardako, Apache, Devon, PetroCanada and Canadian Natural Resources Limited (CNR).



5 The North Sea

5.1 CHALLENGES AND TRENDS

The first 20 years of petroleum operations in the North Sea were marked by large discoveries and high development activity. After nearly 40 years of exploration and production, the situation is now different. The total annual oil production has been stable in recent years, but a considerable drop is expected after 2005. This decline in production is mostly because the largest sandstone fields, Statfjord, Gullfaks and Oseberg, are entering their late production phase. Whereas these fields accounted for 70 per cent of the total oil production in 1990, their share will sink to 35 per cent in 2005 (Figure 5.1).

Gas production will peak somewhat later and fall more slowly. According to current plans, deliveries of gas from North Sea fields will not fall below the present level before about 15 years hence (Figure 5.2). The largest proportion of the gas comes from the Troll field.

The petroleum activities in the North Sea are today marked by increasing unit costs on the mature fields, because production is declining without costs being reduced correspondingly (Figure 5.3).

There is considerable potential for further value creation through improved oil recovery on the large fields in the North Sea. However, this calls for both investment and a large measure of innovation and technological development. For instance, there may be a need for alternative production strategies, restructuring and construction of installations, and development of new methods to extract the remaining resources that are difficult to access.

Discovering and producing resources near the mature fields in the North Sea is a matter of great urgency.

A new aspect in the North Sea is new companies who wish to focus on tail production and development of small discoveries.

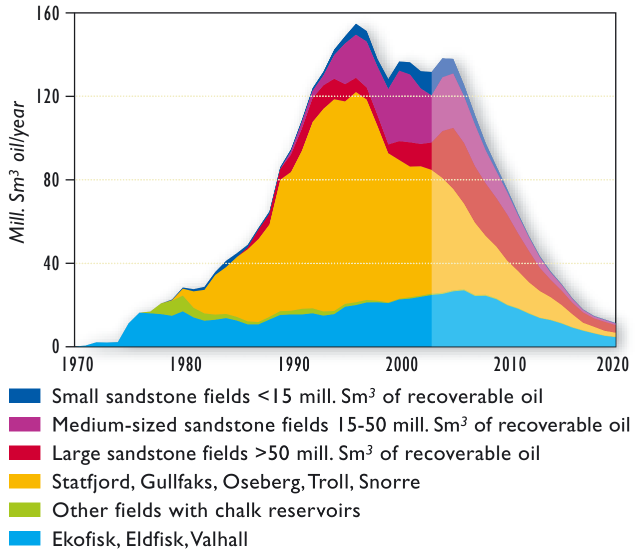


Figure 5.1
Historical and forecasted oil production in the North Sea.

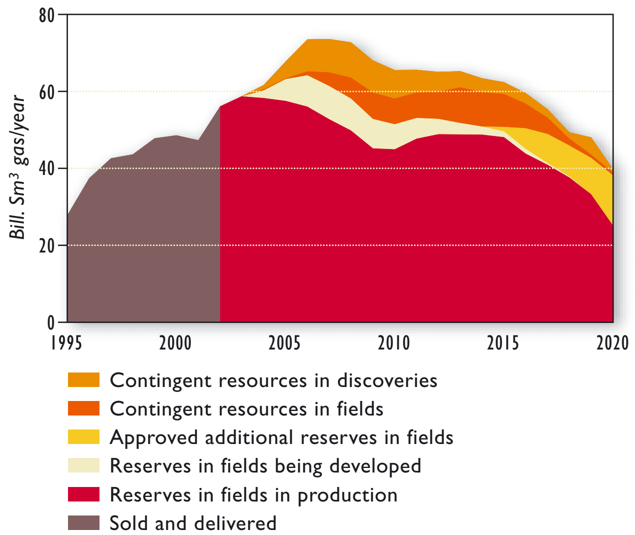


Figure 5.2
Historical and forecasted gas production from fields in the North Sea.

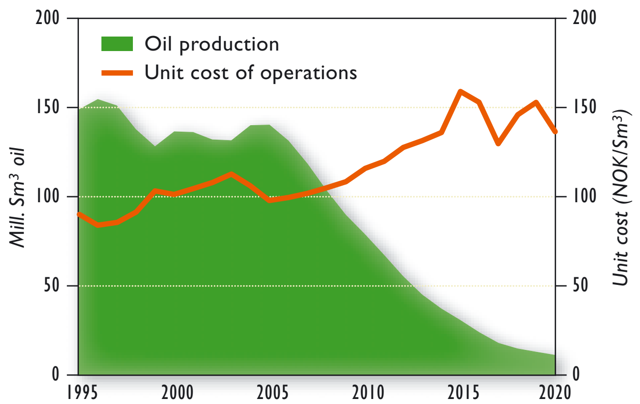


Figure 5.3
Historical and forecasted trends in unit costs and oil production in the North Sea.

5.2 THE RESOURCE BASE

The total petroleum resources in the North Sea are 8039 million Sm^3 o.e., 4383 million Sm^3 of which are oil, 3269 billion Sm^3 gas, 145 million tonnes NGL and 112 million Sm^3 condensate (Figures 5.4 and 5.5). The North Sea is defined as a mature petroleum province where three-quarters of the estimated resources either have been produced or are reserves in fields. Only small quantities are linked to discoveries that have not been developed.

In 2003, 40 fields are in production in the North Sea and several of these have a production horizon beyond 2020. Twelve fields have already ceased production. Five fields are being developed, Kvitebjørn and Grane being the largest of these.

In the coming years, development plans are expected for 14 discoveries containing, all told, approximately 300 million Sm^3 o.e., of which gas forms the largest proportion. All the oil discoveries are small, each containing less than 15 million Sm^3 of recoverable oil. In addition, 20-25 small discoveries may be developed in the longer term if certain technical and economic conditions are met.

A large proportion of the roughly 400 million Sm^3 o.e. of contingent resources in fields depends on the development of new methods to improve recovery or reduce costs.

As regards the undiscovered resources in the North Sea, more than 500 prospects have been recorded. Most of these are small or medium sized, but the majority of the resources are in future discoveries larger than 5 million Sm^3 o.e. (see section 3.2). Since many of the prospects, particularly in the northern part of the North Sea, are located close to existing fields, it may be profitable to develop them as additional resources to those fields as capacity

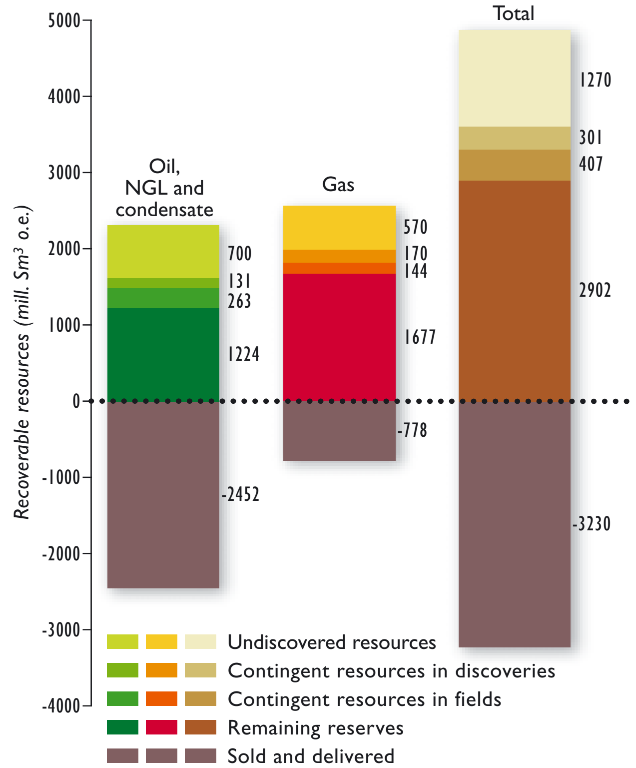


Figure 5.4
Distribution of recoverable liquid and gas resources in the North Sea.

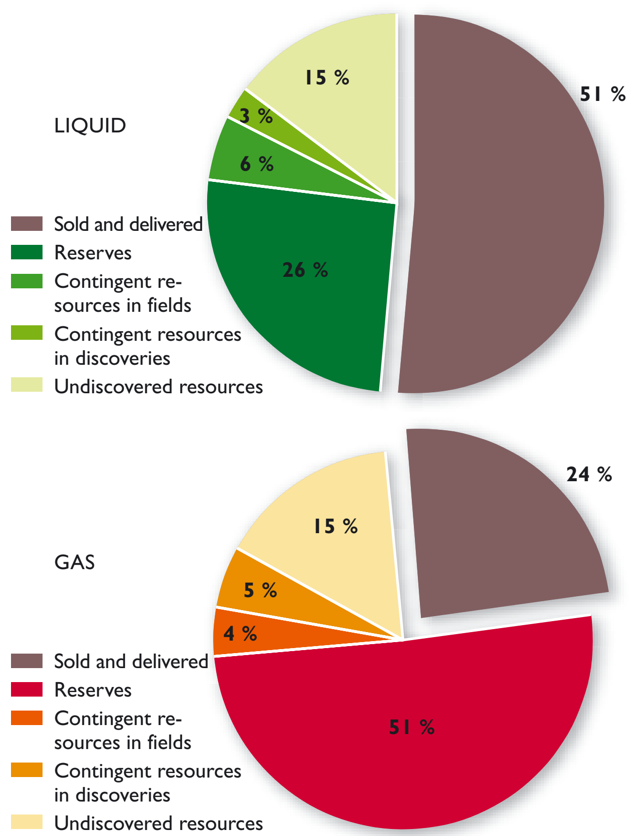


Figure 5.5
Proportions of the liquid and gas resources in the North Sea. Half the liquid resources, but less than a quarter of the gas resources, have been produced.

The petroleum resources on the Norwegian continental shelf 2003

becomes available in facilities and pipelines. Somewhat more liquid (60 per cent) than gas is expected in new discoveries that may be made.

The most prospective areas in the North Sea have probably been awarded. About 60 per cent of the area where the NPD has mapped plays is presently not licensed. The eastern and south-eastern parts of the North Sea (Skagerrak) have not been opened for exploration. There is great uncertainty attached to the possibility of making discoveries there.

5.3 EXPLORATION

The North Sea is the best explored area on the Norwegian continental shelf. After more than 30 years investigation, including over 800 exploration wells, large parts of the North Sea are defined as mature. Mainly small discoveries are expected to be made in these mature areas in the future.

The discovery success in the North Sea is high. On average, a discovery has been made in every other wildcat well (Figures 5.6 and 5.7). However, the growth in resources has been declining in recent years, as can be expected in a mature petroleum province.

On average, 15 wildcat wells were drilled annually in the North Sea until 1998 (Figures 5.7 and 5.8). Exploration activity has declined in recent years and in 2003 between six and eight wildcat wells are planned. Two of these had been completed by 10 June 2003 and one discovery had been made, in well 25/4-7.

The main challenge in the North Sea is to have exploration drilling done at the right time near existing infrastructures. In a situation where the

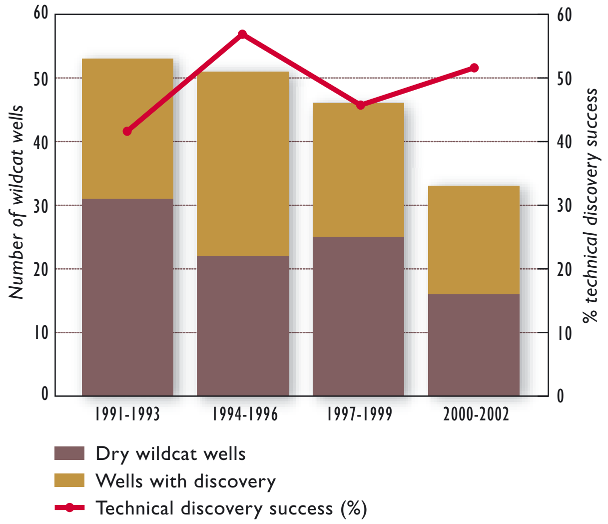


Figure 5.6 Technical discovery success in the North Sea in 1991 - 2002.

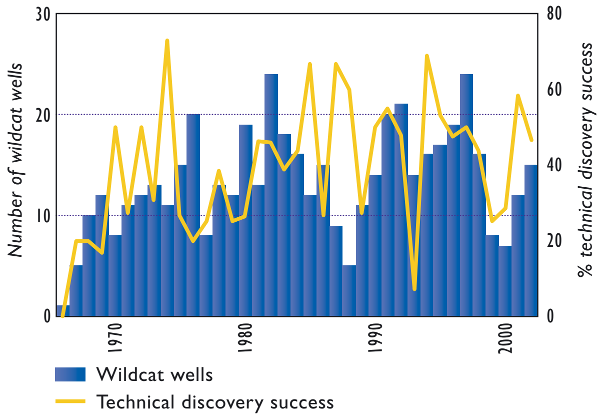


Figure 5.7 Annual technical discovery success in the North Sea for the whole exploration period.

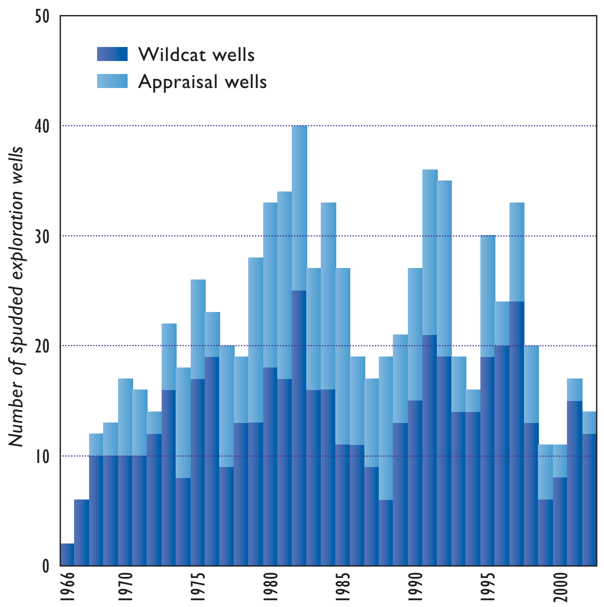


Figure 5.8 Spudded exploration wells in the North Sea.

production from large fields is approaching its late phase, nearby deposits must be discovered, developed and recovered within the lifetime of the installations.

5.4 RESOURCE DEVELOPMENT

The discovered petroleum resources in-place in the North Sea increased steadily until 1983. In the last 20 years, the growth in new resources has been less than the accumulated production. According to present plans, most of the recoverable resources in the North Sea will have been produced in 2030 if no new, profitable discoveries are made, and if the recovery factor does not increase beyond current plans (Figure 5.9).

The estimate of the recoverable resources shows a corresponding gradual reduction in recent years. In addition to the declining growth from new discoveries, the average expected recovery factor for the oil fields is no longer increasing as much as earlier.

One reason for the declining growth in the petroleum resources in recent years is that fewer wildcat wells are being drilled. However, as Figure 5.10 shows, the growth in resources in the North Sea is not only characterised by fewer discoveries but also by the decreasing average size of discoveries. More discoveries must be made if the growth in resources is to increase again.

Increase in reserves

Many of the large oil fields, like Troll, Valhall, Oseberg and Ekofisk, have experienced a substantial increase in their assumed reserves compared with the estimates in their original plan for development and operation (PDO). On average, the estimates of reserves in the North Sea oil fields have risen by 50 per cent (Figure 5.11). The developments in drilling and well technology have contributed significantly to this increase. Improved reservoir characterisation and good results from measures implemented to improve oil recovery are also important reasons for the increase in the reserves.

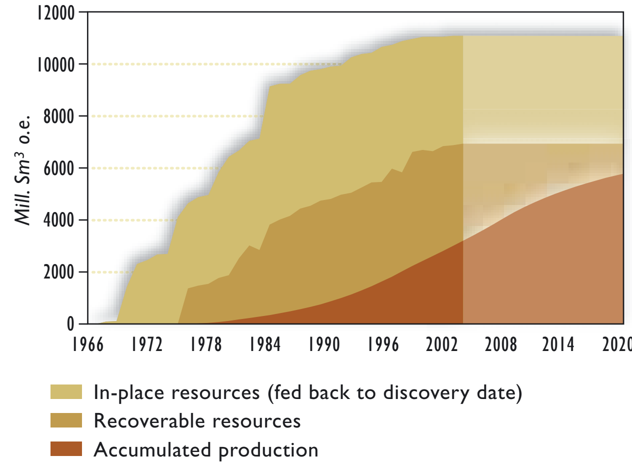


Figure 5.9
Resource development in the North Sea. The figure shows the present-day estimate of the in-place oil and gas resources in all fields and discoveries fed back to when the individual deposit was discovered. The large jumps represent the discovery of Ekofisk in 1969, Statfjord in 1974, Gullfaks in 1976, Oseberg in 1979 and Troll in 1983.

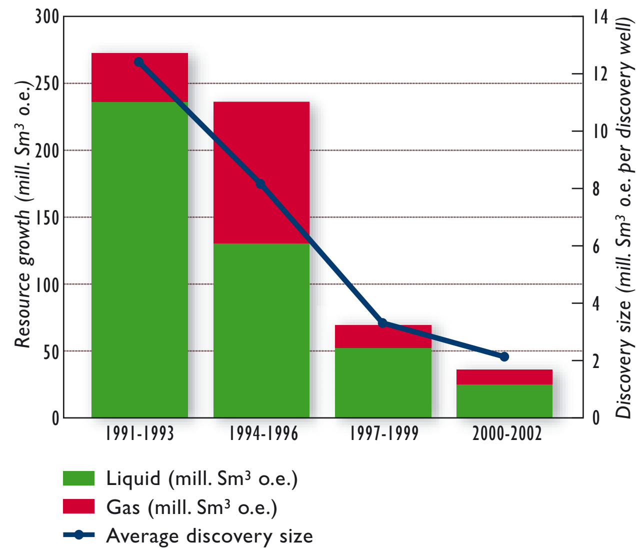


Figure 5.10
Growth in resources from exploration wells and average size of discoveries in the North Sea in the last 12 years. The size of discoveries has decreased in recent years to 15 % of the average in the early 1990s.

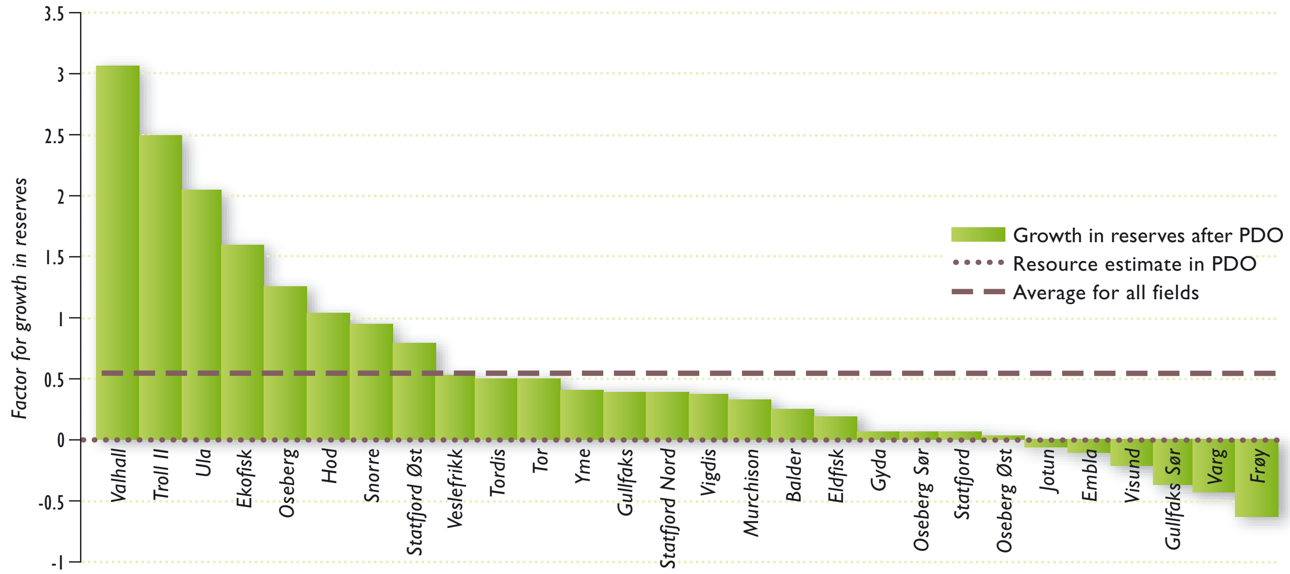


Figure 5.11
Increase in estimated oil reserves in 28 North Sea fields. In several cases, the increase has come in response to extensive new developments.

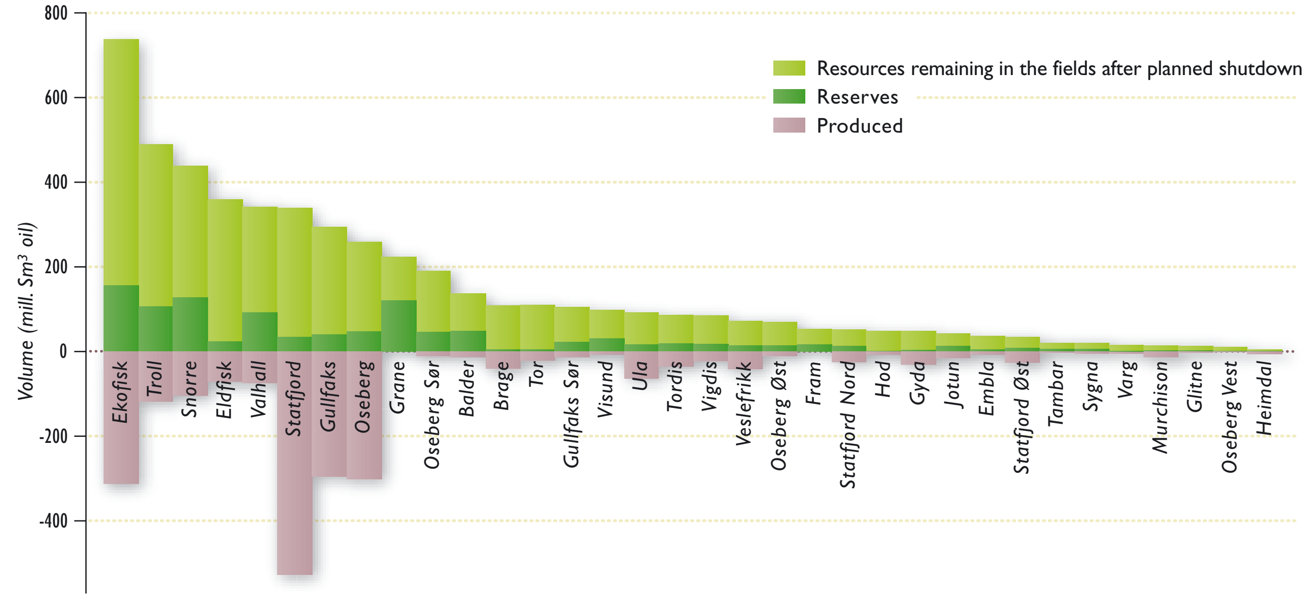


Figure 5.13
Produced and remaining oil reserves and resources in 34 North Sea oil fields.

Recovery factors for oil fields

After 1998, the rise in the average expected recovery factor for the oil fields in the North Sea has been insignificant (Figure 5.12). The many small fields developed in recent years have a lower recovery factor than the average for North Sea oil fields. In addition, fewer decisions on measures to improve oil recovery on the larger oil fields have been taken recently than during the 1990s.

With few exceptions, the largest sandstone fields in the North Sea have the highest recovery factor for oil. Statfjord has an expected recovery factor of 65 per cent, Oseberg 62 per cent and Gullfaks 57 per cent.

The expected recovery factor for oil in the chalk fields in the southern part of the North Sea has risen considerably from its original figure of less than 20 per cent in the 1970s to the present average of 37 per cent. This increase results from extensive measures to improve oil recovery, mainly by water injection. Water-injection projects have included the building of new facilities. The expected oil recovery factor is now 44 per cent on the Ekofisk field, but this will increase further in response to recently approved projects.

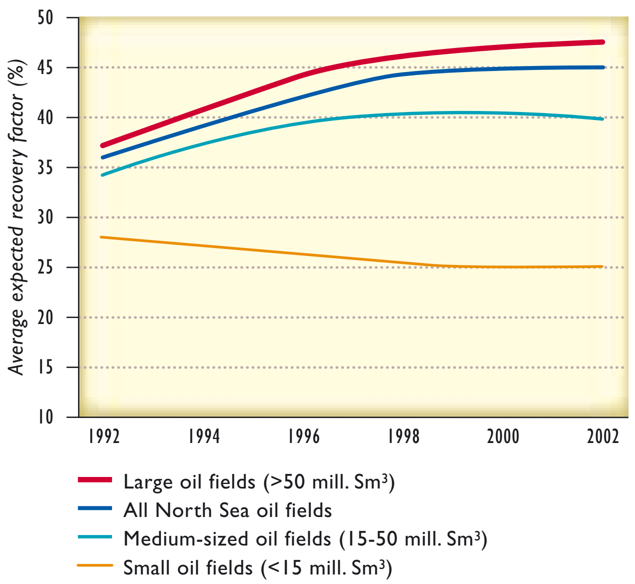


Figure 5.12
Trends in the estimated, average recovery factor for oil fields of various size. The fields are grouped according to the size of the reserves estimated in their original PDO.

The recovery factor for the individual field largely depends on reservoir characteristics, including the type of deposit and the depth of the reservoir. The recovery strategy or drive mechanism is also important. High recovery is achieved through active pressure support in the form of water, gas and WAG (water-alternating-gas) injection. Recovery by pressure depletion, which is normal for small fields, gives a low recovery factor.

5.5 LARGE VALUES IN MATURE FIELDS

Norwegian oil production has been, and is, dominated by the large oil fields in the North Sea. The oil fields with the largest in-place volumes are Ekofisk, Statfjord, Troll, Gullfaks, Oseberg, Snorre, Eldfisk and Valhall (Figure 5.13). These fields have a total of 70 per cent of the in-place oil volumes in the North Sea and have contributed more than 80 per cent of the North Sea oil production to date. Statfjord has already produced 61 per cent of the in-place volume, which corresponds to 94 per cent of the oil reserves for which recovery has been decided. Both Gullfaks and Oseberg have produced nearly 90 per cent of their reserves (Figures 5.14 and 5.15).

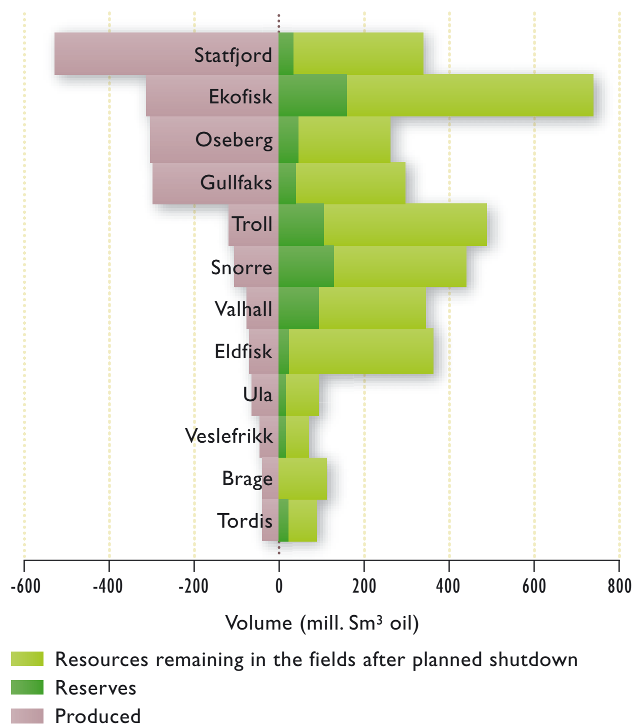


Figure 5.14
Produced oil and remaining reserves and resources in the 12 North Sea oil fields that have produced most so far. Note that only the Norwegian part of Statfjord is represented in the figures.

Substantial volumes of oil will be left in the reservoir after the planned shutdown of the large fields (Figure 5.15). It is therefore most important to focus on identifying and planning measures to improve oil recovery from these fields.

The NPD study of the potential for increased value creation on fields shows that as much as 50 per cent is linked to five large fields and 90 per cent can be obtained from half of the fields that are now in production in the North Sea (Figure 5.16).

The greatest potential is expected to be in the southern part of the North Sea. Of all the fields on the Norwegian continental shelf, Ekofisk has the largest remaining oil reserves, with more than 150 million Sm^3 of oil, and the largest remaining resource potential.

If all the projects identified on the fields had been carried out, the average recovery factor for oil in the North Sea would have increased from the present-day expectation of 45 per cent to more than 50 per cent. Such implementation depends on the absence of any factors to stop the individual projects. Non-profitability and technological problems are often obstacles for realising new projects. Lack of capacity in processing facilities is another reason for possible postponement of projects that would have increased production. A major challenge in many gas-injection projects is obtaining gas for injection to make the project profitable.

The potential for enhanced value creation on the fields can be realised through various projects and measures, as shown in Figure 5.17. Additional wells in existing fields constitute the greatest volumetric potential. Together with measures in drilling and well technology, these account for around 35 per cent. Reservoir blowdown and various injection projects are also of great importance, in addition to developing deposits near the fields.

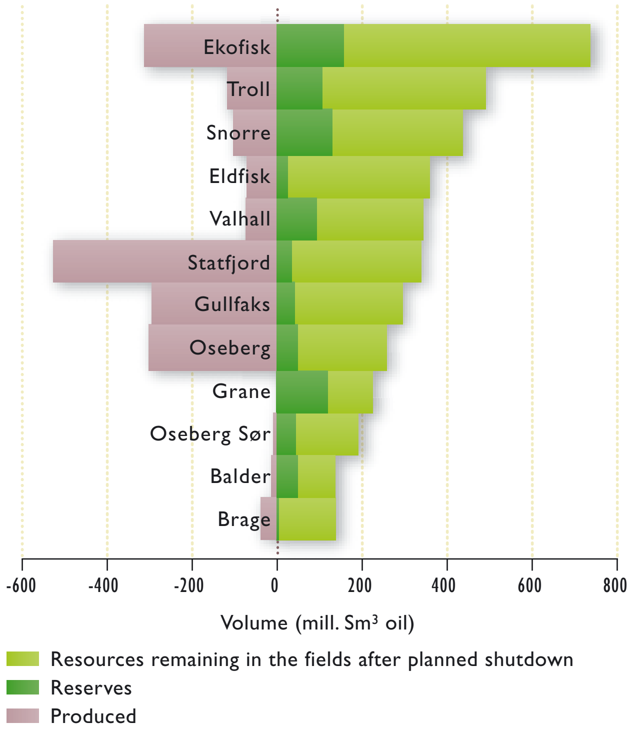


Figure 5.15
Produced oil and remaining reserves and resources in the 12 North Sea oil fields that have most resources remaining. These fields will be responsible for the major part of the oil production in the North Sea over the next ten years.

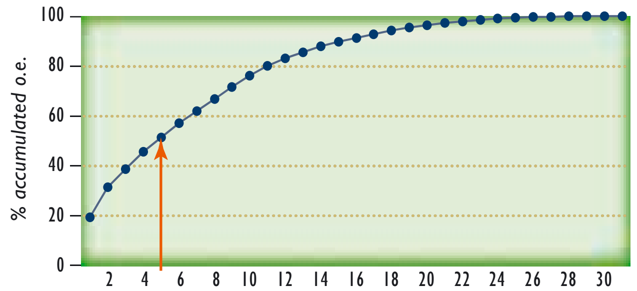


Figure 5.16
Percentage shares of the accumulated potential for improved recovery from North Sea fields, apportioned according to fields. 50 per cent of the total potential is linked to five large fields.

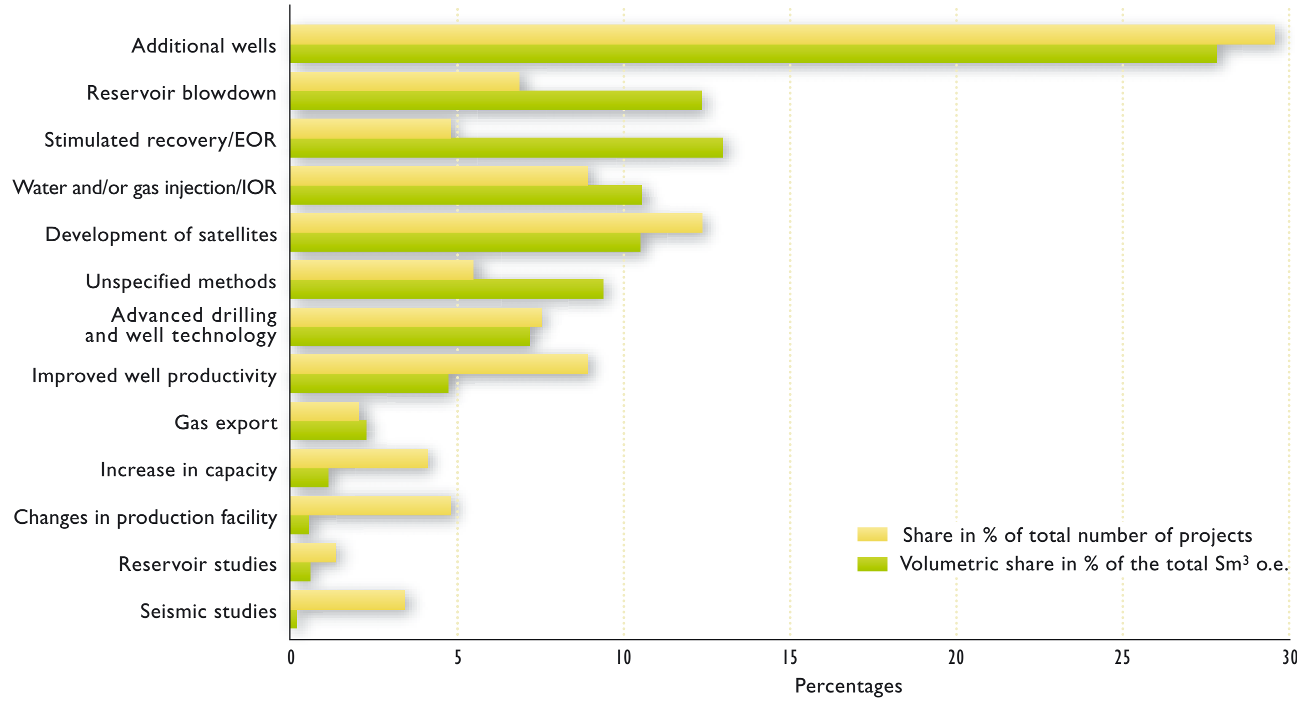


Figure 5.17
Distribution of the potential for improved recovery from various measures planned on fields in production. Most of the projects and the highest potential volumes concern drilling of additional wells.

A large part of the potential in the largest category, "additional wells", presupposes technological development in drilling to improve profitability. Almost half the potential volume for improved recovery of oil and gas from the fields will require technological development to be realised, and most of this is considered to be time critical (Figure 5.18). The greatest potential lies in methods for improved oil recovery, followed by drilling. Developing drilling technology is also considered to be time critical.

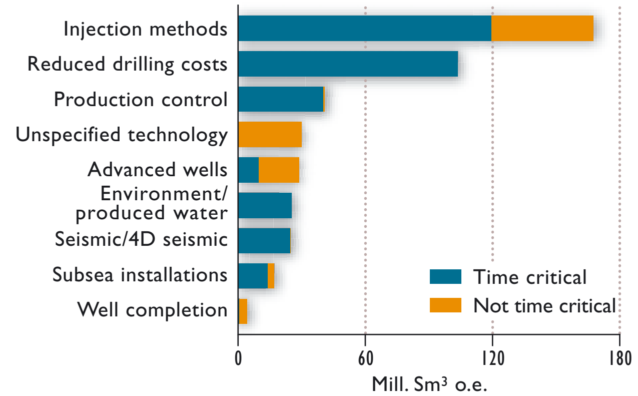


Figure 5.18
Types of technology where there is a need for research and development to be able to realise improved recovery volumes on the fields.

5.6 THE COST SITUATION

High operating costs at several old field centres, combined with falling production in recent years, give higher unit costs. To be able to prolong the economic lifetime of the individual fields it is therefore essential to reduce the operating costs and/or raise the production by phasing in new deposits or implementing measures for improved oil recovery (Figure 5.19).

For the industry, the high operating costs are a great challenge which will necessitate solutions such as transfer of functions to joint facilities or to land (remote control). Pressure on established standards for operations may also arise. Reducing work forces by changing the organisation of maintenance and operation is particularly likely in areas where co-ordination of such functions between several installations is possible, such as the Tampen area.

The forecast made by the operators for the total investments in the North Sea shows a strong decline from about 2005 (Figure 5.20). The larger field developments for which decisions to develop have been taken are expected to be completed by then. Investments in new installations have decreased since 1998 and if no new discoveries are developed, or no additional facilities are built on existing fields, the investments will continue to drop. Investments in subsea developments account for about 30 per cent of the investments in new installations (Figure 5.21).

Modification of existing installations will make up an increasing proportion of the investments in the next few years. This includes major modifications to increase capacity and to adapt the facilities to more stringent environmental demands and late-phase

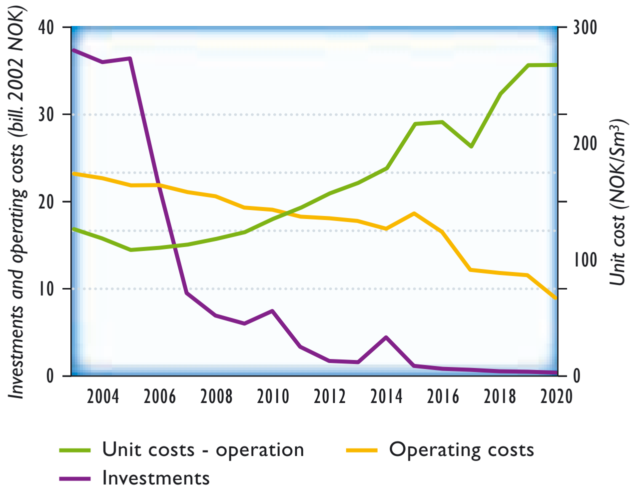


Figure 5.19
Forecasts of unit costs, investments and operating costs in the North Sea (excluding Troll gas).

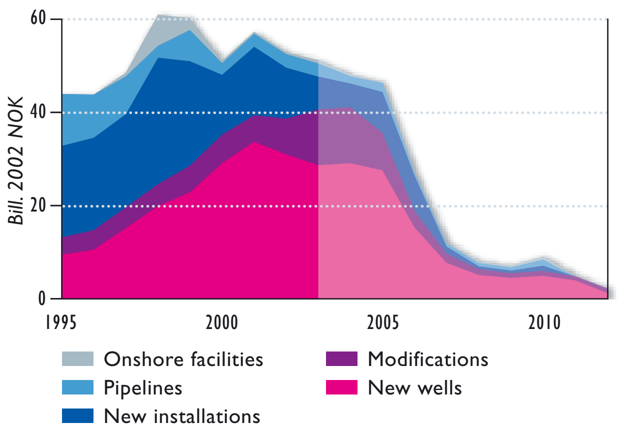


Figure 5.20
Historical and forecasted investments in the North Sea arranged according to type of investment.

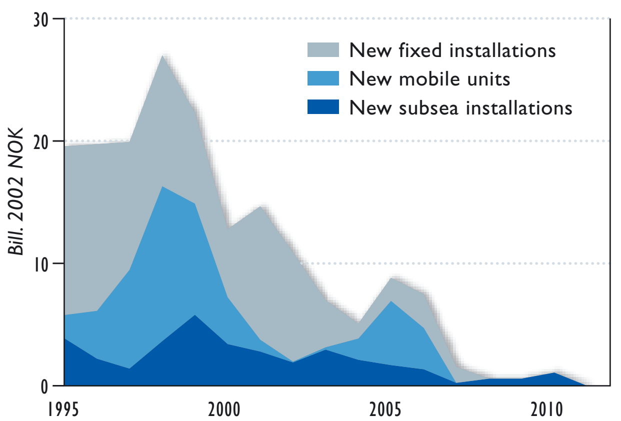


Figure 5.21
Historical and forecasted investments in the North Sea for various types of facilities. The distribution of the investments is uncertain for projects that are being planned. The share in the investments for subsea installations does not seem to increase at the expense of fixed installations.

production. If many of the projects identified for possible increased value creation on the fields can be realised, these investments, in common with investments in new wells, will remain high beyond 2005.

Since the volume per new production well in mature fields is declining, it is vital to reduce drilling costs. This applies especially to fields with subsea development, where mobile drilling units must be used for drilling and well interventions. The average cost per well on such fields is one and a half to twice that on fields with their own drilling rig.

5.7 FIELDS IN LATE-PHASE PRODUCTION

Of the large fields that started production in the 1970s and 1980s, only the largest chalk fields in the far south of the North Sea are still in their plateau phase. Great uncertainty attaches to the duration of the late production phase (Figure 5.22).

There are several ways of maintaining the production. For instance, blowdown can give increased value creation in the late phase of the large fields. This provides for producing the remaining and injected gas in the field, together with accompanying oil and water, without compensating with pressure support (Figure 5.23). The Statfjord field has come far in planning a possible blowdown phase, which may extend the lifetime of the field by around ten years.

A new aspect in the North Sea is new companies who wish to specialise in tail production. There are several examples from the British shelf of a new operator in the late phase being able to revitalise a field and significantly extend its lifetime.

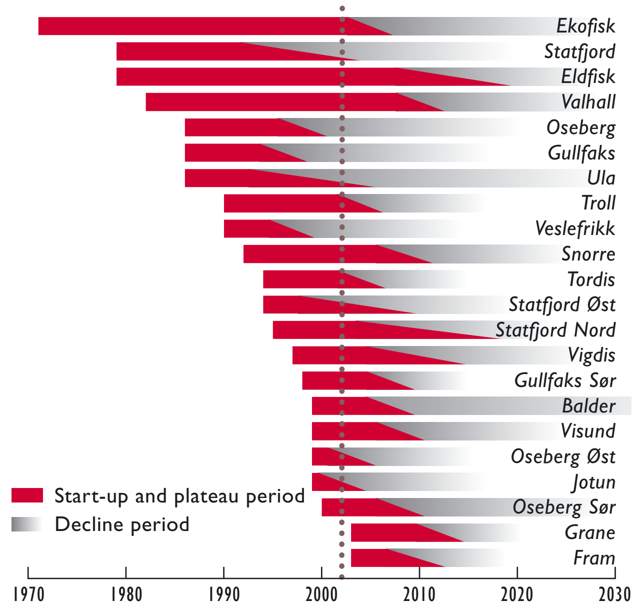


Figure 5.22
Production and decline phases for 22 North Sea fields.

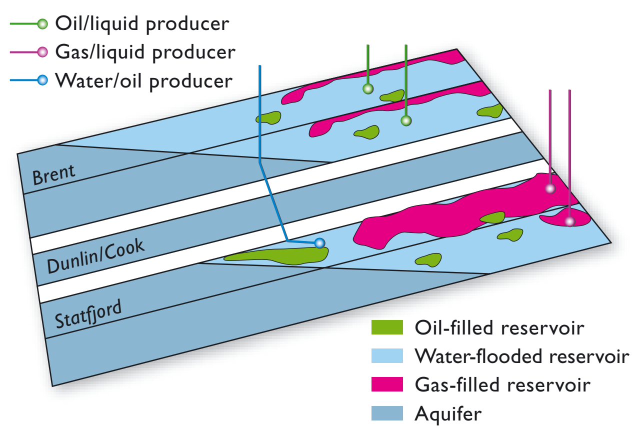
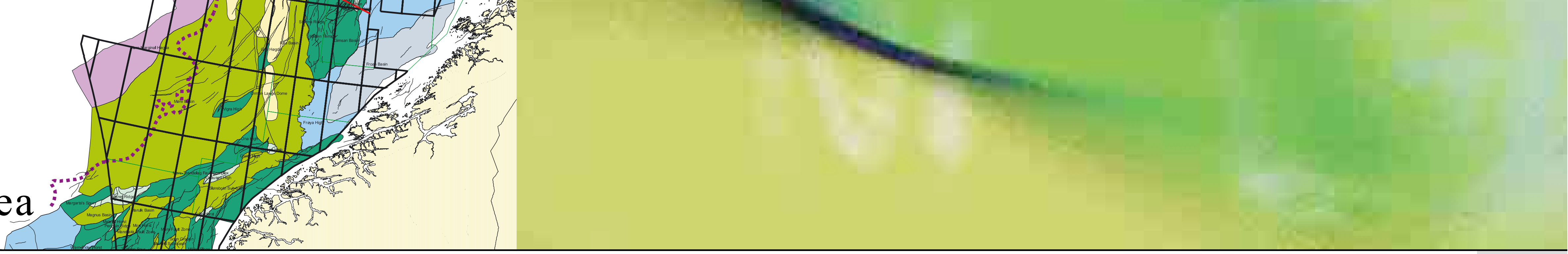


Figure 5.23
The principles of blowdown on the Statfjord field.



6 The Norwegian Sea

6.1 CHALLENGES AND TRENDS

The production in the Norwegian Sea began in 1993 with oil production on the Draugen field.

The gas production will increase markedly in the future, especially after 2007 when 6305/6-1 Ormen Lange is expected to go into production (Figures 6.1 and 6.2).

The total production of liquids from the fields, in contrast to the gas production, will reach the decline phase shortly. The most important discoveries that can help to maintain the production of liquid are 6507/5-1 Skarv and 6407/1-2 Tyrihans, but both require a means to transport gas before they can be developed.

Despite the reduction relative to the earlier estimate, there is a large, undiscovered resource potential in the Norwegian Sea. The result of play analyses shows that about 20 per cent of the undiscovered resources are in the area off Lofoten.

Establishing more capacity to transport gas out of the area is an important premise for continued high exploration activity and maturing of resources in the Norwegian Sea. New, large discoveries may form the basis for new infrastructure. If such discoveries are not made, the establishment of new infrastructure will need to be achieved by co-ordinating small discoveries in different production licences. This will be demanding. A number of small discoveries have already been made which can be developed as satellites to existing infrastructure. Individually, these discoveries have marginal profitability owing to their size and the complexity of their reservoirs.

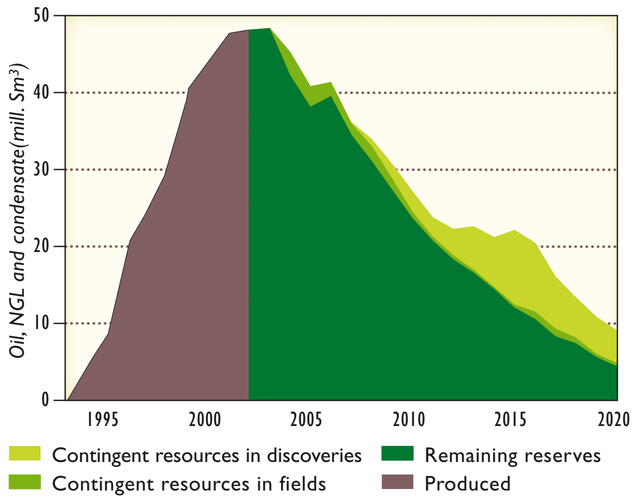


Figure 6.1
Historical and forecasted liquid production from the Norwegian Sea.

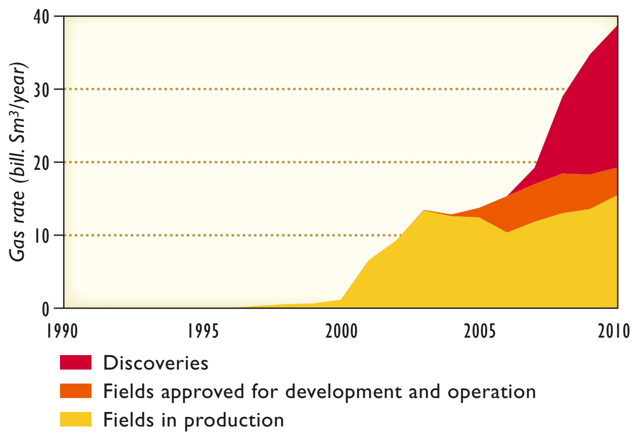


Figure 6.2
Historical and forecasted gas production from the Norwegian Sea.

6.2 THE RESOURCE BASE

The total recoverable petroleum resources in the Norwegian Sea are 3065 million Sm^3 o.e., 977 million Sm^3 of which are oil, 1822 billion Sm^3 gas, 69 million tonnes NGL and 134 million Sm^3 condensate (Figure 6.3).

The reduction in the estimate for the undiscovered resources in the Norwegian Sea affects both the well-known area on the Halten Bank, where most of the discoveries have been made, and the unknown area in the Vøring Basin. The most important play on the Halten Bank is now expected to have fewer and smaller future discoveries than assumed earlier. The play analyses for the Vøring Basin show less likelihood of making discoveries, and smaller discoveries, than previously assumed. Positive drilling results in these areas may change this picture.

Over half of the liquid resources in the Norwegian Sea have either been sold and delivered or are reserves that are approved for production, whereas a third have not yet been discovered.

Undiscovered resources make up 44 per cent of the gas resources. If contingent gas resources in discoveries are included, the proportion rises to 80 per cent. This illustrates a key point, namely that, as regards gas, the proportion of resources for which no decision on production has been taken is large.

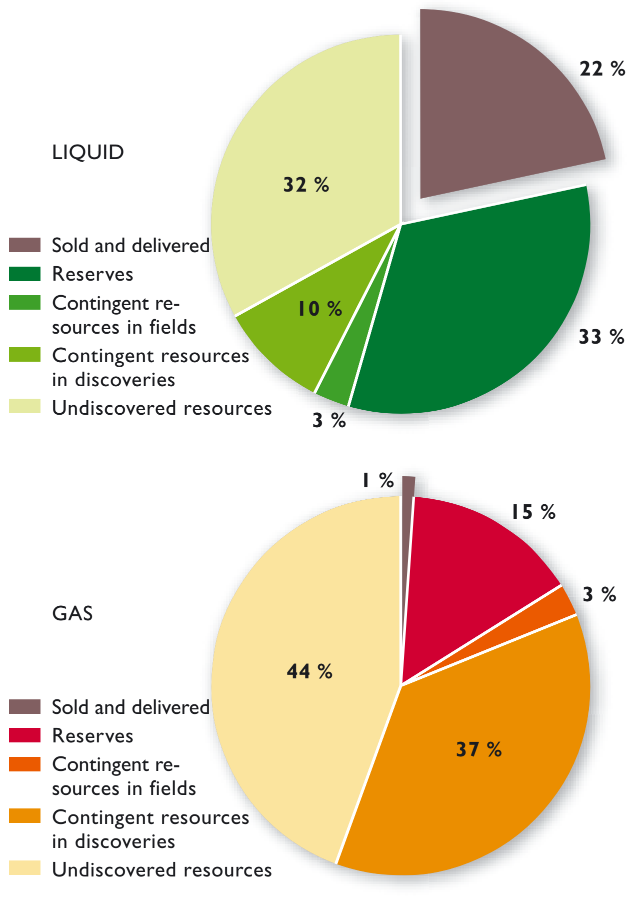


Figure 6.3
Distribution of the liquid and gas resources in the Norwegian Sea.

The petroleum resources on the Norwegian continental shelf 2003

Almost 80 per cent of the remaining, discovered liquid resources are in fields that are in production (Figure 6.4). The situation is the opposite for gas in that a third is linked to fields and the remainder is in discoveries in the planning phase. The gas resources in 6305/5-1 Ormen Lange amount to 375 billion Sm^3 and make up 56 per cent of the total gas resources in discoveries, which are 670 billion Sm^3.

There are 36 discoveries in the Norwegian Sea (Figure 6.5). Eleven of these are categorised as unlikely to be recovered. Approximately 80 per cent of the gas resources in the 36 discoveries have been found during the last 5 years. Apart from 6305/5-1 Ormen Lange, the discoveries in the area are of moderate size and contain moderate amounts of liquids.

Along with 6507/5-1 Skarv and 6407/1-2 Tyrihans, the planning of 6305/5-1 Ormen Lange is furthest advanced. Development of these discoveries will ensure that the majority of the mature gas resources in the area will be recovered.

6.3 EXPLORATION

The first wildcat well in the Norwegian Sea was spudded in 1980 and the first discovery (the Midgard gas discovery, now part of the Åsgard field) was made in 1981. By 31 December 2002, 181 exploration wells had been drilled in the Norwegian Sea (Figure 6.6).

Most of the activity in the Norwegian Sea is taking place in the geological provinces called the Halten Terrace and the Dønna Terrace, often jointly called the Halten Bank. This area is the most mature and in this respect it can be compared with mature areas in the North Sea. The other areas in the Norwegian Sea are comparatively little explored, especially those in deep water, the Møre Basin and the Vøring Basin, and the areas off Lofoten (Nordland VI and VII).

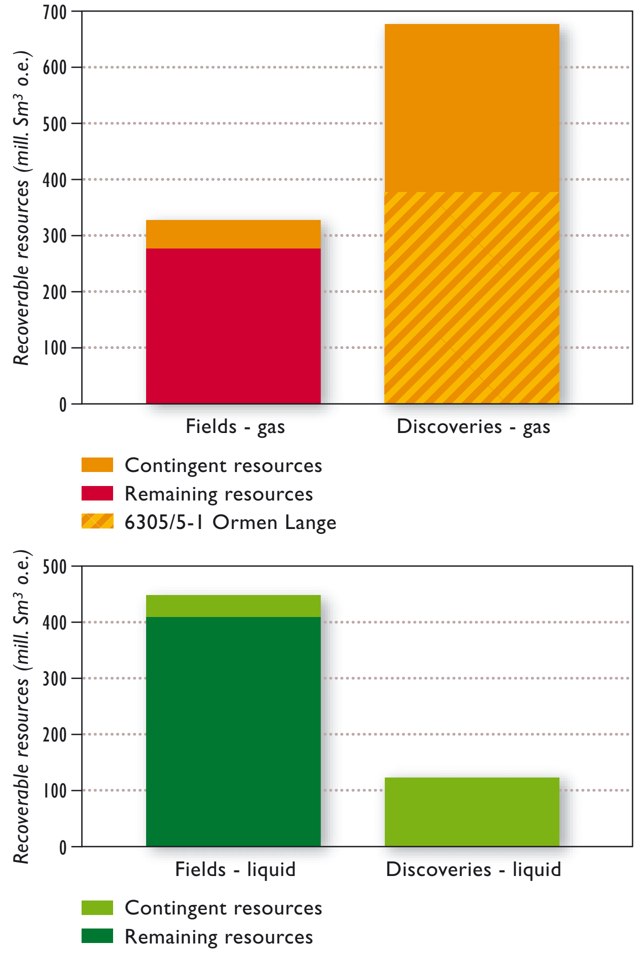


Figure 6.4
Distribution of remaining gas and oil resources in fields and discoveries in the Norwegian Sea.

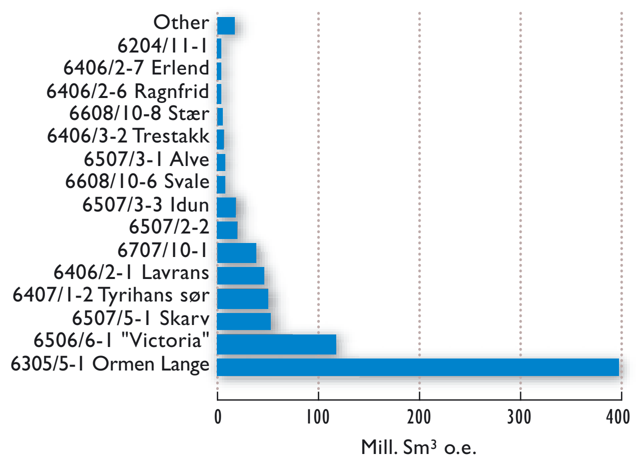


Figure 6.5
Discoveries in the Norwegian Sea arranged according to the size of gas resources.

An average of approximately six wildcat wells have been drilled annually in the last 3 years (2000, 2001 and 2002) (Figure 6.7). It is planned to drill six to eight wildcat wells in the Norwegian Sea in 2003. Two had been completed by 10 June 2003. Well 6608/10-9 made a discovery near the Norne field and well 6706/6-1 on the Naglfar Dome made a technical gas discovery.

Large parts of the Norwegian Sea have been opened for exploration, but the areas along the coast of Nordland, parts of Nordland VI and the whole of Nordland VII, have not been opened. Stortinget (the Norwegian Parliament) voted to open the Vøring and Møre Basins and large parts of Nordland VI for exploration in 1994. Special limitations were attached to the parts of Nordland VI that were opened. Two production licences were awarded in the opened area in Nordland VI in the 15th licensing round in 1996. One well, 6710/10-1 in production licence no. 220, was drilled in 2000 in this area. Petroleum was not discovered. Any further activity depends on the ongoing consideration of the Lofoten-Barents Sea Impact Assessment Report.

The Halten Bank was included in the predefined area announced at the end of May 2003.

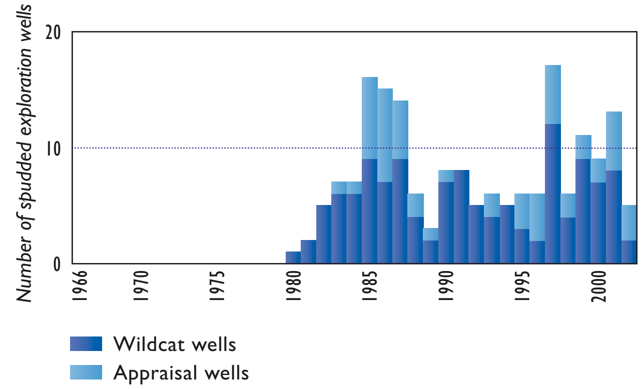


Figure 6.6
Spudded exploration wells in the Norwegian Sea.

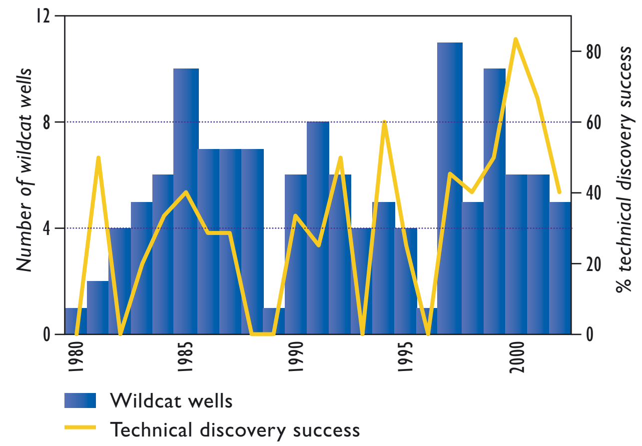


Figure 6.7
Number of wildcat wells per year, and annual technical discovery success in the Norwegian Sea.

The petroleum resources on the Norwegian continental shelf 2003

6.4 RESOURCE DEVELOPMENT

The first wildcat well was drilled in 1980 and 3046 million Sm^3 o.e. have been discovered in the Norwegian Sea up to and including 2002 (Figure 6.8). The large jumps in the figures represent the Midgard discovery in 1981, Draugen in 1984 and 6305/6-1 Ormen Lange in 1997. Twenty-seven wildcat wells were drilled between 1991 and 1996, but they resulted in very little growth in the resources. Several years with appreciable resource growth followed after that.

The total production has increased steadily since 1996, and is expected to increase in the years ahead.

The growth in resources and the average size of discoveries have varied considerably over the years (Figure 6.9).

The oil fields in the Norwegian Sea are Heidrun, Draugen, Njord and Norne. Åsgard is a field consisting of three deposits, Midgard, Smørbukk and Smørbukk Sør. Smørbukk Sør is an oil deposit, Smørbukk is a gas/condensate deposit and Midgard is a gas deposit. Condensate and NGL production thus contribute substantially to the production from the Åsgard field. Figure 6.10 shows the growth in the reserves of oil, NGL and condensate in this field, but only the growth in the oil reserves is shown for the other fields.

Three of the fields, especially Draugen, have seen a substantial net growth in their reserves compared with the estimates given in their PDOs. The main reason for this is better reservoir properties than were assumed in the PDOs. An important reason for the negative development in Njord is that the reservoir has poorer production properties than envisaged when the estimates given in the PDO were determined.

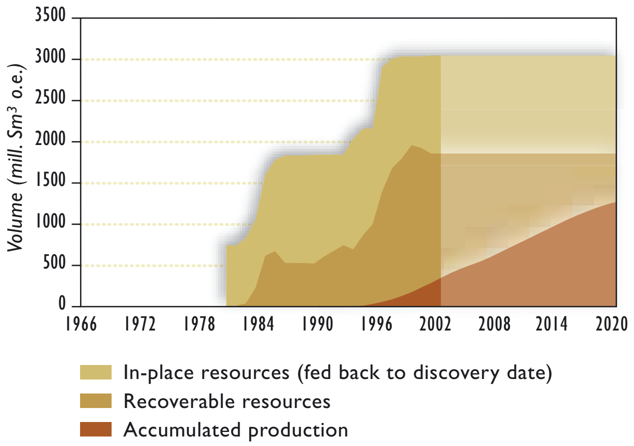


Figure 6.8
Resource development in the Norwegian Sea.

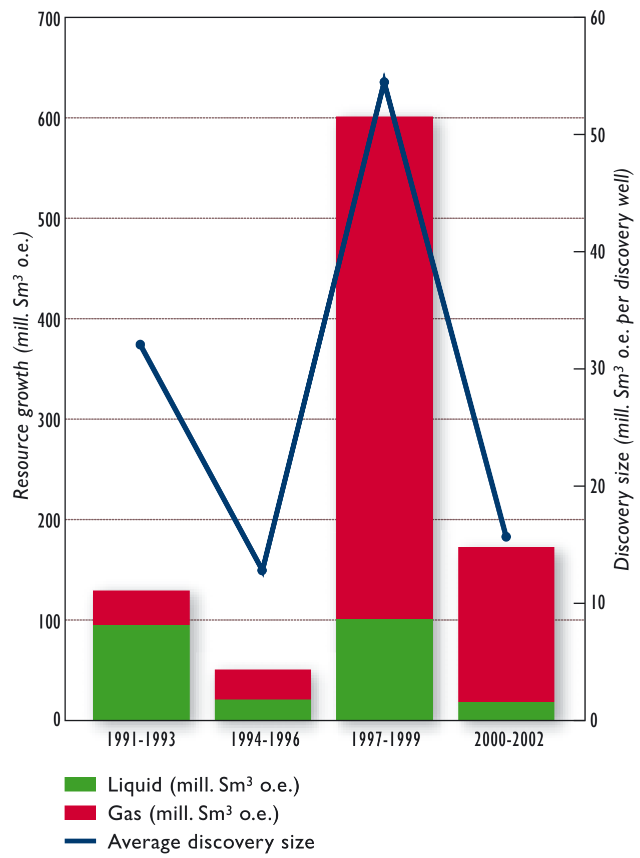


Figure 6.9
Average size of discoveries in the Norwegian Sea in the last 12 years.

The reservoir is more segmented and complicated than originally assumed.

The average recovery factor for oil is 45 per cent for the four oil fields in the Norwegian Sea. The Draugen and Norne fields have recovery factors of 64 and 56 per cent, respectively, which is significantly above the average for oil fields on the continental shelf. The recovery factor for the oil deposit, Smørbukk Sør, on the Åsgard field is about 36 per cent.

Sufficient resources remain in the Norwegian Sea to further raise the recovery factor and the reserves (Figure 6.11).

6.5 INCREASED VALUE CREATION FOR FIELDS IN PRODUCTION

A number of projects with a potential for increased value creation have been identified on all the fields that are in production in the Norwegian Sea. Some of these are projects for improved recovery and some presuppose the use of vacant production capacity to phase in surrounding satellite fields. Likely measures for improved recovery currently being considered include better descriptions of reservoirs, better 4D seismic data, optimisation of the drainage strategy and well arrangement, reservoir monitoring, optimisation of processing capacities, implementation of new technology and injection of gas and water.

In addition to existing fields, the Kristin field is important as regards increased value creation. Production is planned to commence in 2005. Since Kristin will have a very short period on plateau, it is important to plan the phasing in of new discoveries to utilise the capacity available.

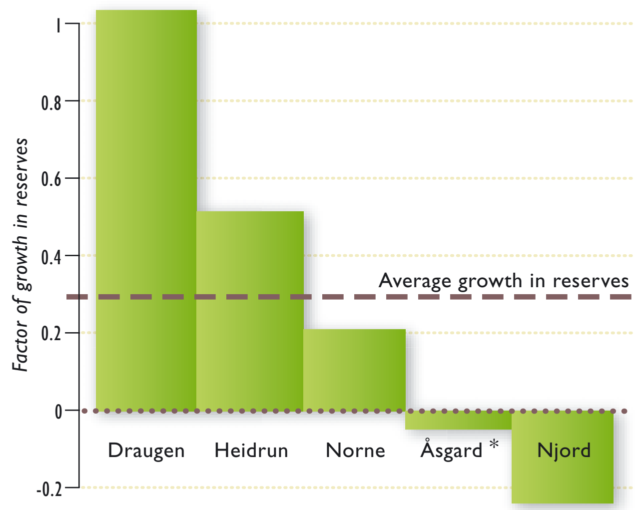


Figure 6.10
Changes in oil reserves relative to reserves estimated in the PDO for fields in the Norwegian Sea. *The growth in reserves for the Åsgard field includes NGL and condensate.

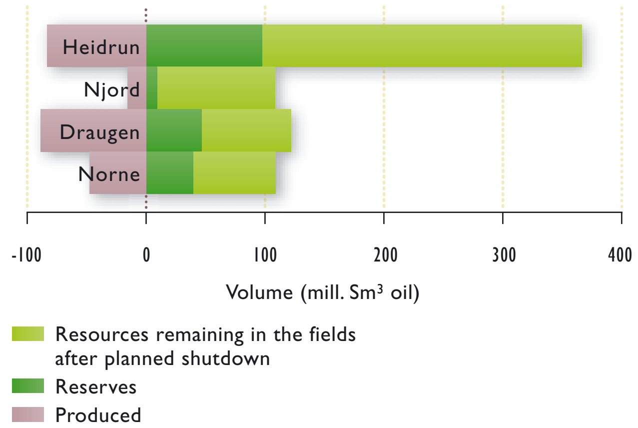


Figure 6.11
Produced oil, reserves and remaining resources according to approved plans.

6.6 GAS TRANSPORT

Åsgard transport (ÅTS) accounts for the greater part of the existing transport capacity out of the area. In addition, there is the Halten pipeline that runs from the Heidrun field to Tjeldbergodden. Additional capacity will become available when a transport pipeline from 6305/5-1 Ormen Lange has been completed. The ÅTS and Halten pipelines are used for wet gas, whereas the pipeline being planned for 6305/5-1 Ormen Lange is for dry gas (Figure 6.12).

The capacity in the Åsgard pipeline is almost fully utilised by existing fields in the area (Figure 6.13). The capacity situation suggests that it may be difficult to obtain sufficient space in the Åsgard pipeline for discoveries in the Norwegian Sea unless the gas in these discoveries is phased in gradually, as capacity becomes available. The ÅTS capacity can be extended, but scarcely enough to fully cover the requirements.

The transport capacity planned for 6305/5-1 Ormen Lange will only to a limited extent cover transport requirements beyond those of the field itself.

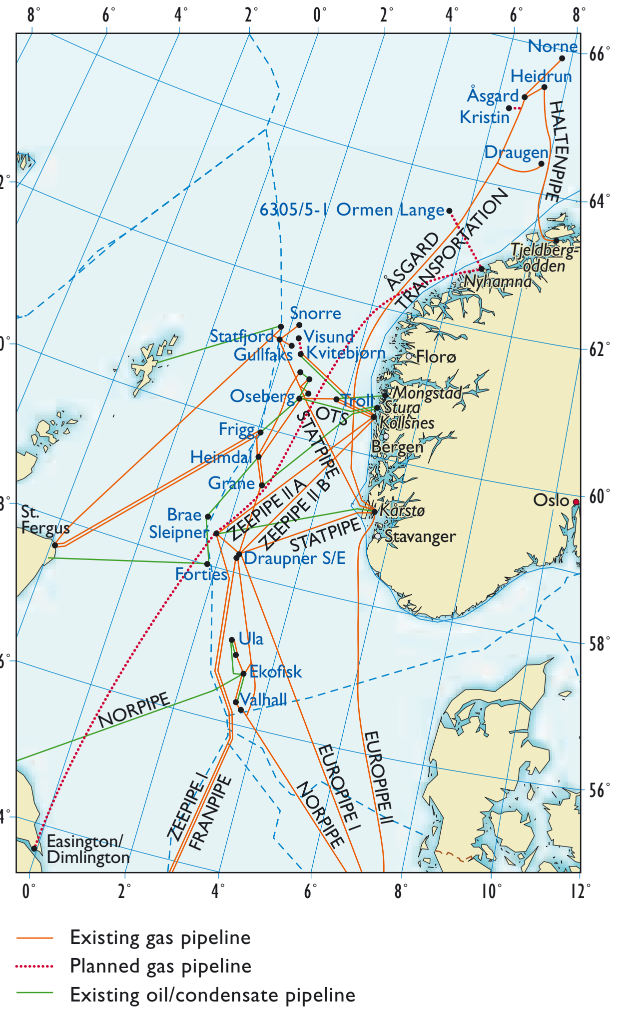


Figure 6.12
Transport systems for gas.

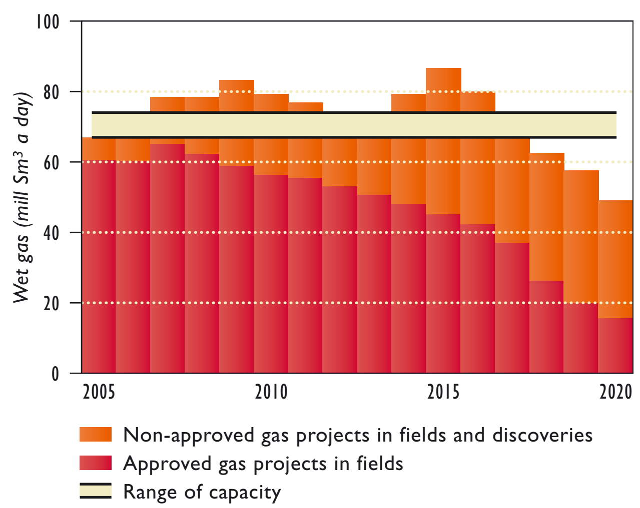


Figure 6.13
Illustration of the capacity situation for the Åsgard transport system. Non-approved gas projects in fields and discoveries include those where a need for transport has been indicated over and above present-day reservations. This applies to the Heidrun, Njord and Åsgard fields, and the 6407/1-2 Tyrihans, 6507/5-1 Skarv, 6507/5-3, 6507/3-3 Idun, 6507/2-2 and 6707/10-1 discoveries.

6.7 THE COST SITUATION

NOK 151 billion (fixed 2002 NOK) have been invested in the development of fields in the Norwegian Sea since the start in 1987. The Heidrun and Åsgard fields account for the dominant proportion. The expected investment level for 2003 is around NOK 13 billion, which is also the sum expected for 2004 and 2005. A large part of the investments in the next few years is expected to be linked to 6305/5-1 Ormen Lange. Otherwise, the investment level in the years ahead will depend on the extent to which new transport capacity is established (Figure 6.14).

Several factors make it more technically and financially demanding to develop and operate fields in the Norwegian Sea than in the North Sea. There will probably be more developments of reservoirs with high pressure and high temperature (HPHT) in the Norwegian Sea. Among the consequences of this are higher drilling costs because of the need for more advanced drilling equipment, higher well costs and more technically demanding development solutions (Figure 6.15). Examples of reservoirs in this category are Smørbukk on Åsgard, the reservoir on Kristin and the reservoirs in discoveries around Kristin.

Longer distances to the markets mean substantially higher gas transport costs compared with the North Sea.

Production in this area will probably also entail higher costs to take care of special environmental concerns. This may, for example, be linked with restrictions regarding when drilling can be undertaken (drilling window) and more stringent demands on development and transport solutions.

Developments in deep water will be more challenging, due to both the deep water and complicated conditions on the sea bed.

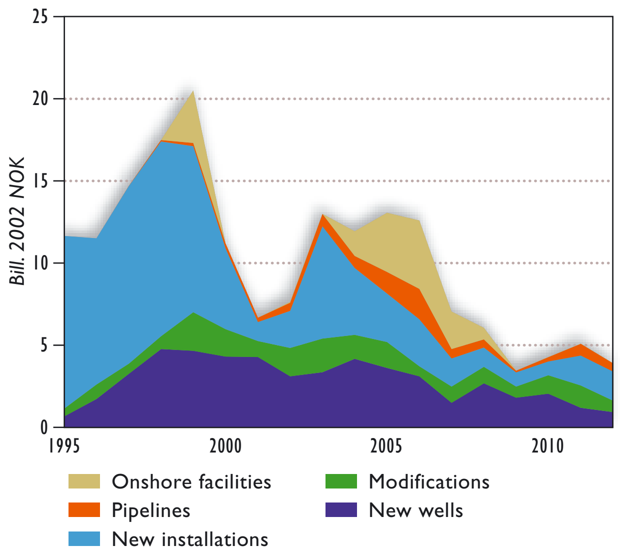


Figure 6.14
Historical and forecasted investments for fields and discoveries in resource categories 0-4 in the Norwegian Sea.

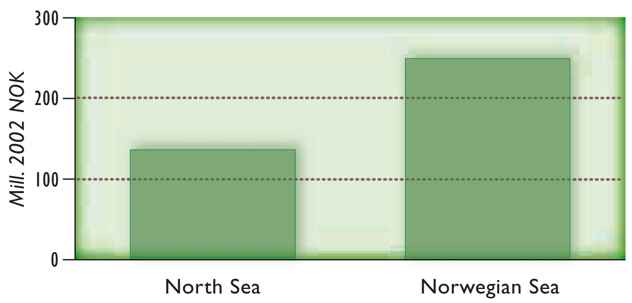


Figure 6.15
Average costs per well for resource categories 0-4 in 1996 - 2002.

7 The Barents Sea

7.1 CHALLENGES AND TRENDS

There are still good possibilities for making both oil and gas/condensate discoveries in the Barents Sea. The results of the latest wells drilled in the Barents Sea were encouraging and the area may prove to add considerably to the already recoverable resources. The Barents Sea and the areas in the Norwegian Sea in deep water and off Lofoten are believed to constitute a petroleum province where it is feasible to make large discoveries in the future.

Solving the transporting of gas is a challenge facing the petroleum activity in the Barents Sea. Transport in a pipeline is not currently expedient. The distance to present-day gas markets is too long. In 2002, it was decided to develop the Snøhvit field using ships to transport the gas in liquefied form. This has provided a basis for possible gas sales from other, future developments in the area, too.

No wells were drilled in the Barents Sea in 2002, nor are any expected to be drilled in 2003. Any further exploration work in the area depends upon the conclusions of the future deliberations of a recently published report regarding the consequences for the environment, fisheries and society in general of year-round petroleum activity in the area. The report has been distributed for comments.

Figure 7.1
Norwegian and Russian sectors of the Barents Sea.

The development of petroleum activity in the Russian sector is an important factor for activity in the Barents Sea (Figure 7.1). Production from the large Prirazlomnoye oil discovery is planned to start at the end of 2005, and Russian authorities expect to announce and award several offshore production licences in the next few years. The results of exploration in the Russian sector may have significance for our understanding of the geology in the Norwegian side. Several fields on land are in production and since 2001 oil has been transported to the market by oil tankers sailing westwards through the Norwegian part of the Barents Sea.

7.2 EXPLORATION

A total of 39 production licences have been awarded and 61 exploration wells have been drilled in the Barents Sea since 1980 (Figure 7.2). Most of the wells have been drilled in or close to the Hammerfest Basin, which is the most explored part of the Barents Sea. The first well in the Hammerfest Basin was drilled in 1980, and the first discovery, 7120/8-1 Askeladd, was made in the fourth well in 1981. The Snøhvit field, which contains gas, condensate and oil, and 7122/7-1 Goliat, an oil discovery, are situated in the Hammerfest Basin.

No wells were drilled in the Barents Sea from 1995 to 2000, mainly because exploration results had been disappointing. To boost activity in the area, changes were made to the external constraints for new allocations in the Barents Sea. The awards following the Barents Sea Project were made in 1997. The oil discovery, 7122/7-1 Goliat, was proven in one of these licences (no. 229) in 2000. Eight exploration wells were drilled in 2000 and 2001. The growth in gas resources has been good and several of the production licences have revealed a number of small and medium-sized gas discoveries (Figures 7.3 and 7.4).

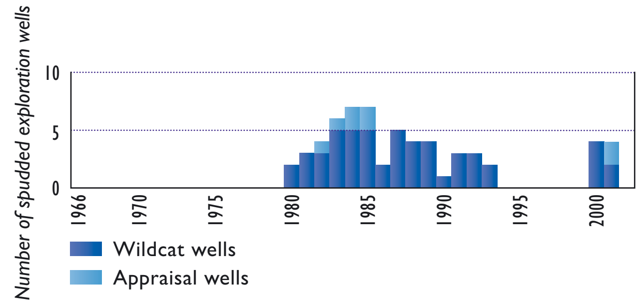


Figure 7.2
Spudded exploration wells in the Barents Sea.

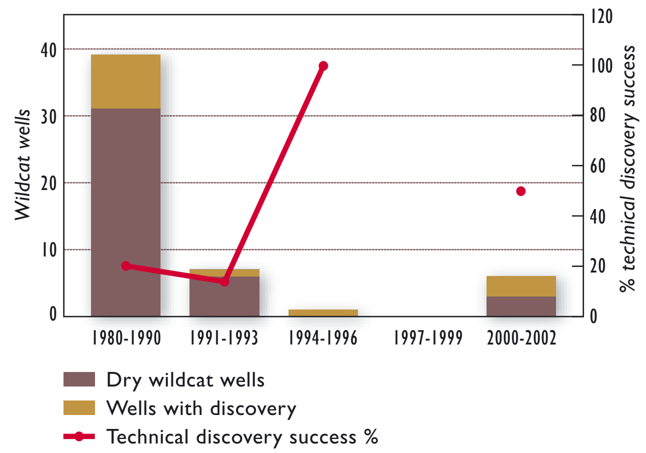


Figure 7.3
Wildcat wells and technical discovery success in the Barents Sea in 1980 - 2002.

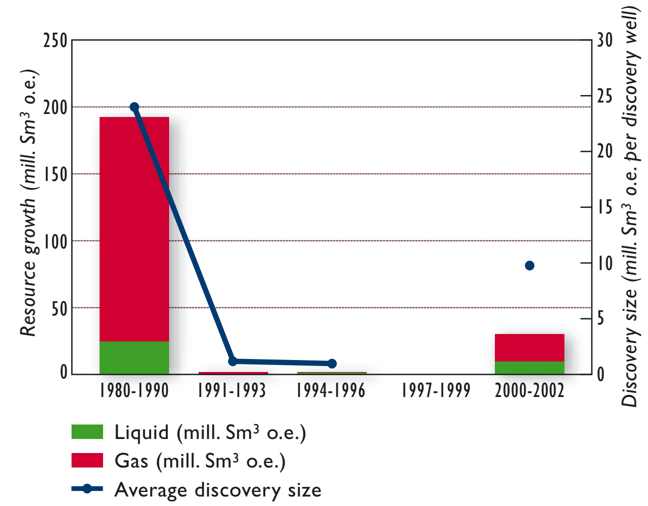


Figure 7.4
Average size of discoveries and recoverable resources discovered in the Barents Sea in 1980 - 2002.

Access to exploration areas

The most recent production licences in the Barents Sea were awarded in 1997. Until recently, the oil companies have shown comparatively little interest for new allocations in the area. Favourable results from the drilling done in 2000 and 2001 and approval of the Snøhvit development have, however, brought increased interest. Stortinget (the Norwegian Parliament) opened up large parts of the Barents Sea south of 74°30' for exploration in 1989. Further awards and drilling must await the outcome of the debate on the Lofoten-Barents Sea Environmental Impact Assessment Report.

7.3 THE RESOURCE BASE

The total petroleum resources in the Barents Sea, as of 31 May 2003, are 1220 million Sm^3 o.e. Approximately 90 per cent of the liquid resources, amounting to 450 million Sm^3 o.e., remain undiscovered (Figure 7.5). The liquid reserves in the Barents Sea, amounting to 6 per cent, comprise NGL and condensate from the Snøhvit field, the oil in the oil zone there being classified as contingent resources.

The gas in the Snøhvit field comprises almost a quarter of the gas resources in the Barents Sea, which amount to 770 billion Sm^3 (Figure 7.6). The remaining three-quarters are undiscovered.

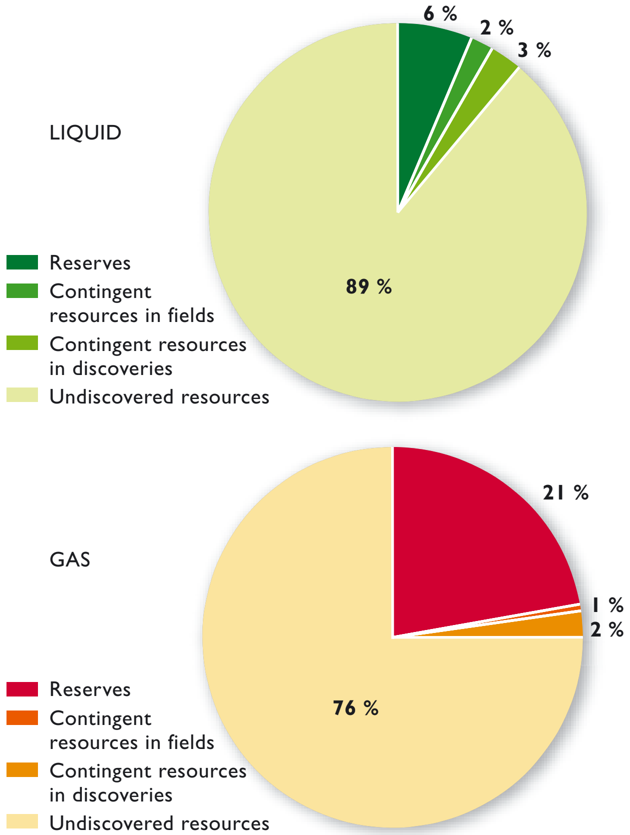


Figure 7.5
Distribution of the total liquid and gas resources in the Barents Sea (450 million Sm^3 o.e. of liquid and 770 billion Sm^3 o.e. of gas).

7.4 DEVELOPMENT

Stortinget (the Norwegian Parliament) approved the plan for development and operation (PDO) and the plan for installation and operation (PIO) for Snøhvit LNG (Liquefied Natural Gas) in March 2002. This is the first field to be developed in the Barents Sea. The development embraces the gas resources in the 7121/4-1 Snøhvit, 7120/8-1 Askeladd and 7120/9-1 Albatross discoveries. Recoverable resources amount to 161 billion Sm^3 of gas, including CO_2, 5 million tonnes of NGL and 18 million Sm^3 of condensate. Production from the Snøhvit field is planned to begin at the end of 2005 and is expected to continue until 2035.

The development comprises sub sea installations that will pipe gas and condensate in a multiphase pipeline to a facility on the island of Melkøya, close to Hammerfest (Figure 7.6). On Melkøya, the gas will be processed and refrigerated to liquefied form (LNG). It will then be sent to the market in specially designed ships. NGL and condensate will be exported separately by ship. CO_2, contained in the gas, will be removed in the facility on Melkøya and returned to the Snøhvit field in a separate pipeline for injection into a geological formation beneath the oil and the gas.

The development does not include the oil zone in the field. The estimate for the recoverable oil resources in the Snøhvit field is approximately 7.9 million Sm^3. A critical time factor is present regarding any extraction of the oil from the field because the start of gas production will lead to loss of pressure and loss of oil if oil production does not start sufficiently early.

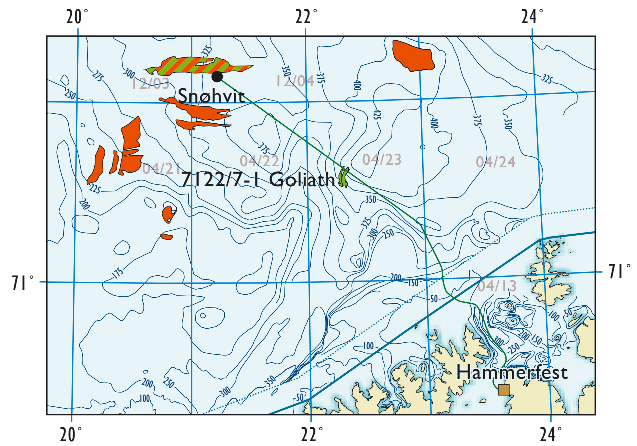


Figure 7.6
Map showing the Snøhvit development.

8 Forecasts

8.1 PRODUCTION

Forecasts have been made for how the resources are expected to be recovered, for costs and for discharges and emissions to the environment. These are based on data from the operators and evaluations on the part of the authorities. Production is continuing to rise and is expected to peak in 2006 at about 275 million Sm³ o.e. (Figure 8.1).

Oil production has remained at a stable, high level since 1996. From 1996 to 2004, it is expected to be between 170 and 182 million Sm³ a year (Figure 8.2). A total production of 785 million Sm³ of oil is predicted in the next 5-year period (2003 - 2007). More than 90 per cent of the oil production up to 2013 will come from fields that are already producing or a decision to develop them has been taken. In the same period, 132 million Sm³ o.e. of NGL and condensate are expected to be produced annually.

According to the forecast, the gas market will rise from the current level of gas sales, approximately 65 billion Sm³ of gas a year, to 110 billion Sm³ in 2010. The proportion of gas in the total production will rise to 50 per cent in 2012 or 2013 (Figure 8.3).

8.2 ASSESSMENT OF PRODUCTION

We still do not know the total oil and gas resources of the Norwegian continental shelf. After 37 years of exploration and 32 years of production, the quantity of undiscovered resources is still uncertain, as, too, is the quantity of discovered resources that can be commercially recovered. Consequently, the longer term forecasts are highly uncertain. The levels of investments and operating costs are most important for the demand for other industries that create many jobs.

Future discharges and emissions to the environment will mainly be determined by the production level and the activities to improve recovery from existing fields. In addition to uncertainty regarding volumes, described in Chapter 2, there will also be uncertainty about future decisions. This applies, among other things, to which projects for improved recovery will be approved for carrying out and how many discoveries will be approved for development. The uncertainty is greatest with respect to the quantity of undiscovered resources that will be discovered and produced. This is partly connected with future exploration activity.

Realising the undiscovered resources presupposes many decisions where profitability for the players is a key element. The profitability of projects on the Norwegian continental shelf is shown in Figure 8.4. The project portfolio consists of all the projects that have been reported to the authorities, and covers resource categories 1-4 (cf. section 2.1).

Many projects are profitable even with an oil price down towards NOK 100 a barrel during the entire production period. The majority of these projects will probably be realised. Several factors may postpone or prevent decisions to implement projects. Important among these are great uncertainty in production and costs, and waiting for vacant capacity on infrastructures. In addition, the companies may have other profitability criteria than those used in socio-economic evaluations.

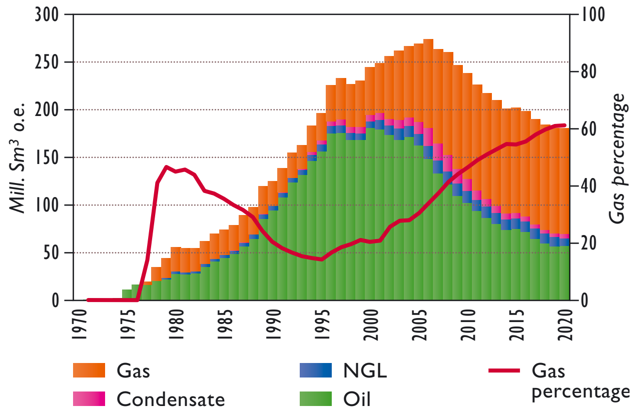


Figure 8.1 Historical production and forecasts for the total production on the Norwegian continental shelf.

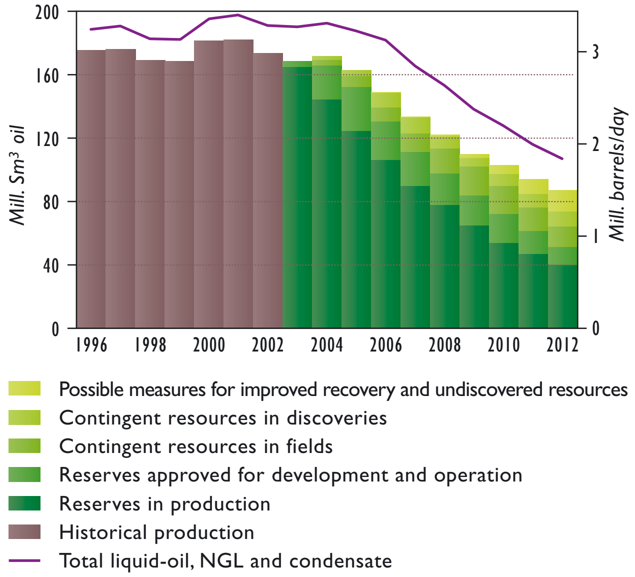


Figure 8.2 Historical oil production from 1996 and forecast until 2012.

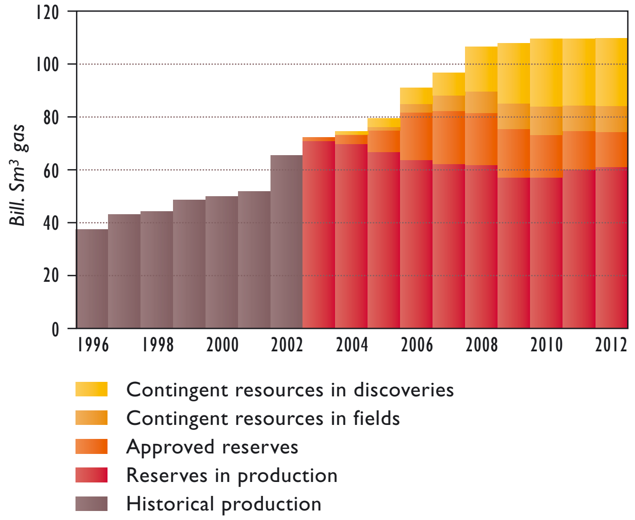


Figure 8.3 Historical gas production from 1996 and forecast until 2012.

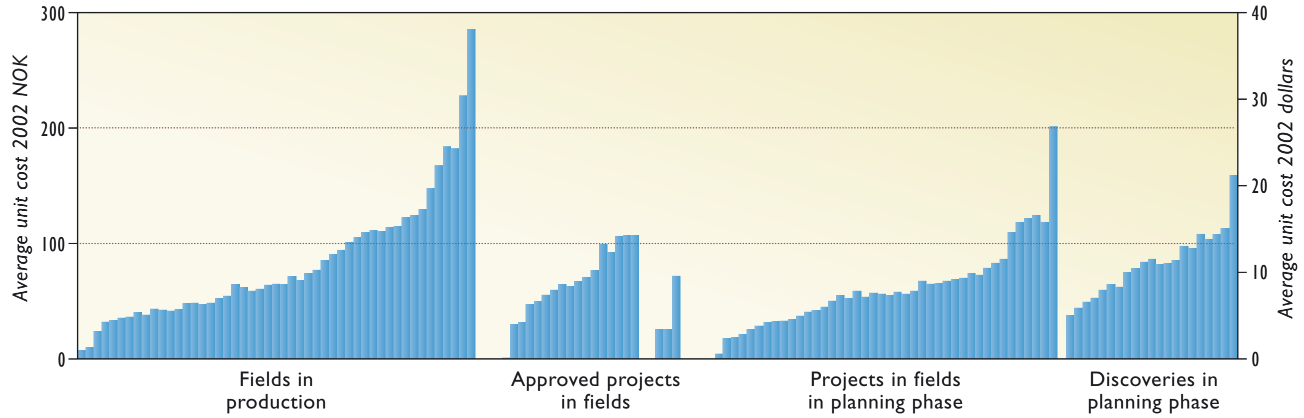


Figure 8.4
Profitability of projects on the Norwegian continental shelf. The estimate is based on a required real return of 7 per cent. Average unit cost indicates the oil price that gives a net present value equal to zero, i.e. the oil price that gives a real return of 7 per cent.

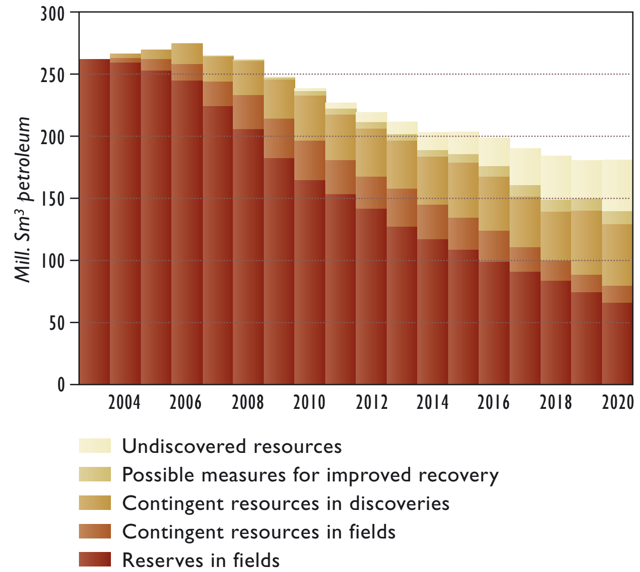


Figure 8.5
Forecasts for the remaining, recoverable resources on the Norwegian continental shelf.

The petroleum resources on the Norwegian continental shelf 2003

8.3 CHALLENGES ATTACHED TO REMAINING RESOURCES

The total forecast shows how the recoverable resources considered in Chapter 2 are now expected to be produced (Figure 8.5). The reserves correspond to expected production from projects that have already been approved. The basis for the forecast concerning discovered resources is the reports from the companies (in autumn 2002) to the authorities in connection with the Revised National Budget for 2003. The basis for the accruement of the undiscovered resources is NPD's estimation of these and an exploration activity like that of the 1990s.

Reserves

Reserves are remaining, recoverable, saleable petroleum resources which the licensees have decided to recover. The estimated reserves in fields may in some cases be difficult to realise with given recovery strategies. In many cases, the costs need to be increased to recover the approved reserves (Figure 8.6). Drilling more wells than planned accounts for most of this increase.

Improved recovery on fields

Improved recovery on fields constitutes 13 per cent of the remaining, recoverable resources. There are more than 100 concrete plans or possible measures for improved recovery on the fields that are currently in production. All told, this represents more than 900 million Sm³ o.e., and around 70 per cent of this is oil. The greatest potential is found in the southern North Sea (Figure 8.7). The average recovery factor for oil has scarcely increased during the last five years (Figure 2.8). It will therefore be difficult to reach the target of a 50 per cent average recovery factor set by the authorities, but this can be achieved if all the concrete projects and possible measures are undertaken. This will, among other things, require different recovery strategies, rebuilding of installations on some fields or building of new ones, and new ways of extracting the remaining resources that are difficult to reach.

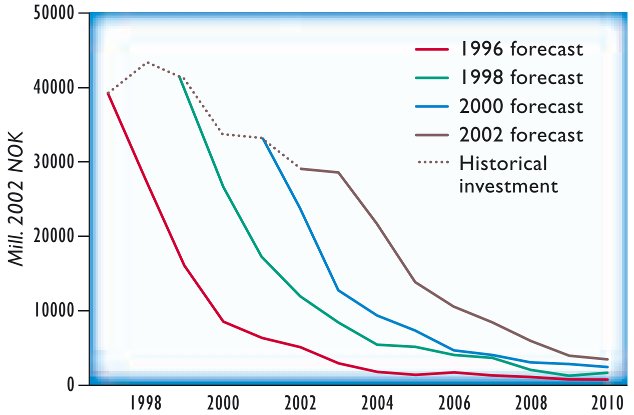


Figure 8.6
Comparison of investment forecasts for fields approved before 1997.

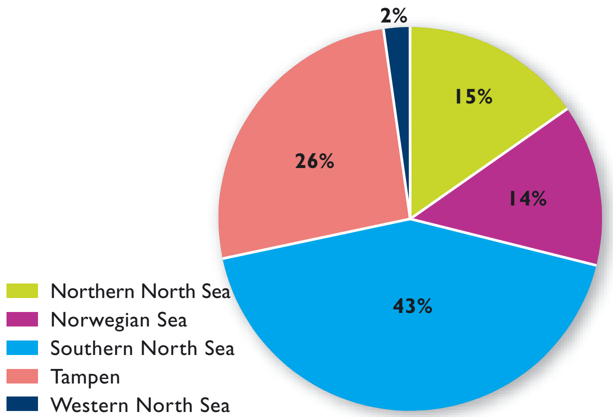


Figure 8.7
Geographical distribution of specific plans or possible measures for improved recovery on fields in production.

Discoveries

Discoveries which have still not been approved for development account for 11 per cent of the remaining, recoverable resources. The portfolio consists of 21 discoveries in the planning phase (resource category 4) and 42 where recovery is likely, but not clarified (resource category 5). The resources make up 1110 million Sm³ o.e., 60 per cent of which are in the planning phase. Discovery 6305/5-1 Ormen Lange alone accounts for a third of the resources (Figure 8.8). A decision to develop this discovery is expected in 2003.

The greatest uncertainty attached to the development of discoveries is access to infrastructure. In addition, some discoveries may be difficult to recover because of reservoir complexity and liquid properties. Moreover, the recovery of resources in discoveries close to the many fields in the North Sea is a matter of urgency in relation to the lifetime of the installations.

Undiscovered resources

Undiscovered resources make up 40 per cent of the remaining, recoverable resources. With the present-day exploration activity, with 12-16 wildcat wells planned in 2003, it will be difficult to find and produce all these resources. An average of 18 wells a year have been drilled in the last 5 years (Figure 4.1). With the expected probability and size of discoveries, the exploration activity should be raised to close on 30 wildcat wells a year for a period, as it was in the 1990s. It may be difficult to get the companies to look for the smaller prospects.

The total undiscovered resources are roughly equally distributed between the North Sea, the Norwegian Sea and the Barents Sea, but almost half of the liquid resources are in the North Sea. It will thus be important to have prospects drilled that are close to existing infrastructures. If drilling in the North Sea does not increase, this will, viewed in isolation, reduce the expectation of recoverable oil resources in the area. In other words, the oil production in 2020 will be two-thirds of the current forecast if the exploration for oil and the growth in oil resources experienced in the last 5 years become representative for the future (Figure 8.9).

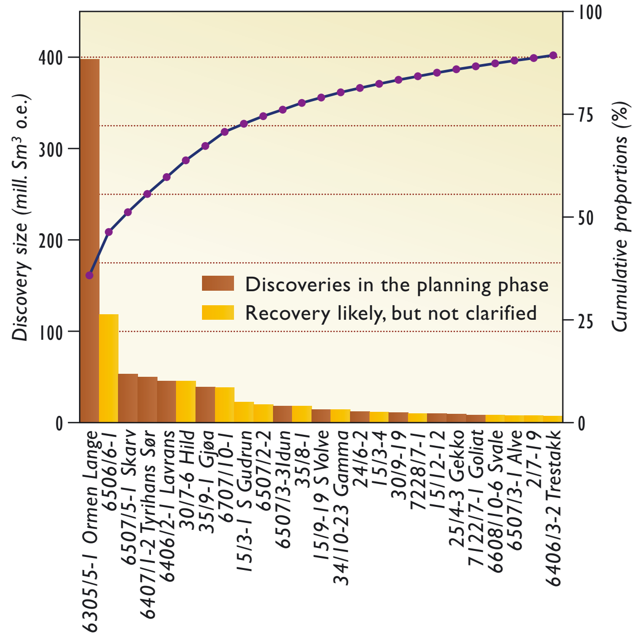


Figure 8.8
Sizes of discoveries and cumulative proportions of discovered resources. The figure shows the 25 largest discoveries that have not been approved for development.

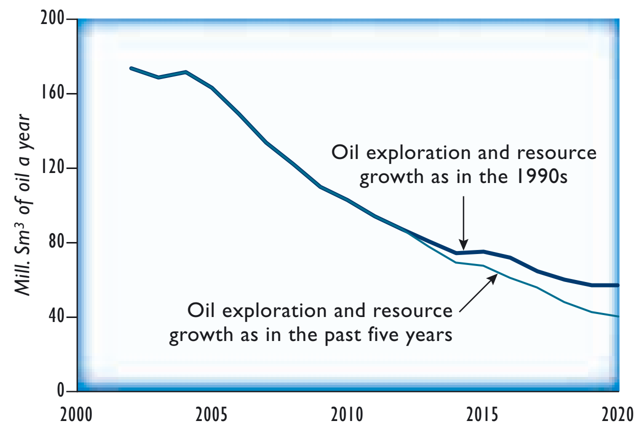


Figure 8.9
Effects of exploration on the total oil production.

The expected sale of gas per year from 2010 has been adjusted from 100 to 110 billion Sm^3. With some discoveries awaiting vacant capacity in established infrastructure, there will not be available capacity for undiscovered gas resources on parts of the shelf until after 2020. The prospect of having to wait a long time before new discoveries can be put into production may reduce the interest for exploring for gas in these areas. Exploration in the next few years will therefore concentrate on prospects that are large enough to form a basis for a new gas pipeline.

8.4 INVESTMENTS AND OPERATING COSTS ON THE NORWEGIAN CONTINENTAL SHELF

It is estimated that the investments in 2003 will be around NOK 65 billion. They will subsequently increase to NOK 67 billion in 2004 and 2005, and thereafter drop to approximately NOK 46 billion in 2006, reaching a level just under NOK 30 billion a year from 2007 onwards (Figures 8.10 and 8.11). The operating costs are expected to remain stable at between NOK 30 and 35 billion a year for the next 10 years.

The uncertainty in the investments is dominated by when investments on discoveries that are in the planning phase will be made, for instance discoveries 6305/5-1 Ormen Lange and 6507/5-1 Skarv. Uncertainty is still attached to the investments in projects that are being developed. Snøhvit is the largest of these. Experience shows that there is a greater chance of getting lower than higher investments in the next three years than forecasted, because of the greater probability of postponements than accelerations of projects. In the longer term, the investments are dominated by when the development of the gas discoveries on the Halten Bank (6507/5-1 Skarv, 6407/1-2 Tyrihans Sør and 6506/6-1 (“Victoria”)), with allied transport investments, and projects in fields that are in production, such as Tampen 2020, will take place. After 2012, uncertainties linked with any future discoveries will dominate the picture.

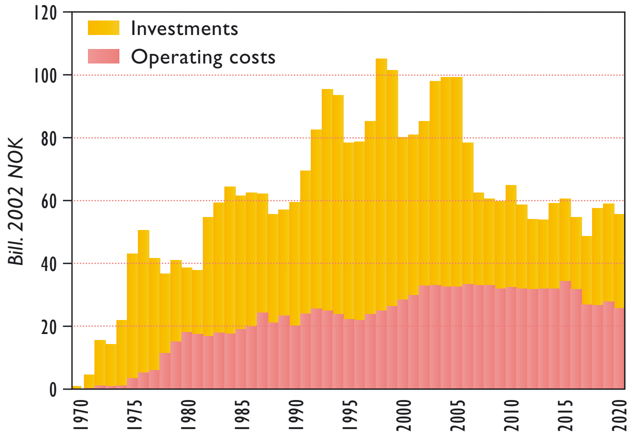


Figure 8.10
Future costs on the Norwegian continental shelf, excluding exploration costs.

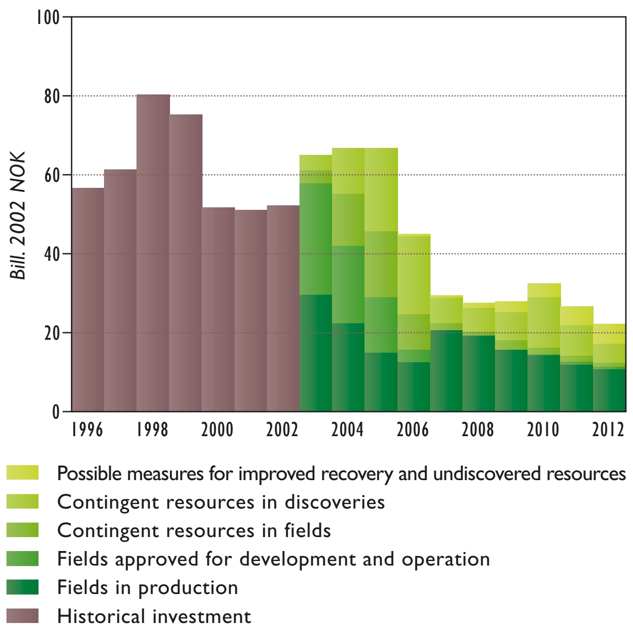


Figure 8.11
Distribution of investments.

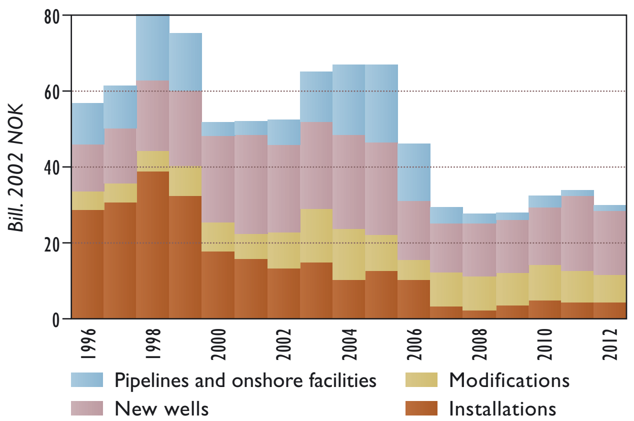


Figure 8.12
Distribution of investments.

The rise in the investments from 2003 to 2005 is mainly caused by increased investments in pipelines and onshore facilities (Figure 8.12). This applies to Snøhvit and pipelines and onshore facilities in connection with the Ormen Lange discovery. The investments in production wells have been stable since 2000, between NOK 22 and 26 billion (2002 NOK). This level is expected to be maintained for at least two more years before dropping to around NOK 15 billion a year. Investments in modifications in 2003 are double those in 2001. This level will last for some years. Towards the end of the present decade, investments in modifications will be 50 per cent higher than they were at the beginning.

It was the large investments in installations that dominated at the end of the 1990s, accounting for 50 per cent of the total investments. Despite an expected high activity level in 2004 and 2005, investments in installations will only comprise 15 per cent of the total investments. Scarcely any investment in permanently located installations is expected (Figure 8.13). Future solutions seem likely to be subsea installations.

8.5 RESOURCE MANAGEMENT AND THE ENVIRONMENT

Production of oil and gas results in emissions to the air and discharges to the sea. The emissions to the air mainly consist of carbon dioxide (CO_2) and nitrogen oxides (NO_X), which derive from power generation on the installations and flaring, and of volatile organic hydrocarbon compounds (nmVOC). The discharges to the sea mainly comprise produced water containing oil and chemical residues, and chemicals from drilling and well activities.

The production level and the type of field and discovery will to varying degrees affect the quantities of the various discharges and emissions.

The level of CO_2 emissions is expected to rise from around 11.7 million tonnes in 2002 to approximately 13.5 million tonnes in 2006, and then to decrease (Figure 8.14). NO_X emissions have remained stable at around 50 000 tonnes a year (Figure 8.15). A gradual reduction is expected from 2006. In the first few years, emissions from fields that are in production, or where development has been approved,

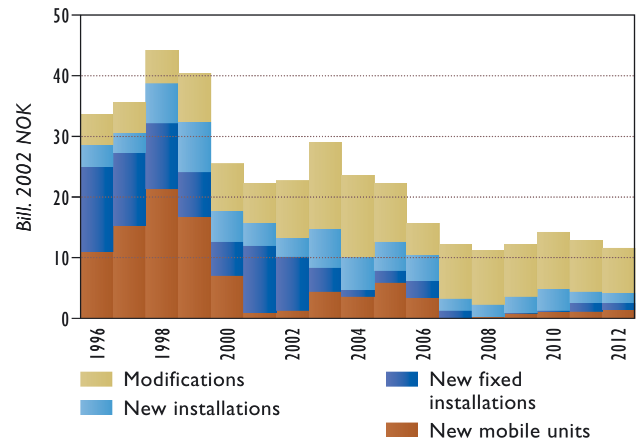


Figure 8.13
Distribution of investments.

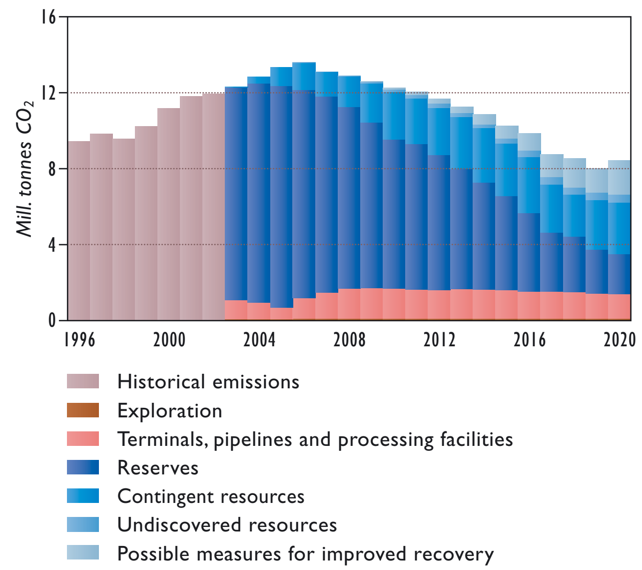


Figure 8.14
Forecasts for CO_2 emissions.

will dominate. Later, the contributions from existing discoveries and any new discoveries may form an increasing proportion of the total emissions.

Increased extraction of gas and oil will raise power consumption and the emissions of CO_2, but the rise will not necessarily be proportional to the production level. Factors that are specific to particular fields, the maturity of the field, its geographical location, the production strategy, transport solutions, the choice of power source and the possibility to use new, environment-friendly technology and energy efficiency measures will affect the emission levels.

Emissions of NOx will also to some extent depend on the level of activity, but here technology exists that can substantially reduce them. Since such technology will normally be fitted on new installations, the increase will not be proportional to the production level.

Emissions of nmVOC are mainly linked with loading and storage of crude oil at sea. Tested technology now exists for recycling nmVOC in connection with these operations, and this will be able to reduce emissions by about 70 per cent. The equipment will be installed between now and 2006. This will result in a major reduction in the emissions. It is first and foremost the amount of production that involves single-point buoy mooring loading which affects the nmVOC emissions (Figure 8.16).

Efforts are being made to achieve zero discharge to the sea. This target means that, in principle, no substances harmful to the environment will be discharged, neither chemical additives nor naturally occurring chemical substances. Emphasis has been placed on the target being achievable within acceptable limits regarding environmental hazards, safety, technology, matters specific to a field and financial constraints. Discharges to the sea will therefore be reduced further in the next few years, irrespective of the activity level.

It is generally more cost effective to install discharge- and emission-reducing technology on new installations than on existing ones. It is simpler and cheaper to achieve high energy efficiency on new installations where this can be incorporated at the design stage.

Technological requirements in the IPPC Directive (Integrated Pollution Prevention and Control), BAT (Best Available Technology), national demands on zero discharge to the sea of substances harmful to the environment and international obligations concerning emissions of greenhouse gases place stringent environmental demands on the petroleum operations. Most of these demands can be met without affecting the quantity of gas or oil produced. A precondition is that opportunity is given to fulfil the demands flexibly and cost effectively so that the operations can still be profitable for both the company and society. If not, it will be difficult to attain the long-term production forecast (Figure 8.1).

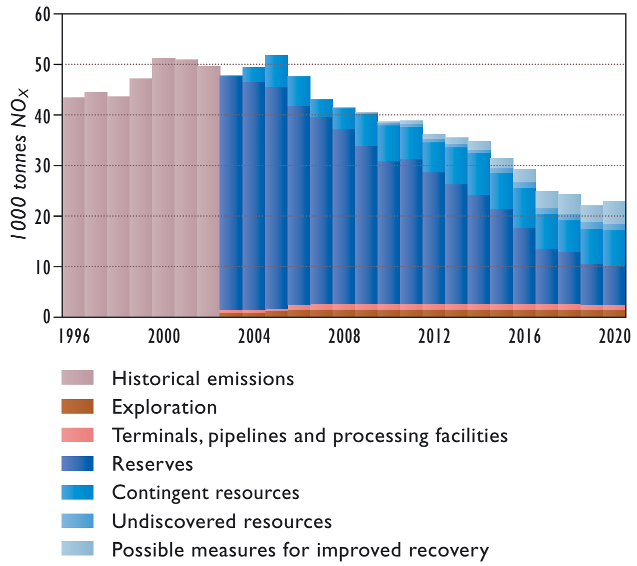


Figure 8.15
Forecasts for NO_X emissions.

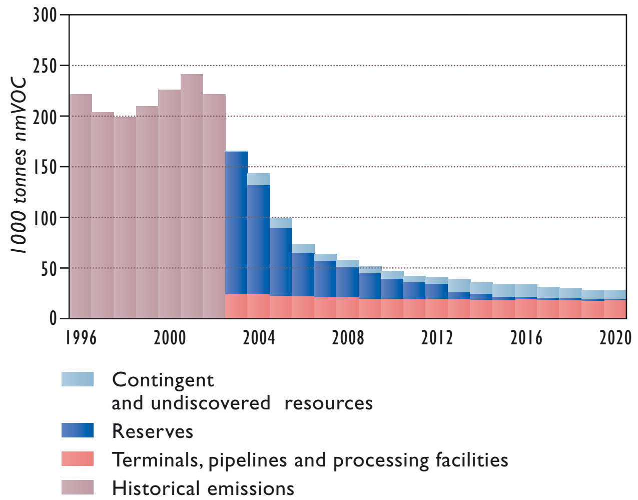


Figure 8.16
Forecasts for nmVOC emissions.