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PETROLEUM RESOURCES ON THE NORWEGIAN CONTINENTAL SHELF

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PREFACE

The minister of petroleum and energy presented White Paper no 28 *An industry for the future – concerning petroleum activities* to the Storting (parliament) immediately before the summer holidays. This painted an optimistic picture of the future for Norway's petroleum industry. For this picture to become a reality, the report notes that a parallel commitment will be required in four areas. We must improve recovery from producing fields. We must develop commercial discoveries. We must explore in areas opened for petroleum activity. And, finally, we must open new areas for such operations. The last time new sections of the Norwegian continental shelf (NCS) were opened in this way was in 1994.

A number of substantial discoveries have been made on the NCS this spring and summer. Great excitement was expressed both in the petroleum industry and in northern Norway when Statoil found oil this spring in the Barents Sea. Total discovered gas in the Barents Sea during the summer, and it became clear later in this season that the structure in which the 16/2-6 ("Avaldsnes") discovery was made by Lundin during 2010 extended into the neighbouring licence, where Statoil made the 16/2-8 ("Aldous Major South") find in August. Although that discovery still needs to be appraised, the area could contain so much oil overall that it enters the top 10 list of discoveries on the NCS and could prove the biggest find there since the 1980s.

These discoveries emphasise that 2011 has so far been one of the most eventful years on the NCS for a long time, and supports the optimistic picture of the future painted by the government. They also confirm the conviction of the Norwegian Petroleum Directorate (NPD) that substantial undiscovered resources remain on the NCS, in both mature and frontier areas. The major new discovery in the North Sea demonstrates the need for long-term thinking, patience, professional ability and creativity. It also underlines the significance of the awards in predefined areas (APA) and the changes made to exploration policy in mature areas. The Lundin discovery occupies acreage awarded in the 2009 APA, while Statoil's is in acreage awarded under the 2000 North Sea round (the predecessor to the APA).

The latest discoveries in the Barents and North Seas give grounds for optimism, and confirm that Norway can continue to be a leading European oil and gas nation far into this century. The agreement on the boundary with Russia also clears the way for exploration operations which open big perspectives for industry and jobs in the far north. The NPD regards the new Norwegian offshore area in Barents Sea East as interesting for petroleum activities, and believes these waters could contain oil and gas to supplement the estimated undiscovered resources on the NCS. Data on this area are nevertheless very limited, and provide an inadequate basis for assessing its resource potential. The NPD accordingly initiated seismic surveying in the summer of 2011.

This resource report provides a survey of petroleum resources on the NCS. It describes and analyses facts which provide an important foundation for continued knowledge-based and predictable administration of these resources. In the NPD's view, the remaining resources can lay the basis for substantial production and value creation over many decades to come. It is important in that context to make new discoveries like those found in 2011, both in mature areas and in frontier regions which have yet to be explored. But it is also crucial that Norway produces all the commercial resources in fields which are already on stream.

However, the resource potential will not be achieved automatically. Realising this potential from producing fields, by developing discoveries and through exploration is challenging. While taking pleasure at the new discoveries, we must dare to meet these challenges. The latter are also discussed in detail in this report, particularly those related to realising the resource potential of producing fields. As the report makes clear, securing a number of measures to improve recovery will be important.

The NPD's resource report for 2011 is being published at the same time as the Storting is debating White Paper no 28 on the petroleum activity. The latter lays the basis for political decisions and choices of direction. It is my hope that this report can supplement the depiction of the position given in the White Paper, elaborate on the background for the measures proposed and help to ensure that these perspectives open the way to good choices of direction for enhancing value creation.

Stavanger, September 2011

Bente Nyland
Director general

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CHAPTER 1. Status and challenges on the NCS

Introduction

This year marks the 45th anniversary of the arrival of *Ocean Traveler* in Norway and the spudding of the first well on the NCS, and the 40th anniversary of the start to oil production from the Ekofisk field in the North Sea. The petroleum industry has experienced economic fluctuations and varying prices for oil and natural gas since these beginnings. Over the period as a whole, however, it has been characterised by growth and rising production.

This expansion has meant that the petroleum sector ranks today as Norway's largest industry measured by value creation, government revenues and export value. It currently contributes about a fifth of total value creation and a quarter of government revenues. Oil and gas account for half of Norway's total export value. According to Statistics Norway, more than 200 000 people are employed directly or indirectly in activities on the NCS. Value creation by the Norwegian oil and gas industry since its start totals NOK 9 000 billion in 2011 money.

Production on the NCS remains high. Norway was the world's seventh largest exporter of oil and the second biggest of gas in 2010. However, oil output has declined from its 2001 peak and is expected to drop further. Gas production is still rising, but that has not prevented overall NCS output from falling since 2004. See figure 1.1.

The resource potential on the NCS is still high. This is underlined by the fact that several large discoveries were made during the first half of 2011 in both the Barents and North Seas, including 7720/8-1 ("Skrugard") and 16/2-8 ("Aldous Major South"). Resources in new discoveries could exceed production in 2011 for the first time since 1997.

In the NPD's view, remaining resources could lay the basis for substantial production and value creation over many decades to come. Opportunities for new discoveries and the potential for improved recovery from existing fields will be particularly important in a long-term perspective.

Technology and expertise have been important in realising the assets on the NCS, and will continue to be so. That relates to exploration, development, optimum recovery from producing fields and developing resources in the far north. A continued focus on research, development and the adoption of new technology will accordingly be crucial for future value creation.

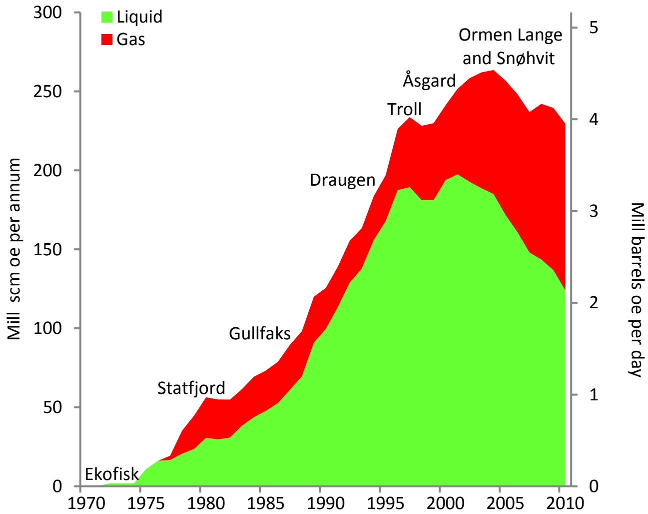


Figure 1.1 Historical petroleum production

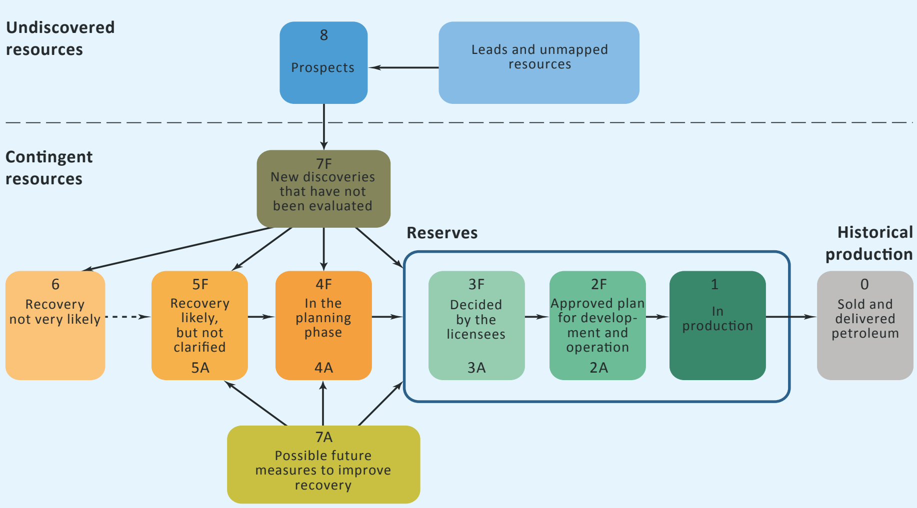
Resource account

The NPD's resource account provides an overview of expected total recoverable petroleum resources, including those still to be discovered. It is based on the NPD's resource classification and builds on data reported from the operator companies, the NPD's own assessments of fields and discoveries, and its estimate of undiscovered resources. See the box on resource classification.

The resource account covers all parts of the NCS except those areas where the available data are inadequate, which involves the continental shelf around Jan Mayen and Barents Sea East. Other areas not currently open for petroleum activity are included in the account.

Production up to 31 December 2010 totalled 5.5 billion standard cubic metres of oil equivalent (scm oe), or roughly 40 per cent of expected recoverable reserves. Total recoverable reserves are estimated to lie within an uncertainty range (P10 and P90) of

Resource classification



The resource classification covers all estimated petroleum resources, both discovered and undiscovered. Petroleum volumes are classified by their maturity.

Resources are divided into the principal classes of historical production, reserves, contingent resources and undiscovered resources. Reserves relate to remaining recoverable petroleum resources in deposits which the licensees have decided to develop. Contingent resources are discovered petroleum volumes still not covered by a development decision. Undiscovered resources are volumes considered to be recoverable but not yet proven by drilling. Whether the estimated resources actually exist is uncertain. The various main classes are divided into sub-classes depending on the maturity of the various projects.

Class	Category		Oil mill scm	Gas bn scm	NGL mill tonnes	Cond mill scm	Total oe mill scm	Change from 2009 mill scm
		FIELD						
Sold and delivered	**0**	Sold and delivered	3 626	1 547	133	95	**5 521**	**233**
Reserves	**1**	In production	664	1 638	90	34	**2 506**	**-98**
	2	Approved for development	102	95	12	1	**221**	**-15**
	3*	Approved by licensees	62	309	13	0	**396**	**67**
		Total reserves	827	2 043	115	35	**3 123**	**-46**
Contingent resources	**4**	In planning phase	178	175	13	3	**382**	**111**
	5	Development probable, but not clarified	227	107	13	1	**360**	**-19**
	7F	Non-evaluated discoveries in connection with fields	5	12	1	2	**21**	**0**
	7A	Possible future measures for improved recovery	140	70			**210**	**-20**
		Total contingent resources in fields	550	364	28	6	**972**	**72**
		DISCOVERIES						
	4	In planning phase	113	139	5	6	**272**	**5**
	5	Development probable, but not clarified	50	144	5	6	**210**	**-36**
	7F	New discoveries, not evaluated	92	73	2	4	**166**	**-37**
		Total contingent resources in discoveries	255	356	11	16	**648**	**-68**
Undiscovered resources							**0**	**0**
	8 and 9	**Prospect possibilities and unmapped resources**	1 200	1 255		115	**2 570**	-710
		Total resources	**6 458**	**5 564**	**287**	**268**	**12 834**	-519
		Total remaining resources	2 832	4 017	154	173	**7 314**	-752

** includes discoveries in RC 3F*

Table 1.1 Resource account at 31 December 2010

10-16 billion scm oe, with an expected value of 13 billion scm oe. See figure 1.2.

The NPD's estimate of total recoverable resources changes over time. Resources are matured through several phases (see the text box on resource classification and table 1.1). New knowledge of geology and reservoir conditions as well as further discoveries change assessments of the resource base. Today's picture differs significantly from the one which prevailed 15 years ago. See figure 1.3.

Future assessments of the resource base will also change in relation to the present evaluation, since estimates incorporate a substantial degree of uncertainty. Depending on whether the figure in the lower or upper part of the uncertainty range in figure 1.2 (10-16 billion scm oe) is applied, production to date totals about 50 or 30 per cent respectively of total recoverable resources.

Unconventional oil and gas resources

Unconventional resources is a collective term for oil and gas deposits which cannot be recovered commercially with conventional production wells and technology, normally because flow to the wells would be very low.

Little attention has been paid so far to unconventional petroleum resources on the NCS, since producing them has been non-commercial to date. As world energy demand grows and oil prices rise, mapping and assessing the recovery of these resources could also be necessary.

No estimates of unconventional petroleum resources on the NCS have been made so far by the NPD. However, it is likely that such resources are substantial but that profitable recovery lies some way off (see chapter 2).

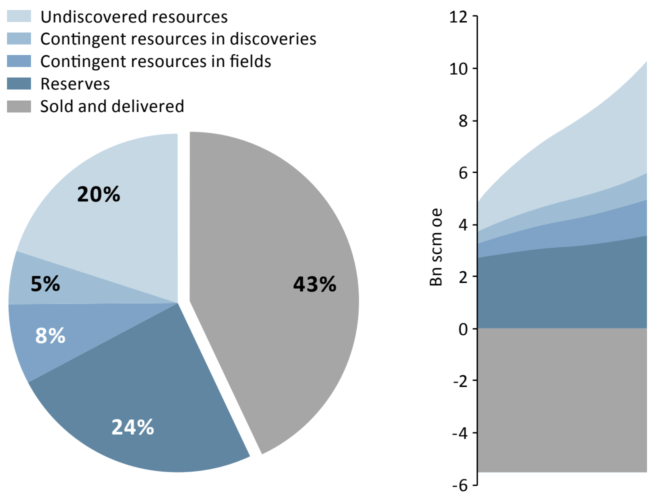


Figure 1.2 Distribution of total recoverable petroleum resources at 31 December 2010, including the uncertainty range

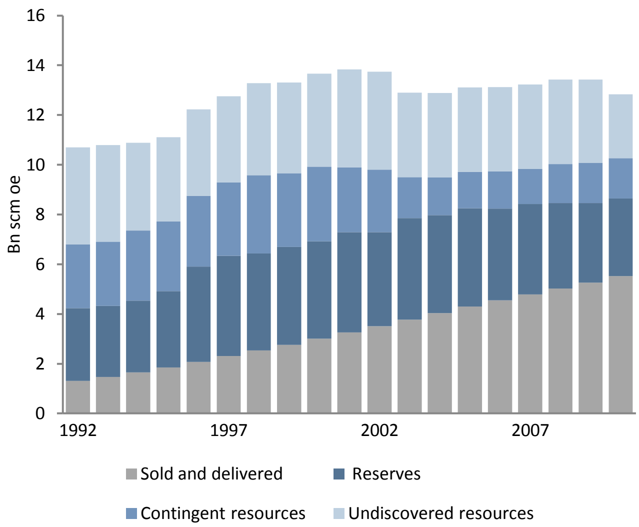


Figure 1.3 The NPD's estimate of expected recoverable petroleum resources, 1992-2010

Future oil and gas production

The authorities produce forecasts for future petroleum production on the NCS. These prognoses build on oil company reporting and the NPD's resource estimate. See the box about production forecasts on page 11. The current production forecast up to 2030 is shown in figure 1.4.

Petroleum output is expected to remain at roughly the same level for the next 10 years, despite a gradual decline in production from the large oil fields. Measures to improve recovery and bring discoveries on stream contribute to maintaining output. After 2020, production from undiscovered resources will account for a growing proportion of the forecast figure.

Uncertainty in the forecasts for the next few years relates primarily to the production of reserves – how much each field can produce, how regularly the fields deliver, how efficiently new wells are phased in, and other projects on the fields. It is also uncertain when discoveries will be developed and brought on stream, and how much they will produce.

Uncertainty increases over the long term because undiscovered resources account for a gradually increasing share of expected output. This uncertainty is greatest in areas still not opened for petroleum activity. In the longer term, it is also uncertain what contribution could be made by technological development in realising the resource base on the NCS.

Challenges for producing fields

Based on today's cessation plans, more than half the oil originally in place will remain in the reservoirs. Figure 1.5 shows how much oil is produced and sold from the biggest oil-producing fields, the size of their remaining reserves, and how much is expected to be left in the ground when they close down.

The potential for increasing recovery factors on today's fields is substantial. Continued efforts to achieve a high recovery factor are accordingly important. Injection, drilling and well maintenance are important for producing existing reserves and could also contribute to raising recovery factors – and thereby reserves – for

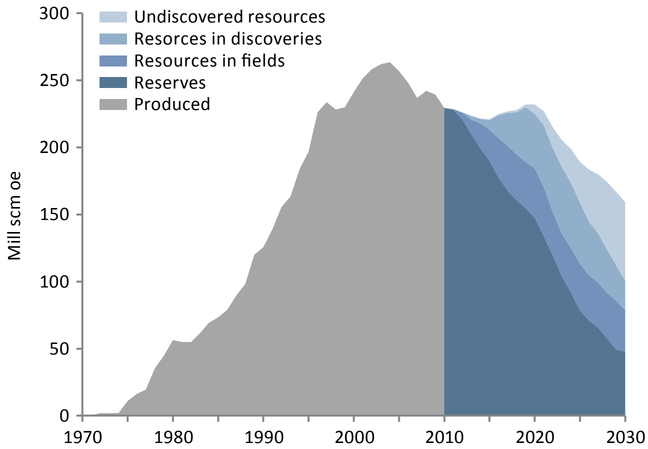


Figure 1.4 Historical petroleum production and forecast production to 2030

the fields. Developing and qualifying advanced injection methods and new technology through field trials could further improve recovery. In the NPD's view, a commitment to measures which can improve the recovery of mobile oil with current techniques is important. So is a continued commitment to developing and implementing methods which could recover currently immobile oil. Close follow-up and facilitation by the authorities have historically proved useful in such processes, and will also play an important role in the future. The NPD also sees that achieving annual production ambitions is demanding on a number of fields, and that fewer wells than planned are being drilled. Well targets will contain ever decreasing volumes in the time to come, and many will not be profitable with today's costs in relation to oil prices. Drilling and maintenance expenditure per well in relation to oil prices therefore represents a challenge. Good cost control and paying greater attention to new drilling methods and technology could make it possible to produce a larger proportion of the resource base. Success here could limit the decline in oil production from the old fields, which may still have a long producing life. Exploiting the potential in the fields will be reviewed in chapter 5.

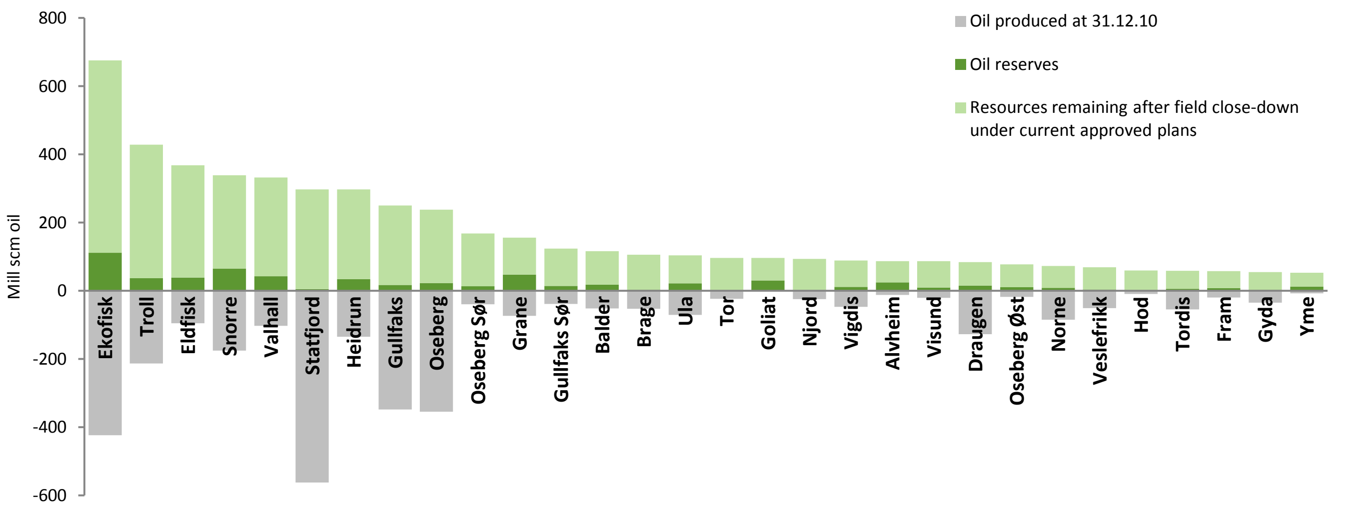


Figure 1.5 Distribution of produced oil, remaining oil reserves and oil resources which will remain in the ground if the fields are closed down in accordance with currently approved plans

Production forecasts

Projecting petroleum production a long way into the future is a demanding exercise. Production forecasts are naturally subject to great uncertainty, which increases with the length of time they cover. The estimate for production from undiscovered resources is particularly uncertain. From the end of this decade, such resources are expected to form a growing and eventually substantial share of total production.

Scenarios can provide a supplementary way to present future petroleum production in order to illustrate the substantial uncertainty inherent in the estimate of remaining recoverable resources. Such scenarios were developed in the NPD's resource report for 2007. Four different future courses for oil and gas production on the NCS up to 2046 were presented, with both downsides and possible upsides identified.

White Paper no 28 (2010-2011) *An industry for the future – concerning petroleum activities* presents a possible course for production on the NCS up to 2040. The White Paper emphasises the opportunities on the NCS, and outlines a plan for taking advantage of these. As a result, a production profile has been developed which incorporates some of the upside as well as opportunities available in the areas not covered by the resource estimate. The resource estimate which forms the basis for the production profile lies within the uncertainty range in the NPD's estimate remaining recoverable resources, which is 4.8-10.6 billion scm oe.

Discoveries

Estimated resources for discoveries not sanctioned for development at 31 December 2010 totalled 650 million scm oe. That amounts to five per cent of total expected recoverable resources on the NCS and nine per cent of remaining recoverable resources. The NPD's analysis shows that commercial discoveries will be developed, but that this may often take time. Important reasons for this are uncertainty over the resource base, discovery size, lack of spare processing capacity and absence of infrastructure. In addition come commercial assessments and strategic considerations for the companies. The scope of resources in discoveries and challenges related to commerciality are reviewed in chapter 4.

Undiscovered resources

Exploration activity on the NCS has been high in recent years, with extensive seismic surveying and a large number of exploration wells (see chapter 3). Maintaining a high level of exploration activity is also necessary in the years to come in order to clarify the potential of the undiscovered resources and to make new discoveries which can be developed.

A third of the estimated remaining recoverable resources have yet to be proven. Estimates for undiscovered resources build on play analysis. Plays are defined on the basis of geological knowledge. The level of uncertainty in the estimates is high, particularly in areas where little is known about the sub-surface (see chapter 2).

The North Sea is the best-mapped area of the NCS. Many wells have been drilled, and the geology is well known. Uncertainty in the estimates for undiscovered resources in the North Sea is accordingly lower than for the other sea areas. Although well explored, with many large discoveries, the North Sea still has a substantial potential. This was recently documented through the 16/2-6 ("Avaldsnes") and 16-/8 ("Aldous Major South") discovery wells.

At 31 December 2010, resource estimates for the North Sea gave a 90 per cent probability that it contains 470 to 1 305 million scm in undiscovered recoverable oil equivalent, with an expected value of 845 million scm oe. See figure 1.6.

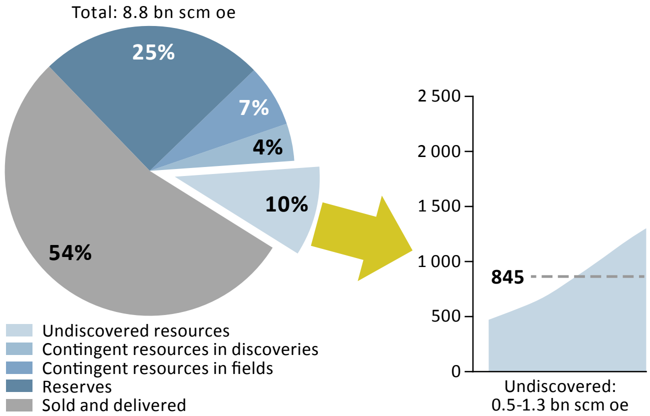


Figure 1.6 Distribution of total recoverable petroleum resources in the North Sea at 31 December 2010, including the uncertainty range for undiscovered resources

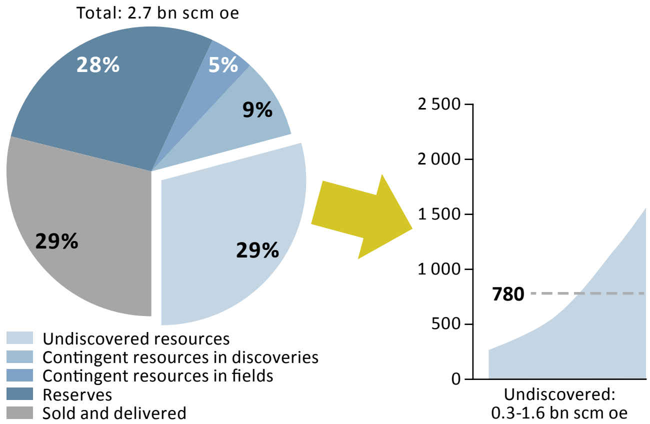


Figure 1.7 Distribution of total recoverable petroleum resources in the Norwegian Sea at 31 December 2010, including the uncertainty range for undiscovered resources

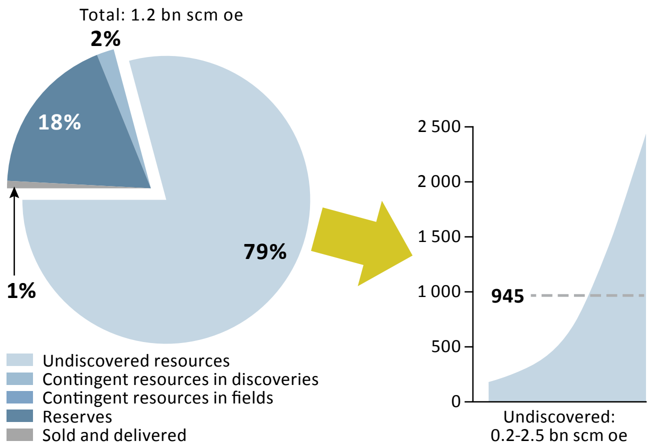


Figure 1.8 Distribution of total recoverable petroleum resources in the Barents Sea at 31 December 2010, including the uncertainty range for undiscovered resources

The knowledge base in the Norwegian Sea varies from good to limited. Resource estimates for these waters give a 90 per cent probability that they contain 260 to 1 580 million scm in undiscovered recoverable oil equivalent, with an expected value of 780 million scm oe. See figure 1.7. Disappointing exploration results in deepwater areas of the Norwegian Sea in recent years have prompted the NPD to reduce its expectations of the oil and gas resources which might exist in this area.

Large areas with little data and few or no exploration wells exist in the Barents Sea. The level of uncertainty is accordingly high. Based on current knowledge, it is estimated with 90 per cent certainty that the area contains 175 to 2 460 scm in undiscovered recoverable oil equivalent, with an expected value of 945 million scm oe. See figure 1.8.

In addition come possible undiscovered resources around Jan Mayen and in the new Norwegian area of Barents Sea East. These areas are not included in today's resource estimate.

Curbing greenhouse gas emissions

Concern for the environment has always been an integral part of Norway's petroleum activity and government regulation of the industry. An extensive set of instruments takes account of the environment in every phase of the business.

Emissions to the air by the petroleum sector derive primarily from burning natural gas in turbines to produce energy, flaring natural gas for safety purposes and burning diesel oil.

The petroleum sector pays Norway's carbon tax and is also subject to the European collaboration on emission allowances. Many measures to cut carbon emissions have been prompted by the carbon tax. Reduced flaring and heat recovery are examples of emission-reducing measures which have had a big effect.

Environment-friendly development solutions and supplying power from shore to installations have the biggest potential for reducing emissions from offshore facilities viewed in isolation.

Several new fields are to be developed with power from shore over the next few years. Ormen Lange, Troll A and Gjøa already receive electricity in this way. Valhall in the southern North Sea sector, on stream since 1982, is now being converted to power from shore. This approach has also been adopted for Goliat in the Barents Sea.

Even if several fields are powered from shore, overall emissions from the sector are unlikely to decline in the next few years. That is because a number of developments will come on stream, while the expected production profile for existing fields indicates that few will be closed down.

Technology and talent

The NCS has a reputation as a technological laboratory for the oil industry. Continuing to develop this position will also be crucial for the level of future production.

Oil companies and suppliers have been honing their skills ever since 1966 on the challenges presented by the North Sea and later also by the Norwegian and Barents Seas. This has resulted in the development of technologies which have contributed to huge value creation from the NCS and which have also become important exports to other petroleum provinces. Examples include crossing the Norwegian Trench with the Statpipe line in 1985, the installation of a floating platform on Snorre in 1992, horizontal wells on Troll, waterflooding on Ekofisk, subsea installations and a production ship on Åsgard, multiphase transport and remote operation for Snøhvit and Ormen Lange, and subsea separation on Tordis. See figure 1.9.

Over almost 45 years of technological progress, Norway's petroleum activity has gradually moved from south to north, from shallow to deep water, and from large fixed installations to subsea developments and remotely controlled solutions. The direction and pace have been determined by sequential access to the resources, the challenges presented by discoveries, and a size of discovery sufficient to finance new technology.

Large fields can carry the financial burden represented by technologi-
cal

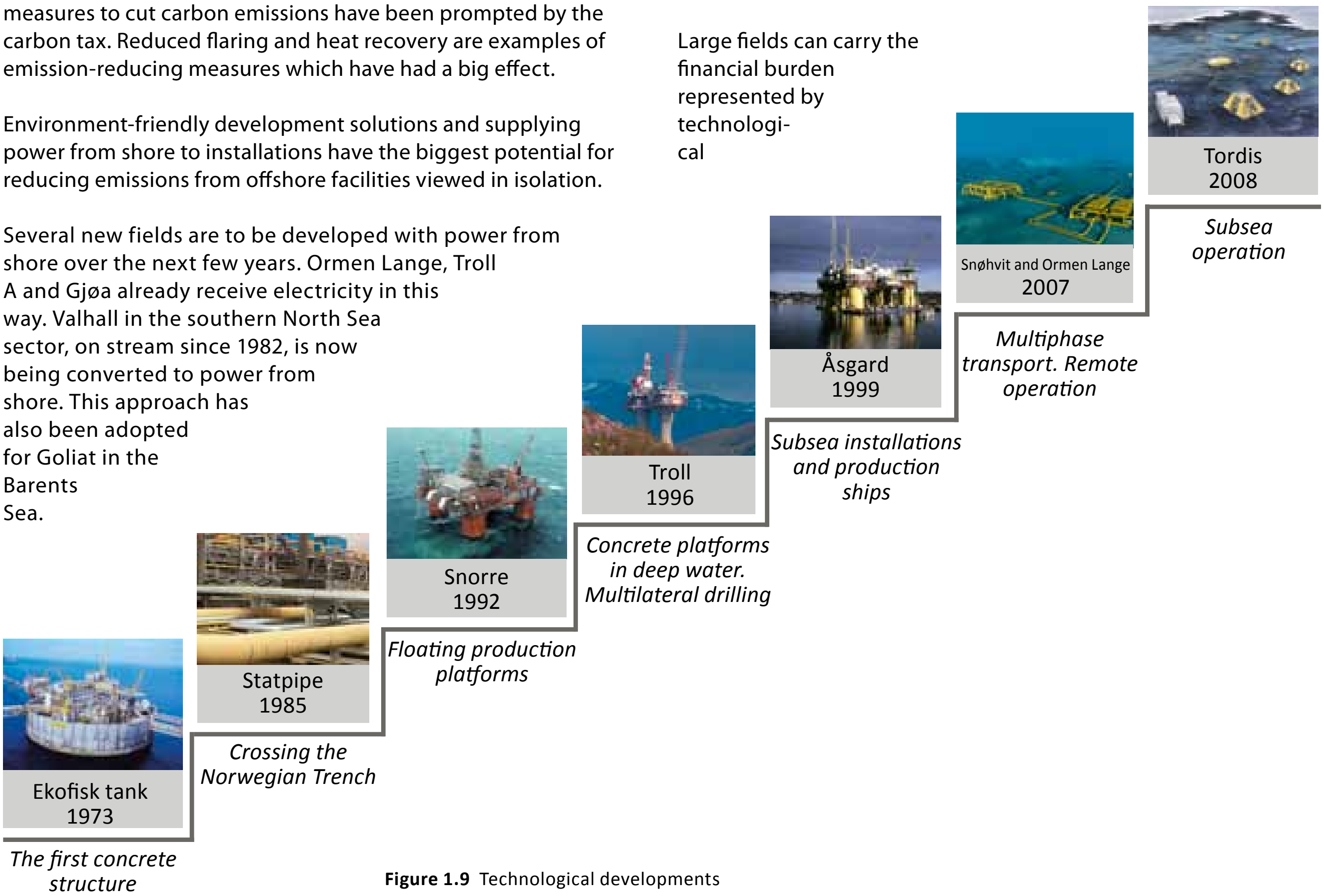


Figure 1.9 Technological developments

development and innovation. They are big enough to reap substantial advantages from the results, while other fields also benefit from the technological progress made. With few exceptions, discoveries made over the past 10 years are less able to carry technological development than Ormen Lange, Åsgard and Troll, for example. Small discoveries call to a greater extent for integrated solutions and for the companies to invest in research and development (R&D) across different production licences.

A number of the big fields are moreover in a late phase, which means that their planning horizon and remaining resources could make it difficult to achieve large-scale pilot trials, not least because these could involve the risk of lost output.

The NPD is worried both about the level of funding devoted to petroleum research and about the growing tendency for many technology projects and pilots to be delayed or cancelled. A continued focus on research and development and the implementation of new technology will be crucial for future value creation on the NCS. Access to human resources and talent is also a critical factor. It is accordingly very important for young people to see that the industry has a long-term perspective and is worth making a commitment to.

Exploration and new areas

Production from the NCS depends in the long term on new discoveries which are capable of being developed. Based on current expectations for the resource base, future production and exploration activity, almost 40 per cent of petroleum output on the NCS in 2030 will derive from discoveries which have yet to be made. The number and size of finds will be crucial for the size of Norway's future production.

Discoveries need to be generally larger than has been the case over the past 10 years if the object is to maintain the level of production over a long period. Although substantial finds have recently been made in both mature and frontier areas, the opportunities for large discoveries are probably greater in parts of the unopened areas than in those already opened.

Extensive unopened areas still exist on the NCS. See figure 1.10. No new areas have been opened to petroleum activities on the NCS since 1994. Political decisions are required on opening further areas. The areas which have not been opened present different challenges, and the time scale from a possible opening process to exploration, discoveries, development and production will vary. The government resolved last autumn that an impact assessment would be conducted for the waters off Jan Mayen with a view to future petroleum activity. The NPD accordingly initiated seismic surveying in the summer of 2011 as part of this impact assessment. In White Paper no 28 (2010-2011) *An industry for the future – concerning petroleum activities,* the government announced that it would initiate a number of measures to prepare for the opening of new areas. Against that background, the NPD also started seismic surveying in Norway's new sea area at the southern end of Barents Sea East.

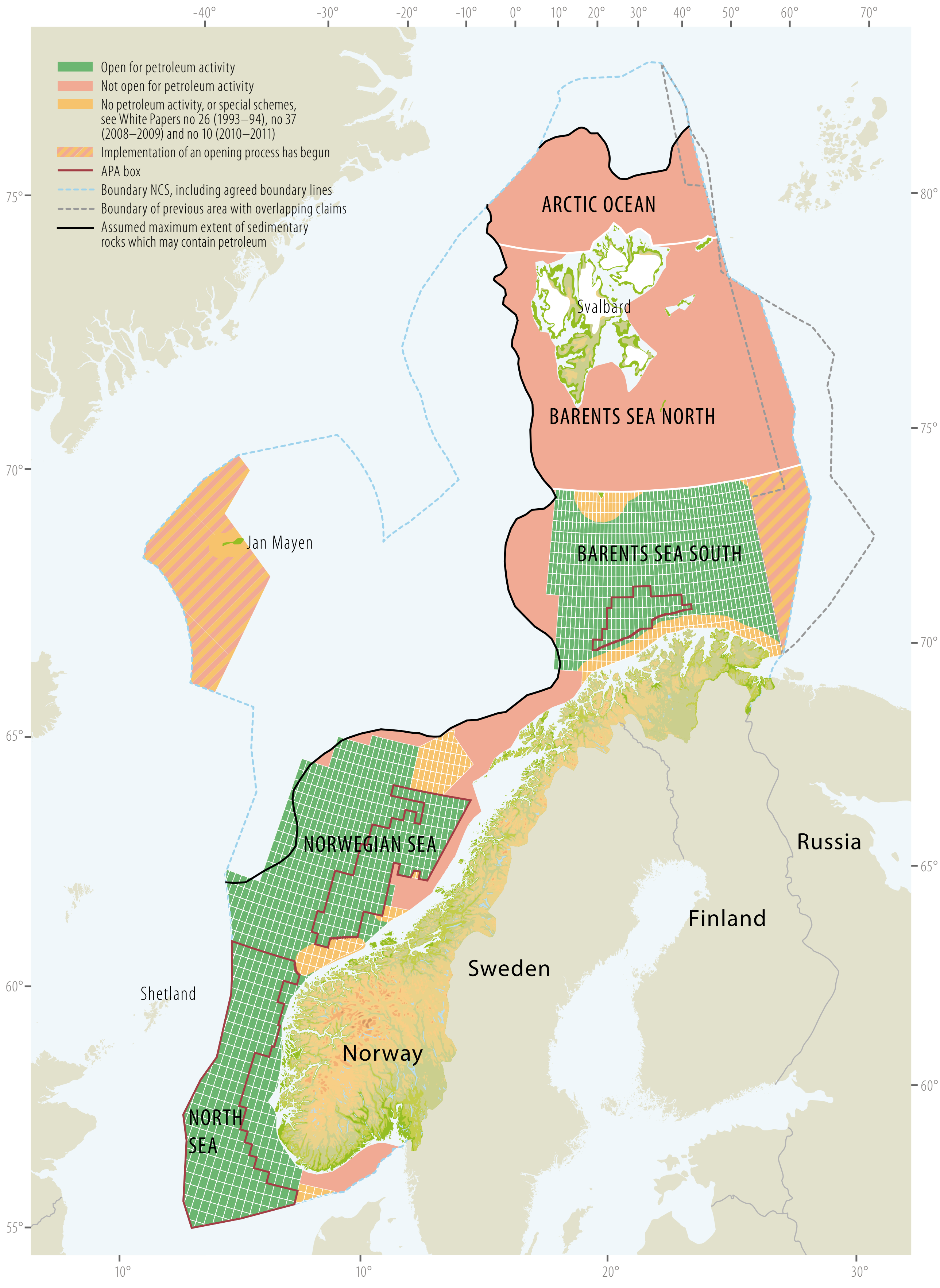


Figure 1.10 Status of petroleum activities on the NCS by area

CHAPTER **2.** Undiscovered resources

Introduction

One of the NPD's most important jobs is to produce estimates of undiscovered resources on the NCS. Good administration of the petroleum resources calls for knowledge of their total volume, both discovered and undiscovered, so that policies can be formulated on the basis of extensive information. The NPD has access to all petroleum data from the NCS, and accordingly possesses the best basis for producing an independent and well-qualified calculation of the total resource potential.

Twenty per cent of estimated resources in the NCS have still to be discovered, which shows the significance of continued mapping, exploration and drilling of wells. See figure 2.1. Although the estimate for undiscovered resources has been slightly reduced from the previous resource report in 2009, the potential for finding more remains considerable.

The statistical expected value for undiscovered resources is roughly similar in the three sea areas making up the NCS, but the biggest upside potential is found in the Barents Sea – where large areas are still little explored.

The estimate presented in this report does not include the waters around Jan Mayen or in Norway's new Barents Sea East area. When new seismic data are available, and these areas have been mapped, the resource base for the NCS will increase. The NPD began to acquire seismic data from these two areas in 2011.

Great uncertainty attaches to the estimate for undiscovered resources, ranging from about one billion scm oe to almost five billion, with an expectation (average) value of 2.6 billion for total resources (liquids and gas). The distribution of undiscovered resources is shown in table 2.1.

Expectations are highest for the Barents Sea, where the estimate accounts for 37 per cent of resources, while the Norwegian Sea has the lowest expectation at 30 per cent. See figure 2.2.

How undiscovered resources are calculated

The NPD calculates undiscovered resources with the aid of a method known as play analysis. This is a recognised approach, used by both companies and governments. Applied by the NPD for many years, it is very suitable for areas where the geology is known, many prospects have been identified and a number of wells have been drilled. The method is accordingly appropriate for large parts of the NCS. It involves systematising and describing the geological understanding of an area. On that basis, the amount of petroleum which could be proven and produced from each play is calculated. See the box on geological plays.

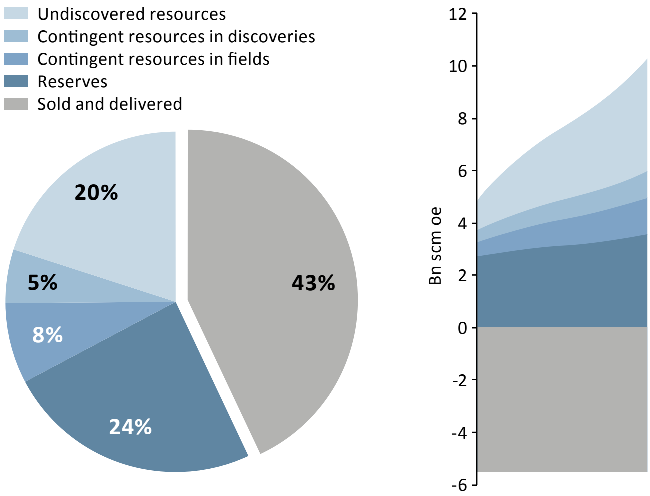


Figure 2.1 Total recoverable resources on the NCS

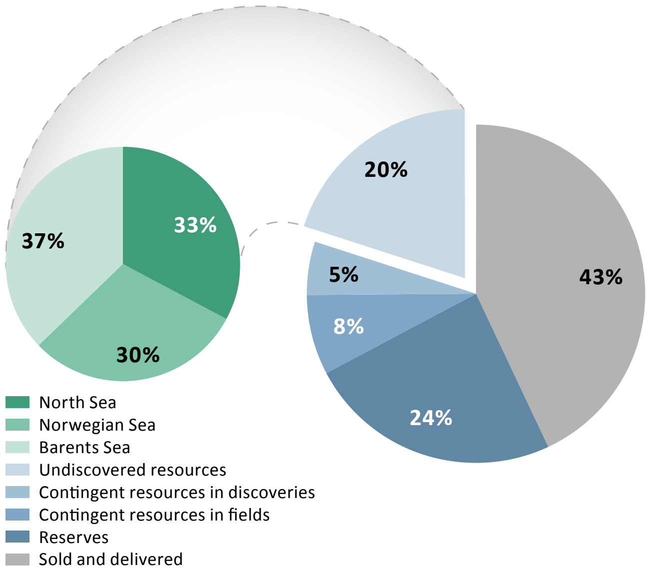


Figure 2.2 Distribution of undiscovered resources by area

	Liquids mill scm oe			**Gas** bn scm			**Total** mill scm oe		
	P 95	*Expec*	*P 5*	*P 95*	*Expec*	*P 5*	*P 95*	*Expec*	*P 5*
North Sea	285	565	910	140	280	465	470	845	1 305
Norwegian Sea	85	325	705	130	455	960	260	780	1 580
Barents Sea	50	425	1 180	80	520	1 460	175	945	2 460
Total	**480**	**1 315**	**2 500**	**420**	**1 255**	**2 540**	**1 020**	**2 570**	**4 800**

Table 2.1 Distribution by area of undiscovered resources with uncertainty range. Liquids are oil and condensate

A geographical area can incorporate a number of plays of varying geological ages – one in the Triassic and another in the Cretaceous, for example. Prospects are the fundamental components in a play analysis, and the number of prospects and the amount of petroleum each of them could produce determine the estimated resources for that play.

A play is characterised by geological factors collectively present in a clearly delineated area (basin), both stratigraphic and geographic: reservoir, source and cap rocks. Mapped and unmapped prospects, discoveries and fields can be found within a single play. See figure 2.3.

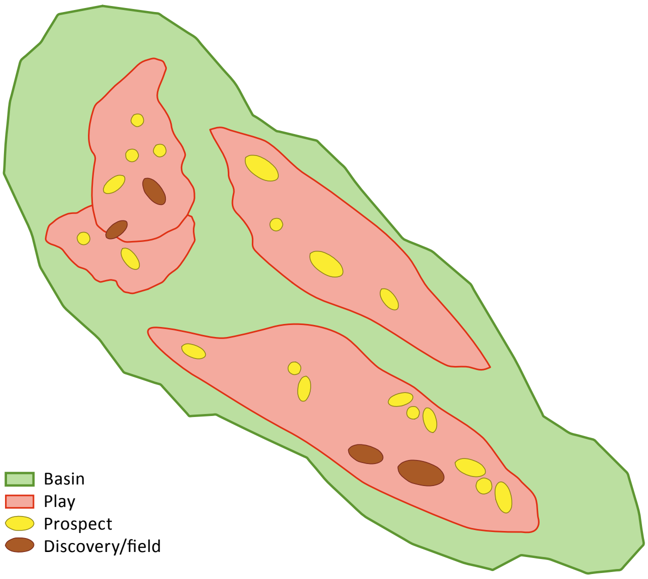


Figure 2.3 The relationship between basin, play, discovery and prospect

A play is defined within a geographically delineated area where a specific set of geological factors is present so that it should be possible to prove petroleum in producible volumes. These factors are:
1) *Reservoir rock*, which is a porous rock where petroleum can accumulate. Reservoir rocks in a specific play will belong to a given stratigraphic level.
2) *Cap rock*, which is a tight (impermeable) rock overlaying a reservoir rock, so that petroleum can migrate no further and accumulates in the reservoir. The resulting trap must have formed before petroleum ceased to migrate into the reservoir.
3) *Source rock*, which is shale, limestone or coal containing organic materials which can be converted into petroleum. The source rock must be mature – in other words, its temperature and pressure are such that petroleum actually forms – and the petroleum must be able to migrate from source rock to reservoir rock.

A prospect is a potential petroleum deposit which has been mapped and where the quantity of possible producible petroleum can be calculated. The prospect's discovery probability is the probability that a well could prove producible petroleum there. In play analysis, the ability to calculate how many prospects could be present in each play is important. The number of possible discoveries and their size must also be assessed. In an area with few or no wells, such assessments are the most important sources of information when developing a resource estimate for the play. The NPD uses new data from mapping and well drilling to update and adjust resource estimates for the relevant plays on a regular basis.

A play is confirmed when a discovery is made in it, and uncertainty no longer prevails over whether the geological factors function. The resource estimates will normally increase when a play has been confirmed. A confirmed play is characterised by a discovery which has proven producible petroleum. The discovery does not need to be commercial. If producible petroleum has still not been confirmed, the play remains unconfirmed. Confirmation of the play is then associated with a probability.

Estimated resources for a play are more uncertain the less is known about the play, and the NPD accordingly specifies resources with an uncertainty range. The NPD's estimate for undiscovered resources also includes the areas which have not been opened for petroleum activity on the NCS, apart from the waters around Jan Mayen and the new Norwegian area of Barents Sea East. Knowledge about reservoirs in fields and in discoveries yet to be developed is important, but dry wells can also provide valuable data on geological conditions. The NPD also draws on information about mapped prospects in its database, which builds on its own and company work on the NCS.

The NPD's prospect database

Play analysis is based on knowledge about the number and size of deposits or prospects in each play. A good database of all mapped prospects is important for the NPD. Through numbered licensing rounds and awards in predefined areas (APA), the NPD has access to extensive mapping of prospects by the oil companies. It also has access to the interpretation work conducted by licensees in the licences through participation in exploration committee meetings. In addition, the NPD's geologists and geophysicists themselves work on extensive prospect mapping. The database contains some 1 500 mapped prospects. The NCS is continuously evaluated, and additional information acquired through seismic mapping and exploration drilling. Each new exploration well leads to the removal of a prospect from the database and, if petroleum is encountered, the prospect is reclassified as a discovery in the database. Mapping can lead to the addition of further prospects.

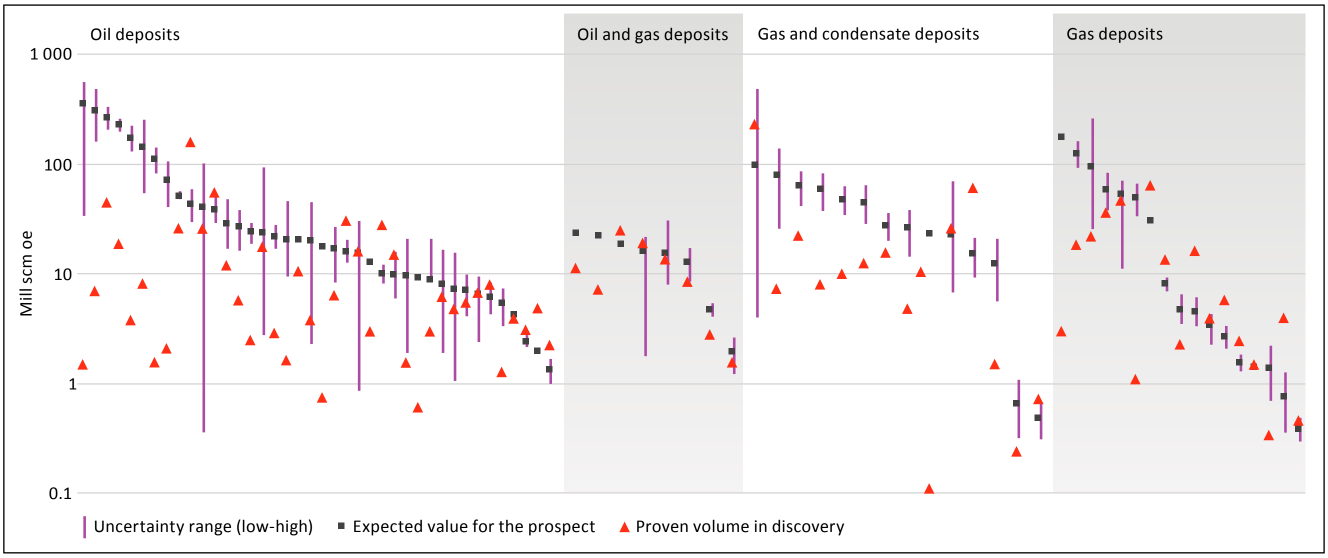


Figure 2.4 Comparison of operator expectations of petroleum volume in 67 deposits before drilling, and the results after drilling

The NPD collates forecasts for and results of exploration drilling. It compares such data as the quantity of petroleum estimated for the prospect with the volume proven by discoveries. It transpires that operators often make over-optimistic estimates of the amount of petroleum in a prospect. That applies in particular to those which prove to contain oil. There are fewer gas prospects, and experience indicates that forecasts and results agree more closely for these.

Sixty-seven discoveries made in 1998-2007 have been analysed by the NPD. Figure 2.4 compares operator company expectations of the volume of petroleum in a prospect before drilling with the amount actually found. Discoveries are ranked by the operator's forecast for resources in place and classified by the type of petroleum. The vertical purple lines show the operator's uncertainty range before drilling, with the expected value as a black square. Red triangles represent the proven volume in the discovery. In this data set, estimated oil in the prospects is 2.5 times greater than the resources proven. Agreement between expectation and result is better for gas than for oil. This could be because gas reservoirs often yield a stronger seismic response, which simplifies mapping of and estimating volume for the deposit.

Excessive estimates from operators present a challenge for the NPD when adding up prospects to be included in a play analysis. Using the volume of resources in these prospects uncritically will mean that the estimate for undiscovered resources in the play becomes too high. A quality check of the prospects is accordingly carried out before incorporating the volume of resources in the analysis.

The NPD uses information and results from discoveries as a quality check for realistic resources in the prospects and expectations of the number of discoveries in each play. If a play analysis makes uncritical use of excessive estimates for the prospects, the actual discovery history will show a poor match with the modelled estimates for future discoveries generated by the analysis.

Play analysis

The NPD has defined 69 plays which all contribute to the estimate for undiscovered resources, as shown in table 2.2.

A little over half the plays have been confirmed by discoveries. Most of these are located in the North Sea, where 19 of 23 plays are confirmed. The smallest number – eight out of 23 – is in the Barents Sea. That reflects the maturity of these areas. Exploration has been pursued longest in the North Sea, and most of this area has been opened for petroleum activity. Large parts of the northern and eastern Barents Sea remain closed, and a number of plays have been defined in the unopened areas.

Area	Confirmed plays	Unconfirmed plays	Total
North Sea	19	4	23
Norwegian Sea	9	10	19
Barents Sea	8	19	27
Total	**37**	**32**	**69**

Table 2.2 Confirmed and unconfirmed plays

Sixteen discoveries were made on the NCS in 2010. None lay in previously unconfirmed plays. The 7220/8-1 ("Skrugard") and 7225/3-1 ("Nordvarg") discoveries in 2011 have encouraged fresh optimism in the Barents Sea. Both were made in previously confirmed Jurassic and Triassic plays. They have little effect on the total resource estimate for the Barents Sea. The 16/2-6 ("Avaldsnes") and 16/2-8 ("Aldous Major South") discoveries in the North Sea were made in previously confirmed Jurassic plays, and have led to a better understanding of possible migration routes on the Utsira High.

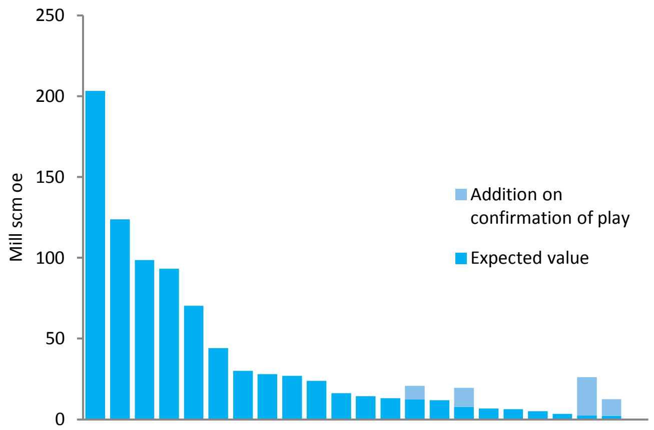


Figure 2.5 Plays in the North Sea

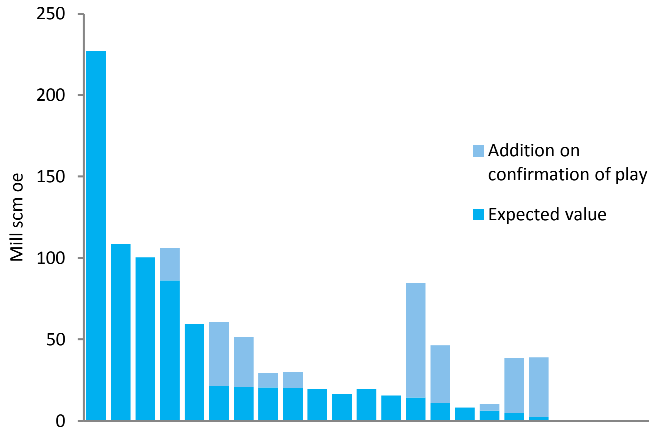


Figure 2.6 Plays in the Norwegian Sea

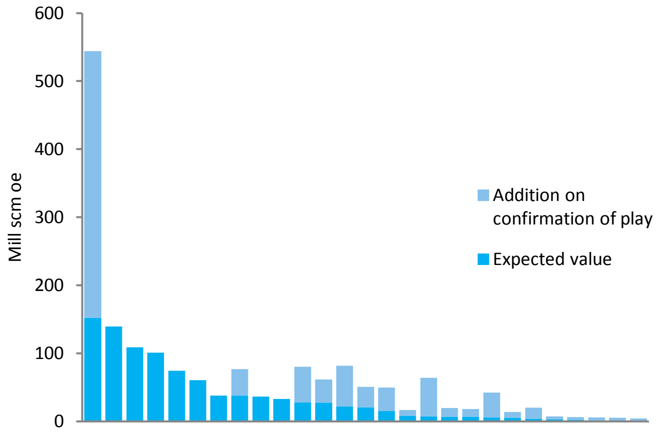


Figure 2.7 Plays in the Barents Sea

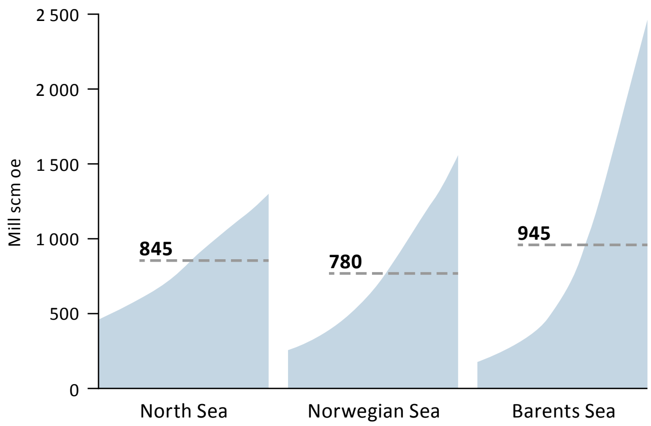
The potential of the 23 plays in the North Sea is indicated with their expected value in figure 2.5. Unconfirmed plays are depicted with a lighter colour above the expected value. This shows the additional potential if the play is confirmed.

Figure 2.6 presents the potential of the 19 plays in the Norwegian Sea with their expected value. The 10 unconfirmed plays are depicted with a lighter colour above the expected value. This shows the additional potential if the play is confirmed.

The potential of the 27 plays in the Barents Sea is shown with their expected value in figure 2.7. The 19 unconfirmed plays are depicted with a lighter colour above the expected value. This shows the additional potential if the play is confirmed.

The additional potential from unconfirmed plays is smallest in the North Sea and largest in the Barents Sea. Estimates for the plays and areas which are best known from exploration activity over a long time contain the lowest level of uncertainty. That combines with the additional potential of the unconfirmed plays and is reflected in the overall uncertainty for the estimates in each area. Figure 2.8 clearly shows that the uncertainty range is narrowest in the North Sea and widest in the Barents Sea. The uncertainty range is expressed as 90 per cent probability. This means that the probability of coming true is 95 per cent for the lowest resource outcome or higher, and five per cent for the highest resource outcome or higher.

Undiscovered resources on the NCS comprise approximately equal volumes of liquids and gas. See figure 2.9. However, big differences exist between the various sea areas, as shown in figure 2.10. Estimates are presented with their expectation (mean) value and uncertainty range.



Figur 2.8 Undiscovered resources with expected value and uncertainty range

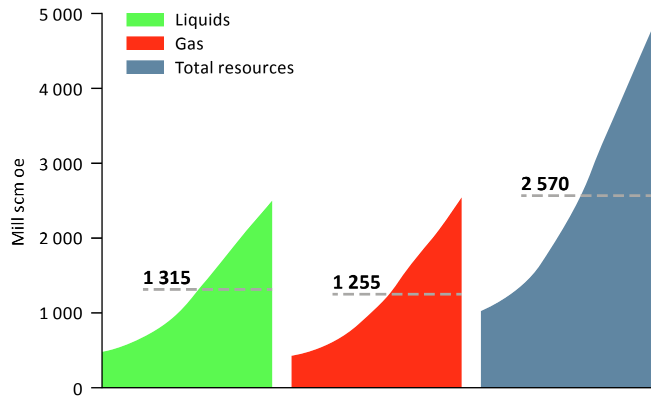


Figure 2.9 Total undiscovered resources divided between oil and gas

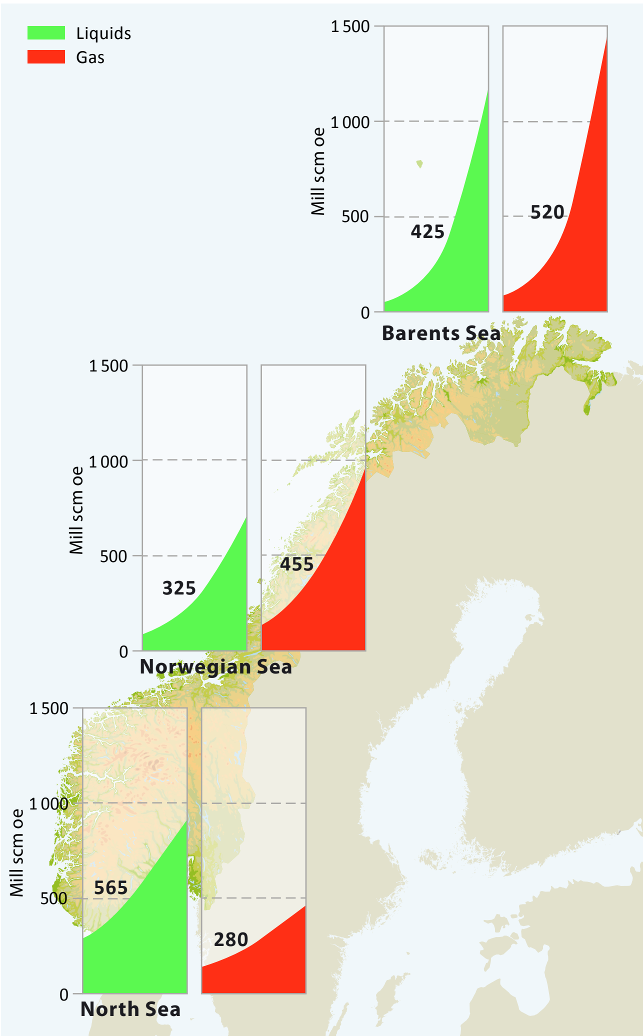


Figure 2.10 Distribution of expected undiscovered liquid and gas resources

Changes to and reductions in estimated undiscovered resources

The NPD regularly publishes new figures for undiscovered resources on the NCS, with the method used unchanged since the mid-1990s. That provides a good basis for comparing the various estimates. Great uncertainty prevails on a frontier continental shelf about the properties of the plays and the opportunities for making discoveries. Comparing the NPD's estimates for undiscovered resources from 1996 to 2010 reveals an increase up to 2002, followed by a decline. See figure 2.11. This is a natural consequence of the maturing of the NCS, increasing volumes of data and growing knowledge of geological conditions. In the mature part of the NCS, it is natural that the estimate of undiscovered resources gradually decreases as prospects are explored by drilling and petroleum is proven. Almost 400 million scm oe were discovered on the NCS from 2006 to 2010.

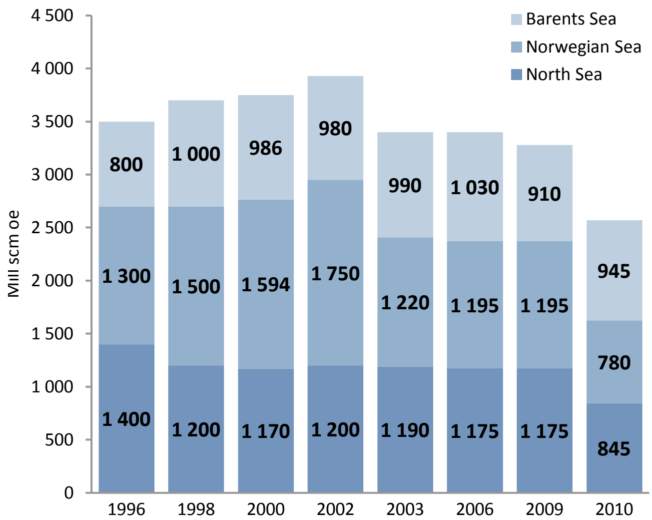


Figure 2.11 The NPD's estimates of total undiscovered resources over time for the North, Norwegian and Barents Seas

Reduced expectations for gas

The reduction in the estimate for undiscovered resources in the North and Norwegian Seas primarily reflects lower expectations for gas discoveries. In the North Sea, the adjustment is largely based on the discovery histories for several plays. These show that more liquids than gas have been proven compared with earlier estimates, particularly in Jurassic reservoirs. The adjustment for the Norwegian Sea partly reflects lower expectations following new mapping off Lofoten, Vesterålen and Senja, where the prospects in a number of areas are smaller than previously assumed. Moreover, exploration results in the Vøring Basin during recent years have failed to live up to expectations. Figures 2.12 and 2.13 present the NPD's estimates for undiscovered liquids and gas in the three latest principal analyses, carried out in 2003, 2006 and 2010.

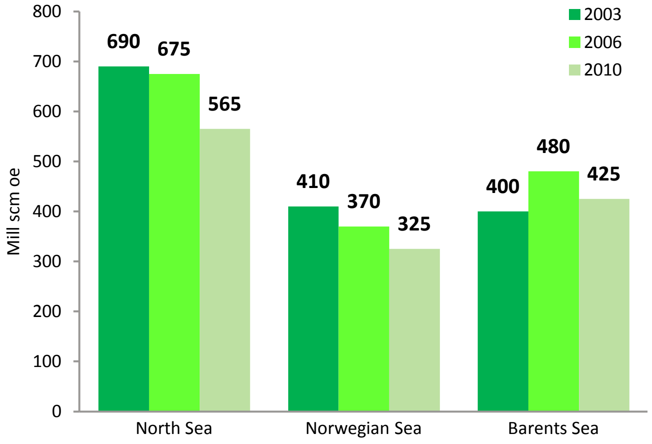


Figure 2.12 The NPD's estimate of undiscovered liquids in the three latest principal analyses for the North, Norwegian and Barents Seas

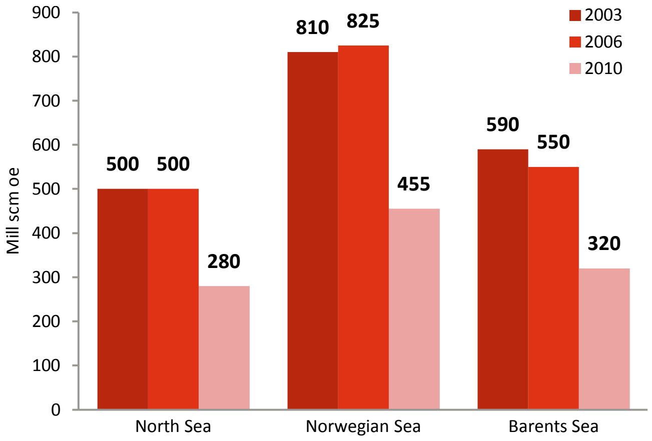


Figure 2.13 The NPD's estimate of undiscovered gas in the three latest principal analyses for the North, Norwegian and Barents Seas

North Sea

The estimate for undiscovered resources in the North Sea has been reduced by 28 per cent since 2006. A number of discoveries have been made in these waters in recent years, totalling almost 200 million scm, but they are generally small. The 16/2-8 ("Aldous Major South") discovery proven in 2011 is not included in the analysis of undiscovered resources. Expectations for Late Jurassic and Palaeocene plays have been cut back substantially on the basis of discoveries and extensive mapping of prospects in the APA process, both by the oil companies and the NPD. Figure 2.14 shows the Palaeocene play where expectations have been reduced the most.

Most discoveries since 2006 have been made in Jurassic and Triassic plays. The reduction in the NPD's estimate largely coincides with the volume of resources discovered.

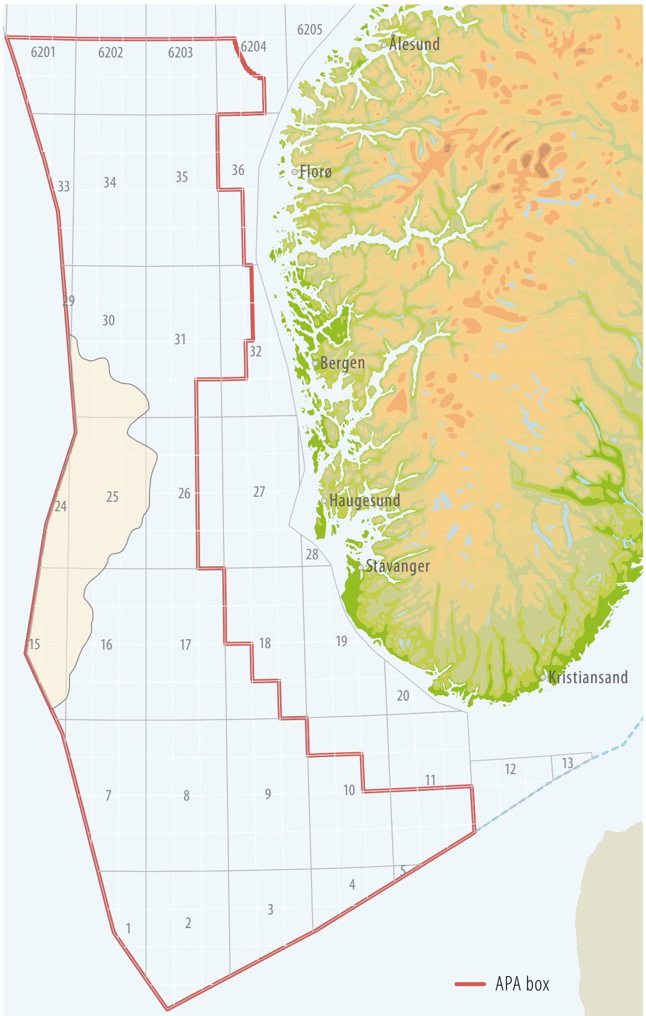


Figure 2.14 The Palaeocene play in the North Sea where expectations have been reduced the most

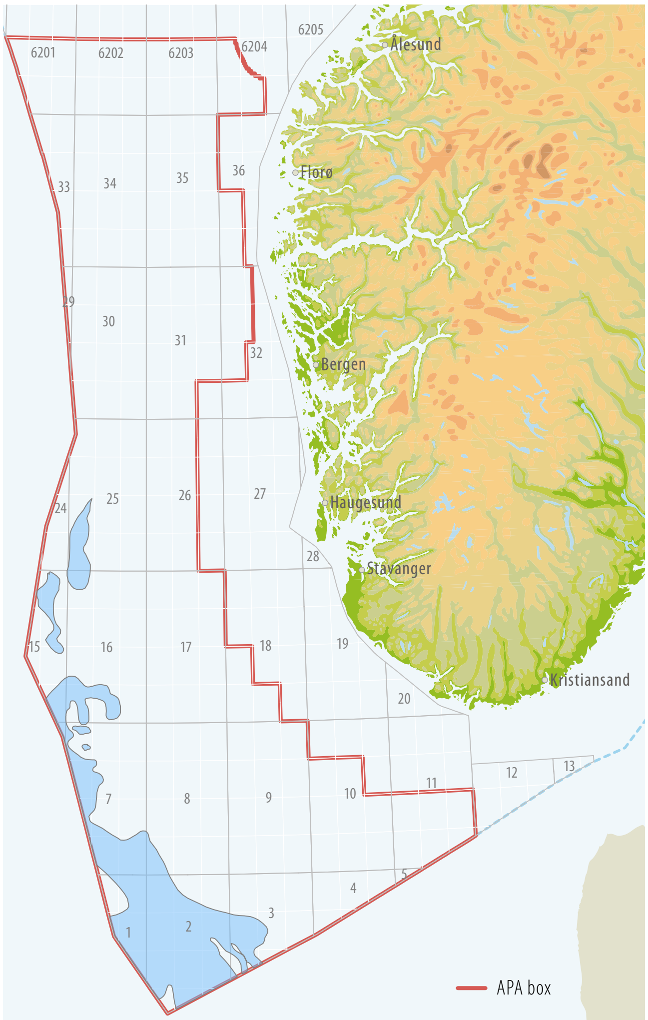


Figure 2.15 The Late Jurassic play in Norway's southern North Sea sector

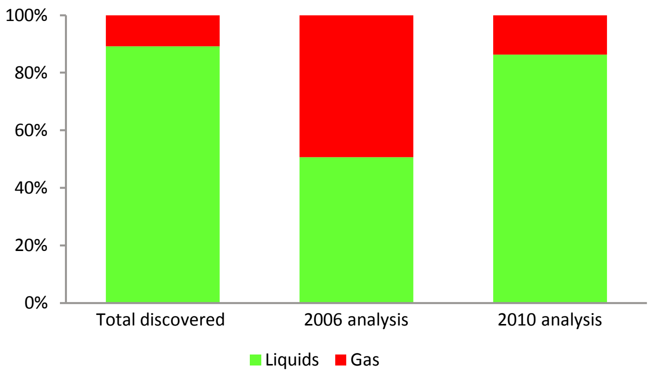
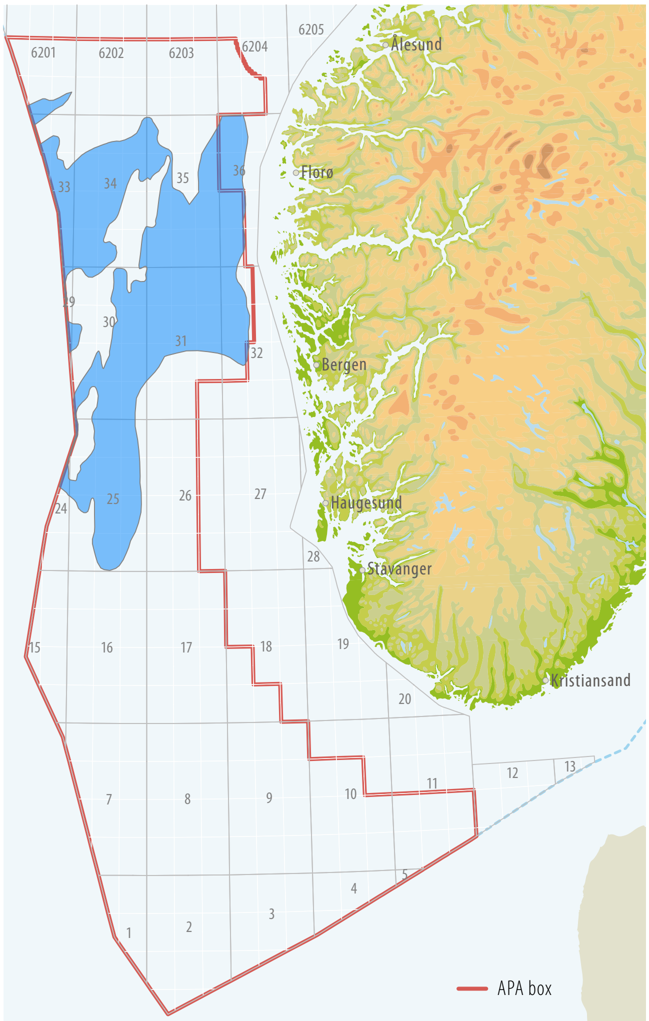


Figure 2.16 Distribution of gas and liquids in the North Sea's Late Jurassic play



Figur 2.17 The Triassic to Middle Jurassic play in Norway's northern North Sea sector

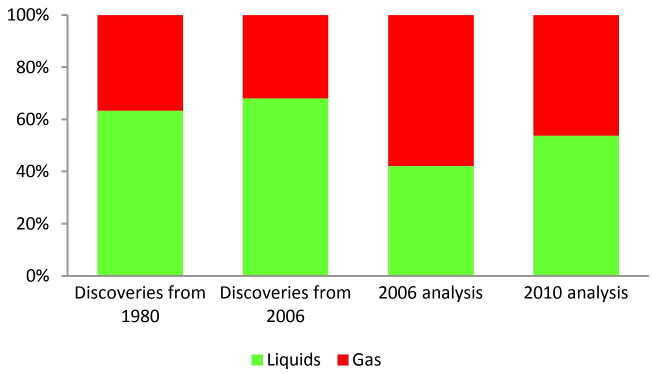


Figure 2.18 Distribution of gas and liquids in the Triassic to Middle Jurassic play

The NPD has adjusted the relationship between liquids and gas in the estimate based on discoveries made. The biggest changes relate to the Upper Jurassic play in Norway's southern North Sea sector – see figures 2.15 and 2.16 – and to the Triassic to Middle Jurassic play in the northern North Sea sector. See figures 2.17 and 2.18.

A relatively larger number of oil and gas discoveries have been made in the Late Jurassic play. In 2006, the NPD expected that considerable volumes of undiscovered gas would be found in this play, which lies deeply buried in the southern North Sea sector. A number of large prospects have been drilled in this area without making substantial discoveries. The NPD's estimate for the play has therefore been reduced and the gas/oil ratio adjusted so that it accords to a greater extent with existing discoveries.

Substantial volumes of both gas and oil have been found in the Triassic to Middle Jurassic play in the northern North Sea sector, and some of the largest fields on the NCS belong to this play.

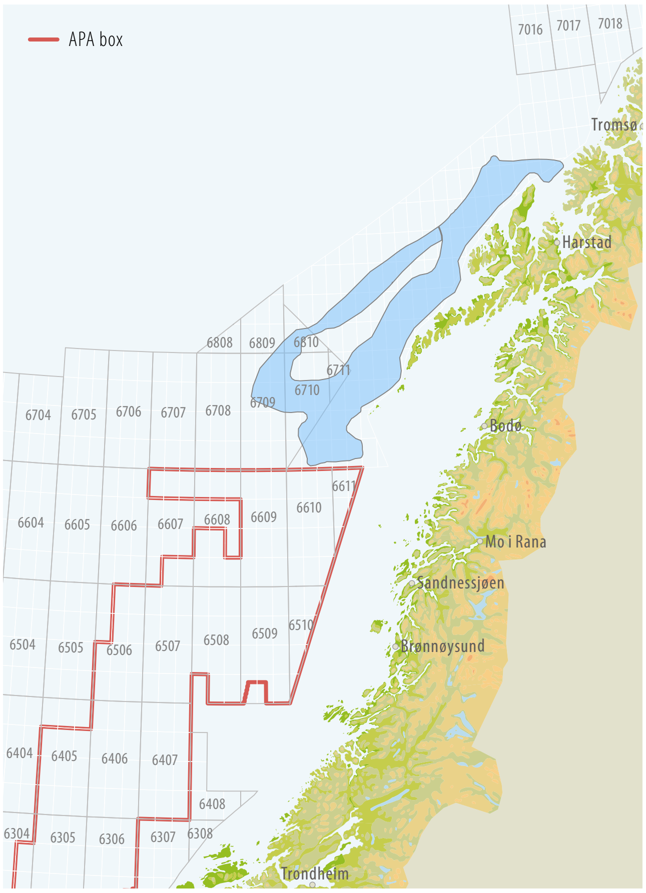


Figure 2.19 The Jurassic play off Lofoten

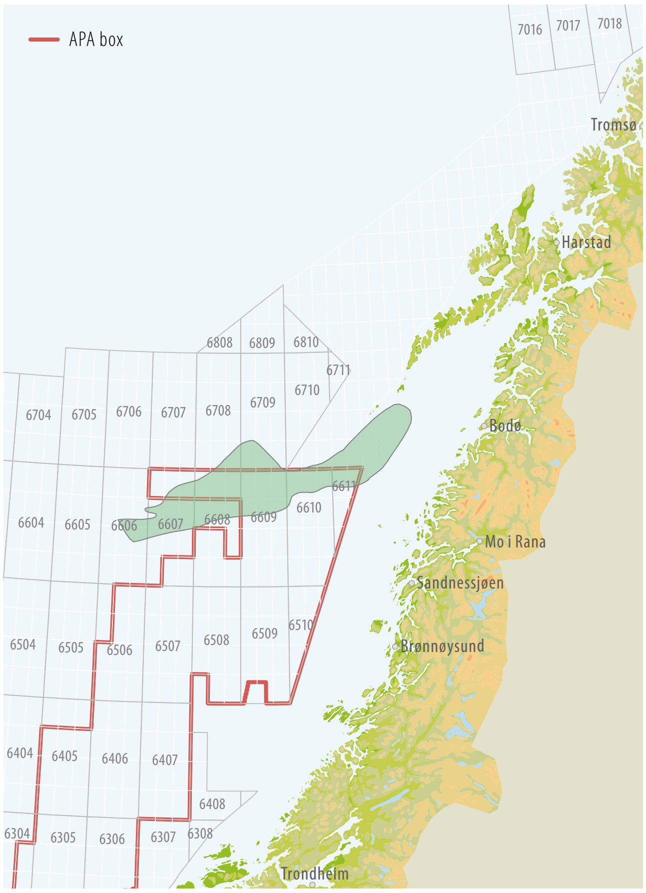


Figure 2.20 The Late Cretaceous play in Nordland III

Figure 2.18 shows that more oil than gas has been discovered since 1980. That trend has continued over the past five years. In 2006, the NPD estimated that a substantial proportion of the undiscovered resources would be gas because deep prospects on both sides of the Viking Graben were interpreted as containing gas. However, exploration drilling since 2006 has shown that the play contains mostly oil, and its gas/oil ratio was adjusted in 2010 to accord better with the discovery history.

Norwegian Sea

The estimate for undiscovered resources in the Norwegian Sea is 35 per cent down from 2006. During these four years, 161 million scm oe have been discovered. Discovery expectations are more or less unchanged for oil, but sharply reduced for gas. This cut largely relates to four plays.

A detailed interpretation of the Jurassic play off Lofoten was conducted by the NPD in 2010. See figure 2.19. Based on a new mapping of prospects, expectations for gas in particular have been sharply reduced in this area.

Because the prospects are smaller than previously assumed and because many of them lie at a shallow depth, expectations for undiscovered gas resources have been reduced.

The Late Cretaceous play in the Nordland III area has been re-evaluated, with the play probability reduced on the basis of certain poorly defined prospects. See figure 2.20. No discoveries have been made in this play.

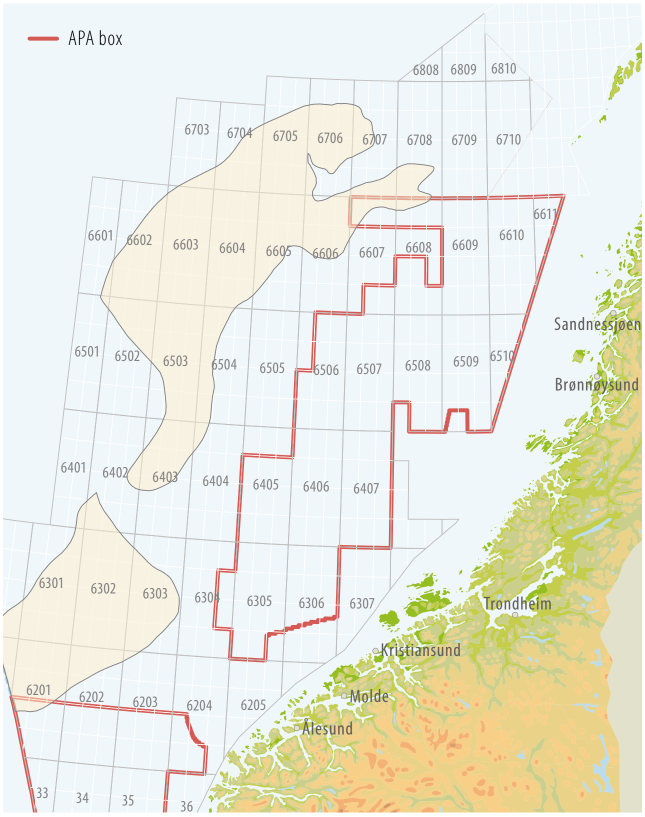


Figure 2.21 One of the Palaeocene plays in the Norwegian Sea

Following disappointing results, including the 6302/6-1 ("Tulipan") discovery and the 6607/2-1 ("Cygnus prospect") well, the estimate for a Palaeocene play in the Møre and Vøring Basins has been reduced.

A Late Cretaceous play in the Vøring Basin arouses great expectations. See figure 2.22. This has been investigated with a number of wells, leading to several discoveries. However, these are smaller than expected. That includes 6603/12-1 ("Gro"). The area has been interpreted thoroughly by a number of companies, and the exploration results have led to a reduction in expectations since 2006 for several of the prospects anticipated to have a Cretaceous reservoir. However, a substantial remaining potential in the play has yet to be explored, so that positive results could be possible in the future.

Barents Sea

The estimate for undiscovered resources in the Barents Sea is by and large unchanged from the NPD's analysis in 2009, as described in the NPD's resource report for that year. A minor change has been made on the basis of the NPD's interpretation of the southernmost part of the Barents Sea, described in the 2010 report on petroleum resources in the sea areas off Lofoten, Vesterålen and Senja. This mapping work identified new prospects and plays in Troms II and on the Egga Margin, so that the 2010 estimate for the Barents Sea is slightly higher than the figure given in 2009.

Unconventional petroleum resources

Unconventional petroleum resources is a collective term for oil and gas deposits which cannot be recovered commercially with conventional production wells and technology, normally because flow to the wells would be very low.

Geological deposits of unconventional gas are characterised by tight rocks requiring a great many production wells and fracturing of the reservoir for the resources to flow to these producers. Another form involves gas bound up in gas hydrates, a solid from which the gas can only be liberated by such means as heating, pressure depletion or replacement with CO_2.

Geological deposits of unconventional oil can occur where the crude is so viscous that it will not flow to conventional production wells. Such oil can be recovered by mining operations or by unconventional techniques such as steam injection. Unconventional oil can also be found in shale, coal or reservoir rocks with very low permeability. In addition, residual oil can be defined as unconventional. This is crude which exists in a permeable reservoir, but in such a low concentration that only water will flow through the rock to the producers.

Rising energy demand and prices are encouraging rapid technological development, so that the dividing line between conventional and unconventional petroleum resources is shifting. Growth in shale gas production since 2005, particularly in the USA, has already become significant for gas markets. If oil prices remain high, faster progress can be expected with the big bitumen and heavy oil fields in Canada and Venezuela.

Technological advances and production of unconventional petroleum primarily occur on land, where well costs are low. Unconventional resources on the NCS have not been mapped so far and are not included in the resource account. The cost of possible recov-

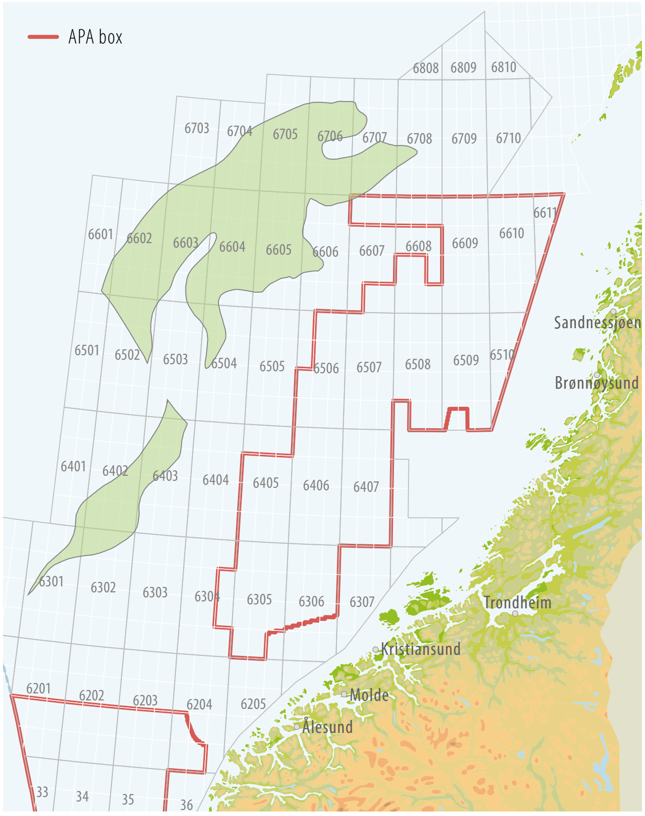


Figure 2.22 One of the Late Cretaceous plays in the Norwegian Sea

ery would be excessive with today's technology. It is nevertheless important to keep abreast of technological developments with an eye to future applications and to be able to predict market trends.

Large volumes in place

In most sedimentary basins, the quantity of unconventional resources in place is many times larger than conventional resources in place. This is because petroleum forms in organically rich claystones, usually at depths of four-six kilometres. The claystones must be saturated with petroleum before oil and gas sweat out and migrate upwards through the overlying sediments on their way to the seabed. Part of the petroleum is caught in traps on the way. Such traps are sealed structures comprising permeable reservoir rocks, and these formations contain the conventional resources. Over geological time, traps can be regarded as temporary residences for the petroleum flowing from source rock to surface. Unconventional resources are bound in the source rock (oil and gas shales), in tight sandstone layers, in carbonate rocks and in coal, and can be captured in gas hydrates, shallow gas pockets or as heavy oil near the surface.

The very large volumes of unconventional resources make them attractive but, even with new technology, it will in many cases be very resource-intensive in terms of costs, energy consumption and environmental burdens to produce even small percentages of the volumes in place.

Norway and the NCS

No unconventional petroleum resources of significance are known in mainland Norway. Organically rich Cambrian shales (alun shales) are widespread, particularly in eastern Norway and Finnmark county, but these have been exposed to such high temperatures that the oil has boiled off. Oil shales of the same age are produced in Estonia and are being investigated in the Skåne area of Sweden. Svalbard contains several layers of organically rich shales, and further investigation of Middle Triassic shale (the Botneheia formation) has been proposed.

The NCS contains a number of active petroleum systems and accordingly also has unconventional resources associated both with deep source rocks and with migration routes to the seabed.

Large volumes of gas are found in deeply buried source rocks in the Central Graben (Ekofisk area) and the Viking Trough in the North Sea, and on the Halten Terrace in the Norwegian Sea. In these areas, gas is also likely to be found at very great depths in sandstones with low permeability (tight gas). A conceivable first step in the future could be to assess recovery of those resources which currently lie on the borderline between unconventional and conventional. The 6506/6-1 ("Victoria") gas discovery on the Halten Terrace is an example of a tight gas find where some of the resources can be produced conventionally. However, large volumes of this gas lie in reservoir rocks with such low permeability that producing it would probably require a great many wells and be extremely expensive with today's technology. Large quantities of hydrocarbons have leaked to the overlying shale layers from the big fields in the Ekofisk area over several million years. These represent a volume in place which cannot be produced commercially today. A very small proportion lies in rather more permeable rocks.

Anthracite coal is able to absorb a great deal of gas and light oil. Coal is a substantial source of gas in many countries which mine it. The gas has traditionally been produced from abandoned coal mines, but "coal bed methane" has become an exploration goal in itself. This is recovered by drilling production wells into coal, which must usually be fractured by one means or another. Studies are also being conducted into the possible use of carbon injection in connection with gas production from coal. On the NCS, coal has been proven in Lower and Middle Jurassic rocks from just off the coast and out to the fields. In areas with infrastructure, thick coal beds have been identified, for example, in the Sleipner formation at the southern end of the Viking Graben and in the Åre formation on the Halten Terrace. Rough estimates have been made of the total quantity of coal on the NCS, but the NPD is not aware of how many of these deposits contain interesting amounts of gas.

Gas hydrates are a combination of water and gas which forms ice-like crystals. Stable under high pressure and low temperature, they are formed naturally where methane is in contact with pore water in deep seas and under thick permafrost. Gas hydrates can form a continuous layer through sediments a few hundred metres beneath the seabed, and methane will often be trapped under the gas hydrate layer. Gas hydrates are very widespread, and pilot studies have been initiated to look at opportunities for recovering gas from such sources in deep water on the Japanese continental shelf (Nankai Trough) and on land in Canada (the Mallik field). Production can be accomplished by either reducing pressure or increasing temperature around the producers, so that the hydrates convert to gas and water. On the NCS, gas hydrates have been proven in the Norwegian Sea north of Storegga, in the western part of the Barents Sea and off Svalbard. The deposits so far proven on the NCS look like being thin and located in clays, and are therefore unsuitable for production. In the Japanese and Canadian pilot studies, the gas hydrates lie in reservoir rocks.

Producing oil fields will end up with residual oil saturations. Several improved oil recovery (IOR) methods, including carbon or surfactant injection, aim to produce oil from reservoirs with residual saturation. Residual oil also occurs naturally as unconventional resources in large rock volumes beneath oil and gas fields where the seabed was eroded during the ice ages. The best-known deposits are found under Troll in the North Sea and in the Hammerfest Basin of the Barents Sea.

Extra-heavy oil and bitumen are very viscous liquids. Bitumen has a viscosity of more than 10 000 cp at reservoir temperature. Deposits may be called tar sands, oil sands, natural asphalt or oil-impregnated sands, and are found in many parts of the world – particularly Canada. Extra-heavy oil is rather less viscous than bitumen, and large deposits occur in Venezuela. Thin layers of sand impregnated with extra-heavy oil have been found on the NCS in association with fields, but no deposits likely to be of commercial interest are proven.

Unconventional petroleum resources

Bitumen and extra-heavy oil

No substantial deposits of bitumen or extra-heavy oil have been identified on land in Norway. Petroleum of this type has been observed in a number of wells on the NCS, but it would be difficult to map and produce. Compared with conventional oil and gas on the NCS, this resource attracts little commercial interest in Norway at the moment.

Oil shale

No substantial quantities of oil shale have been identified on land in Norway. Large deposits probably exist offshore, particularly in Late Jurassic and Cretaceous source rocks. The cost of offshore drilling and production, even in moderate water depths, is currently too high for such deposits to be commercially interesting.

Shale gas

No such resources have been mapped in mainland Norway or on the NCS. It is unlikely to become an important Norwegian resource.

Gas hydrates

Research is currently being pursued into carbon injection in gas hydrates. CO_2 could replace the methane reservoir, liberating the latter gas for production.

Energy from North Sea coal beds

Parts of the North Sea basin contain large coal beds. Substantial volumes have been proven beneath the Sleipner fields. Ideas for exploiting this energy have been suggested, including igniting it and recovering the heat to drive steam-turbine power stations. Substantial coal deposits also exist on the Halten Terrace in the Norwegian Sea, where most of the oil and gas discoveries in these waters lie, and on the Trøndelag Platform close to the coast between Kristiansund and Bodø. Those beds nearest land lie at a moderate depth under the unconsolidated sediments which were deposited during the ice ages.

CHAPTER **3.** Exploration

Introduction

The level of exploration activity on the NCS in recent years has been high. This increase primarily reflects high oil prices and changes to Norwegian exploration policy.

Many discoveries have resulted from the high level of activity. Collectively, however, discoveries in recent years have been too small to replace annual production even though several major finds have been made so far in 2011. The present year could be the first since 1997 in which the resources found are big enough to replace the volume produced.

If production on the NCS is to be maintained at a high level, the size of discoveries must be larger than the average for the past 10 years. Exploration under the basalt layers in deep parts of the Norwegian Sea could open new opportunities, while further discoveries in the North and Barents Seas have encouraged optimism. Opportunities for making large discoveries are probably greatest in parts of the unopened areas on the northern NCS.

Many wells

A total of 1 325 exploration wells had been drilled on the NCS over the 45 years from the first drilling until 31 December 2010. The number of such wells peaked initially in the 1980s, with up to 50 drilled per year. See figure 3.1. A low annual figure for exploration wells characterised the second half of the 1990s and the first five years after 2000.

Over the past three years, the number of exploration wells spudded has been on a par with or greater than the peak period in the early 1980s. The North Sea continues to account for the largest number of such wells.

Increased exploration

A correlation has historically existed between oil prices and the number of wildcat wells drilled on the NCS. This is illustrated by figure 3.2, where the number of wildcats is compared with the oil price in the previous year.

When oil prices rise, the consequence is generally that the number of wildcats increases in the following year. A lot of such wells are spudded in periods with very high oil prices. That occurred in the early 1980s and has been repeated over the past three years. However, this pattern was not so clear in the second half of the 1990s and the first five years after 2000. Oil prices fell sharply during the Asian economic crisis in 1998-99, and the oil companies reacted with a marked cut-back in exploration investment. Oil prices then rose, but exploration remained low for several years.

There were several reasons for the latter development. One could be that exploration activity is particularly affected by price uncertainty. When oil prices change from stable to unpredictable, the result can be lower capital expenditure. Exploration is particularly vulnerable in such conditions because it represents a long-term

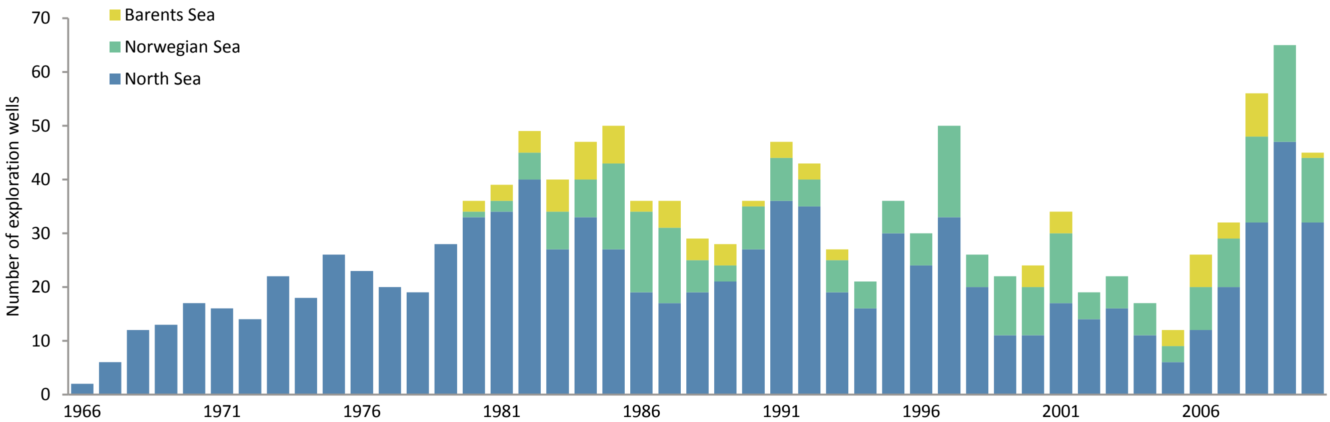


Figure 3.1 Number of exploration wells spudded by area, 1966-2010

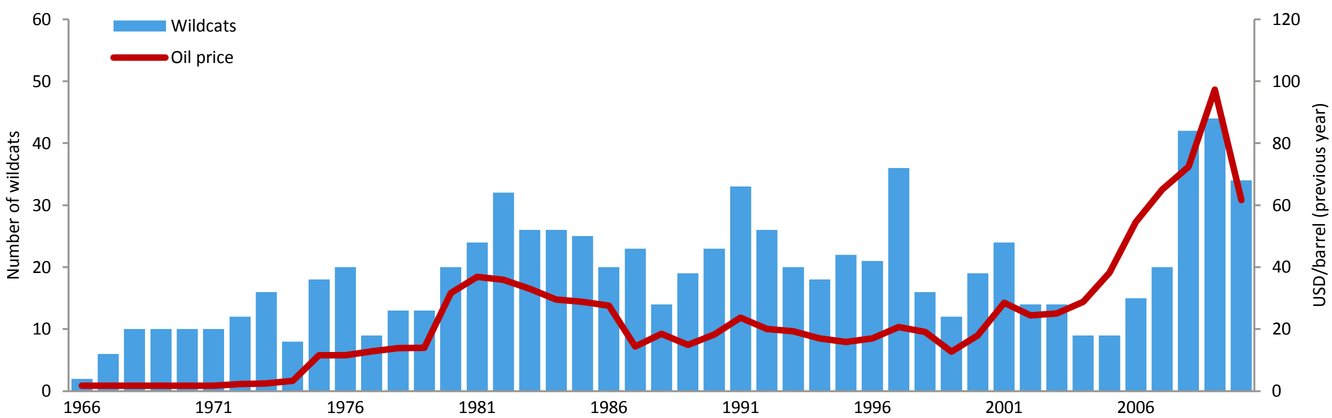


Figure 3.2 Nominal oil prices and number of wildcat wells spudded on the NCS, 1966-2010

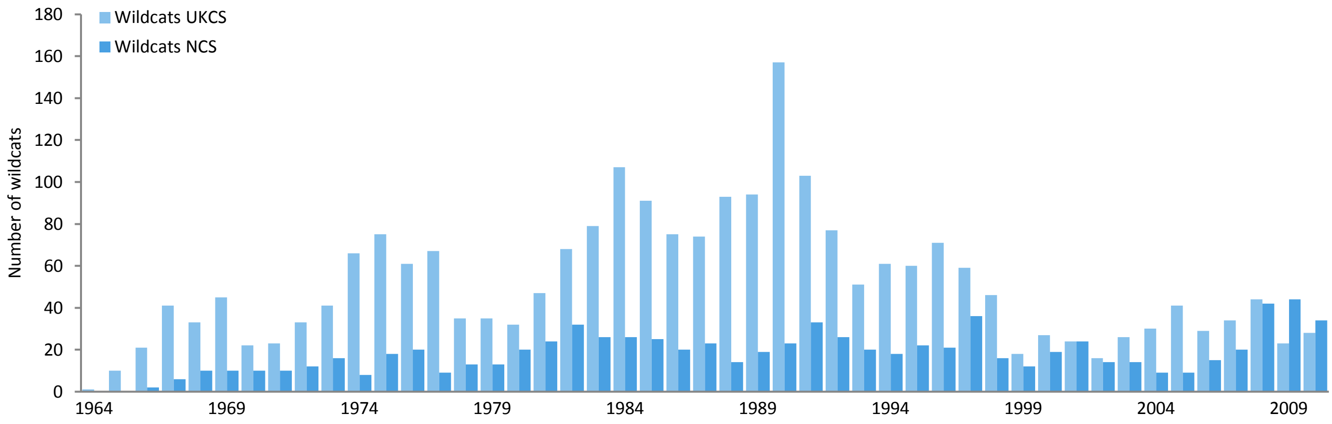


Figure 3.3 Number of wildcats spudded on the NCS and the UKCS, 1964-2010

and risky investment. Financial markets during this period also put heavy pressure on the oil companies to improve their short-term financial performance, which probably contributed to a postponement of exploration spending.

A sharp rise in demand for oil towards 2010 once again boosted prices, which helped to drive up global exploration activity. High oil prices have also generated optimism on the NCS, and thereby contributed positively to the number of exploration wells.

In addition, the Norwegian government has encouraged more exploration in mature areas through policy changes – including easier entry for new players, increased access to acreage, amendments to the area fee and tax changes. These moves may have contributed to a higher number of wildcats on the NCS than on the UK continental shelf (UKCS) over the past two years. See figure 3.3.

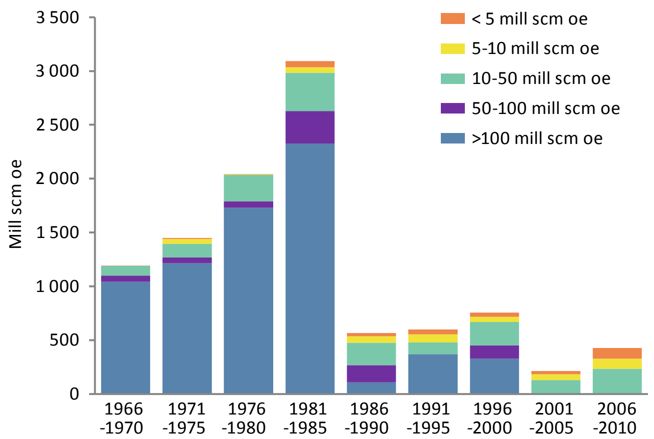


Figure 3.4 Resources in discoveries proven in five-yearly periods by discovery size, 1966-2010

Every little helps

International experience demonstrates that the largest discoveries in a new petroleum province are made early in the exploration phase, and that the size of finds gradually declines. That also holds true for the NCS. In a historical context, discoveries over the past 25 years have been small. However, there will always be exceptions.

The contribution of discoveries to resource growth has been substantially lower over the past 25 years than was the case in the first 20 years of Norway's oil history. This is illustrated by figures 3.4, which shows resource growth from discoveries by discovery size, and 3.5, which presents the cumulative growth in resources on the NCS.

Since 1998, the annual growth in resources has been lower than annual production. This is illustrated by figure 3.6, which shows resource growth and production per annum.

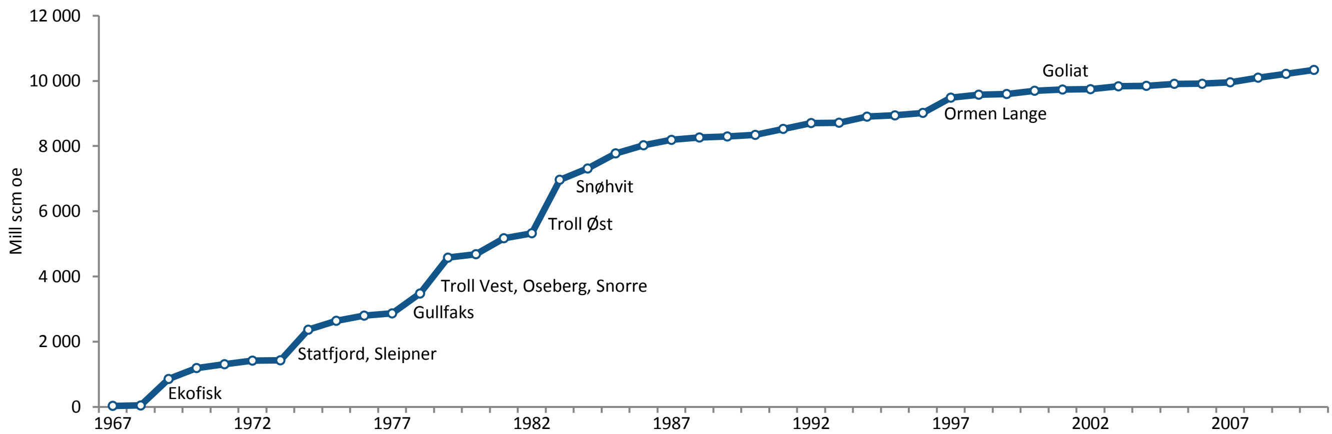


Figure 3.5 Cumulative growth in resources, 1967-2010

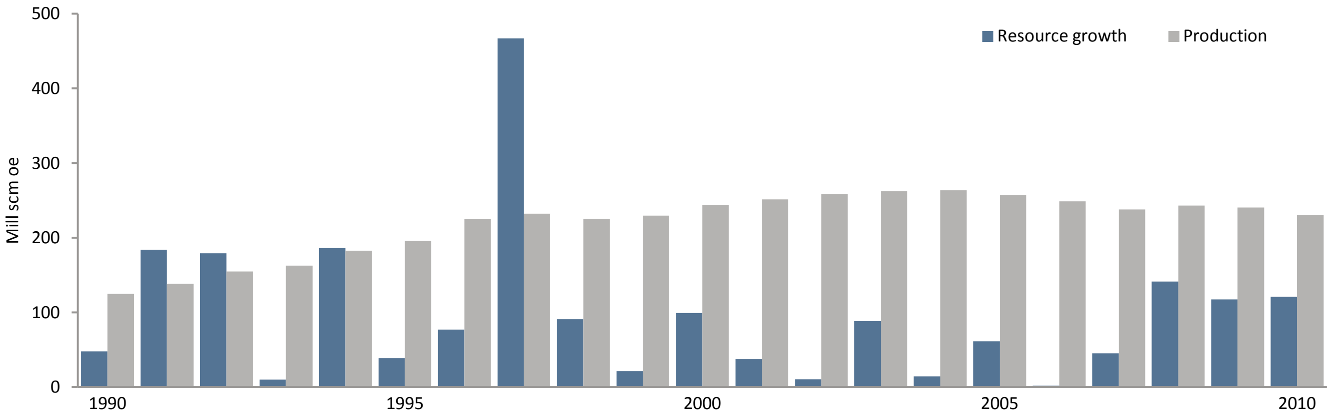


Figure 3.6 Annual resource growth and production, 1990-2010

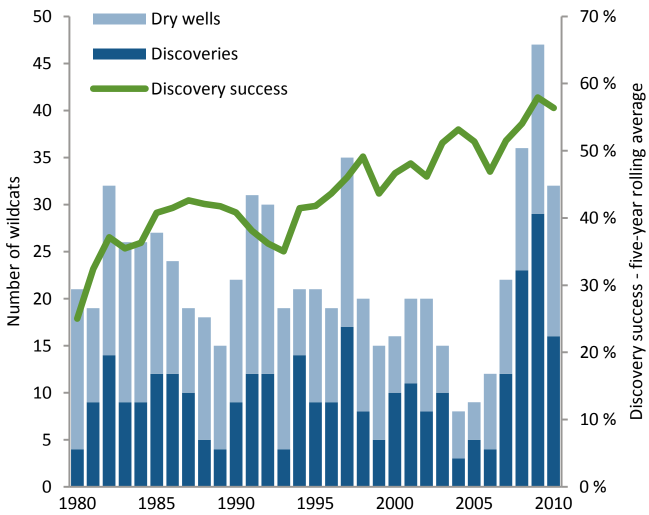


Figure 3.7 Number of completed wildcats, number of discoveries and discovery success on the NCS, 1980-2010

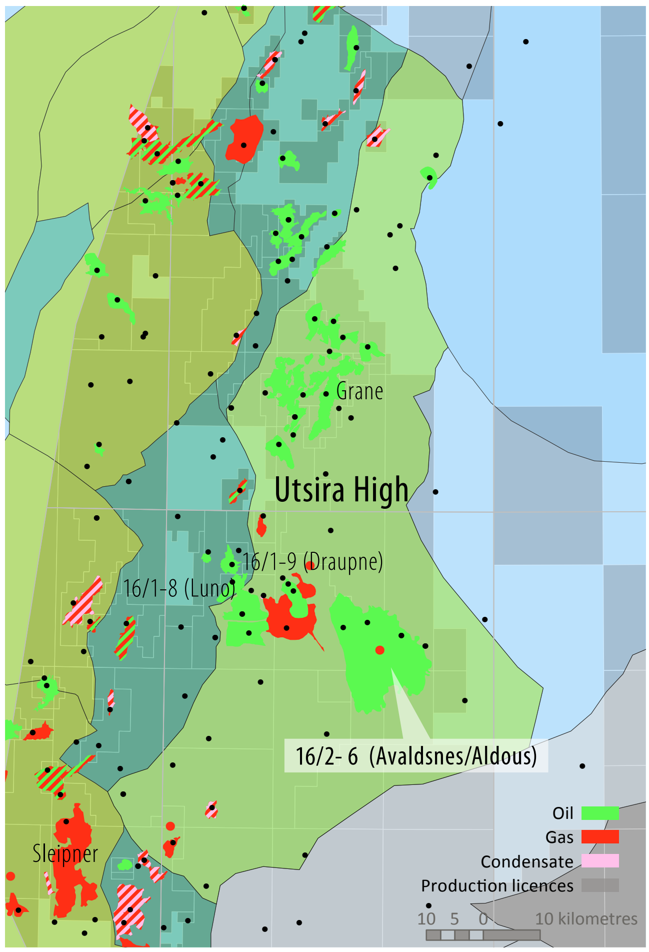


Figure 3.8 The Utsira High in the North Sea

Varied discovery success

The average discovery success on the NCS is very high by international standards. Sequential exploration, technological developments and steadily growing knowledge have enhanced the probability of making new discoveries. Over the past 30 years, discovery success has risen from around 25 per cent in 1980 to roughly 55 per cent in 2010. See figure 3.7.

Most discoveries continue to be made in the North Sea, where discovery success has averaged about 45 per cent since 1967. It has been very high in recent years, at more than 50 per cent. Exciting discoveries are still being made, with new plays being confirmed in areas with a long exploration history. An interesting region is the Utsira High in the central part of Norway's North Sea sector, where 32 exploration wells have been drilled. Although regarded as a mature area, it has yielded new types of reservoirs over the past five years. A number of interesting medium-sized discoveries have been made, such as 16/1-8 ("Luno") and 16/1-9 ("Draupne"). Exploration drilling over the past year has also proven 16/2-6 ("Avaldsnes") and 16/2-8 ("Aldous Major South"), which could jointly become a major new oil discovery on the NCS. Substantial drilling activity is planned in the area during the time to come.

Avaldsnes and Aldous

Wells 16/2-6 ("Avaldsnes") and 16/2-8 ("Aldous Major South") could jointly rank as the largest oil discovery on the NCS since the 1980s. They were drilled about 40 kilometres south of Grane. Both discoveries have been made in a combination of stratigraphic and structural closure, with Upper Jurassic sandstones forming the reservoir. Well data show that the two discoveries share the same oil/water contact, which indicates communication between them. Based on preliminary resource estimates, a stand-alone development is very realistic.

Figure 3.9 Deepwater wells in the Norwegian Sea and proven resources by operator

As in the North Sea, the Norwegian Sea has witnessed a positive trend for discovery success and many finds have been made despite disappointing exploration results also being recorded. Since the deepwater part of this region was opened in 1994, 25 wildcats have been drilled in depths beyond 600 metres. See figure 3.9. The discovery rate in deep water is close to 50 per cent, compared with just over 40 per cent in other parts of the Norwegian Sea.

Fewer discoveries than expected have been made in deep water. Results from deepwater wells indicate that proven expected recoverable resources are less than 40 per cent of the resources expected before drilling.

Sub-basalt in the Norwegian Sea

The sub-surface in the western part of the Norwegian Sea was affected by extensive volcanic activity when the North Atlantic opened about 55 million years ago (early Eocene). Lava flowing from the Earth's interior hardened into layers of basalt, a dark hard rock present beneath the western Norwegian Sea. Sedimentary rocks which could contain petroleum in these areas were largely deposited before the vulcanism began, and accordingly lie beneath the basalt.

This rock is difficult to "see" through, so the challenge is to obtain an impression of the underlying strata. Much work has been devoted to learning more about what lies beneath the basalt, both by companies in production licences and by other projects, such as the Force collaboration.

The NPD's seismic mapping west of the Møre Basin, on the Møre Marginal High, indicates that the latter area was centrally placed in the transport route for sediments from Greenland about 65 million years ago (Palaeocene). See figure 3.10. Coarse-grained sediments were carried by rivers from Greenland eastwards to Jan Mayen and the Møre Marginal High, and deposited as sedimentary fans in the Møre Basin. This process could have deposited reservoir rocks in all three areas during the Palaeocene. The NPD's

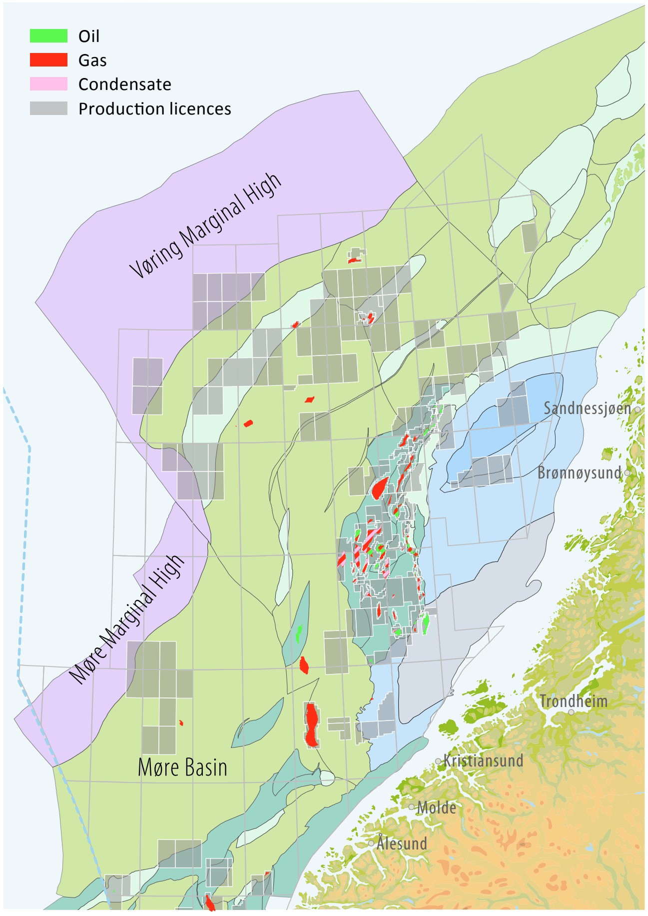


Figure 3.10 The Norwegian Sea with the Møre Marginal High, the Møre Basin and the Vøring Marginal High

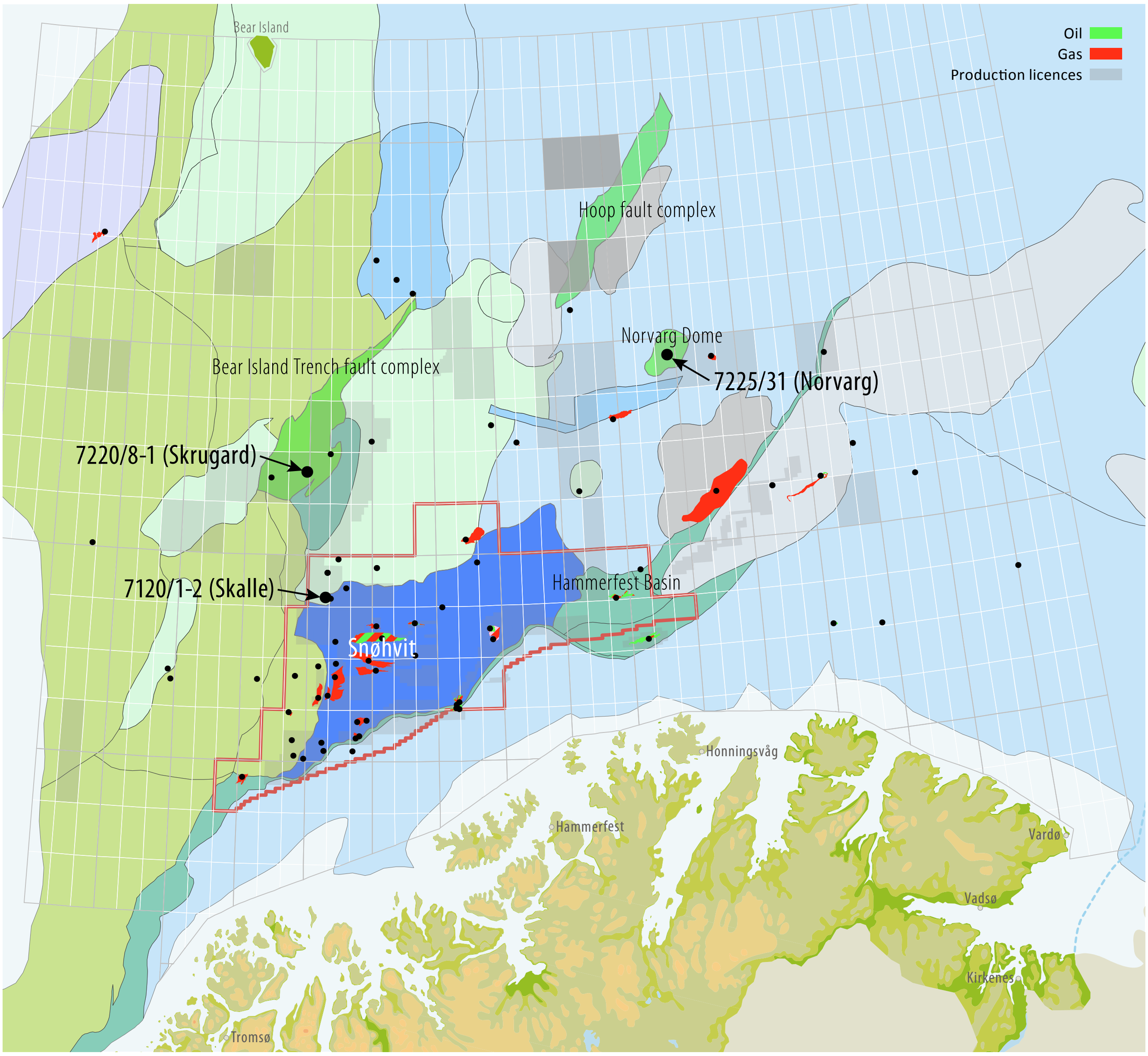


Figure 3.11 Barents Sea South with discoveries to date in 2011

The Force collaboration

FORCE

(Forum for Reservoir Characterisation, Reservoir Engineering and Exploration) is a collaboration between oil companies on the NCS whose main jobs are helping to enhance reserves and to prioritise activities which increase exploration success and petroleum recovery. Activities in Force are organised in two technical committees for improved exploration and improved oil and gas recovery respectively. Each committee has sub-committees for network building and projects.

interpretation of two-dimensional (2D) seismic data has revealed an area of the Møre Marginal High with no basalt cover. This could function as a "keyhole" for looking beneath the basalt layer.

The NPD acquired 2D seismic data on the Møre Marginal High in the summer of 2011. Together with earlier survey results, this material will be used to plan two shallow wells in this area's "keyhole". They are due to be drilled in 2013. Information from these shallow wells will clarify the interpretation of the area. A possible Palaeocene play under the basalt will be highly significant, both for the Møre Marginal High and for prospective areas around Jan Mayen. The play could also be relevant further north – on the Vøring Marginal High, for instance.

Petroleum has been found in and under basalt strata in several parts of the world. The closest discoveries are off Ireland and west of Shetland on the UKCS. Wells have also been drilled to seek petroleum under the basalt on the Faroese continental shelf, so far without success.

Four production licences with prospectivity related to basalt challenges were awarded in the 20th and 21st licensing rounds. No decision has so far been taken on drilling wildcats in any of these licences.

Almost 90 wells have been spudded in the Barents Sea since the first wildcat was drilled there in 1980. The discovery rate in the Hammerfest Basin has been high, even though few of the finds are considered commercial, and stands at roughly 50 per cent compared with just under 40 per cent for the rest of the Barents Sea.

Snøhvit is the only producing field in the Barents Sea. See figure 3.11. This gas field covers the 7121/4-1 (Snøhvit), 7120/8-1 (Askeladd), 7120/7-1 (Askeladd Vest), 7120/7-2 (Askeladd Sentral), 7120/9-1 (Albatross) and 7121/7-1 discoveries. The Goliat oil field is under development. Some discoveries have been made near Snøhvit and Goliat, and the area also contains a number of prospects. The most likely development solution for existing discoveries and possible new finds in the Snøhvit and Goliat area will be to tie them back to existing installations. Stand-alone developments could be relevant for other parts of the Barents Sea.

Seven exploration wells are due to be drilled in the Barents Sea during 2011. The first two (7120/12-5 and 7119/12-4) were dry, while the next three resulted in discoveries (7220/8-1 ("Skrugard"), 7225/3-1 ("Norvarg") and 7120/2-3 ("Skalle")).

fault complex, where production licences 537 and 615 involve commitment drilling. Both oil and gas could be found in this area.

High exploration costs

Exploration costs are incurred by production licences from the time they are awarded until a possible discovery is developed, and comprise spending on seismic surveying, exploration wells, field evaluation and administration. These costs have increased in recent years, reflecting both the growth in exploration activity on the NCS and general cost inflation nationally and internationally. See figure 3.12

Drilling represents the most important single factor in total exploration costs. It can be divided roughly into rig costs and other outlays. Rig costs are determined by the day (rig) rate and the number of drilling days.

Rig rates have increased sharply around the world in recent years. However, they remain higher on the NCS than in other comparable petroleum provinces.

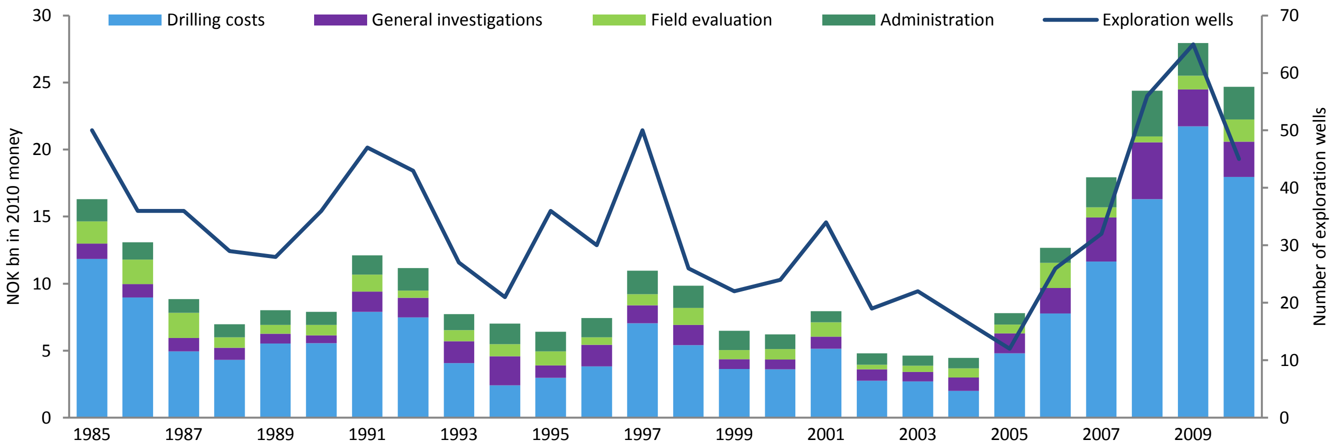


Figure 3.12 Total exploration costs on the NCS by cost category

Ranked as the largest discovery in the Barents Sea since Goliat in 1980, 7220/8-1 ("Skrugard") was drilled about 110 kilometres north of Snøhvit. It lies in a rotated fault block where the reservoir is formed of Jurassic sandstones (of the same age as the Snøhvit reservoir). Based on preliminary resource estimates, a stand-alone development could be realistic.

Representing a new gas discovery on the Bjarmeland Platform, 7225/3-1 ("Norvarg") was drilled in a large dome with reservoirs in the Jurassic and several Triassic levels. Further appraisal drilling will be needed to calculate a resource estimate. The small 7120/2-3 ("Skalle") gas discovery lies in Cretaceous and Jurassic reservoir rocks, 25 kilometres north of the Snøhvit area. A development is likely to involve a tie-back to existing installations on Snøhvit.

Oil and gas discoveries outside the Hammerfest Basin have encouraged increased optimism in the Barents Sea. That could lead to more exploration drilling, particularly in areas close to new discoveries.

Twelve production licences were awarded in the Barents Sea in the 21st round. Three of these lie close to 7220/8-1 ("Skrugard"). Interest in other areas of the Barents Sea is great. One of these is the Hoop

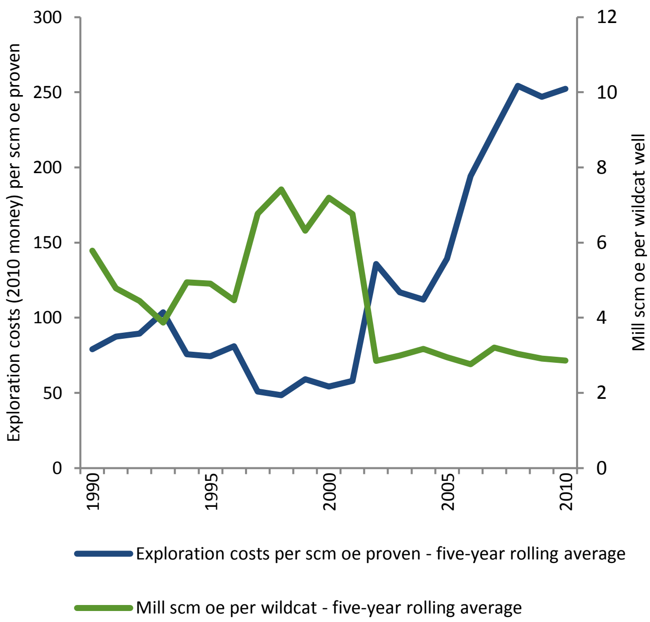


Figure 3.13 Development in finding costs and resource growth per wildcat on the NCS, five-year rolling averages

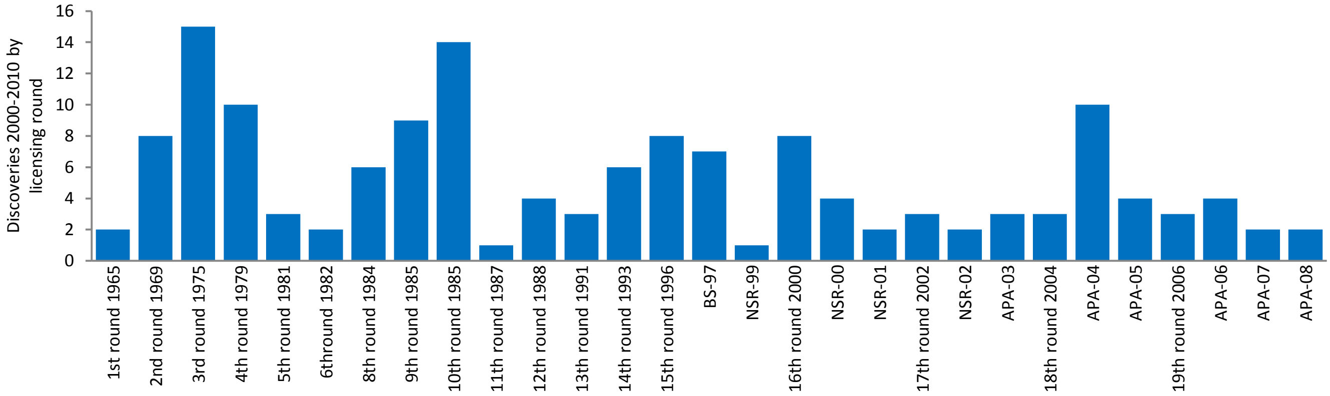


Figure 3.14 Discoveries in 2000-2010 by licensing round. Supplementary awards are placed in the original round

The steep rise in drilling costs and the lack of large new discoveries have contributed to a dramatic increase in finding costs per scm oe discovered. See figure 3.13. Finding costs are an important indicator for companies assessing which petroleum provinces they should invest in.

When the deepwater areas of the Norwegian Sea were opened in 1994, the announcement and award of new licences led to the discovery of Ormen Lange in 1997 and Skarv in 1998. In addition, 6707/10-1 ("Luva") was proven. This led to a rise in resource growth per well and a fall in finding costs per scm oe discovered. Few large discoveries were made in 2000-10. Combined with high rig costs, this led to high average finding costs on the NCS.

Profitable exploration

During the autumn of 2010, the NPD conducted an analysis of exploration profitability in the 2000-10 period. Although discoveries on the NCS were relatively small and exploration costs high during this time, the analysis shows that exploration activities over the period yielded substantial value both for the companies and for the Norwegian community.

A total of 352 exploration wells were spudded during the analysis period, including 242 wildcats and 110 for appraisal. This activity yielded 149 discoveries, which gives a technical finding rate of 62 per cent – very high internationally. Of the wildcats, 219 were drilled in the North Sea.

Exploration wells during the period were drilled in production licences awarded either in recent years or in earlier licensing rounds. Figure 3.14 presents discoveries for the period by the round in which the production licence was awarded.

Recoverable resources proven during 2000-10 totalled 333 million scm oe of gas and 403 million scm of liquids, or 736 million scm oe in all – on a par with the volume in Ekofisk.

Present value in 2010 money is calculated to be roughly NOK 710 billion for the discoveries and about NOK 200 billion for exploration costs. That makes the net present value for the whole period NOK 510 billion in 2010 money. See figure 3.15.

Although gas represented the largest volume discovered in 2000-10, oil found made the biggest contribution to value creation. The analysis also shows that the North Sea provided the highest net present value during the period.

Profitability of exploration

The profitability of exploration is defined as the net present value of discoveries made in a period less associated exploration and planning costs. Only discoveries with a positive present value are taken into account when calculating profitability. Those with a negative present value are assumed to remain undeveloped, and only their exploration costs are included. Production and cost profiles are established for each discovery, so that its profitability can be calculated. Opportunities for making several discoveries in a single production licence complicate the allocation of exploration costs to a specific discovery. In a number of cases, too, exploration costs are reported to Statistics Norway (SSB) collectively for several production licences. Appraisal wells form part of exploration operations and are included.

Price assumptions are based on the forecast from the Ministry of Petroleum and Energy (MPE) – the same input used in the analysis of undiscovered resources off Lofoten and Vesterålen (see www.npd.no). Historical export prices (source: SSB) are also used. These are converted to 2010 money using the consumer price index (CPI). All cash flows are converted to 2010 money and discounted to 2010. A fixed discount rate of seven per cent is applied. A discount rate of four per cent is used for the sensitivity calculation.

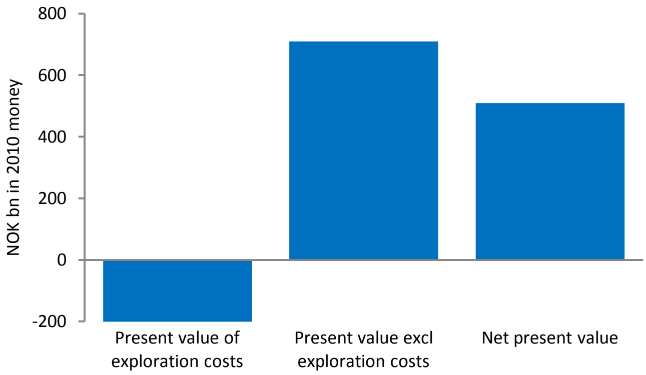


Figure 3.15 Present value of exploration activities, 2000-2010

A substantial proportion of the discoveries during the period lie in mature areas. A number of these can be tied back to existing infrastructure and thereby extend the producing life and enhance the recovery factor for fields currently on stream. This supplementary value of exploration activities in 2000-10 may be substantial, but is not included in the value estimate for exploration activities.

Statoil (including the former Hydro) accounts for more than half the value created through exploration in 2000-10. Figure

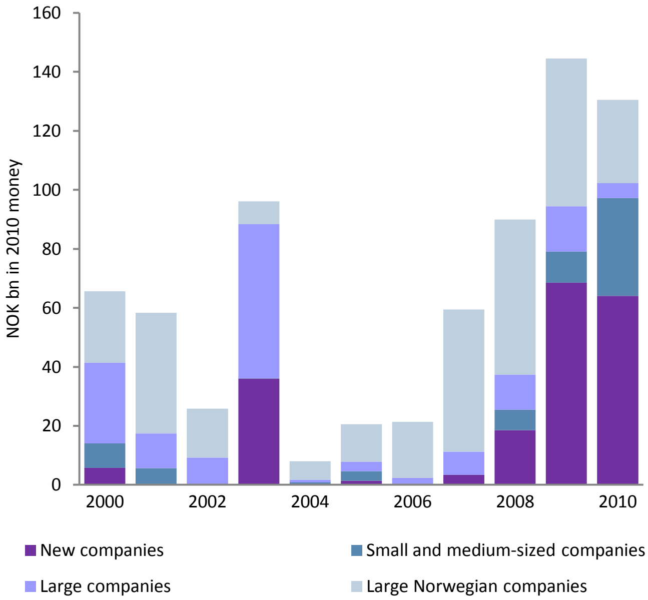


Figure 3.16 Present value excluding exploration costs by licensee

3.16 allocates present value excluding exploration costs for the analysis period by licensee.

The analysis also shows that "new" companies on the NCS have made a substantial contribution, particularly in the past few years. Such companies are defined as those awarded their first production licence after 1999. During the past two years, they have accounted for more than half the value created by exploration.

Unopened areas – mostly in the far north

Half the areas in which oil and gas are expected to be found have yet to be opened for petroleum activity. That applies to the waters around Jan Mayen, the north-eastern Norwegian Sea (parts of Nordland IV and V, Nordland VI and VII, the Vest Fjord and Troms II), Barents Sea North/the Arctic Ocean, the new sea area in Barents Sea East (former area of overlapping claims), parts of Trøndelag I and II, Møre I, the Skagerrak, the coastline off Finnmark and Troms counties, the Bear Island Fan, and the buffer zone around Bear Island.

A number of these areas are interesting for their petroleum potential. However, the level of knowledge, distance to markets and existing infrastructure, environmental assets and other user interests differ between the various areas. The basis for the assessments which need to be made and the time scale from a possible opening process until exploration, discovery, development and production will accordingly vary from area to area. Political decisions are required to open new areas for petroleum activity.

Former area of overlapping claims

The maritime boundary between Norway and Russia in the Barents Sea and the Arctic Ocean has been the subject of negotiations for roughly 40 years. Tentative agreement was reached between the two countries over a boundary in these waters on 27 April 2010. The treaty between Norway and Russia on the maritime boundary and collaboration in the Barents Sea and the Arctic Ocean was signed in Murmansk on 15 September 2010 and ratified on 7 June 2011 in Oslo. It entered into force on 7 July 2011.

This treaty means that the former area of overlapping claims, covering some 175 000 square kilometres, has been divided into two roughly equal parts. These cover areas in both the northern and the southern Barents Sea. The treaty also contains provisions on collaboration between the two sides if oil or gas deposits were to extend across the boundary line. Should such cross-boundary resources be found, the treaty specifies detailed rules and procedures aimed at ensuring their responsible and cost-effective administration.

The NPD regards the new Norwegian area in the Barents Sea as interesting for petroleum activities. Petroleum has been proven to both the east and the west. This raises hopes that it could also exist in Norway's new sea area. Data there are very limited, and provide an inadequate basis for assessing the resource potential. Seismic surveying was accordingly initiated in the summer of 2011. This work has been commissioned by the NPD at the request of the government, and will be completed in 2012.

In connection with updating the integrated management plan for the marine environment in the Barents Sea and off Lofoten – White Paper no 10 (2010-2011) – it was resolved that the MPE will launch an impact assessment pursuant to the Petroleum Activities Act with a view to awarding production licences in the former area of overlapping claims west of the boundary line in Barents Sea South. Assuming that the assessment provides an appropriate basis, the government will present a White Paper which recommends the opening of these areas for petroleum activity. Work on the assessment will begin in the autumn of 2011.

CHAPTER **4.** From discovery to field

Introduction

Resources in discoveries without a decision to develop at 31 December 2010 represent five per cent of total expected resources on the NCS and nine per cent of remaining resources. This proportion has been stable for a number of years, but the average discovery size is smaller than before. History shows that most discoveries will be developed, but that this may take some time. Small discoveries often depend on access to spare capacity in processing and transport facilities to become commercial. In mature areas, as a rule, such discoveries are developed through a tie-in to stand-alone fields. This also contributes to extending the producing life for existing fields substantially beyond the original plans. Large discoveries under development may also be dependent on capacity in existing infrastructure. Coordinated development of several discoveries across production licences can reduce unit costs and make commercial discoveries even more profitable, or permit the development of commercially marginal finds.

Resource base

The total resource estimate for discoveries still without a decision to develop was 650 million scm oe at 31 December 2010. Growth from 16 discoveries during 2010 is estimated at about 80 million scm liquids and 40 billion scm gas. Since a number of the discoveries are still under evaluation, these estimates are uncertain. The discoveries vary in level of maturity and probability of being developed. The NPD's resource classification is broken down into undiscovered resources, contingent resources, reserves and historical production. See the overview of the resource classification in chapter 1.

Liquids and gas are split more or less evenly in discoveries without a decision to develop. Most of the discoveries, which collectively account for the largest part of the resources, lie in the North Sea. See figure 4.1.

A long time can pass before a discovery is considered sufficiently commercial to be developed. Figure 4.2 presents the total resources in discoveries without a decision to develop, broken down by the year of discovery. Reasons why the time from finding to development may be long include reservoir uncertainty, the size and location of the discovery, oil price trends, costs and technology. A number of discoveries made in the 1970s and 1980s are only now being developed. Examples include Valemon and Gudrun, currently under development, and 30/7-6 ("Hild") which is approaching that stage. Factors contributing to a development of these discoveries include new information on the reservoir and

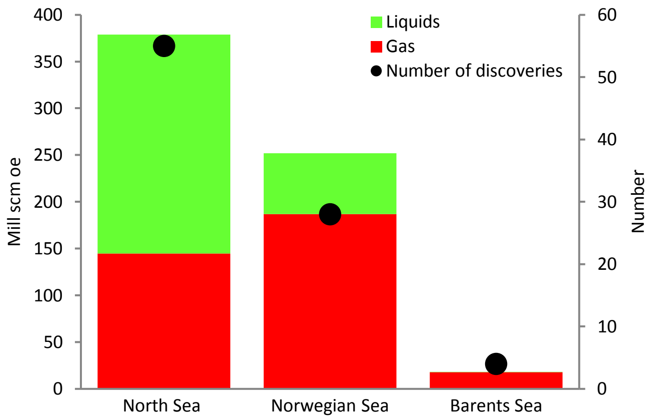


Figure 4.1 Resources in discoveries without a decision to develop at 31 December 2010, broken down by area

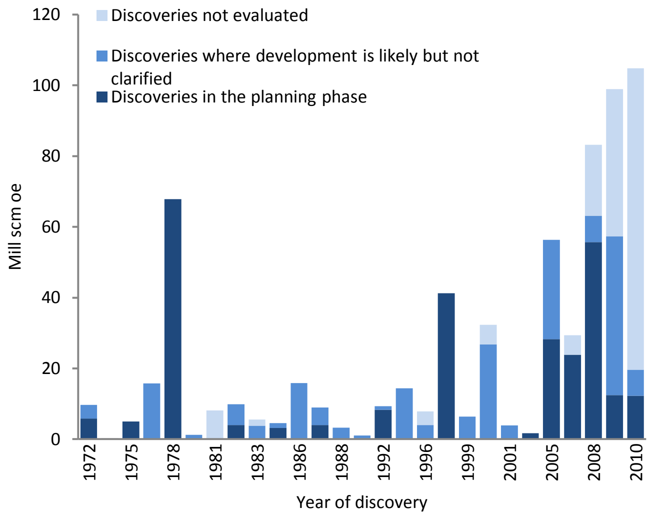


Figure 4.2 The maturity of discoveries without a decision to develop by discovery year at 31 December 2010

geology, changes in licensee composition, operational experience, new technology and sufficiently high oil prices.

Some 100 million scm oe were matured from resources in discoveries to reserves during 2010. Three plans for development and operation (PDOs) were submitted, and four new field developments approved by the authorities. The proportion of discoveries in relation to remaining resources on the NCS has been stable at the present level in recent years. See figure 4.3. This shows that the resources are being matured and developed. However, a successful realisation – in other words, profitable development and production – calls for a big commitment to technology development and adoption, and to expertise.

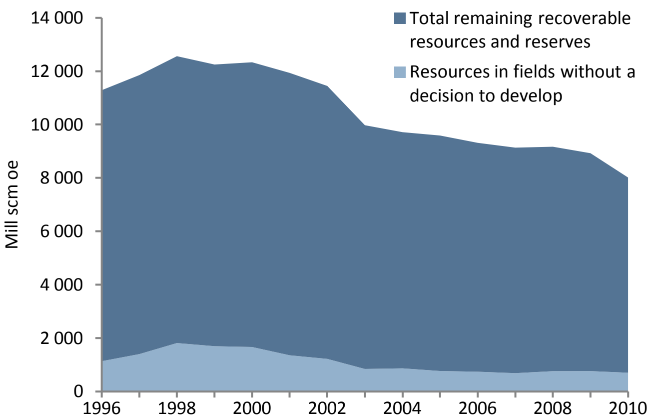


Figure 4.3 Development of resources in discoveries versus total reserves and resources on the NCS, excluding petroleum sold and delivered

Small discoveries

The average size of discoveries without a decision to develop is substantially smaller than for discoveries developed in recent years. See figure 4.4. The calculation of the average size for fields approved in 2004-10 excludes Ormen Lange, with 320 billion scm of gas, which was approved for development in 2004. Normally, the largest discoveries are developed first. Small finds often require different conditions from large ones if they are to be realised. Most discoveries lie in

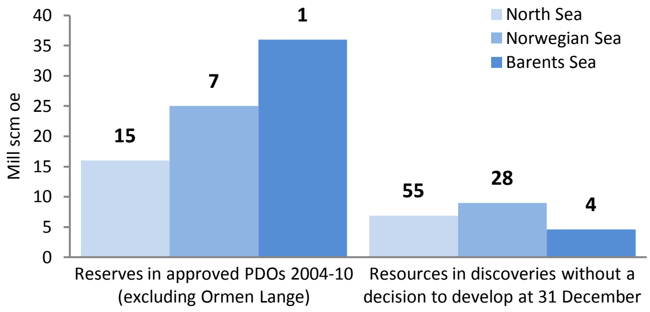


Figure 4.4 Average field and discovery sizes and the number of fields and discoveries by area

the North Sea, but are generally small. With many large developed fields, this provides opportunities for tie-back of the discoveries to existing production facilities – also known as field centres.

Location

The North Sea and parts of the Norwegian Sea have well-developed infrastructures. Being developed with fixed production installations can be cost-effective for the largest discoveries, and provides additional processing capacity for tie-back of new subsea wells.

Using existing infrastructure represents a cost-effective development solution for many of the remaining discoveries, which can help to ensure that they become sufficiently commercial to be developed. Figure 4.5 presents a picture of the distance from discoveries to suitable offshore infrastructure, broken down by discovery size. A large number of discoveries lie less than 50 kilometres from the nearest suitable infrastructure with liquids/gas processing.

Discoveries located up to 10 kilometres from a field centre can be accessed today by extended-reach wells. For longer distances, fixed installations or subsea wells tied back to the field centre represent the most appropriate solutions. Distance from a field centre is primarily important for discoveries which are so small that a commercial stand-alone development is not feasible. As a result, the biggest challenge is to achieve a commercial development for the smallest discoveries which lie relatively far from suitable infrastructure. See the circle in figure 4.5.

Several examples exist of successful development with discoveries located a long way from infrastructure. One is Vega Sør, where

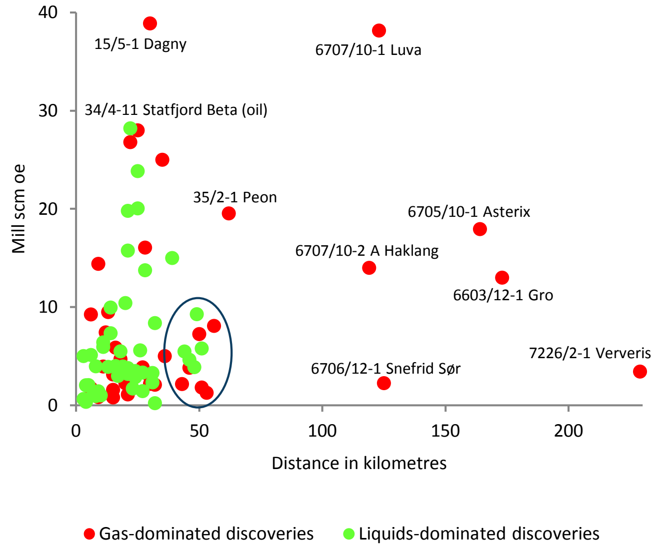


Figure 4.5 Resources in discoveries without a decision to develop at 31 December 2010 and distance to the nearest suitable infrastructure with production facilities

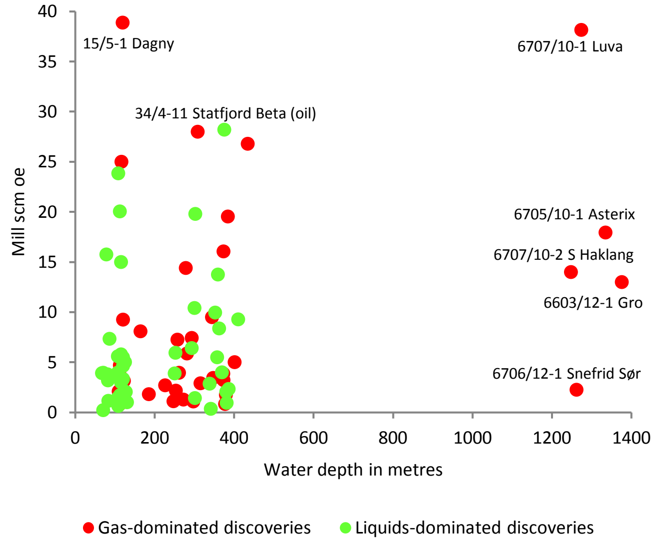


Figure 4.6 Resources in discoveries without a decision to develop at 31 December 2010 and water depth

gas and condensate are carried from a subsea template to the Gjøa installation through a 50-kilometre pipeline via the subsea template on Vega. This represents a substantial distance for multiphase flow transport. Reserves in the small Vega and Vega Sør fields, totalling some 12 and 11 million scm oe respectively, formed the basis for a commercial development together with the roughly 50 million scm oe in Gjøa. All made in the 1980s, these three discoveries were realised through a coordinated development. This shows that the maximum distance for wellstream transport from a subsea development to a field centre is determined by a combination of technology, resource base and costs. The solution for the Vega fields also demonstrates the gain obtained by integrating several small deposits.

Relatively new subsea technology, such as seabed separation and multiphase flow pumping, and further development of tools for simulating multiphase flow have helped to extend the distance from subsea wells to field centres or land-based plants. Wellstreams

PDO and PIO

Before the licensees can develop a discovery, a plan for development and operation (PDO) has to be approved by the authorities. This must explain how the licensees intend to develop and operate the field. A PDO or a plan for installation and operation (PIO) comprises a development/installation section and an impact assessment. The MPE coordinates the administrative process for the plan and receives the NPD's assessments. Developments costing more than a specified limit – currently NOK 10 billion – must be approved by the Storting (parliament).

PDO adviser

The adviser's role includes advice on preparing a PDO/PIO to meet official requirements, explaining administrative procedures, and contributing to effective interaction between the licensee and the authorities. They are meant to simplify the developer's job and make official requirements clear. The development concept must be documented when it has been chosen. With many new players on the NCS in recent years, the need for advice on legislation and government practice has increased.

(comprising gas, condensate and water) are piped 143 and 120 kilometres respectively from subsea wells on Snøhvit and Ormen Lange to land-based plants. Opportunities for multiphase flow from a subsea field to a processing unit are challenged by such factors as transfer distance (horizontal and vertical), wellstream composition, pressure and temperature, and requirements for material quality.

Subsea gas compression represents a new and important technological leap which could help to secure the commercial development of discoveries in deep water and exposed areas, and to improve recovery from existing subsea fields. This technology is under development, and plans exist on a number of fields to implement subsea compression once it has been qualified.

Water depth has not so far been a barrier to developing large discoveries on the NCS. The development of Ormen Lange in 800-1 100 metres of water and far from land was complicated, but made possible by technological progress. The field's resource base permitted an extensive subsea development despite deep water, a low seabed temperature, landslide challenges and a long distance from land. Only gas has so far been discovered in deepwater areas of the NCS. See figure 4.6.

Development solutions

A steadily growing number of discoveries on the NCS are being developed with subsea solutions – in other words, with petroleum recovered via seabed templates for processing on fixed installations or on land. A fixed installation is permanently positioned on the field throughout its producing life. A production ship can also be a fixed installation if it is intended to stay permanently on the field. Subsea wells can be tied back to fixed installations on other fields, known as third-party tie-backs, or installed in combination with floating fixed installations (as on Alvheim, Åsgard and Kristin). From 2005 to 2010, 19 of 22 fields were developed with subsea solutions. Eight further developments were approved by the authorities in 2010 and the first half of 2011. Gudrun and Valemon, for example, are being developed with fixed installations. Subsea wells on Knarr will be tied back to a production ship with storage. Marulk, Gaupe, Trym, Hyme and Visund Sør are subsea developments tied back to existing fixed installations on the NCS, the UKCS and the Danish continental shelf.

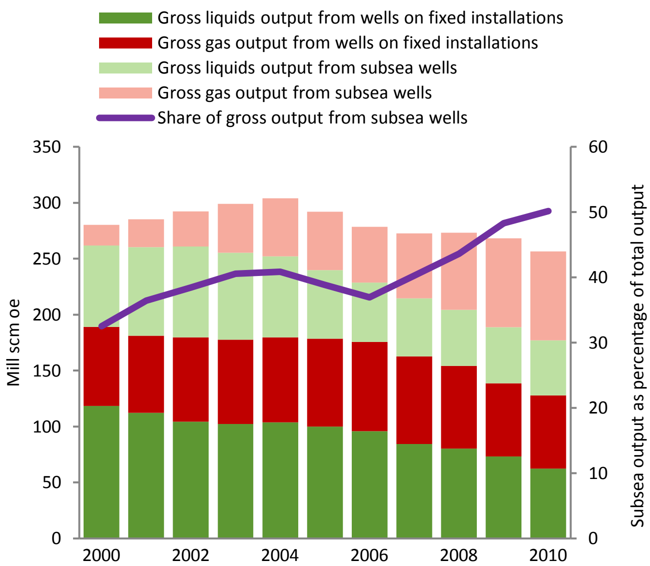


Figure 4.7 Total output from subsea wells and fixed installations, 2000-2010

Tyrihans
is an example of well and subsea technology securing a high level of recovery in a subsea development. Adopting multilateral wells, downhole regulation equipment and seawater injection pumps on the seabed could permit additional oil to be produced from this field. Statoil brought Tyrihans on stream in July 2009, with the wellstream piped 43 kilometres to Kristin for processing and export.

Yttergryta
is an example of a small gas and condensate development in the Norwegian Sea, 33 kilometres east of Åsgard B. Reserves total some two billion scm gas with a low carbon content and some liquids in addition to condensate. The field has been developed with a subsea well and a pipeline via the Midgard subsea template. Gas from Yttergryta helps to reduce the carbon content in the export pipeline from Åsgard. It also contributes to maintaining flow speed in the flowline from Midgard to Åsgard B. The field was brought on stream about 18 months after its discovery. This rapid development could be achieved because sub-surface conditions in the area were well known, and because the subsea installation could be tied back to existing infrastructure on the Åsgard field.

Considerable progress has been made with subsea and floating production facilities over the past 20 years, both technologically and in the number of developments. Subsea solutions have helped to make development more profitable. That applies particularly to small and deepwater discoveries. About half the output on the NCS comes today from subsea wells, and this proportion is rising. See figure 4.7.

The trend towards a growing share of subsea developments is likely to continue. Among reasons for choosing a solution of this kind are the fact that the initial investment is often lower, suitable infrastructure is available, the reservoir extends over a wide area, and the water depth is considerable. However, drilling and maintenance costs may often be higher for a subsea development than with a fixed installation. Further development of technology for cost-efficient well maintenance and drilling of sidetracks through existing subsea wells could therefore make important contributions to profitable measures for improved recovery. FMC Technologies was awarded the NPD's IOR prize in 2009 for developing technology for this purpose.

Fixed installations may offer greater flexibility for making modifications, a lower break-even price for improved recovery measures, and reduced operational risk. Such facilities provide opportunities for permanently installed drilling rigs. The advantages and disadvantages of investing in fixed drilling equipment rather than chartering mobile drilling units as required must be assessed for each development.

This means that the basis exists for studying both surface and subsea solutions for many discoveries.

Simpler, cheaper, faster

Until the 1990s, petroleum activity concentrated mainly on developing large deposits with correspondingly high costs for engineering, development and operation. The decreasing size of discoveries makes it necessary to think along new lines, simplify and do things more cheaply. The challenge for the industry is now to continue developing cost-effective models for both project execution and development solutions. A greater degree of standardisation for the latter and effective coordination of developments can contribute positively to profitability. However, reducing the time from discovery to production start must take account of applicable safety and environmental standards, and not be pursued at the expense of integrated area solutions and good resource management. Standardised development solutions appear to be the most relevant for discoveries where a subsea solution is planned.

Coordination

Creating new stand-alone field centres competes in a number of cases with development solutions which involve tie-backs to established infrastructure and utilisation of spare capacity on fields in the late phase. Long experience has been accumulated on the NCS with coordinated development of discoveries where this offers the most profitable solution. The Petroleum Activities Act requires the coordination of several deposits when this is clearly the rational approach.

Gjøa, Vega and Vega Sør provide an example of a recent coordinated development and production strategy. Coordinating these fields yielded larger expected value creation than three stand-alone developments.

Profitability of discoveries

During the autumn of 2010, the NPD conducted an analysis of exploration profitability in 2000-10. See chapter 3. This analysis also estimated value creation by discoveries during the period. The same economic assumptions were applied in both analyses.

A total of 149 discoveries were made during the period. Eight are included in other finds. Figure 4.8 provides an overview of

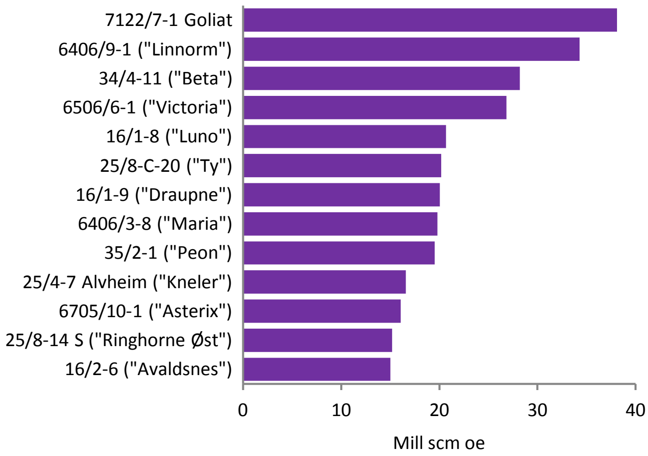


Figure 4.8 Expected recoverable resources in the largest discoveries during the 2000-2010 period

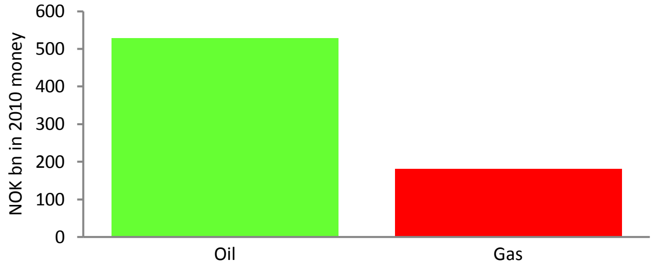


Figure 4.9 Net present value distributed between oil and gas discoveries

the largest discoveries. The resource estimates are based on an expected estimate prepared in connection with the 2009 resource account. Where discoveries made in 2010 and the 6506/6-1 ("Victoria") and 16/1-9 ("Draupne") finds are concerned, the resource account for 2010 has been utilised.

The total growth in resources from discoveries for the whole period was 333 billion scm of gas and 403 million scm of liquids, adding up to 736 million scm oe.

Most of the discoveries included in this analysis have still to be developed. Both the size of recoverable resources in each discovery and their production and cost profiles are therefore uncertain. Nor has a development and operating concept been chosen for many of the discoveries. When production will start, the level of costs, and oil and gas prices are also uncertain, which has a substantial impact on profitability expressed in net present value.

The total net present value of the discoveries is estimated at roughly NOK 710 billion in 2010 money. See figure 4.9. Oil discoveries account for a dominant share of the overall net present value.

Things may take time

The NPD's analysis shows that discoveries without a decision to develop represent substantial value. However, it often takes a long time for this value to be realised. The average lead time from discovery until production starts is 12 years.

Fixed installations have an average lead time of 11 years, while the figure for subsea fields tied back to existing field centres is 13 years. See figure 4.10. History also shows that gas discoveries have a longer lead time than oil finds. Lead times can probably be reduced with simpler and more standardised developments.

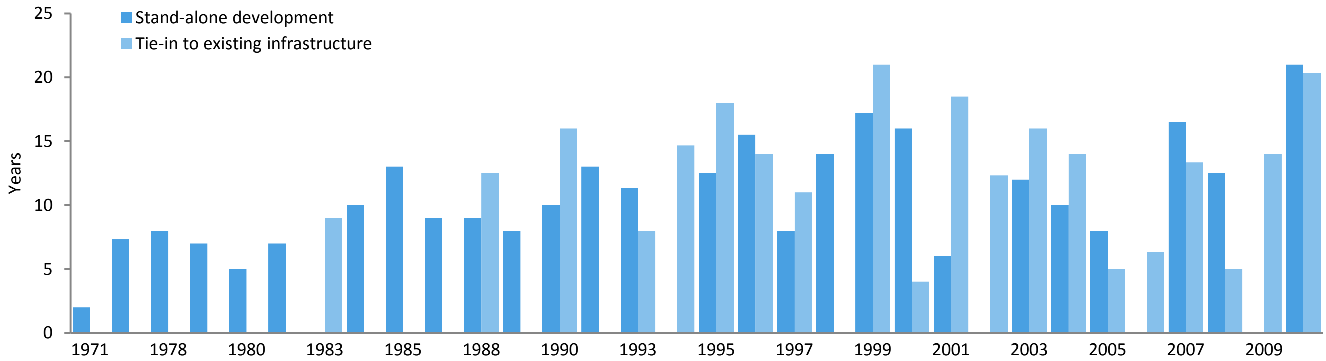


Figure 4.10 Average lead time for fields by year the field came on stream

The NPD's annual survey of conditions delaying the progress of discoveries towards development shows that commercial finds are usually developed. About a third of the project blockers reported to the NPD involve lack of capacity in the infrastructure or the absence of a gas solution. More than a third of reported project blockers involve uncertainty over the resource base and reservoir conditions. In addition come commercial assessments and strategic considerations for the companies.

Area perspective

Substantial resources have been realised by phasing output into a production installation with spare capacity. This is also often beneficial for the licensees of the host field through reduced unit costs and increased reserves, which provide opportunities to extend the production period.

Some field centres will have limited spare capacity to accommodate new discoveries, either owing to production from the main field or because nearby resources are being phased in. Figure 4.11 presents the planned producing life at the PDO date for fields with processing facilities and the extension in producing life based on current plans. As the figure shows, installations with opportunities for tie-backs have a clear tendency for their producing life to be extended beyond the original expectation.

Clarifying the resource potential in the area around existing fields is important. The challenge is to lay integrated plans for an area in order to exploit the resource potential and processing and transport capacity in an optimum socio-economic manner. Differing ownership constellations for infrastructure and in nearby production licences often challenge coordinated area thinking.

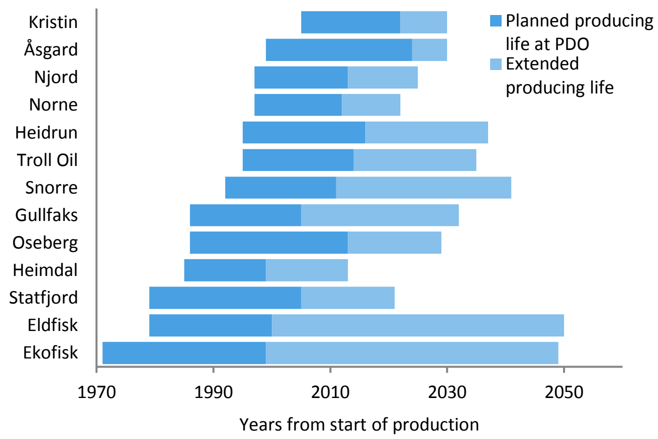


Figure 4.11 Planned producing life at the PDO date for fields with processing facilities, and extended producing life based on current plans

Regulation on the use of installations by others

Based on considerations of good resource management, the purpose of the regulation is to ensure positive incentives for exploration, new field development and improved recovery through effective negotiating processes and appropriate profit-sharing over the use of existing installations. The introduction of the regulation has helped to ensure that time-critical resources close to planned and existing infrastructure can be more easily realised. The regulation establishes the principle that the profit from production should primarily be secured on the field with the resources. Tariffs and other conditions related to the use of installations owned by others must lie at a reasonable level and be calculated on the basis of the services offered.

CHAPTER **5.** Opportunities and challenges for producing fields

Introduction

Oil production on the NCS has fallen in recent years. This decline was expected, but has been rather steeper than earlier assumed. Production has almost halved from its 2001 peak, and is now back at the 1991 level. However, the decline can be restricted through exploration, development of new oil discoveries and a strengthened commitment to IOR on existing fields.

On average, more than half the oil originally in place in the reservoirs will be left in the ground under current plans. Continuing IOR efforts on existing fields is therefore important. Injection as well as drilling and well maintenance are important for producing today's reserves. They could also contribute to increasing reserves in the fields. Recovery could be further improved if advanced injection methods and new technology are developed and qualified through field trials. Close follow-up and facilitation by the authorities have historically proved useful in such processes, and will continue to play an important role in the future.

Development of production

At 31 December 2010, 3.62 billion scm of oil and 1 547 billion scm of gas had been sold and delivered from 82 fields on the NCS. Sixty-nine fields are currently in production, while 13 have ceased to produce. Petroleum activities in Norway began in the North Sea, and this area has been and remains responsible for the largest share of production.

Oil output from the big oil fields in the North Sea has declined since the end of the 1990s. See figure 5.1. This is a natural consequence of the fact that many of the fields were developed in a short space of time. However, production from the Norwegian Sea and a number of small North Sea fields has helped to dampen the declining trend. Forecasts for the next five years expect a further fall, but not one as steep as in recent years.

Gjøa, Vega and Vega Sør in the northern part of Norway's North Sea sector came on stream in 2010, as did Morvin in the Norwegian Sea. All these fields contain a lot of gas and some oil, and all will be produced through pressure depletion. Trym came on stream in February 2011. This is the first Norwegian field to be tied back to a Danish installation. Skarv, Gaupe and Oselvar are due to begin production during the year.

The MPE approved the PDO for supplementary resources on Vigdis and Oseberg Sør, also known as Vigdis Nordøst and Stjerne, in September 2011. Further development of Ekofisk and new development of Eldfisk rank as the biggest investment decisions in 2011. Similar investment has earlier been made on both these fields as well as on Valhall. Ekofisk has been further developed in several stages with new installations, and underwent a major redevelopment in 1998. The recovery strategy was changed on Eldfisk, with a new water injection facility installed there in 2000. The Valhall field centre is currently being replaced, with an anticipated start-up in the first half of 2012. The NPD expects to see renewal activity on a number of fields in the Tampen area of Norway's northern North Sea sector during the near future.

Figure 5.2 shows production developments for oil and the water cut in the liquids flow from wells – both subsea and on fixed installations – for the whole NCS in 2000-10. Overall oil output declined in this period, with the biggest reduction from wells on fixed installations. The produced water cut has increased as a natural consequence of large-scale water injection over a long time to maintain pressure and displace oil in the reservoirs. Subsea wells currently have a lower water cut, but experienced the greatest increase in the 2000-10 period. Producing more water is necessary in order to optimise oil recovery from the fields. That presents a challenge for the production facilities, and also involves environmental challenges. Techniques for sealing the reservoir zones or well sections with the highest water cut have been developed and to some extent adopted. An example of such innovations is provided by valves which automatically shut off sections of the well when water production becomes excessive.

About three-quarters of the produced gas is exported, with the rest being used for injection, processed into natural gas liquids (NGL) and condensate, flared or used as fuel for about 170 gas turbines on the NCS. Injecting gas has made and is continuing to

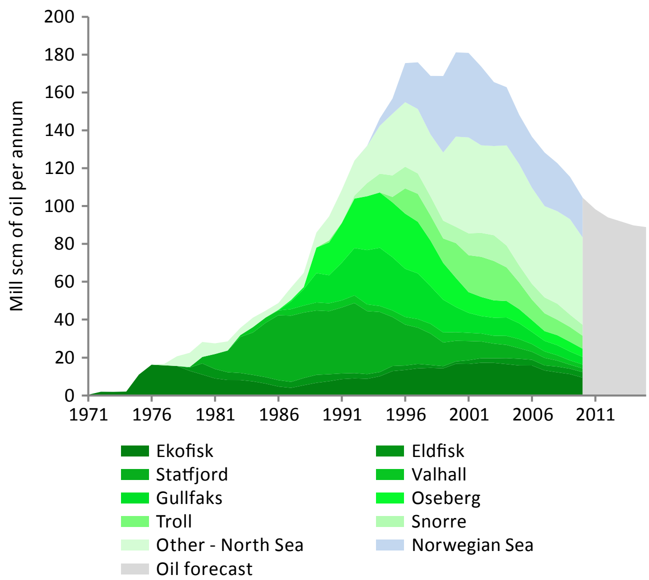


Figure 5.1 Historical oil production and the forecast to 2015. Output is shown in green for North Sea fields and blue for Norwegian Sea fields

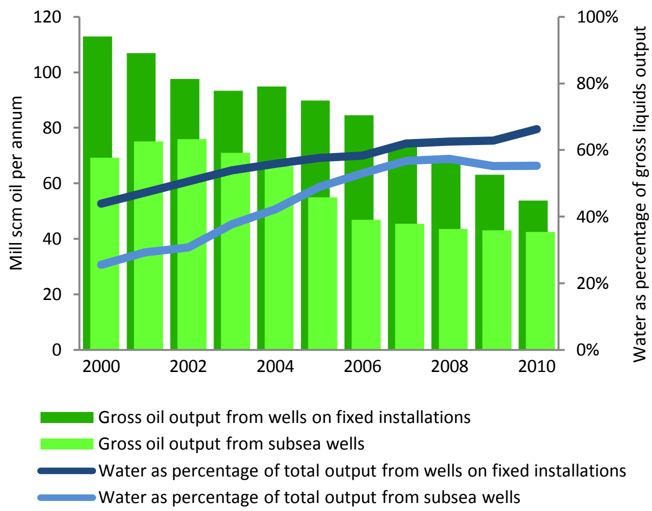


Figure 5.2 Distribution of oil production and water cut from subsea wells and wells on fixed installations, 2000-2010

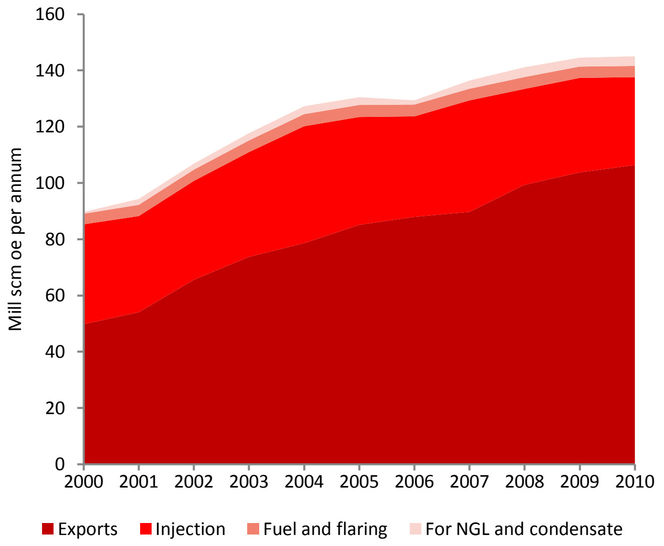


Figure 5.3 Total gas production on the NCS, 2000-2010

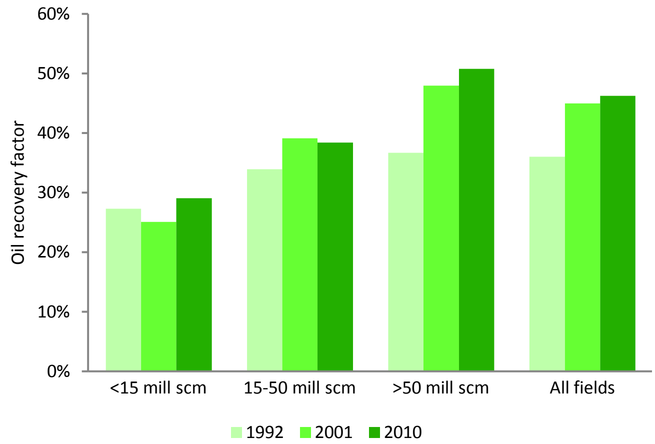


Figure 5.4 Development of the average recovery factor for fields of various sizes

make a substantial contribution to oil recovery. While gas output has risen, the volume used for injection, fuel, NGL, condensate and flaring has stayed more or less constant. The proportion of gas being exported has accordingly increased. See figure 5.3.

Remaining reserves and resources in fields

The expected recovery factor for fields on the NCS, based on existing plans, averages 46 per cent for oil and 70 per cent for gas. This factor varies considerably from field to field and between different reservoirs in the same field. It depends on such considerations as reservoir properties, recovery strategy and the flexibility of production facilities. Figure 5.4 presents the development in the average recovery factor for fields of various sizes and for the NCS as a whole. As the figure shows, the largest fields have a higher recovery factor than smaller ones. This could be because large fields have a long producing life, making it possible to implement a number of measures over time to improve recovery. By and large, fields approved for development in recent years have been small. Limited reserves mean that the facilities installed normally lack the same flexibility as installations on a large field. A number of the small fields also have complex reservoirs, which contributes in turn to a lower oil recovery factor.

Internationally, the average recovery factor for oil fields is estimated at 22 per cent. Good reservoir properties have made a strong contribution to the high factor on the NCS. In addition, extensive research, technology development and close regulatory follow-up have been important in improving recovery. Water and/or gas injection, three- and four-dimensional (3D and 4D) seismic surveys, systematic data acquisition for better reservoir understanding, and drilling more wells than planned when the field was developed have made big contributions to the high recovery factor.

The relationship between produced resources, remaining reserves and contingent resources (see the resource classification in chapter 1) has developed since production began in 1971. Figure 5.5 illustrates this development for total gas and liquid resources. It also presents the size relationship in 2010 and how the resources break down between the three sea areas. Undiscovered resources are excluded. The bulk of the remaining proven resources registered in the NPD's database lie in the North Sea.

A high recovery factor is achieved on a number of fields through a combination of water and gas injection. On average, large fields have a higher recovery factor than small ones, but the variations

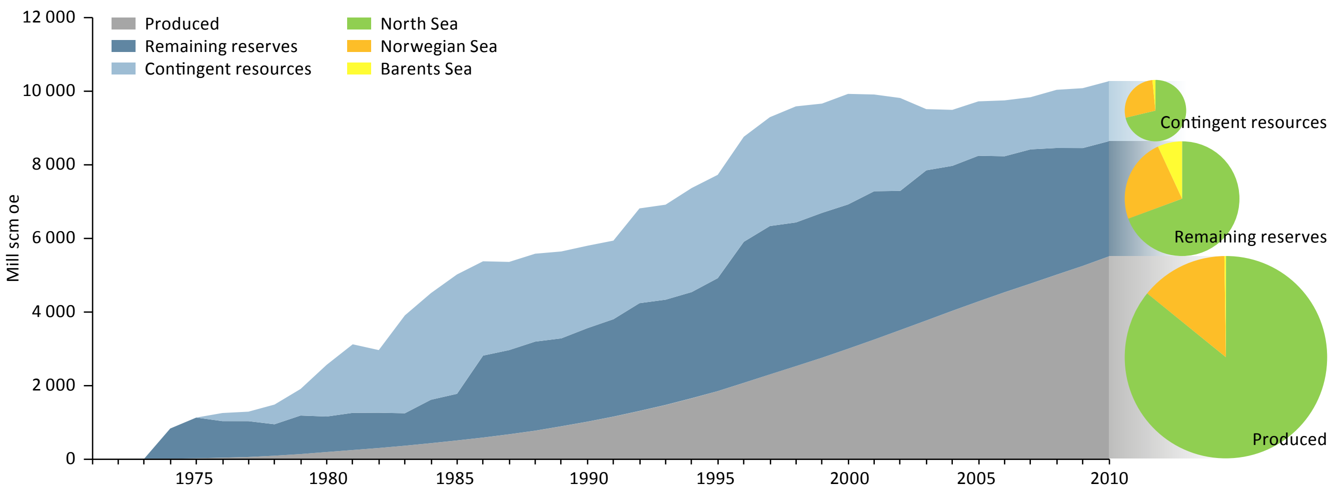


Figure 5.5 Development of proven resources in the resource account and status at 31 December 2010

are once again substantial. This is illustrated in table 5.1, which shows the original volume in place and recovery factor under current plans for the 12 largest oil fields. An increase in the recovery factor for a field could represent substantial value for society, depending on production costs and future price developments. Were the recovery factor to be increased by one per cent on important oil fields such as Heidrun and Snorre, for example, the gross value potential would be about NOK 16-18 billion per field at an oil price of NOK 570 per barrel.

Target for reserve growth

The NPD set a target for reserve growth in 2005 which involved maturing 800 million scm of oil from resources to reserves by 2015. Such growth derives from developing new fields and increasing reserves in producing fields. Figure 5.6 presents gross reserve growth, write-downs and net reserve growth in relation to the target. Sufficient reserves have been matured on an annual basis to attain the target, but write-downs of reserves in fields have put reaching this goal behind schedule. Write-downs mean reducing the reserve estimate for certain fields. Reasons could include updating the reservoir model, a faster-than-expected decline in production, or drilling fewer wells than previously estimated. Oil earlier defined as reserves could thereby get reclassified as resources. Reversals of such write-downs could be possible if action is taken.

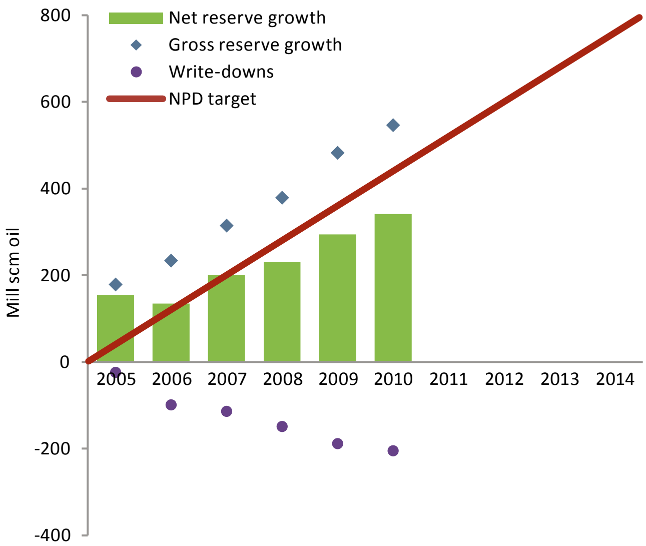


Figure 5.6 Gross reserve growth, write-downs and net reserve growth compared with the NPD's target

Licensees of producing fields identified specific projects and measures in 2010 which they believed could help to increase reserves. These projects and measures can be categorised on the basis of project type. The identified volume is 385 million scm of oil. Figure 5.7 presents identified projects for producing fields by category.

The biggest contribution to reserve growth for producing fields comes from well-related projects, such as drilling new wells or major well maintenance campaigns. Licensees report that new projects for injecting water, gas or water alternating gas (WAG) and enhanced recovery methods will contribute to a smaller proportion of the possible reserve growth.

The NPD estimates that about a quarter of the original oil in place cannot be produced by conventional recovery methods. That is because it cannot be freed from the rocks – in other words, it is immobile. To mobilise and produce this oil, enhanced oil recovery (EOR) methods must be adopted.

Enhanced oil recovery (EOR)

EOR methods include injection of polymers, surfactants, CO_2, low-saline water, silicates and miscible gas.

Field	Oil resources originally in place Mill scm	Oil reserves, incl sold and delivered Mill scm	Recovery factor Per cent	Main drive mechanism
EKOFISK	1 099	534.6	49	Water injection, earlier pressure depletion and compaction drive
STATFJORD	860	567.3	66	Pressure depletion in the late phase. Earlier water, water alternating gas and some gas injection
TROLL	642	250.0	39	Pressure depletion with natural water and gas drive, some gas injection
GULLFAKS	599	365.4	61	Water injection. Some gas and water alternating gas injection
OSEBERG	592	377.2	64	Gas injection. Some water and water alternating gas injection
SNORRE	515	241.2	47	Water, gas and water alternating gas injection
ELDFISK	463	133.8	29	Water injection, earlier pressure depletion and compaction drive
VALHALL	435	145.5	33	Water injection, earlier pressure depletion and compaction drive
HEIDRUN	432	169.0	39	Water injection. Some gas injection and pressure depletion
GRANE	229	120.7	53	Gas injection, from 2011 water injection and gas reinjection
DRAUGEN	212	143.1	68	Natural water drive and water injection
OSEBERG SØR [1]	208	52.6	25	Water and gas injection. Some water alternating gas injection

[1] The Oseberg South field comprises several separate deposits and has been developed with a fixed steel platform tied to several subsea templates. These deposits have differing reservoir properties, and drive mechanisms vary from deposit to deposit.

Table 5.1 The 12 largest oil fields ranked by reserves originally in place at 31 December 2010

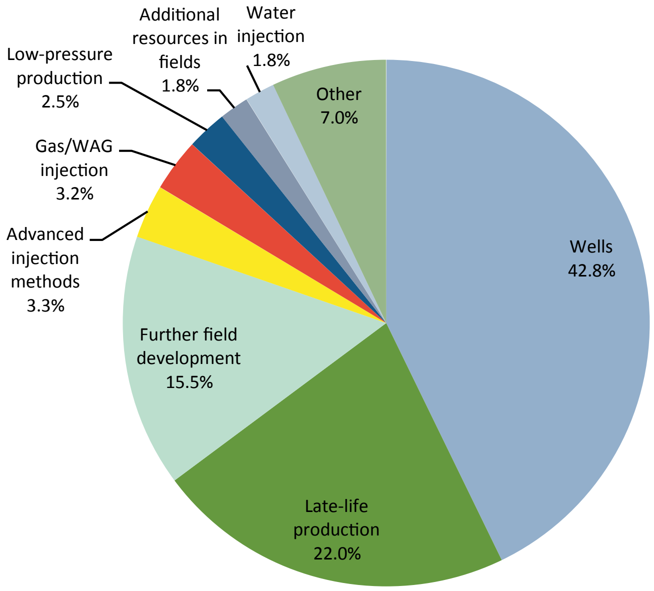


Figure 5.7 Reported resources in plans and methods for reserve growth in producing fields

The NPD carried out a survey in 2007 of the relationship between mobile and immobile oil in the reservoirs. An updating in 2011 for the 12 largest fields shows that 43 per cent of the remaining oil is immobile. Because of differing reservoir properties, the quantity of immobile oil varies from field to field. Chalk fields often have a higher proportion than sandstone ones.

Reaching the NPD's target for reserve growth calls for decisions to be taken on new projects and for write-downs to be minimised. Existing plans must be implemented if the reserves are to be produced. Further reserves could be added by developing and adopting new technology, developing discoveries, extending producing life, redeveloping fields and applying EOR methods.

Petroleum White Paper

The MPE appointed a team of experts – the Åm committee – in 2010 to consider measures for improving the recovery of petroleum resources from existing fields. White Paper no 28 *An industry for the future – concerning petroleum activities* contains a number of the committee's recommended measures. In addition, the MPE has asked the petroleum industry, through the Konkraft collaboration, to assess the measures proposed. The White Paper includes a number of measures based both on the Åm committee's report and on new proposals. Key action proposed on IOR includes:

- intensify follow-up of fields in the late-life phase
- assess the need to strengthen the regulations to ensure that adequate attention is paid to IOR and good resource management
- approve applications to extend the duration of a production licence with the same licensee structure if this makes better resource utilisation more likely, and unless special considerations dictate another course
- place greater emphasis on a majority of shares when determining voting rules on the award of new production licences
- appoint a team of experts to clarify and identify obstacles which limit rig capacity on the NCS, and propose measures to improve the supply of vessels involved in drilling, while encouraging licensees on the NCS to establish rig pools
- work together with key players on the NCS to secure an increased commitment to piloting new technology
- assess the creation of an IOR research centre, based on open competition

Existing technology

Much of the remaining mobile oil in producing fields can in theory be recovered with known and tested technology. Injecting water and gas to maintain reservoir pressure and displace oil, drilling wells, and gathering data to improve reservoir descriptions will accordingly remain important. Data-gathering with 4D seismic surveys provides information on the location of residual petroleum and where production wells should be drilled.

Automation, remote control and condition-based maintenance help to reduce operating costs, which contributes in turn to a longer producing life for the fields. They also extend the time frame for phasing-in new discoveries and implementing additional measures which can improve recovery.

Valhall life-of-field seismic

The Valhall unit and operator BP was awarded the NPD's IOR prize in 2003 for installing the world's first full-scale life-of-field seismic facility. A total of 9 500 sensors linked by 120 kilometres of cable are spread over 35 square kilometres. This installation will help to increase reservoir knowledge, ensure safer and more cost-effective drilling, and give better access to remaining reserves.

Water and gas injection

Injecting water and gas to maintain reservoir pressure and displace oil or condensate is important for production on the NCS. If reservoir pressure declines too much, profitable oil and gas can be lost. Injection is particularly significant for improving liquids recovery. In many cases, injecting gas rather than water achieves better oil drainage.

Water and gas were injected in 30 and 18 fields respectively during 2010. A combination of water and gas injection is used on a number of these fields, while 33 are produced by pressure depletion. That category includes most of the gas and gas/condensate fields. Twenty-two new fields came on stream in 2005-10. Fifteen of them currently produce without injection. Continuous assessment of the drainage strategy for each field is important.

The quantity of water injected for pressure support has declined since 2004. See figure 5.8. That reflects several factors. Water injection was reduced by a total of 12 million cubic metres from 2004 to 2005 on Gullfaks and Draugen. In addition, the Statfjord late-life project began in 2008 with the aim of reducing pres-

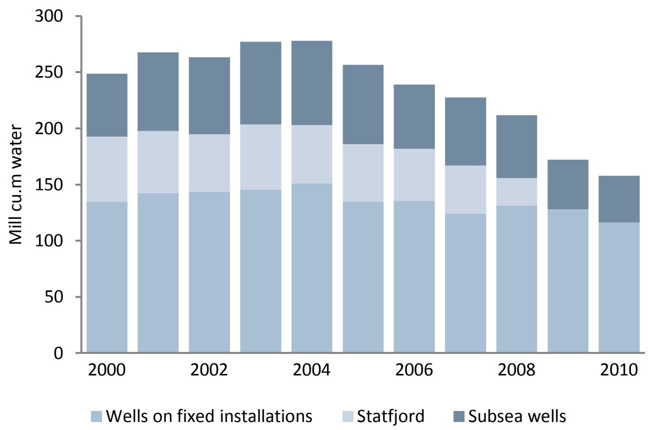


Figure 5.8 Water injection from subsea wells and wells on fixed installations. Statfjord is shown separately

sure as far as possible by halting injection. This is being done to produce as much as possible of the gas which was previously injected, associated gas, and as much as possible of the remaining oil. Water injection was also reduced on other fields in 2004-10, but not to the same extent. Some of the decline reflects shut-in injection wells. This may be part of the drainage strategy on some fields, while injectors may be shut in for long periods on other fields owing to a lack of maintenance. Injection wells represent a long-term recovery measure which is important for prudent resource management and long-term value creation. Giving priority to drilling and maintaining injectors is therefore important.

Annual volumes of injection gas have fluctuated between 30 and 43 billion scm over the past 10 years. See figure 5.9. More gas has been injected in subsea wells than in wells on fixed installations since 2002. Total gas injection has declined since 2004, partly owing to its cessation on Sleipner Øst, Norne and Statfjord for production reasons. Injection has also been reduced on Njord, Oseberg and Åsgard. Gas injection on Tyrihans began in 2008. Grane ceased importing gas in 2010, and now injects only gas produced from the field. Water injection began on Grane in 2011.

Gas production has been deferred on a number of fields with a gas cap over the oil zone in order to recover more crude. Provision is also being made for drilling additional wells and for extending the time frame for other IOR measures. A good example is Oseberg, where increased gas exports have been deferred several times because maintaining gas injection creates higher value.

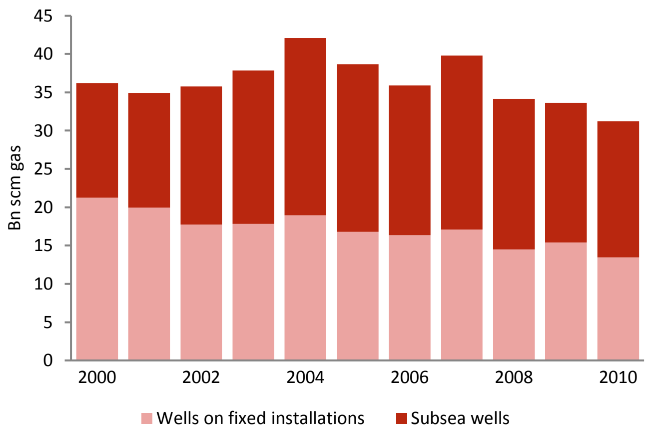


Figure 5.9 Gas injection in subsea wells and wells on fixed installations

Drilling and wells

Most development wells were drilled earlier from fixed installations on the field, but a growing number are now being drilled from mobile units. This is a consequence of many fields being developed in recent years either with fixed installations without a drilling rig or with subsea facilities. However, drilling from fixed installations remains important for realising the resource potential of most large fields on the NCS.

Drilling of development wells peaked in 2001. The number drilled from both fixed installations and mobile units has since declined. See figure 5.10. The drilling peak partly reflected the completion of major developments such as Balder, Jotun, Gullfaks Sør and Åsgard around 2000. Another explanation for the reduction is that companies have failed to fulfil their planned drilling programmes in recent years. Figure 5.11 presents four forecasts in 2007-10 for the number of wells due to be drilled in 2010 on the 12 largest oil fields. Expectations of the number of wells to be drilled in 2010 have declined year on year. New plans defer implementation of the wells. Several factors explain the build-up of this shortfall in drilling and well maintenance. Lack of rig capacity, shortage of personnel and technical equipment, and complex pressure conditions may have delayed or halted the drilling of planned wells.

High costs and lack of capacity have made it difficult to secure rigs for short assignments. Combined with the reluctance of operators to charter rigs unless the partnership commits to a work programme for the whole charter period, this may have contributed to the drilling of fewer wells. The permanent drilling facilities on a number of fields are more than 20 years old. Maintenance needs are growing and leading to greater costs and delays.

Prioritising rig capacity to meet a rising demand for well interventions and maintenance has meant fewer new development wells. Well slots are in short supply on a number of fields. To secure more wells there, they must be drilled as sidetracks from existing wells or slots must be reused. The latter approach can be time-consuming and expensive because existing wells have to be plugged and the slot readied for new drilling. Drilling sidetracks is cost-effective if the existing well path has the necessary quality. A growing amount of rig time is also being devoted to permanent abandonment of wells in order to meet safety and environmental standards. Such work may be at the expense of new development wells and well maintenance.

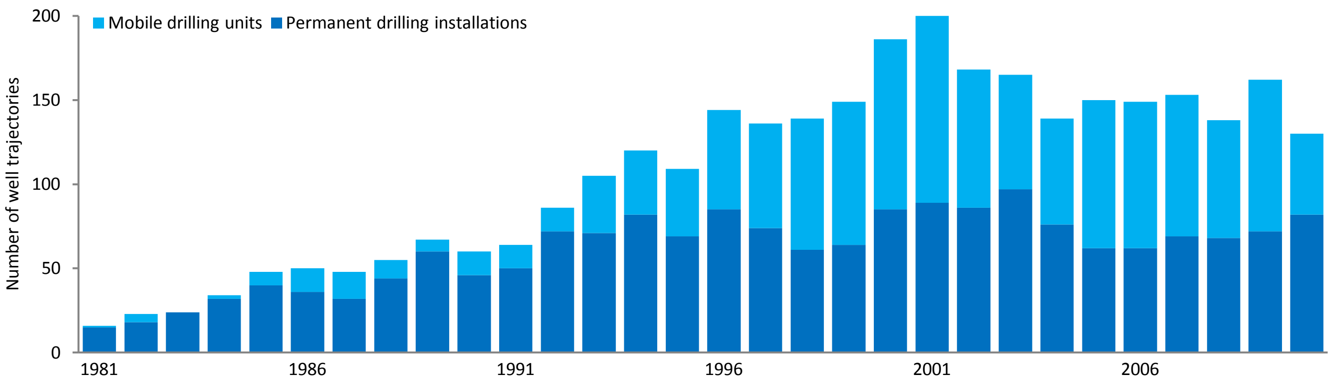


Figure 5.10 Number of development wells spudded, including multilaterals

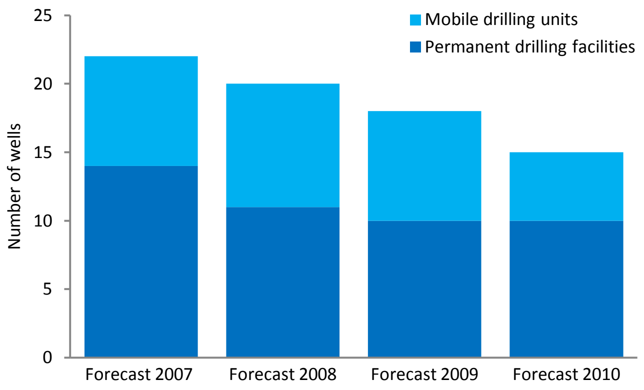


Figure 5.11 Drilling plans for development wells in 2010 on the 12 largest oil fields

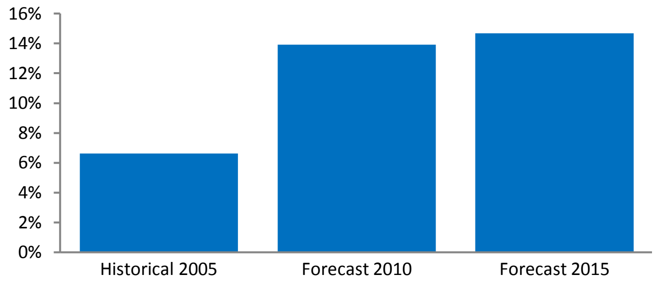


Figure 5.12 Share of well maintenance in ordinary operating costs

The resource-related and financial consequences of the drilling/ well maintenance backlog are difficult to estimate. Production can be recovered after a relatively short period for some wells, while recovering deferred output from others will mean that the field must produce for longer – which could boost costs. Nevertheless, more wells are generally drilled than were planned at the PDO date. The number of wells is often underestimated when preparing the PDO because future and more uncertain drilling targets are not included in the original plans.

As a result of the issues related to rig capacity, growing attention has been paid to improving the position. A gradual increase in the number of drilling units active on the NCS has accordingly occurred. Five new units are expected during 2011, and plans call for more in subsequent years. This is a positive trend. One challenge could be to retain the drilling units already operating on the NCS.

Because of complex geological conditions, such as sub-surface faults, most reservoirs comprise many "pockets" of oil which represent separate drilling targets. One reservoir may have many such targets. A number of these may be substantial, while others are small and marginally commercial.

The biggest and best drilling targets located closest to the installation are normally drilled first. That also yields the highest value creation for a development project. Over time, therefore, the targets drilled become increasingly marginal and this reduces average oil production per well. The distance from installation to drilling target is important for both costs and drilling complexity. Drilling problems can arise later in the field's producing life. That applies particularly when pressure conditions in and above the reservoir change as a result of production. Drilling extended-reach wells to peripheral targets may then become challenging. Many of the large fields now face such challenges.

As wells age, the need for maintenance and the cost of such work rises. See figure 5.12. Maintaining subsea wells calls for mobile units or special vessels. Several operators are now working on specific plans to build "category B" rigs, which can meet the need for subsea well maintenance at a lower cost.

A considerable amount of rig time on fixed installations is devoted to well maintenance. Many permanent drilling facilities need upgrading in the next few years. This requirement has long been known, but it has taken considerable time to decide on the best solution for a specific installation. Upgrading could enhance drilling efficiency in the long term, but fewer wells will be drilled or maintained while such work is being carried out unless mobile drilling units or vessels are used as temporary replacements.

Category B rigs
This rig type is designed to perform well interventions year-round and to use technology for heavy intervention, high-pressure pumping and cementing, as well as light drilling methods such as through-tubing rotary (TTRD) and coiled tubing drilling.

Technology development

Substantial technology development and implementation are being pursued for well quality and for drilling and well operations. This has consequences for both drilling costs and the revenue potential of a well.

An important motivation for technology development is that it will help to reduce drilling costs. These have increased substantially over time. The trend is illustrated in figure 5.13, which presents the average cost of development wells on the NCS adjusted for general price inflation. Higher rig rates and lower drilling efficiency make big contributions to cost growth.

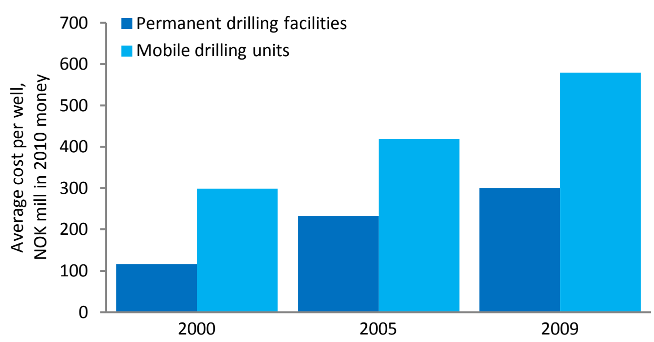


Figure 5.13 The average cost of a development well on the NCS in 2000, 2005 and 2009

The IOR prize for 2009 was awarded by the NPD to FMC Technologies for developing a well control system which permits safe and pressure-controlled drilling of sidetracks through existing subsea wells. Together with Statoil, FMC has developed and tested this technology on Åsgard to produce the world's longest TTRD sidetrack from a mobile rig. The ability to drill low-cost sidetracks opens great opportunities to improve recovery from fields with subsea wells dependent on mobile drilling units. The NPD praised FMC for its purposeful efforts since 1999 to develop cost-effective solutions for improved recovery from subsea wells. FMC has devoted substantial resources to achieving this goal without a guarantee of commercial success. Funds from oil companies and the Demo 2000 programme have covered part of the cost.

Issues which arise as fields age also help to boost costs. One example is the need for pressure and underbalanced drilling to handle reservoirs with low pressure and/or big pressure differences. Intelligent wells can help to improve recovery and to reduce the need for later downhole maintenance, but contribute to higher well costs initially.

The work of drilling sidetracks and maintaining wells on fields without permanent drilling facilities is performed today by more or less the same units which drill new development and exploration wells. Mobile units are often built to carry out complex drilling operations in deep water and a tough climate. That makes them expensive to charter and over-dimensioned for this kind of job. A number of the simpler drilling and well maintenance operations can be conducted using developed and tested technology deployed on smaller units or other vessels designed for this purpose. That could make sidetracks and well maintenance cheaper.

Infrastructure challenges

The North Sea is a mature area with an extensive infrastructure, which costs a lot to maintain and operate. Remaining resources are large, and many of the big fields are in a late-life phase. Lower production and aging of parts of the infrastructure create a need to simplify and renew facilities on fields with resources for several decades to come, so that production can be extended. Small discoveries also require infrastructure if they are to be tied back as a satellite to an installation with production facilities.

Seabed subsidence in the Ekofisk area has contributed to the need for infrastructure renewal. The same applies to Eldfisk and Valhall. Decisions on substantial investment have been taken on all these fields to lay the basis for continued operation over a long period.

The Tampen area involves nine large installations with production facilities on Statfjord, Gullfaks, Snorre and Visund. In addition come a number of subsea installations. As production declines and the infrastructure ages, the need arises to simplify this infrastructure so that remaining resources in the area can be recovered profitably and cost-effectively. This requires in part that licensees coordinate their plans so that possible coordination gains can be achieved. The NPD will follow up possible gains of this kind.

New methods and technology

Subsea technology

Demand for technology which can help to improve recovery from fields developed with subsea installations is set to increase because a growing number of fields are being brought on stream in this way. Additional development with subsea solutions is also conceivable on a number of the large oil fields when they eventually move into late-life production. Two technologies which could contribute to improving recovery are subsea separation and subsea compression.

Subsea separation has already been qualified, and the world's first commercial installation of this kind became operational on Tordis at the end of 2007. The concept is that water and sand are separated out on the seabed before piping the oil to the processing facility. Waste water is injected in a sub-surface aquifer. Separation was a success on Tordis. However, the project was halted in May 2008 when the injected water was found to be seeping back to the surface.

Seabed compression remains to be qualified. The Åsgard licensees have nevertheless resolved to adopt this technology to improve recovery from the Midgard reservoir and the nearby Mikkel field. That could represent the world's first field application for such technology. Boosting wellstream pressure before piping to the processing facility avoids a number of flow-related challenges. Recovery from the field can also be increased because pressure in the wells can be reduced. Subsea compression is being considered for a number of fields, including Ormen Lange and Gullfaks Sør.

Production of immobile oil

Immobile oil offers a big potential. The most promising methods for producing it are injecting water with chemical additives or miscible gases such as hydrocarbon gas or CO_2. Injecting low-salinity water has also been identified as an interesting method.

Various EOR methods were evaluated for use on the NCS in the Spor (1985-91) and Ruth (1992-96) research programmes. A number of pilots were conducted, including ones involving WAG. This resulted in the definition of the latter as a conventional method. Gas and WAG injection have made substantial contributions to the high level of recovery, including on Oseberg and Statfjord.

Silicate gel and polymer-assisted surfactant flooding (PASF) have been tested on Gullfaks, and foam-assisted WAG (Fawag) was tried out on Snorre. Microbial EOR (Meor) formed part of the research programmes and is being used today on Norne. Low oil prices in the 1990s helped to make the use of new injection methods commercially unattractive. Despite today's significantly higher oil prices, very few of the new injection methods have been tested on NCS fields since 2000.

Pilot projects play a key role in developing new drainage strategies. The use of EOR methods is field- or reservoir-specific, but mechanisms described after laboratory tests may have a transfer value between fields in a number of cases.

Various types of risk are associated with testing and adopting new technology. These may boost costs, while the gain in terms of increased oil production is uncertain. In addition comes the risk of deferred and/or lost production.

Injecting CO_2 for IOR has been assessed but not yet adopted on the NCS. Experience from fields on land in the USA and laboratory studies conducted for Norwegian fields show that this method has a substantial potential. Since all Norway's oil is produced offshore, the technical challenges are great. They include corrosion of production facilities and access to adequate quantities of CO_2. In addition, the effectiveness of carbon injection will vary considerable between the different reservoirs.

Full-field application of EOR methods has largely been confined so far to fields on land. That is partly because these do not suffer the space and weight restrictions faced offshore. Logistical challenges are also smaller. The barrier to adopting such technology on offshore fields is therefore higher than on land. However, Total has now initiated the world's first full-scale polymer injection project on its Dalia offshore field.

Using EOR methods on offshore oil fields – Total's Dalia project

Polymer injection on Angola's Dalia field is the first project of its kind in the world. The field lies in deep water (1 200-1 400 metres), comprises highly permeable sandstone (>1D) and contains oil of medium viscosity. It has been developed with subsea wells and produces via a floating production, storage and offloading (FPSO) vessel. The general drainage strategy is water injection via four lines and 31 wells. Production utilises four lines from 37 wells.

Project challenges have included the desire to start polymer injection as early as four years after coming on stream. Others are the wide well spacing, a high salt content and logistics related to injection procedures.

Four injection tests were conducted in 2009 with good results. On that basis, polymer began to be injected in 2010 via one of the four lines. An observation well is to be drilled so that the effect of polymer injection can be established more quickly.

Challenges for pilot projects

With high oil prices, recovery methods previously regarded as unprofitable or marginally commercial could yield commercial projects and represent substantial additional value. That includes some of the EOR methods aimed at producing part of the immobile oil remaining in the reservoir after water injection. Several such techniques need to be qualified, which could include conducting a pilot before a decision can be taken for a major full-field project.

Norwegian oil history shows that pilot projects have created billions of kroner in value. An important example was testing of waterflooding on Ekofisk before the full-scale project was initiated. Another was test production from thin oil zones with horizontal wells before the decision to proceed with the Troll Oil development. Contributions from and involvement by the authorities were important for realising these projects, as well as for gas injection on Oseberg. (See the boxes on Troll Oil and Ekofisk waterflooding). As much as 500 million scm of oil may have been recovered as a result of decisions in these three projects. That represents very substantial value both for the companies concerned and for Norwegian society.

Troll Oil

Troll is Norway's largest gas field, but also contains substantial volumes of oil in thin zones beneath the gas. The licensees believed it would be impossible to recover this oil commercially because drilling technology in the 1980s limited deviated drilling to a maximum angle of 60-70 degrees. This meant that producing the thin oil zones would require too many wells.

The authorities did not want the Troll oil to be lost, as had been the case on Frigg. They required the licensees from an early stage to conduct extensive studies of the recovery potential for the oil. In connection with the unitisation of the two biggest production licences, two operators were named – one for gas (Shell and later Statoil) and one for oil (Norsk Hydro).

New technology was needed for commercial oil recovery from Troll. The authorities accordingly became involved in the efforts to find good technological solutions, and proposed trials with horizontal wells. Hydro studied the method and drilled such a well on Oseberg in a successful trial which ranked as the first use of this technology on the NCS. The oil zones are thicker in Troll Vest than in the eastern section, and opportunities for oil recovery were accordingly regarded as better in this part of the field. A long-term test of oil production using horizontal wells in Troll Vest was conducted in 1989-90 from *Petrojarl* – initially in a 22-metre oil column and then in one 14 metres thick. This successful trial represented a technological breakthrough.

A PDO for the first phase of Troll Vest was approved in 1992, five years after the licensees had concluded that this would not be commercial. Oil production began in 1995, with gas output from Troll A starting the year after.

Ekofisk waterflooding

From *Giant discovery, a history of Ekofisk through the first 20 years*, Stig S Kvendseth, 1988.

"Work to find solutions which could maximise the degree of recovery for the field began right after the discovery had been made ... The degree of recovery was originally estimated to lie between 15 and 19 per cent of the oil reserves ... The main problems were concerned with whether the water in the reservoir would damage the production wells – and to what degree the chalk would manage to absorb the water so that more oil could find its way to the production wells. After a period of laboratory research, equipment for a test phase was installed on the 2/4 Bravo platform early in 1981 ...

"By the fall of 1982, there were sufficient data and prognoses to ascertain that, with the necessary investment, the project was only marginally profitable. The drop in oil prices and the uncertainty in that area which began in January 1983 reduced the economic outlook for the project to an unacceptable level from the point of view of practical economics ... In terms of oil quantities, expectations for the project came to about 170 million barrels.

"In order that the water injection might have optimum effect, Phillips had arrived at a time schedule in 1982 that presupposed a positive decision during the summer of 1983 ... Based on the Phillips group's conclusion that water injection into the lower reservoir – chalk – was not a profitable business venture, negotiations between the group and the [NPD/MPE] were begun in the spring of 1983. [The] NPD had for some time been interested in, and had worked to promote, water injection as a means of reservoir conservation. From the point of view of the Norwegian government, it was good national utilisation of resources to implement the project – plus it would give Norwegian industry welcome work during a difficult period ... The agreement reached modifies the tax terms so as to make them better suited to the nature of the project."

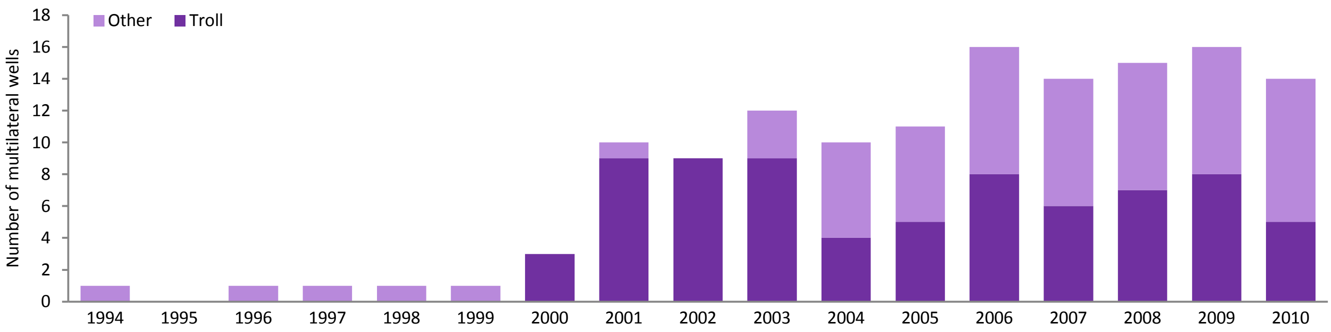


Figure 5.14 Trend for the use of multilateral wells

In addition come substantial spin-offs for other fields on the NCS. Based on the success of waterflooding on Ekofisk, this method has since been implemented on Eldfisk and Valhall and is contributing to a substantial increase in the expected recovery factor and producing life for these chalk fields. The method has also been assessed for full-field application on the Tor and Hod chalk fields. Although waterflooding in chalk fields has been successful, substantial quantities of immobile oil remain in them. Ekofisk is the chalk field with the highest expected recovery on the NCS. Even with full implementation of waterflooding and drilling of an ever growing number of wells, however, it will be difficult to achieve a recovery factor much above 50 per cent.

Spin-offs from the Oseberg gas injection project included the decision by Hydro and its partners to develop Grane and Fram with such injection, based on gas imported from other fields. That formed an important part of the strategy for achieving good resource utilisation on these fields. Gas and WAG injection were also adopted on Oseberg Sør.

Development of well technology in connection with Troll Oil has had big spin-offs for other fields, particularly in the use of multilateral wells. Figure 5.14 shows the trend for such wells on the NCS before and after the Troll development. Troll Oil operator Hydro extended this technology to Njord, Fram, Brage and Grane. Other operators have also adopted it. Several suppliers have developed their own solutions for this type of well. Baker Hughes and Halliburton were awarded the NPD's IOR prize in 2006 for their contributions to these developments.

Long-term thinking and creativity

Two conditions in particular have laid the basis for success on such fields as Ekofisk, Oseberg and Troll: their size, which made it possible to develop new technology for an individual field, and the adoption of such solutions early in the field's lifetime. Such conditions are not present to the same extent on the NCS today. But Norway still has a number of big fields expected to produce oil for many decades to come, such as Ekofisk, Eldfisk, Snorre and Heidrun. That will also apply to large new developments on the NCS.

Important historical decisions on field pilots and implementation have been very important, with substantial spin-offs. With hindsight, it can be seen that results from these projects were not a matter of course. A certain degree of boldness was required there and then from everyone involved. Oil prices are high today. Improved recovery from producing fields is a political goal. Much of the potential lies in the immobile oil which cannot be recovered unless new methods are adopted.

A bold approach is important for maintaining a high level of value creation. Getting as much as possible out of producing fields while infrastructure is still in place will be crucial. Close follow-up by the authorities has earlier proved useful when important decisions are to be taken. That will undoubtedly remain the case. At the same time, it will be crucial to have licensees who combine the willingness to take risks with long-term thinking, professional strength and creativity, and who thereby contribute to extending the limits of the attainable.

Conversion tables

1 scm of oil	=	1 scm oe
1 scm of condensate	=	1 scm oe
1 000 scm of gas	=	1 scm oe
1 tonne of NGL	=	1.9 scm of NGL = 1.9 scm oe

Gas	1 cubic foot	1 000 British thermal unit (Btu)
	1 cubic metre	9 000 kcal
	1 cubic metre	35.3 cubic feet

Crude oil	1 scm	6.29 barrels
	1 scm	0.84 tonnes oe (toe)
	1 tonne	7.49 barrels
	1 barrel	159 litres
	1 barrel/day	48.8 tonnes/year
	1 barrel/day	58 scm /year

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

See also the dictionary on the NPD website at http://www.npd.no/en/About-us/Information-services/Dictionary/

COVER: **Art at the NPD**

M-City
Mariusz Waras, alias M-City, has decorated a large wall in the entrance hall of the NPD's new office building. Details from that artwork are used as design elements in and on the cover of this resource report.

Born at Gdyna in Poland in 1978, Waras describes himself as a graphic artist, an outdoor painter, a traveller and an amateur architect. He graduated from the department of graphic art at the Fine Arts Academy in Gdansk, where he currently lectures. The theme of urban space runs through his output. Works by Waras can be seen on the streets of large cities such as Warsaw, Gdansk, Berlin, Budapest, Paris, London and Prague, as well as in a number of art galleries.

PETROLEUM RESOURCES ON THE NORWEGIAN CONTINENTAL SHELF 2011

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DIRECTORATE