PETROLEUM RESOURCES ON THE NORWEGIAN CONTINENTAL SHELF

2014

FIELDS AND DISCOVERIES

Published by the
Norwegian Petroleum Directorate
Professor Olav Hanssens vei 10
P O Box 600
NO-4003 Stavanger
Telephone: +47 51 87 60 00
Telefax: +47 51 55 15 71
E-mail: postboks@npd.no
Internet: *www.npd.no*

English translation: Rolf E Gooderham
Design/layout: Janne-Beth Carlsen N'Jai
Photos/illustrations: Rune Goa
Printed by: Kai Hansen, Stavanger
Paper: Silk 250/130 gr

ISBN 978-82-7257-151-0

Preface

The petroleum activity contributes substantial value to the Norwegian economy every year, and has created value totalling just over NOK 11 000 billion in 2014 money since it began. Big revenues help to create economic security and jobs nationwide. Petroleum operations have been under way for almost 50 years, and forecasts from the Norwegian Petroleum Directorate (NPD) indicate that profitable production and a high level of activity will continue for many decades to come.

Substantial changes have occurred since the NPD last published a resource report covering fields and discoveries on the Norwegian continental shelf (NCS). A record number of fields are being developed. Both recent discoveries and ones dating as far back as the 1970s have been sanctioned for development. Large new discoveries have also been made.

Johan Sverdrup is one of the five largest oil discoveries ever made on the NCS, and the biggest since 1979. Johan Castberg is the biggest oil discovery in the Barents Sea, and the largest north of the 62nd parallel since 1992. Developing them will contribute to a high level of activity in the next 10-year period. Once on stream, they will account for more than a quarter of Norwegian oil production.

The discovery portfolio is otherwise characterised by a number of smaller discoveries under evaluation. Most are expected to be developed with subsea solutions tied back to nearby fields. Given the right decisions in a long-term perspective, good profitability can be achieved through the interaction between field and discovery. The latter can benefit from established infrastructure, while the field can have their share of costs cut, their producing life extended and work on improving recovery continued. Without good utilisation of existing infrastructure, many of the discoveries will probably fail to be developed or bringing them on stream will be considerably delayed and cost more. In that case, fields will have to cease production earlier and the potential for improved recovery cannot be realised.

For positive development to continue on the NCS, planned projects must be profitable. Recently, attention in the petroleum industry has concentrated on cost trends and profitability. High oil prices have meant increased activity and substantial willingness to invest. The consequence has been a higher level of costs, with pressure on profitability as the result. If costs continue to rise, projects could be postponed or shelved. The NPD will keep this position under close observation.

Cost trends in the petroleum industry represent a challenge both for developing discoveries and for committing to projects which can improve recovery from fields. The government has given rights to the oil companies on the NCS. That also confers a responsibility to mature and recover all commercial resources, and helping to ensure that this happens is the NPD's job as the resource management regulator.

Photo: Emile Ashley

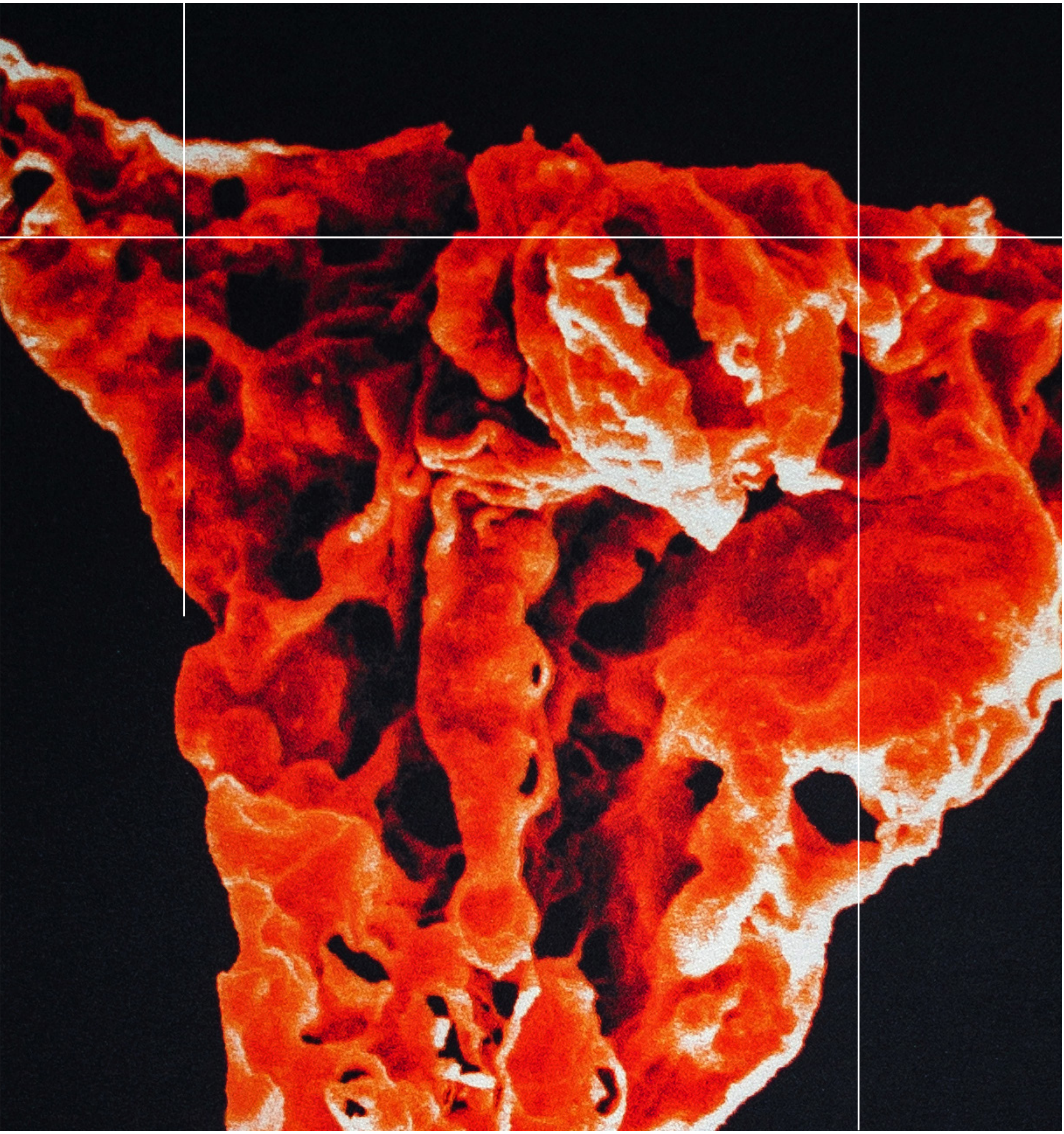
The NPD's budget has been scaled up in 2014 in order to give increased attention to fields on stream. This report demonstrates that many opportunities exist for recovering large quantities of oil and gas from these sources. But that requires licensees to take decisions and to be willing to make a commitment. The NPD will continue its efforts to ensure that value creation from discoveries and fields becomes as large as possible.

A target of 1 200 million Sm^3 has been set by the NPD for the growth in oil reserves during the 2014-23 period. This is somewhat higher than the basis for the NPD's forecast. The gap between forecast and target is expected to be filled by implementing yet more improved recovery measures on the fields and by forthcoming developments delivering even better than planned. It is also assumed that additional commercial discoveries will be made and sanctioned for development during the period.

Jan Bygdevoll
Director, forecasts, analysis and data
Norwegian Petroleum Directorate

Contents

Summary



This report deals with resources in fields and discoveries on the Norwegian continental shelf (NCS) and the NPD's assessment of opportunities for realising the greatest possible value from these. Of remaining resources estimated to total eight billion standard cubic metres (Sm^3), proven quantities account for 4.8 billion Sm^3 or 63 per cent. Seventy-seven fields were in production at 31 December and 13 were being developed, while 88 discoveries were under evaluation for development.

Production over the next few years will come from fields on stream and under development. The NPD estimates that overall oil production on the NCS will remain stable, while gas output increases somewhat. Discoveries which are developed will eventually contribute a steadily increasing share of production.

Fulfilling the forecast for oil and gas production depends on a number of conditions. Key factors will be whether the companies, given the price and cost position they face, can develop and implement profitable projects, and how far it will be possible to maintain and exploit the established infrastructure on the NCS.

The petroleum industry creates great value, and its socio-economic profitability is considerable. High oil and gas prices have created an international boom in the petroleum sector, with high capacity utilisation and substantial cost growth as a consequence. Both the development of discoveries and improved recovery from mature fields become more demanding when costs rise. The growth in costs threatens the profitability of future projects. This represents a challenge for the whole sector, and one which the industry, the suppliers and the government must work to overcome.

Realising the highest possible value from fields and discoveries calls for long-term solutions. An extensive and integrated infrastructure has been developed over time on the NCS. Efficient utilisation of this infrastructure may create great value for Norwegian society. Collectively, just under NOK 3 000 billion in today's money has been invested in installations, pipelines and land facilities. Phasing discoveries into existing fields can exploit this capacity while extending the producing life of the fields. This also provides space for new measures on the fields which can improve recovery from them. At a time when the industry is paying increasing attention to short-term goals, such as the current return on capital invested, choosing good and long-term development solutions will be extremely important.

A substantial number of improved recovery projects are being pursued on the various fields. Additional wells will be required by large proportion of these, and new facilities are needed – both subsea and on the surface – on a number of fields in order to secure them. It will normally be the case that the most profitable resources are recovered first from a field. As production progresses, implementing improved recovery measures can become more demanding. A high level of costs reduces opportunities for pursuing this type of measure.

Discoveries under evaluation for development could contribute substantial production in the time to come. Johan Sverdrup and Johan Castberg are large finds which will require their own installations and infrastructure. Most other discoveries are smaller and lie close to existing infrastructure. Development plans for the bulk of the smaller discoveries are accordingly based on subsea solutions phased into the established fields.

Although a high level of costs presents major challenges, remaining resources in fields and discoveries are also substantial. That represents an important motivation for finding solutions and realising resources. The industry has also faced big challenges earlier, but found solutions. Given that background, the NPD takes a positive view of future progress on the NCS. It believes that the petroleum industry, in collaboration with the government, will overcome the cost challenge so that infrastructure on the NCS can be utilised better and new improved recovery measures can be implemented.

The petroleum activity also has an impact on the environment, particularly through emissions to the air and discharges to the sea. The NPD contributes to the establishment of good solutions and to ensuring that the industry's environmental impact is as small as possible.

This report sets a new target for the growth in oil reserves, which represents an extension of the target introduced in 2005. That was an increase of 800 million Sm^3 in reserves to the end of 2014. Although reserves have increased substantially since 2005, the growth target does not appear to have been met completely.

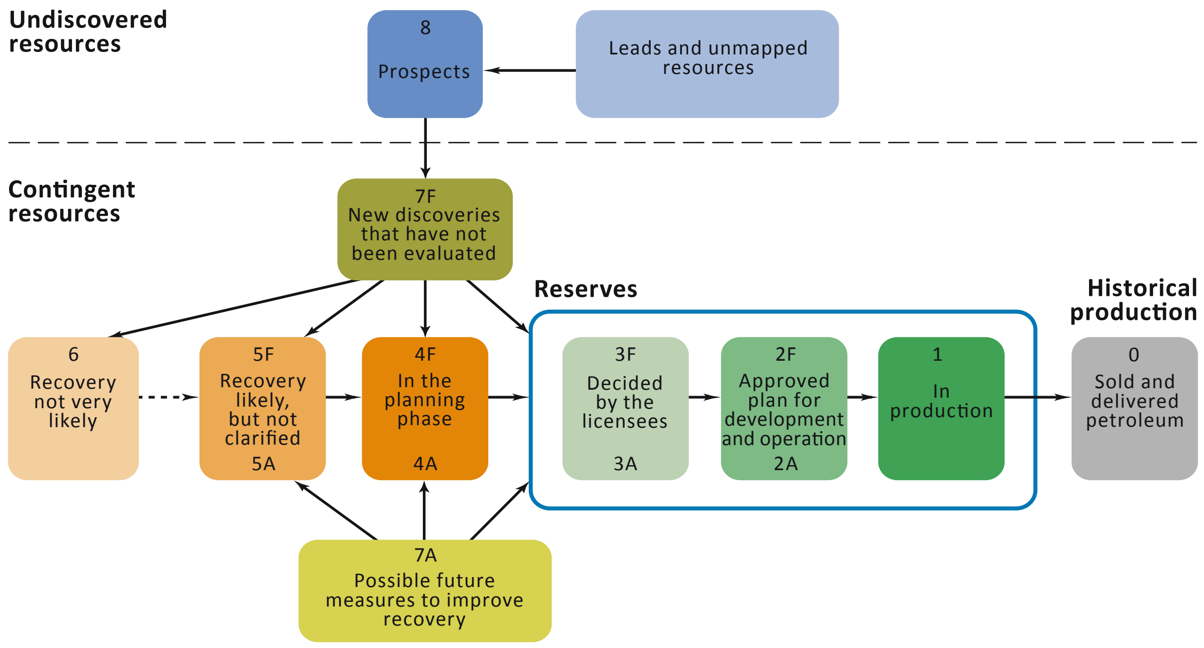
In the NPD's view, decisions on implementing planned projects for improved recovery and developing discoveries will boost reserves by 950 million Sm^3 by the end of 2023. The NPD's target for the 2014-23 period is an increase of 1 200 million Sm^3. It is assumed that the gap between forecast and target will be filled by the implementation of even more measures on the fields, by further optimisation of forthcoming development plans, and by continuing to make commercial discoveries which are sanctioned for development during the period.

Resource classification

A classification system is required in order to maintain an overview of petroleum quantities on the NCS. Resources are classified in accordance with the NPD's classification system, which was developed in 1996 and has remained unchanged since a revision in 2001. Classification embraces the total quantity of recoverable petroleum. Since petroleum is produced through industrial projects, emphasis is placed on the ability to follow these projects through their various phases. A field could be developed in several stages and will therefore embrace a series of projects. The maturity of these varies in terms of design, development and production. The NPD's system classifies petroleum quantities in the individual projects by their maturity.

The system is divided into three classes: reserves, contingent resources and undiscovered resources. Reserves are petroleum quantities covered by a production decision. Contingent resources are recoverable quantities which have been discovered but not sanctioned for development, and projects for improving recovery from the fields. The classification uses the letters F (first) and A (additional) to distinguish between development of discoveries and deposits and measures to improve recovery from a deposit. Undiscovered resources are those petroleum quantities which could be proven by continued exploration and which could be recovered. Quantities produced, sold and delivered comprise aggregated production. All recoverable petroleum quantities are termed resources, with reserves as a special category of these.

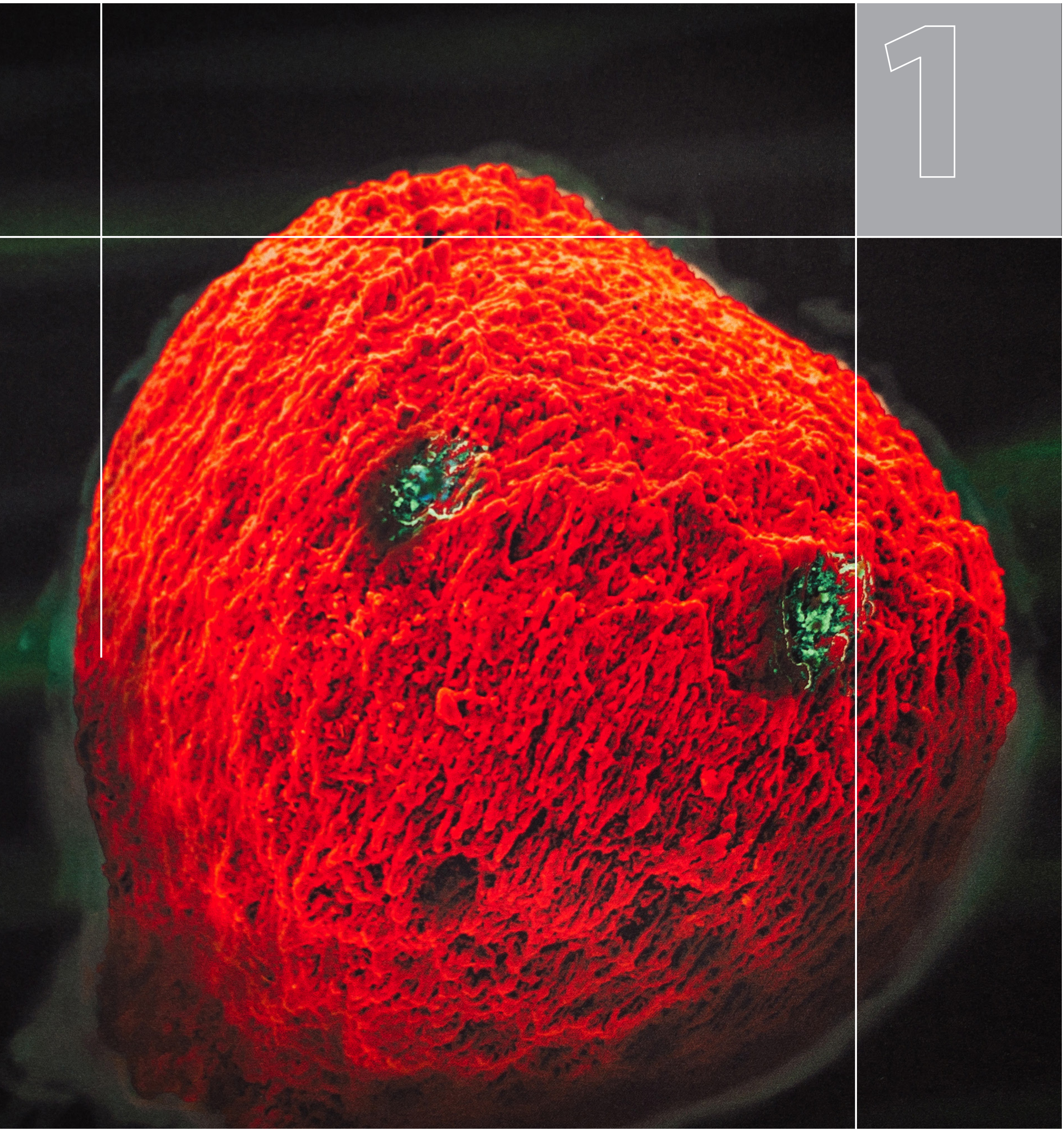
Each class is divided into various categories depending on the status of the projects.



NPD's classification of petroleum resources.

Resources and production

1



1

1.1 Resources

Remaining recoverable resources

The NPD estimated at 31 December 2013 that total recoverable petroleum resources on the NCS corresponded to 14.2 billion Sm³ oe. See figure 1.1. This represents the sum of all petroleum produced and sold since Norwegian petroleum operations began – a total of 6.2 billion Sm³ oe – and remaining recoverable resources estimated at eight billion Sm³ oe.

Remaining resources embrace reserves in fields, resources in improved recovery projects yet to be sanctioned on the fields, resources in discoveries and undiscovered resources – in other words, assumed recoverable quantities which have yet to be found. Proven quantities not yet covered by a development decision are designated contingent resources.

The estimate for remaining resources is uncertain, as the bars in figure 1.1 show. The base value utilised is the statistical expected value. Uncertainty over the total remaining resources ranges from 5.6 billion Sm³ oe (P90) to 11 billion Sm³ oe (P10). The P10 estimate – where a 10 per cent probability exists that the quantity will be larger – is almost twice as large as the P90 – where the probability that the quantity will be bigger is 90 per cent. The difference between the P10 and P90 estimates is greatest for the undiscovered petroleum resources, but uncertainty also prevails over how much can be recovered from existing fields and discoveries.

Barents Sea South-East and the continental shelf around Jan Mayen are now included in the estimate for undiscovered resources. The resource estimates for these areas, which were published in early 2013, are 300 and 90 million Sm³ oe respectively. The uncertainty range for these estimates is substantial. While gas accounts for 80 per cent of estimated resources in Barents Sea South-East, the bulk of resources around Jan Mayen is likely to be oil. More information on the undiscovered resources and mapping of the new areas can be found in the *Resource report – exploration 2013.*

Remaining recoverable resources in fields and discoveries

More than 60 per cent of the remaining recoverable resources are found in existing fields and discoveries. "Field" in this context means both those in production at 31 December 2013 and those where the decision to develop had been taken at that point.

The remaining resources mostly comprise gas, but also include substantial quantities of liquids. While the bulk of the remaining gas is classified as reserves in fields on stream or fields under development, a larger proportion of the liquids is classified as contingent resources in fields and discoveries. See figure 1.2.

Of the proven resources, 66 per cent of the oil and 41 per cent of the gas have already been produced and sold. Forty-two per cent of the remaining oil and 77 per cent of the remaining gas are classified as reserves.

The numbers in figure 1.2 represent the expected value for recovery. Although these resources are proven, the estimates are uncertain. Several factors contribute to this uncertainty, and will vary in line with the maturity and complexity of the projects. The most important relate to geological and flow conditions in the reservoirs and uncertainties about how costs and prices develop. Uncertainty is greatest for resources which have yet to be sanctioned for development.

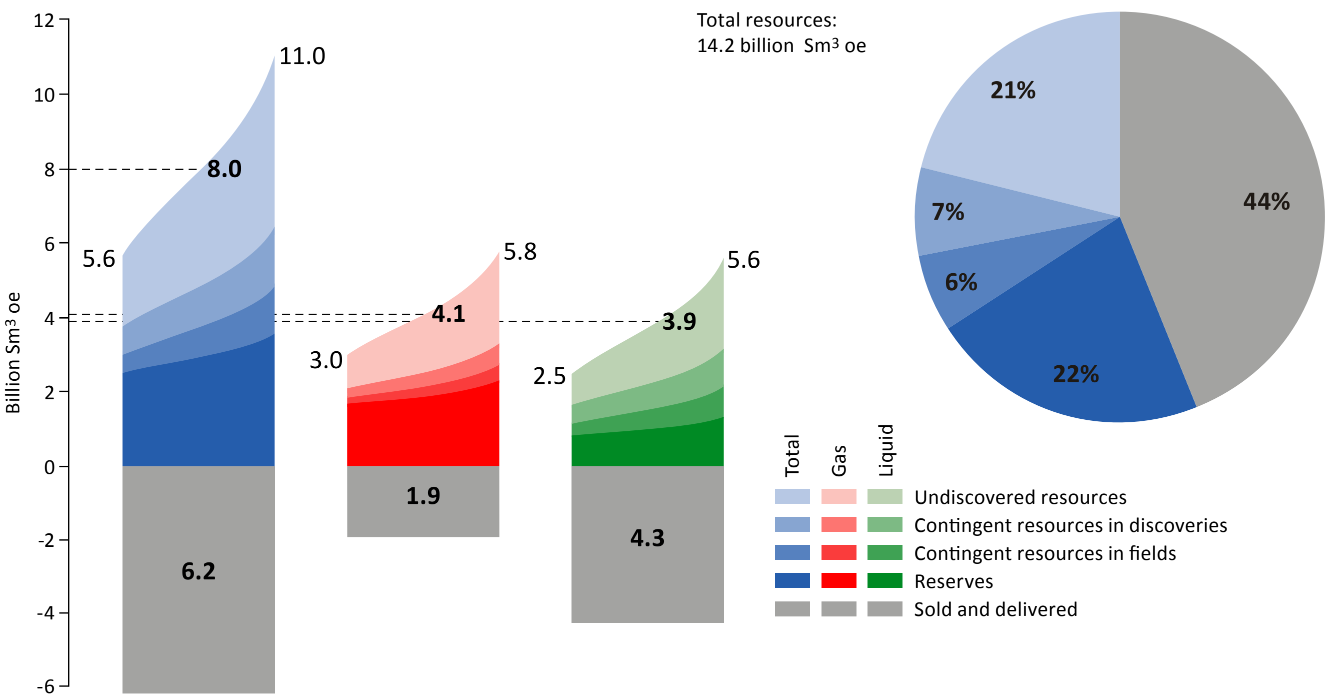


Figure 1.1 Distribution of total recoverable resources and uncertainty in the estimates at 31 December 2013.

[1] Liquid quantities are defined in this report as the sum of oil, natural gas liquids (NGL) and condensate.

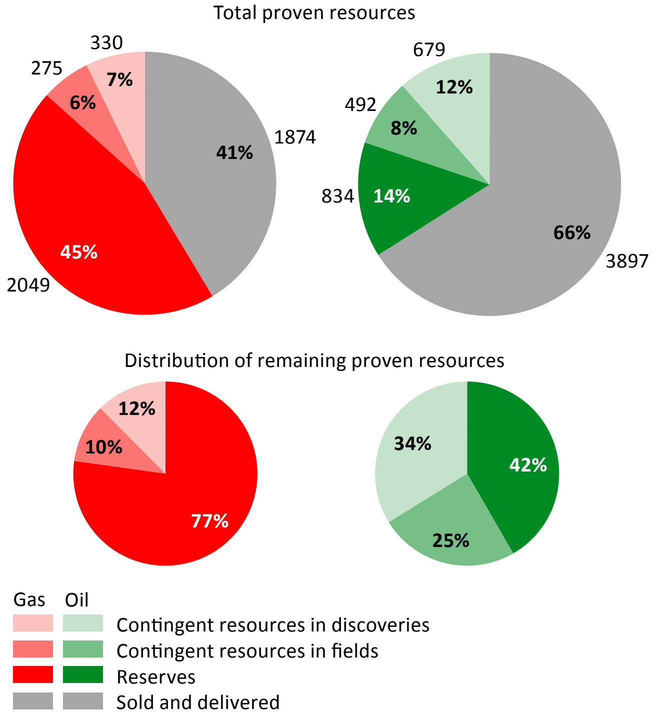


Figure 1.2 Proven oil and gas by various resource categories. The figures outside the topmost pie charts indicate the resources in million Sm³ oe for each category.

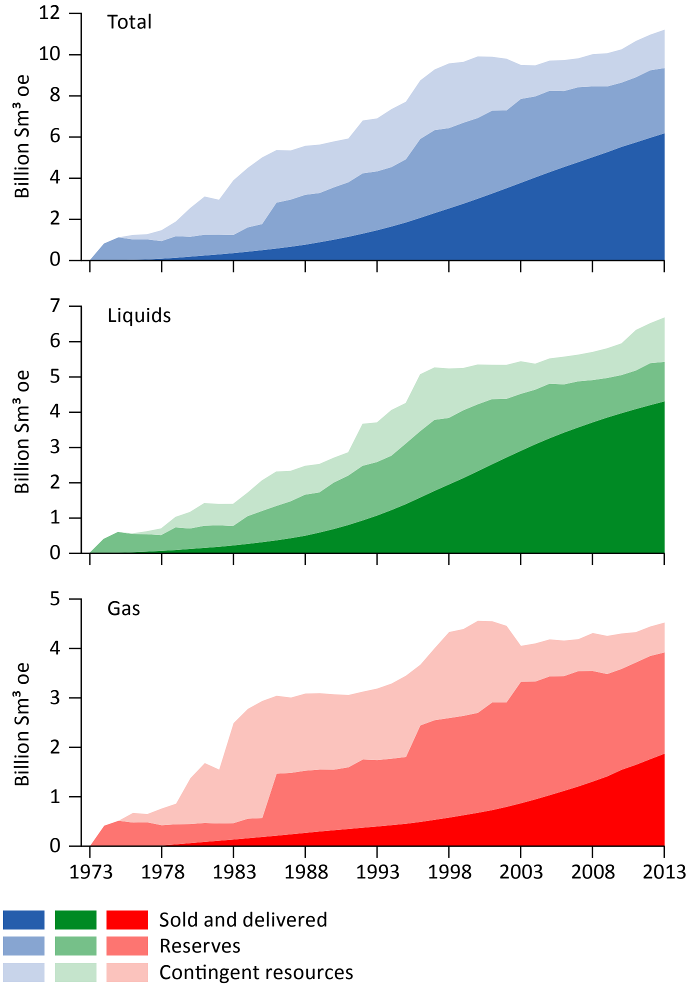


Figure 1.3 Development in estimates of proven resources over time.

1.2 Resource developments

Figure 1.3 presents a comparative overview of developments for proven resources from 1973 to the present day. Based on historical data from the NPD's resource accounts, this figure shows that the addition of new resources, through discoveries and upgrading of estimates for the fields, contributes to the continued existence of large producible quantities.

The figure for the development of gas resources shows with particular clarity how the reserves have increased in marked leaps as decisions are taken to develop large fields. Contingent resources are a combination of expected recovery from new discoveries and measures which could be implemented on fields to improve recovery. A marked rise would normally reflect a large new discovery. Falls could occur because further appraisal of discoveries reveals that these are smaller than first assumed. Estimates for each deposit are uncertain, and this uncertainty can vary from year to year. In 1996-2001, the NPD's expectations for future recovery of gas were over-optimistic because the average recovery factor assumed was too high. Estimates for contingent gas resources were accordingly reduced from 2001. See figure 1.3.

1.3 Production developments

Oil accounts for 63 per cent of the six billion Sm³ oe already produced from the NCS. The growth in output was particularly strong in the 1985-95 period, reflecting the development of a number of large fields in the 1980s and 1990s. The biggest oil fields were brought on stream before 2000.

Production of oil peaked in 2000 and has since been in decline, while gas output has risen after 1995. See figure 1.4. The increase in gas production reflects the development of large gas fields such as Troll, Åsgard and Ormen Lange, with associated pipelines and land facilities. The big oil fields developed in the 1970s and 1980s, such as Ekofisk, Statfjord, Oseberg and Gullfaks, have been very important for overall oil output from the NCS. Production from these fields has declined markedly over the past decade. One of the principal challenges on the NCS is accordingly to utilise spare production capacity by improving recovery and the phasing-in of nearby discoveries.

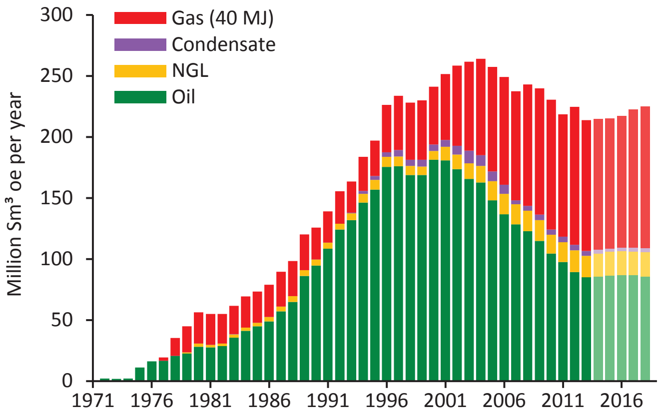


Figure 1.4 Historical production with forecasts for the next few years.[2]

The NPD expects oil production to remain around its present level over the next few years. Gas output from producing fields is expected to increase somewhat during this period. Several large discoveries made in recent years are expected to come on stream during the next 10 years. This will compensate for the natural production decline from fields in operation, and means that production could grow slightly in the years to come. See figure 1.5.

Annual reporting of data to the NPD

The companies are required to report data on an annual basis to the NPD for the fields, discoveries, and transport and land facilities they operate. Reporting embraces projects, resource quantities, and forecasts for production, costs and environmental discharges/emissions. On this basis, the NPD prepares its own forecasts. These are submitted to the Ministry of Petroleum and Energy (MPE), and form among other applications part of the basis for the national budget.

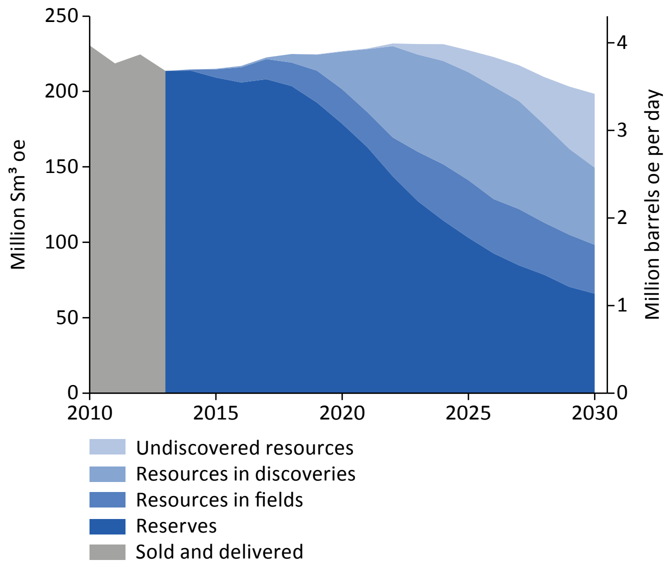


Figure 1.5 Forecast for petroleum production up to 2030.

Production over the next few years will be dominated by fields on stream or under development, with a gradual increase from discoveries where work on development plans is now under way. The contribution from these discoveries is expected to rise from 2020. While anticipated output from Johan Sverdrup and Johan Castberg will be the primary source, a large number of other discoveries are expected to contribute. New discoveries must be made and developed if the production forecast is to be fulfilled in the longer term.

The production forecast is uncertain, and this uncertainty increases with time. Over the next few years, the development of output from and implementation of projects on existing fields will determine whether the forecast will be fulfilled. The start-up time and pace of drilling on the fields currently under development will also affect quantities. Later, decision-making processes, development solutions and production start-up on new fields will represent the biggest sources of uncertainty. Further down the road, a large share of anticipated production will come from the resources which are yet to be discovered. The uncertainty relates primarily to the number and size of future discoveries, and to whether and when they can be brought on stream.

The NPD's production and cost forecasts are based on price and cost levels in the autumn of 2013. Significant alterations in these assumptions will cause changes to project execution and thereby to cost and production forecasts. That would also be the case if the companies amend their requirements for the profitability of individual projects.

[2] The gas 40 MJ value in figure 1.4 represents a normalised volume for gas sold. The gas is sold by energy content rather than volume, and normalised gas has an energy content of 40 MJ per Sm³. This energy content varies from field to field on the NCS. In 2013, the gross calorific value (GCV) for the fields lay between 36.7 and 50.0 MJ per scm depending on the composition of the sales gas. Methane has a GCV of about 37.7 MJ per Sm³.

2 Recovery from producing fields

2

2.1 Production developments

Since Norwegian oil production began in 1971 with test production from Ekofisk, a number of large oil fields have been developed. The big fields, which were brought on stream in the 1970s and 1980s have eventually moved into a mature phase with declining oil rates. At the same time, new field developments have been smaller. The loss of production from the old fields has consequently been only partly offset by bringing new discoveries on stream. Production is now more diversified and spread across more fields than in the past. See figure 2.1.

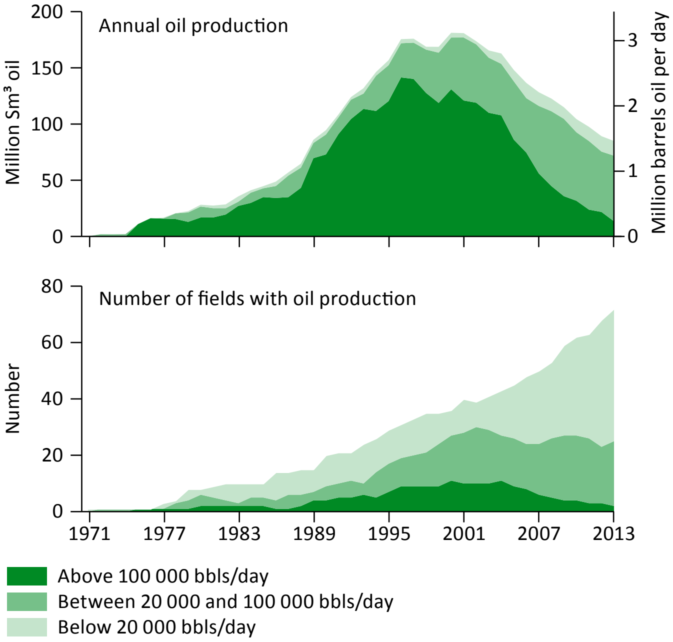


Figure 2.1 Development of historical oil production and number of fields by level of production.

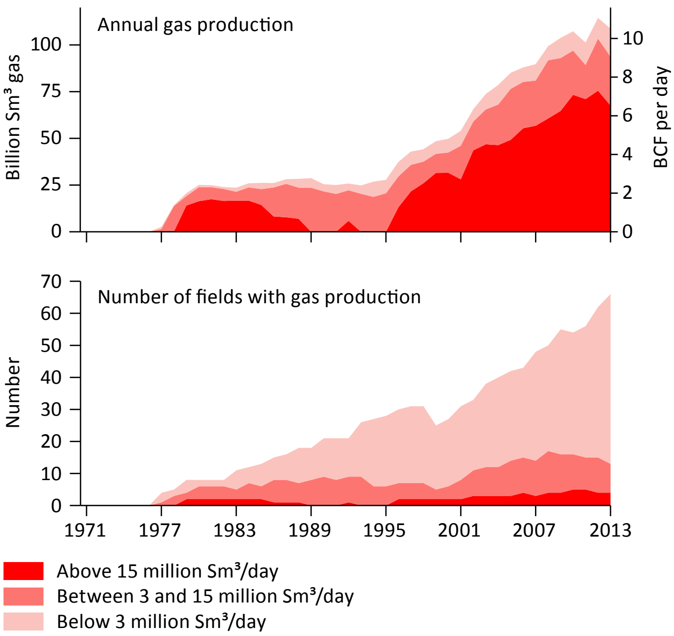


Figure 2.2 Development of historical gas production and number of fields by level of production.

Figure 2.1 presents historical oil production broken down between fields with high, medium and low daily output. Oil production was dominated until well into the 1990s by a few fields with large outputs. Oil production in 1989 was at roughly the same level as in 2013. Fifteen oil-producing fields were on stream in 1989, and 81 per cent of production came from the four of these with daily rates of more than 100 000 barrels. By 2013, the number of oil-producing fields had risen to 72 and the two with production exceeding 100 000 barrels per day accounted for 15 per cent of output.

Oil production is expected to continue declining from fields which have been on stream for many years. Some fields have been revitalised in recent years through the development of new production facilities or an increase in drilling capacity. This will reduce the decline in output to some extent over the next few years. In addition, fields with a large production capacity are coming on stream/under development. As a result, the NPD expects the level of oil production to stabilise over the next few years.

Figure 2.2 presents developments in gas output, broken down by the level of production from the fields. Gas sales from the NCS began in 1977 with the opening of the gas pipelines from Ekofisk to Germany and from Frigg to the UK. Production has been growing steadily since 1996, with the number of fields contributing to this output doubling. The position for gas is that a few fields account for the bulk of output. Four fields provided 62 per cent of production in 2013, with Troll as the largest.

2.2 Cost position

Development and operation of what has become an extensive infrastructure of facilities, pipelines and land-based plants call for large financial resources. Total expenditure, excluding exploration, came to about NOK 250 billion in 2013.

Cost trends on the NCS for operation, investment and other spending are presented in figure 2.3. The growth in expenditure over time reflects both increased activity and price inflation. The rise in the level of costs has been particularly marked since 2005. High oil and gas prices have led to an international boom in the petroleum sector, resulting in high capacity utilisation and a considerable growth in costs.

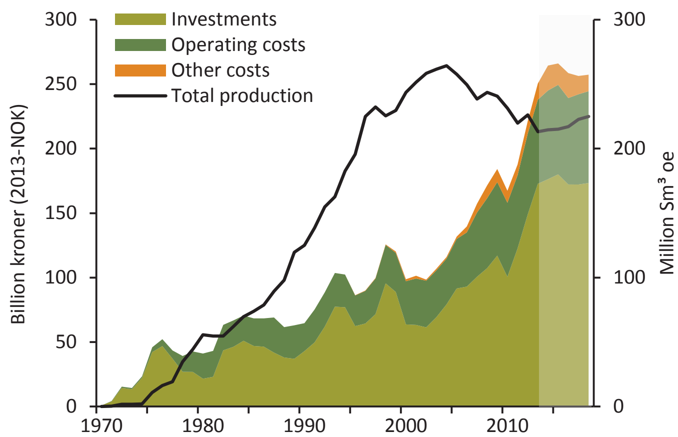


Figure 2.3 Development in costs (forecast 2013-18).

The increase in petroleum industry costs has exceeded price inflation in the general economy by a fairly substantial margin. Figures in this report present costs in fixed prices adjusted to the 2013 level on the basis of the consumer price index (CPI). Price rises over and above the general level inflation are included in the base figures.

Capital spending represents a large proportion of overall expenditure. Figure 2.4 presents investment profiles for field developments where spending began in the 1970s, 1980s and 1990s respectively and up to the present day. As the figure shows, investment in fields which were developed as early as the 1970s and 1980s continues to account for a substantial proportion of total capital spending. More fields in operation accordingly mean higher overall investment. New developments come on top of that.

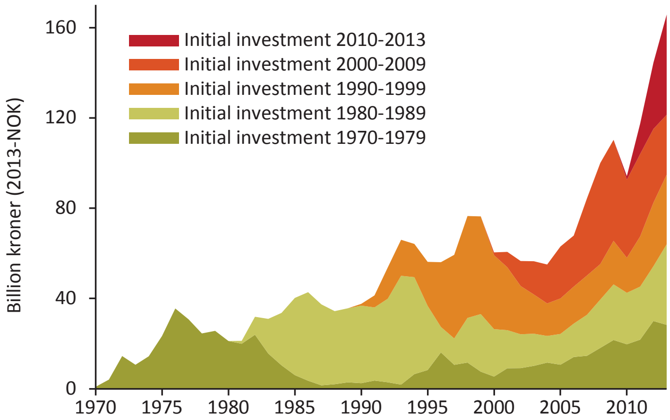


Figure 2.4 Total annual investment in field development by the decade when spending began.

Figure 2.5 presents the development of operating costs and investment. The growth in costs has been substantial for fields on stream in 2000-2013. From 2005 to 2013, the average increase in operating costs and investment was seven and 15 per cent respectively, measured in nominal kroner. These rises were five and 23 per cent in nominal kroner during the final part of the period, from 2010 to 2013.

Drilling new development wells has accounted for about 50 per cent of investment. Operating investment accounted for a further

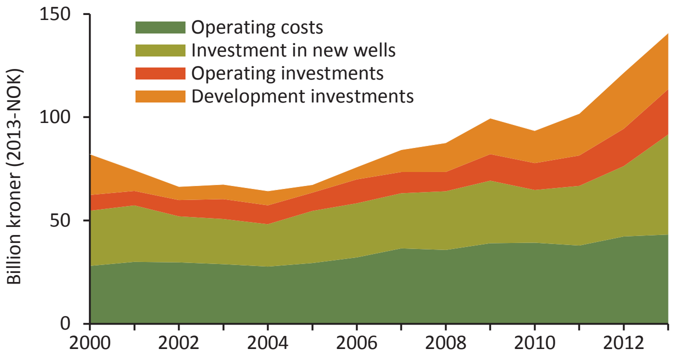


Figure 2.5 Development of investment and operating costs on fields on stream throughout the 2000-13 period.

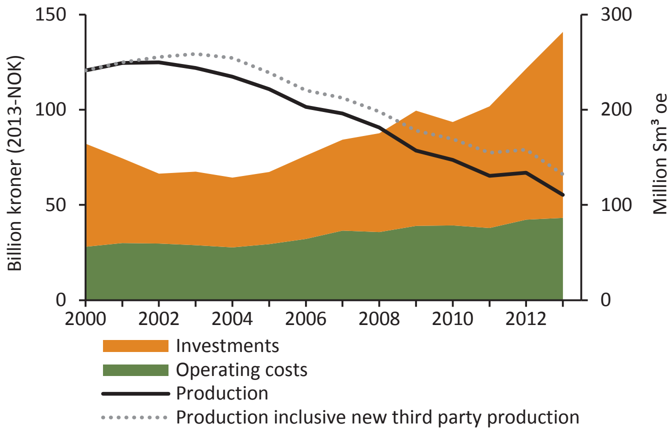


Figure 2.6 Cost and production developments for fields on stream throughout the 2000-13 period.

20 per cent. The latter embraces various types of capital spending required to maintain operation on existing facilities. Costs associated with maintaining technical integrity and production capability are expected to increase on aging installations. The third large investment item is development spending. This has primarily involved the installation of new fixed platforms on fields already in production.

Increasing costs have at the same time been met by a decline in production. The decline has been partly offset by utilising spare production capacity on the facilities to phase in smaller discoveries nearby. Trends for costs, own output and production for others (third-party volumes) are presented in figure 2.6.

The NCS is maturing, and most fields are in a phase with declining production. Because a large proportion of operating costs for a field are independent of the quantity produced, unit costs – defined here as operating costs per unit produced – will rise.

Figure 2.7 illustrates the challenge posed by rising unit costs for fields which have not had third-party processing. The increase in unit costs has been particularly marked in recent years.

Rising costs are a matter of concern. This is because the profitability of an individual project may be threatened if oil prices fall, and could cause the project to be shelved. Cost growth has been particularly strong in drilling. Figure 2.8 presents the trend for the average cost for new development wells drilled from mobile facilities. The average cost of drilling a well has more than doubled since 2002. Considerable variation exists in drilling expenditure per well, and many factors determine the cost of a well. A larger proportion of long and more complex wells could contribute to higher average costs.

A substantial proportion of well costs are closely associated with the time taken. The speed of the drilling process, usually termed drilling efficiency, will have great significance for the cost of the well. One indicator of drilling efficiency is metres drilled per day. This has moved in a negative direction over time on a number of fields. Nevertheless, the most important cause of the cost increase is the rise in prices for the goods and services required to

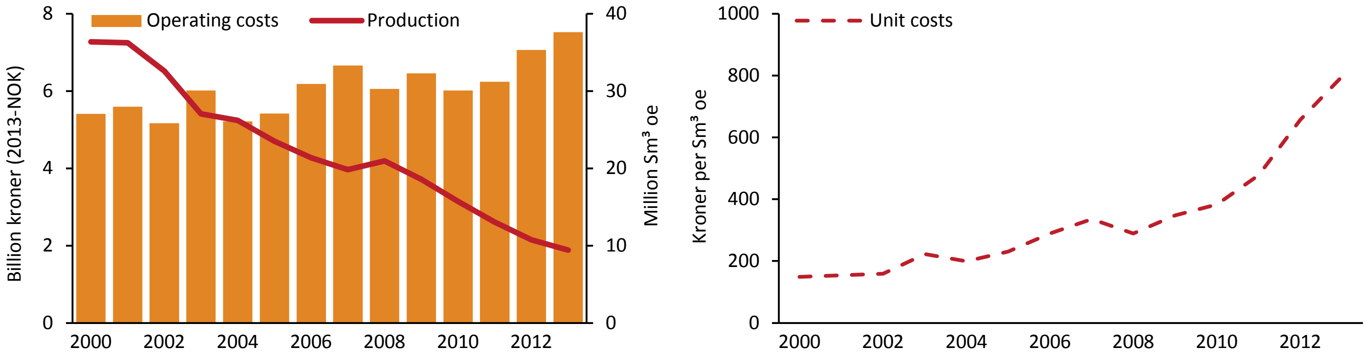


Figure 2.7 Development in operating costs per unit produced for a selected field without third-party processing.

drill a well. Most development wells on the NCS are drilled from mobile units. Rig hire and various forms of well services account for the bulk of the cost of drilling such wells. Rig hire alone comprises 45 per cent of the cost of a well, with well services accounting for roughly another 30 per cent.

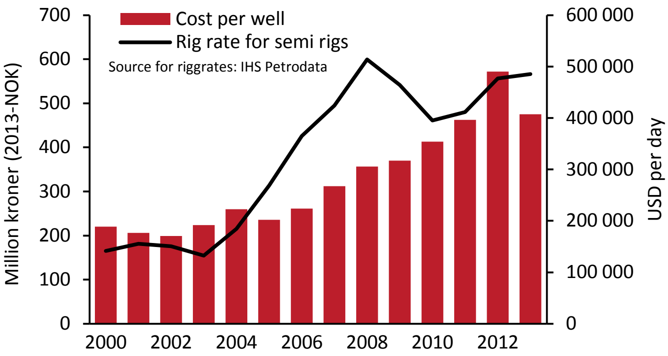


Figure 2.8 Development of average rig rate and well cost for wells drilled from mobile units.

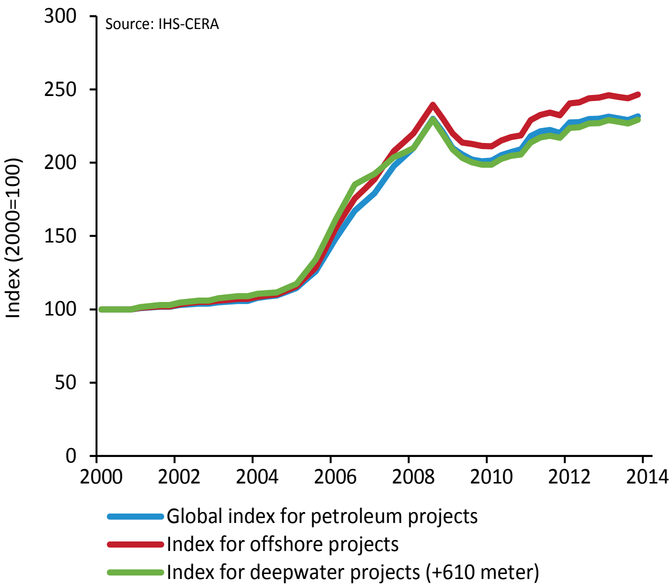


Figure 2.9 Movements in global cost indices for development projects.

In addition to well costs, figure 2.8 illustrates the development in rig rates. These are fixed when contracts are entered into. A substantial time lag may occur between the signing of a contract to use a rig and the point when costs begin to be incurred. Three-four years normally elapses from the award of a newbuilding contract until the rig begins operations. In addition, due to long-term contracts market rates do not immediately affect well costs.

Developments in the level of costs on the NCS must be viewed in relation to international trends. Figure 2.9 shows three investment level indices – one global, one for offshore projects and one confined to deep water projects. According to these data, the level of costs has more than doubled since 2005. Little variation exists between the various indices.

The increase reflects higher prices in various key market areas. Internationally, growth has been particularly strong in the drilling and well sector and in the cost of subsea equipment.

Available statistics are inadequate for comparing international trends with developments on the NCS. *Økt bore- og brønnaktivitet på norsk sokkel (Increased drilling and well activity on the NCS)*, the 2012 report of a commission appointed by the MPE, describes cost trends in the drilling and well sector and identifies a number of factors which boost costs in this area on the NCS.

2.3 Projects on producing fields

New projects with associated investment are sanctioned by the licensees after a thorough evaluation. A number of projects are assessed on fields every year. The 2013 resource account includes 165 specific projects for increased oil and/or gas production and extended producing life. Some projects are approved and implemented, while others are subject to further study, postponed or shelved. The size of these projects varies substantially in terms of both production effects and costs.

Most of the unsanctioned projects on producing fields involve relatively small quantities compared with those which form the basis for new field developments. Many of the well projects which fall into this category have quantities below 2.5 million Sm³ oe. These embrace drilling of one or a few new development wells. Continuous efforts are pursued on the fields to evaluate the basis for new wells. The decision on whether to drill a specific well is based on an assessment of its profitability.

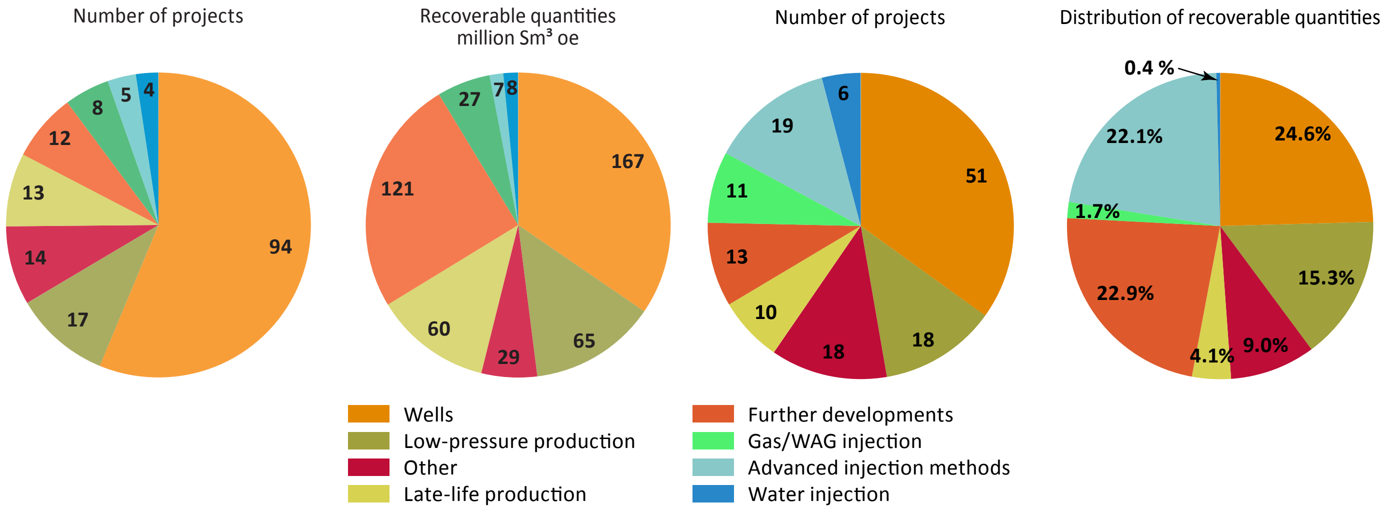


Figure 2.10 Projects in resource categories 4A and 5A by type.

Figure 2.11 Projects in resource category 7A by type.

An overview of various types of unsanctioned projects for improving recovery on producing fields is presented in figures 2.10 and 2.11. While the first of these shows a specific project, the second covers possible but immature measures for improved recovery. Since the latter are considerably more uncertain, the NPD does not consider it appropriate to show them with resource estimates.

About a third of the quantities in the specific projects can be produced by drilling more development wells. See figure 2.10. More wells are also important for projects involving the injection of water and/or gas and further development of the fields. Such projects account for a further 25 per cent of the quantity. Further development of a field embraces major upgrades and projects where new installations are planned. Low-pressure production also represents an important measure for improving gas and oil recovery. The development of subsea compression technology in recent years on Åsgard and Ormen Lange is important for improving recovery on subsea developments.

In the longer term, other types of projects which have been reported as possible future improved recovery measures could also yield substantial additional quantities. Advanced methods account for 19 of 146 possible measures identified, and contribute 22 per cent of the quantity in this category. See figure 2.11. Injection of CO_2 is one example of such methods.

Potential for improved recovery

Work on ensuring the highest possible recovery from a field begins during development planning and installation design. Most oil fields on the NCS already incorporate pressure support through water and/or gas injection from the time they come on stream. Ever better tools for reservoir monitoring help to improve recovery strategies for the fields. Systematic data acquisition and use of production and reservoir information increase understanding of the reservoir's properties throughout the production phase. Improved understanding of where oil and gas are located and where they flow is important for better well placement. New drilling targets are constantly being identified in this way, which means that additional wells need to be drilled.

Remaining reserves in a field are the quantity of oil and/or gas included in the approved plans at any given time. Figure 2.12 presents an overview of the recovery status for the 25 oil fields

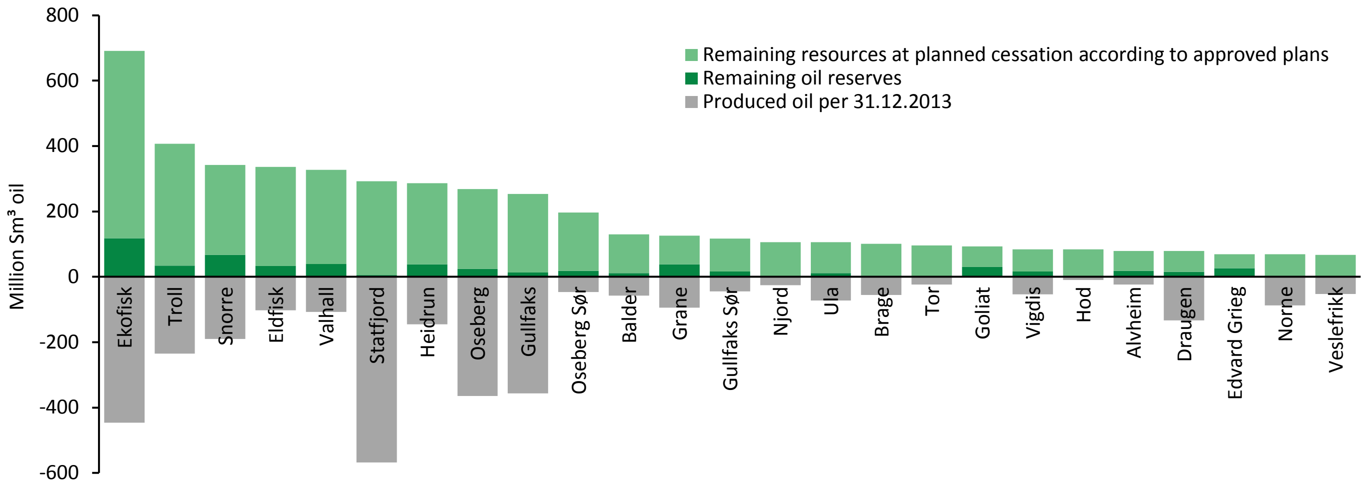


Figure 2.12 Resource overview for the 25 largest oil fields, quantities sold, reserves and remaining oil without new measures.

with the largest quantity of remaining oil in the ground at year end. When projects which improve recovery are sanctioned, reserves will increase and the remaining quantity (light green) will be somewhat reduced.

How much oil can be produced from a field is a function of such factors as reservoir conditions, development solutions, production strategies and available technology. Oil not covered by current production plans forms the basis for improved recovery methods. This oil may be divided into two categories – mobile and immobile. Mobile oil represents mobilisable oil not currently in contact with production wells or injection water/gas. In principle, it can be recovered with the aid of additional wells and longer-lasting use of water and/or gas injection. Immobile oil is stuck to the pore walls in the reservoir, and cannot be squeezed out of the pores and produced by injecting (more) water or gas.

Postponing gas production is an important measure for improved oil recovery (IOR) on some fields. Where fields contain both oil and gas in the same reservoir, the timing of gas production can affect overall oil recovery. As long as the gas is retained in the reservoir or injected back into it, the reservoir pressure can be maintained and more oil produced. When the gas is produced from the reservoir, the pressure will decline and oil will be left behind. On such fields, the deferred revenues from gas production must be weighed against the income from IOR. Deferred production of gas caps and continued gas injection are important IOR measures on fields such as Oseberg, Troll and Visund. The NPD estimates that gas injection in Oseberg has yielded more than 50 million Sm^3 of additional oil.

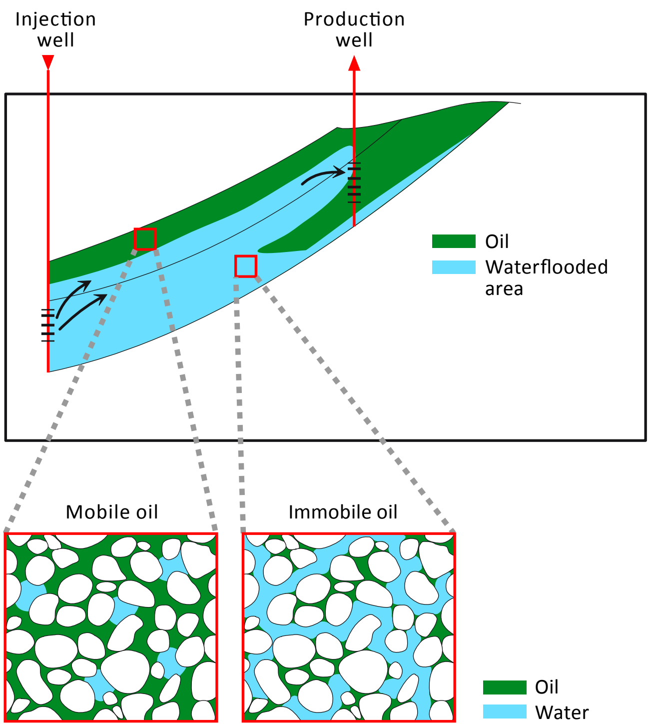


Figure 2.13 Cross-section of a reservoir showing an example of oil and water distribution after waterflooding, and distribution of the liquids at pore level.

IOR methods can be categorised as conventional or advanced. The latter (less mature) methods are often termed enhanced oil recovery (EOR). They involve advanced flooding methods intended to help mobilise part of the immobile oil. See figure 2.13.

Advanced methods have been little used on the NCS. A good deal of research has been and is being conducted into different techniques, and there have been scattered pilot trials and field applications. A continued commitment in this area is important. The government established an IOR centre in 2013 to encourage further efforts. First awarded in 1998, the NPD's IOR prize has been presented to some of the initiatives pursued.

The NPD has been awarding its IOR prize since 1998. It is next due to be presented at ONS 2014 in Stavanger. The prize is given to production licences, companies, project or individuals who have created added value on the NCS through innovative action and plans related to improved oil recovery. It was last awarded in 2012, when the recipients were Statoil's specialists working with gas injection on Oseberg.

Recipients of the NPD's IOR prize:

2012 - Statoil for sub-surface work on Oseberg.
2010 - Professor Tor Austad at the University of Stavanger and the Corec research centre for work on recovering more oil from chalk reservoirs.
2009 - FMC Technologies for developing and testing a technology to increase production from subsea wells.
2008 - No worthy candidate found.
2007 - Talisman for its commitment to mature and marginal fields and for decisions which had already given added value. That applied particularly to the reopening of Yme in the North Sea.
2006 - Halliburton and Baker Hughes for well technology in the thin oil zones on Troll.
2005 - Arne Skauge for his success in bringing research out of the laboratory for pilot testing and implementation on the field.
2004 - The Gullfaks licence for decisions on and implementation of advanced wells for exploration targets outside existing fields and for new methods of dealing with produced water.
2003 - BP and the Valhall Unit for the Life of Field Seismic project on Valhall.
2002 - No worthy candidate found.
2001 - Statoil and Egil Sunde for a pioneering commitment to using bacteria to improve recovery from Norne. This represented the first application of this technique on an offshore field.
2000 - Phillips Petroleum Company for studies and decisions on the IOR project for Ekofisk, not least at a time with low oil prices.
1999 - Saga Petroleum for using foaming agents to stop unwanted gas production and thereby increasing oil production from Snorre.
1998 - Norsk Hydro for the Troll Oil project. The thin oil zones in this field became the biggest oil producer on the NCS in 2002 because somebody believed in something more than just gas production.

Microbial EOR (Meor) is being utilised on Norne. This method involves giving bacteria the opportunity to change the interfacial tension between oil and water so that more of immobile oil is mobilised.

In addition to the oil left behind in parts of the reservoirs with effective displacement, areas will exist where flooding is less effective and where the sweep medium cannot penetrate. The effectiveness of displacement is governed by the form and extent of the reservoir, the quality of the reservoir rocks and the location of the development wells.

Even with good displacement, some oil will remain in the pores. The size of this residual saturation will depend on rock and oil properties. It is also dependent on the properties of the sweep substance being used. Displacement gas usually yields lower residual saturation (five to 15 per cent) than water (10-25 per cent). The proportion of oil recovered where displacement is effective is termed microscopic displacement efficiency.

The EOR methods which could be used to mobilise part of the immobile oil involve altering the surface tension between oil and water or changing wetting properties in the reservoir. The latter are determined by the physical and chemical properties of the liquids and the reservoir rocks, and determine in their turn whether oil or water lies like a film on the pore surface.

Adding surface-active agents (surfactants/tensides) to injection water can help to improve oil recovery by lowering the surface tension between oil and water, and thereby reducing local residual oil saturation. This method is challenging because it demands continuous chemical injection in specific concentrations. OG21[1] considers the technique to have a big potential on the NCS. Developments have so far been confined to laboratory work.

Recent research has established that changes in the salinity of injection water can also reduce immobile oil in flooded areas. However, most oil fields on the NCS inject seawater with a salinity lower than the formation water. As a result, low-salinity waterflooding does not appear to have a big potential in existing fields. Studying this effect with a view to optimising the salinity of injection water is nevertheless important, particularly for new fields. Low-salinity injection water will make polymer additives and surfactant flooding more effective.

Certain advanced methods are directed solely at mobile oil and at more effective displacement or sealing of areas already flooded. These techniques involve the use of chemicals (polymers) which increase the viscosity of injection water or block pore channels so that additional oil can be displaced. When channels are blocked, the water must take new routes and accordingly displaces more oil on the way. See figure 2.14.

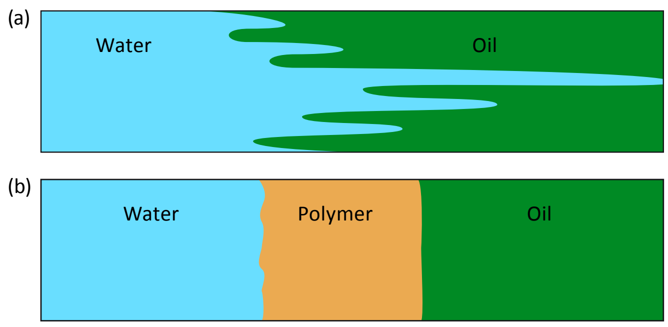


Figure 2.14 Polymer flooding.

Polymer flooding seems to be the method under study by most licensees. It requires the handling of large quantities of chemicals and control of produced water. The technique speeds up oil production and enhances its efficiency. It has not so far been tested on the NCS. Total uses polymer flooding in parts of the Dalia oil field off Angola, where Statoil is a licensee.

Statoil tested silica gel as a water diversion method on Snorre in 2013. A silicate solution is injected and, under the right conditions, a plug forms which directs the injection water into new undrained areas. A ship normally used for well stimulation was deployed for the test. Fresh water and a silicate-containing injection fluid were produced on board and injected into the reservoir. The results are expected in late 2014.

IOR methods call for the development of technology and expertise in specialised disciplines. Research and technological advances are important for coming up with techniques which can improve recovery from producing fields in the years to come. The NPD is working to ensure that such solutions are developed, tested and implemented. Knowledge-sharing is important for accomplishing this efficiently. Through research programmes and other government support schemes, the emphasis is on transferring and applying knowledge and results from technology trials on one field to others on the NCS. Force is a collaboration forum for oil and gas companies and the government which works for better exploration and production solutions. The NPD serves as its secretariat. More information on this initiative can be found at *www.force.org*.

2.4 Target for reserve growth

To ensure that the necessary attention was paid to reserve growth while simultaneously keeping abreast of developments, the NPD's 2005 resource report introduced a target of 800 million Sm^3 (five billion barrels) for the growth in oil reserves up to 2015.

Annual reserve growth is recorded for fields and discoveries. When the decision is taken to develop a discovery, the quantities

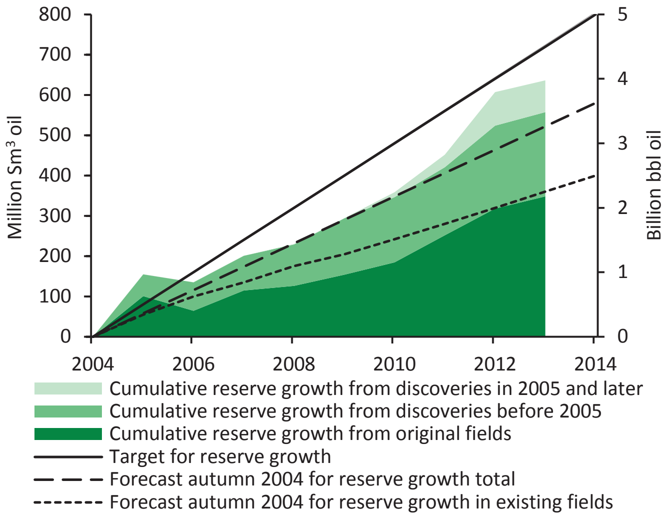


Figure 2.15 Development in oil reserve growth since 2004.

[1] Oil and Gas in the 21st Century. This forum has been established and is chaired by the MPE. Its purpose is to ensure efficient and environment-friendly value creation from Norwegian oil and gas resources. OG21 has brought oil companies, universities, research institutes, the supplies industry and the government together over a common national strategy for petroleum technology.

underpinning this decision are recognised as reserves. The field's reserves change as more is learnt about the reservoir and new projects are sanctioned. Reserve growth represents the change from the previous year's resource account. Figure 2.15 presents the status to date. The coloured areas in the graph illustrate overall reserve growth since 31 December 2004, while the lines indicate the plans which formed the basis for setting the target and for the way to reach it.

Figure 2.15 shows that reserve growth has been at its strongest in recent years, with a flattening out in 2013. The original fields in 2004 (dark green) have experienced the resource growth predicted in the 2004 forecast, but at a slower rate than expected. Contributions from discoveries known when the growth target was formulated have been larger than assumed. In addition, speedy decisions in recent years on developing discoveries made after the target was set have helped to ensure that the realised resource growth has come close to the target. As things currently stand, the target looks unlikely to be reached. A more detailed assessment of target attainment will be presented when the next resource account is published in the spring of 2015.

Since the current target period expires at the end of 2014, the NPD is now setting a new target for growth in oil reserves over the coming 10 years. The basis for this target is provided by the IOR projects for producing fields presented in figure 2.10, and discoveries reviewed in chapter 3. In the NPD's view, decisions to implement these IOR projects and develop the discoveries could yield a growth of 950 million Sm3 in oil reserves by the end of 2023.

The NPD's target for oil reserves in 2014-23 is a growth of 1 200 million Sm^3. See figure 2.16. The gap between the forecast and the target is expected to be filled by the implementation of yet more measures on the fields, by further optimisation of forthcoming development plans and by continued commercial discoveries which are sanctioned for development during the period.

According to the resource account at 31 December 2013, remaining oil reserves totalled 834 million Sm^3. Growth as described above would, with the current production forecast, mean that oil reserves will be larger at the end of the target period than they are today. Figure 2.16 provides a stylised presentation of the forecast for reserve growth and a possible way to reach the target. Relatively little growth is expected in the present year, with a big increase in 2015 – primarily because of an expectation that a development decision will be taken for Johan Sverdrup.

Progress of this order calls for a substantial effort, and many investment decisions need to be taken. To achieve the forecast growth of 950 million Sm^3 in oil reserves, by far the greatest number of the projects planned on the fields must be implemented. Moreover, most of the discoveries currently under evaluation must be sanctioned for development during the period. In order for these decisions to be taken, the projects must be profitable. Developments in costs and prices will be important, but much could still be gained from optimising production methods and enhancing operational efficiency. The target involves an increase of 250 million Sm^3 in oil reserves over and above the reserve growth which forms the basis for the NPD's production forecast.

2.5 Development wells

Drilling new development (production and injection) wells is crucial for production trends. Some NOK 50 billion was spent in 2013 to drill 142 new development wells on producing fields. That represented roughly 50 per cent of total investment on these fields.

Some trends

It will normally be the case that the most profitable resources are recovered from a field first, with their recovery described in the development plan. The further production has progressed, the less profitable an individual improved recovery project would normally be. It can be particularly demanding to achieve profitability for a project which calls for new facilities and extensive conversion and modification of existing installations.

Figure 2.17 shows a marked decline up to 2010 in the number of new development wells on fields which were on stream throughout the 2000-2013 period. In this context, "development wells" embrace new initial wells, sidetracks drilled from an existing well and individual laterals in a multilateral well.

The reduction has been greater than planned. Drilling new wells on older fields has proved more demanding than the plans

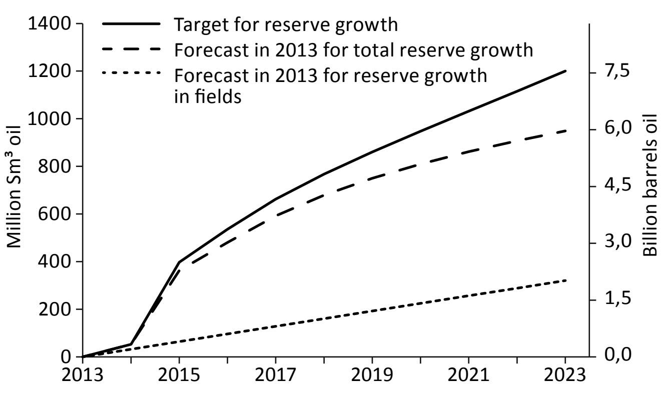


Figure 2.16 The NPD's target for oil reserve growth in the 2014-23 period, with forecasts.

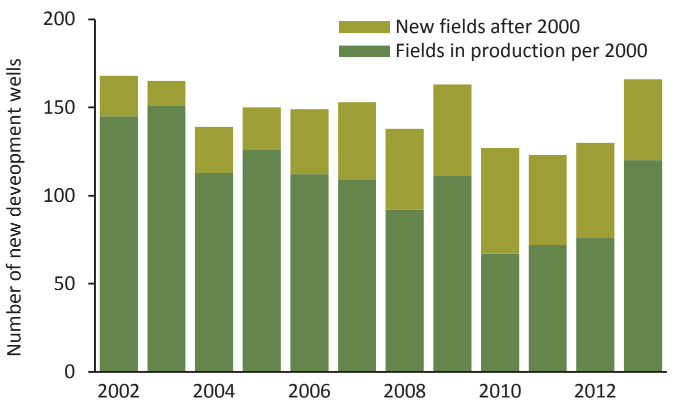


Figure 2.17 Development in the number of new production wells.

assumed. Several factors account for this. On many fields, production and injection over time have affected pressure conditions both within and above the reservoir. The need to upgrade the permanent drilling rigs and their use for well maintenance represent other reasons. All available slots are in use on many fields, restricting opportunities to drill new wells. Another challenge is that residual reserves are located more peripherally in the field as it gets older. That means longer and more complex well paths if drilling is to be done by a permanent rig. A scarcity of mobile rigs has also caused the postponement of wells which could have been drilled on a field.

Before subsea technology was developed in the 1980s, all development wells – with only a few exceptions – were drilled by a rig permanently positioned on a fixed field installation. All the big oil fields developed during the 1970s, 1980s and early 1990s have installations with permanent rigs. Several large fields, such as Troll and Åsgard, have subsequently been developed with subsea-completed wells drilled from mobile units. More wells on fields with permanent rigs are also gradually being drilled from mobile units. Despite the trend towards an increasing proportion of wells drilled by mobile units, permanent rigs are still important for oil production on many large oil fields. That applies not only to drilling new wells but also to necessary maintenance of existing wells.

Wells drilled on fields which were on stream throughout 2000-13 increased again from 2010. Figure 2.18 shows that wells drilled from permanent rigs remained stable at around 35 per year, while new wells from mobile units rose. Growth from 2012 to 2013 primarily reflected drilling of more wells on the Balder, Ekofisk, Eldfisk, Oseberg Sør and Troll fields. The Balder increase related to a current drilling campaign. On Ekofisk and Eldfisk, the rise must be viewed primarily in relation to the Ekofisk Sør and Eldfisk II projects. The main reason on Oseberg Sør is the development of the Stjerne discovery, which is part of Oseberg Sør, while more laterals are being drilled on Troll by increasing the number of rigs on this field. A substantial improvement in the availability of new mobile units has been a precondition for the ability to drill more development wells.

Choosing a development solution with permanent or mobile rigs depends on such considerations as the extent of the reservoir, its complexity and the water depth. Differences in drilling efficiency between permanent and mobile rigs could also be significant for the choice of solution. The most recent field developed with a permanent rig is Kvitebjørn, which came on stream in 2004. Concepts based on mobile rigs have been chosen for all subsequent new developments.

The need for wells is related to their economic life. How long a well will produce depends on such considerations as reservoir properties, production strategy and its design and maintenance. Many of today's production wells have a long producing history. Figure 2.19 presents active wells on a large oil field developed in the 1980s by age. This shows that a substantial proportion of the petroleum produced in 2012 originated from wells which were more than 10 years old.

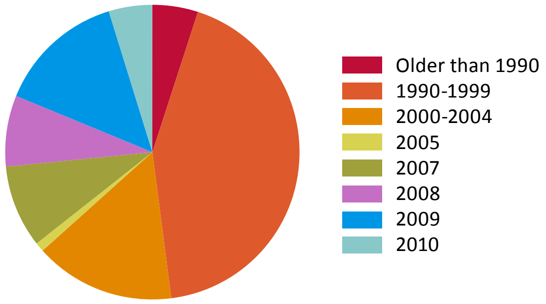


Figure 2.19 Oil production in 2012 for a large oil field developed in the 1980s, by when the wells came on stream.

Production from future wells

The largest and most accessible drilling targets on a field are usually drilled first. Target size is defined by the petroleum production expected from the well. Over time, the targets drilled contain steadily smaller quantities. Distance to the drilling target is also important. The profitability of drilling for resources which are small and/or involve long well paths is accordingly crucial when deciding whether to drill more wells.

Figure 2.20 presents planned development wells on producing fields in 2014, including initial wells, sidetracks and multilaterals. Multilaterals are counted as one well. Wells drilled from both fixed installations and mobile units are included. Expected recoverable resources from the greater part of the wells are less than one

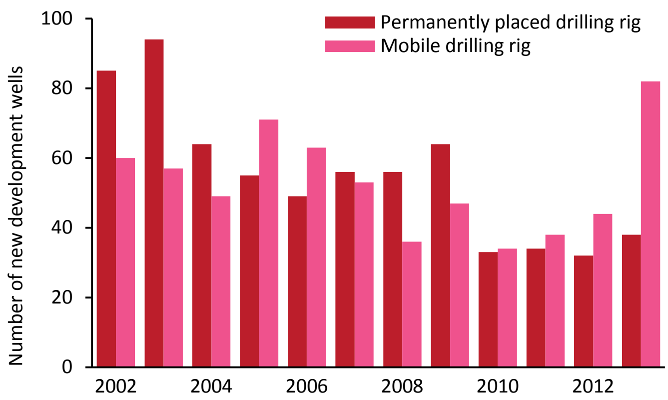


Figure 2.18 Development in the number of new production wells for fields on stream in 2000 – drilled from fixed or mobile units.

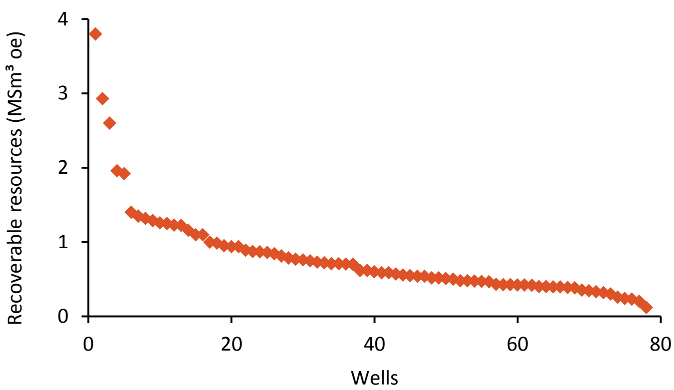


Figure 2.20 The size of well targets due to be drilled on producing fields in 2014.

million Sm³ oe. The median well is expected to yield 0.6 million Sm³ oe.

Combined with a trend towards smaller and more complex well targets, the substantial rise in costs in the drilling and well sector represent a particular challenge for future development on the NCS.

More wells – new infrastructure needed
Many projects on producing fields involve drilling wells to improve recovery. See figure 2.10. But new wells are also important for enhancing the effect of other improved recovery measures. Higher well density is an advantage, for example, with CO_2 injection and polymer flooding. A shorter distance between wells shortens the time between injection and its effect on production. A reduction in response time can help to make this type of project profitable.

While more wells are desirable for improving recovery, problems have been experienced on a number of fields with drilling planned wells. No simple solutions exist for increasing the level of drilling activity, but many possible measures might add up to a substantial contribution. These include (new) methods for handling the technical and reservoir-related challenges faced when drilling on producing fields, and moves to enhance drilling efficiency.

New installations are required on a number of fields in order to boost drilling activity. Existing facilities are usually positioned centrally on the field, which makes it difficult to drill the outer flanks. Furthermore, there is a shortage of well slots on a number of fields. That limits opportunities to drill new wells. To increase drilling activity, new installations could be relevant to shorten wells and provide additional slots.

Additional facilities could be anything from new seabed templates and wellhead platforms to large installations with or without their own drilling rig. Good solutions which make provision for a long-term production strategy will call for substantial investment. Decisions based on a short-term perspective could impede long-term value creation.

Figure 2.21 shows that plans to invest in new facilities, either on the seabed or as wellhead platforms, have been reported for 10 fields in order to drill more wells. In addition, similar evaluations in an early phase for a number of fields. Choice of installation type will affect the production strategy. A platform will normally provide the flexibility to recover larger quantities from an area than a subsea solution.

2.6 Use of spare capacity in existing infrastructure

Substantial investments have been made in infrastructure on the NCS. Capital spending on offshore installations, pipelines and land facilities totals just under NOK 3 000 billion in 2013 money. New field developments can take advantage of existing facilities at nearby hubs, permitting even better use of infrastructure on the old field and extending its producing life.

This report uses the term "hub" for fields with significant joint operation of processing capacity – in other words, equipment for separating the various hydrocarbon types and water from petroleum. Allowing process equipment to be shared between several fields, joint operation is an efficient solution for reducing capital spending as well as operating and unit costs.

Many fields on the NCS are in a phase where production is declining. See figure 2.1. Unit costs will thereby rise, since a large proportion of the cost of operating a field is independent of the quantity of production. This emerges from figure 2.7. Unit costs for a hub provide a more accurate picture of costs in an area than the figures for an individual field. Figure 2.22 provides a simple presentation of the benefits of phasing-in nearby fields. The main field can produce for longer, and neighbouring discoveries are developed in a cost-efficient manner.

Figure 2.22 illustrates that, at an oil price of NOK 4 000 per Sm³ or just over USD 100 per barrel, profitable production from the hub is extended from 23 to 30 years. During this period, the tie-in field is produced and the main field can use the additional producing life to implement its own improved recovery measures. Without this opportunity, certain small discoveries would not have been developed or would have been considerably less profitable, while producing life for the main field would have been shorter.

The number of producing fields has grown steadily since the

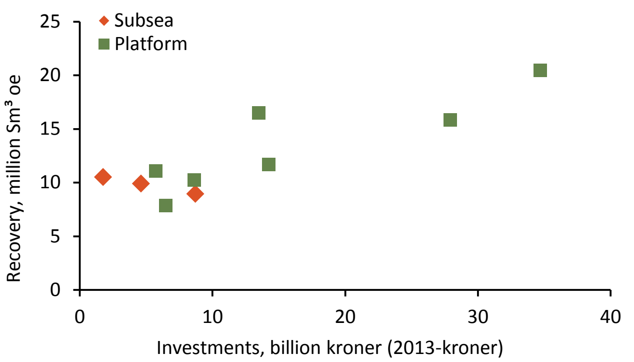


Figure 2.21 Recovery from planned new installations and wells on fields.

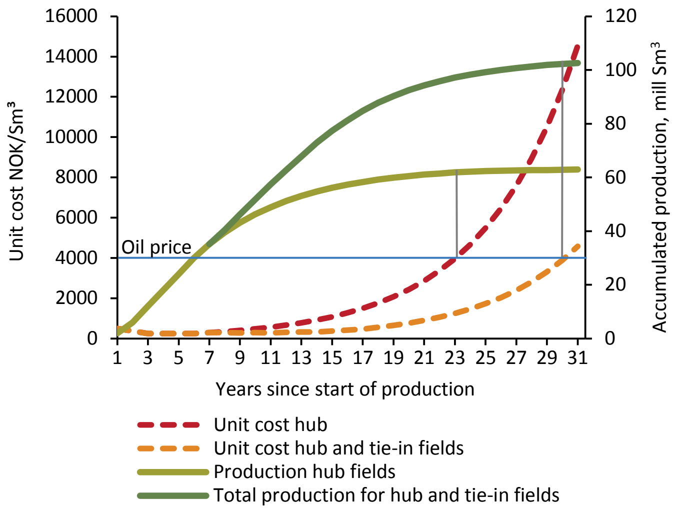


Figure 2.22 Stylised example of cumulative production and unit costs for hubs and phased-in fields.

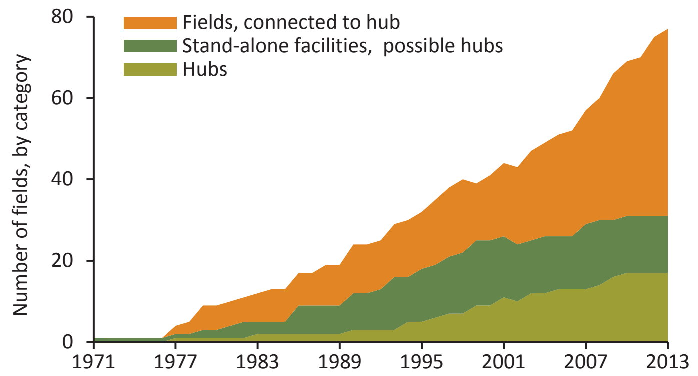


Figure 2.23 Development in the number of hubs, possible hubs and fields tied back to hubs.

late 1970s, with the strongest increase over the past 10 years. That partly reflects high oil prices, which have ensured profitable development, and the many new discoveries made in the period. More fields on the NCS, many with their own processing facilities, provide greater opportunities for profitable phasing-in of nearby discoveries large and small. The fact that the number of hubs in operation is not increasing as rapidly as producing fields means that the share of joint operation on the NCS is rising.

The effect of securing larger quantities by sharing the cost of operating a facility is illustrated in figure 2.24. This presents the development in costs per unit produced under three different assumptions. The bars show how unit costs develop when new third-party quantities are included. If a field's own production were to carry all expenditure, unit costs would increase. In the opposite case, unit costs would be lower had it been possible to maintain the same level of production as at the start of the period.

Production beyond the level originally planned means that the

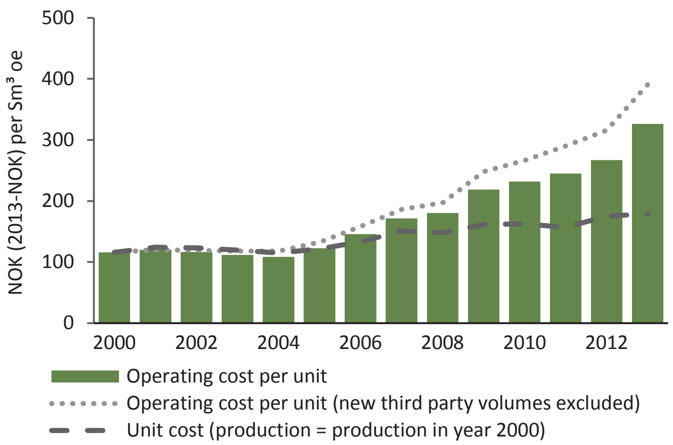


Figure 2.24 Development of unit costs for fields on stream throughout the 2000-13 period.

producing life of the field is extended. Figure 2.25 presents the average change in expected producing life for the individual fields, annually and in total, since 2002. The trend since 2002 is that expected producing life has increased by 12 months for each

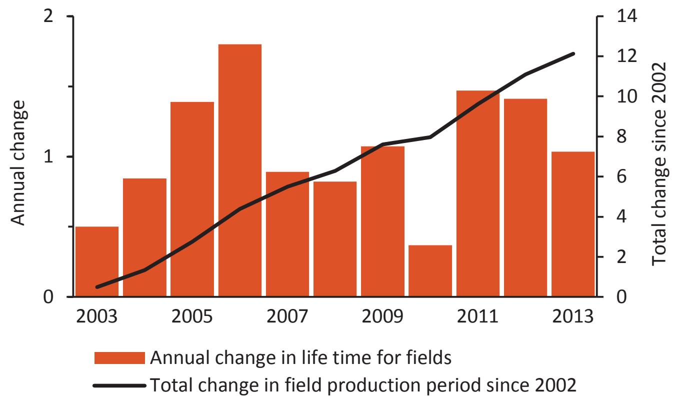


Figure 2.25 Development of expected producing life for fields.

year that passes. The remaining expected producing life is now as long as it was 12 years ago.

Gullfaks is a hub. Process capacity on this field means that it can also receive and treat production from surrounding fields. These are Gullfaks Sør, Gimle (which is produced through wells drilled from Gullfaks C), Tordis and Visund Sør. See figure 2.26.

The government has been concerned to facilitate the use of spare

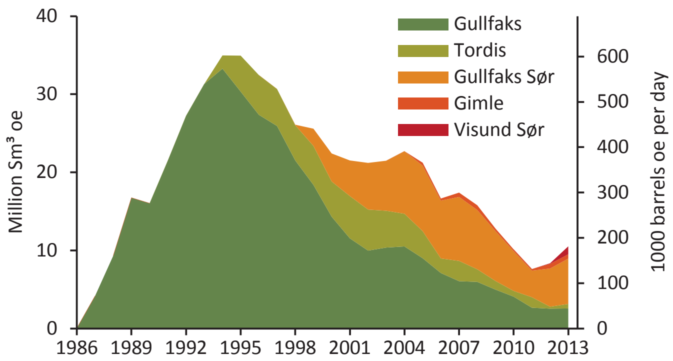
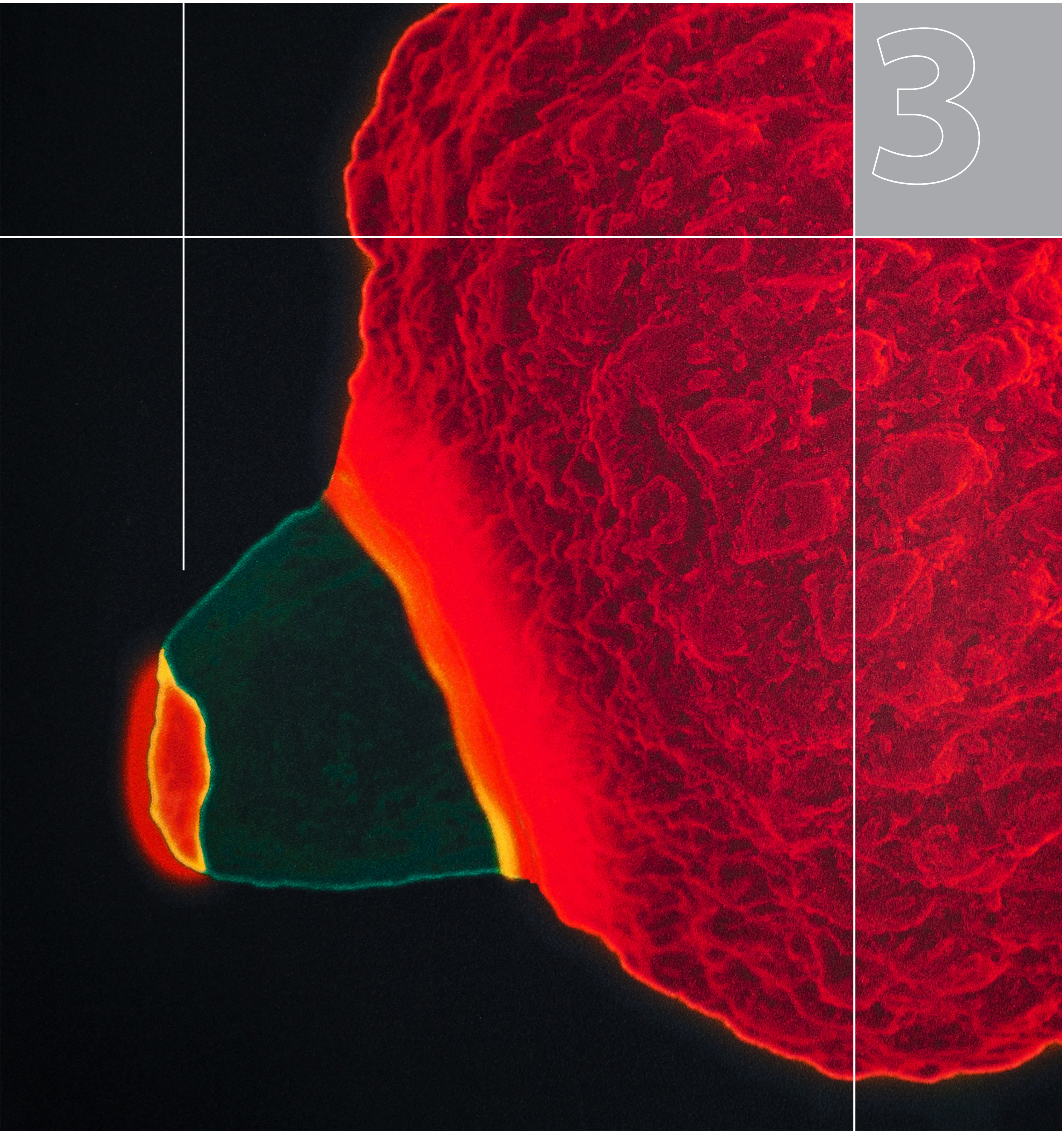


Figure 2.26 Production from the Gullfaks installations, own and third-party quantities.

processing capacity on existing platforms and transport capacity in pipelines. As a result, the MPE has issued a separate regulation on third-party use of facilities (TPA). This helps to make the negotiating process more efficient, and provides parameters for determining tariffs and other conditions. An important principle in agreements on third-party use of facilities is that profit from the production should primarily be taken out on the field. At the same time, such agreements must provide incentives for the owners to maintain capacity on the facility and to make investments in additional capacity.

Discoveries and current field developments

3



3

3.1 Discoveries

Development of the discovery portfolio

A total of 434 discoveries have been made on the NCS since the first exploration well was drilled in 1966 and up to 31 December 2013. Fifty-one per cent of these have been developed or are under development.

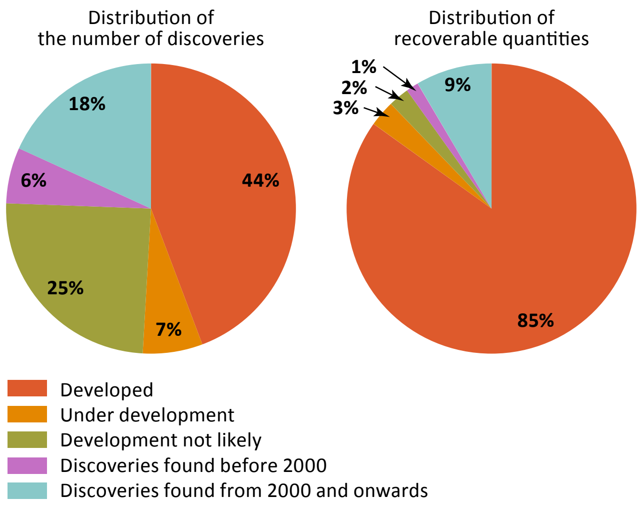


Figure 3.1 Discoveries at 31 December 2013 by development status.

Discoveries still not sanctioned for development but which are under evaluation account for 24 per cent of the total, and divide between those made before 2000 and from that year. See figure 3.1, which shows that 85 per cent of proven resources have already been developed. By comparison, resources in discoveries under evaluation amount to 10 per cent.

About 25 per cent of the discoveries are classified as not very likely to be developed, even in the long term. Their proportion of total resources represents an estimate for possible technically recoverable quantities which are not currently considered to be developed commercially. Should any of these be re-evaluated, they will be included in the portfolio of development projects. See figure 3.3. A few such discoveries have so far reached a decision to develop.

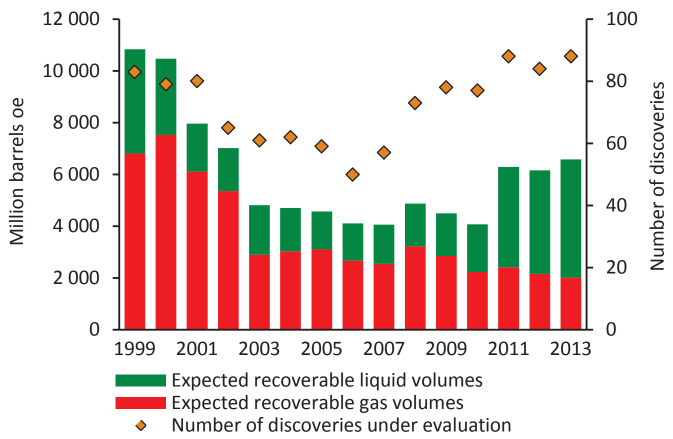


Figure 3.2 Development of the discovery portfolio from 1999 to 2013. Discoveries under evaluation and total resources by liquids and gas.

Changes in the number of discoveries without an approved development plan from 31 December 1999 until 31 December 2013 are presented in figure 3.2. A development can embrace several discoveries. Roughly as many discoveries were made in 2013 as in 1999, while numbers in the intervening years have varied considerably. The decline seen for resources in discoveries early in the period reflected decisions to develop several big fields, such as Grane, Snøhvit and Ormen Lange, with the consequent conversion of their resources to reserves in fields. Johan Sverdrup accounted for the marked increase in oil resources from 2010 to 2011. Figure 3.2 also shows that recoverable quantities were significantly lower in 2013 than in 1999. In other words, the average discovery size measured in recoverable quantity is now smaller.

Discoveries are defined as development projects in figures 3.2 and 3.3 and in the rest of chapter 3. In the planned development of Johan Castberg, for example, the 7220/8-1 Skrugard and 7220/7-1 Havis discoveries represent a single project. More discoveries in the area could be included in the development project if they are assessed as commercial.

Changes in the discovery portfolio from one year to another are depicted in figure 3.3, which presents the status at 31 December in 2012 and 2013, changes which increase/reduce the number of development projects, and new discoveries in 2013. Light-tinted bars in the graph indicate a reduction in the number of development projects.

Figure 3.3 Change in number of discoveries from 2012 to 2013.

Discoveries where recovery is not very likely/non-commercial are not discussed further in this chapter.

Resources in discoveries

Expected recoverable resources in discoveries are estimated to be 1 056 million Sm^3 oe. Of this total, 631 million Sm^3 oe lies in discoveries in the planning phase (RC4), 207 million Sm^3 oe in those where development is likely but not clarified (RC5), and 218 million Sm^3 oe in ones yet to be assessed (RC7).

At 31 December 2013, resources in discoveries accounted for seven per cent of the NPD's estimate of total petroleum resources. Undiscovered resources accounted at the same time for 21 per cent. See figure 1.1. The quantity of expected recoverable resources can change over time, in part as a result of new knowledge about geology and reservoir conditions, technological advances and commercial status.

Discoveries under evaluation

The portfolio comprised 88 discoveries at 31 December 2013. Figure 3.4 provides an overview of resources in discoveries by NCS area. Johan Sverdrup contains 55 per cent of the discovery resources in the North Sea, while Johan Castberg accounts for 51 per cent of those in the Barents Sea. These two stand out because of their size, and represent 43 per cent of the resources in discoveries.

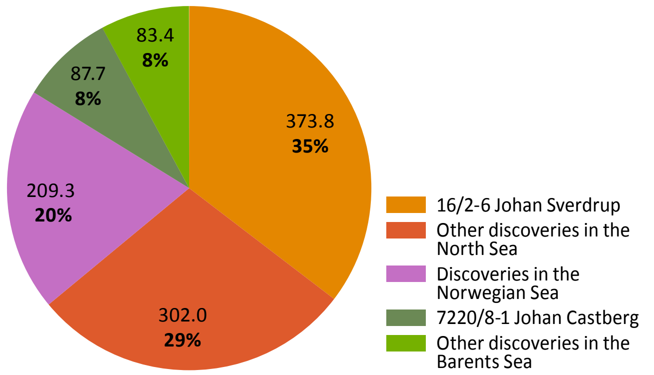


Figure 3.4 Resources in discoveries by NCS area (million Sm3 oe) – Johan Sverdrup and Johan Castberg are shown separately.

Figure 3.5 presents an overview of liquid and gas resources in the discoveries by NCS area. Castberg and Sverdrup are not included. Extensive development studies are currently ongoing for these two. This chapter deals with the many smaller discoveries. Little attention is accordingly given to Castberg and Sverdrup in the rest of the discussion.

The distribution and size of discoveries in the various NCS areas are presented in figure 3.5. Liquids account for 58 per cent of resources in the North Sea, 33 per cent in the Norwegian Sea and 50 per cent in the Barents Sea.

Table 3.1 provides a more detailed overview of the number of discoveries and their size by NCS area. While the average discovery size is weighted towards the big finds, the median size represents the midpoint when ranking discoveries by size.

Area	Number	Average discovery size MSm³ oe	Median discovery size MSm³ oe	Per cent of total
North Sea	52	13.0	4.4	64
Norwegian Sea	27	7.8	3.8	20
Barents Sea	9	19.0	7.0	16
Total	88	12.0	4.7	100

Table 3.1 Overview of the discovery portfolio at 31 December 2013, including Johan Sverdrup and Johan Castberg.

This discovery portfolio is dominated by many small development projects. Closeness to existing infrastructure or unitisation opportunities are crucial for whether and when these will be developed. Most discoveries in the portfolio have been made after 2000, with 42 per cent proven after 2009.

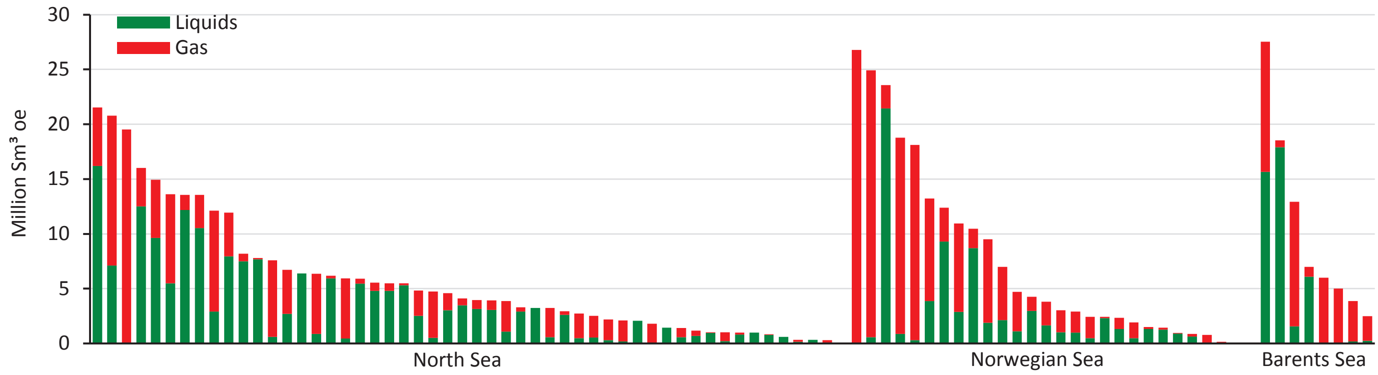


Figure 3.5 Discoveries by NCS area and expected recoverable resources at 31 December 2013.

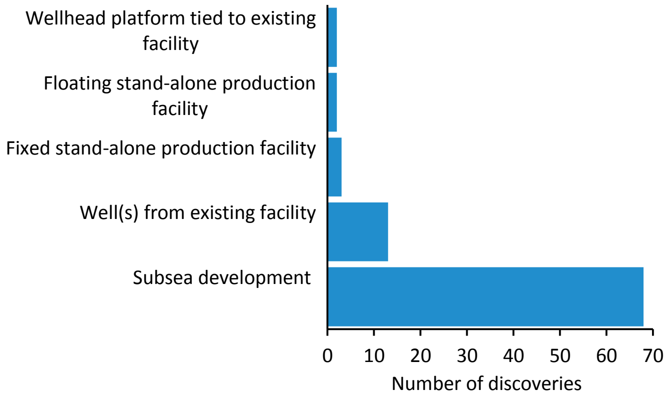


Figure 3.6 Expected development solutions for discoveries.

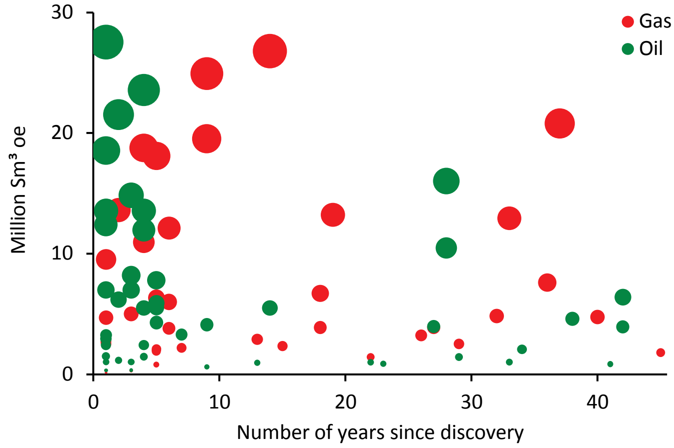


Figure 3.7 Discoveries at 31 December 2013, excluding Johan Sverdrup and Johan Castberg, by number of years since they were made, size and types of hydrocarbons. [1]

New subsea developments

Figure 3.6 provides an overview of possible development solutions for the 88 discoveries at 31 December 2013.

Subsea facilities phased into existing installations represent the most relevant solution for 68 of the 88 discoveries, with a total of 500 million Sm^3 oe of recoverable resources. That gives an average of 7.5 million Sm^3 oe per project.

Wells drilled from existing facilities are also a common development solution for small discoveries close to infrastructure with spare capacity. Recoverable quantities for discoveries planned as well developments total 23 million Sm^3 oe, or an average of 1.7 million Sm^3 oe per project.

In shallow waters, such as the North Sea, simple wellhead installations can be relevant development solutions instead of subsea facilities. Discoveries which require long tie-back to infrastructure with spare capacity, and which cannot justify a stand-alone development on their own, can be brought on stream through the coordinated development of several discoveries.

Figure 3.7 provides an overview of discoveries by the number of years since they were found, their size, and types of hydrocarbons. The oldest discoveries are generally smaller than those made more recently. Sixty per cent of the finds made before 2000 have estimated recoverable quantities of less than four million Sm^3 oe. Complex reservoir conditions and distance from existing infrastructure with spare processing and transport capacity can help to explain why they still remain undeveloped.

Several conditions must be satisfied before discoveries can be phased into existing infrastructure. The most important of these are that spare capacity is available in the infrastructure, that the composition of production from the discovery is compatible with the process and export system, and that that transport distance for the unprocessed wellstream is not too long. Wellstreams which consist primarily of gas are easier to pipe over long distances than those dominated by liquid products.

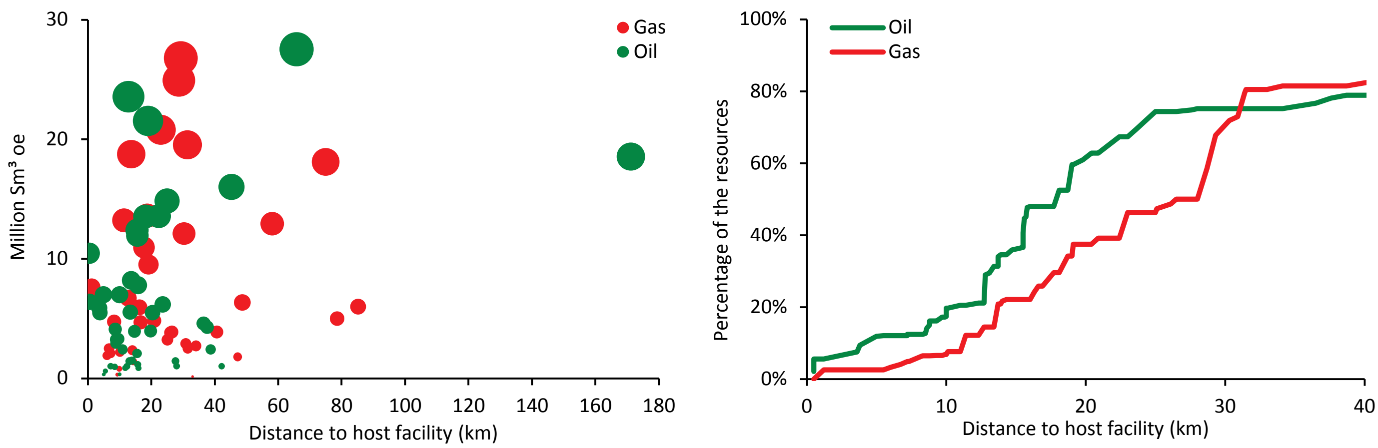


Figure 3.8 Discoveries and resources in discoveries, excluding Johan Sverdrup and Johan Castberg, by distance to infrastructure.

[1] All resources in each discovery are shown in figures 3.7 and 3.8 as either oil or gas discoveries. Those defined as hydrocarbon types oil or oil/gas are grouped as oil discoveries. Those defined as hydrocarbon types gas or gas/condensate are grouped as gas discoveries.

The distance regarded as the maximum for transferring unprocessed wellstreams is constantly increasing. Examples of technologies which contribute to this progress are water separation at the wellhead, insulating and heating transport pipelines, and chemical injection to prevent pipelines being plugged by wax and hydrates. The left-hand graph in figure 3.8 presents the smallest distance to existing or planned infrastructure for each of the discoveries under evaluation, with its associated size. The right-hand graph shows that about 80 per cent of resources in the discoveries lie within a tie-in distance of roughly 40 kilometres. That is the longest distance unprocessed oil wellstreams is transferred on the NCS today.

Profitability assessments

The NPD contributes to creating the greatest possible value for society from oil and gas activities This includes contributing to coordinated development of several discoveries and fields when that represents the best socio-economic solution.

Licensees in a production licence take development decisions based on profitability after tax. Profitability is determined to a great extent by discovery size, development and operating costs, and oil and gas prices. Assessing the uncertainty in these parameters is important for a decision. The profitability requirements applied in sanctioning a project will vary over time, both within and between companies.

The break-even price is a key measure of profitability. For a project, this will be the product price required to cover production costs and the required return on the capital committed. The break-even price can be calculated before and after tax. When a company decides on a development, the break-even price after tax is the relevant consideration. A company's calculation of this factor can deviate somewhat from the break-even price before tax.

Break-even prices for discoveries in the planning phase have been calculated by the NPD, before tax and applying a rate of return of seven per cent.

Figure 3.9 shows that great variations exist in the break-even price, from just over USD 30 per barrel to roughly USD 100 per barrel. As illustrated in figure 3.14, the break-even price has been rising over time. The latest large development projects approved on the NCS have had break-even prices up towards USD 80 per barrel. Although the break-even price says something about the profitability of a project at a given point in time and for a given development concept, it does not embrace all the factors given emphasis when deciding whether to proceed with the project. Uncertainty over the resource base and spare capacity in the infrastructure are the main reasons for failing to sanction most of these discoveries for development.

Figure 3.6 shows that a large proportion of the discoveries under evaluation for development will utilise existing infrastructure, which can be a good socio-economic solution. The producing life of the fields is extended and recovery improves because costs for modifications and new investment can be shared.

The cost structure can vary substantially between various developments, depending on the solutions chosen. See figure 3.10. For some projects, a large proportion of the overall cost is incurred at an early stage in the form of capital spending. In other cases, costs may be more evenly distributed over time as operating expenses or tariffs. Weight is given when taking an investment decision to the amount of capital tied up in a project. Greater capital discipline will raise the threshold for development decisions and shift attention to less capital-intensive solutions. This could mean that the companies will shelve a number of projects which are profitable in a socio-economic perspective but fail to meet internal company requirements. That applies both to the choice of development solution and to how far the project is implemented.

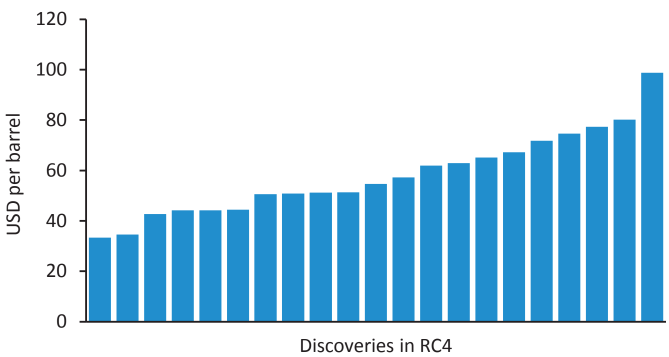


Figure 3.9 Break-even prices in USD (USD 1 = NOK 6) before tax for discoveries in the planning phase (RC4) at 31 December 2013. Calculated by the NPD.

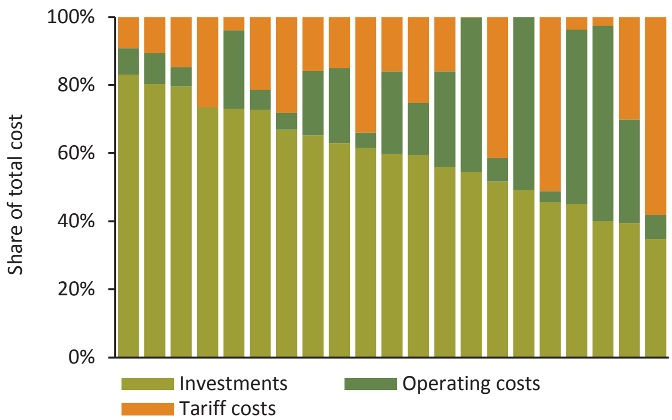


Figure 3.10 Cost structure for discoveries in the planning phase (RC4).

3.2 Fields under development

Thirteen fields were under development at 31 December 2013. See figure 3.11. Goliat and Aasta Hansteen are in the Barents and Norwegian Seas respectively, with all the rest in the North Sea. Aasta Hansteen, Goliat and Knarr are being developed with floating production facilities. Valemon, Martin Linge, Ivar Aasen, Gudrun and Gina Krog involve fixed installations. The remaining four are subsea developments. Reserves in these field developments total 298 million Sm³ oe.

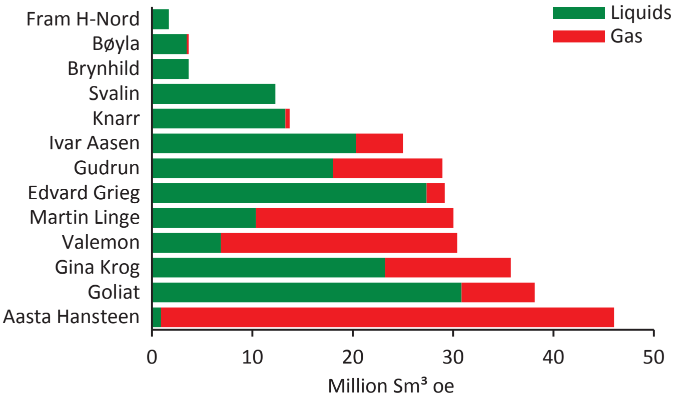


Figure 3.11 Reserves in current field development projects.

Several of the current developments involve discoveries made early in the 1990s or even farther back. This applies to Brynhild (1992), Svalin (1992), Martin Linge (1975), Valemon (1985), Gudrun (1974) and Gina Krog (1974).

Substantial exploration and appraisal activities have been pursued over time in connection with these older discoveries in order to define profitable development projects. More knowledge about such aspects as reservoir conditions has led to considerable changes in estimated recoverable resources and the relationship between liquid and gas. See figure 3.12.

One example is Gina Krog (previously Dagny), which was discovered as far back as 1974. This was initially a small gas discovery set to be phased into Sleipner Øst. The 15/6-9 S well drilled in 2006 proved oil and additional gas resources. A further well in the autumn of 2008 showed that this discovery was in communication with Dagny, which also proved to have an oil zone beneath its gas. Before a development decision was taken, a total of 11 exploration wells had been drilled in the area.

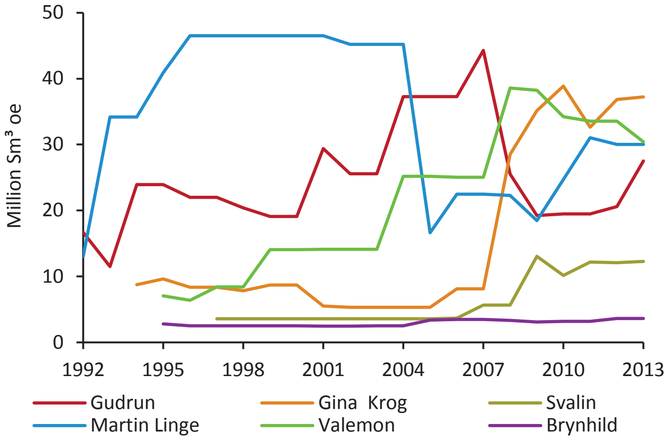


Figure 3.12 Development in estimates for recoverable resources since 1992.

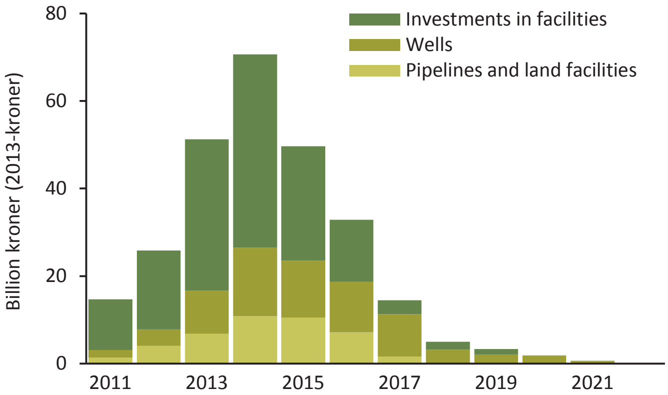


Figure 3.13 Investment forecasts for fields under development by project type.

An extensive portfolio of fields under development, with many stand-alone projects, is an important reason for the high level of investment in recent years. See figure 3.13. Fabricating facilities and drilling wells account for the bulk of this spending. In addition to the fields themselves, investment embraces the laying of new pipelines and modifications/developments at land facilities. The biggest spending here is for Aasta Hansteen, relating to Polarled and development at Nyhamna.

Increased costs and delays represent challenges for many projects. A number of projects, on fields both in production and under development, have experienced a substantial growth in costs compared with the estimates made at the decision date. These issues are discussed in greater detail in the Vurdering av gjennomførte prosjekt på norsk sokkel (Assessment of projects implemented on the NCS) report published by the NPD in 2013 on behalf of the MPE. The quality of early-phase work and the operator's follow-up of the project in the execution phase are two key requirements for avoiding cost overruns.

Figure 3.14 presents the break-even price at the decision date for field developments from 2005 to 2013. Despite considerable variation, the trend is a rising break-even price over time, particularly where platform-based projects are concerned. This increase over time primarily reflects growing costs. Projects with the lowest break-even prices are subsea developments which utilise spare processing capacity on existing facilities.

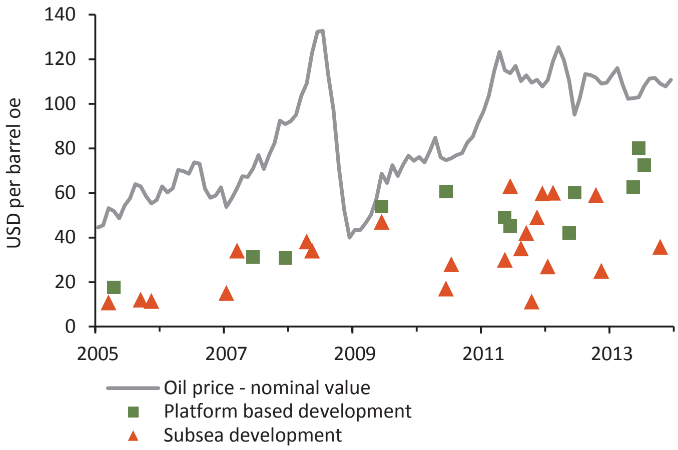


Figure 3.14 Break-even price before tax calculated by the NPD at the decision date for sanctioned field development projects since 2005.

3.3 Lead time

A total of 92 fields had been developed and brought on stream on the NCS by 31 December 2013. Development work began at the southern end of the NCS with Ekofisk, and has moved subsequently into new areas where activity has always begun with a stand-alone project. Small fields in the immediate vicinity have eventually been brought on stream with simpler development solutions. These satellites largely utilise the infrastructure of the stand-alone fields. Examples also exist of several fields being developed simultaneously, with one receiving the facilities for processing and transport. The latter is shown as a stand-alone development while the other fields are treated as satellites in figure 3.15, which presents progress in the number of fields and developments which have come on stream.

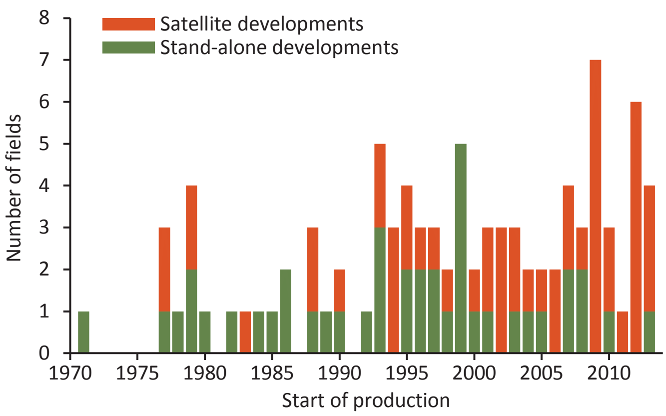


Figure 3.15 Developments by stand-alone and satellite fields.

The gap between making a discovery and bringing it on stream is known as the lead time. The NPD has calculated that this period for an individual discovery averages 11 years. However, big variations exist. Figure 3.16 presents annual average lead times for individual discoveries which have come on stream.

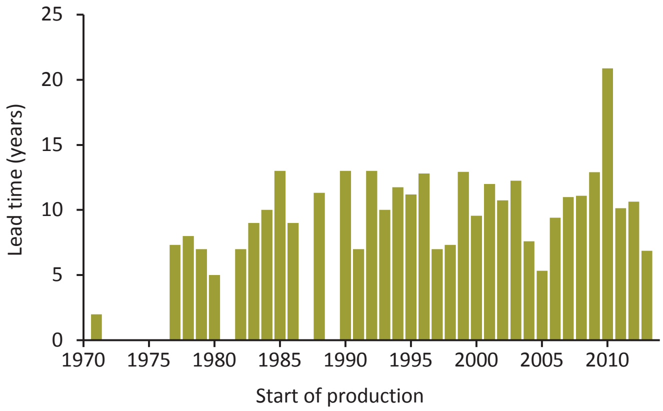


Figure 3.16 Average lead time for individual discoveries.

More than 70 per cent of individual discoveries developed with stand-alone facilities have a lead time of less than 15 years. The bulk of these were discovered between 1980 and 2000. No individual discovery since 2000 has come on stream with stand-alone facilities. See figure 3.17. Those developed have been as satellites and phased into existing installations. See figure 3.18.

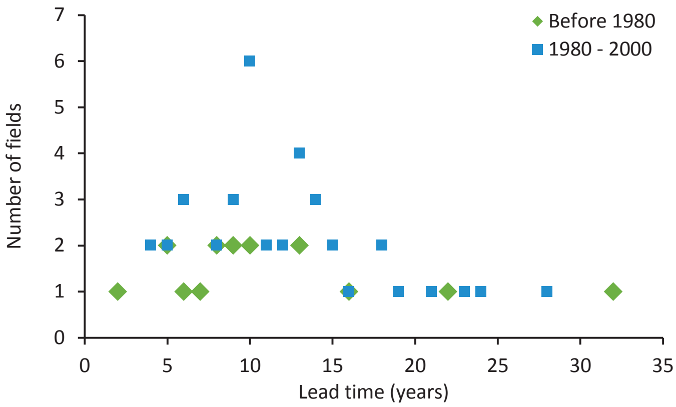


Figure 3.17 Lead time for fields developed with stand-alone installations.

Figure 3.18 shows that satellite deposits discovered before 1980 have a lead time of seven years and above. Early contract awards and standardised equipment – also known as fast-track projects – are important reasons for the short lead times achieved with discoveries made since 2000. This applies to 37 individual discoveries. One example of a discovery which has come on stream quickly is Atla, found in 2010 and on stream by 2012.

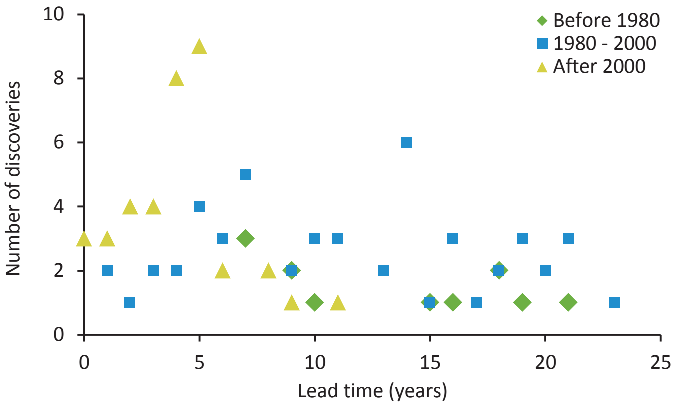


Figure 3.18 Lead time for fields developed as satellites.

3.4 Player diversity

Different players on the NCS can contribute varying expertise to realise the greatest possible value creation. The player picture is a function of production licence awards and different company strategies for exploration, development and farming in/out of licences.

Oil prices were around USD 10 per barrel in the late 1990s, and a substantial consolidation took place. Mergers between the big oil companies had direct consequences for the player picture on the NCS. International companies became fewer in number and even larger in size. That occurred at the same time as the NCS, particularly in the North Sea, developed into a more mature petroleum province which, with discoveries declining in size, presented different challenges than before. Exploring mature areas of the NCS was of limited interest for the large oil companies.

The Norwegian government accordingly adopted a number of measures to increase value creation from mature areas. See the Resource report – exploration for 2013. Key measures included giving more companies the opportunity to become licensees and introducing prequalification and tax refund schemes. Small and medium-sized oil and gas companies and European gas/power companies established themselves on the NCS. So did a number of new Norwegian companies. Player numbers increased from 28 at the end of 2000 to 56 by 31 December 2013. This increase in player diversity has been particularly noticeable in exploration.

Figure 3.19 shows that operator diversity has increased for producing fields in recent years. Statoil and major international companies dominated up to 2000. Over the past 10 years, a growing array of new operators has emerged. More medium-sized companies are acting as operators on the NCS, and several power and gas distributors have become established as oil and gas companies. The number of operators of producing fields on the NCS has almost doubled since 2000.

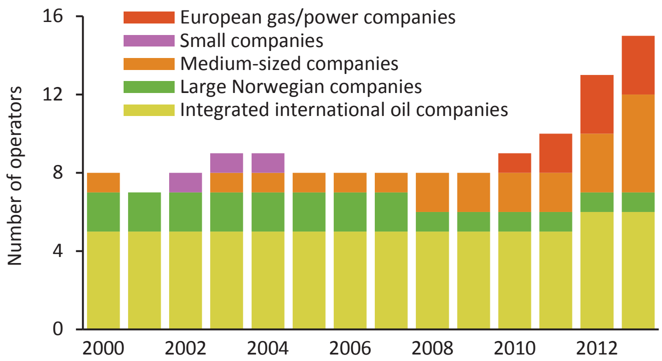


Figure 3.19 Operators for producing fields on the NCS, by type of company.

Table 3.2 below presents today's operators of producing fields by type of company.

Large Norwegian companies	Statoil
Integrated international oil companies	BP, ConocoPhillips, Eni, ExxonMobil, Shell, Total
European gas/power companies	Centrica, DONG, GDF Suez
Medium-sized companies	Det norske, Marathon, Talisman, Wintershall, BG

Table 3.2 Groupings of operators for producing fields on the NCS at 30 January 2014.

The composition of the operator cohort has changed over time. Figure 3.20 shows how the types of companies serving as operators for field developments on the NCS have changed from one period to another. Large integrated companies dominated in the first phase. Phillips was responsible as operator for developing the first field, Ekofisk. Later, the big Norwegian companies Statoil and Norsk Hydro dominated development activities. A larger number of companies now serve as operators in both development and production stages. The pie chart for the most recent period also includes planned developments.

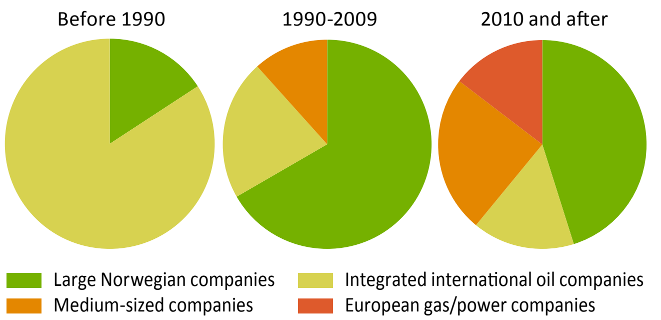
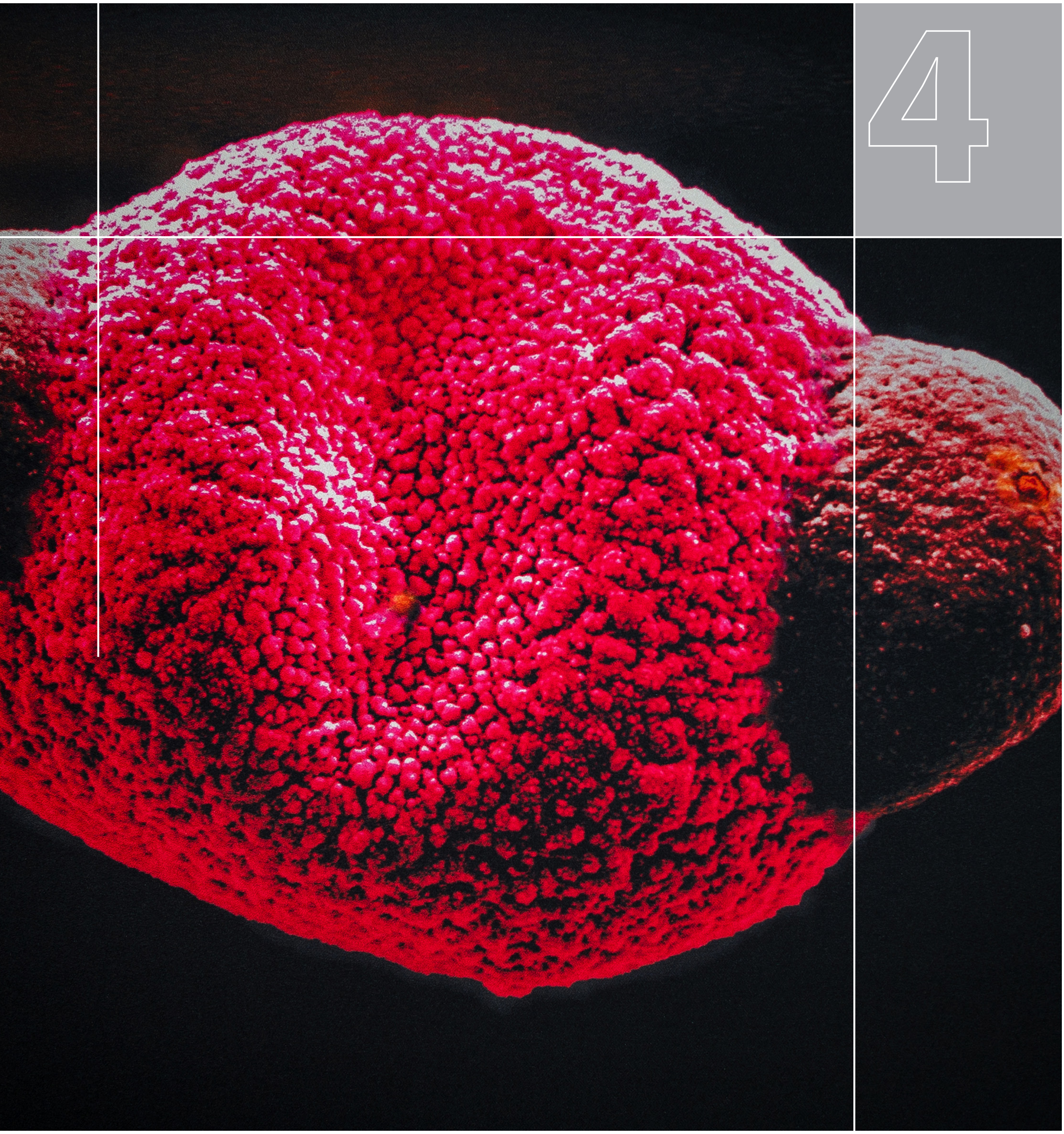


Figure 3.20 Development in types of operator companies for field developments.

Environmental challenges in the operating phase

4



The NPD contributes to the fulfilment of Norway's environmental and climate policy goals. Environmental regulation covers all stages of the industry. It applies when considering whether an area is to be opened for petroleum activities and, later, during exploration and field development. When a field has been developed, environmental assessments are important for specific operational permits, for annual changes to permits, and until cessation of production and disposal of the facilities.

Through the policy framework, the choice of players and technology, and continuous follow-up of activities, the government helps to ensure that requirements are observed and environmental goals attained.

4.1 Emissions to the air

CO_2 and NO_x account for the bulk of emissions. Figure 4.1 presents historical carbon emissions and forecasts up to 2020. Emissions are expected to rise somewhat over the next few years before stabilising thereafter.

Most of the power required on the NCS is provided by gas turbines. As figure 4.2 shows, about 80 per cent of emissions derive from energy production by turbines. Flaring comprises some 10 per cent and engines eight per cent. The Petroleum Act forbids flaring of petroleum in normal operation other than for necessary safety reasons. Safety flaring is regulated by the production permit.

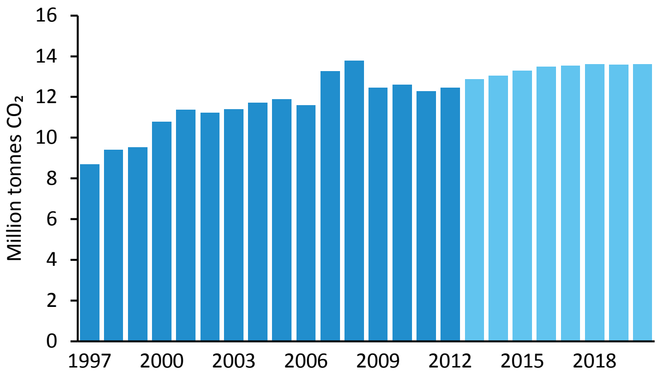


Figure 4.1 Historical emissions and emission forecasts for CO_2 to 2020.

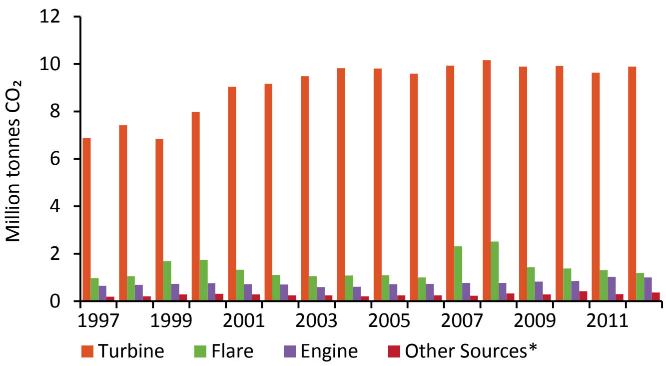


Figure 4.2 Carbon emissions by various combustion sources. Other sources comprise boilers, well testing and direct emissions.

Figure 4.3 presents historical NO_x emissions and forecasts up to 2020. These emissions are expected to be stable over the next few years.

NO_x emissions derive primarily from engines and turbines on the facilities. See figure 4.4. Turbine operation contributes about 60 per cent. All new production facilities brought into operation on the NCS since 2000 have low-NO_x turbines installed. Low-NO_x turbines fuelled only by gas are regarded today as the best available technology (BAT). These turbines reduce NO_x emissions by 50-90 per cent compared with conventional gas turbines. Low-NO_x turbines which can run on both gas and diesel have been operating on the NCS since 2008.

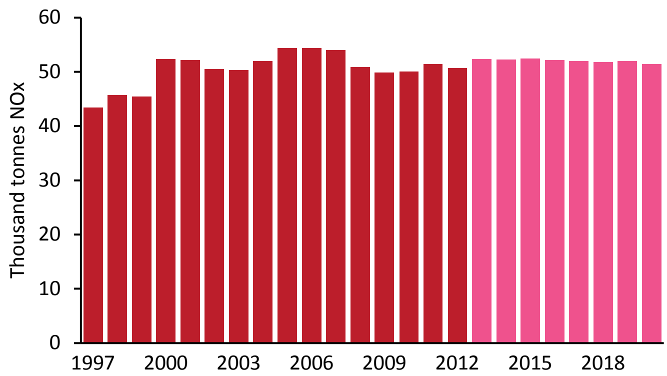


Figure 4.3 Historical emissions and emission forecasts for NO_x to 2020.

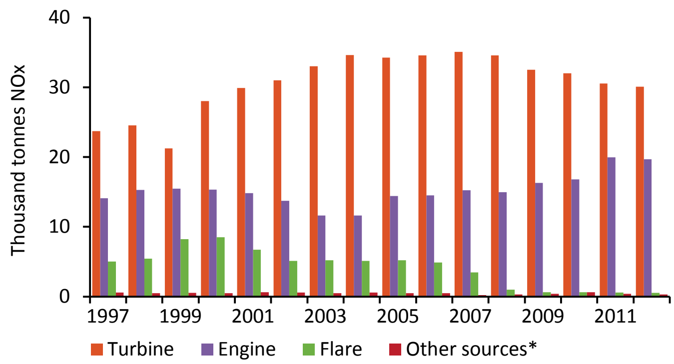


Figure 4.4 NO_x emissions by source. Other sources comprise boilers and well testing.

Total emissions from fixed installations have declined gradually since 2000, while those from mobile units are increasing. The latter primarily meet their power requirements from diesel engines. Many new developments do not have permanent drilling rigs, but use mobile units for drilling and heavier well maintenance.

One method which could help to reduce carbon emissions from the NCS would be to supply more of the power required to operate offshore facilities from the electricity grid on land. Several fields receive or are planned to obtain power from shore. These are Valhall, Martin Linge, Troll A and Gjøa in the North Sea and Goliat off Finnmark. The Johan Sverdrup licensees have chosen a concept based on power from shore for phase I of the development.

The Storting (parliament) requires power from shore to be assessed for all new developments and major conversions of producing fields. Such studies are assessed by the NPD. The abatement cost of installing power from shore on facilities varies considerably between different developments. Features which make this approach more cost-effective include closeness to land, a limited need for process heat, a substantial demand for power, a large electricity grid in the region, and a long producing life for the field.

4.2 Produced water

The volume of produced water has been stable, but is expected to rise somewhat over the next few years. See figure 4.5. In spite of stable production, discharges of produced water have declined somewhat in recent years, reflecting increased produced-water injection on certain fields. The operators have developed treatment capacity for produced water as discharge restrictions have become tighter.

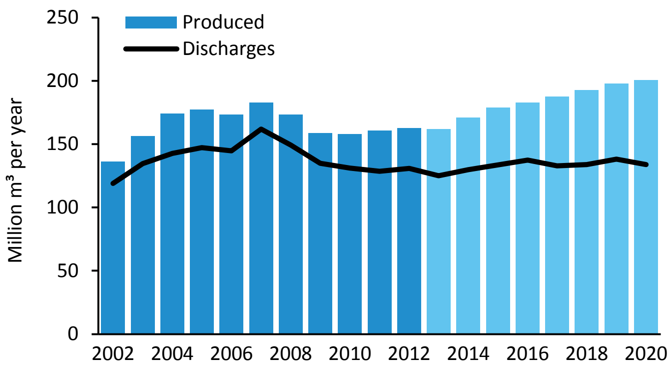


Figure 4.5 Historical volumes and forecasts for produced water and discharges.

Water which accompanies oil and gas production from the reservoir comprises natural supplies from the formations and possible water injected to improve recovery. It is separated from the oil and gas and treated in the process facility. After treatment, formation water still contains some dispersed oil as well as dissolved organic and inorganic compounds. Produced water can also contain residues of various chemicals added to the process. The volume and composition of produced water can vary a great deal from field to field, and over a field's producing life.

In the years leading up to 2000, work was initiated to reduce the risk of damage from increasing discharges of produced water. The target was zero harmful discharges. These efforts led in part to the development of new treatment technology, and new chemicals replaced potentially harmful substances. Over a 10-year period, more than 95 per cent of the chemicals with a potential to harm the environment were replaced. The zero discharge target is regarded as having been attained for environmentally hazardous chemical additives. The petroleum industry accounts for only a small proportion of discharges involving substances on the priority list drawn up by the environmental authorities for phasing out environmental toxins. Efforts to reduce discharges of such substances are continuing. These substances will continue to be used and discharged to the sea to a limited extent in coming years for safety and technical reasons.

Design of the resource report

The design elements in this report are based on microscope photos of such microorganisms as dinoflagellates and bolboforma from the NPD's collections.

Basically yellow and white in colour, these organisms are 95-10 million years old.

They have been adapted by architects Liv-Kristine Ruud and Agnes Selheim in connection with a decorative assignment for the NPD.

NORWEGIAN PETROLEUM
DIRECTORATE

npd.no