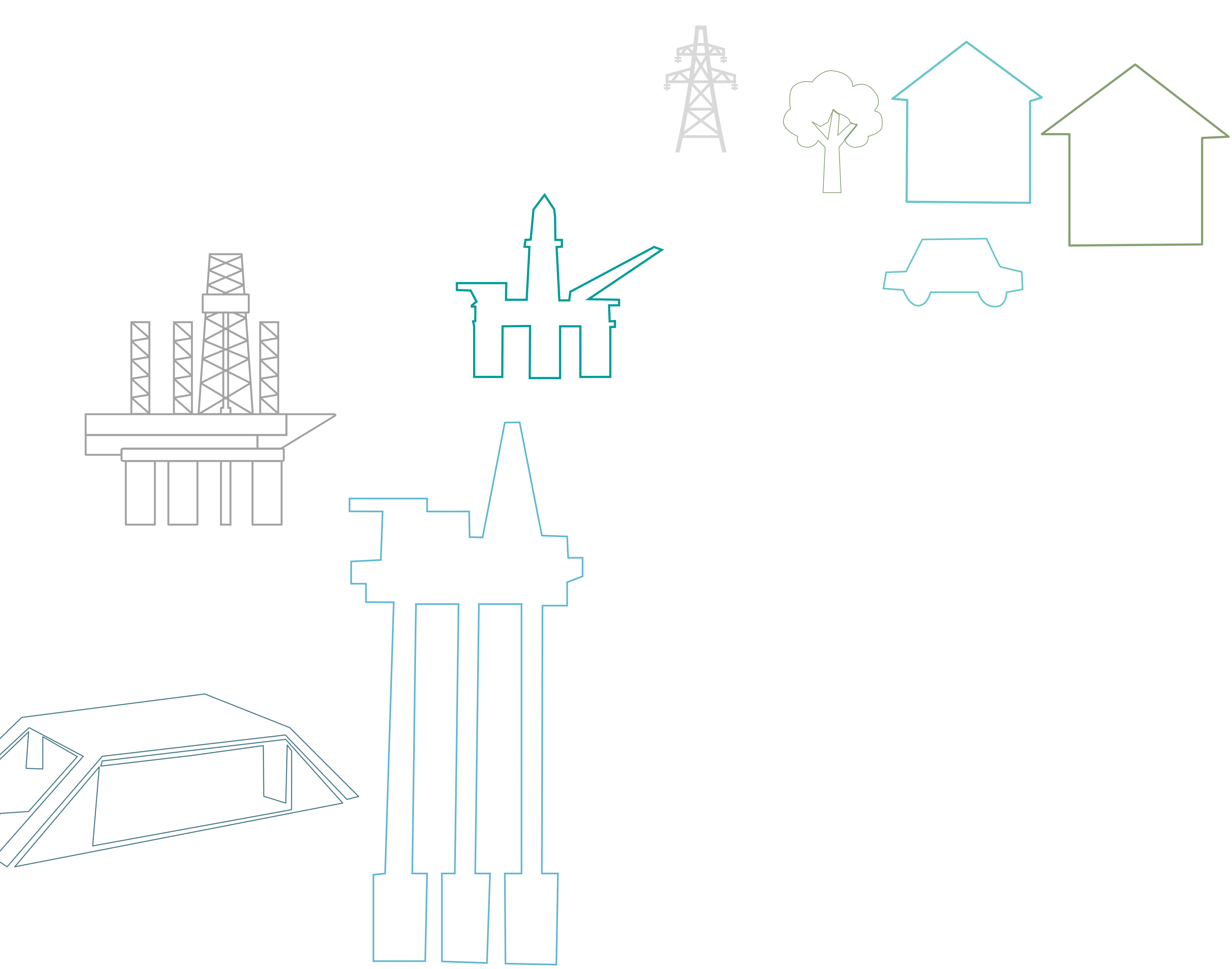
Resource report 2020 Exploration

NORWEGIAN PETROLEUM DIRECTORATE



Foreword

Norway's Petroleum Act specifies that the petroleum resources belong to the Norwegian people and must benefit the whole country. The main object of petroleum policy is to make provision for socioeconomically profitable production of the country's oil and gas resources in a long-term perspective. Our role at the Norwegian Petroleum Directorate is to help ensure the greatest possible value creation for society.

Great challenges are faced at present. The coronavirus epidemic has reduced oil and gas demand, resulting in lower prices. Exploration activity will consequently be lower in 2020, a reminder that petroleum is a cyclical industry with big fluctuations. At the same time, producing energy with reduced emissions is attracting great attention and digitalisation is continuing at an ever-faster pace. Companies, government agencies and individuals find it demanding to keep up.

A solid base of facts and knowledge is essential for government to play a decisive role in resource management and to help ensure that good, long-term decisions are taken. In this report, we present an updated overview of undiscovered petroleum resources on the Norwegian continental shelf (NCS). This shows that, after more than 50 years of activity, roughly half the expected oil and gas resources have yet to be produced and that, of these, just under half remain to be discovered. Big discoveries are still possible across the whole NCS.

Resources on the NCS can lay the basis for petroleum production over many decades. The government makes provision for a steady supply of exploration acreage through regular licensing rounds which contribute to predictability for the industry. The latter has displayed great interest in the latest rounds, and applications were received from 33 companies in this year's awards in predefined areas (APA). That was the same number as the year before, and shows that the NCS remains attractive.

Large oil and gas resources with a low carbon footprint, good storage capacity for CO_2 and opportunities for producing mineral resources from the seabed mean that the NCS is well positioned for a transformation of the energy picture over coming decades. In addition to its duties related to traditional petroleum activities, the NPD has important mapping and follow-up responsibilities for both CO_2 storage and identifying seabed mineral accumulations.

A high level of exploration activity in recent years has resulted in many discoveries. Most of these are relatively small, reflecting the fact that exploration increasingly takes place in mature areas.

However, small discoveries can have good profitability and contribute large revenues to the government when they are tied back cost-effectively to existing infrastructure.

Well-developed infrastructure in the North and Norwegian Seas also makes it attractive to explore for smaller gas accumulations. Gas accounts for roughly half the undiscovered resources on the NCS. More than half of the gas yet to be found in areas opened for petroleum activities is expected to lie in the Barents Sea. Lack of access to available transport infrastructure influences exploration strategies at the companies. Expanding export capacity from the Barents Sea could increase exploration activity there and help to realise a larger share of the resource potential.

Timely exploration close to cost-effective infrastructure can help to keep total unit costs low. Today's unit costs provide the basis for future profitable exploration even with low oil prices. Technology advances and digitalisation could also contribute to increased profitability by reducing exploration risk and enabling more discoveries.

Successful exploration is a precondition for long-term production and export of oil and gas. After 2030, Norwegian output is set to decline substantially unless new discoveries are made. That makes it important to maintain exploration so that further discoveries can be made in both mature and frontier areas. A wide variety of players provides a good starting point. At the same time, it is important that the companies demonstrate a continued willingness to test new exploration concepts and to apply innovative technology and advanced data analytics. Last but not least, they must become even better at ensuring the commercial development of small discoveries.

If the industry succeeds with this, it will be able to go on contributing substantial value to society for a long time to come.

Torgeir Stordal

Torgeir Stordal
Director, Exploration

Resource report 2020
Exploration

Chapter 1

Introduction and summary

Introduction

The resource report for 2020 presents the status for and analyses of the long-term opportunities and challenges facing exploration activities on the NCS. Its objective is to increase understanding of the potential offered by undiscovered resources and the value these may represent for society. The report also identifies the challenges involved in proving and realising this value.

Petroleum operations still represent a large and important part of the Norwegian economy, and account for a substantial proportion of government revenues. After more than 50 years of oil activities, half the total resources remain below ground. A large proportion of these have yet to be discovered (Figure 1.1).

Estimated undiscovered resources total some 3 900 million standard cubic metres of oil equivalent (scm oe). This estimate is uncertain, with an uncertainty range of 2 200 to 6 200 million scm oe. About 40 per cent of the undiscovered resources lie in areas which have still not been opened for petroleum activities.

Successful exploration is a precondition for long-term production and export of oil and gas. Exploration activity has been high in the recent past and, until the coronavirus epidemic, was expected to remain relatively strong in coming years. The slump in oil and gas prices, partly as a consequence of the epidemic, has led the oil companies to reduce their exploration budgets and to cancel or delay exploration wells. The Norwegian Petroleum Directorate (NPD) estimates that about 30 such wells will be drilled in 2020, almost half the number for 2019.

The high level of exploration in recent years has yielded many discoveries. These are relatively small, and reflect the fact that a growing share of exploration takes place in mature parts of the NCS. However, large discoveries are still possible because extensive areas remain less explored. Exploration over the coming decade will have a significant impact on how quickly production and revenues decline after 2030.

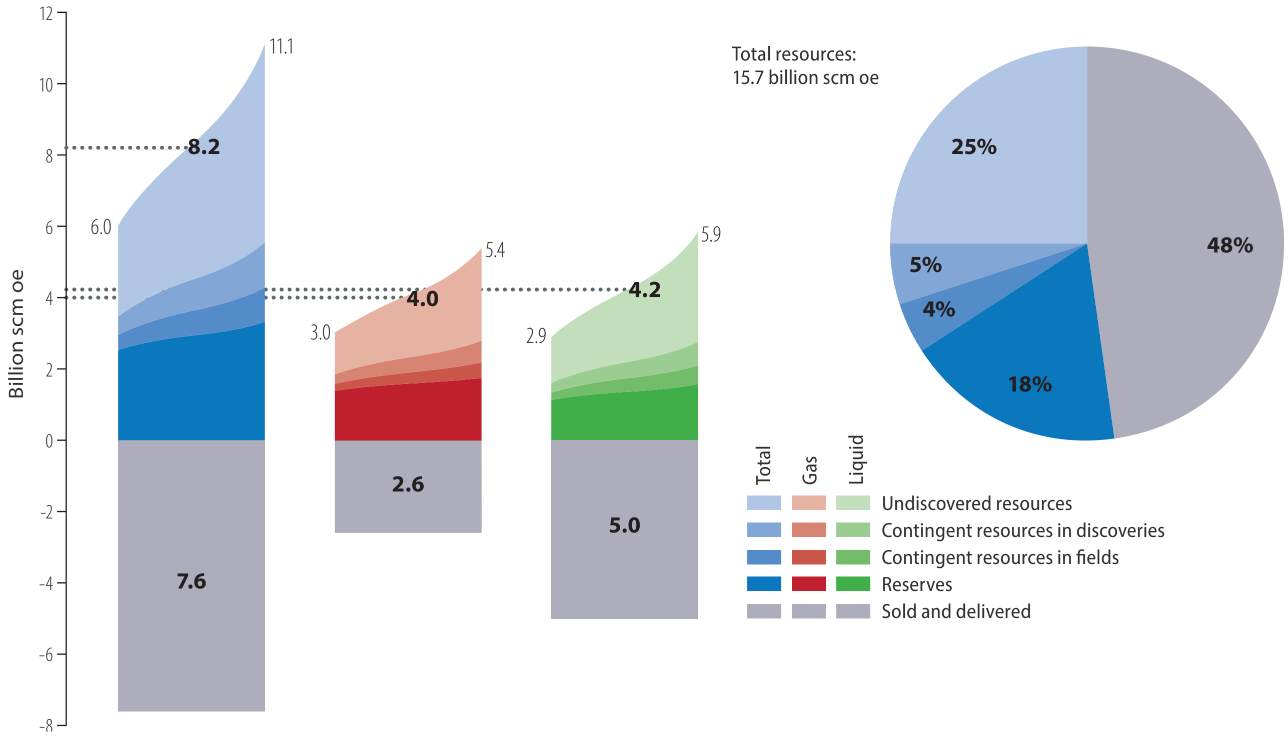


Figure 1.1 Petroleum resources on the NCS

Small discoveries have good profitability and provide substantial revenues to the government when they are tied back cost-effectively to existing infrastructure. During recent decades, such discoveries have contributed a substantial proportion of the total value creation from exploration. Low unit costs provide the basis for profitable future exploration even with low oil prices. In addition, technological progress and digitalisation could help to enhance profitability by reducing exploration risk and increasing the number of discoveries.

Climate policies may also affect future exploration profitability. Like a number of other countries, Norway has undertaken through the Paris agreement to limit global warming to well below 2°C and to seek to restrict it to 1.5°C. The NCS is well positioned to meet the climate challenge. At the same time, this could open new opportunities such as carbon storage, hydrogen production, and exploration for and exploitation of seabed minerals.

Summary

Chapter 2: Exploration trends on the NCS
Good availability of acreage, substantial cost reductions, access to infrastructure and better data coverage have contributed to the drilling of many exploration wells. Many new discoveries have been made, although most are relatively small. Much remains to be discovered in both mature and frontier areas. A significant potential for exploration success is offered by the combination of greater knowledge, new seismic technologies and the application of advanced Big Data analytics. Successful exploration is a critical factor for future production and value creation.

Chapter 3: Undiscovered resources
The NPD’s estimate for undiscovered resources shows that large volumes of oil and gas remain to be discovered in all parts of the NCS. At 3 910 million scm oe, the expected volume represents almost half of Norway’s remaining offshore resources. Roughly 40 per cent of the undiscovered volumes lies in areas which are still not open for petroleum activities.

Chapter 4: Significance of exploration
Exploration for oil and gas has provided huge value for Norwegian society over the past 20 years. All areas of the NCS make important contributions to overall value creation. New discoveries provide the basis for continued activity in the petroleum industry, create big spin-offs for the rest of society, and will be extremely important for future value creation.

Chapter 5: Digitalisation of exploration
Norway’s oil and gas accumulations are increasingly harder to find. Technological progress and digitalisation have provided better data and tools which contribute to increased geological understanding and make it possible to identify new exploration concepts. Digitalisation also provides further opportunities to reduce exploration costs and enhance the efficiency of work processes. That can help to reduce exploration risk and increase the number of discoveries.

Chapter 6: Resources for the future
The NCS is well positioned to meet the climate challenge and the increased economic risk that imposes. At the same time, this challenge opens opportunities for innovation and new commercial activity in such areas as CO_2 storage and exploration for and exploitation of seabed minerals.

Fact box 1.1 Resource classification

The NPD's resource classification system is used for petroleum reserves and resources on the NCS. It is designed to provide the government with the most uniform possible reporting from licensees to the NPD's annual updating of the resource accounts.

"Resources" are a collective term for all the oil and gas which can be recovered. They are classified in the NPD's resource classification system by their level of maturity in terms of how far they have come in the planning process from discovery to production. The classification system was developed in 1996 and revised in 2001 and 2016. Changes in 2016 primarily involved language improvements, including new designations for certain resource classes.

Classification relates to the total recoverable quantities of petroleum. The system is divided into three classes: reserves, contingent resources and undiscovered resources.

All recoverable petroleum quantities are termed resources, and reserves are a special category of these.

Reserves are the petroleum quantities covered by a production decision. Contingent resources embrace both recoverable quantities which have been discovered but are not yet covered by a production decision, and projects to improve recovery from the fields.

The classification utilises the letters "F" (first) and "A" (additional) respectively to distinguish between the development of discoveries and accumulations, and measures to improve recovery from a deposit. Undiscovered resources are those petroleum quantities which could be proven through exploration and recovered. The quantities produced, sold and delivered form aggregate production.

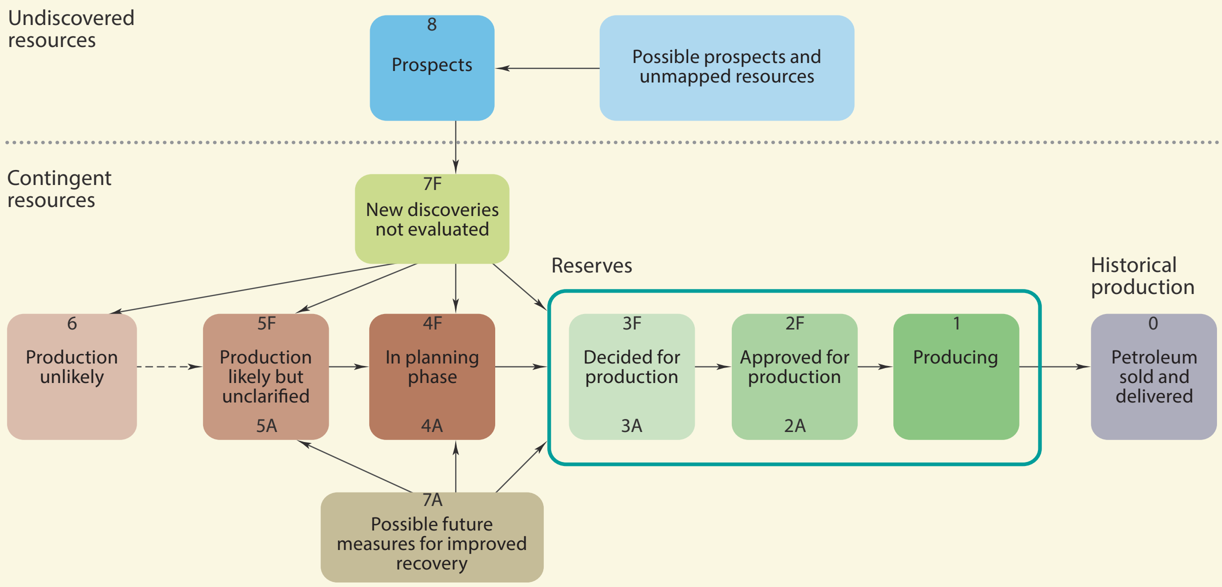
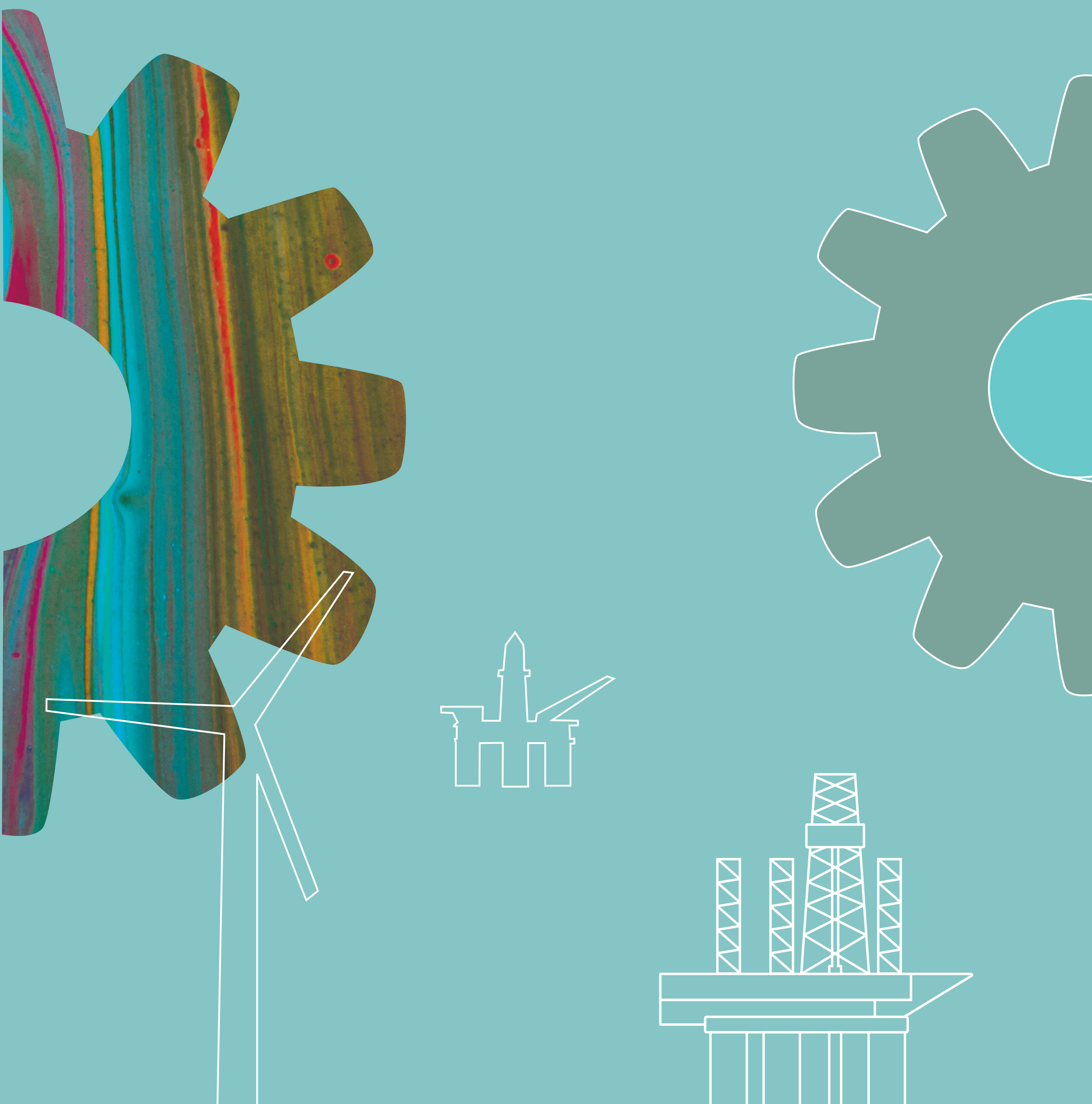


Figure 1.2 Resource classification in 2019

Chapter 2

Exploration trends on the NCS



Good availability of acreage, substantial cost reductions, access to infrastructure and better data coverage have contributed to the drilling of many exploration wells. A lot of new discoveries have been made, most of them relatively small. Much remains to be found in both well explored and less investigated areas. A big potential for exploration success is offered by the combination of greater knowledge, new seismic survey technology and innovative methods for analysing large data volumes. Successful exploration is a critical factor for future production and value creation.

A proud history

Big discoveries
The 50th anniversary of the Ekofisk discovery at the southern end of Norway's North Sea sector was celebrated in 2019. When officially inaugurating production from the field in 1971, just two years later, then prime minister Trygve Bratteli made his celebrated comment that "This could be a red-letter day in Norway's economic history".

Finding Ekofisk sparked great interest in exploring the NCS and several substantial discoveries were made over the next 20 years, such as Statfjord, Gullfaks, Oseberg and not least Troll (Figure 2.1). These fields have formed the backbone in developing Norway as a petroleum nation, both economically and technologically. Discoveries in recent years have been substantially smaller. Nevertheless, large discoveries such as Johan Sverdrup, 7324/8-1 (Wisting) and Johan Castberg are still being made.

A total of 1 714 exploration and 4 800 production wells had been completed on the NCS up to 31 December 2019, with 113 fields brought on stream. Twenty-six of the latter have ceased production. Eight onshore plants have also been built. New technology has been developed and adopted to meet the challenges faced as the most easily accessible resources are produced, and to comply with ever-stricter environmental and safety standards for prudent operations.

Developments have moved from large steel and concrete platforms with processing facilities, permanent personnel and many support functions to solutions based on subsea installations where processing and support are provided from existing facilities or from shore. The extensive infrastructure of field installations, pipelines and land plants has reduced the cost of developing smaller discoveries and increased interest in exploring for minor petroleum accumulations.

Such re-use of infrastructure contributes to greater value creation and efficient resource utilisation, and makes small discoveries profitable.

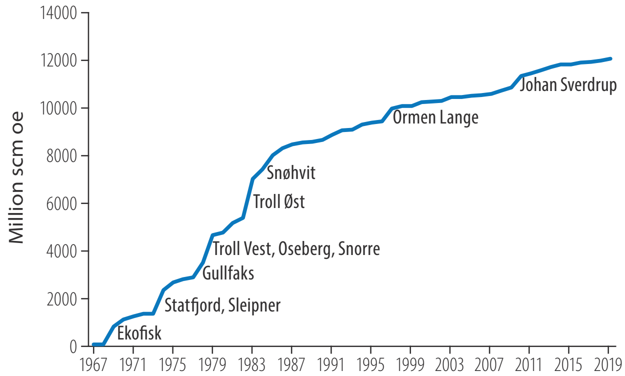


Figure 2.1 Resource growth on the NCS

Successful exploration is a critical factor for future production and value creation

The government has played an active role in developing Norway's petroleum and supplier industries. A gradual build-up has characterised the strategy for resource management and industrial development. Where exploration is concerned, the main rule has been step-by-step progress. This principle means that drilling results should be available for an area before further blocks are offered there. New information will contribute to more effective exploration and fewer dry wells.

Substantial value

Norway's Petroleum Act specifies that the petroleum resources belong to the Norwegian people and must benefit the whole country. Oil and gas production has long been the country's biggest provider of value creation, government revenues, investment and exports. This industry has contributed substantially to making Norway a wealthy nation today. At the beginning of its Oil Age, the country's gross domestic product (GDP) per capita was relatively low compared with many western countries, such as the USA, Sweden and Germany [1] (Figure 2.2). Over subsequent decades, growing petroleum output raised the level of Norwegian incomes. When production peaked in the early 2000s, rising petroleum prices drove incomes even higher.

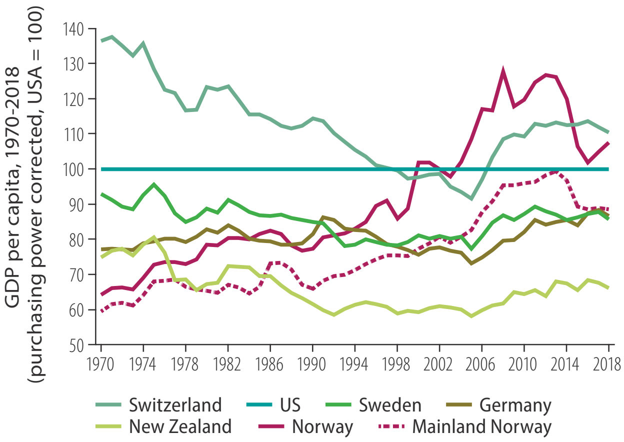


Figure 2.2 GDP per capita, 1970-2018. *Sources: Norges Bank, OECD and Statistics Norway (2020).*

Activities on the NCS have had spin-offs for other industrial sectors. A growing number of companies – not just in the engineering industry – have turned their attention to deliveries for the oil business. New products and technological solutions have been developed. Many firms have found assignments on the NCS to be a springboard into new export markets. Petroleum activities have also contributed to substantial productivity improvements in adjacent industries because oil-related knowledge and technology rubs off on them.

The petroleum sector accounted in 2019 for about 13 per cent of all value creation in Norway and roughly 36 per cent of Norwegian export earnings (Figure 2.3). Total net cash flow to the government from the petroleum industry is estimated at NOK 87 billion in 2020, down by about NOK 170 billion from 2019. Most of these revenues are placed in the oil fund (the Government Pension Fund Global), which had a market value of more than NOK 10 000 billion in October 2020.

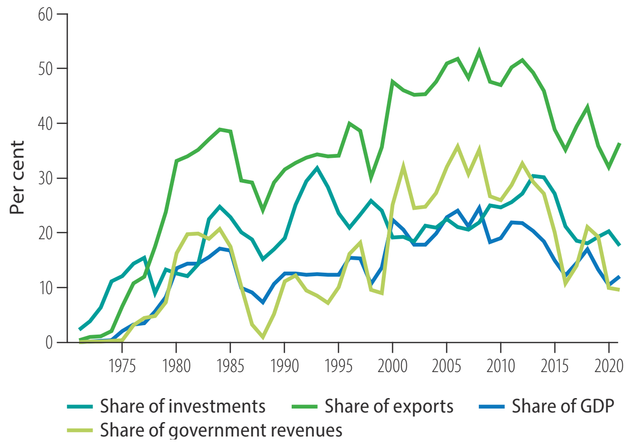


Figure 2.3 Macroeconomic indicators for the oil industry, 1971-2020. *Source: norskpetroleum.no (updated October 2020).*

Even small developments on the NCS would have ranked as substantial industrial projects if they were pursued onshore. A report from Menon Economics [2] for the Ministry of Petroleum and Energy (MPE) shows that about 225 000 people were employed directly or indirectly by the Norwegian petroleum sector in 2017. Value creation per direct petroleum-sector employee in 2019 was about NOK 19 million, compared with roughly NOK 1 million per employee in the mainland economy overallt [3].

High activity level – declining resource growth

Exploration activity has been high in the recent past and, until the coronavirus pandemic began in the spring of 2020, was expected to remain relatively stable at a strong level for the next few years. Measures implemented to reduce the spread of the virus have contributed to reduced demand for petroleum and a fall in oil prices. In the exploration sector, short-term conditions are expected to lead to fewer exploration wells being drilled and fewer seismic surveying assignments.

Historical figures illustrate how oil prices affect drilling, with a clear relationship between (nominal) oil prices and the number of exploration wells (Figure 2.4).

Activity increased sharply after 2006. In addition to higher oil prices, changes made to the regulatory framework in 2003-05 were important for the growth in exploration drilling (fact box 2.1).

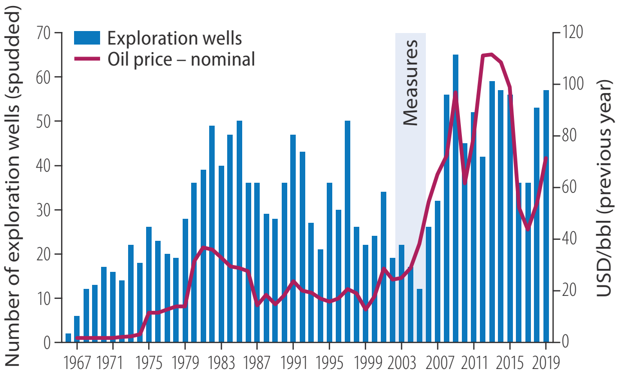


Figure 2.4 Historical development of oil prices and exploration wells

Exploration picked up after oil prices rose in 2017. Fifty-three exploration wells were spudded in 2018, 17 more than the year before, including 31 in the North Sea, 15 in the Norwegian Sea and seven in the Barents Sea (Figure 2.5). Of the 53, 28 were wildcats and 25 were for appraisal. In 2019, 57 wells were spudded – 37 in the North Sea, 15 in the Norwegian Sea and five in the Barents Sea (Figure 2.5). Of these, 43 were wildcats and 14 were for appraisal.

Fact box 2.1 Measures to increase exploration

Around 2000, the level of exploration on the NCS was low – particularly in mature areas. That contributed to low resource growth. The government therefore adopted measures and adjusted framework conditions to encourage competition and increase diversity among the companies. Three measures have been particularly important.

- The prequalification system was established so that companies could have their suitability for participation on the NCS evaluated. Great interest has been shown in prequalifying, and a steady stream of companies are still seeking such advance assessment.

- The awards in predefined areas (APA) scheme, together with adjustments to work programmes, provides companies with opportunities for regular access to exploration acreage and ensures that the NCS is actively investigated. It also facilitates efficient use of oil-company resources and makes sure that relinquished acreage becomes available to players with new ideas. Acreage awarded earlier is thereby also subjected to fresh evaluation.

- The reimbursement system for exploration costs was introduced to ensure equal treatment of companies whatever their tax position. This lowers the entry threshold for new players and facilitates profitable exploration. Under the system, companies can choose whether they want the tax value (78 per cent) of their exploration costs reimbursed by the government in the following year or deducted from taxable income. Established companies with taxable earnings can deduct exploration costs on a continuous basis and thereby reduce their tax bill. Players without such earnings can have the costs either reimbursed or carried forward with compensation for interest (or have the tax value of losses refunded should they withdraw from the NCS). Small companies which have yet to achieve taxable earnings thereby reduce their tied-up capital and improve cash flow.

Most wells in recent years have been drilled close to existing infrastructure (Figure 2.6). Spare capacity in these facilities can make it profitable to explore for and develop ever smaller discoveries. Along with lower costs and good earnings for the companies, this is an important reason why exploration activity has been high in recent years. A good supply of attractive exploration acreage, technological progress in seismic surveying and large volumes of new seismic data have also been important factors (fact box 2.2).

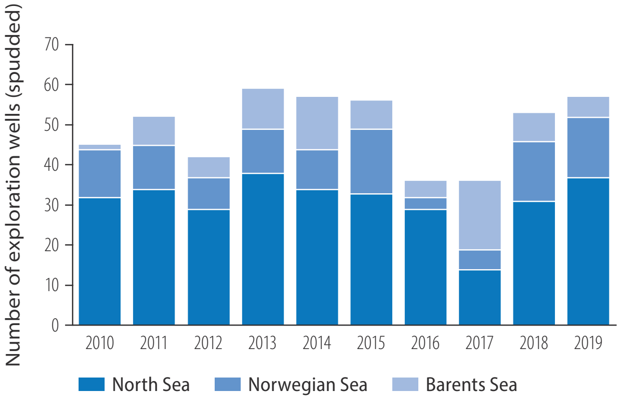


Figure 2.5 Exploration wells spudded by region, 2010-19

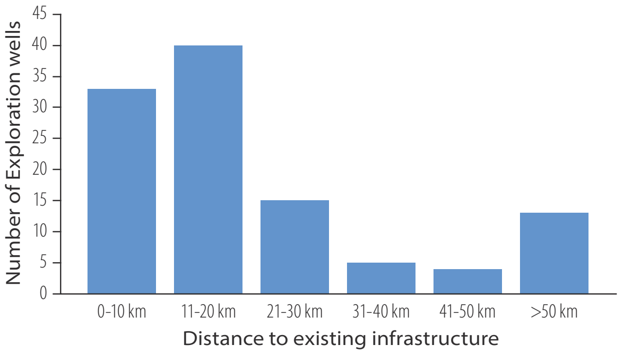


Figure 2.6 Exploration wells 2018-19 and closeness to infrastructure

Fact box 2.2 3D seismic coverage for the past 10 years

Advances in seismic technology during recent years have made subsurface images clearer. Ever larger 3D surveys also contribute to consistent imaging over large areas, which is important for the best possible geological understanding Figure 2.8 and Figure 2.9 show the development in 3D data acquisition across the NCS by oil (proprietary) and survey (for sale or multi-client) companies in 2000-09 and 2010-19.
More and larger areas have been investigated and covered by seismic surveys over the past decade. The oil companies acquired as much seismic data as the survey companies in 2000-09, but the latter were largely responsible for acquisition in the next decade.

A comparison of 3D surveys and average acreage covered per annum shows a reduction from 2012, while average acreage per survey has risen sharply (Figure 2.7). That means a shift to larger 3D surveys, also illustrated in Figure 2.9. It also shows that seismic acquisition has become more efficient in recent decades, with more data acquired per survey.

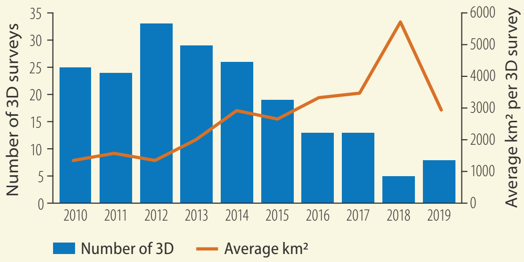


Figure 2.7 3D surveys and average square kilometres acquired, 2010-19

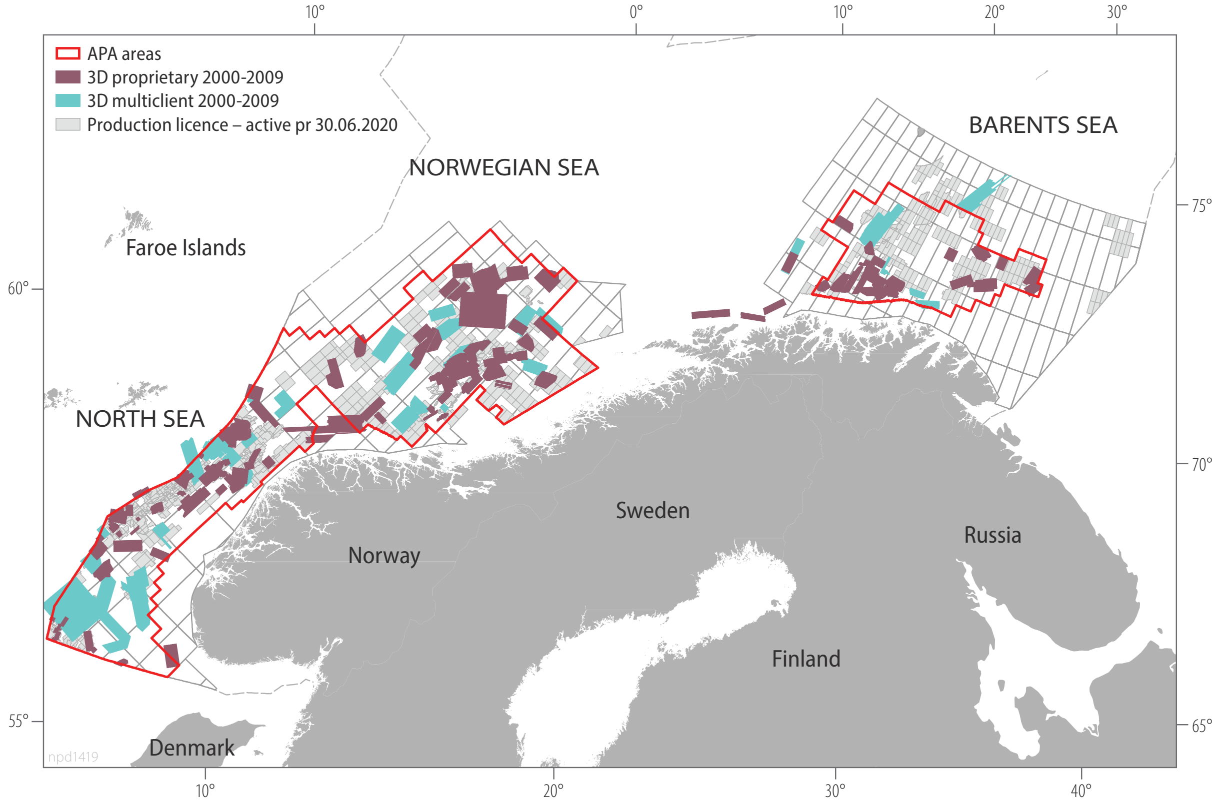


Figure 2.8 3D data acquisition by oil companies (proprietary) and survey companies (for sale or multi-client), 2000-09

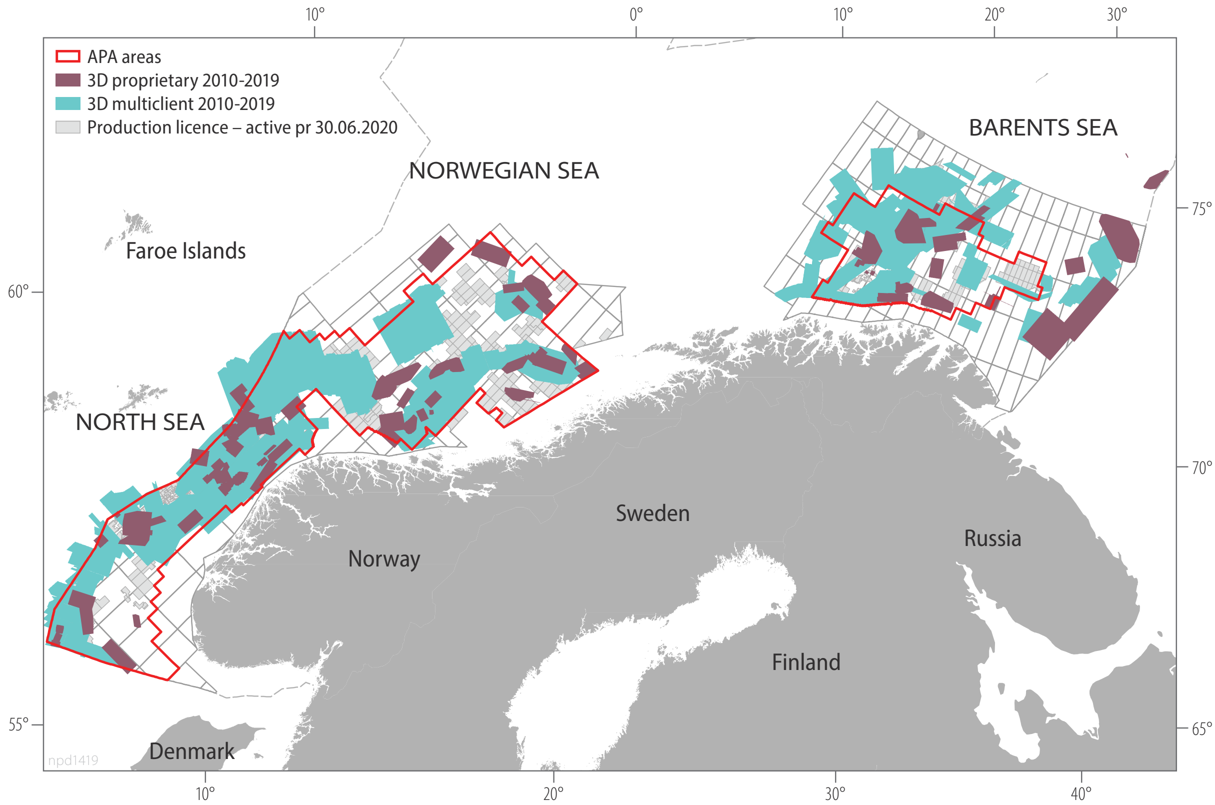


Figure 2.9 3D data acquisition by oil companies (proprietary) and survey companies (for sale or multi-client), 2010-19

Good supply of acreage from licensing rounds

A good supply of attractive acreage from licensing rounds is important for maintaining exploration and laying the basis for new discoveries. Since the restructuring of exploration policy in 2003-05, the number of production licences awarded has risen sharply (Figure 2.10). A total of 151 licences were awarded in the annual APA rounds in 2019-20. These awards have been made to the whole spectrum of companies, from majors to small newcomers to the NCS. The many applications received show that interest in the NCS is high, and that it is competitive in the international market.

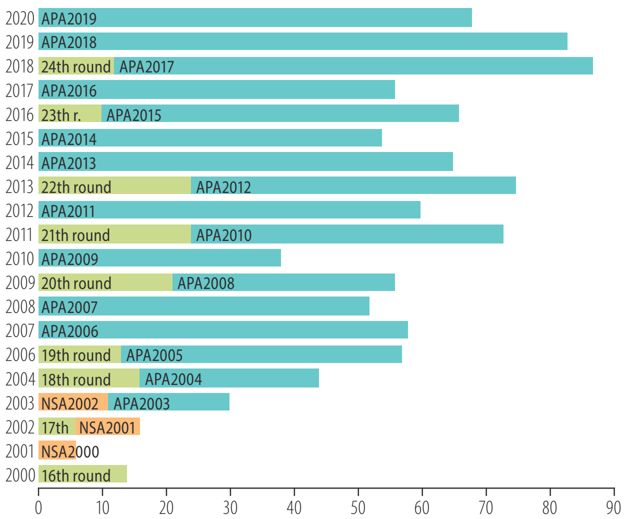


Figure 2.10 Production licences awarded since 2000

The APA has contributed to extensive awards and a marked increase in licenced acreage (Figure 2.11), which now covers much of the North and Norwegian Seas (Figure 2.12). Work programmes in the licences can lay the basis for a high level of exploration in coming years.

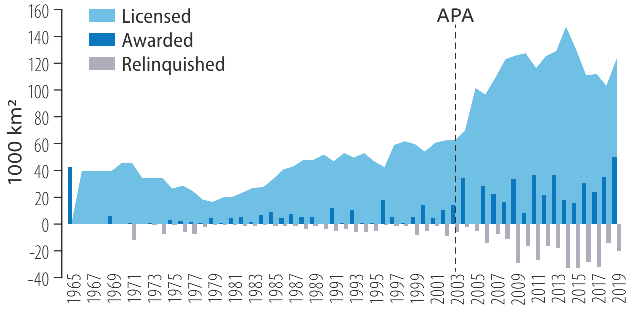


Figure 2.11 Development of available exploration acreage on the NCS

Since the APA scheme was launched, acreage has been awarded and relinquished several times (Figure 2.13). Discoveries are still being made in such areas – including some big discoveries, such as Johan Sverdrup.

Supply of acreage through an active market for purchase and sale of interests

Companies can also access exploration acreage by buying interests in production licences (Figure 2.14). Such activity was record high in 2019. A well-functioning secondary market gives companies the opportunity to build a balanced portfolio of exploration acreage outside the licensing rounds.

Many discoveries

The high level of exploration has yielded many discoveries. Figure 2.15 presents discoveries per annum since 2000 by region. Government measures contributed to a substantial increase in discoveries from 2007.

A total of 31 discoveries were made in 2018-19 – 17 in the North Sea, 10 in the Norwegian Sea and four in the Barents Sea. Preliminary assessments indicate that 2018 and 2019 were the two best exploration years of the past five (Figure 2.16).

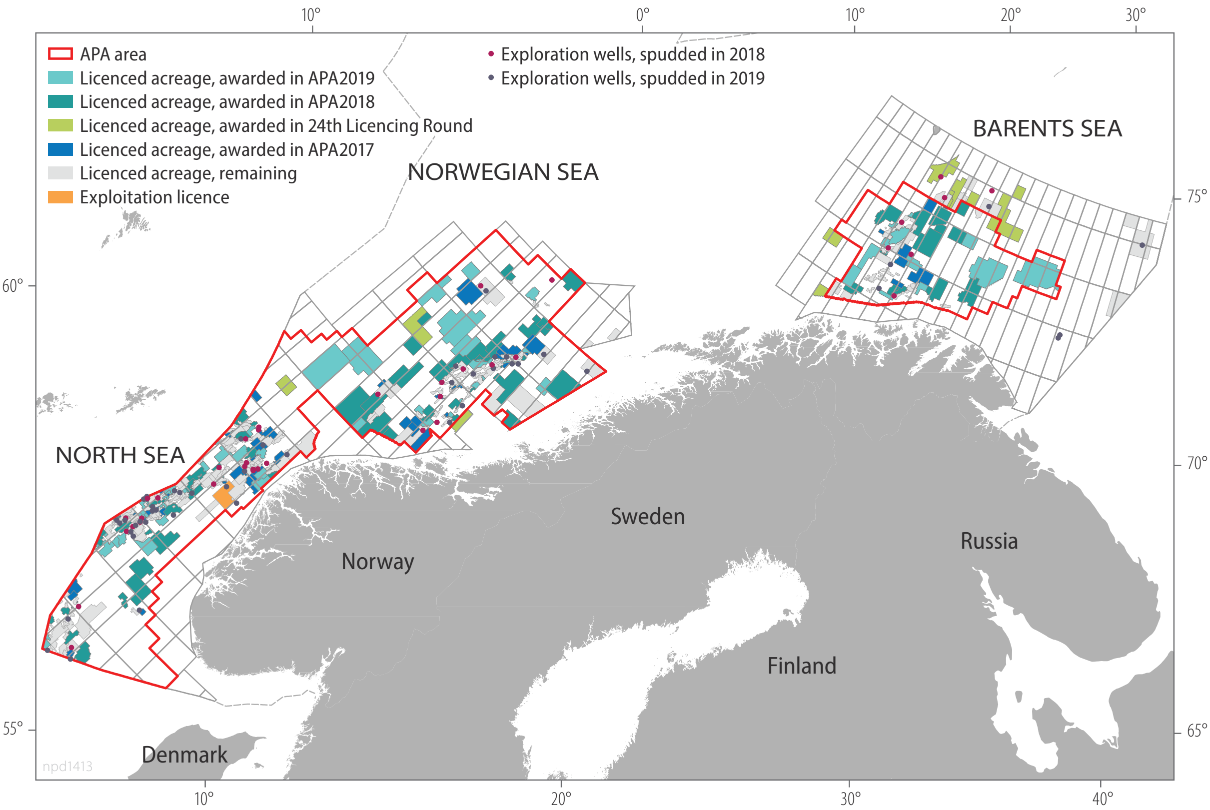


Figure 2.12 Area licensed on the NCS at 31 December 2019

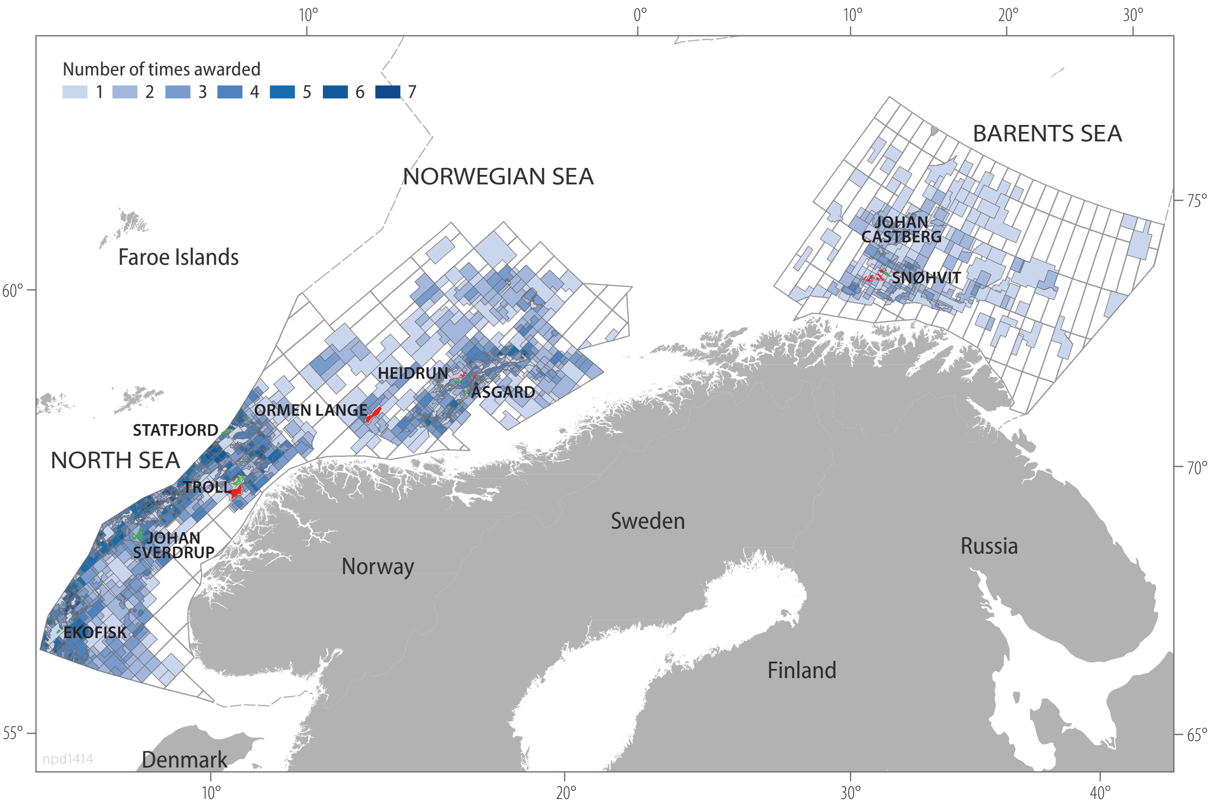


Figure 2.13 Number of times acreage has been awarded

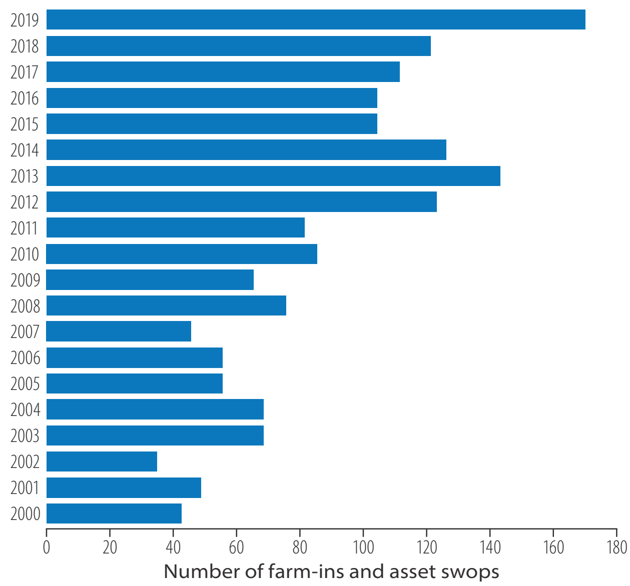


Figure 2.14 Farm-ins and swops of licence interests on the NCS

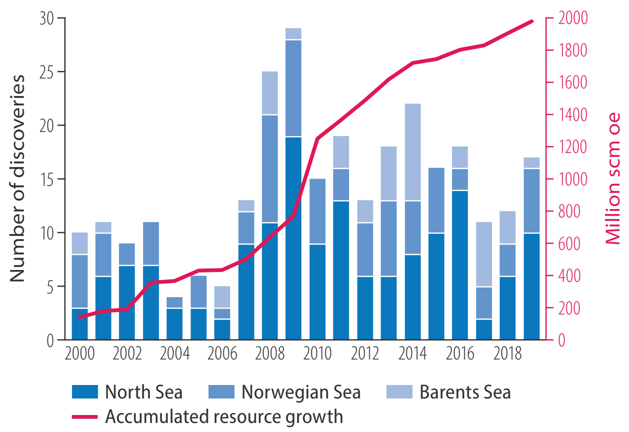


Figure 2.15 Number of discoveries by region and total resource growth, 2000-19

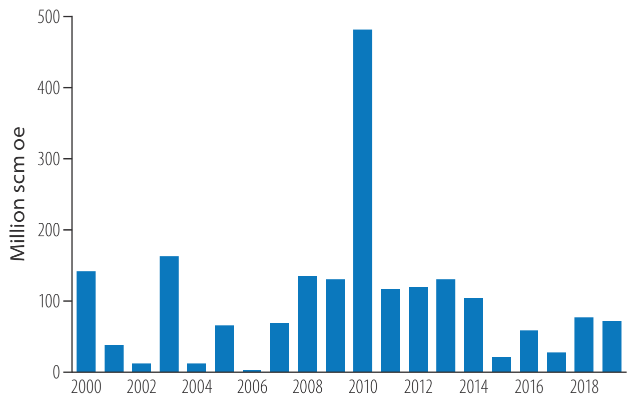


Figure 2.16 Annual resource growth from exploration, 2000-19

Discoveries in different plays give new understanding

Wells have been drilled in a number of plays during recent years, but most frequently in those with Jurassic reservoirs which are already well-explored. More than half the discoveries over the past five years are in Jurassic plays (Figure 2.17). An example of discoveries in less explored plays is 25/2-21 (Liatårnet), proven during 2019 in a Miocene reservoir (Neogene). It is considered to be the first oil discovery in this play on the NCS, although earlier wells in the area have yielded traces of oil. Results from a forthcoming appraisal well will be important in determining whether the discovery can be developed and for further exploration in this play.

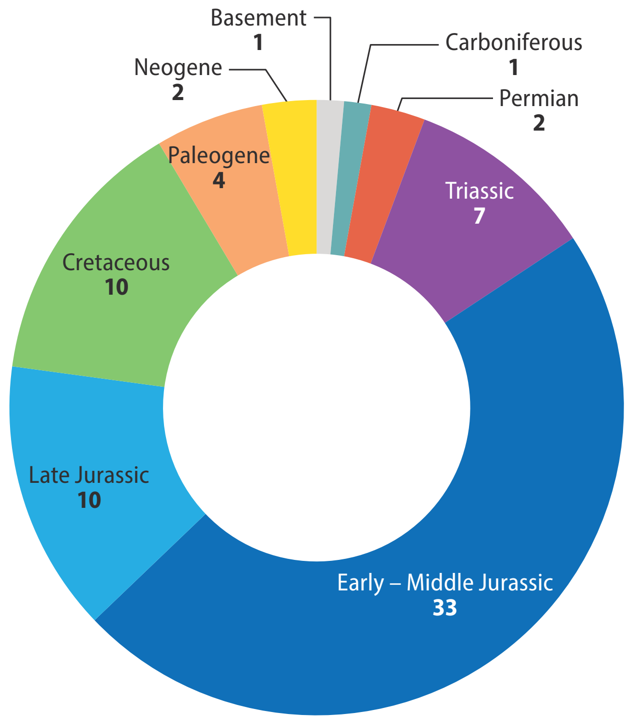


Figure 2.17 Discovery wells by reservoir age, 2015-19

Several discoveries have been made in injectites in the central part of Norway's North Sea sector (fact box 2.3). The latest generation of 3D seismic data, based on broadband technology, has improved imaging of these complex structures and provided a better basis for drilling decisions, well execution and further exploration. Challenges in obtaining sufficiently good seismic images mean that drilling wells horizontal or with specially designed paths still represents the only way of determining injectite extent.

Fact box 2.3 Injectites

Injectites, or intrusive sand accumulations, are created by post-depositional remobilisation and are squeezed through overlying strata. These sediments are redeposited there, either as vertical/ inclined dykes or intruded between strata as horizontal sills (Figure 2.18 [4]). The sands are remobilised from a parent sand. This can happen if large quantities of sediments are deposited very quickly, as a result of glacial erosion, for example - so that pressure on the underlying strata increases.

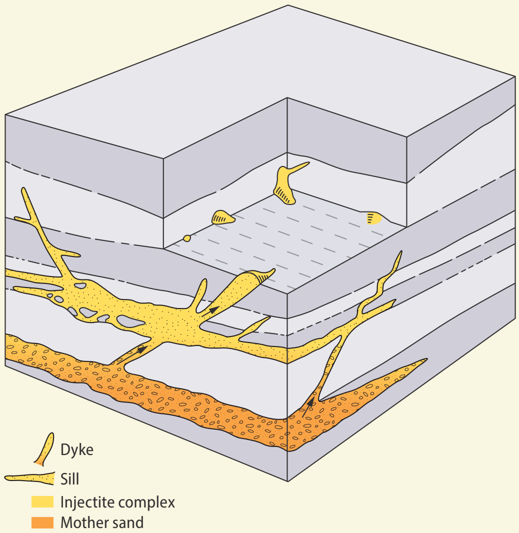


Figure 2.18 Geodiagram of injectites *modified after Hurst et al (2007)*

Plays involving Cretaceous reservoirs are well known in the Norwegian Sea but their petroleum potential has been regarded as limited. Over the past couple of years, however, several discoveries have been made in such formations. This indicates that these plays could have a bigger potential than previously thought, and industry interest in them is therefore greater than before.

Discovery size declining

International experience shows that the largest discoveries are made early in the exploration phase for a new petroleum province, and that their size declines as the area matures. This also applies to the NCS, with some exceptions such as Johan Sverdrup. The average discovery size has been falling for a long time, reflecting the fact that exploration increasingly takes place in mature areas (Figure 2.19).

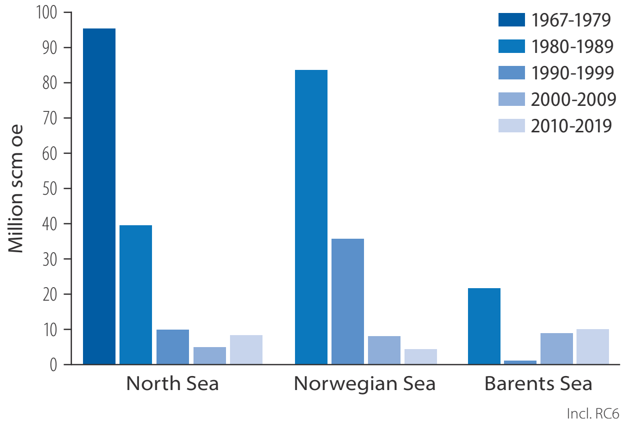


Figure 2.19 Development of average discovery size by region

Access to infrastructure – important for small discoveries

Small discoveries can become profitable by tying them back to nearby infrastructure. Coordinating several minor discoveries can also help to improve the profitability of such tie-ins. A good example is provided by the ongoing Breidablikk development, where plans call for several small discoveries to be jointly developed and phased into the Grane facility in the North Sea. Another is the unitisation of several discoveries in the Halten East area of the Halten Bank in the Norwegian Sea, which could form the basis of a coordinated development tied back to Åsgard B.

New infrastructure – collaboration and coordination

Achieving profitability in small discoveries located far from cost-effective infrastructure is more demanding. In such areas, large new discoveries or coordination of several small discoveries may provide the basis for a stand-alone production facility. Establishing new infrastructure with flexible capacity could lower the financial threshold for developing new discoveries and for exploration activity. Establishing the Polarled pipeline, which carries gas from Aasta Hansteen in the Norwegian Sea to Nyhamna on Norway's west coast, has increased interest in exploring for gas in this part of the NCS (Figure 2.20). Several active licences have been awarded near Polarled in 2018-20.

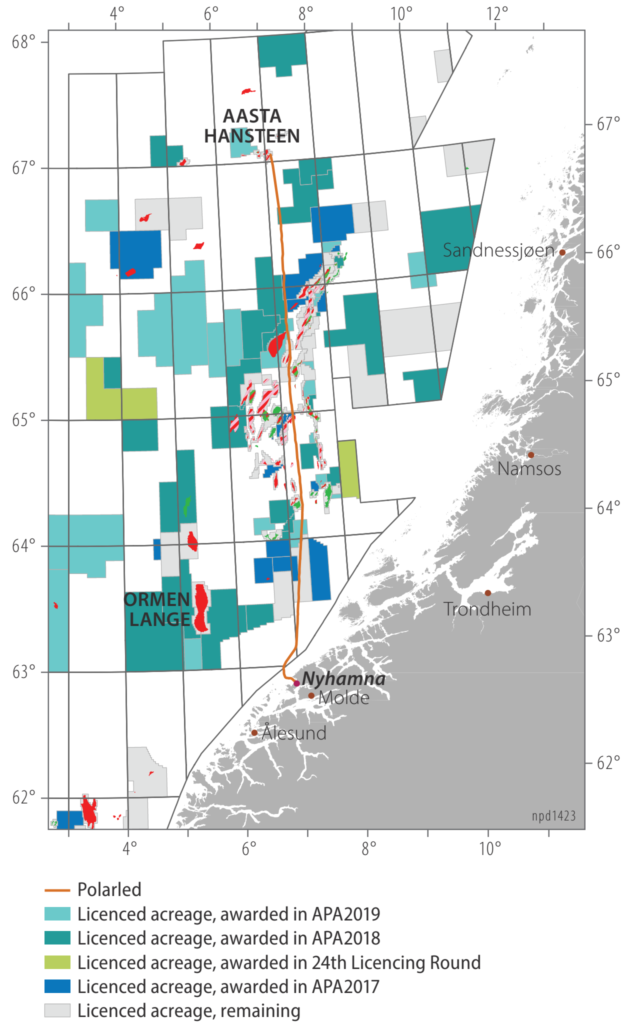


Figure 2.20 Awards near Polarled in the Norwegian Sea, 2018 and 2019

Gas is only exported from the Barents Sea today via Snøhvit's gas liquefaction plant at Melkøya in northern Norway. Existing capacity at this Hammerfest LNG facility will be fully utilised right up to 2050, based on gas in fields on stream and under development. Lack of access to gas infrastructure weakens incentives to explore, and this affects company exploration strategies. Expanding gas export capacity from Barents Sea South could increase exploration. That will be important for realising a larger share of the Barents Sea's resource potential. Studies by Gassco and the NPD show that developing new gas infrastructure in the Barents Sea could be socioeconomically profitable. That calls for collaboration and coordination across production licences and players.

Small discoveries give low materiality and influence the player picture

Although small discoveries can yield a high financial return in percentage terms, their materiality – or net present value (NPV) – is considerably lower than for big discoveries. The majors have traditionally concentrated on large projects. As discovery size declines, NCS developments face strong competition for investment funds and expertise at the majors. The latter appear to be reducing their activities on the NCS because new discoveries and projects are too small. The trend for participation by majors in exploration wells is an indicator of this (Figure 2.21).

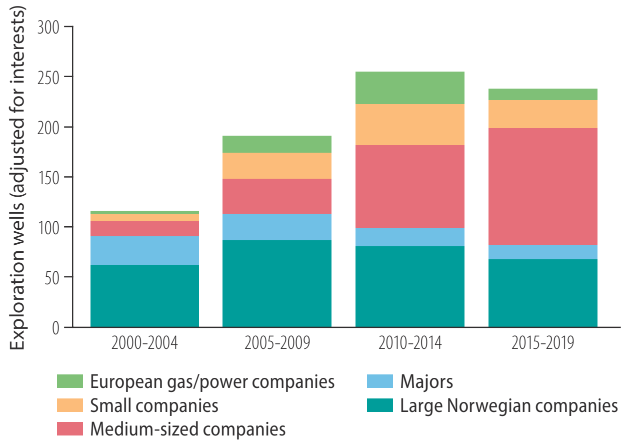


Figure 2.21 Exploration wells by company category, 2000-19 *Licensees (adjusted for licence interests)*

Political measures aimed at increasing player diversity, including the introduction of the APA rounds and the reimbursement system, led to a marked rise in the number of small participants from the mid-2000s. The recent trend is characterised by mergers and acquisitions, which have resulted in a larger number of medium-sized companies, as well as by majors withdrawing from Norway and energy companies selling out of oil and gas and investing in renewables (Figure 2.22).

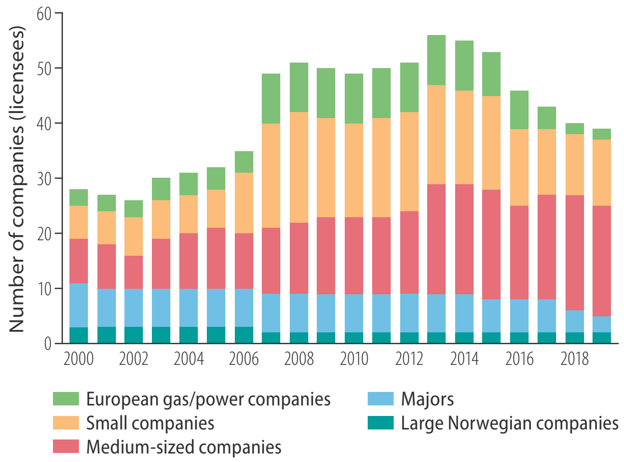


Figure 2.22 Development of the player picture, 2000-19

When the majors withdraw, they open up for other players with different strategies and priorities. ExxonMobil, which recently pulled out of the NCS, had not pursued exploration in the Balder licence (PL 001) during recent decades. Following the licensee change, interest is now being shown in drilling several exploration wells there.

Low resource growth - demanding to replace production

High discovery rate

With the size of discoveries in decline, a high discovery rate is important for maintaining the competitiveness of the NCS. Figure 2.23 presents the technical and commercial discovery rates. The first of these has been variable but high throughout since 1980. This indicates that learning effects and technological advances have offset the increase in geological maturity, so that the rate remains high.

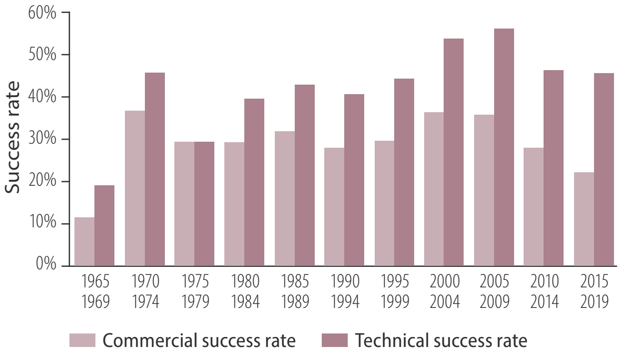


Figure 2.23 Development of the average technical and commercial discovery rates

Although exploration has been profitable in recent decades (Chapter 4 Significance of exploration) the figure shows a declining trend for the commercial discovery rate over the same period. That creates a growing gap between the technical and commercial rates. One reason for this is declining discovery size. Measures which can improve the profitability of small discoveries could help to increase the commercial discovery rate.

Low resource growth

To maintain production, declining output from the big discoveries must be replaced by a larger number of small discoveries. This development is illustrated in Figure 2.24, which shows a growing number of fields on stream and declining production per field. This represents a natural trend in a mature petroleum province. Resource growth from exploration was clearly at its largest for the first 25 years (Figure 2.25). Over the past 25 years, growth – with two substantial exceptions – has been below output on an annual basis. The exceptions are the discoveries of Ormen Lange and Johan Sverdrup in 1997 and 2010 respectively (fact box 2.4).

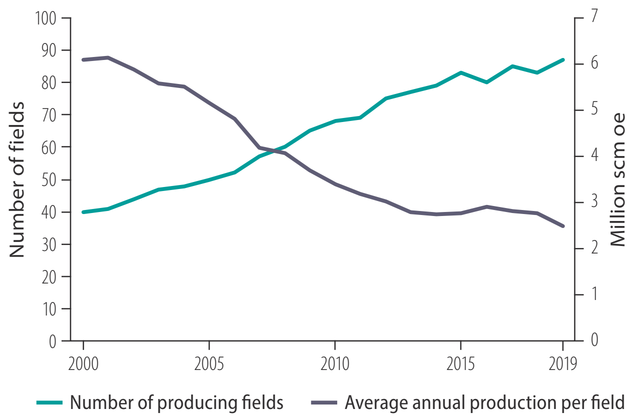


Figure 2.24 Development of producing fields and production per field, 2000-19

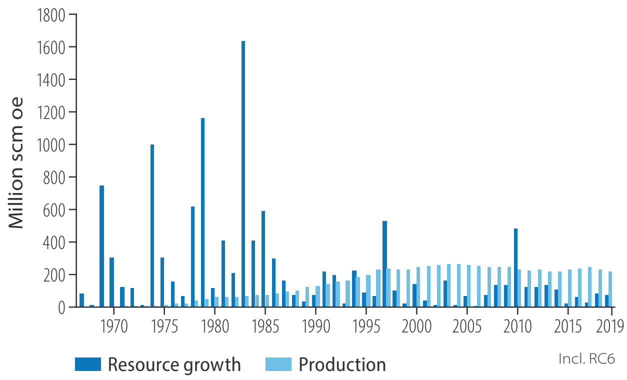


Figure 2.25 Annual resource growth and production

Fact box 2.4 Resource growth

More than 1 140 wildcats have been drilled on the NCS (Figure 2.26) – about 760 in the North Sea, 260 in the Norwegian Sea and 120 in the Barents Sea. Roughly nine billion scm oe has been discovered in the North Sea, 2.3 billion in the Norwegian Sea and 700 million in the Barents Sea (Figure 2.27).

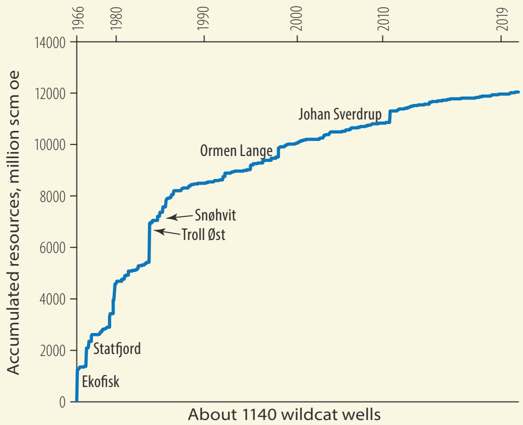


Figure 2.26 Cumulative resource growth on the NCS

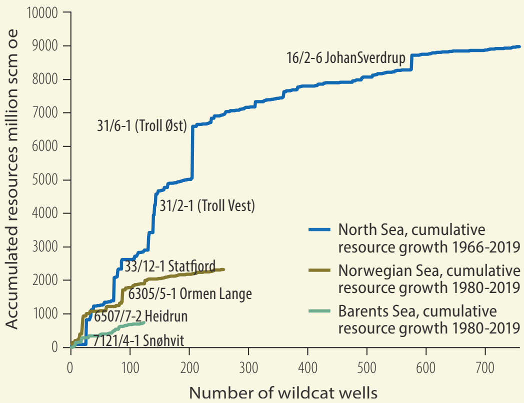


Figure 2.27 Cumulative resource growth in the various NCS regions

From oil to gas

Total production in 2019 was 214 million scm oe (Figure 2.28). This represented a slight decline from the year before, primarily because gas output was lower than expected. The companies opted to produce less gas in response to the market position and low prices. While oil accounted for the bulk of production in 2004, more gas than oil has been produced since 2010. Developments in recent years show that output is declining for oil and remains stable for gas. With Johan Sverdrup and other new fields coming on stream, oil production will rise again over the next few years. The NPD estimates that total output of oil and gas in 2023 will be close to the record level set in 2004.

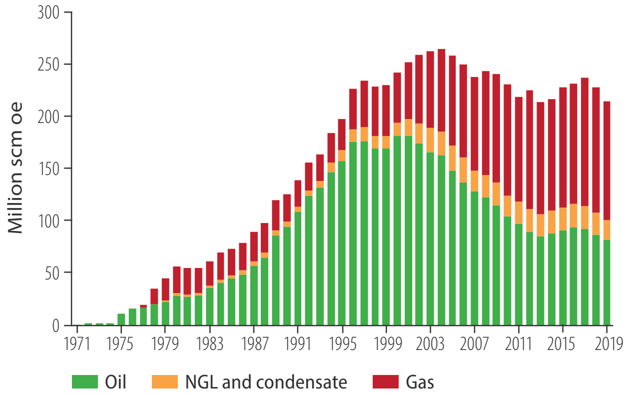


Figure 2.28 Historical production of liquids and gas

The future is undiscovered

Substantial exploration potential
A substantial exploration potential exists in all NCS regions, despite more than 50 years of drilling. Big discoveries are still possible in known and mature areas. In addition comes substantial unexplored acreage. The potential for making large discoveries which can support new infrastructure and contribute to high production is greatest in areas which are underexplored or not open for petroleum activities.

A substantial exploration potential exists in all regions

Up to 2030, an ever-growing share of production must come from contingent resources in discoveries and fields (already proven) and from undiscovered resources (Figure 2.29).

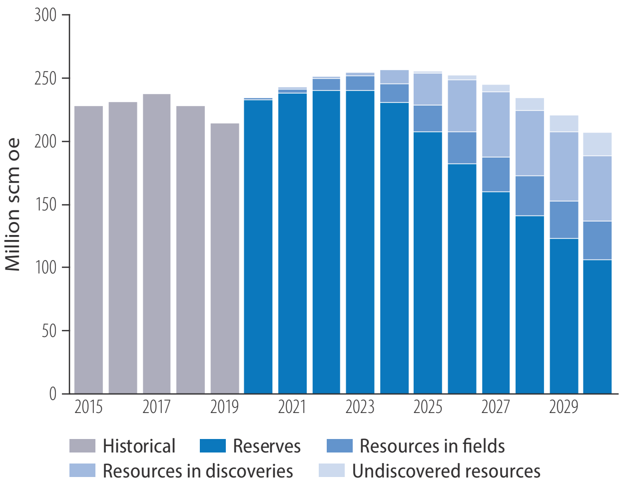


Figure 2.29 Production forecast for the NCS, 2020-30

Regions open for petroleum activities
Undiscovered resources in the areas open for petroleum operations total 685 million scm oe in the North Sea, 470 million in the Norwegian Sea and 1 090 million in the Barents Sea (Figure 2.32). One way of illustrating the size of these resources is to compare the potential with the quantities already proven (Figure 2.30).

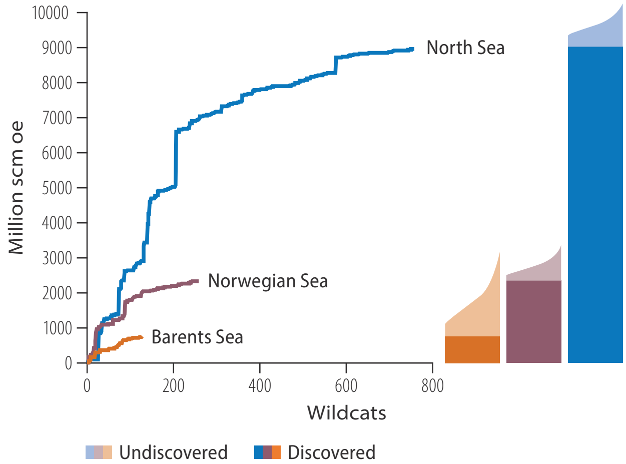


Figure 2.30 Cumulative resources by region *Already proven are shown in dark colours, undiscovered with their uncertainty range in lighter colours.*

Less mature areas
Large structures could be concealed beneath the sub-surface basalt on the Vøring and Møre Marginal Highs on the western edge of the Norwegian Sea (Figure 2.31). Securing good seismic images beneath basalt has proved difficult, and new technology is important for clarifying this potential.

The less mature parts of Barents Sea South still contain large areas with a substantial potential. During recent years, the NPD has evaluated the potential for gas in several younger plays on the western side of this region.

Several discoveries have been made in recent years on the Bjarmeland Platform north of 7324/8-1 (Wisting). The 7324/6-1 (Sputnik) and 7324/3-1 (Intrepid Eagle) discoveries, of oil and gas respectively, show that the Upper Triassic play could have a substantial potential. This is particularly the case at the northern end of the platform. The play extends into Barents Sea North. The NPD's mapping in the latter area also reveals the presence of large carbonate build-ups, or reef structures, which could contain petroleum accumulations. These extend into the northern Bjarmeland Platform.

With a diameter of 45 kilometres, the Mjølnir Impact Crater in the central part of the platform was formed by a meteorite impact. One of the largest unexplored structures in this part of the Barents Sea lies here.

Wells drilled so far in the south-eastern Barents Sea have yielded disappointing results for Jurassic and Triassic plays. The area still has unexplored plays, such as those with carbonate reservoirs. In addition, a potential could exist along the flanks of and in the actual Nordkapp Basin, which has still not been explored. A potential for oil in Carboniferous and Permian plays could exist in areas close to shore on the Finnmark Platform off eastern Finnmark.

Areas not open for petroleum activities

Large areas still exist with a substantial resource potential which are not open for petroleum activities (Figure 2.32). About 40 per cent of the undiscovered resources lie in these areas. Resources yet to be found in the North Sea are primarily located in open areas. Unopened parts of the Norwegian and Barents Seas contain roughly 35 and 55 per cent respectively of their undiscovered resources.

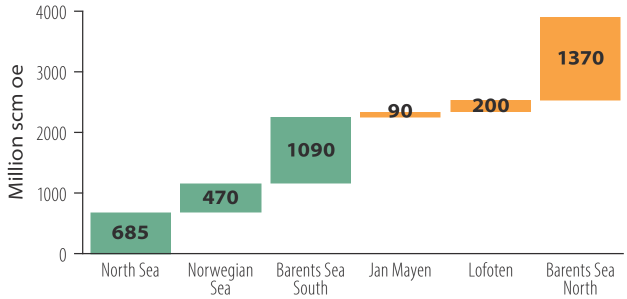


Figure 2.32 Undiscovered resources by opened and unopened areas

Large resource potential in areas not open for petroleum activities

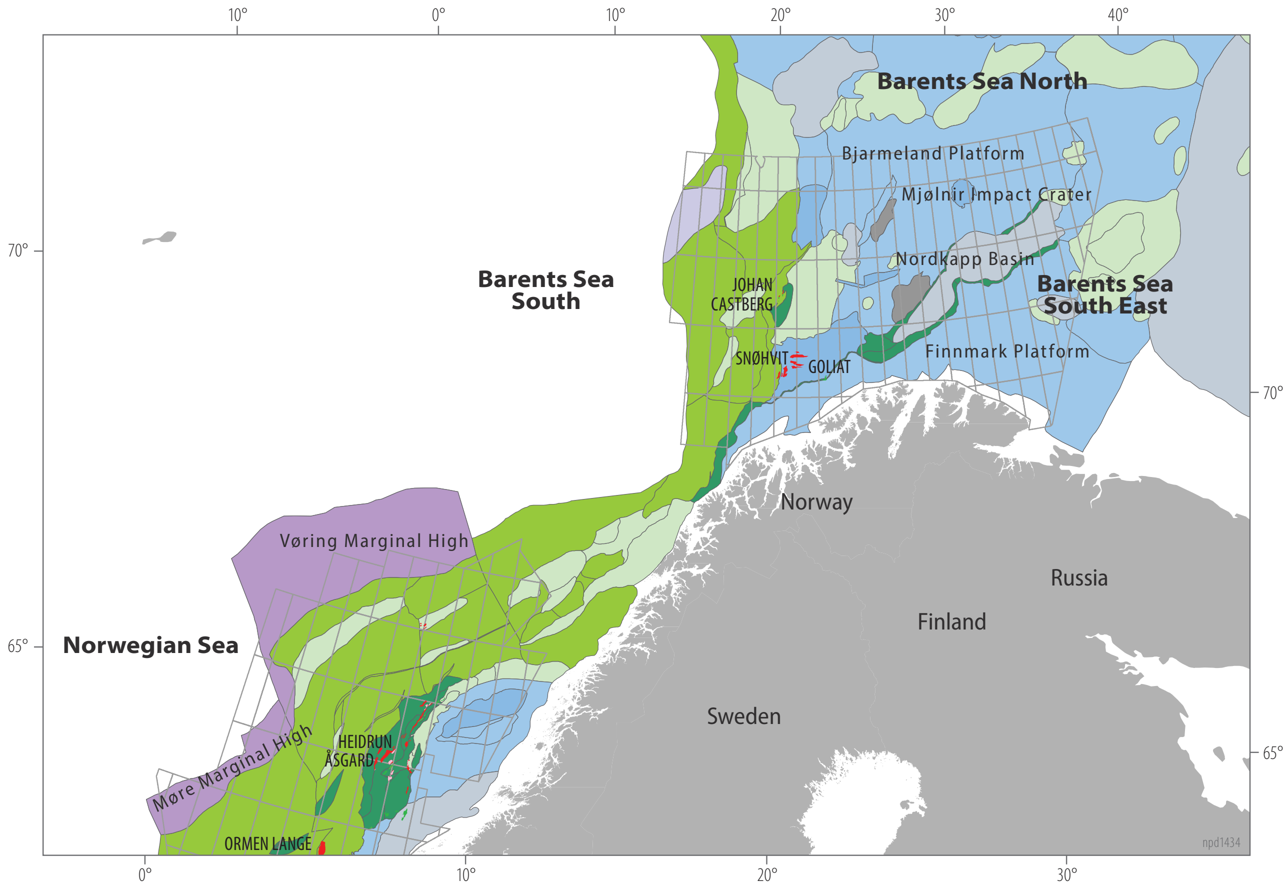


Figure 2.31 Map of the structural elements mentioned

Political decisions are required to open new areas. Only the government is able to acquire information from these parts of the NCS and map them. In 2018-19, the NPD acquired 2D and 3D seismic data and drilled shallow scientific wells in Barents Sea North as part of a systematic multi-year effort to learn more about the northernmost parts of the NCS (Figure 2.33). These data provide important geological information and form a significant part of the basis for estimating resources. Mapping has revealed large structures which may contain oil or gas (Figure 2.34). This is the part of the NCS with the biggest potential petroleum accumulations today (Chapter 3 Undiscovered resources).

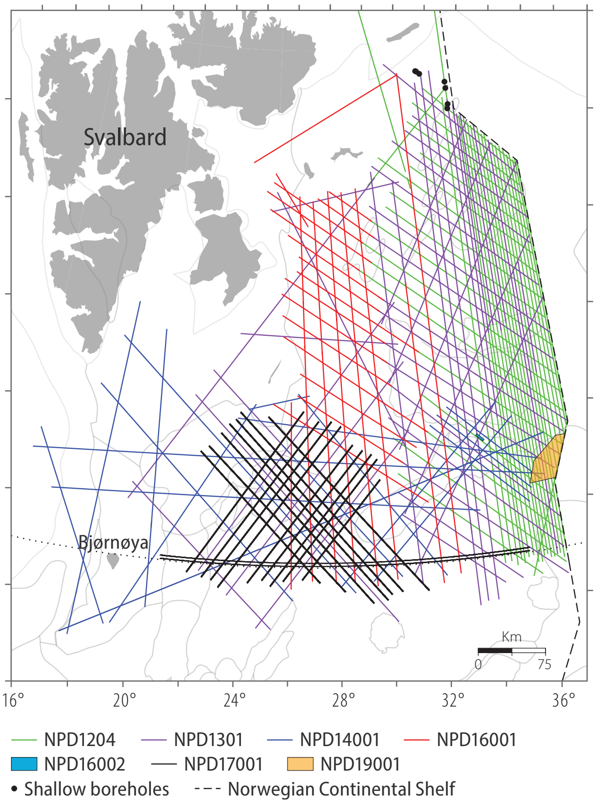


Figure 2.33 NPD data acquisition in Barents Sea North, 2012-19

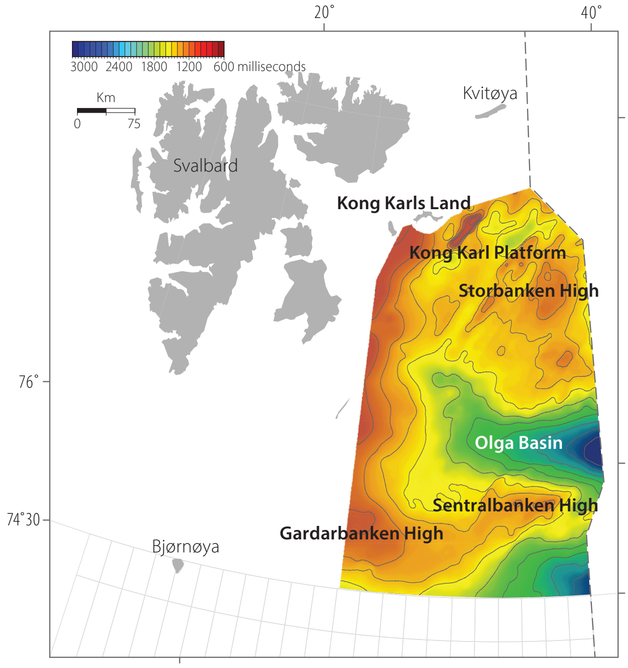


Figure 2.34 Large structures and the extent of mapped areas in Barents Sea North. *Time contour map, top Permian*

Estimates of undiscovered resources in areas not open for petroleum activities are very uncertain owing to limited data coverage and the absence of exploration wells. Continued data acquisition is required in coming years to improve understanding of the petroleum potential and to reduce uncertainty in the estimates. This is important both for good resource management and for protecting national economic interests related to potential cross-border accumulations.

Chapter 3

Undiscovered resources

The NPD's estimate of undiscovered resources shows that large quantities of oil and gas remain to be found in all regions of the NCS. At 3 910 million scm oe, the expectation volume represents almost half the remaining amount. About 40 per cent of the undiscovered resources lie in areas still not open for petroleum activities.

Resource estimate

The estimate for undiscovered resources is updated every other year, most recently by the end of 2019. The number of possible petroleum accumulations (prospects and leads) is an important factor in making this estimate. In recent years, mapped prospects and leads in the NPD's database have risen sharply. This increase is substantial in all parts of the NCS – the North, Norwegian and Barents Seas – and shows that new opportunities for future exploration are constantly being identified. Access to acreage, more and better data, and learning from exploration wells are probably important reasons for this.

Undiscovered resources represent substantial quantities. The expected volume is 3 910 million scm oe, with an uncertainty range of 2 200 (P_{95}) to 6 200 (P_{05}) million scm oe (Figure 3.1). More than 60 per cent of these resources are expected to lie in the Barents Sea, but this is also where the uncertainty in the estimates is highest (Figure 3.2)

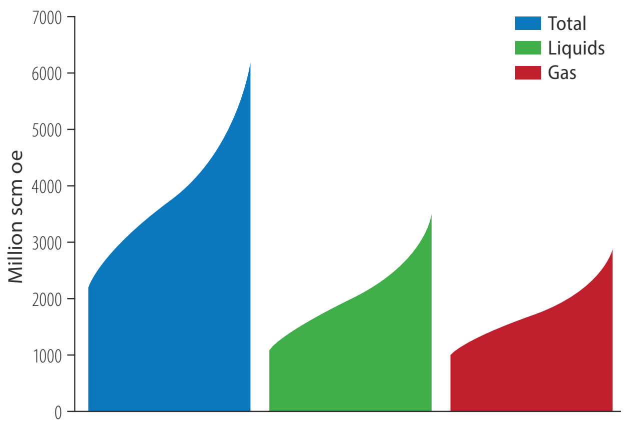


Figure 3.1 Undiscovered resources on the NCS (with uncertainty range)

The undiscovered portion accounts for almost half the remaining resources on the NCS. About 40 per cent lies in areas not open for petroleum activities (Figure 3.3). – off Lofoten, Vesterålen and Senja, around Jan Mayen, and the whole of Barents Sea North. Base data are limited in these areas and uncertainty is thereby greatest there (Figure 3.4).

While these resources are expected for the most part to comprise oil in the North Sea, the proportion of gas should be somewhat higher than oil in the Norwegian and Barents Seas. Barents Sea North, which has still to be opened for petroleum activities, is expected for the most part to contain oil (Figure 3.5). Barents Sea South accounts for the biggest change in the oil-gas distribution since the 2017 update, with the gas estimate now reduced there. The split between oil and gas in the undiscovered resources accords well with the historical discoveries. Liquids account for more than 60 per cent of the discovery volume in the North Sea, about 50 per cent in the Norwegian Sea, and roughly 40 per cent in the Barents Sea.

North Sea

The expected value of undiscovered resources in the North Sea is 685 million scm oe. Although this is the best-explored part of the NCS after more than 55 years of intensive exploration, the NPD expects that as much as 18 per cent of total resources yet to be found lie there (Figure 3.2). This estimate has been reduced somewhat since 2017 because several identified prospects have been drilled. Most discoveries made since 2017 are relatively small, which is typical for a mature petroleum province.

Some of the biggest North Sea oil fields, such as Statfjord, Gullfaks and Oseberg, are in Late Triassic-Middle Jurassic reservoirs. More than 3 300 million scm oe have been proven in this play, but it still contains a substantial number of prospects. Most discoveries are expected to be relatively small (less than five million scm oe), but larger discoveries cannot be excluded.

The NPD also expects that new discoveries will be made in Late Jurassic reservoirs. New prospects are constantly being identified in this play, and a number of small discoveries have recently been made north of the Troll field. Late Jurassic sands form the reservoir in discoveries and fields across large parts of the North Sea, such as the Central Graben, around Ula, the Tampen area and the Horda Platform.

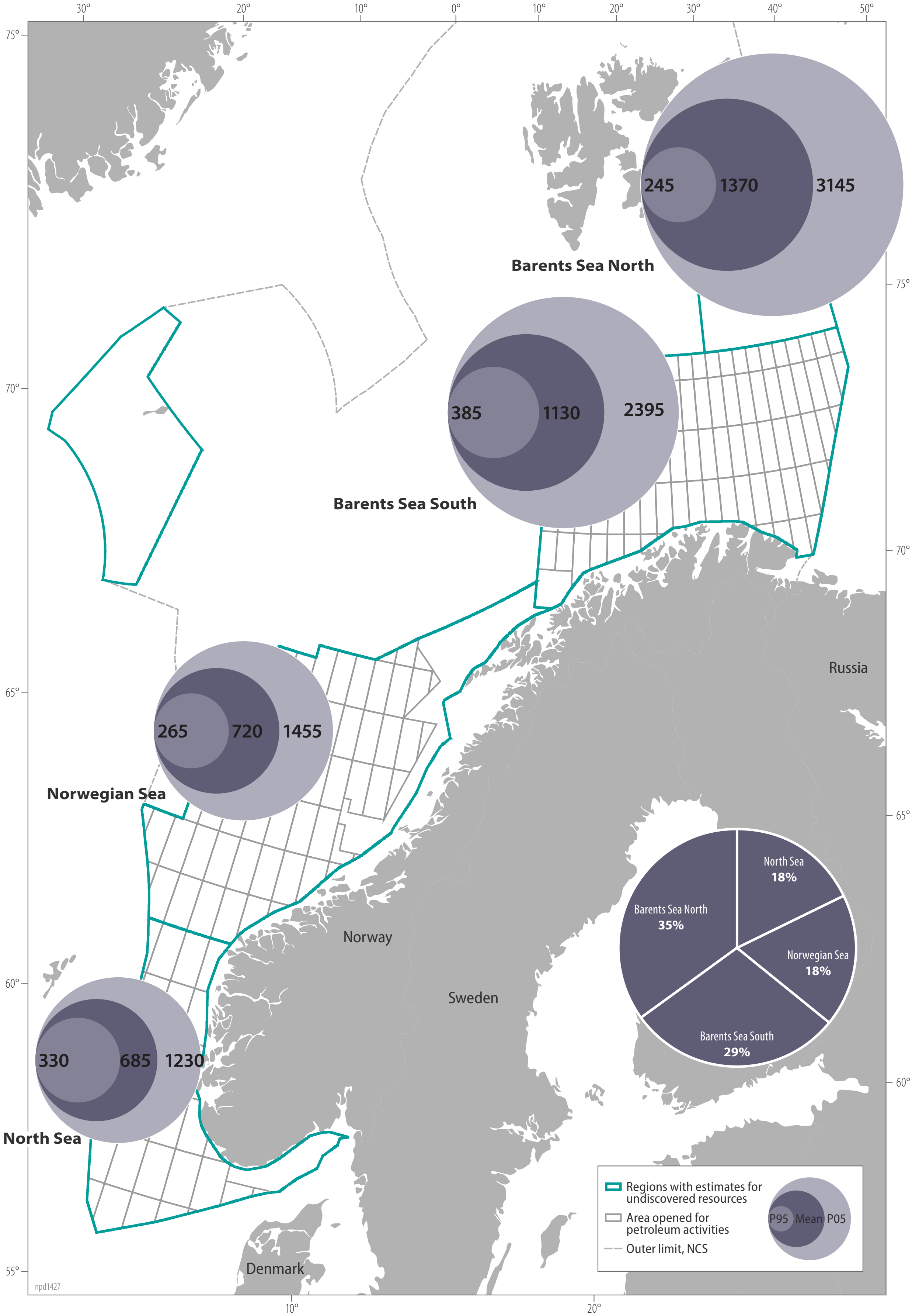


Figure 3.2 Undiscovered resources by region

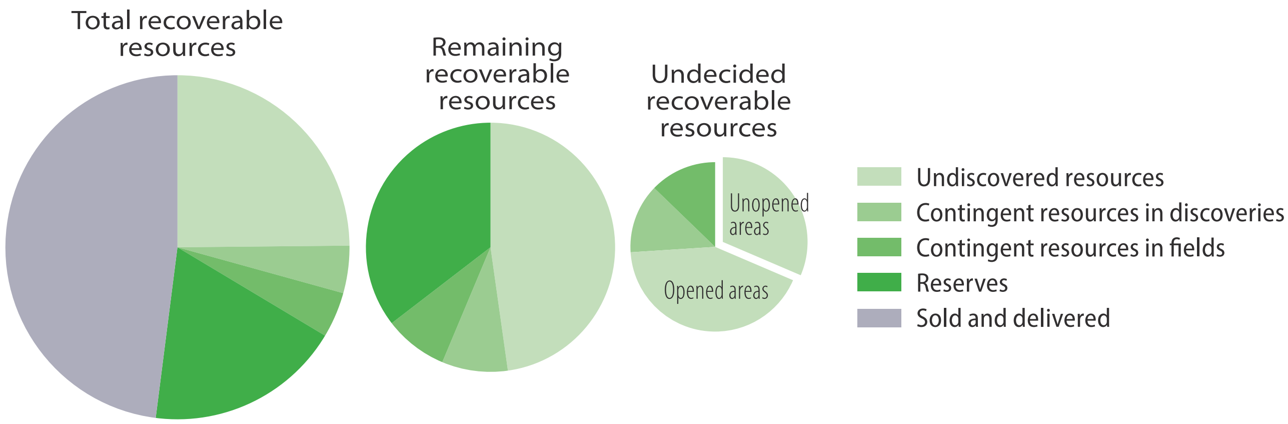


Figure 3.3 Reserves and resources on the NCS

Interesting discoveries have also been made in Palaeogene injectites (fact box 2.3). Examples include 24/9-12 S (Frosk) and 24/9-14 S (Froskelår) near the Bøyla field. Such sands are found in several parts of the North Sea and comprise the main reservoir in the Volund field. They have good reservoir properties, but are often limited in extent and difficult to detect in traditional seismic data. The NPD expects more oil and gas to be found in injectites, since newer seismic techniques provide ever better imaging.

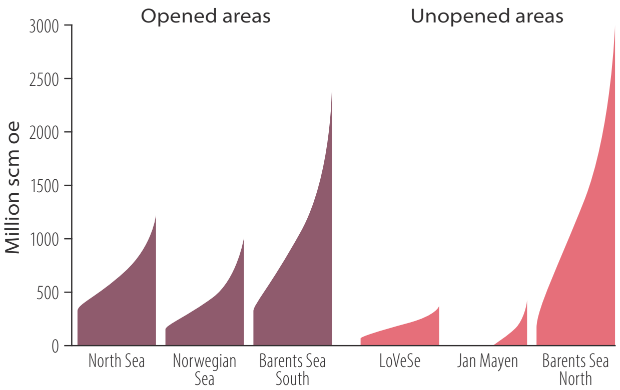


Figure 3.4 Undiscovered resources in opened and unopened areas (with uncertainty range)

Relatively young and shallow sands deposited in the Miocene and Pliocene are found in the North Sea as part of the "Nanna" Member and the Skade and Utsira Formations. That they contain petroleum has long been known, but little systematic exploration has been done. The 25/2-21 (Liatårnet) discovery has made exploration in these reservoirs relevant.

Norwegian Sea

The estimate for expected undiscovered resources in the Norwegian Sea is 720 million scm oe, with gas accounting for about 55 per cent (Figure 3.5).

This figure includes the areas around Jan Mayen and off Lofoten, Vesterålen and Senja which are not open for petroleum activities. Liquids account for almost 75 per cent of the expected value in these parts of the NCS.

Gas accounts for two-thirds of the expected value for the rest of the Norwegian Sea, which has been reduced by 20 million scm oe. That reduction is less than half the size of resources proven by new discoveries in the Norwegian Sea since 2017.

Several discoveries during recent years in Cretaceous sandstones of the Lange Formation have focused greater attention on this stratigraphic level on the Sklinna Ridge and the Halten and Dønna Terraces. Discoveries made in this play since 2017 include 6506/11-10 (Hades) and 6507/3-13 (Black Vulture). Wells have also been drilled in the same play to appraise the 6608/10-17 S (Cape Vulture) oil and gas discovery made in 2017. Although the potential in the play is moderate, additional knowledge and new and better seismic data have prompted a substantial increase in the resource estimate. The possibility of discovering more accumulations of similar size in these areas still exists. Since the play lies in an area with well-developed infrastructure, even small discoveries could have high value.

The 6506/11-10 (Iris) and 6507/2-5 S (Ørn) oil and gas discoveries lie in a play with Early and Middle Jurassic reservoirs. This contains the biggest undiscovered resources in the Norwegian Sea, and has also yielded its largest proven resources – such as 6507/7-2 Heidrun, 6506/12-1 Smørbukk and 6507/11-1 Midgard. Liquids account for about 57 per cent of the proven volume, and were mostly found through many large discoveries early in the exploration phase. The average discovery size has gradually declined, and discoveries in recent years have consisted mostly of gas. The estimate for undiscovered resources has been reduced somewhat from 2017, with gas expected to account for almost 60 per cent.

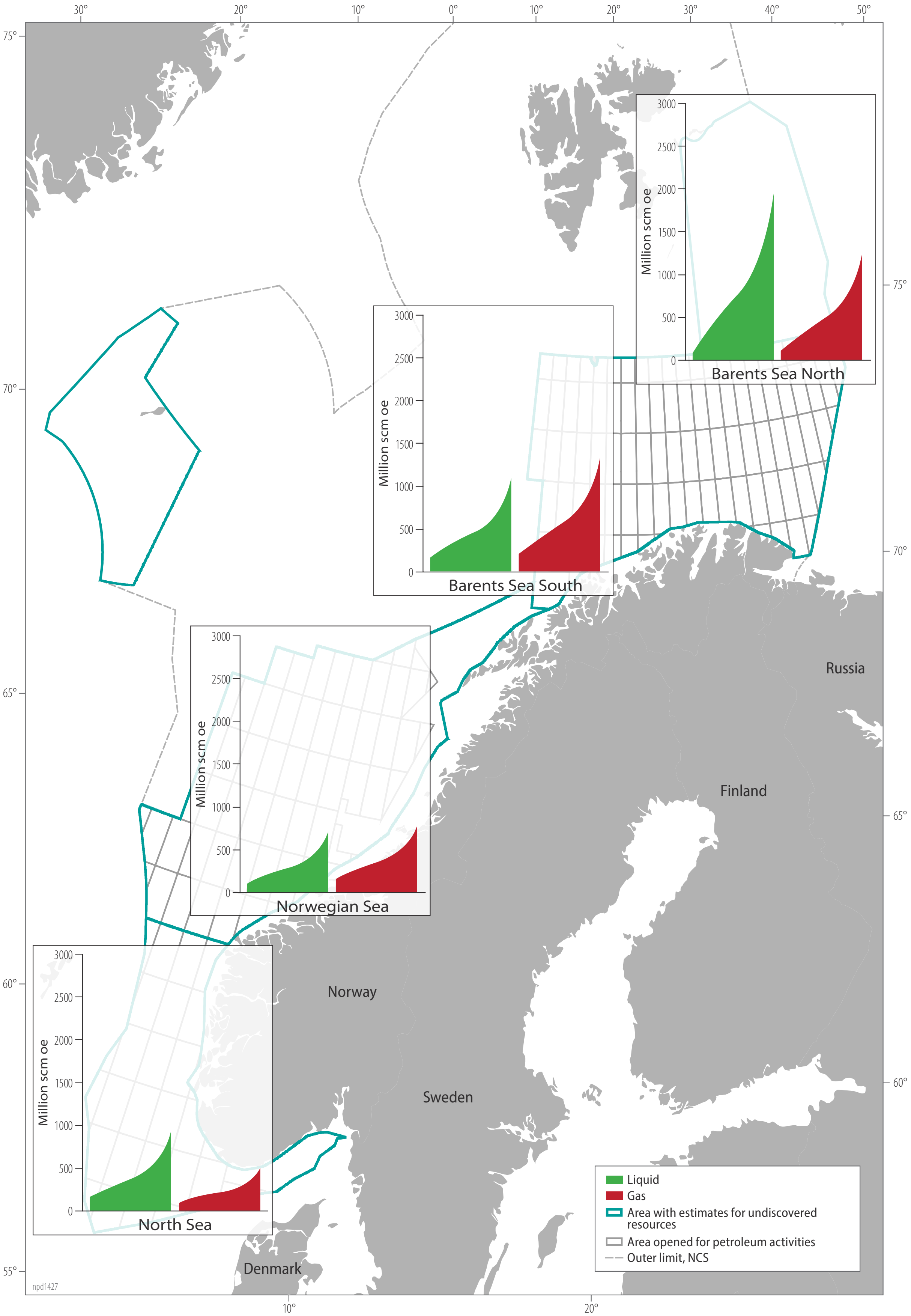


Figure 3.5 Distribution of undiscovered liquids and gas by region

Barents Sea
Although exploration began in the Barents Sea as far back as the early 1980s, and the Hammerfest Basin is now a mature petroleum province, large parts of this region have been relatively little explored. Its large geographical extent is evident from a comparison with areas in the North Sea (Figure 3.6).Several substantial discoveries have been made in various areas, such as 7220/8-1 (Skrugard), 7220/7-1 (Havis), 7220/11-1 (Alta), 7120/1-3 (Gotha) and 7324/8-1 (Wisting). The 7220/8-1 (Skrugard) and 7220/7-1 (Havis) discoveries, together with 7220/7-3 S (Drivis), now make up the Johan Castberg field, which is under development for a planned start-up in 2022.

More than 60 per cent of the expected value of total undiscovered resources on the NCS lies in the Barents Sea and amounts to 2 500 million scm oe. Over half of this lies in areas not open for petroleum activities, mainly in Barents Sea North. Discoveries in the latter area are expected to be bigger than in Barents Sea South. The analyses show that the expected volume of the largest possible oil discoveries has the potential to be among the top 10 on the NCS. However, data in Barents Sea North are limited and no exploration wells have been drilled. All plays are thereby unproven, and uncertainty is large (fact box 3.1).

Forty per cent of the undiscovered resources lie in areas not open for petroleum activities

Barents Sea South
The expected value of undiscovered resources in Barents Sea South has been reduced by 35 million scm oe since 2017. This partly reflects a reduction in the south-eastern part of the area, primarily because of results from wells 7335/3-1 (Korpfjell Deep) and 7132/2-1 and 2 (Gjøkåsen and Gjøkåsen Deep) (Figure 3.6). These encountered water-bearing and poor-quality reservoirs. Expectations have particularly been reduced for Triassic plays (the Kobbe, Klappmyss and Havert Formations).

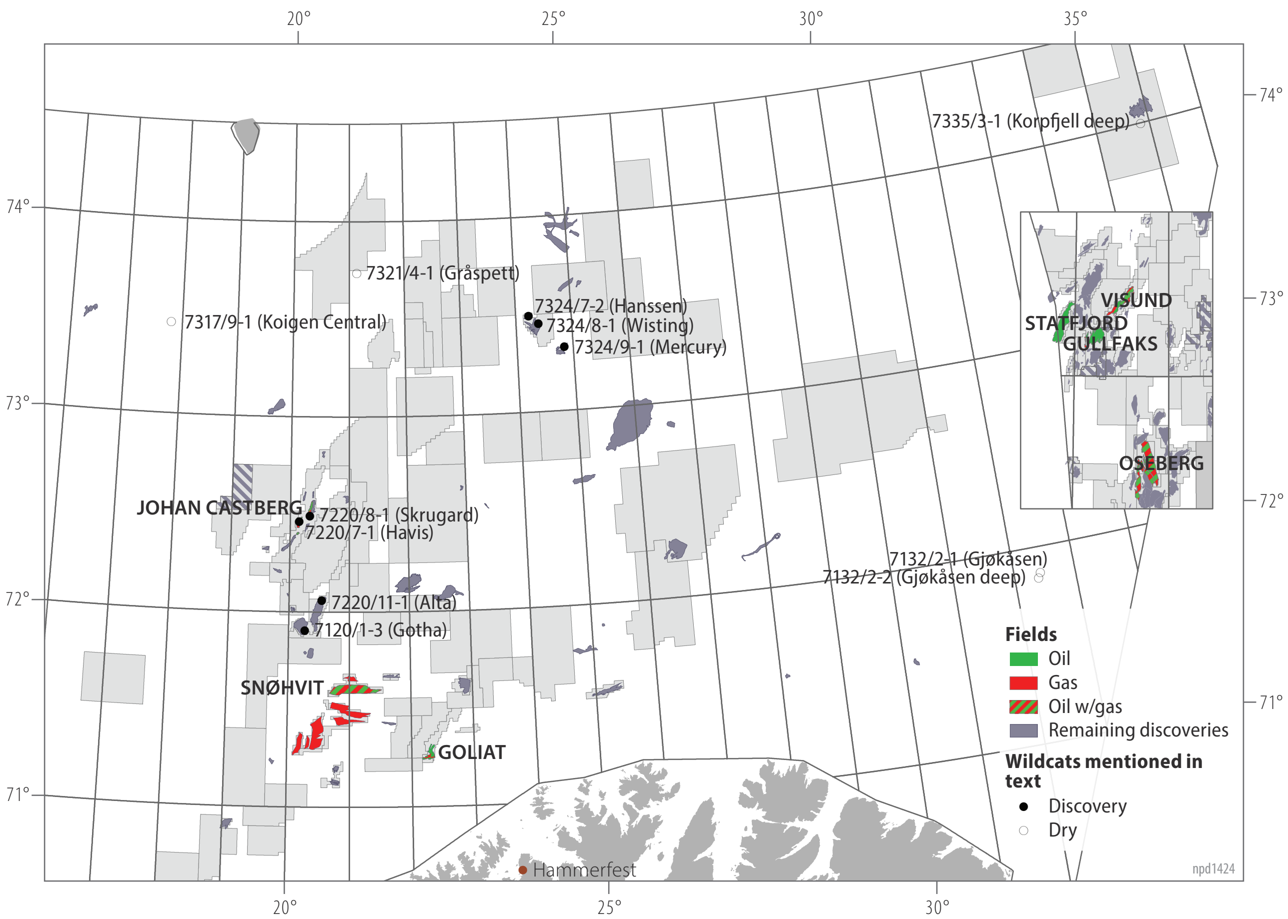


Figure 3.6 Wildcats in the Barents Sea mentioned in the text

On the other hand, the estimate for central parts of Barents Sea South has been upgraded. This moderate rise partly reflects an increase in the number of Jurassic prospects mapped. The volume in some of the newly identified prospects is expected to be larger than predicted in earlier analyses, which contributes to a higher estimate for the associated play.

The play with the largest total resource potential in Barents Sea South includes Jurassic reservoir rocks (the Realgrunnen Sub Group on the Bjarmeland Platform and in the Nordkapp Basin), where the 7324/8-1 (Wisting), 7324/7-2 (Hanssen) and 7324/9-1 (Mercury) discoveries have been made. On the other hand, resources in a corresponding play further west have been downgraded somewhat because of well results such as 7317/9-1 (Koigen Central) and 7321/4-1 (Gråspett).

A new play has been defined in the south-eastern Barents Sea following updated mapping of the Carboniferous-Permian stratigraphic level. This is an analogue of the play involving reservoir rocks in the Gipsdalen Group on the Loppa High and the Finnmark Platform. While the mapping shows many possible petroleum accumulations, the resource potential is very uncertain.

Barents Sea North
The resource estimates for Barents Sea North were presented in 2017 [5], and have not been updated in anticipation of new data. The current expectation value for undiscovered resources in this area is about 1 370 million scm oe. It has not been opened for petroleum operations, the amount of 2D seismic data is limited and there are no exploration wells – only shallow scientific boreholes. The uncertainty in the volume estimates is greatest in this area, since none of the plays have been confirmed by wildcats. Barents Sea North has the biggest resource potential of the unopened areas (Figure 3.4).

Surprises

All data acquired on the NCS can be considered pieces of a jigsaw puzzle. As they are slotted into place, an overall understanding emerges which makes it possible to see the full picture – the whole resource potential on the NCS.

The quantity of data varies between the three regions and declines northwards, since fewer exploration wells have been drilled the further north one goes. In other words, the largest number of pieces has been laid in the North Sea, fewer in the Norwegian Sea and fewest in the Barents Sea. Insight grows as new pieces are added, and uncertainty is reduced.

Each well provides information on which rocks are present, their age, their type and their properties. These data add a real geological content to seismic maps and interpretations. In areas which have been seismically mapped but have few wells, information from each well will be highly significant for predicting geological conditions in the sub-surface. That is characterised as the "geological understanding" of an area (or good insight into what the completed jigsaw looks like).

The value of adding a new piece in less well-known parts of the NCS is high. Drilling information from such an area can be worth a lot if the well has been positioned to provide the maximum possible geological information about the rocks assumed to be the most important. That is particularly true if the information can be extrapolated over all or large parts of the area.

In frontier parts of the NCS, drilling wells can consequently produce positive surprises because base knowledge is smaller than in mature areas. When Draugen was discovered in its day, this field lay in a frontier area where resources were expected in the Fangst Group. Instead, the well encountered extremely good oil-bearing sandstones in the overlying Viking Group. These have subsequently been designated the Rogn Formation.

Exploration will always produce surprises

The 7324/8-1 (Wisting) well yielded a different type of surprise. Oil encountered here in a very shallow reservoir had experienced very little of the biodegradation expected at this depth. Bacteria will normally consume the light components in the crude to leave only heavy components, making the oil viscous and difficult or impossible to produce with conventional methods. Including 7324/7-2 (Hanssen), this discovery contains about 75 million scm oe, and is the largest oil accumulation found in the Barents Sea so far.

Well surprises resulting in unexpected resources are not confined to frontier areas with little data. When discovered in 1978, 15/5-1 (Dagny) – later to become the Gina Krog field –was initially assumed to be a pure gas discovery. About 25 years later, mapping and interpretation utilising much better data than were originally available, along with continuous 3D seismic surveying and data from surrounding wells, led to the definition of the Ermintrude prospect. Drilling 15/6-9 S (Ermintrude) in 2007 proved oil beneath gas/condensate. This led to a reassessment of the whole area and the idea that an oil column might lie beneath the gas in Dagny. Appraisal of the latter in 2008-11 identified a substantial volume of oil beneath the whole Dagny-Ermintrude structure.

The discovery of the unexpectedly large Johan Sverdrup field on the southern Utsira High also demonstrates that both knowledge and understanding can be inadequate, and that surprises are still possible in mature areas. This field lies in that part of the NCS where the very first production licence (PL 001) was awarded and Norway's second exploration well was drilled in 1967. Large oil discoveries to the north and south confirmed functioning petroleum systems in the area. It was to take 40 years of exploration before substantial quantities of petroleum were proven in Utsira High South. Utilising new technology, 3D seismic surveying, existing well data and substantially greater knowledge than four decades earlier allowed new prospects to be defined. Insight into the petroleum system on Utsira High South improved in 2007 with the discovery of 16/1-8 (Luno), now known as the Edvard Grieg field. Geological understanding was turned on its head and existing theories challenged. The question was how petroleum could migrate from west to east on Utsira High South. Johan Sverdrup was proven by 16/2-6 (Avaldsnes) in 2010 and then by 16/2-8 (Aldous) in 2011, which supported the theory that petroleum can migrate through fractured and chemically weathered basement rock. After 30 appraisal wells, this discovery ranks as Norway's third largest oil field. Big surprises can still occur even after 40 years of exploration.

Being aware that unexpected outcomes may occur is in itself knowledge

The examples above show that surprises will always occur in exploration. They are normally termed "serendipitous" by the industry, meaning a happy chance.

But many people believe that serendipity is not a matter of good luck. Instead, it reflects experience and insights acquired over a long time, combined with an open and curious mindset.

Taking account of the unexpected when estimating undiscovered resources is difficult. Surprisingly large discoveries such as Johan Sverdrup will seldom or never be included in the uncertainty range for resource estimates in mature areas. New digital methods, such as machine and deep learning, could yield several surprises in coming years. Being aware that unexpected outcomes may occur is in itself knowledge. But taking this into account in resource classification and estimation is demanding. An attempt is presented in Figure 3.7 [6].

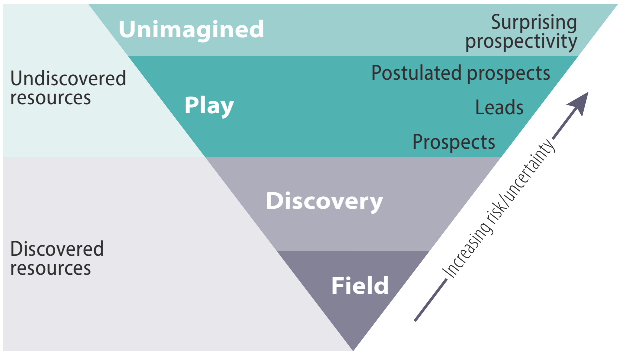


Figure 3.7 Alternative resource classification *Modified from Hall (2011)*

The NPD's resource estimate is based on existing knowledge. In estimating undiscovered resources, its attention is on the uncertainty range, with a downside and an upside which represent the whole span. But it can be challenging to extend this far enough, given that the analyses are to rest on "known" knowledge and data. The NPD has made use of scenarios on several occasions to enlarge the possibility space when base knowledge is limited and uncertain – most recently in assessing the resource base in Barents Sea North (fact box 3.1).

Fact box 3.1 A high resource outcome

To illustrate the possible effect of proving a play, the NPD has described a scenario X [5]. This assumes that an exploration well makes a discovery confirming the Triassic play, which has the highest resource potential. It also assumes that results from this well increases expectations for the gross rock volume in this play. A discovery will enhance the probability for source rocks in other Late Triassic and Jurassic plays in the area.

The scenario illustrates a possible outcome at the extreme edge of the resource distribution. This should be included in the assessment of the possible consequences of opening the areas for exploration. As Figure 3.8 shows, the scenario makes a big change to the resource distribution. The expected value for total recoverable resources increases markedly, and the division between liquids and gas changes correspondingly.

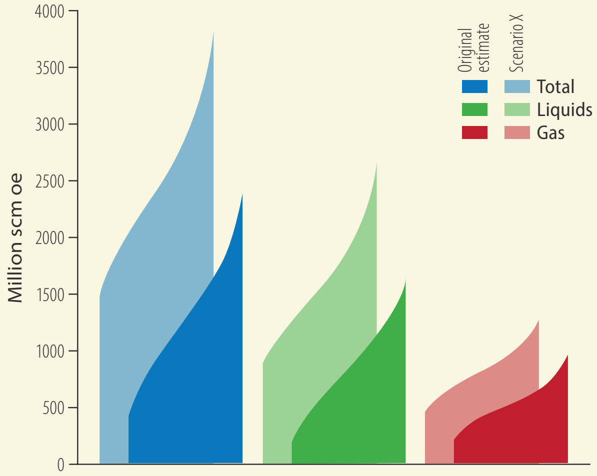


Figure 3.8 New resource distribution with scenario X
Original estimate of the resource distribution in Barents Sea North in dark colours. New estimate of the resource distribution in scenario X in lighter colours.

Estimating undiscovered resources

Estimating undiscovered resources
Mapping and geological evaluation permit plays to be defined (fact box 3.2). In this way, possible petroleum accumulations can be identified.

Undiscovered resources are petroleum which has not been proven by drilling, but which is expected to be recoverable from possible accumulations. The resource classification system is divided between discovered and undiscovered resources (Figure 3.9).

The NPD's estimate of undiscovered resources is based on analyses of more than 70 plays, drawing on large quantities of data from wells, information from licensing-round applications, data

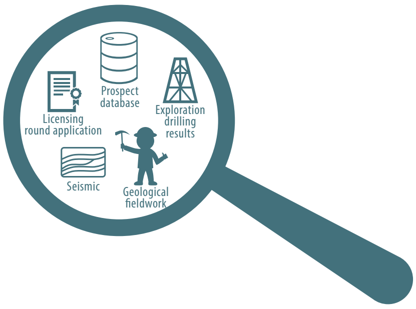


Figure 3.10 Base data for estimating resources

acquired through the NPD's own field work, and seismic mapping (Figure 3.10).These plays are analysed separately, and interdependencies between relevant ones are then incorporated before estimated resources are summed area by area to arrive at a total figure for the North, Norwegian and Barents (South and North) Seas.

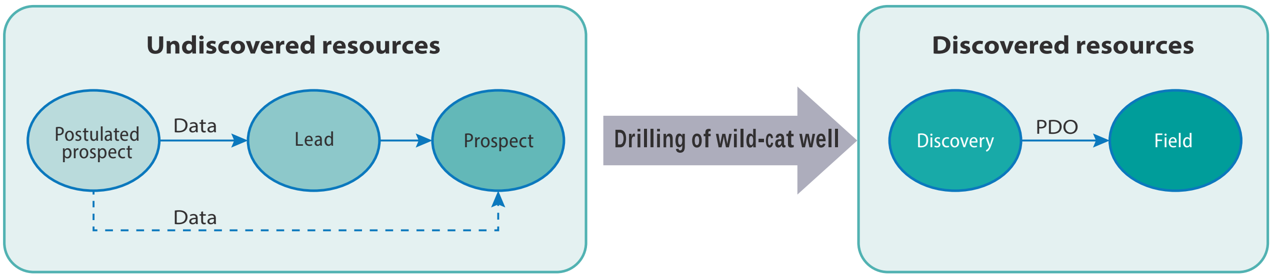


Figure 3.9 Undiscovered versus discovered resources

Fact box 3.2 What is a play?

A play is a geographically delineated area where several geological factors interact so that producible petroleum can be proven (Figure 3.11). Production does not have to be commercial. These factors are as follows.

– A porous reservoir rock, where petroleum can accumulate.

– A trap, which is a tight rock or geological structure encasing the reservoir rock so that petroleum is retained and accumulated.

– A source rock, such as shale, limestone or coal, containing organic material which can be converted to petroleum. This rock must be mature – in other words, temperature and pressure must be such that petroleum actually forms – and a migration route must exist so that petroleum can move from source to reservoir rock.

- A sedimentary basin, which is an area of subsidence in the Earth's crust where thick accumulations have accumulated over geological periods. It may contain several plays.

Figure 3.11 Simplified diagram of plays

The play probability is the likelihood that producible petroleum can be proven. A play is confirmed when such petroleum is proven.

Prospects and leads

Among the most important parameters in the analyses are the number of prospects and leads (possible petroleum accumulations), volumes and the probability of success (fact box 3.3).

The NPD obtains information about mapped prospects through applications for licensing rounds and from documentation in active production licences. Another data source is its own mapping. This information includes where the prospects have been identified (geographical data), age and reservoir type, how much and what types of hydrocarbons they may contain (volume and hydrocarbon phase) and the probability of success. All details about mapped prospects and leads are reviewed and assessed by the NPD before being stored in a database which currently contains information from about 2 500 possible petroleum accumulations. In addition to an assessment of the identified prospectivity, the NPD produces an estimate of postulated prospectivity for each play.

Prospects which have been drilled are categorised as dry or a discovery, and the possible discovery volume is registered. That provides the basis for statistics on discovery success and volume in the various plays. These figures provide important information for use in the analyses. On several occasions, the NPD has analysed prospect volume (pre-drilling) compared with discovery volume, and presented the results [7]. The latter show a tendency to overestimate prospect volumes, while the average estimated probability of success appears to be in line with the average discovery rate.

Fact box 3.3 Prospects and leads

A prospect is a possible petroleum deposit where no drilling has taken place but which has been mapped and a volume calculated. The estimated likelihood of proving oil and/or gas in a given prospect is called the probability of success.

A lead is a possible petroleum trap where available data coverage and quality are inadequate for mapping or delimiting the rock volume.

A postulated prospect (Figure 3.9) is one which could be mapped in the future (but not identified at the moment because, for example, the data are inadequate).

Well results
The NPD also reviews company data reported for discoveries and dry wells. Understanding why a well is dry is important. It could be because the well failed to encounter the reservoir, for example, or because the reservoir quality was poor. Other causes could be the failure of petroleum to migrate into the trap or the absence of a trap (fact box 3.3). The results of this work are used to assess which elements are the most critical (pose the biggest geological risk) in the various plays.

Exploration is learning ...
Although the quantity of data underpinning the analyses is substantial, the estimates will always contain an element of uncertainty. Only drilling wells can prove or disprove discoveries and their size. Uncertainty is lower in an area where many wells have been drilled, because knowledge there has increased through large quantities of well data and geological analyses.

... about complex relationships
A prospect is included in undiscovered resources with risk-weighted petroleum quantities – in other words, the expected (unrisked) volume of a discovery multiplied by the probability of success. A prospect with an expected volume of 100 million scm oe and a 10 per cent probability of success will contribute 10 million scm oe to resources in the play. The outcome of drilling a prospect could influence estimates for undiscovered resources in this play by removing it, either as a discovery or as a dry well.

The result of a well is always significant. If a discovery is made, was it larger or smaller than expected? How did the reservoir and liquid properties compare with expectations? Was the hydrocarbon phase as expected? For its part, a dry well can reveal whether reservoir rocks are present and, if so, what properties they have. Traces of petroleum in the reservoir or the rest of the well could also be significant. A dry well can also establish the presence of a good cap rock over the expected reservoir level, or organically rich rocks which could have functioned as a source for other prospects in the play (fact box 3.4).

Fact box 3.4 Analysing dry exploration wells

Dry well analyses can help to improve company risk estimates by increasing their understanding of the failure to find hydrocarbons. Many companies base these analyses on their own information, but most – with some exceptions – have relatively limited base data. The NPD regularly carries out such analyses utilising data reported to it by the operators for all exploration wells on the NCS.

Base data

Pursuant to section 30 of the Resource Management Regulations on final reporting of geotechnical and reservoir well data, the operators are required to report prognoses for and results of wildcats in a final report submitted no later than six months after drilling has been completed.

The NPD conducted a dry well analysis in 2017 covering wells drilled in 2007-16, with the results published in its 2018 resource report on exploration. This analysis was updated in 2019 and now also includes well results for 2016-19 in addition to the probability of success for all prospects drilled. Its results were presented at the Force conference on petroleum charge and migration in 2019 [8].

More than 300 exploration targets are included in the analysis. These break down between 165 in the North Sea, 70 in the Norwegian Sea and 80 in the Barents Sea. A far larger number of data points than in the other regions make results for the North Sea more conclusive. A single well can test the prospectivity of more than one stratigraphic level. Jurassic rocks could be the primary exploration target, for example, with Triassic sediments as a secondary one.

In its analysis, the NPD has divided the geological risk factors into three main groups – reservoir, source and trap. All must be present for a petroleum deposit to exist. Reservoir covers both presence and quality, source includes presence as well as maturation and migration, while trap embraces closure as well as top and lateral sealing (Figure 3.12). The analysis defines the factor with the lowest probability as the main pre-drilling risk. In those cases where two factors both have the lowest probability, they are weighted equally in the analysis.

Results

In the North Sea, the reasons for dry exploration targets are found to be first and foremost the absence of source (47 per cent), followed by the lack of trap (29 per cent) or reservoir (24 per cent) Figure 3.13. These causes correspond partly with drilling forecasts. The results show that the proportion of dry targets which relate to source is higher than expected. At the same time, trap is found to function more often than predicted. The large proportion of dry targets related to source is rather surprising in such a well-explored part of the NCS as the North Sea, with its world-class Kimmeridge Clay source rock. This is known on the Norwegian side as the Draupne Formation in the northern North Sea sector and the Mandal Formation in the Central Graben. Lack of migration has been cited as a possible explanation for many of the dry targets in operator reporting to the NPD.

The same trend is found in the Norwegian Sea. Source functions less often than predicted and trap more often (Figure 3.14). As the figure shows, source was the main risk in 22 per cent of targets while the results indicate that source is found to fail in more than 40 per cent.

Trap is a clear pre-drilling risk in the Barents Sea (Figure 3.15), and its absence is specified as the main risk for 64 per cent of targets. That is probably attributable to the uplift and erosion history of the area, which creates a high risk with regard to petroleum retention. However, post-drilling results show that the proportion of dry targets almost as frequently reflects the absence of reservoir and source.

The analyses indicate that source is underestimated as a pre-drilling risk in all three regions. Better understanding of source and migration, including in well-explored parts of the NCS, could contribute to increased exploration success.

Reservoir	Presence of reservoir Quality of reservoir
Charge	Presence of source Maturity of source Migration of HC
Trap	Presence of closure Presence of top seal Presence of lateral seal

Figure 3.12 Conditions for making a discovery

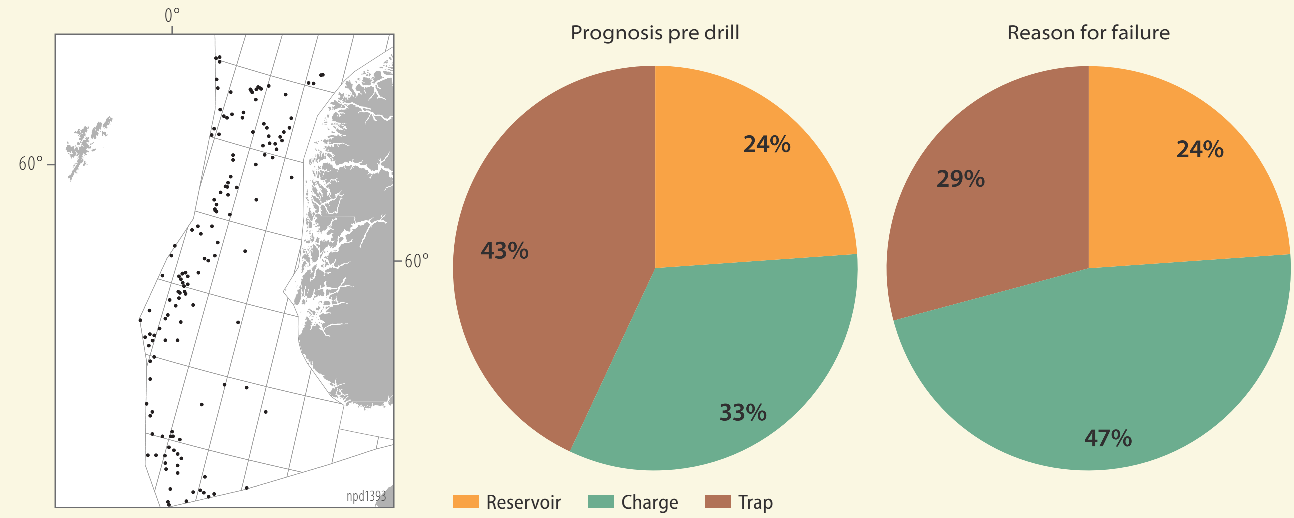


Figure 3.13 Dry exploration targets in the North Sea, 2007-19

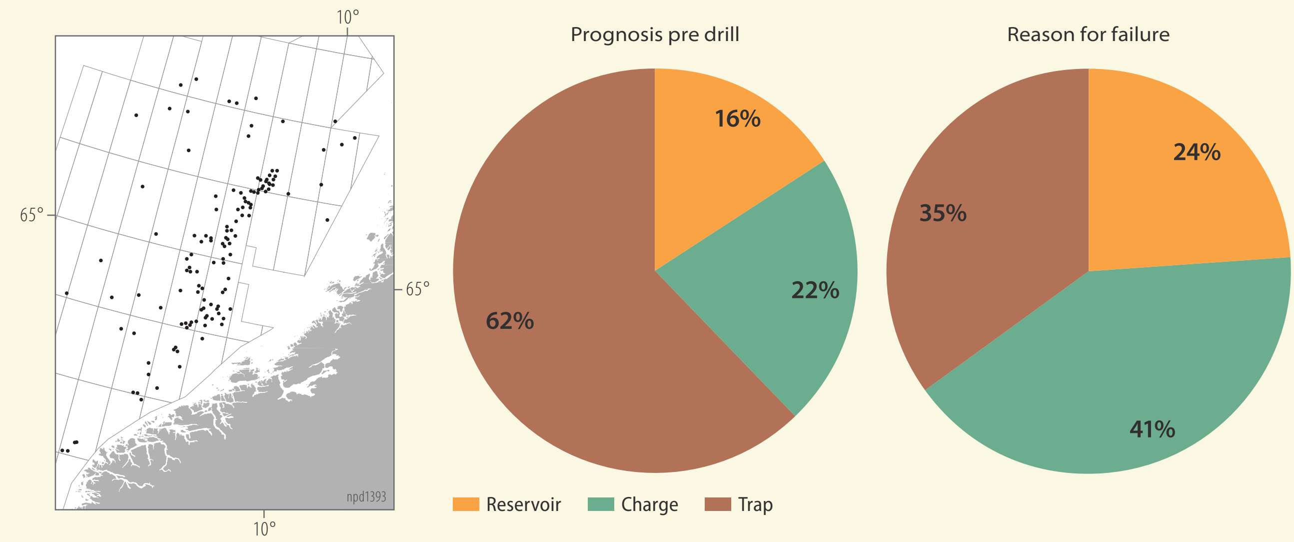


Figure 3.14 Dry exploration targets in the Norwegian Sea, 2007-19

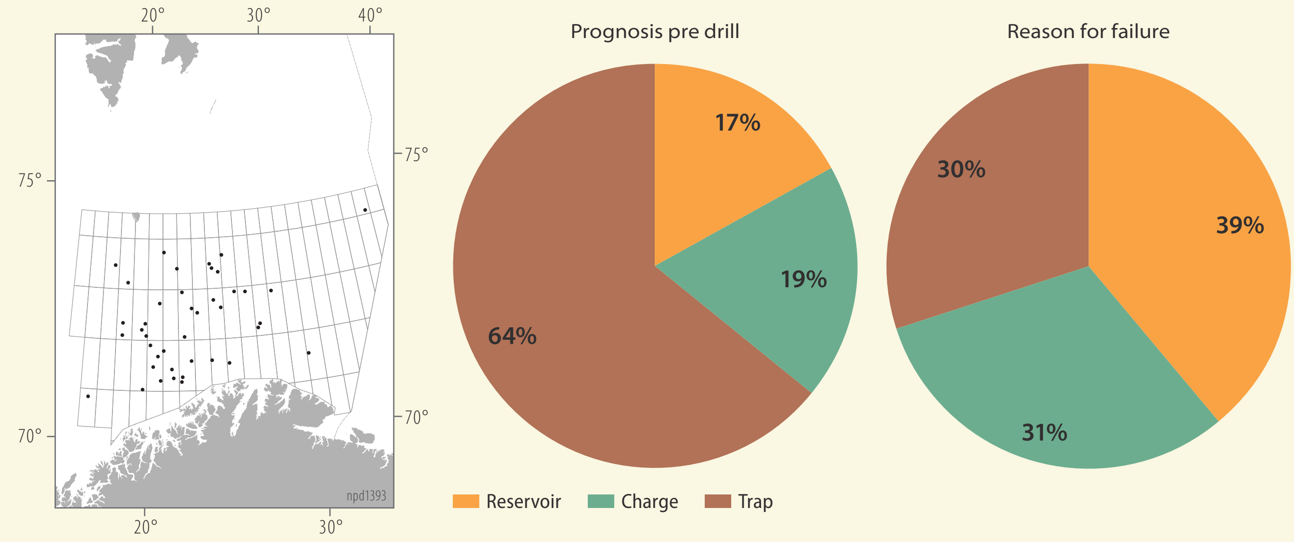


Figure 3.15 Dry exploration targets in the Barents Sea, 2007-19

A discovery will generally have a positive impact on resource estimates. Should it be much smaller than expected, on the other hand, and if the reasons for this can also be extrapolated to more prospects in the play, the effect could be negative. In general, a dry well will affect the estimates negatively but the information it provides can have a positive effect in some cases. The reservoir could be larger or better than expected, for example, or yielded clear traces of hydrocarbons. That might increase the probability of success for other prospects. A dry well in a prospect with a low probability of success will generally have a smaller impact on the total estimate than one in a prospect where the probability was high.

How much the estimates are altered by well results depends both on how much the latter deviate from expectations and on how much data was available before drilling. The estimates will not usually be affected as much in a mature play with many wells and discoveries as they are in a play without discoveries or wells.

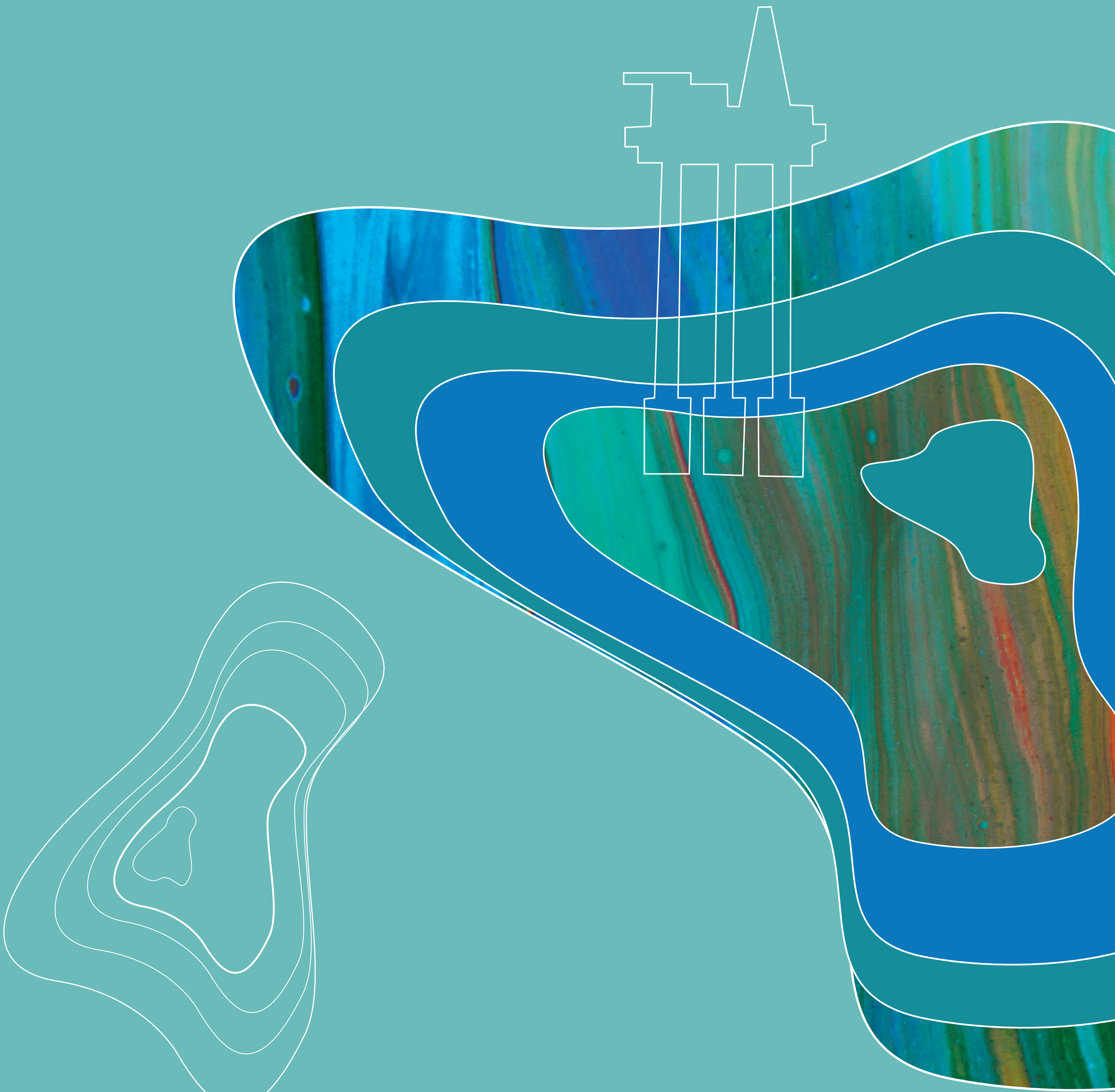
The term "yet to find" is often used for undiscovered resources, but this can easily be interpreted to mean an estimate of what will be discovered rather than the quantity which might be found (if exploration takes place). The NPD's estimate of undiscovered resources covers oil and gas expected to be provable and producible with existing knowledge and technology. It makes no assumptions about commerciality or exploration activity.

Fact box 3.5 Uncertainty in the resource estimate

Uncertainty expresses the range of possible outcomes or results. This can be described in many ways, most often with the aid of high or low estimates. The NPD estimates, for example, that 2 200-6 200 million scm oe remain to be identified on the NCS. Uncertainty is calculated using Monte Carlo simulations (a statistical method), with high and low uncertainties described using statistical concepts. Where undiscovered resources are concerned, the NPD generally uses P_{95} for the low estimate. This means that, given the assumptions applied in the analysis, the probability of a result equal to or larger than the P_{95} value is 95 per cent. P_{05} is used for the high estimate, which means a five per cent probability that the result will be equal to or larger than the P_{05} value. The expectation value is the average value. This is generally defined as the arithmetic mean of all the outcomes in the statistical distribution. It is much used, and has the property that the expectation value for various distributions is the sum of the expectations.

Chapter 4

Significance of exploration



Exploration for oil and gas has provided huge value for Norwegian society over the past 20 years. All areas of the NCS make important contributions to overall value creation. New discoveries provide the basis for continued activity in the petroleum industry, create big spin-offs for the rest of society, and will be extremely important for future value creation.

The basis for discovering and maturing oil and gas resources is laid through technical sub-surface work, primarily in the geosciences. Continuous progress in this discipline is supplemented by new technologies and work processes. Technical studies include understanding where and how oil and gas form, move, accumulate in traps and become retained in sub-surface reservoirs. A lengthy and exacting process may underlie a decision to drill a wildcat. If that makes and confirms a commercial discovery, this is developed with a production facility. When the field comes on stream, it generates the revenues which will cover the costs incurred, the capital spending made and the further investment required.

The analyses presented in this chapter show that investment in petroleum exploration on the NCS has been highly profitable and provided huge value for Norwegian society. In addition to oil and gas revenues, exploration lays the basis for employment and spin-offs in the rest of the national economy.

Oil and gas exploration has provided huge value for Norwegian society

At the same time, the analyses indicate that exploration over the past 20 years has contributed to keeping production high. New discoveries have helped to ensure that existing fields can remain on stream. Without new resources, unit costs on fields would rise and profitability decline as output fell. That makes exploration a precondition for field development and petroleum production. Maintaining output and value creation in the long term depends on a high and continuous level of exploration.

Profitability of exploration

The NPD has calculated the profitability of exploring the NCS from 2000 to 2019. These calculations present direct economic value creation from exploration during the period. This activity has been more profitable over the past 10 years than in the previous decade, and all regions of the NCS have made important contributions to overall value creation. Large discoveries have been important for establishing infrastructure. Exploiting cost-effective existing facilities also permits profitable development of small discoveries. In addition, the NPD's calculations show that, even if oil prices remain low in coming years, it has been profitable to explore for oil and gas.

Exploration has been more profitable over the past 10 years than in the previous decade

Exploration activity and costs in 2000-19
Exploration on the NCS over the past 20 years has been characterised by big fluctuations (figure 4.1). Eight hundred exploration wells were spudded in 2000-19, including 550 wildcats. Over the same period, some NOK 400 billion (2020 value) was invested in exploration (Figure 4.2). That gives an annual average of 40 wells and NOK 20 billion in investment. The oil price has averaged about USD 65 per barrel (bbl) over the past 20 years, but with substantial fluctuations.

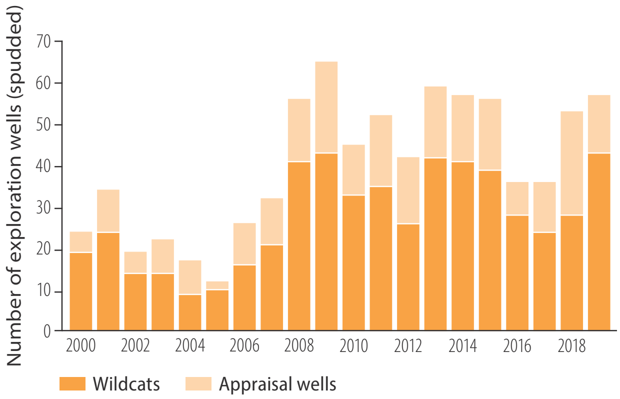


Figure 4.1 Wildcats and appraisal wells, 2000-19

Measured by wells spudded, exploration declined from the end of the 1990s and was at its lowest ebb in 2005 with 12 wells. Targeted government measures and rising oil prices led to a substantial upturn, and 65 exploration wells were drilled in 2009 (Figure 4.1). Sustained high oil prices and levels of activity contributed to a considerable rise in costs. Measures were therefore initiated by the companies to reduce these, enhance operating efficiency and limit capital investment. The oil price slump in 2014 reinforced the need for cost cuts and capital rationalisation, which led to a sharp drop in exploration investment in 2016 and 2017. Activity recovered again in the past two years in line with rising oil prices.

Exploration costs comprise spending incurred from the date a production licence is awarded until a possible discovery is developed, and covers seismic surveying, exploration wells, field evaluation and administration.

Company-related exploration expenditure, primarily in the pre-licence phase, is excluded. Drilling (figure 4.1) represents the most important single element in overall exploration spending. Drilling costs totalled almost NOK 280 billion in 2000-19, comprising about 70 per cent of the total amount spent (Figure 4.2).

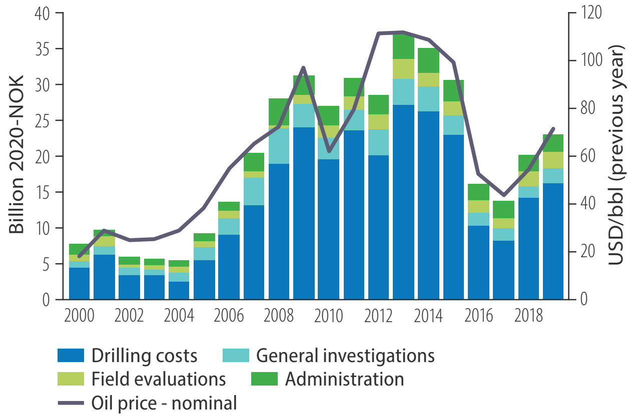


Figure 4.2 Exploration costs and oil price developments, 2000-19

Fact box 4.1 Drilling costs
Drilling costs are divided into positioning, transport, exploration drilling and testing, and drilling vessels (Figure 4.3).

Regional positioning accounts for less than two per cent of total drilling costs, and comprises spending on acquiring and processing geophysical data in order to determine the well location. Representing about eight per cent, transport covers vessel, helicopter and aircraft expenses. Exploration drilling and testing account for more than 50 per cent of the total. This includes planning, drilling, downhole testing and data acquisition, test production, completion and plugging of the well, and other technical services such as rig positioning, inspections, weather forecasting, navigation, readying and clearing up, and cement and mud services. In addition come consumables related to these components. The drilling facility accounts for just under 40 per cent of costs, including hire and other chartering expenses.

Rig hire amounted to more than NOK 90 billion (2020 value) in 2000-19, or about a third of total drilling costs in this period and a quarter of overall exploration spending. Substantial efficiency gains during recent years have helped to reduce drilling costs. An NPD analysis of drilling efficiency over the past decade (2010-19) shows that the cost per exploration well has declined (Figure 4.4) and metres drilled per drilling day are up (Figure 4.5).

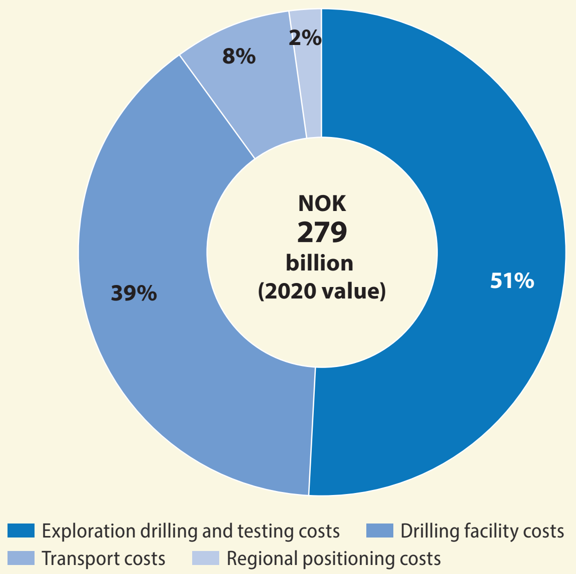


Figure 4.3 Drilling costs by category, 2000-19

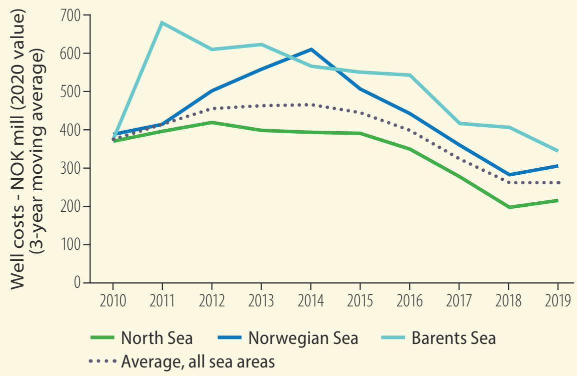


Figure 4.4 Drilling costs per exploration well (well costs) by region, 2010-19

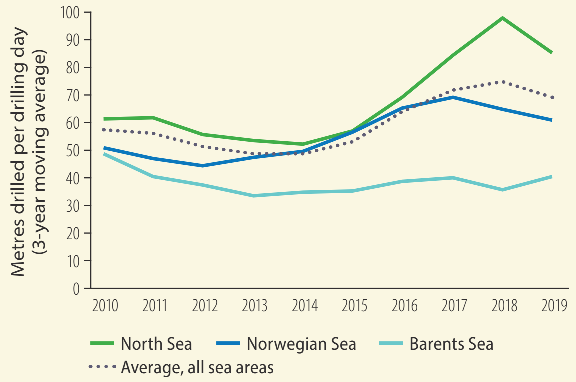


Figure 4.5 Metres drilled per drilling day for exploration wells by region, 2010-19

Methodology and assumptions

The profitability of exploration is defined as calculated revenues from discoveries in the period less all expenses, including exploration and cessation costs (Figure 4.6). Its costs include both successful wells and those which fail to prove resources. Revenue and cost flows are discounted to the same year. All the profitability analyses utilise pre-tax calculations. Indirect effects on or spin-offs to the rest of the economy are not included.

Future oil prices are assumed to rise gradually to USD 50/bbl in 2030 [9]. This is a low estimate compared with earlier profitability calculations and given the average oil price (about USD 65/bbl) over the past 20 years. NOK 2.70 per scm is assumed for the future gas price [9].

The profitability analysis has also been tested with lower and higher prices and various estimates for cost trends. Historical prices for oil, gas and natural gas liquids (NGL) are used for the pre-2020 period. Real discount rates of four and seven per cent have been applied.

Profitability estimates are uncertain because of uncertainties over price as well as with estimated resources and costs. A number of discoveries in the period are still awaiting a development decision (fact box 4.2). How far plans for these discoveries have progressed varies, which means the estimates for resources, production and costs are of varying maturity. Uncertainty will be greatest for the less mature projects. When production will start is another uncertainty which affects the net present value (NPV) of projects.

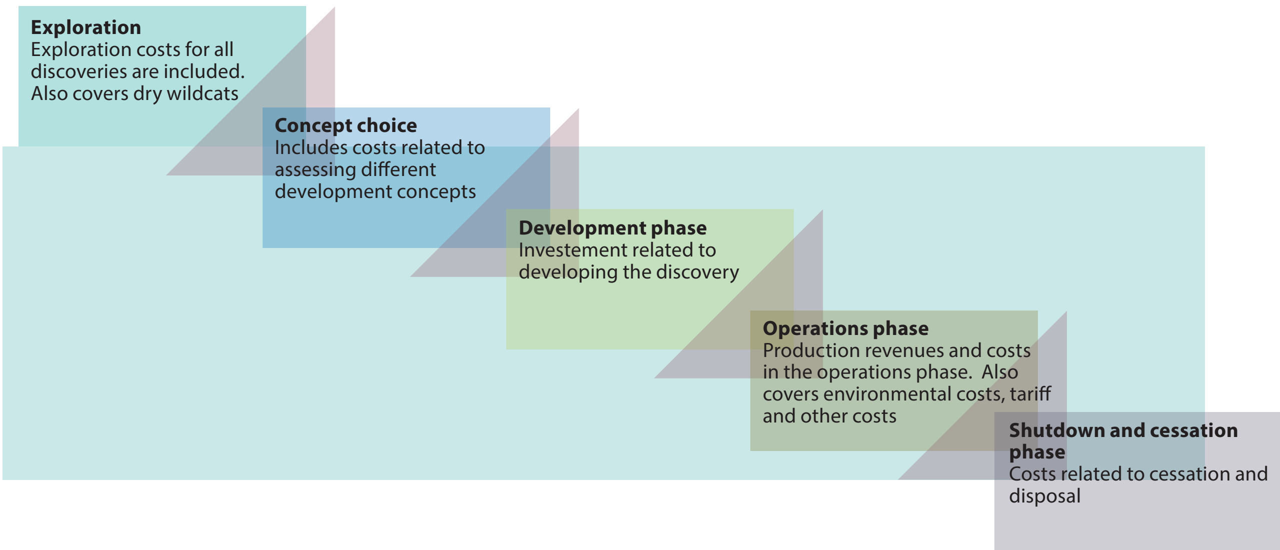


Figure 4.6 The various elements included in the analysis

Fact box 4.2 Discoveries included in the analysis

A total of 285 discoveries have been made over the past 20 years, and 179 are included in the analysis. The 106 excluded are largely categorised in resource class (RC) 6, where production is unlikely (Figure 1.2). The 7435/12-1 (Korpfjell) and 7225/3-1 (Norvarg) discoveries in 2017 and 2011 respectively are examples of ones placed in RC6.

Of those incorporated in the analysis, 68 are already on stream (RC0 and RC1), decided for production or in the planning phase (RC2-RC4), or in a phase where production is likely but unclarified (RC5). Production and cost profiles reported by the operators in connection with the RNB have been used for these. Examples include 16/2-6 Johan Sverdrup from 2010, which is already on stream (RC0 and RC1), 6406/12-3 S Fenja from 2014, which is decided for development (RC2), and 7220/11-1 (Alta) from 2014, where production is likely but unclarified (RC5).

Sixty-two discoveries in the analysis are already being or are in line to be brought on stream with other discoveries in coordinated developments (RC0-RC5). These do not have their own reporting, but fall within other overall profiles. To determine production and cost profiles per discovery, they are calculated as a share of the overall profiles reported by the operators in connection with the RNB. This utilises the base figure for estimated resources per discovery. An example is the discoveries north of Alvheim, Krafla and Askja (the NOAKA area).

The NPD has calculated its own production and cost profiles for 49 of the discoveries, which are being or will be phased into fields developed before the analysis period. An example is 30/9-28 S from 2016, which is part of the Oseberg Sør field. In addition come discoveries which had not been evaluated (RC7F) at 31 December 2019 and do not have their own reporting, such as 35/11-23 (Echino Sør)from 2019, located to the west of the Fram field.

Profitability of exploration over the past 20 years
The profitability of exploration in 2000-19 has been calculated with real discount rates of four and seven per cent. The NPV is estimated to be more than NOK 1 700 billion at a four per cent discount rate (Figure 4.7). The corresponding number at a seven per cent discount rate is NOK 1 200 billion. Total net cash flow is estimated at almost NOK 2 700 billion.

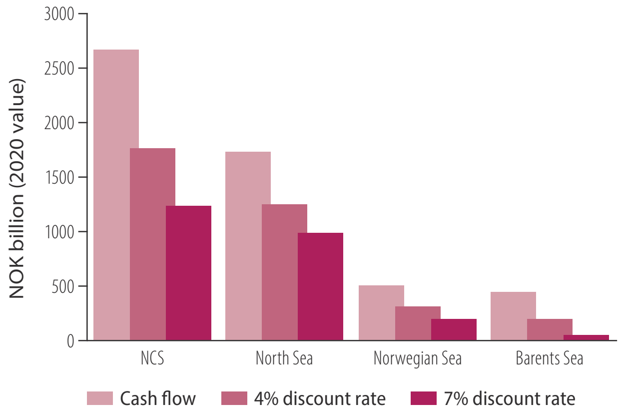


Figure 4.7 NPV from exploration by region, 2000-19

All NCS regions make an important contribution to overall value creation

Exploration over the past 20 years has been profitable in all regions. At a seven per cent discount rate, the North, Norwegian and Barents Seas contributed a positive NPV of NOK 990, 190 and 50 billion respectively. The North Sea made clearly the biggest contribution to value creation, with well-established infrastructure and several substantial discoveries in the period. The Norwegian Sea also contributed positively, with gas revenues playing an important role. Value creation in the Barents Sea has also been positive, but lower than in the other regions. The analysis shows that profitability in the Barents Sea improved substantially over the period in line with rising activity (Faktaboks 4.3 og Figure 4.9).

Fact box 4.3 Infrastructure development and increased profitability in the Barents Sea

The Barents Sea has experienced substantially lower exploration activity than the rest of the NCS, and is therefore significantly less explored than the North or Norwegian Seas. With only two producing fields, it also lags behind the other regions for infrastructure development. The largest discovery so far is 7121/4-1 Snøhvit but, despite being proven as early as 1984, more than 20 years passed before it was developed and came on stream in 2007. Discovered in 2000, 7122/7-1 Goliat began production in 2016 as the Barents Sea's second field centre.

Interest in this region has grown over the past 10 years, which has yielded several discoveries and improved the profitability of exploration in this period (Figure 4.9). Big developments such as 7220/8-1 Johan Castberg (ongoing) and 7324/8-1 (Wisting) can provide the basis for new field developments and be important contributors to future revenues from the Barents Sea. At the same, a more developed infrastructure in this area might also open for profitable production from small discoveries like 7220/7-2 S (Skavl), 7324/7-2 (Hanssen), 7219/9-2 (Kayak) and 7324/6-1 (Sputnik). Development remains unclarified for several Barents Sea discoveries. Discoveries with substantial volumes but no specific development plans include 7319/12-1 (Pingvin) and 7324/3-1 (Intrepid Eagle). Both lie in relinquished acreage. In order for more such discoveries to be realised, Barents Sea infrastructure must be further expanded.

Studies to which the NPD has contributed conclude that sufficient resources are available in discoveries and fields for possible profitable development of more gas export capacity [10]. In addition to providing greater flexibility and improved commerciality for existing oil and gas discoveries, this could incentivise future exploration. That calls for coordination of fields and for development solutions which take care of both oil and gas resources.

Profitability of exploration over the past decade
NPD analyses show that exploration over the past 10 years has been more profitable than in the previous decade. About two-thirds of total revenues from discoveries made in 2000-19 derive from discoveries in the most recent decade (Figure 4.8).

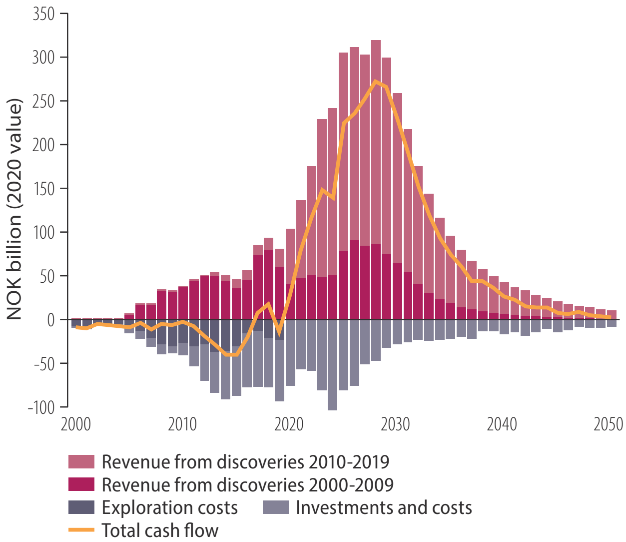


Figure 4.8 Cash flow from exploration, 2000-19

A higher level of exploration activity from 2010-19 resulted in a number of profitable discoveries, and exploration spend over the period yielded a good return to Norwegian society. Figure 4.9 shows that NOK 1 000 invested in North Sea exploration over the past decade has returned more than NOK 3 400. The corresponding figures for the Norwegian and Barents Sea were over NOK 1 500 and almost NOK 2 500 respectively. These numbers represent the NPV per NOK 1000 at a seven per cent discount rate.

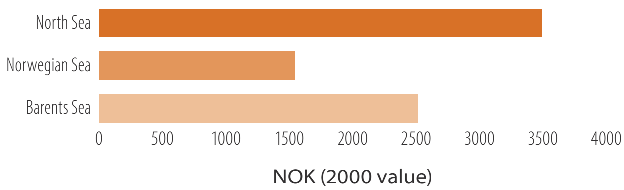


Figure 4.9 NPV (at seven per cent discount rate) per NOK 1 000 invested in NCS exploration, 2010-19

NPV contribution from various discovery types

The 179 discoveries included in the NPD's profitability analysis represent a total resource growth of about 1 650 million scm oe. This portfolio provides an average discovery size of just over nine million scm oe and a median figure slightly above three million scm oe. That the average size is so much higher than the median indicates that the biggest discoveries are significantly larger than the typical ones. About 25 per cent of the resources included in the analysis are provided by 16/2-6 Johan Sverdrup, far and away the most sizeable discovery of the period, which also contributes more than a quarter of total value creation from exploration on the NCS over the past 20 years (Figure 4.10).

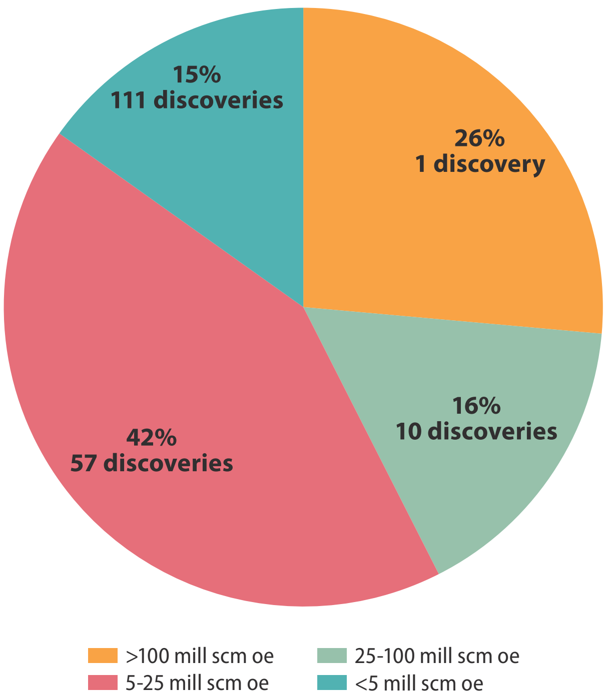


Figure 4.10 NPV contribution from various discovery sizes in 2000-19 (seven per cent discount rate, excluding exploration costs)

In addition to 16/2-6 Johan Sverdrup, 10 discoveries larger than 25 million scm oe were made in the analysis period. These have contributed about 16 per cent of total NPV from exploration over the past 20 years and, like 16/2-6 Johan Sverdrup, provided substantial value creation per discovery. These discoveries are or will be important for developing infrastructure and other discoveries around new or existing field centres. More than 40 per cent of the value creation comes from 57 discoveries in the size range from five to 25 million scm oe, which contribute roughly as much as 16/2-6 Johan Sverdrup and the 10 other largest discoveries combined.

The smallest discoveries also contribute a substantial share of total value creation, since even very small discoveries can show good profitability when developed in a cost-effective way towards existing infrastructure. They are also important for utilising capacity already in place and for enhancing the profitability of fields approaching cessation. Over the past 20 years, discoveries smaller than five million scm oe have accounted for roughly 15 per cent of overall value creation on the NCS.

Small discoveries have made a substantial contribution to overall value creation

Development of unit costs in 2000-19

Unit costs are defined as the total cost per oe produced. All expenses are included (Figure 4.6), including exploration spend which did not result in discoveries. The average unit cost for discoveries over the past 20 years is about USD 22/bbl. This declined from some USD 25/bbl for discoveries in 2000-09 to roughly USD 21/bbl for 2010-19 (Figure 4.11).

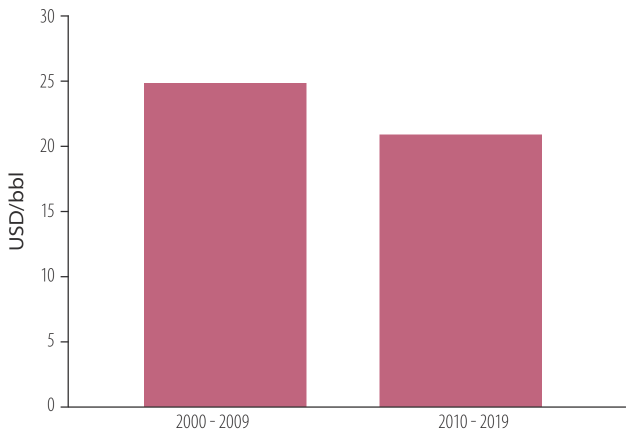


Figure 4.11 Unit costs for discoveries in 2000-09 and 2010-19

Unit costs vary from project to project and depend on several factors, such as discovery size, type of phasing-in, reservoir quality and distance from infrastructure. Figure 4.12 presents average unit costs by region.

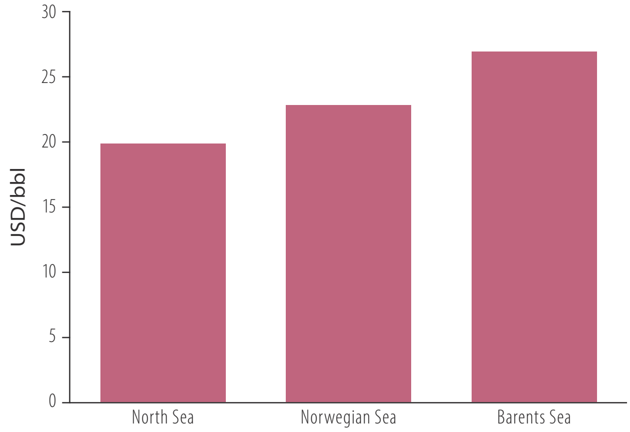


Figure 4.12 Unit costs for discoveries in 2000-2019 by region

The North and Norwegian Seas have the lowest unit costs, in part because of their well-established infrastructure. Large investments which have already been depreciated allow new resources to be phased in with good profitability. Although infrastructure in the Barents Sea is less developed, unit costs in this area are also below USD 30/bbl.

Robust profitability at different price and cost estimates

The profitability analysis has been tested for various price and cost estimates. With a 20 per cent reduction in the price assumptions, oil prices will gradually move towards USD 40/bbl in 2030. A 20 per cent increase in assumptions would mean a gradual rise towards USD 60/bbl over the same period. Gas prices would change correspondingly. At the low or high price estimates, future costs are also expected to show a gradual fall or rise respectively [11].

Figure 4.13 shows that a 20 per cent price rise would give a NPV of about NOK 1 600 billion at a seven per cent discount rate. A similar percentage decline would mean about NOK 800 billion in NPV.

At the same time, the figure shows that the NPV from exploration in 2000-09 is less sensitive to future price changes than in the most recent decade. That is because a larger proportion of discoveries in the earlier period have already been produced and are less affected by future prices (Figure 4.8). Discoveries in the past 10 years will primarily be produced in the time to come, and are therefore more sensitive to future price trends. At a seven per cent discount rate, the NPV from exploration in 2010-19 is about NOK 700 billion with the mid-range price estimate and NOK 400 and 1 000 billion respectively with the lower and upper estimates.

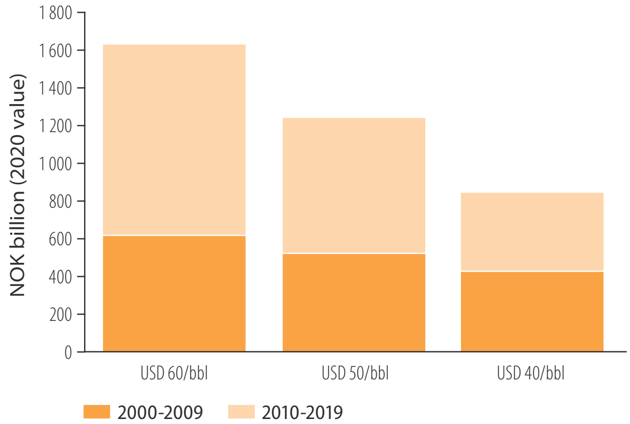


Figure 4.13 NPV from exploration at different prices and seven per cent discount rate, 2000-19

Direct, indirect and external effects

Direct effects

The profitability analysis for exploration over the past 20 years shows direct economic effects of the activity. Direct revenues cover earnings from the recovery and sale of petroleum in the discoveries, which will be determined in turn by the production volume and prices for oil, gas and NGL. Similarly, direct costs cover investment in as well as use of equipment, labour and energy for exploration, development and operation of the projects.

Indirect effects

Indirect economic effects come in addition and, in this context, comprise revenues and costs which are not reflected in the basis for the investment decision, but appear in the budget and accounts for adjacent enterprises and industries. They are popularly referred to as spin-offs. In socioeconomic profitability assessments, the significant consideration in possible socioeconomic analyses of the activity is the sum of all positive and negative indirect effects. Blomgren et al [12] have illustrated the difference between direct (yellow and red circles) and indirect (green circles) effects in Figure 4.14.

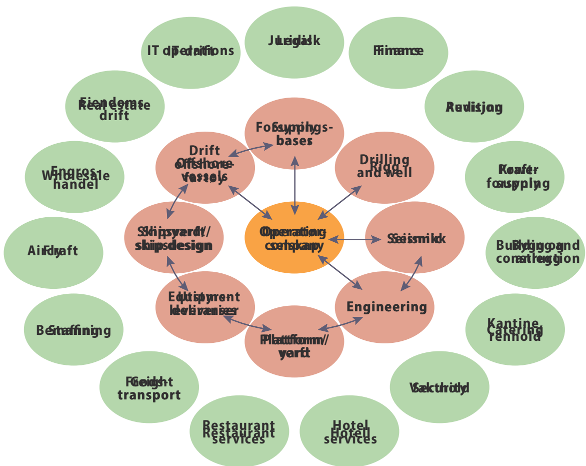


Figure 4.14 Direct and indirect effects *Source: Blomgren et al (2015)*

The exploration profitability analysis does not include these indirect economic effects – in other words, spins-offs in the form of growth impulses to the rest of the economy from exploring for, developing and operating new discoveries during the period.

External effects

In addition to its direct and indirect economic effects, the industry will have external effects in the form of benefits and drawbacks from exploration and production projects which are not reflected in a company's decision base. These are usually split into positive and negative effects.

Exploration and production can have negative effects for other marine activities and impose costs for mitigating the risk of accidents and damage. These effects are regulated through sectoral legislation and are taken into account in part through management plans. In some cases, both coexistence issues and regulation increase costs. Drilling close to coral reefs, for example, will involve the expense of collecting drill cuttings. This spending is implicitly taken into account in the profitability calculations through increased drilling costs. Despite strict regulations, the industry involves a residual risk of acute oil discharges and gas emissions. The possible cost of these is not included in the calculations.

Climate change resulting from CO_2 emissions is another external effect. The most important climate policy instruments for reducing production emissions on the NCS are emission allowances and CO_2 tax (Chapter 6 Resources for the future). These costs are included in the calculations.

Exploration also has positive external effects. One example is increased emergency preparedness which benefits other marine sectors, such as fishing. Another is that information from an exploration well in a frontier area could have a high information value for surrounding production licences. That helps to reduce both risk and costs for further exploration of an area and gives a financial benefit. Provision has been made for realising such gains through the licensing and awards policy and through follow-up of exploration activities. These benefits have not been directly quantified when analysing exploration profitability.

The profitability of small discoveries will often depend on the availability of existing infrastructure. This increases the value of small discoveries and makes their development commercial. In that way, production facilities which are already depreciated and have finished their original function can be reused – an important principle in a circular economy. Exploring near fields and existing infrastructure may also help to extend their producing life. New discoveries can thereby enhance the value of fields and facilities. Development of the Norne area (fact box 4.4) provides an example of increased value for existing fields and facilities. This possible value creation from extended production is not included in the analysis.

Fact box 4.4 Exploring near infrastructure and extended production – the Norne area

The NCS north of the 62nd parallel was opened for petroleum operations in 1980. Until 1990, exploration was extremely disappointing outside Nordland county but very successful off the Trøndelag region.

In the winter of 1989, PL 159 in the Nordland II area was awarded in licensing round 12-B with Statoil as operator. Drilling the Alpha prospect with well 6507/3-1 in the summer of 1990 yielded a discovery later named Alve, which was brought on stream as a satellite tied back to Norne.

Although Alve was relatively small and consisted moreover largely of gas, indications existed that the reservoir might have contained oil. This led Statoil to believe that oil could be present in block 6608/10, covered by PL 128, just to the north of 6507/3-1. Drilling commitments in the licence had already been met and, to retain the acreage after the initial period expired on 28 February 1992, the licensees had to promise another wildcat. Spudded on 28 October 1991, 6608/10-2 was completed on 29 January the following year and Statoil could announce an oil discovery which was later named Norne.

This discovery was substantially larger than the pre-drilling estimate. An appraisal well was drilled in 1993, and a new exploration well in 1994 proved 6608/10-4 (Nordøstsegmentet). A plan for development and operation (PDO) was submitted in June 1994 and approved the following March. Estimated resources were then about 72 million scm of oil and roughly 15 billion scm of gas. The field was developed with a floating production, storage and offloading (FPSO) unit, and came on stream in 1997 – five years and nine months after completing the first discovery well. A plan for installation and operation (PIO) of a gas pipeline tied into Åsgard Transport was submitted in 1997, and the field began producing gas in 2001. The estimated producing life was up to 2012.

Since Norne came on stream in 1997, both exploration and improved recovery have been purposefully pursued in the area. These efforts have resulted in several new discoveries, and reserves have risen substantially. Sixteen wildcats drilled in PL 128 alone have yielded 12 discoveries. Across the Nordland I-V areas, 60 wildcats have produced 28 discoveries since Norne. The two largest are 6507/5-1 Skarv (1998) and 6507/5-3 Ærfugl (2000). A total of more than 310 million scm oe has been found in the area, including roughly 195 million scm oe in the wake of the Norne discovery.

Tie-backs to Norne

The Alve, Marulk, Skuld and Urd fields have been tied back to Norne, and new tie-ins are continuously being evaluated. Collectively, this means that the Norne FPSO will continue producing beyond 2025 – twice as long as originally planned. More than 130 million scm oe will be produced through this facility in 2020t (Figure 4.15).

Over the past five years, almost 80 per cent of production has come from the tied-back fields. Without these, operating the FPSO would not have been commercial. Socioeconomically profitable resources might have been lost if production had ceased too early. Resources from the new fields tied back to Norne can be produced commercially for many years. That has helped to extend tail production on Norne, yielding a far higher return from the field than originally expected.

Spare capacity on and continued profitable operation of the Norne FPSO creates a good basis for more exploration in the area. With fully depreciated infrastructure and cost-effective operation, very small discoveries can also become commercial. That revitalises older discoveries in the area which have not been relevant for tie-back earlier. Such discoveries due to be tied back in coming years include 6507/3-8 (Gjøk) from 2009 and 6608/10-17S (Cape Vulture) from 2017. Other discoveries in the area could also be relevant here, providing a basis for extending profitable production from the Norne FPSO even further.

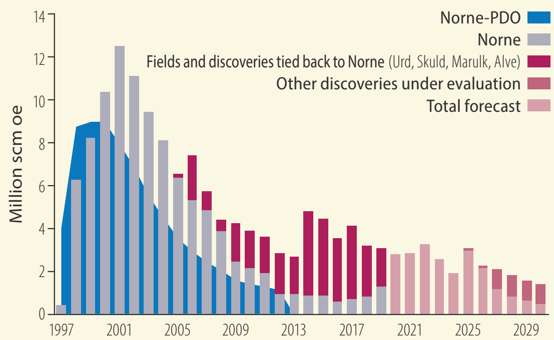


Figure 4.15 Historical and future production for Norne

Tying new discoveries back to existing fields and infrastructure can help to keep down unit costs and incentivise continued exploration in the surrounding area. It is therefore important that phasing in future discoveries occurs early in the tail phase before unit costs get too high (fact box 4.5).

Fact box 4.5 Rising unit costs and timely exploration

Big investments have been made in field and gas transport facilities on the NCS. An expected decline in petroleum production from 2025 means that much spare capacity will become available in several parts of the infrastructure. Exploration in recent years has yielded many discoveries, but these are generally smaller than before (Chapter 2 Exploration trends on the NCS). Phasing into existing facilities will therefore be the most likely development solution for most of them. Spare capacity in the infrastructure will create opportunities for good resource management. But it also presents challenges. Over the next few years, many of the fields will be in a mature phase with declining outputs and thereby rising unit costs. Phasing in discoveries before unit costs get too high is important. Future discoveries thereby depend not only on spare capacity being available, but also on this having sufficiently low unit costs. Timely exploration and development will therefore be increasingly important in ensuring good profitability for future discoveries (Figure 4.16).

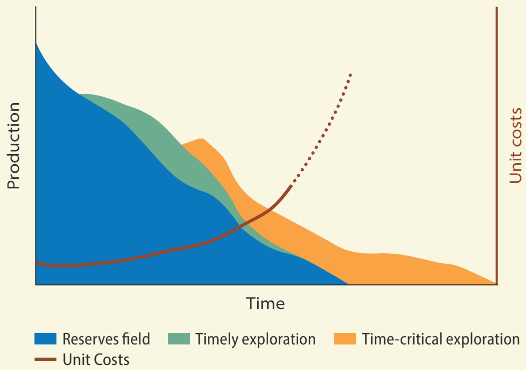


Figure 4.16 Timely and time-critical resources *Timely resources: those phased in while unit costs on the host field are low enough and thereby provide high value creation. Time-critical resources: those phased in at a time when unit costs on the host field are rising quickly. The resources will thereby be produced with lower profitability and/or might be lost.*

Petroleum operations also contribute to considerable positive external effects for adjacent industries through productivity improvements. Analyses by Bjørnland and Torvik [13] show that the petroleum sector has substantial external effects on the rest of the economy in terms of both knowledge and technology development. This industry does not necessarily cause "Dutch disease" by displacing other productive activities. Instead, "infection" from the sector helps to make the wider economy more productive (fact box 4.6). Such productivity effects on the rest of the economy are also excluded from the exploration profitability analysis.

Fact box 4.6 Productivity effects on the wider economy

"Traditional theory assumes that production of resources has limited spin-offs to other industry. If anything, the effect is negative so that increased activity in the oil sector, for example, will displace traditional industries (known as the "Dutch disease"). The problem with the classic Dutch-disease model is that it assumes production of raw materials just happens. To put it simply, the model assumes knowledge is imported and the process of producing raw materials is virtually automated. Our starting point is that this hardly seems to describe Norway's petroleum sector and supplier industry. Instead, we maintain that recovering oil and gas (upstream) and delivering it securely and in accordance with customer requirements (downstream) call for knowledge and technology. If one then allows that knowledge and technology can be transmitted to other industries, the predictions of classical theory are inverted. Raw material wealth can then lead to higher productivity growth in the whole economy ... In other words, the supplier sector, with its hi-tech knowledge, can be an engine for growth in the rest of industry. That generates positive externalities." Bjørnland and Torvik [13].

Exploration for future value creation

The NPD's analyses show that investment in exploration for oil and gas on the NCS has been extremely profitable. This activity also has spin-offs beyond the petroleum sector and contributes to increased productivity in other sectors. To prevent output and value creation declining rapidly, maintaining a high level of exploration for a long time to come will be important.

Production and value creation fall rapidly without new discoveries

Declining production without new resources
Overall output from the NCS is expected to fall rapidly and significantly unless new resources are continuously added. Figure 4.17 shows that a large share of production over the next few years will derive from exploration in the previous decade. More than 40 per cent of resources expected to be produced in 2030 come from discoveries made after 2010. These discoveries will also help to postpone cessation and increase tail output from existing fields.

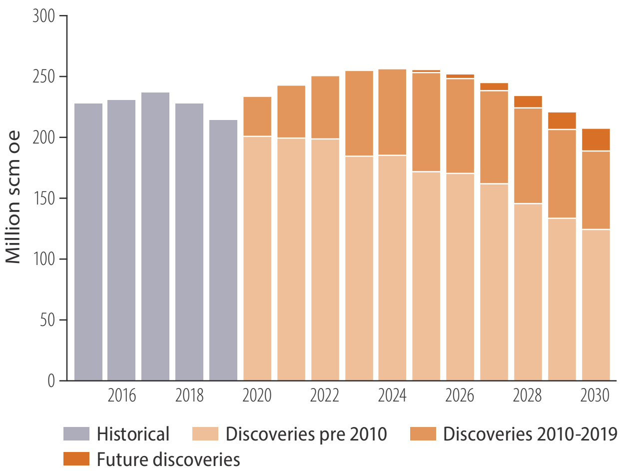


Figure 4.17 Historical and future production

Production will decline substantially after 2030. Forecasts for fields and discoveries reported by the companies for the 2021 national budget show that overall output by 2040 will be about a third of today's level without new resources (Figure 4.18). This will weaken the economics of producing fields, and overall unit costs could rise substantially. Exploration over the next decade will therefore be very significant for the development of production and value creation after 2030. If expected resource growth develops in the same way as in the past 10 years, total output could be about two-thirds of the present level in 2040. Lacking a big discovery, comparable with Johan Sverdrup, expected production in that year would be about half today's figure.

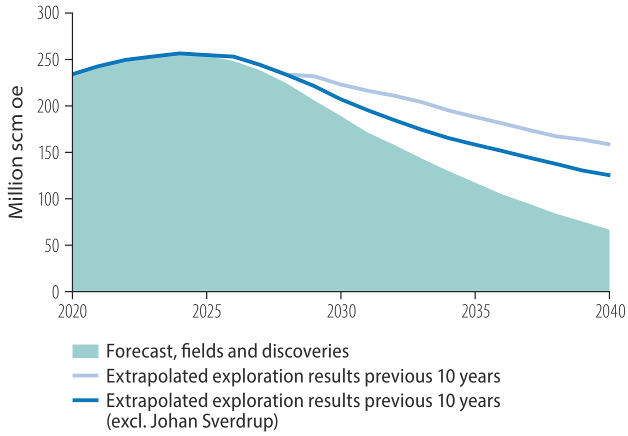


Figure 4.18 Extrapolated production

Future profitability of exploration
Profitability calculations for exploration over the past 20 years show that the return has been very good (Figure 4.7). While the average oil price over this period was about USD 65/bbl, unit costs for discoveries were roughly USD 22/bbl – including exploration costs (Figure 4.11). If average unit costs for discoveries remain low, future exploration will be profitable even with low oil prices (Figure 4.19). By comparison, the sustainable development scenario in the 2020 *World Energy Outlook* from the International Energy Agency (IEA) estimates that oil prices will be USD 53/bbl in 2040. The IEA's stated policies scenario puts the price at USD 76/bbl in 2030 and USD 85/bbl in 2040 [14].

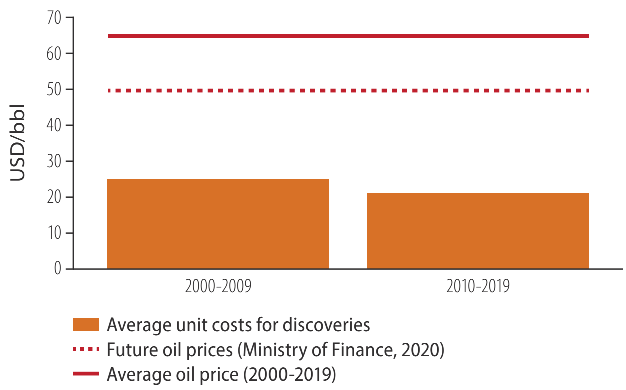


Figure 4.19 Average unit costs for discoveries and oil prices

Greater attention is paid to improving efficiency and reducing unit costs when oil prices are expected to fall. At the same time, it is important to phase in new resources before production declines so much that unit costs become too high (fact box 4.5).

Exploration will be profitable even with low future oil prices

Maintaining diversity, competition and expertise
Exploration is an integrated and important part of operations at most companies with interests in production licences on the NCS. Of the 39 players with such interests at 31 December 2019, 36 had licences in the exploration phase (Figure 4.20).Thirty-three companies applied for new production licences in the 2020 APA round.

Exploration (6)	Production and Exploration (30)	Production (3)
	Equinor, Petoro	
	Conoco Phillips, Shell, Total	
Inpex, Lukoil	Aker BP, Capricorn, Chrysaor, DNO, One-Dyas, Idemitsu, Ineos, Kufpec, Lotos, Lundin, MOL, Neptune Energy, OMV, Repsol, Spirit Energy, Suncor, Vår Energi, Wintershall DEA	
Concedo, Lime, Skagen 44, Source Energy	M Vest Energy, Okea, Pandion Energy, Petrolia, Wellesley	Capeomega, Mime Petroleum, Solveig Gas
	Edison, PGNiG	

Large Norwegian companies
Majors
Medium-sized companies
Small companies
European gas/power companies

Figure 4.20 Licensees on the NCS by company category and focus areas at 31 December 2019

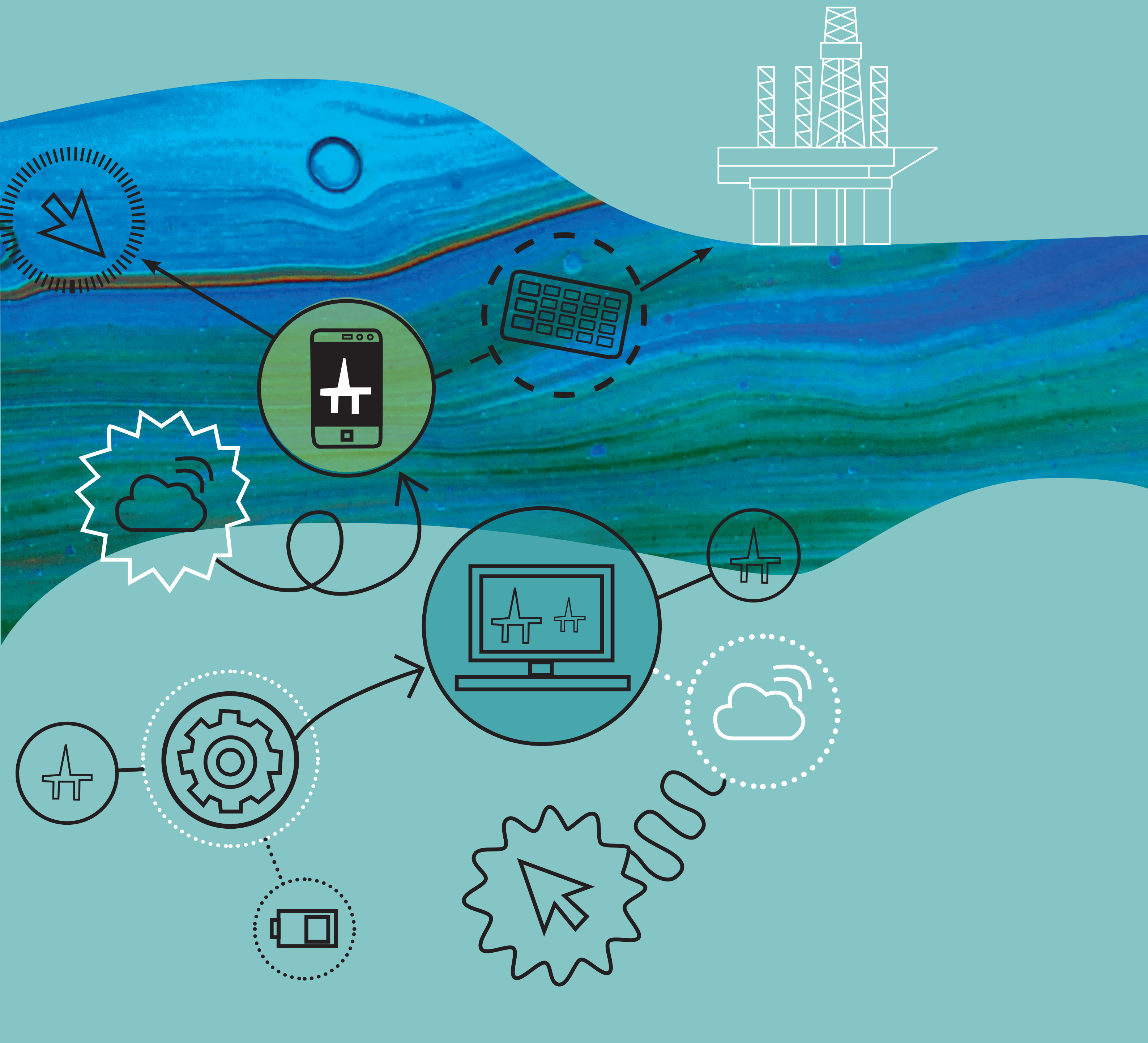
The figure shows that players concerned to explore are represented in all company categories. They differ in experience, ownership composition, risk willingness and priorities. Overall, this ensures a very diversified exploration environment, which lays the basis for innovation, technology development, growth and value creation. Strong competition and a diverse range of players at all levels in the value chain are important for good resource utilisation and for ensuring adequate interest in the opportunities available on the NCS.

Exploration leads to innovation and technology advances

Technological challenges are becoming increasingly complex as resources get more difficult to find. Maintaining diversity and competition in specialist teams is therefore important. Many such groups working on exploration and development are also involved in developing new technology. The petroleum and supplier industries are knowledge-, technology- and capital-intensive. This expertise can play an important role in overcoming tomorrow's energy challenges while also safeguarding the climate and the environment (Chapter 6 Resources for the future). Technology development and innovation are important for reducing greenhouse gas emissions and the transition to a low-emission society.

Chapter 5

Digitalisation of exploration



Norway's oil and gas accumulations are increasingly harder to find. Technological progress and digitalisation have provided better data and tools which contribute to increased geological understanding and make it possible to identify new exploration concepts. Digitalisation also provides further opportunities to reduce exploration costs and enhance the efficiency of work processes. That can help to reduce exploration risk and increase discoveries.

The exploration business has a long tradition of handling large volumes of data through acquisition and processing of geophysical and well data. Exploring for oil is an industry which has moved boundaries for digital technology. Seismic surveys generate enormous quantities of data, and use some of the biggest supercomputers and computer clusters available at any given time for processing and analysis. For many years, advanced modelling and simulation, 3D visualisation and automated geological interpretation have been part of the toolbox for specialists in the exploration business.

Oil and gas exploration moves boundaries for digital technology

Increasing data quantities

Data quantities are growing fast

The NPD is responsible for maintaining knowledge about the petroleum potential of the NCS, serving as a national continental shelf library and disseminating facts and knowledge. That includes making information from all phases of the industry easily accessible, and communicating facts and specialist knowledge to government, industry and society at large (Figure 5.1). The NPD's many years of acquiring and making data publicly available – in part through its fact pages – have given the NCS a competitive advantage in relation to many other petroleum provinces, where securing access to information is more demanding.

The Diskos national data repository for seismic and well information on the NCS (fact box 5.1) held some 10 000 terabytes (10 petabytes) of data at 31 December 2019 and is expanding rapidly (Figure 5.2

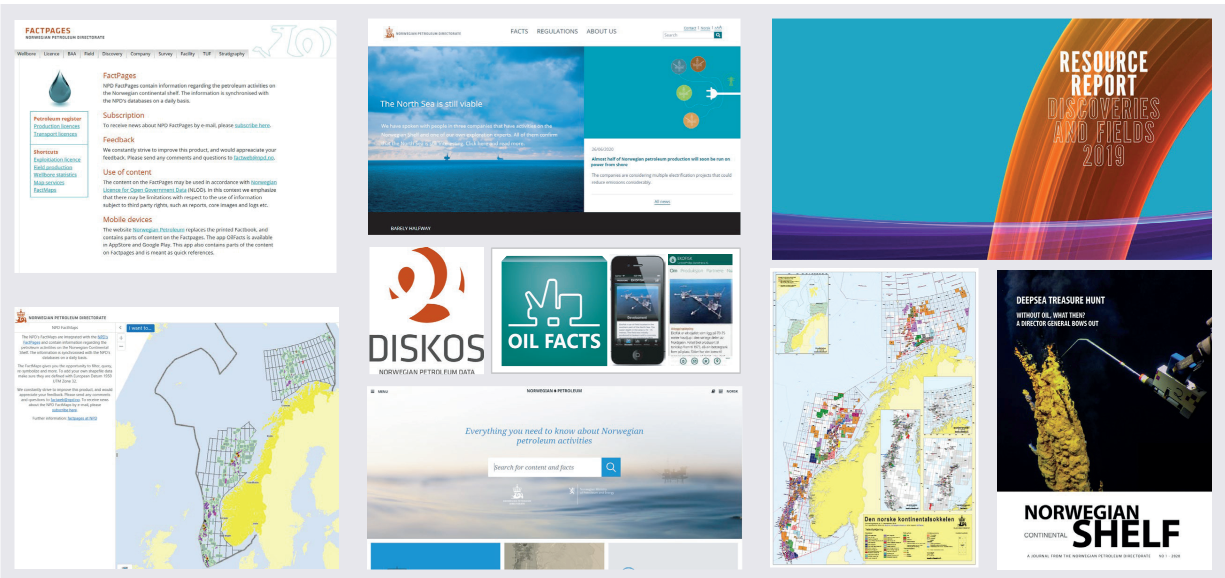


Figure 5.1 Communicating facts

og Figure 5.3). These large quantities of data provide a unique basis for analysing opportunities which can help in making new discoveries.

Fact box 5.1 Diskos

Diskos was established by the NPD and the oil companies on the NCS in 1995. It is owned by the petroleum industry, administered by the NPD and run by an external provider. The contract is renewed at regular intervals pursuant to Norway's Public Procurement Act.

This is a national repository for exploration- and production-related information from the NCS. Data are directly available on the web to members of the Diskos collaboration. The underlying idea is that the oil companies will join forces on storing information, and compete instead over its interpretation. Since Diskos was created, most players currently active on the NCS have joined.

Storage and administrative costs are paid by the companies through an annual membership fee. All members have access through Diskos to released data, their own information and data owned by production licences they have an interest in. The NPD's requirements (and associated guidelines) define which format should be used for reporting, the level of quality and so forth. In recent years, Diskos has also become a data provider to groups other than oil companies, such as oil service firms and consultancies. All universities in Norway and a growing number in the UK and the USA now have access to the repository.

As well as being a solution for joint storage of seismic, well and production data, Diskos provides a platform for swapping and sharing this information. The data can be transferred directly to computers equipped with interpretation tools. Information can be bought and sold by amending user rights in the repository, and the platform provides a practical solution for publishing data when their period of confidentiality has expired.

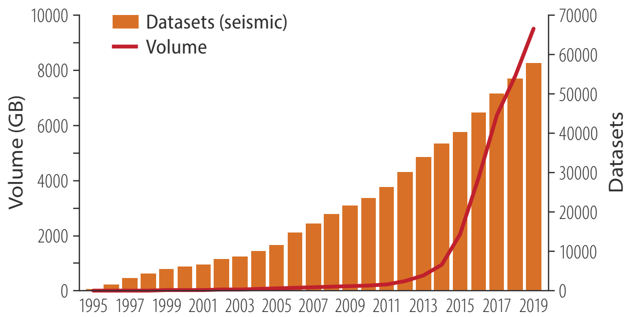


Figure 5.2 Development of seismic data volume in Diskos, 1994-2019

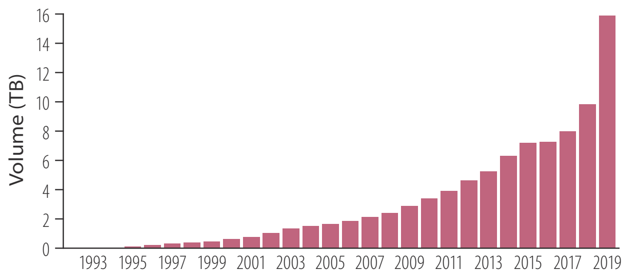


Figure 5.3 Development of well data volume in Diskos, 1994-2019

Making data accessible

Big Data analyses based on machine learning (ML) and artificial intelligence (AI) may provide new information and insights. More and better data, tools and methods can increase geological understanding of the sub-surface and identify new exploration concepts. This is conditional on easy access to digital data.

Data must be made available to all and conditioned for machine reading

More than 50 years of data acquisition and technology development on the NCS have yielded a number of different software tools for data processing and a multitude of partly incompatible file formats, databases and storage systems. The result is that information is difficult to retrieve from one system for use in another, while collating data acquired by different disciplines for cross-disciplinary analysis is challenging. Information can often also be poorly structured and lack metadata, making it hard to detect relationships between objects and assess data quality.

Both storage formats and quality problems can hamper efficient Big Data analyses. Easy accessibility to information is crucial for exploiting the value potential offered by AI and Big Data analysis.

Data must therefore be conditioned – in other words, converted to a format which everyone can use and machines can read. The commitment required for this has been underestimated, and must be given priority if the value potential is to be realised.

Several projects have been initiated to improve the quality of data and make them machine-readable. One example is a project launched by licensees on the NCS, through the Norwegian Oil and Gas Association, to digitalise drill cuttings information from around 1 500 wells and make this available in Diskos.

Several projects have been initiated by the repository to make data machine-readable (fact box 5.2), and Diskos is continuously seeking to develop the database further by adopting new technology and improving ways of working. A priority is to determine how ML and AI can help to improve data quality, particularly for old information and large volumes of unstructured datasets.

Work is also under way at the NPD to make other data available in digital format for analysis. One project aims to digitalise palynological (microfossil) slides submitted to the NPD (Figure 5.5 og Faktaboks 5.3).

Fact box 5.2 Machine-readable core data

The oil companies are required to retain cores from all exploration and production wells on the NCS. Taken from virtually all exploration and a selection of production wells, this material is held in the NPD's Geobank (Figure 5.4). A large number of samples are also stored at Stratum Reservoir in Stavanger, which administers both physical materials and photographs of drill cores. Cores have been retained and photographed ever since the 1970s. In recent years, a project scanned the negatives in order to make them available in Diskos. A total of about 30 000 core images from more than 1 100 wells (drilled before 2000) were digitalised. Financed by Diskos, this work was completed in February 2020. Digitalisation allows the information to be integrated with company data and analysed using new tools such as image recognition and ML.

Figure 5.4 Oil samples in the NPD's Geobank

Fact box 5.3 AVATARA-p - advanced augmented analysis robot for palynology

Operators and consultant laboratories routinely produce palynology slides from core and drill-cutting samples (Figure 5.5) for age-dating and correlation of exploration and development wells. The branch of geology which includes palynology is called biostratigraphy, and biostratigraphers are employed in the petroleum industry to age-date and correlate sediments based on their fossil content

The NPD currently houses 120 000 palynological slides in its Geobank, which will soon increase to more than 200 000. This collection of biopolymer residues preserves crucial elements of Norway's geological history in the form of fossil pollen, spores and microplankton from the last 400 million years.

The archive is a fundamental dataset which has been shared with companies and academia for over 40 years to improve the industry's understanding of the subsurface. That supports improved age interpretation and palaeoenvironmental analysis as the science advances. Both the industry and the nation gain from effective access to palynology slides because biostratigraphic analysis reduces the economic risk of exploration.

At the 14th European Congress on Digital Pathology in Helsinki during 2018, the NPD acquired insight into impressive technological advances in imaging and AI-aided medical diagnosis. Palynologists can now reap the benefits of 20 years of pathology-driven research and development. This has resulted in optical resolution finer than 0.29 microns, digital resolution greater than 20 gigapixels, seamless image stitching and focal plane stacking.

Through the Avatara-p project, the NPD is applying technical advances in digital pathology to geological fields grounded in traditional microscopy. Powerful client servers stream digital slides to the user's desktops in an optical resolution typical of high-end light microscopes. Large 4K or 8K screens give the user an immersive experience which provides more visual information than the narrow fields of view in regular microscopy. The user may annotate specimens for improving taxonomic consensus and discussion between workgroups. In addition, the user interface can export these annotations to generate training sets for ML applications. The pathologist's tools for improving diagnoses through interprofessional communication and decision-making are now available for biostratigraphers through Avatara-p.

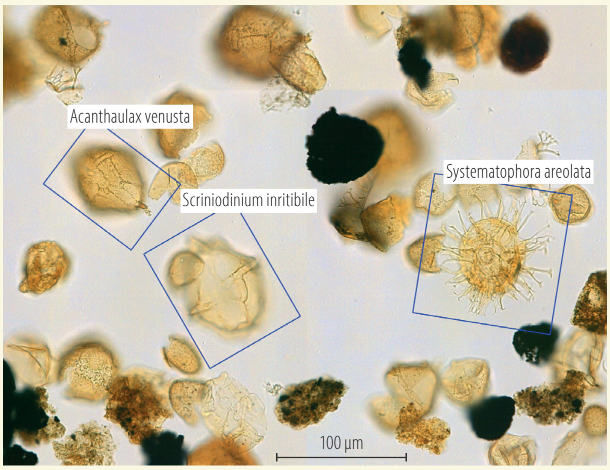


Figure 5.5 Microfossils *Palynological slide of pollen and spores*

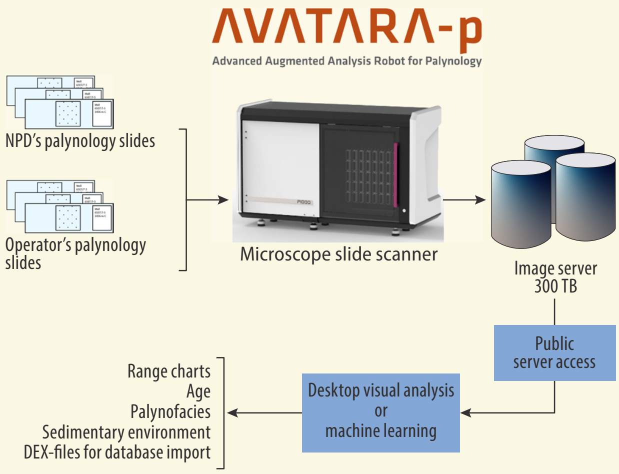


Figure 5.6 NPD scanner for palynological slides

The NPD has also participated in a project with Britain's Oil and Gas Authority (OGA) and the Oil and Gas Technology Centre (OGTC) in Aberdeen to study analysis methods which can quickly and accurately assess structured and unstructured well data. This aims to use the information to identify and classify intervals which might indicate the presence of overlooked petroleum accumulations (fact box 5.4). Part of the work involves organising and cleaning data so that they can be used in analyses.

Intensive efforts are being devoted by a number of industry players to establish data platforms which can liberate information from its original formats and storage systems, and make it more available to applications. Key elements here are developing robust and standardised data models and application programming interfaces (API) for data sharing.

Several of the big companies have joined forces to establish the cloud-based open subsurface data universe (OSDU) platform, which has quickly attracted wide support. The aim is to make all global exploration, production and well data available in the same format on a data platform. Benefits will include even better opportunities for Big Data analyses and improved base data for ML and AI. The group has attracted 133 oil, service and technology companies as members, including BP, Chevron, ConocoPhillips, Equinor, ExxonMobil, Hess, Marathon Oil, Noble Energy, Pandion Energy, Shell, Total, Woodside and Schlumberger.

Fact box 5.4 OGTC/OGA/NPD project

The NPD has contributed to an ML project with the UK authorities. The huge quantity of data acquired from 50 years of exploration on both sides of the North Sea boundary represents a world-class laboratory for increased sub-surface understanding in the area. To be regarded as a pilot, this work is led by the Oil and Gas Technology Centre (OGTC) in Aberdeen. Base data come from more than 8 000 wells in Britain's northern North Sea sector and much of Norway's North Sea acreage (Figure 5.7 [15]). The project has been established under the OGTC's open innovation programme [15] and four companies have been chosen for the specified assignments (Figure 5.8 [16]). Hopefully, this will identify overlooked hydrocarbons as well as encouraging the industry to take the methodology a further step forward – or analyse other variables.

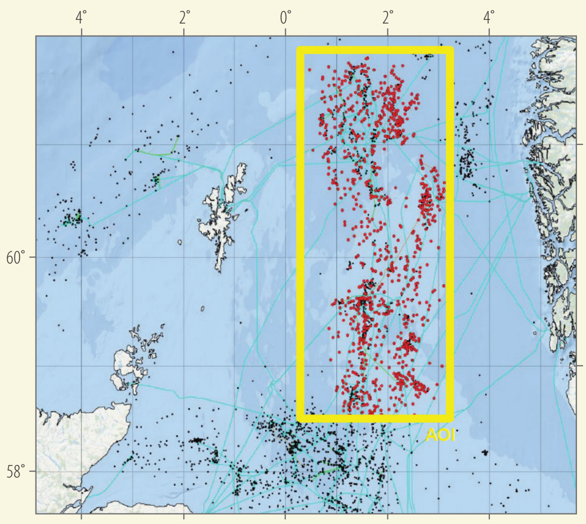
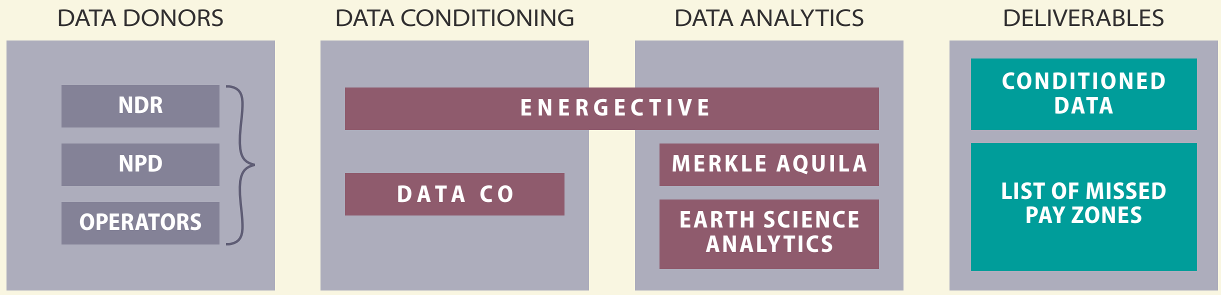


Figure 5.7 Study area for the project on overlooked hydrocarbon zones *Source: OGTC (2018)*



Data input: National Data Repository, Norwegian Petroleum Directory, operator donations - 9 operators

Project deliverables: Ranked list over "overlooked pay" opportunities in order of confidence. Clean conditioned dataset to add to NDR. Comparison and analysis of various ML techniques for data conditioning and analytics.

Figure 5.8 Project to identify overlooked zones with hydrocarbons (missed pay) *Sources: NPD, OGTC, OGA, UK-NDR*

Big Data analysis

Big Data analysis has emerged to meet the need for identifying trends, patterns and significance in the huge quantities of information being generated. This is often done without ties to specific datasets, but across them. Development over time is presented in (Figure 5.9 [17]). Many of the techniques or methods involved, such as data mining, ML and deep learning, are variants of AI.

Generally speaking, data mining refers to the process of extracting information or knowledge from raw data. ML is a sub-sector of the broad AI field, and refers to the use of specific algorithms to identify patterns in raw data and present relationships between the latter in a model. Such models (or algorithms) can then be used to draw conclusions about new datasets or to guide decisions. ML is a well-known term in exploration. Auto-interpretation of seismic data is one example, which has existed for many years and is illustrated in Figure 5.10. ML models can also be constructed from well data and used to predict reservoir properties in the sub-surface. This methodology can also help to improve incomplete datasets by predicting missing information.

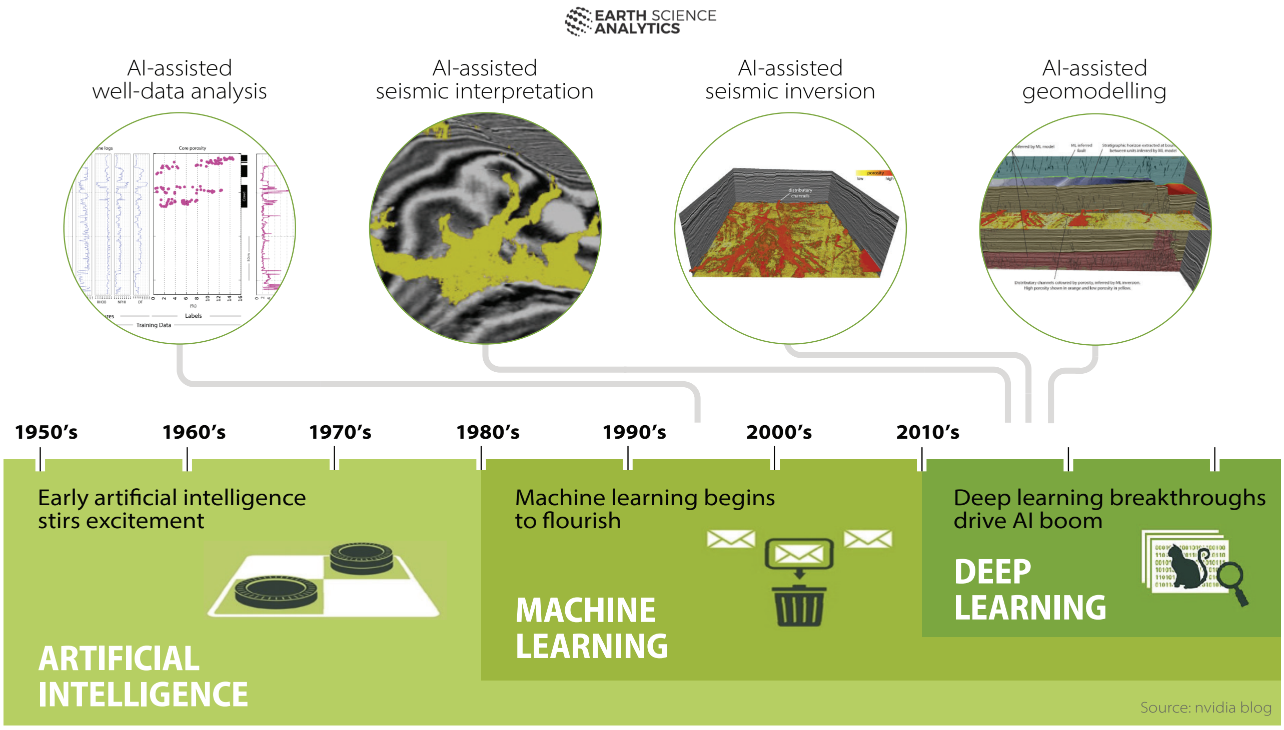


Figure 5.9 AI and data analysis. *modified from Earth Science Analytics and Nvidia blog (2018).*

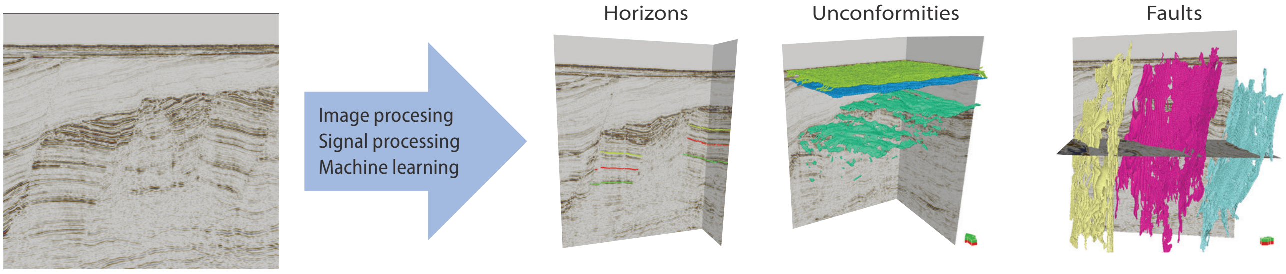


Figure 5.10 Automated seismic interpretation *Source: Lundin Energy*

Substantial value potential

Realising the value potential
So far, the industry has probably only scratched the surface of what could be achieved through digitalisation in the exploration sector to reduce uncertainty, enhance efficiency and find more oil and gas. Rapid advances in recent years mean that an ever-growing number of players have become aware of the opportunities, and great agreement has eventually emerged in the industry that a big potential exists for digitalisation. To succeed, however, it is not enough for the players to invest in their own projects. They must also be able to collaborate with both partners and competitors, be willing to share data, knowledge and technology, and assess their own business model and role in the market. Data utilisation could also present challenges – in an ML context, for example – because of the Copyright Act, even when the information is no longer confidential. It is important that the industry and the government can now find solutions which help to make released data as open as possible. Failure to accomplish this could mean the value potential fails to be realised or takes a long time to come to fruition (fact box 5.5).

Companies must collaborate and be willing to share data, knowledge and technology

The government also plays an important role in helping to customise and share data and knowledge, so that value creation for society is maximised (fact box 5.6).

In the wake of the KonKraft report (fact box 5.5), greater attention has been paid to sharing various types of data and the effects of this. The government has assessed how far the status reports (fact box 5.7) should be made public.

Fact box 5.5 KonKraft (competitiveness of the NCS)
KonKraft is a collaboration arena for the Norwegian Oil and Gas Association, the Federation of Norwegian Industries, the Norwegian Shipowners Association and the Norwegian Confederation of Trade Unions (LO), with two LO members – the United Federation of Trade Unions and the Norwegian Union of Industry and Energy Workers. A KonKraft report in 2018 presented recommendations and proposals for improving the competitiveness of the NCS, including a number which related to digitalisation and collaboration. An important overall point is that industry coordination was essential for realising the potential offered by digitalisation measures. KonKraft observed that the petroleum sector is among the industry which has made the least progress in realising the efficiency and productivity benefits of digitalisation, data accessibility and flow, and collaboration between players. It referred to a McKinsey report which estimates the total annual potential for savings from digitalisation on the NCS to be NOK 30-40 billion. One KonKraft recommendation was for a collective and industry-led initiative to work on measures which involve new forms of digitalised interaction between players in the oil and gas industry. It wanted to see common standards and protocols for storing, sharing and using data [18].

Fact box 5.6 Sharing data creates greater value for society than for a single company

Value creation from data sharing will normally be greater for society than for a single company or production licence. That reflects four key properties of data.

– Digital data can be used and reused in a number of applications, such as different algorithms and programmes, without its value for other users being diminished (a public good).

– Producing digital data could influence a third party positively without the investor in/producer of the data taking account of the effect of its decisions on the third party (a positive external effect).

– Processing digital data provides economies of scale, since it could be more efficient to process and analyse large quantities of information than to process each dataset separately.

– Using digital data offers economies of scope, since merging complementary datasets can provide more insight than keeping them separate.

Coordination problems and reluctance to share data could prevent the full value potential of such sharing being realised. The government therefore plays an active role in ensuring that this happens.

Fact box 5.7 Status reports

Pursuant to section 27 of the Resource Management Regulations, licensees must submit a status (or relinquishment) report to the NPD within three months after a production licence is surrendered, lapses or expires. This must provide details of any acquired data and study results as well as an overview of prospects and leads in the licence. It must also contain an overview of all geotechnical materials and where they are stored, along with information about the storage format(s). A guideline which describes the content of the report can be found on the NPD website. Containing results and assessments which represent interpretations, these reports have not been made public so far. Pursuant to section 85, paragraph 4, sentence 4 of the Resource Management Regulations, the duty of confidentiality for interpreted data runs for 20 years.

Publishing status reports could contribute to more cost-effective exploration. This would improve data access for companies thinking of applying for licences in previously awarded areas. It would also ensure a minimum of experience transfer from earlier licensee groups to their successors, and communicate details of more recent data and studies which new licensees might consider acquiring. As a growing share of the NCS becomes more mature, new production licences will increasingly include acreage already licensed once or more (Figure 2.13).

In some cases, companies are awarded acreage which has been evaluated in detail by previous licensees. On certain occasions, it could make sense for new licensees to re-evaluate the area using new approaches. In other cases, such a reassessment may prove to be a duplication of earlier work which fails to provide new knowledge. Making status reports public can contribute to more cost-effective exploration in that new licensees and others benefit from work done and experience gained in earlier licences covering the same area. That will help to make exploration more efficient both through increased competition and a variety of ideas, and through reduced exploration risk. This confers a socioeconomic benefit. The MPE has published proposals for amending the regulations, including the release of status reports, with a consultation deadline of 1 November 2020.

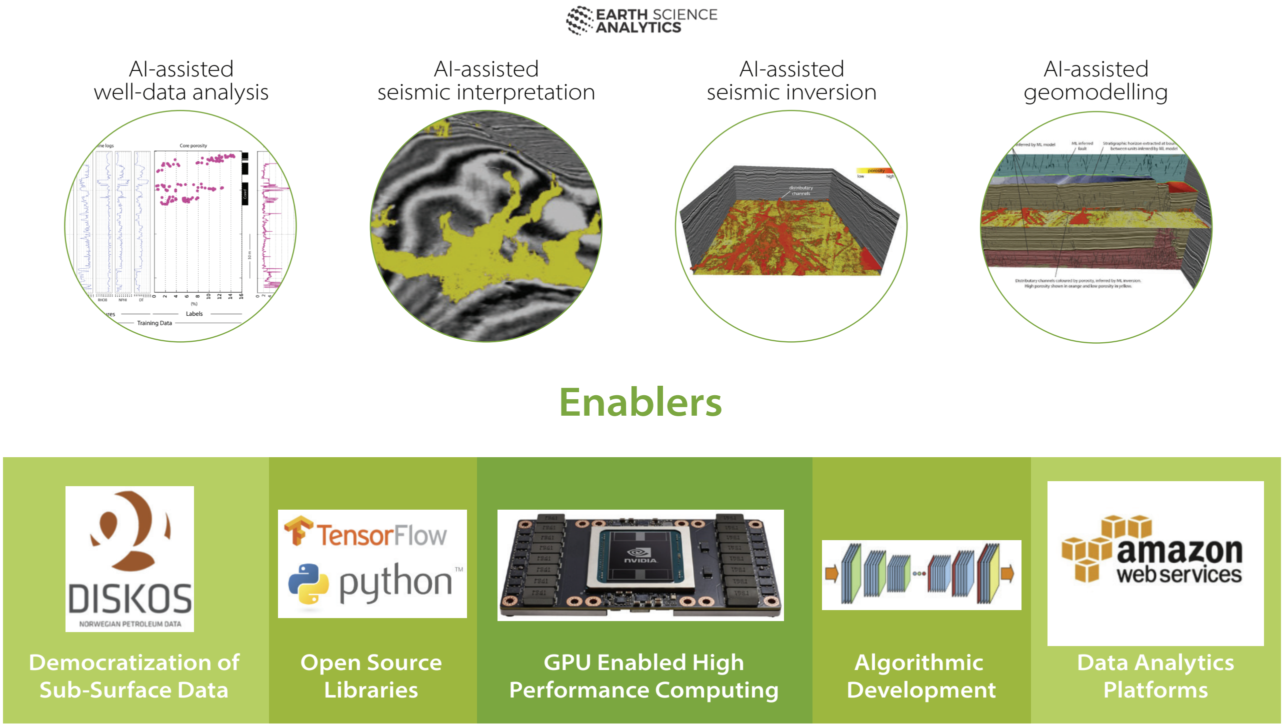


Figure 5.11 Factors for realising the value potential related to digitalisation in the exploration phase. *modified from Earth Science Analytics (2018)*

Democratisation of sub-surface data
Most requirements are in place on the NCS for realising such socioeconomic gains. The most important factors are illustrated in Figure 5.11 [17]. General and simple access to sub-surface data through the NPD, Diskos and other sources allow specialists to experiment with new analysis methods and techniques, and to build data science into their model structure. This presupposes that the industry agrees on standards which permit interoperability (fact box 5.8) and which ensure that functions embedded in company-specific systems can interconnect. In other words, the flow of data between players and applications is simplified, interpretation of shared information is supported and the benefit of datasets assembled across companies and partnerships is made available. Interoperability requirements ensure that players in the industry avoid dependence on a single supplier of platforms and thereby getting locked into their technology choice.

Fact box 5.8 Interoperability

Interoperability is the ability to communicate with, run programmes on or transfer data between different functional units, so that the user needs no special knowledge or skill to get different technical system to work or function together. Only services and systems can become interoperable – no interoperability exists between datasets.

Open-source library

It has also become more common to release source codes, and both general and geoscience-specific open-source libraries have emerged. Access to these makes it considerably simpler to use ML in exploration-related geoscientific analyses.

Algorithm developments

The large size of modern datasets has sparked an explosion in new methods and techniques for information retrieval. As a result, the industry has access to a growing “new” supplier sector through a competent ecosystem of developers and companies producing new algorithms, based in part of the increasing quantity of sub-surface data. The existing supplier industry has also adopted innovative digital tools and working methods. And the big cloud companies offer advanced tools and services for analysing and modelling large datasets.

Data analysis platforms

A great many different data platforms contain important information about the sub-surface on the NCS. Compiling these into a single large open platform would probably make data access more efficient. Such a compilation can be used with advanced ML and algorithms to combine countless databases into a form of hub.

Computing power

The new methods for Big Data analysis are made possible in part by rapid advances in computer processing power and speed, and by combining devices to permit high-performance computing (HPC). This is increasingly offered by the cloud companies, partly in order to optimise data analysis and hopefully shorten the time between exploration and first oil or gas production. Big computer resources will be required if very substantial quantities of data are to be processed, or if they require large parallel calculations. So far, the most cost-effective approach has been to establish this in a supercomputer centre [19].

Supercomputers require heavy investment. According to the industry, however, they could reduce the time from awarding a production licence to making a discovery by many months and cut costs substantially through fewer dry wells. Since establishing supercomputers gives economies of scale, it has largely been the big petroleum industry players who have established data centres with such machines. These normally run at full capacity around the clock. Eni, Total and Petrobras have all recently upgraded their supercomputers and greatly increased available processing power. In addition to the big oil companies, the seismic survey sector makes substantial use of its own supercomputers. Small oil companies which only need heavy computing capacity at intervals, rent this either in the cloud or from specialised players.

Chapter 6

Resources for the future

The NCS is well positioned to meet the climate challenge and the increased economic risk that this imposes. At the same time, the challenge opens opportunities for innovation and new commercial activity in such areas as CO_2 storage and exploration for and exploitation of seabed minerals.

The climate challenge

Strict regulations

Since petroleum activities began on the NCS, stricter requirements have gradually been introduced for prudent operations in environmental and safety terms. The authorities have utilised a number of instruments and regulatory measures to reduce emissions from oil production, including a ban on flaring. It has been the driving force, while the industry has adapted to the requirements. New technology has been developed and adopted to meet the challenges.

Along with international aviation, petroleum is the sector which pays the highest price for CO_2 emissions (Figure 6.1 [20]). The combination of CO_2 tax and emission allowances means that the overall cost of CO_2 emissions for companies on the NCS in 2020 is NOK 700-800 per tonne.

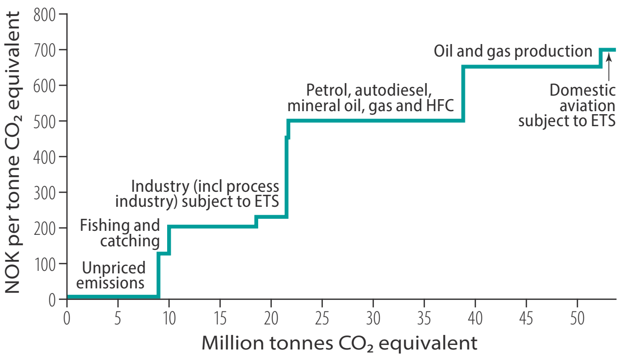


Figure 6.1 Price (tax/allowances) of GHG emissions in Norway *Source: Ministry of Finance (2019)*

That is significantly higher than in any other country with petroleum operations. The high cost of emitting greenhouse gases (GHG) has helped to give Norwegian oil and gas production a low carbon footprint in a global context (Figure 6.2[21]).

Global challenge

Through the Paris agreement, virtually all the world's nations – Norway included – have undertaken to reduce GHG emissions so that the rise in the average global temperature remains well below 2°C compared with the pre-industrial level. They must also strive to limit the increase to 1.5°C. The agreement requires all the parties to submit new or updated national commitments every fifth year.

Norway and Iceland have entered into an agreement with the EU on reducing GHG emissions by at least 40 per cent from the 1990 level up to 2030. Tougher Norwegian targets have been reported under the Paris agreement, with emissions cut by at least 50 per cent and towards 55 per cent in 2030 compared with the 1990 level. Norway wants to meet the stricter target

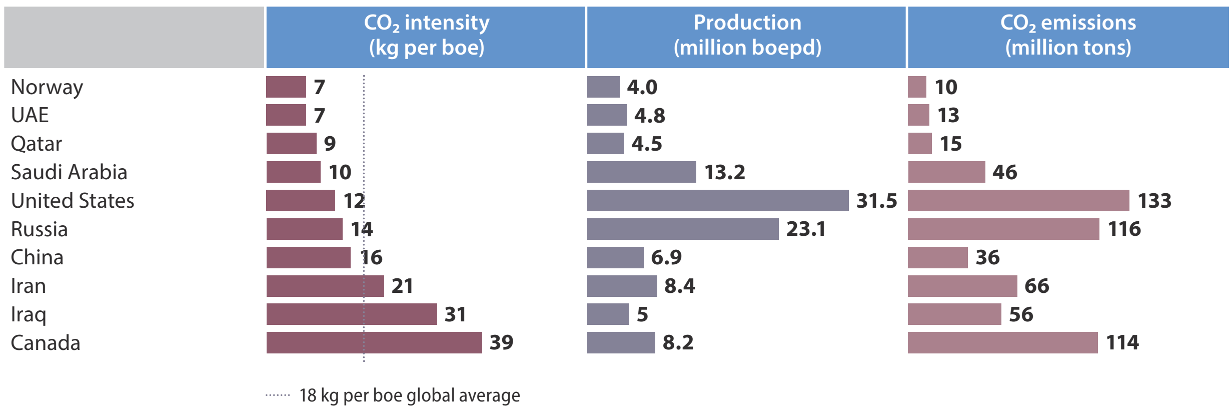


Figure 6.2 Upstream CO2 emissions for the 10 largest oil and gas producing nations in 2018 *Source: Rystad Energy (2020)*

jointly with the EU, and is working to persuade the latter to raise its goal for 2030 to 55 per cent. The European Commission recently proposed such an increase for consideration by the Council and Parliament.

Norwegian gas

Measures by the EU to reach its climate goals include a big commitment in recent years to forms of renewable energy, such as wind and solar power. That has made a positive contribution to reducing CO_2 emissions, but also presents some challenges since this type of energy supply is variable. As the share of renewables rises, the need grows for energy sources which can interact with variable supplies. Gas and regulatable hydropower are very suitable candidates because they can easily swing up and down to match fluctuations in solar and wind power – unlike, for instance, nuclear energy. The combination of gas-fired and wind power both on land and offshore, a high CO_2 price, and energy efficiency improvements have led to a substantial fall in the use of coal-fired electricity in the UK and a decline in CO_2 emissions. As Britain's largest gas supplier (Figure 6.3 [22]), Norway has made an important contribution here. Norwegian gas deliveries to the UK have a lower climate footprint per unit than any other sources (Figure 6.4 [23]).

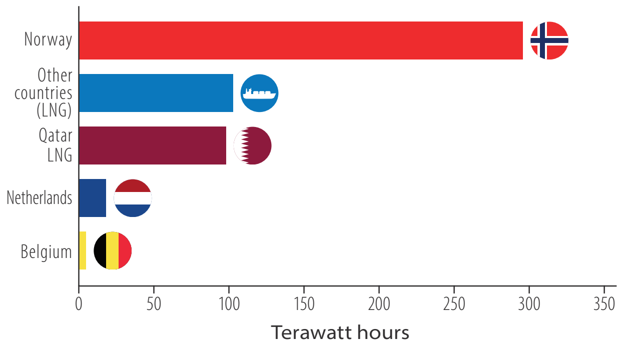


Figure 6.3 Britain's most important import sources – natural gas, 2018 *Source: gov.uk (2020). Belgium is a transit country, mainly for Russian gas.*

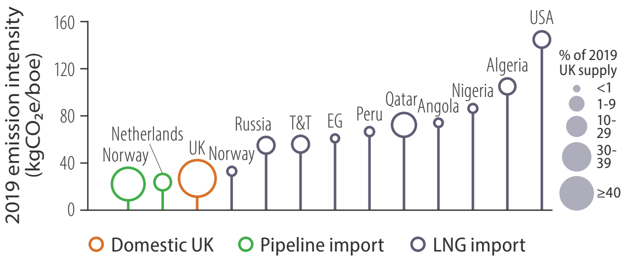


Figure 6.4 Emission intensity for natural gas deliveries to the UK. *Source: OGA (2020)*

Replacing coal with gas and renewables in the power sector generally represents an efficient way of achieving large, fast and reasonably priced emission cuts, since gas releases up to 50 per cent less CO_2 than coal when burnt. Facilitating continued gas exports to Europe and the world is an important part of Norwegian petroleum policy. Big undiscovered gas resources exist on the NCS (Chapter 3 Undiscovered resources).

Renewable energy and seabed minerals

Increasing the generation and use of renewables in order to reduce consumption of fossil fuels is important for reaching the Paris agreement's goals. This energy transformation will call for a substantial commitment to new technology. That primarily involves renewable sources (hydro, wind and solar), improved energy storage and reduced losses (batteries and transmission), less use of fossil fuels (electric vehicles, lighter materials), and advanced and intelligent technical solutions. Most of these areas are mineral-intensive. In the long term, it will be possible to meet a significant part of this demand through recycling. However, population growth and rising prosperity mean a continued expansion in resource consumption which cannot be met immediately from recycled materials. In particular, demand will increase for selected elements such as lithium, cobalt, nickel and manganese as well as certain rare earth elements (REEs). These materials partly occur as accumulations on the ocean floor along the Mid-Atlantic Ridge (MAR). In Norway's exclusive economic zone, they are found in sulphide ore accumulations and manganese crusts. The potential for exploiting and creating value from such possible resources is high, since the Norwegian oil industry is a world leader in marine technology.

CO_2 management

Scenarios from both the UN intergovernmental panel on climate change and the IEA estimate that significant carbon capture and storage (CCS) will be needed to reach the Paris agreement's goals. This involves capturing, transporting and storing CO_2 from such sources as power generation or industrial processes. The purpose of such management is to limit emissions to the air by capturing CO_2 and then storing it safely in deep geological formations.

A growing demand for such storage, including in Europe, may offer new opportunities for value creation on the NCS. CO_2 management could also strengthen the competitiveness of natural gas in relation to other energy forms, and thereby enhance the value of Norwegian gas resource in the long term. In addition, cost-effective CCS could increase the value of gas hydrates, which may exist in large quantities on the NCS [7].

From gas to hydrogen

Hydrogen is an energy bearer with the potential to store large quantities of energy. It is currently produced primarily from fossil fuels such as coal, oil and gas, which liberates CO_2, and is then termed "grey" hydrogen. With CCS, gas can be converted to almost emission-free "blue" hydrogen. Hydrogen can thereby be produced with very low GHG emissions and burnt with none. It can also be produced as "green" hydrogen using renewable energy (fact box 6.1).

The industry is an active driving force for achieving such low-emission solutions on the NCS, where offshore wind power, gas, CCS and hydrogen are important elements (fact box 6.2). Britain has developed a vision for integrating the various energy activities on the UK continental shelf (Figure 6.5 [24]).

This envisages extensive collaboration and coordination to ensure cost-effective and competitive solutions. If these initiatives help to develop a value chain for emission-free hydrogen, demand for natural gas as feedstock in such production could increase. The combination of CCS infrastructure and big gas resources means that Norway is well placed in a potential market for hydrogen.

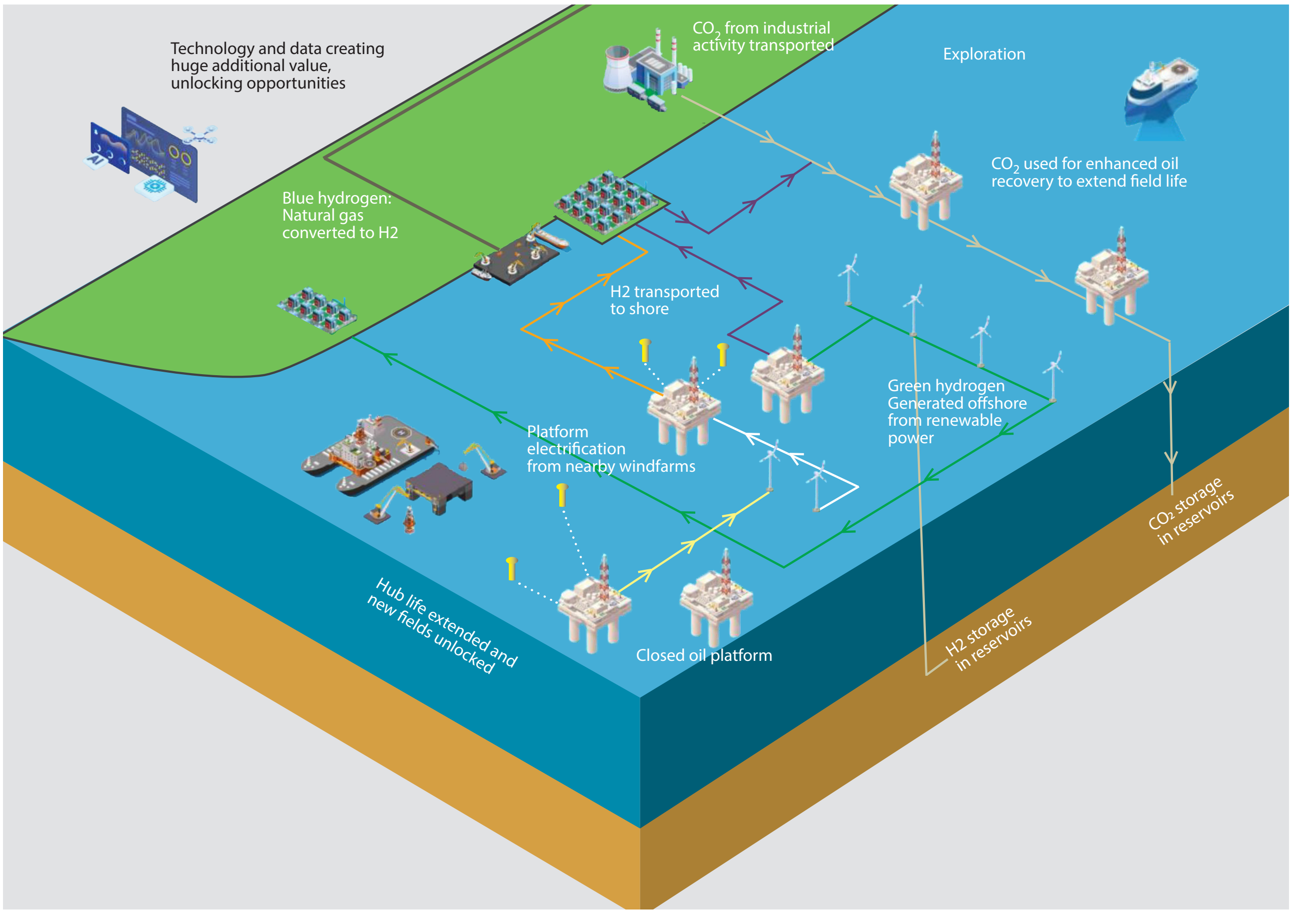


Figure 6.5 Vision for integrating various energy activities, UK *Modified from the OGA (2019)*

Fact box 6.1 Hydrogen

An important measure for reaching the goal of climate neutrality is achieving the conversion from direct use of fossil fuels to emission-free energy bearers such as hydrogen. The latter can be produced with no or very low GHG emissions, and releases none when burnt. This gas is also highly suitable as a long-term energy storage medium without loss of energy content. Hydrogen can replace fossil fuels for many applications in transport, traditional industry, power generation, and in manufacturing synthetic products.
The most relevant production methods are electrolysis, where water is split into hydrogen and oxygen using electricity, and steam reforming with methane split into hydrogen and CO_2. If these processes are to give a climate gain, renewable energy sources have to be used ("green" hydrogen) or the CO_2 from steam reforming must be stored in geological structures using CCS ("blue" hydrogen).

Fact box 6.2 Energy industry of tomorrow on the NCS

The KonKraft partners (fact box 5.5) and Equinor presented new climate targets in January 2020, with offshore wind power, CCS and hydrogen as important elements (Figure 6.6 [25]). The goal is that Norway's oil and gas industry will reduce its GHG emissions by 40 per cent in 2030 compared with 2005, and to near zero in 2050. These ambitious targets can provide a good starting point for utilising the expertise and technological knowledge in the oil sector even further in finding new and better solutions for the climate challenge.

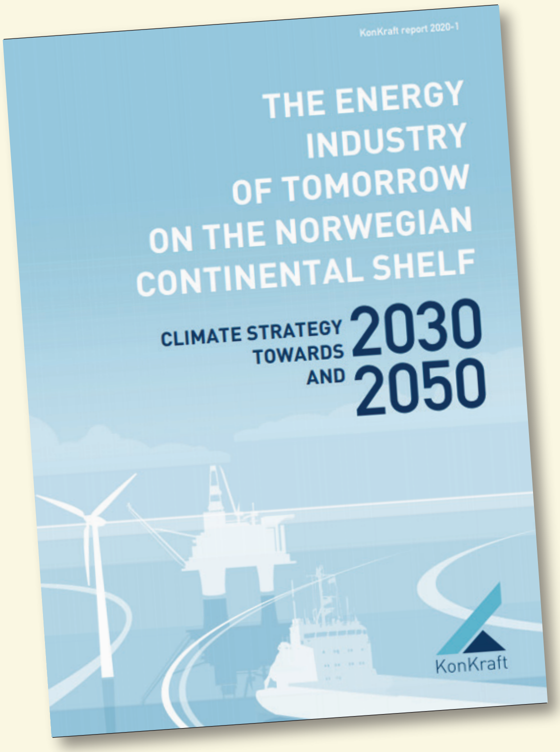


Figure 6.6 Energy industry of tomorrow on the NCS
Source: KonKraft (2020)

Carbon storage on the NCS

First licence awarded for CO_2 storage

Equinor was awarded the very first exploitation licence (EL 001) for CO_2 injection and storage on the NCS in January 2019 (Figure 6.7).

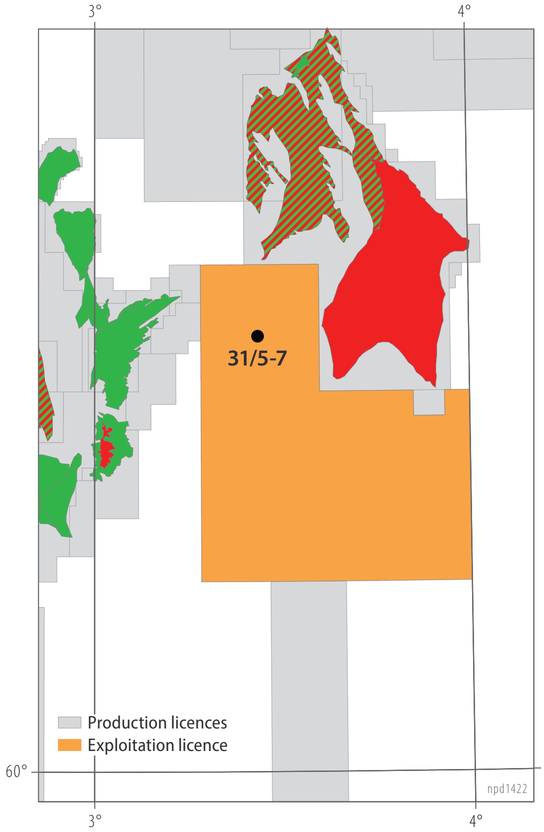


Figure 6.7 Exploitation licence EL 001

Drilling began in December 2019 to identify reservoirs which could provide suitable CO_2 storage. Completed in February 2020, this well 31/5-7 confirmed the presence of a sandstone reservoirs with properties which make it well-suited for CO_2 storage.

The reservoir is water-bearing, and no oil or gas has ever been produced from these formations in this area.

Northern Lights

The Northern Lights project covers CO_2 transport, reception and permanent storage in EL 001 in the northern part of the North Sea. It is being pursued jointly by Equinor, Shell and Total, and is receiving government funding. In May 2020, Equinor unveiled a plan for development and operation (PDO) on behalf of the Northern Lights partnership for CO_2 transport and storage on the NCS. This was submitted to the MPE, and the NPD gave their recommendations in accordance with the CO_2 storage regulations.

Langskip

The government presented Report no 33 (2019-2020) to the Storting (parliament) in September 2020. This sought approval for Longship, a Norwegian demonstration project on full-scale CO_2 management covering capture, transport and storage. Norcem is proposed as the first CO_2 capture project, followed by Fortum Oslo Varme on condition that the latter secures sufficient funding from its own resources and from the EU and other sources. Captured CO_2 from Norcem will be liquefied and sent to Brevik in the port of Grenland for intermediate storage. From there, it will be shipped to a new terminal at Kollsnes outside Bergen before being piped roughly 100 kilometres through a seabed pipeline and injected into a reservoir about 2 600 metres beneath the North Sea for permanent storage (Figure 6.8). Northern Lights is the transport and storage part of the Longship project.

Permanent sub-surface storage

Plans call for CO_2 to be stored in the Cook and Johansen Formations south-west of the Troll field. A staged development involves a first phase with a planned CO_2 capacity of 1.5 million tonnes per annum. However, flexibility to expand this will be built in, and the ability to offer CO_2 storage to other European countries is an important goal.

The project aims to demonstrate that the gas can be stored securely and to help reduce the cost of future projects. Government support is a precondition.

Experience

Norway has long experience with and good expertise on secure CO_2 storage beneath the seabed. Around a million tonnes captured from Sleipner West gas has been injected annually in the North Sea's Utsira formation since 1996. Roughly 700 000 tonnes per annum has also been stored since 2008 near the Snøhvit field in the Barents Sea. This CO_2 is removed from natural gas at the Melkøya liquefaction plant and piped back to a reservoir around 140 kilometres from land.

Regular surveys are conducted to monitor how injected CO_2 is migrating through the storages. This is important to ensure that the gas remains in place, as planned and modelled. Such monitoring primarily utilises seismic survey methods and pressure measurements in the well.

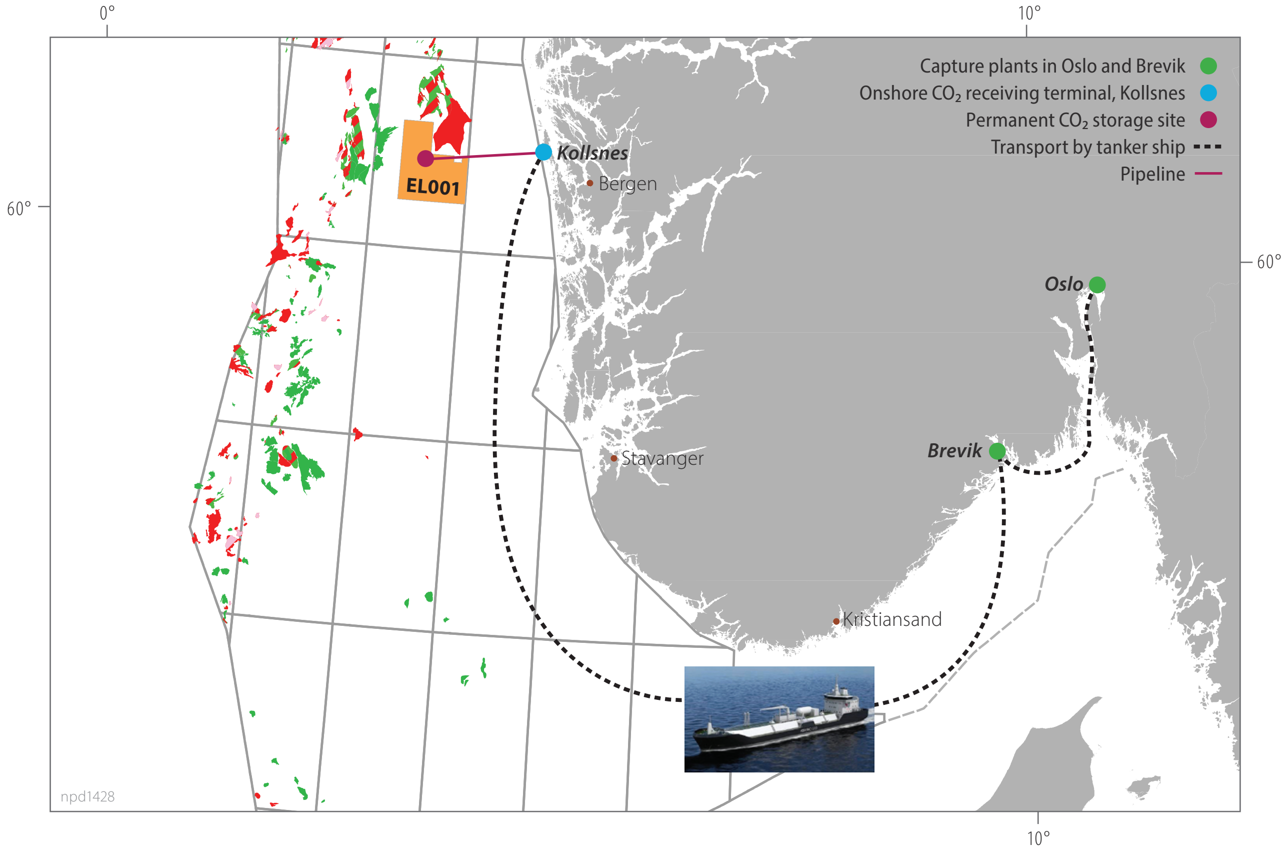


Figure 6.8 Longship – a full-scale CCS project

Fact box 6.3 Storage atlas
The NPD has mapped areas suitable for long-term and secure CO_2 storage on the NCS, resulting in an atlas of such sites (Figure 6.9 [26]). A range of storage opportunities have been evaluated, such as large aquifers, structural closures, abandoned fields and in combination with improved oil recovery. The calculated reservoir volume on the NCS is theoretically sufficient to accommodate more than 80 billion tonnes of CO_2, which corresponds to 1 000 years of Norway's annual emissions at the current rate.

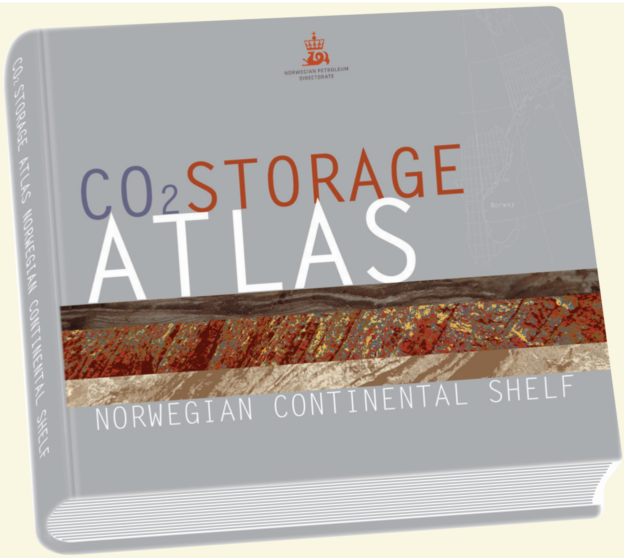


Figure 6.9 CO2 storage atlas *Source: NPD (2014)*

Fact box 6.4 Principles for injecting CO_2

An aquifer may comprise several sedimentary formations and cover a large area. Its rocks must have good porosity and permeability, where water in the pores is in communication. To be suitable for storage, the formations must be at a depth where CO_2 can be held in a super-critical phase (Figure 6.10 [26]). They must be covered by a thick cap of claystone and shale, forming a seal which prevents the CO_2 from migrating to other formations or the seabed. While gaseous under atmospheric pressure, CO_2 will behave as a liquid under the increased pressure and temperature at depths beyond about 800 metres.

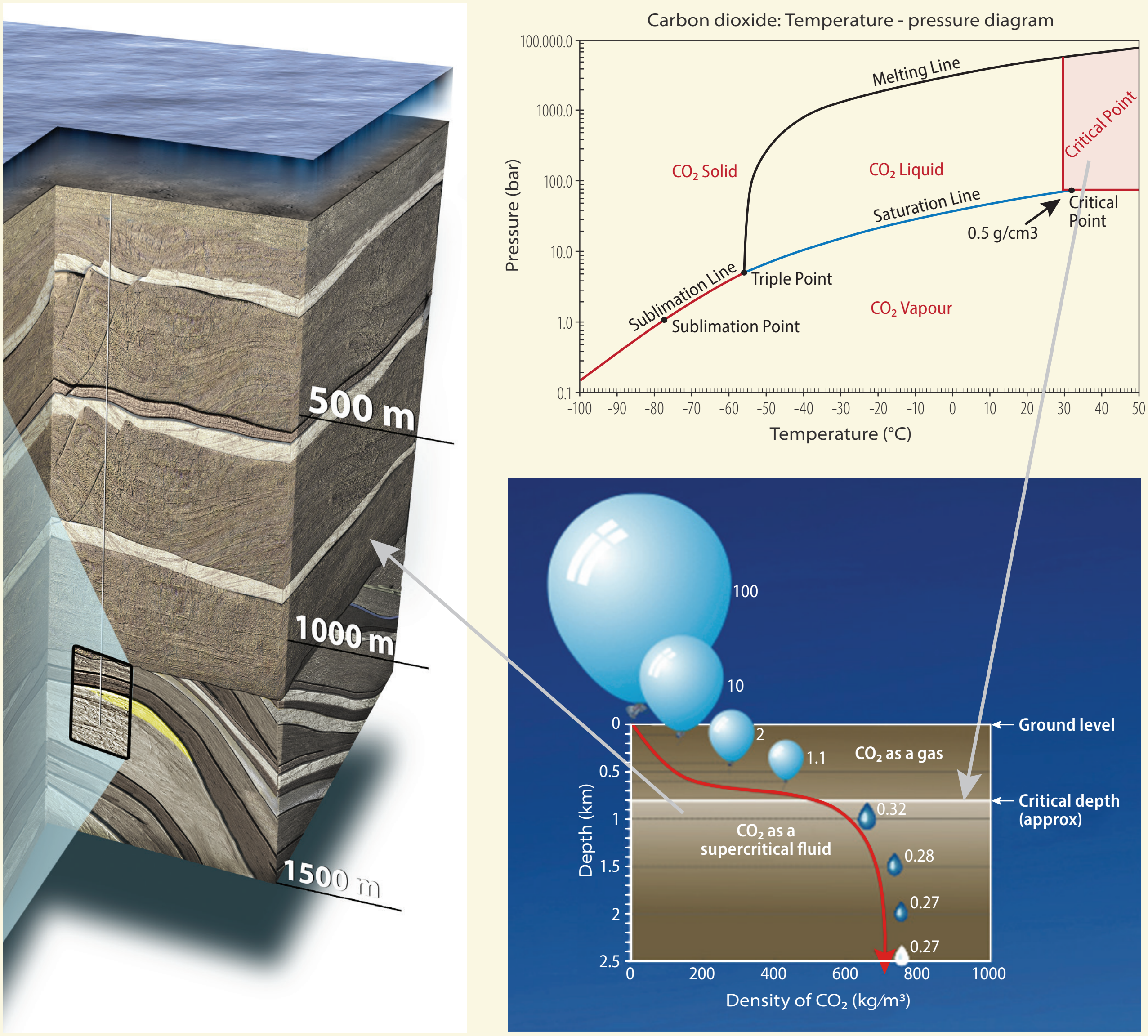


Figure 6.10 Principles for CO2 storage *Source: NPD (2014)*

Seabed minerals

The climate challenge and the digital transformation have increased demand for certain elements, such as lithium, cobalt, nickel and manganese as well as some REEs. These materials occur partly as accumulations on the seabed. In Norway's exclusive economic zone, they are found in massive sulphide ore accumulations and in manganese crusts. The government has decided to begin a process to open the NCS for mineral activities.

Seabed minerals on the NCS contain elements which will be important for the energy and digital transitions

Substantial resources on the NCS
Sulphide ores primarily contain lead, zinc, barium, copper, cobalt, gold and silver, and are linked to hot springs (black smokers) on volcanic spreading ridges. They also occur in collapsed vents forming mounds on the seabed, which are thought to contain the bulk of the sulphide ore resources.

Manganese crusts consist mostly of manganese and iron, plus small quantities of cobalt, nickel, titanium and other less common metals. They grow as laminated accumulations on bare bedrock exposed at the seabed.

No mineral resources are produced from the seabed in any part of Norway's exclusive economic zone, but a number of accumulations have been identified and sampled along the volcanic Mohn Ridge between Jan Mayen and Bear Island. Clear indications of such resources also exist northwards along the Knipovich Ridge (Figure 6.13).

Sulphides
Volcanic activity and heat flows are high along the central axis of the Mid-Atlantic Ridge (MAR). Much of the heat is released through volcanic action, but also comes from hydrothermal areas. These have been stationary for several thousand years, with a stable level of activity where water is heated in the sub-surface and channelled to hot springs on the seabed. This creates a large-scale circulation of seawater through sub-surface rocks along the axis of the spreading ridges. The heated water leaches out metals in the rocks and carries them up to the hot springs on the seabed, where they precipitate as sulphides in the cold water and build up black smokers. A hydrothermal area is active for 10-100 thousand years before expiring and leaving mounds of sulphide ores (Figure 6.11). These form the individual accumulations.

The seabed spreads very slowly in this part of the Atlantic, at less than a centimetre per annum on either side of the axis. Over a million years, a sulphide deposit formed in a hydrothermal area will have moved about 10 kilometres from the axis and been gradually covered by sediments. After roughly two million years, the sulphides will generally be so deeply buried that they are difficult to find with current

Figure 6.11 Inactive sulphide accumulations with collapsed vents *Taken by the K G Jebsen centre for deep sea research at the University of Bergen during the NPD's deepwater expedition, summer 2019.*

technology. This means that interesting ore accumulations will initially be found in a belt 30-40 kilometres wide along the MAR axis

Manganese crusts

Manganese crusts grow on bare rock on subsea ridges and seamounts in most of the deepwater areas of the NCS. The seamounts comprise the wedge-sharped tops of extinct volcanoes which range 500-1 500 metres above the seabed in a zone 200-300 kilometres wide on the flanks of the spreading ridge. Manganese crusts are also found on the Vøring Spur and the Jan Mayen Ridge.

Cold seawater contains dissolved metal compounds originating at hot springs and in runoff from land. Manganese crusts are precipitated directly as thin laminates on the rock. These build up very slowly, at about 0.1 to one centimetre per million years (Figure 6.12).

Fact box 6.5 Managing seabed minerals

The Act relating to mineral activity on the continental shelf (the Seabed Minerals Act) came into force on 1 July 2019 to facilitate exploration for and exploitation of accumulations on the NCS.

Responsibility for seabed minerals has been assigned to the MPE, with the NPD as the regulatory agency supporting the ministry's work.

The NPD is responsible for national administration of all sub-surface data acquired from the NCS, and for mapping seabed mineral accumulations there. This concerns two types of deposit – sulphide ores and manganese crusts.

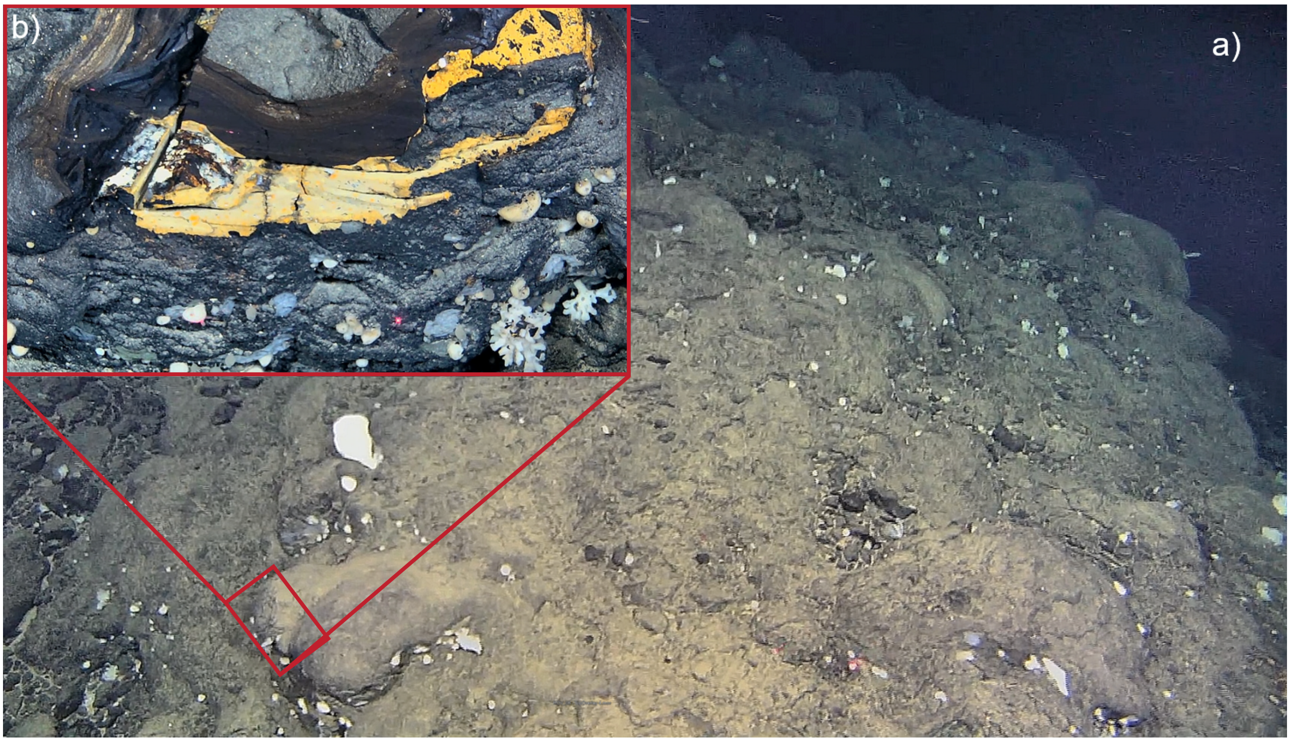


Figure 6.12 Manganese crusts *a) Typical location for sampling crusts. b) Close-up of the sampling site*
Taken by the K G Jebsen centre for deep sea research at the University of Bergen during the NPD's deepwater expedition to the seamounts east of the Mohn Ridge, summer 2019.

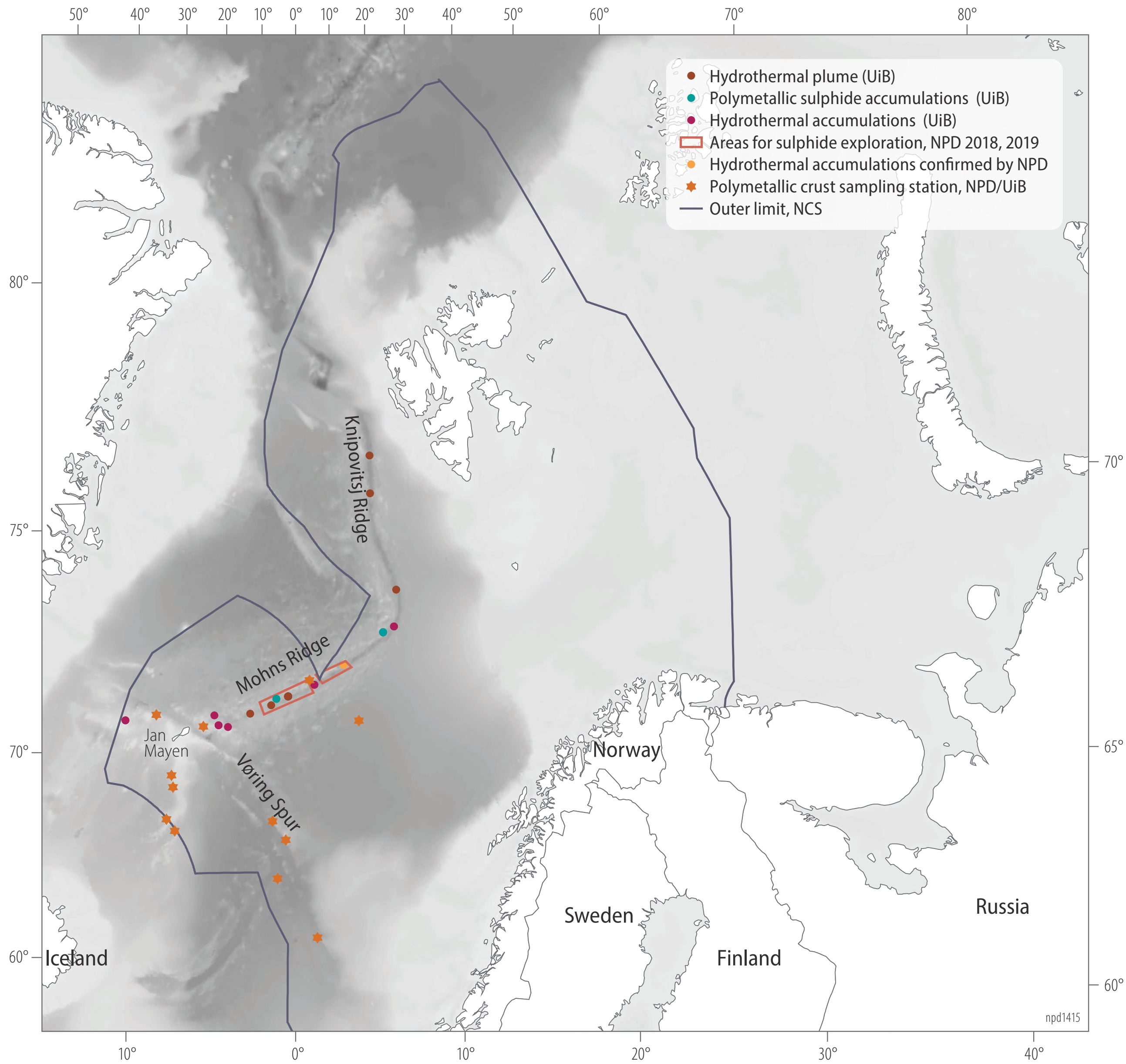


Figure 6.13 Overview of exploration for seabed minerals in the deep NCS by academics and the NPD *Red and green dots show sulphide accumulations associated with currently active and inactive hot springs respectively. Yellow dots show hot water from possible active springs. The pink rectangles show the area discovered by the NPD in 2019 with both active and inactive sub-areas. Yellow stars mark where manganese crusts have been sampled.*

Exploring for seabed minerals on the NCS
Systematic mapping and exploration of the MAR north of Iceland was initiated by the University of Bergen (UiB) in the late 1990s (Figure 6.13). Several active, inactive and extinct hydrothermal areas have subsequently been documented on the NCS. The first hydrothermal sulphide accumulations were identified in 2005 immediately north of Jan Mayen, on the southernmost part of the Mohn Ridge. This part of the ridge system is shallower (around 1 000 metres) and more magmatically productive than further north. This shallow and hydrothermal area contains both active and inactive sub-areas.

The UiB first discovered black smokers further north along the Mohn Ridge more than a decade ago, with Loke Castle as the first (Figure 6.13). Drawing partly on the NPD's big multibeam bathymetric dataset in the Norwegian Sea (acquired for boundary mapping), the UiB identified several sulphide accumulations along the volcanic Mohn Ridge between Jan Mayen and Bear Island, and further north along the Knipovich Ridge.

A multiyear research collaboration was established by the UiB and the NPD in 2010 to map and investigate the seabed in the deeper parts of the Norwegian Sea. On the annual research expeditions, the UiB has concentrated on the spreading ridges and the volcanic processes which deposit sulphides. At the NPD, this work has become part of the general mapping of NCS resources in recent years. It primarily uses the expeditions together with the UiB to investigate manganese crusts.

This collaboration has identified accumulations of the latter, and almost 100 samples have so far been collected. Their thickness ranges from a few millimetres to almost 20 centimetres, and their value varies in line with their content of metals in addition to manganese and iron. In parts of the Pacific, it is the presence of cobalt which makes the crusts economically interesting. Crustal accumulations found so far on the NCS do not contain much cobalt, but they could be economically interesting because of unusually high concentrations of scandium and lithium and a fairly high content of REEs. Analyses show that the crust samples fall into two groups: one with almost twice the amount of REEs as in the Pacific, and the other with a rather lower content of these, particularly lanthanides.

As part of the NPD's mapping of possible mineral resources, it conducted its own expeditions in 2018, 2019 and 2020 to investigate massive sulphide ores from hydrothermal systems on the Mohn Ridge. In the first two years, autonomous underwater vehicles (AUVs) equipped with various geochemical and geophysical measuring devices were utilised. Ship-borne bathymetric (echo sounder) findings were used as background input for the AUVs, which acquired data about 50 metres above the seabed.

A previously unknown area of sulphide deposition, with both active and inactive sub-areas, was discovered in 2018 – initially through geochemical and geophysical measurements by AUV. Visual inspection and confirmation was then carried out using a remotely operated vehicle (ROV) controlled from a mother ship. Named "Fåvne", this area is located in about 3 000 metres of water. Sulphide samples show a generally high content of copper and zinc, and one with high values for cobalt was also taken.

In 2019, the NPD mapped the seabed using three AUVs simultaneously – the first time this had been done in the search for seabed minerals. Most of the geophysical and geochemical instruments used the year before were deployed again. A new inactive sulphide area was identified south-west of Fåvne by measuring the self potential (SP) field, and has been named "Gnitahei".

Further north on the Mohn Ridge, magnetic data indicated three different inactive sulphide areas – Mohnsskatten 1, 2 and 3 (MS1, MS2 and MS3). ROV excursions were conducted on all three, but materials were only retrieved from MS2. MS3 proved to be entirely covered by sediments.

About 100 kilograms of samples, both volcanic rocks and sulphide ores, were collected during the 2019 expedition. Preliminary analyses of Gnitahei have so far identified mostly iron sulphide (pyrites) and smaller quantities of copper, zinc and cobalt. More detailed analyses will be carried out in 2020.

Work continued in 2020 to investigate the thickness of the sulphide accumulations on the Mohn Ridge with a new expedition. Cores were drilled with the first use of coiled tubing in such water depths. In addition, substantial material in the form of rock and sulphide samples was taken from the seabed. This will provide better understanding of volumes and changes in metal composition further down in the sub-surface.

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Professor Olav Hanssens vei 10
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