RESOURCE REPORT
DISCOVERIES AND FIELDS 2019

NORWEGIAN PETROLEUM DIRECTORATE

CONTENTS

Foreword

Petroleum operations rank as one of Norway's most important industries. Oil and gas have yielded huge revenues, which have contributed to developing Norwegian prosperity. Resources on the Norwegian continental shelf (NCS) are sufficient for this business to continue over many decades.

Norway currently accounts for about two per cent of oil and three per cent of gas consumed globally. Although we contribute a modest share of overall production, our petroleum industry is a technological world leader. Expertise, technology development and a commitment to reducing our production footprint are key aspects. We have developed offshore technology which permits safe, efficient and high levels of production with low emissions, and we are a major exporter of technology to other petroleum regions around the world.

The NCS is characterised by a wide variation in discovery size and maturity. Johan Sverdrup comes on stream this autumn as our biggest field development for the past 20 years, and will contribute to a high level of production for a long time to come. Skogul and Utgard will also be starting to produce. The first of these fields ranks as the smallest development ever on the NCS, while the other is a 40-year-old discovery which has finally been developed. This demonstrates the diversity and opportunities on the NCS.

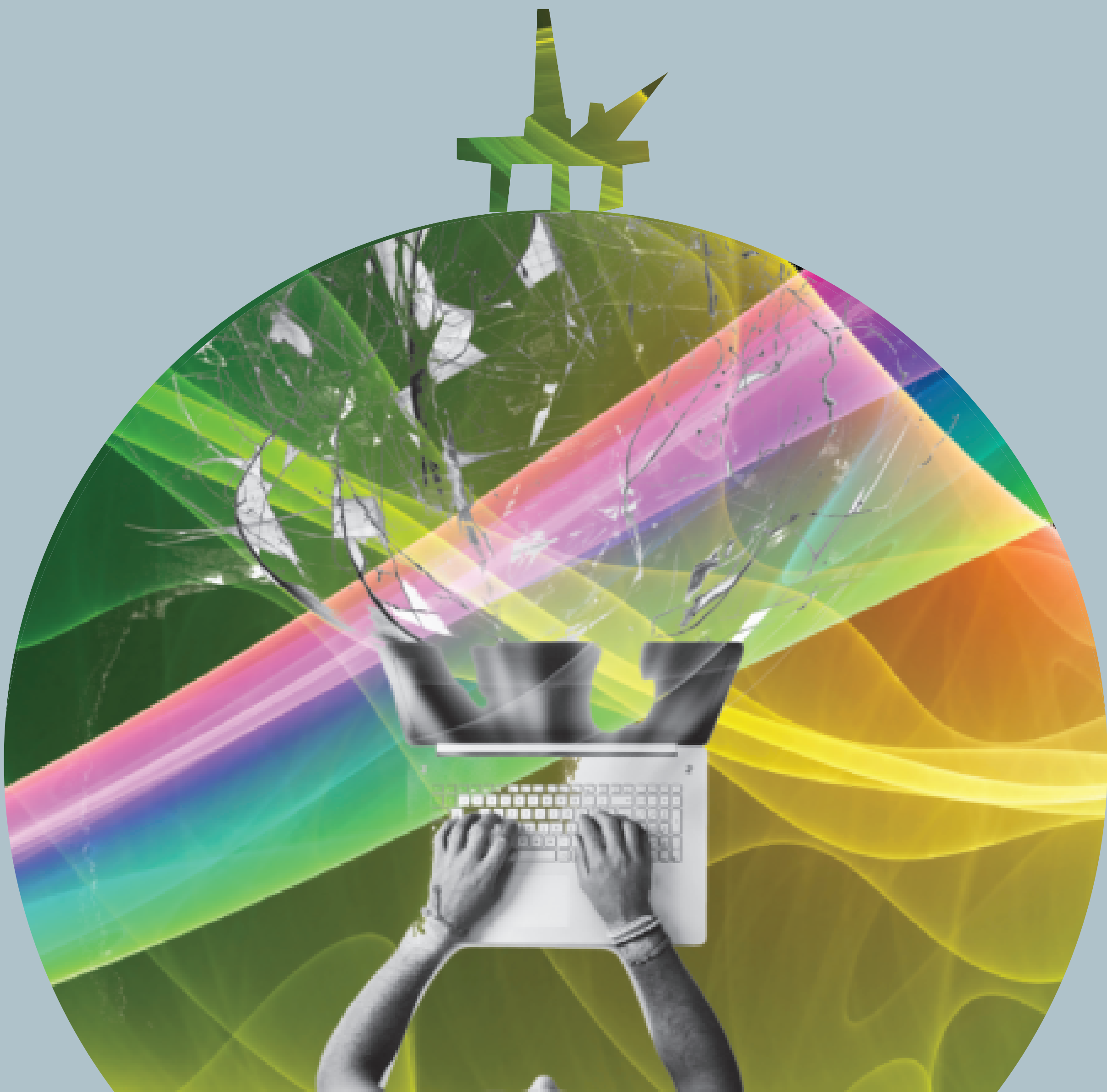
Ensuring that the petroleum industry creates the greatest possible value for society is the main job of the Norwegian Petroleum Directorate (NPD). This year's resource report on fields and discoveries presents facts and analyses which show that good work is being done to create value on the NCS. At the same time, we see a substantial potential for increasing value creation even further. We want to ensure that all profitable barrels are produced, not simply the easiest.

A great deal of oil and gas has been discovered which is not currently covered by production plans. However, new and more cost-effective technology, better use of data and innovative ways of working could make these resources also profitable. Technology and expertise are fundamental for a high and energy-efficient level of production in the future. That calls for both the ability and the willingness to make a continued commitment.

We hope this resource report will be useful for everyone working to create value for society through their work in the industry, and for everyone else seeking to learn about Norway's petroleum resources.

Stavanger, 27 September 2019
Ingrid Sølvberg
Ingrid Sølvberg
Director development and operations

SUMMARY



Summary

Total recoverable resources on the NCS at 31 December 2018 were estimated to be 15.6 billion standard cubic metres (scm) of oil equivalent (oe), including quantities already produced. The expected value of remaining recoverable resources is 8.3 billion scm oe, with roughly half that amount already proven in fields and discoveries. These big volumes provide the basis for a high level of value creation from the oil and gas industry for a long time to come.

At 31 December 2018, there were 85 discoveries where the licensees had yet to submit a plan for development and operation (PDO) to the government. These contain total recoverable resources of 660 million scm oe, and represent 15 per cent of remaining discovered petroleum resources. Roughly half the total resources in the discovery portfolio lie in the North Sea, just under a third in the Norwegian Sea and about a fifth in the Barents Sea. The total investment required to develop the whole portfolio is estimated to be in the order of NOK 400 billion in 2018 value.

The average size of discoveries in the portfolio has declined over the past 20 years. Phasing into existing infrastructure is therefore the most likely development solution for most of them. Maintaining existing infrastructure and utilising its spare capacity are important preconditions for realising the assets in the discovery portfolio. It is also important that new facilities are built with enough flexibility to accept additional resources, and that development and activity are coordinated where that would maximise value for society.

There were 85 producing fields on the NCS at 31 August 2019. Oil and gas production has remained at a high and stable level from the early 2000s, and rising oil output means overall production could reach a new peak in 2023. Reserves in fields increased by about 1 400 million scm oe in 2000-18, equivalent to more than three Johan Sverdrup fields. The reason is that decisions have been taken on a number of different measures for improved recovery from the fields. Better sub-surface understanding, drilling of more wells, improved recovery measures, and greater operational efficiency are factors contributing to increasing reserves and thereby to greater value creation.

More than half the investment on fields in 2018 related to wells. In recent years, cost control and efficiency improvements have cut the average bill per production well by more than 40 per cent. Operating costs on most fields have also been substantially reduced. They fell by 30 per cent on average from 2013 to 2017. New solutions, including automation and remote operation, improved use of data and more efficient operation, could further reduce costs and help to increase production even more.

As production from existing fields declines, more spare capacity will become available in the infrastructure. To exploit this, exploration must be pursued around the mature fields, infrastructure owners must promote spare capacity, and companies must collaborate on phasing in additional resources. Such phasing in helps to reduce unit costs and extend the producing life of the host field, and means that a greater proportion of the resources can be produced.

The NPD has mapped volumes in place for tight reservoirs in 42 discoveries and fields. This work indicates that some 2 000 million scm oe are present. Achieving profitable production from tight reservoirs calls for the development of cost-effective solutions which increase reservoir exposure in the wells so that the oil and gas flow better. Nevertheless, in a number of cases, production can only become profitable through a tie-back to existing infrastructure. Since tight reservoirs are expected to have a long production horizon, deciding on their development before the commercial life of existing infrastructure becomes a constraint will be important.

A study of the potential offered by using advanced methods for enhanced oil recovery (EOR) was conducted by the NPD in 2017. This work has now been updated and expanded to cover more fields and discoveries. A recovery potential of about 350 million scm oe has been estimated, with an uncertainty range from 180 to 500 million scm. EOR could thereby contribute to recovering substantial volumes if the methods are qualified for use on the NCS. To achieve this, it is important that licensees test EOR methods through field pilots.

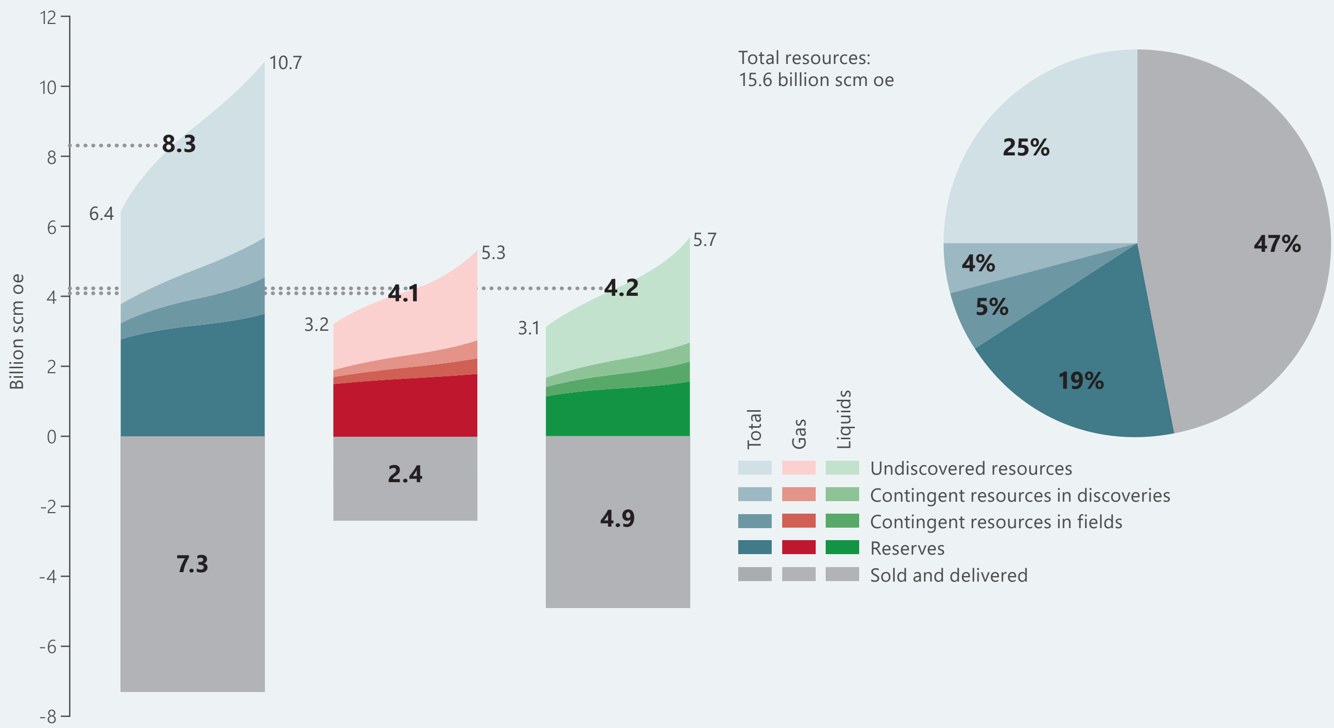
Concern for the natural environment has always been an integrated part of managing Norway's oil and gas resources, and is taken into account in all phases of the activity – from exploration and development to production and field cessation. The industry is subject to strict regulations covering both emissions to the air and discharges to the sea. Financial instruments, such as emission pricing through the CO_2 tax and allowance trading, gives the industry a self-interest in identifying and implementing emission-reducing measures.

Although petroleum production is expected to increase up to 2023, overall CO_2 emissions and produced water discharges are expected to remain stable. This means that both emissions to the air and discharges to the sea per unit produced will decline. Where emissions are concerned, that partly reflects a steady expansion in power from shore. Once the Utsira High area solution becomes operational, more than 40 per cent of production from the NCS will be run with power from shore.

More than half remains

The NPD presents annual resource accounts with an overview of total recoverable petroleum. These build on data reported by the operator companies, the NPD's own assessment of fields and discoveries, and its estimate of undiscovered resources.

Where 2018 is concerned, the accounts show that – after almost 50 years of production – remaining resources still exceed those already produced. At 31 December 2018, total recoverable petroleum resources were estimated at 15.6 billion scm oe. Of this, 7.3 billion scm oe had been produced and sold. The expected value for the remaining recoverable resources was 8.3 billion scm oe. It is estimated that around half of this still remains to be proven. Today's estimate for total recoverable resources is about 50 per cent higher than in 1990.



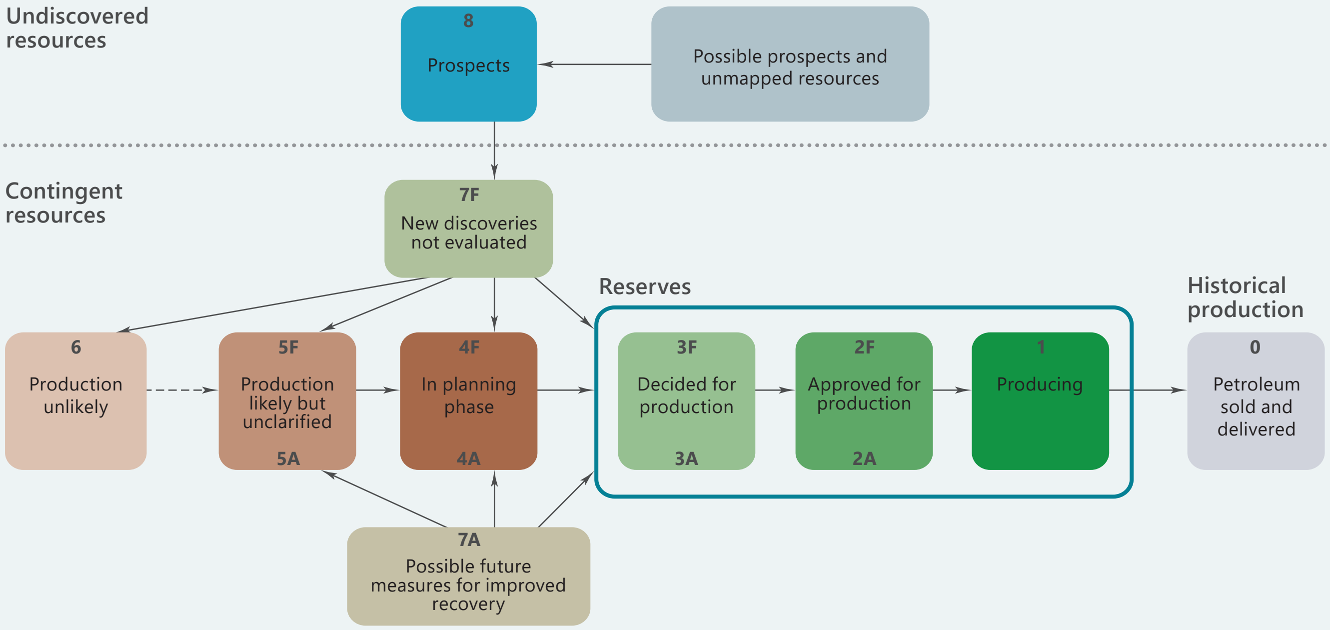
Distribution of total recoverable resources and uncertainty in the estimates at 31 December 2018

Classifying the resources

"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 deposits, 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.



The NPD's resource classification system

chapter 1

DISCOVERIES

Discoveries

At 31 December 2018, there were 85 discoveries where the licensees have yet to submit a PDO to the government. These contain total recoverable resources of 660 million scm oe, and represent 15 per cent of remaining discovered petroleum resources.

Resources in discoveries

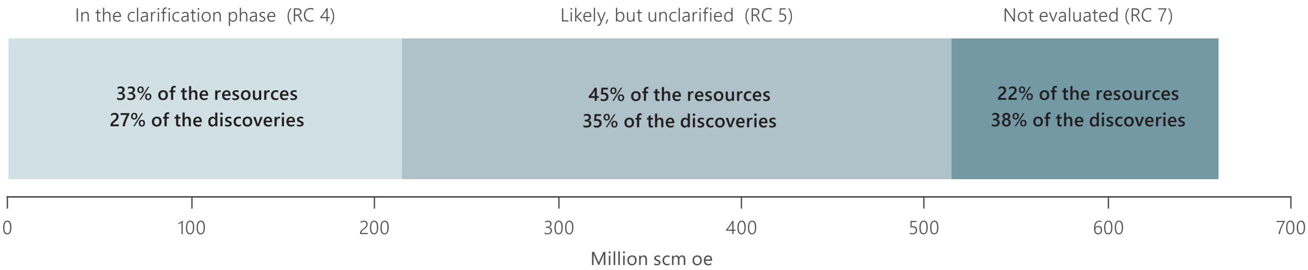


Figure 1.1 *Discovery portfolio by volume and development status*

Resources in the discovery portfolio break down into 360 million scm of liquids (oil, natural gas liquids (NGL) and condensate) and 300 billion scm of gas. The total investment required to develop the whole portfolio is estimated to be in the order of NOK 400 billion in 2018 value. Developments are either in the clarification phase (RC 4), likely but unclarified (RC 5) or not evaluated (RC 7). Figure 1.1 presents the portfolio by development status in resource classes (RCs).

The number of discoveries in the portfolio at 31 December 2018 was about the same as in 1999. However, their average size had declined over the same period from 20.8 to 7.8 million scm of recoverable oe. This is because more of the big discoveries have been developed, while new additions to the portfolio are by and large smaller than before. Figure 1.2 shows how the number of discoveries and volume estimates in the portfolio have developed since 1999.

When discoveries in the portfolio diminish in size, the industry must find solutions which make developments profitable with a smaller resource base. This has so far been successful. More discoveries are being developed and the level of activity on the NCS is high, while technology and profitable solutions for development and production are being created for ever smaller discoveries. Figure 1.3 shows the average size of approved new developments and their total number by decade.

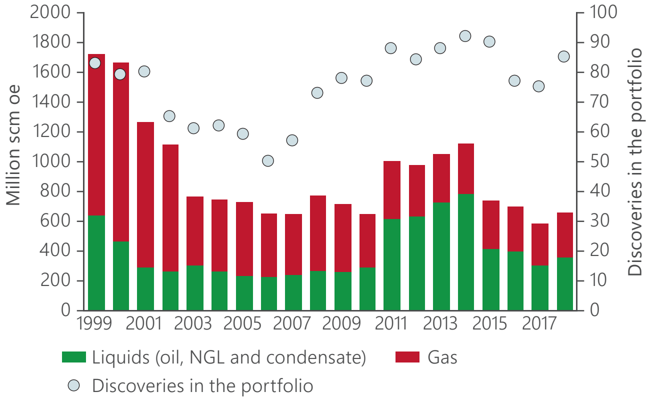


Figure 1.2 *Development of resources and number of finds in the discovery portfolio from 1999 to 2018*[1]

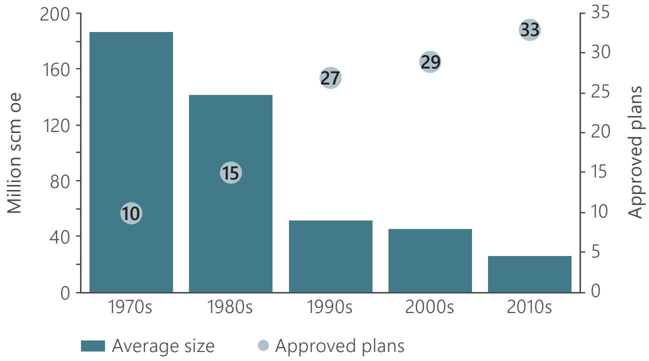


Figure 1.3 *Average size at first PDO and number of approved development plans*

Figure 1.4 presents the number of discoveries and resources in the discovery portfolio by the number of years since they were found. Most discoveries in the present portfolio have been made during the past 20 years.

New discoveries are crucial for maintaining a high level of production in the long term. Many exploration wells have been drilled in 2019. At 31 August, 32 of them had been completed and 10 discoveries made. The level of exploration activity is also expected to remain high next year.

Resources in discoveries by sea area

Most of the discoveries and roughly half the total resources in the discovery portfolio lie in the North Sea, just under a third in the Norwegian Sea and about a fifth in the Barents Sea. The average discovery size is greatest in the Barents Sea, at 10.9 million scm recoverable oe. That is followed by 7.6 million scm oe in the Norwegian Sea and seven million scm oe in the North Sea. Figure 1.5 presents discoveries by sea area and expected recoverable resources.

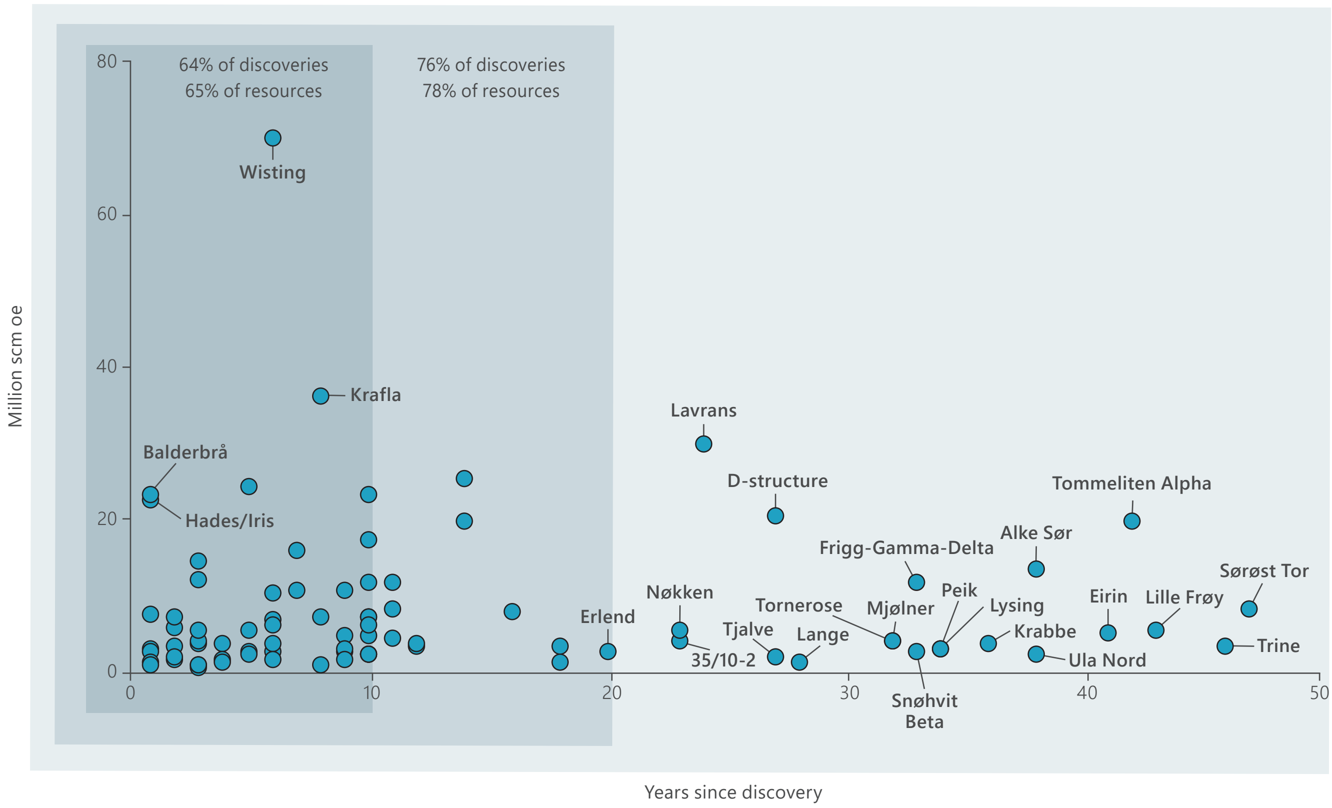


Figure 1.4 *Discoveries and resources in the portfolio by years since discovery*

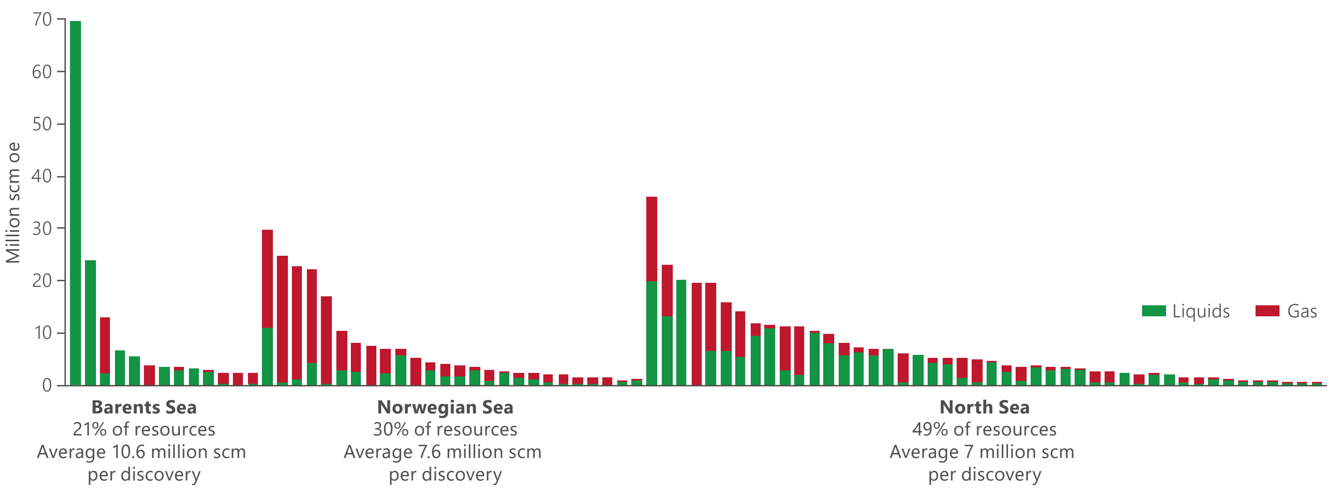


Figure 1.5 *Discoveries by sea area and expected recoverable resources at 31 December 2018*

Many discoveries in the North Sea have estimated recoverable resources below 10 million scm oe. These will probably be developed with subsea facilities and tied back to the extensive infrastructure in the area.

In the Norwegian Sea, 40 billion scm of gas were found during 2018 in 6604/5-1 Balderbrå and 6506/11-10 Hades/Iris, which rank as the biggest gas discoveries on the NCS since 2011. Several other large gas discoveries are also present in this area, and most of these are likely to be tied back to existing infrastructure.

The Barents Sea is a less mature area. Little infrastructure has been developed so far and relatively few discoveries are being considered for development for the moment. At the same time, Wisting in the Barents Sea is the biggest discovery on the NCS. Its licensees are working to mature solutions for a stand-alone development. In the event, that would provide the northernmost oil infrastructure on the NCS.

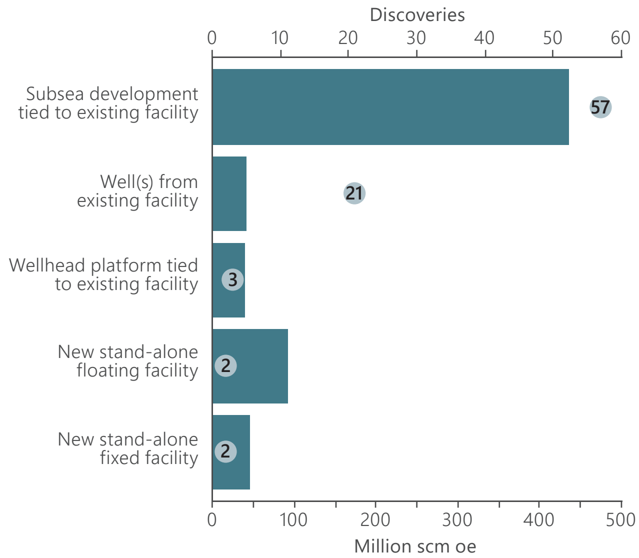


Figure 1.6 *Discoveries and resources in the portfolio by the most probable development solution*

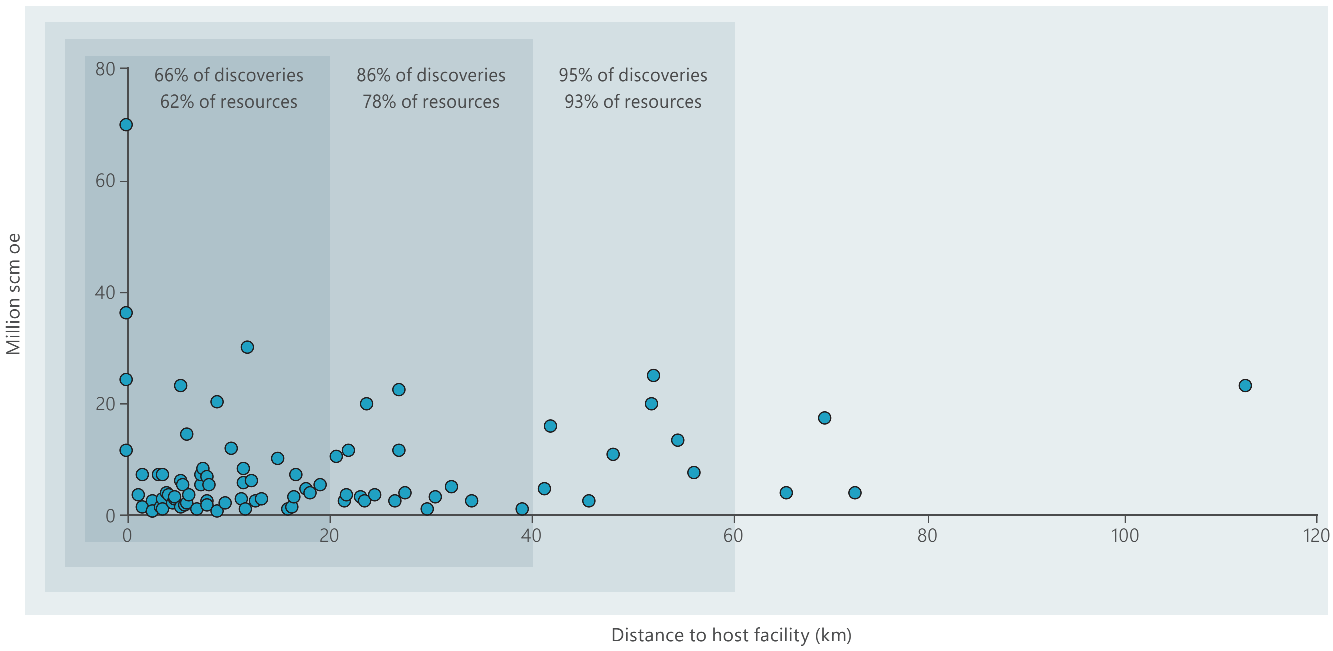


Figure 1.7 *Resources and distance from possible host facilities for discoveries in the portfolio*

Existing infrastructure must be maintained and utilised

Phasing into existing or future infrastructure makes it possible to develop discoveries which are too small to be profitable on their own. This is expected to be the commonest development solution for discoveries in the portfolio.

Current plans indicate that around 80 discoveries amounting to roughly 500 million scm recoverable oe could be developed in this way. Maintaining the infrastructure is a precondition for phasing in discoveries by allowing the technical lifetime of the facilities to be extended if necessary. Figure 1.6 presents the discoveries and resources in the portfolio by the most probable development solution.

Subsea development is also relevant for larger discoveries. Seven of the 10 biggest finds are expected to be developed in this way and phased into a host field. These could collectively represent an investment of more than NOK 60 billion in 2018 value at today's level of costs, and provide good examples of profitable utilisation of existing infrastructure. This includes the Grand development, where plans call for the joint development of several discoveries to be phased into the Grane facility in the North Sea.

Maintaining the infrastructure is a precondition for phasing in discoveries

Transporting unprocessed oil and gas over long distances poses a technical challenge because of the risk that deposits could plug the pipeline. This is particularly a problem for oil discoveries located a long way from possible host facilities. In such cases, measures must be taken to safeguard the transport. One example is the Fenja development, where a technology was assessed for transporting oil in electrically heated pipelines over distances of around 60 kilometres. This type of technology development is crucial for being able to make even better use of the infrastructure.

Figure 1.7 presents the discoveries in the portfolio sorted by size and distance to possible host facilities. About 80 per cent of the discoveries and resources lie within a radius of 40 kilometres. This transfer distance does not normally pose problems for transporting unprocessed oil and gas.

Stand-alone developments

A number of discoveries in the portfolio could be developed jointly, with new stand-alone production facilities. That applies to finds with combined resources of more than 190 million scm oe, which could yield up to NOK 130 billion in investment at 2018 value with today's level of costs. These estimates include redeveloping and phasing in fields which have been shut down (such as Frøy).

It is important that new facilities are built with enough flexibility to accept additional resources, and that development and activity are coordinated where that would be of value for society. The government is working to encourage collaboration across production licences. That is crucial for identifying solutions which create the greatest possible overall value, as in the area between Alvheim and Oseberg in the North Sea and in the Alta-Gohta area of the Barents Sea.

The government is working to encourage collaboration across production licences

From "production unlikely" to development project

The companies are encouraged to relinquish discoveries they have no faith in, so that other players with new ideas get the opportunity to assess them for development. At present, 147 discoveries are classed as "production unlikely" (RC 6). They lie in both active and relinquished production licences, and are regarded today as non-commercial because they are too small, require the development of new technology or lie too far from infrastructure. It is important that these do not get written off, but are re-evaluated at regular intervals in the light of such factors as new technology, available infrastructure and changes to market conditions.

Thirty-seven discoveries of this kind, with combined estimated resources of 150-200 million scm recoverable oe, have had their status changed to possible developments since 2001. Most lie in the "production likely, but unclarified" phase or are to be re-evaluated. Seven of them have been developed or decided for production, and a decision on test production has been taken on another.

All seven discoveries are relatively small and have been or are being phased into existing fields. This demonstrates that even discoveries classed at one point as "production unlikely" can in certain cases be developed through coordination and the use of existing infrastructure.

Shut-down fields can be redeveloped

Twenty-five fields on the NCS have ceased production. Generally speaking, all profitable petroleum in terms of value to society should be produced before fields are shut down. Nevertheless, conditions such as technology development, market changes and new infrastructure could mean that resources not found commercially viable before cessation may become profitable later.

Discoveries must be developed at the right time

The period from proving a discovery until it comes on stream is known as lead time. The average lead time for developing new fields is 12 years, but with big variations from project to project. Apart from a period in the early 2000s, lead time has increased steadily from six years in 1972-78 to 16 in 2014-18.

As the NCS matures, fewer big discoveries are being made. At the same time, spare capacity becomes available in the infrastructure and new technology permits cost-effective development of discoveries which were earlier regarded as non-commercial. This means that an ever-growing number of the old discoveries are being developed and the average lead time is growing. Figure 1.9 shows the average lead time by year of coming on stream.

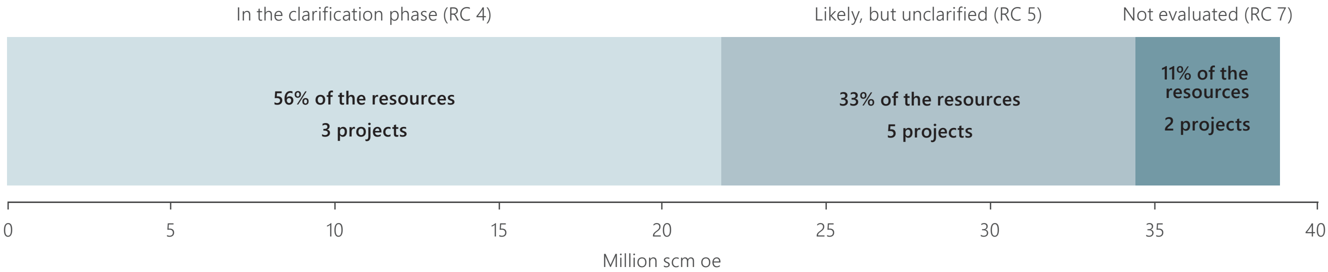


Figure 1.8 *Resources in projects on shut-down fields by redevelopment status (RC)*

At present, 10 projects have been reported to the NPD where the aim is to recover more of the resources in six shut-down fields. These could recover roughly 40 million scm oe, split equally between oil and gas. One example is Tor near Ekofisk. The licensees have submitted a PDO for reopening this field, which ceased production in 2015. Figure 1.8 presents the resources in projects related to shut-down fields by their redevelopment status (RC).

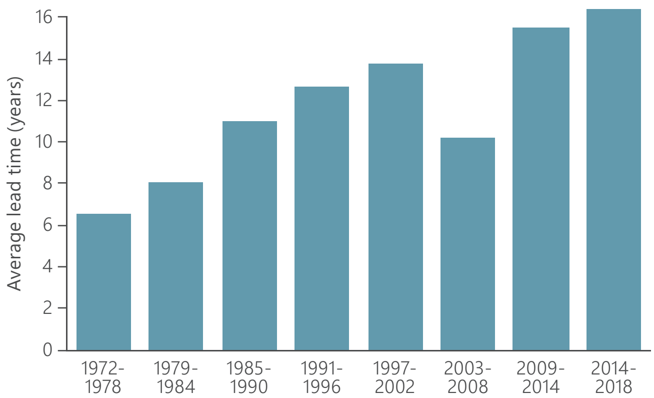
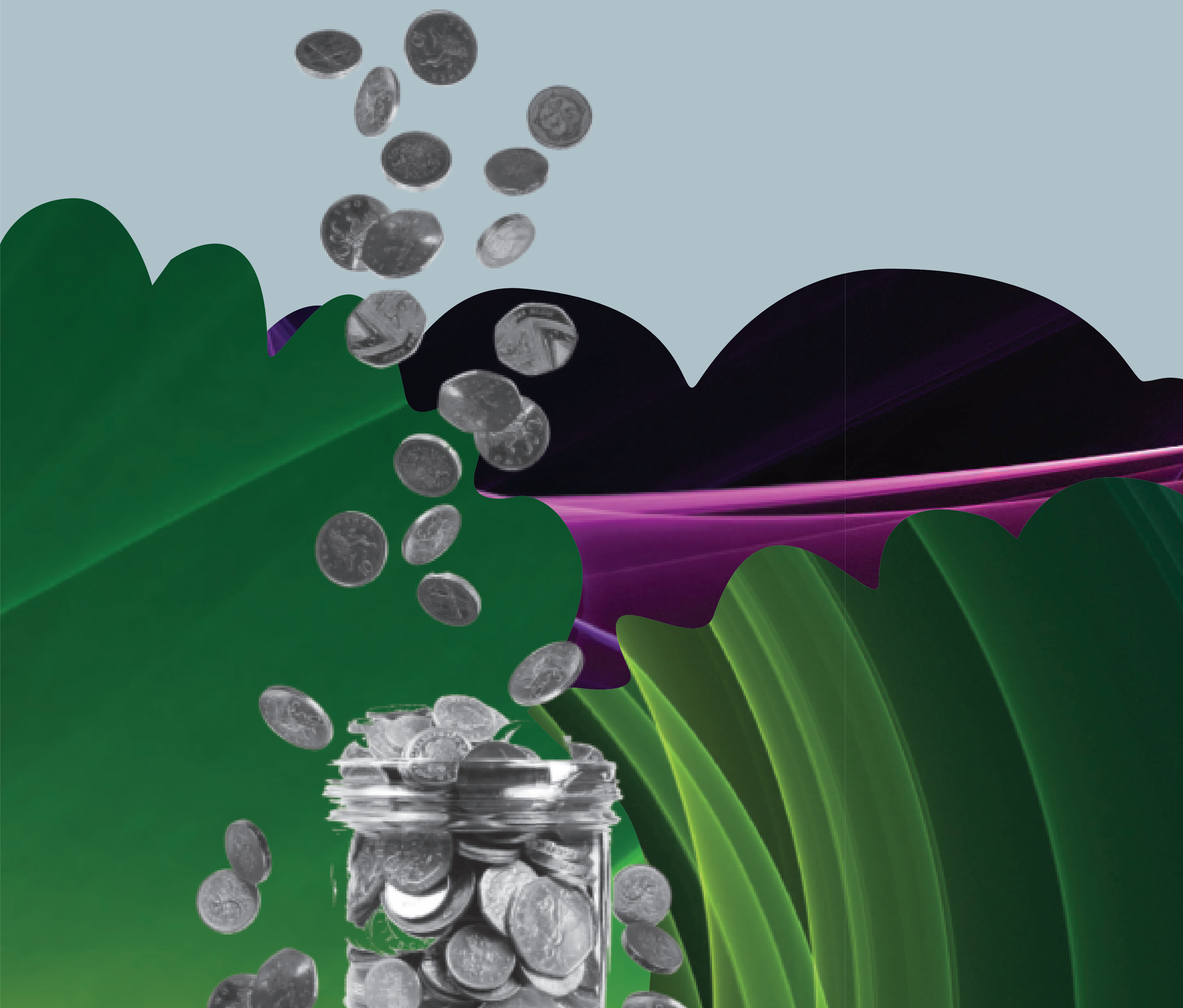


Figure 1.9 *Average lead time by year of coming on stream*

A long lead time for certain discoveries is not necessarily negative. At times, these need to wait for spare capacity in available infrastructure, technological progress, additional resources or changes to market conditions in order to be developed. A good example is Gina Krog, which was proven in 1978 but which was not brought into production because of its small size, complexity and the lack of local infrastructure. Spare capacity and the discovery of additional resources meant that it finally came on stream in 2017.

chapter 2

FIELDS



Fields

Reserves in fields have increased substantially in recent years. Combined with cost cuts, that has yielded high value creation. To maintain this position, the licensees must continue to mature resources to reserves and decide on measures to improve recovery.

Production rising

Eighty-five fields were in production on the NCS at 31 August 2019 – 64 in the North Sea, 19 in the Norwegian Sea and two in the Barents Sea. One new field, Aasta Hansteen, came on stream in 2018. Two more, Oda and Trestakk in the North Sea, have so far begun production in 2019. Plans call for Johan Sverdrup, Utgard and Skogul to come on stream in the autumn of 2019, with Bauge, Martin Linge, Yme, Dvalin and Ærfugl due to follow in 2020.

Forecasts up to 2023 show that production will increase from 2020. New fields coming on stream, including Johan Sverdrup, will more than offset declining oil output from fields currently in production.

The NPD has looked at the development of production for fields by size. They are divided into large (more than 50 million scm oe), medium-sized (15-50 million scm oe) and small (less that 15 million scm oe) categories on the basis of historical production and remaining reserves[2] shown in the 2018 resource accounts.

Figure 2.2 shows that overall liquids production from the large fields declined in 2000-18. That was offset to a certain extent by production from and development of a number of medium-sized and small fields. The share of total oil production deriving from medium-sized and small fields rose from five per cent in 2000 to almost 30 per cent in 2018.

Gas production increased over the same period. This offset the decline in oil output, so that the total figure has remained at a relatively high and stable level. Fields with the highest oil output in 2018 were Troll, Ekofisk and Grane. Troll also came top for gas production, followed by Ormen Lange and Åsgard.

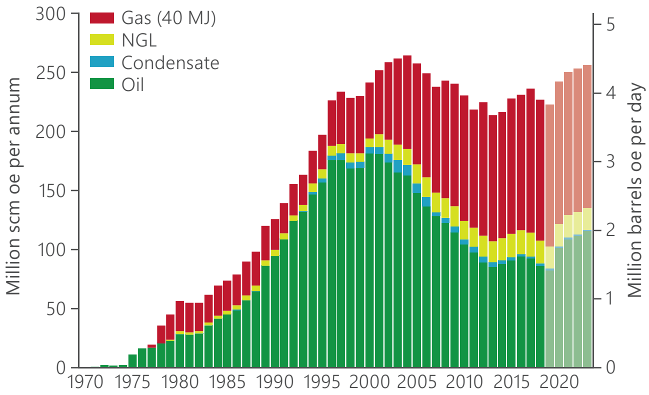


Figure 2.1 *Historical development of production and forecasts up to 2023*

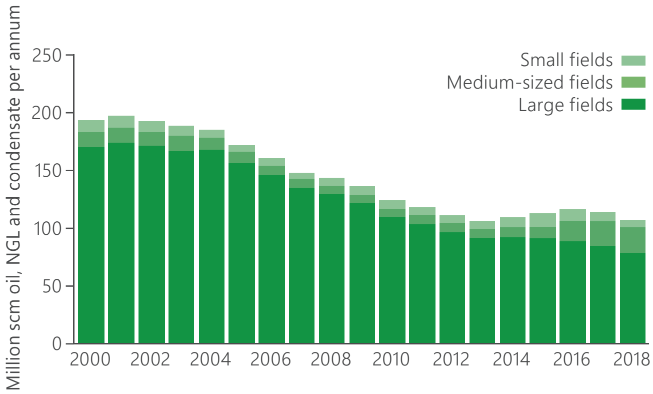


Figure 2.2 *Annual liquids production since 2000 by large, medium-sized and small fields*

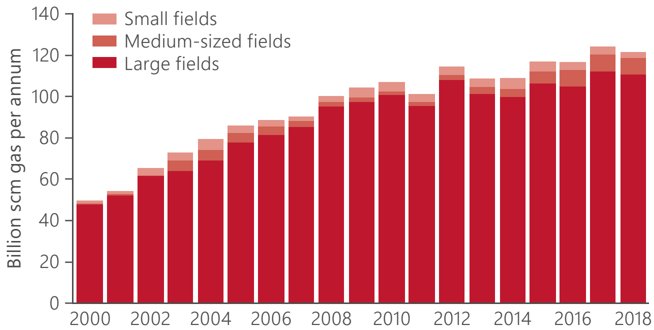


Figure 2.3 *Annual gas production by large, medium-sized and small fields*

Development of oil and gas reserves and resources

Fields account for 85 per cent of remaining proven petroleum resources. Maturing resources by deciding to develop discoveries and adopting improved recovery measures on fields mean that reserves – including those already sold and delivered – are rising.

Original reserves and the quantity sold and delivered increased in 2000-18 by about 3 500 million scm oe, equivalent to more than nine Johan Sverdrup fields

Original reserves and the quantity sold and delivered increased in 2000-18 by about 3 500 million scm oe, equivalent to more than nine Johan Sverdrup fields. Reserves increased more for oil (figure 2.4) than for gas (figure 2.5). This could partly be because less gas than oil has been proven, and because a lack of processing and transport infrastructure in areas of the NCS makes it difficult to develop small gas discoveries.

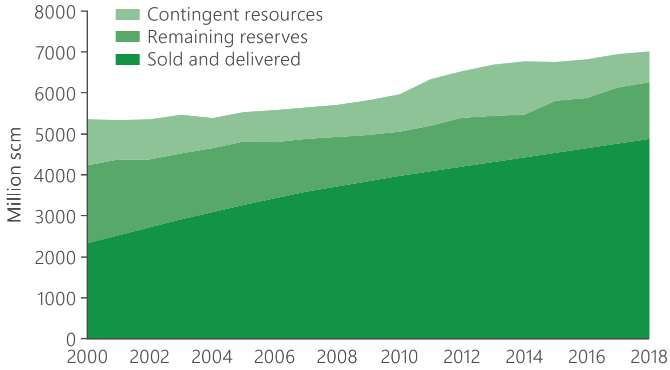


Figure 2.4 *Distribution of oil sold and delivered, remaining oil reserve and contingent oil resources[3]*

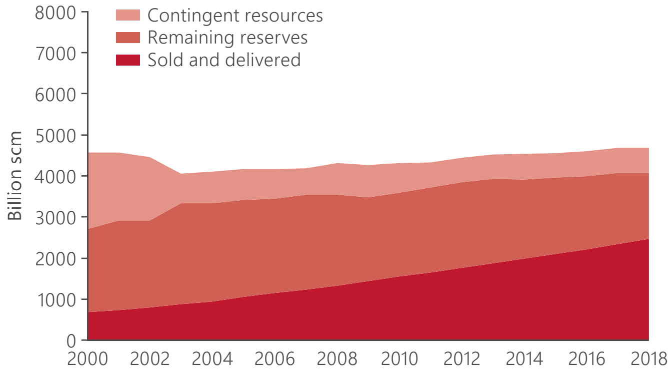


Figure 2.5 *Distribution of sold and delivered gas, remaining gas resources and contingent gas resources[4]*

Recovery factor and reserve growth

The recovery factor is a measure of how large a proportion of resources originally in place can be recovered. However, reservoir properties vary considerably between fields (and parts of fields). This means that the recovery factor is unsuitable as a measure of total recovery from the NCS, but can indicate progress by individual fields over time.

Reserve growth is a specific measure of resources decided for production and converted to reserves. It provides a better overall picture of developments than the recovery factor. In an overall NCS perspective, attention should therefore be directed at reserve growth through the development of profitable resources.

The NPD establishes specific targets for reserve growth. For 2014-23, the ambition is a growth of 1 200 million scm for oil reserves. This goal was established in 2014 and represents an extension of a corresponding target from 2005. The growth curve exceeded the target increase for the first time in 2018.

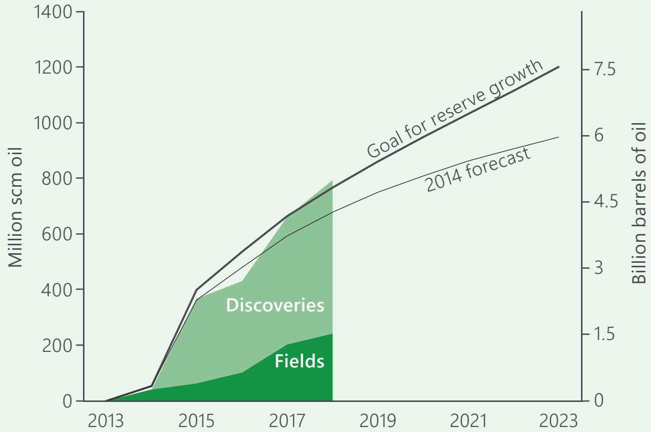


Figure 2.6 *Reserve growth for oil measured against the NPD's forecasts in 2014 and the target increase*

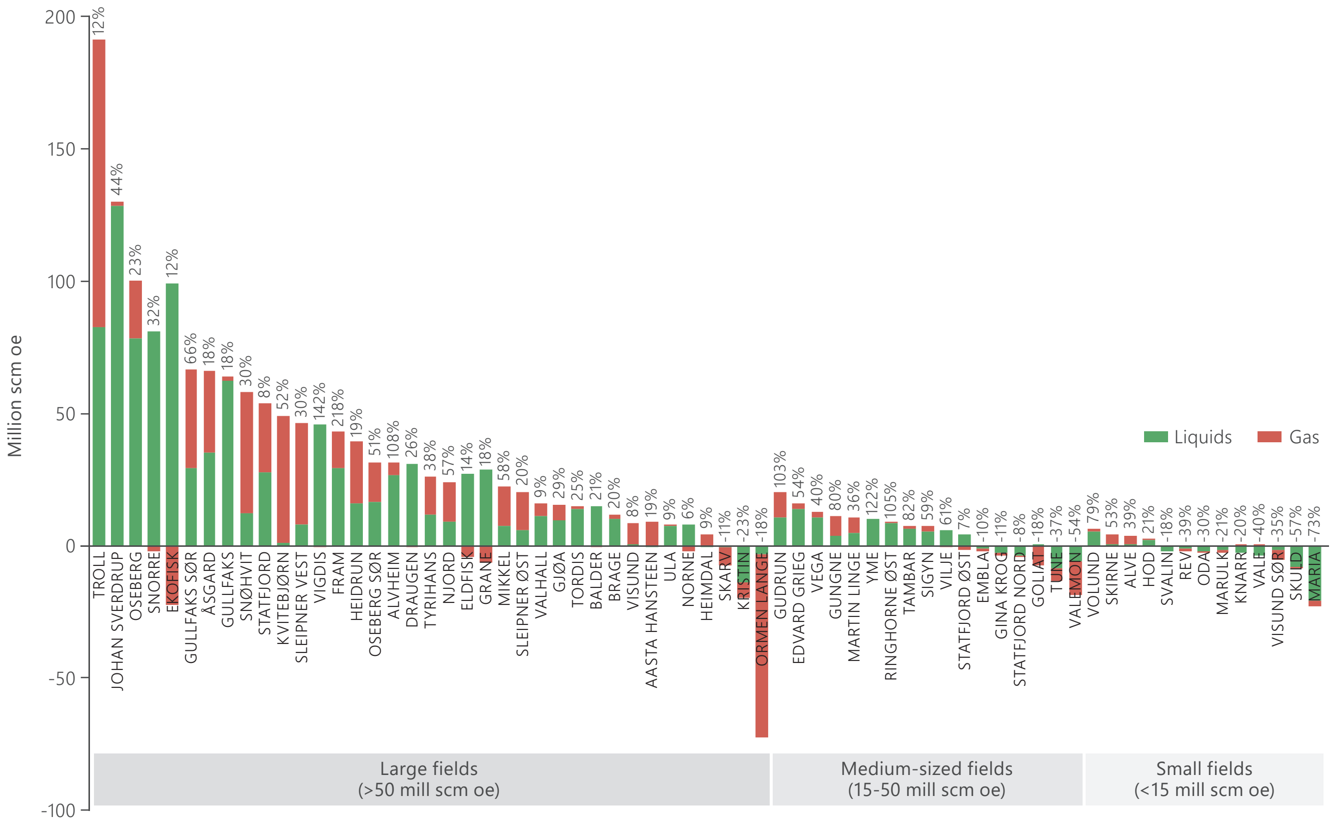


Figure 2.7 *Reserve change for liquids (oil, NGL and condensate) from 2000[5] and 2018 for fields where reserves have changed by more than two million scm oe over the period*

Reserve growth for oil and gas fields

As with production, the NPD has mapped which types of fields make the biggest contribution to reserve growth. The same division into large, medium-sized and small fields is applied, with the increase in reserves measured against the figure for 2000 or in the PDO if the field has been developed since that year. Figure 2.7 presents the results of this mapping, which includes all fields with an absolute change in reserves greater than two million scm oe.

Reserves in fields increased by about 1 400 million scm oe in 2000-18. This corresponds to more than three Johan Sverdrup fields.

Reserves in fields increased by about 1 400 million scm oe in 2000-18, divided into 1 000 million scm liquids and 400 billion scm gas. This corresponds to more than three Johan Sverdrup fields. The rise reflects decisions on improved recovery measures for large and medium-sized fields. Reserves have declined in certain fields, but the quantity involved is small compared with the overall growth.

The biggest increase in total reserves has been on Troll. Where oil is concerned, this mainly reflects new drilling and well technology which gives both more cost-effective wells and higher recovery per well. Drilling has also been pursued continuously on the field with several rigs over many years. Gas reserves have risen because the Troll Phase 3 project for increased gas offtake has been given the go-ahead. Reserves in Johan Sverdrup have grown because the decision has been taken on the second development stage.

Maria and Ormen Lange in the Norwegian Sea are examples of fields where reserves have declined. Production experience and data acquisition have shown that their reservoir properties are poorer than expected, and that the volumes present are below earlier assessments. However, new measures planned on these fields could increase reserves from the 2018 estimates.

Figure 2.8 presents the average change in oil reserves for large, medium-sized and small fields during the period. Oil reserves from large and medium-sized fields increased steadily. The changes varied for small fields and their oil reserves have declined on average.

The resource estimates are uncertain, and all discoveries have resource-related upsides and downsides when developed. However, several factors could explain why reserve growth has been highest for the large fields.

Licensees in large discoveries often take a development decision on the basis of the resources required to achieve profitable production, and build in flexibility which means that additional resources can be realised over time. These provide reserve growth.

Smaller discoveries have a lower resource base. That means it is often the case that fewer appraisal wells are drilled before the PDO, so that the decision base may be relatively more uncertain. It is therefore important that companies planning to develop smaller discoveries maximise data acquisition from wells and other sources in order to reduce uncertainty.

Many fields have been developed with estimated resources below 15 million scm oe since 2000. These collectively contain some 200 million scm oe in reserves.

Despite an average reserve decline, the small fields make an important contribution to total reserves. This demonstrates the importance of continuing to find good solutions in order to make small discoveries commercial, particularly because both discoveries in the portfolio and new finds are becoming smaller.

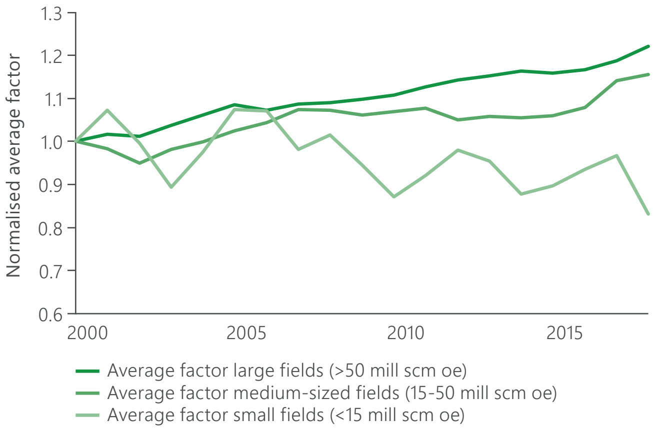


Figure 2.8 *The average[6] change in oil reserves since 2000 for large, medium-sized and small fields*

Vigdis – a subsea development with substantial reserve growth

The PDO for Vigdis was approved in 1994 and the field came on stream in 1997. Reserves were originally estimated at 29 million scm of oil. This field comprises several deposits and has been developed in various stages with seven subsea templates and two satellite wells tied back to Snorre A. Water delivered from Snorre A and Statfjord C is injected for pressure maintenance.

Reserves in Vigdis rose by more than 40 million scm in 2000-18 – an increase of almost 150 per cent. The plan for further development of the field, including new discoveries proven nearby, was approved by the government in 2002, and the PDO for Vigdis Nordøst received approval in 2011. Twelve wildcat and appraisal wells have been drilled on Vigdis, four of them after the original PDO was approved. In addition come 47 development wells, including eight for observation, 27 for production and 12 for injection. An important precondition for the substantial reserve growth on Vigdis has been the existence of available capacity in the host field, Snorre.

The focus on sub-surface understanding and the constant search for new volumes have contributed to a steady increase in Vigdis reserves since 2000. Seismic surveys and good reservoir models have made it possible to identify new drilling targets for both production and injection wells. Another important factor in keeping costs down is coordination benefits with Tordis, a subsea development in the same production licence. Joint drilling and intervention campaigns have provided opportunities to drill a number of wells and pursue more well maintenance, which have in turn increased reserves.

Figure 2.9 *Installing one of the templates on Vigdis. Photo: Equinor*

Vigdis provides a good example of a subsea development where the reserve base has been expanded gradually by adding new deposits to the field. Effective reservoir management of production and water injection are also important factors in increasing reserves. In order to improve recovery in a long future tail phase, a pump is to be installed on the seabed to raise pressure from the wells and thereby accelerate and increase production.

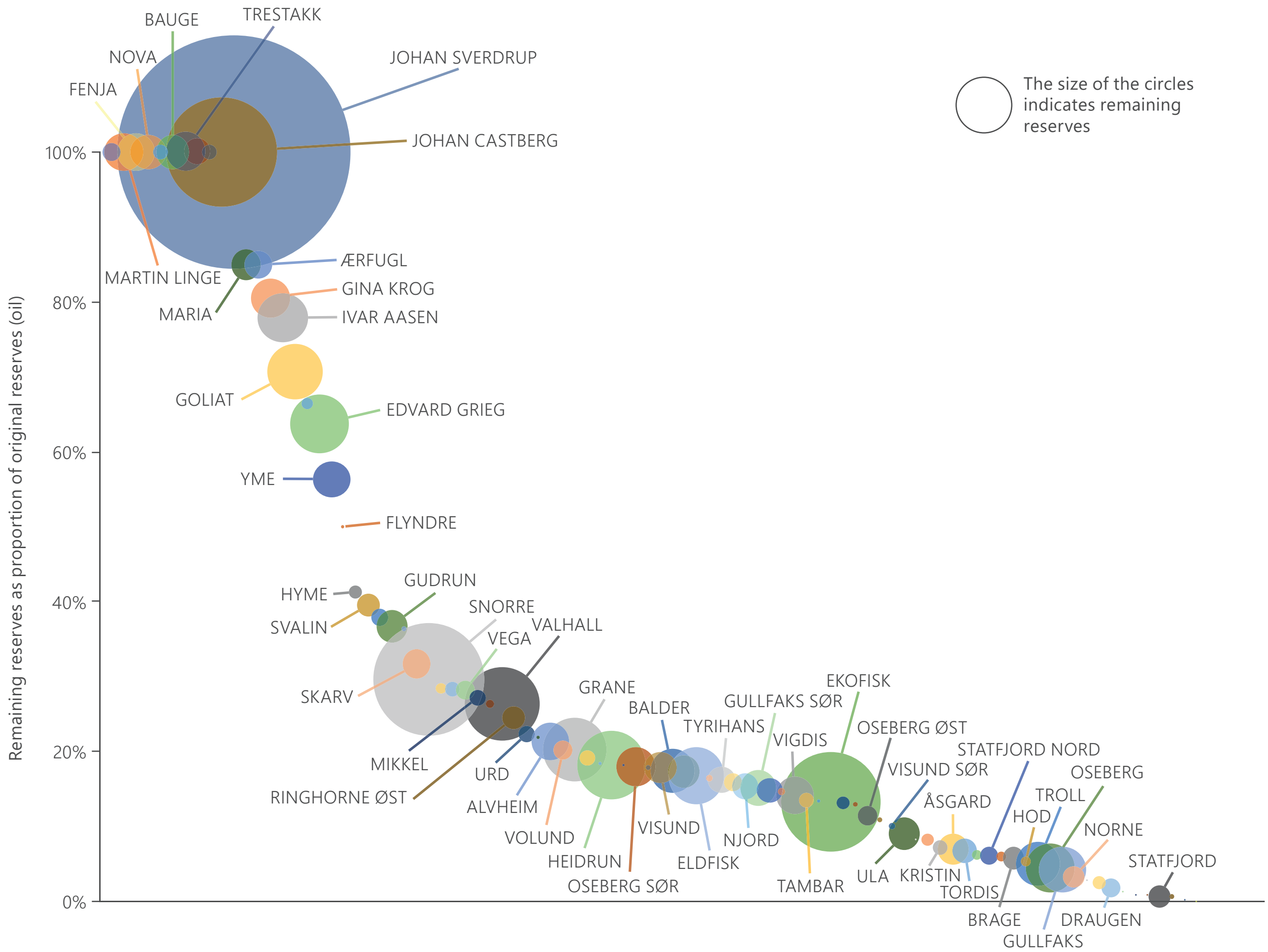


Figure 2.10 *Remaining proportion of the original oil reserves and the size of remaining oil reserves*

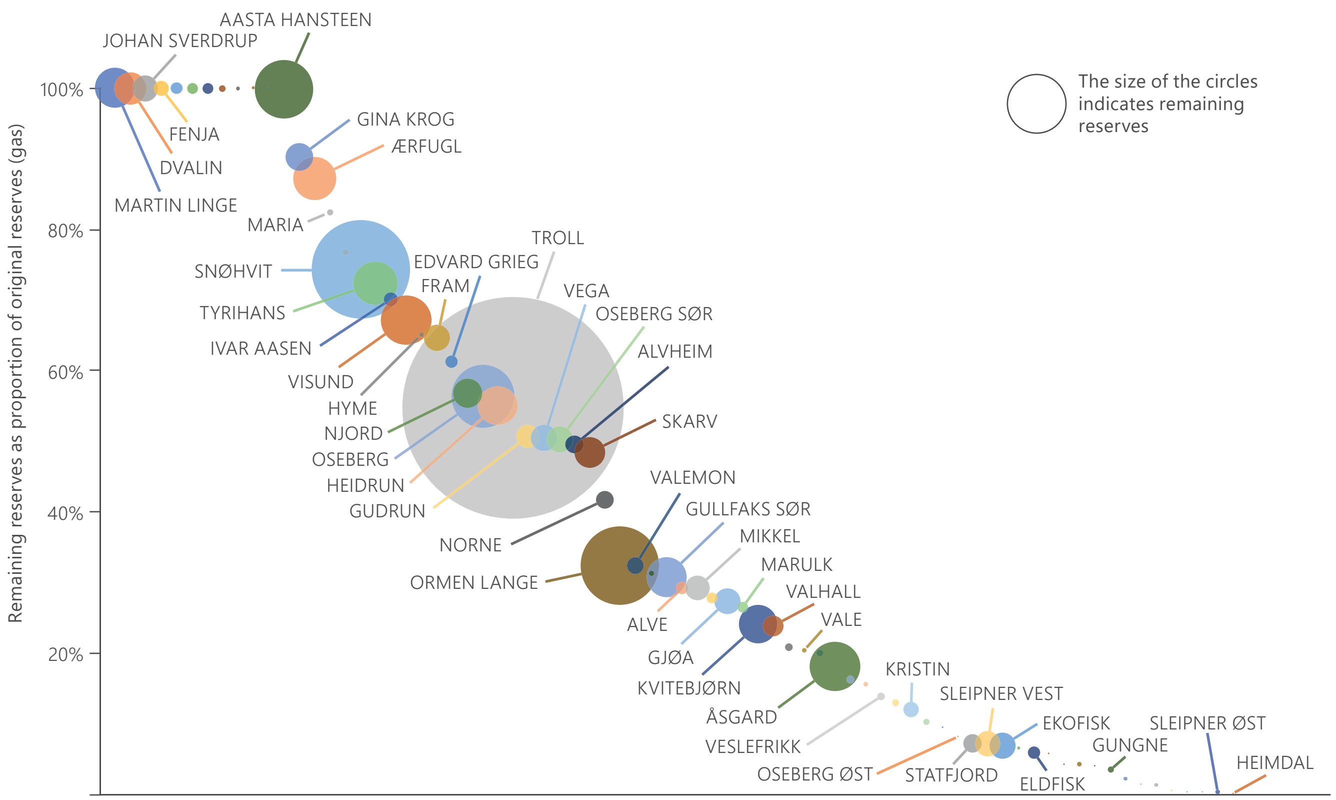


Figure 2.11 *Remaining proportion of the original gas reserves and the size of remaining gas reserves*

A maturing NCS

A number of the large fields are now in a mature phase and have produced a large proportion of their original reserves. At the same time, several fields – such as Johan Sverdrup and Johan Castberg in the North and Barents Seas respectively – are under development and will contribute to a continued high level of production during the 2020s. Figures 2.10 and 2.11 present the remaining share of original oil and gas reserves for a number of fields. The size of the circles indicates remaining reserves.

Fields such as Snorre, Valhall, Grane, Heidrun and Ekofisk still have substantial remaining oil reserves. They nevertheless account for only 15-30 per cent of the original reserves.

Troll is very important for Norwegian gas production, and will remain so for a long time even though almost half its reserves have been produced. Large fields such as Snøhvit, Oseberg, Ormen Lange and Åsgard also have substantial remaining gas reserves. Most of the gas fields under development are medium-sized, such as Martin Linge and Dvalin. Aasta Hansteen is a new gas field in the Norwegian Sea which came on stream in December 2018. This development has established new gas infrastructure in the northern Norwegian Sea.

Measures for improved recovery from fields

Many fields contain substantial oil volumes over and above those covered by production plans, and will be shut down with large quantities of residual oil in their reservoirs. Efforts to adopt improved recovery measures, so that all resources of commercial value to society get produced, are therefore important. Figure 2.12 presents produced oil, remaining oil reserves and residual oil after planned production cessation for the largest oil fields.

The companies reported about 150 specific projects (RCs 4 and 5) in 2018 for increased oil and gas production, covering some 400 million scm oe. In addition to specific projects, possible but non-specific measures for improved oil recovery (RC 7) are reported. The NPD estimates that these measures could lead to the recovery of 200 million scm oe in all. A total of 600 million scm oe were thereby classified as contingent resources in fields at 31 December 2018.

An overview of various types of specific but undecided projects for improving recovery from fields is presented in figure 2.13 by type of project, with associated resources shown in oe.

Reported projects for improving recovery are dominated by new wells, in terms of both number of projects (71) and volume (145 million scm oe). Others which make a big contribution are further developments, particularly subsea projects involving new templates tied back to existing facilities and totalling more than 70 million scm oe of oil, and low pressure production providing 80 million scm oe – primarily gas.

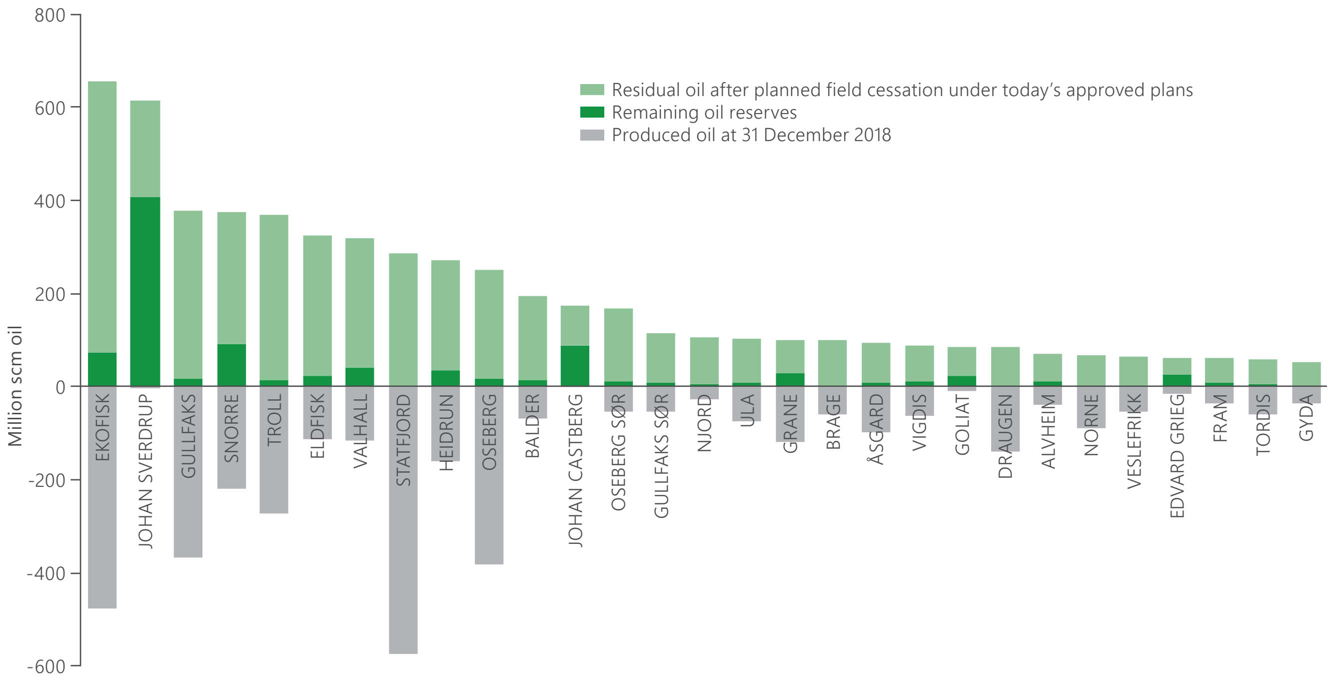


Figure 2.12 *Remaining oil reserves, residual oil after planned production cessation under current plans, and produced oil at 31 December 2018*

Few measures involving the adoption of advanced recovery methods have been reported, and total a modest recoverable volume of two million scm. One of these projects assumes injection of polymer/surfactant, while the others involve fracturing the reservoir to enhance well productivity.

Efforts to adopt improved recovery measures, so that all resources of commercial value to society get produced, are important

Adopting enhanced oil recovery (EOR) methods could contribute to recovering substantial volumes if they are qualified. Proving these methods out on the fields is crucial in this respect. Chapter 3 presents the results of a study on the resource potential offered by advanced techniques on the NCS.

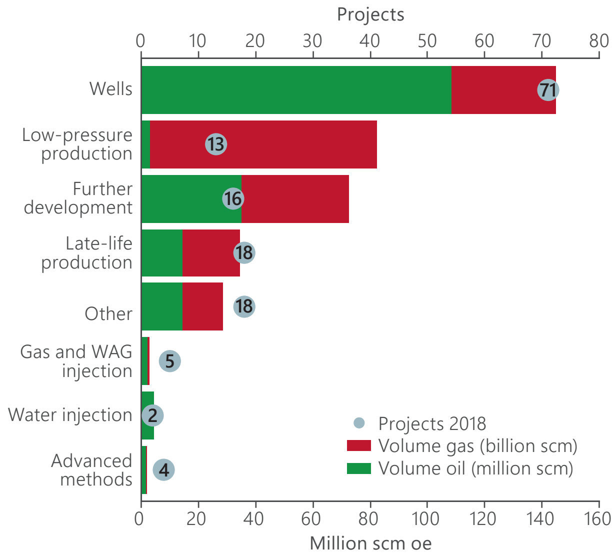


***Figure 2.13** Projects and estimated recoverable volumes for oil by project category*

Low-pressure production on Ormen Lange

Ormen Lange is a mature gas field produced from a subsea system to a process facility on land at Nyhamna in Møre og Romsdal county. It was decided to implement gas compression from the field in two phases – on land and out on the field. Compression facilities were installed on land in connection with the expansion of the gas processing plant at Nyhamna to handle the Aasta Hansteen/Polarled development, and became operational in the fourth quarter of 2017. They aimed both to increase the recovery factor on Ormen Lange and to maintain capacity at the Nyhamna plant when gas from Polarled was introduced, independently of reservoir pressure in Ormen Lange. Compression on land increases the recovery factor from 67 to 75 per cent.

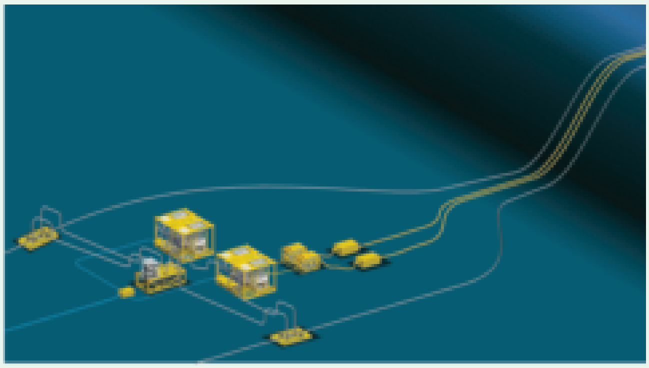


***Figure 2.14** Ormen Lange. Illustration: AS Norske Shell*

The licensees have opted for subsea compression on the field as phase two. This will reduce wellhead pressure more than land-based compression, and thereby improve recovery. The final choice of the subsea concept is expected later in 2019, followed by an investment decision. Subsea compression has the potential to increase the recovery factor to more than 80 per cent.

Gullfaks – success story in the "golden block"

Gullfaks lies in what was known as the "golden block" on its award in 1978. Proven that year, this oil discovery launched a long and rich adventure. The first-stage PDO, approved in 1981, involved two concrete platforms – A and B – installed on the western side of the field. A second PDO in 1985 covered a third concrete platform – C – for the eastern area. Gullfaks serves today as an area centre used by a number of surrounding fields.

The main Gullfaks reservoirs comprise sandstone with good properties. Nevertheless, this has not been a straightforward field to produce, because it is compartmentalised by many cross-cutting faults. Expected recoverable reserves when production began in 1986 were about 210 million scm of oil, based on producing until 2007. Since then, reserve estimates have been regularly increased with new reservoir zones and structures as a result of better-than-expected production properties and continuous measures to improve recovery. Original oil reserves are estimated at 384 million scm. While the expected recovery factor in the PDO was about 44 per cent, this has now passed 62 per cent for the main reservoirs.

Reserve growth on Gullfaks is a success story, where pressure support from water and gas injection, new wells, and reservoir monitoring (including 4D seismic surveying) have resulted in a high level of recovery. Advanced seismic data have been used on the field to position new wells in parts of the reservoir with remaining oil. Wells have been continuously drilled to new reservoir areas, and the distribution of gas and water injection in the various sections of the field has been optimised. Downhole measures and interventions in existing wells also play an important part in the strategy to sustain production. Work is under way to improve drilling capacity, and significantly more wells are now being drilled annually than before. Managed pressure drilling (MPD) has permitted wells which would otherwise have gone undrilled. This technology allows larger pressure differences in a well to be handled.

Until 2013, the understanding was that resources in the tight Shetland/Lista carbonate reservoir overlying Gullfaks were not recoverable. But new information from test production in 2014 demonstrated that the oil could nevertheless be recovered through natural fractures in the formation. A PDO for these resources, with recovery from existing wells, was approved in 2015. A water injection pilot to improve recovery was also implemented. Positive results from this project and extensive reservoir studies laid the basis for a revised plan with water injection as the recovery strategy in 2019. Both production from and injection into the Shetland/Lista reservoir are now under way on Gullfaks.

This project is a good example of the way pilot trials can increase knowledge, which leads in turn to improved recovery from more challenging reservoir zones in existing fields.

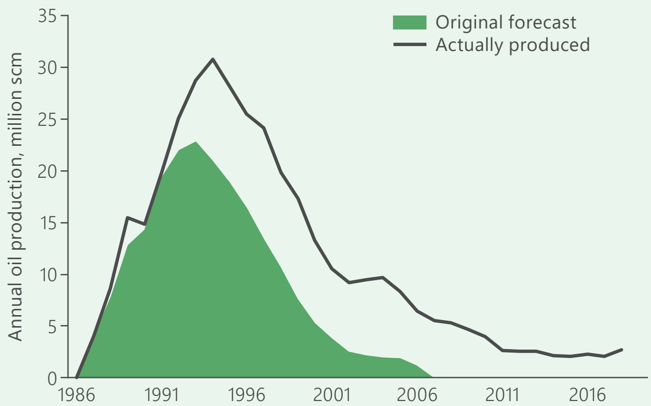


Figure 2.15 *Production profile on Gullfaks*

Development wells

Drilling more development wells is the most important factor for improving recovery. In addition to producing oil and gas, wells are an important source of data acquisition and thereby of better reservoir understanding. Just over NOK 60 billion was invested in fields on stream in 2018. More than half of this spending related to wells. Figure 2.16 presents overall investment by various categories.

In recent years, cost control and efficiency improvements have cut average costs per development well[7] by more than 40 per cent. Technology advances, such as automated and more efficient drilling, could contribute to even further reductions. Lower costs mean that more wells are drilled, and that well targets with a smaller estimated volume become profitable. Figure 2.17 presents the average cost per development well and the number of such wells since 2000. Figure 2.18 presents average well costs since 2000 by type of drilling facility.

Drilling more development wells is the most important factor for improving recovery, and represents an important source for data acquisition and better reservoir understanding

Drilling costs for mobile units have been substantially higher than on fixed facilities. That reflects a big rise in mobile rig rates before 2014 compared with prices in other supplier segments. Since 2014, rates for mobile facilities have fallen sharply. However, many long-term contracts awarded before 2014 have meant that the effect on drilling costs has only been felt gradually.

Acquiring data from subsea wells is normally more expensive than from platform ones. In recent years, the number of subsea wells drilled from mobile facilities has steadily risen. Developing and adopting solutions which allow data to be acquired more cheaply from such wells is therefore important. Examples include tracer technology and the use of fibreoptics (see the fact box on Johan Sverdrup), which can potentially replace expensive downhole interventions in securing important reservoir information.

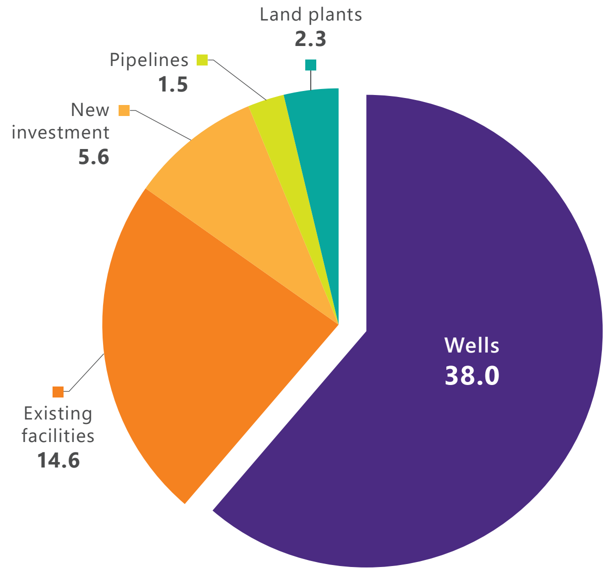


Figure 2.16 *Investment in NOK billion at 2018 value for fields on stream by category*

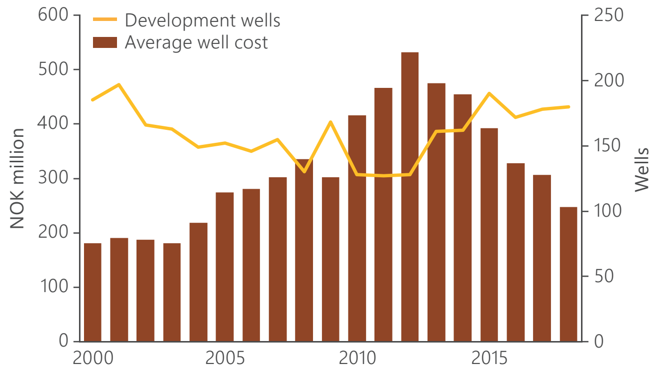


Figure 2.17 *Average cost per development well[8] and development wells per annum*

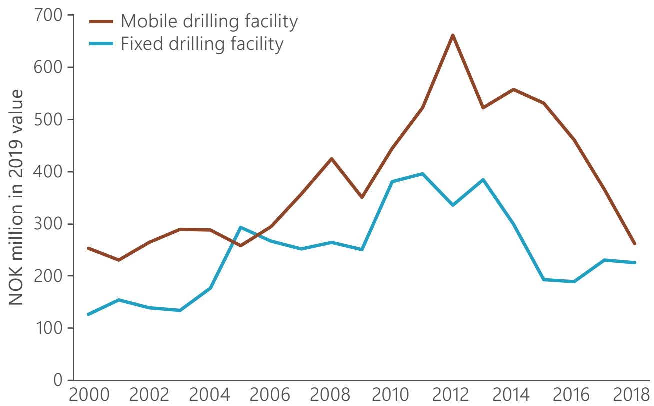


Figure 2.18 *Average drilling costs for fixed and mobile facilities*

Based on input from the IFE

Tracers in wells increase reservoir understanding

Tracers are substances pumped down wells together with water or gas, or positioned in completions. Measuring them in the liquid or gas produced can reveal which zones are active, what type of liquid is flowing where, and how much is being produced. That provides information on which parts of the reservoir are flowing well and which require additional measures to improve recovery.

The first internationally reported use of tracers dates to 1946, when helium gas (He) was injected in California's Elk Hills oil reservoir to study gas flow in the reservoir. Several scattered trials were conducted during the following decade with helium and radioactive hydrogen (HT) in other reservoirs. But it was not until the 1970s and 1980s that tracer technology began to acquire a certain position in the petroleum industry.

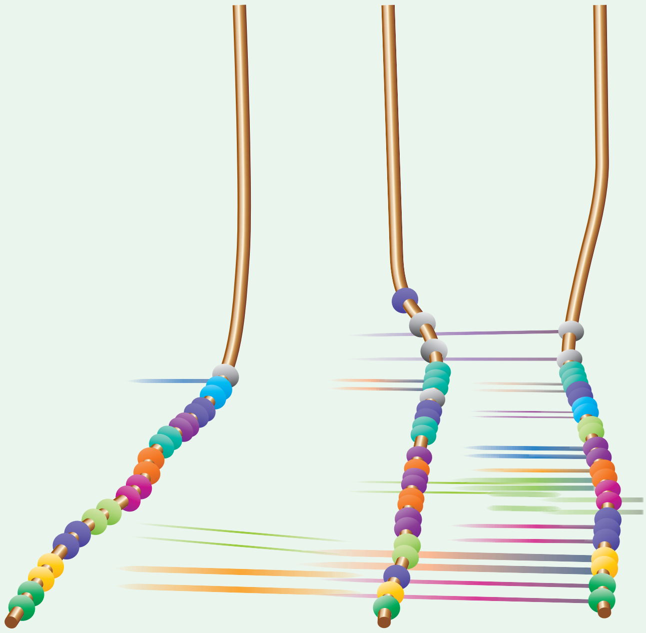


Figure 2.19 *Tracers in wells*

Tracers were first used on the NCS in 1984 to study how drilling fluid influenced well cores. Titrated (radioactive) water (HTO) was added to the drilling fluid during exploration drilling on Snorre.

The first use of tracers in production occurred on Ekofisk and Gullfaks in 1985-87 in order to study the flow of injected water and gas between wells. All the tracers were radioactive. Since the results were positive, the industry wanted to develop non-radioactive alternatives. This was first achieved by the Norwegian Institute for Energy Technology (IFE) in 1988 to measure gas on Ekofisk on behalf of Phillips Petroleum.

In 1990, the "tracer club" was established at the IFE as a programme sponsored by large oil companies, and with the NPD as an observer. This work has resulted in the qualification of new non-radioactive tracers for gas, water and oil.

Considerable work has been done in recent years to develop tracer-based methods for measuring remaining (immobile) oil. The IFE has developed and qualified methods both for waterflooded areas between wells and for investigating the immediate vicinity of an individual well. This plays an important role in efforts to qualify various EOR methods (see chapter 3) through pilot projects.

One or more tracer injections have been performed in many of the reservoirs which are or have been on stream. The aim is to improve the reservoir description by acquiring the better understanding of fluid dynamics required to ensure optimal drainage. Although the value of applying this technology on the NCS and internationally is difficult to measure directly, estimates indicate that it amounts to billions of kroner.

Zone control for improved recovery and lower costs

Managing injection or production along a well path or between laterals is known as zone control. This includes closing off or reducing undesirable inflows of water or gas to a production well, stimulating individual zones to increase output from the specific zones and achieving better clean-up of long horizontal well paths. The main aim is to optimise drainage and production. That could be particularly relevant for wells where formation quality varies considerably, as in tight reservoirs (see chapter 3). Opportunities to exercise zone control provide better reservoir management and thereby improve oil recovery.

The NPD mapped the use of zone control in wells during June 2017. A total of 593 active well paths with zone control were reported by the companies. These included 119 multi-laterals with 301 laterals in all.

Zone control can be conducted in several ways. One involves using inflow control devices (ICDs) and autonomous ICDs (AICDs), which control and correct the pressure drop from the formation to the reservoir. An AICD is the more advanced type, and can measure which liquid is flowing in order to close off or reduce non-oil flows. Another example is the inflow control valve (ICV), which can be controlled hydraulically or electrically from the surface. Zone control can also be exercised by manual methods – running mechanical tools from intervention vessels or drilling rigs into wells to perform operations.

Some fields have a substantial number of well paths with active zone control. Passive or autonomous ICDs are installed along all producing paths on Troll, and many have surface-managed valves for controlling laterals. On Snorre, surface-managed valves have been installed in a considerable number of injection wells as well as in producers. A substantial increase has occurred in the application of more advanced zone control methods over the past decade. Continuing to develop this type of equipment is important for efficient and optimal production from many types of reservoir. Figure 2.20 presents the trend for well paths with zone control.

Analyses of output from oil wells on Troll reveal a clear improvement in production rates after AICDs were introduced. Where Snorre is concerned, studies show that reserves can increase substantially if zone control functions as planned.

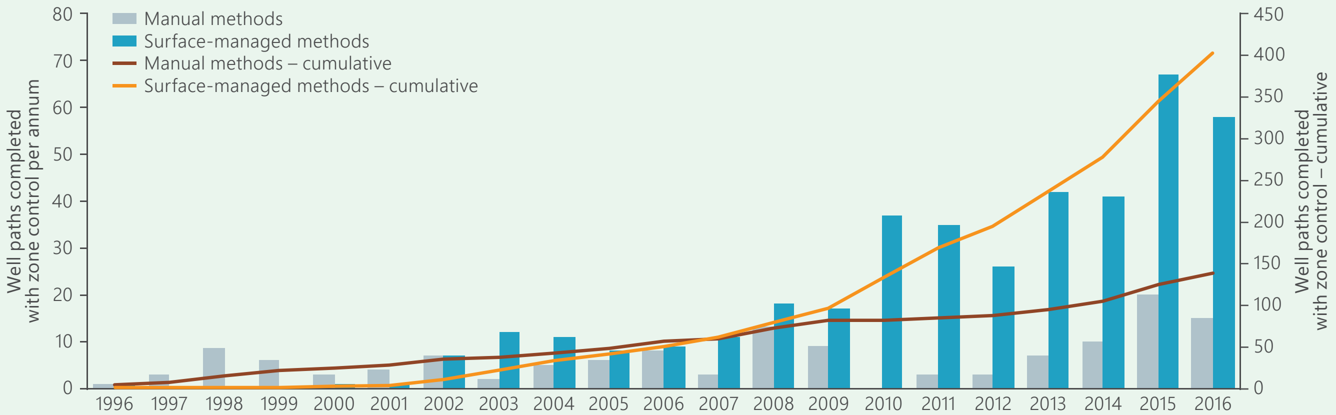


Figure 2.20 *Well paths completed with zone control (ICD is included in both manual and surface-managed methods)*

Costs down on the NCS

Extensive efforts devoted by the industry in recent years to cost control and efficiency improvements have substantially reduced the average operating cost per unit produced (unit cost) since 2013. Figure 2.21 presents the development of total operating and unit costs. Viewed in isolation, reducing the latter means that oil and gas become more profitable to produce, and that more improved recovery measures become profitable and can be adopted. At the same time, the current unit cost is substantially higher than the low point reached in 1995. This could suggest that cost growth to the end of the 2000s has still not been reversed. New solutions incorporating such aspects as automation and remote control, improved use of data and more efficient operation, can help to reduce unit cost even further.

> *Avoiding cost cuts with a short-term focus which are made at the expense of good resource management is important*

Operating costs have been reduced on all the large fields since 2013. The few fields which have seen an increase are in all cases small. The percentage decline has been greatest on small fields. That could partly be because such fields basically have relatively low operating costs, and changes in activity therefore have a bigger impact.

Figure 2.22 presents the change in operating costs at field level from 2013 to 2017. The few fields located above the horizontal line in the figure experienced an increase during the period. However, the great majority of fields recorded a reduction averaging about 30 per cent.

Reduced operating costs for a field are basically positive. This can improve margins, extend the field's producing life, and contribute to higher value creation. At the same time, avoiding cost cuts with a short-term focus which are made at the expense of good resource management is important. Solutions must therefore be chosen which create the greatest possible value in a long-term perspective, and necessary maintenance has to be given priority.

Figure 2.23 presents the development of the individual components in overall operating costs for fields from 2007 to 2018.

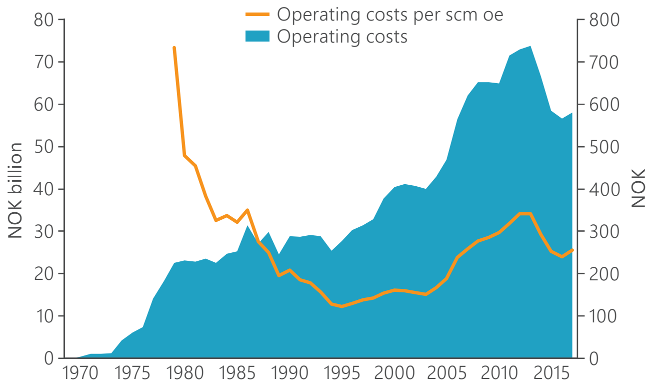


Figure 2.21 *Development of operating and unit costs on the NCS from 1970 to 2018*[9]

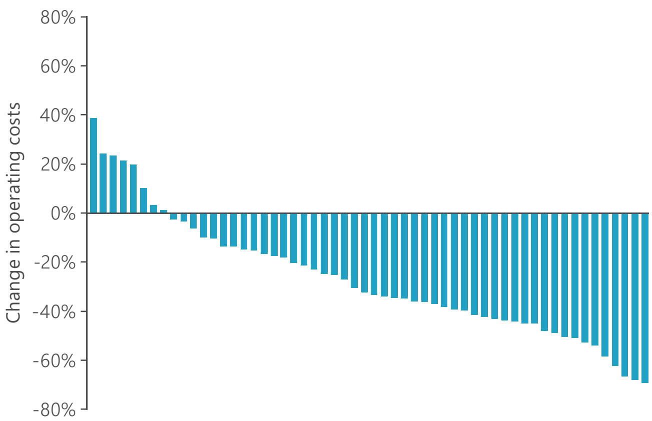


Figure 2.22 *Change in operating costs for fields on stream from 2013 to 2017*

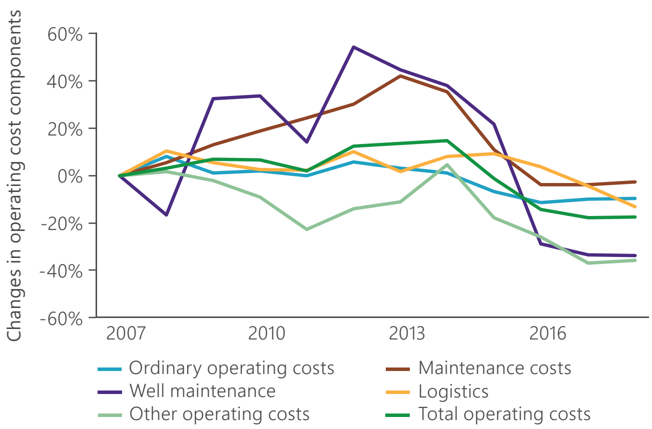


Figure 2.23 *Relative development of components in overall operating costs*

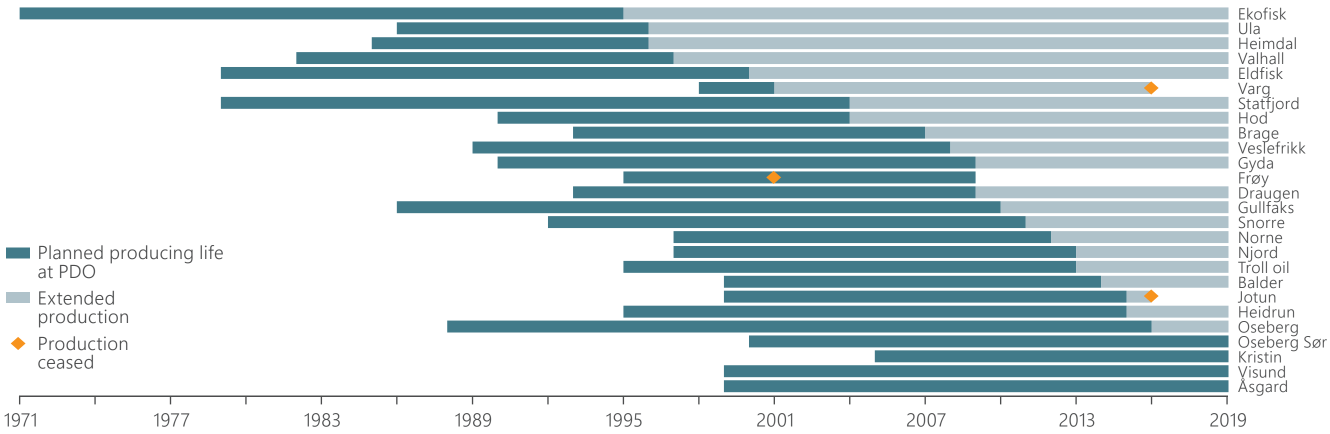


Figure 2.24 *Commercial life for fields compared with their PDOs*

Phasing in additional resources

Virtually all the fields on the NCS produce for considerably longer than envisaged in their PDO. Figure 2.24 presents extended production on a number of the fields compared with the PDO expectation. Lower costs, improved recovery measures, a larger resource base than expected and phasing in new discoveries lengthen their commercial life. A good example is Varg, which ceased production in 2016 after extending its economic life from three to 18 years. Frøy is one of the few fields whose time on stream was shorter than expected. However, plans to reopen it are being pursued.

The effect of phasing in is illustrated in figure 2.25, which presents unit costs for a host field with and without a tie-in. Phasing in helps to reduce unit costs and extend producing life for the host field, and allows more of the resources to be recovered.

Among other factors, opportunities for phasing oil and gas into existing infrastructure are limited by capacity in the process plant on host facilities. Gas fields may also face capacity constraints in the transport systems. As production from existing fields declines, however, spare capacity arises in several parts of the gas infrastructure. This can make searching for gas more attractive, and it is important that the industry exploits this opportunity and intensifies exploration – particularly around infrastructure already in place.

Infrastructure owners must promote spare capacity, and the companies must collaborate to phase in additional resources

Utilising existing capacity is also important for oil fields, particularly because several of the big host producers are already in a mature phase. Exploration must be pursued around the mature fields, infrastructure owners must promote spare capacity, and the companies must collaborate to phase in additional resources. In this way, new resources can be developed and help to increase value creation.

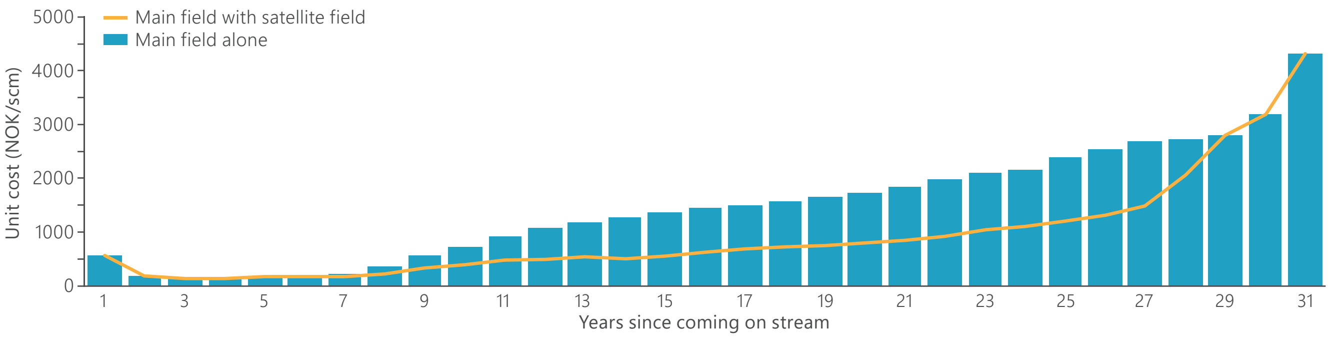


Figure 2.25 *Effect of phasing in on operating costs per unit produced for a typical host field*

The TPA regulations

Agreements on using facilities owned by others to produce, transport or exploit oil and gas are governed by the regulations relating to such use. These third-party access (TPA) regulations aim to ensure efficient utilisation of infrastructure and give licensees good incentives to pursue exploration and production activities.

The TPA regulations specify that a user needing to utilise a facility owned by another party will be entitled to such use on objective and non-discriminatory terms and conditions. However, such use must not be unreasonably to the detriment of the owner's own requirements or of any other user granted the right to use the facility.

Reaching agreement on capacity utilisation in existing infrastructure can be challenging. The TPA regulations contain provisions covering both negotiations and terms of agreement to help implement the process.

Furthermore, infrastructure owners are required to share information so that a user has a sufficient basis for assessing the offer it receives pursuant to the regulations.

The figure below illustrates the Maria field, which provides a good example of a development utilising existing infrastructure from several surrounding fields. Kristin receives the wellstream for processing and onward transport, with stabilised oil sent to Åsgard C for loading into shuttle tankers. Supplies for gas lift are delivered from Åsgard B via Tyrihans, and injection water comes from Heidrun.

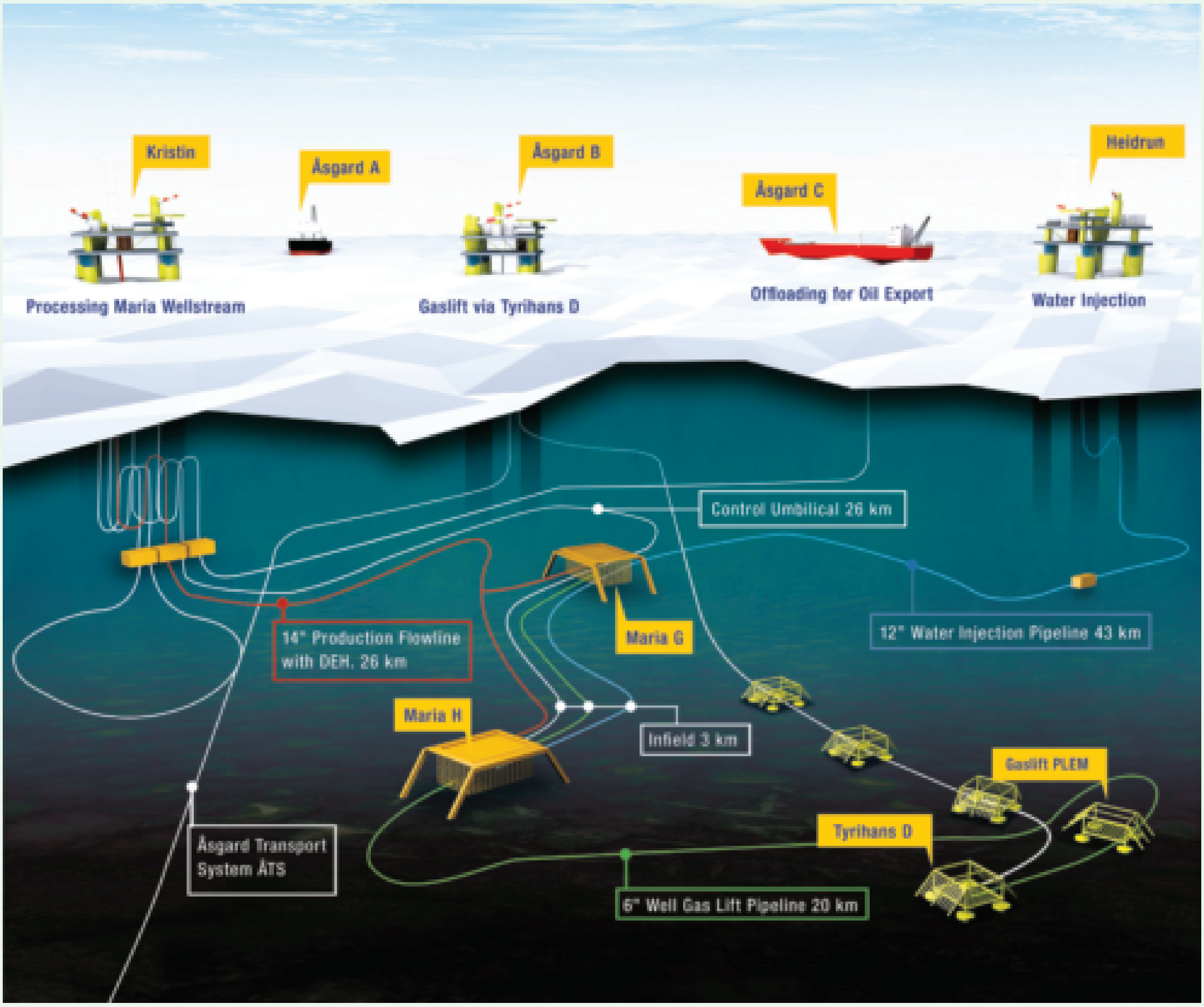


Figure 2.26 *The Maria field in the Norwegian Sea is an example of utilising existing infrastructure. Illustration: Wintershall Dea*

Players

The NCS is dependent on competent players willing to invest in available opportunities. Both the willingness to invest and the ability to mature marginally profitable resources through such approaches as new cost-effective working methods are important for realising the value potential. That applies particularly when new discoveries will increasingly be developed as small subsea projects.

At 31 December 2018, 39 companies were active on the NCS. Twenty-five of these were operators, 13 of them for fields. Figure 2.27 illustrates the changes in the number of field operators and in company type since 2000. A substantial increase in operators has occurred over the past decade, and they include several medium-sized companies.

Figure 2.28 presents total investment in 2000-18 by company category. Medium-sized companies have gradually accounted for a larger proportion of capital

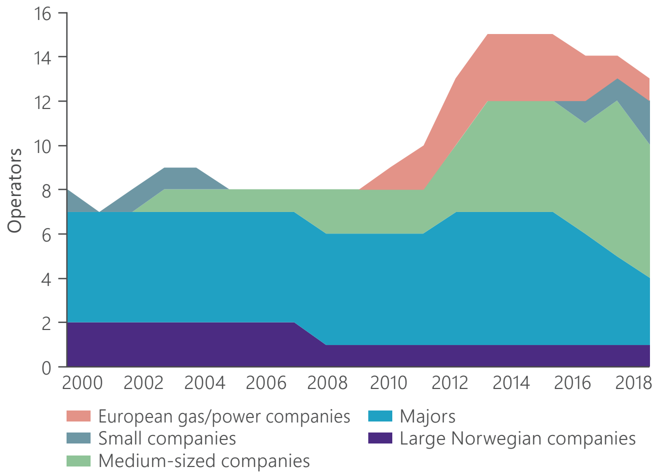


Figure 2.27 *Operators for fields on stream since 2000*

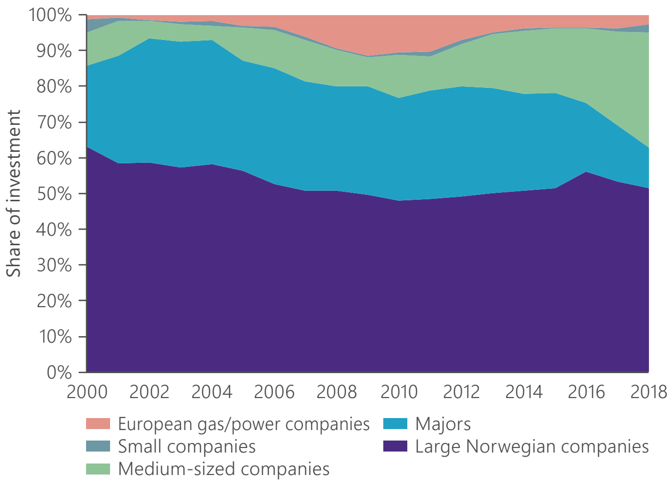


Figure 2.28 *Share of investment on the NCS by company category*

spending. The contribution from majors shows a corresponding reduction.

The NCS often represents a larger proportion of the portfolio for medium-sized companies than it does for the majors. That could make the former more willing to invest because developments in Norway do not have to compete with a large international project portfolio.

Better use of data creates value

KonKraft[10] published *Competitiveness – changing tide on the Norwegian continental shelf* in February 2018. This report was a contribution to KonKraft's work of maintaining the competitiveness of the NCS. Increased coordination, new forms of collaboration and realising the potential offered by digital technology were general themes.

Norway is a pioneer in managing and sharing data. The government facilitates simple access to information through such means as dedicated websites – the fact pages at npd.no as well as norskpetroleum.no. In addition, the forum for reservoir characterisation and reservoir engineering (Force) provides an example of an approach to working where the main objective is to increase collaboration between government, industry and research teams. The forum works to share data and knowledge through various networks and project groups.

Diskos is another example. This national petroleum database rests on a collaboration agreement between the government and the oil companies. Non-oil companies can be associate members, and a number of universities and research institutions are also involved. Diskos is structured to receive such input as sub-surface data reported to the authorities for sharing and exchange between production licences, and to give access to all non-confidential information. Seismic and well data are easily accessible through the service, and much of the information has been made public. The government and the oil companies are currently working on further development of Diskos with the aim of adopting new technology for data storage and utilisation.

As the NCS matures, finding oil and gas deposits becomes more challenging, discoveries are smaller, and resources are more difficult to produce. Cross-industry coordination, with sharing of information and better use of large data volumes, is thereby becoming ever more important. Advances in acquiring, transferring and storing data, and in faster and cheaper calculations, open many new opportunities. Analysing large data volumes can provide new information through innovative ways of collating material or re-evaluating it. At the same time, coordination and collaboration can lead to new ideas, re-use and experience transfer. Another benefit could be a reduced risk of duplicating work. Collaboration and data sharing will also enhance knowledge, improve planning and lead to decisions being taken on a better basis.

Data sharing is crucial for methods which demand large volumes of information. Two examples are the use of artificial intelligence for production optimisation, and automated experience transfer to well planning in order to improve efficiency and cut costs. For such methods to be effective, access is required to large quantities of data.

Being able to handle large data volumes also makes it possible to develop better reservoir modelling tools. That enhances sub-surface understanding, and is expected to contribute to a substantial increase in value creation.

Based on input from Aker BP and Cognite

New methods for utilising data

A standard oil and gas production facility generates a huge amount of data. Many equipment units and components require regular monitoring and maintenance, creating extensive work orders and documentation. In addition come downhole and process plant measurements. An important challenge in the petroleum sector therefore involves being able to organise and manage these data volumes in order to optimise production and maintenance work, and thereby contribute to value creation. Freeing-up and sharing data are necessary for achieving good collaboration between operators, licensees and suppliers.

Cognite aims to collect and extract value from data generated on the fields. This company collaborates closely with Aker BP, which helped to establish it.

A data platform created by Cognite collects all output and operating data throughout the value chain for petroleum production. Information is acquired, for example, from all sensors, pumps, valve systems and piping, and is made available continuously. This gives a better insight into how the system functions, and makes it easier to optimise operation and take the right decisions. Assembling all data in a single platform reduces integration and maintenance costs. Moreover, solutions can be scaled to make them applicable to several fields, and development speed and data flow increase throughout the organisation.

The data platform gives the operator access to both historical and real-time information from the fields. A number of third-party applications and programmes support day-to-day operation of the facilities. Components which interact in the real world are also linked on the platform to provide a complete picture. That makes it possible, for example, to use machine applications for optimisation and automation as well as advanced visualisations and programmes for those requiring access to real-time field data.

Data available on the platform also permit the use of artificial intelligence to improve the efficiency of various processes. Two examples are production optimisation through data-driven and physics-based decisions, and predictive maintenance which ensures that the right work is done at the right time and increases uptime.

Continuous access to real-time data supports the development of new business models between operator and supplier. An example is that a supplier gets paid for the uptime of the equipment it delivers – a pump, for example. The supplier has unrestricted access to “live” data from the pumps so that it can ensure continuous operation. Such new models incentivise efficiency and collaboration between players in the industry.

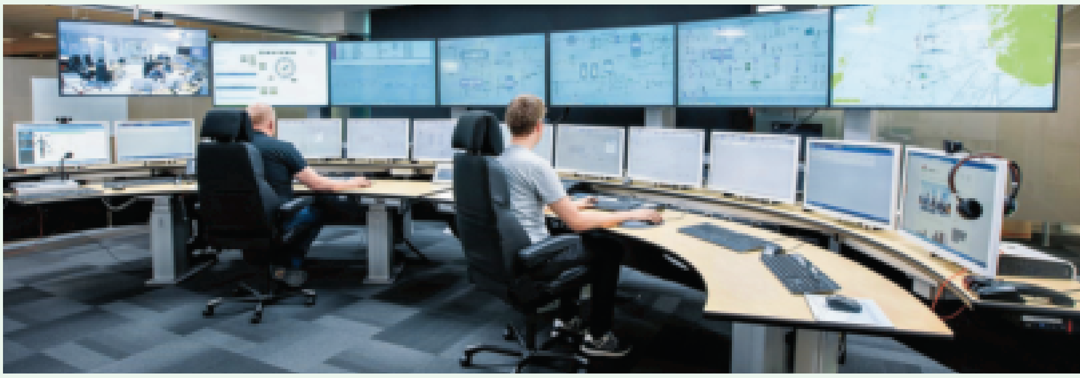


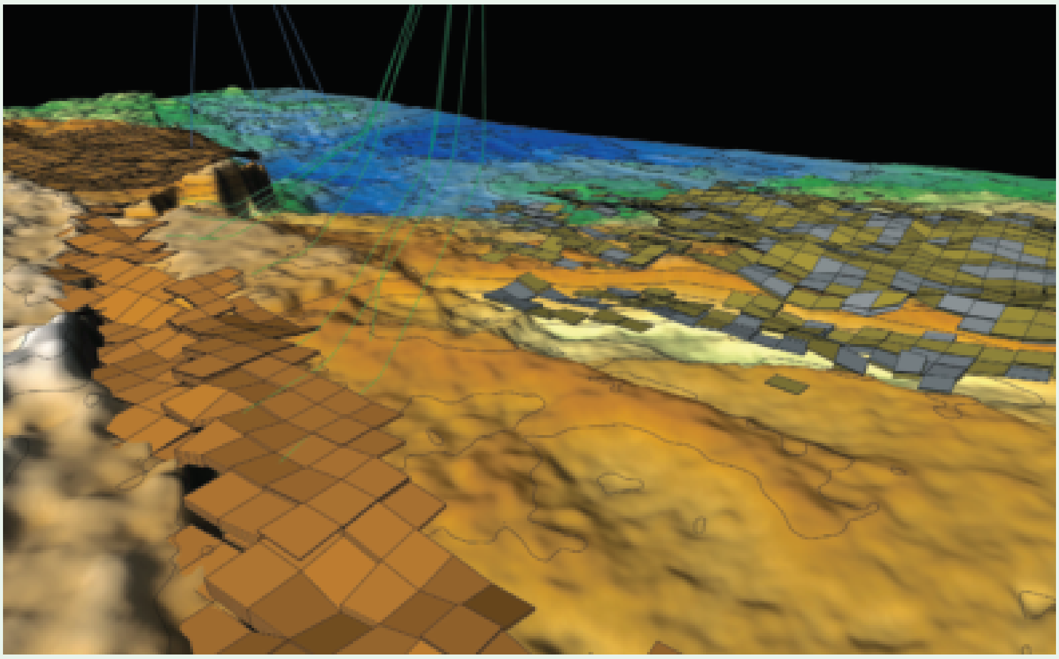
Figure 2.29 *The control room for Ivar Aasen. Photo: Aker BP*

Based on input from Equinor

More intelligent data use boosts value creation on Johan Sverdrup

The licensees on Johan Sverdrup have invested heavily in data collection. That includes installing permanent acquisition systems in wells, on the seabed and on the platforms. These data are needed to meet the ambition of a recovery factor for the field exceeding 70 per cent.

Another important measure for enhancing value creation is a dedicated data acquisition well. The information it yields will provide valuable reservoir insight and make an important contribution to improved oil recovery (IOR) measures.



Figur 2.30 *Reservoarmodell Johan Sverdrup. Illustrasjon: Equinor*

In addition to conventional data acquisition and well instrumentation, distributed fibreoptic measurements throughout the well path have been introduced on Johan Sverdrup to improve reservoir understanding. Data traditionally acquired through campaigns because of the massive quantities involved can now be used live as part of day-to-day production optimisation and well monitoring.

Permanent reservoir monitoring (PRM) based on seismic data has been chosen for the field. Combined with fibreoptic cabling in the wells, this can enhance reservoir understanding and form the basis for an optimised drainage strategy and improved recovery. Current digitalisation projects aim to enhance the efficiency of data flow and storage as well as the use of information from PRM/fibreoptics. Digitalised solutions have also been adopted to achieve easier access to data across specialist tools and different databases.

Physical processes in the Johan Sverdrup reservoir are described through predictive numerical models. These are constantly adapted to commercial requirements and updated continuously with new data and improved understanding. Established technologies, such as fast model update (FMU) with a high level of automation, allow uncertainty about the sub-surface to be continuously updated. Models will increasingly operate at the overlapping interface between the data-driven and the physics-based. Over Johan Sverdrup's producing life, big changes and improvements will occur in the way sub-surface models are defined and how they utilise an exponentially growing quantity of data.

A digital twin has been developed as a copy of the Johan Sverdrup facilities – platforms and subsea templates. This makes it easier to locate equipment. Combining information from the physical world with virtual data (augmented reality) allows the 3D model to be compared with the as-built facilities on the field. The technology has already proved useful for identifying incorrectly installed or missing equipment in the construction phase.

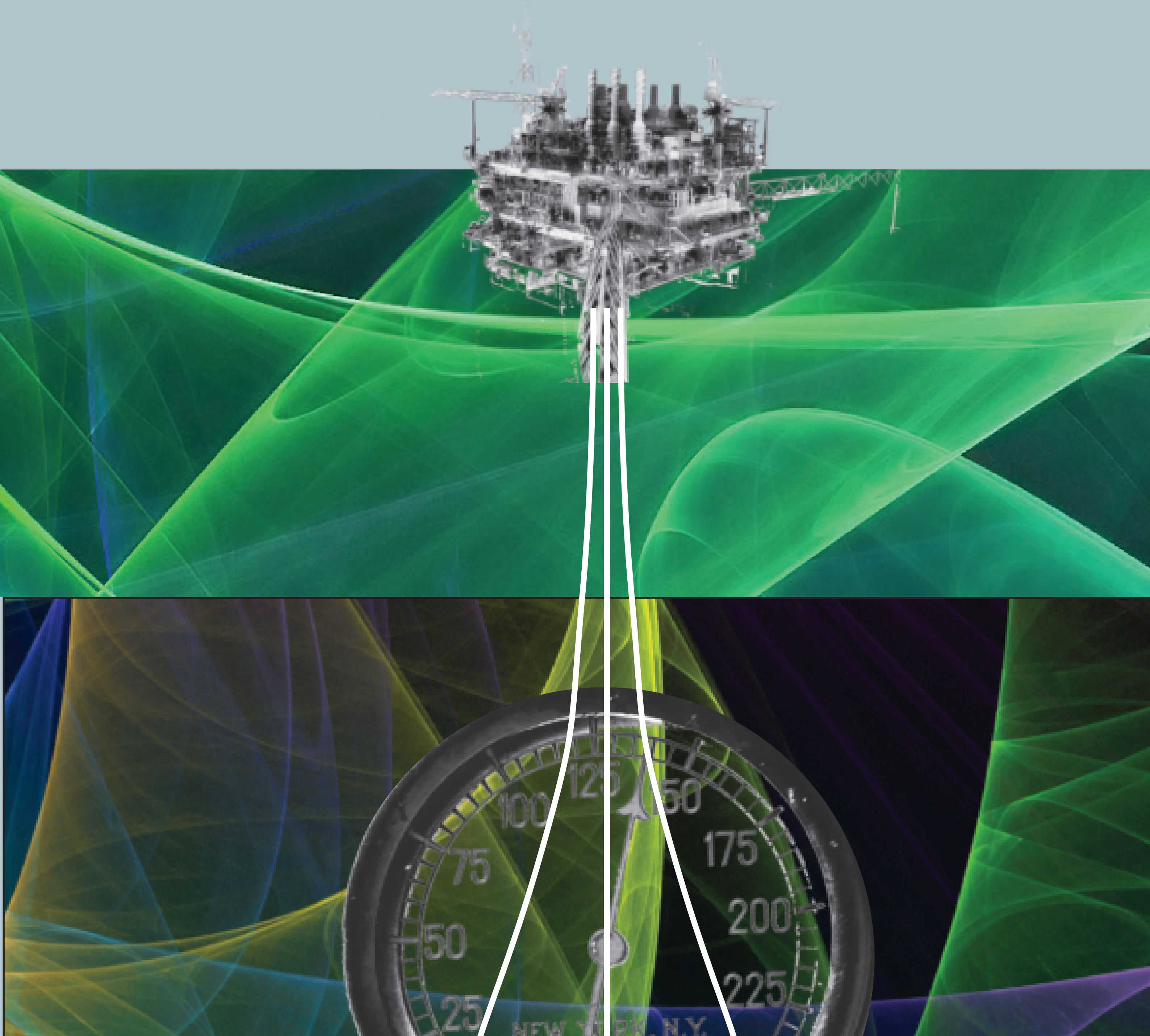
Better understanding of equipment condition in the facilities can reduce the CO_2 footprint by optimising operation of these devices. At the same time, it is possible to transfer a number of inspection tasks from sea to land and thereby achieve a safety gain.

Implementing automated production optimisation provides for increased and more stable output and a lower workload for operators in the central control room.

Much work is also being done to improve data sharing between the field's licensees and the government. Having access to the same data and seeing the same picture is a big advantage for the operator and its partners – Lundin, Petoro, Aker BP and Total – in taking faster and better decisions.

chapter 3

THE CHALLENGING BARRELS



The challenging barrels

A study conducted by the NPD in the autumn of 2018 showed that large quantities of oil and gas are contained in tight reservoirs. It is important that the companies work to achieve profitable recovery of these volumes. In parallel, work by the NPD shows that much immobile oil can be recovered with the aid of various EOR methods. To reduce uncertainty over the recovery potential, these techniques must be tested out on the fields.

Tight reservoirs

Most discoveries and fields have reservoir zones where the oil or gas is difficult to produce. One reason for this could be that the formations are so impermeable (tight) that the hydrocarbons flow poorly. Permeability is measured in Darcy (D).

Tight reservoirs in the discoveries and fields covered by the study contain some 2 000 million scm oe in place

Tight reservoirs on the NCS have been mapped by the NPD in terms of their permeability, with 10 milliDarcy (mD) as the upper limit for inclusion. Such formations often call for the use of unconventional technology to achieve profitable development.

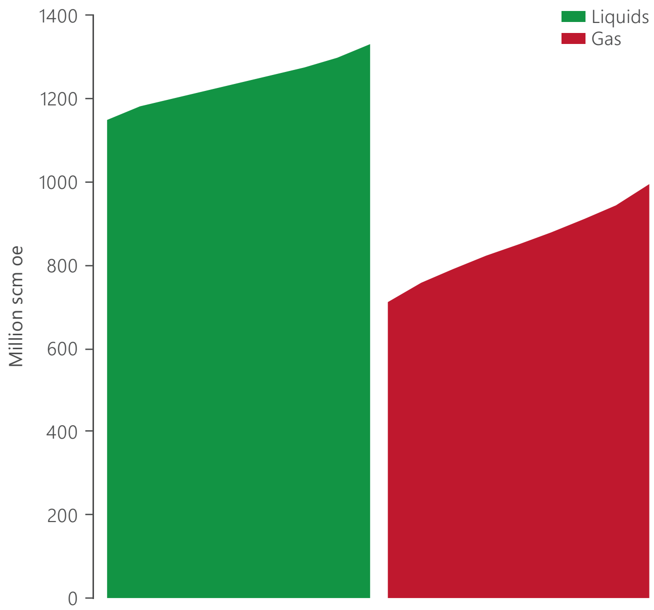


Figure 3.1 *Mapped oil and gas volumes in place in tight reservoirs, including the uncertainty range*

Big oil and gas volumes in place

The operators reported data from tight reservoirs in 30 discoveries and fields. In addition, the NPD performed its own assessment of such formations in a further 12 discoveries.

Tight reservoirs in the 42 discoveries and fields covered by the study contain some 2 000 million scm oe in place. This breaks down into roughly 1 200 million scm of oil and 800 billion scm of gas – which is considerably more, for example, than resources originally in place in Ekofisk, one of the largest fields on the NCS. Figure 3.1 presents the mapped oil and gas volumes with the estimated uncertainty range. The latter is relatively low for the oil volumes in place because a number of the tight reservoirs are found in fields on stream, and are therefore well mapped.

Tight reservoirs by area

North Sea

The estimate for mapped volumes in place in tight reservoirs in the southern part of Norway's North Sea sector is in the order of 750 million scm of oil and 90 billion scm of gas. Most of this lies in carbonate reservoirs in the Ekofisk, Eldfisk and Valhall area. Producible oil has also been identified in the Utsira High basement. That comprises hard and tight rocks but is so heavily fractured and porous in this area that oil has migrated in.

Mapped volumes in tight reservoirs in the northern North Sea sector are estimated at roughly 360 million scm of oil and 80 billion scm of gas. Much of the volume in this area lies in sandstone reservoirs. On Oseberg and Gullfaks, however, large volumes are also found in the overlying Shetland Group chalk and partly in the Lista Formation. Test production of the oil in the Shetland Group chalk has been conducted on Oseberg, but output rates are considered too low to be profitable for the time being. Tight chalk in the Shetland Group is being produced on Gullfaks, with water injection and horizontal wells used to improve recovery. See the fact box in chapter 2.

Norwegian Sea

Mapped volumes in place in tight Norwegian Sea reservoirs are estimated at about 130 million scm of oil and 420 billion scm of gas. These volumes exist exclusively in sandstone reservoirs. A large proportion is found in the Tilje and Garn Formations, which lie deep and have very varying reservoir properties. The Lavrans, Linnorm, Noatun and Njord North Flank 2 and 3 discoveries all contain tight reservoir zones, where the licensees are currently assessing development opportunities using various technologies to improve profitability. Tiny-hole technology used in the tight Garn Formation zones in Smørbukk South provides an example of testing new technical approaches to improve productivity in such rocks. Discoveries have also been relinquished because the licensees have not found the tight zones profitable to develop. An example is 6506/6-1 Victoria in the Norwegian Sea, which has large volumes in place but has been relinquished by the licensees.

Barents Sea

Mapped volumes in place in tight Barents Sea reservoirs are estimated at five million scm of oil and 270 billion scm of gas. Since the Barents Sea is less explored than the North and Norwegian Seas, its resource base is more uncertain. The tight reservoirs in this part of the NCS are found in Triassic sandstones.

Figure 3.3 summarises oil and gas volumes in tight reservoirs by sea area.

Producing from tight reservoirs

Achieving profitable production from tight reservoirs calls for measures to increase exposure to the wells, so that the oil and gas flow better. This can be done by fracturing the formation close to the wells and/or by drilling many well paths in the tight zones.

Various types of fracturing and multilateral wells are currently the most relevant methods for recovering resources in tight reservoirs. Fracturing combined with acid stimulation is used on the carbonate fields in the Ekofisk area. Tiny-hole technology is also appropriate in a number of places, with many holes in the same well increasing exposure to the reservoir and allowing oil and gas to flow more easily into the wells. Where suitable, fracturing combined with water and gas injection can also help to improve recovery.

Tight reservoir zones can be produced together with more permeable ones. Producing both tight and good formations in the same well requires zone control for optimal reservoir management. See the fact box in chapter 2. While this can help to improve recovery from the tight zones, the technology must be further developed and become more cost-effective.

In a number of cases, producing from tight reservoirs can only become profitable if development is based on a tie-back to existing infrastructure. Large volumes and relatively low output rates mean a long production horizon. Solutions which allow the resources to be produced within the operating life of existing infrastructure are therefore important.

A number of projects for producing tight reservoirs are under assessment, have been decided or are under development. A water injection pilot on Gullfaks in the North Sea has contributed to a decision on improved recovery from the tight Shetland/Lista reservoirs. The licensees are assessing various development solutions for the tight reservoirs in 6406/9-1 Linnorm in the Norwegian Sea. Test production is planned for 34/11-2-S Nøkken and 16/1-12 Rolvsnes in the North Sea, and tiny-hole technology has been tested for improving recovery from the tight chalk reservoirs in Valhall. Various completion solutions are also being developed to increase reservoir exposure in the Ekofisk area.

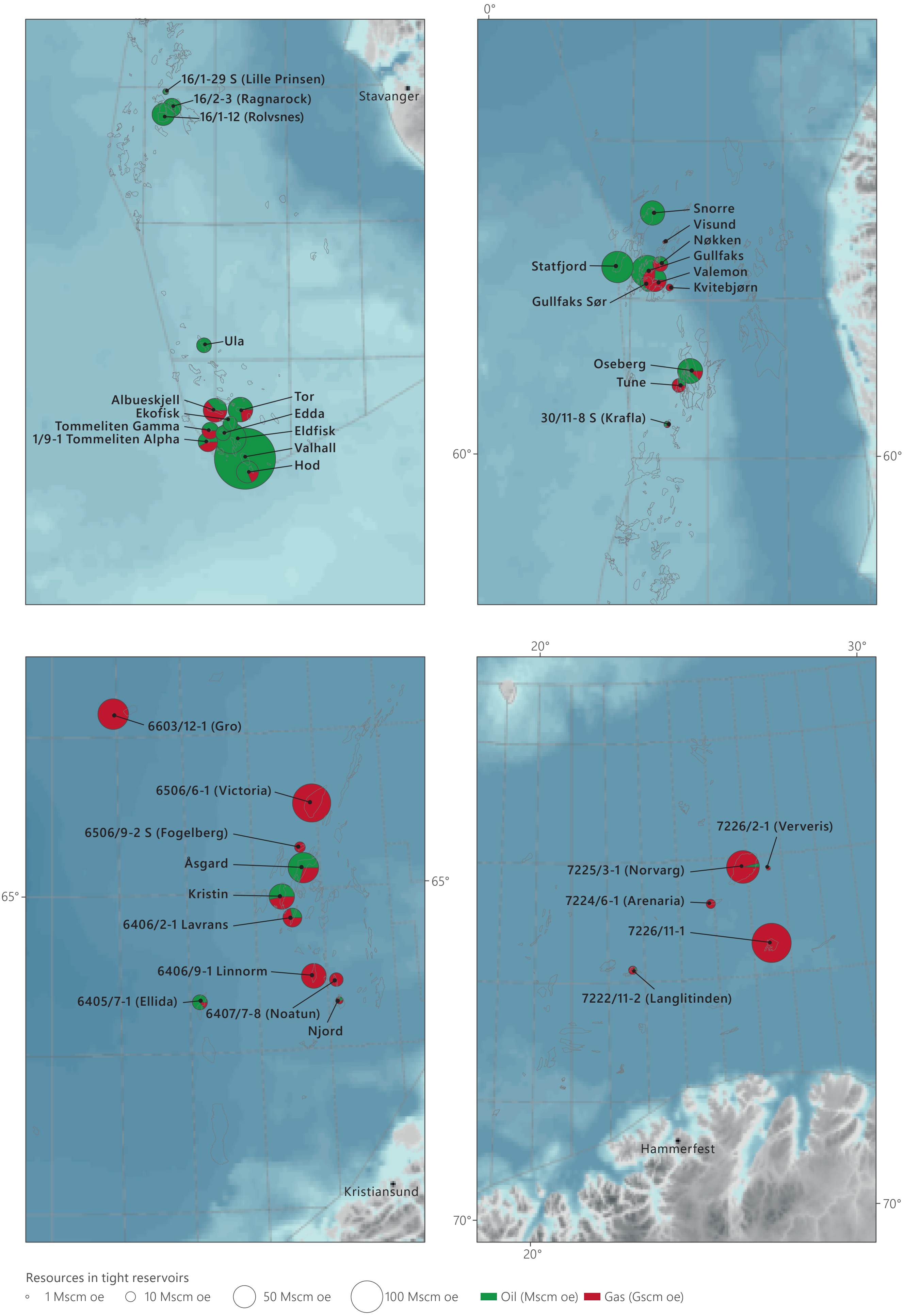


Figure 3.2 *Overview of oil (green) and gas (red) in place in tight reservoirs in the southern and northern parts of Norway's North Sea sector as well as in the Norwegian and Barents Seas*

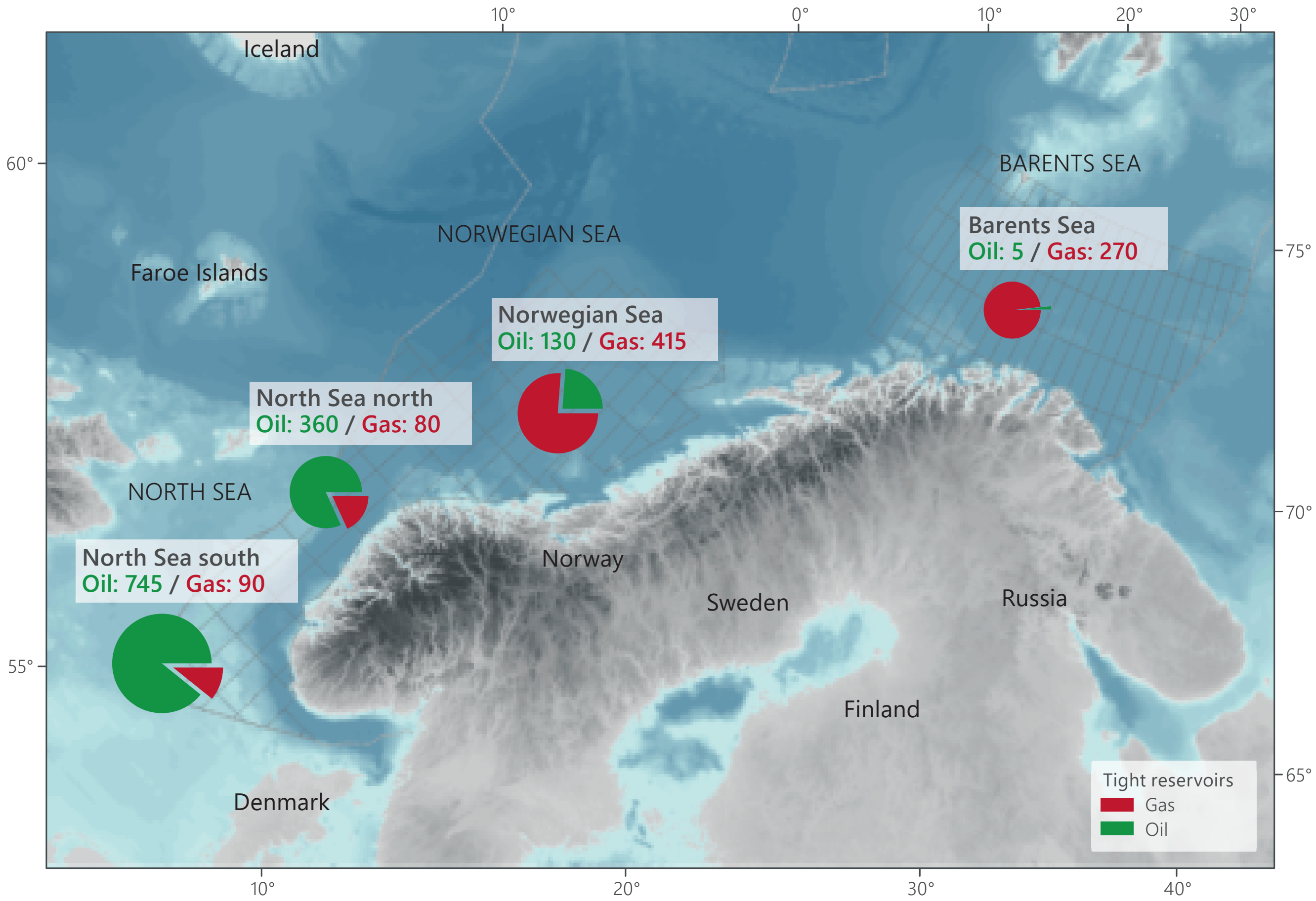


***Figure 3.3** Oil and gas in place in tight reservoirs by area. Amounts in million scm oe*

Recoverable oil and gas volumes in tight reservoirs

The operators have reported recoverable volumes from tight reservoirs for 27 of the 42 discoveries and fields covered by the NPD's study. Estimated recovery factors vary greatly between the different reservoirs. On that basis, the NPD has calculated an average recovery factor of 20 per cent (five to 40 per cent) for oil and 30 per cent (10 to 50 per cent) for gas in the chalk reservoirs. In sandstone reservoirs, the average recovery factor is estimated at 12 per cent (four to 40 per cent) for oil and 25 per cent (18 to 40 per cent) for gas.

Assuming that this applies to all the 42 discoveries and fields in the study, the recovery potential in the mapped tight reservoirs is estimated to be in the order of 450 million scm oe. This breaks down as 200 million scm oe and 250 million scm oe for chalk and sandstone reservoirs respectively. Developing efficient new well technology and more cost-effective development solutions could mean that recovering more of the oil and gas in tight reservoir zones will become profitable.

The recovery potential in the mapped tight reservoirs is in the order of 450 million scm oe of oil and gas

Based on input from Lundin

Recovering oil from fractured basement rock

The 16/1-12 Rolvsnes discovery has a reservoir comprising fractured and weathered crystalline basement rock, with an oil column up to 50 metres high. A successful formation test was performed in well 16/1-28 S during August 2018, and a tie-back to Edvard Grieg has been proposed for test production from June 2021. Following the formation test, the resource estimate was updated to between two and 12 million scm oe.

Test production is intended to observe reservoir behaviour over time in order to evaluate recovery strategies for a possible field development, and whether commercial recovery of the oil is feasible. Particular interest focuses on how water production in the well will develop and whether oil from the porous part of the reservoir contributes to production together with oil from the fractures. Great uncertainty also prevails over the amount of pressure support provided by the underlying aquifer. Lessons learnt from the test will reduce uncertainty related to choice of concept for such aspects as number of production wells, completion solutions, need for pressure support and gas lift, and estimated overall recovery factor.

Experience from fracture-dominated fields globally indicates that a moderate rate of production which permits lateral oil flow to dominate over vertical water flow is a key to optimal resource utilisation. A daily oil production rate of 500 scm is planned. Proximity to the aquifer as well as the fractured reservoir type make water production highly uncertain, and a massive water breakthrough is a possible downside.

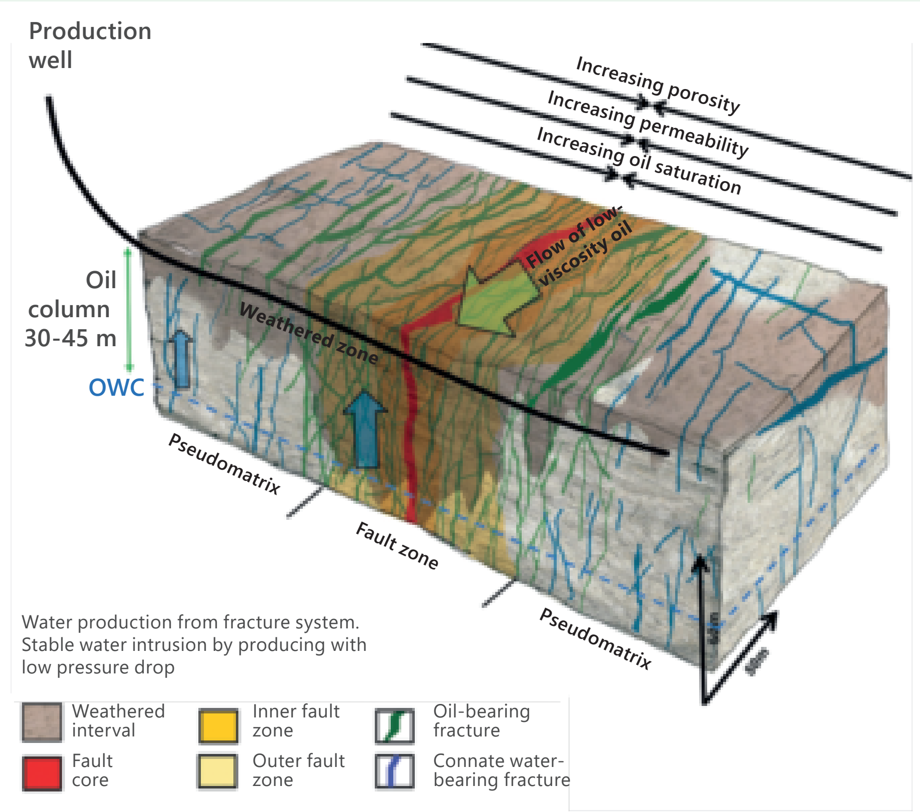


***Figure 3.4** Rolvnes. Illustration: Lundin*

Advanced methods to improve recovery

Water, gas or a combination of these are injected into most oil fields on the NCS to improve recovery. Such injection maintains pressure while also pushing oil through the reservoir and towards the production wells. Nevertheless, substantial quantities of oil remain which cannot be recovered in this way. The NPD estimates that about half this remaining oil is immobile. See the fact box. Recovering part of these resources calls for EOR methods which are more advanced than water and gas injection.

Several EOR techniques involve known technology and are used with fields on land worldwide, but have not so far been applied to any extent offshore. An EOR study conducted by the UK government in 2012 indicated a technical potential of almost 1 000 million scm of oil on the UK continental shelf (UKCS).[11] It is estimated that 10-20 per cent of this could be commercial. On that basis, Britain's Oil and Gas Authority (OGA) and the operators on the UKCS developed an EOR strategy in 2016. That has led to several projects, including injection of low-salinity water and polymers on the Clair Ridge and Captain fields respectively. This demonstrates that EOR can also be implemented on offshore fields comparable with those on the NCS.

Based on input from Norske Shell

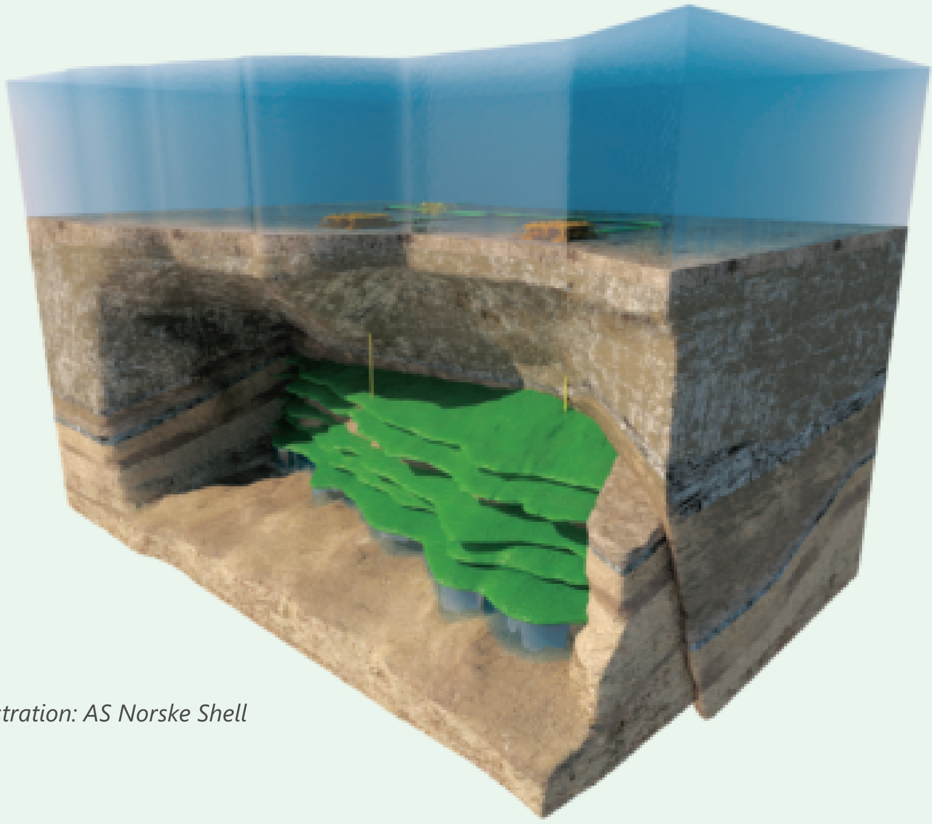
Developing a tight gas reservoir with high pressure and temperature

The 6406/9-1 Linnorm discovery in the Norwegian Sea was proven in 2005 and appraised in 2007. It contains relatively dry gas in a complex and challenging reservoir with high pressure and temperature. The gas also has a high content of CO_2 and H_2S. Today's licensees are Petoro, Total, Equinor and operator Shell.

Comprising the Ile, Tofte and Tilje formations, the reservoir is of variable quality. It has some very good sand units (500-1 500 mD), but also large sections of tight sandstone (0.001-1 mD) with poorer quality which contain gas. Gas in place is estimated at about 90 billion scm, with roughly half of this in tight zones.

The project is now being studied to determine its technical and commercial feasibility. With the next decision gate due in late 2019, several possible solutions are being evaluated. These cover direct subsea tie-back to an export system, phasing into nearby host fields or a stand-alone development.

Opportunities for developing the gas in the tight reservoirs are being assessed. Possible well designs include not only various conventional and/or dedicated types, but also a mix of production wells in conventional and tight reservoirs. Hydraulic stimulation and multizone completion technology are being assessed.



Figur 3.5 *Linnorm. Illustration: AS Norske Shell*

Technical potential

The technical EOR potential in 27 fields and discoveries was mapped by the NPD in 2017. This analysis has now been updated and expanded to 46 fields and discoveries. Based on reservoir data reported to the NPD by the operators, it shows a technical EOR potential of about 700 million scm of recoverable oil. This is almost as much as two Johan Sverdrup fields. Figure 3.6 presents the resource overview for the fields and discoveries studied, including the technical EOR potential.

Fourteen different EOR methods are assessed in the analysis for all fields and discoveries. The technical potential is estimated by summing the potential volume offered by the method which gives the largest volume per field and discovery.

Despite the substantial technical potential, annual reporting to the government shows that only a few projects of this type are under assessment on the NCS.

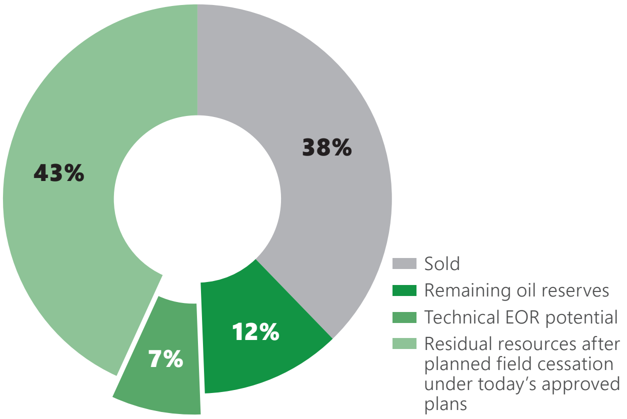


***Figure 3.6** Resource overview[12] for the 46 fields and discoveries in the study, including the technical EOR potential*

Immobile oil

Immobile oil is remaining crude at the pore-scale level after producing with water injection, for example. Recovering more of these volumes calls for the use of EOR methods.

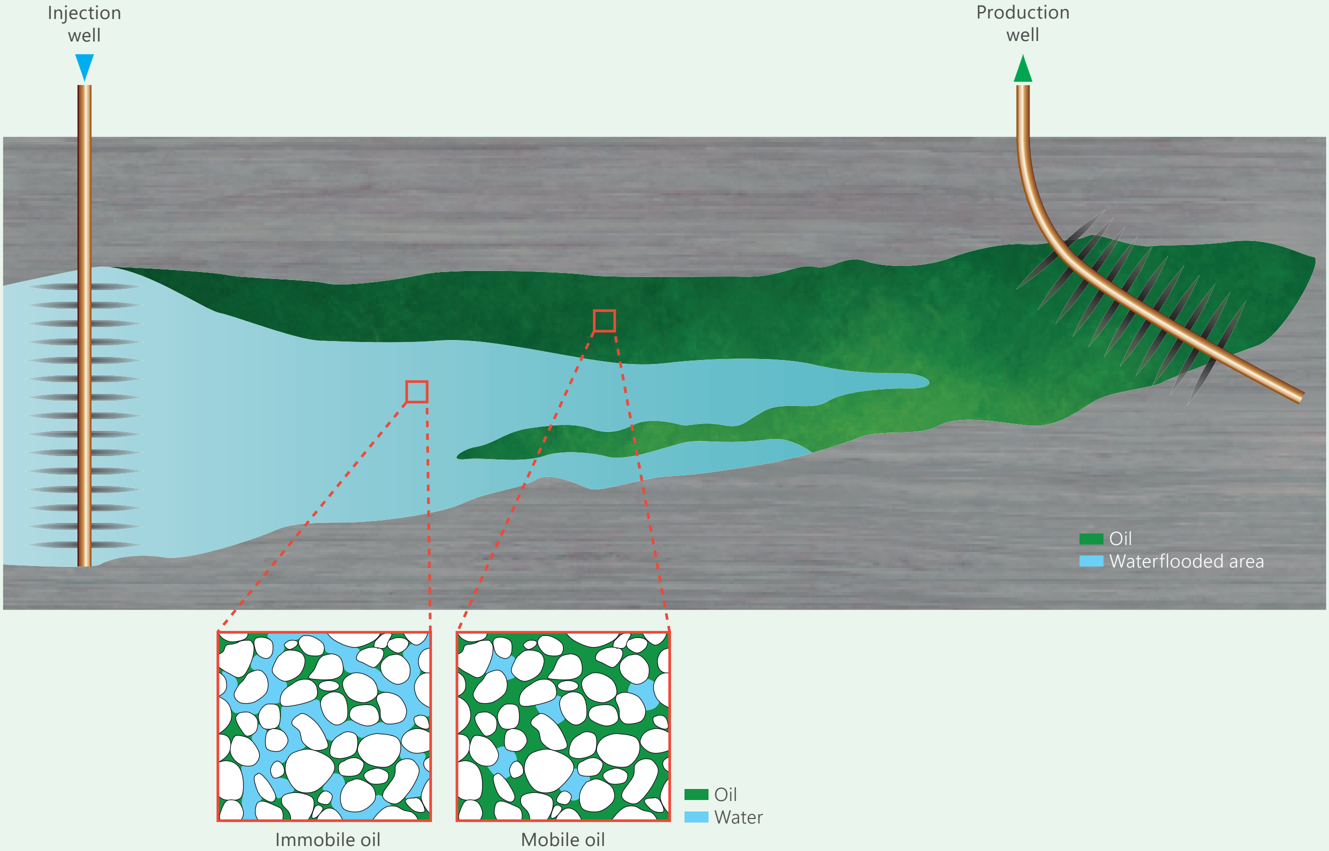


***Figure 3.7** Immobile oil in a reservoir*

Scaled potential

The technical potential does not take account of whether the EOR methods are commercial or practical for possible implementation on the fields. As a result, the NPD has expanded its analysis to look at the effect of factors other than the sub-surface parameters which are significant for EOR projects.

New data were acquired from the operators for the expanded analysis. This information primarily relates to operational criteria which are important for mapping opportunities to adopt EOR methods on planned and existing facilities. The operators themselves have ranked the criteria which could affect implementation of the EOR methods. These include space and weight capacities on facilities, corrosion resistance of the equipment, the water treatment system and distance from infrastructure. The NPD has also estimated production profiles and capital costs as a basis for calculating a present value for each method. A flat oil price of USD 60 per barrel and a discount rate of seven per cent have been assumed.

A scaled EOR potential of 350 million scm of oil has been calculated with an uncertainty range of 180-500 million scm

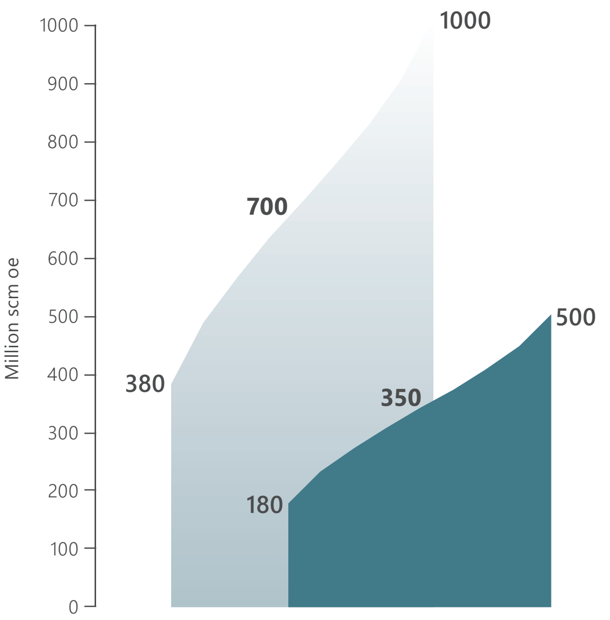


Figure 3.8 *Technical and scaled EOR potential with uncertainty ranges*

Calculating the scaled EOR potential

Identifying a scaled EOR potential for each field and discovery takes account of the factors which affect the opportunities for implementing such measures. An operational and an economic factor, each with a value between 0 and 1, have been defined for each method. These factors are combined to create an overall scaling factor, which indicates the opportunity for adopting an EOR method.

The scaled volume is estimated by multiplying the scaling factor by the technical potential for each EOR method on each field and discovery. Furthermore, the total scaled EOR potential for the whole NCS is calculated by summing the volumes for the EOR method on each field and discovery which has the highest scaled potential and a positive present value (assuming a seven per cent discount rate).

This scaled potential is only valid with statistical relevance when summed over a large number of opportunities, as in this analysis, where it is used to calculate a scaled EOR potential for the whole NCS.

Based on operator reports and the NPD's own assessments, a scaled EOR potential of 350 million scm of oil has been calculated with an uncertainty range of 180-500 million scm. This is almost as much as the reserves in Johan Sverdrup. Figure 3.8 presents both technical and scaled EOR potentials with uncertainty ranges.

Methods ranked differently

The scaled potential in this analysis provides a different internal ranking of methods than the 2017 study. Generally speaking, gas-based methods such as water alternating gas (WAG) injection with miscible hydrocarbon emerge favourably from the scaling, particularly on fields where injection equipment is already installed. Low-salinity and smart water also rank high because of their relatively low cost. The same applies to thermally activated polymers and gels injected directly into the well without major modifications on facilities.

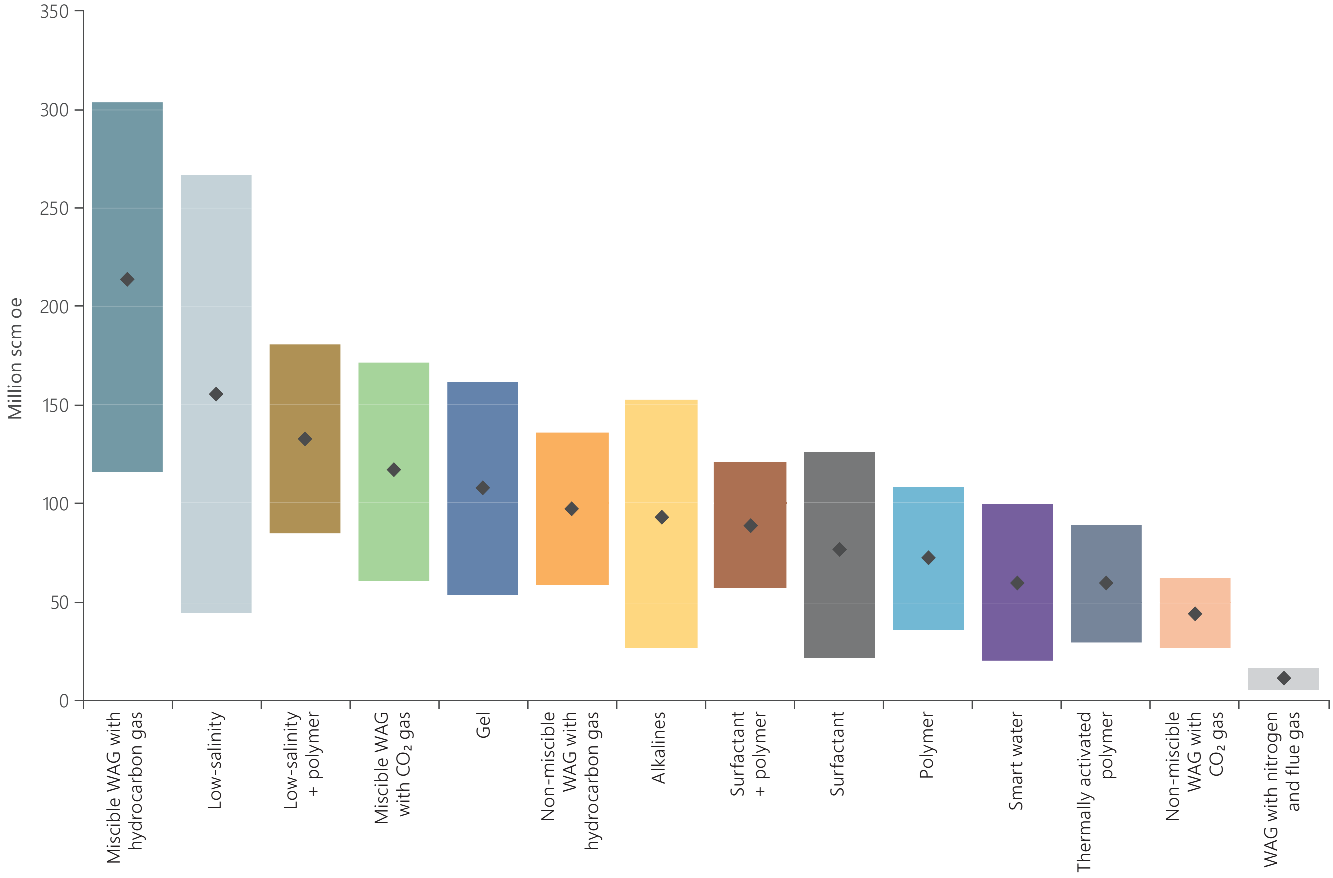


Figure 3.9 *Scaled EOR potential per method with uncertainty range*

Figure 3.9 presents the scaled potential for each method summed for all discoveries and fields in the study. Several EOR solutions have a substantial potential even after scaling. That contrasts with the improved recovery measures reported by the companies, where advanced methods have a modest total recoverable volume of two million scm.

Advanced methods could contribute to recovering substantial volumes if they are qualified. The NPD therefore wants to see an increased commitment to identifying measures which could improve recovery from oil fields on the NCS.

Field pilots

The analysis reveals a substantial potential for EOR. Despite this, the companies are hesitant to adopt these methods on the fields. One reason could be that they are challenging to model. The uncertainty range for recoverable volumes thereby becomes so great that getting projects approved in the companies has proved difficult.

It is important that licensees test EOR methods through field pilots in order to reduce the uncertainty range and verify applicability. Many chemicals used for EOR, for example, are not qualified for use on the NCS, despite showing good results in the lab and fields on land around the world. The need for field pilots is also supported by research teams which have demonstrated the potential of the EOR methods over many years.

It is important that the companies test EOR methods through field pilots in order to reduce the uncertainty range and verify applicability

One example of a field pilot is polymer injection in Johan Sverdrup. A condition set by the government when approving the PDO was that a two-well polymer pilot should be conducted after production began. The purpose is to confirm a possible improved recovery potential and to gain experience in using polymers. Valuable information will also be obtained on opportunities for utilising such injection on other NCS fields.

Figure 3.10 *The Johan Sverdrup field. Illustration: Equinor*

EOR methods

Miscible water alternating gas (WAG) injection with CO_2 or hydrocarbon (HC) gas. Under miscible conditions (which depend in part on pressure, temperature and oil composition), gas and oil will dissolve in each other to create a common phase. These processes make it easier to push oil towards the production wells.

Low-salinity/smart water. Changing the injection water's chemical composition so that its salinity alters can amend wettability in the reservoir. That can help to mobilise part of the immobile oil for production. This method is being assessed, for example, on the carbonate fields in the Ekofisk area.

Low salinity with polymers. This involves a combination of injecting low-salinity water and polymers. Adding the latter increases the injection water's viscosity and makes oil displacement more stable and even.

Combining surfactants with polymers. Adding polymers increases the injection water's viscosity and makes oil displacement more stable and even. Surfactants are added to the injection water to change wettability in the reservoir and reduce surface tension between oil and water. That can mobilise part of the immobile oil.

Gels. The highly permeable zone where the oil has already been produced can be "sealed" by setting a gel plug which forces the water into surrounding undrained areas.

Alkalines. Alkaline substances are added to the injection water and react with the oil, reducing the surface tension between oil and water and altering wettability in the reservoir. This can mobilise part of the immobile oil.

Figure 3.11 *A scientist at work in Stavanger's IOR centre.*
Photo: Jan Inge Haga

Research and development in the petroleum industry

Substantial sums are spent annually on R&D for exploration, development, production and technologies to reduce emissions/discharges. Such investment by the oil companies totalled some NOK 3.7 billion in 2018. Of this, roughly NOK 2.8 billion was charged to Norwegian production licences. Spending was split between research internally by the companies and at external players. About NOK 1.6 billion went to external Norwegian R&D teams (such as the supplies industry, research institutes or the higher education sector). A large proportion of the investment is tax deductible by the companies. The government thereby contributes large sums indirectly.

The SkatteFunn scheme allows small and medium-sized enterprises to deduct 20 per cent of their R&D project costs from income tax. Large enterprises can deduct 18 per cent. The SkatteFunn portfolio in the petroleum sector covered 713 active projects in 2018, with an estimated tax saving of NOK 435 million.

Direct grants are also made to R&D programmes through the Research Council of Norway's Petromaks 2, Demo2000 and Petrosenter programmes. These are directed primarily at universities, research institutes and the supplies industry. Their 2019 budgets total about NOK 380 million. Figure 3.12 shows how the programmes, with their respective budgets, are directed at different types of research.

The government thereby contributes both directly and indirectly (through tax reliefs) to financing the sector's commitment to research and technology development. It therefore expects the amounts invested to result in the development and adoption of new solutions which increase value creation and reduce emissions/discharges from the industry. Sharing knowledge and technology across companies and production licences is also important.

The government expects the substantial amounts invested to result in the adoption of more new technology

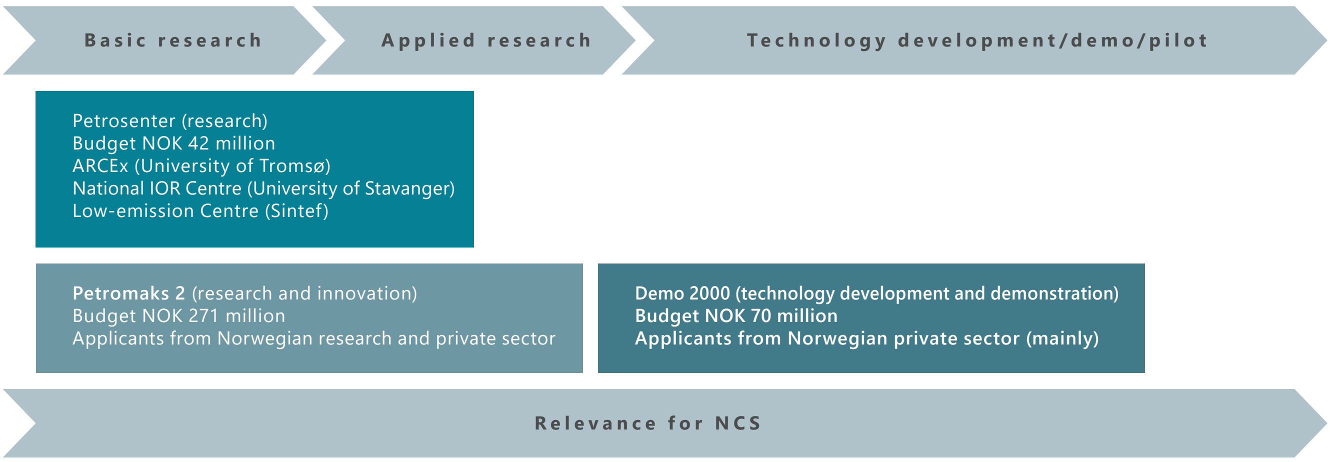


Figure 3.12 *Research Council of Norway R&D programmes for the petroleum sector with their respective budgets*

chapter 4

EMISSIONS, DISCHARGES AND THE ENVIRONMENT

Emissions, discharges and the environment

Concern for the natural environment has always been an integral part of managing Norway's oil and gas resources, and is taken into account in every phase – from exploration, development and operation to field cessation. The industry is subject to strict regulations covering both emissions to the air and discharges to the sea.

Cutting emissions/discharges

The main instruments for restricting greenhouse gas (GHG) emissions are economic – emission trading and the CO_2 tax. This gives companies a permanent self-interest in implementing reduction measures. Norway's reporting to the UN framework convention on climate change estimates that these two instruments contributed to measures which will cut CO_2 emissions from the NCS by almost seven million tonnes in 2020.

While production is expected to rise until 2023, overall CO_2-equivalent emissions and produced water discharges are likely to remain stable

CO_2 emissions from the petroleum sector have been covered by the EU emission trading system (ETS) for GHGs since 2008. The oil companies on the NCS are thereby helping to reduce total emissions within the ETS by 43 per cent from 2005 to 2030. In addition, they pay a high CO_2 tax. Introduced in 1991, this has contributed in combination with the ETS to the implementation of many measures on facilities and at land plants. Substantial resources are devoted to such measures as more efficient gas turbines, enhanced energy efficiency, power-from-shore solutions and carbon storage. This has helped to ensure that Norwegian emissions per unit produced are significantly lower than the average for petroleum-producing countries.[13]

Scientific assessments indicate that petroleum operations have no significant impact on the environmental status of Norway's sea areas. Since operations began on the NCS more than 50 years ago, no acute oil spills have led to beaching or measureable effects on the marine environment.[14] Because major acute spills could nevertheless have an impact, avoiding them is important. Work on zero discharges aims to ensure that no harmful substances are released to the sea on the NCS. To achieve this, discharges are regulated by the government. Releasing produced water containing more than 30 parts per million (ppm) of oil is prohibited. However, most companies on the NCS operate with even more stringent treatment standards, and several inject produced water back into the sub-surface.

Production rising but emissions/discharges remain stable

The NPD prepares annual emission/discharge forecasts covering all activity on the NCS subject to the petroleum tax regime. Predictions for emissions/discharges from future activities are based on decided plans, projects in the planning phase, expected exploration and potential development of undiscovered resources.

Historical and forecast CO_2-equivalent emissions and produced water discharges are presented in figures 4.1 and 4.2, together with historical and forecast output up to 2023. While production is expected to rise until that year, overall CO_2-equivalent emissions and produced water discharges are likely to remain stable. Amounts per unit produced will thereby decline.

Produced water discharges

Discharges to the sea primarily comprise produced water, drill cuttings, and chemical and cement residues from drilling operations. Mitigating measures cover pre-discharge treatment, injection back to the reservoir for pressure support, deposition in the subsurface or shipment to land for treatment as hazardous waste.

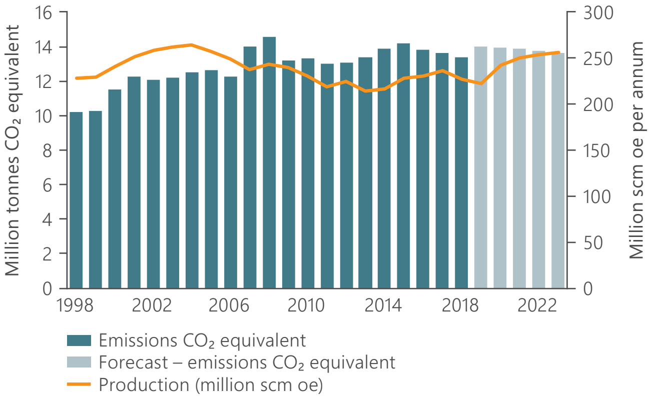


Figure 4.1 *Historical CO_2-equivalent emissions (million tonnes) and NCS production, including forecasts to 2023*

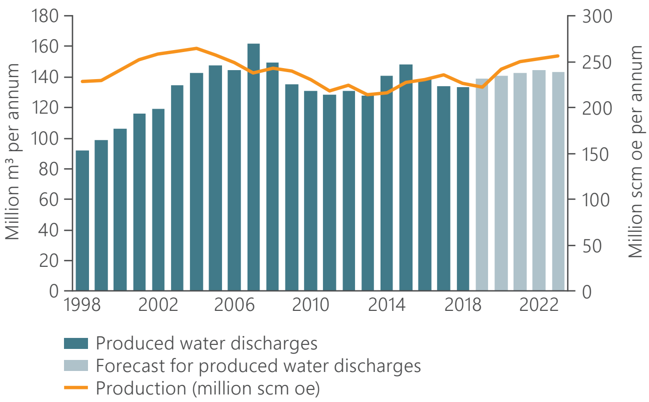


Figure 4.2 *Historical produced water discharges (million m^3) and NCS production, including forecasts to 2023*

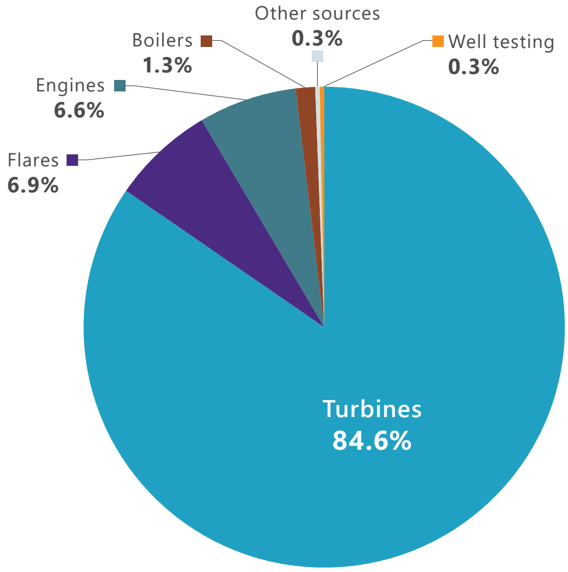


Figure 4.3 *CO_2 emission sources on the NCS, 2018*

Substantial research has been pursued over the past 10-15 years to establish the effect of discharging produced water and the components found in it. This work has shown that the components can harm marine organisms, but generally only at concentrations found close to the discharge point.[15]

On many fields, produced water is injected back into the reservoir as part of the pressure maintenance needed to keep oil production going. Compared with seawater or desalinated water, however, injecting produced water may reduce permeability and complicate reservoir drainage.

The goal of the government and the companies on the NCS is no harmful discharges to the sea. Injection and pre-discharge treatment have substantially reduced the amount of oil released. Billions of kroner have been invested on some fields to treat or inject produced water.

Greenhouse gas emissions

Just under 14 million tonnes of CO_2 equivalent were emitted from the NCS in 2018, about a quarter of Norway's total emissions.[16] Most of the amount released from the NCS derives from gas turbines used to either generate electricity or drive pumps and compressors on the platforms. The biggest potential for emission reduction is therefore offered by efficient turbine operation or introducing alternative power sources. Technologies also exist which can help to cut emissions from other operational areas.

The NPD has identified several types of measures for reducing CO_2 released from petroleum production facilities. These fall into the following categories:

- enhancing energy efficiency
- reducing gas flaring
- power from shore
- power from offshore wind turbines
- thermal power from turbine exhaust heat

Each field is unique. Both the cost of and the potential for emission cuts must always be based on the design, size, production level and remaining producing life of each facility, and be assessed against ETS prices and tax rates.

Enhancing energy efficiency

Using energy more efficiently reduces fuel consumption and thereby CO_2 emissions from the facilities. Energy-efficient turbines mean that less gas is used for power generation, and more can be sold and contribute to value creation. A high level of energy efficiency therefore represents good resource management.

Energy efficiency can also be enhanced through reducing the time taken by energy-intensive activities. Drilling and well operations are particularly relevant. The main purpose of shortening execution time is to cut costs. This also reduces energy consumption and CO_2 emissions.

Reduced gas flaring

Flaring is only permitted for safety reasons. The flare system forms part of a facility's safety system, and must only be used in connection with safe start-up, shutdown and pressure blowdown. Flaring solely for producing oil has been prohibited since production began on the NCS. Norway has been a pioneer in this respect. It has contributed to lower CO_2 emissions and better utilisation of gas resources from the fields.

Reduced flaring must always be viewed in relation to the safety system on a facility. It is expected to be attainable through various technical and operational measures, including improved production regularity, better procedures and flaring strategies, personnel training and reduced blowdown.

Power from shore

Operators have been required since 1996 to assess power supplied from shore in all new developments and for major conversions to existing fields. In most cases, powering an offshore facility in this way will substantially reduce CO_2 emissions from production. Since the NCS is also subject to the EU ETS, such cuts will probably be offset to a great extent by increased emissions in other parts of Europe.

Power from shore means that gas which would otherwise fuel turbines is freed up. Several fields and facilities, such as Valhall, Troll A and Gjøa, have been powered from shore for many years with good results.

Figure 4.4 presents the share of total NCS production powered from shore now or due to be so under current plans. More than 40 per cent of Norwegian output is expected to utilise power from shore in 2023.

The Utsira High fields account for much of the production increase covered by power from shore. Although Edvard Grieg, Ivar Aasen and Gina Krogh run today on gas turbines, they are due to switch to supplies from land when the second stage of Johan Sverdrup comes on stream in 2022. This means the total quantity of oil and gas produced with power from shore is rising, and emissions per unit produced from the NCS are declining. At the same time, the effect of the area solution for power from shore on the Utsira High does not emerge clearly from the emission forecasts in figure 4.1. This is because the Utsira High fields converting from gas turbines have relatively low emissions in an NCS perspective, and because Johan Sverdrup will be powered from shore when it comes on stream.

Power from shore often involves such substantial investment that it becomes uneconomic. This can apply

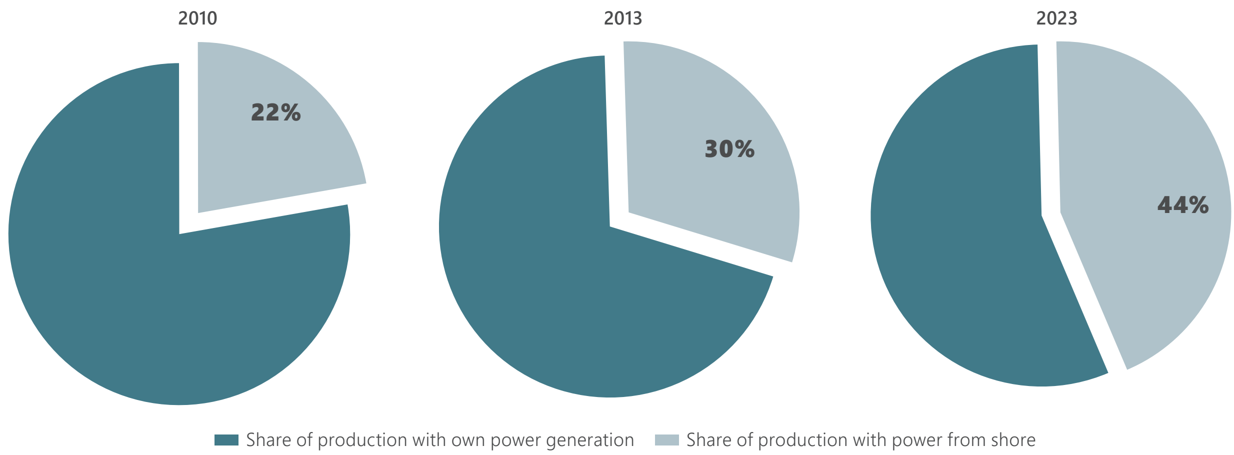


Figure 4.4 *Share of production powered from shore*

both to new facilities and, not least, to the modification of existing installations. Electricity supplies from the onshore grid must also be adequate.

The scope of modification work and the cost of converting a facility to power from shore depends on such factors as whether it is fixed or floating, and the amount of electricity required. Where most facilities are concerned, it is less demanding and expensive simply to replace turbines driving generators with power from shore than to convert completely to the latter. This electricity source is most appropriate for existing facilities in areas which can be supplied with alternating current – in other words, located relatively close to land.

Installing power from shore on new fields and facilities costs less than converting fields already in production to this form of electricity supply.

Offshore wind power

Where wind turbines able to supply electricity to oil and gas facilities are concerned, a distinction is made between fixed and floating installations. Fields on the NCS lie in areas of relatively deep water (70-1 000 metres), so turbines installed on floating units close to the facilities represent the most relevant option.

A challenge with wind turbines is that they cannot operate when conditions are too calm or excessively stormy. This means they cannot meet a facility's power requirements on their own. Wind power is generally better suited as part of a larger grid with other generating units, so that local variations can be evened out.

Supplying oil and gas facilities with offshore wind power is very expensive using current technology. Equinor has now secured NOK 2.3 billion in support from Enova to build a floating wind farm which can deliver electricity to facilities on the NCS. See the fact box on the Hywind Tampen project.

Thermal power

Hot exhaust fumes from gas turbines can be used to drive a turbine for power generation, exploiting thermal energy which would otherwise have been wasted. This represents a way of improving energy efficiency.

However, thermal power depends on heavy and bulky equipment, and finding sufficient spare space and weight capacity on existing facilities can be difficult. Such installations exist today on Oseberg, Eldfisk and Snorre.

New facilities can be tailored more easily to a heavy and bulky thermal power plant than to existing structures. As a rule, their turbines also have greater installed output. That makes it possible to specify a larger thermal power plant with a higher electricity output and an associated reduction in CO_2 emissions.

The cost of installing thermal power is substantial. Access to turbine exhaust heat is also restricted by the fact that a proportion of it is required by the process.

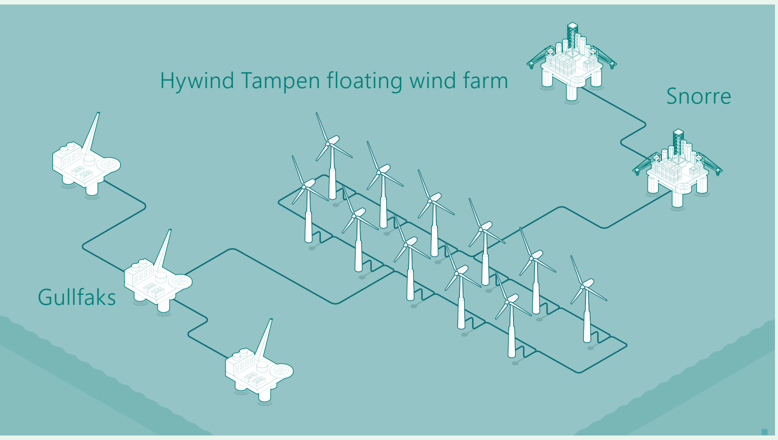


Figure 4.5 *The Hywind Tampen project. Illustration: Equinor*

Hywind Tampen

Hywind Tampen is a wind power project being planned to supply electricity to the Gullfaks and Snorre fields in the Tampen area of the North Sea. It involves 11 floating turbines, each with a capacity of eight megawatts. Plans call for this wind farm to be positioned between the two fields and tied back to them by transmission cables. That could make it possible to operate existing gas turbines at lower load and to shut them down at times. If the companies take an investment decision and the project is approved, annual emissions from the fields are expected to be cut by about 200 000 tonnes of CO_2 and 1 000 tonnes of NO_X. Equinor has therefore secured NOK 2.3 billion in support by Enova. An investment decision is planned in 2019. Regarded as a pilot project, it is due to start up in the third quarter of 2022.

Based on input from ConocoPhillips

Reduced emissions in the Ekofisk area

The Ekofisk area comprises Eldfisk and Embla as well as Ekofisk. These fields have an integrated infrastructure for production, water injection and power supply. Ekofisk also serves as a transport hub for output from other fields.

In connection with the Ekofisk II development in 1998, major changes were made to power supply in the area. The old turbines were replaced by modern low-NO_X units with higher efficiency and lower emissions.

Heat recovery from turbine exhaust fumes, shutting down four old fields and diverting Statpipe around Ekofisk also helped to reduce CO_2 emissions from the area by more than a million tonnes.

Since then, several measures to enhance energy efficiency have been implemented to cut emissions even more. These involve:

- installing low-NO_X turbines and a heat recovery plant with a steam turbine and associated generator to exploit waste heat from power-generating turbine exhausts
- measures to enhance energy efficiency related to water injection
- changing the operating philosophy for gas exports and using a single gas compressor rather than two when conditions permit
- installing transmission cables between facilities to ensure the most energy-efficient power supply in the area.

The two power cables alone provide annual CO_2 emission cuts in the order of 25 000 tonnes. A third cable will become operational in 2019, tying all the Ekofisk-area facilities into a single electricity supply grid which permits further optimisation. Its installation will reduce annual emissions by 900 tonnes of CO_2 and 165 tonnes of NO_X.

Energy production in the Ekofisk area is based today on the best available technology (BAT), which comprises low-NO_X turbines and several heat-recovery units. Enhancing energy efficiency and making modifications have cut emissions over the past decade by 13 per cent, or about 150 000 tonnes of CO_2 since 2008.

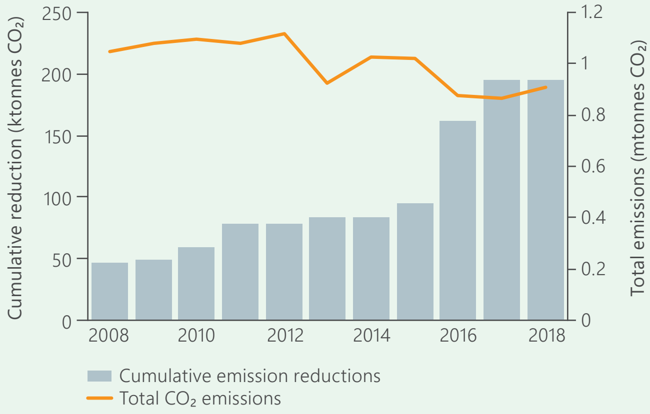


Figure 4.6 *Total emissions and accumulated emission reductions in the Ekofisk area, 2008-18. Source: ConocoPhillips*

Some 20 million scm of gas was flared annually in the Ekofisk area during 2004-09. A number of measures, such as shutting down a flare, introducing targets for flaring reductions, reintroduction of the pilot flare and installation of flare gas recompression, have substantially reduced this. Over the past couple of years, 10-12 million scm of gas have been flared – almost a halving compared with the 2009 level.

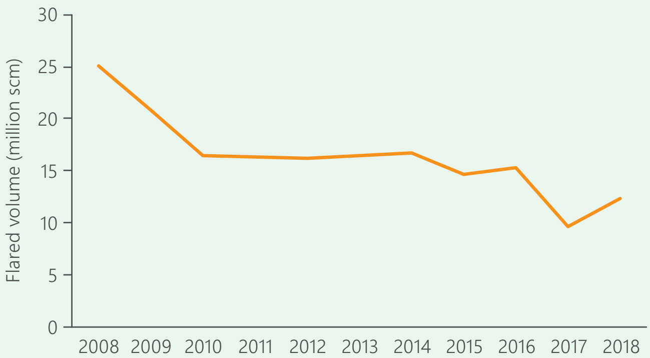


Figure 4.7 *Quantity of gas flared on fields in the Ekofisk area. Source: ConocoPhillips*

Work is under way on even greater reductions, in part through the installation of a new flare gas compressor. Expected annual emission cuts from this project are in the order of 27 000 tonnes of CO_2. That corresponds in total to some nine million scm of gas which can be sold rather than flared.

Footnotes

[1] A discovery is entered in the portfolio the year after its discovery. Johan Sverdrup, for example, was discovered in 2010 and included in the portfolio in 2011.
[2] Reserves are resources covered by a production decision.
[3] Contingent oil resources include both quantities proven but not yet decided for production, and projects which are also not decided to improve recovery from fields.
[4] The NPD's expectations of future gas recovery were over-optimistic in 1996-2002, and estimates for contingent gas resources were adjusted downwards from 2003.
[5] The change in reserves for fields where a PDO was submitted after 2000 is measured against the estimate for reserves when the PDO was submitted.
[6] The average figure is normalised against the figure for reserves in 2000 or against the first reported reserves for fields where a PDO was delivered after 2000.
[7] This figure is based on well paths, but these are referred to here as wells.
[8] Drilling multilaterals on Troll is not included in the base data..
[9] The base data run to 2017. The 2018 figures have been estimated.
[10] 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), represented by the United Federation of Trade Unions and the Norwegian Union of Industry and Energy Workers.
[11] McCormack, M P, Thomas, J M and Mackie, J (2014), *Maximising Enhanced Oil Recovery opportunities in UKCS through collaboration*, SPE paper 172017.
[12] Resources in RCs 4, 5 and 7 are not included in the total.
[13] Sources: International Association of Oil & Gas Producers (IOGP) and Epim Environment Hub (EEH).
[14] Source: Expert Panel.
[15] DNV GL, *Håndtering av produsert vann – erfaringer fra norsk sokkel*, no: 2015-4277, rev 0.
[16] Statistics Norway.

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Conversion tables

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

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

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

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