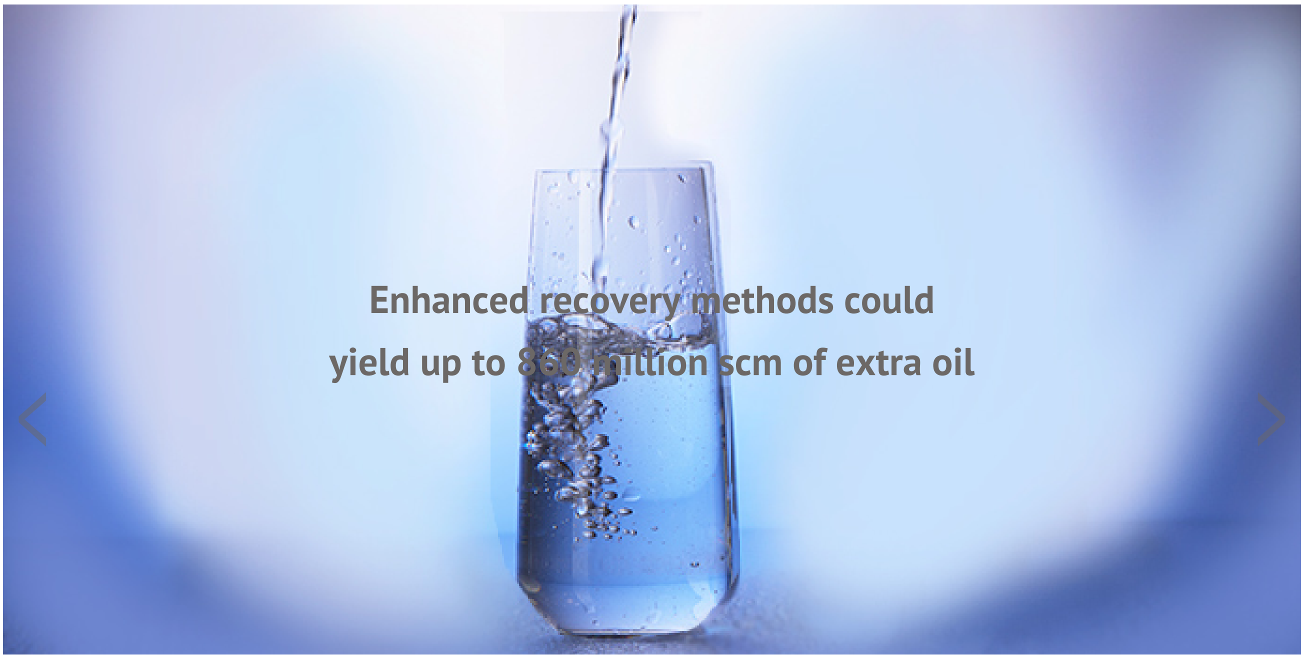
RESOURCE REPORT 2017

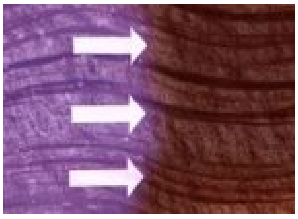
Even more to gain

Oljedirektoratet 14.06.2017

Large quantities of petroleum on the Norwegian continental shelf cannot be recovered profitably today. That includes immobile oil and resources in tight reservoirs. Qualifying and adopting new technology could make producing part of these assets Commercial.



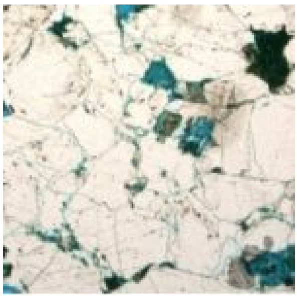
Technical resources are the quantities which could potentially be recovered with technology which has yet to be tested or qualified for use on the Norwegian continental shelf (NCS). Further research and testing which allow such solutions to be adopted is important. This work must done in time to ensure that possible profitable resources are not lost



Large EOR potential on the biggest fields

A big technical potential exists for enhanced oil recovery (EOR). This is estimated at 320-860 million scm in a study commissioned by the NPD and covering the 27 largest oil fields. Testing, qualifying and applying new and improved recovery methods is important for realising the potential

Read more about the EOR potential



Large oil and gas deposits in tight reservoirs

Substantial deposits of oil and gas are contained in tight reservoirs in various parts of the NCS. Such resources are challenging to produce. Developing and adopting new technology on the NCS could make recovering them profitable.

Petroleum deposits in tight reservoirs

Go to the next topic: Recovery

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Enhanced oil recovery (EOR) methods

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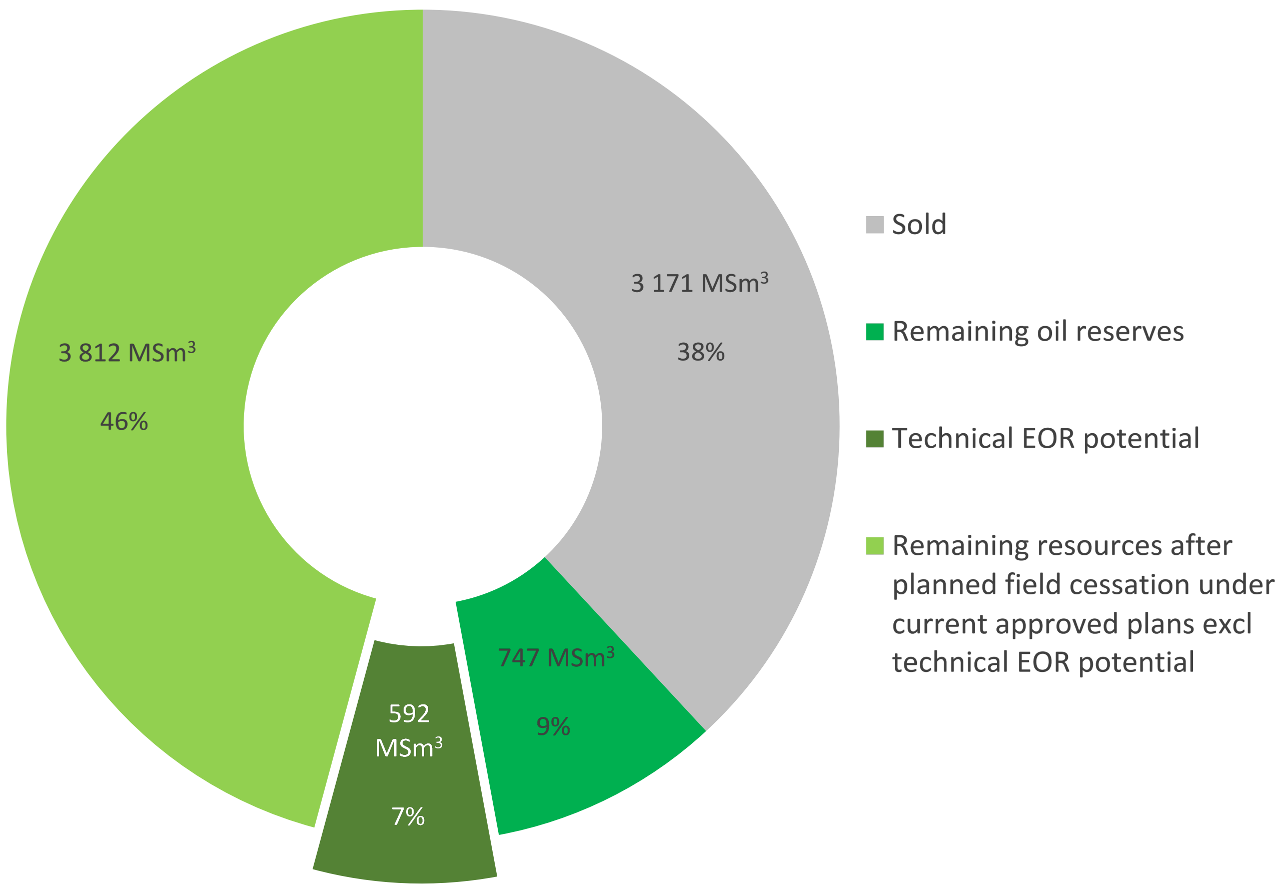
Large oil resources on the Norwegian continental shelf (NCS) cannot be produced with current plans and technology. About half of these call for enhanced oil recovery (EOR) techniques. Testing, qualifying and applying new improved recovery methods within a reasonable time is important if substantial oil volumes on the NCS are not to be lost.

Water and/or gas injection is used on most Norwegian oil fields to improve recovery. This maintains pressure and sweeps the reservoirs, but nevertheless leaves a sizable quantity of oil behind. That applies to both mobile and immobile oil.

Potential on 27 Fields

The figure below presents overall resources in and the technical EOR potential of 27 of the largest fields on the NCS. Although reserves and resources are calculated differently from a technical EOR potential, the figure can give an indication of the size of the latter.



Resource overview and EOR potential on the 27 largest NCS oil fields.

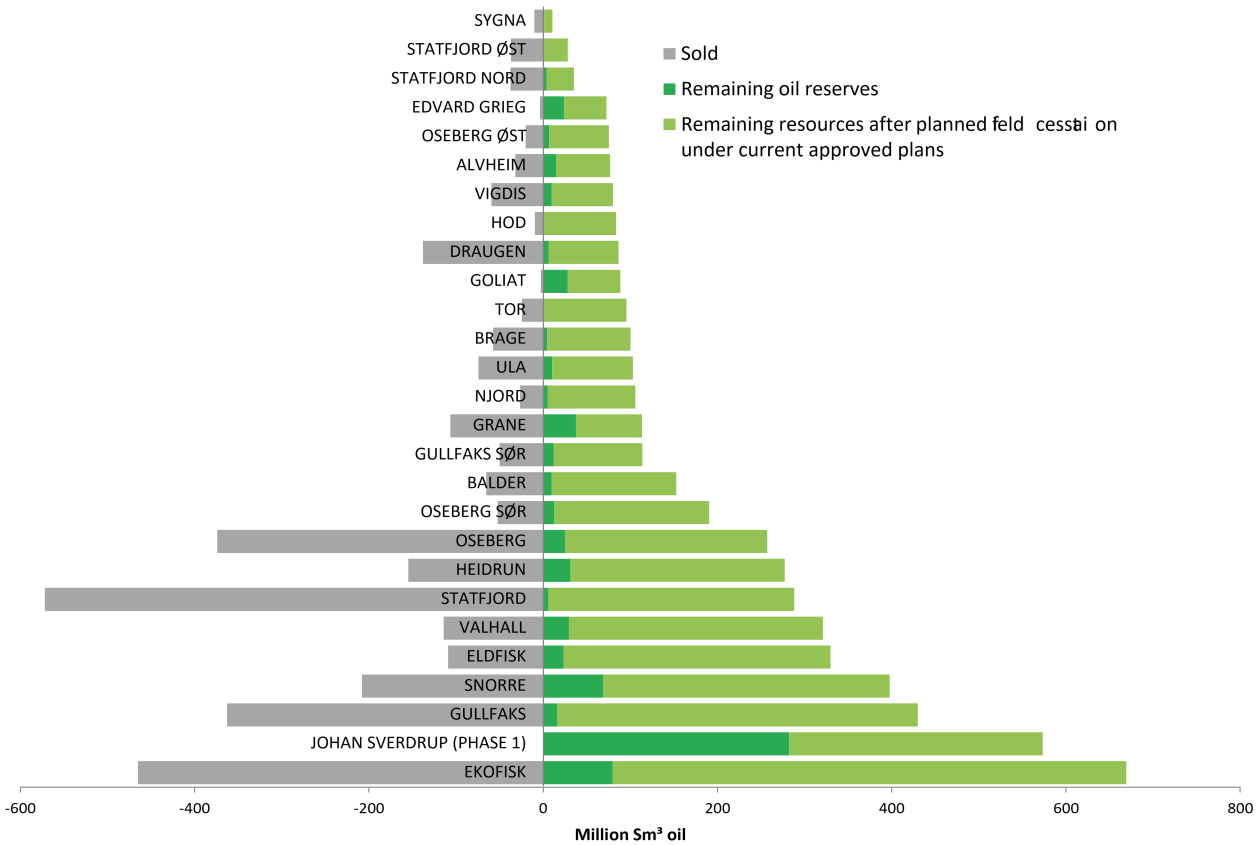
Screening

In cooperation with C Smalley and A Muggeridge from Imperial College in London, the NPD has conducted a screening study which aimed in part to provide an estimate for the technical recovery potential offered by various EOR Methods.

This work covered 27 of the largest fields on the NCS, which contain about two billion scm of immobile oil. The results show an overall technical EOR potential of 320-860 million scm for both mobile and immobile oil.

It is important to emphasise that this is a technical EOR potential. No account has been taken of financial, environmental and operational conditions. Even if only about 10 per cent of the technical potential, for example, yields profitable production, it would represent almost NOK 150 billion in gross sales revenues at an oil price of USD 50 per barrel and an exchange rate of NOK 8 to the USD.

See the article: Positive prospects for producing more



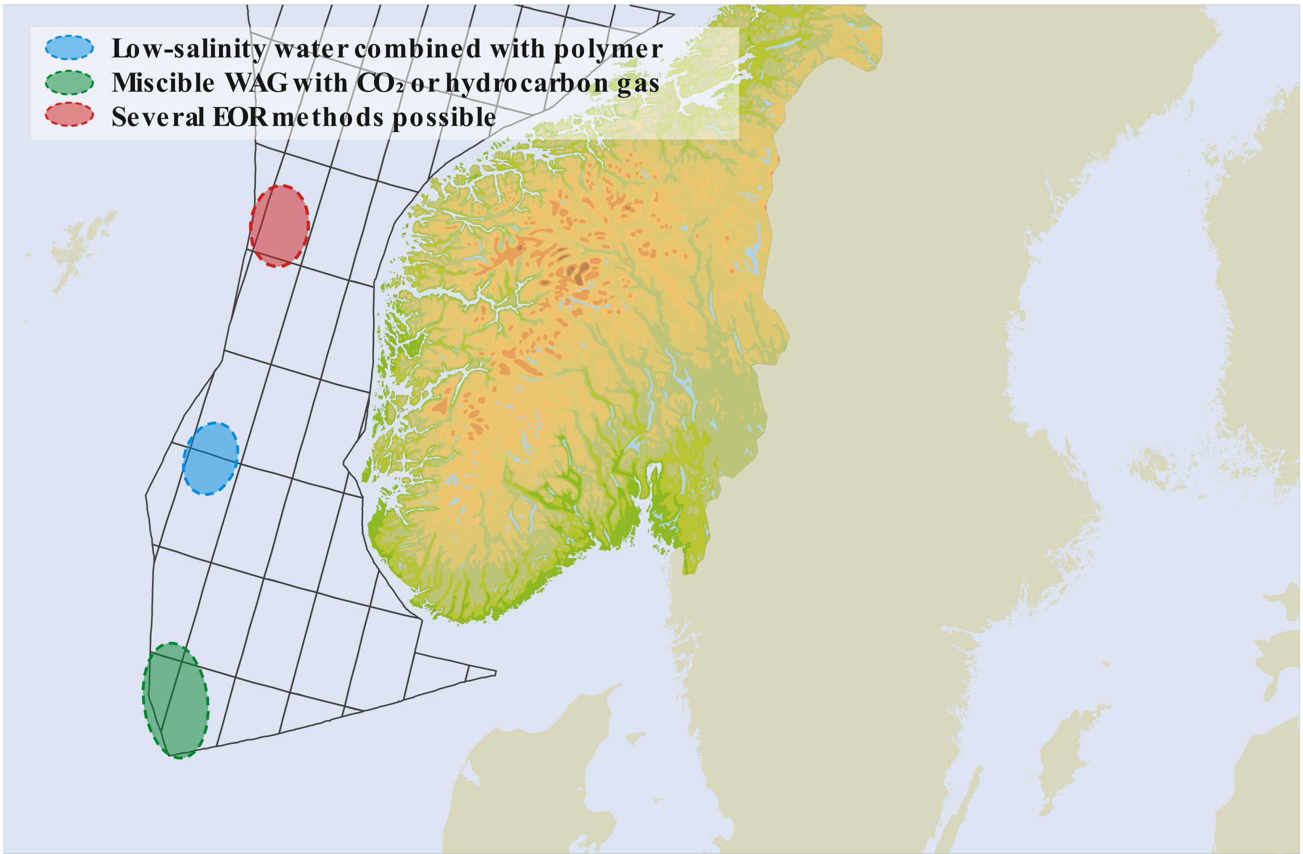
Resource overview for the 27 fields included in the study.

Various EOR methods described

Thirteen different EOR methods were assessed by the screening study. The one with the biggest potential for each field was chosen – in other words, one method per field even where other EOR solutions might have a corresponding effect. The outcome was that seven different EOR methods showed the highest potential for the 27 fields in the study.

Areas which stand out

A geographical analysis of the technical EOR potential has been carried out to identify defined areas where specific methods could be applied. This work shows clear geographical trends for applying the same EOR solution.



Miscible water alternating gas (WAG) injection with CO2 or hydrocarbon gas has the largest potential on the chalk fields at the southern part of Norway's North Sea sector.

On the Utsira High and the surrounding area, injection of low-salinity water combined with polymers is the method with the largest potential. Injecting surfactant combined with polymers is also technically feasible on these fields, offering almost the same potential.

Several different methods have a large potential in the Tampen area of the northern North Sea. Miscible WAG injection would be best for some, while others are likely to benefit most from water-based EOR solutions.

Collaborating over EOR projects across production licences could be appropriate – with joint supply of injectant (chemicals or gas), for example, covering several fields in the same area.

Adopting EOR Methods

Offshore EOR projects generally require substantial investment, and extra oil recovery could be achieved later than with conventional methods. Pilots are also required to clarify uncertainties associated with the recovery potential and technical feasibility. In most cases, pilot tests are essential for large-scale implementation of new technology.

An EOR project could comprise pilot and evaluation phases before possible full-scale adoption. From a company perspective, the cost of a pilot must often be incorporated in the financial assessment of the EOR project. The same applies to probability calculations for a successful pilot and possible successful field implementation.

Total costs and their breakdown between investment and operation for the various EOR methods depend on several factors.

- are ships or new/existing installations used?
- are the field(s) concerned on stream or in the planning phase?
- are new wells required?
- is the time frame for the project long or short?

It can generally be assumed that EOR methods such as CO2 and low-salinity injection are the most capital-intensive, while operating costs form a larger part of the overall bill for injecting polymers, surfactants, gels and alkalines.

An example of a financially sound EOR project is the low-salinity scheme on the BP-operated Clair Ridge field on the UK continental shelf. Due to come on stream in 2018, it is estimated to have a breakeven oil price of USD 3 per barrel.

Pilots can help reduce uncertainty

The government considers pilots to play an important role in data acquisition. Their purpose is to narrow the uncertainty range for the potential and to verify feasibility.

Several EOR methods have been tested and applied on a large scale on land, with a positive outcome. But these solutions have hardly been tested where the Norwegian continental shelf (NCS) and the offshore sector in general are concerned. Factors which make their implementation more demanding offshore include wide well spacing, weight, space and power constraints on existing platforms, and environmental restrictions on discharges to the sea.

As a result, great uncertainty prevails about the recovery potential and whether it is technically and operationally possible to verify feasibility, reduce risk/uncertainty, provide knowledge of possible environmental challenges, and demonstrate an increased recovery potential from adopting the various EOR methods. This is necessary for such technologies to be adopted for improved recovery from the NCS.

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Large petroleum deposits in tight reservoirs

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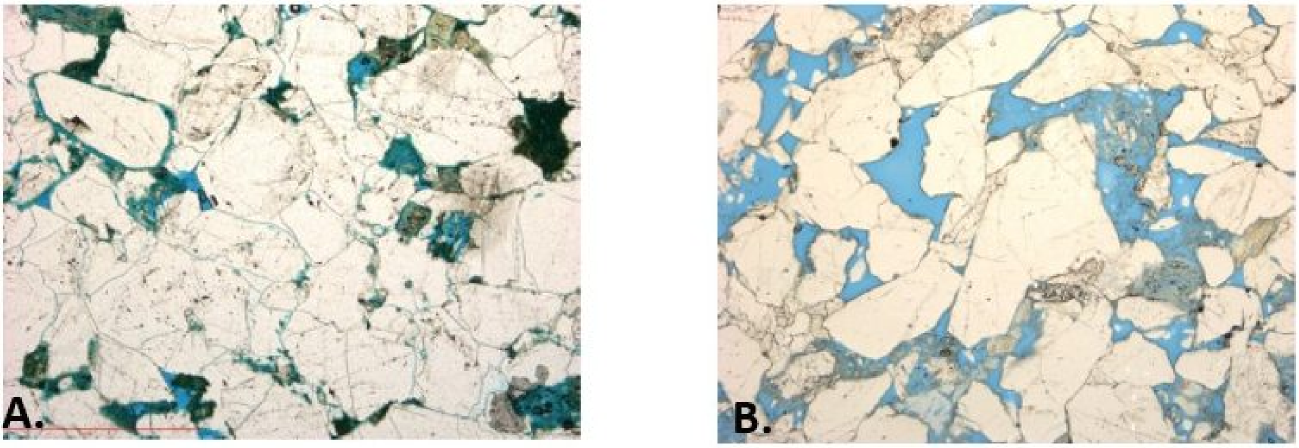
Substantial quantities of oil and gas can be found in tight reservoir zones which are challenging to produce. That applies in part to rocks buried deeper than 4 000 metres in the Central and Viking Grabens in the North Sea and on the Halten Terrace in the Norwegian Sea. A commitment to new and improved technology will be important for boosting the productivity of these challenging reservoirs and thereby making profitable recovery possible.

High pressure, high temperature (HPHT) and cementation as a result of increasing depth help to complicate recovery from tight reservoirs. In some cases, sandstone may have well-preserved porosity and permeability despite great depth. This could reflect the presence of chlorite and kaolinite, which prevent quartz cementation. Smørbukk and 6406/2-1 Lavrans are examples of fields and discoveries in the Norwegian Sea where chlorite has contributed to good reservoir quality.

The alternation between zones with quartz cementation and chlorite presents a challenge in tight reservoirs. As a rule, reliable mapping of the extent of good sand in the reservoir will be difficult. A good understanding of the depositional environment is important for predicting both high- and low-permeability zones in the best possible way.



(A) Sandstone where quartz cementation gives low permeability.
(B) Sandstone where chlorite has been precipitated before cementation and sandstone permeability has been preserved. (Photos: Statoil)

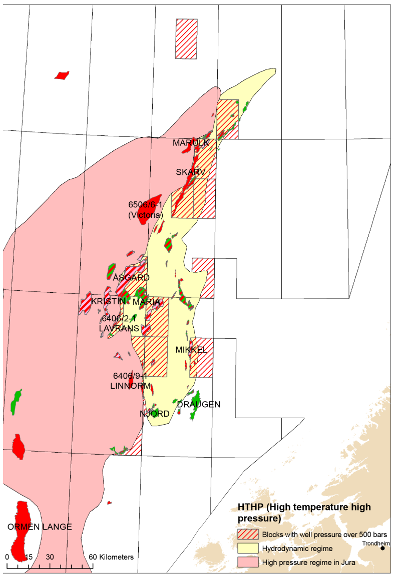
Condensate blocking is one challenge which may be faced in low-permeability gas and condensate fields. When reservoir pressure falls below the dew point, condensate will precipitate and Liquid can accumulate around the well. That lowers the relative permeability of the gas and reduces flow properties in the reservoir, which can lead to poorer well productivity. Certain reservoir zones with low permeability in the HPHT Kristin field present challenges precisely for this reason.

AREAS

Click on the maps to see the various zones.

Norwegian Sea

A number of fields and discoveries which consists completely or partly of tight sandstone reservoirs are located along the western side of the Halten Terrace in the Norwegian Sea. They lie primarily in HPHT areas, as shown in map 1. Large parts of their reservoir rocks are assumed to have tight zones as a result of quartz cementation. Largely of Jurassic age, these rocks lie deeper than 4 000 metres in the Åre, Tilje, Tofte, Ile and Garn formations.



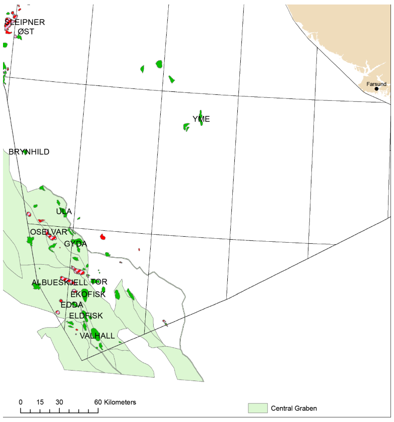
Map 1

Examples of discoveries and fields with tight sandstone reservoirs are 6406/9-1 Linnorm, 6506-1 Victoria and Kristin. These three deposits are estimated to have resources in place of 300-450 million scm oe, of which as much as 250 million scm oe are thought to lie in tight reservoir zones. Up to 30 per cent of the Ile, Tofte and Tilje formations in 6406/2-1 Lavrans have permeabilities of 0.01-0.1 mD. The Garn formation is regarded as tight in 6406/2-1 Lavrans. In the Smørbukk deposit, large resources are estimated to occupy tight reservoir zones in the upper and middle parts of the Tilje formation.

Map 1. *HPHT map of the Norwegian Sea. Fields and discoveries located in the Jurassic high-pressure regime are estimated to contain big remaining resources in tight reservoir zones*

Southern North Sea sector

Large resources are located in tight chalk reservoirs in the Central Graben at the southern part of Norway's North Sea sector (map 2). Recovery from discoveries and fields in these areas faces some of the same challenges encountered in the Norwegian Sea. The chalk deposits have very low permeability, and production from them is often dependent on fracturing the rock. Tor, Albuskjell, Edda and Valhall are examples of fields with large remaining resources in tight chalk reservoirs. The original resources in place in these four fields are estimated to total around 800 million scm oe.



Map 2

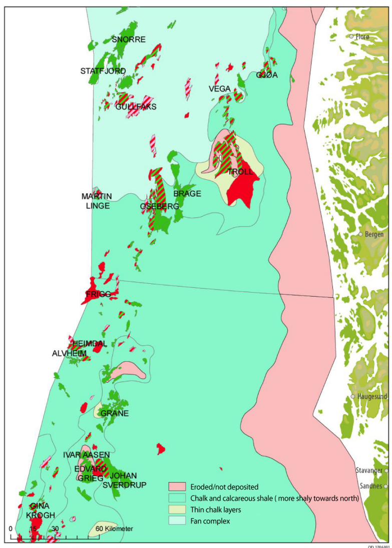
Reservoirs in the Tor, Albuskjell and Edda fields, which have ceased production, comprise the Tor and Ekofisk formations. These alternate between tight and moderately porous layers. Resources originally in place in these fields are estimated at about 300 million scm oe. When they ceased production, their recovery factor was 20-30 per cent. The tight reservoir zones lie primarily in the Ekofisk formation. According to NPD estimates, most of the oil now produced from Tor and Albuskjell came from the Tor formation. This is the easiest formation to produce from. The NPD assumes that large resources remain in the Ekofisk formation.

Valhall is producing from the Tor and Hod formations. The Tor formation is more permeable and produces better than the Hod formation. Resources originally in place in the field are estimated to be just over 500 million scm oe, with a recovery factor of about 35 per cent (resource categories 0-2).

Map 2. *The southern part of Norway's North Sea sector, showing discoveries and fields with large remaining resources in tight chalk reservoirs.*

Northern North Sea sector

Tight reservoirs are also found in the Shetland group, which lies above the main reservoir in the Gullfaks and Oseberg fields (map 3). A revised plan for development and operation (PDO) of Gullfaks secured government approval in 2015. This includes producing the resources proven in the Shetland group.



Map 3

The latter is estimated to contain resources in place of 100-800 million scm oe on Gullfaks and Oseberg. Producing from these rocks has proved challenging, and the recovery factor is very low.

Producible hydrocarbons have been proven in the basement rock on the Edvard Grieg field in the Utsira High area. Such rock is generally hard and tight, but in this area is more porous and fractured as a result of diagenesis and tectonic movements. Hydrocarbons have subsequently migrated into the basement rock.

Map 3. *Extent of the upper part of the Shetland group in the northern part of Norway's North Sea sector. The interpretation has been modified from the FMB software belonging to TGS*.

Technology progress can ensure value creation

An earlier NPD study of a gas discovery with a tight reservoir in the Norwegian Sea found that efficient production would require drainage points created by hydraulic fracturing throughout the reservoir. This method involves generating fractures in a reservoir by injecting water and Chemicals.

READ ALSO: Well technology in tight reservoirs

The Åsgard field has tight zones in the parts of the Tilje formation in Smørbukk, while parts of the Garn formation in Smørbukk Sør are regarded as tight. Hydraulic fracturing has previously been used to boost productivity on Smørbukk.

Åsgard is also the only field on the Norwegian continental shelf (NCS) where the Fishbone technology developed in Norway has been utilised. This was done in a tight reservoir on Smørbukk Sør. The latter was discovered in 1985, but was earlier considered non-commercial because of low-permeability zones. During testing of the technology, about 150 "fishbones" with a diameter of 12 millimetres were drilled 10-12 metres out from the borehole with the aid of rotating turbines.

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FOR MORE INFORMATION, SEE statoil.com Smørbukk Sør Extension

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CO_2 for improved recovery

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Studies of CO_2 injection for enhanced oil recovery (EOR) show positive results. A number of these assessments have been conducted by both the companies and the NPD to see how recovery from producing fields on the Norwegian continental shelf (NCS) could be increased by injecting CO_2. However, insufficient supplies of this gas present a challenge. So does lack of experience from offshore Fields.

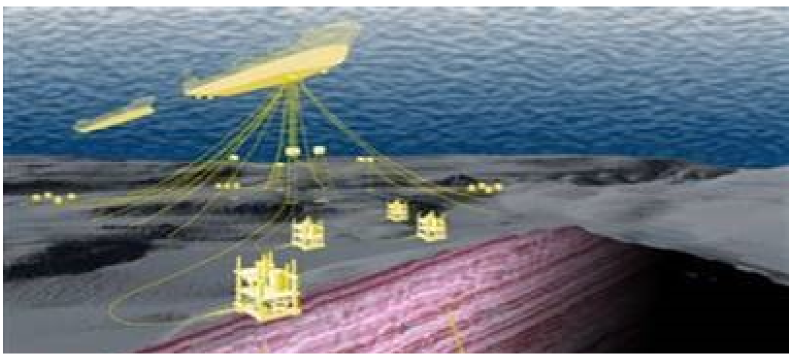
Three different studies have been carried out by the NPD in recent years to assess a possible EOR potential combined with CO_2 storage on oil fields in the North Sea. This work has been presented and discussed at a number of conferences and seminars.

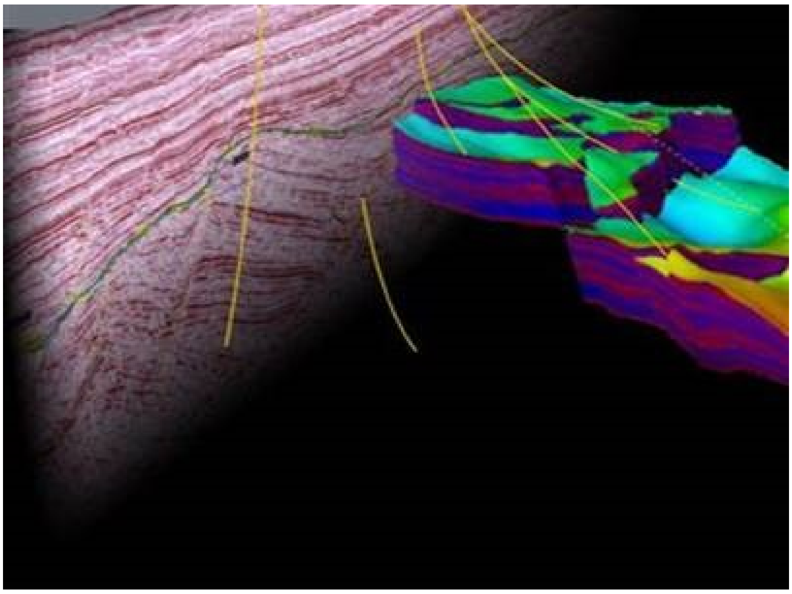
The first was a screening study of 23 North Sea oil fields, which updated an assessment made in 2005. The second covered three different fields with available CO2 of one-three million tonnes injected annually, and the third provided a more detailed study of a mature oil field in the North Sea where 0.7 million tonnes were injected per annum.

This work showed a potential for improving recovery over a range from four to 12 per cent, with an average of about seven per cent and a storage effect for CO_2 in the reservoir of 70-100 per cent. That potential corresponds well with studies done by oil companies and research teams in Norway, as well as with international experience.

Offshore implementation

Several concepts can be considered for CO_2 injection in mature fields. Uncertainty and risk relate primarily to platform conversion and the possible corrosive effect of CO_2 and water on wells and process equipment. However, insufficient supplies of this gas present a challenge. So does lack of experience from offshore fields. The method has been used on land in the USA and Canada for many years, but in fields with much higher well densities than are found offshore.





Experience is needed to obtain a better overview of the real opportunities for improved recovery from CO_2 injection on offshore fields. Many studies and much laboratory work have been carried out. To make further progress, pilot projects with CO_2 injection on offshore fields are required. This could be done with small volumes of injection CO_2 in parts or segments of a field. Such pilot projects could provide valuable experience with a view to large-scale injection in order to realise the extra oil potential.

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