Norwegian Petroleum Technology

A success story

Norwegian Academy of Technological Sciences
Offshore Media Group

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- promote research, education and development within the technological and natural sciences
- stimulate international co-operation within the fields of technology and related fields
- promote understanding of technology and natural sciences among authorities and the public to the benefit of the Norwegian society and industrial progress in Norway.

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Preface

In many ways, the Norwegian petroleum industry is an economic and technological fairy tale. In the course of a little more than 30 years Norway has developed a petroleum industry with world class products and solutions. This book highlights some of the stories behind this Norwegian success.

A strong Norwegian home market has helped Norwegian industries to develop technologies in the absolute forefront. In some important areas, like the subsea market, the Norwegian "oil cluster" became world leaders through companies like Vetco, Aker Kværner and FMC Technologies. Advanced products for the domestic market, with cost effective and flexible solutions, are also sought after in the international market place. Norwegian companies are now involved in some of the world's foremost projects, from Sakhalin in the east to Brazil in the west and Angola in the south.

Norway, with its 4.5 million inhabitants, is a very small country indeed. As an energy supplier, however, Norway will play an increasingly important role. This will require an even stronger emphasis on research, competence and technology development. Today some 75.000 highly qualified people are working directly in the Norwegian petroleum industry, where the domestic market is still strong with large field developments like Snøhvit and Ormen Lange. Norway has established a unique Petroleum Fund, which currently is passing $ 160 billion, and political leaders in resource rich oil countries are looking to Norway for inspiration and guidance.

This book describes some of the best technology stories that have emerged from Norwegian research institutions. Financial support, text and illustrations from the companies and institutions presented in the book have made its publication possible and are gratefully acknowledged. An editorial committee has been responsible for producing the book under the chairmanship of Research Director Ole Lindefjeld of ConocoPhillips, who once demonstrated a multiplier effect of at least 15 times the amount of money that his company had invested in research and development in Norway. The committee hopes that telling these stories of Norwegian technology will demonstrate that research really does pay. The editorial committee has consisted of:

Ole Lindefjeld (chair)	ConocoPhillips
Helge Keilen (editor)	Offshore Media Group
Kari Druglimo	The Research Council of Norway
Siri Helle Friedemann	The Research Council of Norway
Liv Lunde	IFE Institute for Energy Technology
David Lysne	SINTEF Petroleum Research
Kjell Markman	RF Rogland Research
Grethe Schei	SINTEF Petroleum Research
Knut Åm	Norwegian Academy of Technological Sciences (NTVA)

Contents

Leading research centres are of decisive importance for the Norwegian continental shelf

The oil and gas industry is an important part of Norway's national economy, and it has made important contributions to the development of the Norwegian welfare state. One of several factors underlying the creation of value that has taken place during the epoch of Norwegian oil has been the efforts put into petroleum-oriented research and technology development. Together with other facets of our petroleum policy and industrial investment in this sector, petroleum research has been an important part of the development of Norway as an oil-producing country, and in this way has contributed to laying the foundations for the long-term development of this branch of industry.

This book bears clear witness to the role played by Norwegian research centres in the development of the Norwegian petroleum sector in close collaboration with other actors in this industry. ConocoPhillips has taken a very praiseworthy initiative to produce this book in collaboration with Norwegian research institutes and the other parties involved.

The expertise which has been built up in the course of time is in many ways an invisible but decisive factor in the Norwegian petroleum sector. A wide range of examples offer us a picture full of insights into how Norway, as a petroleum nation, has managed to develop leading-edge expertise in the field of petroleum technology. The results illustrated in this volume provide valuable documentation of the important technological advances that have been made in one of the core chapters of the recent industrial history of Norway.

The petroleum sector is an industry with a future. To date, only one third of the oil and gas resources on the Norwegian shelf have been produced. Technological developments on the Norwegian shelf provide good evidence of the potential returns that long-term investment in research offer the state and industry, evidence which emerges clearly from the historical material presented in this book. Investment in research and technology is an important tool for realising the possibilities and challenges that face us as a nation on the continental shelf and for ensuring that industry is capable of maintaining its international competitiveness. As Minister of Petroleum and Energy I lay great weight on this aspect, not least in how I prioritise the authorities' own investment in research. Norway has the possibility of further developing the competence needed to satisfy the demand for advances in research and technology that are essential if the Norwegian petroleum industry is to be able to look forward to successful development in the future. The establishment of a national strategy in petroleum-oriented technology and research, OG21 (Oil and Gas in the 21st Century), has been important as a tool for ensuring that we invest in relevant areas of R&D for the sake of the future.

I strongly believe that Norwegian research will continue to work at the leading edge in core areas of the oil and gas sector. That they should do so will be of decisive importance for the continued creation of value on the Norwegian continental shelf, and for our prospects on the international scene.

Thorhild Widvey
Minister of Petroleum and Energy

Competitive technological capabilities

By Gulbrand Wangen, Managing Director, INTSOK

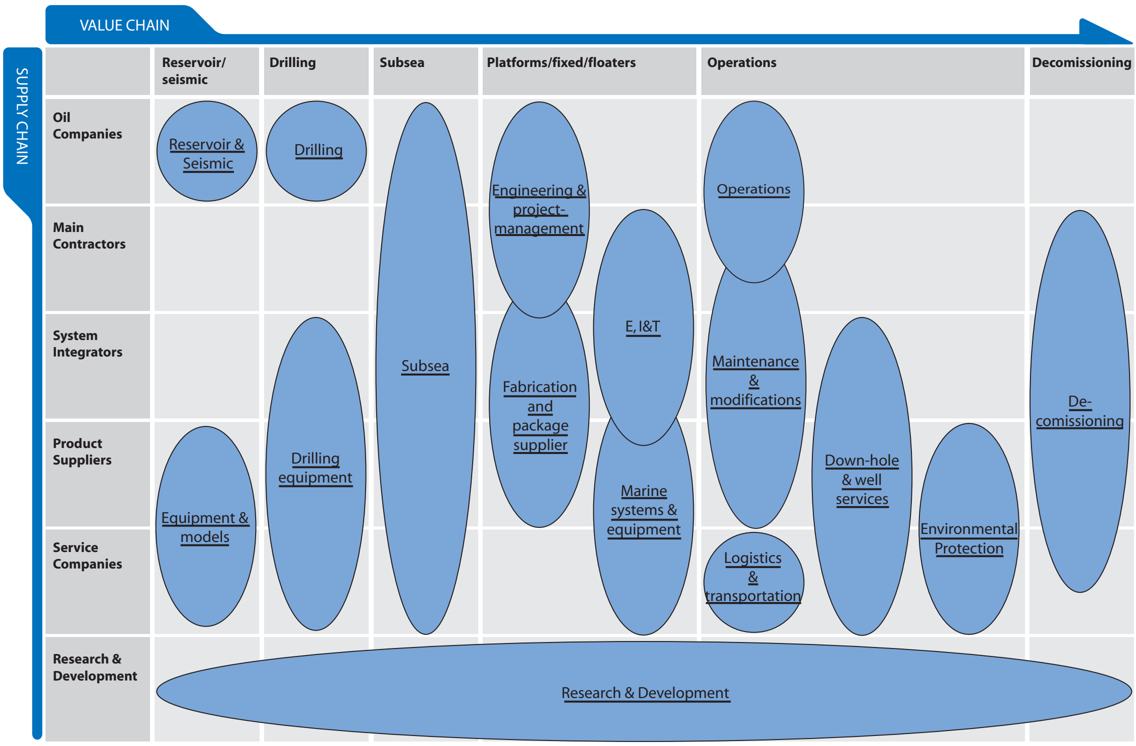
The Norwegian Continental Shelf (NCS) has for 30 years been a laboratory for developing new cost effective solutions and technologies. Research and development have been important in order to reduce costs, increase recovery and secure sound environmental solutions. The major factors in building industrial competitiveness in the Norwegian oil and gas sector are the giant fields and pioneering technological projects, the world class maritime knowledge, innovative and risk willing firms, large R&D investments and strong emphasis on quality and price competition.

The partnering between the oil companies, Norwegian as well as international, the supply industry, the research institutions and academia has made Norway one of the best environments for technological developments. Access to superb engineers and strong project teams has enabled the Norwegian oil industry to deliver on time, quality and cost. The operators on the NCS have also been more willing to use new technological solutions than operators in most other offshore provinces.

Technological success stories

Drilling technology has made it possible to develop fields like Troll Oil – a large thin oil zone under a major gas field. 15 years ago that was seen as uneconomic, but Hydro had the vision and the ambition to go ahead. Troll oil is now producing from 35 branched wells and a further 15 new branched wells are planned.

Technology has been fundamental for the progress seen in reservoir management and enhanced recovery factors. The average recovery factor on the Norwegian Continental Shelf is some 45 per cent and the focus is on increasing the average recovery factor to more than 50 percent. In some of the maturing fields up to 70 percent of oil in place will be produced. Every percentage point growth in recovery adds 30 billion dollars of value to the industry and society.



The Norwegian World Class Cluster Matrix

Technology has also allowed companies to meet ever more stringent environmental requirements, such as no harmful discharges to sea and CO2 storage in subsea reservoirs, like on the Statoil-operated Sleipner field in the Norwegian North Sea.

Floating production and extensive use of subsea technology has revolutionised the way projects are developed and have made new development solutions far more cost effective.

A cluster at the leading edge

A strong domestic market has been and still is the basis for technological development and expansion into the global markets. INTSOK's mapping of the Norwegian petroleum cluster documents that the Norwegian oil industry has developed 16 competitive, leading edge supply chains which enable the companies to win orders internationally.

Technology developed and applied in Norway has already contributed to major export earnings in international projects, and the trend is towards more focus on international opportunities.

Norwegian companies are involved from arctic conditions in Sakhalin, North Caspian and the Barents Sea to deepwater in West Africa, Brazil and Gulf of Mexico. The large projects tend to get the big headlines, but many good ideas are converted to advanced products and services. Most of the INTSOK partners are small and medium-sized companies with an annual turn-over within the oil and gas sector below 10 million dollars. Many of them are supplying a wide range of cost effective and flexible quality products and services to the global market.

Two major concrete gravity base substructures are built for Sakhalin Energy, operated by Shell. One is the Piltun offshore platform, the other is the Lunskoye platform.

The two substructures are amongst the biggest structures ever built in Russia and the varied geometry of the legs puts them amongst the most complex concrete slip forming jobs ever undertaken. They are the first structures of their type to be built in the country, with a Russian content of some 85% and a workforce of some 2,000 Russians involved in their construction.

The developments of the deepwater offshore fields off the coast of Angola are another example. Three Norwegian based companies, FMC Technologies, Aker Kvaerner and Vetco International have secured 75-80 per cent of the subsea market based on the technologies and competences developed on the NCS.

Norwegian research institutions are rapidly expanding their business outside Norway.

SINTEF, a Norwegian research institution with 1800 employees, has some 30 percent of its revenues from outside Norway. The institution has delivered several field development plans in Iran and is also involved in an R&D project on gas based Increased Oil Recovery (IOR) in fractured carbonate reservoirs in the country. The SINTEF Group offers R&D services along the whole hydrocarbon chain, from source rock to end user. The Group provides leading edge tools and solutions within basin modelling, seismic processing, rock mechanics, flow assurance, CO2 deposition, FAWAG (foam assisted water alternating gas injection), LNG, GTL (Gas to liquids), floating production facilities, pipelines, moorings, safety and reliability analysis and subsea power distribution. SINTEF operates the largest multiphase flow laboratory and offshore basin laboratory in the world.

The Institute for Energy Technology (IFE) and SINTEF have developed OLGA, a dynamic software tool for engineering and operation of multiphase production systems. OLGA 2000, marketed by Scandpower Petroleum Technology, has become the market-leading simulator for transient multiphase flow of oil, water and gas in wells and pipelines with process equipment and is used by 100 companies world wide. IFE, the Institute for Energy Technology, has become an internationally recognized centre in the field of internal corrosion of oil and gas pipelines as a result of a series of joint industry projects. IFE's tracer technology is also widely used internationally. The institution carries for example out tracer services on five fields in Venezuela.

RF-Rogaland Research has the world's most advanced full-scale Drilling and Well Centre, with testing sites, flow loops and related laboratories. The research group offers competence in development of environmentally acceptable technologies, geological modelling, reservoir evaluation, drilling, well completion and IOR.

The Norwegian Geotechnical Institute (NGI) has a world leading competence within geotechnics, engineering geology, environmental geotechnology combined with expertise within material properties, modelling and analysis.

Christian Michelsen Research (CMR) has led the development of a sophisticated software based on the Virtual Reality Technology which allow us for three dimensional exploration of complex geological structures and data. This technology is today marketed by Schlumberger.

Major Projects

Value creator on the Norwegian continental

By Stig S. Kvendseth

In 1969, the discovery of oil and gas on Ekofisk turned Norway into a petroleum nation. In the course of 40 years as a participant in this industry, ConocoPhillips has gone beyond the limits of what has been regarded as technologically possible.

The discovery of the Ekofisk reservoir in a chalk formation as the North Sea's first commercial oilfield, the start of production 18 months after the discovery, the construction of the Ekofisk Tank as the first concrete oil and gas platform in the world, the laying of what was then the longest subsea pipelines with their compressor platforms, the jacking up of six steel platforms by six metres on Ekofisk in 1987, water injection into the chalk reservoir, considerably increasing the recovery rate, the development of the Heidrun field with the world's first concrete tension leg platform (TLP) – without storage capacity and carbon fibre risers for great depths. These are just some of the highlights from the story – at the same time as ConocoPhillips is a driving force behind the operating model of the future, and is adopting e-operating methods capable of supporting drilling and production in such distant parts of the world as Vietnam and Alaska.

This enormous development has taken place in collaboration between internal and external professionals and researchers, owners in the production licenses, the service industry, vendors and the Norwegian authorities. ConocoPhillips has challenged – and been challenged by – these groupings to find solutions to problems that have appeared either difficult or on the verge of the impossible. Together, however, we have arrived at solutions that we can all be proud of, and which have found application not only on the Norwegian continental shelf, but have been brought by ConocoPhillips out into a wider world. The company is operating in more than 40 countries and has helped to introduce Norwegian technology and Norwegian companies to the whole world.

Ekofisk

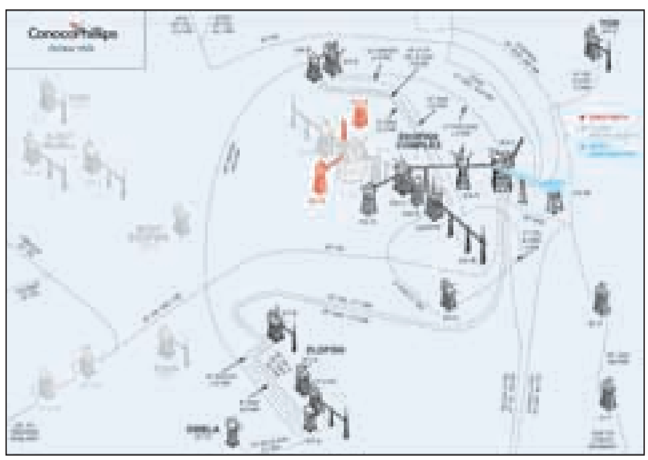
In what follows, we will take the development of the greater Ekofisk area as a good example of what we have achieved via collaboration with the research sector, the service industry, vendors, the authorities and co-venturers.

The creation of value from Ekofisk has undergone an enormous development in the period between 1971 and 2004. The recovery rate from the Ekofisk chalk field has risen from an estimated 17 percent in 1971 to an estimated 46 percent in 2004. Values of 200 billion dollars have been generated until 2004.

When the Ekofisk reservoir was demonstrated as the first major oil reserve in the North Sea in 1969, a number of fundamental questions were raised. Is stable production over a long period of time possible from such a chalk reservoir? Are the environmental conditions in the middle of the North Sea, one of the most hostile seas in the world, such that it would be possible to build safe platforms and infrastructures for profitable oil and gas activities?

35 years later we can be certain that the answers to these questions are positive, and that the geologist who promised to drink all the oil that was produced from the chalk field, didn't know what he was talking about.

Half of the world's petroleum resources are to be found in chalk reservoirs, while sandstone is often a better reservoir rock for oil and gas. Sandstone is often more porous and has better production properties, gives up its oil and gas more willingly, and offers a relatively high recovery rate.



The greater Ekofisk area currently consists of 29 platforms, some 1100 km internal pipelines and two export pipelines – one for crude oil and NGL to Teesside in the UK and one for dry gas to Emden in Germany. Of eight fields in the area, four have already been closed in and 11 platforms are due to be removed by 2013. After more than 30 years of production, Ekofisk is one of the most productive petroleum fields on the Norwegian continental shelf.

1. Phillips Petroleum Company and Conoco Inc. merged in 2002, becoming ConocoPhillips. Both of the former companies had been active on the Norwegian continental shelf since the start of the offshore industry. In what follows, the company is referred to as ConocoPhillips, even though Phillips and Conoco were separate companies at the time of the events described here.

shelf through innovative thinking

Chalk is more dense and yields its oil and gas more slowly and with a lower recovery rate, to put it in simple terms. There are a number of factors that complicate this somewhat schematic presentation, but let us make it as simple as that. When the Ekofisk field was discovered in an enormous chalk reservoir in 1969, it was Holy Writ that fields of this type had low recovery rates, and that production would offer a large number of challenges.

Test production

Ever since the start of production in 1971 this was planned for. Production started in the form of test production from a modified jack-up rig – "Gulftide". History was being made even at this early stage – a jack-up drilling rig was rebuilt for production from four subsea wells. The wells that were brought into production were exploration and appraisal wells. The crude oil production of up to 40,000 barrels a day went straight into tankers via loading buoys. This was done only 18 months after the Ekofisk field had been discovered!

When it turned out that the four wells were sometimes producing 10,000 barrels a day each, and that production was stable, the production properties of the reservoir had been demonstrated. Development could continue on the basis of permanent platforms. In the course of the 70s, the Ekofisk field was developed, as were the six fields known as Cod, West Ekofisk, Tor, Albuskjell, Eldfisk and Edda. Apart from Cod, all the reservoirs were in chalk formations. The pipelne for landing crude oil and NGL to Teesside in the UK was installed, while a gas pipeline was installed to Emden in Germany. The 34 inch, 356 kilometre-long pipeline to Teesside was the first of its type, with two pumping platforms to maintain pressure, and a capacity of one million barrels a day. The gas pipeline to Emden was even longer at 440 km, and larger, with a diameter of 36 inches, and it also had two compressor platforms along its length to maintain the pressure. The capacity of this pipeline was about two billion cubic feet a day.

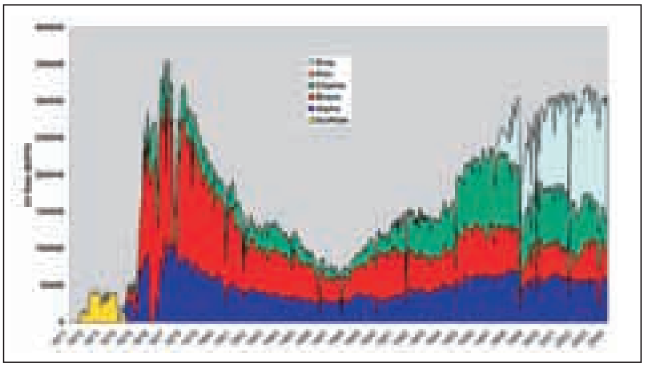
Gas injection

In the Mid-East, where there are many major carbonate reservoirs, large volumes of gas were injected in order to maintain reservoir pressure and thus increase recovery rates. On Ekofisk, the gas was injected before the gas pipeline to Emden was opened in 1977. The Ekofisk owners contracted the sale of the gas to a European consortium led by Ruhrgas; the first ever Norwegian sales contract for gas. After 1977, about one third of the gas produced continued to be injected – partly as pressure support and partly in order to regulate deliveries according to demand.

In 1987, water injection began from a well on the Ekofisk 2/4 K platform. The platform has a bridge connection to Ekofisk 2/4 B. The project was unique, since water injection to chalk formation reservoirs is unusual.

Water injection

The first laboratory test of water injection as a means of pressure support for enhanced recovery started in 1979. The production history of Ekofisk. These laboratory tests did



The production history of Ekofisk. Test production started in 1971. Until 1974, capacity was 40,000 barrels per day. When the permanent platforms came into operation in 1974, production rose rapidly and in the course of a few years it reached its highest level before gradually falling to a low in 1987. During the next few years, the effects of water injection could be seen, and in 2004 production approached an all-time high.

In 1984, the seabed beneath the Ekofisk Complex platforms was found to be subsiding. The effects of compaction of the chalk formation in the reservoir, 3000 metres below the surface were transmitted up to the seabed. In 1987, six steel platforms weighing more than 40,000 tonnes were jacked up, and spool-pieces were installed on the platform legs. A fantastic feat of engineering that is probably without parallel in the history of the offshore industry

not provide unambiguous answers, but the first tentative plans for a possible water injection project for the Ekofisk field were drawn up. The authorities, led by the Norwegian Petroleum Directorate, were a driving force at this point in time, in addition to the company's own experts. In 1981, test of water injection from a well on the Ekofisk 2/4 B platform began. Water was injected into the lower part of the reservoir - the Tor formation. The laboratory tests had shown that it was the chalk in this part of the reservoir that had the greatest water-absorbing capacity, and was thus most capable of displacing the oil towards the production well. The core of the problems concerning the effects of water in chalk reservoirs is the ability of the chalk to absorb water. Furthermore, can the water damage the chalk and thus both help to reduce production capacity and acidify the oil and gas? The risks are great!

Collaboration

During autumn 1982 sufficient data were available to confirm that water injection appeared to be only marginally profitable. As the price of oil was also showing some weakness in January 1983, the economic advantages of water injection were disappearing, at least on the basis of company economics criteria. The Ekofisk owners entered into negotiations with the Norwegian authorities with the aim of improving the general conditions for carrying out the project, which had positive social economic effects. After long negotiations the parties came to agreement; the Ekofisk water injection project was given improved depreciation rates and the project started up.

Gradual development

A separate water injection platform, Ekofisk 2/4 K, was built and installed in the northern part of the Ekofisk field. It started water injection in 1987 in the lower part of the Tor formation. This first phase of the project provided water injection for about a third of the Ekofisk reservoir, with about 350,000 barrels of water being injected every day. In the course of the 90s, the water injection programme was extended several times, with the result that by 2004 it covered the whole Ekofisk reservoir, with an injection capacity of nearly a million barrels of purified seawater a day. The Ekofisk field has turned out to be unique, and the fractured chalk absorbs water particularly well. When production started in 1971, the reservoir pressure was 7000 psi. In 1987, before the start of water injection, it had fallen to 3,500 psi, while by 2004 it was 5,500 psi. In the course of 2004, production has set new records, after 33 years of production. In 2004, Ekofisk, along with Troll, were the biggest petroleum producers on the Norwegian continental shelf! Water injection is not the only reason for this, but it is the most important factor besides developments in well technology, particularly horizontal wells, and the experience and competence developed in dealing with the reservoir by ConocoPhillips, the operator.

Continuous process of research

How has all this been possible?

The answer is complex, and it is a combination of a number of factors. What these factors have in common is an iterative process involving experts on the operational side and scientists, as well as collaboration among the owners, the Norwegian authorities, research institutions and the supply industry.

As early as 1980, the Joint Chalk Research Project was launched by Norwegian and Danish authorities in collaboration with the owners to chalk fields in the North Sea. The project focused on the challenges offered by chalk formation reservoirs. What was special, in an international context too, was that the authorities and industrial companies joined forces in a task of this sort. This area of research has been continued, and was still under way in 2004.

A glimpse of Ekofisk reservoir rock – chalk.

Since the mid-80s, the Ekofisk owners have been supporting studies at the University of Bergen aimed at

1. Phillips Petroleum Company and Conoco Inc. merged in 2002, becoming ConocoPhillips. Both of the former companies had been active on the Norwegian continental shelf since the start of the offshore activity. In what follows, the company is referred to as ConocoPhillips, even though Phillips and Conoco were separate companies at the time of the events described here.

In 2004, the Ekofisk Complex consisted of 11 platforms linked by walkways or bridges. The 12th platform is being built, and will be installed on the field in 2005.

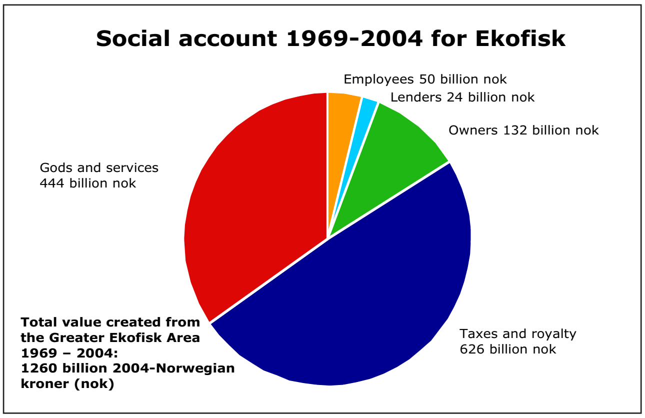
building up a detailed understanding of the fundamental mechanisms involved in water injection in fractured limestone formations. A number of master's and doctoral students have taken part in this programme. The RUTH and SPOR research programmes have taken place in collaboration with The Research Council of Norway. Three-phase flow in chalk and sandstone formations related to the injection of gas and water, has been another area of study. In Norway, SINTEF, Rogaland Research and Reslab have participated in this programme.

Another project has looked at air injection for enhanced oil recovery. ThermicAiroil was partly financed by the EU and both national and international research institutions were participants.

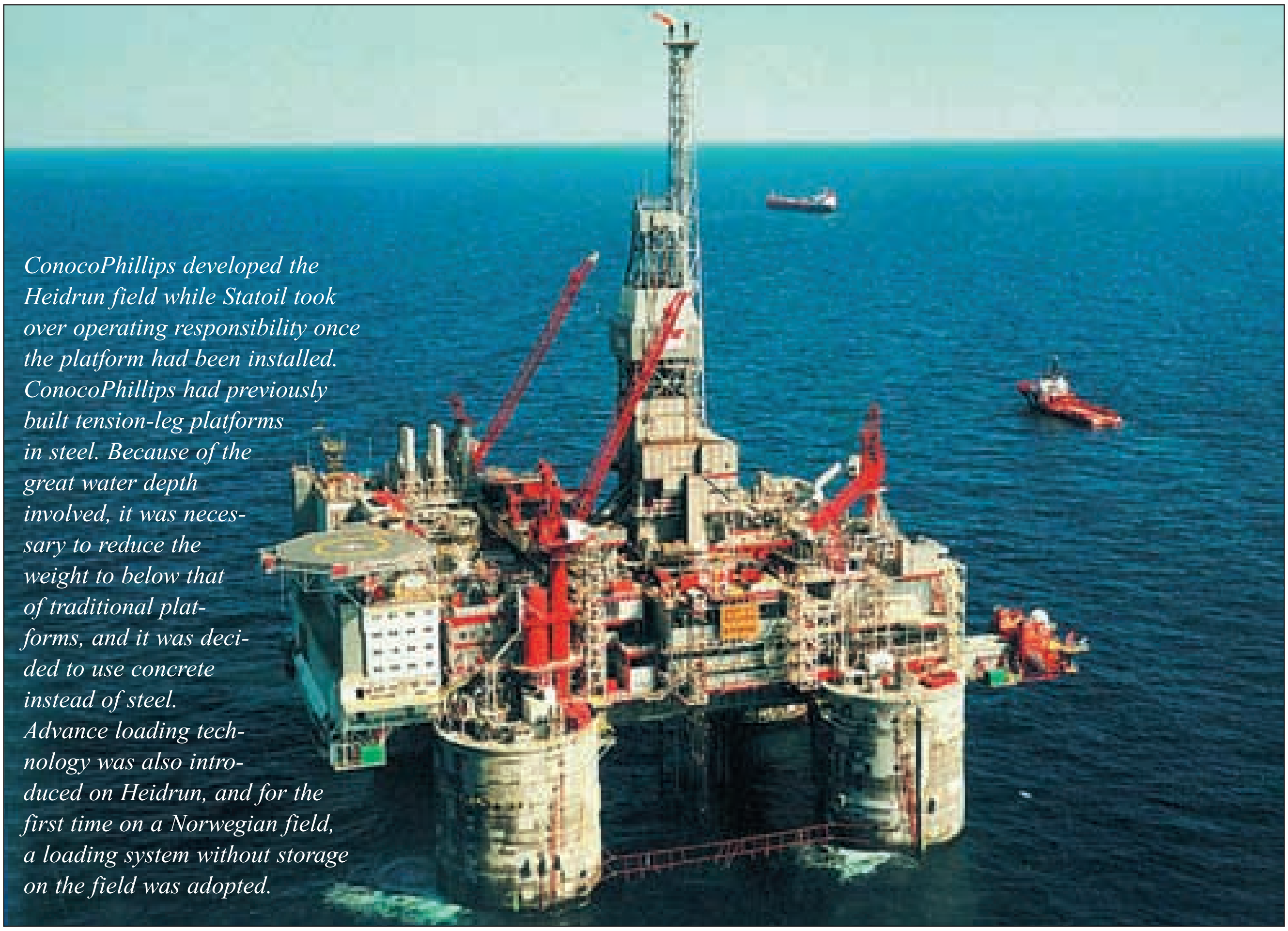
Corec is another project aimed to improve our understanding of the potential for enhanced recovery from the fields in the Ekofisk area. This is a collaborative project involving Rogaland Research and the University of Stavanger. In addition to financial backing, the Ekofisk owners are supplying the project with project data, priorities and, not least, practical experience.

ConocoPhillips developed the Heidrun field while Statoil took over operating responsibility once the platform had been installed. ConocoPhillips had previously built tensionleg platforms in steel. Because of the great water depth involved, it was necessary to reduce the weight to below that of traditional platforms, and it was decided to use concrete instead of steel. Advance loading technology was also introduced on Heidrun, and for the first time on a Norwegian field, a loading system without storage on the field was adopted.

Process of innovation



The social accounts for the greater Ekofisk area show that by the end of 2004 it had created values of 200 billion dollars. Of this total, about 70 billion had gone to goods and services, about 8 billion to salaries, etc., and 4 billion to lenders. The owners are left with about 20 billion, while the Norwegian state has taken more than half in taxes and duties; approximately 100 billion dollars.



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In 1990, water injection also started on the Eldfisk field. Although this field lies within the greater Ekofisk area, its chalk reservoir is different from the Ekofisk field, which is about 20 km north of Eldfisk. It remains to be seen whether water injection will be as effective here as it has been in the Ekofisk reservoir. In 90 percent of chalk reservoirs around the world, water will not force its way into this porous chalk and displace the oil.

ConocoPhillips has been, and still is, a pioneer in the Norwegian petroleum industry. The company has helped to build up expertise in the authorities, research institutes, the supply industry and industry in general. We estimate that we have invested some 250 million dollars in projects at institutes, and we have put our best experts at the disposal of the sector in order to ensure that technology is really transferred in practice. This is what we have done, it is what we are doing today and it is what we will continue to do in the future in order to meet the many major challenges that face this industry in Norway. A continuing process of research, as well as collaboration between scientists and the operational sector, is the basis of successful production of oil and gas from the Norwegian continental shelf.

E-operation is the technology of the future, and it has already been adopted by ConocoPhillips. Drilling operations in the greater Ekofisk area receive support from a centre in Tanager. A fibre-optic cable provides infrastructure that ensures that shore-based staff receive information in real time. Drilling operations in other parts of the world can also be serviced from this centre whenever necessary. The next step in this development is an onshore operation centre put into use in early 2005.

«Invisible» Technology. From Tommeliten to Snøhvit

By Bjørn Vidar Lerøen

The history of Statoil's technology on the Norwegian continental shelf started under water and most of its future will lie under water. The historical departure from this long-term line of development will probably be the concrete and steel platforms and the production vessels, which broke the surface of the water. The rest of the story lies under water and is invisible technology. It started with Tommeliten and it is continuing with Snøhvit.

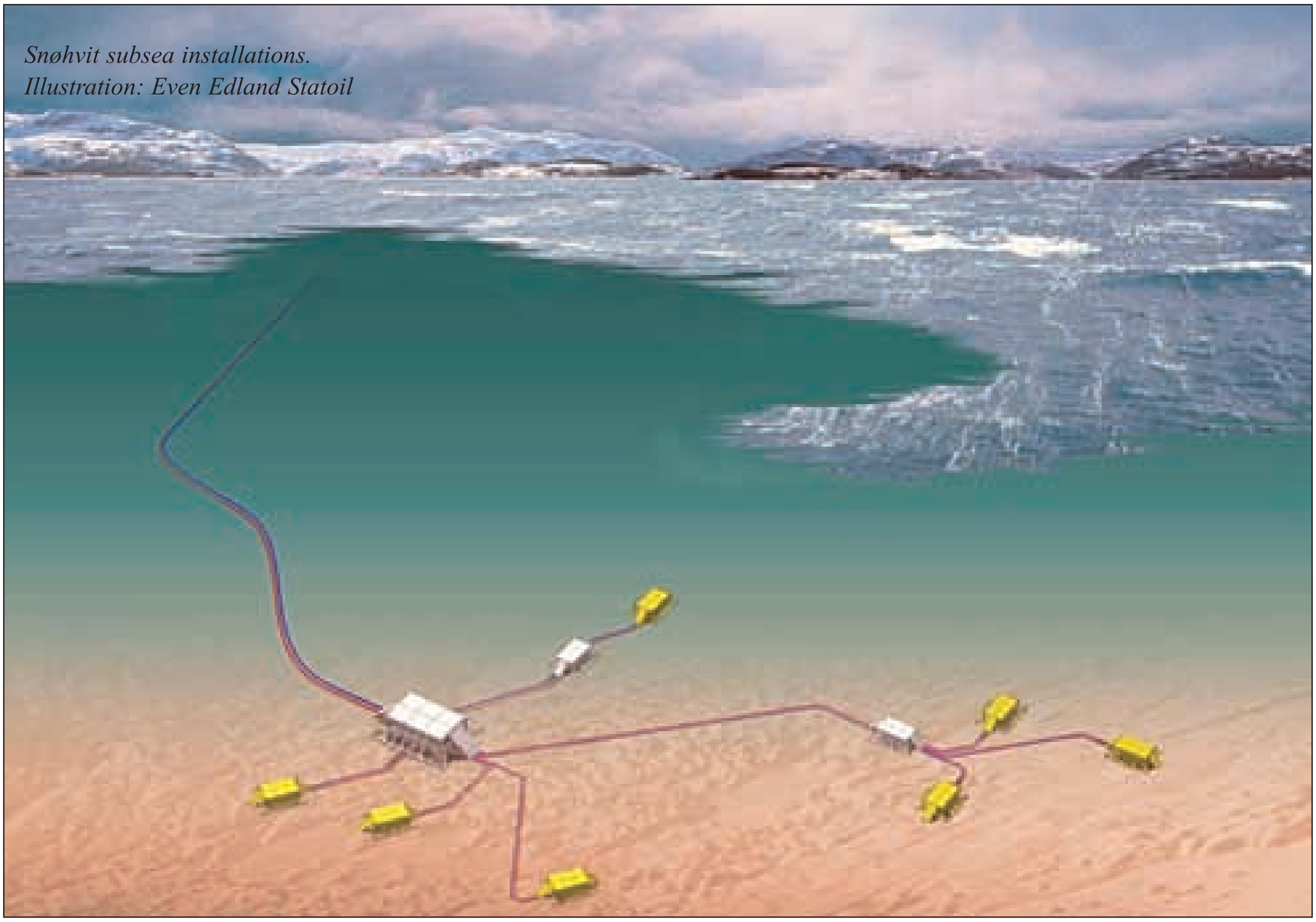
As we enter the 21st century, developments on the Norwegian continental shelf are in obvious transition from visible to invisible technology. Given that perhaps as much as 25% of the world's remaining petroleum reserves lie in the Arctic, technology developments will have to head north too.

The other obvious change on the Norwegian shelf is the transition from oil to gas. Since the early 70's, Norway has developed into one of the most important oil-producing countries in the world. But oil production will gradually diminish, while the production of gas is set to increase significantly.

Statoil is and will continue to be the leading producer of oil and gas on the Norwegian continental shelf. Nowadays, the company is exploiting elsewhere in the world the competence in gas that it has gained on the Norwegian shelf. Among other places, Statoil has established important gas positions in the Caspian Sea and the Sahara Desert in Algeria.

From depth to depth

In 1976, Statoil made its first discovery of oil and gas as an operator. This was made on block 1/9 in the southern North Sea, with exploration well number 167. The discovery, which



Snøhvit subsea installations. Illustration: Even Edland Statoil

Tommeliten was the first subsea field development on the Norwegian continental shelf.

A concrete foundation

Statoil's history of field development and technology was strongly influenced by the choices that were made for Statfjord. Without a single reference project to refer to, in 1973 Statoil was awarded 50% of production licence 037, which covered blocks 33/9 and 33/12, right up to the median-line that delineated the UK sector. This was of decisive importance for Statoil in many ways. The company's first employee, group chief executive Arve Johnsen, had this to say about the importance of licence 037:

"Our assessment was that a major holding in Statfjord would be formative for the newly established Statoil and provide the company with a technological, economic and market foundation, as well as giving us operating experience. All this was important if we were to be in a position to fulfil our allocated role as the leading company on the Norwegian shelf".

Without exaggeration, Statfjord was the field that created an oil company; the leading company on the Norwegian continental shelf. Without Statfjord, Statoil would have been a quite different company, smaller and of less importance.

was given the name of Tommeliten, was not large, but it was important. The company brought its first few litres of oil from the successful test well ashore in a couple of jerrycans. Statoil had become an oil company for real.

Nevertheless, Tommeliten was not Statoil's first development project. The pioneering Arve Johnsen was looking for larger prey and this he found in the form of Gullfaks. Tommeliten was also built as the first subsea development on the Norwegian shelf. Production commenced in 1988 and came to an end ten years later.

Tommeliten belongs not only to the past, but also to the future. Today, Statoil is the second largest operator of subsea wells in the world, after the Brazilian company Petrobras.

There has been a long line of daring investments in new technology from Tommeliten in the very south of the North Sea to Snøhvit, which lies at the threshold of the Barents Sea. These two fields represent two generations of subsea technology and are important milestones in the history of Norwegian technology.

The technology chosen for Statfjord was based on three gigantic integrated platforms with concrete gravity bases and steel decks. These were the introduction to the concrete era on the Norwegian shelf. Before the decision was taken to build the giant concrete platforms on Statfjord, the oil companies that operated on the UK shelf ordered several similar platforms from Norwegian suppliers. The first concrete platform that was towed from Norway to British waters was Beryl A: it had been ordered by Mobil, which was also awarded the responsibility for operating Statfjord.

Nothing visualises the Norwegian age of oil better than these concrete platforms. From the Ekofisk tank to Troll A, Norwegian Contractors (NC) cast almost 30 of these giant structures; no two were alike, but each was matched to the depth and seabed conditions where they were to stand. These concrete giants include the biggest platform in the world - Gullfaks C and the highest in the world – Troll A.

Heidrun, which along with Troll A was the last, so far, to be built for the Norwegian shelf, also represents another speciality; it is the biggest floating tension leg platform in the world.

Statoil was a driving force behind such huge concrete technological solutions. After three of them had been ordered for Statfjord, Statoil's management felt that copying the three Statfjord platforms for Gullfaks would offer major synergy effects. Statoil also went in for concrete for the Sleipner and Troll fields. But that was the end of the concrete story on the Norwegian shelf; at least for the time being.

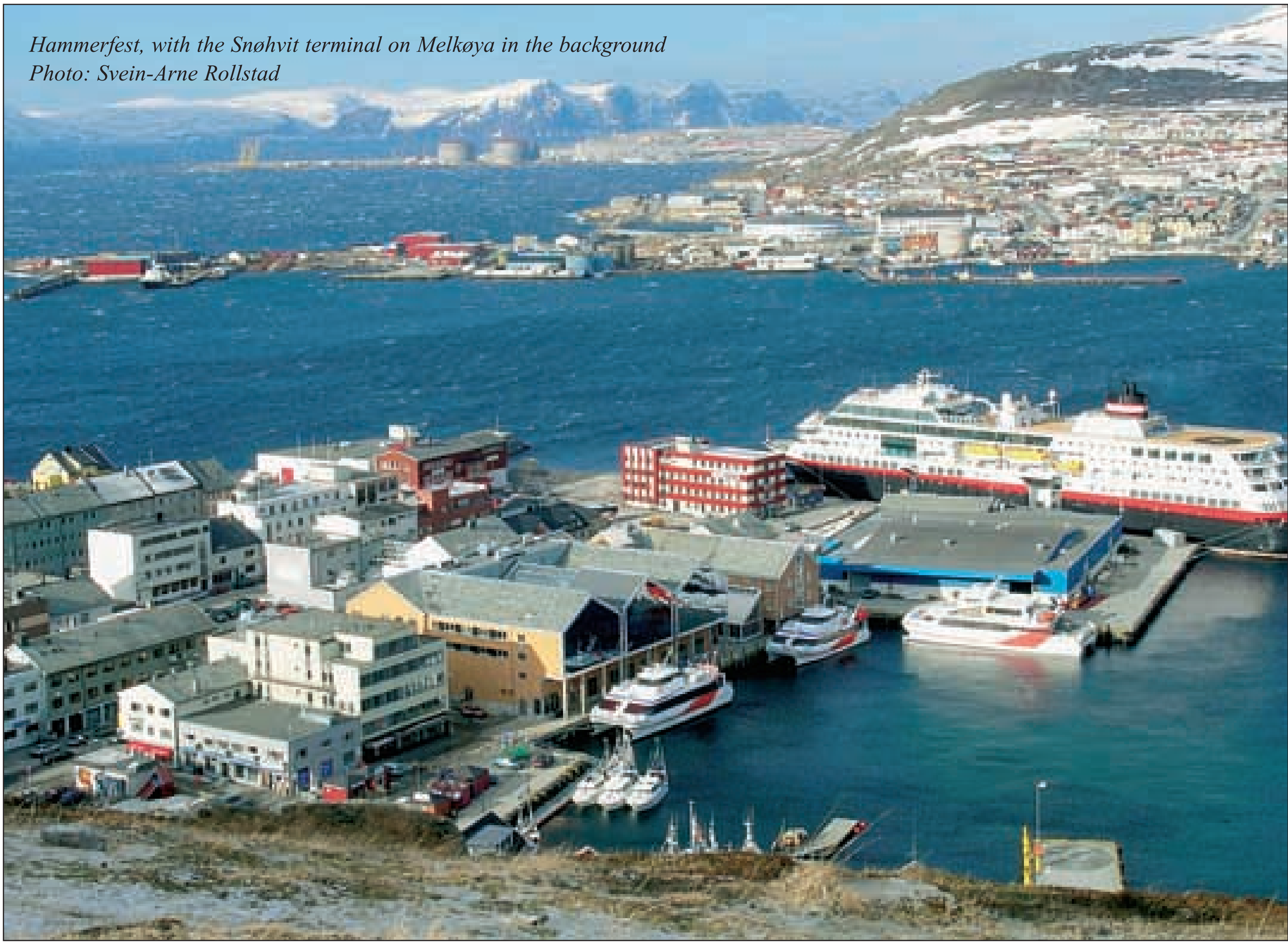
With the benefit of hindsight it may seem as though using three large integrated concrete platforms on Statfjord and Gullfaks was a major exaggeration. Not a great deal of insight is required to realise that if these two field developments and other similar ones, had taken place today, things would have turned out quite differently But that is no reason to conclude that the choice of technology was wrong. The choice must be seen in the light of the technology that was known and available when it was used and thereafter in the light of the results obtained.

November 24, 2004 saw the celebration of 25 years of production on Statfjord. A count would show that the three platforms had already delivered oil worth about 170 billion dollars, half of which has been paid in tax. Thorhild Widvey, Minister of Petroleum and Energy, summed up the situation in her own words: "The partners in the Statfjord licence have paid two million kroner in tax every hour for the past 25 years".

Major value from enhanced recovery

One of the best technology stories from the Norwegian shelf relates to enhanced oil recovery. When the Stafjord field started production in 1979, the Statfjord group was convinced that the limit of recovery was 48.4 percent of the rich Jurassic sandstone reservoir. At that point in time this was a high and rather daring estimate, even though only a few years previously, in a White Paper on the development of this field, the Ministry of Industry had anticipated a recovery rate of 60%. In the White

Gullfaks, one of a total of 30 giant concrete platforms that were built in the 80s and 90s for the Norwegian shelf. Photo: Øyvind Hagen, Statoil



Hammerfest, with the Snøhvit terminal on Melkøya in the background
Photo: Svein-Arne Rollstad

Paper, however, the level of ambition was lowered to 50%. After 25 years of production, 63 percent of Statfjord's reserves have been extracted. The story does not stop there. The aim is now 70% before production is shut in for good . The time horizon for late-phase Statfjord is 2020.

Statfjord is a unique field. On January 16, 1987, its best day ever, the three platforms produced 850,204 barrels of oil.

In the course of 25 years, four billion barrels of oil have been brought up from Statfjord. There are still interesting amounts of oil left in the field, but the late phase will largely be a matter of recovering large volumes of gas with the aid of lower pressures. Of the cash flow of 170 billion dollars billion, between 30 and 40 billion dollars are the result of enhanced recovery.

Statfjord lies in the Tampen area together with the Gullfaks, Snorre and Visund fields and a number of satellite fields. On the basis of the current drainage strategy, which will provide a high recovery rate for all these fields, seven billion barrels of oil will be left in the ground when production under current conditions ceases. But these are current conditions. Given the rate of technology development that we have seen on the Norwegian shelf so far, it is unlikely that such a large amount of oil will simply be abandoned and forgotten.

Floating solutions

In their different variants, the fixed platforms represent the first generation of solutions on the Norwegian shelf. These were followed by the production vessels on Norne and Åsgard, before technology development pointed once again to the depths on Snøhvit.

It is not difficult to see that floating production facilities offer a much higher degree of flexibility, not least in terms of their potential for re-use.

The development of flexible risers from the fixed installations and to the production vessels and floating production platforms was a quite decisive factor in our ability to go in for floating installations.

World champion in pipelines and multiphase flow

As far back as the early 1980s, Statoil believed that multiphase technology would come to be of decisive importance for future field developments on the Norwegian continental shelf. Yet again, a picture of daring: Arve Johnsen was ready and willing to put almost 100 million dollars into the development of a technology whose outcome no-one could predict.

Multiphase technology made a dramatic breakthrough in the development of the Troll gas field. The original plans for the development of this field were based on the concept of an integrated platform for drilling, production, process systems and living quarters. The planning process revealed that such a platform would simply be too heavy and would have too great a draught, which would make it impossible to tow from the shipyard in Norway out to the field.

Statoil challenged Shell, the development operator, with a proposal to move the platform's process plant ashore. The result was the gas treatment terminal at Kollsnes in Øygarden. However, this required the multiphase technology involved to be documented so well that it could be transferred from the drawing board and test loops to industrial use in the North Sea.

The successful introduction of multiphase technology on Troll was of decisive importance for the development of Snøhvit. While the multiphase pipeline from Troll to Kollsnes is 63 kilometres long, the next step was 143.3 kilometres, which is the distance from the subsea installations on Snøhvit to the LNG terminal at Melkøya outside Hammerfest, the northernmost city in the world.

No other company has laid as many kilometres of subsea pipelines as Statoil. When Langeled, the pipeline connection between the Ormen Lange field in the Norwegian Sea and Easington in the UK is ready, Statoil will have laid more than 7,000 kilometres of subsea pipelines from the Norwegian shelf.

When Arve Johnsen was asked what had been Statoil's most important achievement during its fifteen years under his leadership, he replied that it was Statpipe.

Åsgard A. Production vessels replaced concrete platforms, but the future is down in the depths again, on Snøhvit. Photo: Øyvind Hagen, Statoil

Melkøya, with the Snøhvit terminal
Photo: Eivind Leren

The Statfjord field has produced oil worth well over 170 billion dollars, half of which it has given to the Norwegian state in the form of tax and duty.
Photo: Øyvind Hagen, Statoil

Statpipe was a breakthrough in both technological and market terms, which formed the basis of the Norwegian gas machine.

Technological daring

"Statoil will be an early and daring user of technology", said Helge Lund as he took over as the fourth chief executive of the Statoil Group in August 2004. Two of his predecessors had been forced to resign following cost overruns in major projects; Mongstad and Åsgard.

Major deviations from cost estimates – and it is important to remember that these can go in either direction – are difficult to defend in isolation. However, they can be explained in terms of the fact that the development and utilisation of new technology often take place at high cost and with high potential gains.

Statoil's investments in technology, which have taken place in close collaboration with the Norwegian and international supply industry, have been based on the idea that it is important to be in command of the whole value chain: from source to consumer. In the areas of exploration and production on the Norwegian shelf, this involves an ambition to be the leading operating company from the exploration phase and field development and throughout the whole operating phase to tail-end production.

Arve Johnsen, the first head of Statoil, was willing to put almost 100 million dollars into the development of multiphase technology, which got its breakthrough on the Troll field and was of decisive importance for the development of Snøhvit.
Photo: Dag Magne Søyland

Europe's largest offshore development on track

Hydro's innovative subsea solutions on Ormen Lange are taking technological developments on the Norwegian continental shelf a significant step ahead. Development operator Hydro – together with its partners and contractors – are well underway in the execution of this massive gas development project.

With gas reserves close to 400 billion cubic meters and development costs of about 9.5 billion dollars, the Ormen Lange field ranks as the largest development in the European offshore arena. Production from the field is scheduled to commence in October 2007 and will reach its peak by the end of the decade – supplying up to 20 billion standard cubic meters of gas per year – which could cover one fifth of the UK's gas requirements for decades to come.

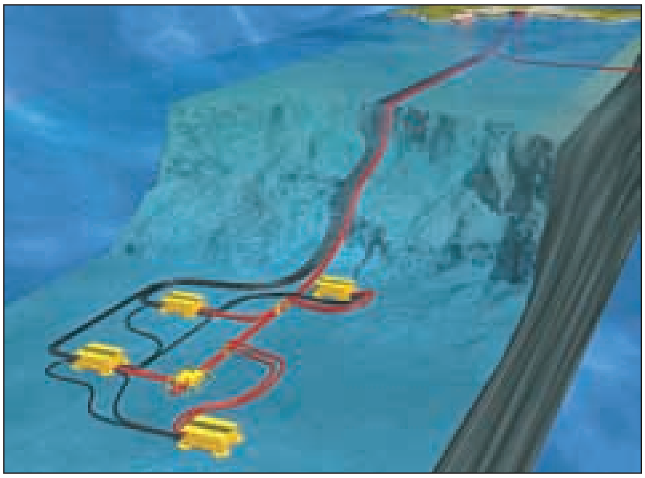
The Ormen Lange gas field was proven by drilling in 1997 and Hydro was selected as operator for the development of the field in December 1999. After an intensive period with studies Hydro decided in 2003 to develop the field without any platforms. The project's subsea production systems, with no sea-surface installations, is at the vanguard of ultra-deep-water production solutions.

The two first remotely controlled subsea production stations will be located 120 km from shore at 850 meters water depths. From these stations, two 30-inch pipelines will transport the well stream to the onshore plant at Nyhamna at the coast of Mid-Norway for processing. The pipelines are laid across extreme irregular seabed with boulders and slide blocks up to 60 meters heights in the Storegga slide. Furthermore- the pipelines are crossing the slide with an inclination up to 40 degrees.

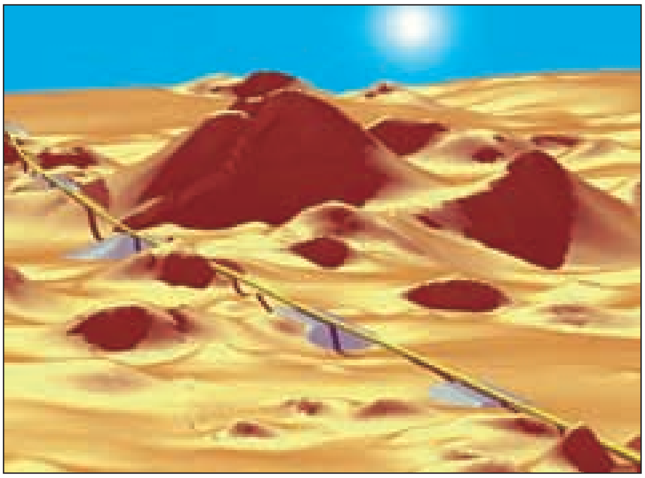
The special water current condition gives water temperatures as low as minus 1° Celsius. Such extreme temperature conditions combined with high pressure can cause gas and water to form hydrates and ice, which again can form plugs in the pipelines. The subsea system has been designed to avoid hydrates, and production simulators will be built to control the entire system to avoid hydrate problems.

Later in the field life when the pressure in the reservoir falls, offshore compression is required to maintain a high production rate. Also for this Hydro has set an ambitious goal: to qualify subsea compression. This station will require power supply equivalent to a city with 20,000 houses. A technology development program has already started, and Hydro hopes to qualify the technology within 2012.

Hydro's belief in innovation and environmentally-friendly utilisation of natural resources means that we are committed to solving these problems in the best possible ways – contributing to the development of innovative solutions for the oil and gas industy, creating jobs and stimulating the economy – and helping to provide Britons and Europeans with heating and energy for years to come.



Ormen Lange – from subsea to shore.



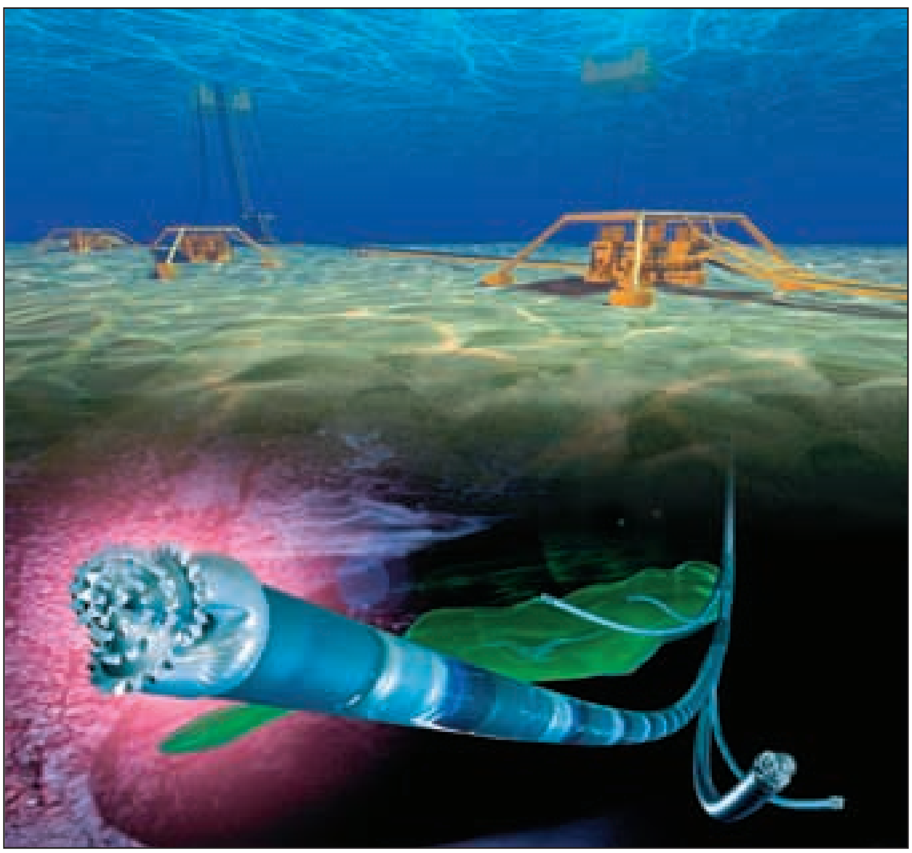
The pipelines are laid across extreme irregular seabed with boulders and slide blocks up to 60 metres in the Storegga slide.

HYDRO

Troll Story – A story of ingenuity

Troll Oil is the oil field that most said would never be an economic development. Two pioneering projects pursued around 1990 were important in making it possible. One was the success in drilling and producing a pilot horizontal well on the field. And the second was the subsea Troll–Oseberg gas injection (TOGI), which produced gas from Troll for injection purposes in the nearby Oseberg field. The successful installation and remote operation of TOGI confirmed that a subsea development in the deep waters, 340 metres, on Troll would be feasible.

Troll Oil covers the thin oil-bearing formations that underlie the huge Troll gas reservoir in the North Sea. Large volumes of oil spread over an area of roughly 450 square kilometres.



Today Troll is Norway's most producing oil field with now recoverable reserves near to 1.5 billion barrels of oil. The solution was horizontal drilling, an obvious solution today, but not so 15 years ago.

New drilling technology has been taken even further and the first five branch oil well was set in production in 2004. Around 30 of the more than 100 producing wells on Troll are multi-laterals. This has been achieved in close cooperation with Halliburton.

Virtual reality is now reality. The "3-D cave", developed in cooperation with CMR has greatly increased the planning of the wells and thanks also to the Auto-Trak tool, Baker Hughes, longer and more precise horizontal wells can be drilled reaching the outer corners of the reservoir.

The installation of the Troll Pilot, the subsea separator, is perhaps the start of a platform free future. The project carried out by ABB in collaboration with Hydro, is a separator installed on the seafloor to remove water from the wellstream before taking it all the way to the platform. This ranks as the world's first subsea processing plant. The aim is to overcome the problem of a high water cut faced in the thin oil zones – down to only 12 metres – in Troll West. This liberates platform capacity, allowing more oil to be produced and processed. This project represents a pioneering advance in transferring platform functions to the seabed.

Hydro's aim is to overcome the problem of a high water cut faced in the thin zones – down to only 12 metres – in Troll West.

Exploration

SINTEF

Research enters the age of oil

The Continental Shelf Institute (IKU), which later merged with SINTEF, played an important role in the studies that led Norway into the age of oil. The Institute was set up by the Ministry of Industry in 1969 under the name of NTNF-K, in order to perform studies of the Norwegian continental shelf and gather data which the authorities would use when they were selecting blocks for licensing rounds. This knowledge has been invaluable for Norway's management of its petroleum resources.

The reasons given by the authorities for setting up IKU were "to obtain the information and expertise that will enable the authorities to dispose of the resources of the shelf in the best interests of the country". NTNF-K was made responsible for four functions: petroleum investigations north of 62° N, long-term scientific investigations, the development of technology and the development of professional expertise. The Institute has changed its name a number of times, and is now known as SINTEF Petroleum Research.

Mapping the upper layers of the seabed

During its first years of existence, one of IKU's main areas of activity was mapping the uppermost strata of the seabed by means of shallow seismics techniques. Extensive collections were also made of material from the seabed, forming the basis of maps of the condition of the seabed.

The material was studied with the aim of determining the usual range of geotechnical characteristics, sediment type, mineralogy, organic geochemistry (characterizing types of source rock and possible hydrocarbon leaks) and dating. Maps of types of seabed were made for large parts of the Norwegian shelf. These were of great value for both the petroleum sector and the fishing industry.

Special studies worth mentioning include the Storegga-raset landslide, which is 800 km long, and is one of the largest submarine slides ever surveyed on the Earth.

Projects in collaboration with industry

Data from Norwegian Arctic regions were important for our understanding of the subsea regions of the Barents Sea, even before exploration drilling for hydrocarbons began there in the early 80s. Svalbard and Bjørnøya is an uplift region of the Barents shelf itself, which means that they are of great value for understanding the whole region.

For this reason, IKU carried out active field work and sampling on Svalbard, often in collaboration with universities and oil companies. These projects fell into several categories: sedimentology studies focused on developing geological models that could also be used in the Barents Sea. Palaeontological studies made it possible to perform good dating and correlations in the new exploration wells in the Barents Sea. Organic geochemical studies were carried out with the aim of mapping and characterising source rock that might be expected to be of importance in the Barents Sea. Integrated studies put all of these studies into a unified context and helped us to produce comprehensive syntheses of the whole northern region.

From the mid-80s onwards, the studies were extended to include Russian, Danish and Canadian colleagues. A great deal of Russian material came to the notice of Western oil companies for the first time as a result of these projects. All in all, more than 100 reports were generated by these projects.

Shallow stratigraphic drilling

Between 1982 and 1994, IKU mapped parts of the Norwegian continental shelf with the aid of shallow, high-resolution seismics, combined with shallow stratigraphic drilling.

This industry-financed work resulted in about 6,600 m of high-quality cores of sedimentary rocks.

The material produced by this drilling programme is still being actively used by the industry. The last drilling campaign for the Norwegian Petroleum Directorate took place in 1998.

Remotely controlled mini-drilling rig used in the 1980ies.

Revolutionary exploration methods

NGI contributed to the development of new geophysical methods for the exploration of oil and gas. The research resulted in the establishment of the company EMGS AS, which has raised enormous interest, both in Norway and abroad. The new approach can carry out exploration for hydrocarbons in a much more efficient way than has been possible until now. The method will reduce considerably the cost of petroleum exploration in deepwater.

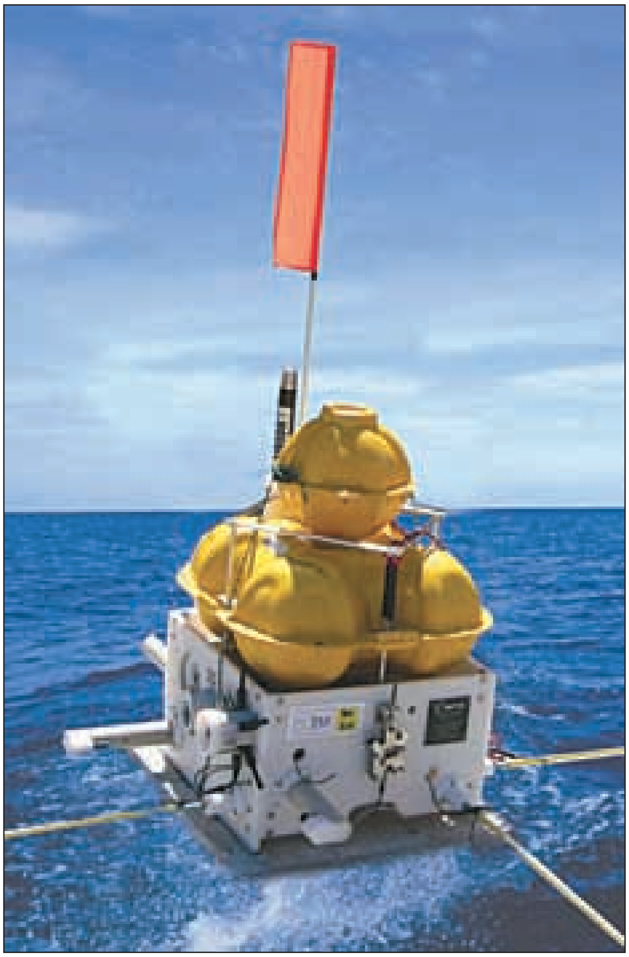
Many of the areas of the world in which hydrocarbon exploration are currently done are in deep water. The Norwegian method was used in several locations, including offshore West Africa, the North Sea, the Norwegian Sea, the Barents Sea, the South China Sea and the Mediterranean. In July 2004, EMGS was purchased by the American investment company Warburg Pincus.

EMGS AS is the result of a long-lasting collaboration between NGI and Statoil. NGI's focus has been on tasks related to the application of electromagnetic methods of petroleum reservoir monitoring and new methods of remote detection (without wells) of hydrocarbons during exploration for new reserves.

Enormous demand

The M/V Geo Angler ship was equipped with EMGS' technology, known as SeaBed Logging (SBL). Geo Angler carried out successful operations in the Far East and West Africa. During the past nine months, EMGS performed a series of geological studies in West Africa, the Mediterranean and the East. In the course of this period, more than 60 geological prospects have been tested for hydro-

M/V Geo Angler with SeaBed Logging technology has been in constant demand since June 2003.



The SBL receiver deployed on the seabed to register low-frequency electromagnetic signals.

carbons. The vessel recently returned to European waters to carry out more studies.

The enormous demand for the new technology demonstrates the importance and relevance of the research. The customers asking for more surveys use the results for both exploration and for delineating the fields.

Can be used in all waters

SBL surveys can be carried out in all sorts of weather and at depths ranging from 200 m to 3000 m, which means that the method can be used for virtually all petroleum surveys offshore.

The large number of tests that have already been carried out show that the EMGS technology patented can be utilised in most types of sedimentary basins and under a wide range of geological conditions. The convincing results obtained so far have led to a growing interest in both the company and its technology, especially abroad.

Petroleum geomechanics

The research that led to the establishment of EMGS is only one of several areas in which NGI actively contributed to innovation bringing new patents and a competitive advantage to the research sponsors, and to the improvement of exploitation of resources on the Norwegian shelf.

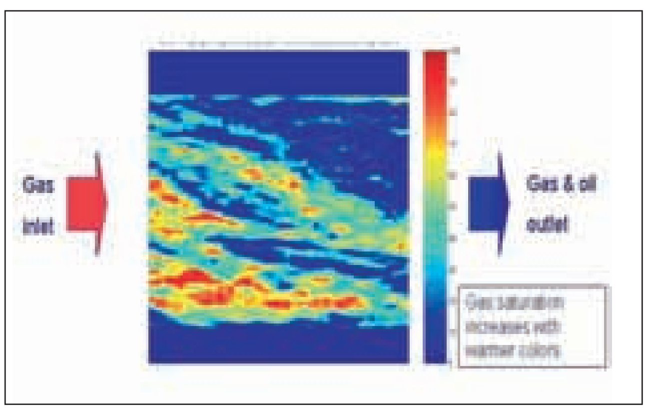
The development of methods for evaluating and explaining the subsidence of the Ekofisk field was the start of petroleum geomechanics as a research field at NGI. Expertise at NGI on the mechanical behaviour of the clay shale sediment and reservoir chalk rock helped lower drilling and well costs.

NGI contributes to enhanced recovery through numerical analyses of mechanical behaviour in and above the reservoir. Included here are flow in fractured formations, laboratory studies, numerical modelling of multiphase flow and evaluation of wellbore stability.

NGI developed a new method of modelling geomechanical problems associated with production from oil and gas reservoirs. The method is based on the development of new modules in commercially available geological modelling software to, for example, analyse reservoir compression, seabed settlement, sand production and wellbore stability.

Water injection reduces the reservoir material strength and stiffness. NGI developed laboratory methods for registering the distribution of fluid and to measure acoustic wave velocity while a sample is being filled with water. The techniques make use of computerised tomography (CT) and acoustic methods.

NGI tested the method for BP on the Valhall field, to document the effects of water injection in oil-saturated chalk. The idea is to enable the creation of a picture of the flow pattern of flow in the chalk material.



CT image of water injection in petroleum reservoirs

KONGSBERG

Untethered raven

In Norse mythology, the god Odin was famous for his wisdom, while the ravens Hugin and Munin flew around the world and brought him back knowledge. The modern HUGIN is a battery-operated, remote-controlled, free-swimming deepwater vehicle that lacks a cable connecting it to its mother vessel, and which can perform detailed mapping surveys of the seabed at depths of up to 3000 metres. HUGIN was developed and built in Norway with a large proportion of technological elements developed in Norway, and it has won international recognition as the most frequently utilised commercial AUV of its type anywhere in the world.

Autonomous Underwater Vehicle (AUV) technology of this sort is essential as a means of reducing the high costs of using the alternative, cable-controlled technology (ROVs) for surveys for subsea construction operations at great depths, as the "umbilical" cables they utilise put severe limits on the critical top speed of the submerged survey vehicle. The mapping systems and operations themselves are more or less identical for ROVs and AUVs, but removing the ROV cable introduces extremely complex technological challenges, in particular, those associated with supplying the vehicle with the necessary energy, communication and control.

In 1994, when Statoil and the Norwegian Defence Research Institute (FFI), Kongsberg Maritime, Nutec and SND joined forces to accelerate a Norwegian initiative in this area, they did so for the following reasons:

- at that time there were already several development projects under way all over the world, focusing on cableless underwater vehicle technology, and these were providing clear indications that they would have important positive cost-cutting effect on potential operations at great depths, even though most of these projects were intended for other operational applications such as oceanography and defence.
- there already existed a number of technological elements that had been developed in Norway; in particular, previously verified critical energy/battery technology, which would be capable of being utilised as core elements of such a project, and which could be combined to provide important new impulses and possibilities for Norwegian technology groups.
- on the basis of Statoil's current expectations and plans, it appeared to be a critical time for the launch of an essential, goal-oriented development effort capable of developing such a cost-saving survey tool for anticipated deep-water operations.

HUGIN 3000 under deployment
Photo: Geoconsult

The first full-scale survey operation to use HUGIN took place in 1997 at depths of 100 – 400 m for Statoil's Åsgard transportation pipeline. This was successful beyond all expectations. This has been followed by a series of successful HUGIN operations at ever greater depths.

A 100 - 1000 metre HUGIN system is now in operation for the Royal Norwegian Navy, while three 3000-metre systems are in commercial operation with C & C Technology in Lafayette, USA, Geoconsult in Bergen and Fugro Survey in Aberdeen. HUGIN's manufacturer, Kongsberg Maritime has also signed a contract to supply a second 4,500 metre system to C & C technology by 2005. The HUGIN AUV thus seems to be the commercially and operationally most successful AUV in the world, particularly in the field of deepwater seabed mapping.

SINTEF

SEMI 3D improves discovery rates

An exploration well typically costs 15 - 25 million dollars. The SEMI basin simulator has reduced the number of dry wells and made significant savings for the oil companies in the course of the past ten years. The improved discovery rate has created huge value for the oil companies and the Norwegian state.

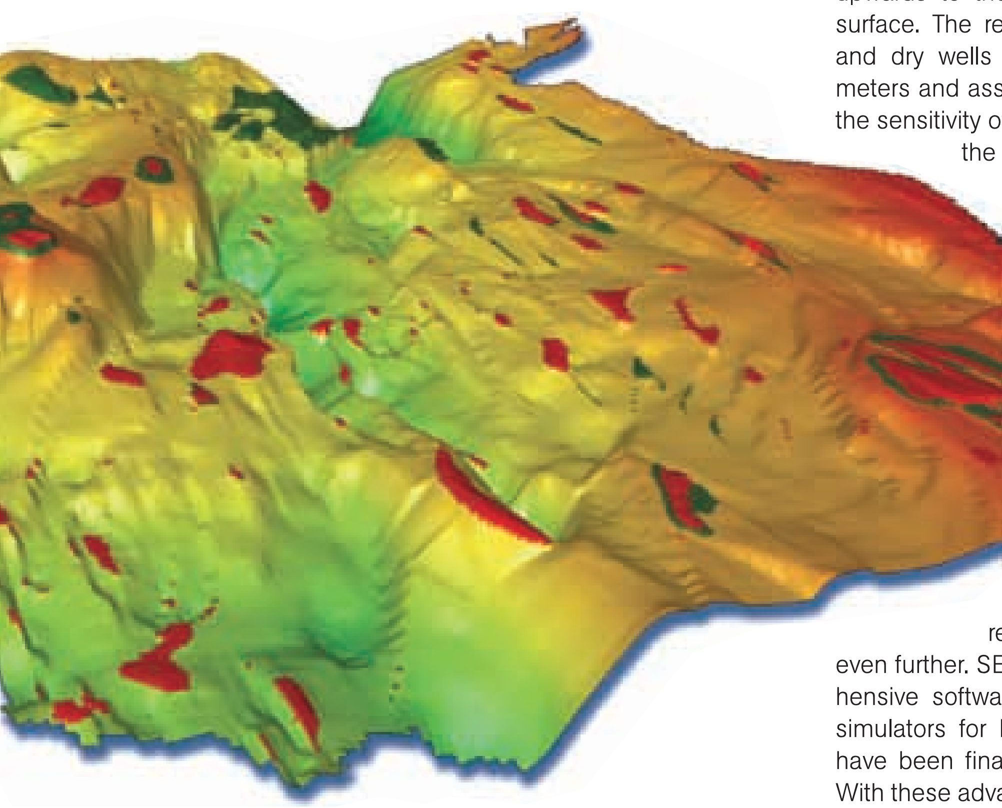
An understanding of the basin and its petroleum system is important for our efforts to find oil and gas. This is why SINTEF has been working on the development of basin modelling software since 1986, and has developed SEMI 3D, which is one of the most advanced basin simulators in the world. A large number of oil companies are using SINTEF's basin simulation software in their everyday exploration activities, and several have improved the success rates of their exploration wells with the aid of these tools. The aim of the project has been to supply the oil companies' exploration divisions with quantitative estimates of oil and gas volumes in undrilled prospects and to predict the most likely hydrocarbon phases and compositions to be expected.

A thorough understanding of the geological development of a basin is essential in order to carry out a rational process of exploration with the lowest possible risk of making poor decisions. This produces a huge number of challenges for the oil companies' exploration departments.

Basin modelling, which aims to understand and quantify geological processes, is a research field in rapid development.

The first version of the SEMI basin modelling software package was developed by SINTEF Petroleum Research in 1986. SEMI employs a raytracing methodology to model the movement of oil and gas in three dimensions along permeable layers. One of the challenges lies in following the hydrocarbons from their source past faults and other barriers until they are caught in a trap, or leak vertically upwards to the next porous layer or all the way to the surface. The results are calibrated against existing fields and dry wells by systematically varying individual parameters and assumptions of the model. This is done to test the sensitivity of the modelled processes to uncertainties in the geological model and thus improve the predictability of finding oil and gas. This has now become a recognised method which is used by the petroleum industry to assist it in quantifying the likelihood of making discoveries in undrilled exploration targets.

This software deals with extremely large geological models of high complexity, and its simulation times are very short in comparison with other 3D basin modelling simulators. This means that it is also possible to perform stochastic simulations in order to reduce the uncertainty of exploration drilling even further. SEMI 3D now forms part of SINTEF's comprehensive software suite, which includes a number of 3D simulators for basin studies. Several of these new tools have been financed by the Research Council of Norway. With these advanced software tools, SINTEF is a participant in every new licensing round on the Norwegian shelf, helping the oil companies to evaluate the blocks that have been advertised for licensing.



The topography of a reservoir level in the northern North Sea. The red and green areas on the highs show modelled accumulations of gas and oil respectively.

Temperature – the most important unknown factor in exploration

Petroleum exploration is characterised by high margins of uncertainty in discovery rates and expected volumes of hydrocarbons. The most important factors influencing the formation of petroleum are temperature and time. The temperature history of a basin is controlled by a number of geological processes that have taken place in the course of the history of the basin.

It has been demonstrated that, to make a realistic construction of the temperature history of a basin, it is extremely important to be able to develop an adequate representation of the geometry of the basin and reconstruct its development in a realistic way. If there are serious errors in the geometry of the present or the past, predictions of the temperature history of the basin will be wrong. It is also important to be able to model other tectonic processes such as salt movements and volcanic activity, as well as other important processes that influence heat flow from the centre of the Earth.

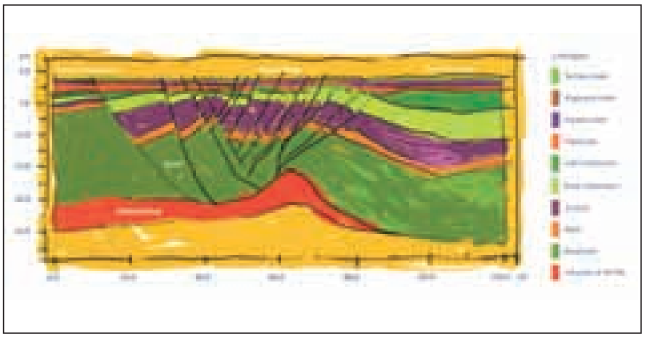
BMT™ is a powerful system for the analysis of interactions between tectonic processes, heat flow, and time of formation of hydrocarbons. The system reconstructs the geometric development of the basin, with modelling of faults, including both normal and reverse faults.

BMT™ is used to simulate the geological processes that influence the temperature history and formation of hydrocarbons throughout the history of a basin, including the following processes:

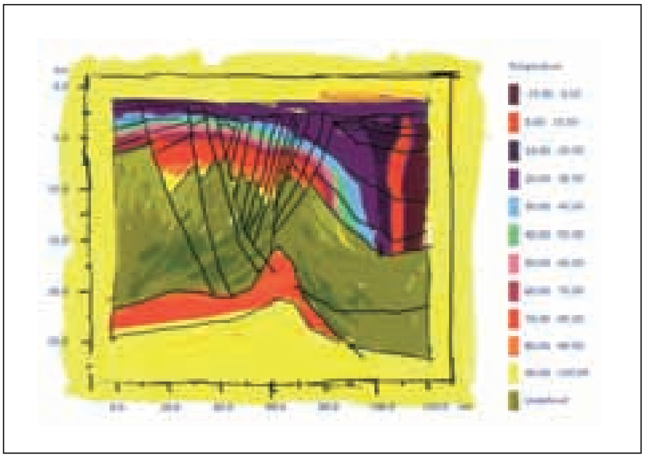
- Sediment deposits - erosion and compaction
- Reconstruction of normal or reverse faults
- Used-guided modelling of salt geometries
- Isostatic response to deposits, erosion and fault activity
- Tectonic response to crust thinning
- Heat flow into the basin as a result of lithosphere thinning
- Hydrocarbon maturation

The combination of tectonic modelling and temperature modelling makes BMT™ a unique tool of its type. It was developed by RF-Rogaland Research by a team of geoscientists, mathematicians and software engineers. The system has been under continuous development since 1987, with the support of the Research Council of Norway, among other sources of finance.

BMT™ has been used by several companies for exploration studies and in research on the Norwegian continental shelf, the Barents Sea, the North Sea and the Norwegian Sea. Several of these studies have been published in international journals. The estimates of temperature history match observed data well. The software has also been used in international studies for example on the UK shelf and in Turkey, Africa, Asia and South America. BMT™ is being used for teaching and research purposes by the Universities of Oslo, Bergen, Tromsø and in Stavanger.



Example of a profile modelled using BMT™. This is a profile of the Gjallar Ridge on the mid-Norwegian shelf, where there has been volcanic/magmatic material (red).



Estimated temperature effects of the intrusion. The maximum effects took place two million years later than the volcanic/magmatic activity.

STATOIL

New geological knowledge creates more efficient oil and gas exploration

The world is currently using much more oil and gas than the petroleum industry manages to find every year, and many investors are sceptical about using large amounts of money to find more, because they do not think that this activity is profitable enough. The industry therefore needs to find more oil and gas, but at lower cost. Statoil's scientists have recently developed a new exploration method that will help to make this possible in the future.

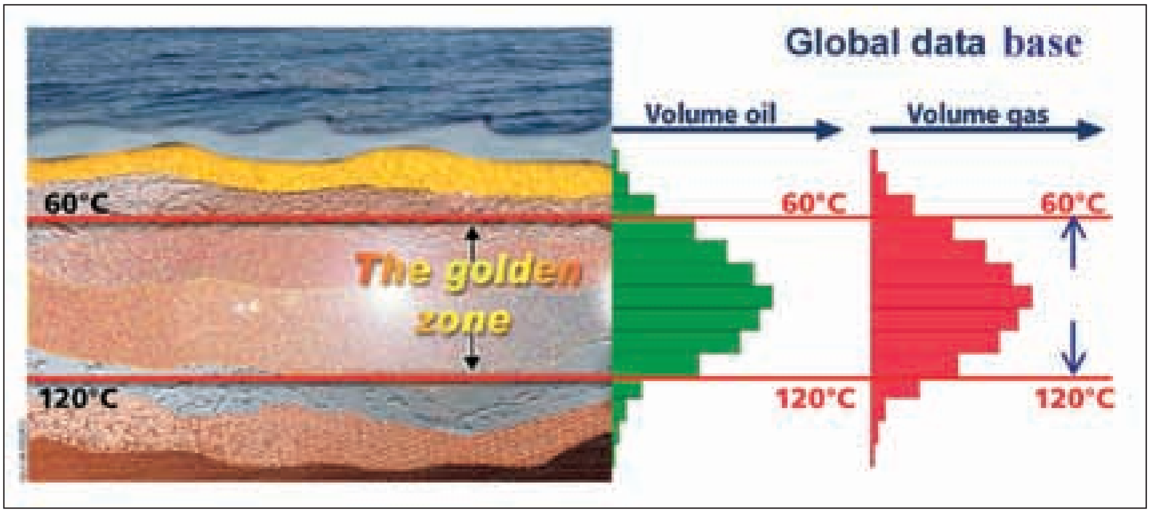
The Golden Zone

It has taken 15 years to develop the exploration method. What we have discovered is that there is a common pattern in the way oil and gas occur in all sedimentary basins. Common knowledge suggests that each basin is unique due to its unique geological history. For this reason we were previously unaware of such common patterns as have now been revealed thanks to a recently developed theory concerning controls on processes operating in sedimentary basins.

The pattern suggested by the theory has been tested and confirmed by data from some 120,000 fields in production and involving most of the petroleum basin of the world. The new pattern emerges if we plot the volume of oil and gas against temperature in sedimentary basins. It turns out that both oil and gas are concentrated in a zone which is determined by the temperature and that around 90% of the worlds hydrocarbons are found in the zone between the 60°C and 90°C isotherms, which is termed the "Golden Zone" and is shown in the figure below.

This zone lies at various depths in different basins, because the temperature increases at different rates as we descend through the sediments. Hence, the "Golden Zone" in the Bombay basin lies at a depth between about 0.8 and 1.6 kilometres (because the temperature increases at a rate of about 80°C/km), while in the North Sea, it lies between about 2.1 and 3.7 km, (because the temperature increases by about 35°C/km). In some basins, the "Golden Zone" lies between 4 and 8 km of burial (because the temperature increases by ca. 15°C/km).

Part of the explanation of this pattern is that temperature turns out to control important processes in sedimentary basins that we used to believe were controlled by stress. The new understanding and description of processes operating in sedimentary basins has lead to a perception of sedimentary basins as (thermally driven) self-organised systems which in turn is the fundamental explanation for the common distribution pattern for oil and gas in all sedimentary basins. The methodology is both simpler (there are fewer important variables to keep an eye on) and more useful (we can say more on the basis of less information) than existing exploration methods. The new method suggests that we can reduce the finding cost per barrel of oil and gas by about half, in comparison with traditional exploration methods as well as improve our environmental and safety performance.



Distribution of oil and gas relative to temperature in sedimentary basins.

Drilling and reservoir

Full-scale Drilling and Well Technology Test Facility

The Ullrigg Drilling and Well Centre (UBBS) is a world-class drilling and well technology laboratory. This unique centre offers the industry a full-scale test facility that can be used to verify new technology. New methods that have considerably improved safety and efficiency of the drilling process have been developed and tested at Ullrigg.

Ullrigg has been the test facility for a large number of projects, including "smart wells" for new field developments. The latest sealing junction technology has been trialled and installed in a specially built multilateral well.

New cementing technology was also tested out as an integrated operation in the Multilateral Technology programme. This test well will be used to trial new technology and to qualify new methods. This multi-branch well is a unique test tool for the whole industry as it faces some of the challenges presented by advanced wells and complex reservoirs in the North Sea. The project was supported by DEMO 2000.

Automated drilling operations

The 1970s brought new jobs and new tasks in exploration and oil production in the North Sea. Drilling represented major challenges, with jobs and technologies that were quite unknown to the Norwegian industry. For a long time, drilling was the least developed area of the offshore petroleum industry's areas of activity. The drilling industry saw no evident need for rapid changes in the level of the technology it employed. Such a need, however, was seen by scientists at Rogaland Research.

In 1981, Rogaland Research launched the "Integrated safety evaluation of drilling operations" project, which had the vision of creating an ideal rig with automated drilling operations directed from a centralised integrated drilling control room. Between 1981 and 1987 the basic elements of the new technology and the way in which drilling rigs were organised were tested and trialled. With the establishment of the drilling technology laboratory and Ullrigg, the world's first full-scale research rig, in 1983, the potential for testing technology under realistic conditions was significantly improved. Shell and Statoil financed this task.

From 1990 until 1995 the IDS programme executed research and testing of equipment: instrumentation and remote control of lifting winches, rotary tables, pipe-handling equipment and mud pumps. Together with newly installed mechanical equipment, the network of computers and advanced software systems form the basis of an efficient remote-controlled automated drilling operation for both the exploration production drilling phases of operations. This programme was financed by ExxonMobil.

Today, drilling operations are organised for the most part along the lines of the original vision of our scientists in 1981: drilling can be carried out more safely, reliably, faster and more cheaply, benefiting all the parties involved.

Hitec, which subsequently merged with National Oilwell, commercialised RF's IDS technology in its SDI – Smart Drilling Instrumentation and Cyberbase product lines. SDI and the Cyberbase control unit are now regarded as the industry standard for the control, monitoring and steering of the drilling process.

Ullrigg's first drilling operations started in November 1984. These resulted in two test wells, one of which was more than 2000 m deep. There are currently seven test wells on the site.

Full-scale testing

The facilities have been regularly upgraded since their installation in 1983. Ullrigg Drilling and Well Centre has developed into a unique world-class laboratory in drilling and well technology. The facility consists of a full-scale offshore-type drilling rig, with seven test wells with geometries equivalent to those found on offshore fields, the longest being more than 2000 m deep. There is also a permanent coiled tubing intervention unit with access to horizontal wells. High pressure and high temperature cells are used to test downhole equipment. The rig and its facilities are particularly attractive as a place to test steerable drilling technology concepts.

IDS is the most advanced drilling system in the world and has helped to revolutionise the drilling industry.

Control of Well Pressure

Drillbench is software, which features tools for calculating pressure and temperature conditions in a well during the drilling process. The software provides complete control of drilling operations, which is vital for reducing risk elements.

Drillbench was developed at RF-Rogaland Research in collaboration with various oil companies. The main components are thoroughly tested and certified in wells at Ullrigg and at other RF laboratories. Additional testing and verification is performed at offshore well sites. The main modules calculates pressure and temperature conditions in a well during the drilling process, as well as friction along the drill string and simulates gas kick, under balanced drilling and cementing. Based on verification using relevant test data, Drillbench is capable of simulating the drilling of vertical, long-range, horizontal and slim wells in shallow, deep and ultra-deep water. Drilling for oil and gas is a challenging undertaking, which requires a high degree of focus on safety. Conventional drilling does not allow the inflow of hydrocarbons during operations. In the event this occurs, a well control situation arises in which the well must be inspected in a safe manner. Other types of operations (i.e. under balanced drilling) allow for hydrocarbons in the well, under the condition that the rig has the appropriate type of equipment available. Regardless of the drilling technique being used, it is absolutely essential that you have control over well pressures and know what to expect in various situations. Take, as an example, the consequences of experiencing an inflow of gas during drilling. Will the well withstand the pressures that are building up and does the surface separator have the required capacity in order to process the gas at the surface? An underestimation of a potential well control situation can involve the added risks to both lives and health.

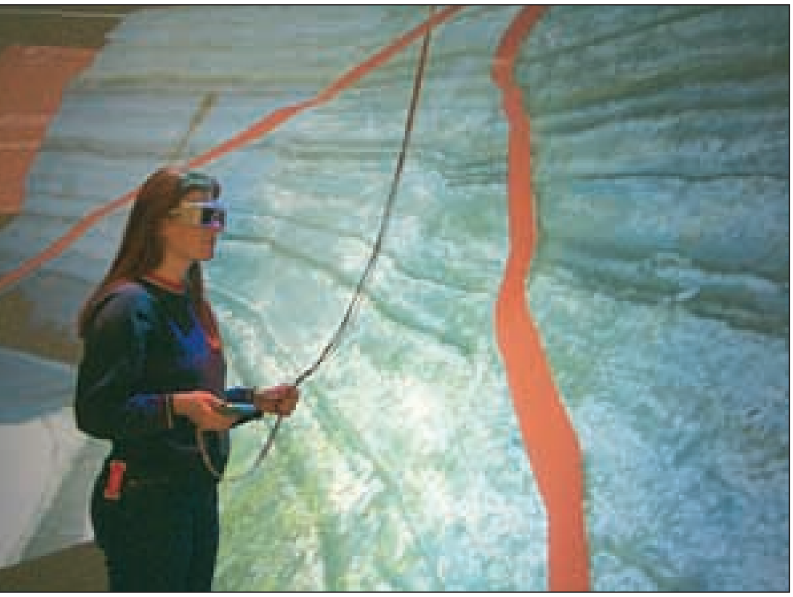
RF-Rogaland Research developed several dynamic simulation models during the 1980s and 1990s, which were intended to support drilling operations. The software we developed was assembled under the brand name Drillbench. Use of these models provides you with a tool, which makes it possible to anticipate pressure levels during drilling operations and allows you to simulate potential well control situations. The models can be used to identify potential well problems, perform procedural verifications and make required improvements as well as giving rig personnel greater understanding of the drilling process. They have been used frequently in connection with planning and review of complex wells (i.e. high pressure and temperatures, deep water and under balanced drilling). Benefits relating to the use of these tools as a direct component in the training of drilling personnel have also been clearly demonstrated. The models have been verified on numerous occasions by comparing lab and field data provided by the Research Council of Norway as well as various oil companies. The offshore tests have been conducted in the North Sea, and there were deep water field tests conducted in Brazil in 2002 in close collaboration with Petrobras.

Drillbench software being used by senior researcher Finn Iversen who works with drilling, well and reservoir modelling at RF-Rogaland Research.

The models have proven themselves to provide a realistic description of the drilling process and are undoubtedly a contributing factor that renders drilling operations safer and more cost effective along with providing greater understanding of the dynamics involved in actual operations. Tools such as these are now being more frequently used by the major oil companies. The demand will also increase as a consequence of wells becoming more and more challenging as it will be necessary to extract resources, which were previously considered to be inaccessible. The Drillbench product was released commercially through Petec Software & Services, a subsidiary of RF-Rogaland Research, prior to the sale of this company to Scandpower Petroleum Technology in 2004.

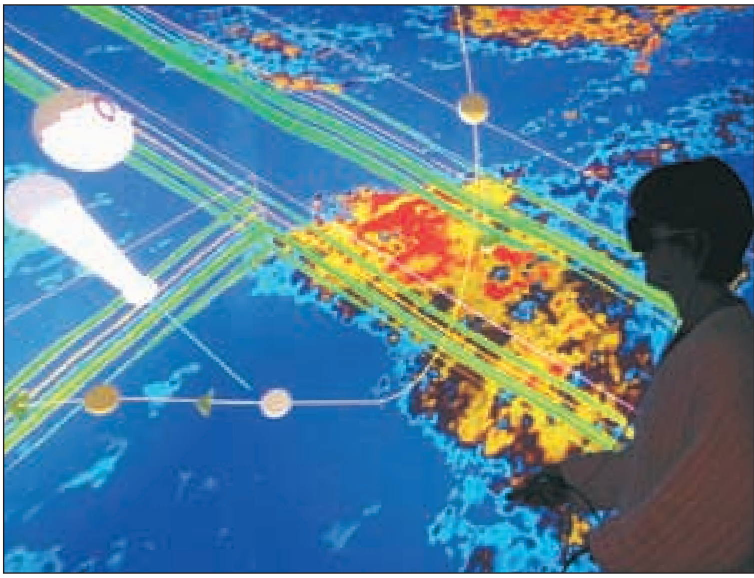
Three-dimensional success from the seabed

In 1997, Norsk Hydro and CMR began a collaboration that has resulted in highly advanced software for use in the petroleum and gas industries. The software utilizes what is known as Virtual Reality (VR) technology to provide users with an effective tool in research on complex three-dimensional structures and data.



CMR's VR software lets you literally dive down to the challenges of the seabed!

The software constantly updates the image on the basis of the user's position and line of sight. In combination with dual imaging, this allows the user the experience of being present in the virtual reality. The application is controlled by means of a three-dimensional pointing device. Through efficient planning and implementation, Norsk Hydro has developed new operational routines based on results obtained using this new software, and with emphasis on co-operative efforts that involve several different fields of expertise. The software comprises a wide spectrum of functions that are frequently required in oil and gas exploration and production. Areas of application include well planning, interpretation of seismic factors, geological modelling, visualization of reservoir models and simulations. The advanced visualization capabilities for processing volumetric data include multi-attribute visualization, which allows the combination of various types of information within the same image. The animation of dynamic data also renders the information more accessible. Furthermore, it is possible to import many different types of data into the virtual reality scenario. For example, images of core samples from well drilling can be inserted so that these may be visualized together with the well bores. A sketching tool is available for the user to make notes and comment on interesting structures during a work session. The software is an effective tool for increasing co-operation and the sharing of experience and knowledge among several fields of professional expertise. In order to achieve an even higher degree of utility from this feature, support for so-called collaborative VR has been implemented, which allows participants in physically separate VR locations to interpret and modify data simultaneously. For example, a well-planning session was conducted with participants in Bergen, Oslo and Houston. This in turn makes possible new methods of collaboration among various groups of professionals who are trying to solve tasks in common. Direct benefits enjoyed by Norsk Hydro include a better understanding of important structures in reservoirs, a reduction in the time used to interpret seismic factors and well planning, better quality of interpretations and models and increased production of oil and gas as a result of better well bores. In 2000 CMR established the subsidiary Inside Reality AS in order to commercialise the project software. Inside Reality was sold to Schlumberger in 2002, and the software is now available all over the world.



Virtual Reality software in use.

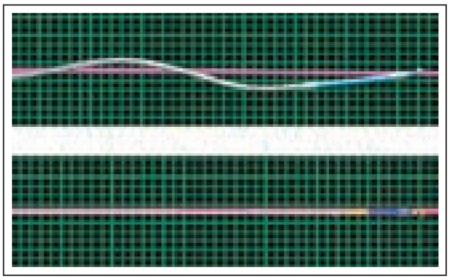
Innovations on Troll

Baker Hughes has been a key partner for Norsk Hydro in the development of Troll. Their technological advances have contributed to making Troll, which at the outset was not supposed to be an oil field, capable of producing about 450,000 barrels of oil daily.

Solutions to tasks that previously were regarded as impossible were identified in connection with the development of the Troll West oil and gas provinces by creating secure guidelines for creative and effective research. The challenge involved in extracting oil at Troll consisted first and foremost of a situation where there was a thin layer of oil between layers of gas and water. Test drilling indicated that there existed a small, vertical window through which the oil might be accessed. It was regarded as a hopeless task to drill efficient production wells unless a new technology could be developed, which would make it possible to accurately drill horizontally into these thin layers of oil. Norsk Hydro therefore entered into a binding partnership with Baker Hughes INTEQ, and a new revolutionary technology based on horizontal drilling was developed for the start of operations on the Troll field. Baker Hughes INTEQ developed such products as Navigator® specifically for drilling at the Troll field, and followed up with a 3D rotary-steerable system – AutoTrak®. The success of these innovations and that of AutoTrak® in particular, is shown not only by the enormous significance they have had at Troll, but also by the extent to which they are in demand among operators all over the world. The Troll wells were among the first horizontal wells drilled in the Norwegian sector. When these techniques were brought into commercial use at Troll in 1992, horizontal drilling was also implemented with great success, on fields like Oseberg, Statfjord and Gullfaks. On Statfjord, current estimates of a realistic recovery rate are 65 – 70% instead of the original 48%. The recovery rate on Ekofisk increased from the original estimates of 17% to 46%. These increases are wholly attributable to research, development of new technology and as always – trial and error!

Navigator®

As the degree of difficulty of reservoir drilling has increased, tolerances for the placement of horizontal sections have become smaller. At the Troll West oil province, drilling was performed in an oil layer with a thickness of approx. 23 m TVD, and Norsk Hydro and Baker Hughes INTEQ therefore entered into a contractual agreement for the development of a PDM motor featuring instrumentation near the drill bit.



The upper photo shows conventional drilling while the lower photo shows drilling with AutoTrak RCLS.

This major improvement in the drilling system was ready for use at the outset of drilling on this oil province, and was used for the second well in the area. It was now possible to maintain tolerances within +/- 1 m vertical depth when drilling along horizontal lengths of up to 2000 m, which was a requirement for drilling on the Troll West oil province at that point in time. The Navigator also became unique in the context of drilling of complex horizontal wells worldwide.

AutoTrak®

After the Troll West oil province was approaching completion of the drilling campaign, drilling at the Troll West gas province continued with an oil layer of about half the thickness (i.e. approximately 12 m TVD). Such a transition required a high degree of accuracy and the implementation of AutoTrak®, a 3D rotary-steerable drilling system, which Baker Hughes INTEQ had been systematically researching and developing for 14 years, in order to enable drilling with tolerances down to +/- 0.5 m vertical depth over horizontal lengths of up to 4700 m. AutoTrak® is an intelligent drilling system with a two way communication link that enables execution of commands during drilling operations, in order to correct direction and angle as well as receiving data at the surface in real-time as the drilling progresses. The development of the AutoTrak® system was originally part of a collaborative project involving Agip ENI for a field in Italy. Norsk Hydro immediately realised that there was a need to utilize this knowledge and technology in the Troll West gas province, and AutoTrak® was promptly implemented for all future drilling on this field. At present the AutoTrak® system has been used to drill more than 3 million metres since the development of the system began, and is the leading 3D rotary-steerable drilling system currently available.

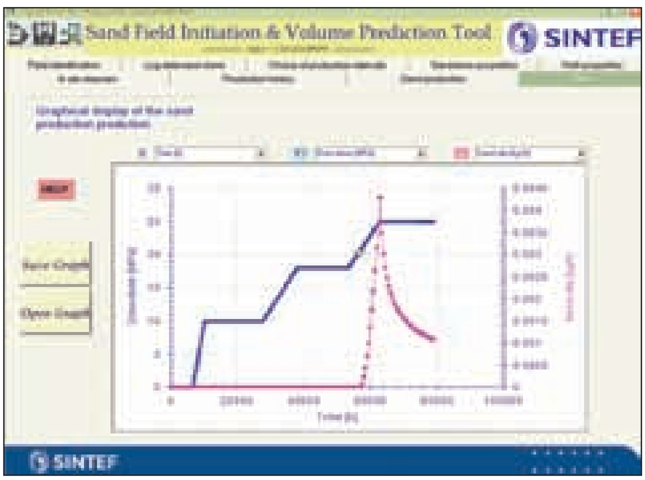
Baker Hughes Incorporated LTD has invested roughly 40,000 hours of research and development in the areas of drilling and well completion expertise at Troll. The competence they possess is utilized extensively in Norwegian fields and at various other locations worldwide.

SINTEF

Good sand control gave increased recovery and increased production

In collaboration with various oil companies, SINTEF has conducted research in the areas of sand production related to oil production since the 1980s. The benefits of their work have included lower installation costs and considerable increases in production.

Weak sandstone reservoirs have traditionally been completed with sand control, i.e. sand screens, hydraulic fracturing or gravel packing (frac-packing, etc.). Sand control has resulted in considerably higher completion costs, and such wells have also demonstrated poor productivity over time due to various forms of plugging of both equipment and the formation rock in close proximity to the well. Based on the support from a dozen or so oil companies, SINTEF Petroleum



Sand Predictor: SINTEF developed tool for predicting sand production.

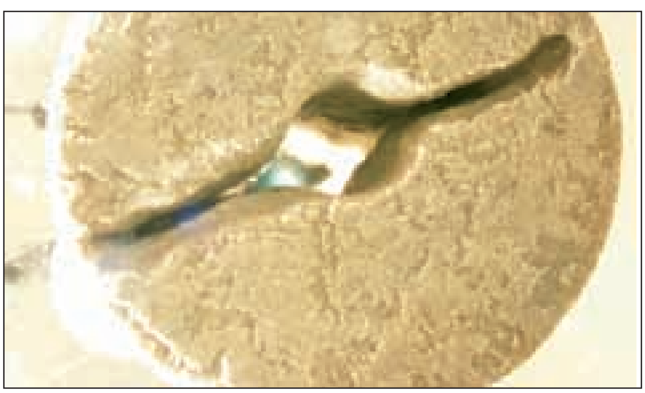


Photo of sandstone after "Cavity Failure" experiment.

Research has conducted research in sand production since the mid-1980s. This extensive research activity has resulted in improved calculation models for predicting when sand production will occur and how much sand will be produced. These models can also be used to optimize the well's location and direction as well as an appropriate completion solution (open hole vs. perforated casing, hydraulic fracturing, etc.). This has resulted in far fewer sand control installations among Norwegian offshore facilities, which has led to lower installation costs and not in the least substantially increased production.

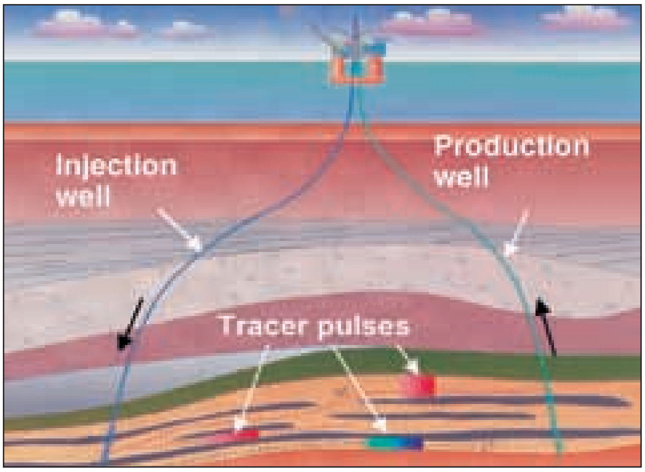
Statoil has examples of wells that have doubled production through active risk management based on just such expertise, and we have observed data indicating an average increase in production of around 40% at a dozen or so wells at Gullfaks/Statfjord. We also have examples of this occurring at other fields such as Statfjord, Oseberg, Varg and Norne. The value of the resulting increase in production is considerable.

This extensive research in sand production has also resulted in a variety of spin-off products. One of these is a tool for the prediction of rock mechanical parameters based on well logs. This product is called LMP (Logging of Mechanical Properties) and is currently utilised by one of the world's largest service companies, Baker Atlas.

Extensive research concerning borehole stability has been conducted by SINTEF since the mid-1980s, which has resulted in the development of testing methods for shale, knowledge of the effects of stratification and drilling fluid exposure, as well as the effects of time. Several of these testing methods comprise testing of cavings from the wellbore wall and cuttings realesed during drilling. This work by SINTEF has led to the development of various methods for classification and models of calculation in order to optimise hole stability during the drilling process. This was decisive for making possible the ERD (Extended Reach Drilling) projects of the 1980s and the development of horizontal drilling technology. Horizontal wells have revolutionized reservoir exploitation and costs related to field development. It is for example difficult to imagine oil production at the Troll field without the existence of such technology. Some petroleum companies did not consider oil production at Troll as commercially viable at one point in time, which represented a view that Hydro's development in the area of horizontal technology put to shame.

Enhanced recovery with tracer technology in reservoirs

Tracing Substance Technology, which was developed by the Institute for Energy Technology (IFE), is an important and costeffective contribution to our better understanding of reservoirs. The technology makes it possible to optimise production and thereby achieve maximum profit. Thanks to IFE's efforts in this field, the Norwegian government and the oil companies have enjoyed considerably increased earnings from oil and gas operations.



Tracers are injected into a well flow through the reservoir and are measured on the platform at the outlet of a production well.

IFE has developed non-radioactive and environmentally friendly tracers, which are in demand among the entire international oil and gas industry. These tracing substances enable operators in the worldwide oil and gas business to obtain unique information about flow characteristics in the reservoirs.

Various types of tracing substances

IFE has spent 40 years developing many types of tracer for use in a wide variety of industry-related conditions. During the last 20 years, special focus has been placed on applications in the oil and gas industry, with particular emphasis on the extraction of oil and gas. An operator at a given oil field can inject a tracer into an oil reservoir in order to map out flow characteristics in the reservoir, in which the oil is present in layers of porous sandstone or limestone. The tracers flow together with the water that is being injected in order to press oil out of these layers. The operator takes samples of the water during production and measures the amount of tracers present in the sample, thereby obtaining valuable information about the reservoir and particularly where there may be remaining oil deposits. Such information makes it easier to formulate strategies for further extraction from the reservoir.

Enormous savings

It is difficult to perform accurate cost/benefit analyses using tracers. However, there is one specific example of an oil company being able to document a savings of more than 15 million dollars by preventing the drilling of unproductive wells. At a field in Columbia, BP used tracers from IFE in an oil reservoir. Without information obtained about blockages in the reservoir, the company would have drilled two useless wells in order to produce oil. Two wells would have represented a cost of 10 - 15 million dollars whereas the tracer operation cost 150 thousand dollars, or about one percent of the cost of two wells. It is even more costly to drill wells offshore, so the potential savings there are even greater. A typical cost estimate for a single offshore well is about 25 million dollars. Tracers are currently used on most fields on the Norwegian continental shelf, and they make important contributions to optimised production.

Comprehensive surveys

IFE carries out comprehensive field surveys for the oil companies. IFE's staff of professionals is experts on how tracers behave in oil fields and they know which substances should be used in different situations. A point worth noting is that the Institute is able to analyse tracers at extremely low concentrations. In the course of a standard field survey, IFE is involved in all phases of the project, including the preliminary work of pumping the tracers down into the reservoir. Once a tracer has been injected into a well, it may take several years before it reaches a production well. The normal routine following an injection is that IFE is sent samples from nearby production wells over the course of several years. It is not unusual to follow a tracer's movement for five or six years. IFE currently carries out 3,000 – 4,000 analyses annually of samples taken from various fields all over the world where the Institute is involved. Based on the results of their analyses, IFE performs studies for optimisation of the reservoir description. For this type of evaluation, the Institute performs simulations using both standard software and special applications software developed by IFE in order to handle the unique challenges related to the tracers' special characteristics.

SINTEF

Foam improves recovery rates on Snorre

SINTEF has been involved in research concerning the use of foam in order to increase the oil recovery during gas injection. The Institute recommended the world's largest foam injection project at the Snorre field, which resulted in increased oil production to a value of about 35 - 45 million dollars.

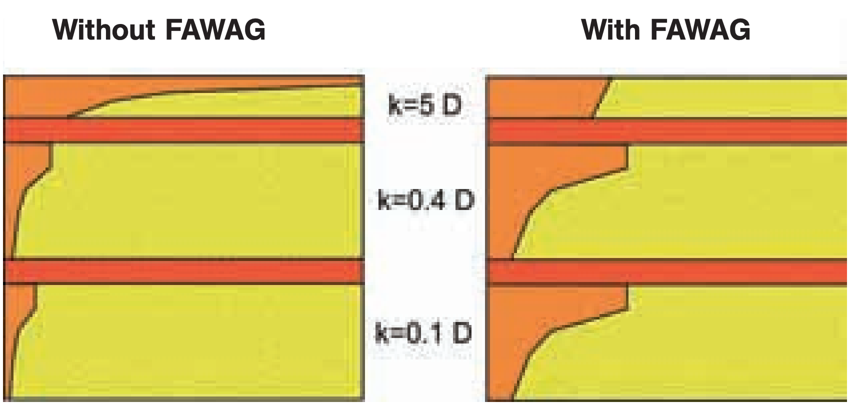
This technology has proved to be extremely successful, and has been tested on the Snorre field, among others. An injection mixture consisting of water with added surfactant and gas is used to control the flow of gas in the reservoir, leading to increased oil production. There is constant focus put on exploiting existing fields by further increasing the recoverable amount of oil and gas. Developments in the use of foam have contributed accordingly. Water and subsequently gas injection have also been successfully tested since production began at the Snorre field in 1992. In order to optimise the effects of the injected gas to an even greater degree, research started early on the use of foam as a means of controlling the flow of injection gas in the reservoir. This work resulted in several field pilots at the Snorre field in parallel with extensive research. SINTEF Petroleum Research participated in this process through both the RUTH and RESERVE research programs as well as projects directly financed by the industry.

On the initiative of SINTEF Petroleum Research, the North Sea's first full scale testing of foam treatment FAWAG (foam assisted water alternating gas injection), began in 1996. A total of 3,000 tons of surfactant concentrate have been injected at the Snorre field and diluted with water, which has resulted in FAWAG being the world's most extensive foam injection project. The results of the foam injection at the western fault block were extremely good and included a considerable and enduring reduction of breakthrough gas produced. SINTEF Petroleum Research has participated in FAWAG through several projects, including both laboratory-based testing of foam injection and simulation studies aimed at predicting the effect of foam in the reservoir. This prolonged activity was concluded in 2000 with an evaluative study of FAWAG. The goal here was to interpret the good results that had been achieved and to acquire a better understanding of how the foam has functioned in the reservoir.

As a result of the FAWAG project, Saga Petroleum ASA received the Norwegian Petroleum Directorate's IOR (Improved Oil Recovery) award in 1999. FAWAG is a good example of how collaboration involving industry, governmental authorities and research institutes can lead to the development and testing of new technologies in the field.

The FAWAG Project on the Snorre Field:

- Injected surfactant: 380 m^3 commercial mixture (38%)
- Stored gas volume: 120 million Sm^3
- Increased oil production: 210-250 000 Sm^3
- Value of increased oil extraction: approximately 35 - 45 million dollars
- Increased oil production from other wells (due to gas-limited production at the field)



Yellow = Oil
Orange = Gas

The FAWAG project at the Snorre field: Operating principle for foam treatment: Without foam most of the gas flows into the high permeability layer. Foam treatment increases the flow resistance in the high permeability layer to a relatively greater degree. The gas is forced into the less permeable layers and into contact with new oil. The oil production increases and the production of breakthrough gas is reduced.

With time as the fourth dimension

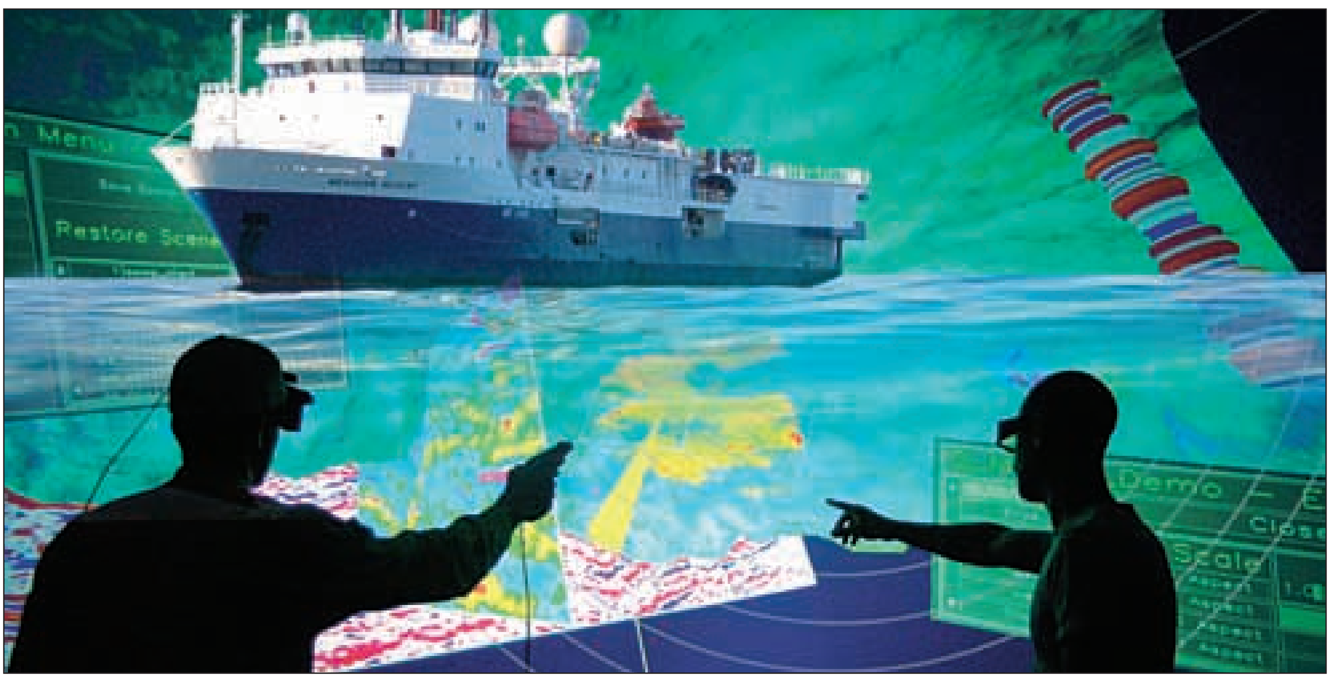
3D seismic and horizontal wells are regarded by industry experts as being two of the most important innovations in the history of oil operations ever. Schlumberger and WesternGeco have led the way for 3D seismic technology from their respective research and development centres right from the outset. Schlumberger and WesternGeco currently invest nearly 100 million dollars annually in research and development in Norway.

Close cooperation between service and oil companies and Norwegian authorities resulted in Geco A/S being established in Oslo in 1972. Today, 32 years later, WesternGeco is the world's largest company specializing in seismic technology, and is led by Schlumberger and jointly owned with Baker Hughes. 3D seismic technology has been vastly improved, and the latest innovation involves the introduction of "production time" as the fourth seismic dimension. So-called 4D seismic or "time-lapse seismic" is used to monitor the movement of oil as it is being produced in a reservoir, similar to the mapping of cloud system movements on a weather map using time-lapse satellite measurements.

4D Seismology

Time-lapse measurements require exactly the same conditions during each recording of seismic data. "We must steer the seismic sources to the same position, navigate each recording line in the same direction and steer the three-kilometre long receiver cables to exactly the same positions," explains Schlumberger's research director, Lars Sønneland. In order to obtain such accuracy the vessels must tow seismic sources and seismic receiver cables equipped with GPS satellite navigation and an acoustic network. The receiver cables are made steerable with the help of small wings, which function similar to aeroplane wings. This technology, developed by WesternGeco in Oslo and manufactured in Knarvik near Bergen, has been extremely well received by customers around the world. It is the Norwegian oil companies Statoil and Norsk Hydro, who have been worldwide leaders in terms of putting this new 4D technology to use.

Time-lapse seismic provides oil companies with such accurate data that oil production can be increased considerably.



3D seismic and horizontal wells are two of the most important innovations in the history of the oil industry, and research is still being actively conducted in these areas. This year alone WesternGeco and Schlumberger will invest nearly $100 million in research and development in Norway. [Montage: Fasett A/S]

Operator Norma Lærdal of Fjord Instruments in Knarvik near Bergen accurately assembles the combined fibre/electric terminal coupling of a "Q-seabed" section.*

On the Norwegian Continental Shelf the value created from investing in 4D technology is estimated to be between 3 – 4 billion dollars. According to Statoil, the added value from the Gullfaks field alone is estimated to 0.6 billion dollars.

Overseas oil companies are now also utilising Norwegian technical know-how. Brazil's national energy company, Petrobras, recently awarded the world's largest 4D seismic project to WesternGeco at the Marlim field offshore Brazil. They state: "Petrobras chose WesternGeco because of their "single-sensor" Q* technology. It is the best technology for the largest deep water reservoir in the world".

3D and 4D seismic generates data on the terabyte scale. Advanced computing systems are therefore required to analyse the data. Schlumberger is researching and developing these analysis systems in Norway and exporting them to oil companies worldwide. Results from the analyses are presented in virtual 3D reservoir models, which can be manipulated with advanced computer graphics. In fact as part of the Petrobras project, geologists in Stavanger and geologists in Rio de Janeiro might be working together, in real time, with the same virtual 3D reservoir, as if they were in the same room. These advanced computing systems are now being expanded to enable remote onshore control when drilling complex horizontal wells offshore. The trend is towards further development of these systems in order to allow remote control of oil production itself – so-called "e-fields" – from onshore control rooms.

Operator Rune Kalheim secures the proper assembly of a "Q- seabed" sensor casing.

Field Development

MARINTEK
SINTEF

Gigantic Offshore Structures

The development of the Troll field has received considerable attention from around the world. The gigantic project involved a variety of challenges in which many research bodies were asked to participate. The world's tallest concrete platform is located in this field, in part thanks to SINTEF.

Based on its vast expertise, SINTEF helped make the so-called Condeep Platforms a reality. SINTEF made contributions in the form of concrete technology, methods for the calculation of wave and current stress, construction techniques and calculation methods relating to foundation work.

Troll

In 1996, the enormous Troll gas field was opened. The world's tallest concrete platform is currently standing on the sea bottom above the Troll gas deposits. Much of the research-based knowledge from SINTEF and NTNU is behind the work with this platform. The Troll platform is the last in a long line of Condeep platforms that are placed on the Norwegian continental shelf. SINTEF/NTNU's contribution to Condeep comprises many disciplines within engineering.

One of the tasks researchers were faced with was the development of a method for calculating wave and current stress factors. This resulted in calculation tools that are used to calculate the behaviour and strength of the platforms as well as calculation methods that make it possible to predict how the ground under the platforms will react when the concrete blocks are positioned on the sea bottom. The Troll platform is the tallest object ever moved by man. The 370 metre high concrete base would have towered over the Eiffel Tower if it had been positioned in the city centre of Paris, and it is constructed to withstand currents and wave stress in the exposed North Sea. This colossus was build by Norwegian Contractors (now a part of Aker Kværner). The concrete used has greater strength while also featuring lower weight than concrete that was previously used in offshore structures. SINTEF has contributed to this work by developing and documenting the material's characteristics. Together with industry players, SINTEF/NTNU has also been involved in the development of the foundation solution, which actually made the Troll giant possible in the first place. This development means that the Institutes now possess expertise concerning concrete technology that has various applications relating to numerous other projects and industries.

The Troll Platform – the tallest object ever moved by man.
Photo: Norsk Hydro

Skirt foundations and suction anchors worldwide

The North Sea has given invaluable experience to a wide variety of Norwegian companies, including NGI. Their acquired expertise concerning skirt foundations and anchoring of platforms is in demand worldwide. NGI is currently in charge of such projects as the geotechnical design for a jack-up platform at the Shah Deniz field in the Caspian Sea.

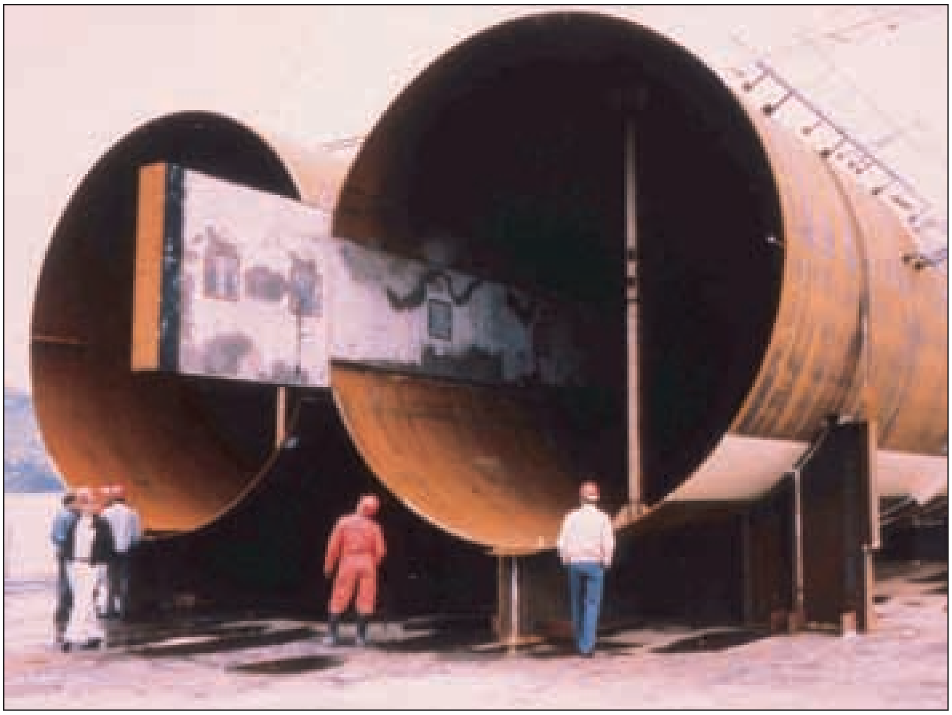
The Shah Deniz assignment is being performed for Technip France who has a contract with AIOC/BP. The foundation consists of multiple skirt foundations, which functions as a gravitational foundation. Gravity base platforms played a key role in the expansion of the oil and gas fields in the North Sea. Measurements of the behaviour of the gigantic structures during construction and regular operation with loads from heavy storms provided unique information for the verification of complex calculations and design of the platforms. This formed the basis for future improvements as one ventured into deeper waters and worse soil conditions. Based on this knowledge, NGI has also been actively involved in the instrumentation and monitoring of bridge structures in Norway and internationally.

Successful testing

The third and final platform of the Gullfaks field in the North Sea is located towards the Norwegian trench at a water depth of 217 m. The soil conditions in the upper layers consist of soft, silty clay and more solid layers of sand. In order to attain satisfactory bearing capacity, the foundation had to be constructed with concrete skirts down to a depth of 22 m. NGI conducted comprehensive testing and calculations in order to confirm whether or not this was possible. In order to reassure Statoil and the other partner companies, Norwegian Contractors and NGI conducted a full-scale penetration experiment out in the field. Two cylinders equipped with a concrete skirt were pressed down to 22 m. The measurement results corresponded quite well with the calculations that were made in advance. Gullfaks C was successfully installed in the field in 1989.

Further development

The Troll platform was one of the last gravity base platforms in the North Sea. It has 36 m long skirts down into the sea bottom. Based on the knowledge gained from such skirt foundations, so-called "suction anchors" were developed as a new concept for anchoring. Extensive research and development of calculation methods and large scale model testing were performed in order to optimise the concept. Together with the company Frank Mohn AS in Bergen, NGI developed systems and equipment for the installation of suction anchors and provide comprehensive services related to both planning and installation processes. Completed project work includes field expansions off the coast of Africa (Nkossa), Brazil (Marlin), the Gulf of Mexico (Diana) and the North Sea (Snorre, Sleipner T, etc.) at depths all the way down to 1500 m. More than 150 suction anchors have now been installed by NGI.



NGI's experience from the North Sea has rendered their expertise on skirt foundations and anchoring of platforms in demand around the world.

AKER KVÆRNER™

Renaissance for concrete expertise from the

Well known and well proven concrete expertise from the North Sea is now finding new applications. Aker Kværner is participating in the construction of two concrete platforms in Sakhalin in Russia. The North Sea has been their laboratory where technology and expertise have been developed over the course of several decades. This knowledge is now being utilised around the world.

The contract for the second phase of the Sakhalin II project in Eastern Russia is important to Aker Kværner for two reasons. Firstly, it strengthens the company's standing in an important market. Furthermore, it provides an opportunity to update and capitalise on the company's world-leading expertise in concrete structures for the oil and gas industry. An increasing number of concrete solutions are now being requested internationally. For a while, many considered the Troll A platform to have been the last concrete platform to be constructed. However, Aker Kværner realised that technology which had proven to be useful under such harsh conditions as those encountered in the North Sea would one day be in demand in other parts of the world. They have kept in contact with other players in the Norwegian concrete industry and maintained key expertise within the company. The main reason for an increasing interest in concrete structures among the world's oil companies is the fact that the oil industry is now moving into ever more inhospitable locations. International oil companies also realise that the expertise and experience gained during the development of Norwegian fields helps serve to ensure the successful completion of such complex projects. When the Russians began planning and constructing the oil fields off the Sakhalin Peninsula, Aker Kværner was involved in the concept development for two similar platforms featuring concrete foundations. Aker Kværner was asked to verify a solution that has been developed by their client in collaboration with other consultants. The structure would be positioned in an area subject to Arctic conditions.

Aker Kværner's experience with both the Arctic region and Norwegian oil and gas fields served as a basis for the verification performed by Aas-Jacobsen, Olav Olsen, Multiconsult and Sveco. It was shown that the structure size could be reduced by 30 percent. The Norwegians were subsequently assigned the task of building the two platform concrete structures. Construction is underway in Nahodka on the Sakhalin Peninsula. Local labour is primarily utilised, while the Norwegians are in charge of planning and construction management. The Sakhalin II project consists of two fields, Piltun-Astokhskoye and Lunskoye. They are located 15 km off the Northeast coast of Russia in

North Sea

waters that are covered with ice for 6 months of the year. The fields contain estimated reserves of 1 billion barrels of oil and 550 billion cubic meters of gas. Year-round production of oil begins in 2006 and production of gas in 2007. The earlier phases of extraction at Sakhalin have been based on seasonal production.

Terminals for liquefied natural gas

Concrete structures are also attracting increased interest internationally for other areas of application, especially for liquefied natural gas (LNG) terminals. Increasing demand for natural gas and decreasing gas production in the vicinity of the major markets is resulting in strong growth in the transport of LNG. For security reasons, it is not normally desirable to have processing plants and storage facilities for gas on land. A viable alternative is to erect LNG terminals at a safe distance from the coast where ships can dock and load the liquid natural gas far away from industrial and residential zones. LNG can be stored in large volumes inside the concrete structures, prior to being regasified and sent through a network of delivery pipelines to consumers. Aker Kværner is currently working on such an LNG terminal for ExxonMobil in the Adriatic Sea off of Italy. The project benefits from expertise sourced from several of Aker Kvaerner's divisions. This collective expertise makes Aker Kværner one of the few suppliers in the world that can provide their client with complete LNG terminals solutions.

Enormous dimensions of the gravity base structure under construction at Sakhalin.

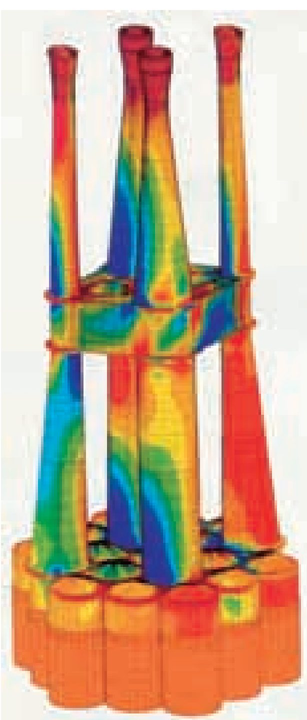
Sakhalin is not only rich in resources, but also enjoys beautiful natural scenery.

The time for the installing massive concrete platforms on the Norwegian continental shelf may well be over, but Aker Kværner is now exporting its concrete expertise and technology to other parts of the world, such as Sakhalin in the Eastern Russia (photo).

The SESAM software platform

DNV's SESAM software is acknowledged as a leading system of analysis for hydrodynamic and structural response in marine constructions. SESAM's software architecture with various modules makes it possible to combine the various software units to a tailored software package.

Typical examples of this are packages for general analysis, for non-linear risers, for joining pipelines, as well as a hull and vessel package. SESAM is the result of a continuous development from as early as the 1960'ies. The increased demand for transport of crude oil and refined products developed a commercial basis for using larger oil tankers. The size went from approximately 60,000 tons dwt around 1969 to more than 300,000 tons ten years later. This development forced the ships engineers to develop new calculation methods.



The Troll platform was designed by the aid of Sesam.

Before this time, the criterion for a vessel's structural strength was mainly based on the long ship strength of the hull beam. When constructing larger vessels, they would also have to analyse the transversal strength of the vessel and the construction process grew more complicated. In 1959, DNV started to employ computers for these calculations. Simultaneously, new and large scale ship yards were constructed in some countries which were able to build the big tankers. These projects required new computer based systems for the design and construction. The first software program was put to use in 1960. This pioneering software was able to solve a total of 200 linear equations. However, the capacity grew gradually through projects both with DNV, NTNU and Norsk Regnesentral. In 1968, DNV established a new unit Computas to secure the commercial development of SESAM-69 that was developed in a first version at NTNU. The element software was the best selling software in Computas, but several other software units within naval construction, offshore, industry, mechanical industry and construction were developed. The software was sold to almost all industrialised countries in the following decade and service centres were opened in all major Veritas offices throughout the world. In the beginning of the 1970'ies, the size of a VLCC (Very Large Crude Carrier) reached nearly 300,000 dwt, and some even talked about ships of up to 1,000,000 dwt. The increase in size required even more precise ship analyses and the dynamic response of the hull was included in the calculations. With full scale measuring, DNV demonstrated, together with Germanische Lloyd, that this method was a prerequisite in order to calculate deformation and stresses in large vessels. So, in 1979, DNV was capable of solving up to 500,000 linear equations. That was also necessary in order to analyse the LNG tankers. But he calculation time was long and the computer needed the whole night in making a single analysis. DNV's new FEM software, SESAM-69, was established as the basis for the new knowledge which had been built into analysis based calculations. Ever after, this has been a part of DNV's basis for the development of design procedures for ships.

The Ekofisk tank

The first big project in which computer software has been used for an offshore construction was the design for the Ekofisk tank. It is an enormous cylinder construction in steel and concrete with 92 meters in diameter and placed on the sea bed at approximately 70 meters depth. In order to calculate the structure, the most advanced computer software was used, together with the recently developed statistically based methods for calculating the strain of the waves on the structure.

Technology transfer

In order to illustrate the technology transfer, it is appropriate to mention that the same methods, the same software, even the same people, were used for the construction of the big LNG tankers. They were also central when the Aker Group designed their new generation mobile platforms, the H3.

The finite element programs were essential tools! The next technological break-through came in 1974 when the enormous concrete platforms, the Condeeps, were launched. The new generation SESAM system allowed for a selection of modules. The non-linear modul FENRIS was based on solving problems for which linear theory was inadequate. The software contained a special application for slim structures with large displacements, such as, for example, marine risers for oil production, and was also used for calculating the capacity of thin plate structures and complex shell structures. The SESAM-80 project developed a new system architecture on the basis of a large number of previous projects that had been carried out by various Norwegian research institutes during the 1970'ies. The main reason for devloping the new system was the need for more comprehensive tools of analysis voiced by DNV. Structural analysis was an essential component in Veritas' work for making the ships, the offshore installations and the industrial work places more safe and secure.

In 1985, the company VERITAS SESAM Systems AS was founded, and the software SESAM was launched on the basis of the new system architecture as it had been defined in the SESAM-80 project. SESAM Interface File (SIF) system had already been introduced and employed. This was an important instrument for standardization of the communication between the pre-processor and the finite element software. The SIF format facilitated an integration of the hydrodynamical software and the element software in SESAM and laid the foundation for automatic load transfer to the structure software. This made SESAM to a complete and well arranged system of analysis. When this extended version of SESAM had been in use for 18 months, approximately 30 offshore jacket structures had been analysed by means of the software. The analysis were incorporated in a database which was designed to cover all the platforms that were operated by the oil companies in the North Sea.

In the late 1980'ies, DNV Research started a huge programme: Reliability of Marine Structures (RMS). The main objective of the project was to develop probabilistic calculations of fatigue for jacket structures, anchored platforms and pipelines as well as a method for how to use the inspection results in order to estimate future damage caused by fatigue. In 1994, the DNV started a project supported by Agip, Brown & Root and Tecnomare in order to commercialize the software designed to estimate damage by fatigue on jacket structures. The result was the probablitity based fatigue software PROFAST for inspection planning.

PROFAST is continually being further developed and is the international market leader in its area today. Through the years, SESAM has continuously been developed by means of new technology. In 1991, the basis for a new development phase was made with the working title SESAM-2000. DNV and its partners invested about 10 million US dollar in a new generation system architecture. The open architecture defined in the SESAM-2000 project was used in the development of a new pre-processor to the WADAM, named HydroD. Moreover, this facililitated an efficient connection to various software modules relating to user interface, load analysis, post processing of data and so on.

Heidrun-plattformen. Foto: Statoil.

MARINTEK

SINTEF

The world's largest ocean basin

New fields are to an increasing degree being developed by means of production vessels and floating rigs. In the planning phase, many companies stop in Trondheim to study the development in greatly reduced versions before they are being built – in the world's largest ocean basin. The result has been increased safety and less expensive development solutions. Floating production has made a number of marginal fields profitable and thus increased the resource influx for the oil companies.

The ocean basin in Trondheim is 80 metres long, 50 metres wide and 10 metres deep. In it, tests of models of floating production facilities are being carried out. Thus, it becomes possible to recreate waves, currents and wind in model scale. The tests often focused at mooring lines, risers and wave motions.

The production vessel Åsgard A.
Photo: Øyvind Hagen, Statoil.

The enormous laboratory basin is run by Marintek of the SINTEF Group. Models of most of the floating production solutions that have been selected on the Norwegian continental shelf, have been tested in this basin. Correspondingly, Marintek has also tested floating production systems designed for deep sea fields in Brazil, the Gulf of Mexico, the Mediterranean Sea and the Far East. Some of the world's largest oil companies are to be found among Marintek's customers. In the ocean basin, they perform the tests as a part of their design process. Partly to make sure that the mooring lines and the marine risers, with the dimensions that have been suggested, will withstand the load they will be subjected to and partly to make sure that the platforms and the vessels are not subjected to unacceptable motions and waves.

In its ocean laboratory, Marintek has tested models that in full scale are among the world's largest floating objects. Among other things, the Institute has launched models of the world's largest production vessel, the world's largest tension leg platform (TLP) as well as models of some of the world's largest semi-submersible platforms.

The photo shows the model tests that were performed prior to the development of the Åsgard field. Here, a model of the Åsgard production vessel is being tested.

Subsea risk of landslides

Research relating to the danger of landslides has provided NGI with expertise that is being used in advanced developments on the sea bed. Recently, NGI was able to assist BP in their development work in the Caspian Sea as BP Development had lost wells on the West Azeri field, because deflection became too big. NGI developed and manufactured inclinometer equipment for the oil company.

In a very short period of time, NGI was able to develop the necessary equipment for BP, on the basis of its many years of experience on the Norwegian continental shelf. The equipment that NGI has developed is designed to monitor the stability of the well casing liners during well drilling on the West Azeri. Two strings, complete with three inclinometers that are designed to monitor the deflection of the well casing liners at depths of 150–180 m under the seabed, were installed.

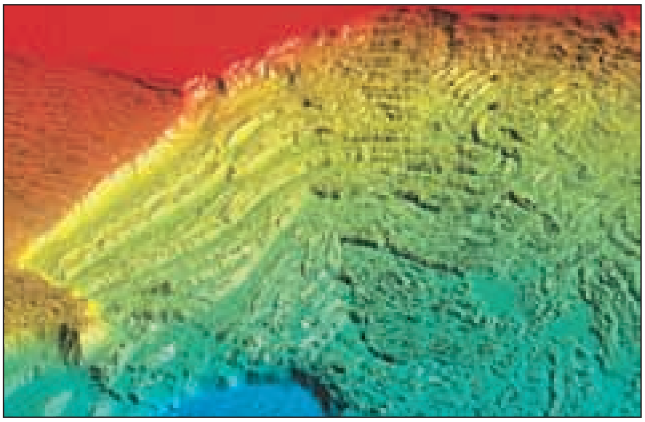
The Storegga landslide

The Ormen Lange field is the second largest gas field on the Norwegian continental shelf. It is situated in the hollow made by the world's largest subsea landslide, the Storegga landslide which involved a huge area, approximately 800 km long.

NGI has been a central partner for Norsk Hydro and the other responsible companies in connection with the assessment of the slope stability and the risk of new landslides in connection with the planned development of the field. The issue relating to Ormen Lange was basically to understand why the Storegga landslide took place some 8000 years ago and also to assess the risk that a similar, or at least an equally dangerous, landslide would happen again.

By measuring, among other things, the pore pressure in the potential landslide release zones over the Ormen Lange field, NGI was able to establish that the risk of a new landslide was so small that the field could be developed. In order to measure the pore pressure in the gliding areas in question under the sea bed, special pore-pressure sensors were installed at depths of 200 to 1000 m below the sea bed. These sensors actively measured how the pore pressure varied over periods of months and years and would provide the geotechnicians with the necessary material to enable them to calculate the risk of a landslide. The readings were made by sending down small remotely operated vehicles (ROVs) to register measured values in computer loggers that were placed in specially designed "houses" on the sea bed.

The project has produced results that have enabled the scientists to describe how the Storegga landslide came to happen and how it involved such a vast area and great volumes (approximately 3500 km^3), even though the slope on the sea bed in the area only was 1-2^{o}. The work on Ormen Lange included geophysical, geological and geotechnical investigations that included long-term measurements of pore pressure. New methods for the analysis and assessment of the risk of landslide have been developed and employed.



Section of the topography of the Storegga area in the Ormen Lange field, showing the result of the enormous land-slide on the sea bed more than 8000 years ago.

NGI

Monitoring offshore and on land

NGI is working on the development of a "best practice" standard for offshore development in order to minimize the risks related to geohazards. This work is being undertaken in co-operation with other institutes and some of the major oil companies. The technology is also being used to develop safeguards against landslides on land.

Monitoring for offshore geohazards

In offshore developments, we are concerned about the hazards to which installations may be subjected. Offshore geohazards are ever more important issues, in which NGI has particular expertise. In co-operation with the University of Oslo, the Norwegian University of Science and Technology, the University of Tromsø and several international oil companies, NGI is developing a "best practice" standard for development projects in which geohazards have to be assessed. The objectives of the development work include:

- optimal localization and protection against damage to the installations
- reduced risk for production losses/delays, pollution and tsunamis
- increased confidence on the part of the authorities, environmental organisations and the general public

The developers and the authorities wish to monitor the fields, both prior to and during the development and during the operational phase. NGI is cooperating with oil companies and international research milieus, as well as through the EU project ASSEM, to develop advanced data-gathering systems and measuring stations that can be deployed on the seabed.

Troll

Troll is the largest GBS (Gravity Base Structure) that has ever been installed, but its instrumentation is in principle the same as in most GBSs (Condeeps) that have been installed. The GBSs are monitored by means of a range of sensors (earth pressure, slope, force, flexion, wave height, setting and so on) and reading systems. The monitoring system enables external stresses on the GBS to be monitored and its reactions to the stresses to be registered. The monitoring system is probably most important when the platforms are being lowered to the seabed. For Troll, there were 32 m deep foundation cells that were to penetrate the sea bed when the platform was lowered into place. The monitoring system monitored, among other things, the height over the sea bed before penetration, the verticality, the ballast system, the pressure on the concrete walls and so on. It was important to monitor that none of the tolerances that had been established for various stresses on the structure were exceeded and the installation process could be adjusted on the basis of readouts from the monitoring system. There was a particular desire to prevent overloading of the central elements in the bottom of the platform. When the platform had been put in place, the monitoring system could be employed to verify the design parameters that had been used in the design of the platform by recording how it reacted, for example, to high waves.

Landslide

The most important reason for landslides is a rise in pore pressure in slopes with low stability. By using systems for local monitoring, early warnings of increased risk of landslides can be given. Geotechnical analysis of the slope stability are carried out for areas in which sloping monitoring is regarded as necessary. Critical gliding surfaces and pore pressure levels may thus be identified for optimal configuration of the monitoring system. Piezometers are installed in the slope for pore pressure measurements. Inclinometer strings or deformation measuring equipment can also be installed when necessary. Other sources of information may also be included in the system. By connecting the local system to a central server, data from the various local stations may be followed up and analysed centrally. If the system is connected to the Internet it may also be made available to a large number of users. A simple local read-out unit may be programmed so that it is adapted to local geotechnical reference criteria, enabling the system also to be used as a local warning system and/or alarm indicator.

Monitoring systems for the seabed

AKER KVÆRNER™

Subsea innovation with a boost

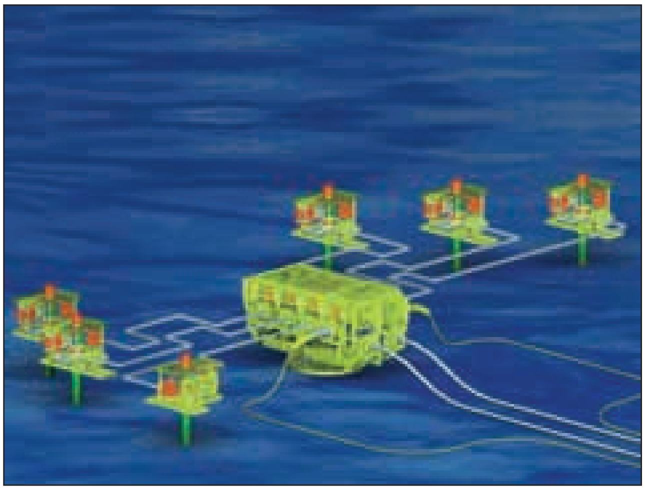
Aker Kværner supplies international leading edge technology and skills for subsea production on the world's largest and most demanding field development projects, Kristin in Norway and Dalia off Angola.

The Kristin field on the Halten Bank outside Mid-Norway sets a world record with its combination of high temperature and high pressure. The Dalia development outside Angola will be one of the the largest production system that has ever been installed under water, at a depth of 1500 m. The solutions required for these developments lift subsea technology to a new level. Aker Kværner's subsidiary Kværner Oilfield Products (KOP) in the Subsea business area manages the technology that tames these challenging oil and gas reserves. The equipment must be qualified and tested to ensure that it will withstand the extreme conditions that will be encountered. Aker Kværner has successfully focused on the manufacture of valve trees (Xmas-trees) at Tranby in Norway for supply all over the world. This highly specialised expertise is in high demand and KOP has developed into a leading supplier in this field.

Verification of wellhead dimensions

Kristin subsea – extreme temperature and pressure

Statoil is the operator of the Kristin field, which has estimated reserves of 35 billion cubic metres of recoverable gas, as well as 35 million cubic metres of condensate. The temperature is 177° C and the pressure is a thousand times higher than atmospheric pressure. The Kristin reservoirs are situated approximately five kilometres below the sea bed and thus they present substantial technological challenges. Aker Kværner has enjoyed very good co-operation with Statoil in dealing with these challenges, and Norwegian expertise has also played an important role in the solutions that have been developed. Kristin will be in operation in October 2005. For Kristin, Aker Kværner supplies the subsea production equipment for 12 wells that will be tied into a new semi-submersible production platform. The platform is currently under construction in Aker Kværner's yard on the island of Stord. The gas will be transported via a new pipeline to the existing gas pipeline from the Asgard field and onwards to the processing facility at Kårstø.



Dalia subsea production system

Dalia subsea – the world's largest

In March 2003, KOP was awarded the contract for the supply of a sub-sea production facility for the huge Dalia development off the coast of Angola by the French oil company Total. Aker Kværner's scope of work consists of engineering, purchase, manufacturing and testing of all equipment necessary for subsea production on the field. This includes equipment for 42 wells, with an option of a further 25 wells. The Dalia field is scheduled to come on-stream in 2006. Dalia is important for the development of Angola as an oil producing nation. For Aker Kværner, it is important to contribute to this development in several ways, including the development of local skills and projects that will contribute to increased industrial activity in Angola. To ensure that local content is well developed, a training programme for Angolan engineers has been established. This include training both in Norway and in Aberdeen, and the engineers will then be incorporated in Aker Kværner's organization, which is being established in order to assist Total during the installation and operation of the subsea facility. A purpose-built service base is currently under construction in Luanda.

FMC Technologies

From hand-drawn sketch to technological success

In response to the requirement to reduce production costs in the oil and gas industry, FMC decided to pursue standardization early in the 1990s, when the company started the development of the very successful Hinge-Over Subsea Template (HOST) project. An individual HOST module weighs around 25 tonnes and a HOST base frame around 100 tonnes. Previously, a base frame would have weighed between 400 and 600 tonnes. This story tells a little about how much less expensive it is to manufacture HOST, and how much easier it is to install.

The HOST project started in 1993. It is a fold-out subsea base frame complete with equipment. It was first introduced in 1994. When folded, a HOST may be passed through the "moonpool" of a floating drilling rig. The moonpool is the hole in the rig through which all work is done. When the HOST has been placed on the sea bed, it is folded out. The system is very cost-effective because it may be constructed from standard elements. At the same time, it is also a very flexible system. For this reason, it was developed further for use at depths of up to 4,000 m. Statoil showed immediate interest in the HOST idea and, in 1994, FMC and Statoil, signed a three-year agreement in which each party contributed more than 6 million US dollar to the development project. Mobil joined as a partner early in 1995, and Elf and Shell in October 1995.

Hand-drawn sketch

HOST is a good example of how ingenious solutions are able to grow in environments where creativity thrives. The managing director of FMC, Tore Halvorsen, presented the very first HOST project to Statoil by means of a simple hand-drawn sketch. The background for his idea for a base frame that could be folded in and then out again was the notion that it ought to be possible to use the rig for more than the traditional purposes of such rigs.

Simple and inexpensive

During the installation of conventional subsea facilities, huge crane vessels have been necessary, and these are expensive to operate. The modular HOST system, on the other hand, can be transported by supply vessels and handled by the regular cranes on the rigs. As well as reducing costs, the HOST modular system provides a high degree of flexibility. It is like a Lego system and may be adapted to an oil company's particular range of field solutions. The building blocks are the same, irrespective of the project involved, and are assembled in such a way that they can be used on any subsea field. FMC is thus able to customise solutions at an "off the shelf" price. HOST has given FMC market opportunities far beyond the North Sea, and therefore it was very suitable for the company's globalization strategy.

Installation of a HOST on the field. The wing elements have not yet been folded out after passage through the rig's moonpool.

Cost-effective subsea development

The oil companies will increasingly focus on saving costs related to wells and well completion. Vecto has carried out a technological development programme that meets the need for cost-effective solutions for subsea developments in deep waters.

The system called NuDeepTM offers the potential for lower installation and operating costs and is qualified and available on the market.

Well equipment

NuDeep TM has included the development of a compact well-head system adapted to the industry's increasing use of "slim and slender" well technology. There is a sharper focus on the costs related to the use of rigs and installation vessels, and a great deal of work has been done on identifying methods in order to reduce time consumption. One example is the installation of a valve tree with a separate vessel, or as a parallel operation from a rig, a measure that is now being adopted in other regions. With the present technology, in which a valve tree can typically weigh around 40 tonnes, there will be handling restrictions (space and the capacity of the lifting equipment). The equipment that has been developed for well completion is called NuComp TM and consists of a super-light conventional valve tree (less than 17 tonnes), together with a ROV-operated tool to pull and install TH plugs. The combination makes it possible to plan batch completions and post-installations of trees by wireline, thus improving the efficiency of rig utilisation and saving considerable costs. The weight is so low that it can easily be handled from most rigs that operate globally, as well as enabling it to be handled by a small vessel (typically an anchor-handling vessel with an A frame). The weight, together with arrangements for the use of "slim riser" technology, also means that the equipment may be installed in much deeper waters with a third-generation rig, and thus it can help make considerable cost savings by avoiding having to mobilize a much more expensive fifth-generation rig. This is important for many regions all over the world.

Manifolds and templates

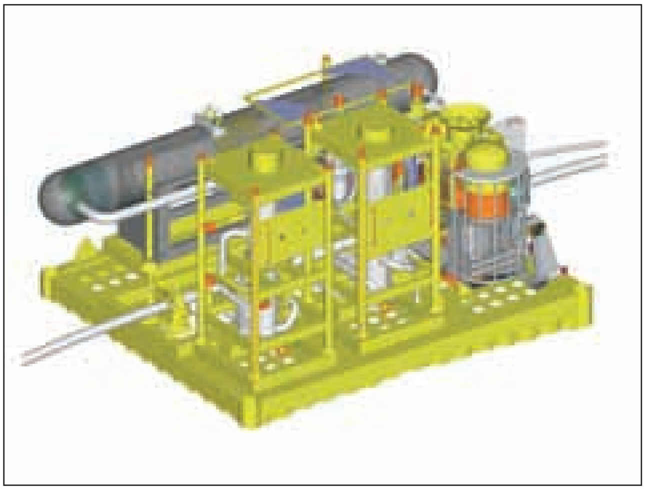
The typical solution for many regions around the world is that of a set of satellite wells connected to a manifold and/or the use of in-line Tees (typical for injection wells). But in the North Sea, the tradition is to use templates. There are many parameters that direct these choices and therefore NuDeep TM (specifically NuFlow TM) is adapted to both alternatives.

In the technology programme, the focus has been on developing modules that are compact and that can be installed from typically small installation vessels (no module weighs more than 65 tonnes). Emphasis has also been put on simple connection systems that do not require special running tools, but that may be landed and connected simply by the use of ROVs. The focus has been on inexpensive installation. This is achieved by the fact that the installation may be undertaken from a less expensive vessel and/or that the installation may be done as a parallel operation from the rig (typical for jumper installations).

Subsea processing

This is an area that has been on the agenda for many years, but in which the oil companies have not met the expectations of the market as to the implementation and employment of the technology. Although Troll Pilot was a big effort for Vecto, which has provided a lot of valuable experience, no new units of this type have been installed or commissioned.

In NuDeep TM, they concluded that the market needs something more than Troll Oil and new and efficient separation technology has been developed to answer the needs



of the market. As more and more developments are carried out in deep waters, a fact that will require more cost-effective solutions, the need for subsea separation increases. Vecto therefore developed a compact light-weight subsea separation module (NuProc TM) that is based on their own separation technology – coalescer. This technology offers a considerably smaller separator than standard technology and provides solutions for separating oil with a low degree of API combined with emulsion issues. The technology has been qualified and demonstrated and contracts for testing the separator on behalf of several oil companies have been signed.

Control systems

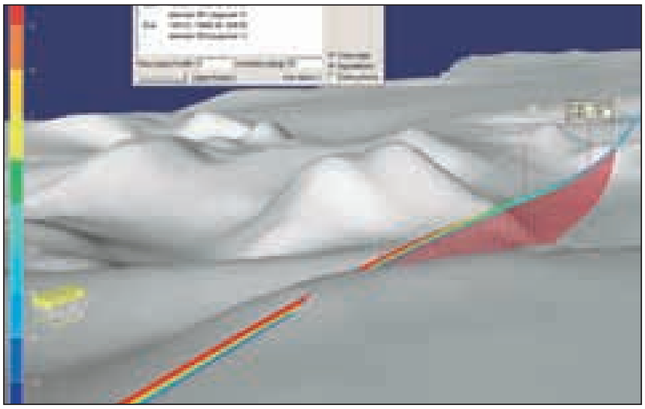
There are at least two challenges related to control systems for deep waters that have been addressed by NuDeep. Smaller valve trees require smaller control units and deeper waters require simpler methods of repair. In order to get smaller valve trees, it was important to reduce the size of the control module. It is not realistic to envisage fewer functions; rather the opposite. The solution, therefore, was to divide the functionality up into smaller modules, each of which could be replaced by only an ROV and a standard torque tool. Thus, a typical control system (NuTrols TM) which is offered as a part of the NuDeep TM programme consists of modules that are connected by flying leads, exchangeable by ROV. This means that the controls of a valve tree or a manifold/template require less space, less or no balance weight and no installation guiding. Nor is a running tool required. Although this concept entails more connections, availability analyses show that availability has increased thanks to reduced repair time.

SIMLA facilitated Ormen Lange subsea to shore

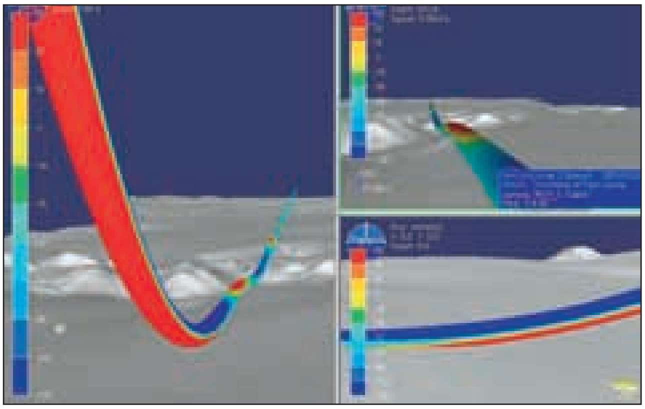
As the world's oil and gas industry moves to increasing water depths, the limits of what is considered to be feasible are broken. New technology develops rapidly, also at Marintek at SINTEF. Marintek has developed tools for design and planning of pipelaying operations (SIMLA) that are particularly useful at large water depths. The gigantic Ormen Lange project is one of the offshore field developments that have gained from applying the new technology.

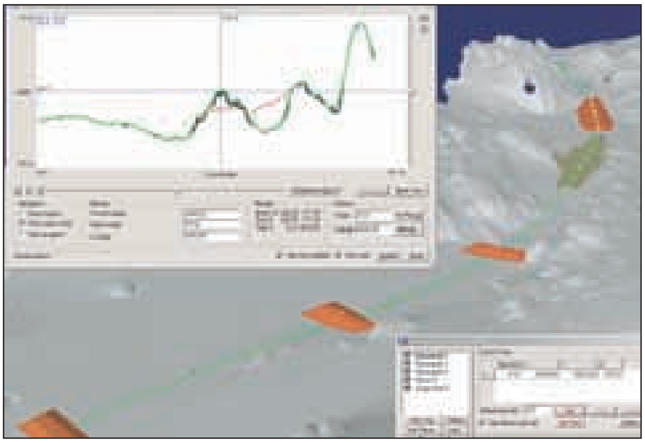
SIMLA is Marintek's recently developed computer tool for analysis of offshore pipelines, specially developed to deal with problems related to deep waters and uneven seabed. SIMLA is able to simulate the installation of an offshore pipeline (laying analysis) while simultaneously taking into account current and the true topography of the seabed. The results of the analysis can be inspected in a "virtual ocean space" created by means of advanced 3D computer graphics in which the seabed is presented as a terrain model together with the pipeline, and where the pipeline may be provided with colour coding reflecting the type of analysis result selected (for example stresses because of tension, external pressure and bending. Illustration: blue=compression, red=tension).

One of the main challenges of the Ormen Lange project was to find routes for the pipelines from the reservoir area directly to Aukra in Møre and Romsdal. The pipelines are to be laid through a subsea landslide area with a very rough topography. In order to lay a pipeline through such an area, it is necessary to dig through a number of heaps and to fill in several hollows on the seabed. This is to avoid, as far as possible, too long free spans along the pipeline route. Marintek's unique tool SIMLA enabled Hydro to evaluate a number of alternative pipeline routes, taking also into account operational aspects during installation. SIMLA allowed the technical risks and the costs related to each alternative to be assessed, so that Hydro was able to select safe and cost-optimal routes. SIMLA has recently been further developed and now also includes functionality for route planning and seabed intervention (dredging and rock dumping). New numerical methods for non-linear time domain analysis and vessel control have also been introduced. Therefore, SIMLA has been a central tool for facilitating subsea to shore as a development concept for the Ormen Lange field. The work of developing SIMLA has been funded by Hydro and The Research Council of Norway (via the DEEPLINE Strategic Institute Programme). In all respects, this has been a useful and profitable investment for Hydro.



SIMLA is unique in the world in the way that it simulates pipelaying with complex seabed topography.





Technical expertise with focus on safety

DNV has more than 30 years experience with offshore pipelines. The company's "Rules for subsea pipelines" appeared for the first time as early as 1976. Today, DNV's Offshore standard for pipelines, first published in 1966, has become an acknowledged standard for deep sub marine pipelines.

Today, the industry focuses first and foremost on cost reduction and on improved safety standards. The result is innovative design and construction methods. Simultaneously, the industry faces new challenges in the form of increasingly deep waters, uneven sea bed, new materials, higher temperatures and pressure. The design of pipelines is an important multi disciplinary task. It involves structural analysis, testing, fracture mechanics, material and corrosion technology, geotechnical assessments and hydrodynamics. The costs of constructing a pipeline to new offshore fields are often one of the main cost elements of the development as such. Thus it may be decisive for the economic analysis of the possibilities for developing the field. Ever since 1999, DNV has invested in many research projects assessing a number of scenarios, including ultra deep waters, in order to develop reliable codes with consistent safety levels; this is facilitating better designs and instalment of more cost effective pipelines offshore.

Superb Project

The "Superb Project" established the foundation for reliability based design of pipelines. This project made the foundation for DNV's "Rules for Submarine Pipelines" in 1996, known in the industry as "DNV '96". This was the first pipe laying code based on a systematic structural reliability approach. It was taken further to a partial coefficient format ("load and resistance factored" design format, LRFD), which introduced flexibility and made it possible for the operators to design within a well defined and consistent safety level and thus reduce costs. Sea bed intervention in connection with pipelines is an important cost driver, particularly in great depths and on uneven sea bed. With the

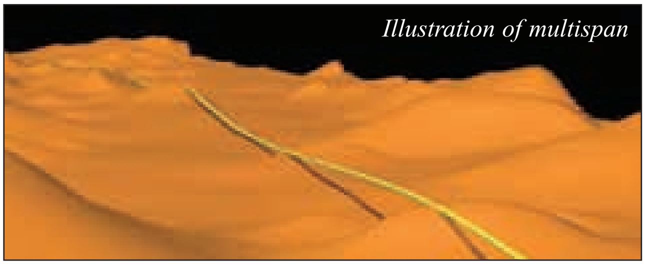


Illustration of multispan


Test of pipelines in 1995

"Multi-span" project, a method for analysing vortex shedding and pipeline dynamics that may lead to fatigue for pipelines in free span, was at hand. The results have been collected and converted to design guidelines for such pipelines. This facilitates performing extensive fatigue calculations and assessments of pipelines rather than having to reduce the span lengths significantly. By permitting longer free spans based on calibrated and well documented analysis, the costs of sea bed intervention are reduced. Today, deep water pipelines are laid with free spans of up to 200 meters, whereas previously, there was a maximum length of 30 meters irrespective of environment and pipe laying conditions.

Corrosion in pipelines

The service life of pipelines is often determined by corrosion. This is particularly true for fields with high temperatures and fields in which corrosive elements are present in the oil. In the project "Functional stability in corroded pipelines", a calculation method for the residual capacity of corroded pipelines has been developed. This facilitates the re-qualification of the pipelines, which makes it possible for the operator to define that a pipeline may be in operation within a defined safety margin in an extra number of years, even after changes in the operational conditions or observation of damage. Recent work within the project "Fracture control of installation methods for pipelines with cyclical plastic moorings" has resulted in a guide for fracture mechanics testing and calculation methods that are used for documenting sufficient resistance against fracture during installation. The method provides considerable cost saving compared to previous tests and calculation methods. A "Hotpipe" structural design guideline for pipelines for high pressure and high temperatures has also been prepared. DNV's long term strategy of investing in and participating in research projects through three decades has given DNV well respected, multi disciplinary expertise within pipelines.

OLGA enables field development without platforms

Traditional oil and gas production has been based upon the separation of oil, gas and water at the wellhead before onwards transport. This approach required the construction of platforms with wells and associated process equipment on top of each well cluster. Since 1980, research has been done to find solutions that do not involve surface installations by transporting non-processed well-stream directly to a nearby infrastructure or directly to an onshore facility.

Sub sea solutions depend critically on transport of untreated well stream e.g. oil, gas and water in the same pipeline – what is known as multiphase transport. The active use of multiphase transport represents a paradigm shift in the way offshore oil and gas fields are developed on the Norwegian continental shelf as well as internationally. Multiphase transport has facilitated the development of smaller satellite fields close to existing platforms. This made possible a simplified solution for the Troll gas field, in which the main part of the process plant was moved onshore, made possible by multiphase transport through the twin pipeline.

In short, multiphase transport

- Provides great savings in the development and operation of offshore fields
- Has made marginal fields profitable
- Has significantly increased the volume of commercially accessible oil and gas reserves throughout the world

The best-known result of multiphase transport research is the computer programme OLGA that, at present, is a world leader in the design and operation of offshore fields with multiphase transport. OLGA was developed in co-operation between SINTEF and the Institute for Energy Technology (IFE) for the Norwegian and international oil industry. The research was carried out in the course of a number of multiclient projects from 1984 to 1995. An important prerequisite for the success of the project was the building of the SINTEF multiphase laboratory, which provided realistic data for how oil and gas flow in a single pipeline, as well as IFE's comprehensive experience in software and modelling two-phase flows of water and vapour in nuclear reactors since the 1960s. SINTEF's multiphase flow laboratory has a one kilometre 8 inch pipe with a capacity of 60,000 barrels/day. The laboratory is the word's largest test facility for multiphase flow. It was built in Trondheim early in the 1980s by ExxonMobil, and after a year it was handed over to SINTEF for future operation. OLGA has made it possible to develop offshore fields as subsea solutions based on multiphase transport. The well stream (oil, water and gas) is transported unprocessed, in a single pipeline, to an existing platform with available capacity, or directly ashore. The development of Snøhvit and Ormen Lange are examples of this solution. Troll is an early example of the use of multiphase transport, which allowed the gas processing facilities to be moved ashore, at great savings in investments and operating costs. Statoil has estimated the saved costs over the lifetime of the field to be around 5 billion dollars. A characteristic of the Norwegian continental shelf is that new fields are small and less accessible. These fields demand less expensive development solutions before they become interesting for commercial exploitation. Multiphase transport will be the key technology used to resolve these challenges. The importance of multiphase technology is illustrated vividly when we know that Snøhvit and Ormen Lange could not have been developed as subsea facilities with long-distance pipeline transport ashore for processing if the results of the past 20 years of research and development in multiphase transport had not been available. The multiphase competence that has been built up through the development of OLGA has been an important prerequisite for a situation in which Norway has been able to build a globally leading supply industry in advanced subsea systems. Examples of such firms are FMC Technologies, VetcoGray and Aker Kværner. These companies export "Norwegian" multiphase technology worldwide for substantial amounts every year. OLGA is commercialised by Scandpower Petroleum Technology AS and holds approximately 90% of the world market for simulation tools of this type. Scandpower Petroleum Technology has around 120 employees and is growing rapidly.

The SINTEF Multiphase Laboratory at Tiller.

FMC Technologies

Technology moving from the platform to the sea bed

Once upon a time, subsea well-heads were new, exciting and a bit risky, but today they are used on a large scale for field development in both Norwegian and international waters.

In the mid 1990s, multiphase pumps were installed on the sea bed, and now technology for processing on the sea bed is on its way. The Norwegian processing milieu is known for bringing forth new technology and new solutions, and subsea processing is no exception. The strongest groups in advanced subsea technology are found in Norway. Field development based on subsea wells connected to a floater is a clearly dominant solution at water depths from a few hundred to several thousand metres. New fields may also be connected up to existing platforms or led directly ashore without going via a separate platform. Subsea wells have had a somewhat lower recovery factor than platform-based solutions with dry well heads, mainly because the latter are characterized by simpler and less expensive well intervention processes. FMC Technologies is a leading global company in subsea production technology, and this has been a natural step in the further development of technology and solutions that help to bring about higher recovery rates for subsea-based field developments. RLWI (Riser Less Well Intervention) and Subsea Processing are important areas of focus which are driven by engineering based in Norway.

Subsea processing

Pumping, separation, re-injection of produced water, gas compression and gas drying are new subsea functions that contribute to increasing recovery rates in subsea-based field developments.

An important challenge has been to gain control of the technical risks. Even through the functions that are to be transferred from an installation on the surface to the bottom

Full-scale test of a subsea separator at CDS Separation Technology

of the sea are well-known in their original form, there are other issues and priorities that have to be considered subsea. One consequence of equipment failure is longer down times and more expensive repairs. This means that development, testing and qualification are essential. FMC Technologies has a tradition of teaming up with leading Norwegian and foreign suppliers of technology to cover special needs outside of FMC's core areas, and with that as a starting point, to develop, test and qualify technology and systems in co-operation with the operating companies. CDS Separation Technology is an example of this, where CDS develops and supplies leading technology for the topside market and FMC Technologies employs their knowledge and technology as a basis for the part related to subsea separation.

Results provide opportunities

Since the late 90s FMC Technologies has been developing technology and concepts for subsea processing. In 2004 it undertook a major qualifying project, in which a full-scale subsea separation and sand handling system was developed and tested in co-operation with Statoill, CDS and FMC. DEMO 2000 and the Norne licence were involved in financing the development. In addition, a number of important components needed in subsea systems have been developed, tested and qualified. Foreign companies are showing increasing interest in this technology as it falls into place, but most prefer to wait and see and to learn from the first installations that will probably come on the Norwegian continental shelf.

Future field development

There are many indicators that suggest that the future will need increasingly advanced subsea technology, and the future is not too many years ahead. Today, we are considering whether important gas fields like Ormen Lange and Snøhvit could produce without any kind of platform at all. In order to achieve this, technology and systems for subsea gas compression must be in place. The industry is well on its way, and again Norwegian and international participants meet in Norway to develop new technology, because here there are people, groups, resources and a milieu for innovation and fresh thinking.

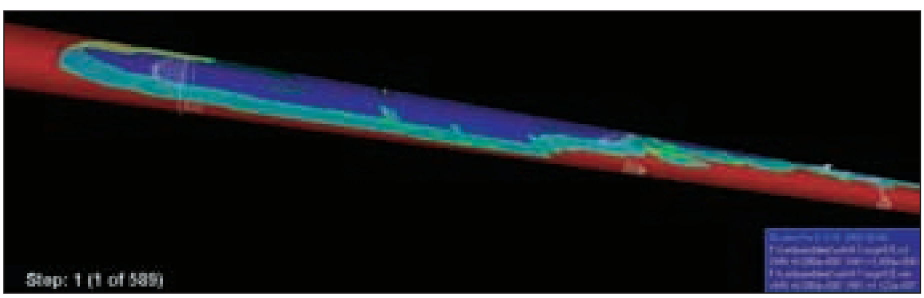
SINTEF

The future design tool for advanced well-flow transport

In the mid 90s, the development of OLGA had come far. There was a need, however, to improve our understanding of the details of multiphase flow in order to increase transport distances and reduce development costs even further. SINTEF started the development of a 2D and a 3D multiphase simulator in 1996 and today, the company has developed the multiphase simulator LEDA which already has brought considerable savings to its customers.

Research on the transport of oil, gas and water in the same pipeline was well documented by the mid-90s. At this point, the industrt was ready to continue to the next stage of development, namely, to design new transport systems complete with precipitation and possible deposition on the pipeline walls of wax, gas hydrates, scale, asphaltenes and even produced sand. Production on the Norwegian continental shelf has begun to mature, which means that water production begin to increase considerably. The fact that the fluids might often be flowing in both directions in the same pipe, with the water and the oil flowing downstream and the gas upstream, made it difficult to continue the development of design tools in only one dimension. SINTEF realized that it had to develop a tool that was able to calculate in 1D, 2D and 3D in order to capture the effect of different complex multiphase phenomena in the design of the pipeline. The Research Council of Norway funded the first five years of the development and gave SINTEF the opportunity to show that it was feasible to develop a tool for this purpose. ConocoPhillips funded the project from 2001 and Total joined it in 2002. In addition to the funding, both companies have also contributed greatly by providing professional expertise in the development work and have thus been very active partners in the project. Today, LEDA is one of the largest development projects in the SINTEF group. LEDA has become a unique design tool in multiphase transport. It consists of a 1D simulator that calculates along the long pipeline stretches in which no great changes take place, but as soon as the pipeline geometry changes or a more complex fluid phenomenon occurs, a 2D or a 3D simulator takes over the calculations and increases the degree of detailing. One of the challenges in multiphase design at the end of the 90s was that a 1D multiphase code provides information that requires considerable knowledge of multiphase modelling to be understood. One of the objectives of LEDA was to make it easier for pipeline engineers anywhere in the world to understand the consequences of their changes in design parameters by a clear visualization of what is going on inside the pipeline. LEDA is now able to show, in a simple manner, how the flows move in a physical sense inside the pipeline and how this picture changes if you change the pipeline diameter, the production rate or the pressure. For an engineer who is about to select a pipeline route, it is important to investigate whether a new route, with a different angle of inclination and topography, will present problems for oil and gas production. LEDA is able to help the engineer to see the effect of this. For some time, LEDA has been employed by ConocoPhillips and Total. After three years of using LEDA, ConocoPhillips has made cost savings of 110 million dollars related to two fields. It is expected that this figure will increase rapidly in the years to come!

A few years ahead, it will be possible to send the well-flow directly from remote fields over much longer distances than today, to onshore terminals or to an existing infrastructure. This will be particularly interesting in northern regions where ice conditions necessitate development on the sea bed and ultra-long multiphase transport ashore. A possible solution is Coldflow, in which gas hydrates and other solids at the wellhead are formed and follow the flow. These are very complex transport systems to design. SINTEF is at the internationally forefront in this area and holds world patents on Coldflow together with BP. In the course of the next few years, LEDA will be developed to enable ultra-long multiphase transport pipelines to be designed with Coldflow.



An example of the detailing that is offered by means of simulations with LEDA. The new information becomes very important for simulating, for example, how sand is deposited in the pipeline, gas hydrates sticks to pipeline walls, etc.

LNG

LNG-transport

Transport of liquefied gas by sea has been going on for more years than many are aware of. The first tanker for liquefied gas was constructed in 1949 in Horten, in accordance with DNV classification. Today, DNV is participating in the design of the newest LNG tankers of up to 250.000 m3.

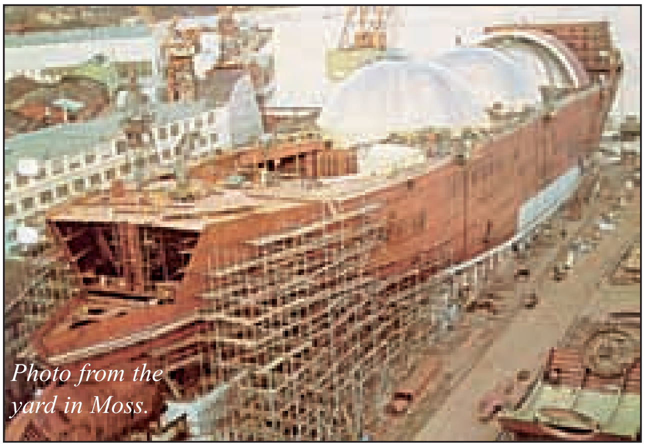


Photo from the yard in Moss.

”Herøya” was constructed with a pressure tank for transportation of LPG and ammonia. Thus DNV was involved in classification and security aboard this type of vessel from an early stage. In 1962, DNV was the first classification company to publish comprehensive rules for gas tankers. One of the greatest challenges within the design and construction of vessels for transportation of liquefied natural gas, LNG, is the low temperature required by the cargo, minus 163 degrees C. This makes most materials that are normally used in ship building unsuitable for the LNG containment. The low temperature also requires a special design to ensure the safety of such vessels. DNV's first engagement in gas tankers was the development of a gas tank system in co-operation with the Norwegian ship owner Øivind Lorentzen and the Bennet Group in Dallas. Various designs were assessed. One of the designs that was not developed further by DNV, a corrugated (waffle plate) membrane tank system, was transferred to French Gazocean. They developed it to the Technigaz LNG system. At the present, the membrane systems Technigaz and Gaztransport holds approximately half of the marked for LNG tankers. Membrane tanks consist of a thin layer, a membrane, that is supported by an insulation layer towards the hull. It is designed to minimize the effect of thermal contraction. An extra barrier may hold the cargo in up to 15 days without damaging the ship, if the membrane tanks were to leak.

The spherical tank

The other half of the LNG tanker market is dominated by the Moss spherical tank. The spherical tank system was pursued by the project co-operation between DNV and Øivind Lorentzen in 1959-1962 and a LPG vessel was constructed with spherical tanks at the Fredrikstad Mek. Verksted in 1961. The concept was further developed for use with LNG by Kværner Moss between 1969 an 1972 with considerable contribution from DNV. The design criteria that form the basis were formulated by DNV in the rules that were issued in 1972. At that point, the standard for the future development of the International Gas Code (1976) for both spherical tanks as well as prismatic tanks was set. To confirm that the design followed the criteria, DNV carried out investigations relative to sloshing movements inside the tank, crack formation, and fatigue of the tanks. In the early 1990'ies, the criteria for the tanks were somewhat modified based on new research related to structural reliability analysis. The basic design concept for the spherical tank is the principle of “leakage before fracture”. This means that if there is found crack formation in the tank, the damage will develop slowly and predictably even under difficult conditions. This entails that at least 15 days will lapse before the crack reaches the critical length for total fracture. Thus the cargo may be unloaded before the damage becomes serious.

Growing market

At the present, there are plans for gas tankers up to 250.000 m^3. These tankers will probably be wider than conventional vessels and will need new designs for the hull and manoeuvring. SINTEF participates in the planning of new types of tankers and DNV undertakes continual studies and tests of tanker designs in co-operation with operators and yards. European and Trans-Atlantic shipping with the Middle East is growing as result of increased gas import. Sloshing and fatigue of the tanks will become increasingly important design parameters because of larger tanks and more demanding maritime conditions. Terminals offshore are becoming preferable because of improved safety and security performance. The gas may be unloaded both in liquefied and gas form. Such solutions imply that the ships must be able to lie by the unloading buoys for up to a week with varying levels of liquid filling without damaging the interior of the tanks.

SINTEF

LNG technology made Snøhvit possible

The Snøhvit field was discovered in 1984. Statoil realized that if the gas were to be sold, it would have to be by means of a LNG facility and transport by sea to the market. The solution was to enter into a comprehensive co-operation with SINTEF and NTNU which resulted in a totally new LNG technology which is being built at Melkøya today.

The LNG facility at Melkøya.
Photo: Øyvind Hagen, Statoil.

One of the great challenges for Snøhvit was the distance to the market. It was regarded as unprofitable to lay a pipeline all the way to Europe, and only one option was left, namely LNG. At that time, the LNG market was dominated by one company and the price of the LNG facility was too high. Statoil needed to develop a knowledge base which would enable them to negotiate, purchase and run a LNG facility. They also wanted to develop the LNG technology further and find less expensive solutions that would make it more attractive to develop Snøhvit. Statoil started a very wide-ranging process of co-operation with SINTEF and NTNU in 1984. The co-operation entailed extensive experimental work that aimed to develop thorough competence in the properties and behaviour of natural gas during refrigeration to the liquefied state. A separate thermodynamic package and a database containing the properties of natural gas at low temperatures were developed. Much of this work was financed by the Research Council of Norway through the Governmental Programme for the Exploitation of Natural Gas (SPUNG) from 1987 to 1994. Statoil funded the development of a large simulator that was capable of simulating the whole LNG process. With this unique tool, it was possible to find energy- and cost-optimal solutions that also resulted in a new LNG facility which was less expensive. One of the greatest challenges was to develop main heat exchangers that would be much less expensive than those that were standard at the time. The main heat exchangers that are used to cool down the natural gas to such low temperatures are among the largest and most expensive components in an LNG facility. In 1995, Statoil initiated a co-operation with Linde of Germany based on candidates and knowledge resulting from the agreement with SINTEF and NTNU. This resulted in an alliance in 1996, in which Statoil and Linde planned and carried out tests of the heat exchanger equipment that Linde was building for LNG purposes. The first small-scale test was carried out at Tjeldbergodden and the next at full industrial scale in Mossel Bay in South Africa, between 1998 and 2001. The tests were 100% successful, both in terms of the calculations and the measurements. When representatives from Shell had observed Linde's heat exchangers in full test, and saw the measurements of the temperature profiles obtained with this equipment, they ordered similar equipment for their next development in Australia. A further nine units have since been ordered, and the first was put in operation in a large facility in 2004.

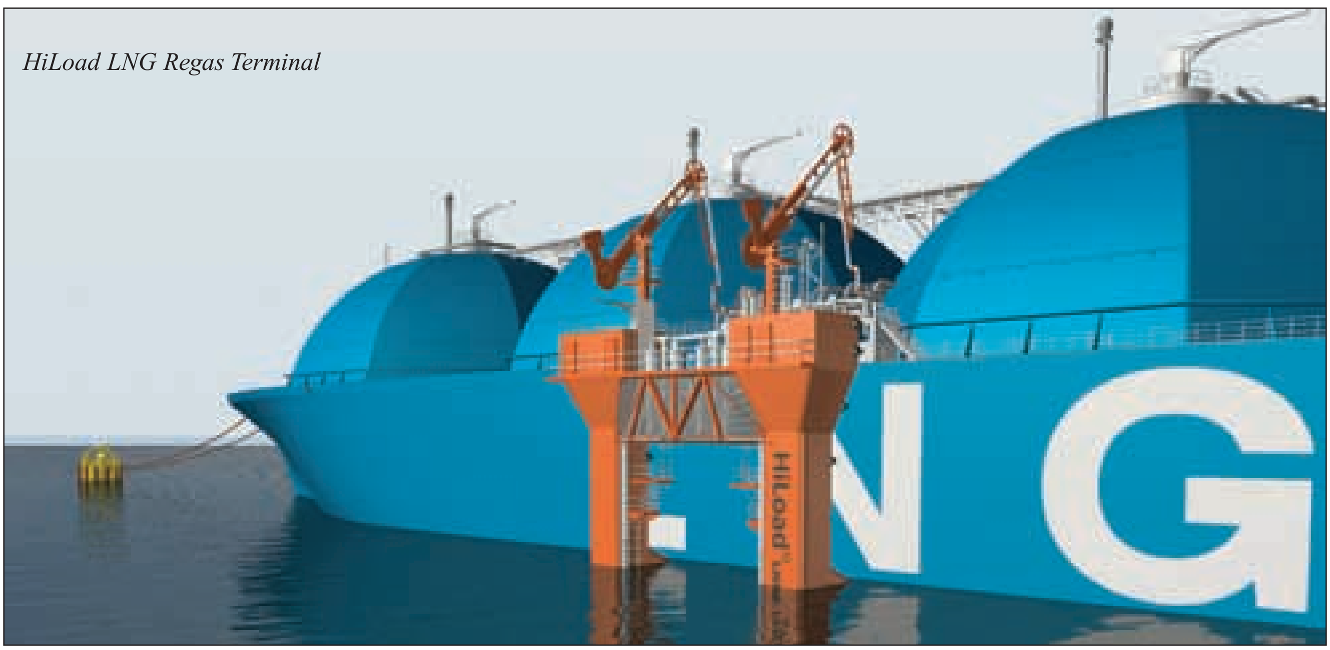
The enormous research work that has been involved in developing the Norwegian LNG technology was headed by Professor Einar Brendeng, who was also a scientist at SINTEF. On September 19, 2003, Einar Brendeng was appointed Knight of the 1st class of the St. Olav Order for his pioneering work. In the course of the past 20 years, a total of 15 doctorates and 50 post-graduate theses in engineering have been completed in the field of LNG technology under the Statoil agreement and the SPUNG programme. Today, most of the PhDs and many graduate engineers have found work in Statoil and provide the core competence and driving force behind Statoil's work on LNG, both on Melkøya and internationally. The vision from 1984 has been accomplished, SINTEF and NTNU have delivered the goods in accordance with the agreement and the results demonstrate the opportunities and the strength that are found in close co-operation between industry, universities and research institutes.

REMORA TECHNOLOGY

Norwegian loading technology may change the world's LNG imports

The transport and import of natural gas in the form of LNG is increasing steadily, as several of the world's great nations have a growing need to import energy. This has lead to a "Klondyke" sentiment in the US, with a number of import terminals currently being planned.

Traditionally, such import terminals have been built on land. However, there is a growing scepticism among local people because of the fear of gas leaks and explosions as a consequence of terrorist attacks or sabotage, environmental pollution of the coastal areas, increased shipping activity, etc. A number of companies have now accepted the consequences of this situation and are planning offshore terminals. The design of offshore solutions will often be a compromise between employing standard LNG vessels and a safe and reliable cargo transfer system. All known solutions have weaknesses in one or both of these areas. LNG is a cold fluid (-163° C) that makes severe demands of materials and equipment. The HiLoad LNG Regas Terminal is unique in the way that it provides high regularity even with the use of standard vessels. In addition, the solution is very competitive in price and delivery. The technology has received widespread acclaim throughout the industry, with Approval in Principle from both DNV and ABS. The solution was also awarded the prestigious Innovation Award during the oil exhibition in Houston in 2004. HiLoad has been designed as half a floating dock that is manoeuvred into position midships of the LNG tanker by means of thrusters. Once in position, the HiLoad is elevated by means of a ballast system until it comes into contact with the bottom of the ship. The contacting surface amounts to several hundred square metres and is covered by rubber fenders to avoid inflicting any damage on the vessel. The contacting surface is surrounded by gaskets which in principle will function as giant suction cups. By just using the existing water pressure, the HiLoad will be pressed to the bottom of the vessel with a force of several thousand tonnes. This formidable contact force permits the HiLoad to be equipped with nearly all kinds of equipment, including an LNG re-gasification facility. Because there is no relative movement between the HiLoad and the vessel, it is possible to use standard loading arms. Large heat exchangers are mounted on the HiLoad, which use sea water to vaporise the cold LNG, after which the gas is brought ashore in pipelines. HiLoad LNG Regas is regarded as a solution for several of the planned LNG terminals in North America. The HiLoad Technology has been developed by Hitec Vision with technical and financial support from ConocoPhillips. The technology is being marketed and further developed by a company called Remora Technology which has its head office in Houston, with branch offices in Arendal and Lagos.



Operations

Better safety and optimal operation

Technology to simulate the processes that take place in petroleum production is very important for the construction and operation of offshore production facilities. In the course of the past 25 years, simulation technology has developed so as to cover the whole value chain from the reservoir to the land-based facility.

Since the mid-80s the Institute for Energy Technology has been working on the development of simulators for transport and processing facilities and contributed to a number of deliveries, either separately or in combination with others.

The first major simulators were made for the Gullfaks and Oseberg platforms. A few examples of subsequent deliveries include those for Veslefrikk, Snorre, Brent, Ekofisk II, Troll, Slagentangen, Rafnes, Kollsnes and Tjeldbergodden. Kongsberg Maritime has delivered these simulators as IFE's partner in process simulation. During the past few years, IFE's main role has been to develop accurate mathematical models for the processing equipment in the facilities and to develop efficient software to handle simulators for large-scale facilities.

All phases

A simulator of a processing facility is used in all phases of the service life of the facility – for planning purposes, for construction and for operational purposes. Potential problems and bottlenecks in the process can be detected and the control system verified and modified before it is brought into use. In this manner, the commissioning of the facility will be simplified, so that time is save and surprises avoided.

In spite of the development of better instrumentation, many conditions may still not be measured or there may be cases in which instrumentation either will be too expensive or insufficiently robust. Therefore, accurate simulation models are also used to calculate important, non-measurable, conditions. A simulator that is directly connected to the measuring system is able to warn about abnormal conditions in the process by comparing the measurements with simulated values. A simulator that starts with a known condition in the process may be used to simulate how the process will behave in the future. This makes it possible to predict undesirable conditions that are about to occur and thus be able to experiment with measures in the simulator before they are adopted.

Increased complexity

The production system on the continental shelf is becoming increasingly complex and operations require steadily better coordination. Simulation models of the total systems help operators to maintain an overview of everything that is going on, and are used to optimize the production process. A simulator is also an efficient tool for teaching operators to control the process better. As well as gaining insight into the normal running of the process, the operator gets the opportunity to train specially on more demanding situations such as start-up, shut-down and malfunctions, as well as accidents that very rarely occur in real life.

In connection with its work on training simulators, IFE has developed knowledge and technology for the planning of functional control rooms. IFE has developed a computer-based tool for verifying that planned control rooms are designed according to the regulations. This has been used by suppliers, for example in order to develop good control rooms on Kvitebjørn, Kristin, Snøhvit and Ormen Lange.

Defective alarm systems have contributed to situations in which disturbances in facilities were not identified before they developed into accidents. Defects in alarm systems have also made it difficult to localize errors that have taken place. For a long time, efficient alarm systems have been an area of research at IFE and results of research in this area now making significant contributions to improving security and efficiency on the Norwegian continental shelf.

IFE has developed accurate models and efficient software for simulation of large petroleum facilities.

A quantum leap in the development of seabed wells

Traditional inspection and maintenance of seabed wells has required a large rig secured by anchors and massive risers that go hundreds of metres down to the sea bed. The innovative aspect of RLWI is the use of cables instead of risers, enabling vessels and light rigs to perform inspections. This saves the operator great expense.

FMC has developed the RLWI technology, which will allow much more extensive maintenance and inspection of wells down to 1/3 of the present level to be carried out. The consequences of the RLWI technology are better resource exploitation. A billion barrels more of oil may be extracted on the Norwegian continental shelf by increasing the recovery rate of oil from seabed wells from an average of 43% to 55%. It will also lead to a reassessment of unprofitable fields and tail-end fields because intervention costs are reduced and the recovery rate is improved.

Secures jobs in Norway

The technology is also helping to secure Norwegian jobs. This is world-leading technology developed in Norway with great potential to exploit advances in subsea wells and developments internationally.

Statoil was the first to qualify the technology. This has given the company an international advantage and may also bring in the Norwegian supply industry. Improved recovery rates and longer service life that could bring in up to one billion barrels of oil worth more than 30 billion dollars, will also help to secure employment in the supply industry.

Environmentally friendly

RLWI is also environmentally friendly. In traditional intervention, the well-flow is led up to a surface vessel. However, with RLWI technology, the well flow is balanced and circulated down on the sea bed.

Great demand

There is a great demand for RLWI technology both on the Norwegian continental shelf and internationally. On the Norwegian continental shelf alone, there are 13 subsea fields and 300 subsea wells. Internationally, there are currently approximately 3000 subsea wells, and the number is growing.

Riserless Light Well Intervention

RF

Inventions which provide cleaner emissions to marine environments

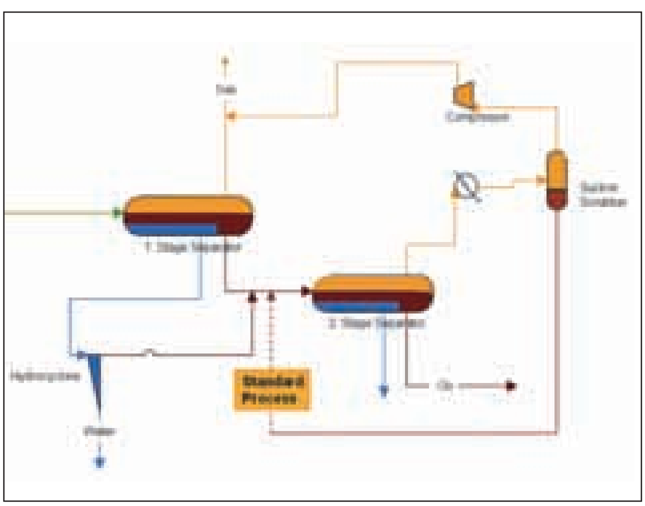
The platforms in the North Sea discharge produced water in large volumes. In a major project known as CTour, scientists at Rogaland Research have developed a process in which the oil and other substances are removed from the produced water before it is discharged, putting us well on the way to the goal of zero emissions!

The Statfjord field on which it was decided to install the CTour process. Photo: RF.

More than 8 million dollars in R&D funding was provided by several oil companies, the Research Council of Norway and the Norwegian Pollution Control Authority (SFT) for this project. Between 1990 and 2000, it is estimated that discharges of produced water rose nearly ten times to 120 million tonnes. The requirement of the authorities is that there should be a maximum of 40 ppm (part per million) oil in the produced water when it is discharged. The CTour technology reduces emissions of harmful components by 70 – 95 per cent, in other words below the acceptable limit set up by the authorities to the oil and gas fields within 2005.

The process

The CTour process involves purifying produced water in offshore processing installations by employing a gas condensate (Natural Gas Liquid, NGL) as solvent. NGL is "borrowed" from the production flow and is returned after use. The standard process for water purification offshore involves the use of hydro cyclones to remove the oil from the water. In the CTour process, the water flow is fed 1 – 2% NGL before entering the cyclone. NGL dissolves dispersed oil particles and improves the efficiency of the cyclone so that another 70 – 95 % of the residual oil in the water is removed at the same time as 90 – 95 % of the aromatic hydrocarbons (PAH; Polyaromatic hydrocarbons and BTX; benzene, tuolene and xylene) are removed.



The CTour process is probably the best (if not the only) process for removing oil and dissolved oil components from large water flows. The patent was submitted in 1995. The original process development was carried out by Rogaland Research with financial support from RF itself, the Research Council of Norway and SFT. When the process had been verified on a laboratory scale in 1998, further development work funded by the oil industry at a cost of approximately 8 million dollars has been carried out to the stage of construction of a mobile test unit.

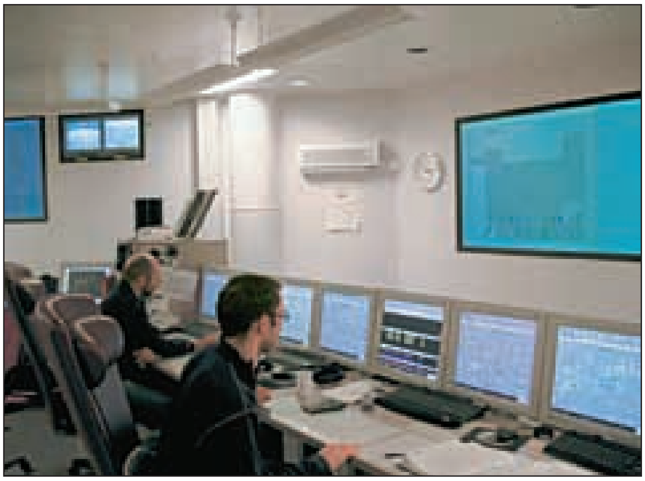
The process has since been verified offshore on three individual platforms. In 2003, the commercial rights were transferred to a new company CTour Process Systems AS: The company expanded rapidly.

At present, it has eight employees and an expected turnover for 2004 is approximately 5 million dollars. To date, decisions have been made to install the CTour process on the Statfjord and on the Ekofisk fields.

Improvements for safety

The control room at the Grane field offshore platform has been equipped by ABB. In it, the focus is not only on ensuring that alarms reach the operators, but that they will reach them in such a way that personnel will be able to react as efficiently as possible.

Grane is an offshore oil platform with a production rate of 214,000 barrels of oil a day. The Grane field is situated 185 km west of Stavanger at a depth of 128 metres. At first sight, a depth of water of 128 m and a reservoir depth of 1700 mbelow sea level is not a deterring challenge – this is routine for developers of oil and gas fields off the Norwegian coast.



The control room at Grane.

If Grane nevertheless deserves to be called a challenging field, this is mainly because the oil is heavy and the pressure in the reservoir is low, which means that natural gas has to be pumped down through injection wells in order to force the oil out of the reservoir. The injection gas is supplied by the Heimdal Gas Centre, 50 km away. This solution will provide a much higher recovery rate than if water had been selected as pressure support, a solution which is by far the most common. After approximately 20 years of production, the injected gas itself may be produced and sold. ABB has supplied, among other things, the complete alarm handling equipment aboard. It filters out all unnecessary alarms if they are triggered as a result of a given course of events. The problem with traditional control rooms is that, in critical situations, personnel often experience an avalanche of alarms and the operator has problems in giving priority to the most important alarms. With the ABB solution, only the most important alarms will emerge on the large screen, while the others are filtered out, enabling the operator to see where corrective measures will have to be directed. The alarm room itself has also been simplified. Everything is aimed at providing the two operators with as good working conditions as possible. Gone are the mimic diagrams that look like decorated Christmas trees and no instruments or lights are visible on the wall. Everything is concentrated on flat screens on the control desk and a large light board. Under normal conditions it will be deactivated. However, in the case of an alarm it will be activated. All conditions that may be read by instruments are viewed on the normal , a system chart for the process part in question will emerge on the large screen and indicate by colour coding the seriousness of the incident. By removing the sound part of the alarms that are given as a result of a malfunction, the operator does not have to spend the first few important seconds responding to auditory alarms instead of concentrating on taking the necessary corrective measures.

The offshore platform at the Grane field includes a control room equipped by ABB.

SINTEF

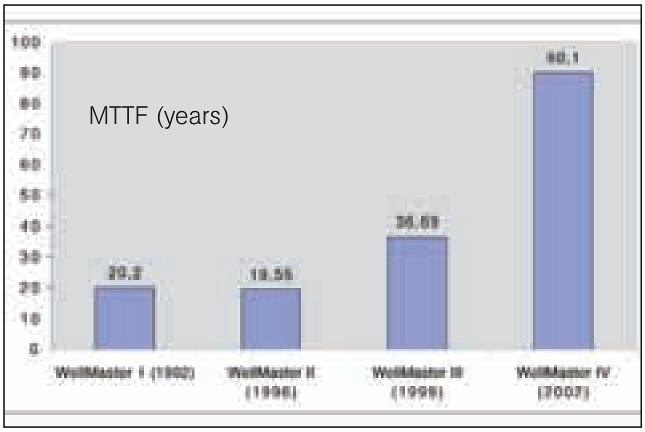
Offshore reliability data

The reliability of exploration and production equipment has an important influence on safety, production availability and maintenance costs. Safe reliable production in the petroleum industry, particularly offshore, is essential in order to provide a high degree of technical integrity. SINTEF's research and project management in this area has led to new international standards and the formation of a new company, ExproSoft.

OREDA

The joint industry project OREDA® (Offshore Reliability Data) has collected experience data in order to determine the frequency and cause of equipment malfunction on offshore oil & gas installations. Failure and maintenance data for equipment on platforms and subsea has been collected since 1981. OREDA is currently being sponsored by eight international oil companies, and the project has established an important source of reliability data in the offshore area for use in design and maintenance planning.

OREDA's main objective is to collect and exchange reliability data among the participating companies, as well as exchanging data and reliability experience with the equipment suppliers. OREDA acts as a forum for the coordination and management of reliability data collection in the petroleum industry.



Documented increase in safety valve reliability via WellMaster presented as an increase in the mean time to failure. (MTTF)

SINTEF has been the project manager for this project since 1992 and has on behalf of the project published several reliability data handbooks that have been sold all over the world. The experiences and knowledge developed in this project has been projected into a separate ISO standard, ISO 14 224 – "Petroleum and natural gas industries – Collection and exchange of reliability and maintenance data for equipment" issued in 1999. This Standard is currently being revised and will be re-issued in 2005

WellMaster®

A reliability study for well completion equipment was launched by SINTEF in 1990, and this was the start of the project known as WellMaster. As many as 16 oil companies have participated in the project and submitted daily reports containing data on any malfunction of the well equipment from more than 2200 wells. WellMaster includes a comprehensive database which describes all the components in each well, with a complete history of how it has worked and malfunctioned.

On the basis of this database, it is possible to calculate the service life and the reliability of each separate well and equipment item. One of the greatest advantages of WellMaster is that oil companies can predict the service life and reliability of new planned wells. WellMaster enables selection of well components based on documented reliability.

This has led to a situation in which the estimated average fault-free service life of TR-SCSSV (tubing mounted 'downhole' safety valves) type valves has improved from 20 years (1992) to 90 years (2002).

This project has been such a success that in 2000, a separate company was formed to commercialize the WellMaster completion software and reliability database as well as to offer upstream sector risk assessment services based on this particular tool. The name of the company is ExproSoft.

The documented improvement in reliability provided by WellMaster has led to a considerable increase in safety levels on offshore installations and provided considerable savings thanks to reduced intervention costs.

The technology has also led to higher production regularity in a number of installations. ConocoPhillips has documented that WellMaster has led to cost reductions in the order of 120 million dollars on the Heidrun TLP.

Multiphase technology

The development of technology for multiphase oil/water/gas flow measurements based on electrical impedance was launched early in the 1980s at Christian Michelsen Research (CMR) in Bergen. The technology provides production engineers with important information about the quantity and distribution of oil, water and gas in a multiphase flow. This provides unique opportunities for optimising production and improving the exploitation of production capacity.

The technology that was developed, while few in the oil companies saw the advantage of multiphase flow measurement, was commercialised by CMR through the establishment of Fluenta AS in 1986. In 2001, Fluenta was acquired by Roxar ASA and has become an important part of Roxar Flow Measurement AS (RFM) in which multiphase flow measurement technology is one of the company's most important products.

Multiphase flow measurement is in great demand all over the world. RFM has sold a total of more than 500 metres, and three out of four are sold beyond the North Sea. They are supplied to all parts of the world where oil and gas are produced. RFM sold 60 units in 2003, and while the number will exceed this level in 2004, RFM sees a potential for several hundred units per year. In 2005, they will launch better and less expensive versions.

Current multiphase flow meters are approximately 1 m long and are sold at a price of between 150,000 and 200,000 dollars. The multiphase flow meters currently under development are smaller and less expensive. The goal is to have one meter per well. Today, the normal situation is to have one meter per manifold which serves between five and ten wells.

The market for installation of multiphase flow meters at each individual well will thus be much greater. The market is growing rapidly as there is a huge demand for high-tech and reliable well-monitoring tools. This is particularly true for subsea wells, for which it is extremely difficult and expensive to obtain up-to-date reliable information about the well, except by using multiphase flow measurement technology. Multiphase flow meters are used in wells at depths of up to 3000 m, for which a focus on reliability and well-designed functional solutions is extremely important.

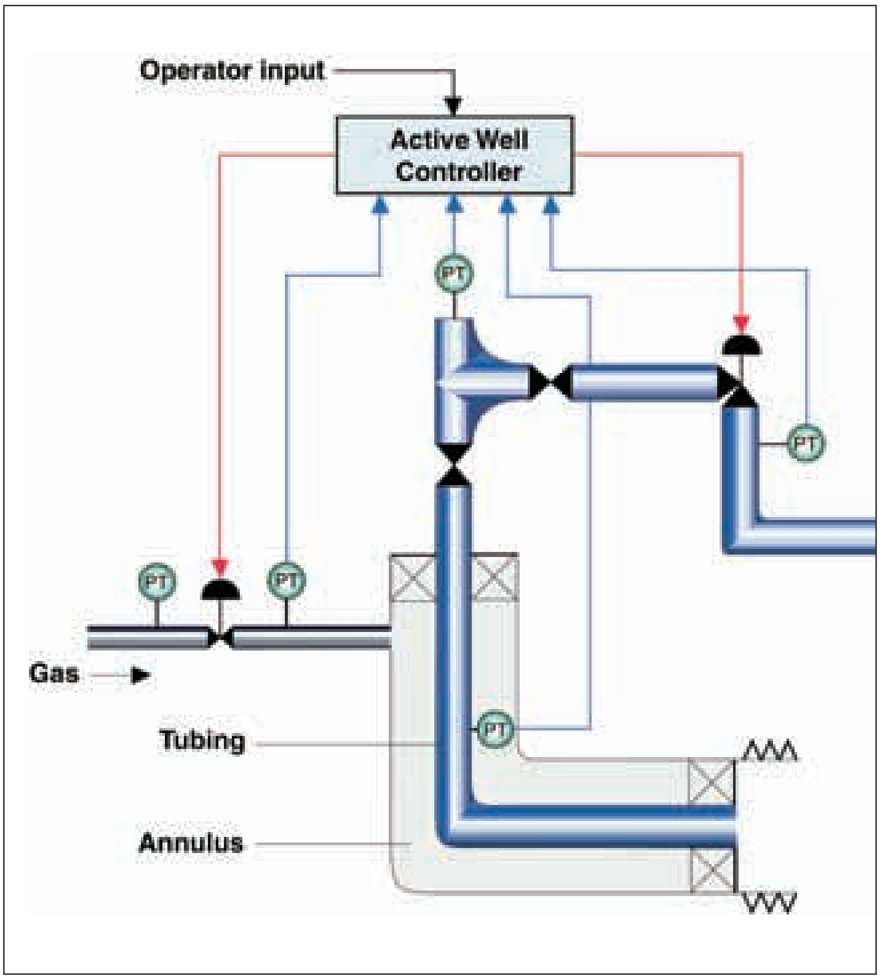
Sand meter SAM 400 installed on a production pipeline.

Field installation of a multiphase flow meter.

Slug control

ABB slug control technology has not only contributed to increased oil production. Wherever it has been implemented, in Norway and elsewhere in the world, it has limited slugging while also reducing flare burning and reducing oil spills to the sea.

For many years, ABB has developed and carried out research on advanced control and optimization systems for the upstream oil and gas industry. Many years of research work in fluid mechanics and cybernetics at the ABB Research Centre at Billingstad in Oslo has resulted in two solutions: Active Well Control and Active Flowline Control, which stabilize slugging wells and pipelines respectively. Both solutions are categorized under the common concept of Slug Control Solutions. Slugging wells and pipelines are those that produce irregularly, almost like waves that break on a beach. Waves that are too big put great stress on the process system on the platforms, while small waves do not fully exploit the potential of the process system. It is much more economical to produce at a constant rate, while the reservoir will not be subjected to great pressure fluctuations. Both slug control solutions use available pressure and temperature from the well and the pipeline as inputs to the model, which is used to calculate the choke aperture which will prevent the well or pipeline from slugging. The choke aperture is regulated continuously so that the pressure in the well is kept relatively constant, without fluctuations. When the pressure in the well or the pipeline fluctuates, it will be appear that large fluid slugs are entering the process system, just as in the wave analogy above. A tremendous slug may force the operator to choke the well, i.e. to close the valve and thus produce less. A slug control solution may help to reduce pressure fluctuations, as shown in the illustration. Both slug control solutions have been implemented by several major international oil companies, also here in the North Sea. They have proven to be very efficient in reducing slugging while helping to reduce flare burning and oil spills into the sea and to improve exploitation of the processing system. Another important effect is increased oil production.



Active Well Control. Blue arrows: Input to the model. Red arrows: Output to the well.

VIEC has increased the production of Troll C

Vetco Aibel AS has developed VIEC, a technology that has increased the production on Troll C and which is now marketed to international companies. The project demonstrates that technology development in Norway is valuable both for the supply industry and for the operators.

Vetco Aibel AS, previously ABB Offshore Systems AS, is a keystone company that supplies technology to the international oil and gas industry. Technology development is the central element in both the national and the international efforts of the company. VIEC is an innovation which has been a great success for the company.

Since 2001, Vetco Aibel has been working on the development of an electrostatic coalescer that was designed to be mounted directly in the separator tank. The coalescer was called VIEC (Vessel Internal Electrostatic Coalescer). The idea behind this equipment was to move the use of electrostatic forces right into the high-pressure separator in order to increase production capacity, reduce separation time, degrade layers of emulsion and reduce the use of chemicals and water in the oil at the separation stage.

Troll C

Norsk Hydro became interested in the technology on the background of emulsion problems on the Troll C installation and in collaboration with the DEMO 2000 programme, a project started in January 2003 aimed at completing the development work and installing VIEC on Troll C in the summer of 2003.

In July 2003, VIEC was installed on Troll C and right away there was a marked improvement in the separation process. It has been in operation ever since and the experience has confirmed that Troll C has had a 5 – 10 % increase in petroleum production, a marked reduction of emulsion-prevention chemicals (80%) which has resulted in reduced operating costs in the neighbourhood of 800 thousand dollars a year. Thus the cost of a VIEC in the Troll C case has been saved on the basis of reduced chemical consumption alone.

Chinese waters

These tests have given Vetco Aibel a product of great international interest. The next VIEC was sold to Bluewater FPSO Munin for use in Chinese waters. Munin started working in October 2004. This shows that technology development in Norway makes for a win-win situation for both the supply industry and the operators, an essential condition if the supply industry is to be able to maintain its international position.

The Troll C platform.
Photo: Terje S. Knudsen, Norsk Hydro.

pH stabilization for corrosion control

IFE has developed a method for corrosion control which has saved the oil companies hundreds of millions in rebuilding costs. The method was developed during the 1990s and involves pH stabilization by means of sodium hydroxide, making it both inexpensive and environmentally friendly.

Corrosion control in wet gas pipelines by means of pH stabilization has been employed both on Åsgard and Huldra. The method has also been introduced in older fields such as Heimdal and there are plans to use it on Snøhvit and Ormen Lange. IFE is collaborating closely with Statoil and Norsk Hydro on optimizing the method for these two major new developments in the Norwegian Sea and the Barents Sea.

IFE is now qualifying pH stabilization for corrosion control for a number of gas fields around the world, in Europe, the Middle East and Australia. The method is an economically attractive alternative for gas fields which in some cases would be impossible to develop safely, and in other cases difficult to develop profitably using other methods of corrosion control.

The problem of internal corrosion

As an integral part of the production of oil and gas, water and carbon dioxide (CO_2) accompany the well-flow. In oil and gas pipelines with a high CO_2 content, internal corrosion attacks with corrosion rate up to 10 mm/year may occur and there are cases of this having caused leaks in pipelines.

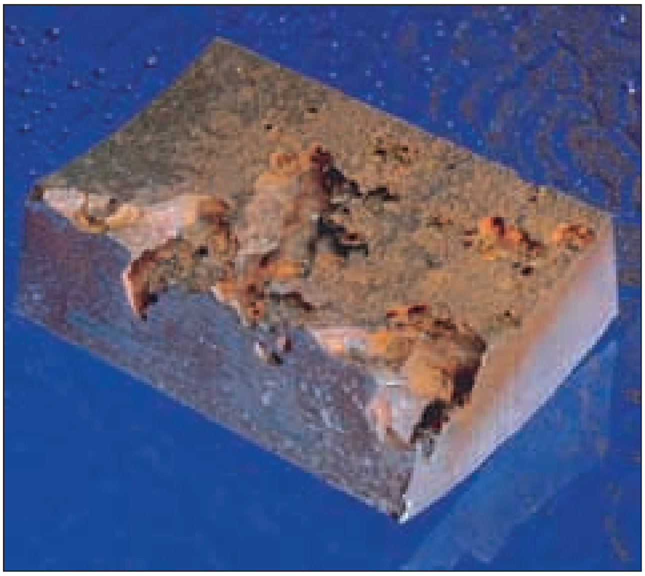
Snøhvit is a gas field with a particularly high CO_2 content and in the assessment of the field in the early 1990s, it was regarded as impossible to transport the gas ashore without separation. At that time, there were no available methods capable of limiting the high corrosion rate that was expected.

Before the development of the Lille-Frigg field, Elf decided to try out a new method to limit corrosion in wet gas pipelines. Adding a base would reduce the acidity of the well flow and corrosion would be reduced through the formation of a protective corrosion product film. Elf decided to study and verify the new method in IFE's laboratories in close collaboration with IFE's corrosion experts. The method was first employed in the North Sea on Lille-Frigg in 1994, and it was soon demonstrated that the method was extremely efficient. The method is now known as pH stabilization.

Just after the start in 1997, the onshore facility for the Troll pipeline at Kollsnes experienced severe operating problems because corrosion products from the pipeline were precipitating in the process facility. Statoil and IFE employed pH stabilization to reduce corrosion in the pipeline and the problems were totally eliminated by adding sodium hydroxide to the pipeline, and rebuilding, that would have cost around 50 million dollars, was avoided.

When pH stabilization is used in gas pipelines, the internal corrosion can be reduced by more than 95 % by the addition of sodium hydroxide. This is an inexpensive and very environmentally friendly solution. Sodium hydroxide is an old and well-known chemical which does not cause harm to water or fish. The sodium hydroxide is regenerated continuously and only a limited refill is necessary every two or three years.

pH stabilization as a means of corrosion control in gas pipelines was developed through research at IFE over a five-year period from 1992 to 1997. At first, it was funded by Elf and later as a joint industry project funded by several international oil companies and the Research Council of Norway, with a total investment of approximately 6 million dollars. The method is now undergoing further development in order to be used in pipelines in which H_2S is present in addition to CO_2.



Corrosion attacks on flowlines from the North Sea. Without treatment the attacks may progress by 10 mm/year.

HVDC on Troll

Troll gas is equivalent to approximately 40% of total Norwegian gas production. ABB are helping make sure that the gas gets ashore. They have supplied the drive system which was the basis for choosing to use land-based hydro-electric power instead of offshore gas turbines.

Troll began to supply gas to Europe in 1996 and will supply gas until 2030. But there is enough gas to keep on producing till 2050.

Since the start of production, the pressure in the gas reservoir has fallen. There is therefore a need for pressure support to get the gas to the process facility at Kollsnes. Statoil decided to use electricity generated onshore to power the new compressors. ABB has supplied all the equipment needed, both onshore and offshore.

The alternative to electricity from land-based power stations would have been offshore gas turbines as a source of power for the compressors. However, this alternative can cause pollution. ABB's estimates show that it would have produced total emissions of 230,000 tonnes of CO_2 and 230 t NOx. With the environment in mind and the environment tax already in force, there are great environmental and economic savings in supplying the compressors at Troll with power generated onshore, provided the electricity is produced in an environmentally friendly way.

Together with Statoil, ABB developed the electric drive system which is based on HVDC (High Voltage Direct Current) LightTM and MotorformerTM technology. The technology has never before been used to supply a production facility offshore with power from land. HVDC LightTM solves the issue less expensively and better than previous techniques. The power is transferred by means of a simple coaxial cable and the transmission loss is only 3%. The power supplied is equivalent to the power consumption of some 25,000 households.

The importance of Troll as one of the big gas producers in Europe means that the cable that is supplying Troll with electricity has to be extremely reliable. Several watertight layers and two layers of armoured steel provide mechanical robustness for the loads it will meet in the North Sea. The cable is also protected by being laid under the sea bed wherever possible.

The onshore facility at Kollsnes and the Troll platform. The distance from land is 80 km.

Biological effect methods: Bio-markers


Fieldwork offshore – collecting mussels and fish

The oil industry has come a long way in identifying potential environmental effects caused by offshore activities. A zero damage objective has been established and embedded in Norwegian legislation. The use of biological effect methods known as bio-markers is an important tool for early identification of environmental damage. For many years, RF-Akvamiljø has been developing and utilising bio-markers in a series of projects in the laboratory and the field.

A substantial part of the research has consisted of developing and employing methods capable of predicting potential environmental damage in cases of discharge to the marine environment (diagnostic tools). RF-Akvamiljø has worked on the development and use of more than 20 diagnostic methods (bio-markers). Support from the Research Council of Norway and collaboration with industry has made it possible to develop methods for monitoring emissions from the oil and gas industry, acute spills (oil spills, etc.) and regular discharges from vessels and industry. Methods have been developed for monitoring environmental pollution in the coastal zone, in deep waters and in Arctic waters. Bio-markers are diagnostic tools that offer us better opportunities to evaluate the health of animals in the sea and how they are affected by environmental toxins. The determination of critical levels and the establishment of a basis for interpreting bio-markers are important goals. In a broader perspective, RF-Akvamiljø is helping to establish diagnostic methods for the ocean environment as an analogue to the methodological apparatus which has been established and is used in the control of human health. The goal as far as the oil industry is concerned is to establish a methodological apparatus which will give it an opportunity to be pro-active and to check that it makes the correct environmental decisions in order to avoid potential negative environmental effects. A few examples are offered to illustrate the areas of use of bio-markers today.

The first example is monitoring the conditions for fish and shellfish in the ocean close to offshore installations. At present, annual investigations are carried out in which fish and shellfish are set out and wild fish in the area around offshore installations are caught. Eight to ten different bio-markers are analysed, some of which are very sensitive to the presence of oil-related components. RF-Akvamiljø has made several cruises in which animals have been set out and samples collected and analysed. The majority of the bio-markers used in this connection are methods that have been used for many years and where RF-Akvamiljø has played a central role in the development and establishment of the basis for their interpretation. Another example concerns investigations of the effects which, in the course time, may reduce marine species' reproductive capacity. This is regarded as being relatively complex to investigate, mostly because it requires long-term tests. Moreover, the effects will vary according to the life stages of the organisms when they are exposed. Damage to the genetic material of marine species is an example of a measurable early effect which may also be thought to entail long-term effects. RF-Akvamiljø has established a number of measurement methods to investigate damage to the genetic material and has evaluated how well the methods work in relation to emissions from the oil industry. The final example is the development of new methods based on experience from human health diagnostic procedures. In 2001, Akvamiljø, thanks to the Research Council of Norway, established a platform based on the employment of proteomics (knowledge of proteins) aimed at investigating effects in the marine environment. Akvamiljø was the first research centre in the world to get a SELDI- TOF for such investigation (an instrument more often used in human cancer research). RF-Akvamiljø has played a key role in the development of a basis for interpreting the effects of environmental toxins in the marine environment which is now being used in connection with oil spills offshore. This will be further developed with the addition of new methods, for example based on proteomics, which may be used on a large scale in monitoring environmental toxins. The RF-Akvamiljø research involves the marine environmental scientists in RF – Rogaland Research and Akvamiljø a/s. Akvamiljø a/s is a non-profit laboratory owned by RF and several universities. The research centre represents one of the largest groups of expertise in eco-toxicology and the marine environment in Norway.

Decommissioning

AKER KVÆRNER™

Decommissioning of the Frigg platforms

Aker Kværner will shortly commence the decommissioning of platforms from the Frigg field, where production of gas ceased in October 2004. Aker Kværner was awarded the removal contract worth 500 million dollars from Total E&P Norge AS. The contract demonstrates Aker Kværner's strong position in the final phase in the service life of a field – decommissioning and dismantling, in which HSE and effective recycling are key issues.

In recent years, Aker Kværner has honed its expertise and facilities for decommissioning and dismantling offshore platforms. The task of decommissioning Frigg is an acknowledgement of the company's expertise, technology and facilities for such dismantling projects. The work of decommissioning the installations will last well into 2009. The Frigg facilities have produced gas from 1977 to 2004 and have created great value in their lifetime. All in all, there are six decks and three jackets to be decommissioned from the Frigg field with a total steel weight of 84,000 tonnes. The largest units such as modules, deck frames and steel jackets will be landed at Aker Stord's specially constructed dismantling facility at Eldøyane on the west coast of Norway. This makes up 77% of the total weight of steel. Approximately 20,000 tonn will be transported by supply vessels and barges to Aker Kvaerner's collaborating partner – the Shetland Decommissioning Company – at its Greenhead base north of Lerwick in the Shetland Isles.

The illustrations show a method that has been developed and patented by Aker Kværner for decommissioning complete steel jackets. Four large steel buoyancy tanks are attached to the jacket and provide it with the extra buoyancy needed to lift it off the seabed. Afterwards, it is towed ashore in a vertical position and then dismantled. This solution does not require divers and will be used for the removal of two steel jackets from Frigg.

HSE and recycling

Aker Kværner's top priority is that decommissioning work will be carried out in accordance with the highest safety and environmental standards. Aker Kværner's contribution to the decommissioning and dismantling of the platforms is primarily based on its expertise and experience within this specialised branch of the oil industry. Platforms may actually be recycled, and Aker Kværner proved this when the ConocoPhillips (UK)'s Maureen Alpha platform and its loading buoy were dismantled at Aker Stord in Norway. The platform had a total height of 239 m and weighed 110,700 tonnes. The recovery factor was 99.5 %.

Maureen was recycled as follows:

59.2 per cent	Quay structures
36.2 per cent	Metals/cables
2,3 per cent	Miscellaneous
1,8 per cent	Equipment
0.5 per cent	For land-filling

Aker Kværner Offshore Partner and its associated company Aker Stord have also previously decommissioned and dismantled the Odin platform from the Norwegian sector for ExxonMobil. The material recovery factor for the Odin platform was 98 per cent. Some of the equipment/ steel structures were reused, while the bulk of the material was melted down and recycled.

Cross-border project

The Frigg field stretches over both the Norwegian and the British continental shelves. Aker Kværner has enterprises on both sides of the North Sea and it can thus offer its customers a cross-border solution. In the case of Frigg, a damaged steel jacket, a platform drilling and production platform and the deck of a processing and compression platform will be decommissioned from the Norwegian sector. From the British sector, the deck of a drilling and production platform, a processing platform, an accommodation platform complete with steel jacket, the base frame of the flare tower and a platform which is positioned a few miles away from the field centre will be decomissioned. Four gravity-base structures (GBS) will be left in the field, one in the Norwegian sector and the other three in the British sector. Norwegian and British authorities have approved the decision to leave the GBSs in the field.

The Future

The Research Council of Norway

PETROMAKS
– a Large Strategic Petroleum R&D Program

The Research Council of Norway is a national strategic body and a funding agency for research activities. The Council serves as a chief source of advice and input into research policy for the Norwegian Government, the central government administration and the overall research community.

The Research Council is presently pushing for a necessary boost in the budget situation of Norwegian R&D. Improvements are to be based on close collaboration between the research sector, industry and the public sector. The Council identifies needs for research and suggests priorities, implementing national policy initiatives through targeted financial schemes.

The overall budget of the Research Council for 2005 is 750 million dollars, financing one sixth of all research carried out in Norway. The Council has established seven large scale programmes which address important social challenges and opportunities; PETROMAKS is one of these large programmes.

Badger Explorer, a rigless concept for hydrocarbon exploration, penetrates the earth and moves the cuttings behind the tool filling the hole plus forcing them into the formation. Photo: ConocoPhillips

Petroleum revenues for another 100 years

The petroleum industry has been the source of a large number of well-paid jobs and enormous revenues to the Norwegian state over the 35 years which have passed since the Ocean Viking exploration rig discovered oil at the Ekofisk field. The present goal is to develop an industry capable of making important contributions to the national economy for another hundred year's a.o through extensive R&D.

PETROMAKS is the umbrella for most of the petroleum-oriented research supported by the Research Council. This large programme covers both long-term basic research and applied research, resulting in the development of new competence as well as innovation. As far as possible, the programme will put into effect the strategy drawn up by the Norwegian industry's strategic body OG21 (Oil and Gas in the 21st Century).

PETROMAKS' Vision:

To develop the petroleum resources and increase value to the Norwegian society through knowledge and business development, and international competitiveness.

PETROMAKS' Goals are to:

Find more oil and gas, increase recovery from existing fields, reduce cost of development and production at the NCS, support business development; and improve HSE in the Norwegian petroleum sector.

Public grants, such as those made by the Research Council of Norway, have supported R&D in the petroleum sector and been an important tool in the development of the petroleum related industry. Currently this industry contributes about one third of the state's revenues, directly and indirectly employing some 240,000 people, according to the Norwegian Petroleum Directorate. Today, around one quarter of the total recoverable reserves on the Norwegian shelf has been produced, and another quarter can be produced using the existing infrastructure. To bring up a large proportion of the remaining fifty percent of the petroleum resources, investments will have to continue in research and technology development for many years to come.

Another 50 years of oil, and 100 more of gas

According to Erik Skaug, the programme manager of PETROMAKS, the overarching goal of the programme is to help ensure another 50 years of oil production and 100 more of gas production. This goal can only be attained through a well considered long-term research effort. It is important to emphasise that research and development in the petroleum sector can be very time-consuming. It is quite common with a time span of 10 – 20 years before commercial results – innovations – stemming from the present research can be observed.

A former research programme SPUNG (Strategic Programme for Natural Gas) is a good illustration of this. SPUNG started 13 years ago, and the programme looked at how to exploit Norwegian gas resources. The knowledge and innovations from this programme are being utilised today at the Snøhvit field, where liquefied natural gas is to be produced.

From American to Norwegian technology

The first phase of the petroleum activity on the Norwegian continental shelf was characterised by its use of American technology and Norwegian rigs. Development of Norwegian petroleum technology and ability to quickly build platforms and rigs during the 70s was based on the local experience and knowledge from the shipping sector, Norwegian authorities developed a strategy based on foreign companies assisting in the development of petroleum industry expertise in Norway, also the philosophy behind the technology agreements launched in 1980. These agreements were based on the idea that licence awards on the Norwegian shelf should include evaluations of research carried out in Norway by the foreign companies. The technology agreements were terminated in 1991; but by then Norwegian petroleum research centres had generated valuable knowledge which made them into "world champions" in areas like multiphase transport.

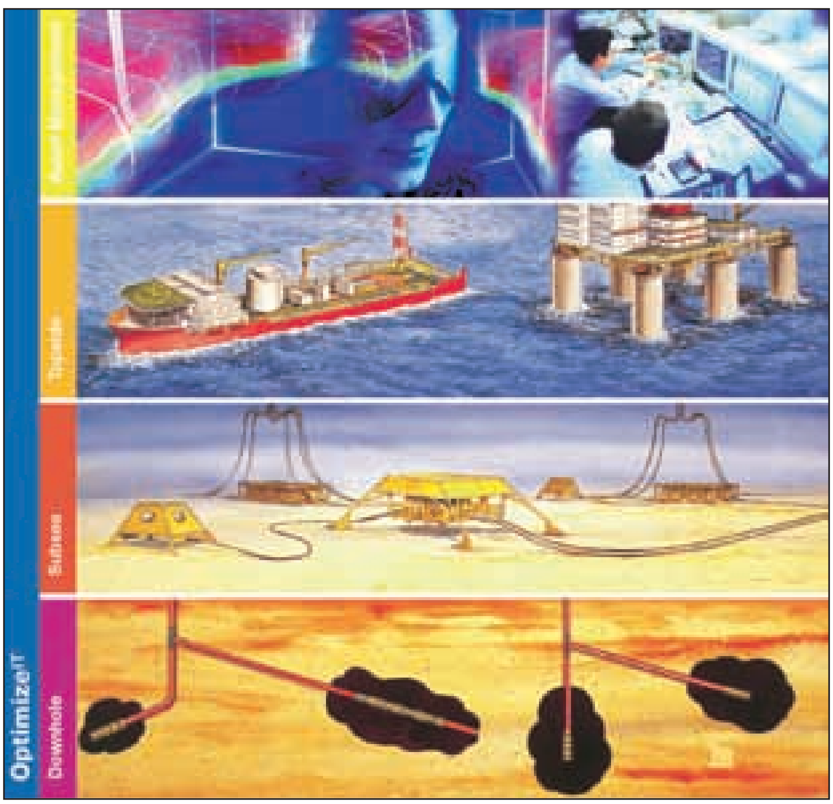
Important tasks for the future

The most important task both for the present and the future is to extract more oil and gas from the fields in production. Reduction of the cost levels on the Norwegian shelf through development of new technology is critical both for further production from mature fields and the development of marginal fields.

Further developments in the area of integrated operations, or E-fields, are very important in this context. E-fields can realise production management of platforms and transportation pipelines through remote control from other installations or from onshore operation centres. Norway is already at the forefront of subsea technology developments, and enjoys prime conditions for becoming a world champion within integrated operations.

PETROMAKS has a total budget of about 30 million dollars for 2005, aiming for further increase in 2006 and the years to come. To raise the exploitation of the resources on the continental shelf significantly for the future, a government funding of 100 million dollars annually is needed for R&D within the Norwegian Petroleum sector.

PETROMAKS is aiming for extensive international collaboration, international institutions and companies are welcome as partners in the PETROMAKS research and development projects.



ABB's Optimize Enhanced Oil Production Suite is a family of systems, solutions and services targeted at increasing oil and gas production. The family integrates rigorous multiphase flow models with state of-the-art control and optimization concepts, and it has been applied by most of the major oil and gas companies. Fundamental, long-term research and development have been prerequisites for successful deployment of the technology in the offshore industry. Photo: ABB

OG21 – Oil and gas in the 21st century

The need for an integrated national effort in petroleum research and development led to the OG21 initiative in 2001. The aim of OG21 has been to outline a strategy for the technology development that will be needed to meet the challenges facing the Norwegian oil and gas industry in the 21st century.

The Ministry of Petroleum and Energy took the initiative to establish OG21, and was joined by representatives from the oil companies, the supplier industry, research institutions, the Research Council of Norway and the Norwegian Petroleum Directorate.

As shown in the figure below, there is a great potential for value creation on the Norwegian continental shelf through technology development that will make hydrocarbon exploration more precise, and lead to better recovery rates. The development of new technology for further processing of the natural gas to increase its value is another area of concern.

It is equally important to make the Norwegian supplier industry more internationally competitive through focussed technology development towards dedicated markets.

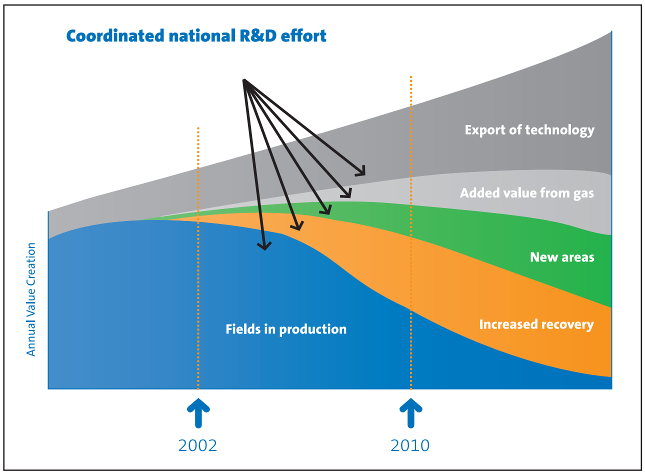
The OG21strategic document was finalised in mid-2002 and defined nine Technology Target Areas (TTAs), shown in the table below.

Within each of these areas, one oil company has been given responsibility for the establishment of a broadly based expert group that has sharpened the strategy and drawn up proposals for research activities. A number of projects have already been launched. So far, industry implementation of the OG21 strategy has been a success.

Governmental participation in implementing the OG21 strategy is of vital importance, and the Research Council of Norway plays a central role in this process. PETROMAKS supporting research and DEMO 2000 supporting demonstration, are two important programmes contributing to the implementation of the OG21 strategy.

OG21 acts as a catalyst in establishing suitable arenas for cooperation within the industry, securing governmental funding for joint projects and contributing to the ongoing information activities needed to obtain a national effort to close the existing technology gaps. To assist this work OG21 has helped to set up meeting places, workshops and conferences.

The most important issue to secure the success of the OG21 strategy is to create win-win situations among the various participants in the petroleum cluster. OG21 is doing this by identifying the multitude of goals that are shared by oil companies, the supplier industry and the public sector. OG21's strategy will be revised in 2005 in order to take the industry's most recent experiences and requirements into account. The international perspective of the Norwegian industry will be given a high priority in this effort.



Area of effort	Company responsible
Zero harmful discharge to sea	ConocoPhillips
30% reduced emissions to air	Shell
Stimulated recovery	Statoil
Cost effective drilling	ExxonMobil
Real-time reservoir management	BP
Deep water floating technology	Norsk Hydro
Long range wellstream transport	Statoil
Seabed/downhole processing	Total
Competitive gas production and offtake	Shell

The table shows which oil companies are responsible for the nine technology target areas in OG21

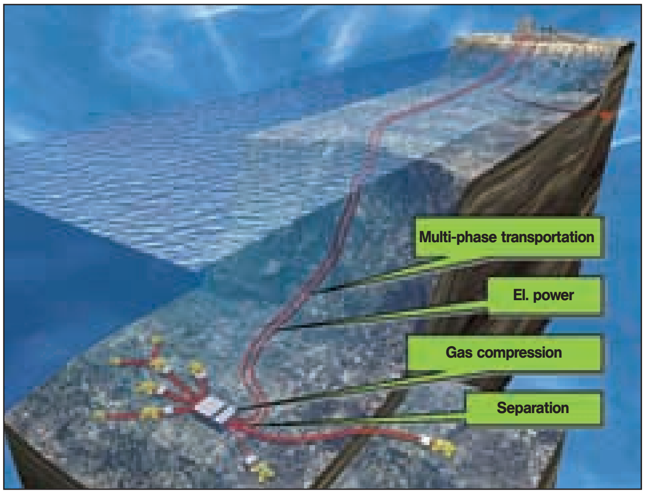
From technology to value

The DEMO 2000 programme is aimed at projects in which new technology for upstream E&P can be demonstrated by means of pilots and field trials.

The Norwegian continental shelf is to be developed further, and the efficiency of developed fields and infrastructure must be maintained at the same time as field recovery rates and exports of Norwegian products are to be increased. These challenges demand long-term investments in technology for improved competitiveness.

DEMO 2000 provides financial and operational support enabling newly developed technology to obtain 'field proven' status via technology demonstration and pilot projects, usually the most expensive and risky links in the RD&D chain that leads to commercial products. For the export industry, it is of decisive importance to have new equipment and products tested and adopted on the domestic market.

Since its start in 1999, the government funding of 45 million dollars has triggered more than three times the funding from oil companies and the supply industry, hence the programme now comprises projects worth more than 190 million dollars. The programme has a further 8 million dollars at its disposal for 2005. Project proposals totalling 1 billion dollars have been received, indicating that the petroleum sector lacks neither the ability nor the will to innovate.



New solutions for bringing gas and oil ashore: a minimum of equipment in the field means major cost savings. Everything can be located on the seabed.

The technological key areas addressed by DEMO 2000 are aligned with the national strategy OG21. Particular emphasis is being placed on subsea processing, multiphase transport, improved reservoir control, better and cheaper wells, floater and subsea solutions for deep waters, and profitable in-field use of gas.

Several projects have already been brought to the stage of successful pilot projects and full-scale field demonstrations in the course of the year. Here are a few examples of such projects:

Seabed seismic source

NGI deployed its prototype unit at the Gullfaks field to test the generation of shear waves for seismic seabed data-gathering, processing and testing using a reference dataset provided by operator Statoil.

Atlantis submerged seabed

This buoyancy unit for exploration wells extend the range of existing rigs to ultra-deep water drilling. A prototype was built and in-shore tested off Stavanger, with a full-scale trial of marine operations. Atlantis has since signed a memorandum of understanding for use on the Chinese continental shelf.

Seabed processing and boosting systems

A major part of the work in DEMO 2000 has been devoted to field testing and qualification of seabed processing and boosting. Examples are FMC Kongsberg Subsea's seabed separation system with integrated sand handling, Aker Kvaerner's Multibooster™ subsea multiphase pump being piloted by CNR at Balmoral in UK as a part of a tail-end strategy to extend field life, and Vetco Gray's NuProc subsea process including OTC Innovation Award-winning VIEC inline coalescer units successfully tested offshore at Troll C.

Subsea gas compressors

DEMO 2000 supported subsea compression projects have enabled the platform-free future compression option for the Ormen Lange Subsea to Shore gas field development. Fibre rope installation systems, light-weight composite risers and tethers, and integrated production umbilicals are other examples related to deep water.

The way forward

DEMO 2000 provides an arena for international collaboration with other offshore technology programs – IFP (France), DeepStar (US), Procap 3000 (Brasil) and ITF (UK).

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