Oil and Gas Production in Denmark 2005

DANISH ENERGY AUTHORITY

Established by law in 1976, the Danish Energy Authority is an authority under the Ministry of Transport and Energy that deals with matters relating to the production, supply and use PRIVATE of energy. On behalf of the Government, its task is to ensure that the Danish energy sector develops in a manner appropriate to society, the environment and safety.

The Danish Energy Authority prepares and administers Danish energy legislation, analyzes and evaluates developments in the energy sector, and makes forecasts and assessments of Danish oil and gas reserves.

The Danish Energy Authority works closely with local, regional and national authorities, energy distribution companies and licensees, etc. At the same time, the Danish Energy Authority maintains relations with international partners in the energy area, including the EU, IEA, as well as the Nordic Council of Ministers.

The Danish Energy Authority
44 Amaliegade
DK-1256 Copenhagen K

Telephone	+ 45 33 92 67 00
Fax	+ 45 33 11 47 43
Homepage:	www.ens.dk
Published:	June 2006
Number printed:	1,500
Frontpage:	Installation of the Dan FG platform, Mærsk Olie og Gas AS
Photos:	Photos made available by Mærsk Olie og Gas AS and ConocoPhillips
Editor:	Helle Halberg, the Danish Energy Authority
Maps and illustrations:	Jesper Jensen, the Danish Energy Authority and Schultz Grafisk/Metaform
Print:	Schultz Grafisk
Printed on:	Cover: 200 g , Content: 130 g
Layout:	Schultz Grafisk and the Danish Energy Authority
Translation:	Rita Sunesen
ISBN	87-7844-578-7
ISSN	0908-1704

NORDISK MILJØMÆRKNING
TRYKSAG
541 176

ISBN 87-7844-579-5 www

PREFACE

The energy sector was an international focus area in 2005. An average oil price of more than USD 54 per barrel, an unsettled energy market and the UN Climate Conference in Montréal contributed to putting energy on the agenda.

In 2005, Denmark launched a number of initiatives expected to maintain the past many years' positive development in the oil and gas sector. In June, the Danish Government presented "Energy Strategy 2025," which formulates the Government's overall policy for handling the long-term challenges in the energy area, including stepped-up international climate requirements and a need for greater competition.

A ramification of the Energy Strategy is the cooperation initiated in 2005 between the authorities, the oil industry and other relevant parties for the purpose of updating the strategy for research, development and education initiatives. The aim is to ensure increased long-term recovery from Danish oil and gas fields.

In spring 2005, the 6th Danish Licensing Round was opened for applications, and 14 new licences were awarded in May 2006. The keen interest shown by oil companies guarantees the continuation of exploration and underpins the expectation that Denmark will remain self-sufficient in oil and gas for several years to come. At the same time, the further development of existing fields still offers good prospects.

In 2005, the DEA began revising the legislative basis for the oil and gas area, and in December a new Act on Safety, etc. on Offshore Installations was passed to replace the previous Offshore Installations Act, dating back 25 years. The new Act will lay the groundwork for a simplified, transparent and user-friendly set of rules that cover all aspects of offshore health and safety regulation.

Copenhagen, June 2006

Ib Larsen

Director General

Drilling of the Hejre well

CONVERSION FACTORS

Reference pressure and temperature for the units mentioned:

		TEMP.	PRESSURE
Crude oil	m^3 (st)	15°C	101.325 kPa
	stb	60°F	14.73 psia[ii]
Natural gas	m^3 (st)	15°C	101.325 kPa
	Nm^3	0°C	101.325 kPa
	scf	60°F	14.73 psia

ii) The reference pressure used in Denmark and in US Federal Leases and in a few states in the USA is 14.73 psia.

In the oil industry, two different systems of units are frequently used: SI units (metric units) and the so-called oil field units, which were originally introduced in the USA. The SI units are based on international definitions, whereas the use of oil field units may vary from one country to another, being defined by tradition.

The abbreviations used for oil field units are those recommended by the SPE (Society of Petroleum Engineers).

Quantities of oil and natural gas may be indicated by volume or energy content. As gas, and, to some extent, oil are compressible, the volume of a specific amount varies according to pressure and temperature. Therefore, measurements of volume are only unambiguous if the pressure and temperature are indicated.

The composition, and thus the calorific value, of crude oil and natural gas vary from field to field and with time. Therefore, the conversion factors for t and GJ are dependent on time. The table below shows the average for 2005 based on figures from refineries. The lower calorific value is indicated.

The SI prefixes m (milli), k (kilo), M (mega), G (giga), T (tera) and P (peta) stand for 10^{-3}, 10^{3}, 10^{6}, 10^{9}, 10^{12} and 10^{15}, respectively.

A somewhat special prefix is used for oil field units: M (roman numeral 1,000). Thus, the abbreviated form of one million stock tank barrels is 1 MMstb, and the abbreviation used for one billion standard cubic feet is 1 MMMscf or 1 Bscf.

Some abbreviations:

kPa	*kilopascal. Unit of pressure. 100 kPa = 1 bar*
Nm^3	*normal cubic metre. Unit of measurement used for natural gas in the reference state 0°C and 101.325 kPa.*
m^3(st)	*standard cubic metre. Unit of measurement used for natural gas and crude oil in a reference state of 15°C and 101.325 kPa.*
Btu	*British Thermal Unit. Other thermal units are J (= Joule) and cal (calorie).*
bbl	*blue barrel. In the early days of the oil industry when oil was traded in physical barrels, different barrel sizes soon emerged. To avoid confusion, Standard Oil painted their standard-volume barrels blue.*
kg·mol	*kilogrammol; the mass of a substance whose mass in kilograms is equal to the molecular mass of the substance.*
γ	*gamma; relative density.*
in	*inch; British unit of length. 1 inch = 2.54 cm*
ft	*foot/feet; British unit of length. 1 ft = 12 in.*
t.o.e.	*tons oil equivalent; this unit is internationally defined as 1 t.o.e. = 10 Gcal.*

	FROM	TO	MULTIPLY BY
Crude oil	m^3 (st)	stb	6.293
	m^3 (st)	GJ	36.3
	m^3 (st)	t	0.86[i]
Natural gas	Nm^3	scf	37.2396
	Nm^3	GJ	0.03967
	Nm^3	t.o.e.	947.55x 10^6
	Nm^3	kg·mol	0.0446158
	m^3 (st)	scf	35.3014
	m^3 (st)	GJ	0.03761
	m^3 (st)	kg·mol	0.0422932
Units of volume	m^3	bbl	6.28981
	m^3	ft^3	35.31467
	US gallon	in^3	231*
	bbl	US gallon	42*
Energy	t.o.e.	GJ	41.868*
	GJ	Btu	947817
	cal	J	4.1868*
	FROM	**TO**	**CONVERSION**
Density	°API	kg/m^3	141364.33/(°API+131.5)
	°API	γ	141.5/(°API+131.5)

**) Exact value*
i) Average value for Danish fields

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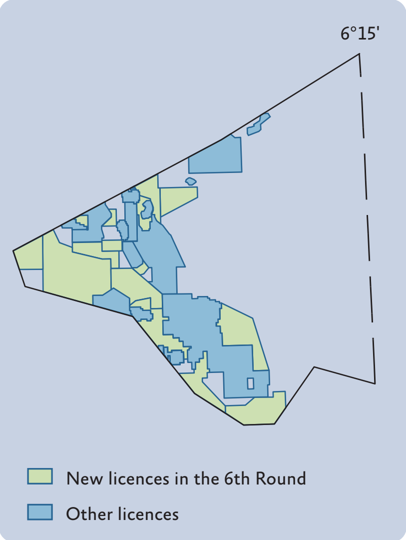
1. LICENCES AND EXPLORATION

Fig. 1.1 New licences in the 6th Round



The award of 14 new licences in the 6th Licensing Round in 2006 has created the basis for extensive exploration activity in the years to come.

In 2005, two 3D/4D seismic surveys and several 2D seismic surveys were carried out in Danish territory, and the area surveyed seismically was thus the largest in five years.

The increased seismic surveying activity signals continued interest in exploring the Danish area, both with a view to discovering new hydrocarbon accumulations and to assessing the extension of hydrocarbon accumulations into the areas surrounding existing fields.

Exploration activity is expected to intensify significantly in the next few years, when the new licensees from the 6th Licensing Round carry out their work programmes for the licensed areas.

6TH LICENSING ROUND

The last licensing round for areas in the Central Graben and adjoining areas was held in 1998, and the majority of the exploration commitments undertaken by the oil companies in 1998 had been fulfilled in 2005. Against this background, the 6th Licensing Round was opened for applications in 2005. In May, oil companies were invited to submit applications for new licences during the period ending on 1 November 2005. At the end of the application period, the DEA had received 17 applications from a total of 20 oil companies. By comparison, a total of 12 and 19 applications were submitted in the 4th and 5th Licensing Rounds, respectively.

In light of the DEA's assessment of the applications and discussions with the applicants, the DEA awarded 14 licences for oil and gas exploration and production in the 6th Round; see Figure 1.1. The location of the new licence areas and the composition of licensees appear from the map at the back of the report, together with a map of all licensed areas in Denmark.

In general, the applications in the 6th Round reflected the fact that comprehensive preliminary studies had been carried out. The work programmes offered were satisfactory, and the applications concerned a number of different exploration prospects, fairly evenly distributed over the area offered for licensing. This made it possible to adjust the areas applied for, whereby most of the applications could be met, with no or minor adjustments of the area applied for.

The combined work programmes under the licences granted in the 6th Round comprise seven firm wells and 12 contingent wells. The licensee is obligated to drill firm wells, while contingent wells are only to be drilled under specifically defined circumstances. In addition, the work programmes comprise obligations to perform seismic surveys and other investigations of varying scope and density over the area applied for. The investments required to meet the unconditional obligations of the 6th Round work programmes are estimated to total DKK 1.3 billion.

In the 6th Licensing Round, licences were also granted to oil companies not previously holding licences in Denmark. Another outcome of the 6th Licensing Round is that the companies Wintershall, Denerco, GeysirPetroleum and Scotsdale, which have not previously acted as operators in Danish territory, have been approved as operators for the new licences.

The Danish North Sea Fund has been awarded the state's 20 per cent share of the new licences. The expenditures of the Danish North Sea Fund for the unconditional work programmes are estimated to total approx. DKK 260 million.

The Danish North Sea Partner and the Danish North Sea Fund
The Danish North Sea Partner is a new state-owned entity administering the Danish North Sea Fund. On behalf of the state, the Fund will hold a share of all new licences for exploration and production of oil and natural gas in Denmark.

The Danish North Sea Fund and the Danish North Sea Partner were set up under a new Act passed in 2005. The Fund is an independent foundation that is to defray the expenditure and receive the revenue associated with the state's participation in the new licences. The Fund will be in charge of the state's 20 per cent share of all new licences in Denmark, both Open Door licences and licences granted in connection with licensing rounds. Previously, DONG A/S was in charge of state participation. From 9 July 2012, the Fund will also be responsible for the 20 per cent state participation in DUC, Dansk Undergrunds Consortium.

More information about the new state-owned entity is available at the Danish North Sea Partner's website www.nordsoeen.dk.

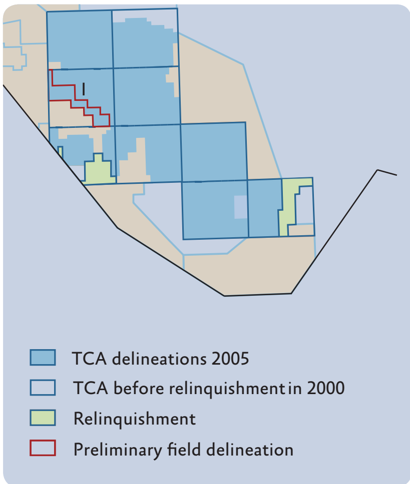
RELINQUISHMENT IN THE CONTIGUOUS AREA

The Sole Concession includes the Contiguous Area (TCA) in the southern part of the Central Graben. The Sole Concession was granted to A.P. Møller in 1962. In 1981, the Danish state and A.P. Møller entered into an agreement according to which the Concessionaires were to relinquish 25 per cent of each of the nine sixteenth blocks making up the Contiguous Area, the areas being relinquished as of 1 January 2000 and again as of 1 January 2005. However, areas that comprise producing fields and areas for which development plans have been submitted for the DEA's approval are exempt from relinquishment.

In 2000, A.P. Møller relinquished 25 per cent of four out of the nine blocks. The remaining blocks were contained entirely within the field borders drawn in connection with the relinquishment procedure. However, the borders around a number of fields were based on a maximum delineation, and the Concessionaires committed themselves to carrying out extensive surveys during the period from 2000 to 2004, in order to make a final delineation in the first half of 2004 at the latest.

On 23 September 2005, following negotiations with the Concessionaires under the Sole Concession of 8 July 1962, the DEA approved the area relinquishment in the Contiguous Area as of 1 January 2005.

Fig. 1.2 Relinquishment in the Contiguous Area



The area relinquishment as of 1 January 2005 comprised 25 per cent of two blocks. In the case of one individual area (area I), a final delineation could not be made with sufficient certainty. The Concessionaires have committed themselves to carrying out surveys in this area that will allow them to make a final delineation by 1 July 2008.

The revised extent of the Contiguous Area and the agreed field delineations appear from Figure 1.2. The new delineation and field borders are shown in Figure 2.3 in the section *Development and production*.

The Concessionaires may retain the remaining area comprised by the Sole Concession until its expiry in 2042. However, if production in a field is discontinued, the relevant field must be relinquished to the state; see the North Sea Agreement of 29 September 2003 between the Minister for Economic and Business Affairs and A.P. Møller.

Open Door procedure

In 1997, an Open Door procedure was introduced for all unlicensed areas east of 6° 15'eastern longitude, i.e. the entire Danish onshore and offshore areas with the exception of the western part of the North Sea.

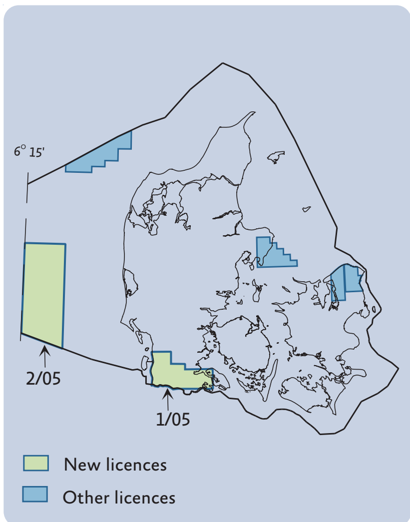
The procedure applies to areas in which no commercial oil or gas discoveries have been made so far. The conditions for granting licences in the Open Door area are therefore more lenient than in the western part of the North Sea, which is subject to a licensing round procedure. Oil companies can continually apply for licences in the Open Door area within an annual application period from 2 January through 30 September.

A map of the area and a letter inviting applications for Open Door areas are available at the DEA's website.

NEW LICENCES

On 6 October 2005, the Minister for Transport and Energy granted two new licences for exploration and production of hydrocarbons in the Open Door area; see Figure 1.3. The newly established Danish North Sea Partner will be in charge of the state's 20 per cent share of the licences.

Fig. 1.3 New Open Door licences



Licence 1/05, comprising an area in southern Jutland, was granted to Odin Energi and WeXco ApS, which is also operator of the licence.

Licence 2/05, comprising an area in the North Sea, was granted to Elko Energy Inc., which is also operator of the licence.

AMENDED LICENCES

The status of licences is continually updated on the DEA's website, www.ens.dk, which also includes a description of all amendments in the form of extended licence terms, the transfer of licence shares and relinquishments.

Extended licence terms

In 2005, the DEA granted an extension of the terms of the licences indicated in Table 1.1. The licence terms were extended on the condition that the licensees carry out additional exploration work in the relevant licence areas.

Table 1.1 Extended licence terms

Licence	Operator	Expiry
6/95	DONG E&P A/S	15-11-2007
4/98	Phillips Petroleum Int. Corp.	15-06-2008
5/98	Phillips Petroleum Int. Corp.	15-06-2008
11/98	DONG E&P A/S	15-12-2006

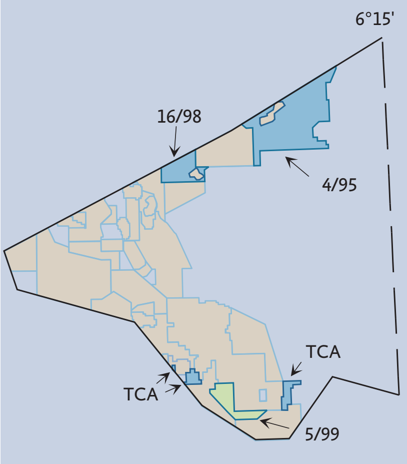
Table 1.2 Partial relinquishment

Licence	Operator	Relinquished
4/95	DONG E&P A/S	15-05-2005
16/98	DONG E&P A/S	15-06-2005

Table 1.3 Terminated licences

Licence	Operator	Terminated
5/99	Mærsk Olie og Gas AS	27-11-2005

Fig. 1.4 Relinquishment west of 6°15' eastern longitude



Conditions of licences

Licences for the exploration for and production of hydrocarbons are granted for an initial six-year term. Each licence includes a work programme specifying the exploration work that the licensee must carry out, including time limits for conducting the individual seismic surveys and drilling exploration wells.

However, some licences may stipulate that the licensee is obligated to carry out specific work, such as the drilling of an exploration well, or to relinquish the licence by a certain date during the six-year term of the licence. After the initial six-year term, the DEA may extend the term of a licence by up to two years at a time, provided that the licensee, upon completing the original work programme, is prepared to undertake additional exploration commitments.

Approved transfers

All contemplated transfers of licences and the relevant transfer conditions must be submitted to the DEA for approval.

The DEA approved the transfer of a 15 per cent share of licence 11/98 to EWE Aktiensgesellschaft in 2005. According to the transfer agreement, the shares held by Wintershall Noordzee B.V., DONG E&P A/S and Denerco Oil A/S were written down by 7 per cent, 5 per cent and 3 per cent, respectively. The transfer became effective on 1 July 2005.

Effective 1 April 2005, Kerr-McGee International ApS transferred its share of licence 1/04 to Kerr-McGee Denmark ApS.

Partial relinquishment

The main part of the area comprised by licence 16/98 was relinquished on 15 June 2005, when the previously extended exploration term expired. From that date, licence 16/98 merely comprises the area within the Cecilie Field delineation

On 15 May 2005, the extended exploration term under licence 4/95 expired, and most of the licence area was relinquished. Following this relinquishment, licence 4/95 only comprises the area within the Nini Field delineation. The licensee group drilled the wells Nolde-1 (1997) and Vivi-1 (2004) in the relinquished area.

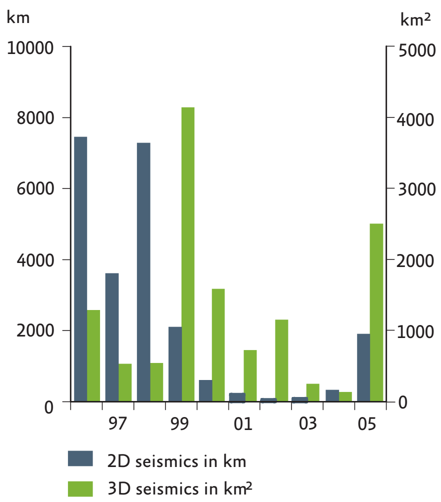
The relinquished areas are shown in Figure 1.4 and Table 1.2.

TERMINATED LICENCES

In 2005, a licence covering an area in the Central Graben was relinquished, whereas no changes were made to the licensed area comprised by the Open Door procedure. The relinquished licence 5/99 appears from Table 1.3 and Figure 1.4.

Generally, data compiled under licences granted in pursuance of the Subsoil Act is protected by a five-year confidentiality clause. However, the confidentiality period is limited to two years for areas where the licence has expired or been relinquished.

Fig. 1.5 Annual seismic surveying activities



Other oil companies thus have an opportunity to procure data for the exploration wells drilled and extensive 3D seismic surveys carried out in the relinquished areas. As a result, the companies are better able to map the subsoil and assess the potential for oil exploration in the relinquished areas.

All information about released well data, including seismic surveying data, etc. acquired in connection with exploration and production activities, is provided by the Geological Survey of Denmark and Greenland.

EXPLORATORY SURVEYS

In 2005, the scope of seismic surveys reached its highest level in more than five years. The level of activity and the areas where seismic surveys were performed appear from Figures 1.5 and 1.7.

DONG E&P A/S carried out a 2D seismic survey south of the Cecilie Field. PGS Geophysical AS was in charge of acquiring the seismic data.

In the period from July to August, 2D seismic surveys were carried out in the Norwegian-Danish Basin. DONG E&P A/S was in charge of seismic data acquisition on behalf of its co-licensees under licence 1/04. The licence area covered by the seismic survey is part of the Open Door area.

In 2005, TGS Nopec carried out a 2D seismic survey in the North Sea. The main part of the survey took place in Norwegian and UK territory, but several seismic lines were extended into Danish territory.

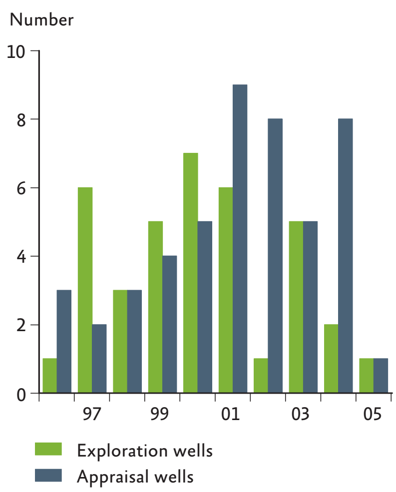
In the period from March to September, 3D and 4D seismic surveys were performed in the Contiguous Area and unlicensed areas in the southwestern part of the Danish continental shelf area. Mærsk Olie og Gas AS conducted the seismic study, with WesternGeco as the contractor in charge of seismic data acquisition.

In August, Amerada Hess ApS carried out 3D/4D seismic surveys of the area covered by licence 7/89 and surrounding areas, with WesternGeco as the seismic survey contractor.

3D/4D seismic surveys

Large areas of the Danish part of the Central Graben are covered by 3D seismic surveys. The seismic data acquired enables detailed three-dimensional mapping of the subsoil. A comparison between new and previous 3D seismic data for the same area yields a fourth dimension: time. Thus, 4D seismic data can provide insight into the changes occurring in a producing field over time. For one thing, 4D seismic data can show the direction of hydrocarbon flow towards the wells and the location of any remaining hydrocarbon pockets. This information helps optimize recovery.

Fig. 1.6 Exploration and appraisal wells



WeXco ApS carried out a surface geochemical survey under licence 1/05. The survey was conducted in southern Jutland and was completed in December 2005.

A surface geochemical survey was also performed under licence 1/03. Tethys Oil carried out the survey and took samples from the onshore part of licence 1/03.

Fig. 1.7 Seismic surveys

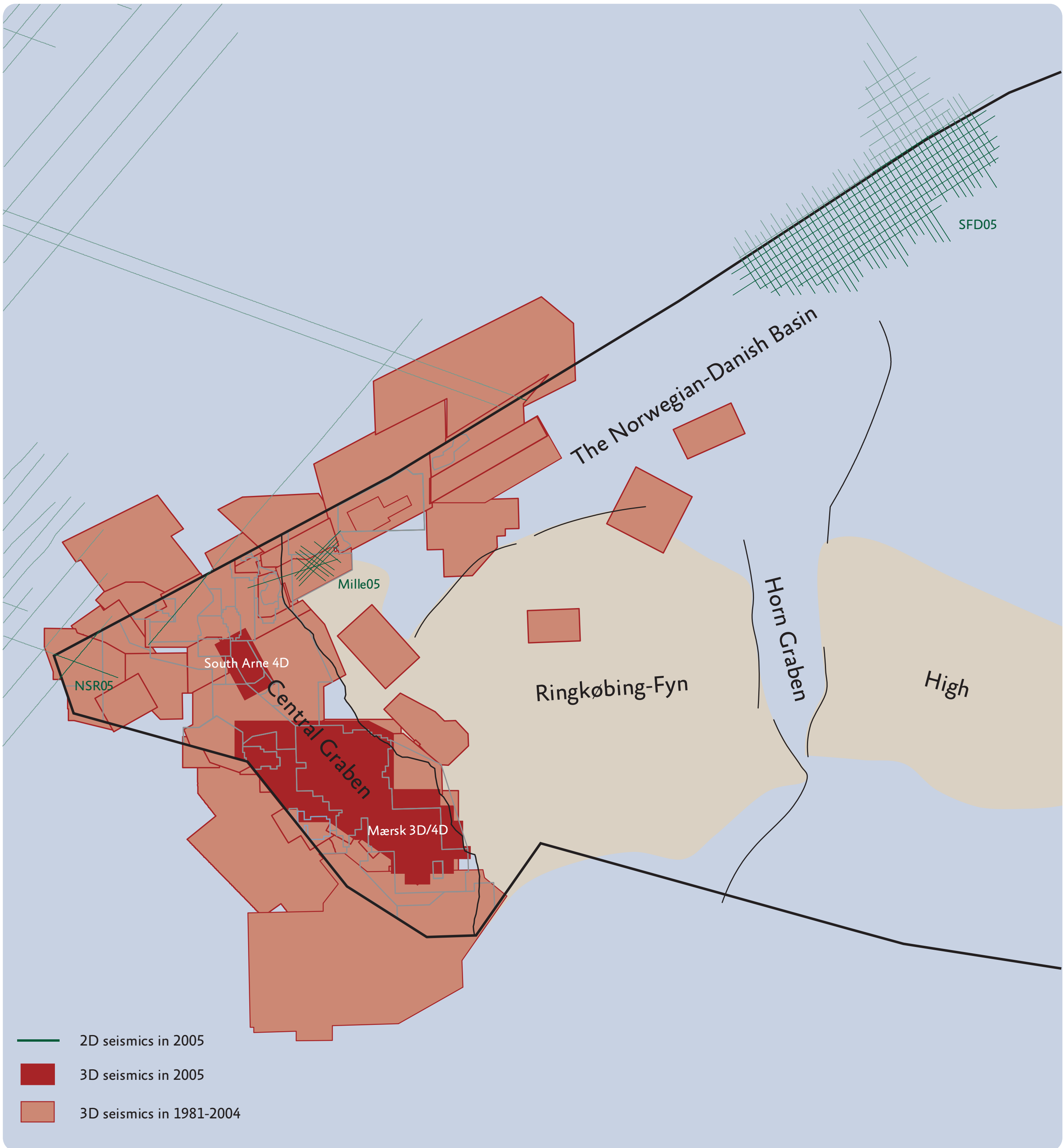
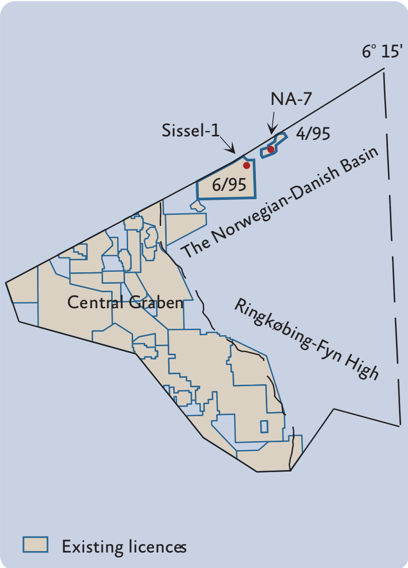


Fig. 1.8 Exploration and appraisal wells



WELLS

In 2005, one exploration well and one appraisal well were drilled. These figures include wells spudded in 2005.

The location of the wells described below appears from Figure 1.8. The appraisal wells drilled in the producing fields are also shown in the field maps in Appendix B.

An outline of all Danish exploration and appraisal wells is available at the DEA's web-site.

Exploration well

Sissel-1 (5605/13-06)

Under licence 6/95, DONG E&P A/S drilled the exploration well Sissel-1. The well was drilled about 15km northeast of the Siri wellhead platform, and the drilling operation ended in March after about ten days. Sissel-1 was drilled as a vertical well, terminating at a depth of 2,057metres in layers of Danian age. The well penetrated a sandstone reservoir of Paleogene age, but did not encounter any definite traces of hydrocarbons.

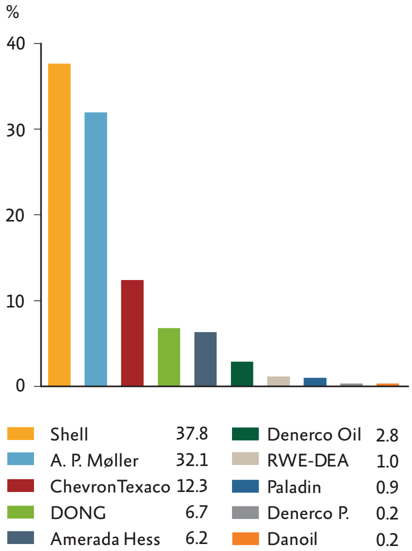
Appraisal well

NA-7 (5605/10-7)

In the period from April to May, DONG E&P A/S drilled the NA-7 appraisal well under licence 4/95. The well was drilled at the Nini Field and was to evaluate the extension of the oil accumulation at the field. The well was drilled to a depth of about 1,700metres in Paleogene sandstone. Subsequently, a horizontal sidetrack, NA-7A, was drilled for production purposes.

2. DEVELOPMENT AND PRODUCTION

Fig. 2.1 Breakdown of oil production by company



The development of Danish oil and gas fields in the North Sea continued at a moderate rate in 2005. Investments declined from DKK 4.3 billion in 2004 to DKK 3.9 billion in 2005.

During the year, additional production and injection wells were drilled in a number of existing fields. The number of wells drilled for production purposes in 2005 totalled ten, against 23 wells in 2004.

In 2005, a total of 19 fields in the Danish sector of the North Sea produced oil and gas. Mærsk Olie og Gas AS is the operator for 15 fields, DONG E&P A/S for three fields and Amerada Hess ApS for one field.

Ten companies received and sold oil from the Danish oil fields in 2005. Figure 2.1 shows the distribution between the individual companies. DUC (Shell, Mærsk Olie og Gas AS and Texaco) continued to account for more than 80 per cent of total production.

In 2005, a total of 378 wells contributed to production, 252 of which were production wells and 126 injection wells. Of the 252 production wells, 220 are oil wells and 32 are gas wells.

To increase the production rate, water and gas are injected into the reservoirs. In 2005, 103 wells injected water and 23 wells injected gas.

Oil production amounted to 21.9 billion m^3 in 2005, the same level as in the five previous years. However, the production figure for 2005 was about 3 per cent lower than the production record from 2004. Figure 2.2 shows the historical development of Danish oil production since 1972, when production started.

It appears from Figure 2.2 that annual oil production increased almost constantly until 2000, after which production began to show signs of stagnation. This seems to indicate that Danish oil production based on the existing, developed fields has reached its production plateau.

Fig. 2.2 Production of oil and gas

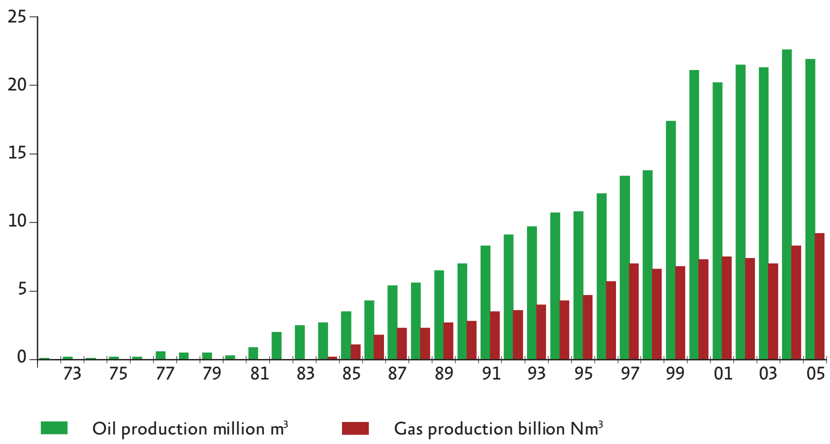
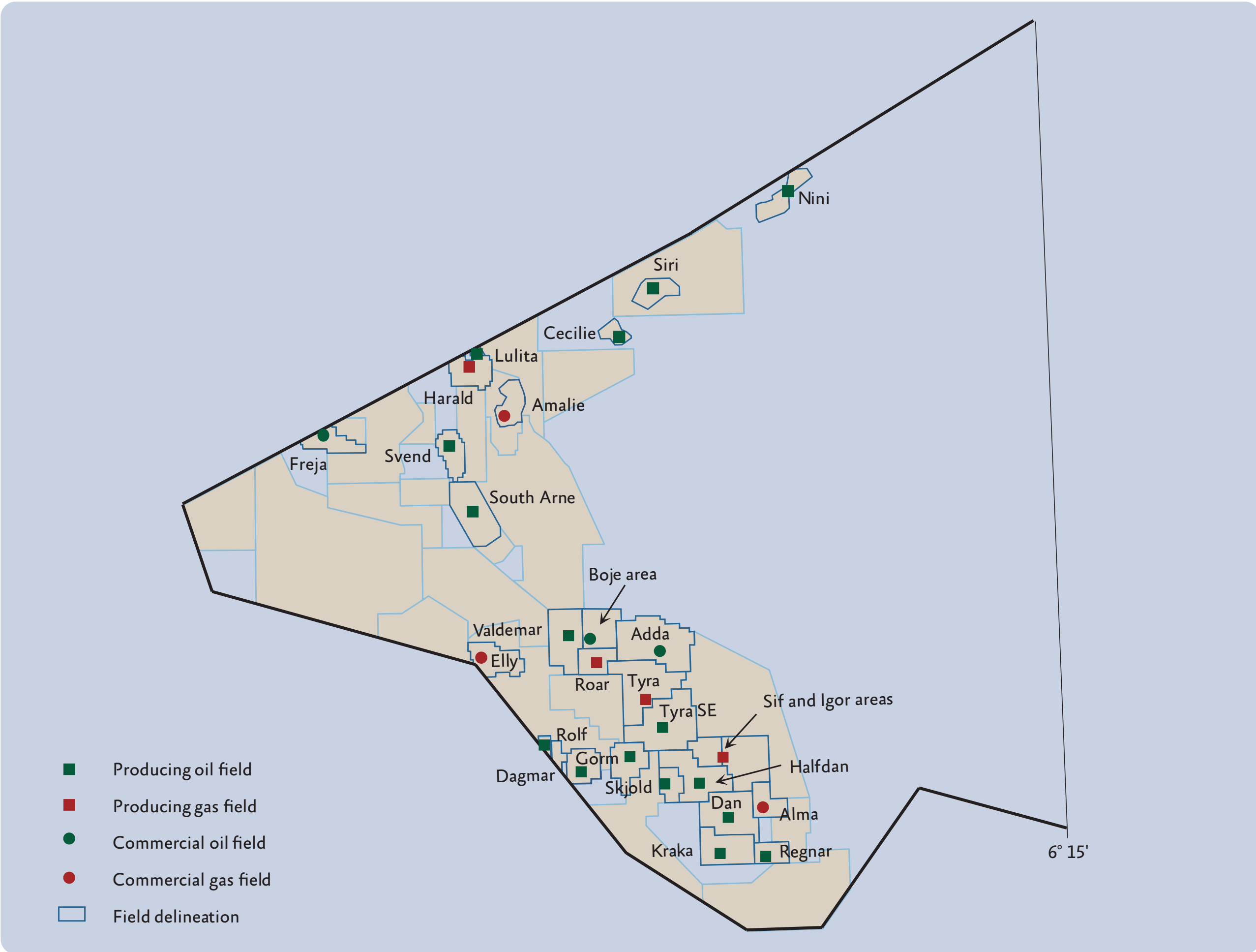


Fig. 2.3 Danish oil and gas fields



Natural gas sales reached an unprecedented 9.21billion Nm^3 in 2005, compared to the previous gas sales record from 2004, amounting to 8.26 billion Nm^3.

Figure 2.2 shows that sales gas production soared in 2004 and 2005 compared to previous years. The increase in gas production is attributable to new agreements for the export of gas through the new export pipeline, connecting Tyra West to the Dutch NOGAT pipeline via the F/3 riser platform. The pipeline was commissioned on 18 July 2004 and had thus been used for a full year in 2005.

Some of the gas produced is injected into certain fields to improve recovery or is used as fuel on the platforms. Moreover, a small volume of gas is flared for technical and safety reasons.

For the second year in a row, the amount of gas injected dropped, due in part to the large gas exports. Thus, only 1.43billion Nm^3 was injected in 2005, and the amount of gas reinjected into the Tyra Field, in particular, was reduced.

In 2005, the use of fuel associated with oil and gas production totalled 0.69 billion Nm^3. In addition, 0.18 billion Nm^3 of gas was flared for technical and safety reasons. The section *The environment* contains an outline of fuel consumption and gas flaring offshore.

Fig. 2.4 Production facilities in the North Sea 2005

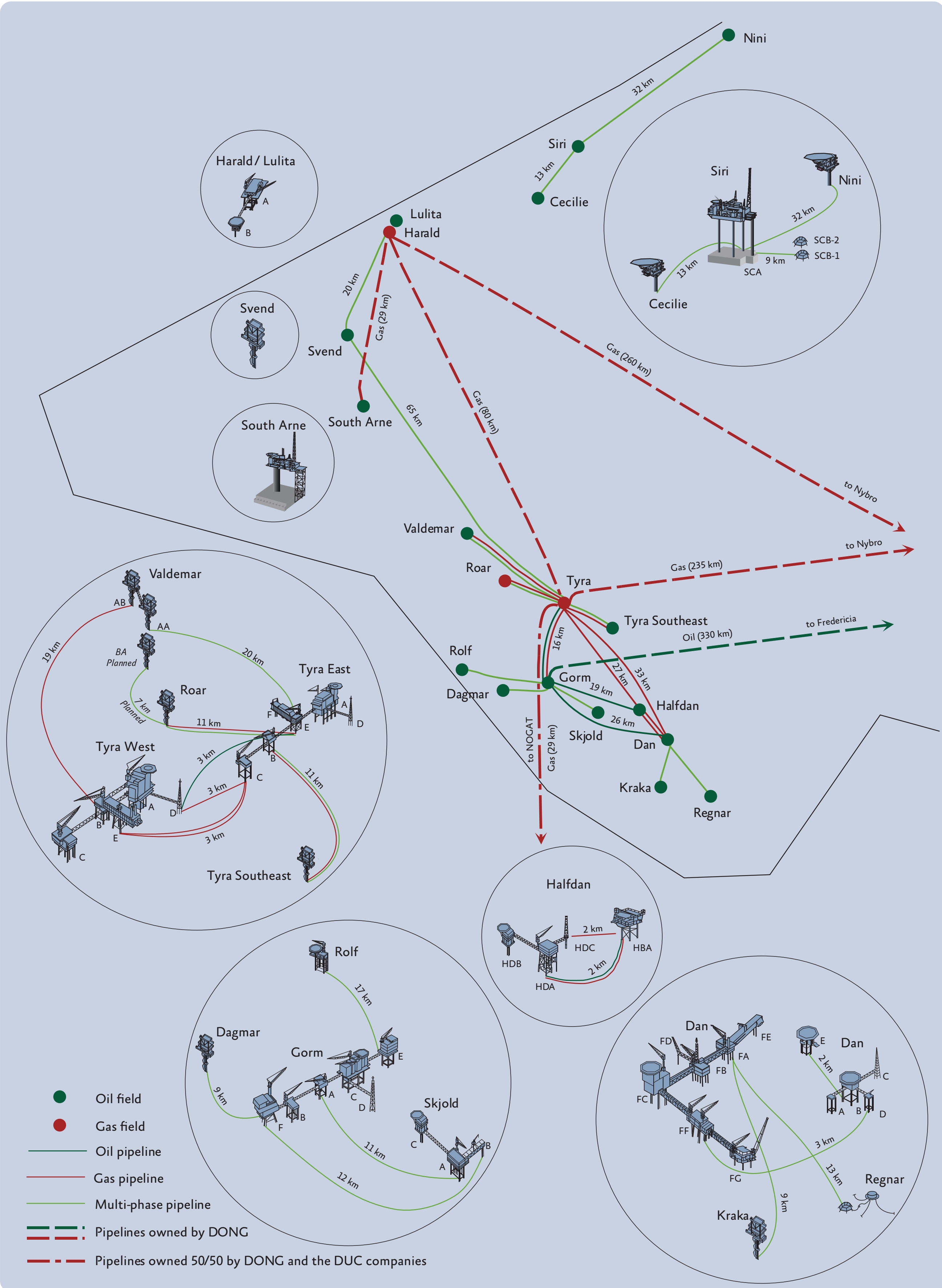
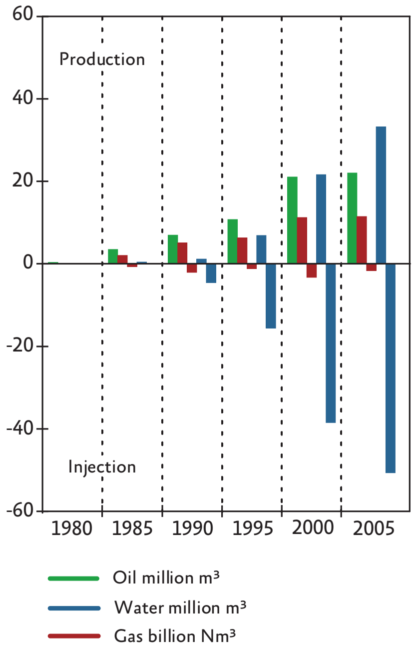


Fig. 2.5 Production and injection



Appendix A shows figures for the production of oil and gas from the individual fields. Gas production is broken down into sales gas, injection gas, fuel gas and flared gas. Moreover, figures are indicated for the production and injection of water as well as for CO_2 emissions. Annual production figures since the startup of production in 1972 are available at the DEA's website, www.ens.dk.

Figure 2.3 shows a map of the producing fields. Figure 2.4 shows existing production facilities in the Danish sector of the North Sea at the beginning of 2006.

Appendix B contains an outline of all producing fields, which includes various facts about the fields and field maps. Wells drilled in 2005 are marked with a light colour on the maps.

INCREASED PRODUCTION

Danish oil production has remained at a high level for the past five years. Maintaining this high production level will depend, among other things, on whether other production can effectively compensate for the declining production rate for existing fields. Such production could be generated by continuously optimizing and improving recovery from existing fields and by discovering and developing new hydrocarbon accumulations in the Danish area.

The use of enhanced recovery methods can improve production. In some of the Danish fields, water or gas is injected to improve recovery, as injection can help maintain pressure in a field. The water injected can also drive the oil towards the producing wells. Figure 2.5 shows how the proportion between oil production and water injection has developed in Danish fields. This figure illustrates how the use of water injection in Danish fields has increased significantly over the past ten years.

Moreover, the recovery method where long horizontal wells are arranged in a pattern of alternate production and injection wells with parallel well trajectories has vastly improved the efficiency of displacement of oil. The use of the Fracture Aligned Sweep Technology (FAST) optimizes this method. The injection wells initially inject water at low pressure, whereby the rock stress field is aligned parallel to the well. Subsequently, the water-injection pressure is increased, causing the rock to fracture along the well trajectory. This generates a continuous water front along the whole length of the well, which drives the oil in the direction of the production wells.

In the Danish sector of the North Sea, the use of horizontal wells and water injection primarily accounted for the pronounced increase in the production rate up through the 1990s. These methods have proved effective in extracting oil from the tight chalk layers containing the bulk of Danish oil reserves.

In addition, a range of other methods can be used to increase oil recovery. These methods are typically used after the field has produced for a period of time, and production has begun declining. Such methods are frequently termed Enhanced Oil Recovery methods (EOR); see Box 2.1. The geological and technical conditions in the individual field determine which methods can be used.

Box 2.1 EOR methods

EOR is an abbreviation for "Enhanced Oil Recovery", which is defined as any method/methods for increasing the amount of oil recoverable.

Recovery methods are divided into primary, secondary and tertiary methods, with tertiary methods being referred to as EOR. However, a complete and unambiguous definition of the technologies comprised by the term EOR has not been established.

Primary recovery is based on the natural drive energy usually existing in a field. Generally, this natural drive results from the excess pressure developed when the oil and/or gas accumulates in the field. There may also be an underlying aquifer (water zone) that can replace the volume produced.

Secondary recovery consists of technologies based on the injection of water or gas to maintain pressure in the field and/or flood the reservoir and thus displace the oil.

Tertiary recovery or EOR methods cover a wide range of improved recovery methods, which, in some cases, can be used after water or gas is injected. Today, a number of EOR methods are used worldwide in areas where conditions permit. In addition, extensive research and development activities are being carried on to develop new EOR methods designed to improve the recovery of oil from existing fields.

Some EOR methods utilize the knowledge of capillary and viscous forces that control formation fluids in a field. These methods are executed by adding chemicals to the injection water. Another method consists of injecting CO_2, which is miscible with oil. The CO_2 oil causes the pressure to increase and lowers the oil's viscosity, making the oil flow more easily towards the producing wells.

Other EOR methods include in-situ combustion, a thermally controlled process where oxygen is added to ignite the oil in the reservoir, thus causing the pressure to increase.

The continued exploitation of mature fields requires ongoing assessments as to whether EOR methods can improve recovery. At the same time, surveys should be made to locate the areas with as yet unproduced oil, for example at the flanks of the fields. In Denmark, increased focus has also been placed on surveying and producing from fields with complex and dynamic oil and gas accumulations. The Halfdan Field is one example.

At the same time, new discoveries continue to be developed in the Danish area, and an increasing number of these discoveries are marginal. This creates challenges in relation to using the existing infrastructure. The development of the Nini and Cecilie Fields, which are satellites to the Siri Field, are examples of marginal discoveries.

The average, expected recovery factor for Danish fields is now in the 20-25per cent range. This is a definite improvement on the expected 5 per cent, the basis used in the initial phase of Danish oil production activity.

Installation of Dan FG

Continuous efforts are being made to improve the recovery factor, and for some of the major Danish fields, the expected recovery factor is now as high as 35 per cent.

Increased oil recovery benefits society substantially. The potential for improving recovery definitely exists, but requires considerable research, development and education initiatives if the recovery from Danish oil and gas fields is to be increased in the long term. The coordinated efforts of universities, research institutions and the oil industry play a vital role, as formulated in the Government's "Energy Strategy 2025," presented in June 2005; see Box 2.2.

PRODUCING FIELDS

The development in production and major development activities in 2005 for a number of fields are outlined below.

The Dan Field

The Dan Field has carried on production since 1972. A new platform, Dan FG, housing facilities for separation, gas compression and water injection, was installed in 2005. At the beginning of 2006, the facilities on the Dan FG platform were still under commissioning.

Drilling operations continued in the field, an injection well and a production well (MFA-13B and MFA-7A) being drilled in the southern part of the western flank. In mid-2005, the operator, Mærsk Olie og Gas AS, submitted a plan for drilling additional wells to expand the existing well pattern at the western flank of the Dan Field.

At the same time, the operator applied for permission to expand the Dan FF platform by an additional well caisson. Following the expansion, the Dan FF platform will have capacity for a total of 40 wells. At the beginning of 2006, the DEA approved the plan and the number of wells required for the optimum exploitation of the western flank.

At the northeastern flank of the Dan Field, the first of six additional wells (MFA-5A) was drilled on the basis of a development plan approved for the area at the beginning of 2005. This plan provides for the drilling of supplementary wells between those already drilled. For a long period, water has been injected to increase recovery in this area, which thus contains sections flooded with water. The presence of these water-flooded sections places great demands on the plans for new wells.

Oil production from the Dan Field was stable throughout 2005, but overall production declined by about 5 per cent compared to 2004. Water production from the field follows the same trend as in previous years, with the water content of production increasing from 56 to 62 per cent.

The Gorm Field

At the beginning of 2005, the DEA approved a plan for further development of the Gorm Field. The field has carried on production since 1981, but the operator, Mærsk Olie og Gas AS has used technical studies to identify areas in the field that are not drained optimally. The approved plan provides for the drilling of four new wells, and also outlines the possibility of drilling up to five additional wells, depending on the experience from the first wells. The plan also provides for an expansion of the produced water treatment plant.

Box 2.2 Research and education strategy

To follow up on "Energy Strategy 2025," the Government has started updating its strategy for coherent research, development and education initiatives related to the oil industry. The purpose is to ensure increased long-term recovery from Danish oil and gas fields, for example by educating and training more new specialists and researchers. Their in-depth knowledge of the special conditions prevailing in the Danish part of the North Sea will help Danish society optimize its exploitation of the great values inherent in the North Sea oil and gas resources.

The strategy, being developed with assistance from internationally renowned experts in the research and education requirements of the oil industry, is based on the major perspectives offered by Danish oil and gas production in the decades to come. A situation with sustained high oil prices will result in an increasing global demand for know-how and technology in hard-to-access oil fields.

In the course of 2005, the first well was drilled (N-58A), and the second spudded. Four older wells not in operation for an extended period were suspended, and the well slots were reused for the new wells.

Production from the Gorm Field dropped by about 15per cent against 2004. The current development activity has not yet impacted the size of production.

The Halfdan Field

The development of the Halfdan Field has occurred in phases and is still ongoing. The Halfdan Field comprises the Halfdan, Sif and Igor areas and contains a large continuous hydrocarbon accumulation at different strata levels. The southwestern part of the field, Halfdan, primarily contains oil in Maastrichtian layers, while the areas towards the north and east, Sif and Igor, primarily contain gas in Danian layers.

In 2005, three gas wells (HBA-18, HBA-19 and HBA-20) were drilled from the HBA platform to the Sif area. Two of the wells were drilled with two separate well sections in the reservoir, as a means of improving drainage from the extended, but relatively thin gas zone in Danian layers; see Figure 2.6.

Of the four wells planned, two new wells were drilled (HBA-8 and HBA-21) in the oil accumulation at the Halfdan Field in 2005. In January 2006, Mærsk Olie og Gas AS applied for permission to drill four additional wells to supplement the existing well pattern.

Since production startup in 1999, oil production from the Halfdan Field has climbed continuously, and in 2005 oil production from the Halfdan Field exceeded production from the Dan Field for the first time, replacing Dan as the largest oil producer in the Danish part of the North Sea. The gas production rates from the Sif and Igor accumulations rose compared to the year production started, 2004.

In autumn 2005, the operator, Mærsk Olie og Gas AS, applied for permission to develop the northeastern part of the Halfdan Field (Igor) further. The plan provides for the establishment of a new, unmanned wellhead platform, Halfdan HCA, with capacity for ten wells, located about 7 km northeast of the existing Halfdan HBA platform.

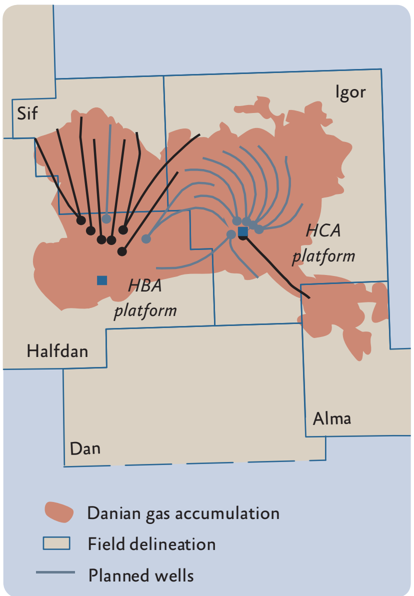
After being separated into liquids and gas at the Halfdan HCA platform, the production is to be transported through two new pipelines to the Halfdan HBA platform. The new pipelines will be hooked up to a new unmanned riser platform, Halfdan HBB, to be located on the northeastern side of the Halfdan HBA platform.

To increase the processing and transportation capacity for production from the Halfdan Field, a new 20" pipeline is planned for transporting oil and produced water between Halfdan HBB/HBA and the Dan FG platform in the Dan Field.

The plan also envisages the establishment of a new accommodation platform, Halfdan HBC, with facilities for 80 persons, to be located at a position about 150metres northeast of the existing platform, Halfdan HBA. A bridge is to interconnect the three Halfdan HBA, HBB and HBC platforms.

This development concept reflects an innovation in the Danish part of the North Sea, as it involves bridge-connecting an accommodation platform with platforms to be designed and operated according to the DEA's regulations for unmanned platforms,

Fig. 2.6 Development in the Halfdan area



which presuppose infrequent manning. Thus, the accommodation platform is primarily to accommodate personnel working on the operator's other platforms.

At the turn of the year 2005/2006, the Halfdan gas wells were hooked up to the wellhead compression facilities at Tyra West. The development plan from autumn 2005 also provides for expanding the capacity of the Tyra West wellhead compression facilities. This expanded capacity will make it possible for the wellhead compression facilities to serve all the planned gas wells in the Halfdan Field, while continuing to serve the Tyra oil wells and the wells in the Harald, Roar, Tyra Southeast and Valdemar Fields.

The plan submitted will involve the drilling of seven new wells, primarily to produce gas from the Igor part of the Halfdan Field. A spiral-shaped well pattern is planned to extend the length of the well sections in the reservoir and ensure equal spacing between them; see Figure 2.6. The total investments associated with the development of the gas accumulation in the Igor part of the Halfdan Field are estimated at DKK 3.7 billion in 2005 prices.

The Harald and Lulita Fields
A plant for processing water production was commissioned in September 2005 at the Harald platform, from which the Lulita Field is also produced.

As production from the Lulita Field was previously limited by the processing capacity available, the new plant made it possible to raise oil production from the field from about 300 barrels per day to about 1,300 barrels per day.

The increased oil production boosted the gas-oil ratio (GOR) by about 50 per cent and the water content of production from 46 to about 55 per cent.

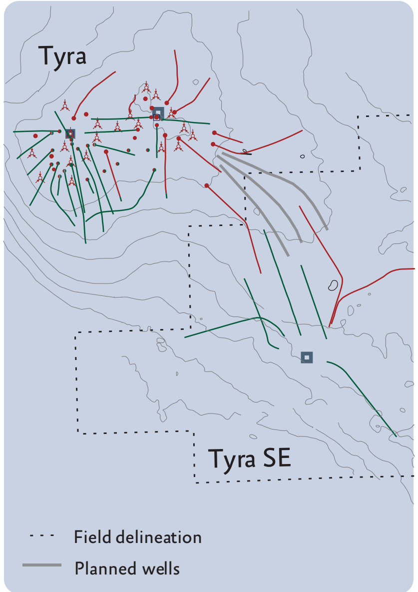
The Nini Field
The Nini Field was discovered in 2000, and production from the field commenced from an unmanned satellite platform to the Siri Field in 2003. DONG E&P A/S is the operator.

The Nini Field is a sandstone field situated in the Siri Fairway. The Nini Field has proved to consist of a number of apparently separate sandbodies. On the basis of information from the wells drilled, an oil production potential has been identified in the Ty formation immediately above the chalk. A development plan for this part of the Nini Field was approved at the beginning of 2006.

Oil production from the Nini Field in 2005 was substantially lower than anticipated, due mainly to rapidly increasing water production and the lack of pressure support. The operator has planned a number of initiatives to improve conditions, and a well was converted to a water injector at the beginning of 2006.

The Tyra Field
A development plan approved in 1999 provided for the drilling of a number of gas wells targeting the Danian reservoir. The wells were to be drilled successively, as and when required, and the number and location were to be currently optimized on the basis of experience from the field.

Fig. 2.7 Tyra and Tyra SE Fields



Plans for the drilling of four additional wells in the area between Tyra and Tyra Southeast matured in 2005, and one of these wells, TEB-24, was drilled. Figure 2.7 shows the drilled well and the three planned wells.

The Tyra oil wells, the wells at Harald, Roar, Tyra Southeast, Valdemar and the gas wells at Halfdan (Sif and Igor) are hooked up to the wellhead compression facilities at Tyra West. This enables production to take place at the lowest possible wellhead pressure. The wells in the Halfdan Field were hooked up to the facilities as recently as the beginning of 2006.

The application for expanding gas production from the Halfdan Field (Igor) increases the required capacity of the wellhead compression facilities in the Tyra Field. Therefore, plans have been made to convert one compressor at Tyra West, with wellhead compression facilities replacing the gas-injection compressor.

In connection with the further development of the Valdemar Field, tie-in works are ongoing at Tyra East and West. At Tyra East, the capacity of the produced-water treatment plant will be expanded.

The Valdemar Field

In the northern part of the Valdemar Field, called the North Jens area, a new unmanned platform, Valdemar AB, with capacity for ten wells, was installed in 2005.The platform is bridge-connected to the existing unmanned platform, Valdemar AA. A new gas pipeline to Tyra West and the high-voltage cable between Tyra West and Valdemar AB were also laid in 2005.

The first of eight wells to be drilled to the Lower Cretaceous reservoir was spudded at the end of 2005. Production has been carried on from this area since 1993.

In 2005, approval was granted to establish a new unmanned platform of the A type, Valdemar BA, with capacity for ten wells, in the southern part of the Valdemar Field, called the Bo area. Production from Valdemar BA will be transported to the Roar Field in a new 16"multiphase pipeline. The pipeline from Valdemar BA will be hooked up to the gas pipeline between Roar and Tyra East on the seabed at the Roar Field.

Initially, six production wells are to be drilled. Drilling operations are expected to start at the end of 2006, and production from the area is scheduled to commence in 2007.

New EIA for Mærsk Olie og Gas AS' activities

In 2005, Mærsk Olie og Gas AS prepared a new EIA (Environmental Impact Assessment) covering DUC's area of activity in the North Sea; see the section on *The environment.*

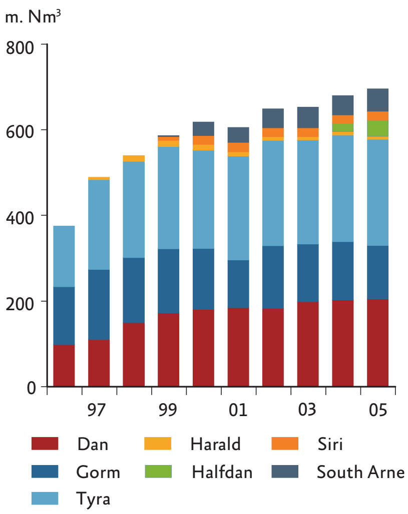
FUTURE FIELDS

A number of minor fields, viz. Adda, Alma, Amalie, the Boje area of the Valdemar Field, Elly and Freja, are expected to undergo development in the coming years.

Details about the fields, including planned commissioning dates, are available from the DEA's website at www. ens.dk.

3. THE ENVIRONMENT

Fig. 3.1 Fuel consumption



The production of oil and gas from Danish offshore installations results in emissions to the atmosphere, including the gases CO_2 and NO_x, as well as discharges into the sea consisting of chemicals and oil residue.

EMISSIONS TO THE ATMOSPHERE

The combustion of oil and natural gas produces CO_2 and NO_x emissions to the atmosphere. Producing and transporting oil and gas require substantial amounts of energy. Furthermore, a considerable volume of gas cannot be utilized for safety reasons or due to the technical design of the plant and has to be flared.

The Danish Subsoil Act regulates the volumes flared and consumed as fuel. The Act on CO_2 Allowances regulates CO_2 emissions.

Gas used as fuel and gas flaring

The volume emitted by the individual installation or field depends on the scale of production as well as plant-related and natural conditions.

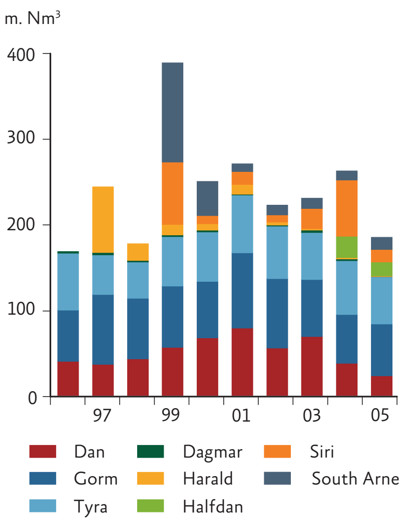
Figures 3.1 and 3.2 show the amounts of gas used as fuel in the processing facilities and the gas flared in the past ten years. Fuel gas accounts for approx. three-fourths of the total volume of gas used and flared offshore.

It appears from Figure 3.1that the use of gas as fuel has increased considerably on the Danish production facilities during the past decade. This is attributable to rising oil and gas production and the general ageing of the fields. The water content of production from the wells increases as the field ages. This requires increased water injection to maintain pressure as well as the use of lift gas, which is injected into the wells to improve productivity.

The use of fuel gas is expected to continue climbing due to the increased capacity requirements for water injection and gas compresssion.

As appears from Figure 3.2, gas flaring varies from year to year, due in part to the tie-in of new fields and the commissioning of new facilities. In 2005, gas flaring totalled 185 million Nm^3, a substantial decrease compared to preceding years and the lowest volume since 1998.

Fig. 3.2 Gas flaring



From 2004 to 2005, the total volume of fuel gas and gas flared dropped by about 77 million Nm^3, equal to a 29 per cent decrease.

The decrease from 2004 to 2005 is mainly due to less gas flaring on the Siri platform, where the volume of gas flared dropped from 65 million Nm^3 in 2004 to 15 million Nm^3 in 2005. The high level of gas flaring in 2003 and 2004 on the Siri platform was attributable to a delay in an expansion of the processing facilities in connection with the tie-in of the Nini and Cecilie Fields. The volume of gas flared on the Siri platform in 2005 corresponds to the volume flared in the years before the tie-in of the new fields.

In 2005, the use of fuel on DUC's installations increased slightly by about 7 million Nm^3 compared to 2004. Gas flaring totalled 156million Nm^3 in DUC's fields in 2005, the lowest level of gas flaring since 1995. Compared to 2004, gas flaring in 2005 was reduced by

Fig. 3.3 CO_2 emissions from production facilities in the North Sea

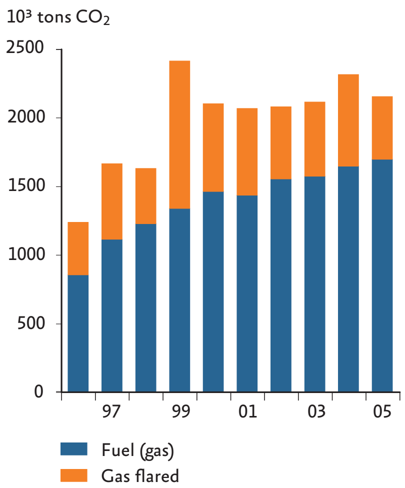
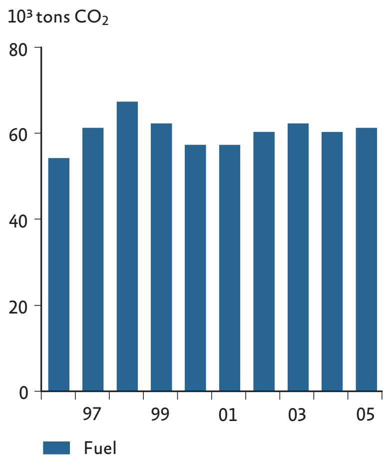


Fig. 3.4 CO_2 emissions from consumption of fuel per m. t.o.e.



30 million Nm^3, equal to a decline of about 16per cent.

On the South Arne platform, the use of fuel gas increased from 45 million Nm^3 in 2004 to 52 million Nm^3 in 2005.Gas flaring rose from 1 1million Nm^3 in 2004 to 14million Nm^3 in 2005.The figures for 2005 do not indicate any significant increase compared to previous years.

CO_2 emissions

Gas consumed as fuel and gas flaring on offshore installations produce CO_2 emissions to the atmosphere. The volume of emissions depends mainly on the energy content of the gas volume, but is unaffected by whether gas is used as fuel or flared.

The development in the emission of CO_2 from the Danish North Sea production facilities since 1996 appears from Figure 3.3.This figure shows that CO_2 emissions totalled about 2.1 million tons in 2005.The Danish offshore facilities account for about 4 per cent of total CO_2 emissions in Denmark.

Figure 3.4 shows the past ten years' development in CO_2 emissions associated with the consumption of gas as fuel, relative to the volume of hydrocarbons produced.

This figure shows that CO_2 emissions due to fuel consumption have generally increased relative to the size of production, from about 50,000 tons of CO_2 per million t.o.e. to about 60,000 tons of CO_2 per million t.o.e. over the past decade.

Among other things, the general increase is due to the rising average age of the Danish fields. Energy consumption per produced t.o.e. increases over the life of a field due to natural conditions. For one thing, the volume of water produced rises through a field's life. This results in an increasing need for water injection to maintain reservoir pressure, as well as the injection of lift gas. Both processes are energy-intensive.

It appears from Figure 3.5 that CO_2 emissions from gas flaring relative to the size of production have shown a generally declining trend since the early 1990s. This trend has been broken in several cases, including in 1997, 1999 and 2004 when the commissioning of new fields and new processing facilities involved the flaring of extraordinary volumes of gas. There was a marked drop in gas flaring from 2004 to 2005.

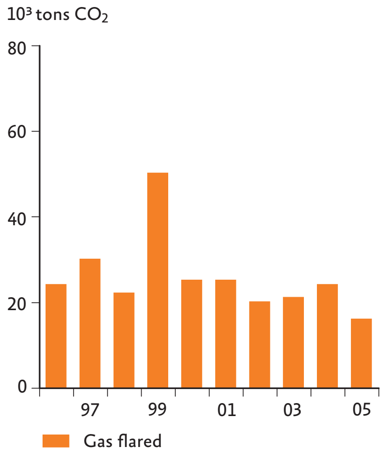
Appendix A includes a table of the volumes of gas used annually as fuel at the individual production centres, the amounts of gas flared annually and related CO_2 emissions.

The European CO_2 allowance scheme

As of 1 January 2005, the scheme covered 377 installations in Denmark, including seven in the offshore sector; see Box 3.1.

In 2005, installations were required to monitor and measure CO_2 emissions from the individual installation. A monitoring plan, which is approved for the installation when the emission permit is issued, describes the monitoring and measurement procedures.

Fig. 3.5 CO_2 emissions from gas flaring per m. t.o.e.



Each installation must calculate CO_2 emissions for 2005 and report them to the DEA and the Allowance Register by 31 March 2006. No later than 30 April 2006, each installation must surrender allowances corresponding to their CO_2 emissions in 2005.

Each installation was informed in October 2004 about how many free allowances it could expect to receive. Allowances are allocated to offshore installations, for example, on the basis of average emissions during the period from 1998 to 2002, or in an amount equal to the emission in 2002, if this figure is higher. In 2002, the offshore sector emitted 2.1 million tons of CO_2, and free allowances averaging 2.2 million tons of CO_2 per year have been allocated to the Danish offshore sector for the period 2005-2007.

Additional free allowances may be allocated for any energy production capacity installed at a later date. For example, allowances have been granted for new facilities on Dan FG. The allowances are transferable and can be traded on the European allowance market.

The Danish Act on CO_2 Allowances has laid down the criteria for allocating free allowances for the first period from 2005 to 2007. For the subsequent period from 2008 to 2012, the Government must have submitted an allocation plan to the European Commission by 30 June 2006 that describes the size of allowances and the criteria for allocating free allowances.

Further information about the CO_2 allowance scheme is available at the DEA's website, www.ens.dk.

Box 3.1 CO_2 emission allowance scheme

As from 1 January 2005, a CO_2 emission allowance scheme applies to large energy-consuming industries, including the offshore sector, as well as a major part of the energy sector. The scheme comprises all 25 EU member states, thus covering more than 10,000 installations in total.

The CO_2 allowance scheme is the cornerstone of the Danish climate strategy to meet Denmark's international obligations under the Kyoto Protocol.

As of 1 January 2005, the scheme covered 377 installations in Denmark, including seven in the offshore sector. An installation is a technical unit consisting of one or more plants situated at the same location.

Installations for producing oil and gas fall under the scheme if their combustion plants have a rated thermal input exceeding 20 MW. The permit applies to both the production of energy for recovering oil and gas and the flaring of hydrocarbons on the installations.

Box 3.2 Types of chemicals

OSPAR divides chemicals into four groups: black, red, yellow and green. The colour codes of the chemicals designate their potential hazard to the environment. The black chemicals are the most hazardous, while the green ones are at the lowest end of the scale, being only slightly hazardous or non-hazardous to the environment.

ACTION PLAN FOR MARINE ENVIRONMENT PROTECTION

In December 2005, the Minister for the Environment published an action plan for protection of the environment in relation to the oil and gas activities in the Danish part of the North Sea. The aim of the action plan is to help ensure that environmental impacts from oil and gas exploration and production are kept within the limits indicated by international and national regulations. Facts about the action plan are available at the website of the Ministry of the Environment, www.mim.dk.

Another aim of the action plan is to help ensure that the objectives and decisions adopted by OSPAR and other international bodies are implemented as soon as possible within the time limits agreed. The offshore action plan will be evaluated in spring 2007.

The action plan contains the following elements and requirements:

Chemicals

By the end of 2005 at the latest, the operators of oil and gas facilities must have discontinued the discharge of all black chemicals; see Box 3.2. Moreover, operators must continually replace chemicals with a view to discontinuing the discharge of so-called red chemicals by the end of 2008, where realistically feasible, and where the use of alternative chemicals will overall present an environmental advantage.

Marine oil discharges

As from 1 January 2006, operators are to observe a threshold value for oil in discharged production water of 30 mg per litre.

Operators must strive continuously to reduce the concentration of oil in discharged production water to the lowest level possible. The authorities and the operators are to prepare a joint report on the potential for further reinjection of produced water and other methods for reducing the discharge of oil with produced water.

Emissions to the atmosphere

Apart from having drawn up the Danish CO_2 allowance scheme, the Danish Environmental Protection Agency is preparing a report on NO_x reductions and the associated costs. The report will cover all sectors and is slated for publication in spring 2006.

The background for the report is the EU Directive on National Emissions Ceilings for Certain Atmospheric Pollutants (NEC Directive 2001/81/EC). For the offshore sector, a working group consisting of the Danish Environmental Protection Agency, the DEA and the North Sea Operators Committee – Denmark (NSOC-D) has been appointed.

Environmental management and environmental reports

In 2006, operators will introduce a certifiable system of environmental management or a similar scheme. From 2006, operators are to prepare an annual environmental report to be made public. The report is to give an account of the environmental impacts resulting from oil and gas production, including emissions to the atmosphere and marine discharges.

1) OSPAR: The Oslo-Paris Convention for the Protection of the Marine Environment of the Northeast Atlantic, including the North Sea.

Supervision and emergency procedures

In 2006, operators will introduce annual certification of offshore laboratories for water sample analyses, etc. The Danish Environmental Protection Agency's supervision of the operators' impact on the marine environment will appear from an annual supervision report, which will be published on the Danish Environmental Protection Agency's website.

NEW EIA FOR MÆRSK OLIE OG GAS AS' ACTIVITIES

In 2005, Mærsk Olie og Gas AS prepared a new Environmental Impact Assessment (EIA) covering DUC's area of activity in the North Sea. The EIA addresses development activities, including the drilling of up to 151 new wells, during the period from 2006 to 2010, in the areas west of 6° 15' in the North Sea, for which Mærsk Olie og Gas AS is the operator. The EIA was subjected to a public hearing during the period from 19 August to 17 October 2005 and will form the basis for the future approval of development plans. The EIA is available at the DEA's website, www.ens.dk.

AGREEMENT ON NATURE MONITORING PROGRAMME

In February 2005, the National Forest and Nature Agency and Mærsk Olie og Gas AS entered into an agreement regarding an offshore environmental monitoring programme for the DUC area in the North Sea. The purpose of the monitoring programme is to improve data about biological conditions in the North Sea. The programme involves the mapping of birds and marine mammals in a representative area around the fixed offshore installations, an assessment of noise impact on porpoises in connection with drilling activities, and the documentation of seabed conditions in connection with the development of facilities or the installation of pipelines.

4. HEALTH AND SAFETY

The companies exploring for and recovering oil and gas from the North Sea are responsible for ensuring that the health and safety risks associated with their activities are "as low as reasonably practicable" (ALARP).

The DEA is the authority supervising health and safety in connection with hydrocarbon exploration, production and transportation in the Danish part of the North Sea.

NEW OFFSHORE SAFETY ACT

A new Act on Safety, etc. on Offshore Installations was passed on 15 December 2005, replacing the Offshore Installations Act from 1981. The new Offshore Safety Act enters into force on 1 July 2006.

The need for a new Act became apparent in 2003-2004when existing legislation was reviewed for the purpose of simplifying legislation in accordance with the Government's action plan.

A well-established industrial sector, an extensive infrastructure and more than 20 years' experience characterize today's offshore sector. The new Act contains the framework for regulating an offshore sector where the infrastructure is expected to continue developing, but where increasing focus will also be placed on automation, efficiency improvements, maintenance, extended service life and the decommissioning of offshore installations.

As before, the Act regulates offshore health and safety issues, including the safety and stability of offshore installations and the employees' working environment and safety.

The areas regulated comprise design, construction, installation, operation, maintenance, major modifications and the decommissioning of offshore installations. The DEA's website, www.ens.dk, includes a review of the principles underlying the new legislation.

Major amendments introduced by the new Offshore Safety Act

The new Offshore Safety Act has introduced a number of amendments compared to the previous Offshore Installations Act from 1981. The most important amendments are outlined below.

The Offshore Safety Act no longer contains provisions on the protection of the marine environment, which is now regulated exclusively by the Marine Environment Protection Act, falling within the province of the Ministry of the Environment. Cooperation between the DEA and the Danish Environmental Protection Agency continues to ensure that issues relating to health, safety and protection of the marine environment are safeguarded based on an overall assessment.

Oil companies must set up a health and safety management system for the design, operation and decommissioning of offshore installations. The relevant provisions of the Act are more precise than the corresponding provisions on management systems in previous legislation. The Act stipulates that the management system must comply with international standards or similar schemes. The new requirements underscore the increased focus on the oil companies' internal control of compliance with legislation, which is a cornerstone of the new Act.

The Offshore Safety Act does not imply that oil companies must apply for new operating permits for existing offshore installations. However, existing offshore installations will be subject to the general provisions of the Act, including the provisions regarding risk assessment and risk reduction.

The new Act contains more detailed provisions regarding emergency preparedness. As before, emergency preparedness consists of procedures to contain fire and explosion, as well as rescue, evacuation and anti-terrorism procedures and a contingency plan to ensure the continued supply of oil and natural gas to Danish society in emergencies. The more detailed provisions result from amendments to the Emergency Preparedness Act and the national emergency plan, harmonizing the offshore companies' civilian emergency duties with those applying in the natural gas and power sectors.

Moreover, the existing Action Committee will carry on under a new name, the Emergency Preparedness Committee. The Action Committee and the future Emergency Preparedness Committee will assist the public authorities in coordinating rescue and containment measures in case of major accidents or oil spills from offshore installations or imminent danger of such occurrences.

According to the new legislation, manning and organizational charts will no longer constitute individual plans requiring separate approval, but will form part of the health and safety case for the individual offshore installation. Consequently, unlike the Offshore Installations Act, the new Act does not contain provisions on a manning board to hear appeals against administrative decisions in cases concerning the manning of offshore installations. Under the provisions of the Offshore Safety Act, appeals against decisions made by the Minister for Transport and Energy or by any authority to which the Minister has delegated some of his powers may be brought before the Energy Board of Appeal.

The Coordination Committee on Offshore Installations has developed into a three-party forum for public authorities and the two sides of industry along the same lines as the Working Environment Council, which is responsible for onshore issues. Therefore, the new Act has changed the name of the Coordination Committee to the Offshore Safety Council, which better reflects the Council's principal duties in relation to preparing rules. The Coordination Committee's previous areas of responsibility have not changed as a result of the new name.

FOCUS AREAS IN 2005

In 2005, the DEA's supervisory efforts were again targeted at improving health and safety conditions on offshore installations.

The DEA's inspection visits focused on the working environment, including work-related injuries and "near-miss" occurrences, one aim being to prevent work-related accidents.

Moreover, during its inspection visits, the DEA checked whether the operators were adhering to their plans for maintaining installations and equipment, particularly whether they were maintaining safety-critical equipment in accordance with their time schedules. Safety-critical equipment is equipment where a single failure would imply a serious risk of an accident, and is used in systems for fire and gas detection, for the shutdown and depressurization of processing plants and for fire-fighting and evacuation, as well as general safety equipment.

The DEA has reviewed all gas leakages registered in 2004 and 2005 when offshore installations were inspected. The aim of the review is for operators to focus on the reasons for gas leakages and thus to prevent them in future.

In addition, supervision in 2005 focused on well control and drilling-related safety equipment on drilling rigs; see Box 4.1.

Box 4.1 Well control – safety issues

An essential element of supervising drilling-related safety issues is the so-called well control equipment. This equipment is used to prevent the uncontrolled escape of pressure or formation fluids. The well control equipment on a drilling rig includes high-pressure valves as well as the auxiliary equipment used to operate the valves and other equipment needed to control pressure and formation fluids in wells during critical situations. Well control equipment is subject to certification and maintenance procedures.

In 2004/2005, the DEA implemented a supervisory project targeted at well control equipment. The aim of the project was to check the safety status of well control equipment on all drilling rigs operating in the Danish sector.

The DEA assessed the conditions based on the certification and maintenance documentation for each individual drilling rig. Thus, in 2004-2005, the DEA carried out well control during inspection visits to the drilling rigs ENSCO 101 Mærsk Endeavour and Noble Byron Welliver.

The DEA has discussed its observations with the oil companies, which have reported back with changes to their procedures. The general conclusion is that the oil companies comply with the systems and procedures established.

The project was completed in 2005 with a report available at the DEA's website, www.ens.dk.

Offshore inspection
In 2005, the DEA carried out 29 offshore inspections, a number of inspections and audits onshore as well as visits to drilling rigs abroad. Inspection visits to fixed production installations, accommodation units and drilling rigs are made at regular intervals, and otherwise when required.

The website, www.ens.dk, includes information about the fixed offshore installations in the Danish part of the North Sea and a list of mobile offshore units operating in Danish waters in 2005.

Follow-up on user survey
In 2004, the DEA conducted a survey to determine how users experienced the DEA's supervision and communication of information. On the basis of this survey, the DEA has launched specific initiatives to improve its dialogue with users offshore.

These initiatives include distributing information about new rules and regulations when the DEA makes offshore inspection visits. The information is distributed in the form of printed copies of rules and regulations, guidelines, annual reports, etc. The operators are also encouraged to give their employees electronic access to the DEA's offshore legislation and publications. Moreover, at information meetings held during offshore inspections, the DEA briefs the personnel about new regulations and guidelines.

The DEA has also proposed that the meeting held when concluding the offshore inspection, at which inspection results are presented, could be made open to all employees on board the installation.

In addition, the DEA intends to prepare an information leaflet describing its supervision of the offshore area as well as existing rules and regulations. The leaflet will be prepared once the new Offshore Safety Act has entered into force, as the Act will result in changes to the regulatory basis as well as the method of supervision.

Noise and vibrations
Special focus areas in 2005 included noise and vibrations, both onshore and offshore.

Noise is hazardous, and its harmful effects are gaining growing recognition. Therefore, anti-noise campaigns were conducted in 2005, both in a Danish and a European context.

Offshore installations have numerous noise sources, and they are difficult to eliminate completely. As part of its supervision of offshore installations, the DEA has therefore investigated how, for example, the Workplace Assessment (WPA) deals with noise conditions.

Common European rules regulating noise at the workplace have been laid down. Limit values as well as upper and lower action values for daily noise exposure and for impulse noise have been fixed; see Box 4.2. Previously, no independent rules relating to vibrations existed, but in 2005, common European rules were introduced in this area.

Box 4.2 Noise limit values and action values

Limit values
The Executive Order indicates limit values for employee noise exposure, which may not be exceeded. A limit value has been fixed for instantaneous noise exposure (impulse noise) as well as for total noise exposure over a 12-hour working day. An assessment of whether the limit values have been exceeded must make allowance for the employee's use of hearing protection.

Action values
The Executive Order specifically requires that attempts must be made to reduce the noise level in an area if it is so high (action value) that the noise exposure may result in hearing defects or other health problems for the employees. The use of any hearing protection is not taken into account when the action values are determined.

If an upper action value is exceeded, the employer is required, among other things, to investigate the causes and plan and take measures to eliminate employee noise exposure or limit the noise exposure as much as possible. If a lower action limit is exceeded, the employer's obligations include informing employees about the risk of potential hearing defects and instructing them in the use of hearing protection.

The provisions of the Executive Orders on Noise and Vibrations correspond to the provisions laid down by the National Working Environment Authority for onshore companies.

AUDIT OF CLASSIFICATION SOCIETIES FOR THE OFFSHORE INDUSTRY

In the autumn of 2005, the DEA launched a project to assess the operators' use of classification societies.

The project was based on an audit performed by the DEA in 2003 of the operators' internal control of their activities for the purpose of assessing whether the companies complied with the rules regarding internal control. Certificates from classification societies can partially replace internal control, for which reason the DEA has conducted an audit to assess whether the certificates issued and the associated verification can ensure and document that offshore installations comply with applicable legislation and regulations. The project was completed at the beginning of 2006. The audit showed that the investigated operators' use of a classification society worked satisfactorily. Thus, the certificates issued by the classification society have served as an adequate replacement for parts of the operators' internal control, in accordance with the purpose of the relevant legislation.

WORK-RELATED ACCIDENTS

Work-related accident is a generic term for work-related accidents and work-related diseases. Work-related accidents on offshore installations must be reported to the DEA. The "near-miss" occurrences mentioned in the reporting guidelines must be reported to the DEA; see the section below on "near-miss" occurrences.

Table 4.1 Reported accidents broken down by category

Categories	Fixed	Mobile
Falling/tripping	9	6
Substances and materials	1	0
Use of work equipment	10	1
Electrical accidents	1	0
Handling goods	3	1
Crane/lifting operations	1	2
Other	2	0
Total	**27**	**10**

Table 4.2 Expected* absence due to accidents reported in 2005

Duration	Fixed	Mobile
1-3 days	0	2
4-14 days	9	2
2-5 weeks	14	5
More than 5 weeks	3	1
Undisclosed	1	0
Total	**27**	**10**

*) *From 2006, the actual absence from work will also be reported.*

Work-related accidents

Preventing work-related accidents

To prevent work-related accidents, we need to understand the root causes of accidents. In focusing on the work-related accidents reported, the DEA aims, among other things, to keep up the safety organization's efforts to identify the causes of the accidents continuously. The DEA reviews all work-related accidents reported during inspection visits to the offshore installations affected.

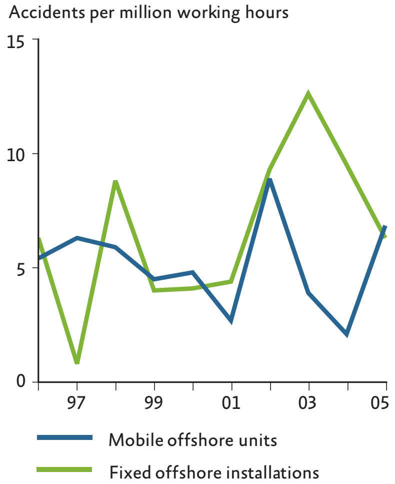
Work-related accidents reported

Work-related accidents resulting in incapacity to work for one or more days beyond the injury date must be reported. Accidents may be reported by means of a reporting form or through the electronic reporting system, EASY. Employers are obligated to report accidents, while all other parties are entitled to file reports.

In 2005, the DEA received a total of 38 reports on work-related accidents. One of the accidents reported came under the province of the Danish Veterinary and Food Administration. Thus, the calculation of accident frequency below was based on a total of 37 reports, 27 on fixed offshore installations, including accommodation units, and ten on mobile offshore units.

The accidents are broken down by category, as shown in Table 4.1. Table 4.2 indicates the expected periods of absence from work attributable to the accidents reported, broken down on fixed and mobile offshore units.

Fig. 4.1 Accident frequency on offshore installations



Accident frequency

Every year, the DEA calculates the overall accident frequency, which is defined as the number of accidents reported per million working hours.

In 2005, ten work-related accidents were reported for offshore mobile units, including drilling rigs, pipe-laying barges and crane barges, and the number of working hours totalled 1.46 million. Accordingly, the accident frequency for mobile offshore units was calculated at 6.9 accidents per million working hours in 2005.

The number of work-related accidents on fixed offshore installations and accommodation units totalled 27 in 2005.The companies operating in the Danish sector in 2005 have stated that the number of working hours totalled 4.28 million for fixed offshore installations and associated accommodation units. The accident frequency for fixed offshore installations and accommodation units was calculated at 6.3 accidents per million working hours in 2005.

The accident frequency for fixed as well as mobile offshore units has remained at the same level for the past ten years; see Figure 4.1.

The overall accident frequency for mobile units and fixed offshore installations as well as accommodation units came to 6.4 in 2005.

Accident frequency in other industries

The rules regarding the reporting of work-related accidents for offshore installations are the same as those applicable to onshore industries. Accidents occurring onshore must be reported to the National Working Environment Authority and to the DEA if occurring on an offshore installation.

Work-related accident in the derrick on Mærsk Endeavour

On 26 March 2005, a potentially serious work-related accident occurred in the derrick on the drilling rig Mærsk Endeavour.

The accident caused injury to the employee handling drill pipe during drilling operations. The relevant employee was working on a platform at a height of about 30 metres above the drilling floor.

During such work, employees wear several safety lines to provide fall protection. One of these lines got caught by very heavy equipment being lowered in the derrick. The employee was close to being pulled off the work area and was injured by the forceful pull on the safety line.

Investigations into the root causes of the accident led the DEA to demand immediate improvements to the safety conditions in the derrick on Mærsk Endeavour.

The DEA required other drilling rigs operating in the Danish area where the working conditions might present a similar risk to submit revised safety assessments and make any requisite changes.

Erroneously marked piping caused work-related accident
On 6 December 2005, an employee became unconscious as a result of an occurrence on the Dan FG platform.

Before starting on a sandblasting job, the employee put on a breathing apparatus, but fell unconscious immediately. A colleague nearby noticed and removed the employee's breathing apparatus. The employee was still breathing, but was unconscious for two to three minutes. He was transferred by helicopter to Esbjerg Hospital.

Onsite investigations showed that the nitrogen and oxygen supply piping had been interchanged. When the breathing apparatus was connected to the erroneously marked pipe, the employee inhaled nitrogen instead of oxygen.

The DEA has investigated the matter, and the accident has caused the company to change its safety management procedures.

Like the DEA in Denmark, the Petroleum Safety Authority in Norway and the Health and Safety Executive in Great Britain calculate offshore accident frequencies. However, different reporting rules mean that the accident frequencies cannot be compared directly.

The National Working Environment Authority calculates the accident frequency for onshore industries in Denmark on the basis of the number of accidents reported proportionate to the entire workforce, i.e. the number of employees.

The National Working Environment Authority uses workforce statistics indicating the number of persons who had their main job in the relevant industry in November in the year in question. The DEA uses the number of working hours reported by operators and rig owners.

Table 4.3 Accident frequencies in offshore and other industries 2004

Industry	Frequency
Offshore installations in 2004*	7.1
Offshore installations in 2005*	6.4
Total onshore industries in 2004	9.8
Shipyards	35.7
Earthwork, building and road construction	20.1
Masonry, joinery and carpentry	14.2
Insulation and installation work	15.2
Chemical industry	12.0
Heavy raw materials and semi-manufactures**	12.6

*) *Overall accident frequency for fixed offshore installations, accommodation units and mobile offshore units.*

**) *"Heavy raw materials and semi-manufactures" covers many industries, but some of the subgroups include the extraction of crude oil and natural gas and technical services related to oil and gas extraction activities.*

Table 4.3 shows the DEA's accident frequencies and figures from the National Working Environment Authority's annual calculation for 2004. This calculation is based on the assumptions that the total number of working days in onshore industries is 222 days per year and that each working day averages 7.12 working hours. On this basis, the accident frequency has been calculated at 9.8 for all 50 onshore industries.

Moreover, the DEA has calculated the accident frequency for the industries whose jobs partly resemble those in the offshore sector. The accident frequencies calculated for offshore installations and for a number of comparable onshore industries also appear from Table 4.3.

Work-related diseases

A work-related disease is defined as an illness or a disease that is due to long-term exposure to work-related factors or the conditions under which the work is performed, and which has been acknowledged as such by the National Working Environment Authority. In 2005, the DEA received two reports of suspected work-related diseases attributable to work on an offshore installation.

Box 4.3 Categories of hydrocarbon releases

Class I:
> 10 kg/sec. or more than 100 kg in total

Class II:
1-10 kg/sec. or more than 10 kg in total

Class III:
0.1-1 kg/sec. or more than 1 kg in total

One of the suspected work-related diseases was contracted in 2004 on an offshore installation, but was not reported until 2005. After long-term use of the same work equipment, an employee developed shoulder pains. The other suspected work-related disease is attributable to work involving heavy lifting and pushing on a mobile offshore unit. After several years of work with pipe handling, including heavy lifting and pushing, an employee suffered increasing pains, mainly in his shoulder.

"Near-miss" occurrences

"Near-miss" occurrences are defined as occurrences that could have directly led to an accident involving personal injury or damage to the offshore installation. The occurrences to be reported to the DEA are listed in the Guidelines on Reporting Accidents; see the section below under *New and amended rules and regulations*. The reporting guidelines will be adjusted in 2006 on the basis of experience from 2005.

In 2005, the DEA received six reports on "Near-misses" on offshore installations.

Two of the "near-miss" occurrences took place on mobile offshore units. In both instances, a part of the top drive on the rig dropped about 30 metres to the drilling floor. No-one was injured. The operators have investigated the incidents.

In connection with the third "near-miss" occurrence, a crane executed a heavy-lifting operation on a mobile offshore unit. The crane could not perform the operation correctly, and the lifting operation was stopped. The crane was inspected, and the operator investigated the incident.

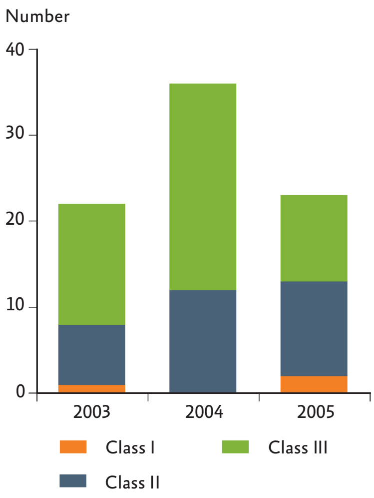
The three remaining "near-miss" occurrences concern gas leakages; see below. The operators have made investigations into all three occurrences and have submitted their reports to the DEA. Following an assessment of the reports, the DEA has found no reason to follow up the occurrences.

GAS LEAKAGES

Gas leakages, also termed accidental hydrocarbon releases, were a focus area of the DEA's supervision in 2004 and 2005. Depending on type and size, gas leakages must now be reported as "near-miss" occurrences if they fall into classes I and II; see Box 4.3. On a voluntary basis, operators reported class III releases in 2005.

The releases are reported with an indication of date, type and size of release, and are broken down into three categories; see Figure 4.2. A total of 23 releases were reported in 2005. The DEA has taken up all class I and class II releases with the operators.

Fig. 4.2 Accidental hydrocarbon releases



Gas leakage on the Siri platform

In connection with a gas leakage on the Siri platform on 10 February 2005, the DEA issued five improvement notices to the operator, DONG E&P A/S. The operator followed up on the improvement notices and also revised its internal procedures in this connection. The DEA closed its file on the five improvement notices following a satisfactory inspection visit to the Siri Field in July 2005.

STAR platform at the Roar Field

MANNING OF PLATFORMS WITHOUT HELIDECKS

At the end of the 1980s, the concept of unmanned platforms was developed to exploit marginal fields. Platforms without a helideck are classified as type A, and platforms with a helideck as type B.

The requirements for the safety systems on type A platforms are based on the assumption that they are rarely manned, and that they will only be manned in daylight hours and under weather conditions permitting safe access to the platform by boat.

Thus, when choosing a type A platform, the operator must expect that the weather conditions will not always allow personnel to access the platform by boat. For example, this may give rise to situations where operations cannot be resumed after a shutdown, with a consequent loss of production. In contrast, when choosing a type B platform with a helideck, the operator is largely independent of weather conditions when manning the platform.

Considering that the platforms would be mostly unmanned, the DEA stipulated in 2002 that the operator of an unmanned platform was to limit the number of visits by boat to type A platforms as much as possible, and that the number of visits could not exceed 30 per year, with due consideration paid to the wave height.

With certain modifications, this scheme continued to apply for the period until June 2004. However, the limits imposed on the frequency of visits implied that every visit to an unmanned platform had to be planned efficiently for the purpose of performing the tasks at hand. Another implication was that operators dispatched as many people as possible per visit and extended the visit for as long as possible, also under bad weather conditions.

In order to reduce the number of persons taking part in each visit to unmanned platforms, the DEA and the offshore industry parties represented on the Coordination Committee on Onshore Installations agreed on another scheme for dispatching personnel by boat to unmanned platforms, effective as of 1 December 2005. Based on experience during a trial period from June 2004 to November 2005, the new scheme limits the number of visits to 15per year in case of wave heights exceeding 1½metres. As part of the scheme, the number of visits, the number of persons per visit and wave height, etc. must be recorded.

The DEA will supervise compliance with the new scheme in connection with inspection visits to offshore installations.

THE EUROPEAN WORKING ENVIRONMENT WEEK IN 2005

Every year, a European Working Environment Week is held. It is arranged by the European Environment Agency and is supported by the European Commission, the European Parliament, trade unions and employers' associations. The Working Environment Week is an information campaign aimed at raising awareness of working environment issues and promoting activities to make Europe a healthier and safer place to work.

The subject of the European Working Environment Week held in 2005 was noise. According to the WHO, noise-induced hearing loss is the most common irreversible occupational hazard worldwide. In addition to causing hearing loss, noise may also be a contributory factor in accidents, work-related stress and other diseases caused in conjunction with other risk factors at the workplace.

Denmark was represented by the National Working Environment Authority, the DEA, the Danish Maritime Authority, the Civil Aviation Administration and the two sides of industry.

INTERNATIONAL COOPERATION

The DEA cooperates with the public authorities of the other North Sea countries on issues related to health and safety.

Cooperation takes place multilaterally through NSOAF (North Sea Offshore Authorities Forum) and bilaterally with individual public authorities. In addition, the DEA cooperates with the key organizations within the oil and gas industry. Additional information about international cooperation is available at the DEA's website.

The objective of cooperation in NSOAF, established in 1992, is to ensure that health and safety conditions are continuously improved in relation to offshore activities in the North Sea.

In 2005, NSOAF took the initiative to arrange a meeting about health and safety between the public authorities and the offshore industry. The meeting was held in November 2005 with a large attendance from the oil industry. At the meeting, the participants discussed a number of specially selected, important issues, including the integrity of offshore structures, lifting equipment, well control, safety training and the ageing workforce.

Moving towards a common standard for offshore training

In April 2006, NSOAF is expected to accept a proposal drafted by IADC (International Association of Drilling Contractors) concerning a common standard for the basic safety training course required for working on a drilling rig. Subsequently the BOSIET (Basic Offshore Safety and Introduction to Emergency Response Training) course offered by IADC will be valid in all North Sea countries, thus making it easier for drilling rigs and employees to work across borders.

Moreover, NSOAF has initiated international cooperation with operators, the purpose being to ensure mutual international recognition of the safety courses for employees on fixed offshore installations.

NEW AND AMENDED RULES AND REGULATIONS IN 2005

Registration and reporting of work-related injuries, etc.

The Executive Order on the Registration and Reporting of Work-Related Injuries, etc. on Offshore Installations entered into force on 1 February 2005.

Guidelines to the Executive Order have been prepared (the reporting guidelines), including a description of the "near-miss" occurrences that must be reported and a detailed description of the information to be given when work-related injuries are reported.

Substances and materials

The Executive Order on Suppliers' Obligations Relating to Substances and Materials on Offshore Installations and the Executive Order on Work Involving Substances and Materials entered into force on 17 January 2005.

The new provisions consist mainly of the implementation of an EU Directive on a threshold value for the content of chromate in cement. The onshore regulations now apply to suppliers of substances and materials for use on offshore installations. The National Working Environment Authority supervises this area. However, the DEA carries out supervision if chemicals for use on offshore installations are imported through a non-Danish supplier.

Workplace assessment (WPA) to include absence due to illness
On 1 February 2005, new regulations entered into force for offshore installations, according to which absence due to illness is to be included in the Workplace Assessment (WPA) and in the safety organization's assessment of the working environment. Corresponding regulations applicable to onshore activities entered into force on 1 January 2005.

Due process protection related to use of compulsory measures and duties of disclosure
The Act on Due Process Protection in connection with the Public Administration's Use of Compulsory Measures and Duties of Disclosure entered into force on 1 January 2005 and enacts a number of principles already established in practice.

The Act sets up specific rules applying to the public administration in connection with, e.g., inspection visits and rules on duties of disclosure.

Protection against vibration exposure
On 6 July 2005, new provisions to implement an EU Directive entered into force. These provisions fix the limit values for hand-arm and full-body vibration exposure, as well as a so-called action value. The provisions correspond to those applicable onshore.

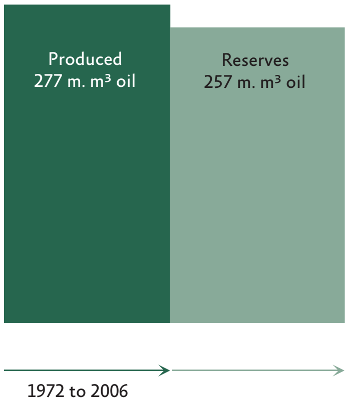
Protection against noise exposure
As a result of an EU Directive, the work of replacing the noise regulations from 1999 was initiated in 2005. The new regulations entered into force on 15 February 2006 and, like the regulations on vibrations, contain limit and action values as well as provisions regarding special conditions to be taken into account in connection with the risk assessment.

Consolidated Act on the Continental Shelf
In 2005, the Consolidated Act on the Continental Shelf from 1979 and subsequent amendments were combined in a new Consolidated Act.

Design of fixed offshore installations
In 2005, a new set of guidelines to replace the previous ones from 1992 was issued. These guidelines consist mainly of updated provisions arising from amendments to legislation and international standards. The guidelines have been prepared in cooperation with operator companies and employer organizations in the offshore industry through the Coordination Committee on Offshore Installations.

5. RESERVES

Fig. 5.1 Production and reserves



The DEA makes an assessment of Danish oil and gas reserves annually. At 1 January 2006, oil reserves were estimated at 257 million m^3 and gas reserves at 122 billion Nm^3.

The DEA's new assessment shows a decline in oil and gas reserves of 4 and 8 per cent, respectively, compared to the assessment made at 1 January 2005. The decrease in reserves is mainly attributable to production in 2005, but also to the moderate exploration activity in 2005.

The total ultimate recovery of oil expected has been written up by 11 million m^3 compared to last year's assessment. Oil production amounted to 22 million m^3 in 2005, and oil reserves have thus declined by 11 million m^3.

At 1 January 2006, 277 million m^3 of oil had been produced, with reserves amounting to 257 m^3. Accordingly, total production during the period 1972-2005 amounts to 52 per cent of the ultimate recovery expected; see Figure 5.1. This means that Danish oil production has now passed the half-way mark.

It is expected that technological developments and any new discoveries resulting from exploration activity, including from the 6th Licensing Round, will add new reserves to future assessments.

The development in oil reserves for the past decade appears from Figure 5.2, and current reserves are at the same level as the average for the period illustrated. However, the figure shows that oil reserves have declined in the past four years.

The average oil recovery factor expected for Danish fields is 24 per cent, an increase of 1 percentage point relative to last year's assessment; see Figure 5.2. The average recovery factor is the ratio of ultimate recovery to total oil-in-place. The 1 percentage point increase is due mainly to an upward adjustment of the recovery factors for the Halfdan and Tyra Southeast Fields.

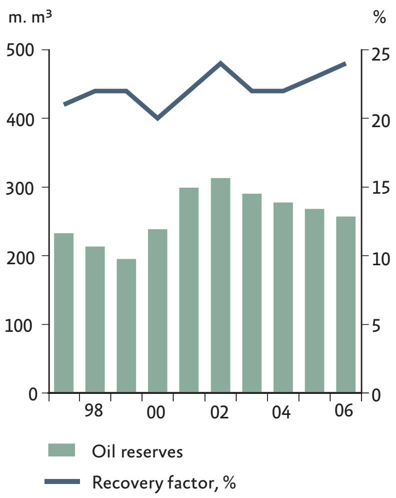
R/P RATIO AND PRODUCTION

Oil reserves can be put into perspective by calculating the ratio of reserves to the previous year's production. Such a calculation results in a so-called *R(reserves) / P(production)* ratio, which is an indicator of the calculated number of years for which oil production is estimated to be sustained at the same level.

Based on the new assessment of reserves, the R/P ratio is 12, meaning that oil production is calculated to be sustainable at the 2005 level for the next 12 years. The R/P ratio was also 12 according to the assessment made at 1 January 2005.

The R/P ratio is frequently used because it yields a comparable measure of how long reserves will last. However, this ratio cannot replace an actual forecast, especially not where large variations in the size of future production are expected; see Figure 5.5 and the accompanying text on the twenty-year production forecast.

Fig. 5.2 Oil reserves and recovery factor



RESERVES ASSESSMENT

The reserves reflect the amounts of oil and gas that can be recovered by means of known technology from structures where wells have encountered hydrocarbons, under the prevailing economic conditions.

The volume of hydrocarbons-in-place that can be recovered over the life of a field is termed the ultimate recovery. Thus, the difference between ultimate recovery and the volume produced at any given time constitutes the reserves.

The method used by the DEA in calculating the reserves and preparing the production forecasts is described in Box 5.1.

Box 5.1 Categories of reserves

The method used by the DEA in calculating the reserves makes allowance for the uncertainty involved in all the parameters used in the calculation. For each oil and gas field, the reserves assessed are expressed by three values: *low*, *expected* and *high*, reflecting the margins of uncertainty tied to the oil and gas reserves in the relevant field.

Ongoing recovery

This category includes the reserves that are recoverable with the use of existing production facilities and wells. It is assumed that ordinary maintenance and workover operations are performed to ensure the continued functioning of the existing facilities.

Approved recovery

If production has not yet been initiated under an approved development plan or any part of an approved plan, the reserves assessed to be recoverable are categorized as approved recovery.

This applies to the development of new fields as well as extensions and modifications of existing installations.

Planned recovery

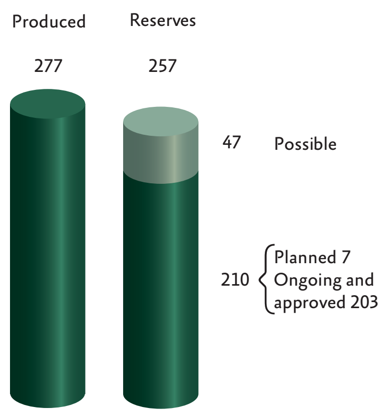
Planned recovery denotes projects described in a development plan that is being considered by the authorities. Likewise, the reserves attributable to discoveries for which a declaration of commerciality has been filed are termed planned recovery.

Possible recovery

Possible recovery denotes reserves recoverable with the use of known technology, i.e. technology which is currently used in areas where the conditions are comparable to those prevailing in the North Sea. For instance, this includes water injection on a larger scale than before or wider application of horizontal wells.

For discoveries for which a declaration of commerciality has not yet been filed, the recoverable reserves are categorized as possible recovery. This category also includes recovery from discoveries considered to be non-commercial.

Fig. 5.3 Oil recovery, m. m³



Few major producers

It is characteristic that a few fields only have produced the bulk of Danish oil, and that the oil reserves are concentrated in relatively few fields.

Dan, Gorm and Skjold are the three oldest, producing Danish fields. These fields account for 62 per cent of total oil production, and due to their development with horizontal wells and water injection, they still contain considerable reserves.

The reserves of the Dan, Gorm, Skjold, Halfdan and South Arne Fields are estimated to represent about 75 per cent of total Danish oil reserves. The remaining 25 per cent of reserves derive from more than 30 fields and discoveries.

On average, the overall recovery factor for all Danish fields and discoveries is estimated at 24 per cent. In fields like Dan, Gorm and Skjold, where the production conditions are favourable, an average recovery factor of about 38 per cent is expected, based on such recovery methods as water and gas injection. However, the assessment also includes contributions from the relatively large oil accumulations in the Tyra and Tyra Southeast Fields, where the recovery factors are fairly low due to difficult production conditions.

Table 5.1 shows the DEA's assessment of oil and gas reserves, broken down by field and category.

A low, expected and high estimate of reserves is given for each individual field, in order to illustrate the uncertainty attached to the assessment. In assessing Denmark's total reserves, it is not realistic to assume that either a high or a low figure will prove accurate for all fields. Therefore, an overall reserves assessment for many fields should be based on the expected value.

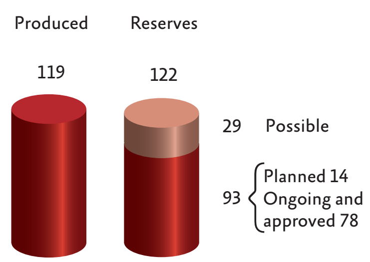
It appears from Figure 5.3 that the expected amount of oil reserves ranges from 210 to 257 million m^3. The difference between the two figures, 47 million m^3, equals the reserves in the possible recovery category. The reserves assessed for the planned and possible recovery categories, respectively, reflect the increasing uncertainty as to whether such reserves can be exploited commercially.

Likewise, Figure 5.4 illustrates that the expected amount of gas reserves ranges from 93 to 122 billion Nm^3. Gas production figures represent the net production, i.e. produced gas less reinjected gas. It should be noted that the amounts of gas stated deviate from the amounts that can be marketed as natural gas. The difference (10-15 per cent) represents the amounts used or flared on the platforms in the production process.

There have been several revisions of the DEA's reserves assessment compared to the assessment made in January 2005. These revisions are attributable to more production experience and new reservoir models of some of the fields resulting from improved knowledge of such fields.

The areas where significant revisions have been made are described below.

Fig. 5.4 Gas recovery, bn. Nm³



Note: Rounded figures

Ongoing and approved recovery

In the planned recovery category, the reserves assessment made in January 2005 included the reserves recoverable from the further development of the Dagmar Field and the development of the Bo area in the Valdemar Field.

Table 5.1 Production and reserves at 1 January 2006

	OIL, million m^3				GAS, billion Nm^3			
	Ultimate recovery				Ultimate recovery			
	Produced	Reserves			Produced	Reserves		
		Low	Exp.	High		Low	Exp.	High
Ongoing and approved								
Adda	-	0	1	1	-	0	0	0
Alma	-	0	1	1	-	1	1	2
Boje area	-	1	1	1	-	0	0	0
Cecilie	1	0	0	0	0	-	-	-
Dagmar	1	0	0	1	0	0	0	0
Dan	81	34	64	109	21	3	7	14
Elly	-	1	1	1	-	4	4	4
Gorm	53	7	15	26	7	1	1	2
Halfdan	24	32	75	137	7	5	13	22
Harald	7	1	1	1	18	3	5	7
Kraka	4	1	2	3	1	1	1	2
Lulita	1	0	0	1	0	0	0	1
Nini	2	0	1	2	0	-	-	-
Regnar	1	0	0	0	0	0	0	0
Roar	2	0	0	1	13	1	4	6
Rolf	4	0	0	1	0	0	0	0
Siri	9	1	2	5	0	-	-	-
Skjold	38	4	8	11	3	0	1	1
South Arne	15	*	15	*	4	*	6	*
Svend	6	1	1	2	1	0	0	0
Tyra	23	1	4	7	40	17	21	24
Tyra Southeast	2	1	1	2	3	3	7	11
Valdemar	3	6	9	13	1	4	7	11
Subtotal	**277**		**203**		**119**		**78**	
Planned								
Amalie	-	*	2	3	-	*	3	5
Freja	-	1	1	2	-	0	0	0
Halfdan	-	2	4	6	-	6	11	17
Subtotal			**7**				**14**	
Possible								
Prod. fields	-	10	21	34	-	7	12	21
Other fields	-	0	1	2	-	0	0	0
Discoveries	-	16	26	38	-	8	17	31
Subtotal			**47**				**29**	
Total	**277**		**257**		**119**		**122**	
January 2005	255		268		109		132	

** Not assessed*
Note: Rounded figures

The development plans for Dagmar and Valdemar were approved in August and September 2005, respectively, and the production from these field developments has therefore been included in the ongoing and approved recovery category.

Recovery from the Dan Field has been written up as a result of production experience and the fact that the western flank of the field is to be further developed according to a plan approved in March 2006. This plan is described in more detail in the section *Development and production*.

Recovery from the Skjold Field and the southern part of the Halfdan Field has been written up on the basis of positive production experience.

The South Arne reserves have been adjusted to reflect the most recent plans for further developing the field.

Table 5.2 Oil production forecast, million m^3

	2006	2007	2008	2009	2010
Ongoing and approved					
Adda	-	-	-	-	0.5
Alma	-	-	-	0.2	0.1
Boje area	-	-	-	-	-
Cecilie	0.1	0.1	0.1	0.0	0.0
Dagmar	0.0	0.1	0.1	0.0	0.0
Dan	6.0	5.3	4.8	4.4	3.9
Elly	-	-	-	0.1	0.1
Gorm	2.1	1.9	1.5	1.3	1.0
Halfdan	6.3	6.0	5.8	5.4	4.8
Harald	0.2	0.2	0.1	0.1	0.1
Kraka	0.2	0.2	0.1	0.1	0.1
Lulita	0.1	0.1	0.0	0.0	0.0
Nini	0.2	0.3	0.2	0.1	0.1
Regnar	0.0	0.0	0.0	0.0	0.0
Roar	0.1	0.1	0.1	0.0	0.0
Rolf	0.1	0.1	0.1	0.0	0.0
Siri	0.7	0.7	0.4	0.3	0.2
Skjold	1.1	0.9	0.8	0.7	0.6
South Arne	2.0	1.9	1.7	1.3	1.1
Svend	0.2	0.2	0.1	0.1	0.1
Tyra	0.6	0.5	0.4	0.3	0.3
Tyra SE	0.4	0.2	0.2	0.1	0.1
Valdemar	0.6	1.0	1.4	1.1	0.8
Total	**21.1**	**19.7**	**17.8**	**15.8**	**14.1**
Planned	**0.0**	**0.6**	**0.6**	**0.6**	**0.5**
Planned course of production	**21.2**	**20.4**	**18.4**	**16.4**	**14.6**
Possible	**-**	**0.4**	**0.8**	**2.4**	**4.3**
Possible course of production	**21.2**	**20.8**	**19.3**	**18.8**	**18.9**

Note: Rounded figures

Planned recovery

In September 2005, a plan was submitted for the production of gas from the north-eastern part of the Halfdan Field (Igor). This plan is described in more detail in the section *Development and production*.

In January 2006, a plan was submitted for the southwestern part of the Halfdan Field, providing for the drilling of additional wells to expand the existing well pattern.

When this report went to press, the DEA was reviewing the above-mentioned plans, for which reason the pertinent reserves have been included in the planned recovery category.

Possible recovery

The DEA has reviewed a number of options for enhancing recovery with the use of known technology, i.e. technology that is used today under conditions comparable to those prevailing in the North Sea.

Based on reservoir calculations and general estimates of investments, operating costs and oil price developments, it is assessed that implementing water-injection projects in the Dan, Gorm, Halfdan, South Arne and Tyra Southeast Fields can augment the oil reserves.

It is projected that drilling horizontal wells will further increase the production potential for the Bo area of the Valdemar Field.

Finally, discoveries that are under appraisal are included in this category.

PRODUCTION FORECASTS

Based on the assessment of reserves, the DEA prepares production forecasts for the recovery of oil and natural gas in the next five and twenty years, respectively. The forecasts use the same categorization as the reserves assessment, and include the categories ongoing, approved, planned and possible recovery.

The forecast including planned recovery illustrates the planned course of production, while the forecast including possible recovery illustrates the possible course of production. Figures 5.5a and 5.5b illustrate the correlation between the reserves assessment and the forecasts.

Fig. 5.5a Oil reserves, planned and possible recovery

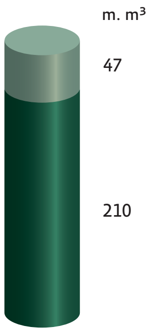
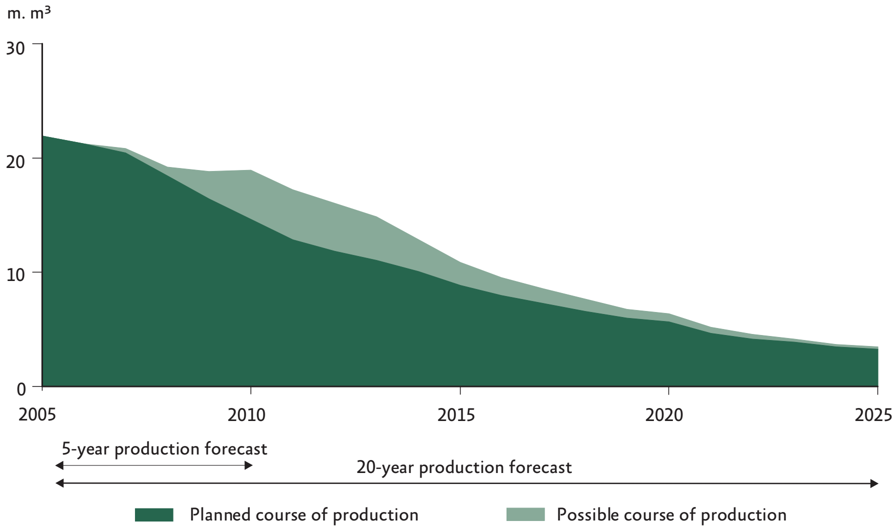


Fig. 5.5b Production forecasts for oil in the period 2006-2025



Fields are incorporated into the production forecast from the time production startup is approved or from the earliest date on which production can be commenced.

Five-year production forecast

The oil production expected according to the five-year forecast appears from Table 5.2 and is illustrated by Figure 5.5b.

For 2006, oil production is expected to total 21.2 million m^3, equal to about 366,000 barrels of oil per day. This is a 7 per cent upward adjustment compared to last year's forecast for 2006, which is due mainly to increased production estimates for the Dan, Halfdan and South Arne Fields.

Planned course of production

Compared to the planned recovery estimate in last year's report, the production estimate has been written up for the five years covered by the forecast. Major revisions of production estimates are reviewed below.

The production estimate for Halfdan has been revised upwards based on the most recent production experience.

The production estimates for the Siri and South Arne Fields have been adjusted to reflect previous production experience and the most recent plans for further development of the fields.

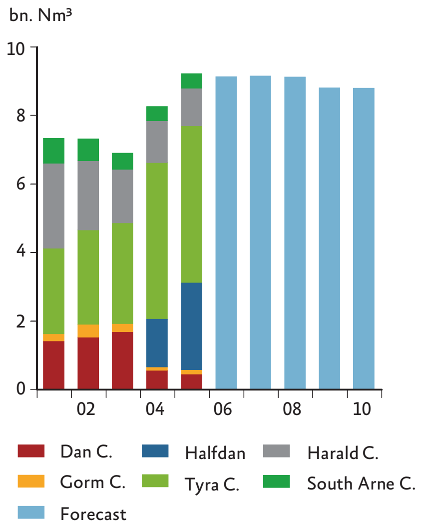
As a consequence of the approved plan for the Bo area of the Valdemar Field, the production expected from the development has been included.

The expectations for production from the remaining fields are largely unchanged in relation to last year's report. The planned recovery category comprises the future development of Freja and Halfdan.

Possible course of production

Table 5.2 includes contributions from the possible recovery category.

Fig. 5.6 Natural gas production broken down by processing centre and estimated future sale of natural gas



Within the possible recovery category, the production potential is based on the DEA's assessment of possibilities for initiating further production not based on development plans submitted.

The forecast for the possible recovery category shows a declining trend, with annual oil production averaging 19.8 million m^3, equal to about 341,000 barrels of oil per day, during the forecast period.

The possible recovery category includes the future further development of the Dan, Gorm, Halfdan, South Arne, Tyra Southeast and Valdemar Fields, as well as the development of the Hejre discovery.

Compared to the possible recovery estimate in last year's report, the production estimate has been written up by an average of 3 per cent during the forecast period. This is primarily attributable to an upward adjustment of production expectations for Dan, Halfdan and South Arne and to the inclusion of the Hejre discovery in the forecast.

Natural gas production estimates are given in Figure 5.6. The forecast includes natural gas production resulting from new contracts for the export of gas through the pipeline from Tyra West via the NOGAT pipeline to the Netherlands. The production forecast in Table 5.2 includes additional condensate production resulting from increased gas production under new export contracts.

Twenty-year production forecast

A forecast covering 20 years is most reliable in the first part of the period. The methods used in making the forecasts imply that production will decline after a short number of years.

Planned and possible courses of production

The forecasts for both planned and possible recovery show a downward trend; see Figure 5.5b. Around 2015, production according to the possible recovery scenario is estimated to constitute about 50 per cent of the production in 2005. Thus, the forecast projects a downward plunge in oil production. The decrease in production is not evenly distributed, as a decrease of approximately 3 million m^3 of oil is forecast for the period from 2005 to 2010 whereas a decrease of about 8 million m^3 is forecast for the period from 2010 to 2015.

Due to investments in the further development of existing fields and the development of new fields, the production forecast is thus expected to decline moderately during the period from 2005 to 2010. The forecast does not predict major developments after 2010, and therefore oil production is estimated to plummet from 2010 and onwards.

This decline is expected to be curbed as a result of technological developments and any new discoveries made as part of the ongoing exploration activity, including the 6th Licensing Round.

Natural gas production

As opposed to the production of oil, which can always be sold at the current market price, the production of natural gas requires that long-term sales contracts have been concluded.

Since the start of gas sales in 1984, natural gas produced under A.P. Møller's Sole Concession has been supplied under gas sales contracts concluded between the DUC companies and DONG Naturgas A/S. The present gas sales contracts do not stipulate a fixed total volume, but rather an annual volume that will be supplied for as long as DUC considers it technically and financially feasible to carry on production at this level.

In 1997, a contract was concluded between the Amerada Hess group and DONG Naturgas A/S for the sale of gas from the South Arne Field, and, in 1998, a contract was concluded with DONG Naturgas A/S for the sale of the DONG group's share of gas produced from the Lulita Field. In addition, the forecast includes the natural gas production resulting from new contracts for the export of gas through the pipeline from Tyra West via the NOGAT pipeline to the Netherlands.

The DEA's forecast for the possible course of production includes gas sales totalling approximately 170 billion Nm^3 until the year 2020 under the contracts with DUC. In addition, the possible course of production for the South Arne Field accounts for about 10 billion Nm^3.

Self-sufficiency

The DEA prepares forecasts of the consumption of oil and natural gas in Denmark, and according to the DEA's most recent forecast, the total Danish production of oil and natural gas will exceed consumption up to and including 2015.

The forecasts of consumption and production diverge significantly around 2015. The consumption forecasts show a slightly increasing trend, while the production forecasts indicate a marked downward trend because they do not predict the further development of known fields or the development of new discoveries from that time onwards. However, technological developments and any new discoveries made as part of the ongoing exploration activity, as referred to below, are expected to contribute with additional production and thus prolong Denmark's period of self-sufficiency in oil and natural gas.

Compared to the forecasts published in "Energy Strategy 2025", the DEA has made slight upward adjustments to the oil and natural gas production forecasts as well as a minor writedown of the oil consumption forecast; see Box 5.2. Compared to the forecast in "Energy Strategy 2025", the natural gas consumption forecast has been written down from 2010 as a consequence of the "Action plan for renewed energy conservation" of 10 June 2005.

RESOURCES

The DEA's reserves assessment is based on the assumption that the reserves can be recovered by means of known technology. Moreover, only reserves in structures where wells have encountered hydrocarbons are included.

In previous annual reports, the DEA supplemented its reserves assessment by estimates of the volumes recoverable by means of new technology as well as the potential for recovery from structures in which no exploration drilling has taken place.

These volumes are termed *resources* below. It should be emphasized that such an estimate is subject to great uncertainty.

Box 5.2 "Energy Strategy 2025"

Production forecasts
The oil and natural gas production forecasts in "Energy Strategy 2025"are based on the reserves assessment in the report "Oil and Gas Production in Denmark 2004", supplemented by assessments of the potential for technological development and exploration.

Consumption forecasts
The oil and natural gas consumption forecasts in "Energy Strategy 2025"represent the so-called "basic scenario", which does not include the effect of new initiatives.

Self-sufficiency in oil
On the basis of the forecast in the reserves assessment, Denmark is expected to be self-sufficient in oil until 2015.When the potential for technological development and exploration is included, self-sufficiency in oil is anticipated to last beyond 2025, if the full estimated potential is realized.

Self-sufficiency in natural gas
On the basis of the forecast in the reserves assessment, Denmark is expected to be self-sufficient in natural gas until around 2015.Technological developments are estimated to contribute much less to the reserves forecast for natural gas than for oil, but the period of self-sufficiency may prove to be longer, depending on the results of exploration activity.

The report "Oil and Gas Production in Denmark in 2004" estimated that the increase in oil production due to technological developments would correspond to a roughly 5 percentage-point increase in the average recovery factor, or more than 100 million m^3.

It should be noted that an assumption stating that the average recovery factor for oil will increase by about 5 percentage points is based on an evaluation of historical developments, as it is impossible to foresee which new techniques will contribute to additional production and thus to estimate the impact of these techniques on production. For gas fields, last year's reserves assessment was supplemented by an estimated contribution from technological developments of about 10 billion Nm^3 of gas.

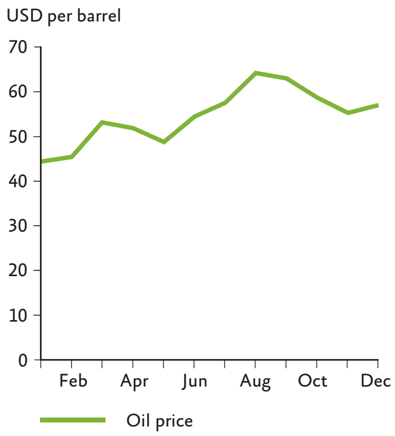
Increased recovery resulting from new technologies is described in more detail in the section *Development and production*. It should be emphasized that any new recovery methods must be implemented while the fields are still producing, as it is generally not economically feasible to introduce new technology once a field has been decommissioned. This means that a limited period is available for the introduction of new technologies, see box 2.1.

In connection with the 6th Licensing Round, the DEA made an assessment of the hydrocarbon resources in structures where no exploration drilling had been carried out as yet, the so-called exploration potential.

The exploration potential was estimated at 205 million m^3 of oil and 152 billion Nm^3 of gas in mid-2003. The report "Oil and Gas Production in Denmark 2003" contains a description of the assessment and the methodology used. Moreover, the actual assessment is available at the DEA's website, www.ens.dk.

6. ECONOMY

Fig. 6.1 Oil price development in 2005



Oil and gas production plays an essential role for the Danish economy in many respects. One positive effect of hydrocarbon production is Denmark's self-sufficiency in energy since 1997.

Oil and gas production also impacts positively on Denmark's economy via the state's tax revenue, the balance of trade and balance of payments as well as profits for the stakeholders in the oil and gas sector.

VALUE OF OIL AND GAS PRODUCTION

Three factors influence the value of oil and gas production: the development in production, the international crude oil price and the dollar exchange rate. External factors determine both the oil price and dollar exchange rate.

The average quotation for a barrel of Brent crude oil was USD 54.4 in 2005. This represents an increase of 42 per cent compared to 2004. The average dollar exchange rate in 2005 was DKK 6 per USD, the same level as in 2004. Figure 6.1 illustrates the oil price development in 2005, and Box 6.1 provides more details about this development.

The higher oil price level meant that the value of Danish oil and gas production in 2005 continued on the upward curve started in the preceding years. The value of Danish oil and gas production totalled DKK 53.5 billion in 2005, up 37 per ent on the year before, even though oil production in 2005 declined relative to 2004 and the dollar exchange rate remained unchanged.

According to preliminary estimates for 2005, oil production accounts for about DKK 44.9 billion and gas production for DKK 8.6 billion of the total production value. The breakdown of production in 2005 on the ten producing companies in Denmark appears from Figure 2.1 in the section *Development and production*.

The DEA prepares forecasts of the future development of production based on the reserves assessment; see *Reserves*.

Appendix C contains a detailed outline of financial key figures from 1972 to 2005.

DEGREES OF SELF-SUFFICIENCY

In 2005, the total production of oil, gas and renewable energy was 58 per cent higher than total energy consumption. This is an increase compared to the year before, when production exceeded consumption by 53 per cent. Thus, the development started in 1997, when Denmark became self-sufficient in energy, continues.

In 2005, oil and gas production exceeded total energy consumption by 41 per cent, the same level as the year before. Oil and gas production in 2005 exceeded total oil and gas consumption by 122 per cent in 2005.

Table 6.1 shows the development in the degrees of self-sufficiency projected by the DEA for the next five years. Scenario A shows Danish oil and gas production relative to total domestic consumption of oil and gas, and scenario B shows Danish oil and gas production relative to total domestic energy consumption. Scenario C shows the expected development in the total production of oil, gas and renewable energy relative to total energy consumption in Denmark.

Box 6.1 Oil price development

Historical development of oil prices

Seen against the increases in recent years, oil prices may appear high from a present-day perspective. Figure 6.2 shows the nominal and real development in the oil price. In 2005, the average oil price was DKK 327 per barrel. As appears from the figure, today's oil price would have to increase beyond DKK 574 per barrel to reach the same level as during the oil crisis in 1981.

Spot and future markets

The spot price is the price for immediate delivery of oil. Oil is not only traded on a day-to-day basis, but can also be bought under a contract for future delivery, a futures contract. Oil companies want to hedge the selling price for oil, so they trade a substantial volume of their oil on the futures market.

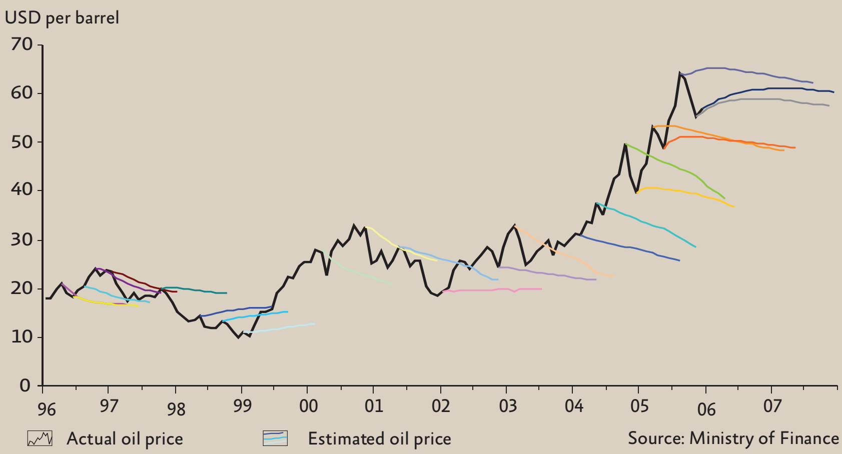
The oil price agreed by buyer and seller in the futures contract is called the settlement price, which thus reflects the buyer's and seller's future price expectations. Like the spot price, the price of oil futures is also determined primarily by supply and demand.

Figure 6.3 shows the trend in spot prices and futures prices at specific dates during the period from 1996 to 2005. Accordingly the figure reflects the oil price expected by the market at intervals in the period from 1996 to 2005.

As appears from Figure 6.3, trade in oil under futures contracts has generally been based on an expectation that oil prices decline when spot prices have shown an upward trend for a prolonged period. Conversely, the figure illustrates that when spot prices have shown a downward trend for a period of time, the market expects increasing oil prices.

Fig. 6.2 Nominal and real oil price development 1972-2005

Fig. 6.3 Actual and estimated oil price 1996-2007



Source: Ministry of Finance

The table shows an increase compared to the corresponding scenarios outlined in the report "Oil and Gas Production in Denmark 2004". This is due mainly to the writedown of expected energy consumption made when "Energy Strategy 2025" was prepared in June 2005. The production of oil and gas is expected to decline over the period: see the section *Development and production*.

As appears from Table 6.1, the DEA expects Denmark to continue being self-sufficient in energy for the next five years. The section on *Reserves* contains a more detailed assessment of the future degrees of self-sufficiency in oil and gas.

IMPACT OF PRODUCTION ON THE DANISH ECONOMY

Oil and gas production makes Denmark self-sufficient in energy and also allows for exports. Thus, the oil and gas activities have a favourable impact on both the balance of trade and the balance of payments current account.

The balance of trade for oil and natural gas

With a surplus on the balance of trade for oil and natural gas of DKK 24.8 billion, the uninterrupted development that started in 1995, when Denmark recorded its first surplus on trade in oil and gas, continues in 2005. In 2005, this surplus increased by 26 per cent from 2004, primarily because of the high oil price level.

Impact on the balance of payments

The surplus production of oil and gas is exported and thus impacts positively on the balance of payments.

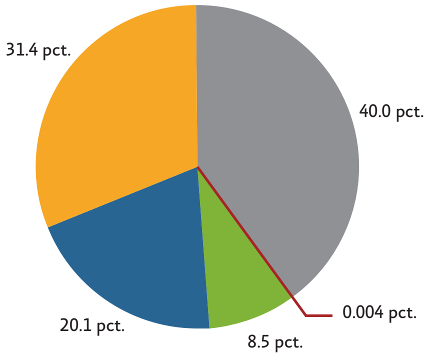
The DEA prepares an estimate of the impact of oil and gas activities on the balance of payments current account for the next five years on the basis of its own forecasts for production, investments, operating and transportation costs. In addition, a number of assumptions are made about import content, interest expenses and the oil companies' profits from the hydrocarbon activities.

Table 6.1 Degrees of self-sufficiency

	2006	2007	2008	2009	2010
Production in PJ					
Oil	768	755	700	681	685
Gas	390	399	409	403	411
Renewable energy	140	140	144	137	139
Energy consumption (PJ)					
Total	834	834	843	842	858
Degrees of self-sufficiency (%)					
A	216	214	201	187	186
B	139	138	132	129	128
C	156	155	149	145	144

A. Oil and gas production vs. oil and gas consumption
B. Oil and gas production vs. total energy consumption
C. Production of oil, gas and renewable energy vs. total energy consumption

Fig. 6.4 State revenue in 2005



This year's calculations have been made on the basis of four oil price scenarios of USD 35, 45, 60 and 80 per barrel, respectively, and a dollar exchange rate of DKK 6.32 per USD. The purpose of making calculations for the different price scenarios is to illustrate how sensitive the economy is to fluctuations in the oil price. A price of USD 35 per barrel is close to the International Energy Agency's long-term oil price forecast.

Table 6.2 shows the individual items used in calculating the impact of oil and gas activities on the balance of payments in the USD 45 oil price scenario. The lower part of the table also shows the calculated impact on the balance of payments current account when using the price scenarios of USD 35 and USD 60 as well as the high price scenario of USD 80.

Assuming that the oil price is USD 45 per barrel, the oil and gas activities will have an estimated DKK 32-33billion impact on the balance of payments current account per year.

State revenue

The Danish state derives proceeds from North Sea oil and gas production via direct revenue from various taxes and fees: *corporate income tax, hydrocarbon tax, royalty, the oil pipeline tariff, compensatory fee and profit sharing.*

Further, the state receives indirect revenue through DONG E&P A/S' participation in oil and gas activities. DONG E&P A/S is a subsidiary of Dong Energy, in which the Danish state has a 73 per cent stake.

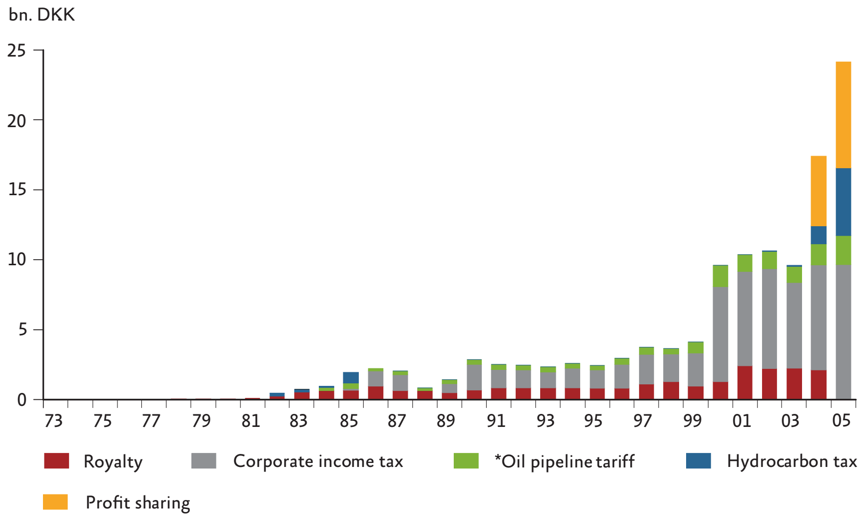
In 2005, a new state-owned entity was established, the Danish North Sea Partner, which administers the Danish North Sea Fund. The Danish North Sea Fund is the state participant in new licences for oil and natural gas exploration and production in Denmark; see the fact box in the section *Exploration*.

Corporate income tax is the chief source of state revenue. Figure 6.4 shows the breakdown of state tax revenue in 2005. State revenue from hydrocarbon production in the North Sea aggregated DKK 122.5 billion in 2005 prices in the period 1963-2005.

Table 6.2 Impact of oil/gas activities on the balance of payments, DKK billion, 2005 prices, price scenario (45 USD/bbl)

	2006	2007	2008	2009	2010
Production value	46	45	43	42	42
Import content	4	4	4	3	3
Balance of goods and services	42	41	39	39	39
Transfer of interest and dividends	8	8	7	7	6
Balance of payments current account	33	33	32	32	33
Balance of payments current account, price scenario (35 USD/bbl)	25	25	24	25	28
Balance of payments current account, price scenario (60 USD/bbl)	43	43	41	41	43
Balance of payments current account, price scenario (80 USD/bbl)	57	56	53	53	55

Fig. 6.5 Development in total state revenue from oil/gas production 1972-2005, DKK billion, 2005 prices



**Incl. compensatory fee*
Note: Accrual according to the Finance Act (year of payment)

By way of illustration, the associated production value totalled DKK 410.5billion during the same period, while the aggregate value of the licensees' expenses for exploration, field developments and operations was DKK 198.7 billion.

Box 6.2 contains a specification of the state's revenue base in the form of taxes and fees on oil and gas production. In addition, an outline of the financial terms and conditions is available at www.ens.dk.

Figure 6.5 shows the development in total state revenue since 1972, broken down on the individual taxes and fees. Table 6.3 shows the development in state revenue for the past five years.

When the tax system was restructured in connection with the agreement of 29 September 2003 concluded between the Danish Government and A.P. Møller-Mærsk (the North Sea Agreement), the rules on tax deductibility were changed, resulting in higher hydrocarbon tax payments and a steeper progressive rate. This means that the higher profits the companies generate, the higher the proportion they have to pay in tax. Consequently, higher oil prices result in increased revenue for the state.

Table 6.3 State revenue over the past five years, DKK million, nominal prices

	2001	**2002**	**2003**	**2004**	**2005**
Hydrocarbon tax	0	65	64	1,251	4,854
Corporate income tax	6,273	6,794	5,943	7,351	9,661
Royalty	2,247	2,110	2,181	2,104	1
Oil pipeline tariff*	1,114	1,169	1,144	1,496	2,053
Profit sharing	-	-	-	4,890	7,595
Total	**9,634**	**10,138**	**9,331**	**17,092**	**24,163**

** Incl. 5 per cent compensatory fee*
Note: Accrual according to the Finance Act (year of payment)

Box 6.2 State revenue from North Sea oil and gas production

The taxes and fees imposed on the production of oil and gas secure an income for the state. Corporate income tax and hydrocarbon tax are collected by the Danish Ministry of Taxation, Central Customs and Tax Administration, while the collection of royalty, the oil pipeline tariff, the compensatory fee and the profit sharing is administered by the DEA. Moreover, the DEA supervises the metering of the amounts of oil and gas produced on which the assessment of state revenue is based.

Below, an outline is given of the state's sources of revenue, based on the statutory provisions applicable in 2005. The applicable rules are outlined at the DEA's website.

Corporate income tax

Corporate income tax is the most important source of revenue related to oil and gas. With effect from 1 January 2005, the corporate income tax rate was lowered from 30 to 28 per cent.

Hydrocarbon tax

This tax was introduced in 1982 with the aim of taxing windfall profits, for example as a result of high oil prices.

Royalty

Older licences include a condition regarding the payment of royalty, which is payable on the basis of the value of hydrocarbons produced, after deducting transportation costs. New licences contain no requirement for the payment of royalty.

Profit sharing

From 1 January 2004 and until 8 July 2012, the Concessionaires and their partners under the Sole Concession are to pay 20 per cent of their profits before tax and net interest expenses.

Oil pipeline tariff

DONG Olierør A/S owns the oil pipeline from the Gorm Field to Fredericia. The users of the oil pipeline pay a fee to DONG Olierør A/S, which includes a profit element of 5 per cent of the value of the crude oil transported. DONG pays 95 per cent of the proceeds from the 5 per cent profit element to the state, termed the oil pipeline tariff.

Compensatory fee

Any parties granted an exemption from the obligation regarding connection to and transportation through the oil pipeline are required to pay the state a fee amounting to 5 per cent of the value of the crude oil and condensate comprised by the exemption.

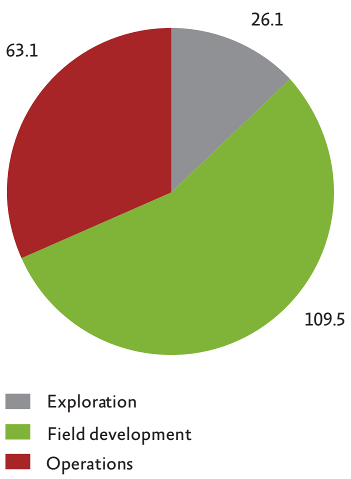
DONG E&P A/S

DONG E&P A/S is a fully paying participant in the licences granted in the 4th and 5th Licensing Rounds and in the Open Door area, with a 20 per cent share. In some cases, DONG E&P A/S has supplemented this share on commercial terms by purchasing additional licence shares. DONG E&P A/S holds a share in the individual licences on the same terms as the other licensees, and therefore the company pays taxes and fees to the state.

Danish North Sea Fund

In future, the Danish state, represented by the Danish North Sea Fund, will participate in all new licences with a 20 per cent share.

Fig. 6.6 Total costs of all licensees, 1963-2005
DKK billion, 2005 prices



For the next five years, the Ministry of Taxation estimates that the state's revenue will total about DKK 16 billion per year from 2006 to 2010, based on the USD 35 oil prie scenario. An oil price scenario of USD 80 per barrel is estimated to yield state revenue of about DKK 47 billion per year; see Table 6.4. The revenue is expected to stabilize in the various scenarios because a decline in production is expected to even out the reduced possibilities for deducting hydrocarbon allowances.

It should be noted that future estimates of corporate income tax and hydrocarbon tax payments are subject to uncertainty with respect to oil prices and the dollar exchange rate. In addition, uncertainty attaches to the calculations because they are based on various stylized assumptions, some of which concern the companies' finance costs.

THE LICENSEES' FINANCES

Investments in the development of existing and new fields account for more than half the licensees' total expenses. During the period from 1963 to 2005, the licensees' total expenses amounted to DKK 198.7 billion, broken down as shown in Figure 6.6. The expenses for exploration, field developments and operations (including administration and transportation) accounted for 13,55 and 32 per cent, respectively, of total expenses.

Table 6.4 Expected state revenue from oil and gas production, DKK billion, nominal prices*

		2006	2007	2008	2009	2010
Corporate income tax	80 USD/bbl	16.9	16.8	16.1	15.9	16.1
	60 USD/bbl	12.1	11.9	11.5	11.4	11.3
	45 USD/bbl	8.5	8.3	8.0	8.0	7.9
	35 USD/bbl	6.1	5.9	5.7	5.7	5.5
Hydrocarbon tax	80 USD/bbl	14.4	14.3	14.3	14.8	14.7
	60 USD/bbl	9.5	9.5	9.6	9.7	9.6
	45 USD/bbl	5.9	5.9	6.1	6.2	6.1
	35 USD/bbl	3.5	3.5	3.7	3.9	3.8
Profit sharing	80 USD/bbl	13.5	13.3	13.0	13.0	12.8
	60 USD/bbl	9.8	9.6	9.4	9.4	9.3
	45 USD/bbl	7.0	6.8	6.7	6.7	6.6
	35 USD/bbl	5.2	4.9	4.9	4.9	4.8
Royalty	80 USD/bbl	0.0	0.0	0.0	0.0	0.0
	60 USD/bbl	0.0	0.0	0.0	0.0	0.0
	45 USD/bbl	0.0	0.0	0.0	0.0	0.0
	35 USD/bbl	0.0	0.0	0.0	0.0	0.0
Oil pipeline tariff**	80 USD/bbl	3.1	3.1	2.9	2.9	3.0
	60 USD/bbl	2.3	2.3	2.2	2.2	2.2
	45 USD/bbl	1.7	1.7	1.6	1.6	1.7
	35 USD/bbl	1.4	1.4	1.3	1.3	1.3
Total	80 USD/bbl	48.0	47.5	46.4	46.6	46.6
	60 USD/bbl	33.8	33.3	32.7	32.7	32.4
	45 USD/bbl	23.2	22.7	22.4	22.6	22.3
	35 USD/bbl	16.1	15.6	15.6	15.8	15.5

** Assumed annual inflation rate of 1.8 per cent*
*** Incl. 5 per cent compensatory fee*
Source: Ministry of Finance

Exploration costs

For 2005, total exploration costs are preliminarily estimated at DKK 0.5 billion. Thus, the total costs of exploration for new discoveries increased slightly compared to 2004, when exploration costs were calculated at DKK 0.3 billion. For the past two years, the costs of exploration were somewhat below the average for the past ten years, amounting to DKK 0.6 billion in nominal prices.

The issuing of new licences in the 6th Licensing Round in 2006 will impact positively on exploration activity in future years. In 2006 and 2007, exploration costs are expected to increase to DKK 0.6 billion and DKK 0.7 billion, respectively, in 2005 prices. For the subsequent years, exploration costs are expected to decline slightly, dipping to an estimated DKK 0.4 billion during the period from 2008 to 2010.

Investments in field developments

The largest expense item in the licensees' budget is the development of existing fields and new fields. Development activities are estimated to total DKK 4 billion for 2005. Thus, development activity declined somewhat compared to 2004, when total investments were calculated at DKK 5.1 billion. By comparison, annual investments averaged DKK 4.6 billion during the period from 1996 to 2005; see table 6.5.

In 2005, the development activities in the Dan, Halfdan, Tyra and Valdemar Fields represented the bulk of investments, accounting for 75 per cent of total investments in 2005. During the past five years, total investment activity was also dominated by the Dan, Halfdan and Tyra Fields, as well as the South Arne and Nini Fields. Thus, during the period from 2001 to 2005, these fields accounted for 70 per cent of total development costs.

Table 6.5 Investments, DKK million, nominal prices

	2001	2002	2003	2004	2005*
Cecilie		223	660	309	5
Dan	367	437	943	750	749
Gorm	240	242	107	108	291
Halfdan	1,518	2,412	1,779	1,124	683
Harald	(1)	0	4	22	53
Kraka	61	3	-	2	-
Nini		285	1,288	319	190
Roar	-	-	-	-	-
Rolf	-	-	37	4	-
Siri	176	111	406	425	79
Skjold	89	5	77	8	11
South Arne	578	849	764	764	286
Svend	115	223	-	-	-
Tyra	198	85	305	459	1,065
Tyra Southeast	357	569	82	96	-
Valdemar	316	(1)	200	52	554
NOGAT pipeline	-	-	766	664	12
Not allocated	12	31	(31)	2	5
Total	**4,025**	**5,475**	**7,386**	**5,107**	**3,983**

** Estimate*

Fig. 6.7 Operating costs per barrel, 1986-2005, nominal prices, DKK

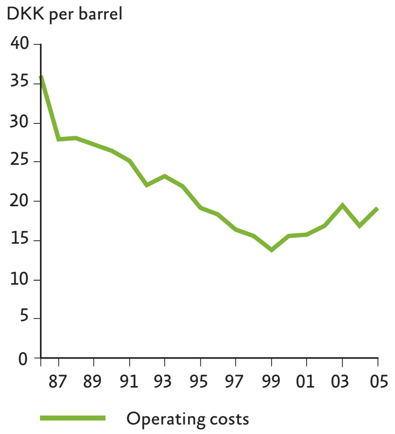


Table 6.6 shows the DEA's estimate of development activity for the period from 2006 to 2010.The estimate is based on ongoing, approved, planned and possible investments. The forecast of possible field development activities is based on the DEA's assessment of the potential for initiating further production beyond the production for which development plans have already been submitted; see the section *Reserves*.

Compared to its estimate in the annual report for 2004, the DEA has written up estimated investments for the period 2006-2010, primarily because a higher activity level is expected in some of the fields, particularly the South Arne, Tyra and Valdemar Fields.

Operating, administration and transportation costs

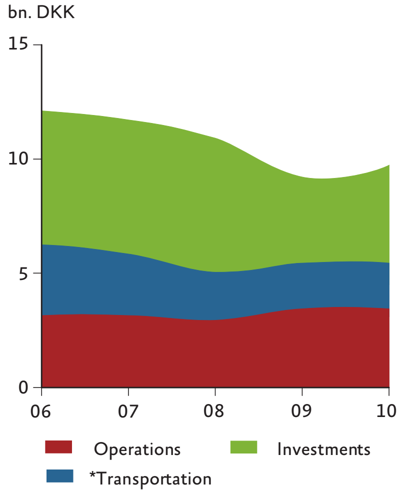
For 2005, the DEA has calculated operating, administration and transportation costs at DKK 3.8 billion. This amount is higher than in 2004, in part because higher oil prices have driven up transportation costs.

Figure 6.7 shows the development in operating costs per barrel of oil during the period from 1986 to 2005.The figure shows that operating costs dropped from DKK 36 per barrel to about DKK 20 per barrel in 2005.The drop in operating costs is primarily attributable to economies of scale resulting from growing production.

Table 6.6 Estimated investments in development projects, 2006-2010, DKK billion, 2005 prices

	2006	2007	2008	2009	2010
Ongoing and approved					
Adda	-	-	0.4	0.1	-
Alma	-	0.4	0.1	-	-
Cecilie	0.0	0.0	0.0	0.0	0.0
Dagmar	0.1	-	-	-	-
Dan	0.8	0.2	0.3	-	-
Elly	0.0	0.4	0.2	-	-
Gorm	0.2	0.0	-	-	-
Halfdan	0.3	-	-	-	-
Harald	0.0	0.1	-	-	-
Kraka	-	-	-	-	-
Lulita	-	-	-	-	-
Nini	0.4	0.3	0.0	0.0	0.0
Regnar	-	-	-	-	-
Roar	-	-	-	-	-
Rolf	-	-	-	-	-
Siri	0.1	0.2	0.0	0.0	0.0
Skjold	-	-	-	-	-
South Arne	0.4	0.6	0.1	0.0	0.0
Svend	-	-	-	-	-
Tyra	1.4	0.9	0.3	-	1.4
Tyra Southeast	-	-	-	-	-
Valdemar	1.0	1.0	0.1	-	-
Total	**4.9**	**3.9**	**1.5**	**0.2**	**1.4**
Planned	0.9	1.7	0.5	0.2	0.1
Possible	0.2	0.3	3.8	3.4	2.8
Expected	**5.9**	**5.9**	**5.9**	**3.8**	**4.3**

Fig. 6.8 Investments in fields, operating and oil transportation costs, 2005 prices



*Incl. 5 per cent pipeline tariff/compensatory fee

Generally, the oil companies' costs of production are also affected by oil price increases, for one thing because of increasing demand. For this reason, the increase in operating costs since 1998 is partly attributable to increasing oil prices; see Box 6.1.

Total crude oil transportation costs consist of the operating costs and capital cost associated with the use of the oil pipeline from the Gorm Field to shore, as well as the 5 per cent fee payable on the basis of the production value of the crude oil transported. The Siri, South Arne, Nini and Cecilie Fields are exempt from the obligation to use the oil pipeline, but must instead pay a compensatory fee constituting 5 per cent of the production value of the crude oil. The oil produced is transported to shore by tanker.

Figure 6.8 illustrates the DEA's estimate of developments in operating and transportation costs for the years to come. Because of higher oil prices and higher oil price forecasts, the estimate of transportation costs is substantially higher than the corresponding figure in the 2004 report. In addition, the dollar exchange rate is expected to be higher in 2006 than in 2005.

AMOUNTS PRODUCED AND INJECTED

Production and sales

OIL *thousand cubic metres*

	1972-95	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	Total
Dan	25,575	3,799	3,858	4,767	5,745	6,599	6,879	6,326	5,929	6,139	5,712	81,328
Gorm	24,805	2,941	3,045	2,865	3,384	3,110	2,180	2,887	2,838	2,469	1,978	52,503
Skjold	21,271	2,065	2,011	1,896	1,825	1,975	1,354	1,659	1,532	1,443	1,310	38,342
Tyra	12,987	1,446	1,263	931	892	1,000	872	801	918	723	773	22,606
Rolf	3,166	113	96	92	77	83	51	51	104	107	79	4,020
Kraka	1,699	340	315	314	404	350	253	157	139	199	211	4,380
Dagmar	916	23	17	13	10	8	4	6	7	2	0	1,005
Regnar	660	41	27	43	29	14	33	18	19	19	16	920
Valdemar	522	161	159	95	86	77	181	353	435	491	423	2,984
Roar	-	320	427	327	259	285	317	175	121	98	94	2,424
Svend	-	836	1,356	635	521	576	397	457	280	326	324	5,706
Harald	-	-	794	1,690	1,332	1,081	866	578	425	314	237	7,318
Lulita	-	-	-	143	224	179	66	24	20	19	35	710
Halfdan	-	-	-	-	222	1,120	2,965	3,718	4,352	4,946	6,200	23,523
Siri	-	-	-	-	1,593	2,118	1,761	1,487	925	693	703	9,280
South Arne	-	-	-	-	757	2,558	2,031	2,313	2,383	2,257	2,371	14,670
Tyra SE	-	-	-	-	-	-	-	493	343	580	614	2,029
Cecilie	-	-	-	-	-	-	-	-	166	310	183	659
Nini	-	-	-	-	-	-	-	-	391	1,477	623	2,492
Total	**91,601**	**12,087**	**13,367**	**13,810**	**17,362**	**21,134**	**20,207**	**21,505**	**21,327**	**22,612**	**21,886**	**276,897**

Production

GAS *million normal cubic metres*

	1972-95	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	Total
Dan	10,013	1,249	1,116	1,343	1,410	1,186	1,049	945	786	764	651	20,514
Gorm	10,409	677	609	633	537	426	306	480	339	216	218	14,849
Skjold	1,901	161	189	146	154	158	104	123	92	77	93	3,197
Tyra	34,793	3,838	4,229	3,638	3,878	3,826	3,749	3,948	3,994	4,120	3,745	73,760
Rolf	134	5	4	4	3	4	2	2	4	5	3	169
Kraka	516	95	85	106	148	119	100	52	25	23	24	1,292
Dagmar	137	4	3	2	2	2	1	1	3	2	0	158
Regnar	40	4	2	4	2	1	3	1	2	2	1	62
Valdemar	177	57	89	54	49	55	78	109	151	218	208	1,245
Roar	-	1,332	1,964	1,458	1,249	1,407	1,702	1,052	915	894	860	12,833
Svend	-	85	152	84	65	75	48	61	43	38	34	684
Harald	-	-	1,092	2,741	2,876	2,811	2,475	2,019	1,563	1,232	1,091	17,900
Lulita	-	-	-	69	181	160	27	6	5	5	13	466
Halfdan	-	-	-	-	37	178	522	759	1,142	1,449	2,582	6,669
Siri	-	-	-	-	142	197	176	157	110	63	115	959
South Arne	-	-	-	-	167	713	774	681	544	461	484	3,824
Tyra SE	-	-	-	-	-	-	-	447	452	1,233	1,337	3,469
Cecilie	-	-	-	-	-	-	-	-	14	24	15	53
Nini	-	-	-	-	-	-	-	-	29	107	49	186
Total	**58,119**	**7,506**	**9,534**	**10,281**	**10,901**	**11,316**	**11,116**	**10,844**	**10,213**	**10,934**	**11,523**	**162,287**

The monthly production figures for 2005 are available on the Danish Energy Authority's homepage www.ens.dk

Fuel*

GAS *million normal cubic metres*

	1972-95	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	Total
Dan	520	97	109	148	172	179	184	182	198	201	205	2,194
Gorm	1,009	135	164	152	149	142	111	146	135	137	124	2,405
Tyra	1,063	142	210	224	239	229	243	245	242	249	247	3,334
Dagmar	21	-	-	-	-	-	-	-	-	-	-	21
Harald	-	-	5	14	14	13	10	9	8	8	7	88
Siri	-	-	-	-	8	21	22	21	20	19	21	133
South Arne	-	-	-	-	3	32	34	45	49	45	52	260
Halfdan	-	-	-	-	-	-	-	-	-	20	39	59
Total	**2,613**	**375**	**488**	**539**	**585**	**618**	**604**	**648**	**652**	**679**	**694**	**8,494**

Flaring*

	1972-95	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	Total
Dan	1,458	40	36	43	56	67	79	55	71	37	23	1,964
Gorm	946	60	81	71	71	66	88	81	66	57	61	1,647
Tyra	467	67	46	42	58	58	68	61	54	63	55	1,038
Dagmar	116	2	3	2	2	2	1	1	3	2	-	135
Harald	-	-	77	19	12	7	11	3	1	1	1	133
Siri	-	-	-	-	73	9	15	9	23	65	15	208
South Arne	-	-	-	-	114	41	9	11	12	11	14	212
Halfdan	-	-	-	-	-	-	-	-	4	25	16	45
Total	**2,986**	**168**	**243**	**177**	**386**	**250**	**270**	**222**	**234**	**262**	**185**	**5,382**

Injection

	1972-95	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	Total
Gorm	7,951	26	62	24	25	45	4	14	6	4	3	8,164
Tyra	11,301	1,225	1,778	2,908	3,074	3,104	2,773	2,535	2,312	1,612	1,285	33,906
Siri**	-	-	-	-	61	167	139	126	109	111	143	856
Total	**19,252**	**1,251**	**1,840**	**2,933**	**3,160**	**3,316**	**2,916**	**2,675**	**2,428**	**1,727**	**1,431**	**42,926**

Sales*

	1972-95	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	Total
Dan	8,591	1,211	1,058	1,261	1,371	1,238	1,412	1,521	1,682	551	448	20,344
Gorm	2,538	622	495	535	448	334	209	364	228	99	126	5,998
Tyra	22,140	3,878	4,400	2,060	1,870	1,971	2,493	2,776	2,948	4,580	4,598	53,712
Harald	-	-	1,010	2,777	3,032	2,950	2,482	2,013	1,558	1,228	1,096	18,145
South Arne	-	-	-	-	50	640	730	625	483	406	418	3,353
Halfdan	-	-	-	-	-	-	-	-	-	1,403	2,528	3,931
Total	**33,269**	**5,712**	**6,963**	**6,633**	**6,770**	**7,133**	**7,326**	**7,299**	**6,900**	**8,267**	**9,214**	**105,483**

** The names refer to processing centres.*
*** Gas from the Cecilie and Nini Fields is injected into the Siri Field.*

Production

CO_2 EMISSIONS *thousand tons*

	1972-95	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	Total
Fuel	5,946	853	1,110	1,226	1,343	1,476	1,459	1,577	1,591	1,642	1,690	19,912
Flaring	6,797	382	553	402	1,126	645	646	535	564	664	456	12,771
Total	**12,744**	**1,235**	**1,664**	**1,628**	**2,469**	**2,122**	**2,104**	**2,112**	**2,154**	**2,306**	**2,146**	**32,683**

CO_2 emissions from the use of diesel oil have not been included.
CO_2 emissions have been calculated on the basis of parameters specific to the individual year and the individual installation.

Production

WATER *thousand cubic metres*

	1972-95	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	Total
Dan	4,682	1,543	1,845	2,976	4,220	5,277	6,599	6,348	7,183	8,053	9,527	58,254
Gorm	7,283	1,964	2,906	3,177	3,468	3,980	3,353	4,017	4,420	5,173	5,252	44,993
Skjold	3,436	2,738	3,635	3,938	3,748	4,333	2,872	3,007	3,525	3,688	4,270	39,190
Tyra	5,887	2,162	2,215	2,020	2,033	3,046	2,545	2,261	3,039	2,977	3,482	31,667
Rolf	2,022	380	390	411	366	358	181	168	270	308	290	5,145
Kraka	810	272	287	347	329	256	352	306	208	426	320	3,912
Dagmar	1,443	507	408	338	246	241	102	160	375	90	3	3,914
Regnar	640	299	164	407	363	139	475	257	316	396	352	3,808
Valdemar	45	34	61	52	55	48	150	272	310	325	792	2,142
Roar	-	14	96	146	199	317	386	301	476	653	662	3,250
Svend	-	2	64	272	582	1,355	954	1,051	1,330	1,031	1,309	7,951
Harald	-	-	-	5	15	39	98	78	43	15	12	306
Lulita	-	-	-	3	5	11	23	14	14	15	38	123
Halfdan	-	-	-	-	56	237	493	367	612	2,099	2,825	6,689
Siri	-	-	-	-	319	1,868	2,753	3,041	2,891	1,648	1,692	14,212
South Arne	-	-	-	-	15	60	119	390	751	1,124	800	3,258
Tyra SE	-	-	-	-	-	-	-	250	596	466	437	1,748
Cecilie	-	-	-	-	-	-	-	-	25	331	637	993
Nini	-	-	-	-	-	-	-	-	3	63	729	796
Total	**26,247**	**9,916**	**12,072**	**14,093**	**16,019**	**21,566**	**21,456**	**22,287**	**26,386**	**28,879**	**33,429**	**232,350**

Injection

	1972-95	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	Total
Dan	12,530	8,245	8,654	11,817	14,964	17,464	18,176	16,123	18,063	20,042	20,281	166,358
Gorm	16,367	8,112	8,642	8,376	8,736	10,641	6,549	8,167	7,066	7,551	7,251	97,460
Skjold	25,690	5,712	6,320	6,291	5,866	6,520	4,805	6,411	6,386	6,451	6,045	86,497
Halfdan	-	-	-	-	82	13	620	2,532	5,162	5,759	9,710	23,879
Siri	-	-	-	-	1,236	3,778	4,549	4,507	3,383	1,681	1,347	20,481
South Arne	-	-	-	-	-	52	1,991	4,397	5,316	4,947	5,608	22,310
Nini	-	-	-	-	-	-	-	-	71	916	502	1,489
Cecilie	-	-	-	-	-	-	-	-	-	87	194	281
Total	**54,588**	**22,069**	**23,616**	**26,484**	**30,884**	**38,469**	**36,689**	**42,138**	**45,446**	**47,435**	**50,937**	**418,755**

Water injection includes the injection of produced water and seawater. Most of the water produced in the Gorm, Skjold, Dagmar and Siri Fields is reinjected.

PRODUCING FIELDS

THE CECILIE FIELD	
Location:	Blocks 5604/19 and 20
Licence:	16/98
Operator:	DONG E&P A/S
Discovered:	2000
Year on stream:	2003
Producing wells:	3
Water-injection wells:	1
Water depth:	60 m
Field delineation:	22.6 km^2
Reservoir depth:	2,200 m
Reservoir rock:	Sandstone
Geological age:	Paleocene
Reserves at 1 January 2006:	
Oil:	0.4 million m^3
Gas:	0.0 billion Nm^3
Cum. production at 1 January 2006:	
Oil:	0.66 million m^3
Gas:	0.05 billion Nm^3*
Water:	0.99 million m^3
Cum. injection at 1 January 2006:	
Water:	0.28 million m^3
Production in 2005:	
Oil:	0.18 million m^3
Gas:	0.02 billion Nm^3*
Water:	0.64 million m^3
Injection in 2005:	
Water:	0.19 million m^3
Total investments at 1 January 2006:	
2005 prices	DKK 1.2 billion

** The gas is injected into the Siri Field.*

REVIEW OF GEOLOGY

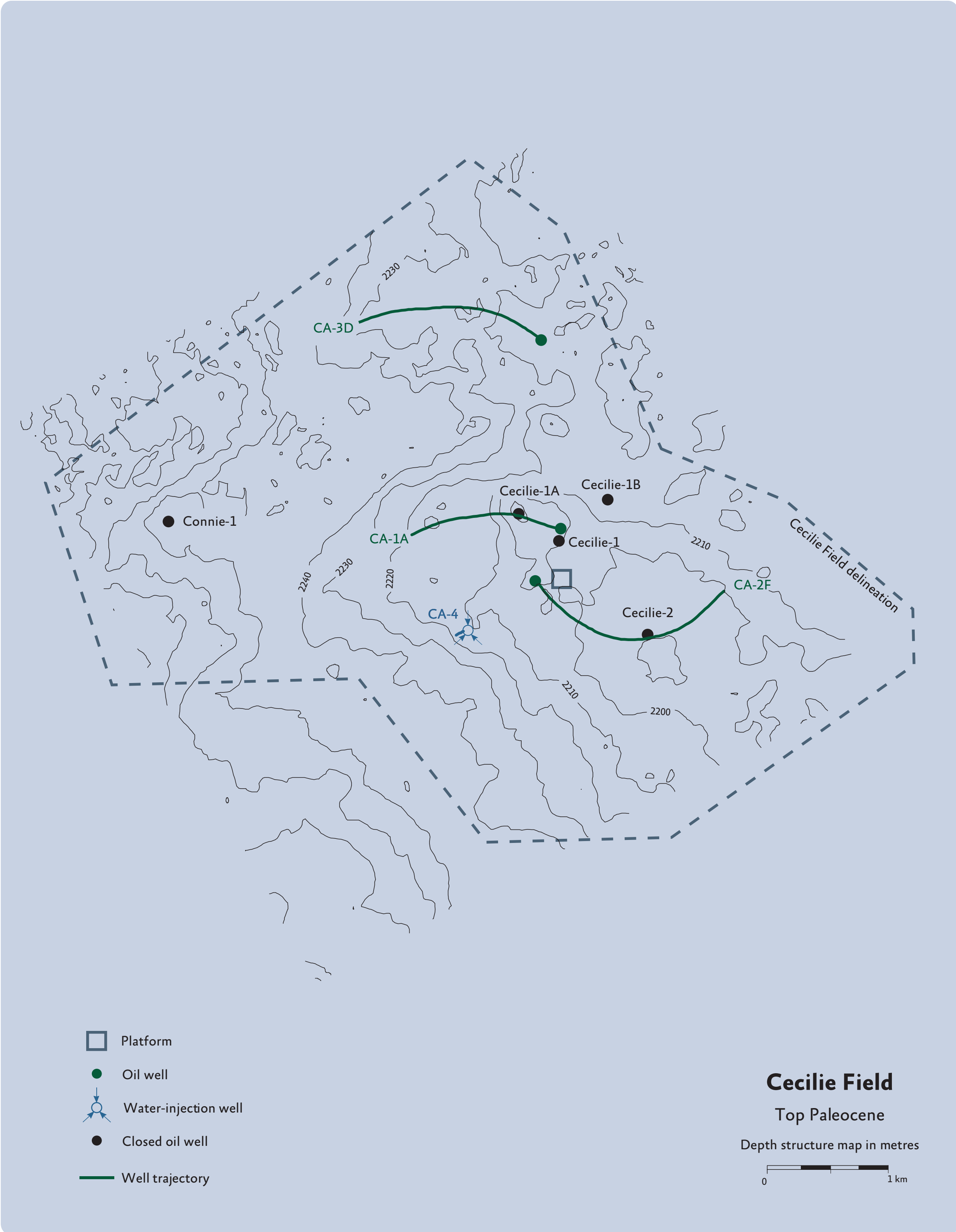
The Cecilie accumulation is a combined structural and stratigraphic trap. It is an anticlinal structure induced through salt tectonics, delimited by faults and redeposited sands. The Cecilie Field also comprises the Connie accumulation.

PRODUCTION STRATEGY

Recovery is based on water injection to maintain reservoir pressure. The production wells have been drilled in the crest of the structure, while water is injected in the flank of the field.

PRODUCTION FACILITIES

The Cecilie Field is a satellite development to the Siri Field with one unmanned wellhead platform with a helideck. The unprocessed production is transported to the Siri platform through a 12" multiphase pipeline. The oil is processed at the Siri platform and exported to shore via tanker. The gas produced is injected into the Siri Field. Injection water is transported to the Cecilie Field through a 10" pipeline.



CA-3D
2230
Cecilie-1A
Cecilie-1B
Connie-1
CA-1A
Cecilie-1
2210
Cecilie Field delineation
2240
2230
2220
CA-2F
CA-4
Cecilie-2
2210
2200
Platform
Oil well
Water-injection well
Closed oil well
Well trajectory
Cecilie Field
Top Paleocene
Depth structure map in metres
0
1 km

THE DAGMAR FIELD	
Prospect:	East Rosa
Location:	Block 5504/15
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1983
Year on stream:	1991
Producing wells:	2
Water depth:	34 m
Area:	9 km^2
Reservoir depth:	1,400m
Reservoir rock:	Chalk and Carbonates
Geological age:	Danian, Upper Cretaceous and Zechstein
Reserves at 1 January 2006:	
Oil:	0.4 million m^3
Gas:	0.0 billion Nm^3
Cum. production at 1 January 2006:	
Oil:	1.01 million m^3
Gas:	0.16 billion Nm^3
Water:	3.91 million m^3
Production in 2005:	
Oil:	0.00 million m^3
Gas:	0.00 billion Nm^3
Water:	0.00 million m^3
Total investments at 1 January 2006:	
2005 prices	DKK 0.5 billion

REVIEW OF GEOLOGY

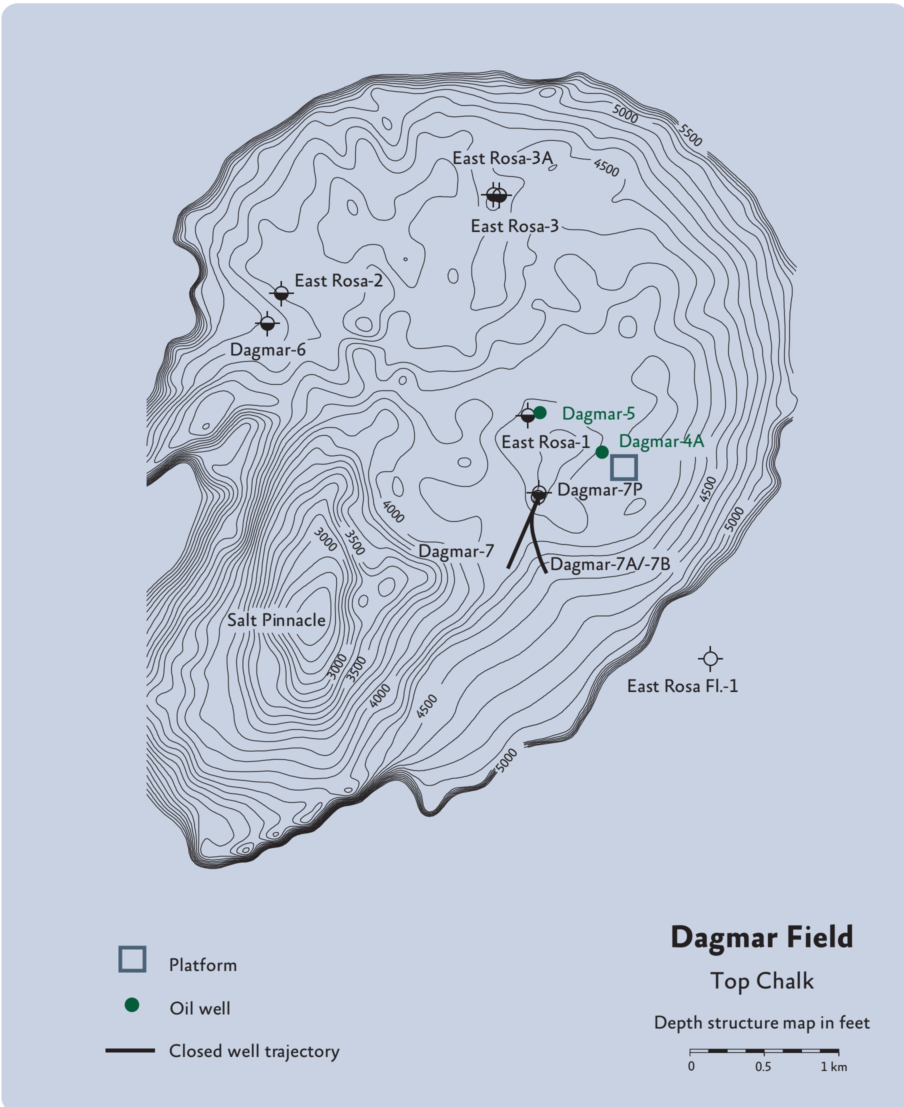
The Dagmar Field is an anticlinal structure, induced through salt tectonics. The uplift is very pronounced, and the Dagmar oil reservoir is situated closer to the surface than any other hydrocarbon reservoirs in Danish territory. The reservoir is heavily fractured (compare Skjold, Rolf, Regnar and Svend). However, the water zone does not appear to be particularly fractured.

PRODUCTION STRATEGY

The recovery strategy for the Dagmar Field is based on achieving the highest possible production rate from the wells. Initially, the oil production rates were high in the Dagmar Field, but it has not been possible to sustain the good production performance characterizing the Skjold, Svend and Rolf Fields.

PRODUCTION FACILITIES

The Dagmar Field is a satellite development to Gorm with one unmanned wellhead platform of the STAR type without a helideck. The unprocessed production is transported to the Gorm F platform, where separate facilities for handling the sour gas from the Dagmar Field have been installed. The small amount of gas produced from Dagmar is flared due to its high content of hydrogen sulphide.



THE DAN FIELD	
Prospect:	Abby
Location:	Block 5505/17
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1971
Year on stream:	1972
Producing wells:	59
Water-injection wells:	47
Water depth:	40 m
Field delineation:	121 km^2
Reservoir depth:	1,850m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2006:	
Oil:	64.0 million m^3
Gas:	7.3 billion Nm^3
Cum. production at 1 January 2006:	
Oil:	81.36 million m^3
Gas:	20.52 billion Nm^3
Water:	58.24 million m^3
Cum. injection at 1 January 2006:	
Water:	166.38 million m^3
Production in 2005:	
Oil:	5.74 million m^3
Gas:	0.66 billion Nm^3
Water:	9.51 million m^3
Injection in 2005:	
Water:	20.30 million m^3
Total investments at 1 January 2006:	
2005 prices	DKK 25.2 billion

REVIEW OF GEOLOGY

Dan is an anticlinal structure induced through salt tectonics. A major fault divides the field into two reservoir blocks, which, in turn, are intersected by a number of minor faults. The chalk reservoir has high porosity, although low permeability. There is a gas cap in the field.

PRODUCTION STRATEGY

Recovery from the field is based on the simultaneous production of oil and injection of water. Water injection was initiated in 1989, and later high-rate water injection was introduced in large sections of the field. The high injection pressure causes the injected water to fracture the chalk, ensuring the rapid distribution of water throughout the reservoir. Injecting large amounts of water quickly stabilizes and increases the reservoir pressure in the oil zone. Oil recovery is optimized by flooding the largest possible reservoir volume with water.

In addition, production takes place from the western flank of the Dan Field. In this part of the field, production takes place from long horizontal wells arranged in a pattern of alternate production and injection wells with parallel well trajectories, whereby the oil is forced towards the production wells.

PRODUCTION FACILITIES

The Dan Field comprises six wellhead platforms, DA, DD, DE, DFA, DFB and DFE, a combined wellhead and processing platform, DFF, a processing platform, DFG, two processing and accommodation platforms, DB and DFC, and two gas flare stacks, DC and DFD.

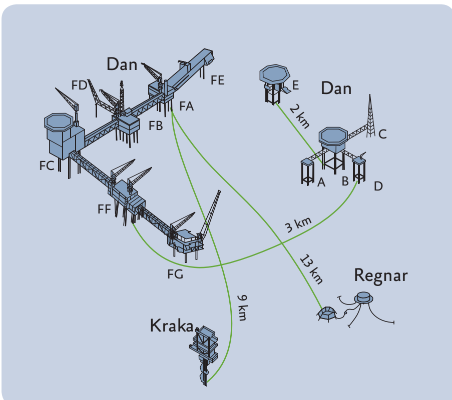
The Dan DA, DB, DC and DD platform complex is located about 3 km from the Dan F platforms, while Dan DE is an unmanned satellite platform with a helideck.

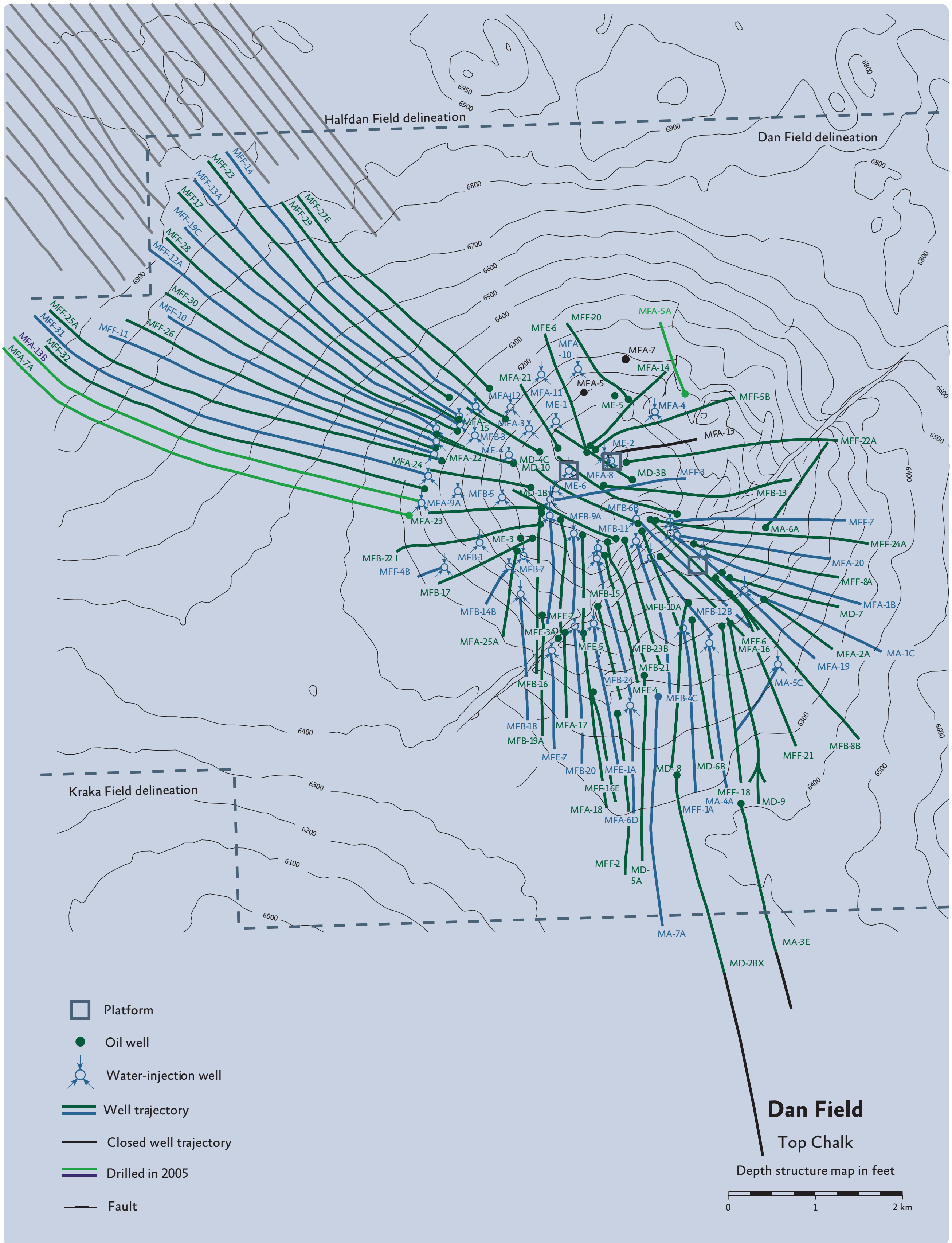
The seven platforms at the Dan F complex are interconnected by bridges. The newest platform, the DFG processing platform, was installed in 2005. At the beginning of 2006, the platform facilities were still under commissioning.

At the Dan Field, there are facilities for receiving production from the adjacent Kraka and Regnar satellite fields, as well as for receiving gas produced at the Halfdan Field. The Dan installations supply the Halfdan Field with injection water.

After final processing, the oil is transported to shore via the riser platform, Gorm E. The gas is pre-processed and transported to Tyra East for final processing. Treated production water from Dan and its satellite fields is discharged into the sea.

New, expanded accommodation facilities for 97 persons on the DFC platform were brought into use in 2006. The DB platform has accommodation facilities for five persons.




Dan Field
Top Chalk
Depth structure map in feet
0
1
2 km
Halfdan Field delineation
Dan Field delineation
Kraka Field delineation
Platform
Oil well
Water-injection well
Well trajectory
Closed well trajectory
Drilled in 2005
Fault
MFF-14
MFF-23
MFF-13A
MFF17
MFF-19C
MFF-28
MFF-12A
MFF-27E
MFF-29
MFF-30
MFF-10
MFF-26
MFF-11
MFF-25A
MFF-31
MFF-32
MFA-13B
MFA-7A
MFE-6
MFF-20
MFA-5A
MFA-7
MFA-14
MFA-5
MFA-21
MFA-12
MFA-11
ME-1
ME-5
MFA-4
MFF-5B
MFA-13
MFF-22A
ME-2
MD-3B
MFF-3
MD-4C
MD-10
ME-6
MFA-8
MFA-24
MFA-22
MFB-5
MD-1B
MFB-13
MFA-9A
MFA-23
MFB-9A
MFB-11
MA-6A
MFF-7
MFF-24A
ME-3
MFB-1
MFB-7
MFF-4B
MFB-17
MFB-14B
MFB-15
MFA-20
MFF-8A
MFA-1B
MD-7
MFB-10A
MFB-12B
MFE-2
MFE-3A
MFA-25A
MFE-5
MFB-23B
MFB-21
MFF-6
MFA-16
MFA-2A
MA-1C
MFA-19
MA-5C
MFB-16
MFB-24
MFE-4
MFB-4C
MFB-18
MFA-17
MFB-19A
MFE-7
MFB-20
MFE-1A
MD-8
MD-6B
MFF-21
MFB-8B
MFF-16E
MFF-18
MA-4A
MD-9
MFA-18
MFF-1A
MFA-6D
MFF-2
MD-5A
MA-7A
MA-3E
MD-2BX
6950
6900
6800
6700
6600
6500
6400
6300
6200
6100
6000

THE GORM FIELD	
Prospect:	Vern
Location:	Blocks 5504/15 and 16
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1971
Year on stream:	1981
Producing wells:	33
Gas-injection wells:	2
Water-injection wells:	14
Water depth:	39 m
Field delineation:	33 km^2
Reservoir depth:	2,100 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2006:	
Oil:	15.0 million m^3
Gas:	1.4 billion Nm^3
Cum. production at 1 January 2006:	
Oil:	52.51 million m^3
Net gas:	6.69 billion Nm^3
Water:	44.99 million m^3
Cum. injection at 1 January 2006:	
Gas:	8.16 billion Nm^3
Water:	97.46 million m^3
Production in 2005:	
Oil:	1.99 million m^3
Net gas:	0.22 billion Nm^3
Water:	5.24 million m^3
Injection in 2005:	
Gas:	0.00 billion Nm^3
Water:	7.25 million m^3
Total investments at 1 January 2006:	
2005 prices:	DKK 12.1 billion

REVIEW OF GEOLOGY

Gorm is an anticlinal structure induced partly due to salt tectonics. A major fault extending north-south divides the field into two reservoir blocks. The western reservoir block is intersected by numerous, minor faults.

PRODUCTION STRATEGY

In 1989, water injection was initiated in the reservoir. The production strategy for the Gorm Field is to maintain reservoir pressure. Water injection, combined with the influx of water from the aquifer and compaction in the reservoir, maintains the pressure and thus upholds a balanced production rate in terms of reservoir volume. Water injection takes place both at the flank of the field and from the bottom of the reservoir below the oil zone.

If gas export to Tyra is interrupted, the gas is injected into the Gorm Field.

PRODUCTION FACILITIES

The Gorm Field consists of two wellhead platforms, Gorm A and B, one processing and accommodation platform, Gorm C, one gas flare stack, Gorm D, one riser platform, Gorm E (owned by DONG Olierør A/S) and one combined wellhead, processing and riser platform, Gorm F.

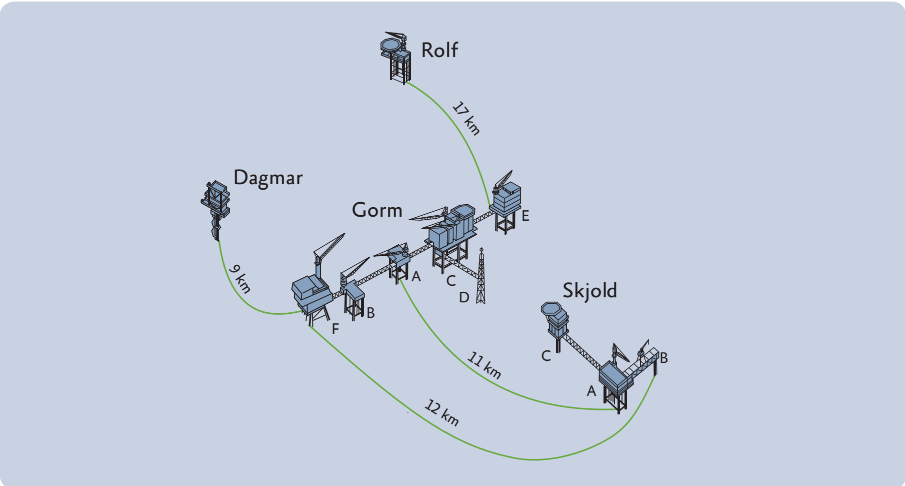
Gorm receives production from the satellite fields, Skjold, Rolf and Dagmar. The Gorm installations supply the Skjold Field with injection water and lift gas and the Rolf Field with lift gas. The gas produced is sent to Tyra East. The stabilized oil from all DUC's facilities is transported ashore via the riser platform Gorm E.

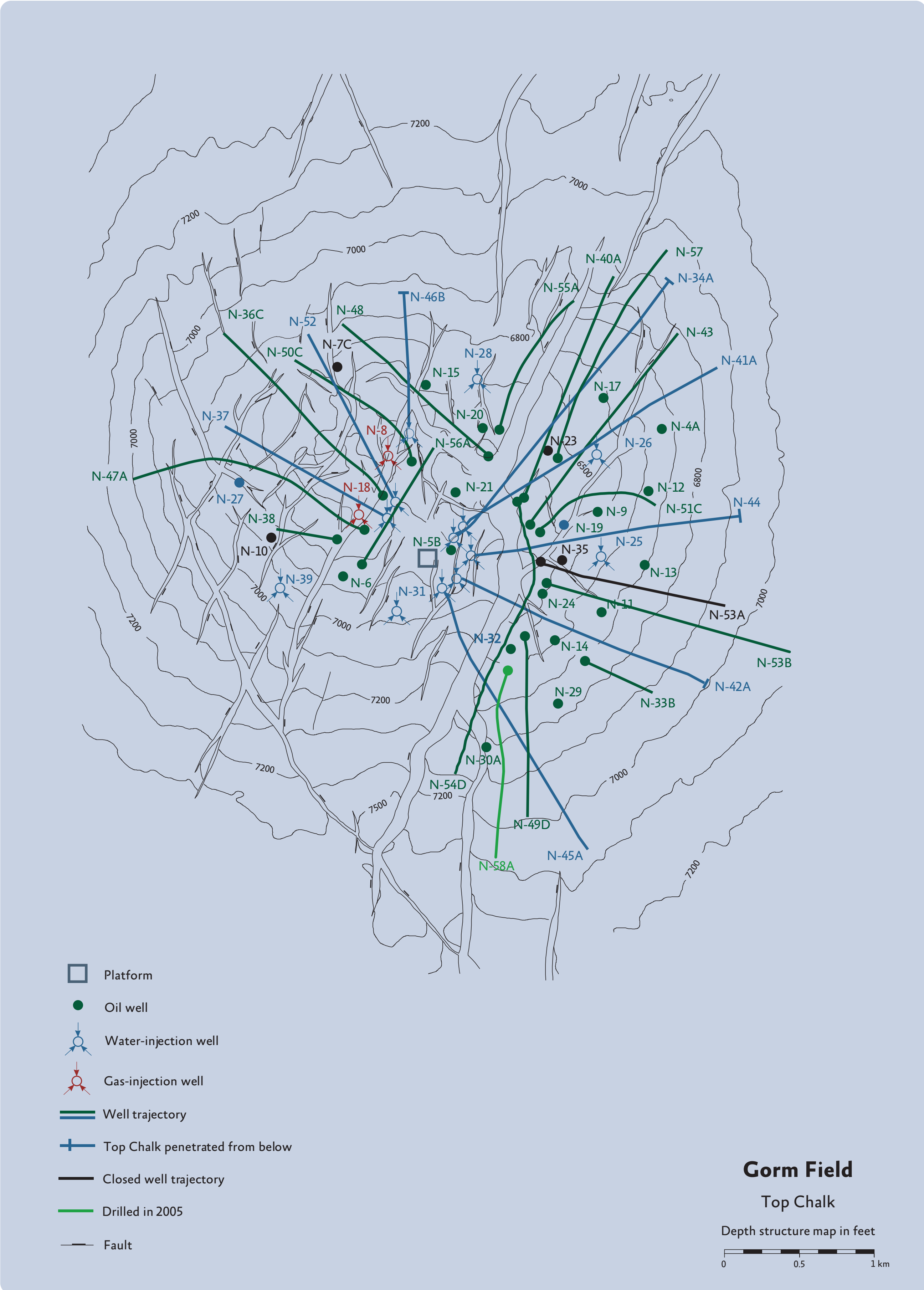
The processing facilities on the Gorm C platform consist of an oil stabilization plant for treating the oil from the Rolf Field, a produced-water treatment plant and facilities for processing and compressing the gas produced.

The processing facilities on the Gorm F platform consist of two oil stabilization plants, one receiving the sour oil and gas from the Dagmar Field, and the other receiving the production from the Gorm and Skjold Fields.

The Gorm F platform houses wellhead compression facilities to reduce the wellhead pressure in the Gorm and Skjold wells.

There are accommodation facilities on the Gorm C platform for 98 persons.




N-57
N-40A
N-34A
N-55A
N-46B
N-36C
N-48
N-52
N-7C
N-50C
N-43
N-41A
N-28
N-15
N-17
N-37
N-20
N-4A
N-8
N-23
N-56A
N-26
N-47A
N-18
N-21
N-12
N-27
N-51C
N-44
N-9
N-38
N-19
N-5B
N-25
N-10
N-35
N-13
N-39
N-6
N-31
N-24
N-11
N-53A
N-32
N-14
N-53B
N-42A
N-29
N-33B
N-30A
N-54D
N-49D
N-45A
N-58A
7200
7000
6800
6500
7500
Platform
Oil well
Water-injection well
Gas-injection well
Well trajectory
Top Chalk penetrated from below
Closed well trajectory
Drilled in 2005
Fault
Gorm Field
Top Chalk
Depth structure map in feet
0
0.5
1 km

THE HALFDAN FIELD, INCLUDING SIF AND IGOR

Prospect:	Nana (Halfdan)
Location:	Blocks 5505/13 and 5504/16
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1999 (Halfdan and Sif) 1968 (Igor)
Year on stream:	1999 (Halfdan) 2004 (Sif and Igor)
Oil-producing wells:	23 (Halfdan)
Water-injection wells:	22 (Halfdan)
Gas-producing wells:	6 (Sif)
Water depth:	43 m
Field delineation:	107km^2 (Halfdan) 109 km2 (Igor) 40 km^2 (Sif)
Reservoir depth:	2,050-2,100m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2006:	
Oil:	74.7 million m^3
Gas:	13.0billion Nm^3
Cum. production at 1 January 2006:	
Oil:	23.52million m^3
Gas:	6.66 billion Nm^3
Water:	6.70 million m3
Cum. injection at 1 January 2006:	
Water:	23.83 million m^3
Production in 2005:	
Oil:	6.17million m^3
Gas:	2.58billion Nm^3
Water:	2.84 million m^3
Injection in 2005:	
Water:	9.66 million m^3
Total investments at 1 January 2006:	
2005 prices	DKK 9.0 billion

REVIEW OF GEOLOGY

The Halfdan Field comprises the Halfdan, Sif and Igor areas and contains a large continuous hydrocarbon accumulation at different strata levels. The southwestern part of the field primarily contains oil in Maastrichtian layers, while the area towards the north and east primarily contains gas in Danian layers.

The accumulation is contained in a limited part of the chalk formation, which constituted a structural trap in earlier geological times. The structure gradually disintegrated, and the oil began migrating away from the area due to later movements in the reservoir layers. This means that today the structure does not appear from maps of the chalk surface, and that the oil continues to migrate. However, an accumulation of oil and gas still exists due to the low permeability of the reservoir. This porous, unfractured chalk is similar to that found in the western flank of the Dan Field.

PRODUCTION STRATEGY

Recovery is based on the Fracture Aligned Sweep Technology (FAST), where long horizontal wells are arranged in a pattern of alternate production and injection wells with parallel well trajectories. The injection wells initially inject water at low pressure, whereby the rock stress field is aligned parallel to the well. Subsequently, the water-injection pressure is increased, causing the rock to fracture along the well trajectory and generating a continuous water front along the whole length of the well, which drives the oil in the direction of the production wells. The injection wells are produced for a period of time before being converted to water injection. The injection wells are stimulated with acid, which makes it possible to inject large volumes of water.

The production of gas from Danian layers is based on primary recovery, using the reservoir pressure.

PRODUCTION FACILITIES

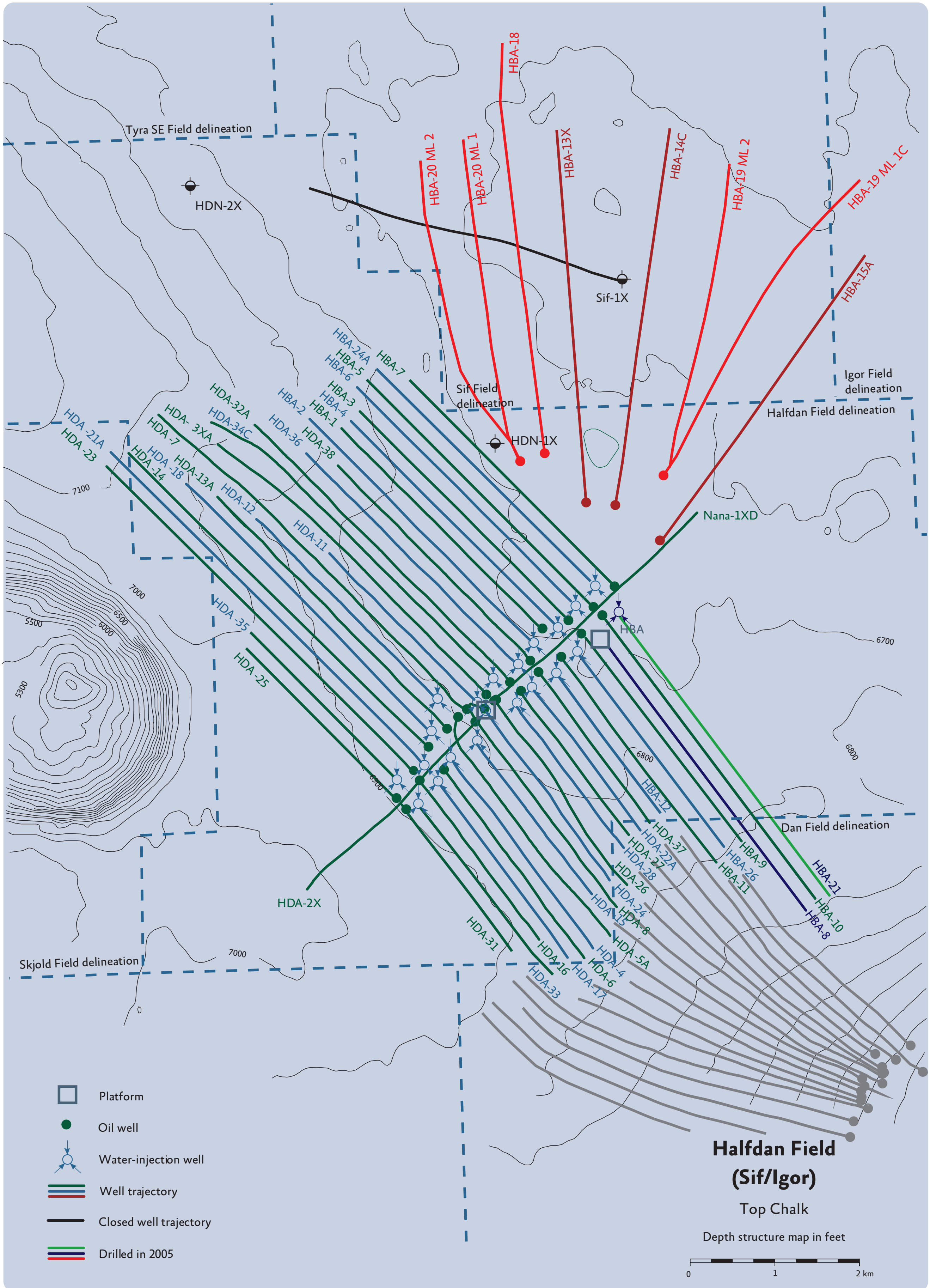
The Halfdan Field comprises a combined wellhead and processing platform, HDA, one accommodation platform, HDB, one gas flare stack, HDC, and an unmanned satellite wellhead platform, HBA, without a helideck. The HBA satellite platform is located about 2 km from the other Halfdan platforms, which provide it with electric power injection water and lift gas.

Production from the oil wells is transported through a multiphase pipeline for processing at the HDA platform, while production from the Sif and Igor gas wells and from two oil wells is separated by a two-phase separator into a liquid and a gas flow. The liquid is piped through the multiphase pipeline to the HDA platform for processing. After separation at the HDA platform, the oil/condensate is transported to Gorm E in the Gorm Field for final processing and export ashore.

Halfdan HDC and Tyra West are interconnected by a gas pipeline, which is hooked up via a riser to the gas installations on the Halfdan HBA platform. Gas pipelines also connect Halfdan HDA and Dan.

The gas from the HBA platform is transported to Tyra West, while the gas from Halfdan HDA is transported to Dan for export ashore via Tyra East or to Tyra West via Halfdan HBA for export to the Netherlands through the NOGAT pipeline.

The Dan installations supply the Halfdan Field with injection water. Treated production water from Halfdan is discharged into the sea. The Halfdan HDB platform has accommodation facilities for 32 persons.


Tyra SE Field delineation
HDN-2X
Sif-1X
HDN-1X
Sif Field delineation
Igor Field delineation
Halfdan Field delineation
Nana-1XD
HBA
Dan Field delineation
Skjold Field delineation
HDA-2X
HBA-18
HBA-20 ML 2
HBA-20 ML 1
HBA-13X
HBA-14C
HBA-19 ML 2
HBA-19 ML 1C
HBA-15A
7100
7000
6500
6000
5500
5300
6700
6800
Platform
Oil well
Water-injection well
Well trajectory
Closed well trajectory
Drilled in 2005
Halfdan Field
(Sif/Igor)
Top Chalk
Depth structure map in feet
0
1
2 km

THE HARALD FIELD	
Prospect:	Lulu/West Lulu
Location:	Blocks 5604/21and 22
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1980 (Lulu)
	1983 (West Lulu)
Year on stream:	1997
Gas-producing wells:	2 (Lulu), 2 (West Lulu)
Water depth:	64 m
Field delineation:	56 km^2
Reservoir depth:	2,700and 3,650m, respectively
Reservoir rock:	Chalk (Lulu)
	Sandstone (W. Lulu)
Geological age:	Danian, Upper Cretaceous and Middle Jurassic
Reserves at 1 January 2006:	
Oil and condensate:	0.9 million m^3
Gas:	4.8 billion Nm^3
Cum. production at 1 January 2006:	
Oil and condensate:	7.32million m^3
Gas:	17.90billion Nm^3
Water:	0.31 million m^3
Production in 2005:	
Oil and condensate:	0.24 million m^3
Gas:	1.09billion Nm^3
Water:	0.01 million m^3
Total investments at 1 January 2006:	
2005 prices	DKK 3.5 billion

REVIEW OF GEOLOGY

The Harald Field consists of two accumulations, Lulu (Harald East) and West Lulu (Harald West), which contain gas mainly.

The Lulu structure is an anticline induced through salt tectonics. The gas zone is up to 75metres thick and extends over an area of 6.5 km^2.

The West Lulu structure is a tilted Jurassic fault block. The sandstone reservoir is of Middle Jurassic age, and is situated at a depth of about 3,600 metres. The effective thickness of the sandstone is 100 metres.

PRODUCTION STRATEGY

Recovery from both the Lulu and the West Lulu reservoir takes place by gas expansion, supplemented by a moderate, natural influx of water into the reservoir.

Production from the Harald Field is based on the aim of optimizing the production of liquid hydrocarbons in the Tyra Field. This assumes that the Tyra reservoir pressure is stabilized by maximizing production from the other gas fields and thus minimizing the drainage from the Tyra Field. Therefore, increased production from the Harald Field helps optimize the Tyra production conditions.

PRODUCTION FACILITIES

The Harald Field comprises a combined wellhead and processing platform, Harald A, and an accommodation platform, Harald B.

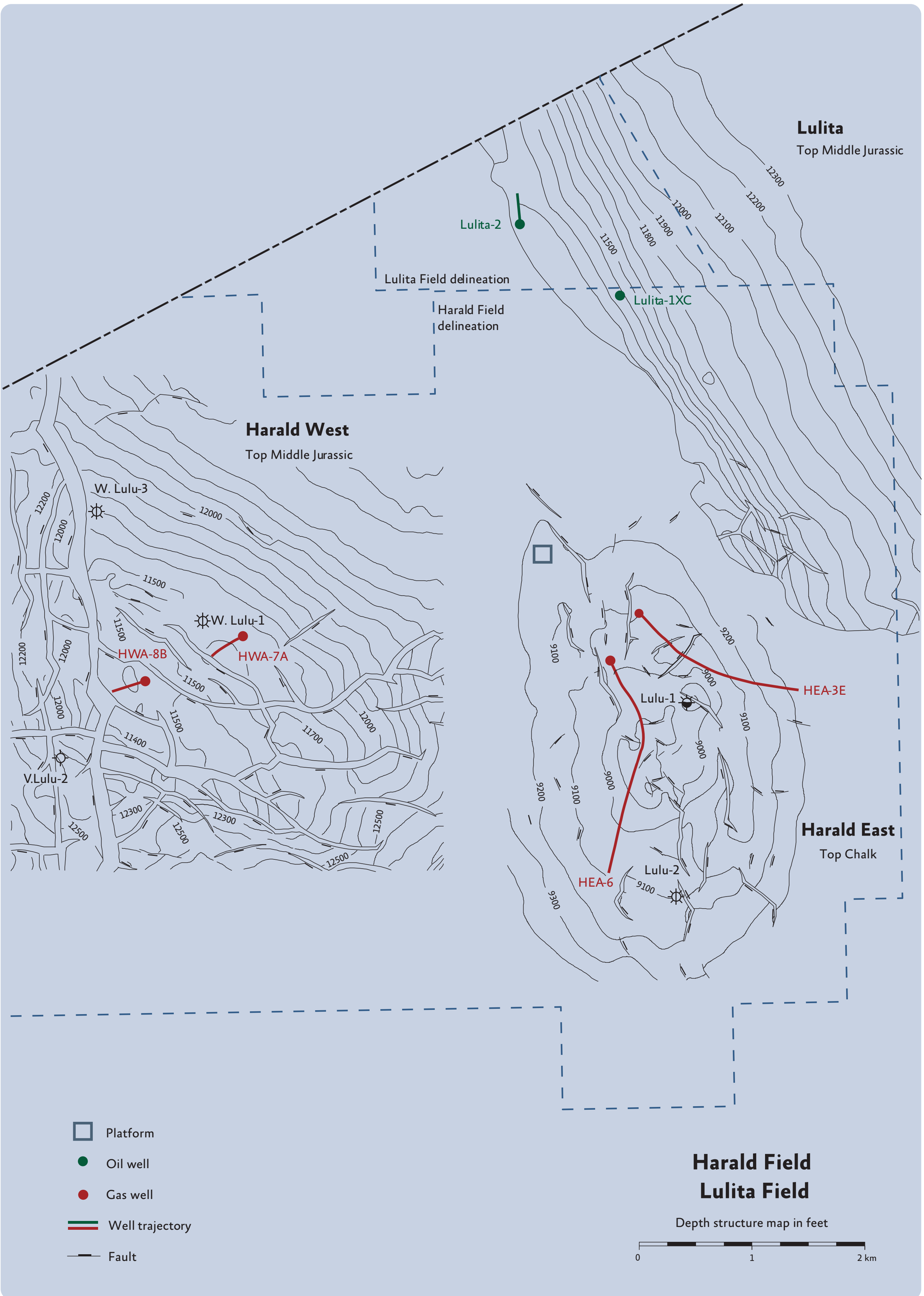
The processing facilities consist of a separation plant as well as gas-processing facilities.

The unprocessed condensate and the processed gas are transported to Tyra East.

In 2005, facilities for processing the water produced from Harald and Lulita were commissioned. Treated production water is discharged into the sea.

The Harald Field is hooked up to the gas pipeline that transports gas from the South Arne Field to Nybro. Normally, no gas is exported from Harald through the pipeline.

The Harald Field has accommodation facilities for 16persons.


Lulita
Top Middle Jurassic
12300
12200
12100
12000
11900
11800
11500
Lulita-2
Lulita Field delineation
Lulita-1XC
Harald Field
delineation
Harald West
Top Middle Jurassic
W. Lulu-3
12200
12000
11500
W. Lulu-1
HWA-8B
HWA-7A
11700
11400
V.Lulu-2
12300
12500
HEA-3E
Lulu-1
9000
9100
9200
9300
HEA-6
Lulu-2
Harald East
Top Chalk
Platform
Oil well
Gas well
Well trajectory
Fault
Harald Field
Lulita Field
Depth structure map in feet
0
1
2 km

THE KRAKA FIELD	
Prospect:	Anne
Location:	Block 5505/17
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1966
Year on stream:	1991
Producing wells:	7
Water depth:	45 m
Field delineation:	81km^2
Reservoir depth:	1,800m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2006:	
Oil:	1.9million m^3
Gas:	1.2billion Nm^3
Cum. production at 1 January 2006:	
Oil:	4.39 million m^3
Gas:	1.29billion Nm^3
Water:	3.92 million m^3
Production in 2005:	
Oil:	0.22 million m^3
Gas:	0.02 billion Nm^3
Water:	0.33 million m^3
Total investments at 1 January 2006:	
2005 prices	DKK 1.5billion

REVIEW OF GEOLOGY

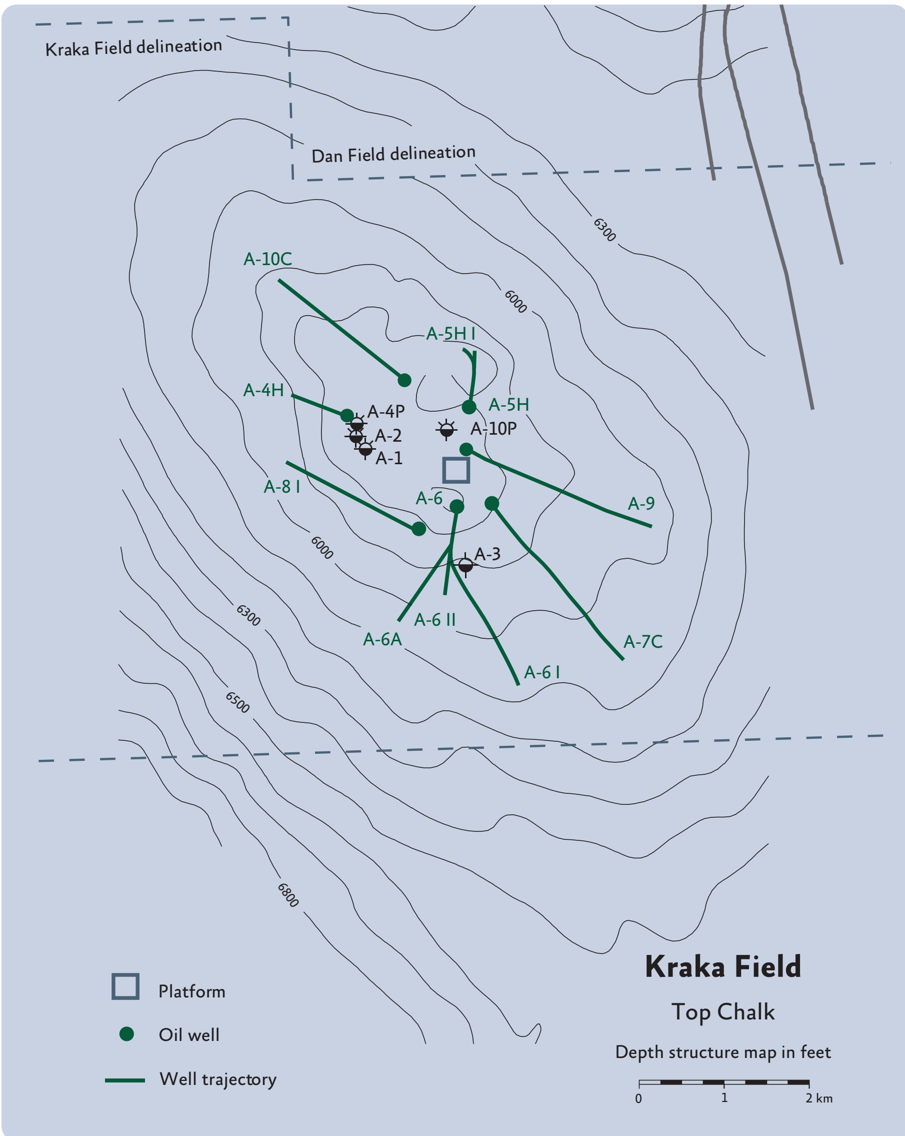
Kraka is an anticlinal structure induced through salt tectonics, which has caused some fracturing in the chalk. The chalk reservoir has reasonable porosity, although low permeability. The thin oil pay zone is further characterized by high water saturations, and has a minor overlying gas cap.

PRODUCTION STRATEGY

Recovery from Kraka is based on the natural expansion of the gas cap and aquifer support. Accordingly, the individual wells are produced at the lowest possible bottom-hole pressure. Oil production from the field is maximized by prioritizing gas lift in wells with a low water content and a low gas-oil ratio.

PRODUCTION FACILITIES

Kraka is a satellite development to the Dan Field with one unmanned wellhead platform of the STAR type without a helideck. The production is transported to the Dan FC platform for processing and export ashore. Lift gas is imported from the DFF platform.



THE LULITA FIELD	
Location:	Blocks 5604/18and 22
Licence:	Sole Concession (50 per cent), 7/86 (34.5 per cent) and 1/90(15.5per cent)
Operator:	Mærsk Olie og Gas AS
Discovered:	1992
Year on stream:	1998
Producing wells:	2
Water depth:	65 m
Area:	3 km^2
Reservoir depth:	3,525m
Reservoir rock:	Sandstone
Geological age:	Middle Jurassic
Reserves at 1 January 2006:	
Oil:	0.4 million m^3
Gas:	0.4 billion Nm^3
Cum. production at 1 January 2006:	
Oil:	0.71 million m^3
Gas:	0.47 billion Nm^3
Water:	0.12 million m^3
Production in 2005:	
Oil:	0.04 million m^3
Gas:	0.01 billion Nm^3
Water:	0.04 million m^3
Total investments at 1 January 2006:	
2005 prices	DKK 0.1 billion

REVIEW OF GEOLOGY

The Lulita Field is a structural fault trap with a Middle Jurassic sandstone reservoir. The accumulation consists of oil with a gas cap.

PRODUCTION STRATEGY

The production of oil and gas is based on natural depletion.

PRODUCTION FACILITIES

Production from the Lulita Field takes place from the fixed installations in the Harald Field. Thus, the Lulita facilities are hosted by the Harald A platform, and the Harald platform processing equipment also handles production from the Lulita Field. In the Harald Field, facilities for processing water production were commissioned in 2005.

Together with condensate from the Harald Field, the oil produced is transported through a 16"pipeline to Tyra East for export ashore. The gas produced in the Lulita Field is transported to Tyra through the 24" pipeline connecting Harald with Tyra East and into the export lines. The water produced at the Lulita Field is processed at the Harald Field facilities and subsequently discharged into the sea.

The Harald A platform has special equipment for separate metering of the oil and gas produced from the Lulita Field.

The map of the Harald Field includes the Lulita Field.

THE NINI FIELD	
Location:	Blocks 5605/10and 14
Licence:	4/95
Operator:	DONG E&P A/S
Discovered:	2000
Year on stream:	2003
Producing wells:	5
Water-injection wells:	2
Water depth:	60 m
Field delineation:	48.8 km^2
Reservoir depth:	1,700m
Reservoir rock:	Sandstone
Geological age:	Paleogene
Reserves at 1 January 2006:	
Oil:	1.1million m^3
Gas:	0.0 billion Nm^3*
Cum. production at 1 January 2006:	
Oil:	2.49 million m^3
Gas:	0.19 billion Nm^3*
Water:	0.80 million m^3
Cum. injection at 1 January 2006:	
Water:	1.49 million m^3
Production in 2005:	
Oil:	0.62 million m^3
Gas:	0.05 billion Nm^3*
Water:	0.73 million m^3
Injection in 2005:	
Water:	0.50 million m^3
Total investments at 1 January 2006:	
2005 prices	DKK 1.9billion

** The gas is injected into the Siri Field.*

REVIEW OF GEOLOGY

The Nini accumulation is defined by a combined structural and stratigraphic trap, the anticlinal structure being induced through salt tectonics. The reservoir consists of channel sands deposited in the Siri Fairway. The Nini Field also includes the Nini West area.

PRODUCTION STRATEGY

The production strategy is to maintain reservoir pressure by means of water injection. The gas produced is injected into the Siri Field.

PRODUCTION FACILITIES

Nini is a satellite development to the Siri Field with one unmanned wellhead platform with a helideck. The unprocessed production is transported through a 14"multiphase pipeline to the Siri platform where it is processed and exported to shore via tanker. Injection water and lift gas are transported from the Siri platform to the Nini platform through a 10"pipeline and a 4" pipeline, respectively.

NA-6C
NA-4B
NA-7D
NA-1
NA-2B
NA-3B
NA-5
1650
1660
1670
1680
1690
1700
1710
1720
1730
1740
1750
1760
1770
1780
Platform
Oil well
Water-injection well
Well trajectory
Drilled in 2005
Nini Field
Top of Paleogene reservoirs
Depth structure map in metres
0
0.5
1 km

THE REGNAR FIELD	
Prospect:	Nils
Location:	Block 5505/17
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1979
Year on stream:	1993
Producing wells:	1
Water depth:	45 m
Field delineation:	20 km^2
Reservoir depth:	1,700m
Reservoir rock:	Chalk and Carbonates
Geological age:	Upper Cretaceous and Zechstein
Reserves at 1 January 2006:	
Oil:	0.1 million m^3
Gas:	0.0 billion Nm^3
Cum. production at 1 January 2006:	
Oil:	0.92 million m^3
Gas:	0.06 billion Nm^3
Water:	3.81 million m^3
Production in 2005:	
Oil:	0.02 million m^3
Gas:	0.00 billion Nm^3
Water:	0.36 million m^3
Total investments at 1 January 2006:	
2005 prices	DKK 0.2 billion

REVIEW OF GEOLOGY

The Regnar Field is an anticlinal structure, induced through salt tectonics. The reservoir is heavily fractured (compare Skjold, Rolf, Dagmar and Svend).

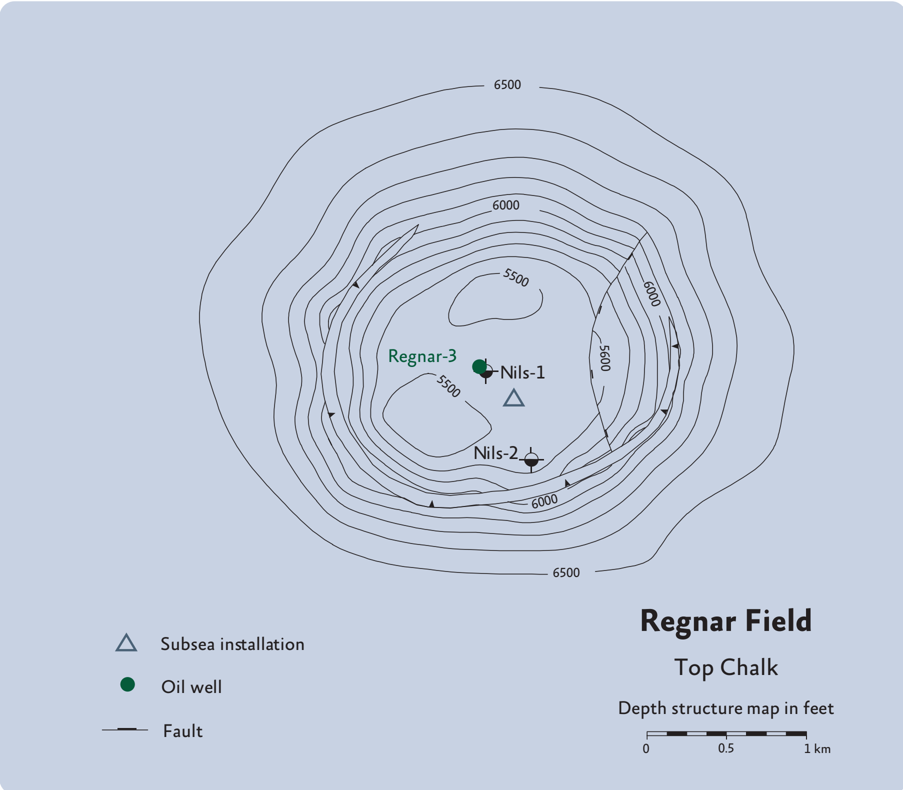
PRODUCTION STRATEGY

Production in the Regnar Field takes place from one vertical well on the crest of the structure. The oil is displaced towards the producing well by water flowing in from the aquifer. The production strategy is to displace and produce as much of the oil as possible from the tight matrix of the formation.

PRODUCTION FACILITIES

The Regnar Field has been developed as a satellite to the Dan Field. Production takes place in a subsea-completed well. The production is transported by pipeline in multiphase flow to Dan FC for processing and export ashore.

The well is remotely monitored and controlled from the Dan FC platform.



THE ROAR FIELD

Prospect:	Bent
Location:	Block 5504/7
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1968
Year on stream:	1996
Gas-producing wells:	4
Water depth:	46 m
Field delineation:	41 km^2
Reservoir depth:	2,025m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2006:	
Oil and condensate:	0.4 million m^3
Gas:	3.5 billion Nm^3
Cum. production at 1 January 2006:	
Oil and condensate:	2.42 million m^3
Gas:	12.83 billion Nm^3
Water:	3.25 million m^3
Production in 2005:	
Oil and condensate:	0.09 million m^3
Gas:	0.86 billion Nm^3
Water:	0.66 million m^3
Total investments at 1 January 2006:	
2005 prices	DKK 0.6 billion

REVIEW OF GEOLOGY

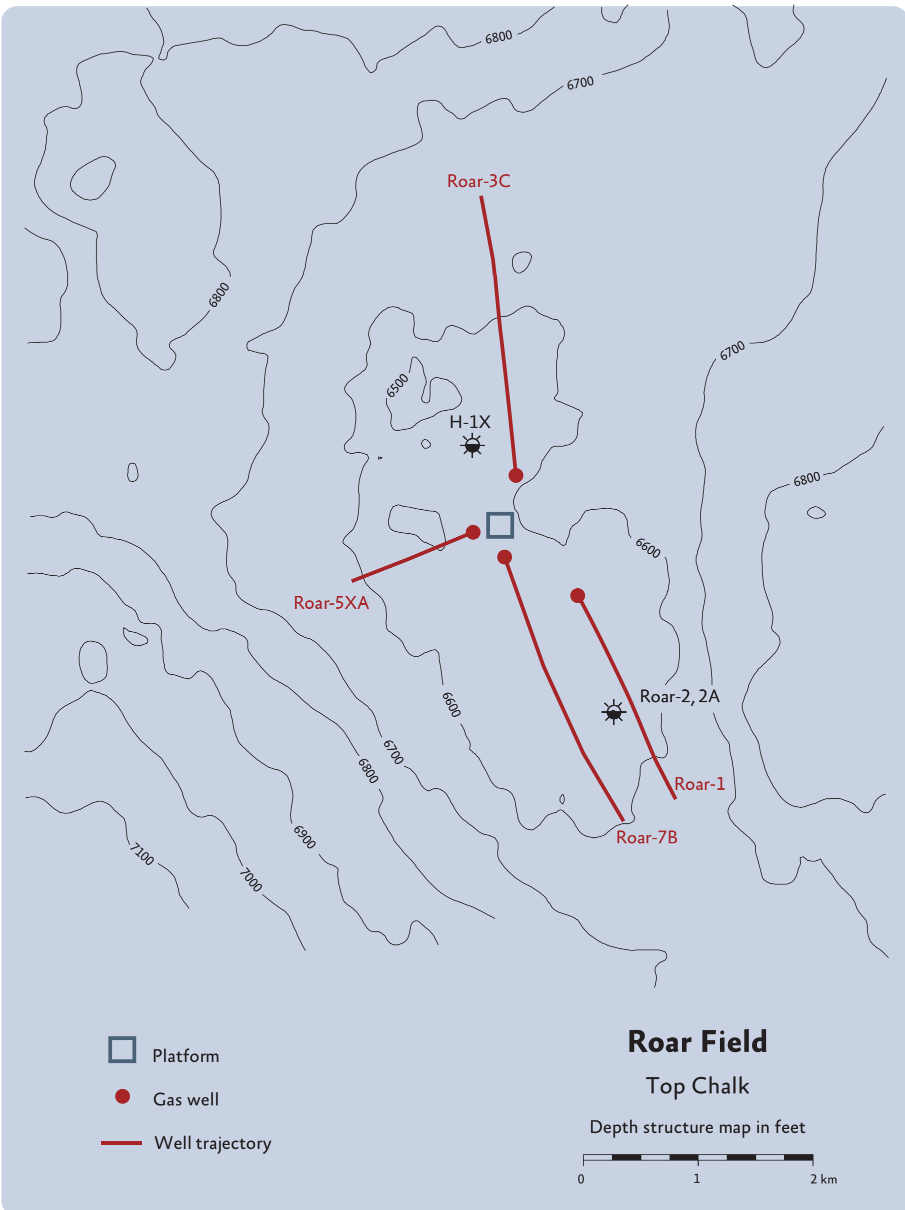
The Roar Field is an anticlinal structure, induced through tectonic uplift. The accumulation consists of free gas containing condensate. The reservoir is only slightly fractured.

PRODUCTION STRATEGY

The production strategy for the Roar Field is to optimize the production of liquid hydrocarbons in the Tyra Field. This assumes that the Tyra reservoir pressure is stabilized by maximizing production from the other gas fields and thus minimizing the drainage from the Tyra Field. Therefore, increased production from the Roar Field helps optimize the Tyra production conditions.

PRODUCTION FACILITIES

The Roar Field has been developed as a satellite to the Tyra Field with an unmanned wellhead platform of the STAR type without a helideck. The production is separated into gas and liquids before being transported to Tyra East in two pipelines for further processing and subsequent export ashore. A pipeline from Tyra East supplies chemicals to the Roar platform.



THE ROLF FIELD

Prospect:	Middle Rosa
Location:	Blocks 5504/14and 15
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1981
Year on stream:	1986
Producing wells:	2
Water depth:	34 m
Area:	8 km^2
Reservoir depth:	1,800m
Reservoir rock:	Chalk and Carbonates
Geological age:	Danian, Upper Cretaceous and Zechstein
Reserves at 1 January 2006:	
Oil:	0.4 million m^3
Gas:	0.0 billion Nm^3
Cum. production at 1 January 2006:	
Oil:	4.02 million m^3
Gas:	0.17billion Nm^3
Water:	5.15 million m^3
Production in 2005:	
Oil:	0.08 million m^3
Gas:	0.00 billion Nm^3
Water:	0.29 million m^3
Total investments at 1 January 2006:	
2005 prices	DKK 1.0billion

REVIEW OF GEOLOGY

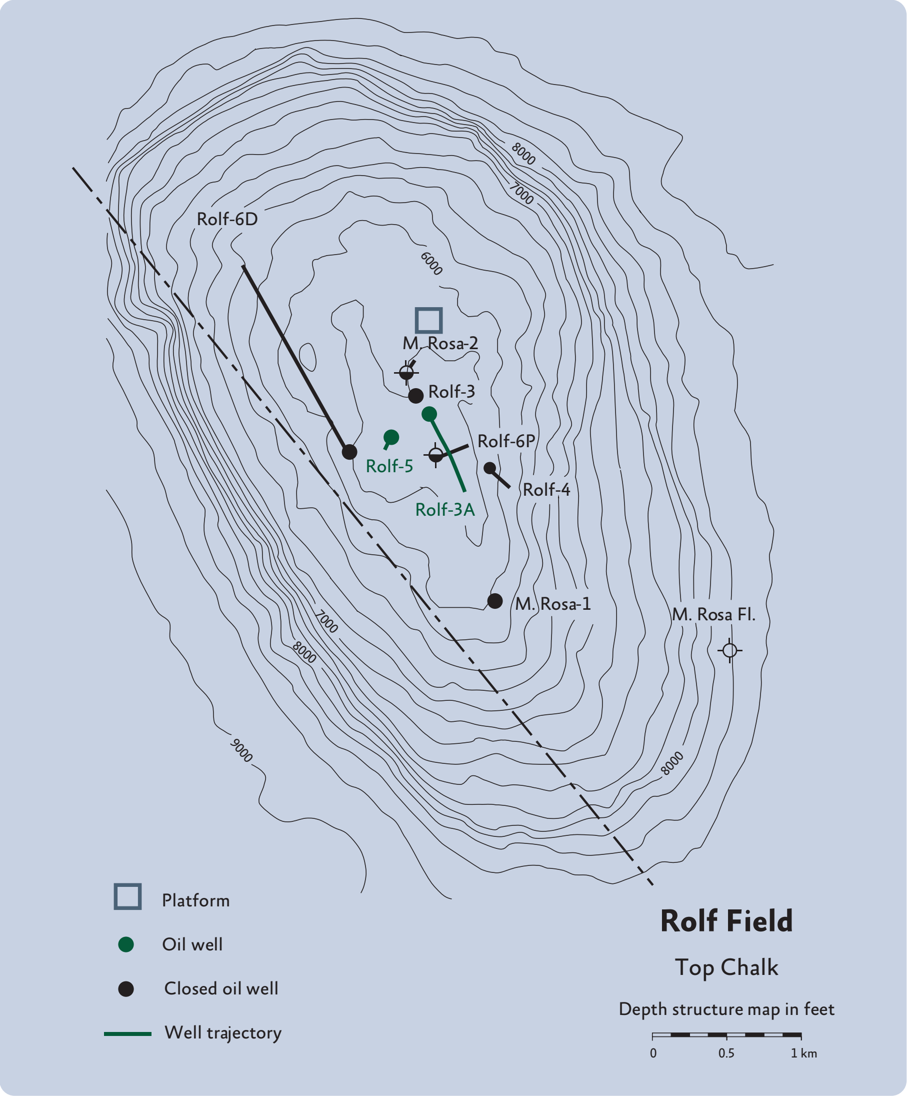
Rolf is an anticlinal structure created through salt tectonics. The chalk reservoir is heavily fractured (compare Skjold, Dagmar, Regnar and Svend).

PRODUCTION STRATEGY

Production from the Rolf Field takes place from two wells drilled in the crest of the structure. The oil is displaced towards the producing wells by the water flow from an underlying aquifer. The natural influx of water from the water zone corresponds to the volume removed due to production in the central part of the structure. To date, it has not been found necessary to add energy to the reservoir by water injection.

PRODUCTION FACILITIES

The Rolf Field is a satellite development to the Gorm Field with one unmanned wellhead platform. The platform is provided with a helideck. The production is transported to the Gorm C platform in the Gorm Field for processing. Rolf is also supplied with power and lift gas from the Gorm Field.



THE SIRI FIELD	
Location:	Block 5604/20
Licence:	6/95
Operator:	DONG E&P A/S
Discovered:	1995
Year on stream:	1999
Producing wells:	5 (Siri central)
	1 (Stine segment 1)
	2 (Stine segment 2)
Water-/Gas-injection wells:	2 (Siri central)
Water-injection wells:	1 (Stine segment 1)
Water depth:	60 m
Field delineation:	42 km^2
Reservoir depth:	2,060 m
Reservoir rock:	Sandstone
Geological age:	Paleocene
Reserves at 1 January 2006:	
Oil:	2.2 million m^3
Gas:	0.0 billion Nm^3
Cum. production at 1 January 2006:	
Oil:	9.28 million m^3
Net gas:	0.10 billion Nm^3
Water:	14.21 million m^3
Cum. injection at 1 January 2006:	
Gas:	0.86 billion Nm^3*
Water:	20.48 million m^3
Production in 2005:	
Oil:	0.70 million m^3
Gas:	0.03 billion Nm^3
Water:	1.69 million m^3
Injection in 2005:	
Gas:	0.14 billion Nm^3*
Water:	1.35 million m^3
Total investments at 1 January 2006:	
2005 prices	DKK 4.8 billion

** Gas from the Cecilie and Nini Fields is injected into the Siri Field.*

REVIEW OF GEOLOGY

The Siri Field is a structural trap with a Paleocene sandstone reservoir. The accumulation consists of oil with a relatively low content of gas. Recovery takes place from Siri central as well as from the neighbouring Stine segments 1 and 2.

PRODUCTION STRATEGY

The recovery strategy for Siri central is to maintain the reservoir pressure close to the initial pressure, based on the injection of water and gas, and the volume of water injection is balanced with the volume of liquid produced from the reservoir. In addition, gas from the Cecilie and Nini Fields is injected into the Siri Field.

The recovery from Stine segment 1 is based on water injection to maintain reservoir pressure. Previously, recovery from Stine segment 2 was based on natural depletion, but water injection will be initiated in SCA-7 in 2006.

PRODUCTION FACILITIES

The Siri central and Stine segment 2 installations comprise a combined wellhead, processing and accommodation platform. The processing facilities consist of a separation plant that treats the hydrocarbons produced from Siri/Stine and from Nini and Cecilie. The water produced in the Siri Field and satellite fields is processed at Siri. Normally, the water produced is injected into the Siri Field and its satellite fields. The platform also houses equipment for injecting gas and water.

The Stine segment 1 development consists of a subsea installation and a 6” multiphase pipeline for transporting production to the Siri platform. Lift gas and injection water are supplied from the Siri platform.

The oil produced is piped to a 50,000 m^3 storage tank on the seabed. When the tank is full, buoy-loading facilities are used to transfer the oil to a tanker.

The Siri Field has accommodation facilities for 60 persons.


Siri Field
Depth structure map in metres
0
1
2 km
Siri Central
Top Heimdal sandstone
Siri North
Top Heimdal sandstone
Stine segment 1
Top Hermod sandstone
Stine segment 2
Top Hermod sandstone
SCB-2
SCB-1X
Siri-3A
Siri-3
2000
SCA-7C
SCA-6
Siri-4
Siri-5
2030
2040
SCA-5A
SCA-5
2070
SCA-8
Siri-1
SCA-4
SCA-2
SCA-10
SCA-3A
SCA-1B
SCA-11A
Siri-2
2060
Platform
Subsea installation
Oil well
Gas- and water-injection well
Closed well
Well trajectory
Closed well trajectory

THE SKJOLD FIELD

Prospect:	Ruth
Location:	Block 5504/16
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1977
Year on stream:	1982
Producing wells:	19
Water-injection wells:	9
Water depth:	40 m
Field delineation:	33 km^2
Reservoir depth:	1,600m
Reservoir rock:	Chalk
Geological age:	Danian, Upper Cretaceous and Zechstein
Reserves at 1 January 2006:	
Oil:	7.8 million m^3
Gas:	0.6 billion Nm^3
Cum. production at 1 January 2006:	
Oil:	38.33 million m^3
Gas:	3.20 billion Nm^3
Water:	39.16 million m^3
Cum. injection at 1 January 2006:	
Water:	86.36 million m^3
Production in 2005:	
Oil:	1.30 million m^3
Gas:	0.09 billion Nm^3
Water:	4.24 million m^3
Injection in 2005:	
Water:	5.90 million m^3
Total investments at 1 January 2006:	
2005 prices	DKK 5.3 billion

REVIEW OF GEOLOGY

The Skjold Field is an anticlinal structure, induced through salt tectonics. The edge of the structure is mainly delimited by a series of ring faults. The reservoir is intersected by numerous, minor faults in the central part of the structure. At the flanks of the structure, the reservoir is less fractured. Unusually favourable production properties have been shown to exist in the reservoir.

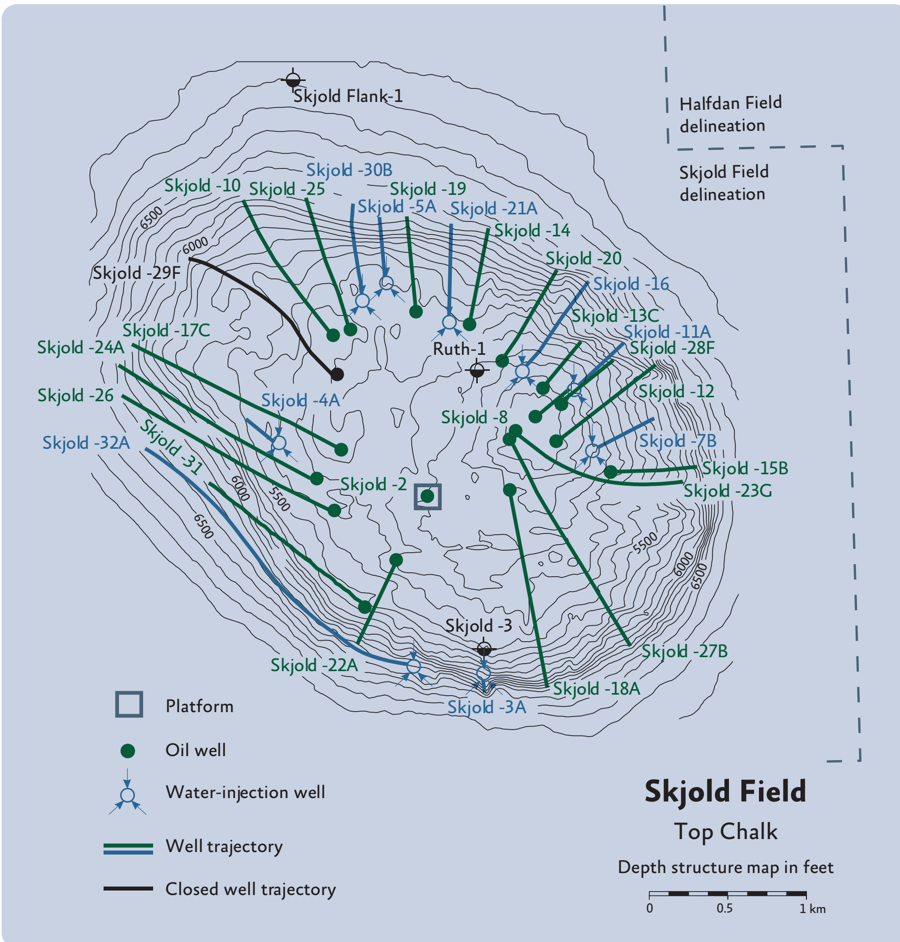
PRODUCTION STRATEGY

During the first years after production startup, oil was produced from the crestal, central part of the reservoir. In 1986, water injection was initiated in the reservoir. Today, oil from the Skjold Field is mainly produced from horizontal wells at the flanks of the reservoir. The production and injection wells are placed alternately in a radial pattern. The recovery of oil is optimized by flooding the main parts of the reservoir with as much water as possible. Water injection has stabilized the reservoir pressure above the bubble point of the oil.

PRODUCTION FACILITIES

The Skjold Field comprises a satellite development to the Gorm Field, including two wellhead platforms, Skjold A and B, as well as an accommodation platform, Skjold C. There are no processing facilities at the Skjold Field, and the production is transported to the Gorm F platform for processing. The Gorm facilities provide the Skjold Field with injection water and lift gas.

The Skjold C platform has accommodation facilities for 16persons.



THE SOUTH ARNE FIELD	
Location:	Blocks 5604/29 and 30
Licence:	7/89
Operator:	Amerada Hess ApS
Discovered:	1969
Year on stream:	1999
Producing wells:	11
Water-injection wells:	6
Water depth:	60 m
Field delineation:	93 km^2
Reservoir depth:	2,800 m
Reservoir rock:	Chalk
Geological age:	Danian, Upper Cretaceous and Lower Cretaceous
Reserves at 1 January 2006:	
Oil:	14.8 million m^3
Gas:	5.9 billion Nm^3
Cum. production at 1 January 2006:	
Oil:	14.67 million m^3
Gas:	3.82 billion Nm^3
Water:	3.26 million m^3
Cum. injection at 1 January 2006:	
Water:	22.31 million m^3
Production in 2005:	
Oil:	2.37 million m^3
Gas:	0.48 billion Nm^3
Water:	0.80 million m^3
Injection in 2005:	
Water:	5.61 million m^3
Total investments at 1 January 2006:	
2005 prices	DKK 8.9 billion

REVIEW OF GEOLOGY

South Arne is an anticlinal structure, induced through tectonic uplift, which has caused the chalk to fracture. The structure contains oil with a relatively high content of gas. The field is the deepest chalk field in Denmark.

PRODUCTION STRATEGY

The production of oil and gas is based on pressure support from water injection.

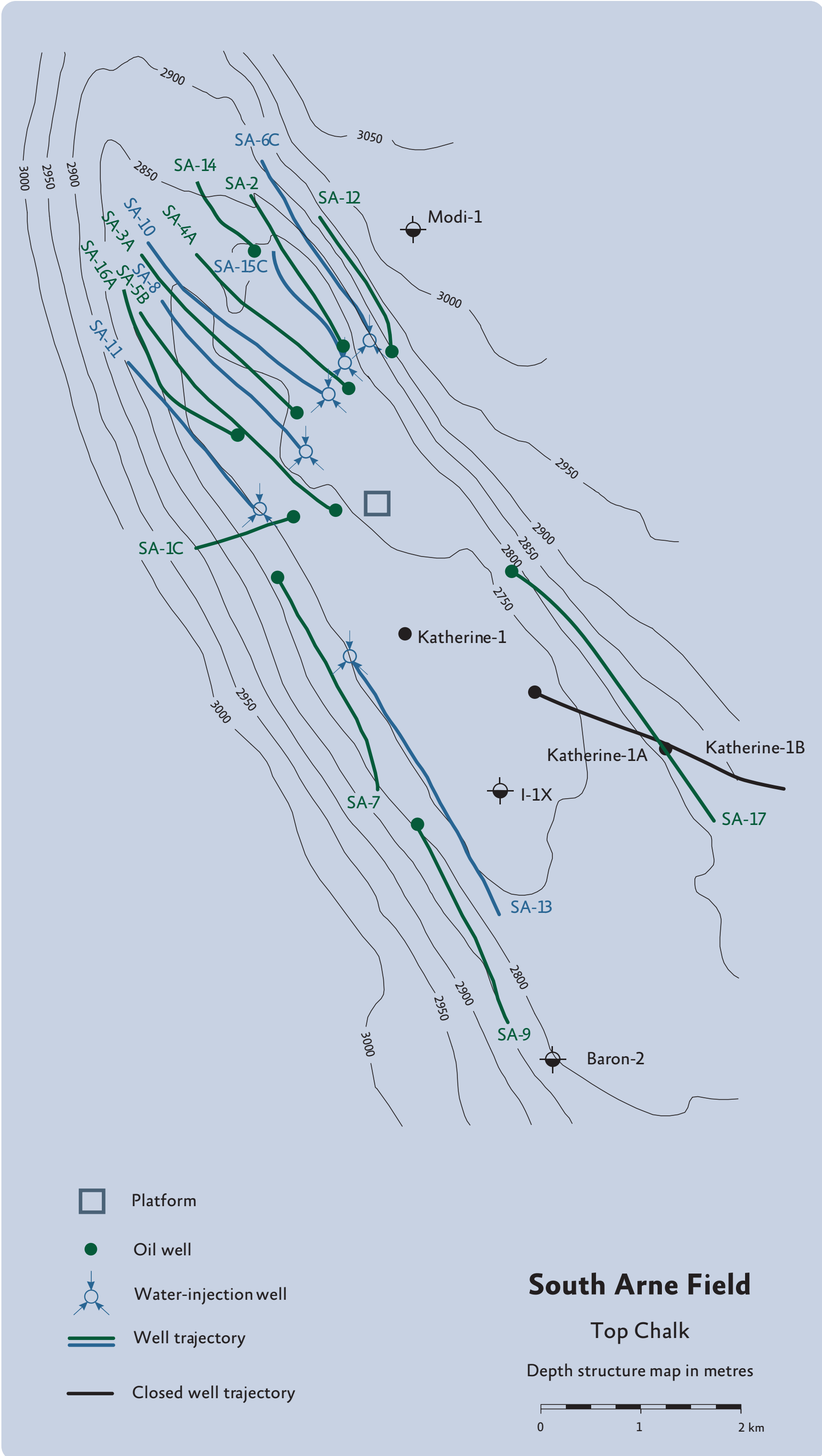
PRODUCTION FACILITIES

The South Arne Field installations comprise a combined wellhead, processing and accommodation platform.

The processing facilities consist of a separation plant that treats the production as well as gas-processing facilities. The platform also houses equipment for water injection. In order to prevent fouling of the injection wells and the reservoir due to scale deposition, special facilities have been installed to remove sulphur from the seawater injected into the field. Some of the water produced is injected into the field, while the rest is processed and discharged into the sea.

The oil produced is piped to an 87,000 m^3 storage tank on the seabed, and subsequently transferred to a tanker by means of buoy-loading facilities. The gas produced is exported through a gas pipeline to Nybro on the west coast of Jutland.

The South Arne Field has accommodation facilities for 57 persons.



SA-6C
SA-14
SA-2
SA-12
Modi-1
SA-10
SA-3A
SA-4A
SA-16A
SA-8
SA-5B
SA-15C
SA-11
SA-1C
Katherine-1
Katherine-1A
Katherine-1B
I-1X
SA-7
SA-17
SA-13
SA-9
Baron-2
2900
3050
2850
3000
2950
2800
2750
Platform
Oil well
Water-injection well
Well trajectory
Closed well trajectory
South Arne Field
Top Chalk
Depth structure map in metres
0
1
2 km

THE SVEND FIELD

Prospect:	North Arne/Otto
Location:	Block 5604/25
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1975 (North Arne) 1982 (Otto)
Year on stream:	1996
Producing wells:	4
Water depth:	65 m
Field delineation:	48 km^2
Reservoir depth:	2,500 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2006:	
Oil:	1.0 million m^3
Gas:	0.1 billion Nm^3
Cum. production at 1 January 2006:	
Oil:	5.71 million m^3
Gas:	0.68 billion Nm^3
Water:	7.96 million m^3
Production in 2005:	
Oil:	0.32 million m^3
Gas:	0.03 billion Nm^3
Water:	1.32 million m^3
Total investments at 1 January 2006:	
2005 prices	DKK 1.2 billion

REVIEW OF GEOLOGY

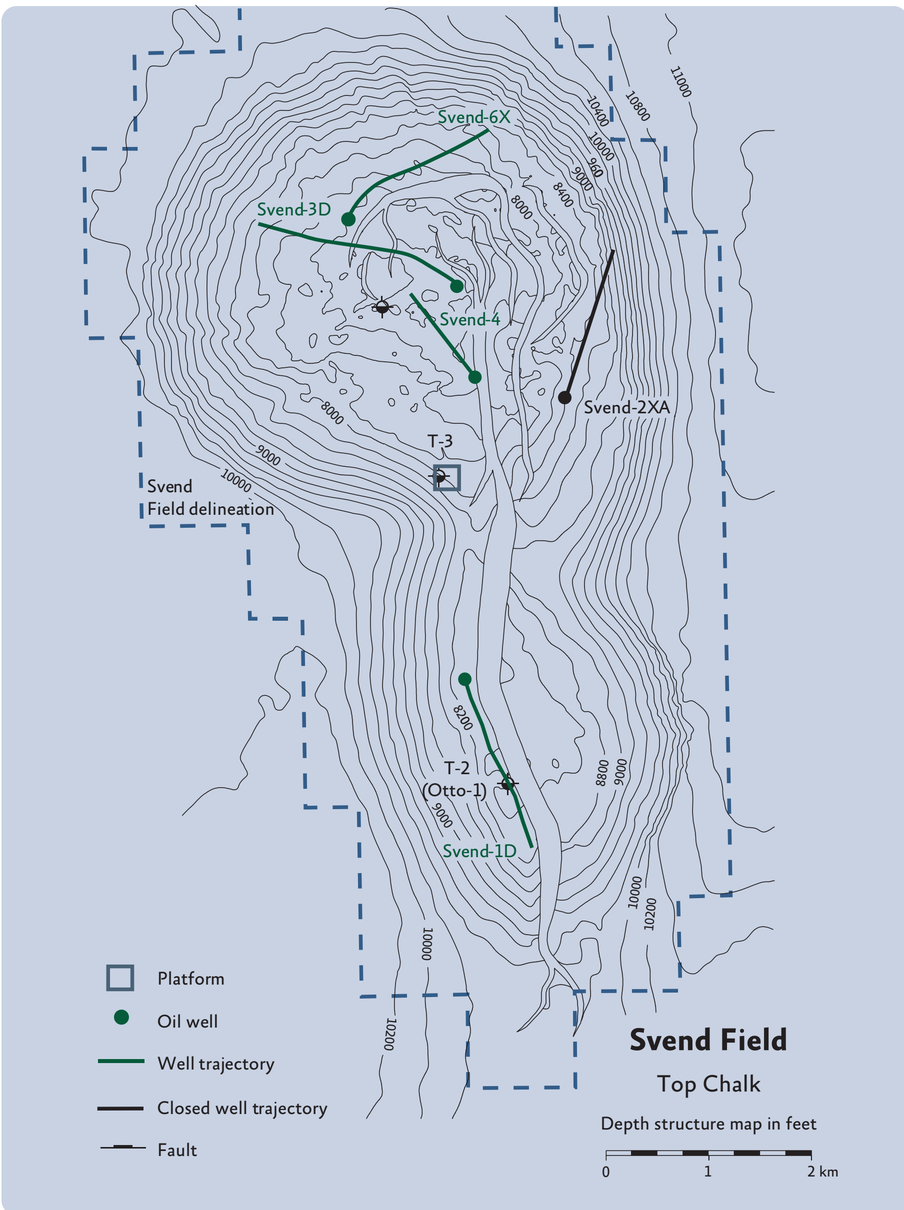
The Svend Field is an anticlinal structure, induced through salt tectonics. This led to fracturing of the chalk in the reservoir and divided the field into a western and an eastern block, separated by a major fault. The northern reservoir of the Svend Field is situated about 250 metres higher than the southern reservoir. The northern reservoir has proved to have unusually favourable production properties.

PRODUCTION STRATEGY

Production from the Svend Field is based on primary recovery at a reservoir pressure above the bubble point of the oil.

PRODUCTION FACILITIES

The Svend Field has been developed as a satellite to the Tyra Field with an unmanned wellhead platform of the STAR type without a helideck. The hydrocarbons produced are piped to Tyra East for processing and export ashore. The Svend Field is connected to the 16" pipeline from Harald to Tyra East.



THE TYRA FIELD	
Prospect:	Cora
Location:	Blocks 5504/11 and 12
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1968
Year on stream:	1984
Gas-producing wells:	16
Oil-/Gas-producing wells:	28
Producing/Injection wells:	20
Water depth:	37-40 m
Area:	90 km^2
Reservoir depth:	2,000 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2006:	
Oil and condensate:	4.0 million m^3
Gas:	20.5 billion Nm^3
Cum. production at 1 January 2006:	
Oil and condensate:	22.61 million m^3
Net gas:	39.85 billion Nm^3
Water:	31.67 million m^3
Cum. injection at 1 January 2006:	
Gas:	33.91 billion Nm^3
Production in 2005:	
Oil and condensate:	0.77 million m^3
Net gas:	2.46 billion Nm^3
Water:	3.48 million m^3
Injection in 2005:	
Gas:	1.29 billion Nm^3
Total investments at 1 January 2006:	
2005 prices	DKK 26.2 billion

REVIEW OF GEOLOGY

The Tyra Field is an anticlinal structure created by tectonic uplift. The accumulation contains free gas with condensate, overlying a thin oil zone. The reservoir is only slightly fractured.

PRODUCTION STRATEGY

The production strategy is not to deteriorate condensate and oil production conditions by reducing the reservoir pressure at an early stage. Increased gas production from DUC's other fields, in particular the Harald and Roar gas fields, meets the objective of optimizing the recovery of liquid hydrocarbons from the Tyra Field. Any excess production of gas is reinjected into the Tyra Field in order to increase the recovery of oil and condensate. Thus, the Tyra Field acts as a buffer.

PRODUCTION FACILITIES

The Tyra Field installations comprise two platform complexes, Tyra West (TW) and Tyra East (TE).

Tyra West consists of two wellhead platforms, TWB and TWC, one processing and accommodation platform, TWA, and one gas flare stack, TWD, as well as a bridge module installed at TWB and supported by a four-legged jacket, TWE.

The Tyra West processing facilities include a plant for pre-processing oil and condensate production from the wells at Tyra West. Moreover, the Tyra West complex houses gas-processing facilities and facilities for the injection and/or export of gas and processing facilities for the water produced. Oil and condensate are transported to Tyra East for final processing.

Tyra West has wellhead compression facilities, to which the Tyra oil wells and satellite wells are connected, including Roar, Tyra Southeast, Valdemar and Harald, and from 2006 also the gas wells in Halfdan. Tyra West receives the gas produced at Halfdan and Valdemar.

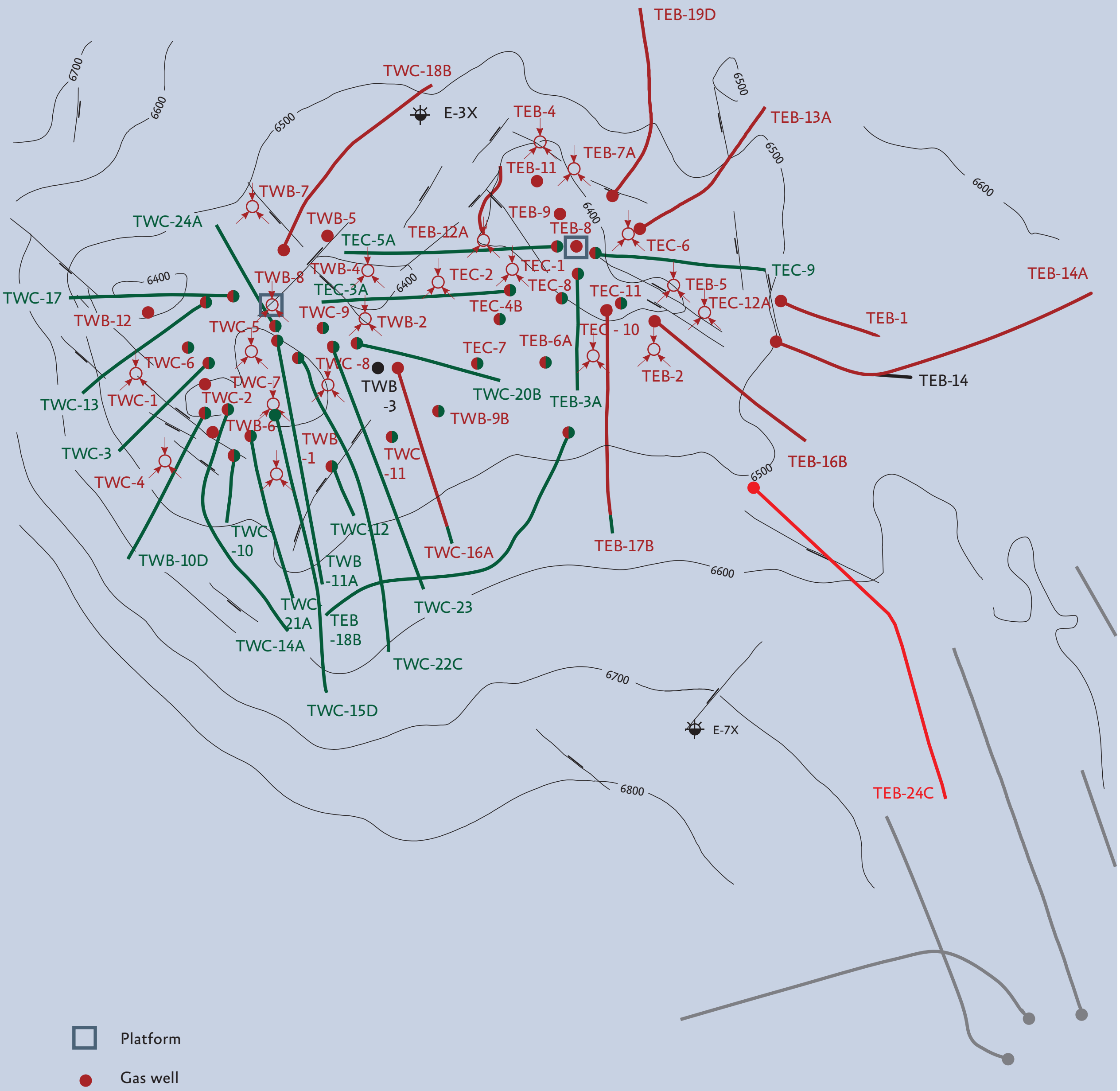
Tyra East consists of two wellhead platforms, TEB and TEC, one processing and accommodation platform, TEA, one gas flare stack, TED, and one riser platform, TEE, as well as a bridge module supported by a STAR jacket, TEF.

Tyra East receives production from the satellite fields, Roar, Svend, Tyra Southeast and Harald/Lulita, as well as gas production from the Gorm and Dan Fields and liquid production from Valdemar. The Tyra East complex includes facilities for the final processing of gas, oil, condensate and water.

The two platform complexes in the Tyra Field are interconnected by pipelines in order to yield maximum operational flexibility and reliability of supply. Oil and condensate production from the Tyra Field and its satellite fields is transported ashore via Gorm E, while the bulk of gas produced is transported from TEE at Tyra East to shore and the rest is transported from TWE at Tyra West to the NOGAT pipeline for export ashore in the Netherlands.

Treated production water from the Tyra Field and its satellite fields is discharged into the sea.

Tyra East has accommodation facilities for 96 persons, while there are accommodation facilities for 80 persons at Tyra West.



Platform

Gas well

Oil well with gas

Gas-injection well

Well trajectory

Drilled in 2005

Fault

Tyra Field

Top Chalk

Depth structure map in feet

0 1 2 km

THE TYRA SOUTHEAST FIELD	
Location:	Block 5504/12
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1991
Year on stream:	2003
Oil-producing wells:	5
Gas-producing wells:	2
Water depth:	38 m
Field delineation:	113 km^2
Reservoir depth:	2,050 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2006:	
Oil:	1.2 million m^3
Gas:	7.1 billion Nm^3
Cum. production at 1 January 2006:	
Oil:	2.03 million m^3
Gas:	3.47 billion Nm^3
Water:	1.75 million m^3
Production in 2005:	
Oil:	0.61 million m^3
Gas:	1.34 billion Nm^3
Water:	0.44 million m^3
Total investments at 1 January 2006:	
2005 prices	DKK 1.2 billion

REVIEW OF GEOLOGY

The Tyra Southeast Field is an anticlinal structure created by a slight tectonic uplift of Upper Cretaceous chalk layers. The structure is divided into two blocks separated by a northeastern-southwestern fault zone. The relief is less pronounced in this formation than in the Tyra Field. The structure is part of the major northwestern-southeastern uplift zone that also comprises Roar, Tyra and parts of the Halfdan Field.

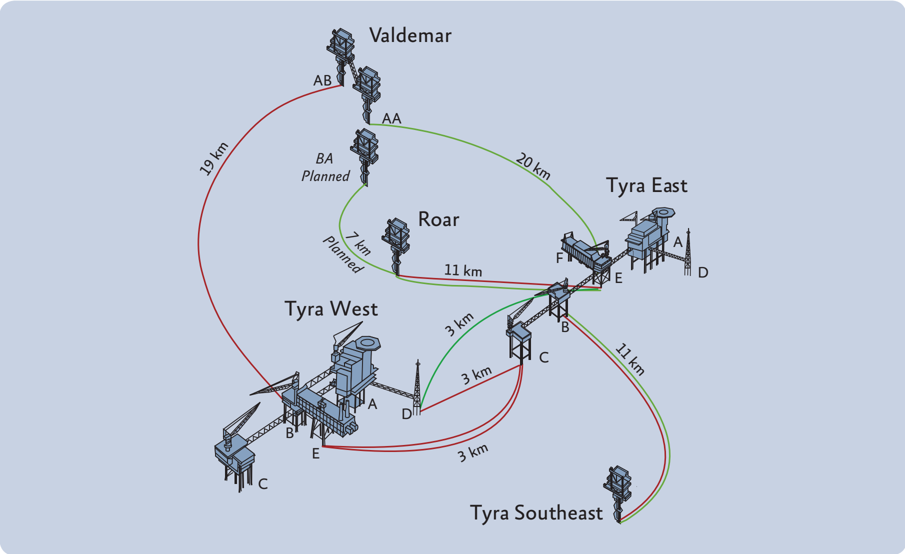
The Tyra Southeast accumulation contains free gas overlying an oil zone in the south-eastern part of the field.

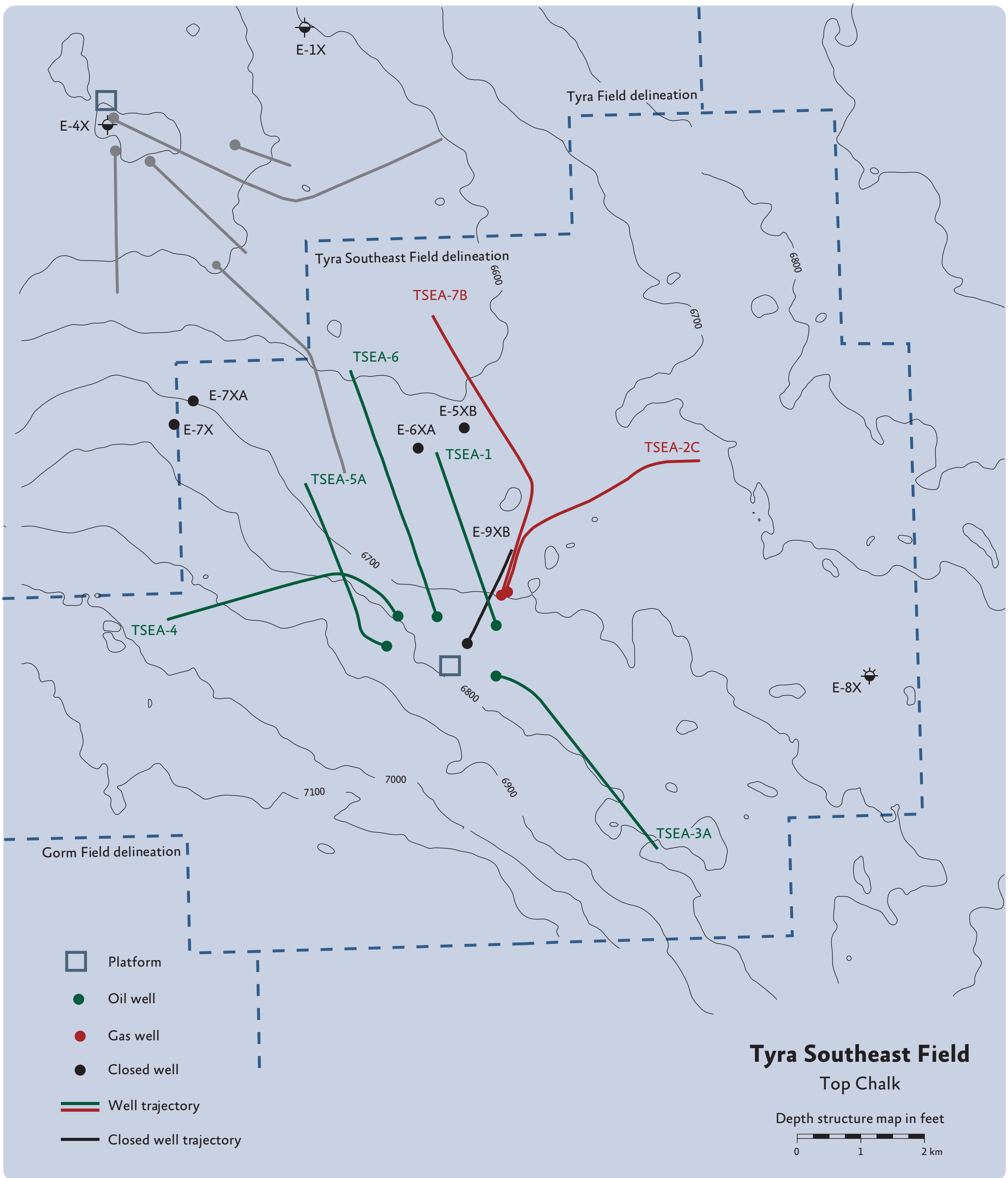
PRODUCTION STRATEGY

Production from the Tyra Southeast Field is based on natural depletion.

PRODUCTION FACILITIES

The Tyra Southeast Field has been developed as a satellite to the Tyra Field with an unmanned wellhead platform of the STAR type. After separation into a gas and a liquid phase, the production is transported to Tyra East in two pipelines to be processed and subsequently exported ashore.




E-1X
E-4X
Tyra Field delineation
Tyra Southeast Field delineation
TSEA-7B
TSEA-6
E-7XA
E-7X
E-5XB
E-6XA
TSEA-1
TSEA-2C
TSEA-5A
E-9XB
TSEA-4
E-8X
TSEA-3A
6600
6700
6800
6900
7000
7100
Gorm Field delineation
Platform
Oil well
Gas well
Closed well
Well trajectory
Closed well trajectory
Tyra Southeast Field
Top Chalk
Depth structure map in feet
0
1
2 km

THE VALDEMAR FIELD	
Prospect:	Bo/North Jens
Location:	Blocks 5504/7and 11
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1977 (Bo)
	1985 (North Jens)
Year on stream:	1993 (North Jens)
Producing wells:	8
Water depth:	38 m
Field delineation:	96 km^2
Reservoir depth:	2,000 m
	(Upper Cretaceous)
	2,600 m
	(Lower Cretaceous)
Reservoir rock:	Chalk
Geological age:	Danian, Upper and
	Lower Cretaceous
Reserves at 1 January 2006:	
Oil:	9.3 million m^3
Gas:	6.6 billion Nm^3
Cum. production at 1 January 2006:	
Oil:	2.98 million m^3
Gas:	1.25billion Nm^3
Water:	2.14million m^3
Production in 2005:	
Oil:	0.42 million m^3
Gas:	0.21billion Nm^3
Water:	0.79 million m^3
Total investments at 1 January 2006:	
2005 prices	DKK 2.5 billion

REVIEW OF GEOLOGY

The Valdemar Field consists of a northern reservoir called North Jens and a southern reservoir called Bo, which are both anticlinal chalk structures associated with tectonic uplift.

Valdemar comprises several separate reservoirs. Oil and gas have been discovered in Danian/Upper Cretaceous chalk, and large volumes of oil-in-place have been identified in Lower Cretaceous chalk. While the properties of the Upper Cretaceous reservoirs are comparable to other Danish fields like Gorm and Tyra, the Lower Cretaceous chalk possesses challenging production properties due to its extremely low permeability.

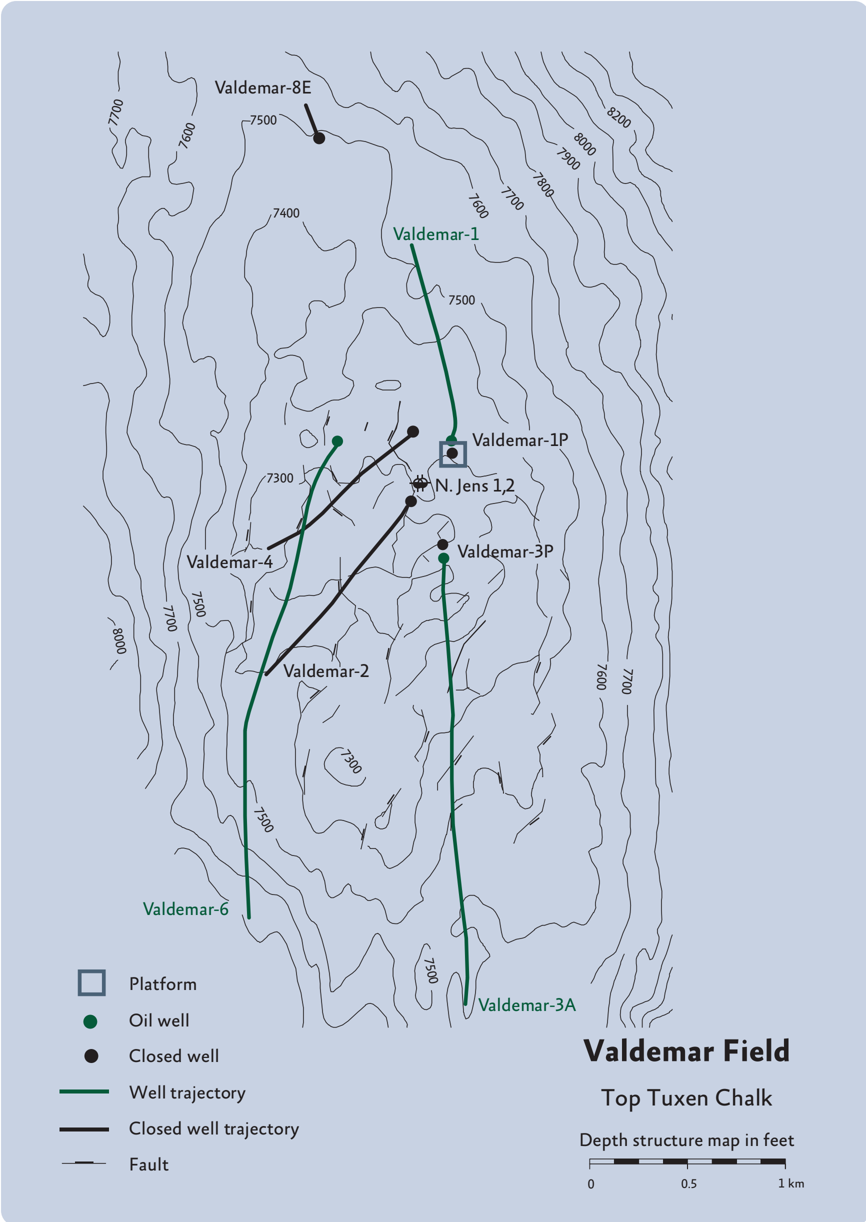
PRODUCTION STRATEGY

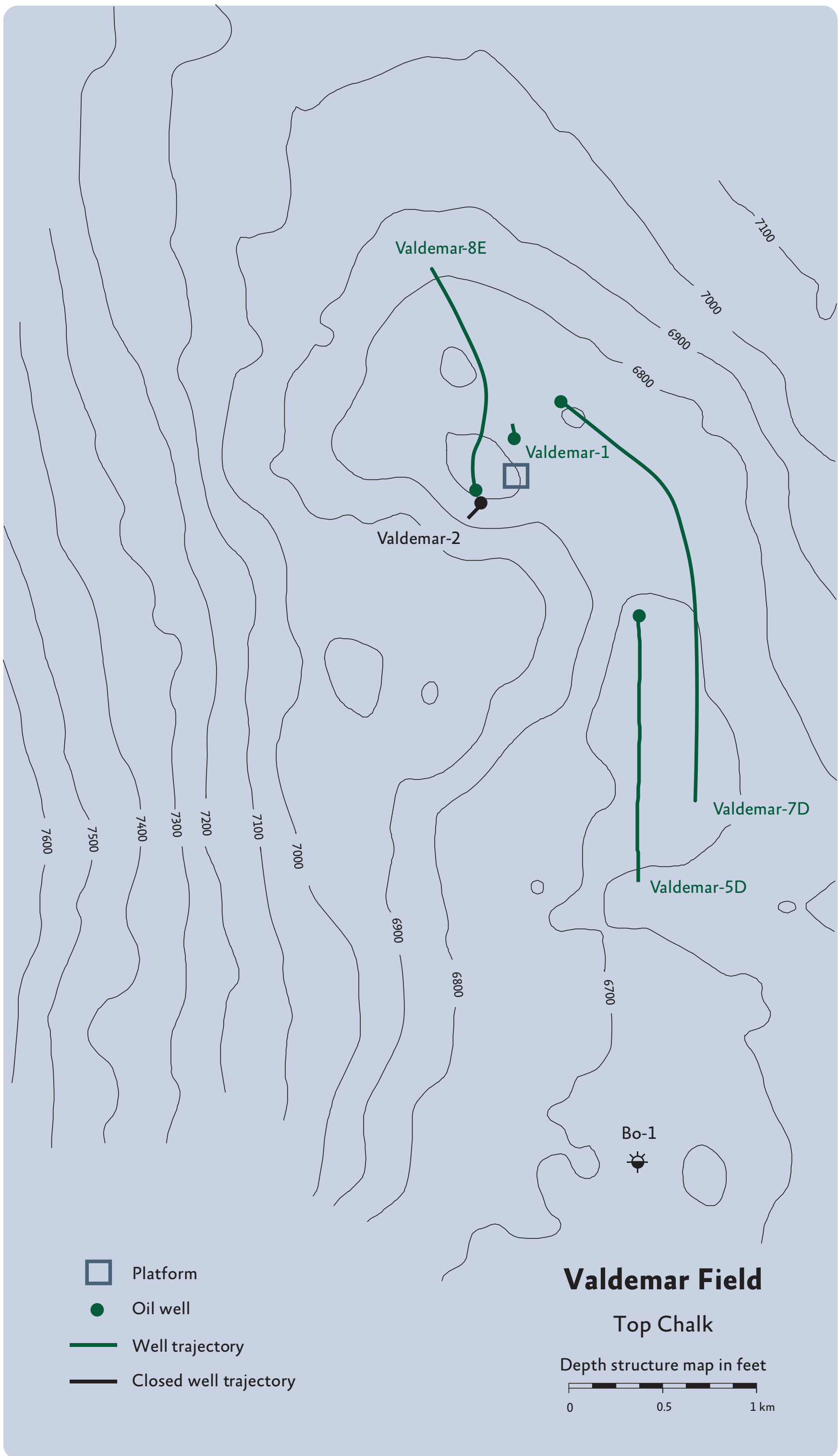
Production from the field is based on primary recovery. The development of a production method based on long horizontal wells with numerous sand-filled, artificial fractures has made it possible to exploit the Lower Cretaceous reservoir commercially. In addition, recovery takes place from Danian/Upper Cretaceous layers.

PRODUCTION FACILITIES

The North Jens area of the Valdemar Field has been developed as a satellite to the Tyra Field with two bridge-connected, unmanned wellhead platforms of the STAR type, Valdemar AA and AB, without helidecks. At the Valdemar AB platform, commissioned in 2005, production from both platforms is separated into liquids and gas. The liquids produced, consisting of oil and water, are transported to Tyra East for processing and export of the oil ashore, while the gas produced is piped to Tyra West for processing and export ashore. The Valdemar AA/AB complex is provided with chemicals from Tyra East and with power from Tyra West.

Production from the Bo area of the Valdemar Field is expected to start in 2007.


Valdemar-8E
7700
7600
7500
7400
8200
8000
7900
7800
7700
7600
Valdemar-1
7500
Valdemar-1P
N. Jens 1,2
7300
Valdemar-4
Valdemar-3P
7500
7700
8000
Valdemar-2
7600
7700
7300
7500
Valdemar-6
7500
Valdemar-3A
Platform
Oil well
Closed well
Well trajectory
Closed well trajectory
Fault
Valdemar Field
Top Tuxen Chalk
Depth structure map in feet
0
0.5
1 km

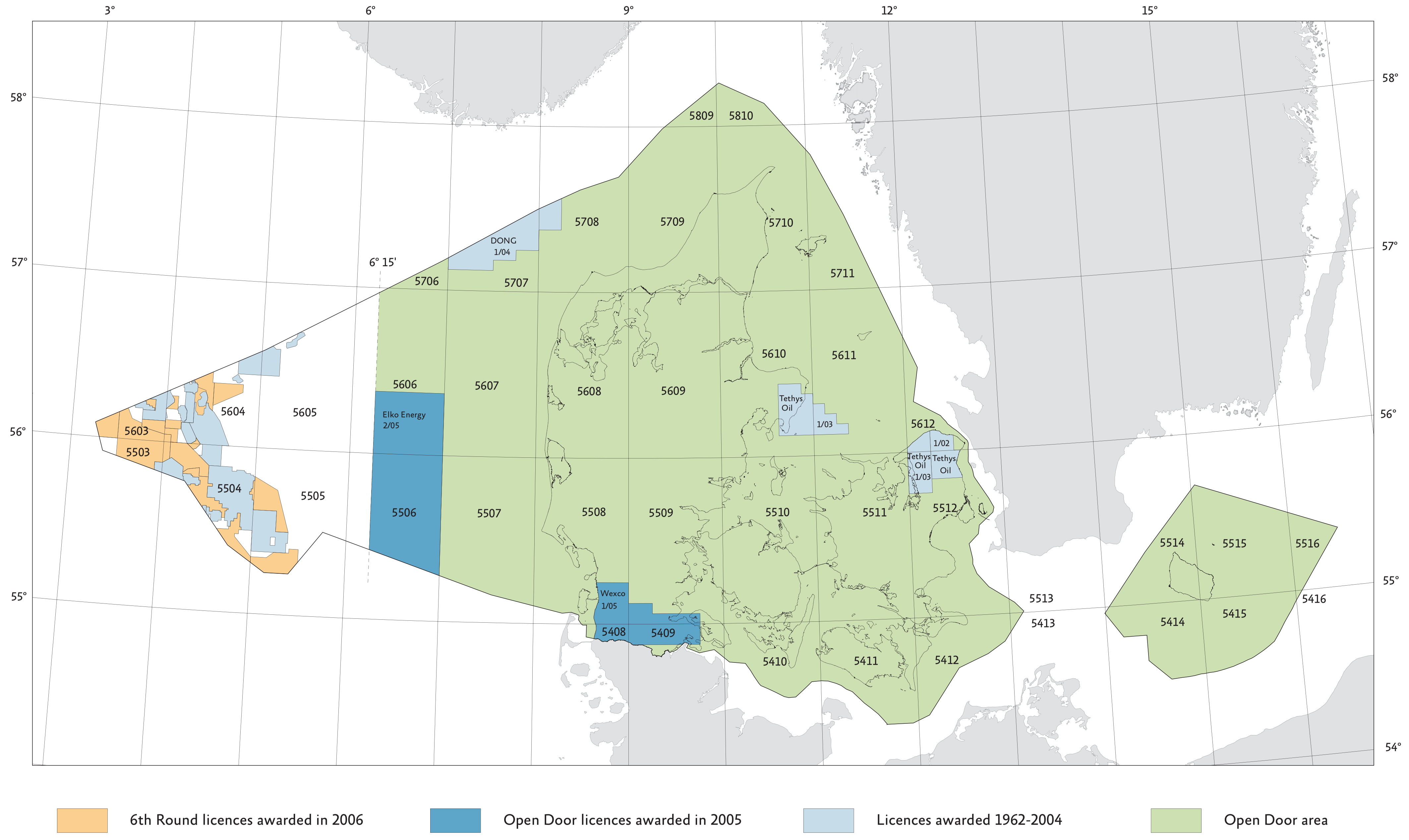

Valdemar-8E
Valdemar-1
Valdemar-2
Valdemar-7D
Valdemar-5D
Bo-1
7100
7000
6900
6800
6700
7600
7500
7400
7300
7200
Platform
Oil well
Well trajectory
Closed well trajectory
Valdemar Field
Top Chalk
Depth structure map in feet
0
0.5
1 km

FINANCIAL KEY FIGURES

	Investments in field dev. DKK million	Field operating costs DKK million[1]	Exploration costs DKK million	Crude oil price USD/bbl[2]	Exchange rate DKK/USD	Inflation per cent[3]	Net foreign-currency value DKK billion[4]	State revenue DKK million
1972	105	29	30	3.0	7.0	6.7	-3.2	-
1973	9	31	28	4.6	6.1	9.3	-4.0	1
1974	38	57	83	11.6	6.1	15.3	-9.2	1
1975	139	62	76	12.3	5.8	9.6	-8.5	2
1976	372	70	118	12.9	6.1	9.0	-9.5	4
1977	64	85	114	14.0	6.0	11.1	-10.4	5
1978	71	120	176	14.1	5.5	10.0	-9.5	21
1979	387	143	55	20.4	5.3	9.6	-13.7	19
1980	956	163	78	37.5	5.6	12.3	-18.6	29
1981	1,651	320	201	37.4	7.1	11.7	-20.1	36
1982	3,884	534	257	34.0	8.4	10.1	-20.6	231
1983	3,554	544	566	30.5	9.1	6.9	-17.8	401
1984	1,598	1,237	1,211	28.2	10.4	6.3	-18.3	564
1985	1,943	1,424	1,373	27.2	10.6	4.7	-17.6	1,192
1986	1,651	1,409	748	14.9	8.1	3.7	-7.3	1,400
1987	930	1,380	665	18.3	6.8	4.0	-5.9	1,328
1988	928	1,413	424	14.8	6.7	4.5	-3.7	568
1989	1,162	1,599	366	18.2	7.3	4.8	-3.2	1,024
1990	1,769	1,654	592	23.6	6.2	2.6	-2.7	2,089
1991	2,302	1,898	986	20.0	6.4	2.4	-1.9	1,889
1992	2,335	1,806	983	19.3	6.0	2.1	-0.4	1,911
1993	3,307	2,047	442	16.8	6.5	1.2	-1.7	1,811
1994	3,084	2,113	151	15.6	6.4	2.0	-0.5	2,053
1995	4,164	1,905	272	17.0	5.6	2.1	0.3	1,980
1996	4,260	2,094	470	21.1	5.8	2.1	0.4	2,465
1997	3,760	2,140	515	18.9	6.6	2.2	1.4	3,171
1998	5,382	2,037	406	12.8	6.7	1.8	0.9	3,125
1999	3,531	2,118	656	17.9	7.0	2.5	3.5	3,630
2000	3,113	2,813	672	28.5	8.1	2.9	14.9	8,695
2001	4,025	2,756	973	24.4	8.3	2.4	12.6	9,634
2002	4,703	3,102	1,036	24.9	7.9	2.4	14.5	10,137
2003	6,619	3,522	789	28.8	6.6	2.1	15.3	9,255
2004	4,457	3,349	340	38.2	6.0	1.2	19.7	17,092
2005*	3,922	3,760	538	54.4	6.0	1.8	24.8	24,163

Nominal prices
1) Incl. transportation costs
2) Brent crude oil
3) Consumer prices
4) Oil products and natural gas (external trade statistics, Statistics Denmark)
**) Estimate*

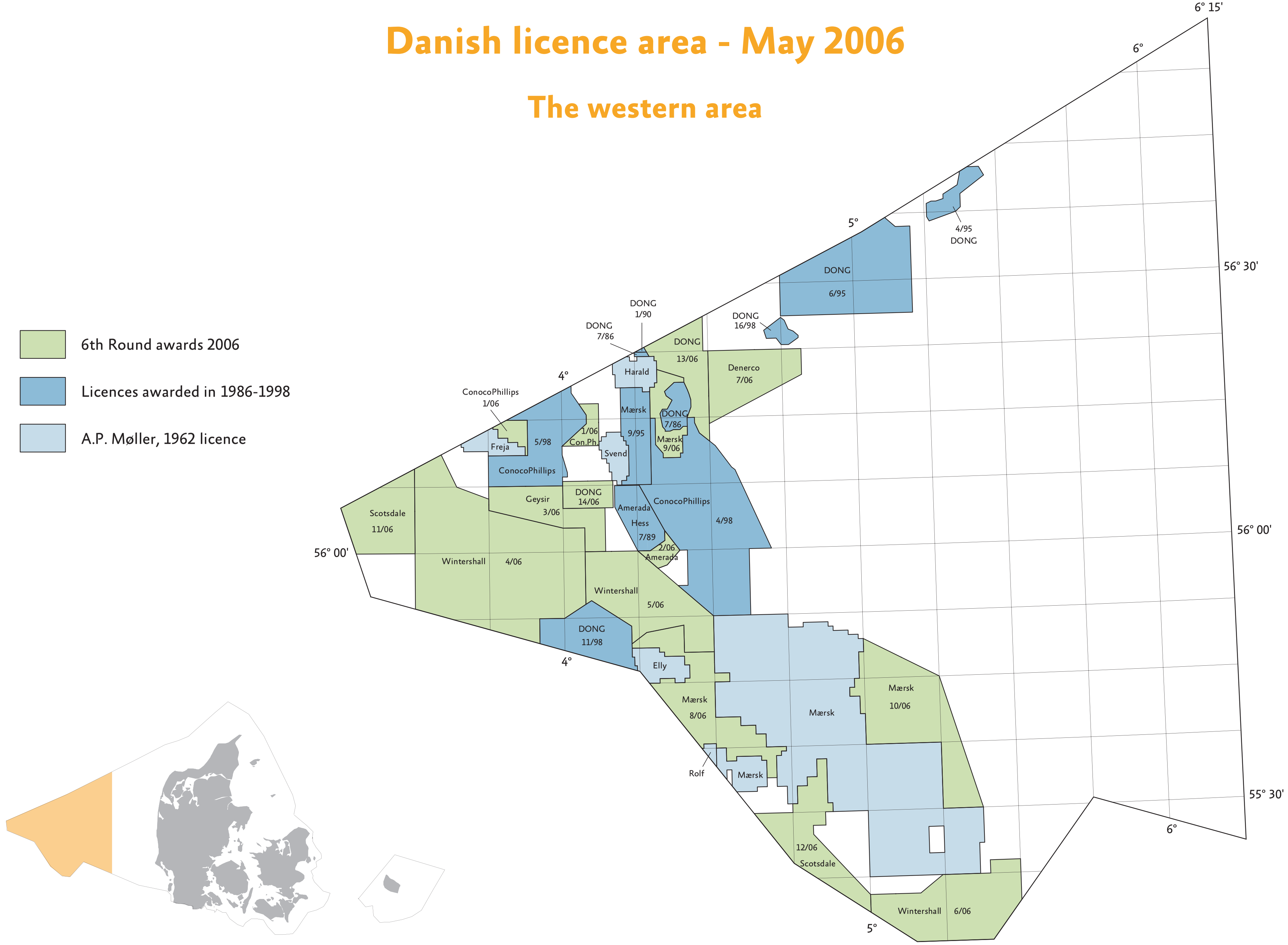
Danish licence area - May 2006



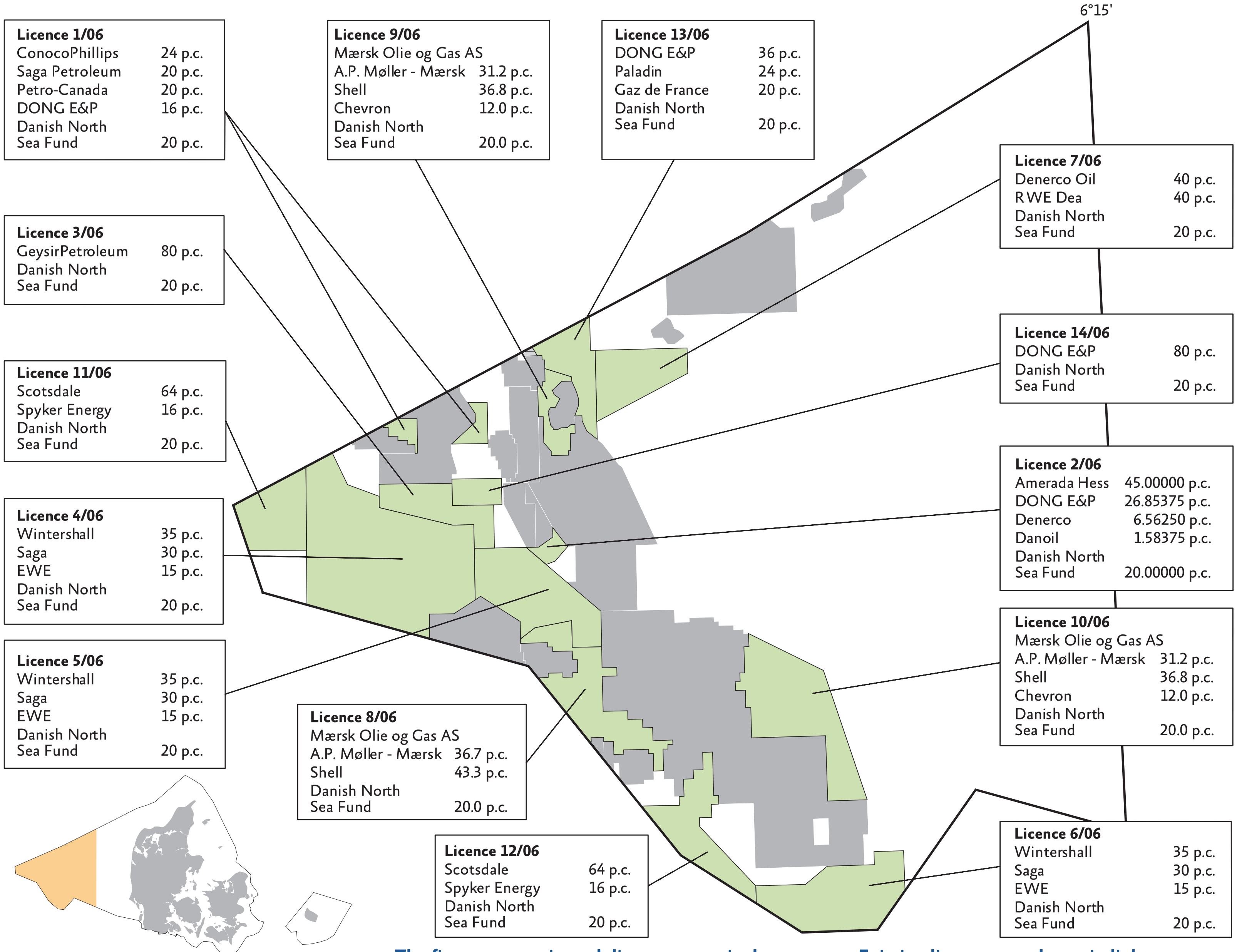
Danish licence area - May 2006

The western area

- 6th Round awards 2006
- Licences awarded in 1986-1998
- A.P. Møller, 1962 licence



Danish 6th Round licence awards - May 2006



The first company in each licence group is the operator. Existing licences are shown in light grey.

Danish Energy Authority
Amaliegade 44
DK-1256 Copenhagen K

Tel +45 33 92 67 00
Fax +45 33 11 47 43

CVR-nr: 59 77 87 14

ens@ens.dk
www.ens.dk

In 1966, the first discovery of oil and natural gas was made in Denmark. Since 1986, the Danish Energy Authority has published its annual report "Oil and Gas Production in Denmark".

As in previous years, the report for 2005 describes exploration and development activities in the Danish area. The report also contains a review of production and the health, safety and environmental aspects of oil and gas production activities.

In addition, the report contains an assessment of Danish oil and gas reserves and a section on the impact of hydrocarbon production on the Danish economy.

The report can be obtained from the Danish Energy Authority's Internet bookstore, www.ens.dk/publications. The report is also available on the Danish Energy Authority's homepage, www.ens.dk.

DANISH ENERGY AUTHORITY

ISBN: 87-7844-578-7