Danish Energy Authority

Oil and Gas Production in Denmark 2004

PREFACE

Oil production set a new record in 2004, surpassing the previous production record from 2002 by 5 per cent. In 2004, gas sales also reached an unprecedented level.

The large production figure and high oil price level helped raise the value of oil and gas produced in 2004 to almost DKK 39 billion. As a result, the state received a record-high amount of just over DKK 18 billion in taxes and fees, almost double the amount received in 2003.

The increase in production is attributable to investments in the continued development of a number of existing fields. One of the Danish Energy Authority's focus areas in connection with field developments and operations is to ensure that health and safety standards in Danish territory continue to rank among the highest in the North Sea countries in future.

The exploration for hydrocarbons in the Danish sector of the North Sea commenced in 1966. After almost 40 years' exploration and production, new results show attractive possibilities for future exploration.

Four of the 12 exploration wells drilled under the licences awarded in the 5th Licensing Round led to hydrocarbon discoveries. Two discoveries have already been brought on stream, while two discoveries in deeper-lying Jurassic sandstone are still under appraisal. An appraisal well drilled in 2004 confirmed the extension of the discovery and the potential for production from these layers. This has underscored the exploration potential of Jurassic sandstone in Danish territory.

In spring 2005, the 6th Licensing Round was opened, inviting applications for areas in the Central Graben and adjoining areas. In 2003, the Danish Energy Authority assessed the hydrocarbon potential for the Danish part of the Central Graben and the Siri Fairway, estimating that Danish territory still holds major hydrocarbon potential. Combined with the very high oil price level, this assessment is expected to sustain oil companies' interest in the Danish area. Continued exploration is a prerequisite for the oil and gas sector's ability to contribute positively to the Danish economy in the years ahead.

Copenhagen, June 2005

Ib Larsen

Director General

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. This report uses SI units. 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 2004 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.*

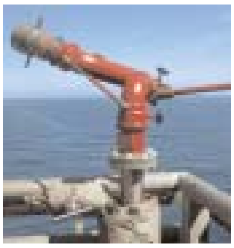
in — *inch; British unit of length. 1 inch = 2.54 cm*

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.*

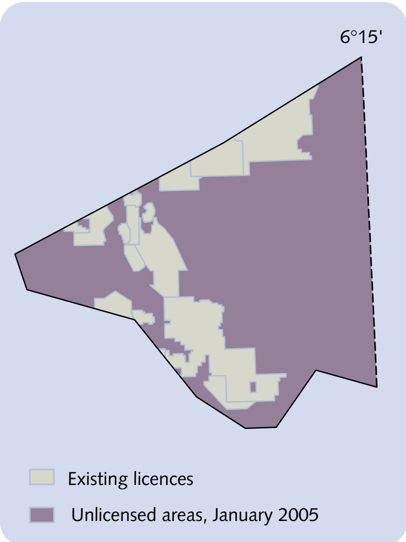
	FROM	TO	MULTIPLY BY
Crude oil	m^3 (st)	stb	6.293
	m^3 (st)	GJ	36.3
	m^3 (st)	t	0.86[i]
Natural gas	Nm^3	scf	37.2396
	Nm^3	GJ	0.03977
	Nm^3	t.o.e.	949.89×10^{-6}
	Nm^3	kg·mol	0.0446158
	m^3 (st)	scf	35.3014
	m^3 (st)	GJ	0.03574
	m^3 (st)	kg·mol	0.0422932
Units of volume	m^3	bbl	6.28981
	m^3	ft^3	35.31467
	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*



1. LICENCES AND EXPLORATION

Fig. 1.1 Unlicensed areas



In 2004, a total of ten exploration and appraisal wells were drilled in Danish territory, meaning that the level of exploration activity from 2003 was maintained.

In several cases, the appraisal wells drilled in 2004 led to an upward adjustment of reserves for existing fields, thus showing that the accumulations of hydrocarbons bordering on existing fields still represent an exploration objective. In addition, the Hejre-2 well confirmed the presence of hydrocarbons in deeper-lying Jurassic sandstone layers.

6TH LICENSING ROUND

Since 1983, applicants for licences in the Danish area have been invited to participate in licensing rounds. A total of five licensing rounds have been held, and in 1996 the Open Door procedure was introduced for areas east of 6°15' eastern longitude.

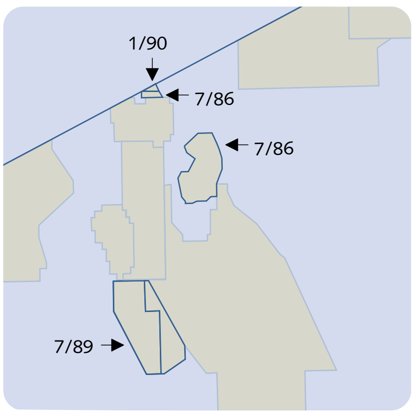
Areas in the Central Graben and adjoining areas have not been offered for licensing in the past seven years. The 6th Licensing Round has now been opened, and the deadline for submitting applications is 1 November 2005. Fig. 1.1 shows the unlicensed areas as of 1 January 2005. The open area offered for licensing comprises all unlicensed areas west of 6°15' eastern longitude, corresponding to 73 per cent of the total area of 19,744 km^2.

Moreover, a few of the current licences have been delineated in terms of depth, as the licences granted since the 1st Licensing Round in 1984 have included a standard term stipulating that when a licence is extended for production purposes, the accumulation must be delineated in terms of area as well as depth. The licences currently delineated in terms of depth appear from Fig. 1.2. Therefore, besides applying for the open, unlicensed areas, oil companies can also apply for exploration licences covering the deeper-lying layers under the accumulations comprised by the licences indicated.

The more detailed conditions and rules applicable to the 6th Licensing Round appear from the Danish Energy Authority's website, www.ens.dk

Most of the work obligations undertaken by the oil companies in the 5th Licensing Round in 1998 have been fulfilled.

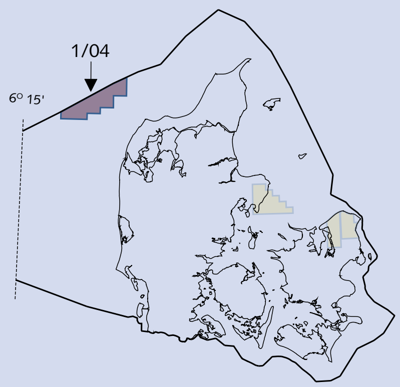
Fig. 1.2 Licences delineated in terms of depth



Four of the 12 exploration wells drilled under the licences awarded in the 5th Licensing Round have led to hydrocarbon discoveries. The Cecilie Field came on stream in 2002 and the Connie accumulation in 2004. The Svane and Hejre discoveries made in deeper-lying Jurassic sandstone are still under appraisal, and the Hejre-2 appraisal well produced positive confirmation of the Hejre discovery in 2004; see below. The well confirmed the extension and potential for production from the hydrocarbon accumulation and underscored the exploration potential of Jurassic sandstone in Danish territory.

Exploration in the Danish sector of the North Sea commenced almost 40 years ago. Nevertheless, new results continue to show attractive possibilities for future exploration. In 2003, the Danish Energy Authority assessed the hydrocarbon

Fig. 1.3 New Open Door licence



New state-owned entity

To date, DONG Efterforskning og Produktion A/S has managed state participation in licences for exploration for and production of hydrocarbons. Consequent to the political agreement on partially privatizing DONG E&P A/S, the company cannot manage the state's participation in new licences. Therefore, a new organization must be set up to undertake this responsibility.

In future, a new state-owned entity, to be established in 2005, will be able to manage the state's paying 20 per cent interest in new licences. This state-owned entity will undertake the administration of state participation in new licences issued in the 6th Licensing Round and in the Open Door procedure.

From 2012, the state-owned entity may also be in charge of the state's 20 per cent share of DUC. The state participation in DUC is a consequence of the agreement of 20 September 2003 made between the Minister for Economic and Business Affairs and A.P. Møller- Mærsk.

potential for the Danish part of the Central Graben and the Siri Fairway. This assessment shows that Danish territory still holds major hydrocarbon potential. The assessment is available in the report "Oil and Gas Production in Denmark 2003" at the Danish Energy Authority's website, www.ens.dk.

NEW LICENCE

On 2 November 2004, the Minister for Economic and Business Affairs granted CLAM Petroleum Danske B.V., Kerr-McGee International ApS, Arco Denmark Ltd. and DONG E&P A/S a licence for exploration for and production of hydrocarbons. DONG E&P A/S is in charge of the state's 20 per cent share and is also operator of the licence. This licence, numbered 1/04, comprises an area in the eastern part of the North Sea at the border towards Norway; see Fig. 1.3. Thus, this is the last licence under which DONG E&P A/S will administer the state's share.

The licence was awarded under the Open Door procedure, which applies to the whole area east of 6°15' eastern longitude. The Open Door procedure is an open invitation to oil companies to apply for licences in the above-mentioned area.

AMENDED LICENCES

The outline of licences on the Danish Energy Authority's website at www.ens.dk is continually updated and describes all amendments in the form of extended licence terms, the transfer of licence shares and relinquishments.

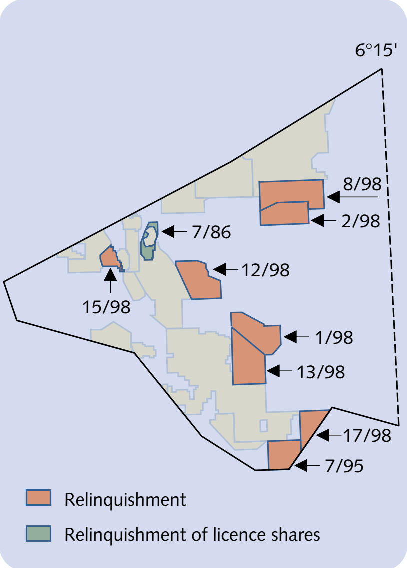
Extended licence terms

In 2004, the Danish Energy Authority 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 undertake to carry out additional exploration work in the relevant licence areas.

Table 1.1 Extended licence terms

Licence	Operator	Expiry
4/95	DONG E&P A/S	15-05-2005
6/95	DONG E&P A/S	15-05-2005
9/95	Mærsk Olie og Gas AS	01-01-2007
4/98	Phillips Petroleum Int. Corp.	15-06-2006
5/98	Phillips Petroleum Int. Corp.	15-06-2006
11/98	DONG E&P A/S	15-12-2005
16/98	DONG E&P A/S	15-06-2005

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



Licences for exploration for and production of hydrocarbons are usually 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 Danish Energy Authority may extend the term of a licence by up to two years at a time, provided that the licensee, upon carrying out the entire 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 Danish Energy Authority for approval.

Effective 1 January 2004, Odin Energi A/S increased its share of licence 1/02 to 10 per cent by taking over a 5 per cent share from Tethys Oil AB.

Effective 1 May 2004, Amerada Hess ApS transferred its 42 per cent share of licence 11/98 to Wintershall Noordzee B.V.

Other amendments with regard to licence shares or areas etc. are mentioned in the outline of licences at the Danish Energy Authority's website.

Table 1.2 Partial relinquishment

Licence	Operator	Relinquished
7/86	DONG E&P A/S	07-10-2004

Partial relinquishment

The delineation of the Amalie Field, comprised by licence 7/86, was revised in 2004. This licence was awarded in 1986 in the 2nd Licensing Round. Hydrocarbons were encountered in Jurassic sandstone, and in 1991 the Amalie Field was declared commercial. DONG E&P A/S is operator for the oil companies holding the licence.

The relinquished areas appear from Fig. 1.4 and Table 1.2.

TERMINATED LICENCES

All licences relinquished in 2004 covered areas in and around the Central Graben, so no changes have occurred in the area comprised by the Open Door procedure. The licences relinquished appear from Table 1.3 and Fig. 1.4.

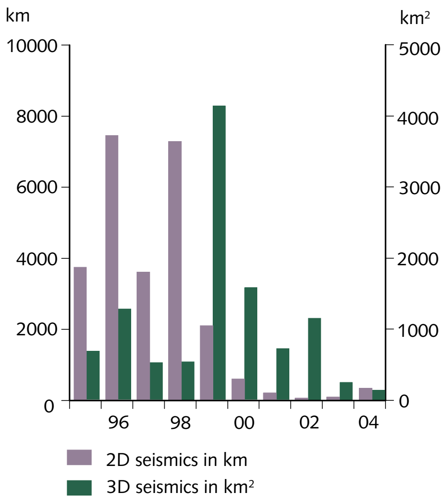
Table 1.3 Terminated licences

Licence	Operator	Terminated
7/95	Mærsk Olie og Gas AS	15-11-2004
1/98	Clam Petroleum Danske B.V.	15-06-2004
2/98	Clam Petroleum Danske B.V.	15-06-2004
8/98	Kerr-McGee International ApS	15- 06-2004
12/98	Amerada Hess ApS	15-06-2004
13/98	Noble Energy (Europe) Limited	15-09-2004
15/98	Mærsk Olie og Gas AS	15-09-2004
17/98	Mærsk Olie og Gas AS	15-06-2004

Generally, data compiled under licences granted in pursuance of the Danish Subsoil Act is protected by a five-year confidentiality clause. However, the confidentiality period is limited to two years for licences that expire or are relinquished.

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.

Fig. 1.5 Annual seismic surveying activities



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

The level of activity and the areas where seismic surveys were performed appear from Figs. 1.5 and 1.7.

In 2004, 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.

Under licence 6/95, DONG E&P A/S performed a 4D seismic survey of the Siri Field in spring 2004.

The fourth dimension of a 4D seismic survey is time. A comparison between new and previous 3D seismic data provides information about the changes occurring in the reservoir over time. This improves understanding of the reservoir and optimizes recovery.

WELLS

In 2004, two exploration wells and eight appraisal wells were drilled; see Fig. 1.6. These statistics include wells spudded in 2004.

The location of the wells described below appears from Fig. 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 Danish Energy Authority's website.

Exploration wells

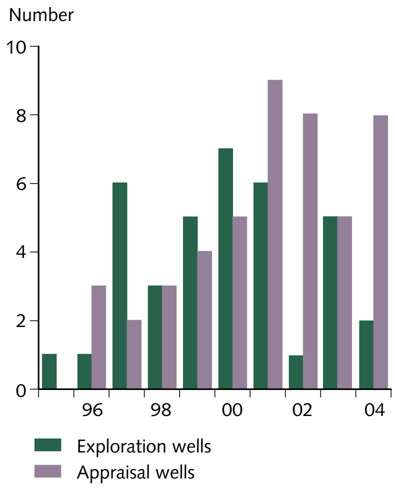
Vivi-1 (5605/10-5)

Under licence 4/95, DONG E&P A/S drilled the exploration well Vivi-1. The well was drilled about 15 km northeast of the Nini Field, and the drilling operation ended in September after about 14 days. Vivi-1 was drilled as a vertical well, terminating at a depth of 1,727 metres in chalk of Danian age. Subsequently, a sidetrack, Vivi-1A, was drilled to investigate another exploration target. The well encountered hydrocarbons in Paleogene sandstone, from which cores were taken for evaluation.

Fasan-1 (5505/9-3)

The Fasan-1 exploration well was drilled about 20 km east of the Tyra Field in the North Sea. As operator of licence 13/98, EDC (Denmark) drilled the well in cooperation with DONG E&P A/S. Fasan-1 was drilled as a vertical well and terminated at a depth of 3,761 metres in sediments of Upper Jurassic age. The Fasan-1 well only partially confirmed the geological model, encountering minor traces of hydrocarbons.

Fig. 1.6 Exploration and appraisal wells

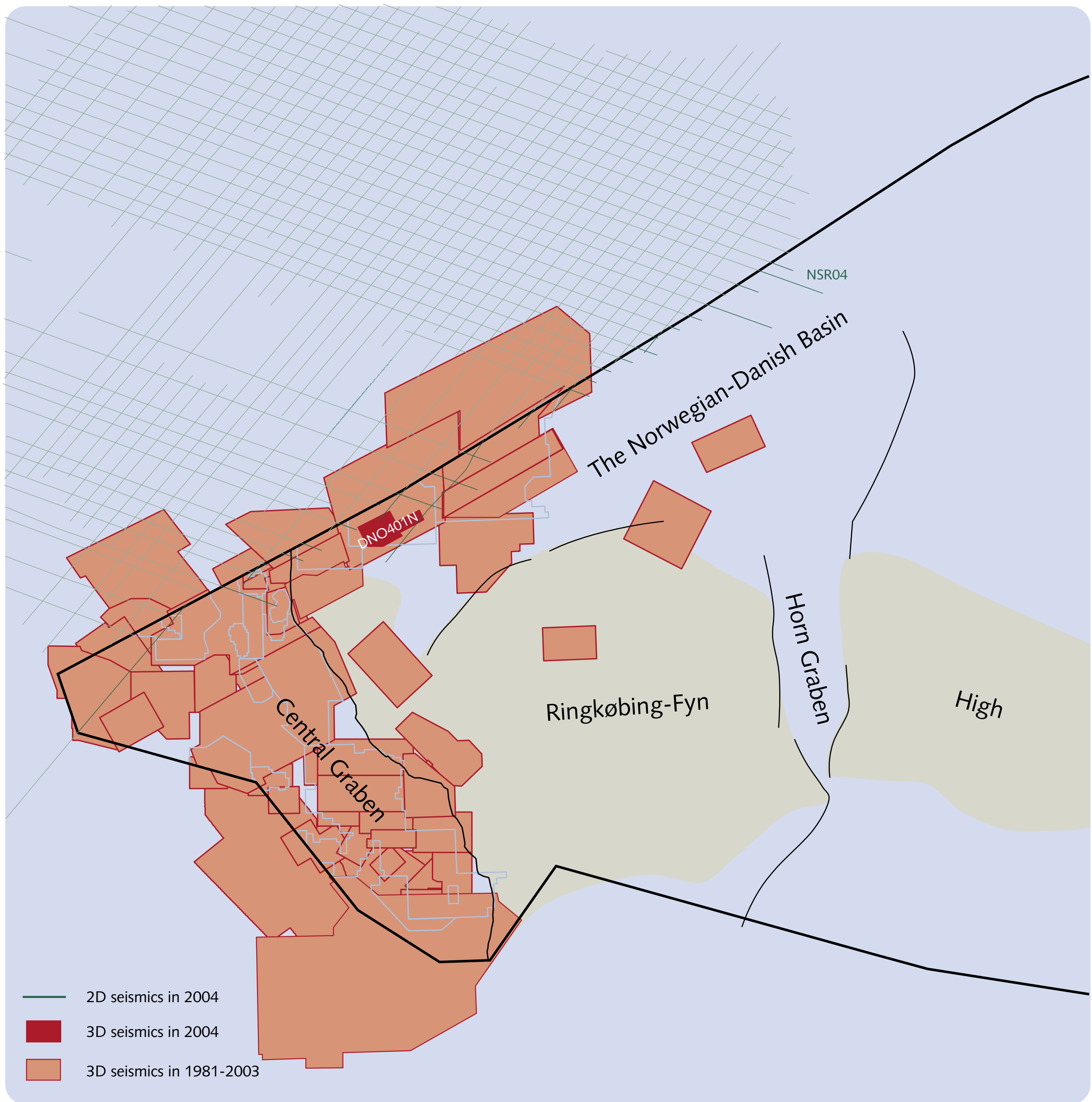


Appraisal wells

Bo-2X (5504/7-12)

In June-July 2004, Mærsk Olie og Gas AS drilled the Bo-2X appraisal well. The well was drilled in the southern part of the Valdemar Field, in the so-called Bo area. Exploration drilling has previously been carried out in this area, and the

Fig. 1.7 Seismic surveys



appraisal well was drilled to evaluate the extension of the accumulation. Bo-2X was drilled as a vertical well and terminated in Lower Cretaceous layers. The well encountered hydrocarbons, and the Danish Energy Authority has subsequently received a development plan for the area; see the section entitled *Development.*

SCB-1X (5605/13-4)

As operator of licence 6/95, DONG E&P A/S drilled the SCB-1X appraisal well. This well was to evaluate the extension of oil between the Stine segment 1 and Stine segment 2 accumulations at the Siri Field. The well encountered oil in Paleogene layers, as expected. Subsequently, a horizontal sidetrack for production purposes was drilled in the Stine segment 1 accumulation.

CA-3 (5604/20-10)

In July 2004, DONG E&P A/S finished drilling the CA-3 appraisal well under licence 16/98. The well was drilled from the Cecilie platform to evaluate the extension of the Connie oil accumulation northwest of the producing Cecilie accumulation. Both the Cecilie and Connie oil accumulations are reservoired in Paleogene sandstone. Subsequently, a horizontal sidetrack, CA-3D, was drilled into the northern part of the area, from where production has been initiated.

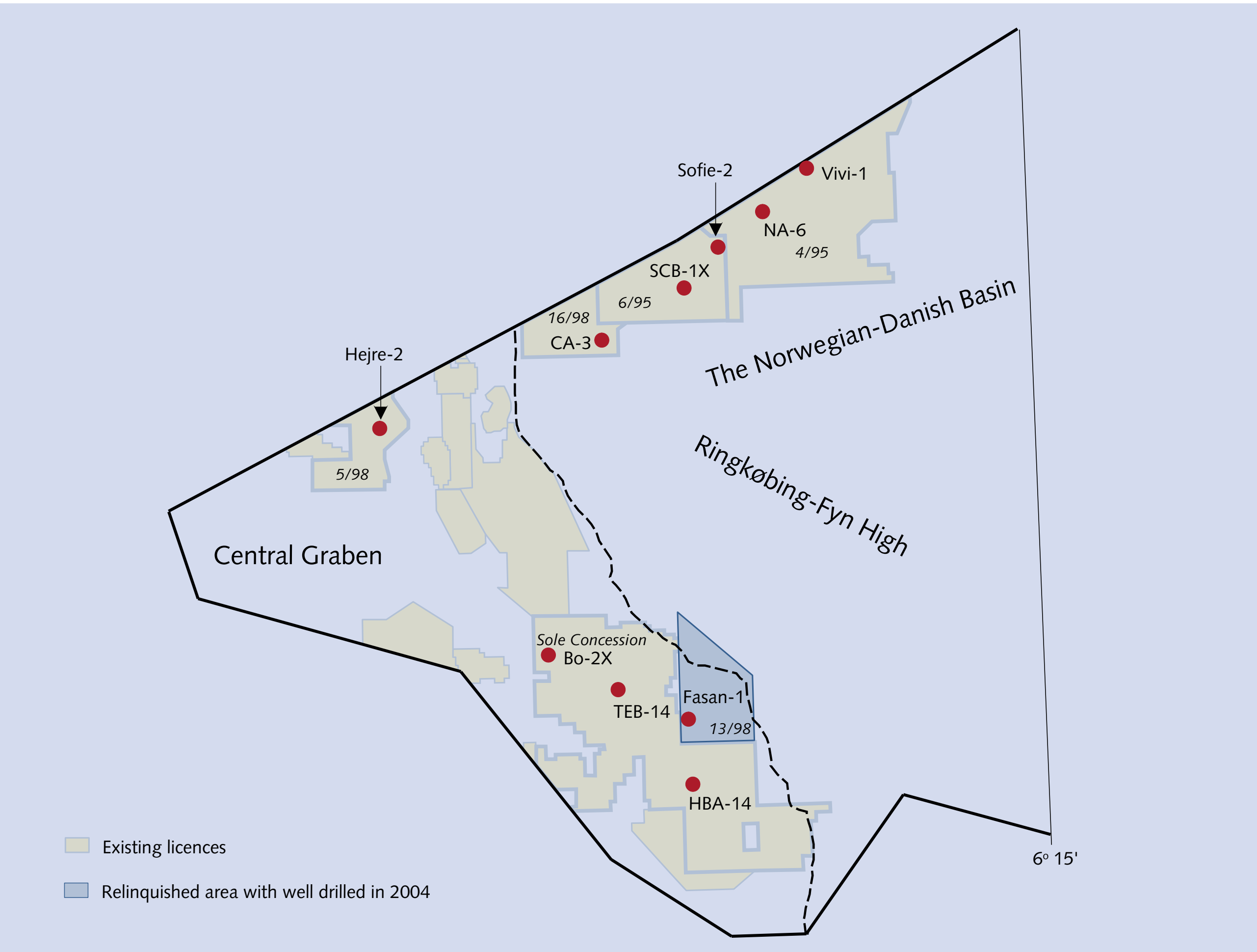
HBA-14 (5505/13-10)

In August-November 2004, Mærsk Olie og Gas AS drilled the appraisal and production well HBA-14. Before drilling the horizontal reservoir section, the operator drilled a pilot hole through layers of Danian and Maastrichtian age. HBA-14 was drilled from the HBA platform in the Halfdan Field to evaluate the gas accumulation in the Halfdan area. The well has carried on production since November.

NA-6 (5605/10-6)

In September-November, DONG E&P A/S drilled a production well, NA-6C, at the Nini Field under licence 4/95. Before the location of the horizontal production interval was finally determined, a pilot hole, NA-6B, was drilled to evaluate the extension of the oil accumulation in Paleogene sandstone.

Fig. 1.8 Exploration and appraisal wells



Sofie-2 (5605/13-05)

As operator for the oil companies holding licence 6/95, DONG E&P A/S finished drilling the Sofie-2 appraisal well in December 2004. The Sofie oil accumulation was encountered in 2003 and is located between the Nini Field and the Siri Field. Sofie-2 was drilled as a vertical well, terminating at a depth of 1,951 metres in Danian chalk. A sidetrack, Sofie-2A, was subsequently drilled to delineate the accumulation towards the northwest. Sofie-2/2A showed the accumulation to be more complex than expected, and the discovery is now under closer evaluation.

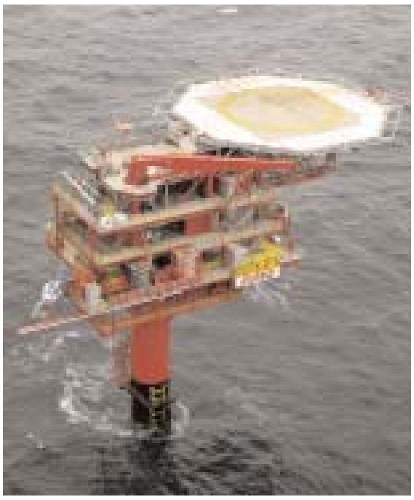
Hejre-2 (5603/28-05)

ConocoPhillips Petroleum International Corporation Denmark, operator for the oil companies holding licence 5/98, began drilling the appraisal well Hejre-2 in November 2004. Hejre-2 was drilled about 1 km northeast of the Hejre-1 well, which encountered hydrocarbons in 2001. The well was drilled as a vertical well and terminated at a depth of 5,399 metres in layers of pre-Jurassic age. During a production test, the well produced hydrocarbons with good production rates.

TEB-14 (5504/12-12)

In October-December 2004, Mærsk Olie og Gas AS drilled the production and appraisal well TEB-14/14A in the southeastern part of the Tyra Field. This well was drilled considerably farther east than the existing Tyra wells. Pilot holes were drilled into deeper layers at the middle and at the end of the well. The objective was to obtain information about layer boundaries and fluid composition.

2. DEVELOPMENT



The development of Danish oil and gas fields in the North Sea continued at a high rate in 2004. Production from three new fields commenced in 2003, and the development of these fields continued in 2004.

Production from the Halfdan Field within the Sif delineation was initiated from the HBA platform in July 2004, and additional wells targeting this area have been drilled. At the same time, new processing facilities on the Halfdan HDA platform, with a capacity of 120,000 barrels of oil per day, have been commissioned.

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 2004 totalled 23, against 24 wells in 2003.

At the end of the year, applications for approval of development plans for the Dan, Gorm and Dagmar Fields and the Bo area of the Valdemar Field were submitted.

Fig. 2.3 shows existing production facilities in the Danish sector of the North Sea at the beginning of 2005.

Appendix B provides a survey of all the producing fields, including factual information about the fields and maps. Wells drilled in 2004 are marked with a light colour on the maps.

DEVELOPMENT OF EXISTING FIELDS

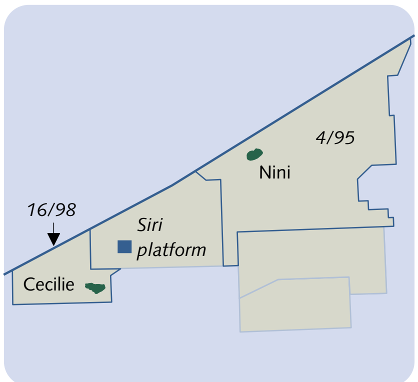
The Cecilie Field

The Cecilie Field, discovered in 2000, is situated in the Siri Fairway in the northern part of the Danish sector; see Fig. 2.1. DONG E&P A/S is the operator of the field.

Production from the field commenced from an unmanned satellite to the Siri platform in August 2003. Production from the Cecilie Field is conveyed to the Siri platform for processing, storage and further transport.

Development continued in 2004 with the drilling of an additional production well, CA-2C, and an injection well, CA-4.

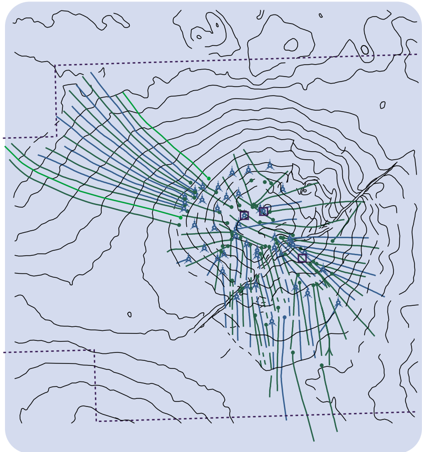
Fig. 2.1 Field development in the *Siri Fairway*



The composition of the reservoir has proved to be complex, being composed of apparently separate sandbodies. In addition, the wells have demonstrated that the depth of the oil-water contact varies in the individual parts of the reservoir. Several of the wells had pilot holes drilled before the production interval was drilled.

In 2004, the Danish Energy Authority approved a plan for exploiting the Connie accumulation, part of the Cecilie Field. In 2004, an appraisal well, CA-3, targeting this accumulation was drilled from the installations at the Cecilie Field. Subsequently, a horizontal sidetrack, CA-3D, was drilled into the northern part of the area; see the field map in Appendix B. The amounts produced from the Connie accumulation and the rest of the Cecilie Field are substantially below expected.

Fig. 2.2 The Dan Field



The Dagmar Field

The Dagmar Field came on stream in 1991. In December 2004, the operator, Mærsk Olie og Gas AS, applied for approval for further developing the Dagmar Field. The plan provides for the drilling of one well from the existing platform in the field, a step expected to increase reserves by about 550,000 m^3 of oil.

The Dan Field

The Dan Field has carried on production since 1972, but still holds potential for further development.

Towards the end of 2003, an updated well pattern for the western flank towards the Halfdan Field was approved, which provided for the drilling of four additional wells.

In 2004, a production well, MFF-27E, was drilled in the northern part of the western flank. Moreover, an injection well, MFF-31, was drilled in the southern part of the western flank in 2004. Initially, this well will produce oil, but will subsequently be converted to water injection. The two remaining wells, scheduled for 2005, will be drilled in the southern part of the western flank.

In 2002, a plan to change recovery strategy was approved for the area under the gas cap in the southeastern reservoir block of the field. So far, production from this area has been carried out with conventional water injection, i.e. at rates sufficiently low to prevent the injection process from causing the reservoir rock to fracture. Tests with high-rate water injection have been initiated on a preliminary basis. The test period runs until 1 October 2005. In 2005, a new processing platform, DFG, will be installed in the field.

In the summer of 2004, the operator, Mærsk Olie og Gas AS, submitted an application for approval of a further development plan for the Dan Field. A new study has identified areas in the field that are not drained optimally. The plan, approved at the beginning of 2005, provides for the drilling of up to six new wells in the northeastern part of the field.

The Gorm Field

In the Gorm Field, a single horizontal production well was redrilled in 2004.

The operator, Mærsk Olie og Gas AS, submitted a plan for further developing the field in September 2004. This field has carried on production since 1981. Technical studies have identified areas in the field that are not drained optimally, and the plan provides for the drilling of four new wells. Accordingly, plans have also been made to expand and improve the capacity of the processing facilities. Moreover, the plan outlines the possibility of drilling up to five additional wells, depending on the experience from the first wells.

The Halfdan Field

In 2004, one milestone in the Danish part of the North Sea was the production startup of the processing facilities at the Halfdan Field. The facilities are placed on the combined wellhead and processing platform, Halfdan HDA, and have a capacity of 120,000 barrels of oil per day.

Since the operator, Mærsk Olie og Gas AS, brought the field on stream in 1999, the oil and gas produced have been processed at the Gorm and Dan Fields, respectively.

Fig. 23 Production facilities in the North Sea 2004

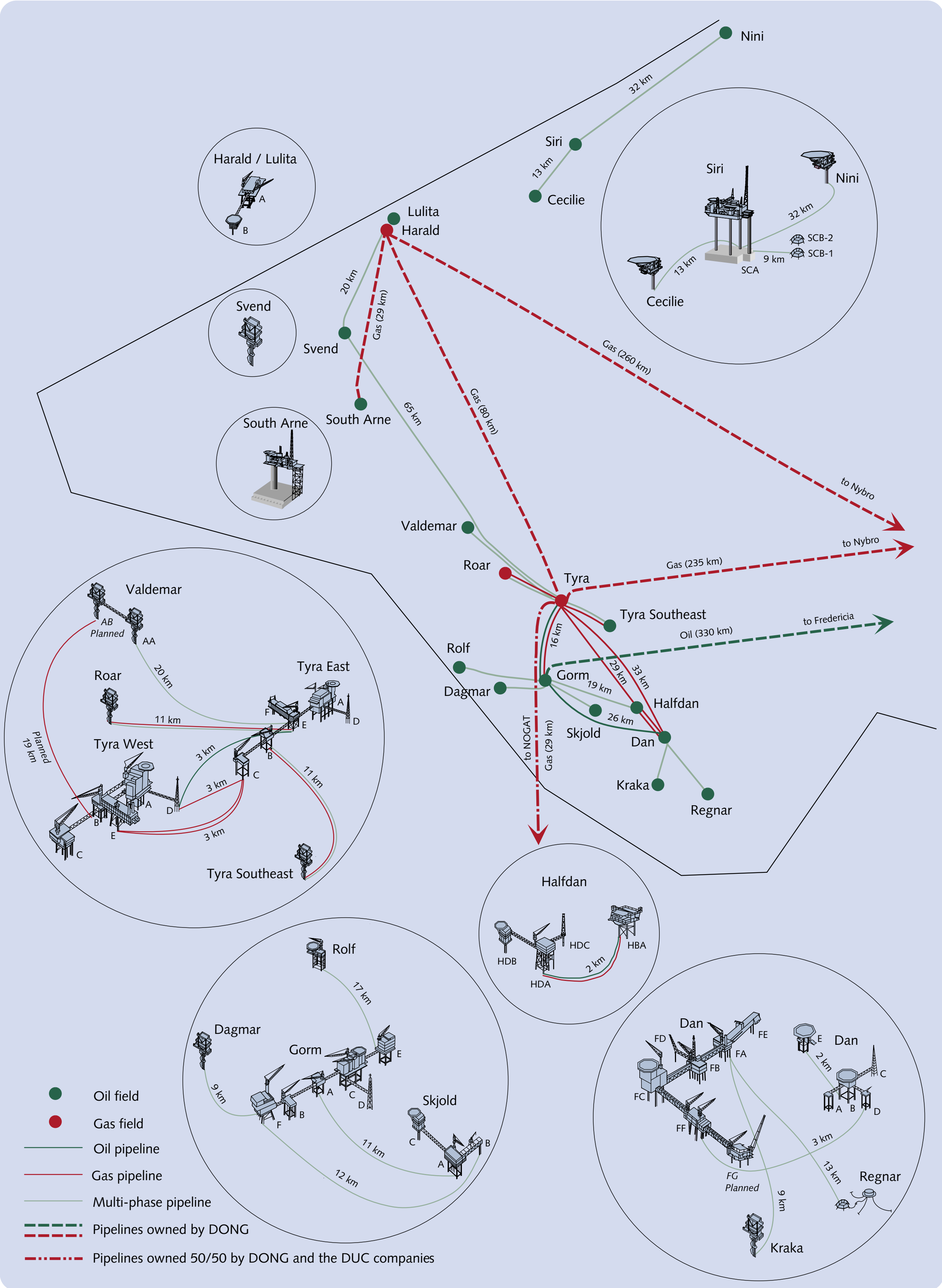
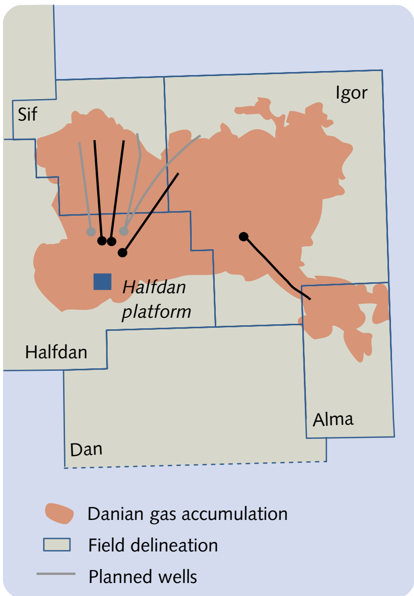


Fig. 2.4 Development in the Halfdan area



The new facilities make it possible to convey the gas directly to Tyra West from the HDC platform in the Halfdan Field and through a branch of the pipeline at HBA. The stabilized crude oil is transported to shore via the riser platform, Gorm E.

The development of the Halfdan Field has occurred in several phases and is still ongoing. During 2004, two production wells and four water-injection wells were drilled. They have all begun producing, as the water-injection wells are to produce oil for a period prior to conversion.

In 2004, the Danish Energy Authority approved a plan for further developing the field with another four wells, two production wells and two injection wells. The intention is to drill the wells in the northeastern part of the field, which may have potential for further development.

The overall development plan for the field comprises a total of 50 wells, 27 production wells and 23 water-injection wells.

The Halfdan Field; Sif and Igor

Previously, Halfdan, Sif and Igor have been described as three more or less distinct fields. Certain parts of the accumulation have been termed Halfdan Northeast. However, it has now been established with a high degree of certainty that Halfdan, Sif and Igor are a large contiguous hydrocarbon accumulation at different strata levels; see Fig. 2.4.

The area towards the north and east contains gas, primarily in Danian layers, while the southwestern part primarily contains oil in Maastrichtian layers.

The Danish Energy Authority has approved an overall plan for exploiting the Danian section of the accumulation.

The first part of the development, consisting of three wells, was completed in 2004. These wells were drilled from the Halfdan HBA platform in the Halfdan Field. From here, the gas is conveyed through a two-phase separator before being transported through the pipeline to Tyra West. The liquid phase is mingled with the oil produced from the Halfdan Field, and final processing takes place at the Halfdan HDA facilities.

The second phase of the development plan consists of the drilling of an additional three wells. Fig. 2.4 shows the projected wells.

The fourth well was spudded in February 2005. The well is planned with one main well bore and one lateral well bore in the reservoir. This technique has not previously been used in Danish territory. Gas will be produced from both well bores, and it will subsequently be possible to re-stimulate the well bores individually.

The Nini Field

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

The Nini and Cecilie Fields are both sandstone fields located in the Siri Fairway. Like Cecilie, the Nini Field has proved to consist of a number of apparently sepa-

rate sandbodies. In order to determine the optimum location of the production sections of the wells, a number of pilot holes have been drilled in both fields.

Development activity in 2004 centred on the northeastern part of the field; see the field map in Appendix B. The well NA-4A encountered the oil-bearing sandbodies in this area in 2003.

The pilot hole for the NA-6 well encountered further hydrocarbons, and the results determined the location of the production section, NA-6C.

Moreover, the NA-4A well was redrilled in 2004. The new well section, NA-4B, was placed in an area closer to the platform than NA-6C. The NA-4B well is expected to be later converted to water injection to maintain reservoir pressure.

The Siri Field

The modification of the processing facilities on the Siri platform resulting from the tie-in of the Cecilie and Nini Fields was completed in mid-2004 with the commissioning of a new compressor. This has reduced the need for flaring gas on the platform, as the gas produced can be reinjected into the reservoir. DONG E&P A/S is the operator.

Within the Siri Field delineation, the accumulation named Stine segment 1 was developed in 2004. This segment is situated about 10 km east of the Siri platform. Because of the distance to the Siri platform and the size of the accumulation, the development took place from a subsea installation. The development consists of a production well and a water-injection well to maintain pressure. This is the second accumulation in Danish territory that is being exploited from a subsea installation.

The production well was drilled in combination with an appraisal well, SCB-1X, targeting the area between Stine segments 1 and 2; see the field map in Appendix B. The well encountered oil in the area, with the oil-water contact differing from that found in segment 1 and segment 2. The production section of the SCB-1 well was then drilled in the upper part of the reservoir in segment 1, and subsequently the water-injection well, SCB-2, was drilled into the water zone. Production from this segment meets expectations.

The South Arne Field

In 2004, the operator, Amerada Hess ApS, drilled three new horizontal wells in the South Arne Field.

In the northern part of the field, a new water-injection well was drilled for the main purpose of providing pressure support to the SA-2 production well. A section of the new well penetrated the Danian reservoir. The well results showed that the production well SA-2, which produces from the underlying Maastrichtian reservoir, reduces pressure in the Danian reservoir.

After a short-term production test, water-injection was initiated.

A new production well was drilled in the northwestern part of the field. Pressure conditions along the well path were not as expected, so the well became shorter than anticipated.

The exploration and appraisal well, Katherine-1, was drilled at the end of 2003 in the South Arne Field. Results from this well spurred the drilling of a production well, SA-17, in the southeastern part of the field at the end of 2004.

In the course of 2005, the licensee expects to collect new seismic data for use in redrawing the map of the South Arne Field. On the basis of this new map and other data, the licensee plans to drill more development wells in the field in the years to come.

The Tyra Field

In 2003-04, a new 26" gas pipeline from Tyra West to the F/3 platform in the Dutch sector was established. This pipeline hooks up to the NOGAT pipeline, which exports gas to the Netherlands. The pipeline has a capacity of 15 million Nm^3 per day and was commissioned on 18 July 2004.

The owners of the new pipeline are DONG (50 per cent), Shell (23 per cent), A.P. Møller (19.5 per cent) and Texaco (7.5 per cent). Mærsk Olie og Gas AS is the operator of the pipeline.

At the turn of the year, about 7 million Nm^3 per day was exported through the pipeline. The increased export has engendered a need for more gas wells to be drilled. Consequently, drilling activity was resumed at Tyra East after a three-year interval.

A development plan approved in 1999 provided for 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.

A great deal of data has been collected from the area, including from the wells drilled into the Tyra Southeast Field; see below. Against this background, the well TEB-14/14A was drilled in the Tyra Field. The well was drilled substantially further towards the east than the existing Tyra wells. At the same time, pilot holes

were drilled at the middle and at the end of the well section to procure information about layer boundaries and fluid composition. This information indicates a potential for drilling additional wells.

The Tyra Southeast Field

Production from the Tyra Southeast Field commenced in 2002, and a seventh gas production well was drilled in the field in 2004; see the field map in Appendix B. Mærsk Olie og Gas AS is the operator.

Approval has also been obtained to expand the existing water-processing facilities at Tyra East, which treat produced water from Tyra Southeast.

As appears from the field map in Appendix B, the two easternmost wells have been designated as gas wells. The wells have, however, also encountered oil in the area, although the oil zone proved thinner than anticipated.

The Valdemar Field; the Bo area

On 30 December 2004, Mærsk Olie og Gas AS applied for approval for further developing the Bo area of the Valdemar Field. The Bo-2X appraisal well was drilled in the summer of 2004 and encountered better oil saturations and porosities in the area than previously assumed.

On the basis of the well results, 3D seismic data for the area was reinterpreted. This data creates the foundation for a plan to develop and produce oil and gas from the area.

The plan provides for the establishment of a new platform to accommodate ten wells as well as pipelines to the Roar platform. Initially, six production wells are to be drilled. Thus, an additional four wells can be drilled at a later date.

Based on the six production wells planned, the production figure is estimated at 24 million barrels of oil and 3 billion m^3 of gas. The production of oil and gas from the Bo area is expected to commence in the course of 2007.

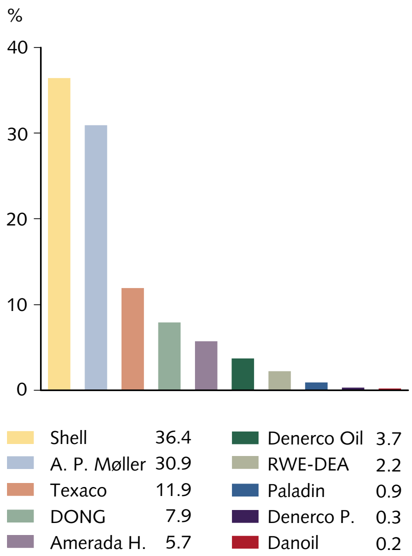
FUTURE FIELDS

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; see Fig. 3.4.

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

3. PRODUCTION

Fig. 3.1 Breakdown of oil production by company



Oil production in 2004 set a new record, exceeding the previous production record from 2002.

At the same time, the sale of gas reached an all-time high in 2004, and gas production was initiated from the Sif/Igor area of the Halfdan Field. The commissioning of a new pipeline for gas export in 2004 made the increase in gas sales possible.

In 2004, a total of 250 wells contributed to the production of oil and gas in the Danish sector of the North Sea. Production took place from 130 wells, 28 of which are gas production wells.

In several fields, water is injected to maintain the pressure. One hundred water-injection wells accomplish this task, two of which co-inject water and gas. A total of 20 wells are used for injecting gas.

In 2004, ten companies received and sold oil from the Danish fields. Fig. 3.1 shows each company's percentage contribution to total oil production in 2004.

OIL PRODUCTION

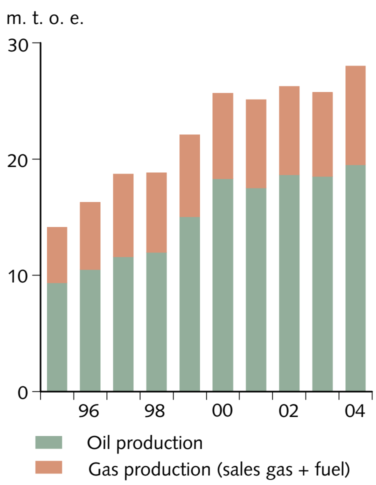
With a production figure of 22.6 million m^3, oil production in 2004 set a new record, surpassing the previous production record from 2002 by 5 per cent. In 2002, total oil production amounted to 21.5 million m^3. The development in total oil production appears from Fig. 3.2.

The increase in oil production is attributable to the continued development of existing fields. In about half of all existing fields, oil production rose as a result of continued development; see the section entitled *Development*.

NATURAL GAS PRODUCTION

The natural gas production figure of 10.93 billion Nm^3 for 2004 was somewhat below the record set in the year 2000, when natural gas production totalled 11.31 billion Nm^3. Natural gas sales, however, soared to an unprecedented 8.26 billion Nm^3 in 2004. The previous gas sales record was from 2001, amounting to 7.33 billion Nm^3.

Fig. 3.2 Production of oil and gas

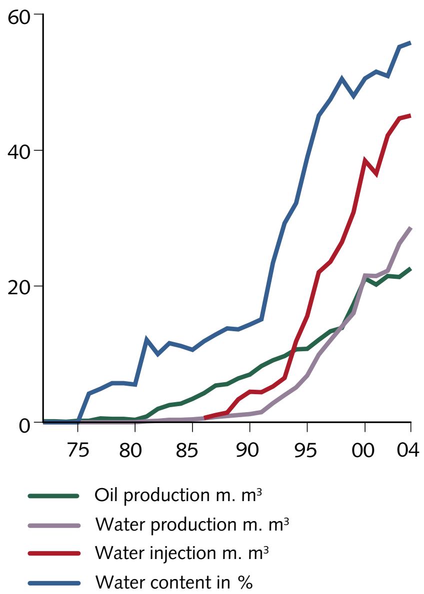


The increase in gas sales is attributable to a new pipeline for gas export, connecting Tyra West to the F/3 platform on the Dutch NOGAT pipeline; see the section *Development*. The pipeline was commissioned on 18 July 2004 and has a capacity of 15 million Nm^3 per day. In 2004, about 10 per cent of all gas sold was exported through the NOGAT pipeline. Less than half the capacity of the new pipeline was utilized in 2004.

The increased amount of sales gas means a drop in the amount of gas reinjected into the fields. In 2004, 1.73 billion Nm^3 of gas was reinjected against 2.43 billion Nm^3 in 2003. This corresponds to a reduction of nearly 30 per cent.

The amount of gas used as fuel in offshore oil and gas production increased by 4 per cent to 0.68 billion Nm^3 in 2004. In addition, 0.26 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. 3.3 Development in oil and water production



WATER INJECTION AND PRODUCTION

Water injection boosts the production of oil in a large number of oil fields. In 2004, the amount of water injected into Danish oil fields totalled 45.1 million m^3.

The amount of water produced increased to 28.6 million m^3 in 2004. Thus, the water content of total liquid production amounts to almost 56 per cent.

Water injection has considerably improved oil recovery from many Danish fields compared to natural depletion, but it has also increased the amount of water produced together with the oil; see Fig. 3.3. This figure shows the development in annual oil and water production, water injection and the water content of production.

Water injection was initiated in the Skjold Field in 1986, with the Dan and Gorm Fields following in 1989.

When water injection was introduced for Danish fields, about 5 per cent of the ultimate recovery estimated today had been produced.

In the following period, until 1991, an additional 5 per cent of the ultimate recovery estimated today was produced, with a low water content of less than 15 per cent. Two factors account for the slow increase in water content during the period until 1991, viz. that new wells generally produce oil with low water content and that a number of large fields, Gorm, Skjold and Rolf, were brought on stream during the period in question.

In the subsequent period from 1991 to 1998, the water content increased to about 50 per cent of total liquid production. This was because water production soared in the old fields and only minor, new fields were brought on stream.

In the period from 1998 to 2002, the water content constituted about 50 per cent due to the startup of production from new, major fields, South Arne, Siri and Halfdan. An additional 25 per cent of the estimated ultimate recovery was produced during this interval.

PRODUCING FIELDS

The production of oil and gas in Danish territory commenced in 1972 from the Dan Field. Since then, oil production has climbed over the years as new fields were developed and existing fields further developed.

Production derived from 19 fields in 2004. The production of gas was initiated from the Sif/Igor area of the Halfdan Field in 2004. Fig. 3.4 shows a map of the producing fields.

Appendix A shows figures for the production of oil and gas from the individual fields. Appendix A also provides figures for water production and injection, fuel consumption and gas flaring and gas injection, as well as a table of CO_2 emissions from the North Sea installations. Annual production figures since 1972 can be obtained from the Danish Energy Authority's website, www.ens.dk.

Production from chalk and sandstone reservoirs

The bulk of Danish oil is produced from accumulations in chalk. In 2004, approx. 90 per cent of oil production derived from chalk reservoirs, while the remaining approx. 10 per cent came from sandstone accumulations.

These two types of formations differ greatly in terms of porosity and permeability. Porosity indicates what proportion of the reservoir rock consists of microscopic voids (pores) that may contain oil, gas or water. Chalk fields typically have a porosity of up to 30-45 per cent, while the porosity of sandstone fields rarely exceeds 25 per cent.

Permeability indicates the ability of fluids or gas to flow through the reservoir. The higher the permeability, the easier the fluids flow. The permeability of sandstone is typically many orders of magnitude higher than the permeability of chalk reservoirs. This difference means that producing hydrocarbons takes longer from chalk fields.

The production scenario for a well or field depends on a number of reservoir properties, such as the volume and permeability of the reservoir, including the permeability of fractures, and any pressure support from a gas cap and/or water zone.

During production, fluids are removed from the pores in the reservoir, and the pressure drops. This causes the remaining gas, oil and water to expand. At the same time, the pores in the reservoir may compact. In turn, the ensuing pressure increases, thus enhancing recovery. Chalk has generally proved to be weaker than sandstone, which means that with a given pressure drop in the reservoir, chalk is more inclined to compact than sandstone. The presence of water further weakens the strength of the chalk.

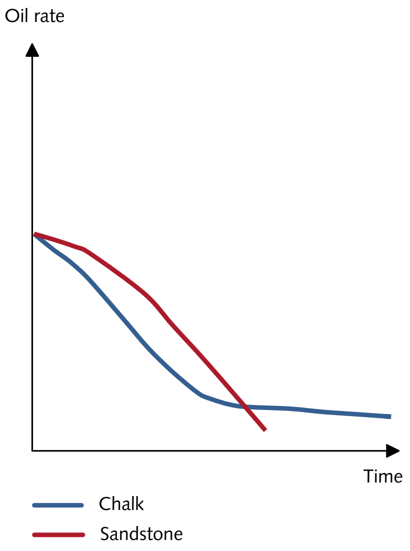
The water zone will expand when the pressure drop from the oil zone reaches the aquifer, thus causing water to flow into the pores previously filled with oil. This gives some Danish fields high, natural pressure support, which usually raises the recovery factor. In fields with insufficient pressure support, water is therefore frequently injected to maintain pressure and displace the oil in the pores. This applies to all types of reservoirs.

The typical production profiles of reservoirs in chalk and sandstone fields reflect the large differences between the reservoir properties. Fig. 3.5 shows typical production scenarios for chalk and sandstone.

It appears from the figure that when oil is produced from sandstone reservoirs, relatively high production rates are achieved for a fairly short period, meaning that the reservoir is depleted very quickly. In contrast, production from a chalk field extends over a longer period of time, as oil flows much slower through chalk. This results in production that tapers off over a prolonged period, with lower production rates. In Danish territory, a number of chalk fields have produced for more than 20 years.

Fortunately, the effective permeability of Danish chalk fields is frequently higher than the natural permeability of the actual chalk material. This is because the fractures naturally occurring in the chalk increase the reservoir's permeability. In such cases, the production profile will often be a combination of the two profiles shown in Fig. 3.5. During the initial period of production, the flow rate is dominated by the high-permeable fractures, later declining to reflect the low permeability of the chalk.

Fig. 3.5 Production scenario in chalk and sandstone



The method used for reporting production from individual fields differs slightly from previous editions of the report "Oil and Gas Production in Denmark"; see Box 3.1.

Appendix B provides a schematic overview of the producing oil and gas fields. Production developments in 2004 for a number of fields are briefly outlined below.

The Kraka Field

During the first half of 2004, workover operations on the existing wells were performed, so all wells are now producing again. This has caused the average daily production figure for the field to rise by about 40 per cent in 2004 relative to 2003.

The Rolf Field

The Rolf-6D well was originally abandoned as a production well because it did not encounter producible oil. Due to problems with the two remaining production wells, Rolf-6D produced water during the period from 2002 to 2004 to maintain a sufficiently high temperature in the export pipeline. This resulted in a small

Box 3.1 Allocation of production

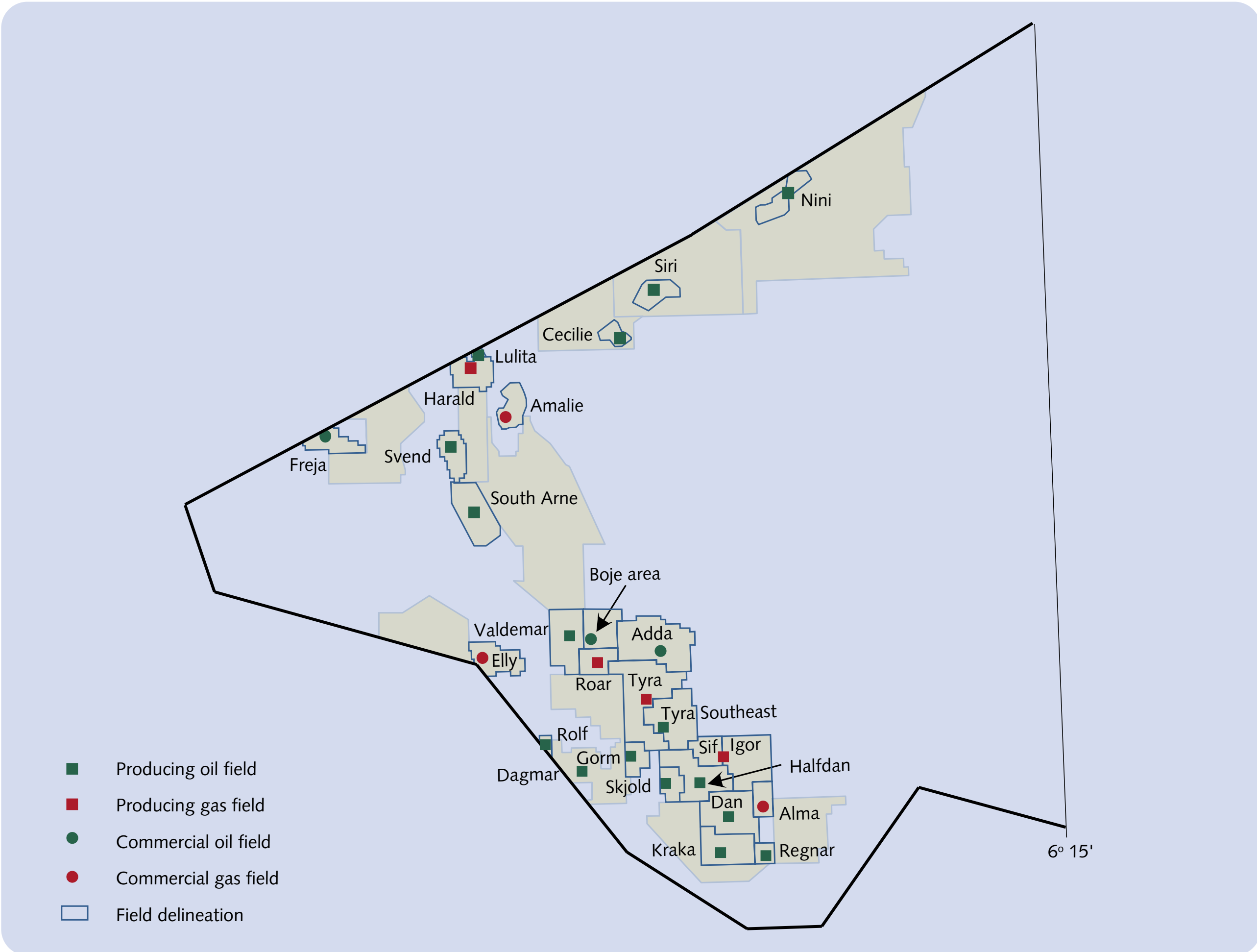
Fig. 3.4 shows the producing fields in Danish territory. Field delineations, which are administrative delineations of the oil and gas accumulations, are shown around several of the fields. Particularly in the Contiguous Area, the fields are closely spaced and contain oil and gas in different layers. As more is learned about the fields, some of the accumulations have proved in several cases to extend from one delineated field into the neighbouring delineated field. For example, it has become evident that one gas accumulation in Danian layers extends from the Igor delineation towards the east through the Sif delineation and into the Halfdan delineation. Likewise, the underlying Maastrichtian oil zone in Halfdan extends into the Sif delineation.

In several cases, production from these fields occurs through long, horizontal wells. From one of the Halfdan platforms, a long gas well has been drilled that produces gas from within the Halfdan, Sif and Igor Field delineations. In the same way, several oil wells have been drilled from the Dan Field into the Halfdan Field delineation, and vice versa.

Previously, the tax position was affected by how the production from such wells was calculated and allocated to the respective delineated fields. However, with effect from 1 January 2004, this no longer applies for fields comprised by the Sole Concession as a consequence of the North Sea Agreement from 2003 and amendments to the Hydrocarbon Tax Act.

Consequently, the production from Sif/Igor is no longer determined separately, but is included in production from the Halfdan Field. Generally, production from oil and gas wells is now allocated to the fields from which the wells were drilled.

Fig. 3.4 Danish oil and gas fields



production of oil, which was drawn into the well. With the two other wells permanently back in operation, production from Rolf-6D has been suspended again.

Sif and Igor (the Halfdan Field)

This area contains a gas accumulation that extends across the Halfdan, Sif and Igor Field boundaries.

In 2003, a production test was initiated from the well in the Sif part of the Halfdan Field, and in 2004 permanent gas production commenced. Moreover, a well extending into Igor was drilled in 2004; see the section *Development*. The wells drilled have production zones lying within the field delineations of Halfdan and Sif as well as Igor. Production conditions in this area have proved more difficult than expected.

The accumulation is exploited from the Halfdan Field installations, and the production from Sif and Igor is reported together with production from the Halfdan Field in Appendix A.

The Siri Field
The Siri Field consists of Siri Central and the neighbouring Stine 1 and 2 segments. Total oil production from the Siri Field and the neighbouring Stine 1 and 2 segments dropped by about 25 per cent in 2004 compared to the year before. One reason for the drop was that a few wells in the Siri Field were shut down during periods of 2004 due to problems with handling the gas produced.

Production declined even though production from the Stine segment 1 commenced in May 2004 from the SCB-1 well. In October 2004, the SCB-2 injection well was used to initiate water injection in this segment.

The Tyra Southeast Field
Oil production commenced in the Tyra Southeast Field in 2002, and the seventh production well was drilled in 2004; see the field map in Appendix B. The well produces gas mainly, and the field has proved to contain more gas than assumed in the development plan.

The Valdemar Field
The Valdemar Field produces from two reservoirs in Lower Cretaceous and Upper Cretaceous layers, respectively.

Oil production from this field was 15 per cent higher in 2004 than in 2003. This increase results from the continued positive impact of two new production wells drilled in 2003. The stable, low water content of production has confirmed the potential of the Lower Cretaceous reservoir, and the licensee has applied for approval for further developing the Lower Cretaceous reservoir; see the section *Development*.

4. DEVELOPMENT OF THE GORM FIELD

The Gorm Field has produced oil and gas since 1981 and is thus one of the oldest fields in Danish territory. Since production startup, the field has been developed in a series of different phases. Among other things, these phases reflect the growing knowledge about the field as well as technological developments.

The Gorm Field is a typical Danish oil field. For this reason, a review of the field's history can help illustrate the rapid development of oil and gas fields in the Danish sector of the North Sea.

Although the field has produced for 24 years, there are still plans to further develop the field. At the end of 2004, the Danish Energy Authority received a plan for enhancing oil recovery from the field. The plan provides for the drilling of additional wells in the field and an expansion of the production facilities.

THE GORM RESERVOIR

The subsoil below and around the Gorm Field consists of basement rock overlain by alternate clay and sandstone deposits. During the Zechstein period about 250 million years ago, salt beds were also deposited, covering most of the North Sea. The salt beds are superimposed by a number of layers, including chalk deposited during the Cretaceous to Danian ages. Some of these approx. 65-million-year-old chalk layers constitute the reservoir in the Gorm Field. Subsequently, the salt beds became partially liquefied under the weight of these layers, a process resulting in salt pillows that intruded vertically into the chalk layers and formed salt diapirs. The salt intrusion has formed a bulge in the chalk layers at the Gorm Field, a so-called dome structure that traps the oil.

A main fault also intersects the chalk deposits of the dome structure, dividing the field into two parts; see Fig. 4.1. Subsequently, the area was exposed to subsidence and the further depositing of sand and clay.

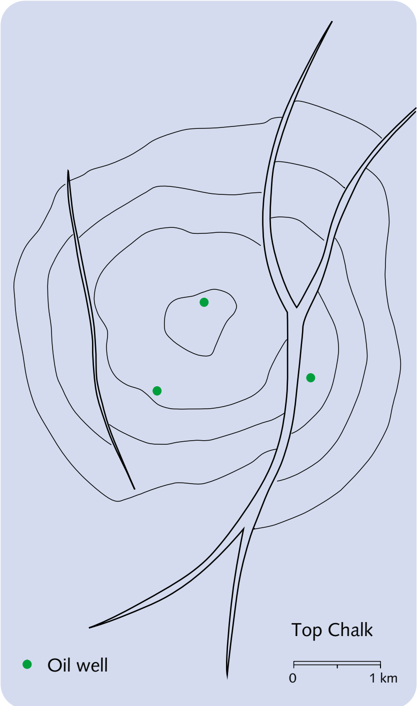
Today, the chalk layers from which oil and gas are produced lie about 2,100 metres below the surface of the sea.

The chalk consists mainly of skeletal material from microorganisms that once lived in the sea, including coccoliths, foraminifera and dinoflagellates. Moreover, the chalk deposits contain a percentage of void space, which may contain oil, gas and water, termed the porosity of the chalk. In the Gorm Field, the porosity reaches a level of about 40 per cent in the reservoir layers from which oil is produced, while the porosity declines towards the flanks of the field.

The possibility of recovering oil depends on the ability of oil to flow through the reservoir, the so-called permeability. The permeability of the Gorm Field is highest in the fractured areas at the centre of the field, with permeability falling substantially in the flanks of the field.

The oil produced in the Gorm Field is assumed to have been formed from Jurassic claystone containing organic material. Hydrocarbons are formed when such layers are exposed to high temperatures and pressures over millions of years.

Fig. 4.1 The Vern (Gorm) structure map in 1978



The oil thus generated migrated through the subsoil and was trapped in the dome created from the salt intrusion into the chalk. Overlying, impervious layers, consisting of Paleogene claystone and marl (cap rock), stopped the further migration of hydrocarbons.

EXPLORATION WELL NO. 16

The first hydrocarbon exploration well in the Danish sector of the North Sea was drilled in 1966. This well led to the discovery of the Kraka oil field. In the years 1968-69, the Tyra, Igor and Roar gas fields were discovered, followed by the discovery of the Dan oil field in spring 1971. At that time, a total of 15 exploration and appraisal wells had been drilled onshore and in the North Sea in the area comprised by the Sole Concession.

Well no. 16 was drilled in the so-called Vern structure in May-June 1971. As the first well drilled in the Vern structure, N-1 encountered oil.

In 1975 and 1976, two additional exploration and appraisal wells were drilled in the Vern structure. The first three wells, N-1, N-2 and N-3, appear from Fig. 4.1, which also shows the existing mapping of the crestal part of the chalk structure in the field.

Following the decision to recover oil from the Vern structure, the new oil field was named the Gorm Field. The field was named after "Gorm the Old", a Danish king reigning until the year 958.

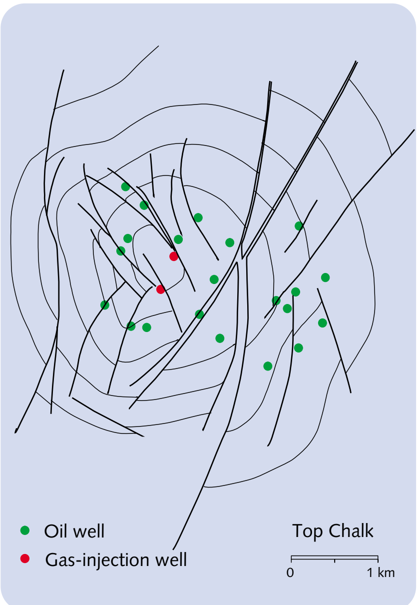
The Gorm Field is located within the area covered by the Sole Concession from 1962. Mærsk Olie og Gas AS is the operator of the Gorm Field.

DEVELOPING THE GORM FIELD

Initial phase of the development

Based on the results from the first three exploration and appraisal wells, thorough studies of the geological and reservoir conditions in the area were carried out.

Fig. 4.2 The Gorm Field in 1986



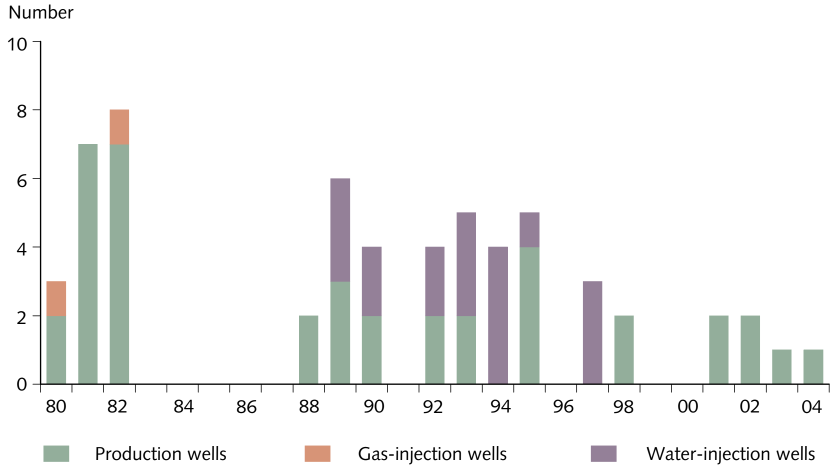
This resulted in a plan for initiating oil and gas production from the field. In 1979-1981, a total of five platforms were planned and installed, all interconnected by bridges. Two platforms were designed to host the wells planned, and the other platforms consisted of an accommodation and processing platform, a gas flare stack as well as a platform from which oil could be transported to shore through a projected pipeline.

This initial phase saw the drilling of 16 production wells and two wells for reinjection of produced gas. Fig. 4.2 shows a map of the crestal part of the chalk structure from 1986, including all 18 wells.

Fig. 4.3 shows the number of production and injection wells drilled in the Gorm Field since 1980.

The production of oil and gas from the Gorm Field commenced in May 1981. After the startup of oil production from the Gorm Field, Danish oil production increased substantially. During the period 1978-1982, a total amount of about DKK 2.3 billion (nominal prices) was invested in the initial phase of the development; see Fig. 4.8.

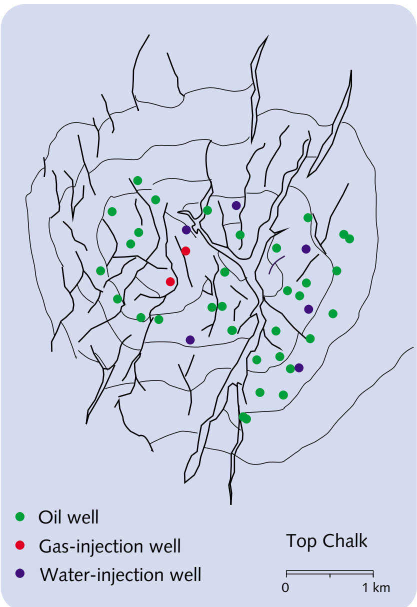
Fig. 4.3 New wells in the Gorm Field



During the period 1981-1984, the oil from the Gorm Field was loaded directly onboard tankers at the field. In May 1984, the oil pipeline from the Gorm E platform to Fredericia was commissioned. Since then, all oil produced from the Gorm Field has been transported through this pipeline. The oil pipeline, owned by DONG Olierør A/S, is also used to transport oil from a number of other oil fields.

During the first years of production, oil was produced by natural depletion, meaning that the naturally high reservoir pressure forced the oil towards the wells and up to the surface. In step with production, the reservoir pressure gradually declined, making it more difficult for the oil to flow up to the surface. Therefore, gas lift was introduced for several of the production wells towards the end of the 1980s.

Fig. 4.4 The Gorm Field in 1991



Startup of water injection

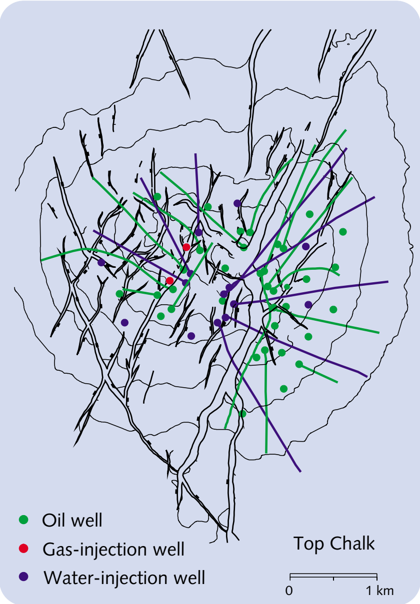
In autumn 1987, plans were made to establish water injection in the Gorm Field. Mærsk Olie og Gas AS had gained its first positive experience from water injection into chalk fields after initiating water injection in the Skjold Field in 1986.

In 1989, tests with injecting treated seawater into the Gorm Field commenced. The purpose was to maintain pressure and thus improve oil recovery. Concurrently, more new production wells were drilled. During the first few years, water for injection into the Gorm Field was supplied through a pipeline from the Skjold Field.

Water injection also proved successful for the Gorm Field, so in 1991, a new development plan that focused on extending water injection to major parts of the field was prepared. Fig. 4.4 shows a map of the Gorm Field as it appeared in 1991, including the first water-injection wells. It also appears that no horizontal wells had as yet been drilled.

In 1991, a new platform was installed in the field, making it possible to drill more wells in the field. Moreover, the platform housed processing equipment, including water-injection pumps. The equipment on the new platform was designed to handle production containing hydrogen sulphide. Hydrogen sulphide occurs naturally in

Fig. 4.5 The Gorm Field in 2003



certain oil fields (e.g. the Dagmar Field), and may also form when seawater is injected.

As a result of the development plan from 1991, a total of ten new production wells and 13 water-injection wells were drilled up through the 1990s; see Fig. 4.3. At this point, long horizontal wells were drilled, which improved recovery substantially; see Figs. 4.5 and 4.6. In addition, old production wells were converted to water injection.

As appears from Fig. 4.6, immense volumes of water have been injected into the field since the mid-1990s. The aim is to reestablish high pressure in the reservoir. Waterflooding of the reservoir also improves oil recovery.

Optimizing production

During the period 2001-2003, six production wells were drilled, some to replace older wells. Damaged sections of the older wells failed to drain the reservoir satisfactorily.

Fig. 4.5 shows a map of the Gorm Field from 2003, including all wells currently used for production and injection. Appendix B contains miscellaneous technical information about the Gorm Field as of 1 January 2005 and a more detailed map.

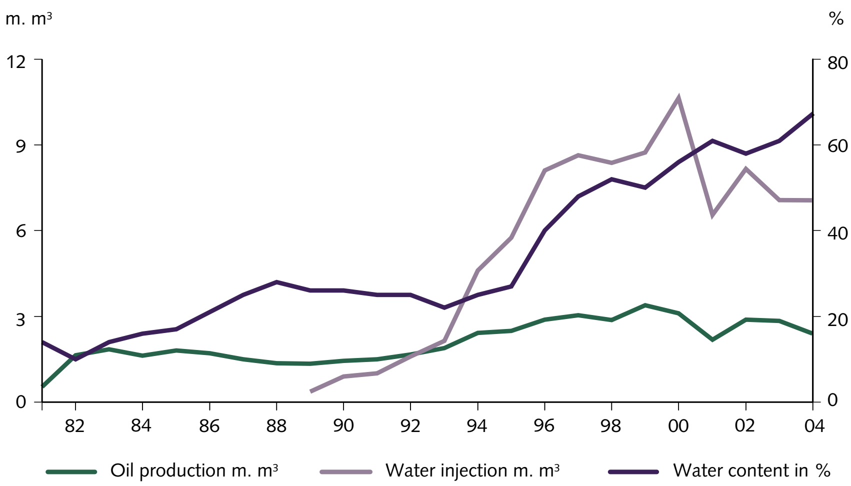
Development means more knowledge

The Gorm Field was initially developed on the basis of data from three wells and experience from other fields in the area.

However, the following years' development and production activities enabled large amounts of data and experience to be compiled. Consequently, greater and more detailed knowledge about the field has been continually accumulated, including about its geological structure.

A comparison of the four figures with field maps shows how the top chalk structure (the reservoir) has been mapped over the years. The main division of the

Fig. 4.6 Oil production in the Gorm Field



field into an eastern and a western block, separated by a main fault extending north-south, is a recurrent feature of all maps.

The figures also show that drilling continued in ever-larger parts of the field as more was learned about the structure of the field and the distribution of oil and gas in the reservoir.

PRODUCTION FROM THE FIELD

Oil production

From 1981 when oil and gas production from the Gorm Field commenced until 1 January 2005, the field produced a total of 50.42 million m^3 of oil and 14.63 billion Nm^3 of gas.

Total oil production from the Gorm Field represented a 20 per cent share of total Danish oil production during the period from 1972 through 2004, equal to 255 million m^3. Fig. 4.6 shows the annual production of oil, annual water injection and the content of water relative to total liquid production for the Gorm Field.

On the basis of production experience, investments in new production and injection wells and new processing equipment have been continually made; see above. These investments impacted on the trend in both oil and water production; see Fig. 4.6.

Interestingly, the field recorded its highest annual oil production figure in 1999 – as much as 18 years after the first oil was produced from the field. Moreover, it appears from the figure that annual water injection increased substantially through the 1990s, subsequently boosting oil production. However, this has also stepped up water production. Thus, the water content of liquid production rose from about 26 per cent in 1990 to about 68 per cent at the end of 2004.

Gas production

The Gorm Field has a moderate content of gas, produced together with oil and water. During the first years of the life of the field, the bulk of the gas produced was reinjected into the reservoir. This was done to avoid gas flaring and to maintain pressure in the field.

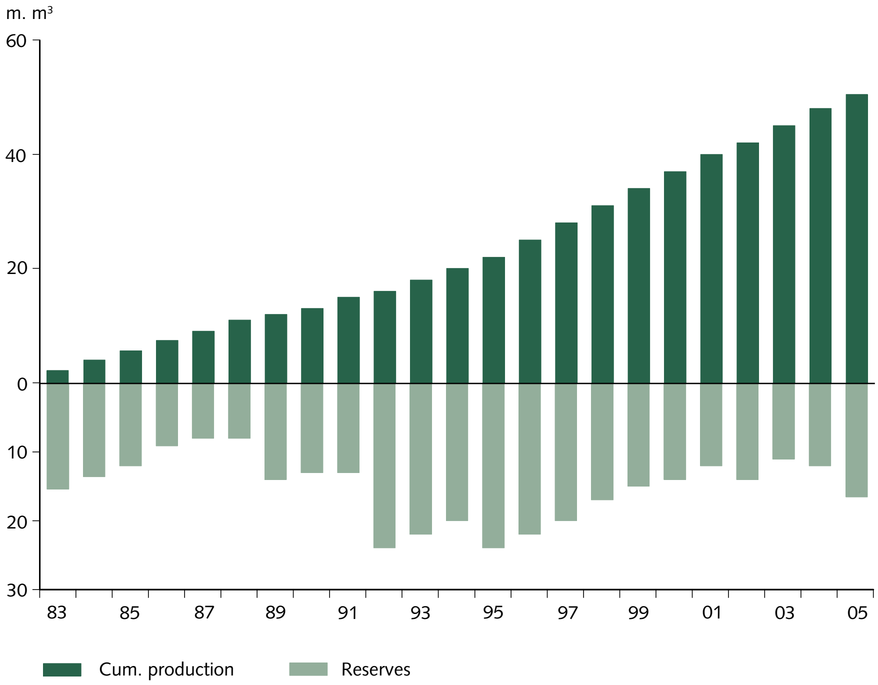
Since 1993, gas is no longer injected on a continuous basis. Instead, the gas produced is transported to the Tyra Field, from where it is exported ashore. However, small volumes of gas are reinjected in situations where the gas cannot be exported, e.g. due to temporary shutdowns of the gas-receiving facilities at the Tyra Field.

Reserves

Development and production generate more and improved knowledge about the field. Therefore, the amounts of oil recoverable from a field are continuously assessed. Such a reserves assessment is based on the principles mentioned in the section *Reserves.*

Fig. 4.7 shows the assessments of oil reserves in the Gorm Field and cumulative oil production since 1981. The sum total of these figures constitutes the expected ultimate recovery of oil from the Gorm Field.

Fig. 4.7 Oil production and reserves for the period 1983-2005



Until the end of 1988, ultimate oil recovery was assessed at 19 million Nm^3. Assessments regarding water injection indicated that ultimate recovery from the field might become somewhat higher. Particularly in connection with the development plan from 1991, the assessment of ultimate oil recovery was written up considerably, to 40 million Nm^3. Since then, it has proved possible to continue adjusting the assessment upwards. Thus, as of 1 January 2005, ultimate oil recovery from the Gorm Field is estimated at 67 million Nm^3.

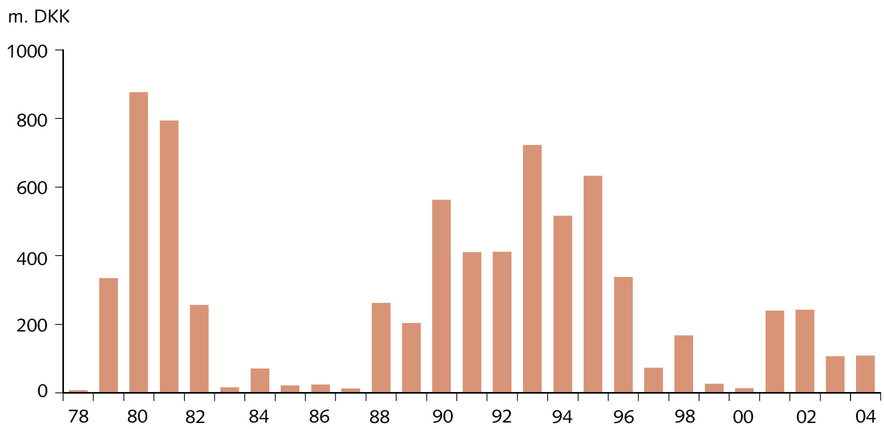
During the period from 1983 to 2005, the estimate of ultimate oil recovery from the Gorm Field increased from 18 million Nm^3 to 67 million m^3, thus more than tripling. The higher figure results from greater knowledge about the structure of the field as well as the development and application of new technologies, such as horizontal wells and water injection.

Based on present-day knowledge about the oil-in-place in the Gorm Field, the estimated recovery factor for oil increased from about 10 per cent at the beginning of the 1980s to about 39 per cent at the end of 2004. The recovery factor indicates the ratio of ultimate recovery to total oil-in-place.

Investments and operating costs

The above-mentioned increase in the ultimate recovery of oil has been contingent upon continuous investments in new platforms and wells and new processing facilities in the field. Fig. 4.8 shows the trend for investments in fixed installations and wells in the Gorm Field in nominal prices. A comparison of this figure with Fig. 4.3 shows that investments in drilling new wells have continuously been made.

Fig. 4.8 Investments in the Gorm Field, 2004 prices



A total of DKK 11.6 billion, in 2004 prices, has been invested in developing the field. This is equal to about DKK 170 per m^3 o.e. that is expected to be recovered from the Gorm Field until production from the field discontinues, based on the assessment made at 1 January 2005. To this must be added the cost of financing the investments. Moreover, it should be noted that investments will subsequently be required for the decommissioning of the installations.

The cost of operating the Gorm Field has fluctuated over the years, ranging between DKK 100 and DKK 250 per produced m^3 o.e. in 2004 prices over the last 20 years. Operating costs must be expected to vary over time and to increase per produced unit towards the end of the life of an oil field.

New development plan

Ongoing efforts are made to improve oil and gas recovery from the fields in the North Sea. In the autumn of 2004, Mærsk Olie og Gas AS submitted a plan for further developing the Gorm Field. The plan is based on an integrated study of geological and reservoir models, which have been updated with experience gained through the production history of the field. The study has identified areas in the field that are not drained optimally, and therefore the plan provides for the drilling of four new wells. At the same time, it is planned to expand and improve the capacity of the processing facilities.

The new wells are estimated to enhance recovery from the Gorm Field by about 3 million m^3 of oil until the year 2020. Total investments associated with the development are estimated at DKK 500 million, with well costs accounting for DKK 360 million.

Depending on experience from the first four wells, the plan outlines the option for drilling up to five additional wells.

Thus, oil recovery from the Gorm Field can still be improved, and in spring 2005, the Danish Energy Authority approved the development plan submitted. The first of the new wells is expected to be spudded in the course of 2005.

5. THE ENVIRONMENT

Fig. 5.1 Fuel consumption

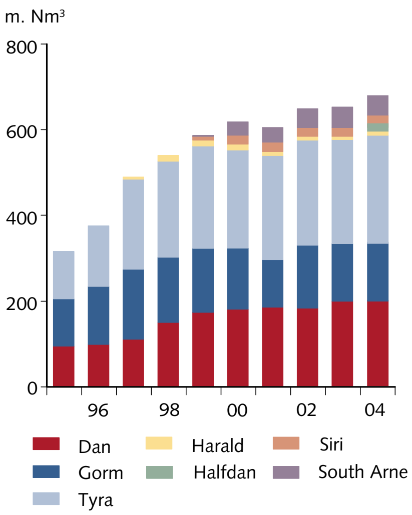
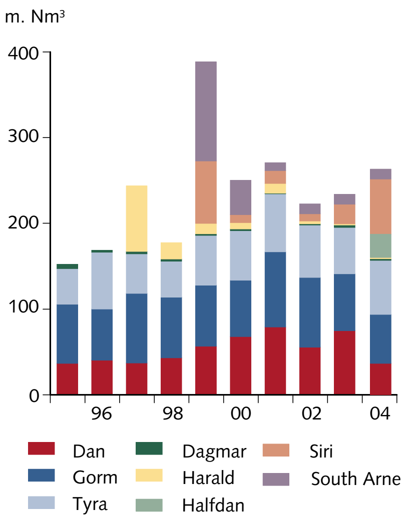


Fig. 5.2 Gas flaring



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

EMISSIONS TO THE ATMOSPHERE

The consumption and flaring of gas produce emissions to the atmosphere. The Danish Subsoil Act regulates the amounts flared and consumed as fuel. CO_2 emissions are regulated by the Act on CO_2 Allowances, while other greenhouse gases are not currently regulated.

Gas used as fuel and gas flaring

The production and transportation of oil and natural gas require substantial amounts of energy. Furthermore, a sizeable amount of gas that cannot be utilized for safety reasons or due to the technical design of the plant has to be flared. Gas consumed as fuel accounts for approx. three-fourths of the total volume of gas consumed and flared offshore. The volume of CO_2 and NO_x emitted by the individual installation or field depends on the scale of production as well as plant-related and natural conditions.

Figs. 5.1 and 5.2 show the amounts of gas used as fuel in the processing facilities and the gas flared in the past ten years. It appears from Fig. 5.1 that 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. Moreover, the amounts of gas flared have increased, but, as Fig. 5.2 shows, the annual variations are much higher for gas flaring.

From 2003 to 2004, the total amounts of gas used as fuel and gas flared increased by 59 million Nm^3. This corresponds to an overall increase of about 7 per cent, with gas used as fuel increasing by 27 million Nm^3 (4 per cent) and gas flaring increasing by 32 million Nm^3 (14 per cent).

The increase from 2003 to 2004 is mainly attributable to the Siri platform, where gas flaring climbed from 23 million Nm^3 in 2003 to 65 million Nm^3 in 2004. This approaches a tripling of gas flaring on the Siri platform, representing two-thirds of the total increase for 2004. Compared with a "normal" year for Siri (2000-2002), the figure has jumped five-fold.

The vast increase on the Siri platform results from the considerable delay in the expansion of the processing facilities, planned in conjunction with the tie-in of the new Nini and Cecilie Fields. The level of flaring was normalized in the course of November. Thus, gas flaring only totalled about 1 million Nm^3 in December 2004.

In 2004, the consumption of fuel on DUC's installations increased by about 30 million Nm^3, primarily due to the new processing facilities in the Halfdan Field; see the section entitled *Development.* At the same time, the DUC fields have reduced gas flaring by 10 million Nm^3, or about 5 per cent.

On the South Arne platform, the consumption of fuel gas decreased from 49 million Nm^3 in 2003 to 45 million Nm^3 in 2004. Gas flaring has been maintained at a low level, remaining largely unchanged.

Fig. 5.3 CO_2 emissions from production facilities in the North Sea

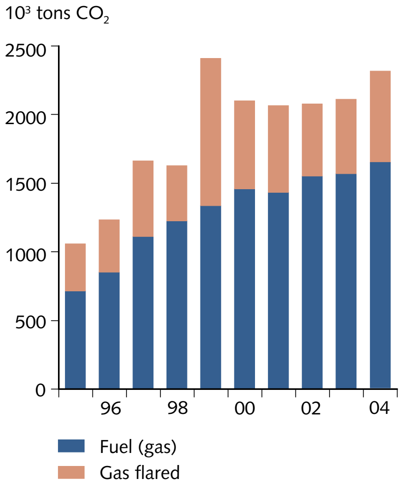
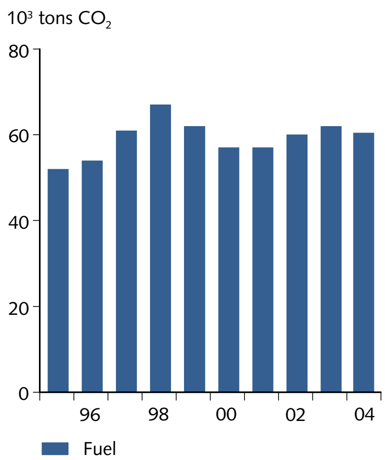


Fig. 5.4 CO_2 emissions from consumption of fuel per m. t.o.e.



CO_2 emissions

Gas consumed as fuel and gas flaring on offshore installations produce CO_2 emissions to the atmosphere. The amount 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 North Sea production facilities since 1995 appears from Fig. 5.3. This figure shows that CO_2 emissions totalled about 2.3 million tons in 2004. The production facilities in the North Sea account for about 4 per cent of total CO_2 emissions in Denmark.

Fig. 5.4 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. It appears from this figure 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. However, emissions declined slightly from 2003 to 2004.

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. One example is water injection, which improves the recovery factor for the reservoirs, but also requires additional consumption of energy.

It appears from Fig. 5.5 that emissions of CO_2 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 and 1999 when the startup of new fields required the flaring of extraordinary amounts of gas. As recently as 2004, the downward trend also reversed as a result of major gas flaring in the Siri Field and the commissioning of the Halfdan Field processing facilities.

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

The European CO_2 allowance scheme

As from 1 January 2005, a CO_2 emission allowance scheme applies to a major part of the energy sector and energy-heavy industries, including the offshore sector. The scheme comprises all 25 EU member states, thus covering more than 10,000 production units in the EU.

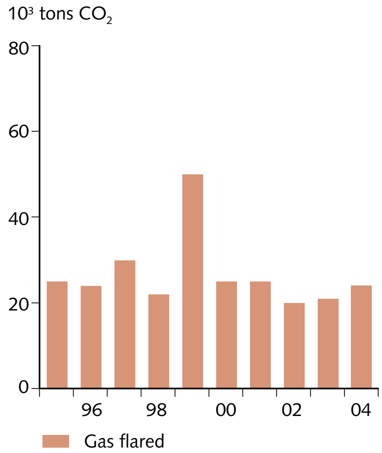
The CO_2 allowance scheme is an essential element of the Danish climate strategy to meet Denmark's international obligations under the Kyoto Protocol.

In June 2004, the Danish Parliament passed an Act on CO_2 Allowances, which regulates the Danish share of the scheme. As of 1 January 2005, the scheme covers 377 production units in Denmark, including seven in the offshore sector.

A production unit is a technical unit consisting of one or more plants situated at the same location. Production units for producing oil and gas fall under the scheme if their combustion installations have a rated thermal input exceeding 20 MW. The allowance applies to both the production of energy for recovering oil and gas and the flaring of hydrocarbons on such production units.

In the offshore sector, a production unit consists of all installations in a field, whether placed on one or more platforms or processing hydrocarbons from several fields.

Fig. 5.5 CO_2 emissions from gas flaring per m. t.o.e.



In October 2004, permits for emitting CO_2 were granted to the offshore production units comprised by the allowance scheme. The permit also requires the individual production units to monitor and measure CO_2 emissions from the production unit. A monitoring plan, which is approved for the production unit when the emission permit is issued, describes how the production unit will carry out the monitoring and measurement.

Each production unit was informed in October 2004 about how many free allowances it could expect to receive for the initial period 2005-2007. The main rule is that allowances are allocated 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. Allowances averaging 2.2 million tons of CO_2 per year have been allocated to the offshore sector. In January 2005, these free allowances were credited to an account for each production unit in the Allowance Register. The allowances are transferable and can be traded on the European allowance market.

DISCHARGES INTO THE SEA

A range of chemicals is needed for the work of exploring and exploiting North Sea oil and gas reservoirs. These chemicals may occur naturally or be manufactured with special properties, and they must be used with due consideration for the working environment and the impact on the surrounding environment. The same applies to products extracted from the subsoil, i.e. hydrocarbons and any natural substances associated with hydrocarbons.

Substances extracted from the subsoil are generally handled in closed systems, while the chemicals used are transported from land and added to the processes. Residual products from production are transported to shore for processing, recycling or waste disposal or are discharged at the site, depending on the environmental assessments made.

The Danish Energy Authority supervises the storage and use of chemicals in the working environment on drilling rigs and production facilities in the Danish sector of the North Sea, while the Danish Environmental Protection Agency supervises the impact of chemicals on the surrounding environment. The two authorities work together to regulate this area.

The Danish Environmental Protection Agency grants permission for marine discharges based on various requirements, including those laid down in international cooperation with the other North Sea countries. This cooperation takes place under the auspices of the Oslo-Paris convention from 1992 (OSPAR), which entered into force in 1998. The OSPAR *Offshore Industry Committee (OIC)* deals with conditions offshore. At the same time, international efforts to formulate an EU strategy for the marine environment are ongoing.

OIC's current work includes establishing environmental goals for marine discharges of chemicals from drilling operations and production activities, as well as implementing these goals.

The OSPAR activities include work on long-term generation goals for 2020, and a number of recommendations have been adopted to meet them. As a result, in 2006 the maximum permissible concentration of dispersed oil is to be reduced from 40 mg per litre to 30 mg per litre in discharged, treated production water. At the same time, the total discharge of oil into the sea is to be reduced by 15 per cent compared to the amount discharged in 2000.

EIA for offshore activities

In order that the Danish Energy Authority can grant its approval for new offshore oil and gas development projects, an evaluation of how the planned project will affect the environment, a so-called Environmental Impact Assessment (EIA), must be made available. According to the applicable EIA rules, an Environmental Impact Assessment must be subjected to a public hearing and submitted to the pertinent authorities for consultation. The comment period is minimum eight weeks.

In 2004, no new Environmental Impact Assessments were prepared in connection with development activities in the North Sea. All of the development activities approved by the Danish Energy Authority in 2004 were covered by previously prepared EIAs, thus having been submitted to public hearings.

6. HEALTH AND SAFETY

The companies exploring for, recovering and producing oil and gas in the North Sea are responsible for ensuring that their activities are always carried on in a safe and sound manner.

The Danish Energy Authority handles the supervision of activities and working conditions in the Danish part of the North Sea. Thus, the Danish Energy Authority must approve new installations and any changes to existing installations. Likewise, the Authority must approve mobile offshore units before they enter Danish waters.

FOCUS AREAS IN 2004

The Danish Energy Authority's supervisory efforts in 2004 were, inter alia, targeted at preventing work-related accidents.

Equipment maintenance is an important safety factor in the operators' safety management systems. Consequently, at inspection visits in 2004, the Danish Energy Authority checked whether the operators were adhering to their plans for maintaining installations and equipment, particularly whether they were performing maintenance of safety-critical equipment in accordance with their time schedules. Safety-critical equipment is equipment 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.

Since the autumn of 2004, the Danish Energy Authority has reviewed registered gas leakages together with the offshore management when inspecting offshore installations. The aim is to increase attention on and improve prevention of gas leakages; see below. In addition, the supervision focused on well control and drilling-related safety equipment on drilling rigs; see Box 6.1.

Offshore inspection

In 2004, the Danish Energy Authority carried out 34 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.

An outline of all inspection visits is available at the Danish Energy Authority's website, www.ens.dk. The website also 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 2004.

User survey of the Danish Energy Authority's supervision

On behalf of the Danish Energy Authority, Rambøll Management conducted a questionnaire survey among employees on North Sea offshore installations in the summer of 2004. The objective of the survey was to provide information about how offshore personnel experience and rate the Danish Energy Authority's inspections.

About 1,700 employees were invited to participate in the survey, and 497 responded, corresponding to about 29 per cent. One-third of the respondents are members of the safety organizations on the offshore installations where they work.

Box 6.1 Drilling-related safety equipment on drilling rigs

The Danish Energy Authority has supervisory responsibility for drilling-related safety conditions on drilling rigs.

An essential element of upholding safety standards is the so-called well control equipment. This equipment is used to prevent the uncontrolled escape of pressure or formation fluids from wells.

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. Compliance with these procedures is essential to safety standards on drilling rigs.

Against this background, the Danish Energy Authority decided to implement a supervisory project targeted at well control equipment. The aim of the project is to check the safety aspects of well control equipment on all rigs operating in the Danish sector.

In the initial stages of the project, the Danish Energy Authority reviewed the certification and maintenance documentation for each individual rig. Next, the Danish Energy Authority is to assess the safety of the equipment by reviewing the documentation received and conducting inspection visits / audits on selected drilling rigs. To this end, the Danish Energy Authority carried out a well control audit on the drilling rig ENSCO 101 in 2004.

The project will be carried on in 2005 and completed with a report.

The results of the survey led the Danish Energy Authority to take some initiatives aimed at improving its communication of information and dialogue. For example, during all offshore inspections in the spring of 2005, the Danish Energy Authority informed personnel about the new Executive Order on the Reporting of Accidents, etc. Moreover, the Danish Energy Authority hands out copies of new statutory provisions during inspection visits.

Rambøll Management's report and the Danish Energy Authority's follow-up plan can be found at the Danish Energy Authority's website, www.ens.dk.

ACCIDENTS, DISEASES AND "NEAR-MISS" OCCURRENCES

Preventing work-related accidents

The Danish Energy Authority finds that a thorough investigation into work-related accidents can help prevent such accidents. Therefore, during inspection visits to the offshore installations concerned, the Danish Energy Authority reviewed all work-related accidents occurring in 2004, including the role of the safety organizations and their follow-up on the accidents.

Table 6.1 Reported accidents broken down by category

Categories	Mobile	Fixed
Falling/tripping	14	1
Substances and materials	1	0
Use of technical equipment	7	2
Falling objects	2	0
Handling goods	6	0
Crane/lifting operations	2	0
Other	8	1

Table 6.2 Expected absence on fixed offshore installations

Duration	No. of reports
1-3 days	3
4-14 days	22
2-5 weeks	6
More than 5 weeks	8
Undisclosed	1

Table 6.3 Expected absence on mobile offshore units

Duration	No. of reports
1-3 days	1
4-14 days	0
2-5 weeks	0
More than 5 weeks	2
Undisclosed	1

The Danish Energy Authority urges the safety organizations to make investigations into the root causes of the accidents an ongoing priority. In 2005, the Danish Energy Authority will continue to review accidents during inspection visits and to follow up on the work-related accidents reported.

Work-related accidents reported

Work-related accidents on offshore installations resulting in incapacity to work for one or more days beyond the injury date must be reported to the Danish Energy Authority.

To make it easier to report work-related accidents offshore, the electronic reporting system, EASY, now includes a special option for the offshore sector for the purpose of reporting accidents; see Box 6.2.

In 2004, the Danish Energy Authority received 44 reports on work-related accidents. The accidents are broken down by category, as shown in Table 6.1. The expected periods of absence from work attributable to the accidents reported are indicated in Tables 6.2 and 6.3.

Of the 44 work-related accidents reported, 40 occurred in connection with operation, maintenance and/or construction works on board fixed production installations and accommodation units. One of these accidents occurred during the victim's time off on a fixed offshore installation. This accident is included in Tables 6.1 and 6.2, but was not included when the accident frequency stated below was calculated.

The remaining four accidents occurred on mobile offshore units (drilling rigs).

None of the accidents reported in 2004 were fatal. However, on 24 May 2004, a serious accident occurred on the drilling rig ENSCO 71. On the basis of the ensuing investigation into the circumstances of the accident, the Danish Energy Authority reported the incident to the police.

Accident frequency

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

According to the companies operating in the Danish sector in 2004, the number of working hours totalled 4.11 million for fixed production installations and associated accommodation units. On mobile offshore units, such as drilling rigs and crane barges, working hours totalled 1.92 million in 2004.

The accident frequency calculated for fixed production installations and accommodation units in 2004 is 9.5 per million working hours. For mobile offshore units, the accident frequency has been calculated at 2.1 per million working hours.

The number of reported work-related accidents on fixed production installations fell from 49 in 2003 to 39 in 2004, while the number of working hours on fixed production installations and accommodation units in 2004 increased substantially compared to 2003. Overall, this results in a decline in the accident frequency from 12.6 in 2003 to 9.5 in 2004.

Four work-related accidents were reported for mobile offshore units in 2004, as compared to 11 reports in 2003. The number of working hours on mobile off-

Box 6.2 Reporting offshore work-related injuries

In February 2005, a new Executive Order on the registration and reporting of work-related injuries and "near-miss" occurrences entered into force.

To make it easier to report work-related accidents offshore, the electronic reporting system, EASY, now includes a special option for the offshore sector for reporting accidents. EASY was developed by the National Working Environment Authority and the National Board of Industrial Injuries.

In 2004, about 36 per cent of the reports were received via EASY. Only companies with a Danish enterprise registration (CVR) number can join the EASY system and thus report accidents electronically.

In 2004, a number of EASY information and demonstration meetings were held with operators in the Danish sector, as well as all contractors reporting work-related accidents in 2003.

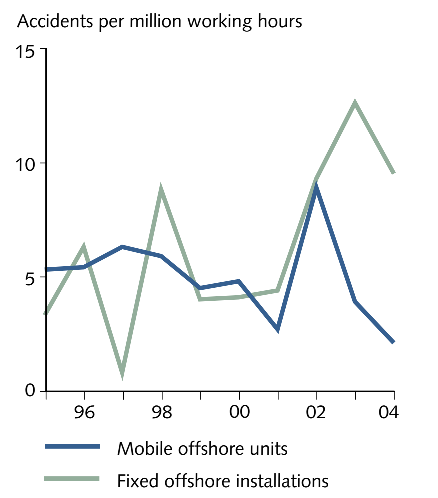
To date, the offshore option of EASY is only meant to handle the reporting of work-related accidents. Property damage to the offshore installation and "near-miss" occurrences must still be reported directly to the Danish Energy Authority. Work-related diseases must still be reported to the National Working Environment Authority.

The Danish Energy Authority's website, www.ens.dk, contains a direct link to EASY and additional material about reporting procedures.

shore units also fell from 2003 to 2004. The accident frequency calculated for mobile offshore units dropped from 3.9 in 2003 to 2.1 in 2004. Fig. 6.1 shows the annual accident frequency for the past ten years.

From 2005, the Danish Energy Authority can request information about the actual period of absence attributable to accidents. This will provide a better basis for differentiating future accident evaluations. The information can be obtained from employers as a result of the new Executive Order on the Registration and Reporting of Work-Related Injuries, etc.

Fig. 6.1 Accident frequency on offshore installations



Work-related diseases

In 2004, the Danish Energy Authority received three reports of work-related diseases that were suspected to be attributable to work on an offshore installation. To date, none of the three diseases reported have prevented the resumption of work. A skin disorder is the main diagnosis made for two of the employees concerned, while the main diagnosis for the third employee was a muscular/skeletal disorder.

An outline of the percentage distribution by main diagnosis of the work-related diseases reported to the Danish Energy Authority since 1993 is shown at the Danish Energy Authority's website, www.ens.dk.

"Near-miss" occurrences

"Near-miss" occurrences are defined as occurrences that could have directly led to

an accident or damage to the offshore installation or vessel. The occurrences to be reported to the Danish Energy Authority in future are listed in the Guidelines on Reporting Accidents, available at the Danish Energy Authority's website.

In 2004, the Danish Energy Authority received five reports on "Near-misses" on offshore installations.

Two of the "near-miss" occurrences concern gas leakages; see below. In the case of these two occurrences, the operator carried out a more detailed investigation and sent the reports to the Danish Energy Authority.

The third "near-miss" occurrence concerned a sprained foot. This was reported as both a work-related accident and a "near-miss" occurrence, the reason being that the employee could have suffered a much more serious injury.

The fourth occurrence took place on a mobile offshore unit. An employee climbed outside the railing, where there was a 3-metre drop, without putting on a safety harness. Another employee witnessed the incident, and the operation was stopped immediately.

The last of the "near-miss" occurrences reported was observed during an internal safety inspection. It was ascertained that an inexpedient change had been made to the design of equipment for working at heights (man-riding operations). The report stated that as a result of the inspection, the equipment was modified before being used again, so as to prevent a potential accident.

All "near-miss" occurrences reported, including gas leakages, were followed up in 2004.

Collision with drilling rig

On Friday, 12 March 2004, a supply vessel collided with a leg of the drilling rig ENSCO 71. The freestanding drilling rig was carrying out drilling work for DONG E&P A/S at a location at the Siri Field in the North Sea. There was only minor damage to the leg of the drilling rig and the supply vessel, and the occurrence did not result in any personal injury.

GAS LEAKAGES

Gas leakages were a focus area in 2004. Depending on type and size, gas leakages, also termed accidental hydrocarbon releases, must now be reported as "near-miss" occurrences.

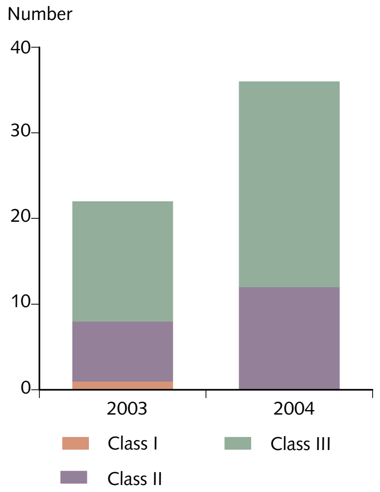
At the request of the Danish Energy Authority, the operators reported gas leakages occurring at the individual installations in 2003 and 2004. The releases are reported with an indication of date, type and size of release, and are broken down into three categories; see Box 6.2. A total of 22 hydrocarbon releases were reported in 2003, broken down into one release in class I, seven releases in class II and 14 releases in class III; see Fig. 6.2. For 2004, 36 hydrocarbon releases were reported, distributed on no releases in class I, 12 releases in class II and 24 releases in class III. The Danish Energy Authority has taken up all class I and class II releases with the operators.

In 2005, the Danish Energy Authority will have a better opportunity for continuous follow-up, as hydrocarbon releases in classes I and II will be reported currently, as opposed to 2003 and 2004 when they were reported quarterly.

Box 6.3 Categories of hydrocarbon releases

Class I: > 10 kg/sec. or more than 100 kg for a short duration
Class II: 1-10 kg/sec. or more than 10 kg for a short duration
Class III: 0.1-1 kg/sec. or more than 1 kg for a short duration

Fig. 6.2 Accidental hydrocarbon releases



OFFSHORE INSTALLATIONS REGULATIONS

New Offshore Installations Act

In 2004, the Danish Energy Authority made preparations to draft a new Bill to replace the existing Offshore Installations Act, which dates back almost 25 years.

A new Act will provide the offshore sector with a contemporary legal basis for the work related to health and safety offshore. In addition, it will help keep safety standards in the Danish offshore sector among the highest in the North Sea countries.

The Minister for Transport and Energy is expected to present the Bill in the Danish Parliament at the end of 2005.

New and amended rules and regulations

An outline of all applicable Executive Orders is available at the Danish Energy Authority's website.

Executive Order on the Use of Work Equipment

In 2004, the Executive Order on the Use of Work Equipment on Offshore Installations was amended. The amendment serves to extend this Executive Order to work done at heights, including work involving scaffolding, rappelling, ladders and lifting devices.

Executive Order on Heavy-Current Installations and Electrical Equipment

The rules on electrical equipment on offshore production installations were amended in 2004. Consequently, the rules applicable offshore and onshore now differ only slightly.

Executive Order on the Registration and Reporting of Work-Related Injuries, etc.

A new Executive Order on the Registration and Reporting of Work-Related Injuries, etc. on offshore installations entered into force on 1 February 2005. In cooperation with the unions and the employers' organizations offshore, the Danish Energy Authority prepared these new provisions in 2004.

Guidelines to the Executive Order have been prepared, 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.

Regulations on substances and materials

The regulations on suppliers' obligations relating to substances and materials on offshore installations and the use of substances and materials were amended at the end of 2004, entering into force on 17 January 2005.

The amendments 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. The Danish Energy Authority carries out supervision if chemicals for use on offshore installations are imported through a non-Danish supplier.

Regulations on including absence due to illness in the Workplace Assessment

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
In 2004, the Danish Parliament passed an Act on Due Process Protection in connection with the Public Administration's Use of Compulsory Measures and Duties of Disclosure. The Act 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, including rules providing protection against self-incrimination when the public administration imposes a duty of disclosure on a natural or legal person in a specific case.

REDUCING ADMINISTRATIVE BURDENS

Towards fulfilling the Government's objective of reducing administrative burdens for the business community, the Ministry of Economic and Business Affairs set up an Administrative Burden Committee within the energy sector in 2004, with the participation of relevant trade organizations and companies. The Committee is tasked with making proposals for relief specifically targeted at helping ease administrative burdens already from 2005. In addition, the Administrative Burden Committee is to draw up an overall plan for reducing administrative burdens until 2010.

Immediately before the turn of the year 2004/2005, the Committee presented a list of proposals for simplifying the energy area, including an overall time schedule for the further work to be performed. Thirty proposals relate specifically to the offshore area, and five were adopted upon their presentation. These proposals concern removal of the requirement to submit various routine reports to supervisory authorities and the requirement to obtain advance permission for flaring gas offshore. At the same time, the oil companies have been informed that dispensing with the permission procedure may not lead to increased flaring.

A number of the other proposals are likely to be implemented when a new Offshore Safety Bill, expected to be introduced at end-2005, is passed, while other proposals for reducing administrative burdens are awaiting the oil companies' initiative with respect to a simplified reporting form and procedure.

OFFSHORE SAFETY TRAINING

The North Sea countries cooperate in maintaining high standards for safety training offshore.

In 2004, NSOAF *(North Sea Offshore Authorities' Forum)* asked IADC *(International Association of Drilling Contractors)* to draft a proposal for a compulsory, basic safety course for all employees working offshore in the North Sea countries. This work is expected to be completed before the end of 2005.

A parallel initiative is being launched by a working group composed of representatives of oil and gas producers in the North Sea countries (DK, N, NL and UK). The result of this work is expected to be available by mid-2006.

7. RESERVES

Fig. 7.1 Production and reserves

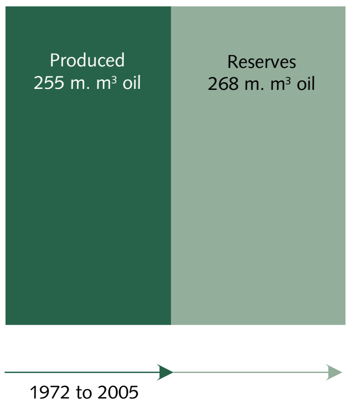
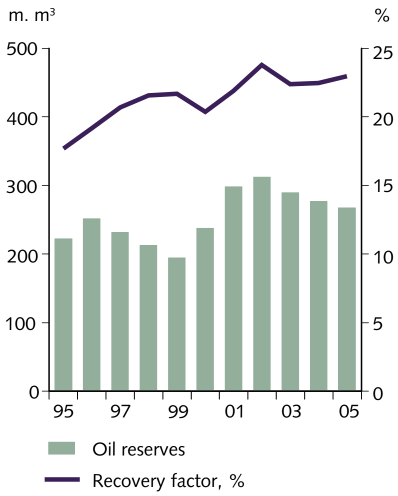


Fig. 7.2 Oil reserves and recovery factor



The Danish Energy Authority makes an assessment of Danish oil and gas reserves annually. At 1 January 2005, oil reserves were estimated at 268 million m^3 and gas reserves at 132 billion Nm^3.

The Danish Energy Authority's new assessment shows a decline in both oil and gas reserves of 3 per cent compared to the assessment made at 1 January 2004. The decrease in reserves is mainly attributable to production in 2004.

The ultimate recovery of oil expected has been written up by 14 million m^3 compared to last year's assessment. Oil production amounted to 22.6 million m^3 in 2004, and oil reserves have thus declined by 9 million m^3 in total.

At 1 January 2005, 255 million m^3 of oil had been produced, meaning that total production accounts for almost half of the ultimate recovery expected; see Fig. 7.1. The volumes produced have not previously accounted for so large a share of ultimate recovery, and on the basis of the current reserves assessment, Danish oil production has reached the half-way mark. However, technological development and any new discoveries resulting from exploration activity may add new reserves to future assessments.

The development in oil reserves appears from Fig. 7.2, and existing reserves just exceed the average for the period illustrated. The average oil recovery factor expected for Danish fields was 23 per cent, an increase of 1 percentage point relative to last year's assessment; see Fig. 7.2. The average recovery factor is the ratio of ultimate recovery to total oil-in-place.

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 2004 level for the next 12 years. The R/P ratio was 13 according to the assessment made at 1 January 2004.

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 Fig. 7.7 and the accompanying text on the twenty-year production forecast.

ASSESSMENT OF RESERVES

The reserves reflect the amounts of oil and gas that can be recovered by means of known technology from proven hydrocarbon accumulations 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 Danish Energy Authority in calculating the reserves and preparing the production forecasts is described in Box 7.1.

Box 7.1 Categories of reserves

The method used by the Danish Energy Authority 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.

Table 7.1 shows the Danish Energy Authority'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 Fig. 7.3 that the expected amount of oil reserves ranges from 219 to 268 million m^3. The difference between the two figures, 49 million m^3, equals

Fig. 7.3 Oil recovery, m. m³

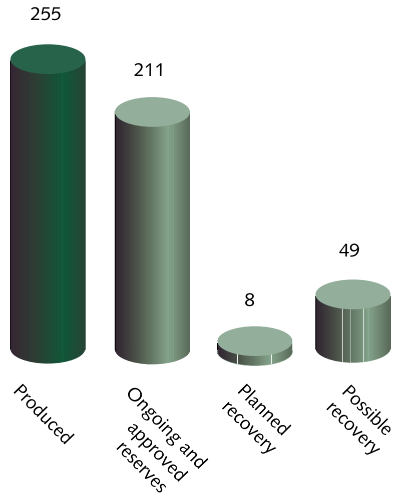
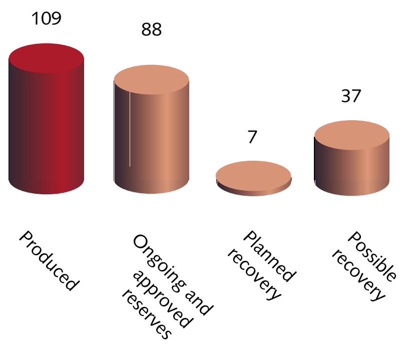


Fig. 7.4 Gas recovery, bn. Nm³



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, Fig. 7.4 illustrates that the expected amount of gas reserves ranges from 95 to 132 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 consumed or flared on the platforms in the production process.

Last year's reserves assessment specified the reserves of Halfdan and Sif/Igor, as they were considered to be more or less distinct fields. It has now been established with a high degree of certainty that Halfdan and Sif/Igor are one large contiguous hydrocarbon accumulation at different strata levels, and in future the three fields will be referred to collectively as the Halfdan Field. The area towards the north and east contains gas, primarily in Danian layers, while the southwestern part primarily contains oil in Maastrichtian layers.

There have been several revisions of the Danish Energy Authority's assessment of reserves compared to the assessment made in January 2004. These revisions are attributable to more production experience and new reservoir models of some of the fields resulting from improved knowledge of the fields. The areas where significant revisions have been made are described below.

Ongoing and approved recovery

In the planned recovery category, the reserves assessment made in January 2004 included the reserves recoverable from the development of the North Jens area in the Valdemar Field and from the establishment of water-processing facilities on the Harald platform to handle production from Lulita. In June 2004, the Valdemar development plan was approved, and the pertinent reserves have therefore been included under ongoing and approved recovery. Moreover, in connection with the commissioning of the facilities to handle production from the Lulita Field, the relevant reserves have been transferred to the ongoing and approved recovery category.

The reserves of the Cecilie Field have been written down due to new well data and production experience.

The Dan Field reserves have been written up as a result of production experience and the fact that the northeastern part of the field is to be further developed according to a plan approved in February 2005. This plan is described in more detail in the section *Development*.

The reserves in the Gorm Field have been written up on the basis of positive production experience and the fact that a plan for further developing the field was approved in spring 2005. This plan is described in more detail in the section *Development*.

The oil reserves in the southern part of the Halfdan Field have been written up, because production experience has been positive and the field is to be further developed on the basis of a plan approved in June 2004. Production experience has led to a writedown of the gas reserves in the northeastern part of Halfdan (the Sif part).

Table 7.1 Production and reserves at 1 January 2005

	OIL, million m³				GAS, billion Nm³			
	Ultimate recovery				Ultimate recovery			
	Produced	Reserves			Produced	Reserves		
		Low	Exp.	High		Low	Exp.	High
Ongoing and approved recovery:								
Adda	-	0	1	1	-	0	0	0
Alma	-	0	1	1	-	1	1	2
Boje area	-	1	1	1	-	0	0	0
Cecilie	0	0	1	1	-	-	-	-
Dagmar	1	0	0	0	0	0	0	0
Dan	76	32	67	120	20	4	10	19
Elly	-	1	1	1	-	4	4	4
Gorm	50	8	17	26	6	1	2	3
Halfdan	17	36	78	141	4	8	15	32
Harald	7	1	1	2	17	4	6	8
Kraka	4	0	2	3	1	1	1	2
Lulita	1	0	0	1	0	0	0	1
Nini	2	1	2	3	-	-	-	-
Regnar	1	0	0	0	0	0	0	0
Roar	2	0	1	1	12	2	5	8
Rolf	4	0	0	1	0	0	0	0
Siri	9	1	2	3	-	-	-	-
Skjold	37	3	7	9	3	0	1	1
Svend	5	1	1	1	1	0	0	0
South Arne	12	*	15	*	3	*	6	*
Tyra	22	1	5	8	37	19	23	27
Tyra Southeast	1	3	4	5	2	5	10	13
Valdemar	3	4	6	8	1	2	4	5
Subtotal	**255**		**211**		**109**		**88**	
Planned recovery								
Amalie	-	*	2	3	-	*	3	5
Freja	-	1	1	2	-	0	0	0
Dagmar	-	0	1	1	-	0	0	0
Valdemar	-	2	4	6	-	2	3	6
Subtotal			**8**				**7**	
Possible recovery								
Prod. fields	-	14	29	48	-	11	27	46
Other fields	-	0	1	2	-	0	0	0
Discoveries	-	12	20	33	-	4	11	20
Subtotal			**49**				**37**	
Total	**255**		**268**		**109**		**132**	
January 2004	232		277		100		136	

** Not assessed*

The Dan and Halfdan Fields are estimated to have the largest oil reserves in this category, and the estimated reserves of these two fields account for about two-thirds of the category's total reserves.

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

Planned recovery
In December 2004, plans were submitted for further developing the Dagmar Field and the Bo area of the Valdemar Field. The Danish Energy Authority is currently reviewing these plans, for which reason the pertinent reserves have been included in the planned recovery category. The plans are described in more detail in the section *Development*.

Possible recovery
The Danish Energy Authority 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 recoverable oil reserves.

It is projected that drilling horizontal wells will further increase the potential for producing oil from the Bo area of the Valdemar Field and gas from the northeastern part of the Halfdan Field.

Finally, discoveries that are under appraisal are included in this category, e.g. Hejre and Svane. This category also includes discoveries that are considered to be non-commercial based on current technology and prices.

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 about two-thirds 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 23 per cent. In fields like Dan, Gorm and Skjold, where the production conditions are favourable, an average recovery factor of about 37 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.

PRODUCTION FORECASTS
Based on the assessment of reserves, the Danish Energy Authority prepares production forecasts for the recovery of oil and natural gas in the next five and twenty years, respectively.

Table 7.2 Oil production forecast, million m³

	2005	2006	2007	2008	2009
Ongoing and approved					
Adda	-	-	-	-	-
Alma	-	-	-	-	0.2
Boje area	-	-	-	-	-
Cecilie	0.2	0.1	0.1	0.1	0.0
Dagmar	0.0	0.0	0.0	0.0	0.0
Dan	6.1	5.6	5.2	4.9	4.5
Elly	-	-	-	-	0.1
Gorm	2.3	2.2	2.0	1.6	1.3
Halfdan	5.9	5.9	5.7	5.4	5.1
Harald	0.3	0.2	0.2	0.2	0.2
Kraka	0.2	0.2	0.1	0.1	0.1
Lulita	0.1	0.1	0.1	0.0	0.0
Nini	1.3	0.4	0.2	0.1	0.1
Regnar	0.0	0.0	0.0	0.0	0.0
Roar	0.1	0.1	0.1	0.1	0.0
Rolf	0.1	0.1	0.1	0.1	0.0
Siri	0.6	0.5	0.4	0.2	0.2
Skjold	1.2	1.0	0.8	0.7	0.6
Svend	0.2	0.2	0.1	0.1	0.1
South Arne	1.9	1.6	1.5	1.3	1.2
Tyra	0.6	0.5	0.4	0.3	0.3
Tyra Southeast	0.4	0.3	0.3	0.3	0.2
Valdemar	0.4	0.6	0.8	0.8	0.7
Total	**22.0**	**19.6**	**17.9**	**16.2**	**14.9**
Planned	**0.1**	**0.2**	**0.4**	**0.9**	**0.8**
Planned course of production	**22.1**	**19.8**	**18.3**	**17.2**	**15.7**
Possible	**-**	**-**	**1.7**	**2.9**	**3.3**
Possible course of production	**22.1**	**19.8**	**20.0**	**20.1**	**19.0**

Five-year production forecast

The five-year forecast uses the same categorization as the assessment of reserves, and includes the categories ongoing, approved, planned and possible recovery. Fields are incorporated into the production forecast from the time production start-up is approved or from the earliest date on which production can be commenced.

Expected oil production appears from Table 7.2. In this table, the oil production figures including planned recovery illustrate the planned course of production, while the figures including possible recovery illustrate the possible course of production. Fig. 7.5 shows production in recent years as well as the planned and possible courses of production.

For 2005, oil production is expected to total 22.1 million m³, equal to about 381,000 barrels of oil per day. The forecasts for both planned and possible recovery show a declining trend. However, the forecast for possible recovery remains largely constant for the period from 2006 to 2009.

Planned course of production

In relation to the planned course of production in last year's forecast, expected production figures have been changed. Thus, the changes in the production forecast consist of a writedown for the years 2005 and 2006 and a write-up for the years 2008 and 2009.

The forecasts for 2005 and 2006 were revised mainly because of a writedown in production for the Cecilie and South Arne Fields, while the write-up for the years 2008 and 2009 is mainly attributable to an upward adjustment of production for the Dan, Gorm and Halfdan Fields.

Major revisions of production estimates are reviewed below.

The production estimate for Dan has been adjusted in light of the most recent production experience and includes contributions from further development of the northeastern part of the field.

In spring 2005, the Danish Energy Authority approved a postponement of production startup from the Boje area until 1 January 2011, and the production estimate has been adjusted accordingly.

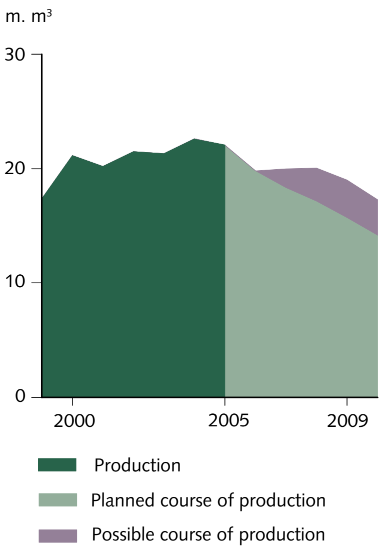
For Cecilie, production in the forecast period has been written down due to new well data and production experience.

Production estimates for the Gorm and Halfdan Fields have been adjusted in light of the most recent production experience and include contributions from further development of the fields. The Dan and Halfdan Fields are projected to be the fields recording the largest production during the forecast period, accounting for an average share of total production of 58 per cent in the planned recovery category.

The production estimate for the South Arne Field has been adjusted to reflect the most recent plans for further development of the field.

The production estimate for the Valdemar Field has been adjusted in light of the most recent production experience and includes contributions from further development of the North Jens area.

Fig. 7.5 Production and forecasts for the period 2000-2009



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 Valdemar.

Possible course of production

Table 7.2 includes contributions from the possible recovery category. Within the possible recovery category, the production potential is based on the Danish Energy Authority'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 20.2 million m³, equal to about 348,000 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.

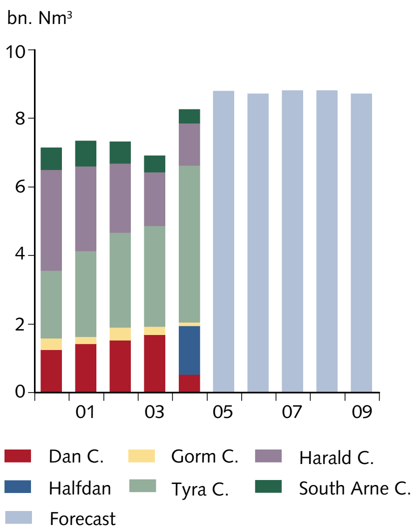
Compared to the possible recovery estimate in last year's report, the production estimate has been written down by an average of 12 per cent during the forecast period. Primarily, this is because parts of the production plans outlined in the possible recovery category in last year's forecast are expected to be implemented later than assumed last year.

Natural gas production estimates are given in Fig. 7.6. 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 7.2 includes additional condensate production resulting from increased gas production under new export contracts.

Twenty-year production forecast

The method used for making the 20-year forecast for the planned and possible courses of production is the same as for the five-year forecast. A forecast covering 20 years is most reliable in the first part of the period. Moreover, the methods used in making the forecasts imply that production must be expected to decline after a short number of years.

Fig. 7.6 Natural gas production broken down by processing centre and estimated future sale of natural gas



Planned and possible courses of production

The forecasts for both planned and possible recovery show a downward trend; see Fig. 7.7. Mid-way through the forecast period, production according to the possible recovery scenario is estimated to constitute about 50 per cent of the production estimate for 2005. Thus, the forecast projects a downward plunge in oil production.

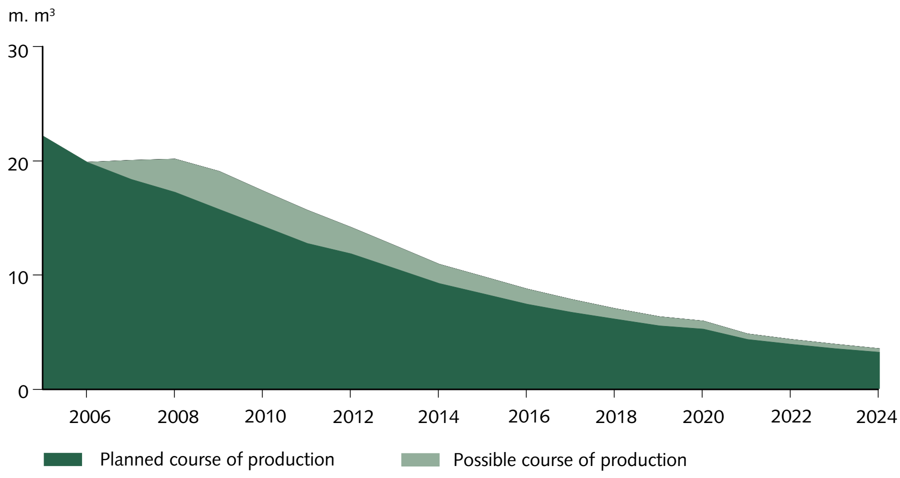
This decline can possibly be curbed as a result of technological development and any new discoveries made as part of the ongoing exploration activity.

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

Fig. 7.7 Production forecasts for the period 2005-2024



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 Danish Energy Authority's forecast for the possible course of production is based on the contracts with DUC providing for total gas supplies of approx. 170 billion Nm^3 until the year 2020. In addition, the possible course of production for the South Arne Field accounts for 8 billion Nm^3.

RESOURCES

The Danish Energy Authority'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.

As a supplement to the reserves assessment, the Danish Energy Authority has estimated 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.

Potential for technological development

Ongoing technological development is anticipated in society in general, and, more specifically, the oil industry.

The oil industry is expected to continue developing and to cut the cost of existing technologies as well as to develop new technologies that can boost production. Other industries may also make technological advances useful to the oil industry. Society in general will also offer technological innovations that can be used by the oil industry. One example is the development of increasingly powerful computers and more intelligent equipment.

The average recovery factor for oil is 23 per cent according to the reserves assessment, and this assessment is supplemented by an estimated contribution from technological development that corresponds to a roughly 5 percentage-point increase in the average recovery factor, or more than 100 million m^3 of oil.

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.

When new technology is used to recover oil, gas will also be produced. The volume of this gas is highly uncertain, but will presumably be of minor importance. It is therefore assumed that it will be used as fuel in the production of oil. As regards production from gas fields, it may be mentioned that drilling horizontal wells is the only commercially feasible means of recovery from thin gas zones, such as the northeastern part of the Halfdan Field.

Future technological developments are also expected for the recovery of gas. For example, the use of horizontal wells to exploit thin gas zones will become more efficient. For gas fields, the reserves assessment has been supplemented by an estimated contribution from technological developments of about 15 billion Nm^3 of gas. This contribution is close to total gas recovery for the Roar Field.

Exploration potential

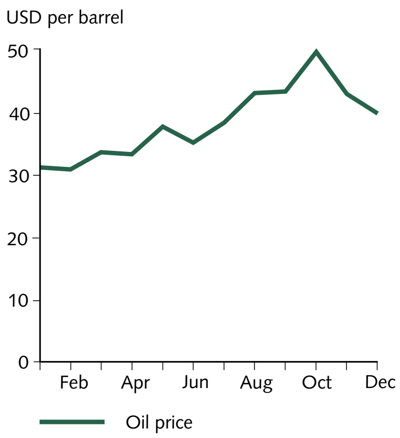
In connection with the 6th Licensing Round, the Danish Energy Authority has assessed the hydrocarbon resources in structures where no exploration drilling has been carried out as yet, the so-called exploration potential.

The exploration potential has been assessed exclusively for the Central Graben in the Danish sector and the Siri Fairway, as these areas cover all producing fields and commercial discoveries in Danish territory. Moreover, these two areas form part of the same hydrocarbon system, where the hydrocarbons have been formed mainly from Jurassic clay from the Farsund Formation. The Danish Energy Authority has chosen to limit the assessment to the Danish part of the Central Graben and the Siri Fairway because the hydrocarbon potential in the rest of Denmark is difficult to assess and thus subject to great uncertainty.

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.

8. ECONOMY

Fig. 8.1 Oil price development in 2004



Oil and gas production impacts positively on the Danish economy in several respects. By producing hydrocarbons, Denmark has become self-sufficient in energy. Moreover, the production of oil and gas generates a socio-economic surplus that boosts the Danish oil and gas sector. At the same time, the Danish state gets a share of this surplus through taxation and by participating in oil and gas production activities.

CRUDE OIL PRICE AND DOLLAR EXCHANGE RATE

The value of the Danish oil and gas produced is mainly affected by how the international crude oil price and the dollar exchange rate develop.

The average quotation for a barrel of Brent crude oil was USD 38.2 in 2004. This price is substantially higher than in 2003, when the average quotation was USD 28.8 per barrel.

Fig. 8.1 shows the development in the oil price in 2004, while the historic figures are available in *Appendix C*. In 2004, the dollar exchange rate averaged about DKK 6 per USD, a rate lower than the average for 2003; see *Appendix C*.

VALUE OF OIL AND GAS PRODUCTION

The total value of Danish oil and gas production was calculated at about DKK 39 billion in 2004, which is a 27 per cent increase compared to the level in 2003. The high production value in 2004 is attributable to the relatively high oil price level in 2004. Compared to 2003, the total production figure also rose slightly, see the section *Production*, but this increase was accompanied by a minor fall in the dollar exchange rate.

The preliminary figures for 2004 show that oil production represented a value of DKK 32.6 billion, and gas production a value of DKK 6.3 billion. The breakdown of production in 2004 on the ten producing companies appears from Fig. 3.1 in the section *Production*.

How the production value will develop in future depends mainly on the production volume, the development of the dollar exchange rate and finally future oil and gas prices. The Danish Energy Authority prepares forecasts of the future development of production, based on known and possible reserves. As the development in the dollar exchange rate and oil prices is difficult to predict, forecasts of the development in production value will be subject to a high degree of uncertainty.

DEGREES OF SELF-SUFFICIENCY

Due to the production of oil and gas, Denmark has been self-sufficient in energy since 1997. In 2004, the total production of oil, gas and renewable energy was 53 per cent higher than total energy consumption. This is an increase compared to the year before, when production exceeded consumption by 41 per cent. In 2004, oil and gas production exceeded total energy consumption by 38 per cent and total oil and gas consumption by 111 per cent.

Table 8.1 shows the development in the degrees of self-sufficiency projected by the Danish Energy Authority 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. As appears from the table, the Danish Energy Authority expects Denmark to continue being self-sufficient in energy for the next five years.

IMPACT OF PRODUCTION ON THE DANISH ECONOMY

While making Denmark self-sufficient in energy, oil and gas production also affects the Danish economy positively in two other areas. Thus, the 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 gas

Since 1995, Denmark has had a surplus on the balance of trade for oil and gas. The balance of trade shows the difference between the value of total imports and total exports of oil and gas.

For 2004, the surplus on the balance of trade has been estimated at just over DKK 19 billion. This is a substantial increase compared to 2003, when the comparable surplus slightly exceeded DKK 15 billion. This increase is due in part to the relatively high level of oil prices.

Impact on the balance of payments

A share of the oil and gas produced is consumed in Denmark, thus replacing the energy imports otherwise required, while the rest is exported.

The Danish Energy Authority prepares an estimate of the impact of oil and gas activities on the balance of payments current account for the next five years. The Danish Energy Authority bases this estimate on its own forecasts of production, investments and operating and transportation costs. This estimate is subject to a number of assumptions about import content, interest expenses and the oil companies' profits from the hydrocarbon activities.

These calculations have been made on the basis of a low, an intermediate and a high oil price scenario of USD 20, USD 30 and USD 40 per barrel, respectively, and a dollar exchange rate of DKK 5.8 per USD. The calculations for the three price scenarios illustrate how sensitive the economy is to fluctuations in the oil price.

Table 8.1 Degrees of self-sufficiency

	2005	2006	2007	2008	2009
Production in PJ					
Oil	803	721	728	731	692
Gas	376	377	380	387	392
Renewable energy	141	141	142	148	141
Energy consumption (PJ)					
Total	850	852	860	877	884
Degrees of self-sufficiency (%)					
A	217	200	200	196	179
B	139	129	129	127	123
C	155	145	145	144	139

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

Table 8.2 shows the individual items used in calculating the impact of oil and gas activities on the balance of payments in the USD 30 oil price scenario. The lower part of the table also shows the calculated impact on the balance of payments current account when using the low price scenario of USD 20 and the high price scenario of USD 40, respectively. The upper part of the table shows the socio-economic production value, defined as the sum total of the production values of oil and gas. The import content of expected expenses is then deducted from the socio-economic production value. Finally, dividends and interest payments transferred abroad are deducted, thus yielding the impact of oil and gas activities on the balance of payments current account.

Assuming that the oil price is USD 30 per barrel, the oil and gas activities will have an estimated DKK 20-22 billion impact on the balance of payments current account during the period 2005-2009. The low and high oil price scenarios show that oil prices greatly influence how the oil and gas activities affect the Danish economy.

State revenue

The state's proceeds from North Sea oil and gas production can be subdivided into two sources of revenue. For one thing, the state generates revenue from various taxes and fees: *corporate income tax, hydrocarbon tax, royalty, profit sharing, the oil pipeline tariff* and *compensatory fee*. For another, the state receives indirect revenue through DONG E&P A/S' participation in oil and gas activities.

Corporate income tax is the chief source of state revenue. During the period 1962-2004, the state's revenue from hydrocarbon production in the North Sea totalled about DKK 97.8 billion in 2004 prices. Of this amount, corporate income tax accounts for 55.5 per cent, royalty for 24.6 per cent, the oil pipeline tariff for 12.5 per cent, hydrocarbon tax for 2.4 per cent and profit sharing for 5.0 per cent. By way of illustration, the associated production value totalled DKK 377.4 billion during the same period, while the aggregate value of the licensees' expenses for exploration, field developments and operations was DKK 184.7 billion.

The Government's agreement of 29 September 2003 with A. P. Møller-Mærsk involved amendments to Danish tax legislation, which became effective on 1 January 2004. These amendments will impinge on the state's future revenue from oil and gas production. The main elements of the agreement are outlined at the Danish Energy Authority's website, www.ens.dk.

Box 8.1 and Appendix D contain a brief specification of the state's revenue base in the form of taxes and fees on oil and gas production.

Table 8.2 Impact of oil/gas activities on the balance of payments, DKK billion, 2004 prices, intermediate price scenario (30 USD/bbl)

	2005	2006	2007	2008	2009
Socio-economic production value	31	28	28	28	27
Import content	3	2	2	1	1
Balance of goods and services	28	26	27	27	26
Transfer of interest and dividends	6	5	6	6	6
Balance of payments current account	**22**	**21**	**21**	**21**	**20**
Balance of payments current account, low price scenario (20 USD/bbl)	**15**	**15**	**16**	**15**	**15**
Balance of payments current account, high price scenario (40 USD/bbl)	**29**	**27**	**28**	**28**	**27**

Box 8.1 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 profit sharing and the collection of royalty, the oil pipeline tariff and the compensatory fee are administered by the Danish Energy Authority. Moreover, the Danish Energy Authority 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 2004. With effect from 1 January 2004, these provisions were amended. The amendments are outlined in Appendix D, while more detailed information can be found at the Danish Energy Authority's website.

Corporate income tax

Corporate income tax is the most important source of revenue related to oil and gas. Revenue from corporate income tax payments was not generated until the beginning of the 1980s, for one thing because oil and gas activities require fairly heavy investments that are deductible as depreciation allowances over a number of years.

Hydrocarbon tax

This tax was introduced in 1982 with the aim of taxing windfall profits, for example as a result of high oil prices. Hydrocarbon tax became payable for a few years during the first half of the 1980s and again from 2002 and onwards. Together with declining investments in fields recording a profit, the relatively high oil prices since the end of the 1990s and the rise in oil production in Danish territory mean that the losses brought forward from previous years for setoff against the income subject to hydrocarbon tax have slowly dropped to a level where they can no longer offset the profits recorded by the fields. With effect from 1 January 2004, the Hydrocarbon Tax Act was amended in respect of the Sole Concession and licences granted after 1 January 2004; see *Appendix D.*

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. The holders of the Lulita share of licences 7/86 and 1/90 pay royalty based on the size of production attributable to their share of the field. Since 1 January 2004, the Sole Concession has no longer included a condition regarding the payment of royalty.

Profit sharing

With effect 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 the corporate income tax base, after deducting 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. So far, the compensatory fee is payable on production from the South Arne, Siri, Nini and Cecilie Fields.

DONG Efterforskning & Produktion 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 at the current rates. Since DONG E&P A/S is a wholly state-owned company, its financial result reflects the value of the state's interest. DONG E&P A/S recorded a loss of DKK 49 million for 2004. The state's revenue from its ownership of DONG E&P A/S consists of dividend payments and the rising value of the company's shares.

Fig. 8.2 Development in total state revenue from oil/gas production 1972-2004, DKK billion, 2004 prices

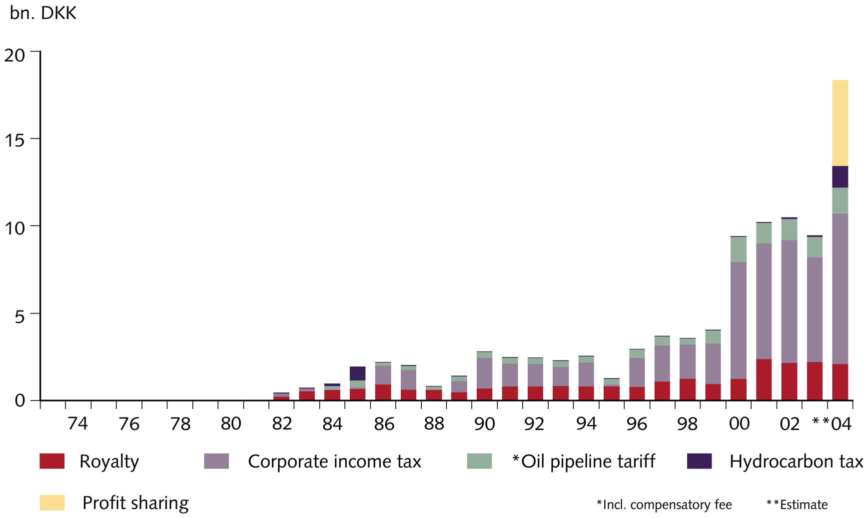


Fig. 8.2 shows the development in total state revenue broken down on the individual taxes and fees. It appears that from the year 2000, state revenue from hydrocarbon production in the North Sea has increased substantially, an increase that is due to the positive development of production combined with high oil prices. Table 8.3 shows that state revenue from hydrocarbon production amounted to DKK 18.3 billion in 2004, while revenue for the period 2000-2003 was just under DKK 10 billion per year. The high level of revenue in 2004 is due to the high oil price and to the fact that DUC paid both royalty for 2003 and a profit share for 2004 under the Sole Concession.

For the past five years, the state has received tax payments from companies other than the DUC companies. These tax payments were made by the companies holding shares in the Siri Field (licence 6/95), the South Arne Field (licence 7/89) and the Lulita share of licences 7/86 and 1/90. An outline of the companies holding shares in the individual licences is available at the Danish Energy Authority's website, www.ens.dk.

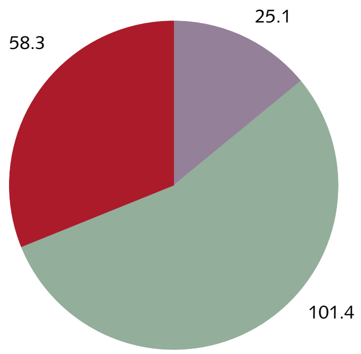
To illustrate the development for the next five years, the Ministry of Taxation has calculated that the state's revenue, based on the USD 20 oil price scenario, will total DKK 4.9 billion in 2005 and then decrease to about DKK 4.2 billion in 2009. The USD 40 price scenario is estimated to yield state revenue of DKK 17.1 billion in 2005, decreasing to about DKK 15.8 billion in 2009; see Table 8.3.

Table 8.3 State revenue over the past five years, DKK million, nominal prices

	2000	2001	2002	2003	2004*
Hydrocarbon tax	-	-	65	64	1,251
Corporate income tax	6,170	6,273	6,794	5,943	8,598
Royalty	1,153	2,247	2,110	2,181	2,104
Oil pipeline tariff**	1,372	1,114	1,169	1,144	1,496
Profit sharing	-	-	-	-	4,890
Total	**8,695**	**9,634**	**10,138**	**9,331**	**18,339**

** Estimate*
*** Incl, 5 per cent compensatory fee*
Note: Payments received during the year

Fig. 8.3 Total costs of all licensees, 1963-2004
DKK billion, 2004 prices



It should be noted that future estimates of corporate income tax and hydrocarbon tax payments are subject to a high degree of 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.

Estimates of future state revenue from the activities in the North Sea assume, among other things, that the oil companies trade oil at the oil price assumed. In this connection, it should be noted that some oil companies hedge prices for part of their production to ensure a certain degree of price stability. During periods with rising oil prices, this may mean that oil companies will trade at below-market prices, and vice versa during periods of declining oil prices.

THE LICENSEES' FINANCES

Fig. 8.3 shows the breakdown of the licensees' expenses during the period from 1963 to 2004. It appears from this figure that the licensees' expenses for exploration, field developments and operations (including transportation) in respect of producing fields were calculated at about DKK 25.1 billion, DKK 101.4 billion and DKK 58.3 billion, respectively.

Exploration costs

In 2004, exploration costs totalled DKK 0.3 billion, a considerably lower figure than in 2003, when exploration activity resulted in total costs of about DKK 0.8 billion. In comparison, exploration costs averaged DKK 0.6 billion in nominal prices during the period 1995-2004.

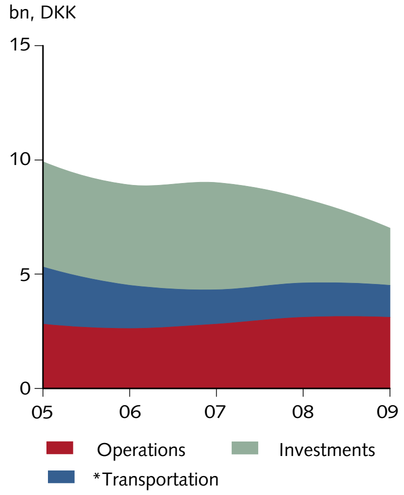
The Danish Energy Authority estimates that the level of exploration costs will increase in 2005 and 2006. This is because the 6th Licensing Round, opened in spring 2005, is expected to have a positive impact on exploration activity.

Table 8.4 Expected state revenue from oil and gas production, 2005-09, DKK billion, 2004 prices*

		2005	2006	2007	2008	2009
Corporate income tax	40 USD/bbl	7,0	6.2	6.3	6.3	6.0
	30 USD/bbl	4.6	4.0	4.1	4.1	3.9
	20 USD/bbl	2.3	2.0	1.5	1.9	1.9
Hydrocarbon tax	40 USD/bbl	3.5	3.2	3.8	4.0	3.7
	30 USD/bbl	1.4	1.2	1.7	1.9	1.7
	20 USD/bbl	0.0	0.0	0.0	0.0	0.0
Profit sharing	40 USD/bbl	5.1	4.8	4.9	4.9	4.7
	30 USD/bbl	3.5	3.3	3.3	3.3	3.2
	20 USD/bbl	1.9	1.8	1.4	1.7	1.7
Royalty	40 USD/bbl	0.0	0.0	0.0	0.0	0.0
	30 USD/bbl	0.0	0.0	0.0	0.0	0.0
	20 USD/bbl	0.0	0.0	0.0	0.0	0.0
Oil pipeline tariff**	40 USD/bbl	1.5	1.3	1.4	1.4	1.3
	30 USD/bbl	1.1	1.0	1.0	1.0	1.0
	20 USD/bbl	0.7	0.7	0.7	0.7	0.6
Total	**40 USD/bbl**	**17.1**	**15.5**	**16.3**	**16.5**	**15.8**
	30 USD/bbl	10.6	9.5	10.1	10.3	9.8
	20 USD/bbl	4.9	4.4	3.5	4.3	4.2

*Payments received during the year
**Incl. 5 per cent compensatory fee
Note: The calculations are based on a corporate tax rate of 30 per cent.

Fig. 8.4 Investments in fields, operating and oil transportation costs, 2004 prices



*Incl. 5 per cent pipeline tariff/compensatory fee

Investments in field developments

Fig. 8.3 shows that investments in field developments account for the largest share of the licensees' total expenses during the period 1963-2004. Development activity was lower in 2004 than in 2003. Total investments in field developments have been preliminarily estimated at DKK 5 billion for 2004.

In 2004, the DUC companies' share of total investments in field developments accounted for 59 per cent, while their share of total production accounted for about 80 per cent.

The Halfdan, Dan and South Arne Fields and the NOGAT pipeline represented more than 66 per cent of total investments in field developments in 2004. The largest single investment in 2004 was the continued development of the Halfdan Field, involving the installation of new processing facilities and the drilling of six additional wells; see the section entitled *Development*.

The Danish Energy Authority's estimate of future investments in field developments is based on ongoing, approved, planned and possible field developments. The estimate of possible investments in field developments is based on the Danish Energy Authority's assessment of the potential for initiating further production beyond the production for which development plans have already been submitted; see the section *Reserves*.

Table 8.6 shows the Danish Energy Authority's estimate of investments in field developments for the period from 2005 to 2009. Compared to its estimate at 1 January 2004, the Danish Energy Authority has written up estimated investments in field developments for 2005, due mainly to additional investments in the Dan,

Table 8.5 Investments, DKK million, nominal prices

	2000	2001	2002	2003	2004*
Cecilie	-	-	223	660	307
Dan	403	367	437	943	754
Gorm	12	240	242	107	108
Halfdan	886	1,518	2,412	1,779	1,141
Harald	175	(1)	0	4	22
Kraka	0	61	3	-	2
Nini	-	-	285	1,288	317
Roar	17	-	-	-	-
Rolf	0	-	-	37	4
Siri/Stine	53	176	111	406	337
Skjold	404	89	5	77	6
Svend	-	115	223	-	-
South Arne	761	578	849	764	784
Tyra	330	198	85	305	438
Tyra SE	2	357	569	82	105
Valdemar	60	316	(1)	200	52
NOGAT pipeline	-	-	-	299	664
Not allocated	50	111	218	248	14
Total	**3,153**	**4,123**	**5,661**	**7,197**	**5,056**

**Estimate*

Halfdan and Gorm Fields. Estimated investments in 2006 have been written down relative to 1 January 2004, which is attributable to a writedown in the *possible* recovery category. The estimate of investments for the rest of the period is largely unchanged; see the section *Reserves*.

Operating, administration and transportation costs

Operating and administration costs have been preliminarily estimated at DKK 2.8 billion for 2004, which is a slight decline compared to 2003.

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 a 5 per cent profit element, which is 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.

Fig. 8.4 illustrates the Danish Energy Authority's estimate of developments in operating and transportation costs for the years to come.

Table 8.6 Investments in development projects, DKK billion, 2004 prices

	2005	2006	2007	2008	2009
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	-	-	-	-	-
Dan	1.4	0.3	-	-	-
Elly	-	0.0	0.4	0.2	-
Gorm	0.4	0.1	0.0	0.0	-
Halfdan	0.8	-	-	-	-
Harald	0.0	-	-	-	-
Kraka	-	-	-	-	-
Lulita	-	-	-	-	-
Nini	0.1	0.0	0.0	0.0	0.0
Regnar	-	-	-	-	-
Roar	-	-	-	-	-
Rolf	-	-	-	-	-
Siri	-	-	-	-	-
Skjold	-	-	-	-	-
Svend	-	-	-	-	-
South Arne	0.2	0.1	0.0	0.0	0.0
Tyra	0.3	0.2	0.2	-	-
Tyra SE	0.1	0.0	0.1	-	-
Valdemar	0.6	0.7	0.3	-	-
Total	**3.9**	**1.5**	**1.5**	**0.8**	**0.2**
Planned	0.1	0.7	0.7	0.2	0.1
Possible	0.6	2.2	2.5	2.7	2.3
Expected	**4.6**	**4.4**	**4.7**	**3.7**	**2.5**

AMOUNTS PRODUCED AND INJECTED OIL thousand cubic metres

Production and sales

	1972-94	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	Total
Dan	21,862	3,713	3,799	3,858	4,767	5,745	6,599	6,879	6,326	5,929	6,139	75,616
Gorm	22,267	2,494	2,879	3,045	2,865	3,384	3,110	2,180	2,887	2,838	2,469	50,420
Skjold	19,257	1,979	2,023	2,011	1,896	1,825	1,975	1,354	1,659	1,532	1,443	36,954
Tyra	11,356	1,631	1,447	1,263	931	892	1,000	872	801	918	723	21,834
Rolf	3,028	216	218	96	92	77	83	51	51	104	107	4,124
Kraka	1,230	469	340	315	314	404	350	253	157	139	199	4,169
Dagmar	881	35	23	17	13	10	8	4	6	7	2	1,005
Regnar	574	86	41	27	43	29	14	33	18	19	19	904
Valdemar	357	165	161	159	95	86	77	181	353	435	491	2,561
Roar	-	-	319	427	327	259	285	317	175	121	98	2,329
Svend	-	-	836	1,356	635	521	576	397	457	280	326	5,382
Harald	-	-	-	794	1,690	1,332	1,081	866	578	425	314	7,081
Lulita	-	-	-	-	143	224	179	66	24	20	19	675
Halfdan	-	-	-	-	-	222	1,120	2,965	3,718	4,352	4,947	17,324
Siri	-	-	-	-	-	1,593	2,118	1,761	1,487	925	693	8,576
South Arne	-	-	-	-	-	757	2,558	2,031	2,313	2,383	2,257	12,299
Tyra SE	-	-	-	-	-	-	-	-	493	343	580	1,415
Cecilie	-	-	-	-	-	-	-	-	-	166	310	476
Nini	-	-	-	-	-	-	-	-	-	391	1,477	1,869
Total	**80,812**	**10,788**	**12,087**	**13,367**	**13,810**	**17,362**	**21,134**	**20,207**	**21,505**	**21,327**	**22,614**	**255,012**

Production GAS million normal cubic metres

	1972-94	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	Total
Dan	8,682	1,331	1,249	1,116	1,343	1,410	1,186	1,049	945	786	764	19,863
Gorm	9,645	761	674	609	633	537	426	306	480	339	216	14,625
Skjold	1,713	188	160	189	146	154	158	104	123	92	77	3,102
Tyra	30,954	3,839	3,843	4,229	3,638	3,878	3,826	3,749	3,948	3,994	4,120	70,019
Rolf	128	9	9	4	4	3	4	2	2	4	5	173
Kraka	388	128	95	85	106	148	119	100	52	25	23	1,269
Dagmar	132	5	4	3	2	2	2	1	1	3	2	157
Regnar	33	7	4	2	4	2	1	3	1	2	2	61
Valdemar	124	52	57	89	54	49	55	78	109	151	218	1,037
Roar	-	-	1,327	1,964	1,458	1,249	1,407	1,702	1,052	915	894	11,967
Svend	-	-	85	152	84	65	75	48	61	43	38	650
Harald	-	-	-	1,092	2,741	2,876	2,811	2,475	2,019	1,563	1,232	16,809
Lulita	-	-	-	-	69	181	160	27	6	5	5	453
Halfdan	-	-	-	-	-	37	178	522	759	1,142	1,449	4,086
Siri	-	-	-	-	-	142	197	176	157	110	63	844
South Arne	-	-	-	-	-	167	713	774	681	544	461	3,340
Tyra SE	-	-	-	-	-	-	-	-	447	452	1,233	2,132
Cecilie	-	-	-	-	-	-	-	-	-	14	24	38
Nini	-	-	-	-	-	-	-	-	-	29	107	136
Total	**51,798**	**6,321**	**7,506**	**9,534**	**10,281**	**10,901**	**11,316**	**11,116**	**10,844**	**10,213**	**10,934**	**150,763**

The monthly production figures for 2004 are available on the Danish Energy Authority's homepage www.ens.dk

GAS million normal cubic metres

Fuel*

	1972-94	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	Total
Dan	428	93	97	109	148	172	179	184	182	198	201	1,990
Gorm	899	111	135	164	152	149	142	111	146	135	137	2,281
Tyra	954	111	142	210	224	239	229	243	245	242	249	3,087
Dagmar	21	-	-	-	-	-	-	-	-	-	-	21
Harald	-	-	-	5	14	14	13	10	9	8	8	80
Siri	-	-	-	-	-	8	21	22	21	20	19	112
South Arne	-	-	-	-	-	3	32	34	45	49	45	208
Halfdan	-	-	-	-	-	-	-	-	-	-	20	20
Total	**2,303**	**314**	**375**	**488**	**539**	**585**	**618**	**604**	**648**	**652**	**679**	**7,799**

Flaring*

	1972-94	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	Total
Dan	1,422	36	40	36	42	56	67	79	55	71	37	1,941
Gorm	877	69	60	81	70	71	66	88	81	66	57	1,587
Tyra	425	42	67	46	42	58	58	68	61	54	63	983
Dagmar	111	5	2	3	2	2	2	1	1	3	2	135
Harald	-	-	-	77	19	12	7	11	3	1	1	132
Siri	-	-	-	-	-	73	9	15	9	23	65	194
South Arne	-	-	-	-	-	114	41	9	11	12	11	198
Halfdan	-	-	-	-	-	-	-	-	-	-	25	25
Total	**2,836**	**152**	**168**	**243**	**175**	**386**	**250**	**270**	**222**	**230**	**262**	**5,194**

Injection

	1972-94	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	Total
Gorm	7,923	28	26	62	24	25	45	4	14	6	4	8,161
Tyra	10,169	1,132	1,225	1,778	2,908	3,074	3,104	2,773	2,535	2,312	1,612	32,621
Siri**	-	-	-	-	-	61	167	139	126	109	111	713
Total	**18,091**	**1,160**	**1,251**	**1,840**	**2,933**	**3,160**	**3,316**	**2,916**	**2,675**	**2,428**	**1,727**	**41,495**

Sales*

	1984-94	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	Total
Dan	7,254	1,338	1,211	1,058	1,261	1,371	1,238	1,412	1,521	1,686	551	19,899
Gorm	1,788	750	622	495	535	448	334	209	364	228	99	5,872
Tyra	19,533	2,607	3,878	4,400	2,060	1,870	1,971	2,493	2,776	2,948	4,580	49,115
Harald	-	-	-	1,010	2,777	3,032	2,950	2,482	2,013	1,558	1,228	17,049
South Arne	-	-	-	-	-	50	640	730	625	483	406	2,935
Halfdan	-	-	-	-	-	-	-	-	-	-	1,403	1,403
Total	**28,574**	**4,695**	**5,712**	**6,963**	**6,633**	**6,770**	**7,133**	**7,326**	**7,299**	**6,903**	**8,267**	**96,273**

** The names refer to processing centres.*

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

CO_2 EMISSIONS thousand tons

	1972-94	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	Total
Fuel	5,231	715	853	1,110	1,224	1,538	1,436	1,444	1,541	1,590	1,641	18,323
Flaring	6,451	345	382	553	403	1,127	646	647	531	564	663	12,312
Total	**11,682**	**1,060**	**1,235**	**1,663**	**1,627**	**2,665**	**2,082**	**2,091**	**2,072**	**2,154**	**2,304**	**30,635**

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,

WATER thousand cubic metres

Production

	1972-94	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	Total
Dan	3,407	1,275	1,543	1,845	2,976	4,220	5,277	6,599	6,348	7,183	8,055	48,729
Gorm	6,319	948	1,921	2,906	3,177	3,468	3,980	3,353	4,017	4,420	5,173	39,683
Skjold	2,076	1,337	2,679	3,635	3,938	3,748	4,333	2,872	3,007	3,525	3,688	34,837
Tyra	4,136	1,749	2,161	2,215	2,020	2,033	3,046	2,545	2,261	3,039	2,977	28,183
Rolf	1,629	443	490	390	411	366	358	181	168	270	308	5,013
Kraka	559	251	272	287	347	329	256	352	306	208	426	3,591
Dagmar	989	464	507	408	338	246	241	102	160	375	90	3,921
Regnar	244	396	299	164	407	363	139	475	257	316	396	3,456
Valdemar	25	20	34	61	52	55	48	150	272	310	325	1,350
Roar	-	-	14	96	146	199	317	386	301	476	653	2,588
Svend	-	-	2	64	272	582	1,355	954	1,051	1,330	1,031	6,642
Harald	-	-	-	-	5	15	39	98	78	43	15	293
Lulita	-	-	-	-	3	5	11	23	14	14	15	85
Halfdan	-	-	-	-	-	56	237	493	367	612	2,147	3,913
Siri	-	-	-	-	-	319	1,868	2,753	3,041	2,891	1,648	12,520
South Arne	-	-	-	-	-	15	60	119	390	751	1,124	2,458
Tyra SE	-	-	-	-	-	-	-	-	250	596	466	1,312
Cecilie	-	-	-	-	-	-	-	-	-	25	331	355
Nini	-	-	-	-	-	-	-	-	-	3	63	67
Total	**19,384**	**6,882**	**9,922**	**12,072**	**14,093**	**16,020**	**21,566**	**21,456**	**22,287**	**26,386**	**28,929**	**198,996**

Injection

	1972-94	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	Total
Dan	6,646	5,884	8,245	8,654	11,817	14,964	17,464	18,176	16,123	18,063	20,042	146,078
Gorm	10,618	5,749	8,112	8,642	8,376	8,736	10,641	6,549	8,167	7,066	7,551	90,208
Skjold	21,705	3,985	5,712	6,320	6,291	5,866	6,520	4,805	6,411	6,386	6,451	80,452
Halfdan	-	-	-	-	-	82	13	620	2,532	5,162	5,759	14,169
Siri	-	-	-	-	-	1,236	3,778	4,549	4,507	3,383	1,681	19,134
South Arne	-	-	-	-	-	-	52	1,991	4,397	5,316	4,947	16,702
Nini	-	-	-	-	-	-	-	-	-	71	916	987
Cecilie	-	-	-	-	-	-	-	-	-	-	87	87
Total	**38,969**	**15,618**	**22,069**	**23,616**	**26,484**	**30,884**	**38,469**	**36,689**	**42,138**	**45,446**	**47,435**	**367,818**

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

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:	13.4 km^2
Reservoir depth:	2,200 m
Reservoir rock:	Sandstone
Geological age:	Paleocene
Reserves at 1 January 2005:	
Oil:	0.6 million m^3
Gas:	0.0 billion Nm^3 *
Cum. production at 1 January 2005:	
Oil:	0.48 million m^3
Gas:	0.04 billion Nm^3 *
Water:	0.36 million m^3
Cum. injection at 1 January 2005:	
Water:	0.09 million m^3
Production in 2004:	
Oil:	0.31 million m^3
Gas:	0.02 billion Nm^3 *
Water:	0.33 million m^3
Injection in 2004:	
Water:	0.09 million m^3
Total investments at 1 January 2005:	
2004 prices	DKK 1.2 billion

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

REVIEW OF GEOLOGY

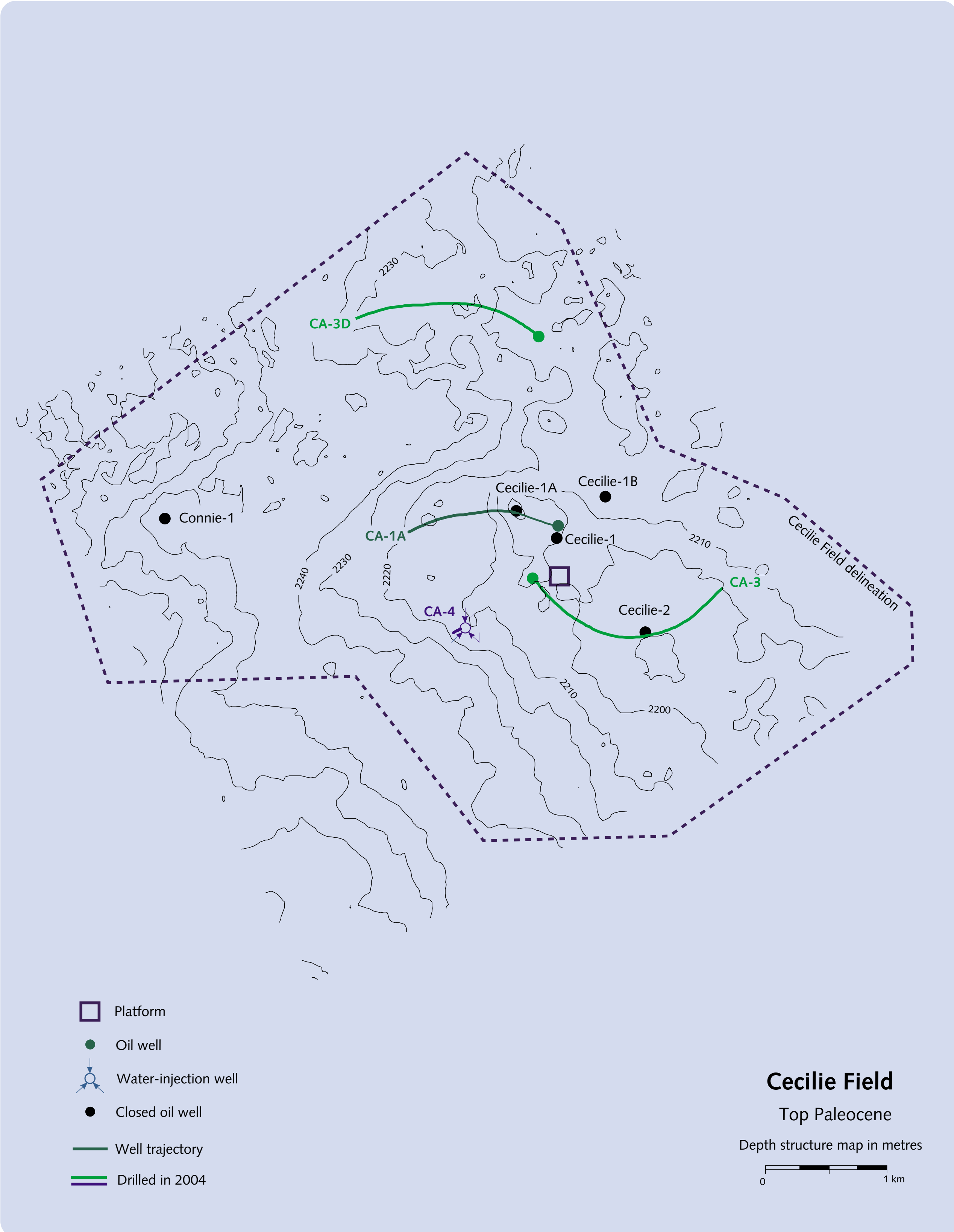
The Cecilie accumulation is a combined structural and stratigraphic trap. It is an anticlinal structure induced through salt tectonics, delimited by faults and redeposited sands.

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 conveyed 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-3
CA-4
Cecilie-2
2210
2200
Platform
Oil well
Water-injection well
Closed oil well
Well trajectory
Drilled in 2004
Cecilie Field
Top Paleocene
Depth structure map in metres
0
1 km

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 km²
Reservoir depth:	1,400 m
Reservoir rock:	Chalk and Carbonates
Geological age:	Danian, Upper Creta-ceous and Zechstein
Reserves at 1 January 2005:	
Oil:	0.6 million m³
Gas:	0.1 billion Nm³
Cum. production at 1 January 2005:	
Oil:	1.01 million m³
Gas:	0.16 billion Nm³
Water:	3.98 million m³
Production in 2004:	
Oil:	0.00 million m³
Gas:	0.00 billion Nm³
Water:	0.15 million m³
Total investments at 1 January 2005:	
2004 prices	DKK 0.4 billion

REVIEW OF GEOLOGY

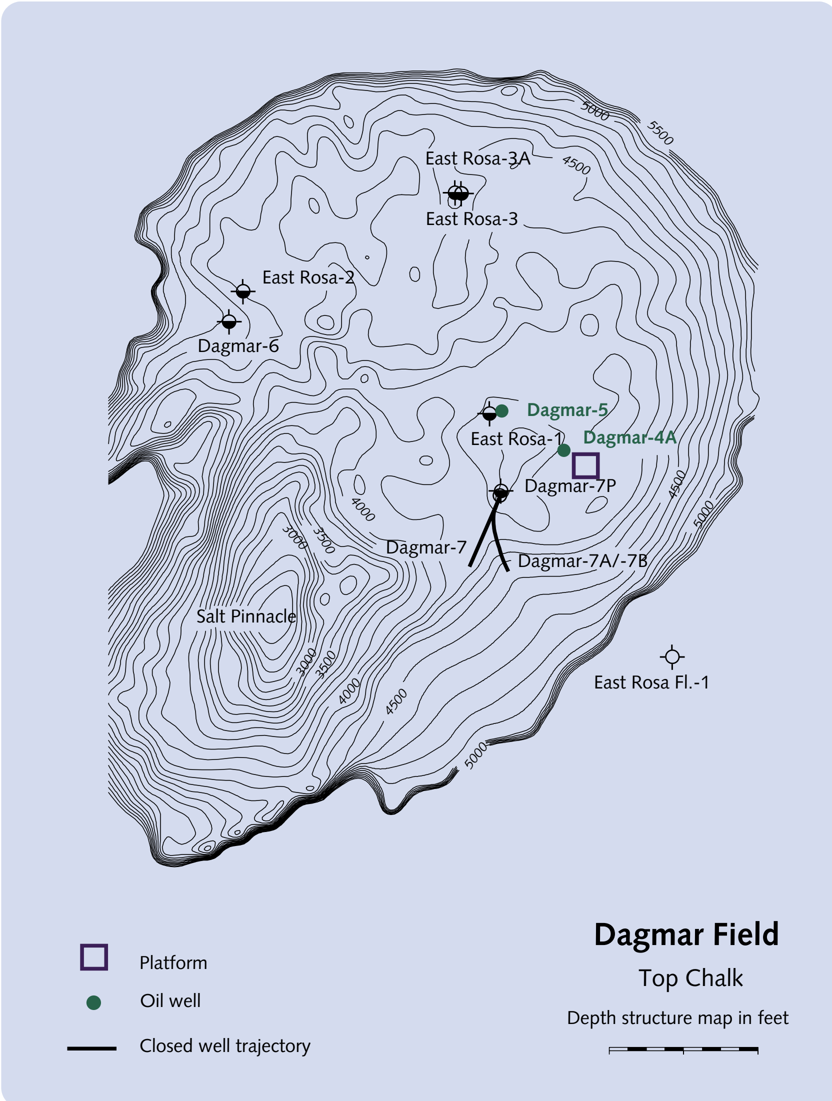
The Dagmar field is an anticlinal structure, induced through Zechstein salt tectonics. The uplift is so pronounced that the Dagmar oil reservoir is situated closer to the surface than any other hydrocarbon reservoirs in Danish territory. The reservoir is heavily fractured (compare Skjold, Rolf, Regnar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

PRODUCTION STRATEGY

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 well-head platform of the STAR type. The unprocessed production is transported to the Gorm F platform in the Gorm Field, where special 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 the high content of hydrogen sulphide.



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:	58
Water-injection wells:	48
Water depth:	40 m
Field delineation:	121 km^2
Reservoir depth:	1,850 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2005:	
Oil:	66.9 million m^3
Gas:	9.7 billion Nm^3
Cum. production at 1 January 2005:	
Oil:	75.62 million m^3
Gas:	19.82 billion Nm^3
Water:	48.60 million m^3
Cum. injection at 1 January 2005:	
Water:	144.56 million m^3
Production in 2004:	
Oil:	6.14 million m^3
Gas:	0.72 billion Nm^3
Water:	7.92 million m^3
Injection in 2004:	
Water:	18.52 million m^3
Total investments at 1 January 2005:	
2004 prices	DKK 24.0 billion

REVIEW OF GEOLOGY

Dan is an anticlinal structure partly 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 pressure involved 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 builds up the reservoir pressure in the oil zone. The recovery of oil is optimized by flooding the largest possible reservoir volume with water.

In addition, production takes place in the western flank of the Dan Field. Recovery is also based on water injection in this part of the field.

PRODUCTION FACILITIES

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

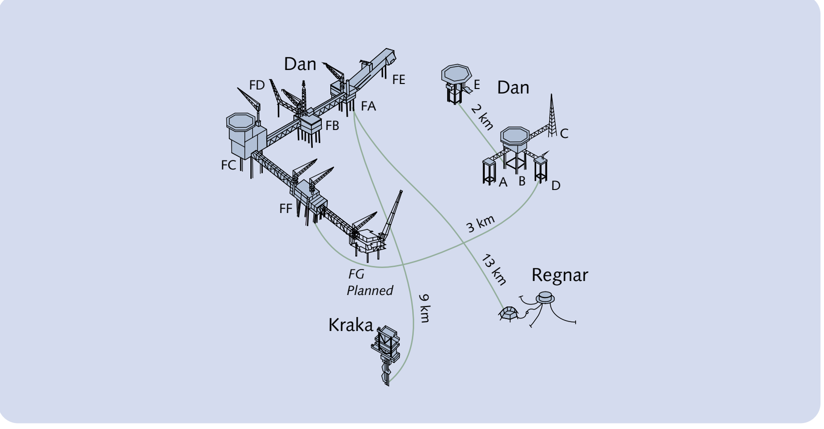
The Dan DA, DB, DC and DD platform complex is located about 3 km from the Dan F platforms, while Dan E is an unmanned satellite platform with a helideck.

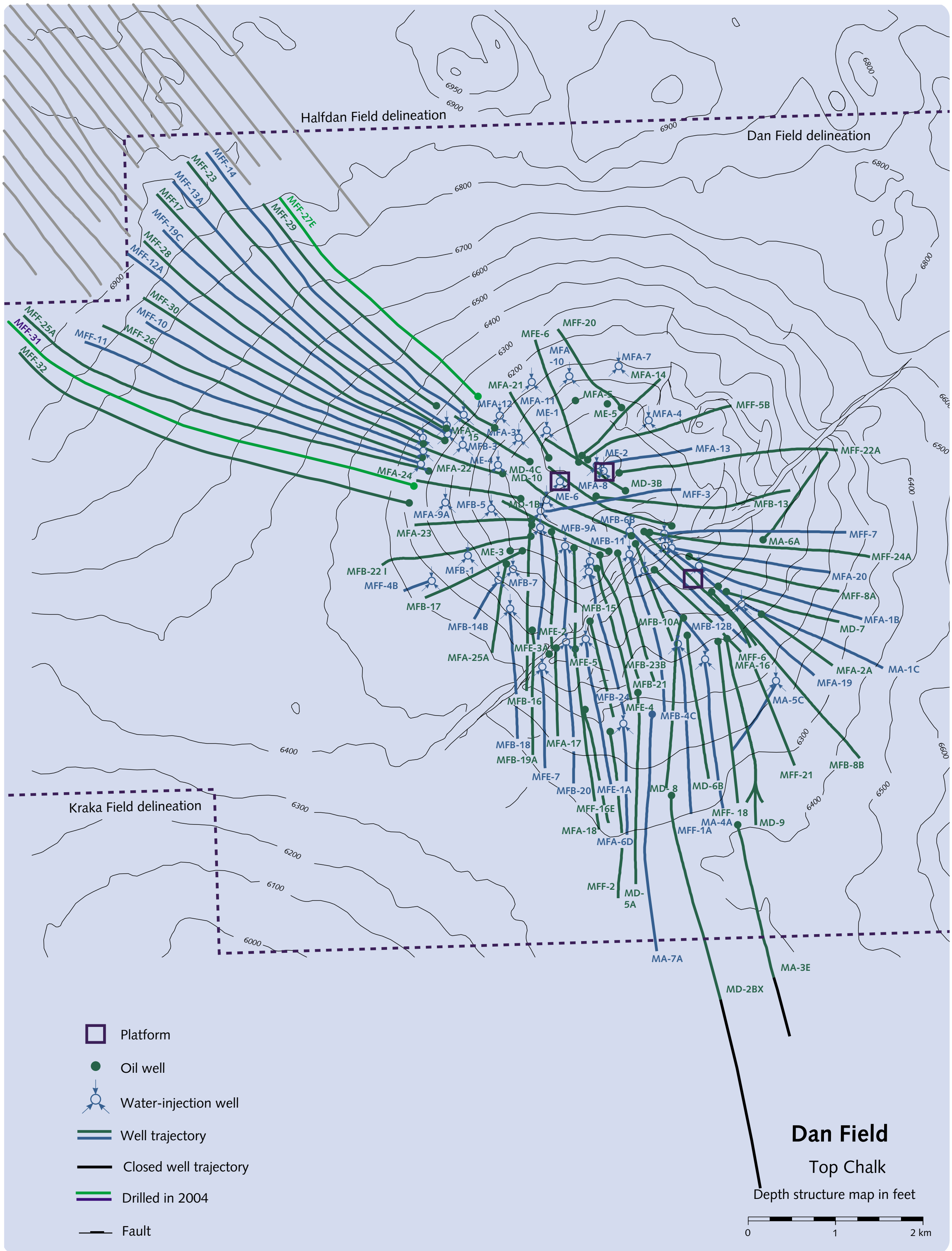
In 2002, the Danish Energy Authority approved the establishment of an additional processing platform, DFG, scheduled to be installed in 2005 and bridge-connected to DFF.

At the Dan Field, there are receiving facilities for the production from the adjacent Kraka and Regnar satellite fields. 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.

In the Dan Field, there are accommodation facilities for 86 persons on the DFC platform and five persons on the DB platform. The DFC facilities are currently being expanded to accommodate 96 persons.




Halfdan Field delineation
Dan Field delineation
Kraka Field delineation
6950
6900
6800
6700
6600
6500
6400
6300
6200
6100
6000
MFF-14
MFF-23
MFF-13A
MFF-17
MFF-19C
MFF-28
MFF-12A
MFF-27E
MFF-29
MFF-30
MFF-10
MFF-26
MFF-11
MFF-25A
MFF-31
MFF-32
MFF-20
MFE-6
MFA-10
MFA-7
MFA-14
MFA-21
MFA-5
MFA-12
MFA-11
ME-1
ME-5
MFA-4
MFF-5B
MFA-15
MFA-3
MFB-3
MFA-13
MFF-22A
ME-2
ME-4
MFA-22
MD-4C
MD-10
MFA-24
MFA-8
MD-3B
MFF-3
MFB-13
ME-6
MFB-5
MD-1B
MFA-9A
MFB-6B
MFA-23
MFB-9A
MFF-7
MA-6A
MFB-11
MFF-24A
ME-3
MFB-22 I
MFB-1
MFF-4B
MFB-7
MFA-20
MFF-8A
MFB-17
MFB-15
MFA-1B
MFB-14B
MFE-2
MFB-10A
MFB-12B
MD-7
MFE-3A
MFA-25A
MFE-5
MFB-23B
MFF-6
MFA-16
MFA-2A
MA-1C
MFA-19
MFB-21
MFB-24
MFE-4
MFB-4C
MA-5C
MFB-16
MFB-18
MFA-17
MFB-19A
MFB-8B
MFE-7
MFF-21
MFB-20
MFE-1A
MD-8
MD-6B
MFF-16E
MFF-18
MA-4A
MD-9
MFA-18
MFF-1A
MFA-6D
MFF-2
MD-5A
MA-7A
MA-3E
MD-2BX
Platform
Oil well
Water-injection well
Well trajectory
Closed well trajectory
Drilled in 2004
Fault
Dan Field
Top Chalk
Depth structure map in feet
0
1
2 km

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:	36
Gas-injection wells:	2
Water-injection wells:	14
Water depth:	39 m
Field delineation:	33 km²
Reservoir depth:	2,100 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2005:	
Oil:	16.6 million m³
Gas:	1.9 billion Nm³
Cum. production at 1 January 2005:	
Oil:	50.42 million m³
Net gas:	6.46 billion Nm³
Water:	39.68 million m³
Cum. injection at 1 January 2005:	
Gas:	8.16 billion Nm³
Water:	89.70 million m³
Production in 2004:	
Oil:	2.47 million m³
Net gas:	0.21 billion Nm³
Water:	5.17 million m³
Injection in 2004:	
Gas:	0.00 billion Nm³
Water:	7.04 million m³
Total investments at 1 January 2005:	
2004 prices	DKK 11.6 billion

REVIEW OF GEOLOGY

Gorm is an anticlinal structure 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. Oil production from the field is based on extending the use of water injection to the whole field. Water is injected into the water and oil zones of the field. There are 36 producing wells in the field, but four of the wells have been out of operation for a prolonged period due to mechanical problems.

If gas exports to Tyra are 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.

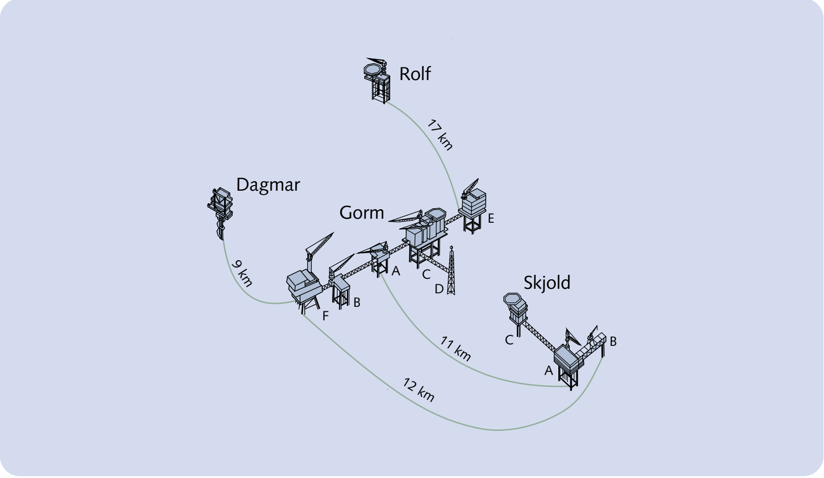
Gorm receives production from the satellite fields, Skjold, Rolf and Dagmar. The Gorm Field installations supply the Skjold Field with injection water and lift gas and the Rolf Field with lift gas. The gas produced is sent to Tyra East. The stabilized oil from all DUC's processing facilities is transported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

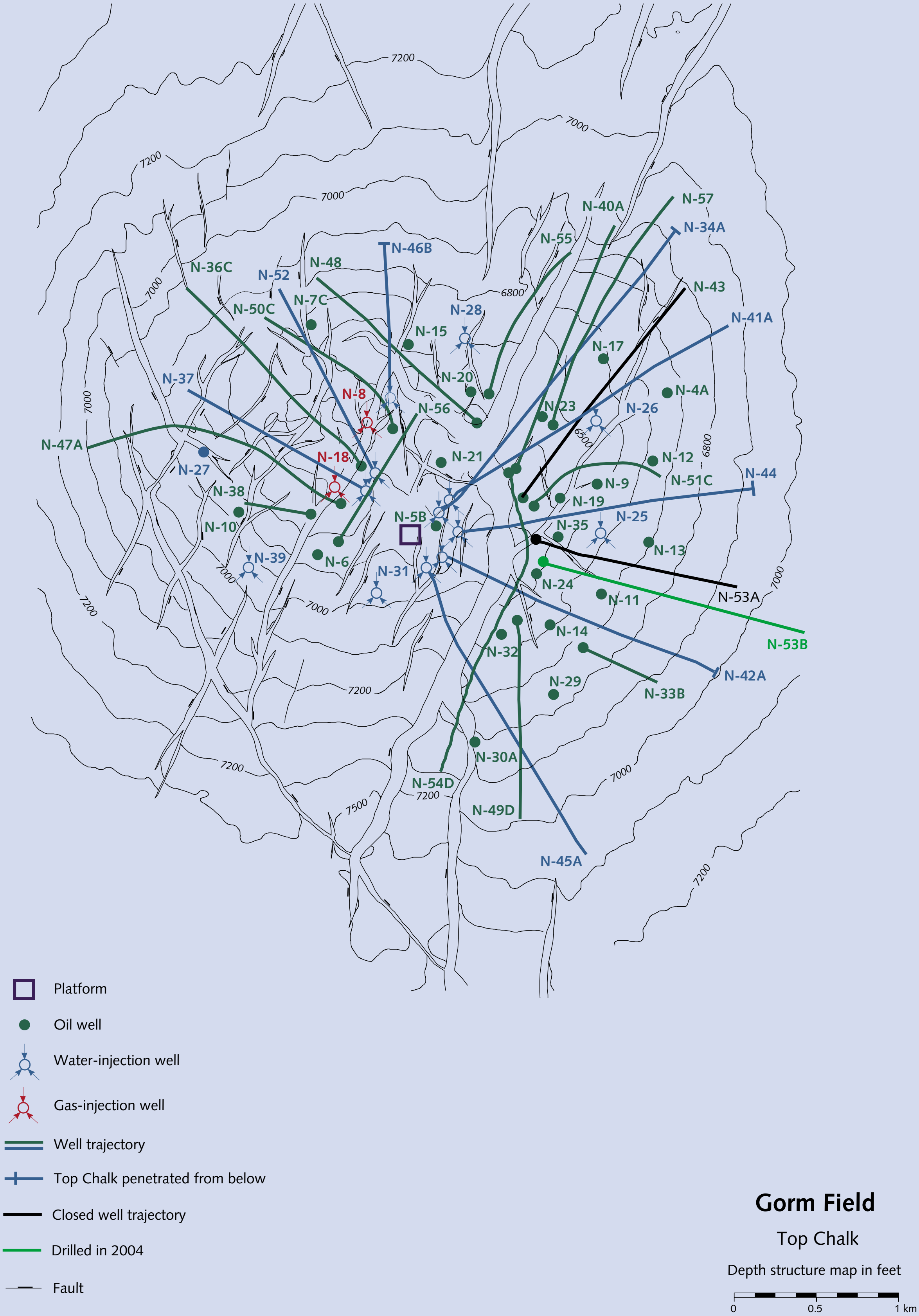
The processing facilities on the Gorm C platform consist of an oil stabilization plant, where the oil from the Rolf Field is processed, produced-water treatment plant and facilities for processing and compressing the gas produced.

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.





Gorm Field

Top Chalk

Depth structure map in feet

HALFDAN FIELD INCLUDING SIF AND IGOR

Prospect:	Nana (Halfdan)/Sif/Igor
Location:	Blocks 5505/13 and 5504/16
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1998 (Halfdan and Sif) 1968 (Igor)
Year on stream:	1999 (Halfdan) 2004 (Sif and Igor)
Oil-producing wells:	28 (Halfdan)
Water-injection wells:	17 (Halfdan)
Gas-producing wells:	3 (Sif)
Water depth:	43 m
Field delineation:	100 km^2 (Halfdan) 109 km^2 (Igor) 40 km^2 (Sif)
Reservoir depth:	2,050-2,100 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2005:	
Oil:	78.1 million m^3
Gas:	14.5 billion Nm^3
Cum. production at 1 January 2005:	
Oil:	17.32 million m^3
Gas:	4.13 billion Nm^3
Water:	3.40 million m^3
Cum. injection at 1 January 2005:	
Water:	13.87 million m^3
Production in 2004:	
Oil:	4.95 million m^3
Gas:	1.49 billion Nm^3
Water:	1.75 million m^3
Injection in 2004:	
Water:	5.46 million m^3
Total investments at 1 January 2005:	
2004 prices	DKK 8.2 billion

REVIEW OF GEOLOGY

Previously, Halfdan, Sif and Igor have been described as three more or less distinct accumulations. The northern parts of the accumulation were termed Halfdan Northeast. It has now been established with a high degree of certainty that Halfdan, Sif and Igor are a large contiguous 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 pocket in chalk layers, which constituted a structural trap in earlier geological times. Due to later movements in the reservoir layers, the structure gradually disintegrated, and the oil began migrating away from the area. 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

The recovery of oil from the field is based on pressure support from water injection. In the southern and western parts of the accumulation, the oil wells are arranged in a pattern of alternate production and injection wells with parallel well trajectories, about 180 metres apart. The injection wells are stimulated with acid, which makes it possible to inject large volumes of water.

The regular spacing of the wells optimizes the flooding of the reservoir, thus enhancing recovery. The injection wells are used for production for a period of time before being converted to water injection. The production of gas from Danian layers is based on primary recovery, using the reservoir pressure.

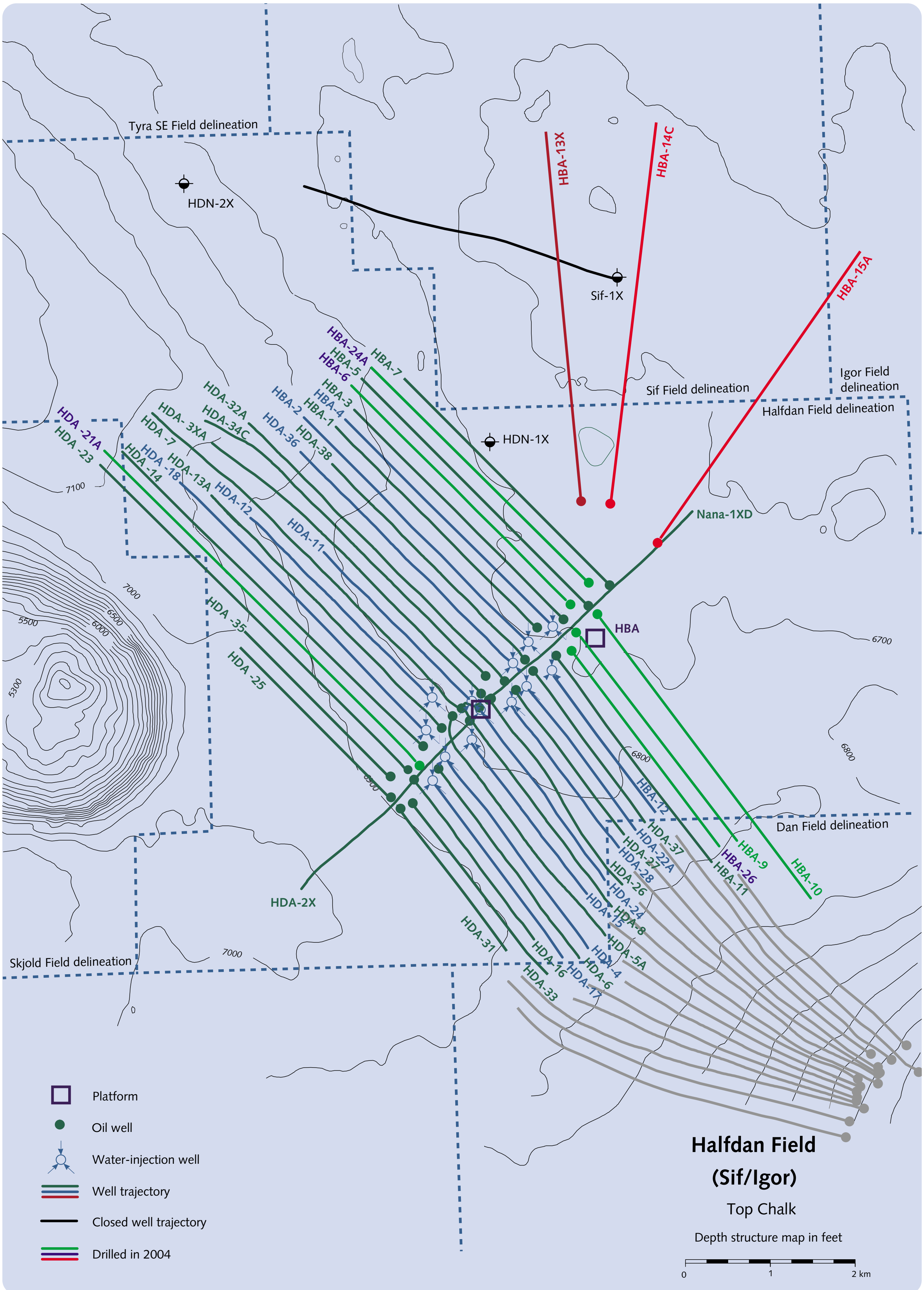
PRODUCTION FACILITIES

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 electricity, injection water and lift gas. The Halfdan Field receives production from Sif and Igor through special installations on the HBA platform.

Production from the oil wells is conveyed through a multiphase pipeline for processing at the HDA platform, while production from the Sif and Igor gas 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 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 Sif/Igor installations on the HBA platform is conveyed 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 and Sif/Igor is discharged into the sea. The Halfdan HDB platform has accommodation facilities for 32 persons.



Tyra SE Field delineation
HDN-2X
HBA-13X
HBA-14C
Sif-1X
HBA-15A
Igor Field delineation
Sif Field delineation
Halfdan Field delineation
HDN-1X
Nana-1XD
HBA
Dan Field delineation
Skjold Field delineation
HDA-2X
HBA-24A
HBA-5
HBA-6
HBA-7
HBA-3
HBA-4
HBA-1
HBA-2
HDA-36
HDA-38
HDA-32A
HDA-34C
HDA- 3XA
HDA -7
HDA -21A
HDA -23
HDA -18
HDA -14
HDA-13A
HDA-12
HDA-11
HDA -35
HDA -25
HDA-31
HDA-16
HDA-33
HDA-6
HDA-17
HDA-4
HDA-5A
HDA-8
HDA-24
HDA-15
HDA-26
HDA-28
HDA-27
HDA-22A
HDA-37
HBA-12
HBA-9
HBA-26
HBA-11
HBA-10
7100
7000
6500
6000
5500
5300
6700
6800
7000
Platform
Oil well
Water-injection well
Well trajectory
Closed well trajectory
Drilled in 2004
Halfdan Field
(Sif/Igor)
Top Chalk
Depth structure map in feet
0
1
2 km

HARALD FIELD

Prospect:	Lulu/West Lulu
Location:	Blocks 5604/21 and 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:	2,700 and 3,650 m, respectively
Reservoir rock:	Chalk (Lulu)
	Sandstone (West Lulu)
Geological age:	Danian/Upper Cretaceous (Lulu)
	Middle Jurassic (West Lulu)
Reserves at 1 January 2005:	
Oil and condensate:	1.3 million m^3
Gas:	5.8 billion Nm^3
Cum. production at 1 January 2005:	
Oil and condensate:	7.08 million m^3
Gas:	16.81 billion Nm^3
Water:	0.29 million m^3
Production in 2004:	
Oil and condensate:	0.31 million m^3
Gas:	1.23 billion Nm^3
Water:	0.02 million m^3
Total investments at 1 January 2005:	
2004 prices	DKK 3.4 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 75 metres 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 letting the gas expand, 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 presupposes 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

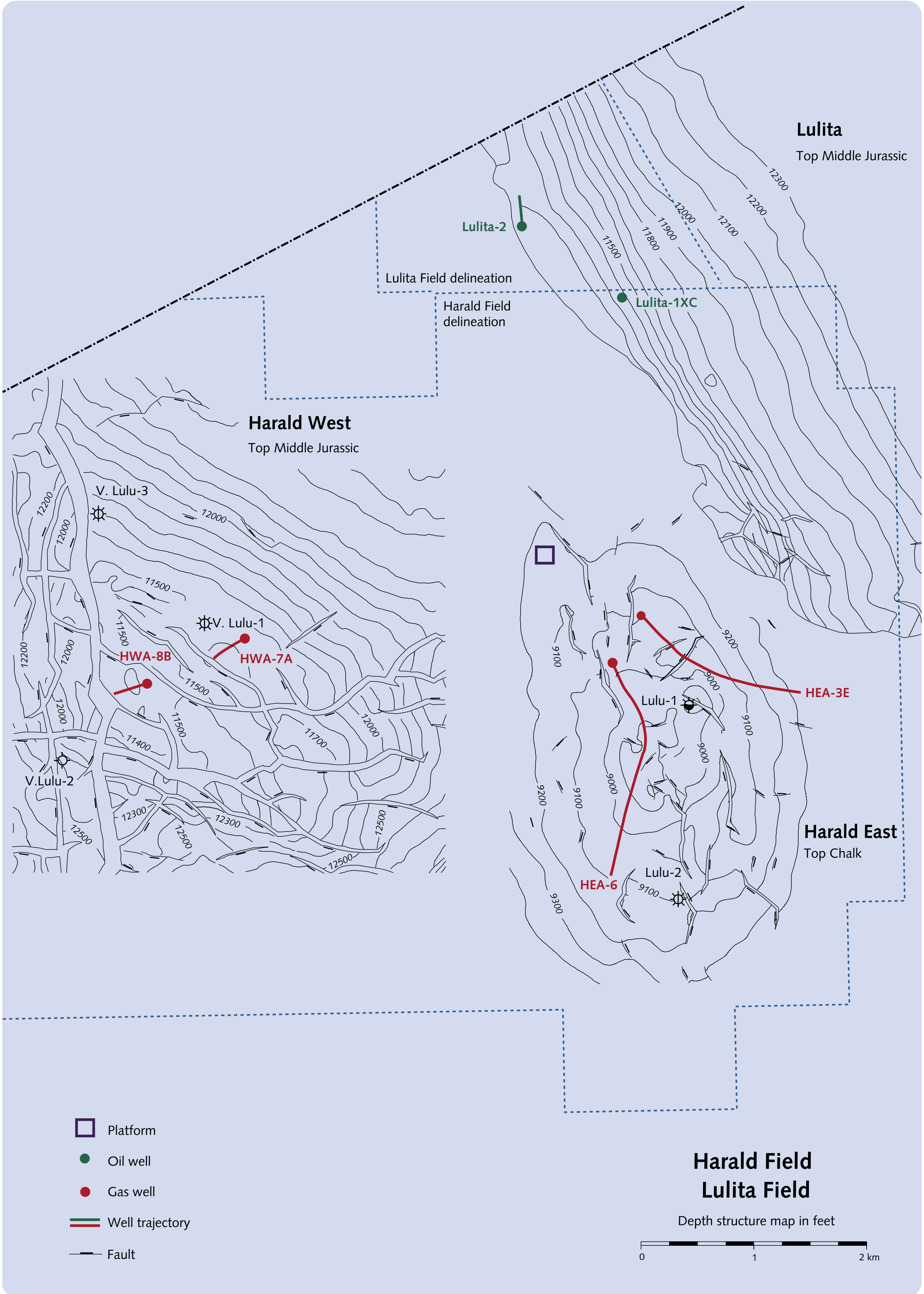
The Harald Field comprises a combined wellhead and processing platform, Harald A, and an accommodation platform, Harald B.

The processing facilities consist of a plant that separates the hydrocarbons produced and a plant for processing the gas produced.

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

The Harald Field is hooked up to the gas pipeline that conveys 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 16 persons.


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

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:	81 km^2
Reservoir depth:	1,800 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

Reserves at 1 January 2005:

Oil:	1.5 million m^3
Gas:	1.2 billion Nm^3

Cum. production at 1 January 2005:

Oil:	4.17 million m^3
Gas:	1.27 billion Nm^3
Water:	3.58 million m^3

Production in 2004:

Oil:	0.20 million m^3
Gas:	0.02 billion Nm^3
Water:	0.42 million m^3

Total investments at 1 January 2005:

2004 prices	DKK 1.5 billion

REVIEW OF GEOLOGY

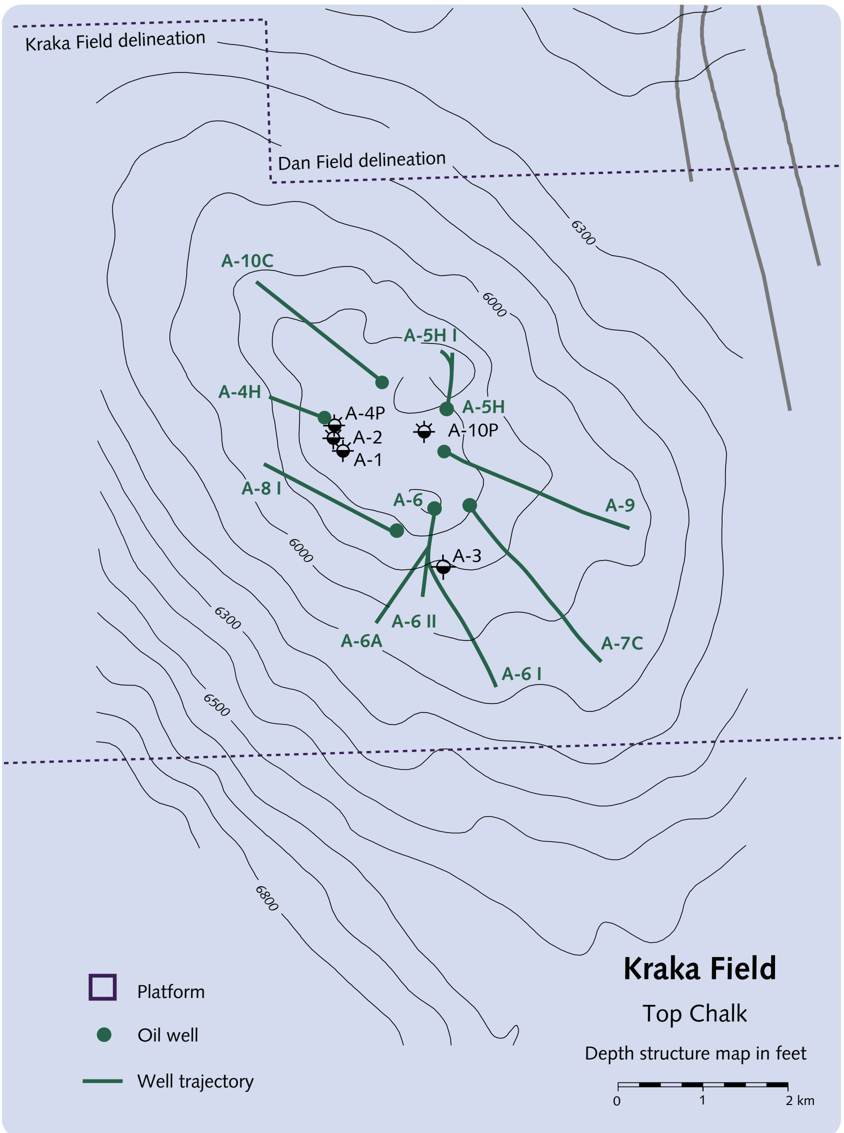
Kraka is an anticlinal structure induced through salt tectonics, which to a certain degree has caused fracturing in the chalk. The chalk reservoir has reasonable porosity, although low permeability. The thin oil pay zone is further characterized by high water saturations. There is a minor gas cap in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

PRODUCTION STRATEGY

The production of oil and gas from the field is based on natural depletion, meaning no secondary recovery techniques are used, either in the form of gas or water injection. Measures are continuously taken to optimize production so as to liberate as much oil, and as little water, as possible from the tight chalk formation.

PRODUCTION FACILITIES

Kraka is a satellite development to the Dan Field with one unmanned wellhead platform of the STAR type. The production is transported to the Dan FC platform for processing and export ashore. Lift gas is imported from the Dan FF platform.



LULITA FIELD

Location:	Blocks 5604/18 and 22
Licence:	Sole Concession (50 per cent), 7/86 (34.5 per cent) and 1/90 (15.5 per cent)
Operator:	Mærsk Olie og Gas AS
Discovered:	1992
Year on stream:	1998
Producing wells:	2
Water depth:	65 m
Area:	3 km²
Reservoir depth:	3,525 m
Reservoir rock:	Sandstone
Geological age:	Middle Jurassic
Reserves at 1 January 2005:	
Oil:	0.4 million m³
Gas:	0.4 billion Nm³
Cum. production at 1 January 2005:	
Oil:	0.68 million m³
Gas:	0.45 billion Nm³
Water:	0.09 million m³
Production in 2004:	
Oil:	0.02 million m³
Gas:	0.01 billion Nm³
Water:	0.02 million m³
Total investments at 1 January 2005:	
2004 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 wellheads are hosted by the Harald A platform, and the Harald platform facilities also handle production from the Lulita Field.

Together with condensate from the Harald Field, the oil produced is conveyed 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, from where it is transported to shore.

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.

NINI FIELD

Location:	Blocks 5605/10 and 14
Licence:	4/95
Operator:	DONG E&P A/S
Discovered:	2000
Year on stream:	2003
Producing wells:	4
Water-injection wells:	2
Water depth:	60 m
Field delineation:	48.8 km^2
Reservoir depth:	1,700 m
Reservoir rock:	Sandstone
Geological age:	Paleogene
Reserves at 1 January 2005:	
Oil:	2.4 million m^3
Gas:	0.0 billion Nm^3 *
Cum. production at 1 January 2005:	
Oil:	1.87 million m^3
Gas:	0.14 billion Nm^3 *
Water:	0.07 million m^3
Cum. injection at 1 January 2005:	
Water:	0.99 million m^3
Production in 2004:	
Oil:	1.48 million m^3
Gas:	0.11 billion Nm^3 *
Water:	0.06 million m^3
Injection in 2004:	
Water:	0.92 million m^3
Total investments at 1 January 2005:	
2004 prices	DKK 1.9 billion

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

REVIEW OF GEOLOGY

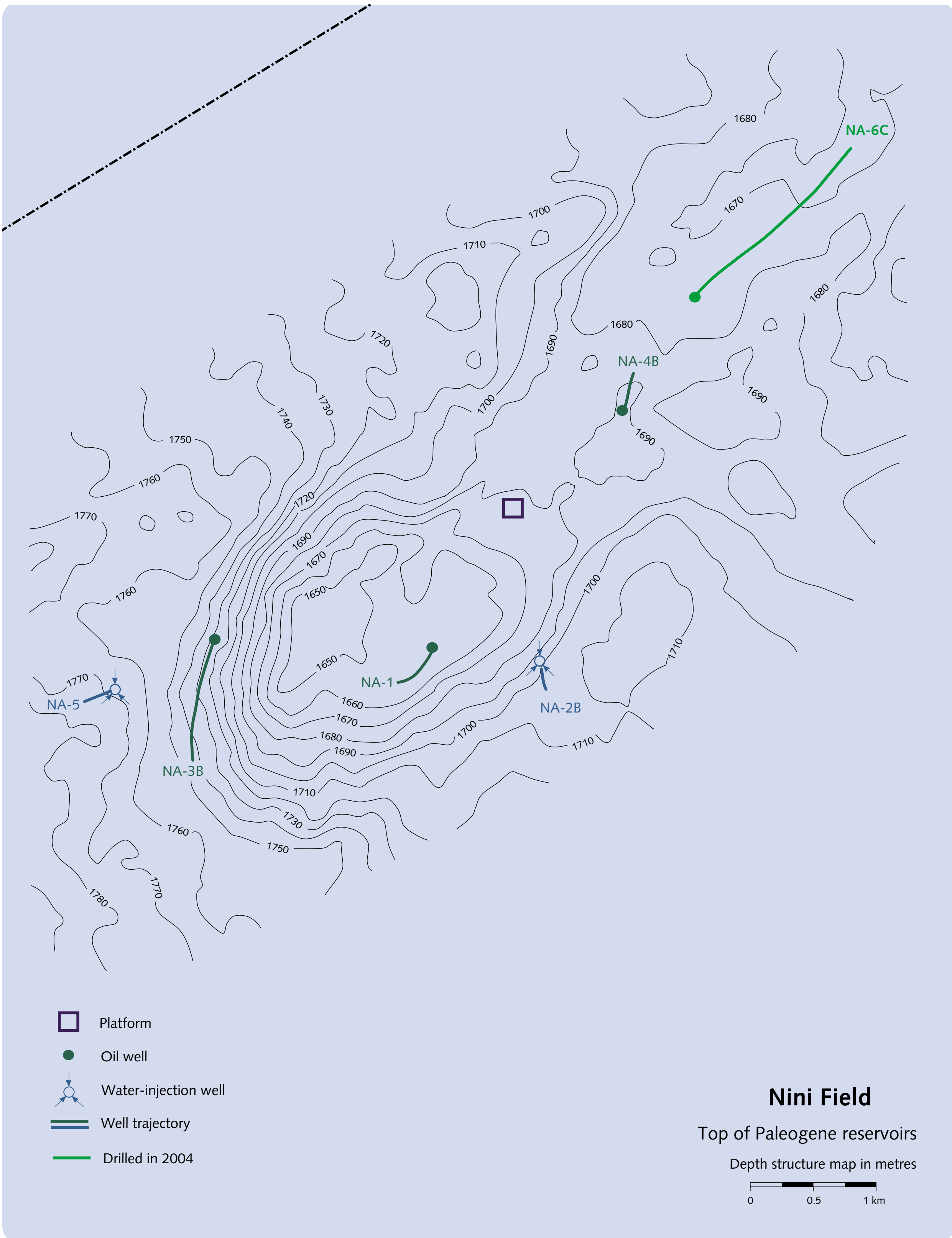
The Nini accumulation is defined by a combined structural and stratigraphic trap, the anticlinal structure being induced through salt tectonics. The reservoir consists of channel sands deposited in the Siri Fairway. The Nini Field also includes the Nini West area.

PRODUCTION STRATEGY

The production strategy is based on water injection to maintain reservoir pressure. 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 conveyed from the Siri platform to the Nini platform through a 10" pipeline and a 4" pipeline, respectively.



NA-6C
NA-4B
NA-1
NA-2B
NA-5
NA-3B
1650
1660
1670
1680
1690
1700
1710
1720
1730
1740
1750
1760
1770
1780
Platform
Oil well
Water-injection well
Well trajectory
Drilled in 2004
Nini Field
Top of Paleogene reservoirs
Depth structure map in metres
0
0.5
1 km

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 km²
Reservoir depth:	1,700 m
Reservoir rock:	Chalk and Carbonates
Geological age:	Upper Cretaceous and Zechstein
Reserves at 1 January 2005:	
Oil:	0.1 million m³
Gas:	0.0 billion Nm³
Cum. production at 1 January 2005:	
Oil:	0.90 million m³
Gas:	0.06 billion Nm³
Water:	3.45 million m³
Production in 2004:	
Oil:	0.02 million m³
Gas:	0.00 billion Nm³
Water:	0.39 million m³
Total investments at 1 January 2005:	
2004 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).

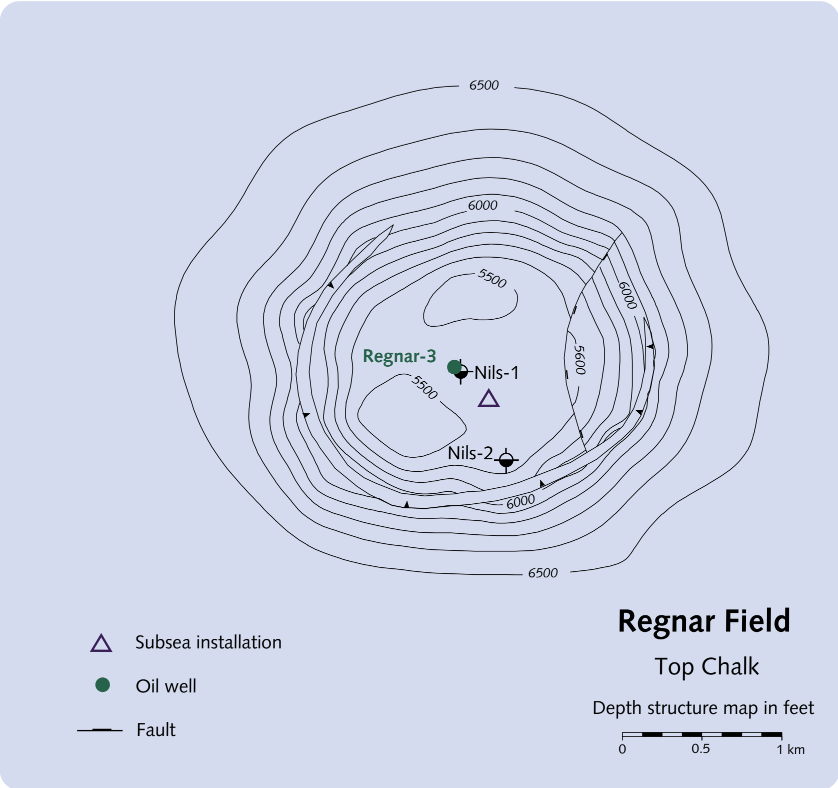
PRODUCTION STRATEGY

Production in the Regnar Field is carried on from a vertical well drilled in the crest of the structure. The oil is forced towards the production well by water flowing in from the water zone. The production strategy is to displace and produce as much of the oil as possible from the tight part of the formation, the matrix.

PRODUCTION FACILITIES

The Regnar Field has been developed as a satellite to the Dan Field. Production takes place in a subsea-completed well. The hydrocarbons produced are conveyed 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.



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 km²
Reservoir depth:	2,025 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2005:	
Oil and condensate:	0.5 million m³
Gas:	4.9 billion Nm³
Cum. production at 1 January 2005:	
Oil and condensate:	2.33 million m³
Gas:	11.97 billion Nm³
Water:	2.57 million m³
Production in 2004:	
Oil and condensate:	0.10 million m³
Gas:	0.89 billion Nm³
Water:	0.63 million m³
Total investments at 1 January 2005:	
2004 prices	DKK 0.6 billion

REVIEW OF GEOLOGY

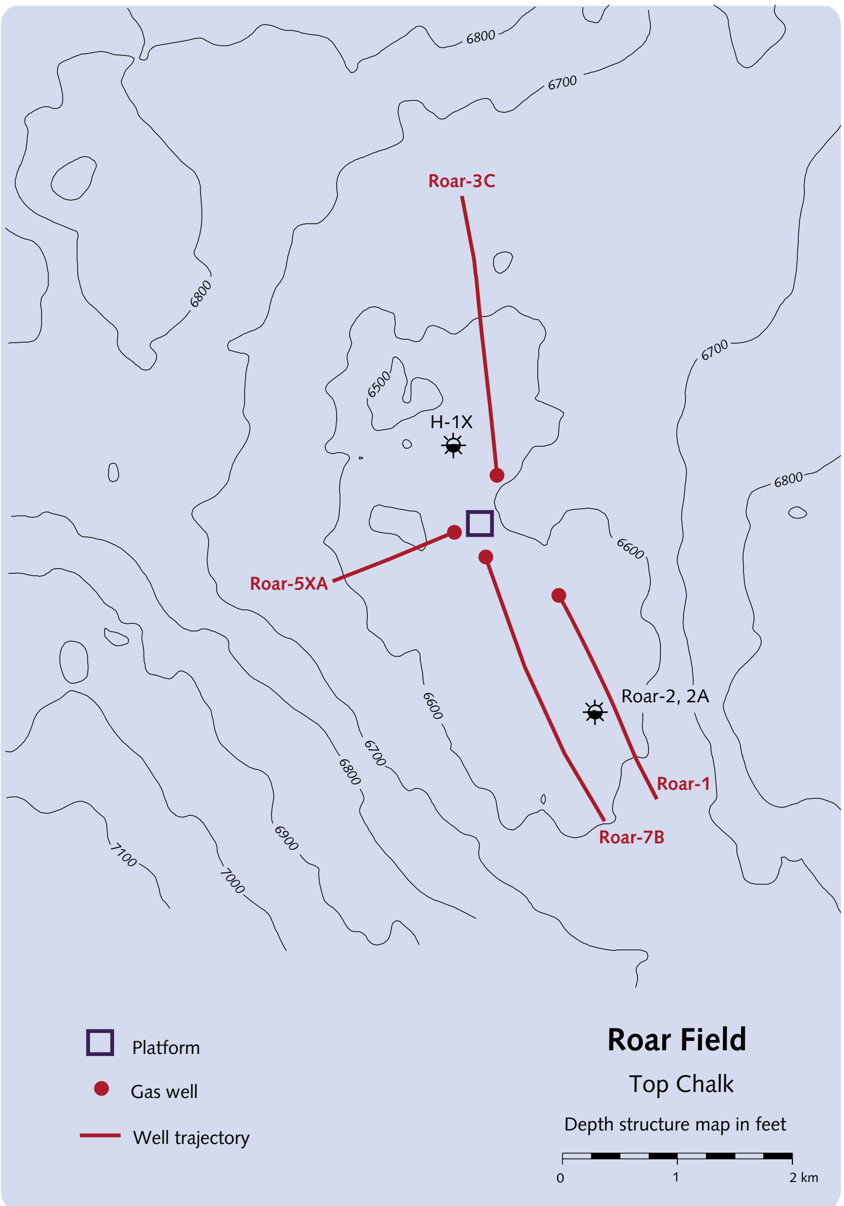
Roar is an anticlinal structure, induced through tectonic uplift. The accumulation consists of free gas containing condensate. The reservoir is only slightly fractured.

PRODUCTION STRATEGY

Production from the Roar Field is based on the aim of optimizing the production of liquid hydrocarbons in the Tyra Field. This presupposes 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. 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.



ROLF FIELD

Prospect:	Middle Rosa
Location:	Blocks 5504/14 and 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:	1,800 m
Reservoir rock:	Chalk and Carbonates
Geological age:	Danian, Upper Cretaceous and Zechstein
Reserves at 1 January 2005:	
Oil:	0.4 million m^3
Gas:	0.0 billion Nm^3
Cum. production at 1 January 2005:	
Oil:	4.12 million m^3
Gas:	0.17 billion Nm^3
Water:	5.01 million m^3
Production in 2004:	
Oil:	0.11 million m^3
Gas:	0.01 billion Nm^3
Water:	0.31 million m^3
Total investments at 1 January 2005:	
2004 prices	DKK 1.0 billion

REVIEW OF GEOLOGY

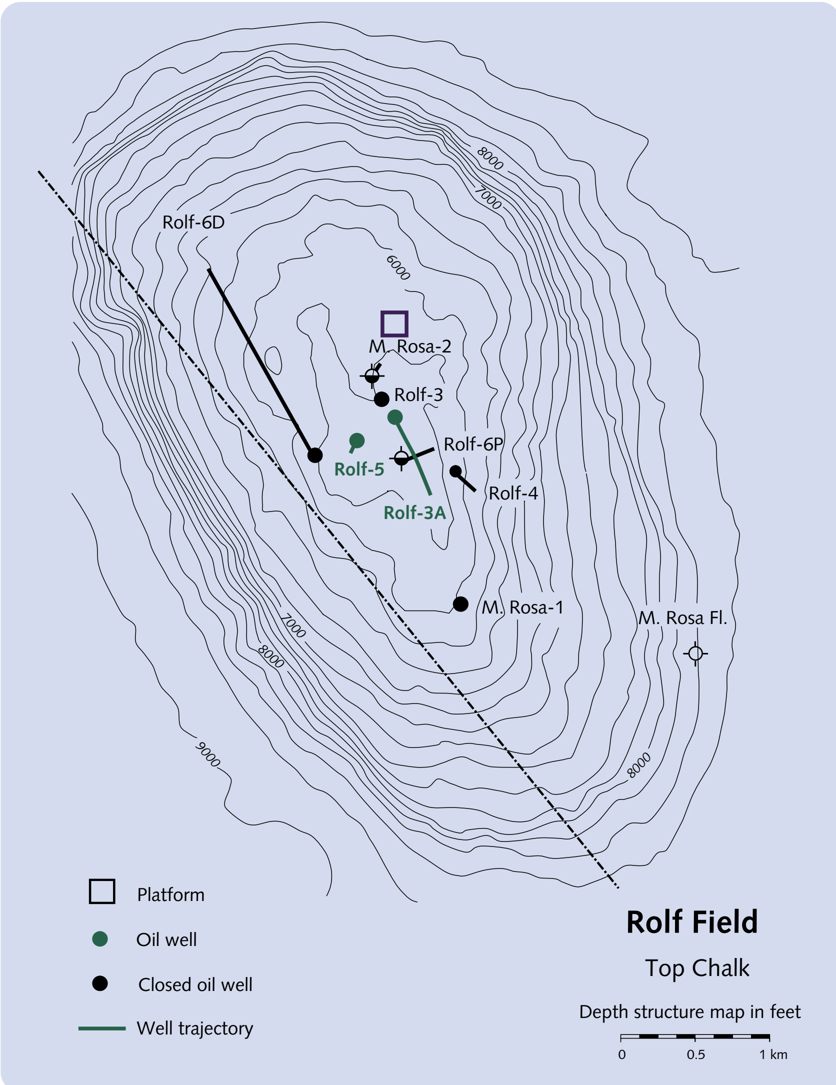
Rolf is an anticlinal structure created through salt tectonics. The chalk reservoir is heavily fractured (compare Skjold, Dagmar, Regnar and Svend).

PRODUCTION STRATEGY

Production from the Rolf Field takes place from two wells drilled in the crest of the structure. The oil is forced towards the producing wells by the water flowing in from an underlying water zone. 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 production is transported to the Gorm C platform in the Gorm Field for processing. Rolf is also supplied with electricity and lift gas from the Gorm Field.



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 2005:	
Oil:	1.9 million m^3
Gas:	0.0 billion Nm^3
Cum. production at 1 January 2005:	
Oil:	8.58 million m^3
Net gas:	0.13 billion Nm^3
Water:	12.52 million m^3
Cum. injection at 1 January 2005:	
Gas:	0.71 billion Nm^3 *
Water:	19.13 million m^3
Production in 2004:	
Oil:	0.69 million m^3
Gas:	- 0.05 billion Nm^3 *
Water:	1.65 million m^3
Injection in 2004:	
Gas:	0.11 billion Nm^3 *
Water:	1.68 million m^3
Total investments at 1 January 2005:	
2004 prices	DKK 4.7 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 from Siri Central is based on the production of oil through the co-injection of water and gas. Measures are taken to maintain the reservoir pressure at a level close to the initial pressure, and the volume of water injected 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.

The recovery from Stine segment 2 is based on natural depletion.

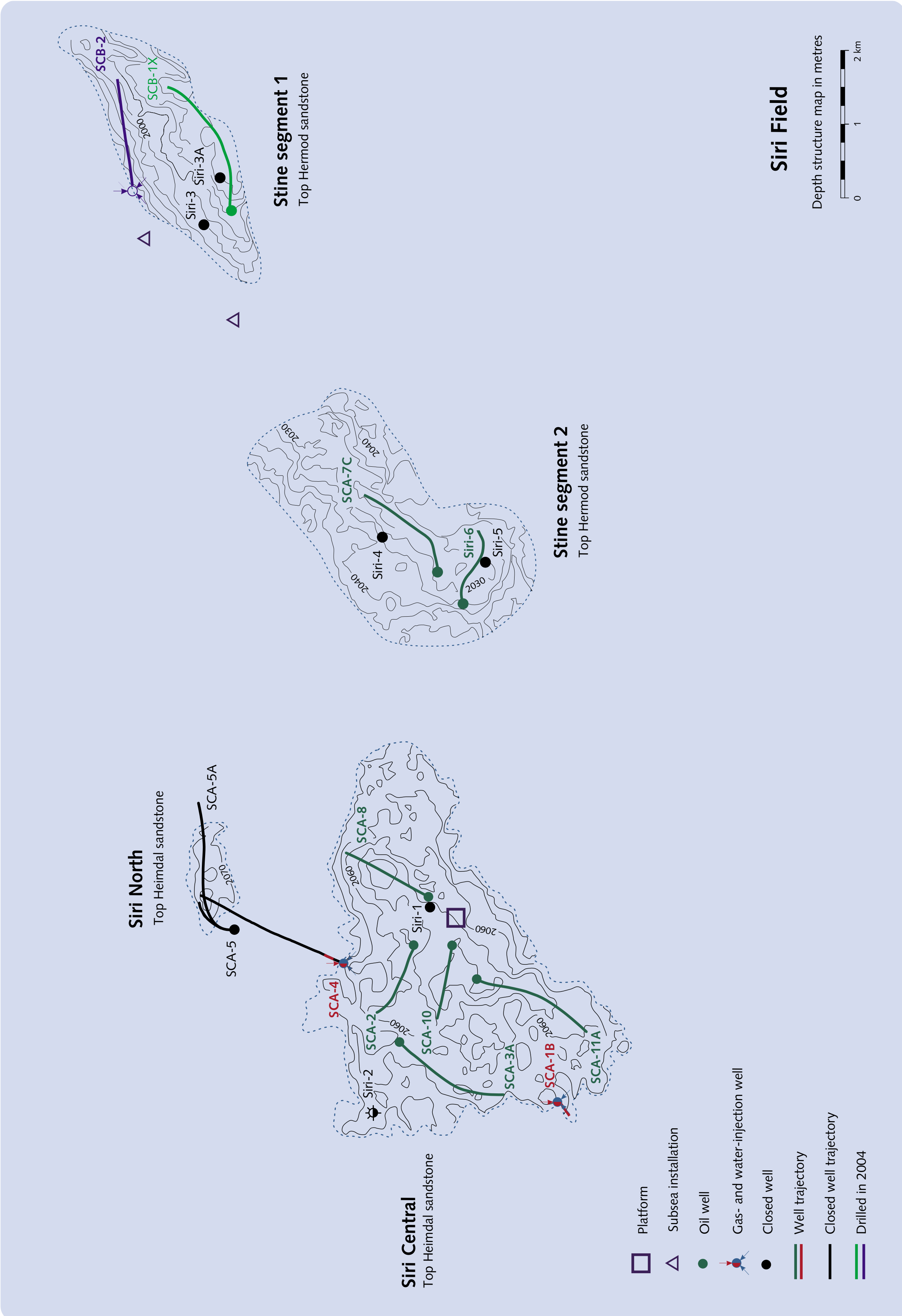
PRODUCTION FACILITIES

The Siri Central and Stine segment 2 installations comprise a combined wellhead, processing and accommodation platform. The platform houses equipment for co-injecting gas and water.

The oil produced is conveyed 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.

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.


Siri Field
Depth structure map in metres
0
1
2 km
Stine segment 1
Top Hermod sandstone
Stine segment 2
Top Hermod sandstone
Siri North
Top Heimdal sandstone
Siri Central
Top Heimdal sandstone
SCB-2
SCB-1X
Siri-3
Siri-3A
2000
SCA-7C
Siri-4
Siri-6
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
Drilled in 2004

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 km²
Reservoir depth:	1,600 m
Reservoir rock:	Chalk
Geological age:	Danian, Upper Cretaceous and Zechstein
Reserves at 1 January 2005:	
Oil:	6.5 million m³
Gas:	0.5 billion Nm³
Cum. production at 1 January 2005:	
Oil:	36.95 million m³
Gas:	3.10 billion Nm³
Water:	34.84 million m³
Cum. injection at 1 January 2005:	
Water:	80.45 million m³
Production in 2004:	
Oil:	1.44 million m³
Gas:	0.08 billion Nm³
Water:	3.69 million m³
Injection in 2004:	
Water:	6.45 million m³
Total investments at 1 January 2005:	
2004 prices	DKK 5.2 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.

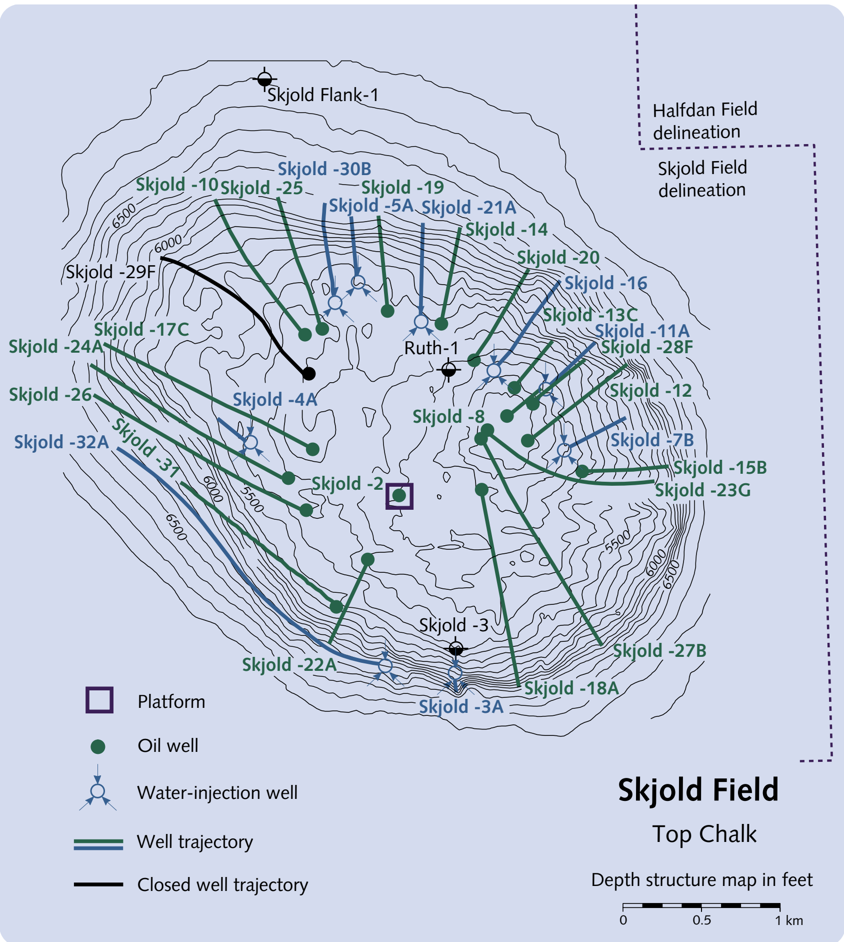
PRODUCTION STRATEGY

During the first years after production startup, oil was produced from the crestal, central part of the reservoir. Water injection was initiated in the reservoir in 1986. 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 greatest possible part of the reservoir with as much water as possible. The injection of water 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 in the Gorm Field for processing. The Gorm facilities provide the Skjold Field with injection water and lift gas. At Skjold C, there are accommodation facilities for 16 persons.



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 2005:	
Oil:	15.4 million m^3
Gas:	6.2 billion Nm^3
Cum. production at 1 January 2005:	
Oil:	12.30 million m^3
Gas:	3.34 billion Nm^3
Water:	2.46 million m^3
Cum. injection at 1 January 2005:	
Water:	16.70 million m^3
Production in 2004:	
Oil:	2.26 million m^3
Gas:	0.46 billion Nm^3
Water:	1.12 million m^3
Injection in 2004:	
Water:	4.95 million m^3
Total investments at 1 January 2005:	
2004 prices	DKK 8.5 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

In the initial development phase, the recovery of oil and gas from the field was based on natural depletion, i.e. without the use of gas or water injection. Pressure support from water injection has subsequently been established.

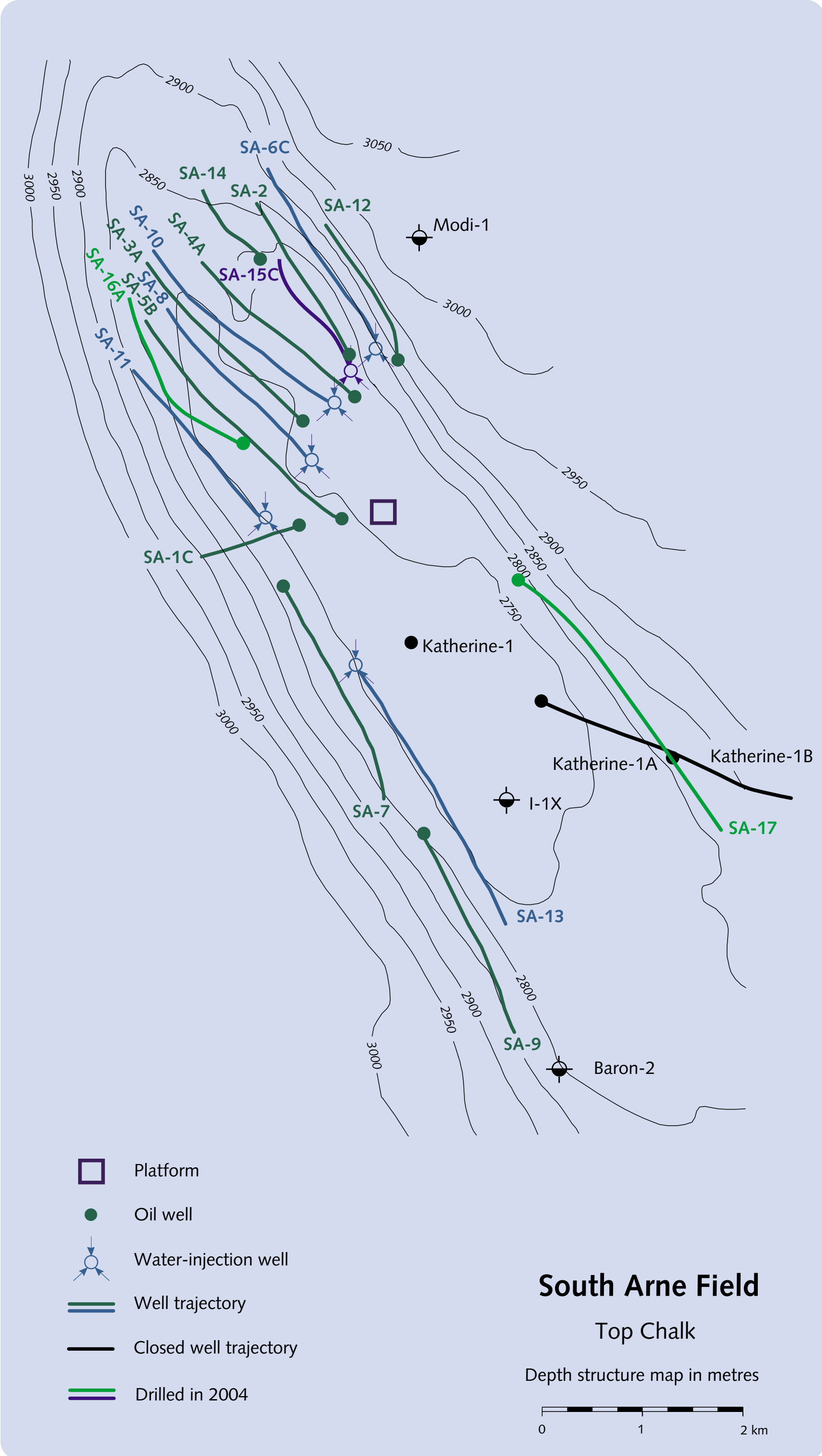
PRODUCTION FACILITIES

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

The processing facilities consist of a plant that separates the hydrocarbons produced as well as gas-processing facilities. The platform also houses equipment for water injection. In order to prevent fouling in and around the injection wells, the seawater injected into the field is pre-processed. After a trial period, most of the produced water is reinjected into the field.

The oil produced is conveyed to an 87,000 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 gas produced is transported 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-5B
SA-8
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
Drilled in 2004
South Arne Field
Top Chalk
Depth structure map in metres
0
1
2 km

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 km²
Reservoir depth:	2,500 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2005:	
Oil:	0.8 million m³
Gas:	0.1 billion Nm³
Cum. production at 1 January 2005:	
Oil:	5.38 million m³
Gas:	0.65 billion Nm³
Water:	6.73 million m³
Production in 2004:	
Oil:	0.33 million m³
Gas:	0.04 billion Nm³
Water:	1.12 million m³
Total investments at 1 January 2005:	
2004 prices	DKK 1.1 billion

REVIEW OF GEOLOGY

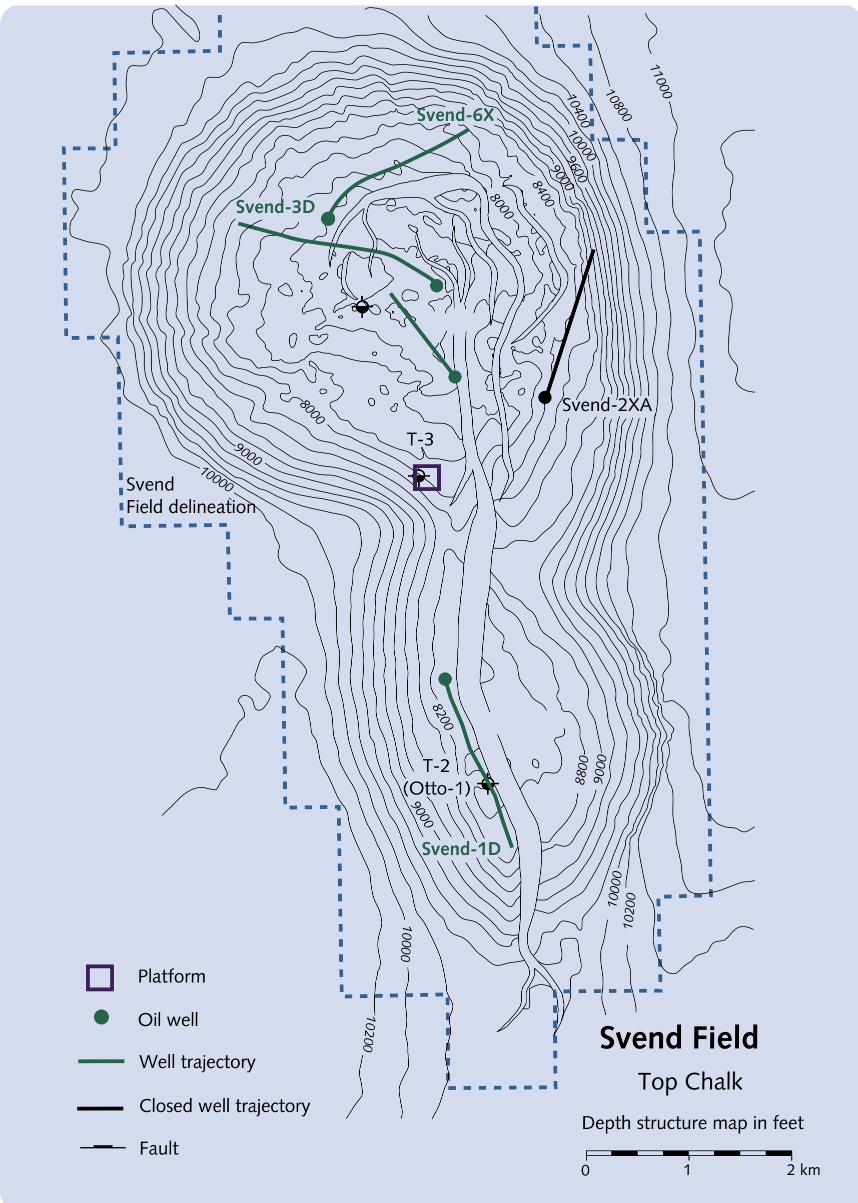
The Svend Field is an anticlinal structure, induced through salt tectonics. This led to fracturing of the chalk in the reservoir and divided the field into a western and an eastern block, separated by a major fault. The northern reservoir of the Svend Field is situated about 250 metres higher than the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

PRODUCTION STRATEGY

Oil and gas production from the Svend Field is based on primary recovery at a 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. The hydrocarbons produced are conveyed to Tyra East for processing and export ashore. The Svend Field is connected to the 16" pipeline from Harald to Tyra East.



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:	15
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 2005:	
Oil and condensate:	4.5 million m^3
Gas:	23.0 billion Nm^3
Cum. production at 1 January 2005:	
Oil and condensate:	21.83 million m^3
Net gas:	37.40 billion Nm^3
Water:	28.26 million m^3
Cum. injection at 1 January 2005:	
Gas:	32.62 billion Nm^3
Production in 2004:	
Oil and condensate:	0.72 million m^3
Net gas:	2.51 billion Nm^3
Water:	3.05 million m^3
Injection in 2004:	
Gas:	1.61 billion Nm^3
Total investments at 1 January 2005:	
2004 prices	DKK 24.7 billion

REVIEW OF GEOLOGY

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

PRODUCTION STRATEGY

Attempts are made not to deteriorate condensate and oil production conditions by reducing the reservoir pressure at too early a 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 enhance 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 plant for pre-processing oil and condensate production from the wells at Tyra West. Moreover, the Tyra West complex houses 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 has wellhead compression facilities to which the Tyra oil wells and satellite wells, including Harald, are connected.

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.

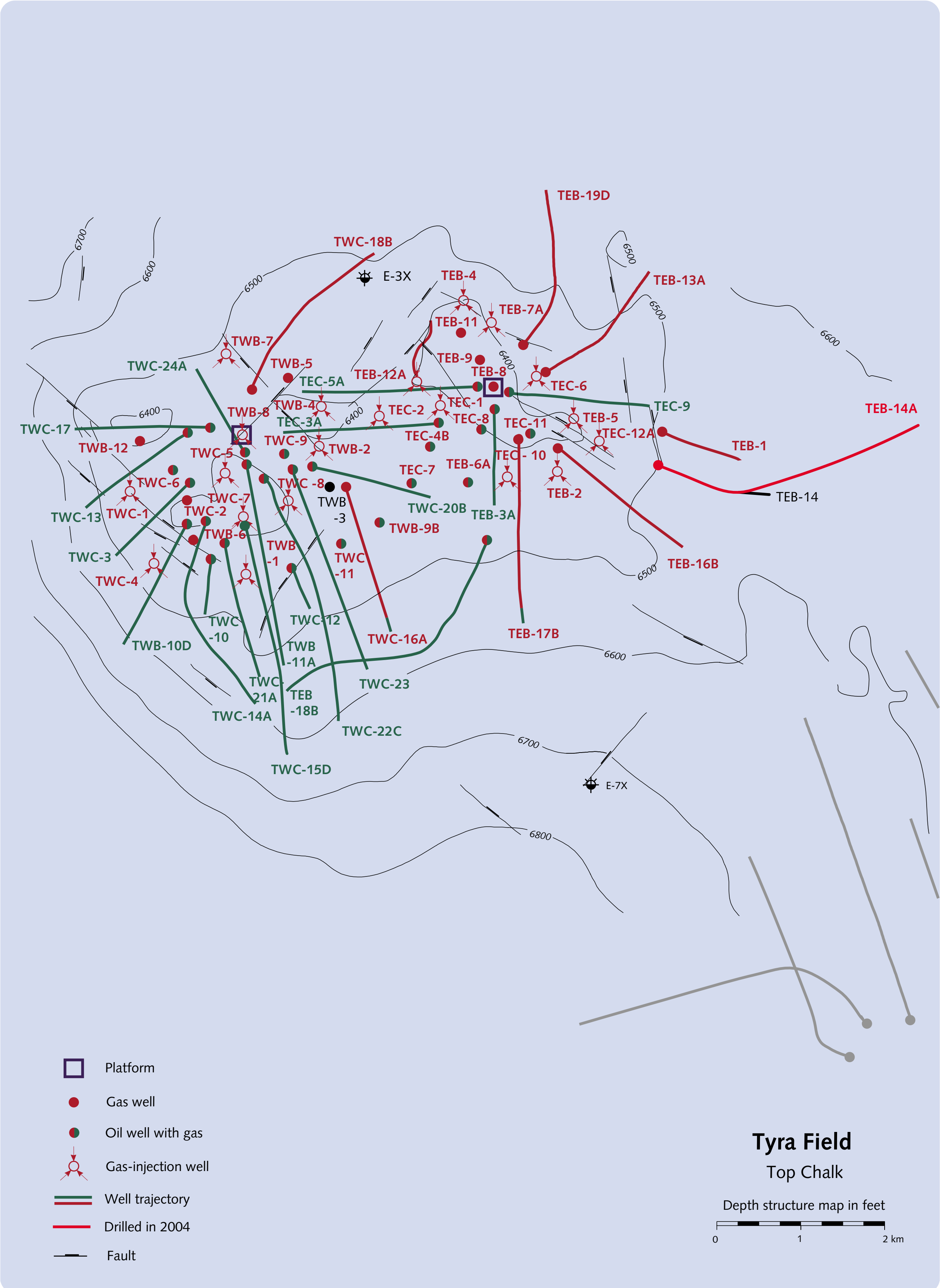
Tyra East receives production from the satellite fields, Valdemar, Roar, Svend, Tyra Southeast and Harald/Lulita, as well as gas production from the Gorm and Dan Fields. The Tyra East complex includes facilities for the final processing of gas, oil, condensate and water.

Tyra West receives the gas produced in the Halfdan Field. The Tyra West complex includes facilities for the final processing of gas and water. Oil and condensate are transported to Tyra East for final processing. The two platform complexes in the Tyra Field are interconnected by pipelines in order to generate the 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 gas produced is transported from TEE at Tyra East to shore and 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.


TEB-19D
TWC-18B
E-3X
TEB-4
TEB-13A
TEB-7A
TEB-11
TWB-7
TWB-5
TEB-9
TWC-24A
TEC-5A
TEB-12A
TEB-8
TEC-6
TEC-9
TEB-14A
TWB-4
TEC-1
TWB-8
TEC-2
TEB-5
TWC-17
TEC-3A
TEC-8
TEC-11
TEC-12A
TEB-1
TWC-9
TEC-4B
TWB-12
TWC-5
TWB-2
TEC-10
TEC-7
TEB-6A
TWC-6
TWC-8
TEB-2
TWB-3
TEB-14
TWC-7
TWC-13
TWC-1
TWC-2
TWC-20B
TEB-3A
TWB-6
TWB-9B
TWB-1
TWC-11
TWC-3
TEB-16B
TWC-4
TWC-10
TWC-12
TWC-16A
TEB-17B
TWB-10D
TWB-11A
TWC-21A
TEB-18B
TWC-23
TWC-14A
TWC-22C
TWC-15D
E-7X
6400
6500
6600
6700
6800
Platform
Gas well
Oil well with gas
Gas-injection well
Well trajectory
Drilled in 2004
Fault
Tyra Field
Top Chalk
Depth structure map in feet
0
1
2 km

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 km²
Reservoir depth:	2,050 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2005:	
Oil:	4.0 million m³
Gas:	10.0 billion Nm³
Cum. production at 1 January 2005:	
Oil:	1.42 million m³
Gas:	2.13 billion Nm³
Water:	1.32 million m³
Production in 2004:	
Oil:	0.58 million m³
Gas:	1.23 billion Nm³
Water:	0.48 million m³
Total investments at 1 January 2005:	
2004 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 Sif/Igor.

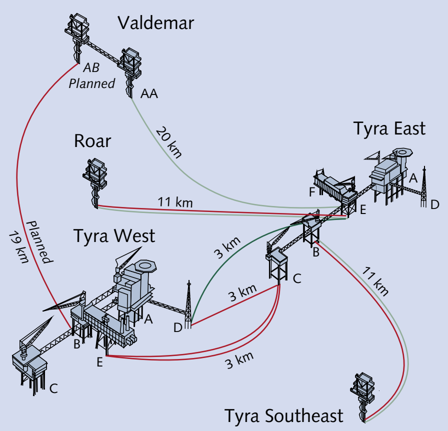
The Tyra Southeast accumulation consists of free gas overlying an oil zone in the southeastern part of the field.

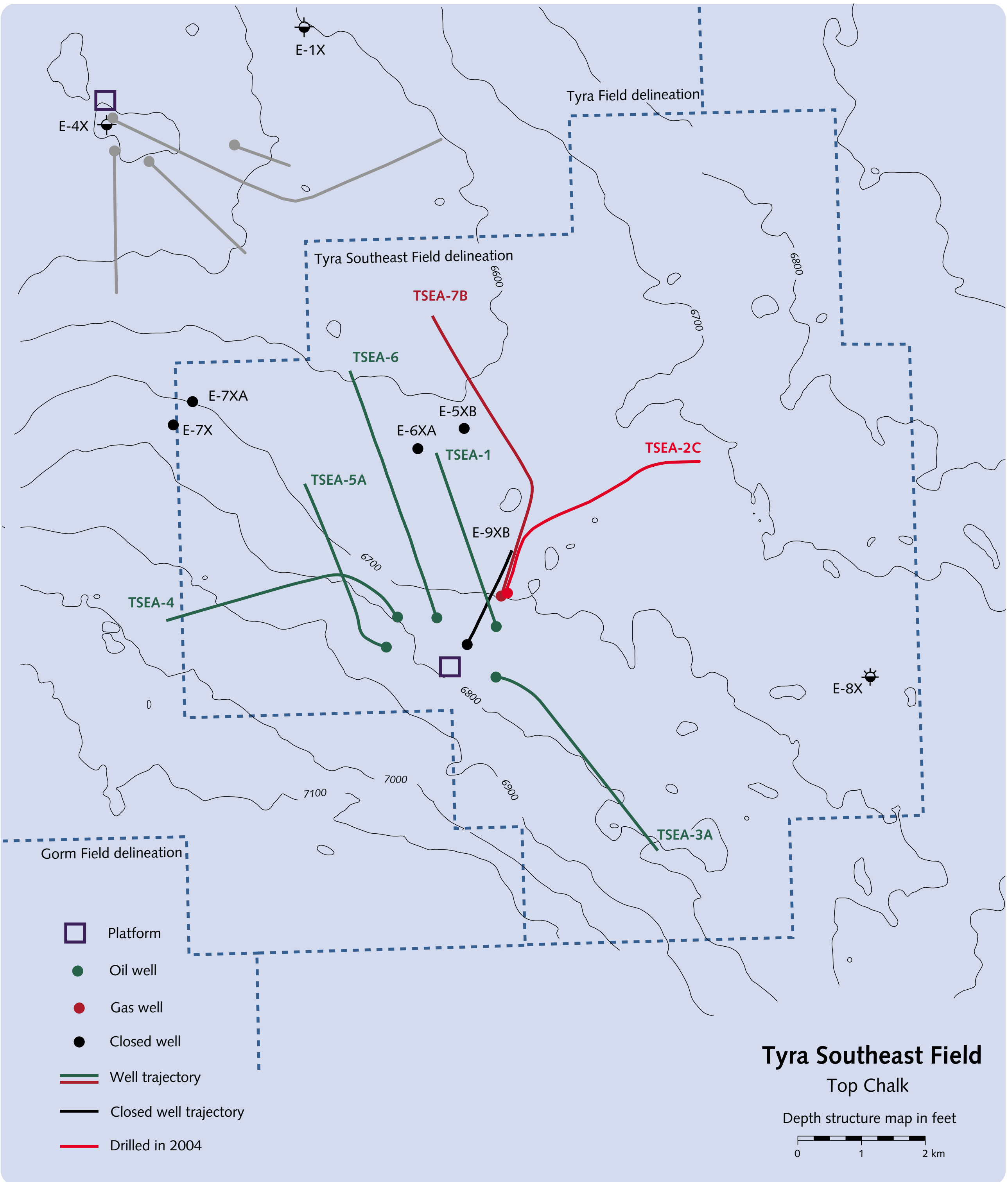
PRODUCTION STRATEGY

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
6600
6700
6800
TSEA-7B
TSEA-6
E-7XA
E-7X
E-5XB
E-6XA
TSEA-1
TSEA-2C
TSEA-5A
E-9XB
6700
TSEA-4
6800
E-8X
7000
7100
6900
TSEA-3A
Gorm Field delineation
Platform
Oil well
Gas well
Closed well
Well trajectory
Closed well trajectory
Drilled in 2004
Tyra Southeast Field
Top Chalk
Depth structure map in feet
0
1
2 km

VALDEMAR FIELD

Prospect:	Bo/North Jens
Location:	Blocks 5504/7 and 11
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1977 (Bo)
	1985 (North Jens)
Year on stream:	1993 (North Jens)
Producing wells:	6
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 2005:	
Oil:	9.7 million m^3
Gas:	6.8 billion Nm^3
Cum. production at 1 January 2005:	
Oil:	2.56 million m^3
Gas:	1.04 billion Nm^3
Water:	1.36 million m^3
Production in 2004:	
Oil:	0.49 million m^3
Gas:	0.22 billion Nm^3
Water:	0.33 million m^3
Total investments at 1 January 2005:	
2004 prices	DKK 1.9 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 vast amounts 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 very difficult production properties due to its extremely low permeability.

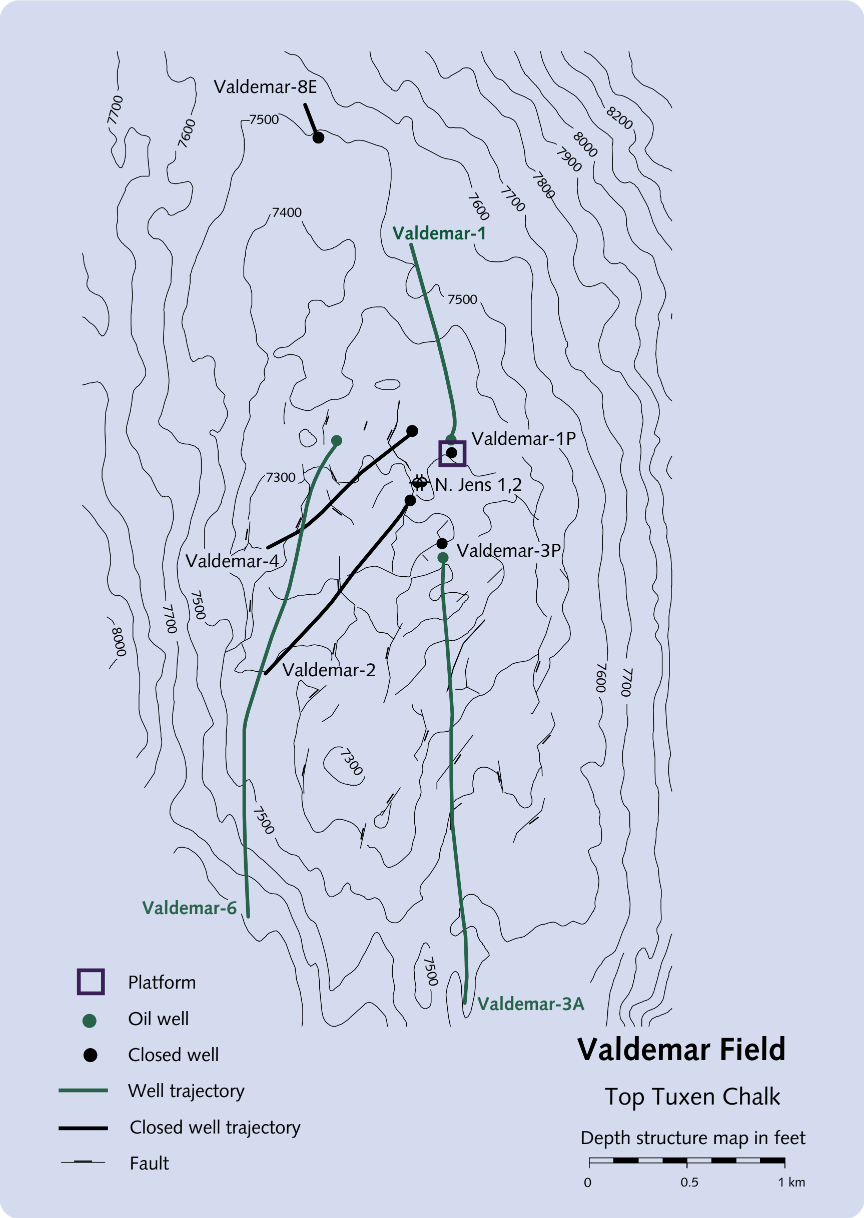
Production from the field is based on primary recovery.

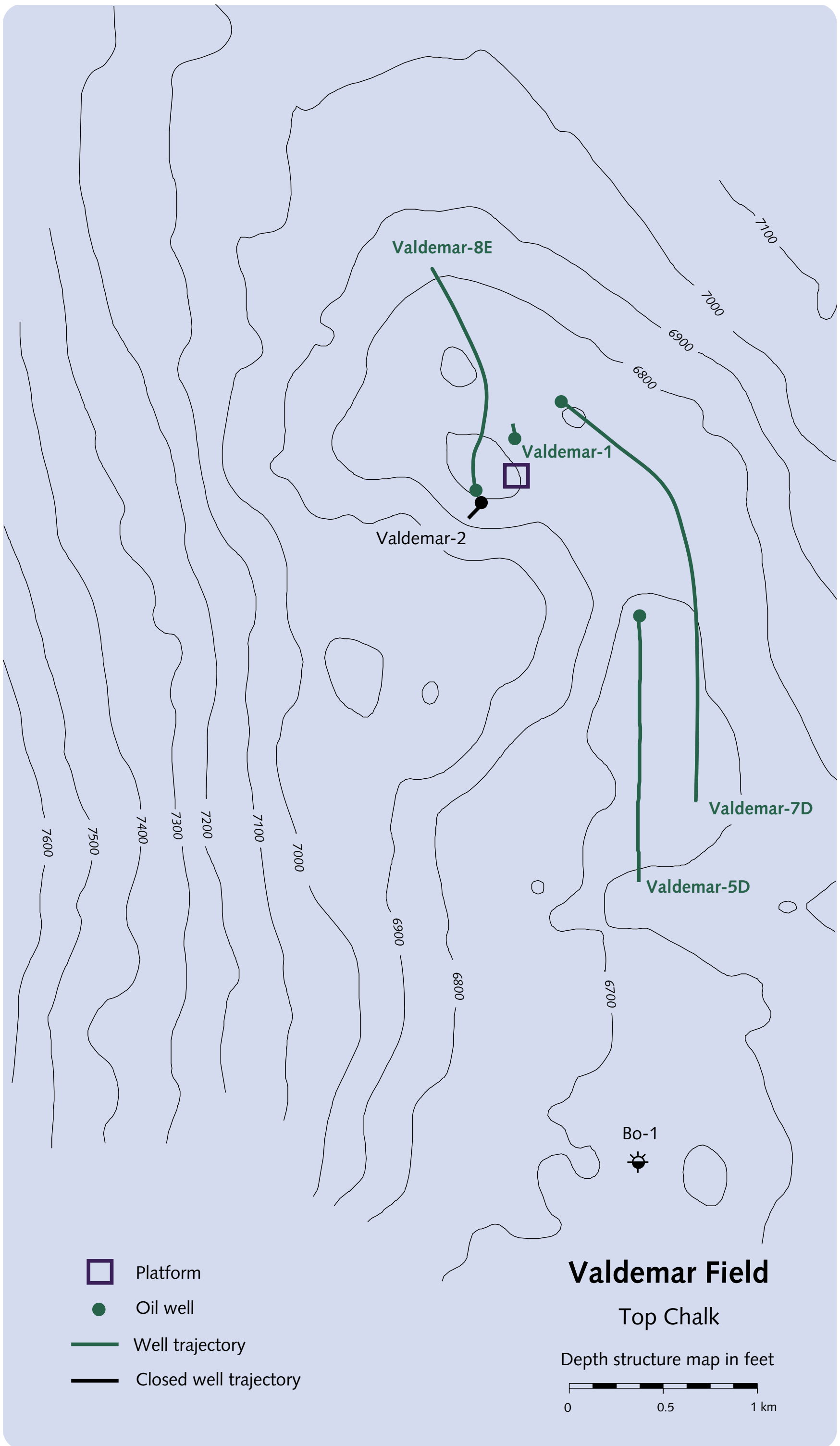
PRODUCTION STRATEGY

The development of a recovery technique based on drilling 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 an unmanned wellhead platform of the STAR type. The hydrocarbons produced are conveyed to Tyra East for processing and export ashore.


Valdemar-8E
Valdemar-1
Valdemar-1P
N. Jens 1,2
Valdemar-4
Valdemar-3P
Valdemar-2
Valdemar-6
Valdemar-3A
7300
7400
7500
7600
7700
7800
7900
8000
8200
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
7600
7500
7400
7300
7200
7100
7000
6900
6800
6700
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	7	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	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	747	14.9	8.1	3.7	-7.3	1,399
1987	930	1,380	664	18.3	6.8	4.0	-5.9	1,328
1988	928	1,413	424	14.8	6.7	4.5	-3.6	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	-2.6	2,089
1991	2,302	1,898	985	20	6.4	2.4	-1.9	1,889
1992	2,335	1,806	983	19.3	6	2.1	-0.2	1,911
1993	3,307	2,047	442	16.8	6.5	1.2	-0.1	1,811
1994	3,084	2,113	151	15.6	6.4	2.0	-0.3	2,053
1995	4,164	1,904	272	17	5.6	2.1	0.6	1,980
1996	4,260	2,094	470	21.1	5.8	2.1	0.8	2,465
1997	3,760	2,140	515	18.9	6.6	2.2	1.7	3,171
1998	5,381	2,037	406	12.8	6.7	1.8	1.3	3,125
1999	3,531	2,118	656	17.9	7	2.5	6.9	3,630
2000	3,113	2,813	672	28.5	8.1	2.9	15.3	8,695
2001	4,025	2,756	973	24.4	8.3	2.4	13.0	9,634
2002	4,703	3,102	1,036	24.9	7.9	2.4	14.9	10,138
2003	6,619	3,522	789	28.8	6.6	2.1	15.2	9,311
2004*	4,378	3,334	309	38.2	6.0	1.2	19.3	18,339

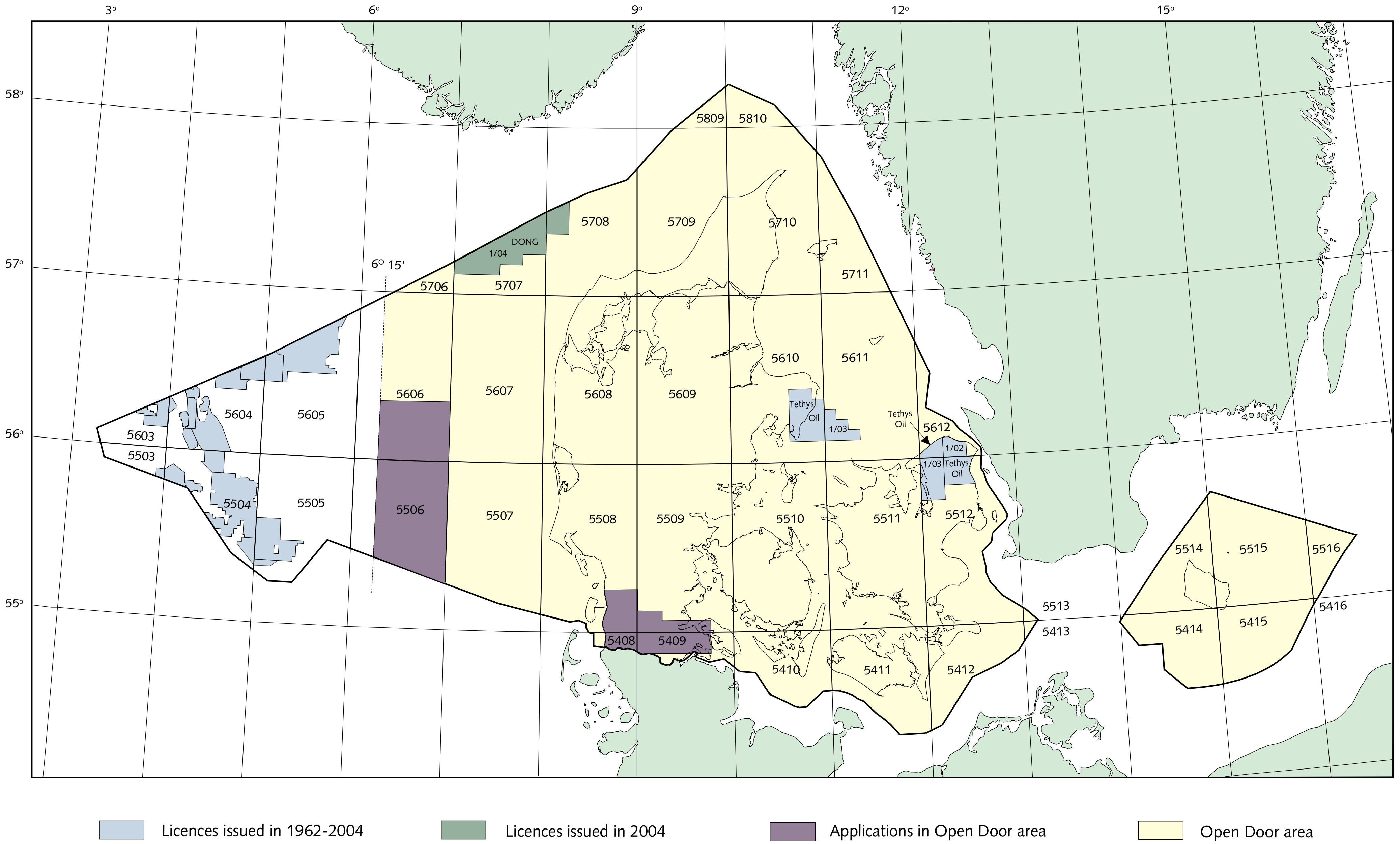
Nominal prices
1) Incl. transportation costs
2) Brent crude oil
3) Consumer prices
4) Oil products and natural gas
**) Estimate*

EXISTING FINANCIAL CONDITIONS

	Sole Concession at 1 January 2004	Licences granted before 1 January 2004*	Licences granted after 1 January 2004
Corporate income tax	30 per cent Deductible from the hydrocarbon tax base.	30 per cent Deductible from the hydrocarbon tax base.	30 per cent Deductible from the hydrocarbon tax base.
Hydrocarbon tax	52 per cent Allowance of 5 per cent over 6 years (a total of 30 per cent) for investments. Transitional rules for investments and unutilized field losses made before 1 January 2004.	70 per cent Allowance of 25 per cent over 10 years (a total of 250 per cent) for investments.	52 per cent Allowance of 5 per cent for 6 years (a total of 30 per cent) for investments.
Royalty	No	2nd round licences pay royalty as follows: 1000 bbl/day — Rate 0 – 5 — 2 per cent 5 – 20 — 8 per cent 20 - — 16 per cent Deductible from the corporate income tax and hydrocarbon tax bases.	No
Oil pipeline tariff/ compensatory fee	5 per cent until 8 July 2012, after which no tariff/fee is payable. The oil pipeline tariff can be offset against hydrocarbon tax, but not against the corporate tax and hydrocarbon tax bases	5 per cent The oil pipeline tariff/compensatory fee is deductible from the corporate income tax and hydrocarbon tax bases.	5 per cent until 8 July 2012, after which no tariff/fee is payable. The oil pipeline tariff can be offset against hydrocarbon tax, but not against the corporate tax and hydro-carbon tax bases.
State participation	20 per cent from 9 July 2012	20 per cent 1st, 2nd and 3rd rounds: state parti-cipation with carried interest in the exploratory phase. A paying interest, depending on the size of production, in the develop-ment and production phases. 4th and 5th rounds and Open Door procedure: fully paying interest.	20 per cent
Profit sharing	From 1 January 2004 to 8 July 2012, 20 per cent of the profit before tax and before net interest expenses is payable.	No	No

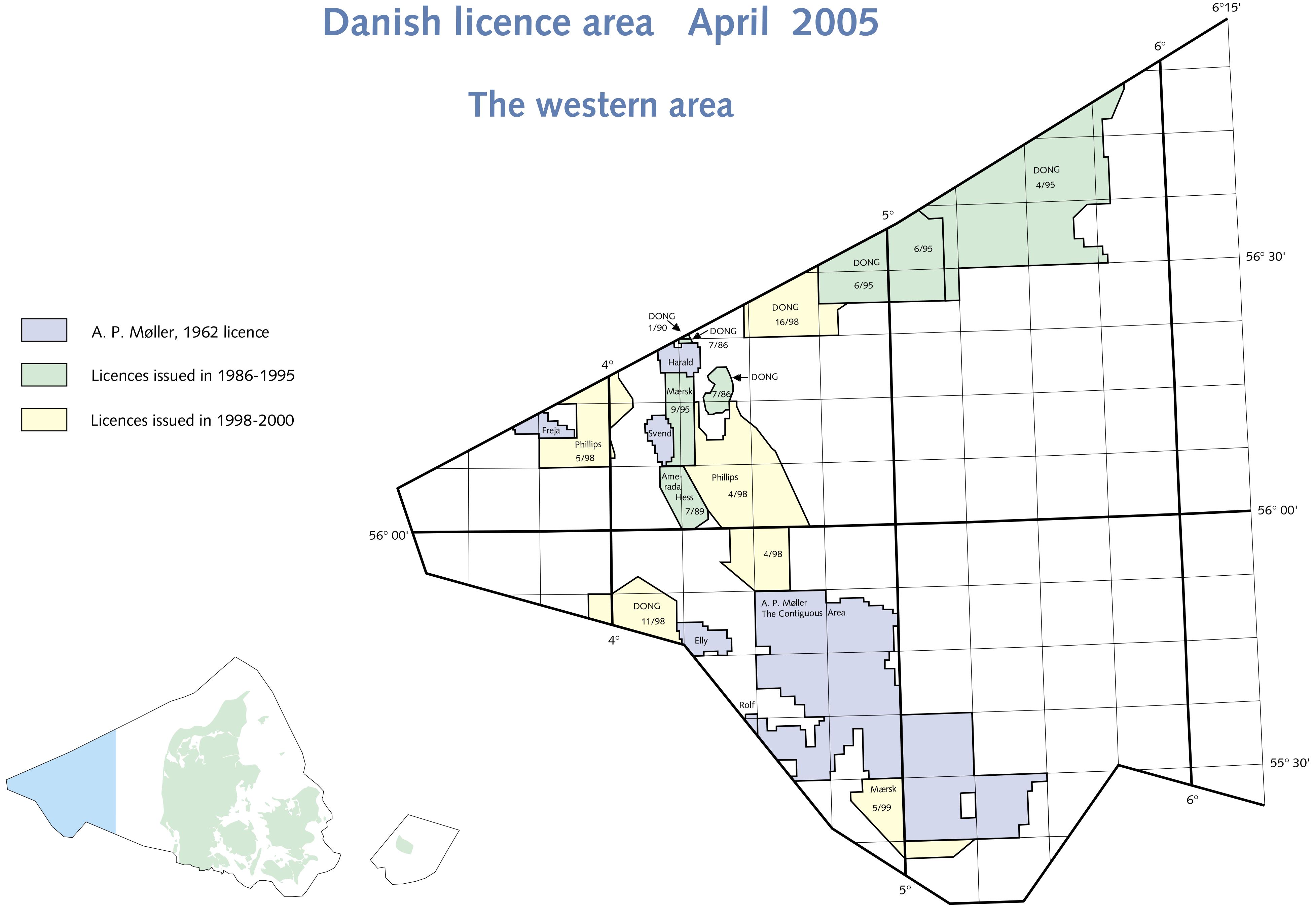
** At the licensees' request, licences granted before 1 January 2004 may be taxed according to the "new" hydrocarbon tax rules in the 2004 tax return*

Danish licence area April 2005



Danish licence area April 2005

The western area



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 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.

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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 2004 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.

This year's report also includes a special section on the development of the Gorm Field since its discovery in 1971.

The report can be obtained from the Danish State Information Centre, tel. +45 7010 1881, an official telephone service directly connecting callers to anywhere in the public sector, or from the Danish Energy Authority's Internet bookstore, www.danmark.dk/netboghandel. The report is also available on the Danish Energy Authority's homepage, www.ens.dk.

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