Danish Energy Authority

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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 2002 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 oil and gas production on the Danish economy.

Finally, this year's report includes a special section on global oil reserves.

The report can be obtained from the Danish Energy Information Centre, tel. +45 70 21 80 10, on request and is also available on the Danish Energy Authority's homepage, www.ens.dk.

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Oil and Gas production in Denmark 2002

Danish Energy Authority

Oil and Gas Production in Denmark 2002

Established by law in 1976, the Danish Energy Authority is an authority under the Ministry of Economic and Business Affairs 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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PREFACE

Throughout 2002, the oil and gas sector has been in the spotlight, both in Denmark and internationally.

The production of oil and natural gas from the North Sea continues to play a pivotal role for Danish society, and is the main reason why Denmark has now been self-sufficient in energy for a number of years. The competitive and reliable supply of energy helps provide a good growth platform for the Danish economy. At the same time, the production of hydrocarbons contributes to state revenue in the form of taxes and duties.

Once again, the Danish oil and gas sector recorded a high level of activity in 2002. Thus, a number of field development plans were approved, resulting in large-scale investments in new installations in the Danish sector. In addition, 2002 saw a repeat of previous years' record-high production figures.

Safety on board the North Sea offshore installations was a major issue in 2002. As a follow-up to the incident in the Gorm Field in 2001, the Norwegian SINTEF institute prepared a report on the safety conditions. In response to this report, the Danish government presented an action plan in 2002 with the aim of implementing the report's recommendations regarding the Danish facilities in the North Sea. This action plan involves intensified safety supervision by the Danish Energy Authority.

The global political situation and the international economy influence the production of oil and the oil price. Moreover, the world's energy supplies, and thus global oil reserves, remain key issues. Therefore, this year's report includes a special section on global energy consumption and oil reserves.

Copenhagen, May 2003

Ib Larsen

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 2002. The lower calorific value is indicated.

The SI prefixes m (million), 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.*

g — *gamma; relative density.*

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

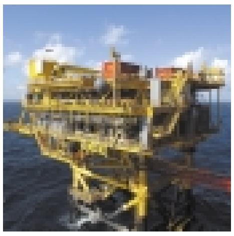
ft — *foot/feet; British unit of length. 1 ft = 12 in.*

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	0.040
	Nm^3	kg·mol	0.0446158
	m^3 (st)	scf	35.3014
	m^3 (st)	GJ	0.0379
	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*

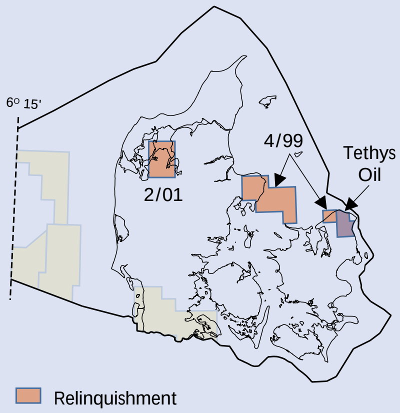
	FROM	TO	CONVERSION
Density	°API	kg/m^3	141364.33/(°API+131.5)
	°API	γ	141.5/(°API+131.5)

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



1. LICENCES AND EXPLORATION

Fig. 1.1 New and Relinquished Open Door Licences



With one new exploration well and eight appraisal wells, exploration activity dropped slightly in 2002 as compared to the year before. Spudded in 2001, the Phillips group's Svane-1 well reached its final depth in 2002 and made the deepest discovery of hydrocarbons recorded to date in Danish territory. The DONG group encountered another oil accumulation at the Nini Field in the Siri Fairway.

The Danish Energy Authority expects a higher level of exploration activity in 2003, including the drilling of six to eight new exploration wells.

Since 1984, applications for licences have been invited in licensing rounds at three- to five-year intervals. Since licences were most recently awarded in the licensing round in June 1998, the Danish Energy Authority has started preparing to invite applications for areas west of 6°15' eastern longitude in 2004.

NEW LICENCES

On 9 July 2002, the Minister for Economic and Business Affairs granted Tethys Oil AB a licence for exploration and production of hydrocarbons in northeastern Zealand; see Fig. 1.1. Tethys Oil AB, a company incorporated in Sweden, is the operator of the licence, numbered 1/02. It was awarded under the so-called Open Door procedure, which is an open invitation to oil companies to apply for licences for all unlicensed areas east of 6°15' eastern longitude. As in all other Open Door licences, the state-owned company DONG Efterforskning og Produktion A/S (DONG E&P A/S) holds a 20% share of the licence.

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 2002, 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	Expiry
4/95	15-05-2003
6/95	15-11-2003
7/95	15-11-2004
9/95	15-11-2003

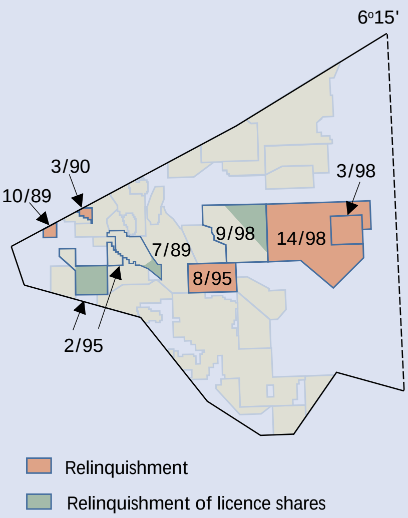
Approved Transfers

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

Effective 1 August 2002, DONG E&P A/S took over the Siri Field operatorship from Statoil Efterforskning og Produktion A/S. Thus, for the first time, DONG E&P A/S has become the operator of a producing field.

By 1 July 2002, Statoil had sold all its Danish licence shares to the other oil companies in the three licences involved. The total sales price was DKK 1 billion. DONG E&P A/S, DENERCO Oil A/S and Paladin Oil Denmark Limited took over Statoil's 40% share of Siri licence 6/96. Statoil also sold its 37.642% shares of two licences in the Lulita Field to DONG E&P A/S, DENERCO Oil A/S and DENERCO Petroleum A/S.

Fig. 1.2 Relinquishment West of 6°15' Eastern Longitude



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

Partial Relinquishment

The DONG group relinquished a large share of licence 2/95, comprising one block, on 1 March 2002.

The Amerada Hess group relinquished part of the area comprised by licence 7/89 on 1 May 2002. The relinquished area is situated southeast of the South Arne Field and includes the Nora-1 exploration well, in which DUC discovered hydrocarbons in Middle Jurassic sandstone in 1983.

On 15 June 2002, the Agip group relinquished the northeastern part of the Ringkøbing-Fyn High area comprised by licence 9/98.

The relinquished areas appear from Fig. 1.2.

Licences for exploration and production of hydrocarbons are initially granted for a 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 either 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.

TERMINATED LICENCES

Licences for areas in and around the Central Graben and the Open Door area were relinquished in the course of 2002. The licences relinquished appear from Table 1.2 and Figs. 1.1 and 1.2. In addition, Open Door licence 2/01, for which Sterling Resources (UK), Ltd. was operator, was relinquished on 5 January 2003.

Table 1.2 Terminated Licences

Licence	Operator	Terminated
10/89	Mærsk Olie og Gas AS	20-12-2002
3/90	Mærsk Olie og Gas AS	13-07-2002
8/95	Mærsk Olie og Gas AS	15-11-2002
3/98	Marathon Petroleum Denmark, Ltd.	15-06-2002
14/98	Mærsk Olie og Gas AS	15-06-2002
4/99	Northern Petroleum (UK)	01-11-2002

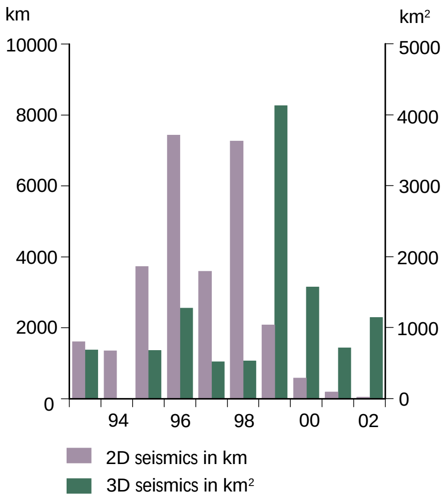
EXPLORATORY SURVEYS

The scope of seismic surveys was greater in 2002 than 2001. The level of activity and the areas where seismic surveys were performed appear from Figs. 1.3 and 1.4.

In February 2002, DONG E&P A/S resumed a 3D seismic survey initiated under licence 4/95 in the latter half of 2001, which had to be suspended because of bad weather conditions. The new seismic data are to be used for further exploration of the area south of the Nini Field.

In July-September 2002, Fugro Geoteam carried out a 3D seismic survey in the southern part of the Central Graben. The survey was part of a major programme that also comprised areas in German and Dutch continental shelf territory. The new data are an important supplement to the 3D data previously acquired in Danish territory.

Fig. 1.3 Annual Seismic Surveying Activities



In March 2002, DENERCO Oil A/S acquired a single 2D seismic line in Danish territory as part of a survey under its German licence in the North Sea.

Onshore, the holders of licence 1/01 in South Jutland and licence 2/01 in the Salling area collected soil samples for geochemical surveys. Because small amounts of hydrocarbons naturally seep from oil or gas accumulations to the surface over a period of time, this method makes it possible to evaluate the chance of making oil or gas discoveries by analyzing the samples.

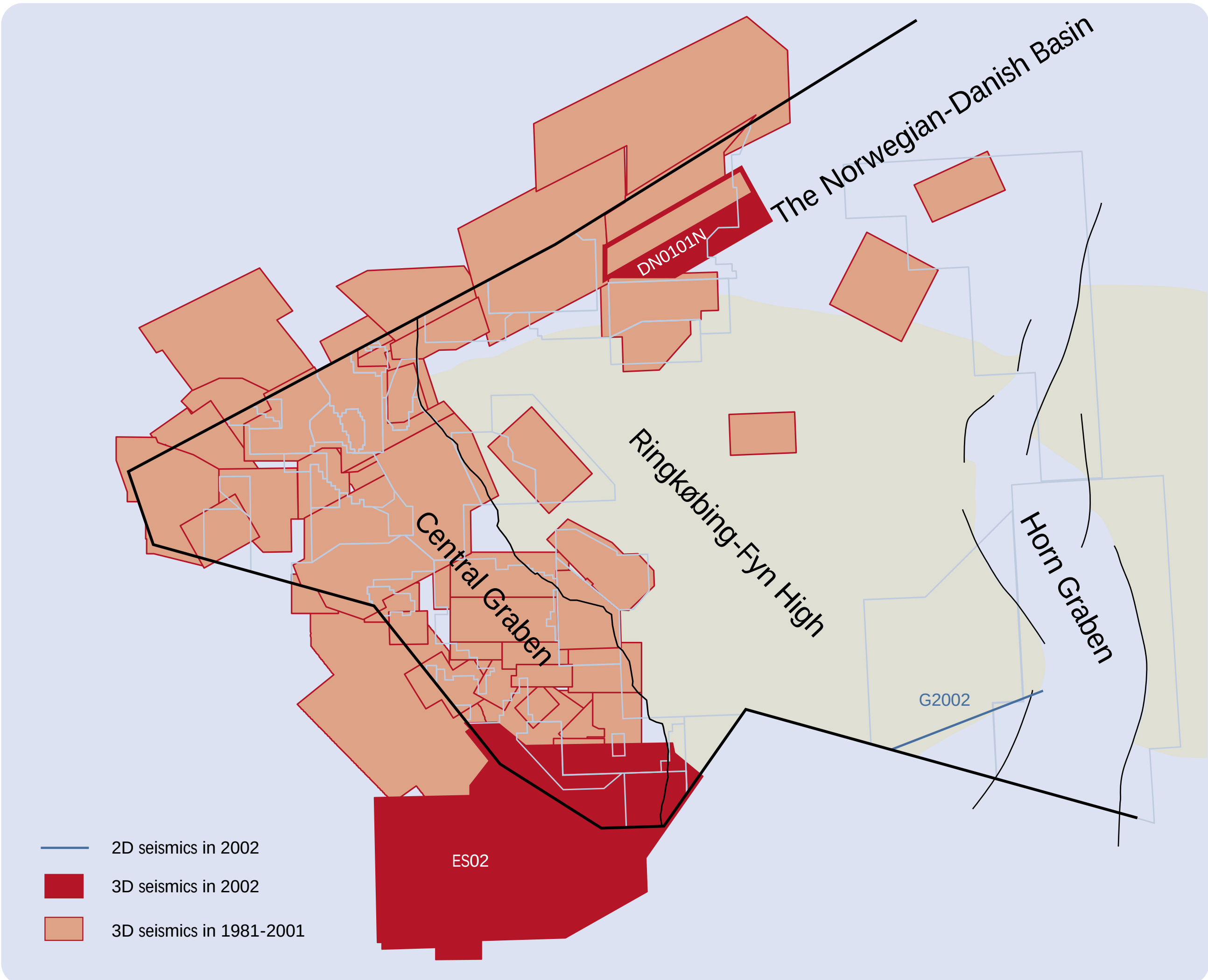
WELLS

In 2002, one exploration well and eight appraisal wells were drilled; see Fig. 1.5. These statistics include wells spudded in 2002.

The location of the wells described below appears from Fig. 1.6. 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.

Fig. 1.4 Seismic Surveys



Exploration Wells

Initiated in 2000, the cooperation between DONG E&P A/S and a number of licensees to drill exploration wells continued in 2002 with the completion of the Svane-1 well. Subsequent exploration objectives were prospects in the Siri Fairway, in more shallow layers.

Since the Phillips group spudded the deep and time-consuming Svane-1 exploration well under licence 4/98 in 2001, this well is included in the statistics for 2001. However, the well results were not available until mid-2002, for which reason they were not mentioned in the 2001 report on Oil and Gas Production in Denmark.

Svane-1 (5604/26-4) was drilled as a vertical well with a sidetrack (Svane-1A) to a vertical depth of 5,867 metres below sea level and terminated in Mesozoic layers. A production test was carried out in the well under very difficult conditions. Gas and condensate was produced from several sandstone layers of Upper Jurassic age.

Being the deepest well drilled to date in Danish territory, the Svane-1A well has demonstrated further exploration potential in deeper layers of the Danish Central Graben. The production properties and the size of the accumulation are now being evaluated more closely.

Oscar-1 (5604/32-1)

Under licence 12/98, Amerada Hess ApS drilled the Oscar-1 exploration well in October 2002 in cooperation with DONG E&P A/S. This licence covers an area of the Ringkøbing-Fyn High due east of the Central Graben. Oscar-1 was carried to a depth of 2,439 metres below sea level and terminated in chalk of early Palaeocene age. The well results were disappointing, and no hydrocarbon discovery was made.

Appraisal Wells

Nini-4 (5605/10-4)

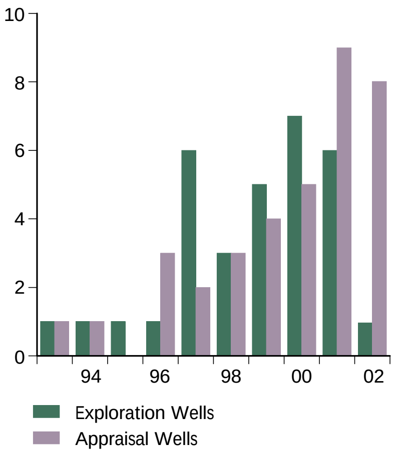
The DONG group's Nini-4 well was drilled west of the previous wells drilled in the Nini Field under licence 4/95. Nini-4 was drilled as a vertical well to a depth of 1,849 metres below sea level and terminated in chalk presumed to be of Danian age. The well encountered an additional oil accumulation in Palaeogene sandstone. To determine the extent of the accumulation more exactly, a sidetrack, Nini-4A, was drilled into the water zone.

Siri-5 (5604/20-8)

Siri-5 was drilled as a vertical well in the southern part of Stine segment 2, an oil accumulation situated east of Siri Central. The well reached a depth of 2,108 metres below sea level and terminated in the Våle Formation right above the chalk. The Siri-5 well confirmed the expected presence of oil in the Palaeocene sandstone reservoir in the southern part of the Stine segment 2 area.

Subsequently, a deviated sidetrack, Siri-5A, was drilled to gather further information about the reservoir and the extent of the oil accumulation. On the basis of the results from Siri-5/5A, the holder of licence 6/95 decided to drill a horizontal production well from the Siri platform to the Siri-5 area.

Fig. 1.5 Exploration and Appraisal Wells



Cecilie-2 (5604/20-9)

Under licence 16/98, the Cecilie-2 appraisal well penetrated the Palaeocene oil-bearing sandstone reservoir 1.2 km southeast of the Cecilie-1 well, which encountered the Cecilie oil accumulation in 2000. Cecilie-2 was drilled as a vertical well, terminating at a depth of 2,347 metres below sea level in chalk of Maastrichtian age. The new data from this well are to be used for planning future production wells.

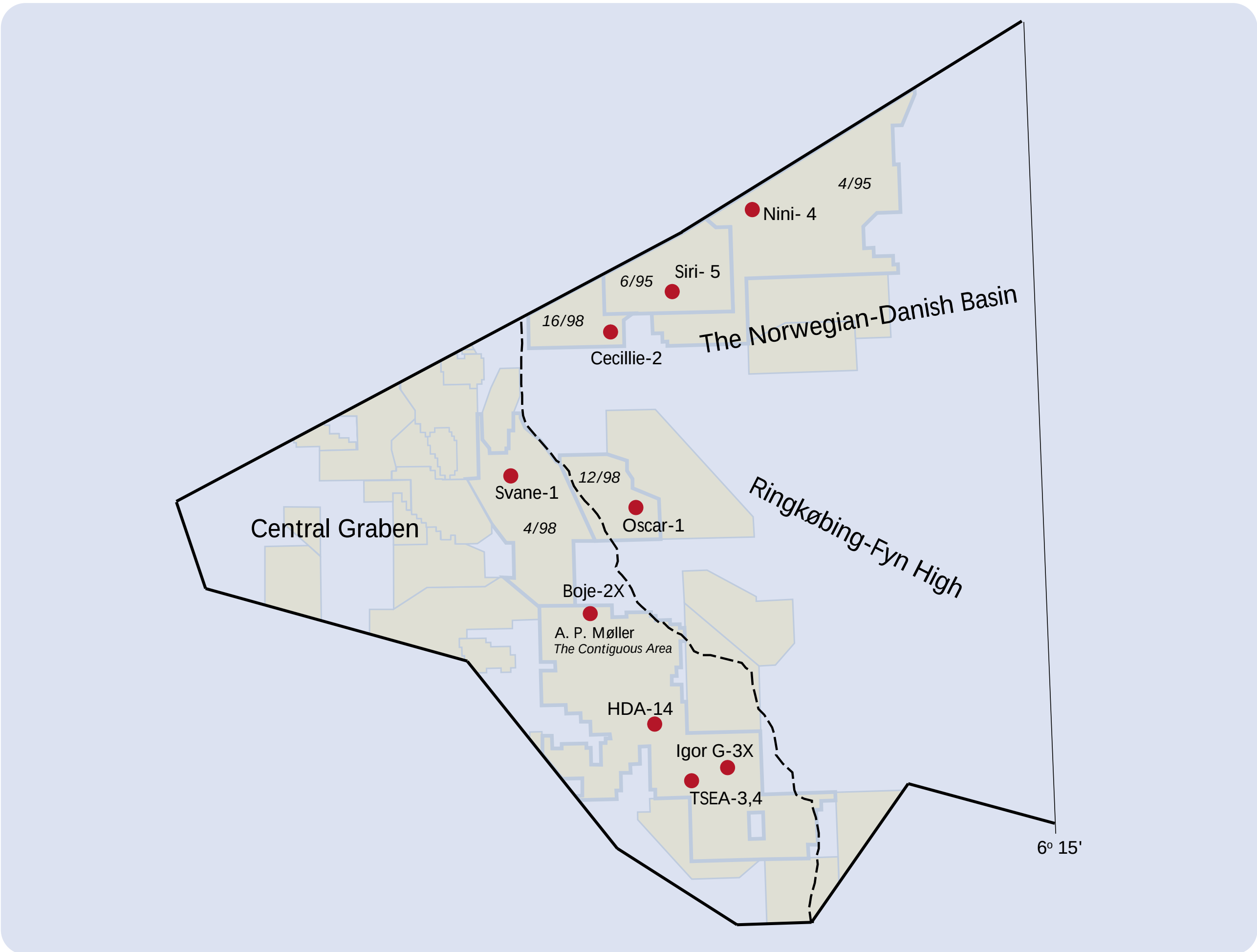
Boje-2X (5504/7-9)

In September 2002, Mærsk Olie og Gas AS spudded the Boje-2X well in the Boje area. The previous Boje-1 well encountered hydrocarbons in both Danian chalk and Lower Cretaceous chalk. Initially, a pilot hole was drilled in Boje-2X to delineate the Lower Cretaceous accumulation, and subsequently a horizontal production section was drilled in Danian chalk. The well was left in a condition that allows it to be used for production at a later date.

Igor G-3X (5505/13-8)

In June-November 2002, Mærsk Olie og Gas AS drilled the Igor G-3X appraisal well in the Igor area, where two previous wells have encountered gas in Danian chalk. On the basis of the results from Igor G-3X and other data, Mærsk Olie og

Fig. 1.6 Exploration and Appraisal Wells



Gas AS submitted a development plan for the Danian gas accumulation in the Halfdan/Sif/Igor area at the end of 2002; see the section entitled *Development*. The Igor G-3X well has been left in a condition that allows it to be used for production at a later date.

TSEA-3 and *TSEA-4*
In connection with Mærsk Olie og Gas AS's development of the Tyra Southeast Field, two production wells were extended to delineate the accumulation more precisely. Tyra Southeast contains oil and gas in Danian and Maastrichtian chalk. The horizontal TSEA-3 well was drilled in a southerly direction, while the horizontal TSEA-4 well delineates the accumulation towards the west. Both wells are now used for production.

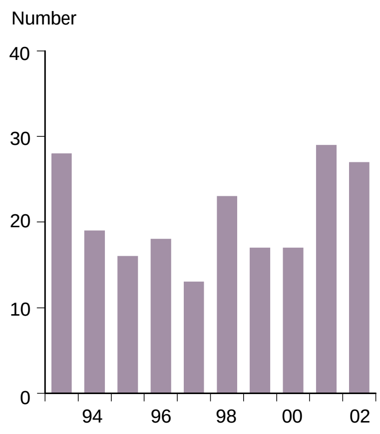
HDA-14
The horizontal HDA-14 well, drilled in the Halfdan Field by Mærsk Olie og Gas AS in January-March 2002, was extended much further than originally planned in order to delineate the Maastrichtian oil accumulation towards the northwest. The Halfdan Field contains oil and gas in both Danian and Maastrichtian chalk. The HDA-14 well is now used for production.

Geothermal Well
Margretheholm-1 (5512/11-01)
At the Amagerværket power plant in the Greater Copenhagen Area, DONG E&P A/S drilled a deep well in the summer of 2002 to investigate the potential for utilizing hot water in sandstone layers in the subsoil for heat generation. Margretheholm-1 was drilled to a depth of 2,676 metres below sea level and terminated in the basement.

The well encountered sandstone reservoirs, as expected. Although drilled for geothermal purposes, the well is interesting from a hydrocarbon perspective, as the results may provide substantial insight into the structure of the subsoil. To date, very few onshore oil/gas exploration wells have been drilled in Zealand. The well is not included in the statistics in Fig. 1.6.

2. DEVELOPMENT

Fig. 2.1 Development Wells



As in previous years, 2002 saw busy development activity in the Danish sector of the North Sea. Two new platforms were commissioned in the Tyra Southeast and Halfdan Fields, and 27 new development wells were drilled, two fewer than in the record year of 2001; see Fig. 2.1.

During the year, the Danish Energy Authority approved a number of development plans for both new and existing fields. Most of these projects have already been initiated.

Fig. 2.3 shows the existing production installations in the Danish sector of the North Sea.

Appendix B provides a survey of all the producing fields, including maps of the individual fields. Wells drilled in 2002 are marked with a lighter colour than the old wells.

DEVELOPMENTS IMPLEMENTED IN 2002

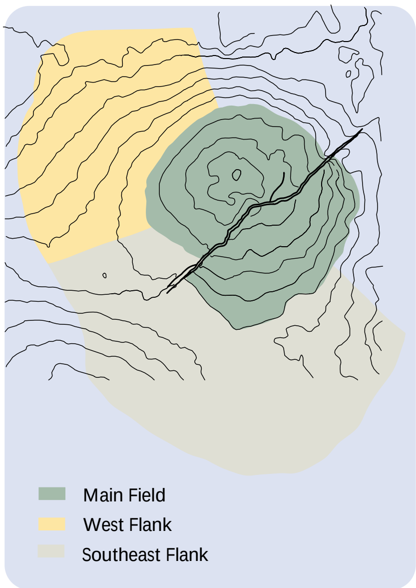
The Dan Field

Over the years, the drainage area at the Dan Field has been extended several times, the operator, Mærsk Olie og Gas AS, having continually assessed the potential for further recovery; see Fig. 2.2.

Most recently, a development plan for the field was approved in 2001 involving development of the western flank towards the Halfdan Field. In keeping with this plan, three production wells were drilled in 2002 in the southernmost part of this flank area; see the field map in Appendix B. Concurrently, three existing wells were converted to water injection. In total, the plan calls for eight new wells to be drilled and six wells to be converted to water injection in the western flank area.

In December 2002, a plan was also approved to change recovery strategy for the area under the gas zone in the middle of the field.

Fig. 2.2 Dan Field with Flank Areas

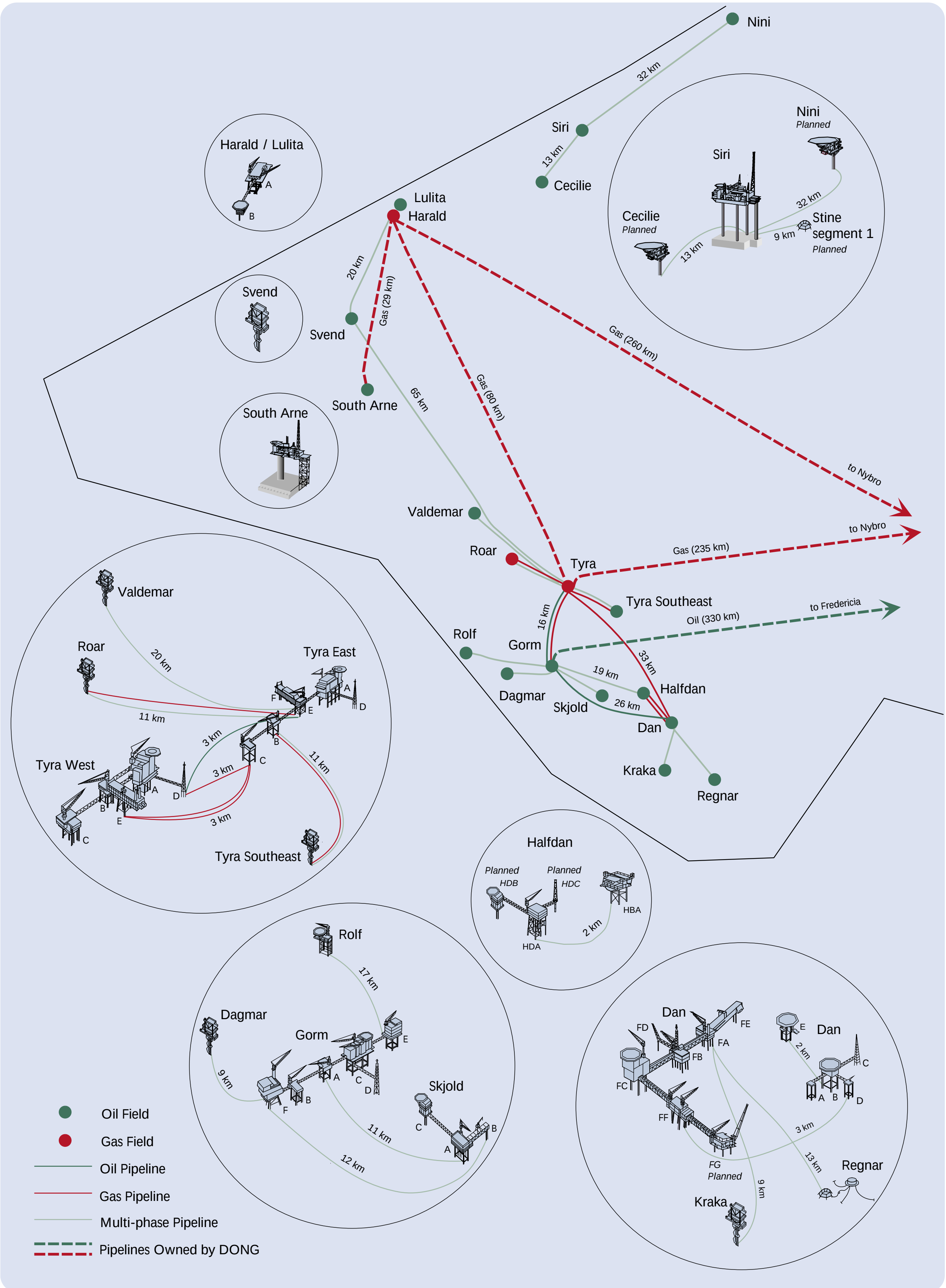


In recent years, high-rate water injection has been used in most of the central part of the structure. To date, however, production from the area under the gas zone in the southernmost block of the Dan Field has been carried out with conventional water injection, i.e. at rates sufficiently low to prevent the injection process from causing the reservoir rock to fracture.

Experience from previous production gives reason to expect that converting to high-pressure injection will enhance oil production in this area as well. The estimated increase in oil production is based on an assumed improvement in displacement combined with the fact that oil has only limited upward movement into the gas zone.

In 2002, a new water-injection system was installed on the Dan FF platform. This system will supply injection water to the Dan and Halfdan Fields. The system will increase the injection capacity by 180,000 barrels of water per day, thus expanding the overall installed water injection capacity at the Dan Field to approx. 600,000 barrels of water per day.

Fig. 2.3 Production Facilities in the North Sea 2002



The Danish Energy Authority approved a plan for further development of the production processing and water-injection capacity in 2001. Since then, the estimated capacity requirement has increased. Therefore, the Authority approved a modification of the project in 2002, which involves establishing a new processing platform, the Dan FG, which will be bridge-connected with the Dan F complex.

The Dan FG platform is to be equipped with new facilities, including a production separation system, a purification system for produced water, a gas-treatment and compression system and a water-injection system. The new platform is scheduled for installation in 2004.

The Gorm Field

In 2002, three wells were drilled at the Gorm Field, one of which is a replacement well for the northeastern part of the field. The collapse of the outer parts of two production wells had resulted in unsatisfactory drainage in this area.

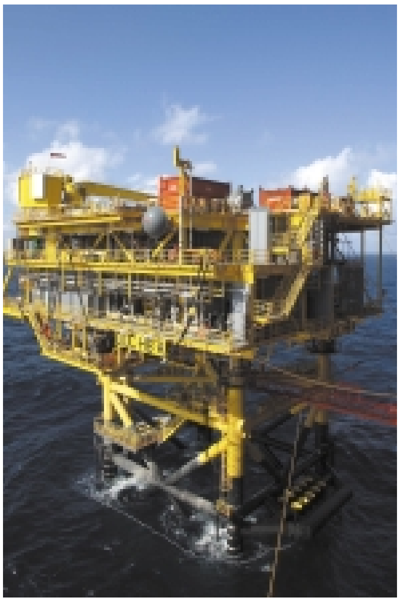
The two other production wells targeted an area extending towards the main fault, where drainage was less satisfactory than in the rest of the field; see the field map in Appendix B.

With regard to the implementation of the approved plans, four wells at the crest of the structure still remain to be converted to water injection.

The Halfdan Field

The Halfdan Field was discovered in 1999 and brought on stream already in 2000. Since the first development plan, two additional development phases have been approved. The overall planned development now comprises a total of 46 wells, 25 production wells and 21 water-injection wells. In all, 13 wells were drilled at the field in 2002.

As of end-2002, 21 wells are producing, while water is being injected into nine wells; see the field map in Appendix B. Two drilling rigs are expected to drill the remaining 16 wells during 2003 and 2004.



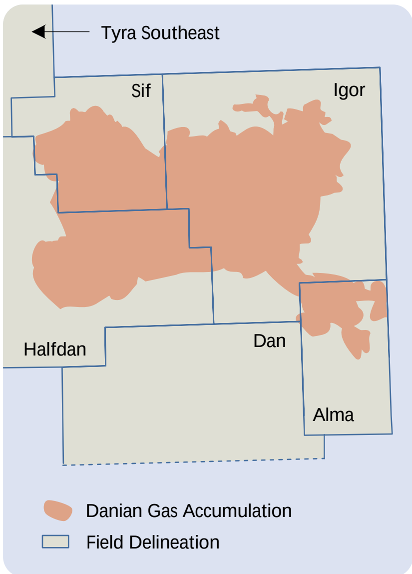
In May 2002, a new satellite platform, approx. 2 km north of the existing platform HDA, was installed when phase 3 of the Halfdan Field development was implemented. The new HBA platform can host 30 wells, and a total of 16 wells are planned to be drilled from this platform in phase 3. The platform includes a test separator for test production from single wells. In 2002, the test separator was used for two-phase separation of the production, so that gas and liquid were piped separately to Halfdan HDA and to the Dan and Gorm Fields for further processing. The HBA platform receives injection water, lift gas and electric power from the HDA platform.

During phase 3 of the Halfdan development, additional processing equipment will also be installed on the Halfdan HDA platform, including separation equipment, purification equipment for produced water and gas-treatment and compression equipment. Furthermore, a 32-person accommodation platform and a gas flare stack will be installed, both with bridge-connection to the HDA platform. The new equipment is scheduled for installation in mid-2003.

The Halfdan Northeast Area

In recent years, appraisals based on data from new wells, including the G-3X, and

Fig. 2.4 Halfdan Northeast – Danian Gas Accumulation



other data have been carried out in the area northeast of the Halfdan Field; see the section on *Exploration*.

The area contains a gas reservoir that covers large parts of the area north of the Dan Field, including the Sif and Igor accumulations and parts of the Halfdan Field. The reservoir may also extend across the Alma field delineation. Collectively, this area is called Halfdan Northeast; see Fig. 2.4.

In December 2002, the Danish Energy Authority received a development plan for Halfdan Northeast. The plan involves phased development, with the later phases being contingent upon gas sales and other factors. According to this plan, the first development phases for this area will be implemented from the HBA satellite platform at the Halfdan Field, from where the gas is planned to be conveyed to Tyra West through a 24" pipeline.

The Svend Field

In late 2001, the Svend-6 well was drilled as an appraisal well in the northern part of the field; see the field map in Appendix B. Production from the well commenced in May 2002. The well did not demonstrate the presence of further reserves in the Svend Field.

The South Arne Field

In connection with the implementation of the development plan for this field, the drilling of development wells in the field continues. In 2002, two new injection wells and one new production well were drilled. The current development phase comprises the drilling of up to nine new wells.

One of the injection wells was drilled in the southwestern part of the South Arne Field in order to improve production from this area. The other injection well was drilled in the northwestern part of the field, while a production well was drilled in the northeastern area.

Water injection in this field continues to produce good results. In 2002, the operator, Amerada Hess ApS, focused on continued injection of large water volumes into the chalk reservoir. The purpose of maintaining the reservoir pressure and flooding the oil-bearing layers is to ensure that oil output from this field continues to approximate the platform's maximum processing capacity.

In the coming years, more wells are expected to be drilled in the field, both for production and for water-injection purposes.

The Tyra Field

At Tyra West, a new purification plant for produced water was commissioned in 2002. The purification technology used is based on hydrocyclonic treatment.

Further in 2002, reinforcement works were carried out for certain parts of the load-bearing steel structures of the Tyra West platforms. This was necessitated by the heavier waveloading that results from continued subsidence of the seabed above the reservoir.

The Tyra Southeast Field was brought on stream in 2002; see below. This involved a number of tie-in works at Tyra East, where Tyra Southeast's production is processed.

The Tyra Southeast Field

New data from a series of wells in 2001 led to an updated plan for the development of the area southeast of the Tyra Field. The plan involves the drilling of up to six production wells.

In autumn 2001, a STAR-type platform with simple production facilities was installed at the field. The production is separated at the field into a gas phase and a liquid phase for piping to existing facilities at Tyra East for further processing.

Production from the Tyra Southeast Field commenced in March 2002. During 2002, five wells in the area came on stream, four of which were drilled in 2002. Experience with production from the area has been disappointing.

The Valdemar Field, the North Jens Area

In September 2002, the Danish Energy Authority approved a plan for further development of the North Jens Area in the Valdemar Field. The plan involves drilling two horizontal appraisal and production wells, both in the Upper Cretaceous oil zone. The drilling of these wells is scheduled for the beginning of 2003.

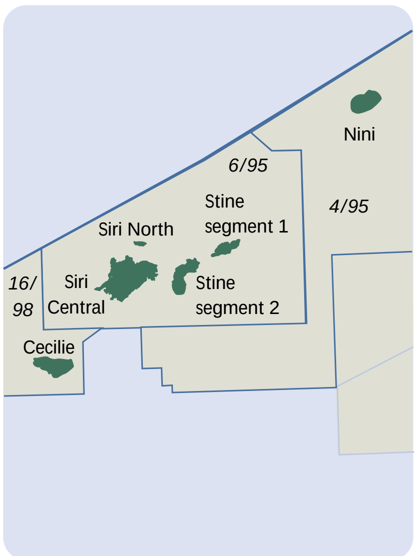
New Pipeline for Exporting Gas

In 2002, the Danish Energy Authority considered two applications to establish a new pipeline for exporting gas from the Danish sector of the North Sea to the European Continent. In spring 2003, the Authority approved a new 26” gas pipeline from the Tyra West E platform to the F/3 platform in the Dutch sector. From there, gas will be conveyed through the existing NOGAT pipeline to the Netherlands. The new pipeline, with a capacity of 15 million Nm^3/day, will be owned by DONG (50%), Shell (23%), A.P. Møller (19.5 %) and Texaco (7.5%) and operated by Mærsk Olie og Gas AS.

NEW FIELDS

In 2002, development plans were approved for a number of new fields in the Siri Fairway, where the reservoir rock is sandstone. The existing platform at the Siri Field plays a major part in the development of this area; see Fig. 2.5.

Fig. 2.5 Field Development in the *Siri Fairway*



The Siri Field

As the first field in this area, the Siri Field was brought on stream in 1999. Since then, production has been initiated from another oil reservoir located within the Siri Field, Stine segment 2; see the field map in Appendix B. The development of this area was implemented from the platform at Siri Central.

In August 2002, DONG E&P A/S took over the operatorship of the Siri licence after Statoil Efterforskning og Produktion A/S.

Tie-in of the Nini and Cecilie Fields

The tie-in of the two future fields, Nini and Cecilie, see below, involves alteration and expansion of the Siri platform facilities. A number of preliminary works were carried out in 2002.

The production from the Nini and Cecilie Fields will be conveyed to the Siri platform. According to plans, the gas and water production from these fields is to be injected into the Siri Field. This is meant to help enhance oil recovery from the Siri Field. Injection water and lift gas for Nini and Cecilie will be supplied from the Siri platform.

Stine segment 1
In 2002, the Danish Energy Authority approved a development plan for Stine segment 1, situated east of Siri Central. The development of Stine segment 1 provides for a subsea installation comprising a production well and an injection well. A pipeline will convey the production to the Siri platform for processing, storage and further transportation, while injection water and lift gas will be supplied from the Siri platform.

Stine segment 2
In 2001, the SCA-7 appraisal well for Stine segment 2 was drilled from the Siri platform. After the completion of a test production run, the well was subsequently put on stream. Oil production from the well has been higher than expected, while water production has been lower.

In 2002, DONG E&P A/S subsequently applied for approval of a plan to develop the segment further. Among other things, the approved plan involved drilling a delineation well to obtain data on such parameters as oil volume and reservoir pressure. Data collected from this well were to form the basis for a decision on whether to develop segment 2 further by drilling additional development wells.

In November 2002, DONG E&P A/S drilled the planned delineation well, the Siri-5, which extended into the southern part of the segment. On the basis of the well results, another horizontal production well, the SCA-6, will be drilled in segment 2 in early 2003.

Concurrently, the Danish Energy Authority granted permission to use water injection in Stine segment 2. The need for and possibility of maintaining the reservoir pressure by injecting water will be evaluated on an ongoing basis. This may involve converting production wells into injection wells at a later stage.

The Nini and Cecilie Fields
DONG E&P A/S also operates two adjacent licences in the Siri Fairway. In 2000, the drilling of exploration wells in this area led to the discovery of two new oil accumulations, Nini and Cecilie. Plans for the development and production from the two new fields were approved in June 2002.

Because the estimated reserves in the Nini and Cecilie Fields are limited, the fields will be developed as satellites to the Siri platform. The production from these fields will be conveyed to the Siri platform for processing, storage and further transportation.

The development of the Nini Field includes installing an unmanned platform and drilling up to seven wells. The Cecilie Field will also be provided with an unmanned platform and up to eight wells. A helideck will be installed on both platforms, and each platform can accommodate up to ten wells. In both fields, production is based on injecting water into the reservoir in order to maintain the pressure. The Nini and Cecilie Fields are expected to come on stream in summer 2003. At the end of 2002, the construction of platforms and pipelines was well underway. Their installation is scheduled for spring 2003.

FUTURE FIELDS
The development of a number of minor fields, viz. Adda, Alma, Amalie, the Boje area, Elly and Freja, is planned for the coming years. Details about the fields, including planned commissioning dates, are available from the Danish Energy Authority's website at www.ens.dk.

3. PRODUCTION

OIL PRODUCTION IN 2002

Danish oil production rose to 21.5 million m^3 in 2002. This is Denmark's highest annual oil output to date and a 6% increase over the year before. Compared to the record-high year of 2000, however, the increase is just under 2%.

The fact that several of the fields were able to maintain a normal production level throughout the year contributed significantly to this increase. However, it should be taken into account that production from a number of fields was temporarily suspended or reduced in 2001 in the aftermath of the Gorm Field incident.

The record oil production seen in 2002 is mainly due to a marked increase in production from the Halfdan Field. During the last two years, the Halfdan Field has moved into another league, ranking only second to the Dan Field, which continues to be the Danish field with the highest oil production.

Over the last five years, Danish oil production has grown by 61%. This remarkable growth means that the total volume of oil produced in the last six years equals the combined output from the first 25 years of oil production in Denmark; see Fig. 3.1.

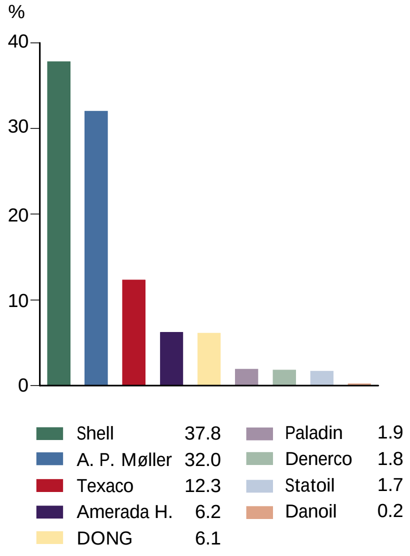
In 2002, the average daily oil production was just under 59,000 m^3, enough to fill a tank with a base area the size of a large football field (105 x 68 metres) and a height of approx. 8 metres.

At the end of 2002, oil was produced from a total of 17 fields; see Fig. 3.4. The vast majority of the oil produced in 2002 came from the following six fields: Dan, Gorm, Halfdan, Siri, Skjold and South Arne. Collectively, these fields accounted for 86% of Danish oil production.

The oil produced in the 15 fields operated by Mærsk Olie og Gas AS is conveyed through a pipeline to receiving facilities in Fredericia. The oil from the South Arne and Siri Fields, operated by Amerada Hess ApS and DONG E&P A/S, respectively, is loaded into tankers at the fields.

Fig. 3.1 Oil Production 1972-2002

Fig. 3.2 Breakdown of Oil Production by Company



The production from the fields is distributed to the companies having shares in the individual licences. A list of all groups of companies with a licence to explore for and produce oil and gas in Denmark may be seen at the Danish Energy Authority's website www.ens.dk. This list of licensees is continuously updated.

In 2002, nine companies received and sold oil and natural gas from the Danish fields. Fig. 3.2 shows each company's percentage contribution to total oil production in 2002. As in preceding years, production continued to be dominated by the Shell, A.P. Møller and Texaco companies, which accounted for a combined 82% of Danish oil production in 2002.

PRODUCTION OF NATURAL GAS

In 2002, 7.3 billion Nm^3 of natural gas was supplied to DONG Naturgas A/S from the North Sea fields, or 0.4% less than in 2001.

A total of 10.84 billion Nm^3 of natural gas was produced from the fields, 2.68 billion Nm^3 of which was reinjected, primarily into the Tyra Field, in order to boost oil production.

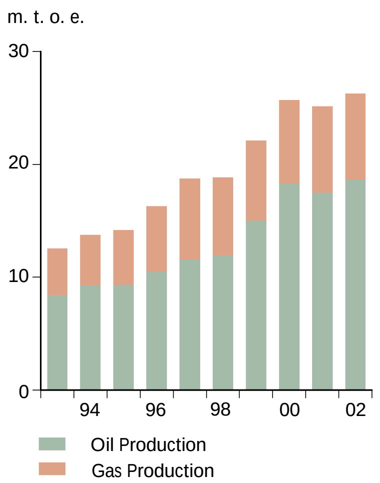
Net gas production, i.e. the volume of gas produced and consumed, is therefore 8.16 billion Nm^3. The difference between net gas produced and natural gas supplied (11% of net gas production) was either utilized as fuel or flared at the platforms. Flaring is carried out for technical and safety reasons. The section on *The Environment* provides a detailed description of gas flaring and fuel consumption.

WATER PRODUCTION

In addition to oil and gas, the fields also produce water. In recent years, the water content of the production has grown, so that today water makes up 51% of the total liquid production from all the fields.

Water injection into the fields has also been considerably stepped up over the last few years, as a large number of projects involving injection/high-rate injection have been implemented. Water injection is used to maintain the reservoir pressure and to flood the reservoir in order to boost recovery. At present, the total volume of water injected into the fields nearly equals the combined production of oil and water.

Fig. 3.3 Production of Oil and Natural Gas



PRODUCING FIELDS

Danish production of oil and gas started in 1972 with the commissioning of the Dan Field. In 1981, production from the Gorm Field was commenced, and up through the 1980s three additional fields, viz. Skjold, Tyra and Rolf, were brought on stream. They were followed by several new fields, so that, by the end of 2002, oil and gas were produced from a total of 17 fields. In 2003, production is planned to start up in two new fields, Nini and Cecilie.

Fig. 3.3 shows the development in Danish production of oil and gas in the period 1993-2002. 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.

Fig. 2.3 shows the existing production installations in the North Sea. They comprise 44 platforms, a subsea installation at the Regnar Field and two buoy loading facilities at the South Arne and Siri Fields.

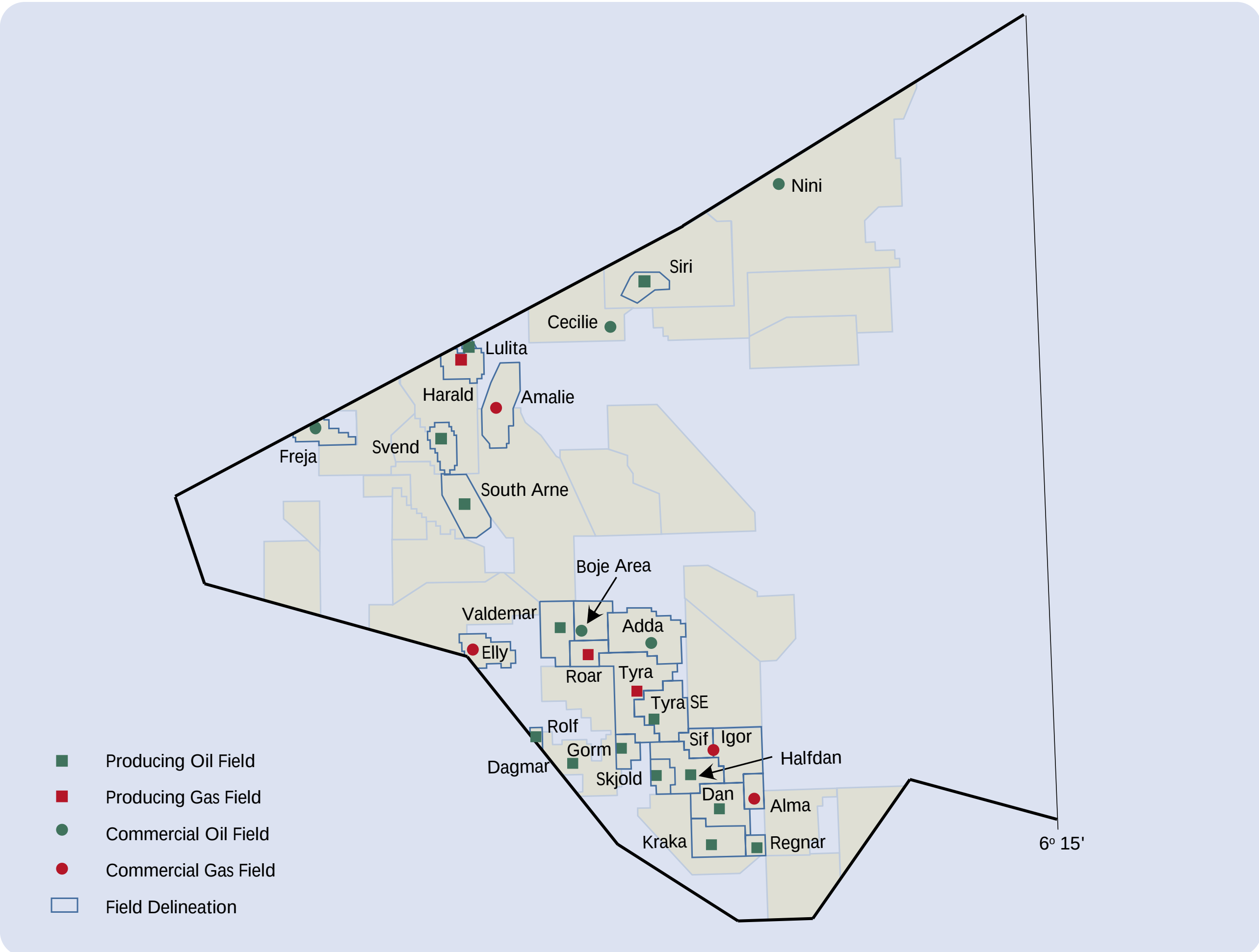
Appendix B provides a schematic overview of the producing oil and gas fields. Major production developments in 2002 are briefly outlined below.

The Dan Field

After 13 years of continuous growth in oil production from the Dan Field, production dropped approx. 600,000 m^3, or 9%, from 2001 to 2002. The Dan Field facilities have limited processing capacity. This makes it necessary to prioritize the fields whose production is processed at the Dan Field. The fall in production from the Dan Field is partly due to production from the Halfdan Field, which has a lower gas/oil ratio (GOR), being given higher priority than the Dan Field production. However, the Dan Field continues to be the Danish field with the largest oil production.

Since production was started in 1972, this field has yielded an overall 63.5 million m^3 of oil, or 30% of total Danish oil production.

Fig. 3.4 Danish Oil and Gas Fields



In volume terms, the field's water production equals its oil production. In 2002, the volume of water injected into the field to ramp up oil production exceeded the combined oil and water production.

High-rate water injection was used in large parts of the field. In addition, a plan was approved in 2002 for the application of high-rate water injection in a central area of the Dan Field; see the section on *Development*.

Three new wells were drilled in 2002 in the western flank of the Dan Field, towards the Halfdan Field. Another three wells in the area were converted to water injection in 2002. The production from new wells is somewhat higher than expected, which makes for a higher average production level. Total production from the Dan Field is estimated to have peaked.

The Gorm Field

Following an incident at the Gorm Field in May 2001, production was temporarily suspended. It was subsequently resumed, initially at a reduced rate, however. Throughout 2002, production was back to its normal level, and total oil production from the Gorm Field was therefore 32% higher than in 2001. Large volumes of water are produced in conjunction with the oil. In 2002, water production accounted for 58% of the total liquid production. The most recently drilled wells have performed better than expected. However, total production from the field is decreasing, albeit at a rate slower than expected.

The Halfdan Field

The establishment of new wells has considerably improved oil production from the Halfdan Field. In 2002, oil production from this field rose by 27% compared to 2001. To a certain extent, the processing capacity available at the Gorm and Dan Fields limits the production from the Halfdan Field. The plan is to overcome this limitation by installing additional processing capacity in 2003.

Recovery from the field is supported by water injection. In 2002, water injection was initiated in a number of wells, and large volumes of water are now being injected into the field. The water content of the liquid production was approx. 9% in 2002.

The Siri Field

In contrast to almost every other field in Denmark whose reservoir layers are situated in chalk, the Siri Field produces oil and gas from sandstone. The field's oil production fell by 16% in 2002 compared to 2001. At the same time, water production increased by 10%. The water content of the production now hovers around 67%.

The Skjold Field

The Skjold Field produced approx. 22% more oil in 2002 than in 2001. This was chiefly attributable to the exceptionally low production level in 2001 caused by the temporary suspension of operations following the Gorm Field incident. From a long-term perspective, however, production from this field is on the decline.

The South Arne Field

In recent years, the focus has been on more widespread use of water injection in the South Arne Field. As a result, more than twice the amount of water was injected into the reservoir in 2002 compared to 2001. The purpose of water injection is to reestablish the reservoir pressure. Combined with the production from new wells, use of this technique generated a 14% increase in oil production in 2002 over the preceding year.

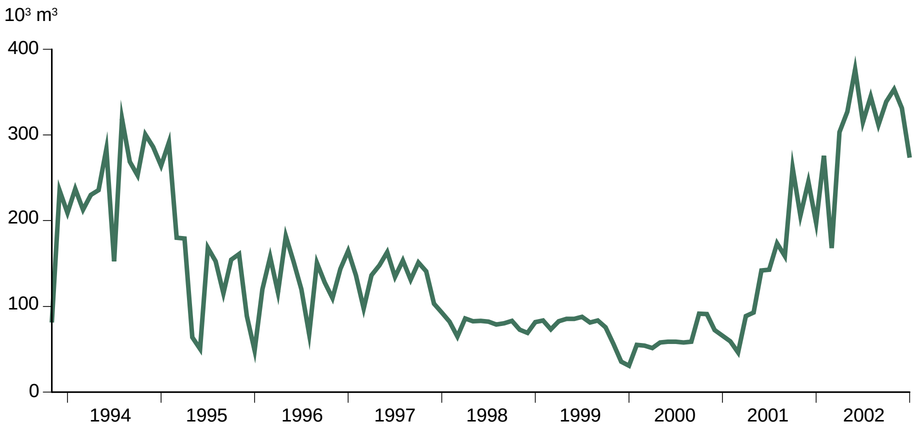
The Tyra Southeast Field

Production from the field was commenced in March 2002. After an initially high output level, the production rate fell dramatically, now lying significantly below estimates.

The Valdemar Field

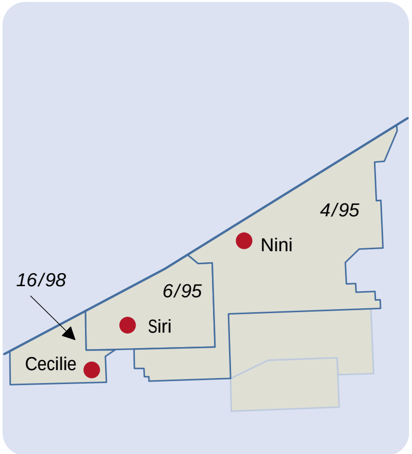
In 2002, the field achieved a monthly production in excess of 1,100 m^3, corresponding to just over 7,000 barrels per day, the highest output in the field's almost decade-long history; see Fig. 3.5. This performance rate is attributable to the drilling of two new wells in 2001, one in the Danian/Upper Cretaceous chalk and one in Sola-Tuxen. The latter well, in particular, shows encouraging production potential. Two additional wells are slated to be drilled in Danian/Upper Cretaceous chalk in 2003.

Fig. 3.5 Oil Production from the Valdemar Field



4. THE ENVIRONMENT

Fig. 4.1 EIA Target Area



EIA FOR OFFSHORE ACTIVITIES

It is a requirement for obtaining approval of offshore projects that applicants undertake an evaluation of how the planned activities will affect the environment, a so-called Environmental Impact Assessment (EIA).

EIAs must be submitted for development projects above a certain size. For projects that fall below the thresholds fixed for production volumes and pipeline dimensions, for example, a screening must first be carried out to determine whether an EIA is required.

In 2002, an Environmental Impact Assessment was prepared in connection with the approval for developing the Stine segment 1 area in the Siri Field and the Nini and Cecilie Fields. The EIA covers the development of licence areas 4/95, 6/95 and 16/98, where these fields are situated; see Fig. 4.1.

EIAs Trigger New Requirements

Generally, when production facilities are to be established and operated at new locations in the Danish sector of the North Sea, a requirement is usually made for the performance of surveys of bottom sediments and bottom fauna near the installations.

Such surveys include a base-line examination of conditions prior to the start-up of the offshore activities and a survey to assess the effects caused by the activity. The companies include the results of these surveys in the EIAs for their North Sea development projects.

As a result of the public hearings held in 2001 and 2002 on the new EIAs for the development of the Halfdan Field and of the Siri, Nini and Cecilie Fields, the Danish Energy Authority decided to stipulate a requirement for supplementary surveys in its development permits.

Surveys of Fish Fry and Fish Populations

The additional requirements stipulated in the Danish Energy Authority's development permits involve supplementary surveys to evaluate the importance of the areas concerned as spawning grounds for pelagic fish (species swimming in the ocean as distinguished from species living on the seabed) and surveys of the fish populations in the relevant North Sea areas.

Both Mærsk Olie and Gas AS, operator of the Halfdan Field, and DONG E&P A/S, operator of Siri, Nini and Cecilie, have planned scientific expeditions for 2003 in these areas to collect fish eggs and fish larvae and to catch fish specimens.

The purpose of the supplementary surveys is to learn more about the importance of these areas to North Sea fish populations and to improve the basis for assessing the impact of offshore activities on fish stocks.

Surveys of the Presence of Small Marine Mammals and Birds

Current scientific knowledge about small marine mammals and birds in the areas that are to be developed is based on general surveys of population levels and habitats for these animal species in the North Sea.

In addition, the oil companies operating in the North Sea have participated for several years in a project to map the occurrence of small marine mammals in the areas surrounding a number of the fixed offshore installations in the North Sea. The mapping is based on observations of the particular species reported to the Fisheries and Maritime Museum in Esbjerg.

The new requirements stipulated in the Danish Energy Authority's development permits also mean that scientifically based examinations must be undertaken to establish the extent to which the areas concerned are the physical habitats of various small marine mammals and birds.

COOPERATION UNDER THE OSPAR CONVENTION

The oil, gas and water brought to the surface from the reservoirs are processed at the installations. Before being discharged to the sea, the water produced undergoes treatment and purification to conform with the various standards applicable to such discharges.

The Danish Environmental Protection Agency lays down the requirements applying to marine discharges, which are based, among other things, on the results achieved in the international cooperative effort on implementing the Oslo-Paris Convention (OSPAR). This Convention covers the North-East Atlantic, including the North Sea. The main member states are Norway, Great Britain, the Netherlands, Germany and Denmark. The Danish Energy Authority assists the Danish Environmental Protection Agency in technical, health and safety matters relating to the OSPAR cooperation.

Further information on OSPAR may be obtained from www.ospar.org.

Substances Occurring Naturally in the Subsoil

OSPAR is conducting efforts to define target limits for the oil content in marine discharges of produced water. The oil occurs partly as non-dissolved oil drops (aliphates), partly as dissolved compounds (aromates).

The current threshold value for the concentration of non-dissolved oil (aliphates) in production water discharges is 40 mg/litre, measured at the individual discharge points. This threshold will be lowered to 30 mg/litre in 2006. The offshore industry accepts the stricter requirement, and compliance will probably not pose any major difficulties, since the average discharge concentration today is already less than 30 mg/litre.

A requirement has been adopted to reduce the total amount of oil discharged into the sea by at least 15% by 2006 compared to overall discharges in the reference year 2000. The Danish fields may have difficulty complying with this requirement, because they widely use the recovery method of injecting large amounts of water into the tight chalk reservoirs, which further increases the volumes of produced water that will need to be purified and disposed of.

On the issue of marine discharges of dissolved oil, concerted efforts are ongoing within the OSPAR framework. In March 2003, Denmark submitted a proposal for further work in this area under the Offshore Industry Committee (OIC). As a result of the OIC's discussion of this proposal, supplementary measurements of

Fig. 4.2 Fuel Consumption

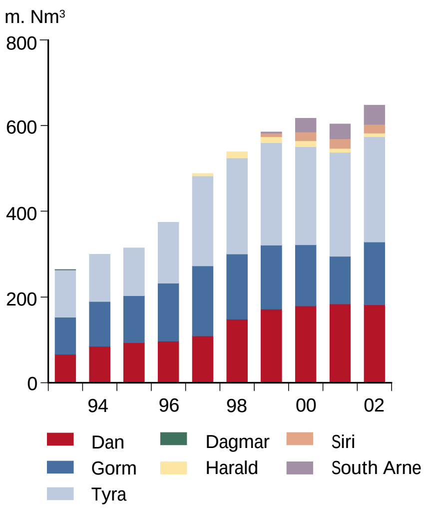


Fig. 4.3 Gas Flaring

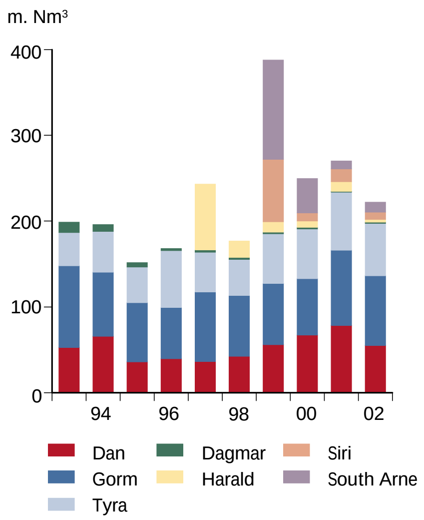
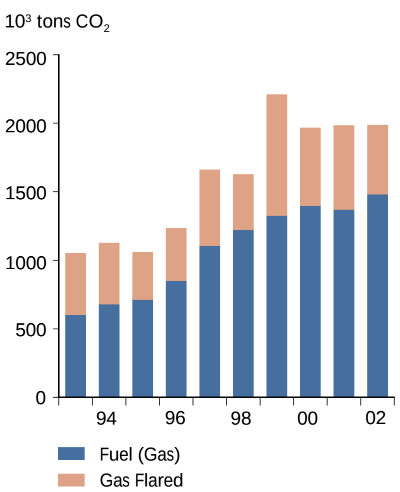


Fig. 4.4 CO_2 Emmisions from Production Facilities in the North Sea



actual discharge levels will be carried out in 2004 on a comparable basis. Using the data obtained, Denmark is then to
submit a specific proposal for the handling of aromatic compounds in discharged production water.

It should be mentioned that no thoroughly tested purification techniques for aromates are available to the offshore industry today. A major effort in this area therefore lies ahead, the scope of which depends on the requirements emerging from the OSPAR activities.

There is a continuing need for further developing techniques and equipment for purifying production water in step with the tightening of requirements for discharges into the sea. Treatment is also required for water disposed of by injection into the subsoil. Here, the necessary level of purification depends on such factors as the nature of the layers into which the water is injected. The techniques developed must be effective, but in order to be attractive to the offshore industry, they should also have documented reliability and cost-effectiveness.

Use of Chemicals on Offshore Installations

A wide range of chemicals is used on the North Sea offshore installations in the recovery and processing of oil and gas. Before any such chemical is delivered to the offshore installations, the operator must, via the manufacturer, document its composition and environmental hazards. Using this information, the operator must then obtain permission from the Danish Environmental Protection Agency to transport, use and, if relevant, discharge the chemical concerned.

CO_2 EMISSIONS FROM OFFSHORE INSTALLATIONS

Gas Used as Fuel and Gas Flaring

Producing and transporting oil and natural gas requires substantial amounts of energy. Furthermore, a sizable amount of gas that cannot be utilized for safety or technical reasons has to be flared.

Due to the consumption of gas for energy production purposes and gas flaring, the North Sea installations release CO_2 into the atmosphere. The volume emitted by the individual installation or field depends on the scale of production as well as on plant-related and natural conditions.

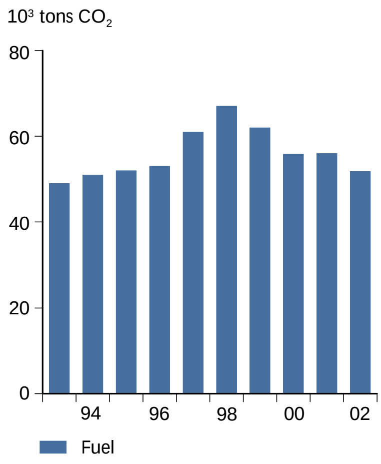
Gas consumed as fuel accounts for approx. three-fourths of the total volume of gas consumed and flared offshore.

The amounts of gas used as fuel in the processing facilities and the gas flared in the past ten years are illustrated by Figs. 4.2 and 4.3.

It appears from these figures that over the past decade, rising production and the general ageing of the fields have escalated the use of gas as fuel on the Danish production facilities in the North Sea. The volume of gas flared was considerably above average in 1999 due to problems in connection with the commissioning of the new production facilities at Siri and South Arne.

From 2001 to 2002, the amounts of gas flared dropped by some 50 million Nm^3, or about 20%. The main reason for this decline was the normalization of operations, particularly at the Dan Field, after the Gorm Field incident in May 2001.

Fig. 4.5 CO_2 Emissions from Consumption of Fuel per m. t.o.e.



In 2002, flaring in the South Arne Field remained at the same low level as the year before, while flaring in the Siri Field declined significantly compared to 2001. This decrease is attributable to the normalized operation of the Siri gas compressors, which caused a great deal of problems in 2001.

CO_2 Emissions in 2002

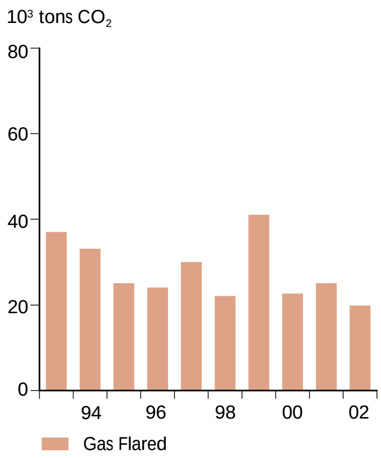
The development in the emission of CO_2 from the North Sea production facilities since 1993 appears from Fig. 4.4. This figure shows that total CO_2 emissions in 2002 amounted to about 2.0 million tons, the same as in 2001. The production facilities in the North Sea account for about 3-4% of total CO_2 emissions in Denmark.

Fig. 4.5 shows the development in CO_2 emissions associated with the consumption of fuel, relative to the volume of hydrocarbons produced.

It appears from this figure that CO_2 emissions due to fuel consumption, relative to the size of production, peaked in 1998 at 67,000 tons of CO_2 per million t.o.e. Since then, emissions have gradually decreased to about 50,000 tons of CO_2 per million t.o.e., the same level as ten years ago.

Fig. 4.6 shows that emissions of CO_2 from gas flaring relative to the size of production have declined steadily since the early 1990s, except in 1997 and 1999 when the commissioning of the Harald, Siri and South Arne facilities resulted temporarily in extraordinary amounts of gas being flared. Thus, in 2002, gas flaring relative to the volume of production reached the lowest level recorded in the past decade.

Fig. 4.6 CO_2 Emissions from Gas Flaring per m. t.o.e.



Relative to the scale of production, the Danish sector of the North Sea has many production facilities. All things being equal, this limits the possibility of improving energy efficiency and thus reducing the CO_2 emission per produced t. o. e. However, the choice of technical equipment also plays a pivotal role for the energy efficiency of the facilities and the need for flaring. The Danish Energy Authority is currently reviewing the scope for further improvement of the energy efficiency and reduction of gas flaring at the North Sea production facilities, as part of an overall climate strategy.

5. HEALTH AND SAFETY

Safety on board offshore installations in the North Sea has a major impact on employees' health and welfare. Moreover, a safety flaw may have profound financial consequences for the oil companies. The accident in the Gorm Field in 2001 meant that two persons suffered minor burns. The accident also cost more than DKK 1 billion in lost oil and gas production.

The companies exploring for 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. In this context, statutory requirements impose a duty on the companies to set up systems for managing and controlling health and safety on board the installations.

ACTION PLAN FOR FOLLOW-UP ON SINTEF REPORT

The gas explosion in the Gorm Field in May 2001 triggered criticism about the safety conditions in the field. As a result of this criticism, the Norwegian SINTEF institute was asked to investigate the safety conditions on board the Gorm Field installations. SINTEF submitted its report in August 2002. The incident is described in "Oil and Gas Production in Denmark 2001".

SINTEF concludes that since the explosion in May 2001, many measures have been taken to tighten safety precautions. However, after its review, SINTEF could still point to areas where the operator, Mærsk Olie og Gas AS, can improve conditions. The report and the operator's comments are available at the Danish Energy Authority's website www.ens.dk.

The Government prepared an action plan based on the recommendations made in the SINTEF report for improving safety in the Gorm Field. This action plan consists of seven points, see Box 5.1, that follow up on the report's recommendations regarding the Gorm Field and other Danish offshore installations.

The various measures in the action plan aim to spur on oil companies to improve health and safety at work on North Sea oil and gas installations. As an element in the action plan, the Danish Energy Authority will intensify its supervision of health and safety issues on board offshore installations from 2003 and onwards.

Another element is to review the rules regarding health and safety at work on offshore installations. Together with representatives of the offshore industry and other public authorities, the Danish Energy Authority has drawn up a plan for this work, aimed at easing the administrative burdens for offshore companies. The rules and guidelines envisaged by the plan are now being prepared.

ESCAPE OF CHEMICALS IN THE DAN FIELD

On 22 December 2002, sodium hydrogen sulphite was accidentally released at the Dan FF platform. As a result, the Admiral Danfleet Headquarters had to airlift 12 persons by helicopter to Esbjerg Hospital. The incident occurred when a pipe section in the water-injection system was being replaced. The chemical escaped from the system due to faulty operation of the valves meant to seal off the relevant pipe section from the remaining system. Consequently, the persons working close to the point of leakage had varying exposure to the chemical.

Box 5.1 The Seven-Point Action Plan

1. Follow-up on all 35 recommendations in the SINTEF report.

2. Before the end of December 2002, the Danish Energy Authority will have completed extraordinary inspection visits to all manned production facilities.

3. In 2003, the Danish Energy Authority will make routine inspection visits to all manned and unmanned production facilities. The Authority will also make inspection visits to mobile installations operating on the Danish continental shelf for more than one year. From 2004, the inspection frequency for all manned installations will be double that of 2002.

4. Before summer 2003, the Danish Energy Authority will perform a systematic audit of the operators' (Mærsk Olie og Gas, Amerada Hess and DONG E&P) safety management systems and similar systems.

5. The Danish Energy Authority will review the safety analysis for the Gorm Field, and will use this review as a basis for reviewing the safety analyses for the other fields. The entire review will be completed before the end of 2003.

6. The Danish Energy Authority will investigate whether the operators' registration and treatment of accidents and dangerous occurrences meet the recommendations of the SINTEF report. This work will be completed by 1 May 2003.

7. In close cooperation with the two sides of industry and within the framework of the Coordination Committee, efforts to update and improve the efficiency of rules and regulations in the offshore area have been initiated. The guidelines for the design of the fixed installations in the North Sea will be updated to ensure that they are adequate and contemporary. The work on such rules and regulations is expected to be completed before the end of 2003.

Box 5.2 Accidents by Category

- The victim falls, slips or trips over objects
- Crush injury
- Poisoning
- Use of tools
- Falling objects
- Other

Sodium hydrogen sulphite is used as an oxygen scavenger. The scavenger is added to the injection water to remove the oxygen from the water and thus protect the piping against corrosion. Sodium hydrogen sulphite involves a health risk and acts as a local irritant, as it emits sulphur dioxide, which is toxic. Persons who have inhaled or consumed sulphur dioxide need medical attention, as at worst they may suffer pulmonary oedema.

Both the operator, Mærsk Olie og Gas AS, and the Danish Energy Authority reacted to the incident immediately by sending an investigation team and an inspector, respectively, to the scene of the incident. The condition of the 12 exposed persons was also closely monitored. The incident was considered serious because of the potential injury to several poisoned persons. The impact on the environment and production was marginal.

In the course of 24 December, it became evident that the extent of personal injury was limited to temporary discomfort during the escape and for the next couple of days, and on 26 December all 12 persons were fit for work again.

In agreement with the Danish Energy Authority, Mærsk Olie og Gas AS has subsequently changed its procedures and work routines to ensure that a similar situation does not reoccur.

Mærsk Olie og Gas AS' report on the incident and the Danish Energy Authority's inspection report can be viewed at the Danish Energy Authority's website www.ens.dk.

PERSONAL INJURIES ON OFFSHORE INSTALLATIONS

In keeping with applicable legislation, the Danish Energy Authority receives reports on work-related accidents, work-related diseases and situations that might have resulted in an accident, so-called dangerous occurrences, on offshore installations. Accordingly, personal injuries resulting in an incapacity for work for one or more days beyond the injury date must be reported to the Danish Energy Authority. Personal injuries are defined as accidents and poisoning resulting in injury.

On an annual basis, the Danish Energy Authority normally receives about 20 notifications of such work-related accidents. The number of reported cases of work-related diseases and dangerous occurrences varies, but is generally lower.

In 2002, the number of work-related accidents reported increased for both fixed production installations and mobile offshore units.

Table 5.1 Absence due to Accidents on Fixed Offshore Installations, 2002

Duration	No. of reports
1-3 days	4
4-14 days	16
2-5 weeks	6
More than 5 weeks	3
Undisclosed	1

Work-Related Accidents

In 2002, the Danish Energy Authority received 52 reports on work-related accidents, of which 30 occurred in connection with the operation and maintenance of fixed production installations and on board accommodation units. The remaining 22 accidents occurred on other mobile installations, comprising drilling rigs, pipe-laying barges, crane barges and vessels carrying on exploration and production activities. None of the accidents reported in 2002 were fatal.

The accidents can be broken down by category, as shown in Box 5.2.

Table 5.2 Absence due to Accidents on Mobile Offshore Units, 2002

Duration	No. of reports
1-3 days	3
4-14 days	7
2-5 weeks	6
More than 5 weeks	3
Undisclosed	3

Of the 30 accidents on fixed production installations, ten were caused by the victims tripping or falling while going about their daily routines on board the installations, six by the victims suffering a crush injury, three by poisoning, four by the use of tools, one by lightning, while six can be attributed to other causes. Of the 12 persons evacuated from the Dan Field after being exposed to sodium hydrogen sulphite, only one person is included in these statistics, as the rest were not injured in the sense of the law.

The expected periods of absence from work on fixed installations are indicated in Table 5.1, and are based on figures reported by operators.

All 22 accidents on mobile offshore units occurred on drilling rigs. Table 5.2 shows the periods of absence from work expected for mobile offshore units, based on figures reported by the oil companies.

Accident Frequency

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

The companies operating in the Danish sector of the North Sea in 2002 have stated that the number of working hours totalled 3.22 million for fixed production installations and associated accommodation units, while the comparable figure is 2.46 million working hours for mobile offshore units.

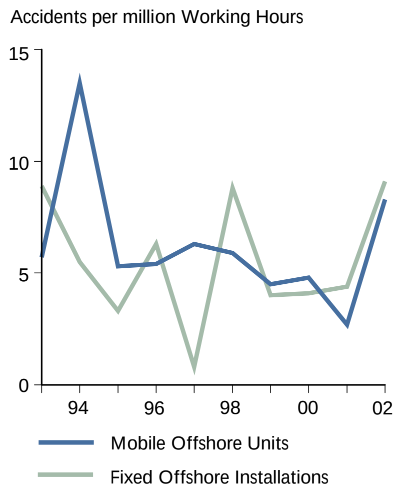
Thus, in 2002, the accident frequency was 9.1 per million working hours for fixed production installations and accommodation units, and 8.9 per million working hours for mobile offshore units.

Fig. 5.1 shows the annual accident frequency for the past ten years. When related to the accident frequency for comparable industries onshore, the accident frequency offshore continues to be low.

Development in Work-Related Accidents

From 2001 to 2002, the number of work-related accidents on fixed production installations rose from 18 to 30, which corresponds to an increase in accident frequency from 4.0 to 9.1.

Fig. 5.1 Accident Frequency on Offshore Installations



On mobile offshore units, the number of work-related accidents also increased from 2001 to 2002. In 2001, the Danish Energy Authority received reports on seven work-related accidents, as compared to 22 reports in 2002.

The Danish Energy Authority has asked the involved operators in the North Sea to give an account of this increase in accident frequency, and particularly of the reasons. In addition, the Danish Energy Authority will focus on accident prevention as part of its intensified supervision in 2003.

The number of accidents on offshore installations is low, and is therefore subject to great statistical uncertainty. It is not possible to conclude on the basis of the figures alone whether the increased number of accidents is attributable to an actual decrease in safety level.

The breakdown of work-related accidents by category has not changed from previous years. Nor has any substantial change occurred in the breakdown of the expected periods of absence reported for fixed offshore installations. The majority of work-related accidents in 2002 resulted in between one and 14 days of absence from work.

Work-Related Diseases

In 2002, the Danish Energy Authority received a total of 12 reports of suspected or diagnosed work-related diseases that were attributable to work on an offshore installation.

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

Dangerous Occurrences

In 2002, the Danish Energy Authority received a total of six reports on dangerous occurrences on offshore installations, of which five can be attributed to fixed production installations.

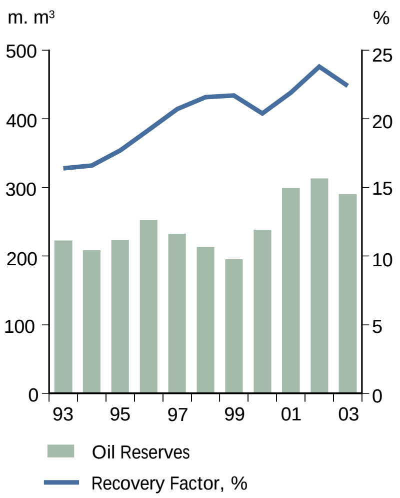
On fixed production installations, all the dangerous occurrences are due to disregard of safety procedures, which also applies to the dangerous occurrence reported for mobile offshore units.

In addition, the Danish Energy Authority has received a total of 55 reports regarding gas leaks in processing piping.

As part of the Government's action plan for follow-up on the SINTEF report, the Danish Energy Authority has launched an investigation into the oil companies' registration and analysis of dangerous occurrences. The aim of this investigation is to provide the companies with data clarifying the underlying reasons for the occurrences, and thus to prevent repetitions. Concurrently, the Danish Energy Authority is preparing to introduce a uniform practice for reporting dangerous occurrences.

6. RESERVES

Fig. 6.1 Oil Reserves and Recovery Factor



An assessment of Danish oil and gas reserves is made annually by the Danish Energy Authority.

The Danish Energy Authority's assessment at 1 January 2003 shows a decline in oil and gas reserves of 7% and 9%, respectively, compared to the assessment made at 1 January 2002. This decrease is mainly attributable to production in 2002. Oil reserves have been estimated at 290 million m^3 and gas reserves at 129 billion Nm^3.

The overall oil recovery factor, i.e. the ratio of ultimate recovery to total oil in place, fell from 24% to 22% relative to the year before; see Fig. 6.1. This decline is mainly due to a write-up of the oil in place in the Halfdan Northeast accumulation.

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 13, meaning that oil production is calculated to be sustainable at the 2002 level for the next 13 years. As the R/P ratio was 15 according to last year's assessment, this year's figure is slightly lower than the year before.

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. 6.5 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 oil 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 6.1.

Table 6.1 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, for a large number of fields, the total assessment of reserves should be based on the expected value.

Box 6.1 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.

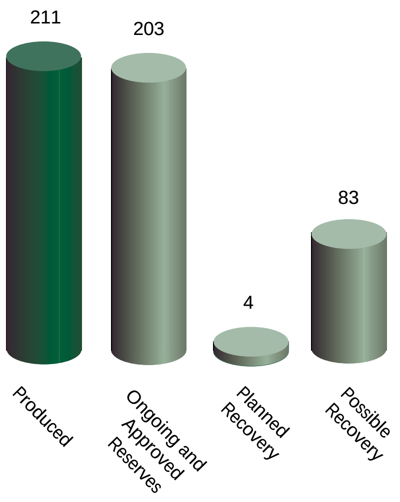
For discoveries for which a declaration of commerciality has not yet been filed, the recoverable reserves are categorized as possible recovery. This category also includes recovery from discoveries considered to be non-commercial.

Table 6.1 Production and Reserves at 1 January 2003

	OIL, million m^3				GAS, billion Nm^3			
	Ultimate Recovery				Ultimate Recovery			
	Produced	Reserves			Produced	Reserves		
		Low	Exp.	High		Low	Exp.	High
Ongoing and Approved Recovery:								
Adda	-	1	1	1	-	0	0	1
Alma	-	0	1	1	-	1	1	2
Boje Area	-	1	1	1	-	0	0	0
Cecilie	-	3	4	5	-	-	-	-
Dagmar	1	0	0	0	0	0	0	0
Dan	64	30	55	81	18	2	7	12
Elly	-	0	1	1	-	2	5	7
Gorm	45	8	11	14	6	1	1	2
Halfdan	8	41	69	99	2	4	7	11
Harald	6	1	2	3	14	4	6	9
Kraka	4	1	2	3	1	0	1	2
Lulita	1	0	0	0	0	0	0	0
Nini	-	3	4	6	-	-	-	-
Regnar	1	0	0	0	0	0	0	0
Roar	2	0	1	2	10	4	7	10
Rolf	4	0	1	1	0	0	0	0
Siri	7	3	4	5	-	-	-	-
Skjold	34	6	11	16	3	0	1	2
Svend	5	1	1	2	1	0	0	0
South Arne	8	*	24	*	2	*	8	*
Tyra	20	3	6	9	33	23	27	31
Tyra Southeast	0	2	3	4	0	6	9	11
Valdemar	2	2	2	3	1	1	2	4
Subtotal	**211**		**203**		**92**		**82**	
Planned Recovery:								
Amalie	-	*	2	3	-	*	3	5
Freja	-	1	1	2	-	0	0	0
Halfdan Northeast	-	1	1	2	-	7	15	24
Subtotal			**4**				**19**	
Possible Recovery:								
Prod. fields	-	31	62	94	-	4	8	11
Other fields	-	1	2	3	-	5	10	15
Discoveries	-	7	19	43	-	3	11	22
Subtotal			**83**				**28**	
Total	**211**		**290**		**92**		**129**	
January 2002	190		313		84		141	

** Not assessed*

Fig. 6.2 Oil Recovery, m. m³



It appears from Fig. 6.2 that the expected amount of oil reserves ranges from 207 to 290 million m^3. The difference between the two figures, 83 million m^3, equals the reserves in the possible recovery category. The reserves assessed for the planned and possible recovery categories, respectively, reflect the increasing uncertainty as to whether such reserves can be exploited commercially.

Likewise, Fig. 6.3 illustrates that the expected amount of gas reserves ranges from 101 to 129 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%) represents the amounts consumed or flared on the platforms in the production process.

There have been several revisions of the Danish Energy Authority's assessment of reserves compared to the assessment made in January 2002. 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 2002 included the reserves recoverable from the development of the Boje area and the Cecilie and Nini Fields, based on the development plans submitted for these fields. These plans were approved in 2002, and the pertinent reserves have therefore been included under ongoing and approved recovery.

Production experience has led the Danish Energy Authority to write down the reserves of the Harald and Tyra Southeast Fields.

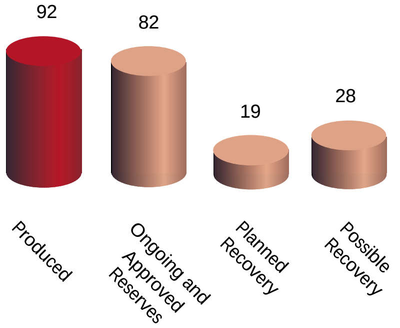
The Danish Energy Authority has written up the reserves of the Dan Field, as a plan for its further development was approved in December 2002.

The Halfdan and Dan Fields are estimated to have the largest oil reserves in this category, and the reserves of the Halfdan Field alone account for one-third of the category's total reserves.

Planned Recovery

In December 2002, a plan was submitted for exploiting the Halfdan Northeast gas accumulation in the Igor, Sif and Halfdan Fields. The Danish Energy Authority is currently reviewing this plan, for which reason the reserves of this accumulation have been included in the planned recovery category. The plan replaces the plans previously submitted for the Igor and Sif Fields.

Fig. 6.3 Gas Recovery, bn. Nm³

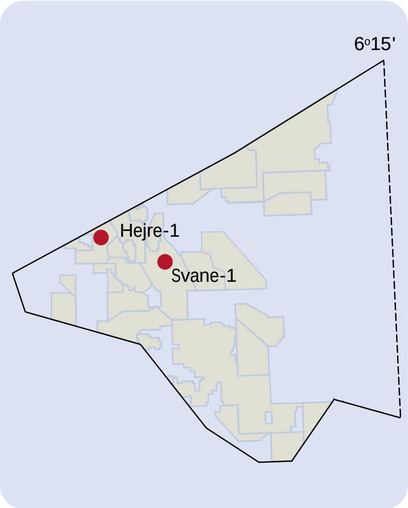


Possible Recovery

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 the recoverable oil reserves can be augmented by implementing water-injection projects in a number of fields.

Fig. 6.4 Discoveries under Appraisal



The drilling of horizontal wells is considered to further increase the production potential of the Boje area, Halfdan Northeast and Valdemar.

Finally, discoveries that are under appraisal are included in this category, e.g. Hejre; see Fig. 6.4. The contribution from the Svane discovery has not been included. This category also includes discoveries that are considered to be non-commercial based on current technology and prices.

On average, the overall recovery factor for all Danish fields and discoveries is about 22%. In fields like Dan, Gorm and Skjold, where the production conditions are favourable, an average recovery factor of 38% 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 20 years, respectively.

Five-Year Production Forecast

The five-year forecast uses the same categorization as the assessment of reserves, and includes only the categories ongoing, approved, and planned 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 6.2. The oil production forecast shown in this table illustrates the planned course of production, and the total production figure shows an increasing trend until 2004, after which production is expected to decline. For 2003, oil production is expected to total 21.9 million m^3, equal to about 378,000 barrels of oil per day.

In relation to last year's forecast, expected production figures have generally been written down for the five-year period covered by the forecast. The largest downward adjustment of production figures, about 11%, has been made for 2003, which is chiefly attributable to the writedown of reserves for the Tyra Southeast and South Arne Fields.

The operational and processing capacity available limits production from the Halfdan Field. Consequently, production estimates for 2003 have been written down because full-scale production has been postponed.

Moreover, the production estimates for 2003 have been written down because the Cecilie and Nini Fields will be put on stream later than originally planned.

In the forecast made in January 2002, the planned recovery category included expected production from the development of the Boje area, Cecilie, Nini, Igor and Sif. The development of the Boje area, Cecilie and Nini was approved in June 2002, and the contribution from these fields has now been included in the ongoing and approved recovery category. In December 2002, a plan was submitted

Table 6.2 Oil Production Forecast, million m³

	2003	2004	2005	2006	2007
Ongoing and Approved:					
Adda	-	-	0.5	0.1	0.0
Alma	-	-	-	-	0.1
Boje Area	-	-	0.4	0.2	0.1
Cecilie	0.2	1.0	0.9	0.8	0.5
Dagmar	0.0	0.0	0.0	0.0	0.0
Dan	6.8	6.4	5.8	5.5	4.6
Elly	-	-	-	-	0.2
Gorm	2.7	1.9	1.5	1.2	1.0
Halfdan	4.4	6.1	6.0	5.7	5.3
Harald	0.4	0.3	0.3	0.2	0.2
Kraka	0.2	0.2	0.1	0.1	0.1
Lulita	0.0	0.0	0.0	0.0	0.0
Nini	0.2	1.1	1.1	0.9	0.6
Regnar	0.0	0.0	0.0	0.0	0.0
Roar	0.2	0.2	0.1	0.1	0.1
Rolf	0.1	0.1	0.1	0.1	0.1
Siri	0.9	1.0	0.7	0.3	0.2
Skjold	1.6	1.2	1.0	0.9	0.9
Svend	0.4	0.3	0.2	0.2	0.1
South Arne	2.3	2.5	2.4	2.2	2.0
Tyra	0.8	0.7	0.7	0.6	0.5
Tyra Southeast	0.3	0.5	0.3	0.3	0.2
Valdemar	0.3	0.3	0.3	0.3	0.3
Subtotal	**21.9**	**23.9**	**22.5**	**19.5**	**17.3**
Planned:	**0.0**	**0.1**	**0.5**	**0.4**	**0.4**
Expected:	**21.9**	**24.0**	**22.9**	**19.8**	**17.7**

for exploiting the Halfdan Northeast gas accumulation in the Igor, Sif and Halfdan Fields, as mentioned above. The Danish Energy Authority is currently considering this plan. By 2005, Halfdan is expected to be the field producing the most oil, accounting for a 25% share of total production.

Production experience has led to a write-up of the estimated production from the Siri Field for the period covered by the forecast. In addition, the production expected from the development of Stine segment 1 in the Siri Field has been included in the forecast. The development of this area was approved in June 2002. The forecast also includes the production expected from the development of Stine segment 2, approved in October 2002.

The production estimate for the South Arne Field has been adjusted to reflect the recent plans for further development of the field. The Tyra Southeast Field came on stream in March 2002, and in light of production experience, the production estimate has been written down compared to last year.

In July 2002, the Danish Energy Authority granted an application to postpone the commissioning of the Alma and Elly Fields until 1 January 2007, and the production expected from these fields has been adjusted accordingly.

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

Natural gas production estimates are given in Fig. 6.5, broken down by processing centre.

As mentioned in the section on *Development*, in March 2003 the Danish Energy Authority approved the establishment of a natural gas pipeline for exporting gas from Tyra to the European Continent. The investment forecast includes the cost of this pipeline, but, since no contracts have as yet been concluded, the five-year forecast includes no natural gas production resulting from new gas export contracts. Nor does the production forecast in Table 6.2 include any additional condensate production that may result from increased gas production under new export contracts.

Twenty-Year Production Forecast

The twenty-year forecast has been prepared on the basis of the reserves assessment. However, unlike the five-year forecast, the possible recovery category is also included.

In preparing the forecast until 2022, it has been assumed that the course of production will be determined on the basis of the technical potential of the fields, without taking legal and operational constraints into account.

Within the category possible recovery, 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 Danish Energy Authority estimates that there is further production potential in several fields, for instance based on the use of water injection.

Fig. 6.5 Natural Gas Production (Forecast) Broken down by Processing Centre

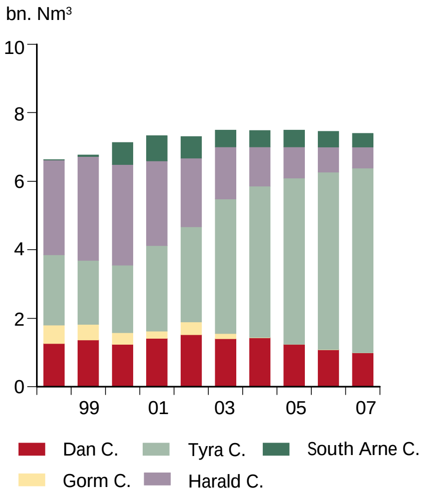


Fig. 6.6 shows this year's production forecast compared to previous years' forecasts. It appears from this year's forecast that oil production is expected to peak at about 28 million m^3 in 2005, after which it is expected to decline.

In the period from 1990 to 1995, production was expected to increase, due mainly to further field developments based on horizontal wells and water injection. The upward trend forecast from 1995 to 2000 was primarily attributable to the expected development of the Siri, South Arne and Halfdan discoveries.

For the period 2000 to 2003, the forecast growth in production was chiefly due to further development of the Halfdan Field and the expected development of the Cecilie and Nini discoveries.

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.

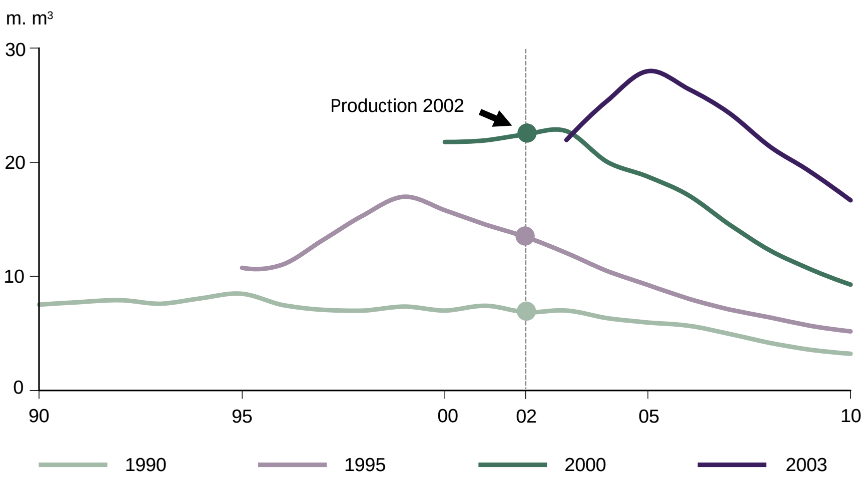
To illustrate the uncertainty associated with the forecasts, Fig. 6.5 shows some of the previous oil production estimates made for 2002. The forecast from 1990 estimated 2002 production at 6.8 million m^3. The production figure recorded in 2002 was 21.5 million m^3. Thus, actual production was almost triple the production figure forecast some ten years earlier.

The forecast from 1995 estimated the production for 2002 at 13.2 million m^3. Since 1995, new discoveries have been made and put on stream very shortly afterwards. This applies to such fields as the Siri, South Arne and Halfdan Fields. Deducting the production of these fields from actual production in 2002 leaves a result of 14.0 million m^3. This means that the forecast from 1995 reasonably reflects the actual production recorded in 2002 for the fields included in the 1995 forecast.

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 70% of total oil production, and due to their development with horizontal wells and water injection, they still contain considerable reserves; see Fig. 6.7.

Fig. 6.6 Forecasts for the Period 1990-2010



The Halfdan and South Arne Fields were brought on stream in 1999 and are not yet fully developed.

The reserves of the Dan, Gorm, Skjold, Halfdan and South Arne Fields are estimated to represent about 80% of total Danish oil reserves. The remaining 20% of reserves derive from more than 30 fields and discoveries.

The downward plunge of oil production that is estimated in the forecasts can possibly be curbed as a result of new discoveries made, e.g. in connection with the exploration activity initiated in the Fifth Licensing Round, as well as by advances in technological research and development.

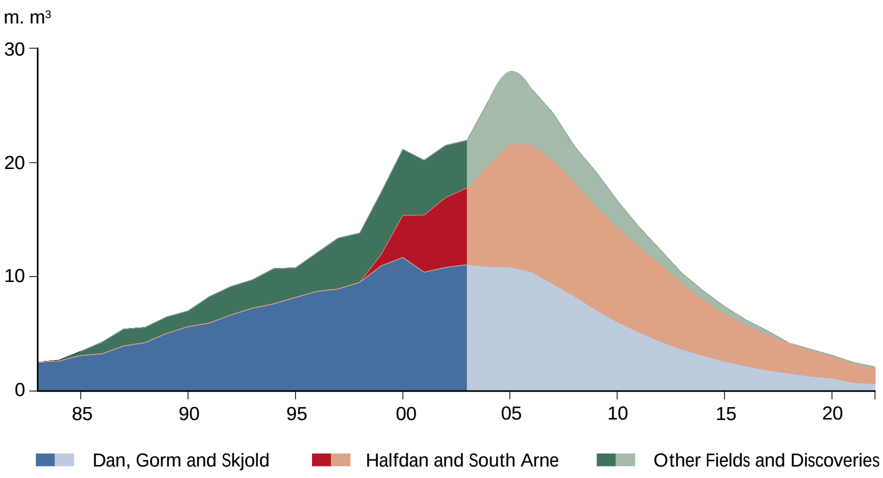
As opposed to the production of oil, which can always be sold at the current market price, the production of natural gas requires that long-term sales contracts have been concluded.

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

In 1997, a contract was concluded between the Amerada Hess group and DONG Naturgas A/S for the sale of gas from the South Arne Field, and, in 1998, a contract was concluded with DONG Naturgas A/S for the sale of the DONG group's share of gas produced from the Lulita Field.

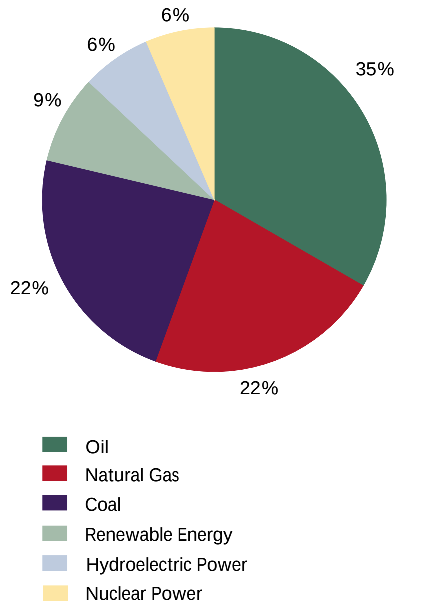
The Danish Energy Authority's forecast for the planned course of production is based on the contracts with DUC providing for total gas supplies of approx. 140 billion Nm^3 until the year 2012. In addition, the planned course of production for the South Arne Field accounts for 5 billion Nm^3.

Fig. 6.7 Oil Production and Forecasts for the Period 1983-2022



7. GLOBAL OIL RESERVES

Fig. 7.1 Breakdown of Global Energy Consumption



Source: BP Statistical Review of World Energy, June 2002, and the IEA

Periodically, the viewpoint that global oil reserves will soon be exhausted is propounded. At the beginning of the 1970s, the so-called Rome Club presented a scenario forecasting the depletion of global oil reserves by about 2003.

ENERGY CONSUMPTION

Global energy consumption is distributed on many different types of fuel, ranging from animal manure to nuclear power, and the consumption of the different fuel types is not always particularly well documented. Since fuels such as oil, natural gas, coal, nuclear power and hydroelectric power are traded commercially, the consumption of these fuel types is fairly well documented. These fuels are frequently termed primary energy forms.

The breakdown of global consumption by fuel is shown in Fig. 7.1.

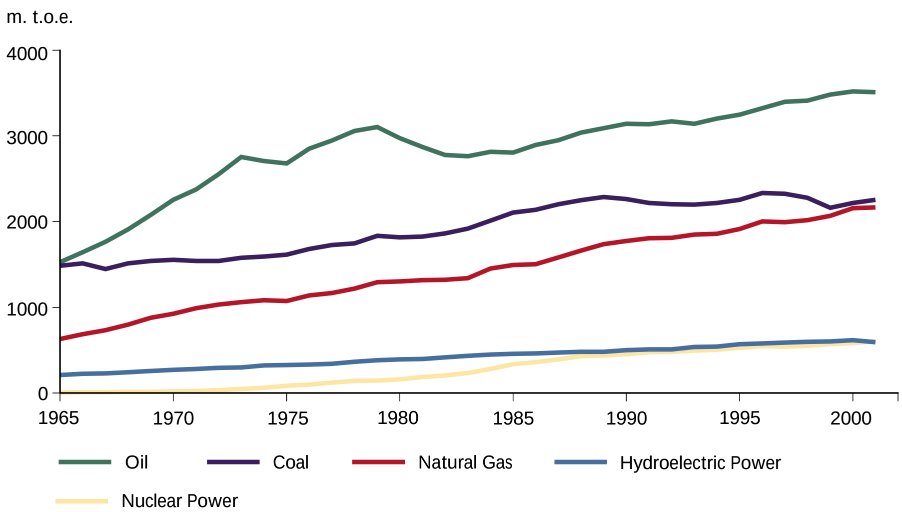
Oil is our chief energy resource, accounting for a share of about 35%. Next in line are natural gas and coal, with almost equal shares of about 22% each. Nuclear energy and hydroelectric power play a minor role, each representing about 6% of total consumption. Renewable energy comprises biomass mainly, and accounts for about 9% of total consumption.

Remarkably, the consumption of oil and natural gas accounts for more than half the world's energy consumption. Consumption of the principal energy source, oil, exceeds the consumption of the second-most important energy source, natural gas, by more than 50%.

Oil as the Principal Energy Source

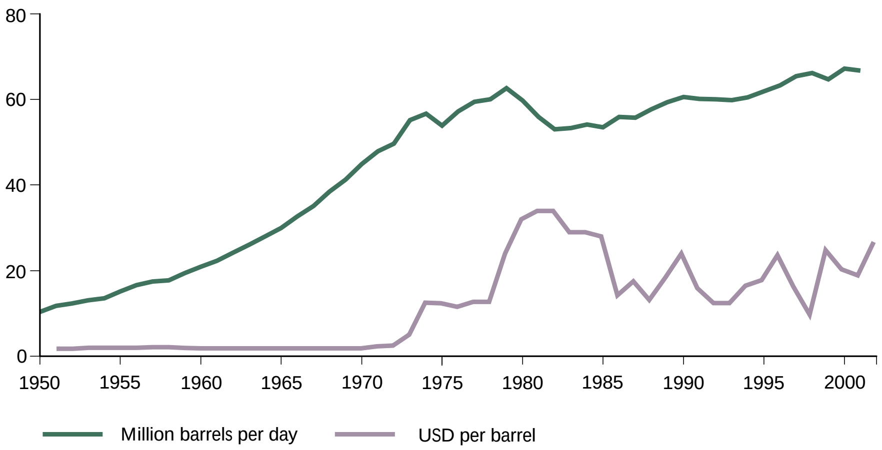
Fig. 7.2 shows the development in global energy consumption broken down by primary energy forms. It appears that the consumption of the different energy forms has generally climbed over the years. Moreover, the figure shows that oil consumption rose sharply until 1973, when the first oil crisis set in. After some

Fig. 7.2 Global Energy Consumption



Source: BP's website

Fig. 7.3 Global Crude Oil Production and Price*



**The crude oil price is the export price for Saudi Arabian Light (current prices)*

fluctuations, oil consumption began rising again in the mid-1980s, but at a considerably lower rate.

OIL PRODUCTION

Crude oil continues to be an international commodity, with its price set on the world market. Consequently, the production and price of crude oil are based on well-documented historical data. Fig. 7.3 shows global crude oil production and crude oil prices since 1950.

The figure illustrates the above-mentioned sharp rise in oil production until the beginning of the 1970s. The growth in production is remarkable, production increasing fivefold in that time span. During this period of surging production, crude oil prices remained low and stable.

In 1972, the so-called Rome Club published a report that included forecasts for worldwide oil production. Based on historical trends, one of the forecasts prophesied exponential growth in oil consumption, but a mere year later events occurred that would radically change the assumptions underlying the forecast.

In 1973, and again in 1979, oil prices increased when the Organization of Petroleum Exporting Countries, OPEC, limited the supply of crude oil on the world market. The associated price hikes affected oil consumption, and production stagnated. From the mid-1980s, production rose again after a price decline, but not as steeply as before.

OIL RESERVES

Globally, oil is our principal source of energy. Assessments of global oil reserves therefore attract great interest, including for reasons of supply.

Oil reserves are typically defined as the amounts of oil that can be recovered by means of known technology from proven oil accumulations under the prevailing economic conditions. Oil exploration and recovery methods undergo continuous technological development, and the oil and gas sector also operates under changing economic conditions.

Table 7.1 Crude Oil Reserves at 1 January 2002 and Production in 2001

	Reserves bn. bbls	Production m. bbls/d
North America	54	11
South and Central America	96	6
Europe	19	6
Former Soviet Union	57	8
Middle East	686	21
Africa	77	7
Asia Pacific	44	7
Total World	1032	67

Source: OGJ, December 23, 2002 edition

Assessments of global reserves frequently use the term *proven reserves*, which are the reserves that are recoverable with reasonable certainty. Table 7.1 and Fig. 7.4 show the world's proven crude oil reserves at 1 January 2002 and production in 2001.

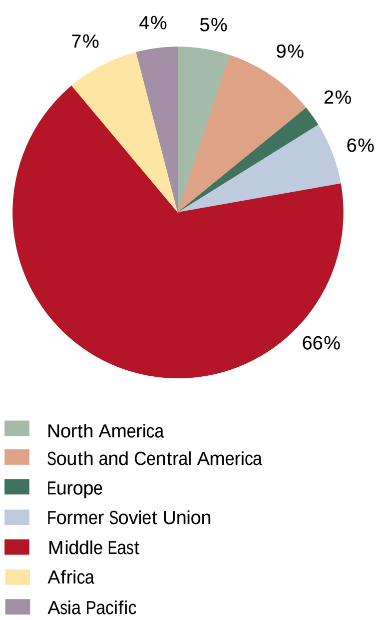
Oil reserves can be put into perspective by calculating the so-called R(reserves)/P(production) ratio; see the definition in the section on *Reserves*. As the R/P ratio indicates a calculated length of time the current reserves will last, an increasing ratio is a positive indicator, whereas a decreasing ratio is a negative indicator.

The R/P ratio is 42 when calculated on the basis of world oil reserves, meaning that oil production is calculated to be sustainable at the 2001 level for the next 42 years. The comparable ratio for Denmark's oil reserves is provided in the section on *Reserves*.

Fig. 7.4 shows that about two-thirds of global oil reserves are expected to be recoverable from the Middle East, while only about one-third of world oil production takes place in the Middle East. Conversely, the rest of the world accounts for as much as two-thirds of production, with only one-third of total reserves being attributed to it.

The same relation can be expressed by calculations showing that the Middle East has reserves for about 90 years' production at the current rate of production, while the rest of the world will only have reserves for about 21 years' production. Notably, about 80% of the oil produced in the Middle East is exported. This makes it fairly certain that international markets will become increasingly dependent on oil from the Middle East.

Fig. 7.4 Breakdown of Global Crude Oil Reserves



THE HISTORICAL DEVELOPMENT OF RESERVES

An extensive chronological summary of global crude oil reserves estimates is available from the Oil and Gas Journal (OGJ). Fig. 7.5 shows OGJ's estimates of global crude oil reserves, the first one dating back to 1 January 1952.

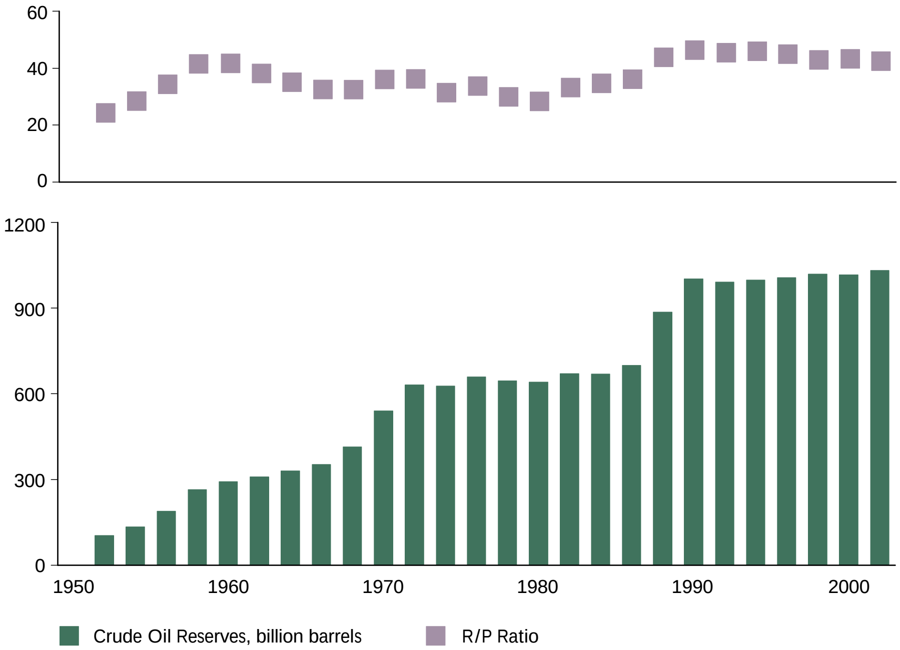
Because the chronological summary covers a 50-year period with data of varying quality, an estimate from the 1950s cannot be compared to one from the 1990s. The data may include reserves assessments that, although they have been made on a technical basis, also incorporate politically motivated revaluations.

It is noteworthy that reserves largely remain constant or even tend to grow. This means that the reserves have been written up by an amount equal to or higher than the production for the year. The reason that reserves grow over time is not only the discovery of new oil accumulations, but also the increasing volumes that can be recovered from known accumulations.

Moreover, it should be noted that the R/P ratio determined typically varies between 30 and 45, meaning that the R/P ratio has thus been roughly constant for a period of about 50 years. Viewed in a longer perspective, the fact that the R/P ratio has remained almost constant, even over a period of growing production/consumption, must be considered highly positive.

Reserves estimates are relevant for a limited period of time. Thus, at the beginning of the 1970s, crude oil reserves were estimated at just over 600 billion barrels;

Fig. 7.5 Global Crude Oil Reserves and R/P Ratio



see Fig. 7.5. In the subsequent period, until around the year 2000, production reached the same figure, which means that the reserves estimated at that time have been recovered in less than 30 years. This example indicates that the reserves estimates shown primarily reflect how large an exploration effort the oil companies have considered necessary to safeguard their future. If more money had been spent on exploration, the reserves and the R/P ratio would presumably have increased.

OIL RESOURCES

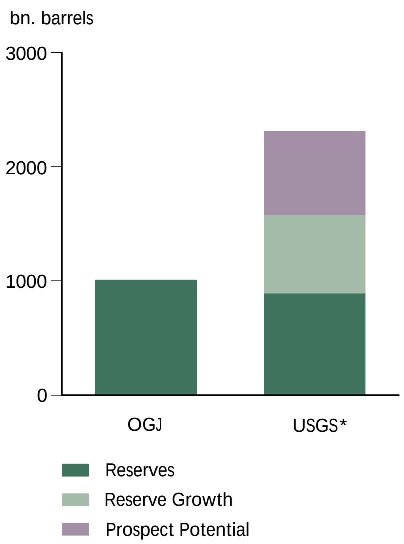
The definition of reserves incorporates assumptions as to when a recovery potential can be categorized as a reserve. As mentioned above, it is assumed that the reserves assessed can be recovered by means of known technology under the prevailing economic conditions. Moreover, reserves estimates only include the recovery from accumulations in which oil has been encountered.

Outside the framework of a reserves assessment, the recovery potential of accumulations in which no wells have been drilled, so-called prospects, can be estimated. In addition, the estimated recovery from an oil field frequently increases when the field is developed and production starts, e.g. as a result of technological development. This is termed *reserve growth*. Collectively, such volumes are called resources, and are potential additions to a reserves assessment.

The U. S. Geological Survey (USGS) has made assessments of global crude oil reserves and resources. It divides its resource assessment into resources attributable to *reserve growth* and to prospects. Fig. 7.6 shows the USGS assessment and compares it with a similar assessment from the OGJ.

The volumes of reserves according to the two different assessments are almost identical. The resources estimated in each of the categories *reserve growth* and prospects are almost equal in size, and combined they increase recoverable

Fig. 7.6 Global Crude Oil Resources



*Includes natural gas liquids (NGLs) for the USA amounts by about 150% relative to estimated reserves. Thus, according to the USGS, the resources attributed to the categories *reserve growth* and prospects represent a considerable potential.

Reference is also made to the report on “Oil and Gas Production in Denmark 2000”, which contains a section on Denmark’s resources.

UNCONVENTIONAL OIL DEPOSITS

The above-mentioned assessment of resources made by the USGS assesses so-called conventional oil, where wells are assumed to recover the oil from hydrocarbon accumulations.

The so-called unconventional oil deposits can also be included in future recovery potential. Such deposits include oil shale, tar sand and extra heavy oil. The production of unconventional oil amounted to about 1 million barrels per day in 2000. Although the deposits are considered to be very large, production presupposes a considerable, permanent increase in oil prices.

Unconventional accumulations of oil shale and tar sand can only be exploited by processing vast amounts of material in expensive production plants. The large volumes of material processed cause disposal problems. Likewise, the extraction of oil from such deposits is highly energy-intensive. Steam, for example, is used to extract tar from sand. The amount of energy required for the steam production process equals half the amount of energy contained in the tar oil. This means that total CO_2 emissions from recovery and consumption are almost as high as for coal.

WHEN WILL OIL SUPPLIES BECOME SCARCE?

As appears from above, the existing oil production potential can cover consumption for many years ahead. Nevertheless, the possibility that oil will become scarce in the mid- to long-term view (10-20 years) cannot be excluded. This is because exploiting both the unconventional deposits and many of the conventional oil accumulations will require technological innovation or new exploration and recovery in difficultly accessible parts of the world. Therefore, the maturing of such potential requires both time and money.

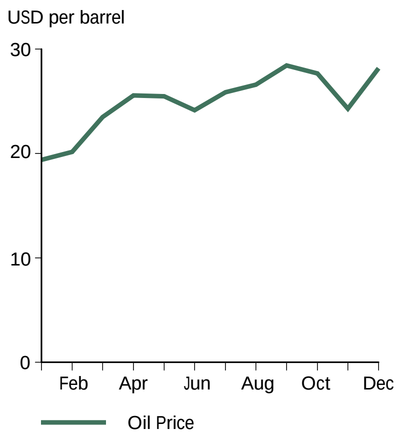
Oil prices that remain at a high level in future (USD 20-25 per barrel or more) will provide the necessary incentive to invest in new oil recovery technologies. High oil prices will also stimulate investments in renewable energy, which will curb the growth of oil consumption or lead to an actual decline in consumption.

However, if oil prices remain low (about USD 10 per barrel) for a long period of time, little money will be available for developing new recovery technology, and investments in renewable energy will become less attractive.

In such a scenario, one might fear that global oil consumption will soar until supplies can no longer meet demand, after which oil prices will skyrocket until the shortage can be alleviated a few years later.

8. ECONOMY

Fig. 8.1 Oil Price in 2002



Since 1997, Denmark has been self-sufficient in energy, mainly as a result of the production of oil and natural gas in the North Sea. The production of hydrocarbons has a positive impact on the Danish economy, as it favourably affects the Danish balance of payments and generates revenue for the state.

CRUDE OIL PRICE AND DOLLAR EXCHANGE RATE

The production value of oil and natural gas depends on the development of the international crude oil price and the dollar exchange rate.

The average oil price, as quoted for Brent oil, was USD 24.9 per barrel in 2002. This is the same level as in 2001, when oil prices averaged USD 24.4 per barrel.

In January 2002, the average oil price slightly exceeded USD 19 per barrel, while the average for December 2002 was just over USD 28 per barrel. As appears from Fig. 8.1, the oil price increased from USD 19 to USD 28 per barrel during the period from January to September 2002, when the price peaked at USD 28.4 per barrel.

The uncertainty about a possible war in Iraq contributed to driving up oil prices in the latter half of 2002, while higher production, particularly in the OPEC countries, combined with a falling demand for oil due to the worldwide economic decline pulled prices in the opposite direction.

OPEC has made it a goal to keep oil prices within the USD 22-28 range per barrel, and has basically succeeded in the past few years. However, from a historical perspective, this is a relatively high price; by comparison, the average price in the 1990s hovered just above USD 18 per barrel.

In 2002, the average dollar exchange rate was DKK 7.9 per USD. This represents a fall compared to 2001, when the average dollar exchange rate was DKK 8.3 per USD. The development in the dollar exchange rate has curbed the increase in oil prices in terms of Danish kroner, and thus in the production value of the oil produced in the Danish part of the North Sea.

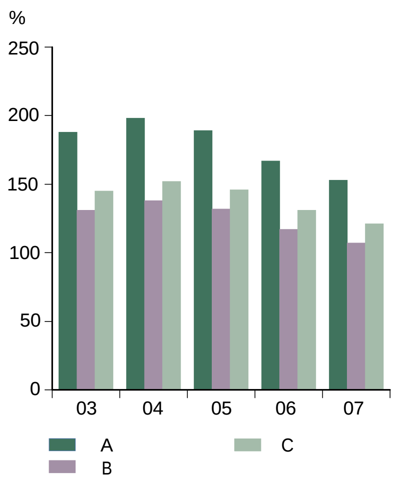
VALUE OF OIL AND GAS PRODUCTION

The estimated value of Danish oil and gas production totalled about DKK 32.6 billion in 2002, a 4% rise compared to 2001. Relative to the increase in oil production, the hike in production value is marginal, due to the lower dollar exchange rate. However, when viewed in a historical perspective, the production value estimated for 2002 is still considered to be very high.

Preliminary estimates for 2002 show that oil production represented a value of DKK 26.5 billion, and gas production a value of DKK 6.1 billion. The breakdown of production in 2002 on the nine producing companies appears from Fig. 3.2 in the section on Production.

How the production value will develop in the years ahead depends both on production and the trend in oil and gas prices and the dollar exchange rate. Based on known reserves, the Danish Energy Authority prepares oil and gas production

Fig. 8.2 Degrees of Self-Sufficiency



A. Oil and gas production vs domestic oil and gas consumption.
B. Oil and gas production vs domestic energy consumption.
C. Total energy production vs total domestic energy consumption.

forecasts; see the section on Reserves. The development in oil prices is difficult to predict, so any estimate of how the production value will develop in the years to come will be subject to great uncertainty.

DEGREES OF SELF-SUFFICIENCY

Denmark has been self-sufficient in energy since 1997. Total Danish production of oil, natural gas and renewable energy in 2002 was about 43% higher than total energy consumption. This represents an increase over the year before, when production exceeded consumption by 37%. In 2002, oil and natural gas production alone exceeded total energy consumption by 30% and total oil and gas consumption by 85%.

Table 8.1 and Fig. 8.2 show the development in the degrees of self-sufficiency projected by the Danish Energy Authority for the next four years.

Column A shows the extent to which the production of oil and natural gas from the North Sea covers domestic oil and natural gas consumption. Since 1991, Denmark has been self-sufficient in oil and gas, and in 2003 Danish oil and natural gas production is expected to exceed consumption by about 88%.

It appears from column B that total oil and natural gas production in 2003 is estimated to exceed Denmark's total energy consumption by about 31%.

Column C indicates how large a share of total energy consumption is covered by Denmark's production of oil, natural gas and renewable energy. In 2003, production is expected to exceed consumption by 45%.

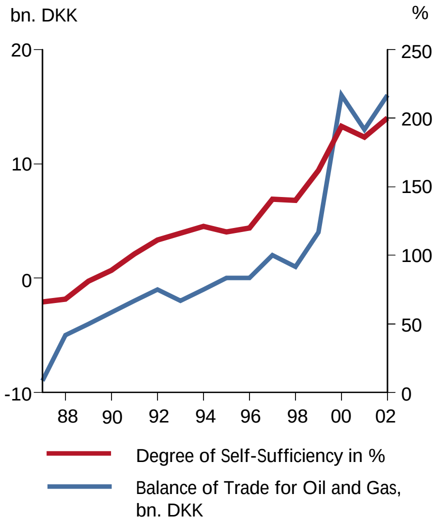
IMPACT OF PRODUCTION ON THE DANISH ECONOMY

The oil and natural gas activities have a favourable impact on the Danish economy. In addition to contributing to Denmark's self-sufficiency in energy, the activities impact positively on the balance of trade and the balance of payments current account.

Table 8.1 Degrees of Self-Sufficiency

	2003	2004	2005	2006	2007
Production (PJ)					
Crude Oil	799	874	835	722	644
Gas	295	294	295	293	297
Renewable Energy	116	121	125	125	126
Energy Consumption (PJ)					
Total	832	846	858	869	880
Degrees of Self-Sufficiency (%)					
A	188	198	189	167	153
B	131	138	132	117	107
C	145	152	146	131	121

Fig. 8.3 The Balance of Trade for Oil and Gas and Degree of Self-Sufficiency, 2002 Prices



The Balance of Trade for Oil and Natural Gas

The balance of trade for oil and natural gas expresses the difference between the value of total imports and total exports of oil and natural gas products; see Fig. 8.3.

Since 1995, Denmark has had a surplus on the balance of trade for oil and natural gas products. This surplus has been preliminarily estimated at DKK 16 billion for 2002, the highest surplus ever recorded.

Impact on the Balance of Payments

The production of oil and natural gas has a positive impact on the balance of payments. A share of production is exported, and the share consumed in Denmark replaces the energy imports otherwise required.

The Danish Energy Authority has prepared an estimate of the effect of oil and gas activities on the balance of payments current account for the next five years. The estimate is based on the Danish Energy Authority's forecasts of production, investments and operating and transportation costs. Moreover, a number of assumptions have been made about import content, interest expenses and profits on the hydrocarbon activities.

Finally, calculations have been made on the basis of a low, an intermediate and a high oil price scenario of USD 22, USD 25 and USD 28 per barrel, respectively, and a dollar exchange rate of DKK 7 per USD. The lowest and the highest price scenarios represent the minimum and maximum OPEC oil price targets. The intermediate scenario represents the average level of oil prices for the past two years. The price scenarios merely serve to illustrate how sensitive economic projections are to fluctuations in the oil price.

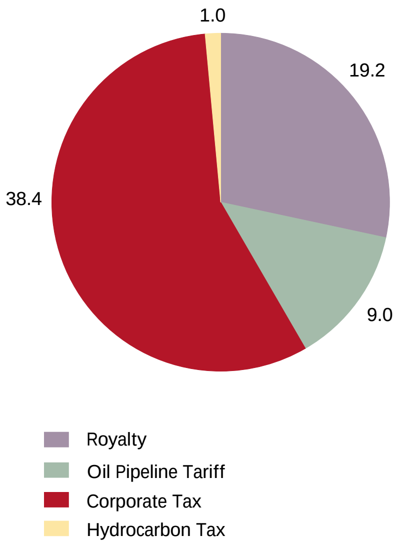
Table 8.2 shows the individual items used in calculating the effect of oil and gas activities on the balance of payments in the intermediate oil price scenario. The table also shows the calculated effect on the balance of payments current account when the low and high oil price scenarios are used.

The socio-economic production value is defined as the sum total of the production value of produced oil and the production value of natural gas consumption and natural gas exports. The import content of expected expenses is then deducted from the socio-economic production value. Finally, estimated dividends and interest payments transferred abroad are deducted, thus yielding the effect of oil and gas activities on the balance of payments current account.

Table 8.2 Effect of Oil/Gas Activities on the Balance of Payments, DKK billion, 2002 prices, Intermediate Price Scenario (25 USD/bbl)

	2003	2004	2005	2006	2007
Socio-Economic Production Value	30	32	31	27	25
Import Share	6	4	2	2	1
Balance of Goods and Services	24	28	29	25	24
Transfer of Interest and Dividends	6	7	7	6	5
Balance of Payments Current Account	**18**	**21**	**22**	**20**	**18**
Balance of Payments Current Account					
Low Price Scenario (22 USD/bbl)	**14**	**17**	**19**	**16**	**15**
High Price Scenario (28 USD/bbl)	**18**	**23**	**24**	**21**	**21**

Fig. 8.4 Total State Revenue from Oil/Gas Production 1972-2002, DKK billion, 2002 Prices



Assuming that the oil price is USD 25 per barrel, the oil and gas activities will have an estimated DKK 18-22 billion impact on the balance of payments current account. In the low oil price scenario, the impact will be in the DKK 14-19 billion range, compared to DKK 18-24 billion in the high oil price scenario. The three scenarios show that oil prices greatly influence how the oil and gas activities affect the Danish economy. The assumed dollar exchange rate of DKK 7 per USD is based on the current low exchange rate. A higher dollar exchange rate will increase the positive impact of oil and gas activities on the balance of payments, while a lower exchange rate will have the opposite effect.

State Revenue

The state generates direct revenue from North Sea oil and gas production via five different taxes and fees: *corporate tax, hydrocarbon tax, royalty and oil pipeline tariff/compensatory fee.* In addition, the state receives an annual dividend payment from DONG E&P A/S. At the end of 2002, the state's aggregate revenue from oil and gas production amounted to DKK 67.5 billion in 2002 prices, while the aggregate production value amounted to DKK 279.2 billion. The corresponding aggregate value of the licensees' expenses for exploration, field developments and operations was DKK 160.2 billion.

Box 8.1 specifies the state's revenue base in the form of taxes and fees on hydrocarbon production. Fig. 8.4 shows total state revenue broken down on the individual taxes and fees.

Table 8.3 shows state revenue over the past five years. These figures illustrate that state revenue has increased marginally from 2001 to 2002. This is attributable to the falling dollar exchange rate, which, combined with an unchanged average oil price, has decreased the production value of oil produced in the North Sea.

For the past four 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.

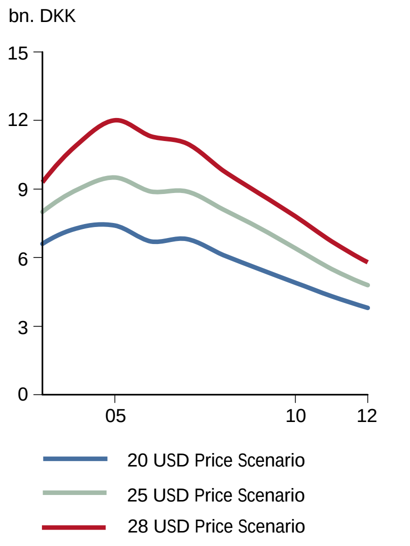
Based on the USD 22 oil price scenario, the Ministry of Taxation's five-year revenue forecast shows that the state's total revenue will come to DKK 6.6 billion in 2003, then hovering at around DKK 7 billion until the year 2007. The USD 28 price scenario is estimated to yield state revenue of DKK 9.3 billion in 2003, increasing to almost DKK 11 billion in 2007. The forecast in Table 8.4 is based on a stylized calculation.

Table 8.3 State Revenue over the Past Five Years, DKK million, Nominal prices

	1998	1999	2000	2001	2002*
Hydrocarbon Tax	0	0	0	0	65
Corporate Tax	1,721	2,082	6,170	6,273	6,794
Royalty	1,098	854	1,153	2,247	2,109
Oil Pipeline Tariff**	310	619	1,401	1,114	930
Total	**3,129**	**3,556**	**8,724**	**9,633**	**9,898**

* *Estimate*
***Including 5% compensatory fee*

Fig. 8.5 Taxes and Fees, 2003-2012, 2002 Prices



In recent years, oil prices have been relatively high and production has increased in the Danish area. Combined with declining investments in profit-yielding fields, this means that the losses brought forward from previous years for setoff against the income subject to hydrocarbon tax have shrunk over the years. Therefore, the Ministry of Taxation estimates that the losses brought forward will no longer be able to outweigh the profits from the fields.

The estimates of future corporate and hydrocarbon tax payments have made no allowance for the oil companies' strong incentive to invest when they become liable to hydrocarbon tax.

Due to the large tax allowances obtainable in connection with investing in hydrocarbon activities, the Ministry of Taxation considers it altogether doubtful that hydrocarbon tax will actually become payable in any more than a few isolated years.

In addition to the uncertainty about oil prices and the dollar exchange rate, the future estimates of corporate and hydrocarbon tax payments are subject to uncertainty because the calculations are based on various stylized assumptions, some of which concern the companies' financing costs.

Fig. 8.5 shows that tax revenue will decline in step with the projected development of production.

THE FINANCES OF THE LICENSEES

During the period from 1963 to 2002, the licensees' expenses for exploration, field developments and operations (including transportation) in respect of producing fields totalled DKK 23.1 billion, DKK 88 billion and DKK 49 billion, respectively, in 2002 prices. The aggregate production value for the period amounted to DKK 279 billion in 2002 prices.

Table 8.4 Expected State Revenue from Oil and Gas Production, DKK billion, 2002 Prices

	2003	2004	2005	2006	2007
Corporate Tax USD 22/bbl	3.8	4.4	4.5	3.9	3.8
USD 25/bbl	*4.7*	*5.4*	*5.4*	*4.7*	*4.6*
USD 28/bbl	*5.6*	*6.4*	*6.4*	*5.6*	*5.4*
Hydrocarbon Tax	0.1	0.1	0.1	0.4	0.6
	0.1	*0.4*	*0.9*	*1.4*	*1.6*
	0.2	*1.0*	*2.1*	*2.7*	*2.5*
Royalty	1.7	1.7	1.7	1.5	1.5
	2.0	*2.0*	*1.9*	*1.7*	*1.7*
	2.2	*2.2*	*2.2*	*2.0*	*1.9*
Oil Pipeline Tariff*	1.0	1.1	1.0	0.9	0.8
	1.1	*1.2*	*1.2*	*1.0*	*0.9*
	1.3	*1.4*	*1.3*	*1.2*	*1.0*
Total	**6.6**	**7.3**	**7.3**	**6.7**	**6.7**
	7.9	*9.0*	*9.4*	*8.8*	*8.8*
	9.3	*11.0*	*12.0*	*11.5*	*10.8*

** Including compensatory fee*

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 tax and hydrocarbon tax are collected by the Danish Ministry of Taxation, Central Customs and Tax Administration, while the collection of royalty, the oil pipeline tariff and the compensatory fee is administered by the Danish Energy Authority. Moreover, the Danish Energy Authority supervises the metering of the amounts of oil and natural gas produced on which the assessment of state revenue is based.

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

Hydrocarbon tax
The Hydrocarbon Tax Act was introduced in 1982 with the aim of taxing windfall profits, for example as a result of high oil prices. In addition, the Act provides an incentive for the companies to reinvest in further exploration and development activities in order to ensure increased and better exploitation of the resources in the subsoil. Hydrocarbon tax only became payable for a few years during the first half of the 1980s and in 2002, with total hydrocarbon tax payments amounting to approx. DKK 983 million in 2002 prices.

Royalty
Under the terms of A.P. Møller's Sole Concession, royalty is payable on the basis of production. For the Sole Concession, royalty at the rate of 8.5% is payable on the total value produced after deducting transportation costs. In addition, 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. New licences contain no requirement for the payment of royalty.

Oil pipeline tariff
The oil pipeline tariff is a tax payable by DONG Olierør A/S, which 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% of the value of the crude oil transported. DONG pays 95% of the income from the 5% 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% of the value of the crude oil and condensate comprised by the exemption. To date, the compensatory fee has only become payable on the production from the South Arne and Siri Fields.

DONG Efterforskning & Produktion A/S
DONG E&P A/S is a fully paying participant in the licences granted in the Fourth and Fifth Licensing Rounds and in the Open Door Procedure, with a fixed 20% share. In some cases, DONG E&P A/S has supplemented this share on commercial terms by purchasing additional licence shares. As DONG E&P A/S holds a share in the individual licences on the same terms as the other licensees, 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' profit after tax for 2002 amounts to DKK 343 million.

In 2001, the Danish Energy Authority asked the Department of Accounting and Auditing at the Copenhagen Business School to perform an analysis and assessment of the financial results generated by the A.P. Møller companies from their activities in the Danish sector of the North Sea since 1962. The analysis is based on the A.P. Møller companies' official financial statements for the period 1962-2001 and was carried out by Associate Professor Carsten Krogholt Hansen.

A report presenting the findings of the analysis was published in May 2003. This report is available at the Danish Energy Authority's website www.ens.dk.

Exploration Costs

The Danish Energy Authority has preliminarily estimated total exploration costs in 2002 at DKK 1.0 billion, the licences from the Fifth Round accounting for about half the total amount. The DUC companies' exploration activity under the Sole Concession and under new licences represents a 42% share of total exploration costs in 2002.

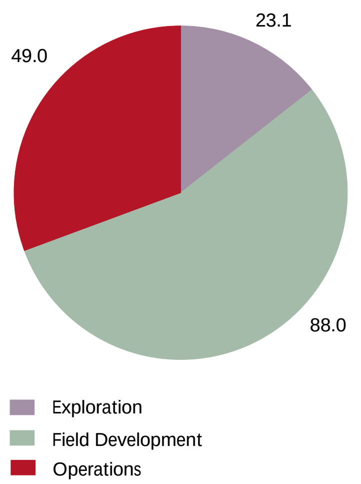
With one new exploration well and eight appraisal wells, exploration activity was slightly lower in 2002 than the year before. In 2003, the Danish Energy Authority is anticipating intensified exploration activity, including the drilling of six to eight exploration wells; see the section on *Exploration*. The high activity level is expected to be sustained in 2004, after which it is projected to fall.

Table 8.5 Investments in Development Projects, DKK million, Nominal Prices

	1998	1999	2000	2001	2002*
Adda	67	–	–	–	–
Cecilie	–	–	–	–	200
Dan	1,076	273	403	367	436
Gorm	167	26	12	240	241
Halfdan	–	204	886	1,518	2,412
Harald	99	32	175	–	–
Kraka	118	0	0	61	–
Nini	–	–	–	–	285
Roar	0	80	17	–	–
Rolf	0	1	0	–	–
Siri/Stine	1,538	848	53	175	19
Skjold	16	399	404	89	–
Svend	13	189	–	115	224
South Arne	2,133	1,371	761	543	948
Tyra	169	152	330	198	75
Tyra Southeast	–	–	–	357	654
Valdemar	0	–	60	316	–
Not allocated	-19	-48	10	12	2
Total	**5,378**	**3,528**	**3,111**	**3,991**	**5,496**

**Estimate*

Fig. 8.6 Total Costs of all Licensees, 1963- 2002, DKK billion, 2002 Prices



Investments in Field Developments

Total investments in field developments for 2002 have been preliminarily estimated at DKK 5.5 billion, representing an increase of about DKK 1.5 billion compared to 2001. Investments in two of the DUC companies' fields, Tyra Southeast and Halfdan, account for a large share of this increase.

The DUC companies account for more than 70% of total investments in 2002 and for about 82% of total oil production in 2002; see the section on *Production*.

With 13 wells drilled and a new satellite platform, the Halfdan Field represents by far the largest investment in 2002; see the section on *Development*. Other major investments included the drilling of wells in the Tyra Southeast Field and further development of the South Arne Field. As in 2000 and 2001, the Halfdan and South Arne Fields account for more than half the total investments in field developments in 2002.

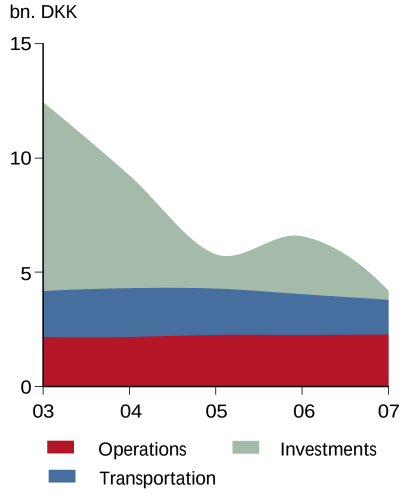
The Danish Energy Authority's estimate of investments in field developments for future years has been written up significantly compared to the forecast made at 1 January 2002.

In 2003, field development costs are expected to total about DKK 8.3 billion, representing a DKK 2.4 billion increase over last year's projection. This increase is largely attributable to the continued development of the Dan Field. In addition, investments have been made in the Siri Field, and, finally, preliminary works have

Table 8.6 Investments in Development Projects, DKK billion, 2002 Prices

	2003	2004	2005	2006	2007
Ongoing and Approved					
Adda	–	0.4	–	0.1	–
Alma	–	–	–	0.4	–
Cecilie	0.7	0.1	–	–	–
Dan	1.2	0.9	0.4	0.4	–
Elly	–	–	0.2	0.4	–
Gorm	0.1	–	0.2	0.3	–
Halfdan	1.7	0.4	–	–	–
Nini	0.8	0.2	–	–	–
Rolf	–	–	–	–	–
Siri/Stine	0.6	0.1	–	–	–
Skjold	0.1	–	–	–	–
Svend	–	–	–	–	–
South Arne	0.5	1.0	–	–	–
Tyra	0.4	0.7	0.6	0.6	0.1
Tyra Southeast	0.3	0.1	–	–	–
Valdemar	0.3	0.3	–	–	–
Total	**6.6**	**4.4**	**1.5**	**2.3**	**0.2**
Planned	1.7	0.6	0.1	0.2	0.2
Expected	**8.3**	**4.9**	**1.5**	**2.5**	**0.4**

Fig. 8.7 Projected Investments in Fields, and Operating and Oil Transportation Costs, 2002 Prices



been carried out in connection with the tie-in of two new fields, Nini and Cecilie. The development of these four fields accounts for about 40% of the total investments projected for 2003.

Investments projected for 2004 have been written up by DKK 1.1 billion relative to last year, chiefly because a further development of the South Arne Field has been postponed from 2003 to 2004.

The investment forecast for 2005 has been written up slightly compared to last year, while the forecast for 2006 has been adjusted upwards by DKK 1.3 billion. This upward adjustment is attributable to the development of a number of minor fields, viz. Adda, Alma, Amalie and Elly, as well as to the Gorm Field.

Operating and Transportation Costs

In recent years, annual operating and administration costs have totalled about DKK 2.0 billion. Preliminary figures show that total operating and administration costs amounted to about DKK 2.3 billion in 2002, which is slightly higher than the 2001 level.

Total crude oil transportation costs consist of the operating costs and capital cost associated with the use of the oil pipeline from the Gorm Field to shore, as well as the 5% profit element, which is payable on the basis of the production value of the crude oil transported.

The Siri and the South Arne Fields are exempt from the obligation to use the oil pipeline, but must instead pay a compensatory fee constituting 5% of the production value of the crude oil. The oil produced is transported to shore by tanker.

Fig. 8.7 illustrates the Danish Energy Authority's estimate of developments in operating and transportation costs as well as projected investment costs for the years to come.

AMOUNTS PRODUCED AND INJECTED — OIL thousand cubic metres

Production and sales

	1972-92	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	Total
Dan	15,104	3,262	3,496	3,713	3,799	3,858	4,767	5,745	6,599	6,879	6,326	63,549
Gorm	17,958	1,889	2,421	2,494	2,879	3,045	2,865	3,384	3,110	2,180	2,887	45,112
Skjold	15,439	2,103	1,715	1,979	2,023	2,011	1,895	1,825	1,975	1,354	1,659	33,979
Tyra	7,969	1,639	1,748	1,631	1,447	1,263	931	892	1,000	872	801	20,193
Rolf	2,761	176	92	216	218	96	92	77	83	51	51	3,912
Kraka	349	390	490	469	340	315	314	404	350	253	157	3,832
Dagmar	780	67	33	35	23	17	13	10	8	4	6	996
Regnar	-	145	429	86	41	27	43	29	14	33	18	865
Valdemar	-	53	304	165	161	159	95	86	77	181	353	1,635
Roar	-	-	-	-	319	427	327	259	285	317	175	2,110
Svend	-	-	-	-	836	1,356	635	521	576	397	457	4,777
Harald	-	-	-	-	-	794	1,690	1,332	1,081	866	581	6,344
Lulita	-	-	-	-	-	-	143	224	179	66	22	634
Halfdan	-	-	-	-	-	-	-	222	1,120	2,965	3,718	8,025
Siri	-	-	-	-	-	-	-	1,593	2,118	1,761	1,487	6,959
South Arne	-	-	-	-	-	-	-	757	2,558	2,031	2,313	7,659
Tyra SE	-	-	-	-	-	-	-	-	-	-	493	493
Total	**60,361**	**9,724**	**10,727**	**10,788**	**12,087**	**13,367**	**13,810**	**17,362**	**21,134**	**20,208**	**21,504**	**211,072**

Production — GAS million normal cubic metres

	1972-92	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	Total
Dan	6,082	1,336	1,263	1,331	1,249	1,116	1,343	1,410	1,186	1,049	945	18,312
Gorm	7,947	775	922	761	674	609	633	537	426	306	479	14,069
Skjold	1,333	195	185	188	160	189	146	154	158	104	124	2,934
Tyra	23,454	3,853	3,646	3,839	3,843	4,229	3,638	3,878	3,826	3,749	3,948	61,905
Rolf	116	8	4	9	9	4	4	3	4	2	2	165
Kraka	144	125	119	128	95	85	106	148	119	100	52	1,221
Dagmar	111	13	8	5	4	3	2	2	2	1	1	153
Regnar	-	8	25	7	4	2	4	2	1	3	1	57
Valdemar	-	29	96	52	57	89	54	49	55	78	109	668
Roar	-	-	-	0	1,327	1,964	1,458	1,249	1,407	1,702	1,052	10,159
Svend	-	-	-	0	85	152	84	65	75	48	61	569
Harald	-	-	-	-	0	1,092	2,741	2,876	2,811	2,475	2,020	14,015
Lulita	-	-	-	-	-	-	69	181	160	27	5	443
Halfdan	-	-	-	-	-	-	-	37	178	522	759	1,496
Siri	-	-	-	-	-	-	-	142	197	176	157	671
South Arne	-	-	-	-	-	-	-	167	713	774	681	2,335
Tyra SE	-	-	-	-	-	-	-	-	-	-	447	447
Total	**39,188**	**6,342**	**6,269**	**6,321**	**7,506**	**9,534**	**10,281**	**10,901**	**11,316**	**11,116**	**10,845**	**129,617**

The monthly production figures for 2002 are available on the Danish Energy Authority's homepage www.ens.dk

GAS million normal cubic metres

Fuel*

	1972-92	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	Total
Dan	276	66	85	93	97	109	148	172	179	184	182	1,591
Gorm	707	87	104	111	135	164	152	149	142	111	146	2,010
Tyra	732	110	110	111	142	210	224	239	229	243	245	2,596
Dagmar	20	1	0	0	0	0	0	0	0	0	0	21
Harald	-	-	-	-	-	5	14	14	13	10	9	64
Siri	-	-	-	-	-	-	-	8	21	22	21	73
South Arne	-	-	-	-	-	-	-	3	32	34	45	114
Total	**1,735**	**264**	**299**	**314**	**375**	**488**	**539**	**585**	**618**	**604**	**648**	**6,469**

Flaring*

	1972-92	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	Total
Dan	1,303	53	66	36	40	36	43	56	67	79	55	1,833
Gorm	707	95	75	69	60	81	71	71	66	88	81	1,463
Tyra	338	39	48	42	67	46	42	58	58	68	61	866
Dagmar	91	12	8	5	2	3	2	2	2	1	1	130
Harald	-	-	-	-	-	77	19	12	7	11	3	130
Siri	-	-	-	-	-	-	-	73	9	15	9	105
South Arne	-	-	-	-	-	-	-	114	41	9	11	175
Total	**2,439**	**199**	**196**	**152**	**168**	**243**	**177**	**386**	**250**	**270**	**222**	**4,702**

Injection

	1972-92	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	Total
Gorm	7,433	420	70	28	26	62	24	25	45	4	14	8,151
Tyra	7,347	1,451	1,371	1,132	1,225	1,778	2,908	3,074	3,104	2,773	2,535	28,698
Siri	-	-	-	-	-	-	-	61	167	139	126	493
Total	**14,779**	**1,871**	**1,441**	**1,160**	**1,251**	**1,840**	**2,933**	**3,160**	**3,316**	**2,916**	**2,675**	**37,341**

Sales*

	1984-92	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	Total
Dan	4,648	1,350	1,256	1,338	1,211	1,058	1,261	1,371	1,238	1,412	1,521	17,662
Gorm	549	376	863	750	622	495	535	448	334	209	364	5,545
Tyra	15,038	2,281	2,214	2,607	3,878	4,400	2,060	1,870	1,971	2,493	2,776	41,586
Harald	-	-	-	-	-	1,010	2,777	3,032	2,950	2,482	2,013	14,263
South Arne	-	-	-	-	-	-	-	50	640	730	625	2,046
Total	**20,235**	**4,007**	**4,332**	**4,695**	**5,710**	**6,963**	**6,633**	**6,770**	**7,133**	**7,326**	**7,299**	**81,103**

**The names refer to processing centers.*

CO_2 EMISSIONS thousand tons

	1972-92	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	Total
Fuel	3,964	603	683	717	857	1,115	1,232	1,337	1,412	1,380	1,481	14,780
Flaring	5,574	454	448	347	384	555	404	882	571	617	507	10,744
Total	9,538	1,057	1,131	1,064	1,241	1,670	1,636	2,219	1,983	1,988	1,988	25,524

WATER thousand cubic metres

Production

	1972-92	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	Total
Dan	1,509	781	1,117	1,275	1,543	1,845	2,976	4,220	5,277	6,601	6,354	33,499
Gorm	4,938	557	824	948	1,921	2,906	3,177	3,468	3,980	3,360	4,017	30,097
Skjold	369	817	889	1,337	2,679	3,635	3,938	3,748	4,333	2,878	3,006	27,629
Tyra	1,842	1,005	1,290	1,749	2,161	2,215	2,020	2,033	3,046	2,545	2,371	22,277
Rolf	1,204	265	161	443	490	390	411	366	358	181	171	4,438
Kraka	176	195	188	251	272	287	347	329	256	353	311	2,963
Dagmar	228	395	367	464	507	408	338	246	241	102	160	3,456
Regnar	-	0	244	396	299	164	407	363	139	475	258	2,745
Valdemar	-	1	24	20	34	61	52	55	48	150	287	731
Roar	-	-	-	-	14	96	146	199	317	386	301	1,460
Svend	-	-	-	-	2	64	272	582	1,355	953	1,099	4,329
Harald	-	-	-	-	-	-	5	15	39	98	78	235
Lulita	-	-	-	-	-	-	3	5	11	23	14	57
Halfdan	-	-	-	-	-	-	-	56	237	493	368	1,155
Siri	-	-	-	-	-	-	-	319	1,868	2,753	3,041	7,981
South Arne	-	-	-	-	-	-	-	15	60	119	390	584
Tyra SE	-	-	-	-	-	-	-	-	-	-	212	212
Total	**10,265**	**4,016**	**5,103**	**6,882**	**9,922**	**12,072**	**14,093**	**16,020**	**21,566**	**21,471**	**22,438**	**143,848**

Injection

	1972-92	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	Total
Dan	1,304	1,534	3,808	5,884	8,245	8,654	11,817	14,964	17,464	18,176	16,099	107,948
Gorm	3,866	2,140	4,612	5,749	8,112	8,642	8,376	8,736	10,009	6,462	8,167	74,872
Skjold	15,358	2,836	3,511	3,985	5,712	6,320	6,291	5,866	6,132	4,750	6,411	67,172
Halfdan	-	-	-	-	-	-	-	82	13	54	1,931	2,080
Siri	-	-	-	-	-	-	-	1,236	3,778	4,549	4,507	14,070
South Arne	-	-	-	-	-	-	-	-	44	1,885	4,381	6,310
Total	**20,528**	**6,510**	**11,931**	**15,618**	**22,069**	**23,616**	**26,484**	**30,884**	**37,441**	**35,876**	**41,497**	**272,454**

Water injection includes the injection of produced water and sea water. Most of the water produced in the Gorm, Skjold, Dagmar and Siri Fields is re-injected.

PRODUCING FIELDS

DAGMAR

Prospect:	East Rosa
Location:	Block 5504/15
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1983
Year on stream:	1991
Producing wells:	2
Water depth:	34 m
Area:	9 km^2
Reservoir depth:	1,400 m
Reservoir rock:	Chalk and Carbonates
Geological age:	Danian, Upper Cretaceous and Zechstein
Reserves at 1 January 2003:	
Oil:	0.1 million m^3
Gas:	0.0 billion Nm^3
Cum. production at 1 January 2003:	
Oil:	1.00 million m^3
Gas:	0.15 billion Nm^3
Water:	3.46 million m^3
Production in 2002:	
Oil:	0.006 million m^3
Gas:	0.001 billion Nm^3
Water:	0.16 million m^3
Tot. investments at 1 January 2003:	
2002 prices	DKK 0.4 billion

REVIEW OF GEOLOGY

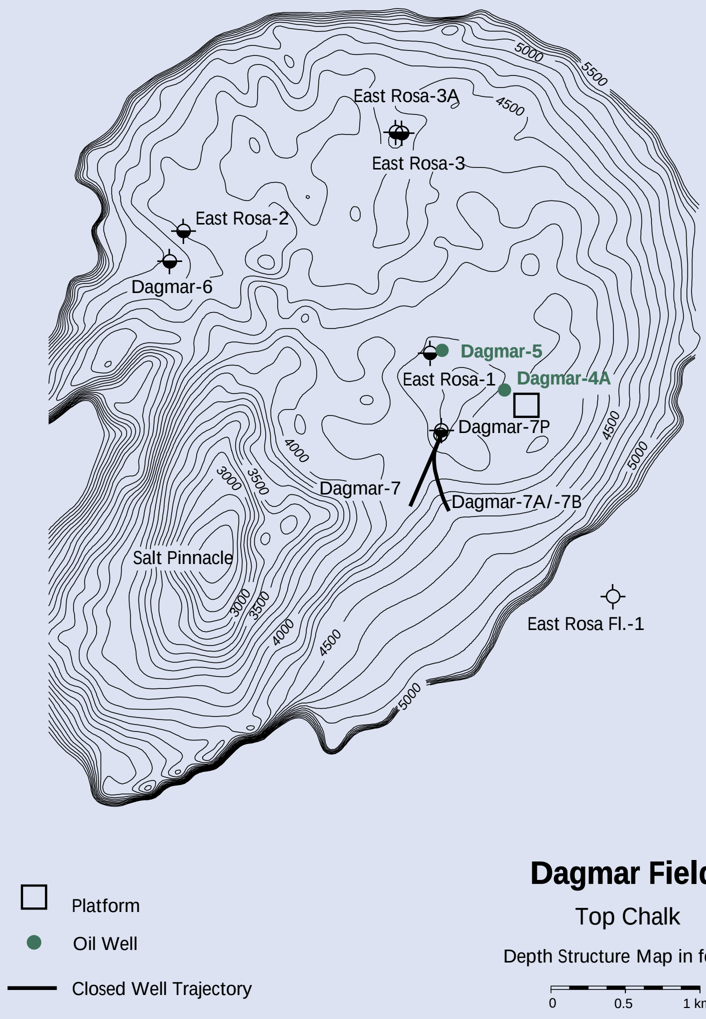
The Dagmar field is an anticlinal structure, induced through Zechstein salt tectonics. The uplift is so pronounced that the Dagmar oil reservoir is situated closer to the seabed than any other hydrocarbon reservoirs in Danish territory. The reservoir is heavily fractured (compare Skjold, Rolf, Regnar 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 including one unmanned production 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 relatively small amount of gas produced from Dagmar is flared due to the high content of hydrogen sulphide.



Dagmar Field

Top Chalk

Depth Structure Map in feet

DAN

Prospect:	Abby
Location:	Block 5505/17
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1971
Year on stream:	1972
Producing wells:	60
Water-injection wells:	44
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 2003:	
Oil:	54.6 million m^3
Gas:	6.9 billion Nm^3
Cum. production at 1 January 2003:	
Oil:	63.55 million m^3
Gas:	18.31 billion Nm^3
Water:	33.50 million m^3
Cum. injection at 1 January 2003:	
Water:	107.95 million m^3
Production in 2002:	
Oil:	6.32 million m^3
Gas:	0.95 billion Nm^3
Water:	6.35 million m^3
Injection in 2002:	
Water:	16.10 million m^3
Total investments at 1 January 2003:	
2002 prices	DKK 21.1 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.

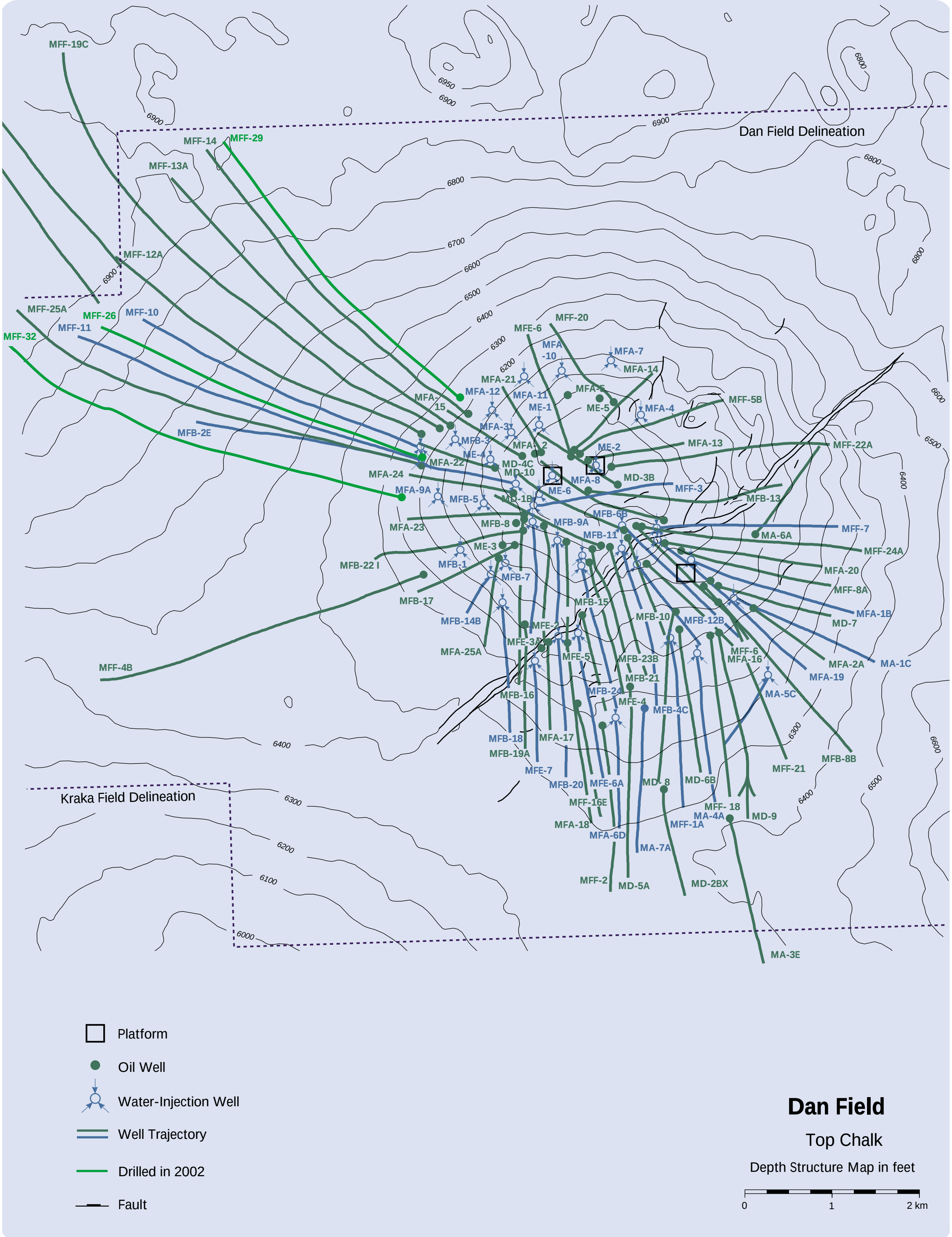
PRODUCTION FACILITIES

The Dan Field installations comprise six wellhead platforms (DA, DD, DE, DFA, DFB and DFE), two processing/accommodation platforms (DB and DFC) and two gas flare stacks (DC and DFD), as well as a combined wellhead and processing platform (DFF).

At the Dan Field, there are receiving facilities for the production from the Kraka and Regnar satellite fields. Moreover, the Dan Field installations handle gas production from the Halfdan Field and also provide the Halfdan Field with injection water.

After final processing, the oil is transported to shore via the booster platform, Gorm E. The gas is pre-processed and transported to Tyra East for final processing.

In the Dan Field, there are accommodation facilities for 86 persons on the DFC platform and five persons on the DB platform.


Dan Field Delineation
Kraka Field Delineation
MFF-19C
MFF-14
MFF-29
MFF-13A
MFF-12A
MFF-25A
MFF-26
MFF-10
MFF-11
MFF-32
MFB-2E
MFF-4B
MFE-6
MFF-20
MFA-10
MFA-7
MFA-14
MFA-21
MFA-12
MFA-11
MFA-15
ME-1
MFA-5
ME-5
MFA-4
MFF-5B
MFA-3
MFB-3
MFA-2
ME-2
MFA-13
MFF-22A
ME-4
MFA-22
MD-4C
MD-10
MFA-24
MFA-8
MD-3B
MFA-9A
MFB-5
ME-6
MFF-3
MFB-13
MFB-6B
MFA-23
MFB-8
MFB-9A
MFF-7
MFB-11
MA-6A
ME-3
MFF-24A
MFB-22 I
MFB-1
MFB-7
MFA-20
MFF-8A
MFB-17
MFB-15
MFA-1B
MFB-14B
MFB-10
MFB-12B
MD-7
MFE-2
MFE-3
MFA-25A
MFF-6
MFA-16
MFA-2A
MA-1C
MFE-5
MFB-23B
MFA-19
MFB-21
MFB-24
MA-5C
MFB-16
MFE-4
MFB-4C
MFB-18
MFA-17
MFB-19A
MFE-7
MFF-21
MFB-8B
MFB-20
MFE-6A
MD-8
MD-6B
MFF-16E
MFF-18
MA-4A
MD-9
MFA-18
MFF-1A
MFA-6D
MA-7A
MFF-2
MD-5A
MD-2BX
MA-3E
6950
6900
6800
6700
6600
6500
6400
6300
6200
6100
6000
Platform
Oil Well
Water-Injection Well
Well Trajectory
Drilled in 2002
Fault
Dan Field
Top Chalk
Depth Structure Map in feet
0
1
2 km

GORM

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:	35
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 2003:	
Oil:	11.2 million m³
Gas:	1.1 billion Nm³
Cum. production at 1 January 2003:	
Oil:	45.11 million m³
Net gas:	5.92 billion Nm³
Water:	30.10 million m³
Cum. injection at 1 January 2003:	
Gas:	8.15 billion Nm³
Water:	74.87 million m³
Production in 2002:	
Oil:	2.89 million m³
Net gas:	0.48 billion Nm³
Water:	4.02 million m³
Injection in 2002:	
Gas:	0.01 billion Nm³
Water:	8.17 million m³
Total investments at 1 January 2003:	
2002 prices	DKK 10.8 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.

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

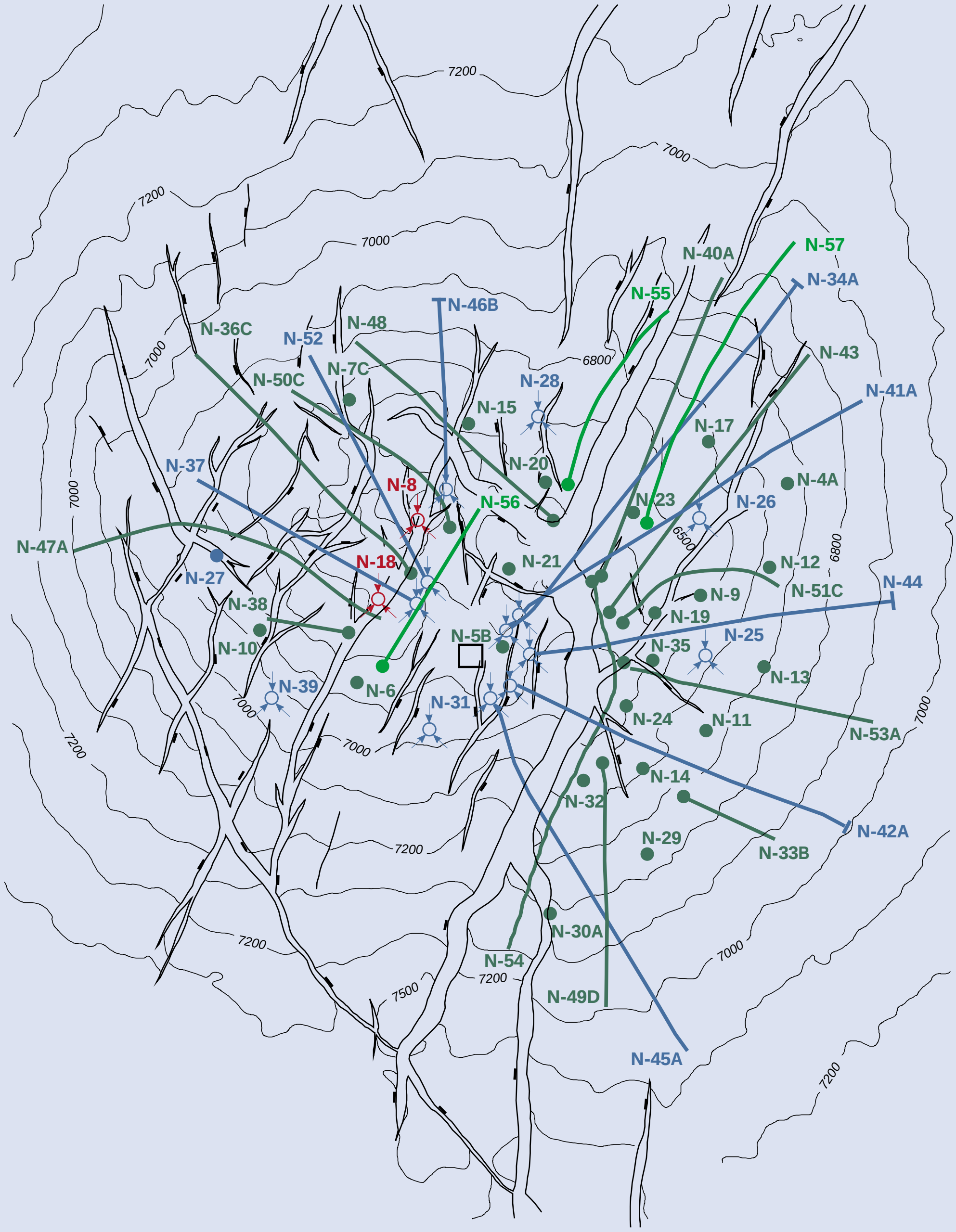
Gorm receives production from the satellite fields, Skjold, Rolf and Dagmar, as well as the liquids (hydrocarbons and water) produced in the Halfdan Field. The Gorm Field installations supply the Skjold Field with injection water and lift gas and the Rolf Field with lift gas. The gas produced is sent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

The processing facilities on the Gorm C platform consist of an oil stabilization plant, where the oil from the Rolf and Halfdan Fields is processed, plant for purifying the water produced 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 well-head pressure in the Gorm and Skjold wells.

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



Platform

Oil Well

Water-Injection Well

Gas-Injection Well

Well Trajectory

Top Chalk penetrated from below

Drilled in 2002

Fault

Gorm Field

Top Chalk

Depth Structure Map in feet

0 0.5 1 km

HALFDAN

Prospect:	Nana
Location:	Blocks 5505/13 and 5504/16
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1999
Year on stream:	2000
Producing wells:	23
Water-injection wells:	9
Water depth:	43 m
Field delineation:	107 km^2
Reservoir depth:	2,100 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2003:	
Oil:	69.2 million m^3
Gas:	7.1 billion Nm^3
Cum. production at 1 January 2003:	
Oil:	8.03 million m^3
Gas:	1.50 billion Nm^3
Water:	1.16 million m^3
Cum. injection at 1 January 2003:	
Water:	2.08 million m^3
Production in 2002:	
Oil:	3.72 million m^3
Gas:	0.76 billion Nm^3
Water:	0.37 million m^3
Injection in 2002:	
Water:	1.93 million m^3
Total investments at 1 January 2003:	
2002 prices	DKK 5.1 billion

REVIEW OF GEOLOGY

The Halfdan accumulation is found in a pocket in chalk layers and 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 towards the southeast, in the direction of the Dan Field. This means that today the structure does not appear from maps of the chalk surface, and that the oil continues to migrate. However, there is still an accumulation of oil and gas due to the low permeability of the reservoir. This type of trap has only been encountered in the Halfdan Field in Danish territory.

This porous, unfractured chalk is similar to that found in the western flank of the Dan Field. There is a gas cap above the northeastern part of the oil accumulation.

PRODUCTION STRATEGY

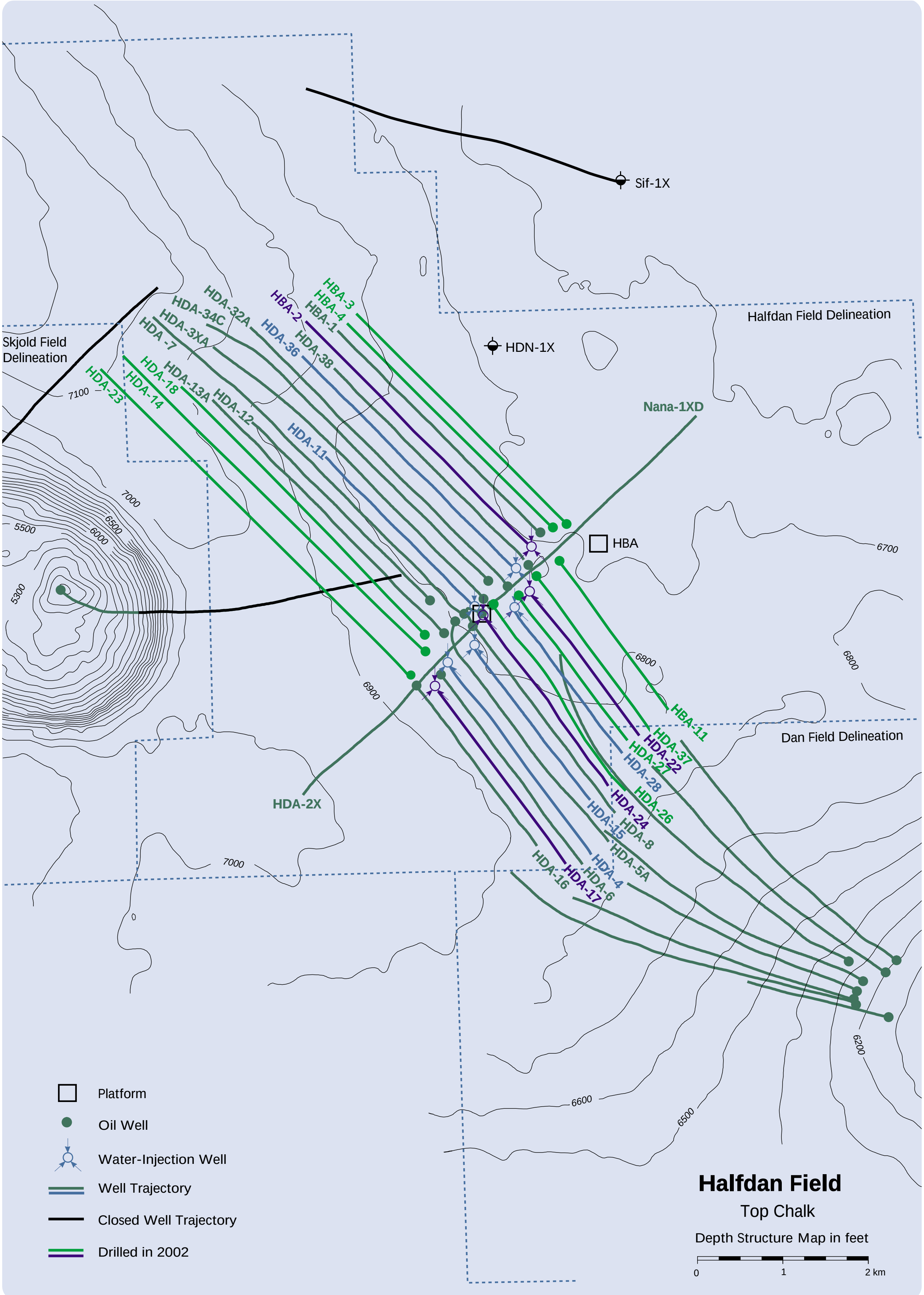
The recovery of oil and gas from the field is based on pressure support from water injection. The wells are arranged in a pattern of alternate production and injection wells with parallel well trajectories, about 180 metres apart. The injection wells are stimulated with acid, which makes it possible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

The regular spacing of the wells optimizes the flooding of the reservoir, thus enhancing recovery.

PRODUCTION FACILITIES

The installations in the field consist of a wellhead platform (HDA) with minimal production facilities. The operation of the wellhead platform is supported by a drilling rig. Production is separated into a gas and a liquid phase (oil and water). The liquid production is conveyed by pipeline to the Gorm Field, and the gas produced is transported through a pipeline to the Dan Field. The Gorm and Dan Field installations process the production from the Halfdan Field. In addition, Dan supplies the Halfdan Field with injection water. Another wellhead platform (HBA) is placed about 2 km northeast of the HDA platform. As a temporary measure, the separated hydrocarbons produced at the HBA platform are conveyed via the HDA platform to the Gorm and Dan Fields for final processing.

In 2003, the HDA platform installations are to be further expanded by adding a processing module for three-phase separation with water-processing and gas-processing/-compression facilities. Moreover, it is contemplated to install a 32-person accommodation platform (HDB) and a flare stack (HDC), both with bridge connection to the HDA platform.



Halfdan Field

Top Chalk

Depth Structure Map in feet

HARALD

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
Producing wells:	2 (Lulu), 2 (West Lulu)
Water depth:	64 m
Field delineation:	56 km²
Reservoir depth:	2,700 m 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 2003:	
Oil and condensate:	2.0 million m³
Gas:	6.4 billion Nm³
Cum. production at 1 January 2003:	
Oil and condensate:	6.34 million m³
Gas:	14.02 billion Nm³
Water:	0.24 million m³
Production in 2002:	
Oil and condensate:	0.58 million m³
Gas:	2.02 billion Nm³
Water:	0.08 million m³
Total investments at 1 January 2003:	
2002 prices	DKK 3.2 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 km².

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 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

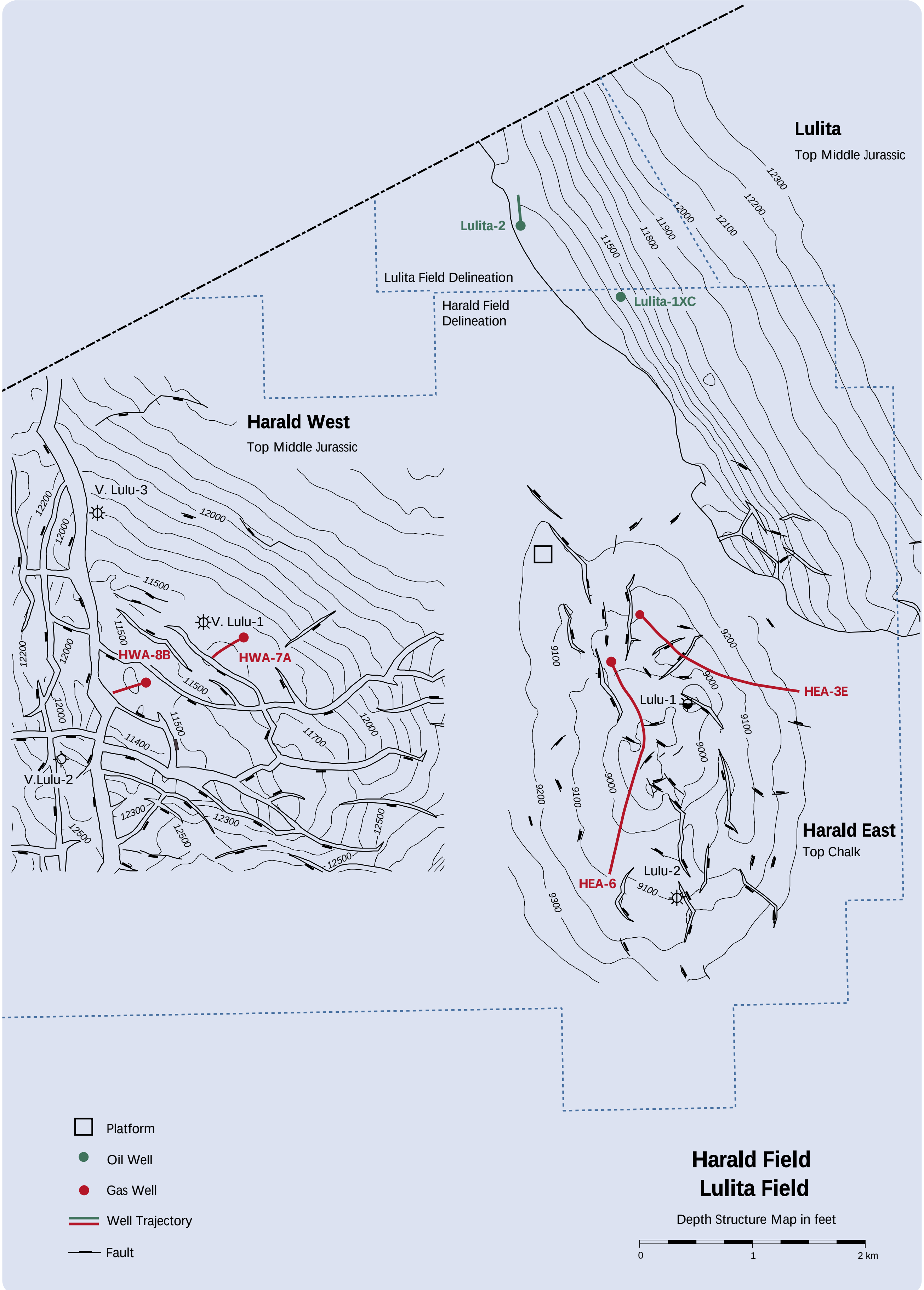
The Harald Field installations comprise a combined wellhead and processing platform (Harald A) and an accommodation platform (Harald B).

The processing facilities consist of a plant that separates the hydrocarbons produced, as well as a plant for the final processing of 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-1XC
Lulita Field Delineation
Harald Field
Delineation
Harald West
Top Middle Jurassic
V. Lulu-3
12000
12200
11500
V. Lulu-1
HWA-8B
HWA-7A
11500
11400
11700
12000
V.Lulu-2
12300
12500
Harald East
Top Chalk
9200
9100
9000
Lulu-1
HEA-3E
HEA-6
Lulu-2
9300
Platform
Oil Well
Gas Well
Well Trajectory
Fault
Harald Field
Lulita Field
Depth Structure Map in feet
0
1
2 km

KRAKA

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 km²
Reservoir depth:	1,800 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2003:	
Oil:	1.6 million m³
Gas:	1.2 billion Nm³
Cum. production at 1 January 2003:	
Oil:	3.83 million m³
Gas:	1.22 billion Nm³
Water:	2.96 million m³
Production in 2002:	
Oil:	0.16 million m³
Gas:	0.05 billion Nm³
Water:	0.31 million m³
Total investments at 1 January 2003:	
2002 prices	DKK 1.4 billion

REVIEW OF GEOLOGY

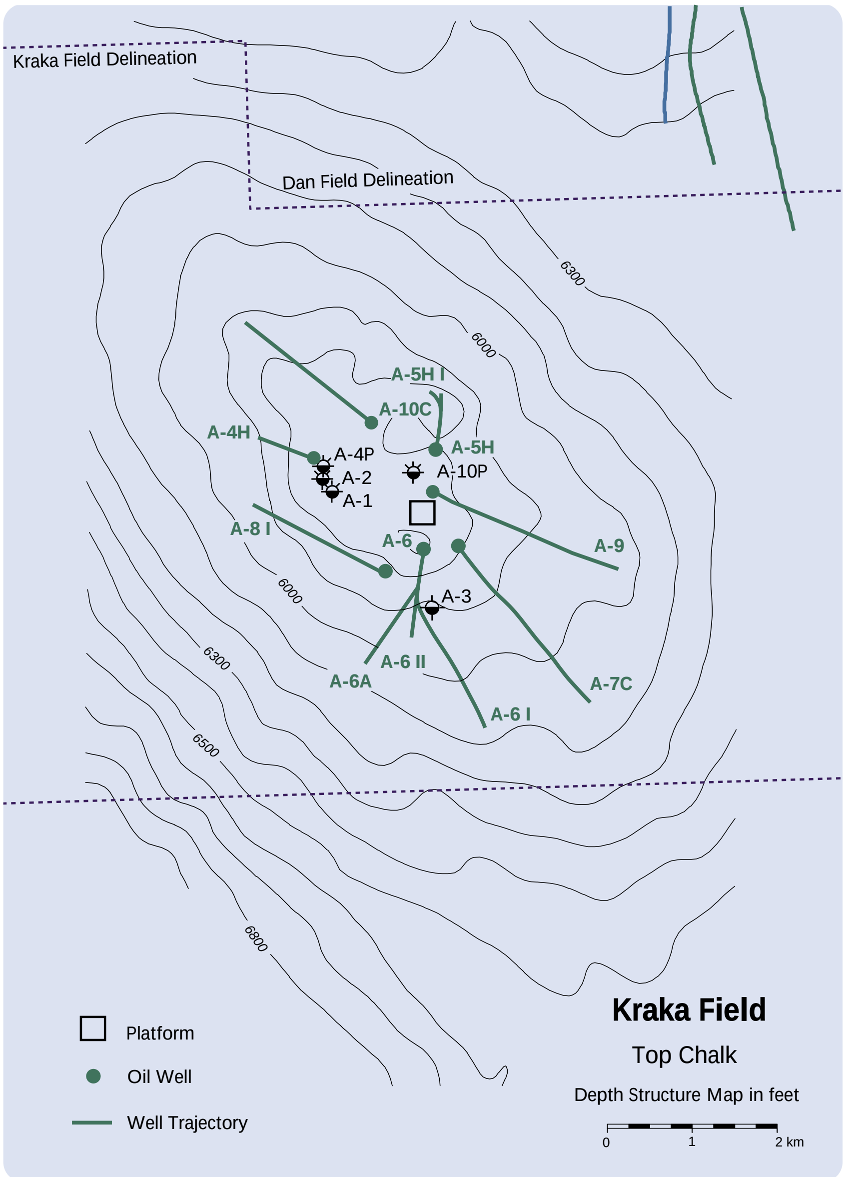
Kraka is an anticlinal structure induced through salt tectonics, which to a certain degree has caused fracturing in the chalk. The chalk reservoir has reasonable porosity, although low permeability. The thin oil pay zone is further characterized by high water saturations. There is a minor gas cap in 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. Attempts are currently being made 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 an unmanned production platform of the STAR type. The produced oil and gas are transported to the Dan FC platform for processing and export ashore. Lift gas is imported from the Dan FF platform.



LULITA

Location:	Blocks 5604/18 and 22
Licence:	Sole Concession (50%), 7/86 (34.5%) and 1/90 (15.5%)
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 2003:	
Oil:	0.2 million m³
Gas:	0.1 billion Nm³
Cum. production at 1 January 2003:	
Oil:	0.63 million m³
Gas:	0.44 billion Nm³
Water:	0.06 million m³
Production in 2002:	
Oil:	0.02 million m³
Gas:	0.01 billion Nm³
Water:	0.01 million m³
Total investments at 1 January 2003:	
2002 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.

REGNAR

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 2003:	
Oil:	0.1 million m³
Gas:	0.0 billion Nm³
Cum. production at 1 January 2003:	
Oil:	0.87 million m³
Gas:	0.06 billion Nm³
Water:	2.75 million m³
Production in 2002:	
Oil:	0.02 million m³
Gas:	0.00 billion Nm³
Water:	0.26 million m³
Total investments at 1 January 2003:	
2002 prices	DKK 0.2 billion

REVIEW OF GEOLOGY

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

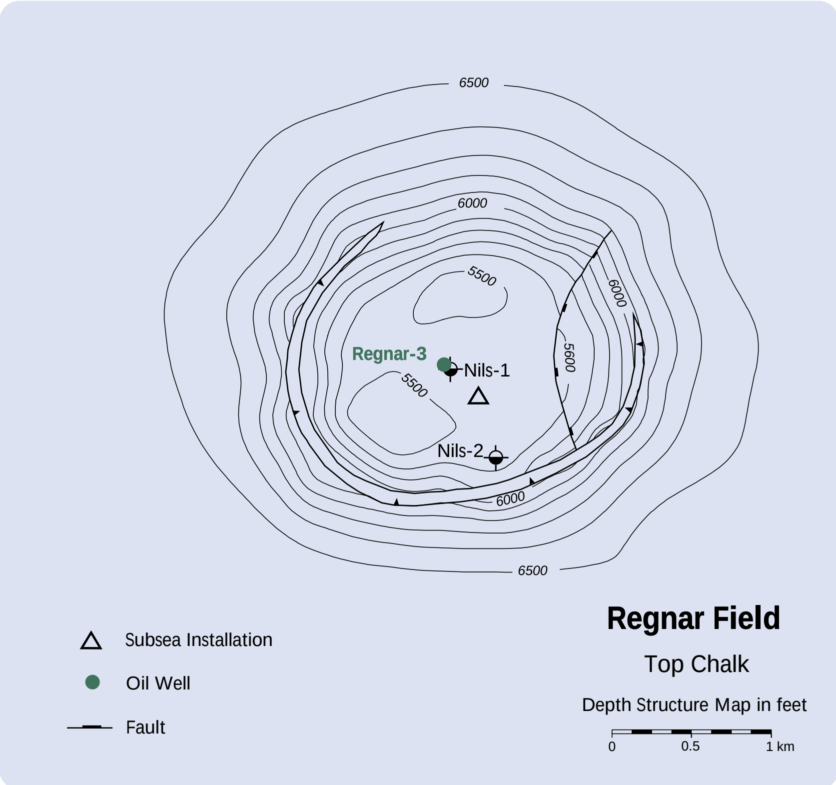
PRODUCTION STRATEGY

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 multi-phase flow to Dan FC for processing and export ashore.

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



ROAR

Prospect:	Bent
Location:	Block 5504/7
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1968
Year on stream:	1996
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 2003:

Oil and condensate:	0.9 million m³
Gas:	6.7 billion Nm³

Cum. production at 1 January 2003:

Oil and condensate:	2.11 million m³
Gas:	10.16 billion Nm³
Water:	1.46 million m³

Production in 2002:

Oil and condensate:	0.18 million m³
Gas:	1.05 billion Nm³
Water:	0.30 million m³

Total investments at 1 January 2003:

2002 prices	DKK 0.6 billion

REVIEW OF GEOLOGY

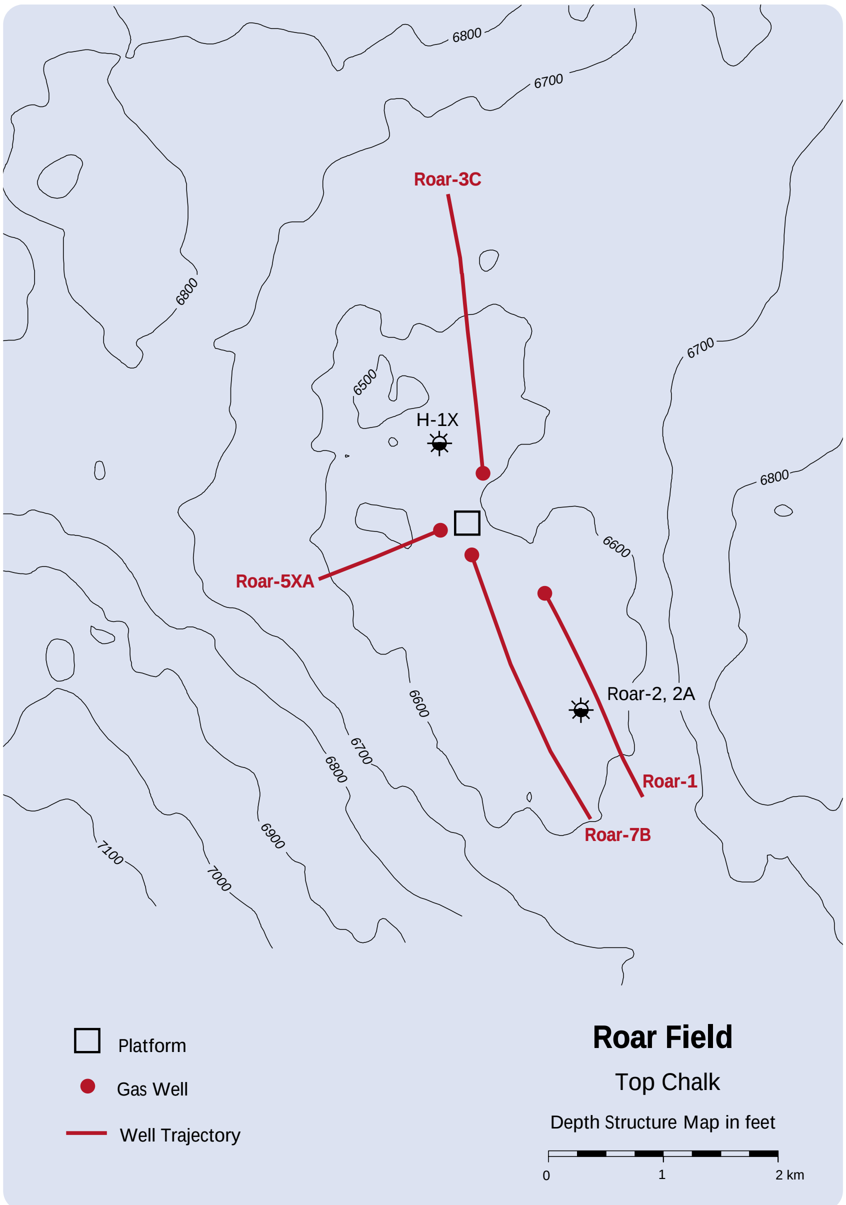
Roar is an anticlinal structure, induced through tectonic uplift. The accumulation consists of free gas containing condensate. The reservoir is only slightly fractured.

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 hydrocarbons produced are conveyed through two pipelines to Tyra East for processing and export ashore.



ROLF

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 km²
Reservoir depth:	1,800 m
Reservoir rock:	Chalk and Carbonates
Geological age:	Danian, Upper Cretaceous and Zechstein
Reserves at 1 January 2003:	
Oil:	0.6 million m³
Gas:	0.0 billion Nm³
Cum. production at 1 January 2003:	
Oil:	3.91 million m³
Gas:	0.17 billion Nm³
Water:	4.44 million m³
Production in 2002:	
Oil:	0.05 million m³
Gas:	0.00 billion Nm³
Water:	0.17 million m³
Total investments at 1 January 2003:	
2002 prices	DKK 0.9 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).

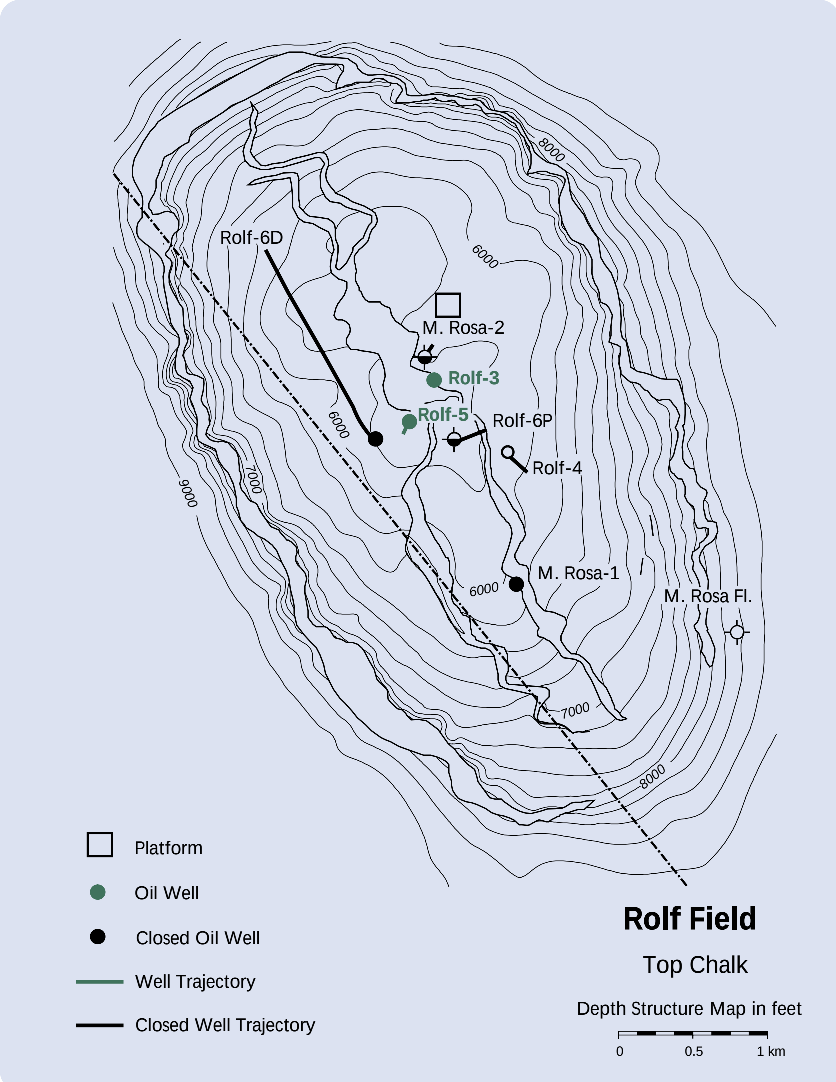
PRODUCTION STRATEGY

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 an unmanned wellhead platform.

The production is transported to the Gorm C platform for processing. Rolf is supplied with electricity and lift gas from the Gorm Field.



SIRI

Location:	Block 5604/20
Licence:	6/95
Operator:	Statoil Efterforskning og Produktion A/S until 31 July 2002 DONG Efterforskning og Produktion A/S from 1 August 2002
Discovered:	1995
Year on stream:	1999
Producing wells:	6
Water- and gas-injection wells:	2
Water depth:	60 m
Field delineation:	42 km^2
Reservoir depth:	2,060 m
Reservoir rock:	Sandstone
Geological age:	Palaeocene
Reserves at 1 January 2003:	
Oil:	3.7 million m^3
Gas:	0.0 billion Nm^3
Cum. production at 1 January 2003:	
Oil:	6.96 million m^3
Net gas:	0.18 billion Nm^3
Water:	7.98 million m^3
Cum. injection at 1 January 2003:	
Gas:	0.49 billion Nm^3
Water:	14.07 million m^3
Production in 2002:	
Oil:	1.49 million m^3
Net gas:	0.03 billion Nm^3
Water:	3.04 million m^3
Injection in 2002:	
Gas:	0.13 billion Nm^3
Water:	4.51 million m^3
Total investments at 1 January 2003:	
2002 prices	DKK 3.6 billion

REVIEW OF GEOLOGY

The Siri Field is a structural trap with a Palaeocene sandstone reservoir. The accumulation consists of oil with a relatively low content of gas.

PRODUCTION STRATEGY

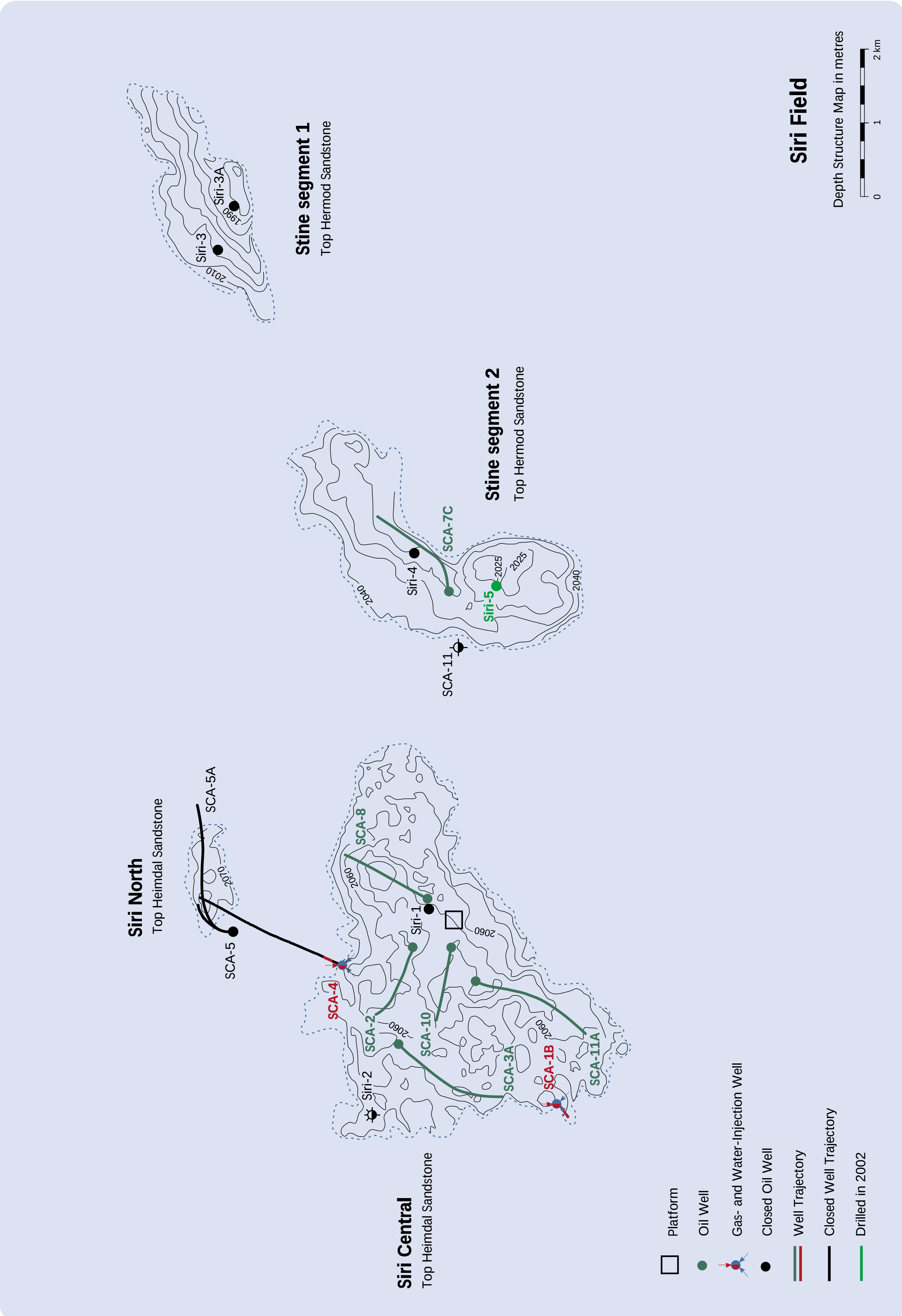
Recovery from the field is based on the production of oil through the co-injection of water and gas. Attempts are made to maintain the reservoir pressure at a level close to the initial pressure, and the volume of water injected is balanced with the volume of liquid produced from the reservoir.

PRODUCTION FACILITIES

The Siri Field installations comprise a combined wellhead, processing and accommodation platform. The processing facilities consist of a plant that separates the hydrocarbons produced. The platform also 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, the oil is transferred to a tanker by means of buoy loading facilities.

The Siri Field has accommodation facilities for 60 persons.



Siri Field
Depth Structure Map in metres
0
1
2 km
Stine segment 1
Top Hermod Sandstone
Siri-3
Siri-3A
1990
2010
Stine segment 2
Top Hermod Sandstone
SCA-7C
Siri-4
Siri-5
2025
2025
2040
2040
SCA-11
Siri North
Top Heimdal Sandstone
SCA-5A
SCA-5
2010
Siri Central
Top Heimdal Sandstone
SCA-8
Siri-1
2060
2060
2060
2060
SCA-4
SCA-2
SCA-10
SCA-3A
SCA-1B
SCA-11A
Siri-2
Platform
Oil Well
Gas- and Water-Injection Well
Closed Oil Well
Well Trajectory
Closed Well Trajectory
Drilled in 2002

SKJOLD

Prospect:	Ruth
Location:	Block 5504/16
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1977
Year on stream:	1982
Producing wells:	21
Water-injection wells:	7
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 2003:	
Oil:	10.9 million m³
Gas:	1.0 billion Nm³
Cum. production at 1 January 2003:	
Oil:	33.98 million m³
Gas:	2.93 billion Nm³
Water:	27.63 million m³
Cum. injection at 1 January 2003:	
Water:	67.17 million m³
Production in 2002:	
Oil:	1.66 million m³
Gas:	0.12 billion Nm³
Water:	3.01 million m³
Injection in 2002:	
Water:	6.41 million m³
Total investments at 1 January 2003:	
2002 prices	DKK 4.8 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

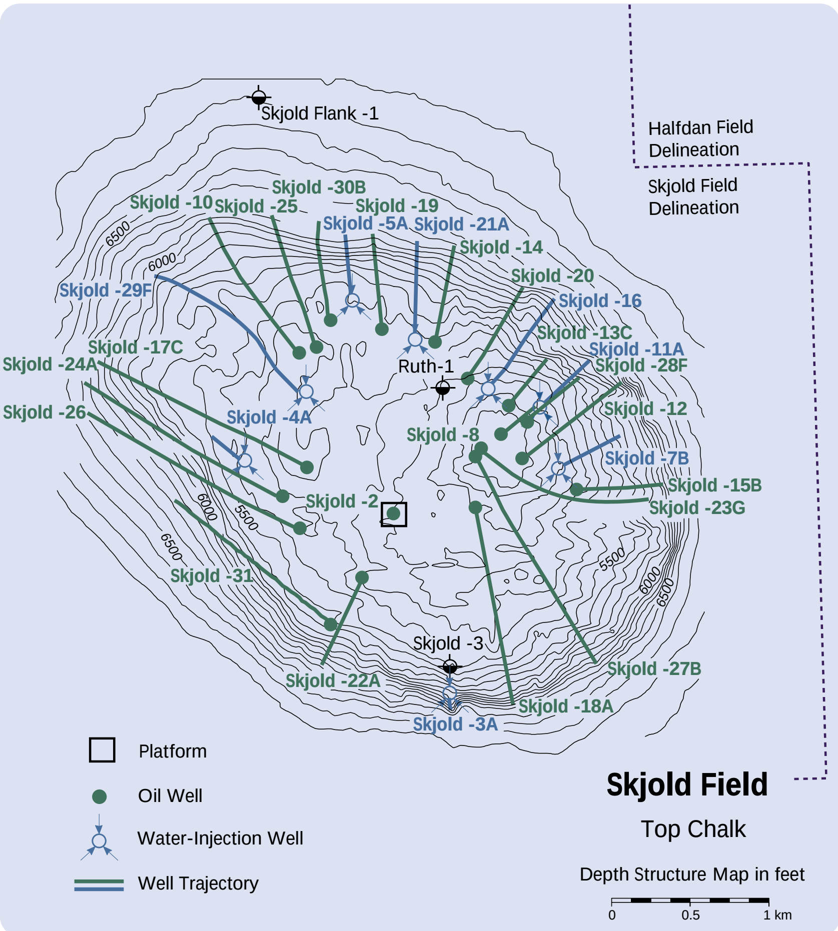
During the first years after production start-up, oil was produced from the crestal, central part of the reservoir. Water injection was initiated in the reservoir in 1986. Today, oil from the Skjold Field is mainly produced from horizontal wells at the flanks of the reservoir. The production and injection 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

Location:	Blocks 5604/29 and 30
Licence:	7/89
Operator:	Amerada Hess ApS
Discovered:	1969
Year on stream:	1999
Producing wells:	8
Water-injection wells:	5
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 2003:	
Oil:	24.4 million m^3
Gas:	7.9 billion Nm^3
Cum. production at 1 January 2003:	
Oil:	7.66 million m^3
Gas:	2.34 billion Nm^3
Water:	0.58 million m^3
Cum. injection at 1 January 2003:	
Water:	6.43 million m^3
Production in 2002:	
Oil:	2.31 million m^3
Gas:	0.68 billion Nm^3
Water:	0.39 million m^3
Injection in 2002:	
Water:	4.40 million m^3
Total investments at 1 January 2003:	
2002 prices	DKK 6.7 billion

REVIEW OF GEOLOGY

South Arne is an anticlinal structure, induced through tectonic uplift (both of the Danian/Upper Cretaceous and Lower Cretaceous), 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

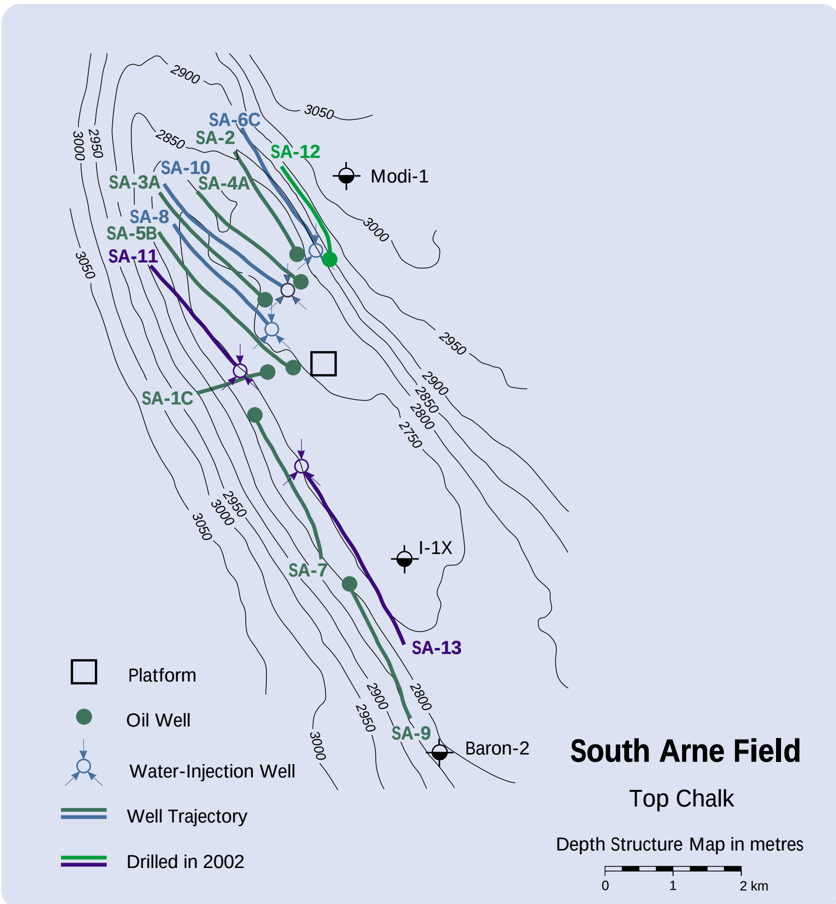
In the initial development phase, the recovery of oil and gas from the field was based on natural depletion, i.e. without the use of gas or water injection. The wells have good production properties. Pressure support from water injection has subsequently been established.

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 the depositing of sparingly soluble salts in and around the injection wells, a system for removing the sulphate ions from the seawater prior to injection has been installed.

The oil produced is conveyed to an 87,000 m^3 storage tank on the seabed. When the tank is full, the oil is transferred to a tanker by means of buoy loading facilities. 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.



SVEND

Prospect:	North Arne/Otto
Location:	Block 5604/25
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1975 (North Arne) and 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 2003:	
Oil:	1.4 million m³
Gas:	0.2 billion Nm³
Cum. production at 1 January 2003:	
Oil:	4.78 million m³
Gas:	0.57 billion Nm³
Water:	4.33 million m³
Production in 2002:	
Oil:	0.46 million m³
Gas:	0.06 billion Nm³
Water:	1.10 million m³
Total investments at 1 January 2003:	
2002 prices	DKK 1.1 billion

REVIEW OF GEOLOGY

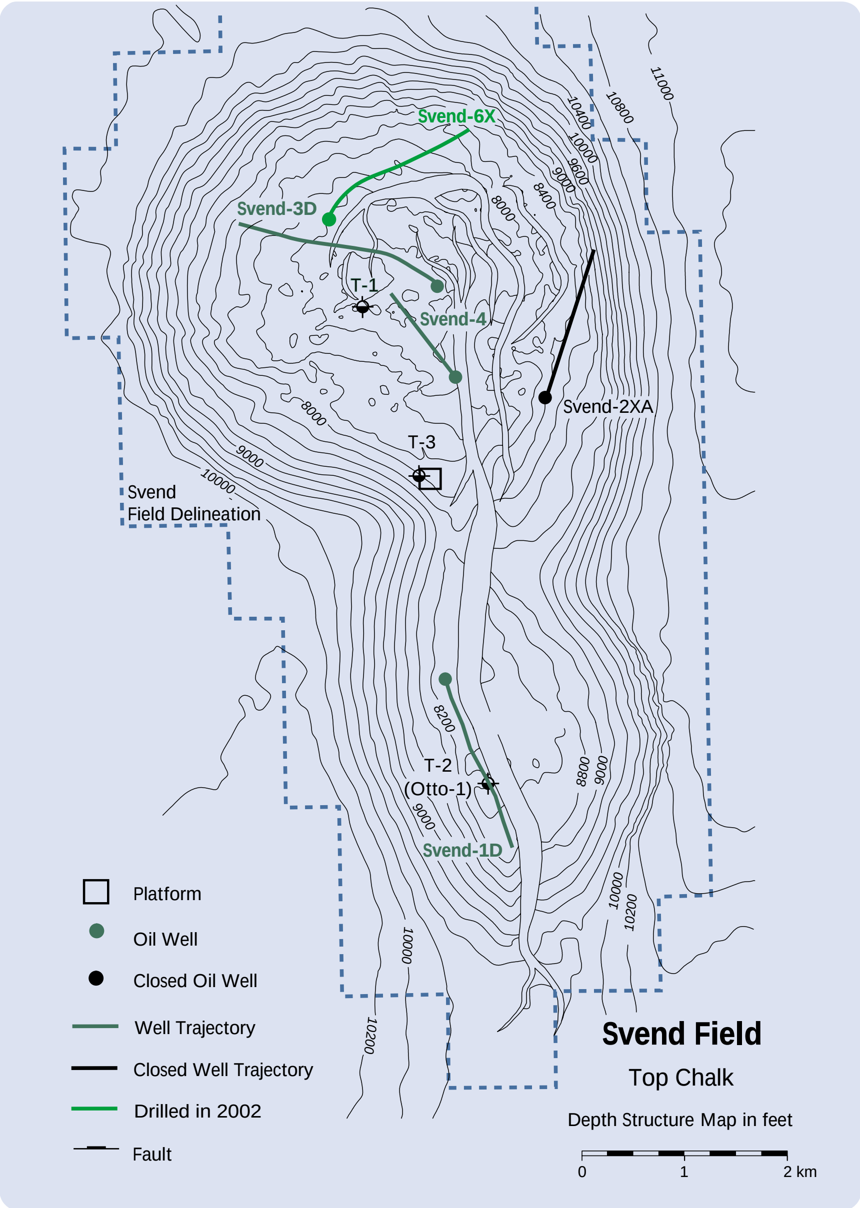
The Svend Field is an anticlinal structure, induced through salt tectonics. This led to fracturing of the chalk in the reservoir and divided the field into a western and eastern block, separated by a major fault. The northern reservoir of the Svend Field is situated about 250 metres higher than the southern 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 STAR platform. 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	
Prospect:	Cora
Location:	Blocks 5504/11 and 12
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1968
Year on stream:	1984
Producing wells:	42
Producing/ injection wells:	20
Water depth:	37-40 m
Area:	90 km²
Reservoir depth:	2,000 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2003:	
Oil and condensate:	6.2 million m³
Gas:	27.1 billion Nm³
Cum. production at 1 January 2003:	
Oil and condensate:	20.19 million m³
Net gas:	33.21 billion Nm³
Water:	22.28 million m³
Cum. injection at 1 January 2003:	
Gas:	28.70 billion Nm³
Production in 2002:	
Oil and condensate:	0.80 million m³
Net gas:	1.41 billion Nm³
Water:	2.37 million m³
Injection in 2002:	
Gas:	2.54 billion Nm³
Total investments at 1 January 2003:	
2002 prices	DKK 22.6 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

As far as natural gas supplies are concerned, the Tyra Field acts as a buffer, so that if the other Danish oil and gas fields do not produce sufficient gas to meet the contractual obligation to supply gas to DONG Naturgas A/S, the balance is supplied from the Tyra Field.

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 the 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.

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/ 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 processing and compression 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.

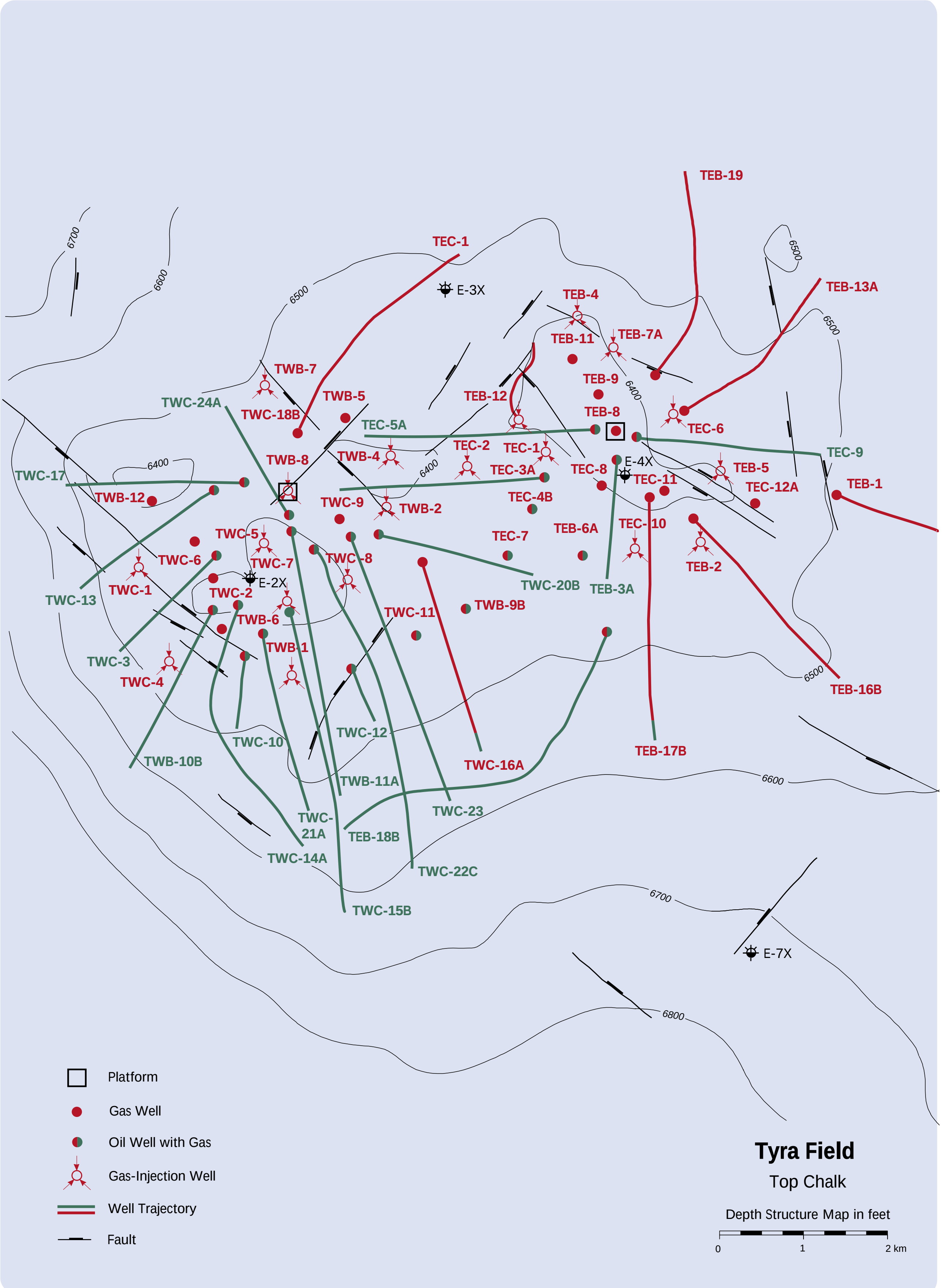
Tyra East consists of two wellhead platforms (TEB and TEC), one processing/ accommodation platform (TEA), one gas flare stack (TED), and one riser platform (TEE), as well as a bridge module supported by a STAR jacket (TEF).

The Tyra East complex includes facilities for the final processing of gas, oil, condensate and water. The bridge module houses the facilities for receiving and handling production from the Valdemar, Roar, Svend and Harald Fields, as well as plant for processing the water produced by the satellite fields.

The two platform complexes in the Tyra Field are interconnected by pipelines in order to generate the maximum operational flexibility and reliability of supply.

The oil and condensate produced at Tyra and its satellite fields are transported to shore via Gorm E, while the gas produced at the Tyra Centre is transported to shore via the TEE platform together with the gas production from the Dan, Gorm and Harald Centres.

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


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

TYRA SOUTHEAST

Location:	Block 5504/12
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1991
Year on stream:	2002
Producing wells:	5
Water depth:	38 m
Field delineation:	113 km^2
Reservoir depth:	2,050 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2003:	
Oil:	2.5 million m^3
Gas:	8.6 billion Nm^3
Cum. production at 1 January 2003:	
Oil:	0.49 million m^3
Gas:	0.45 billion Nm^3
Water:	0.21 million m^3
Production in 2002:	
Oil:	0.49 million m^3
Gas:	0.45 billion Nm^3
Water:	0.21 million m^3
Total investments at 1 January 2003:	
2002 prices	DKK 1.0 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 NE-SW fault zone. The relief is less pronounced in this formation than in the Tyra Field. The structure is part of the major NW-SE uplift zone that also comprises the Roar, Tyra and Igor Fields.

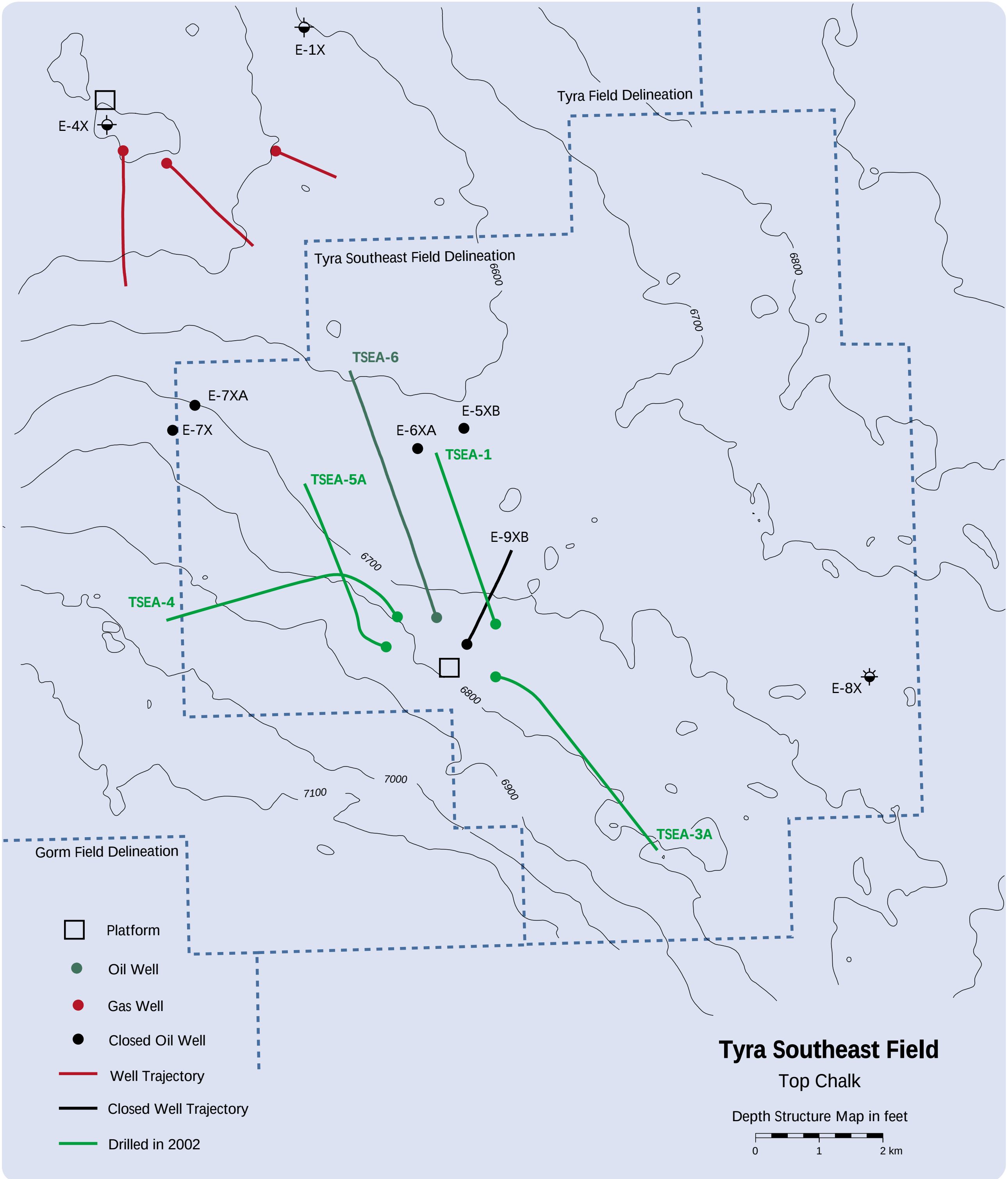
The Tyra Southeast accumulation consists of free gas overlying an oil zone in the southeastern part of the field.

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 Tyra, including an unmanned production 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-6
E-7XA
E-7X
E-5XB
E-6XA
TSEA-1
TSEA-5A
E-9XB
TSEA-4
E-8X
6800
7000
7100
6900
TSEA-3A
Gorm Field Delineation
Platform
Oil Well
Gas Well
Closed Oil Well
Well Trajectory
Closed Well Trajectory
Drilled in 2002
Tyra Southeast Field
Top Chalk
Depth Structure Map in feet
0
1
2 km

VALDEMAR

Prospects:	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 2003:	
Oil:	1.8 million m^3
Gas:	1.8 billion Nm^3
Cum. production at 1 January 2003:	
Oil:	1.64 million m^3
Gas:	0.67 billion Nm^3
Water:	0.73 million m^3
Production in 2002:	
Oil:	0.35 million m^3
Gas:	0.11 billion Nm^3
Water:	0.29 million m^3
Total investments at 1 January 2003:	
2002 prices	DKK 1.6 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.

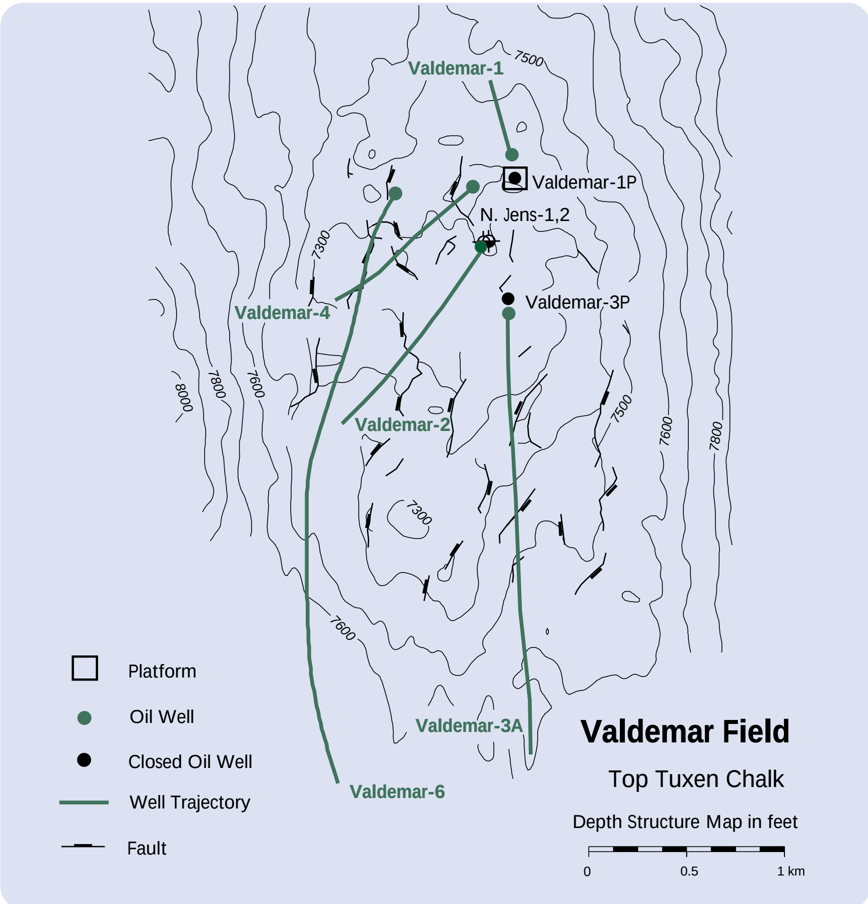
Production from the field is based on primary recovery.

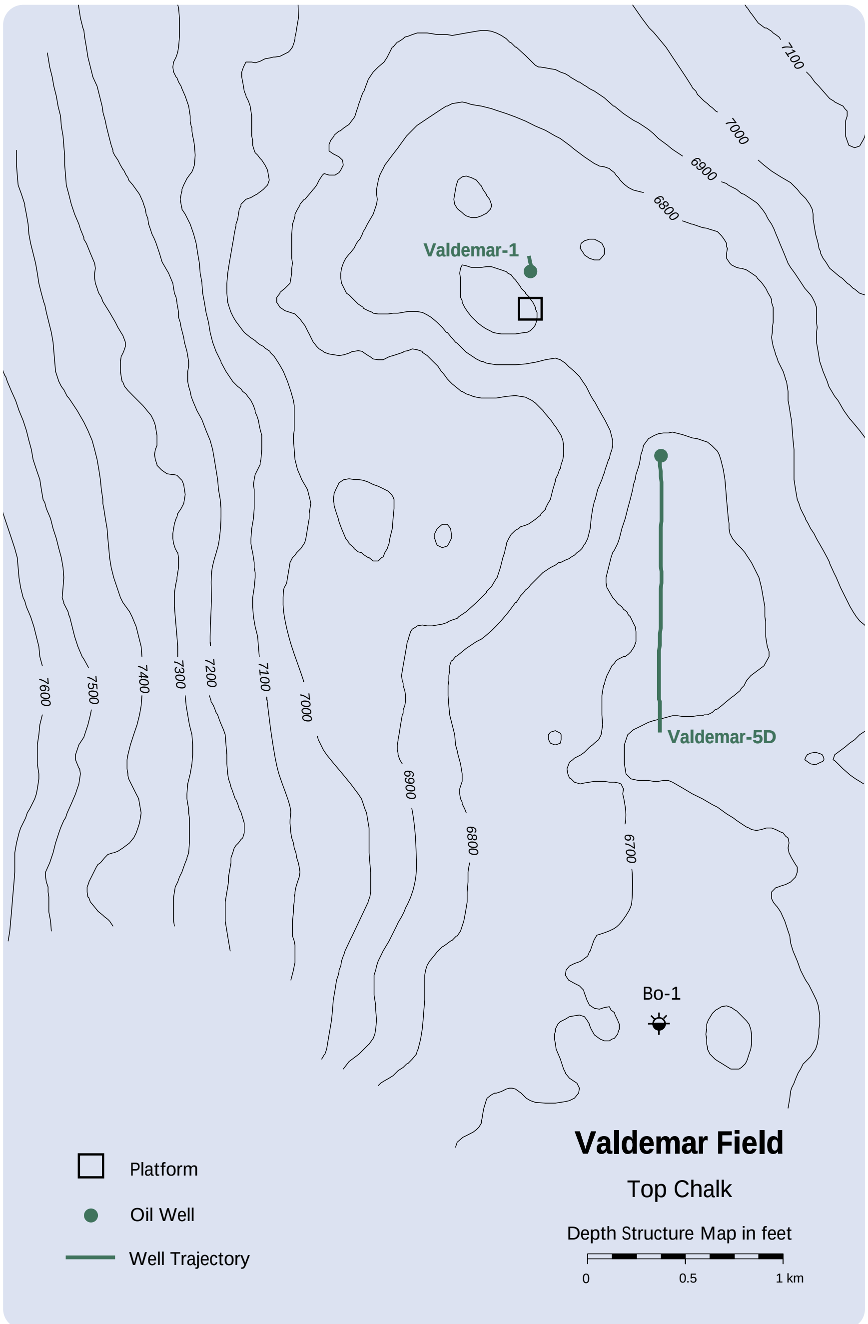
PRODUCTION STRATEGY

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 Valdemar Field (the North Jens reservoir) has been developed as a satellite to Tyra, including an unmanned production platform of the STAR type. The production is transported to Tyra East for processing and export ashore.





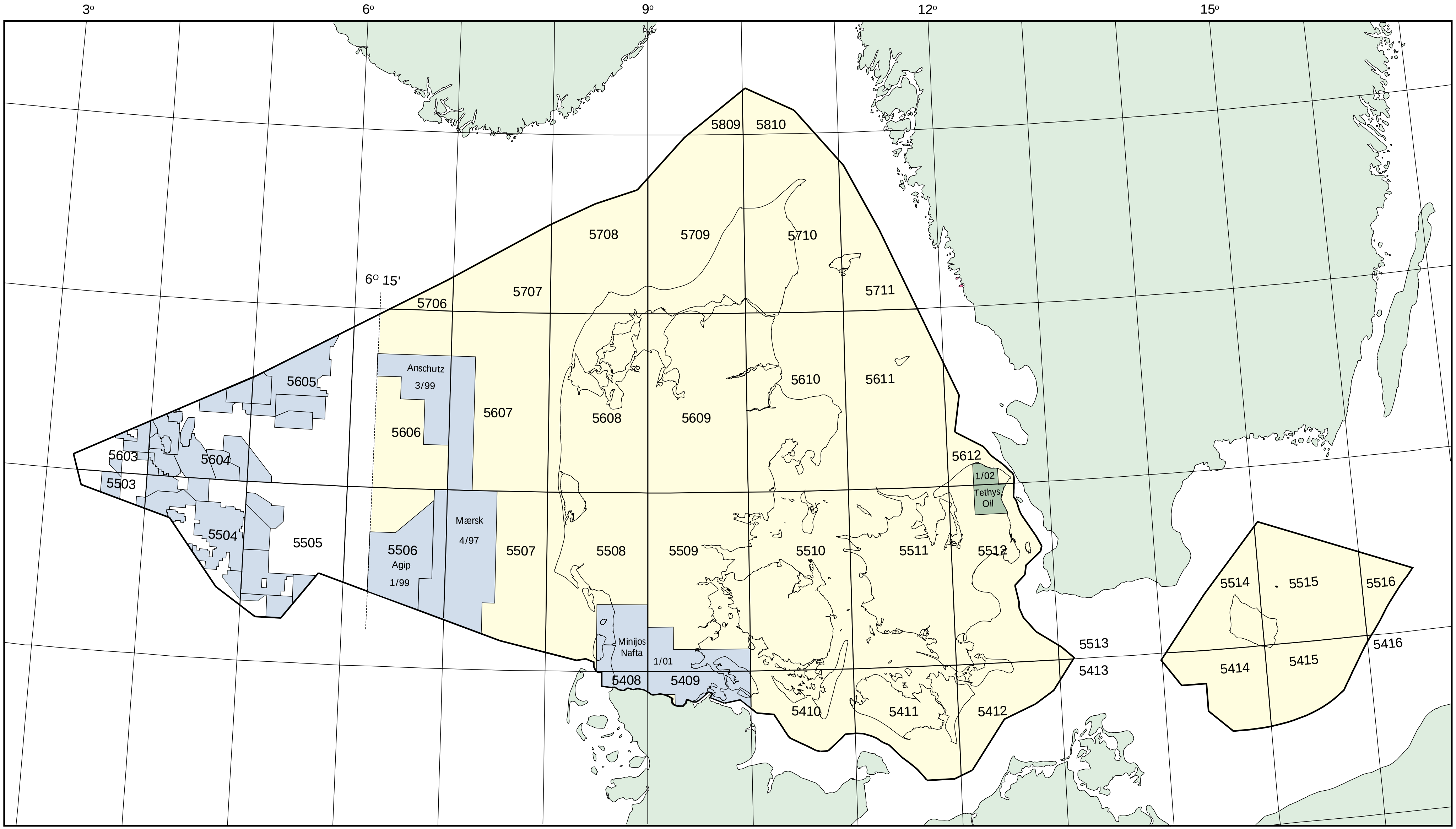
Valdemar-1
Valdemar-5D
Bo-1
7600
7500
7400
7300
7200
7100
7000
6900
6800
6700
Platform
Oil Well
Well Trajectory
Valdemar Field
Top Chalk
Depth Structure Map in feet
0
0.5
1 km

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 %[3]	Net Foreign-Currency Value DKK billion[4]	State Revenue DKK million
1972	105	29	30	3.0	7.0	6.6	-3.2	-
1973	9	31	28	4.6	6.1	9.4	-4.0	1
1974	38	57	83	11.6	6.1	15.2	-9.2	1
1975	139	62	76	12.3	5.8	9.7	-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	10.1	-9.5	21
1979	387	143	55	20.4	5.3	9.6	-13.7	19
1980	956	163	78	37.5	5.6	12.3	-18.6	29
1981	1,651	320	201	37.4	7.1	11.7	-20.1	36
1982	3,884	534	257	34.0	8.4	10.2	-20.6	234
1983	3,554	544	566	30.5	9.1	6.9	-17.8	399
1984	1,598	1,237	1,211	28.2	10.4	6.3	18.3	488
1985	1,943	1,424	1,373	27.2	10.6	4.7	-17.6	1,289
1986	1,651	1,409	747	14.9	8.1	3.6	-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	4.6	-3.7	568
1989	1,162	1,599	366	18.2	7.3	4.8	-3.2	1,024
1990	1,769	1,654	592	23.6	6.2	2.6	-2.7	2,089
1991	2,302	1,898	985	20.0	6.4	2.4	-1.9	1,889
1992	2,335	1,806	983	19.3	6.0	2.1	-0.4	1,911
1993	3,307	2,047	442	16.8	6.5	1.2	-1.7	1,811
1994	3,084	2,113	151	15.6	6.4	2.0	-0.5	2,053
1995	4,164	1,904	272	17.0	5.6	2.1	0.3	1,980
1996	4,257	2,094	470	21.1	5.8	2.1	0.4	2,465
1997	3,781	2,140	515	18.9	6.6	2.2	1.4	3,171
1998	5,306	2,037	406	12.8	6.7	1.9	0.9	3,129
1999	3,531	2,157	563	17.9	7.0	2.5	3.5	3,556
2000	3,100	2,816	627	28.5	8.1	2.9	14.9	8,724
2001	3,991	2,420	1,076	24.4	8.3	2.3	12.5	9,633
2002*	5,494	2,730	965	24.9	7.9	2.4	15.6	9,898

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

Danish Licence Area January 2003



Licences issued in 1962-2001

Licence issued in 2002

Open Door Procedure

Danish Licence Area January 2003

The Western Area