PREFACE

2000 was yet another prosperous year for Danish oil and gas activities. As in previous years, oil production set a new record, and at the same time the Danish Energy Agency has made the largest upward adjustment of oil reserves ever.

The outlook for the years to come is optimistic in a number of areas, including hydrocarbon exploration. The special *Resources* section in this year's report contains estimates of the oil potential in the Danish part of the North Sea, the production potential in structures as yet unexplored and the potential in using new technology. This additional oil potential is estimated at 100-150 million m^3 of oil for the next ten-year period.

The unprecedented write-up of the Danish reserves made this year is due, for one thing, to the discovery of a new type of accumulation where hydrocarbons extend over large areas between existing fields and are not, as previously, accumulated in "bulges" in the subsoil. Exploration for such accumulations is expected to intensify in light of their great potential. In March 2001, Mærsk Olie og Gas AS submitted a plan for a major, further development of the Halfdan oil field, one of the new types of accumulation.

Finally, the very high oil price level during the year also affected oil and gas activities. The oil companies' earnings have increased significantly, as has the incentive to invest in further exploration and production. Another consequence of the high oil price level is record-high revenue for the state in the form of taxes and fees from the oil producing companies.

If the favourable development in the oil and gas sector is sustained, Denmark will be self-sufficient in oil and gas for many years to come.

Copenhagen, June 2001

Ib Larsen

Ib Larsen

Director

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 and the so-called oil field 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 in this Report are those recommended by the SPE (Society of Petroleum Engineers).

The density of oil is often expressed in API gravity or degrees API: °API. The conversion factors are shown in the formulae below.

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 2000. The lower calorific value is indicated.

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

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

Some abbreviations:

kPa — *kilopascal. Unit of pressure. 100 kPa = 1 bar*

Nm^3 — *Normal cubic metre. Unit of measurement used for natural gas in the reference state 0°C and 101.325 kPa.*

m^3 (st) — *Standard cubic metre. Unit of measurement used for natural gas and crude oil in a reference state of 15°C and 101.325 kPa.*

Btu — *British Thermal Unit. Other thermal units are J (= Joule) and cal (calorie).*

bbl — *Blue barrel. In the early days of the oil industry when oil was traded in physical barrels, different barrel sizes soon emerged. To avoid confusion, Standard Oil painted their standard-volume barrels blue.*

kg·mol — *kilogrammol; the mass of a substance whose mass in kilograms is equal to the molecular mass of the substance.*

γ — *gamma; relative density.*

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

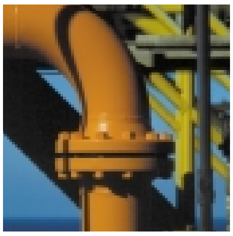
ft — *foot/feet; British unit of length. 1 ft = 12 in.*

t.o.e. — *tons oil equivalent; this unit is internationally defined as 1 t.o.e. = 10 Gcal.*

	FROM	TO	MULTIPLY BY
Crude Oil	m^3 (st)	stb	6.293
	m^3 (st)	GJ	36.3
	m^3 (st)	t	0.84[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	0.0373
	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. EXPLORATION

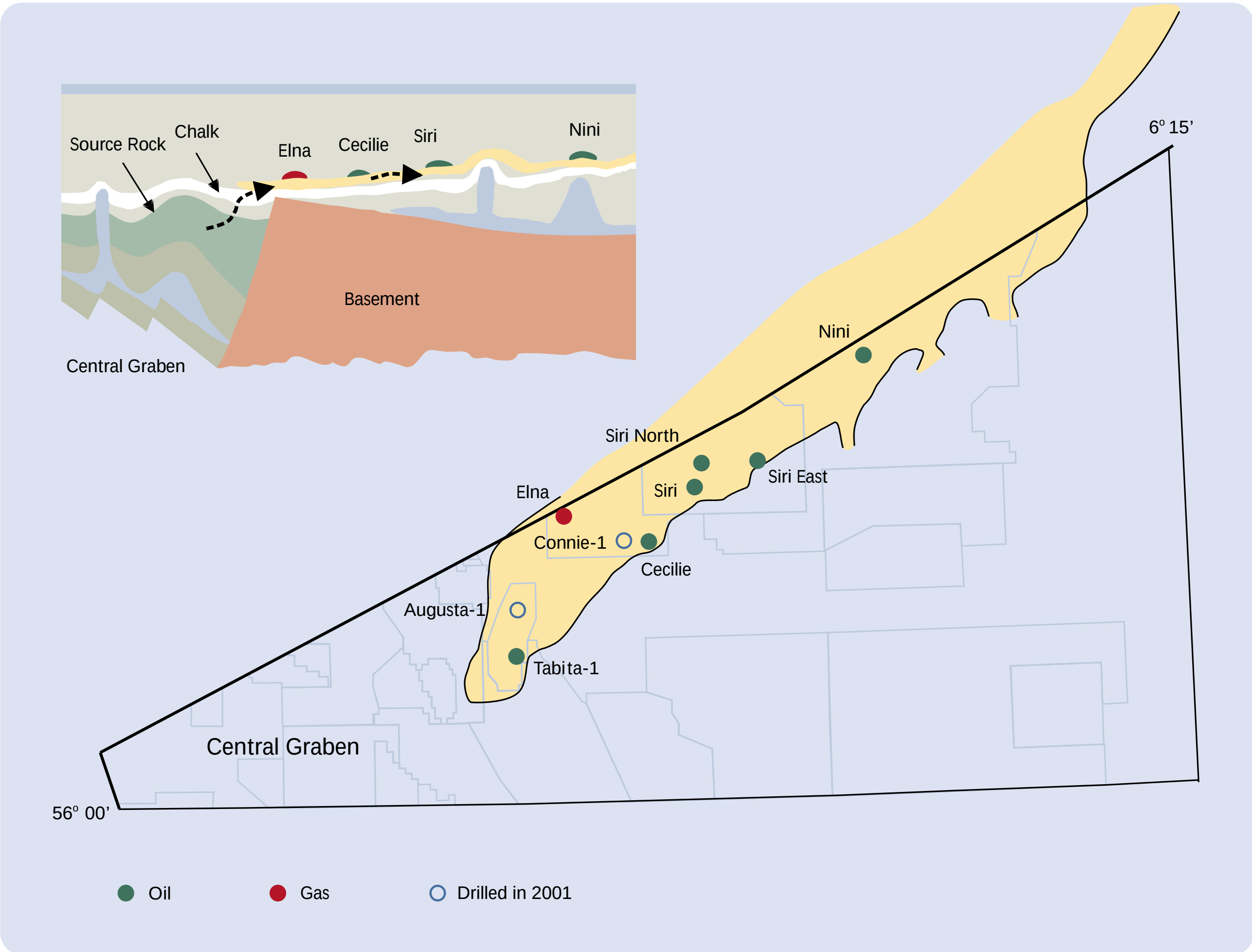
Exploration activity was high in 2000 due to drilling operations initiated by the licensees under the licences granted in the Fifth Licensing Round. Two of the seven exploration wells drilled during the year encountered new oil deposits outside the Central Graben. The Danish Energy Agency expects drilling activities to continue at the same high level in 2001.

EXPLORATION OF THE SIRI FAIRWAY

Exploration activities east of the Central Graben in 2000 led to the discovery of two new oil deposits, Nini and Cecilie. Both deposits are located in the so-called *Siri Fairway*, see Fig. 1.1, where a total of six oil discoveries and a single gas/condensate discovery have been made to date. The other four oil discoveries are Siri, Siri East, Siri North and Tabita-1. Elna, the gas/condensate accumulation, was encountered already in 1985, but was relinquished in 1988 by the then licensee.

The Statoil group has carried on production from the Siri Field since 1999. Siri North was producing temporarily in 1999 from a well drilled from the Siri Field to Siri North. After a brief production period, the well was converted into an injec-

Fig 1.1 Cross-section and Map of the *Siri Fairway*



tion well serving the Siri Field. The Statoil group is presently considering development options for Siri East (Stine).

The holders of the two licence areas in which Nini and Cecilie were discovered are currently making a more detailed appraisal of the new finds in order to examine the possibilities of their development.

The Siri Fairway, situated close to the Norwegian/Danish border, is the designation of a geological area where Palaeogene sandstone reservoirs have trapped hydrocarbons migrating from the Central Graben.

When the deposition of chalk in North West Europe ended approx. 60 million years ago, there was a marked change in depositional regime. The slow-rate deposition process was followed by an uplift of the Scandinavian basement. As a result, the area was exposed to erosion, and the erosion products, i.e. clays and sands, were carried into the prehistoric ocean. The area that included the Siri Fairway was then located in a large, westward sloping valley, presumably 100-200 metres below sea level.

From time to time, the more easterly seabed deposits became unstable. This led to extensive subsea landslips, in which clays and sands were transported into the valley. Fortunately, the sands and clays were generally separated in the process, with the sand forming more or less extensive layers surrounded by clays. Today, these sand layers include the reservoirs in which the above-mentioned discoveries were made.

But the actual formation of oil and gas took place further west, in the Central Graben. More than 145 million years ago, in the Jurassic period, high-organic sediments were deposited in this area. Due to the later subsidence in the Central Graben, these layers were buried at a depth where the temperature was so high that organic matter was converted into hydrocarbons.

Part of these hydrocarbons migrated through the overlying strata into the sand layers of the Siri Fairway. The discovery of the Siri Field in 1995 proved that the hydrocarbons had been able to migrate over a distance of at least 25 kilometres from the Central Graben. After the drilling of the DONG group's most recent appraisal well in the Nini oil deposit, this distance has increased to 65 kilometres.

Oil exploration in the Siri Fairway continues in 2001 with DONG Efterforskning og Produktion A/S (DONG E & P A/S) drilling the Connie-1 exploration well and the Augusta-1 appraisal well. The Statoil group is also contemplating new wells in the Siri area for 2001.

AREAS RELINQUISHED IN THE CONTIGUOUS AREA

On 17 July 2000, following negotiations with the Concessionaires pursuant to the Sole Concession of 8 July 1962, the Danish Energy Agency approved the relinquishment of areas in the Contiguous Area as at 1 January 2000. According to the 1981 agreement between the Danish State and A.P. Møller, the Concessionaires are to relinquish 25% of each of the nine sixteenth blocks comprised by the Contiguous Area at 1 January 2000 and again at 1 January 2005. Areas that include producing fields and areas for which development plans have been submitted to the Danish Energy Agency for approval are exempted from relinquishment.

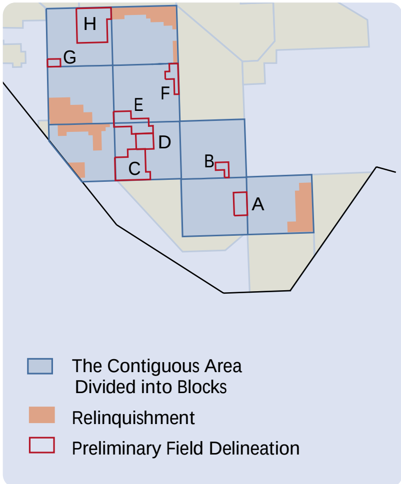


Fig. 1.2 Relinquishment in The Contiguous Area

In four out of the nine blocks, 25% has already been relinquished. In the other blocks, the fields delineated in connection with the relinquishment cover the whole area of the block. The delineation of these fields was also approved by the Danish Energy Agency on 17 July 2000.

The new boundaries in the Contiguous Area are shown in Fig. 1.2. The new delineation and field boundaries appear from Fig. 2.1 in the section on *Development and Production*.

However, the boundaries established for a number of fields are maximum boundaries. With regard to areas A, B, C, D, E, F, G and H, it has not yet been possible to fix final boundaries with sufficient certainty. In these areas, the Concessionaires have undertaken to carry out extensive surveys as soon as possible, so that the final boundaries may be established before 1 July 2003. For area E, however, the deadline is 1 July 2004.

In cases where the extent of the hydrocarbon accumulations does not justify the delineation made, the Danish Energy Agency will reduce the delineated areas accordingly subject to negotiation with the Concessionaires. Areas located beyond the established boundaries will be relinquished immediately. However, the areas to be relinquished in each block cannot exceed 25%.

On 25 August 2000, the Danish Energy Agency approved work programmes for the Contiguous Area for the period 1 January 2000 to 31 December 2005. The work programmes describe the exploration activities foreseen in the years to come for the nine blocks that make up the Contiguous Area. The programmes cover a six-year term, but are reviewed every third year, i.e. next time at 1 January 2003. The studies and drilling activities planned for the first three-year period will form the basis for continued exploration activities in the Contiguous Area in the period 2003-2005.

NEW LICENCES

Open Door Procedure

The submission of two new applications in 2000 shows continued interest in exploring in the Open Door area.

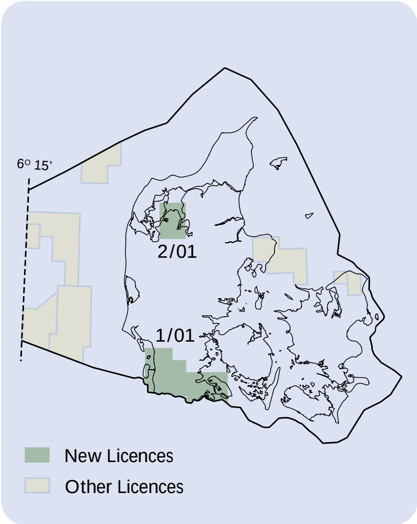
Under the Open Door procedure, applications are invited for all unlicensed areas east of 6°15' East longitude every year in the period from 2 January through 30 September. DONG E & P A/S is to have a 20% share of all licences in the Open Door area.

The two applications were submitted on 18 and 29 September 2000 by the Minijos Nafta group and the Sterling group, respectively. On 5 March 2001, the Minister for Environment and Energy granted each applicant a licence for exploration and production of hydrocarbons.

Licence 1/01 covers a major area in South Jutland. The participating companies are UAB Minijos Nafta (operator), Sterling Resources (UK) Ltd., Dansk Venture Olieefterforskning ApS and DONG E & P A/S.

Licence 2/01 applies to an area near Salling in North Jutland. The companies participating in this licence are Sterling Resources (UK) Ltd. (operator), Dansk Efterforskningsselskab ApS and DONG E & P A/S.

Fig. 1.3 New Open Door Licences



The location of the new licence areas is shown in Fig. 1.3. The companies' shares in the licences appear from Appendix A.

The work programmes for Open Door licences are generally divided into phases, which means that the licensees undertake further work commitments with each new phase. Considering the preliminary work done, the holders of several of the licences previously granted in the Open Door area have decided to continue their exploration activities.

Allocation of Neighbouring Block

On 25 September 2000, the Minister for Environment and Energy granted the DENERCO group the licence to a minor area in a block adjacent to licence 16/98. The neighbouring block has an area of 23 km^2 and is now included under licence 16/98. The amendment appears from the map of the Danish licence area at the back of the report.

AMENDED LICENCES

Extended Licence Terms

In 2000, the exploration term for licence 3/90 was extended by two years to expire on 13 July 2002. Mærsk Olie og Gas AS is operator for the licence, which comprises an area at the Norwegian/Danish border.

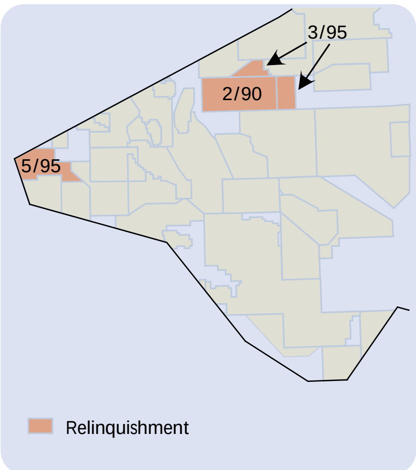
Relinquished Areas

Licences 2/90 and 3/95 expired on 3 July 2000. The companies DENERCO OIL A/S, RWE-DEA AG, DONG E & P A/S, Amerada Hess Energi A/S and LD Energi A/S participated in both licences, for which DONG E & P A/S was operator. Since the licences were granted in 1990 and 1995, the licensees have carried out 2D seismic surveys and drilled two exploration wells, one of which, Francisca-1, encountered a minor gas accumulation in Oligocene sandstone.

Licence 5/95 expired on 15 May 2000. The licence was shared by the companies Phillips Petroleum International Corporation Denmark (operator), Amerada Hess Efterforskning ApS, DONG E & P A/S, Pelican A/S Danmark, DENERCO OIL A/S and Premier Oil BV. The Phillips group collected 3D seismic data in 1996, but did not drill any exploration wells.

The relinquished areas are shown in Fig. 1.4.

Fig. 1.4 Relinquishment outside The Contiguous Area



Due to the expiry of the licences, the confidentiality period for data from seismic surveys and wells established under the above-mentioned licences has been reduced to two years.

The relinquishment of areas under A.P. Møller's Sole Concession is described above.

Approved Transfers

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

In licence 4/95, Mobil Erdgas-Erdöl GmbH and Enterprise Oil Denmark Ltd. withdrew from the group. Their shares of 27.5% and 20% were taken over by DONG E & P A/S, RWE-DEA AG and DENERCO OIL A/S as at 1 November 2000. Mobil and Enterprise did not participate in the drilling of the Nini-1 exploration well in summer 2000, as this activity was performed as a *sole risk* operation by the other group participants.

In connection with the allocation of a neighbouring block to the holders of licence 16/98, the companies entered into an agreement under which a 2% share was transferred to DONG E & P A/S, which has thus increased its share to 22%, while DENERCO OIL A/S and LD Energi A/S have reduced their shares by 1% each. The transfer is effective as at 15 June 1998, the date on which the licence was granted.

On 19 December 2000, the Danish Energy Agency approved the termination of the State's carried interest in licence 7/86 (the Amalie share). The state participation was managed by DONG E & P A/S. In this connection, DONG E & P A/S' share in the licence was increased by 2.888% to a total of 28.205%.

In licence 13/98, Pogo Denmark Inc. transferred the company's 40% share to Pogo Denmark ApS, a wholly-owned subsidiary of Pogo Producing Company. The transfer is effective from 1 July 2000.

On 12 December 2000, Amerada Hess converted its two Danish subsidiaries, Amerada Hess A/S and Amerada Hess Energi A/S, into private limited companies. The new subsidiaries are Amerada Hess ApS and Amerada Hess Energi ApS.

Fig.1.5 Seismic Surveys in 2000

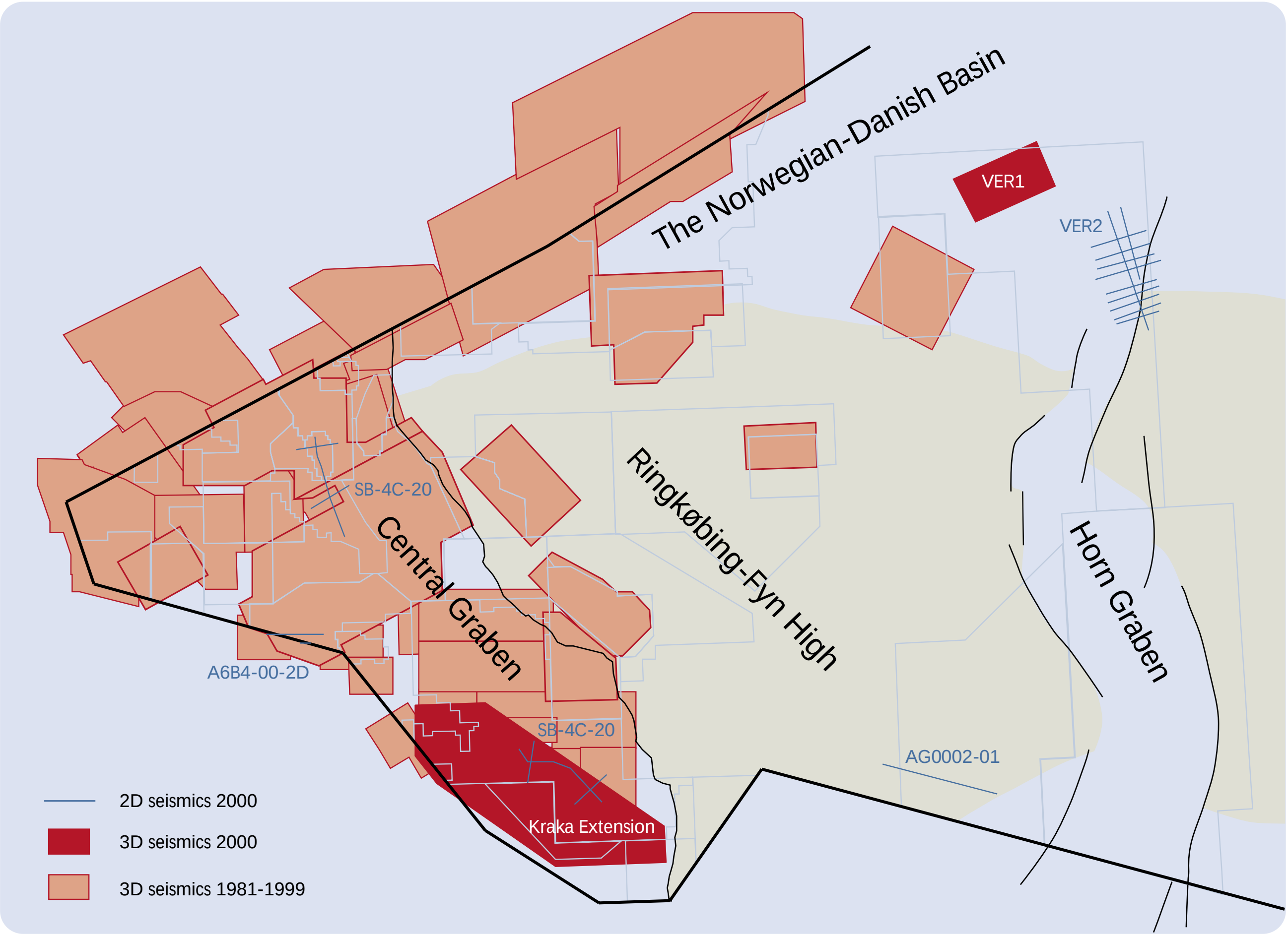


Fig. 1.6 Annual Seismic Surveying Activities

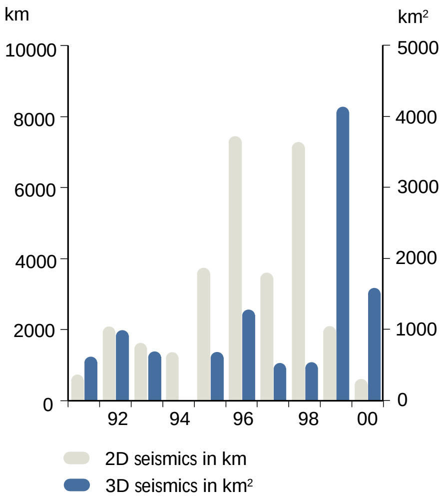
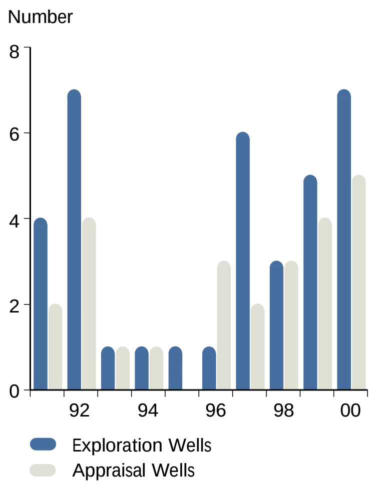


Fig. 1.7 Exploration and Appraisal Wells



The composition of the groups of companies participating in each of the licences granted in the Danish area appears from Appendix A. The Danish Energy Agency's homepage at *www.ens.dk* provides a similar outline, which is updated each time the composition of a group changes.

EXPLORATION ACTIVITIES

Exploratory Surveys

The completion in 1999 of the extensive 3D seismic programmes in the Fifth Round areas was followed by a lower level of activity in 2000; see Figs. 1.5 and 1.6.

The largest 3D survey, covering the Mærsk group's neighbouring-block licence 5/99 and the southern part of the Contiguous Area, was performed by Mærsk Olie og Gas AS.

In the Norwegian-Danish Basin, Anschutz Overseas Corporation was responsible for acquiring both 2D and 3D seismic data in licence 3/99, which is located in the area comprised by the Open Door procedure.

On the Ringkøbing-Fyn High, Norsk Agip carried out an aeromagnetic survey of licences 9/98 and 1/99. In addition, the company acquired a single 2D seismic line and samples of the seabed for geochemical examination in the 1/99 licence area.

Geco-Prakla performed seismic surveys at the Skjold, Dan and Kraka Fields, as well as at the Svend and South Arne Fields. The seismics were recorded using a hydrophone cable placed on the sea floor. This technique improves the conditions for subsoil mapping in areas where the layers overlying the actual fields contain small amounts of gas that may interfere with the results obtained by conventional recording techniques.

In connection with 2D seismic surveying of a deposit discovered in A6/B4, a German licence area, Wintershall extended a few lines into Danish territory.

With regard to onshore activities, Sterling Resources (UK) Ltd. collected samples for a geochemical survey of licence 5/97 in North Zealand.

In the Greater Copenhagen Area, DONG A/S carried out both onshore and offshore 2D seismic surveys in order to examine the possibilities for harnessing geothermic energy as a supplement to heat supply based on cogenerated heat and electricity. This is the first time that seismic surveys have been carried out in the Greater Copenhagen Area, which has been a white spot on the geological map to date.

Appendix B provides further information about exploratory surveys in 2000.

Wells

In 2000, seven exploration and five appraisal wells were drilled; see Fig. 1.7. These statistics include wells spudded in 2000. Some of the included appraisal wells were drilled as combined appraisal and production wells in connection with field developments.

Two of the exploration wells encountered new oil discoveries east of the Central Graben. One of these accumulations, Cecilie, was the first to be discovered under the new licences granted in the Fifth Round.

In 2000, four exploration wells were drilled in cooperation between operators and DONG E & P A/S' drilling division (the former Danop). This cooperation, which is based on a long-term contract with the drilling rig ENSCO 70 and associated subcontractors, will continue in 2001. The operators of the licences involved are responsible for establishing the wells, while DONG E & P A/S assists in the day-to-day technical management of the drilling operations. The cooperation involves both operational and financial benefits for the companies.

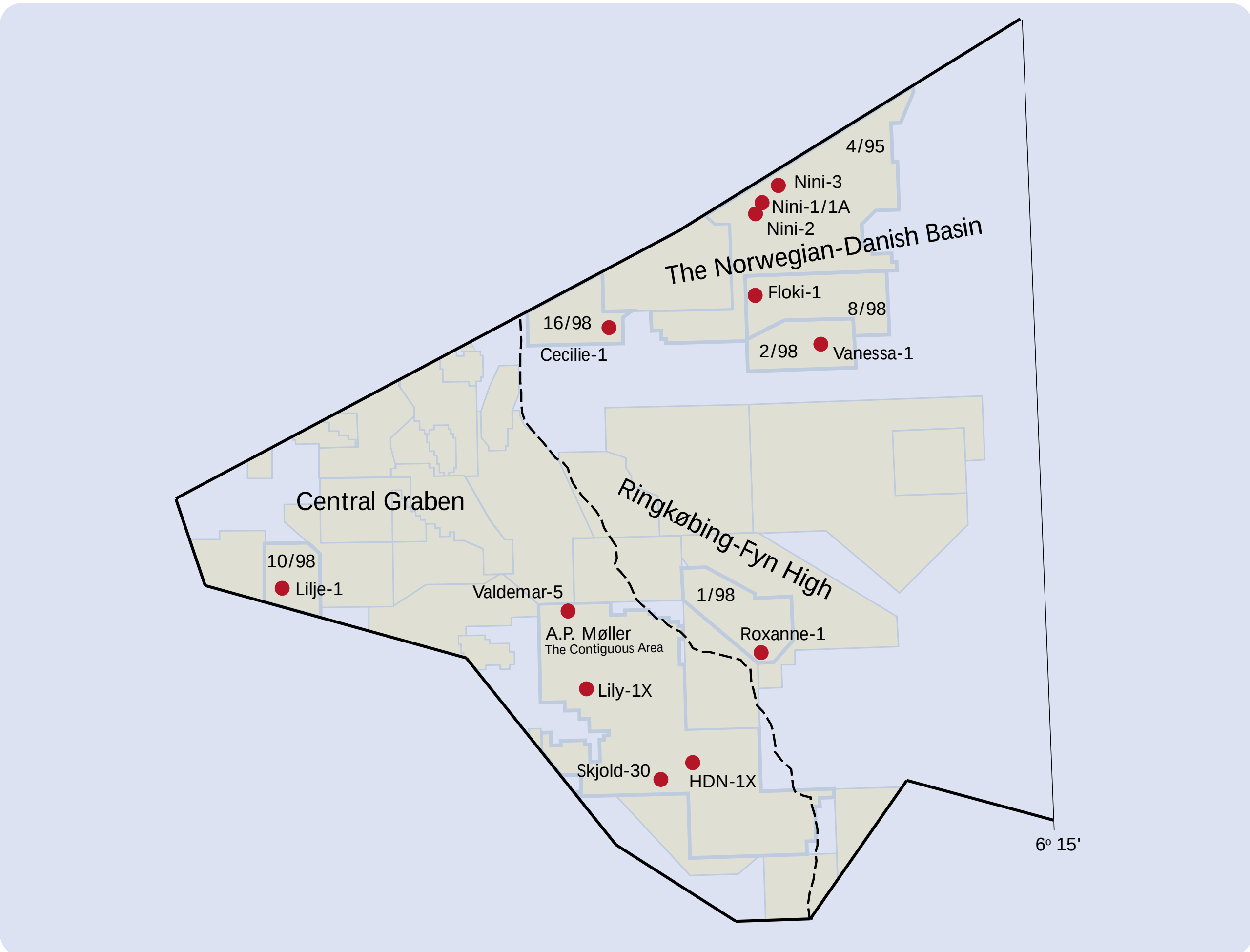
The location of the wells described below appears from Fig. 1.8. In addition, the Skjold-30 well is shown on the field map in Appendix D.

Roxanne-1 and Vanessa-1

In April-May 2000, CLAM Petroleum Danske B.V., operator of licence 1/98, drilled the first exploration well under the new Fifth Round licences. Roxanne-1 was carried to a depth of 2,009 metres and terminated in Upper Cretaceous layers. The well was drilled on the Ringkøbing-Fyn High in an area close to the Central Graben, but no hydrocarbons were found.

In September 2000, CLAM Petroleum Danske B.V. drilled the Vanessa-1 exploration well in a more easterly part of the Ringkøbing-Fyn High in the licence area designated 2/98. The well was 1,757 metres deep and terminated in chalk presumed to be Danian. No hydrocarbons were encountered.

Fig. 1.8 Exploration and Appraisal Wells



Lilje-1

This exploration well was drilled in the Central Graben in May-June 2000 by Norsk Agip, operator for the companies participating in licence 10/98. The well was sunk to a depth of 3,694 metres and terminated in Zechstein carbonates. Only minor shows of hydrocarbons were found.

Nini-1/1A, Nini-2 and Nini-3

In July-August 2000, DONG E & P A/S drilled the Nini-1 exploration well in licence 4/95. Nini-1 was carried to a depth of 1,813 metres and terminated in Upper Cretaceous layers. The well encountered oil in Palaeogene sandstone. A sidetrack to the well was drilled to allow more thorough appraisal of the size of the oil accumulation. This sidetrack, designated Nini-1A, confirmed the presence of oil-bearing sands. A production test yielded oil at a maximum rate of 5,856 barrels per day.

In connection with the appraisal of the new oil discovery, DONG E & P A/S established two appraisal wells, Nini-2 and Nini-3, in December 2000 and January 2001. Nini-2 was drilled to a depth of 1,742 metres and terminated in chalk presumed to be Danian. Nini-3 was also drilled into the chalk and was carried to a depth of 1,811 metres. Like Nini-1, the two appraisal wells confirmed the presence of oil in Palaeogene sandstone.

Floki-1

In September 2000, Kerr-McGee International ApS, operator of licence 8/98, drilled the Floki-1 exploration well in the Norwegian-Danish Basin. The well was carried to a depth of 1,840 metres and terminated in chalk of presumed Danian age. No hydrocarbons were found, but the well encountered well-developed reservoir sandstone of Palaeogene age.

Cecilie-1/1A/1B

As operator of licence 16/98 for the DENERCO group, DONG E & P A/S drilled the Cecilie-1 exploration well in October-December 2000. Cecilie-1 was sunk to a depth of 2,319 metres and terminated in chalk of presumed Danian age. The well encountered oil in Palaeogene sandstone, and was thus the first discovery to be made under the licences granted in the Fifth Round. In a production test run, oil was produced at the rate of 1,888 barrels per day. However, the production rate was limited due to technical factors.

In order to evaluate the extent of the oil deposit, a sidetrack, Cecilie-1A, was subsequently drilled, which confirmed the discovery.

A second sidetrack, Cecilie-1B, was drilled to examine a nearby exploration target. However, Cecilie-1B only encountered traces of hydrocarbons in Palaeogene sandstone.

Lily-1X

In January 2000, Mærsk Olie og Gas AS drilled the Lily-1X exploration well at a position south of the Roar Field. The well did not confirm the expected hydrocarbon saturations in the chalk.

HDN-1X

In autumn 2000 Mærsk Olie og Gas AS drilled the HDN-1X appraisal well in the northern part of the Halfdan Field. On the whole, the well confirmed the expected hydrocarbon saturations in the chalk.

Fig. 1.9 Stenlille Gas Storage Facilities

Skjold-30

Mærsk Olie og Gas AS drilled the Skjold-30 well from the Skjold Field to examine the production and injection potential existing in the northern flank of the Skjold Field and the potential of the northwestern part of the Halfdan Field. The well has now started producing.

Valdemar-5

In December 2000, Mærsk Olie og Gas AS began drilling an appraisal well from the Valdemar platform. The drilling operation will continue in 2001.

Stenlille-19

In July-August 2000, DONG Naturgas A/S drilled the Stenlille-19 appraisal well in the Stenlille gas storage facility on Zealand; see Fig. 1.9. Since 1994, DONG has stored natural gas in sandstone layers in the Gassum Formation. Stenlille-19 was drilled to a greater depth than any of the previous wells to allow investigation of the storage potential of the deeper-lying Bunter Formation. Test production from the Bunter Formation is scheduled from the beginning of 2001 for the purpose of a more detailed examination of its reservoir properties.

RELEASED WELL DATA

Generally, data collected under licences granted in pursuance of the Danish Subsoil Act are protected by a five-year confidentiality clause. However, the confidentiality period is limited to two years for licences, which expire or are relinquished. In 2000, data regarding the following exploration wells were released:

Well	Well no.	Operator
Siri-1	5601/20-1	Statoil Efterforskning og Produktion A/S
Frida-1	5605/21-2	DONG E & P A/S
Francisca-1	5604/24-1	DONG E & P A/S

A list of all Danish exploration and appraisal wells is available on the Danish Energy Agency's homepage, *www.ens.dk*.

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

2. DEVELOPMENT AND PRODUCTION

As a result of a sustained high level of development activities in the North Sea, the year 2000 set another record for oil and gas production. The most striking event was the installation of a wellhead platform in the Halfdan Field in autumn 2000 followed by start-up of production through the new facilities.

At the beginning of 2001, oil and/or gas were produced from a total of 16 Danish fields. The Halfdan platform is number 42 of a series of platforms installed in the Danish part of the North Sea in connection with oil and gas recovery. Hydrocarbons are extracted from underground reservoirs and conveyed through 193 wells to the production facilities. Another 88 wells are used for the injection of gas and/or water.

In 2000, 17 wells were drilled in the producing fields. Fourteen of these were production wells, while the remaining three were established primarily as water-injection wells. Appendix D provides a schematic outline and maps of the individual producing fields. Wells drilled in 2000 are indicated by a special symbol.

Fig. 2.1 is a map showing the location of the Danish producing fields, expected future field developments (commercial fields) and field delineation. The field

Fig. 2.1 Danish Oil and Gas Fields

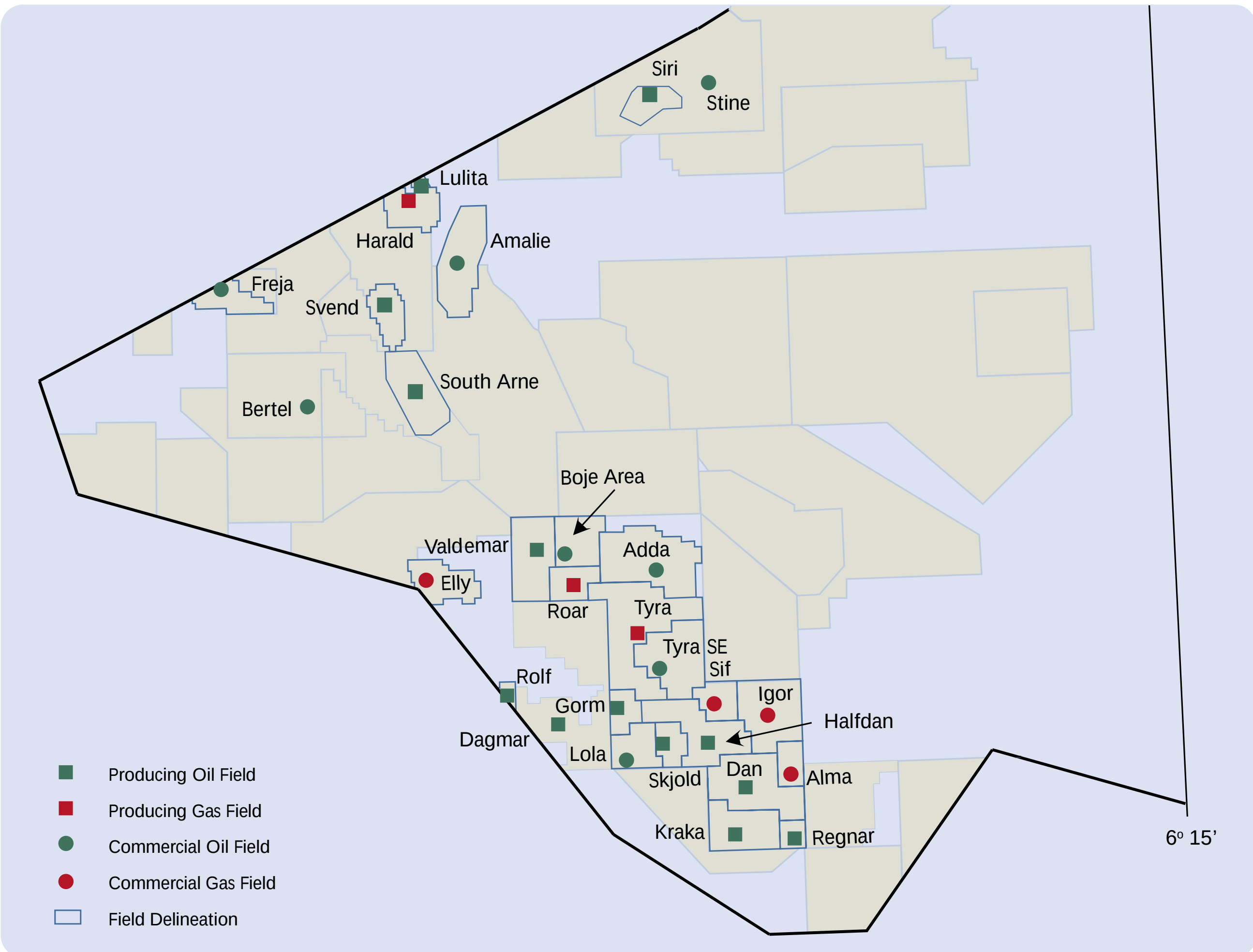


Fig. 2.2 Breakdown of Oil Production by Company

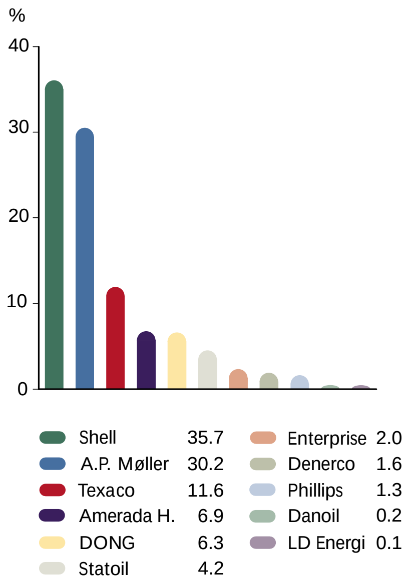
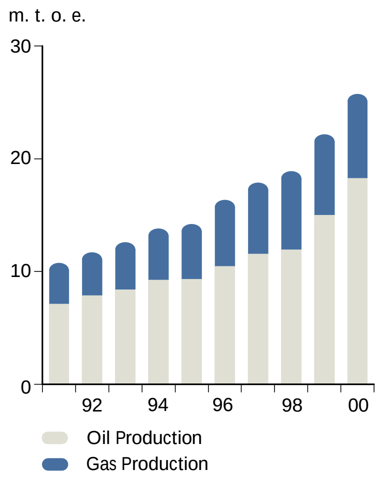


Fig. 2.3 Production of Oil and Natural Gas



delineation indicated for the Contiguous Area also includes the preliminary boundaries defined for this area. Details of the field delineation in the Contiguous Area are given in the section entitled *Exploration*.

At the end of 2000, the Danish Energy Agency considered an application for approval of a development plan for the southeastern flank of the Dan Field, a revised plan for the development of Tyra South East and a development plan for the Stine Field. In March 2000, the Agency received a plan for further development of the Halfdan Field.

PRODUCTION RECORD

The upward trend in Danish oil production continued in 2000 for the fifth year running. Total production amounted to 21.11 million m^3 of oil, which is 22% higher than in 1999 and corresponds to an average production rate of about 364,000 barrels per day.

Mærsk Olie og Gas AS, Amerada Hess ApS and Statoil Efterforskning og Produktion A/S are operators and are responsible for the technical aspects of producing oil and gas from the North Sea fields. In addition to these operator companies, a number of other companies participate in the individual licences. The composition of the company groups appears from Appendix A.

Each company controls a share of the oil and gas produced that corresponds to its percentage share in the licence concerned. In 2000, 11 companies received and sold oil and gas from the Danish fields. Fig. 2.2 shows total Danish oil production broken down by participating company.

In the closing months of the year, DONG Olierør A/S completed an upgrading of pumping equipment that will increase the transport capacity of the pipeline from Gorm E to Fredericia to approx. 330,000 barrels of oil per day.

Gross gas production amounted to 11.29 billion Nm^3 in 2000, of which 3.32 billion Nm^3 was reinjected into the fields. Thus, net gas production amounted to 7.98 billion Nm^3 in 2000.

In 2000, 7.11 billion Nm^3 of gas was supplied to DONG Naturgas A/S. The difference between the net gas produced and the amount of gas sold (11% of the net gas) was either utilized as fuel or flared on the platforms. Gas is flared solely for safety and technical reasons. The volume of gas flared in 2000 was lower than the relatively large volumes flared in 1999. The section *Health, Safety and Environment* provides more details about gas flaring.

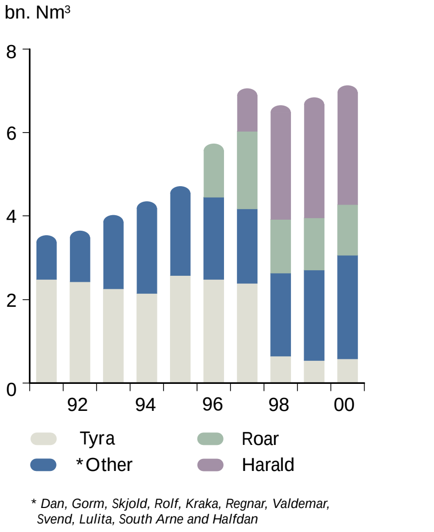
Fig. 2.3 shows trends in Danish oil and gas production for the period 1991 – 2000, while Fig. 2.4 shows the trend in gas supplied to DONG Naturgas A/S over the last decade. Appendix C provides an outline of the oil and gas production since 1972 when the first oil was produced from the Dan Field.

PRODUCING FIELDS

Highlights of the activities at the producing fields in 2000 are given below. Appendix D contains an outline of all producing fields.

Fig. 2.5 shows the distribution of the oil production by field, and Fig. 2.6 shows existing North Sea production facilities.

Fig. 2.4 Natural Gas Supplies Broken down by Field



The Dan Field

In 2000, a development plan for the western flank of the Dan Field was approved. As a result, five new production wells were established in this area. These wells contributed to the 15% increase in field output in 2000 compared with the preceding year. Furthermore, continued water injection has helped maintain oil production from older wells. There was a marginal rise in the production of water from the field, meaning that water now accounts for approx. 44% of the total liquids produced.

The Dan Field, which was brought on stream in 1972, is the oldest field in Danish territory. Nevertheless, oil output from the Dan Field has increased almost every year since production started. In 1980, the field produced 0.34 million m^3 of oil, in 1990 1.58 million m^3, and in 2000 a record-high 6.60 million m^3. Over the years, the field has been in a process of continuous development, including establishment of additional wells, implementation of water injection and installation of new processing facilities. Overall, about DKK 20 billion (2000 prices) has been invested in the development of the Dan Field.

On the Dan FC platform, the pumping equipment of the gas compression plant was upgraded in 2000. The added capacity is needed for handling the increased gas output from the Halfdan Field, which is transported to the Dan Field.

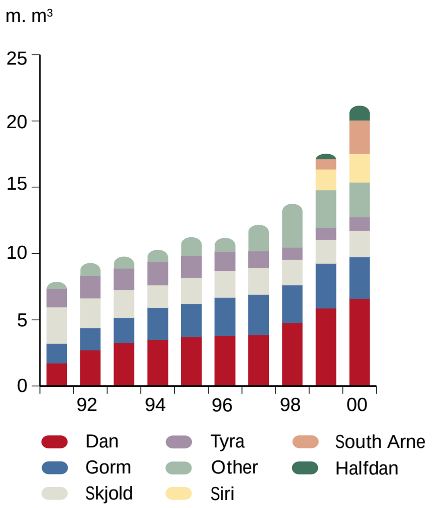
The Halfdan Field

In September 2000, a wellhead platform was installed in the Halfdan Field. The platform can host 32 wells and is equipped with a minimum of processing facilities. The operation of the wellhead platform is supported by a drilling rig.

While the field's first production wells were being drilled, oil and gas were produced through provisional equipment placed on the *Mærsk Endeavour* drilling rig. After the installation of the wellhead platform, production now takes place through the new facilities.

The oil and water produced are conveyed through a pipeline to the Gorm Field for processing, and gas is piped to the Dan Field. In addition, a pipeline imports water from the Dan Field for injection at the Halfdan installation. In this connection, a conversion of the processing plants on the Gorm and Dan Fields has been initiated.

Fig. 2.5 Distribution of Oil Production by Field

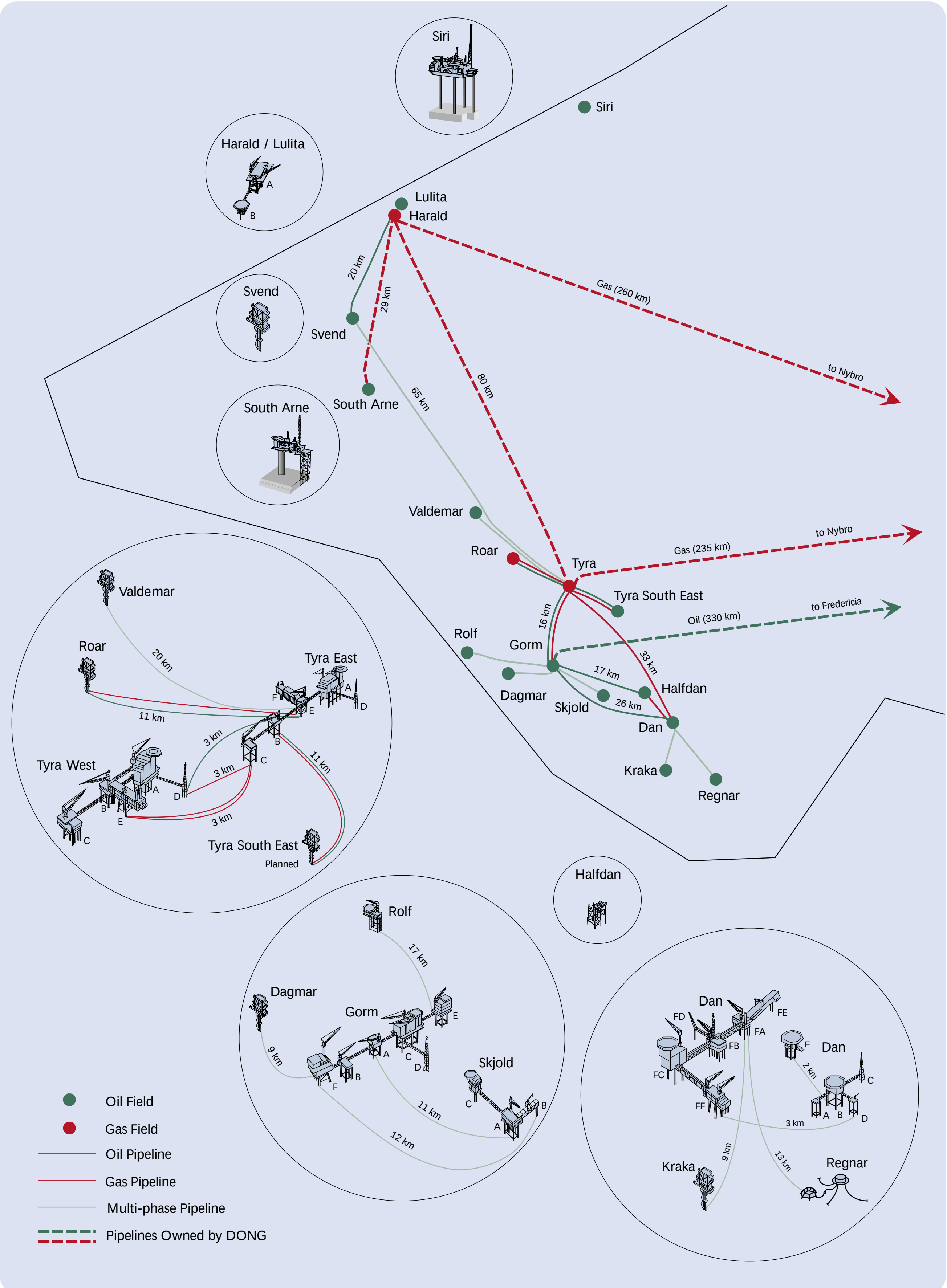


In 2000, three new wells - two production wells and one water-injection well - were drilled in the field. As mentioned in the description of the Skjold Field below, the Skjold-30 well was drilled to appraise the extent of the Halfdan Field towards the northwest.

Oil production went up in 2000 as the completed wells were connected to the production facilities, and the new wells were completed. Almost 18% of the total liquids produced was water.

Additional wells are to be drilled in the Halfdan Field in the years ahead. In autumn 2000, the Danish Energy Agency approved a new development plan for this field. The plan involves establishing up to seven new production wells and implementing water injection in the field through eight new injection wells. The development calls for further modification and extension of the facilities in the Gorm and Dan Fields. In March 2001, the Danish Energy Agency received a plan for further development of the field. The plan provides for the establishment of

Fig. 2.6 Production Facilities in the North Sea 2000



an independent processing plant, an accommodation platform and a new wellhead platform. The plan also foresees the drilling of many new wells.

The Harald Field

In 2000, a gas well was drilled in the eastern flank of the Lulu structure, which makes up the eastern part of the Harald Field. The well also revealed a potential for oil production from this part of the field.

The Siri Field

Oil production from the Siri Field fell slightly in 2000. The decline was curbed, however, by re-perforating a number of production wells in the autumn. Throughout 2000, there was a marked rise in water production, which now accounts for approx. 47% of the total liquids produced.

The Skjold Field

In 2000, three new production wells were established in the Skjold Field in accordance with the field development plan approved by the Danish Energy Agency in 1999. In August 2000, the Danish Energy Agency also approved the drilling of a well (Skjold-30) in the northern flank of the field. Besides serving as a production well for the area, the well will also be used to estimate how far the Halfdan Field extends towards the northwest.

The South Arne Field

To date, oil and gas have been recovered from this field without pressure support from water injection. As a result, the reservoir pressure has dropped since summer 1999 when production started. Due to insufficient processing plant capacity, the increased gas output has led to a fall in oil production.

In 2000, work was proceeding to establish pressure support by means of water injection. In this connection, two water-injection wells were drilled and injection equipment was made operational. In order to prevent salt depositing in and around the injection wells, a system for removing the sulphate ions from the sea water prior to injection was installed.

During the year, there was a slight fall in oil production, primarily because gas production went up. The water production continued at the same very modest level. Only about 2% of the total liquids produced is water.

In 2000, the Danish Energy Agency approved a pilot project for water injection and a plan for phased implementation of water injection in the entire field. The first phase involves the drilling of three injection wells. It is expected that additional production and injection wells will be established in the field.

The Tyra Field

Two new production wells were drilled in the Tyra Field in 2000, both in the oil zone. One of the wells was drilled for the additional purpose of evaluating the potential for production of oil from the southernmost flank of the Tyra Field. The well showed that there is no potential for further oil production from this part of the field.

Work was initiated to convert the injection compressor on the Tyra West A platform into wellhead compression facilities. This will make it possible to reduce the wellhead pressure for wells in the Tyra Field and the surrounding satellite fields.

In this connection, the flow in a number of pipelines between Tyra East and Tyra West was rerouted, and the separation plant in Tyra East was extended.

NEW FIELD DEVELOPMENTS

In 2000, the Danish Energy Agency approved plans for development and production from the Lola Field and the Boje area, as well as a further development of the Valdemar Field.

The plan provides for development of the Lola Field to take place from either the Skjold or the Gorm Field, and the first step will probably be the drilling of a production well.

Recovery from the Boje area is to take place through a production well to be drilled from the Roar Field platform.

The approved development plan for the Valdemar Field involves the drilling of up to three wells from the Valdemar and Roar platforms.

In autumn 2000, the Danish Energy Agency also received an application for permission to produce from the southeastern flank of the Dan Field and a revised plan for the organization of the production from Tyra South East.

The Danish Energy Agency also received an application in December 2000 for permission to produce from the Stine Field, a new field located east of the Siri Field. The field was discovered during the drilling of Siri-3 in 1996. Development of the Stine Field depends on the outcome of further drilling operations in the area.

Appendix E contains an outline of future field developments approved by the Danish Energy Agency.

NATURAL GAS STORAGE FACILITIES

DONG Naturgas A/S has two natural gas storage facilities at its disposal, one at Lille Torup near Viborg in Jutland, and one at Stenlille on Zealand.

The Lille Torup and Stenlille storage facilities provide an extraction capacity of 410 million Nm^3 and 400 million Nm^3, respectively, totalling about 810 million Nm^3.

The Stenlille-19 appraisal well was drilled in summer 2000. It will provide new knowledge about the deeper-lying strata below the Stenlille gas storage facility. These layers may provide added storage capacity for the facility at a later stage. The appraisal is supported by EU funds.

A modification of the Stenlille facility has improved DONG Naturgas A/S' ability to meet its short-term objective of supplying customers with gas in case of failing gas supplies from the North Sea on very cold winter days.

DONG Naturgas A/S has also set a long-term gas supply policy that makes allowance for accidents that may interrupt the gas supplies carried ashore through the 30" pipeline from the Tyra Field for up to 30 days.

With an extraction volume of 810 million Nm^3 and an agreement with DUC for gas to be landed through the 24" pipeline from Tyra via Harald to shore, DONG Naturgas A/S will also be able to achieve the above-mentioned long-term objective.

3. HEALTH, SAFETY AND ENVIRONMENT

WORKING CONDITIONS ON NORTH SEA INSTALLATIONS

The North Sea production facilities, drilling rigs, platforms and vessels used in oil and gas exploration and production are the working place of some 2000 people. They work in shifts, and a manning level of approx. 600 is maintained at all times. Major production facilities include an accommodation module that houses sleeping quarters, canteen and recreational facilities for personnel, as well as offices and other functional areas.

Working Hours

Daily working hours offshore are typically 12 hours. On wellhead platforms, the normal work pattern is two weeks' work offshore followed by three weeks off ashore. Drilling rig work schedules vary, and may involve working offshore for up to three weeks followed by three weeks off. The work schedule on board vessels follows the usual practice in shipping.

Working and Leisure Environment

Creating a safe and healthy environment for offshore personnel, both on and off shift, is a major concern. Like at workplaces onshore, the operating company cooperates with its employees through a safety organization to meet this objective, and good results have been achieved, including a low rate of work-related injuries; see the section on Reporting Industrial Injuries.

Like onshore personnel, offshore workers are exposed to various health risks, such as chemicals, noise, heavy lifting, etc., not to mention workplace accidents.

Normal operation on offshore installations involves a wide variety of tasks, such as control room work, office work, chemicals handling, inspection and repair of faulty equipment, maintenance work, such as welding, scaffolding and painting work. A number of service functions are related to the accommodation facilities, e.g. kitchen work, cleaning, changing linen, laundry work, etc. In addition, various types of waste have to be handled before being brought ashore.

Noise is a major problem on offshore installations, and is due partly to the compact construction of the processing equipment and partly to the fact that the equipment is mounted on steel structures.

The most important job on the drilling rigs is the actual drilling, which to a large extent still involves manual handling of drill piping, exposing personnel to musculoskeletal overexertion. Further health risks may arise from contact with drilling mud during the drilling operation and in connection with producing and introducing drilling mud into the well bore. Noise is also an important factor on the drill floor and in the *shale shaker* room where the cuttings are separated from the drilling mud, which is reused. A few modern drilling rigs use an automatic drilling process, which means that the above-mentioned risk factors do not occur to the same degree.

As distinct from onshore personnel, offshore workers live at their workplace. Furthermore, there is no immediate escape from hazardous situations. A need has therefore been recognized for establishing a system that ensures coordinated behaviour in dangerous situations that may call for evacuation of the installation.

This is achieved by means of a contingency plan, which is maintained through regular drills.

Offshore installations have facilities for treating personnel for mild disorders and minor injuries, provided that transfer to an onshore care unit is not required. Each installation employs a health worker, a *medic*, who is responsible for providing this health care in cooperation with the safety organization. In this connection, a treatment room equipped with the necessary medical supplies and equipment has been established.

Operators on the production installations and the main contractor for drilling rigs and other mobile installations are under a legal obligation to assess the health and safety conditions under which the work is carried out (cf. Executive Order No. 127 of 6 March 1996 on the Performance of Work, etc. on Offshore Installations). To follow up on this assessment, an action plan is prepared identifying the type and timing of measures to be taken to ensure optimal hazard prevention. The action plan is based on: (1) A safety case reviewing major accident risks, and (2) A Work Place Assessment (WPA) evaluating the working environment exposures. In addition, a safety management system must be established, which, i.a., must ensure and document compliance with applicable legislation.

In 2000, the supervisory authorities focused on the Work Place Assessments (WPAs) to be carried out by operators of fixed offshore installations and drilling rigs operating in Danish territory. In both the short and the longer term, WPA efforts are expected to result in major improvements in the physical as well as the organizational conditions on offshore installations.

ENVIRONMENTAL IMPACT OF OFFSHORE INSTALLATIONS

The activities on the installations involve the discharge of various substances into the sea. Measures are taken to minimize such discharges by technical means.

A large proportion of the water produced together with the oil and gas is discharged from the production installations into the sea, after being separated from the oil and gas in a separator and further purified. The water discharged contains small amounts of the oil produced and the chemical additives used in the production. An international threshold value has been established for the oil content in aqueous discharges from offshore sources. This threshold value is evaluated on an ongoing basis through the Oslo-Paris (OSPAR) Commission, the international commission for the protection of the marine environment. In addition, the Danish Environmental Protection Agency lays down specific conditions for the content of other substances in such discharges.

CO, NO_x and a variety of other substances are released to the atmosphere as a result of the production of energy needed to operate the installations. In addition, gas is flared for technical and safety reasons. It is endeavoured to minimize the release of combustion products to the atmosphere by making energy production more efficient and using equipment that minimizes the need for gas flaring.

REGULATION AND SUPERVISION

Together with the working environment on board ships and vessels engaged in oil and gas activities, matters concerning the working environment, safety and protection of the environment in connection with the design, construction and operation of equipment on wellhead platforms, other platforms and drilling rigs are governed by the Danish Act on Certain Offshore Installations of 1981. The provisions of this Act largely correspond to the statutory provisions governing onshore working environment conditions, but are adapted to the special conditions prevailing offshore.

Environmental issues are governed by various statutes. Marine discharges are regulated by the Danish Offshore Environment Act, which is administered by the Danish Environmental Protection Agency. The technical design of offshore installations is governed by the Danish Offshore Installations Act, in order to ensure the use of the best available technique (BAT) for reducing marine discharges. Emergency prepared-ness in matters concerning marine pollution from offshore installations is also regulated under the Danish Offshore Installations Act. The requirement for an Environmen-tal Impact Assessment (EIA) is laid down in the Danish Subsoil Act.

The supervision of health, safety and environmental matters is handled by the Danish Energy Agency, the Danish Maritime Authority and the Danish Environmental Protection Agency and, with regard to special areas, by a number of other authorities. The allocation of supervisory tasks is outlined in Box 3.1. In practice, the authorities cooperate on these tasks.

Box 3.1 Supervision of Health, Safety and Environment

The Danish Energy Agency:
- Working environment, welfare and safety conditions related to the design, construction and operation of production installations.
- Environmental protection measures implemented on the installations.
- Environmental Impact Assessment (EIA).

The Danish Maritime Authority:
- Design, structural strength, buoyancy and layout of drilling rigs and other mobile installations, as well as any equipment of a maritime nature on board such installations.
- Life-saving appliances and launching systems on production installations.

The Danish Environmental Protection Agency:
- Marine discharges from offshore installations.
- Emergency preparedness against marine pollution caused by offshore installations.

The Danish Ministry of Food, Agriculture and Fisheries:
- Food safety.

The National Board of Health:
- Offshore medic work; layout and equipment of treatment room.
- Radioactive sources.

The Civil Aviation Administration:
- Helicopter safety, including safety on helidecks.

Thus, like workplaces in shipping and aviation, offshore installations are not governed by the Danish Working Environment Act, nor are they subject to supervision by the National Working Environment Authority.

INCIDENTS ON OFFSHORE INSTALLATIONS IN 2000

The definition of fixed offshore installations covers oil and gas production facilities plus pipelines. At the end of 2000, there were 42 platforms and hundreds of pipeline kilometres for field-to-field and field-to-shore transportation of oil, gas and water in the Danish sector of the North Sea. In addition, one field has been developed with a subsea production facility, and subsea oil storage facilities have been established in two fields.

Box 3.2 Mobile Offshore Installations in the Danish Sector in 2000

DRILLING RIGS

Mærsk Olie og Gas
Mærsk Endeavour, all year
Maersk Exerter, all year
Transocean Shelf Explorer, all year
Noble Byron Welliver, all year
ENSCO 71, from late December
Drilling rigs used by Mærsk Olie og Gas in the drilling of production wells in various fields and in exploratory drilling

Amerada Hess
Noble Kolskaya, all year
Drilling rig used by Amerada Hess in cooperation with DONG E&P for drilling production wells in the South Arne Field

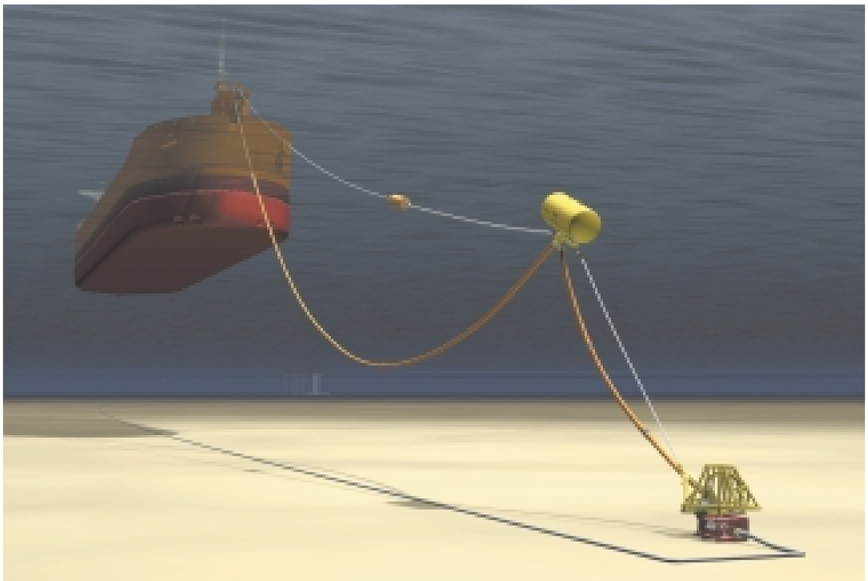
DONG E&P
ENSCO 70, from mid-April
Drilling rig used by DONG E & P as operator and in partnership with other operators to drill exploration wells in various licence areas

Statoil Efterforskning og Produktion
Statoil did not perform drilling operations in the Danish sector, but kept the drilling rig
Noble George Sauvageau moored at the Siri Field until mid-February (awaiting weather conditions permitting its relocation).

OTHER MOBILE OFFSHORE INSTALLATIONS

Mærsk Olie og Gas
Seaway Falcon, until the beginning of February
Pipelaying barge used for installing pipelines in connection with the Halfdan project

SSCV Thialf, 7 days in September
Crane barge used to install the Halfdan platform



Mobile offshore installations include drilling rigs, pipe-laying barges, crane barges and accommodation platforms/flotels, as well as ships used in connection with oil and gas exploration or production, e.g. during the construction of a fixed offshore installation. Box 3.2 lists all mobile offshore installations operating in the Danish sector in 2000.

Some of the major incidents related to health, safety and environment recorded on the installations in 2000 are described below.

Tanker loading incident at South Arne

In the Siri and South Arne Fields, subsea facilities for storing the crude oil produced have been established. In both fields, the storage tanks were provided with a buoy loading system of the SAL type (Single Anchor Loading).

In the SAL system, the pipeline from the storage tanks is connected via a swivel to a riser for fluid transfer, which is hooked up to the tanker's loading system. The swivel is fixed to a suction anchor placed at the seabed, which also serves as the attachment point for the mooring line that keeps the tanker on position during the loading operation. The seabed swivel allows the flow and mooring lines to weathervane freely with the tanker.

During a transfer of crude oil from the South Arne storage tank to the *Nordic Savonita* shuttle tanker on 7 May 2000, approx. 640 m^3 of oil was accidentally discharged into the sea. The oil spillage was caused by a leakage in the SAL system's hose connection between the subsea swivel and the tanker's loading point. The leakage was due to improper operation of the system.

The oil spillage was discovered by the standby vessel *Esvagt Gamma*, which was assisting in the transfer of oil from the storage tank in the South Arne Field to the tanker. As soon as the leakage had been observed, the loading operation was stopped and the oil spill preparedness activated.

In this way, it was possible to collect about 240 m^3 of the oil spill, corresponding to about 38%. The rest of the oil dissolved in the sea and/or evaporated.

After the incident, Amerada Hess ApS met with representatives of the company that had supplied the SAL system, representatives from the standby vessel and the tanker to analyze the incident. Based on this analysis, Amerada Hess ApS changed a number of the SAL system's design features and operating procedures. Together with the Danish Environmental Protection Agency, the Danish Energy Agency has followed the company's evaluation of the incident.

During the process of evaluating the incident, close contact was also maintained with Statoil, the operator of the Siri Field. Statoil is expected to make similar changes to the design and operation of the SAL system installed in the Siri Field.

Leakage in the Kraka-Dan Pipeline

During a routine subsea inspection of the 9 kilometre long 10" pipeline between the Kraka A and Dan FA platforms, Mærsk Oil og Gas AS discovered gas bubbles seeping up from the seabed.

The pipeline was exposed at the location concerned, and inspection revealed a small hole in the pipeline. It was therefore decided to make a provisional repair of the hole by installing an encirclement sleeve. After a pressure test, oil transport through the pipeline was resumed at reduced pressure.

Closer inspection showed that the hole in the pipeline was very likely caused by a high level of bacterial activity in the pipeline. The operator is therefore currently considering whether to replace certain sections of the pipeline.

In light of the Kraka pipeline incident, the Danish Energy Agency and Mærsk Oil og Gas AS have agreed that in 2001 the company is to perform internal inspection using *intelligent pigging* of a number of the company's multi-phase interfield pipe-lines in the North Sea.

Subsidence in the Tyra Field

The extraction of hydrocarbons from the Tyra Field reduces fluid pressure in the hydrocarbon-bearing chalk layers. This pressure reduction causes compaction of the overlying layers and consequent subsidence of the seabed surface. As a result, platforms installed on the subsiding seabed will experience a gradual rise in sea level and a corresponding rise in the level at which the waves impact the structure. The changing load pattern makes it necessary to reassess the structural strength of the platforms, and such analysis may reveal a need to modify the structural parts of the platforms to ensure that they have the necessary strength to withstand the changed load regime.

The seabed in the Tyra Field has been subsiding since production began in the mid-1980s, and the overall subsidence is now about 2 metres. Work to reinforce the Tyra West A platform began in 1999 when three hollow structural elements were filled with concrete.

The ongoing analyses are expected to result in further reinforcement of the platforms in the coming years. The seabed subsidence may also make it relevant to change the applications for which the platforms are used. Thus, it may be necessary to relocate equipment from the cellar decks of the platforms due to the impaired safety of personnel and equipment.

Fig. 3.1 Fuel Consumption

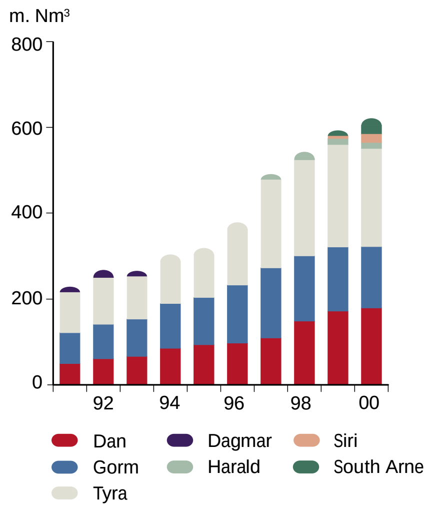
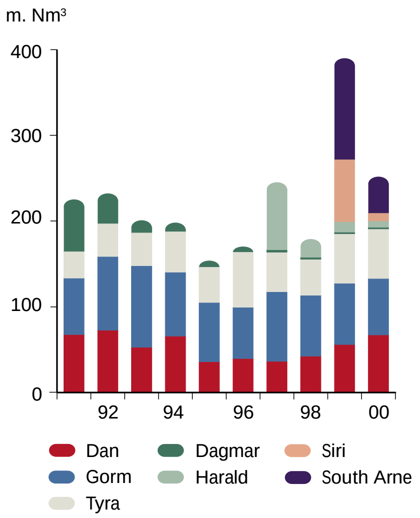


Fig. 3.2 Gas Flaring



Reinforcement of the Older Platforms in the Dan Field

Some of the platforms in the Dan Field date back to the 1970s. Calculations have shown these platforms to lack the sufficient strength to withstand maximum wave loads under all conditions. The Danish Energy Agency has therefore required that the Dan B complex be demanned under weather conditions involving wave heights beyond a certain maximum level.

However, recent analyses have shown that it is possible to reinforce the platform structure to such a degree that sufficient safety is ensured at loads equal to 50 years of wave impact, which is a commonly accepted design criterion. Such structural changes were implemented in 2000 when 28 structural elements were reinforced with high-strength concrete.

After the structural properties of the platforms have been improved, the Danish Energy Agency has granted its approval for maintaining the manning level of the Dan B complex in weather conditions that previously required evacuation of the platforms.

New Drilling Rigs in Danish Territory

In 2000, the operator company ENSCO put two jack-up drilling rigs into service in the Danish sector. The accommodation facilities on these rigs did not meet Danish regulatory requirements, for example, with regard to the size and functionality of their recreational facilities. By cooperating, the company and the Danish Energy Agency came up with solutions to reduce the most important non-compliances without any major impact on operations.

At the same time, solutions were found that are presumed to ensure full compliance with Danish rules and regulations. However, this involves conversion work on a scale that cannot be implemented while the rigs are in operation.

Permissions for use were obtained for the rigs on condition that the most important non-compliances were rectified immediately. Furthermore, an agreement was entered into with ENSCO to the effect that the major construction works would be carried out in summer 2001 and spring 2002.

DEVELOPMENT IN CO EMISSIONS

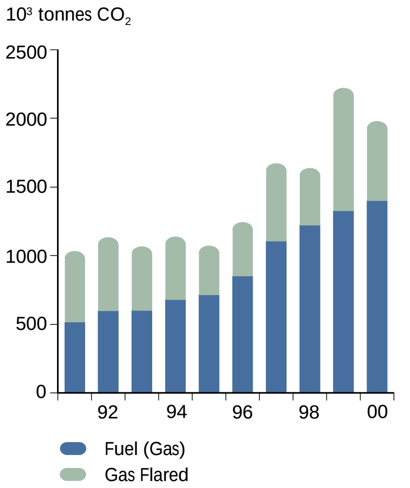
Gas Used for Energy Production and Flaring

Producing and transporting oil and natural gas requires substantial amounts of energy. Part of the gas production is used as fuel in gas turbines driving electric generators, gas compressors and water-injection pumps. Furthermore, a sizable amount of gas that cannot be utilized for safety or technical reasons has to be flared.

The installations in the North Sea emit CO in quantities that hinge upon the scale of production, the technical design of the installations and natural conditions. Relative to the scale of production, the Danish sector of the North Sea has many production facilities. This limits the possibility of improving energy efficiency.

The amounts of gas used as fuel in the processing facilities and the gas flared in the past ten years are illustrated by Figs. 3.1 and 3.2.

Fig. 3.3 CO_2 Emissions from Production Facilities in the North Sea



It appears from these figures that during the past decade rising production has escalated the use of gas as fuel on the Danish production facilities in the North Sea. The level of gas flaring in 1999 was considerably higher than in previous years, but in 2000 flaring was again down to the earlier level. The extraordinarily high amount of gas flared in 1999 was due to major problems in connection with the commissioning of the new production facilities at Siri and South Arne.

CO_2 Emissions in 2000

The production facilities in the North Sea account for about 3% of total CO_2 emissions in Denmark. The development in the emission of CO_2 from the North Sea production facilities since 1991 appears from Fig. 3.3. This figure shows that total CO_2 emissions in 2000 amounted to about 2.0 million tonnes. This is a decrease of about 0.2 million tonnes, or 10%, as compared to 1999.

Fig. 3.4 shows the development in the consumption of fuel on the North Sea production facilities and the associated CO_2 emissions compared to the size of production.

The figure shows a slightly increasing trend in CO_2 emissions due to fuel consumption relative to the size of production over the period 1991-2000. From a level of about 50,000 tonnes of CO_2 per million t.o.e. up to 1996, fuel consumption relative to the size of production rose between 1997 and 1999 by 10-15%. In 2000, specific consumption dropped again, reaching a level of only about 5% above consumption at the beginning of the decade.

CO_2 emissions 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 new production facilities in fields such as Harald, Siri and South Arne resulted temporarily in extraordinary amounts of gas being flared; see Fig. 3.5. In 2000, the CO_2 emission level relative to the size of production almost equalled the record-low level of 1998 when it was approx. 22,000 tonnes per m. t.o.e.

REPORTING INDUSTRIAL INJURIES

Work-Related Accidents

All industrial injuries sustained offshore must be reported to the Danish Energy Agency. Thus, a work-related accident must be reported if the injured person is unfit for work for one day or more in addition to the day of the accident.

In 2000, the Danish Energy Agency received 18 reports on accidents offshore, broken down as nine accidents on mobile offshore installations and nine on production installations. None of the accidents reported were fatal or involved any serious disabling injury.

All nine accidents on mobile offshore installations occurred on drilling rigs. Six out of the nine accidents were reported to have occurred during work on drill floors and in derricks and one in an engine room, while the particulars of the last two accidents have not been disclosed. Most of the accidents occurred in connection with the manual handling of drill piping and other equipment.

Fig. 3.4 CO_2 Emissions from Consumption of Fuel

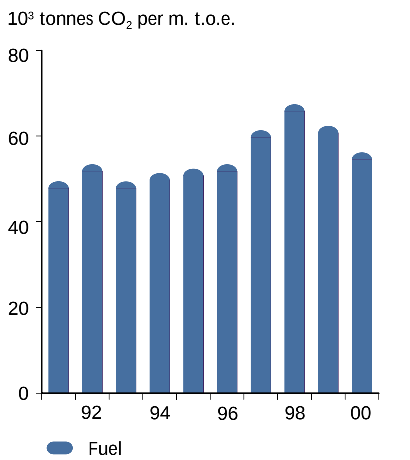
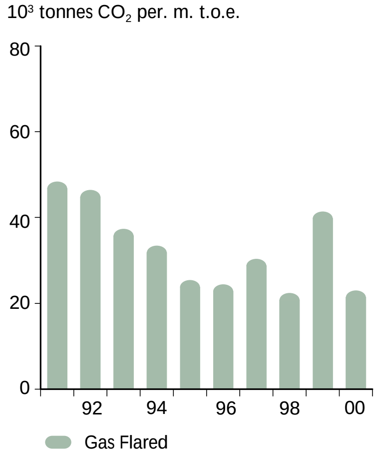


Fig. 3.5 CO_2 Emissions from Gas Flaring



For the mobile offshore installations, the expected periods of incapacity for work break down as follows:

4-14 days:	5 reports
2-5 weeks:	1 report
More than 5 weeks:	3 reports

The reports on accidents occurring on production installations comprise accidents sustained in connection with the operation and maintenance of the installations. Accidents reported for flotels are attributed to production installations, but no accidents on flotels were reported in 2000.

Of the nine accidents on production installations, three are attributable to tripping and falling incidents on board the installations, while the rest can be attributed to heavy lifting (1), colliding with (2) or being jammed against various objects (2), and other causes (1).

For these accidents, the following periods of incapacity for work were reported:

1-3 days:	2 reports
4-14 days:	2 reports
2-5 weeks:	2 reports
More than 5 weeks:	3 reports

Table 3.1 Accident Frequency on Offshore Installations per million Working Hours

Year	Production Installations	Mobile Installations
1991	9.0	7.4
1992	7.1	11.5
1993	8.9	5.7
1994	5.5	13.5
1995	3.3	5.3
1996	6.3	5.4
1997	0.8	6.3
1998	8.8	5.9
1999	4.0	4.5
2000	4.1	4.8

Table 3.2 Dangerous Occurrences Reported in 2000

Type of installation	Cause	Incident	Damage or injury
Drilling rig	Defective sub below top drive	Leakage of 3.5 m^3 of crude oil and 6500 Nm^3 of gas from the drill string	None
Drilling rig	Improper attachment of crane straps	Three pipes fell off a pallet being lifted by a crane due to improper mounting of the crane straps	Property damage
Drilling rig	Wrong procedure	While lowering the drill string, the top drive "fished" a winch wire in the derrick. As a result, the blower hose was ripped off and fell to the drill floor	Property damage
Drilling rig	Metal fatigue	Breakage of four bolts due to metal fatigue caused the fall of a stopper assembly, including the mounting plate and bolts	Property damage

Fig. 3.6 Accident Frequency on Offshore Installations

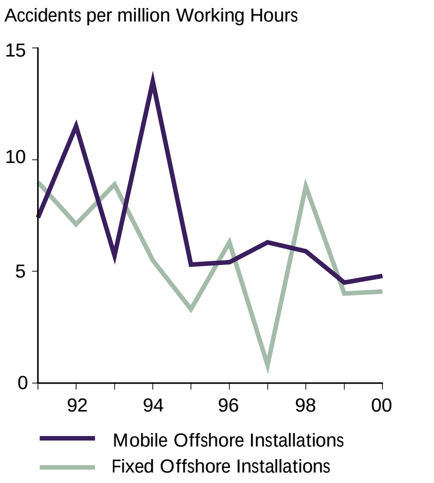
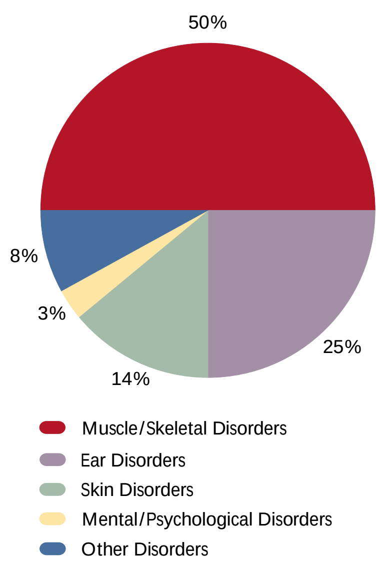


Fig. 3.7 Work-Related Diseases Reported, 1993-2000



Accident Frequency

When the work-related accidents reported for fixed offshore production installations are related to the number of hours worked (2.18 million hrs.), it yields an accident frequency of 4.1 per million working hours. Likewise, when the work-related accidents on mobile offshore installations reported in 2000 are related to the number of hours worked on these installations (1.88 million hrs.), it yields an accident frequency of 4.8 per million working hours. This accident frequency is attributable to drilling rigs only. No work-related accidents were recorded in 2000 on other mobile offshore installations, for which the total number of working hours was about 44,000. The number of working hours is based on information received from the companies (about 12 hours per day).

Table 3.1 and Fig. 3.6 show the accident frequency for each year in the period from 1991 to 2000 for fixed offshore production installations, including flotels, and for mobile offshore installations. Compared to the accident frequency for comparable industries on shore, the accident frequency offshore is very low.

Work-Related Diseases

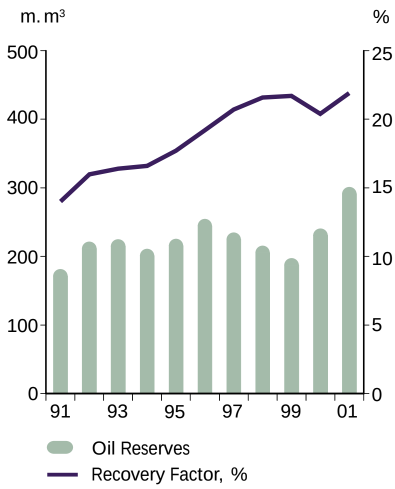
If a doctor suspects or ascertains that a disease has been induced by work on offshore installations, the Danish Energy Agency must be notified. The number of such notifications is very low. In 2000, the Danish Energy Agency received only one notification, which was submitted by the National Radiation Protection Institute and concerned exposure to radiation beyond the recommended maximum level during work on a drilling rig. Since 1993, the Danish Energy Agency has been notified of 37 presumed or recognized work-related diseases. Fig. 3.7 shows the work-related diseases reported in 2000 broken down by main diagnosis.

Reporting Dangerous Occurrences

The occurrence of a hazardous situation that might have resulted in an accident, a so-called dangerous occurrence, must be reported to the Danish Energy Agency. As shown in Table 3.2, the Danish Energy Agency received a total of four notifications of dangerous occurrences in 2000, all four occurring on the same installation, where the number of working hours in 2000 was 0.34 million. This gives a dangerous occurrence frequency rate of 11.6 per million working hours.

4. RESERVES

Fig. 4.1 Oil Reserves and Recovery Factor



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

The assessment made by the Danish Energy Agency at 1 January 2001 shows an increase in oil reserves of 26% in relation to the assessment at 1 January 2000, while gas reserves are largely unchanged. The increase in oil reserves is attributable mainly to a write-up of reserves in the Halfdan Field. Moreover, the reserves of several fields have been reassessed.

This year, oil reserves are estimated at 299 million m^3, an increase of 61 million m^3. The record-high production in 2000 amounted to 21.1 million m^3, and total expected oil recovery has therefore been written up by 82 million m^3 compared to last year's assessment.

LARGEST OIL RESERVES EVER

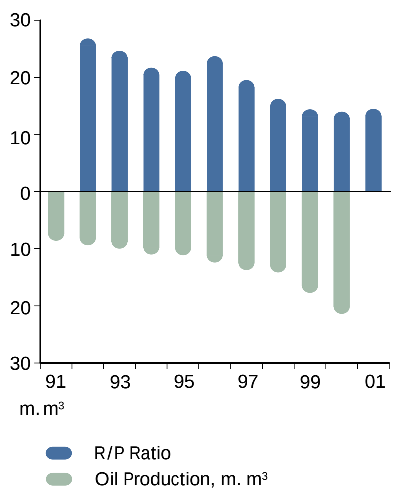
The 299 million m^3 oil reserves estimate is the highest made by the Danish Energy Agency to date. Despite the record-high oil production in 2000, the Danish Energy Agency has also written up reserves by 61 million m^3, the largest upward adjustment ever made by the Danish Energy Agency.

Since 1990, oil reserves have been estimated at 200 million m^3, thus remaining fairly constant. This year's reserves assessment of 299 million m^3 is a marked deviation from this trend; see Fig. 4.1.

The overall recovery factor, the ratio of ultimate recovery to total oil in place, increased from 20% to 22% compared to the year before; see Fig. 4.1. The main reason for this increase is a reassessment of the reserves in several fields, including the Halfdan Field.

Viewed in a greater perspective, the recovery factory has gone up from 14% to 22% since 1990, an increase of approx. 50% generated by the further development of fields through the drilling of horizontal wells and the use of water injection.

Fig. 4.2 R/P Ratio and Oil Production



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 14, meaning that oil production is calculated to be sustainable at the 2000 level for the next 14 years.

The R/P ratio has dropped from 28 to 14 since 1990. The declining R/P ratio is mainly attributable to sharply increasing production. Production has tripled during this period; see Fig. 4.2.

If the reserves had not been reassessed since 1990, the depletion caused by production would have reduced reserves in 2001 to a mere 43 million m^3. The R/P ratio for these reserves would have meant that production at the 2000 level could be upheld for only two years.

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 the section on the twenty-year production forecast and Fig. 4.6.

ASSESSMENT OF RESERVES

The reserves reflect the amounts of oil and gas that can be recovered by means of known technology from structures with proven hydrocarbon reserves under the prevailing economic conditions.

Box 4.1 Categories of Reserves

The method used by the Danish Energy Agency 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.

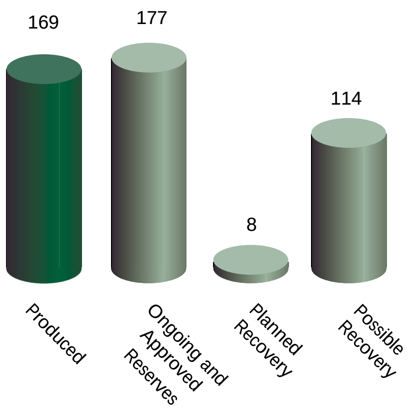
Table 4.1 Production and Reserves at 1 January 2001

OIL, million m³				
	Ultimate Recovery			
	Produced	Reserves		
		Low	Exp.	High
Ongoing and Approved Recovery:				
Adda	-	1	1	1
Alma	-	0	1	1
Boje Area	-	0	0	1
Dagmar	1	0	0	0
Dan	50	25	55	87
Elly	-	0	1	1
Gorm	40	6	12	21
Halfdan	1	25	41	60
Harald	5	3	4	5
Igor	-	0	0	0
Kraka	3	1	3	5
Lola	-	0	1	1
Lulita	1	0	1	1
Regnar	1	0	0	0
Roar	2	1	2	2
Rolf	4	0	1	2
Siri	4	2	3	5
Skjold	31	5	13	20
South Arne	3	17	32	*
Svend	4	0	1	2
Tyra	19	3	7	11
Valdemar	1	1	1	1
Subtotal	**169**		**177**	
Planned Recovery:				
Amalie	-	1	2	3
Bertel	-	1	1	2
Freja	-	1	2	3
Sif	-	0	1	2
Tyra S.East	-	1	1	2
Subtotal			**8**	
Possible Recovery:				
Prod.Fields	-	47	89	142
Other Fields	-	6	11	18
Discoveries	-	6	13	26
Subtotal			**114**	
Total	**169**		**299**	
January 2000	148		238	

GAS, billion Nm³				
	Ultimate Recovery			
	Produced	Reserves		
		Low	Exp.	High
Ongoing and Approved Recovery:				
Adda	-	0	0	1
Alma	-	1	1	2
Boje Area	-	0	0	0
Dagmar	0	0	0	0
Dan	16	3	9	14
Elly	-	2	5	7
Gorm	5	1	1	2
Halfdan	0	4	5	8
Harald	10	11	14	18
Igor	-	1	2	4
Kraka	1	0	1	2
Lola	-	0	0	0
Lulita	0	0	1	1
Regnar	0	0	0	0
Roar	7	3	7	11
Rolf	0	0	0	0
Siri	-	-	-	-
Skjold	3	0	1	2
South Arne	1	5	8	*
Svend	0	0	0	0
Tyra	31	26	30	33
Valdemar	0	2	2	4
Subtotal	**76**		**86**	
Planned Recovery:				
Amalie	-	1	3	5
Bertel	-	0	0	0
Freja	-	0	0	0
Sif	-	2	5	8
Tyra S.East	-	5	6	8
Subtotal			**15**	
Possible Recovery:				
Prod.Fields	-	10	18	29
Other Fields	-	10	20	33
Discoveries	-	1	5	11
Subtotal			**43**	
Total	**76**		**144**	
January 2000	68		142	

** Not assessed*

Fig. 4.3 Oil Recovery, m. m³



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 Agency in calculating the reserves and preparing the production forecasts is described in Box 4.1.

Table 4.1 shows the Danish Energy Agency'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.

It appears from Fig. 4.3 that the expected amount of oil reserves ranges from 185 to 299 million m^3. The difference between the two figures, 114 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. The reserves in the ongoing/approved and possible recovery categories are the highest figures assessed by the Danish Energy Agency to date.

Likewise, Fig. 4.4 illustrates that the expected amount of gas reserves ranges from 101 to 144 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, which can be marketed as natural gas. The difference (10-15%) represents the amounts consumed or flared on the platforms.

There have been several revisions of the Danish Energy Agency's assessment of reserves compared to the assessment made in January 2000. These revisions are attributable to new discoveries, 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 2000 included the reserves recoverable from the development of the Boye area and the Lola Field, as well as from the further development of the Valdemar and South Arne Fields, based on the development plans submitted. These plans were approved in 2000, and the recovery from the above-mentioned fields has therefore been included under ongoing and approved recovery.

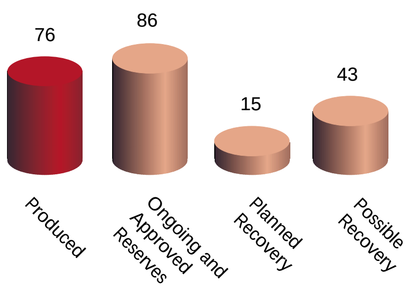
In addition, a further development plan was approved for the Halfdan Field in December 2000, resulting in a write-up of reserves for this field.

The reserves of the Siri Field have been written down on the basis of production experience.

Planned Recovery

In December 2000, a revised plan for the development of Tyra South East was submitted.

Fig. 4.4 Gas Recovery, bn. Nm³



Possible Recovery

The Danish Energy Agency has reviewed a number of options for enhancing recovery with the use of known technology, i.e. technology which 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 reserves can be augmented considerably by implementing water-injection projects in a number of fields.

The drilling of horizontal wells is considered to further increase the production potential of the Kraka, Svend, Valdemar, Igor, Sif and Tyra South East Fields.

Finally, a number of discoveries that are under evaluation are included in this category, e.g. Nini and Cecilie. This category also includes discoveries that are considered to be non-commercial based on current technology and prices.

The total amount of oil that is recoverable with the use of known technology corresponds to only approx. 22% of the hydrocarbons in place in Danish territory.

However, in fields like Dan, Gorm and Skjold, where the production conditions are favourable, an average recovery factor of 34% of the oil in place is expected, based on the assumption that known methods are used, including water and gas injection.

The total oil reserves also include contributions from the relatively large accumulations in the Tyra and Valdemar Fields, where the recovery factors are fairly low due to the difficult production conditions.

Table 4.2 Oil Production Forecast, million m^3

	2001	2002	2003	2004	2005
	Ongoing and Approved:				
Adda	-	-	0.5	0.1	0.0
Alma	-	-	-	0.1	0.1
Boje Area	-	-	0.1	0.1	0.0
Dagmar	0.0	0.0	0.0	0.0	0.0
Dan	6.4	5.6	4.9	4.1	3.7
Elly	-	-	-	0.2	0.2
Gorm	2.9	2.4	1.6	1.2	0.9
Halfdan	2.7	3.2	3.2	3.2	3.2
Harald	0.9	0.7	0.5	0.3	0.3
Igor	-	-	-	0.1	0.0
Kraka	0.3	0.3	0.3	0.3	0.3
Lola	-	-	0.1	0.1	0.1
Lulita	0.1	0.1	0.1	0.1	0.0
Regnar	0.0	0.0	0.0	0.0	0.0
Roar	0.4	0.3	0.2	0.1	0.1
Rolf	0.1	0.1	0.1	0.1	0.1
Siri	1.3	0.6	0.4	0.3	0.1
Skjold	1.5	1.2	1.0	1.0	1.0
South Arne	2.5	2.7	2.8	2.7	2.6
Svend	0.3	0.2	0.1	0.1	0.0
Tyra	1.0	0.9	0.9	0.9	0.8
Valdemar	0.2	0.4	0.3	0.3	0.2
Total	**20.6**	**18.7**	**17.2**	**15.0**	**13.7**
Planned	**-**	**0.2**	**0.6**	**0.9**	**1.2**
Expected	**20.6**	**18.9**	**17.8**	**16.0**	**14.8**

PRODUCTION FORECASTS

Based on the assessment of reserves, the Danish Energy Agency prepares production forecasts for the recovery of oil and natural gas in Denmark.

The present five-year forecast shows the Danish Energy Agency's expectations for production until the year 2005. In addition, the twenty-year forecast shows the Danish Energy Agency's assessment of the production potential for oil and natural gas in the longer term.

Five-Year Production Forecast

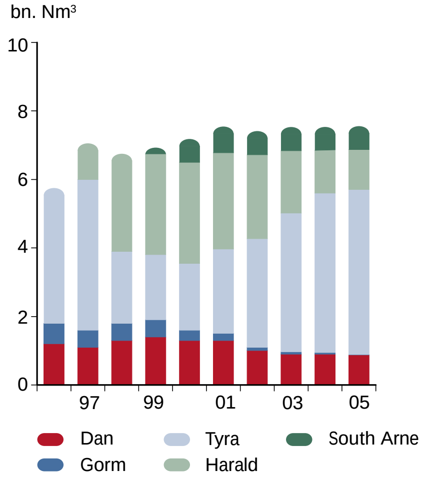
The five-year forecast uses the same categorization as the assessment of reserves, and includes only the categories ongoing, approved, and planned recovery.

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.

As appears from Table 4.2, oil production is expected to reach approx. 20.6 million m^3 in 2001, equal to about 355,000 barrels of oil per day. After that time, production is expected to decline.

The forecast operates on the assumption that oil production will not be subject to any restrictions in terms of capacity or transportation. The production from Siri and South Arne is exported via buoy loading facilities, while the capacity of

Fig. 4.5 Natural Gas Production Broken down by Processing Centre



DONG Olierør A/S's oil pipeline facilities has been estimated at approx. 330,000 barrels per day, and is currently being increased to approx. 360,000 barrels per day.

In relation to the forecast in the Danish Energy Agency's 1999 Report on Oil and Gas Production in Denmark, expected production figures have been written up by an average of 7.5% during the period covered by the forecast. The main reason for the upward adjustment is that the expected recovery from the further development of the Halfdan Field has been included in the forecast. In addition, the production estimates for several fields have been adjusted upwards.

The revisions to the production forecast are dealt with below.

In the forecast made in January 2000, the planned recovery category included expected recovery from the development of the Boje area and the Lola Field, as well as from the planned further development of the Valdemar and South Arne Fields. As mentioned in connection with the reserves assessment, these contributions have now been included in the ongoing and approved recovery category.

Based on production experience, expected production figures have been written up for the Dan, Gorm and Svend Fields, and written down for the Siri and Skjold Fields.

The expectations for production from the remaining fields are largely unchanged in relation to last year's assessment.

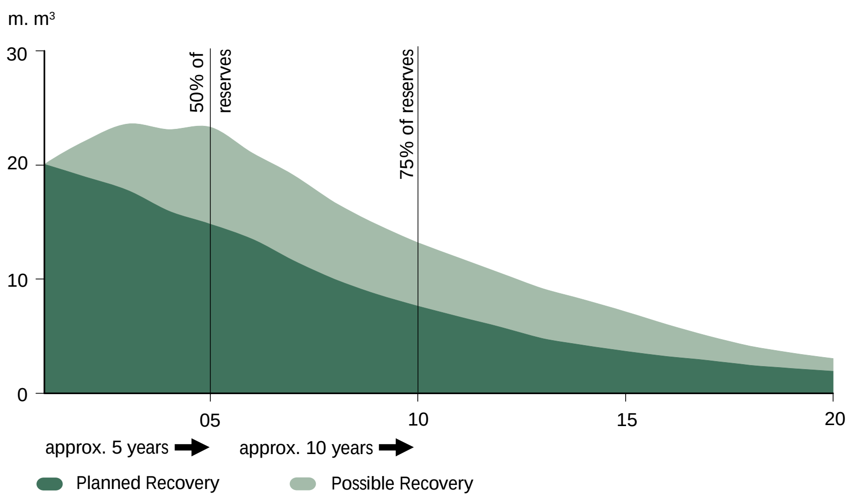
The planned recovery category comprises the future development of Bertel, Freja, Sif and Tyra South East.

Natural gas production estimates are given in Fig. 4.5, broken down by processing centre.

Twenty-Year Production Forecast

The twenty-year forecast has been prepared according to the same method as the

Fig. 4.6 Oil Production Forecast



five-year forecast, and thus uses the same categorization as the assessment of reserves. However, unlike the five-year forecast, the possible recovery category is also included.

In preparing the forecast until 2020, 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.

Fig. 4.6 illustrates two oil production scenarios. The curve illustrating planned recovery is simply a continuation of the development shown in Table 4.2, while the second curve also includes possible recovery.

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

The Danish Energy Agency estimates that the increased use of water injection in several fields represents further oil production potential, and moreover, that a potential for enhancing recovery from the Kraka, Svend, Valdemar, Igor, Sif and Tyra South East Fields exists.

It appears from Fig. 4.6 that annual oil production for the planned recovery category will peak at a level of about 21 million m^3 in 2001, after which production is expected to decline. For the possible recovery category, production is projected to increase to approx. 23 million m^3 in 2003. From 2003 to 2005, production is expected to remain fairly constant, hovering around the approx. 23 million m^3 level, after which it is expected to fall.

If the assumptions underlying the forecasts prove correct, and if no new discoveries are made, 50% and 75% of Danish oil reserves will have been recovered in roughly five and ten years, respectively.

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.

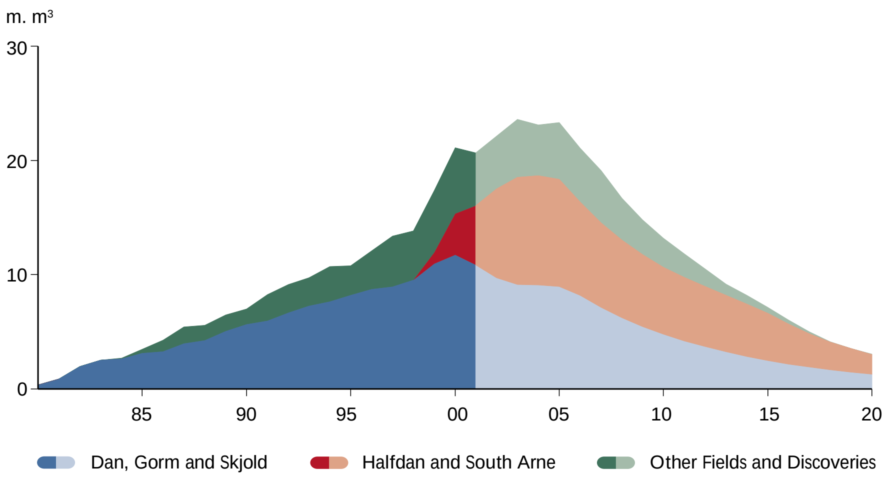
Dan, Gorm and Skjold are the three oldest, producing Danish fields. These fields account for about 70% of total oil production, and due to their development with horizontal wells and water injection, they still contain considerable reserves; see Fig. 4.7.

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.

Although the forecast covers a period of 20 years, it is only possible to predict the development for a few years ahead. Thus, the methods used in making the forecasts imply that production must be expected to decline after a short number of years.

Fig. 4.7 Oil Production and Forecasts for the Period 1981-2020



The downward plunge of oil production 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. The section entitled Resources gives an overall estimate of the amount of resources existing in the Danish part of the North Sea.

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.

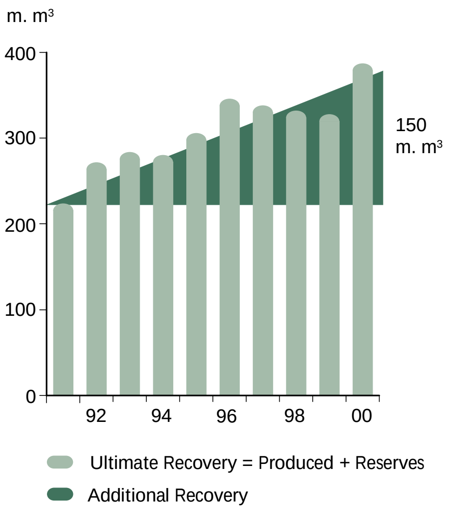
Since the start of gas sales in 1984, natural gas produced under A.P. Møller's Sole Concession has been supplied under gas sales contracts concluded between DUC and DONG Naturgas A/S. The present gas sales contracts do not stipulate a fixed total volume, but rather a fixed annual volume that will be 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 between the Statoil group and DONG Naturgas A/S for the sale of the Statoil group's share of the gas produced from the Lulita Field.

The Danish Energy Agency's forecast for the planned course of production is based on the contracts with DUC providing for total gas supplies of approx. 130 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.

5. RESOURCES

Fig. 5.1 Ultimate Oil Recovery



The Danish Energy Agency's annual assessment of reserves includes only reserves encountered by wells drilled in structures with proven hydrocarbon deposits, and is subject to the condition that the assessed reserves can be recovered using known technology.

Fig. 5.1 is a diagram of the Agency's annual ultimate oil recovery assessments for 1991 - 2000. It shows a general upward adjustment of the recovery and a total write-up for the period of approx. 150 million m^3, or about 3/4 of the 1991 estimate.

This major revaluation is due primarily to new discoveries or further development of existing fields, for example, by using new technology.

As a supplement to the annual assessment of reserves, this section presents an estimate of the recovery potential from structures in which no wells have been drilled (so-called prospects), and the amount of reserves that may be recovered using new technology (referred to below as *resources*). It should be emphasized that estimates of resources are subject to a high degree of uncertainty. The concepts 'ultimate recovery', 'reserves' and 'resources' are defined in Fig. 5.2.

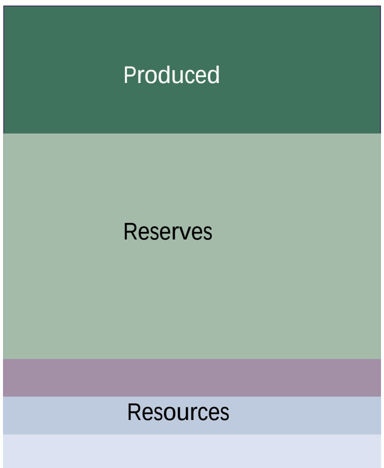
EXPLORATION POTENTIAL

Exploration for oil and gas is based on models and theories of how hydrocarbons may migrate from the source rock in which they originate into certain types of traps containing reservoirs where hydrocarbons can accumulate. The three most important exploration models relating to the area for which licensing rounds are held, i.e. the area west of 6°15' East longitude, are all based on the migration of hydrocarbons from the known Jurassic source rock in the Central Graben; see Fig. 5.6.

The three general models underlying most of the exploration activities carried out in the Central Graben and the adjoining eastern areas are shown below. Each model is illustrated by an S curve showing how far exploration has progressed to date and by a map of potential areas of new hydrocarbon discoveries.

Fig. 5.2 Definition of Resources

Ultimate Recovery = Produced + Reserves



Lower Cretaceous/Jurassic/Triassic Sandstones

Exploration of the deeper-lying sandstones in strata of Lower Cretaceous, Jurassic and Triassic age began already in 1966 when the second offshore well was drilled in Danish territory. Although a number of successful oil and gas exploration wells were drilled in the following years, it was not until about the mid-1980s that the first commercial discoveries were made (Harald and Gert/Freja).

Since the First Licensing Round in 1984, many of the new licensees have explored these deeper-lying sandstones. However, it has proved difficult to find good sandstone reservoirs in deeper-lying strata. Due to the conditions under which the sediments were deposited, many of these sand layers extend over a limited area only. Furthermore, it is difficult, even with modern seismic techniques, to obtain accurate images of the deeper-lying layers. The possibilities of predicting the location of such reservoirs are therefore far more limited than, for example, locating reservoirs in Cretaceous chalk deposits.

By the end of 2000, almost 50 exploration wells based on this general exploration model had been drilled in the area west of 6°15'. The wells were drilled into

Fig. 5.3 Lower Cretaceous/Jurassic/Triassic Sandstone

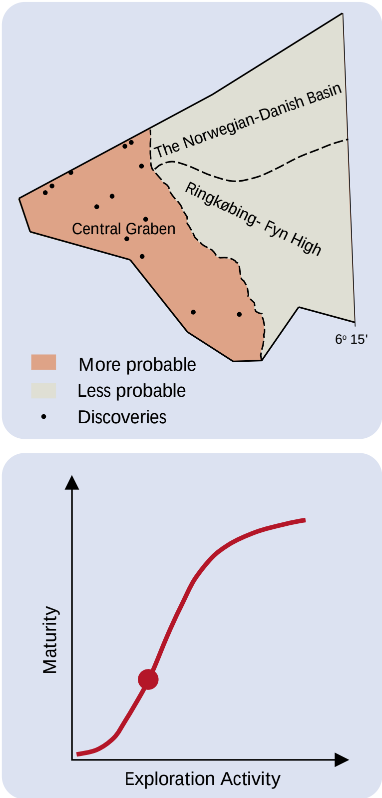
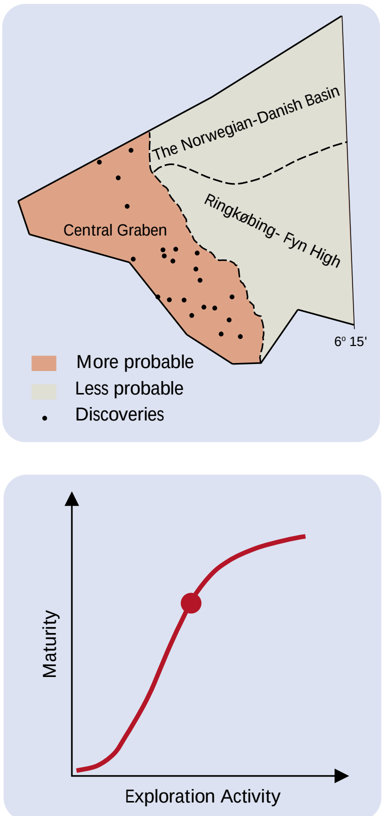


Fig. 5.4 Chalk



structural traps, typical fault traps, and stratigrafic traps formed by sand layers wedging out between the dominating clay deposits; see Fig. 5.3.

About 1/3 of these wells led to discoveries, of which seven have been declared commercial to date.

In the years ahead, the oil companies will continue their exploration of the sandstone layers from the Lower Cretaceous, Jurassic and Triassic periods, and further commercial discoveries are foreseen.

Chalk

From 1966, when the very first Danish well to be drilled offshore struck oil in the chalk, the exploration models based on Danian/Upper Cretaceous chalk reservoirs were for many years essential to exploration. This first discovery was developed into what is today known as the Kraka Field.

Until the mid-1980s, wells were drilled into all major "bulges" in the chalk of the Central Graben. Many of these wells encountered oil and gas deposits that still form the most important source of Danish oil and gas production.

Between the mid-1980s and the early 1990s, exploration of the chalk had almost ceased, since the oil companies had difficulty identifying new prospects by means of conventional exploration techniques.

In recent years, however, the development of new exploration methods has gained momentum. In the area of geophysics, improved techniques for processing seismic data have been devised. Thus, it has now become possible, on the basis of data from wells previously drilled in the chalk, to identify areas where chalk layers have good porosity and thus a potential for containing hydrocarbons. At the same time, much deeper insight has been gained into the mechanisms that cause hydrocarbons to migrate from the older Jurassic source rock into the chalk reservoirs.

Finally, the combination of detailed knowledge of the microscopic fossils found in the chalk and the use of downhole measuring equipment during the drilling process has made it possible to route horizontal wells very accurately through the oil- and gas-bearing chalk layers.

These methods and techniques have in recent years enabled the oil companies to explore more subtle traps in the chalk and make new discoveries, among which, of course, the Halfdan deposit in the Contiguous Area is by far the largest.

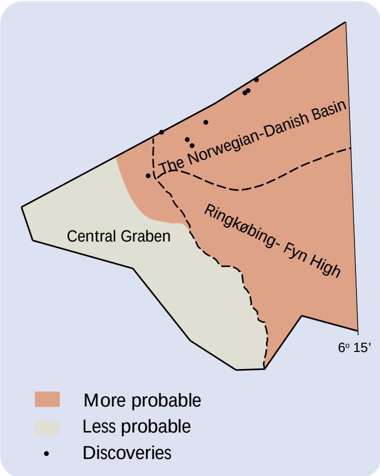
By the end of 2000, a total of approx. 35 exploration wells had been drilled targeting the chalk, about 50% of which encountered hydrocarbons; see Fig. 5.4. All but one of these discoveries have been declared commercial.

Judging from experience gained in recent years, the chalk presumably still holds important oil accumulations, and will therefore continue to be a major exploration target in the years ahead.

Palaeogene Sandstone

The Statoil group's discovery of the Siri deposit in 1995 brought the Palaeogene exploration models into focus, since the drilling of the Siri-1 well confirmed the hydrocarbon potential of the Palaeogene sandstones east of the Central Graben.

Fig. 5.5 Palaeogene Sandstone



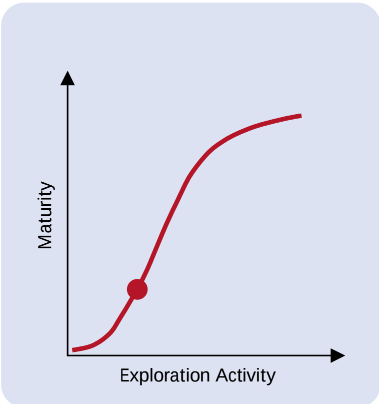


Fig. 5.6 Stratigraphic Column

System	Series	Stage	m. years
Neogene			24
Palaeogene		Danian	65
Cretaceous	Upper	Maastrichtian	
	Lower	Aptian Barremian	146
Jurassic	Upper Middle Lower		208
Triassic	Upper Middle Lower		245
Permian	Upper	Zechstein	
	Lower		290
Carboniferous			363

Palaeogene sandstones played an important part in several of the applications submitted in the Fifth Licensing Round, during which ten licences were granted in the area east of the Central Graben. As mentioned in the section on *Exploration*, several oil discoveries have been made in recent years, and the exploration activities have demonstrated that hydrocarbons formed in the source rock in the Central Graben are able to migrate eastward over great distances.

The Elna-1 well, which was drilled in 1985 and was the first well that encountered hydrocarbons in Palaeogene sandstones, was the first of 14 exploration wells based on this model, seven of which have led to the discovery of hydrocarbons; see Fig. 5.5.

The drilling of these wells contributed considerably to improving the exploration model for Palaeogene sandstones, e.g. by adding to our understanding of sedimentary models and seismic methods. The last few years have marked a breakthrough for this exploration model, and further exploration will probably lead to new discoveries in the immediate future.

Other Models

All commercial discoveries made to date involve hydrocarbons formed in the Central Graben under geological conditions that allowed them to force their way into the chalk and sandstone reservoirs, as described above.

Exploration activities carried out in British and Norwegian territory have also revealed a hydrocarbon potential in older sandstones and chalk layers of Devonian, Carboniferous and Permian age. In Danish territory, very few wells have been drilled to the great depths at which these layers are generally found. As a result, there is insufficient basis for assessing the chances of similar discoveries in the Danish sector of the North Sea.

In the Open Door Area, which constitutes the largest part of the Danish licence area, 70 exploration wells have been drilled to date, most of them on shore. Exploration activities have revealed good reservoirs in the underground layers. However, it has not been possible to demonstrate the presence of sufficient source rock. Recoverable hydrocarbons have only been found in South Jutland, where Permian carbonates have been the subject of oil exploration for a number of years. However, these activities have not led to the discovery of hydrocarbons on a commercially viable scale.

Geological assessments of the Open Door Area have uncovered the potential existence of source rocks in which hydrocarbons have formed. Oil and gas discoveries may therefore be expected also in this area, and the oil companies continue their efforts to find the first commercial decovery.

Potential Recovery from Prospects

Based on present knowledge of the subsoil in the area west of 6°15', the Danish Energy Agency estimates that new oil reserves on a scale of about 50-100 million m^3 may be discovered within the coming decade. The estimate is based on a statistical evaluation of the size of potential new discoveries and an assessment of the chances of making discoveries in the prospects that will become the target of exploration activities in the coming years. Naturally, such estimates are subject to a high degree of uncertainty, and the amount of actual reserves may turn out to be both larger and smaller than estimated. It should also be taken into account that future exploration efforts may reveal a potential for further discoveries.

Fig. 5.7 Oil Production

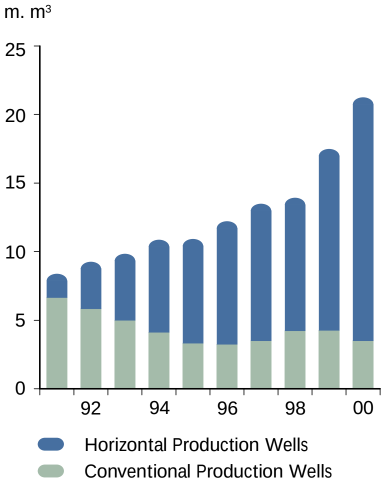
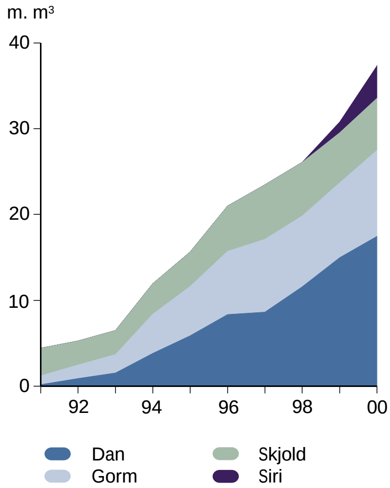


Fig. 5.8 Water Injection



TECHNOLOGICAL DEVELOPMENT

Within the last decade, techniques for seismic data processing, horizontal drilling and water injection have developed dramatically. Each of these new technologies represents a so-called technology leap with a considerable impact on ultimate recovery.

Seismic Processing

Technological progress in the area of seismic data processing has made it possible to map high-porous parts of a reservoir. This enables prospecting companies to localize new fields and identify oil-bearing flank areas near existing oil fields. The Halfdan deposit is an example of a discovery based on improved seismic processing techniques.

Horizontal Wells

The use of horizontal wells has been essential to the development of the relatively tight Danish chalk fields, because the reservoirs are drained more effectively by this method. Fig. 5.7 shows oil production from conventional and horizontal wells, respectively. Production from the first horizontal well began in 1987, and production from horizontal wells has increased dramatically since 1991.

Horizontal wells currently account for approx. 80% of total production, but in numerical terms they represent only about 2/3 of the existing wells. This means that the average output from a horizontal well is twice as high as from a conventional well. Moreover, horizontal wells are often placed in areas where production conditions are more difficult than in the case of conventional wells, which means that the actual productivity of a horizontal well is more than twice that of a conventional well.

Water Injection

Water injection was first used in the Skjold Field in 1986 and was introduced in the Dan and Gorm Fields in 1989. It has proved an effective method for displacing the oil in tight chalk, and based on experience from these operations, the fields were developed further, and the volumes of water injected have increased massively since 1993; see Fig. 5.8.

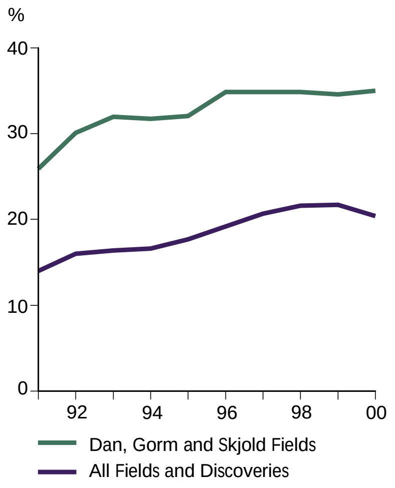
Fig. 5.9 traces developments in the estimated recovery factor for the Dan, Gorm and Skjold Fields, showing that the recovery factor has risen from 25% to 35% in about five years.

The estimate of hydrocarbons in place did not change significantly during this period, whereas expected reserves (including the potential in the category 'possible recovery') were written up by about 80 million m^3 of oil, due to development of the fields with horizontal wells and water-injection facilities.

The volume of mobile oil present in these fields, i.e. oil recoverable by flooding of the whole reservoir, accounts for about 50% of the hydrocarbons in place. Thus, the above-mentioned recovery factor reflects that about 70% of the mobile oil reserves is expected to be recovered.

For clarification, Fig. 5.9 also shows the overall recovery factor for all fields and discoveries included in the assessment of reserves. Over the period under review, the recovery factor increased from 14% to 20%, or by about 50%, as a result of further development of the fields with horizontal wells and water-injection

Fig. **5.9** Recovery Factor



facilities. The fall recorded from 1999 to 2000 is mainly a result of a reassessment and upward adjustment of the oil in place in the Tyra Field and a consequent reduction in the oil recovery factor for this field.

Potential Recovery due to Technological Progress

Two technological trends are foreseen: (1) An evolutionary process of refining existing techniques and improving their cost effectiveness, and (2) development of new techniques based on technology leaps.

A forecast has been made for the next decade of the potential recovery of further oil resources from a number of fields that may result from the availability of more efficient and/or cheaper technology, for example for drilling and completing horizontal wells. The volume of these oil resources is estimated at about 50 million m^3, but the estimate is subject to great uncertainty. Thus, each percentage point increase in the average recovery factor corresponds to a 20 million m^3 addition to the amount of recoverable oil resources.

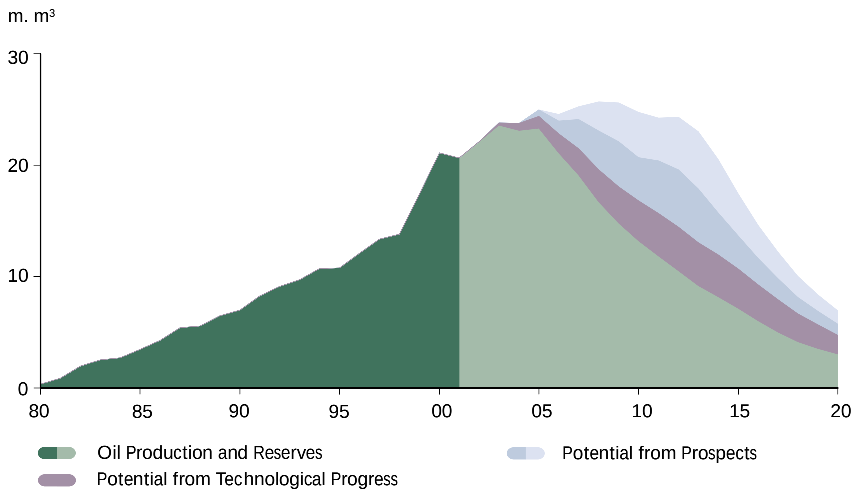
It is difficult to predict the kind of new techniques that will be developed as a result of technology leaps and therefore impossible to forecast the resource potential from this category of technological innovation. It should be mentioned, however, that if a technology leap were to make it possible to recover some of the oil now considered non-mobile, the potential would be impressive. Thus, if it becomes possible to recover 10% of the oil in the Dan, Gorm and Skjold Fields currently classified as non-mobile, the potential will be about 30 million m^3.

TOTAL RESOURCES

The Danish Energy Agency estimates the total oil resources from prospects and technological progress in the coming decade at between 100 and 150 million m^3, or about 33% and 50% of the reserves assessment as at 1 January 2001.

The Agency has made an empiric forecast for the production potential from prospects and technological progress. Fig. 5.10 shows historical oil production 1980 - 2000 and the Agency's production forecast for the period up to 2020 on the basis of assessed reserves and resources. The reserves forecast is identical with the

Fig. 5.10 Oil Production and Forecasts for the Period 1980-2020



"possible recovery" scenario shown in Fig. 4.6 in the section on *Reserves*, and as regards the potential from prospects, two scenarios are shown, illustrating the span between the two estimates.

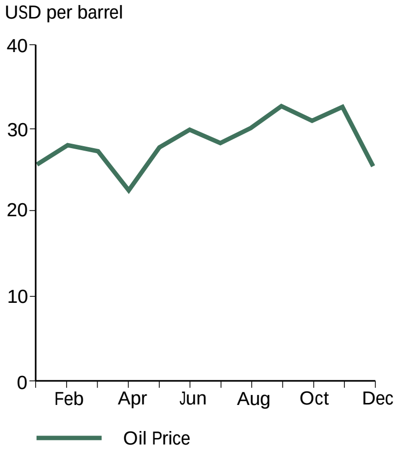
Oil production increased steadily over the period 1980 – 2000, except in 1999 and 2000 when it surged due to the start-up of production from the Siri and South Arne Fields.

For 2001 - 2005, oil production is expected to increase to about 25 million m^3. Depending on the number and size of the discoveries made, production is then expected either to drop or continue at a level of about 25 million m^3 up to and including the year 2010, after which a decline is expected.

The assessment of resources from prospects and technological progress relates to the decade ahead. Assuming that all potential discoveries made during that time are developed within a five-year time frame, the Agency's total production forecast for the period after 2015 is likely to express a conservative estimate. Similarly, new technology leaps may increase production beyond the level indicated in Fig. 5.10.

6. ECONOMY

Fig. 6.1 Oil Price in 2000



The oil and gas production from the North Sea has a positive impact on the Danish economy. Since 1991, Denmark has been self-sufficient in oil and gas. Moreover, in 2000 Denmark was self-sufficient in energy for the fourth year in a row, mainly as a result of its oil and gas production. This production also favourably affects the Danish balance of payments and generates revenue for the state.

CRUDE OIL PRICE AND DOLLAR EXCHANGE RATE IN 2000

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

Last year was characterized by high oil prices. The oil price increase that commenced in March 1999, bringing the average oil price for 1999 to almost USD 18 per barrel, continued throughout most of 2000; see Fig. 6.1. At the end of 2000, the average oil price, as quoted for Brent oil, was USD 25 per barrel, on a par with the price level prevailing at the beginning of 2000. This apparent stability masks major fluctuations. In April, the average oil price amounted to about USD 22 per barrel, while it exceeded USD 32 per barrel in September and November. The lowest daily quotation in 2000 was USD 20.42 per barrel in April, and the highest USD 37.81 per barrel in September. The average oil price for the whole of 2000 was about USD 28 per barrel.

OPEC has made it a goal to keep the oil price within the USD 22-28 range per barrel, and basically succeeded in 2000. 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. The price level in 2000 seems particularly steep seen against the very low price level prevailing in December 1998, when the price quoted for Brent oil fell below USD 10 per barrel.

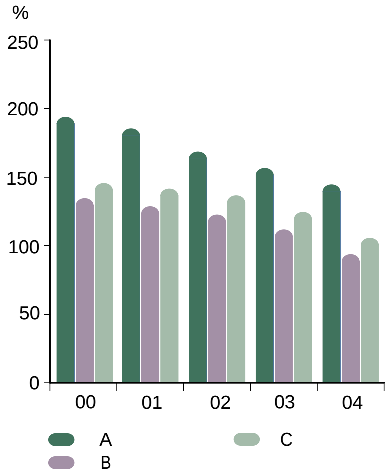
There are several reasons why the price skyrocketed from less than USD 10 per barrel to about USD 28 per barrel in so short a time. OPEC, which accounts for about 40% of the world's oil production, successfully limited the supply of oil in 2000. At the same time, the global demand for oil grew by 1.1%, bringing demand in 2000 to about 75.6 million barrels of oil per day. The relatively low level of oil stockpiles throughout the world also significantly affected the oil price, leading to major price fluctuations as a consequence of the insecurity that the stock depletion has engendered about supplies.

In 2000, the average dollar exchange rate was DKK 8.09 per USD. This represents a sharp increase compared to 1999, when the average dollar exchange rate was DKK 6.97 per USD. The development in the dollar exchange rate has fuelled the oil price increase in terms of Danish kroner, thus raising 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 total Danish oil and gas production rose to about DKK 32.9 billion in 2000, a 96% increase over 1999. The increase is chiefly due to oil prices and the dollar exchange rate, which were much higher than in 1999. Moreover, the size of production exceeded the 1999 figure.

Fig. 6.2 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.

In 1999, the value of oil production was DKK 14.3 billion, while the value of gas production was estimated at DKK 2.5 billion. Preliminary estimates for 2000 show that oil production represented a value of DKK 28.5 billion, and gas production a value of about DKK 4.4 billion. The breakdown of production in 2000 on the 11 producing companies appears from Fig. 2.2 in the section on *Development and Production*. It can be used as an approximation of the individual companies' share of the total production value.

How the production value will develop in the years ahead depends both on production and the trend in oil prices and the dollar exchange rate. Considering the amount of known reserves, the Danish Energy Agency estimates that oil production will remain at the same level in 2001 as in 2000 and then start declining if no new development initiatives are taken. Gas production is expected to remain constant for a number of years. However, the development in oil prices is very 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. The total production of oil, gas and renewable energy in 1999 was about 18% higher than total energy consumption. Production in 2000 is forecast to exceed consumption by about 45%; see Table 6.1.

Fig. 6.2 illustrates the expected development in self-sufficiency. The figure shows three different degrees of self-sufficiency.

Column A shows the expected development in the total production of oil and natural gas relative to total consumption. Since 1991, Denmark's total oil and gas production has exceeded total oil and gas consumption. In 2000, production exceeded consumption by about 93%.

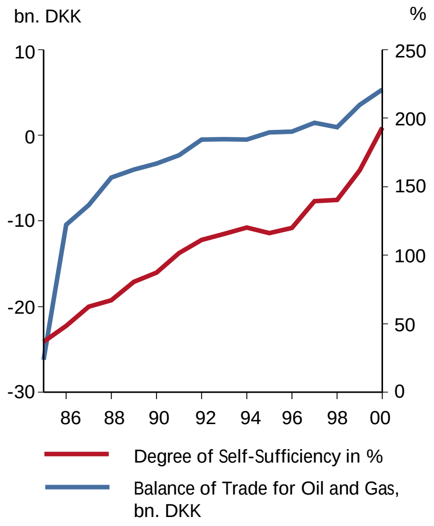
Column B shows the expected development in the production of oil and natural gas relative to total energy consumption. If oil and gas were the only sources of energy, Column B illustrates the extent to which oil and gas production would

Table 6.1 Degrees of Self-Sufficiency

	2000	2001	2002	2003	2004
Production (PJ)					
Crude Oil	758	752	689	648	581
Gas	338	295	295	295	295
Renewable Energy	92	98	110	116	117
Energy Consumption (PJ) *					
Total	820	815	806	851	945
Degrees of Self-Sufficiency (%)					
A	193	185	168	156	144
B	134	128	122	111	93
C	145	141	136	124	105

** Including fuel consumption offshore*

Fig. 6.3 The Balance of Trade for Oil and Gas and Degree of Self-Sufficiency, 2000 Prices



cover total domestic energy consumption. In 1999, total oil and gas production exceeded total energy consumption for the first time, production being 9% higher than consumption. For 2000, the production of oil and gas is estimated to be 34% higher than total energy consumption.

Column C indicates the expected development in the production of oil, gas and renewable energy relative to total energy consumption. As mentioned above, Denmark has been self-sufficient in energy since 1997. The Danish Energy Agency anticipates that Denmark will continue being self-sufficient in energy until the year 2005. The degree of self-sufficiency is forecast to peek in 2000, with total energy production exceeding total energy consumption by about 45%.

IMPACT OF PRODUCTION ON THE DANISH ECONOMY

The oil and gas activities in the North Sea have a favourable impact on the Danish economy. Thus, oil and gas production positively affects the balance of payments as well as state revenue.

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.

Since the mid-1980s, the deficit on the balance of trade for oil and gas products has been gradually decreasing, in 1995 becoming a DKK 293 million surplus. This auspicious development continued throughout the 1990s, and a record-high DKK 5.3 billion surplus was recorded in 2000; see Fig. 6.3.

The development in the degree of self-sufficiency and the trend seen in the balance of trade are, to some extent, interrelated. A high degree of self-sufficiency will reduce the need for importing energy products, which will benefit the balance of trade. Conversely, a scenario of self-sufficiency accompanied by a deficit on the balance of trade for oil and natural gas is conceivable. In contrast to the degree of self-sufficiency, the development in the balance of trade depends not only on the size of production, but also on the composition and price trend of the oil products traded. If imports are made up of oil products that are more processed than exports, the balance of trade may show a deficit despite a self-sufficiency degree greater than 100.

The Impact of Oil and Gas Production 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.

Based on assumptions about oil prices and the dollar exchange rate, the Danish Energy Agency has prepared an estimate of the effect of oil and gas activities on the balance of payments on current account in the years to come. The estimate is based on a low and a high oil price scenario of USD 18 and 25 per barrel, respectively. Moreover, both scenarios operate on the assumption that the dollar exchange rate will be DKK 8.55 per USD in 2001 and DKK 7.83 per USD for the rest of the period. It should be noted that the two alternative price scenarios do not indicate the Danish Energy Agency's expectations as to future oil price developments, but merely serve to illustrate the sensitivity of economic projections to fluctuations in the oil price.

Table 6.2. Effect of Oil/Gas Activities on the Balance of Payments, DKK billion, 2000 Prices, "Normal" Price Scenario (USD 18/bbl)

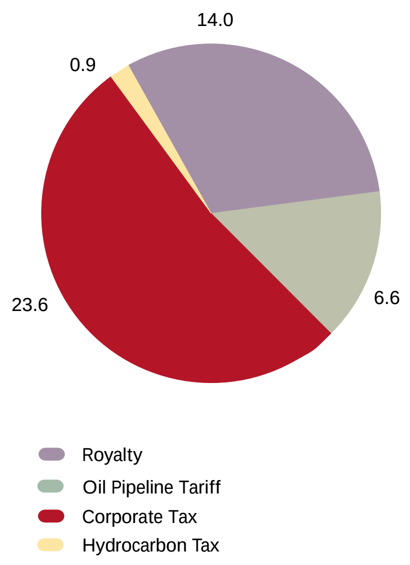
	2001	2002	2003	2004
Socio-Economic Production Value	25.2	21.6	20.6	19.6
Import Share	4.0	3.7	3.3	1.3
Balance of Goods and Services	21.2	18.0	17.3	18.2
Transfer of Interest and Dividends	6.0	6.4	4.9	5.0
Balance of Payments, Current Account	**15.1**	**11.6**	**12.4**	**13.2**
Balance of Payments, Current Account, "High" Price Scenario (USD 25/bbl)	**20.6**	**16.2**	**17.3**	**18.5**

It appears from Table 6.2 that the effect of the oil and gas activities on the balance of payments on current account can be determined as follows: First, the socio-economic production value is calculated by adding the production value of oil and the production value of gas consumption and gas exports. Second, the balance of goods and services is determined by deducting the import content of the companies' investments and operating costs from the socio-economic production value. Finally, the companies' dividends and interest payments transferred abroad are deducted, and the effect of the oil and gas activities on the balance of payments on current account results.

The table shows the calculated effect of oil and gas activities on the balance of payments when using the two different oil price scenarios. Moreover, the individual stages of the calculation (subtotals) are shown for the low price scenario.

Assuming that the oil price is USD 18 per barrel, the oil and gas activities will have a DKK 11-15 billion impact on the balance of payments on current account, while the impact will be in the DKK 16-20 billion range in the high oil price scenario. The two scenarios show that oil prices greatly influence how favourably the oil and gas activities will affect the Danish economy.

Fig. 6.4 Total State Revenue from Oil/Gas Production 1972-2000, DKK billion, 2000 Prices



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, oil pipeline tariff/compensatory fee*. In addition, the state receives an annual dividend payment from DONG E & P. See Box 6.1 for a more detailed specification of the revenue the state generates on hydrocarbon production.

At the end of 2000, the state's aggregate revenue from oil and gas production amounted to about DKK 45.0 billion in 2000 prices. Fig. 6.4 shows total state revenue broken down on the individual taxes and fees.

The high oil price and dollar exchange rate in 2000 greatly influenced state revenue. Thus, the state's total revenue, amounting to about DKK 8.3 billion in 2000, has more than doubled compared to 1999. As Table 6.3 illustrates, the state revenue generated from oil and gas production rose by about DKK 4.5 billion relative to 1999. Apart from the oil price impact, the reason for this striking growth is that the DUC companies pay royalty on the previous year's production. Consequently, the royalty received by the state in 1999 was based on the production figure for 1998, when oil prices were very low. The state's royalty payments from the DUC companies for 2000 are based on the production value in 1999, when oil prices

Box 6.1 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 Agency. Moreover, the Danish Energy Agency 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 the oil and gas sector requires fairly heavy investments, which are deductible as depreciation allowances over a number of years. With effect from 1 January 2001, the corporate tax rate was reduced from 32% to 30%.

Hydrocarbon tax

This tax 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, with total hydrocarbon tax payments amounting to approx. DKK 870 million in 2000 prices. In 2000, the Ministry of Taxation reviewed the current legislation on hydrocarbon tax, and concluded that the present form of taxation may distort the oil companies' incentive to invest. Subsequently, the Ministry of Taxation has appointed a committee that is to lay the groundwork for introducing a new hydrocarbon tax system for future licences. The committee is to have completed its work by October 2001.

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 Statoil group is to pay royalty based on the size of the production attributable to its share of the Lulita Field. New licences contain no requirement for the payment of royalty.

Oil pipeline tariff

DONG Olierør A/S owns the oil pipeline from the Gorm Field to Fredericia. The users of the oil pipeline pay a fee to DONG Olierør A/S, which includes a profit element of 5% 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

The Danish Oil Pipeline Act was amended in June 1997. The amendment stipulated that any parties granted an exemption from the obligation regarding connection to and transportation through the oil pipeline are required to pay a fee to the State 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

As DONG E & P 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 and thus contributes to the state's direct revenue from hydrocarbon production. Since DONG E & P is a wholly state-owned company, its financial result reflects the value of the state's interest. In addition, the state receives an annual dividend payment from the parent company, DONG A/S, amounting to DKK 191 million in 2000 on the basis of its 1999 annual accounts. Furthermore, DONG E & P contributed DKK 25 million to its parent company DONG A/S.

Table 6.3 State Revenue over the Past Five Years, DKK million, Nominal Prices

	1996	1997	1998	1999	2000
Hydrocarbon Tax	0	0	0	0	0
Corporate Tax	1,408	1,743	1,599	2,310	5,750
Royalty	663	944	1,097	854	1,155
Oil Pipeline Tariff*	393	444	310	619	1,401
Total	**2,464**	**3,131**	**3,006**	**3,783**	**8,306**

** Including compensatory fee*

were climbing, making the revenue from royalty payments considerably higher in 2000 than in 1999. The same will apply in 2001, when the DUC companies will pay royalty on the basis of the very high production value in 2000, regardless of subsequent oil price developments.

Moreover, for the past three years, the state has received tax payments from companies other than DUC. 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. It appears from Appendix A which companies hold shares in the individual licences. The state-owned company DONG E & P A/S participates in the production from these three fields.

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. Thus, DONG E & P A/S participates on the same terms as the other companies, paying its share of expenses and receiving the corresponding share of profit.

The form of state participation adopted in the Fourth and Fifth Licensing Rounds does not influence the profitability of a given project, but only the size of the financial result, since the companies' exploration, investment and operating costs are reduced by the same share as their income. The main objective of state par-

Table 6.4 Expected State Revenue from Oil and Gas Production, DKK billion, 2000 Prices

	2001	2002	2003	2004	2005
Corporate Tax USD 18/bbl	3.4	3.2	2.6	2.5	2.2
USD 25/bbl	*4.9*	*4.8*	*3.9*	*3.9*	*3.5*
Hydrocarbon Tax	0.0	0.0	0.0	0.0	0.0
	0.0	*0.0*	*0.9*	*2.0*	*1.9*
Royalty	2.0	1.4	1.2	1.1	1.1
	2.0	*1.9*	*1.6*	*1.5*	*1.4*
Oil Pipeline Tariff*	0.8	0.7	0.6	0.5	0.5
	1.1	*0.9*	*0.9*	*0.8*	*0.7*
Total	**6.2**	**5.3**	**4.4**	**4.1**	**3.7**
	8.0	*7.6*	*7.3*	*8.1*	*7.5*

* Including compensatory fee

Fig. 6.5 Taxes and Fees, 2001-2012, DKK billion 2000 Prices

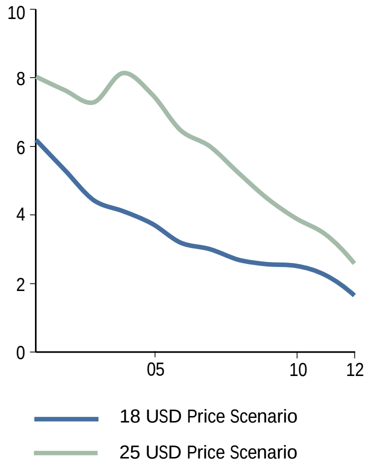
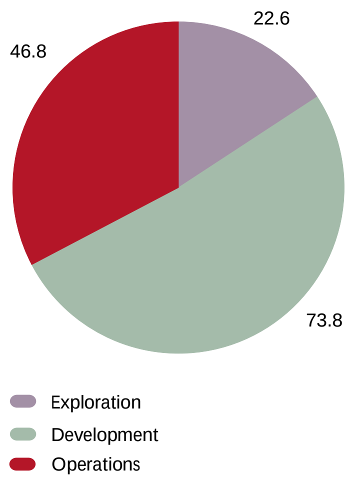


Fig. 6.6 Total Costs of all Licensees 1963-2000, DKK billion, 2000 Prices



ticipation in the licences is to secure the state a share in the proceeds from oil and gas recovery.

The Danish Energy Agency's five-year revenue forecast shows, based on the USD 18 price scenario, that the state's total revenue will come to DKK 6.2 billion in 2001 and then drop to DKK 3.7 billion until the year 2005; see Table 6.4. In the USD 25 price scenario, state revenue is estimated to total DKK 8.0 billion in 2001 and decline to DKK 7.5 billion in 2005. State revenue does not fall at the same rate in the high oil price scenario because hydrocarbon tax will become payable from 2003. If the companies make investments other than those shown in Table 6.6 or the oil price deviates from the price assumed, the result will be different. The future estimates of corporation and hydrocarbon tax payments are further subject to uncertainty because the calculations are based on various assumptions, including regarding the companies' financing of their investments. These facts are not known to the Danish Energy Agency.

Fig. 6.5 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 2000, the licensees' expenses for exploration, field developments and the operation of producing fields totalled DKK 22.6 billion, DKK 73.8 billion and DKK 46.8 billion, respectively; see Fig. 6.6.

Exploration Costs

Total exploration costs in 2000 have been preliminarily estimated at DKK 0.7 billion, the same level as in 1999. The sustained high level of activity is due mainly to the licensees' start-up of the drilling activity provided for in the licences issued in the Fifth Licensing Round. Thus, in 2000 a total of seven exploration wells and five appraisal wells were drilled, two of which led to oil discoveries; see the section on *Exploration*.

The Danish Energy Agency expects the level of activity to remain high in 2001 and total exploration costs to increase to about DKK 1 billion. The Danish Energy Agency currently projects that the activity level will gradually taper off in the years to come.

Investments in Field Developments

Total investments in field developments for 2000 have been preliminarily estimated at DKK 2.9 billion, of which DUC accounts for about 85%. The installation of the wellhead platform in the Halfdan Field was one of the largest field development investments made in 2000. Other major investments made during the year comprised the ongoing establishment of pressure support through water injection and the installation of a system for removing sulphate ions in the South Arne Field.

Table 6.5 Investments in Development Projects, DKK million, Nominal Prices

	1996	1997	1998	1999	2000*
Adda	-	-	144	-	-
Dan	1,708	1,272	1,076	273	402
Gorm	336	73	167	26	12
Halfdan	-	-	-	205	886
Harald	1,079	486	99	32	175
Kraka	1	99	118	-	-
Lulita	11	81	-	-	-
Roar	-	72	2	80	17
Rolf	-	1	-	-	-
Siri	-	760	1,538	839	44
Skjold	35	1	16	398	404
South Arne	592	2,133	1,237	615	-
Svend	-	164	-	189	-
Tyra	731	236	170	152	332
Valdemar	80	1	-	-	60
Not allocated	40	75	28	-	-
Total	**4,021**	**3,913**	**5,491**	**3,431**	**2,947**

** Estimate*

Combined, the development of the Halfdan and South Arne Fields accounted for half the total investments made in 2000. Moreover, the drilling of 17 wells accounts for a share of investment costs; see Table 6.5.

Compared to last year, the Danish Energy Agency expects investment activity to increase for the years ahead; see Table 6.6. Thus, total field development costs are projected to amount to DKK 4.7 billion in 2001, a DKK 2.2 billion increase relative to last year's projection. This write-up is mainly attributable to the development of the South Arne and Halfdan Fields. In aggregate, these two fields account for more than half the total development costs. Although the activity level is expected to diminish in subsequent years, the investment forecast has still been written up compared to the forecast made in 1999.

Operating and Transportation Costs

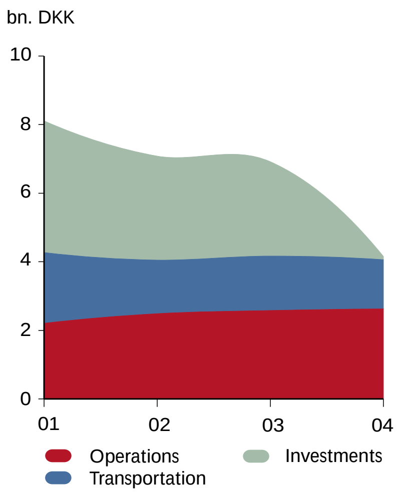
In recent years, annual operating and administration costs have ranged between DKK 1.5 billion and DKK 2.0 billion. Preliminary figures show that total costs amounted to about DKK 2.6 billion in 2000, a major increase compared to the year before. This increase chiefly stems from the start-up of production from the Halfdan, Siri and South Arne Fields.

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 Fredericia, as well as the 5% profit element, which is payable on the basis of the value of the crude oil transported.

Table 6.6 Investments in Development Projects, DKK billion, 2000 Prices

	2001	2002	2003	2004	2005
Ongoing and Approved					
Adda	0.0	0.2	-	-	-
Alma	-	-	0.4	-	0.2
Boje Area	-	-	0.1	-	-
Dan	0.3	-	-	-	-
Elly		0.2	0.7	-	-
Gorm	0.3	-	-	-	-
Halfdan	1.6	1.2	0.1	-	-
Harald	-	0.2	0.3	-	-
Igor	-	0.1	0.3	-	-
Lola	-	0.2	-	-	-
Lulita	0.1	-	-	-	-
Roar	0.1	-	-	-	-
Siri (Statoil)	0.1	-	-	-	-
Skjold	-	-	-	-	-
South Arne (Amerada Hess)	1.1	0.7	0.6	-	-
Svend	-	-	-	-	-
Tyra	0.1	0.1	0.2	0.1	0.1
Valdemar	0.1	0.1	-	-	-
Total	**3.8**	**3.0**	**2.7**	**0.1**	**0.2**
Planned	0.9	1.2	0.6	0.1	0.2
Expected	**4.7**	**4.2**	**3.4**	**0.2**	**0.5**

Fig. 6.7 Investments in Fields, and Operating and Oil Transportation Costs, DKK billion, 2000 Prices



Neither the Siri Field nor the South Arne Field makes use of the oil pipeline from the Gorm Field to shore, but conveys the oil through a buoy loading system on board tankers, which transport the oil to shore. The two 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 oil.

Fig. 6.7 illustrates the Danish Energy Agency's expected development in operating, transportation and investment costs for the years to come. It appears from the figure that transportation costs are projected to remain fairly stable in the years ahead.

7. RESEARCH

According to *Energy 21*, the Government's action plan, research in the energy sector should support the achievement of the long-term energy policy objectives. Oil and natural gas research should aim to localize as many of the subsoil resources as possible and provide the means for rational exploitation of the resources. Research should also further the development of technological solutions that may help reduce the environmental impact of activities associated with the exploration for and recovery of oil and gas.

State-subsidized research in the oil and gas sector is conducted under the Energy Research Programme (ERP) and under the auspices of the EU and the Nordic Council of Ministers. In addition, goal-oriented research is carried on within the framework of the Joint Chalk Research programme, which is financed by Norwegian and Danish oil companies, with the Norwegian and Danish energy authorities as participants.

ENERGY RESEARCH PROGRAMME (ERP)

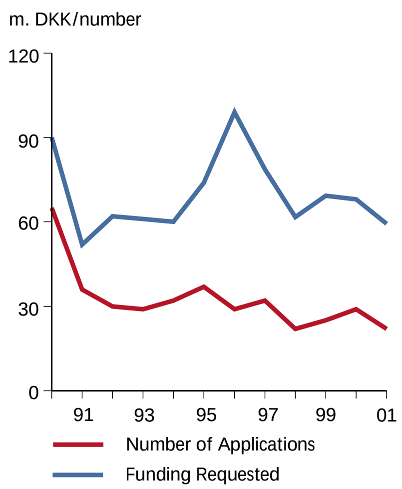
The Minister for Environment and Energy may grant financial support to research and development activities aimed at supporting the development of new forms of energy, better and cleaner energy utilization, energy saving measures and improved recovery methods.

Funds are provided within the framework of the national budget. In 2000, the funds appropriated to the energy research programme under the Danish Finance Act totalled DKK 110.2 million.

Each year, a programme is drawn up in which the research topics eligible for support are identified and prioritized, with due regard being paid to aspects of energy, society and the environment, as well as to the objectives set for Danish energy policy.

Oil and gas research is one of the six current programme areas under ERP. Under this heading, support is granted for projects in the following areas: exploration, recovery methods, equipment and installations, as well as special North Atlantic oil and gas issues. In order to ensure fast implementation of research findings, support is primarily given to project-oriented research with a general time frame of not more than three years. Special consideration is further given to projects that lie between basic and demonstration research. In addition to these general and scientific criteria, each proposed project is evaluated on the basis of such factors as relevancy to the Government's energy policy and scientific merits, including novelty value and rooting in a scientific environment. Other aspects considered are plans and options for utilizing project findings and the degree of self-financing.

Fig. 7.1 Applications Received



ERP 2001

In 2000, funding in the amount of DKK 59.4 million for 22 projects was applied for within the Oil and Gas programme area. This is less than in 1999, both in terms of number of projects and size of funding applied for.

As shown in Fig. 7.1, there was a slight, but steady fall in the number of applications throughout the 1990s, a trend that continued in 2000. This downward trend was not matched by a reduction in the size of funds applied for.

Fig. 7.2 Funding Broken down by Research Area

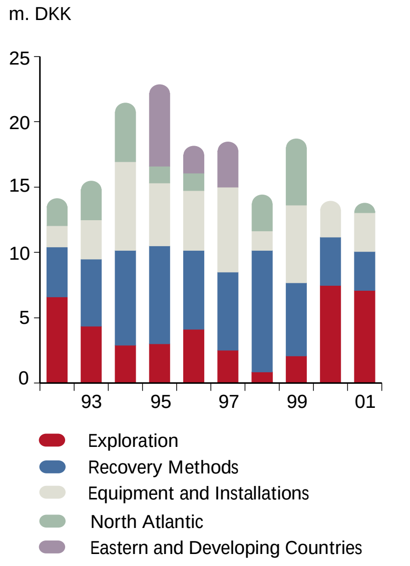
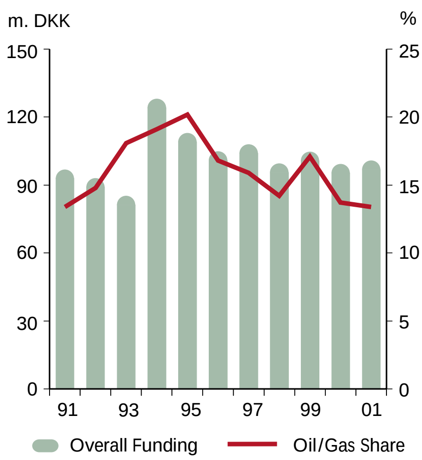


Fig. 7.3 Oil/Gas Share of Overall Funding



The evaluation and prioritization of the applications submitted under ERP 2001 resulted in the granting of a total of DKK 13.4 million distributed on six projects. This is in line with the total support granted to oil and gas research under ERP 2000, where nine projects shared total funding of DKK 13.5 million. This indicates an increase in the average grant provided for each project.

The six projects are distributed as follows: three under Exploration and one under each of the three remaining programme headings Recovery Methods, Equipment & Installations and North Atlantic Issues. As appears from Fig. 7.2, overall funding in the Recovery Methods and Equipment & Installations programme areas was relatively high during most of the period, while the support granted in the Exploration area was correspondingly low. Over the last few years, how-ever, the individual areas have become more evenly balanced with regard to public finan-cing.

As shown in Fig. 7.3, public funding of projects in the Oil and Gas programme area in the 1990s equalled about 14-20% of the total funding granted for all programme areas. Since the mid-1990s, the percentage of finance provided for this area has been falling, while the overall funding made available at the begin-ning of each year has remained fairly constant. In this connection it should be mentioned that adjustments may be made during the year due to the actual project implementation or the complete or partial abandonment of projects.

Recent years' oil price developments, including periods with relatively high price levels, have not discernibly affected requests for grants in the Oil and Gas area.

Under the six subsidized projects, research will be conducted for a total amount of DKK 26.1 million, including self-financing and industrial contributions. The subsidized projects are listed in Appendix G.

ERP PROJECTS COMPLETED IN 2000

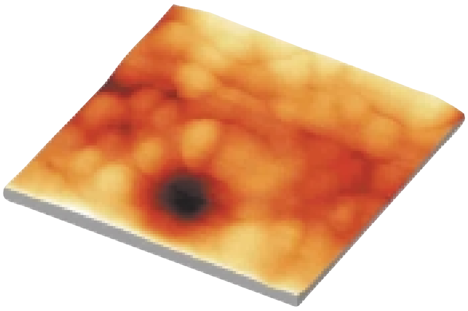
In 2000, nine projects subsidized under the Oil and Gas programme area were completed. The projects under each programme heading are outlined below. For further information, see Appendix G.

The reports documenting the completed projects are kept at the library of Risø and may be obtained on loan. Information on ongoing and completed projects can be found via Risø's web site *www.risoe.dk/nei*.

Exploration

In the Exploration programme area, the project *Clay Minerals and Silica in Chalk Reservoirs with respect to Source Area, Diagenesis and Reservoir Properties (1313/98-0005)* was completed with the Geological Survey of Denmark and Greenland as the perfor-ming organization. The content of quartz and clay minerals in Danian and Upper Cretaceous chalk from a number of North Sea fields was examined by high-reso-lution microscopy and mass spectrometry. The development of special laboratory techniques made it possible to obtain more accurate measurements.

The examination of these minerals revealed the presence of at least three major mineral groups. Special interest attaches to the discovery of the so-called *nano-silica*, which may indicate the presence of previously unnoticed barriers in the reservoir with great impact on the reservoir's recovery potential. The project further demonstrated a difference in the clay mineral content of Danian and



Maastrichtian chalk, respectively. The examination results also rendered it probable that the predominant clay minerals consist mainly of detrital material arriving from weathering sites west of the Contiguous Area during the deposition of the chalk.

The picture to the left is an atomic force microscope image of nano-silica, 10,000 Å.

Examination of magnetic signatures in samples from the Dan Field showed a pronounced magnetic cyclicity in the chalk, reflecting its clay mineralogy. It was concluded that the cyclicity of the chalk is not fully explained by the formation of carbonate or the detrital input, but that it could be the result of small changes in the composition and volume of clay minerals.

A new classification method was developed and used in the project *Geophysical and Geostatistical Reservoir Characterization of Chalk Fields including Application in Reservoir Simulation (1313/97-0005),* performed by Ødegaard A/S. This method relies on a production estimate based on stochastic reservoir models without the use of reservoir simulation.

The examinations were based on data from the Roar Field. The seismic data were inverted for acoustic impedance and porosity using a low-frequency model. In addition, Poisson's ratio was determined by AVO analysis. The impedance was adjusted for liquid content and used in the stochastic reservoir characterization for porosity and permeability.

Based on geostatistics, a method was developed for determining the effect of geological uncertainty on an anticipated field output. Ranking of geostatistical reservoir realizations makes it possible to select a high-output and a low-output scenario.

Recovery Methods

In the Recovery Methods programme area, four independent subreports were completed under the PRIORITY project, which examines the possibilities of enhancing recovery from Danish Lower Cretaceous reservoirs. At a later stage, the results from the subprojects will be collected in one final report, which will also contain an evaluation of the extent to which the research findings may be realized in North Sea fields.

The project entitled *Structural Development of the Valdemar Field (1313/97-0008, I.4.b),* performed by the Geological Survey of Denmark and Greenland, mapped the field's deformation history and structural development. The report estimates that overpressure in the Lower Cretaceous could be the combined result of factors such as subsidence and pressure leakage from Jurassic layers. It further suggests that the presence of a regional pressure gradient of 5 psi/km in geological time can only be explained by the occurrence of barriers transversely to the direction of flow. However, the precise nature of such barriers has not yet been established. North-south oriented fracture zones developed along the structure during the Tertiary Period, while an east-west oriented fracture system formed between the North Jens and Bo structures, which may explain the observed pressure gradient. The report finally concludes that hydrocarbons may have migrated from the Bo to the Roar area in the early Tertiary.

The project *Equilibrium Mechanisms during the Formation of a Petroleum Reservoir (1313/97-0008, II.2.d),* conducted at the Technical University of Denmark, examined the effect of various equilibrium processes on the state of balance in low-permeability chalk. The examination addressed the issue of whether geological time is sufficient to establish an equilibrium condition between the various reservoir phases. The distribution of reservoir phases is often based on the assumption that the various phases are in a state of mechanical and thermodynamic equilibrium. However, this would require that the formation of the reservoir was completed a long time ago, and that the equilibrium mechanisms work fast relative to geological time. The findings show that equilibrium at the water-oil contact level is established within a geological time scale with deviations of down to a few metres/ kilometre. The gravitational separation of water and oil and the formation of the associated transition zone take place at a considerably faster rate. In contrast, achieving a condition of diffusion equilibrium is a slow process that needs a geological time scale.

The project *Injection Water and Brine Compatibility (1313/97/0008,II.1.g)*, conducted at the Technical University of Denmark, dealt with the issue of salt precipitation as a result of incompatibility between the injected sea water and the formation water. The study examined the effect of pressure and temperature on the compatibility and variations in permeability in connection with miscible-phase displacement of formation water by injection water due to the precipitation of salts, primarily calcium carbonate. Results from the test well demonstrated that the injection water and the formation water are compatible at surface temperature and atmospheric pressure, while precipitation occurs at reservoir temperatures. At reservoir temperature combined with high pressure, on the other hand, the precipitate will dissolve. It is unlikely that even the worst cases of reduced permeability are caused by precipitate. Instead, the reduction may be attributable to volume variations in the clay minerals.

The project *Surfactant Well Treatment (1313/97-0008, II.3.b)*, conducted at the Technical University of Denmark, examined the effect of submitting the reservoir to surface treatment before water injection to reduce the surface tension between the injection water and reservoir oil. Laboratory tests showed that at high pressures this treatment may considerably reduce the amount of residual oil after production. However, contrary to expectations, the surface treatment did not have the effect of cleaning the area around the well conduit.

Equipment and Installations

Three projects were completed in the Equipment and Installations programme area.

Under the project *Requalification of Offshore Structures (1313/97-0014)*, performed by the Danish Hydraulic Institute, new methods for analyzing the load-carrying capacity and measures to extend the life of offshore structures were developed and described. New models were developed for determining design parameters for waves, currents, water levels and wind loads. In addition, a sustainable model was developed for determining the directional distribution of design waves. Finally, a new model was developed for the short-term distribution of maximum wave and wave crest heights.

Based on probabilistic models, the project studied possible ways of prolonging the service life of existing platforms, preventing pipeline upheaval due to temperature differences by predicting a number of critical parameters, and lastly, optimizing crack inspection techniques. All the above-mentioned factors influence the life cycle of the structures.

The project *Wax Deposition in Offshore Pipeline Systems (1313/97-0020)*, performed by CALSEP A/S, addressed the problems related to the transportation of waxy oil, during which wax may under certain conditions precipitate and be deposited on the pipe wall. A commercial model was developed to determine the rate and spatial distribution of the wax layer build-up in the pipeline. The model calculates the impact of wax deposition on the basis of temperature and pressure loss in the pipeline and estimates the degree of wax deposition along the line. Wax deposition is further estimated as a function of shear rate effects.

The project *Free Span Burial Inspection Pig (1313/99-0013)*, conducted by FORCE, constituted phase A of a continuation of the original project of the same title, supported under ERP 91. By means of "pigging" (sending measuring equipment through the pipeline), the instrument ("pig") will detect whether a given pipeline is buried or exposed, and whether there are any free spans along the line. The method relies on natural gamma radiation from the surroundings. However, radiation from radioactive radon in the gas flowing through the pipeline may interfere with the detector results. Part of the project was therefore devoted to developing a method to eliminate this interference. The project demonstrated with a high degree of probability that internal inspection of pipelines may provide data revealing free spans, burial and loss of protective concrete coating. This method is considerably less costly than inspection from a ship, and furthermore allows pipeline inspection during winter.

Phase B of the continued project is subsidized under ERP 2000. This phase is dedicated to implementing the equipment design concept developed in phase A.

JOINT CHALK RESEARCH (JCR)

Energy 21 emphasizes the need to strengthen the international commitment of Danish energy research, including with regard to oil and gas exploration and recovery.

After the completion of the Fifth Phase in April 2000, the Joint Chalk Research programme, which is based on cooperation between a number of oil companies and the Danish and Norwegian authorities, has entered the project design stage for the Sixth Phase. There is a generally positive attitude towards continuing this cooperation, and possibly even extending it by admitting new companies.

At a steering group meeting in autumn 2000, a number of proposals were submitted for new research topics, including proposals for areas that had not previously enjoyed much attention, e.g. geophysical methods and blowdown of gas zones.

The programme activities are typically divided into three-year phases, each centred on a specific topic. The cost of each phase is approx. DKK 17 million. The initiation of the Sixth Phase is scheduled for 2001.

OTHER RESEARCH

The Phillips group, which holds licences 4, 5 and 6/98, is allocating resources to research and job training throughout the licence period. In this connection, the group supported the following research projects in 1999:

Gravity and magnetic interpretation of North Sea structure with emphasis on the Central Graben. Performed by the University of Copenhagen.

Fault geometry, fault overlap zones and the growth history of faults. Performed by the University of Aarhus.

Upper Jurassic shelf-slope systems of the Danish Central Graben: Sequence stratigraphy and controls on emplacement of deltaic and deep marine reservoir sandstones in an active rift setting. Performed by the University of Copenhagen.

Study of Jurassic reservoir quality and diagenesis in the Danish Central Graben, licences 4/98, 5/98 and 6/98. Performed by the Geological Survey of Denmark and Greenland.

8. STATUTES AND EXECUTIVE ORDERS

In 2000, several new executive orders and amendments to statutes relating to oil and gas activities were introduced. The majority of these orders and amendments are described below.

Payment for Use of the Oil Pipeline to Shore

Executive Order No. 212 of 21 March 2000 on Payment for the Transportation of Crude Oil and Condensate.

In March, a revised executive order was issued regarding the payment for transporting crude oil and condensate through DONG Olierør A/S' pipeline from the Gorm Field to Fredericia. This revision was made because more parties are using the pipeline after the holders of the Lulita share of licences 7/86 and 1/90 began transporting their share of oil from the Lulita Field through the pipeline. The Executive Order lays down rules on budgeting and accounting for the costs of using the pipeline, as well as rules regulating the fees payable by the users of the pipeline.

Specifications for Pressure Equipment and Construction Plant Equipment

Executive Order No. 298 of 22 April 2000 on Aerosols, Pressure Vessels, Simple Pressure Vessels, Pressure-Bearing Equipment and Construction Plant Equipment on Offshore Installations.

This Executive Order contains the EU design requirements for equipment of this type used on offshore installations. As a result of this Executive Order, new rules have been introduced and existing rules updated. The requirements are identical to those applicable to equipment used on shore.

Implementation of the Aarhus Convention
(Convention on Access to Information, Public Participation in Decision-Making and Access to Justice in Environmental Matters)

The "Aarhus Act". Act No. 447 of 31 May 2000 on the Amendment of Certain Environmental Acts.

Executive Order No. 884 of 21 September 2000 on the Environmental Impact Assessment of Projects for the Recovery of Hydrocarbons and for the Establishment of Pipelines in Danish Sea Territory and the Danish Continental Shelf.

In passing this statute, the Danish Parliament implemented the Aarhus Convention in Denmark. The Convention was signed on 25 June 1998 at the Pan-European Conference of Environment Ministers, *Environment for Europe*, which was held in Aarhus under the auspices of the UN and hosted by the Danish Minister for Environment and Energy. In addition to Denmark, 34 other European countries, including the EU Member States, signed the Convention.

The Convention addresses citizens' access to information, their right to take part in decision-making processes, to lodge complaints and have decisions reviewed in matters related to the environment.

In the offshore area, the implementation of this Convention has resulted in amendments to the Subsoil Act, the Continental Shelf Act and the Executive Order on Environmental Impact Assessments.

With these amendments, new provisions on complaint procedures were incorporated in the two above-mentioned statutes, extending the right to file complaints with the Energy Complaints Board against any project permits and approvals granted by the Danish Energy Agency that are assumed to have a major impact on the environment. Consequently, a permit may not be utilized until the four-week time limit for lodging complaints has expired. The projects in question are set out in the Executive Order on the Environmental Impact Assessment of Projects for the Recovery of Hydrocarbons and for the Establishment of Pipelines in Danish Sea Territory and the Danish Continental Shelf.

The other two elements in the Convention, viz. public participation in environmental decision-making and the access of citizens to information on the environment, were implemented by an amendment to the Executive Order on Environmental Impact Assessments and an amendment to the Act on Freedom of Access to Environmental Information.

A new provision was inserted in the Executive Order on Environmental Impact Assessments according to which the Danish Energy Agency must also state which permits are to be obtained from other public authorities for a given project when informing the public about its receipt of an application for a permit or approval of a project comprised by the provisions of the Executive Order.

The definition of environmental information now encompasses more types of information than before, and more public authorities than previously are required to provide public access to their files in accordance with the Act on Freedom of Access to Environmental Information. Thus, the obligation to give the public access to information on the environment now also applies to bodies that have public responsibility for the environment and are subject to public control. Accordingly, a publicly owned company such as DONG will be comprised by the new provisions on freedom of access to environmental information.

Health and Safety Training of Safety Representatives, etc.

Executive Order No. 907 of 25 September 2000 on Health and Safety Training of Safety Representatives, etc. on Offshore Installations.

As from 15 October 2000, new rules were introduced on an employer's duty to ensure that the members of a safety group receive the necessary training in health and safety issues. The members of the group are required to participate in courses on these subjects. The Danish Energy Agency must make sure that the content of such courses is satisfactory. This Executive Order replaces the previous rules on safety training.

Third-Party Access to Upstream Pipelines

Executive Order No. 1090 of 6 December 2000 on Access to Upstream Pipeline Networks.

Following the adoption by the Danish Parliament of the Natural Gas Supply Act in 2000, rules regarding third-party access to using upstream pipelines for the transportation of natural gas were issued. These rules were introduced as part of Denmark's implementation of the EU Directive on the liberalization of the natural gas market.

The rules entitle third parties to transport natural gas in upstream pipelines against payment. A party desiring access to upstream pipelines will have to negotiate with the owner or operator of the pipeline. The Energy Regulatory Authority supervises the reasonableness of prices and conditions and may mediate or make decisions in case of disagreement.

New Rules on Paintwork

Executive Order No. 1181 of 15 December 2000 on Paintwork, etc. on Offshore Installations.

As from 1 January 2001, new rules regulating paintwork on offshore installations entered into force. The Executive Order sets down rules on the labelling and storing of paints and related products, including epoxy resins and isocyanates, and on the precautionary measures to be taken when using these products. At the same time, the existing rules on polyurethane and epoxy products and code-numbered products on fixed offshore installations have been abolished.

Safety Training and Drills

Executive Order No. 1208 of 17 December 2000 on Safety Training, Drills, etc. on Certain Offshore Installations.

Effective 1 January 2001, new rules on safety training and drills on certain offshore installations were introduced. They replace the previous rules from 1988. The most important change is that safety training refresher courses are now to be held every fourth year, as compared to every third year. As from the same date, persons paying regular visits to offshore installations may participate in a one-day refresher course. All other personnel are required to complete a two-day course. With this amendment, the rules have been adapted to the practice existing in the other North Sea countries.

Permits for Laying Power Cables

Act No. 1276 of 20 December 2000 to Amend the Continental Shelf Act.

As a result of this amendment, the laying of power cables over the Danish continental shelf was made subject to the granting of a permit, in the same way as for pipelines. The public authorities may charge payment by the hour for their work on processing applications for permission to lay pipelines and power cables and the associated supervisory work. Finally, strict liability to compensate for any damage or loss caused by pipelines and power cables has been introduced.

Revised Executive Order on the Filing of Data

A new draft Executive Order on the submission of samples and other information about the Danish subsoil in pursuance of section 34 of the Subsoil Act has been prepared in cooperation with the Geological Survey of Denmark and Greenland.

The purpose of the new Executive Order is to update the existing rules due to advances in technology, particularly in the IT area, which have changed the way of acquiring and transmitting data.

The two sides of industry have been consulted on the draft Executive Order, which is expected to be introduced in the course of 2001.

LICENCES IN DENMARK

Licence	Sole Concession of 8 July 1962
Operator	Mærsk Olie og Gas AS
Licence granted	8 July 1962
Blocks	5504/7, 8, 11, 12, 15, 16;
	5505/13, 17, 18
	(The Contiguous Area)
	5504/5, 6 (Elly)
	5603/27, 28 (Freja)
	5504/10, 14 (Rolf)
	5604/25 (Svend)
	5604/21, 22 (Harald)
Area (km²)	1724.2
	(The Contiguous Area)
	64.0 (Elly)
	44.8 (Freja)
	8.4 (Rolf)
	48.0 (Svend)
	55.7 (Harald)

Company	Share (%)
Shell Olie- og Gasudvinding Danmark B.V.	46.000
A.P. Møller (Concessionaires)	39.000
Texaco Denmark Inc.	15.000

Licence	7/86 (the Amalie share)
Operator	DONG Efterforskning og Produktion A/S
Co-operator	Amerada Hess ApS
Licence granted	24 June 1986 (2nd Round)
Blocks	5604/22, 26
Area (km²)	106.8

Company	Share (%)
Amerada Hess Energi ApS	41.105
DONG Efterforskning og Produktion A/S	28.205
DENERCO OIL A/S	19.929
LD Energi A/S	10.761

Licence	7/86 (the Lulita share)
Operator	DONG Efterforskning og Produktion A/S
Co-operator	Statoil Efterforskning og Produktion A/S
Licence granted	24 June 1986 (2nd Round)
Block	5604/22
Area (km²)	2.6

Company	Share (%)
Statoil Efterforskning og Produktion A/S	37.642
DONG Efterforskning og Produktion A/S	27.184
DENERCO OIL A/S	24.260
LD Energi A/S	10.914

Licence	7/89
Operator	Amerada Hess ApS
Co-operator	DONG Efterforskning og Produktion A/S
Licence granted	20 December 1989 (3rd Round)
Blocks	5504/2; 5604/25, 29, 30
Area (km²)	261.6

Company	Share (%)
Amerada Hess ApS	65.690
DONG Efterforskning og Produktion A/S	25.000
DENERCO OIL A/S	7.500
Danoil Exploration A/S	1.810

Licence	7/89 (the South Arne share)
Operator	Amerada Hess ApS
Co-operator	DONG Efterforskning og Produktion A/S
Licence granted	20 December 1989 (3rd Round)
Blocks	5604/29, 30
Area (km²)	93.3

Company	Share (%)
Amerada Hess ApS	57.47875
DONG Efterforskning og Produktion A/S	34.37500
DENERCO OIL A/S	6.56250
Danoil Exploration A/S	1.58375

Licence	8/89
Operator	DONG Efterforskning og Produktion A/S
Co-operator	Amerada Hess ApS
Licence granted	20 December 1989 (3rd Round)
Blocks	5603/32; 5604/29
Area (km²)	234.0

Company	Share (%)
Amerada Hess ApS	63.263
DONG Efterforskning og Produktion A/S	23.624
DENERCO OIL A/S	10.564
Danoil Exploration A/S	2.549

Licence	10/89
Operator	Mærsk Olie og Gas AS
Licence granted	20 December 1989 (3rd Round)
Block	5603/27
Area (km²)	27.1

Company	Share (%)
A.P. Møller	26 2/3
Shell Olie- og Gasudvinding Danmark B.V.	26 2/3
Texaco Denmark Inc.	26 2/3
DONG Efterforskning og Produktion A/S	20.000

Licence	1/90
Operator	DONG Efterforskning og Produktion A/S
Technical assistant	Statoil Efterforskning og Produktion A/S
Licence granted	3 July 1990
Block	5604/18
Area (km²)	1.2

Company	Share (%)
Statoil Efterforskning og Produktion A/S	37.642
DONG Efterforskning og Produktion A/S	27.184
DENERCO OIL A/S	24.260
LD Energi A/S	10.914

Licence	3/90
Operator	Mærsk Olie og Gas AS
Licence granted	13 July 1990
Block	5603/28
Area (km²)	29.6

Company	Share (%)
Shell Olie- og Gasudvinding Danmark B.V.	36.800
A.P. Møller	31.200
DONG Efterforskning og Produktion A/S	20.000
Texaco Denmark Inc.	12.000

Licence	1/95
Operator	Amerada Hess ApS
Co-operator	DONG Efterforskning og Produktion A/S
Licence granted	15 May 1995 (4th Round)
Blocks	5503/2, 3; 5603/30, 31
Area (km²)	187.8

Company	Share (%)
Amerada Hess ApS	40.000
Premier Oil B.V.	20.000
DENERCO OIL A/S	20.000
DONG Efterforskning og Produktion A/S	20.000

Licence	2/95
Operator	DONG Efterforskning og Produktion A/S
Co-operator	Amerada Hess ApS
Licence granted	15 May 1995 (4th Round)
Blocks	5503/3, 4; 5603/31; 5604/29
Area (km²)	331.1

Company	Share (%)
Amerada Hess ApS	63.263
DONG Efterforskning og Produktion A/S	23.624
DENERCO OIL A/S	10.564
Danoil Exploration A/S	2.549

Licence	4/95
Operator	DONG Efterforskning og Produktion A/S
Licence granted	15 May 1995 (4th Round)
Blocks	5604/20; 5605/7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17
Area (km²)	1087.5

Company	Share (%)
DONG Efterforskning og Produktion A/S	40.000
RWE-DEA AG	30.000
DENERCO OIL A/S	25.000
EWE AG	5.000

Licence	6/95
Operator	Statoil Efterforskning og Produktion A/S
Co-operator	DONG Efterforskning og Produktion A/S
Licence granted	15 May 1995 (4th Round)
Blocks	5604/16, 20; 5605/13, 17
Area (km²)	414.1

Company	Share (%)
Statoil Efterforskning og Produktion A/S	40.000
Enterprise Oil Denmark Ltd.	20.000
DONG Efterforskning og Produktion A/S	20.000
Phillips Petroleum Int. Corp. Denmark	12.500
DENERCO OIL A/S	7.500

Licence	7/95
Operator	Mærsk Olie og Gas AS
Licence granted	15 May 1995 (4th Round)
Block	5505/22
Area (km²)	195.9

Company	Share (%)
A.P. Møller	26 2/3
Shell Olie- og Gasudvinding Danmark B.V.	26 2/3
Texaco Denmark Inc.	26 2/3
DONG Efterforskning og Produktion A/S	20.000

Licence	8/95
Operator	Mærsk Olie og Gas AS
Licence granted	15 May 1995 (4th Round)
Blocks	5504/3, 4
Area (km²)	326.0

Company	Share (%)
Shell Olie- og Gasudvinding Danmark B.V.	36.800
A.P. Møller	31.200
DONG Efterforskning og Produktion A/S	20.000
Texaco Denmark Inc.	12.000

Licence	9/95
Operator	Mærsk Olie og Gas AS
Licence granted	15 May 1995 (4th Round)
Blocks	5604/21, 22, 25, 26
Area (km²)	218.5
Company	**Share (%)**
Shell Olie- og Gasudvinding Danmark B.V.	36.800
A.P. Møller	31.200
DONG Efterforskning og Produktion A/S	20.000
Texaco Denmark Inc.	12.000

Licence	1/98
Operator	CLAM Petroleum Danske B.V.
Licence granted	15 June 1998 (5th Round)
Blocks	5505/1, 5, 6
Area (km²)	285.5
Company	**Share (%)**
CLAM Petroleum Danske B.V.	80
DONG Efterforskning og Produktion A/S	20

Licence	1/97
Operator	Norsk Agip A/S
Licence granted	15 September 1997 (Open Door)
Blocks	5606/14, 18
Area (km²)	428.6
Company	**Share (%)**
Agip Denmark B.V.	80.000
DONG Efterforskning og Produktion A/S	20.000

Licence	2/98
Operator	CLAM Petroleum Danske B.V.
Licence granted	15 June 1998 (5th Round)
Blocks	5605/18, 19, 22, 23
Area (km²)	231.9
Company	**Share (%)**
CLAM Petroleum Danske B.V.	80
DONG Efterforskning og Produktion A/S	20

Licence	4/97
Operator	Mærsk Olie og Gas AS
Licence granted	15 September 1997 (Open Door)
Blocks	5506/4, 8, 12, 16, 20, 24; 5507/1, 2, 5, 6, 9, 10, 13, 14, 17, 18, 21, 22, 25, 26
Area (km²)	3335.7
Company	**Share (%)**
A.P. Møller	40.000
Shell Olie- og Gasudvinding Danmark B.V.	40.000
DONG Efterforskning og Produktion A/S	20.000

Licence	3/98
Operator	Marathon Petroleum Denmark, Ltd.
Licence granted	15 June 1998 (5th Round)
Blocks	5605/28; 5605/32
Area (km²)	216.4
Company	**Share (%)**
Marathon Petroleum Denmark, Ltd	80
DONG Efterforskning og Produktion A/S	20

Licence	5/97
Operator	Sterling Resources Ltd.
Licence granted	15 September 1997 (Open Door)
Blocks	5512/2; 5612/30
Area (km²)	406.8
Company	**Share (%)**
Odin Energi ApS	60.000
Sterling Resources (UK) Ltd.	20.000
DONG Efterforskning og Produktion A/S	20.000

Licence	4/98
Operator	Phillips Petroleum Int. Corp. Denmark
Licence granted	15 June 1998 (5th Round)
Blocks	5604/26, 27, 30, 31; 5504/2, 3
Area (km²)	604.4
Company	**Share (%)**
Phillips Petroleum Int. Corp. Denmark	30
Saga Petroleum Danmark AS	25
Veba Oil Denmark GmbH	25
DONG Efterforskning og Produktion A/S	20

Licence	5/98
Operator	Phillips Petroleum Int. Corp. Denmark
Licence granted	15 June 1998 (5th Round)
Blocks	5603/24, 28; 5604/21, 25
Area (km²)	232.6

Company	Share (%)
Phillips Petroleum Int. Corp. Denmark	30
Saga Petroleum Danmark AS	25
Veba Oil Denmark GmbH	25
DONG Efterforskning og Produktion A/S	20

Licence	6/98
Operator	Phillips Petroleum Int. Corp. Denmark
Licence granted	15 June 1998 (5th Round)
Blocks	5504/1, 2; 5604/29
Area (km²)	213.8

Company	Share (%)
Phillips Petroleum Int. Corp. Denmark	30
Saga Petroleum Danmark AS	25
Veba Oil Denmark GmbH	25
DONG Efterforskning og Produktion A/S	20

Licence	7/98
Operator	Enterprise Oil Denmark
Co-operator	DONG Efterforskning og Produktion A/S
Licence granted	15 June 1998 (5th Round)
Blocks	5505/1, 2, 3, 6, 7, 10
Area (km²)	583.4

Company	Share (%)
Enterprise Oil Denmark	60
DENERCO OIL A/S	20
DONG Efterforskning og Produktion A/S	20

Licence	8/98
Operator	Kerr-McGee International ApS
Licence granted	15 June 1998 (5th Round)
Blocks	5605/18, 19
Area (km²)	359.1

Company	Share (%)
Kerr-McGee International ApS	40
ARCO Denmark Limited	40
DONG Efterforskning og Produktion A/S	20

Licence	9/98
Operator	Norsk Agip A/S
Licence granted	15 June 1998 (5th Round)
Blocks	5604/28, 32; 5605/25, 29
Area (km²)	721.2

Company	Share (%)
Agip Denmark B.V.	80
DONG Efterforskning og Produktion A/S	20

Licence	10/98
Operator	Norsk Agip A/S
Licence granted	15 June 1998 (5th Round)
Blocks	5503/3, 7
Area (km²)	169.5

Company	Share (%)
Agip Denmark B.V.	80
DONG Efterforskning og Produktion A/S	20

Licence	11/98
Operator	DONG Efterforskning og Produktion A/S
Licence granted	15 June 1998 (5th Round)
Blocks	5503/8; 5504/1, 2, 5, 6
Area (km²)	352.8

Company	Share (%)
Amerada Hess ApS	42
Veba Oil Denmark GmbH	20
DONG Efterforskning og Produktion A/S	25
DENERCO OIL A/S	13

Licence	12/98
Operator	Amerada Hess ApS
Licence granted	15 June 1998 (5th Round)
Blocks	5604/27, 28, 31, 32
Area (km²)	276.2

Company	Share (%)
Amerada Hess ApS	50
DENERCO OIL A/S	30
DONG Efterforskning og Produktion A/S	20

Licence	13/98
Operator	EDC (Europe) Ltd.
Licence granted	15 June 1998 (5th Round)
Blocks	5505/5, 9
Area (km²)	328.0
Company	**Share (%)**
EDC (Denmark)	40
Pogo Denmark ApS	40
DONG Efterforskning og Produktion A/S	20

Licence	17/98
Operator	Mærsk Olie og Gas AS
Licence granted	15 June 1998 (5th Round)
Blocks	5505/19, 23
Area (km²)	146.1
Company	**Share (%)**
Shell Olie- og Gasudvinding Danmark B.V.	36.80
A.P. Møller	31.20
DONG Efterforskning og Produktion A/S	20.00
Texaco Denmark Inc.	12.00

Licence	14/98
Operator	Mærsk Olie og Gas AS
Licence granted	15 June 1998 (5th Round)
Blocks	5505/3,4; 5605/26, 27, 28, 30, 31, 32; 5606/25
Area (km²)	1355.9
Company	**Share (%)**
A.P. Møller	26 2/3
Shell Olie- og Gasudvinding Danmark B.V.	26 2/3
Texaco Denmark Inc.	26 2/3
DONG Efterforskning og Produktion A/S	20

Licence	1/99
Operator	Norsk Agip A/S
Licence granted	15 February 1999 (Open Door)
Blocks	5506/4, 7, 8, 10, 11, 12, 14, 15, 16, 18, 19, 22, 23
Area (km²)	1792.1
Company	**Share (%)**
Agip Denmark B.V.	80
DONG Efterforskning og Produktion A/S	20

Licence	15/98
Operator	Mærsk Olie og Gas AS
Licence granted	15 June 1998 (5th Round)
Block	5604/25
Area (km²)	70.5
Company	**Share (%)**
Shell Olie- og Gasudvinding Danmark B.V.	36.80
A.P. Møller	31.20
DONG Efterforskning og Produktion A/S	20.00
Texaco Denmark Inc.	12.00

Licence	2/99
Operator	Gustavson Associates Inc.
Licence granted	20 March 1999 (Open Door)
Blocks	5707/16, 19, 20, 22, 23, 24, 26, 27, 30, 31
Area (km²)	1329.4
Company	**Share (%)**
Gustavson Associates Inc.	80
DONG Efterforskning og Produktion A/S	20

Licence	16/98
Operator	DONG Efterforskning og Produktion A/S
Licence granted	15 June 1998 (5th Round)
Blocks	5604/15, 18, 19, 20
Area (km²)	216.9
Company	**Share (%)**
DENERCO OIL A/S	37.000
LD Energi A/S	24.000
DONG Efterforskning og Produktion A/S	22.000
RWE-DEA AG	17.000

Licence	3/99
Operator	The Anschutz Overseas Corporation
Licence granted	20 March 1999 (Open Door)
Blocks	5606/10, 11, 12, 15, 16, 20, 24; 5607/9, 13, 17, 21, 25, 29
Area (km²)	2791.2
Company	**Share (%)**
Anschutz Denmark ApS	80
DONG Efterforskning og Produktion A/S	20

Licence	4/99
Operator	Amerada Hess ApS
Licence granted	1 May 1999 (Open Door)
Blocks	5610/19, 20, 23, 24, 28; 5611/21, 22, 25, 26, 30; 5612/29
Area (km²)	2372.1

Company	Share (%)
Courage Energy Inc.	32
Odin Energi ApS	20
DONG Efterforskning og Produktion A/S	20
Amerada Hess ApS	16
Emerald Energy Denmark Limited	12

Licence	1/01
Operator	UAB Minijos Nafta
Licence granted	5 March 2001 (Open Door)
Blocks	5408/3, 4; 5409/1, 2, 3, 4, 6, 7, 8; 5508/23, 24, 27, 28, 31, 32; 5509/25, 29, 30, 31, 32
Area (km²)	3851.4

Company	Share (%)
Dansk Venture Olieefterforskning	40
UAB Minijos Nafta	20
Sterling Resources (UK), Ltd.	20
DONG Efterforskning og Produktion A/S	20

Licence	5/99
Operator	Mærsk Olie og Gas AS
Licence granted	27 November 1999 (neighbouring block)
Blocks	5504/20, 24; 5505/21
Area (km²)	187.3

Company	Share (%)
A.P. Møller	80
DONG Efterforskning og Produktion A/S	20

Licence	2/01
Operator	Sterling Resources (UK), Ltd.
Licence granted	5 March 2001 (Open Door)
Blocks	5608/8, 12,16; 5609/5, 9,13
Area (km²)	1278.6

Company	Share (%)
Sterling Resources (UK), Ltd.	75
DONG Efterforskning og Produktion A/S	20
Dansk Efterforskningsselskab ApS	5

The licence shares indicated are those appearing from the licences issued. Reference is made to the maps of the Danish licence area at the back of the report. The list and the maps will be updated on the Danish Energy Agency's homepage www.ens.dk.

EXPLORATORY SURVEYS 2000

Survey Licence	Operator Contractor	Type	Initiated Completed	Area Block no.	Acquired in 2000
Kraka Extension **5/99, 7/95, DSO**	Mærsk Olie og Gas AS PGS Exploration AS	Offshore 3D seismics	20-04-2000 21-06-2000	CG 5504, 5505	1,345 km²
VER1, VER2 **3/99**	Anschutz Denmark ApS Geco-Prakla	Offshore 3D/2D seismics	15-06-2000 13-07-2000	NDB 5606, 5607	225 km² 165 km
A6B4-00-2D **Excl.**	Wintershall Noordzee B.V. Fugro Geoteam AS	Offshore 2D seismics	16-04-2000 16-04-2000	CG 5504	9 km *)
AG0002-01 **1/99**	Norsk Agip Gardline Surveys	Offshore 2D seismics	25-01-2000 26-01-2000	RFH 5506	26 km
SB-4C-20 **Spec.**	Geco-Prakla Geco-Prakla	Offshore 2D seismics	07-06-2000 18-06-2000	CG 5504, 5505, 5604	72 km
HGS **Geothermal Energy**	DONG A/S Rambøll/Thor	Offshore 2D seismics	02-10-2000 05-10-2000	NDB, HVB 5512	231 km
HGS **Geothermal Energy**	DONG A/S Rambøll/Thor	Onshore 2D seismics	19-10-2000 23-11-2000	NDB, HVB 5512	83 km
5/97	Sterling Resources Ltd. Wexco	Onshore Geochemical	06-04-2000 28-04-2000	NDB 5512, 5612	131 samples
AGS00 **1/99**	Norsk Agip GEUS	Offshore Geochemical	30-08-2000 14-09-2000	RFH 5506	19 samples
AGM001,AGM002 **9/98, 1/99**	Norsk Agip Fugro Airborne Surveys	Offshore Aeromagnetic	02-08-2000 05-08-2000	RFH 5506, 5604, 5605	3,705 km

DSO=The Contiguous Area, CG=Central Graben, HG=Horn Graben, NDB=Norwegian-Danish Basin, RFH=Ringkøbing-Fyn High, HVB=Höllviken Basin

**) Only the Danish share of the survey has been included.*

AMOUNTS PRODUCED AND INJECTED

OIL thousand cubic metres

Production and Sales

	1972-90	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Total
Dan	10,682	1,723	2,699	3,262	3,496	3,713	3,799	3,858	4,767	5,745	6,599	50,344
Gorm	14,796	1,501	1,661	1,889	2,421	2,494	2,879	3,045	2,865	3,384	3,110	40,045
Skjold	10,425	2,734	2,281	2,103	1,715	1,979	2,023	2,011	1,896	1,825	1,975	30,967
Tyra	4,914	1,386	1,669	1,639	1,748	1,631	1,447	1,263	931	892	1,000	18,520
Rolf	2,164	293	304	176	92	216	218	96	92	77	83	3,810
Kraka	-	144	205	390	490	469	340	315	314	404	350	3,422
Dagmar	-	475	305	67	33	35	23	17	13	10	8	986
Regnar	-	-	-	145	429	86	41	27	43	29	14	815
Valdemar	-	-	-	53	304	165	161	159	95	86	77	1,100
Roar	-	-	-	-	-	0	319	427	327	259	285	1,617
Svend	-	-	-	-	-	0	836	1,356	635	521	576	3,923
Harald	-	-	-	-	-	-	0	794	1,690	1,332	1,081	4,897
Lulita	-	-	-	-	-	-	-	-	143	224	179	547
Halfdan	-	-	-	-	-	-	-	-	-	222	1,120	1,342
Siri	-	-	-	-	-	-	-	-	-	1,593	2,118	3,711
South Arne	-	-	-	-	-	-	-	-	-	757	2,535	3,293
Total	**42,981**	**8,256**	**9,125**	**9,724**	**10,727**	**10,788**	**12,087**	**13,367**	**13,810**	**17,362**	**21,111**	**169,338**

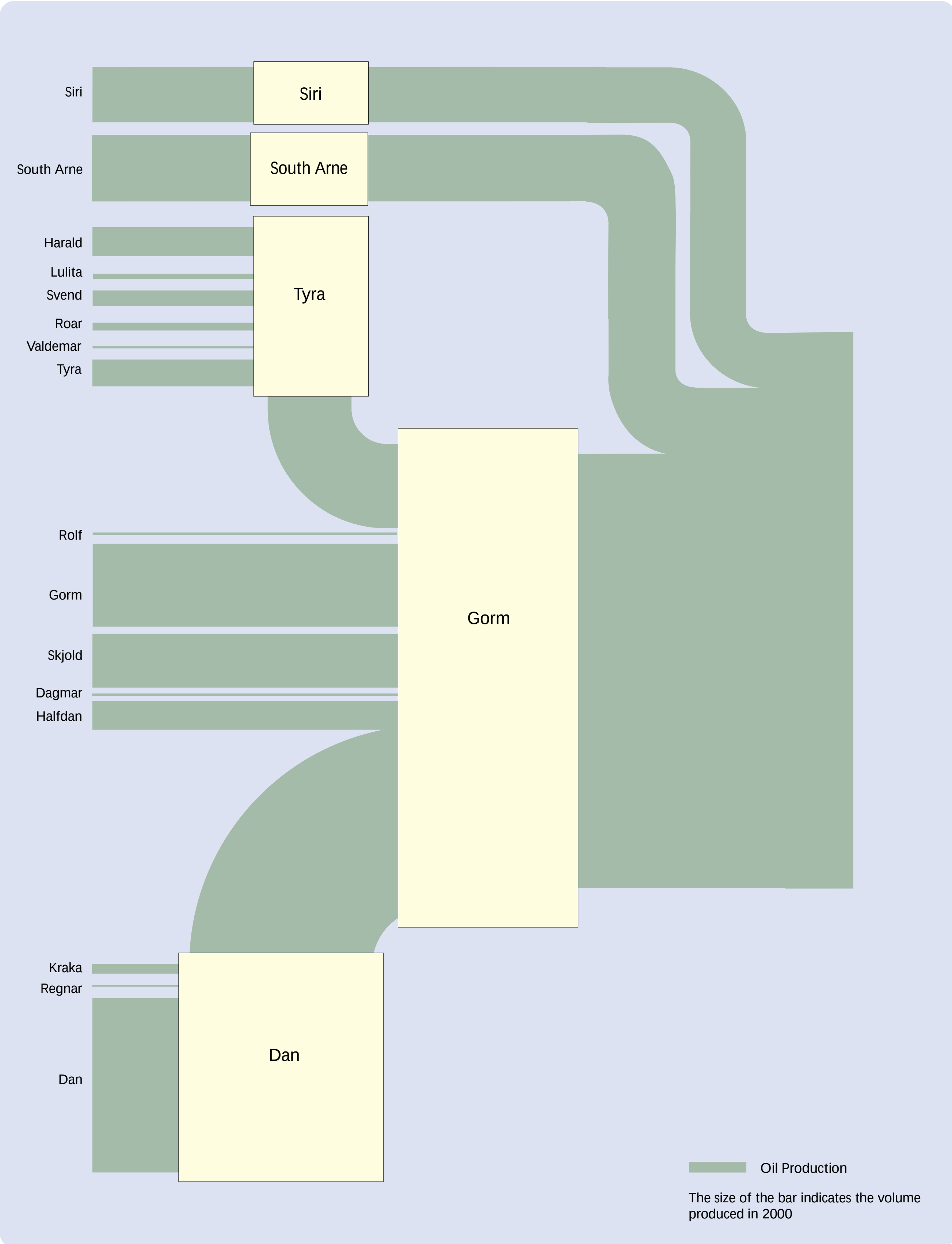
Production

GAS million normal cubic metres

	1972-90	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Total
Dan	4,147	879	1,056	1,336	1,263	1,331	1,249	1,116	1,343	1,410	1,186	16,318
Gorm	6,261	843	844	775	922	761	674	609	633	537	426	13,284
Skjold	887	233	212	195	185	188	160	189	146	154	158	2,707
Tyra	15,838	3,672	3,944	3,853	3,646	3,839	3,843	4,229	3,638	3,878	3,810	54,192
Rolf	92	12	12	8	4	9	9	4	4	3	4	161
Kraka	-	56	88	125	119	128	95	85	106	148	119	1,069
Dagmar	-	65	46	13	8	5	4	3	2	2	2	150
Regnar	-	-	-	8	25	7	4	2	4	2	1	53
Valdemar	-	-	-	29	96	52	57	89	54	49	55	481
Roar	-	-	-	-	-	0	1,327	1,964	1,458	1,249	1,407	7,404
Svend	-	-	-	-	-	0	85	152	84	65	74	460
Harald	-	-	-	-	-	-	0	1,092	2,741	2,876	2,811	9,519
Lulita	-	-	-	-	-	-	-	-	69	181	160	410
Halfdan	-	-	-	-	-	-	-	-	-	37	178	215
Siri	-	-	-	-	-	-	-	-	-	142	197	338
South Arne	-	-	-	-	-	-	-	-	-	167	706	873
Total	**27,225**	**5,760**	**6,203**	**6,342**	**6,269**	**6,321**	**7,506**	**9,534**	**10,281**	**10,901**	**11,294**	**107,634**

The monthly production figures for 2000 are available on the Danish Energy Agency's homepage www.ens.dk

WHERE DOES THE OIL ORIGINATE



GAS million normal cubic metres

Fuel

	1972-90	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Total
Dan	166	49	61	66	85	93	97	109	148	172	179	1,225
Gorm	554	73	81	87	104	111	135	164	152	149	142	1,752
Tyra	524	98	109	110	110	111	142	210	224	239	229	2,108
Dagmar	-	7	13	1	0	0	0	0	0	0	0	21
Harald	-	-	-	-	-	-	-	5	14	14	13	46
Siri	-	-	-	-	-	-	-	-	-	8	21	29
South Arne	-	-	-	-	-	-	-	-	-	3	32	35
Total	**1,244**	**227**	**264**	**264**	**299**	**314**	**375**	**488**	**539**	**585**	**617**	**5,216**

Flaring

	1972-90	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Total
Dan	1,162	68	73	53	66	36	40	36	43	56	67	1,699
Gorm	556	65	86	95	75	69	60	81	71	71	66	1,295
Tyra	268	31	39	39	48	42	67	46	42	58	58	737
Dagmar	-	58	33	12	8	5	2	3	2	2	2	128
Harald	-	-	-	-	-	-	-	77	19	12	7	115
Siri	-	-	-	-	-	-	-	-	-	73	9	82
South Arne	-	-	-	-	-	-	-	-	-	114	40	154
Total	**1,986**	**223**	**230**	**199**	**196**	**152**	**168**	**243**	**177**	**386**	**250**	**4,209**

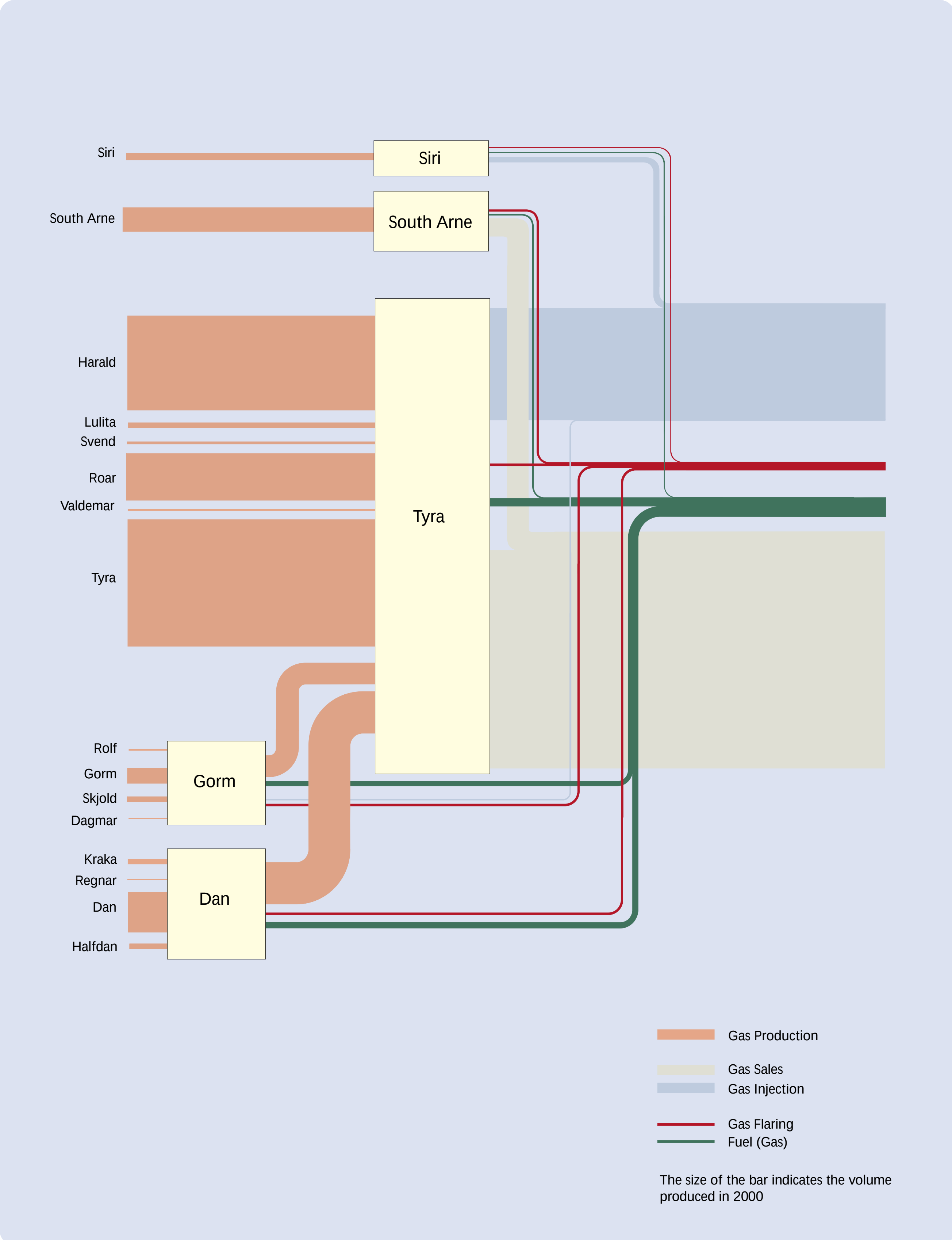
Injection

	1972-90	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Total
Gorm	5,987	735	711	420	70	28	26	62	24	25	45	8,133
Tyra	4,911	1,066	1,370	1,451	1,371	1,132	1,225	1,778	2,908	3,074	3,104	23,390
Siri	-	-	-	-	-	-	-	-	-	61	167	228
Total	**10,897**	**1,801**	**2,081**	**1,871**	**1,441**	**1,160**	**1,251**	**1,840**	**2,933**	**3,160**	**3,316**	**31,750**

Sales

	1972-90	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Total
Dan	2,819	818	1,010	1,350	1,256	1,338	1,211	1,058	1,261	1,371	1,238	14,730
Gorm	143	215	191	376	863	750	622	495	535	448	334	4,972
Tyra	10,135	2,476	2,426	2,281	2,214	2,607	3,878	4,400	2,060	1,870	1,955	36,302
Harald	-	-	-	-	-	-	-	1,010	2,777	3,032	2,950	9,768
South Arne	-	-	-	-	-	-	-	-	-	50	634	685
Total	**13,097**	**3,509**	**3,628**	**4,007**	**4,332**	**4,695**	**5,712**	**6,963**	**6,633**	**6,770**	**7,111**	**66,458**

WHERE DOES THE GAS ORIGINATE



CO_2 EMISSIONS thousand tonnes

	1972-90	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Total
Fuel	2,842	515	598	600	679	713	850	1,107	1,222	1,366*	1,401	11,840
Flaring	4,509	506	522	452	445	345	381	552	401	880	568	9,554
Total	**7,333**	**1,021**	**1,121**	**1,052**	**1,125**	**1,058**	**1,231**	**1,659**	**1,624**	**2,247**	**1,969**	**21,395**

** Including diesel oil*

WATER thousand cubic metres

Production

	1972-90	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Total
Dan	720	276	513	781	1,117	1,275	1,543	1,845	2,976	4,220	5,277	20,544
Gorm	3,832	522	583	557	824	948	1,921	2,906	3,177	3,468	3,980	22,720
Skjold	13	17	339	817	889	1,337	2,679	3,635	3,938	3,748	4,333	21,745
Tyra	776	395	671	1,005	1,290	1,749	2,161	2,215	2,020	2,033	3,046	17,361
Rolf	657	197	350	265	161	443	490	390	411	366	358	4,087
Kraka	-	46	130	195	188	251	272	287	347	329	256	2,300
Dagmar	-	21	206	395	367	464	507	408	338	246	241	3,193
Regnar	-	-	-	-	244	396	299	164	407	363	139	2,012
Valdemar	-	-	-	1	24	20	34	61	52	55	48	294
Roar	-	-	-	-	-	-	14	96	146	199	317	773
Svend	-	-	-	-	-	-	2	64	272	582	1,355	2,276
Harald	-	-	-	-	-	-	-	-	5	15	39	59
Lulita	-	-	-	-	-	-	-	-	3	5	11	20
Halfdan	-	-	-	-	-	-	-	-	-	56	237	293
Siri	-	-	-	-	-	-	-	-	-	319	1,868	2,187
South Arne	-	-	-	-	-	-	-	-	-	15	59	74
Total	**5,999**	**1,474**	**2,792**	**4,016**	**5,103**	**6,882**	**9,922**	**12,072**	**14,093**	**16,020**	**21,565**	**99,938**

Injection

	1972-90	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Total
Dan	259	180	865	1,534	3,808	5,884	8,245	8,654	11,817	14,964	17,464	73,673
Gorm	1,254	1,015	1,598	2,140	4,612	5,749	8,112	8,642	8,376	8,736	10,009	60,243
Skjold	9,329	3,238	2,791	2,836	3,511	3,985	5,712	6,320	6,291	5,866	6,132	56,011
Halfdan	-	-	-	-	-	-	-	-	-	82	13	95
Siri	-	-	-	-	-	-	-	-	-	1,236	3,778	5,014
South Arne	-	-	-	-	-	-	-	-	-	-	47	47
Total	**10,842**	**4,433**	**5,253**	**6,510**	**11,931**	**15,618**	**22,069**	**23,616**	**26,484**	**30,884**	**37,444**	**195,084**

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 km²
Reservoir depth:	1,400 m
Reservoir rock:	Chalk and Carbonates
Geological age:	Danian, Upper Cretaceous and Zechstein
Reserves at 1 Jan. 2001:	
Oil:	0.0 million m³
Gas	0.0 billion Nm³
Cum. production at 1 Jan. 2001:	
Oil:	0.99 million m³
Gas:	0.15 billion Nm³
Water:	3.19 million m³
Production in 2000:	
Oil:	0.01 million m³
Gas:	0.00 billion Nm³
Water:	0.24 million m³
Tot. investments at 1 Jan. 2001:	
2000 prices	DKK 0.4 billion

REVIEW OF GEOLOGY

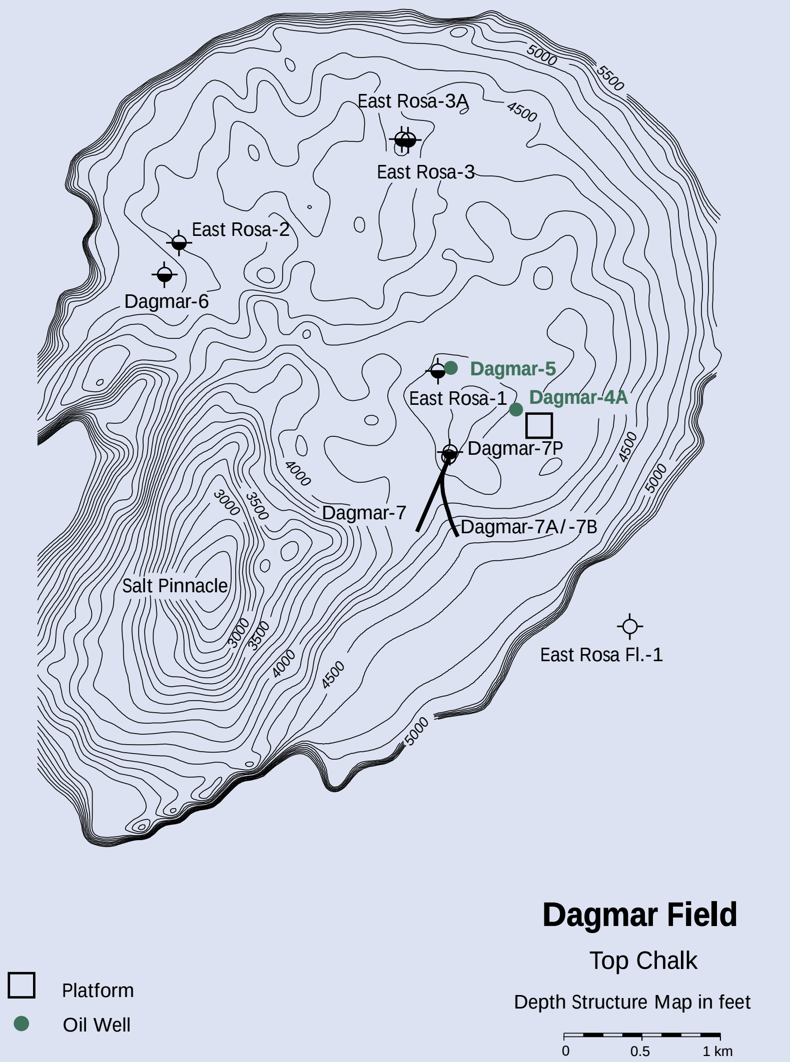
The Dagmar field is an anticlinal structure, induced through Zechstein salt tectonics. The uplift is so pronounced that the Dagmar reservoir is situated closer to the surface than any other hydrocarbon reservoirs in Danish territory. The reservoir is heavily fractured (compare Skjold, Rolf, Regnar and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

PRODUCTION STRATEGY

Initially, the oil production rates were high in the Dagmar Field, but it has not been possible to sustain the good production performance characterizing the Skjold, Svend and Rolf Fields.

PRODUCTION FACILITIES

The Dagmar Field is a satellite development to Gorm 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:	57
Water-injection wells:	40
Water depth:	40 m
Area:	45 km²
Reservoir depth:	1,850 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 Jan. 2001:	
Oil:	55.1 million m³
Gas:	8.6 billion Nm³
Cum. production at 1 Jan. 2001:	
Oil:	50.34 million m³
Gas:	16.32 billion Nm³
Water:	20.54 million m³
Cum. injection at 1 Jan. 2001:	
Water:	73.67 million m³
Production in 2000:	
Oil:	6.60 million m³
Gas:	1.19 billion Nm³
Water:	5.28 million m³
Injection in 2000:	
Water:	17.46 million m³
Tot. investments at 1 Jan. 2001:	
2000 prices	DKK 19.7 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. 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 northwestern flank of the Dan Field based on natural depletion, which means that no energy is added to the reservoir by water injection.

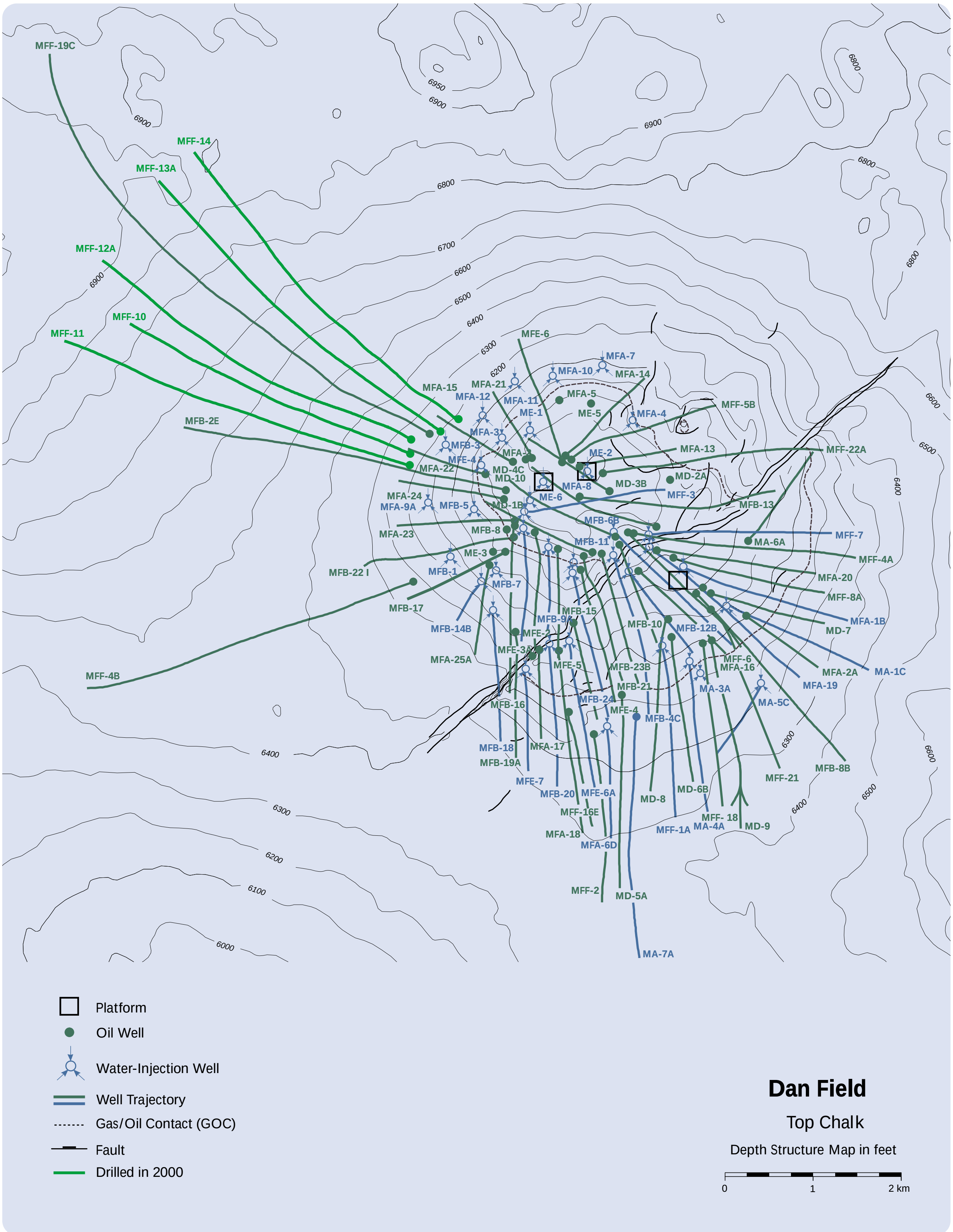
PRODUCTION FACILITIES

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.



Platform
Oil Well
Water-Injection Well
Well Trajectory
Gas/Oil Contact (GOC)
Fault
Drilled in 2000
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:	31
Gas-injection wells:	2
Water-injection wells:	14
Water depth:	39 m
Area:	12 km²
Reservoir depth:	2,100 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 Jan. 2001:	
Oil:	12.2 million m³
Gas:	1.3 billion Nm³
Cum. production at 1 Jan. 2001:	
Oil:	40.05 million m³
Net gas:	5.15 billion Nm³
Water:	22.72 million m³
Cum. injection at 1 Jan. 2001:	
Gas:	8.13 billion Nm³
Water:	60.24 million m³
Production in 2000:	
Oil:	3.11 million m³
Net gas:	0.38 billion Nm³
Water:	3.98 million m³
Injection in 2000:	
Gas:	0.05 billion Nm³
Water:	10.01 million m³
Tot. investments at 1 Jan. 2001:	
2000 prices	DKK 10.0 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).

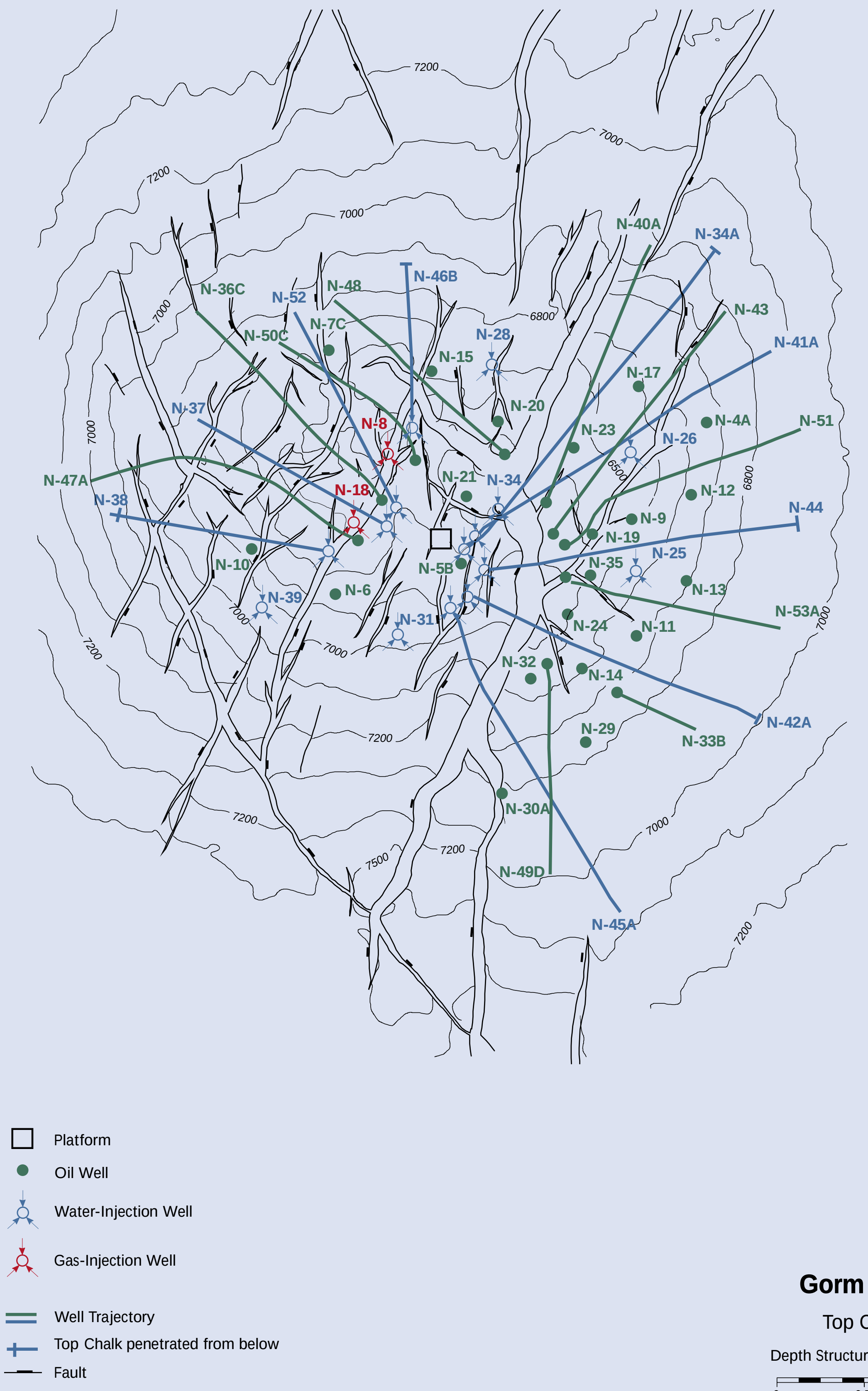
Gorm receives production from the satellite fields, Skjold, Rolf and Dagmar, as well as the liquids (hydrocarbons and water) produced in the Halfdan Field. The Gorm Field installations supply the Skjold Field with injection water and lift gas and the Rolf Field with lift gas. The gas produced is sent 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 wellhead pressure in the Gorm and Skjold wells.

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



Gorm Field

Top Chalk

Depth Structure Map in feet

HALFDAN

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:	5
Water-injection wells:	1
Water depth:	43 m
Area:	70 km²
Reservoir depth:	2,100 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 Jan. 2001:	
Oil:	41.2 million m^3
Gas:	4.8 billion Nm^3
Cum. production at 1 Jan. 2001:	
Oil:	1.34 million m^3
Gas:	0.22 billion Nm^3
Water:	0.29 million m^3
Cum. injection at 1 Jan. 2001:	
Water:	0.10 million m^3
Production in 2000:	
Oil:	1.12 million m^3
Gas:	0.18 billion Nm^3
Water:	0.24 million m^3
Injection in 2000:	
Water:	0.01 million m^3
Tot. investments at 1 Jan. 2001:	
2000 prices	DKK 1.1 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 not previously been encountered in Danish territory.

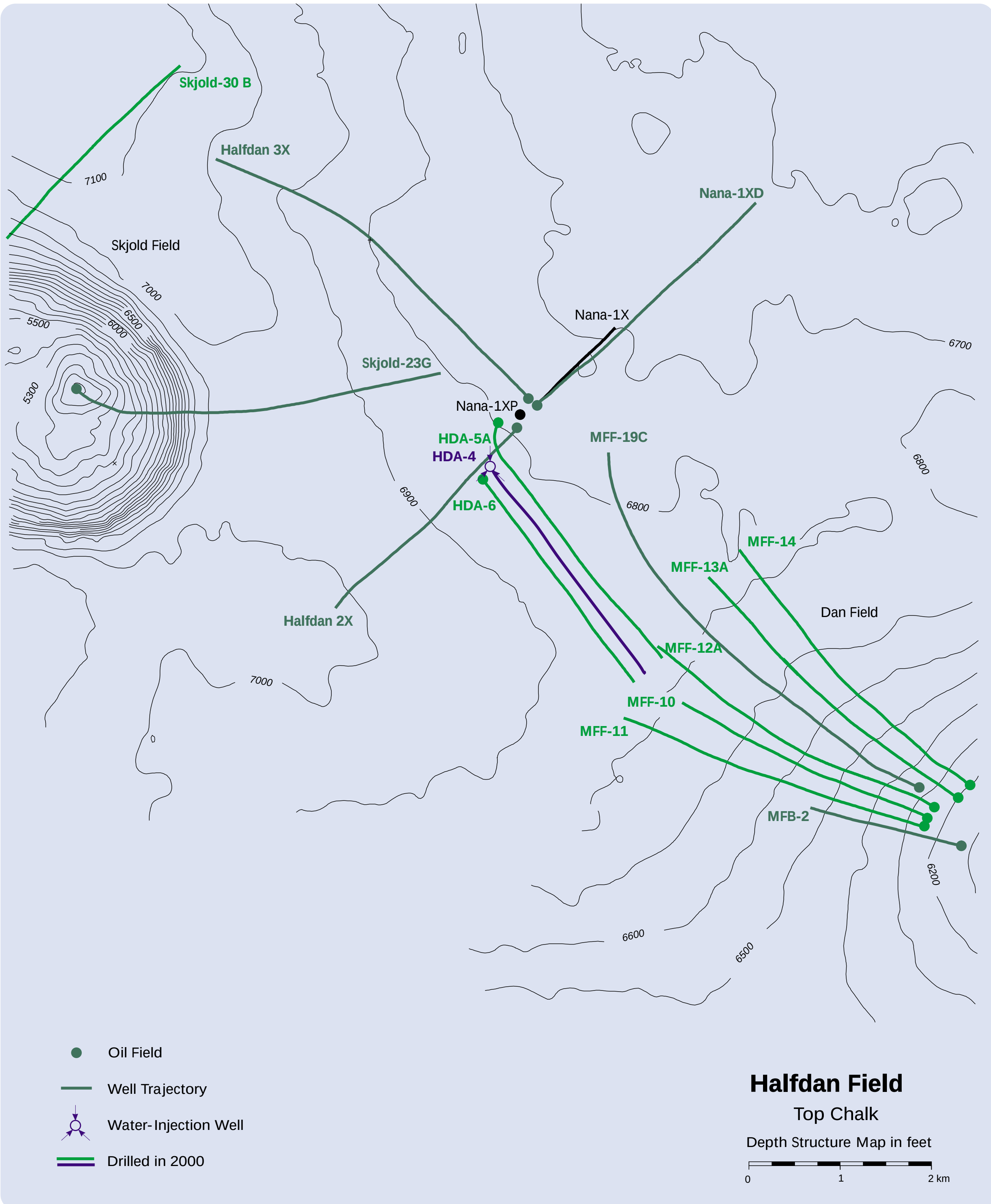
This porous, unfractured chalk is similar to that found in the western part of the Dan Field. There is a gas cap above the northeastern part of the oil accumulation.

PRODUCTION STRATEGY

In the initial development phase, the recovery 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. The pressure in the reservoir is boosted in step with the completion of water-injection wells.

PRODUCTION FACILITIES

The installations in the field consist of a wellhead platform 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.


Skjold-30 B
Halfdan 3X
7100
Skjold Field
7000
6500
6000
5500
5300
Nana-1XD
Nana-1X
6700
Skjold-23G
Nana-1XP
HDA-5A
HDA-4
MFF-19C
HDA-6
6900
6800
6800
MFF-14
MFF-13A
Dan Field
Halfdan 2X
MFF-12A
7000
MFF-10
MFF-11
MFB-2
6200
6600
6500
Oil Field
Well Trajectory
Water-Injection Well
Drilled in 2000
Halfdan Field
Top Chalk
Depth Structure Map in feet
0
1
2 km

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
Area:	25 km^2
Reservoir depth:	2,700 m (Lulu)
	3,650 m (West Lulu)
Reservoir rock:	Chalk (Lulu)
	Sandstone (West Lulu)
Geological age:	Danian/Upper Cretaceous (Lulu)
	Middle Jurassic (West Lulu)
Reserves at 1 Jan. 2001:	
Oil and condensate:	4.0 million m^3
Gas:	14.1 billion Nm^3
Cum. production at 1 Jan. 2001:	
Oil and condensate:	4.90 million m^3
Gas:	9.52 billion Nm^3
Water:	0.06 million m^3
Production in 2000:	
Oil and condensate:	1.08 million m^3
Gas:	2.81 billion Nm^3
Water:	0.04 million m^3
Tot. investments at 1 Jan. 2001:	
2000 prices	DKK 3.1 billion

REVIEW OF GEOLOGY

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

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

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

PRODUCTION STRATEGY

Recovery from both the Harald East and the Harald West 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

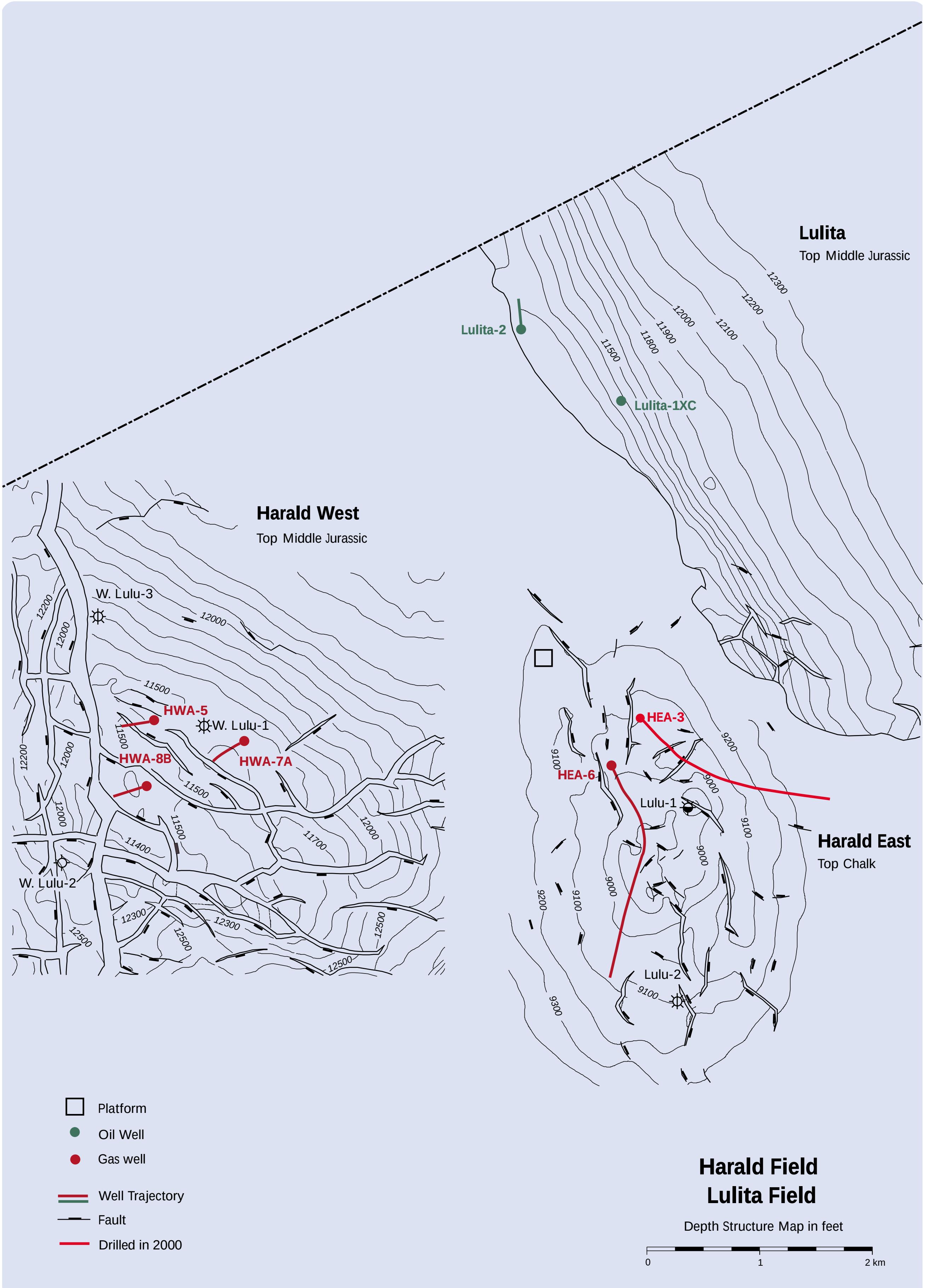
The Harald Field installations comprise a combined wellhead and processing platform (Harald A) and an accommodation platform (Harald B).

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
Lulita-2
Lulita-1XC
12300
12200
12100
12000
11900
11800
11500
Harald West
Top Middle Jurassic
W. Lulu-3
W. Lulu-1
W. Lulu-2
HWA-5
HWA-8B
HWA-7A
12000
11500
11700
11400
12300
12500
12200
Harald East
Top Chalk
HEA-3
HEA-6
Lulu-1
Lulu-2
9000
9100
9200
9300
Platform
Oil Well
Gas well
Well Trajectory
Fault
Drilled in 2000
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
Area:	20 km^2
Reservoir depth:	1,800 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 Jan. 2001:	
Oil:	2.7 million m^3
Gas:	0.9 billion Nm^3
Cum. production at 1 Jan. 2001:	
Oil:	3.42 million m^3
Gas:	1.07 billion Nm^3
Water:	2.30 million m^3
Production in 2000:	
Oil:	0.35 million m^3
Gas:	0.12 billion Nm^3
Water:	0.26 million m^3
Tot. investments at 1 Jan. 2001:	
2000 prices	DKK 1.3 billion

REVIEW OF GEOLOGY

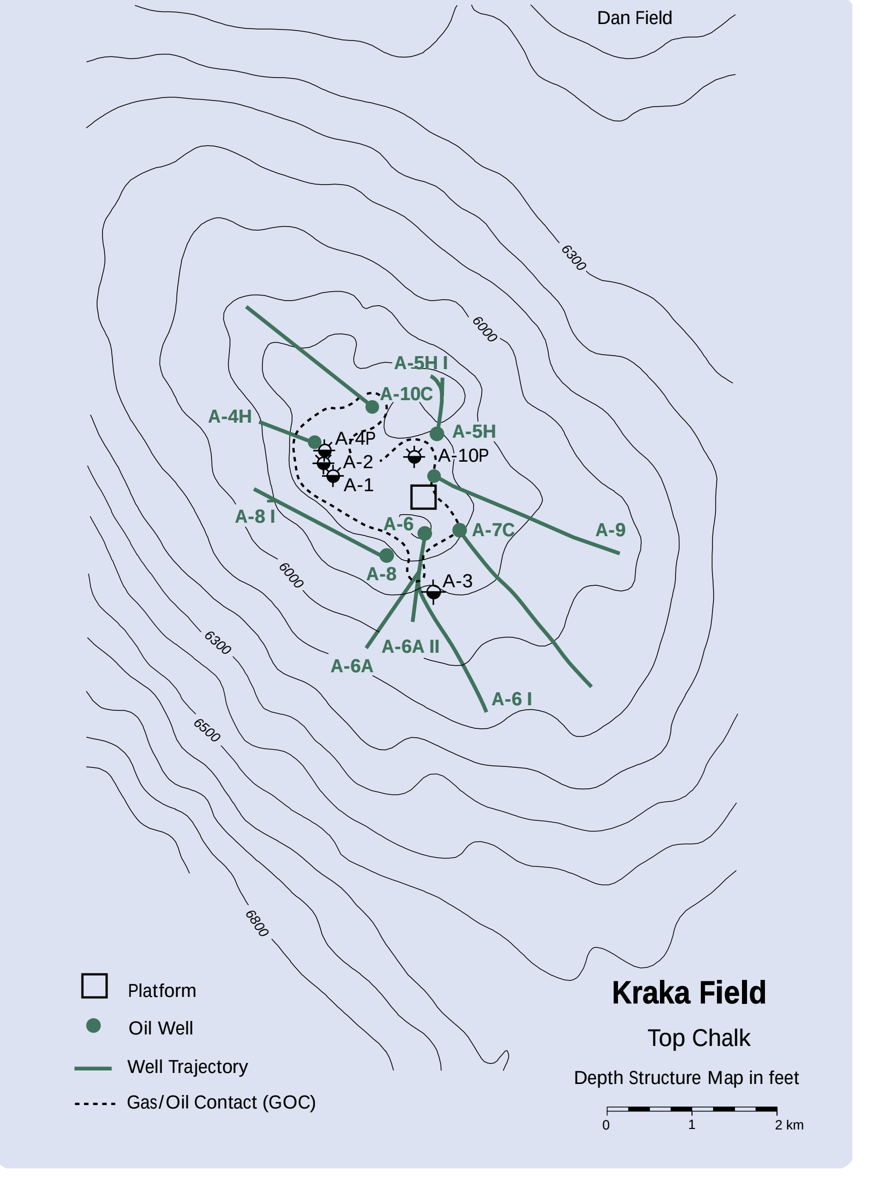
Kraka is an anticlinal structure induced through salt tectonics, which to a certain degree has caused fracturing in the chalk. The chalk reservoir has high porosity, although low permeability. The thin oil pay zone is further characterized by high water saturations. There is a minor gas cap in the reservoir.

PRODUCTION STRATEGY

Production 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 gas, 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 Jan. 2001:	
Oil:	0.6 million m³
Gas:	0.6 billion Nm³
Cum. production at 1 Jan. 2001:	
Oil:	0.55 million m³
Gas:	0.41 billion Nm³
Water:	0.02 million m³
Production in 2000:	
Oil:	0.18 million m³
Gas:	0.16 billion Nm³
Water:	0.01 million m³
Tot. investments at 1 Jan. 2001:	
2000 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
Area:	8 km^2
Reservoir depth:	1,700 m
Reservoir rock:	Chalk and Carbonates
Geological age:	Upper Cretaceous and Zechstein
Reserves at 1 Jan. 2001:	
Oil:	0.1 million m^3
Gas:	0.0 billion Nm^3
Cum. production at 1 Jan. 2001:	
Oil:	0.82 million m^3
Gas:	0.05 billion Nm^3
Water:	2.01 million m^3
Production in 2000:	
Oil:	0.01 million m3
Gas:	0.00 billion Nm3
Water:	0.14 million m3
Tot. investments at 1 Jan. 2001:	
2000 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).

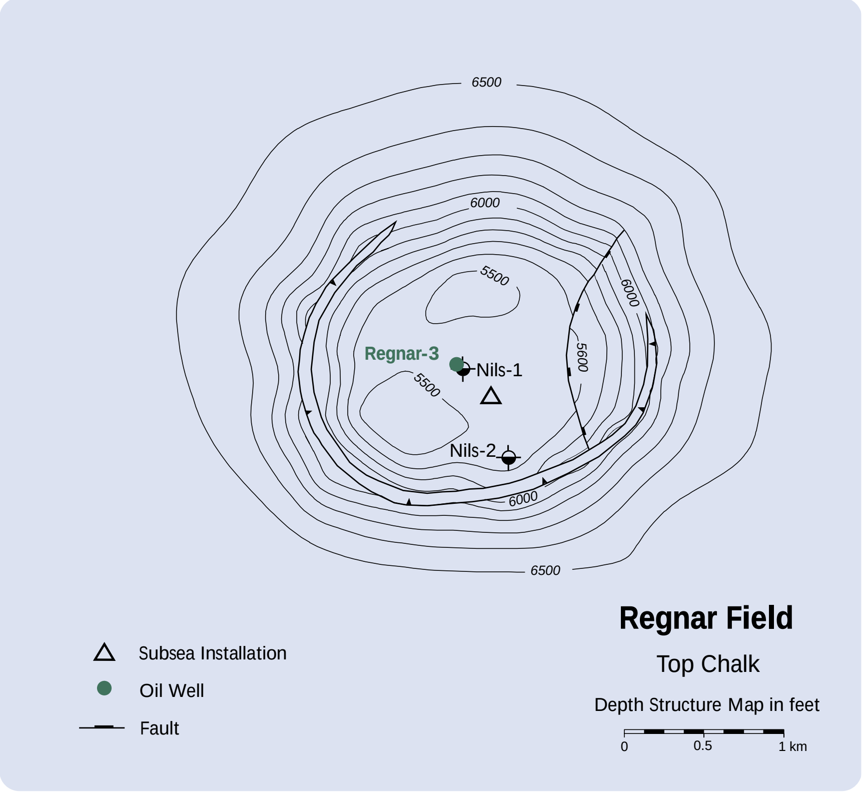
PRODUCTION STRATEGY

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:	3
Water depth:	46 m
Area:	14 km²
Reservoir depth:	2,025 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 Jan. 2001:	
Oil and condensate:	1.5 million m³
Gas:	6.8 billion Nm³
Cum. production at 1 Jan. 2001:	
Oil and condensate:	1.62 million m³
Gas:	7.40 billion Nm³
Water:	0.77 million m³
Production in 2000:	
Oil and condensate:	0.29 million m³
Gas:	1.41 billion Nm³
Water:	0.32 million m³
Tot. investments at 1 Jan. 2001:	
2000 prices	DKK 0.6 billion

REVIEW OF GEOLOGY

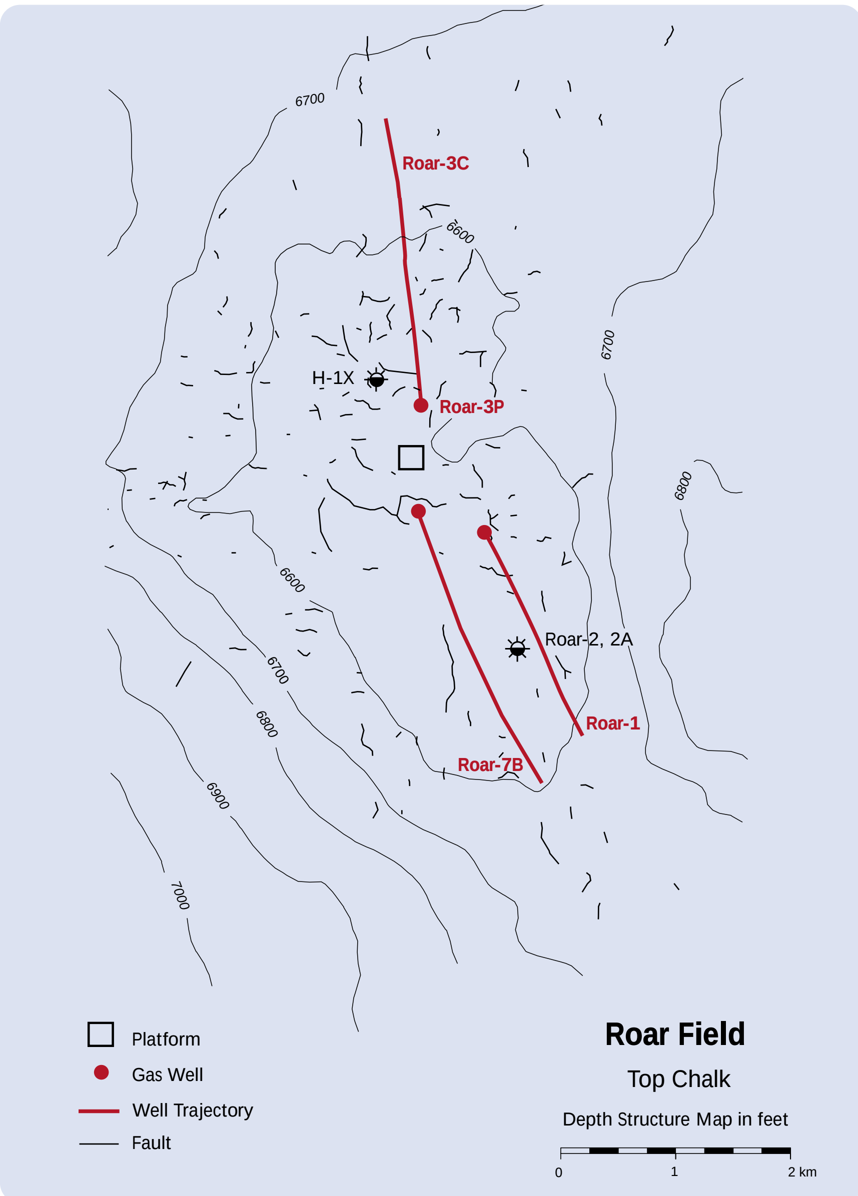
Roar is an anticlinal structure, induced through tectonic uplift. The accumulation consists of free gas containing condensate. The reservoir is only slightly fractured.

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 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 km^2
Reservoir depth:	1,800 m
Reservoir rock:	Chalk and Carbonates
Geological age:	Danian, Upper Creta-ceous and Zechstein
Reserves at 1 Jan. 2001:	
Oil:	0.7 million m^3
Gas:	0.0 billion Nm^3
Cum. production at 1 Jan. 2001:	
Oil:	3.81 million m^3
Gas:	0.16 billion Nm^3
Water:	4.09 million m^3
Production in 2000:	
Oil:	0.08 million m^3
Gas:	0.00 billion Nm^3
Water:	0.36 million m^3
Tot. investments at 1 Jan. 2001:	
2000 prices	DKK 0.9 billion

REVIEW OF GEOLOGY

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

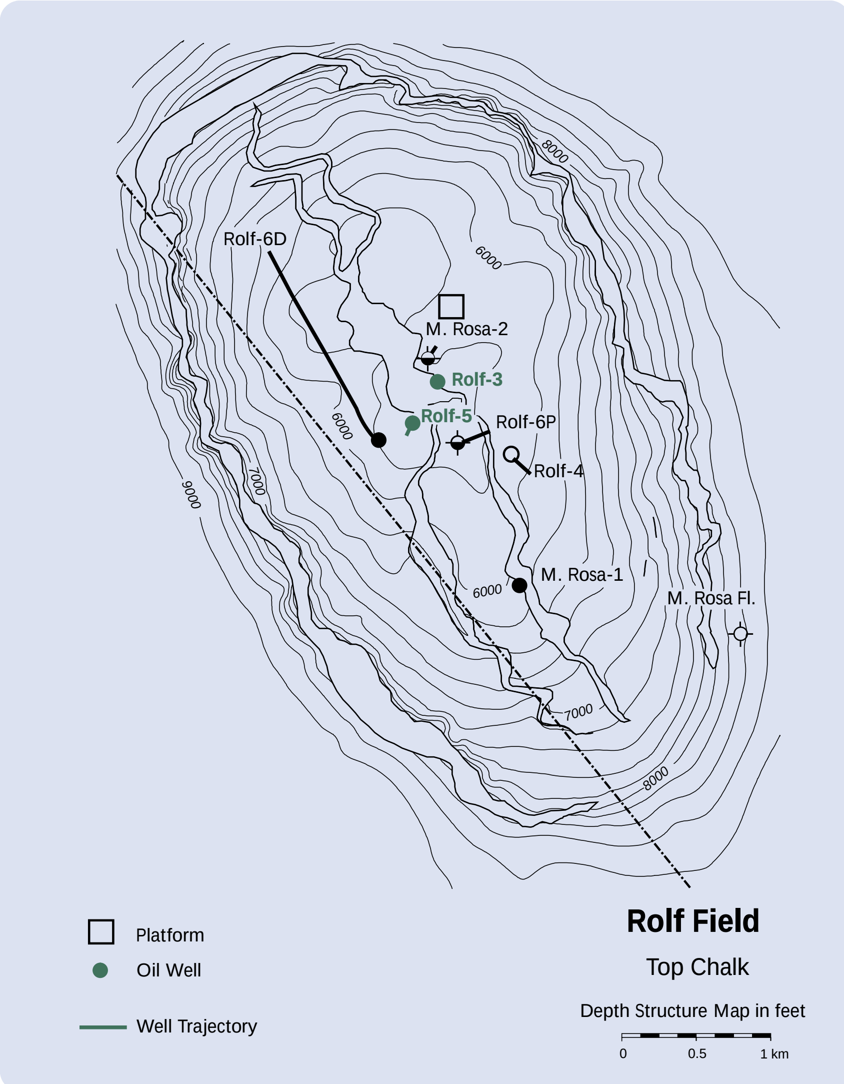
PRODUCTION STRATEGY

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
Discovered:	1995
Year on stream:	1999
Producing wells:	5
Water- and gas-injection wells:	2
Water depth:	60 m
Area:	30 km²
Reservoir depth:	2,060 m
Reservoir rock:	Sandstone
Geological age:	Palaeocene

Reserves at 1 Jan. 2001:

Oil:	3.0 million m³
Gas:	0.0 billion Nm³

Cum. production at 1 Jan. 2001:

Oil:	3.71 million m³
Net gas:	0.11 billion Nm³
Water:	2.19 million m³

Cum. injection at 1 Jan. 2001:

Gas:	0.23 billion m³
Water:	5.01 million m³

Production in 2000:

Oil:	2.12 million m³
Net gas:	0.03 billion Nm³
Water:	1.87 million m³

Injection in 2000:

Gas:	0.17 billion m³
Water:	3.78 million m³

Tot. investments at 1 Jan. 2001:

2000 prices	DKK 3.3 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

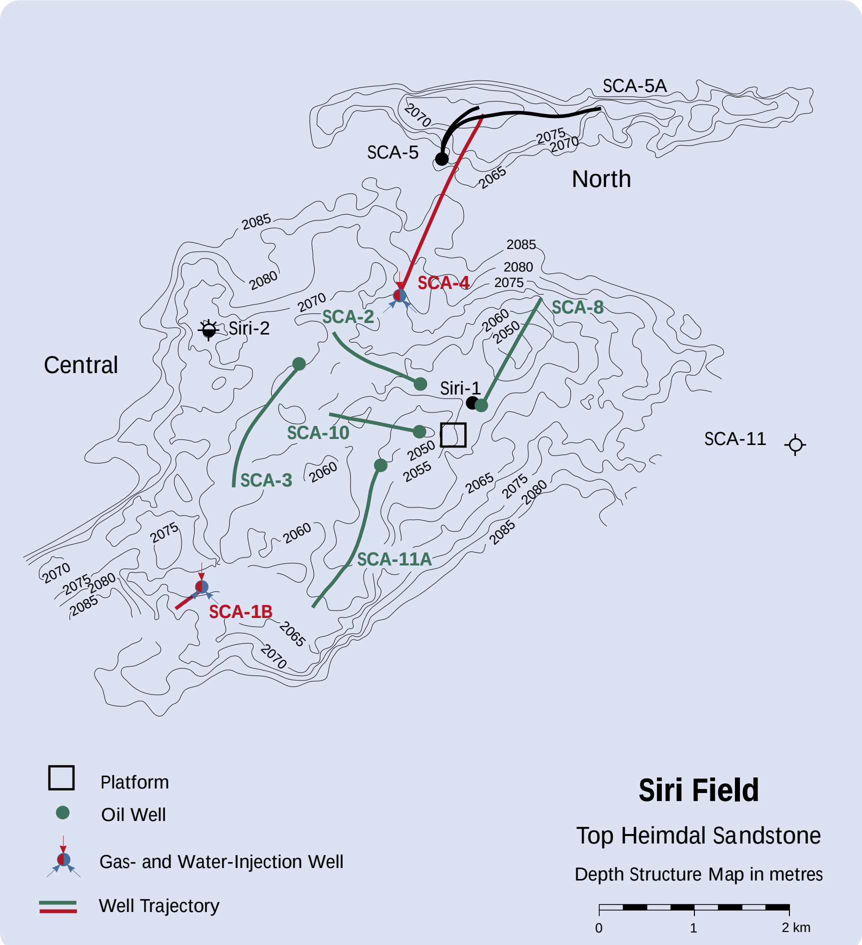
Recovery from the field is based on the production of oil through the co-injection of water and gas. Attempts are made to maintain the reservoir pressure at a level close to the initial pressure, and the volume of water injected is balanced with the volume of liquid produced from the reservoir.

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 m³ storage tank on the sea bed. 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.



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
Area:	10 km²
Reservoir depth:	1,600 m
Reservoir rock:	Chalk
Geological age:	Danian, Upper Cretaceous and Zechstein
Reserves at 1 Jan. 2001:	
Oil:	12.6 million m³
Gas:	1.1 billion Nm³
Cum. production at 1 Jan. 2001:	
Oil:	30.97 million m³
Gas:	2.71 billion Nm³
Water:	21.75 million m³
Cum. injection at 1 Jan. 2001:	
Water:	56.01 million m³
Production in 2000:	
Oil:	1.98 million m³
Gas:	0.16 billion Nm³
Water:	4.33 million m³
Injection in 2000:	
Water:	6.13 million m³
Tot. investments at 1 Jan. 2001:	
2000 prices	DKK 4.6 billion

REVIEW OF GEOLOGY

The Skjold Field is an anticlinal structure, induced through salt tectonics. Along most of its edge, the structure is 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

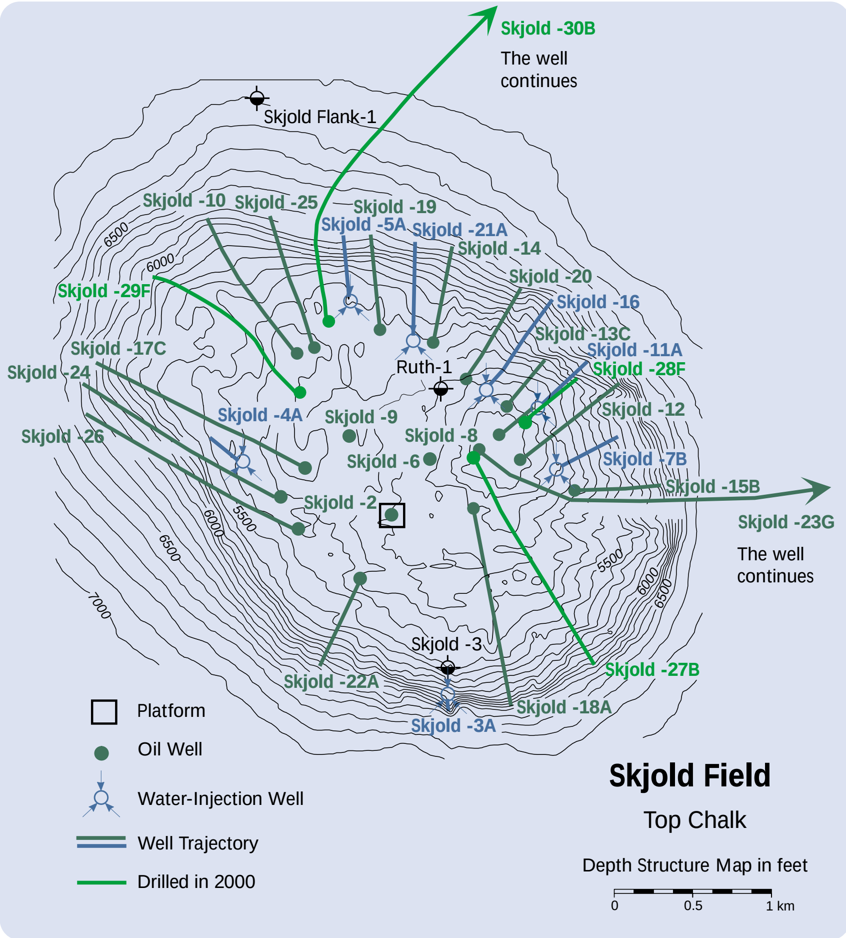
During the first years after production start-up, oil was produced from the crestal, central part of the reservoir. Water injection was initiated in the reservoir in 1986. Today, oil from the Skjold Field is mainly produced from horizontal wells at the flanks of the reservoir. The production and injection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

At Skjold C, there are accommodation facilities for 16 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:	3
Water depth:	65 m
Area:	25 km²
Reservoir depth:	2,500 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 Jan. 2001:	
Oil:	0.9 million m³
Gas:	0.1 billion Nm³
Cum. production at 1 Jan. 2001:	
Oil:	3.92 million m³
Gas:	0.46 billion Nm³
Water:	2.28 million m³
Production in 2000:	
Oil:	0.58 million m³
Gas:	0.07 billion Nm³
Water:	1.36 million m³
Tot. investments at 1 Jan. 2001:	
2000 prices	DKK 0.7 billion

REVIEW OF GEOLOGY

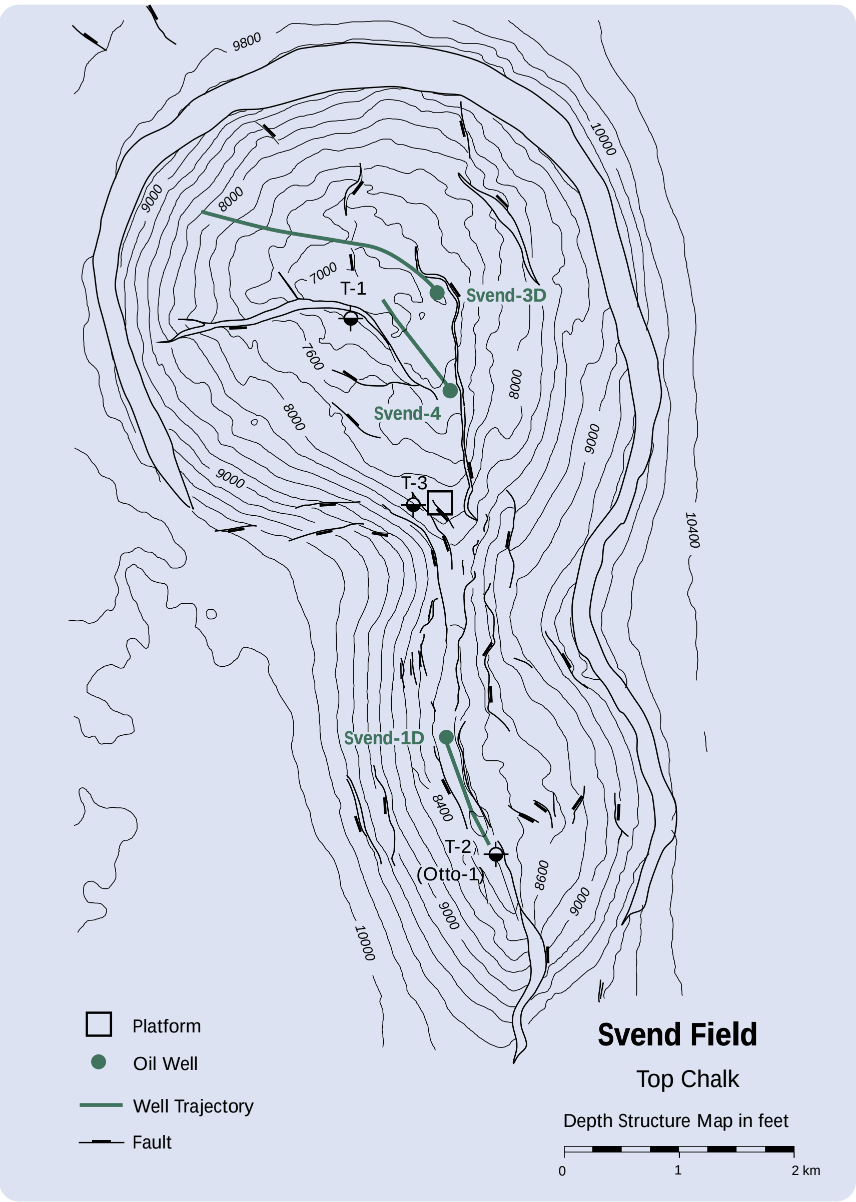
The Svend Field is an anticlinal structure, induced through salt tectonics. This has led to fracturing of the chalk in the reservoir. The Svend Field consists of a northern reservoir called North Arne, and a southern reservoir called Otto. The Otto reservoir is situated 250 metres deeper than the North Arne reservoir. The North Arne reservoir has proved to have unusually favourable production properties.

PRODUCTION STRATEGY

Oil and gas production from the Svend Field is currently 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.



SOUTH ARNE

Location:	Blocks 5604/29 and 30
Licence:	7/89
Operator:	Amerada Hess ApS
Discovered:	1969
Year on stream:	1999
Producing wells:	6
Water-injection wells:	2
Water depth:	60 m
Area:	17 km^2
Reservoir depth:	2,800 m
Reservoir rock:	Chalk
Geological age:	Danian, Upper Cretaceous and Lower Cretaceous
Reserves at 1 Jan. 2001:	
Oil:	31.7 million m^3
Gas:	8.2 billion Nm^3
Cum. production at 1 Jan. 2001:	
Oil:	3.29 million m^3
Gas:	0.87 billion Nm^3
Water:	0.07 million m^3
Cum. injection at 1 Jan. 2001:	
Water:	0.05 million m^3
Production in 2000:	
Condensate:	2.54 million m^3
Gas:	0.71 billion Nm^3
Water:	0.06 million m^3
Injection in 2000:	
Water:	0.05 million m^3
Tot. investments at 1 Jan. 2001:	
2000 prices	DKK 4.7 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

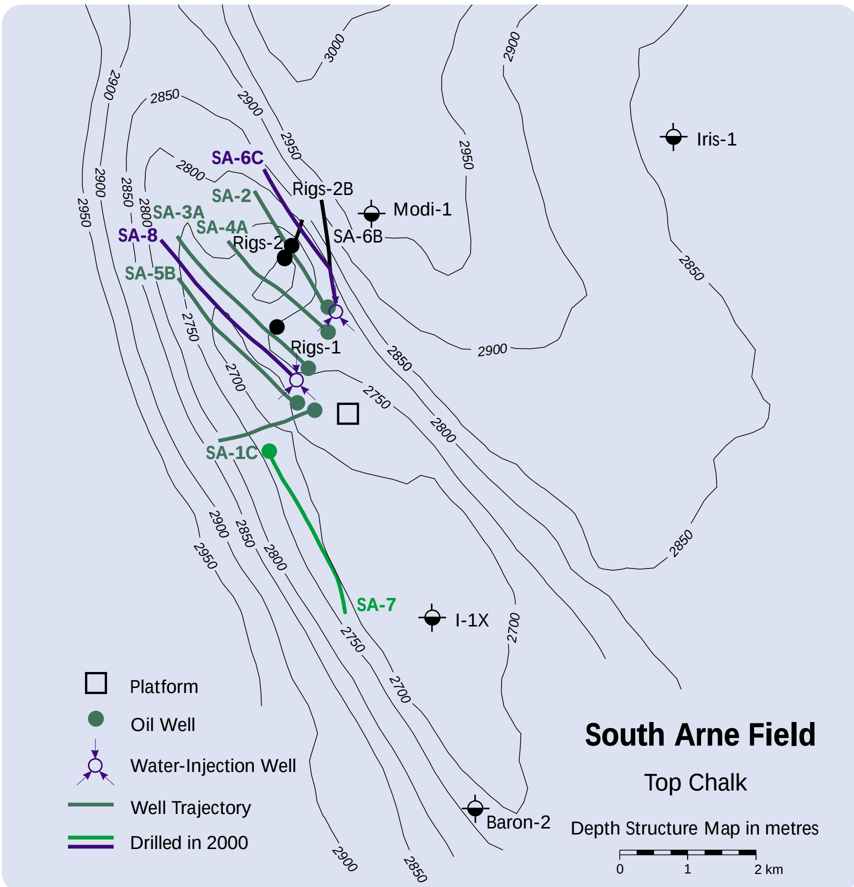
In the initial development phase, the recovery of oil and gas from the field is based on natural depletion, meaning no secondary recovery techniques are used, either in the form of gas or water injection. The wells have good production properties. Additional production wells are planned to be drilled in the field. Pressure support from water injection is being established in the field.

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 sea water prior to injection has been installed.

The oil produced is conveyed to an 87,000 m^3 storage tank on the sea bed. 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.



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:	40
Producing/ injection wells:	20
Water depth:	37-40 m
Area:	90 km^2
Reservoir depth:	2,000 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 Jan. 2001:	
Oil and condensate:	7.2 million m^3
Gas:	29.5 billion Nm^3
Cum. production at 1 Jan. 2001:	
Oil and condensate:	18.52 million m^3
Net gas:	30.80 billion Nm^3
Water:	17.36 billion m^3
Cum. injection at 1 Jan. 2001:	
Gas:	23.39 billion Nm^3
Production in 2000:	
Oil and condensate:	1.00 million m^3
Net gas:	0.71 billion Nm^3
Water:	3.05 million m^3
Injection in 2000:	
Gas:	3.10 billion Nm^3
Tot. investments at 1 Jan. 2001:	
2000 prices	DKK 21.7 billion

REVIEW OF GEOLOGY

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

PRODUCTION STRATEGY

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 Dansk 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 in the gas zone 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.

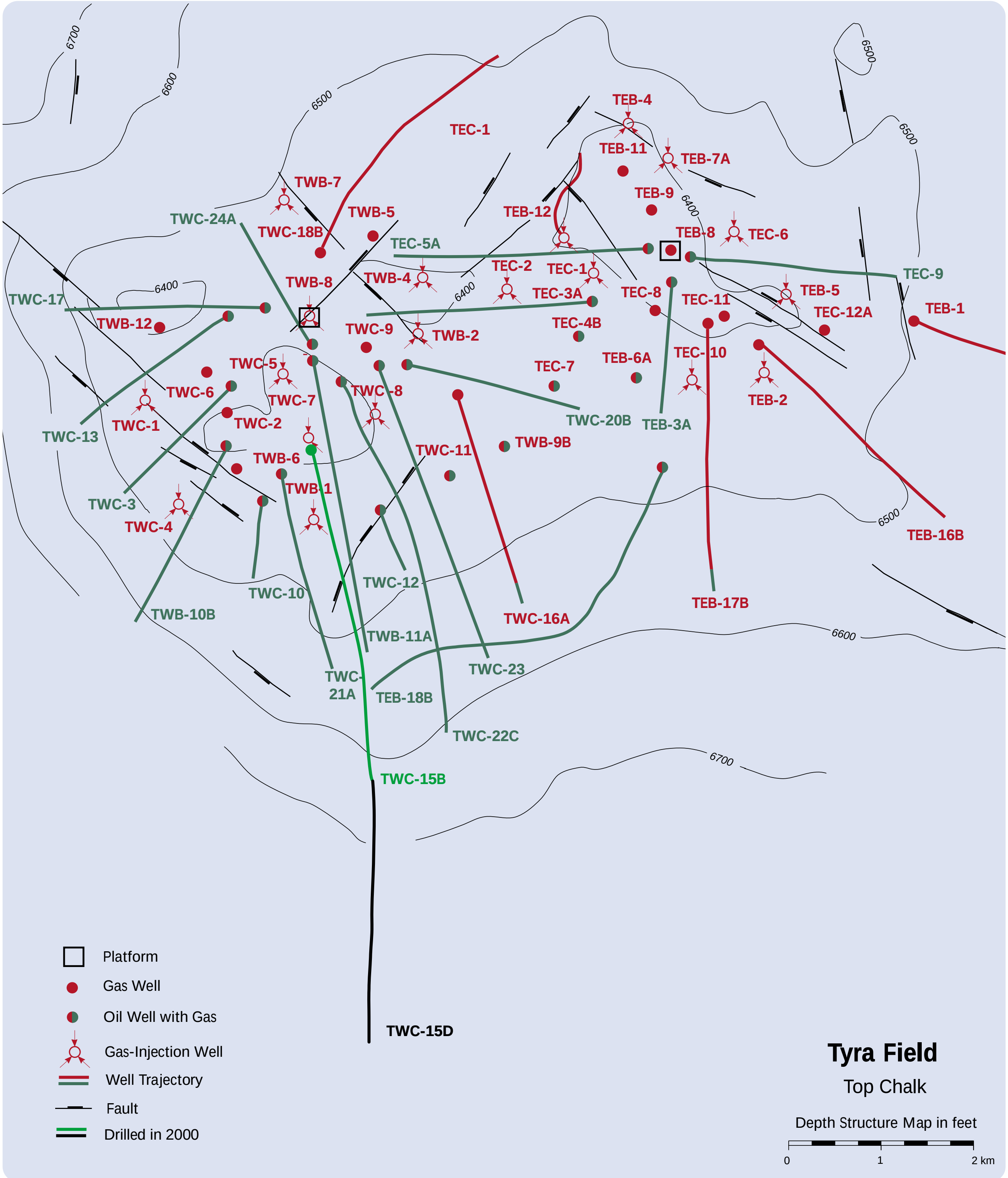
Tyra East consists of two wellhead platforms (TEB and TEC), one processing/ accommodation platform (TEA), one gas flare stack (TED), and one riser platform (TEE), as well as a bridge module supported by a STAR jacket (TEF).

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, together with the gas production from the Dan, Gorm and Harald Centres, is transported to shore via the TEE platform.

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



Tyra Field
Top Chalk
Depth Structure Map in feet
0
1
2 km
Platform
Gas Well
Oil Well with Gas
Gas-Injection Well
Well Trajectory
Fault
Drilled in 2000
TEC-1
TEB-4
TEB-11
TEB-7A
TEB-9
TEB-12
TEB-8
TEC-6
TEC-9
TEB-5
TEC-12A
TEB-1
TEC-11
TEC-10
TEB-2
TEB-16B
TEB-17B
TWB-7
TWB-5
TWC-24A
TWC-18B
TEC-5A
TEC-2
TEC-1
TEC-3A
TEC-8
TWB-8
TWB-4
TWC-17
TWB-12
TWC-9
TWB-2
TEC-4B
TEB-6A
TEC-7
TWC-5
TWC-6
TWC-7
TWC-8
TWC-1
TWC-2
TWC-13
TWC-20B
TEB-3A
TWB-9B
TWC-11
TWB-6
TWB-1
TWC-3
TWC-4
TWC-10
TWC-12
TWB-10B
TWC-16A
TWB-11A
TWC-23
TWC-21A
TEB-18B
TWC-22C
TWC-15B
TWC-15D
6400
6500
6600
6700

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:	4
Water depth:	38 m
Area:	15 km² Upper Cretaceous 15 km² Lower Cretaceous
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 Jan. 2001:	
Oil:	0.9 million m³
Gas:	2.1 billion Nm³
Cum. production at 1 Jan. 2001:	
Oil:	1.10 million m³
Gas:	0.48 billion Nm³
Water:	0.29 million m³
Production in 2000:	
Oil:	0.08 million m³
Gas:	0.06 billion Nm³
Water:	0.05 million m³
Tot. investments at 1 Jan. 2001:	
2000 prices	DKK 1.2 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.

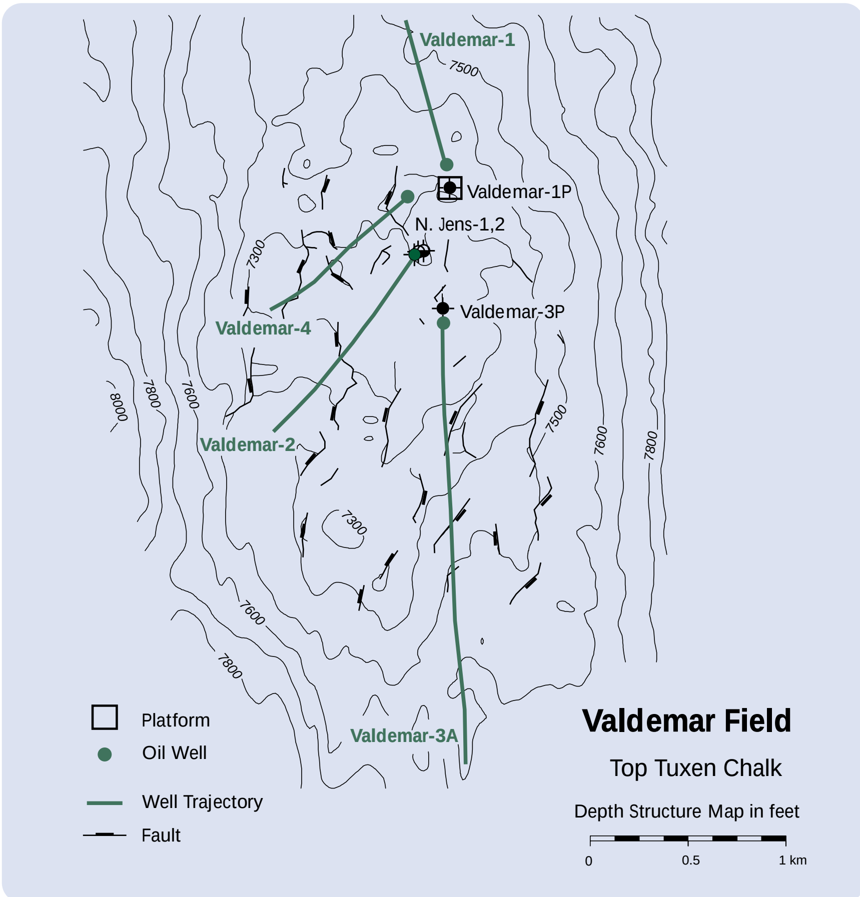
Valdemar comprises several separate reservoirs. Oil and gas have been discovered in Danian/Upper Cretaceous chalk, and vast amounts of oil in place have been identified in Lower Cretaceous chalk. While the properties of the Upper Cretaceous reservoirs are comparable to other Danish fields like Gorm and Tyra, the Lower Cretaceous chalk, although featuring high porosity, 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. Expectations for production from the North Jens reservoir are subdued. It is uncertain which recovery techniques may enhance the recovery of oil from this extremely tight reservoir.

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.



For all the above-mentioned fields, the size of the area indicated is that of the main field. In several of the fields, production also takes place from the flanks.

FUTURE FIELD DEVELOPMENTS

Field name	Adda
Location:	Block 5504/8
Licence:	Sole Concession of 8 July 1962
Operator:	Mærsk Olie og Gas AS
Discovered:	1977
Dev. plan approved:	1990
Year on stream:	2003
Water depth:	38 m
Reservoir depth:	2,200 m and 2,300 m
Reservoir rock:	Chalk
Geological age:	Upper and Lower Cretaceous
Type of hydrocarbons:	Oil and gas

Field name	Alma
Location:	Block 5505/17
Licence:	Sole Concession of 8 July 1962
Operator:	Mærsk Olie og Gas AS
Discovered:	1990
Dev. plan approved:	1995
Year on stream:	2003
Water depth:	43 m
Reservoir depth:	3,600 m
Reservoir rock:	Sandstone
Geological age:	Jurassic
Type of hydrocarbons:	Gas

Field name	Boje Area
Location:	Block 5504/7
Licence:	Sole Concession of 8 July 1962
Operator:	Mærsk Olie og Gas AS
Discovered:	1982
Dev. plan approved:	2000
Year on stream:	2003
Water depth:	40 m
Reservoir depth:	2,000 and 2,500 m
Reservoir rock:	Chalk
Geological age:	Danian, Upper and Lower Cretaceous
Type of hydrocarbons:	Oil

Field name	Elly
Location:	Block 5504/6
Licence:	Sole Concession of 8 July 1962
Operator:	Mærsk Olie og Gas AS
Discovered:	1984
Dev. plan approved:	1995
Year on stream:	2002
Water depth:	40 m
Reservoir depth:	3,200 m and 4,000 m
Reservoir rock:	Chalk and sandstone
Geological age:	Upper Cretaceous and Jurassic
Type of hydrocarbons:	Gas

Field name	Freja (former Gert)
Location:	Blocks 5603/27 and 28
Licence:	Sole Concession of 8 July 1962
Operator:	Mærsk Olie og Gas AS
Discovered:	1984
Water depth:	70 m
Reservoir depth:	4,900 m
Reservoir rock:	Sandstone
Geological age:	Upper Jurassic
Type of hydrocarbons:	Oil

Field name	Igor/Sif
Location:	Block 5505/13/Block 5504/16
Licence:	Sole Concession of 8 July 1962
Operator:	Mærsk Olie og Gas AS
Discovered:	1968/1999
Dev. plan approved:	1990/-
Year on stream:	2004/-
Water depth:	44 m
Reservoir depth:	2,000 m/2,050 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Type of hydrocarbons:	Gas/gas and oil

Field name	Lola
Location:	Block 5504/15
Licence:	Sole Concession of 8 July 1962
Operator:	Mærsk Olie og Gas AS
Discovered:	1975
Dev. plan approved:	2000
Year on stream:	2003
Water depth:	43 m
Reservoir depth:	2,200 m
Reservoir rock:	Chalk and sandstone
Geological age:	Danian, Upper Cretaceous and Middle Jurassic
Type of hydrocarbons:	Oil and gas

Field name	Tyra South East
Location:	Block 5504/12
Licence:	Sole Concession of 8 July 1962
Operator:	Mærsk Olie og Gas AS
Discovered:	1991
Dev. plan approved:	A plan has been submitted to the Danish Energy Agency
Year on stream:	2002
Water depth:	41 m
Reservoir depth:	2,000 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Type of hydrocarbons:	Oil

FINANCIAL KEY FIGURES

	Inv. in Field Dev. DKK million	Field Op. 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	32	28	3.0	7.0	6.6	-3.2	-
1973	9	34	83	4.6	6.1	9.3	-4.0	1
1974	38	58	76	11.6	6.1	15.2	-9.2	1
1975	139	64	118	12.3	5.8	19.6	-8.5	2
1976	372	71	114	12.9	6.1	10.3	-9.5	4
1977	64	88	176	14.0	6.0	11.2	-10.4	5
1978	71	128	55	14.1	5.5	10.0	-9.2	21
1979	387	146	78	20.4	5.3	9.6	-13.7	19
1980	956	169	201	37.5	5.6	12.3	-18.6	29
1981	1,651	402	257	37.4	7.1	11.7	-20.1	36
1982	3,948	652	566	34.0	8.4	10.2	-20.6	234
1983	3,528	615	1,264	30.5	9.1	6.9	,17.8	399
1984	1,596	1,405	1,211	28.2	10.4	6.3	-18.3	488
1985	1,953	1,677	1,373	27.2	10.6	4.7	-17.6	1,289
1986	1,695	1,533	747	14.9	8.1	3.6	-7.3	1,399
1987	908	1,560	664	18.3	6.8	4.0	-5.9	1,328
1988	897	1,550	424	14.8	6.7	4.6	-3.7	568
1989	1,153	1,819	366	18.2	7.3	4.8	-3.2	1,024
1990	1,738	1,924	592	23.6	6.2	2.6	-2.7	2,089
1991	2,260	2,176	986	20.0	6.4	2.4	-1.9	1,889
1992	2,402	2,080	983	19.3	6.0	2.1	-0.4	1,911
1993	3,358	2,324	442	16.8	6.5	1.2	-0.4	1,811
1994	3,140	2,395	151	15.6	6.4	2.0	-0.3	2,053
1995	4,167	2,176	272	17.0	5.6	2.1	-0.3	1,980
1996	4,259	2,491	470	21.1	5.8	2.1	0.4	2,465
1997	3,825	2,772	521	18.9	6.6	2.2	1.4	3,131
1998	5,425	2,429	446	12.8	6.7	1.9	1.0	3,007
1999	3,431	2,192	704	17.9	7.0	2.5	3.5	3,784
2000*	2,947	2,577	726	28.5	8.1	2.3	5.4	8,306

Nominal Prices

1) Including transportation costs (profit element included)

2) Brent crude oil

3) Consumer prices

4) Oil products and natural gas

**Estimate*

ERP PROJECTS

ERP Projects Funded under ERP

Reference no. 1313/	Project Title	Budget DKK 1,000	Funding DKK 1,000	Participating Institutions/ Businesses
01-0001	Genetic High-Resolution Stratigraphy of the Upper Maastrichtian – Danian Chalk	6,480	3,723	**GEUS,** University of Copenhagen
01-0004	Modelling of Dynamic Fluid Contacts in Chalk Reservoirs	3,808	2,461	**GEUS,** COWI01-0006
01-0006	Rock Physics of Impure Chalk Sequences	3,000	1,000	**GEUS,** DTU-IGG, Ødegaard A/S, Amerada Hess, DONG E&P
01-0012	Streamline Based Compositional Simulation	4,111	2,953	**DTU-IVC-SEP,** Mærsk Olie og Gas AS, DONG E&P, Chevron
01-0019	Reliability Assessment of Wave Response of Offshore Structures	7,472	3,000	**DHI,** University of Aalborg, DTU-IMM, Rambøll
01-0022	Geological Correlation of Mesozoic-Palaeogene Sequences in the Canadian-Greenland Shelf Area	1,250	250	**GEUS,** Phillips Petroleum, Greenland Home Rule Authority
Total		**13,387**	**26,121**	

ERP Projects Completed in 2000

Reference no. 1313/	Project Title	Participating Institutions/ Businesses
97-0005	Geophysical and Geostatistical Reservoir Characterization of Chalk Fields including Application in Reservoir Simulation	**Ødegaard A/S,** GEUS, COWI
97-0008 (subreport I.4.b) PRIORITY project	Structural Development of the Valdemar Field	**GEUS,** DTU-IGG
97-0008 (subreport II.2.d) PRIORITY project	Equilibrium Mechanisms during the Formation of a Petroleum Reservoir	**DTU-IVC-SEP**
97-0008 (subreport II.1.g) PRIORITY project	Injection Water and Brine Compatibility	**DTU-IVC-SEP**
97-0008 (subreport II.3.b) PRIORITY project	Surfactant Well Treatment	**DTU-IVC-SEP**
97-0014	Requalification of Offshore Structure**s**	**DHI,** Rambøll
97-0020	Wax Deposition in Offshore Pipeline Systems	**CALSEP A/S**
98-0005	Clay Minerals and Silica in Chalk Reservoirs with respect to Source Area, Diagenesis and Reservoir Properties	**GEUS,** University of Aarhus, University of Scotland - Research and Reactor Centre, Moscow Geological Institute
99-0013	Free Span Burial Inspection Pig	**FORCE,** DONG E&P

Project Leader in bold type. *GEUS = Geological Survey of Denmark and Greenland* *DTU = Technical University of Denmark*
DHI = Danish Hydraulic Institute

ORGANIZATION

The Danish Energy Agency is an institution under the Ministry of Environment and Energy. The Agency deals with matters relating to the production, supply and consumption 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 Agency prepares and administers Danish legislation, analyzes and evaluates developments in the energy sector, makes assessments and prepares forecasts.

The Danish Energy Agency has 16 divisions, as well as a few staff functions linked to Management. The administration of oil and gas activities is handled by the 9th and 10th divisions of the Agency, assisted by the 3rd and 7th divisions to some extent. How responsibilities between the oil and gas divisions are divided is dealt with in more detail below.

At the turn of the year 2000/2001, the Agency employed about 265 employees, about 31 of whom are involved in the administration of oil and gas activities.

The administration of oil and gas activities is handled by:

9th Division: Safety in the Oil/Gas Sector

Head of division: Uffe Danvold

Activities concerning safety, working environment and other environmental issues under the provisions of the Danish Offshore Installations Act, the Subsoil Act and the Continental Shelf Act. Approving mobile and fixed installations as well as pipelines. Supervising the safety, working environment and other environmental aspects of offshore installations and pipelines, as well as monitoring drilling operations in terms of safety. Approving and supervising manning tables and organizational charts, as well as undertaking the tasks related to membership of the Action Committee, the Coordination Committee and the Average Commission for Offshore Installations. Monitoring supplies conveyed through the transmission systems belonging to DONG Naturgas A/S and supervising the technical safety aspects of the gas storage facilities established by DONG Naturgas A/S. Considering political and administrative issues related to DONG Olierør A/S and the Danish Oil Pipeline Act. Moreover, the division draws up regulations in this area. Advising the Bureau of Minerals and Petroleum (BMP) under the Greenland Home Rule Authority on legal and technical issues.

10th Division: Exploration and Production of Oil and Gas

Head of division: Søren Enevoldsen

Supervising exploration and production activities in terms of resources, as well as financial and legal aspects. Licensing policy and administration, licensing rounds and the awarding of licences. Approving appraisal programmes and work programmes. Evaluating declarations of commerciality. Approving development plans and production profiles. Addressing matters concerning the obligation to connect production facilities to existing pipelines and exemptions from payment of the pipeline fee. Matters concerning unitization. Geological evaluations and reservoir engineering. Preparing analyses, evaluating the potential and making forecasts of

Danish oil and gas reserves. Evaluating commercial viability, including work on energy plans. Considering political and administrative issues related to DONG Efterforskning og Produktion A/S. Advising the BMP under the Greenland Home Rule Authority on legal and technical issues related to licensing, as well as providing ad hoc assistance to the Faroe Islands' administrative authorities. Responsibility for the Danish Energy Agency's oil/gas-related system exports.

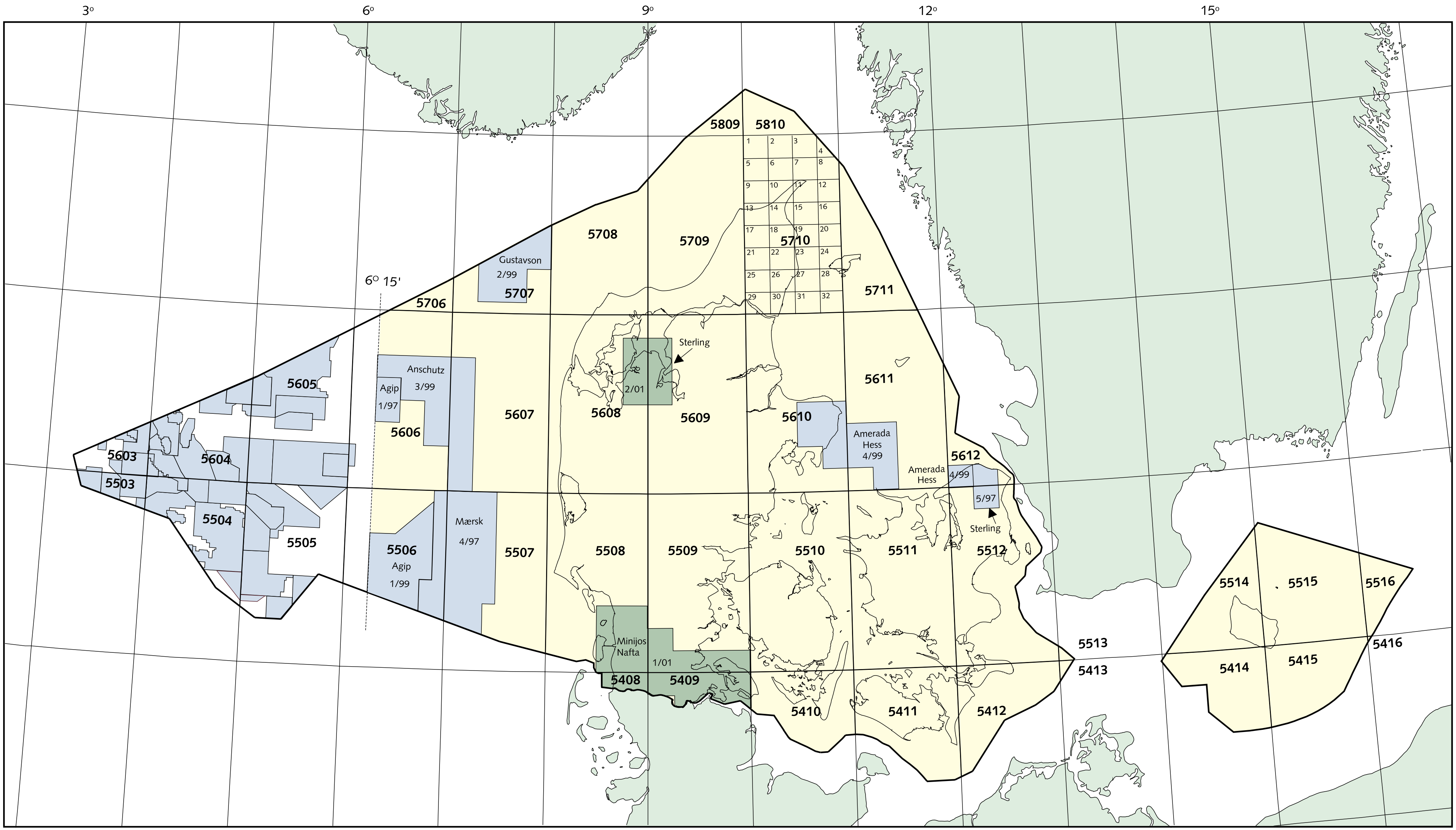
3rd Division: Research and Development

Head of division: Kai Worsaae
National and international activities regarding energy research, including research related to oil and natural gas. The national activities include administering energy research programmes, research policy proposals and statements, as well as acting as the secretariat of the Advisory Oil and Natural Gas Research Committee. The international activities relate mainly to the EU research programmes, the IEA and the Nordic Energy Research Programme. Administering renewable energy development programmes.

7th Division: Electricity and Natural Gas Supply

Head of division: Thomas Bastholm Bille
Legal/administrative and financial issues falling within the scope of the Danish Electricity Supply Act and relating to transmission and grid companies, undertakings with a public service obligation and system operators. Moreover, issuing and supervising licences and approving regulations, approving applications for expanding the transmission network, including submarine cables, and administering regulations regarding the connection of environmentally friendly electricity works and combined heat and power (CHP) stations, including tariffs. Legal/administrative and financial issues within the framework of the Natural Gas Supply Act. Issuing and supervising licences, approving expansions of the transmission system and natural gas storage facilities and market liberalization issues. Financial, legal and organizational matters related to natural gas supplies and natural gas companies. Matters concerning the DONG group. Acting as the secretariat of the Energy Regulatory Authority in technical and energy-related matters.

Danish Licence Area March 2001



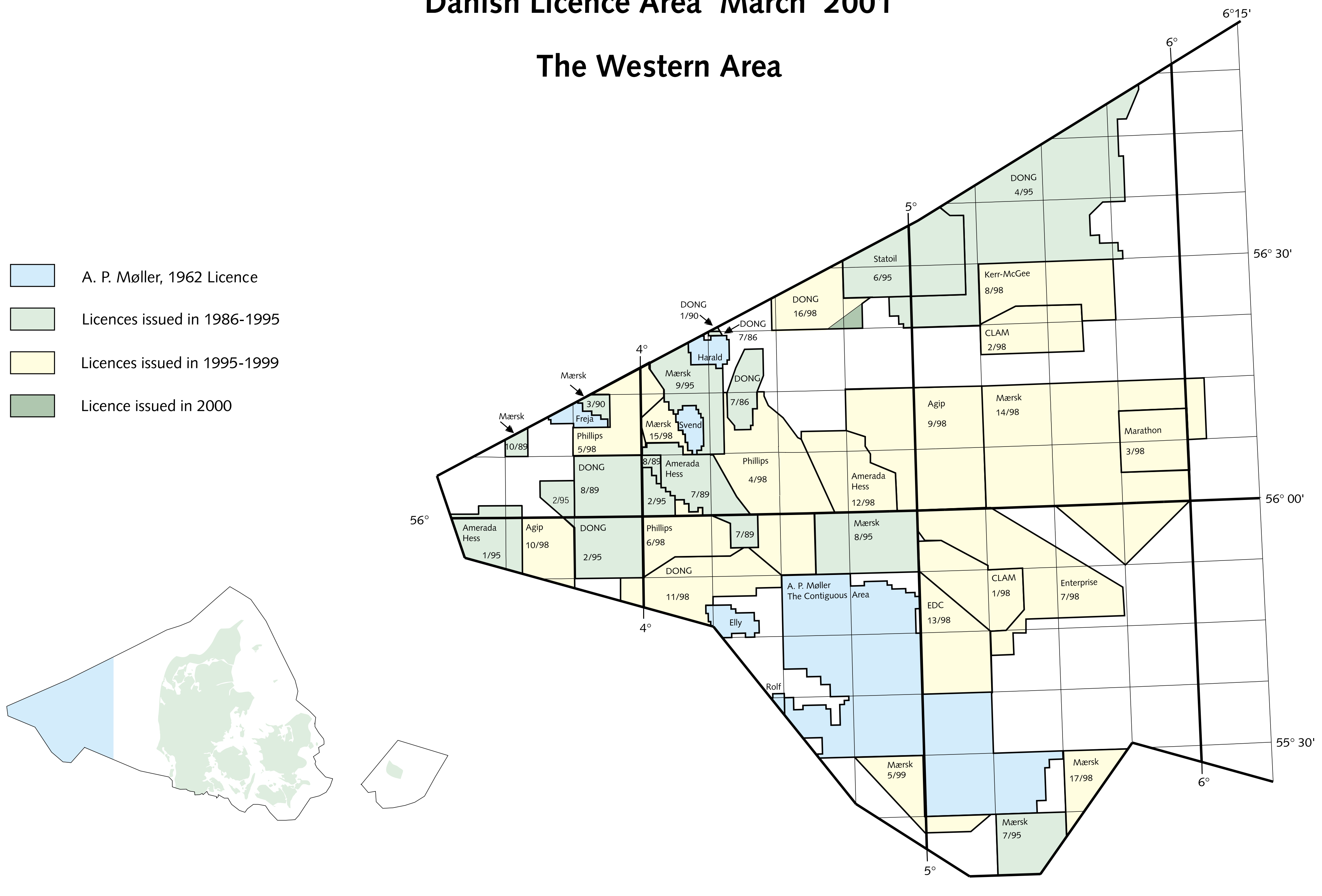
Licences issued in 1962-2000

Licences issued in 2001

Open Door Procedure

Danish Licence Area March 2001

The Western Area



Danish Licence Area March 2001

The Western Area