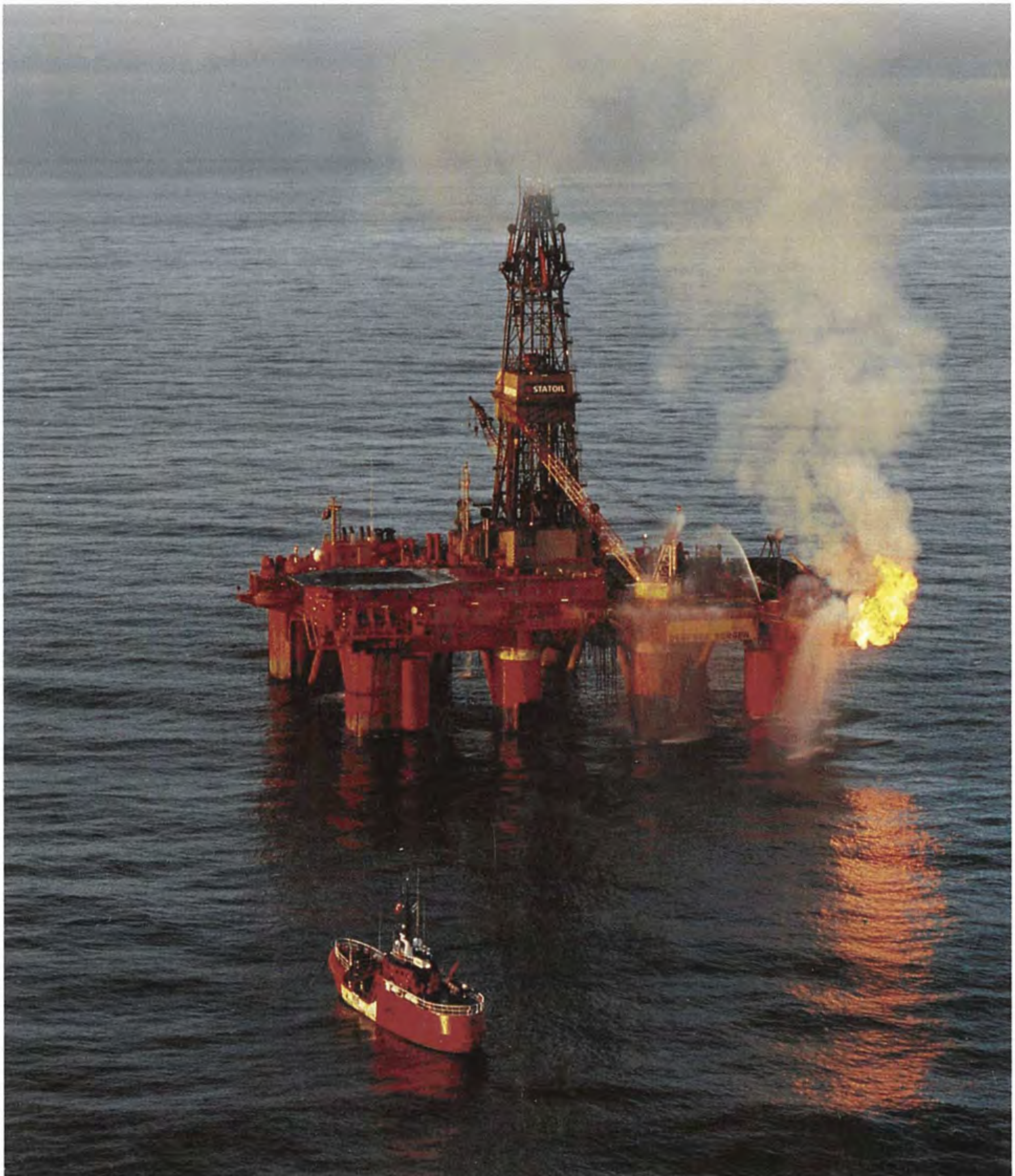
MINISTRY OF ENVIRONMENT AND ENERGY

Danish Energy Agency



Oil and Gas Production in Denmark 1995

Preface

The 1995 report is the tenth report published by the Danish Energy Agency on developments in exploration and production of oil and natural gas in Denmark.

The past decade has seen rapid technological developments within the oil and gas industry, particularly with regard to drilling and completion technology and stimulation techniques. At the same time, the techniques developed are adjusted to meet the increasing demand for protection of the environment.

The Danish producing fields are continually evaluated, resulting in an optimization of production strategies. Thus, horizontal drilling and water injection, including high-rate water injection, are widely used techniques in the Gorm, Skjold and Dan Fields, and a condensate project for the recirculation of gas is ongoing in the Tyra Field.

Over the past ten years, technological developments and improved understanding of the reservoirs in the North Sea have led to a 55% increase in the expected recovery factor. Thus, the projected level of recoverable reserves has been written up from 163 million m^3 in 1987 to 252 million m^3 in 1996. These developments in the Danish Energy Agency's reserve assessment and forecasts are described in more detail in the section entitled *Decade Review of Oil Reserves and Forecasts.*

In addition, the development in 1995 has led to increased optimism about the outlook for the next decade. In the Fourth Licensing Round, great interest was displayed in exploration in Danish territory. Thus, in May 1995, nine new exploration and production licences were issued.

The first exploration well drilled under these licences, the Statoil group's Siri-1 well, encountered substantial amounts of oil. The well was drilled in an area with a different geological setting than other discoveries made so far in Danish territory, and therefore gives rise to great optimism about future exploration results.

Copenhagen, May 1996

Ib Larsen

Ib Larsen
Director

Conversion Factors

1 m^3 Crude Oil = 0.858 tonne ≈ 36.6 GJ

1 m^3 Motor Gasoline = 0.75 tonne ≈ 32.9 GJ

1 m^3 Middle Distillate = 0.84 tonne ≈ 35.9 GJ

1 m^3 Heavy Fuel Oil = 0.98 tonne ≈ 39.6 GJ

1 barrel = 0.159 m^3

1 t.o.e. = 41.868 GJ

1 t.o.e. ≈ 1.143 m^3 Crude Oil

1 t.o.e. ≈ 1.065 Nm^3 Natural Gas

1.000 Nm^3 Natural Gas = 37,239 scf ≈ 39.3 GJ

1 Nm^3 Natural Gas = 1.057 Sm^3

1 tonne Steam Coal ≈ 24.7 GJ

1 tonne Coal (other) ≈ 26.5 GJ

Nm^3 (normal cubic metre), at 0°C, 101.325 kPa

Sm^3 (standard cubic metre), at 15°C, 101.325 kPa

scf (standard cubic foot), at 15.6°C, 101.56 kPa

Contents

1. Exploration

New licences for exploration and production were granted in May 1995, as a result of the Fourth Licensing Round. This led to great seismic surveying activity under the new licences, but only one group proceeded to the drilling stage already the same year. However, the drilling of this first well resulted in what is considered to be the largest oil discovery in Denmark since the Skjold Field was discovered in 1977.

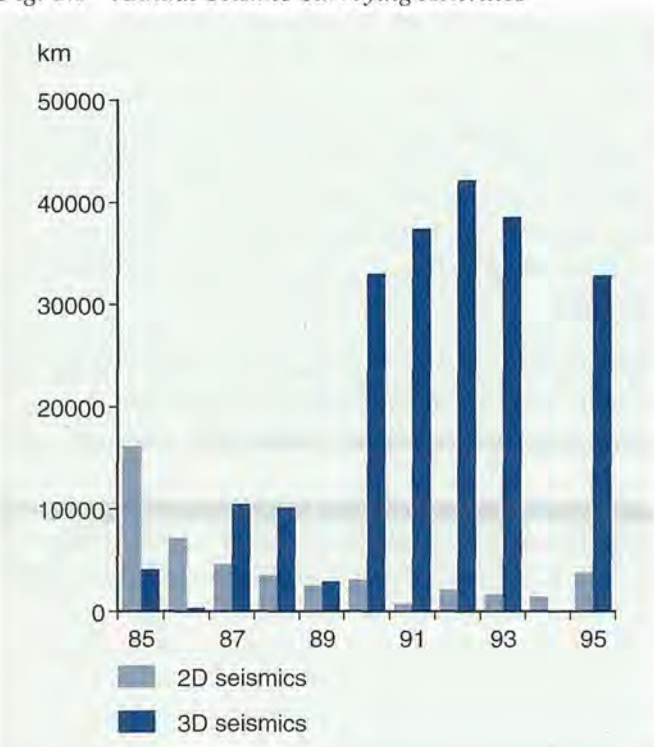
An outline of the companies that hold licences for exploration and production in Danish territory is shown in Appendix B. The map of licence areas at the back of the report shows the geographic location of licences awarded.

The Fourth Licensing Round

In May 1995, nine new licences were granted in the Fourth Licensing Round. The round was opened in July 1994, and when the time limit for submitting applications expired in January 1995, 12 applications had been received from applicants representing 17 companies.

Applications were invited for the area west of 6°15' east longitude. This area comprises the Central Graben and is delimited towards the east by the estimated potential extension of hydrocarbons generated in the Central Graben.

Fig. 1.1 Annual Seismic Surveying Activities



The Fourth Licensing Round is described in more detail in the report *Oil and Gas Production in Denmark, 1994.*

Exploratory Surveys

After the decline in activities last year, seismic surveying activity picked up in 1995 (Fig. 1.1). The renewed activity is due mainly to the new licences granted in the Fourth Licensing Round, as the majority of the licensees prepared for exploration by carrying out seismic surveys. In addition, seismic surveying data were collected in connection with the appraisal of discoveries and as part of the continued exploration activity under the licences granted in the Third Licensing Round.

Onshore seismic surveys were carried out in connection with mapping existing gas storage facilities and considering the establishment of a new facility.

Appendix D contains an outline of the individual seismic programmes.

Drilling Activities

In 1995, only one exploration well was spudded in Danish territory, viz. the Statoil group's Siri-1 well in the western part of the Norwegian-Danish Basin. However, drilling activity is expected to escalate considerably already from 1996, once the results of the seismic surveys made in the new areas awarded in the Fourth Licensing Round have been interpreted.

Siri-1 (5604/20-1)

In drilling the Siri-1 well, Statoil was the first company to embark on drilling operations in the areas encompassed by the Fourth Licensing Round. The drilling of this well led to what is considered one of the most important discoveries in Danish territory for many years. The well was drilled in the Norwegian-Danish Basin about 25 km from the Central Graben, where all previous commercial oil and gas discoveries have been made (Fig. 1.3).

The new discovery was made in sandstone layers of Tertiary age. In the course of a production test, oil was produced at a rate of 925 m^3/day (5,818 barrels/day) together with associated gas. The well terminated in the chalk at a depth of 2,200 metres.

Appraisal Activities

Amalie

The Statoil group completed the appraisal of the Amalie gas discovery made in 1991, reaching the conclusion that the accumulation is commercially exploitable. Amalie is thus the second commercial discovery to be made wholly or partly outside DUC's licence areas, the first being the Lulita discovery, which was declared commercial by the Statoil group in 1994.

South Arne

As part of the further appraisal of the South Arne oil discovery, the Amerada Hess group carried out a 3D seismic survey of the chalk structure in the summer of 1995. The Rigs-1 well, which was completed in early 1995, confirmed the production potential of the accumulation. Based on the new seismic surveying data and other appraisals of the reservoir, the licensees will decide in the course of 1996 whether exploitation of the accumulation is commercially viable.

Siri

Following the oil discovery made by the Siri-1 well, the Statoil group has now initiated a major 3D seismic survey in cooperation with GecoPrakla, a seismic surveying company.

This survey covers Danish as well as Norwegian territory. The seismic data collected will be part of the basis for appraising the discovery.

Fig. 1.2 Exploration and Appraisal Wells

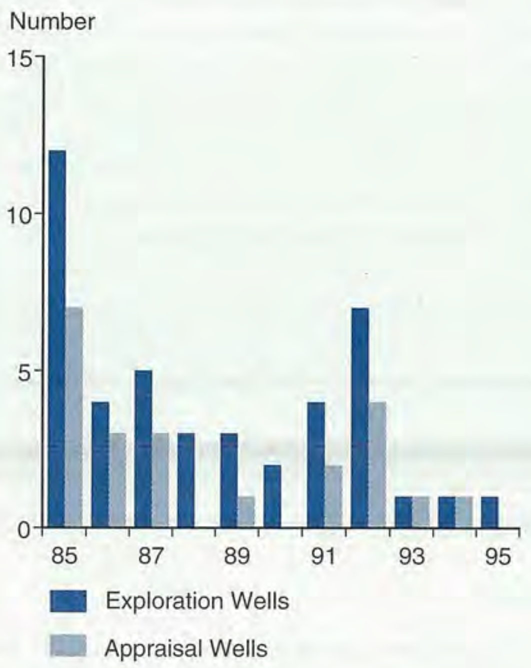
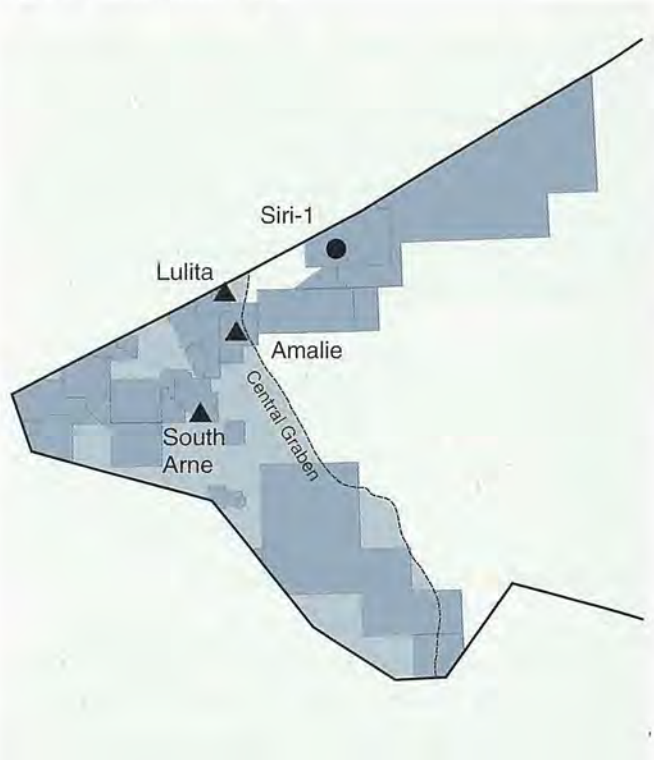


Fig. 1.3 Location Map



Extended Licence Terms

In order to continue appraising the South Arne discovery and mapping the exploration potential in the area, in 1995 the Amerada Hess group was granted a two-year extension of licence 7/89, which will thus expire in December 1997.

In the summer of 1995, the Amerada Hess group collected 3D seismic surveying data over the areas covered by licence 8/89 and licence 2/95, which the group was awarded in the Fourth Licensing Round. The seismic surveys will be continued in 1996 in order to establish a basis for analyzing the exploration potential of the area. Consequently, the licensees were granted a two-year extension of the term of licence 8/89, viz. until December 1997.

The Mærsk group also obtained a two-year extension of licence 10/89 in order to continue its appraisal of the exploration potential in this licence area.

After declaring the Lulita discovery commercial, the Statoil group was granted an extension for production purposes. The extension was granted in respect of part of licence 7/86 and part of licence 1/90. With a view to initiating production in the Amalie Field, the Statoil group submitted an application at the beginning of 1996 for an extension of that part of licence 7/86 that comprises the Amalie discovery.

Transfer of Licence Shares

Upon acquiring *EAC Energy A/S,* an EAC subsidiary, Amerada Hess A/S took over shares of the Statoil group licences 7/86, 1/90 and 2/90, by 5.06%, 5.06% and 6.10%, respectively, with effect from January 1, 1995. The name of the company was subsequently changed to *Amerada Hess Energi A/S.*

With retroactive effect from May 15, 1995, when licence 2/95 was issued in the Fourth Licensing Round, *Danoil Exploration A/S* took over a 2.55% licence share from *Amerada Hess A/S,* which thus retained a 66.89% share of the licence. Accordingly, Danoil acquired the same percentage share as in the neighbouring licence area, where the same group of companies hold a share of licence 8/89.

Phillips Petroleum International Corporation Denmark took over a 12.50% share of licence 6/95 from *DENERCO K/S* and *Statoil Efterforskning og Produktion A/S,* also with retroactive effect from May 15, 1995. As a result of this transfer, Statoil and DENERCO hold licence shares of 40.00% and 7.50%, respectively.

Relinquishments

In 1995, four licences were relinquished.

The DOPAS group, which was awarded an area near Løgumkloster in South Jutland following a special licensing round in 1992, relinquished its licence in August 1995. In 1993, the group drilled a well to obtain further data about the accumulation of hydrocarbons encountered in the Løgumkloster-1 well in 1980. However, the most recent well was unable to confirm the expectations for this accumulation.

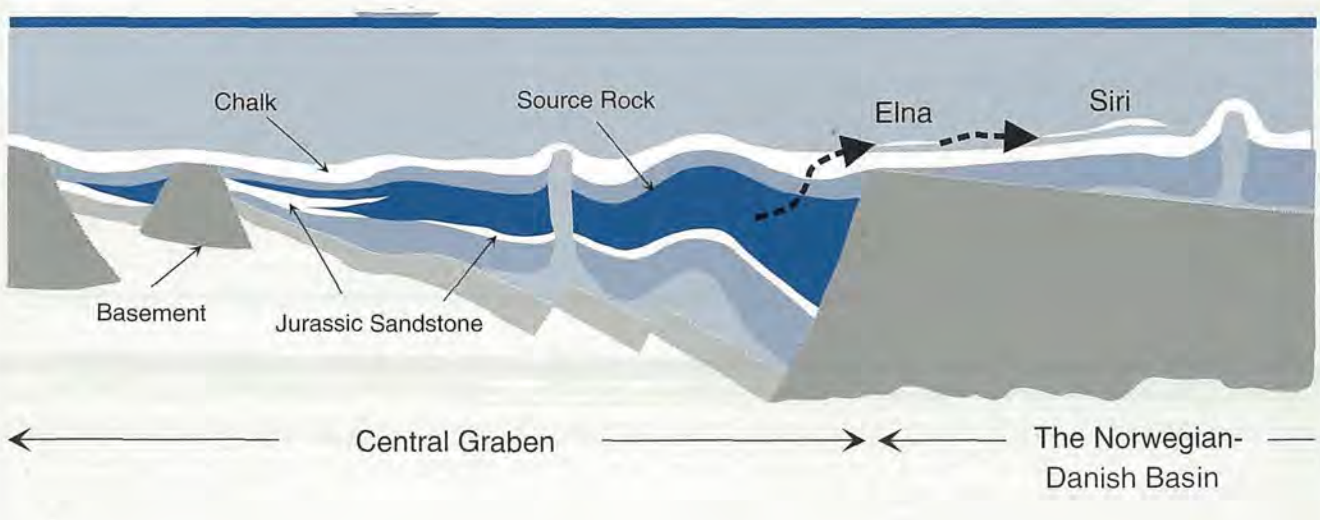
In December 1995, the Amoco group's three licences expired: 1/89 and 2/89 in the Central Graben and 3/89 in the Norwegian-Danish Basin. In 1992, Amoco drilled exploration wells under licences 1/89 and 3/89.

In addition, the Amoco group participated in a joint venture to drill an exploration well at the Norwegian-Danish border under licence 2/89, together with the licensees on the Norwegian side of the border. However, none of these wells yielded the results expected. Amoco, a major contributor to Danish exploration activities since the First Licensing Round in 1984, has thus ceased to be a licensee.

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.

Fig. 1.4 Cross-section of the Central Graben and the Western Part of the Norwegian-Danish Basin



In 1995, data regarding the following exploration wells were released:

Gert-4	5603/27-4	Mærsk
Alma-1	5505/17-10	Mærsk
Skarv-1	5504/10-2	Amoco
Ida-1	5606/13-1	Amoco
Løgumkloster-2	5508/32-3	Danop

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

Confirmation of New Exploration Model

As mentioned above, in drilling the Siri-1 well, the Statoil group made a major discovery outside the Central Graben. This discovery marks the first successful effort to explore for hydrocarbons in Tertiary sandstone in Danish territory.

Tertiary sandstone layers have been subject to extensive exploration for several years in the Norwegian and UK sectors, and major oil and gas discoveries have been made. Based on this experience, the companies in the Statoil group have now successfully applied the same exploration model in the Danish sector of the North Sea.

The hydrocarbons in Danish oil and gas discoveries were formed primarily in connection with the subsidence and associated heating of organically rich clay deposits of Late Jurassic age in the Central Graben. Moreover, the subjacent Middle Jurassic layers contributed to the formation of oil and gas in certain areas. From this source rock, oil and gas subsequently migrated into the known fields and discoveries in chalk and in Late and Middle Jurassic sandstone (see Fig. 1.4).

In 1985, DUC made a gas and condensate discovery in Palaeocene sandstone in the Elna-1 well. However, it was concluded that there was no basis for commercial production, and the area was subsequently relinquished. The Elna discovery is located immediately above the edge of the Central Graben, and is thus quite close to the source rock.

The Siri discovery was made about 25 km east of the Central Graben, which demonstrates that oil can migrate over long distances.

The extent of the area lying within this distance from the source rock is about 3,000 km^2. The relevant area has not been explored very thoroughly in terms of drilling, and up-to-date seismic data is very scant in some places. Thus, while an average of two to three exploration wells have been drilled per block (1 block covers about 225 km^2) in the Central Graben, only three wells in total have been drilled along the border zone.

Further exploration of this area will determine whether corresponding discoveries can be made in Tertiary sandstone or other reservoirs. In addition, it is essential to investigate whether hydrocarbons have migrated over greater distances than established so far, and whether the exploration model can thus be applied to a larger area.

2. Production

In 1995, Danish oil and gas production came from nine fields, the oil fields of Dan, Gorm, Skjold, Rolf, Kraka, Dagmar, Regnar and Valdemar, as well as the Tyra gas field. All the fields are situated in the southern region of the Central Graben.

Dansk Undergrunds Consortium, DUC, is in charge of recovery from all these fields. The operator is Mærsk Olie og Gas AS.

The map in Fig. 2.1 shows the location of the nine Danish producing fields and fields under development.

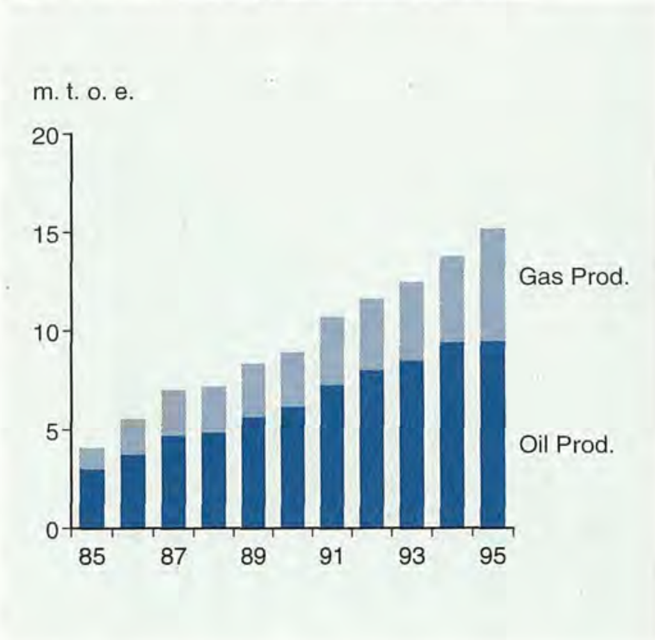
Oil and Gas Production

Total oil and condensate production in 1995 amounted to 10.79 million m^3, equal to 9.46 million tonnes, while gas production amounted to 6.32 billion Nm^3 (normal cubic metres). This means that the high 1994 production level has been maintained.

Of the total amount of gas produced, 3.84 billion Nm^3 was produced in the Tyra Field, while the balance was associated gas produced in conjunction with oil in the other fields.

Fig. 2.1 Danish Fields in the North Sea

Fig. 2.2 Production of Oil and Natural Gas



Of the gas produced, 4.70 billion Nm^3 (75%) was supplied to Dansk Naturgas A/S, while 1.16 billion Nm^3 (18%) was reinjected into the Gorm and Tyra Fields in order to enhance the recovery of liquid hydrocarbons. The rest of the gas produced was consumed or flared on the platforms.

Fig. 2.2 shows the development of Danish oil and gas production in the period from 1985 to 1995. Gas production comprises gas supplied to Dansk Naturgas A/S and gas used for energy supplies to the platforms.

Further information about annual oil and gas production for the period from 1972 to 1995 is shown in Appendix E, which also provides an outline of the monthly production of oil and gas in the individual fields for 1995.

Fig. 2.3 shows the development in gas supplies to Dansk Naturgas A/S in the period 1985 to 1995, broken down by the Tyra gas field, the Dan oil field and a combined figure for the remaining fields.

Appendix E contains an outline of gas sales from start-up in 1984 until 1995, broken down by field.

Gas Flaring

A proportion of the gas produced (4.8%) was used for energy supplies to the platforms in the North Sea, while a slightly smaller amount (2.4%) had to be flared without being utilized. Thus, in 1995, the amount of gas used for energy supplies (as fuel) constituted 314 million Nm^3.

Fig. 2.3 Natural Gas Supplies Broken down by Field

The gas not utilized (flared) in 1995 amounted to a total of 152 million Nm^3. The gas is flared for safety reasons mainly, but the processing undertaken in the production facilities also necessitates flaring. Of the gas flared, 5 million Nm^3 was sour gas (i.e. containing hydrogen sulphide) from the Dagmar Field. All gas produced in the Dagmar Field is flared due to the problems connected with utilizing the poisonous gas from the field.

1995 Developments in General

Development activities in 1995 concentrated mainly on the Gorm, Skjold and Tyra Fields. Further development of the Dan Field was initiated in the course of the year. In addition, platforms were installed in the two new fields, Roar and Svend, and the drilling of the first development wells in these fields commenced towards the end of the year.

In the Gorm Field, the last five wells to be drilled according to the development plan were completed, and a third deck to accommodate processing facilities was installed on the Gorm F platform.

The Skjold Field development plan was implemented in 1995 with the drilling of five horizontal wells.

In the Tyra Field, ongoing development was continued with the installation of a platform on Tyra West to support a bridge module housing gas compression facilities, etc. Likewise, a bridge module has been installed at Tyra East, comprising facilities for receiving production from the new northern fields, Svend and Roar. Moreover, two new modules with processing facilities have been installed.

In June 1995, a plan for further development of the Dan Field was approved, based on extending water injection to the whole field, including high-rate water injection. Immediately following approval, development activities commenced, and two existing wells were redrilled to new bottomhole locations.

The development of DUC's fields in the Northern Area of the Central Graben was initiated in 1995, when production facilities were installed in the Svend oil field, followed by the installation of production facilities in the Roar gas field. In the autumn, the first development wells in both fields were spudded. The Roar Field was brought on stream with one producing well on January 7, 1996, and production is expected to start in the Svend Field in May, 1996.

In June 1995, a minor development plan for the Valdemar Field was approved, providing for the drilling of up to two further wells.

In February and March 1995, development plans were also approved for the two small gas fields, Elly and Alma. The Elly Field is to be developed as an unmanned satellite to Tyra East by 1999. The Alma Field will be developed as an unmanned satellite to the Dan F complex, and will be brought on stream by the year 2003.

Production Wells

In 1995, 16 new horizontal or highly deviated production and injection wells were completed in connection with developing the Danish fields in the North Sea. Two of these are existing wells that have been redrilled. The number of wells drilled is slightly lower than the year before, when 19 wells were completed. However, the number of new wells is expected to increase again in 1996, due mainly to the development of the Dan Field, which will involve the drilling of numerous new wells.

At the turn of the year 1995/1996, the number of wells in operation totalled 215. In the course of 1995, the number of horizontal wells in operation was brought up to a total of 100, viz. 83 production wells and 17 water-injection wells.

The development in the number of production wells completed in the period from 1985 to 1995 is shown in Fig. 2.4.

The breakdown of the 16 new production wells completed in 1995 is as follows: Five wells in each of the Gorm and Skjold Fields, three in the Tyra Field, two in the Dan Field and one in the new Roar gas field. In addition to these 16 new wells, an existing, horizontal well in the Dan Field was extended by means of the coiled tubing drilling technique.

Producing Fields

The Danish producing oil and gas fields are grouped round three processing centres, the Dan, Gorm and Tyra Centres. The following description of the nine Danish oil and gas fields that were producing at end-1995 is based on this grouping of fields.

The subsequent section describes the field developments in progress in 1995 in more detail, including the Roar and Svend Fields, which were brought on stream at the beginning of 1996.

Figs. 2.5, 2.8 and 2.11 contain maps showing the location of the three centres. The existing and approved production and pipeline facilities for the three centres appear from Figs. 2.6, 2.9 and 2.12. Installations under construction at the end of 1995 are distinguishable by their colour.

Fig. 2.4 Production Wells

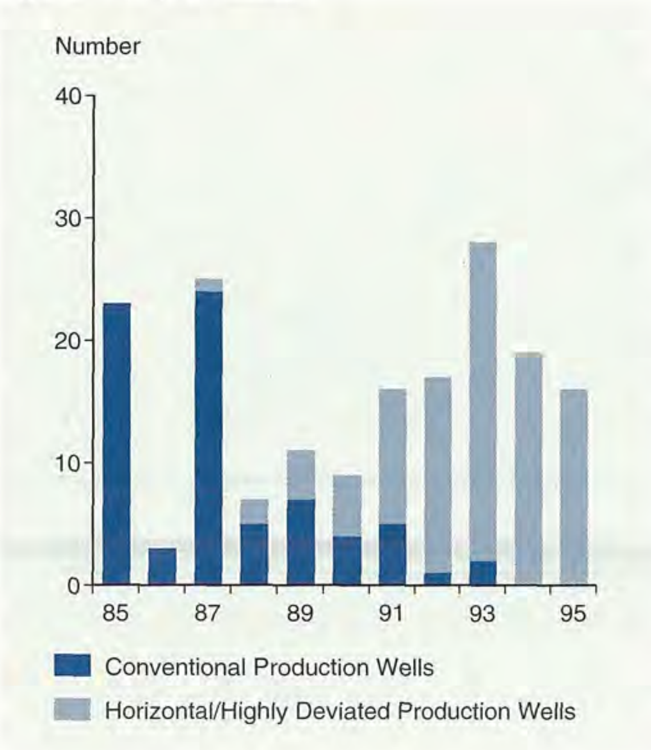
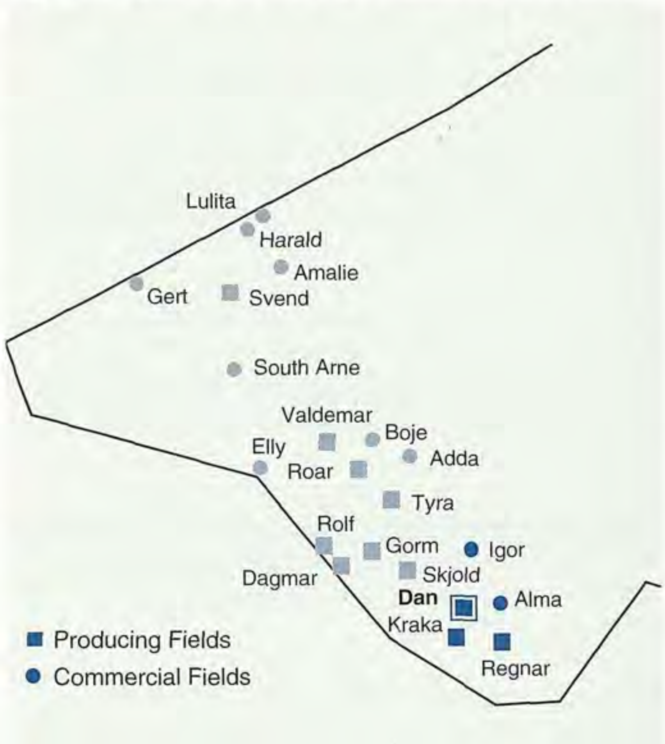


Fig. 2.5 Danish Oil and Gas Fields, the Dan Centre



Appendix G provides an outline - with supplementary data - of producing fields, field developments in progress as well as new field developments.

The Dan Centre

This centre comprises the Dan, Kraka and Regnar Fields. The Igor and Alma Fields, as yet undeveloped, are also to be hooked up to Dan as satellites. The development in oil production from the fields at the Dan Centre is shown in Fig. 2.7. In 1995, oil production from the Dan Centre totalled 4.27 million m^3.

Total gas production from the fields at the Dan Centre amounted to 1.47 billion Nm^3 in 1995, of which 1.34 billion Nm^3 was transported to shore via the Tyra Centre. The rest of the gas was used as fuel or flared.

Dan

Dan is an oil field with a gas cap. Production was initiated in 1972.

After processing at the Dan FC platform, oil and gas are transported to shore through the Gorm and Tyra Centres, respectively.

Production from the field is based on water injection, which was initiated in 1989. The most recent development plan from 1995 provides for high-rate water injection. The high pressure used means that when injected, the water makes extensive fractures in the reservoir through which the water is distributed. Thus, the oil is displaced very efficiently through the tight chalk reservoir.

The use of high-rate water injection means that large amounts of water can be injected into the reservoir at low cost, as this method is based on fewer conventional wells.

The development plan involves a major expansion of the Dan production facilities, including the establishment of a new wellhead and processing platform, Dan FF. This development plan is expected to be fully implemented in the course of 1999.

The processing facilities in the field will be expanded considerably; for one thing, the water-injection capacity will be doubled, and the water-processing capacity will be more than quadrupled.

According to the plan, 42 wells were to be drilled, of which 28 were new wells, while the remaining 14 were existing wells that were to be redrilled. The criterion for selecting the wells to be redrilled is poor oil production properties, due to large gas or water production. The development plan provides for the conversion of a number of production wells into water-injection wells over the next few years.

However, the well pattern is currently being optimized, already resulting in a reduction of the number of new wells. This reduction has been made possible by combining several production/injection objectives in one individual well.

Redrilling wells, i.e. reusing slots, helps reduce the expected development costs, allowing drilling operations to commence immediately upon approval of the plan, as it was not nessesary to await installation of the new platform.

In 1995, two existing wells were redrilled; thus, two deviated wells have been replaced by a new horizontal injection well and a new horizontal production well.

Moreover, at the beginning of 1995, a horizontal production well at the western flank of the field was extended by means of a comparatively new drilling technique, coiled tubing drilling. This was the first time that such a

Fig. 2.6 Production Facilities in the North Sea, 1996, the Dan Centre

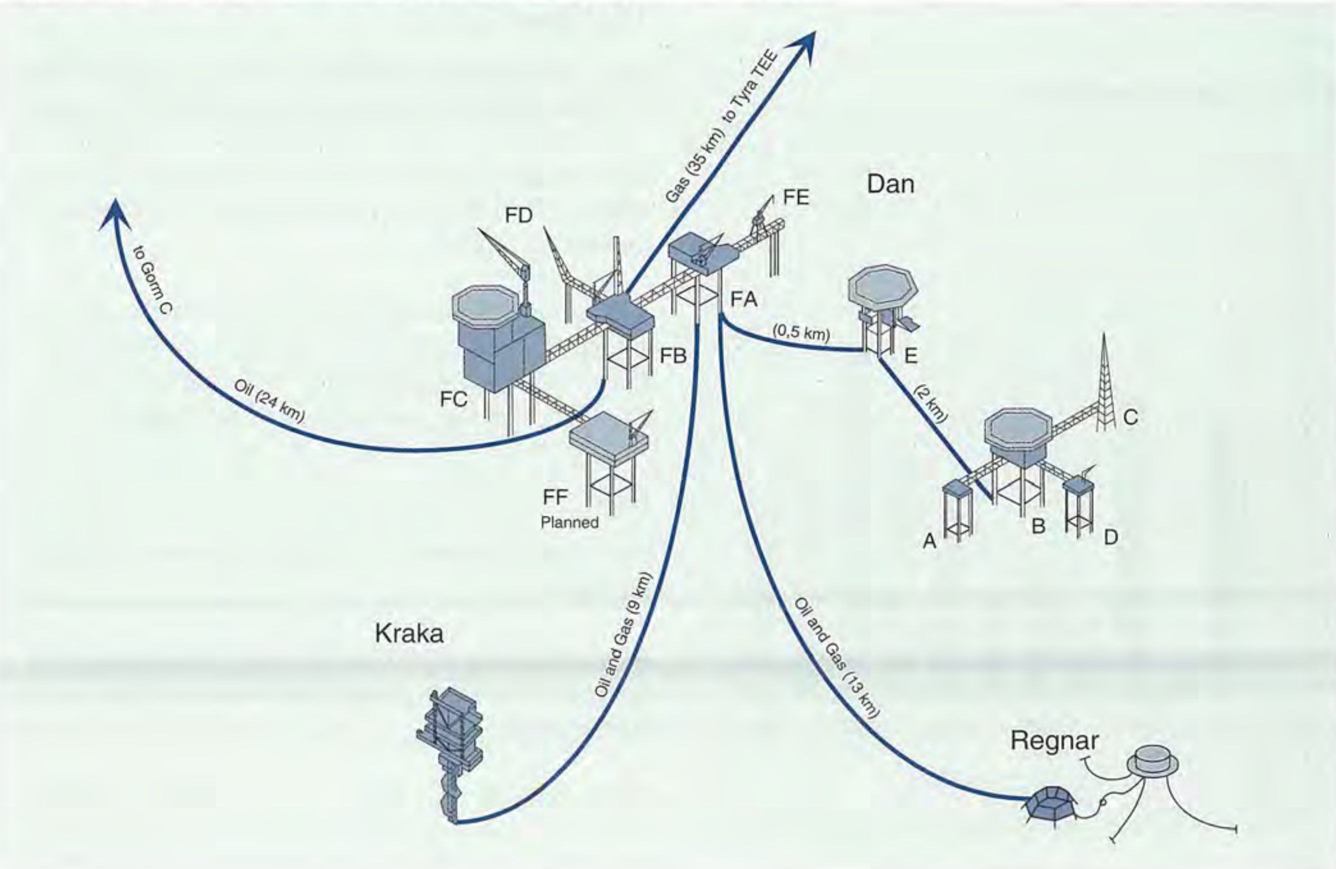
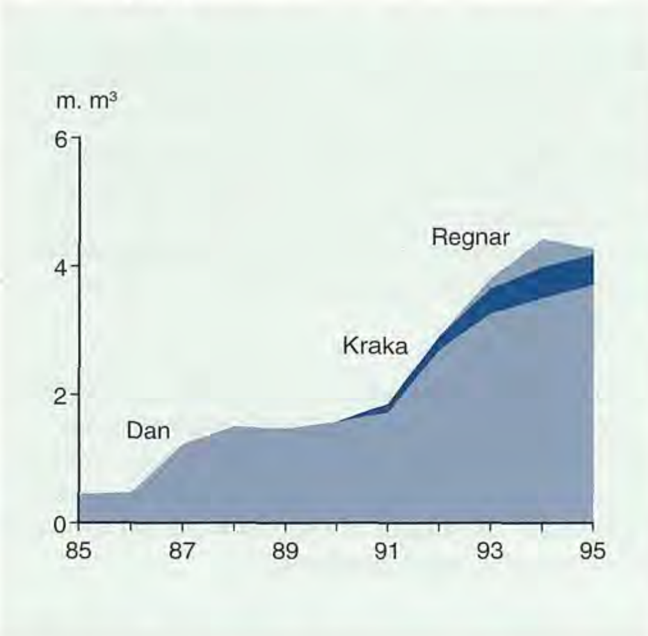


Fig. 2.7 Oil Production from the Fields at the Dan Centre



drilling operation from an offshore installation was carried out in Denmark without the use of a drilling rig. In addition, a total of five wells were converted into water-injection wells in the course of 1995.

At end-1995, there were 48 producing oil wells in the Dan Field, of which 32 were horizontal. These wells were supplemented by 26 water-injection wells.

At end-1995, a total of 12.53 million m^3 of water had been injected into the Dan Field, of which 5.88 million m^3 was injected in 1995. From 1994 to 1995, water-injection increased by 54%, due to the installation of new water-injection facilities in 1994.

In 1995, Dan produced 3.71 million m^3 of oil compared to 3.50 million m^3 in 1994. Gas production amounted to 1.33 billion Nm^3 in 1995.

Kraka

Kraka is an oil field with a gas cap. The field, which is located approx. 7 km southwest of the Dan Field, has been developed as a satellite to the Dan Field. Production from the field was initiated in 1991.

The first phase of the field development consists of the completion of six horizontal wells, of which the last three commenced producing in 1993/94. Production experience from these wells, in particular, is encouraging, and expectations for future recovery from the field have grown considerably.

According to the Ministry of Energy's most recent approval from 1994, DUC is to submit a plan for the second phase of the further development of the field in the course of 1996.

In 1995, 0.47 million m^3 of oil was produced at the Kraka Field, as compared to 0.49 million m^3 in 1994.

Regnar

The Regnar Field is an oil field situated approx. 13 km southeast of the Dan Field. The field was brought on stream in 1993 from a subsea-completed well. The subsea production system is remotely controlled from Dan FC. Oil is produced from a single vertical well.

The field consists of a small accumulation of oil in a heavily fractured chalk reservoir, with the same characteristics as other Danish fields, such as Skjold, Rolf and Dagmar.

It was expected that the Regnar Field would have a fairly short production life span, because it was considered most likely that only the oil in the fractures was recoverable. At the time of production startup, anticipated recoverable reserves were put at 0.52 million m^3, equal to 80% of the estimated oil-in-place in the fractures.

In 1995, 0.09 million m^3 of oil was produced at the Regnar Field, as compared to 0.43 million m^3 in 1994. Thus, total oil production from the field amounted to 0.67 million m^3, which is nearly 30% more than the originally expected recoverable reserves. This indicates that oil may also be produced from the tight matrix of the formation. Therefore, the field will probably be able to produce at a low production rate for a number of years to come.

The Gorm Centre

This Centre is composed of the Gorm Field and the satellite fields, Skjold, Rolf and Dagmar. The pipeline owned by DORAS leads from the Gorm Centre, conveying oil and condensate from the Danish fields in the North Sea to the west coast of Jutland, and from there to the terminal facilities near Fredericia on the east coast. Fig. 2.8 shows the location of the Gorm Centre, while Fig. 2.9 shows the production facilities at the Gorm Centre in 1996.

The development in oil production from the fields at the Gorm Centre is shown in Fig. 2.10. It appears from this figure that production, particularly from the Skjold and Rolf Fields, increased in 1995.

Gorm

Gorm is an oil field situated 27 km northwest of the Dan Field. The field was brought on stream in 1981.

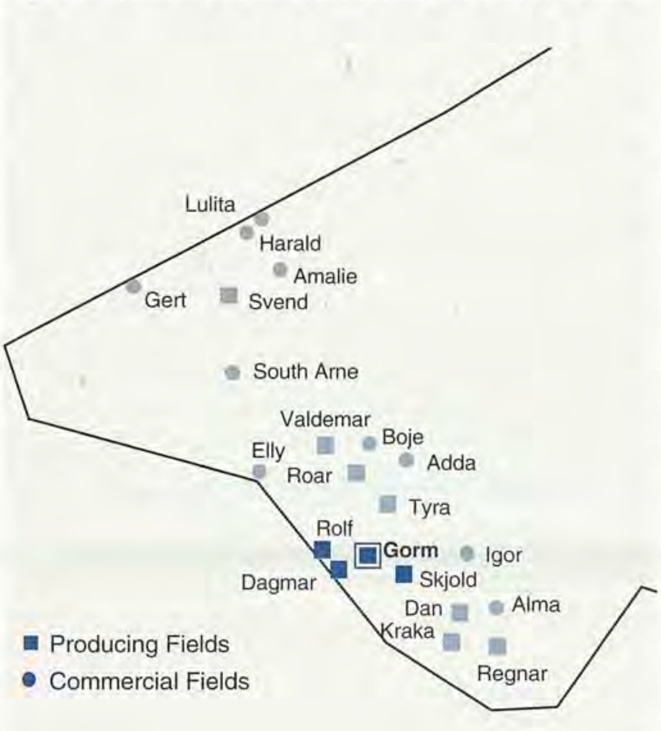
The reservoir, which consists of Danian and Late Cretaceous chalk, is divided by a major fault into two reservoir blocks with different reservoir characteristics. In connection with drilling one of the long horizontal wells in 1993, it was ascertained that another minor fault block containing hydrocarbons is situated in the western part of the field. This part of the Gorm Field is still being appraised.

The production of oil from the field is based on extending the use of water injection to the whole field. The previous use of gas injection at the crest of the structure will be phased out.

Initially, oil will be recovered from the mid-flank areas of the reservoir, with simultaneous water injection in the flanks. In a later phase, recovery will be moved towards the crest of the structure, while water injection will be initiated in the areas where oil was produced previously.

In June 1995, a third deck was installed on the Gorm F platform. This deck accommodates a new separator, two injection pumps and water-processing facilities. Since the commissioning of this deck, the separation of the Gorm and Skjold production has taken place at the Gorm F platform.

Fig. 2.8 Danish Oil and Gas Fields, the Gorm Centre



In 1994, a plan for the western block of the field was approved. Yet another plan was approved which provides for the installation of a fourth deck housing wellhead compression facilities and a new test separator, scheduled for completion in 1997. The wellhead compression facilities will reduce the wellhead pressure in the Gorm and Skjold wells, and will also improve the utilization of lift gas in the Gorm, Skjold and Rolf Fields.

In 1995, three horizontal production wells and one horizontal injection well were drilled. In addition, a new horizontal sidetrack was drilled in a production well in the eastern block. The results from drilling these wells confirm that the strategy of injecting water at the bottom of the reservoir works as intended.

The total number of production wells in the Gorm Field has now reached 30, while the number of water-injection wells totals 13. To this must be added two gas-injection wells, which are used primarily when gas production exceeds export capacity. The plan is to convert these wells into production wells in 1997.

In 1995, 5.75 million m^3 of water was injected into the Gorm Field, relative to 4.61 million m^3 in 1994. A total of 16.37 million m^3 of water has been injected into the Gorm Field. Gas injection has nearly been phased out, and in 1995, only 28 million Nm^3 of gas was injected. Since 1981, a total of 7.95 billion Nm^3 of gas has been injected into the field.

In 1995, the Gorm Field produced 2.49 million m^3 of oil, almost equal to production in 1994.

Skjold

Skjold is an oil field located 10 km southeast of the Gorm Field. The oil produced is conveyed in multiphase flow to the Gorm Field for processing, and the Skjold wells are supplied with lift gas and injection water from the Gorm Field.

Production was initiated in 1982, and already in 1986, water injection in the reservoir commenced.

The experience from using water injection in the field is positive. In recent years, new wells have encountered zones with low oil saturations within the reservoir section, which means that the water has effectively displaced the oil.

Throughout 1995, a total of five new wells were drilled in the field: one horizontal and three highly deviated oil production wells, as well as one deviated water-injection well. In addition, several of the new wells have been prepared for both production and water injection purposes.

With the completion of these wells, the development plan most recently approved was fully implemented. This has brought up the number of producing wells to 14, while six water-injection wells are in operation in the Skjold Field.

However, there is still believed to be potential for further developing the field, particularly in the flanks of the reservoir.

In 1995, Skjold produced 1.98 million m^3 of oil, which is 0.26 million m^3 more than in 1994. In 1995, 3.99 million m^3 of water was injected into the Skjold Field, as compared to 3.44 million m^3 the year before.

Rolf

Rolf is an oil field situated 15 km west of the Gorm Field. In 1986, the field, developed as a satellite field to Gorm, was brought on stream. Production takes place from two wells.

In 1993, the Ministry of Energy approved a final plan for recovery from the Rolf Field, which involves no further development of the field for the time being. After a period of continued monitoring of production properties in the field, DUC is to submit updated versions of these reservoir studies not later than 1997, in order for them to be reviewed by the Danish Energy Agency.

The planned installation of wellhead compression at Gorm F in 1997, which allows better utilization of the lift gas at the Gorm Centre, will result in a minor increase of recovery from the Rolf Field. The Rolf production will continue to be processed at the Gorm C facilities.

In 1995, the field produced 0.22 million m^3 of oil against 0.09 million m^3 the year before. The water-pro-

Fig. 2.9 Production Facilities in the North Sea, 1996, the Gorm Centre

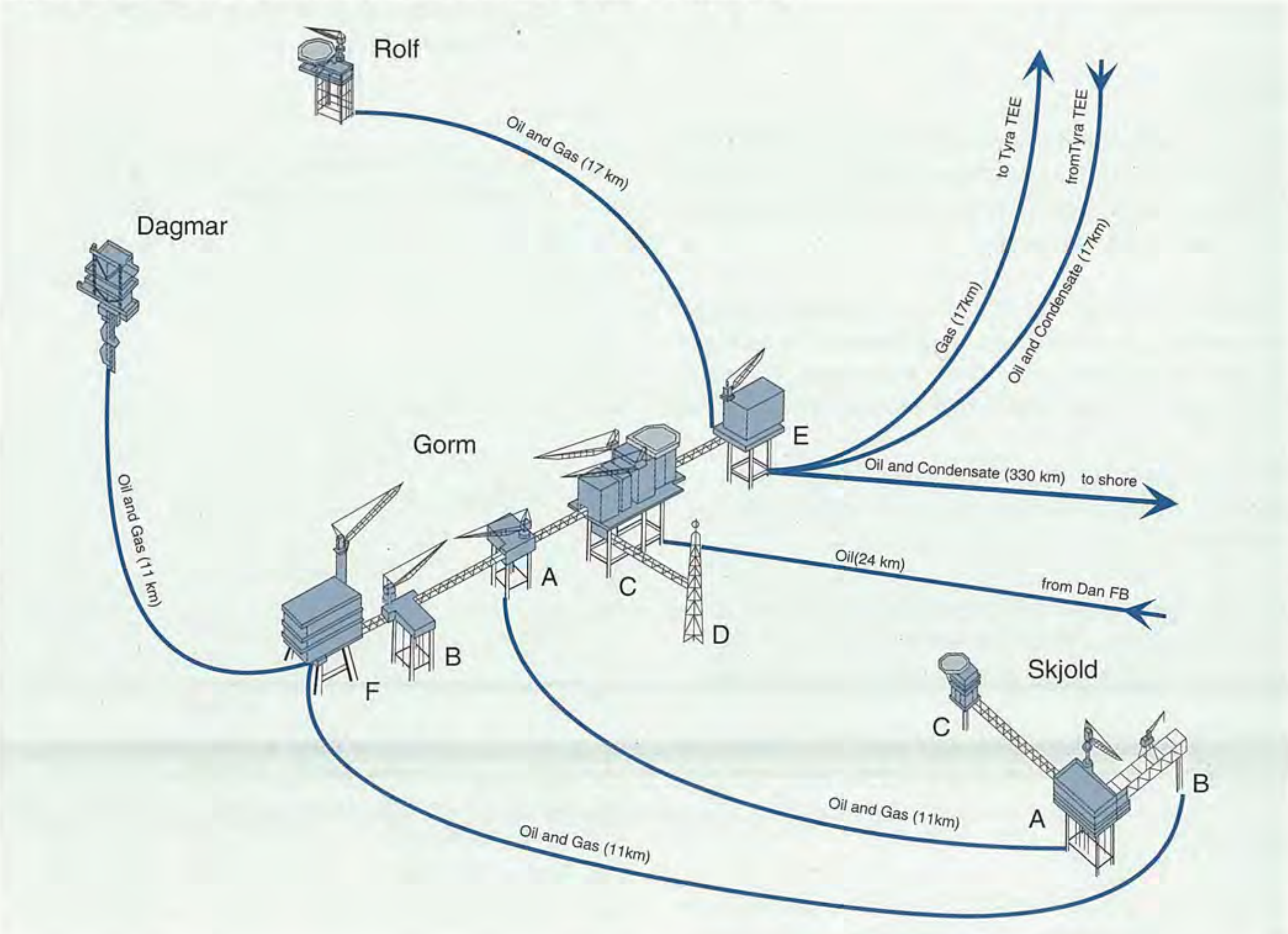
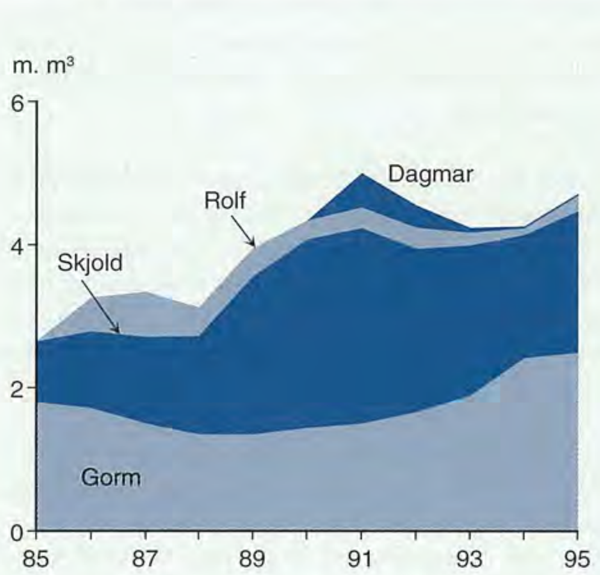


Fig. 2.10 Oil Production from the Fields at the Gorm Centre



cessing capacity of the Gorm Field set limits to production from the Rolf Field in 1994, and the increase recorded in 1995 is due mainly to increased water-processing availability.

Dagmar

Dagmar is an oil field situated 10 km west of the Gorm Field. The field, which has been developed as a satellite to Gorm, was brought on stream in 1991. Production takes place from two wells.

Due to the high content of hydrogen sulphide in the associated gas, the production from Dagmar is processed by special facilities on the Gorm F platform. The poisonous gas from the field is flared without being utilized.

Based on the production experience to date, plans for further development of the field have so far been suspended.

In 1995, the Dagmar Field produced 0.03 million m^3 of oil, corresponding to production in 1994. This might indicate that production from the field has stabilized.

Gas production amounted to 5 million Nm^3, which was flared.

The Tyra Centre

In 1995, production from the Tyra Centre derived from the Tyra Field and the satellite field, Valdemar, which was brought on stream in 1993. In addition, the Roar and Svend Fields were brought on stream at the beginning of 1996. The Tyra Field is situated 15 km northwest of the Gorm Field.

The Harald Field is expected to be connected to the Tyra Field in 1997, and subsequently the production from the small satellite fields, Adda, Elly and Tyra Southeast, is expected to be hooked up to the Tyra Field installations.

Tyra

Tyra comprises a large gas cap overlying a thin black oil zone. The reservoir consists of Danian and Late Cretaceous chalk. Production commenced in 1984, and from 1987, part of the gas produced was reinjected into the reservoir in order to utilize the excess production capacity to increase the production of condensate. The annual injection capacity of the ten injection wells in the field totals more than 2 billion Nm^3 of dry gas.

As a result of the 1992 development plan, the Tyra Field installations were extended considerably in 1995. The extension was made in consideration of the substantial increase in gas sales to Dansk Naturgas A/S as from 1997, and with a view to connecting the Svend, Roar and Harald Fields to Tyra.

Fig. 2.11 Danish Oil and Gas Fields, the Tyra Centre, and Fields in the Northern Area

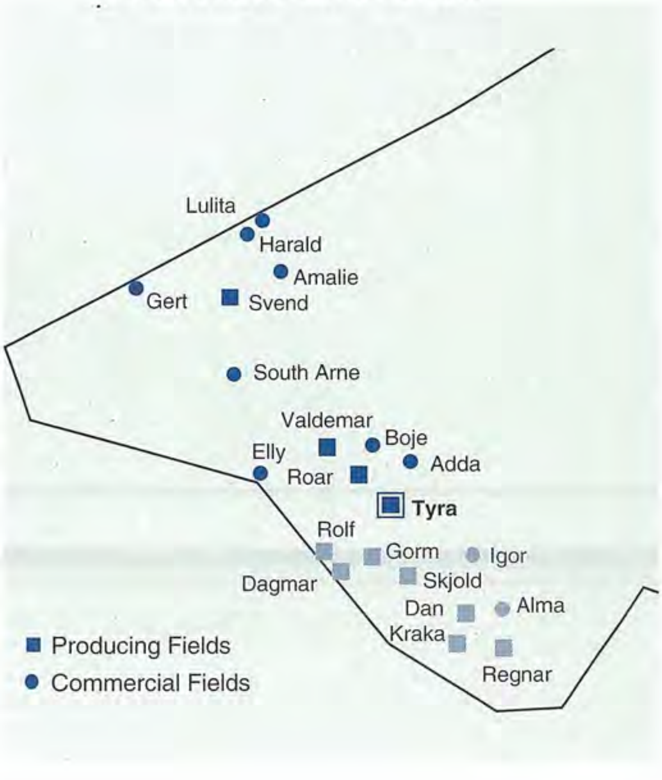
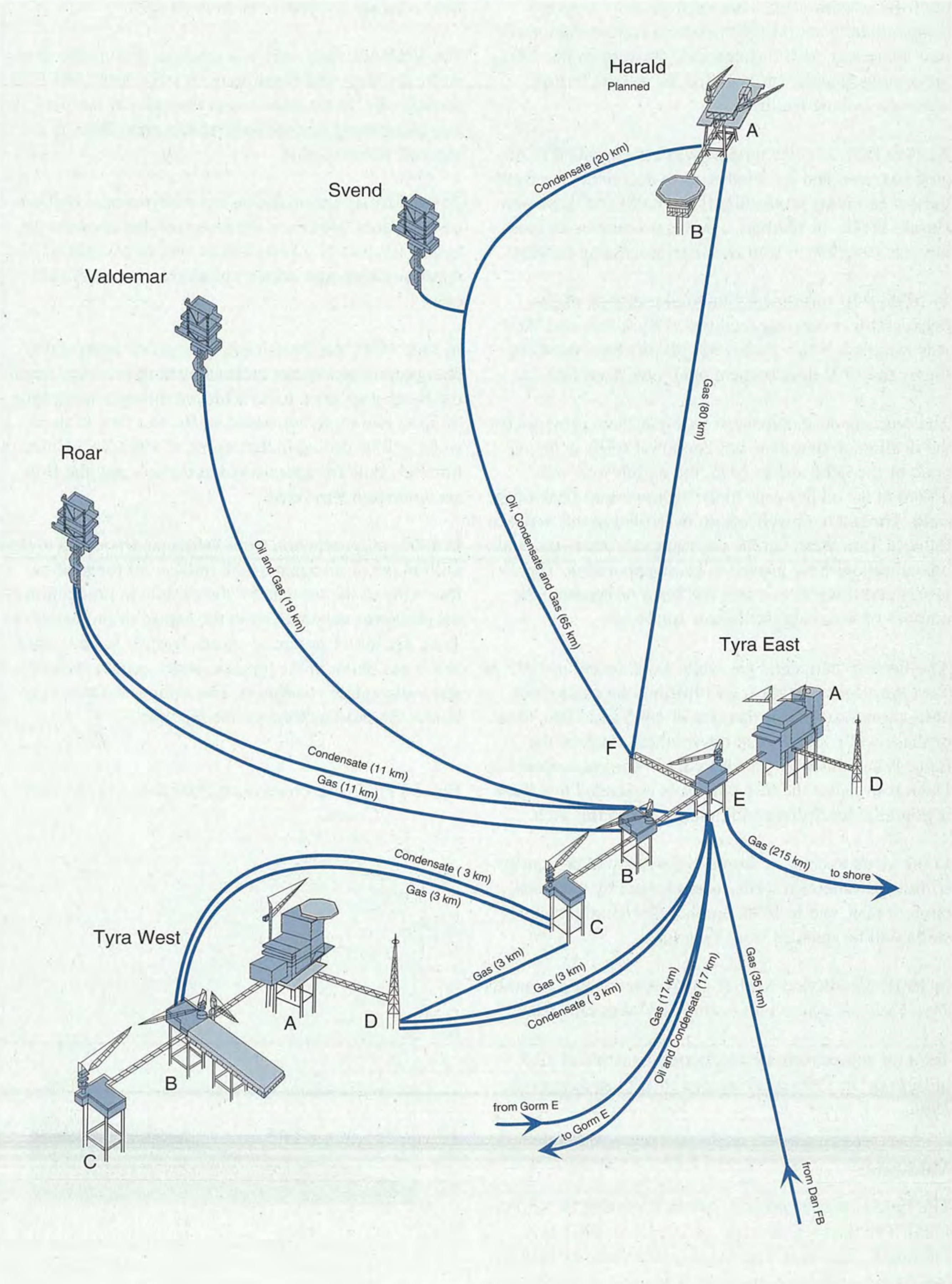


Fig. 2.12 Production Facilities in the North Sea, 1996, the Tyra Centre and the Northern Area



Thus, in August 1995, the jacket of the Tyra West E platform was installed. This platform is to support a bridge module housing gas injection compression facilities. Moreover, an IPF (Integrated Production Facilities) processing module was installed, as well as further water-processing facilities.

At Tyra East, a bridge module was also installed in August last year, and this module is to accommodate facilities for receiving production from the Svend, Roar and Harald Fields. In addition, a new gas compressor module was installed, as well as water-processing facilities.

In 1995, a 10" pipeline for internal transport of gas between the processing facilities at Tyra East and West was installed, which means that all pipelines provided for by the 1992 development plan have been laid.

The ongoing development of the Tyra Field provides for the drilling of up to nine horizontal oil wells in the oil zone of the field, and in 1995, the eighth well was drilled in the oil pay zone in the southwestern flank of the field. The ninth oil well was to be drilled in the northern flank of Tyra West, but the reservoir characteristics and oil saturations have proved to be disappointing. Therefore, the drilling of this well has been postponed. The number of horizontal wells now totals 16.

Another two horizontal gas wells were drilled in 1995 at Tyra West for the purpose of fulfilling the contractual obligation to supply further gas in 1995 and 1996. One of these wells was sunk in the southern flank of the field. When this well was drilled, oil was encountered in Danian strata for the first time. It is estimated that there is potential for drilling additional wells in this area.

In the years to come, a number of wells will be converted into gas-injection wells, as envisaged by the development plan, and in 1996, another three horizontal gas wells will be spudded from Tyra East.

In 1995, 3.84 billion Nm^3 of gas was recovered from the Tyra Field, of which 1.13 billion Nm^3 was reinjected.

Total oil and condensate production constituted 1.63 million m^3 in 1995, as compared to 1.75 million m^3 in 1994.

Valdemar

The field is located approx. 20 km northwest of the Tyra Field. The field was brought on stream in 1993 as a satellite to Tyra East. Production takes place from three horizontal wells from the North Jens area in the northern part of the field. The main reservoir of the Valdemar oil field consists of chalk of Barremian age.

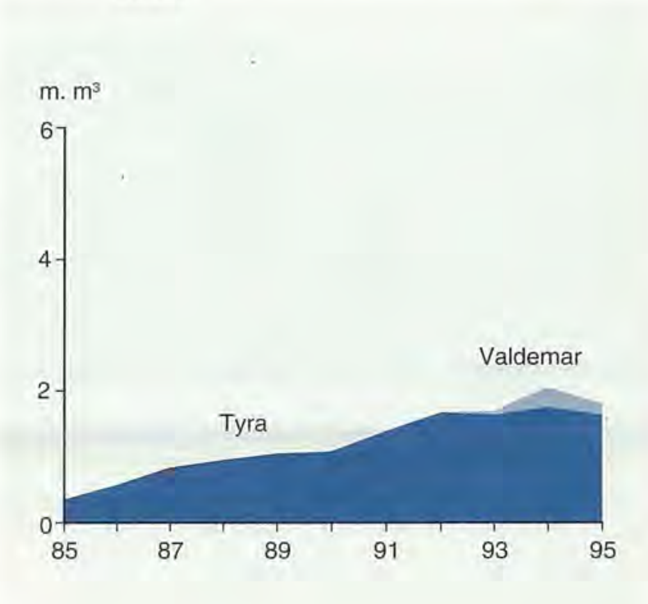
The Valdemar discovery was made in drilling the three wells Bo, Boje and North Jens, in 1977, 1982 and 1985, respectively. In the most recent mapping of the field, it was ascertained that the easternmost area, Boje, is a separate accumulation.

The Valdemar accumulation has vast potential by Danish standards. However, the reservoir that contains the largest amount of oil consists of very tight chalk of Aptian/Barremian age, which makes recovery very difficult.

In June 1995, the Danish Energy Agency approved a plan proposing a minor enhancement of recovery from the North Jens area, to be achieved through the drilling of up to two more horizontal wells. The first of these wells will be drilled in the course of 1996. In addition, a time schedule for appraising the Bo area and the Boje accumulation was fixed.

In 1995, oil production from Valdemar amounted to 0.17 million m^3 of oil against 0.30 million m^3 the year before. One of the reasons for the decline in production is the problems encountered in the export of production to Tyra. The water produced causes hydrate to be formed in the gas phase in the pipeline under certain pressure and temperature conditions. This solid substance may hinder the passage through the pipeline.

Fig. 2.13 Oil and Condensate Production at the Tyra Centre



Field Developments in Progress

Roar

Like the Tyra Field, Roar comprises a gas cap overlying a thin black oil zone. The field is situated 10 km northwest of the Tyra Field.

The Roar accumulation was discovered in 1968. In 1993, the Danish Energy Agency approved a development concept that involved developing the field as a satellite to Tyra East with an unmanned wellhead platform of the STAR type. The development project consists of the drilling of two horizontal wells, one in the northern part of the field, and one in the southern part.

In the summer of 1995, three pipelines were laid from Roar to Tyra: a 16" gas pipeline and an 8" pipeline for oil and condensate, to which a 2 1/2" glycol pipeline has been connected. Thus, gas and liquid are separated in the field before the produced hydrocarbons are conveyed to the reception facilities at Tyra East.

In August 1995, the platform jacket was installed in the field, and the first well was completed in December 1995. The thin oil zone was appraised on the basis of the pilot hole. It proved that the oil pay zone in the area was so thin that it was impossible to exploit it by means of a separate well finger within the oil zone.

The topside facilities were installed at the end of December, and production from the first well in the field was initiated on January 7, 1996. The Roar Field thereby became the second producing gas field in the Danish area.

Svend

The Svend Field consists of two oil reservoirs situated 60 km northwest of the Tyra Field: a northern reservoir called North Arne, which was discovered in 1975, and a southern reservoir called Otto, discovered in 1982.

The development of the field commenced in 1995, and in August that year, an unmanned STAR wellhead platform, specially designed for larger water depths, was installed in the field.

The field is being developed as a satellite to the Tyra Field, and the production will be transported to Tyra East through a pipeline section connected to the Harald-Tyra oil pipeline. Thus, in the summer of 1995, the Svend Field was hooked up to Tyra East by means of a 16" pipeline. The last section of the pipeline connecting the Svend and Harald Fields will be laid in 1996.

The development concept so far provides for the drilling of two horizontal wells, one in each structure. In October 1995, the well in the southern part of the field was spudded, and production from this well is expected to commence in May 1996.

Harald

Harald consists of two gas accumulations 80 km north of Tyra, just south of the border between the Norwegian and Danish sectors. The Harald Field comprises the following discoveries: Lulu from 1980 and West Lulu from 1983. The Harald West reservoir consists of sandstone, while the main reservoir in Harald East consists of chalk.

In December 1995, Mærsk Olie og Gas AS applied for approval of a revised development concept for the field. The revision implies that the whole Harald Field will be developed from one single platform complex. The complex consists of a four-legged processing and wellhead platform connected by a bridge to an accommodation platform of the STAR type for operational and maintenance personnel. The revised concept was approved by the Danish Energy Agency in March 1996.

The plan is to drill three wells at Harald West and two wells at Harald East.

The gas produced in the Harald Field will be transported through a gas pipeline, owned by Dansk Naturgas A/S, via Tyra East to shore, while the condensate flow will be conveyed through an oil and condensate pipeline to Tyra East. This pipeline will also transport the Svend production to the Tyra Field.

Drilling operations were initiated at Harald West in March 1996, and production startup from this part of the field is scheduled for 1997. Thus, the Harald West Field will be the first field in Danish territory that produces from a sandstone formation.

In addition, the development concept allows for production from the neighbouring Lulita Field from the Harald installations.

Other Fields

Appendix G2 contains an outline with key figures of the fields for which development plans have been submitted, primarily the Igor Field, whose development was approved in 1990, and the Elly and Alma Fields, for which the Danish Energy Agency approved plans for development and production at the beginning of 1995. In addition, in 1991, development plans were submitted for the Gert Field, on which no decision has been made as yet, and for the Adda Field, which was approved in 1990. In January 1996, an updated plan was submitted for the Adda Field. So far, no development plan for the Lulita Field has been submitted for approval.

For further particulars, reference is made to the previous editions of the Danish Energy Agency's Report on Oil and Gas Exploration and Production in Denmark.

Natural Gas Storage Facilities

Dansk 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 Stenlille storage facility, based on the injection of natural gas into a sandstone structure filled with water, was inaugurated in 1994. This storage facility is being expanded, with another well drilled in 1995 for injection into/extraction from a subjacent fifth zone, in addition to an observation well. At the end of 1995, a total volume of 600 million Nm^3 had been injected into the storage facility. When a total amount of 800 million Nm^3 has been injected, the available extraction capacity will be about 300 million Nm^3.

In 1996, a new drilling campaign will be initiated, as it is planned to sink additional boreholes to the fifth zone.

At Lille Torup, six caverns have been established in a salt dome with a total extraction capacity of 300 million Nm^3 of natural gas. At present, this storage facility is being expanded by a seventh cavern that will bring up total capacity to 420 million Nm^3 of natural gas in mid-1997.

As a result of the gas sales contract concluded between Dansk Naturgas A/S and Dansk Undergrunds Consortium for annual supplies of up to 7.5 billion Nm^3 of natural gas as from 1997, Dansk Naturgas A/S has begun reviewing the company's natural gas storage requirements. Consequently, in 1995, seismic surveys were carried out in order to collect the data necessary for deciding whether to expand the existing storage facilities or to establish a new one.

3. Reserves

Assessment of Reserves

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 January 1, 1996 shows an increase in oil reserves of 13% and a decline in gas reserves of 6%. Oil reserves are estimated to amount to 252 million m^3, the highest figure ever.

Compared to last year's assessment, total expected oil and condensate reserves have been written up by 40 million m^3. Production in 1995, which exceeded production in the record year 1994 by 0.1 million m^3, amounted to almost 11 million m^3. Thus, the increase in oil reserves totals 29 million m^3. The amount of reserves assessed implies that it will be possible to sustain oil production at the 1995 level for the next 23 years.

The reserves reflect the amounts of oil and gas that can be recovered by means of known technology under the prevailing economic conditions. The method used by the Danish Energy Agency in calculating the reserves and preparing the production forecasts is described at the end of this section.

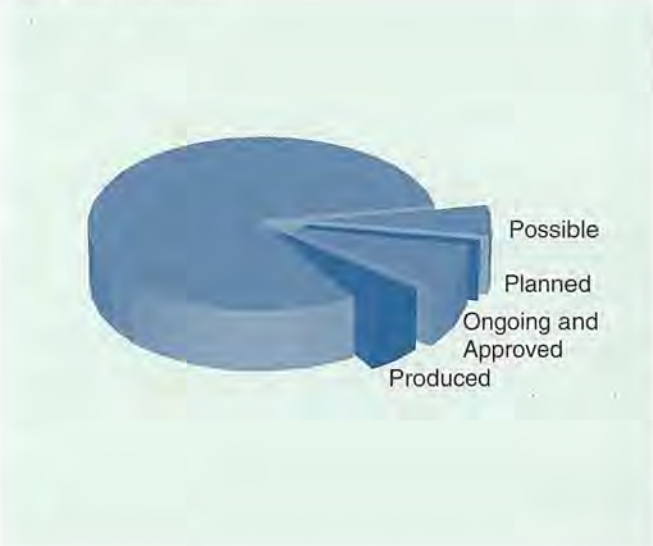
The reserves are illustrated by Fig. 3.1, where the relative size of the individual categories reflects the recovery of oil and condensate, and Table 3.1 shows the Danish Energy Agency's assessment of oil, condensate and gas reserves, broken down by field and category.

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. 3.2 that the expected amount of oil and condensate reserves ranges from 152 to 252 million m^3. The reserves assessed for planned and possible recovery, respectively, reflect the increasing uncertainty as to whether such reserves can be exploited commercially.

Likewise, Fig. 3.3 illustrates that the expected amount of gas reserves ranges from 125 to 169 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

Fig. 3.1 Reserves



which can be marketed as natural gas, the difference representing the amounts flared or consumed on the platforms, viz. 10-15% of total production.

There have been several revisions of the Danish Energy Agency's assessment of reserves compared to the assessment made in January 1995. These revisions are attributable to new field models resulting from improved knowledge of the fields, more production experience, and one new discovery.

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

Ongoing and Approved Recovery

The additional reserves derived from further development of the Dan and Valdemar Fields are included under ongoing and approved recovery, as these field developments were approved in June 1995.

The Tyra reserves have been revised in accordance with the most recent models and production experience from the field.

The reserves of the Roar Field have been reassessed due to new well data.

Finally, the Adda reserves estimate has been written up on the basis of a new development concept for the field.

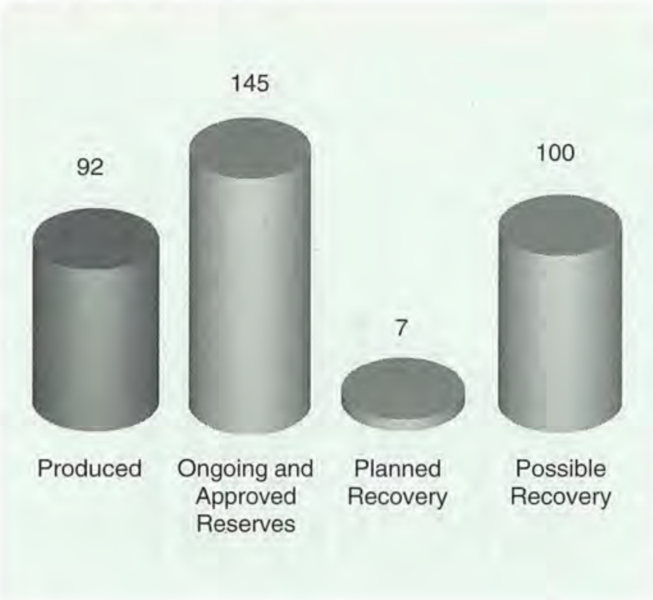
Planned Recovery

Amalie has been included under planned recovery, as the structure was declared commercial in February 1996.

Table 3.1 Assessment of Reserves at January 1, 1996

Oil and Condensate, million m³					Gas, billion Nm³				
	Produced	Low	Exp.	High		Produced	Low	Exp.	High
Ongoing and Approved Recovery					**Ongoing and Approved Recovery**				
Dan	26	52	77	103	Dan	10	8	13	18
Kraka	2	1	3	4	Kraka	1	<1	1	1
Regnar	1	<1	<1	<1	Regnar	<1	<1	<1	<1
Igor	-	<1	<1	<1	Igor	-	1	2	3
Alma	-	<1	1	1	Alma	-	1	1	2
Gorm	25	10	22	34	Gorm	2	2	4	6
Skjold	21	5	15	26	Skjold	2	<1	1	2
Rolf	3	1	2	3	Rolf	<1	<1	<1	<1
Dagmar	1	<1	<1	<1	Dagmar	<1	<1	<1	<1
Tyra	13	5	8	12	Tyra	23	41	53	65
Valdemar	1	1	2	2	Valdemar	<1	1	1	1
Svend	-	3	5	7	Svend	-	<1	1	1
Roar	-	2	3	3	Roar	-	10	14	19
Adda	-	<1	1	1	Adda	-	<1	<1	1
Elly	-	<1	1	1	Elly	-	2	5	7
Harald	-	5	7	9	Harald	-	20	25	31
Subtotal	**92**		**145**		**Subtotal**	**39**		**120**	
Planned Recovery					**Planned Recovery**				
Gert	-	1	2	3	Gert	-	<1	<1	<1
Lulita	-	3	4	5	Lulita	-	1	1	2
Amalie	-	1	2	3	Amalie	-	1	3	5
Subtotal			**7**		**Subtotal**			**5**	
Possible Recovery					**Possible Recovery**				
Prod. Fields	-	26	44	63	Prod. Fields	-	8	16	24
Other Fields	-	3	6	11	Other Fields	-	4	7	12
Discoveries	-	21	50	77	Discoveries	-	6	21	38
Subtotal			**100**		**Subtotal**			**44**	
Total	**92**		**252**		**Total**	**39**		**169**	
January 1995	81		223		January 1995	34		180	

Fig. 3.2 Oil Production



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.

The drilling of horizontal wells is considered to further increase the production potential of the oil zone in the Tyra Field as well as that of the tight Barremian chalk reservoirs in the Kraka, Valdemar and Adda Fields.

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 additional water-injection projects in a number of fields.

Finally, a number of discoveries that are under evaluation are included in this category. Thus, the reserves of the South Arne and Siri discoveries have been included. The category also includes discoveries that have been declared non-commercial, based on current technology and prices.

Further Production Potential

Total assessed recovery of oil and condensate, with the use of known technology, corresponds to only approx. 19% of the hydrocarbons in place in Danish territory.

In fields like the Dan, Gorm and Skjold Fields, where the production conditions are favourable, an average recovery factor of 35% of the hydrocarbons in place is expected, based on the assumption that known methods are used, including water and gas injection.

The total oil reserves recoverable also include contributions from the relatively large accumulations in the Valdemar and Tyra Fields. However, these contributions are expected to be quite low due to the very difficult production conditions.

Because of these fairly low recovery factors, there is an incentive for the oil companies and authorities to develop methods to improve the recovery of oil, so-called IOR (improved oil recovery) methods.

Production Forecasts

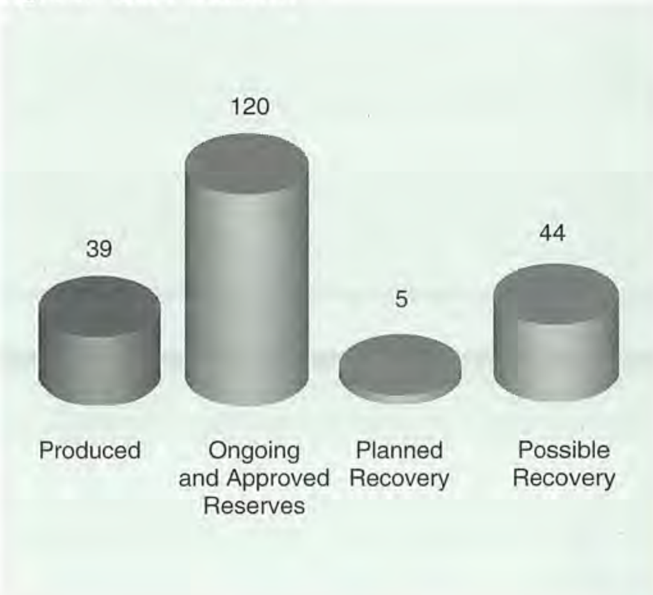
Based on the assessment of reserves, the Danish Energy Agency prepares production forecasts for the recovery of oil and natural gas in Denmark.

The present five-year forecast shows the Danish Energy Agency's expectations regarding activities until the year 2000. 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 startup is approved or from the earliest date on which production can be commenced.

Fig. 3.3 Gas Production



As appears from Table 3.2, oil production is expected to reach approx. 11.8 million m³, equal to about 200,000 barrels/day in 1996, and is then anticipated to increase to 13.8 million m³ in 1998. After that time, production is expected to decline. It should be noted that a production level around 14 million m³ exceeds the current capacity of DORAS' oil pipeline installations.

In relation to the forecast in the Danish Energy Agency's report from spring 1995, expected production figures have been written up for the period 1996 to 1998, and written down for the years 1999 and 2000.

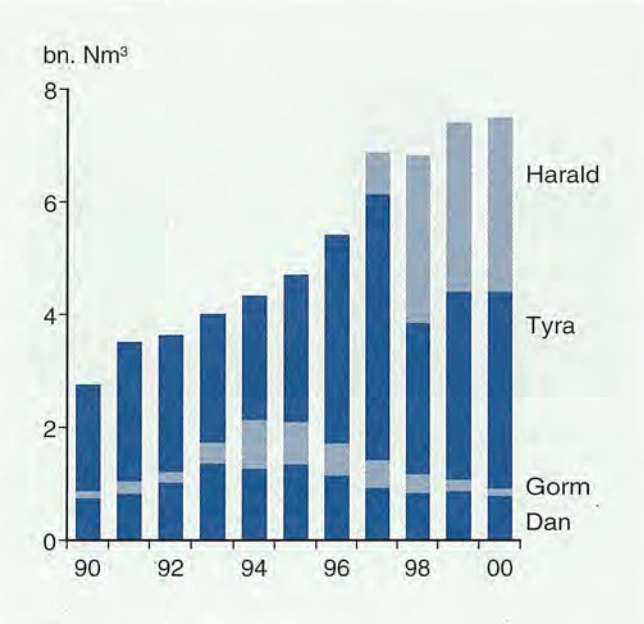
Within the categories *ongoing* and *approved recovery*, an increase in production is expected in the Dan, Gorm and Skjold Fields as a consequence of favourable production experience. Oil production figures for the Tyra Field have been written down for the next few years, due to the most recent production experience.

The *planned recovery* category includes the future development of the Gert, Lulita and Amalie discoveries.

Tabel 3.2 Oil and Condensate Production Forecast, million m³

	1996	1997	1998	1999	2000
Ongoing and Approved					
Dan	4.1	4.2	4.4	4.9	5.1
Kraka	0.4	0.3	0.3	0.2	0.2
Regnar	0.0	0.0	0.0	-	-
Igor	-	-	-	0.0	0.0
Gorm	2.6	2.8	2.9	2.3	1.9
Skjold	1.8	1.8	1.4	1.3	1.1
Rolf	0.2	0.2	0.2	0.2	0.1
Dagmar	0.0	0.0	0.0	-	-
Tyra	1.5	1.4	1.0	0.8	0.7
Valdemar	0.2	0.2	0.3	0.2	0.2
Roar	0.3	0.4	0.3	0.3	0.3
Svend	0.6	0.7	0.6	0.5	0.4
Adda	-	-	0.5	0.1	0.0
Elly	-	-	-	0.2	0.1
Harald	-	0.4	1.5	1.3	1.0
Total	**11.8**	**12.5**	**13.5**	**12.2**	**11.1**
Planned	-	0.1	0.3	0.6	1.3
Expected	**11.8**	**12.6**	**13.8**	**12.8**	**12.4**

Fig. 3.4 Natural Gas Sales Broken down by Processing Centre



Expected sales of natural gas under the existing contract are shown in Fig. 3.4, broken down by four processing centres.

Twenty-Year Production Forecast

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

Fig. 3.5 illustrates two oil and condensate production scenarios. The curve illustrating planned recovery is simply a continuation of the curve shown in Table 3.2. The second curve includes the *possible recovery* catagory, which is broken down by expected recoverable reserves under licences granted before and after 1981, respectively.

Planned production will increase to about 14 million m³ in 1998, after which production is expected to decline.

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.

Thus, the Danish Energy Agency estimates that the increased use of water injection in certain fields represents further oil production potential, and moreover, that a potential for enhancing recovery from the oil zone in the Tyra Field as well as from the Kraka, Valdemar and Adda Fields exists.

The forecast also includes potential further production from discoveries that are being evaluated at this time.

It appears from Fig. 3.5 that production is expected to increase to about 19 million m^3 around the year 2000, which means that the production potential will be almost double the current level for a few years. After the year 2001, production is estimated to decline to about 6 million m^3 in 2010, bringing the production potential to about half the current level.

As mentioned above, the expectations for future oil production are based on the gratifying production results recorded in recent years. However, it should be emphasized that the assessment of possible recovery is subject to great uncertainty.

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, Danish natural gas has been supplied under two gas sales contracts from 1979 and 1990, respectively, providing for total supplies of 93 billion Nm^3.

In 1993, a supplementary agreement was concluded between DUC and Dansk Naturgas A/S for the sale of additional gas supplies. The new gas sales contract does 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.

According to the Danish Energy Agency's forecast for the planned course of production, the maximum gas production plateau will be 7.5 billion Nm^3, and total gas supplies under the existing contracts will amount to 130 billion Nm^3 until the year 2012.

The forecast for the possible course of production predicts total gas supplies of 146 billion Nm^3 during the period of the forecast, with a plateau of 7.5 billion Nm^3.

Further Production Potential

The oil production scenario outlined above is not to be considered the upper limit of Danish production potential.

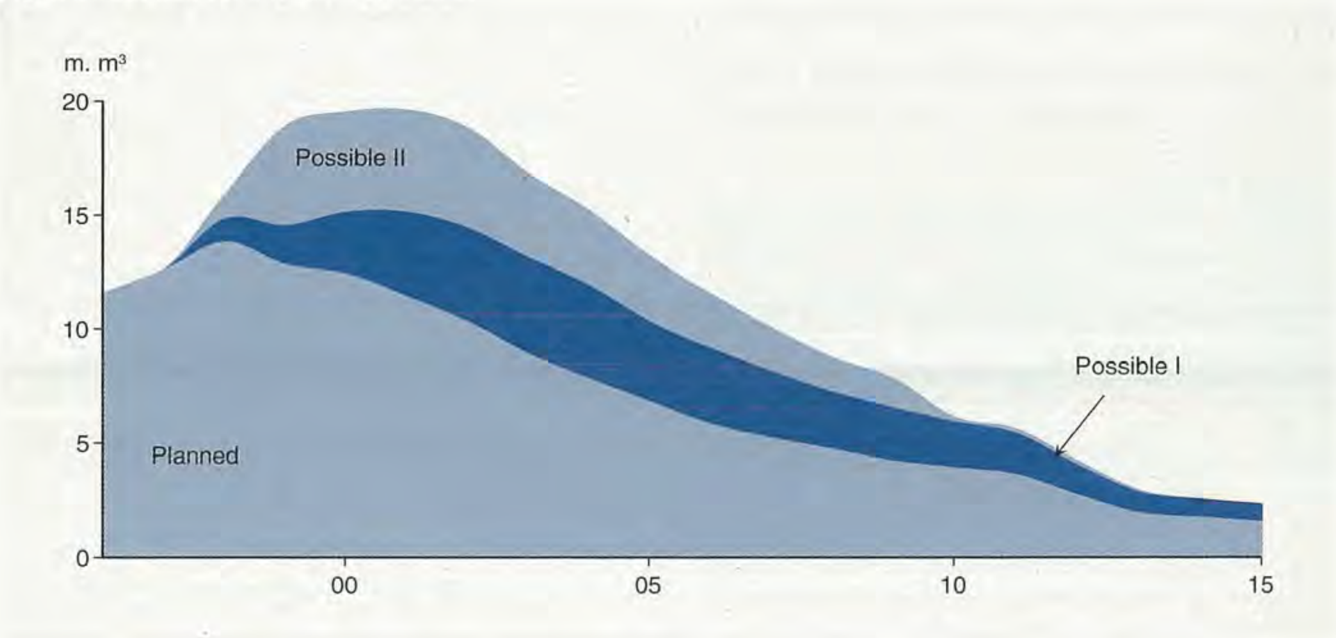
Further production is possible if current efforts to develop enhanced recovery methods and improve equipment are continued and intensified. Moreover, the experience gained from the current development of the fields is expected to provide new opportunities for enhancing recovery.

Finally, the results of ongoing exploration activities are expected to lead to further production potential.

Methods and Definitions

As in previous years, the assessment only includes reserves in structures in Danish territory where the presence of hydrocarbons has been conclusively established through drilling and testing.

Fig. 3.5 Oil and Condensate Production



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.

Only a percentage of the oil and gas in place can be recovered. The amount of oil and gas that can be recovered throughout the life of the field is termed the ultimate recovery. Thus, the difference between ultimate recovery and the amounts of oil and gas produced at any given time constitutes the reserves.

Categories of Reserves

The projects which are ongoing or for which the operator has submitted plans are divided into three categories: *ongoing, approved* and *planned recovery.*

The Danish Energy Agency assesses the reserves recoverable under *possible recovery* projects for which the operator has not submitted specific plans to the authorities. The categories of reserves are defined as follows:

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 a development plan has been approved, and production has not yet been initiated, 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.

4. Decade Review of Oil Reserves and Forecasts

When will oil reserves be depleted?

One of the questions that crops up at intervals is *When will Danish oil reserves be depleted?* Naturally, the answer depends on the amount of reserves, and the rate at which they can be recovered.

For the past 10 years, the Danish Energy Agency has used the same classification system for assessing reserves and making oil and gas production forecasts. Therefore, it might be a good idea to take a look at the development in production, reserves and forecasts over the years.

Production and reserves

Annual oil production increased from about 4 million m^3 in 1986 to almost 11 million m^3 in 1995, meaning that the amount of oil produced annually almost tripled during the period under review.

In 1987, expected oil and condensate reserves were assessed at 163 million m^3, while the corresponding figure was 252 million m^3 in 1996. Thus, reserves have increased by more than 50% since 1987.

In the period from 1987 to 1995, the total production figure was 74 million m^3. In other words, if it had been possible to assess recoverable reserves in 1987 on the basis of the knowledge currently available, the 1987 reserves would have amounted to 326 million m^3 (252 + 74), and not 163 million m^3.

Fig. 4.1 Oil and Condensate Production and Reserves

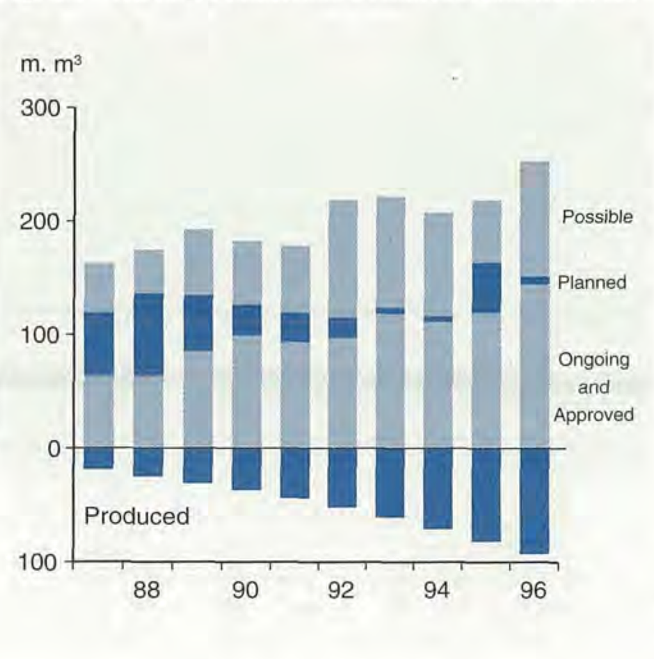


Fig. 4.2 Extent of Resources

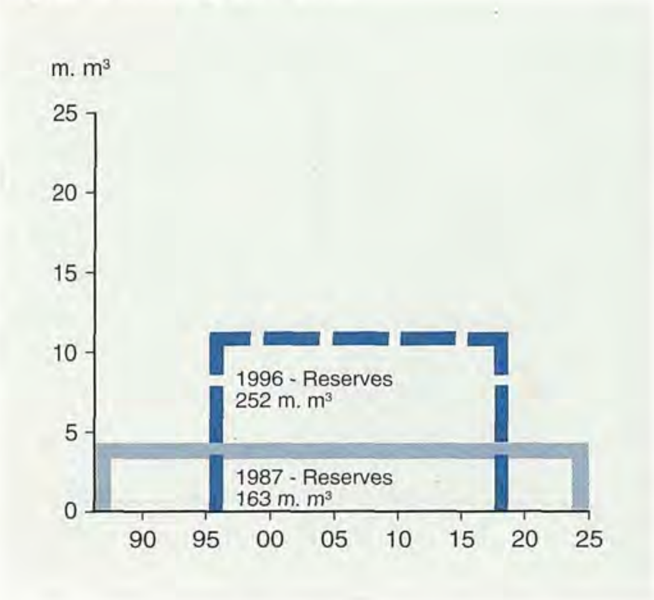


Fig. 4.1 shows production figures and expected oil reserves for the period from 1987 to 1996.

There are three main reasons that reserves have grown in spite of rapidly increasing production. Firstly, the operator of DUC, *Mærsk Olie og Gas AS,* has been a frontrunner in the development of horizontal drilling technology and low-cost developments, which has led to continuous reassessment of reserves. Secondly, water-injection development projects for the major oil fields have increased the amount of recoverable reserves, and the expected efficiency of water injection has also increased steadily. Thirdly, new discoveries were made in the period under review.

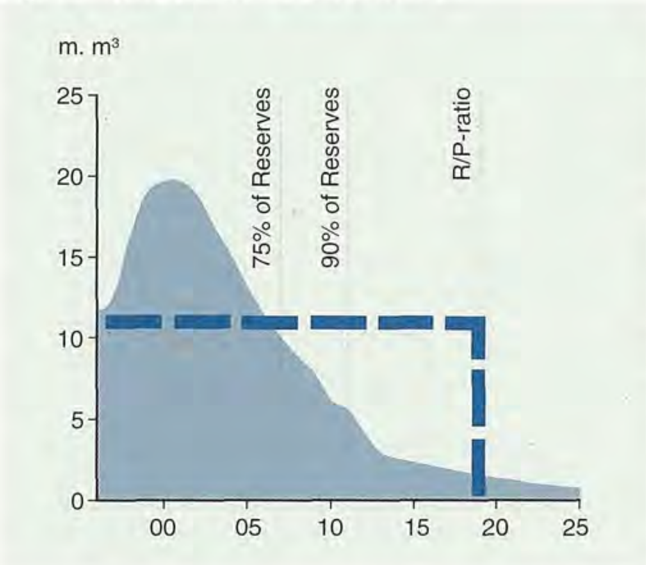
R/P ratio

A simple way of putting reserves into perspective is to calculate 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 number of years for which oil production can be sustained. Thus, the time when oil reserves will be depleted can be calculated on the basis of these assumptions.

In 1987, the R/P ratio was 38, meaning that oil production was estimated as sustainable at the 1986 level until the year 2025. For 1996, the R/P ratio is 23, which means that oil production at the 1995 level is estimated as sustainable until the year 2019; see Fig. 4.2.

Although these production life spans are subject to some uncertainty, they indicate the size of reserves in relation to the production level at the time of the calculation.

Fig. 4.3 1996 Forecast and R/P Ratio



Even though production almost tripled over the period, the increase in reserves from 1987 to 1996 means that the estimated time that oil resources will be depleted remains largely the same, viz. around 2020-2025.

Another way of interpreting the increase in reserves is that if the assessment of reserves had not been changed since 1987, this would reduce the 1996 reserve figure to 89 million m^3 (163-74), on the basis of the amount produced. The R/P ratio for this reserve figure would have meant that production could only be maintained until the year 2004.

Forecasts

Based on the most recent R/P ratio, oil reserves will be depleted around the year 2019, but what do production forecasts actually show? The oil and condensate production forecast is shown in Fig. 4.3 together with the R/P ratio. The production forecast is identical with the curve including the category possible recovery in Fig 3.5.

According to the forecast, annual production is expected to increase from 11.8 million m^3 in 1996 to about 19 million m^3 around the year 2000, after which it will decline to approx. 3 million m^3 around the year 2013. Subsequently, production will decline steadily until the year 2025.

The forecast indicates that 75% of reserves are expected to be recovered by 2007, and 90% by 2011.

Thus, the forecast shows that the bulk of reserves will have been recovered by the year 2010. On the face of it, this time span looks short, but production from field developments typically extends over a period of about 15 years. Further, in most cases, production peaks within the first five-year production period and subsequently declines.

Consequently, there is an explanation for the course of the production forecast, but naturally great uncertainty attaches to the size of production, in absolute terms, during the period covered by the forecast.

The R/P ratio is used frequently, because it provides a comparable figure for the extent of resources. However, this ratio cannot replace an actual forecast, particularly not if major variations in future production are expected.

Why do forecasts always prove wrong?

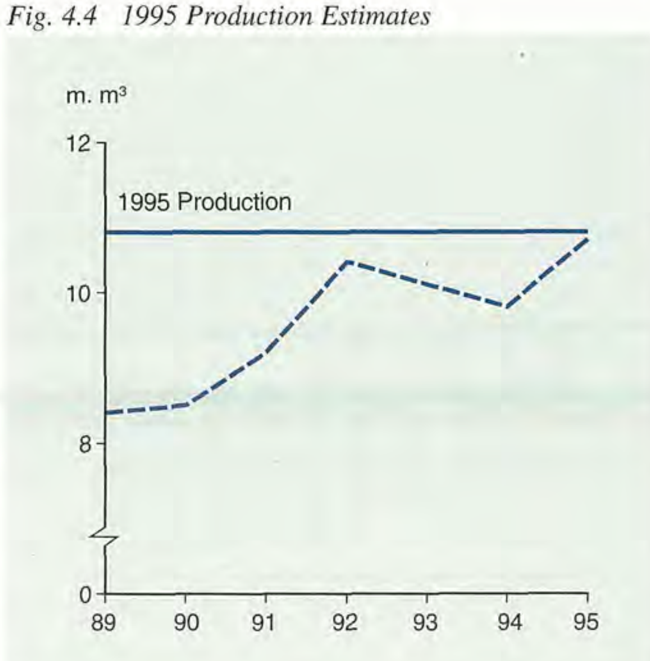
It is a well-established fact that it is difficult to make predictions about the future. However, as the production of oil is highly significant for the economy, it is necessary to prepare forecasts for future production.

Every year since 1989, the Danish Energy Agency has published a 20-year forecast for Danish oil and condensate production.

Taking status

To illustrate how true or untrue the forecasts have proved to be, the historical estimates of 1995 production are shown in Fig. 4.4. For instance, in 1990, the 1995 production figure was put at 8.5 million m^3. The actual production figure for 1995 was 10.8 million m^3, about 25% higher than the estimate made in 1990.

Fig. 4.4 1995 Production Estimates



It appears from the illustration that all the 1995 production figures are conservative estimates, but that they approximate the actual figure. Thus, the production forecast made in the beginning of 1995 only deviates 1% from the actual figure.

Thus, the historical data indicate that the Danish Energy Agency's forecasts are generally conservative in nature.

There are two reasons why the forecasts have been conservative. One is that it was difficult to predict the production effect of using water injection. The other is the rapid development of the horizontal drilling technique, making it difficult to assess the production potential.

Outlook

Based on historical development, it would be natural to contemplate the outlook for the future according to the forecasts. Fig. 4.5 shows the historical expectations for future oil and condensate production.

The 1990 and 1992 forecasts indicated an almost constant production figure for the first ten years of the period covered by the forecast, viz. 7.5 and 10.5 million m^3, respectively, after which production was expected to decline.

According to the 1994 and 1995 production forecasts, production was expected to peak around the year 1999, the peak figures being 14 and 17 million m^3, respectively, after which production was expected to decline to about 5 million m^3 in the year 2010.

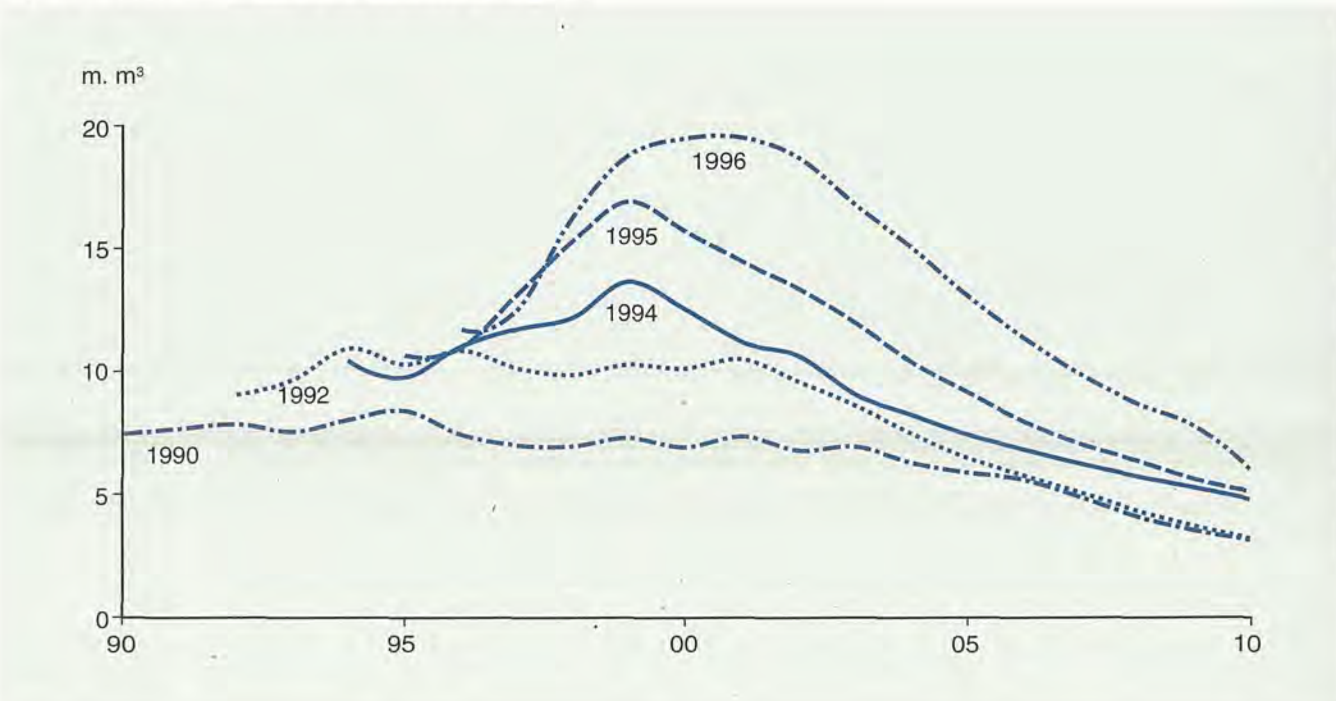
The Danish Energy Agency's most recent forecast estimates that production will peak at about 19 million m^3 around the year 2000, which means that, for a couple of years, production potential will be approx. double the present level. After the year 2001, production is expected to decline to about 6 million m^3 in 2010, which is almost half the current production potential. Thus, the forecast shows great variations within a period of only 15 years.

Therefore, it appears that expectations about the future production of oil have grown steadily over the past few years, and the most recent forecasts indicate increasing production figures. Peak production should be reached about five years after the commencement of the forecast period, after which production is expected to decline.

The increase in expected production figures made from year to year up to 1995 is due mainly to the further development of the fields, based on the use of the horizontal drilling technique and water injection. In contrast, the upward adjustment of reserves from 1995 to 1996 results mainly from the prospects of new discoveries.

Production forecasts are made by combining the forecasts for the individual fields. A fairly large degree of certainty attaches to some of these forecasts, while there is a great difference between the highest and lowest

Fig. 4.5 Forecasts Made in the Period 1990-1996



reserve estimate in other forecasts, which are therefore subject to great uncertainty.

When the estimates are uncertain for several major fields, the overall forecast will generally be subject to great uncertainty. This is the case for the Danish Energy Agency's most recent production forecast.

Based on the experience from previous forecasts, it is likely, however, that the most recent forecast will also prove conservative. There are several reasons for this. For one thing, the forecast does not include estimates of any new discoveries that may be made as a result of ongoing exploration activities.

For another, it must be expected that there is potential for further production if the efforts to improve oil recovery methods and equipment are carried on and intensified. However, it should be emphasized that it is possible that the forecast may prove overly optimistic.

5. Economy

Economic Assumptions

Crude Oil Prices and the Dollar Exchange Rate

The average international crude oil price (as quoted for Brent oil) in 1995 was USD 16.99 per barrel as compared to USD 15.81 per barrel in 1994, equal to a 7.5% increase.

From January to May 1995, the crude oil price increased from USD 16.59 per barrel to USD 18.32 per barrel. However, in the summer of 1995, oil prices declined, averaging USD 15.78 in July. The decline in prices is attributable to several factors. Among others, oil production from the North Sea was much larger than expected, and the growth in demand did not meet market expectations.

The cold weather towards the end of the year reversed this downward trend, with the oil price ending at USD 17.80 per barrel in December 1995.

The USD exchange rate declined over the first four months of the year from DKK 6.04 per USD in January to DKK 5.44 per USD in April. From April and onwards, the exchange rate fluctuated around DKK 5.50 per USD. For the year as a whole, the average USD exchange rate was DKK 5.60 per USD against DKK 6.35 per USD in 1994. Thus, overall, the USD exchange rate dropped by 11.8%.

Fig. 5.1 Oil Price and Dollar Exchange Rate, 1995

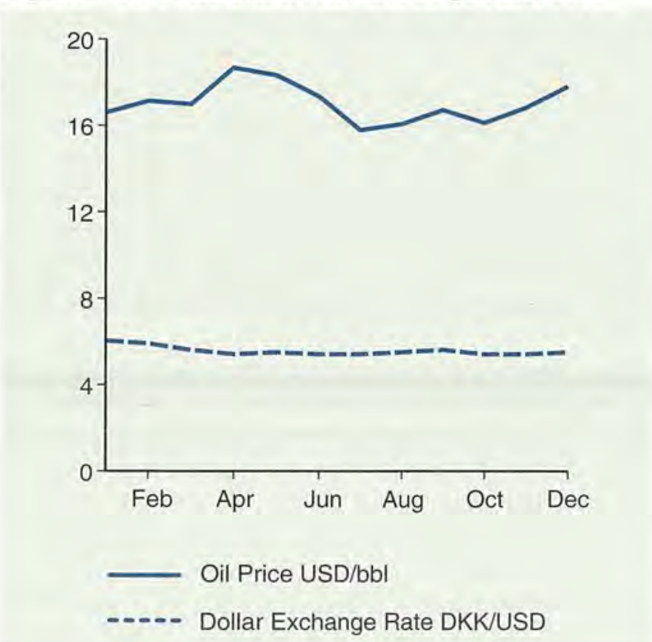
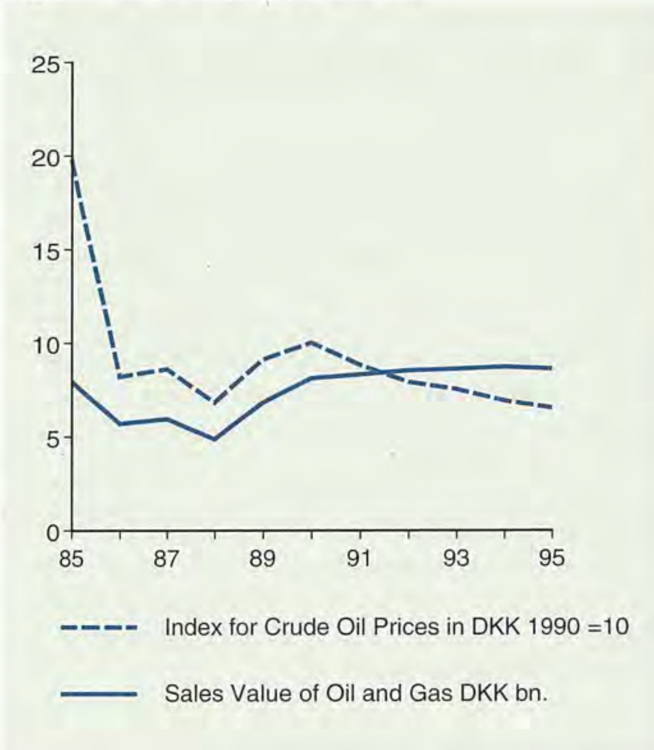


Fig. 5.2 Sales Value of Oil and Gas



The development in oil prices and the dollar exchange rate in 1995 appears from Fig. 5.1.

Future Oil Prices

This report does not contain an actual forecast of future crude oil prices, in that great uncertainty attaches to such forecasts. Instead, two different crude oil price scenarios have been used. One scenario assumes a constant price in real terms of USD 17 per barrel (corresponding to the average price for 1995), and the other operates with a linear increase in oil prices from USD 19 per barrel in 1996 to USD 28 per barrel in 2005, after which the price is assumed to be constant in real terms. The high and the low price scenarios will be used as a basis for calculations made later in this section. In the calculations, the expected prices of natural gas and selected oil products have been based on the assumptions stated with respect to the development in the price of crude oil.

Sales Value of Danish Oil and Gas Production

Despite the decline in oil prices since the Gulf crisis in 1990/91, the sales value of Danish oil and gas production has risen in recent years. Nevertheless, the sales value deteriorated slightly in 1995. Thus, the sales value of oil decreased from DKK 6,709 million in 1994 to DKK 6,455 million in 1995, while the sales value of natural gas went up from DKK 2,000 million to DKK 2,189 million.

This deterioration in value in the total sales value of oil and gas was caused by the above-mentioned decline in the USD exchange rate. In 1995, oil and gas production continued the climb from previous years, although in a more restrained form.

As mentioned in the section on *Reserves,* the Danish Energy Agency expects a considerable increase in oil and natural gas production in the years to come. Accordingly, the forecast as at January 1, 1996, shows that oil production will increase from 10.79 million m^3 in 1995 to 13.84 million m^3 in 1998. Likewise, due to the contracts made between Dansk Naturgas AS and DUC, a pronounced increase will be recorded in gas production over the next few years.

Fig. 5.2 shows the development in the value of the oil produced and the natural gas sold. Based on the production forecasts, the sales value of oil and natural gas is expected to continue rising in future, based on the assumption of constant prices.

Denmark's Energy Balance

Degrees of Self-Sufficiency

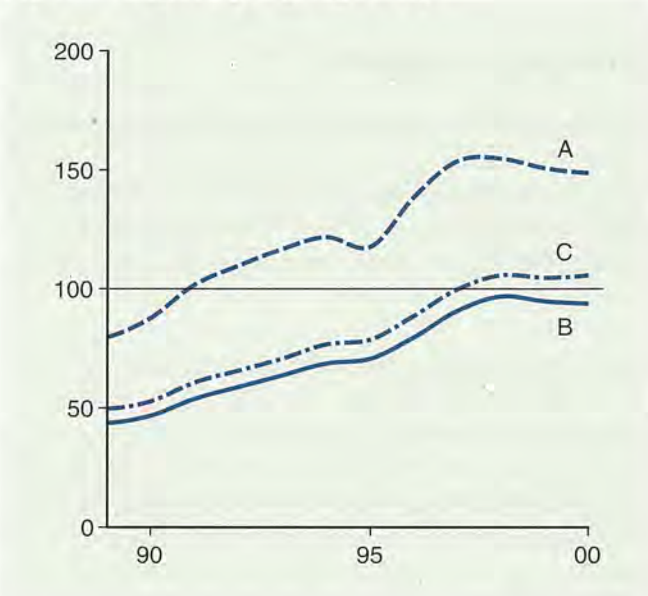
Due to many years of steady growth in oil and gas production, the degree of self-sufficiency has continued to rise. Likewise, total oil and natural gas production con-

Tabel 5.1 Production and Consumption

	1996	1997	1998	1999	2000
Production					
Crude Oil					
m toe	10.30	10.99	12.11	11.21	10.87
m m^3	11.77	12.56	13.84	12.81	12.42
Natural Gas					
m toe	5.54	6.99	7.06	7.65	7.74
m Nm^3	5.85	7.45	7.52	8.15	8.25
Of which					
Sales Gas	5.40	6.87	6.81	7.40	7.50
Consump. Offshore	0.45	0.58	0.71	0.75	0.75
Renewable Energy					
m toe	1.74	1.81	1.85	1.89	2.27
Total Energy Consumption *)					
m toe	19.63	19.81	19.77	19.68	19.69
PJ	822	829	828	824	825
Degree of Self-Sufficiency %					
A)	139	154	155	151	149
B)	80	91	97	95	94
C)	89	100	106	105	106

*) Including Fuel Consumption Offshore
A) Oil and gas production vs domestic oil and gas consumption
B) Oil and gas production vs total domestic energy consumption
C) Total energy production vs total domestic energy consumption

Fig. 5.3 Degrees of Self-Sufficiency



tinues to increase relative to total energy consumption. The highly favourable development in the degrees of self-sufficiency is expected to be sustained in future years.

Fig. 5.3, Table 5.1 and Appendix F1 show the development in self-sufficiency based on three different methods: The expected production of hydrocarbons is correlated to expected domestic hydrocarbon consumption (A) and to total domestic energy consumption (B). Finally, the degree of self-sufficiency is calculated by correlating total domestic energy production - including renewables - to total domestic energy consumption (C).

Only minor changes have been made in the expectations of degrees of self-sufficiency. The degrees of self-sufficiency for 1996 have been written up, due mainly to the markup of oil production for 1996. Towards the end of the period, oil reserves are estimated to decline, resulting in diminishing degrees of self-sufficiency in 1999 compared to last year's forecast (see the section on *Reserves*). It should be noted that the Danish Energy Agency's projection of consumption figures from March 1995 is being revised, which will presumably affect the expected degrees of self-sufficiency.

Already in 1991, Denmark achieved a 100% degree of self-sufficiency in hydrocarbons (A). The degree of self-sufficiency is expected to increase even further in the years to come and to reach 155% in 1998. This expectation is based in particular on the assessment of future oil production, which is expected to peak in 1998. Even though the degree of self-sufficiency in oil is more than 100%, this does not mean that Denmark is a net exporter of all oil products. In the past, Denmark has been a net importer of petrol products and aviation fuel. However, following an expansion of refinery capacity in 1995, Denmark is expected to become a net exporter of petrol products in 1996.

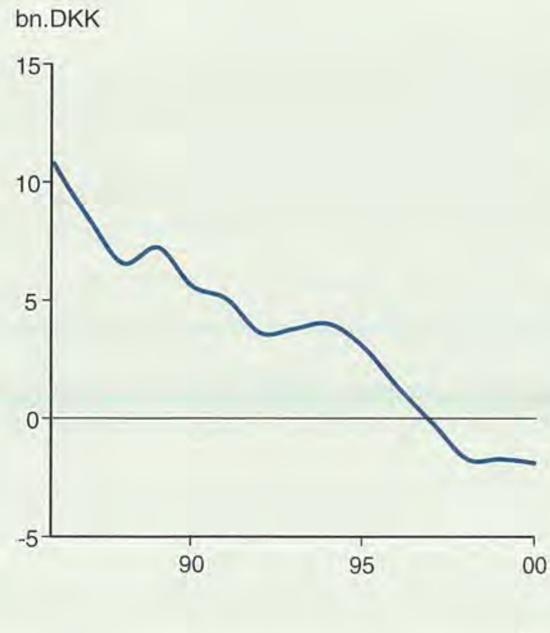
Based on the current oil and gas production forecasts, the supply situation is expected to be so favourable in 1997/98 that the overall production of oil, natural gas and renewable energy will exceed Denmark's total energy consumption. However, in light of current expectations for oil and gas reserves, this situation is estimated to last for a fairly short period if no new discoveries are made.

Net Foreign-Currency Expenditure

The net foreign-currency expenditure has been calculated in terms of its immediate effect on energy product items in the balance of trade. The calculation does not take into account the cost of imports for field developments and the transfer of dividends, etc. abroad.

It appears from Fig. 5.4 that there has been a marked decline in the net foreign-currency expenditure over the past ten years. Before oil prices plummeted in 1985, the net foreign-currency expenditure on energy thus exceeded DKK 20 billion. When disregarding the brief recovery of oil prices resulting from the Gulf War, oil prices

Fig. 5.4 Net Foreign-Currency Expenditure on Energy Imports



Tabel 5.2 Effect of Oil/Gas Activities on the Balance of Payments, DKK billion, 1995 Prices, Increasing Real Oil Prices

	1996	1997	1998	1999	2000
Socio-Economic Production Value	11.3	14.4	17.1	17.5	18.6
Import Share	4.8	4.5	2.8	2.9	1.3
Balance of Goods and Services	6.5	9.9	14.3	14.6	17.3
Transfer of Interest and Dividends	3.9	5.8	6.8	6.0	6.0
Balance of Payments Current Account	2.6	4.1	7.5	8.5	11.3
At constant oil prices (USD 17/bbl)	2.0	2.7	5.3	5.8	7.9

gradually declined until 1994. Combined with increased Danish production, this development results in an estimated net foreign-currency expenditure on energy of about DKK 3 billion in 1995.

The Danish Energy Agency has calculated the net foreign-currency expenditure for the period 1996-2000 on the basis of the assumptions stated in Table 5.1 with respect to the development in the gross consumption of energy and in the production of oil and gas. Based on the current estimates of consumption and the scenario with increasing crude oil prices, as outlined above, the calculations show net earnings from energy exports as from 1997. These net earnings are anticipated to rise further in the following years. The development will be less conspicuous based on a constant oil price scenario. Historical net foreign-currency expenditure is shown in Appendix F2.

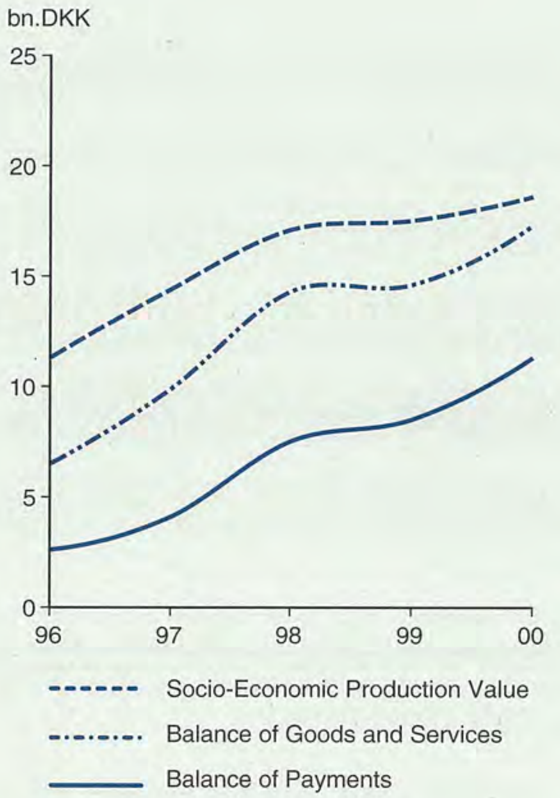
Effect on Balance of Payments

As in previous years, the future direct effect of Danish oil and gas production on the balance of payments has been estimated in order to supplement the calculations of net foreign-currency expenditure on energy, which is affected by energy prices as well as Danish production.

Denmark's increased oil and gas production in recent years has favourably affected the balance of payments on current account. This trend is expected to become more pronounced in the years to come.

The production of oil and natural gas improves the balance of payments, due partly to the direct earnings

Fig. 5.5 Effect of Oil/Gas Activities on the Balance of Payments



derived from exporting part of the production, and partly to the foreign-currency expenditure saved, in that a share of production is used for domestic consumption, thus eliminating the need for energy imports otherwise required. Accordingly, the development in the socio-economic value of production shown in Fig. 5.5 and Table 5.2 reflects the value of direct export revenue and the cost of imports saved.

When the import share of investments and operating costs is subtracted, the effect on the balance of goods and services results. In turn, the direct effect on the balance of payments on current account can be calculated when interest and dividends transferred abroad are deducted.

The effect on the balance of payments is very sensitive to fluctuations in the price of crude oil. The calculations based on increasing real prices show that the direct net effect on the balance of payments increases to about DKK 11 billion in the year 2000. In the scenario based on a constant price of USD 17 per barrel, the net effect on the balance of payments will be about DKK 8 billion in 2000.

Tabel 5.3 DUC's Investments in Development Projects, DKK million, Nominal Prices

	1991	1992	1993	1994	1995*)
Dan	915	1,244	1,081	412	526
Kraka	87	97	79	175	3
Regnar	-	21	168	1	-
Gorm	409	411	722	516	632
Skjold	297	196	453	556	265
Rolf	50	-	-	-	-
Dagmar	77	2	-	-	-
Tyra	274	372	380	1,158	1,449
Valdemar	21	27	375	106	1
Roar	12	1	2	25	289
Svend	51	-11	5	55	200
Harald	5	-4	6	149	810
Not allocated	62	46	88	-14	9
Total	**2,260**	**2,402**	**3,358**	**3,140**	**4,184**

*) Estimate

The Finances of the Licensees

Costs of Exploration, Development and Operation

Since the end of the 1980s, investments in the North Sea have shown an upward trend, which is also reflected by the development in oil and gas production.

Tabel 5.4 Investments in Development Projects, DKK billion, 1995 Prices

	1996	1997	1998	1999	2000
Ongoing and Approved					
Dan	2.1	1.3	0.9	1.0	-
Igor	-	-	-	0.3	-
Gorm	0.2	0.1	-	-	-
Skjold	0.1	-	-	-	-
Tyra	1.0	0.8	0.3	0.8	0.7
Valdemar	0.1	0.1	-	-	-
Svend	0.1	0.3	-	-	-
Roar	0.2	0.1	-	-	-
Adda	-	0.2	-	-	-
Elly	-	0.4	0.4	-	-
Harald	1.2	1.3	0.6	-	-
Total	**5.0**	**4.6**	**2.2**	**2.1**	**0.7**
Planned	0.2	0.2	0.5	0.9	-
Expected	0.2	0.3	0.3	0.2	0.1
Expected, total	**5.4**	**5.1**	**3.0**	**3.2**	**0.8**

In 1995, investments amounted to about DKK 4.2 billion, which is a 33% increase compared to the year before. Vast expenditure (about DKK 1.4 billion) was incurred in the development of the Tyra Field in order to increase gas supplies as a consequence of the gas sales contract concluded between Dansk Naturgas A/S and DUC in 1993. Further, major expenses were involved in the development of the Harald Field, expected to be brought on stream in 1997. The activities carried on in the individual fields in 1995 are described in more detail in the section on *Production.*

In the years to come, the current trend of investment activity is expected to continue. It is estimated that investments in 1996 will reach a level of about DKK 5 billion. As in 1995, the high 1996 investment level is attributable to the ongoing development of the Dan, Tyra and Harald Fields. In 1997 and 1998, the principal activities are expected to centre around the Dan and Harald field developments. In addition, investments are anticipated to be made in new fields to be brought on stream towards the end of this decade.

Moreover, the Danish Energy Agency envisages that there is additional potential for developments and further developments of a number of fields, which will also affect the investment level in the years to come. A case in point is the future development of the Siri discovery, made by the Statoil group in December 1995 (see the section on *Exploration*).

Fig. 5.6 Costs of Exploration, DKK million, Nominal Prices

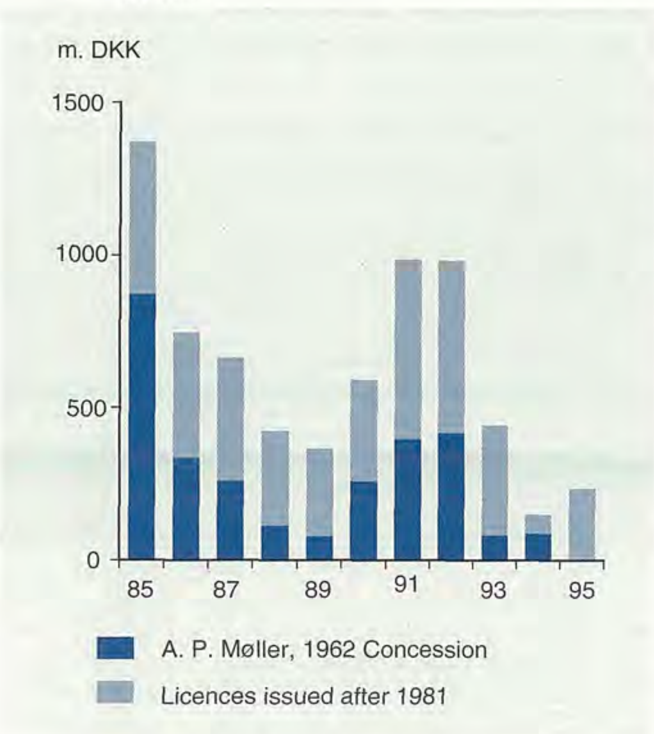
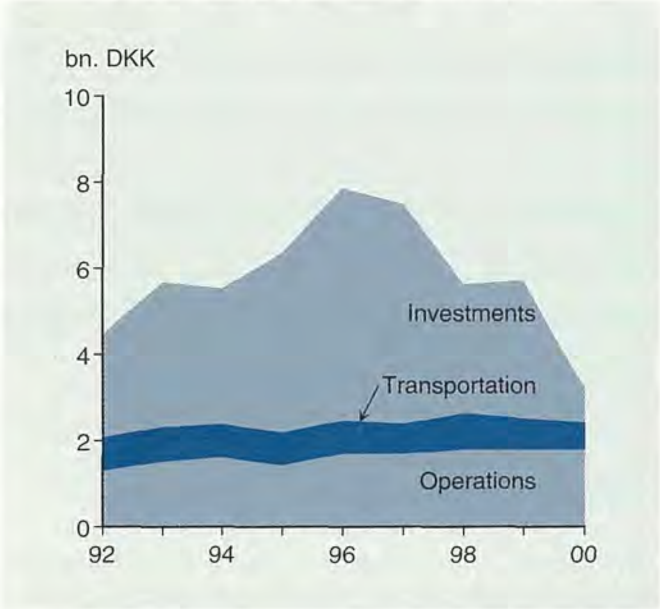


Fig. 5.7 Investments in Fields, Operations and Transportation, DKK billion, Nominal Prices



Historical investments are shown by field in Table 5.3, while future expected investments are shown in Table 5.4.

Exploration activity intensified in 1995 as a result of the new licences granted in the Fourth Licensing Round. A further increase in activity is also expected in future, both as a consequence of the work programmes to be completed under the licences from the Fourth Licensing Round, and due to the Danish Energy Agency's expectation for the Siri discovery to have a spillover effect on activities. Based on the current work programmes, exploration expenditure is estimated to fluctuate between about DKK 300 and 400 million per year for the next few years. Fig. 5.6 shows the development in exploration costs over the past ten years.

The costs of administering and operating oil and gas production facilities have remained at a fairly constant level in the past few years, viz. about DKK 1.5 billion annually. In light of the ongoing, approved and planned investments, an increase in operating costs is expected.

With regard to transportation costs, the payments towards the capital cost and operating costs of the oil pipeline have declined slightly, while payments of the profit element in the transportation fee have gone up as a result of the increase in oil production, among other things. The capital cost is expected to fall in future years, while operating costs will presumably remain almost unchanged. Further, payments of the profit element are expected to increase. Fig. 5.7 shows the historical development in investments, operating costs and transportation costs, as well as the costs projected for the future.

Tabel 5.5 Pretax Results of the DUC Companies, DKK million, Nominal Prices

	1989	1990	1991	1992	1993	1994
Income	6,716	7,692	8,446	8,468	8,741	8,723
Op. Costs *)	1,654	1,858	2,070	2,023	2,299	2,209
Interest Exp.	680	234	336	267	297	314
Exc.-Rate Adj.	+85	+282	-182	-167	-408	632
Gross Income	4,468	5,882	5,858	6,011	5,737	6,833
Depreciation	1,553	1,600	2,373	2,126	2,386	2,716
Pretax Result	**2,915**	**4,282**	**3,485**	**3,885**	**3,351**	**4,117**

*) incl. Transportation Costs and Exploration Costs charged to expense

Tabel 5.6 State Revenue from Oil/Gas Production, DKK million, Nominal Prices

	1991	1992	1993	1994	1995*)
Hydrocarbon Tax	0	0	0	0	0
Corporate Tax	990	1,000	866	1,106	1,138
Royalty	639	666	664	670	667
Profit Element	264	274	277	281	271
Total	**1,893**	**1,940**	**1,807**	**2,057**	**2,076**

*) Estimate

Financial Results of the DUC Companies

The financial results recorded by the DUC companies on oil and gas production activities are affected by several variables. The development in oil and gas production in particular, which is largely determined by the investment level, as well as the trend of oil and gas prices and the dollar exchange rate, have a major impact on the companies' financial results and taxable income.

Since being awarded the Sole Concession in 1962, DUC has incurred exploration costs of about DKK 7.5 billion, development costs of about DKK 35 billion and operating and transportation costs (including payments of the profit element) of about DKK 25 billion. At the same time, DUC has recorded income of about DKK 100 billion. Total state taxes and duties paid (including payments of the profit element) amount to about DKK 20 billion. The above amounts are expressed in current Danish kroner.

The increased value of production and the growth in investments in recent years are reflected by DUC's pretax results. It appears from Table 5.5 that income and depreciation have increased somewhat, and that the pretax result for 1994 exceeded that recorded in previous years.

State Revenue

The state revenue derived from oil and gas production consists of four elements: *corporate tax, royalty, the oil pipeline tariff associated with the transportation of oil,* and *hydrocarbon tax.*

Corporate tax and hydrocarbon tax are assessed and collected by the Danish Ministry of Taxation, Central Customs and Tax Administration. The assessment and collection of royalty and the oil pipeline tariff are handled by the Danish Energy Agency.

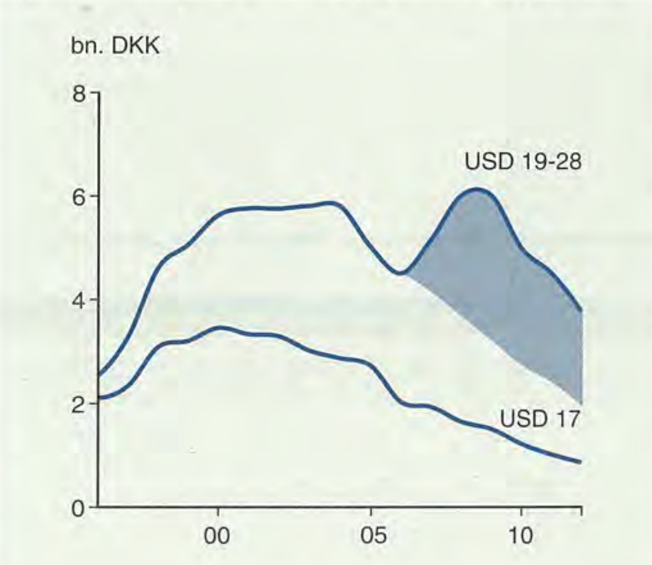
The total income from oil and gas production activities has remained at a level of about DKK 2 billion in recent years, but is expected to increase in the years ahead. Based on a constant oil price scenario, total income is estimated to be in the DKK 3.5 billion range around the year 2000. Based on an increasing price scenario, the total income level will rise to about DKK 5-6 billion.

The historical figures for state revenue are indicated in Table 5.6, while the revenue expected for the future is shown by Table 5.7. The future revenue derives from DUC's activities only. Towards the end of the 1990s, revenue is also expected from a few fields which are held by licensees other than DUC.

Corporate tax

The DUC companies did not become liable to pay corporate tax until the beginning of the 1980s. At end-1995, state revenue from corporate tax payments totalled about DKK 8.5 billion in nominal prices. In recent years, the corporate tax paid has amounted to about DKK 1 billion a year. As mentioned above, income from production is

Fig. 5.8 Taxes and Duties, DKK billion, 1995 Prices



*Tabel 5.7 Expected State Revenue from Oil/Gas Production, DKK billion, 1995 Prices *)*

	1996	1997	1998	1999	2000
Hydrocarbon Tax	0.0 (0.0)	0.0 (0.0)	0.0 (0.0)	0.0 (0.0)	0.0 (0.0)
Corporate Tax	1.3 (1.0)	1.7 (1.0)	2.7 (1.6)	3.1 (1.7)	3.6 (2.0)
Royalty	0.9 (0.8)	1.1 (0.9)	1.4 (1.0)	1.4 (1.0)	1.4 (1.0)
Profit Element	0.4 (0.3)	0.4 (0.4)	0.5 (0.4)	0.5 (0.4)	0.5 (0.4)
Total	**2.6 (2.1)**	**3.2 (2.3)**	**4.6 (3.0)**	**5.0 (3.1)**	**5.5 (3.4)**

*) Assessed amounts
( ) Based on constant oil prices

anticipated to increase sharply in future years. As a result, corporate tax payments are estimated to increase.

Hydrocarbon tax
Hydrocarbon tax was introduced by a Parliamentary Act in 1982. The objective of the Act was to levy a special tax on high profits, e.g. attributable to high oil prices. Hydrocarbon tax only became payable for a few years at the beginning of the 1980s, with total hydrocarbon tax payments amounting to less than DKK 1 billion. In light of the investments and prices expected for the next few years, it must be considered unlikely that hydrocarbon tax can be levied. In the longer term, hydrocarbon tax will become payable in case of a high oil price scenario. Fig. 5.8 shows the expected development in the hydrocarbon tax levied in the case of a high and a low price scenario.

The oil pipeline tariff
The users of the oil pipeline are obliged to pay the costs relating to its operation. In addition, the transportation fee incorporates a profit element of 5% of the value of the crude oil transported. The owner of the pipeline, Dansk Olierør A/S, pays an annual tax to the state, below referred to as the oil pipeline tariff. In recent years, this pipeline tariff has constituted 95% of the income from the 5% profit element. Up to and including 1995, the pipeline tariff payable by Dansk Olierør A/S yielded about DKK 3 billion in revenue for the state. Thus, the proceeds from the profit element depend on the amount of oil transported and the price of oil. In the past few years, the increase in the amount transported has more than outweighed the decline in oil prices. Assuming that no changes are made in the tariff payable to the state, state revenue is expected to increase in future years, provided that oil prices do not drop.

Royalty
Royalty is currently only paid by DUC. The royalty payable by DUC is levied as 8.5% of the value of oil and gas produced, after deducting the cost of transporting the oil. Since 1972, total royalties of DKK 7.5 billion have been paid. For several years now, the amounts of royalty paid have amounted to more than DKK 0.5 billion. As is the case for the oil pipeline tariff, the Danish Energy Agency expects the revenue derived from royalty to increase in the years to come due to the anticipated growth in oil and gas production.

Metering Oil and Gas Production

In order to ensure a correct assessment of the various taxes and duties, the amount of oil and gas produced is metered according to specific guidelines.

The total amount of gas produced is metered at Tyra East and at Dansk Olierør A/S's terminal facilities in Fredericia in connection with the lifting of the oil. The figures obtained upon metering sold gas at Tyra East are used as a basis for calculating the royalty payable. Likewise, the amounts of oil metered upon lifting from Fredericia are used to calculate royalty and the profit element of the transportation fee.

Further, the allocation of production to individual fields is made on the basis of measurements at the individual processing centres and test separator measurements for each well.

6. Safety and Health

The Danish Energy Agency supervises safety, health and environmental matters in connection with the exploration and production of oil and natural gas in the Danish part of the North Sea.

The more maritime aspects of safety supervision are handled by the Danish Maritime Authority, especially such matters as concern the design, strength, buoyancy, layout and maritime equipment of mobile offshore installations, and matters concerning the life-saving equipment, etc. on fixed offshore installations.

The National Agency of Environmental Protection handles the environmental aspects of the supervision relating to emergency preparedness in case of pollution of the sea from offshore operations, and also monitors discharges into the sea of substances and materials from offshore installations.

Environmental matters are dealt with in a separate section of the report entitled *Environment.*

Fixed Offshore Installations

Preparing the field developments in the Northern Area and establishing the necessary infrastructure meant that 1995 was characterized by major development activities, in particular in the Tyra Field, which is central to the development of the northern fields. In addition, development activities in a number of the other producing fields have continued.

Thus, large-scale installation works have been carried out in the Gorm, Skjold, Tyra and the Svend and Roar Fields. In the Gorm and Tyra Fields, new modules for expanding existing processing facilities have been installed. Completely new production facilities have been installed in the Roar and Svend Fields, which will be brought on stream in 1996. Drilling operations were carried out in all the above-mentioned fields in 1995.

The installation works also include the laying of a total of 100 km of pipelines for transporting oil and gas between the individual platforms in the North Sea.

Accordingly, the Svend platform was connected to Tyra East by a 16" pipeline having a length of 65 km. In 1996, this will be extended by an 18 km pipeline hooking up Svend with the Harald Field. In the immediate vicinity of the respective platforms, the pipeline - as the first in Danish territory - is provided with subsea safety valves, which means that the pipeline flow can be interrupted in case of an accident or emergency. This was done to comply with one of the recommendations made in the *Lord Cullen* report from 1990, which was prepared following the explosion on the UK production platform, *Piper Alpha,* in 1988.

The Roar platform has been connected to Tyra East by three pipelines, having an extension of 11 km each: a 16" gas pipeline and an 8" condensate pipeline, to which a $2^{1}/_{2}$" glycol pipeline has been connected.

In addition, a 10" pipeline has been laid for internal transport of injection gas between Tyra East and West.

The work of installing the above-mentioned pipeline facilities commenced in March and was completed in November 1995.

Further, the safety and environmental aspects of the development plans for a number of fields, including Dan, Elly, Alma and Valdemar, were dealt with; see the section on *Production.*

In connection with the implementation of development plans approved in recent years, the Danish Energy Agency subsequently considered and approved several applications for building and installation permits, and also issued permissions for use.

Here, as in previous years, the Danish Energy Agency has focused in particular on the safety aspects of the individual installations, which are documented in the safety assessments submitted, as well as on company safety management systems. The Danish Energy Agency has also continued its efforts to ensure a satisfactory working environment on the new fixed offshore installations, placing particular emphasis on reducing noise levels.

Mobile Offshore Installations

The implementation of the large-scale installation works in the above-mentioned fields in 1995, as in previous years, involved a number of mobile offshore installations in the North Sea, such as drilling rigs, pipe-laying barges, flotels and crane vessels.

Thus, Mærsk Olie og Gas AS employed four drilling rigs to drill a number of production wells, two owned by A. P. Møller, viz. the *Maersk Exerter* and *Mærsk Endeavour,* the *Shelf Explorer* contracted from the UK company, Transocean Drilling Ltd., and the *Neddrill 10* from the Dutch company, Neddrill.

Moreover, at the end of 1995, Statoil Efterforskning og Produktion A/S drilled the exploration well Siri-1 with the drilling rig *Deepsea Bergen,* contracted from the Norwegian company Odfjell Drilling and Consulting Co. A/S.

The pipe-laying barge *Lorelay* (Allseas) was also employed to lay the above-mentioned pipelines.

The lifting operations associated with installation works in the Gorm, Tyra, Svend and Roar Fields were carried out by the crane barge *DB 102,* contracted from Heeremac, a Dutch company.

Throughout 1995, the development activities necessitated an increase in the manpower offshore. In this connection, Mærsk Olie og Gas AS employed two accommodation platforms, viz. A.P. Møller's *Mærsk Explorer* and the *Neddrill Kolskaya,* contracted from the Dutch company Neddrill.

In cooperation with the Danish Maritime Authority, the Danish Energy Agency issued permissions for use for the various drilling rigs and vessels, and approved manning tables and organizational charts for the individual installations. This involved granting a five-year permission to use the drilling rig *Maersk Exerter.* Further, the Danish Energy Agency routinely supervised the operation of the individual mobile installations with respect to safety and working environment aspects.

In addition to the layout of living quarters on mobile offshore installations, which were upgraded substantially in several instances, noise and the use of chemicals were the primary issues considered. On the pipe-laying barges, attention was focused mainly on working conditions for welding pipes together. The ventilation and extraction of welding fumes on the barges were improved, following a demand made in this respect by the Danish Energy Agency.

In 1995, the pipe-laying barge *Stena Apache* (contracted from Coflexip Stena Offshore, formerly Stena Offshore) was granted a five-year permission for use on the Danish continental shelf, following substantial upgrading of accommodation facilities and an improvement in safety and health conditions. The barge is expected to carry out work in the Danish sector in 1996.

New Regulations

As before, new regulations within the oil and gas sector were drafted in cooperation with representatives from the industry serving on the Coordination Committee, a committee appointed pursuant to the Danish Act on Certain Marine Installations.

In 1995, the Danish Energy Agency issued Executive Order No. 76 of February 1, 1995 on numerically coded products on fixed offshore installations. A corresponding Executive Order for mobile offshore installations is being prepared.

In addition, in 1995, the Danish Energy Agency prepared a number of Executive Orders, e.g. to implement various EU Directives. The following Executive Orders were issued at the beginning of 1996:

- Executive Order No. 64 of February 7, 1996 on substances and materials used on offshore installations.
- Executive Order No. 127 of March 6, 1996 on the performance of work, etc. on offshore installations.
- Executive Order No. 128 of March 6, 1996 on the layout of places of work, etc. on offshore installations.

Notification of Industrial Injuries

The 1995 statistics on reported industrial injuries offshore fall into two categories: statistics of work-related accidents reported and statistics of presumed or recognized work-induced conditions reported.

Fig. 6.1 Work-Related Accidents

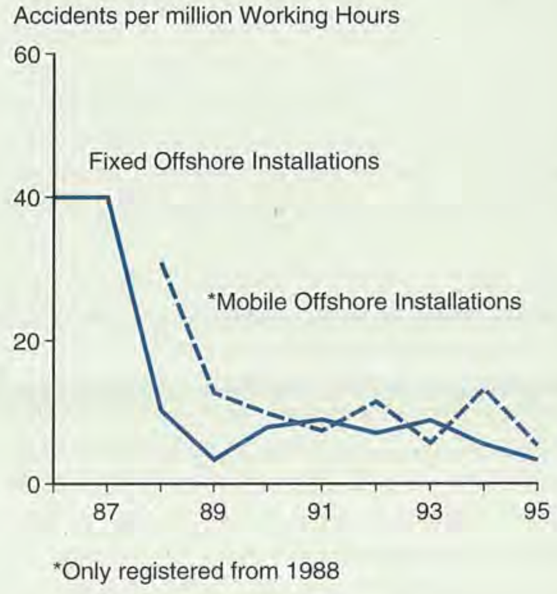


Table 6.1 Accidents per million Working Hours

Year	Fixed	Mobile
1988	10.3	31.0
1989	3.4	12.7
1990	7.9	9.9
1991	9.0	7.4
1992	7.1	11.5
1993	8.9	5.7
1994	*5.5	13.2
1995	3.3	5.3

* Altered in relation to the figure stated in *Oil and Gas Production in Denmark 1994.*

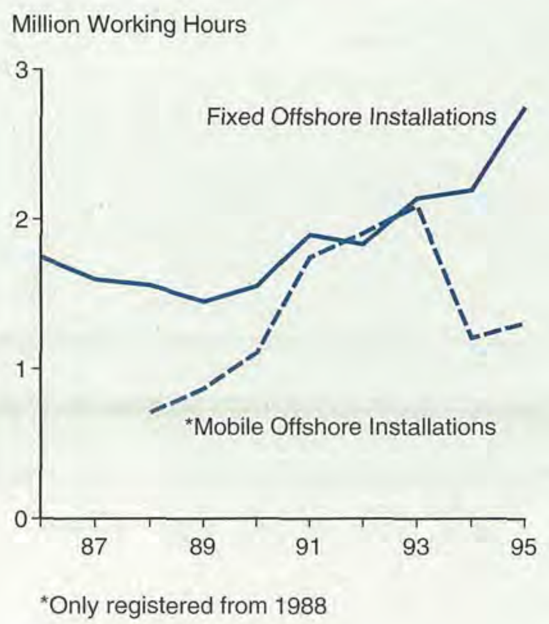
Work-Related Accidents

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

In 1995, the Danish Energy Agency received 16 reports on accidents offshore, broken down as nine accidents on fixed offshore installations together with flotels, and seven on other mobile offshore installations.

None of the accidents resulted in death or serious personal injury.

Fig. 6.2 Number of Working Hours on Offshore Installations



When the nine reported work-related accidents on fixed offshore installations are related to the number of hours worked (2.8 million hrs.), it yields an accident frequency of 3.3 per million working hours. Moreover, when the seven work-related accidents on mobile offshore installations, excluding flotels, reported in 1995 are related to the number of hours worked on these installations (1.3 million hrs.), it yields an accident frequency of 5.3 per million working hours.

The number of working hours is calculated on the basis of information received from the companies and the person-on-board lists, based on an average workday of 13 hours.

Table 6.1 and Fig. 6.2 show the accident frequency for each year in the period from 1988 to 1995 for mobile and fixed offshore installations, together with flotels. The figures shown comprise accidents related to all work functions, including the operation of the above-mentioned facilities and installation works performed on them.

It appears from the above-mentioned statistics that the low accident frequency of previous years has been maintained for both fixed and mobile offshore installations.

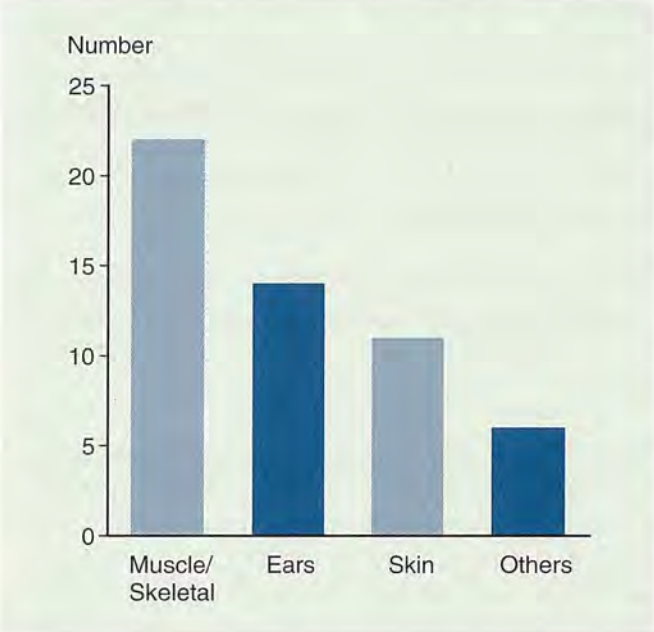
By way of comparison, the accident frequency for Danish onshore industries since 1988 hovered around 50 per million working hours. In 1994, the accident frequency for onshore industries was 51.7 per million working hours. *(The Danish Employers' Confederation, Work-Related Accidents 1994).*

Fig. 6.2 shows the number of working hours on fixed and mobile offshore installations in the North Sea. The number of hours worked on mobile offshore installations increased somewhat in 1995 as compared to 1994. For fixed offshore installations, the number of working hours increased in 1995 by about 25% in relation to the number of working hours in 1994, and by about 50% as compared to 1992. This is due mainly to the major

Table 6.3 Number of Presumed or Recognized Work-Induced Conditions Reported

Diagnosis	1993	1994	1995
Muscle-skeletal conditions	1	1	2
Ear conditions	2	1	0
Skin diseases	1	0	0
Other conditions	2	0	0
Total	**6**	**2**	**2**

Fig. 6.3 Number of Presumed or Recognized Work-Induced Conditions Reported, 1985-95



installation and construction works made necessary by the field developments in progress in the Northern Area of the Danish sector.

Presumed or Recognized Work-Induced Conditions

If a doctor suspects or ascertains that a condition has been induced by work on offshore installations, the Danish Energy Agency must be notified.

Since 1993, the Danish Energy Agency has been notified of ten presumed or recognized work-induced conditions. These conditions are distributed on the following main diagnostic groups: *muscle-skeletal conditions, ear conditions, skin diseases* and *other conditions.* Muscle-skeletal conditions denote conditions in the back, shoulders, arms or legs.

Table 6.3 illustrates the distribution on diagnostic groups of the conditions reported in the years 1993, 1994 and 1995, while Fig. 6.3 shows the distribution in the period from 1985 to 1995.

Not all of the notifications received can be attributed directly to fixed or mobile offshore installations. Consequently, the table below shows injuries sustained or suspected on both fixed and mobile offshore installations.

International Cooperation

As part of the cooperation carried out in 1995 with the supervisory authorities from other countries in the North Sea area on safety and working environment matters, the Danish Energy Agency held the usual, annual meetings with supervisory authorities from the individual countries. In addition, the Danish Energy Agency participated in cooperation within the North Sea Offshore Authorities Forum (NSOAF) on safety training and safety assessments. The Danish Energy Agency held the chairmanship of NSOAF in 1995, and thus hosted the annual meeting in May 1995.

The Danish Energy Agency also continued its work under the auspices of the Safety and Health Commission for the Mining and Other Extractive Industries under the EU Commission (SHCMOEI).

In environmental matters, the Danish Energy Agency, in cooperation with the National Agency of Environmental Protection, participated in the Paris/Oslo Commission's Offshore Forum (GOP).

7. Environment

Environmental considerations have had an increasing impact on society in recent years. This has also led to more focus on protecting the environment in connection with the award of licences and the location, design and operation of offshore installations.

The increased interest in the environmental aspect of activities in the North Sea is not exclusive to Denmark. Internationally, increasing interest in controlling the marine environment has been shown in the past few years, and consequently in limiting the environmental impact of offshore installations.

In Denmark, the environmental matters relating to offshore installations are regulated primarily by the Act on the Marine Environment and the Act on Certain Marine Installations. Danish legislation imposes obligations on both the National Agency of Environmental Protection and the Danish Energy Agency for protection of the environment.

The obligations of the National Agency of Environmental Protection relate primarily to discharges from platforms and their effect on the surrounding environment, as well as the preparedness to contain oil spills. The obligations of the Danish Energy Agency relate mainly to the design, equipment and operation of platforms. Cooperation between the two agencies ensures coordinated efforts.

The Danish Energy Agency bases its approach on the premise that integrated protection of environmental and safety matters will optimize results in both areas.

In recent years, it has been considered increasingly important to limit any impact on the environment by ensuring that the companies involved use the most environmentally friendly technology and working methods available. In this context, the supervision activities will be targeted at the operators' assessment of the impact of the activity on the environment, and at their associated control procedures.

Reduction of CO_2 emissions

Large amounts of energy are used in the production and transportation of oil and natural gas, and it is also necessary to flare gas on offshore installations, to the extent that such gas cannot be utilized for safety or technical reasons. Therefore, offshore installations emit CO_2 in quantities that depend on the scope of production and geological and technical conditions related to the installations.

Many production facilities have been established relative to the size of Danish oil and gas production, which limits the possibilities for utilizing the energy effectively. Vast amounts of natural gas are produced, and transporting gas to shore consumes great amounts of energy. At the same time, Danish oil accumulations are found mainly in reservoirs with difficult production properties, meaning that the best method of extraction involves water injection or other techniques that require large amounts of energy.

The Danish Energy Plan, 'Energy 2000', set up the first objective for reducing CO_2 emissions from total Danish energy consumption, including energy production on offshore installations. However, the plan did not specify any targets for reducing CO_2 emissions on offshore installations.

In 1993, Denmark acceded to the Climate Convention, which encompasses all CO_2 emissions in the territories of the countries acceding to the Convention, and thus also emissions from the offshore sector, including the flaring of gas. Therefore, total emissions from the offshore sector were included in the Danish report for 1994 made under the Climate Convention.

In order to meet the objective set in 'Energy 2000' for reducing total Danish CO_2 emissions by 20% in the period 1988-2005, the increased use of natural gas plays a central role. Particularly the use of natural gas in local, combined heat and power stations has contributed to reducing Danish CO_2 emissions.

The large growth in natural gas sales and the increase in oil production stepped up CO_2 emissions from energy production in the North Sea from 0.8 million tonnes in 1988 to more than 1.1 million tonnes in 1993. The forecast prepared by the Danish Energy Agency on the basis of current development plans and expectations for future gas sales shows that CO_2 emissions are estimated to increase to 2.6 million tonnes by 1998.

Although these emissions are considerably lower than the reductions in CO_2 emissions achieved through increased gas sales onshore, the figure is nonetheless important in terms of meeting the target for limiting CO_2 emissions.

Therefore, it was decided in 1993 to map out the options available for reducing CO_2 emissions from the production facilities in the North Sea. Mærsk Olie og Gas AS, the operator for all producing Danish fields, submitted a report on energy and emissions of greenhouse gases at the turn of the year 1994/95. Based on this report, the Danish Energy Agency has embarked on a fact-finding mission for the purpose of evaluating the potential for reducing CO_2 emissions.

The preliminary conclusions drawn from this work show that efforts to reduce CO_2 emissions from production facilities in the North Sea should focus on fixed offshore installations. Mobile offshore installations only operate temporarily in Danish waters, thus accounting for a scant 10% of emissions.

As far as the fixed offshore installations are concerned, CO_2 emissions derive from three main sources: gas compression for transporting natural gas to shore, water and gas injection, which plays a central role in extracting oil, and gas flaring, which is done mainly for safety reasons.

In order to limit energy consumption, it is important for the methods and equipment used on the production facilities to be efficient in terms of energy consumption. These methods are upgraded constantly, and present-day technology is more energy-efficient in several areas than at the time the main Danish production facilities were established. However, the Danish Energy Agency does not consider major restructuring of the existing facilities to be technically or financially feasible.

However, it is expected that the offshore sector, like other Danish industries, will invest reasonable amounts in limiting emissions of greenhouse gases.

Thus, the most effective way to reduce CO_2 emissions, with due allowance given for the associated costs, is being considered. This objective must be accorded high priority when making decisions on any expansion or major reconstruction of existing facilities, or on new field developments.

One case in point is the ongoing development of the Dan Field. In connection with this project, it has been decided to use the opportunity to transfer some energy-intensive processes from the less efficient equipment on the old facilities to the new energy-efficient equipment. This change will help reduce the increase in CO_2 emissions that results from the major expansion of the Dan Field production capacity.

Assessment of Effects on the Environment

In connection with approving the design, construction, installation and commissioning of offshore installations, the protection of safety interests is taken into account, and this automatically involves a number of environmental aspects.

However, it follows from the EU Council Directive on the assessment of the effects of certain public and private projects on the environment that the member states are to ensure, prior to establishing specific installations defined in the Directive, that the environmental impact of such installations is evaluated and that the general public affected is heard.

The amendments to the Danish Subsoil Act in 1995 were made primarily for the purpose of implementing the Licensing Directive, but also implemented the *Council Directive on the assessment of effects on the environment,* in so far as offshore projects falling under the Danish Subsoil Act are concerned. The amendments became effective on July 1, 1995.

The Danish Energy Agency now intends to draft more specific regulations regarding environmental impact assessments, including requirements for the content and scope of the review that is to form the basis for an assessment, as well as regulations concerning the procedure for public hearings, etc. These regulations will be prepared in cooperation with the parties involved.

8. Research

Energy Research Programme 1996

The Energy Research Programme (ERP 96) is financed by funds provided for in the Danish Finance Act. In 1995, funding in the amount of DKK 120 million was granted for 70 projects. Of these, ten concerned research into subjects related to oil and natural gas, with budgeted costs totalling DKK 30 million. Actual funding in the amount of DKK 18 million was granted for these projects, equal to approx. 60% of the total amount budgeted.

The Danish Energy Agency has the administrative and professional responsibility for considering and evaluating project applications submitted. The Agency bases its undertakings to fund projects on an evaluation made in cooperation with the Advisory Oil and Natural Gas Research Committee.

As in past years, the principal criterion for funding is the importance of the projects to society and their relevance in terms of energy. Priority has been accorded to the following four areas of research: *exploration, recovery, equipment and installations* as well as *arctic oil and gas projects.*

Within these areas, high priority is given to the following studies:

- Finding reservoir rock in the Central Graben.
- Finding source rock outside the Central Graben.
- Improving the measuring technique for testing enhanced recovery methods.
- Proceeding with stochastic reservoir modelling.
- Optimizing design and equipment.
- Projects to catalyze the interest in exploration in Arctic areas.

In addition, funding was granted for projects to be undertaken in cooperation with Eastern European and developing countries. Emphasis was placed on projects that incorporate research and development activities that can be carried out and later used in cooperation with businesses and institutions in the countries in question.

International Relations

In recent years, the Danish Energy Agency has closely coordinated international energy research, both through its representation on international committees and by supporting the integration of national projects into major international projects.

Within the area of oil and natural gas, the most important cooperative activities relate to the Chalk Research Programme, the Nordic Energy Research Programme, the non-nuclear EU programmes *Joule* and *Thermie,* as well as the IOR cooperation under the auspices of the International Energy Agency (IEA).

Chalk Research Programme

This research programme was started in 1982 on the initiative of Norwegian and Danish authorities. The objective is to solve the special problems associated with recovery from chalk formations. The expenses for the programme are shared between seven oil companies carrying on production in the North Sea, including Mærsk Olie og Gas AS.

The programme has been implemented in four phases. The fourth phase, which was initiated in 1994, is expected to be completed by the end of 1996. In this phase, research is being continued on the following topics: *characterizing chalk, water injection,* and *mechanical properties of chalk.*

EU Research and Development Programmes

The fourth EU framework programme for research, technological development and demonstration was announced in 1994. Total funding under the programme amounts to about DKK 8 billion. Within the energy area, two non-nuclear sub-programmes have been initiated, *Joule* (research and development) and *Thermie* (demonstration). From the Danish point of view, the area of oil and natural gas has been given satisfactory prominence, as the priority given to most subjects coincides with Danish priorities.

The proportion of Danish projects within subjects related to hydrocarbons, unlike Danish representation in other subjects, was not satisfactory in the first round of applications. According to EU authorities, the quality of the Danish projects did not meet the level of former programme rounds, and the projects that could be expected to result in the development of any real novelties were few and far between.

The Nordic Energy Research Programme

Under the Nordic Energy Research Programme, funds are allocated to senior researchers and students carrying on research who participate in inter-Nordic research cooperation at Nordic universities. The Danish participation in this cooperation is financed by the Energy Research Programme (ERP), and the Danish Energy Agency is represented on the executive research committee in charge of the programme. In addition, researcher representatives from Denmark are on the expert committees.

The Petroleum Technology Expert Committee considers applications for funding within the area of oil and gas activities. In 1995, the Expert Committee awarded grants to eight recipients of PhD scholarships and three professors and senior researchers.

The Nordic Energy Research Programme launched a new four-year programme in 1995. The following topics related to hydrocarbons are prioritized by this new programme: *petroleum fluids, oil technology and petrophysics* (upstream operations), as well as *catalysis, separation processes and reactive distillation* (downstream operations).

Organization

The Danish Energy Agency is an institution under the Ministry of Environment and Energy. The Agency handles all technical matters and administrative tasks within the energy area, in which connection the Agency prepares all energy-related matters to be submitted to the Minister, and handles relations and coordination with external parties.

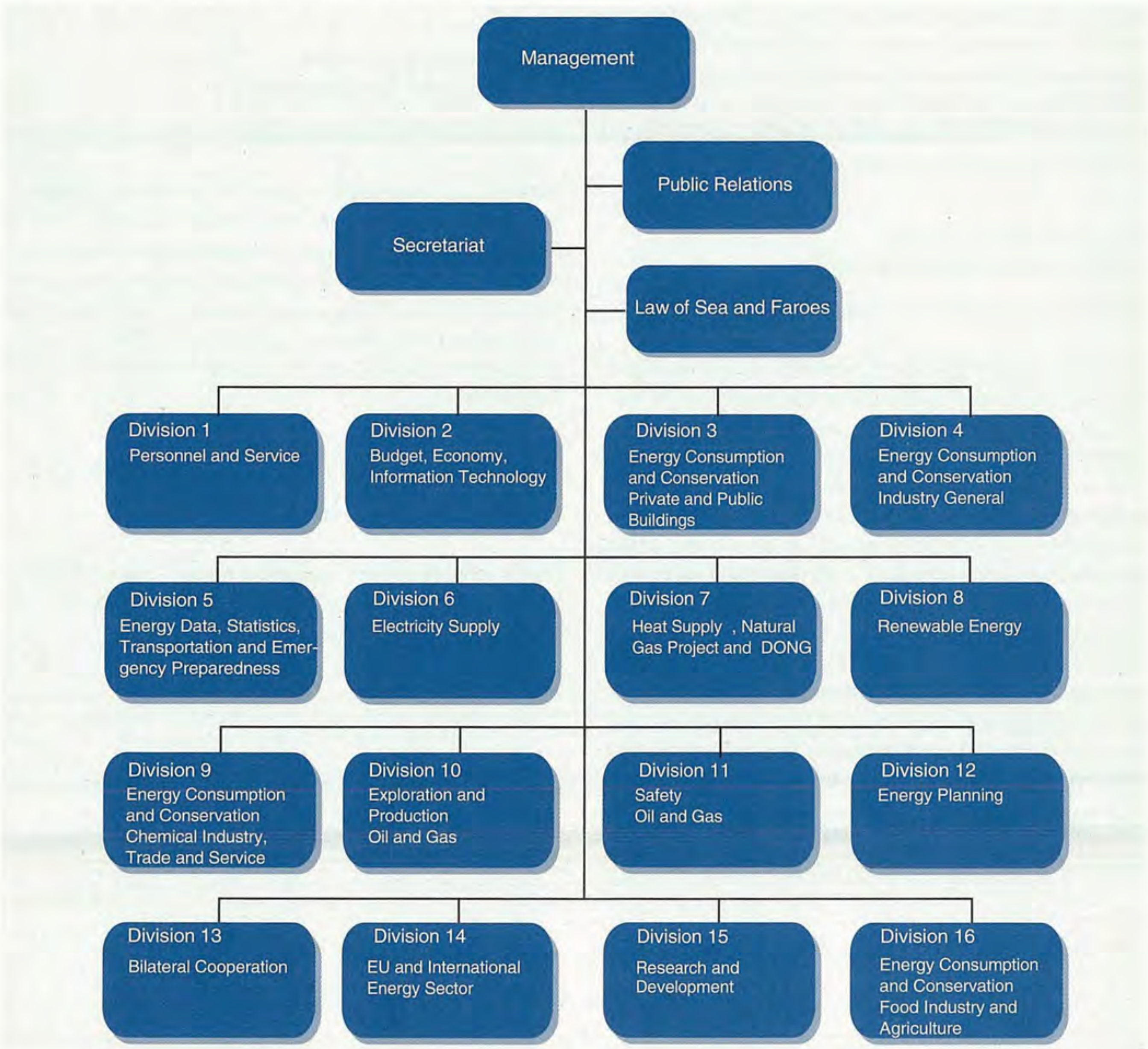
The organization of the Danish Energy Agency is shown by Fig. A.1.

The Danish Energy Agency has 16 divisions, in addition to the special unit responsible for matters relating to the law of the sea and advising the Faroese Home Rule authorities. The Agency also acts as secretariat for the Mineral Resources Administration for Greenland.

The administration of oil and gas activities is handled by the 10th and 11th divisions of the Agency, assisted by the 7th and 15th divisions and the Law of the Sea Unit 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 1995/96, the Agency employed the equivalent of about 270 full-time employees, about 40 of whom are involved in the administration of oil and gas activities.

Fig. A.1 Organizational Chart of the Danish Energy Agency



Appendix A

The administration of oil and gas activities is handled by:

The Tenth 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 tariff. Matters concerning unitization and safe production. 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 DOPAS. Responsibility for the Danish Energy Agency's oil/gas-related system exports.

The Eleventh 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 Act on Certain Marine Installations and the Subsoil 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 Dansk Naturgas A/S and supervising the technical safety aspects of the gas storage facilities established by Dansk Naturgas A/S. Considering political and administrative issues related to DORAS. Moreover, the division draws up regulations in this area.

The Seventh Division: Heat Supply, the Natural Gas Project and DONG

Head of division: Thomas Bastholm Bille

Activities under the provisions of the Danish Heat Supply Act, expanding decentralized heat and power systems and using environmentally friendly energy sources. Legal/administrative and financial issues. Approving projects and hearing appeals under the Heat Supply Act. Agenda 21 planning and work on the 'Brundtlandby' project. Act on Subsidies to Promote Connection to Coal-Fired Combined Heat and Power Systems. Matters concerning the DONG group and the regional natural gas companies. The financial, legal, technical and organizational matters related to the implementation of the natural gas project. Parliamentary Acts on natural gas supplies and matters concerning the purchase and export of natural gas.

The Fifteenth Division: Research and Development

Head of division: Stefan Hultberg

National and international activities regarding energy research. 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.

The Law of the Sea and the Faroe Islands Unit

Commissioner: Jørgen Nørgaard

Issues relating to the Convention on the Law of the Sea, the delimitation of the continental shelf, as well as advising the Faroese Home Rule authorities.

Licences in Denmark

Dansk Undergrunds Consortium (DUC):

The Sole Concession of July 8, 1962
Blocks: 5504/5 and 6 (Elly)
Blocks: 5603/27 and 28 (Gert)
Blocks: 5504/10 and 14 (Rolf)
Block: 5604/25 (Svend)
Blocks: 5604/21 and 22 (Harald)
Blocks: 5504/7, 8, 11, 12, 15 and 16
5505/13, 17 and 18 (Contiguous Area)

Company	Share
Shell Olie- og Gasudvinding Danmark BV	46.00%
A.P. Møller (Concessionaires)	39.00%
Texaco Denmark Inc.	15.00%

Mærsk Olie og Gas AS is operator

2nd and 3rd Round Groups:

Licence 7/86
Blocks: 5604/22 and 26

Company	Share
Statoil Efterforskning og Produktion A/S	33.54%
DOPAS	25.32%
Total Marine Danmark	15.19%
DENERCO K/S	11.39%
LD Energi A/S	9.49%
Amerada Hess Energi A/S	5.06%

Statoil is operator and Danop will be operator in a development phase

Licence 7/89
Block: 5504/2
Blocks: 5604/25, 29 and 30

Company	Share
Amerada Hess A/S	65.69%
DOPAS	25.00%
DENERCO K/S	7.50%
Danoil Exploration A/S	1.81%

Amerada Hess is operator

Licence 8/89
Block: 5603/32
Block: 5604/29

Company	Share
Amerada Hess A/S	58.72%
DOPAS	28.17%
DENERCO K/S	10.56%
Danoil Exploration A/S	2.55%

Danop is operator

Licence 10/89
Blocks: 5603/27 and 31

Company	Share
A.P. Møller	26.67%
Shell Olie- og Gasudvinding Danmark BV	26.67%
Texaco Denmark Inc.	26.67%
DOPAS	20.00%

Mærsk Olie og Gas AS is operator

Licences awarded in 1990:

Licence 1/90
Block: 5604/18

Company	Share
Statoil Efterforskning og Produktion A/S	33.54%
DOPAS	25.32%
Total Marine Danmark	15.19%
DENERCO K/S	11.39%
LD Energi A/S	9.49%
Amerada Hess Energi A/S	5.06%

Statoil is operator and Danop is co-operator

Licence 2/90
Blocks: 5604/23 and 24

Company	Share
Statoil Efterforskning og Produktion A/S	40.42%
Total Marine Danmark	18.31%
DENERCO K/S	13.73%
LD Energi A/S	11.44%
DOPAS	10.00%
Amerada Hess Energi A/S	6.10%

Danop is operator

Licence 3/90
Block: 5603/28

Company	Share
Shell Olie- og Gasudvinding Danmark BV	36.80%
A.P. Møller	31.20%
DOPAS	20.00%
Texaco Denmark Inc.	12.00%

Mærsk Olie og Gas AS is operator

4th Round Groups:

Licence 1/95
Blocks: 5503/2 and 3
Blocks: 5603/30 and 31

Company	Share
Amerada Hess A/S	40.00%
Premier Oil BV	20.00%
DENERCO K/S	20.00%
DOPAS	20.00%

Amerada Hess is operator, Danop is co-operator

Licence 2/95
Blocks: 5503/3 and 4
Block: 5603/31
Block: 5604/29

Company	Share
Amerada Hess A/S	66.89%
DOPAS	20.00%
DENERCO K/S	10.56%
Danoil Exploration A/S	2.55%

Danop is operator, Amerada Hess is co-operator

Licence 3/95
Blocks: 5604/19 and 20
Block: 5605/21

Company	Share
Statoil Efterforskning og Produktion A/S	56.60%
DOPAS	20.00%
DENERCO K/S	13.23%
LD Energi A/S	10.17%

Danop is operator, Statoil is co-operator

Licence 4/95
Block: 5604/20
Blocks: 5605/4, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16 and 17
Blocks: 5606/1, 5 and 9

Company	Share
Mobil Erdgas-Erdöl GmbH	27.50%
RWE-DEA AG	20.00%
Wintershall AG	20.00%
DOPAS	20.00%
EWE AG	12.50%

Danop is operator

Licence 5/95
Blocks: 5603/30 and 31

Company	Share
Phillips Petroleum Int. Corp. Denmark	35.00%
Amerada Hess A/S	20.00%
DOPAS	20.00%
Pelican A/S Danmark	15.00%
DENERCO K/S	5.00%
Premier Oil BV	5.00%

Phillips is operator

Licence 6/95
Blocks: 5604/16 and 20
Blocks: 5605/13 and 17

Company	Share
Statoil Efterforskning og Produktion A/S	40.00%
Enterprise Oil Exploration Ltd.	20.00%
DOPAS	20.00%
Phillips Petroleum Int. Corp. Denmark	12.50%
DENERCO K/S	7.50%

Statoil is operator, Danop is co-operator

Licence 7/95
Block: 5505/22

Company	Share
A.P. Møller	26.67%
Shell Olie- og Gasudvinding Danmark BV	26.67%
Texaco Denmark Inc.	26.67%
DOPAS	20.00%

Mærsk Olie og Gas AS is operator

Licence 8/95
Blocks: 5504/3 and 4

Company	Share
Shell Olie- og Gasudvinding Danmark BV	36.80%
A.P. Møller	31.20%
DOPAS	20.00%
Texaco Denmark Inc.	12.00%

Mærsk Olie og Gas AS is operator

Licence 9/95
Blocks: 5604/21, 22, 25 and 26

Company	Share
Shell Olie- og Gasudvinding Danmark BV	36.80%
A.P. Møller	31.20%
DOPAS	20.00%
Texaco Denmark Inc.	12.00%

Mærsk Olie og Gas AS is operator

Please note that the figures have been rounded off.

Exploration and Appraisal Wells, 1986-1995

Well Number	Operator Drilling Rig	Lat. North Long East	Total Depth Formation	Spudded Completed
Lulu-2 5604/22-2	Mærsk Olie og Gas AS Mærsk Endeavour	56°19'06" 04°17'31"	3603 metres U. Permian	1985-12-15 1986-03-18
Diamant-1 5603/32-2	Phillips Glomar Labrador 1	56°00'23" 03°53'44"	4204 metres L. Permian	1986-01-11 1986-03-18
East Rosa-3 5504/15-5	Mærsk Olie og Gas AS Dyvi Epsilon	55°35'37" 04°36'31"	1569 metres U. Permian	1986-01-20 1986-03-19
East Rosa Fl.-1 5504/15-6	Mærsk Olie og Gas AS Mærsk Endeavour	55°33'51" 04°37'54"	3037 metres U. Jurassic	1986-03-24 1986-04-30
Ravn-1 5504/01-2	Amoco Dyvi Epsilon	55°52'36" 04°13'52"	4968 metres L.,Permian	1986-03-24 1986-07-21
Mi. Rosa Fl.-1 5504/15-7	Mærsk Olie og Gas AS Mærsk Endeavour	55°35'27" 04°31'33"	3035 metres L. Cretaceous	1986-05-04 1986-06-11
West Lulu-4 5604/21-6	Mærsk Olie og Gas AS Mærsk Endeavour	56°19'05" 04°10'17"	3814 metres L. Triassic	1986-07-28 1986-09-13
Gwen-2 5604/29-3	Mærsk Olie og Gas AS Mærsk Endeavour	56°06'52" 04°04'10"	4363 metres L. Triassic	1986-09-30 1986-12-15
Mejrup-1 5608/19-1	Phillips Kenting 36	56°22'39" 08°40'36"	2481 metres U. Triassic	1987-03-22 1987-04-29
Felicia-1 5708/18-1	Statoil Mærsk Guardian	57°26'18" 08°18'41"	5280 metres L. Permian	1987-07-04 1987-12-03
Gert-3 5603/28-2	Mærsk Olie og Gas AS Mærsk Endeavour	56°12'43" 03°45'49"	5003 metres Palaeozoic	1987-07-21 1987-10-28
Ibenholt-1 5605/20-1	Phillips Dyvi Sigma	56°23'26" 05°58'29"	2558 metres Precambrian	1987-08-11 1987-09-24
Deep Gorm-1 5504/16-5	Mærsk Olie og Gas AS Zapata Scotian	55°34'04" 04°45'50"	3823 metres Triassic	1987-08-18 1987-12-04
Ravn-2 5504/05-1	Amoco Dan Earl	55°50'34" 04°13'40"	4466 metres Triassic	1987-09-16 1987-11-17
Elly-2 5504/06-2	Mærsk Olie og Gas AS Neddrill Trigon	55°47'19" 04°19'04"	4104 metres Triassic	1987-11-15 1988-05-31
Jeppe-1 5603/28-3	Norsk Hydro Mærsk Guardian	56°11'04" 03°54'36"	5047 metres L. Permian	1987-12-10 1988-03-02
Borg-1 5508/32-2	Danop Kenting 34	55°02'57" 08°48'23"	3063 metres Palaeozoic	1988-04-18 1988-05-29
Gulnare-1 5604/26-1	Statoil Mærsk Endeavour	56°10'13" 04°26'41"	4735 metres U. Jurassic	1988-06-04 1988-09-19
Tordenskjold-1 5503/03-2	Danop Neddrill Trigon	55°56'19" 03°32'31"	3702 metres L. Permian	1988-12-14 1989-02-04
Pernille-1 5514/30-1	Norsk Hydro Glomar Moray Firth	55°00'54" 14°18'43"	3589 metres Silurian	1989-04-09 1989-06-06
Stina-1 5414/07-1	Amoco Glomar Moray Firth	54°47'20" 14°37'44"	2482 metres Silurian	1989-06-12 1989-07-11
Falk-1 5504/06-3	Amoco Glomar Moray Firth	55°50'01" 04°18'50"	4200 metres U. Triassic	1989-07-24 1989-09-05
Gert-4 5603/27-4	Mærsk Olie og Gas AS Mærsk Endeavour	56°13'18" 03°43'48"	5363 metres U. Permian	1989-11-02 1990-05-16
Alma-1 5505/17-10	Mærsk Olie og Gas AS Mærsk Giant	55°28'58" 05°12'33"	3882 metres Triassic	1990-03-18 1990-08-16
Amalie-1 5604/26-2	Statoil Neddrill Trigon	56°14'39" 04°22'02"	5320 metres Jurassic	1990-08-01 1991-06-17
E-5 5504/12-4	Mærsk Olie og Gas AS West Sigma	55°40'25" 04°53'11"		1991-02-05 1991-05-11
Skjold Fl.-1 5504/16-6	Mærsk Olie og Gas AS West Kappa	55°33'23" 04°53'51"		1991-05-10 1991-09-22
Eg-1 5503/04-2	Agip Neddrill Trigon	55°57'09" 03°58'25"	4500 metres Permian	1991-06-24 1991-09-23
Baron-1 5604/30-2	Norsk Hydro Mærsk Jutlander	56°01'44" 04°15'29"	999 metres	1991-07-25 1991-08-01
Baron-2 5604/30-3	Norsk Hydro Mærsk Jutlander	56°01'44" 04°15'29"	5100 metres U. Jurassic	1991-08-01 1992-01-13
Elly-3 5504/06-5	Mærsk Olie og Gas AS Mærsk Endeavour	55°47'19" 04°22'02"		1991-09-12 1992-02-12
TWC-3P 5504/11-3	Mærsk Olie og Gas AS Mærsk Giant	55°42'56" 04°44'56"		1991-09-14 1991-11-24
S.E.Adda-1 5504/08-5	Mærsk Olie og Gas AS Mærsk Giant	55°47'56" 04°55'07"		1992-01-26 1992-03-05
Dagmar-6 5504/15-8	Mærsk Olie og Gas AS Mærsk Endeavour	55°35'04" 04°35'50"		1992-02-22 1992-04-11
E-6 5504/12-5	Mærsk Olie og Gas AS Mærsk Giant	55°40'29" 04°53'22"		1992-03-12 1992-05-12
Lulita-1 5604/22-3	Mærsk Olie og Gas AS Mærsk Giant	56°20'46" 04°16'24"	3749 metres M. Jurassic	1992-05-17 1992-12-20
E-7 5504/12-6	Mærsk Olie og Gas AS West Sigma	55°40'43" 04°49'24"		1992-06-11 1992-07-18
Bertel-1 5603/32-3	Danop West Omikron	56°02'12" 03°58'03"	4810 metres Triassic	1992-06-27 1992-10-07
Ida-1 5606/13-1	Amoco Ross Explorer	56°32'11" 06°06'58"	1663 metres Triassic	1992-09-14 1992-09-30
Rita-1 5603/27-5	Mærsk Olie og Gas AS Mærsk Endeavour	56°09'09" 03°34'13"	4758 metres Triassic	1992-09-18 1993-03-03
Skarv-1 5504/10-2	Amoco Ross Explorer	55°43'14" 04°24'58"	3935 metres Triassic	1992-10-04 1992-11-17
Jelling-1 5509/10-1	Danop Kenting 31	55°44'22" 09°22'33"	1933 metres Precambrian	1992-10-05 1992-10-24
Alma-2 5505/17-11	Mærsk Olie og Gas AS Shelf Explorer	55°29'50" 05°13'37"		1992-10-18 1993-02-06
Løgumkloster-2 5508/32-3	Danop Kenting 31	55°02'00" 08°56'32"	2768 metres L. Permian?	1993-09-01 1993-10-17
Tabita-1 5604/26-3	Statoil Glomar Moray Firth	56°13'37" 04°23'47"	4313 metres U. Jurassic	1993-09-13 1993-12-10
E-8 5504/12-7	Mærsk Olie og Gas AS West Kappa	55°05'22" 04°59'12"		1994-04-10 1994-06-06
Rigs-1 5604/29-4	Amerada Hess Mærsk Giant	56°05'22" 04°12'53"	3050 metres L. Cretaceous	1994-12-26 1995-02-25
Siri-1 5604/20-1	Statoil Deepsea Bergen	56°29'11" 04°54'57"	2197 metres L. Tertiary	1995-11-28 1995-12-24

Appendix D

Exploratory Surveys 1995

Survey	Operator Contractor	Type	Initiated Completed	Area	Collected in 1995
DN95D	DANGAS Thor Geophysikalische Prospektion	Onshore 2D	1995-11-01 1995-12-05	Jutland Ll. Torup	33 km
DN950	DANGAS Geco-Prakla	Onshore 2D	1995-08-14 1995-08-18	Zealand Stenlille	10 km
DK95N 4/95	Danop Geoteam A/S	Offshore 2D	1995-08-09 1995-09-03	The North Sea 5604, 5605, 5606	1,806 km
DK95 9/95	Mærsk Olie og Gas A/S Geco-Prakla	Offshore 2D	1995-08-21 1995-09-07	Central Graben 5604	785 km
DK95 8/95	Mærsk Olie og Gas A/S Geco-Prakla	Offshore 2D	1995-09-07 1995-09-16	Central Graben 5504	396 km
DK95 7/95	Mærsk Olie og Gas A/S Geco-Prakla	Offshore 2D	1995-09-16 1995-09-22	Central Graben 5505	361 km
ST9510 6/95	Statoil Gardline Surveys Ltd.	Offshore 2D	1995-07-09 1995-09-22	The North Sea 5604, 5605	339 km
South Arne 7/89	Amerada Hess Geco-Prakla	Offshore 3D	1995-06-22 1995-06-21	Central Graben 5604	8,808 km
Tønder-95	DANGAS Geco-Prakla	Onshore 3D	1995-08-29 1995-10-20	Southern Jutland Tønder	1,944 km
DN95 2/95 + 8/89	Danop Geco-Prakla	Offshore 3D	1995-06-22 1995-08-13	Central Graben 5603, 5503	16,339 km
PAG95 1/95 + 5/95	Phillips/Amerada Geco-Prakla	Offshore 3D	1995-12-04 Not completed	Central Graben 5503, 5603	5,681 km

Danish Oil Production 1972-1995, million m^3

Year	Dan	Gorm	Skjold	Tyra	Rolf	Kraka	Dagmar	Regnar	Valdemar	Total
1972	0.11									**0.11**
1973	0.15									**0.15**
1974	0.10									**0.10**
1975	0.19									**0.19**
1976	0.23									**0.23**
1977	0.58									**0.58**
1978	0.49									**0.49**
1979	0.49									**0.49**
1980	0.34									**0.34**
1981	0.34	0.53								**0.87**
1982	0.31	1.64	0.02							**1.97**
1983	0.27	1.84	0.40							**2.51**
1984	0.36	1.62	0.65	0.07						**2.70**
1985	0.45	1.80	0.85	0.35						**3.45**
1986	0.47	1.72	1.07	0.57	0.47					**4.30**
1987	1.23	1.50	1.21	0.84	0.63					**5.41**
1988	1.50	1.35	1.37	0.95	0.40					**5.57**
1989	1.47	1.35	2.21	1.05	0.39					**6.47**
1990	1.58	1.44	2.63	1.08	0.27					**7.00**
1991	1.72	1.50	2.73	1.39	0.29	0.14	0.47			**8.24**
1992	2.70	1.66	2.28	1.67	0.30	0.21	0.31			**9.13**
1993	3.26	1.89	2.10	1.64	0.18	0.39	0.07	0.15	0.05	**9.73**
1994	3.50	2.42	1.72	1.75	0.09	0.49	0.03	0.43	0.30	**10.73**
1995	3.71	2.49	1.98	1.63	0.22	0.47	0.03	0.09	0.17	**10.79**
Total	**25.55**	**24.75**	**21.22**	**12.99**	**3.24**	**1.70**	**0.91**	**0.67**	**0.52**	**91.55**

Danish Gas Production 1972-1995, billion Nm^3

Year	Dan	Gorm	Skjold	Tyra	Rolf	Kraka	Dagmar	Regnar	Valdemar	Total
1972	0.02									**0.02**
1973	0.03									**0.03**
1974	0.03									**0.03**
1975	0.06									**0.06**
1976	0.07									**0.07**
1977	0.17									**0.17**
1978	0.16									**0.16**
1979	0.16									**0.16**
1980	0.07									**0.07**
1981	0.08	0.08								**0.16**
1982	0.08	0.27	<0.01							**0.35**
1983	0.08	0.43	0.04							**0.55**
1984	0.13	0.51	0.06	0.26						**0.96**
1985	0.21	0.64	0.07	1.11						**2.03**
1986	0.24	0.78	0.10	1.63	0.02					**2.77**
1987	0.44	0.88	0.10	2.65	0.03					**4.10**
1988	0.60	0.98	0.11	3.36	0.02					**5.07**
1989	0.71	0.89	0.19	3.52	0.02					**5.33**
1990	0.80	0.81	0.22	3.30	0.01					**5.14**
1991	0.88	0.84	0.23	3.67	0.01	0.06	0.07			**5.76**
1992	1.06	0.84	0.21	3.94	0.01	0.09	0.05			**6.20**
1993	1.34	0.78	0.19	3.85	0.01	0.13	0.01	0.01	0.03	**6.35**
1994	1.26	0.92	0.19	3.65	<0.01	0.12	0.01	0.03	0.10	**6.27**
1995	1.33	0.76	0.19	3.84	0.01	0.13	0.01	0.01	0.05	**6.32**
Total	**10.01**	**10.41**	**1.90**	**34.78**	**0.14**	**0.53**	**0.15**	**0.05**	**0.18**	**58.14**

A large amount of gas has been reinjected

Appendix E2

Natural Gas Supplies from Danish Fields 1984-1995, million Nm³

Year	Dan	Kraka	Regnar	Gorm	Skjold	Rolf	Dagmar	Tyra	Valdemar	Total
1984	7	-	-	19	2	-	-	192	-	**220**
1985	49	-	-	0	0	-	-	1015	-	**1064**
1986	211	-	-	116	14	3	-	1460	-	**1804**
1987	378	-	-	21	2	1	-	1898	-	**2300**
1988	534	-	-	96	11	1	-	1629	-	**2271**
1989	639	-	-	55	12	1	-	1977	-	**2684**
1990	737	-	-	99	27	1	-	1889	-	**2753**
1991	769	49	-	167	46	2	-	2484	-	**3517**
1992	932	78	-	151	38	2	-	2427	-	**3628**
1993	1228	115	7	298	75	3	-	2262	17	**4005**
1994	1128	104	24	715	145	3	-	2149	59	**4327**
1995	1214	117	6	596	147	7	-	2572	35	**4695**
Total	**7826**	**463**	**37**	**2333**	**519**	**24**	**-**	**21955**	**111**	**33268**

Monthly Oil and Condensate Production 1995, thousand m³

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	1995
Dan	325	292	320	312	314	293	311	288	311	322	311	315	**3713**
Kraka	51	40	40	37	39	40	41	36	36	40	34	34	**469**
Regnar	10	8	9	8	8	7	7	6	6	6	5	5	**86**
Gorm	199	193	223	218	211	188	228	239	210	205	186	194	**2494**
Skjold	137	124	151	135	172	184	180	199	180	180	162	174	**1979**
Rolf	8	14	19	22	22	10	16	20	20	22	20	22	**216**
Dagmar	4	4	4	3	3	3	3	3	2	3	2	1	**35**
Tyra	146	137	149	148	139	142	115	106	120	140	141	146	**1631**
Valdemar	29	18	18	6	5	17	15	12	15	16	9	5	**165**
Total	**910**	**831**	**934**	**890**	**913**	**885**	**916**	**907**	**902**	**934**	**870**	**897**	**10788**

Monthly Gas Production 1995, million Nm³

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	1995
Dan	118	108	121	115	117	108	103	99	107	109	109	120	**1331**
Kraka	13	10	11	10	11	11	12	10	10	11	10	10	**128**
Regnar	<1	<1	<1	<1	<1	<1	<1	<1	<1	<1	<1	<1	**7**
Gorm	68	60	72	65	67	58	69	63	61	62	57	59	**761**
Skjold	14	13	16	15	18	19	18	19	15	14	12	14	**188**
Rolf	<1	<1	<1	<1	<1	<1	<1	<1	<1	<1	<1	<1	**9**
Dagmar	<1	<1	<1	<1	<1	<1	<1	<1	<1	<1	<1	<1	**5**
Tyra	399	338	380	344	276	295	244	202	242	341	374	407	**3840**
Valdemar	7	8	5	2	1	5	5	4	6	6	3	2	**52**
Total	**619**	**539**	**605**	**553**	**492**	**496**	**452**	**399**	**443**	**545**	**566**	**613**	**6321**

Domestic Energy Consumption 1972-1995, Distributed on Fuels, as well as Energy Production (million t.o.e.) and Degree of Self-Sufficiency (per cent)

	Oil	Natural Gas[1])	Coal	Renewable Energy, etc.	Total	Energy Production	Self-Sufficiency A	B	C
1972	17.9	-	1.2	0.3	**19.4**	0.4	<1	<1	2
1973*)	17.4	-	1.9	0.2	**19.5**	0.3	<1	<1	2
1974*)	15.9	-	1.7	0.2	**17.8**	0.3	<1	<1	2
1975	15.2	-	2.0	0.3	**17.6**	0.5	1	1	3
1976	16.0	-	2.9	0.4	**19.2**	0.6	1	1	3
1977	16.0	-	3.3	0.4	**19.6**	0.9	3	3	4
1978	16.0	-	4.0	0.4	**20.5**	0.9	3	2	4
1979	15.9	-	4.8	0.5	**21.2**	0.9	3	2	4
1980	13.2	-	5.7	0.6	**19.5**	0.9	2	2	5
1981	11.6	0.0	6.0	0.7	**18.3**	1.5	7	4	8
1982	10.8	0.0	6.2	0.8	**17.9**	2.5	16	10	14
1983	10.2	0.1	6.6	0.8	**17.8**	3.1	22	13	17
1984	10.2	0.2	7.1	0.9	**18.3**	3.5	25	14	19
1985	10.4	0.7	7.4	0.9	**19.3**	4.9	36	21	25
1986	10.2	1.2	7.4	1.0	**19.7**	6.5	48	28	33
1987	9.7	1.5	7.7	1.1	**20.0**	8.0	63	35	40
1988	9.0	1.6	7.7	1.1	**19.4**	8.3	67	37	43
1989	8.6	1.8	7.6	1.2	**19.1**	9.6	80	44	50
1990	8.3	1.9	7.6	1.2	**18.9**	10.2	88	47	53
1991	8.3	2.1	7.8	1.3	**19.5**	12.0	102	54	6
1992	8.3	2.2	7.7	1.5	**19.6**	13.0	110	59	66
1993	8.1	2.5	7.5	1.5	**19.5**	13.9	117	64	71
1994	8.4	2.7	6.8	1.5	**19.4**	15.1	122	70	78
1995*)	8.8	3.1	6.4	1.6	**19.8**	15.6	118	71	79

Climatic correction has not been applied, as opposed to other surveys of consumption

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 domestic energy consumption
*) Estimate
[1]) Including fuel consumption offshore

Appendix F2

Financial Key Figures

	Investments in Field Development DKK million	Operating Costs for Fields 1) DKK million	Exploration Costs 2) DKK million	Crude Oil Price 3) USD/bbl	Exchange Rate DKK/USD	Inflation Rate 4) per cent	Net Foreign-Currency Expenditure on Energy Import DKK million
1972	105	32	28	3.0	7.0	6.6	3.3
1973	9	34	83	4.6	6.1	9.3	4.3
1974	38	58	76	11.6	6.1	15.2	9.8
1975	139	64	118	12.3	5.8	19.6	9.4
1976	372	71	114	12.3	6.1	9.0	10.3
1977	64	88	176	14.0	6.0	11.2	11.4
1978	71	128	55	14.0	5.5	10.0	10.9
1979	387	146	78	20.4	5.3	9.6	15.5
1980	956	169	201	37.5	5.6	12.3	21.2
1981	1651	402	257	37.4	7.1	11.7	25.9
1982	3948	652	566	34.0	8.4	10.2	25.9
1983	3528	615	1264	30.5	9.1	6.9	21.9
1984	1596	1405	1211	28.2	10.4	6.3	22.8
1985	1953	2256	1373	27.2	10.6	4.7	23.4
1986	1694	1598	747	14.7	8.1	3.6	11.2
1987	908	1655	664	18.3	6.8	4.0	8.7
1988	897	1604	424	14.8	6.7	4.6	6.7
1989	1153	1821	366	18.2	7.3	4.8	7.4
1990	1738	1924	592	23.5	6.2	2.6	5.7
1991	2260	2173	986	20.0	6.4	2.4	5.1
1992	2402	2080	983	19.3	6.0	2.1	3.6
1993	3358	2324	442	16.8	6.5	1.2	3.8
1994	3140	2395	151	15.6	6.4	2.0	4.0
1995*	4184	2235	236	17.0	5.6	2.1	3.0

Nominal Prices 1) Including transportation costs 2) All licences 3) Danish crude oil 4) Consumer prices *) Estimate

Producing Fields

The Dan Centret:

Field name	Dan
Prospect:	Abby
Location:	Block 5505/17
Concessionaire:	A.P. Møller
Operator:	Mærsk Olie & Gas AS
Discovered:	1971
Year on stream:	1972
Producing wells:	48
of which horizontal:	32
Injection wells:	26
of which horizontal:	8
Water depth:	40 m (131 ft)
Acreage:	20 km^2 (5,000 acres)
Reservoir depth:	1,850 m (6,070 ft)
Reservoir rock:	Chalk
Geological age:	Danian and Late Cretaceous

Reserves and Production

Reserves at January 1, 1996	
Oil:	76.9 million m^3 (484 MMbbls)
Gas:	13.1 billion Nm^3 (488 BSCF)
Cumulative Production:	
Oil:	25.57 million m^3 (161 MMbbls)
Gas:	10.01 billion Nm^3 (373 BSCF)
Cumulative Injection:	
Water:	12.53 million m^3 (79 MMbbls)

Review of Geology

Dan is an anticlinal structure induced through salt tectonics of the Zechstein/Triassic. 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 adequate porosity, although strongly reduced permeability. There is a gas cap in the field. In 1989, water injection was initiated in the reservoir to enhance oil recovery.

Production Facilities

The field installation comprises six wellhead platforms (A, D, E, FA, FB and FE), two processing/accommodation platforms (B and FC) and two gas flare stacks (C and FD).

The older processing facilities at Dan B have since 1987 been used for temporary, individual well production testing only.

Processing of the produced oil and gas takes place mainly at Dan FC. These processing facilities, which handle the combined production from the fields at the Dan Centre, consist of an oil stabilization plant and a gas dehydration plant. Final processing of the produced oil is performed prior to export ashore via the booster platform, Gorm E. The gas is pre-processed at Dan FC and transported to Tyra East for final processing. The water-injection capacity is 8.7 million m^3 per year (150,000 bbls per day).

There are accommodation facilities for 91 persons in the Dan Field, Dan FC accommodating 86 persons.

Field name	Kraka
Prospect:	Anne
Location:	Block 5505/17
Concessionaire:	A.P. Møller
Operator:	Mærsk Olie & Gas AS
Discovered:	1966
Year on stream:	1991
Producing wells:	6
of which horizontal:	6
Water depth:	45 m (148 ft)
Acreage:	20 km^2 (5,000 acres)
Reservoir depth:	1,800 m (5,900 ft)
Reservoir rock:	Chalk
Geological age:	Danian

Reserves and Production

Reserves at January 1, 1996	
Oil:	2.9 million m^3 (18 MMbbls)
Gas:	0.8 billion Nm^3 (30 BSCF)
Cumulative Production:	
Oil:	1.70 million m^3 (11 MMbbls)
Gas:	0.52 billion Nm^3 (19 BSCF)

Appendix G1

Review of Geology

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

Production Facilities

Kraka is a satellite development to Dan, including an unmanned production platform of the STAR type hosting six wells. The produced oil and gas are transported to Dan FC for processing and export ashore.

Field name	Regnar
Prospect:	Nils
Location:	Block 5505/17
Concessionaire:	A.P. Møller
Operator:	Mærsk Olie & Gas AS
Discovered:	1979
Year on stream:	1993
Producing wells:	1
Water depth:	45 m (148 ft)
Acreage:	8 km^2 (2,000 acres)
Reservoir depth:	1,700 m (5,600 ft)
Reservoir rock:	Chalk and Carbonates
Geological age:	Late Cretaceous and Zechstein

Reserves and Production

Reserves at January 1, 1996	
Oil:	0.1 million m^3 (1 MMbbls)
Gas:	< 0.1 billion Nm^3 (1 BSCF)
Cumulative Production:	
Oil:	0.66 million m^3 (4 MMbbls)
Gas:	0.04 billion Nm^3 (1 BSCF)

Review of Geology

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

Production Facilities

The Regnar Field has been developed as a satellite to the Dan Field. Production takes place in a subsea-completed well. The unprocessed production is transported to Dan FC.

The Gorm Centre:

Field name	Gorm
Prospect:	Vern
Location:	Blocks 5504/15 and 16
Concessionaire:	A.P. Møller
Operator:	Mærsk Olie & Gas AS
Discovered:	1971
Year on stream:	1981
Producing wells:	30
of which horizontal:	7
Gas injection wells:	2
Water injection wells:	14
of which horizontal:	9
Water depth:	39 m (128 ft)
Acreage:	12 km^2 (3,000 acres)
Reservoir depth:	2,100 m (6,900 ft)
Reservoir rock:	Chalk
Geological age:	Danian and Late Cretaceous

Reserves and Production

Reserves at January 1, 1996	
Oil:	21.7 million m^3 (137 MMbbls)
Gas:	3.9 billion Nm^3 (145 BSCF)
Cumulative Production:	
Oil:	24.76 million m^3 (156 MMbbls)
Gas:	10.41 billion Nm^3 (388 BSCF)
Net gas:	2.46 billion Nm^3 (92 BSCF)
Cumulative Injection:	
Gas:	7.95 billion Nm^3 (296 BSCF)
Water:	16.37 million m^3 (103 MMbbls)

Review of Geology

Gorm is an anticlinal structure due to Zechstein salt tectonics. A major fault extending north-south divides the field into two reservoir blocks. The western reservoir block is heavily fractured.

Initially, there was no gas cap in the Gorm Field, but since the field was brought on stream, the injection of gas has resulted in the formation of an artificial gas cap in the western block. Gas injection is being phased out. In 1989, water injection was initiated in the reservoir.

Production Facilities

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

The Gorm C processing facilities consist of an oil stabilization plant and plant for the final processing of gas, as well as gas reinjection and water-injection facilities.

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

The water-injection capacity at the Gorm Centre constitutes 12.2 million m^3 per year (210,000 bbls per day).

In 1995, the Gorm F platform was extended by a third deck to accommodate the water-processing facilities and a new water-injection pump. Any future desulphurization facilities will also be placed on this deck. In 1997, wellhead compression will be established on a planned fourth deck to reduce the wellhead pressure in the Gorm and Skjold wells. In addition, a new test separator will be installed on this deck.

The gas that is not injected is conveyed to Tyra East. The stabilized oil from the processing facilities at the Dan, Tyra and Gorm Centres is exported ashore via the Gorm E booster platform.

There are accommodation facilities on Gorm C for 98 persons.

Field name	Skjold
Prospect:	Ruth
Location:	Block 5504/16
Concessionaire:	A.P. Møller
Operator:	Mærsk Olie & Gas AS

Discovered:	1977
Year on stream:	1982
Producing wells:	14
of which horizontal:	7
Water injection wells:	6
Water depth:	40 m (131 ft)
Acreage:	10 km2 (2,500 acres)
Reservoir depth:	1,600 m (5,200 ft)
Reservoir rock:	Chalk
Geological age:	Danian and Late Cretaceous

Reserves and Production

Reserves at January 1, 1996	
Oil:	15.1 million m^3 (95 MMbbls)
Gas:	1.2 billion Nm^3 (45 BSCF)
Cumulative Production:	
Oil:	21.22 million m^3 (134 MMbbls)
Gas:	1.90 billion Nm^3 (71 BSCF)
Cumulative Injection:	
Water:	25.62 million m^3 (161 MMbbls)

Review of Geology

The Skjold Field is an anticlinal structure induced through Zechstein salt tectonics. The structure is intersected by a series of ring faults along the flank, while the crest of the structure is intersected by numerous, more randomly distributed minor faults. Unusually good production properties have been shown to exist in the crestal part of the reservoir. In 1986, water injection was initiated in the reservoir.

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. Skjold B and C, both of the STAR type, were installed in 1993/94. They are both connected by bridges to Skjold A.

There are no processing facilities at the Skjold Field, and the production is transported to facilities on the Gorm platform, which also houses facilities providing the Skjold Field with injection water and lift gas.

Appendix G1

At Skjold C, there are accommodation facilities for 16 persons.

Field name	Rolf
Prospect:	Middle Rosa
Location:	Blocks 5504/14 and 15
Concessionaire:	A.P. Møller
Operator:	Mærsk Olie & Gas AS
Discovered:	1981
Year on stream:	1986
Producing wells:	2
Observation well:	1
Water depth:	34 m (112 ft)
Acreage:	8 km2 (2,000 acres)
Reservoir depth:	1,800 m (5,900 ft)
Reservoir rock:	Chalk and Carbonates
Geological age:	Danian, Late Cretaceous and Zechstein

Reserves and Production

Reserves at January 1, 1996	
Oil:	2.1 million m^3 (13 MMbbls)
Gas:	0.1 billion Nm^3 (4 BSCF)
Cumulative Production:	
Oil:	3.24 million m^3 (20 MMbbls)
Gas:	0.14 billion Nm^3 (5 BSCF)

Review of Geology

Rolf is an anticlinal structure created through Zechstein salt tectonics. The chalk reservoir is heavily fractured resulting in favourable reservoir conductivity (compare Skjold). The aquifer in the Rolf Field has proved highly efficient.

Production Facilities

The Rolf Field is a satellite development to the Gorm Field with an unmanned wellhead platform. The unprocessed production is transported to the Gorm C platform. Rolf is also supplied with lift gas from the Gorm Field.

Field name	Dagmar
Prospect:	East Rosa
Location:	Block 5504/15
Concessionaire:	A.P. Møller
Operator:	Mærsk Olie & Gas AS
Discovered:	1983
Year on stream:	1991
Producing wells:	2
Water depth:	34 m (112 ft)
Acreage:	9 km2 (2.200 acres)
Reservoir depth:	1.400 m (4.600 ft)
Reservoir rock:	Chalk and Carbonates
Geological age:	Danian, Late Cretaceous and Zechstein

Reserves and Production

Reserves at January 1, 1996	
Oil:	< 0.1 million m^3 (1 MMbbls)
Gas:	< 0.1 billion Nm^3 (1 BSCF)
Cumulative Production:	
Oil:	0.92 million m^3 (6 MMbbls)
Gas:	0.14 billion Nm^3 (5 BSCF)

Review of Geology

The Dagmar field is an anticlinal structure, induced through Zechstein salt tectonics. The structure is heavily fractured, resulting in favourable reservoir conductivity (compare Skjold, Rolf and Regnar). Initially, production rates were high, but they declined very rapidly. The production experience seems to indicate that the production characteristics are less favourable than in the Skjold 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 Gorm F, where special facilities for handling the sour gas from the Dagmar Field have been installed. The gas from Dagmar is flared without being utilized due to the high content of hydrogen sulphide.

The Tyra Centre:

Field name	Tyra
Prospect:	Cora
Location:	Blocks 5504/11 and 12
Concessionaire:	A.P. Møller
Operator:	Mærsk Olie & Gas AS
Discovered:	1968
Year on stream:	1984
Producing wells:	45
of which horizontal:	19
Gas injection wells:	10
Water depth:	37-40 m (121-131 ft)
Acreage:	90 km2 (22,000 acres)
Reservoir depth:	2,000 m (6,600 ft)
Reservoir rock:	Chalk
Geological age:	Danian and Late Cretaceous

Reserves and Production

Reserves at January 1, 1996	
Oil:	3.3 million m^3 (21 MMbbls)
Condensate:	4.9 million m^3 (31 MMbbls)
Gas:	52.7 billion Nm^3 (1.96 TSCF)
Cumulative Production:	
Oil:	5.92 million m^3 (37 MMbbls)
Condensate:	7.06 million m^3 (44 MMbbls)
Gas:	34.80 billion Nm^3 (1.29 TSCF)
Net gas:	11.31 billion Nm^3 (0.42 TSCF)
Cumulative Injection:	
Gas:	23.49 billion Nm^3 (0.87 TSCF)

Review of Geology

The Tyra Field is an anticlinal structure. The accumulation consists of a gas cap containing condensate, overlying a thin black oil zone. A gas recycling project was initiated in 1987 at Tyra West in order to enhance condensate production. The horizontal drilling technique makes it possible to exploit the oil zone, as well.

Production Facilities

The Tyra Field installations comprise two platform complexes, Tyra West (W) and Tyra East (E). Tyra West consists of two wellhead platforms, TWB and TWC, one processing/accommodation platform (TWA), and one gas flare stack (TWD). 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).

The Tyra West processing facilities include plant for preprocessing production from the wells at Tyra West. Moreover, the Tyra West complex houses gas injection facilities. Oil, condensate and the gas that is not reinjected are transported to Tyra East for final processing. The years to come will see a major extension of the production facilities at Tyra West, including the installation of new gas processing facilities and a bridge module supported by a four-leg platform at the TWB platform. The bridge module will house new gas processing and compression facilities. In 1995, the jacket of the four-leg platform was installed. There are accommodation facilities for 80 persons at Tyra West.

The Tyra East complex includes facilities for the final processing of gas, oil, condensate and water. Tyra East was extended in 1995 by a bridge module supported by a STAR platform at the TEE platform. This bridge module houses the facilities for receiving and handling production from the future satellite fields. At Tyra East, there are accommodation facilities for 96 persons.

The oil and condensate produced at the Tyra Centre are transported to shore via Gorm E, while gas production from the other processing centres in the Dan and Gorm Fields is conveyed to Tyra East for export ashore.

Field name	Valdemar
Prospects:	Bo/North Jens
Location:	Blocks 5504/7 and 11
Concessionaire:	A.P. Møller
Operator:	Mærsk Olie & Gas AS
Discovered:	1977 (Bo), 1985 (North Jens)
Year on stream:	1993 (North Jens)
Producing wells:	3
of which horizontal:	3
Water depth:	38 m (125 ft)
Late Cretaceous reservoir:	
Acreage:	15 km^2 (3,750 acres)
Reservoir depth:	2,000 m (6,600 ft)

Early Cretaceous reservoir:	
Acreage:	15 km^2 (3,750 acres)
Reservoir depth:	2,600 m (8,500 ft)
Reservoir rock:	Chalk
Geological age:	Danian, Late and Early Cretaceous

Reserves and Production

Reserves at January 1, 1996	
Oil:	1.8 million m^3 (11 MMbbls)
Gas:	1.0 billion Nm^3 (37 BSCF)

Cumulative Production:	
Oil:	0.52 million m^3 (3 MMbbls)
Gas:	0.18 billion Nm^3 (7 BSCF)

Review of Geology

Valdemar comprises several separate reservoirs, i.e. oil and gas reservoirs in chalk of Danian/Maastrichtian and Campanian age and oil reservoirs in chalk of Aptian/Barremian age (Tuxen formation). The properties of the Late Cretaceous reservoirs are comparable to other Danish fields like Gorm and Tyra, while the Aptian/Barremian chalk possesses very difficult production properties. The development of the recovery technique based on the drilling of long horizontal wells with sand-filled, artificial fractures has so far shown encouraging results, however.

Previously, the Boje area was considered part of the Valdemar Field. In 1995, new mapping of the field showed that the Boje area is not contiguous with the North Jens and Bo areas, but is a separate accumulation.

Production Facilities

The Valdemar Field (the North Jens area) 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.

New Field Developments

Field name	Roar
Prospect:	Bent
Location:	Block 5504/7
Concessionaire:	A.P. Møller
Operator:	Mærsk Olie & Gas AS
Discovered:	1968
Dev. plan approved:	1993
Year on stream:	January 7, 1996
Water depth:	46 m (150 ft)
Reservoir depth:	2,070 m (6,800 ft)
Reservoir rock:	Chalk
Geological age:	Danian and Late Cretaceous

Field name	Harald
Prospects:	Lulu/West Lulu
Location:	Blocks 5604/21 and 22
Concessionaire:	A.P. Møller
Operator:	Mærsk Olie & Gas AS
Discovered:	1980 (Lulu) 1983 (West Lulu)
Dev. plan approved:	1993
Year on stream:	1997 (at the latest)
Water depth:	64 m (210 ft)
Reservoir depth:	2,700 m (8,900 ft) 3,650 m (12,000 ft), resp.
Reservoir rock:	Chalk (Lulu) Sandstone (West Lulu)
Geological age:	Danian and Late Cretaceous and Middle Jurassic, resp.

Field name	Svend
Prospects:	North Arne/Otto
Location:	Block 5604/25
Concessionaire:	A.P. Møller
Operator:	Mærsk Olie & Gas AS
Discovered:	1975 (Nord Arne) 1982 (Otto)
Dev. plan approved:	1993
Year on stream:	May 1996
Water depth:	65 m (213 ft)
Reservoir depth:	approx. 2,500 m (8,200 ft)
Reservoir rock:	Chalk
Geological age:	Danian and Late Cretaceous

Field name	Adda
Location:	Block 5504/8
Concessionaire:	A.P. Møller
Operator:	Mærsk Olie & Gas AS
Discovered:	1977
Dev. plan approved:	1990
Year on stream:	1999 (at the latest)
Water depth:	38 m (125 ft)
Late Cretaceous reservoir:	
Reservoir depth:	2,200 m (7,200 ft)
Reservoir rock:	Chalk
Early Cretaceous reservoir:	
Reservoir depth:	2,300 m (7,500 ft)
Reservoir rock:	Chalk

Appendix G2

Field name	Igor
Location:	Block 5505/13
Concessionaire:	A.P. Møller
Operator:	Mærsk Olie & Gas AS
Discovered:	1977
Dev. plan approved:	1990
Year on stream:	1999 (at the latest)
Water depth:	38 m (125 ft)
Reservoir depth:	2,200 m (7,200 ft)
Reservoir rock:	Chalk
Geological age:	Danian and Late Cretaceous

Field name	Elly
Location:	Block 5504/6
Concessionaire:	A.P. Møller
Operator:	Mærsk Olie & Gas AS
Discovered:	1984
Dev. plan approved:	1995
Year on stream:	1999 (planned)
Water depth:	40 m (131 ft)
Reservoir depth:	3,200 m and 4,000 m (10,500 ft and 13,000 ft)
Reservoir rock:	Chalk and sandstone
Geological age:	Late Cretaceous and Jurassic

Field name	Gert
Location:	Block 5603/27 and 28
Concessionaire:	A.P. Møller
Operator:	Mærsk Olie & Gas AS
Discovered:	1984
Dev. plan submitted:	1991
Water depth:	70 m (230 ft)
Reservoir depth:	4,900 m (16,100 ft)
Reservoir rock:	Sandstone
Geological age:	Late Jurassic

Field name	Alma
Location:	Block 5505/17
Concessionaire:	A.P. Møller
Operator:	Mærsk Olie & Gas AS
Discovered:	1990
Dev. plan approved:	1995
Year on stream:	2003 (planned)
Water depth:	43 m (141 ft)
Reservoir depth:	3,600 m (11,800 ft)
Reservoir rock:	Sandstone
Geological age:	Jurassic

Danish Licence Area May 1996

The Western Area