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

As in previous years, the report for 2010 describes exploration and development activities in the Danish area as well as production. Moreover, the report describes the use of the Danish subsoil for purposes other than oil and gas production, including the exploitation of geothermal energy and the potential for Carbon Capture and Storage (CCS).

The report also contains a review of the health and safety aspects of oil and gas production activities, the environment and climate.

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

The report can be obtained from the DEA's website: www.ens.dk

DANISH ENERGY AGENCY

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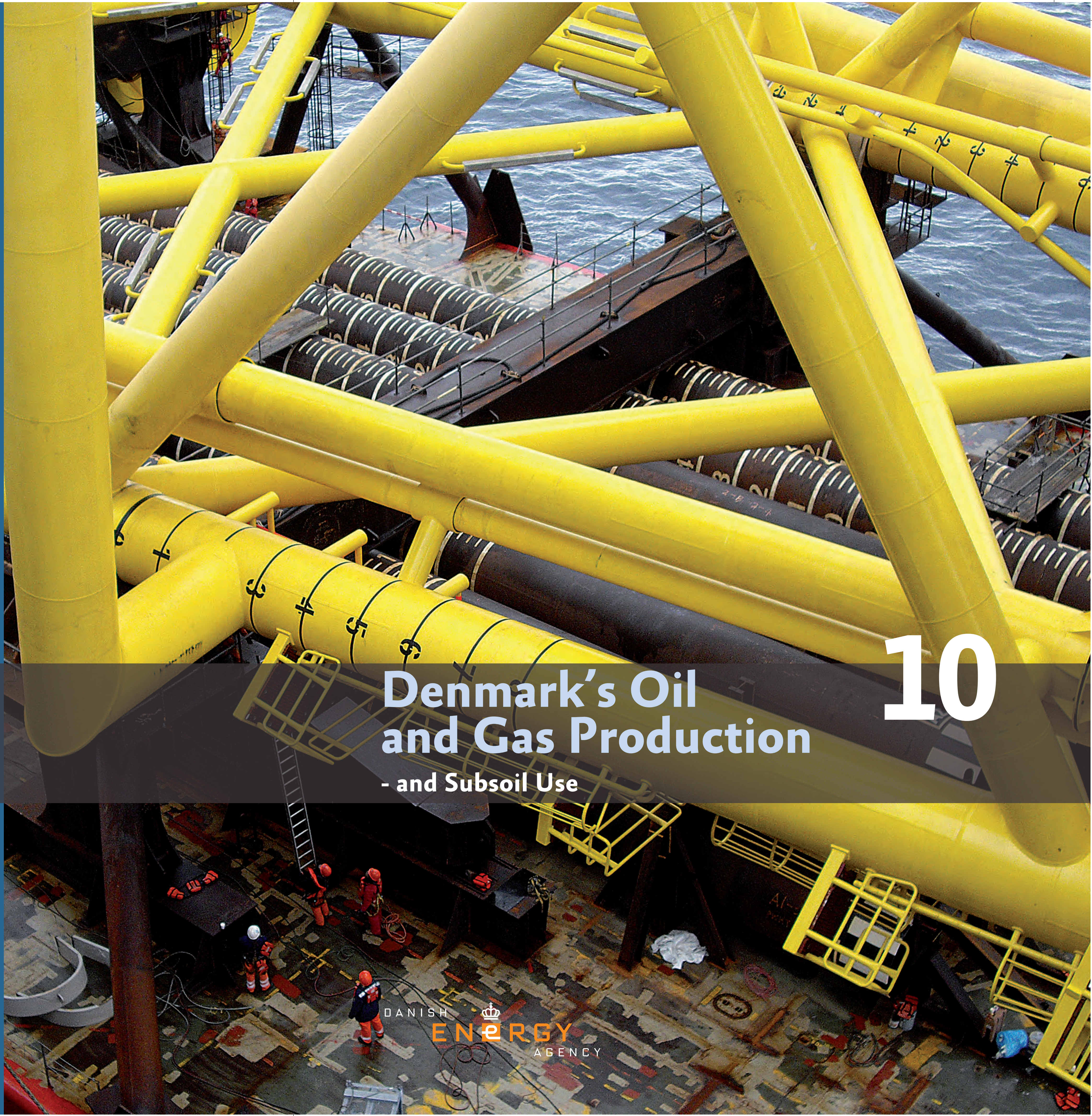

Denmark's Oil and Gas Production 10

- and Subsoil Use

DANISH ENERGY AGENCY

The Danish Energy Agency, DEA, was established in 1976 and is placed under the Ministry of Climate and Energy. The DEA works nationally and internationally with tasks related to energy supply and consumption, including renewable energy and security of supply, as well as CO_2-reducing measures. Thus, the DEA is responsible for the entire chain of tasks related to energy production and supply, transport and consumption, including improved energy efficiency and energy savings, renewable energy research and development projects, national CO_2 targets and initiatives to reduce the emission of greenhouse gases.

In addition, the DEA performs analyses and assessments of climate and energy developments at national and international level, and safeguards Danish interests in international cooperation on climate and energy issues.

The DEA advises the Minister on climate and energy matters and administers Danish legislation in these areas.

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PREFACE

Crane in action on drilling rig.

It is gratifying to see that new discoveries are still being made after almost 50 years of exploration in the Danish sector of the North Sea. In 2010, two exploration wells led to new oil discoveries – Solsort and Sara. The number of exploration wells in 2011 promises to be the highest in ten years. Moreover, the Minister for Climate and Energy has asked the DEA to begin preparations for inviting applications for new licences. This work has been initiated, with the aim of inviting applications for unlicensed areas in 2013.

The positive outlook is supported by the expectation that Denmark will be a net exporter of oil and natural gas until 2019 and 2012, respectively. These periods will be longer if new discoveries and new technology are included in the forecasts.

The DEA continues to focus on the safety and energy-efficiency of oil and gas production, including a reduction of environmental impacts. The serious incident that took place not in the North Sea, but in the Gulf of Mexico in 2010 stresses the need for this focus. An explosion on the semi-submersible drilling rig "Deepwater Horizon" killed 11 men and caused an oil spill that continued for nearly three months. One reason for this tragedy and the major environmental disaster has proved to be the companies' non-compliance with procedures.

The Minister for Climate and Energy and the Danish operators have agreed on an action plan to reinforce the measures for reducing energy consumption offshore. The action plan has resulted in lower energy consumption on the installations and reduced gas flaring in most fields. The DEA expects to enter into negotiations with the oil companies about a new action plan in this area as part of the Government's Energy Strategy 2050.

The format of "Denmark's Oil and Gas Production" has been changed this year in an effort to produce a more streamlined publication and better cohesion between the report and the DEA's website. Some of the more statistical parts of the report – most importantly the appendix describing the producing fields – have been moved to the DEA's website, www.ens.dk.

It is my hope that the new format continues to give the reader a good outline of and update on the use of the Danish subsoil.

Copenhagen, June 2011

Ib Larsen

Ib Larsen

CONTENTS

1 LICENCES AND EXPLORATION

After almost 50 years of exploration in the Danish sector of the North Sea, new discoveries are still being made. Two exploration wells were drilled in 2010 and both resulted in new oil discoveries – Solsort and Sara.

The issuing of three new licences confirms the oil companies' continuing interest in the Danish sector. Plans to invite applications for new licences will ensure continuity in oil and gas exploration.

EXCITING EXPLORATION AHEAD

It appears that the number of exploration wells in 2011 will be the highest for ten years. According to the oil companies' budgets, more than DKK 1 billion will be invested in on- and offshore oil and gas exploration in the Danish sector.

Onshore, there are plans for the drilling of two wells. In spring 2011, the American oil company GMT Exploration Company is to drill a well east of Givskud in Jutland under licence 2/07. This will be followed by a well under licence 1/05 at Felsted in South Jutland, to be drilled in the summer by the Polish state-owned oil company Polskie Górnictwo Naftowe i Gazownictwo SA (PGNiG). It is five years since the last onshore well for oil and gas was drilled in Denmark.

In the North Sea, the drilling of four to six wells is anticipated. PA Resources ApS has submitted plans for two wells under licence 12/06 in the southern part of the Central Graben. A number of other companies are in the process of finalizing their plans for wells to be drilled during the year.

Some of the planned wells will test new exploration models. An exploration model describes the geological preconditions which must be met in order for an oil or gas discovery to be possible. The most important preconditions are the presence of a source rock which has formed the hydrocarbons and the presence of reservoir layers where the hydrocarbons can accumulate.

PLANS TO INVITE APPLICATIONS FOR NEW LICENCES

In early 2011, the Minister for Climate and Energy asked the DEA to begin preparations for inviting applications for new licences.

The most recent licensing round in the area west of 6° 15' eastern longitude resulted in the issuing of 14 new licences in 2006. The agreements with the oil companies concerning the exploration work required to be carried out under the licences generally run for a term of six years. A number of the agreed exploration wells have already been drilled. At least seven exploration wells were to be drilled under the 6th Round licences. The oil companies' mapping of the licence areas has resulted in the identification of additional drilling targets. Once these exploration programmes are implemented over the next few years, the DEA expects a total of ten exploration wells to have been drilled in the 6th Round areas.

The well-developed infrastructure makes it possible to exploit oil and gas accumulations which would otherwise have been too expensive to develop. It is therefore important to utilize the existing infrastructure as best possible during its lifetime and to locate the subsoil accumulations that remain undiscovered. The DEA has therefore begun establishing the framework that will enable the oil companies to continue their exploration after the current exploration agreements have been fulfilled.

Before applications for the unlicensed areas can be invited, the Minister for Climate and Energy is required under the provisions in the Danish Subsoil Act to submit the plans and conditions to the Energy Policy Committee of the Danish Parliament. The DEA intends to schedule the work with the aim of inviting applications in 2013. This work will include an assessment of the financial conditions that will apply to a future licensing process.

NEW LICENCES

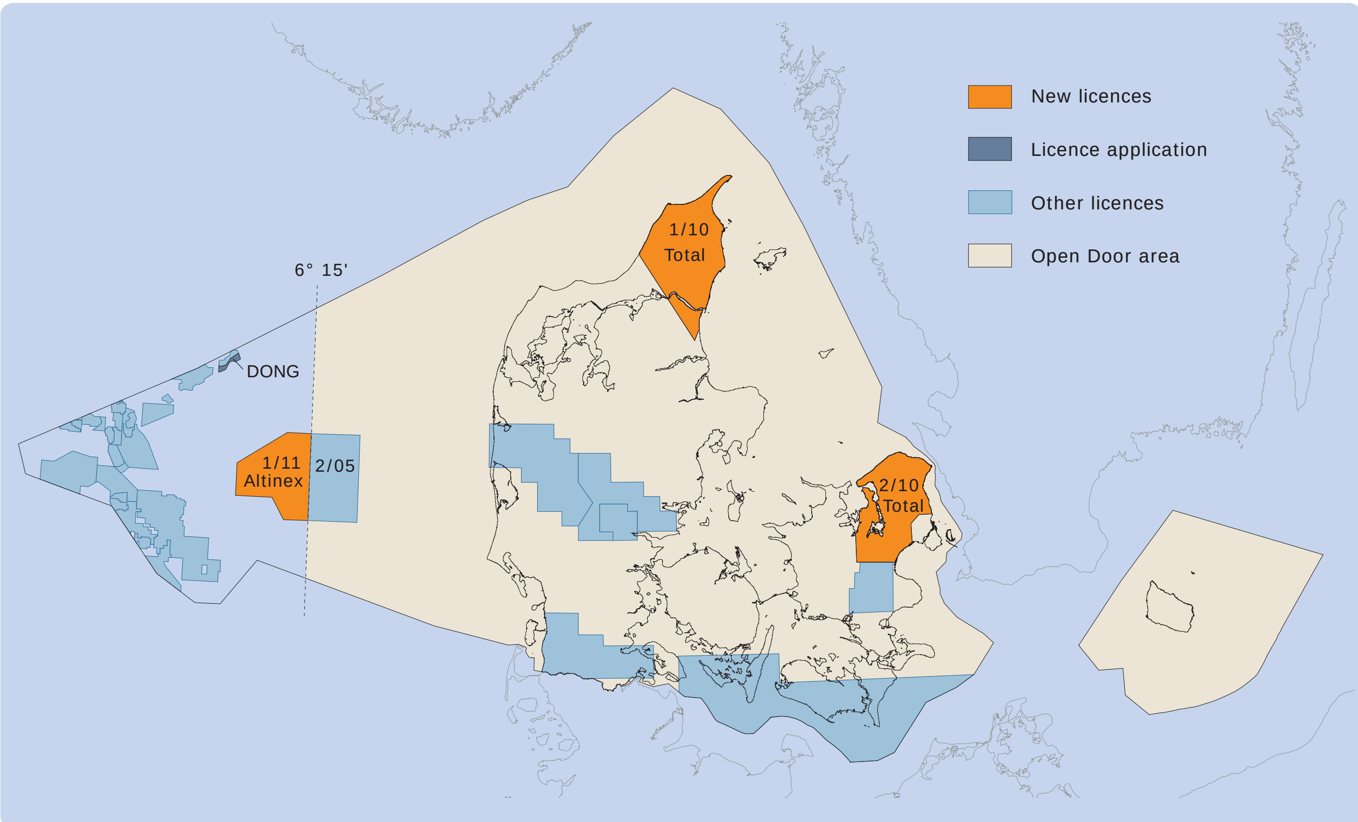
In 2010, the Minister for Climate and Energy issued two new licences for exploration and production of hydrocarbons in the Open Door area; see box 1.1 and figure 1.1.

The two licences – 1/10 and 2/10 – were issued on 5 June 2010 to Devon Energy Netherlands BV, with an 80 per cent share, and to the Danish North Sea Fund, with a 20 per cent share.

Licence 1/10 covers an area in northern Jutland, while licence 2/10 covers an area in northern Zealand.

Devon Energy Netherlands BV was subsequently taken over by the French oil company Total. Thus, Total has taken over Devon's shares and operatorships under the two licences via the company incorporated in the Netherlands, now called Total E&P Denmark B.V.

Fig. 1.1 New licences and application under consideration



Box 1.1

Open Door procedure
In 1997, an Open Door procedure was introduced for all unlicensed areas east of 6° 15′ eastern longitude, i.e. the entire Danish onshore and offshore areas with the exception of the westernmost part of the North Sea. The Open Door area is shown in figure 1.1 and appendix F1. In the westernmost part of the North Sea, applications are invited in licensing rounds.

Oil companies can continually apply for licences in the Open Door area within an annual application period from 2 January through 30 September. If the DEA receives more than one application for the same area, the first-come, first-served policy applies according to the licence conditions. This means that the first application to be considered is that received first.

To date, no commercial oil or gas discoveries have been made in the Open Door area. Open Door applications are therefore subject to more lenient work programme requirements than in the western part of the North Sea.

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

The Minister for Climate and Energy issues the licences after submitting the matter to the Parliamentary Energy Policy Committee.

On 27 January 2011, the Minister for Climate and Energy granted a new licence to Altinex Oil Denmark A/S, which has a 47 per cent share, Elko Energy A/S, which has a 33 per cent share, and the Danish North Sea Fund, which has a 20 per cent share. The licence was granted on the basis of an application for a so-called neighbouring block submitted by the above-mentioned companies, which also hold the adjacent licence 2/05. The new licence covers an area of the North Sea west of licence 2/05; see figure 1.1.

As the operator of licence 4/95, DONG E&P A/S submitted an application on 7 December 2010 for a neighbouring block to the area due south of the Nini Field in the North Sea. The application is currently being processed by the DEA.

AMENDED LICENCES

All contemplated licence transfers and extensions and the associated conditions must be submitted to the DEA for approval.

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

The maps of the licence areas in appendices F1 and F2 show the licences as at April 2011.

Transferred licence shares

With effect from 22 December 2009, PA Resources AB transferred its shares of

licences 9/95 and 9/06 to PA Resources Denmark ApS. PA Resources ApS is a wholly-owned subsidiary of PA Resources AB.

Devon Energy Netherlands B.V. was taken over by Total Holding Netherland B.V. with effect from 5 June 2010. Thus, the French oil company Total has taken over Devon's shares and operatorships of licences 1/10 and 2/10 via the company incorporated in the Netherlands, now called Total E&P Denmark B.V.

With effect from 1 June 2010, DONG E&P A/S transferred 15 per cent shares of licences 4/98 and 3/09 to VNG Danmark ApS, a subsidiary of the German company Verbundnetz Gas AG. VNG has not previously participated in Danish licences.

Effective 1 April 2010, Elko Energy A/S transferred a 47 per cent share of licence 2/05 to Altinex Oil Denmark A/S. Thus, Elko has reduced its share of the licence from 80 per cent to 33 pent. On 10 March 2011, the DEA approved the takeover by Altinex Oil Denmark A/S of the licence operatorship from Elko Energy.

DONG Central Graben E&P Ltd. transferred its operatorship of licence 4/98 to DONG E&P A/S with effect from 1 January 2009.

With effect from 1 July 2010, EWE Aktiengesellschaft transferred its shares of licences 4/06 and 5/06 to its wholly-owned subsidiary EWE ENERGIE AG.

GMT Exploration Company reduced its share of licence 2/07 from 55 per cent to 40 per cent. The 15 per cent share was transferred to the co-licensee Jordan Dansk Corporation, which thus increased its share from 25 per cent to 40 per cent. The transfer became effective on 1 January 2010. GMT has subsequently established a Danish branch, GMT Exploration Company Denmark ApS, and the DEA has approved the transfer of the company's 40 per cent share and operatorship of the licence to the Danish branch, effective 21 September 2010.

Spyker Energy SAS has transferred its 16 per cent share of licence 12/06 to Danoil Exploration A/S (8 per cent) and to Spyker Energy ApS (8 per cent). The transfer to Danoil became effective on 1 January 2011, while the transfer to Spyker's Danish subsidiary became effective on 11 March 2011.

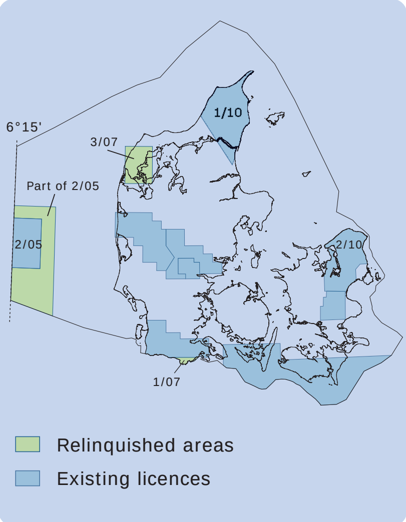
Extended licence terms

In 2010 and at the beginning of 2011, the DEA extended the terms of the licences shown in table 1.1 for the purpose of further exploration. The licence terms are generally extended on the condition that the licensees undertake to carry out additional exploration work in the relevant licence areas.

Table 1.1 Licences extended for the purpose of further exploration

Licence	Operator	Expiry
4/98	DONG E&P A/S	1 Jan 2013 (the Solsort part until 29 Jun 2011)
1/05	PGNiG	6 Apr 2012
2/05	Altinex Oil Denmark A/S	27 Jan 2013
8/06	Mærsk Olie og Gas A/S	22 May 2013

Fig. 1.2 Areas relinquished in the Open Door area



Terminated licences and area relinquishment

Licence 1/07, comprising an area at the German/Danish border in South Jutland, expired on 1 June 2010. The licence was held by Geo-Center-Nord G.m.b.H. (80 per cent) and the Danish North Sea Fund (20 per cent).

Licence 3/07 in the Open Door area was relinquished on 12 February 2011. The licence, comprising an area in northwestern Jutland, was held by DONG E&P A/S (80 per cent) and the Danish North Sea Fund (20 per cent). Geochemical surveys in 2007 and 2008 showed traces of hydrocarbons, and the licensee performed a 2D seismic survey in 2009.

The licensee holding licence 2/05 in the Open Door area relinquished about two-thirds of the original licence area with effect from 27 January 2011.

The changes in the Open Door area appear from figure 1.2.

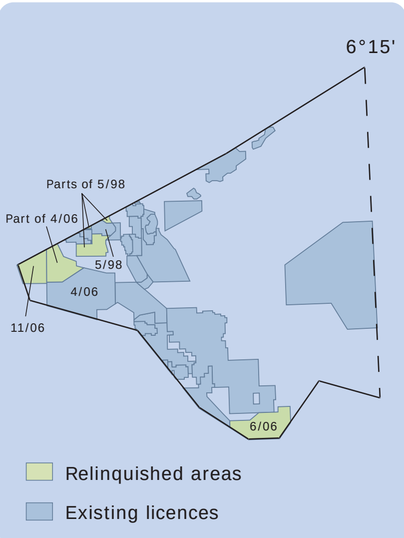
The holders of licences 5/98 and 1/06 submitted a declaration of commerciality for the Hejre oil accumulation in May 2010. Against this background, the DEA granted the licensees an extension for the purpose of production in respect of the areas in which the Hejre accumulation is located. The extension was granted until 15 October 2010 and covers part of licence 1/06 and part of licence 5/98. The licence for the remaining part of the 5/98 area expired on the same date.

Licence 6/06 was relinquished on 22 May 2010. This licence, comprising an area in the southern part of the Central Graben, was held by Wintershall Noordzee B.V. (35 per cent), Bayerngas Petroleum Danmark AS (30 per cent), EWE Aktiengesellschaft (15 per cent) and the Danish North Sea Fund (20 per cent). On the same date, the Wintershall group relinquished 25 per cent of licence 4/06 in the western part of the Central Graben.

Licence 11/06, comprising an area in the westernmost part of the North Sea, was relinquished on 15 November 2010. The licence was held by PA Resources UK Ltd. (64 per cent), Spyker Energy SAS (16 per cent) and the Danish North Sea Fund (20 per cent).

The changes in the area west of 6° 15′ eastern longitude are shown in figure 1.3.

Fig. 1.3 Areas relinquished west of 6°15' eastern longitude



Box 1.2

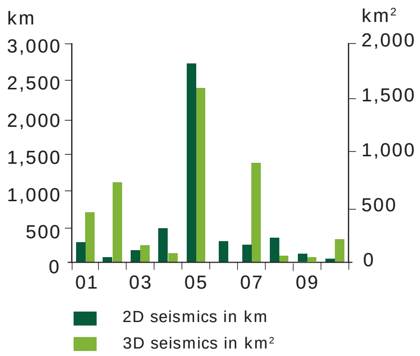
Access to exploration data

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

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

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

Fig. 1.4 Seismic data acquired during the period 2001-2010



EXPLORATORY SURVEYS

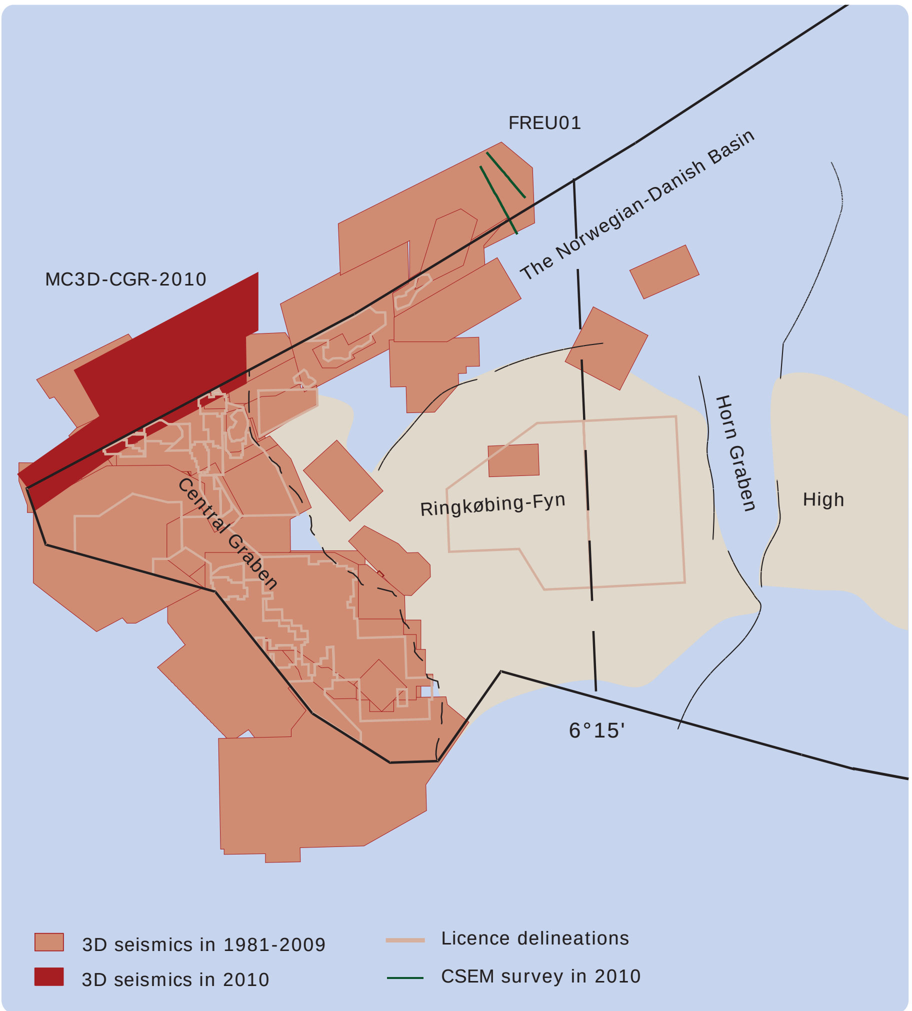
The level of activity for seismic surveys in 2001-2010 is shown in figure 1.4. Figure 1.5 shows the location of the exploratory surveys in the North Sea. The DEA's website contains an overview with supplementary information regarding the exploratory surveys mentioned below.

In the Central Graben, PGS Geophysical AS carried out a 3D seismic survey, MC3D-CGR-2010, during July-August 2010. This survey was particularly aimed at the Norwegian sector, but also covered an area of 300 km² on the Danish side of the border; see figure 1.5.

Further east in the Norwegian-Danish Basin, in March 2010 Rocksource ASA carried out a CSEM (electromagnetic) survey designated FREU01. The survey was carried out in the company's Norwegian licence area but concerned the Danish area to a lesser extent; see figure 1.5.

Onshore, in early 2010 Polskie Górnictwo Naftowe i Gazownictwo SA (PGNiG) completed the 3D seismic survey which the company had begun during the autumn

Fig. 1.5 Geophysical surveys west of 6°15' eastern longitude

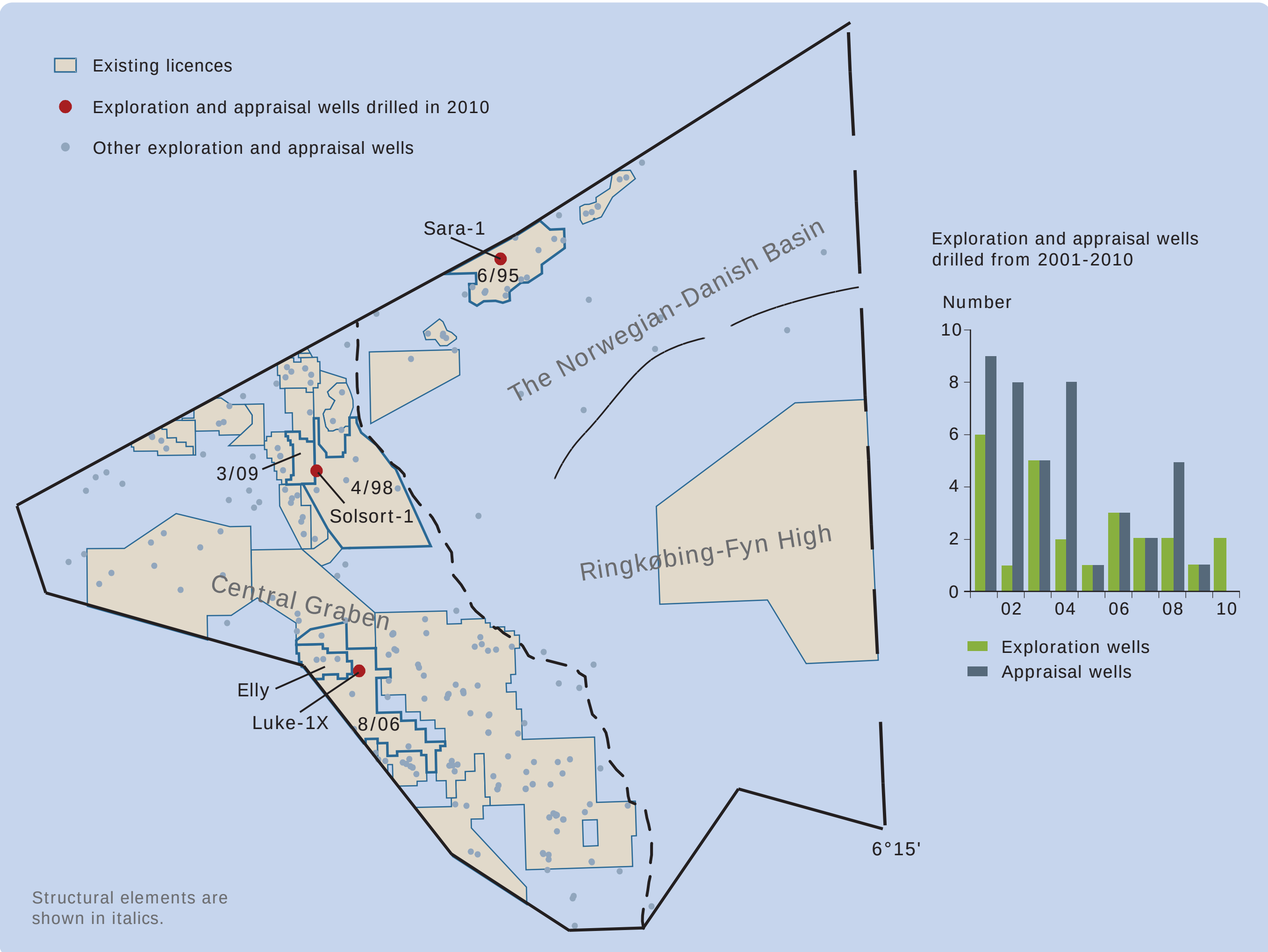


of 2009 in the eastern part of South Jutland. During 2010, an area of approx. 40 km² was covered and some 2D lines were also acquired for use in mapping the exploration potential of licence 1/05, for which PGNiG is operator.

During September 2010, Danica Resources ApS and Danica Jutland ApS collected soil samples in the companies' licence areas in mid-Jutland and on the islands of Lolland, Falster, Als and Langeland. The samples are being used for a geochemical analysis, which will show whether there are indications of oil or gas accumulations in the subsoil.

During August-September 2010, Viborg Fjernvarme acquired approx. 20 km of 2D seismic lines in and around Hjarbæk Fjord north of the town of Viborg. This investigation was carried out with the aim of identifying the opportunities for producing geothermal energy (see also chapter 2).

Fig. 1.6 Exploration and appraisal wells drilled in 2010 west of 6°15' eastern longitude



WELLS

During 2010, two exploration wells were drilled in the Central Graben and oil discoveries were made in both wells; see figure 1.6. These statistics only include wells spudded in 2010.

The Luke-1X well, which discovered gas under licence 8/06 due east of the Elly Field, was completed in February 2010, but is included in the statistics for 2009 and referred to in more detail in the annual report for 2009.

An outline of all Danish exploration and appraisal wells is available at the DEA's website, www.ens.dk.

Exploration wells

Solsort-1 (5604/26-05)
As operator for licence 4/98 DONG E&P A/S drilled the Solsort-1 exploration well in the Central Graben in September-December 2010. The Solsort-1 well was drilled in a joint venture between the licensees of the two licences 4/98 and 3/09, with each licensee contributing 50 per cent to the drilling operation. Licence 3/09 was issued in 2009 for a so-called neighbouring block to licence 4/98.

Solsort-1 was drilled as a vertical well and terminated in chalk layers presumed to be of Danian age at a depth of 3,041 metres below mean sea level. The well discovered oil in sandstone layers above the chalk. Core drilling was carried out, measurements made and oil samples taken. In order to assess the extent and quality of the oil discovery further, three sidetracks were drilled in different directions.

In addition to DONG E&P A/S, Bayerngas Danmark ApS, VNG Danmark ApS and the Danish North Sea Fund took part in drilling the well. The oil companies will now assess the results from Solsort-1 in more detail and draw up a plan for the additional work required to determine whether the oil discovery can be exploited commercially (evaluation programme).

Sara-1 (5604/16-01)
During the period from December 2010 to January 2011, DONG E&P A/S drilled the exploration well Sara-1 approx. 8 km north of the Siri Field under licence 6/95.

The Sara-1 well was carried out as a 'sole risk' well by DONG E&P A/S alone, as the other two companies holding the licence – Altinex Oil Denmark A/S and Siri (UK) Limited – did not wish to take part in the drilling operation.

Sara-1 was drilled as a deviated well and terminated in chalk layers at a depth of 2,075 metres below mean sea level. The well discovered oil in sandstone layers of Palaeocene age above the chalk. In order to assess the extent and quality of the oil discovery further, one sidetrack was drilled to a position approx. 1½ km from the main well. In the sidetrack, core drilling was carried out, fluid samples taken and extensive measurements made.

The results from Sara-1 will now be analyzed in more detail by DONG before a plan is drawn up for the additional work required to evaluate the discovery (evaluation programme).

2 USE OF THE SUBSOIL

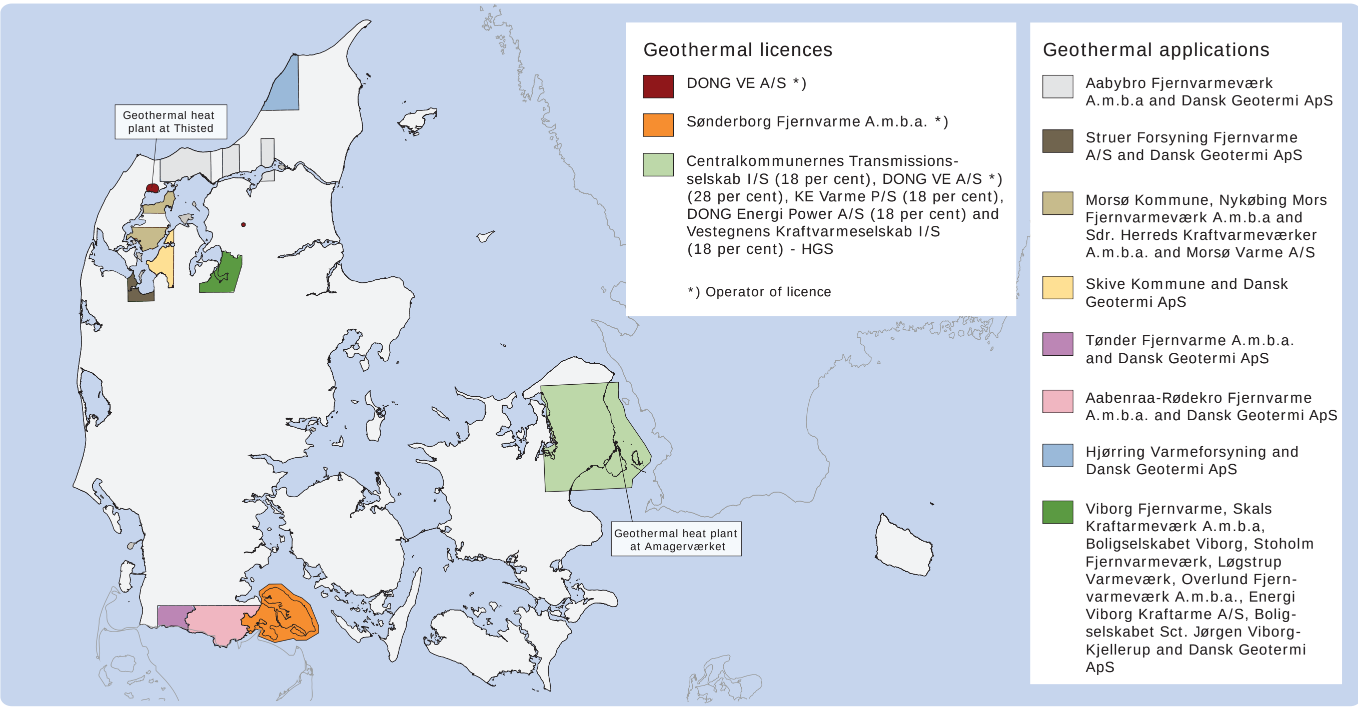
The use of the Danish subsoil for various purposes is regulated by the Act on the Use of the Danish Subsoil, usually referred to as the Danish Subsoil Act. This chapter describes use of the subsoil for purposes other than oil and gas production. In Denmark, the subsoil is also used to produce salt, explore for and produce geothermal heat and store natural gas. In addition, the framework for storing CO_2 in the subsoil is being defined. The Danish Subsoil Act is expected to be amended before the summer recess in 2011, one aim being to implement the EC Directive on the geological storage of carbon dioxide.

GEOTHERMAL HEAT PRODUCTION

In autumn 2009, the DEA published the report "Geothermal Energy – heat from the interior of the Earth, status and possibilities in Denmark". The DEA published a follow-up report in May 2010, "Geothermal Energy – heat from the interior of the Earth, international experience, financial issues and the challenges of geothermal heat production in Denmark". Both reports are available (in Danish) at the DEA's website, www.ens.dk. The main conclusions drawn from the 2009 report – regarding a large technical potential for exploiting geothermal energy in Denmark – were discussed in the DEA's report "Denmark's Oil and Gas Production – and Subsoil Use, 2009".

It was concluded in the report from May 2010 that the greatest challenges associated with establishing geothermal heat plants in Denmark are financial issues and the risks regarding the presence of subsoil sandstone layers with adequate production potential. The report also concluded that the heating price reflecting the production costs of geothermal plants is basically competitive compared with other heat production.

Fig. 2.1 Geothermal licences and applications at end-2010



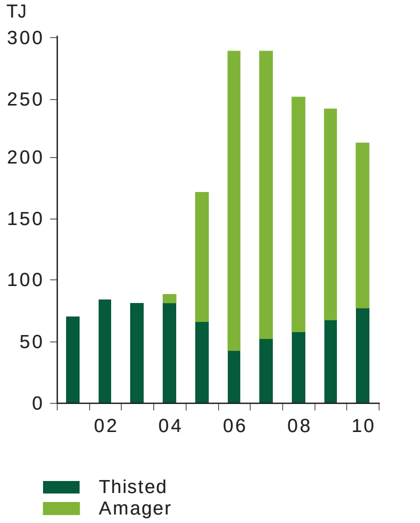
In the summer of 2010, DONG relinquished unutilized areas covered by its licence from 1983 to explore for and produce geothermal heat. Apart from a delimited area comprising the geothermal plant at Thisted and a small area comprising DONG's geothermal well at Aars, the remaining parts of the licence areas were relinquished. Figure 2.1 shows the areas covered by the licence from 1983.

To give all interested parties an opportunity to apply for a licence to explore for and produce geothermal energy, an open invitation for new applications to explore for and produce geothermal energy for district heating production was issued in autumn 2010. On 1 October 2010, the DEA presented the procedure for submitting such applications. In this connection, standard terms for licences to explore for and produce geothermal energy for district heating production were also presented. Applications for new licences could be submitted for the first time on 1 December 2010. Subsequent applications for new licences can be submitted twice a year, the deadlines being 1 February and 1 September. The application procedure (in Danish) appears from the DEA's website, www.ens.dk.

By the application deadline on 1 December 2010, the DEA had received a total of eight applications for licences for exploration and production of geothermal energy. The areas covered by these eight applications appear from figure 2.1, which also shows the existing licences for geothermal energy. Prior to the application period ending on 1 December 2010, the DEA had already received a number of applications for new geothermal energy licences. The relevant applicants were asked to confirm their applications and given an opportunity to make any adjustments to them. These applications are among the eight applications submitted by 1 December 2010. The DEA began processing the applications at the end of 2010. Before the Minister for Climate and Energy can issue the new licences, the matter must be submitted to the Energy Policy Committee of the Danish Parliament.

There are currently two geothermal heat plants in Denmark. The Thisted plant has been producing heat since 1984, and a plant at Amager since 2005. Figure 2.2 shows the production of geothermal energy during the past ten years. In total, 213 TJ of geothermal energy was produced for district heating purposes during 2010, which corresponds to the heat consumption of about 3,200 households. This is about 12 per cent less than in 2009, a decline caused by lower production from the Amager plant on account of technical issues.

Fig. 2.2 Production of geothermal energy 2001-2010



New geothermal plant at Sønderborg

In 2007, a licence to explore for and produce geothermal energy was issued, covering the municipality of Sønderborg. The area covered by the licence is shown in figure 2.1. The licence was granted to DONG VE A/S and Sønderborg Fjernvarme A.m.b.a. After seismic surveys of the subsoil were performed and the geological conditions in the area assessed, two wells were drilled in the first half of 2010 for the purpose of producing geothermal energy from a new plant. Production from the new plant is expected to start at the beginning of 2012.

The first well, Sønderborg-1, was drilled as a deviated well to a vertical depth of 2,401 metres, but did not encounter the sandstone layers expected at this depth. Instead it was decided to exploit higher sandstone layers at a depth of about 1,150 metres. Therefore, a sidetrack, Sønderborg-1A, was drilled to a vertical depth of 1,202 metres. In this well, a production test resulted in the production of water at a temperature of about 48° C. The next well, Sønderborg-2, was drilled to a depth of 1,247 metres, and

a production test in this well also resulted in the production of hot water. The two wells are spaced about 10 metres apart at the surface and about 700 metres apart at about 1,200 metres' depth in the subsoil sandstone layers from which the hot water is to be produced. Sønderborg Fjernvarme has disclosed that the cost of drilling the two wells totalled DKK 125 million.

In the autumn of 2010, DONG VE A/S withdrew from the licence, now held by Sønderborg Fjernvarme A.m.b.a. exclusively. In this connection, Sønderborg Fjernvarme A.m.b.a. has entered into an agreement with a consultancy company regarding technical assistance related to the geothermal plant and associated issues.

STORAGE OF CO_2

The potential for reducing atmospheric CO_2 emissions is an issue considered in many contexts. One possibility is to capture and then store CO_2 from major point sources such as power stations and major industrial plants. This technology is often referred to as 'CCS', which stands for 'Carbon Capture and Storage'.

CO_2 must be stored at locations with suitable geological conditions. Before such locations can be designated, a number of detailed investigations and assessments must be made to evaluate the appropriateness of the subsoil for CO_2 storage. There are a number of similarities between the technology for storing CO_2 and for storing natural gas in the subsoil.

Another possibility is to inject the CO_2 into the oil fields of the North Sea, which has the benefit of enabling more oil to be produced from the fields. Thus, the injection of CO_2 in an oil field can release more oil from the layers, oil that would not otherwise be recoverable with today's production technology. This method has not yet been introduced in the North Sea oil fields, but investigations are being carried out to determine the viability of such a project in the years to come.

In March 2010, Vattenfall submitted an application for a licence to use the subsoil for storing CO_2 in the Vedsted structure northwest of Aalborg. It has been agreed with Vattenfall that a decision on the application will not be made until the provisions of the CCS Directive have been implemented into Danish legislation; see below.

Casing is installed in well at Sønderborg.

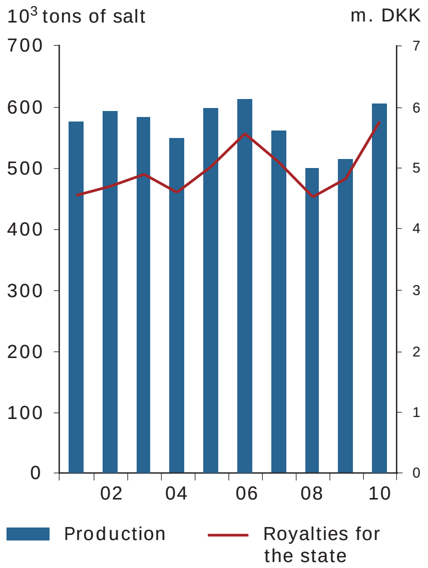
AMENDMENT OF THE SUBSOIL ACT

In April 2009, the EU adopted a Directive on the geological storage of carbon dioxide, the so-called CCS Directive. In the autumn of 2010, the DEA carried out a consultation process regarding a draft Bill to amend the Danish Subsoil Act, including proposed provisions to implement the provisions of the CCS Directive. In February 2011, following this consultation, the Minister for Climate and Energy presented a Bill in the Danish Parliament on an amendment of the Subsoil Act. The more technical aspects of the CCS Directive will be implemented into an executive order. The introduction of the Amendment Bill does not involve any decision on the use of CO_2 storage in Denmark. The Bill sets up a legal framework for the use of CO_2 storage in the event that it is decided to introduce this technology in Denmark.

The Bill to amend the Subsoil Act also includes proposals for other amendments.

The Bill proposes authorizing the right to refrain from processing uninvited new applications for licences to explore for and produce one or more raw materials. This makes it possible to prioritize the use of the subsoil for various purposes. The Bill also

Fig. 2.3 Salt production and state revenue from royalties, 2001-2010



proposes adding special provisions to the Act on the exploration for and production of geothermal energy, including on the procedure for submitting applications for new licences. Moreover, the Bill proposes revising the provision that entitles the Minister for Climate and Energy to stipulate coordinated production and utilization of installations for producing, processing and transporting oil and gas. The aim is to ensure the optimum utilization of the infrastructure with a view to extending the useful life of existing oil and gas fields and the production from new marginal fields.

GAS STORAGE

There are currently two gas storage facilities in Denmark. One facility is located at Stenlille on Zealand and is owned by DONG Storage A/S, while the other is situated at Lille Torup in northern Jutland and is owned by Energinet.dk Gaslager A/S.

In the spring of 2011, both companies were granted an extension of their licences for storing natural gas in the subsoil. Thus, the term of the licences has been extended until 2037.

More information about the Stenlille and Lille Torup gas storage facilities is available in the DEA's report "Denmark's Oil and Gas Production – and Subsoil Use, 2009".

SALT EXTRACTION

In Denmark, salt is extracted at one location only. The company Akzo Nobel Salt A/S extracts the salt from the Hvornum salt diapir about 8 km southwest of Hobro. The company has an exclusive licence for the production of salt from the Danish subsoil. The salt is used for consumption and for use as industrial salt and road salt.

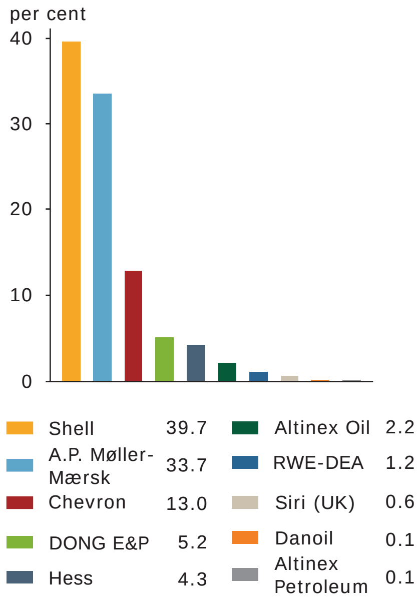
The production of salt totals about 500,000 to 600,000 tons per year, and the Danish state receives about DKK 5 million a year in royalties. Figure 2.3 shows the past ten years' production of salt and the Danish state's revenue in the form of royalties.

3 PRODUCTION AND DEVELOPMENT

Generally, the level of oil and gas activity in the Danish part of the North Sea remained high throughout 2010. The year was characterized by the addition of six new producing wells and by the startup of production from the Nini East platform. In addition, a major programme to optimize the production from existing wells and installations had a positive impact on production in 2010.

Fig. 3.1 Location of production facilities in the Danish North Sea 2010

Fig. 3.2 Breakdown of oil production by company



PRODUCTION IN 2010

To date, Danish oil and gas production has been carried on exclusively from offshore installations in the North Sea. Production in 2010 derived from 19 fields, of which 15 are operated by Mærsk Olie og Gas A/S, three by DONG E&P A/S and one by Hess Denmark ApS. Figure 3.1 shows the location of production installations and of major production pipelines.

A description of each individual field with an indication of wells, production figures and reserves is available at the DEA's website, www.ens.dk.

A total of ten companies contribute to Danish production, and DUC (Dansk Undergrunds Consortium) accounted for 86 per cent of oil production in 2010. Figure 3.2 shows all the companies' shares of total oil production in 2010.

During 2010, production in the North Sea took place from 283 active production wells, of which 198 were oil wells and 85 were gas wells. In addition, 108 active water-injection wells and 5 gas-injection wells contributed to production.

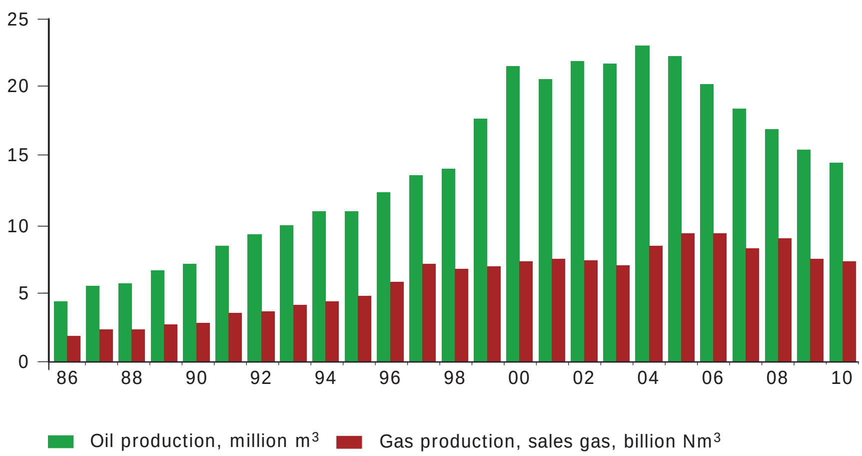
Oil production in 2010

Oil production in 2010 totalled 14.2 million m³, a 6 per cent decline compared to 2009. This reflects the trend of oil production since 2005, which has continued downwards at the rate of 3-9 per cent a year. This trend is partly due to ageing fields, of which the oldest field, Dan, started producing in 1972. Attempts are being made to offset the future decline in production by optimizing the production from existing fields based on existing and new technology and by developing new fields. The development in oil and gas production over the past 25 years appears from figure 3.3. Appendix A gives an outline of the amounts of oil produced and injected since 1972, broken down by field.

Apart from the expected decline in Danish oil production, the short-term shutdown of fields in connection with maintenance, repairs and modifications also contributed to the falling production figure. However, these shutdowns affected production much less than expected.

In a few fields, improved production has been achieved in old wells as a result of clean-up and refurbishment programmes as well as process optimization.

Fig. 3.3 Production of oil and sales gas 1986-2010



Installation of substructure for the Halfdan BD platform, 2010.

The new wells brought on stream in some fields in 2010 either improved production or postponed the decline in production from the relevant field for a period of time.

Gas production in 2010

The production of natural gas totalled 8.1 billion Nm³ in 2010, of which 7.1 billion Nm³ of gas was sales gas. This was a 2.5 per cent decline compared to 2009.

The remainder of the gas produced was either reinjected into selected fields to improve recovery or used as fuel on the platforms. A small volume of unutilized gas was flared for technical and safety reasons. The volumes of gas consumed as fuel and flared are described in the chapter *Environment and climate*, and an outline of the development since 1972 appears from appendix A.

Water production and water injection in 2010

Oil and gas production wells produce water as a by-product. Nevertheless, a high amount of energy is required to handle the water produced, as the content of water relative to the total liquids produced in the Danish part of the North Sea reached 72 per cent in 2010. In some of the old fields, the water content is now as high as 90 per cent. The water may derive from a natural water zone under the oil zone in the reservoir or from injection wells.

The production of water in 2010 dropped by 0.9 per cent compared to 2009. This figure should be viewed in light of the fact that five small fields did not carry on production for up to four months in 2009 and thus produced no water, either.

The injection of water in 2010 declined by 2.3 per cent on 2009, a continuation of the trend since 2007. The operators have an interest in reducing water injection to an absolute minimum in order to prevent the injected water from flowing into the production wells.

DEVELOPMENT ACTIVITY IN 2010

A total of six new production wells were drilled and completed in Danish fields in 2010. Thus, in terms of development drilling, the general activity level was lower in 2010 than in 2009, but the activity level is expected to increase again in 2011.

The above-mentioned wells and additional development activities represented total investments of DKK 4.9 billion, a decrease of about 27 per cent compared to 2009.

A description of the individual fields, including development and investment activities, as well as maps showing the location of the most important wells is available at the DEA's website, www.ens.dk.

Approved development plans and ongoing activities

The South Arne Field

In the South Arne Field, the development plan approved in 2009 was realized in 2010. Development of the field will take place in phases divided into individual stages, and the drilling of the two wells SA-20 and SA-21 in 2010 represented the first stage of the third development phase. As part of the development plan, the SA-17 well was plugged and abandoned.

On 25 June 2010, the operator applied for approval of the second stage of the third development phase for the field, consisting of the establishment of and subsequent production from two new platforms with a total of 11 new wells. One of the two new platforms will be an unmanned wellhead platform (WHP-N) about 2.5 km north of the existing South Arne platform. The other new platform will be a wellhead platform (WHP-E) placed east of the existing South Arne platform and connected to it by a bridge. In connection with the development, the necessary modifications will also be made for the purpose of hooking up the platforms to the existing installation and infrastructure, including pipeline connections from the existing installation to the new facilities.

The costs of the development project comprised by the application are estimated at more than DKK 5 billion, and production from the new wells will total about 5.6 million m^3 of oil and about 1.2 billion Nm^3 of gas. The development was initiated at the end of 2010, with production startup scheduled for the end of 2012. The plan was approved on 1 October 2010 and was published in the daily press on 6 October 2010.

The Dagmar Field

No production took place in the Dagmar Field in 2010, and the operator is still working on a reassessment of the field's potential and commerciality. A final plan is pending, but the field is not facing imminent decommissioning and removal of the installations.

The Tyra and Adda Fields

Development activity in the Tyra Field in 2010 consisted of a new well, TEB-23E, drilled from the Tyra East B platform. The well was approved in October 2009 and had originally been planned as a long-reach horizontal well with well sections drilled into the reservoirs of both the Tyra and Adda Fields. The well section projected to terminate in the Adda Field was not drilled due to geological conditions.

The results from the TEB-23E well in the Tyra Field are to be used, among other things, to assess the possibilities of developing the Adda Field as an independent field. As yet, no production has taken place in the Adda Field.

The Valdemar Field

As part of a development plan approved in 2004, two new wells, VAB-5 and VAB-2, were drilled in the Valdemar Field in 2010.

An additional well, VBA-6E, was spudded in 2010 and will be completed in 2011. This well was approved as part of a development plan in 2009.

Installation of substructure for the Halfdan BD platform, 2010.

The Halfdan Field

In the Halfdan Field, work proceeded in 2010 on installing the new Halfdan BD platform, which was approved in 2008 as part of the fourth phase of the field development plan. The platform will be commissioned in 2011.

As mentioned in the annual report for 2009, the HBB-9 well was spudded in 2009, and it was completed in 2010 from the Halfdan Field's HBB platform.

The Siri Field

As described in last year's annual report, problems were observed in 2009 in a subsea structure that supports the well caisson forming part of the Siri installation. A tem-

porary support structure to secure the caisson was established in January 2010, and efforts are still being made to find the best possible permanent solution. The plans for this work are expected to be available in the first half of 2011.

The Kraka Field
An extensive workover programme has been carried out for the existing wells in the Kraka Field, including the replacement of production tubing in the wells.

An application to plug and abandon the A-4H well and drill a new well, A-11, from the same location was approved in the autumn of 2010. The drilling of A-11 was started in 2010 and completed in 2011.

The exploration and appraisal wells drilled in 2010 are described in more detail in chapter 1, *Licences and exploration*.

Development plans received in 2010 but awaiting approval at the turn of the year 2010/2011

The Halfdan Field
The operator, Mærsk Olie og Gas A/S, applied for approval of a plan for the further development of the Halfdan Field on 5 November 2010.

The application requested permission to drill and produce from up to four new oil production wells from the existing wellhead module. The first part of the plan consists of drilling a well from Halfdan DA, and depending on the well results, the potential for drilling an additional three wells from Halfdan DA will be assessed.

The costs of the first well are estimated to total about DKK 256 million. Production from the well is estimated to amount to about 0.23 million m^3 of oil and about 0.19 billon Nm^3 of gas during the life of the well. The development plan is to be carried out at the beginning of 2011. The DEA processed the application at the turn of the year 2010/2011 and granted its approval in March 2011.

The Thialf crane vessel at the Halfdan B complex, 2010.

The Hejre Field
On 4 November 2010, the operator, DONG E&P A/S, applied for approval of the development of the Hejre Field, where no production has previously taken place. The field is located in Danish territory at the northern end of the Central Graben.

The application envisages the establishment of, and production from, a new offshore installation and five new wells. The projected offshore installation comprises a combined accommodation, wellhead and processing platform. The installation's processing capacity is estimated at 6,000 m^3 of oil per day, and the accommodation facilities are expected to accommodate a maximum of 70 persons. As part of the field development, pipelaying will also be carried out in connection with hooking up the platform to the existing infrastructure in the North Sea.

The geological conditions in the Hejre field require equipment for handling high pressures and high temperatures (HPHT equipment). The operator anticipates to produce both oil and wet gas, which will require the establishment of special technical installations.

The costs of the field development are expected to total about DKK 9 billion, and production from the wells is estimated to total about 16 million m^3 of oil and about 10 billion Nm^3 of gas during the term of the project. The field development is expected to start in 2014, with production startup scheduled for 2015. At the turn of the year 2010/2011, the DEA was considering the application and carrying on a dialogue with the operator.

Information about approved development plans and plans under consideration is also available at the DEA's website, www.ens.dk.

4 HEALTH AND SAFETY

Health and safety on fixed and mobile offshore units in the Danish continental shelf area are regulated by the Danish Offshore Safety Act and regulations issued under the Act. The Offshore Safety Act with associated regulations can be found at the DEA's website.

The Offshore Safety Act entered into force on 1 July 2006, but some of the regulations issued under the previous Act on offshore safety were upheld by the new Act, being gradually replaced by new provisions in the form of executive orders and associated guidelines. As a result of this process, the Offshore Safety Act became fully implemented in 2010.

The Offshore Safety Act is based on the premise that the companies should set high health and safety standards and reduce risks as much as reasonably practicable. Moreover, the Offshore Safety Act presupposes that the companies have a health and safety management system enabling them to control their own risks and ensure compliance with statutory rules and regulations.

Together with the Danish Maritime Authority, the DEA supervises the companies' risk control and compliance with rules and regulations. The DEA also cooperates with various national authorities as well as national and international organizations, including the Offshore Safety Council, the Danish Environmental Protection Agency and the North Sea Offshore Authorities Forum (NSOAF), regarding continuous improvements to health and safety conditions on the offshore installations.

High health and safety standards are vital to the almost 3,000 people who have their workplace on offshore installations in the Danish continental shelf area.

SUPERVISION OF HEALTH AND SAFETY ON THE NORTH SEA INSTALLATIONS

Working on offshore installations in the Danish continental shelf area should be safe. Through annual inspections and dialogue with the companies, the DEA therefore strives to ensure that the health and safety level in the Danish offshore sector remains among the highest in the North Sea countries.

The three main types of supervision are immediate inspections, project supervision and operations supervision.

Immediate inspections

Immediate inspections are carried out in connection with work-related accidents and major near-miss occurrences. In the event of immediate inspections, the DEA will assist in clarifying the sequence of events in cases where the police are involved, while the DEA will be solely responsible for this clarification if the police are not involved.

Project supervision

Project supervision consists of supervising new facilities and major modifications to existing offshore installations.

Operations supervision

The majority of inspections concern operations and comprise announced regular inspections, unannounced inspections and the supervision of special topics.

Energy Endeavour.

Box 4.1

Supervision of psychological working environment

The DEA supervised the psychological working environment in 2009 and 2010.

Psychological working environment is included under “Other risks” in sections 14, 16 and 19 of Executive Order No. 729 of 3 July 2009 on Health and Safety Management on Offshore Installations, etc. These risks include workload, time pressure, work rotation, influence on own work, noise and lack of undisturbed rest. Other risks are unclear definition and prioritization of tasks, and lack of managerial support and feedback.

The DEA reviewed the operating companies’ management system onshore to clarify how the system embodies psychological working environment. Inspections were subsequently carried out offshore to examine whether the management system is followed in practice, including whether there is a need to adapt the inspections with particular focus on psychological working environment.

The general conclusion with regard to the onshore inspections was that psychological working environment was not adequately defined in the companies’ management system and that factors relating to psychological working environment are not specifically considered in the risk assessments, but are considered indirectly in the assessment of other risk factors. In a few companies it was found that procedures for dealing with psychological working environment (work breaks, solitary work, and how to raise the topic for discussion) did not exist.

The general conclusion with regard to the offshore inspections was that good camaraderie, a tone of civility and mutual trust prevailed on board the installations. There is a general acceptance that situations of a personal nature or related to work can arise which necessitate a return home outside the normal rotation schedule. The right to say no and to rearrange job priorities when busy is also generally accepted.

Absence due to illness on the installations could not be attributed to the psychological working environment on board.

Catering deadlines are generally tight so adequate manning is important in this area.

Information sharing and good communication between employees and between employees and management are essential to a good psychological working environment, particularly in the case of organizational changes.

For contract personnel, not knowing the duration of employment is a stress factor.

The DEA found the psychological working environment on the offshore installations to be satisfactory and that none of the installations required a follow-up, adapted inspection with particular focus on this area. In the view of the DEA, the inspections have created a greater awareness and understanding among the companies and the employees of the issues relating to psychological working environment.

Helideck, Mærsk Resolve.

Regular inspections
Usually, the DEA carries out annual inspections of the operating conditions on all manned fixed installations and mobile units. Among other things, the annual inspection covers three fixed inspection items: a review of work-related accidents, hydrocarbon gas releases and the maintenance of safety-critical equipment.

Unannounced inspections
Unannounced inspections are carried out if announcing the inspection would compromise its purpose, e.g. when checking compliance with the regulations regarding rest periods, accommodation facilities and emergency procedures for the increased manning of installations, painting projects, etc. Moreover, unannounced inspections are carried out if unlawful circumstances are reported, or if otherwise warranted by employee health and safety considerations.

An unannounced inspection differs from the annual inspection of operations in the sense that the programme normally only focuses on two or three relevant issues.

Supervision of special topics
The supervision of special topics consists of inspections in which one specific topic is considered. Since 2007, the DEA has been focusing on:
- Work-related accidents (2007)
- Noise (2008)
- Psychological working environment (2009 - 2010)
- Musculoskeletal disorders (2010 - 2011)

The ongoing supervision of musculoskeletal disorders has been divided into three phases:
- Phase 1: The DEA's review of relevant parts of the company's management system
- Phase 2: Onshore information meeting at the DEA with the participation of all parties
- Phase 3: The DEA's offshore review (integrated part of the announced regular inspection of operations)

INSPECTIONS IN 2010
In 2010, the DEA carried out 32 offshore inspections, distributed on 19 inspections of manned production installations, two inspections of unmanned production installations and 11 inspections of mobile units, i.e. drilling rigs and accommodation units. The DEA made one immediate inspection on the mobile unit ENSCO 71 to follow up on a work-related accident.

Three inspections were carried out unannounced. Two of these inspections were carried out on the fixed installations Dan E and Tyra West, and the third on Mærsk Reacher, a mobile unit. The inspections did not result in the identification of any highly safety-critical conditions.

Three of the inspections on mobile units were carried out as extraordinary inspections of the BOP (blow-out prevention) equipment and procedures applied on the installations. These inspections were made to follow up on the Deepwater Horizon incident; see box 4.2.

In addition, the DEA made eight inspections of the onshore bases of operators and operating companies, as well as two inspections of their contractors' premises.

BOP valves.

Box 4.2

The Deepwater Horizon incident in the Gulf of Mexico

On 20 April 2010, an explosion occurred on the Deepwater Horizon mobile drilling rig, which was carrying out drilling operations in the Macondo Field. The drilling was being undertaken at a water depth of 1,544 metres and the explosion was caused by gas gushing uncontrolled out of the borehole.

Eleven people died, the drilling rig sank and, over a period of three months, more than 4 million barrels (800,000 m^3) of oil flowed up from the approx. 5,600 metre deep well and out into the Gulf of Mexico. The cause of this tragedy and the subsequent calamitous environmental effects has been identified as the failure of a number of independent barriers, which could have prevented the incident or averted the consequences of the incident. The explosion occurred during the drilling of the Macondo well.

In contrast to the situation in the Gulf of Mexico, the water depths in the Danish sector of the North Sea are less than 100 metres and drilling is carried out using jack-up drilling rigs, which stand on the seafloor and have the safety valve arrangement (Blow-out Preventer, compressed-air bank, emergency shutdown system, etc.) located in a dry and accessible location on the drilling rig beneath the drilling floor.

As an immediate response to the tragedy, the DEA carried out inspections of the safety valve arrangements on the three drilling rigs which were carrying out drilling operations at the time in the Danish offshore area. During these inspections, no safety-related deficiencies were identified in connection with well-control equipment, its maintenance or the procedures used for testing this equipment. Nor were any deficiencies identified in connection with procedures for shutting down the wells in an emergency, or in connection with awareness of these procedures among the personnel.

The DEA takes part in the ongoing analyses and evaluations that are carried out under the auspices of the EU and in international cooperation (see www.ens.dk), with the aim of learning from the tragedy and implementing the lessons learned in the regulation of drilling operations, particularly for drilling operations under difficult conditions, which in the Danish area means deep wells under high pressure and temperature conditions.

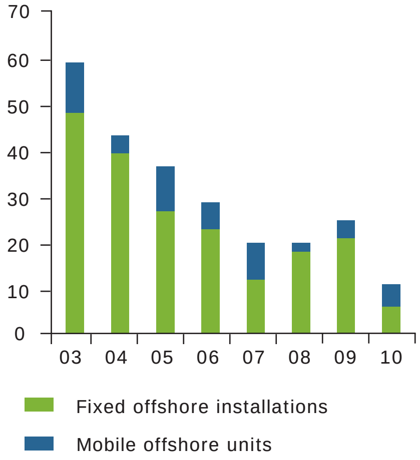
The European Commission has announced common EU regulation of this during 2011.

Finally, the DEA carried out an inspection of a drilling rig in Singapore before granting it a permit to operate in the Danish area.

An outline of all inspections in 2010 is available at the DEA's website, www.ens.dk.

As in previous years, supervision in 2010 focused on work-related accidents, near-miss occurrences, hydrocarbon releases, the maintenance of safety-critical equipment and the companies' management systems. Moreover, the DEA continuously supervises the emergency response system offshore.

Fig. 4.1 Number of work-related accidents on offshore installations, 2003-2010



WORK-RELATED INJURIES

Work-related injury is a generic term for work-related accidents and work-related diseases. Work-related accidents on offshore installations must be reported to the DEA; see box 4.3. Doctors are under a duty to report work-related diseases to the DEA, the Danish Working Environment Authority and the National Board of Industrial Injuries.

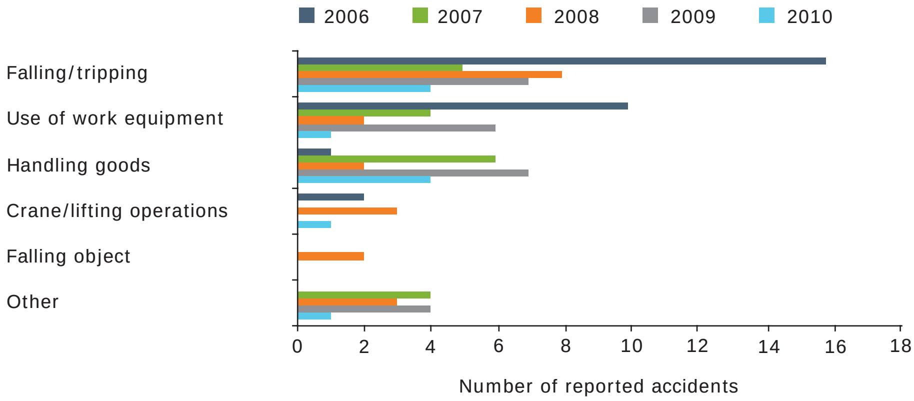
Work-related accidents

The DEA registers and processes all reported work-related accidents on Danish offshore installations and evaluates the follow-up procedures taken by the companies. At the DEA's first inspection after an accident, the work-related accident is addressed at a meeting with the safety organization on the installation. This procedure applies to all work-related accidents. In case of serious accidents, the DEA carries out an immediate inspection on the relevant installation in cooperation with the police.

The general aim of the DEA's follow-up on work-related accidents is to ensure that the companies and their safety organizations take concerted action to reinforce preventive measures on offshore installations.

In 2010, the DEA registered a total of 11 reports concerning work-related accidents, six on fixed offshore installations, including mobile accommodation units, and five on other mobile offshore units. The accidents are broken down by category in table 4.1 and figure 4.2.

Fig. 4.2 Number of work accidents on offshore installations in 2006-2010 distributed on cause of accident



Box 4.3

Reporting work-related accidents
Work-related accidents resulting in incapacity to work for one or more days beyond the injury date must be reported.

Employers are obliged to report accidents, but all other parties are entitled to file reports.

"An injured person who is unable to fully perform his or her ordinary duties" is considered to be unfit for work.

Table 4.2 indicates the actual periods of absence from work, broken down on fixed and mobile offshore units.

Over the previous years, the DEA has received a few delayed reports of work-related accidents, usually because the consequences of an incident appear later. This means that the accidents were reported too late to be included in the DEA's annual report for the relevant year.

When accidents are reported belatedly, the DEA restates the figures for work-related accidents in previous years. Thus, work-related accidents occurring in 2010, but reported in a later year, will be included in future annual reports.

Table 4.1 Reported accidents broken down by cause of accident

Cause of accident	Fixed	Mobile
Falling/tripping	3	1
Use of work equipment	1	0
Handling goods	1	3
Crane/lifting operations	0	1
Other	1	0
Total	**6**	**5**

Table 4.2 Actual absence due to reported work-related accidents in 2010

Duration	Fixed	Mobile
1-3 days	0	0
4-14 days	4	0
2-5 weeks	2	1
More than 5 weeks	0	2
Undisclosed	0	2
Total	**6**	**5**

In 2010, the DEA received one report of an accident that occurred in 2009. The statistics for 2009 have therefore been restated to include this accident, and discrepancies may occur when comparisons are made with figures in previous annual reports.

Accident frequency

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

Box 4.4

Scalding accident in laundry on fixed offshore installation

On 22 July 2010, a catering employee was scalded in a laundry accident. Believing that a washing machine had finished washing, the employee was scalded by hot water (90°C) when opening the door, sustaining second-degree burns to the lower legs and feet. The injury was immediately treated with cold water and the employee airlifted by helicopter to Esbjerg Hospital.

The DEA followed up on the accident at its next inspection on the installation and was informed that an indicator fault had been discovered in this type of washing machine. The fault had subsequently been rectified to prevent the door from being opened unless the wash cycle was complete. All washing machines had also been connected to the coldwater supply. The other installations in the North Sea were notified accordingly.

The DEA considers the matter closed.

Box 4.5

Lifting accident on the drilling rig ENSCO 71

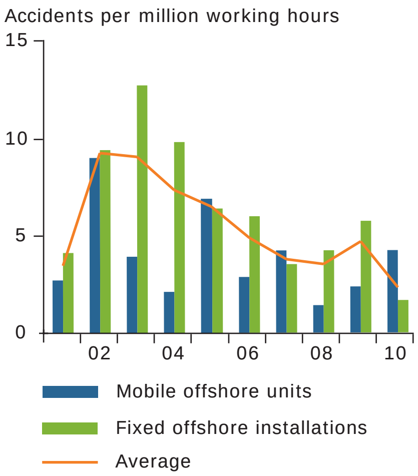
The accident took place on 11 June 2010 during routine lifting of casing (weight approx. 800 kg) from the main deck. While being lowered, the casing began to move and struck the employee who was helping guide it with a rope. The injured person, an experienced contract worker, was struck on the leg and sustained a twisted kneecap among other injuries. The person concerned was standing on a small platform and had a clear view of the port-side crane that was performing the lift.

The injured person was immediately flown by helicopter to Odense Hospital where he was found to have suffered serious knee injuries as well as contusions to the head and body.

The DEA investigated the scene of the accident together with the South Jutland Police. The DEA considered that although he had a clear view of the crane, the injured person’s view of the load at the time of the accident was restricted (partly by the Koomey unit and partly by casing positioned behind the Samson posts).

The operating company (ENSCO Netherlands Ltd.) has subsequently carried out a number of initiatives, including modifying all Work Instructions relating to safe work areas. A new Work Instruction focusing on job planning has also been drawn up. In addition, a new procedure for providing an improved introduction for contract personnel has been established.

Fig. 4.3 Offshore accident frequency



The overall accident frequency for fixed offshore installations and mobile offshore units in recent years appears from figure 4.3, which also shows that the overall accident frequency for fixed and mobile units was 2.3 in 2010. This is a decrease compared to 2009, when the overall accident frequency came to 4.6.

For mobile offshore units alone, five work-related accidents were recorded in 2010, and the number of working hours totalled 1.2 million. Thus, the accident frequency for mobile offshore units increased from 2.4 in 2009 to 4.2 in 2010.

The number of work-related accidents on fixed offshore installations and mobile accommodation units, which is calculated on a combined basis, totalled six in 2010. The operating companies have stated that the number of working hours in 2010 totalled 3.6 million on these offshore installations. The accident frequency for fixed offshore installations is thus 1.7 for 2010, a decrease on 2009 when the accident frequency came to 5.7.

Because of the relatively low number of accidents on offshore installations, merely a few accidents may change the picture from year to year. Thus, the trend over a number of years, and not the development from one year to another, provides the overall picture of the accident frequency.

Onshore accident frequency

The DEA has compared the accident frequency on Danish offshore installations with the onshore accident frequency, as shown in table 4.3.

Box 4.6

Work-related accidents calculated by the Danish Working Environment Authority

The Danish Working Environment Authority calculates the incidence of work-related accidents for onshore industries in Denmark on the basis of the number of accidents reported proportionate to the entire workforce, i.e. the number of employees. The Danish Working Environment Authority uses register-based labour force statistics from Statistics Denmark ("RAS statistics"), which are workforce statistics indicating the number of persons who had their main job in the relevant industries in November of the year preceding the year of calculation. The annual statistics compiled by the Danish Working Environment Authority indicate the incidence per 10,000 employees. Thus, for all onshore industries, the incidence was 150 reports per 10,000 employees in 2009.

This incidence is not directly comparable with the calculation of accidents relative to the number of hours worked (for example, per 1 million working hours). Converting the number of employees to the number of working hours would only result in an approximation, as it is assumed that one employee corresponds to one full-time equivalent (FTE). The figures for onshore companies are converted on the assumptions that the total number of working days is 222 days per year and that each working day averages 7.12 working hours, a full-time equivalent of 1,580 hours.

A total of 42,544 work-related accidents were reported for onshore companies in 2009. With a workforce of 2,831,120 employees (~ approx. 4.5 billion working hours)

Flare stack, Halfdan A.

Table 4.3 Accident frequencies in Danish offshore and onshore industries

Industry	**Frequency**						
	2004	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Offshore installations*	7.1	6.4	4.9	3.7	3.5	4.6	2.3
Total onshore industries	10.2	11.0	11.2	11.0	10.7	9.5	
Of which:							
- Shipyards	38.5	50.6	57.6	47.4	48.7		
- Earthwork, building and road construction	21.3	23.5	24.0	23.5	21.3		
- Masonry, joinery and carpentry	15.0	18.0	17.5	16.7	16.4		
- Insulation and installation work	16.1	18.7	18.9	19.8	19.9		
- Chemical industry	12.4	13.1	12.2	15.4	10.6		
- Heavy raw materials and semi-manufactures**	12.7	12.1	11.1	14.5	13.8		

*) *Overall accident frequency for fixed offshore installations and mobile offshore units.*
**) *"Heavy raw materials and semi-manufactures" covers many industries. For example, some of the subgroups within "Heavy raw materials and semi-manufactures" include the extraction of crude oil and natural gas and technical services related to oil and gas extraction activities.*

in 2009, the accident frequency in 2009 for all onshore industries can be calculated at 9.5 reports per 1 million working hours. The calculation is based on the assumptions described in box 4.6. The Danish Working Environment Authority has not yet calculated the number of work-related accidents and the number of employees for 2010.

The Danish Working Environment Authority changed the number of industries in its standard grouping in 2009. Previously, the standard grouping comprised 49 industries. This classification has now been changed to 36 different industries, which means that the figures for individual industries in 2009 are not comparable to the figures by industry for previous years. Therefore, the table only shows the overall accident frequency for onshore industries for 2009.

Work-related diseases

A work-related disease is defined as an illness or a disease that is due to long-term exposure to work-related factors or the conditions under which the work is performed on the offshore installation.

As from 1 July 2008, doctors have been obliged to report all diagnosed or suspected work-related diseases to the DEA. In addition, doctors must still report work-related diseases to the Danish Working Environment Authority and the National Board of Industrial Injuries.

To ensure that the DEA has received all reports of suspected work-related diseases attributable to work on an offshore installation, the DEA has awaited data from the Danish Working Environment Authority.

The Danish Working Environment Authority has completed its work regarding work-related diseases for 2009, but has not yet published statistics for 2010.

Box 4.7

Reporting near-miss occurrences
Near-miss occurrences are defined as occurrences that could have directly led to an accident involving personal injury or damage to the offshore installation. The occurrences to be reported to the DEA are specified in the Guidelines on Reporting Accidents, available at the DEA's website, www.ens.dk.

For 2009, the DEA received 19 reports on suspected work-related diseases from the Danish Working Environment Authority, based on a doctor's assessment that the relevant work-related disease was primarily contracted due to work on an offshore installation. The diseases reported for 2009 are distributed on five hearing injuries, seven musculoskeletal disorders, five skin disorders/eczema, one vibration injury and one psychological disorder.

NEAR-MISS OCCURRENCES

Major near-miss occurrences must be reported to the DEA; see box 4.7. In 2010, the DEA received a total of 11 reports on near-miss occurrences, which is much lower than in 2009.

Hydrocarbon gas releases are also defined as near-miss occurrences; see the section *Hydrocarbon gas releases*.

Box 4.8

The Accident Investigation Board
The Accident Investigation Board is composed of a group of impartial persons appointed by the Minister for Climate and Energy, and its objective is to investigate major incidents on offshore installations. Such incidents must have caused serious personal injury or damage to the installation and equipment on the installation, or they must have occurred due to external factors with resulting fatalities, serious personal injury or serious damage to the installation. In this context, serious personal injury is understood as injuries resulting in permanent disability and injuries resulting in illness absence of more than five weeks.

The objective of the Accident Investigation Board's work is to clarify how the incident arose and developed, its scope and adverse impact, as well as technical and organizational issues that may have had relevance for the incident.

If the Accident Investigation Board calls in experts or other persons to take part in an investigation made by the Board, the experts or persons in question must also be impartial.

HYDROCARBON GAS RELEASES

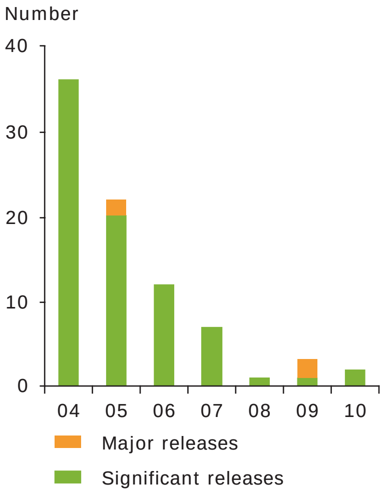
The operating companies are obliged to report all *major releases* and *significant releases* of hydrocarbons to the DEA immediately.

Major releases are releases of more than 300 kg or with a release rate of more than 1 kg/sec. for more than five minutes.

Significant releases are releases of 1-300 kg or with a release rate of 0.1-1 kg/sec. with a duration of two to five minutes.

In 2010, two significant releases were reported, of which one was caused by the incorrect assembly of two flanges. The release is estimated to have lasted six minutes, with a release rate of 0.07 kg/sec. The quantity released is estimated at 25 kg. The second release occurred during a leak test in which a blind plug was not reinserted due to an

Fig. 4.4 Accidental hydrocarbon gas releases, 2004-2010



oversight. The release had a duration of about 30 seconds, with a release rate of 0.08 kg/sec. A quantity of about 2.5 kg was released.

Since the DEA targeted its focus at accidental hydrocarbon gas releases, the total number of releases has dropped from 36 in 2004 to two releases in 2010; see figure 4.4. This decrease shows that the companies' efforts to reduce accidental hydrocarbon gas releases have been efficient.

APPROVALS AND PERMITS GRANTED IN 2010

The supervision of health and safety on fixed and mobile offshore units in the Danish continental shelf area involves granting approvals and permits for design, commissioning and modifications, as well as for the decommissioning of offshore installations.

Approvals and permits under the Offshore Safety Act

The overall design of a production installation must be approved according to section 27 of the Offshore Safety Act prior to detailed project design and construction.

Before production can commence, the installation must have an operating permit in accordance with section 28 of the Offshore Safety Act. Similarly, a mobile offshore unit, such as a drilling rig, must have an operating permit prior to use in Danish territory.

In the case of significant modifications to existing installations that impact the risk of major accidents, the operating company must apply for a permit for modifications under section 29 of the Offshore Safety Act.

Before an offshore installation is decommissioned, the licensee must apply for a permit in accordance with section 31 of the Offshore Safety Act.

In 2010, the DEA granted the following approvals and permits for fixed installations and mobile units as well as a pipeline in the Danish sector of the North Sea:

The South Arne Field

A permit has been issued for the development of the South Arne Field with two new platforms with a total of 11 wells and a pipeline between the platforms. One platform will be an unmanned wellhead platform approx. 2.5 km north of the existing South Arne platform. The other platform will be a wellhead platform located east of the South Arne platform to which it will be connected by a bridge.

In connection with the development, a number of permits have been issued to carry out modifications in preparation for hooking up the new platforms to the existing South Arne processing plant.

A permit has also been issued to increase manning of the South Arne platform and increase the occupancy of ten cabins in connection with preparations for the development project. The permit was issued for a period of four months and has subsequently been extended by three months.

The Halfdan Field

A permit has been issued for temporary changes to production on Halfdan A in the Halfdan Field. Furthermore, a permit has been issued to increase occupancy of 12 cabins on Halfdan A for a period of four months and to increase occupancy of 22 cabins for a period of 2½ months.

Halfdan B, accommodation.

The Dan Field
A permit has been issued for the establishment of a 20" riser on Dan FG in the Dan Field, as well as a permit to use ENSCO 70 for additional accommodation.

The Gorm Field (including the Skjold Field)
A permit has been issued to use Safe Esbjerg for extra accommodation at Gorm F in the Gorm Field. In addition, permits have been issued to increase occupancy of the cabins on Gorm and Skjold for a period of seven days.

The Tyra Field (including the Harald and Valdemar Fields)
A permit has been issued to enable Mærsk Resolve to carry out drilling operations at Tyra East B in the Tyra Field. Moreover, a permit has been issued to use Safe Esbjerg for extra accommodation at Tyra East with a bridge connection to platforms A and B.

For Valdemar BA, a permit has been issued for alteration of the operational conditions while Mærsk Resolve is situated adjacent to the platform as a drilling unit.

In addition, a permit has been issued to increase occupancy of the cabins on Tyra West for a period of seven days.

For Harald, a permit has been issued for increased occupancy of five cabins throughout 2010 in connection with the tie-in of Trym. In December 2010, the permit was extended to 31 July 2011.

Mobile units
Mærsk Reacher, ENSCO 70 and Safe Esbjerg were granted new operating permits in 2010. Permits were also issued for modifications to Mærsk Reacher, Mærsk Resolve, ENSCO 70, ENSCO 71 and Safe Esbjerg in connection with operations around fixed offshore installations.

Energy Endeavour, Mærsk Reacher, Atlantic Rotterdam and Noble George Sauvageau all left the Danish continental shelf area during 2010.

5 ENVIRONMENT AND CLIMATE

Exhausts from gas turbines on the South Arne offshore installation.

Exploration and production of hydrocarbons impact the environment, both through emissions to the atmosphere of gases like CO_2 (carbon dioxide) and NO_x (nitrogen oxide) and through the discharge of chemicals and oil residues into the sea. Another environmental impact consists of noise from the seismic acquisition of data about the subsoil and the construction of installations.

ENERGY EFFICIENCY OFFSHORE

The energy policy agreement entered into between the Government, the Danish Social Democrats, the Danish People's Party, the Socialist People's Party, the Danish Social-Liberal Party and New Alliance on 21 February 2008 set out goals for the development of Danish energy consumption during the period 2008-2011. One of the general goals in this energy agreement is to reduce gross Danish energy consumption by 2 per cent in 2011 and 4 per cent in 2020 relative to the level in 2006. As a follow-up to this agreement, the DEA, supported by the Danish operators, prepared the report entitled *"Increased energy efficiency in oil and gas production – review and proposals"*, December 2008. Based on this report, the Minister for Climate and Energy and

Box 5.1

Action plan to improve the energy efficiency of North Sea oil and gas production

One of the central elements in the existing action plan is the operators' commitment to introducing energy management, based on the principles laid down in the energy management standard. This means that the focus on energy efficiency has been maintained and strengthened, both in daily operations and in the planning of new projects. Thus, the operators have integrated energy efficiency into their policies and set goals for energy-efficiency initiatives in their energy management systems. For example, the operators have implemented the following specific initiatives:

- Transition to more energy-efficient operation of generators, pumps and compressors
- Reduction of energy consumption for lighting
- Better monitoring of wells, which reduces water production and the consumption of lift gas
- Better monitoring of equipment

In the action plan, the operators have undertaken to continue the optimization of operations with the aim of reducing the flaring of gas. Activities carried out in order to reduce the amount of flaring include:

- revised control and modification of selected process systems at both the Dan and the Gorm installations, enabling the recovery of gas flared,
- a systematic overhaul and repair of valves that have previously leaked gas to the flare system, and
- a reduction in the number of process equipment stoppages and a consequent reduction in blow-downs to the flare systems through better maintenance and an even stronger focus on stable operating conditions.

The action plan also incorporated a work schedule for making further analyses. These analyses have now been carried out, and the results were presented at the beginning of May 2010, along with a status report on the implementation of the action plan. The action plan and the status report are available at the DEA's website, www.ens.dk.

Box 5.2

Addendum to the amended action plan concerning recovery of flared gas
A portion of the flared gas can be recovered by means of installing and using gas recovery systems. Such systems exist on the platforms in Norway and on the Siri platform in the Danish sector of the North Sea. During normal operating conditions, the gas fed into the flare system is accumulated and compressed and then returned to the processing facilities on the platform.

The flared gas consists of gas to be flared for safety reasons and gas to be flared for technical reasons. At the end of 2008, it was established that approx. 60 per cent is flared for technical reasons, with safety flaring accounting for approx. 40 per cent. Flaring for technical reasons can be reduced by establishing flare gas recovery systems, while the flaring of gas for safety reasons can be reduced by a stronger focus on operational optimization.

In February 2010, the action plan was amended, to provide for the establishment of a newly developed flare gas recovery plant at Tyra West, instead of at Harald as originally agreed in the action plan. Both installations are operated by Mærsk Olie og Gas A/S. It has been agreed that Mærsk Olie og Gas will carry out an assessment of the pilot plant for flare gas recovery at Tyra West by 1 June 2011. When the results are available, Mærsk Olie og Gas and the DEA will consider at which other installations the operators can install flare gas recovery systems as from 2013.

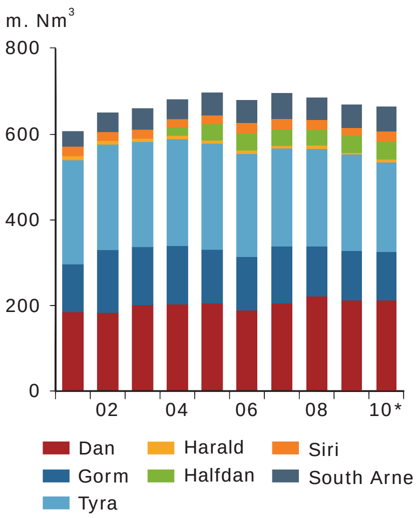
To follow up on the action plan, Hess Denmark ApS has analyzed the opportunities for establishing a flare gas recovery plant at South Arne and has subsequently decided to establish a plant, which is expected to become operational in mid-2012.

the Danish operators agreed in April 2009 to launch an action plan to reinforce the measures for reducing energy consumption offshore. The action plan was then supplemented by an addendum in February 2010.

This action plan contains a series of initiatives aimed at improving energy efficiency, which are collectively expected to result in a 3 per cent reduction of energy consumption during the period 2006-2011, compared with the previously expected increase of 1.5 per cent. These initiatives will thus result in total savings of around 4.5 per cent relative to 2006, about one quarter of which will come from a reduction in gas flaring as a result of operational changes.

One of the issues in Energy Strategy 2050 is the Government's preparation of a new action plan to improve the energy efficiency of North Sea oil and gas production. The new action plan, which is to be drawn up in agreement with the oil companies carrying on production in the North Sea, is to cover a period extending beyond the current plan period. The new action plan is expected to be negotiated in mid-2011.

Fig. 5.1 Fuel consumption (gas)



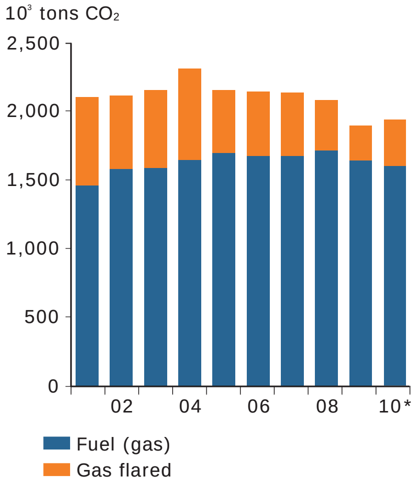
*As from 2006, the figures have been based on verified CO_2 emission data from reports filed under the the Act on CO_2 Allowances

EMISSIONS TO THE ATMOSPHERE

Emissions to the atmosphere consist of such gases as CO_2 and NO_x.

The combustion and flaring of natural gas and diesel oil produce CO_2 emissions to the atmosphere. Producing and transporting oil and gas require substantial amounts of energy. Furthermore, a volume of gas has to be flared for safety or plant-related

Fig. 5.2 CO_2 emissions from production facilities in the North Sea



*As from 2006, the figures have been based on verified CO_2 emission data from reports filed under the the Act on CO_2 Allowances and have included CO_2 emissions from diesel combustion

reasons. Gas is flared on all offshore platforms with production facilities, and for safety reasons gas flaring is necessary if the installations must be emptied of gas quickly.

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

The Danish Subsoil Act regulates the volumes of gas flared, while CO_2 emissions (including from flaring) are regulated by the Danish Act on CO_2 Allowances.

Consumption of fuel

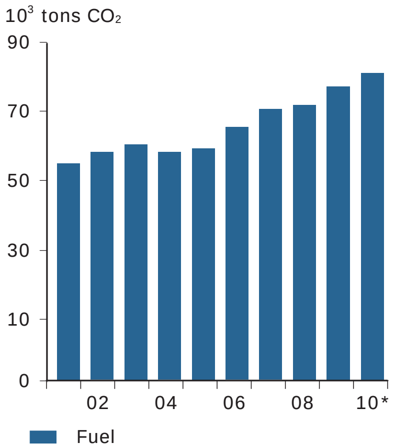
Fuel gas accounted for close to 85 per cent of total gas consumption offshore in 2010. The remaining 15 per cent was flared. The development in the use of gas as fuel on Danish production installations appears from figure 5.1. The general increase until 2007 is attributable to rising oil and gas production and ageing fields. The main reason for the sharp drop from 2008 is energy-efficiency measures taken by the operators.

In recent years, the steadily ageing fields have particularly impacted on fuel consumption. Natural conditions in the Danish fields mean that energy consumption per produced ton oil equivalent (t.o.e.) increases the longer a field has carried on production. This is because the water content of production increases over the life of a field, and oil and gas production therefore accounts for a relatively lower share of total production. Assuming unchanged production conditions, this increases the need for injecting lift gas, and possibly water, to maintain pressure in the reservoir. Both processes are energy-intensive.

The development in the emission of CO_2 from the North Sea production facilities since 2001 appears from figure 5.2. This figure shows that CO_2 emissions totalled about 1.89 million tons in 2010, the next lowest level in the past ten years and only a slight increase on 2009.

It appears from figure 5.3 that CO_2 emissions due to fuel consumption have increased relative to the size of hydrocarbon production over the past decade. The reason for this increase is that oil and gas production has dropped more sharply than fuel con-

Fig. 5.3 CO_2 emissions from consumption of fuel per m. t.o.e.



*As from 2006, the figures have been based on verified CO_2 emission data from reports filed under the the Act on CO_2 Allowances and have included CO_2 emissions from diesel combustion

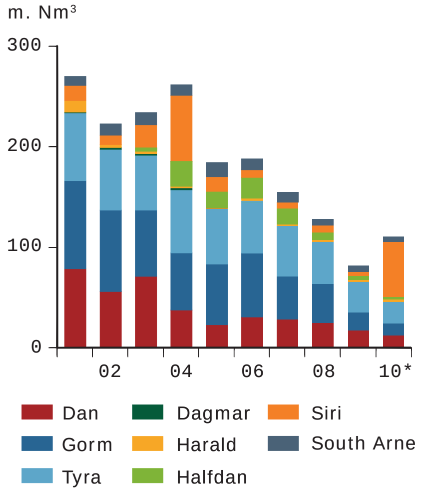
Box 5.3

Siri

Since production started at the end of March 2010 at Nini East, which forms part of the Nini Field, flaring on the Siri platform has been markedly higher than previously. The reason is that the properties of the produced gas are incompatible with the gas compressor at Siri due to a design fault. As a result, the capacity of the compressor is too low.

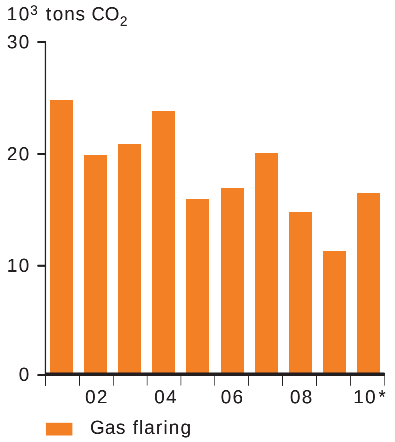
At the request of the DEA, DONG E&P A/S submitted a report in August 2010, showing how flaring can be reduced. DONG E&P A/S stated that a number of measures had been implemented to reduce flaring from the area. Parts of the compressor have been replaced; production from the Cecilie Field has been shut down for a period of time; and production from the Nini East Field has been reduced. Work is also proceeding on other process optimization measures to reduce flaring. In January 2011, the compressor was upgraded in order to increase its capacity.

Fig. 5.4 Gas flaring



*As from 2006, the figures have been based on verified CO_2 emission data from reports filed under the the Act on CO_2 Allowances

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



*As from 2006, the figures have been based on verified CO_2 emission data from reports filed under the the Act on CO_2 Allowances and have included CO_2 emissions from diesel combustion

sumption, which means that CO_2 emissions due to fuel consumption have increased relative to the size of production.

Gas flaring

The flaring of gas declined substantially from 2006 to 2010 in all fields with the exception of the Siri Field, which was affected by special technical conditions (see Box 5.3). This development is attributable to more stable operating conditions on the installations, changes in operations and focus on energy efficiency. As appears from figure 5.4, which shows the volumes of gas flared, flaring varies considerably from one year to another. The large fluctuation in 2004 is partially due to the tie-in of new fields and the commissioning of new facilities. In 2010, gas flaring totalled 116 million Nm³, of which flaring at Siri accounted for almost 50 per cent.

The volume of gas flared depends in part on the design and layout of the individual installation, but not on the volumes of gas or oil produced.

In 2010, CO_2 emissions from flaring came to 0.33 million tons of CO_2 out of total CO_2 emissions from the offshore sector of 1.89 million tons, i.e. 17.5 per cent of total emissions. All CO_2 emissions are comprised by the CO_2 allowance scheme.

Emissions from flaring declined steadily from 2004 to 2009, but increased again in 2010. However, if Siri's share of flaring is disregarded, total flaring decreased for all other fields from 2009 to 2010. The production of hydrocarbons has declined during the past decade, and thus the volume of gas flared per t.o.e. produced increased until 2007; see figure 5.5. The volume of gas flared per t.o.e. produced fell from 2008 to 2009, increasing again in 2010. However, if Siri is excluded from the calculation, there was a further decline in flaring from about 12 to 9.6 ktons of CO_2 per million t.o.e., which means that for the majority of fields the reduction in flaring was substantial enough to offset the fall in hydrocarbon production.

MARINE ENVIRONMENTAL IMPACTS

The production of hydrocarbons in Denmark currently takes place offshore, and this production and the drilling of wells result in marine discharges and atmospheric emissions. Likewise, exploration activities take place offshore, e.g. the acquisition of seismic data, which is carried out by emitting pressure waves (noise) into the sea. Thus, marine flora and fauna are exposed to direct impacts. In partnership with many other authorities and organizations, the DEA contributes to protecting the marine environment as best possible through the regulation of offshore activities.

Marine discharges

Controlled discharges of chemicals, oil residue and subsoil waste material are made into the sea in connection with oil and gas production and the drilling of new wells. In addition, unintentional spills may occur, particularly due to the failure of equipment or materials.

To reduce the environmental impact from discharged chemical residue, environmentally hazardous chemicals are substituted by less hazardous ones where possible. Water containing residue from the production processes is treated and purified in several stages before being discharged into the sea.

Marine discharges are regulated by the Danish Marine Environment Protection Act and the Minister for the Environment's Offshore Action Plan, which sets limits for

The Dan B offshore installation.

the discharge of oil and chemicals in produced water. Through agreements under the international OSPAR Convention on the protection of the marine environment, Denmark has committed itself to regulating discharges in the same way as the other Contracting Parties. The objective of the OSPAR Convention is to protect the marine environment of the North-East Atlantic, including the North Sea.

A mixture of gas, oil and water flows into the wells from the subsoil, and this mixture is separated in a processing plant on the platforms. While gas and oil represent a value, the water is an inconvenient residual product. As the natural bottomhole pressure in the wells decreases over time, it is necessary in Danish fields to pump water down into the subsoil from the platforms to maintain the pressure. This gradually increases the volume of water in the production wells, so that today around three times as much water as oil is "produced". As the water injected to boost pressure is predominantly treated seawater, great efforts are being made to replace seawater with treated produced water, so that the quantities of residual products discharged into the sea with produced water can be reduced further.

One of the challenges associated with reinjecting produced water into the chalk reservoirs that make up the majority of Danish oil fields is to achieve adequate water treatment in order to avoid a reduction in the reservoir's performance and increased wear on equipment.

Exploration activity and protection of the environment

Generally, exploration activity such as preliminary investigations (e.g. seismic surveys) and exploration wells will not require an Environmental Impact Assessment (EIA).

When submitting an application for a project, e.g. an exploration well or a seismic survey, the applicant must include all necessary information about the project and its impact on international protection areas. On this basis, the DEA will decide whether an impact assessment is required.

Projects assumed to impact an international protection area will only be permitted if the impact assessment shows that the project will not interfere with the protection area designation basis. The DEA will decide whether the application for approval of the project is to include an impact assessment. Applicants should take into account that it may take longer time to obtain a permit for a project if the DEA arrives at the conclusion that an impact assessment is required.

The DEA may attach special terms and conditions to a permit or an approval for the purpose of protecting the environment, nature or cultural heritage. Such terms and conditions may place restrictions on the project; for example, time limits may be imposed for noise-generating activities in some areas. A case in point is a condition stipulating that whales, which are protected under the EU Habitats Directive, must not be disturbed during periods when the relevant species is particularly sensitive to disturbances, e.g. during the mating and breeding season.

As mentioned above, whales belong to the species protected by the EU Habitats Directive. This means that the implementation of projects, including exploration activity, must not disturb them in their natural habitats. Permission for a project will not be granted if the project would harm an international protection area significantly. Applications for exploration activity must include sufficient information for the DEA

The Tyra East offshore installation.

to assess whether the activity might cause disturbance of any species protected by the EU Habitats Directive.

One of the standard conditions included in approvals or permits is that companies must use what is known as a "soft start procedure" when carrying out noise-generating activity. The soft start procedure is based on slowly increasing the sound level from the sound source up to the operational level. If marine mammals are observed at a distance of less than 200 metres from the sound source, the soft start procedure must be postponed. The soft start procedure must be carried out in accordance with a set of "best practice" guidelines prepared by the National Environmental Research Institute ("NERI").

The conditions that are imposed in connection with the approval of marine activities are partly based on the latest data and information concerning the presence and behaviour of the marine mammals that live in the Danish offshore area. The DEA continually reassesses and updates the conditions as new knowledge about the subject is acquired in order to ensure compliance with the requirements of the Habitats Directive concerning the strict protection of, e.g., marine mammals.

At the end of 2009, the DEA received preliminary reports from Mærsk Olie og Gas A/S concerning the provisional results from two monitoring programmes relating to, e.g., the behaviour and distribution of porpoise in the western area of the North Sea. Mærsk Olie og Gas A/S had monitoring programmes carried out as part of the company's obligations in connection with oil and gas operations. Based on the results in the reports, the DEA instigated work that involved the consultation of NERI and the Nature Agency. This work was to clarify whether further initiatives would be required to ensure the best protection of marine mammals. Against this background, the DEA assessed that there is a need for collecting more data, including about the periodic occurrence of porpoises in the western part of the Danish North Sea sector. The monitoring programme will be launched in the course of 2011.

The Marine Strategy Framework Directive

The Marine Strategy Framework Directive (Directive 2008/56/EC establishing a framework for community action in the field of marine environmental policy) sets out a common approach for the Member States with the objective of maintaining or achieving good environmental status in the marine environment by the year 2020 at the latest. The Marine Strategy Framework Directive requires each Member State to prepare and implement marine strategies for its territorial waters. As part of these strategies, the Member States must prepare basic analyses which describe the status and impacts on the territorial waters, set goals concerning natural and environmental status and associated indicators, and establish initiative and monitoring programmes to maintain or achieve good environmental status for the marine areas.

The aim of the marine strategies is to protect, conserve and prevent deterioration of the marine environment and, insofar as is possible, restore marine ecosystems in areas where negative impacts have already occurred. A further aim is to reduce and prevent pollution of the marine environment and its harmful effects. By adopting an ecosystem-based approach to the management of human activity, it is to be ensured that the combined pressure from these activities will be kept within levels that are compatible with the achievement of good environmental status, and that marine ecosystems will retain the ability to cope with the human-induced changes to which they are exposed.

In Denmark, the Directive has been implemented through the Marine Strategy Act (Act No. 522 of 26 May 2010 on Marine Strategy), which entered into force on 25 July 2010.

The Danish Nature Agency under the Ministry of the Environment has instigated a series of activities as part of the preparation of basic analyses of Danish territorial waters, descriptions of good environmental status and proposals for environmental goals, which must all be available by 15 July 2012. The DEA is monitoring the work in a group of authority representatives which was set up in this connection.

An integrated maritime strategy
In July 2010, the Government issued "An integrated maritime strategy". This strategy presents an integrated picture of the policies that apply to Denmark's territorial waters in addition to an overview of the initiatives and specific measures which are either already in place or planned. The aim is to create good opportunities for commercial development for the maritime industries through an integrated approach. The strategy covers maritime industries in a broad sense, including oil and gas recovery and other use of the subsoil in Danish territorial waters.

The strategy is aimed at five general goals:

1. Good development opportunities for the maritime industries
2. Reduced greenhouse gas emissions and reduced atmospheric pollution
3. Protection of the marine environment and coastal zone
4. Improved safety at sea
5. Coordination of initiatives in the maritime field

The strategy represents a follow-up to the EU's "Integrated Maritime Policy", which among other things points to an integrated approach to maritime policy and the benefits of enhanced coordination by the Member States of their maritime initiatives.

The DEA is the responsible authority for some of the initiatives in the strategy, including:

- working to ultimately achieve mutual recognition of a number of offshore training courses among the North Sea countries,
- working to ensure that the recovery of oil and gas is carried out in an energy-efficient manner, see the action plan to improve the energy efficiency of North Sea oil and gas production 2009-2011,
- striving to ensure that Danish oil and gas reserves are utilized optimally and safely with respect for the environment, through better recovery methods, and
- monitoring international developments concerning the storage of CO_2 in the subsoil, and considering any Danish CO_2 storage initiatives against this background.

"An integrated maritime strategy" (in Danish) can be found at the website of the Ministry of Economic and Business Affairs: http://www.oem.dk/publikationer/2010/en-samlet-maritim-strategi.

ENVIRONMENTAL IMPACT ASSESSMENTS (EIAs)

Flare stack on the South Arne offshore installation.

Regulation – a new executive order
On 15 April 2010, the previous Executive Order on EIAs was superseded by Executive Order No. 359 of 25 March 2010 on Environmental Impact Assessment (EIA) of Inter-

national Protection Areas and the Protection of Certain Species in connection with Projects to Produce Hydrocarbons, Establish Pipelines, etc. in the Sea Territory and the Continental Shelf.

With a number of clarifications, the new Executive Order on EIAs upholds the previous rules concerning the preparation of Environmental Impact Assessments in connection with major development projects for the recovery of hydrocarbons or the establishment of major pipelines in Danish territorial waters.

The Executive Order now includes detailed rules concerning the preparation of impact assessments for projects in territorial waters that are covered by the Subsoil Act or the Continental Shelf Act if the projects are likely to significantly affect Natura 2000 sites.

Finally, the Executive Order on EIAs contains new rules concerning the protection of certain species of animal, which are strictly protected under the Habitats Directive, in connection with projects in Danish territorial waters covered by the Subsoil Act or the Continental Shelf Act. This is currently of relevance with regard to the protection of otters, all species of whale, including porpoises, and the North Sea houting, a fish species.

6 RESOURCES

The DEA makes an assessment of Danish oil and gas resources annually.

The DEA uses a classification system for hydrocarbons to assess Denmark's oil and gas resources. The assessment of resources is used as a basis for preparing oil and gas production forecasts, which can be used, among other things, to provide an estimate of future state revenue. The aim of the classification system is to determine resources in a systematic way. A description of the classification system is available at the DEA's website, www.ens.dk.

ASSESSMENT OF RESOURCES IN 2011

The quantities produced and the Danish resources assessed according to the DEA's classification system appear from table 6.1. Two figures are indicated for gas: net gas, which consists of production less gas reinjected; and sales gas, which is production less gas reinjected, gas used as fuel and gas flared. The DEA uses the quantity of sales gas to assess resources, whereas previous resources assessments were based on the quantity of net gas. The quantity of net gas is shown in the table to enable a comparison with the DEA's previous assessments.

Table 6.1 Production and resources calculated at 1 January 2011

	Oil (m. m³)	Net gas (bn. Nm³)	Sales gas (bn. Nm³)
Production	361	164	146
Reserves	143	66	52
Contingent resources	42	35	31
Technological resources	100		15
Prospective resources	45		30

A more detailed assessment of production, reserves and contingent resources appears from appendix B.

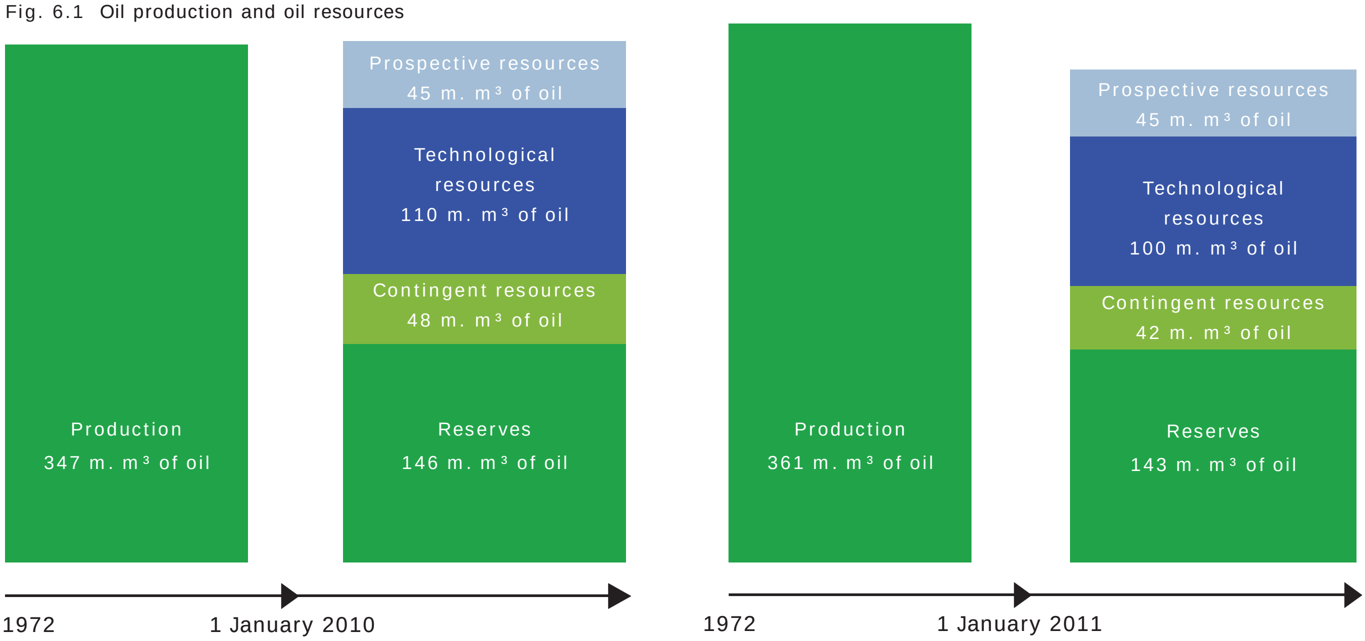
Production in 2010 consisted of 14.2 million m³ of oil and 7.9 billion Nm³ of net gas or 7.1 billion Nm³ of sales gas.

Figure 6.1 shows a comparison between last year's oil resources and the current assessment. The sum total of reserves and contingent resources of 194 million m³ of oil in 2010 should be compared with the sum total of reserves and contingent resources of 185 million m³ in 2011. Oil production totalled 14.2 million m³ in 2010 and the estimate of future recovery has been adjusted upwards by 5 million m³, which results in a difference of 9 million m³ of oil between the two assessments. The upward adjustment of future recovery is due mainly to new development opportunities.

The estimate of enhanced oil recovery due to new technology, called technological resources, has declined by 10 million m³ compared to last year's assessment. The technological resources are assumed to amount to 5 per cent of total oil-in-place, and the reduction is due to a downward adjustment of total oil-in-place.

Prospective oil resources have been assessed at 45 million m³, and this assessment is unchanged compared to last year.

Fig. 6.1 Oil production and oil resources



For the purpose of assessing net gas, the sum total of reserves and contingent resources of 101 billion Nm³ in 2011 should be compared with the sum total of reserves and contingent resources of 105 billion Nm³ in 2010. Gas production in 2010 totalled 7.9 billion Nm³, and the estimate of future recovery has been written up by 4 billion Nm³, which means that the difference between the two assessments amounts to 4 billion Nm³ of gas. The upward adjustment of future recovery is due mainly to an increase of the reserves in the Tyra Field.

In estimating the consumption of gas as fuel and gas flared, it has been assumed that the majority of the processing facilities, for example the Tyra facilities, are expected to produce during the whole forecast period. The total consumption of gas as fuel and gas flared for the reserves and contingent resources classes is estimated at 18 billion Nm³ of gas.

The estimate of gas recoverable by means of new technology is 15 billion Nm³ and is unchanged compared to last year's assessment.

Prospective gas resources have been assessed at 30 billion Nm³, and this assessment is unchanged compared to last year.

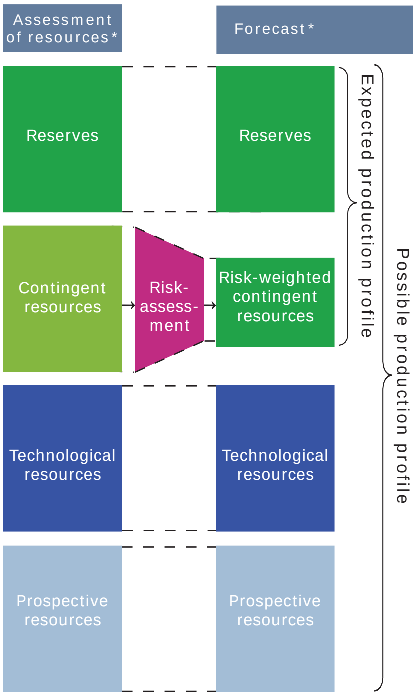
The resources assessment forms the basis for the DEA's preparation of oil and gas production forecasts.

PRODUCTION FORECASTS, SPRING 2011

The DEA prepares both short- and long-term forecasts for expected Danish oil and gas production.

The basis for the DEA's forecasts is an expected production profile, and in principle it is equally probable that the forecast turns out to be too optimistic or too pessimistic.

Fig. 6.2 Correlation between the DEA's assessment of resources and production forecast



* The assessment of resources and the forecast are shown with the colour code for oil.

The production forecasts are based on the assessed resources. As far as contingent resources are concerned, the resources assessment is adjusted by estimating the probability that the development projects comprised by the resources assessment will be implemented; see figure 6.2.

For oil, the risk assessment means that the difference between contingent resources and risk-weighted contingent resources is around 25 million m³ of oil. About 10 million m³ of oil is attributable to resources in discoveries not comprised by an exploration licence, while the balance consists of a reduction resulting from the probability weighting of the development projects.

For gas, the risk assessment means that the difference between contingent resources and risk-weighted contingent resources ranges around 15 billion m³ of gas. Of this amount, about 10 billion Nm³ of gas consists of resources in discoveries not comprised by an exploration licence, while the balance is a reduction resulting from the probability weighting of the development projects.

The DEA's forecasts of oil and gas production and of the investments and operating costs associated with production are used, among other things, for calculating expected state revenue from oil and gas production.

In addition, the DEA uses the oil and gas production forecasts together with its consumption forecasts to determine whether Denmark is a net importer or exporter of oil and gas. Denmark is a net exporter of energy when energy production exceeds energy consumption, calculated on the basis of energy statistics.

To illustrate the potential for prolonging Denmark's period as a net exporter of oil and gas due to the use of new technology and new discoveries resulting from exploration activity, a forecast of total resources has been made. The forecast based on total resources is termed the possible production profile.

The expected production profile forms the basis for the DEA's preparation of its five-year forecast.

Five-year production forecast

The DEA prepares five-year forecasts of oil and gas production to be used by the Danish Ministry of Finance for its forecasts of state revenue. The DEA publishes the five-year forecast in its report "Denmark's Oil and Gas Production – and Subsoil Use". Moreover, the forecast is revised every autumn.

Oil

For 2011, oil production is expected to total 12.6 million m³, equal to about 217,000 barrels of oil per day; see table 6.2. This is a reduction of 11 per cent relative to 2010, when oil production totalled 14.2 million m³. Compared to last year's estimate for 2011, this is a writedown of 2 per cent.

Oil production is expected to decline during the five-year period from 2011 to 2015. Minor adjustments have been made for the period 2011 to 2014 relative to last year's forecast, while a major writedown of 16 per cent has been made for 2015, which is primarily attributable to the postponed production startup of the Hejre Field. A more detailed forecast is available at the DEA's website, www.ens.dk.

Sales gas

Sales gas production is estimated at 4.8 billion Nm³ for 2011; see table 6.2. Compared to last year's forecast for 2011, this is a 9 per cent writedown, which is due mainly to a longer maintenance shutdown period at the Tyra Field than previously assumed.

A significant writedown of 18 per cent has been made for 2015 relative to last year's forecast, which, as mentioned under oil, is primarily attributable to the postponed production startup of the Hejre Field.

Table 6.2 Expected production profile for oil and sales gas

	2011	2012	2013	2014	2015
Oil, m. m³	12.6	11.6	10.9	9.5	9.3
Sales gas, bn. Nm³	4.8	4.3	3.8	4.2	4.5

Net exports/net imports for the next 20 years

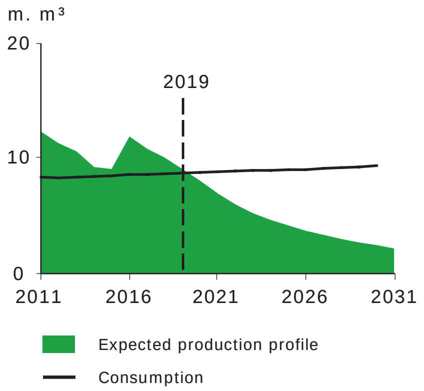
Every year, the DEA prepares a 20-year forecast for the production of oil and sales gas, based on the expected production profile.

A forecast covering 20 years is most reliable in the first part of the period. The methods used in making the forecast imply that production will decline after a short number of years. The reason is that all commercial development projects are implemented as quickly as possible. Therefore no development projects have been planned for the latter part of the forecast period, even though it must be assumed that development projects will also be undertaken during that period if the oil companies consider such projects to be commercial.

The expected production profile for oil shows a generally declining trend; see figure 6.3. However, production is expected to increase in 2016 due to the development of new fields and the further development of some existing fields. About ten years from now, production is expected to constitute approx. 50 per cent of production in 2011.

Figure 6.3 shows the consumption forecast from "The DEA's baseline scenario, April 2011". The baseline scenario is a scenario in which it is assumed that no measures will be taken other than those already decided with a parliamentary majority. Therefore, the baseline scenario is not a forecast of future energy consumption, but a description of the development that could be expected during the period until 2030 based on a number of assumptions regarding technological developments, prices, economic trends, etc., assuming that no new initiatives or measures are taken.

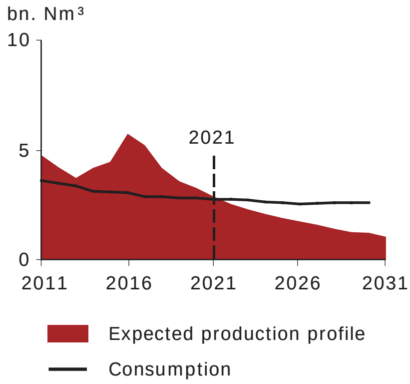
Fig. 6.3 Expected production profile, oil



Based on these production and consumption assumptions, Denmark is expected to be a net exporter of oil up to and including 2019. However, it should be noted that the amount of production in 2014 and 2015 is not expected to differ significantly from consumption.

As opposed to oil, which is most frequently sold as individual tanker loads from the North Sea at the prevailing market price, the production of sales gas is subject to the condition that sales contracts have been concluded. Such contracts may either be long-term contracts or spot contracts for very short-term delivery of gas.

Fig. 6.4 Expected production profile, sales gas



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

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

In addition, the forecast includes the gas production resulting from contracts for the export of gas through the pipeline from Tyra West via the NOGAT pipeline to the Netherlands.

All the above-mentioned contributions have been included in the production forecast for sales gas. The forecast based on the expected production profile for sales gas is shown in figure 6.4. The forecast shows a generally declining trend, as is the case for oil. However, production is expected to increase in 2015 and 2016 due to the development of new fields and the further development of some existing fields. The forecast indicates the quantities expected to be technically recoverable. However, as mentioned above, the actual production depends on the sales based on existing and future gas sales contracts.

According to international regulations, the consumption of fuel associated with production must be included in the calculation of energy consumption, but here this fuel consumption has been deducted to allow a comparison with production. Denmark is anticipated to be a net exporter of sales gas up to and including 2021 based on the expected production profile; see figure 6.4. However, it should be noted that the amount of production in 2013 is not expected to differ significantly from consumption.

However, technological developments and any new discoveries made as part of the ongoing exploration activity are expected to contribute with additional production and thus prolong Denmark's period as a net exporter of oil and sales gas.

Net exports/net imports based on total resources
A forecast based on total resources can be divided into the following contributions:

Expected production profile, technological resources and prospective resources.

It should be emphasized that estimates of the technological resources and prospective resources are subject to great uncertainty.

The DEA's estimate of technological oil resources is based on a five percentage point increase of the average recovery factor for Danish fields and discoveries. The average recovery factor is the ratio of ultimate recovery to total oil originally in place.

Based on the reserves assessment and risk-weighted contingent resources, the average expected recovery factor for oil is 26 per cent.

The assumption that the average recovery factor for oil can be increased by five percentage points is based on an evaluation of historical developments. Thus, the average recovery factor increased by nine percentage points during the period from 1990 to 2000. There has been no significant increase in the recovery factor since 2000. However, it is very difficult to predict which new technologies will contribute to production in future and to estimate the amounts contributed by such technologies.

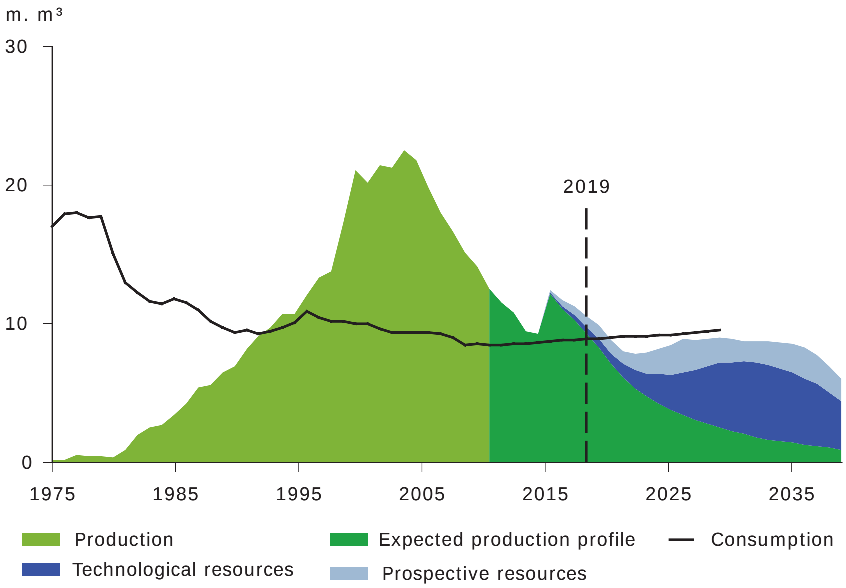
Most of the five per cent contribution from technological developments is expected to derive from new techniques used for injecting CO_2 into the large producing fields where recovery is based on water injection, while the remaining minor contributions will derive from other technological initiatives. It has been assumed that CO_2 injection will contribute to production during the period from 2020-25. The remaining contributions to increased production from other initiatives are assumed to be spread over the forecast period as from 2016.

An analysis – instigated by Mærsk Olie og Gas A/S, the Danish North Sea Fund and the DEA – was performed by the well-known University of Texas in Austin, which demonstrates that the best way to substantially increase oil production from the largest Danish fields is to inject CO_2 into the fields. The analysis is available at the DEA's website, www.ens.dk.

The recovery factor for the large producing fields with water injection is expected to be 33 per cent. The total oil originally in place in these fields accounts for more than half the total oil originally in place in the Danish subsoil. Therefore, the assessment of technological oil resources is subject to a nine percentage point increase of the average recovery factor for these fields. When including the estimated technological resources, an average recovery factor of 42 per cent is expected for the large oil fields.

Any new recovery methods must be implemented while the fields are still producing, as the introduction of new technology will usually not be financially viable once a

Fig 6.5 Production and possible production profile, oil



field has been decommissioned. This means that a limited period is available for the development and introduction of new technology.

The DEA's estimate of prospective resources is based on the exploration prospects known today in which exploration drilling is expected to take place. Moreover, the estimate includes assessments of the additional prospects expected to be demonstrated later in the forecast period.

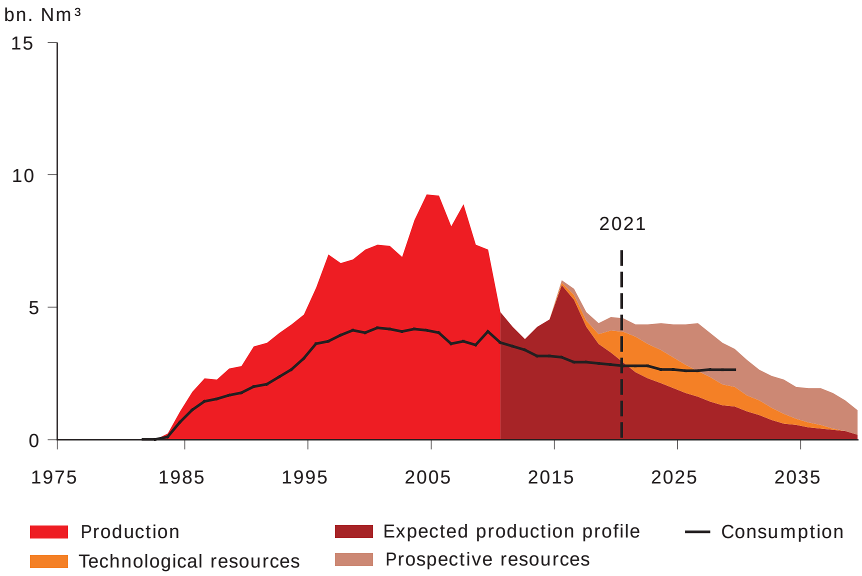
The oil production forecast is divided into the three above-mentioned contributions, the expected production profile, technological resources and prospective resources, which are shown in figure 6.5 along with the consumption forecast from "The DEA's baseline scenario, April 2011".

It appears from the figure that Denmark is anticipated to be a net exporter of oil for nine years up to and including 2019, based on the expected production profile. The period in which Denmark will be a net exporter can be assessed fairly reliably for the expected production profile, as the production deriving from this contribution is known with a great degree of certainty and is expected to decline substantially, while consumption is expected to remain fairly constant.

The oil production forecast that includes technological resources and prospective resources varies somewhat from 2016 to around 2035, after which estimated production is expected to decline. If technological and prospective resources are included, they will contribute substantially to reducing Denmark's net oil imports from around 2025 to around 2035.

Figure 6.6 shows the sales gas production forecast, divided into the expected production profile, technological resources and prospective resources. The figure also shows the consumption forecast from "The DEA's baseline scenario, April 2011". It appears from the figure that Denmark is anticipated to be a net exporter of sales gas for 11 years up to and including 2021, based on the expected production profile.

Fig 6.6 Production and possible production profile, sales gas



For sales gas, the DEA anticipates no significant contribution from technological resources for producing fields because current technology has already generated a much higher recovery factor than for oil. However, a contribution reflecting the potential for developing new well technology has been included.

When including technological resources and prospective resources, the DEA estimates that Denmark will be a net exporter of gas for just over 20 years reckoned from 2011.

7 ECONOMY

Oil and gas production from the North Sea has an impact on the Danish economy, and thus on the balance of trade and balance of payments, through the Danish state's tax revenue and the profits generated by the players in the oil and gas sector, and not least, it provides jobs for numerous people.

Denmark has been self-sufficient in energy since 1997 due to the production of hydrocarbons mainly, but also because of energy savings and the utilization of renewable energy. Thus, Denmark is the only EU country that is a net exporter of energy.

VALUE OF OIL AND GAS PRODUCTION

Three factors influence the value of oil and gas production: the volume of production, the international crude oil price and the dollar exchange rate.

The average quotation for a barrel of Brent crude oil was USD 79.5 in 2010 against USD 61.6 in 2009, an increase of almost 30 per cent.

Figure 7.1 illustrates the oil price trend in 2010. The year was characterized by a fairly stable oil price of about USD 75 per barrel, with a slightly increasing trend towards the end of the year. It appears from figure 7.1 that the EUR/USD rate was relatively stable throughout 2010. Figure 7.2 shows the oil price development in USD from 1972 to 2010.

The average dollar exchange rate in 2010 was DKK 5.6 per USD. This is an increase of almost 4 per cent compared to 2009 when the average dollar exchange rate was DKK 5.4 per USD.

The slightly increasing dollar exchange rate and the markedly higher oil price in USD relative to the average price in 2009 caused the oil price in DKK to rise by almost 37 per cent from 2009 to 2010. The average price for a barrel of Brent crude oil in DKK increased from DKK 326.1 in 2009 to DKK 446.7 in 2010.

Fig 7.1 Oil prices, 2010, USD and EUR

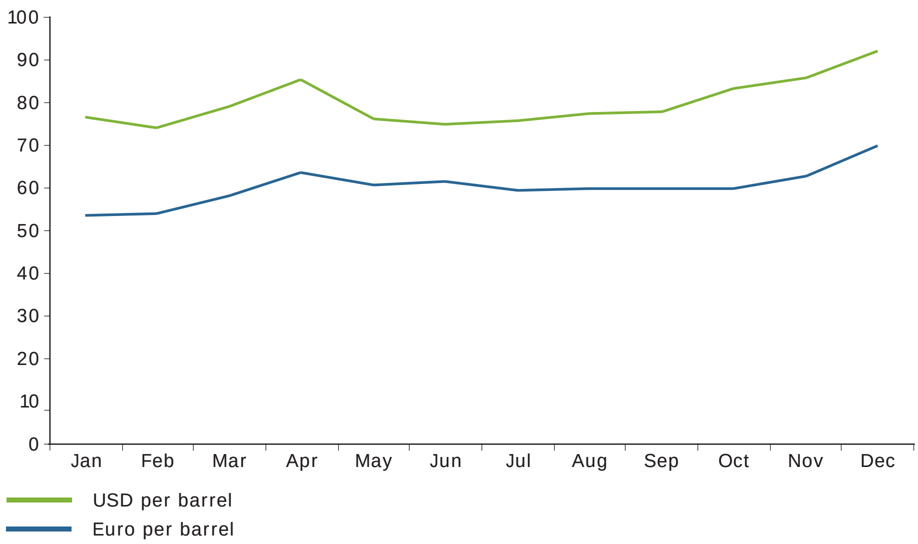
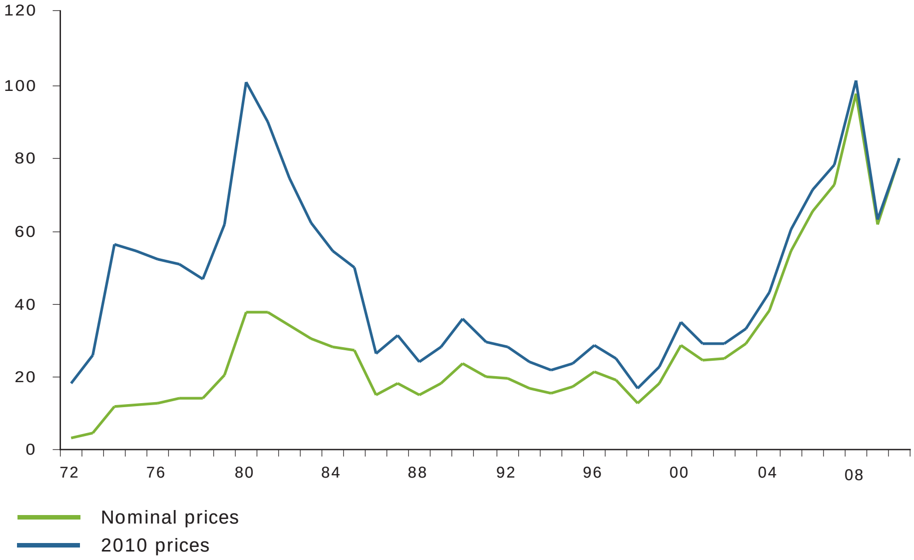


Fig 7.2 Oil price development 1972-2010, USD per barrel



According to preliminary estimates for 2010, oil production accounts for about DKK 40.4 billion and gas production for about DKK 10.6 billion of the total production value.

The total estimated value of Danish oil and gas production in 2010 is DKK 51 billion, an increase of about 18 per cent on the year before. The production value rose because the higher oil price and dollar exchange rate more than offset the decline in production.

The breakdown of oil production in 2010 on the ten producing companies in Denmark appears from figure 3.2 in chapter 3, *Production and development*.

The DEA prepares forecasts of the future development of production based on the reserves assessment; see chapter 6, *Resources*.

Appendix C contains a detailed outline of financial key figures from 1972 to 2010.

IMPACT OF PRODUCTION ON THE DANISH ECONOMY

Oil and gas production contributes to Denmark being a net exporter of energy. This export has a favourable impact on both the balance of trade and the balance of payments current account.

The balance of trade for oil and natural gas

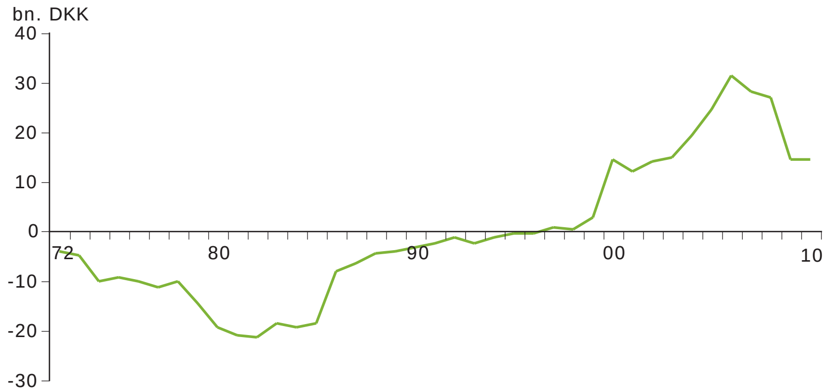
Figure 7.3 shows the trend in Denmark's external trade in oil and natural gas. Since 1995, Denmark has had a surplus on the balance of trade for oil and gas.

The surplus amounted to DKK 15.1 billion in 2010, the same level as 2009, but a pronounced decline from the surplus in the record years 2005 to 2008.

Impact on the balance of payments

The DEA prepares an estimate of the impact of oil and gas activities on the balance of payments current account for the next five years on the basis of its own forecasts for

Fig 7.3 Balance of trade for oil and natural gas 1972-2010, nominal prices



production, investments, operating and transportation costs. The underlying calculations are based on a number of assumptions about import content, interest expenses and the oil companies' profits from the hydrocarbon activities.

This year, the DEA's five-year forecast has been prepared for three different oil price scenarios. The three scenarios are based on an oil price of USD 70, 110 and 150 per barrel and a dollar exchange rate of DKK 5.38 per USD for the years 2011-2013. For 2014 and 2015, the dollar exchange rate is assumed to be DKK 5.54 and DKK 5.70 per USD, respectively. An oil price of USD 110 per barrel reflects the IEA's long-term oil price forecast in the "New policies scenario" (2009 prices).

The purpose of preparing three scenarios is to illustrate the sensitivity of balance-of-payments effects to fluctuations in the oil price. Thus, the only variable in the three scenarios is the oil price. The calculations include no dynamic or derived effects.

Table 7.1 shows the individual items used in calculating the impact of oil and gas activities on the balance of payments in the USD 110 oil price scenario. The lower part of the table also shows the calculated impact on the balance of payments current account when using the price scenarios of USD 70 and USD 150 per barrel.

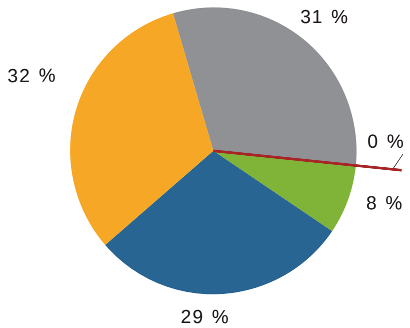
Assuming that the oil price is USD 110 per barrel, the oil and gas activities will have an estimated DKK 29-39 billion impact on the balance of payments current account

Table 7.1 Impact of oil/gas activities on the balance of payments, DKK billion, 2010 prices, price scenario 110 USD/bbl.

	2011	2012	2013	2014	2015
Socio-economic production value	55	50	47	43	44
Import content	4	5	6	5	6
Balance of goods and services	50	45	41	38	38
Transfer of interest and dividends	12	11	10	9	9
Balance of payments current account	39	34	32	29	29
Balance of payments current account, price scenario 70 USD/bbl	26	23	21	20	20
Balance of payments current account, price scenario 150 USD/bbl	51	46	42	39	39

Note: Based on the DEA's five-year forecast

Fig 7.4 State revenue in 2010



per year during the period 2011-2015. Moreover, it appears that a higher oil price intensifies the impact, and vice versa.

State revenue

The Danish state derives proceeds from North Sea oil and gas production via direct revenue from various taxes and fees: corporate income tax, hydrocarbon tax, royalty, the oil pipeline tariff, compensatory fee and profit sharing. The sources of revenue are described in more detail at the DEA's website, www.ens.dk.

In addition to the direct revenue from taxes and fees, the Danish state receives indirect revenue from the North Sea by virtue of its shareholding in DONG Energy, generated by DONG E&P A/S' participation in oil and gas activities. In the long term, the state will also receive revenue through the Danish North Sea Fund.

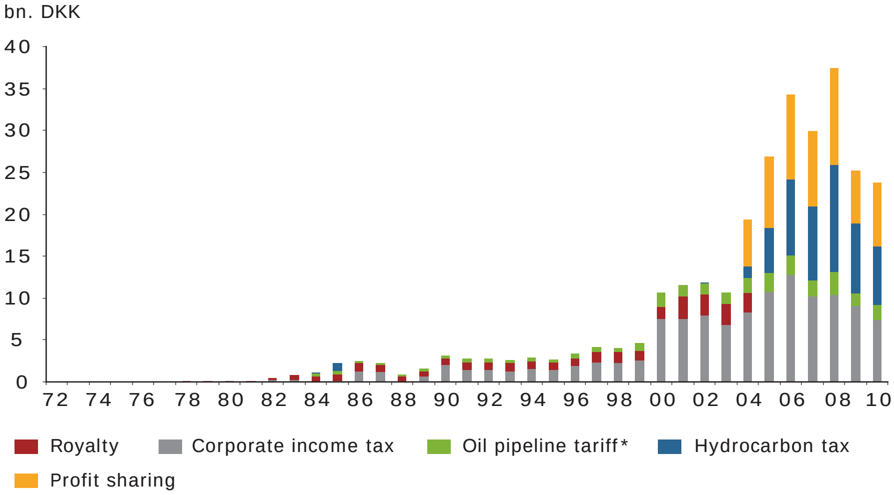
A more detailed explanation of the state's revenue base in the form of taxes and fees from oil and gas production is available at the DEA's website, www.ens.dk, and in appendix D.

With a share of about 32 per cent, profit sharing is the main source of state revenue. Figure 7.4 shows the breakdown of state tax revenue in 2010.

State revenue from hydrocarbon production in the North Sea aggregated DKK 287 billion in 2010 prices in the period 1963-2010. Figure 7.5 shows the development in state revenue from 1972 to 2010. The cumulative production value was DKK 752 billion during the same period, while the aggregate value of the licensees' expenses for exploration, field developments and operations was DKK 280 billion (2010 prices).

The development in 2010 was characterized by a fall in production and an increase in the oil price and dollar exchange rate. Total revenue is estimated at DKK 23.7 billion for 2010, a decline of almost 4 per cent from 2009.

Fig 7.5 Development in total state revenue from oil and gas production 1972-2010, 2010 prices



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

Table 7.2 shows total state revenue for the past five years, broken down on the individual taxes and fees.

Table 7.2 State revenue over the past five years, DKK million, nominal prices

	2006	2007	2008	2009	2010**
Hydrocarbon tax	8,282	8,245	12,405	8,250	6,943
Corporate income tax	11,738	9,475	10,092	8,876	7,374
Royalty	1	2	2	0	0
Oil pipeline tariff*	2,156	1,815	2,511	1,431	1,824
Profit sharing	9,322	8,348	11,145	6,027	7,594
Total	**31,499**	**27,885**	**36,155**	**24,584**	**23,735**

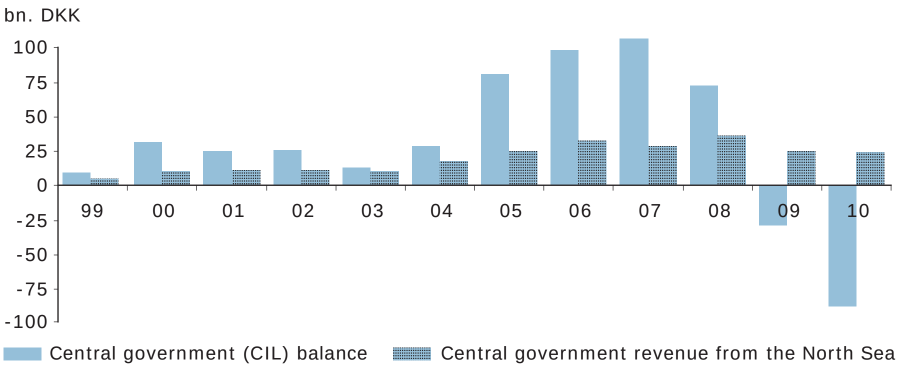
** Incl. 5 per cent compensatory fee*
*** Estimate*
Note: Accrual according to the Finance Act (year of payment)

State revenue has grown substantially since 2003 on account of the higher oil price level. Another reason for this growth is that the Danish Government concluded an agreement with A.P. Møller - Mærsk, the so-called North Sea Agreement, in 2003. The agreement involved a restructuring of tax allowances, which resulted in steeper progressive tax rates. Information about Dansk Undergrunds Consortium's (DUC's) pre-tax profits can be found at www.ens.dk. As in previous years, this information will also be submitted to the Energy Policy Committee of the Danish Parliament.

The state's share of oil company profits is estimated at 61 per cent for 2010, calculated by year of payment. The marginal income tax is about 71 per cent according to the new rules, including profit sharing, and about 29 per cent according to the old rules, excluding hydrocarbon tax. The rules regarding the hydrocarbon allowance mean that companies taxed according to the old rules do not pay hydrocarbon tax in practice. Licences awarded before 2004 are taxed according to the old rules.

Figure 7.6 shows the proportion of revenue from the oil and gas activities to the central government balance on the current investment and lending account. As appears from the figure, state revenue from the Danish part of the North Sea contributed to reducing the central government deficit in 2010.

Fig. 7.6 Central government (CIL) balance and central government revenue from the North Sea



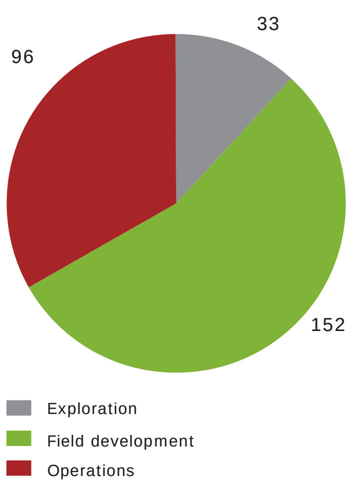
Note: The CIL balance (central government balance on the current investment and lending account) is the difference between total central government revenue and total central government expenditure

Table 7.3 Expected state revenue from oil and gas production, DKK billion, nominal prices*

		2011	2012	2013	2014	2015
Corporate income tax base before taxes, fees and profit sharing	150 USD/bbl	71.0	63.2	57.9	54.9	56.3
	110 USD/bbl	49.1	43.0	39.2	37.0	37.7
	70 USD/bbl	27.1	22.9	20.5	19.1	19.1
Corporate income tax	150 USD/bbl	13.8	13.7	14.4	13.5	13.9
	110 USD/bbl	9.5	9.2	9.7	9.1	9.3
	70 USD/bbl	5.1	4.9	5.0	4.7	4.7
Hydrocarbon tax	150 USD/bbl	14.8	16.4	18.6	17.7	18.3
	110 USD/bbl	9.7	10.8	12.5	11.5	11.9
	70 USD/bbl	4.6	5.2	6.3	5.7	6.0
Profit sharing	150 USD/bbl	12.6	6.8	0.0	0.0	0.0
Danish North Sea Fund post-tax profits**	150 USD/bbl	0.0	1.9	3.6	3.4	3.5
	110 USD/bbl	8.9	4.8	0.0	0.0	0.0
	110 USD/bbl	0.0	1.3	2.4	2.3	2.4
	70 USD/bbl	5.1	2.8	0.0	0.0	0.0
	70 USD/bbl	0.0	0.7	1.3	1.3	1.3
Royalty	150 USD/bbl	0.0	0.0	0.0	0.0	0.0
	110 USD/bbl	0.0	0.0	0.0	0.0	0.0
	70 USD/bbl	0.0	0.0	0.0	0.0	0.0
Oil pipeline tariff***	150 USD/bbl	3.0	1.6	0.5	0.5	0.6
	110 USD/bbl	2.2	1.2	0.4	0.4	0.4
	70 USD/bbl	1.4	0.7	0.2	0.2	0.3
Total	150 USD/bbl	44.3	40.4	37.1	35.2	36.3
	110 USD/bbl	30.3	27.3	25.0	23.3	24.1
	70 USD/bbl	16.3	14.3	12.9	11.9	12.3
The state's share (per cent)	150 USD/bbl	62.3	64.0	64.0	64.1	64.5
	110 USD/bbl	61.7	63.6	63.8	63.1	63.9
	70 USD/bbl	60.2	62.4	62.9	62.2	64.3

** Assumed annual inflation rate of 1.8 per cent*
*** On 9 July 2012, the Danish North Sea Fund will join DUC with a 20 per cent share. The Danish North Sea Fund is liable to pay tax, for which reason the revenue from state participation appears under different headings, including in corporate income tax and hydrocarbon tax revenue. The Danish North Sea Fund's post-tax profits accrue to the state. However, it should be noted that the Fund must first repay loans raised with the Danish central bank and finance its continuous investments before delivering any profits to the state.*
**** Incl. 5 per cent compensatory fee*
Source: Ministry of Taxation
Note 1: Based on the DEA's five-year forecast
Note 2: Accrual according to the National Accounts (income year)

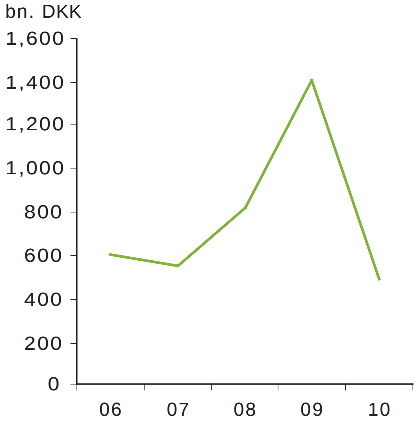
Fig. 7.7 All licensees' total costs, 1963-2010, DKK billion, 2010 prices



For the next five years, the Ministry of Taxation estimates that the state's total revenue will range from DKK 23 to DKK 30 billion per year from 2011 to 2015, based on the USD 110 oil price scenario. Table 7.3 shows the development in expected state revenue for the three different oil price scenarios of USD 70, 110 and 150 per barrel. It also appears from the table that the state's share of profits increases when the oil companies generate increasing earnings due to higher oil prices, for example. The revenue from the Danish North Sea Fund is included as from 2012 at the same time as revenue from profit sharing is phased out. This is because the Danish state, via the Danish North Sea Fund, will join DUC with a 20 per cent share as of 9 July 2012.

Future estimates of corporate income tax and hydrocarbon tax payments are subject to uncertainty with respect to oil prices, production volumes and the dollar exchange

Fig. 7.8 Exploration costs 2006-2010, nominal prices



rate. In addition, uncertainty attaches to the calculations because they are based on various stylized assumptions, some of which concern the companies' finance costs.

Investments and costs

In the same way that oil prices impact on state revenue from production in the North Sea, the licensees' initiatives play a vital role in both the current and future activity level and thus potential revenue.

Figure 7.7 shows the breakdown of the licensees' costs during the period from 1963 to 2010. Investments in the development of existing and new fields account for more than half the licensees' total costs. The costs of exploration, field developments and operations (including administration and transportation) account for 12, 54 and 34 per cent, respectively, of total costs.

Exploration costs

Figure 7.8 illustrates the development in exploration costs from 2006 to 2010. The preliminary figures for 2010 show that exploration costs dropped by about 65 per cent from 2009 to 2010, the reason being that more deep exploration wells were drilled in 2009. For 2010, total exploration costs are preliminarily estimated at slightly less than DKK 0.5 billion.

In 2011-2013, investments in exploration are expected to total about DKK 2.3 billion. The activities will include further exploration both onshore and in the Danish part of the North Sea.

Investments in field developments

The most cost-intensive activity for the licensees is the development of new and existing fields. Investments in field developments are estimated to total almost DKK 5 billion in 2010, a decline of about DKK 1.8 billion compared to the previous year. The investment level in 2010 is slightly below the past decade's average annual investments of about DKK 5.5 billion. Figure 7.9 illustrates investments in field developments over the period 2006-2010. A table showing the investments by field is available at the DEA's website, www.ens.dk.

Fig. 7.9 Investments in field developments 2006-2010, nominal prices

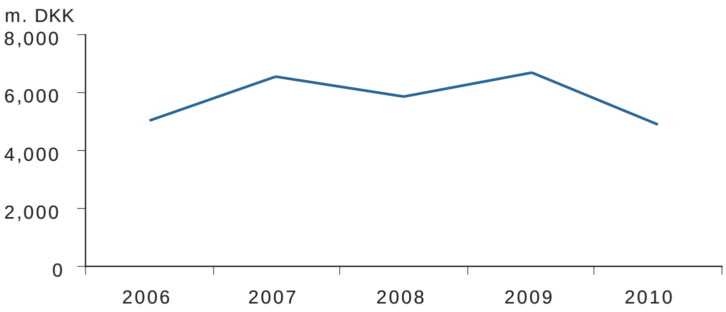
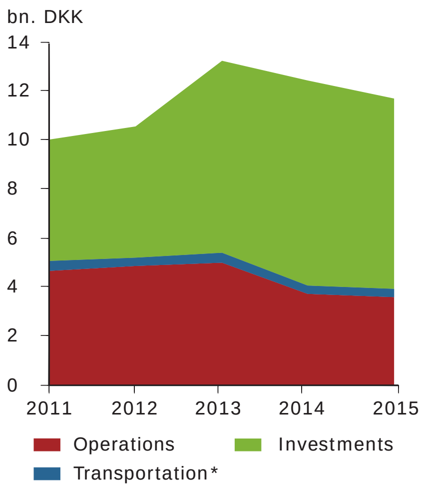


Table 7.4 shows the DEA's estimate of investments in development activity for the period from 2011 to 2015. The estimate is based on the following resource categories: ongoing recovery and approved for development, justified for development and risk-weighted contingent resources; see chapter 6, *Resources*.

Fig. 7.10 Investments in fields and operating and oil transportation costs, 2010 prices



*Excl. pipeline tariff/compensatory fee

Table 7.4 Estimated investments in development projects, 2011-2015, DKK billion, 2010 prices

	2011	2012	2013	2014	2015
Ongoing and approved	3,843	2,992	2,242	1,297	2,043
Justified for development	1,004	2,420	1,859	2,214	3,173
Risk-weighted contingent resources	416	2,292	4,161	4,197	4,798
Expected, total	**5,263**	**7,704**	**8,262**	**7,708**	**10,014**

The investments in the category ongoing recovery and approved for development are shown broken down by field at the DEA's website, www.ens.dk.

Operating, administration and transportation costs

For 2010, the DEA has calculated operating, administration and transportation costs at DKK 5.1 billion, a decline of about 4 per cent compared to the year before.

Figure 7.10 illustrates the DEA’s estimate of developments in investments and operating and transportation costs for the period 2011-2015.

APPENDIX A: AMOUNTS PRODUCED AND INJECTED

Production and sales **OIL** *thousand cubic metres*

	1972 -2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
Dan	50,343	6,879	6,326	5,929	6,139	5,712	5,021	4,650	4,241	3,549	2,979	101,768
Gorm	40,150	2,180	2,887	2,838	2,469	1,978	1,897	1,639	1,053	924	923	58,940
Skjold	31,044	1,354	1,659	1,532	1,443	1,310	1,214	1,015	989	918	835	43,314
Tyra	18,519	872	801	918	723	773	845	764	551	415	856	26,036
Rolf	3,627	51	51	104	107	79	89	103	78	76	60	4,426
Kraka	3,422	253	157	139	199	211	222	176	112	37	67	4,995
Dagmar	986	4	6	7	2	0	-	-	0	-	-	1,005
Regnar	815	33	18	19	19	16	11	0	-	-	-	930
Valdemar	1,101	181	353	435	491	423	470	881	1,268	1,410	909	7,922
Roar	1,618	317	175	121	98	94	51	35	28	30	24	2,591
Svend	3,923	397	457	280	326	324	296	299	278	195	190	6,965
Harald	4,897	866	578	425	314	237	176	139	114	65	70	7,881
Lulita	547	66	24	20	19	35	68	55	47	24	36	940
Halfdan	1,342	2,965	3,718	4,352	4,946	6,200	6,085	5,785	5,326	5,465	5,119	51,304
Siri	3,711	1,761	1,487	925	693	703	595	508	598	326	286	11,593
South Arne	3,315	2,031	2,313	2,383	2,257	2,371	1,869	1,245	1,139	1,164	1,065	21,152
Tyra SE	-	-	493	343	580	614	446	377	429	374	225	3,880
Cecilie	-	-	-	166	310	183	116	88	66	38	33	998
Nini	-	-	-	391	1,477	624	377	323	355	159	544	4,250
Total	**169,360**	**20,207**	**21,505**	**21,327**	**22,612**	**21,886**	**19,847**	**18,084**	**16,672**	**15,169**	**14,223**	**360,891**

Production **GAS** *million normal cubic metres*

	1972 -2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
Dan	16,318	1,049	945	786	764	651	561	456	467	364	360	22,723
Gorm	13,291	306	480	339	216	218	207	175	119	109	99	15,558
Skjold	2,708	104	123	92	77	93	77	69	60	58	87	3,548
Tyra	54,203	3,749	3,948	3,994	4,120	3,745	3,792	3,916	3,130	2,007	1,664	88,268
Rolf	153	2	2	4	5	3	4	4	3	3	3	186
Kraka	1,069	100	52	25	23	24	28	28	36	8	12	1,404
Dagmar	150	1	1	3	2	0	-	-	0	-	-	158
Regnar	53	3	1	2	2	1	1	0	-	-	-	63
Valdemar	481	78	109	151	218	208	208	355	593	510	791	3,703
Roar	7,409	1,702	1,052	915	894	860	489	367	417	398	213	14,718
Svend	460	48	61	43	38	34	28	28	24	16	27	807
Harald	9,519	2,475	2,019	1,563	1,232	1,091	927	781	690	400	592	21,291
Lulita	410	27	6	5	5	13	38	33	30	15	18	599
Halfdan	215	522	759	1,142	1,449	2,582	2,948	2,675	3,104	3,401	2,886	21,682
Siri	338	176	157	110	64	112	55	47	63	44	67	1,232
South Arne	880	774	681	544	461	485	366	234	225	271	248	5,169
Tyra SE	-	-	447	452	1,233	1,337	1,108	848	889	939	911	8,164
Cecilie	-	-	-	14	22	13	8	6	4	2	2	71
Nini	-	-	-	29	109	46	28	24	26	12	76	350
Total	**107,656**	**11,116**	**10,844**	**10,213**	**10,934**	**11,517**	**10,873**	**10,046**	**9,879**	**8,559**	**8,056**	**209,693**

The monthly production figures for 2010 are available at the DEA's website, www.ens.dk

Fuel*

GAS *million normal cubic metres*

	1972-2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
Dan	1,225	184	182	198	201	205	209	222	225	207	206	3,264
Gorm	1,752	111	146	135	137	124	124	132	117	116	111	3,005
Tyra	2,108	243	245	242	249	247	241	228	233	219	208	4,463
Dagmar	21	-	-	-	-	-	-	-	-	-	-	21
Harald	46	10	9	8	8	7	8	7	7	4	8	123
Siri	29	22	21	20	19	20	24	25	25	19	27	251
South Arne	35	34	45	49	45	52	53	55	51	52	55	525
Halfdan	-	-	-	-	20	39	39	39	39	39	37	253
Total	**5,216**	**604**	**648**	**652**	**679**	**694**	**698**	**708**	**697**	**656**	**652**	**11,904**

As from 2006, the figures have been based on verified CO_2 emission data from reports filed under the Act on CO_2 Allowances.

Flaring*

	1972-2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
Dan	1,699	79	55	71	37	23	29	27	25	16	12	2,073
Gorm	1,295	88	81	66	57	61	61	48	41	19	12	1,828
Tyra	737	68	61	54	63	55	51	43	43	32	23	1,230
Dagmar	128	1	1	3	2	0	-	-	0	-	-	135
Harald	115	11	3	1	1	1	2	2	2	2	3	145
Siri	82	15	9	23	65	15	6	7	7	4	58	290
South Arne	154	9	11	12	11	14	11	11	7	7	6	253
Halfdan	-	-	-	4	25	16	20	17	8	4	2	95
Total	**4,210**	**270**	**222**	**234**	**262**	**184**	**180**	**154**	**132**	**85**	**116**	**6,049**

As from 2006, the figures have been based on verified CO_2 emission data from reports filed under the Act on CO_2 Allowances.

Injection

	1972-2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
Gorm	8,133	4	14	6	4	3	0	-	-	-	-	8,164
Tyra	23,390	2,773	2,535	2,312	1,612	1,285	761	1,094	119	451	89	36,419
Siri	228	139	127	109	111	135	61	45	61	35	60	1,111
Total	**31,750**	**2,916**	**2,676**	**2,428**	**1,727**	**1,423**	**821**	**1,139**	**180**	**486**	**149**	**45,694**

Sales*

	1972-2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
Dan	14,730	1,412	1,521	1,679	1,681	1,804	1,862	1,653	1,293	947	1,200	29,780
Gorm	4,972	209	364	228	99	126	103	66	23	33	64	6,286
Tyra	36,318	2,493	2,776	2,948	4,580	4,598	4,574	4,143	4,652	3,163	3,283	73,528
Harald	9,768	2,482	2,013	1,558	1,228	1,096	954	804	710	408	598	21,619
South Arne	690	730	625	483	406	419	302	168	167	212	198	4,401
Halfdan	-	-	-	4	274	1,172	1,370	1,215	2,020	2,560	1,798	10,412
Total	**66,478**	**7,326**	**7,299**	**6,900**	**8,267**	**9,215**	**9,164**	**8,049**	**8,865**	**7,324**	**7,140**	**146,027**

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

Emissions

CO_2 EMISSIONS *thousand tons*

	1972-2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
Fuel	11,955	1,459	1,577	1,591	1,642	1,694	1,675	1,690	1,670	1,572	1,559	28,082
Flaring	9,905	646	535	564	664	457	470	449	354	241	331	14,616
Total	**20,861**	**2,104**	**2,112**	**2,154**	**2,306**	**2,151**	**2,144**	**2,139**	**2,025**	**1,813**	**1,890**	**41,700**

CO_2 emissions from the use of diesel oil were not included 1972 through 2005.
CO_2 emissions have been calculated on the basis of parameters specific to the individual year and the individual installation.
As from 2006, the figures have been based on verified CO_2 emission data from reports filed under the Act on CO_2 Allowances and have included CO_2 emissions from diesel combustion.

Production

WATER *thousand cubic metres*

	1972-2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
Dan	20,544	6,599	6,348	7,183	8,053	9,527	10,936	12,152	13,946	12,889	12,111	120,288
Gorm	22,779	3,353	4,017	4,420	5,173	5,252	4,822	4,708	3,976	4,737	4,904	68,140
Skjold	21,828	2,872	3,007	3,525	3,688	4,270	4,328	3,885	3,636	3,855	3,895	58,790
Tyra	17,364	2,545	2,261	3,039	2,977	3,482	3,150	2,725	3,103	2,677	1,980	45,303
Rolf	3,928	181	168	270	308	290	316	383	349	381	281	6,854
Kraka	2,300	352	306	208	426	320	297	359	436	183	166	5,353
Dagmar	3,183	102	160	375	90	3	-	-	13	-	-	3,927
Regnar	2,012	475	257	316	396	352	255	1	-	-	-	4,064
Valdemar	294	150	272	310	325	792	937	854	925	812	1,207	6,876
Roar	773	386	301	476	653	662	498	560	586	624	275	5,793
Svend	2,276	954	1,051	1,330	1,031	1,309	1,205	1,200	1,022	804	664	12,846
Harald	59	98	78	43	15	12	12	18	21	11	37	405
Lulita	20	23	14	14	15	38	92	96	91	49	65	515
Halfdan	293	493	367	612	2,099	2,825	3,460	4,086	4,766	4,814	5,519	29,334
Siri	2,187	2,753	3,041	2,891	1,641	1,683	2,032	2,528	2,686	1,778	2,868	26,087
South Arne	73	112	370	857	1,127	1,790	1,830	1,861	2,174	2,334	2,068	14,597
Tyra SE	-	-	250	596	466	437	377	669	602	716	568	4,681
Cecilie	-	-	-	25	331	637	651	576	456	266	317	3,258
Nini	-	-	-	0	63	730	822	619	660	522	195	3,612
Total	**99,911**	**21,449**	**22,268**	**26,490**	**28,875**	**34,410**	**36,019**	**37,280**	**39,448**	**37,452**	**37,121**	**420,721**

Injection

	1972-2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
Dan	73,673	18,176	16,123	18,063	20,042	20,281	21,520	20,230	19,275	16,712	15,148	259,244
Gorm	60,875	6,549	8,167	7,066	7,551	7,251	6,544	6,678	5,251	4,777	4,408	125,116
Skjold	56,399	4,805	6,411	6,115	5,607	6,045	5,711	6,098	4,989	5,285	4,155	111,621
Halfdan	95	620	2,532	5,162	5,759	9,710	11,026	12,107	12,727	11,485	11,945	83,169
Siri	4,966	4,549	4,517	3,383	1,683	1,350	1,973	3,499	2,695	1,692	2,692	32,998
South Arne	58	1,991	4,397	5,332	4,949	5,608	5,362	4,296	4,279	3,872	3,427	43,571
Nini	-	-	-	81	918	502	912	413	883	501	1,558	5,766
Cecilie	-	-	-	-	93	198	30	91	42	97	47	598
Total	**196,067**	**36,689**	**42,148**	**45,201**	**46,603**	**50,945**	**53,077**	**53,412**	**50,141**	**44,420**	**43,379**	**662,084**

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

APPENDIX B: PRODUCTION, RESERVES AND CONTINGENT RESOURCES AT 1 JANUARY 2011

OIL, m. m³	Produced	Resources Exp.
		Reserves
Ongoing recovery and approved for development		
Cecilie	1.0	0.3
Dagmar	1.0	0.0
Dan	101.8	17.0
Gorm	58.9	5.5
Halfdan	51.3	49.2
Harald	7.9	0.4
Kraka	5.0	0.6
Lulita	0.9	0.3
Nini	4.3	2.2
Regnar	0.9	0.0
Roar	2.6	0.1
Rolf	4.4	0.6
Siri	11.6	1.2
Skjold	43.3	8.6
South Arne	21.1	14.5
Svend	7.0	0.4
Tyra**	29.9	11.3
Valdemar	7.9	9.3
Justified for development	-	22
Subtotal	**361**	**143**
		Contingent resources
Development pending	-	*22*
Development unclarified	-	*8*
Development not viable	-	*11*
Subtotal		**42**
Total	**361**	**185**
January 2010	347	194

GAS, bn. Nm³	Net produced*	Resources Net gas* Exp.	Resources Sales gas* Exp.
		Reserves	
Ongoing recovery and approved for development			
Cecilie	0.1	-	-
Dagmar	0.2	0.0	0
Dan	22.7	2.7	0
Gorm	7.4	0.6	0
Halfdan	21.7	12.7	10
Harald	21.3	2.6	3
Kraka	1.4	0.1	0
Lulita	0.6	0.2	0
Nini	0.4	-	-
Regnar	0.1	0.0	0
Roar	14.7	0.6	1
Rolf	0.2	0.0	0
Siri	0.1	-	-
Skjold	3.5	0.7	0
South Arne	5.2	3.1	2
Svend	0.8	0.0	0
Tyra**	60.0	25.7	21
Valdemar	3.7	6.2	6
Justified for development	-	11	9
Subtotal	**164**	**66**	**52**
		Contingent resources	
Development pending	-	*21*	*19*
Development unclarified	-	*4*	*4*
Development not viable	-	*10*	*9*
Subtotal		**35**	**32**
Total	**164**	**101**	**84**
January 2010	156	105	85

*) Net production: historical production less injection
Net gas: future production less injection
Sales gas: future production less injection and less fuel gas and flaring
**) Tyra Southeast included

APPENDIX C: FINANCIAL KEY FIGURES

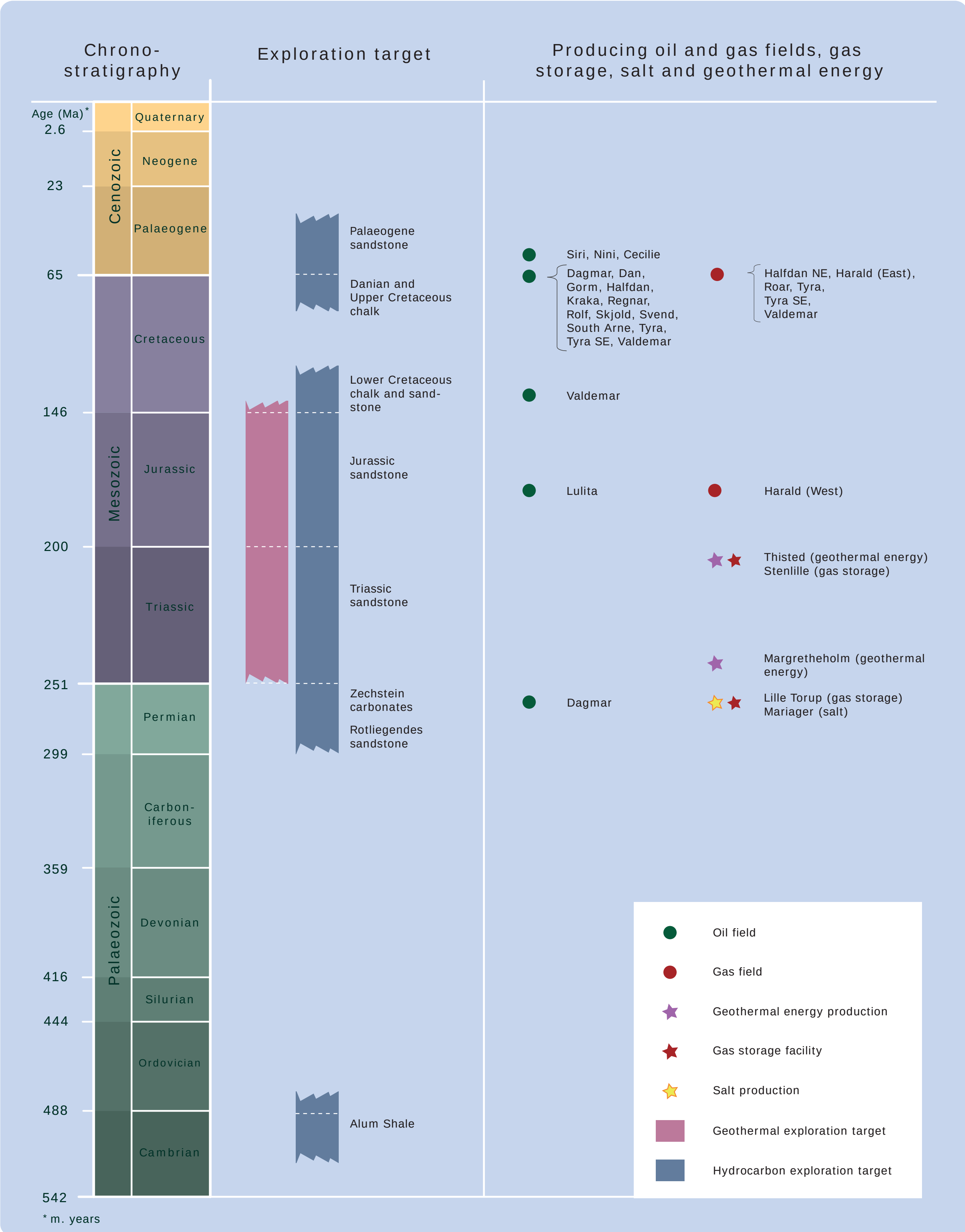
	Investments in field dev. DKK million 5)	Field operating costs DKK million 1)	Exploration costs DKK million	Crude oil price USD/bbl	Exchange rate DKK/USD	Inflation per cent 3)	Net foreign-currency value DKK billion 4)	State revenue DKK million
1972	105	29	30	3.0	7.0	6.7	-3.2	-
1973	9	31	28	4.6	6.1	9.3	-4.0	1
1974	38	57	83	11.6	6.1	15.3	-9.2	1
1975	139	62	76	12.3	5.8	9.6	-8.5	2
1976	372	70	118	12.9	6.1	9.0	-9.5	4
1977	64	85	114	14.0	6.0	11.1	-10.4	5
1978	71	120	176	14.1	5.5	10.0	-9.5	21
1979	387	143	55	20.4	5.3	9.6	-13.7	19
1980	956	163	78	37.5	5.6	12.3	-18.6	29
1981	1,651	320	201	37.4	7.1	11.7	-20.1	36
1982	3,884	534	257	34.0	8.4	10.1	-20.6	231
1983	3,554	544	566	30.5	9.1	6.9	-17.8	401
1984	1,598	1,237	1,211	28.2	10.4	6.3	-18.3	564
1985	1,943	1,424	1,373	27.2	10.6	4.7	-17.6	1,192
1986	1,651	1,409	747	14.9	8.1	3.7	-7.3	1,399
1987	930	1,380	664	18.3	6.8	4.0	-5.9	1,328
1988	928	1,413	424	14.8	6.7	4.5	-3.7	568
1989	1,162	1,599	366	18.2	7.3	4.8	-3.2	1,024
1990	1,769	1,654	592	23.6	6.2	2.6	-2.7	2,089
1991	2,302	1,898	985	20.0	6.4	2.4	-1.9	1,889
1992	2,335	1,806	983	19.3	6.0	2.1	-0.4	1,911
1993	3,307	2,047	442	16.8	6.5	1.2	-1.7	1,811
1994	3,084	2,113	151	15.6	6.4	2.0	-0.5	2,053
1995	4,164	1,904	272	17.0	5.6	2.1	0.3	1,980
1996	4,260	2,094	470	21.1	5.8	2.1	0.4	2,465
1997	3,760	2,140	515	18.9	6.6	2.2	1.4	3,171
1998	5,381	2,037	406	12.8	6.7	1.8	0.9	3,125
1999	3,531	2,118	656	17.9	7.0	2.5	3.5	3,630
2000	3,113	2,813	672	28.5	8.1	2.9	14.9	8,695
2001	4,025	2,756	973	24.4	8.3	2.4	12.6	9,634
2002	5,475	3,102	1,036	24.9	7.9	2.4	14.5	10,137
2003	7,386	3,522	789	28.8	6.6	2.1	15.3	9,255
2004	5,104	3,289	340	38.2	6.0	1.2	19.7	17,092
2005	3,951	3,760	578	54.4	6.0	1.8	24.8	24,163
2006	5,007	4,744	600	65.1	5.9	1.9	31.5	31,499
2007	6,524	4,129	547	72.5	5.4	1.7	28.3	27,885
2008	5,879	5,402	820	97.2	5.1	3.4	27.1	36,155
2009	6,686	5,284	1,413	61.6	5.4	1.3	15.0	24,584
2010*	4,864	5,060	487	79.5	5.6	2.3	15.1	23,735

Nominal prices
1) Incl. transportation costs
2) Brent crude oil
3) Consumer prices, source: Statistics Denmark
4) Surplus on the balance of trade for oil products and natural gas, source: external trade statistics, Statistics Denmark
5) Investments include the NOGAT pipeline
**) Estimate*

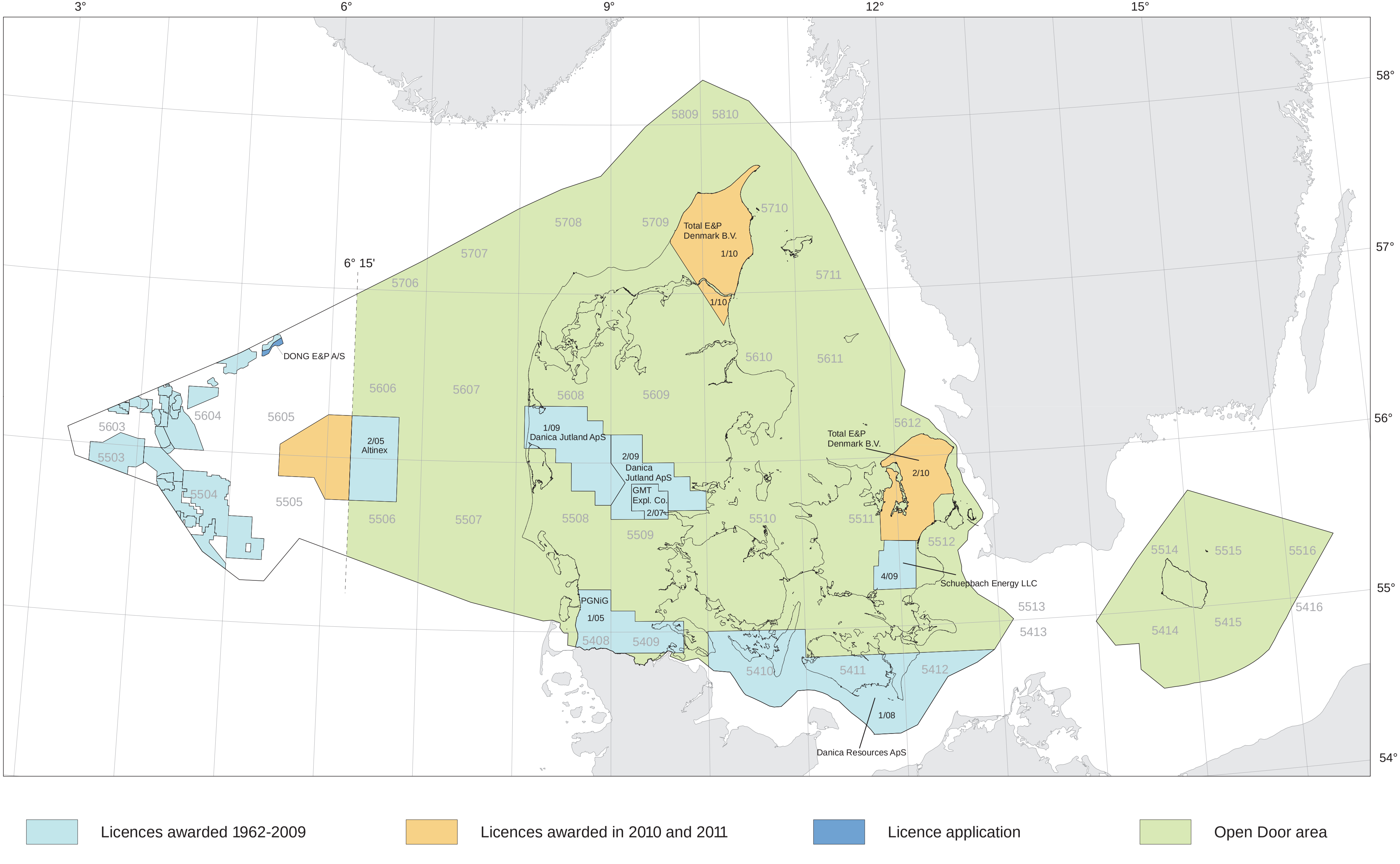
APPENDIX D: EXISTING FINANCIAL CONDITIONS

	Sole Concession at 1 Jan. 2004	Licences granted before 1 Jan. 2004	Licences granted after 1 Jan. 2004
Corporate income tax	25 per cent Deductible from the hydrocarbon tax base.	25 per cent Deductible from the hydrocarbon tax base.	25 per cent Deductible from the hydrocarbon tax base.
Hydrocarbon tax	52 per cent Allowance of 5 per cent over 6 years (a total of 30 per cent) for investments. Transitional rules for investments and unutilized field losses made before 1 January 2004.	70 per cent Allowance of 25 per cent over 10 years (a total of 250 per cent) for investments.	52 per cent Allowance of 5 per cent for 6 years (a total of 30 per cent) for investments.
Royalty	No	2nd Round licences pay royalty as follows: 1,000 bbl/day Rate 0 - 5 2 per cent 5 - 20 8 per cent 20 - 16 per cent Deductible from the corp. income tax and hydrocarbon tax bases.	No
Oil pipeline tariff/ compensatory fee	5 per cent until 8 July 2012, after which no tariff/fee is payable. The oil pipeline tariff/compensatory fee can be offset against hydrocarbon tax, but not against the corporate tax and hydrocarbon tax bases.	5 per cent The oil pipeline tariff/compensatory fee is deductible from the royalty base and the corporate income tax and hydrocarbon tax bases.	5 per cent until 8 July 2012, after which no tariff/fee is payable. The oil pipeline tariff/compensatory fee can be offset against hydrocarbon tax, but not against the corporate tax and hydrocarbon tax bases.
State participation	20 per cent from 9 July 2012	20 per cent 1st, 2nd og 3rd Rounds: State participation with carried interest in the exploratory phase. A paying interest, depending on the size of production, in the development and production phases. 4th and 5th Rounds and Open Door procedure: fully paying interest.	20 per cent
Profit sharing	From 1 January 2004 to 8 July 2012, 20 per cent of the taxable profit before tax and before net interest expenses is payable.	No	No

APPENDIX E: GEOLOGICAL TIME SCALE

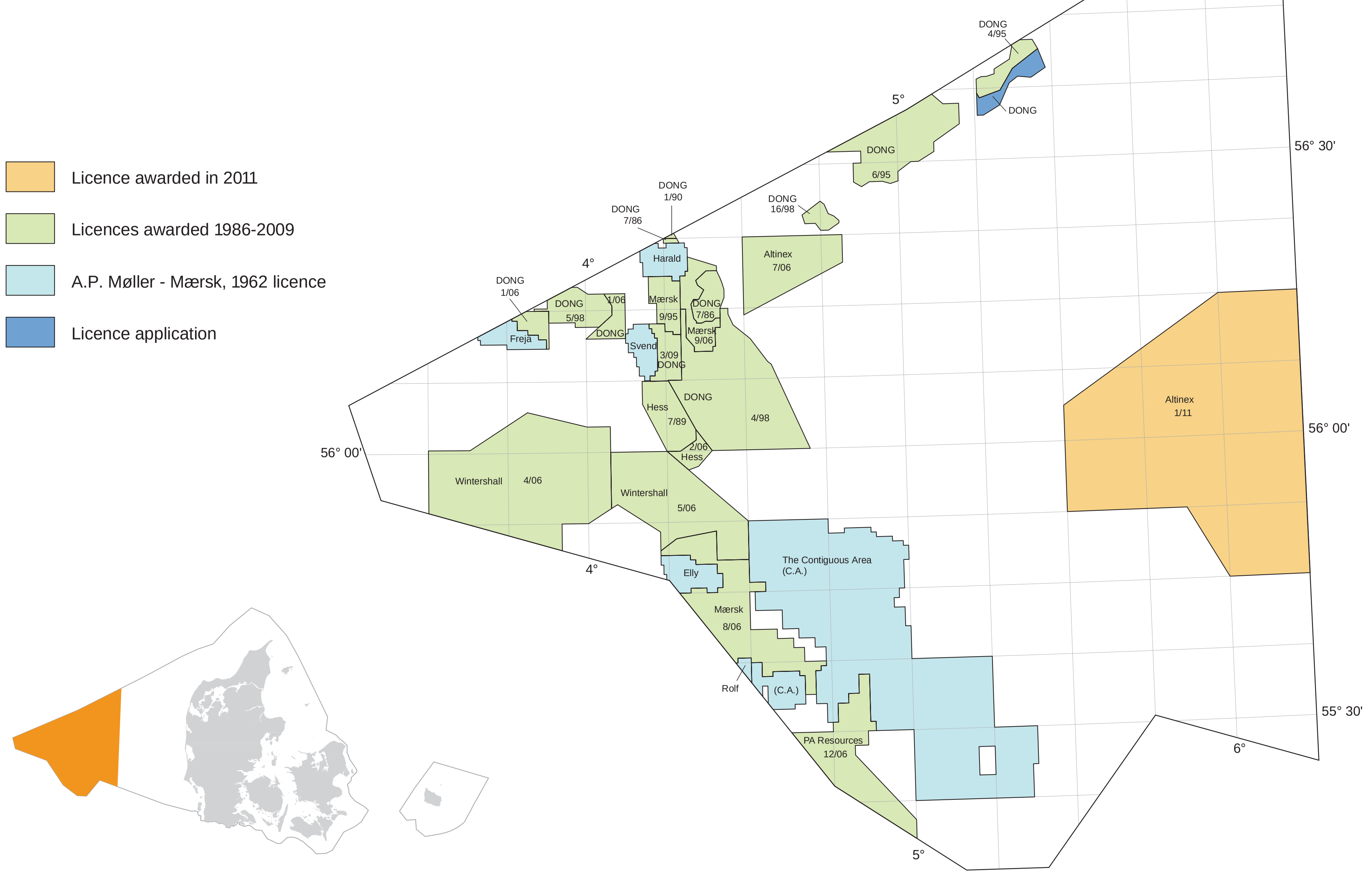


Appendix F1: Danish licence area - March 2011



Appendix F2: Danish licence area - March 2011

The western area



CONVERSION FACTORS

Reference pressure and temperature for the units mentioned:

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

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

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

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

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

The composition, and thus the calorific value, of crude oil and natural gas vary from field to field and with time. Therefore, the conversion factors for ton (t) and gigajoule (GJ) are dependent on time. The lower calorific value is indicated.

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

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

Abbreviations:

kPa	*kilopascal. Unit of pressure. 100 kPa = 1 bar.*
psia	*pound per square inch absolute.*
m^3(st)	*standard cubic metre. Unit of measurement used for natural gas and crude oil in a reference state: 15°C and 101.325 kPa in this report.*
Nm^3	*normal cubic metre. Unit of measurement used for natural gas in the reference state 0°C and 101.325 kPa.*
scf	*standard cubic foot/feet. Unit of measurement used for natural gas in a reference state: 15°C and 101.325 kPa in this report.*
stb	*stock tank barrel. Barrel in a reference state of 15°C and 101.325 kPa. Used for oil.*
bbl	*blue barrel. In the early days of the oil industry when oil was traded in physical barrels, different barrel sizes soon emerged. To avoid confusion, Standard Oil painted their standard-volume barrels blue.*
kg · mol	*kilogram-mole. The mass of a substance whose mass in kilograms is equal to the molecular mass of the substance.*
γ	*gamma. Relative density.*
Btu	*British Thermal Unit. Other thermal units are J (= Joule) and cal (calorie).*
t.o.e.	*tons oil equivalent. This unit is internationally defined as 1 t.o.e. = 10 Gcal.*
in	*inch. British unit of length. 1 inch = 2.54 cm.*
ft	*foot/feet. British unit of length. 1 foot = 12 in = 0.3048 m.*

	FROM	TO	MULTIPLY BY
Crude oil	m^3 (st)	stb	6.293
	m^3 (st)	GJ	36.55[i]
	m^3 (st)	t	0.85[i]
Natural gas	Nm^3	scf	37.2396
	Nm^3	GJ	0.03946[i]
	Nm^3	t.o.e.	$942.49 \cdot 10^{-6}$ [i]
	Nm^3	kg · mol	0.0446158
	m^3 (st)	scf	35.3014
	m^3 (st)	GJ	0.03741[i]
	m^3 (st)	kg · mol	0.0422932
Units of volume	m^3	bbl	6.28981
	m^3	ft^3	35.31467
	US gallon	in^3	231*
	bbl	US gallon	42*
Energy	t.o.e.	GJ	41.868*
	GJ	Btu	947,817
	cal	J	4.1868*
	FROM	**TO**	**CONVERSION**
Density	°API	kg/m^3	141,364.33/(°API+131.5)
	°API	γ	141.5/(°API+131.5)

**) Exact value.*
i) Average value for Danish fields for 2010.