OIL AND GAS PRODUCTION IN DENMARK 2013

and Subsoil Use

DANISH ENERGY AGENCY

Preface

While the EU countries' dependency on imported natural gas, mainly from Norway, Russia and Northern Africa, is approaching 70 per cent, Denmark has been supplied with gas from its North Sea fields since the 1980s and has also exported natural gas, primarily to Sweden and Germany. This production has significantly impacted our security of supply and balance of trade. As appears from this year's report on Denmark's oil and gas production, Denmark is expected to continue being a net exporter of natural gas up to and including 2025.

Large quantities of oil and gas still remain to be discovered in the Danish areas, and the DEA recently opened the 7th Licensing Round with a view to maintaining a high activity level in Denmark and opening up opportunities for making new discoveries. The DEA looks forward to receiving applications for new licences for oil and gas exploration and production in the western part of the North Sea up until the application deadline on 20 October 2014. The new licences are slated to be issued at the beginning of 2015. In future the plan is to launch new licensing rounds every other year.

The overhaul of the terms and conditions for hydrocarbon production in the North Sea was completed in 2013, and it was decided to harmonize tax conditions for Danish North Sea production. Following this overhaul, the Danish Government initiated work on an overall oil and gas strategy in cooperation with the industry, the aim being to ensure that we exploit North Sea oil and gas resources efficiently. An important element of this strategy will be to consider the existing North Sea infrastructure in the form of production facilities and pipelines, an essential prerequisite for the commercial exploitation of new discoveries. In addition, the potential for increasing recovery from known fields will be investigated.

The work on this strategy and the new procedure with more frequent licensing rounds will help lay the foundation for many years of future oil and gas production.

The DEA is currently changing the format of "Denmark's Oil and Gas Production". As in the past two years, the report will only be published electronically at the DEA's website, www.ens.dk. This year, however, the DEA has further streamlined the report by focusing on the information value of data and by incorporating the appendices into the relevant chapters. The intention is to make it easier to find specific facts about Danish oil and gas production.

In July 2013 the European Commission adopted a Directive on Offshore Safety. The Directive has meant a separation between the regulatory functions relating to offshore safety and offshore resources. Therefore, the report no longer contains information about health and safety on the North Sea oil and gas installations.

Copenhagen, June 2014

Morten Bæk

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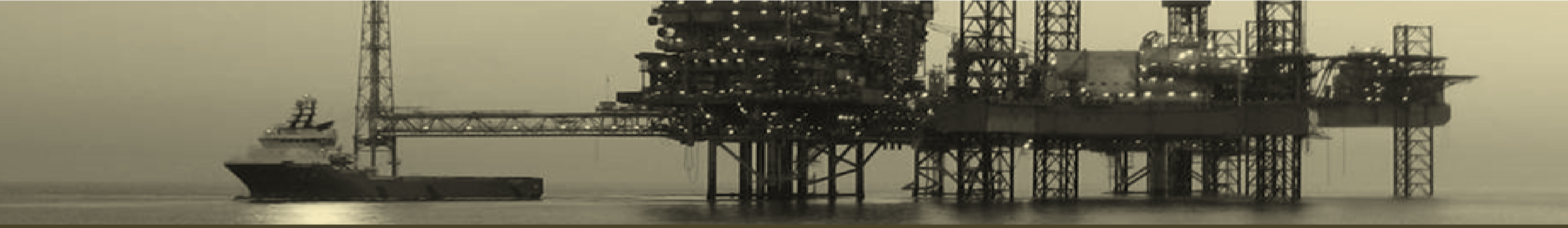


1. PRODUCTION

Oil production in 2013 totalled 10.2 million m^3, a 13 per cent decline compared to 2012. Natural gas exports fell by 18 per cent to 4.0 billion Nm^3.

Last year saw a number of planned and unplanned shutdowns of various fields, which meant that only 12 out of 19 fields were actually in production during the last five months of 2013. The Siri, Nini and Cecilie Fields were particularly hard hit and were shut down during the second half of 2013 due to a crack being identified on 17 July 2013 in the tank console supporting the well caisson under the Siri platform.

The production from South Arne was affected by the further development of the field, consisting of the establishment of a new independent platform and the drilling of new wells north of the existing platform. The first well under this development plan came on stream at the end of November 2013. The drilling of new wells and commissioning of the northern platform are continuing in 2014.

The partners in the Sole Concession, which comprises 15 of the 19 producing fields in the Danish part of the North Sea, continued to focus on the maintenance of existing wells and platforms in 2013. A major modification was carried out at Tyra in both 2012 and 2013 in connection with optimizing the processing facilities, now placed at Tyra West. However, production was also impacted by unplanned shutdowns of several fields, including due to the replacement of a flare tip at Tyra West and of a riser valve at Harald.

An outline of all 19 producing fields can be found in chapter 7, *Producing fields.*

Production figures for each year are available at the DEA’s website, www.ens.dk. These statistics date back to 1972, when Danish production started from the Dan Field.

Production facilities in the North Sea

Figure 1.1 Location of production facilities in the North Sea 2013.

All producing fields in Denmark are located in the North Sea and appear from this figure, which also shows the key pipelines. In total there are 19 producing fields of varying size, and three operators are responsible for production from these fields: DONG E&P A/S, Hess Denmark ApS and Mærsk Olie og Gas A/S.

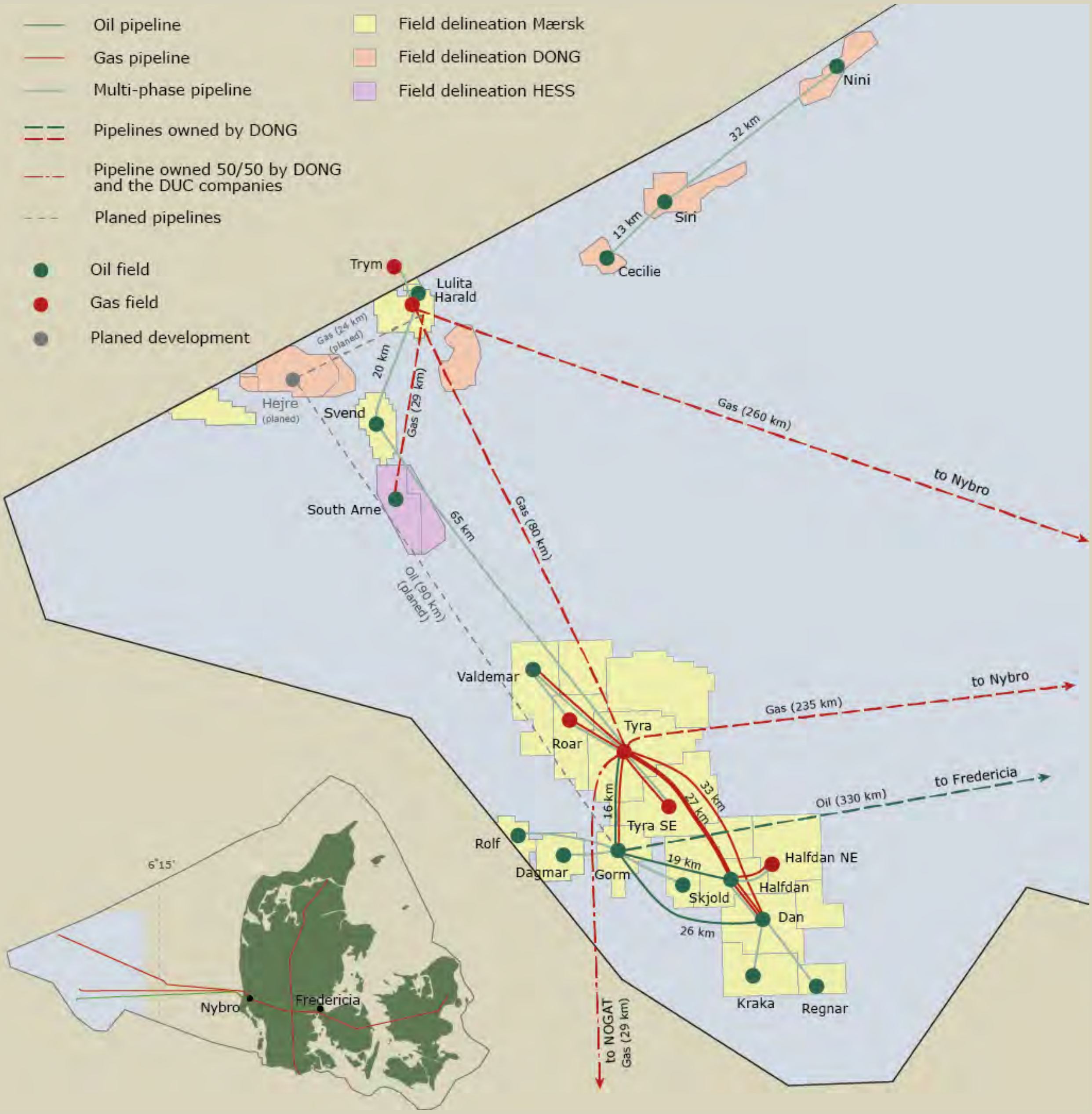


Figure 1.2. Breakdown of oil production by company in 2013.

A total of 11 companies participate in production from Danish fields. DUC is the largest oil producer and gas exporter, accounting for 89 per cent of oil production and 97 per cent of gas exports.

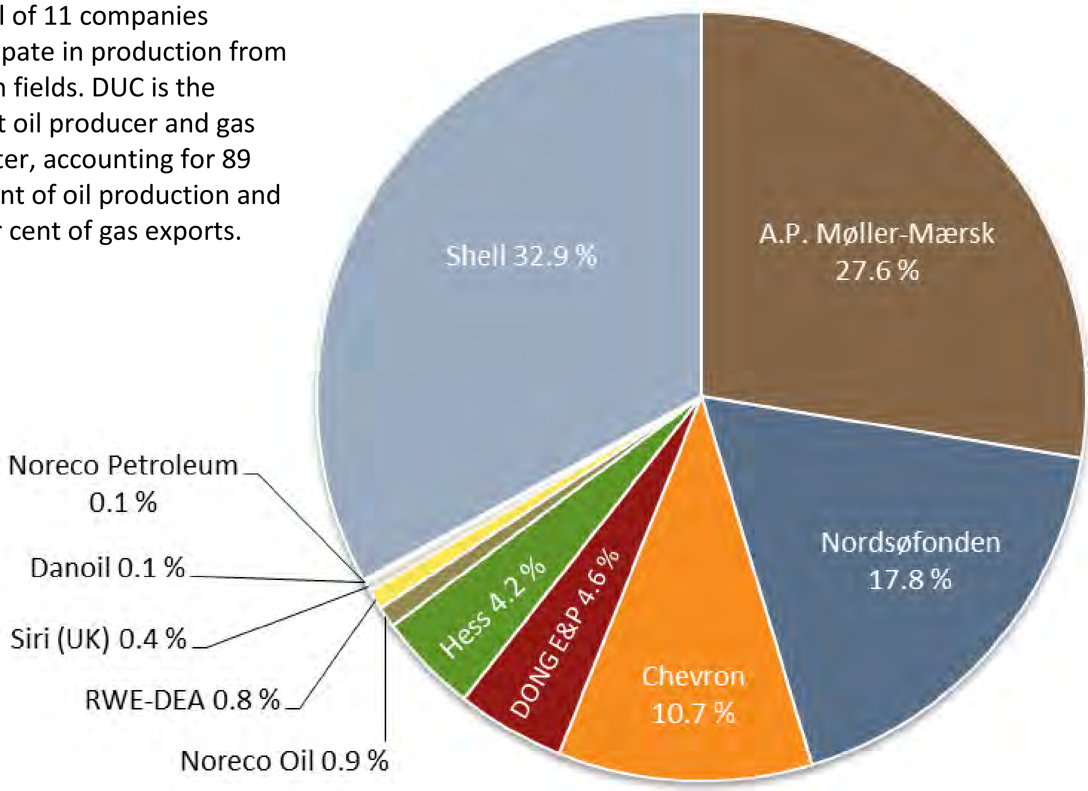
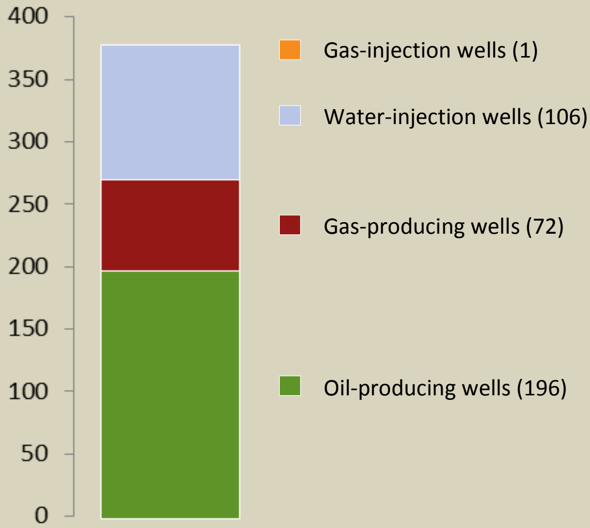


Figure 1.3. Active wells in the North Sea in 2013.

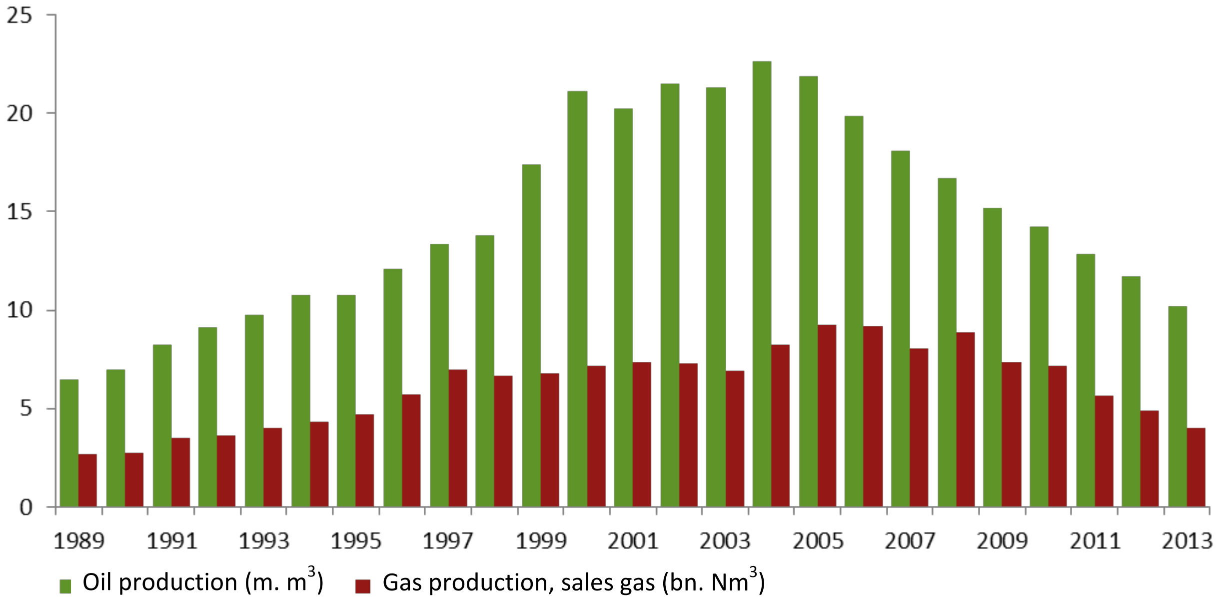
In 2013 production in the Danish part of the North Sea derived from a total of 375 active wells, of which 196 were oil-producing wells and 72 were gas-producing wells. In addition, 106 active water-injection wells and one gas-injection well contributed to production.



Production in 2013

Figure 1.4. Production of oil and gas 1989-2013.

Oil production in 2013 totalled 10.2 million m^3 (175,602 barrels/day), a 13.2 per cent decline compared to 2012. The production of natural gas totalled 4.7 billion Nm^3 in 2013, of which 4.0 billion Nm^3 of gas was exported ashore as sales gas, an 18.2 per cent decline on 2012.



As expected, production from the Danish part of the North Sea is continuing the declining trend that started in 2004. The main reason for this trend is that the majority of fields have already produced the bulk of the anticipated recoverable oil. In addition, these ageing fields require more maintenance as regards wells, pipelines and platforms. This maintenance work often causes a loss or delay in production, as the wells and possibly even the entire platform must be shut down while the work is carried out.

The development of existing and new fields may help counter the declining production. In addition, the implementation of both known and new technology may help optimize and increase production from existing fields. Read more about future planned developments in chapter 6, *New field developments*, and the development of existing fields in chapter 7, *Producing fields*.

Table 1.1. Oil, production *Thousand cubic metres*

	1972-2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	I alt
Dan	75,616	5,712	5,021	4,650	4,241	3,549	2,979	2,474	2,260	2,045	108,548
Gorm	50,525	1,978	1,897	1,639	1,053	924	923	713	593	543	60,788
Skjold	37,032	1,310	1,214	1,015	989	918	835	778	679	605	45,376
Tyra	21,832	773	845	764	551	415	856	744	626	521	27,929
Rolf	3,940	79	89	103	78	76	60	1	0	0	4,427
Kraka	4,170	211	222	176	112	37	67	170	129	101	5,394
Dagmar	1,005	0	0	0	0	0	0	0	0	0	1,005
Regnar	904	16	11	0	0	0	0	0	0	0	930
Valdemar	2,561	423	470	881	1,268	1,410	909	817	844	777	10,360
Roar	2,330	94	51	35	28	30	24	16	2	4	2,613
Svend	5,382	324	296	299	278	195	190	145	171	183	7,463
Harald	7,081	237	176	139	114	65	70	95	79	25	8,080
Lulita	675	35	68	55	47	24	36	36	32	17	1,025
Halfdan	17,323	6,200	6,085	5,785	5,326	5,465	5,119	4,905	4,617	4,150	64,976
Siri	8,576	703	595	508	598	326	286	161	238	131	12,123
South Arne	12,299	2,371	1,869	1,245	1,139	1,164	1,066	1,004	803	700	23,660
Tyra SE	1,415	614	446	377	429	374	225	165	148	98	4,291
Cecilie	476	183	116	88	66	38	33	39	33	17	1,087
Nini	1,868	624	377	323	355	159	544	569	475	268	5,563
I alt	255,011	21,886	19,847	18,084	16,672	15,169	14,223	12,834	11,727	10,185	395,639

Table 1.2. Gas, production. *Million normal cubic metres*

	1972-2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
Dan	19,863	651	561	456	467	364	360	327	330	416	23,796
Gorm	14,631	218	207	175	119	109	99	67	52	60	15,736
Skjold	3,104	93	77	69	60	58	87	69	62	70	3,748
Tyra	70,014	3,745	3,792	3,916	3,130	2,007	1,664	1,320	1,404	1,618	92,611
Rolf	165	3	4	4	3	3	3	0	0	0	186
Kraka	1,269	24	28	28	36	8	12	46	35	20	1,504
Dagmar	157	0	0	0	0	0	0	0	0	0	158
Regnar	61	1	1	0	0	0	0	0	0	0	63
Valdemar	1,037	208	208	355	593	510	791	579	515	368	5,164
Roar	11,972	860	489	367	417	398	213	171	24	28	14,940
Svend	650	34	28	28	24	16	27	24	27	20	878
Harald	16,809	1,091	927	781	690	400	592	573	541	174	22,579
Lulita	453	13	38	33	30	15	18	20	19	11	650
Halfdan	4,086	2,582	2,948	2,675	3,104	3,401	2,886	2,343	1,709	1,389	27,123
Siri	845	112	55	47	63	44	67	48	48	35	1,362
South Arne	3,340	485	366	234	225	271	248	238	194	167	5,769
Tyra SE	2,132	1,337	1,108	848	889	939	911	626	610	306	9,707
Cecilie	36	13	8	6	4	2	2	3	3	1	78
Nini	138	46	28	24	26	12	76	57	40	22	469
I alt	150,764	11,517	10,873	10,046	9,879	8,559	8,057	6,511	5,613	4,704	226,522

Figure 1.5. Use of gas production, 1989-2013.

Sales gas accounted for about 85 per cent of total gas production. 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 is flared for technical and safety reasons.

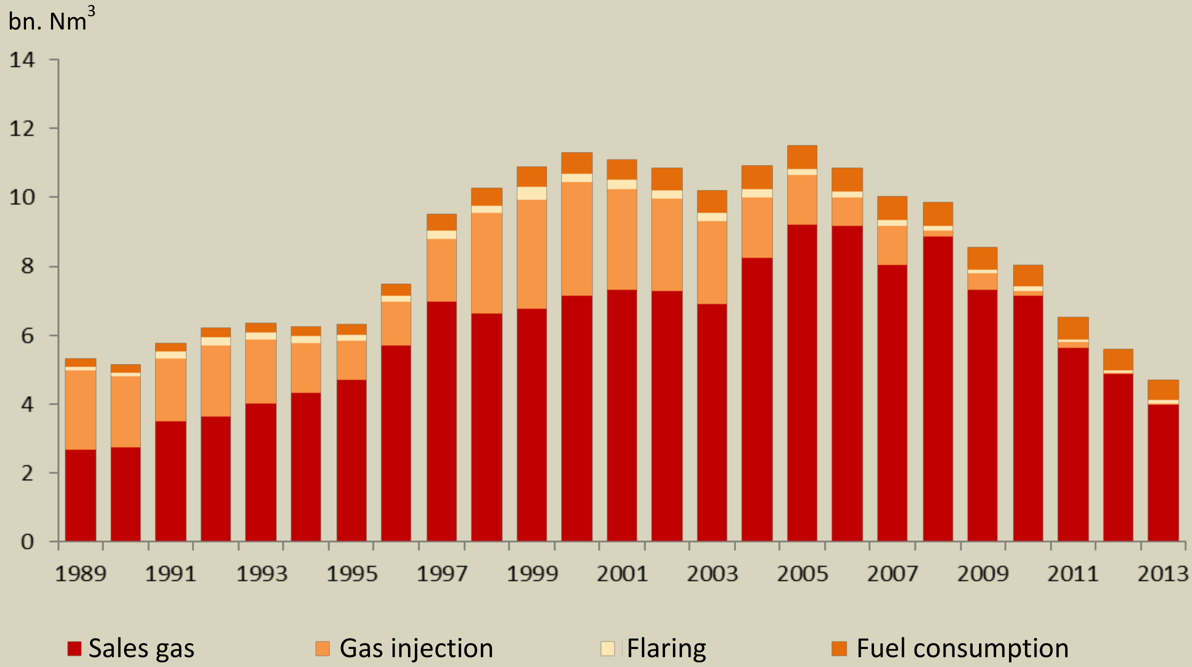
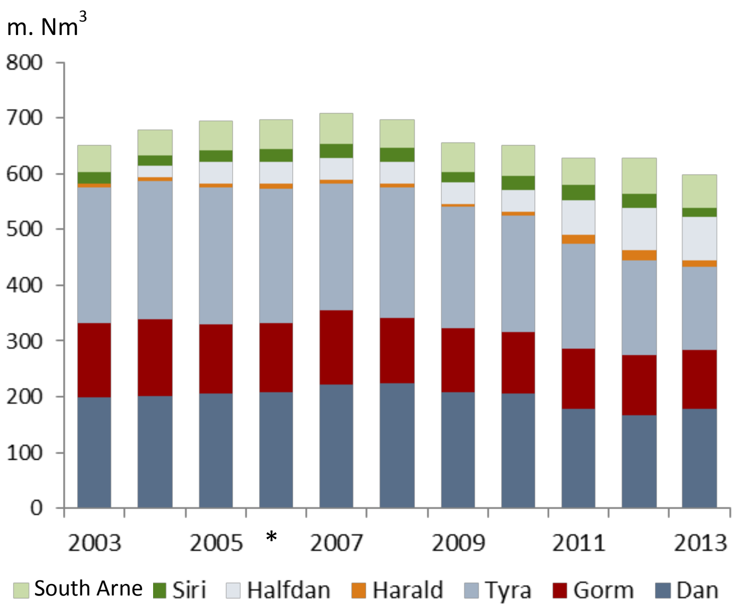


Figure 1.6 Consumption of fuel (gas).



Fuel gas accounted for 86 per cent of total gas consumption offshore in 2013. The remaining 14 per cent was flared. 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 and onwards is energy-efficiency measures taken by the operators.

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

Table 1.3 Gas, export of sales gas produced in Denmark *Million normal cubic metres*

	1972-2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
Tyra East	92,450	6,669	6,698	5,720	6,666	5,551	6,228	4,807	3,739	2,808	141,336
South Arne	2,935	419	302	168	167	212	199	180	130	108	4,820
Tyra West	873	2,127	2,164	2,161	2,032	1,560	715	648	994	1,066	14,339
I alt	**96,258**	**9,215**	**9,164**	**8,049**	**8,865**	**7,324**	**7,142**	**5,635**	**4,863**	**3,981**	**160,496**

Note: *Sales gas supplied from Tyra East and South Arne is exported through the pipeline to Nybro. Sales gas supplied from Tyra West is exported through the NOGAT pipeline to the Netherlands.*

Table 1.4. Gas, fuel. *Million normal cubic metres*

	1972-2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
Dan	1,990	205	209	222	225	207	206	179	167	178	5,778
Gorm	2,281	124	124	132	117	116	111	107	107	105	5,604
Tyra	3,087	247	241	228	233	219	208	188	171	150	8,058
Dagmar	21	0	0	0	0	0	0	0	0	0	43
Harald	80	7	8	7	7	4	8	16	17	12	247
Siri	112	20	25	25	25	19	27	28	26	16	433
South Arne	208	52	53	58	53	54	55	41	64	60	906
Halfdan	20	39	39	39	38	39	36	62	76	77	485
I alt	**7,799**	**694**	**697**	**711**	**699**	**658**	**651**	**620**	**628**	**597**	**21,553**

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

Table 1.5. Gas, flaring. *Million normal cubic metres*

	1972-2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
Dan	1,941	23	32	29	25	17	12	13	13	14	4,058
Gorm	1,587	61	61	48	41	19	12	14	15	18	3,463
Tyra	983	55	54	56	44	32	23	28	25	41	2,323
Dagmar	135	0	0	0	0	0	0	0	0	0	270
Harald	132	1	2	2	2	2	3	3	2	11	292
Siri	194	15	6	7	7	4	58	6	4	3	497
South Arne	198	14	11	11	7	7	6	11	5	3	471
Halfdan	29	16	20	17	8	4	5	6	6	7	145
I alt	**5,198**	**184**	**185**	**169**	**132**	**85**	**119**	**81**	**71**	**97**	**11,519**

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

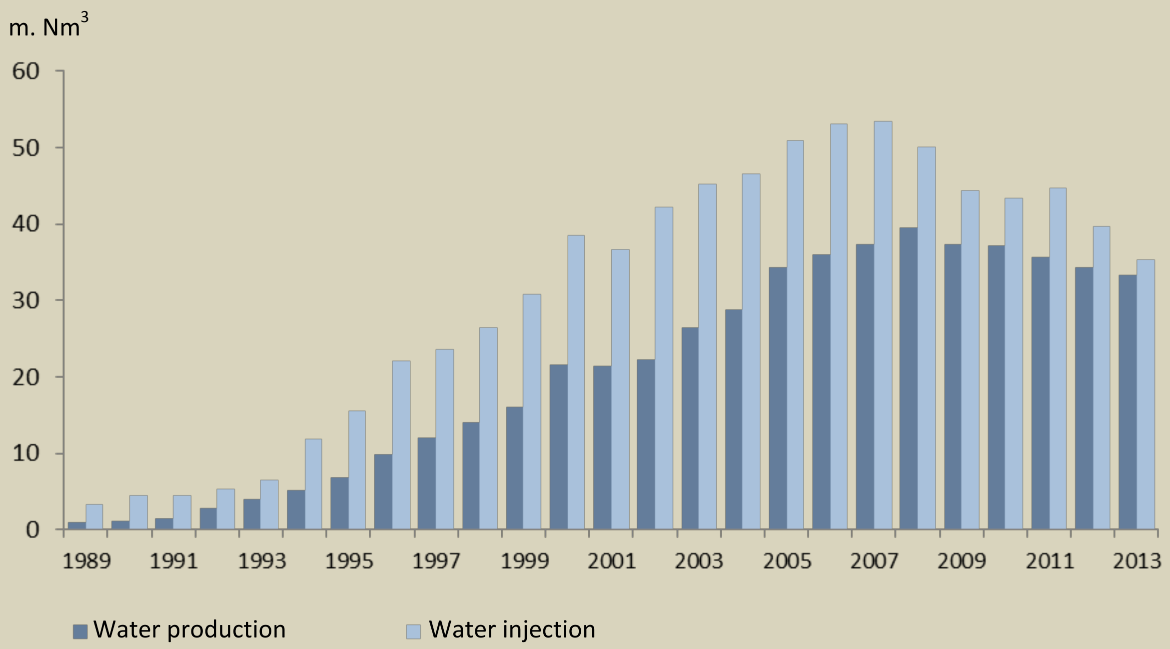
Table 1.6. Gas, injection. *Million normal cubic metres*

	1972-2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
Gorm	8,161	3	0	0	0	0	0	0	0	0	8,164
Tyra	32,621	1,285	761	1,094	119	451	89	94	0	0	36,514
Siri	714	135	61	45	61	35	57	74	62	41	1,285
I alt	**41,496**	**1,423**	**821**	**1,139**	**180**	**486**	**146**	**168**	**62**	**41**	**45,963**

Figure 1.7. Water production and water injection 1989-2013.

Water is produced as a by-product in connection with the production of oil and gas. The water can originate from natural water zones in the subsoil and from the water injection that is carried out in order to enhance oil production.

The content of water relative to the total liquids produced in the Danish part of the North Sea is increasing and reached 76.6 per cent in 2013. A high amount of energy is required to handle these large volumes of produced water, as high as about 90 per cent for some of the old fields. In 2013 water production totalled 32.3 million Nm^3, a 3.3 per decline cent compared to 2012. Water injection in 2013 dropped by 10.9 per cent relative to 2012.



Since 2008 water production has declined mainly due to falling oil and gas production. The water content of total liquid production is increasing for most fields; see above. The operators are attempting to reverse this trend, for one thing by closing off production from zones with high water production.

Table 1.7. Water, production. *Thousand cubic metres*

	1972-2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	I alt
Dan	48,727	9,527	10,936	12,152	13,946	12,889	12,111	11,059	10,468	11,207	153,021
Gorm	39,742	5,252	4,822	4,708	3,976	4,737	4,904	4,654	3,897	3,658	80,349
Skjold	34,920	4,270	4,328	3,885	3,636	3,855	3,895	3,861	3,978	4,023	70,651
Tyra	28,185	3,482	3,150	2,725	3,103	2,677	1,980	1,811	1,516	2,063	50,692
Rolf	4,855	290	316	383	349	381	281	8	0	0	6,861
Kraka	3,591	320	297	359	436	183	166	358	237	170	6,119
Dagmar	3,911	3	0	0	13	0	0	0	0	0	3,927
Regnar	3,456	352	255	1	0	0	0	0	0	0	4,064
Valdemar	1,350	792	937	854	925	812	1,207	1,026	893	916	9,711
Roar	2,588	662	498	560	586	624	275	200	34	59	6,087
Svend	6,642	1,309	1,205	1,200	1,022	804	664	585	685	712	14,828
Harald	293	12	12	18	21	11	37	113	152	47	716
Lulita	85	38	92	96	91	49	65	73	86	48	722
Halfdan	3,864	2,825	3,460	4,086	4,766	4,814	5,519	6,149	6,139	6,099	47,721
Siri	12,513	1,683	2,032	2,528	2,686	1,778	2,868	2,593	2,879	1,481	33,040
South Arne	2,539	1,790	1,830	1,861	2,174	2,285	2,068	1,883	2,317	2,198	20,945
Tyra SE	1,312	437	377	669	602	716	568	485	440	235	5,841
Cecilie	355	637	651	576	456	266	317	452	390	179	4,279
Nini	63	730	822	619	660	522	195	330	297	166	4,405
I alt	**198,992**	**34,410**	**36,019**	**37,280**	**39,448**	**37,402**	**37,121**	**35,640**	**34,408**	**33,260**	**523,979**

Table 1.8. Water, injection. *Thousand cubic metres*

	1972-2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	I alt
Dan	146,078	20,281	21,520	20,230	19,275	16,712	15,148	14,508	11,684	10,148	295,585
Gorm	90,208	7,251	6,544	6,678	5,251	4,777	4,408	5,459	3,709	3,549	137,834
Skjold	79,338	6,045	5,711	6,098	4,989	5,285	4,155	4,374	5,093	4,956	126,045
Halfdan	14,169	9,710	11,026	12,107	12,727	11,485	11,945	12,277	10,912	10,921	117,280
Siri	19,098	1,350	1,973	3,499	2,695	1,692	2,692	3,201	3,020	1,592	40,810
South Arne	16,727	5,608	5,362	4,296	4,279	3,872	3,427	3,240	4,104	3,660	54,576
Nini	999	502	912	413	883	501	1,558	1,365	1,151	549	8,832
Cecilie	93	198	30	91	42	97	47	221	35	0	854
I alt	**366,709**	**50,945**	**53,077**	**53,412**	**50,141**	**44,420**	**43,379**	**44,646**	**39,709**	**35,376**	**781,815**

Emissions to the atmosphere

Emissions to the atmosphere consist of such gases as CO_2 (carbon dioxide) and NO_x (nitrogen oxide).

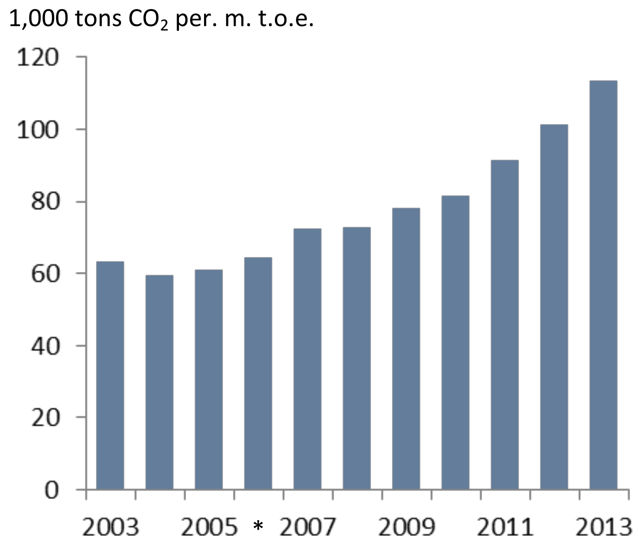
The combustion of natural gas and diesel oil and gas flaring produce CO_2 emissions to the atmosphere. Producing and transporting oil and gas require substantial amounts of energy. Furthermore, a certain volume of gas has to be flared for safety or plant-related reasons. Gas is flared on all offshore platforms with production facilities, and for safety reasons gas flaring is necessary in cases where 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.

Figure 1.8. CO_2 emissions from consumption of fuel per m. t.o.e.

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

In recent years, the steadily ageing fields have particularly impacted fuel consumption.



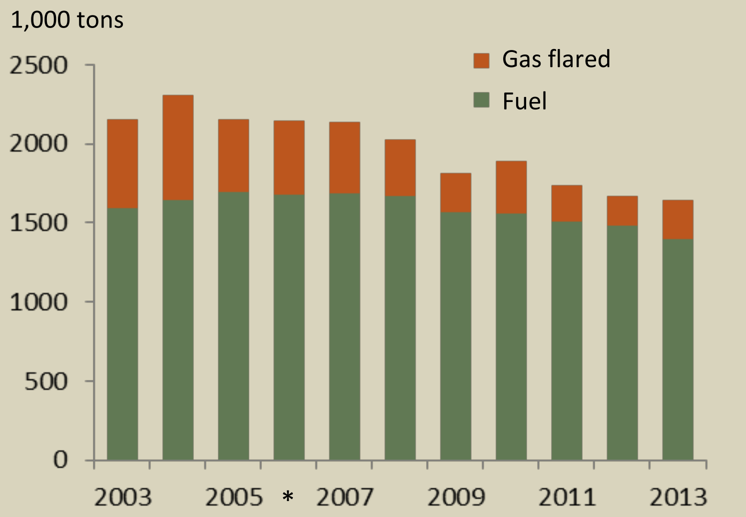
**) As from 2006, the figures have been based on verified CO_2 emission data from reports filed under the Act on CO_2 Allowances and have included CO_2 emissions from diesel combustion on the production facilities.*

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.

Figure 1.9. CO_2 emissions from production facilities in the North Sea.

CO_2 emissions from the production facilities in the North Sea totalled about 1.682 million tons in 2013, thus confirming the falling emissions trend over the past decade.

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.



**) 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 on the production facilities.*

Table 1.9. CO_2 emissions. *Thousand tons*

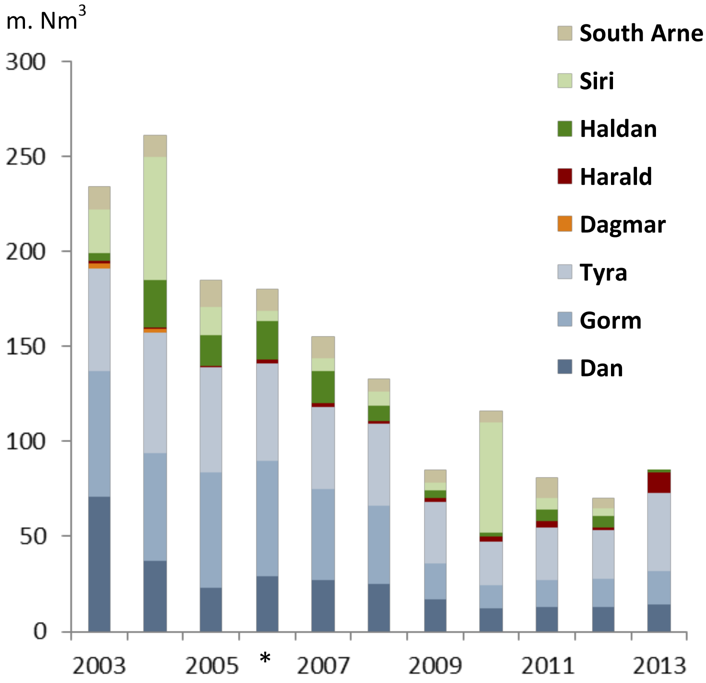
	1972-2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
Fuel	18,223	1,694	1,675	1,690	1,670	1,572	1,559	1,510	1,503	1,432	**50,751**
Flaring	12,314	457	470	449	354	241	331	230	192	250	**27,603**
Total	**30,538**	**2,151**	**2,144**	**2,139**	**2,024**	**1,813**	**1,890**	**1,740**	**1,695**	**1,682**	**78,354**

From 2006 the figures have been based on verified CO_2 emission data from reports filed under the Danish Act on CO_2 Allowances and have included CO_2 emissions from diesel combustion on the production facilities.

The calculation did not include CO_2 emissions from the combustion of diesel oil up to and including 2005. Until 2005 CO_2 emissions were calculated by using parameters specific to the individual years and the individual production facilities.

Figure 1.10. Gas flaring.

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. Gas flaring totalled 97 million Nm^3 in 2013, a 36 per cent increase on 2012.



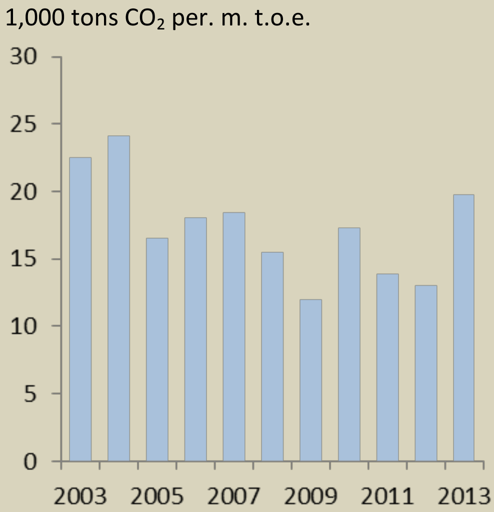
*) *As from 2006, the figures have been based on verified CO_2 emission data from reports filed under the Act on CO_2 Allowances.*

Generally, the flaring of gas has declined substantially in the past ten years due to more stable operating conditions on the installations, changes in operations and focus on energy efficiency, such as the use of flare gas recovery systems at South Arne and Siri. However, flaring may vary considerably from one year to another, frequently because of the tie-in of new fields, the commissioning of new facilities or the temporary shutdown of platforms, which makes it necessary to vent the pressure and evacuate the gas from the extensive inter-field pipelines before flaring it. For example, such major shutdowns led to additional flaring in 2010 at Siri and in 2013 at Tyra and Harald in particular.

Figure 1.11. CO_2 emissions from flaring per m. t.o.e.

The production of hydrocarbons has declined over the past decade, but the volume of gas flared per ton oil equivalent (t.o.e.) produced has not followed the same increasing trend as fuel consumption; see figure 1.8.

In 2013 CO_2 emissions from flaring per m. t.o.e. were significantly higher than in the preceding two years, up about 50 per cent on the year before. This is due to a combination of falling hydrocarbon production and increased flaring in 2013.



2. RESOURCES AND FORECASTS

The DEA uses a classification system for hydrocarbons to assess Denmark's oil and gas resources. 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. Based on the assessment of resources, the DEA prepares short- and long-term oil and gas production forecasts.

Resources

Reserves have been estimated at 107 million m^3 of oil and 37 billion Nm^3 of sales gas. Reserves have been revised downwards compared to the previous assessment from 2012, mainly attributable to production in 2012 and 2013.

Compared to the previous assessment, contingent oil resources have been revised upwards by 7 million m^3 due to higher expectations for the potential at South Arne. Moreover, prospective resources have been adjusted upwards by 10 million m^3 of oil relative to the previous assessment, as additional prospects have been matured for exploration drilling. The remaining categories are almost unchanged compared to the 2012 assessment.

Short-term forecast

For 2014 the DEA expects production to total 9.9 million m^3 of oil, equal to about 171,000 barrels of oil per day, and 4.5 billion Nm^3 of sales gas, equal to a combined total of about 253,000 barrels of oil equivalent per day.

During the forecast period from 2014 to 2018, the DEA expects a general decline in production; however, for 2016 and 2017, the production level is expected to stabilize, the main reason being startup of production from the Hejre Field.

Long-term forecast

Denmark is anticipated to be a net exporter of oil for eight years up to and including 2021, based on the expected production profile. If technological and prospective resources are included, they will contribute substantially to reducing Denmark's net oil imports from around 2025 until after 2035.

Denmark is anticipated to be a net exporter of sales gas for 12 years up to and including 2025, based on the expected production profile. If technological and prospective resources are included, Denmark is estimated to remain a net exporter until after 2035.

Resources

Figure 2.1. Resource assessment by category.

A more detailed assessment of production, reserves and contingent resources appears from table 2.1.

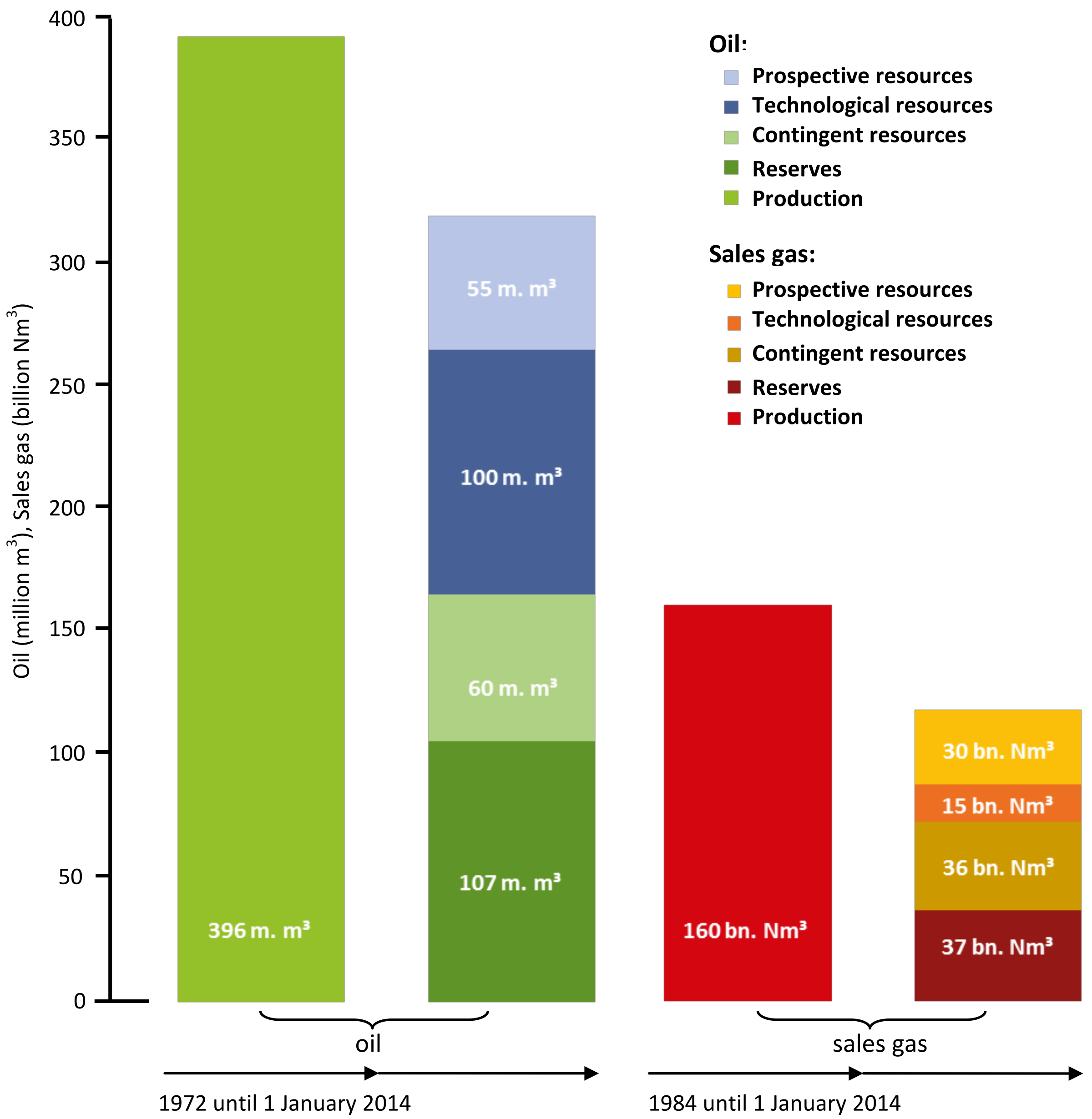


Table 2.1. Production, reserves and contingent resources at 1 January 2014.

OIL, m. m^3	Production	Resources
		Reserver
Ongoing recovery and approved for development		
Cecilie	1.1	0.2
Dagmar	1.0	0.0
Dan	108.5	13.8
Gorm	60.8	3.0
Halfdan	65.0	35.9
Harald	8.1	0.2
Hejre	-	16.2
Kraka	5.4	0.8
Lulita	1.0	0.1
Nini	5.6	1.1
Regnar	0.9	0.0
Roar	2.6	0.1
Rolf	4.4	0.0
Siri	12.1	1.1
Skjold	45.4	6.4
Svend	7.5	0.5
South Arne	23.7	12.9
Tyra (inc. Tyra	32.2	7.7
Valdemar	10.4	5.9
Justified for development	-	1
Subtotal	**396**	**107**
		Contingent resources
Development pending	-	*29*
Development unclarified	-	*20*
Development not viable	-	*11*
Subtotal		**60**
Total	**396**	**167**
January 2012	374	181

GAS, bn. Nm^3	Net production*	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	23.8	2.6	0
Gorm	7.6	0.3	0
Halfdan	27.1	6.9	5
Harald	22.6	1.3	1
Hejre	-	10.0	9
Kraka	1.5	0.2	0
Lulita	0.7	0.1	0
Nini	0.5	-	-
Regnar	0.1	0.0	0
Roar	14.9	1.7	1
Rolf	0.2	0.0	0
Siri	0.1	-	-
Skjold	3.7	0.4	0
Svend	0.9	0.1	0
South Arne	5.8	2.6	2
Tyra (inc. Tyra SE)	65.8	16.5	13
Valdemar	5.2	2.6	2
Justified for development	-	3	2
Sum	**181**	**48**	**37**
		Contingent resources	
Development pending		*14*	*10*
Development unclarified		*18*	*17*
Development not viable		*10*	*10*
Subtotal		**42**	**36**
Total	**181**	**90**	**73**
January 2012	170	95	79

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

Short-term forecast (five-year forecast)

The DEA prepares annual five-year forecasts of oil and gas production to be used by the Danish Ministry of Finance for its forecasts of state revenue.

Table 2.2 Expected production profile for oil and sales gas.

	2014	2015	2016	2017	2018
Olie, m. m^3	9,9	9,5	9,8	10,2	9,3
Sales gas, bn. Nm^3	4,5	4,0	3,7	3,8	3,8

Oil

For 2014 the DEA expects oil production to total 9.9 million m^3, equal to about 171,000 barrels of oil per day; see table 2.2. This is a reduction of 3 per cent relative to 2013, when oil production totalled 10.2 million m^3. Compared to last year's estimate for 2014, this constitutes a downward revision of 6 per cent, mainly attributable to the lower production figure expected by the DEA for the Halfdan Field.

During the forecast period until 2018, the DEA expects a general decline in oil production; however, for 2016 and 2017, production is expected to increase, due mainly to production from the Hejre Field.

Compared to last year's forecast, the DEA has revised the oil production estimate downwards for the period from 2014 to 2018 by an average of 12 per cent, mainly as a result of the lower production expected from the Halfdan Field and the postponed production startup of the Hejre Field.

Sales gas

The DEA estimates that sales gas production will total 4.5 billion Nm^3 for 2014; see table 2.1. This is an increase of 13 per cent relative to 2013, when production totalled 4.0 billion Nm^3. Compared to the estimate for 2014 made by the DEA last year, this is an upward revision of 10 per cent based mainly on the DEA's expectation of higher gas production in the Tyra Field.

During the forecast period until 2018, the DEA expects a general decline in the production of sales gas; however, after 2016, the production level is expected to stabilize, due mainly to production from the Hejre Field.

Compared to last year's forecast, the DEA has revised the production estimate downwards for the period from 2014 to 2018 by an average of 17 per cent, mainly as a result of the DEA postponing the commissioning date for various discoveries.

Long-term forecast

Metrics for long-term forecast and consumption forecast

The long-term forecast is divided into three contributions, the expected production profile, technological resources and prospective resources.

The expected production profile is a forecast of production from existing fields and discoveries based on existing technology. The expected production profile is based on the reserves assessment and risk-weighted contingent resources.

Technological resources are an estimate of the volumes recoverable by means of new technology. The DEA's estimate of technological oil resources is based on an increase of the average recovery factor for Danish fields and discoveries of 5 percentage points from 26 to 31 per cent. For example, new technology could consist of the development of drilling techniques, well technology and injection methods. Apart from technological developments, the cost may be lowered for various techniques and the expansion and operation of installations. For sales gas, the DEA anticipates no significant contribution from technological resources because current technology has already generated a much higher recovery factor than for oil.

Prospective resources are an estimate of the volumes recoverable from future new discoveries made as a result of ongoing exploration activity and future licensing rounds. The estimate 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.

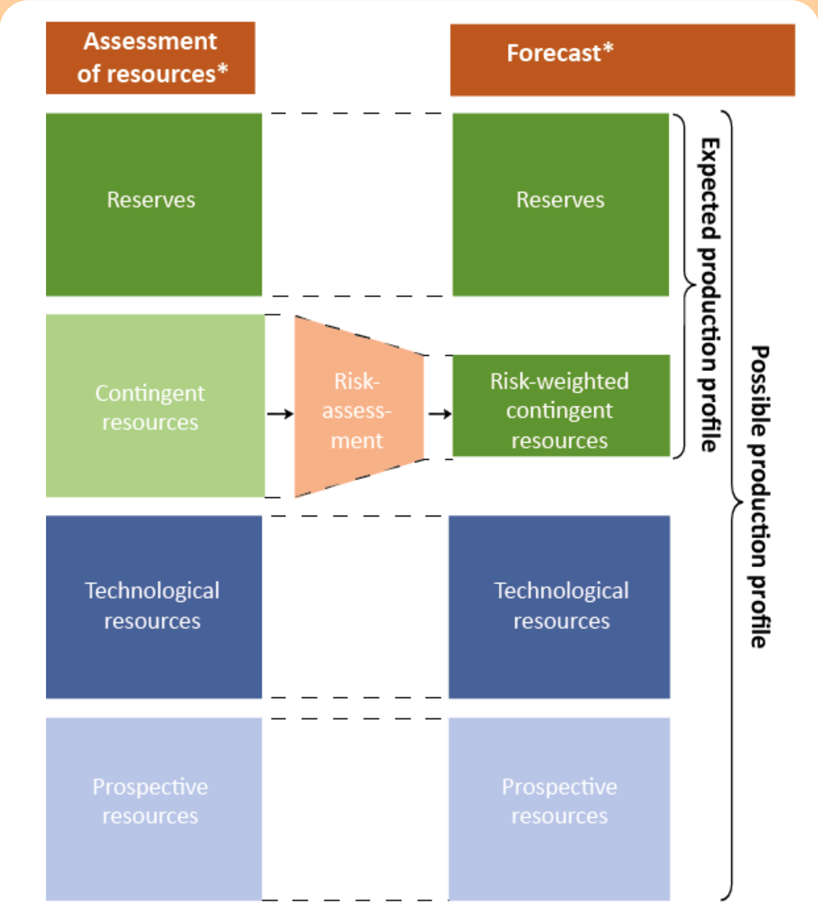
The consumption forecast from "The DEA's baseline scenario, 2012" is a scenario in which it is assumed that no measures will be taken other than those already decided with a parliamentary majority. Therefore, the baseline scenario is not a forecast of future energy consumption, but a description of the development that could be expected during the period until 2035 based on a number of assumptions regarding technological developments, prices, economic trends, etc., assuming that no new initiatives or measures are taken.

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.

Figure 2.2. Correlation between the DEA's resource assessment and production forecast.

The DEA's production forecasts are based on the assessed resources and show the expected profile of production. In principle, it is equally probable that the forecast turns out to be too optimistic or too pessimistic.

As far as contingent resources are concerned, the resource assessment is adjusted by estimating the probability that the development projects comprised by the resource assessment will be implemented.



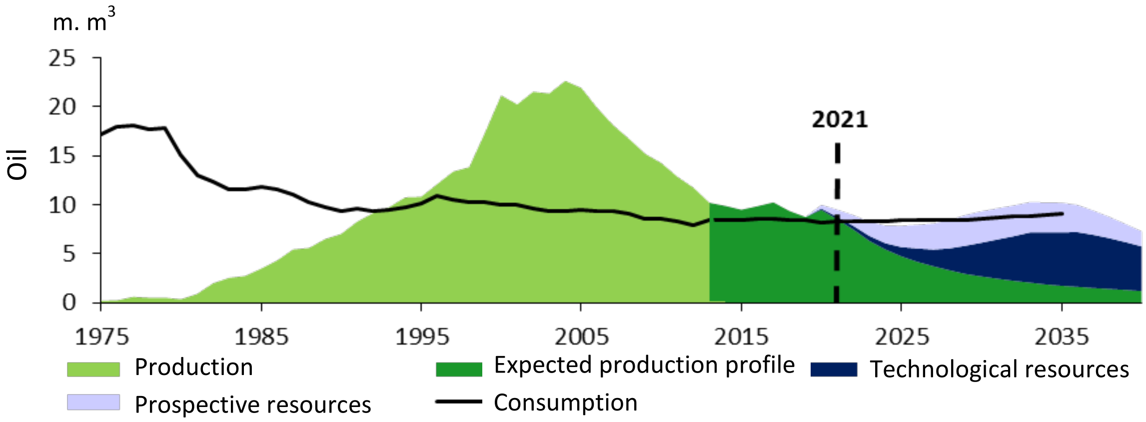
* *The assessment of resources and the forecast are shown with the colour code for oil.*

For oil, the risk assessment means that the difference between contingent resources and risk-weighted contingent resources ranges around 30 million m^3 of oil. Of this difference, about 10 million m^3 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.

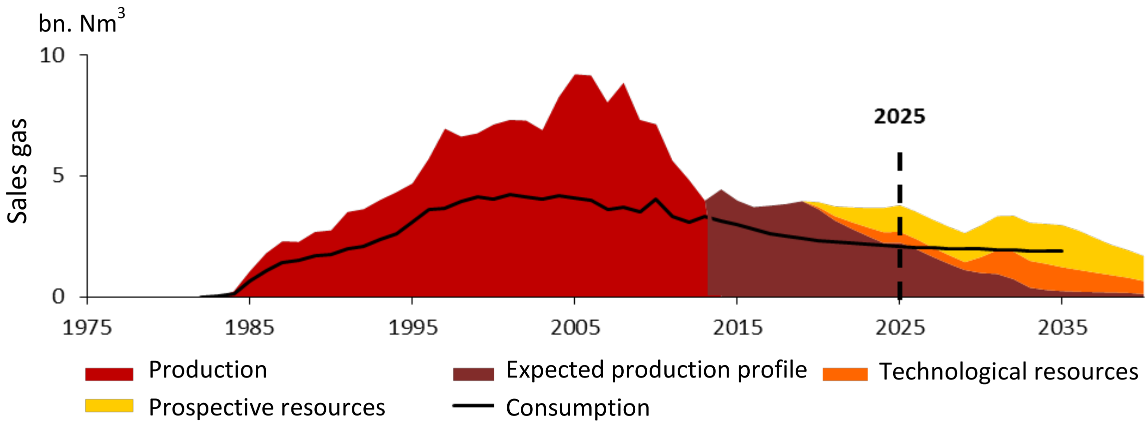
For gas, the risk assessment means that the difference between contingent resources and risk-weighted contingent resources ranges around 25 billion Nm^3 of gas. Of this difference, about 10 billion Nm^3 of gas is attributable to resources in discoveries not comprised by an exploration licence, while the balance is a reduction resulting from the probability weighting of the development projects

Figure 2.3. Production and possible production profiles for oil and sales gas.
Long-term oil and sales gas forecasts are shown together with the consumption forecast from "The DEA's baseline scenario, 2012".

Denmark is anticipated to be a net exporter of oil for eight years up to and including 2021, based on the expected production profile. If technological and prospective resources are included, they will contribute substantially to reducing Denmark's net oil imports from around 2025 until after 2035.



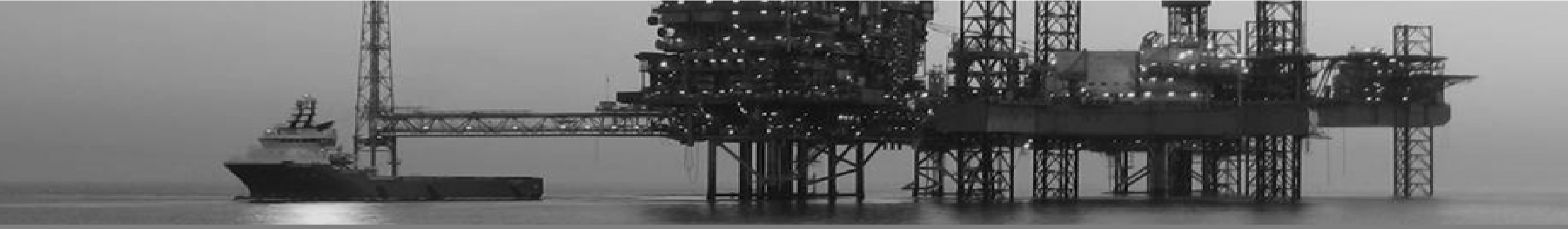
Denmark is anticipated to be a net exporter of sales gas for 12 years up to and including 2025, based on the expected production profile. If technological and prospective resources are included, Denmark is estimated to remain a net exporter until after 2035.



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.

The sales gas forecast indicates the quantities that the DEA expects it will be technically feasible to recover. However, the actual production depends on the sales based on existing and future gas sales contracts.

Replacement of flare tower on the Tyra West platform. Foto: Stig Busk Jespersen



3. ECONOMIC AND SOCIETAL IMPACTS

Since 1995, oil and gas production from the North Sea has generated a surplus on the balance of trade for oil and gas and contributed to denmark's current status as a net exporter of oil and gas. Tax revenue and the profits made by the oil and gas sector have a positive impact on the danish economy, while the north sea activities have also created many workplaces both on-and offshore.

The Danish state generated revenue of DKK 22.1 billion from North Sea oil and gas production in 2013. State revenue was down by about 12 per cent on 2012, which is due to a fall in production and lower oil prices.

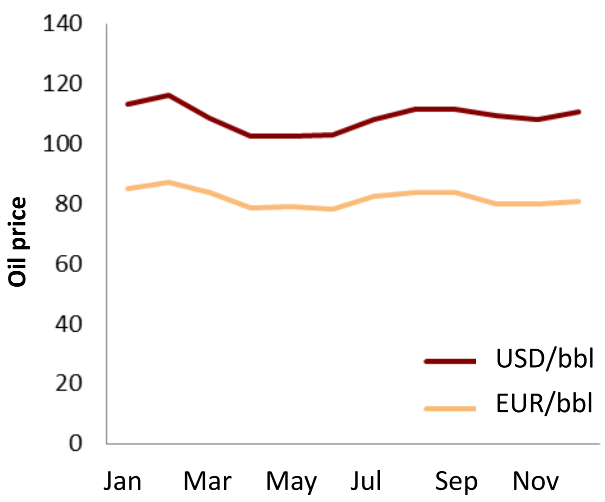
State revenue from hydrocarbon production in the North Sea aggregated DKK 383 billion in 2013 prices in the period 1963-2013. The associated production value totalled about DKK 965 billion during the same period, while the aggregate value of the licensees' expenses for exploration, field developments and operations was about DKK 333 billion (2013 prices). Field developments and investments totalled about DKK 178 billion in 2013 prices, thus accounting for more than half the licensees' aggregate costs.

According to preliminary estimates for 2013, oil production accounts for about DKK 41.4 billion and gas production for DKK 9.3 billion of the total production value. The total estimated value of Danish oil and gas production in 2013 is thus DKK 50.7 billion, a decline of close to 12 per cent compared to the production value in 2012. The production value is determined by the international crude oil price, the dollar exchange rate and the volume of production.

Investments in field developments are estimated to total about DKK 7.0 billion for 2013, an increase of about 21 per cent on 2012. This increase is particularly attributable to the development of the Hejre Field. By comparison, annual investments in field developments have averaged about DKK 5.5 billion in the past ten years. The preliminary figures for 2013 show that exploration costs slightly exceeded DKK 1.3 billion in 2013. These costs comprise the oil and gas companies' total exploration costs, including for exploration wells and seismic surveys.

The state's total revenue is estimated to range from DKK 20 to DKK 25 billion per year from 2014 to 2018. During the same period, investments are estimated to total about DKK 48.6 billion, corresponding to about DKK 9.7 billion per year. Annual operating, administration and transportation costs are estimated at about DKK 9.1 billion for the next five years. Total exploration costs for the next five years are expected to amount to about DKK 7 billion.

Figure 3.1. Oil prices, USD and EUR. Monthly development in the Brent spot oil price in 2013.



The year was characterized by a fairly stable oil price of about USD 109 per barrel. Amounting to USD 108.7 per barrel in 2013, the average oil price declined relative to the oil price of USD 111.7 per barrel in 2012. It further appears that the USD/EUR exchange rate was stable during the year.

In 2013 the average dollar exchange rate was DKK 5.6 per USD, a decline of about 3.5 per cent relative to the rate of DKK 5.8 per USD in 2012.

The fall in the dollar exchange rate and in the oil price caused the oil price in DKK terms to drop from DKK 646.9 in 2012 to DKK 610.7 in 2013, equal to a 5.6 per cent decline.

Figure 3.2. Oil price development 1972-2013, USD per barrel in fixed and current prices.

The two oil crises in 1973 and 1979 are clearly illustrated by the steep price increases. The figure also shows that the oil price reached a record high in 2011 of about USD 115 per barrel in 2013 prices.

Balance of trade for oil and natural gas.
Statistics Denmark is reassessing its compilation method for foreign trade statistics. Therefore, it serves no meaningful purpose to reproduce the balance of trade in this report. The most recent statistics available are from 2010, when the balance of trade for oil and gas came to DKK 12.15 billion.

During the year to come, the DEA expects to be able to publish the usual diagram at www.ens.dk and in next year's edition of this report.

State revenue

Figure 3.3. Breakdown of state revenue from oil and natural gas production from the North Sea in 2013.

State revenue from the North Sea activities derives from hydrocarbon tax, corporate income tax, royalty, the compensatory fee and oil pipeline tariff, of which hydrocarbon tax and corporate income tax are the main sources of revenue, accounting for 45 and 40 per cent, respectively.

In addition to taxes and fees, the Danish state receives revenue from the North Sea through Nordsøfonden, which has managed the state's 20 per cent share of all new licences since 2005. Since 9 July 2012, Nordsøfonden has also managed the state's 20 per cent share of Dansk Undergrunds Consortium (DUC), whose other partners are A.P. Møller – Mærsk, Shell and Chevron.

In addition, the state generates indirect revenue from its shareholding in DONG Energy, as this company's subsidiary, DONG E&P A/S, participates in oil and gas exploration and production in the North Sea.

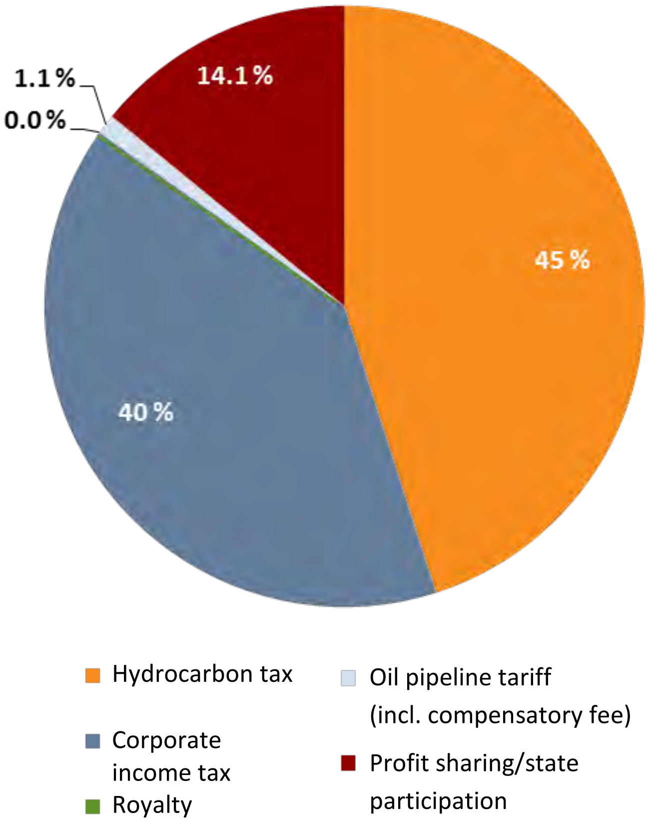


Table 3.1. Existing financial conditions.

	Sole Concession at 1 January 2004	Licences granted before 1 January 2004	Licences granted after 1 January 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 losses from before 1 January 2004.	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 losses from before 1 January 2014.	52 per cent Allowance of 5 per cent over 6 years (a total of 30 per cent) for investments
Royalty	No.	No.	No.
Oil pipeline tariff/ compensatory fee	No.	No.	No.
State participation	20 per cent	20 per cent *)	20 per cent
Profit sharing	No.	No.	No.

**) The state's share in a few of the remaining licences has increased due to a licence condition regarding increased state participation relative to the volume of production.*

Figure 3.4. Central government (CIL) balance and central government revenue from the North Sea, current prices.

The figure shows the proportion of oil revenue to the central government balance on the current investment and lending account (CIL balance), which is the difference between total central government revenues and state expenditures. As appears from the figure, revenue from the Danish part of the North Sea contributed to generating a central government surplus in 2013.

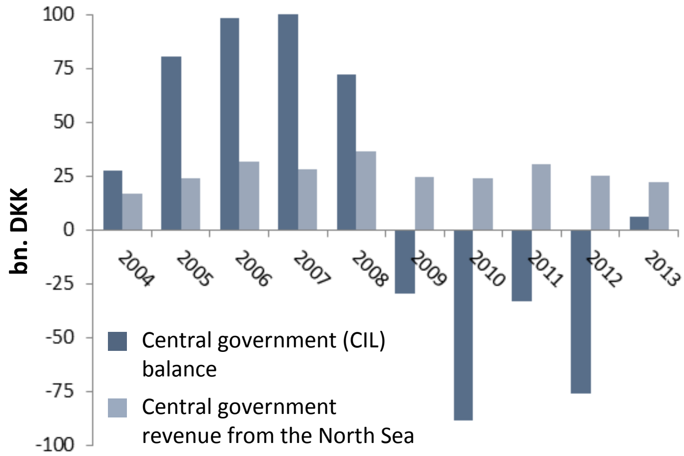


Figure 3.5. Development in total state revenue from oil and gas production 1972-2013.

State revenue from hydrocarbon production in the North Sea aggregated DKK 383 billion in 2013 prices in the period 1972-2013. Compared to 2012, state revenue dropped by about 12 per cent in 2013 due to a decline in production. State revenue is estimated at DKK 22.1 billion for 2013.

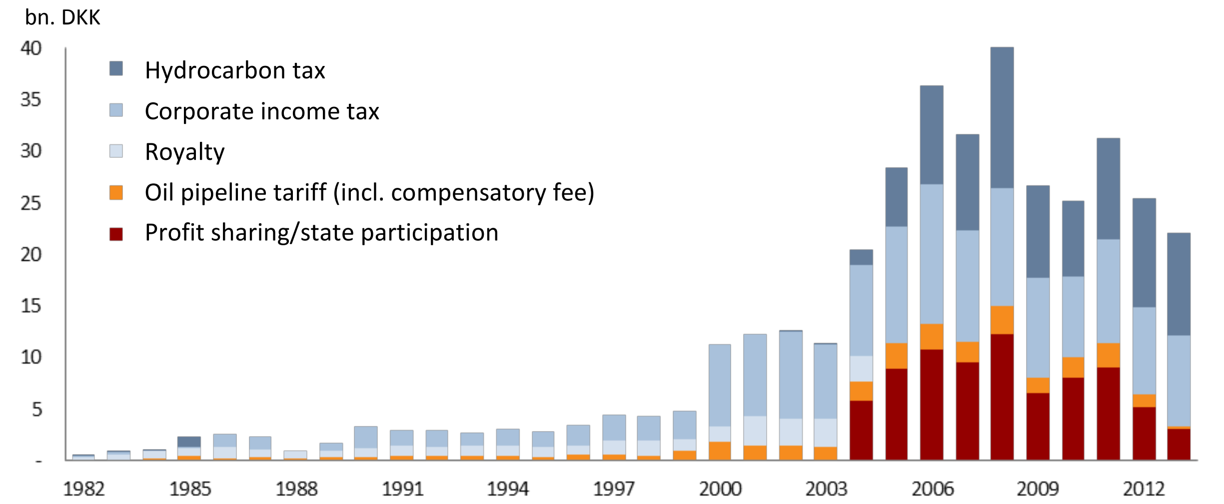


Table 3.2. State revenue over the past five years, DKK million, current prices.

The state's share of oil company profits is estimated at 63 per cent for 2013, including state participation. The marginal income tax rate is about 64 per cent according to the new rules, excluding state participation. When including state participation, about 71 per cent of earnings in the top tax bracket will accrue to the state according to the new rules.

According to the old rules, the marginal tax rate is about 29 per cent when 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 were taxed according to the old rules up to and including 2013.

From 1 January 2014, all companies are taxed according to the new rules. However, transitional rules apply to licences being transferred from the old to the new tax regime, such that the new tax rules are phased in over a period of time.

	2009	2010	2011	2012	2013
Hydrocarbon tax	8,254	6,940	9,521	10,467	9,951
Corporate income tax	8,876	7,377	9,754	8,304	8,782
Royalty	0	0	1	2	1
Oil pipeline tariff*	1,431	1,824	2,201	1,337	239
Profit sharing/state participation**	6,027	7,594	8,819	5,090	3,116
Total	**24,588**	**23,736**	**30,296**	**25,200**	**22,089**

** Incl. revenue deriving from compensatory fee.*
*** The figures from 2009 until mid-2012 relate to profit sharing. The calculation as from 9 July 2012 covers state participation (Nordsøfonden's post-tax profits). The figure for 2013 consists of payments made by Nordsøfonden and post-adjustments of profit sharing for previous years.*
Note: Accrual according to the Finance Act (year of payment).

Table 3.3. State revenue from oil and gas production, DKK billion, current prices.

Based on the IEA's long-term oil price forecast in the "New policies scenario" of USD 130 per barrel (2012 prices) and the DEA's production forecast, an estimate of the development in state revenue from the North Sea over the next five years has been prepared together with the Ministry of Taxation. Accordingly, the state's total revenue is estimated to range from DKK 20 to DKK 25 billion per year from 2014 to 2018.

			2014	2015	2016	2017	2018
Tax base before taxes and fees	170	US$/td	54.3	50.3	52.5	56.0	54.2
	130	US$/td	37.3	34.0	35.6	38.2	37.4
	90	US$/td	21.2	17.7	18.8	20.3	20.6
State revenue							
- Corporate income tax	170	US$/td	13.8	13.0	13.1	14.3	13.6
	130	US$/td	9.6	8.9	9.0	9.7	9.3
	90	US$/td	5.7	4.8	4.5	5.1	5.1
- Hydrocarbon tax	170	US$/td	18.8	17.1	16.4	19.5	18.8
	130	US$/td	13.0	11.0	10.5	11.2	12.3
	90	US$/td	7.3	5.7	4.7	4.8	4.6
- Nordsøfonden post-tax profits**	170	US$/td	3.4	2.6	2.0	1.9	3.1
	130	US$/td	2.3	1.7	1.1	1.1	2.2
	90	US$/td	1.2	0.7	0.2	0.2	1.4
Total	170	US$/td	36.0	32.7	31.5	35.7	35.4
	130	US$/td	25.0	21.5	20.5	22.0	23.8
	90	US$/td	14.2	11.2	9.4	10.1	11.2
The state's share (per cent)**	170	US$/td	66.2	64.9	60.0	63.8	64.3
	130	US$/td	66.9	63.1	57.7	57.5	63.7
	90	US$/td	66.7	63.3	50.0	49.6	54.4

** Based on an annual inflation rate of 1.8 per cent and existing Danish legislation.*

*** Nordsøfonden 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. Nordsøfonden's post-tax profits accrue to the state. However, it should be noted that Nordsøfonden must finance its continuous investment before delivering any profits to the state.*

***** The state's share, incl. state participation.*

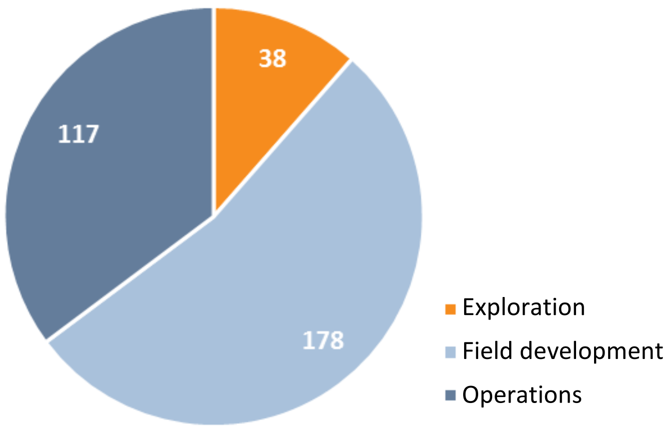
Source: The Danish Ministry of Taxation.

Note 1: Based on the DEA's five-year forecast.

Note 2: Accrual according to the National Accounts (income year).

Investments and costs

Figure 3.6. All licensees' total costs 1963-2013, DKK billion, 2013 prices.



Field developments and investments totalled about DKK 178 billion in 2013 prices, thus accounting for more than half the licensees' aggregate costs of about DKK 333 billion.

The costs of operations, including administration and transportation, exploration and field developments account for 35, 12 and 53 per cent, respectively, of total costs

Figure 3.7. Development in total exploration costs 2009-2013, current prices.

Exploration costs include the oil companies' expenses for both exploration wells and seismic surveys.

The preliminary figures for 2013 show that exploration costs increased about 22 per cent compared to the year before, amounting to about DKK 1.3 billion.

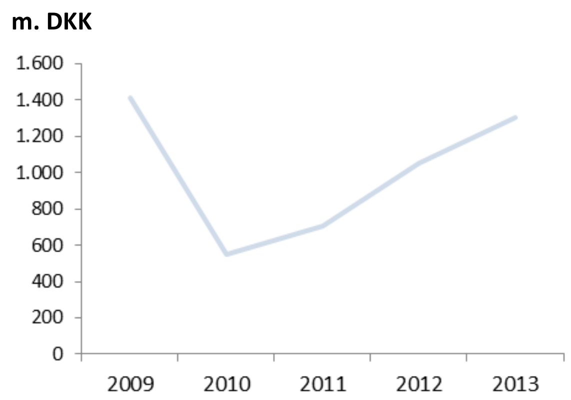
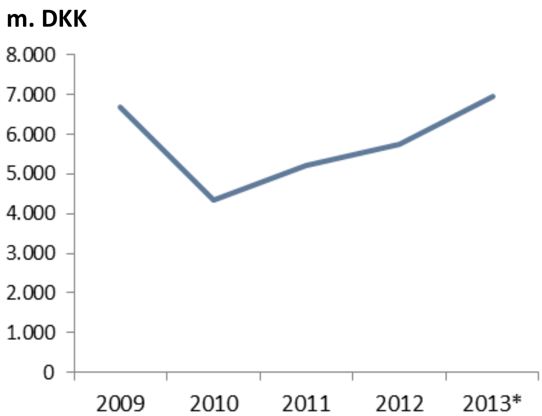


Figure 3.8. Investments in field developments in the North Sea 2009-2013, current prices.



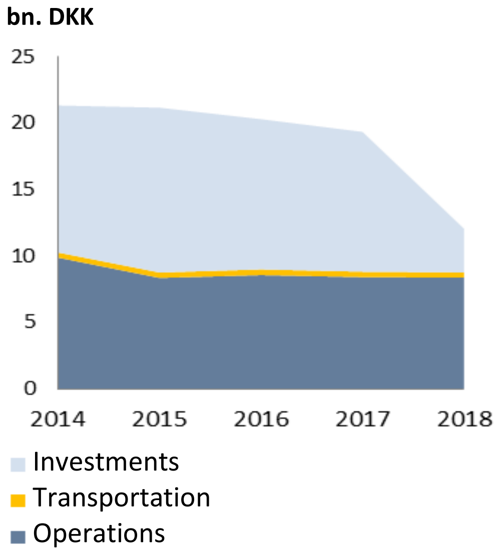
** Estimate*

Accounting for about 55 per cent of total costs, field developments and investments are the licensees' most cost-intensive activity.

Investments in field developments are estimated to total about DKK 7.0 billion for 2013, an increase of about 21 per cent on 2012.

Over the past ten years, annual investments in field developments have averaged about DKK 5.5 billion.

Figure 3.9. Expected development in investments and operating and transportation costs 2014-2018.



The expected development in investments and operating and transportation costs from 2014 to 2018 is based on the following resource categories: ongoing recovery and approved for development, justified for development, and risk-weighted contingent resources; see chapter 2.

For the next five years, investments in field developments are estimated to total DKK 49 billion.

Table 3.4. Expected investments in field developments 2014-2018, DKK million, 2013 prices.

	2014	2015	2016	2017	2018
Ongoing and approved	10,671	10,799	6,156	4,333	33
Justified for development	-	179	604	894	-
Risk-weighted contingent resources	398	1,428	4,549	5,300	3,245
Total expected investments	**11,068**	**12,406**	**11,309**	**10,527**	**3,278**

Table 3.5. Financial key figures

	Investments in field dev.	Field operating costs	Exploration costs	Crude oil price	Dollar exchange rate	Inflation	Balance of trade	State revenue
	DKK million 1)	DKK million 2)	DKK million	USD/bbl 3)	DKK/USD	per cent 4)	DKK billion 5)	DKK million 6)
1972	105	21	30	3.0	7.0	6.7	-	0
1973	9	23	28	4.6	6.1	9.3	-	1
1974	38	44	83	11.6	6.1	15.3	-	1
1975	139	47	76	12.3	5.8	9.6	-	2
1976	372	53	118	12.9	6.1	9.0	-	4
1977	64	61	114	14.0	6.0	11.1	-	5
1978	71	83	176	14.1	5.5	10.0	-	21
1979	387	120	55	20.4	5.3	9.6	-	19
1980	956	83	78	37.5	5.6	12.3	-	29
1981	1,651	197	201	37.4	7.1	11.7	-	36
1982	3,884	407	257	34.0	8.4	10.1	-	231
1983	3,554	431	566	30.5	9.1	6.9	-	401
1984	1,598	1,099	1,211	28.2	10.4	6.3	-	564
1985	1,943	1,275	1,373	27.2	10.6	4.7	-	1,192
1986	1,651	1,217	747	14.9	8.1	3.7	-	1,399
1987	930	1,167	664	18.3	6.8	4.0	-	1,328
1988	928	1,210	424	14.8	6.7	4.5	-	568
1989	1,162	1,409	366	18.2	7.3	4.8	-	1,024
1990	1,769	1,450	592	23.6	6.2	2.6	-	2,089
1991	2,302	1,670	985	20.0	6.4	2.4	-	1,889
1992	2,335	1,560	983	19.3	6.0	2.1	-	1,911
1993	3,307	1,816	442	16.8	6.5	1.2	-	1,811
1994	3,084	1,907	151	15.6	6.4	2.0	-	2,053
1995	4,164	1,707	272	17.0	5.6	2.1	-	1,980
1996	4,260	1,915	470	21.1	5.8	2.1	-	2,465
1997	3,760	1,946	515	18.9	6.6	2.2	-	3,156
1998	5,381	1,797	406	12.8	6.7	1.8	-	3,158
1999	3,531	1,910	656	17.9	7.0	2.5	-	3,786
2000	3,113	2,577	672	28.5	8.1	2.9	-	8,305
2001	4,025	2,557	973	24.4	8.3	2.4	-	9,630
2002	5,475	2,802	1,036	24.9	7.9	2.4	-	10,106
2003	7,386	3,380	789	28.8	6.6	2.1	-	9,330
2004	5,104	3,174	340	38.2	6.0	1.2	-	17,102
2005	3,951	4,005	578	54.4	6.0	1.8	-	24,163
2006	5,007	5,182	600	65.1	5.9	1.9	-	31,500
2007	6,524	4,129	547	72.5	5.4	1.7	-	27,885
2008	5,879	5,402	820	97.2	5.1	3.4	-	36,481
2009	6,686	5,284	1,413	61.6	5.4	1.3	-	24,588
2010	4,174	5,471	548	79.5	5.6	2.3	12.15	23,736
2011	4,920	6,699	706	111.4	5.4	2.8	-	30,296
2012	5,323	7,281	1,055	111.7	5.8	2.4	-	25,199
2013*	6,960	8,442	1,302	108.7	5.6	0.8	-	22,089

Current prices
1) Investments include pipeline to the NOGAT pipeline.
2) Incl. transportation costs. Operating costs have been adjusted for the whole period.
3) Dubai prices have been used from 1972 through 1975, Brent prices from 1976 through 1990, and prices extracted from the DEA's price database from 1991 and onwards.
4) Consumer prices, source: Statistics Denmark.
5) Net foreign-exchange value – Surplus on the balance of trade for oil products and natural gas, source: External trade statistics from Statistics Denmark. It should be noted that Statistics Denmark is reassessing its compilation method for foreign trade statistics. Therefore, the most recent statistics available are from 2010.
**) Estimate*

Reinforcement of the subsea structure on the Siri platform.

4. LICENCES

Although the first exploration and production licence was granted more than 50 years ago, interest in exploring for oil and gas North Sea remains high.

Six licensing rounds have been held in the past, with the 7th Licensing Round being opened on 24 April 2014. Like previous licensing rounds, the new round comprises all unlicensed areas west of 6° 15’ eastern longitude. More information about the 7th Licensing Round is available on the next page and at the website www.oilgasin.dk.

To date, no commercial oil or gas discoveries have been made in the Open Door area. Therefore, more lenient requirements apply to the oil companies’ exploration obligations than in the licensing round area in the western part of the North Sea. The Open Door procedure allows oil companies to apply for – and be awarded – licences within an annual application period from 2 January through 30 September, based on the first-come, first-served policy.

In 2013 and the first half of 2014, two new licences were granted and two licences relinquished in the Open Door area.

Figure 4.1. The Danish licence area

7th Licensing Round

7th Danish Licensing Round 2014

www.oilgasin.dk

The 7th Licensing Round was opened on 24 April 2014, and the licensing round documents specified the selection criteria and terms applicable to future licences. As in previous licensing rounds, emphasis will be placed on the scope of exploration that the oil companies offer to carry out to demonstrate the presence of additional oil and gas accumulations. The deadline for submitting applications is 20 October 2014 at noon. The DEA expects to be able to issue new licences in spring 2015. Further information about the licensing round is obtainable at the website www.oilgasin.dk.

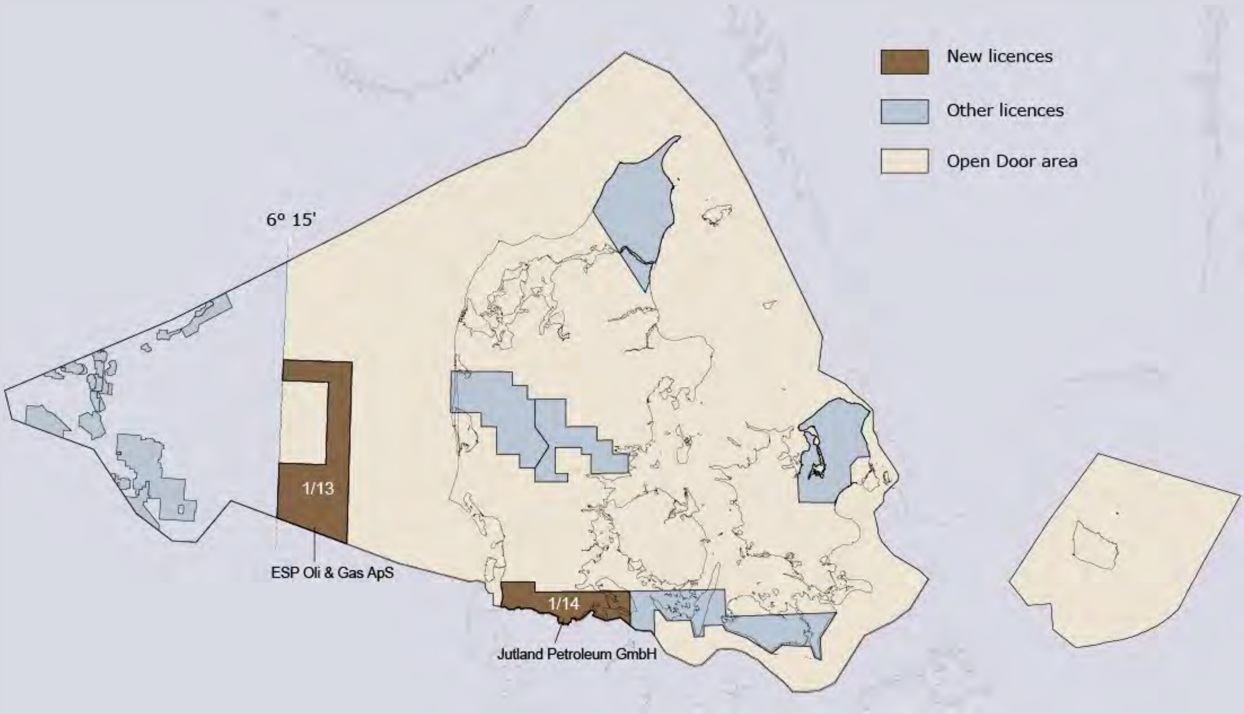
The licensing round forms part of an overall plan for future invitations for oil licence applications in the western part of the North Sea, i.e. the area west of 6° 15’ eastern longitude (see figure 4.1). The plan is to launch future licensing rounds at intervals of about one year, starting one year after the completion of the most recent round.

The aim of the 7th Round and future licensing rounds is to create a basis for maintaining exploration and production activity and thus preserving and further developing the knowledge and expertise about the Danish subsoil that the oil companies have accumulated. It is essential to find as much as possible of the oil and gas in place in the Danish subsoil so as not to miss the opportunity for prolonging the period during which the existing infrastructure can be utilized.

Before the licensing round was opened, the environmental impacts of the plan for continued oil and gas exploration and production in the area were subjected to an extensive assessment. The assessment outcome and the numerous consultation responses received in this connection identified the need for implementing an array of measures, for example to protect marine mammals in the area. Moreover, the cumulative effects of the oil and gas activities must be monitored. Several of these initiatives have been incorporated into the 7th Licensing Round documents, while others have been addressed in other contexts, for example in permits for seismic surveys. More information about these initiatives is available at the DEA’s website, www.ens.dk.

New licences

Figure 4.2. New licences in 2013 and the first half of 2014.



Two new licences have been granted in the Open Door area – one in 2013 and one in 2014.

Licence 1/13 was granted to Nikoil Limited (80 per cent) and Nordsøfonden (20 per cent) on 17 April 2013. Nikoil Limited subsequently transferred its share to E&P Oil & Gas ApS.

Licence 1/14 was granted to Jutland Petroleum GmbH (80 per cent) and Nordsøfonden (20 per cent) on 20 May 2014.

Amended licences

Table 4.1: Transfer of licence shares.

Licence	Share	From	To	Effective date
1/08	12,5 %	Danica Jutland ApS	New World Resources ApS	12-08-2012
1/08	12,5 %	Danica Jutland ApS	New World Resources ApS	31-01-2013
8/06 sub-area B	5,5 %	A.P. Møller - Mærsk A/S	Chevron Denmark, Branch of Chevron Denmark Inc., USA	15-01-2013
8/06 sub-area B	6,5 %	Shell Olie- og Gasudvinding Danmark B.V. (Holland), Dansk Filial	Chevron Denmark, Branch of Chevron Denmark Inc., USA	15-01-2013
1/09	12,5 %	Danica Jutland ApS	New World Jutland ApS	15-01-2013
2/09	12,5 %	Danica Jutland ApS	New World Jutland ApS	15-09-2012
5/06	30 %	Bayerngas Petroleum Danmark A/S	Wintershall Noordzee B.V.	22-10-2013
5/06	15 %	EWE Vertrieb GmbH	Wintershall Noordzee B.V.	22-10-2013
9/95	3,7 %	Danoil Exploration A/S	Noreco Oil Denmark A/S	22-05-2012
1/13	80 %	Nikoil Limited	ESP Oil & Gas ApS	17-04-2013
1/12	30 %	DONG E&P A/S	DONG E&P DK A/S	17-12-2013
5/06	16,36 %	Wintershall Noordzee B.V.	Nordsøfonden	02-01-2014
12/06	40 %	PA Resources UK Limited	Dana Petroleum Denmark B.V.	01-01-2013
7/86 Amalie part	40,077 %	Hess Energi ApS	Hess Denmark ApS	01-01-2014

Table 4.2: Extended licences.

Licence	Operator	Extended to	Purpose
4/98	DONG E&P A/S	01-03-2013	Exploration
4/98	DONG E&P A/S	29-06-2013	Exploration
4/98	DONG E&P A/S	29-06-2015	Exploration
8/06 sub-area B	Mærsk Olie og Gas A/S	22-05-2016	Exploration
1/08	New World Resources Operations ApS	31-05-2014	Exploration
5/06	Wintershall Noordzee B.V.	02-01-2016	Exploration
12/06	PA Resources UK Limited	22-05-2016	Exploration
9/95	Mærsk Olie og Gas A/S	22-11-2015	Exploration
1/08	New World Resources Operations ApS	31-03-2016	Exploration

Note: Subject to certain conditions, the provisions of section 13(1) of the Danish Subsoil Act allow extending a licence for up to two years at a time for the purpose of further exploration. Section 13(2) of the Act stipulates that, subject to specific conditions being met, the licence term may be extended for up to 30 years with a view to production in areas that contain commercial accumulations that the licensee plans to exploit.

Figure 4.3. Relinquishment of licences.

In 2013 and the first half of 2014, 11 areas in the licensing round area and two areas in the Open Door area were relinquished. In some of the licence areas, only the area below a certain depth has been relinquished. A more detailed description appears from table 4.3.

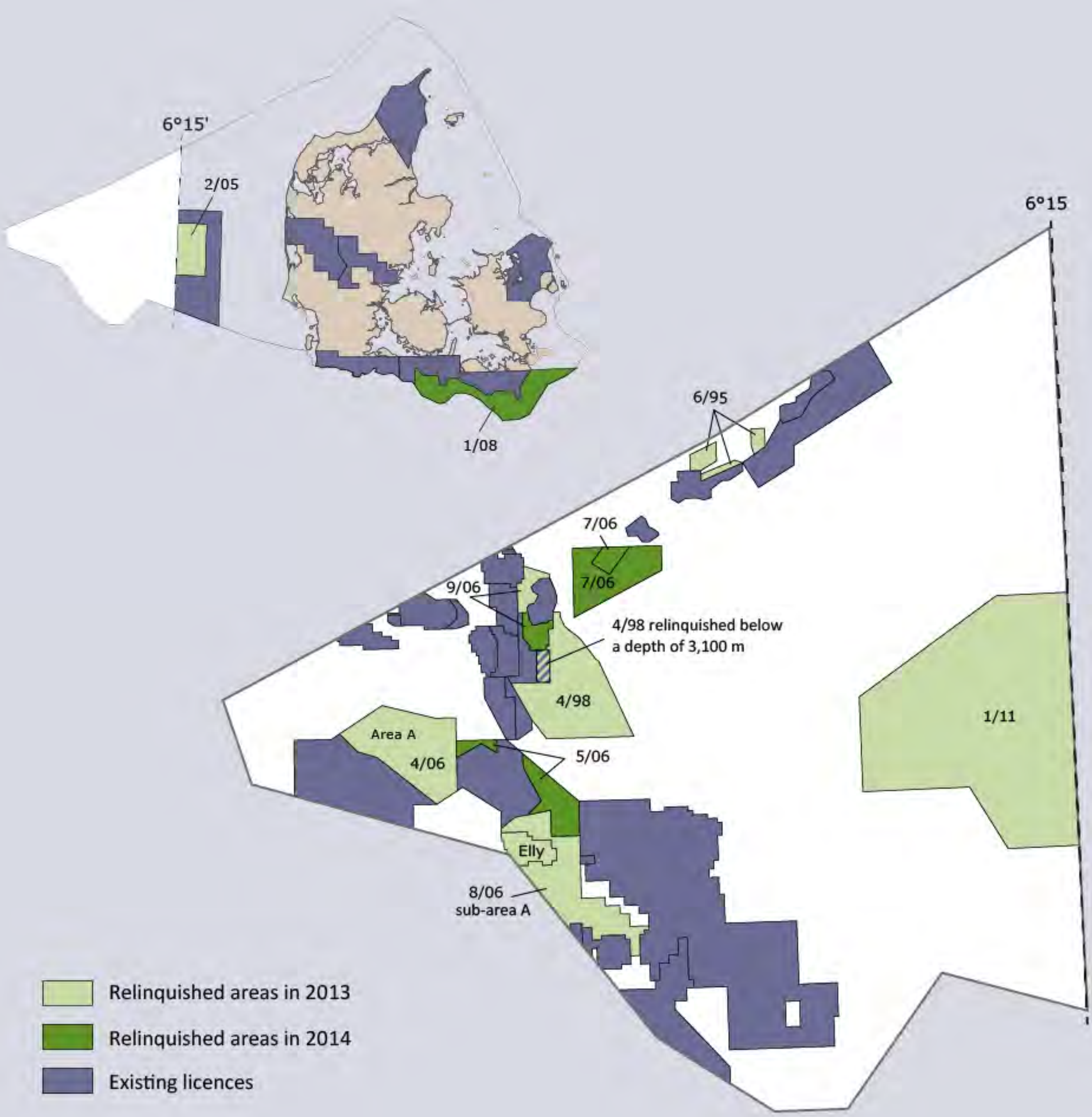


Table 4.3: Terminated licences and areas relinquished (also see figure 4.3).

Licence	Operator	Scope	Effective date
4/98	DONG E&P A/S	Partial	01-01-2013
	The relinquished area contains the Svane structure in which the Svane-1 well in 2002 encountered gas under high pressure in Upper Jurassic sandstone. The licensee has kept the northwestern part of the licence area, which is assessed to contain part of the Solsort accumulation.		
2/05 and 1/11	Noreco Oil Denmark A/S	The entire licence area	27-01-2013
	The companies holding the two neighbouring licences were Noreco Oil Denmark A/S (47 per cent), Elko Energy A/S (33 per cent) and Nordsøfonden (20 per cent). The Luna-1 exploration well was drilled under licence 1/11 at the beginning of 2012 in a joint venture between the two licensees.		
9/06	Mærsk Olie og Gas A/S	Nordlige del af tilladelsesområdet	01-10-2013
		Hele tilladelsesområdet	01-04-2014
	The companies holding the licence were A.P. Møller - Mærsk A/S (31.2 per cent), PA Resources Denmark ApS (26.8 per cent), Noreco Oil Denmark A/S (12.0 per cent), Danoil Exploration A/S (10.0 per cent) and Nordsøfonden (20.0 per cent). In 2008-2009 the licensee drilled the Gita-1X exploration well under licence 9/95 in a joint venture with the holder of that licence.		
6/95	DONG E&P A/S	Partial	15-11-2013
	The licensee has kept the area of the licence covered by the Siri field delineation.		
8/06 sub-area A	Mærsk Olie og Gas A/S	The entire sub-area	15-11-2013
	The oil companies holding the licence were Shell Olie- og Gasudvinding Danmark B.V. Holland, Danish Branch (43.3 per cent), A.P. Møller - Mærsk A/S (36.7 per cent) and Nordsøfonden (20.0 per cent). The companies drilled two exploration wells under the licence: Ebba-1X in 2007/2008 and Luke-1X in 2009/2010. Luke-1X encountered gas in Middle Jurassic sandstone east of the Elly Field.		
Sole Concession of 8 July 1962	Mærsk Olie og Gas A/S	The Elly Field	15-11-2013
	As agreed with their partners, A.P. Møller – Mærsk decided to relinquish the area comprised by the Elly Field delineation. The exploration and appraisal wells Elly-1X (1984), Elly-2X (1987/1988) and Elly-3X (1991/1992) demonstrated the presence of the Elly gas/condensate accumulation in Middle Jurassic sandstone and gas/condensate in Upper Jurassic sandstone and in Upper Cretaceous chalk.		
4/06 sub-area A	Wintershall Noordzee B.V.	The entire sub-area	22-11-2013
	The companies holding the licence were Wintershall Noordzee B.V. (35 per cent), Bayerngas Petroleum Denmark AS (30 per cent), EWE Betrieb GmbH (15 per cent) and Nordsøfonden (20 per cent). A 3D seismic survey was carried out in 2007, and the Spurv-1 exploration well was drilled in April-June 2013.		
5/06	Wintershall Noordzee B.V.	Partial	02-01-2014
	In connection with an extension of the exploration term, part of the licence area was relinquished.		
9/06	Mærsk Olie og Gas A/S	The entire licence area	01-04-2014
7/06	DONG E&P A/S	Partial	22-04-2014
		The entire licence area	22-05-2014
	The companies holding the licence were DONG E&P A/S (40 per cent), RWE Dea AG (40 per cent) and Nordsøfonden (20 per cent). The licensee drilled the Rau-1 exploration well in 2007 and discovered oil in Palaeocene sandstone.		
1/08	DONG E&P A/S	Partial	31-05-2014
	In connection with an extension of the exploration term of the licence, most of the offshore area covered by the licence was relinquished.		

Existing licences

Table 4.4: Licences and licensees at 1 June 2014.
The location of the licences is shown on the licence maps in figures 4.4 and 4.5.

Licence	Sole Concession of 8 July 1962	Company	Share (%)
Operator	**Mærsk Olie og Gas A/S**	Shell Olie- og Gasudvinding Danmark B.V. Holland. Danish Branch.	36,8
Licence granted	08-07-1962		
Licence expiry date	08-07-2042	A.P. Møller - Mærsk A/S and Mærsk Olie og Gas A/S (Concessionaires)	31,2
Blocks	5504/7, 8, 11, 12, 15, 16; 5505/13, 17, 18 ("Contiguous Area")		
	5603/27, 28 (Gert)	Chevron Denmark, Branch of Chevron Denmark Inc., USA	12,0
	5504/10, 14 (Rolf)		
	5604/25 (Svend)	Nordsøfonden	20,0
	5604/21, 22 (Harald/Lulita)		
Area (km²)	1478.8 ("Contiguous Area")		
	44.8 Gert		
	8.4 (Rolf)		
	48.0 (Svend)		
	55.7 (Harald/Lulita)		

Licence	7/86 (Amalie part)	Company	Share (%)
Operator	**DONG E&P A/S** Hess Denmark ApS is co-operator	Hess Danmark ApS	40,077
Licence granted	24-06-1986 (2nd Round)	DONG E&P A/S	30,000
Licence expiry date	14-08-2026	Noreco Oil Denmark A/S	19,431
Blocks	5604/22, 26	Noreco Petroleum Denmark A/S	10,492
Area (km²)	47.0		
Delineation by depth (mbmsl *)	5,500		

Licence	7/86 (Lulita part)	Company	Share (%)
Operator	**DONG E&P A/S**	DONG E&P A/S	43,594
Licence granted	24-06-1986 (2nd Round)	Noreco Oil Denmark A/S	38,904
Licence expiry date	08-03-2026	Noreco Petroleum Denmark A/S	17,502
Blocks	5604/22		
Area (km²)	2.6		
Delineation by depth (mbmsl *)	3,750		

Licence	7/89 (South Arne Field)	Company	Share (%)
Operator	**Hess Denmark ApS.** DONG E&P A/S is co-operator	Hess Denmark ApS	61,51572
Licence granted	20-12-1989 (3rd Round)	DONG E&P A/S	36,78930
Licence expiry date	17-02-2027	Danoil Exploration A/S	1,69498
Blocks	5604/29, 30		
Area (km²)	93.2		
Delineation by depth (mbmsl *)	Eastern part: 3,200 Western part: 5,100		

Licence	1/90 (Lulita)	Company	Share (%)
Operator	**DONG E&P A/S**	DONG E&P A/S	43,594
Licence granted	03-07-1990	Noreco Oil Denmark A/S	38,904
Licence expiry date	08-03-2026	Noreco Petroleum Denmark A/S	17,502
Blocks	5604/18		
Area (km²)	1.2		
Delineation by depth (mbmsl *)	3,750		

Licence	4/95 (Nini Field)	Company	Share (%)
Operator	**DONG E&P A/S**	DONG E&P A/S	40
Licence granted	15-05-1995 (4th Round)	RWE Dea AG	30
Licence expiry date	18-06-2032	Noreco Oil Denmark A/S	30
Blocks	5605/10, 14		
Area (km²)	44.6		
Delineation by depth (mbmsl *)	1,950		

Licence	6/95 (Siri Field)	Company	Share (%)
Operator	DONG E&P A/S	DONG E&P A/S	70
Licence granted	15-05-1995 (4th Round)	DONG E&P (Siri) UK Limited	30
Licence expiry date	18-07-2027		
Blocks	5604/16, 20; 5605/13, 17		
Area (km²)	63.1		

Licence	9/95	Company	Share (%)
Operator	**Mærsk Olie og Gas A/S**	A.P. Møller - Mærsk A/S	42,6
Licence granted	15-05-1995 (4th Round)	DONG E&P A/S	27,3
Licence expiry date	22-11-2015	Noreco Oil Denmark A/S	20,1
Blocks	5604/21, 22, 25, 26	Danoil Exploration A/S	10,0
Area (km²)	55.6		

Licence	4/98	Company	Share (%)
Operator	**DONG E&P A/S**	DONG E&P A/S	35
Licence granted	15-06-1998 (5th Round)	Bayerngas Danmark ApS	30
Licence expiry date	29-06-2015	VNG Danmark ApS	15
Blocks	5604/26, 30	Nordsøfonden	20
Area (km²)	62.9		
Delineation by depth (mbmsl *)	Eastern part: 3,100		

Licence	5/98 (Hejre Field)	Company	Share (%)
Operator	**DONG E&P A/S**	DONG E&P A/S	60
Licence granted	15-06-1998 (5th Round)	Bayerngas Petroleum Danmark AS	25
Licence expiry date	15-10-2040	Bayerngas Danmark ApS	15
Blocks	5603/24, 28; 5604/21, 25		
Area (km²)	76.6		
Delineation by depth (mbmsl *)	6,000		

Licence	16/98 (Cecilie Field)	Company	Share (%)
Operator	**DONG E&P A/S**	Noreco Oil Denmark A/S	37
Licence granted	15-06-1998 (5th Round)	Noreco Petroleum Denmark A/S	24
Licence expiry date	18-06-2032	DONG E&P A/S	22
Blocks	5604/19, 20	RWE Dea AG	17
Area (km²)	22.6		
Delineation by depth (mbmsl *)	2,400		

Licence	1/06 (Hejre Field)	Company	Share (%)
Operator	**DONG E&P A/S**	DONG E&P A/S	48
Licence granted	22-05-2006 (6th Round)	Bayerngas Petroleum Danmark AS	20
Licence expiry date	15-10-2040	Bayerngas Danmark ApS	12
Blocks	5603/28; 5604/21, 25	Nordsøfonden	20
Area (km²)	22.0		
Delineation by depth (mbmsl *)	6,000		

Licence	4/06 (Sub-area B)	Company	Share (%)
Operator	**Wintershall Noordzee B.V.**	Wintershall Noordzee B.V.	80
Licence granted	22-05-2006 (6th Round)	Nordsøfonden	20
Licence expiry date	22-01-2015		
Blocks	5603/31; 5503/3, 4, 7, 8;		
Area (km²)	356.5		

Licence	5/06	Company	Share (%)
Operator	**Wintershall Noordzee B.V.**	Wintershall Noordzee B.V.	63,64
Licence granted	22-05-2006 (6th Round)	Nordsøfonden	36,36
Licence expiry date	02-01-2016		
Blocks	5504/1, 2, 5, 6		
Area (km²)	209.1		

Licence	8/06 (Sub-area B)	Company	Share (%)
Operator	**Mærsk Olie og Gas A/S**	Shell Olie- og Gasudvinding Danmark B.V. Holland. Dansk Filial.	36,8
Licence granted	22-05-2006 (6th Round)		
Licence expiry date	22-05-2016	A.P. Møller - Mærsk A/S	31,2
Blocks	5504/7	Chevron Denmark, Filial af Chevron Denmark Inc., USA	12,0
Area (km²)	5.8	Nordsøfonden	20,0

Licence	12/06	Company	Share (%)
Operator	**Dana Petroleum Denmark B.V.**	Dana Petroleum Denmark B.V	40
Licence granted	22-05-2006 (6th Round)	PA Resources UK Ltd.	24
Licence expiry date	22-05-2016	Spyker Energy ApS	8
Blocks	5504/16, 19, 20, 24	Danoil Exploration A/S	8
Area (km²)	229.4	Nordsøfonden	20

Licence	1/08	Company	Share (%)
Operator	**New World Resources Operations ApS**	Danica Resources ApS	55,0
Licence granted	31-03-2008 (Open Door)	New World Resources ApS	25,0
Licence expiry date	31-03-2016	Nordsøfonden	20,0
Blocks	5410/1, 2, 3, 4, 5, 6, 7, 8, 9, 11, 12; 5411/5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16; 5412/5, 9		
Area (km²)	2,885.3		

Licence	1/09	Company	Share (%)
Operator	**New World Operations ApS**	Danica Jutland ApS	55,0
Licence granted	17-05-2009 (Open Door)	New World Jutland ApS	25,0
Licence expiry date	17-06-2014	Nordsøfonden	20,0
Blocks	5508/3, 4, 7, 8; 5509/1, 5; 5608/21, 22, 23, 25, 26, 27, 28, 29, 30, 31, 32		
Area (km²)	2,439.7		

Licence	2/09	Company	Share (%)
Operator	**New World Operations ApS**	Danica Jutland ApS	55,0
Licence granted	17-05-2009 (Open Door)	New World Jutland ApS	25,0
Licence expiry date	17-06-2014	Nordsøfonden	20,0
Blocks	5509/1, 2, 3, 5, 7, 8, 9, 10, 11, 12; 5609/25, 26, 29, 30		
Area (km²)	1,666.3		

Licence	3/09	Company	Share (%)
Operator	**DONG E&P A/S**	DONG E&P A/S	35
Licence granted	29-06-2009	Bayerngas Danmark ApS	30
Licence expiry date	29-06-2015	VNG Danmark ApS	15
Blocks	5604/25,26,29,30	Nordsøfonden	20
Area (km²)	51.3		

Licence	1/10	Company	Share (%)
Operator	**Total E&P Denmark B.V.**	Total E&P Denmark B.V.	80
Licence granted	05-06-2010 (Open Door)	Nordsøfonden	20
Licence expiry date	05-06-2016		
Blocks	5609/4; 5610/1, 2, 5, 6; 5709/16, 19, 20, 23, 24, 27, 28, 32; 5710/7, 10, 11, 13, 14, 17, 18, 19, 21, 22, 23, 25, 26, 27, 29, 30		
Area (km²)	2,971.7		

Licence	2/10	Company	Share (%)
Operator	**Total E&P Denmark B.V.**	Total E&P Denmark B.V.	80
Licence granted	05-06-2010 (Open Door)	Nordsøfonden	20
Licence expiry date	05-06-2016		
Blocks	5511/4, 8, 12, 16; 5512/1, 2, 3, 5, 6, 7, 9, 10, 13, 14; 5611/32; 5612/26, 29, 30, 31		
Area (km²)	2,288.9		

Licence	1/12	Company	Share (%)
Operator	**DONG E&P A/S**	DONG E&P A/S	50
Licence granted	23-11-2012	DONG E&P DK A/S	30
Licence expiry date	23-11-2018	Nordsøfonden	20
Blocks	5605/7, 10, 11, 13, 14, 17		
Area (km²)	288.3		

Licence	1/13	Company	Share (%)
Operator	**ESP Oil & Gas ApS**	ESP Oil & Gas ApS	80
Licence granted	17-04-2013 (Open Door)	Nordsøfonden	20
Licence expiry date	17-04-2019		
Blocks	5506/4, 8, 10, 11, 12, 14, 15, 16, 18, 19, 20, 22, 23, 24; 5606/22, 23, 24, 28, 32		
Area (km²)	3,633.5		

Licence	1/14	Company	Share (%)
Operator	**Jutland Petroleum GmbH**	Jutland Petroleum GmbH	80
Licence granted	21-04-2014 (Open Door)	Nordsøfonden	20
Licence expiry date	21-04-2020		
Blocks	5408/3, 4; 5409/1, 2, 3, 4,5,6,7,8; 5508/31,32		
Area (km²)	1,524.2		

* mbmsl: an abbreviation of metres below mean sea level

Figure 4.4. Danish licence area – June 2014.

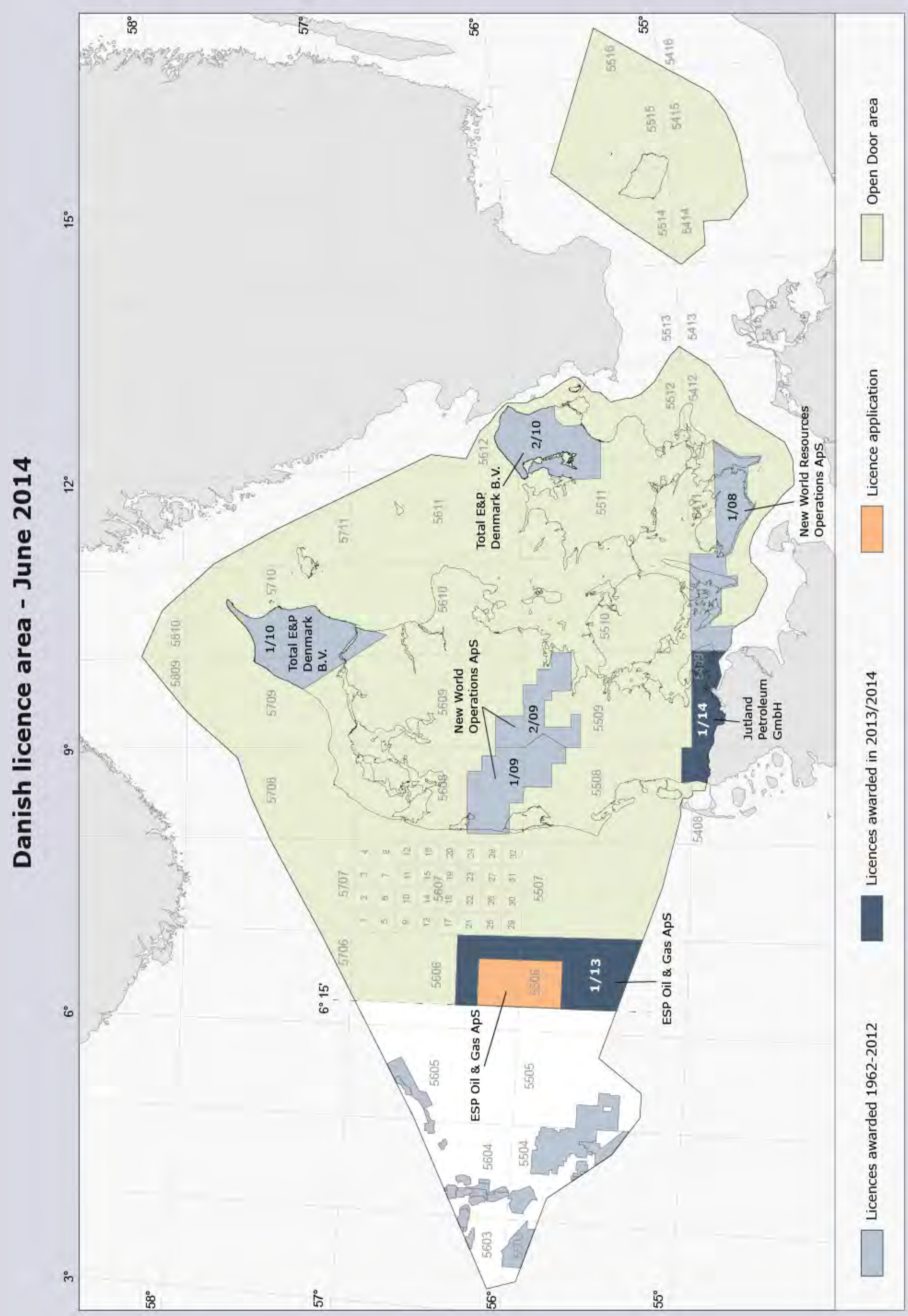
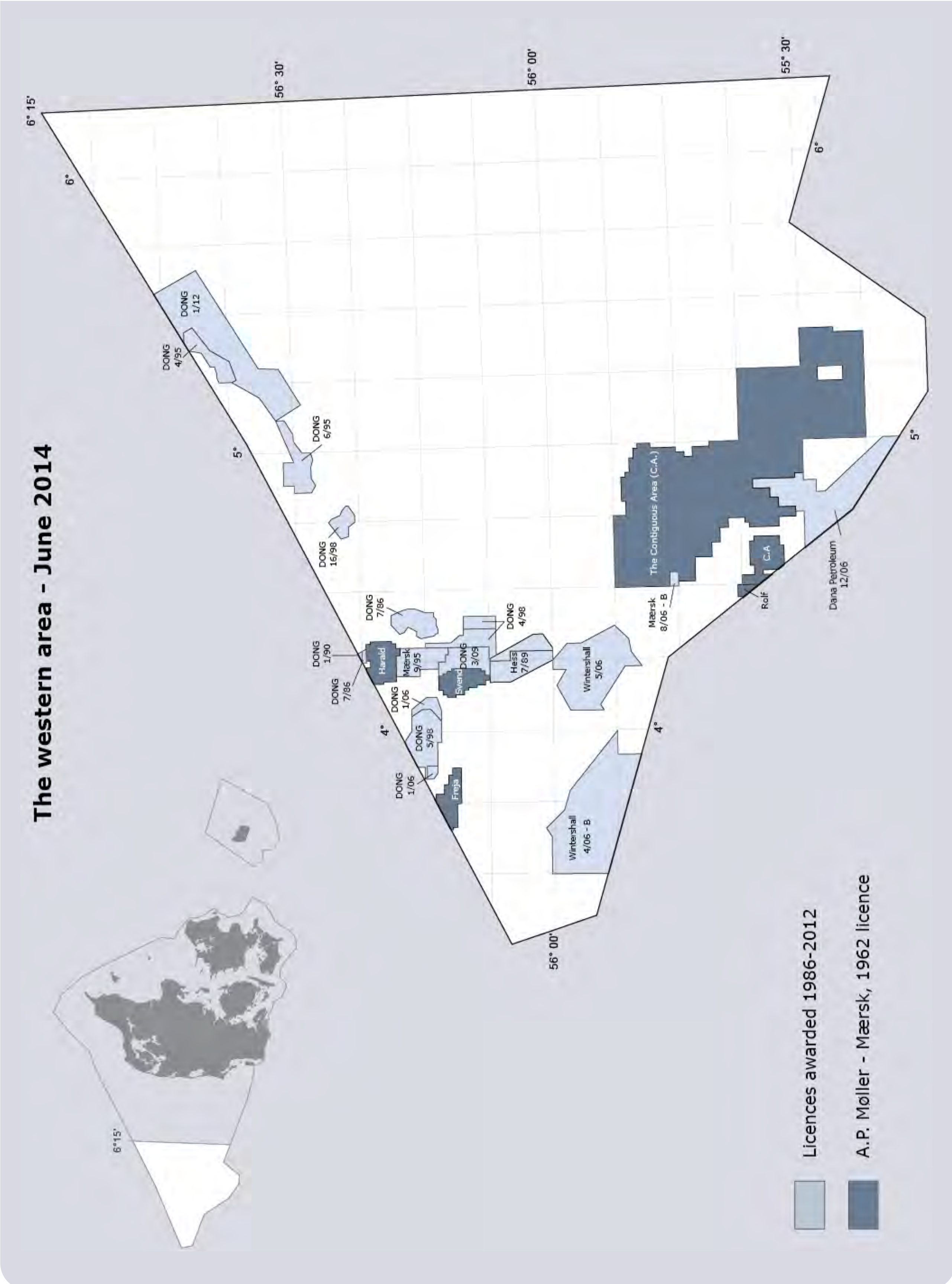


Figure 4.5. Danish licence area, west – June 2014.



5. EXPLORATION

Exploration is essential for maintaining a high activity level in the North Sea and opening up opportunities for making new discoveries while utilizing the existing North Sea infrastructure as best possible. This can help generate economic growth and new revenue for Danish society.

Exploratory surveys

In 2013 the plans to launch the 7th Licensing Round led to increased interest from the enterprises that carry out seismic surveys for the purpose of reselling seismic data to the oil companies. This resulted in the performance of a major regional 2D deep seismic survey in the North Sea and the acquisition of up-to-date 3D seismic data, including in areas with outdated or lacking data coverage. Seismic data is an essential prerequisite for the oil companies' identification of the prospects of making new oil and gas discoveries.

Seismic, geochemical and aerogravimetric surveys have been performed in connection with onshore oil exploration, and onshore seismic surveys have also been conducted with the aim of identifying opportunities for producing geothermal energy.

Exploration and appraisal wells

In 2013 three exploration and appraisal wells were drilled – all in the western part of the North Sea. None of these wells led to new discoveries. In connection with drilling the Solsort-2 appraisal well, DONG E&P A/S carried out test production from the Solsort oil accumulation, and also drilled sidetracks to evaluate the extent of the accumulation. This information has now been included in the licensees' background data for assessing the potential for initiating recovery from the accumulation.

The oil companies' plans for 2014 envisage the drilling of six exploration and appraisal wells. Therefore, 2014 will be a year of particularly high exploration activity in the Danish area

Exploratory surveys

Figure 5.1. Geophysical surveys west of 60 15' eastern longitude.

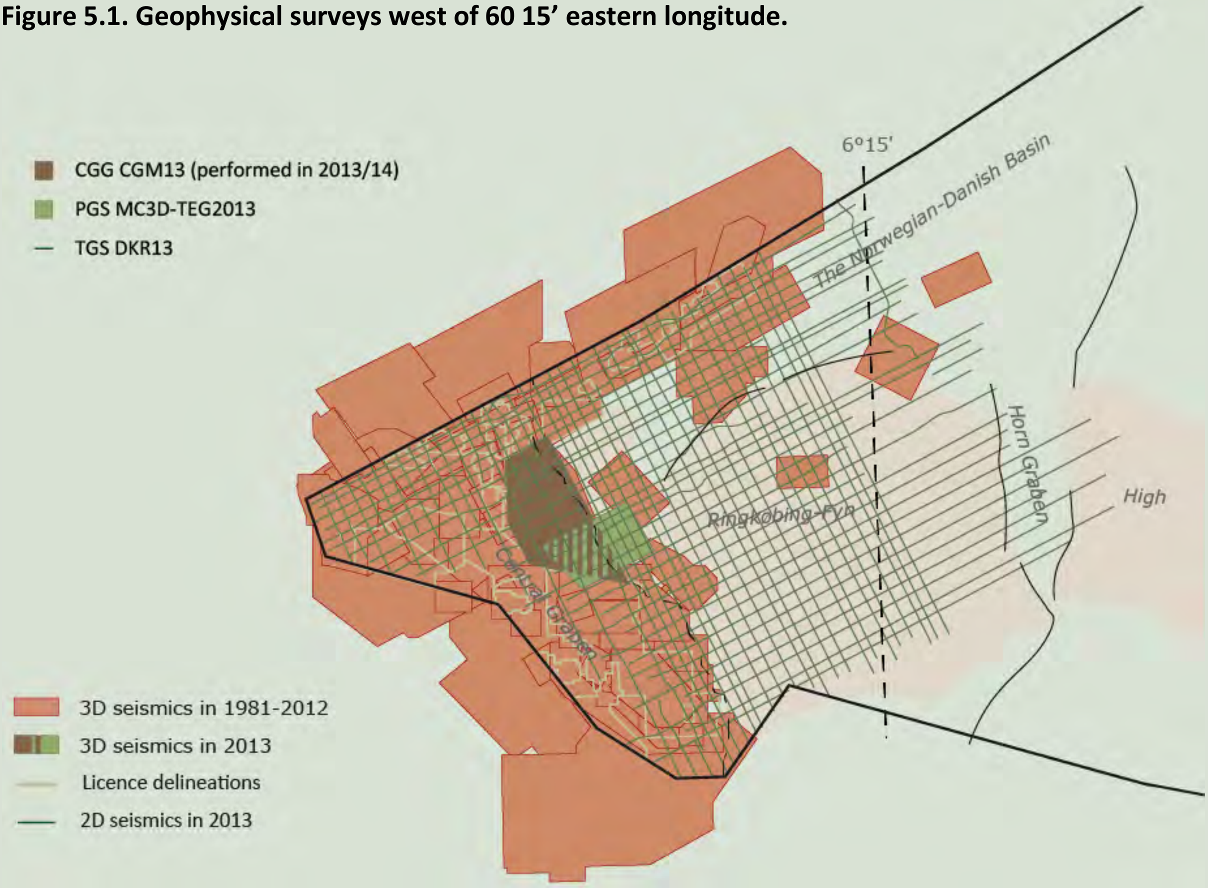


Figure 5.2. Seismic data acquired 1995-2013.

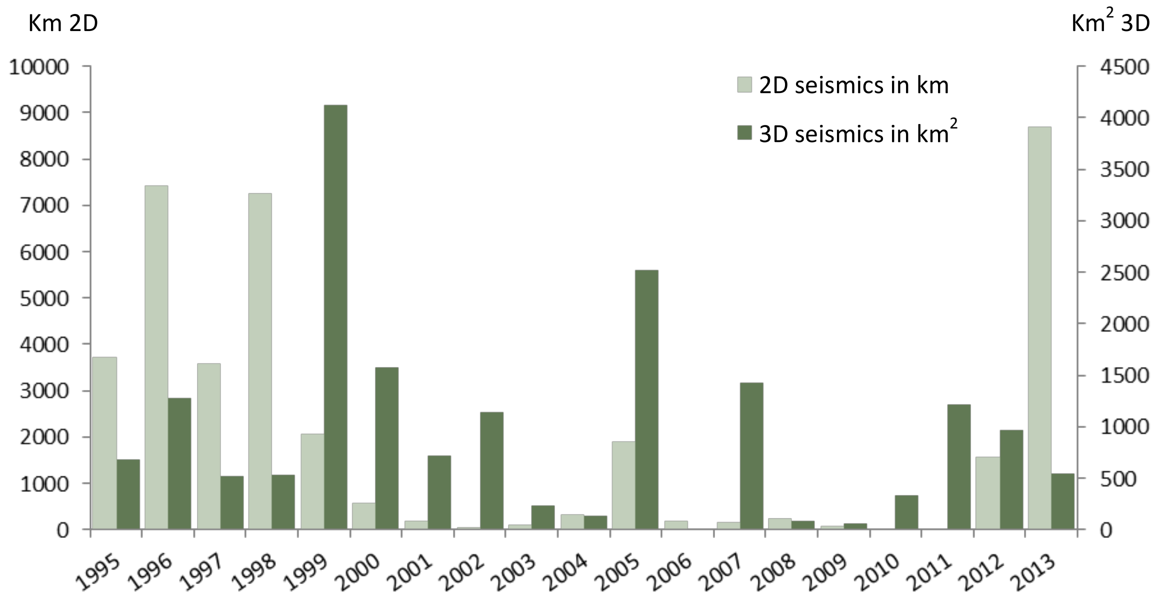
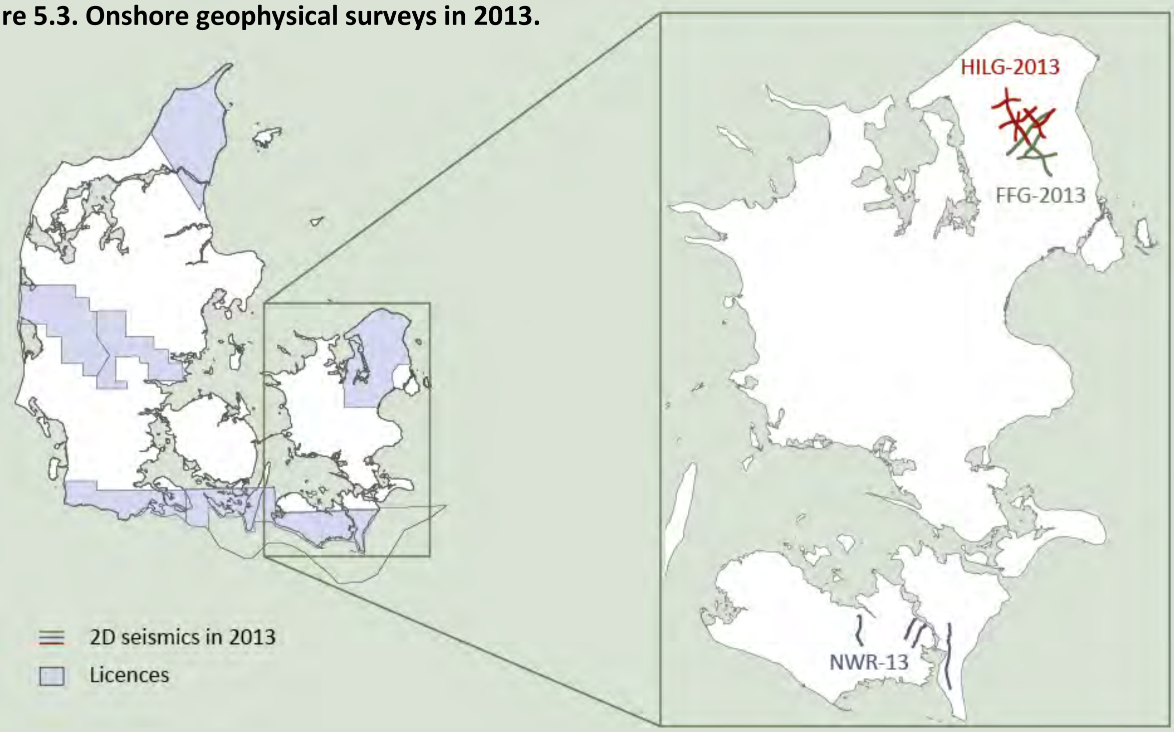


Table 5.1. Exploratory surveys in 2013.

Survey Licence	Operator Contractor	On-/Offshore Type	Initiated Completed	Area	Acquired in 2013
NWR-13 1/08	New World Operations ApS Tesla Exploration International Limited	Onshore 2D seismics	21-01-2013 30-01-2013	Lolland	38.5 km
DKR13 Section 3	TGS-Nopec Geophysical Company ASA TGS-Nopec Geophysical Company ASA	Offshore 2D seismics	24-04-2013 06-08-2013	North Sea	8,575.8 km
FFG-2013 G2012-06 & section 3	Farum Fjernvarme a.m.b.a. DMT GmbH & Co. KG	Onshore 2D seismics	24-05-2013 17-06-2013	Zealand	40.4 km
Denmark AGG Survey 2/10	Total E&P Denmark B.V. Fugro	Onshore Airborne Gravity Gradiometer (AGG) survey	19-08-2013 19-09-2013	Zealand	12,607.3 km
HILG-2013 G2013-02	Hillerød Varme A/S Geofizyka Kraków S.A.	Onshore 2D seismics	07-09-2013 26-09-2013	Zealand	46.9 km
MC3D TEG2013 Section 3	PGS Geophysical AS PGS Geophysical AS	Offshore 3D seismics	18-10-2013 21-11-2013	North Sea	540.4 km²

Figure 5.3. Onshore geophysical surveys in 2013.



Wells

Table 5.2. . Exploration and appraisal wells in 2013 and the first half of 2014.

Well*	Purpose	Licence	Operator	Drilling period	Area	Drilling result
SPURV-1 5504/01-04	Exploration	4/06	Wintershall Noordzee	2013-04-21 2013-06-12	Offshore The Central Graben	Dry
SOLSORT-2 5604/26-06	Appraisal	3/09	DONG E&P A/S	2013-08-21 2013-12-20	Offshore The Central Graben	Oil in Paleocene sandstone
BO-4X 5504/07-16	Appraisal and exploration	Sole Concession	Mærsk Olie og Gas A/S	2013-09-05 2013-10-05	Offshore The Central Graben	Dry
NENA-1 5605/14-01	Exploration	1/12	DONG E&P A/S	2014-01-24 2014-02-14	Offshore The Norwegian-Danish Basin	Dry

** Click the name of the well to link to the associated press release*

Figure 5.4. Exploration and appraisal wells drilled from 1992 to 2013.

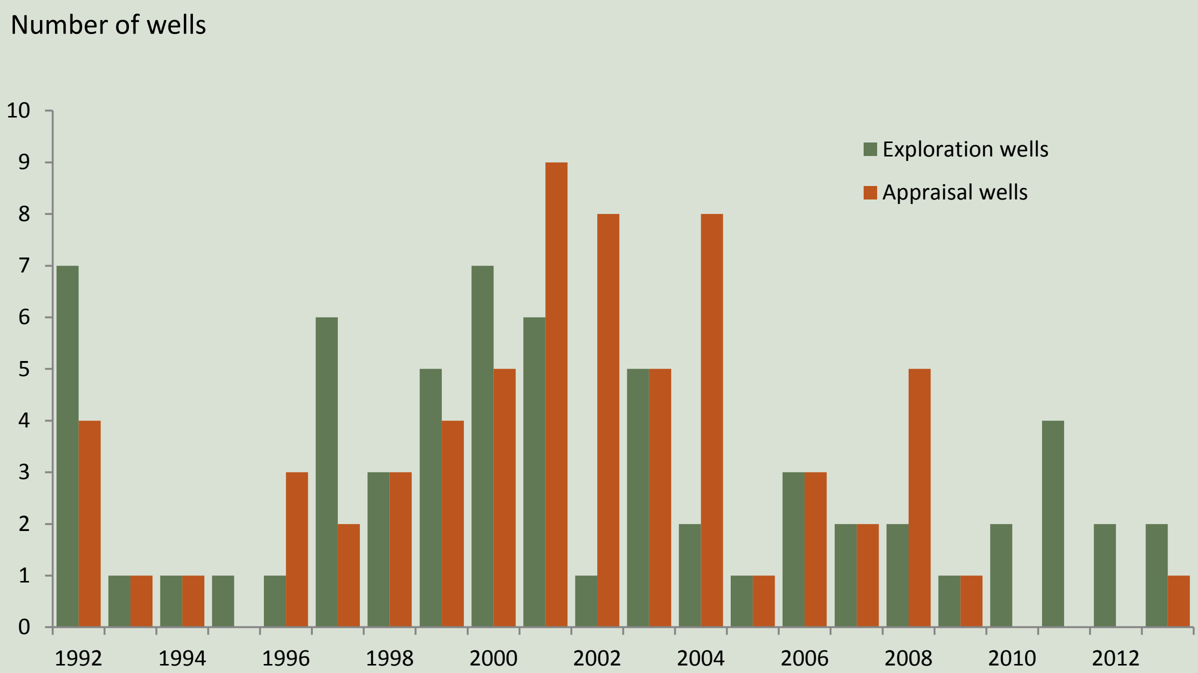


Figure 5.5. Exploration and appraisal wells in 2013/14 west of 6^0 15' eastern longitude.

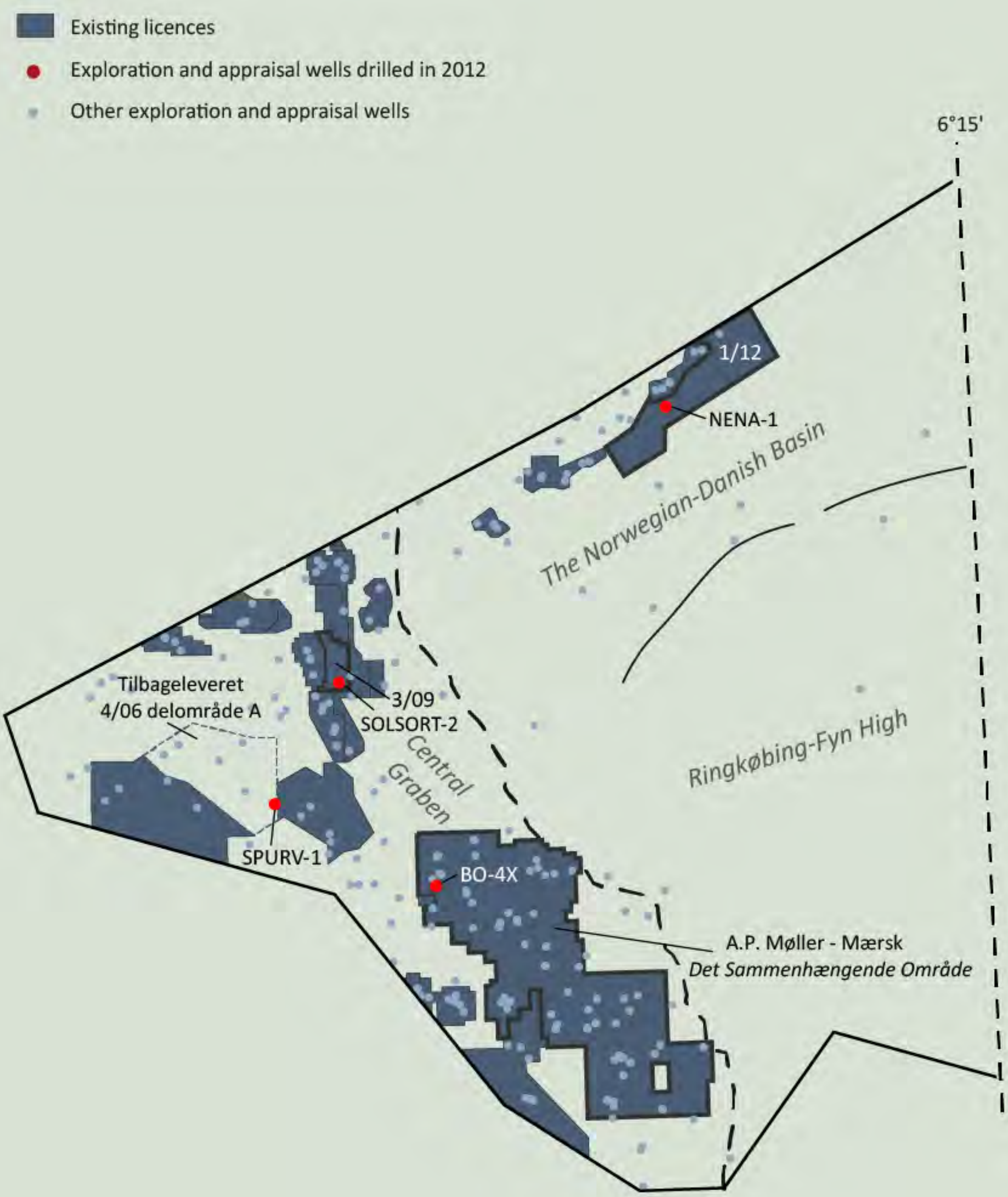


Figure 5.6. Geological time scale

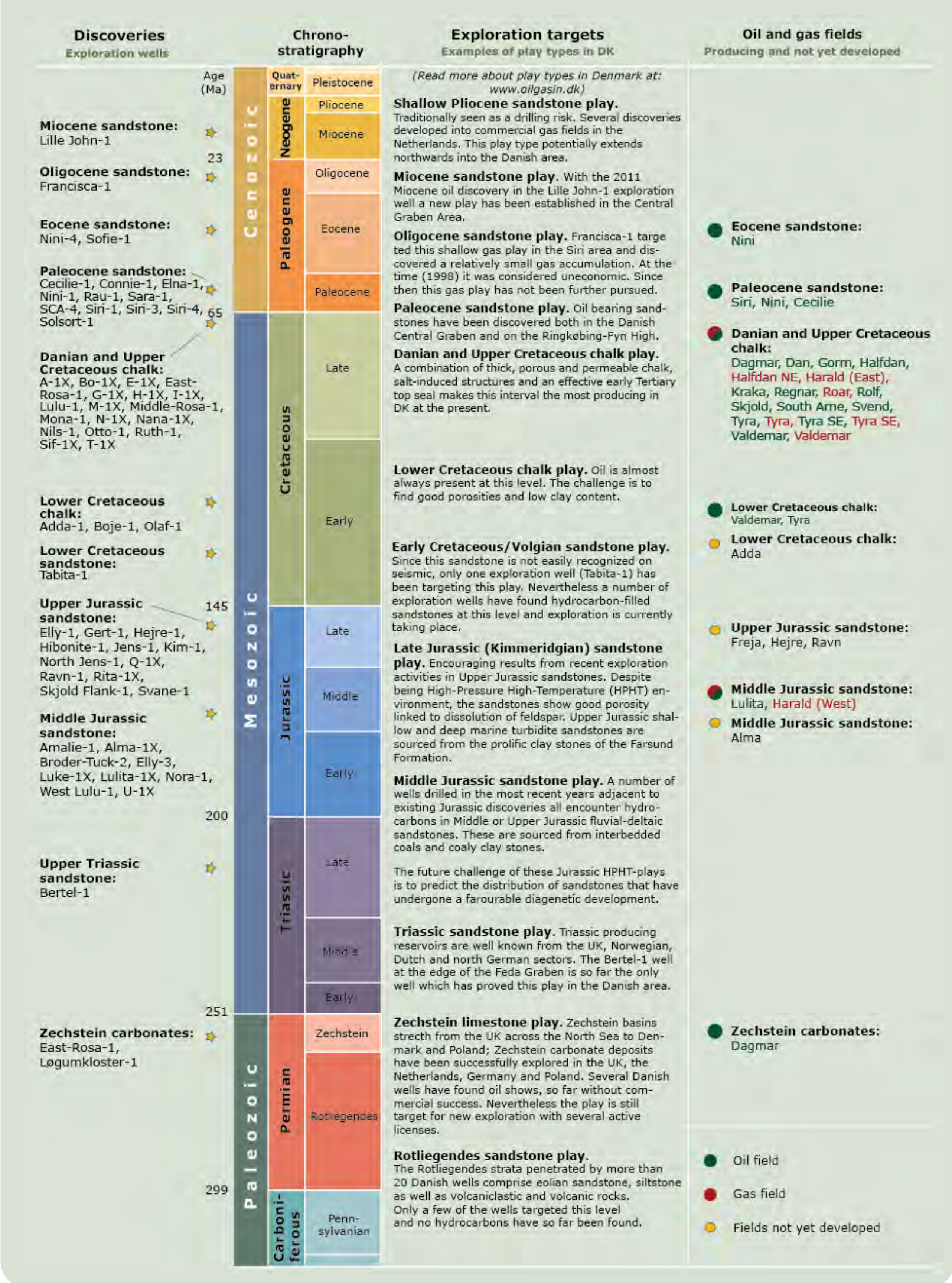


Figure 5.7. Exploration wells and discoveries in the Open Door area.

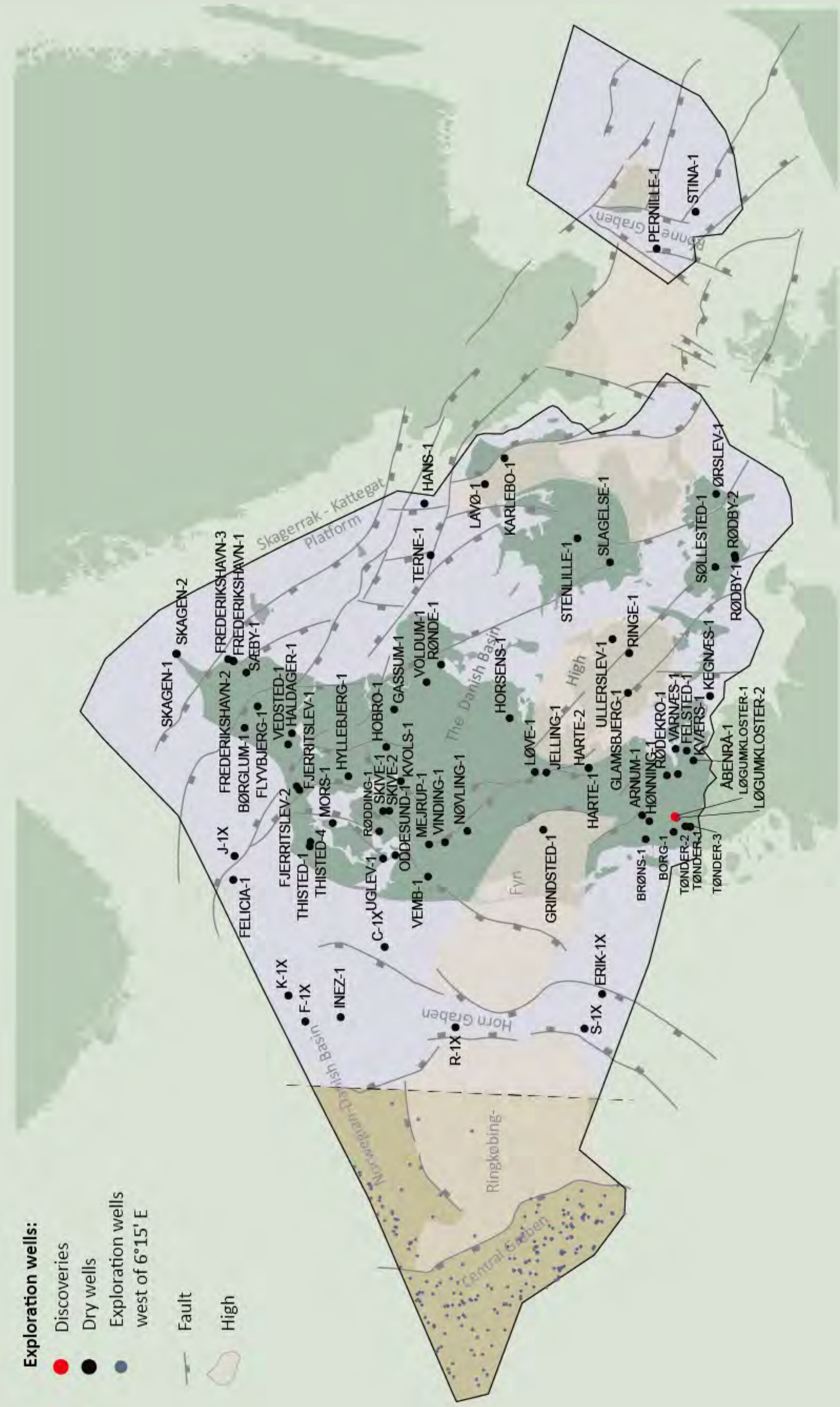
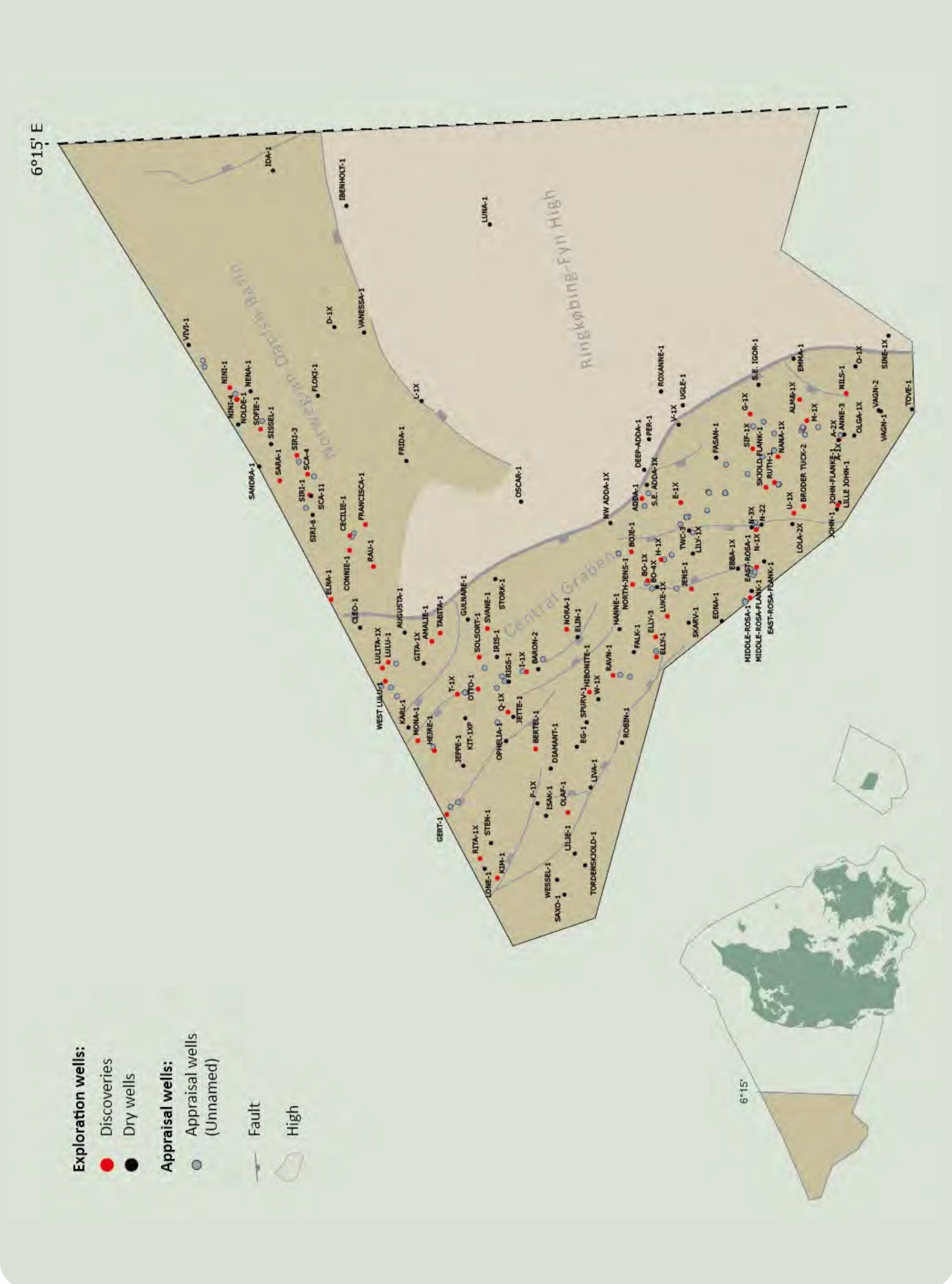


Figure 5.8. Exploration wells and discoveries in the licensing round area.



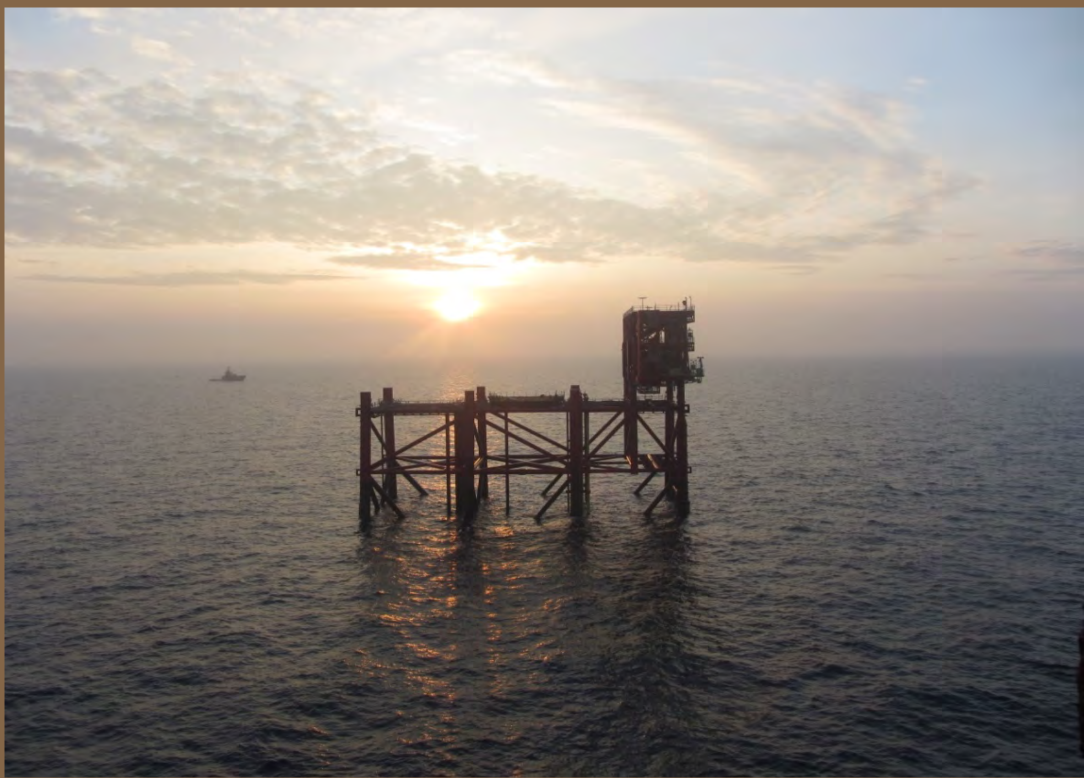
6. DEVELOPMENT OF NEW FIELDS

When a discovery is assessed to be commercial, the deliberations about development of the field begin. A new field may be developed by means of the existing infrastructure or new developments.

This year's report introduces a new chapter presenting approved development plans. The aim is to provide an overview of future production facilities, etc.

The development of one new field, the Hejre Field, is under way in the North Sea. The field development plan was approved in 2011.

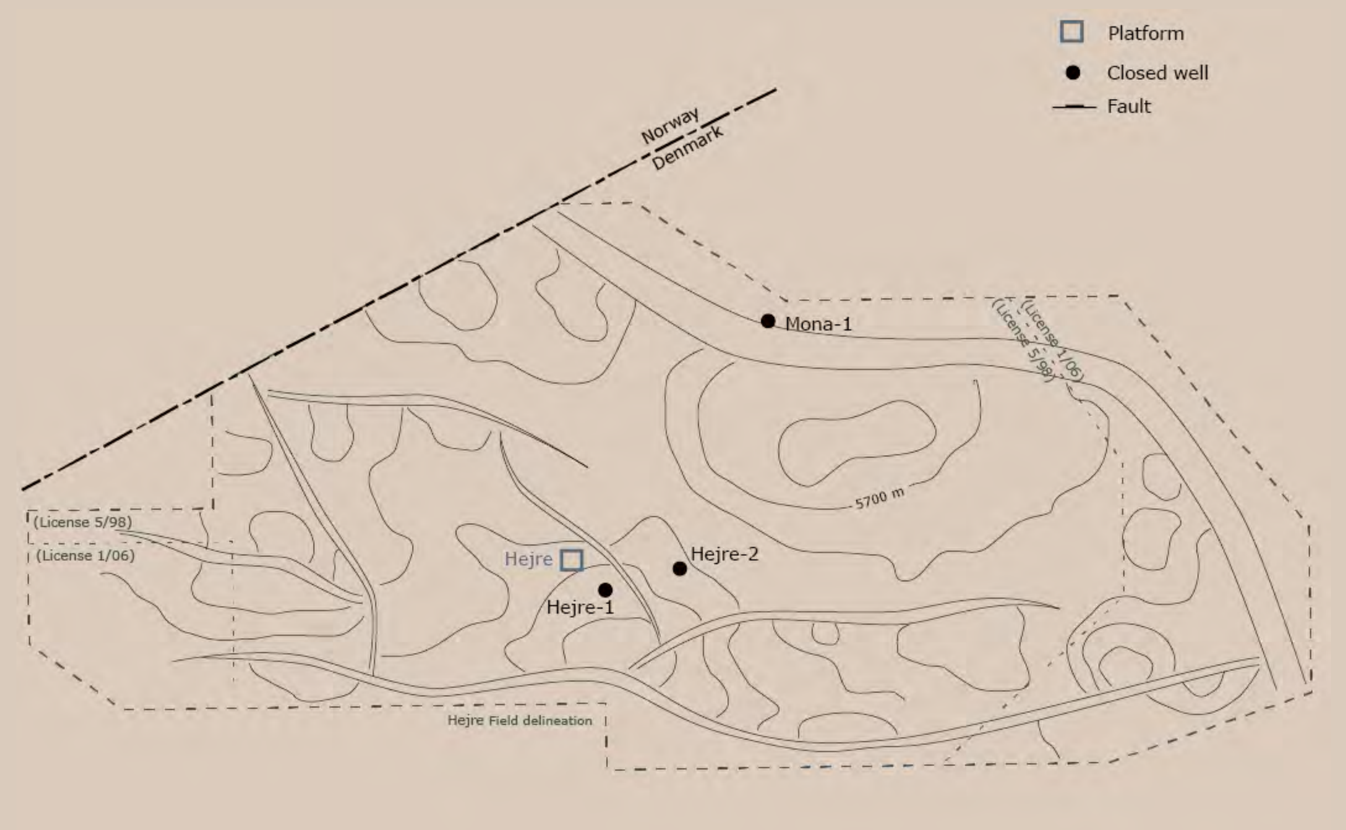
A description of development projects undertaken in 2013 in producing fields can be found in chapter 7, Producing fields.

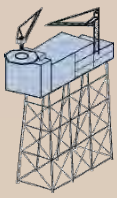


Jacket with wellhead module in the Hejre Field, June 2014.

THE HEJRE FIELD

Field data	At 1 January 2014
Licence:	5/98 and 1/06
Operator:	DONG E&P A/S
Discovered:	2001
First oil expected:	2016
Water depth:	68 m
Field delineation:	98.6 km^2





Hejre

RESERVOIR DATA

Reservoir rock: Sandstone
Geological age: Upper Jurassic
Reservoir depth: 5,000-6,000 m (HPHT)
Reservoir thickness: approx. 30 m
Liquid: Light oil
Pressure: 1,010 bars
Temperature: 160 ℃
Reserves: Oil: approx. 16 m. m^3
Gas: approx. 10 bn. Nm^3

INSTALLATION DATA

Planned wells:
Production: 5
Water injection: 0
Manning: max. 70 persons
Platform type: Eight-leg combined accommodation, wellhead and processing platform

Export:
Oil: 90 km new pipeline to Gorm E
Gas: 24 km new pipeline to existing infrastructure

7. PRODUCING FIELDS

By the beginning of 2014 the Danish sector of the North Sea had a total of some 55 platforms and 19 producing oil and gas fields, which are continuously being developed. Maersk Oil and Gas is the operator of 15 fields, while DONG is the operator of three fields and Hess on one field.

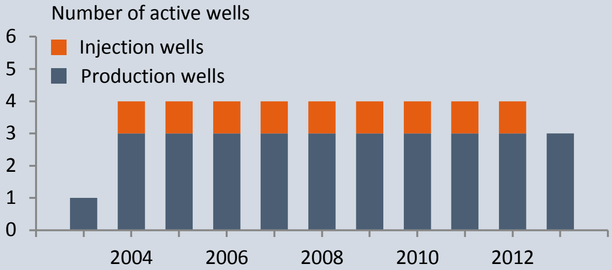
Recovery from the Danish fields was in 2013 made from approx. 400 wells. There was injected water and/or gas in 106 wells to improve recovery from a total of 270 wells contributing to the production. Two new oil production wells were drilled in 2013, SAN-1 in the South Arne Field and HBB-3 in the Halfdan Field.

There is a continuous focus on optimization and maintenance of old wells. 20 wells in the Dan, Gorm and Valdemar Fields have undergone repair or maintenance activities that required the use of a drilling rig. Other wells were maintained with other equipment.

Legend for field data

DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2014
2013-prices DKK 1.52 billion



DEVELOPMENT AND INVESTMENT

Total investments comprise the costs of developing installations and wells.

The chart shows the number of wells that were active in the individual years.

The wells are divided into production wells and injection wells. The chart shows the primary function of the wells in the relevant year, either production or injection. A well may be used for production for part of a year and then be converted to injection for the rest of the year.

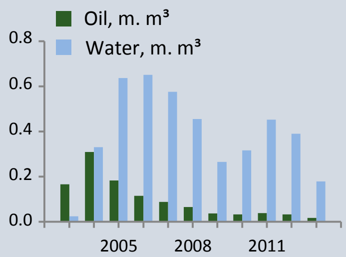
Injection well Production well Production/Injection well*

*Only relevant for the Tyra field. A few wells alternate between injection and production.

PRODUCTION

Cum. production at 1 January 2014

Oil:	1.09	m. m³
Gas:	0.08	bn. Nm³
Water:	4.28	m. m³



PRODUCTION OF OIL, GAS AND WATER

The chart shows the primary production from the individual fields, i.e. oil or gas as well as water. The figures show the cumulative production of oil, gas and water until 1 January 2014.

Oil field (e.g. Dan) Oil, m. m³ Gas, bn. Nm³ Water, m. m³

At the time of production startup, the percentage of oil produced is high, but over time, the percentage of water produced increases. When oil flows from the reservoir to the surface, it degases and lower gas production is thus achieved.

Gas field (e.g. Harald) Oil and condensate, m. m³ Gas, bn. Nm³ Water, m. m³

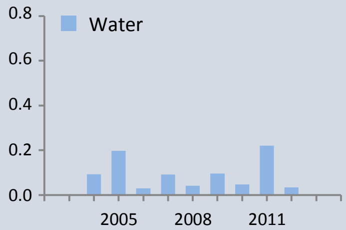
Production from a gas field consists of gas, water and condensate, which is a light oil. Due to the pressure difference between reservoir and surface, the gas condenses at the surface, which means that liquid hydrocarbons (condensate) are also produced.

Oil and gas field (e.g. Tyra Southeast) Oil and condensate, m. m³ Gas, bn. Nm³ Water, m. m³

Some fields contain both oil and gas reservoirs. Oil, gas, condensate and water are produced from these fields.

INJECTION

Cum. injection at 1 January 2014
Water: 0.85 m. m³



INJECTION OF WATER AND GAS

The chart shows the primary injection in the individual fields, i.e. water or gas. The figures show the cumulative injection of water and gas until 1 January 2014. The injection method is not used for all fields.

Injecting water into oil reservoirs maintains the reservoir pressure while forcing oil towards the production wells. The injection of gas also maintains pressure in the reservoir. Moreover, the gas affects the viscosity of hydrocarbons.

Fields with water injection (e.g. Halfdan) Water, m. m³

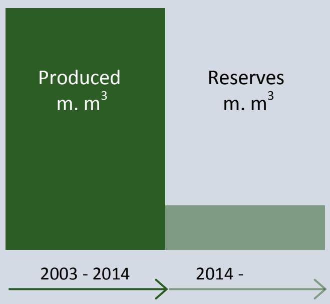
In the Halfdan Field, for example, water is injected to displace the oil towards the production wells.

Fields with gas injection (e.g. Tyra) Gas, bn. Nm³

In a few fields, gas is injected to optimize the production of liquid hydrocarbons.

RESERVES

Oil:	0.2	m. m³
Gas:	0	bn. Nm³



RESERVES COMPARED TO CUMULATIVE PRODUCTION

Figures for oil and gas reserves are indicated for each individual field.

The chart shows the relationship between the amounts produced until 1 January 2014 and the estimated hydrocarbons-in-place, the reserves.

Produced

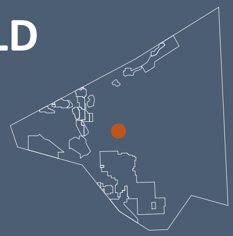
The cumulative production of oil or gas until 1 January 2014.

Reserves

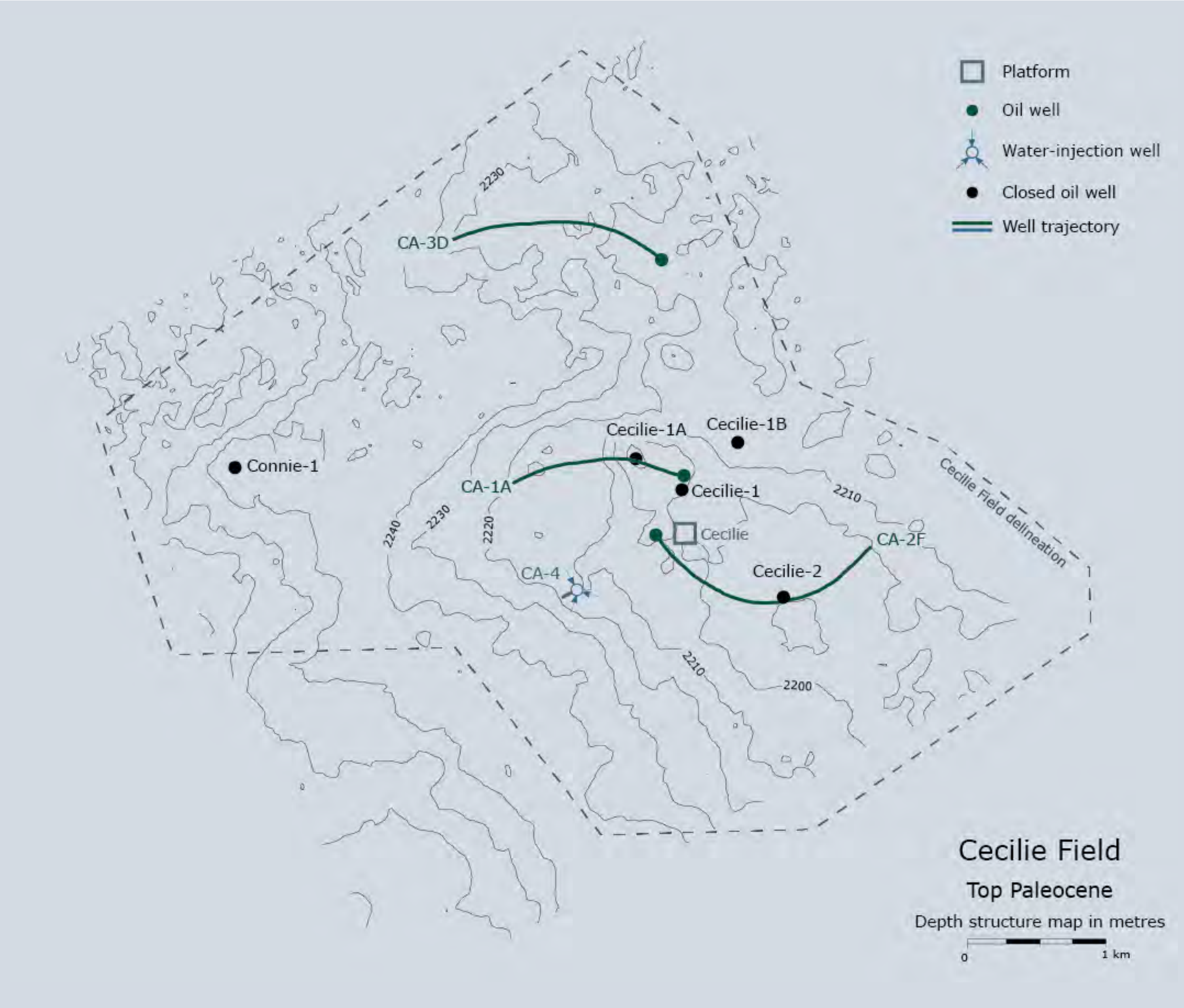
The estimated amounts of oil and gas that can be recovered by means of known technolandy under the prevailing economic conditions.

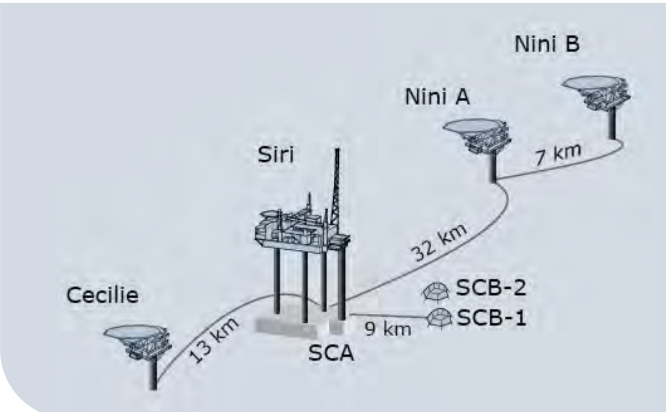
For gas fields, both the amounts produced and the reserves have been calculated on a net gas basis.

THE CECILIE FIELD



Location:	**Block 5604/19 and 20**
Licence:	**16/98**
Operator:	**DONG E&P A/S**
Discovered	**2000**
Year on stream:	**2003**

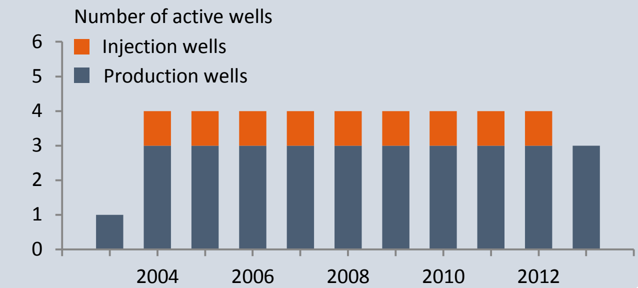




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2014

2013-prices DKK 1.52 billion



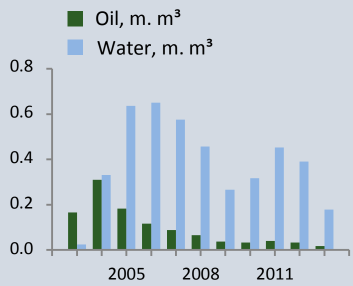
FIELD DATA At 1 January 2014

Oil prod. wells:	3
Gas prod. wells:	1
Water depth:	60 m
Field delineation:	23 km^3
Reservoir depth:	2,200 m
Reservoir rock:	Sandstone
Geological age:	Paleocene

PRODUCTION

Cum. production at 1 January 2014

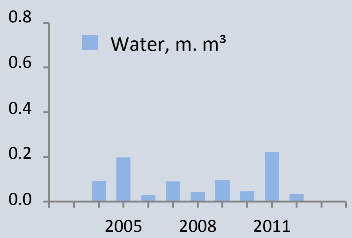
Oil:	1.09	m. m³
Gas:	0.08	bn. Nm³
Water:	4.28	m. m³



INJEKTION

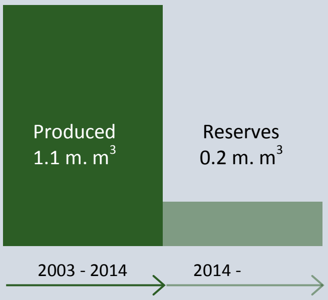
Cum. injection at 1 January 2014

Water:	0.85	m. m³



RESERVES

Oil:	0.2	m. m³
Gas:	0	bn. Nm³



REVIEW OF GEOLOGY, THE CECILIE FIELD

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

PRODUCTION STRATEGY

Recovery is based on water injection to maintain reservoir pressure. To assess its effect, water injection has been suspended for periods of time. The production wells have been drilled in the crest of the structure, while water is injected in the flank of the field.

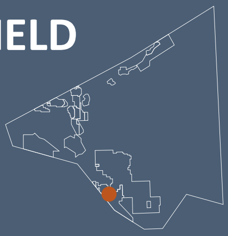
PRODUCTION FACILITIES

The Cecilie Field is a satellite development to the Siri Field with one unmanned wellhead platform with a helideck. The unprocessed production is transported to the Siri platform through a 12” multiphase pipeline. The oil is processed at the Siri platform and exported to shore via tanker. The gas produced is injected into the Siri Field. Injection water is transported to the Cecilie Field through a 10” pipeline.

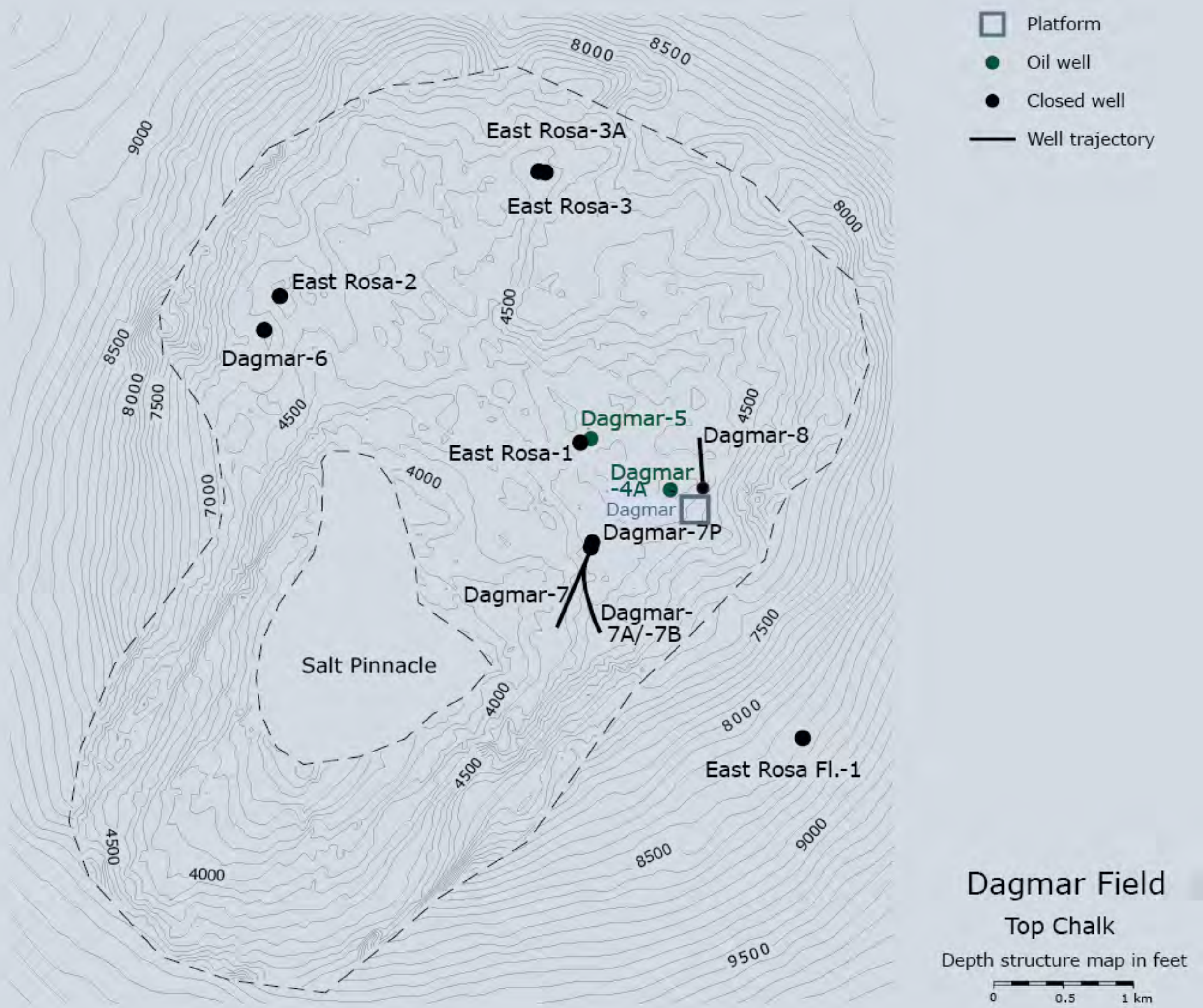
FIELD DEVELOPMENT

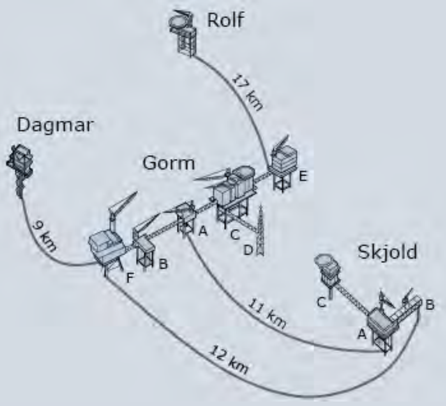
No major field development activities in 2013.

THE DAGMAR FIELD



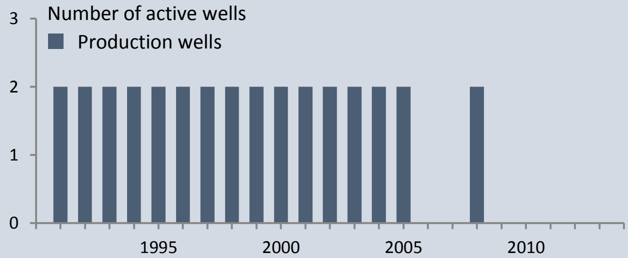
Prospect:	**East Rosa**
Location:	**Block 5504/15**
Licence:	**Sole Concession**
Operator:	**Mærsk Olie og Gas A/S**
Discovered	**1983**
Year on stream:	**1991**





DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2014
2013-prices DKK 0.54 billion



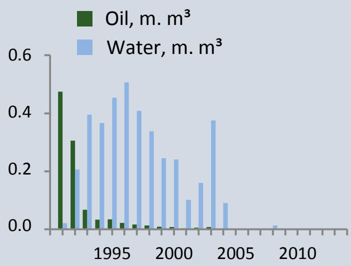
FIELD DATA At 1 January 2014

Production wells:	2
Water depth:	34
Field delineation:	50 km^2
Reservoir depth:	1,400 m
Reservoir rock:	Chalk and Dolomit
Geological age:	Danian, Upper Cretaceous and Zechstein

PRODUCTION

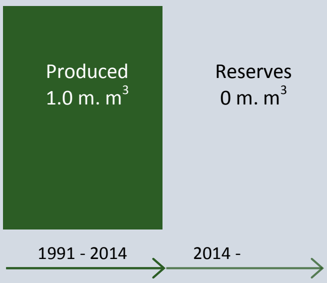
Cum. production at 1 January 2014

Oil:	1.01	m. m³
Gas:	0.16	bn. Nm³
Water:	3.93	m. m³



RESERVES

Oil:	0	m. m³
Gas:	0	bn. Nm³



REVIEW OF GEOLOGY, THE DAGMAR FIELD

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

PRODUCTION STRATEGY

Both wells in the field have been closed in. The recovery strategy for the Dagmar Field was based on achieving the highest possible production rate from the wells. Initially, the oil production rates were high in the Dagmar Field, but later it was not possible to sustain the good production performance from the matrix. In 2006 and 2007 the two production wells in the field were closed in. When reopened in 2008, the wells produced very little oil with a water content of 98 per cent in a production test. Therefore, the wells were closed in again, and the potential of the field is being reassessed.

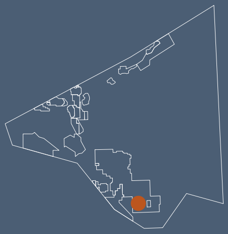
PRODUCTION FACILITIES

The Dagmar Field is a satellite development to the Gorm Field with one unmanned wellhead platform without a helideck. The unprocessed production can be transported to the Gorm F platform, where separate facilities for handling the sour gas from the Dagmar Field have been installed. The small amount of gas produced from Dagmar was flared due to its high content of hydrogen sulphide.

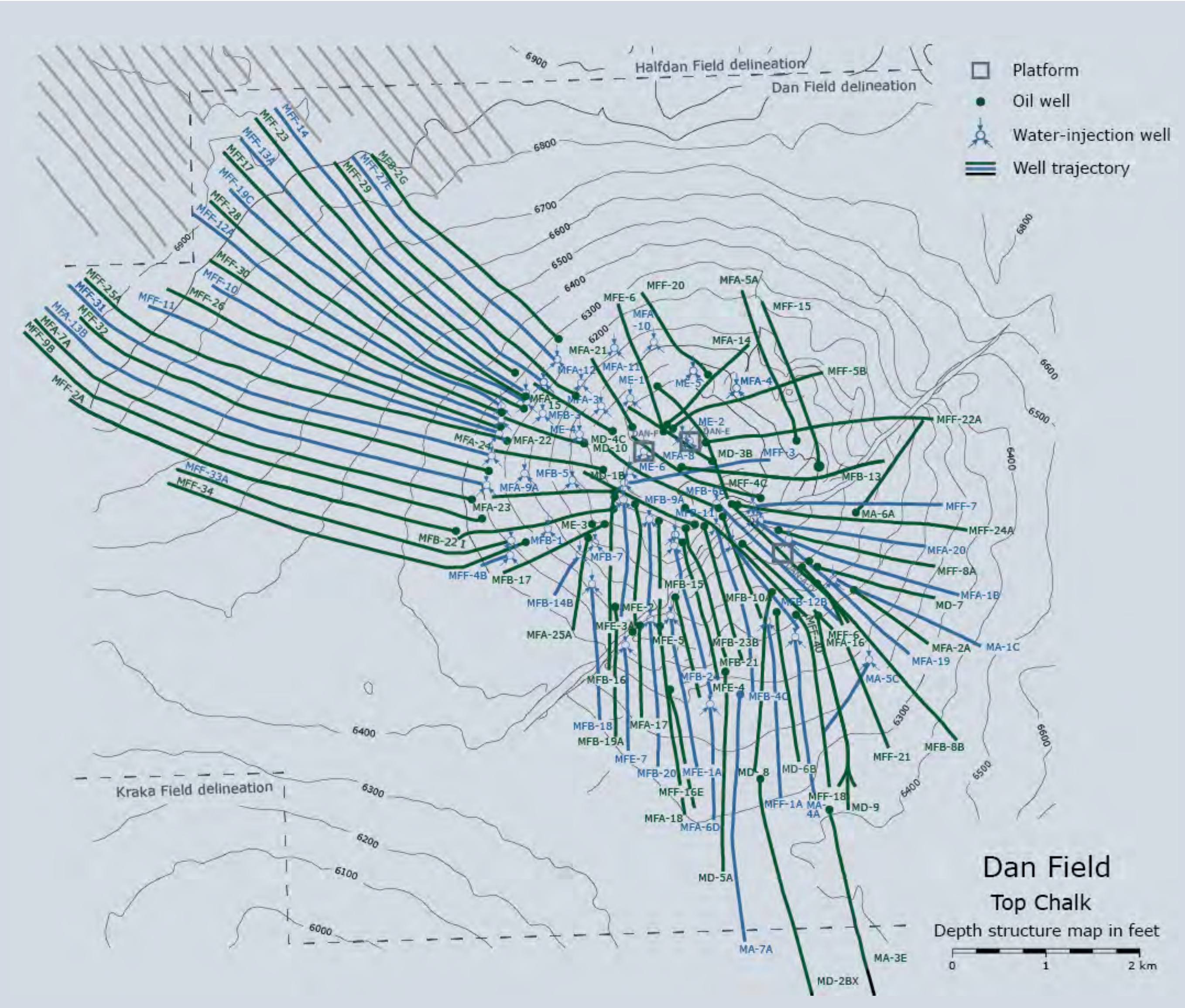
FIELD DEVELOPMENT

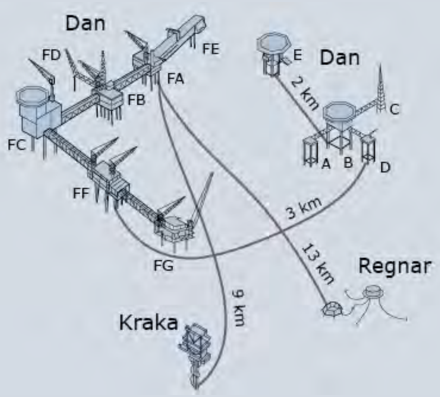
No major field development activities in 2013.

THE DAN FIELD



Prospect:	**Abby**
Location:	**Block 5505/17**
Licence:	**Sole Concession**
Operator:	**Mærsk Olie og Gas A/S**
Discovered	**1971**
Year on stream:	**1972**

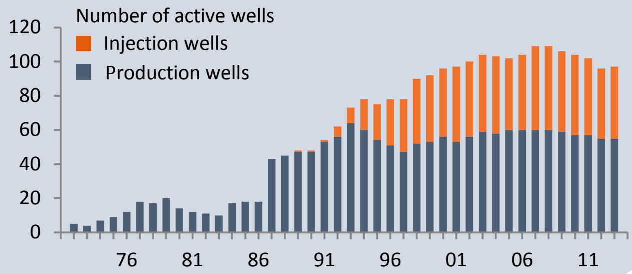




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2014

2013-prices DKK 32.65 billion



FIELD DATA — At 1 January 2014

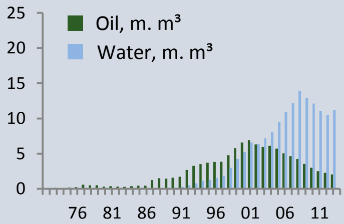
Oil prod. wells: 61
Gas prod. wells: 48

Water depth: 40 m
Field delineation: 104 km
Reservoir depth: 1,850 m
Reservoir rock: Chalk
Geological age: Danian and Upper Cretaceous

PRODUCTION

Cum. production at 1 January 2014

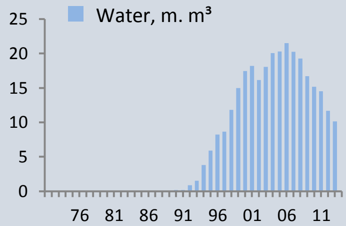
Oil:	108.55	m. m³
Gas:	23.80	bn. Nm³
Water:	153.02	m. m³



INJEKTION

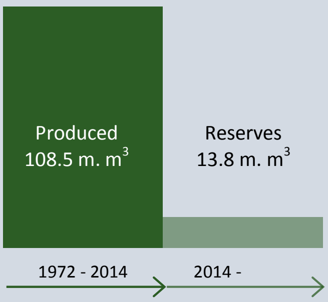
Cum. injection at 1 January 2014

Water:	295.58	m. m³



RESERVES

Oil:	13.8	m. m³
Gas:	2.6	bn. Nm³



REVIEW OF GEOLOGY, THE DAN FIELD

The Dan Field is an anticlinal structure induced through salt tectonics. A major fault divides the field into two reservoir blocks, which, in turn, are intersected by a number of minor faults. The chalk reservoir has high porosity and low permeability. The Dan Field has a gas cap.

Recovery takes place from the central part of the Dan Field and from large sections of the flanks of the field. Particularly the western flank of the Dan Field, close to the Halfdan Field, has demonstrated good production properties. The presence of oil in the western flank of the Dan Field was not confirmed until 1998 with the drilling of the MFF-19C well, which also established the existence of the Halfdan Field.

PRODUCTION STRATEGY

Recovery from the field is based on the simultaneous production of oil and injection of water to maintain reservoir pressure. Water injection was initiated in 1989 and has gradually been extended to the whole field. The recovery of oil is optimized by flooding the reservoir with water to the extent possible.

PRODUCTION FACILITIES

The Dan Field comprises two manned installations, Dan B and Dan E, consisting of five wellhead platforms, A, D, FA, FB and FE, a combined wellhead and processing platform, FF, a processing platform with a flare tower, FG, two processing and accommodation platforms, B and FC, and two gas flare stacks, C and FD. In addition, the field has an unmanned injection platform, E.

On the Dan F installation there are facilities for receiving production from the adjacent unmanned Kraka and Regnar satellite fields, as well as for receiving some of the gas produced at the Halfdan Field. The Dan F and Dan E installations supply the Halfdan Field with injection water.

After final processing, the oil is transported to shore via the Gorm installation. The gas is pre-processed and transported to the Tyra East installation for final processing. Production water from the Dan Field and its satellite fields is treated at the Dan F installation before being discharged into the sea.

In the Dan Field there are accommodation facilities for 95 persons on the FC platform and five persons on the B platform. The accommodation facilities are supplemented by flotels during the execution of major construction works and maintenance programmes.

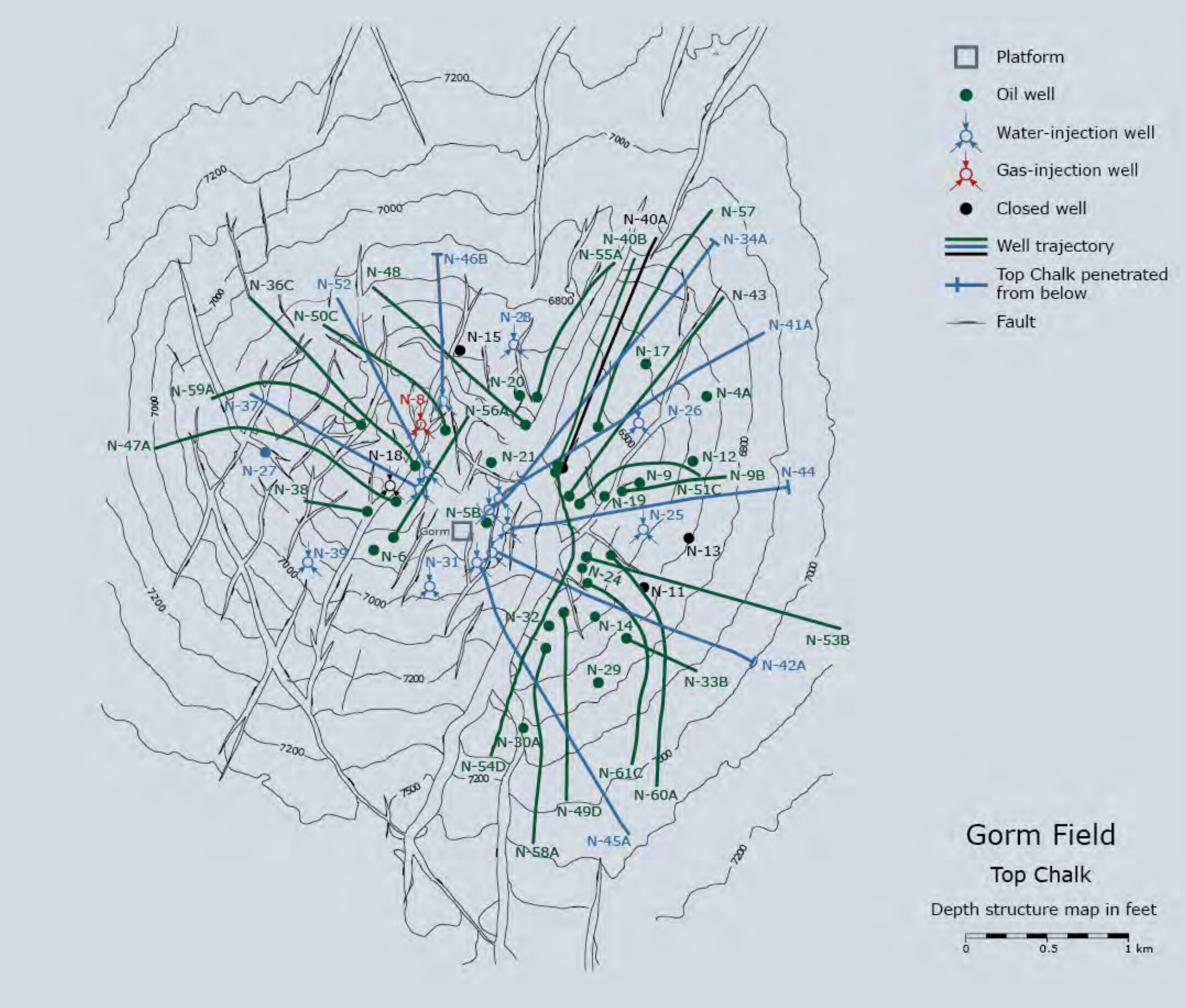
FIELD DEVELOPMENT

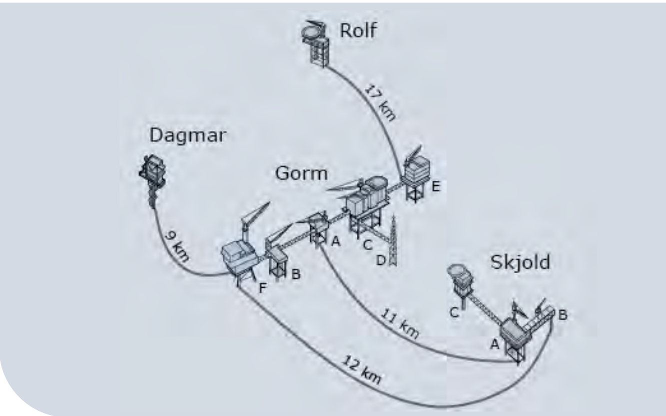
A major modification project is being carried out at Dan B for the purpose of converting it into an unmanned installation in 2015.

A programme for the maintenance and repair of existing wells is being implemented.

THE GORM FIELD

Prospect:	**Vern**
Location:	**Block 5505/17**
Licence:	**Sole Concession**
Operator:	**Mærsk Olie og Gas A/S**
Discovered	**1971**
Year on stream:	**1981**

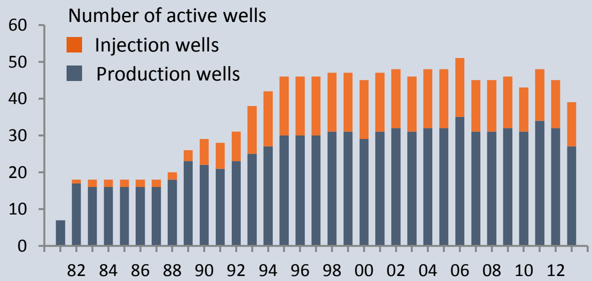




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2014

2013-prices DKK 15.91 billion



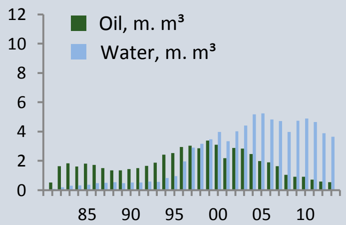
FIELD DATA — At 1 January 2014

Oil prod. wells:	32
Gas inj. wells:	1
Water inj. Brønde:	14
Water depth:	39 m
Field delineation:	63 km^2
Reservoir depth:	2,100 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

PRODUCTION

Cum. production at 1 January 2014

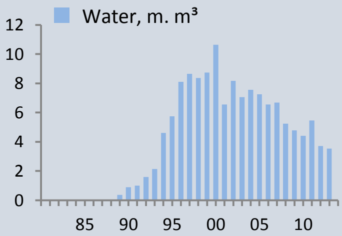
Oil:	60.79	m. m^3
Gas:	15.74	bn. Nm^3
Water:	80.35	m. m^3



INJEKTION

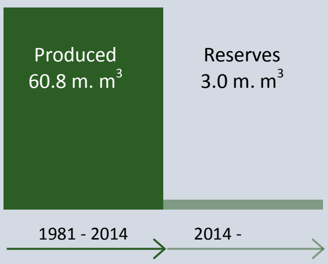
Cum. injection at 1 January 2014

Water:	137.83	m. m^3
Gas:	8.16	bn. Nm^3



RESERVES

Oil:	3.0	m. m^3
Gas:	0.3	bn. Nm^3



REVIEW OF GEOLOGY, THE GORM FIELD

The Gorm Field is an anticlinal structure induced through salt tectonics. A major fault extending north-south divides the field into two reservoir blocks. The western reservoir block is intersected by numerous, minor faults.

PRODUCTION STRATEGY

The production strategy for the Gorm Field is to maintain reservoir pressure through water injection, which was initiated in 1989. In addition, the influx of water from the aquifer and compaction in the reservoir stimulate production. Water injection takes place both at the flank of the field and the bottom of the reservoir. Produced water is reinjected.

PRODUCTION FACILITIES

The Gorm Field consists of two wellhead platforms, Gorm A and B, one processing and accommodation platform, Gorm C, one gas flare stack, Gorm D, one riser and export platform, Gorm E (owned by DONG Oil Pipe A/S) and one combined wellhead, processing and riser platform, Gorm F.

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

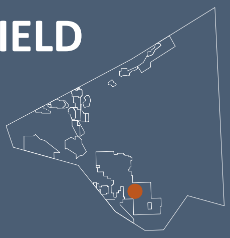
There are accommodation facilities on the Gorm C platform for 98 persons.

FIELD DEVELOPMENT

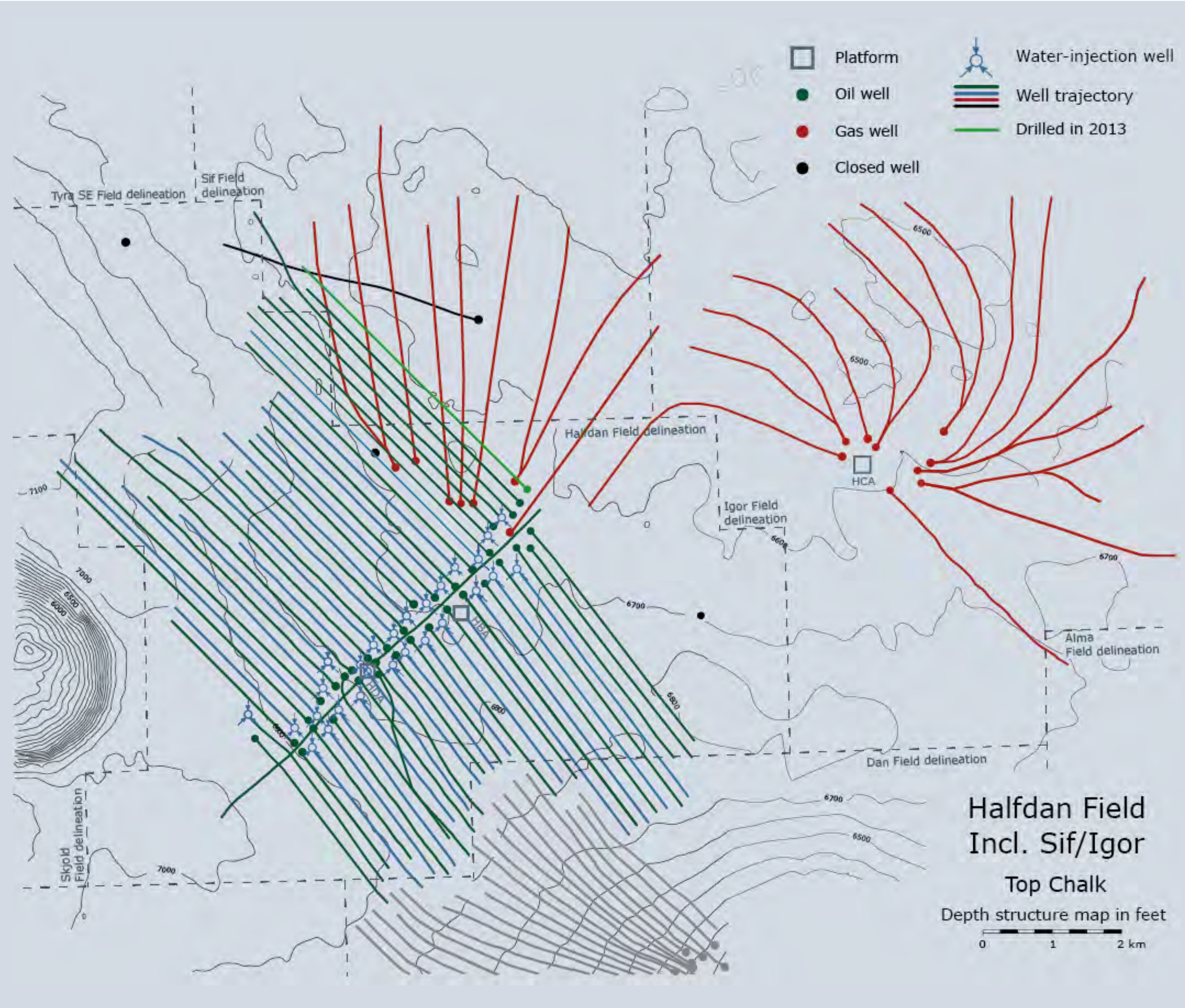
Various drilling operations have been conducted without new production being initiated.

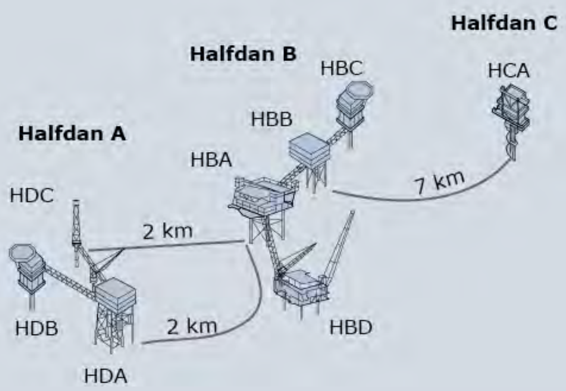
THE HALFDAN FIELD

INCL. SIF AND IGOR



Prospect:	Nana, Sif and Igor
Location:	Block 5505/13 and 5504/16
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas A/S
Discovered	1968, 1999
Year on stream:	1999,2004 and 2007

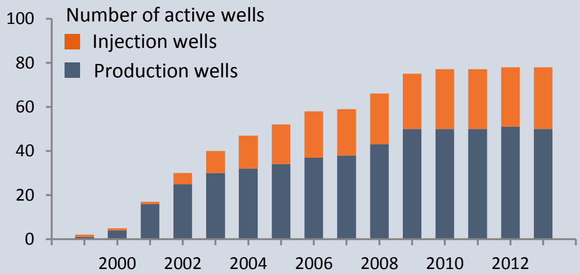




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2014

2013-prices DKK 23.27 billion



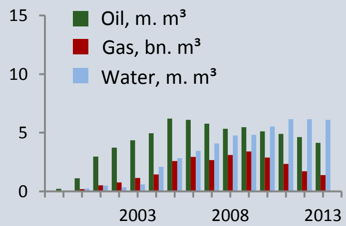
FIELD DATA — At 1 January 2014

Oil prod. wells:	38 (Halfdan)
Water inj. wells:	27 (Halfdan)
Gas prod. wells:	16 (Sif and Igor)
Reservoir depth:	2.030-2.100
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

PRODUCTION

Cum. production at 1 January 2014

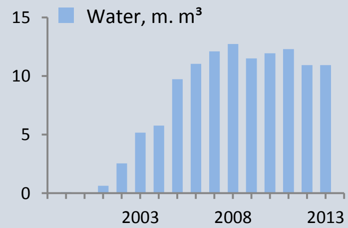
Oil:	64.98	m. m³
Gas:	27.12	bn. Nm³
Water:	47.72	m. m³



INJEKTION

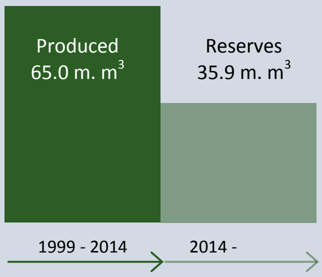
Cum. injection at 1 January 2014

Water:	117.28	m. m³



RESERVES

Oil:	35.9	m. m³
Gas:	6.9	bn. Nm³



REVIEW OF GEOLOGY, THE HALFDAN FIELD

The Halfdan Field comprises the Halfdan, Sif and Igor areas and contains a continuous hydrocarbon accumulation. The southwestern part of the field primarily contains oil in Maastrichtian layers, while the area towards the north and east primarily contains gas in Danian layers.

The accumulation is contained in a limited part of the chalk formation, which constituted a structural trap in earlier geological times. The structure gradually disintegrated, and the oil began migrating away from the area due to later movements in the subsoil. However, the oil and gas deposits have migrated a short distance only due to the low permeability of the reservoir. This porous, unfractured chalk is similar to that found in the western flank of the Dan Field.

PRODUCTION STRATEGY

Recovery is based on the Fracture Aligned Sweep Technology (FAST), where long horizontal wells are arranged in a pattern of alternate production and water-injection wells with parallel well trajectories. Varying the injection pressure in the well causes the rock to fracture. This generates a continuous water front along the whole length of the well, which drives the oil in the direction of the production wells.

The production of gas from Danian layers is based on primary recovery from multilateral horizontal wells, using the reservoir pressure. The Sif wells extend from the Halfdan BA platform in a fan-like pattern, while the Igor wells form a helical pattern from the Halfdan CA platform.

PRODUCTION FACILITIES

The Halfdan Field comprises two installations, Halfdan A and Halfdan B, as well as an unmanned wellhead platform, Halfdan CA. The distance between Halfdan A and Halfdan B is about 2 km.

Halfdan CA is located about 7 km northeast of the Halfdan B complex.

The Halfdan A complex has accommodation facilities for 32 persons, while there are accommodation facilities for 80 persons at the Halfdan B complex.

From the Halfdan A installation (HDA), HP gas can be imported and exported through a 12" pipeline to the Dan installation, and LP gas can be exported through another 12” pipeline. Lift gas is exported/imported between Halfdan A and Halfdan B through a 6” pipeline.

The Dan installation supplies both Halfdan A and Halfdan B with injection water through a 16” pipeline. Injection water is transported to Halfdan B via Halfdan A.

Treated production water from Halfdan A and Halfdan B is discharged into the sea. No produced water is discharged from Halfdan CA.

Halfdan A and Halfdan B have their own power supply, but a 3 kW cable has been laid between Halfdan A and Halfdan B that can be used in case of power failure, etc. Halfdan CA is provided with power from Halfdan B.

FIELD DEVELOPMENT

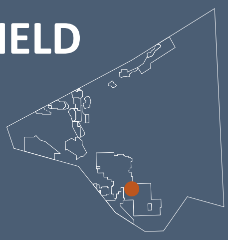
In 2013 a new oil production well, HBB-3, approved in 2012, was drilled.

On 1 October 2013 the DEA approved a further development plan for the Halfdan Northeast Field, providing for the drilling of a gas production well. The costs of drilling and hooking up the well are expected to total about DKK 280 million, and production is estimated at 270 million Nm³ of gas and 27,000 m³ of oil during the life of the well.

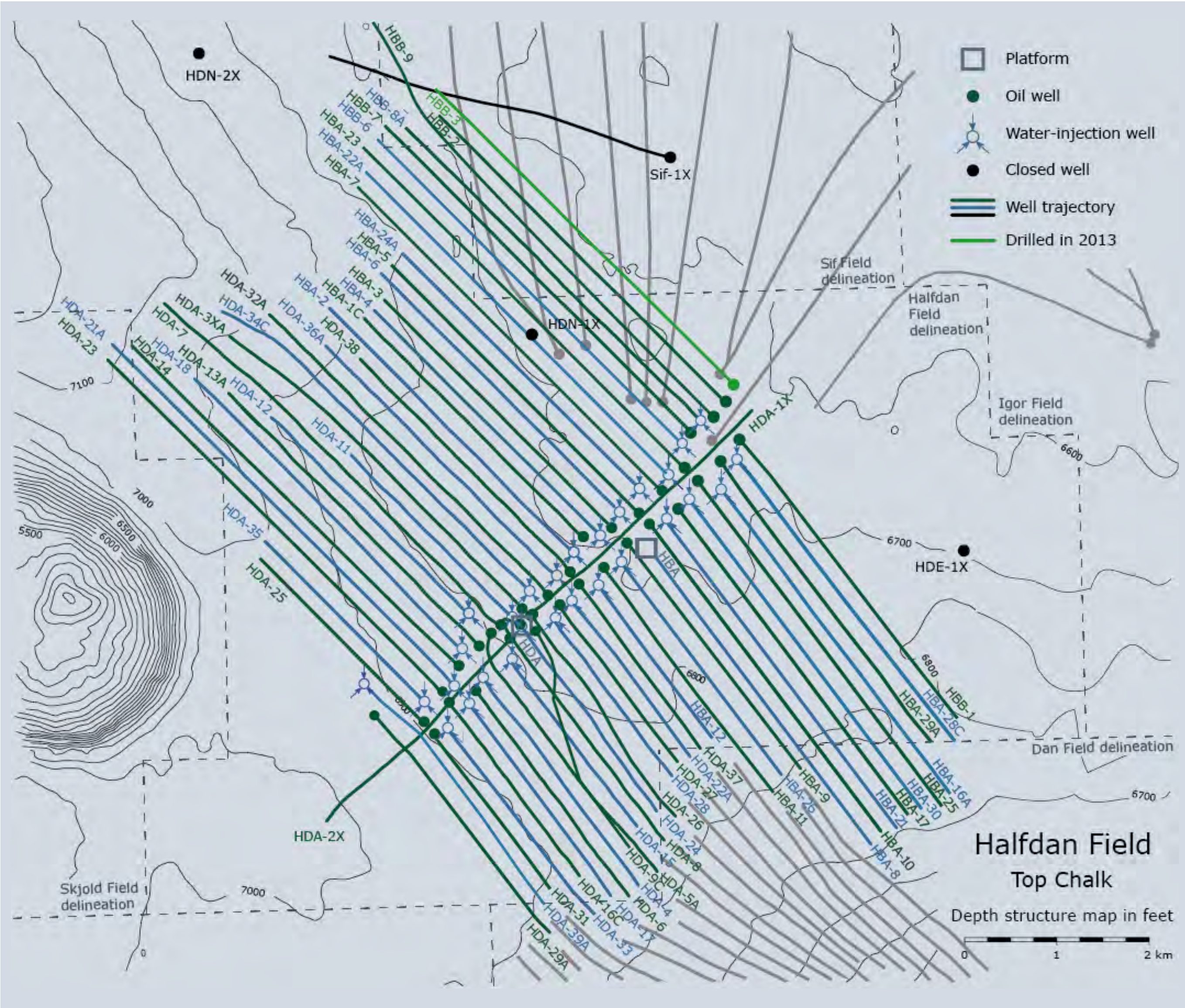
More details about the facilities can be found on the next two pages.

THE HALFDAN FIELD

(MAIN FIELD)



Prospect:	Nana, Sif and Igor
Location:	Block 5505/13 and 5504/16
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas A/S
Discovered	1999
Year on stream:	1999



FIELD DATA

At 1 January 2014

Oil prod. wells:	38 (Halfdan)
Water inj. wells:	27 (Halfdan)
Water depth:	43 m
Field delineation:	100 km^2
Reservoir depth:	2,100
Reservoir rock:	Chalk
Geological age:	Upper Cretaceous

Halfdan A consists of a combined processing and wellhead platform, HDA, an accommodation platform, HDB, and a gas flare stack, HDC. The platforms are interconnected by combined foot and pipe bridges.

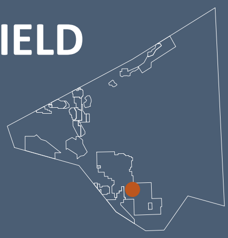
The gas produced at Halfdan A is transported to Tyra West through a 24” pipeline. The oil produced is conveyed to Gorm through a 14” pipeline.

Halfdan B consists of a wellhead platform, HBA, a riser and wellhead platform, HBB, an accommodation platform, HBC, and a processing platform, HBD. The platforms are interconnected by combined foot and pipe bridges.

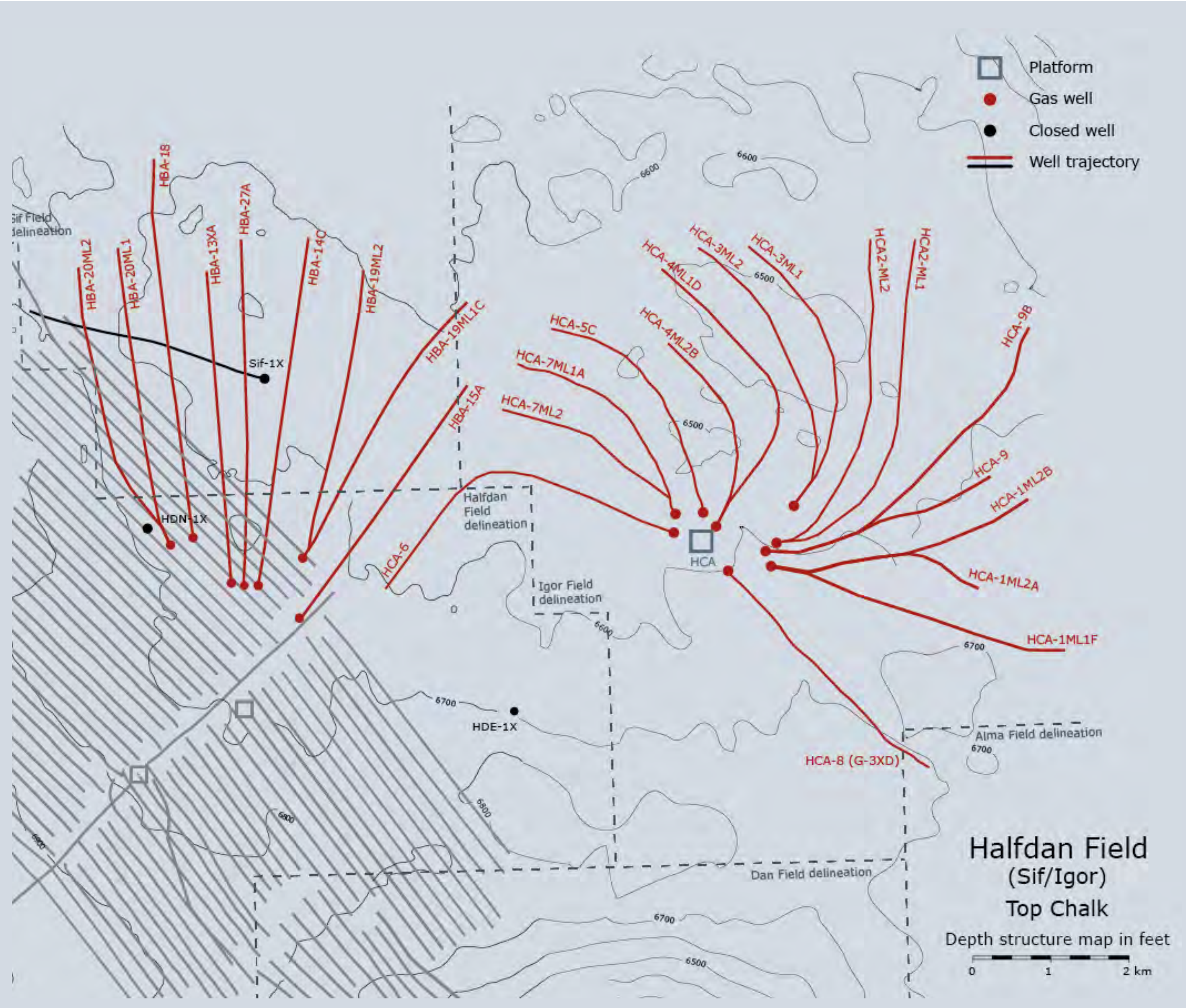
The gas is conveyed through a 16” pipeline, which is connected to a 24" pipeline leading to Tyra West. The oil is transported through a 14" pipeline to the riser at Halfdan A, from where it is transported to Gorm through the 14" pipeline connecting Halfdan with Gorm.

THE HALFDAN FIELD

(NORTHEAST)



Prospect:	**Sif and Igor**
Location:	**Block 5505/13**
Licence:	**Sole Concession**
Operator:	**Mærsk Olie og Gas A/S**
Discovered	**1968 (Igor), 1999 (Sif)**
Year on stream:	**2004 (Sif) and 2007 (Igor)**



FIELD DATA

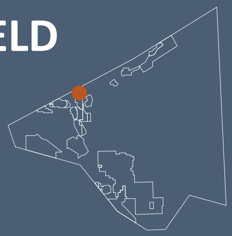
At 1 January 2014

Gas prod. wells:	7 (Sif) and 9 (Igor)
Water depth:	44 m (Sif) and 45 m (Igor)
Field delineation:	40 km^2 (Sif) 109 km^2 (Igor)
Reservoir depth:	2,030
Reservoir rock:	Chalk
Geological age:	Danian

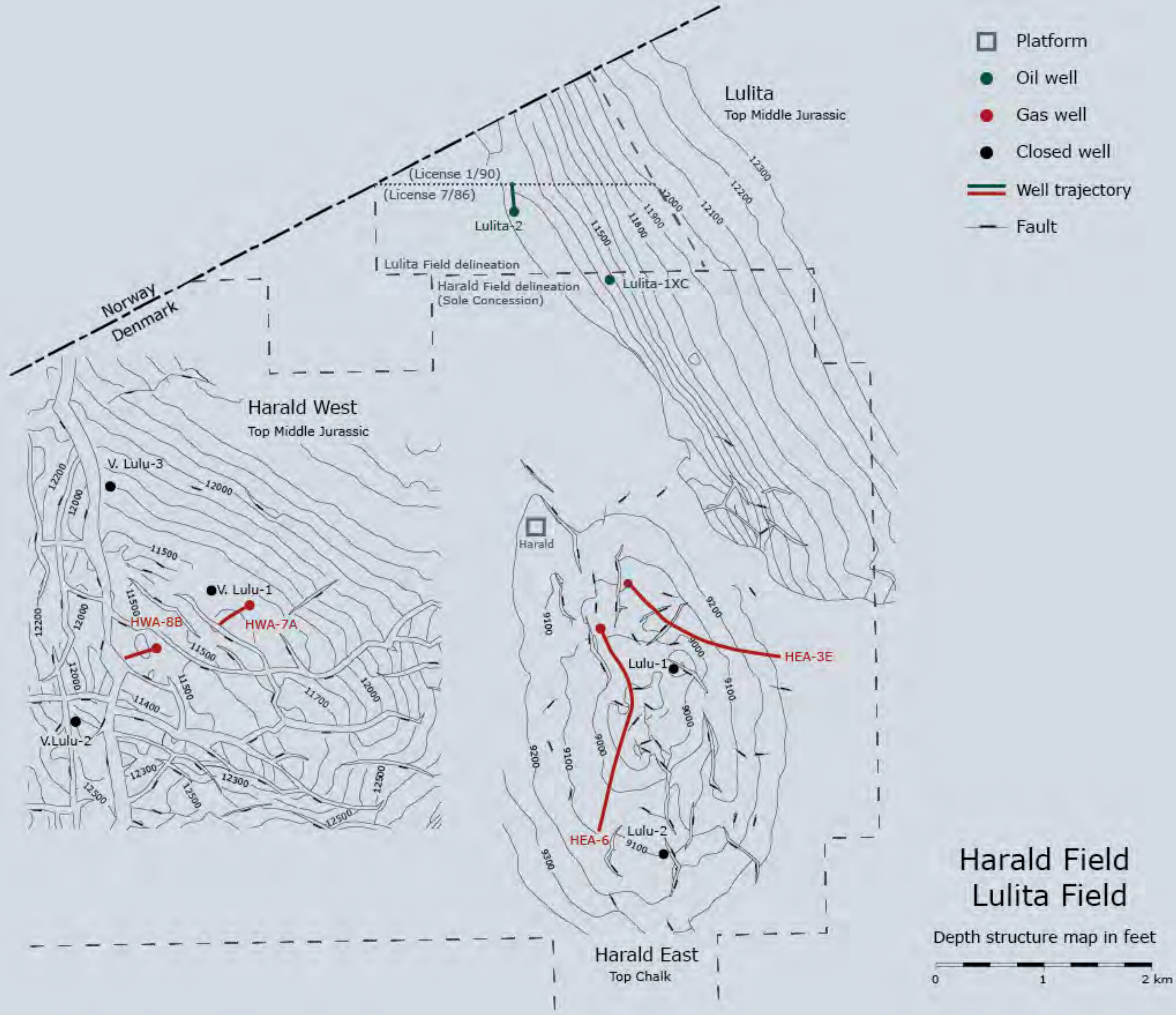
After being separated into liquids and gas, the production from the Halfdan CA platform is transported through two pipelines to the Halfdan B complex.

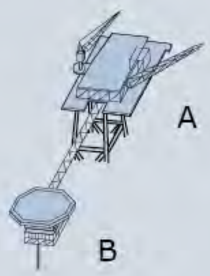
The gas is conveyed via the Halfdan B riser to Tyra West, while condensate is transported to Halfdan B (HBD) for processing. From Halfdan B, the oil is then transported to the Gorm installation via the riser on the Halfdan A complex (HDA).

THE HARALD FIELD



Prospect:	**Lulu/West Lulu**
Location:	**Block 5604/21 and 22**
Licence:	**Sole Concession**
Operator:	**Mærsk Olie og Gas A/S**
Discovered	**1980 (Lulu) - 1983 (West Lulu)**
Year on stream:	**1997**

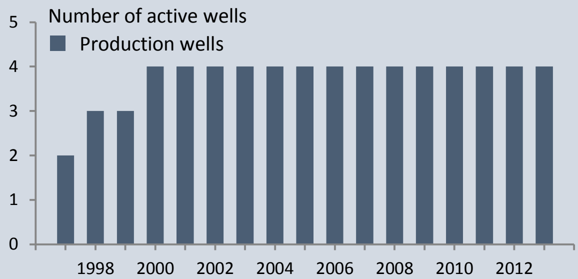




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2014

2013-prices DKK 4.41 billion



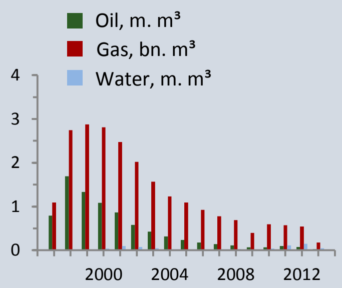
FIELD DATA At 1 January 2014

Gas prod. wells:	2 (Harald East)
Gas prod. wells:	2 (Harald West)
Water depth:	64 m
Field delineation:	56 km^2
Reservoir depth:	2,700 m (Harald East) 2,650 m (Harald West)
Reservoir rock:	Chalk (Harald East) Sandstone (Harald West)
Geological age:	Danian/Upper Cretaceous (Harald East) and Middle Jurassic (Harald West)

PRODUCTION

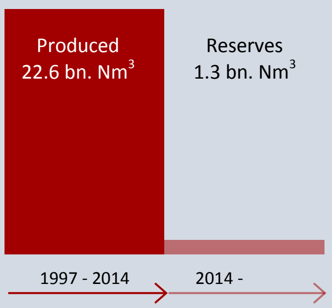
Cum. production at 1 January 2014

Oil:	8.08	m. m^3
Gas:	22.58	bn. Nm^3
Water:	0.72	m. m^3



RESERVES

Oil:	0.2	m. m^3
Gas:	1.3	bn. Nm^3



REVIEW OF GEOLOGY, THE HARALD FIELD

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

The Harald East structure is an anticline induced through salt tectonics. The gas zone is up to 75 m thick.

The Harald West structure is a tilted Jurassic fault block. The sandstone reservoir is of Middle Jurassic age, and is 100 m thick.

PRODUCTION STRATEGY

Recovery from both the Harald East and the Harald West reservoir takes place by gas expansion, with a moderate, natural influx of water into the reservoir.

Production from the Harald Field is based on the aim of optimizing the production of liquid hydrocarbons in the Tyra Field. By maximizing the drainage from the other gas fields, gas drainage from Tyra is minimized.

PRODUCTION FACILITIES

The Harald Field comprises a combined wellhead and processing platform, Harald A, and an accommodation platform with a helideck, Harald B.. The unprocessed condensate and the processed gas are transported to Tyra East. Treated production water is discharged into the sea.

The Harald Field is hooked up to the gas pipeline that transports gas from the South Arne Field to the Nybro gas-processing facilities. Normally, no gas is exported from Harald through the South Arne pipeline.

The Norwegian Trym gas field is connected by an 8" multiphase pipeline to the Harald Field, from where the production is transported to Tyra East. The Harald A platform has special equipment for separate metering of the oil and gas produced from Trym.

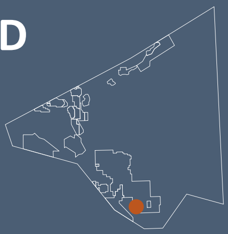
The Harald Field has accommodation facilities for 16 persons.

For more information, reference is made to the Lulita Field, which also uses the Harald A platform for processing purposes.

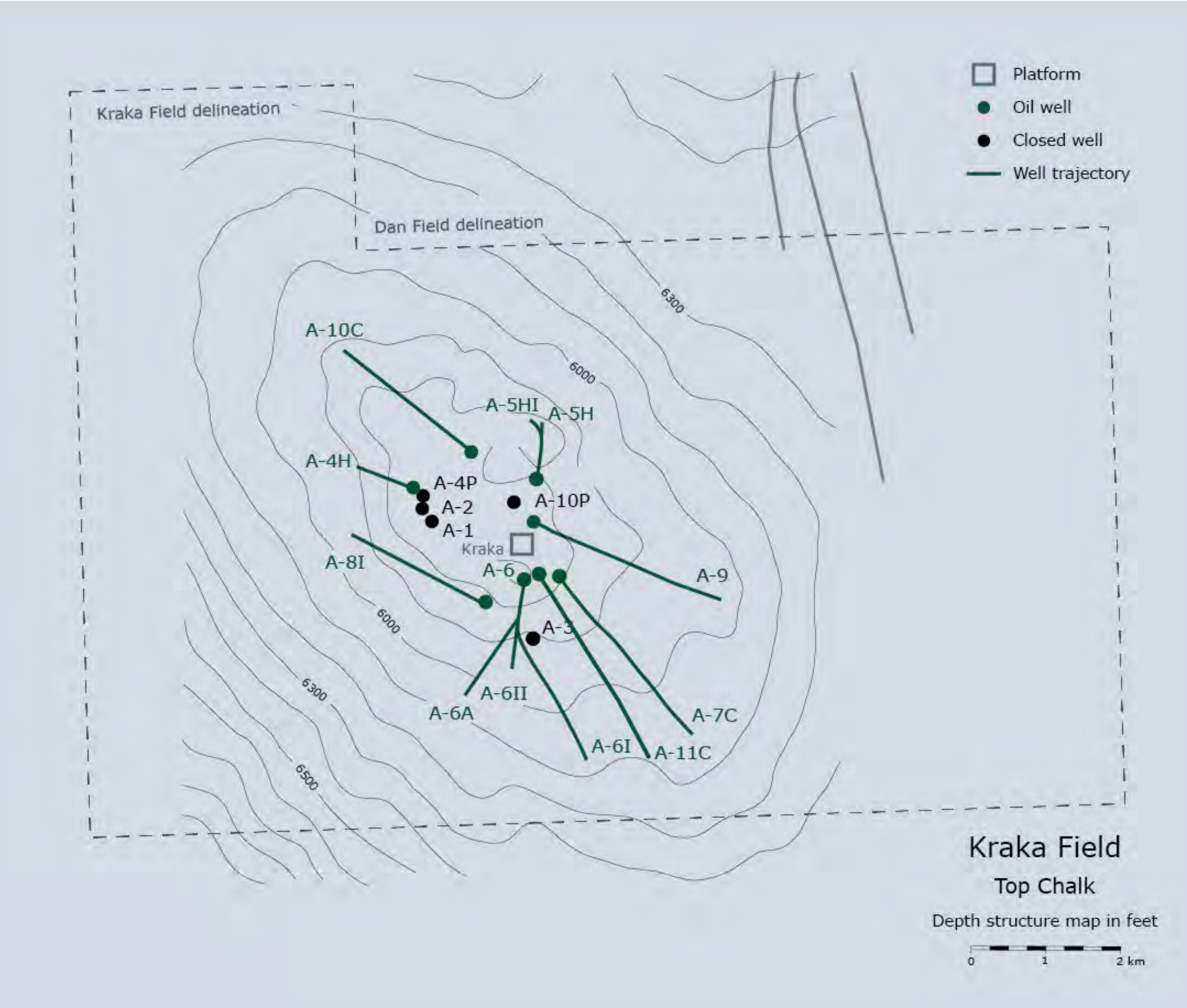
FIELD DEVELOPMENT

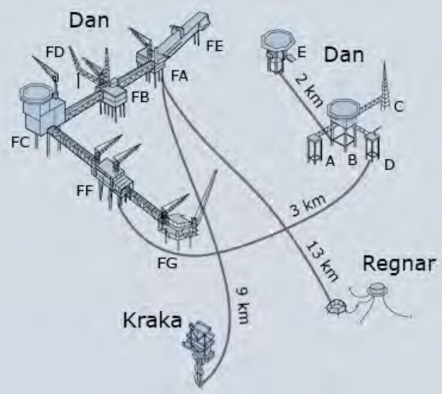
No major field development activities in 2013.

THE KRAKA FIELD



Prospect:	**Anne**
Location:	**Block 5505/17**
Licence:	**Sole Concession**
Operator:	**Mærsk Olie og Gas A/S**
Discovered	**1966**
Year on stream:	**1991**

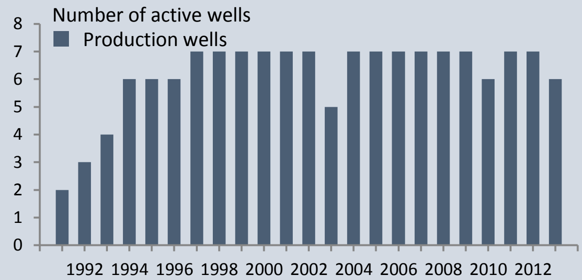




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2014

2013-prices DKK 2.04 billion



FIELD DATA At 1 January 2014

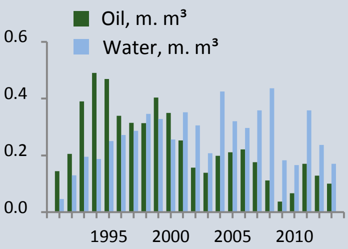
Production wells: 8

Water depth: 45 m
Field delineation: 81 km^2
Reservoir depth: 1,800 m
Reservoir rock: Chalk
Geological age: Danian and Upper Cretaceous

PRODUCTION

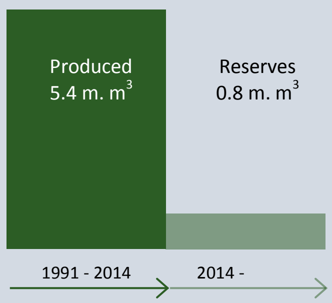
Cum. production at 1 January 2014

Oil:	5.39	m. m^3
Gas:	1.50	bn. Nm^3
Water:	6.12	m. m^3



RESERVES

Oil:	0.8	m. m^3
Gas:	0.2	bn. Nm^3



REVIEW OF GEOLOGY, THE KRAKA FIELD

Kraka is an anticlinal structure induced through salt tectonics, which has caused some fracturing in the chalk. The reservoir has medium-good porosity, but low permeability. The thin oil pay zone is further characterized by high water saturations. There is a minor gas cap in the field.

PRODUCTION STRATEGY

Recovery from Kraka is based on the natural expansion of the gas cap and aquifer support. The individual wells are produced at the lowest possible bottom-hole pressure. Oil production from the field is maximized by prioritizing gas lift in wells with a low water content and a low gas-oil ratio.

PRODUCTION FACILITIES

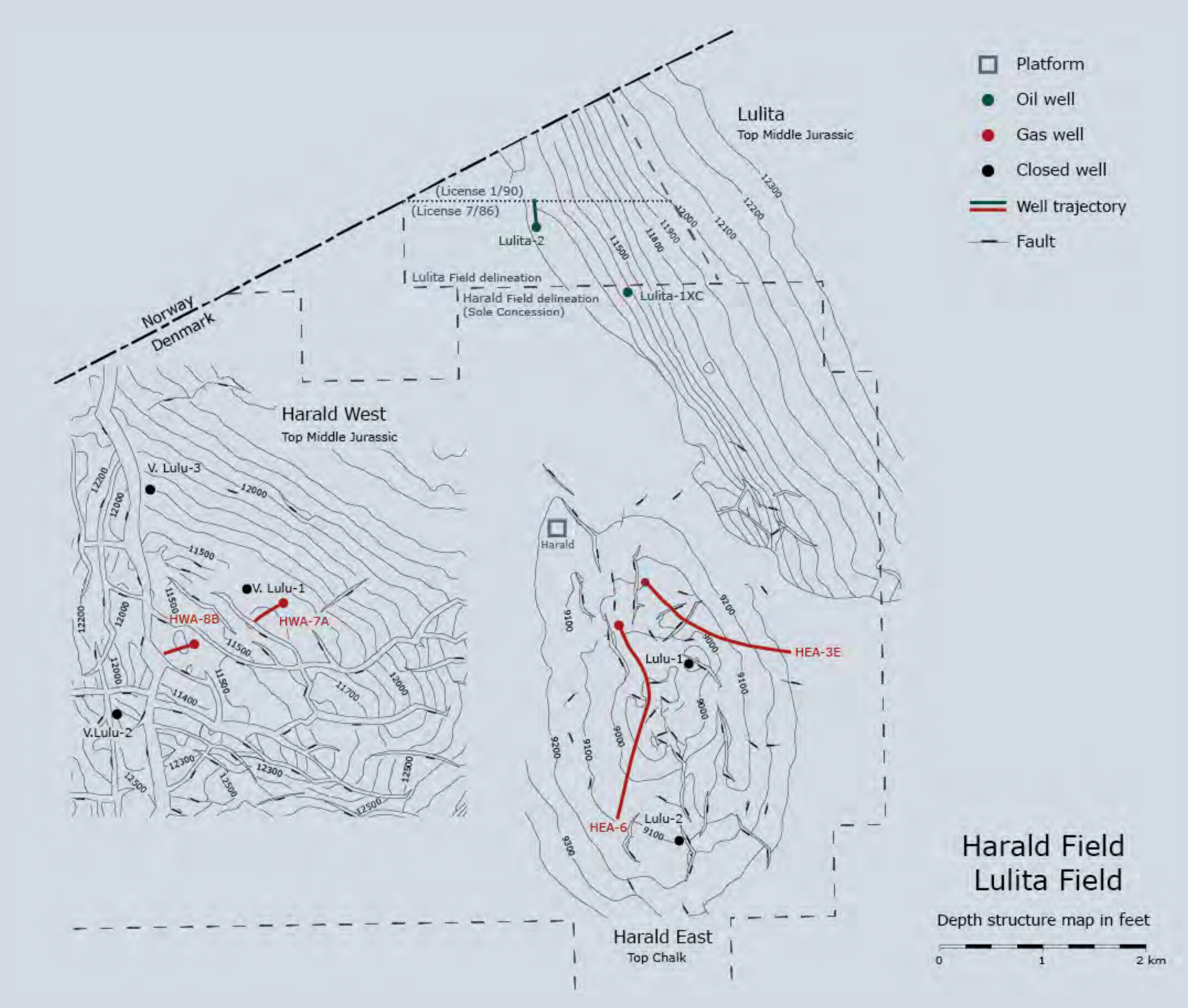
Kraka is a satellite development to the Dan Field with one unmanned wellhead platform without a helideck. The production is transported to the Dan F installation for processing and then exported ashore. Lift gas is imported from the Dan F installation.

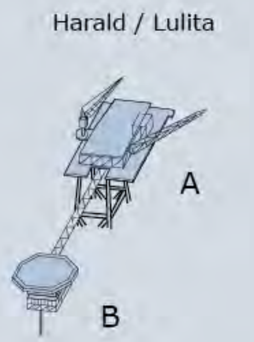
FIELD DEVELOPMENT

No major field development activities in 2013.

THE LULITA FIELD

Location: Block 5604/22
Licence: Sole Concession (50 pct.), 7/86 (34,5 pct) and 1/90 (15,5 pct)
Operator: Mærsk Olie og Gas A/S
Discovered 1992
Year on stream: 1998

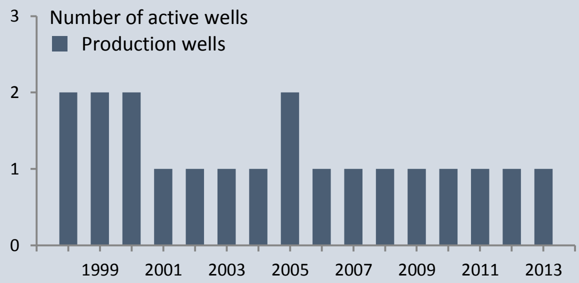




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2014

2013-prices DKK 0.11 billion



FIELD DATA At 1 January 2014

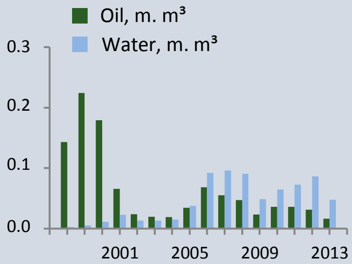
Production wells: 2

Water depth: 65 m
Field delineation: 4 km^2
Reservoir depth: 3,525 m
Reservoir rock: Sandstone
Geological age: Middle Jurassic

PRODUCTION

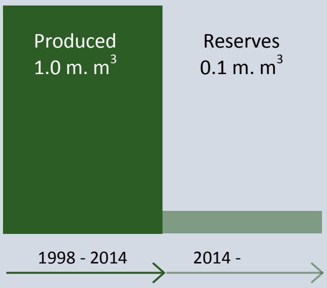
Cum. production at 1 January 2014

Oil:	1.02	m. m³
Gas:	0.65	bn. Nm³
Water:	0.72	m. m³



RESERVES

Oil:	0.1	m. m³
Gas:	0.1	bn. Nm³



REVIEW OF GEOLOGY, THE LULITA FIELD

The Lulita Field is a structural fault trap with a Middle Jurassic sandstone reservoir. The accumulation consists of oil with a gas cap.

PRODUCTION STRATEGY

The production of oil and gas is based on natural depletion.

PRODUCTION FACILITIES

Production from the Lulita Field takes place from the fixed installations in the Harald Field. Thus, the Lulita facilities are hosted by the Harald A platform, and the Harald platform processing equipment also handles production from the Lulita Field.

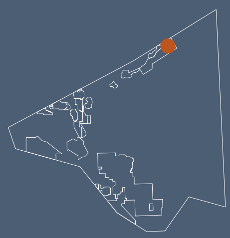
Together with condensate from the Harald Field, the oil produced is transported through a 16” pipeline to Tyra East for export ashore. The gas produced in the Lulita Field is transported to Tyra through the 24” pipeline connecting Harald with Tyra East, from where it is transported to shore. The water produced at the Lulita Field is processed at the Harald Field facilities and subsequently discharged into the sea.

The Harald A platform has special equipment for separate metering of the oil and gas produced from the Lulita Field.

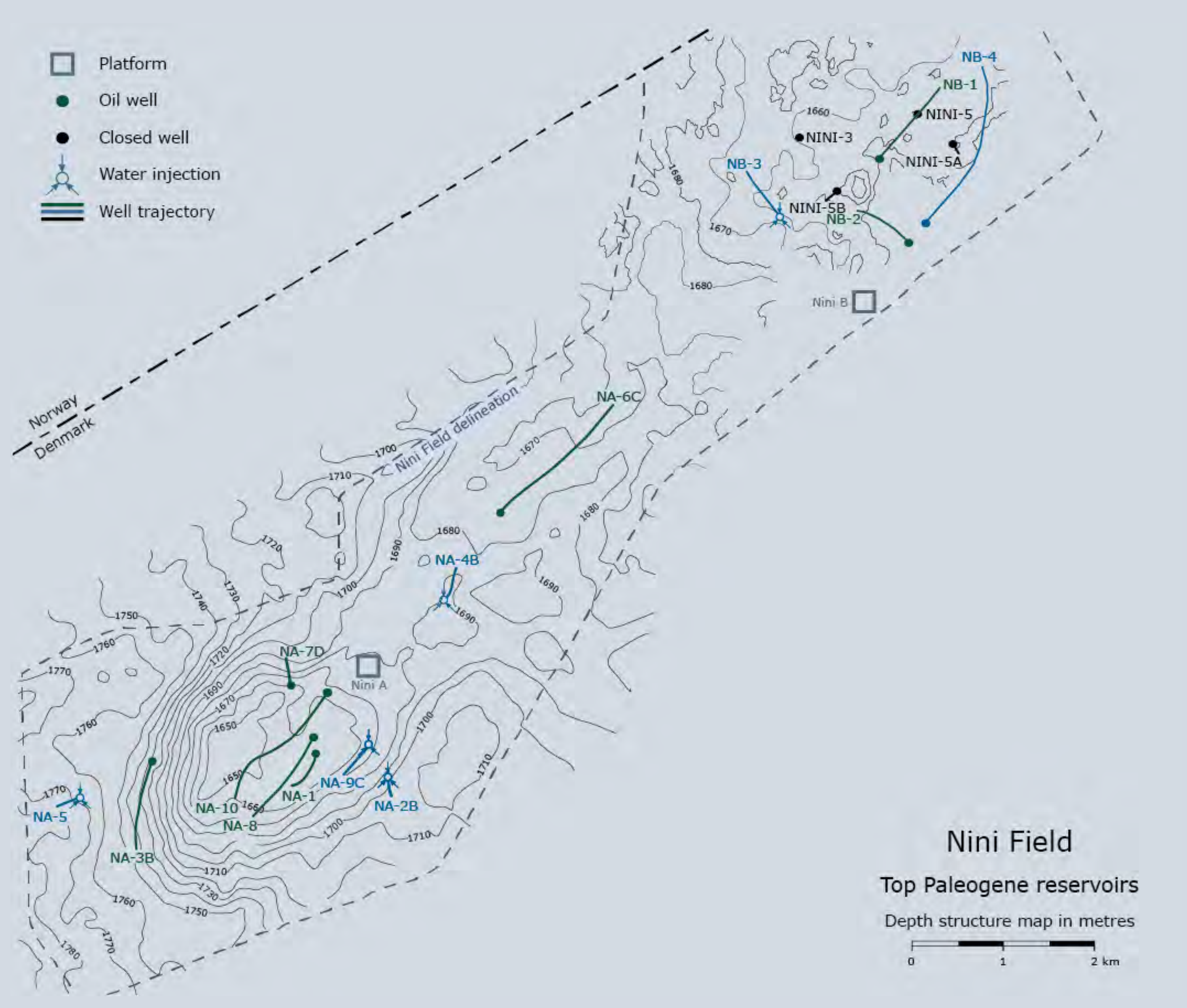
FIELD DEVELOPMENT

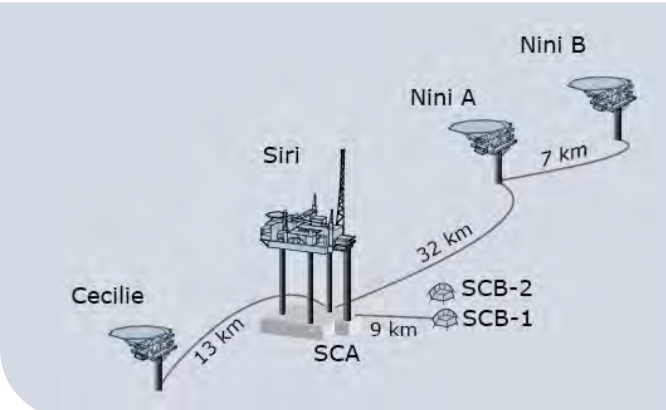
No major field development activities in 2013.

THE NINI FIELD



Location:	Block 5605/10 and 14
Licence:	4/95
Operator:	DONG E&P A/S
Discovered	2000
Year on stream:	2003

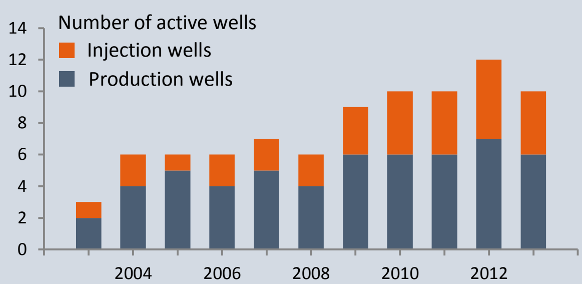




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2014

2013-prices DKK 5.26 billion



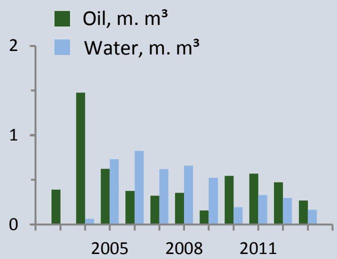
FIELD DATA
At 1 January 2014

Production wells:	8
Water inj. wells:	6
Water depth:	60 m
Field delineation:	45 km^2
Reservoir depth:	1,700 m
Reservoir rock:	Sandstone
Geological age:	Eocene/Paleocene

PRODUCTION

Cum. production at 1 January 2014

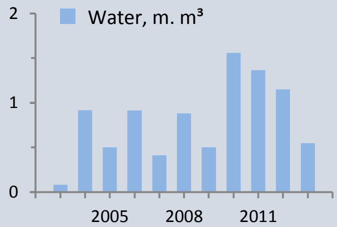
Oil:	5.56	m. m^3
Gas:	0.47	bn. Nm^3
Water:	4.40	m. m^3



INJEKTION

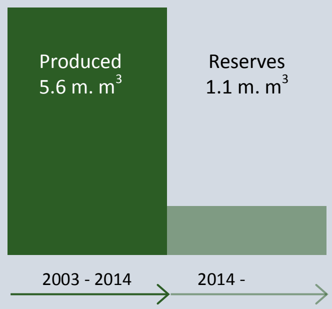
Cum. injection at 1 January 2014

Water:	8.83	m. m^3



RESERVES

Oil:	1.1	m. m^3
Gas:	0	bn. Nm^3



REVIEW OF GEOLOGY, THE NINI FIELD

The Nini accumulation is defined by a combined structural and stratigraphic trap, the anticlinal structure being induced through salt tectonics. The reservoir consists of sands deposited in the Siri Fairway. The field comprises more or less well-defined accumulations.

PRODUCTION STRATEGY

The production strategy is to maintain reservoir pressure by means of water injection. The gas produced is injected into the Siri Field.

PRODUCTION FACILITIES

Nini (NA) and Nini East (NB) are satellite developments to the Siri Field with two unmanned wellhead platforms, both with a helideck. The Nini East platform was installed in 2009, and production from the platform started in 2010.

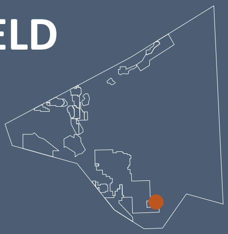
The unprocessed production from Nini East is sent through an 8” multiphase pipeline to Nini. From here, total production from Nini East and Nini is transported through a 14” multiphase pipeline to the Siri platform. The production is processed on the Siri platform and exported to shore via tanker. Siri supplies Nini and Nini East with injection water and lift gas via the Nini platform. Injection water is supplied through a 10” pipeline and lift gas through a 4” pipeline.

The old 10” water-injection pipeline from Siri (SCA) to Nini (NA) was replaced by a new one in 2009, at the same time being extended by a further pipeline to Nini East (NB).

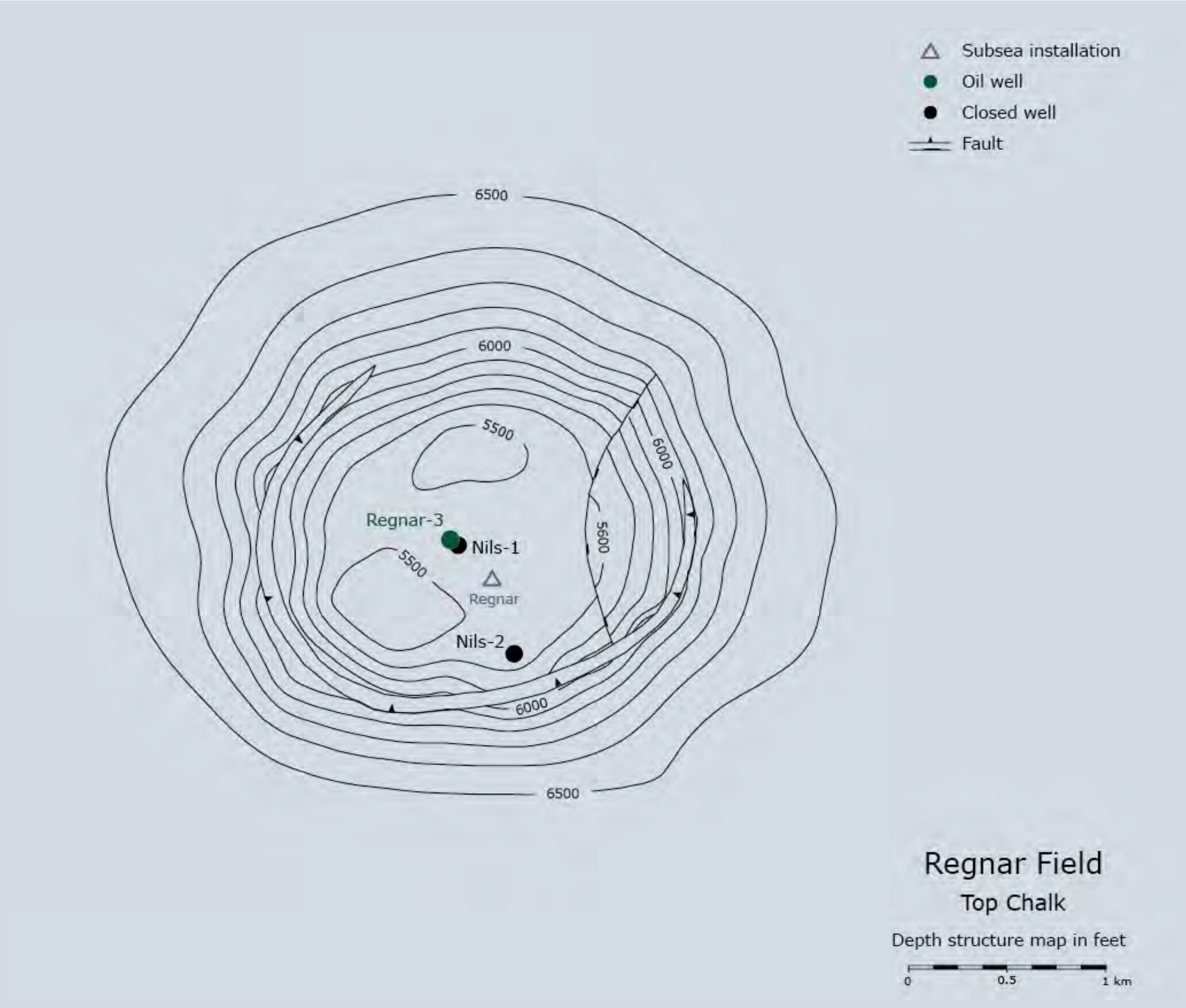
FIELD DEVELOPMENT

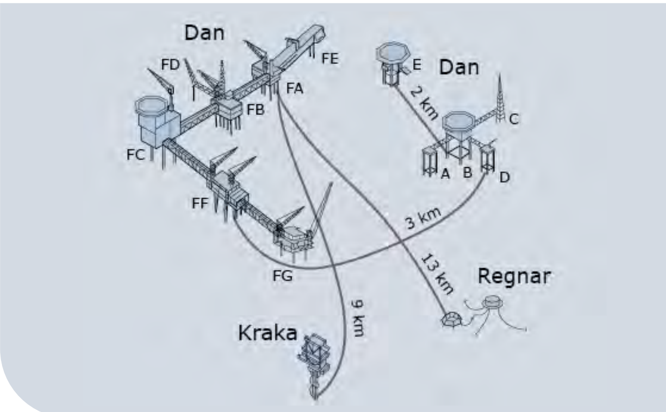
No major field development activities in 2013.

THE REGNAR FIELD



Prospect:	**Nils**
Location:	**Block 5505/17**
Licence:	**Sole Concession**
Operator:	**Mærsk Olie og Gas A/S**
Discovered	**1979**
Year on stream:	**1993**

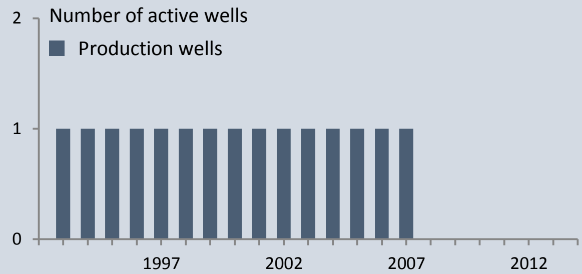




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2014

2013-prices DKK 0.29 billion



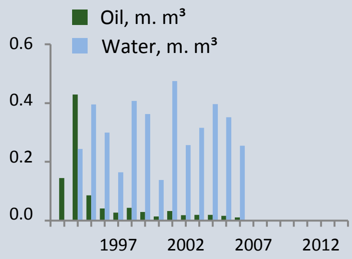
FIELD DATA
At 1 January 2014

Production wells:	1
Water depth:	45 m
Field delineation:	34 km^2
Reservoir depth:	1,700 m
Reservoir rock:	Chalk
Geological age:	Upper Cretaceous

PRODUCTION

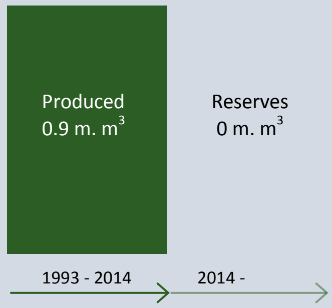
Cum. production at 1 January 2014

Oil:	0.93	m. m^3
Gas:	0.06	bn. Nm^3
Water:	4.06	m. m^3



RESERVES

Oil:	0	m. m^3
Gas:	0	bn. Nm^3



REVIEW OF GEOLOGY, THE REGNAR FIELD

The Regnar Field is an anticlinal structure induced through salt tectonics. The reservoir is heavily fractured.

PRODUCTION STRATEGY

Production in the Regnar Field takes place from one vertical well on the crest of the structure. The oil is displaced towards the producing well by water flowing in from the underlying aquifer. The production strategy is to displace and produce as much of the oil as possible from the matrix of the formation.

The Regnar Field has been shut down in recent years due to problems with the equipment.

PRODUCTION FACILITIES

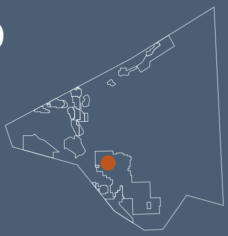
The Regnar Field has been developed as a satellite to the Dan Field and production takes place in a subsea-completed well. The production is transported by a multiphase pipeline to the Dan F installation for processing and export ashore.

The well is remotely monitored and controlled from the Dan F installation.

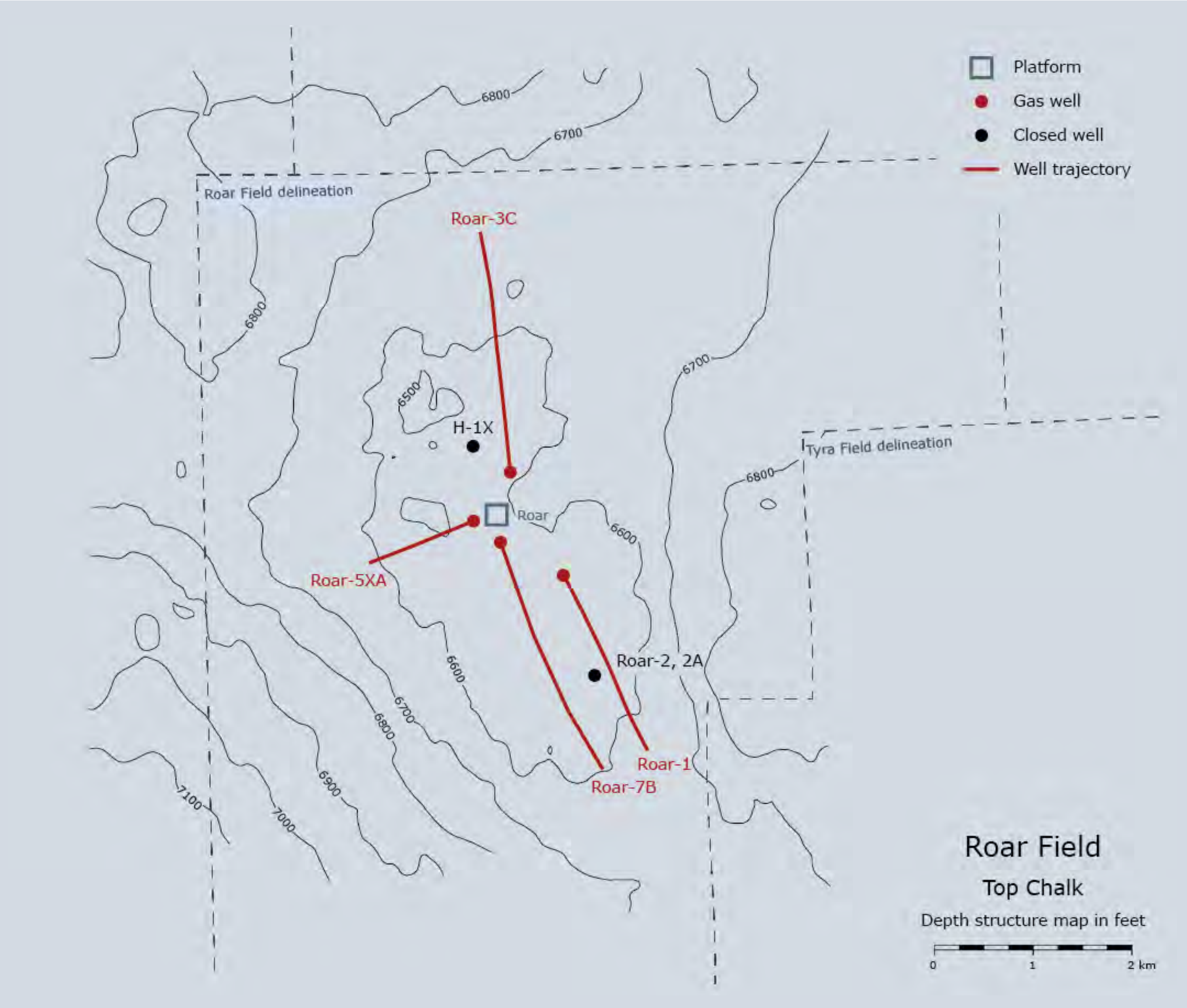
FIELD DEVELOPMENT

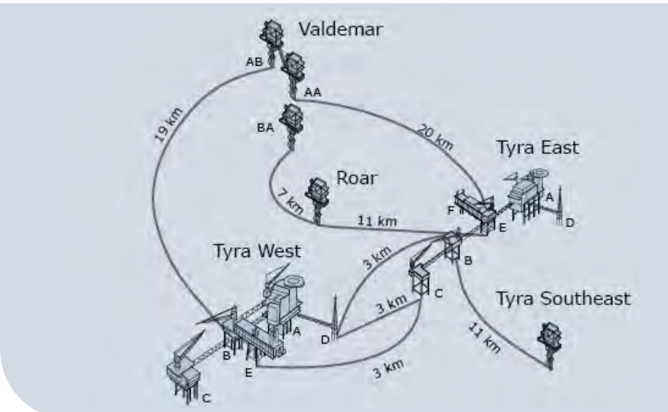
No major field development activities in 2013.

THE ROAR FIELD



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

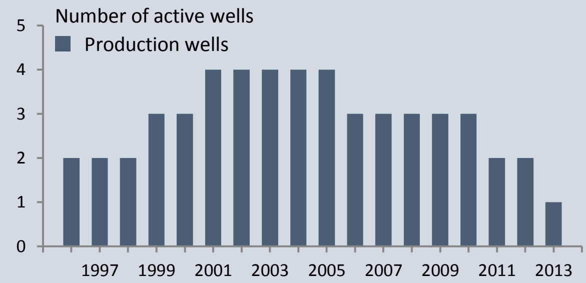




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2014

2013-prices DKK 0.74 billion



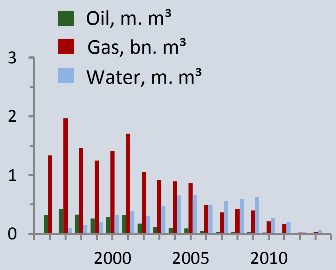
FIELD DATA — At 1 January 2014

Gas prod. wells:	4
Water depth:	46 m
Field delineation:	84 km^2
Reservoir depth:	2,025
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

PRODUCTION

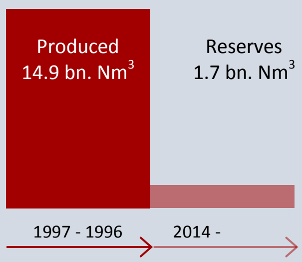
Cum. production at 1 January 2014

Oil:	2.61	m. m^3
Gas:	14.94	bn. Nm^3
Water:	6.09	m. m^3



RESERVES

Oil:	0.1	m. m^3
Gas:	1.7	bn. Nm^3



REVIEW OF GEOLOGY, THE ROAR FIELD

The Roar Field is an anticlinal structure created by tectonic uplift. The accumulation consists of gas containing condensate. The reservoir is only slightly fractured.

PRODUCTION STRATEGY

Recovery from the Roar Field takes place by gas expansion. The production strategy for the Roar Field is to optimize the production of liquid hydrocarbons in the Tyra Field by maximizing production from the other gas fields and thus minimizing gas drainage from Tyra.

PRODUCTION FACILITIES

The Roar Field has been developed as a satellite to the Tyra Field with an unmanned wellhead platform of the STAR type, without a helideck. The production is separated into gas and liquids before being transported to Tyra East in two pipelines for further processing and subsequent export ashore. A pipeline from Tyra East supplies chemicals to the Roar platform.

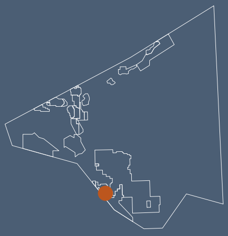
A 16” multiphase pipeline has been established from the Valdemar BA platform to Tyra East via the Roar Field, which transports the gas from Roar to Tyra East.

FIELD DEVELOPMENT

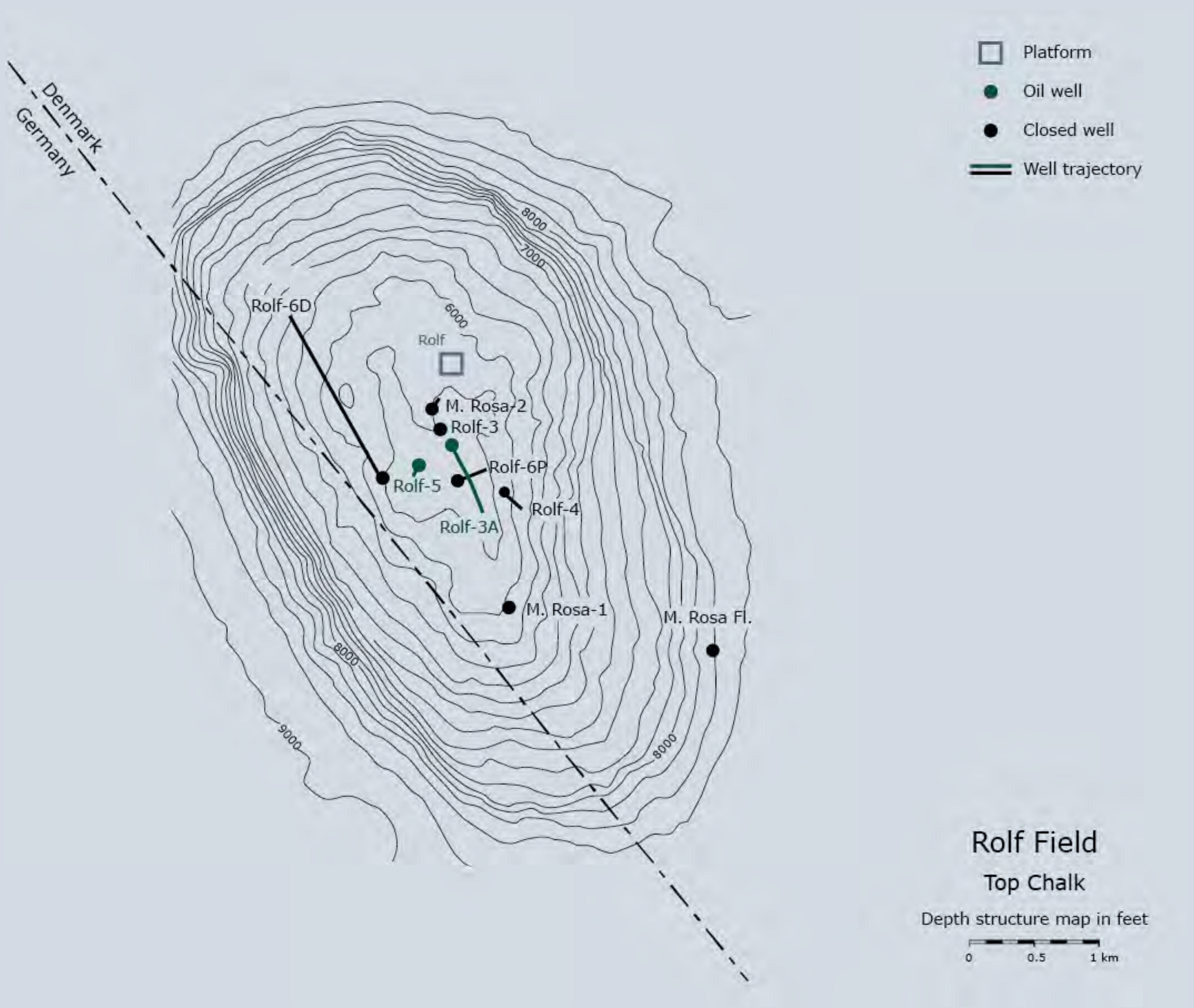
On 8 November 2013 the DEA approved a further development plan for the Roar Field, providing for the drilling of up to three new wells. The wells are to be drilled from the existing three wellhead modules available on the Roar platform. The drilling costs are estimated at DKK 300 million per well.

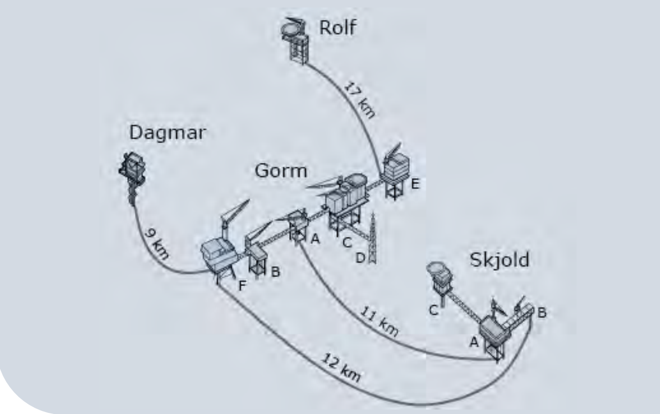
Initially, the plan is to drill the first well in the summer of 2015. During the life of the well, production is estimated to total about 0.3 billion Nm^3 of gas.

THE ROLF FIELD



Prospect:	**Midt Rosa**
Location:	**Block 5504/14 and 15**
Licence:	**Sole Concession**
Operator:	**Mærsk Olie og Gas A/S**
Discovered	**1981**
Year on stream:	**1986**

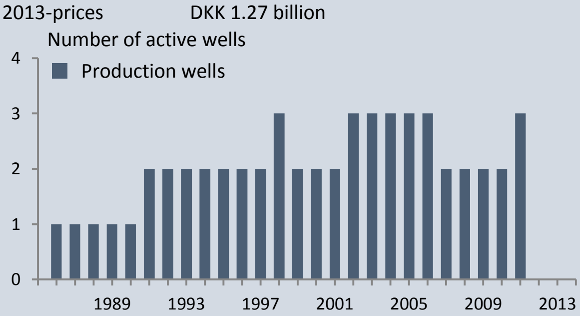




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2014

2013-prices DKK 1.27 billion



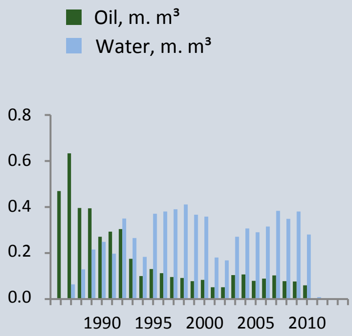
FIELD DATA At 1 January 2014

Production wells:	3
Water depth:	34 m
Field delineation:	22 km^2
Reservoir depth:	1,800 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

PRODUCTION

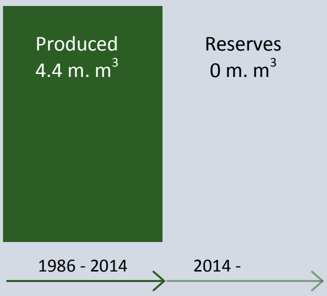
Cum. production at 1 January 2014

Oil:	4.43	m. m³
Gas:	0.19	bn. Nm³
Water:	6.86	m. m³



RESERVES

Oil:	0	m. m³
Gas:	0	bn. Nm³



REVIEW OF GEOLOGY, THE ROLF FIELD

The Rolf Field is an anticlinal structure induced through salt tectonics. The reservoir is heavily fractured.

PRODUCTION STRATEGY

Production from the Rolf Field takes place from two wells drilled in the crest of the structure. The oil is displaced towards the producing wells by the water flow from an underlying aquifer. The natural influx of water from the water zone corresponds to the volume removed due to production in the central part of the structure.

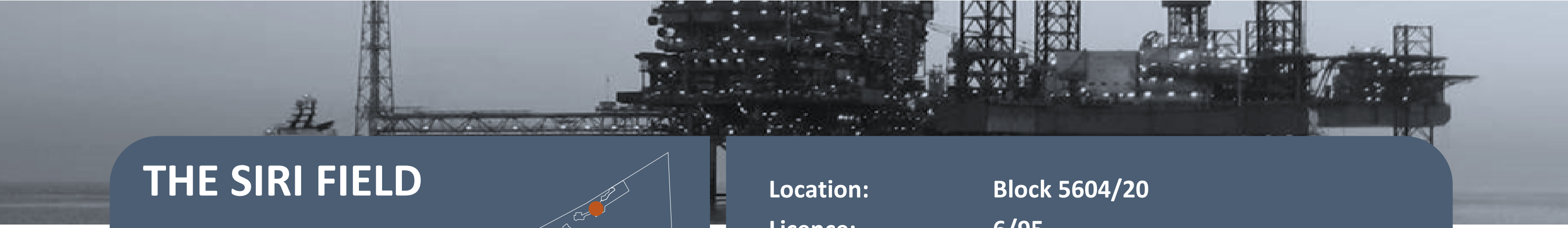
Production from the Rolf Field has been suspended since March 2011 due to a leak in the pipeline from the Rolf Field to the Gorm Field. Efforts are being made to reach a solution.

PRODUCTION FACILITIES

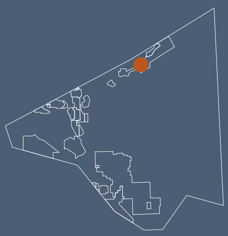
The Rolf Field is a satellite development to the Gorm Field with one unmanned wellhead platform with a helideck. The production is transported to the Gorm C platform for processing. Rolf is also supplied with lift gas from the Gorm Field. The power supply cable from Gorm to Rolf is not used because it has been damaged for a prolonged period of time. Instead diesel generators are used to supply power for the Rolf Field.

FIELD DEVELOPMENT

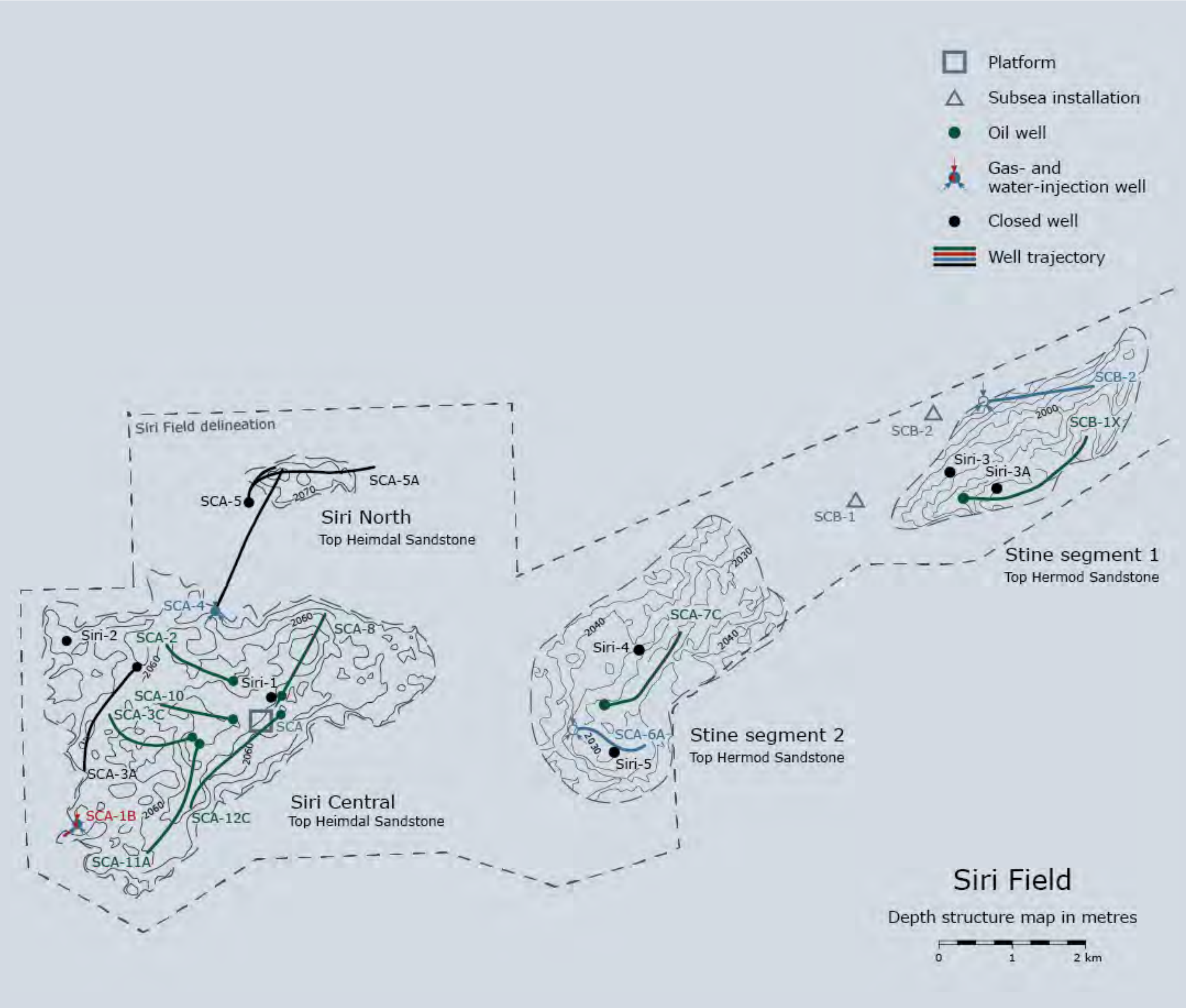
No major field development activities in 2013.

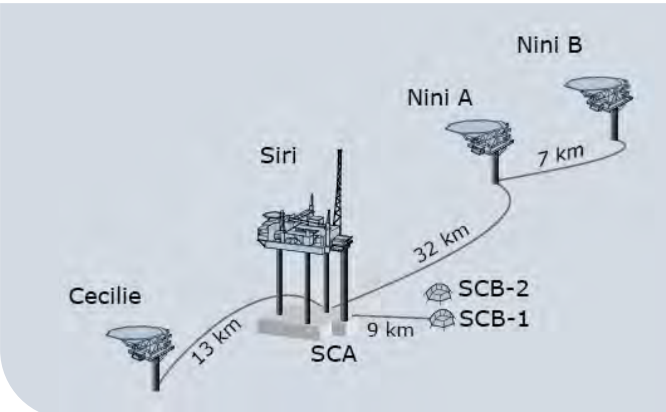


THE SIRI FIELD



Location:	Block 5604/20
Licence:	6/95
Operator:	DONG E&P A/S
Discovered	1995
Year on stream:	1999

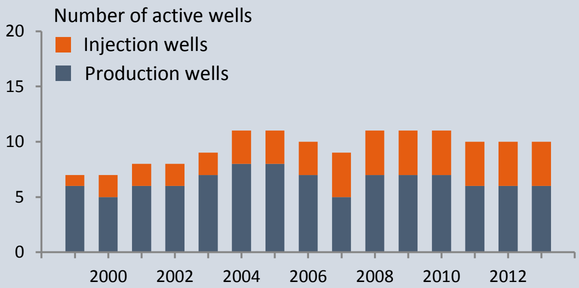




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2014

2013-prices DKK 7.39 billion



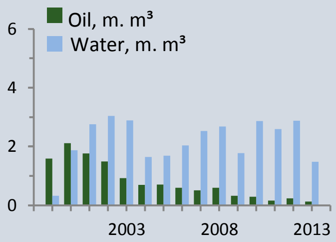
FIELD DATA — At 1 January 2014

Production wells:	6 (Siri central) 1 (Stine segment 1) 1 (Stine segment 1)
Water/gas Injection wells:	2 (Siri central) 1 (Stine segment 1) 1 (Stine segment 1)
Water depth:	60 m
Field delineation:	63 km^2
Reservoir depth:	2,060 m
Reservoir rock:	Sandstone
Geological age:	Paleocene

PRODUCTION

Cum. production at 1 January 2014

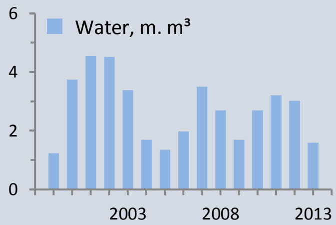
Oil:	12.12	m. m³
Gas:	1.36	bn. Nm³
Water:	33.04	m. m³



INJEKTION

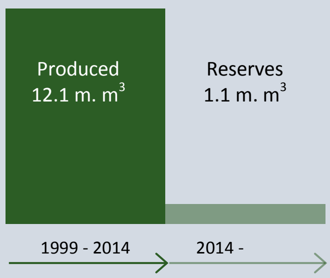
Cum. injection at 1 January 2014

Gas:	1.28	bn. Nm³
Water:	40.81	m. m³



RESERVES

Oil:	1.1	m. m³
Gas:	0	bn. Nm³



REVIEW OF GEOLOGY, THE SIRI FIELD

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

PRODUCTION STRATEGY

Recovery takes place from Siri Central as well as from the neighbouring Stine segments 1 and 2. The strategy for producing oil from Siri Central is to maintain reservoir pressure by means of the co-injection of water and gas. In addition, gas from the Cecilie and Nini Fields is injected into the Siri Field.

The recovery from Stine segment 1 is based on water injection to maintain reservoir pressure. Before 2006, when water injection was initiated, recovery from Stine segment 2 was based on natural depletion.

PRODUCTION FACILITIES

Siri and Stine segment 2 (SCA) comprise a combined wellhead, processing and accommodation platform.

The processing facilities consist of a plant that separates the hydrocarbons produced and a plant for processing the water produced. The platform also houses equipment for co-injecting gas and water.

Stine segment 1 (SCB) has been developed as a satellite to the Siri platform and consists of two subsea installations with a production well and an injection well.

Production from SCB is conveyed to the SCA platform for processing. The SCA platform also supplies injection water and lift gas to the satellite installations at SCB, Nini, Nini East and Cecilie. The water-injection pipeline to Nini was replaced in 2009 and extended by a further pipeline to Nini East. Injection water is supplied to SCB via a branch of this pipeline.

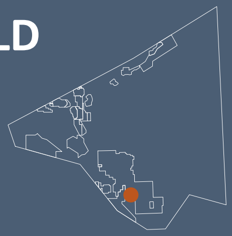
The oil produced is piped to a 50,000 m^3 storage tank on the seabed, and subsequently transferred to a tanker by means of buoy-loading facilities.

The Siri Field has accommodation facilities for 60 persons.

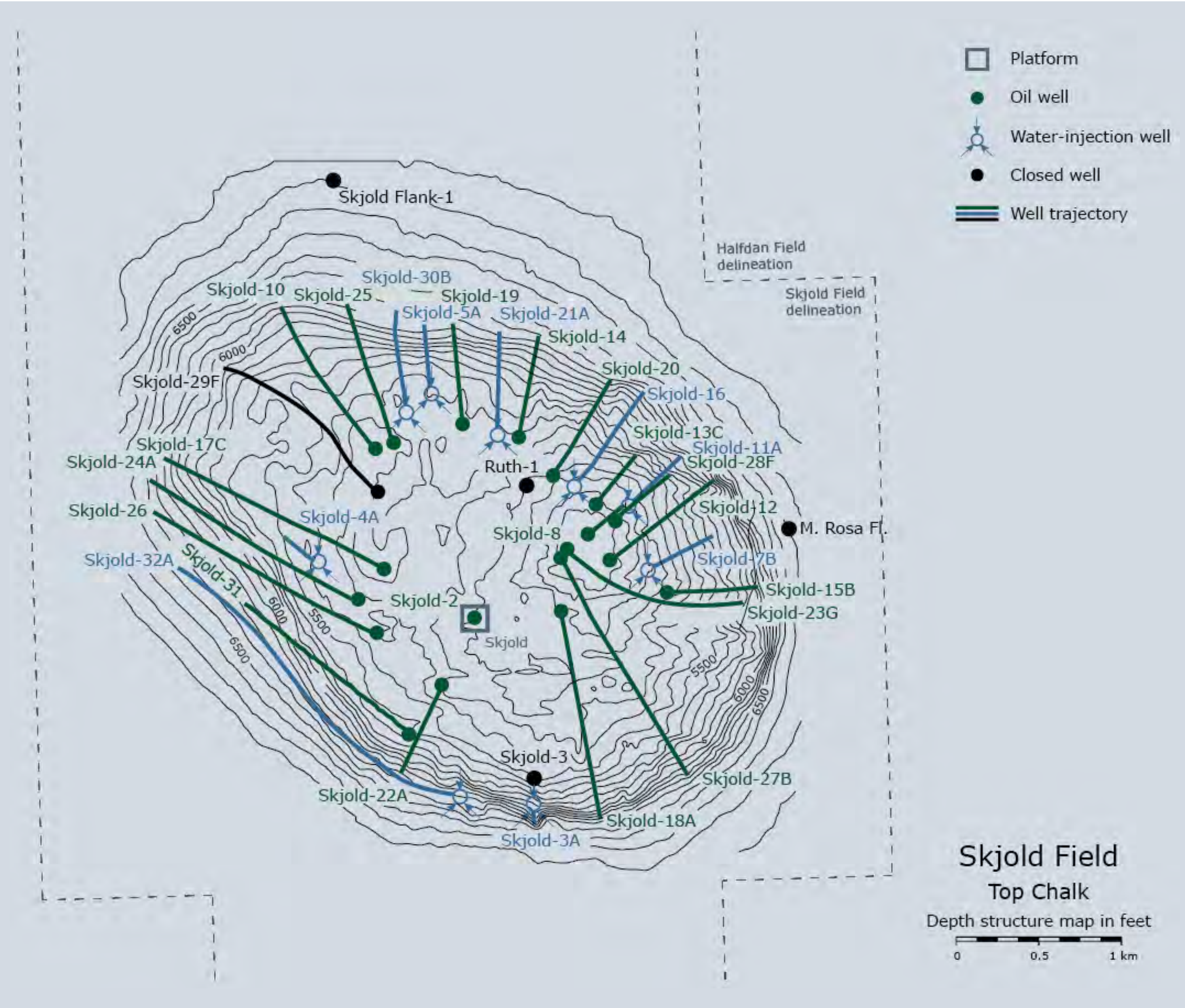
FIELD DEVELOPMENT

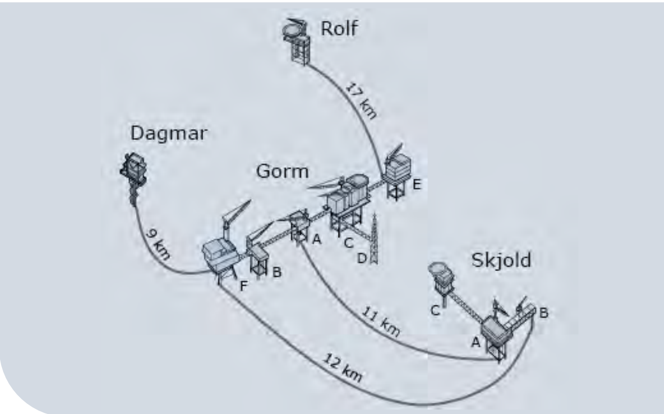
Efforts are still being made to reinforce the subsea structure. Until a stable solution has been established, the installation will be shut down for safety reasons during the periods when the expected wave height exceeds six metres.

THE SKJOLD FIELD



Prospect:	**Ruth**
Location:	**Block 5504/16**
Licence:	**Sole Concession**
Operator:	**Mærsk Olie og Gas A/S**
Discovered	**1977**
Year on stream:	**1982**

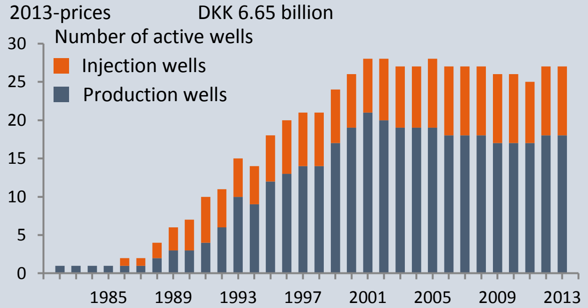




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2014

2013-prices	DKK 6.65 billion



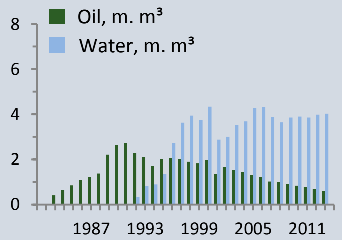
FIELD DATA At 1 January 2014

Production wells:	19
Injection wells:	9
Water depth:	40 m
Field delineation:	33 km^2
Reservoir depth:	1,600 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

PRODUCTION

Cum. production at 1 January 2014

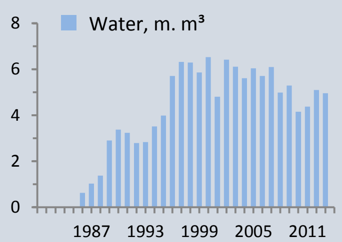
Oil:	45.38	m. m³
Gas:	3.75	bn. Nm³
Water:	70.65	m. m³



INJEKTION

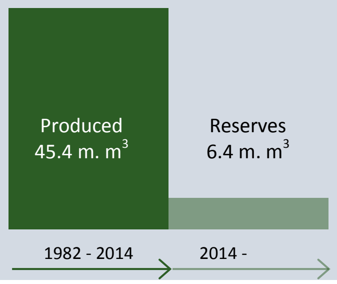
Cum. injection at 1 January 2014

Water:	126.04	m. m³



RESERVES

Oil:	6.4	m. m³
Gas:	0.4	bn. Nm³



REVIEW OF GEOLOGY, THE SKJOLD FIELD

The Skjold Field is an anticlinal structure induced through salt tectonics. The reservoir is intersected by numerous, minor faults in the central part of the structure. At the flanks of the structure, the reservoir is less fractured. Unusually favourable production properties have been shown to exist in the reservoir.

PRODUCTION STRATEGY

The strategy for producing oil from Skjold is to maintain reservoir pressure by means of water injection. Oil is mainly produced from horizontal wells at the flanks of the reservoir, where the production and injection wells are placed alternately in a radial pattern.

PRODUCTION FACILITIES

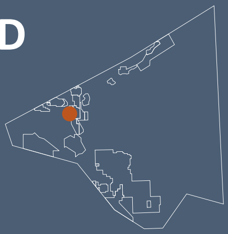
The Skjold Field comprises a satellite development to the Gorm Field, including two wellhead platforms, Skjold A and B, as well as an accommodation platform, Skjold C. There are no processing facilities at the Skjold Field, and the production is transported to the Gorm F platform for processing. The Gorm facilities provide the Skjold Field with injection water and lift gas. Produced water is reinjected.

The Skjold C platform has accommodation facilities for 16 persons.

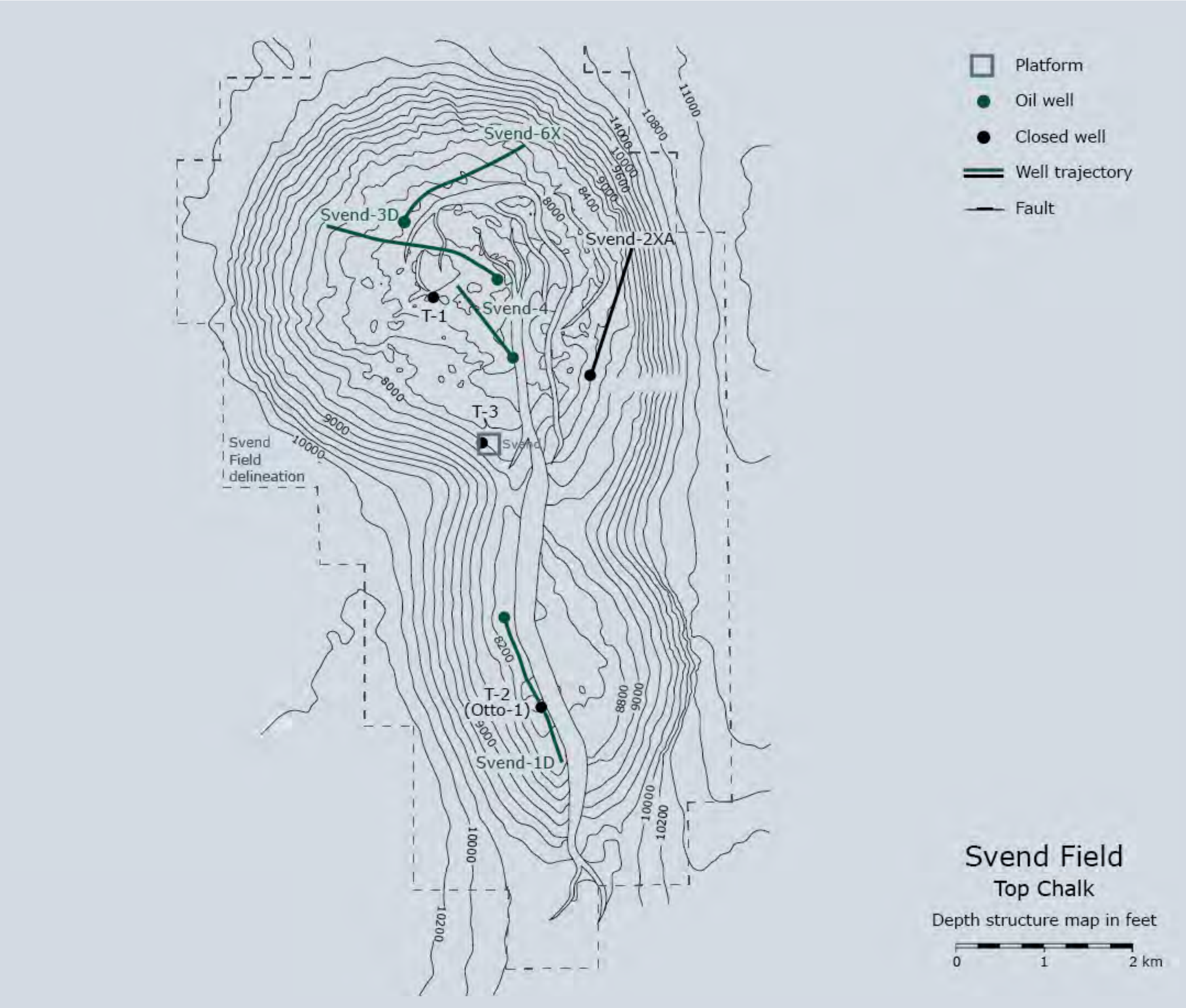
FIELD DEVELOPMENT

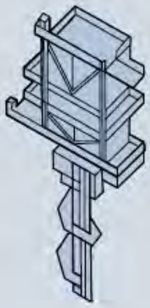
No major field development activities in 2013.

THE SVEND FIELD



Prospect:	**North Arne/Otto**
Location:	**Block 5604/25**
Licence:	**Sole Concession**
Operator:	**Mærsk Olie og Gas A/S**
Discovered	**1975 (North Arne) - 1982 (Otto)**
Year on stream:	**1996**

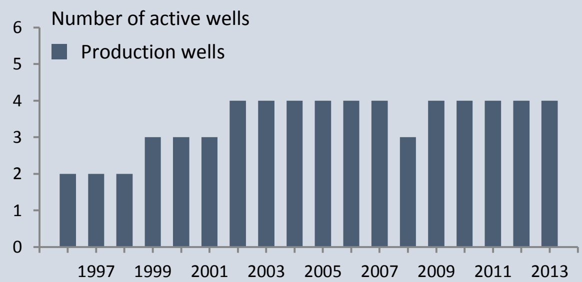




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2014

2013-prices DKK 1.37 billion



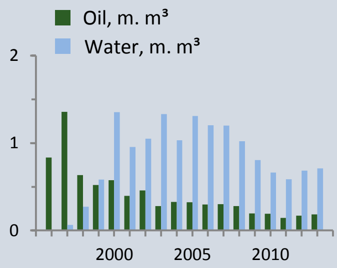
FIELD DATA At 1 January 2014

Production wells:	4
Water depth:	65 m
Field delineation:	48 km^2
Reservoir depth:	2,500 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

PRODUCTION

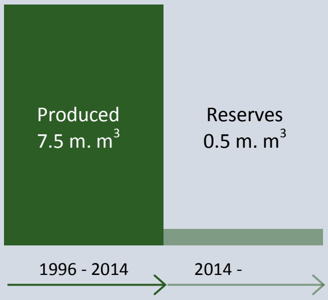
Cum. production at 1 January 2014

Oil:	7.46	m. m³
Gas:	0.88	bn. Nm³
Water:	14.83	m. m³



RESERVES

Oil:	0.5	m. m³
Gas:	0.1	bn. Nm³



REVIEW OF GEOLOGY, THE SVEND FIELD

The Svend Field is an anticlinal structure induced through salt tectonics. This led to fracturing of the chalk in the reservoir, with a major north-south fault dividing the field into a western and an eastern block. In addition, the southern reservoir of the Svend Field is situated about 250 m lower than the northern reservoir. The northern reservoir has proved to have unusually favourable production properties.

PRODUCTION STRATEGY

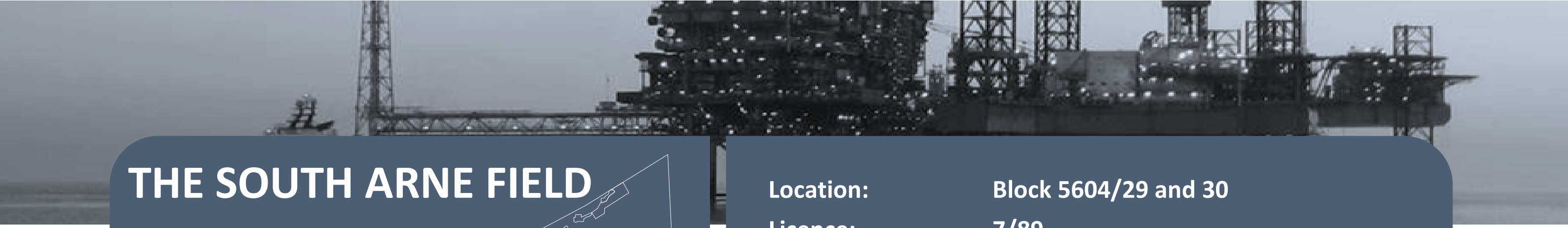
Production is based on primary recovery at a reservoir pressure above the bubble point of the oil, while ensuring maximum production uptime for the wells at the same time.

PRODUCTION FACILITIES

The Svend Field has been developed as a satellite to the Tyra Field with one unmanned wellhead platform of the STAR type, without a helideck. The hydrocarbons produced are piped to Tyra East for processing and export ashore. The Svend Field is connected to the 16" pipeline from Harald to Tyra East.

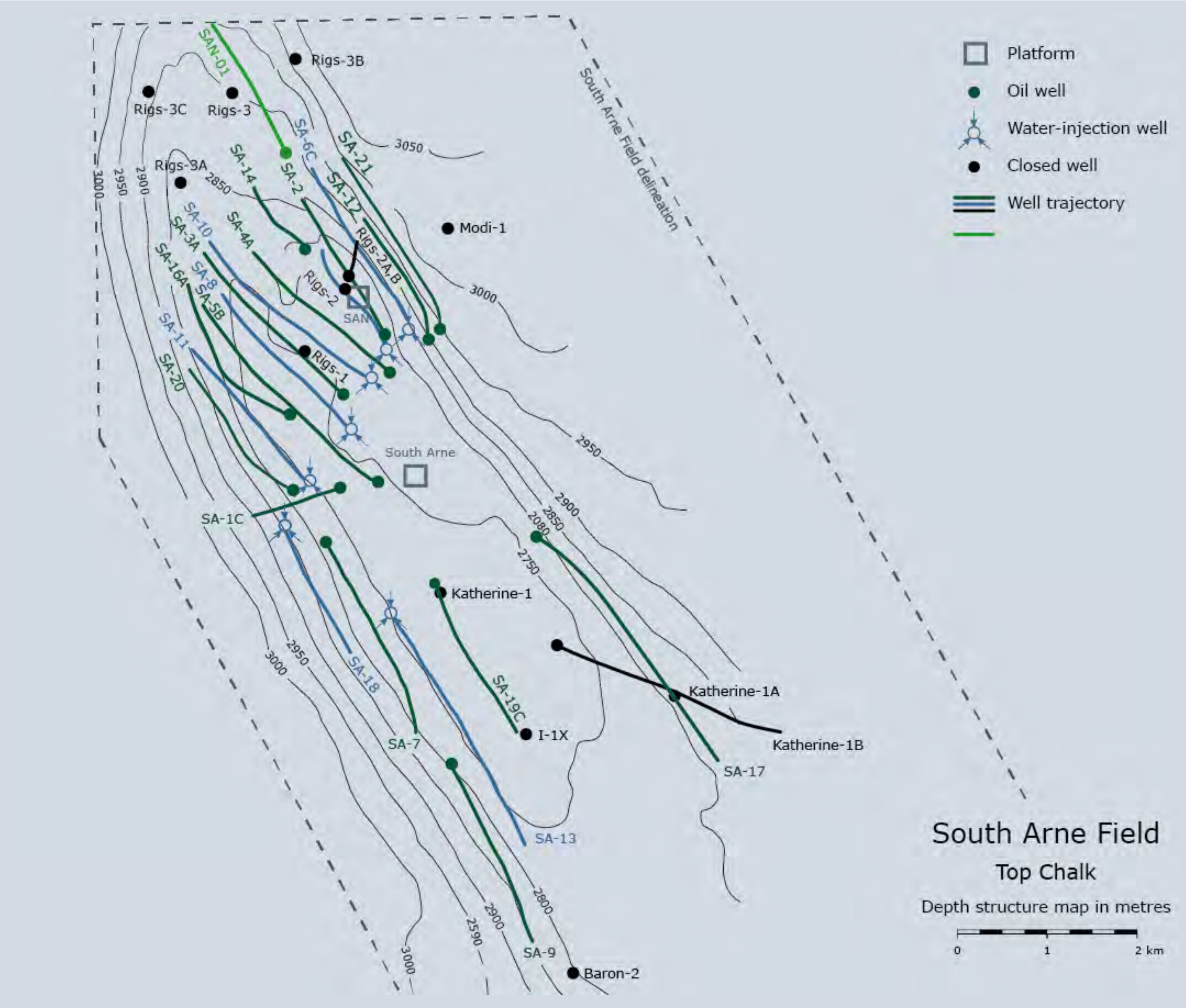
FIELD DEVELOPMENT

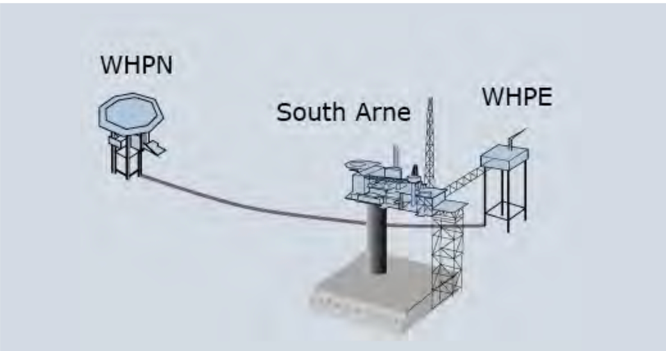
No major field development activities in 2013.



THE SOUTH ARNE FIELD

Location:	Block 5604/29 and 30
Licence:	7/89
Operator:	Hess Denmark A/S
Discovered	1969
Year on stream:	1999

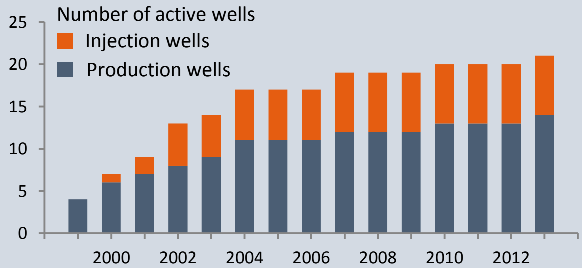




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2014

2013-prices DKK 17.45 billion



FIELD DATA At 1 January 2014

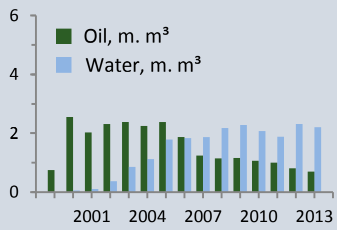
Production wells: 14
Waterinj. wells: 7

Water depth: 60 m
Field delineation: 93 km^2
Reservoir depth: 2,800 m
Reservoir rock: Chalk
Geological age: Danian and Upper Cretaceous

PRODUCTION

Cum. production at 1 January 2014

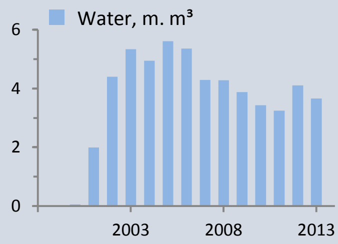
Oil:	23.66	m. m^3
Gas:	5.77	bn. Nm^3
Water:	20.95	m. m^3



INJEKTION

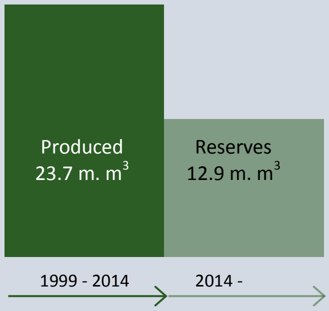
Cum. injection at 1 January 2014

Gas:	4.20	bn. Nm^3
Water:	54.58	m. m^3



RESERVES

Oil:	12.9	m. m^3
Gas:	2.6	bn. Nm^3



REVIEW OF GEOLOGY, THE SOUTH ARNE FIELD

South Arne is an anticlinal structure induced through tectonic uplift, which has caused the chalk to fracture. The structure contains oil with a relatively high content of gas.

PRODUCTION STRATEGY

The production of hydrocarbons is based on pressure support from water injection.

PRODUCTION FACILITIES

The South Arne complex consists of a combined wellhead, processing and accommodation platform, connected by a bridge to a wellhead platform, WHPE, and an unmanned satellite platform, WHPN.

The processing facilities consist of a plant that separates the hydrocarbons produced. The oil produced is conveyed to an 87,000 m^3 storage tank on the seabed and is exported ashore by tanker. The treated gas is exported by pipeline to Nybro. Some of the water produced is injected into the field, while the rest is processed and discharged into the sea. Processing facilities have been installed to treat the injection water before it is injected.

The two new wellhead platforms have been hooked up to the South Arne platform and its infrastructure. WHPN is an unmanned platform with a helideck and is placed about 2.5 km north of the existing South Arne platform. WHPE is placed about 80 m east of the existing South Arne platform and connected to it by a combined foot and pipe bridge.

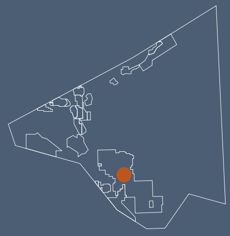
A bundle pipeline has been established between WHPN and WHPE. The bundle incorporates a production pipeline, lift gas and water-injection pipelines and power supply cables, etc.

South Arne has accommodation facilities for 75 persons.

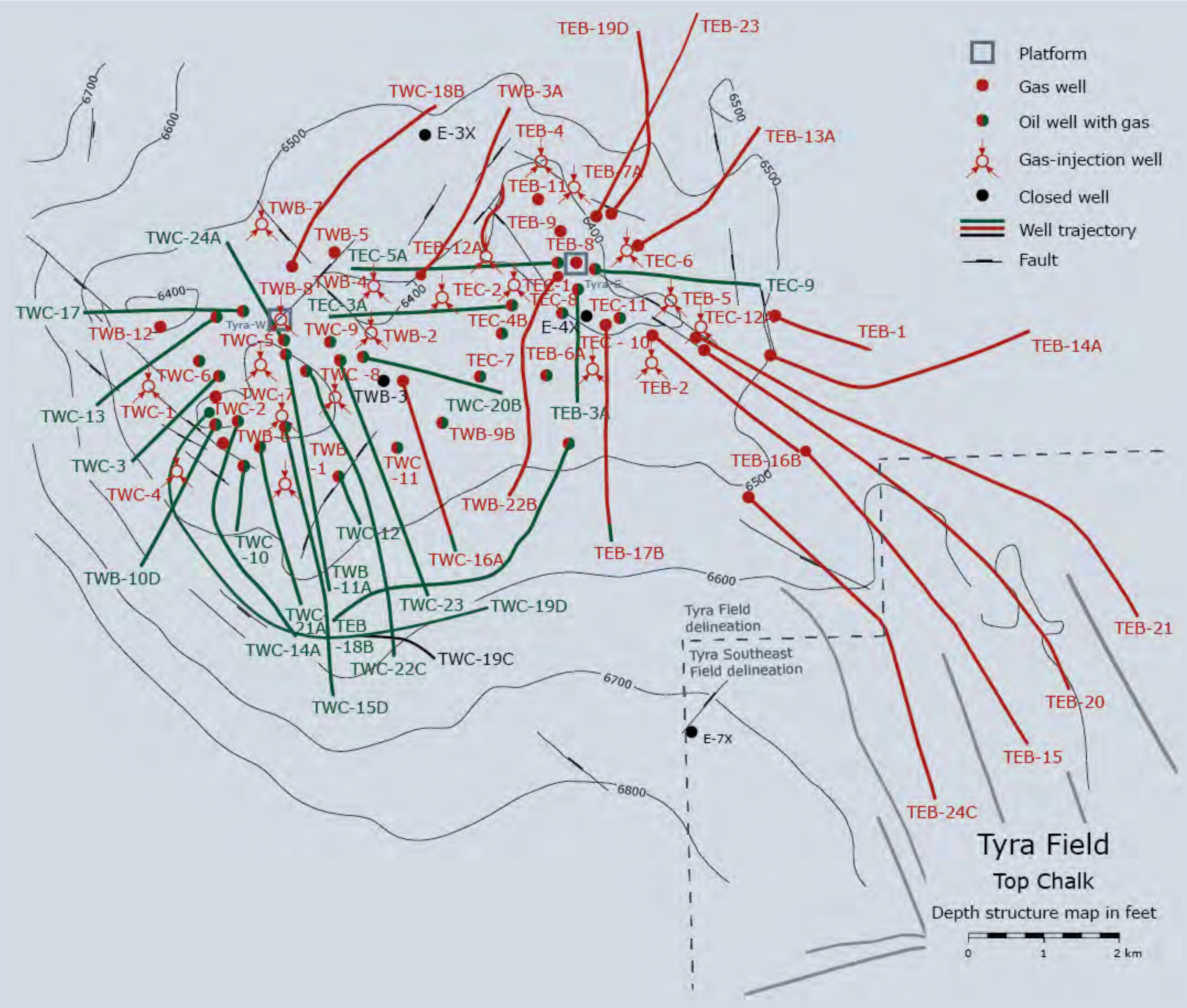
FIELD DEVELOPMENT

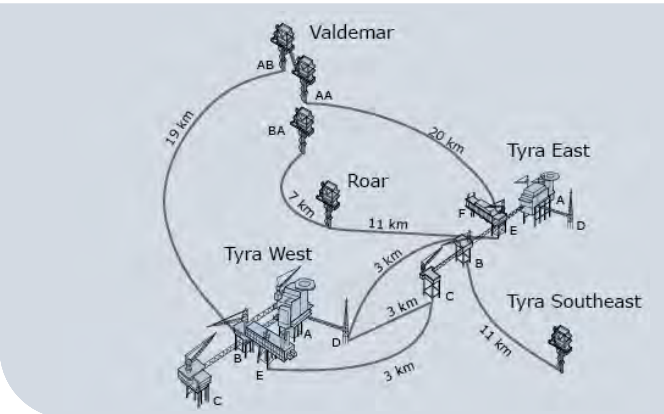
One new oil production well, SAN-1, was drilled in 2013 and the accommodation facilities were expanded by 18 single cabins in 2014.

THE TYRA FIELD



Prospect:	**Cora**
Location:	**5504/11 and 12**
Licence:	**Sole Concession**
Operator:	**Mærsk Olie og Gas A/S**
Discovered	**1968**
Year on stream:	**1984**

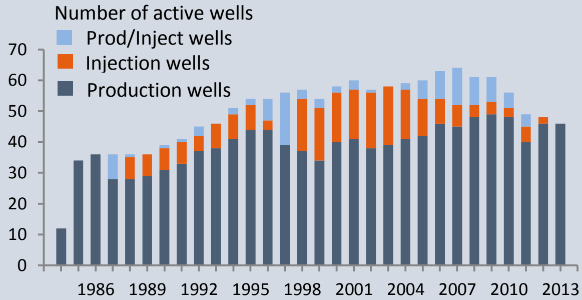




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2014

2013-prices DKK 37.80 billion



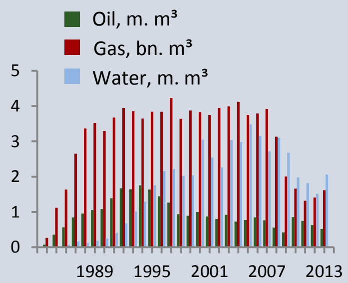
FIELD DATA — At 1 January 2014

Gas prod. wells:	22
Oil/gas prod. wells:	29
Prod / inj. wells:	18
Water depth:	37-40 m
Field delineation:	177 km^2
Reservoir depth:	2,000 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

PRODUCTION

Cum. production at 1 January 2014

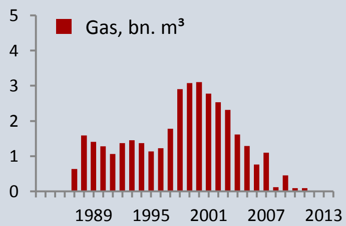
Oil:	27.93	m. m^3
Gas:	92.61	bn. Nm^3
Water:	50.69	m. m^3



INJEKTION

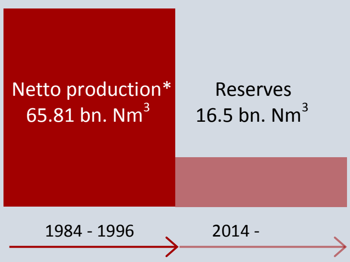
Cum. injection at 1 January 2014

Gas:	36.51	bn. Nm^3



RESERVES*

Oil:	7.7	m. m^3
Gas:	16.5	bn. Nm^3



* The chart shows the combined figures for Tyra and Tyra SE; netto production is historical production minus injection.

REVIEW OF GEOLOGY, THE TYRA FIELD

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

PRODUCTION STRATEGY

The Tyra Field acts as a buffer, which means that gas from other fields can be injected into the Tyra Field during periods of low gas consumption and thus low gas sales, for example in summer. When the demand for gas increases, the gas injected in the Tyra Field is produced again. The injected dry gas helps delay the decrease in gas cap pressure, thus optimizing the recovery of oil from the Tyra Field. Thus, using the Tyra Field as a buffer helps ensure that the condensate and oil production conditions do not deteriorate as a consequence of the reservoir pressure dropping at too early a stage. Thus, increased gas production from DUC's other fields, in particular the Harald and Roar gas fields, optimizes the recovery of liquid hydrocarbons from the Tyra Field.

PRODUCTION FACILITIES

The Tyra Field installations comprise two platform complexes, Tyra West (TW) and Tyra East (TE).

Tyra West consists of two wellhead platforms, TWB and TWC, one processing and accommodation platform with a helideck, TWA, and one gas flare stack, TWD, as well as a bridge module, TWE, for gas processing and compression placed at TWB.

The Tyra West processing facilities are used to pre-process oil and condensate production from the wells at Tyra West. Moreover, the Tyra West complex houses gas-processing facilities and facilities for the injection and/or export of gas as well as processing facilities for the water produced. All gas from the DUC platforms is finally processed at Tyra West to meet the sales gas specifications before being exported to NOGAT or the Nybro gas-processing facilities via Tyra East. The water produced is processed at Tyra West and subsequently discharged into the sea.

Tyra East consists of two wellhead platforms, TEB and TEC, one processing and accommodation platform with a helideck, TEA, one gas flare stack, TED, and one riser platform, TEE, as well as a bridge module, TEF, with receiving facilities.

Tyra East receives production from the satellite fields, Valdemar AA/AB and BA, Roar, Svend, Tyra Southeast and Harald/Lulita/Trym, as well as gas production from the Gorm, Dan and Halfdan Fields. The gas from the Dan and Halfdan Fields is primarily routed via TYW, but may also be routed via TYE. The Tyra East complex includes facilities for the processing of gas, oil, condensate and water. The water produced is processed at Tyra East and subsequently discharged into the sea.

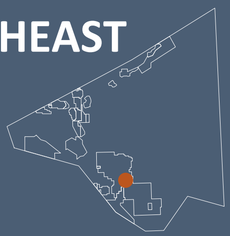
As part of the Tyra Field's infrastructure, the two platform complexes, Tyra West and Tyra East, are interconnected by pipelines. Individual pipelines help ensure flexibility in production, which is particularly the case for oil fields. Oil and condensate production from the Tyra Field and its satellite fields is transported ashore via Gorm E. The bulk of gas produced is transported ashore from TEE at Tyra East to the Nybro gas-processing facilities, and the rest is transported from the E platform at Tyra West to the NOGAT pipeline.

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

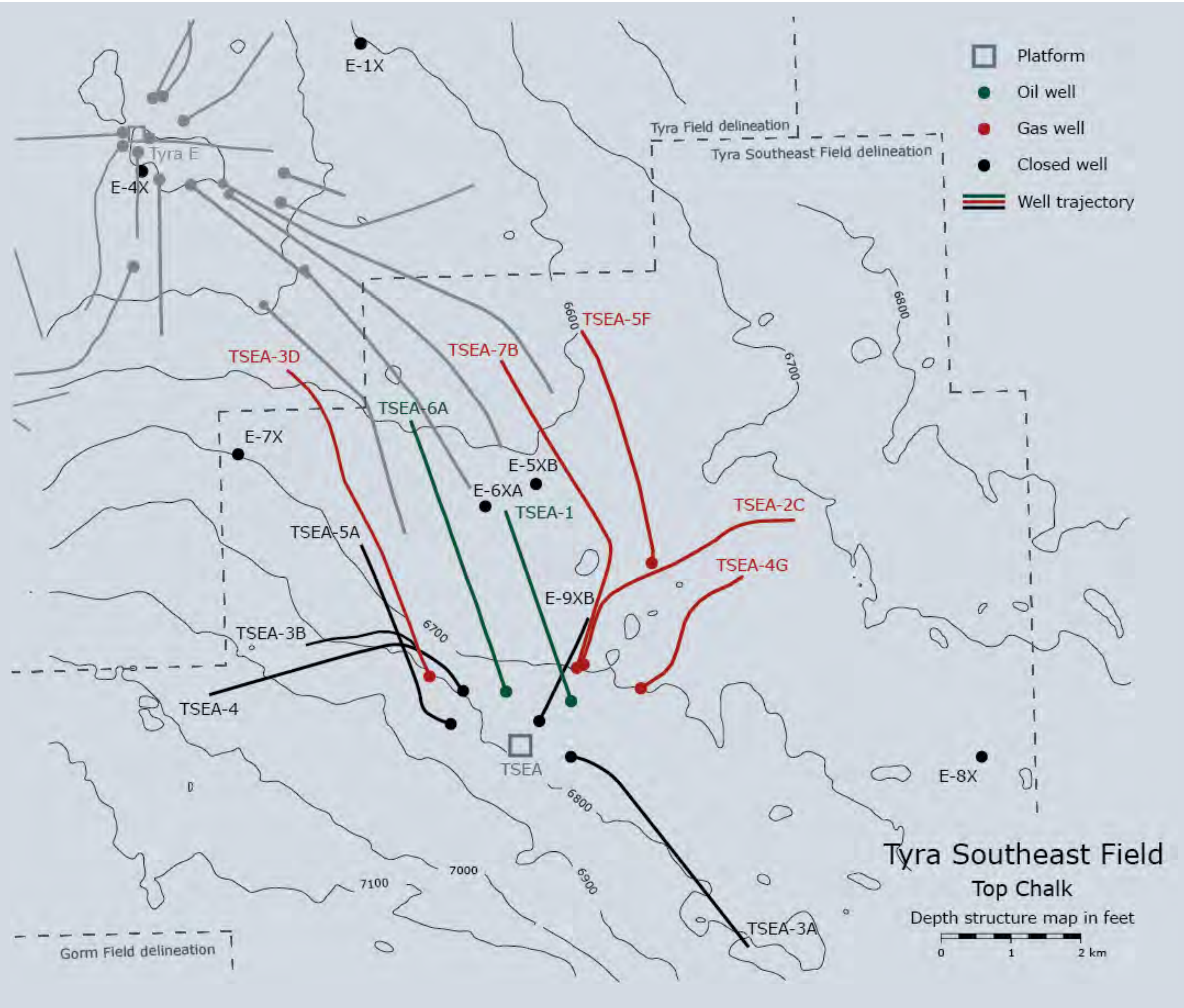
FIELD DEVELOPMENT

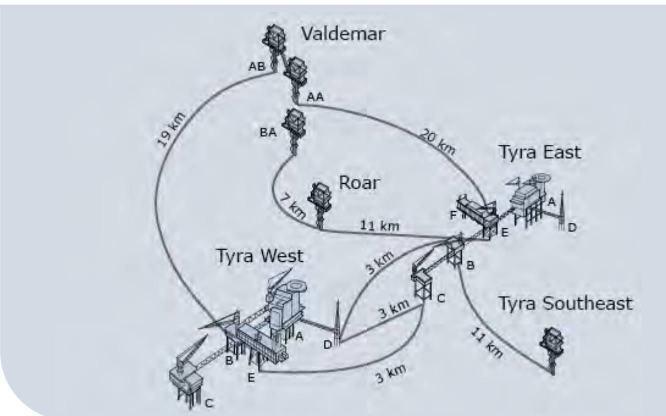
Work was carried out on a structural modification of the installation in 2013.

THE TYRA SOUTHEAST FIELD



Licence:	Sole Concession
Operator:	Mærsk Olie og Gas A/S
Discovered	1992
Year on stream:	2002

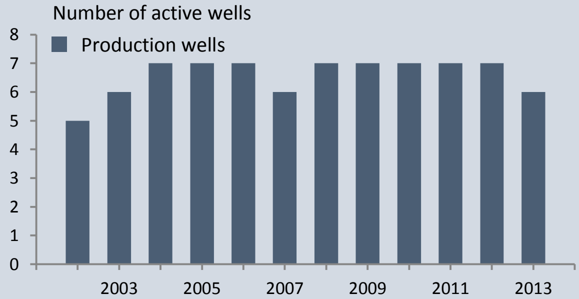




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2014

2013-prices	DKK 2.64 billion



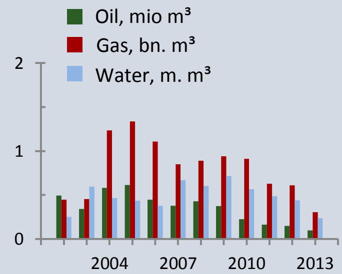
FIELD DATA At 1 January 2014

Oil prod. wells:	2
Gas prod. wells:	5
Water depth:	38 m
Field delineation:	142 km^2
Reservoir depth:	2,050 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

PRODUCTION

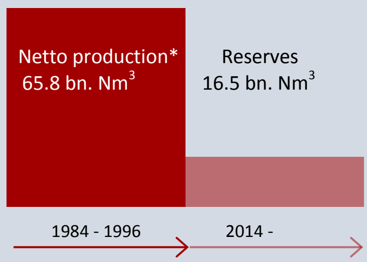
Cum. production at 1 January 2014

Oil:	4.29	m. m³
Gas:	9.71	bn. Nm³
Water:	5.84	m. m³



RESERVES*

Oil:	7.7	m. m³
Gas:	16.5	bn. Nm³



*The chart shows the combined figures for Tyra and Tyra SE; netto production is historical production minus injection.

REVIEW OF GEOLOGY, THE TYRA SOUTHEAST FIELD

The Tyra Southeast Field is an anticlinal structure created by a slight tectonic uplift of Upper Cretaceous chalk layers. The structure is divided into two blocks separated by a NE-SW fault zone. The structure is part of the major uplift zone that also comprises Roar, Tyra and parts of the Halfdan Field.

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

PRODUCTION STRATEGY

The production of oil and gas is based on natural depletion.

PRODUCTION FACILITIES

The Tyra Southeast Field has been developed as a satellite (TSEA) to the Tyra Field with one unmanned platform of the STAR type.

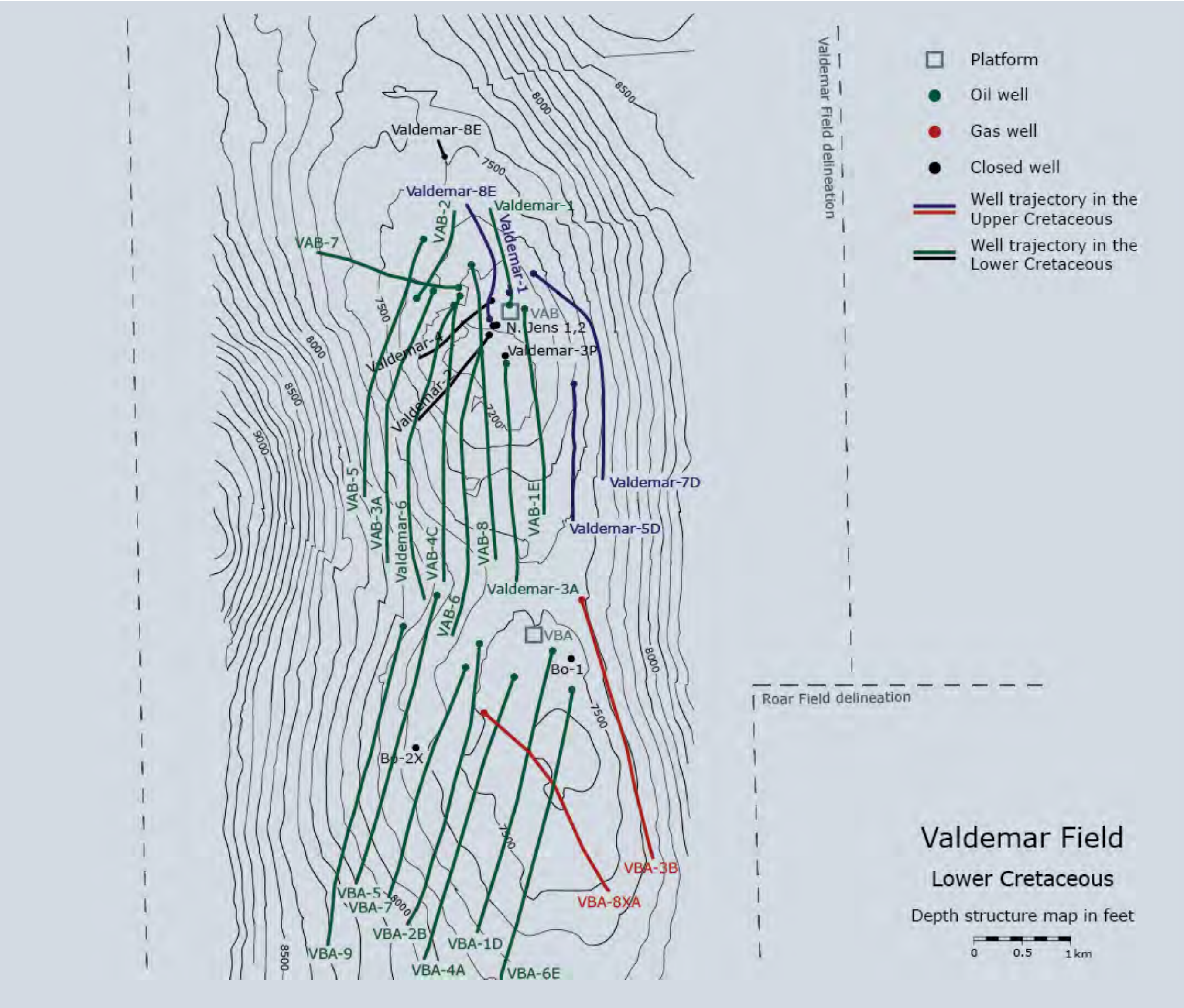
FIELD DEVELOPMENT

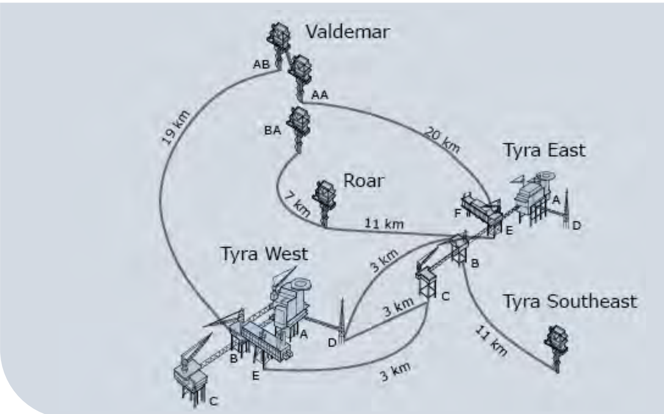
In 2013 permission was granted for further developing Tyra Southeast with a new four-leg platform (TSEB) with capacity for 16 wells, to be connected by a bridge to TSEA, and for a new lift gas pipeline between Tyra East and Tyra Southeast to serve the new and existing wells. The pipeline will be hooked up to TSEB. Power supply and control signal cables will run parallel to the pipeline. TSEB, the pipeline and the bridge connection to TSEA will be installed in 2014.

The production is separated into gas and liquids before being transported to Tyra East for further processing.

THE VALDEMAR FIELD

Prospect:	**Bo/North Jens**
Location:	**Block 5504/7 and 11**
Licence:	**Sole Concession**
Operator:	**Mærsk Olie og Gas A/S**
Discovered	**1977 (Bo) - 1985 (North Jens)**
Year on stream:	**1993 (North Jens) - 2007 (Bo)**

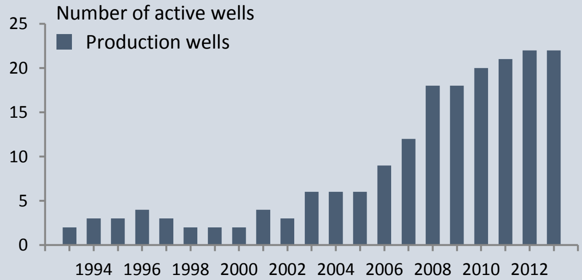




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2014

2013-prices DKK 9.11 billion



FIELD DATA

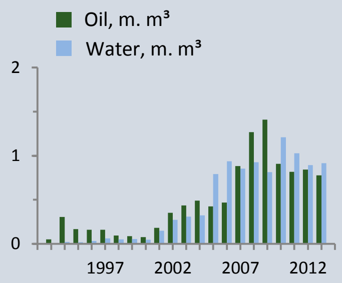
At 1 January 2014

Oil prod. wells:	21
Gas prod. wells:	2
Water depth:	38 m
Field delineation:	110 km2
Reservoir depth:	2,000 m (Upper Cretaceous) 2.600 m (Lower Cretaceous)
Reservoir rock:	Chalk
Geological age:	Danian, Upper and Lower Cretaceous

PRODUCTION

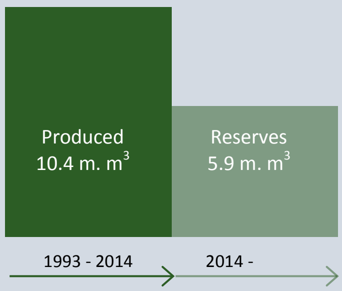
Cum. production at 1 January 2014

Oil:	10.36	m. m³
Gas:	5.16	bn. Nm³
Water:	9.71	m. m³



RESERVES

Oil:	5.9	m. m³
Gas:	2.6	bn. Nm³



REVIEW OF GEOLOGY, THE VALDEMAR FIELD

The Valdemar Field consists of a northern reservoir called North Jens and a southern reservoir called Bo, which are both anticlinal chalk structures associated with tectonic uplift.

The Valdemar Field comprises several separate accumulations. Oil and gas have been discovered in Danian/Upper Cretaceous chalk, and large volumes of oil have been identified in Lower Cretaceous chalk. The extremely low-permeable layers in the Lower Cretaceous chalk possess challenging production properties in some parts of the Valdemar Field, while the Bo area has proven to have better production properties. The properties of the Upper Cretaceous reservoirs are comparable to other Danish fields like Gorm and Tyra.

The Upper and Lower Cretaceous reservoirs have been developed in both the Bo and North Jens areas.

PRODUCTION STRATEGY

The production of oil is based on natural depletion. The development of a production method based on long horizontal wells with numerous sand-filled, artificial fractures has made it possible to exploit the Lower Cretaceous reservoir commercially. In addition, recovery takes place from Danian/Upper Cretaceous layers.

PRODUCTION FACILITIES

The North Jens area of the Valdemar Field has been developed as a satellite to the Tyra Field with two bridge-connected, unmanned wellhead platforms of the STAR type without helidecks, Valdemar AA and AB. Production is separated at the Valdemar AB platform. The liquids produced are piped to Tyra East for processing and export ashore, while the gas produced is piped to Tyra West. The Valdemar AA/AB complex is provided with chemicals from Tyra East and with power from Tyra West.

The Bo area of the Valdemar Field has been developed with an unmanned wellhead platform of the STAR type without a helideck, Valdemar BA. A 16” multiphase pipeline transports the production from Valdemar BA to Tyra East via Roar.

FIELD DEVELOPMENT

No major field development activities in 2013.

8. GEOTHERMAL HEAT AND OTHER USE OF THE SUBSOIL

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. All these activities are regulated by the Act on the Use of the Danish Subsoil, usually referred to as the Subsoil Act.

Geothermal heat is recovered from the hot salt water that is present in porous and permeable sandstone layers in the subsoil. Geothermal heat can be found in large parts of Denmark and can be utilized for the production of district heating. There are currently three plants producing geothermal heat for district heating purposes. A plant at Thisted has been producing heat since 1984, a plant in Copenhagen since 2005, and a new plant at Sønderborg since 2013.

When the energy policy agreement was concluded on 22 March 2012, a special fund totalling DKK 35 million for the years 2012-2015 was set up to promote renewable energy (RE) technology in district heating (geothermal energy, large-scale heat pumps, etc.).. At the end of 2013, the publication “Analysis regarding heat pumps and heat storage technologies” was issued, and in January 2014 the two reports entitled "Analysis of options for managing risks in geothermal projects" and "Roadmap for geothermal energy projects” were presented. The three reports are available in Danish at the DEA’s and other websites. In the years ahead, the screening for geothermal potential in various Danish towns and cities will be completed, district heating grids will be adapted to the use of geothermal energy, and the work on a web-based GIS platform with data about the subsoil will also be completed.

Figure 8.1. Geothermal licences at 1 June 2014.

Two new licences to explore for and produce geothermal energy were issued in 2013, covering areas near Brønderslev and Hillerød. The figure shows the areas covered by the new licences issued in 2013, as well as the licences that were relinquished and expired in 2013 and the period until 1 June 2014.

During the summer and autumn of 2013, Farum Fjernvarme and Hillerød Kraftvarme carried out seismic surveys to identify the potential for producing geothermal energy. Farum Fjernvarme acquired about 40 km and Hillerød Kraftvarme about 48 km of 2D seismic lines by means of vibroseismic equipment.

Applications for new licences to explore for and produce geothermal energy can be submitted twice a year, the deadlines being 1 February and 1 September. The more detailed terms and conditions are available at the DEA's website, www.ens.dk.

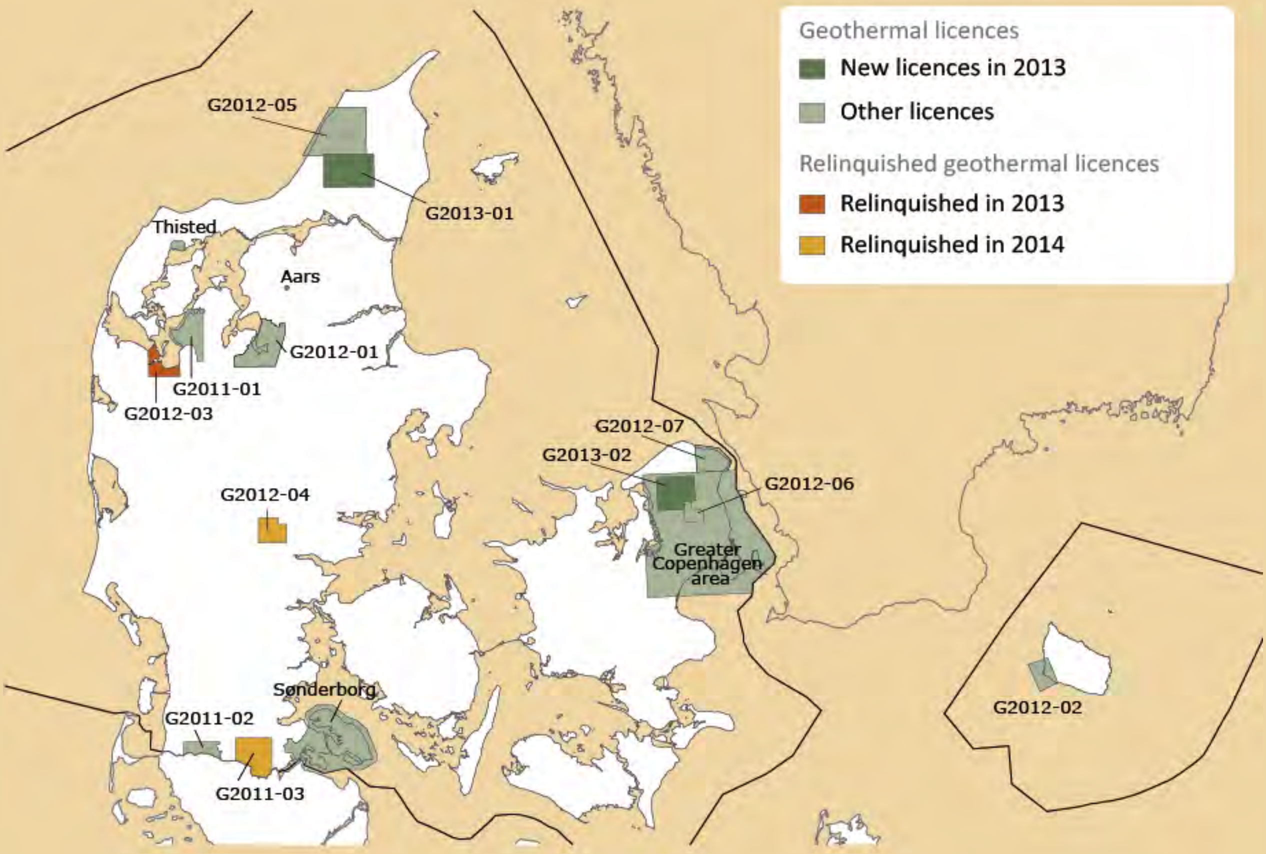


Table 8.1. Relinquished and expired licences in 2013 and first half of 2014.

Relinquished/expired licences in 2013		Relinquished/expired licences in 2014	
Aars	DONG VE A/S	**G2011-03**	Aabenraa-Rødekro Fjernvarme A.m.b.a.
G2012-03	Struer Forsyning Fjernvarme A/S	**G2012-04**	Givskud Zoo

Table 8.2. Existing geothermal licences and operators at 1 June 2014.

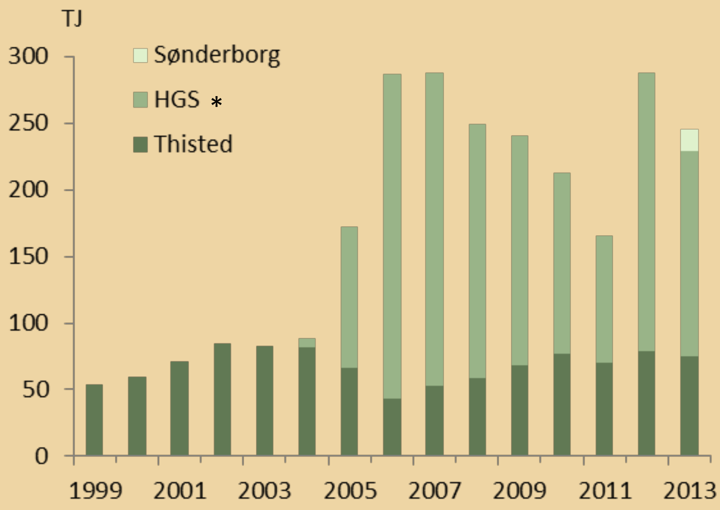
Licence	Operator	Effective date
Sole Concession of 8 December 1983 to explore and produce geothermal energy	Thisted Varmeforsyning A.m.b.a.	1983-12-08
Licence to explore and produce geothermal energy in the greater Copenhagen area	DONG VE A/S	2001-02-19
Licence to explore and produce geothermal energy in the Sønderborg-area	Sønderborg Fjernvarme A.m.b.a.	2007-10-11
G2011-01	Skive Geotermi A/S	2011-11-30
G2011-02	Tønder Fjernvarme-selskab A.m.b.a.	2011-11-30
G2012-01	Energi Viborg Kraftvarme A/S	2012-01-26
G2012-02	Rønne Varme A/S	2012-01-26
G2012-05	Hjørring Varmeforsyning	2012-06-14
G2012-06	Farum Fjernvarme A.m.b.a.	2012-06-14
G2012-07	Forsyning Helsingør Varme A/S	2012-06-14
G2013-01	Brønderslev Varme A/S	2013-06-27
G2013-02	Hillerød Kraftvarme ApS	2013-06-27

Production of geothermal energy

Figure 8.3. Production of geothermal energy in the past 15 years, 1999-2013.

In total, 245 TJ of geothermal energy was produced for district heating production during 2013. This corresponds to the heat consumption of about 3,700 households, a 14.7 per cent decline in total production compared to 2012.

The fall in production is due mainly to decreasing injection capacity at the HGS geothermal energy plant in Copenhagen.



** Hovedstadsområdets Geotermiske Samarbejde (the Metropolitan Geothermal Alliance); DONG VE is the operator.*

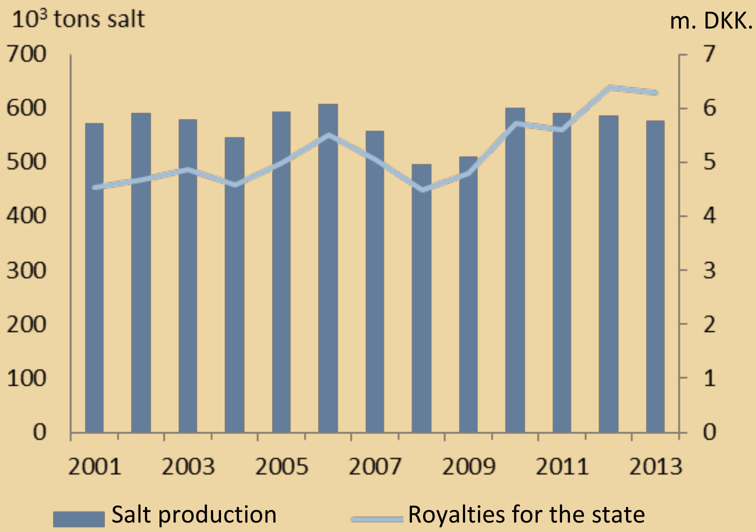
Gas storage facilities

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.

Salt production

Figure 8.3. Salt production and state revenue from royalties, 2001-2013.

The production of salt came close to 580,000 tons in 2013, and state revenue from royalties amounted to about DKK 6.2 million for the year.



In Denmark, salt is extracted at one location only, at Hvornum about 8 km southwest of Hobro, where the company Akzo Nobel Salt A/S carries on production of salt from the Danish subsoil. The company previously had an exclusive licence for the production of salt from the Danish subsoil. The licence was issued in 1963 for a 50-year term, thus expiring in 2013. In 2010 the company was granted a new licence to replace the existing one. As from 2013, the new licence only covers the Hvornum salt diapir and an area around the Suldrup salt diapir southwest of Aalborg. The salt is used for consumption and for use as industrial salt and road salt.

Conversion factors

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.

Reference pressure and temperature for the units mentioned:

		TEMP.	PRESSURE
Cude 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

	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	0.03955[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*
Density	**FROM**	**TO**	**CONVERSION**
	°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 2012.

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: 60°F and 14.73 kPa in this report.*
stb	*stock tank barrel; barrel in a reference state of 60°F and 14.73 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-volumen barrels blue.*
kg · mol	*kilogram-mol. 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.	*ton oil equivalent. This unit is internationally defined as: 1 t.o.e.=10 Gcal.*

The Danish Energy Agency, DEA, was established in 1976 and is placed under the Ministry of Climate, Energy and Building. The DEA works nationally and internationally with tasks related to energy supply and consumption and 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, as well as national CO_2 targets and initiatives to reduce the emission of greenhouse gases.

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

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

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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 2013 contains a description of exploration and development activities and a review of production in the Danish area. The report also describes the use of the Danish subsoil for purposes other than oil and gas production, focusing on exploration and production of geothermal energy for district heating purposes.

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

As in the past two years, the report is only published electronically at the Danish Energy Agency's website, www.ens.dk

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