12 Fields in production

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Explanation of the tables in chapters 12–14

Interests in fields do not necessarily correspond with interests in the individual production licences (unitised fields or ones for which the sliding scale has been exercised have a different composition of interests than the production licence). Because interests are shown up to two decimal places, licensee holdings in a field may add up to less than 100 per cent. Interests are shown at 1 January 2004.

Recoverable reserves originally present refers to reserves in resource categories 0, 1, 2 and 3 in the NPD's classification system (see the definitions below).

Recoverable reserves remaining refers to reserves in resource categories 1, 2 and 3 in the NPD's classification system (see the definitions below).

Resource category 0: Petroleum sold and delivered
Resource category 1: Reserves in production
Resource category 2: Reserves with an approved plan for development and operation
Resource category 3: Reserves which the licensees have decided to develop

Explanation of the figures

- Oil: 1 000 b/d
- Gas: bn scm/year
- NGL: mill tonnes/year
- Condensate: mill scm/year

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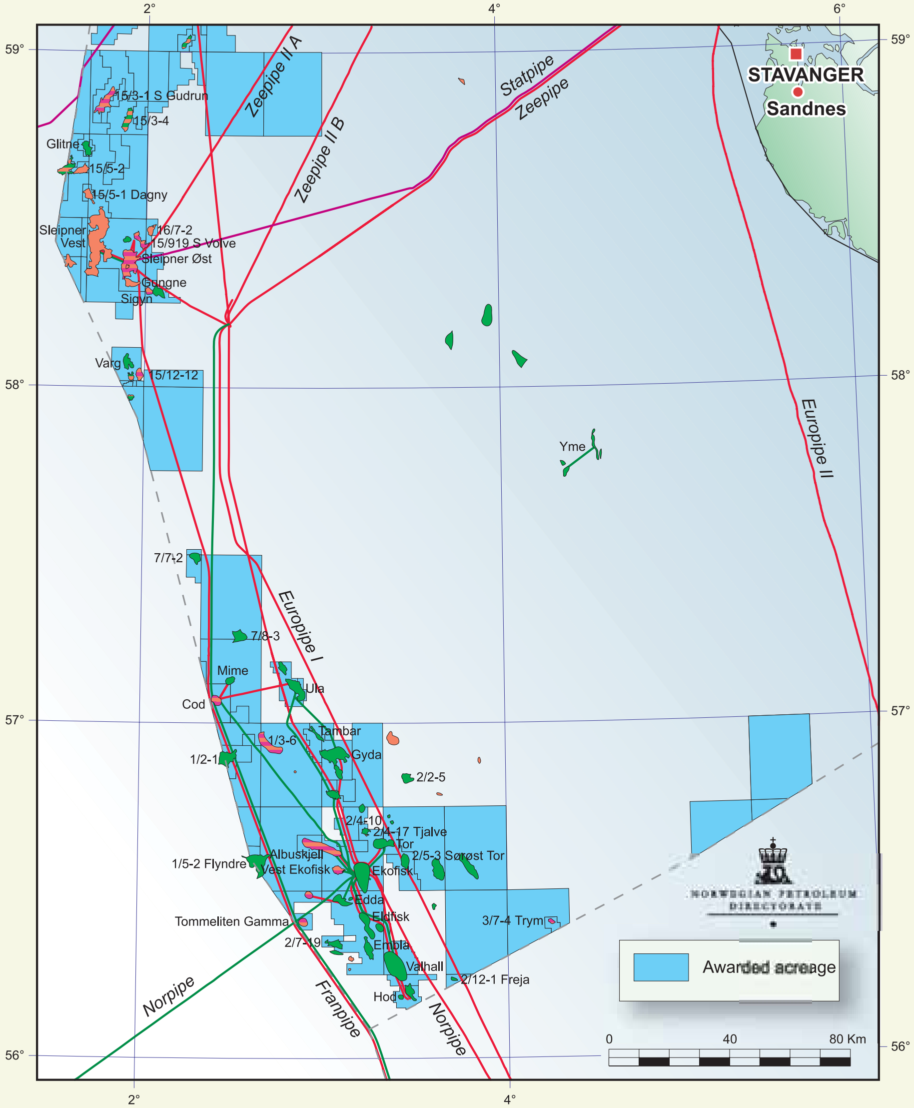
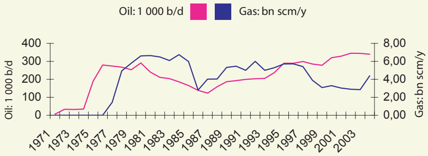


Southern North Sea sector

The southern part of Norway's North Sea sector became important for the country at an early stage, with Ekofisk as the first Norwegian offshore field to come on stream more than 30 years ago. Ekofisk serves as a hub for petroleum operations in this area, with surrounding developments utilising the infrastructure which ties it to continental Europe and Britain. Norwegian oil and gas is exported from Ekofisk to Teesside in the UK and Emden in Germany respectively.

North of Ekofisk are the Sleipner fields. Sleipner East on stream in 1993, followed by Sleipner West in 1996. In addition to producing substantial quantities of gas and condensate, these fields serve as a hub for the gas transport system on the NCS.

Although production from this part of the NCS has lasted for many years, remaining resources in the region are substantial. Oil and gas output is accordingly expected to continue beyond another three decades.



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Ekofisk area (Ekofisk, Eldfisk and Embla)

Ekofisk, Eldfisk and Embla

Blocks and production licences	Blocks 2/4 and 2/7 - production licence 018. Both blocks awarded in 1965.	
Progress	On stream in 1971 (Ekofisk), 1973 (Embla)	
Operator	ConocoPhillips Skandinavia AS	
Licensees	Total E&P Norge AS	39.90%
	ConocoPhillips Skandinavia AS	35.11%
(rounded off to	Eni Norge AS	12.39%
two decimal places)	Norsk Hydro Produksjon a.s	6.65%
	Petoro AS[1]	5.00%
	Statoil ASA	0.95%
Recoverable reserves	Originally present:	Remaining at 31.12.03:
	633.5 mill scm oil	222.1 mill scm oil
	242.7 bn scm gas	82.4 bn scm gas
	19.5 mill tonnes NGL	4.9 mill tonnes NGL
Production	Estimated production in 2004: Oil: 339 000 b/d Gas: 4.4 bn scm NGL: 0.4 mill tonnes	
Transport	Oil is piped through the Norpipe system to Teesside in the UK, while gas is piped to Emden in Germany.	
Investment	Total investment[2] is likely to be NOK 222.8 bn (2004 value). NOK 188.9 bn (2004 value) had been invested at 31.12.03.	
Operating organisation	Stavanger	
Main supply base	ConocoPhillipsbasen, Tananger	

[1] Petoro AS serves as the licensee for the SDFI.

[2] Including Albuskjell, Cod, Ekofisk West and Tor.

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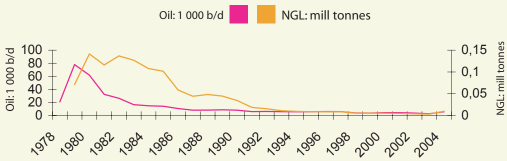

Ekofisk area cont (Tor)

Tor

Blocks and production licences	Block 2/4 - production licence 018. Awarded in 1965. Block 2/5 - production licence 006. Awarded in 1965.	
Progress	Government approval: 1973 On stream in 1978	
Operator	ConocoPhillips Skandinavia AS	
Licensees	Total E&P Norge AS	48.20%
(rounded off to	ConocoPhillips Skandinavia AS	30.66%
two decimal places)	Eni Norge AS	10.82%
	Norsk Hydro Produksjon a.s	5.81%
	Petoro AS[1]	3.69%
	Statoil ASA	0.83%
Recoverable reserves	Originally present:	Remaining at 31.12.03:
	27.4 mill scm oil	5.7 mill scm oil
	12.0 bn scm gas	1.3 bn scm gas
	1.3 mill tonnes NGL	0.1 mill tonnes NGL
Production	Estimated production in 2004: Oil: 6 000 b/d Gas: 0.09 bn scm NGL: 0.01 mill tonnes	
Transport	Oil is piped through the Norpipe system to Teesside in the UK, while gas is piped to Emden in Germany.	
Investment	Total investment is likely to be NOK 8.6 bn (2004 value). NOK 8.6 bn (2004 value) had been invested at 31.12.03.	
Operating organisation	Stavanger	
Main supply base	ConocoPhillipsbasen, Tananger	

[1] Petoro AS serves as the licensee for the SDFI.

The Ekofisk area comprises the Ekofisk, Eldfisk, Embla and Tor fields, which lie in 70-75 metres of water. In addition come Albuskjell, Cod, Edda and West Ekofisk, which have ceased production.

This area has been developed in five phases. Ekofisk and its central processing facilities were developed in two stages, with production starting in 1971. Cod and West Ekofisk represented phase three. Oil was initially loaded into tankers on the fields, but has been piped since 1975 through the Norpipe line to Teesside in the UK. Pipeline transport of gas through Norpipe to Emden in Germany began in 1977.

Approved by the authorities in 1975, the fourth development phase covered Albuskjell, Eldfisk and Edda. The last of these came on stream in 1979. The fifth phase was prompted by a desire to improve recovery from Ekofisk, and the 2/4-K water injection platform began operation in December 1987. Expanded several times, water injection capacity on the field is currently just under one mill b/d.

The Edda platform was modified in 1988 to receive gas from the Tommeliten field. A decision to develop the Embla field south of Ekofisk was taken in 1990, with production starting in 1993.

A new plan for development and operation of the Ekofisk field (Ekofisk II) received approval in 1994, when the licence for the Ekofisk area was extended to 2028. A new Ekofisk field centre comprising two platforms has been installed on the field. The 2/4-X wellhead platform was put in place during the autumn of 1996, followed by the 2/4-J processing and transport installation in August 1997. Ekofisk II came on stream in August 1998, and is expected to produce for the next 30 years.

The Ekofisk, Eldfisk, Embla and Tor fields are tied back to the new field centre, and will thereby remain on stream. Ordinary production from Cod, Edda, Albuskjell and West Ekofisk has ceased.

A total of 29 platforms are installed in the Ekofisk area. In connection with the development of the new field centre, many of these installations have already been shut in. On the basis of the cessation plan for Ekofisk I submitted to the authorities in the autumn of 1999, it was resolved in December 2001 to remove 14 steel structures and the topside on the concrete Ekofisk tank to land for recycling of their materials. The bulk of this removal work is due to be completed by 2013.

The plan for development and operation of Eldfisk water injection was approved in 1997. It involves a new platform, 2/7-E, with equipment for water injection, gas lift and gas injection on the Eldfisk field, tied back to one of the existing installations by a bridge. The development was completed in 2000.

Declining pressure in Ekofisk has caused seabed subsidence, and operator ConocoPhillips initiated efforts in 1985 to safeguard the platforms against this effect. Six of nine steel platforms in the Ekofisk centre were therefore jacked up by six metres in 1987, and a protective concrete wall was installed around the Ekofisk tank in 1989. Seabed subsidence has slowed substantially after waterflooding stabilised the pressure. Since production started in 1971, the seabed has subsided by about seven metres. The new platforms, which came on stream in 1998, have been designed to cope with up to 20 metres of seabed subsidence.

The Ekofisk Growth development was approved in 2003. It aims to improve recovery from Ekofisk by 182 mill boe. This project comprises a new 2/4M platform, 25 wells, increased processing capacity and the laying of a power cable for shared electricity supplies.

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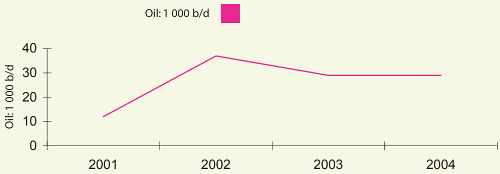
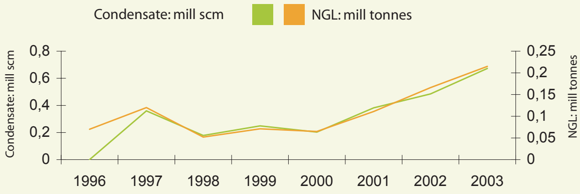


Glitne

Blocks and production licences	Block 15/5 - production licence 048B. Awarded 1977, carve-out 2001. Block 15/6 - production licence 029B. Awarded 1977, carve-out 2001.
Progress	Government approval: September 2000. Production start-up: 29 August 2001.
Operator	Statoil ASA
Licensees	Statoil ASA 58.90% Total E&P Norge AS 21.80% Det Norske Oljeselskap AS 10.00% Dong Norge AS 9.30%
Recoverable reserves	Originally present: 6.9 mill scm oil Remaining at 31.12.03: 2.3 mill scm oil
Production	Estimated production in 2004: Estimated p Oil: 29 000 b/d
Investment	Total investment is likely to be NOK 1.2 bn (2004 value) NOK 1.2 bn (2004 value) had been invested at 31.12.03.
Operating organisation	Trondheim
Main supply base	Dusavik

Glitne was proven in 1995 and lies in 110 metres of water 40 km north-west of the Sleipner area. Its development solution is based on leasing the *Petrojarl 1* production ship. Oil from Glitne is processed and stored on the vessel before being transferred to shuttle tankers. Associated gas is used for fuel or gas lift, with surplus gas being injected back below ground. Since Glitne came on stream, measures have been initiated to improve recovery from the field. This will extend its producing life.



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Gungne

Block and production licence	Block 15/9 - production licence 046. Awarded 1976.	
Progress	Government approval: August 1995 Production start-up: April 1996	
Operator	Statoil ASA	
Licensees	Statoil ASA	52.60%
	Esso Expl & Prod Norway AS	28.00%
	Total E&P Norge AS	10.00%
	Norsk Hydro Produksjon a.s	9.40%
Recoverable reserves	Originally present:	Remaining at 31.12.03:
	9.9 bn scm gas[1]	9.9 bn scm gas
	1.3 mill tonnes NGL	0.4 mill tonnes NGL
	3.1 mill scm condensate	0.3 mill scm condensate
Production	Estimated production in 2004: Gas: 1.19 bn scm NGL: 0.14 mill tonnes Condensate: 0.36 mill scm	
Investment	Total investment is likely to be NOK 1 bn (2004 value). NOK 1 bn (2004 value) had been invested at 31.12.03.	
Operating organisation	Stavanger	
Main supply base	Dusavik	

[1] Applies collectively for Sleipener East and Sleipner West.

Proven in 1982, Gungne is a satellite of Sleipner East and lies in 83 metres of water. It came on stream in April 1996 through a well drilled from Sleipner A. An additional well to the field was completed in 2001.

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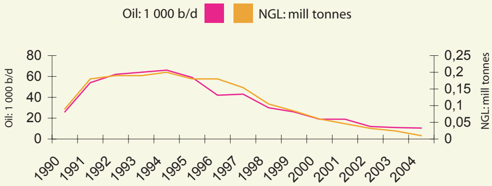
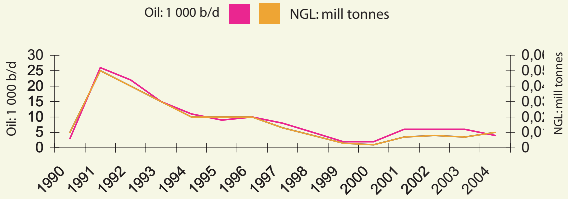


Gyda (incl Gyda South)

Block and production licence	Block 2/1 - production licence 019B. Awarded 1977. Block 1/3 - production licence 065. Awarded 1981.	
Progress	Government approval: June 1987 Production start-up: June 1990	
Operator	Talisman Energy Norge AS	
Licensees	Talisman Energy Norge AS Dong Norge AS Norske AEDC A/S	61.00% 34.00% 5.00%
Recoverable reserves	Originally present: 36.2 mill scm oil 6.1 bn scm gas 1.9 mill tonnes NGL	Remaining at 31.12.03: 4.5 mill scm oil 0.8 bn scm gas 0.1 mill tonnes NGL
Production	Estimated production in 2004: Oil: 11 000 b/d NGL: 0.01 mill tonnes	
Investment	Total investment is likely to be NOK 15.8 bn (2004 value). NOK 13.7 bn (2004 value) had been invested at 31.12.03.	
Operating organisation	Stavanger	
Main supply base	Sola	

The Gyda field was proven in 1980, and has been developed with an integrated steel platform in 66 metres of water. Oil is piped to a tie-in with the Ula pipeline and on via the Ekofisk Centre to Teesside, while gas goes through a dedicated pipeline to the Ekofisk Centre for sale to the Ekofisk group. Government approval to develop the Gyda South satellite was given in 1993. This field is being drained with two extended-reach wells drilled from the Gyda platform. Gyda South came on stream in 1995.



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Hod

Block and production licence	Block 2/11 - production licence 033. Awarded 1969.	
Progress	Government approval: June 1988 Production start-up: September 1990	
Operator	BP Norge AS	
Licensees	Amerada Hess Norge AS	25.00%
	BP Norge AS	25.00%
	Enterprise Oil Norge AS	25.00%
	Total E&P Norge AS	25.00%
Recoverable reserves	Originally present: 8.3 mill scm oil 1.6 bn scm gas 0.2 mill tonnes NGL	Remaining at 31.12.03: 0.7 mill scm oil 0.2 bn scm gas
Production	Estimated production in 2004: Oil: 4 000 b/d Gas: 0.04 bn scm NGL: 0.01 mill tonnes	
Investment	Total investment is likely to be NOK 2.2 bn (2004 value) NOK 2.2 bn (2004 value) had been invested at 31.12.03	
Operating organisation	Stavanger	
Main supply base	ConocoPhillipsbasen/Akerbasen, Tananger	

Hod has been developed with an unstaffed wellhead platform in 72 metres of water, remotely controlled from the Valhall field 13 km further north. Oil and gas are separated and metered on the Hod platform, and piped as a two-phase flow for final processing on Valhall.

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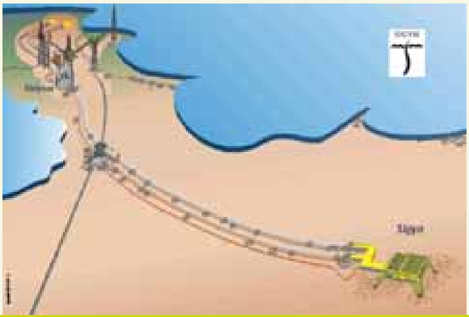
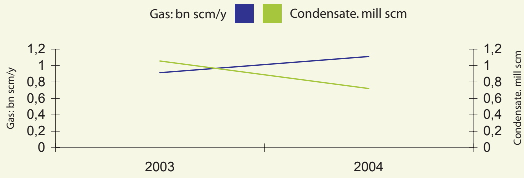
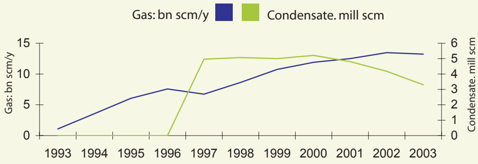




Sigyn

Block and production licence	Block 16/7 - production licence 072. Awarded 1981.	
Progress	Government approval: August 2001 Production start-up: December 2002	
Operator	Esso Expl & Prod Norway AS	
Licensees	Statoil ASA Esso Expl & Prod Norway AS Norsk Hydro Produksjon a.s	50.00% 40.00% 10.00%
Recoverable reserves	Originally present: 6.7 bn scm gas 1.9 mill tonnes NGL 5.0 mill scm condensate	Remaining at 31.12.03: 5.8 bn scm gas 1.6 mill tonnes NGL 4.0 mill scm condensate
Production	Estimated production in 2004: Gas: 1.11 bn scm NGL: 0.27 mill tonnes Condensate: 0.72 mill scm	
Investment	Total investment is likely to be NOK 2.1 bn (2004 value) NOK 2.1 bn (2004 value) had been invested at 31.12.03	
Operating organisation	Stavanger	
Main supply base	Dusavik	

Sigyn was proven in 1982 and lies in roughly 70 metres of water in the Sleipner area. The field is tied back to Sleipner A. After processing on that platform, Sigyn gas is exported via the Sleipner dry gas system. Its condensate travels in the existing pipeline from Sleipner to Kårstø.



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Sleipner West

Block and production licence	Block 15/6 - production licence 029. Awarded 1969. Blocks 15/8, 15/9 - production licence 046. Awarded 1976.	
Progress	Government approval: December 1992 Production start-up: August 1996	
Operator	Statoil ASA	
Licensees	Statoil ASA	49.50%
(rounded off to two	Esso Expl & Prod Norway AS	32.24%
decimal places)	Total E&P Norge AS	9.41%
	Norsk Hydro Produksjon a.s	8.85%
Recoverable reserves	Originally present:	Remaining at 31.12.03[1]:
	108.2 bn scm gas	76.1 bn scm gas
	8.2 mill tonnes NGL	5.9 mill tonnes NGL
	28.3 mill scm condensate	8.8 mill scm condensate
Production	Estimated production in 2004: Gas: 10.11 bn scm NGL: 0.5 mill tonnes Condensate: 1.32 mill scm	
Investment	Total investment is likely to be NOK 24.4 bn (2004 value). NOK 21.4 bn (2004 value) had been invested at 31.12.03.	
Operating organisation	Stavanger	
Main supply base	Dusavik	

[1] Combined for Sleipner East and West.

Sleipner West was proven in 1974 and lies in 110 metres of water. It has been tied back to Sleipner East, and shares the same operations organisation. Sleipner West is produced through two installations: the Sleipner B wellhead platform and the Sleipner T gas treatment facility. Unprocessed wellstreams from Sleipner B are piped the 12 kilometres to Sleipner T, which is linked by a bridge to Sleipner A on the Sleipner East field. Carbon dioxide is removed from the wellstream on the T platform and injected into a sub-surface formation. The gas is piped to continental Europe while its condensate is landed at Kårstø. Plans call for precompression to start on Sleipner T in the autumn of 2004.

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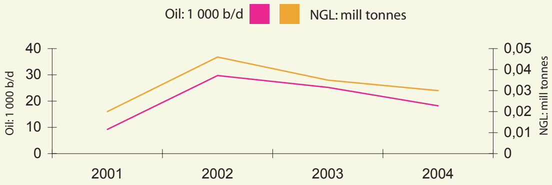
See graph on page 79

Sleipner East

Block and production licence	Block 15/9 - production licence 046. Awarded 1976.	
Progress	Government approval: December 1986 Production start-up: August 1993	
Operator	Statoil ASA	
Licensees	Statoil ASA	49.60%
	Esso Expl & Prod Norway AS	30.40%
	Norsk Hydro Produksjon a.s	10.00%
	Total E&P Norge AS	10.00%
Recoverable reserves	Originally present:	Remaining at 31.12.03[1]:
	63.5 bn scm gas	76.1 bn scm gas
	12.4 mill tonnes NGL	5.9 mill tonnes NGL
	27.1 mill scm condensate	8.8 mill scm condensate
Production	Estimated production in 2004: Gas: 1.38 bn scm NGL: 0.43 mill tonnes Condensate: 0.8 mill scm	
Investment	Total investment is likely to be NOK 36.4 bn (2004 value). NOK 35.2 bn (2004 value) had been invested at 31.12.03.	
Operating organisation	Stavanger	
Main supply base	Dusavik	

[1] Combined for Sleipner East and West.

Sleipner East was discovered in 1981 and lies in 82 metres of water. It has been developed with the integrated Sleipner A production, drilling and quarters platform, two templates for subsea wells, a riser platform and a flare stack. The gas is piped to continental Europe while its condensate is landed at Kårstø. The Loke satellite has been developed with a single subsea well tied back to Sleipner A. After the Ty formation had been drained in 1997, the well was extended to the Hugin/Skagerrak formation and brought back on stream in 1998. Sigyn has been developed with full wellstream transfer to Sleipner A and began production in 2002.



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Tambar

Blocks and production licences	Block 1/3 - production licence 065. Awarded 1981. Block 2/1 - production licence 019B. Awarded 1977.
Progress	Government approval: April 2000 Production start-up: July 2001
Operator	BP Norge AS
Licensees	BP Norge AS 55.00% Dong Norge AS 45.00%
Recoverable reserves	Originally present: 7.3 mill scm oil, 2.0 bn scm gas, 0.2 mill tonnes NGL Remaining at 31.12.03: 3.5 mill scm oil, 2.0 bn scm gas, 0.1 mill tonnes NGL
Production	Estimated production in 2004: Oil: 18 000 b/d NGL: 0.03 mill tonnes
Investment	Total investment is likely to be NOK 1.5 bn (2004 value). NOK 1.5 bn (2004 value) had been invested at 31.12.03.
Operating organisation	Stavanger
Main supply base	Sola

Tambar was proven in 1982 and lies in 68 metres of water, about 16 km south-east of Ula and roughly 12 km north-west of Gyda. The field has been developed with an unstaffed wellhead platform tied back to Ula. Its production is exported to Ula for processing and onward transport by pipeline via Ekofisk to Teesside in the UK. Gas from Tambar is being injected into Ula and accordingly helps to improve recovery from the latter.

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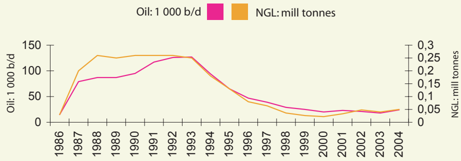
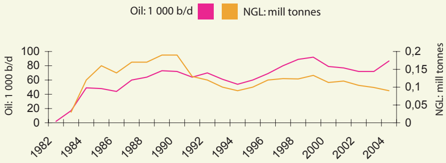


Ula

Block and production licence	Block 7/12 - production licence 019. Awarded 1965.	
Progress	Government approval: May 1980 Production start-up: October 1986	
Operator	BP Norge AS	
Licensees	BP Norge AS	80.00%
	Svenska Petroleum Exploration A/S	15.00%
	Dong Norge AS	5.00%
Recoverable reserves	Originally present:	Remaining at 31.12.03:
	78.6 mill scm oil	14.0 mill scm oil
	4.0 bn scm gas	0.2 bn scm gas
	3.0 mill tonnes NGL	0.5 mill tonnes NGL
Production	Estimated production in 2004: Oil: 24 000 b/d NGL: 0.05 mill tonnes	
Investment	Total investment is likely to be NOK 20.8 bn (2004 value). NOK 20 bn (2004 value) had been invested at 31.12.03.	
Operating organisation	Stavanger	
Main supply base	Sola	

Proven in 1976, Ula lies in about 70 metres of water and has been developed with three conventional steel platforms – for processing, drilling and quarters respectively. Oil is carried by the Ula pipeline to Ekofisk and on through Norpipe to Teesside. Associated gas from Ula is injected back into the reservoir in combination with water, helping to improve recovery. Alternatively, gas from Ula could be exported via a two-way pipeline to Gyda and piped on to Emden via Ekofisk.



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Valhall (incl Valhall flanks and Valhall water injection)

Blocks and production licences	Block 2/8 - production licence 006B. Awarded 1965, carve-out 2000. Block 2/11 - production licence 033B. Awarded 1969, carve-out 2001.	
Progress	Government approval: June 1977 Government approval: November 2000 (Valhall water injection) Government approval: November 2001 (Valhall flanks) Production start-up: October 1982	
		BP Norge AS
Licensees (rounded off to two decimal places)	BP Norge AS Amerada Hess Norge AS Enterprise Oil Norge AS Total E&P Norge AS	28.09% 28.09% 28.09% 15.72%
Recoverable reserves	Originally present: 166.5 mill scm oil 26.9 bn scm gas 4.2 mill tonnes NGL	Remaining at 31.12.03: 87.4 mill scm oil 11.0 bn scm gas 1.6 mill tonnes NGL
Production	Estimated production in 2004: Oil: 87 000 b/d Gas: 1.15 bn scm NGL: 0.09 mill tonnes	
Investment	Total investment is likely to be NOK 53.5 bn (2004 value) NOK 40.7 bn (2004 value) had been invested at 31.12.03	
Operating organisation	Stavanger	
Main supply base	ConocoPhillipsbasen/Akerbasen, Tananger	

Valhall has been developed in 70 metres of water with platforms for drilling, production/compression, quarters and water injection, as well as two unstaffed wellhead platforms on its flanks. The flank installations came on stream in May 2003 and January 2004 respectively. Water injection also began from the injection platform in January 2004. Oil from Valhall is piped via Ekofisk to Teesside, while the gas goes directly to Emden via Gassled's Norpipe Gas line.

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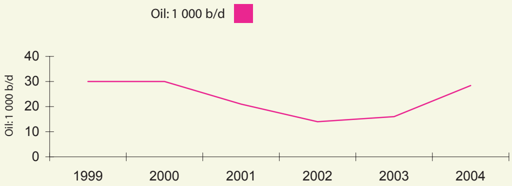


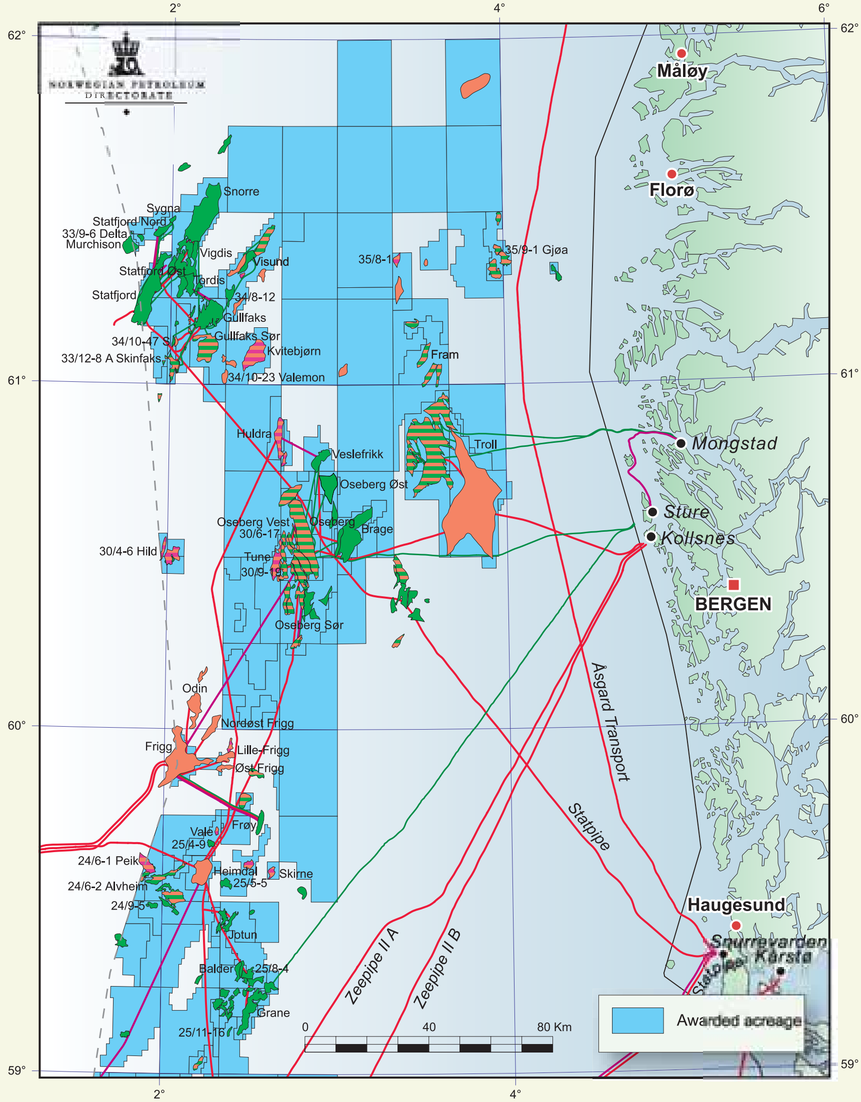
Varg

Block and production licence	Block 15/12 - production licence 038. Awarded 1975.	
Progress	Government approval: May 1996 Production start-up: December 1998	
Operator	Pertra AS	
Licensees	Pertra AS Petoro AS[1]	70.00% 30.00%
Recoverable reserves	Originally present: 9.3 mill scm oil	Remaining at 31.12.03: 2.9 mill scm oil
Production	Estimated production in 2004: Oil: 28 000 b/d	
Investment	Total investment is likely to be NOK 5.5 bn (2004 value). NOK 5.5 bn (2004 value) had been invested at 31.12.03.	
Operating organisation	Trondheim	
Main supply base	Tananger	

[1] Petoro AS serves as the licensee for the SDFI.

Varg was proven in 1984 and lies in 84 metres of water south of Sleipner East. The field has been developed with an unstaffed wellhead platform and a production ship which provides integrated oil storage. These two units are linked by flexible flowlines for oil production as well as water and gas injection, and by umbilicals for power supply and control.

Oil from Varg is transferred to shuttle tankers from the production ship. The production ship was sold in 1999 to Petroleum Geo Services (PGS), which also took over management responsibility for the vessel. The cessation plan for Varg was approved by the government in November 2001. However, further discoveries have been made near Varg and new production wells drilled on the field. This has exterded the producing life of the field, and the exact date for a final shutdown remains to be clarified.



Northern North Sea sector

The main areas in the northern part of Norway's North Sea sector are Tampen, Troll/Oseberg and Frigg/Heimdal. Tampen contains a number of fields, including Statfjord, Snorre, Gullfaks, Visund, Vigdis and Tordis. Several of these rank among Norway's largest oil fields. Although this is a mature petroleum province, its resource potential remains considerable. Troll has a very important function in gas deliveries from the NCS, but has also become a substantial oil producer. The Oseberg area includes Brage and Veslefrikk as well as Oseberg itself. Oil production from this part of the NCS is declining, but will remain substantial for many years to come. Oseberg is set to increase its gas deliveries. Heimdal has developed into a gas centre which provides processing services for surrounding fields. Production from Frigg is likely to cease in 2004, after many years of operation.

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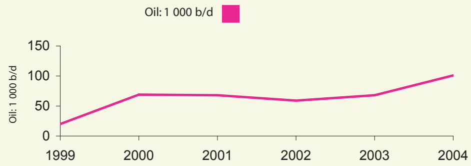


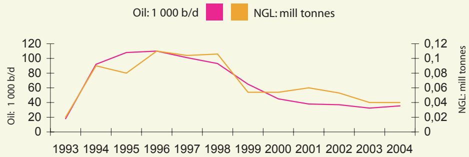
Balder (incl Ringhorne)

Blocks and production licences	Block 25/11 - production licence 001. Awarded 1965. Block 25/8 - production licence 027. Awarded 1969. Block 25/8 - production licence 027C. Awarded 1969, carve-out 2000. Blocks 25/8 and 25/11 - production licence 169. Awarded 1991.	
Progress	Government approval: February 1996 Production start-up: October 1999 Ringhorne approval: May 2000 Production start-up: February 2003	
Operator	Esso Expl & Prod Norway AS	
Licensee	Esso Expl & Prod Norway AS	100.00%
Recoverable reserves	Originally present: 76.8 mill scm oil 2.8 bn scm gas	Remaining at 31.12.03: 60.5 mill scm oil 2.8 bn scm gas
Production	Estimated production in 2004: Oil: 102 000 b/d	
Investment	Total investment is likely to be NOK 25.3 bn (2004 value). NOK 21 bn (2004 value) had been invested at 31.12.03.	
Operating organisation	Stavanger	
Main supply base	Dusavik	

Balder was proven in 1967 and lies 190 km west of Stavanger. The water depth is roughly 125 metres. Balder has been developed with a production ship tied to subsea templates. Oil is processed and stored on the ship before being transferred to shuttle tankers.

The Storting approved the Ringhorne development in May 2000. Covering several structures close to Balder, it involves an integrated drilling, well and quarters platform with first-stage separation. This has been tied back to the Balder ship via a flowline for further processing and export of the oil.

In 2003, the operator installed three flowlines which tie Balder and Ringhorne to the Jotun field. Starting in 2004, oil from Ringhorne will be exported via both Balder and Jotun, while gas from Ringhorne and Balder is exported via Jotun.



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Brage

Blocks and production licences	Block 30/6 - production licence 053B. Awarded 1979, carve-out 1998. Block 31/4 - production licence 055. Awarded 1979. Block 31/7 - production licence 185. Awarded 1991.	
Progress	Government approval: March 1990 Production start-up: September 1993	
Operator	Norsk Hydro Produksjon a.s	
Licensees	Norsk Hydro Produksjon a.s	20.00%
(rounded off to two	Paladin Resources Norge AS	20.00%
decimal places)	Esso Expl & Prod Norway AS	16.34%
	Petoro AS[1]	14.26%
	Statoil ASA	12.70%
	Eni Norge AS	12.26%
	OER Oil AS	4.44%
Recoverable reserves	Originally present:	Remaining at 31.12.03:
	47.4 mill scm oil	4.2 mill scm oil
	2.5 bn scm gas	0.5 bn scm gas
	0.8 mill tonnes NGL	0.1 mill tonnes NGL
Production	Estimated production in 2004: Oil: 36 000 b/d NGL: 0.04 mill tonnes	
Investment	Total investment is likely to be NOK 17.2 bn (2004 value). NOK 17.1 bn (2004 value) had been invested at 31.12.03.	
Operating organisation	Bergen	
Main supply base	Mongstad	

[1] Petoro AS serves as the licensee for the SDFI.

The Brage field has been developed in 140 metres of water with an integrated steel production, drilling and quarters platform. Production began in 1993 and went off plateau in 1998. Oil goes by pipeline to Oseberg A for onward transmission through the Oseberg Transport System (OTS) to the Sture terminal near Bergen, while gas is carried in a line tied to Statpipe for onward transport. A plan for development and operation of the Sognefjord formation was approved in October 1998. One well in this formation is currently producing, and several more are under consideration.

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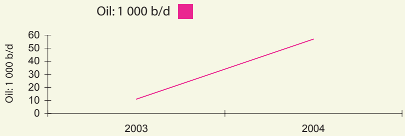
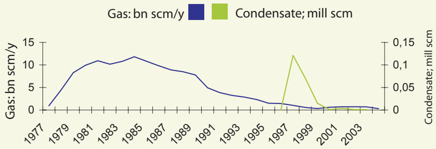


Fram

Block and production licence	Block 35/11 - production licence 090. Awarded 1984.	
Progress	Government approval: March 2001 Production start-up: October 2003	
Operator	Norsk Hydro Produksjon a.s	
Licensees	Norsk Hydro Produksjon a.s	25.00%
	Mobil Development Norway AS	25.00%
	Statoil ASA	20.00%
	Gaz de France Norge AS	15.00%
	Idemitsu Petroleum Norge AS	15.00%
Recoverable reserves	Originally present	Remaining at 31.12.03
	16.1 mill scm oil	15.4 mill scm oil
	3.7 bn scm gas	3.7 bn scm gas
	0.1 mill tonnes NGL	0.1 mill tonnes NGL
Production	Estimated production in 2004: Oil: 57 000 b/d	
Investment	Total investment is likely to be NOK 3.9 bn (2004 value). NOK 3.9 bn (2004 value) had been invested at 31.12.03.	
Operating organisation	Bergen	
Main supply base	Mongstad	

Fram lies in the northern North Sea, about 22 km north of Troll C. This development embraces a reservoir in the Fram/Gjøa area and involves two subsea templates tied back to Troll C. The gas is separated from the liquids on that platform for injection back into the reservoir during the first phase. It will later be exported via Troll A to Kollsnes. The oil is sent to Mongstad through Troll Oil Pipeline II. Fram operations are integrated with Troll C, which is also operated by Norsk Hydro.



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Frigg

Block and production licences	Blocks 25/1 - production licence 024. Awarded 1969. 60.82 per cent lies on the Norwegian side, 39.18 per cent in the UK sector.	
Progress	Government approval: June 1974 Production start-up: September 1977	
Operator	Total E&P Norge AS	
Licensees	Total E&P UK plc	54.79%
(rounded off to two	Norsk Hydro Produksjon a.s	19.99%
decimal places)	Total Oil Marine plc	13.06%
	Statoil ASA	12.16%
Recoverable reserves	Originally present: 116.6 bn scm gas 0.5 mill scm condensate	Remaining at 31.12.03: 1.3 bn scm gas
Production	Estimated production in 2004: Gas: 0.31 bn scm. Production is expected to cease in the summer of 2004.	
Investment	Total investment is likely to be NOK 36.5 bn (2004 value). NOK 36.5 bn (2004 value) had been invested at 31.12.03.	
Operating organisation	Stavanger	
Main supply base	Dusavik	

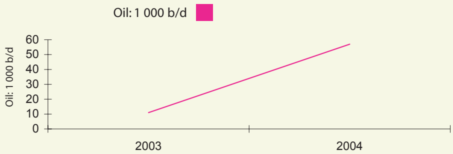
The unitisation agreed by the Frigg partners, which gives Norway a 60.82 per cent share, was approved by the UK and Norwegian authorities under a treaty between the two countries on joint exploitation. Production started in 1977 and reached plateau in October 1979. Frigg went off plateau in October 1987.

Located in about 100 metres of water, the field installations also processed Frøy's oil and gas from the summer of 1995 until the latter field ceased production in March 2001.

In addition, Britain's Alwyn field utilises the Frigg installations, while gas from North-East Frigg, Odin, East Frigg and Lille-Frigg was processed there until production from these fields ceased in May 1993, August 1994, December 1997 and March 1999 respectively. The government decided not to acquire the North-East Frigg, East Frigg, Odin, Lille-Frigg and Frøy installations.

A cessation plan for Frigg was submitted to the authorities in November 2001 and approved by the government on 26 September 2003. It includes the removal of steel topsides and jacket as well as the topside supported by the TCP2 concrete gravity base structure. These units will be taken to land for disposal. The decommissioning decision covered all the Norwegian installations with the exception of the TCP2 GBS, which is dealt with in a Proposition presented to the Storting in 2004.

(Agreement between Norway and the UK relating to exploitation of the Frigg field reservoir and the use of installations and pipelines for exploitation and transmission of hydrocarbons. See Proposition no 183 (1975-76) and Recom no 113 (1976-77) to the Storting.)



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Grane

Blocks and production licences	Block 25/11 - production licence 001. Awarded 1965. Block 25/11 - production licence 169 B1. Awarded 1991, carve-out 2000. Block 25/11 - production licence 169 B2. Awarded 1991, carve-out 2000.	
Progress	Government approval: June 2000 Production start-up: September 2003	
Operator	Norsk Hydro Produksjon a.s	
Licensees	Norsk Hydro Produksjon a.s Petoro AS[1] Esso Expl & Prod Norway AS Norske ConocoPhillips AS	38.00% 30.00% 25.60% 6.40%
Recoverable reserves	Originally present 120.0 mill scm oil	Remaining at 31.12.03 119.1 mill scm oil
Production	Estimated production in 2004: Oil: 150 000 b/d	
Investment	Total investment is likely to be NOK 16.5 bn (2004 value) NOK 12.6 bn (2004 value) had been invested at 31.12.03	
Operating organisation	Bergen	
Main supply base	Mongstad	

[1] Petoro AS serves as the licensee for the SDFI.

Proven in 1991, Grane lies in 127 metres of water east of Balder. It has been developed with an integrated drilling, production and quarters platform. Oil production began from Grane in September 2003 and will reach a plateau of just over 200 000 b/d in 2005-09.

The oil is transported by the Grane Oil Pipeline to the Sture terminal for storage, metering and export. Oil in the field is heavy and complicated to recover, and its production requires gas injection into the reservoir. Since Grane contains very little associated gas, injection volumes must be acquired elsewhere and a pipeline has accordingly been laid to the field from Heimdal.

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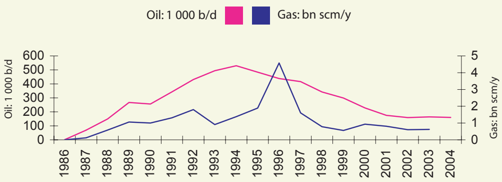

Gullfaks (incl Gullfaks West)

Blocks and production licences	Block 34/10 - production licence 050. Awarded 1978. Block 34/10 - production licence 050B. Awarded 1995.	
Progress	Government approval: October 1981 (Gullfaks phase I – platforms A and B). Production start-up: December 1986	
Operator	Statoil ASA	
Licensees	Statoil ASA Petoro AS[1] Norsk Hydro Produksjon a.s	61.00% 30.00% 9.00%
Recoverable reserves	Originally present: 341.9 mill scm oil 22.8 bn scm gas 2.1 mill tonnes NGL	Remaining at 31.12.03: 37.2 mill scm oil 2.1 bn scm gas 0.5 mill tonnes NGL
Production	Estimated production in 2004: Oil: 160 000 b/d	
Investment	Total investment is likely to be NOK 112.7 bn (2004 value). NOK 106.6 bn (2004 value) had been invested at 31.12.03.	
Operating organisation	Bergen	
Main supply bases	Coast Center Base, Sotra and Florø	

[1] Petoro AS serves as the licensee for the SDFI.

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Gullfaks was discovered in 1978 and lies in 130-220 metres of water. The field has been developed with three concrete gravity based platforms – Gullfaks A, B and C. Gullfaks A and C are integrated production, drilling and quarters units, while oil and gas from Gullfaks B are piped to the A or C installations for further treatment and storage.

Stabilised oil is stored in the A and C platforms and loaded into tankers via buoys. Gas is being injected back into Gullfaks from 2002.

The Gullfaks installations form an important part of the infrastructure in the Tampen area. The wellstream from Tordis is transferred to and processed on Gullfaks C, while stabilised crude from Vigdis and Visund is stored on and shipped from the A platform.

Development approval for the small Gullfaks West satellite was given by the government in January 1993. This field is being drained by a horizontal well drilled from Gullfaks B. Draining Gullfaks Lunde through wells drilled from Gullfaks C was approved in November 1995, and this field came on stream in 1996.

In recent years, Gullfaks A and C have been modified to receive and process oil and gas from Gullfaks South. This satellite has been developed with subsea wells remotely operated from the A platform (see the next section).

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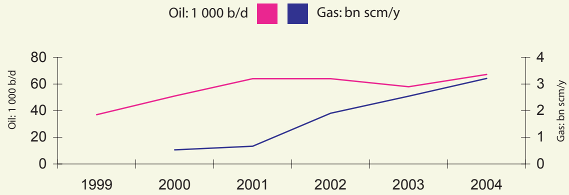

Gullfaks South (incl Rimfaks and Gullveig)

Blocks and production licences	Block 34/10 - production licence 050. Awarded 1978. Block 34/10 - production licence 050B. Awarded 1995. Block 33/12 - production licence 037B. Awarded 1973, carve-out 1998.	
Progress	Government approval (phase I): March 1996 Government approval (phase II): June 1998 Production start-up (phase I): October 1998 Production start-up (phase II): October 2001	
Operator	Statoil ASA	
Licensees	Statoil ASA Petoro AS[1] Norsk Hydro Produksjon a.s	61.00% 30.00% 9.00%
Recoverable reserves	Originally present: 34.0 mill scm oil 34.4 bn scm gas 3.9 mill tonnes NGL	Remaining at 31.12.03: 17.7 mill scm oil 28.9 bn scm gas 3.5 mill tonnes NGL
Production	Estimated production in 2004: Oil: 67 000 b/d Gas: 3.21 bn scm NGL 0.35 mill tonnes	
Investment	Total investment is likely to be NOK 26.2 bn (2004 value). NOK 22.5 bn (2004 value) had been invested at 31.12.03.	
Operating organisation	Bergen	
Main supply bases	Coast Center Base, Sotra og Florø	

[1] Petoro AS serves as the licensee for the SDFI.

Gullfaks South, which also includes the separate Rimfaks and Gullveig structures, is a satellite to Gullfaks and lies in the same water depth. The licensees have pursued a phased development of Gullfaks South.

Gullfaks South phase I embraces the production of oil and condensate. Associated gas is injected back into the reservoirs. This phase comprises eight subsea installations tied back to Gullfaks A for processing, storage and loading of oil and condensate.

Phase II embraces production and export of the gas resources and associated liquids. The development solution is based on subsea installations tied back to Gullfaks A and C. Gas production from Gullfaks South began in the autumn of 2001. After processing, rich gas is transported to Kårstø via a pipeline which ties into Statpipe. Following removal of the NGL, dry gas is piped on to continental Europe. Oil and condensate are stabilised, stored and loaded by existing facilities on the platforms.

In connection with phase II, Gullfaks A and C have been upgraded to expand their gas processing and export capacity.

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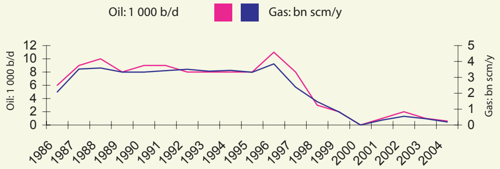


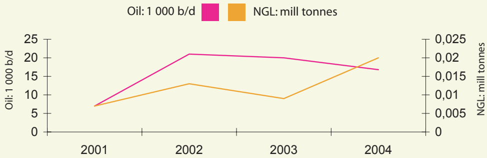
Heimdal

Block and production licence	Block 25/4 - production licence 036 BS. Awarded 2003.	
Progress	Government approval: June 1981 Production start-up: December 1985	
Operator	Norsk Hydro Produksjon a.s	
Licensees	Marathon Petroleum Norge A/S	23.80%
(rounded off to two	Petoro AS[1]	20.00%
decimal places)	Statoil ASA	20.00%
	Norsk Hydro Produksjon a.s	19.27%
	Total E&P Norge AS	16.76%
	AS Uglands Rederi	0.17%
Recoverable reserves	Originally present: 7.1 mill scm oil 42.2 bn scm gas	Remaining at 31.12.03: 0.8 mill scm oil
Production	Estimated production in 2004: Oil: 1 000 b/d Gas: 0.19 bn scm Production is expected to cease in 2005. Heimdal will continue providing processing and transport services as a gas centre.	
Investment	Total investment is likely to be NOK 19.7 bn (2004 value). NOK 19.7 bn (2004 value) had been invested at 31.12.03.	
Operating organisation	Bergen	
Main supply base	Dusavik	

[1] Petoro AS serves as the licensee for the SDFI.

The field was declared commercial in 1974, and the government exercised its option to secure participation in 1982. Heimdal has been developed with an integrated steel platform in 120 metres of water.

In 1998, the MPE received development plans for the Heimdal gas centre, which involved installing a new riser platform as well as modifying and upgrading the existing installation. The MPE approved the plan for development and operation of the Heimdal gas centre in February 1999, and the project came on stream in 2000. It ensures long-term operation of the Heimdal platform by using its capacity to process gas from Huldra and other surrounding fields.



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Huldra

Blocks and production licences	Block 30/2 - production licence 051. Awarded 1979. Block 30/3 - production licence 052B. Awarded 2001.	
Progress	Government approval: February 1999 Production start-up: November 2001	
Operator	Statoil ASA	
Licensees	Petoro AS[1]	31.96%
(rounded off to two	Total E&P Norge AS	24.33%
decimal places)	Norske ConocoPhillips AS	23.34%
	Statoil ASA	19.66%
	Paladin Resources Norge AS	0.50%
	Svenska Petroleum Exploration A/S	0.21%
Recoverable reserves	Originally present:	Remaining at 31.12.03:
	4.7 mill scm oil	2.3 mill scm oil
	12.9 bn scm gas	7.2 bn scm gas
	0.1 mill tonnes NGL	0.1 mill tonnes NGL
Production	Estimated production in 2004: Oil: 17 000 b/d Gas: 2.75 bn scm NGL: 0.02 mill tonnes	
Investment	Total investment is likely to be NOK 7.1 bn (2004 value) NOK 7 bn (2004 value) had been invested at 31.12.03.	

[1] Petoro AS serves as the licensee for the SDFI.

Huldra was proven in 1982 and lies in 125 metres of water. It has been developed with a normally unstaffed wellhead platform remotely operated from Veslefrikk 16 km away. Condensate is piped to Veslefrikk B for processing and onward transport to the crude oil terminal at Sture through the Oseberg Transport System (OTS). The rich gas is piped 145 km to the Heimdal field for processing and export to customers via either the Statpipe/Norpipe system to continental Europe or the Vesterled line to the UK.

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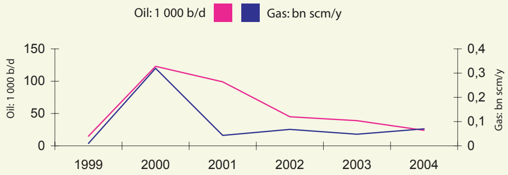


Jotun

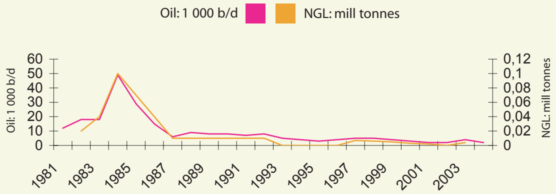
Blocks and production licences	Block 25/8 - production licence 027B. Awarded 1969, carve-out 1999. Block 25/7 - production licence 103B. Awarded 1985, carve-out 1998.	
Progress	Government approval: June 1997 Production start-up: October 1999	
Operator	Esso Expl & Prod Norway AS	
Licensees	Esso Expl & Prod Norway AS	45.00%
	Enterprise Oil Norge AS	45.00%
	Det Norske Oljeselskap AS	7.00%
	Petoro AS[1]	3.00%
Recoverable reserves	Originally present: 25.4 mill scm oil 0.6 bn scm gas	Remaining at 31.12.03: 7.1 mill scm oil
Production	Estimated production in 2004: Oil: 24 000 b/d Gas: 0.07 bn scm	
Investment	Total investment is likely to be NOK 11.3 bn (2004 value). NOK 10.6 bn (2004 value) had been invested at 31.12.03.	
Operating organisation	Stavanger	
Main supply base	Dusavik	

[1] Petoro AS serves as the licensee for the SDFI.

Jotun comprises the Elli, Elli South and Tau West reservoirs, proven in 1994-95. The field lies about 25 km north of Balder and 165 km west of Haugesund, in 126 metres of water. It has been developed with a floating production, storage and offloading (FPSO) unit and a wellhead platform. Ship and platform are tied together by flowlines for oil and gas production and for water injection, as well as power and control cables.

The wellhead platform is normally unstaffed. Oil production is transported by shuttle tankers. Gas is exported through a pipeline tied into the Statpipe system.

From 2004, Jotun will also receive oil and gas from Balder and Ringhorne for processing and onward transport.



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Murchison

Block and production licence	Block 33/9 - production licence 037C. Awarded 2000. The Norwegian share is 22.2 per cent, while the British share is 77.8 per cent.	
Progress	Production start-up: September 1980	
Operator	CNR International (UK) Limited	
Licensees (rounded off to two decimal places)	CNR International (UK) Limited	68.72%
	Statoil ASA	11.52%
	Ranger Oil (UK) Limited	9.08%
	Norske ConocoPhillips AS	2.68%
	Esso Expl & Prod Norway AS	5.55%
	A/S Norske Shell	2.22%
	Enterprise Oil Norge AS	0.23%
Recoverable reserves (Norwegian share)	Originally present:	Remaining at 31.12.03:
	13.6 mill scm oil	0.3 mill scm oil
	0.4 bn scm gas	0.1 bn scm gas
	0.4 mill tonnes NGL	0.1 mill tonnes NGL
Production (Norwegian share)	Estimated production in 2004: Oil: 2 000 b/d	
Investment	The Norwegian share of total investment is likely to be NOK 7.6 bn (2004 value). NOK 7.5 bn (2004 value) had been invested at 31.12.03.	
Operating organisation	Aberdeen, UK	
Main supply base	Peterhead, UK	

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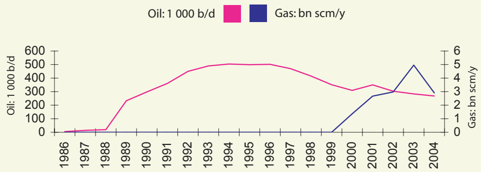
An integrated steel production, drilling and quarters platform has been installed on Murchison, which was discovered in August 1975. Both Norwegian and UK shares of the oil and NGL are landed through the Brent system to Sullom Voe in Shetland, with the gas piped to St Fergus on the Scottish mainland. CNR International (UK) took over as operator in 2002 from Kerr McGee North Sea (UK) Ltd.

(Agreement between Norway and the UK relating to the exploitation of the Murchison reservoir and the offtake of petroleum therefrom. See Proposition no 15 (1980-81) and Recom no 57 (1980-81) to the Storting. Supplementary agreement of 16 October 1979. See Proposition no 68 (1981-82) and Recom no 169 (1981-82) to the Storting.)



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Oseberg (incl Oseberg West, Oseberg East and Oseberg South)

Blocks and production licences	Block 30/6 - production licence 053. Awarded 1979. Block 30/9 - production licence 079, awarded 1982, and production licence 104, awarded 1985. Block 30/12 - production licence 171 B. Awarded 2000	
Progress	Government approval: June 1984 Oseberg West approval: December 1988 Oseberg East approval: October 1996 Oseberg South approval: June 1997 Production start-up (Oseberg field): December 1988	
Operator	Norsk Hydro Produksjon a.s	
Licensees (rounded off to two decimal places)	Norsk Hydro Produksjon a.s Petoro AS[1] Statoil ASA Total E&P Norge AS Mobil Development Norway AS Norske ConocoPhillips AS	34.00% 33.60% 15.30% 10.00% 4.70% 2.40%
Recoverable reserves	Originally present: 440.2 mill scm oil 108.9 bn scm gas	Remaining at 31.12.03: 100.0 mill scm oil 96.0 bn scm gas
Production	Estimated production in 2004: Oil: 270 000 b/d Gas: 3.4 bn scm	
Investment	Total investment is likely to be NOK 105.3 bn (2004 value). NOK 95.1 bn (2004 value) had been invested at 31.12.03.	
Operating organisation	Bergen	
Main supply base	Mongstad	

[1] Petoro AS serves as the licensee for the SDFI.

In connection with the sale of SDFI assets in 2002, licence interests were harmonised in the Oseberg area – the Oseberg Unit (Oseberg and Oseberg West), Oseberg East and the Oseberg South Unit. This harmonisation was intended to ensure more efficient overall development of the area across the underlying production licence boundaries.

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Most of the original oil and gas reserves in the Oseberg area were in the Oseberg Unit. After more than 15 years of production, remaining oil reserves in the Oseberg Unit now correspond approximately to those in Oseberg South. The Oseberg Unit contains the most substantial share of gas reserves in the area.

The first development phase for Oseberg comprised a two-platform field centre. Oseberg A is a production and quarters platform on a concrete gravity base structure, while Oseberg B is a drilling and injection platform with a steel jacket. The second development phase embraced Oseberg C, a steel production, drilling and quarters platform which stands roughly 14 km north of the field centre. Total processing capacity for Oseberg is about 500 000 barrels of oil per day. The platforms stand in around 100 metres of water. Production from the Oseberg field centre in 2004 is expected to total 147 000 b/d of oil and 2.1 bn scm of gas.

Oil from Oseberg is piped through the Oseberg Transport System (OTS) to the Sture terminal near Bergen. The field centre installations are also used to process oil and gas from Oseberg East and South. Oil from these fields, and from Brage and Veslefrikk, is then piped through the OTS from Oseberg A to Sture.

Oseberg D, a steel platform with gas processing and export facilities, was tied to the field centre by a bridge in the spring of 1999. Gas deliveries to continental Europe began from Oseberg in October 2000 through the new Oseberg Gas Transport pipeline which ties into the Statpipe system at Heimdal.

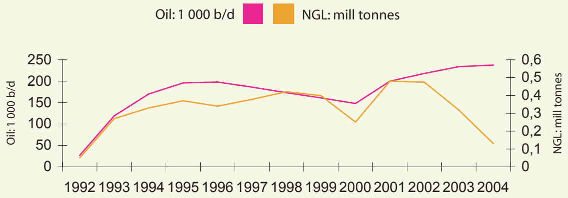
A plan for development and operation (PDO) of Oseberg West Flank was approved by the government in December 2003. This development lies nine km west of the Oseberg field centre, and plans call for it to be developed with a subsea template. Production is expected to start in September 2005.

Comprising several structures south of Oseberg, Oseberg South was proven during 1984 in about 100 metres of water. Six of its structures are included in the approved development plan. The latter involves a platform for partial processing of the oil before it is piped to the Oseberg field centre for further processing and transport to land through the OTS. Gas production is injected back underground, and possible export of these reserves will occur in a later phase. The northern part of the field is being produced through wells drilled from the Oseberg field centre.

A revised PDO for the Oseberg South J structure was approved by the government in May 2003. Located seven km south of the Oseberg South platform, this structure is due to be developed with a subsea template. Production is expected to start in 2004.

Oil began to flow from Oseberg South in February 2000 through a production well drilled from the Oseberg field centre. The Oseberg South platform came on stream in September 2000, and is expected to continue producing until 2028. Production from Oseberg South in 2003 is expected to be 92 000 b/d of oil and 1.18 bn scm of gas.

Located in 160 metres of water in the north-eastern part of the Oseberg area and south of Veslefrikk, Oseberg East was proven in 1981 and has been developed with a platform for quarters, drilling and first-stage separation of oil, water and gas. Crude is piped to Oseberg A for further processing and onward transport via the OTS to Sture. Production from Oseberg East in 2003 is expected to be 30 500 b/d of oil and 0.1 bn scm of gas.



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Snorre (incl Snorre B)

Blocks and production licences	Block 34/4 - production licence 057. Awarded 1979. Block 34/7 - production licence 089. Awarded 1984.	
Progress	Government approval: May 1988 Production start-up: August 1992	
Operator	Statoil ASA	
Licensees	Petoro AS[1]	30.00%
(rounded off to two	Norsk Hydro Produksjon a.s	17.65%
decimal places)	Statoil ASA	14.40%
	Esso Expl & Prod Norway AS	11.16%
	Idemitsu Petroleum Norge AS	9.60%
	RWE Dea Norge AS	8.88%
	Total E&P Norge AS	5.95%
	Amerada Hess Norge AS	1.18%
	Enterprise Oil Norge AS	1.18%
Recoverable reserves	Originally present:	Remaining at 31.12.03:
	236.9 mill scm oil	119.1 mill scm oil
	6.9 bn scm gas	2.0 bn scm gas
	5.3 mill tonnes NGL	1.8 mill tonnes NGL
Production	Estimated production in 2004: Oil: 238 000 b/d Gas: 0.07 bn scm NGL: 0.13 mill tonnes	
Investment	Total investment is likely to be NOK 71 bn (2004 value). NOK 59 bn (2004 value) had been invested at 31.12.03.	
Operating organisation	Stavanger	
Main supply base	Florø	

[1] Petoro AS serves as the licensee for the SDFI.

Proven in 1979, Snorre lies east of Statfjord in about 300-350 metres of water. Its southern area has been developed with a tension leg platform and a subsea production system. This part of the field contained about 150 mill scm of Snorre's original recoverable oil reserves.

A plan for development and operation of the northern part of the field (Snorre B) was approved in June 1998. This project involves a semi-submersible drilling and production platform, which came on stream in June 2001. Oil and gas from Snorre are piped to Statfjord for final processing, storage and export.

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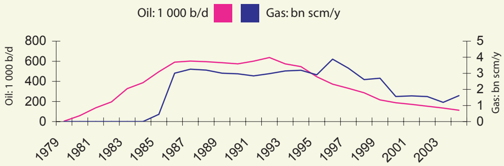

Statfjord

Blocks and production licence	Blocks 33/9 and 33/12 - production licence 037. Awarded 1973. Norway's share of the field is 85.47 per cent, Britain's is 14.53 per cent.	
Progress	Government approval: 1976 Production start-up: November 1979	
Operator	Statoil ASA	
Licensees	Statoil ASA	44.34%
(rounded off to two	Esso Expl & Prod Norway AS	21.37%
decimal places)	Norske ConocoPhillips AS	10.33%
	A/S Norske Shell	8.55%
	Conoco (UK) Ltd	4.84%
	ChevronTexaco UK Ltd	4.84%
	BP Petroleum Development Ltd	4.84%
	Enterprise Oil Norge AS	0.89%
Recoverable reserves	Originally present:	Remaining at 31.12.03:
(Norwegian share)	556.6 mill scm oil	21.9 mill scm oil
	57.2 bn scm gas	9.6 bn scm gas
	14.4 mill tonnes NGL	3.7 mill tonnes NGL
Production (Norwegian share)	Estimated production in 2004: Oil: 113 000 b/d Gas: 1.61 bn scm NGL: 0.43 mill tonnes	
Investment	The Norwegian share of total investment is likely to be NOK 117.5 bn (2004 value). NOK 113 bn (2004 value) had been invested at 31.12.03.	
Operating organisation	Stavanger	
Main supply bases	Coast Center Base, Sotra and Florø	

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Proven in 1974, Statfjord lies in about 145 metres of water and extends into the UK North Sea. A treaty has been concluded between the UK and Norway on the exploitation of the Statfjord field. It has been developed with three fully-integrated platforms supported by gravity base structures featuring concrete storage cells. These installations have a combined processing capacity of 850 000 b/d. Each platform is tied to a buoy for loading stabilised oil into tankers. The platforms came on stream in November 1979, November 1982 and June 1985 respectively.

Gas sales began in October 1985. Norway's share has been sold to a consortium of European buyers and is piped to Emden in Germany via the Statpipe/Norpipe system. The UK share of gas output has been sold to British Gas, and is landed in the UK via the Far North Liquids and Associated Gas System (Flags). Oil transport is organised by K/S Statfjord Transport, in which Statoil has a 50 per cent interest.

A unitisation agreement has been signed between the UK and Norwegian licensees. The operatorship for production licence 037 and the unitised field was transferred from Mobil to Statoil on 1 January 1987.

Oil and gas from Snorre, Sygna, Statfjord East and Statfjord North are processed on and exported from the Statfjord installations.

(Agreement between Norway and the UK relating to the Statfjord reservoir and the transmission of petroleum therefrom. See Proposition no 15 (1980-81) and Recom no 57 (1980-81) to the Storting.)

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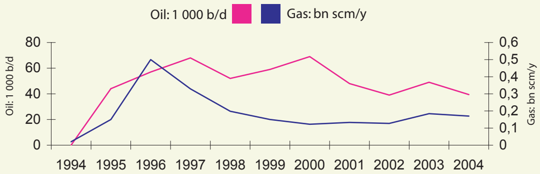
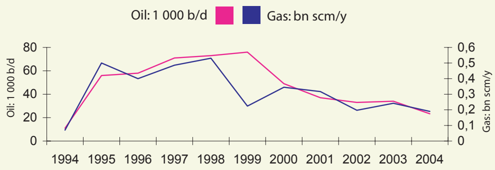


Statfjord North

Block and production licence	Block 33/9 - production licence 037. Awarded 1973.	
Progress	Government approval: December 1990 Production start-up: January 1995	
Operator	Statoil ASA	
Licensees (rounded off to two decimal places)	Petoro AS[1] Statoil ASA Esso Expl & Prod Norway AS Norske ConocoPhillips AS A/S Norske Shell Enterprise Oil Norge AS	30.00% 21.88% 25.00% 12.08% 10.00% 1.04%
Recoverable reserves	Originally present: 39.7 mill scm oil 2.6 bn scm gas 0.9 mill tonnes NGL	Remaining at 31.12.03: 11.5 mill scm oil 1.1 bn scm gas 0.5 mill tonnes NGL
Production	Estimated production in 2004: Oil: 39 000 b/d Gas: 0.17 bn scm NGL: 0.06 mill tonnes	
Investment	Total investment is likely to be NOK 7.8 bn (2004 value). NOK 7.4 bn (2004 value) had been invested at 31.12.03.	
Operating organisation	Stavanger	
Main supply bases	Coast Center Base, Sotra	

[1] Petoro AS serves as the licensee for the SDFI.

Discovered in 1977, Statfjord North is about 17 km north of Statfjord. It has been developed with subsea installations in 250-290 metres of water, tied back to Statfjord C for processing and export.



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Statfjord East

Blocks and production licences	Block 33/9 - production licence 037. Awarded 1973. Block 34/7 - production licence 089. Awarded 1984.	
Progress	Government approval: December 1990 Production start-up: September 1994	
Operator	Statoil ASA	
Licensees	Petoro AS[1]	30.00%
(rounded off to two	Statoil ASA	25.05%
decimal places)	Esso Expl & Prod Norway AS	17.70%
	Norsk Hydro Produksjon a.s	6.64%
	Norske ConocoPhillips AS	6.04%
	A/S Norske Shell	5.00%
	Idemitsu Petroleum Norge AS	4.80%
	Total E&P Norge AS	2.80%
	RWE Dea Norge AS	1.40%
	Enterprise Oil Norge AS	0.52%
Recoverable reserves	Originally present: 35.8 mill scm oil 4.0 bn scm gas 1.5 mill tonnes NGL	Remaining at 31.12.03: 7.5 mill scm oil 1.7 bn scm gas 0.8 mill tonnes NGL
Production	Estimated production in 2004: Oil: 23 000 b/d Gas: 0.19 bn scm NGL: 0.07 mill tonnes	
Investment	Total investment is likely to be NOK 7.2 bn (2004 value). NOK 6.3 bn (2004 value) had been invested at 31.12.03.	
Operating organisation	Stavanger	
Main supply bases	Coast Center Base, Sotra	

[1] Petoro AS serves as the licensee for the SDFI.

Statfjord East was discovered in 1976 and lies about seven km north-east of Statfjord. It has been developed with subsea installations in 150-190 metres of water, tied back to Statfjord C for processing and export.

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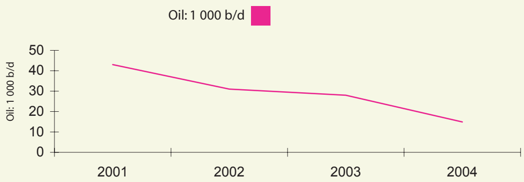
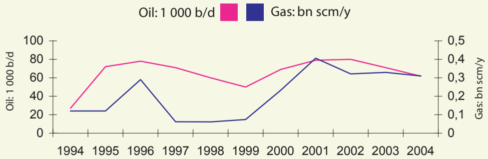


Sygna

Blocks and production licences	Block 33/9 - production licence 037. Awarded 1973. Block 34/7 - production licence 089. Awarded 1984.	
Progress	Government approval: April 1999 Production start-up: August 2000	
Operator	Statoil ASA	
Licensees (rounded off to two decimal places)	Petoro AS[1]	30.00%
	Statoil ASA	24.73%
	Esso Expl & Prod Norway AS	18.48%
	Norske ConocoPhillips AS	6.65%
	Norsk Hydro Produksjon a.s	5.98%
	A/S Norske Shell	5.50%
	Idemitsu Petroleum Norge AS	4.32%
	Total E&P Norge AS	2.52%
	RWE Dea Norge AS	1.26%
	Enterprise Oil Norge AS	0.57%
Recoverable reserves	Originally present: 10.2 mill scm oil	Remaining at 31.12.03: 3.6 mill scm oil
Production	Estimated production in 2004: Oil: 15 000 b/d	
Investment	Total investment is likely to be NOK 2.3 bn (2004 value). NOK 2.1 bn (2004 value) had been invested at 31.12.03	
Operating organisation	Stavanger	
Main supply base	Florø	

[1] Petoro AS serves as the licensee for the SDFI.

Proven in 1996, this field straddles the boundary between production licences 037 (Statfjord) and 089 (Snorre). Sygna has been developed with a subsea installation tied back to Statfjord C. Water injection capacity to the Statfjord North area was upgraded in 1999 in order to supply Sygna with injection water.



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Tordis (incl Tordis East and Borg)

Block and production licence	Block 34/7 - production licence 089. Awarded 1984.	
Progress	Government approval: May 1991 Production start-up: June 1994	
Operator	Statoil ASA	
Licensees	Petoro AS[1]	30.00%
	Statoil ASA	28.22%
	Norsk Hydro Produksjon a.s	13.28%
	Esso Expl & Prod Norway AS	10.50%
	Idemitsu Petroleum Norge AS	9.60%
	Total E&P Norge AS	5.60%
	RWE Dea Norge AS	2.80%
Recoverable reserves	Originally present:	Remaining at 31.12.03:
	58.1 mill scm oil	18.0 mill scm oil
	5.0 bn scm gas	1.9 bn scm gas
	1.7 mill tonnes NGL	0.7 mill tonnes NGL
Production	Estimated production in 2004: Oil: 62 000 b/d Gas: 0.31 bn scm NGL: 0.12 mill tonnes	
Investment	Total investment is likely to be NOK 9.3 bn (2004 value). NOK 8.6 bn (2004 value) had been invested at 31.12.03	
Operating organisation	Stavanger	
Main supply base	Florø	

[1] Petoro AS serves as the licensee for the SDFI.

The Tordis area embraces Tordis East and Borg as well as Tordis itself. Lying between Snorre and Gullfaks, Tordis was discovered in 1987 and came on stream in July 1994. A subsea development in about 200 metres of water is tied back to Gullfaks C, where the wellstream is processed.

Tordis East, Borg and another structure (STUJ) have been developed with subsea installations tied back to the Tordis production facilities, and came on stream in December 1998, July 1999 and December 2001 respectively.

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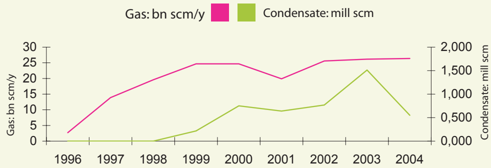

Troll phase I

Blocks and production licences	Block 31/2 - production licence 054. Awarded 1979. Blocks 31/3, 31/5 and 31/6 - production licence 085. Awarded 1983. Blocks 31/3 and 31/6 - production licence 085C. Awarded 2002	
Progress	Government approval: December 1986 Production start-up: February 1996	
Operator	A/S Norsk Shell was operator for the development phase. Statoil ASA is operator for the production phase.	
Licensees (rounded off to two decimal places)	Petoro AS[1]	56.00%
	Statoil ASA	20.80%
	Norsk Hydro Produksjon a.s	9.78%
	A/S Norske Shell	8.10%
	Total E&P Norge AS	3.69%
	Norske ConocoPhillips AS	1.62%
Recoverable reserves	Originally present: 1 325.7 bn scm gas 31.6 mill tonnes NGL 1.6 mill scm condensate	Remaining at 31.12.03: 1 162.6 bn scm gas 31.6 mill tonnes NGL
Production	Estimated production in 2004: Gas: 26.39 bn scm NGL: 0.55 mill tonnes	
Investment	Total investment is likely to be NOK 61.3 bn (2004 value). NOK 48.2 bn (2004 value) had been invested at 31.12.03.	
Transport	Gas from Troll is transported from Kollsnes through Zeepipe to Zeebrugge and Statpipe/Norpipe to Emden. The Franpipe line to Dunkerque has also been used since 1998. Condensate is shipped from Mongstad.	
Operating organisation	Bergen	
Main supply base	Ågotnes	

[1] Petoro AS serves as the licensee for the SDFI.

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Discovered in 1979, Troll lies about 65 km off Kollsnes near Bergen and comprises two main structures: Troll East and Troll West. The first of these primarily occupies blocks 31/3 and 31/6, while most of Troll West is found in block 31/2. Roughly two-thirds of the field's recoverable gas reserves are thought to lie in Troll East.

A staged development has been pursued, with phase I covering gas reserves in the eastern region and phase II focusing on the oil reserves in Troll West. Phase III will cover gas reserves in the latter area.

The original phase I plan, approved in 1986, called for an integrated production, drilling and quarters platform in 330 metres of water, but this was amended in the spring of 1990 to a single wellhead platform and a land-based processing plant at Kollsnes near Bergen. NGL is piped to the Vestprosess plant at Mongstad. The authorities approved these revised proposals in December 1990.

Ownership of the Kollsnes plant was transferred from the Troll licensees to the Gassled participants on 1 February 2004.

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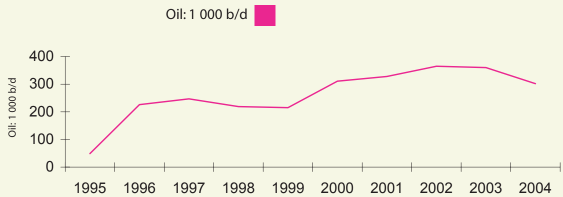

Troll phase II

Blocks and production licences	Block 31/2 - production licence 054. Awarded 1979. Blocks 31/3, 31/5 and 31/6 - production licence 085. Awarded 1983. Blocks 31/3 and 31/6 - production licence 085C. Awarded 2002	
Progress	Government approval: May 1992 Production start-up: September 1995	
Operator	Norsk Hydro Produksjon a.s	
Licensees	Petoro AS[1]	56.00%
(rounded off to two	Statoil ASA	20.80%
decimal places)	Norsk Hydro Produksjon a.s	9.78%
	A/S Norske Shell	8.10%
	Total E&P Norge AS	3.69%
	Norske ConocoPhillips AS	1.62%
Recoverable reserves	Originally present: 230.6 mill scm oil Gas reserves are included under Troll phase I.	Remaining at 31.12.03: 92.1 mill scm oil
Production	Estimated production in 2004: Oil: 302 000 b/d.	
Investment	Total investment is likely to be NOK 66.4 bn (2004 value). NOK 61.7 bn (2004 value) had been invested at 31.12.03.	
Operating organisation	Bergen	
Main supply base	Mongstad	

[1] Petoro AS serves as the licensee for the SDFI.

A thin oil layer underlies the whole Troll field, but is only sufficiently thick for commercial recovery in the Troll West region. The latter divides into oil and gas provinces, where the thickness of the oil-bearing zones is 22-27 and 11-14 metres respectively. Test production from the two provinces in 1990 and 1991 yielded positive results.

Crude is being produced from the oil province with horizontally-drilled wells tied back to the Troll B floating production platform. All 20 of the planned production wells are currently in operation, together with one gas injector. The crude is landed through Troll Oil Pipeline I to the terminal at Mongstad near Bergen. Associated gas is exported via the Troll A platform on Troll East to the Kollsnes processing plant.

Oil production from the first Troll B well cluster in the gas province began during November 1995. At 31 December 2003, 36 of 38 planned wells tied back to Troll B were in operation in the gas province.

The floating Troll C production platform came on stream in late October 1999 to recover oil from the northern part of the gas province. At 31 December 2003, 45 of 55 production wells were in operation in addition to a water injector for the Troll Pilot project. Oil from Troll C is landed through Troll Oil Pipeline II to Mongstad, with associated gas exported via Troll A.

Testing of the Troll Pilot, a subsea separation plant, began in the summer of 2000. Since then, a total of two mill scm of water has been separated from the wellstream and injected back into the reservoir.

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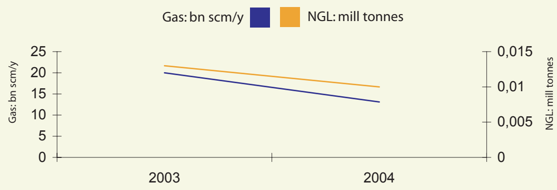


Tune

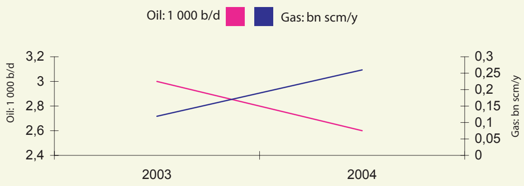
Blocks and production licences	Block 30/5 - production licence 034. Awarded 1969. Block 30/6 - production licence 053. Awarded 1979. Block 30/8 - production licence 190. Awarded 1993.	
Progress	Government approval: December 1999 Production start-up: 28 November 2002	
Operator	Norsk Hydro Produksjon a.s	
Licensees	Petoro AS[1] Norsk Hydro Produksjon a.s Total E&P Norge AS	40.00% 40.00% 20.00%
Recoverable reserves	Originally present: 2.7 mill scm oil 12.9 bn scm gas 0.1 mill tonnes NGL	Remaining at 31.12.03: 1.6 mill scm oil 12.9 bn scm gas
Production	Estimated production in 2004: Oil: 13 000 b/d Gas 3.4 bn scm, NGL 0.01 mill tonnes	
Investment	Total investment is likely to be NOK 3.7 bn (2004 value). NOK 3.7 bn (2004 value) had been invested at 31.12.03.	

[1] Petoro AS serves as the licensee for the SDFI.

Tune is a gas and condensate field proven in 1995, about 10 km west of the Oseberg field centre. The bulk of its reserves lie in production licence 190, but part of them extends into production licences 034 and 053. Licence interests in 034 and 190 are the same, and the Tune licensees have purchased production rights for the reserves extending into 053.

Phase I of the development covers four production wells drilled from a subsea installation centrally placed on the field and tied back to Oseberg D through two 12-inch flowlines and an umbilical. A Tune receiving module has been built on Oseberg D.

Tune condensate will be stabilised at the Oseberg field centre and piped to Sture through the Oseberg Transport System. Gas from the field is being injected in Oseberg, while the Tune licensees receive sales gas in exchange from the Oseberg Unit at the inlet to the Oseberg Gas Transport system.



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Vale

Block and production licence	Block 25/4 - production licence 036. Awarded 1971.	
Progress	Government approval: March 2001 Production start-up: 31 May 2002	
Operator	Norsk Hydro Produksjon a.s	
Licensees (rounded off to two decimal places)	Marathon Petroleum Norge A/S Norsk Hydro Produksjon a.s Total E&P Norge AS AS Uglands Rederi	46.90% 28.53% 24.24% 0.32%
Recoverable reserves	Originally present: 0.9 mill scm oil 2.6 bn scm gas	Remaining at 31.12.03: 0.7 mill scm oil 2.4 bn scm gas
Production	Estimated production in 2004: Oil: 3 000 b/d Gas: 0.26 bn scm.	
Investment	Total investment is likely to be NOK 2 bn (2004 value). NOK 1.5 bn (2004 value) had been invested at 31.12.03.	

Proven in 1991, Vale lies 16 km north of Heimdal and has been developed with a single subsea well, a seabed template and a 16.5-km flowline. The latter is tied back to the Heimdal platform for processing the wellstream. Existing pipeline systems are being used to export the field's output.

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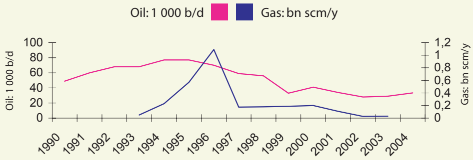


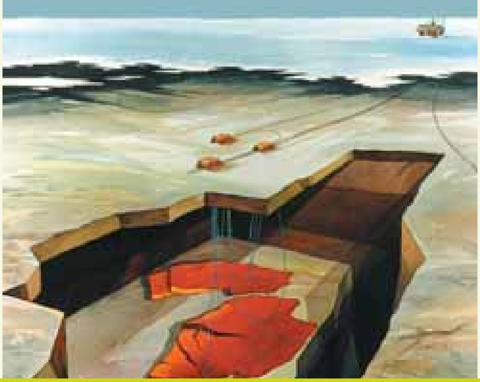
Veslefrikk

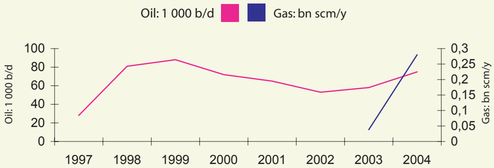
Blocks and production licences	Block 30/3 - production licence 052. Awarded 1979. Block 30/6 - production licence 053. Awarded 1979.	
Progress	Government approval: June 1987 Production start-up: December 1989	
Operator	Statoil ASA	
Licensees	Petoro AS[1]	37.00%
	Statoil ASA	18.00%
	Total E&P Norge AS	18.00%
	RWE Dea Norge AS	13.50%
	Paladin Resources Norge AS	9.00%
	Svenska Petroleum Exploration A/S	4.50%
Recoverable reserves	Originally present: 55.0 mill scm oil 2.2 bn scm gas 1.1 mill tonnes NGL	Remaining at 31.12.03: 11.4 mill scm oil 0.1 bn scm gas
Production	Estimated production in 2004: Oil: 33 000 b/d	
Investment	Total investment is likely to be NOK 17.4 bn (2004 value). NOK 16.3 bn (2004 value) had been invested at 31.12.03.	
Operating organisation	Bergen	
Main supply bases	Coast Center Base, Sotra and Florø	

[1] Petoro AS serves as the licensee for the SDFI.

Proven in 1981, Veslefrikk has been developed with the fixed A wellhead platform and the B semi-submersible for processing and quarters in about 175 metres of water. The oil is piped to Oseberg A for onward transmission through the Oseberg Transport System (OTS) to the terminal at Sture near Bergen, while the gas travels via Statpipe.

Veslefrikk B was taken to land in the summer of 1999 to reinforce its steel hull and to make the modifications required to receive Huldra condensate from the autumn of 2001. The normally unstaffed platform on the latter field is remotely operated from Veslefrikk B.





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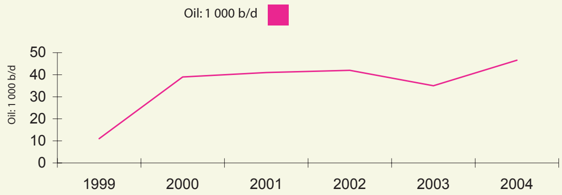
Vigdis

Block and production licence	Block 34/7 - production licence 089. Awarded 1984.	
Progress	Government approval: December 1994 Production start-up: January 1997	
Operator	Statoil ASA	
Licensees	Petoro AS[1]	30.00%
	Statoil ASA	28.22%
	Norsk Hydro Produksjon a.s	13.28%
	Esso Expl & Prod Norway AS	10.50%
	Idemitsu Petroleum Norge AS	9.60%
	Total E&P Norge AS	5.60%
	RWE Dea Norge AS	2.80%
Recoverable reserves	Originally present:	Remaining at 31.12.03:
	42.1 mill scm oil	16.4 mill scm oil
	3.2 bn scm gas	3.2 bn scm gas
	0.4 mill tonnes NGL	0.3 mill tonnes NGL
Production	Estimated production in 2004: Oil: 75 000 b/d	
Investment	Total investment is likely to be NOK 10.4 bn (2004 value). NOK 9.4 bn (2004 value) had been invested at 31.12.03.	

[1] Petoro AS serves as the licensee for the SDFI.

Located between Snorre and Gullfaks, Vigdis was discovered in 1986 and began production in January 1997. It has been developed with subsea installations in 280 metres of water. These are tied back to Snorre, where the petroleum is processed. Stabilised crude oil is transferred via a dedicated pipeline to Gullfaks A for storage and loading into tankers.

The Vigdis extension project was approved by the government in December 2002 and came on stream in the autumn of 2003. This development extends production from the existing field.



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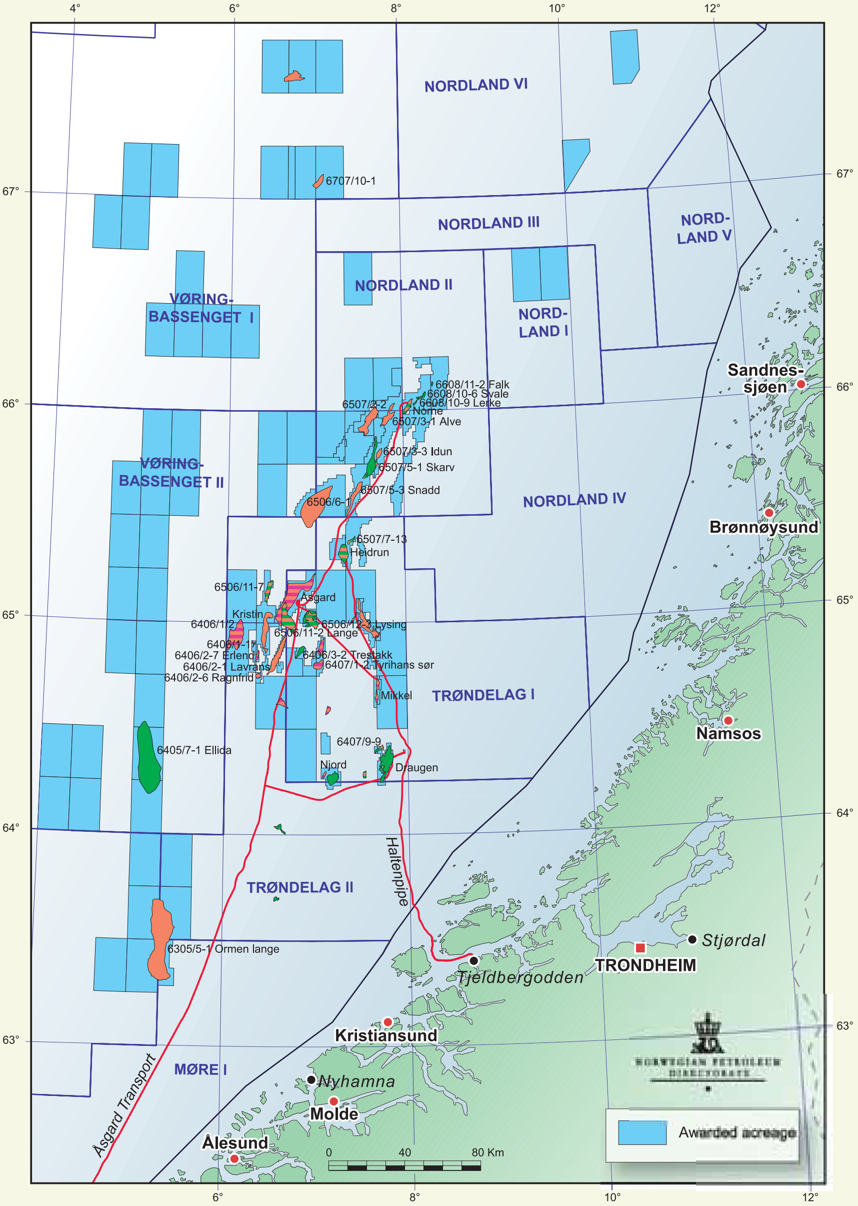
Visund

Block and production licence	Block 34/8 - production licence 120. Awarded 1985.	
Progress	Government approval: March 1996 Production start-up: April 1999	
Operator	Statoil ASA	
Licensees	Statoil ASA Petoro AS[1] Norsk Hydro Produksjon a.s Norske ConocoPhillips AS Total E&P Norge AS	32.90% 30.00% 20.30% 9.10% 7.70%
Recoverable reserves	Originally present: 33.3 mill scm oil 55.5 bn scm gas 6.7 mill tonnes NGL	Remaining at 31.12.03: 23.4 mill scm oil 55.5 bn scm gas 6.7 mill tonnes NGL
Production	Estimated production in 2004: Oil: 47 000 b/d	
Investment	Total investment is likely to be NOK 20.9 bn (2004 value). NOK 15.9 bn (2004 value) had been invested at 31.12.03.	
Operating organisation	Bergen	
Main supply base	Florø	

[1] Petoro AS serves as the licensee for the SDFI.

Proven in 1986, Visund lies east of Snorre. It has been developed with a steel-hulled floating platform for production, drilling and quarters, with oil piped to Gullfaks A for storage and export.

Visund gas export was approved by the government in October 2002. This project involves a new pipeline from Visund to tie into the Kvitebjørn gas pipeline for onward transport to Kollsnes. The gas will be processed in the NGL plant at Kollsnes and transported through the existing pipeline to continental Europe.



Norwegian Sea

The Norwegian Sea was opened for exploration in connection with the fifth offshore licensing round in 1979. The Draugen oil field was the first Norwegian Sea discovery to be developed, and came on stream in October 1993. Heidrun, Njord, Norne, Åsgard and Mikkel have since started production, while a plan for development and operation (PDO) for Kristin was approved in 2001. Roughly 20 per cent of Norway's oil production derived from the Norwegian Sea in 2002. This region also contains substantial gas resources, including the Ormen Lange field.

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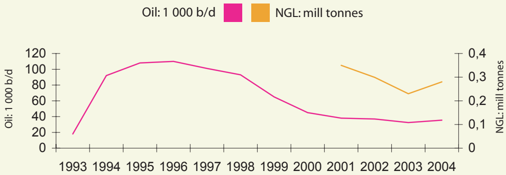


Draugen

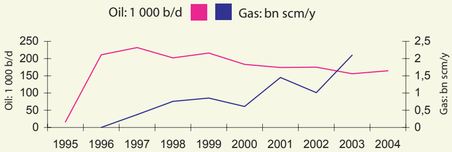
Block and production licence	Block 6407/9 - production licence 093. Awarded 1984.	
Progress	Government approval: December 1988 Production start-up: October 1993	
Operator	A/S Norske Shell	
Licensees	Petoro AS[1]	47.88%
	A/S Norske Shell	26.20%
	BP Norge AS	18.36%
	Chevron Texaco Norge AS	7.56%
Recoverable reserves	Originally present:	Remaining at 31.12.03:
	132.2 mill scm oil	36.8 mill scm oil
	6.0 bn scm gas	5.3 bn scm gas
	1.9 mill tonnes NGL	1.0 mill tonnes NGL
Production	Estimated production in 2004: Oil: 142 000 b/d Gas: 0.22 bn scm NGL: 0.28 mill tonnes	
Investment	Total investment is likely to be NOK 25.9 bn (2004 value). NOK 25.4 bn (2004 value) had been invested at 31.12.03.	
Operating organisation	Kristiansund	
Main supply base	Kristiansund	

[1] Petoro AS serves as the licensee for the SDFI.

Draugen was discovered in 1984 in 251 metres of water, and has been developed with a concrete monotower gravity base structure supporting an integrated topside. The field is currently producing from six horizontal platform wells.

Reserves consist mainly of oil. Associated gas is piped to Kårstø via a tie-in with the Åsgard Transport trunkline. Oil is loaded into shuttle tankers on the field via two flowlines which link the platform with a floating loading buoy.

Garn West, a separate oil deposit in the Draugen field, was developed and brought on stream in 2001 with two subsea wells tied back via a flexible flowline to the Draugen platform. A similar structure, Rogn South, was developed and brought on stream via Garn West during 2002.



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Heidrun

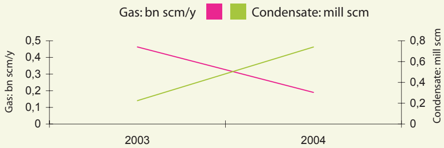
Blocks and production licences	Block 6507/7 - production licence 095. Awarded 1984. Block 6507/8 - production licence 124. Awarded 1986.	
Progress	Government approval: May 1991 Production start-up: October 1995	
Operator	Statoil ASA	
Licensees	Petoro AS[1]	58.16%
(rounded off to two	Norske ConocoPhillips AS	24.29%
decimal places)	Statoil ASA	12.43%
	Eni Norge AS	5.12%
Recoverable reserves	Originally present:	Remaining at 31.12.03:
	175.0 mill scm oil	84.0 mill scm oil
	40.7 bn scm gas	33.9 bn scm gas
	2.6 mill tonnes NGL	2.4 mill tonnes NGL
Production	Estimated production in 2004: Oil: 165 000 b/d Gas: 0.65 bn scm NGL: 0.1 mill tonnes	
Investment	Total investment is likely to be NOK 62 bn (2004 value). NOK 53.6 bn (2004 value) had been invested at 31.12.03.	
Operating organisation	Stjørdal	
Main supply base	Kristiansund	

[1] Petoro AS serves as the licensee for the SDFI.

The Heidrun field was discovered in 1985 and lies in some 350 metres on the Halten Bank off mid-Norway. A revised development plan submitted in December 1989 was approved by the government, and embraces a concrete tension leg platform (TLP).

Heidrun's northern flank is being developed with subsea installations in order to phase in resources in this part of the field.

Associated gas from Heidrun is carried in the dedicated Haltenpipe line to Tjeldbergodden in mid-Norway for conversion to methanol. The separate Heidrun gas export pipeline ties into the Åsgard Transport system to transport gas to Kårstø.

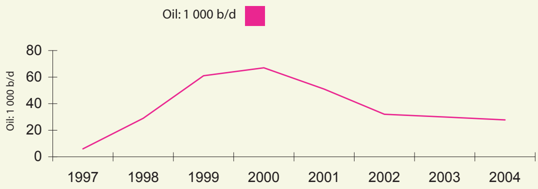


Mikkel

Blocks and production licences	Block 6407/6 - production licence 092. Awarded 1984. Block 6407/5 - production licence 121. Awarded 1986.	
Progress	Government approval: September 2001 Planned production start-up: October 2003	
Operator	Statoil ASA	
Licensees	Statoil ASA	41.62%
	Mobil Development Norway AS	33.48%
	Norsk Hydro Produksjon a.s	10.00%
	Eni Norge AS	14.90%
Recoverable reserves	Originally present	Remaining at 31.12.03
	23.9 bn scm gas	23.5 bn scm gas
	5.9 mill tonnes NGL	5.8 mill tonnes NGL
	6.7 mill scm condensate	6.5 mill scm condensate
Production	Estimated production in 2004: Gas: 0.19 bn scm NGL: 0.44 mill tonnes Condensate: 0.74 mill scm	
Investment	Total investment is likely to be NOK 2 bn (2004 value) NOK 1.9 bn (2004 value) had been invested at 31.12.03	
Operating organisation	Stjørdal	
Main supply base	Kristiansund	

Proven in 1987, Mikkel lies in 220 metres of water on Halten Bank East, about 40 km south of Åsgard's Midgard deposit and 40 km north of Draugen. The plan for development and operation was approved in September 2001 and the field came on stream in October 2003.

The field has been developed with two subsea templates housing a total of four production wells tied back via Midgard to Åsgard B. Condensate is separated on the platform, with the rich gas being piped through Åsgard Transport to Kårstø for separation of the NGL. After being stabilised, condensate is stored and shipped away together with Åsgard's own production.



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Njord

Blocks and production licences	Block 6407/7 - production licence 107. Awarded 1985. Block 6407/10 - production licence 132. Awarded 1987.	
Progress	Government approval: June 1995 Production start-up: September 1997	
Operator	Norsk Hydro Produksjon a.s	
Licensees	Norsk Hydro Produksjon a.s	20.00%
	Gaz de France Norge AS	20.00%
	Mobil Development Norway AS	20.00%
	Ruhrgas Norge AS	15.00%
	Paladin Resources Norge AS	15.00%
	Petoro AS[1]	7.50%
	OER Oil AS	2.50%
Recoverable reserves	Originally present: 23.0 mill scm oil	Remaining at 31.12.03: 6.9 mill scm oil
Production	Estimated production in 2004: Oil: 28 000 b/d.	
Investment	Total investment is likely to be NOK 10.9 bn (2004 value). NOK 10.9 bn (2004 value) had been invested at 31.12.03.	
Operating organisation	Kristiansund	
Main supply base	Kristiansund	

[1] Petoro AS serves as the licensee for the SDFI.

Njord was proven in 1986 and lies in 330 metres of water about 30 km west of Draugen. Coming on stream in September 1997, the field has been developed with a steel-hulled semi-submersible production, drilling and quarters platform - Njord A. Subsea wells are tied back to this facility, with oil stored in a dedicated vessel - Njord B - located 2.5 km from the production platform.

The crude is transferred via a flowline, with power supplied by cable from the platform. Oil is loaded into shuttle tankers for transport to the market. Njord B is remotely operated from the A platform except during discharging operations and maintenance campaigns.

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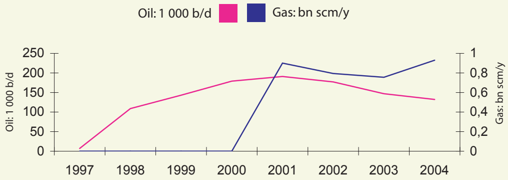
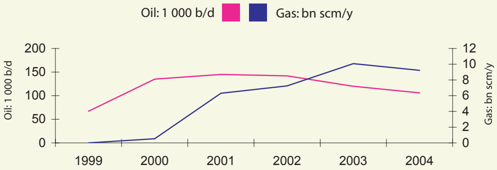


Norne

Blocks and production licences	Block 6608/10 - production licence 128. Awarded 1986. Block 6508/1 - production licence 128B. Awarded 1998.	
Progress	Government approval: March 1995 Production start-up: November 1997	
Operator	Statoil ASA	
Licensees	Petoro AS[1]	54.00%
	Statoil ASA	25.00%
	Norsk Hydro Produksjon a.s	8.10%
	Eni Norge AS	6.90%
	Enterprise Oil Norge AS	6.00%
Recoverable reserves	Originally present:	Remaining at 31.12.03:
	87.4 mill scm oil	31.8 mill scm oil
	13.7 bn scm gas	11.0 bn scm gas
	1.8 mill tonnes NGL	1.6 mill tonnes NGL
Production	Estimated production in 2004: Oil: 132 000 b/d Gas: 0.93 bn scm NGL: 0.12 mill tonnes	
Investment	Total investment is likely to be NOK 18.8 bn (2004 value). NOK 16.4 bn (2004 value) had been invested at 31.12.03.	
Operating organisation	Harstad	
Main supply base	Sandnessjøen	

[1] Petoro AS serves as the licensee for the SDFI.

Norne lies in 380 metres of water, about 80 km north of Heidrun and roughly 200 km from the north Norwegian coast. The field has been developed with a production and storage ship tied to subsea templates. Flexible risers carry wellstreams to the vessel, which weathervanes around a cylindrical turret moored to the seabed. This ship carries processing facilities on its deck and storage tanks for oil. Processed crude can be transferred over the stern to tankers. A pipeline tied into the Åsgard Transport system has been laid for gas export.



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Åsgard

Blocks and production licences	Block 6407/2 - production licence 074. Awarded 1982. Block 6407/3 - production licence 237. Awarded 1998. Block 6506/11 - production licence 134. Awarded 1987. Block 6506/12 - production licence 094. Awarded 1984. Block 6507/11 - production licence 062. Awarded 1981. Block 6406/3 - production licence 094B. Awarded 2002	
Progress	Government approval: June 1996 Production start-up: May 1999	
Operator	Statoil ASA	
Licensees	Petoro AS[1]	35.50%
	Statoil ASA	25.00%
	Norsk Hydro Produksjon a.s	9.60%
	Eni Norge AS	14.90%
	Total E&P Norge AS	7.65%
	Mobil Development Norway AS	7.35%
Recoverable reserves	Originally present:	Remaining at 31.12.03:
	69.6 mill scm oil	34.3 mill scm oil
	193.1 bn scm gas	171.4 bn scm gas
	34.7 mill tonnes NGL	34.7 mill tonnes NGL
	45.9 mill scm condensate	37.4 mill scm condensate
Production	Estimated production in 2004: Oil: 106 000 b/d Gas: 9.22 bn scm NGL: 1.72 mill tonnes Condensate: 3.9 mill scm	
Investment	Total investment is likely to be NOK 59 bn (2004 value). NOK 55.8 bn (2004 value) had been invested at 31.12.03.	
Operating organisation	Stjørdal	
Main supply base	Kristiansund	

[1] Petoro AS serves as the licensee for the SDFI.

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Åsgard comprises the Midgard, Smørbukk and Smørbukk South discoveries, made in 1981, 1984 and 1985 respectively. Water depths are in the 240-300 metre range.

The field has been developed with the Åsgard A production ship for oil and condensate, which came on stream in May 1999, and the Åsgard B floating gas platform. The latter began production in October 2000.

Rich gas is piped to Kårstø north of Stavanger for processing and fractionation of the liquid components, with the dry gas sent on to continental Europe through the Europipe II line.

Fields which have ceased production

The following fields had ceased to produce at 31 December 2003:

Albuskjell

Blocks	1/6 and 2/4
Development approved	1975
Cessation plan/ decommissioning	The cessation plan was approved by the authorities on 21 December 2001 and in Report no 47 (1999-2000) to the Storting.
Production start-up	1979
Production ceased	1998
Total production over field lifetime	Oil: 7.4 mill scm Gas: 15.5 bn scm NGL: 1 mill tonnes

Cod

Block	7/11
Development approved	1973
Cessation plan/ decommissioning	The cessation plan was approved by the authorities on 21 December 2001 and in Report no 47 (1999-2000) to the Storting.
Production start-up	1977
Production ceased	1998
Total production over field lifetime	Oil: 2.9 mill scm Gas: 7.3 bn scm NGL: 0.5 mill tonnes

East Frigg

Block	25/1 and 25/2
Development approved	1984
Cessation plan/ decommissioning	Storting proposition no 8 (1998-1999) and Report no 47 (1999-2000) to the Storting.
Production start-up	1988
Production ceased	1997
Total production over field lifetime	Gas: 9.4 bn scm Condensate: 0.1 mill scm

Edda

Block	2/7
Development approved	1975
Cessation plan/ decommissioning	The cessation plan was approved by the authorities on 21 December 2001 and in Report no 47 (1999-2000) to the Storting.
Production start-up	1979
Production ceased	1998
Total production over field lifetime	Oil: 4.8 mill scm Gas: 2.1 bn scm NGL: 0.2 mill tonnes

Frøy

Blocks	25/2 and 25/5
Development approved	1992
Cessation plan/ decommissioning	The cessation plan was approved by the authorities on 29 May 2001 and Report no 47 (1999-2000) to the Storting.
Production start-up	1995
Production ceased	2001
Total production over field lifetime	Oil: 5.6 mill scm Gas: 1.7 bn scm Condensate: 0.1 mill tonnes

Lille-Frigg

Block	25/2
Development approved	1991
Cessation plan/ decommissioning	Storting proposition no 53 (1999-2000) and Report no 47 (1999-2000) to the Storting.
Production start-up	1994
Production ceased	1999
Total production over field lifetime	Gas: 2.3 bn scm Condensate: 1.3 mill scm

Mime

Block	7/11
Development approved	1992
Cessation plan/ decommissioning	Storting proposition no 15 (1996-1997) and Report no 47 (1999-2000) to the Storting.
Production start-up	1990
Production ceased	1993
Total production over field lifetime	Oil: 0.4 mill scm Gas: 0.1 bn scm

North-East Frigg

Blocks	25/1 and 30/10
Development approved	1980
Cessation plan/ decommissioning	Storting proposition no 36 (1994-95)
Production start-up	1983
Production ceased	1993
Total production over field lifetime	Gas: 11.6 bn scm

Odin

Blocks	30/10
Development approved	1980
Cessation plan/ decommissioning	Storting proposition no 50 (1995-1996) and Report no 47 (1999-2000) to the Storting.
Production start-up	1984
Production ceased	1994
Total production over field lifetime	Gas: 27.3 bn scm

Tommeliten Gamma

Block	1/9
Development approved	1986
Cessation plan/ decommissioning	Storting proposition no 53 (1999-2000) and Report no 47 (1999-2000) to the Storting.
Production start-up	1988
Production ceased	1998
Total production over field lifetime	Oil: 3.9 mill scm Gas: 9.7 bn scm NGL: 0.6 mill tonnes

West Ekofisk

Block	2/4
Development approved	1973
Cessation plan/ decommissioning	The cessation plan was approved by the authorities on 21 December 2001 and in Report no 47 (1999-2000) to the Storting.
Production start-up	1977
Production ceased	1998
Total production over field lifetime	Oil: 12.2 mill scm Gas: 26.0 bn scm NGL: 1.4 mill tonnes

Yme

Block	9/1, 9/2 and 9/5
Development approved	1995
Cessation plan/ decommissioning	The cessation plan was approved by the authorities on 4 May 2001
Production start-up	1996
Production ceased	2001
Total production over field lifetime	Oil: 7.9 mill scm

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