Norwegian Petroleum Directorate

ANNUAL REPORT 1994

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«The overall objective of the Norwegian Petroleum Directorate is to promote the sound management of Norwegian petroleum resources having a balanced regard for the natural, safety-related, environmental, technological and economic aspects of the petroleum activities in the context of society at large.»

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Director General's Statement

RESOURCES

The resource account for the Norwegian continental shelf shows that the volumes of discovered recoverable petroleum resources have increased considerably in 1994.

The growth in oil resources is approximately 200 million Sm^3 o.e., whereas the growth in gas resources is approximately 80 million Sm^3 o.e. The aggregate growth in resources is consequently approximately 280 million Sm^3 o.e., which represents about the same level as in 1993.

The level of exploration drilling activities has been lower in 1994 than in previous years. The results however have been good, and almost half of the resource increment is attributable to new discoveries.

Discoveries have been made in 14 of 22 completed wildcat wells and hydrocarbons have been proven in all the 5 appraisal wells that have been completed.

Out of the new discoveries, ten have been made in the North Sea, three in the Norwegian Sea and one in the Barents Sea.

A few of the discoveries are large, but most are small. Some of these, however, are located in the vicinity of existing infrastructure and thus they represent interesting additional resources to fields already in production (Hod, Sleipner Øst and Veslefrikk) and areas being considered with a view to development (Oseberg Sør and the Snorre area).

There are several reasons for the favourable exploration results, but most important is presumably an improved data quality as a result of extensive acquisition of 3D seismic over the last years.

A considerable adjustment upwards of the reserves in many fields on the Norwegian continental shelf has also been made in 1994. The largest ones have been for Gullfaks, Oseberg, Snorre, Statfjord, Tordis, Troll, Veslefrikk and Valhall. These adjustments upwards are to a great extent the result of a very conscious effort over a long period of time in projects aiming to increase the recovery factor for oil. This area still represents a large potential. The Norwegian Petroleum Directorate has estimated this potential to be in the order of magnitude 500 million Sm^3 oil, which means that the average recovery factor will increase from 39 % to 47 %.

The total production from the Norwegian continental shelf in 1994 was 180 million Sm^3 o.e., made up of approximately 153 million Sm^3 o.e. of oil and approximately 27 million Sm^3 o.e. of gas.

Oil production was up 13 % and gas sales increased by 8 % compared to the previous year. Despite increased production there has been a net growth in discovered petroleum resources in 1994 of about 100 million Sm^3 o.e., with an even distribution on oil and gas.

New estimates of total Norwegian petroleum resources indicate an order of magnitude around 11 billion Sm^3 o.e. The discovered resources, including the improved oil recovery potential, make up for 2/3 of this, whereas the undiscovered resources represent about 1/3.

The distribution of undiscovered resources shows that approximately 40 % are expected to be discovered in the North Sea, about 40 % in the Norwegian Sea and a little more than 20 % in the Barents Sea.

A high degree of uncertainty is however attached to estimates of undiscovered resources. This is in particular true of areas in the Norwegian Sea which have not previously been open to exploration activities. These areas, which comprise Møre and the Vøring basins in deep waters far from shore and parts of the areas closer to the shore (Nordland 4, 5 and 6), were opened for exploration drilling in 1994. The total surface of these areas is approximately 171,000 km^2.

Selected blocks from these new areas and areas in the Norwegian Sea and the North Sea which have previously been opened for exploration activities will form the basis of the 15th concession round planned to be implemented in 1995.

Norway has signed gas sales agreements which over a 10-year period will bring the annual export volumes up from the current level of 27 billion Sm^3 to about 60 billion Sm^3. In this connection, issues related to gas resource management in a long-term perspective have also been focused. Evaluations in connection with entry into new gas sales agreements and consideration of associated transport alternatives have received high priority in 1994.

The Norwegian Petroleum Directorate places great emphasis on the preparation of area studies in order to see prospective field developments in a total resource management perspective. During 1994, the main focus has been on possible gas development of Haltenbanken and in the northern North Sea.

During 1994, the Norwegian Petroleum Directorate has considered Plan for Development and Operation (PDO) for Norne, Vigdis, Yme, and for the first stage of the oil development of the Troll Vest gas province. In addition, PDOs for additional resources in respect of the fields Hod, Snorre and Veslefrikk have been considered. The further operation of Ekofisk is ensured through the approval of the PDO for Ekofisk II. Also, a Plan for Construction and Operation (PCO) for Zeepipe IIB has been considered.

Four new fields have come on stream in 1994, Gullfaks Vest, Lille-Frigg, Statfjord Øst and Tordis, while production has been terminated from two fields, Mime and Odin.

The Norwegian Petroleum Directorate's international engagement in resource management issues has increased in 1994. This is a result of increasing demand for the services of the Norwegian Petroleum Directorate from a number of countries that are in the process of establishing and organising a national petroleum management. These services are partly channelled through NORAD and PETRAD, but the Norwegian Petroleum Directorate also has individual bilateral agreements of co-operation with some countries.

The Norwegian Petroleum Directorate took an active part in the NORSOK work, both as a participant in the forum, in the steering group and in the various working groups.

The DISKOS project, based on co-operation between the Norwegian Petroleum Directorate and central participants among the oil companies, has developed a common geodata base which makes the large volumes of data more readily available to the users. The aim of the project is to reduce the costs involved in managing the vast data volumes already acquired, and which will be acquired in the years to come. Geodata used by the Norwegian Petroleum Directorate as well as the oil companies are to be stored in a common data base, situated in Kunnskapsparken ('The Science Park') at Ullandhaug in Stavanger. The data are made available via a high capacity network and a software programme developed under the direction of the NPD. The DISKOS project may well serve as a model for industrial development and co-operation to realise improved profitability on the Norwegian continental shelf.

The Norwegian Petroleum Directorate regards research and development in reservoir description and reservoir technology as an important part of the work to realise the great potential represented by improved oil recovery. The co-operation programme PROFIT and the state research programme RUTH are central in this connection. The programmes are directed and administered by the Norwegian Petroleum Directorate. The PROFIT programme is now being concluded, and the Norwegian Petroleum Directorate is engaged in preparing a new co-operation programme, FORCE (Forum for reservoir characterization and reservoir engineering) which is to concentrate on the same issues.

SAFETY AND WORKING ENVIRONMENT

One person died in an accident in the petroleum activities in 1994. Although a certain risk must be accepted in the activities, it will remain a matter of the highest priority to ensure that the industry takes the utmost care to prevent the loss of lives.

The frequency of other accidents with personal injury has been at about the same level as in the previous year. There has however been an increase in reported cases of work related diseases, which is presumed to be linked with the fact that the reporting procedures for such diseases are now beginning to become effective. In addition to the individual suffering, work related diseases are costing society vast amounts, and it is consequently important that the operators through effective reporting contribute to providing a better basis for priority efforts in this area.

A considerable number of gas leaks continue to occur on the installations. This is a matter of concern, primarily because of the great damage potential for this type of incidents. Supervision of the measures taken by the operators to gain control of this problem has shown that in addition to technical improvements, it is also important to address organisational issues and attitudes in relation to this matter. It is therefore noted with satisfaction that the industry is demonstrating increased engagement in and willingness to implement systematic measures to curb the problem.

Development of a statutory framework for the application of the Working Environment Act to the petroleum activities has now been completed on the part of the Norwegian Petroleum Directorate. In this work the Directorate has placed emphasis on active participation from the interested parties in the industry. It has not been a purpose to introduce new and more stringent requirements in relation to the working environment, but to clarify and systematise already existing requirements. The Norwegian Petroleum Directorate hopes that the new legislation will prove to be an effective tool for the industry as well as for the authorities in achieving a cost-effective establishment and continued development of a good working environment.

The revised safety legislation under the Petroleum Act has now been in force for more than two years. Seen from the Norwegian Petroleum Directorate's point of view, the experience has been good, and the Directorate is pleased to note that the feedback from the industry is also predominantly positive. In the present phase the applicable legislation will be under continual consideration with regard to the need for review. The present format of the legislation, based on result oriented requirements and supported by guidelines and standards, simplifies considerably adaption of the activities to the technological development and to the development of society at large. The legislation also places a considerable responsibility on the industry itself with regard to co-operation in the further standardisation efforts.

Overall experience from the statutory supervision indicates that the petroleum activities are carried out within adequate safety limits and that in essence they are carried out in compliance with the legislation requirements to safety and working environment. The supervision has nevertheless established that certain weaknesses exist in the parties' control systems in certain areas. It is a basic requirement for a supervisory regime based on internal control that such systems are in place, and that they function according to intentions.

Supervision of mobile installations in the petroleum activities according to the Working Environment Act shows that there are still great variations with regard to implementation and compliance with the requirements of the Working Environment Act. In this field, therefore, the industry as well as the Norwegian Petroleum Directorate still have a priority commitment area that will require future efforts. The Directorate is pleased to note, however, that, inter alia as a result of the supervision carried out, processes seem to have been initiated in the operating and contracting companies which indicate that conscious efforts are being made to come to grips with these problems.

Development trends envisaged in the years ahead entail a number of challenges to the industry, e.g. in connection with petroleum development in deep waters and drilling in deep waters at high reservoir pressures, while at the same time the requirements to cost-effective development and operation are increasingly in focus. During 1994 the Norwegian Petroleum Directorate has carried out studies as well as supervisory activities which have been particularly aimed at creating the best possible basis for an effective supervision to see that these challenges are successfully met by the industry.

An increasing interest is registered with regard to the Norwegian regulatory regime. A number of countries wish to establish a functional set of regulations stipulating definite aims for the activities through result oriented requirements. Much interest has also been shown in the Norwegian model for implementation of an independent, public statutory supervision, where a total perspective philosophy, co-ordination and co-operation between the parties constitute central elements.

Stavanger, 20 March 1995

Fredrik Hagemann

Fredrik Hagemann
Director General

1. Duties and administration

1.1 DUTIES OF THE NORWEGIAN PETROLEUM DIRECTORATE

The duties of the Norwegian Petroleum Directorate are set out in special instructions of 1 October 1992. Duties have also been assigned to the Norwegian Petroleum Directorate by delegation of authority. Such authority is delegated either in direct pursuance of acts/regulations or by individual administrative decisions of delegation from a superior authority. Delegation applies to parts of:

a) The Petroleum Act, of 23 March 1985 no. 11, embracing:
  - the Petroleum Regulations, Royal Decree of 14 June 1985
  - the Safety Regulations, Royal Decree of 28 June 1985
  - the Internal Control Regulations, Royal Decree of 28 June 1985
  - the Safety Zone Regulations, Royal Decree of 9 October 1987

b) The Working Environment Act, of 4 February 1977 no. 4, embracing:
  - the Working Environment Regulations, Royal Decree of 27 November 1992

c) The CO_2 Act, of 21 December 1990, No.72

d) The Tobacco Act, of 9 March 1973, no. 14, embracing
  - the Tobacco Injuries Regulations, Royal Decree of 8 July 1988

e) The Svalbard Act, of 17 July 1925, no. 11, embracing
  - Regulations concerning safe practices in exploration and exploration drilling for petroleum deposits on Svalbard, Royal Decree of 25 March 1988

f) Act relating to scientific research and exploration for and exploitation of subsea natural resources other than petroleum resources, of 21 June 1963 No. 12, embracing
  - Regulations relating to scientific research for natural resources on the Norwegian continental shelf etc., Royal Decree of 31 January 1969

g) Provisional regulations concerning littering and pollution caused by petroleum activities on the Norwegian continental shelf, Royal Decree of 26 October 1979

1.2 OBJECTIVE

The overall objective of the Norwegian Petroleum Directorate is to promote the sound management of the Norwegian petroleum resources having a balanced regard for the natural, safety-related, environmental, technological and economic aspects of the petroleum activities in the context of society at large.

1.3 ADMINISTRATION

1.3.1 ORGANISATION

As from 1 January 1994 a restructuring of the Resource Management Division took effect. A new department was established: the Strategy and Planning Departement, with a Planning Section. Furthermore, a new section was established in the Exploration Department: Section for exploration analyses. The Exploration Department and the Operations Department were merged into one department: The Development Planning and Operations Department, with 5 sections: Reservoir Evaluation Section Southern North Sea; Reservoir Evaluation Section Northern North Sea; Reservoir Evaluation Section the Norwegian Sea/the Barents Sea/Troll; Technology Section and Petroleum Economics Section.

1.3.2 STAFF

At the end of the reporting period the Norwegian Petroleum Directorate had 354 authorised positions. In addition, 4 positions are funded by Norad, the Norwegian Directorate for Development Cooperation. One new position was authorised in the Safety and Working Environment Division in 1994. At year end 1994 there were 374 members of staff in service and 11 on leave.

The Directorate took on 14 new members of staff in permanent positions. Out of these, 11 came from oil-related activities, 2 from the public sector and 1 was newly qualified.

Number of staff leaving was 10. This represents 2.8 percent of total authorised positions.

1.3.3 BUDGET AND ECONOMY

The Norwegian Petroleum Directorate employed NOK 269,272,619 for its various duties in 1994.

The amount was appropriated as follows:

Outlays		
- Operating budget	NOK	201,160,474
- Supervision costs		9,215,256
- Geological and geophysical surveys		55,403,047
- Projects re. safety and working environment		3,493,842
Total	NOK	269,272,619

Of the operating budget, payroll costs account for NOK 121,438,691; lease and operation of buildings NOK

25,819,952. The remainder, NOK 53,901,831, covers costs of consultants, operation of the weather ship, external assistance, travel, training, computer systems operation, new investments in equipment, etc.

The Norwegian Petroleum Directorate is required to carry out certain specific tasks, such as:

- Clearance of seabed	NOK	4,721,768
- Administration of the RUTH/ PROFIT research programmes		1,223,763
- Contribution to the PETRAD foundation		1,500,000

Increasingly, the budget situation compels the Norwegian Petroleum Directorate to enforce strict priorities. Emphasis is consequently placed on the work to improve the available planning tools.

Revenues

In addition to production royalties, area fees and carbon dioxide tax totalling NOK 9,292,025,007, the Norwegian Petroleum Directorate received NOK 139,446,760 in revenues.

For 1994 the breakdown of revenues was as follows:

- Exploration fees	NOK	1,440,000
- Commission fees		2,757,738
- Reimbursed supervision costs		56,043,206
- Sale of released test material		2,972,497
- Sale of publications		4,703,119
- Kindergarten fees		2,475,850
- Reimbursed for job schemes		712,655
- Reimbursed from other government agencies		2,516,839
- Reimbursed from the National Insurance Administration		1,279,904
- Sale of seismic data		63,742,611
- Credit interest, bank		240,482
- Miscellaneous		561,859

1.3.4 INFORMATION

During the report period great interest has been shown in information from the Norwegian Petroleum Directorate from Norwegian and foreign institutions, the press and other media, companies and individuals. A number of foreign media representatives have, for example, visited the Norwegian Petroleum Directorate, individually or in groups, in order to familiarise themselves with the Directorate and the petroleum activities. The Norwegian Petroleum Directorate staff have also to a considerable extent participated as visiting lecturers in various forums.

The NPD Annual Report occupies a central position in the Directorate's information activities. The 1993 Annual Report was presented to the press in May.

The Directorate's internal magazine Oss Direkte was published in four issues in 1994, as planned.

There were 44 press releases issued in 1994, the majority of them in connection with the completion of exploration wells.

1.3.5 DOCUMENT AND INFORMATION MANAGEMENT

The number of petitions received for inspection of documents was 169. This is approximately the same level as in 1993. Reply time to these enquiries varies somewhat, but on average it is about three days.

This year special emphasis has been placed on improving the quality of recordings in the filing system. 20 percent of the Norwegian Petroleum Directorate's employees have received training in the use of a new computer file data base module. The in-house use of the Central File shows continued growth after last year's considerable increase.

Library utilisation has become stabilized after the considerable expansion in 1993. The library receives a large number of external enquiries, but borrows less from other libraries. Use of data base services shows an increase for the Norwegian Petroleum Directorate as for other libraries. The library now subscribes to a CD-ROM based data base.

Online use of the reference data base OIL from the Norwegian State Computer Centre shows an increase of 13 percent. The number of subscribers and orders for reprints of OIL and Oil Index is approximately on the same level as last year.

The Infoil/Sesame data base contains information on current and completed research projects within the petroleum activities. This data base has been available in diskettes, CD-ROM and via the host base STN (Scientific and Technical Network) in Karlsruhe, and from the EU's own computer base Eurobases, Brussels.

For a number of years it has proved difficult to increase the use of Infoil/Sesame. The number of subscribers is too low in relation to the resources employed. The Norwegian Petroleum Directorate has therefore concluded that it is not reasonable to use considerable resources for a product utilized in such limited extent. The Norwegian Petroleum Directorate's participation in the production of Infoil/Sesame consequently ceased per 31 December 1994. In later years other distribution channels have emerged which may be more suitable for distribution of research information. The contents of the data base will be made available to the co-operating partners for further development.

2. Resource Management on the Norwegian continental shelf

2.1 INTRODUCTION

The objective of the Norwegian Petroleum Directorate is to promote actively the sound management of the petroleum resources in order to maximise the creation of value on the Norwegian continental shelf, and to act as the key advisory and executive body for the Ministry of Industry and Energy in this field. This objective can only be achieved if the Directorate at all times has a general overview of the petroleum resources, and evaluates alternatives for prudent exploration, development and recovery of the resources. Such overviews and evaluations constitute the basis for giving advice to the central authorities with respect to prudent management of the petroleum resources.

The resource management activities on the Norwegian continental shelf were again high in 1994, both as regards exploration, development, and operation.

The Resource Division was underwent a reorganisation at the year end 1993/1994. The background for this was an increasing need for integration of the development and operating phases, and at the same time a need for higher efficiency in staff and planning work. The Resource Division will retain the phased, product oriented basic organisation. One adaptation has been made, however, in combining the two phases development and operation to form one Development Planning and Operations Department. The staff and planning work has been combined in a new Strategy and Planning Department, which also handles international co-operation and co-ordinates the R&D engagements of the Resource Division.

2.2 REVISION AND DEVELOPMENT OF LEGISLATION/PROLO/NORSOK

The Ministry of Industry and Energy has commenced an extensive work of revising the Petroleum Act, project PROLO 94. Issues in connection with the EEA agreement, the need to regulate the final disposal of installations, follow-up of recommendations from the industry in connection with the NORSOK project and other issues constitute the basis for this work.

The Norwegian Petroleum Directorate has been an active participant in this process, and legal expertise as well as various other expert environments have made very significant contributions in this work. A Proposition to the Odelsting (O.prp.) is expected to be submitted to the Storting in spring, immediately before the closing date of the 15th concession round.

An objective in this work has been to modernise the Act, e.g. by including less detailed regulation in the Act, and at the same time to restructure the Act to make it thematically more tidy and simpler to relate to.

When this work is completed the subordinate detailed legislation will have to be updated in line with the amendments which have been carried out to the Act.

2.3 EFFICIENCY PROJECT - NORSOK

The NORSOK procject (NORsk SOkkels Konkurranseposisjon - the competitive position of the Norwegian Continental Shelf) was established in the summer of 1993 following an initiative by Minister of Industry Finn Kristensen. The purpose of the project was, through establishing a structured co-operation between oil companies, supply industry, shipowners, research institutions, employers' and employees' organisations and authorities, to increase the competitive situation of the Norwegian Continental Shelf in an international context. The project was in many ways a Norwegian follow-up of the CRINE project which has been carried out in the UK. (Cost Reduction Initiative for the New Era).

The Norwegian Petroleum Directorate has contributed actively in the work through participation in the Development and Operations Forum, in the steering group and with observers in the seven working groups. In order to follow up the work and to co-ordinate initiatives from the Norwegian Petroleum Directorate, a separate NORSOK project was established in the Norwegian Petroleum Directorate at an early stage in the process.

2.4 EXPLORATION LICENCES AND PRODUCTION LICENCES

2.4.1 NEW EXPLORATION LICENCES

Per 31 December 1994, a total of 220 exploration licences had been granted. Such licences are valid for three years. The following licences were awarded in 1994:

Company	Licence No.
Conoco Norway Inc.	215
NOPEC a.s	216
A/S Norske Shell	217
Western Geophysical Co of America	218
Geoteam Exploration	219
Amarok A/S	220

2.4.2 SCIENTIFIC EXPLORATION

As of 31 December 1994 a total of 283 licences had been granted for scientific exploration on the Norwegian continental shelf.

As shown in Table 2.4.2, seven such licences were granted in 1994.

Table 2.4.2
Licenses for scientific exploration for natural resources

Licenses	Institution	Subject				Area
		Geo-physics	Geo-logy	Bio-logy	Other	
277/94	Norges geologiske undersøkelse				Aero-magnetic surveys	Areas off Nordland
278/94	Norges geologiske undersøkelse				Marine-gravimetric surveys	Areas off Mid-Norway 62°N-65°N
279/94	Universitetet i Bergen	X				Areas around Øygarden in Hordaland to block 31/4
280/94	Polar Marine Geology Expedition St. Petersburg Russland	X				Norskerenna Storegga Spitsbergen Knipowich
281/94	Norsk Polarinstitutt	X	X			Northern margin of Svalbard
282/94	Universitetet i Tromsø	X				Estuary of Tana river/ Tana fjord
283/93	Universitetet i Tromsø	X	X			Western Barents Sea/ Northeastern Norwegian Sea

2.4.3 PRODUCTION LICENCES

No new production licences were granted in 1994.

An overview of licensing rounds with production licences, allocated area, relinquished and existing areas is shown in Table 2.4.3.a. Table 2.4.3.b shows Norwegian and foreign shares in the licensing rounds and Figure 2.4.3 shows explorations wells drilled in each licensing round. Licensees, operators and other information on active production licences are shown in section 7.7.

Fig. 2.4.3
Exploration wells drilled in each licensing round

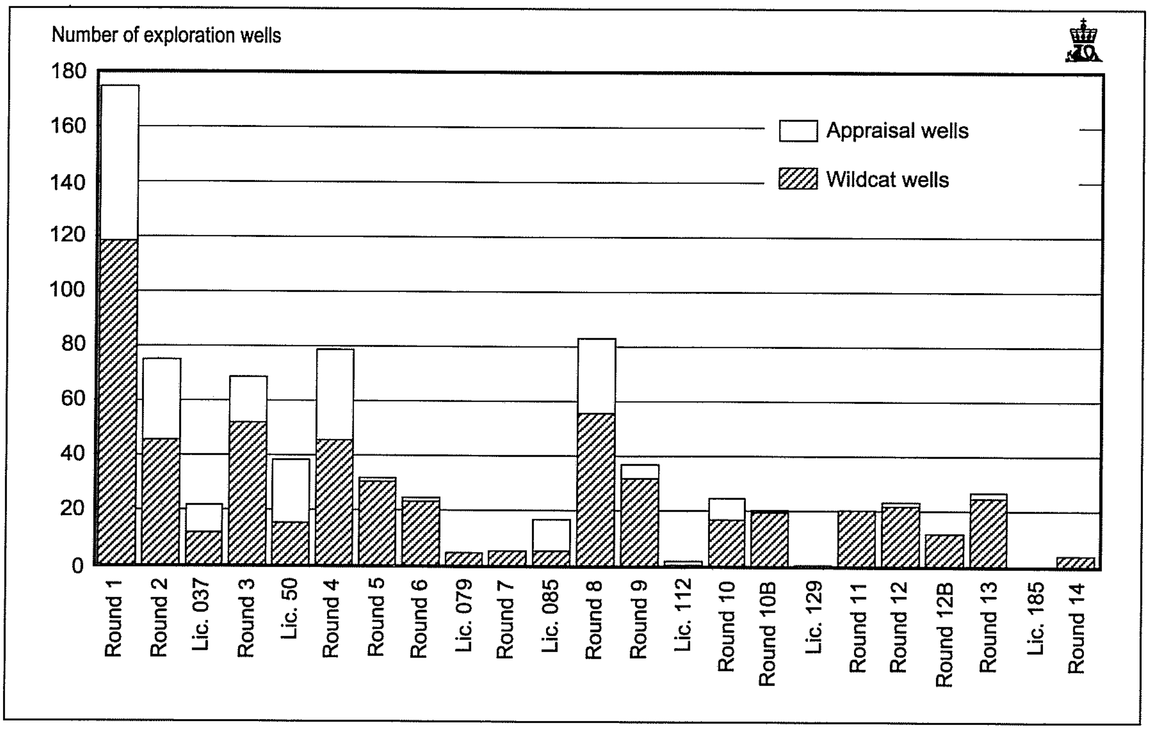


Table 2.4.3.a Production licenses and acreages as of 31 December 1994

Lic. round	Allocated	Production license no.	No of blocks * Allocated	Blocks relinguished	Area km² allocated	Area km² relinguished	Area km² in license
1.	1.9.1965	001-021	74	59	39842.476	36371.712	3470.764
	7.12.1965	022-022	4	4	2263.565	2263.565	
	12.9.1977	019B	2		617.891		617.891
2.	23.5.1969	023-031	9	1	4107.833	2345.199	1762.634
	30.5.1969	032-033	2		746.285	376.906	369.379
	14.11.1969	034-035	2		1024.529	564.837	459.692
	11.6.1971	036-036	1		523.937	262.047	261.89
or.	10.8.1973	037-037	2		586.834	295.157	291.677
3.	1.4.1975	038-040 og 042	7	5	1840.547	1603.469	237.078
	1.6.1975	041-041	1	1	488.659	488.659	
	6.8.1976	043-043	2		604.558	555.553	49.005
	27.8.1976	044-044	1		193.076	90.417	102.659
	3.12.1976	045-046	4	2	1270.682	814.708	455.974
	7.11.1977	047-047	2	2	368.363	368.363	
	18.2.1977	048-048	2	1	321.5	203.498	118.002
	23.12.1977	049-049	1	1	485.802	485.802	
or	16.6.1978	050-050	1		500.509	151.962	348.547
4.	6.4.1979	051-058	8	2	4007.887	2557.37	1450.517
5.	18.1.1980	059-061	3	3	1108.078	1108.078	
	27.3.1981	062-064	3	1	1099.522	867.542	231.98
	23.4.1982	073-078	6	2	2311.912	1849.47	462.442
6.	21.8.1981	065-072	9	3	3218.945	2149.358	1069.587
or.	20.8.1982	079-079	1		102.167		102.167
7.	10.12.1982	080-084	5	5	2082.966	2082.966	
or.	8.7.1983	085-085	3		1521.16	725.816	795.344
or.	11.9.1992	085B	2		27.166		27.166
8.	9.3.1984	086-100	17	3	6338.273	4348.802	1989.471
9.	1.3.1985	101-111	13	2	5293.054	3206.103	2086.951
or.	26.7.1985	112-112	1		260.215	129.958	130.257
10a	23.8.1985	113-120	9	2	3075.433	2260.559	814.874
10b	28.2.1986	121-128	9	3	3828.258	1895.282	1932.976
or.	11.7.1986	129-129	1	1	225.393	225.393	
11.	10.4.1987	130-137	11	7	4163.711	3335.559	828.152
	29.5.1987	138-142	11	7	2975.807	2370.732	605.075
12a	8.7.1988	143-153	16	2	4701.019	1651.327	3049.692
12b	9.3.1989	154-162	13	7	5031.262	2312.12	2719.142
13.	1.3.1991	163-184	36	8	12076.889	2737.546	9339.343
or.	13.9.1991	185-185	1		25.535		25.535
14.	10.9.1993	186-202	31		10509.919		10509.919
			326	134	129771.617	83055.835	46715.782

* block or parts of blocks

or = allocations made outside licensing rounds

Table 2.4.3.b
Licensing rounds. Norwegian and foreign shares as of 31 December 1994

Licensing rounds	Year	Number of blocks	Share % Norwegian	Share % foreign	Operator % Norwegian	Operator % foreign
1	1965	78	8	92	0	100
2	1969-1971	14	15	85	0	100
Statfjord	1973	2	52	48	0	100
3	1974-1978	22	58	42	63	37
Ula (19B)	1977	2	50	50	0	100
Gullfaks	1978	1	100	0	100	0
4	1979	8	58	42	68	32
5	1980	12	66	34	92	8
6	1981	9	64	36	50	50
Prod. lic. 079	1982	1	100	0	100	0
7	1982	5	60	40	80	20
Prod. lic.. 085	1983	3	100	0	100	0
Prod. lic. 085B	1992	2	69	31	100	0
8	1984	17	60	40	60	40
9	1985	13	43	57	62	38
Prod. lic. 112	1985	1	67	33	0	100
10A	1985	9	64	36	67	33
10B	1986	9	65	35	56	44
Prod. lic. 129	1986	1	67	33	100	0
11	1987	22	59	41	62	38
12A	1988	16	58	42	38	62
12B	1989	13	64	36	67	33
13	1991	36	66	34	64	36
Prod. lic.185	1991	1	69	31	100	0
14	1993	31	68	32	47	53

2.4.4 TRANSFER OF INTERESTS

In the course of 1994, the following transfers of interests were approved in accordance with Section 61 in the Act of 22 March 1985 No. 11 relating to petroleum activities. These are shown below in chronological order:

Production licence 109
Operator: Norsk Hydro a.s

Den norske stats oljeselskap a.s (Statoil) and Norsk Hydro A.s. have, effective from 1 January 1994, taken over 5.000 % each of Esso Exploration & Production Norway A/S' 10.000% share in production licence 109.

The following is now the current equity distribution in production licence 109:

Conoco Petroleum Norge A/S	10.000 %
Norsk Hydro Petroleum a.s	20.000 %
Mobil Development Norway A/S	15.000 %
Den norske stats oljeselskap a.s (Statoil)	55.000 %

Production licence 008
Operator : Elf Petroleum Norge A/S

Norsk Agip A/S, Norsk Hydro a.s. and TOTAL Norge A/S have given up their shares of 5.220%, 12.400% and 27.472% respectively, in production licence 008. The shares were, effective from 1 January 1994, taken over by Norminol A/S.

The following is now the current equity distribution in production licence 008:

Elf Petroleum Norge A/S	32.376 %
Elf Rex Norge A/S	4.536 %
Norminol A/S	46.308 %
Phillips Petroleum Company Norway	14.780 %
Den norske stats oljeselskap a.s (Statoil)	2.000 %

Production licence 064
Operator: Den norske stats oljeselskap a.s (Statoil)

Effective from 1 January 1994, Esso Exploration & Production Norway A/S has transferred its 25.000 % share with 19.250 % to Den norske stats oljeselskap a.s (Statoil) and 5.750 % to Norsk Hydro Produksjon a.s.

The following is now the current equity distribution in production licence 064:

Den norske stats oljeselskap a.s (Statoil)	69.250 %
Elf Petroleum Norge A/S	5.000 %
Norsk Hydro Produksjon a.s.	20.750 %
Phillips Petroleum Norsk A/S	5.000 %

Production licence 065
Operator: Elf Petroleum Norge A/S

Effective from 19 January 1994, Enterprise Oil Norwegian A/S took over 10.000 % of Den norske stats oljeselskap a.s (Statoil)'s share in production licence 065.

The following is now the current equity distribution in production licence 065:

A/S Norske Shell	15.000 %
BP Petroleum Dev. of Norway AS	8.333 %
Den norske stats oljeselskap a.s (Statoil)	40.000 %
Elf Petroleum Norge A/S	16.667 %
Enterprise Oil Norwegian A/S	20.000 %

Production licence 001, 027 and 028
Operator: Esso Exploration & Production Norway A/S

Esso Exploration & Production Norway A/S has, effective rom 19 January 1994, transferred a 50.000 % share in parts of the areas of 3 production licences to Enterprise Oil Norwegian A/S. The production licences are 001, 027 and 028.

Esso excludes those parts of the production licences which comprise the Balder area from the transfers.
Those parts of the production licences including the new shareholders, will receive the additional designation 'P' after the licence number.

The following is now the current equity distribution in production licences 001, 027 and 028:
Esso Exploration & Production Norway A/S 100.000 %

The distribution in 001 P, 027 P and 028 P is:

Esso Exploration & Production Norway A/S	50.000 %
Enterprise Norwegian Oil A/S	50.000 %

Production licence 009
Operator: Elf Petroleum Norge A/S

Effective from 1 March 1994, Elf Petroleum Norge A/S took over the shares of Norsk Hydro a.s. and Norminol A/S in production licence 009. The shares are 26.800 % and 1.216 % respectively.

The following is now the current equity distribution in production licence 009:

Norsk Agip A/S	5.220 %
Elf Petroleum Norge A/S	60.302 %
Elf Rex Norge A/S	3.420 %
Phillips Petroleum Company Norway	14.780 %
TOTAL Norge A/S	16.188 %

Production licence 070
Operator: Norsk Hydro Produksjon a.s.

Effective from 1 January 1994, Amoco Norway Oil Company took over the shares of Norske Conoco A/S of 7.350 % in production licence 070.

The following is now the current equity distribution in production licence 070:

Amoco Norway Oil Company	14.700 %
Norsk Hydro Produksjon a.s.	24.500 %
Saga Petroleum a.s	9.800 %
Den norske stats oljeselskap a.s (Statoil)	51.000 %

Production licence 073
Operator: Den norske stats oljeselskap a.s (Statoil)

Effective from 1 April 1994, TOTAL Norge A/S took over 6.667 % and Norsk Hydro took over 13.333 % of Amoco Norway Oil Company's 20.000 % share in production licence 073.

The following is now the current equity distribution in production licence 073:

Norsk Hydro Produksjon a.s.	16.667 %
Den norske stats oljeselskap a.s (Statoil)	50.000 %
TOTAL Norge A/S	33.333 %

This also comprises Tyrihans Sør and Tyrihans Nord with the same distribution.

Production licence 171
Operator: Norsk Hydro Produksjon a.s.

Effective from 1 June 1994, TOTAL Norge A/S transferred its 10.000 % share in production licence 171 to Saga Petroleum a.s.

The following is now the current equity distribution in production licence 171:

Norsk Hydro Produksjon a.s.	30.000 %
Saga Petroleum a.s	20.000 %
Den norske stats oljeselskap a.s (Statoil)	50.000 %

Production licences 114, 153 and 157
Effective from 1 August 1994, Saga Petroleum a.s purchased all the shares of Petrobas Norge A/S. Petrobas Norge A/S had shares of 10.000 % in each of the abovementioned production licences.

The shares will be administered by a newly established subsidiary company of Saga Petroleum a.s, Petrosaga AS.

Operator Prod. licence 114:	Den norske stats oljeselskap a.s (Statoil)
Operator Prod. licence 153:	Norsk Hydro a.s.
Operator Prod. licence 157:	Den norske stats oljeselskap a.s (Statoil)

Production licences 051, 087, 095, 104, 109 115 and 124
By letter dated 8 September 1994, the The Ministry of Industry and Energy (MIE) gave its consent to the transfer of all the shares of Conoco Petroleum Norge A/S in the seven abovementioned production licences to Norske Conoco A/S.

Operator Prod. licence 051:	Den norske stats oljeselskap a.s (Statoil)
Operator Prod. licence 087:	Norsk Hydro Produksjon a.s.

Operator Prod. licence 095: Norske Conoco A/S
Operator Prod. licence 104: Norsk Hydro Produksjon a.s.
Operator Prod. licence 109: Norsk Hydro Produksjon a.s.
Operator Prod. licence 115: TOTAL Norge A/S
Operator Prod. licence 124: Den norske stats oljeselskap a.s (Statoil)

Production licence 037
Operator: Den norske stats oljeselskap a.s (Statoil)

Amoco Norway A/S has, effective from 5 october 1994, transferred its 1.042 % share in production licence 037 to Norske Conoco A/S.

The following is now the current equity distribution in production licence 037:

Amerada Hess Norge A/S	1.042 %
Conoco Norge A/S	11.042 %
Enterprise Oil Norwegian A/S	1.042 %
Esso Exploration & Production Norway A/S	10.000 %
Mobil Development Norway A/S	15.000 %
Saga Petroleum a.s	1.875 %
A/S Norske Shell	10.000 %
Den norske stats oljeselskap a.s (Statoil)	50.000 %

Production licence 038
Operator: Den norske stats oljeselskap a.s (Statoil)

Esso Exploration & Production Norway A/S has, effective from 10 November 1994, transferred its 50.000 % share in production licence 038 to Saga Petroleum a.s.

The following is now the current equity distribution in production licence 038:

Saga Petroleum a.s	50.000 %
Den norske stats oljeselskap a.s (Statoil)	50.000 %

BP Petroleum Company of Norway AS has, effective from 10 November 1994, transferred its shares of 5.000 % in production licence 069 and 15.000 % in production licence 157 to DNO Olje A/S.

Production licence 069
Operator: Norske Conoco A/S

The following is now the current equity distribution in production licence 069:

Deminex (Norge) A/S	5.000 %
DNO Olje A/S	5.000 %
Norske Conoco A/S	25.000 %
Norsk Hydro Produksjon a.s.	15.000 %
Den norske stats oljeselskap a.s (Statoil)	50.000 %

Production licence 157
Operator: Den norske stats oljeselskap a.s (Statoil)

The following is now the current equity distribution in this production licence:

Den norske stats oljeselskap a.s (Statoil)	50.000 %
DNO Olje A/S	15.000 %
Norske Conoco A/S	10.000 %
Petrosaga AS	10.000 %
Phillips Petroleum Norsk A/S	15.000 %

Britoil Norge A/S has, effective from 10 November 1994, transferred a share of 8.000 % in each of the production licences 092 and 121 to DNO Olje A/S.

Production licence 092
Operator: Den norske stats oljeselskap a.s (Statoil)

The following is now the current equity distribution in production licence 092:

Den norske stats oljeselskap a.s (Statoil)	50.000 %
Britoil Norge A/S	2.000 %
DNO Olje A/S	8.000 %
Mobil Development Norway A/S	40.000 %

Production licence 121
Operator: Den norske stats oljeselskap a.s (Statoil)

The following is now the current equity distribution in production licence 121:

Den norske stats oljeselskap a.s (Statoil)	50.000 %
Britoil Norge A/S	2.000 %
Mobil Development Norway A/S	20.000 %
DNO Olje A/S	8.000 %
Norsk Hydro Produksjon a.s.	20.000 %

Production licence 158
Operator: BP Petroleum Development of Norway A/S

DNO Olje A/S has, effective from 10 November 1994, transferred its 10.000 % share in production licence 158 with 6.000 % to BP Petroleum Development of Norway A/S and 4.000 % to Britoil Norge A/S, respectively.

The following is now the current equity distribution in production licence 158:

BP Petroleum Development of Norway AS	36.000 %
Britoil Norge A/S	4.000 %
Den norske stats oljeselskap a.s (Statoil)	50.000 %
TOTAL Norge A/S	10.000 %

Production licence 166
Operator: Deminex (Norge) A/S

Den norske stats oljeselskap a.s (Statoil) has, effective from 18 November 1994, taken over the share of 10.000 % of BP Petroleum Development of Norway A/S in production licence 166.

The following is now the current equity distribution in production licence 166:

Deminex (Norge) A/S	30.000 %
A/S Norske Shell	10.000 %
Den norske stats oljeselskap a.s (Statoil)	60.000 %

Production licence 117
Operator: Saga Petroleum a.s

Norsk Agip A/S has, effective from 23 November 1994, transferred its 20.000 % share in production licence 117 with 10.000 % each to Saga Petroleum a.s. and Amerada Hess Norge A/S.

The following is now the current equity distribution in production licence 117:

Amerada Hess Norge A/S	10.000 %
Norsk Fina A/S	15.000 %
Saga Petroleum a.s	25.000 %
Den norske stats oljeselskap a.s (Statoil)	50.000 %

Production licence 143
Operator: Phillips Petroleum Norsk A/S

õMV Norge A/S has, effective from 23 November 1994, transferred its share of 10.000 % in production licence 143 to Amoco Norway A/S. This was the only share for õMV Norge A/S on the Norwegian continental shelf.

The following is now the current equity distribution in production licence 143:

Amoco Norway A/S	10. 000 %
Enterprise Oil Norwegian A/S	15.000 %
Phillips Petroleum Norsk A/S	25.000 %
Den norske stats oljeselskap a.s (Statoil)	50.000 %

Production licence 113
Operator: Amerada Hess Norge A/S

Norsk Hydro has, effective from 13 December 1994, transferred its share of 25.000 % in production licence 113 to Amerada Hess Norge A/S. Amerada Hess Norge A/S also takes over as operator.

The following is now the current equity distribution in production licence 113

Amerada Hess Norge A/S	50.000 %
Den norske stats oljeselskap a.s (Statoil)	50.000 %

Production licence 008
Operator: Saga Petroleum a.s

Effective from 21 December 1994, Norminol A/S took over the shares of 32.376 % from Elf Petroleum Norge A/S, 4.536 % from Elf Rex Norge A/S, 14.780 % from Phillips Petroleum Norway A/S and 2.000 % from Den norske stats oljeselskap a.s (Statoil) in production licence 008. At the same time, Norminol transferred 100.000 % of its shares to Saga Petroleum a.s. Saga Petroleum a.s took over as operator in the production licence.

The following is now the current equity situation in production licence 008:

Saga Petroleum a.s	100.000 %

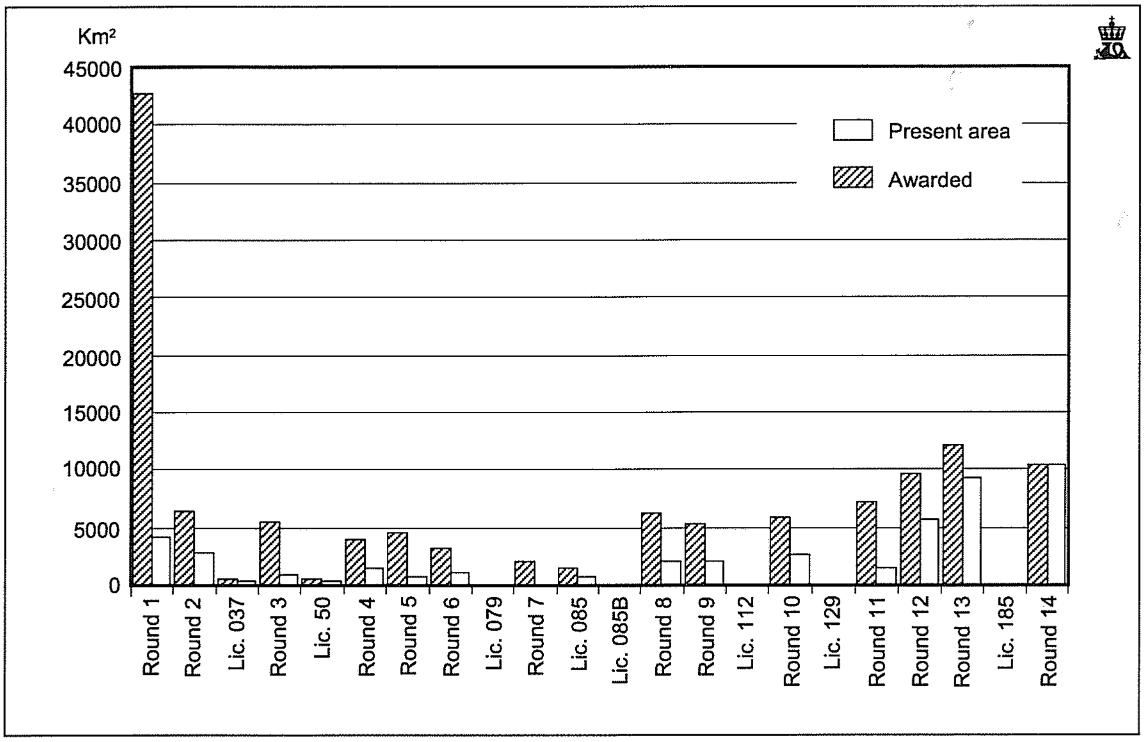
Production licence 097
Operator: Norsk Hydro Produksjon a.s.

Effective from 21 December 1994, Norsk Hydro Produksjon a.s. took over 2.500 %, Den norske stats oljeselskap a.s (Statoil) 6.250 % and Amerada Hess Norge A/S 1.250 %

Table 2.4.5
Relinquishments

Prod. lic.	Operator	Block	Original area km^2	Relinquished area km^2	Area lic. km^2
016	Phillips	17/12	2.203.126	2.203.126	0.000
030	Esso	30/10	464.254	344.418	119.836
040	Hydro	29/9, 30/7	534.405	493.362	41.043
051	Statoil	30/2	504.440	425.401	79.039
073	Statoil	6407/1	440.392	366.913	73.479
087	Hydro	16/4	539.346	539.346	0.000
089	Saga	34/7	446.846	130.719	316.127
090	Mobil	35/11	500.509	249.919	250.590
093	Shell	6407/9	448.529	261.513	187.016
094	Statoil	6506/12	436.310	122.052	314.258
095	Conoco	6507/7	432.220	217.324	214.896
109	Hydro	7120/2, 7120/3	646.061	503.549	142.512
111	Esso	7120/1	323.030	323.030	0.000
121	Statoil	6407/5	444.465	417.846	26.619
129	Hydro	25/1	225.393	225.393	0.000
145	BP	1/9, 2/7	250.555	134.696	115.859
148	Statoil	7/4, 7/7	543.438	272.284	271.154
149	Esso	16/3	535.510	535.510	0.000
150	Fina	24/9	375.258	188.780	186.479
151	Elf	25/3	520.058	520.058	0.000
165	Esso	10/7	558.364	558.364	0.000
179	Hydro	7122/2, 7122/3	646.061	646.061	0.000
184	Hydro	7316/4, 7316/5 and 7316/8	882.769	882.769	0.000

Fig. 2.4.5
Awarded and present areas in each licensing round



of Esso Exploration & Production Norway A/S' 10.000 % share in production licence 097.

The following is now the current equity distribution in production licence 097:

Amerada Hess Norge A/S	11.250 %
Deminex (Norge) A/S	10.000 %
Den norske stats oljeselskap a.s (Statoil)	56.250 %
Norsk Hydro Produksjon a.s.	22.500 %

2.4.5 RELINQUISHMENTS AND SURRENDERS

Relinquishment or surrender of acreage occurred in 23 production licences in 1994. In nine of the production licences the entire area was relinquished. This is shown in Table 2.4.5. The originally allocated and present acreages are shown in Figure 2.4.5.

2.5 SURVEYS AND EXPLORATION DRILLING

2.5.1 GEOPHYSICAL AND GEOLOGICAL SURVEYS

Seismic data were acquired from a total of 759,368 kilometers on the Norwegian continental shelf in 1994. The number of kilometers refers to cmp-line kilometers. Figure 2.5.1 shows the development in recent years with regard to the number of cmp-line kilometers compiled.

2.5.1.1 The Norwegian Petroleum Directorate's geophysical and geological surveys in 1994

The Norwegian Petroleum Directorate acquired 4,641 km of 2D seismic in 1994, see Figure 2.5.1.1.a. In addition, shallow seismic lines were acquired in connection with localisation of shallow drilling on Nordflaket. Figure 2.5.1.1.b shows the areas of collection of seismic data.

Barents Sea Nord

This year priority was given to acquiring deep seismic data from the very north of the Barents Sea. The data were collected using the vessel «Master Odin», operated by the company PGS Exploration. A wide source array and a 3000 meter long cable were used. In total, 4592 km were acquired in the Barents Sea Nord area.

Barents Sea Sør

A few short test lines totalling 49 km were shot at Lopphøgda.

Processing

The Norwegian Petroleum Directorate has finalised the processing of the data from 1993. A good deal of reprocessing of older seismic data from the northern Barents Sea was performed also in 1994, and major improvements have to a certain extent been achieved.

Gravimetric data

In connection with seismic surveys in the Barents Sea, approximately 6000 km of gravimetric data were acquired.

Geological surveys

In 1994 the Norwegian Petroleum Directorate carried out

Fig. 2.5.1
Seismic surveys on the Norwegian continental shelf 1962-1994

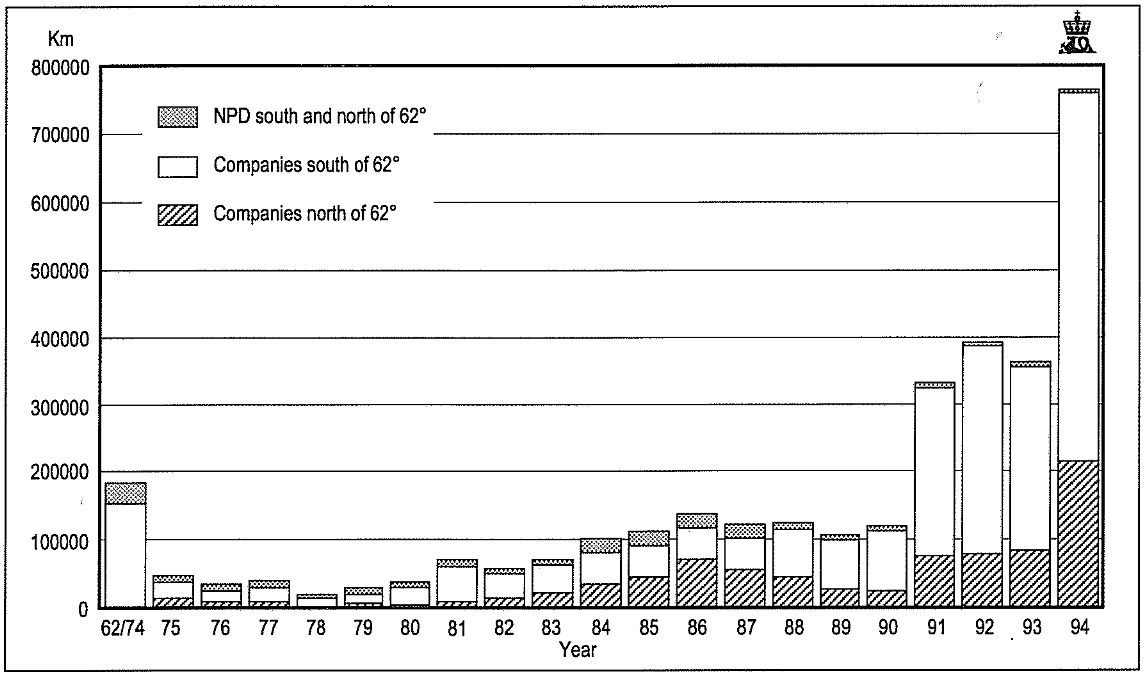


Fig. 2.5.1.1.a
Seismic surveys conducted by the Norwegian Petroleum Directorate

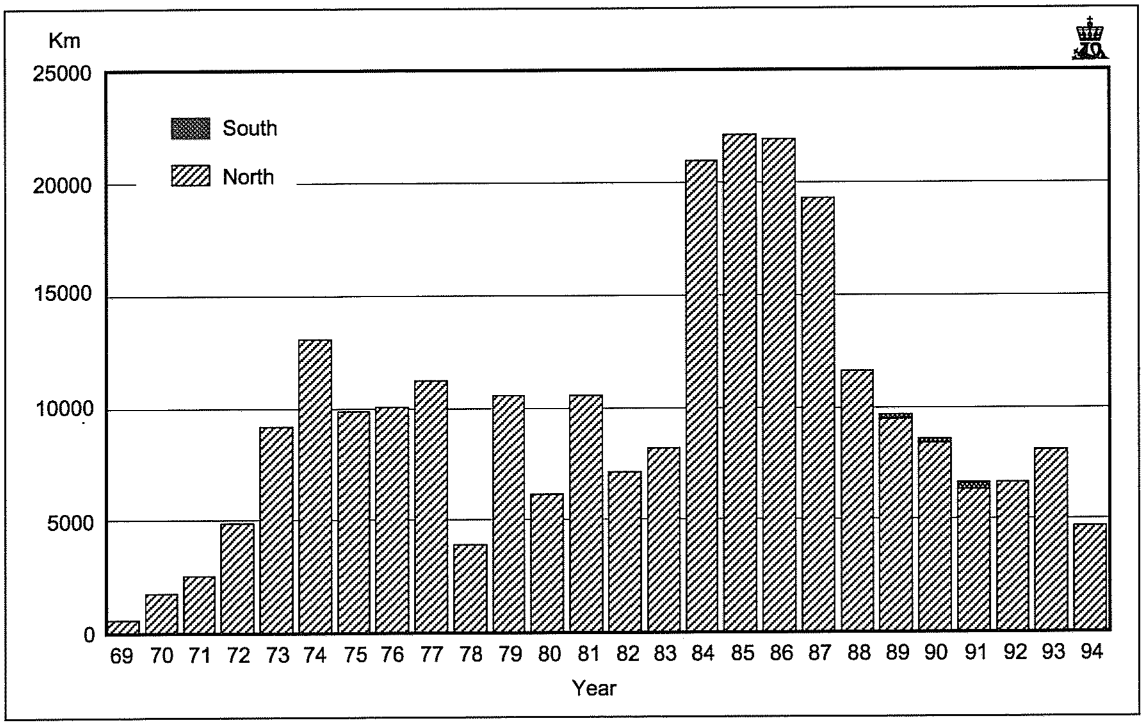
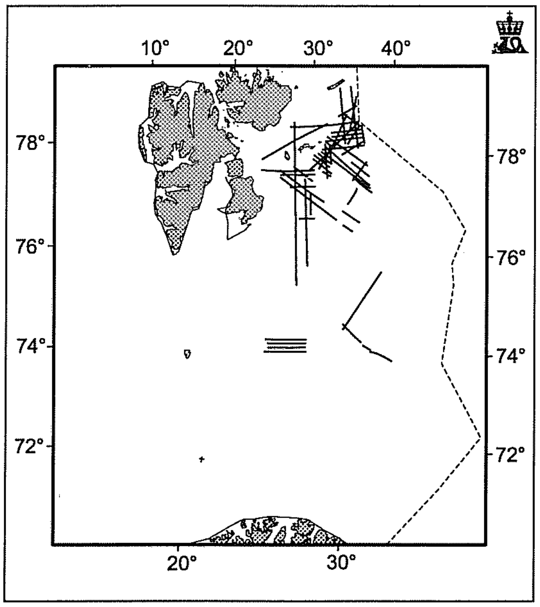


Fig. 2.5.1.1.b
Geophysical surveys in the Barents Sea



shallow drilling in the area Barents Sea Nord. The survey comprised five locations on Nordflaket, located between Spitsbergen and Bjørnøya, in areas not opened to exploration drilling.The purpose of this type of surveys is to provide supplementary geological information to the maps based on seismic data. This is necessary in order to be able to evaluate the area adequately. The total collection of core was 455 meters, and comprised rock types of Mesozoic and Cenozoic age. It is planned to make these data available to the industry during 1995.

The quarternary overburden varied from 2 meters to more than 110 meters. Due to technical problems during core drilling, three of the locations were moved and re-drilled.

The following drillings were carried out:

Location	Co-ordinates	Depth below sea bed
7517/12-U-01	75°14'16.4"N 17°44'59.2"E	200.00 m
7618/10-U-01	76°07'30.8"N 18°17'24.2"E	28.80 m
7618/10-U-02	76°07'30.6"N 18°17'25.0"E	13.60 m
7618/10-U-03	76°07'30.6"N 18°17'27.4"E	22.40 m
7617/11-U-01	76°07'29.6"N 17°32'51.2"E	30.25 m
7617/11-U-02	76°07'29.6"N 17°33'05.7"E	154.05 m
7616/11-U-01	76°07'23.3"N 16°26'09.0"E	69.25 m
7616/11-U-02	76°07'40.5"N 16°29'07.7"E	47.80 m
7418/01-U-01	74°52'33.3"N 18°05'48.8"E	126.15 m

2.5.1.2 Companies' geophysical surveys

In 1994, a total of 754,727 cmp-line kilometers of seismic was shot on the Norwegian continental shelf under the direction of the oil companies and seismic acquisition contractors. Of the total shot, 725,611 km are 3D seismic surveys. 545,380 km were acquired in the Nord Sea and 209,347 km in the Norwegian Sea and the Barents Sea. The activity level in the North Sea increased by 274,505 km compared with 1993. The activity in the Norwegian Sea and the Barents Sea increased by 127,577 km.

Norwegian oil companies shot some 276,473 cmp-line kilometers of seismic, an increase of 96,945 km from 1993. Foreign oil companies shot 322,057 cmp-line kilometers, which is an increase of 238,187 km compared with 1993.

A total of 156,197 cmp-line kilometers of commercial seismic was shot by Geco-Prakla, CGG, Geoteam Exploration, Simon, and NOPEC. This represents an increase of 66,950 km compared with 1993.

2.5.1.3 Sale of seismic data

In 1994, the Norwegian Petroleum Directorate recorded income from the sale of seismic data packages amounting to NOK 51 million.

2.5.1.4 Reporting and release of data and material from the continental shelf

In connection with supervision of the petroleum activities on the Norwegian continental shelf, the Norwegian Petroleum Directorate is supplied with copies of reports, borehole logs and continuous, representative samples of drill cuttings and cores. The Norwegian Petroleum Directorate also receives oil samples from all tested wells.

As of 31 December 1994, the Norwegian Petroleum Directorate had stocks totalling 87,711 meters of core material from 977 wells, 390,252 samples of washed cuttings from 1062 wells, and 469,227 wet samples from 1318 wells.

In addition there are oil and condensate samples from 267 wells.

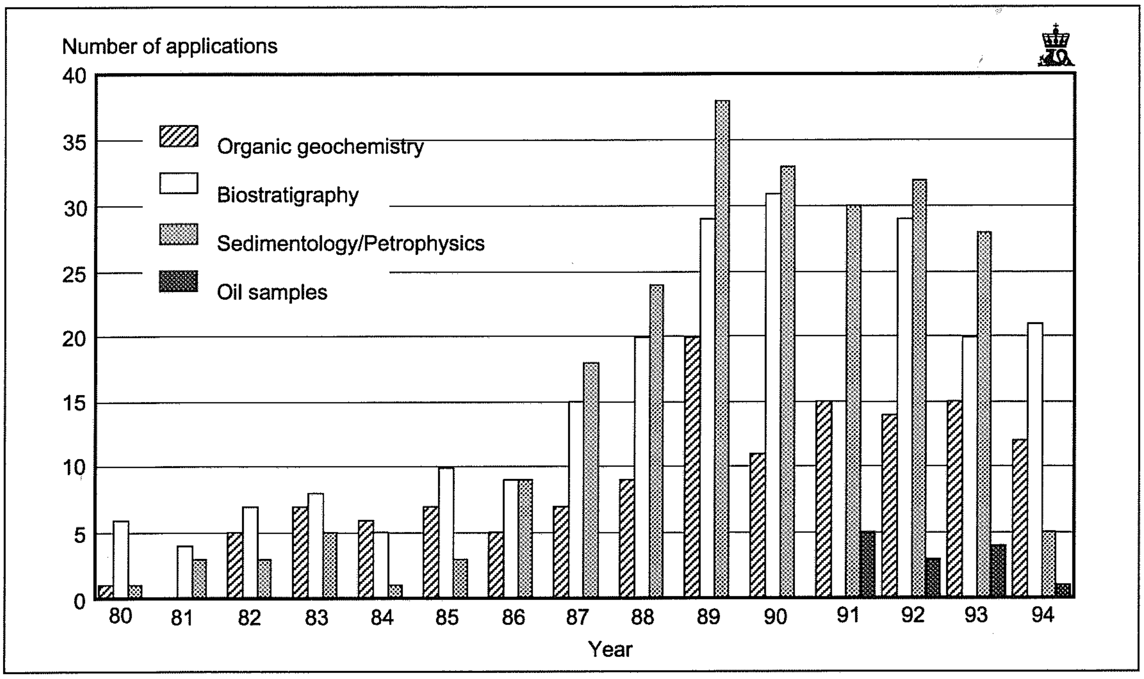
This includes material from foreign wells, mainly from the UK sector of the North Sea, but also including Svalbard, Hopen and Andøya. In connection with NORAD assignments, the Norwegian Petroleum Directorate also has material from Tanzania and Mozambique.

In 1994 the Norwegian Petroleum Directorate has received 5,274 m cores, 13,550 samples of washed cuttings, 20,828 wet samples and 20 oil samples.

The Norwegian Petroleum Directorate is responsible for the publishing of data and release of material inter alia for purposes of education and research. Geological and geophysical data are normally released five years after well completion. The licensees' interpretations are not released. «Well Data Summary Sheets» (WDSS) are issued annually.

This publication shows which wells have been released and what core and log materials are available from the various wells. Some technical data and test results are also given as well as a composite log with lithology specification of each well.

Fig. 2.5.1.4
Applications for samples by subject



In addition to its WDSS summaries, the Norwegian Petroleum Directorate issues annual publications which in addition to information on released material also contain a summary of each production licence on the Norwegian continental shelf; licence number, allocation date, operator, allocated acreage, present acreage, licensees and their license shares, geographical coordinates for areas, some data about each well drilled in the production licence, and a map of the area with the wells plotted in. Also included are some historical data and tables from the drilling activities.

Information of this type is also available in digital format on diskette or magnetic tape.

Reference is also made to the Norwegian Petroleum Directorate's Publication List.

In the Norwegian Petroleum Directorate's core study room it is possible to examine the core materials, drill cuttings and wet samples, and in special cases material from these may be made available for study and analysis outside the confines of the Directorate.

Applications for the release of geological samples should be addressed to the Release Committee at the Norwegian Petroleum Directorate. In 1994, 39 applications were considered. Of these, 12 were for organic geochemistry studies, 21 for biostratigraphy, 5 for sedimentology and petrophysics, and 1 for oil-condensate samples. A total of about 186 kg of sample material was released.

Figure 2.5.1.4 shows the demand for specimens broken down by the disciplines organic geo-chemistry, biostratigraphy, sedimentology/ petrophysics and oil samples.

The Norwegian Petroleum Directorate's core study room was in 1994 used by guests from 22 different companies/institutions for the study of cores and/or geological sampling. The core study room has been used 250 days by external guests in addition to 90 days by the Norwegian Petroleum Directorate's employees.

As of 31 December 1994, the Norwegian Petroleum Directorate had released 315 seismic surveys comprising 252,132 line kilometers of seismic. The released seismic consisted of 277 surveys in the North Sea and 38 in the Norwegian Sea. Table 7.1.b gives an overview of released seismic data. A list of the released surveys is to be found in the publication «Released Seismic Surveys, Volumes A and B». «Volume A» contains seismic survey packages for the North Sea, while «Volume B» contains packages for the Norwegian Sea.

2.5.2 EXPLORATION DRILLING

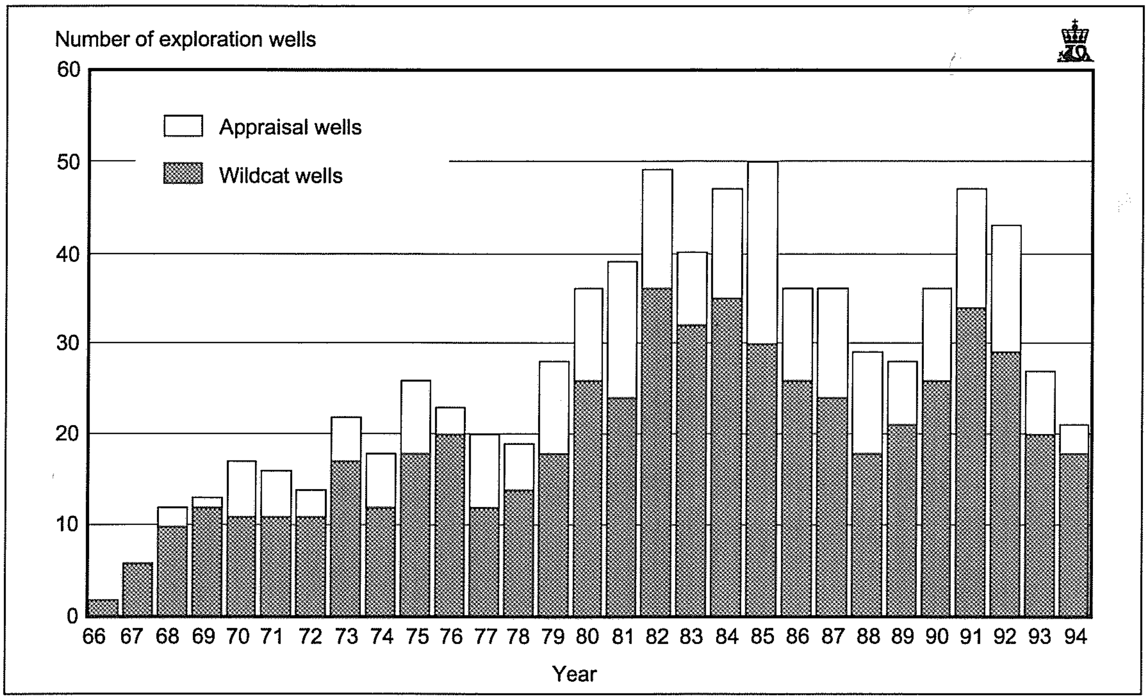
At year end 93/94, drilling of eight exploration wells was in progress.

In 1994, 21 new exploration wells were spudded, of which 18 were wildcats and 3 appraisal wells. Drilling activities in 1994 comprised 13 wildcats and 3 appraisal wells in the North Sea, and 5 wildcats in the Norwegian Sea. In addition, 6 suspended exploration wells were reentered for further work.

At year end 1994/1995, 3 exploration wells were in progress.

As of 31 December 1994, a total of 800 exploration wells had been spudded on the Norwegian continental shelf: 573 wildcats and 227 appraisal wells, see Figure 2.5.2.a. and Table 7.2.a.

Fig. 2.5.2.a
Exploration wells drilled on the Norwegian continental shelf



In 1994, 26 exploration wells were completed on the Norwegian continental shelf, consisting of 21 wildcats and 5 appraisal wells. The geographical distribution of the wells is as follows: 15 wildcats and 5 appraisal wells in the North Sea, 5 wildcats in the Norwegian Sea and one wildcat in the Barents Sea.

The operators for the drilling operations completed in 1994 were as follows: Statoil 9, Norsk Hydro 6, Saga 3, Amoco 2, Fina 2, BP 2 and Esso and Mobil 1 each.

A wildcat well is the first well being drilled to explore a clearly defined geological unit. An appraisal well is a well drilled to determine extent and size of discoveries. All exploration wells are spudded with one of these classifications. If it later becomes clear that the well does not fulfill the criteria for the classificaiton it has received, it is reclassified. On the Norwegian continental shelf, 71 exploration wells have been reclassified.

As of 31 December 1993, 771 exploration wells had been completed or suspended on the Norwegian continental shelf, comprising 549 wildcats and 222 appraisal wells.

Table 7.3.f gives a list of exploration wells started or completed in 1993.

In all, 45 exploration wells had been temporarily abandoned on the Norwegian continental shelf at the end of the year.

Suspended exploration wells on the Norwegian continental shelf for which equipment has been inetalled on the sea bed are as follows:

2/01-09 A	25/02-13	30/09-13 S
2/04-15 S	25/04-06 S	31/02-16 SR
2/04-17	25/05-04	31/02-18 A
2/07-23 S	25/08-05 S	31/05-04 AR
2/07-25 S	25/11-16	31/05-05
2/10-02	30/02-01	34/04-07
2/12-02 S	30/03-04	34/08-04 A
7/12-08	30/03-06 S	34/10-34
7/12-09	30/09-07	6407/07-02 R
9/02-04 S	30/09-08 R	6407/07-04
15/09-19 SR	30/09-09	6506/12-08
15/12-06 S	30/09-10	6507/08-04
15/12-09 S	30/09-12 A	6608/10-03

Figures 2.5.2.b, c and d show wells drilled in the three provinces on the Norwegian continental shelf (North Sea, Norwegian Sea and Barents Sea) in 1994.

The Norwegian companies Den norske stats oljeselskap a.s (Statoil), Norsk Hydro a.s and Saga Petroleum a.s. have been operators for 15 of the spudded wells, cor-responding to 71.4 percent. The remaining 6 wells were operated by Esso, Amoco, Mobil, BP and Fina. See Table 7.3.c for details.

2.5.2.1 Distribution of prospect types

Exploration activities in 1994 were largely targeted at Jurassic sandstone prospects. Of the 21 exploration wells spudded, 15 had Jurassic strata as their main prospect. Of the other main prospects, two were in Cretaceous and four in Tertiary strata.

Of the secondary prospects, one was in Tertiary, one in Cretaceous, four in Jurassic and one in Triassic strata.

2.5.2.2 New discoveries in 1994

A total of 21 wildcats were completed in 1994. In addition, wildcat well 2/4-18 R was drilled, but since the pilot hole 2/4-18 was drilled and temporarily abandoned in 1993, 2/4-18 R is not included in the well statistics for 1994. There have been 14 discoveries, of which seven have been confirmed through formation testing.

Exploration well	Operator	Hydrocarbons	Formation tested
2/7-29	BP Norge	Oil	No
2/11-10 S	Amoco Norge	Oil/gas	Yes
15/9-20 S	Statoil	Gas	No
24/9-5	Norske Fina A/S	Oil	No
25/8-5 S	Esso Norge	Oil	Yes
30/3-6 S	Statoil	Oil/gas	Yes
30/9-15	Norsk Hydro	Oil	No
30/9-16	Norsk Hydro	Oil/gas	Yes
34/7-23 S	Saga Petroleum	Oil	No
34/11-1	Statoil	Gas	Yes
6204/11-1	Statoil	Oil/gas	No
6407/8-2	BP Norge	Oil/gas	No
6608/10-4	Statoil	Oil	Yes
7128/4-1	Statoil	Oil/gas	Yes

Block 2/7

BP Norway has as operator of production licence 145 drilled wildcat 2/7-29. The well was drilled to 4851 meters below sea level and terminated in Permian rock. The purpose was to test two Jurassic prospects and one Permian prospect. A minor oil discovery was made in the topmost Jurassic prospect. Traces of hydrocarbons were present in the bottom Jurassic prospect, while the Permian prospect turned out to be water bearing. The well was not production tested, but an extensive amount of data was compiled in the form of core samples, pressure tests, and liquid samples.

Block 2/11

Amoco Norway has as operator of production licence 033 drilled the 2/11-10 S wildcat well. The well was drilled from the Hod installation to test a stratigraphic trap north-east of the Hod field.

The well was drilled to a depth of 2873 meters below sea level and terminated in Late Cretaceous rock. Oil was found in Late Cretaceous rock, and formation testing was carried out in the Ekofisk and Tor formations. The maximum well flow rate was measured to 83 Sm^3 oil and 55 Sm^3 formation water per day. The gas/oil ratio was measured to 120 Sm^3 / Sm^3 . The specific gravity of the oil was 0.86 g/cm^3 and the specific gravity of the gas was 0.84 relative to air. Production is now in progress from this well via the Hod installation.

Block 15/9

Statoil has as operator of production licence 046 drilled the production well 15/9-A-22 on Sleipner Øst. The well was extended into Triassic rocks and the lower part of the well is classified as wildcat 15/9-20 S. A minor accumulation of gas was proven in Triassic sandstone which were not formation tested. Traces of gas were also proven in Cretaceous rock. This level was formation tested, but due to poor reservoir properties the gas could not be produced.

Block 24/9

Norske Fina A/S has as operator of production licence 150, block 24/9, drilled the 24/9-5 wildcat well in a structure north in the block.

The well was drilled to a depth of 2831 meters below sea level and terminated in Late Cretaceous rock . Oil was proven in Tertiary sandstone of the Balder formation. The well was not production tested. Results from the appraisal well 24/9-6 drilled immediately after 24/9-5 show that the discovery is relatively small.

Block 25/8

Esso Norge has as operator of production licence 027 drilled wildcat 25/8-5 S. The well, which was drilled in a structure between the Balder discovery and the Heimdal field, was drilled to a vertical depth of 2887 meters below sea level, and was terminated in Triassic rock. Oil was proven in Paleocene sandstone. The well was formation tested, and the results showed that the reservoir has good production properties. Particularly encouraging is that the oil proven in this well has a considerably lower density than for example the oil in the neighbouring discoveries 25/11-1 Balder and 25/11-15 Hermod. This is favourable with a view to possible production of the resources in this discovery. The average production rate was 1115 Sm^3 oil per day through a 50 mm choke. The oil density was measured to 0.85 g/cm^3 .

It is still too early to say anything with certainty about the size of the discovery, but the Norwegian Petroleum Directorate considers the discovery very interesting.

Block 30/3

Statoil has as operator of production licence 052, block 30/3, drilled the wildcat well 30/3-6 S in a stucture south of the Veslefrikk field, and has made a small oil/condensate and gas discovery.

The well was drilled to a depth of 3720 meters below sea level and terminated in Early Jurassic rock. Oil/condensate and gas were encountered in Middle Jurassic rock types. The well was long-term tested and is planned to be completed as producer tied in with Veslefrikk.

Block 30/9

Norsk Hydro has as operator of production licence 104, block 30/9, drilled the wildcats 30/9-15 and 30/9-16.

30/9-15 was drilled in a structure just south-east of the Oseberg field. Hydrocarbons have earlier been proven in other structures in this area.

The well was drilled to a depth of 2741 meters below sea level and terminated in Jurassic rock. Oil was proven in Middle Jurassic sandstone strata. The discovery is relatively small and was not formation tested.

30/9-16 was drilled south of the Oseberg field in a structure extending into the neighbouring block 30/12, production licence 171. The well was drilled to a depth of 3528 meters below sea level and terminated in Early Jurassic rocks. Oil and gas were proven in Middle Jurassic sandstone strata. Two formation tests were run, one oil test and one gas test. The test results were good. The maximum flow rate from the oil zone was measured to 1600 Sm^3 oil per day through a 28.6 mm choke. The gas/oil ratio was 166 Sm^3/Sm^3 and the oil density 0.83 g/cm^3. The maximum flow rate from the gas zone was measured to 721,000 Sm^3 gas per day through a 25.4 mm choke. The gas/oil ratio was 2.900 Sm^3/Sm^3 and the gas density 0.71 relative to air. The discovery is of medium size. The result is particularly interesting as the chances of finding hydrocarbons in other structures in the area have increased.

Block 34/7

Saga Petroleum has as operator of production licence 089 drilled the 34/7-23 S wildcat in a structure south-west of the Snorre field. The well was drilled to a vertical depth of 2864 meters and terminated in Jurassic rock. Hydrocarbons were found in Late Jurassic rock. The well was not formation tested.

The discovery was made at the same stratigraphic level as the discovery in 34/7-21 and -21 A, which were drilled somewhat more to the south-east. The drilling proves that the area represents an interesting hydrocar-

Fig. 2.5.2.b
Exploration wells drilled in the North Sea in 1994

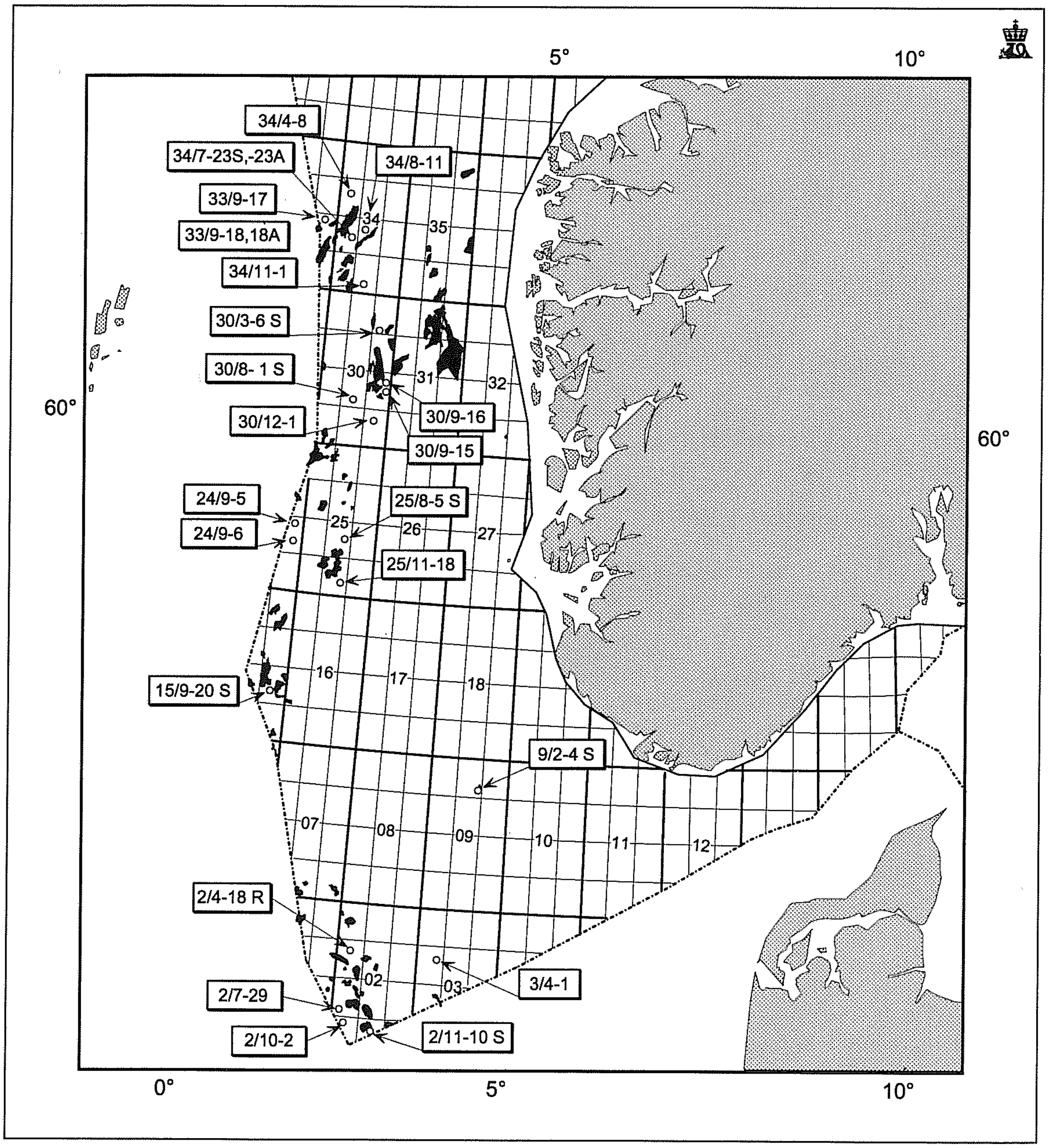
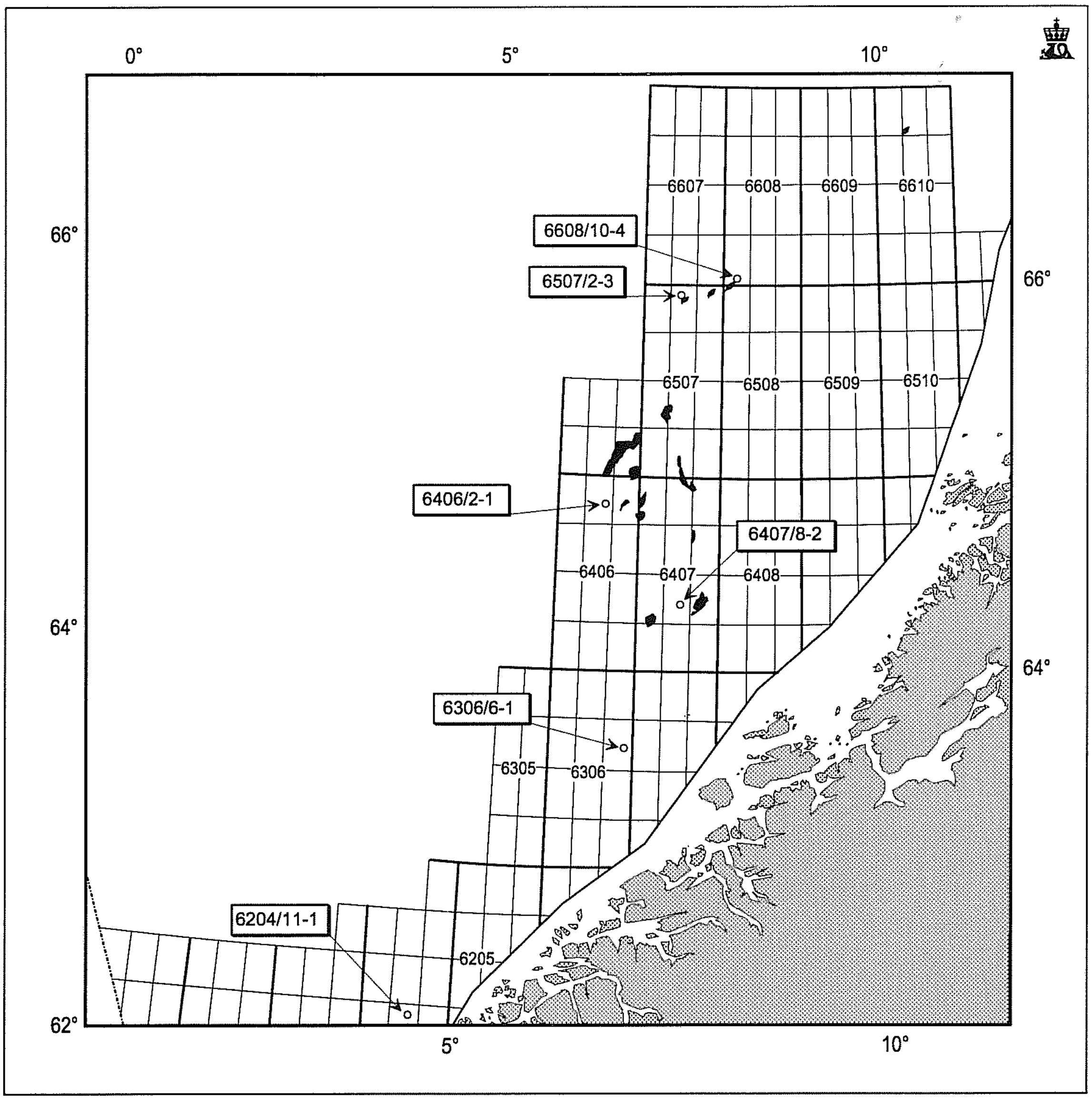


Fig. 2.5.2.c
Exploration wells drilled in the Norwegian Sea in 1994



bon potential, but that there is a problem in determining the lateral extent and the development of the reservoir sand. Consequently it is difficult to say anything with certainty on the size of the discovery until more drilling and further geological survey have been carried out.

Block 34/11

Statoil has as operator of production licence 193, block 34/11, drilled the wildcat well 3/11-1. The well was drilled in a structure centrally in the block, east of the gas discovery 34/10-23 Gamma.

The well was drilled to a depth of 4556 meters below sea level and terminated in Early Jurassic rocks (Statfjord formation).

Gas was proven in Middle Jurassic sandstone strata (the Brent group). The well was formation tested. Maximum flow rate was measured to 800,000 Sm^3 gas and 500 Sm^3 condensate per day through a 15.9 mm choke. Condensate density was measured to 0.79 g/cm^3 , and the gas/oil ratio was 1660 Sm^3 /Sm^3 . The test results were considered good.

It is still too early to say anything with certainty about the size of the discovery, but preliminary evaluations indicate that it may be relatively large. Its location near existing discoveries and fields is favourable with regard to possible development and production.

Block 6204/11

Statoil has as operator of production licence 175, blocks 6204/10 and 6204/11, drilled the wildcat well 6204/11-1, in an area where no wells have previously been drilled. The well was drilled to a vertical depth of 2943 meters below sea level and terminated in Triassic rock. Reservoir rock was found at several levels. One of these contained traces of oil, and a gas discovery was made in another. The well was not formation tested as the remaining data were considered to be sufficient to evaluate reservoir properties and resource potential.

Block 6407/8

BP Norge has as operator of production licence 158, block 6407/8, drilled wildcat 6407/8-2 in a structure located between Draugen and Njord. The structure extends into block 6407/11, production licence 176. The well was drilled to a vertical depth of 1925 meters below sea level and terminated in assumed Triassic rock.

A discovery was made of gas and oil in Jurassic sandstone. The discovery is relatively small, and was therefore not formation tested.

Block 6608/10

Statoil has as operator of production licence 178, blocks 6608/10 and 6608/11, drilled the wildcat well 6608/10-4 in a separate structure directly east of Norne. The well

Fig. 2.5.2.d
Exploration well drilled in the Barents Sea in 1994

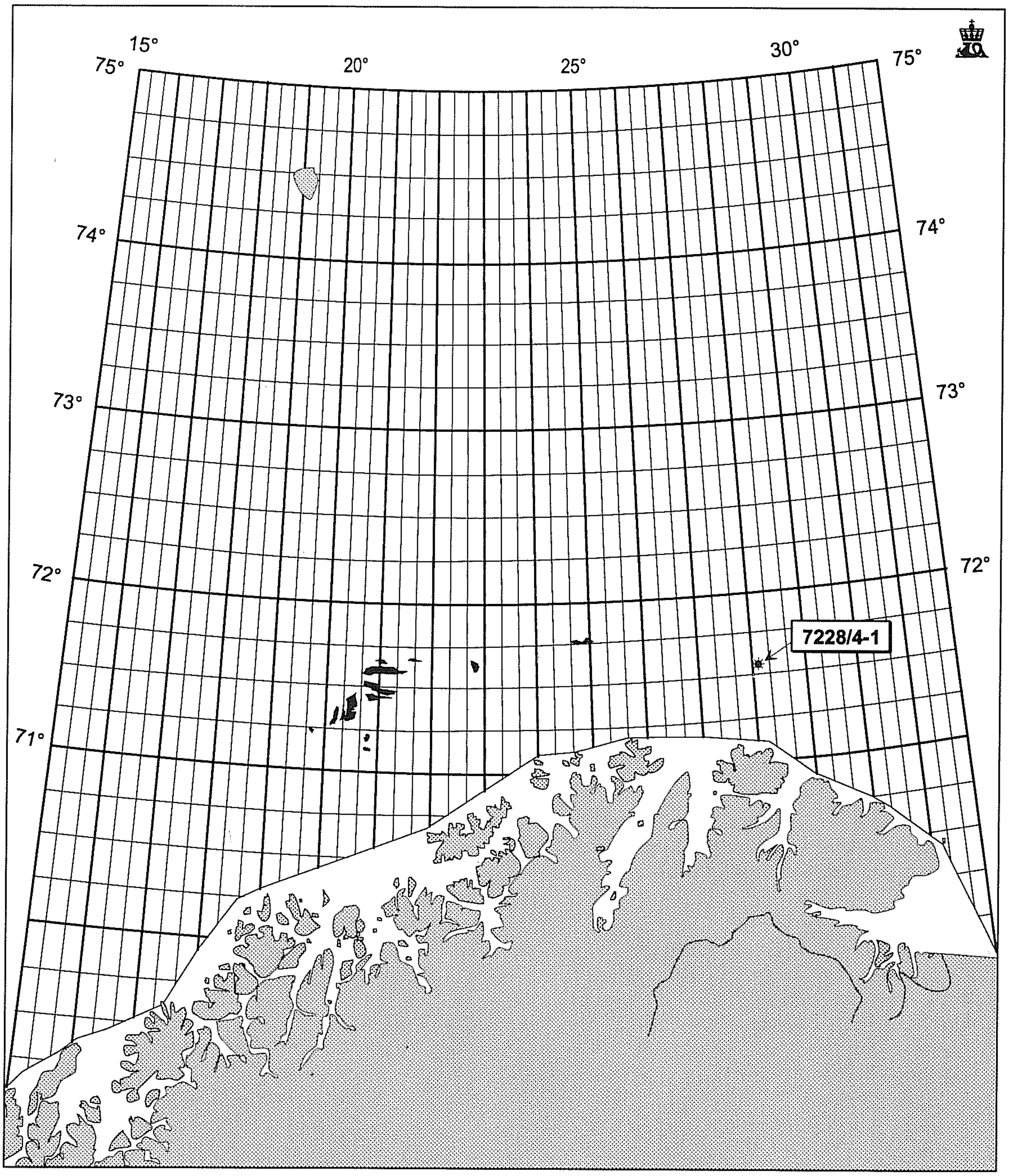
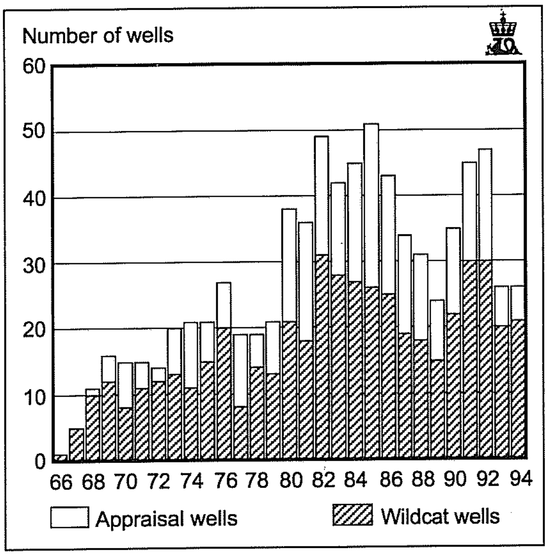


Fig. 2.5.2.e
Exploration wells completed each year after re-classification



was drilled to a vertical depth of 2777 meters below sea level and terminated in Early Jurassic rock. Oil was proven. The formation testing showed a maximum of 660 Sm^3 of oil and 55,500 Sm^3 of gas per day through a 19 mm choke. The gas/oil ratio was measured to 83 Sm^3 /Sm^3 . The discovery is small, but the location near Norne makes it interesting.

Block 7128/4
Statoil has as operator of production licence 180, block 7128/4, drilled the wildcat well 7128/4-1 in the souteastern part of the Finnmark platform. The well was drilled to a total depth of 2506 meters below sea level and terminated in Precambrian rock. Oil and gas were proven in Late Permian rock. The test showed 290,000 Sm^3 of gas and 25 Sm^3 of oil per day through a 71 mm choke. Due to technical problems encountered during the test, the extent to which the test results are representative with regard to the production properties of the reservoir, is uncertain. The discovery is small, but it is the first time hydrocarbons capable of being produced have been proven in the area. The well has therefore confirmed a new play model, and this is encouraging for further exploration activities in the area.

2.5.2.3 Further details of other drilling operations

Block 2/4
Saga Petroleum han as operator of production licence 146, block 2/4, drilled the 2/4-18 R wildcat. The well was drilled in the same structure where Saga previously has had major operational problems due to high pressure.

The well was drilled to 5258 meters below sea level and terminated in Late Jurassic rock. Analyses confirmed the presence of a hydrocarbon bearing sandstone of limited thickness. The well was not formation tested. The resources proven in this well are regarded too small to be classified as a discovery, but in cannot be excluded that this stucture represents an interesting upside potential.

Block 3/4
Amoco Norge has as operator of production licence 006, block 3/4, drilled the 3/4-1 wildcat on the eastern flank of the Søgne basin.

The well was drilled to a depth of 3063 meters below sea level and terminated in Permian rock. No hydrocarbons were proven in this well.

Block 9/2
Statoil has as operator of production licence 114, block 9/2, drilled appraisal well 9/2-4 S in the southern part of the Yme field.

The well was drilled to a depth of 3290 meters below sea level and terminated in Middle Jurassic rock. The drilling has resulted in the recoverable reserves of the Yme field being adjusted upwards from 3.4 million Sm^3 to 5.8 million Sm^3 . 9/2-4 S has however been temporarily plugged with view to the possibility of being used as a future production well.

Block 24/9
Norske Fina A/S has as operator of production licence 150, block 24/9, drilled appraisal well 24/9-6 in a structure in the northern part of the block. The purpose was to determine the extent and size of the oil discovery 24/9-5.

24/9-6 was drilled to a depth of 2226 meters below sea level and terminated in Early Tertiary rock. The result of the drilling showed that the discovery in 24/9-5 is relatively small.

Block 25/11
Norsk Hydro has as operator of production licence 169, blocks 25/11 and 25/8, drilled the 25/11-18 appraisal well in the 25/11-15 discovery Hermod.

The well was drilled to a depth of 1851 meters below sea level and terminated in Cretaceous rock. Oil was found in Paleocene sandstone, as was the case in well 25/11-15. The appraisal well has confirmed the geological model and the reservoir estimate for the Hermod discovery. The result of the well is consequently encouraging. The well was not formation tested.

The lower part of the well was drilled by means of coil tubing. This is the first time this drilling technology is used on the Norwegian continental shelf. Valuable knowledge and experience was gained, and coil tubing/ slim hole drilling can in the future lead to considerable savings in drilling costs. Due to technical problems resulting in the inability to log well 25/11-18, a technical sidetracking was carried out, 25/11-18 T2.

Block 30/8
Norsk Hydro is as operator of production licence 190, block 30/8, in the process of drilling wildcat 30/8-1 S in a structure north-east in the block. Drilling was not completed by year end.

Block 30/12

Norsk Hydro has as operator of production licence 171, block 30/12, drilled wildcat 30/12-1 south of the Oseberg field. The well was drilled to a depth of 3619 meters below sea level and terminated in Jurassic rock

No hydrocarbons were proven in the well.

Block 33/9

Mobil has as operator of production licence 172, block 33/9, completed drilling of wildcat well 33/9-17.

The well was drilled to a total depth of 3207 meters below sea level and terminated in Middle Jurassic rock..

No hydrocarbons were proven in this wildcat welll.

Statoil has as operator of production licence 037, block 33/9, completed drilling of wildcat well 33/9-18. The well was drilled to a total depth of 3230 meters below sea level and terminated in Jurassic rock. No hydrocarbons were proven in the well.

Statoil has as operator of production licence 037, block 33/9, commenced drilling of wildcat well 33/9-18 A. The well is drilled as a sidestep out from the well 33/9-18. The expected reservoir level was not yet reached at year end.

Block 34/4

As operator of production licence 057, block 34/4, Saga Petroleum has completed drilling of wildcat well 34/4-8.

The well was drilled to a total depth of 3085 meters below sea level and terminated in Triassic rock. No trace of hydrocarbons were proven in this wildcat well.

Block 34/7

Saga Petroleum has as operator of production licence 089 drilled wildcat well 34/7-23 A in the discovery 34/7-23 S. The well was drilled immediately following 34/7-23 and as a sidestep to this well. It was drilled to a total depth of 2764 meters and the well was terminated in Jurassic rock. Hydrocarbons were proven in Late Jurassic rock. A formation test was run giving a stable oil flow of 1087 Sm^3 per day through a 19.1 mm choke.

Block 34/8

Norsk Hydro has as operator of production licence 120, block 34/8, completed drilling and formation testing of appraisal well 34/8-11. The purpose of the drilling was to determine resource basis and reservoir continuity in the middle segment of the Visund discovery. The well was vertically drilled between the wells 34/8-8 and 34/8-10 S to 3117 meters below sea level. The drilling was terminated in rocks belonging to the Dunlin group, of Jurassic age. Oil was proven in the Brent group. A formation test at this level showed maximum flow rate measured to 1259 Sm^3 oil per day and 301,300 Sm^3 gas per day through a 15.9 mm choke. This gives a gas/oil ratio of 239 Sm^3/Sm^3. Test results are considered good, and the well confirmed the previous expectations to resource quantity and production properties in this part of the Visund discovery.

Block 6306/6

Statoil has as operator of production licence 198, block 6306/6, drilled wildcat 6306/6-1 in a structure south in the block. The well was drilled to a vertical depth of 1293 meters below sea level and terminated in bedrock. No traces of hydrocarbons were proven and the well was classified as dry.

Block 6406/2

Saga Petroleum is as operator of production licence 199 block 6406/2, in the process of drilling in a structure located south of Smørbukk. Drilling was not completed by year end.

Block 6507/2

Norsk Hydro has as operator of production licence 122, block 6507/2, drilled wildcat 6507/2-3 in a structure on the borderline between block 6507/2 and 6507/3. The well was drilled to a vertical depth of 3950 meters below sea level and terminated in Jurassic rock.

2.5.2.4 Svalbard

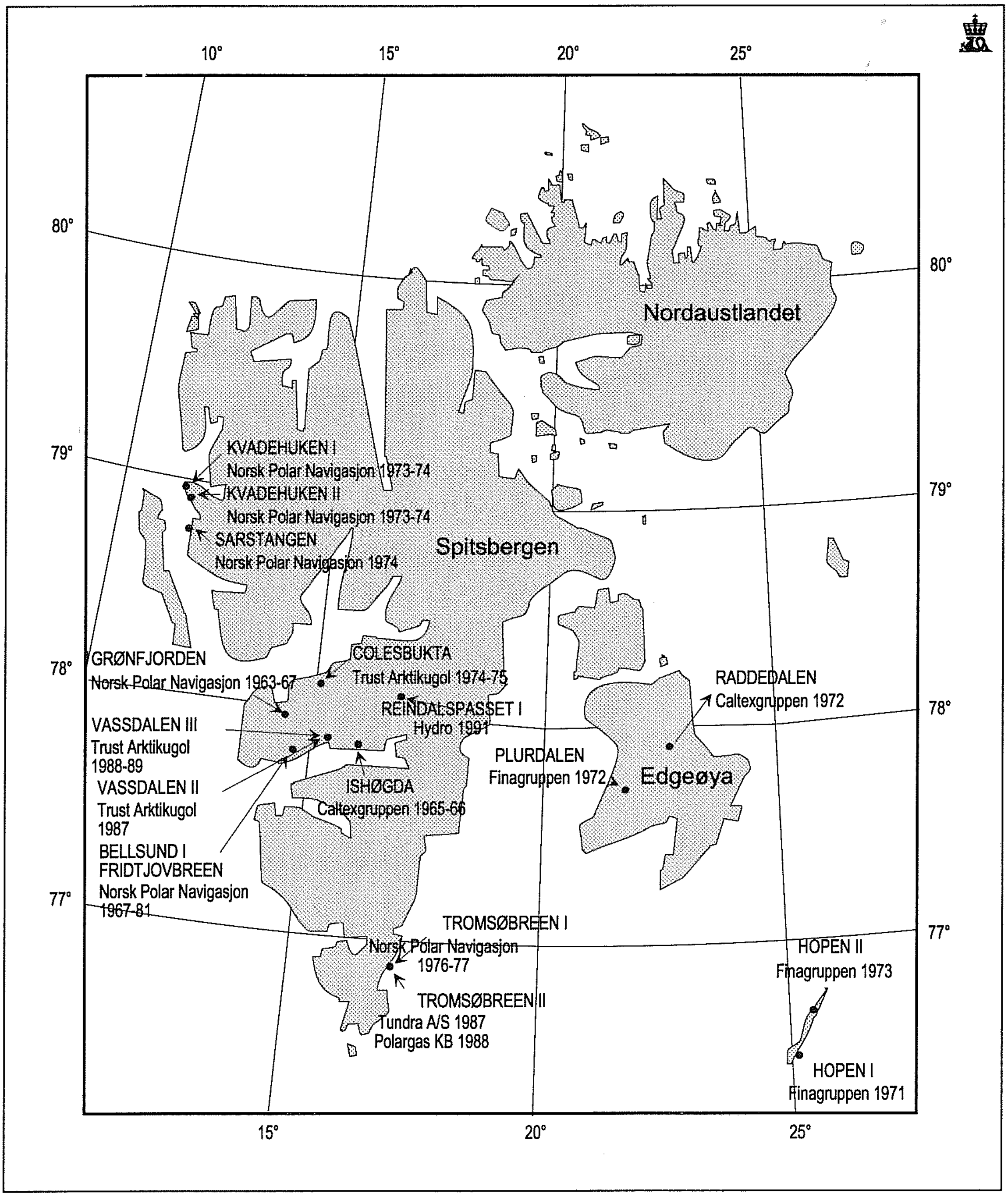
Store Norske Spitsbergen Kullkompani (SNSK) has carried out drilling of wildcat well 7814/12-1, Kapp Laila-1. The drilling was carried out on the acerage of the Russian coalmining company Trust Arktikugol, and the basis for the drilling was a co-operation agreement between SNSK and Trust Arktikugol. Through a co-operation project between SNSK and Norsk Hydro, the drilling project has been in a position to draw on Norsk Hydro's expertise in the oil and gas activities.

The well Kapp Laila-1 was drlled on the south side of Isfjorden, 2.5 km west of Kapp Laila. The purpose of the well was to test the hydrocarbon potential in Tertiary sandstones from the Firkanten formation and Lower Cretaceous sandstones from the Helvetia mountain formation. The drilling terminated in sandstone, slate and limestone of Early Cretaceous age. The drilling was stopped due to drilling technological and safety reasons at a depth of 503.5 meters. Traces of oil and gas were proven, but the well was not formation tested.

The drilling was carried out by means of an upgraded coal drilling rig. In addition, a BOP arrangement with associated control system was installed, together with a complete drilling mud circulation system.

The drilling programme was a slim hole programme, and this is the first time such a programme has been carried out on Svalbard. Table 7.3.g shows drilling activities on Svalbard, and Figre 2.5.2.4 shows drilling locations on Svalbard.

Fig. 2.5.2.4
Well locations on Svalbard



2.6 DISCOVERIES

2.6.1 DISCOVERIES WITHOUT FIRM DEVELOPMENT PLANS

The Ekofisk area

This is the area on the Norwegian continental shelf which has been in production for the longest period of time, from 1971. An overview of fields and discoveries is shown in Fgure 2.8.4.a. Typical for the area is that most of the production is from chalk fields, whereas most exploration prospects are focused on sandstone at deeper levels. A major work is now being done to define remaining potential also in chalk rocks in the area, particularly in the areas around existing fields. Several small discoveries have been made in the area, and some of these can be tied in with existing installations. Other discoveries are in too isolated locations or are for other reasons considered not to be commercial at the present time.

1/9-1 Tommeliten Alpha

Tommeliten Alpha is located south of Tommeliten Gamma in Block 1/9, production licence 044, which was granted in 1976. The field was Statoil's first discovery as operator. In 1994, new geological work based on new 3D seismic was carried out. The result of this study has led to a reduction of recoverable resources to 2.7 billion Sm^3 of gas and 2.5 million Sm^3 of oil.

2/4-17 Tjalve

This discovery was made in 1992. It is in production licence 018, which was granted in 1965 with Phillips Petroleum as operator. Recoverable reserves are estimated to 1.0 milion Sm^3 of oil and 2.1 billion Sm^3 of gas. The discovery was evaluated in 1994 and is by the operator considered not to be commercial at the present time.

2/5-3 Sørøst Tor

This discovery is in production licence 006, which was granted in 1965 with Amoco as operator. The Norwegian Petroleum Directorate estimates recoverable resources to 2.5 million Sm^3 oil and 2 billion Sm^3 gas.

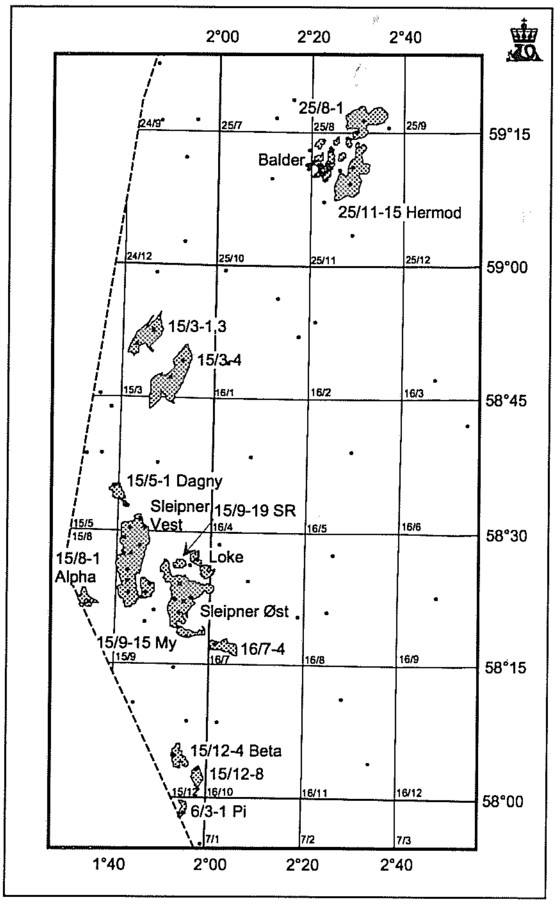
2/12-1 Mjølner

Mjølner is located in production licence 113, which was granted in 1985. The discovery is located near the borderline between the Norwegian and the Danish continental shelves. The A segment, from which production is planned to take place, lies, according to the Norwegian operator, 100 % within the Norwegian sector, and recoverable resources in the segment are estimated by Norsk Hydro to be 1.5 million Sm^3 oil and 0.7 billion Sm^3 gas. Norsk Hydro has, in co-operation with the operator in the Danish sector, reprocessed the 3D seismic. The commerciality declaration was presented in June 1992. Following takeover of Norsk Hydro's shares, Amerada Hess takes over as operator for Mjølner effective from 1 January 1995, while Mærsk is the operator for the Gert field located near the borderline on the Danish side.

3/7-4 Trym

Trym is located in production licence 147, allocated in 1988. Shell is operator. The discovery is in a structure crossing the borderline between the Danish and Norwegian sectors. This structure was originally called Trym. In 1992 drilling was carried out in the Danish sector on the southern part of the same structure, and oil was proven. This discovery was named Lulita. Shell's interpretation of the 3D seismic for the entire structure divides it into three segments, two of them extend into the Norwegian sector. Trym is held to be 100 % Norwegian. The Lulita discovery is believed to extend into the Norwegian sector. Statoil-Denmark is operator for Lulita on the Danish side. Recoverable resources from Trym are

Fig. 2.6.a
Fields and discoveries in the Sleipner and Balder area



according to Shell's estimate 4.1 billion Sm^3 gas and 1.1 million Sm^3 condensate. Development studies were undertaken in 1994 for Trym and Lulita in a joint programme with the Danish operator.

Sleipner and Balder area

In addition to Sleipner Øst and Loke, which are in production, and Sleipner Vest, which is decided to be developed, the area consists of a number of other discoveries, see Figure 2.6.a. Sleipner Øst and Loke came into production in the autumn 1993 and are discussed in more detail in section 2.8.7. Sleipner Vest is further discussed in section 2.7.2. The area around Sleipner contains a number of relatively small gas/condensate discoveries which are expected to be tied in with the infrastructure in the area. In and around Balder, there have been a number of discoveries of structures containing viscous oil.

15/8-1 Alpha

The discovery was made in production licence 046 in 1982 in the Hugin formation at Triassic/Jurassic level. The operator estimates recoverable resources to 4.3 billion Sm^3 gas and 3.6 million tonnes NGL.

25/8-5 S

Esso made a discovery in 1994 in licence 027 P in well 25/8-5S, which is located between Heimdal and the Balder discovery. The discovery was made in the Heimdal formation of Paleocene age. The production test demonstrated good production properties in the reservoir. 3D seismic was shot over the discovery in 1994, so that it can be mapped in detail by the operator in 1995. In addition, an appraisal well has been planned.

Other discoveries

Two discoveries have been made in block 15/3: one gas/condensate discovery in wells 15/3-1,3 in 1975 and one gas/oil discovery in well 15/3-4 in 1982. The Norwegian Petroleum Directorate's estimate of recoverable resources in 15/3-1,3 is 10.5 billion Sm^3 gas and 5.2 million Sm^3 oil.

Statoil discovered oil in 1993 on block 15/9 in the 15/9-19 SR well in Jurassic/Triassic rocks, just north of Sleipner Øst. The operator estimates recoverable resources to 6.6 million Sm^3 oil and 0.7 billion Sm^3 gas.

There are many small gas discoveries in the area which are assumed to be tied in with the Sleipner installation.

The Frigg area

This is an area where gas fields have been in production since 1977, see Figure 2.8.9.a. Several small discoveries have been made in the area, including oil. Skirne and Byggve have been considered as potentially attractive for development, but they are dependent on, inter alia, a solution for gas. The same applies to development of Vale.

24/6-1 Peik

Peik was proven in 1985. The production licence is No. 088, allocated in 1984 with TOTAL Norge A/S as operator. In 1987, hydrocarbons were proven in the UK sector.

The operator's estimate of recoverable resources is 0.9 million Sm^3 oil and 3.1 billion Sm^3 gas.

25/2-5 Lille Frøy

This discovery is located in production licence 026, allocated in 1969 with Elf the operator. Well 25/2-5 proved oil in 1976. The well 25/2-15 was completed drilled north-east of the 25/2-5 and 25/2-13 structure in 1993 and produced negative results. The operator plans to interpret the structure. There are no plans for development. The operator's estimate of recoverable resources is 1.2 million Sm^3 oil and 1.2 billion Sm^3 gas.

25/4-6S Vale

This discovery is located in production licence 036 which was allocated in 1981 with Elf as operator. Gas rich in condensate was proven in 1991. The licensees are currently working towards a commerciality declaration. The most probable development concept is a subsea installation with tie-in to either Frigg or Heimdal. The operator estimates recoverable resources at 1.0 billion Sm^3 gas and 3.1 million Sm^3 oil.

25/5-3 Skirne

This field is situated in production licence 102. Elf is operator for the production licence which was allocated in 1985. The discovery was proven by well 25/5-3 in the Brent group in 1990. The Norwegian Petroleum Directorate 's estimate of recoverable resources is 3.3 billion Sm^3 gas and 0.3 million tonnes NGL.

25/5-4 Byggve

This field is situated in production licence 102. Elf is operator for the production licence which was allocated in 1985. The discovery was proven by well 25/5-4 in the Brent group in 1991. The Norwegian Petroleum Directorate 's estimate of recoverable resources is 2.6 billion Sm^3 gas and 0.6 million Sm^3 oil. Further mapping is required before a possible decision on development can be taken.

30/7-6 R Hild

Hild is situated in production licence 040 and 043 with Norsk Hydro and TOTAL Norge A/S as operators, see Figure 2.6.c. The gas discovery was proven by well 30/7-6 in 1977. Production licence 040 was granted in 1975 and comprises the blocks 29/9 and 30/7. Production licence 043 was granted in 1976 and comprises the blocks 29/6 and 30/4. Development will entail negotiations regarding co-ordination of the production licences.

The operator's estimate of recoverable resources is 6.6 million Sm^3 oil and 27.6 billion Sm^3 gas. Further drilling is required before a decision on development can be taken.

The Oseberg area

A number of discoveries have been proven in the area which are planned to be produced as satellites to existing infrastructure, see Figure 2.6.b. West of Oseberg field centre, mainly in production licence 053, lies the discovery 30/6-18 Kappa in the Statfjord formation. There are no firm development plans for this discovery.

Gullfaks, Statfjord and Snorre area

There is a very high activity in this area with a number of fields in production or in the process of being developed. In addition there are several discoveries in the area, see Figure 2.8.12.a.

34/7-21 and 34/7-23 S

The discoveries are located in production licence 089 operated by Saga Petroleum. Both discoveries have proven oil in Late Jurassic rock.

The discovery 34/7-21, located north-west of the Tordis field, was proven in November 1992. A sidestep, 34/7-21 A, was drilled for appraisal of the oil discovery. The sidestep confirmed the discovery, but showed that the lateral development and extent of the reservoir sand is difficult to map. The operator's estimate of recoverable resources is 13.6 million Sm^3 oil.

The discovery 34/7-23 S, located south-west of the Vigdis field, was proven in March 1994. To improve the delimitation of the reservoir, a sidestep to the well was drilled, 34/7-23 A. The operator's estimate of in-place resources for this discovery is in the region of 18 million Sm^3 oil. Great uncertainty is attached to the lateral extent of the reservoir and continuity in the two discoveries. The operator is planning several appraisal wells in the area. Based on the proven resources, the operator is considering a tie-in of the 34/7-21 discovery with Tordis and the 34/7-23S discovery with Vigdis.

34/10-23 Gamma

34/10-23 Gamma is located in production licence 050, with Statoil as the operator. The discovery is about 14 kilometers south of the Gullfaks field. The discovery was proven in 1985 by well 34/10-23 which proved gas in Middle Jurassic sandstone. Appraisal well 34/10-35 was drilled in the northern part of the structure in 1992 and similarly proved gas in Jurassic sandstone. The Norwegian Petroleum Directorate estimates that recoverable resources are 69 billion Sm^3 gas and 6 million Sm^3 oil.

The Troll area

There is very high activity in connection with development of the considerable oil and gas resources of the Troll field. A number of discoveries in the area are now being considered for development as separate solutions or possibly as satellites to approved infrastructures in the area.

35/11-2, 35/11-4 R and 35/11-7

Block 35/11 was allocated in 1984 by production licence 090. Mobil is the operator. Seven wells have been drilled of which three proved hydrocarbons. The hydrocarbons are present in several reservoir layers.

Well 35/11-2 was drilled north in the block in 1987. The estimates of recoverable resources are 4.6 million Sm^3 oil and 4.9 billion Sm^3 gas.

Well 35/11-4 R was drilled in 1991, and 35/11-7 in 1992 just east of that well in the south-eastern part of the block. Interpretation of 3D seismic has caused the resource estimate for the two discoveries to be adjusted downwards by approximately 50% , which has led to a reduction of activities with regard to further apparaisal and development. The estimates of recoverable resources are 9 million Sm^3oil for each of the discoveries and 8.6 billion Sm^3 gas and 4.0 billion Sm^3 gas for 35/11-4 R and 35/11-7, respectively.

The Norwegian Sea

The development activities have been considerable over the last years, cf. Figure 2.6.d, and have until now primarily been aimed at development of the oil resources in the area. Work is in progress with regard to various development concepts for a co-ordinated development of the considerable gas resources in the area.

6406/3-2 Trestakk

Trestakk is an oil discovery proven in production licence 091 in 1986. Recoverable resources are estimated by the operator to be 4.8 million Sm^3 oil if associated gas is reinjected. The reservoir is of Middle Jurassic age, with low permeability and in a deep location. This is expected to give a low well productivity.

6407/1-2 Tyrihans Sør and 6407/1-3 Tyrihans Nord

Tyrihans Sør was proven in 1983 and Tyrihans Nord was proven in 1984 in production licence 073.

There is probably pressure communication through a commonaquifer. Tyrihans Sør is classed as a gas/condensate discovery, while Tyrihans Nord contains an oil zone with an overlying gas cap. The reservoirs are of Middle Jurassic age. The size of the oil zone in Tyrihans Nord is uncertain since no oil-water contact has been proven. The operator's estimates for total recoverable resources are 9.6 million Sm^3 oil/condensate and 26.9 billion Sm^3 gas.

The Barents Sea

About 250 billion Sm^3 recoverable gas has been proven in the Barents Sea, cf. Figure 2.6.b. In addition there is a thin oil zone in the 7121/4-1 Snøhvit discovery.

7121/4-1 Snøhvit

Snøhvit is situated in the following blocks: 7120/6; 7121/4; 7121/5 and 7120/5. Norsk Hydro is the operator of production licence 097, (block 7120/6) and Statoil is the operator of production licences 099 (block 7121/4) and 110. Production licences 097 and 099 were allocated in 1984, while production licence 110 was allocated in 1985. Snøhvit was proven in 1984 and the reservoir is of Jurassic age. There is no existing infrastructure in the area. The Norwegian Petroleum Directorate's estimates for recoverable resources are 83 billion Sm^3 gas, 6.7 million Sm^3 oil and 9.2 million tonnes NGL. Due to the long distance to traditional Norwegian gas markets, pipeline transportation of the gas does not seem financially interesting. A development of the discovery would therefore probably include a refrigeration plant to produce liquified natural gas, LNG, or possibly some other use.

Snøhvit also contains a thin oil zone. Due to the narrowness of the zone and average to poor reservoir properties, the oil is difficult to produce.

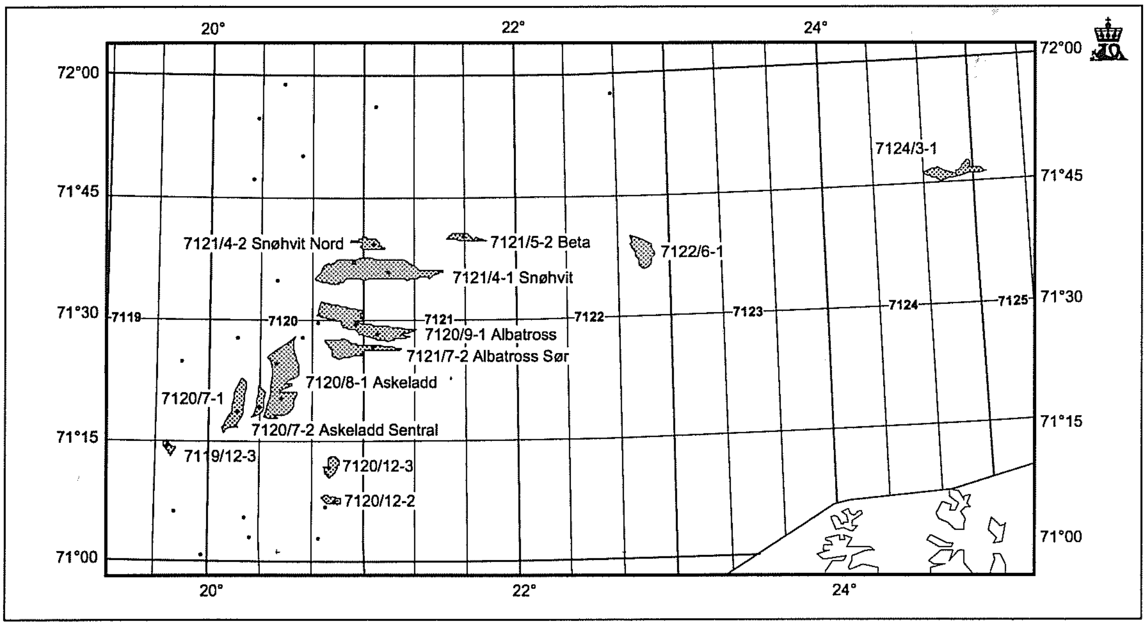
7120/8-1 Askeladd and 7120/7-2 Askeladd Sentral

Statoil is the operator of the discoveries which were made in 1981 and 1983. The reservoir consists of Jurassic sandstone, and contains gas and condensate. Earlier the discoveries were considered as one discovery with a resource volume of 59.7 billion Sm^3 of gas. This resource estimate has been split up so that Askeladd has recoverable gas resources of 49.8 billion Sm^3 gas and Askeladd Sentral has 9.9 billion Sm^3 gas.

7120/9-1 Albatross and 7121/7-2 Albatross Sør

The discoveries are located in blocks 7120/6, 7120/9 and 7121/7. The operators are Norsk Hydro and Statoil. The discoveries were proven in 1982 and 1986 and contain gas. The reservoir is of Jurassic age. The Norwegian Petroleum Directorate's estimate of total recoverable resources is 52.5 billion Sm^3 gas.

Fig. 2.6.b
Discoveries in the Barents Sea



2.6.2 DISCOVERIES WITH FIRM DEVELOPMENT PLANS

9/2-1 Yme

Yme is located in production licence 114, which was granted in 1985. Statoil is the operator. The field is in the Egersund basin and was proven by well 9/2-1. There is no infrastructure in the area. An updated plan for development and operation was submitted to the authorities in October 1994 and is expected to be approved in early 1995. The suggested development concept is based on use of a jack-up installation and a storage tanker with buoy loading to ship. Well 9/2-4S was drilled in this structure during the first quarter of 1994, cf. Figure 2.5.2.b.The results from the well were positive. The operator's estimates for recoverable resources are 5.8 million Sm³ oil. In 1994, 3-D seismic was shot over prospective areas in the production licence, and an appraisal well is planned to be drilled in 1995 on the 9/2-3 discovery in the Beta Øst structure. Production start for Yme is planned for autumn 1995.

Sleipner and Balder area

15/5-1 Dagny

The discovery is located in production licence 048, with Norsk Hydro as operator. 15/5-1 is classified as a gas/condensate discovery. Since the discovery extends into block 15/6, it must be unitised with the licensees in block 15/6.

The Norwegian Petroleum Directorate's estimates for recoverable resources are 6.1 billion Sm³ gas, and 1.4 million tonnes NGL. The plan for development and operation will be submitted in the autumn of 1995 at the earliest. Start-up may be in the autumn of 1997. The most probable development concept is a subsea installation with tie-in to nearby infrastructure.

15/9-15 My

The discovery was made in 1974 and is located in production licence 046. The operator's estimates of recoverable resources are 4.4 billion Sm³ gas, and 1.9 million tonnes NGL. The My reservoir is located deeper than Sleipner Øst, and is expected to be unaffected by production from Sleipner Øst. Statoil, who is the operator, is considering hooking the field up to Sleipner Øst as a satellite.

15/12-4 Beta

This discovery is located in production licence 038 awarded in 1974 with Statoil as operator. Statoil estimates the recoverable resources to be 12.3 million Sm³ oil. The licensees are evaluating various development concepts, and at the same time the geological data are being further processed for more information. The preliminary plans are to start production in 1997 at the earliest. Saga has in 1994 bought Esso's 50% share and has applied to take over as operator from Statoil.

25/11-1 Balder

Oil was proven in Balder in 1967 by exploration well 25/11-1, but it was not until well 25/11-5 was drilled in 1974 that this discovery was considered interesting. The discovery is located in blocks 25/10 and 25/11 in production licences 001 and 028, both operated by Esso. Esso holds 100 % of production licence 001. The recoverable resources have been estimated by the operator to be 32.2 million Sm³ oil. Balder contains relatively viscous oil in several structures. The reservoir sandstone is not very well consolidated, though other reservoir parameters are good. An extended test was carried out in summer 1991 using the production ship Petrojarl I. This test gathered valuable production information. The operator has not yet decided on further progress for Balder, but a new appraisal well is planned in 1995. Further development of the discovery will be considered in conjunction with Hermod.

25/11-15 Hermod

Norsk Hydro discovered oil in well 25/11-15 east of Balder in 1991, production licence 169. During 1994, appraisal well 25/11-18 has been drilled, and the results from this well are presently being considered. In addition, interpretation of new 3 D seismic shot across the area is in progress. The operator is considering test production from the Hermod discovery. As the Balder discovery, Hermod contains relatively viscous oil. The Norwegian Petroleum Directorate's preliminary estimates of recoverable resources in Hermod are 60 million Sm^3 oil and 1.8 billion Sm^3 gas. The operator's estimates are 42.6 million Sm^3 oil and 0.7 billion Sm^3 gas. Parts of the discovery are located in production licence 001. Further development of the Hermod discovery will be considered in conjunction with Balder.

The Oseberg area

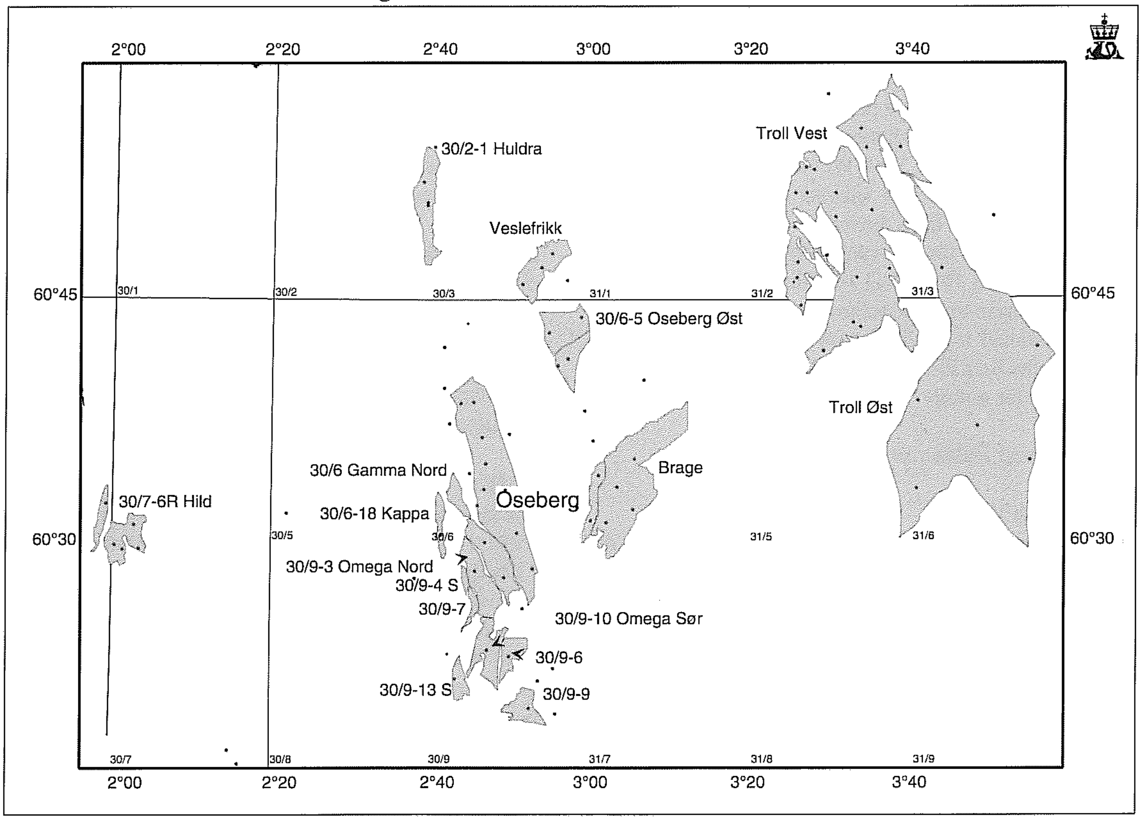
30/2-1 Huldra

Huldra is a gas discovery located northwest of Veslefrikk. The bulk of the field lies in block 30/2 in production licence 051, although the field also extends into production licence 052 in block 30/3. Statoil operates both licences. The field was declared commercial summer 1991. Gas has been proven in the Brent group. Recoverable resources are 22.3 billion Sm^3 gas and 7.9 million Sm^3 condensate. Both a stand-alone installation with processing capacity and a wellhead unit tied in to existing processing facilities in the area are considered feasible. Plan for development and operation may be submitted to the authorities in the middle of 1995, and the field could come on stream in 1999 provided gas sales allocations fall into place.

30/6-5 Oseberg Øst

Oseberg Øst is located within production licence 053 in block 30/6, about 14 kilometers from Oseberg C. The discovery comprises two structures divided by a sealing fault. Four wells have been drilled on the discovery. Both structures contain several oil bearing strata of variable porosities and permeabilities in the Brent group, and there are a number of different oil-water contacts. The recoverable resources are estimated by the Norwegian Petroleum Directorate to be 19 million Sm^3 oil and 1.0 billion Sm^3 gas. Norsk Hydro, the operator, declared the discovery commercial in June 1991. Possible development concepts under evaluation are a subsea installation and wellhead platform with tie-in to Oseberg C. The partners plan to maintain pressure by means of water or water alternating gas (WAG) injection. The plan for development and operation is expected to be submitted to the authorities summer 1996.

Fig. 2.6.c
Fields and discoveries in the Oseberg and Troll area



Oseberg Sør area

South of the Oseberg field a number of discoveries of oil and gas have been made in production licences 079 and 104, 30/9-3 Omega Nord, 30/9-10 Omega Sør, 30/9-13S, 30/9-4S, 30/9-7, 30/9-9, and 30/9-6. The operator estimates the recoverable resources for this area to be 35.6 million Sm^3 oil and 9.6 billion Sm^3 gas. The area is very complex with regard to resources, and there is considerable uncertainty regarding the resource estimate. Work is in progress with view to reduce this uncertainty prior to development.

Development strategy is being evaluated and most of the interesting concepts are based on using the Oseberg field centre for processing and onward transportation. 30/9-3 Omega Nord can be reached using wells from the Oseberg field centre and can be produced from the centre, depending on the number of available well slots. This discovery will most likely be the first component of a phased field development. The Norwegian Petroleum Directorate estimates recoverable reserves in 30/9-3 Omega Nord to be 16.6 million Sm^3 oil and 8.0 billion Sm^3 gas. Commerciality declaration and plan for development and operation is espected to be submitted autumn 1996.

The Gullfaks, Statfjord and Snorre area

34/7-22 Tordis Øst

This discovery is located in the south-eastern part of block 34/7, production licence 089, with Saga Petroleum as operator. The discorery was made in September 1993 by well 34/7-22. Oil was proven in sandstones belonging to the Brent group. The operator estimates the recoverable resources to be somewhat less than 5.5 million Sm^3 oil.

The operator has concluded that the discovery is commercial, and has requested the partners' approval for this. Commerciality is dependent on the possibility of production of the resources by subsea wells with tie-in to the production facility on the Tordis field. Plan for development and operation may be submitted at the end of 1995. Production start could be in 1997.

34/8-1 Visund

The Visund discovery is in block 34/8, which is in production licence 120 allocated in 1985. Norsk Hydro is the operator. The first discovery was made in the Brent group by well 34/8-1 in 1986. Well 34/8-3 was drilled in 1988 and proved hydrocarbons in a Brent segment further north. In 1992, three wells were drilled in this structure, of which 34/8-4 A and 34/8-8 proved oil in the Statfjord formation and the Brent group, respectively. In 1993, well 34/8-10 S proved hydrocarbons in several reservoir levels. To improve the limitation of the oil reservoir and verify fluid type in the Brent group, well 34/8-11 was drilled in 1993/94. Three dimensional seismic has been shot over the entire structure. Visund has proven resources in the Brent group, and in the Amundsen, Statfjord and Lunde formations. The operator's estimates of recoverable resources are 47 million Sm^3 oil and condensate, and 51 billion Sm^3 gas.

The water depth in the area is 310-380 meters. The preliminary plans involve a phased field development, with an oil and a gas production phase. Various development concepts are being considered, both separate production facilities and a tie-in to Gullfaks C. The plan for development and operation may be submitted in 1995.

34/10-2 Gullfaks Sør

Gullfaks Sør lies in the middle of block 34/10, about nine kilometers south of the Gullfaks field. Block 34/10 was allocated in 1978 with Statoil as operator, see description of Gullfaks in section 2.8.12.

Gullfaks Sør is structurally complex. Hydrocarbons have been proven in the Brent group and Statfjord formation. The Brent reservoir contains both gas and oil. Several unconnected gas/oil and oil/water contacts have been detected in the Brent reservoir. The Statfjord reservoir contains a thicker oil zone than Brent, with a small gas cap. Ten wells have been drilled to reservoir level in the Gullfaks Sør discovery.

The operator has in 1994 completed a new seismic interpretation of the discovery. This new interpretation has not entailed significant volume changes.

A number of development concepts are being considered for Gullfaks Sør. They comprise joint solutions with gas connection from other fields in the area and with various transportation solutions.

34/10-17 Rimfaks

Rimfaks is a new name for 34/10-17 Beta. The operator has in 1994 carried out a feasibility study for this discovery. Rimfaks was proven in 1983 by the wildcat 34/10-17, which is the only well drillied in the structure. Rimfaks is located on the boundary line between block 34/10 and 33/12, about 15 kilometers southwest of the Gullfaks field. Statoil operates both production licences.

Rimfaks consists of several fault segments. Estimate of recoverable liquid in the Brent formation is from 11 million Sm^3 to 30 million Sm^3.

The operator has in 1994 completed the work with a new detailed geological model for the field.

The model is based on information from the wells 34/10-17 and 33/9-6, and on remapping of the field by means of new 3D seismic. The new volume estimates from the operator entail a considerable adjustment upwards of the estimated in-place oil and gas in the field compared to earlier estimates. An appraisal well will be drilled early in 1995 in order to reduce the uncertainty in the resource basis. The plan is to maintain pressure in the field by means of gas injection and a development concept with subsea templates and reception facilities on the Gullfaks A installation. Based on present plans, pruduction start-up will be in 1998.

The Norwegian Sea

6407/7-1 S Njord

Njord is an oil discovery in the two blocks 6407/7 and 6407/10. Norsk Hydro is operator for production licences 107 and 132, allocated in 1985 and 1987. A total of seven exploration wells have been drilled in the two blocks, four of which proved oil, in the Tilje and Åre formation of Jurassic age. The main structure consists of a western and an eastern segment with a complex fault pattern. The western segment is considered to be produced by depressurisation and limited water injection, whereas maintenance of pressure by means of gas injection will be an option for the eastern segment. Experience from production may however lead to alternative drainage mechanisms. Reproduction and export of injected gas may be an option towards the expiry of the lifetime of the field if a gas option for Haltenbanken is realised.

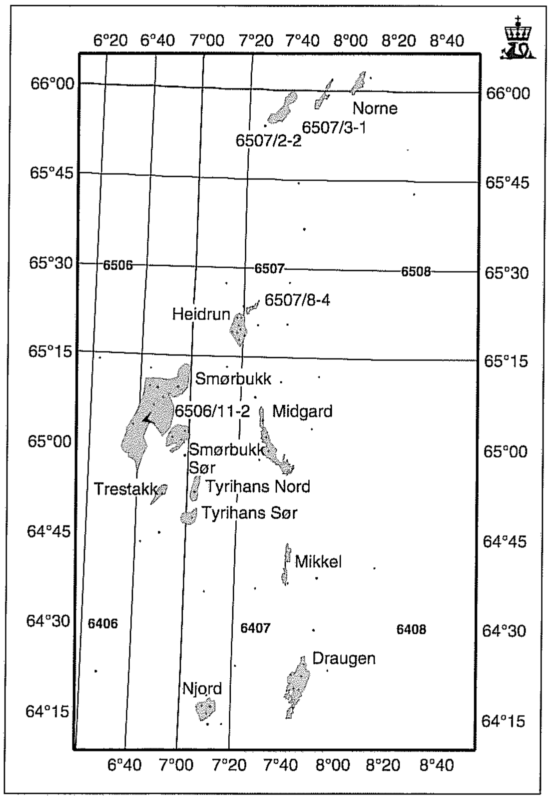
The Norwegian Petroleum Directorate 's estimates of recoverable resources are 35 million Sm³ oil and 7.2 billion Sm³ associated gas.

The operator declared the discovery commecial in October 1994. The licensees are aiming to submit a plan for development and operation in the first quarter of 1995.

6507/11-1 Midgard, 6506/12-1 Smørbukk and 6506/12-3 Smørbukk Sør

The main part of the Midgard discovery is situated in blocks 6507/11 and 6407/2, under production licences 062 and 074, with Saga Petroleum as operator. The discovery was made in 1981 and is located at a water depth of 250 - 270 meters. It was declared commercial by the operator in autumn 1991.

Fig. 2.6.d
Fields and discoveries in the Norwegian Sea



All in all there are seven exploration wells in the area, four of which were drilled in the structure which is split into four structural segments. The discovery is mainly a gas discovery with some condensate and a thin oil zone.

Reservoir properties are good. The Norwegian Petroleum Directorate's estimates of recoverable resources are 87 billion Sm³ gas, 1.3 million Sm³ oil, and 13 million tonnes NGL. The reservoir is planned to be produced by means of depressurisation.

The main part of the Smørbukk discovery lies in block 6506/12 which is comprised by production licence 094, allocated in 1984. Statoil is the operator. The discovery was made in 1985 and contains gas, condensate and oil with a comparatively high gas/oil ratio. Water depth in the area is about 290 meters. A total of five exploration wells have been drilled on Smørbukk, of which four are in block 6506/12 and one in block 6506/11. The operator's estimates of recoverable resources are 35 million tonnes NGL and 95 billion Sm³ recoverable gas. The estimate of recoverable volumes of NGL presupposes that part of the produced gas is reinjected into the reservoir.

Smørbukk Sør lies in the southern part of block 6506/12. It was proven in 1985 and has later been confirmed by two appraisal wells.

Statoil is the operator. The discovery is about 10 km from Smørbukk at a water depth of about 300 meters. The Norwegian Petroleum Directorate's estimates of recoverable resources in Smørbukk Sør are 31 million Sm³ oil/condensate and 24 billion Sm³ gas.

The discovery was declared commercial in January 1992.

In the autumn 1994, Statoil and Saga Petroleum signed a co-operation agreement which entails that Statoil will take over the responsibility as operator for Midgard. Statoil thus becomes the operator for all three discoveries.

The licensees of the three discoveries Smørbukk, Smørbukk Sør and Midgard furthermore plan, by 1 March 1995, to sign an agreement entailing that the discoveries will have a common group of owners. This co-ordination agreement will mean that all owners have similar commercial interests in each of the fields. According to the operator, this will contribute to ensuring the necessary progress in the work of developing a common, cost effective development concept for the discoveries.

During the autumn, the operator has prepared several alternative development concepts for a co-ordinated development of the three discoveries. All solutions are based on a subsea installation at Smørbukk Sør and Midgard, and field centre at Smørbukk.The final choice of development alternative will according to the operator be made in June 1995, and a possible decision for development will depend on the result of the gas allocations to be carried out in autumn 1995.

6608/10-2 Norne

The Norne discovery is situated in block 6608/10, some 85 kilometers north of Heidrun and 200 kilometers off the Nordland coast. Production licence 128 was awarded in

1986. Statoil operates the field. The discovery lies in an area with a water depth of 360-380 meters, and was proven in January 1992. The Norwegian Petroleum Directorate has estimated the recoverable resources at 76.2 million Sm^3 oil and 15.6 billion Sm^3 gas. A plan for development and operation (PDO) was submitted to the authorities in September 1994. The Norwegian Petroleum Directorate's evaluation of the PDO was forwarded to the The Ministry of Industry and Energy in December 1994.

The Storting will consider the PDO early in March 1995.The discovery is planned to be produced using a subsea well system connected to a combined production and storage vessel. The oil will be transported from the field by shuttle tankers. All gas is planned injected into the reservoir. The development concept is however prepared with a view to future gas export. The cost estimate for the field development is NOK 7.8 billion. Production start is fixed to 1 July 1997.

2.7 FIELDS DECIDED TO BE DEVELOPED

2.7.1 GYDA SØR

Production licence 019B

Licensees

Den norske stats oljeselskap a.s (Statoil)	50.0000 %
BP Norway Limited U.A (operator)	26.6250 %
Norske Conoco A/S	9.3750 %
Norske AEDC Ltd	5.0000 %
Norske MOECO Ltd	5.0000 %
K/S A/S Pelican & Co	4.0000 %

Field history

Gyda Sør is situated in block 2/1 and constitutes an extension of the Gyda field towards the southeast; see Figure 2.8.4.a. Plan for development and operation was approved by Royal Decree in July 1993. Two wells wells have been drilled in this structure. Planned production start of Gyda Sør is March 1995. The last planned year of production is the year 2000.

Reservoir

No pressure communication has been observed between Gyda Sør and Gyda. It is none the less possible that there may be communication via the aquifer. The seismic mapping shows that Gyda Sør is a structure subdivided by faults into a number of segments. It is not clear whether these faults are sealing.

The plan is to produce the reservoir from a long range well drilled from the Gyda installation. The operator estimates recoverable reserves in Gyda Sør to be 1.5 million Sm^3 oil, 0.9 billion Sm^3 gas, and 0.2 million tonnes NGL.

Development concept

The planned production well from the Gyda installation to Gyda Sør will extend about 5700 meters in the horizontal direction. Processing will utilise the existing installations on Gyda. The gas treatment systems and in particular the gas export compressor may be limiting factors for oil production from Gyda Sør.

Transportation

Gas and oil produced from Gyda Sør will be carried from the Gyda installation using the transport system for gas and oil already in place. Produced NGL will generally go with the oil flow.

Costs

Total investment costs for Gyda Sør are anticipated to be about 310 million 1994-NOK from 1993 to 1998.

2.7.2 SLEIPNER VEST

Production licences 046 and 029

Licensees

Den norske stats oljeselskap a.s (Statoil) (operator)	49.5029 %
Esso Norge a.s	32.2394 %
Norsk Hydro Produksjon a.s	8.8465 %
Elf Petroleum Norge A S	8.4701 %
TOTAL Norge A/S	0.9411 %

Field history

Sleipner Vest is located in the blocks 15/6, 15/9 and 15/8, see Figure 2.6.a. The production licences 046 and 029 were granted in 1969 and 1976 respectively. Statoil is operator of production licence 046 while Esso is operator of production licence 029. The field was discovered by wildcat 15/6-3 in 1974. The Storting approved the development of the field in 1992. Sleipner Vest is planned to be ready for production in October 1996.

A co-ordination agreement for the two production licences has been entered into per 1 July 1994.

Reservoir

Sleipner Vest is a gas/condensate field. The reservoir consists of sandstone in the Hugin formation laid down in the Jurassic period. The field reserves are estimated to be 126.9 billion Sm^3 gas and 33.7 million tonnes NGL. The Sleipner Vest gas contains up to 9 volume % CO_2 (not included in the reserves estimate).

Development concept/transportation

The first phase of the development consists of a wellhead installation, Sleipner B, and an installation for processing and CO_2 removal, Sleipner T, see Figure 2.8.7. Sleipner B will be located in the southern part of the Sleipner Vest field with transfer of the well flow to the Sleipner T installation. Sleipner T will be located near Sleipner A so as to exploit common utility systems.

Further development of the northern areas of Sleipner Vest is planned using subsea templates or wellhead installations with transfer of the well flow to Sleipner B.

The gas will be included in a marketing and injection co-operation project with Sleipner Øst. Sleipner Vest has been awarded the gas sale in connection with the contracts agreed in 1991 through the exercise of the 30 percent options under the Troll gas sales agreements. NGL will be transported to Kårstø through a joint condensate pipeline from Sleipner Øst.

Costs

At the end of 1994, the investment in the Sleipner Vest field was about 5 billion 1994-NOK. Total development costs are estimated to be about 19.5 billion 1994-NOK from 1991 to the year 2010.

2.7.3 FRØY

Production licences 026 and 102.

Licensees

Den norske stats oljeselskap a.s (Statoil)	53.9600 %
Elf Petroleum Norge A/S (operator)	24.7573 %
TOTAL Norge A/S	15.2346 %
Norsk Hydro Produksjon a.s	6.0481 %

Field history

Frøy is located in blocks 25/2 and 25/5, see Figure 2.8.9.a. Production licences 026 and 102 were allocated in 1969 and 1985, respectively. The field was proven in 1987 by well 25/5-1. The plan for development and operation of Frøy was approved by the Storting (Parliament) in May 1992.

The project is delayed and planned production start is altered from January 1995 to July 1995. Delay and overexpenditure are mainly due to the fact that modification work on TCP2 (Frigg) proved to be more extensive than planned.

Reservoir

Frøy is an oil field and the Norwegian Petroleum Directorate's reserves estimates are 14 million Sm³ oil and 3 billion Sm³ gas.

Development concept/transportation

The field is to be developed using a wellhead platform with single-stage separation. Oil and gas will be transported in separate pipelines to Frigg for further processing and metering. Onward transportation will take place in the existing transport system for gas to the UK and in a new oil pipeline, Frostpipe, which was put into operation in 1994, to Oseberg. Five production wells have been predrilled in 1994.

Costs

At the end of 1994, the investment in the Frøy field was about 4.5 billion 1994-NOK. Total development costs are estimated to be about 5.8 billion 1994-NOK.

2.7.4 TROLL

Production licences 054 and 085.

Licensees

Den norske stats oljeselskap a.s (Statoil)	74.57600 %
A/S Norske Shell	8.28800 %
Norsk Hydro Produksjon a.s	7.68800 %
Saga Petroleum a.s	4.08000 %
Elf Petroleum Norge A/S	2.35344 %
Norske Conoco A/S	1.66113 %
TOTAL Norge A S	1.35343 %

Field history

The Troll field is located in blocks 31/2, 31/3, 31/5 and 31/6, see Figure 2.6.c. Production licences 054 (block 31/2) and 085 were allocated in 1979 and 1983, respectively. The field was proven in 1979 by exploration well 31/2-1 in Troll Vest. This part of the Troll field was declared commercial in 1984. Until then, 15 wells had been drilled on the block to delineate the extent of the field.

The gas resources in Troll Øst were proven in 1983 by well 31/6-1. Subsequent drilling formed the basis for unitisation of the field between the licensees.

Development of Troll comprises the following phases, see Figure 2.7.4:

TOGI:	Troll-Oseberg gas injection
Troll I:	Development of gas reserves in Troll Øst
Troll II:	Development of oil reserves in Troll Vest
Troll III:	Development of gas resources in Troll Vest

Reservoir

The Troll field has a gas column over 200 meters thick, under this there is an oil column. The western part of the field, Troll Vest oil province, for the most part located in block 31/2, has an oil column of 22 - 26 meters. In Troll Vest gas province, the oil column is 12-14 meters. In Troll Øst, the thickness of the proven oil layer varies from zero to four meters. The reservoir dates from the Late Jurassic period and the Sognefjord formation constitutes the principal reservoir for the gas and oil in the field.

The Norwegian Petroleum Directorate's estimates for the reserves in Troll Øst are 285 billion Sm³ gas and 20 million tonnes NGL. The oil reserves for the Troll Vest oil province are 61 million Sm³. The Norwegian Petroleum Directorate's estimate for the in-place reserves in Troll Vest gas province is 421 million Sm³, of which about 10 million Sm³ are decided to be developed on connection with the decision relating to the first subsea installation (the H cluster). The Norwegian Petroleum Directorate's estimates that the recoverable reserves in those parts of the gas province which have not been decided to be developed are 35 - 40 million Sm³.

TOGI

A subsea production system, Troll Oseberg Gas Injection (TOGI), has been built, which is controlled from the Oseberg field centre and supplies gas from Troll Øst for injection in the Oseberg field. The production and delivery of TOGI gas started in February 1991. TOGI supplied 3.3 million Sm³ gas to Oseberg in 1994.

Norsk Hydro is the operator for development and operation of TOGI. During the period 1987 to and including 1991, TOGI investments were about 1994-NOK 2.9 billion. Total operating costs for 1994 are approximately NOK 125 million.

Troll phase I: Development of gas reserves in Troll Øst
A/S Norske Shell is the development operator for Troll phase I. Statoil will according to agreement take over the responsibility as operator when the field comes on stream.

The plan for development and operation was approved by the Storting in December 1986. The operator was asked to submit a revised plan with a more detailed description of the installation and processsing equipment. A revised plan was approved in December 1990.

The revised development plan for Troll phase I entails the production of the gas reserved in Troll Øst from the Troll A installation, with transfer of the well flow to the gas processing plant at Kollsnes via two multiphase pipelines. At the onshore processing facility the condensate will be separated from the gas and the condensate will be transported to the Sture terminal for further transport to the marketplace. The dry gas will be compressed and exported from the Kollsnes facility by pipeline to the Continent.

The first gas is expected to be available at Troll A in the fourth quarter of 1995, and gas deliveries to buyers is planned to commence 1 October 1996.

At year end 1994, investments in the Troll phase I totalled appx. 1994-NOK 23.7 billion. Total investments are anticipated to be about 1994-NOK 35 billion from 1979 up to and including the year 2006.

Troll phase II: Development of oil reserves in Troll Vest
Troll phase II involves development of the oil in the Troll Vest oil province and the first step in a step-by-step development of the oil in the Troll Vest gas province (the H cluster). Norsk Hydro is the operator both for the development phase and the operational phase.

Troll Vest oil province
The plan for development and operation (PDO) was approved by the Storting in May 1992. The oil reserves in the Troll Vest oil province are to be produced from the Troll B installation.

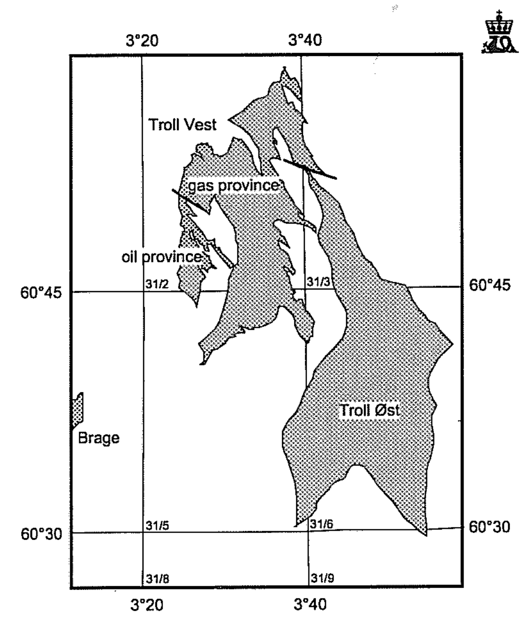
In accordance with the licensees' present plans, production start is envisaged in October/November 1995, which is between one and two months earlier than planned start-up according to the PDO.

Troll Vest oil province will be developed with 18 oil producers and one gas injector, deployed in four subsea stations, which in turn are connected up to the Troll B. Troll B will in addition have capacity for hook-up of a furher five subsea installations from the Troll Vest gas province. The oil is transported from the Troll B installation via the Troll pipeline, "Troll oljerør" approximately 90 km to Mongstad.

Together with the oil, significant quantities of gas will be produced, and this will be exported from the Troll B via pipeline to the Troll A installation. The gas will be landed at Kollsnes together with the gas/condensate from Troll Phase I.

Troll Vest gas province
Troll Vest gas province involves development of the part

Fig. 2.7.4
The Troll field



of the Troll field which is located between Troll Øst and Troll Vest oil province, see Figure 2.7.4. The oil column is here 12 - 14 meters thick. The plan for development and operation (PDO) of the first subsea installation for production of oil south in the Troll Vest oil province (the H cluster) was adopted by Royal Decree in May 1994.

The subsea installation will be connected to the riser base for the Troll B-installation via two 7 km long, parallell pipelines. The oil will be processed together with oil from the Troll Vest oil province. Production start-up was in the plan for development and operation planned to be 1 October 1996, but it is now expected to be 1 January 1996.

At year end 1994, a total of about 11.7 billion 1994-NOK had been invested in Troll phase II. Total investments are anticipated to be about 1994-NOK 18.9 billion from 1991 up to and including the year 1998.

Troll phase III: Development of gas resources in Troll Vest
A future development of the gas resources in Troll Vest gas province will constitute phase III of the Troll field development.

Approved and future production of the oil resources in Troll Vest (Phase II) is time critical in relation to production of gas both from Troll Øst and Troll Vest. It is uncertain when a major gas drainage from Troll Vest should start. For reservoir technical reasons, it is with the current understanding of the reservoir important that gas production from Troll Øst and Troll Vest is terminated at approximately the same time.

Clarification of these matters will be decisive with regard to choice of concept for Troll Phase III and the production start-up time.

2.7.5 STATFJORD NORD

Production licence 037.

Licensees

Den norske stats oljeselskap a.s (Statoil) (operator)	50.0000 %
Mobil Development Norway A/S	15.0000 %
Norske Conoco A/S	11.0420 %
A/S Norske Shell	10.0000 %
Esso Norge a.s	10.0000 %
Saga Petroleum a.s	1,8750 %
Amerada Hess Norge A/S	1,0420 %
Enterprise Oil Norwegian A S	1.0420 %

Field history

Statfjord Nord is situated in block 33/9, production licence 037, which was awarded in 1973, see Figure 2.8.12.a. The plan for development and operation of Statfjord Nord was approved by Royal Decree in November 1990. Statoil is operator for the field.Production start is January 1995. There exists a unitisation agreement between Statfjord Nord and Statfjord Øst which means Statfjord Nord and Statfjord Øst have a common project administration and joint use of systems on Statfjord C. In 1994 Amoco Norway A/S sold its share (1.0420 %) in production licence 037 to Norske Conoco A/S.

Reservoir

Reserves are estimated to be 29 million Sm^3 oil and 2.4 billion Sm^3 gas. This estimate assumes eight production wells and oil production until the year 2014. The field is now planned to be drained using six production wells and four water injection wells. Any decision to drill two extra wells will be deferred until after production start-up for the field.

Development concept/transportation

The field will be developed with subsea installations connected to the Statfjord C platform. The subsea installations will consist of three templates, two for production and one for water injection. The well flow, which consists of oil, gas and water, will be carried in two pipelines to Statfjord C for processing, storage and onward transportation. Statfjord Nord and Statfjord Øst will use common systems on Statfjord C.

The first oil from Statfjord Nord was delivered at Mongstad 27 December 1994 by the test vessel Crystal Sea.

Metering system

The Statfjord satellites are metered in a common metering system to fiscal standard on Statfjord C. Return allocation to the individual satellite takes place on the basis of test separator metering.

Costs

At year end 1994 approximately 3.3 billion 1994-NOK had been invested in Statfjord Nord. Total investments are expected to reach about 4 billion 1994-NOK for the period 1990 until 2009.

2.7.6 VIGDIS

Production licence 089.

Licensees

Den norske stats oljeselskap a.s (Statoil)	55.4 %
Esso Exploration & Production Norway A/S	10.5 %
Idemitsu Petroleum Norge a.s	9.6 %
Norsk Hydro Produksjon a.s.	8.4 %
Saga Petroleum a.s (operator)	7.0 %
Elf Petroleum Norge A/S	5.6 %
Deminex Norge a.s	2.8 %
DNO Olje A/S	0.7 %

Field history

The Vigdis field is situated in block 34/7, see Figure 2.8.12.a. Production licence 089 was awarded in 1984. The eastern part of Vigdis was proven in 1986 by well 34/7-8. Three wells have later been drilled for further exploration and appraisal of the field. The plan for development and operation was approved by Royal Decree in December 1994. Production start-up is planned for July 1997.

Reservoir

Large faults split the field into three main segments: a western, a middle and an eastern segment. The reservoir in the western and middle segment consists of sandstones in the upper and lower part of the Brent group. Reserves are estimated to be 33.9 million Sm^3 oil and 2.4 billion Sm^3 associated gas, based on a production time of 15 years. There is a potential for additional resources in adjacent structures, particularly in the eastern segment. The production mechanism is pressure maintenance by means of water injection.

Development concept/transportation

The field is planned to be developed with subsea completed wells, eight production wells and four water injection wells. The well flow will be carried to the Snorre TLP for processing and measuring. The stabilised oil will be carried by a separate pipeline to Gullfaks A for storage and shipment. The gas is planned to be injected into the Snorre reservoir.

Costs

At year end 1994, a total of about 110 million 1994-NOK had been invested in the Vigdis field. Total investments are estimated to be about 1994-NOK 4.9 billion. This includes modification work at Snorre and costs for oil export piping to Gullfaks A.

2.7.7 HEIDRUN

Poduction licence 095 and 124.

Licensees after unitisation

Den norske stats oljeselskap a.s (Statoil)	76.2500 %
Norske Conoco A/S (operator)	18.1250 %
Neste Petroleum a.s	5.0000 %
DNO Olje a.s	0.6250 %

Field history
The fiels is situated in blocks 6507/7 and 6507/8, see Figure 2.6.d. Production licence 095 (block 6507/7) was awarded in 1984, and production licence 124 (block 6507/8) was awarded in 1986.

The Heidrun field was discovered in 1985 and declared commercial in December 1986. Plan for development and operation of the field was submitted in November 1987, which comprised early production. The plan was approved, but the licensees discontinued the work of implementing the approved solution. The operator then submitted a revised plan in December 1989. This plan was approved by the Storting in May 1991. The decision relating to application of the associated gas was however postponed. In November 1991, the Government presented a proposal recommending landing of associated gas at Tjeldbergodden for production of methanol. This concept was approved by the Storting (Parliament) in February 1992. Statoil will take over as operator of Heidrun from Conoco in the operational phase. Production start-up is planned for autumn 1995.

Reservoir
The field contains oil with a overlying gas cap. The reservoir comprises several geological formations and fault segments. For optimal resource exploitation the gas cap should be produced after the bulk of the oil. Much uncertainty is attached to the reserves estimates for Heidrun. The Norwegian Petroleum Directorate's estimates are 87.3 million Sm^3 oil and 37.8 billion Sm^3 gas. The operator's estimates are 119 million Sm^3 oil and 45 billion Sm^3 gas. The variations in reserves estimates are primarily due to differences in seismic and petrophysical interpretation.

Development concept/transportation
Water depth is about 350 meters. The field will be developed using a floating concrete tension leg unit installed over a subsea template with 56 well slots. The plan calls for 35 production wells, 11 water injection wells and two gas injection wells. Six of the water injectors will have subsea completion. The production capacity for oil will be 35,000 Sm^3 a day, while maximum treatment capacity for water and gas will be 24,700 m^3 and 4.7 million Sm^3 a day respectively. Oil will be exported by means of a new concept based on direct shipboard loading (DSL), without the use of offshore oil storage.

Gas application
Associated gas will be reinjected into the reservoir during the period 1995-96, and subsequently landed to Tjeldbergodden for methanol production as from the first quarter 1997. Production of the gas cap is not to take place until the end of the oil production period.

Costs
At year end 1994, a total of about 22.2 billion 1994-NOK had been invested in Heidrun. Total investments are expected to be about 1994-NOK 29.7 billion from 1988 to 2011.

2.8 FIELDS IN PRODUCTION

2.8.1 HOD
Production licence 033

Licensees

Amoco Norway Oil Company (operator)	25.0000 %
Amerada Hess Norge A/S	25.0000 %
Enterprise Oil Norwegian A/S	25.0000 %
Elf Petroleum Norge A/S	25.0000 %

Field history
The Hod field is situated in block 2/11, see Figure 2.8.4.a. Production licence 033 was allocated in 1969, and the field was discovered in 1974. The field is located about 12 kilometers south of the Valhall field. Parts of the block have later been relinquished, and parts of the relinquished acreage have been included in production licence 068. The plan for development and operation of Hod was approved by the Storting in 1988, and production from the field was commenced in October 1 990. An exploration well was drilled from the production installation in spring 1994, on a mapped structure in the north. Oil was discovered, and the well was reclassified as production well in June 1994.

Production
Hod is the southernmost chalk field in the Norwegian part of the North Sea, producing from reservoir zones in the Ekofisk, Tor and Hod formations. Production is in progress from five wells, of which three are horizontal. Reserves are estimated at 7.9 million Sm^3 oil, 2.1 billion Sm^3 gas and 0.3 million tonnes of NGL.

Production installations
The development features an unmanned production installation. Oil and gas are separated by means of a separation unit and then metered before being piped to Valhall for further processing.

Transportation
Oil and gas are transported in a single pipeline to Valhall and from there carried through the existing transportation systems to Emden and Teesside.

Metering system
Oil and gas are metered on Hod. The metering system is part of the Valhall-Hod system for the distribution of hydrocarbons.

Costs
At year end 1994, a total of about 1.2 billion 1994-NOK had been invested. Total investments in the Hod field from and including 1988 to and including 2011 are estimated to be 1.3 billion 1994-NOK The operating costs for 1994 were NOK 260 million, including tariffs.

2.8.2 VALHALL

Production licences 006 and 033

Licensees after unitisation of Valhall

Amoco Norway Oil Company (operator)	28.09377 %
Amerada Hess Norge A/S	28.09376 %
Enterprise Oil Norwegian A/S	28.09376 %
Elf Petroleum Norge A/S	15.71871 %

Field history

Valhall is located primarily in block 2/8, see Figure 1.8.4.a, which contains 92.8 percent of the reserves (production licence 006). The remaining 7.2 percent lie in block 2/11 (production licence 033 in which each partner owns 25 percent). Production licence 006 was awarded in 1965, and production licence 033 was awarded in 1969. Valhall was discovered in 1975. The field development plan was approved by the Storting in 1977, and production from the field started in the autumn 1982

Production

The Valhall field is located south-east of Eldfisk. The field produces from upper chalk limestone, from the Tor and Hod formations. Horizontal wells have been drilled on this field since 1991. Towards the year end 1994, 11 out of 27 production wells were horizontal. Reserves are estimated at 100.79 million Sm³ oil, 26.3 billion Sm³ gas and 4.1 million tonnes NGL. The recovery factor for oil is estimated at around 30 %. A test project with water injection in a centrally located well was carried out during the period 1990-93.

The licensees started the planning of further development of the field autumn 1994. An amended plan for development and operation is expected to be submitted in spring 1995.

Production installations

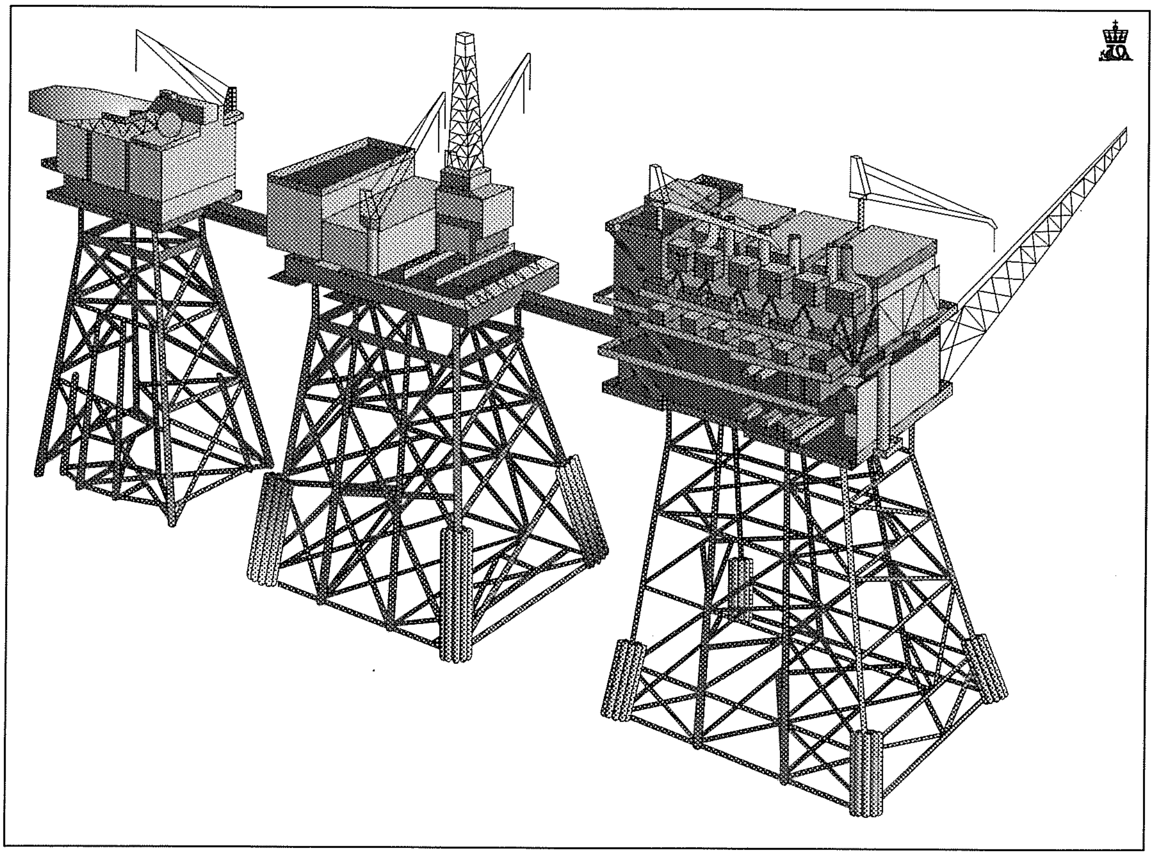
The development of Valhall comprises living quarters, drilling, production and riser installations. The three first mentioned installations are located on the Valhall field and connected to each other by gangways. Figure 2.8.2 shows details of these installations. The riser installation 2/4 - for which Phillips Petroleum Company Norway A/S is the operator - is connected to the Ekofisk centre.

Oil is separated from gas on Valhall by using two separation units. The gas is compressed, dried and checked for dew point. The heavier gas fractions, natural gas liquids (NGL), are separated on Valhall in a fractioning column and are then mainly transported in the oil flow.

Transportation

The oil including NGL is transported by pipeline to Ekofisk for further transport to Teesside. Gas is carried in a separate pipeline to Ekofisk for further transport to Emden.

Fig. 2.8.2
Installations on Valhall



Metering system
Oil and gas are fiscally metered on the riser platform 2/4-G. The fiscal metering systems are part of the Ekofisk system for hydrocarbon distribution.

Costs
At year end 1994, a total of about 14.6 billion 1994-NOK had been invested. Total investments in the Valhall field from August 1977 up to and including year 2030 are estimated to be about 22 billion 1994-NOK The operating costs for 1994 were NOK 1.1 billion, including tariffs.

2.8.3 TOMMELITEN GAMMA
Production licence 044

Licensees

Den norske stats oljeselskap a.s (Statoil) (operator)	70.6400 %
Norske Fina A/S	20.2300 %
Norsk Agip A/S	9.1300 %

Field history
Production licence 044 was allocated in 1976, and embraces block 1/9 south-west of the Ekofisk area, see Figure 2.8.4.a. Tommeliten Gamma was discovered in 1978.

The plan for development and operation of Tommeliten Gamma was approved by the Storting in 1986, and production start-up was October 1988.

Production
The reservoir consists of chalk rocks, located in the Ekofisk and Tor formation. Production from Tommeliten Gamma is processed on the Edda installation. A portion of the gas is used as gas lift on Edda and thus extends the economic lifetime of the Edda field. Total reserves are estimated at 3.76 million Sm^3 oil, 9.66 billion Sm^3 gas and 0.54 million tonnes NGL.

Production installations
The Gamma structure has been developed using subsea completion wells. The entire production is transported to Edda for first stage separation.

Transportation
Following the first stage separation on Edda, the Tommeliten Gamma gas is taken by pipeline to the Ekofisk centre for further drying, and is subsequently transported by Norpipe to Emden.

The oil from Tommeliten Gamma is transferred from Edda to Ekofisk centre for further transportation via the pipeline to Teesside.

Metering system
The existing metering systems have been rebuilt and upgraded to support the separate metering of oil and gas from both the Edda field and Tommeliten Gamma on Edda.

Costs
At year end 1994, a total of about 3 billion 1994-NOK had been invested in Tommeliten Gamma, which is also the estimate for total investments from 1986 up to and including 1997. The operating costs for 1994 were around NOK 470 million, including tariffs.

2.8.4 EKOFISK AREA
Production licence 018

Licensees

Phillips Petroleum Company Norway A S (operator)	36.9600 %
Norsk Fina A/S	30.0000 %
Norsk Agip A/S	13.0400 %
Elf Petroleum Norge A/S	7.5940 %
Norsk Hydro Produksjon a.s	6.7000 %
Total Norge A/S	3.5470 %
Den norske stats oljeselskap a.s (Statoil)	1.0000 %
Elf Rex Norge A/S	0.8550 %
Norminol	0.3040 %

Production licence 018 comprises the fields Cod, Edda, Ekofisk, Eldfisk, Embla and Vest Ekofisk. Cod lies in block 7/11, Edda, Embla and Eldfisk in block 2/7 and Ekofisk and Vest Ekofisk in block 2/4. See Figure 2.8.4.a.

The Albuskjell field, located in blocks 1/6 and 2/4, is split between production licences 018 and 011. The Albuskjell equity distribution is as follows:

Phillips Group	50.0000 %
A/S Norske Shell	50.0000 %

The Tor field, located in blocks 2/4 and 2/5, is split between production licences 018 and 006. The Tor field production licence interests are distributed as follows:

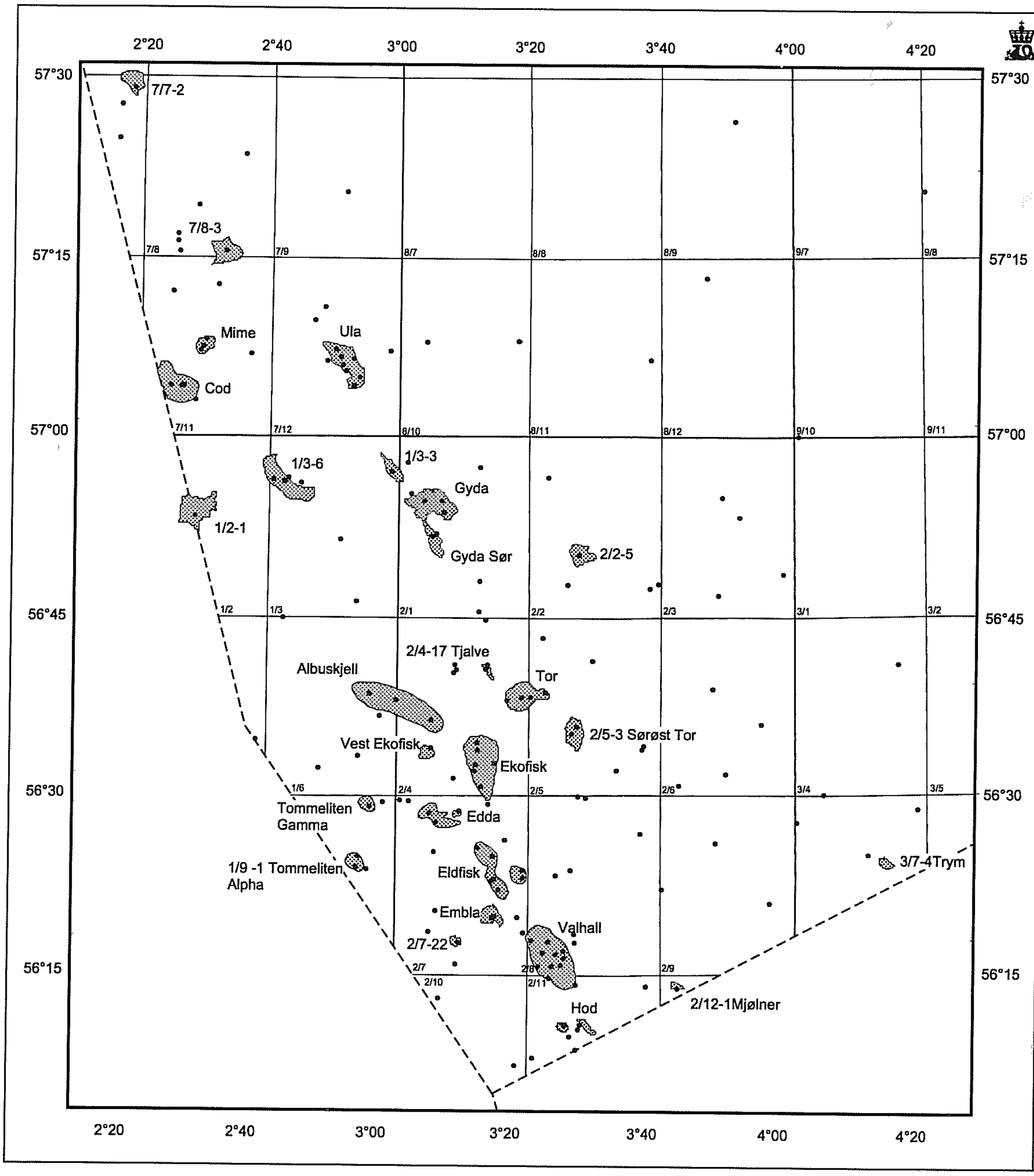
Phillips Group	73.7487 %
Amoco Group	26.2513 %
(licensees as Valhall)	

As a result of approval of new development of the Ekofisk field, the ownership structure in production licence 018 will be altered as from 1 January 1999. The SDFI will have a share of 5.0000 %. The present licensees' shares will be reduced correspondingly.

Field history
The Ekofisk area consists of eight fields in production: Albuskjell, Cod, Edda, Ekofisk, Eldfisk, Embla, Tor and Vest Ekofisk, see Figure 2.8.4.b. Cod was discovered in 1968. Ekofisk was discovered in 1969 and was, as the first discovery on the Norwegian continental shelf, declared commercial in 1970. The other fields in the area were discovered between 1969 and 1974. Production from Ekofisk started in June 1971. The last field to come on stream in the area was Embla, which started production in May 1993.

In 1993 the authorities demanded a revised plan for development and operation to be submitted for production licence 018. This plan, which was approved by the Storting in December 1994, the so-called Ekofisk-II project, comprised two new installations at Ekofisk. During 1996 a new wellhead installation accommodating 50

Fig. 2.8.4.a
Fields and discoveries in the Ekofisk area



wells will be in place. In autumn 1998, a new process and transportation installation will be in place. Both installations will be designed to tolerate a further 14 meters subsidence of the sea bed due to reservoir compaction. The plan entails tie-in of the fields Eldfisk and Embla to the new centre. Possible tie-in to the remaining fields in production licence 018 will be considered.

The fields Cod and Embla produce from sandstone strata. The other fields in the area produce from chalk. The Ekofisk field is the largest field in the area. Reserves are estimated at 360 million Sm³ oil and 151 billion Sm³ gas. Eldfisk is the second largest field in the area with reserves estimated at 71 million Sm³ oil and 45 billion Sm³ gas. Figure 2.8.4.a shows the location of the fields.

Production

The Ekofisk area has been developed in several stages. From June 1971 to May 1974, oil was produced from four wells which had been completed on the sea bed on the Ekofisk field. The fields Cod, Tor and Vest Ekofisk were developed and tied in with the Ekofisk centre at the same time as an oil pipeline was laid to Teesside and a gas pipeline was laid to Emden. The pipelines came on stream in 1975 and 1977 respectively. Before the gas line was completed, the gas had been re-injected into the Ekofisk field. The second development stage involved the tie-in of the fields Albuskjell, Edda and Eldfisk to the Ekofisk field centre. Embla was developed using a sporadically manned wellhead installation remotely controlled from Eldfisk Alpha.

All the fields in the Ekofisk area were originally developed with depressurisation as the drive mechanism.

Limited gas injection, implementation of full-scale water injection and improved understanding of the reservoir have all contributed to a considerable increase of the recovery factor of the actual Ekofisk field. Estimates of the recovery factor for oil has increased from originally 18 % to over 35 %. Production flows from two formations on the Ekofisk field, namely the Tor formation and the overlying Ekofisk formation. Water injection started in 1981 with a limited field test in the Tor formation. Injection on a larger scale commenced in 1987. The area under injection has gradually been expanded, first to the lower part and in 1993 also to the upper part of the Ekofisk formation. Two horizontal wells have been drilled on this field in 1993/94. Preliminary evaluations of the production are promising with regard to future drainage of the flank areas. The operator is also considering the possibilites for increasing oil recovery from the field even further both by means of conventional methods and by more advanced methods such as combined gas and water injection and the use of chemicals.

The Eldfisk field produces from three separate structures by means of depressurisation. The recovery factor for oil is low, approximately 19 %. Four horizontal wells have been drilled at Eldfisk during 1994, three in the 2/7-B structure and one in the 2/7-A structure. Various methods to improve recovery in excess of the preliminary plans are being considered.

On the Tor field, water injection from a single well was commenced in 1992. During 1994 the injection capacity has been upgraded. Injection is currently carried out from two wells on the field. The first horizontal well drilled in the Ekofisk area came on stream in 1992 on the Tor field.

The original plan for Embla was for development in several phases. Later the development has been limited to one wellhead installation accommodating 18 wells. By September 1993 a total of four wells had come on stream. Revised plan for development and operation for Embla was received by the authorities in December 1994.

Subsidence

Subsidence of the seabed has been observed on the Ekofisk, Eldfisk, and Vest Ekofisk fields. In November 1984 it was found that the sea bed at the Ekofisk centre had subsided. Measurements have since shown that the total subsidence as of 15 December 1994 is 6.3 meters. Figure 2.8.4.c shows subsidence readings at 2/4-H in the period 1985-94. The rate of subsidence in 1994 was in excess of 35 cm a year.

The subsidence of the seabed is caused by the highly porous reservoir rock being pressed together by overlying rocks due to depletion of the reservoir. There is still some doubt about the mechanism by which the reservoir volume reduction takes place and how it is transferred to the sea bed. In order to limit further subsidence and well problems related to compaction of the Ekofisk reservoir, the net reservoir recovery is to be limited. This is done by a combination of water and gas injection. In 1994, an average of 110,000 m^3 of water and 2 million Sm^3 of gas have been injected daily to balance the extraction of oil and gas.

Transportation

The gas is transported by pipeline to Emden. The oil, containing the NGL fraction, is carried by pipeline to Teesside. Here the transport capacity is augmented by boosting the operating pressure. As a further measure, anti-friction chemicals are added, giving a total current transportation capacity of more than 95,000 Sm^3 a day. During the maintenance halt in August 1994, a Y piece was fitted on the oil pipeline to Teesside some 50 km from Ekofisk. This makes it possible to connect up oil pipes from the J-block on the British continental shelf and if applicable also other British fields.

Metering systems

Sales metering of oil, NGL and natural gas takes place at the terminals in Teesside and Emden. Total oil and gas deliveries to the Teesside and Emden pipelines from the area are metered and analysed on the Ekofisk tank. In addition, oil and gas production are metered on the individual satellite platforms before being transferred by pipeline to the Ekofisk field centre, with the exception of production from the fields Vest Ekofisk and Ekofisk itself, which are metered on the Ekofisk tank. Upgrading and modernisation has been carried out in 1994 of the technical equipment of the metering stations in Teesside, Emden and on Ekofisk, Eldfisk and 2/4-G.

Costs

Ekofisk II is to be completed in 1998. During the period 1994-1998, investments in Ekofisk II are estimated to 19 billion 1994-NOK. Out of this, investment in a new process and transportation installation represents NOK 9.8 billion, and investment in connection with a new wellhead installation represents NOK 4.6 billion. The operating costs will be significantly reduced in connection with start-up of Ekofisk II. Operating costs for 1994 were in excess of NOK 8 billion, including tariffs. This figure will be reduced to around NOK 4 billion in the year 2000.

Fig. 2.8.4.b
Installations in the Ekofisk area

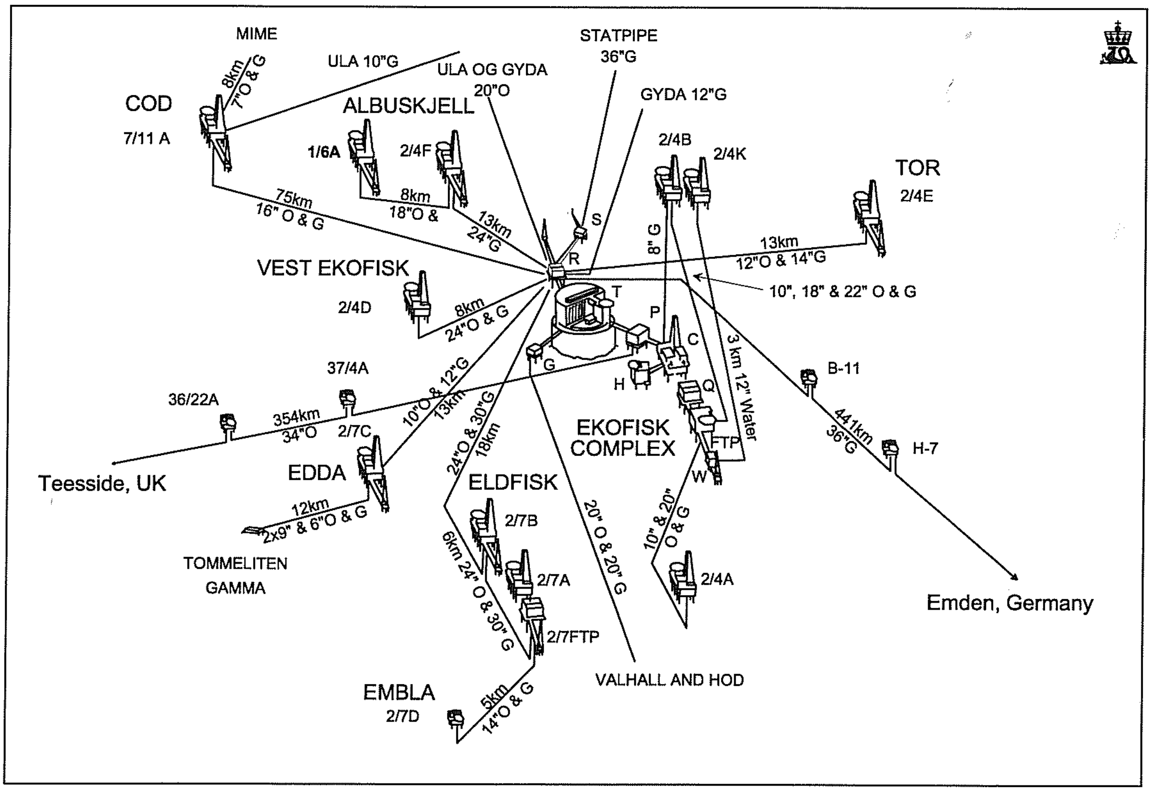
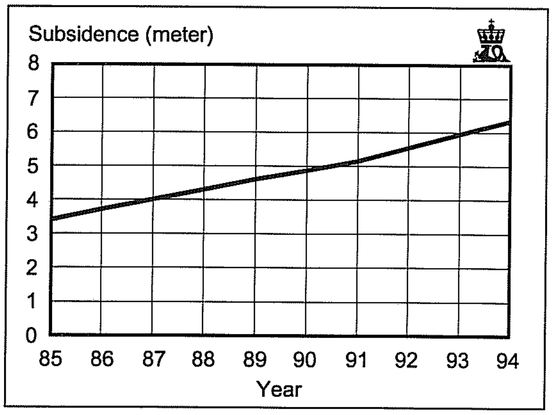


Fig. 2.8.4.c
Ekofisk field
Total subsidence measured at 2/4-H



2.8.5 GYDA

Production licence 019B

Licensees

Den norske stats oljeselskap a.s (Statoil)	50.0000 %
BP Norway Limited U.A (operator)	26.6250 %
Norske Conoco A/S	9.3750 %
Norske AEDC Ltd	5.0000 %
Norske MOECO Ltd	5.0000 %
K/S A/S Pelican & Co	4.0000 %

Field history

The Gyda field is located in block 2/1; see Figure 2.8.4.a. The field was proven in 1985. The plan for development and operation was approved by the Storting in spring 1987. Gyda came on stream in June 1990.

Production

The reservoir is in Upper Jurassic sandstone. Total reserves estimates are 30.6 million Sm³ oil, 3.9 billion Sm³ gas and 1.7 million tonnes NGL. Gyda is produced using water injection as driving mechanism.

Oil production in 1994 was higher than forecast as sandstone with very good production properties has been encountered in the north-western part of the field, the C-sand units. The last year of production is expected to be 2008.

Production installations

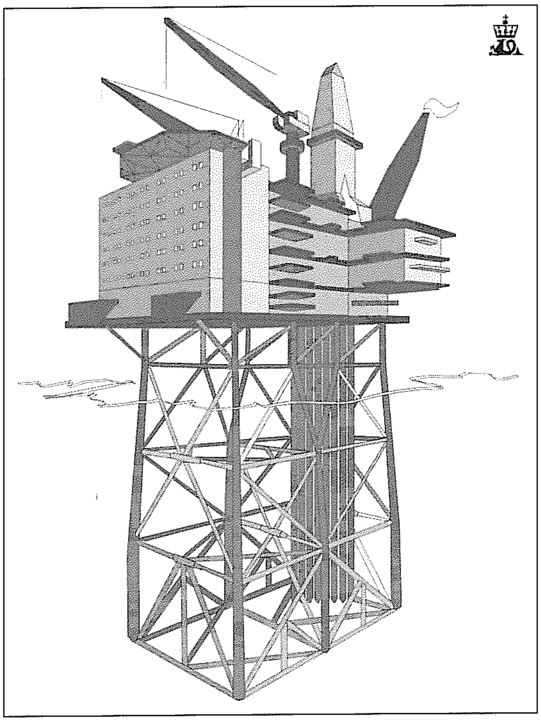
The development concept for the field comprises a combined drilling, living quarters and processing installation with a steel jacket, see Figure 2.8.5.

Current production capacity is 14,000 Sm³ oil per day and 1.8 million Sm³ gas a day. The water injection capacity is 24,500 m³ per day. In connection with production from Gyda Sør an increase in the gas capacity by modification of the existing gas export compressor is considered.

Transportation

The oil is transported to Ekofisk via the Ula pipeline and from there to Teesside. The gas is transported in a separate pipeline to Ekofisk for further transport to Emden.

Fig. 2.8.5
Installation on Gyda



Metering system
Oil and gas production is metered to fiscal standard before being piped to Ekofisk. The metering systems are included in the Ekofisk system for distribution of hydrocarbons.

Costs
At year end 1994, a total of about 8.5 billion 1994-NOK had been invested in the Gyda field. Total investments are expected to be about 1994-NOK 9.1 billion from 1988 to the year 2000. Operating costs in 1994 were approximately NOK 1 billion, including tariffs.

2.8.6 ULA
Production licence 019A

Licensees

BP Norway Limited U.A (operator)	57.5000%
Svenska Petroleum Exploration A S	15.0000 %
Den norske stats oljeselskap a.s (Statoil)	12.5000%
Norske Conoco A/S	10.0000 %
K/S A/S Pelican & Co	5.0000 %

Field history
The field is situated in block 7/12, see Figure 2.8.4.a. It was discovered in 1976. The plan for development and operation was approved in 1984. Production from the Ula field started in October 1986.

Production
The reservoir consists of Jurassic sandstones. Ula is produced using water injection as driving mechanism. The water front is now advancing from the north and east towards the central parts of the field, and production now has an increasing amount of water. Production will decline gradually until forecast production stop in 2007.

Test production from an underlying Triassic reservoir is scheduled to start in 1995. The purpose of the test is to investigate volume, productivity and possible communication with the reservoir in the Ula formation. The operator's reserves estimates for the Triassic reservoir are in the order of 0.1 to 0.8 million Sm³ oil.

Production installations
The development concept involves three conventional steel installations for production, drilling and living quarters, respectively, see Figure 2.8.6.

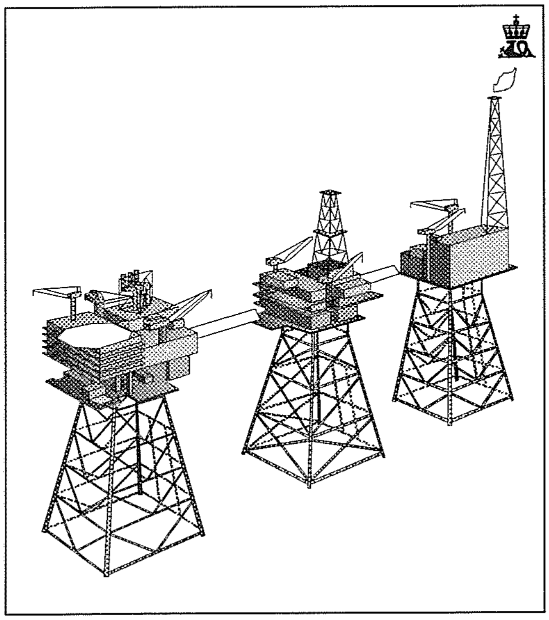
Current production capacity is 24,000 Sm³ oil per day and 1.6 million Sm³ gas a day. The water injection capacity was upgraded in 1992 to 32,000 Sm³ a day. The capacity for treatment of produced water was increased in 1994 from 6,500 Sm³ per day to about 19,000 Sm³ per day. From mid December 1994, all produced water at Ula is reinjected.

All 18 well slots are now in use. New wells are planned to be side drilled from existing wells.

Transportation
The oil is carried by pipeline via Ekofisk to Teesside. Statoil is operator for the pipeline. The gas is transported by pipeline via Cod to Ekofisk and then on to Emden.

Metering system
The oil and gas production is metered to fiscal standard before being transported by pipeline to Ekofisk. The metering systems are part of the Ekofisk hydrocarbon distribution system.

Fig 2.8.6
Installations on Ula



Costs
At year end 1994, about 12 billion 1994-NOK had been invested in the Ula field. Total investments are expected to be about 1994-NOK 12.9 billion from 1983 to the year 2000. Operating costs in 1994 were approximately NOK 1.8 billion, including tariffs.

2.8.7 SLEIPNER AREA

2.8.7.1 Sleipner Øst
Production licence 046

Licensees

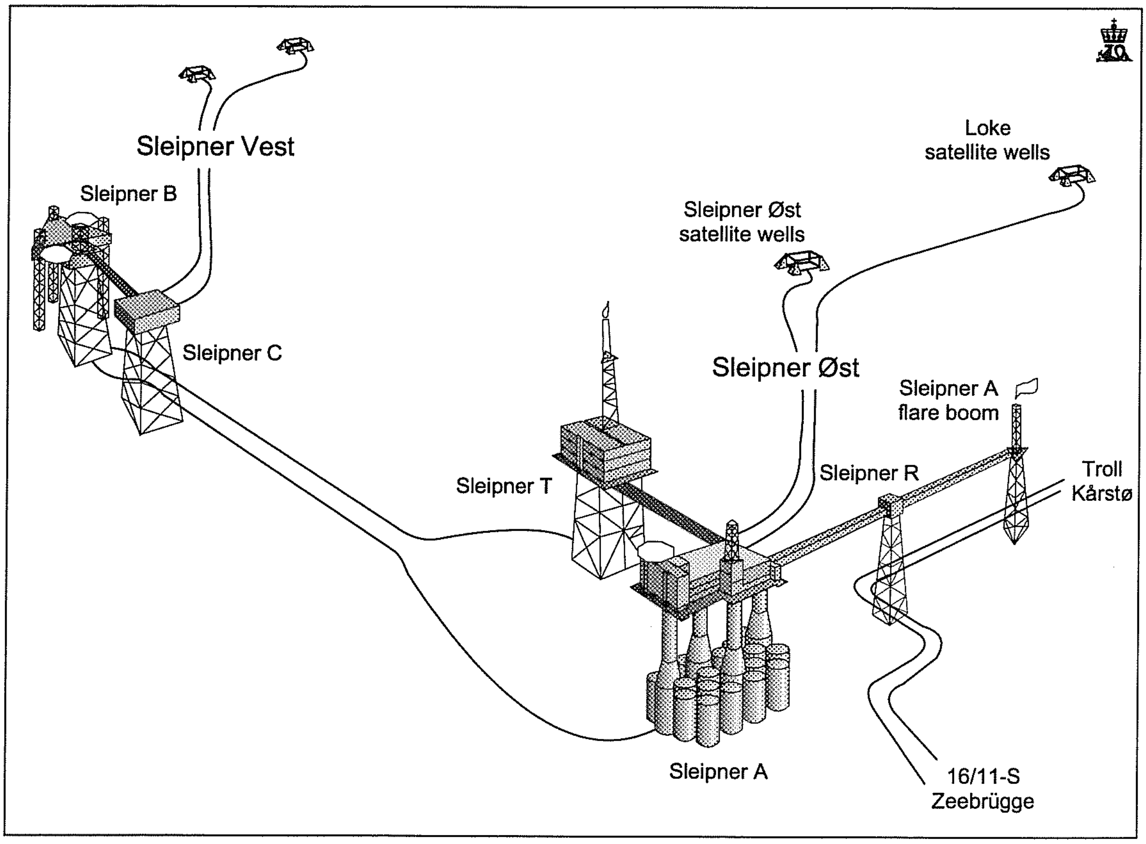
Den norske stats oljeselskap a.s (Statoil) (operator)	49.6000 %
Esso Norge A/S	30.4000 %
Norsk Hydro Produksjon a.s	10.0000 %
Elf Petroleum Norge A/S	9.0000 %
TOTAL Norge A/S	1.0000 %

Field history
The production licence was allocated in 1976 and comprises the blocks 15/8 and 15/9, see Figure 2.6.a. The plan for development and operation was approved by the Storting in 1986. Sleipner Øst came on stream in August 1993.

Production
Two reservoir strata have been proven in Sleipner Øst, one in Tertiary, Heimdal formation, and one in Jurassic/ Triassic, Hugin formation. The reserves have been estimated to 47.8 billion Sm^3 gas and 30.4 million tonnes NGL. Nine wells have now been drilled from the Sleipner A installation, seven gas producers and two gas injectors. In addition, two production wells have been drilled from the sea bed template of Sleipner Øst. New wells are planned to be drilled from the Sleipner A installation until 1997. This comprises production wells as well as injection wells. It has been decided that gas will be re-injected into Sleipner Øst to increase the production of condensate from the field. New 3D seismic has been shot over the field in 1994, to provide better information on both the Heimdal and the Hugin formations.

Production installations
Sleipner Øst is developed with an integrated process, drilling and accommodation installation with a four-shafted gravity base structure, see Figure 2.8.7. In addition, a separate marine riser installation with bridge connection to the process installation has been built, as well as a sea bed template with two wells for draining of the northern part of the field.

Fig 2.8.7
Existing and projected installations in the Sleipner area



Transportation
The condensate is landed at Kårstø through a 508 mm diameter pipeline fromo the Sleipner A installation to Kårstø, 250 km in length. The gas is transported by pipeline both to Zeebrugge in Belgium and through the Statpipe/Norpipe system to Emden in Germany.

Metering systems
Produced gas and condensate are metered on the installation to fiscal standard.

Costs
At year end 1994, about 22.5 billion 1994-NOK had been
invested in the Sleipner Øst field. Total investments are expected to be about 1994-NOK 23 billion from 1987 to 1996. Operating costs in 1994 were approximately NOK 2 billion, including tariffs.

2.8.7.2 LOKE
Production licence 046

Licensees

Den norske stats oljeselskap a.s (Statoil) (operator)	49.6000 %
Esso Norge a.s	30.4000 %
Norsk Hydro Produksjon a.s	10.0000 %
Elf Petroleum Norge A/S	9.0000 %
TOTAL Norge A/S	1.0000 %

Field history
The production licence was allocated in 1976 and is the same as for Sleipner Øst, see Figure 2.6.a. The field was proven by well 15/9-17 in 1983. The plan for development and operation was approved by the Storting in 1991 and Loke came on stream in September 1993.

Production
Two reservoir strata corresponding to the reservoir strata in Sleipner Øst have been proven, but it is only the reservoir in the Heimdal formation that is being drained. The Heimdal formation in Loke has pressure communication with the Heimdal formation in Sleipner Øst. Production of Sleipner Øst will affect the pressure in Loke. Production from Loke will therefore prevent loss of large volumes of hydrocarbons in the aquifer between Loke and Sleipner Øst. Loke will be drained from one well. The reserves for the Heimdal formation are estimated to be 0.7 billion Sm^3 gas and 0.42 million tonnes NGL.

Production installations
Loke will be produced by means of a subsea production system with transfer of the well flow to the Sleipner A installation, see Figure 2.8.7.

Costs
At year end 1994, about 650 million 1994-NOK had been invested in the Loke field, which will also represent the total investments in the field. Operating costs in 1994 were approximately NOK 98 million, including tariffs.

2.8.8 HEIMDAL
Production licence 036

Licensees

Den norske stats oljeselskap a.s (Statoil)	40.0000 %
Marathon Petroleum Company (Norway)	23.7980 %
Elf Petroleum Norge A/S (operator)	21.5140 %
Norsk Hydro Produksjon a.s	6.2280 %
TOTAL Norge A/S	4.8200 %
Saga Petroleum a.s	3.4710 %
Ugland Construction Company A/S	0.1690 %

Field history
Production licence 036 was allocated in 1971 and covers block 25/4, see Figure 2.8.9.a . With respect to that part of the production licence which embraces Heimdal, the Norwegian State has exercised its option.

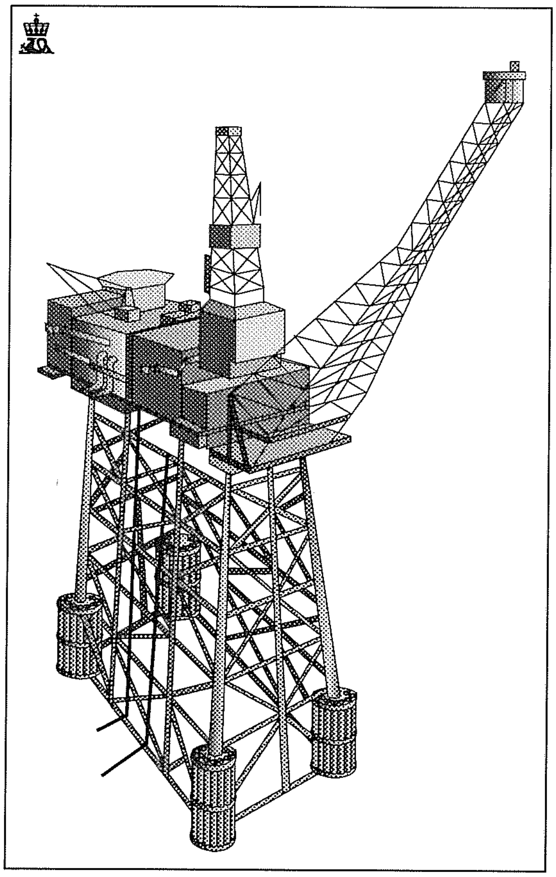
The field was proven in 1972 , and declared commercial in April 1974. Landing of the gas to the Continent was approved by the Storting in 1981, and the landing concept for condensate to the UK was approved by the Storting in 1983. Production from the Heimdal field started in 1985.

Production
The field produces from the Heimdal formation, which consists of Palaeocene sand. Reserves are estimated to be 38.6 billion Sm^3 gas and 6.5 million Sm^3 oil/condensate. Ten wells have been drilled from the field installation, nine producers and one observation well. Because of the powerful water drive in the field, pressure decline and water ascent are both carefully monitored. Production has reached plateau level. In October 1992, development of a Jurassic deposit located beneath the main reservoir received approval. The reservoir turned out to have smaller reserves than first assumed, and it was decided not to produce from this reservoir.

Production installations
Heimdal has been developed with an integrated steel jacket structure combining drilling, production and living quarters functions, see Figure 2.8.8. Delivery of gas via Emden began in February 1986. Some corrosion has been proven in the production facilities on the installation. This has been repaired in 1994, so that the installation is back to full production capacity.

Transportation
The gas from the Heimdal field is transported through Statpipe. The pipeline from Heimdal is tied in with the Statpipe system at the 16/11-S riser platform. The condensate is transported in a separate pipeline from Heimdal to Brae in the British sector. From the Brae field the condensate goes to Cruden Bay in Scotland.

Fig. 2.8.8
Installation on Heimdal



Metering system
Both the gas and the condensate production are metered to fiscal standard on the installation.

Costs
At year end 1994, about 14 billion 1994-NOK had been invested in Heimdal, which also represents the total investments in the field from 1981 to 1998. Operating costs in 1994 were approximately NOK 2.3 billion, including tariffs.

2.8.9 FRIGG AREA

2.8.9.1 Frigg
Production licence 024

Licensees

Norwegian share (60.8200 %)	
Elf Petroleum Norge A/S (operator)	25.1910 %
Norsk Hydro Produksjon a.s	19.9920 %
TOTAL Norge A/S	12.5960 %
Den norske stats oljeselskap a.s (Statoil)	3.0410 %
British share (39.1800 %)	
Elf Exploration UK Ltd	26.1200 %
Total Oil Marine Ltd	13.0600 %

Field history
Elf Petroleum Norge A/S is the operator of the Frigg field and Total Oil Marine Ltd the operator of the pipeline system and the St Fergus terminal in Scotland.

The Frigg field is situated in blocks 25/1 and 30/10 on the Norwegian continental shelf and in blocks 10/1, 9/5 and 9/10 on the British continental shelf, see Figure 2.8.9.a. The field has been unitised, and 60.82 % of the gas reserves are by agreement deemed to belong to the Norwegian licensees.

Frigg was proven in 1971 and development was approved by the Storting in 1974. Production start-up was September 1977.

Production
The field produces gas from the Frigg formation, which consists of Eocene sand. The reserves are estimated to be 184 billion Sm³ gas. On CDP1 all production wells have been permanently plugged, whereas on DP2 there are 15 wells available for production. All of these have reduced production potential due to water influx in the wells. Future development of produced water volume will be decisive with regard to the shutdown time for the field.

Production installations
The field was developed in three phases. Phase 1 comprises one production and one processing installation in the British part of the field and a quarters platform (CDP1, TP1 and QP). Production from Phase 1 started in September 1977.

Phase 2 comprises one production and one processing installation located in the Norwegian part of the field (DP2 and TCP2). Production from Phase 2 started in summer 1978. Figure 2.8.9.b shows the installations on the Frigg field.

Phase 3 of the development comprises the installation of three turbine driven compressors on the TCP2 installation. The compressor plant is necessary to compensate for the declining reservoir pressure. The plant was put in operation in autumn 1981.

Gas from Nordøst Frigg (until 8 May 1993), Odin (until 1 August 1994), Øst Frigg and Lille-Frigg is processed and metered on Frigg. New modules for processing of gas and condensate from these fields have been installed on TCP2. Transport of gas from the Alwyn North field on the British side takes place via TP1.

TP1 has been converted from a processing facility to a riser platform. TCP2 has been modified to adapt the compressor plant to altered pressure conditions and reduced gas volumes. After termination of production at Odin, the main compressors have been shut down. In addition, two of the three process trains on TCP2 has been decommissioned.

Modification work has been done on TCP2 in order to process gas from Frøy. This work will continue in 1995.

Transportation
The gas is transported 355 kilometers to St Fergus in Scotland through two 813 mm diameter pipelines. In order to increase the transport system capacity, two tur-

bine driven compressors, each of 38,000 bhp, were in 1983 installed on the compressor platform MCP-01, located halfway between Frigg and Scotland. The capacity increase was necessary to enable transportation of the gas from the Odin field. As a result of reduced transportation capacity requirement, these compressors have now been removed and the installation is unnmanned.

Metering system - Frigg area

Gas export via the pipeline to St. Fergus is metered to fiscal standard collectively for the Norwegian Frigg fields. The contribution from the Frigg field is determined by deducting the contributions from Øst Frigg and Lille-Frigg from the total gas export. Condensate that has been separated out is metered separately and transported in the oil pipeline (Frostpipe) to Oseberg and onwards to the Sture terminal.

Costs

At year end 1994, about 25 billion 1994-NOK had been invested in Frigg, which is also the estimate for total investments in the Norwegian part of the field over the field lifetime. Operating costs in 1994 were approximately NOK 400 million, including tariffs. Operating costs for the transportation system are excluded in these figures.

2.8.9.2 Øst Frigg

Production licence 024 (block 25/1), production licence 026 (block 25/2), and production licence 112 (previously relinquished part of block 25/2, reallocated in 1985), see Figure 2.8.9.a.

Licensees in the unitised Øst Frigg field

Elf Petroleum Norge A/S (operator)	37.225 %
Norsk Hydro Produksjon a.s	32.112 %
TOTAL Norge A/S	20.232 %
Den norske stats olieselskap a.s (Statoil)	10.431 %

Field history

Øst Frigg, which is a gas field, consists of two structures located in blocks 25/1 and 25/2. The reserves are split with 21.593 % in production licence 024, 77.536 % in production licence 026, and 4.871 % in production licence 112. The landing application was approved in 1984. Production commenced in August 1988 and the sale of gas in October 1988.

Production

The two principal structures, Alpha and Beta, were discovered in 1973 and 1974, respectively. They are part of the same pressure system as the Frigg field.

The reserves are estimated to be 8.9 billion Sm³ gas. This is subdivided as follows: 5.4 billion Sm³ in the Alpha structure and 3.5 billion Sm³ in the Beta structure.

Originally there were 5 production wells on the field; out of these one has been permanently closed down and one is temporarily closed down as from 1 November 1994.

Production installations

The Øst Frigg development consists of two sea bed templates for production wells with a common gas pipeline to TCP2. These subsea production systems are remotely controlled from Frigg. The gas is processed on TCP2 and fed into the Frigg field transportation system. The gas is sold to British Gas Corporation under the existing sales agreement.

Costs

Total investments in the field are expected to be about 2.8 billion 1994-NOK. The operating costs for 1994 amounted to about 400 million kroner, including tariffs.

2.8.9.3 Lille-Frigg

Lille-Frigg is situated in block 25/2 production licence 026, see Figure 2.8.9.a.

Licensees

Elf Petroleum Norge A/S (operator)	41.4200 %
Norsk Hydro Produksjon a.s	32.8700 %
TOTAL Norge A/S	20.7100 %
Den norske stats oljeselskap a.s (Statoil)	5.0000 %

Field history

The production licence was allocated in 1969. Hydrocarbons were proved in wildcat well 25/2-4 in 1975. The work in connection with a commerciality declaration was started after the drilling of well 25/2-12 in 1988. The plan for development and operation was approved by Royal Decree in September 1991 and production commenced in May 1994.

Reservoir

Lille-Frigg is a combined gas/condensate field. The reservoir lies in the Brent group in a fault block which is an extension of the Heimdal ridge. The reserves estimates are 7 billion Sm³ gas and 3.6 million Sm³ condensate sold as oil.

Fig. 2.8.9.a
Fields and discoveries in the Frigg area

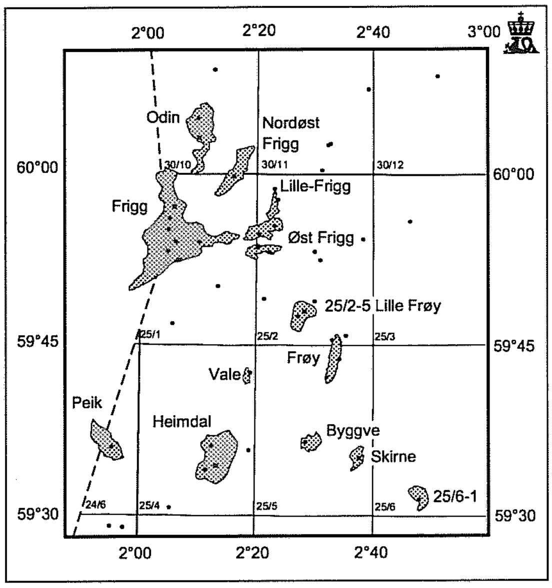
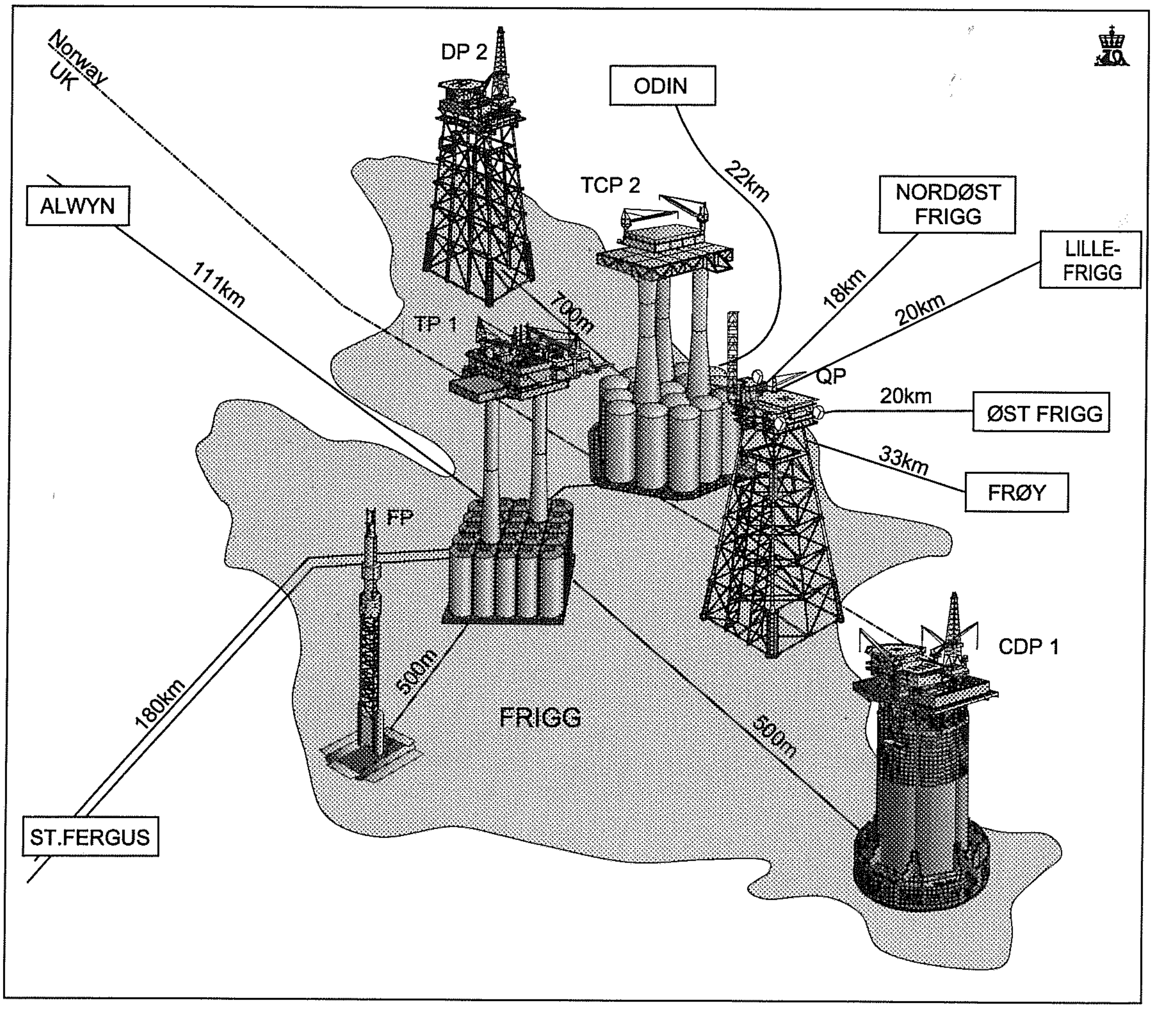


Fig. 2.8.9.b
Installations in the Frigg area



Developmenty concept/transportation
The Lille-Frigg field is developed using a subsea installation remotely controlled from Frigg. Development is based on three production wells with depressurisation as the drive mechanism. It is possible to tie in two extra wells. The untreated wellflow is conducted under high pressure directly to Frigg for treatment. The gas is transported to St. Fergus in the existing pipeline. Stabilised condensate is carried in Frostpipe to Oseberg, and from there onwards to the oil terminal at Stura.

Metering
The condensate transported in the Frostpipe pipeline is metered to fiscal standard on Frigg. Gas export to St. Fergus is metered on Frigg.

Costs
At year end 1994, about 4 billion 1994-NOK had been invested in Lille-Frigg, which is also the estimate for total investments in the field over the field lifetime. Total operating costs in 1994 were approximately NOK 270 million, including tariffs.

2.8.10 OSEBERG AREA

2.8.10.1 Oseberg
Production licences 053 and 079

Licensees in the unitised Oseberg field

Den norske stats oljeselskap a.s (Statoil)	64.78379 %
Norsk Hydro Produksjon a.s (operator)	13.68186 %
Saga Petroleum a.s	8.55276 %
Elf Petroleum Norge a.s	5.76959 %
Mobil Development Norway a.s	4.32720 %
TOTAL Norge A/S	2.88480 %

The Oseberg field extends into two blocks: block 30/6 in production licence 053 allocated in 1979, and block 30/9 in production licence 079 which was allocated in 1982. See Figure 2.6.c.

The part of the production licences which covers Oseberg has now been unitised for the two production licences. In 1993, the licensees completed a new unitisation accord for blocks 30/6 and 30/9. This resulted in the following field equities, as from 1 January 1994:

Production licence 053 61.8171 %
Production licence 079 38.1829 %

Field history

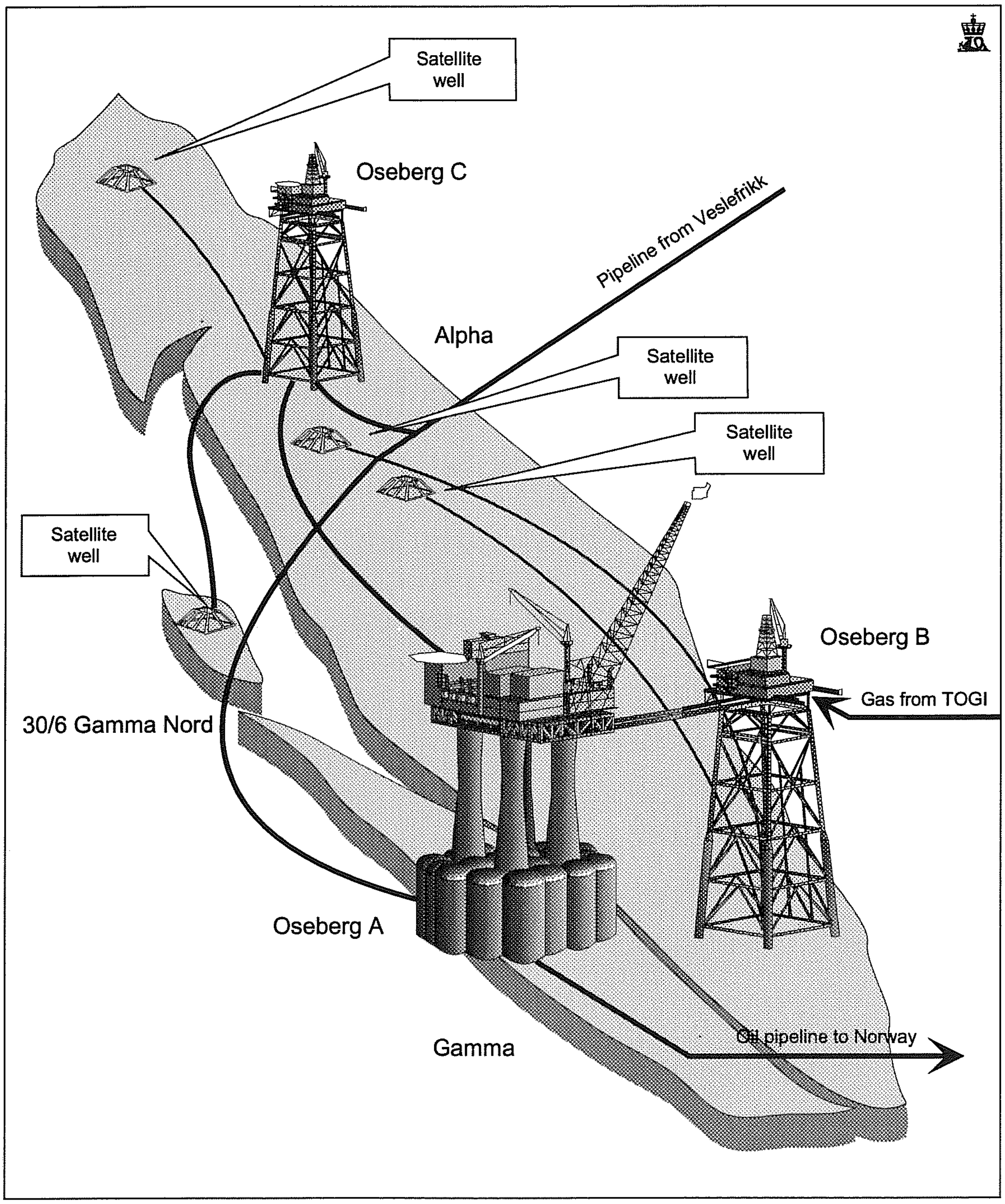
The plan for development and operation was approved by the Storting in 1984. Production start-up for the Oseberg field centre took place in December 1988. The Oseberg C installation came on stream on in September 1991.

Production

The first discovery proved gas in 1979, while later drillings proved oil with a gas cap. The field consists of several reservoirs in the Brent group in multiple structures. The main reservoirs are found in the Oseberg formation in the Alpha and Gamma structures.

The reserves were adjusted upwards in 1994 and are now estimated at 310 million Sm³ oil, including approximately 13 million Sm³ NGL. Although the original plans

Fig. 2.8.10
Installations on Oseberg



did not call for horizontal wells, the majority of recent producers have been drilled horizontally, with good results.

The gas reserves in Oseberg are about 110 billion Sm^3, including the recoverable part of injected gas from TOGI and 30/6 Gamma Nord. It has not yet been determined when gas export from Oseberg will start.

Production installations

The Oseberg field was developed in two phases. Phase 1 was developed with a field centre in the south comprising two installations. Oseberg A comprises a process and quarters installation with a gravity base, and Oseberg B comprises a drilling and water injection installation with a steel jacket. The central part of the field is drained using two subsea completion wells tied in to the field centre. The mean oil processing capacity is about 55,000 Sm^3 a day.

Phase 2 involves development of the northern part of the field. In the revised Oseberg plan the C installation was upgraded from a satellite unit to an integrated production, drilling and quarters (PDQ) installation employing the services of a support vessel during the drilling phase. The mean oil processing capacity is some 20,000 Sm^3 a day. For an overview of the installations, see Figure 2.8.10.

Metering system

Oseberg A and Oseberg C are equipped with metering stations for fiscal metering of stabilised oil before transportation by pipeline to Stura. The purchase of injection gas from Troll (TOGI) is metered in the fiscal gas metering station installed on Oseberg A. Stabilised oil from two jetty facilities tied in with two identical fiscal oil metering stations is exported from the Sture terminal.

Costs

At year end 1994, about 45 billion 1994-NOK had been invested in the Oseberg field. The total investment is expected to be about 1994-NOK 52 billion from 1983 until 1999. The operating costs in 1994 were around NOK 5 billion, including tariffs.

2.8.10.2 30/6 GAMMA NORD

Production licence 053

Licensees

Den norske stats oljeselskap a.s (Statoil)	59.4000 %
Norsk Hydro Produksjon a.s (operator)	12.2500 %
Elf Petroleum Norge a.s	9.3330 %
Saga Petroleum a.s	7.3500 %
Mobil Development Norway a.s	7.0000 %
TOTAL Norge a.s	4.6670 %

Field history

Gamma Nord is comprised by production licence 053, allocated in 1979, see Figure 2.6.c. 30/6 Gamma Nord is included in the revised development plan for the northern part of the Oseberg field. The field came on stream in October 1991.

Production

The Gamma Nord structure is situated west of the Oseberg field. It is a rotated fault block whose hydrocarbon bearing strata are part of the Statfjord formation. A layer of rich, coal bearing shale divides the Statfjord formation into an upper and a lower reservoir zone. Gas was proven first with a thin oil zone in the upper part of Statfjord. In order to recover as much of the oil as possible before depleting the gas a horizontal well was selected. In connection with the drilling of this well, oil was also proven in the lower part of the reservoir. The producer is a subsea completion well that is tied in to Oseberg C. Oil production from the horizontal well has proceeded much better than forecast. All gas produced is reinjected into the Oseberg field.

The reserves are estimated to 1.3 million Sm^3 oil and 6.2 billion Sm^3 gas.

The second well is decided to be drilled. Well flow from this well is planned to be carried to Oseberg B for further processing. Simplified fiscal metering will take place on Oseberg A.

Metering system

A simplified metering system for fiscal metering of oil and gas has been developed based on oil and gas measurements from the test separator at Oseberg C.

Costs

At year end 1994, 585 million 1994-NOK had been invested in 30/6 Gamma Nord. Total investments are expected to be about 1994-NOK 900 million from 1988 to 1995. Operating costs in 1994 were some 100 million NOK, including tariffs.

2.8.11 VESLEFRIKK

Production licence 052

Licensees

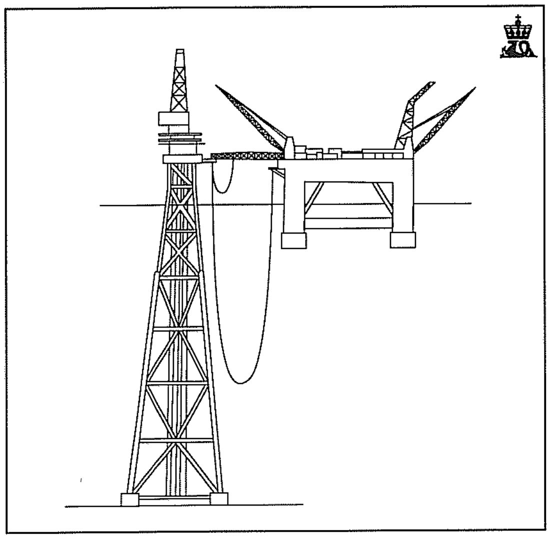
Den norske stats oljeselskap a.s (Statoil) (operator)	55.0000 %
TOTAL Norge A/S	18.0000 %
Deminex (Norge) A/S	11.2500 %
Norsk Hydro Produksjon a.s	9.0000 %
Norske Deminex A/S	4.5000 %
Svenska Petroleum Exploration A/S	2.2500 %

Field history

The field is located in the southeast of block 30/3, see Figure 2.6.b. Production licence 052 was allocated in 1979. The plan for development and operation was approved by the Storting in April 1987. An updated reservoir management plan, prepared after pre-drilling of six production wells, was submitted in September 1989. The field started production in December 1989.

Plan for development and operation of the Statfjord formation was approved by Royal Decree in June 1994. Upper Brent and the I-area of the field were declared commecial in August 1994, and the plan for development and operation of the deposits was approved in December 1994.

Fig. 2.8.11
Installations on Veslefrikk



Production

The field produces from reservoirs in the lower part of the Brent group and Dunlin group (Intra Dunlin Sand). Reserves have been adjusted upwards in 1994, and are estimated at 52.8 million Sm³ oil, including the reserves in the Statfjord formation and Upper Brent. The amount of recoverable associated gas is estimated to be 2.3 billion Sm³ dry gas and 0.9 million tonnes NGL.

The production strategy for the reservoirs in the Brent group and the Dunlin group is to maintain reservoir pressure by means of water injection. Certain wells will however be controlled with a lower well pressure than boiling point pressure. WAG injection in the main reservoirs is being considered. Production start from the Statfjord formation is planned for 1997. The reservoir is planned to be drained with a horizontal producer, and recovery is increased by recirculation of the gas in a horizontal injector. The Statfjord formation has a gas cap and a higher content of associated gas than the other reservoirs.

Production installations

The field has been developed using a fixed wellhead installation with a steel jacket and a semi-submersible installation containing processing facilities and living quarters, see Figure 2.8.11. The wellhead unit is installed above a template with six pre-drilled wells. There are 13 producing wells and seven water injection wells. The semi-submersible installation is moored and hooked up to the fixed wellhead unit. Water injection was initiated in spring 1991.

Transportation

An oil pipeline is connected to the Oseberg Transport System for transportation to the Sture terminal. Gas is carried through the Statpipe system. A temporary agreement has been entered into on exchange of produced gas volumes between Veslefrikk and Heimdal.

Metering system

Produced oil and gas are metered at Veslefrikk before onward transport to Sture and Kårstø, respectively.

Costs

At year end 1994, about 9 billion 1994-NOK had been invested in the Veslefrikk field. Total investments are expected to be about 1994-NOK 9.8 billion from 1987 to 2009. Operating costs in 1994 were approximately NOK 1.4 billion, including tariffs.

2.8.12 GULLFAKS AND GULLFAKS VEST

Production licence 050

Licensees

Den norske stats oljeselskap a.s (Statoil) (operator)	85.0000 %
Norsk Hydro Produksjon a.s	9.0000 %
Saga Petroleum a.s	6.0000 %

Field history

Gullfaks lies in the northeastern part of block 34/10 and covers an area of about 200 square kilometers, see Figure 2.8.12.a. The field was discovered in 1978. Due to the phased development, separate development plans for phases 1 and 2 were approved in 1981 and 1985, respectively. The phase 1 concept embraced the A and B installations, while the C installation covers phase 2. Production from the field started in December 1986. The Gullfaks field produces oil with associated gas.

Production

The Gullfaks field contains oil in Jurassic sandstone. Gullfaks is a relatively shallow accumulation having fault groups in several angled and rotated fault blocks. The blocks vary in slope and the area is in some places heavily eroded. The structural features in the eastern section are difficult to identify due to poor seismic data quality. The geological complexity of the field has been confirmed during the production drilling. The faults are however not as sealing as initially assumed.

The reservoirs in phases 1 and 2 are separated by a north-south fault. A certain degree of communication has been proven in the northern area. Fault lines more than 1000 meters apart limit the field in the south, east and north-east.

Reserves approved for development are split between the Brent group, the Cook formation and Statfjord formation. The reserves estimates were in October 1994 adusted upwards from 253 to 281 million Sm³ oil (excluding the Lunde formation). This represents a recovery factor of 50 %. The reserves estimate is based on production up to and including the year 2006.

The drive mechanism in the field is primarily pressure maintenance by means of water injection, although alternative methods of increasing the recovery factor have in part also been introduced. New well completion and stimulation methods have been tested with encouraging results. Water alternating gas (WAG) injection is carried out where this method is suitable. The same applies to horizontal wells. The injection of thin gel is also a possible method for increased recovery on Gullfaks.

Production installations

Gullfaks A and B are both Condeep type gravity base platforms with steel frame topside, see Figure 2.8.12.b. The C installation is essentially made as a copy of Gullfaks A. All three are fully integrated process, drilling and quarters platforms, but Gullfaks B has a simplified process facility with only first-stage separation. The water depth varies between about 140 meters (Gullfaks A, B) and 217 meters (Gullfaks C).

Gullfaks A, which is located in the south-western part of the field, started production in December 1986. The process capacity for oil is in 1994 increased from 52,000 to 60,000 Sm^3 oil per day, whereas the water capacity is 35,000 m^3 per day. Gullfaks A has a water injection capacity of 75,000 m^3 a day. Gullfaks A is also fitted for gas injection. At year end, two gas injection wells were in operation. Two seabed wells were plugged in 1994 due to high production of hydrogen sulphide.

Gullfaks B is located in the north-western part of the field and came on stream in February 1988. Its process capacity is 30,000 Sm^3 oil per day. Oil from Gullfaks B is transferred to Gullfaks A and Gullfaks C for further processing and storage. Water injection capacity is 30,000 m^3 a day. In addition, injection water can also be sourced from Gullfaks A.

Gullfaks C was placed in the eastern part of the field for production of the phase 2 reserves. Production started at year end 1989/1990. Process capacity of the installation is 50,000 Sm^3 oil, an increase of 10,000 Sm^3 from 1993, and 30,000 m^3 water a day. Up to 75,000 m^3 of water can be injected on a daily basis, an increase of 15,000 m^3 from 1993. It was decided in 1994 to install a compressor for injection of gas also on Gullfaks C. The compressor will be in operation from autumn 1995. The Lunde reservoir is planned to be drained from Gullfaks C.

Gullfaks Vest

Gullfaks Vest is an oil field located in block 34/10, north-west of Gullfaks, see Figure 2.8.12.a. The field was proven by exploration well 34/10-34 in summer 1991. Based on the results of that well, reserves were estimated to be 3.7 million Sm^3. Production from this field is

Fig. 2.8.12.a
Fields and discoveries in the Gullfaks, Statfjord and Snorre areas

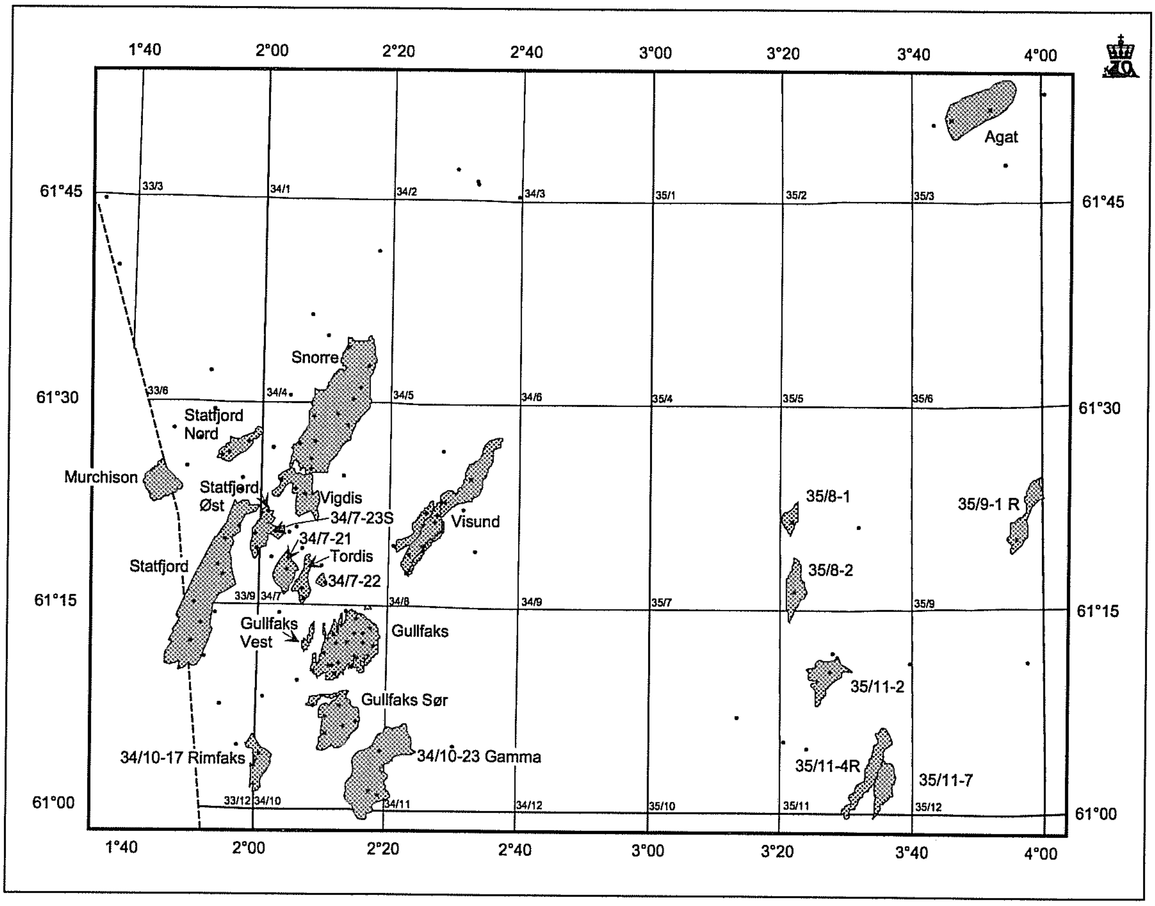
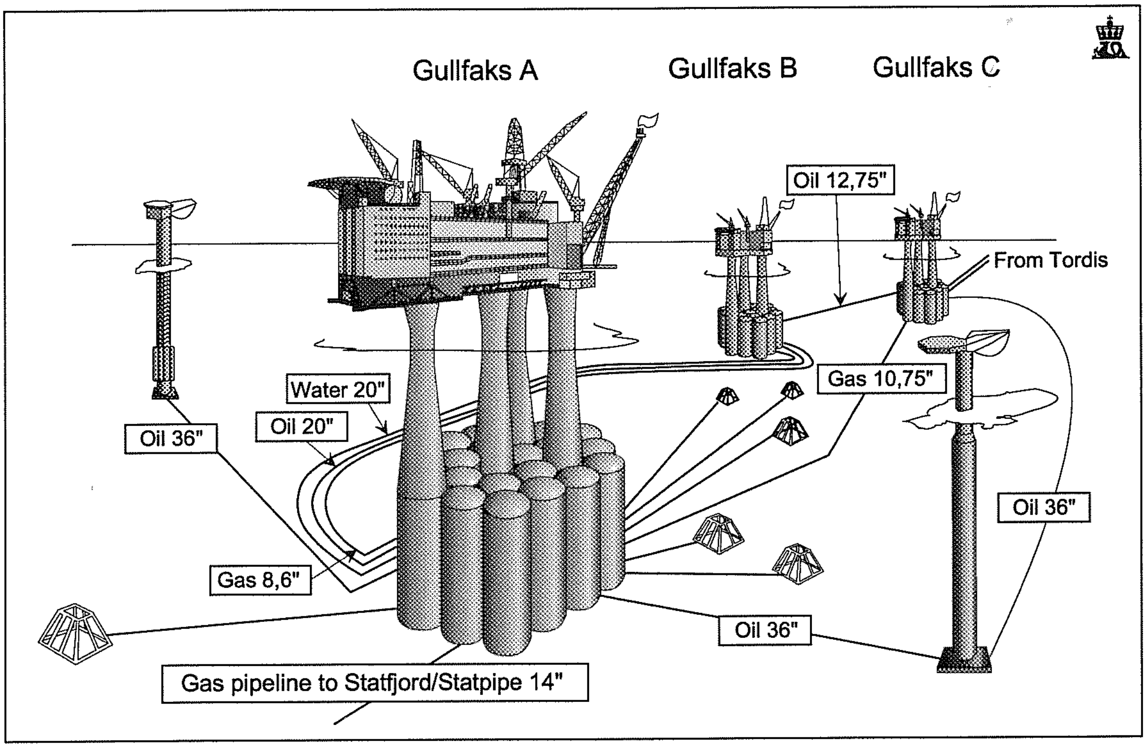


Fig. 2.8.12.b
Installations on Gullfaks



planned to be by means of two horizontal production wells and natural water drive.

Production started in May 1994. On the basis of experience gained from the first well, estimated reserves have been reduced to 2.9 million Sm³, and one well is now considered sufficient. Expected lifetime has now been reduced to five years.

Gullfaks as infrastructure

In addition to Gullfaks Vest, the installations will also be used for production from Tordis and Vigdis. In May 1994 deliveries started from Tordis to Gullfaks C, where the oil is treated. A new first stage separator has been built at Gullfaks C. Otherwise, existing equipment is being used.

It was further decided in 1994 that treated oil from Vigdis (via Snorre) is to be delivered to Gullfaks A for storage and shipment via tanker.

The Gullfaks installations are also in question for 34/10-2 Gullfaks Sør, 34/10-17 Rimfaks and 34/8-1 Visund as well as other discoveries in the area. The licensees of Gullfaks, production licence 050, have with reference among other things to this, applied for extension of the acerage in the production licence to include areas that can be reached with wells from Gullfaks A and B.

Metering system and transportation

Both Gullfaks A and C have storage cells for storage of the stabilised oil. The oil is metered and exported via offshore loading buoys to tankers. Processed rich gas is subject to fiscal metering on Gullfaks A and C before being exported into the Statpipe system via Statfjord C. Oil from Gullfaks is metered by means of a test separator on Gullfaks B. The Tordis wellflow is metered following first stage separation on Gullfaks C.

The measured and analysed volumes are then subjected to further treatment in the process facility on Gullfaks C prior to loading of oil and delivery of gas to Statpipe. Fiscal metering of oil from Vigdis will take place on Snorre.

Costs

At year end 1994, about 67 billion 1994-NOK had been invested in Gullfaks, and 0.2 billion in Gullfaks Vest. Total investments over the lifetime of the field are about 1994-NOK 71 billion for Gullfaks, and 0.2 billion for Gullfaks Vest. Operating costs including tariffs are for 1994 estimated to be NOK 4.6 billion, including Gullfaks Vest.

2.8.13 TORDIS

Production licence 089

Licensees

Den norske stats olieselskap a.s (Statoil)	55.4000 %
Esso Norge a.s	10.5000 %
Idemitsu Petroleum Norge a.s.	9.6000 %
Norsk Hydro Produksjon a.s	8.4000 %
Saga Petroleum a.s (operator)	7.0000 %
Elf Petroleum Norge A/S	5.6000 %
Deminex (Norge) A S	2.8000 %
DNO Olje A/S	0.7000 %

Field history

Tordis is situated in block 34/7, which was granted by production licence 089 in 1984, see Figure 2.8.12.a. The field was proven by the 34/7-12 wildcat in 1987. An appraisal well, 34/7-14, was drilled on the field in autumn 1989. Based on these two wells the field was declared commercial, and the plan for development and operation was approved by the Storting in May 1991.

Production from the field started in June 1994.

Production

The Tordis field reservoir consists of sandstones found in the upper and lower part of the Brent group, of Middle Jurassic age. Faults divide the field into three main segments, one southern, one western and one eastern segment. The reserves estimates were adjusted upwards in 1994 and are currently 29 million Sm³ oil. This adjustment is based on a new seismic interpretation and well data from the first three production wells. The driving mechanism of the field is pressure maintenance by water injection.

Production installations

The field is developed using sea bed completed wells. The plan calls for five producers and two water injectors in all.

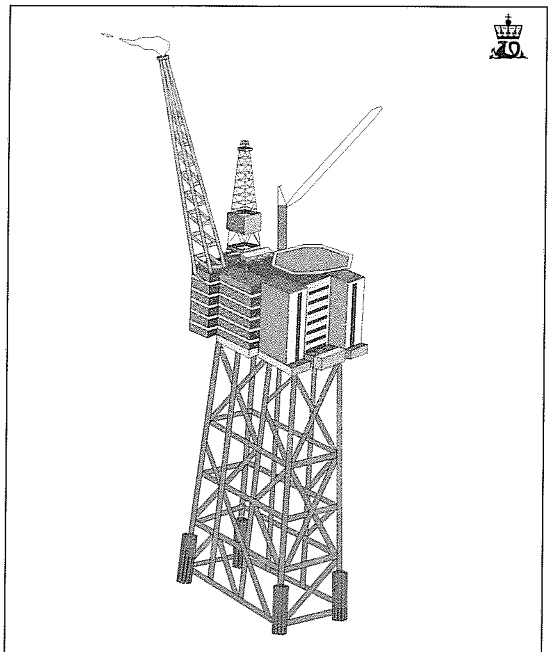
Transportation system

The wellflow will be carried to Gullfaks C for processing. The oil is metered and exported via loading buoys to tanker. The gas is transported via the Statpipe system.

Metering system.

The wellflow from Tordis is separated in a separate one-stage process on Gullfaks C. Oil and gas are metered and analysed, and undergo further treatment in the existing process facility. The metering and analysis results are used to determine the Tordis field's share of the total volume of hydrocarbons delivered from Gullfaks C.

Fig. 2.8.14
Installation on Brage



Costs

At year end 1994, about 3.3 billion 1994-NOK had been invested in Tordis. Total investments over the lifetime of the field are estimated to be about 1994-NOK 3.8 billion. Operating costs for 1994 are estimated to NOK 300 million, including tariffs.

2.8.14 BRAGE

Production licences 053, 055 and 185

Licensees in the unitised Brage field

Den norske stats oljeselskap a.s (Statoil)	46.9567 %
Esso Norge a.s	16.3434 %
Norsk Hydro Produksjon a.s (operator)	22.4182 %
Neste Petroleum a.s	12.2575 %
Saga Petroleum a.s	0.5248 %
Elf Petroleum Norsk a.s	0.6664 %
TOTAL Norge A/S	0.3332 %
Mobil Development Norway a.s	0.4998 %

Field history

The bulk of the Brage field is situated in block 31/4, which was allocated by production licence 055 in 1979, see Figure 2.6.c. The field also extends into block 30/6 (production licence 053), and into the northern part of block 31/7. This section of block 31/7 was in 1991 allocated to the licensees of production licence 055 as production licence 185. The distribution is 92.86 % for 055 and 7.14 % for 053, applicable from 29 September 1993.

With effect from 1 January 1993, 10 % of the equity interests in production licences 055 and 185 were in addition transferred from Statoil and the Norwegian State to Norsk Hydro. The plan for development and operation received approval by the Storting in spring 1990. Brage commenced production in September 1993.

Production

Oil has been proven in two formations providing a basis for development: Statfjord and Fensfjord. In the Sognefjord formation small volumes of oil and gas were proven. This reservoir has not yet been incorporated in the development plans.

Five production wells and one water injection well were pre-drilled. Production takes place from the Statfjord and Fensfjord reservoirs. The field reserves are 46.2 million Sm³ oil.

Production installations

The field is developed with an integrated production, drilling and quarters installation with a steel jacket, see Figure 2.8.14.

Transportation

The oil is transported by pipeline to Oseberg and from there through the Oseberg pipeline to Sture. A gas pipeline is tied to the Statpipe line.

Metering system

Fiscal metering of oil and gas production takes place on the installation..

Costs

At year end 1994, about 9.2 billion 1994-NOK had been invested in the Brage field. Total investment costs from 1990 to 1997 are expected to be about 1994-NOK 10.4 billion. Operating costs for 1994 were approximately NOK 1.2 billion, including tariffs.

2.8.15 STATFJORD AREA

2.8.15.1 Statfjord

Production licence 037

Licensees:

Norwegian share (85.46869 %)	
Mobil Development Norway A/S	12.820304 %
Den norske stats oljeselskap a.s (Statoil) (operator)	42.734348 %
Norske Conoco A/S	9.437169 %
Esso Norge A S	8.546869 %
A/S Norske Shell	8.546869 %
Saga Petroleum a.s	1.602534 %
Amerada Hess Norge A/S	0.890300 %
Enterprise Oil Norwegian A/S	0.890300 %
British share (14.53131 %)	
Conoco North Sea Inc.	4.843769 %
BP Petroleum Development Ltd	4.843769 %
Chevron U.K. Ltd	4.843769 %

Field history

Production licence 037 was allocated in 1973. It covers blocks 33/9 and 33/12, see Figure 2.8.12.a. The Statfjord field extends into the UK sector. The field was proven in spring 1974 and declared commercial the same year. In 1976 the field was approved for development, and it came on stream in 1979. Mobil operated the field until 1 January 1987, when Statoil acquired the operatorship. The Statfjord field is Norway's largest oil field.

The start-up of production from the Dunlin reservoir entailed a change of ownership of 0.23 % in favour of Norway.This change was made applicable as from 1 July 1994. In 1994 Amoco Norway Oil Company also sold its share (1.0420 %) in production licence 037 to Norske Conoco A/S.

Production

The total reserves of oil were adjusted upwards in 1994 and are now estimated at 620 million Sm³ oil. The volume of recoverable associated gas is estimated at 66.6 billion Sm³ dry gas and 18.3 million tonnes NGL. NGL is extracted from the gas at Kårstø. The recovery strategy pursued is based on maximising the production rates and recovery factor by controlling the pressure conditions in the reservoirs. This is achieved by injection of water into the Brent reservoir and injection of gas into the upper part of the Statfjord reservoir. A gas cap has now developed at the top of the Statfjord reservoir, which has resulted in an increase in the gas/oil ratio in many producers in this reservoir. The operator has planned upflank water injection into the upper Statfjord reservoir, and water alternating gas (WAG) injection in the lower part of the Statfjord reservoir. Production from the Dunlin reservoir started in January 1994. This reservoir has a limited volume of resources in comparison with the Brent and Statfjord reservoirs.

In order to achieve better exploitation of the remaining reserves, the operator is continually updating the recovery strategy for the field. The strategy involves both an increase in the number of wells originally planned, plus extensive re-use of the wells in many reservoir zones. Using horizontal wells and long-range high-deviation wells is another element of the strategy.

Horizontal wells have been drilled in both the Brent and Statfjord reservoirs, and long-range high-deviation wells or horizontal wells have been drilled into the geologically more complex eastern and northern parts of the field. Gas injection into the Brent reservoir will be evaluated in 1995.

Production installations

The field has been developed in three phases using three fully integrated platforms, Statfjord A, B and C, see Figure 2.8.15.

Statfjord A

The Statfjord A installation is situated near the centre of the Statfjord field. It is a fully integrated platform with a concrete gravity base consisting of 14 storage cells and three columns. The topsides are of steel. The crude oil processing capacity is currently about 67,000 Sm³ a day split between two production trains. The water treatment capacity is about 31,300 Sm³ per day. The installation started production in November 1979 and has been developed with 25 producers, ten water injectors and four gas injectors. Oil is loaded via one of the three offshore loading systems on the field. The storage capacity for oil on the installation is 175,000 Sm³ .

The Snorre field came on stream in August 1992. Snorre production is received at Statfjord A following second stage separation at Snorre TLP. This means that Statfjord A is now producing close to its maximum processing capacity. In 1994, Statfjord A had an average production of about 26,000 Sm³ of its own oil per day.

Statfjord B

The Statfjord B installation is located in the southern part of the Statfjord field. It is a fully integrated platform with a concrete gravity base, consisting of 24 storage cells and four columns. The topsides are of steel. Production capacity is about 40,000 Sm³ a day from one production train. The Statfjord B water treatment capacity has been upgraded to roughly 40,000 m³ a day. The installation came on stream in November 1982. Statfjord B has been developed with 28 producers, nine water injectors and two gas injectors. In 1994, Statfjord B had an oil production of about 38,000 Sm³ a day. This was achieved by using a test separator as a production separator for limited periods of time.

The installation has an integral crude storage capacity of 302,000 Sm^3.

In the same way as the other installations on Statfjord, Statfjord B delivers gas to Statpipe. In addition, gas is delivered to the UK gas network via the NLGP (Northern Leg Gas Pipeline).

Statfjord C

The Statfjord C installation is situated in the northern part of the Statfjord field. It is a fully integrated installation, structurally identical to Statfjord B. The production capacity is 43,500 Sm^3 through one production train. The water treatment capacity of Statfjord C has been upgraded to approximately 50,000 m^3 in the same way as Statfjord B. Statfjord C came on stream in June 1985 and has been developed with 24 producers, eight water injectors and two gas injectors. The work of preparing Statfjord C to receive production from the Statfjord satellites is ongoing. The Statfjord Øst production started up as a test production 25 September 1994. Statfjord Nord delivered its first oil by means of the test ship Crystal Sea in December 1994 and regular operation via the Statfjord C facilities will start in January 1995. In 1994, Statfjord C had an average oil production of about 38,000 Sm^3 per day.

The Statfjord satellites have a separate inlet separator on Statfjord C with a capacity of around 24,000 Sm^3 oil.

Due to the limited processing capacity on Statfjord C in relation to the well potential and possible production from the Statfjord satellites, it has been planned to upgrade the oil processing capacity to around 52,000 Sm^3 in 1995.

Transportation systems

Gas is transported via the Statpipe pipeline and sold in Emden, while NGL is extracted at Kårstø for sale there. The UK takes off its part of the gas through the NLGP (Northern Leg Gas Pipeline) from Statfjord B to Shell's terminal in St Fergus, Scotland, where the gas is sold.

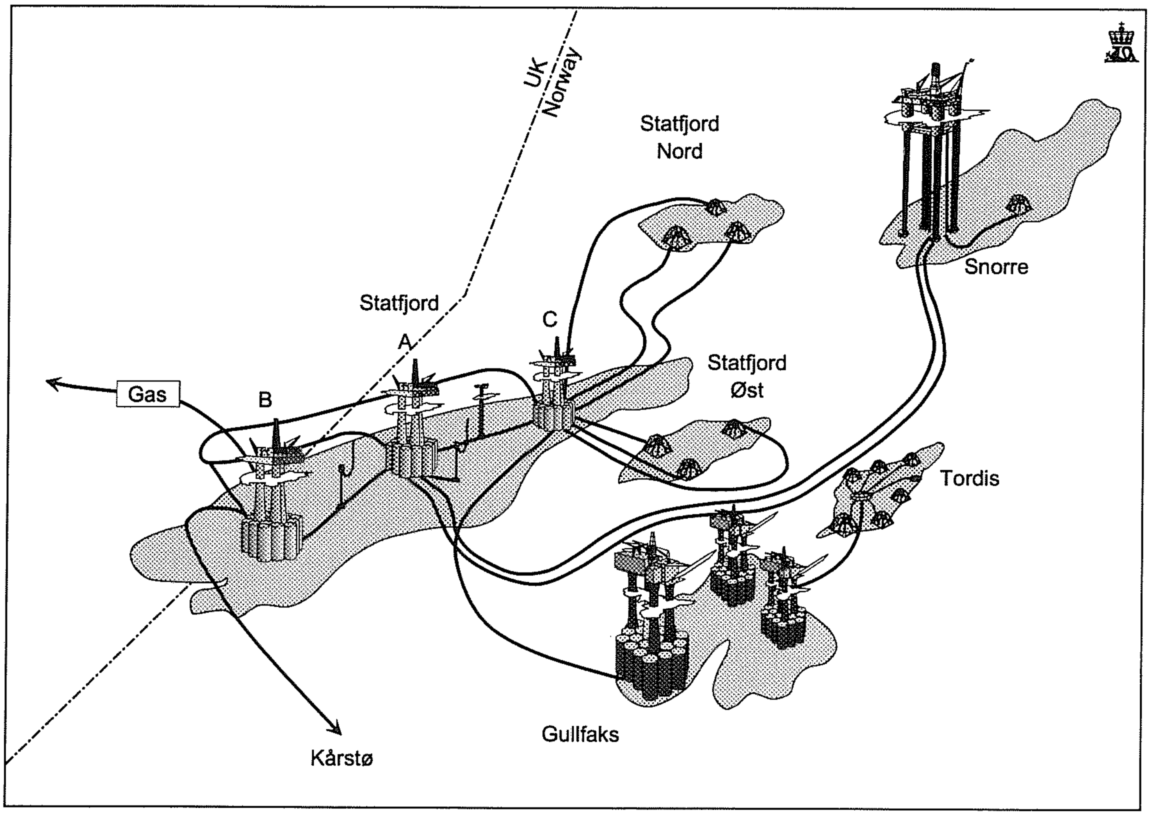
Stabilised oil is stored in storage cells on each installation before being pumped into shuttle tankers via one of the three offshore buoy loading systems on the field.

Metering system

Oil and gas are metered to fiscal standard on each of the three platforms. Since Snorre started producing, Statfjord A's own production has been determined as the difference between the total quantity metered at Statfjord A less the quantity metered at Snorre.

A similar concept is used for metering Statfjord C's production after the Statfjord satellites have started production. The distribution between satellites will be determined by metering at the test separator, while the aggregate volume from satellites will be metered to fiscal standard.

Fig. 2.8.15
Installations and infrastructure in the Statfjord, Gullfaks and Snorre areas



Costs

At year end 1994, about 71 billion 1994-NOK had been invested in the Statfjord field. Total investments are expected to be about 1994-NOK 74 billion from 1974 to 2009. Operating costs in 1994 were approximately NOK 6.5 billion. The increase in operating costs compared with the Annual Report for 1993 is due to changed calculation procedure (in 1994 tariff costs are included).

2.8.15.2 Statfjord Øst

Production licences 037 and 089

Licensees

The sliding scale has been exercised in the licence, and the licensees in the unitised field are:

Den norske stats oljeselskap a.s (Statoil) (operator)	52.7000 %
Esso Norge a.s	10.2500 %
Mobil Development Norway A/S	7.5000 %
Norske Conoco A/S	5.5200 %
A/S Norske Shell	5.0000 %
Idemitsu Petroleum Norge a.s.	4.8000 %
Saga Petroleum a.s	4.4400 %
Norsk Hydro Produksjon a.s	4.2000 %
Elf Petroleum Norge A/S	2.8000 %
Deminex (Norge) A/S	1.4000 %
Amerada Hess Norge a.s	0.5200 %
Enterprise Oil Norwegian A/S	0.5200 %
DNO Olje A/S	0.3500 %

Field history

Statfjord Øst is situated in production licences 037 and 089, see Figure 2.8.12.a. Production licence 037 covers blocks 33/9 and 33/12 which were allocated in 1973. Production licence 089 covers block 34/7 which was allocated in 1984. Plan for development and operation of Statfjord Øst was approved by Royal Decree in November 1990.

A unitisation agreement for Statfjord Øst was signed in June 1991 and distributes the reserves 50/50 on each of the two production licences 037 and 089. Statfjord Øst came on stream in October 1994 and production is expected to continue until the year 2007. In 1994, Amoco Norway A/S sold its share (1.0420 %) in production licence 037 to Norske Conoco A/S.

Production

The oil reserves are estimated at 19.4 million Sm^3 and the gas reserves are estimated at 2.4 billion Sm^3.

Results from production wells drilled in the autumn 1993 show that the reservoir rock volume is larger than assumed earlier.

Production installations/transportation

The field has been developed with subsea installations connected to the Statfjord C platform. The subsea installations consist of three templates: two for production and one for water injection. The well flow, which comprises oil, gas and water, will be carried in two pipelines to Statford C for processing, storage and export. The plan is to drain the fields using six production wells and four water injection wells.

Metering system

The Statfjord satellites are metered to fiscal standard by a common metering system on Statfjord C. Return allocation to the individual satellite is done on the basis of test separator metering.

Costs

At year end 1994, about 3.4 billion 1994-NOK had been invested in Statfjord Øst. Total investments are expected to be about 1994-NOK 3.6 billion from 1990 to 2008. Operating costs in 1994 were approximately NOK 105 million, including tariffs.

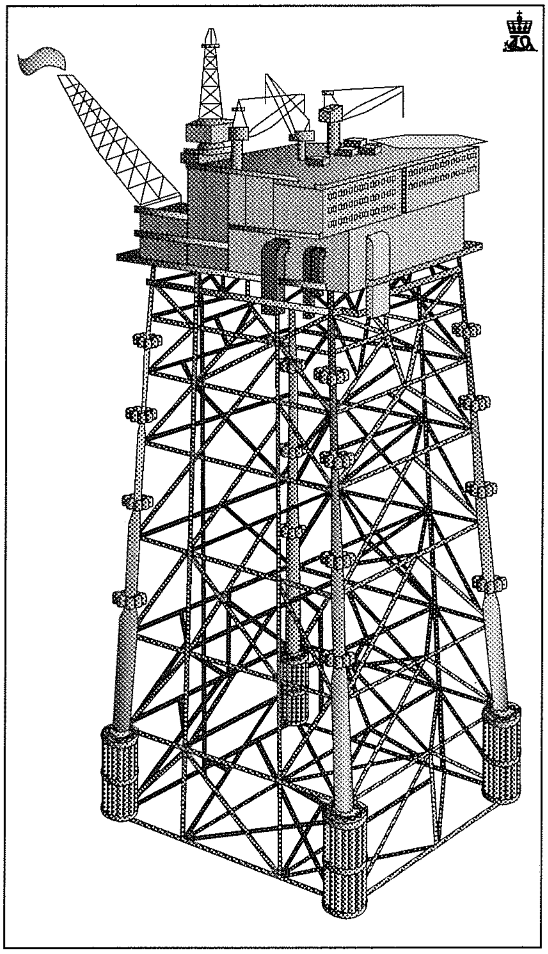
2.8.16 MURCHISON

Production licence 037

Licensees:

British share (77.8 %)	
Conoco (UK) Ltd (operator)	-
Oryx UK Energy Company	51.8667 %
Chevron UK Ltd	25.9333 %

Fig. 2.8.16
Installation on Murchison



Norwegian share (22.2%)	
Den norske stats oljeselskap a.s (Statoil)	11.1000%
Mobil Exploration Norway Inc	3.3300 %
Norske Conoco A/S	2.4513 %
Esso Norge a.s	2.2200 %
A/S Norske Shell	2.2200 %
Saga Petroleum a.s	0.4162 %
Amerada Hess Norge A/S	0.2313 %
Enterprise Oil Norwegian A/S	0.2313 %

Field history

The field was proven in August 1975 and is situated in block 211/19 in the British sector and block 33/9 in the Norwegian sector, see Figure 2.8.12.a. The Norwegian share is 22.2 %. The development of the Murchison field was initiated in 1976 by the UK licensees. In 1979, the British and Norwegian licensees entered into an agreement for joint exploitation of the Murchison field. Production started in 1980.

Effective from 1 July 1994, the Conoco (UK) share (25.9334 %) has been taken over by Oryx UK. Oryx has applied to take over as operator of the field as from January 1995. The licensees have approved the change of operator. The change of operator must be approved by British and Norwegian authorities. Effective from 1 September 1994, Norske Conoco has taken over Amoco Norway's share (0.2313 %).

Production

The reserves for the field as a whole are 54 million Sm³ oil and 1.5 billion Sm³ gas in the Brent group. The field has been producing at almost maximum fluid processing capacity since 1981, and the water treatment capacity has been increased several times. 1984 was the last year of plateau production. All the production wells are now producing with a high cut of water. Gas lift is used in some wells. Several production wells are closed down due to mechanical problems or very high water production.

Production installations

The field has been developed with an integrated steel jacket structure with a production capacity of 26,200 Sm³ oil a day, see Figure 2.8.16. Present production from this field is around 3000 Sm³ oil per day.

Transportation

The Norwegian part of the gas is landed via the NLGP (Northern Leg Gas Pipeline) to the Brent field in the UK sector, and then on to St. Fergus in Scotland via the FLAGS (Far North Liquified and Associated Gas Gathering System). Gas deliveries through NLGP started in July 1983. The Murchison crude is carried by pipeline to Sullom Voe in the Shetland Isles.

Metering system

Produced oil and gas are metered to fiscal standard on the installation.

Costs

At year end 1994, just short of 4.9 billion 1994-NOK had been invested. Total investments for the Murchison field up to the year 2001 are expected to be about 1994-NOK 4.9 billion. Operating costs in 1994 were approximately NOK 270 million, including tariffs. These figures refer to the Norwegian share (22.2 %).

2.8.17 SNORRE

Production licences 057 and 089

Licensees in the unitised Snorre field

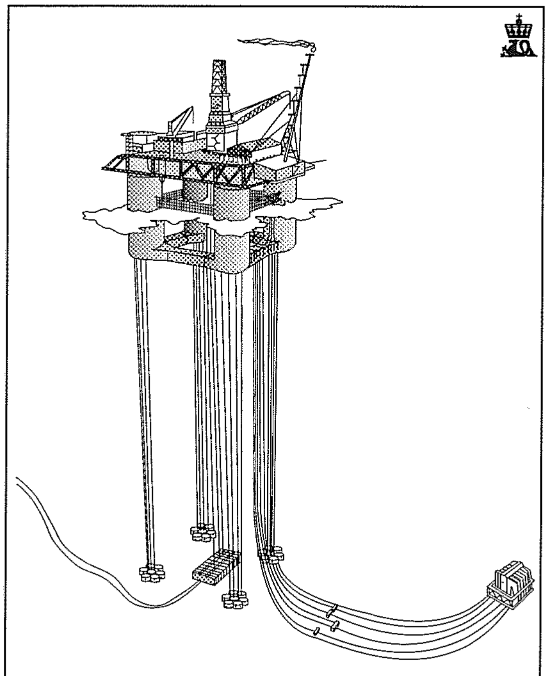
Den norske stats olieselskap a.s (Statoil)	41.4000 %
Saga Petroleum a.s (operator)	11.2559 %
Esso Norge a.s	10.3323 %
Deminex (Norge) A/S	10.0348 %
Idemitsu Petroleum Norge a.s.	9.6000 %
Norsk Hydro Produksjon a.s	8.2658 %
Elf Petroleum Norge A/S	5.5106 %
Amerada Hess Norge A/S	1.4559 %
Enterprise Oil Norwegian A/S	1.4559 %
DNO Olje A/S	0.6888 %

Field history

The Snorre field is situated in blocks 34/4 and 34/7. Block 34/4 was allocated under production licence 057 in 1979. Block 34/7 was granted under production licence 089 in 1984. The ownership is unitised according to an assessed distribution of the reserves of 30 % in block 34/4 and 70 % in block 34/7, respectively. The plan for development and operation of Snorre was approved by the Storting in 1988. Production was commenced in August 1992.

An revised plan for development and operation, comprising development of the upper part of the Lunde for-

Fig. 2.8.17
Installations on Snorre



mation, upgrading of the processing capacity of Snorre and increased use of gas injection in the reservoir, was approved in 1994.

Production

The Snorre field consists of several large fault segments which are not believed to be in general communication with each other. The reservoir rocks are fluvial sandstones in the Statfjord formation (Lower Jurassic) and in the Lunde formation (Upper Triassic). The reservoir intervals vary from broad, continuous channel belts where reservoir communication is good, to more narrow isolated channel belts where communication is poorer.

The reserves estimates for Snorre were adjusted upwards in 1994 to 173 million Sm³ oil, based on production until the year 2021. The reserves from the upper part of the Lunde formation constitute in excess of 30 million Sm³ and are planned to be produced using water injection as driving mechanism. Use of horizontal and high-deviation wells drilled from the installation is part of the strategy. Regular production from the Lunde formation starts in January 1995.

Water alternating gas injection (WAG) is expected to produce improved oil recovery on Snorre, and the operator is planning to use this driving mechanism for the whole Statfjord formation. A pilot project for WAG has been initiated for collection of data.

Production installations

The water depth over the Snorre field varies from 300 meters in the south to 370 meters in the north. In the plan the field will be developed in two phases. Phase 1 consists of a floating Tension Leg Platform in the south and subsea completed wells in the central part of the field, see Figure 2.8.17. Oil and gas are separated in two stages at Snorre before being transported onwards in separate oil and a gas pipelines to Statfjord A for further processing.

Increased reserves basis and increased need for gas injection have resulted in a decision to upgrade the process facility on Snorre. This includes an increase of the capacity for oil treatment and gas injection to 39,000 Sm³ and 5 million Sm³ per day, respectively. This upgrading is to be completed before 1997. In addition, the process facility on Snorre is to be upgraded in connection with phase-in of Vigdis.

Phase 2 of the development involves depletion of the northern part of the field. Final decision regarding development of phase 2 has not yet been taken.

Transportation

Snorre crude will be sold via a loading system on Statfjord A. The gas will be transported through the Statpipe system via Statfjord A. In 1997 a separate pipeline from Snorre to Gullfaks A is to be installed for transport of stabilised oil from Vigdis.

Metering system

Oil and gas are metered to fiscal standard on the Snorre platform.

Costs

At year end 1994, about 24 billion 1994-NOK had been invested in Snorre. Total investments for the development of Snorre Phase 1, including the upgrading of the process capacity and production from the Lunde formation, are estimatod at NOK 29 billion. Development of the northern part of Snorre with subsea completed wells will represent an addition to this, estimated at 4 billion 1994-NOK. Operating costs in 1994 are estimated at NOK 2.5 billion, including tariffs.

2.8.18 DRAUGEN

Production licence 093

Licensees

Den norske stats oljeselskap a.s (Statoil)	65.0000 %
A/S Norske Shell (operator)	21.0000 %
BP Norway Limited U.A	14.0000 %

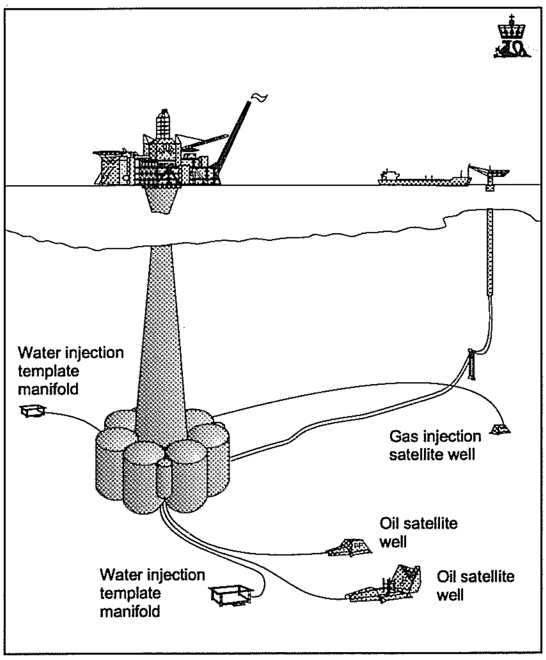
Field history

The Draugen field is situated in block 6407/9, see Figure 2.6.d. Production licence 093 was allocated in 1984 and the field was proven the same year. The field was declared commercial in September 1987. Plan for development and operation was approved by the Storting in December 1988. Oil production from the Draugen field started in October 1993.

Production

Reserves are estimated to 92 million Sm³ oil. The field will produce until the year 2021 by means of water injection as driving mechanism.

Fig. 2.8.18
Installations on Draugen



The main reservoir consists of Late Jurassic sandstone. In the western part of the field, some of the Middle Jurassic sandstone sequence is also oil-bearing. A shale stratum of varying thickness separates the underlying and mainly water-bearing Middle Jurassic sandstones from the main reservoir. In the western and northern parts of the field this layer of shale is thin and possibly absent in some places. This fact, and a number of minor faults in the field, raise concerns about early water production in some oil wells.

The associated gas is reinjected into a nearby, water-carrying structure. Recoverable resources for the associated gas are 4.4 billion Sm³ .

Production installations

The field was developed with a concrete gravity base platform with integrated topsides; see Figure 2.8.18. The installation has ten well slots and a total of 34 J pipes.

The main reservoir will be produced using six production wells. The field is currently producing from five production wells. Two of the production wells are subsea completed. Drilling of the sixth well has been indefinitely postponed. The Middle Jurassic reservoir is planned to start production in 1998 through the seventh well that is drilled from the installation.

Pressure support for the production will be by means of five subsea completed water injection wells. After a number of delays water injection on the field was commenced in September 1994 following the installation of a filter system for injection water. At year end 1994 the volume of water injection was not yet adequate to provide full pressure support.

The gas injection, which takes place via one well, has until now been virtually without interruption since start-up in 1993.

From August 1994 until year end, oil production from Draugen has been stable and high. Upgrading of the production capacity on Draugen is being considered.

Transportation

Stabilised crude is stored in integrated storage tanks. The oil is exported via a floating loading platform (FLP) to a tanker.

Metering system

A fiscal metering station has been installed on Draugen.

Costs

At year end 1994, about 13.9 billion 1994-NOK had been invested in the Draugen field. Total investments are estimated to 1994-NOK 15.4 billion from 1988 to 2021. Operating costs in 1994 were approximately NOK 740 million, including tariffs.

2.9 FIELDS WHERE PRODUCTION HAS CEASED

2.9.1 MIME

Production licence 070

Licensees

Den norske stats oljeselskap a.s (Statoil)	51.0000%
Norsk Hydro Produksjon a.s (operator)	24.5000 %
Amoco Norway Oil Company	14.7000 %
Saga Petroleum a.s	9.8000 %

Field history

Mime is a small oil field seven kilometers north of Cod, in block 7/11.

The field was discovered in 1982. Production started as test production in October 1990. The plan for development and operation of the field was approved by the Storting in November 1992. In November 1993 production from Mime was temporarily suspended due to the precipitation of asphaltenes in the well. In November 1994 the well was finally plugged, as recompletion was not a commercial proposition. The reservoir consists of Upper Jurassic sandstone in the Ula formation. Mime was produced from one well, centrally located on the structure. The production took place via a subsea completed well with connection to the Cod installation.

Total production for the field was 0.4 million Sm³ oil. This corresponds to a recovery factor of about 4 % of originally in-place oil.

Costs

Total investment costs for the field are 1994-NOK 360 million. Operating costs in 1994 were NOK 36 billion, of which 32 million were connected with well work, primarily plugging of the well.

2.9.2 NORDØST FRIGG

Production licence 024 (block 25/1)

Licensees in the unitised Nordøst Frigg field

Elf Petroleum Norge A/S (operator)	41.4200 %
Norsk Hydro Produksjon a.s	32.8700 %
TOTAL Norge A/S	20.7100 %
Den norske stats oljeselskap a.s (Statoil)	5.0000 %

Poduction licence 030 (block 30/10)

Esso Norge a.s	100 %

Field history

Nordøst Frigg is located in blocks 25/1 and 30/10, see Figure 2.8.9.a, and a redistribution of the gas reserves in August 1984 assigned 42 % and 58 % repectively to each of the blocks.

The field was proven in 1974. The final development plan was adopted in 1980, and the field came on stream in December 1983. Production from the field ceased 8 May 1993.

The reservoir belongs to the same sedimentation system as the Frigg field. Pressure measurements made before production start-up showed that the reservoir communicates with the Frigg field via the underlying aquifer.

The total volume produced gas from Nordøst Frigg was 11.4 billion Sm³ . This corresponds to a recovery factor of about 57 %. The field was developed with six wells drilled through a subsea template. The wells were connected to a control station, consisting of a steel column and a deck with various equipment. The control station was not permanently manned, but remotely controlled from Frigg.

Costs

Total investment costs for the field for the period from 1982 to 1993 were 1994-NOK 3.2 billion. Operating costs in 1994 were approximately NOK 10 million, including tariffs.

Cessation plan

Plan for future disposal of the installation on Nordøst Frigg was submitted to the authorities 30 August 1991, and a decision is envisaged in spring 1995.

2.9.3 ODIN

Production licence 030

Licensees

Esso Norge a.s 100%

Field history

The Odin field lies in block 30/10; see Figure 2.8.9.a. This gas field was proven in 1974 and the field development plan approved by the Storting in 1980. Production from the field started in April 1984 and ceased 1 August 1994.

The field produced from the same sedimentation system as the Frigg field. Pressure readings taken before production start-up showed that the Odin field communicates with Frigg through the underlying aquifer. The Odin reservoir is losing pressure faster than the other Frigg area fields due to its very limited aqua-drive.

In spring 1990, water breakthrough was detected in the southernmost well of the field. This was expected, but it occurred earlier than anticipated. New studies indicated that the residual reserves were less than assumed and the lifetime of the field was reduced.

The total volume produced from the field was 26.6 billion Sm^3 gas. This corresponds to a recovery factor of about 71 %.

The field was developed using a small steel jacket structure with simplified processing and drilling facilities and comparatively small living quarters.

Water was separated from the gas on the Odin installation and methanol injected for hydrate control purposes. The gas was then sent by pipeline to the TCP2 platform on Frigg for further processing before delivery through the Norwegian pipeline to St Fergus.

Costs

Total investment costs for the field during the period from 1978 to 1994 are estimated to approximately 1994-NOK 4.6 billion. Operating costs in 1994 were approximately NOK 630 million, including tariffs.

Cessation plan

Plan for future disposal of the installation is expected to be submitted to the authorities in 1995.

2.10 TRANSPORTATION SYSTEMS FOR OIL AND GAS

2.10.1 EXISTING TRANSPORTATION SYSTEMS

There are four landing pipelines for oil/condensate and four for gas from the Norwegian continental shelf to shore. A sketch of the transport systems for oil/condensate and gas covering the Norwegian sector of the North Sea is shown in Figure 2.10. The UK share of gas from Statfjord is carried via the NLGP to Shell's terminal in St Fergus. The oil pipeline from the Ekofisk area runs to Teesside in the UK. Oil from Oseberg, Brage and Veslefrikk is transported to the Sture terminal at Øygarden.

Oil and condensate from Lille-Frigg is transported via a separate pipeline to Oseberg. Condensate from Heimdal is taken via the UK Brae and Forties systems to the BP operated Kinneil terminal outside Edinburgh. This pipeline mainly transports British oil and condensate. Condensate from Sleipner is transported to Kårstø. The Statpipe and Norpipe gas pipelines were tied together in 1985 and both lead to Emden in Germany. Gas from Frigg is piped to Total' s terminal at St Fergus in Scotland. The Zeepipe gas pipeline ends up in Zeebrügge in Belgium. As of yet only Zeepipe phase 1, which is the pipeline running south from Sleipner, has entered service.

Gas transportation, Statpipe

Ownership structure:

Den norske stats oljeselskap a.s (Statoil)	58.2500 %
Elf Petroleum Norge A/S	10.0000 %
Norsk Hydro Produksjon a.s	8.0000 %
Mobil Development Norway A S	7.0000 %
Esso Exploration and Production Norway A/S	5.0000 %
A/S Norske Shell	5.0000 %
Norske Conoco A/S	2.7500 %
Saga Petroleum a.s	2.0000 %
TOTAL Norge A/S	2.0000 %

Statoil is the operator of the system which comprises:

- wet gas pipeline from Statfjord to Kårstø
- separation and fractioning plant at Kårstø, plus storage and loading facility
- dry gas pipeline from Heimdal, dry gas pipeline from Kårstø to riser platform in block 16/11, and pipeline from this installation to the 2/4-S riser platform at the Ekofisk field centre.

After production start-up, the Gullfaks, Veslefikk, Snorre and Brage fields were tied in to the Statpipe system upstream of the Kårstø facility.

Kårstø

The first North Sea gas was landed to Kårstø in March 1985. Delivery of dry gas from the terminal started in October 1985. The transport capacity from Statfjord to Kårstø is 25 million Sm^3 per day. This capacity will be fully exploited in 1995-1996. In order to process and forward this volume of gas the Kårstø terminal is being modified, including the laying of a bypass line from the wet gas side to the dry gas side of the plant. The gas transport compressors at Kårstø have been upgraded to cope with the changed transportation requirements after the tie-in of Statpipe and Zeepipe.

In connection with the Sleipner field development, a new facility for treatment of the condensate piped from Sleipner to Kårstø has been built at Kårstø. Propane and butanes will be separated from the condensate and stored in common tanks with LPG products from Statpipe. The processed condensate is stored in separate tanks pending shipment from the terminal.

Metering system

Metering of the gas delivered from the Kårstø termmal is undertaken in compliance with the current rules and regulations for gas metering.

Metering of propane, butanes and naphtha is carried out based on a dynamic metering system. A new loading jetty with associated dynamic metering station has been erected for Sleipner condensate.

Gas transportation, Norpipe

The pipeline transportation system for natural gas from the Ekofisk field centre to Emden in Germany is owned by Norpipe A/S. Gas from the Ekofisk area and Statpipe is delivered to Norpipe. Norpipe A/S is a limited company owned 50 % by Statoil and 50 % by the Phillips Group. Phillips Petroleum Company Norway is the technical operator of the pipeline, while Statoil looks after the economic and administrative functions.

A bypass line from Statpipe to Norpipe avoiding the Ekofisk field centre is planned in connection with the building of Ekofisk II.

The gas pipeline is 442 km long and has an inside diameter of 869 mm (outside diameter 36"). The gas pipeline is divided into 3 by two compressor stations both located on the German continental shelf.

Design capacity for the gas pipeline is approximately 59.3 million Sm^3 per day. Gas sales vary from about 40 million Sm^3 per day in summer to about 54 million Sm^3 per day in the winter.

Emden

Ownership structure:

Phillips Petroleum Company Norway	36.960 %
Norske Fina A/S	30.000 %
Norske Agip A/S	13.040 %
Elf Petroleum A/S	7.096 %
Norsk Hydro Produksjon a.s.	6.700 %
TOTAL Norge A/S	3.047 %
Den norske stats oljeselskap a.s (Statoil)	2.000 %
Elf Rex Norge A/S	0.855 %
Norminol A/S	0.304 %

Phillips Petroleum Norsk A/S is the operator on behalf of the Phillips group. Work to connect Europipe and Norpipe in Germany was in progress in 1994.

Etzel gas terminal

Ownership structure:

Ruhrgas	70.00000 %
Den norske stats oljeselskap a.s (Statoil)	20.10000 %
A/S Norske Shell	2.40000 %
Esso Norge a.s	2.40000 %
Norsk Hydro Produksjon a.s	2.40000 %
Saga Petroleum a.s	1.20000 %
Elf Petroleum Norge A/S	0.68955 %
Norske Conoco A/S	0.42090 %
TOTAL Norge A/S	0.38955 %

The German gas distribution company Ruhrgas came in heavily on the ownership side in 1994 in the Etzel terminal.

Work to tie the Etzel gas terminal in with Europipe was in progress in 1994.

The existing Etzel gas metering station has in 1994 been upgraded to enable the metering both of the gas transported between Europipe and Norpipe and gas to and from the Etzel gas terminal. This work will be completed in 1995.

The direct metering of volumes to and from the terminal will now be carried out by a new metering station at the Etzel terminal.

Gas transportation Frigg

The Norwegian Frigg pipeline is owned by the Norwegian Frigg licensees. The ownership interests are:

Norsk Hydro Produksjon a.s	32.8700 %
Elf Petroleum Norge A/S	26.4200 %
Den norske stats oljeselskap a.s (Statoil)	24.0000 %
TOTAL Norge A/S (operator)	16.7100 %

The installation MCP-01 is a compressor station, midway between Frigg and St Fergus. It is owned 50 % by Norwegian interests. The compressors have now been removed and the installation is unmanned. Some UK fields are connected to the Norwegian Frigg pipeline via the MCP-01.

As long as the installation was manned, their volumes were determined by metering on MCP-01. Since the installation has been unmanned, the volumes from the British fields are metered on the individual installations.

St Fergus

This terminal is owned by the Norwegian Frigg licensees and UK Frigg licensees (Elf UK 66.2/3 % and Total UK 33.1/3 %). The various processing modules on the terminal are owned either by one partner group or by both. Total Oil Marine UK is the operator.

Oil transportation Norpipe A/S

The pipeline system for transportation of oil from the Ekofisk field centre to Teesside in the UK is owned by Norpipe A S. Oil from the fields in the Ekofisk area, and from the nearby fields Valhall, Hod, Ula, Gyda and

Tommeliten Gamma, is delivered to Norpipe. There is also an agreement to transport oil from the British Judy and Joanne fields. Installation of a Y piece on the pipeline enables connection of oil pipes from the J block and possible other British fields.

Norpipe A/S is a limited company owned 50 % each by Statoil and the Phillips Group. Phillips Petroleum Company Norway is the technical operator of the pipeline, while Statoil looks after the economic and administrative functions.

Teesside

Ownership of the Teesside terminal facilities is split between Norpipe A/S and the Phillips Group through Norpipe Petroleum UK Ltd and Norsea Pipeline Ltd. The operator is Phillips Petroleum Company UK Ltd.

Oil transportation Oseberg

A pipeline for transportation of stabilised oil from Oseberg to the Sture terminal was laid in summer 1987. The pipeline has an inside diameter of 670 mm (outside diameter 28") and a capacity of 95,000 Sm^3 per day. However, by adding drag reducers it is possible to increase the capacity to about 115,000 Sm^3 a day. The greatest water depth for the pipeline is about 350 meters.

The plant, including the Sture terminal, is owned and operated by a joint venture, I/S Oseberg Transport System (OTS). Partners in this venture are the Oseberg field licensees. Norsk Hydro is the operator of the pipeline and the terminal. The Oseberg Transport System (OTS) entered service when Oseberg came on stream. Veslefrikk and Lille-Frigg are later connected to the OTS.

Oseberg Transport System comprises the following main elements:

- pipeline equipment on Oseberg A
- pipeline to shore
- onshore pipeline
- terminal.

Zeepipe

Ownership structure:

Den norske stats oljeselskap a.s (Statoil)	70.0000 %
Norsk Hydro Produksjon a.s	8.0000 %
A/S Norske Shell	7.0000 %
Esso Norge a.s	6.0000 %
Elf Petroleum Norge A/S	3.2985 %
Saga Petroleum a.s	3.0000 %
Norske Conoco A/S	1.7015 %
TOTAL Norge A/S	1.0000 %

Zeepipe is a gas transportation system which will carry gas from Kollsnes in Øygarden to the Continent. Phase I of the project comprises a pipeline approximately 800 km long with an inside diameter of 966 mm, (outside diamter 40") from Sleipner to Zeebrügge in Belgium and a pipeline approximately 40 km long with an inside diameter of 725 mm, (outside diamter 30") from Sleipner to the 16/11-S riser platform. Phase 1, including the terminal in Zeebrügge, was completed in 1993. Capacity without compression will be 13 billion Sm^3 gas a year.

Frostpipe

Ownership structure:

Den norske stats oljeselskap a.s (Statoil)	50.0000 %
Elf Petroleum Norge A/S (operator)	22.0000 %
TOTAL Norge A.S	14.2500 %
Norsk Hydro Produksjon a.s	13.7500 %

Development

Frostpipe is a pipeline roughly 80 kilometers in length with an inside diameter of 374 mm (outside diameter 16"), for transportation of stabilised crude and condensate from Frigg to Oseberg. The transport system has a capacity of 16,000 Sm^3 per day. The plan for construction and operation was approved by the Royal Decree in April 1992. The transportation system is primarily built to carry fluids from Lille-Frigg and Frøy and it came into service at production start-up of Lille-Frigg in spring 1994.

2.10.2 PROJECTED TRANSPORTATION SYSTEMS

Zeepipe

Ownership structure:

Den norske stats oljeselskap a.s (Statoil)	70.0000 %
Norsk Hydro Produksjon a.s	8.0000 %
A/S Norske Shell	7.0000 %
Esso Norge a.s	6.0000 %
Saga Petroleum a.s	3.0000 %
Elf Petroleum Norge A/S	3.2985 %
TOTAL Norge A/S	1.0000 %
Norske Conoco A/S	1.7015 %

Further development by Phases II-A, II-B and IV is planned for the Zeepipe transport system for gas from Troll and Sleipner.

Development of phase II-A has been approved. This phase involves a pipeline about 300 kilometers long with inside diameter 966 mm (outside diameter 40") from Kollsnes to Sleipner. The plan calls for the pipeline to enter service in 1996.

Development of phase II-B has been approved. A plan for construction and operation for phase II-B was submitted to the authorities in autumn 1994. This phase will include a pipeline from Kollsnes to the new marine riser platform 16/11-E. The pipeline will have an inside diameter of 966 mm (outside diameter 40"). The pipeline is planned to come into service in autumn 1997.

Phase IV is currently under preparation. A plan for construction and operation of phase IV is to be submitted in February 1995. Several alternative concepts are being considered. Possible starting point is 16/11 and Sleipner with possible terminus in Emden (Germany), Zeebrugge (Belgium) or Dunkerque (France). The plan is for phase IV to enter service in autumn 1998.

Europipe

Ownership structure:

Den norske stats oljeselskap a.s (Statoil)	70.0000 %
Norsk Hydro Produksjon a.s	8.0000 %
A/S Norske Shell	7.0000 %
Esso Norge a.s	6.0000 %
Saga Petroleum a.s	3.0000 %
Elf Petroleum Norge A S	3.2985 %
TOTAL Norge A/S	1.0000 %
Norske Conoco A/S	1.7015 %

Europipe comprises a third pipeline to the Continent. The work of building the roughly 600 kilometer long pipeline with an inside diameter of 966 mm (outside diameter 40 ") is well underway. The pipeline starts from the new riser platform 16/11-E and will end up in Emden in Germany. The system will be able to accommodate compression units between 16/11-E and Emden. Without compression, the capacity will be about 13 billion Sm^3 gas a year. With compression the capacity can be lifted to about 18 billion Sm^3 gas a year. Problems associated with approval of the landing site in Germany have led to delays for parts of the facility. Development is now according to plan and it is expected that the pipeline system will be operational from autumn 1995.

Troll

Ownership structure:

Den norske stats oljeselskap a.s (Statoil)	74.57600 %
A/S Norske Shell	8.28800 %
Norsk Hydro Produksjon a.s	7.68800 %
Saga Petroleum A/S	4.08000 %
Elf Petroleum Norge A/S	2.35344 %
Norske Conoco A/S	1.66113 %
TOTAL Norge A/S	1.35343 %

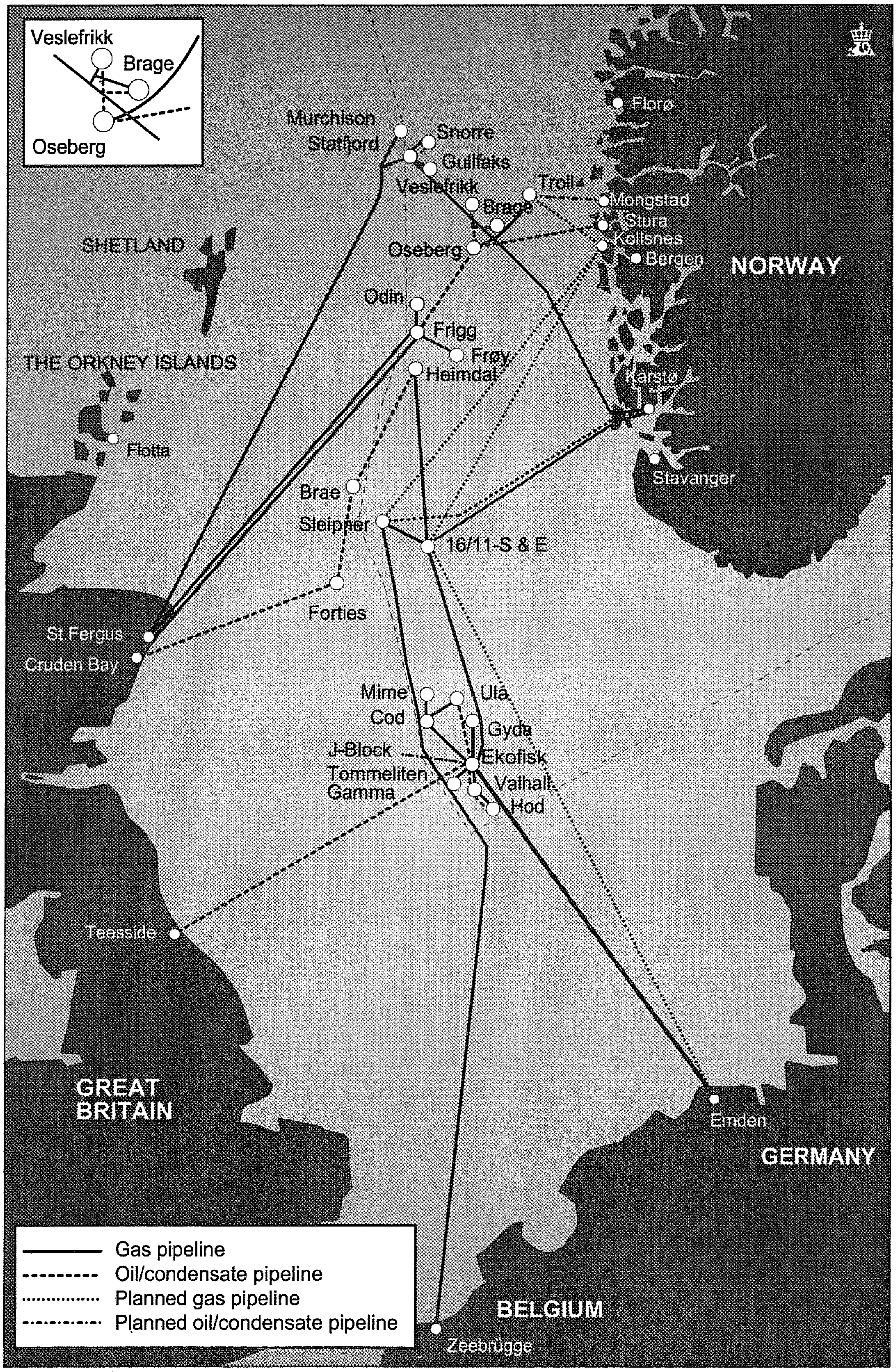
Landing Troll oil

When the Storting approved the plan for development and operation of Troll phase II in May 1992, the transport solution for the oil from the field had not been clarified. In autumn 1992, the licensees decided to land the oil from Troll B to Mongstad. The development and operation of the transport system is carried out by a Statoil operated partnership. All the licensees in the Troll field are represented in this partnership. The plan for construction and operation (PCO) of Troll Oljerør was approved by the authorities in December 1993. According to the PCO, Troll Oljerør will have capacity to transport oil from Troll Vest oil and gas province, and be ready to receive and transport oil from Troll B 1 January 1996.

According to the licensees' current plans, Troll Oljerør is expected to be able to receive oil from Troll B for transport to Mongstad during 4th quarter of 1995.

At the year end 1994, a total of about 1994-NOK 340 million had been invested in the Troll Oljerør pipeline. Total investments are expected to be approximately 1994-NOK 970 million from 1993 to and including 1996.

Fig. 2.10
Transportation systems for oil and gas from Norwegian North Sea fields



2.11 FINAL PRODUCTION AND DISPOSAL OF INSTALLATIONS

The question to what extent a coastal state should be ordered to remove its installations from the continental shelf once their useful life has finally expired is of great importance to Norway. Removal of installations on the Norwegian continental shelf will with few exceptions be considerably more expensive and technically complex than in other parts of the world. At present, Norway has about 70 installations, either producing petroleum, under planning or under construction. Several possible solutions exist for disused installations; see Figure 2.11.

The cost of complete removal of all installations is estimated to roughly NOK 50 billion (including shutdown costs). A high degree of uncertainty is attached to this figure. Under the legislation for removal of installations the State has to bear a considerable proportion of the costs of removal.

In autumn 1989, the International Maritime Organization (IMO) adopted international guidelines for removal of installations on the continental shelf.

The main points of the IMO guidelines are:

- All installations whose use is finally over and which are at a sea depth of less than 75 meters and have a base (jacket) weighing less than 4,000 tonnes shall be removed.

- All installations deployed after 1 January 1998 whose use is finally over and which are at a sea depth of less than 100 meters and have a base (jacket) weighing less than 4,000 tonnes shall be removed.

- For other installations the question of removal will be determined on the basis of the individual coastal state's evaluation in each case. Said evaluation shall weigh considerations of safety at sea, other users of the sea, environmental impact and living resources, the costs and safety hazards of removal. Alternative uses and other reasonable grounds to allow the installation to remain wholly or partially in place must at the same time be considered.

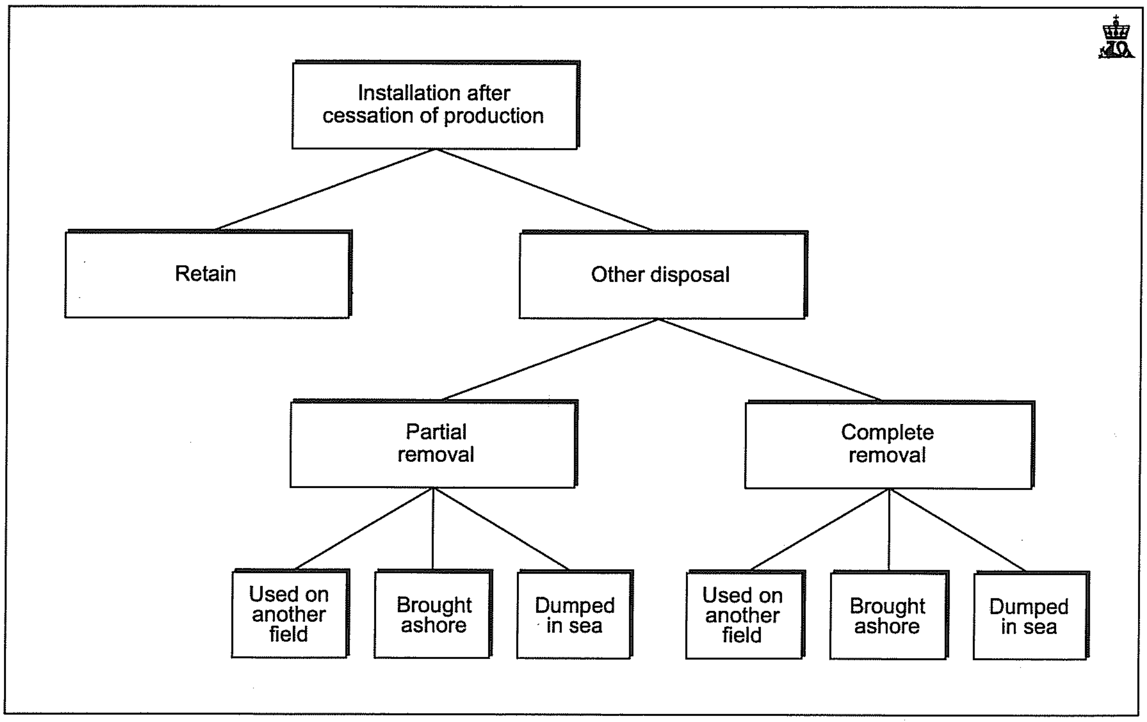
- Should a coastal state determine that an installation shall be removed to below the sea surface, a free height of minimum 55 meters of water shall be left below the sea surface.

- Should a coastal state determine that an installation shall remain wholly or partially in place such that it protrudes above the sea surface, then adequate maintenance shall be carried out to prevent disintegration of the installation.

- After 1 January 1998 no installations shall be emplaced which it is technically impossible to remove.

The adopted IMO rules are issued in the form of guidelines. Consequently they will not be legally binding on the states involved. On the other hand, the rules will have considerable moral force and it would be politically difficult for states to ignore them.

Fig. 2.11
Alternative disposal of disused installations



At the request of the Ministry of Industry and Energy, the Petroleum Act Committee prepared a draft set of rules for disposal of installations on the Norwegian continental shelf. The Committee's recommendation was given in Norwegian Public Report NOU 1993: 25: "Termination of petroleum production - future disposal of installations" submitted to the Minister in June 1993.

The Committee suggests amendments in the form of a new chapter in the Petroleum Act. The new provisions are in part a continuation of current rules and in part they constitute new regimes.

The introduction of a cessation plan will constitute the most important decision basis for the authorities when the time comes to decide on the disposal of offshore installations. The cessation plan shall embrace the licensee's proposed disposal of installations once the licence has expired or they are no longer in use.

The preparation of a cessation plan within specified time limits means that the issue has to be considered ahead of time, allowing a decision on disposal of the installations to be made reasonably in advance of production shutdown or expiration of the licence.

2.12. PETROLEUM RESOURCES

2.12.1 RESOURCE ACCOUNTING

The Norwegian Petroleum Directorate's resource account is a summary of the originally marketable and the remaining petroleum quantities on the Norwegian continental shelf. Changes in the resource account result from new discoveries, and from adjustments in resource estimates for existing fields and discoveries, due to new mapping or new recovery technology, or a combination of both factors. The remaining reserves are also reduced as a result of production.

Classification system

The Norwegian Petroleum Directorate has in 1994 re-

Fig. 2.12.1.a
The resource account for the Norwegian continental shelf

		OIL (10^6 Sm^3)	GAS (10^9 Sm^3)	NGL (10^6 tons)	SUM (10^6 Sm^3 o.e.)
3 fields where production has ceased		0	39	0	39
31 fields in production (original reserves)	Present plan	2258	717	89	3090
	Impr. recovery	414			414
8 fields decided to be developed	Present plan	237	1016	54	1323
	Impr. recovery	87			87
22 discoveries with firm development plans		395	853	62	1328
54 discoveries without firm development plans		140	490	28	665
16 discoveries in relinquished areas		11	110		121
42 new discoveries and small techn. discoveries		80	70		150
Sum discoveries and fields		3621	3294	233	7217
Undiscovered resources		1435	2090		3525
Sold as of 31.12.94		1155	427	38	1631

Reserves

Fig. 2.12.1.b
Geographical distribution of resources on the Norwegian continental shelf

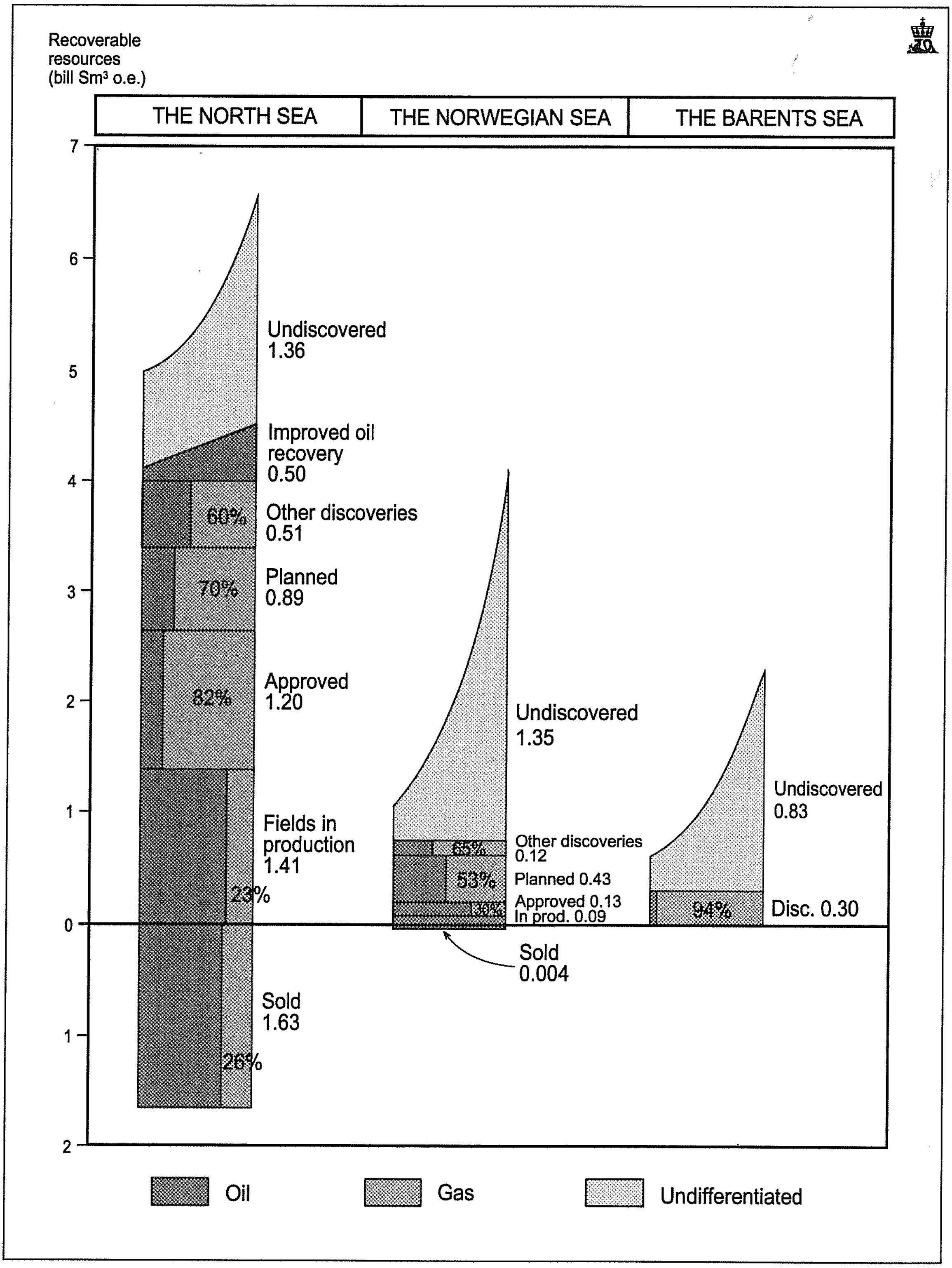


Table 2.12.1.a
Change in discovered resources 1993-1994

Growth in discovered resources	OIL 10^6 Sm^3	GAS 10^9 Sm^3	NGL 10^6 tons	O. E. 10^6 Sm^3
New discoveries	65.0	55.0		120.0
Old discoveries booked in 1994	34.6	43.9		78.5
Changes in estimates	-17.2	-19.9	91.7	82.1
Production	-145.9	-26.6	-5.8	-180.0
Total change 1993-1994	-63.5	52.4	85.9	100.6

Table 2.12.1.b
Original petroleum reserves in fields having ceased production

	ORIGINAL RECOVERABLE			
	OIL 10^6 Sm^3	GAS 10^9 Sm^3	NGL 10^6 tons	O. E. 10^6 Sm^3
Mime	0.4	0.1		0.5
Nordøst Frigg		11.8	0.1	11.9
Odin		26.6		26.6
Sum	0.4	38.5	0.1	39.1

vised its classification system for discovered resources. Distinction is made between 7 classes: fields where production has ceased, fields in production, fields decided to be developed, discoveries with firm development plans, discoveries without firm development plans, discoveries in relinquished areas, and one class for small, technical discoveries and new discoveries where evaluation is not completed. In respect of the last two classes, the Norwegian Petroleum Directorate only publishes total estimates for the resources. Resources is a generic term used for all types of petroleum volumes.

Reserves comprise recoverable resources in accordance with approved plans for fields in production and for fields decided to be developed. Reserves are consequently classified under the three first classes. Distinction can be made between originally recoverable and remaining reserves.

To receive the designation discovery, a well must have proven mobile hydrocarbons in a separate geological structure or a separate stratigraphic level. This can be done both by testing of the production properties of the formation (DST) and by using various sampling equipment (RFT/FMT, MDT etc.) A discovery is called a field when the plan for development and operation (PDO) has been approved by the authorities. Any discovery and any field has only one discovery well. This means that wildcat wells which prove resources that are or will be included in the resource figure for an existing discovery or field, are not considered to be new discoveries. The discovery year is the year the discovery well was completed.

Undiscovered resources

The undiscovered resources comprise mapped prospects as well as unmapped resources in areas where play models have been defined. The Norwegian Petroleum Directorate carried out a new analysis in 1994 of the undiscovered petroleum resources on the Norwegian continental shelf, see Figure 2.12.1.a and 2.12.1.b. There is always great uncertainty attached to such analyses. The difference between the lowest and the highest possible estimate is attempted illustrated in Figure 2.12.1.b. The size given for undiscovered resources is the statistical expected value.

Discoveries made in 1994

During 1994, mobile hydrocarbons were proven in 14 wildcat wells. They were: 2/7-29, 2/11-10 S, 15/9-20 S, 24/9-5, 25/8-5 S, 30/3-6 S, 30/9-15, 30/9-16, 34/7-23 S, 34/11-1, 6204/11-1, 6207/8-2, 6608/10-4 and 7128/4-1. Hydrocarbons have also been proven in 30/8-1 S, but this well was not completed at the year end. Only a small number of the discoveries have been finally evalutated, but a preliminary estimate of the increase in resources due to new discoveries in 1994 will be in the region of 85-150 million Sm³ o.e.

Registration of past discoveries

In addition to the current year's discoveries mentioned above, the following past discoveries are now included in the resources accounts: 2/7-22, 34/7-22 and 7120/7-2 Askeladd Sentral. The incremental resources attributable to these discoveries total 6.1 million Sm³ oil and 11.3 billion Sm³ gas. In addition, an estimate of total resources in the classes for discoveries in relinquished areas and for small, technical discoveries has been included in 1994. A number of these have until now not been included in the Norwegian Petroleum Directorate's resources estimate. This means an increase in the registered estimates of discovered resources of altogether 28.5 million Sm³ oil and 32.6 billion Sm³ gas. In all the incremental resources attributable to these past discoveries represent 34.6 million Sm³ oil and 43.9 billion Sm³ gas.

Adjustment of resource estimates for existing fields and discoveries

For fields having terminated production in 1994, fields in production and fields decided to be developed, as well as discoveries with and without firm development plans, the present resource account status shows that, relative to the previous year's Annual Report, oil resources have decreased by 17.2 million Sm³ and gas resources by 19.9 billion Sm³. NGL resources have increased greatly by 91.7 million tonnes, see Table 2.12.2.

In 1994, reporting routines from the companies to the Norwegian Petroleum Directorate were altered somewhat so that some previoulsy classified oil resources now are reported as NGL (which includes condensate). This accounts for the bulk of the increase in the NGL figures .

For details relating to resource adjustments, reference is made to subsection 2.12.2.

Production

Recovery of petroleum on the Norwegian continental shelf in

1994 amounted to 145.9 million Sm³ oil, 26.6 billion Sm³ gas, and 5.8 million tonnes NGL (including condensate).

Resources status

The Norwegian Petroleum Directorate's resources status from 1993 to 1994 show that the increase in discovered oil and gas resources are somewhat greater than the depletion. There is a small reduction in the estimate for oil of 63.5 million Sm³. This is partly due to the fact that some previous oil reserves are now reported as NGL. The estimate for gas is increased by 52.4 billion Sm³ and NGL is increased by 85.9 million tonnes.

The resource account for the Norwegian continental shelf is illustrated in Figure 2.12.1 .a and the geographical distribution of the resources in Figure 2.12.1 .b. The resources in the individual fields and discoveries on the Norwegian continental shelf are set out according to the new resource classification system (cf. above) in the following tables:

- Original petroleum reserves in fields where production has ceased (Table 2.12.1.b)
- Petroleum reserves in fields in production (Table 2.12.1.c)
- Petroleum reserves in fields decided to be developed (Table 2.12.1.d)
- Petroleum resources in discoveries with firm development plans (Table 2.12.1.e)
- Petroleum resources in discoveries without firm development plans (Table 2.12.1.f)
- Petroleum resources in discoveries in relinquished areas, in small, technical discoveries and in new discoveries (Table 2.12.1.g)

Table 2.12.1.c
Petroleum reserves in fields in production

	ORIGINAL RECOVERABLE				REMAINING		
	OIL 10^6 Sm³	GAS 10^9 Sm³	NGL 10^6 tons	O.E. 10^6 Sm³	OIL 10^6 Sm³	GAS 10^9 Sm³	NGL 10^6 tons
North Sea:							
Albuskjell	7.4	15.8	1.0	24.5	0.3	1.0	0.0
Brage	46.2	2.0	0.8	49.2	39.8	1.8	0.7
Cod	2.9	7.3	0.5	10.9	0.2	0.5	0.0
Edda	4.8	2.1	0.2	7.2	0.5	0.2	
Ekofisk	359.7	150.8	14.1	528.8	167.4	60.4	6.1
Eldfisk	70.7	44.9	3.7	120.4	14.9	20.9	1.1
Embla	5.0	3.0	0.3	8.4	2.9	2.4	0.2
Frigg 1)		110.9	0.4	111.4		0.9	0.0
Gullfaks	281.0	21.5	2.2	305.4	134.1	11.5	1.1
Gullfaks Vest	2.9	0.3		3.2	2.4	0.3	
Gyda	30.6	3.9	1.7	36.7	14.9	1.9	0.8
Heimdal 2)	6.5	38.6		45.1	2.2	9.0	
Hod	7.9	2.0	0.3	10.3	3.4	1.2	0.2
Lille-Frigg	3.6	7.0		10.6	3.2	6.5	
Loke 3) 4)	1.4	5.8	0.7	8.1	1.4	5.8	0.7
Murchison 5)	12.0	0.4	0.3	12.8	0.5	0.1	0.0
Oseberg	310.0	88.9		398.9	173.0	88.9	
Sleipner Øst 4)		47.8	30.4	87.3		43.0	27.2
Snorre	173.3	6.9	3.6	184.9	155.0	6.2	2.9
Statfjord 6)	530.0	57.0	16.0	607.8	128.7	29.2	8.0
Statfjord Øst	19.4	2.4	0.7	22.7	18.8	2.4	0.7
Tommeliten Gamma	3.8	9.7	0.5	14.2	0.6	2.6	0.1
Tor	21.3	10.8	1.1	33.5	1.9	0.5	0.0
Tordis	29.0	2.0	1.0	32.3	27.4	1.9	1.0
Ula	69.1	4.7	2.7	77.3	21.1	1.6	0.7
Valhall	100.7	26.3	4.1	132.3	61.4	18.5	2.5
Veslefrikk	52.8	2.3	0.9	56.3	34.1	1.9	0.3
Vest Ekofisk	12.2	27.2	1.4	41.2	0.2	1.9	0.0
Øst Frigg		8.8	0.1	8.9		0.6	0.0
30/6 Gamma Nord	1.3	6.2		7.5	0.5	6.2	
Sum	2165.5	717.3	88.7	2998.1	1010.9	329.9	54.6
Norwegian Sea:							
Draugen	92.0			92.0	88.0		
Sum	92.0			92.0	88.0		
Total	2257.5	717.3	88.7	3090.1	1098.9	329.9	54.6

1) Norwegian share only: 60.82 %
2) NGL, sold as oil
3) Reserve estimate includes the Heimdal Formation (producing) and the Jurrasic/Triassic reservoir (development plan under consideration).
4) Petroleum from Loke and Sleipner Øst is sold combined. Total production from the two fields is subtracted from Sleipner Øst.
5) Norwegian share only: 22,2 %
6) Norwegian share only: 85,46869%

Table 2.12.1.d
Petroleum reserves in fields decided to be developed

		OIL 10^6 Sm^3	GAS 10^9 Sm^3	NGL 10^6 tons	O.E. 10^6 Sm^3
North Sea:	Frøy	13.9	3.0	0.2	17.2
	Gyda Sør	1.5	0.9	0.2	2.7
	Sleipner Vest		126.9	33.7	170.7
	Statfjord Nord	29.0	2.4		31.4
	Troll Vest (phase 2) oil	71.0	17.5		88.5
	Troll Øst (phase 1)		825.0	20.0	851.0
	Vigdis	33.9	2.4		36.3
	Sum	149.3	978.1	54.1	1197.7
Norwegian Sea	Heidrun	87.3	37.8		125.1
	Sum	87.3	37.8		125.1
	Total	236.6	1015.9	54.1	1322.8

Table 2.12.1.e
Petroleum resources in discoveries with firm development plans

	OIL 10^6 Sm^3	GAS 10^9 Sm^3	NGL 10^6 tons	O.E. 10^6 Sm^3
North Sea:				
Troll Vest (phase 3) gas		463.0	10.8	477.0
9/2-1 Yme	5.8			5.8
15/5-1 Dagny		6.1	1.4	7.9
15/9-15 My		4.4	1.9	6.9
15/12-4 Beta	12.3			12.3
25/11-1 Balder	32.2			32.2
25/11-15 Hermod	60.0	1.8		61.8
30/2-1 Huldra	7.9	22.3		30.2
30/6-5 Oseberg Øst	19.0	1.0		20.0
30/9-3 Omega Nord	16.6	8.0		24.6
30/9-6	2.0	0.2		2.2
30/9-7	0.9			0.9
30/9-10 Omega Sør	3.2			3.2
34/7-22 Tordis Øst	5.5			5.5
34/8-1 Visund	47.0	51.0		98.0
34/10-2 Gullfaks Sør	25.6	56.1		81.7
34/10-17 Rimfaks	13.0	10.0		23.0
Sum	251.0	623.9	14.1	893.2
Norwegian Sea:				
6407/7-1 S Njord	35.0	7.2		42.2
6506/12-1 Smørbukk		95.0	35.0	140.5
6506/12-3 Smørbukk Sør	31.0	24.0		55.0
6507/11-1 Midgard	1.3	87.0	13.0	105.2
6608/10-2 Norne	76.2	15.6		91.8
Sum	143.5	228.8	48.0	434.7
Total	394.5	852.7	62.1	1327.9

Fields where production has ceased

In 1994, production ceased from the fields Mime and Odin, so that at the year end a total of three fields had ceased production on the Norwegian continental shelf, see Table 2.12.1.b.

Reserves in fields in production/decided to be developed

Per 31 December 1994, 42 development projects (including three fields which had ceased production) had been decided to be developed on the Norwegian continental shelf, one more than per 31 December the previous year. The new development project is Vigdis. There are however several new plans for development and operation submitted for consideration by the authorities, and it is expected that several major and minor developments will be approved in 1995.

Four new fields came on stream in 1994: Gullfaks Vest, Lille-Frigg, Statfjord Øst and Tordis. Thus, at year end there were 31 fields in production on the Norwegian continental shelf, see Table 2.12.1.c. Of the two fields in the Norwegian Sea, only Draugen is in production. Heidrun is expected to start production in the course of 1995. Eight fields have been decided to be developed, but are not in production yet, see Table 2.12.1.d. Troll Vest oil (Phase 2) and Troll Vest gas (Phase 3) are separate development projects and are consequently listed with own resources in Table 2.12.1.d. and e.

The total originally recoverable reserves are 4.45 billion Sm^3 o.e., which split into 2.68 billion Sm^3 o.e. oil/NGL and 1.77 billion Sm^3 o.e. gas. In addition there is identified a potential for improved oil recovery of 0.5 billion Sm^3.

Per 31 December 1994, the total production is 1204 million Sm^3 o.e. oil/NGL and 427 billion Sm^3 o.e. gas.This represents 31 % of discovered oil/NGL and 13 % of discovered gas. The figures include the potential for improved oil recovery.

Resources in discoveries with firm development plans

At year end, 22 discoveries are considered to have firm development plans, see Table 2.12.1.e. This includes discoveries where plan for development and operation has been submitted to the authorities and is under consideration. This category also includes discoveries where it has been signalled that such plan will be submitted in the foreseeable future (2-3 years), and where the operator and the licensees display considerable activity. The petroleum resources for these discoveries total 1.3 billion Sm^3 o.e. Out of this, 0.9 billion Sm^3 are in the North Sea and 0.4 billion Sm^3 in the Norwegian Sea.

Resources in discoveries without firm development plans

Table 2.12.1.f shows a list of discoveries on the Norwegian continental shelf which at present are without firm development plans. This list does not include discoveries in relinquished areas, small technical discoveries or

Table 2.12.1.f
Petroleum resources in discoveries without firm development plans

	OIL 10^6 Sm³	GAS 10^9 Sm³	NGL 10^6 tons	O.E. 10^6 Sm³
North Sea:				
1/2-1 1)	3.0			3.0
1/3-3	1.2	0.3		1.5
1/3-6	3.3	5.8		9.1
1/9-1 Tommeliten Alpha	2.5	2.7	0.5	5.9
2/4-17 Tjalve	1.0	2.1		3.1
2/5-3 Sørøst Tor	2.5	2.0		4.5
2/7-22	0.6	1.4		2.0
2/12-1 Mjølner	1.5	0.7		2.2
3/7-4 Trym	1.1	4.1		5.2
6/3-1 Pi	0.8			0.8
7/7-2	2.7	0.1		2.8
7/8-3	6.2			6.2
15/3-1.3	5.2	10.5		15.7
15/3-4	2.2	1.3		3.5
15/8-1 Alpha		4.3	3.6	9.0
15/9-19 SR	6.5			6.5
15/12-8	0.6	1.3		1.9
16/7-4	1.4	8.0		9.4
24/6-1 Peik 1)	0.9	3.1		4.0
25/2-5 Lille Frøy	1.2	1.5	0.3	3.1
25/4-6 S Vale	1.3	1.0	0.3	2.6
25/5-3 Skirne		3.3	0.3	3.7
25/5-4 Byggve	0.6	2.6		3.2
25/6-1	2.0			2.0
25/8-1	7.0			7.0
30/6-18 Kappa	1.0	3.6		4.6
30/7-6 R Hild	6.6	27.6		34.2
30/9-13 S	7.5	1.7		9.2
30/9-4 S	0.3	0.2		0.5
30/9-9		1.7		1.7
34/7-21	13.6			13.6
34/10-23 Gamma	6.0	69.0		75.0
35/9-1 R	5.0	11.5		16.5
35/11-2	4.6	4.9		9.5
35/11-4 R	9.0	8.6		17.6
35/11-7	9.0	4.0		13.0
Sum	117.9	188.9	5.0	313.2
Norwegian Sea:				
6406/3-2 Trestakk	4.8			4.8
6407/1-2 Tyrihans Sør	11.5	5.1		18.1
6407/1-3 Tyrihans Nord	2.5	15.4	2.0	20.5
6407/6-3 Mikkel		18.2	3.7	23.0
6506/11-2		1.6	2.8	5.2
6507/2-2	0.5	2.6		3.1
6507/3-1		11.0		11.0
6507/8-4	7.3	1.9		9.2
Sum	15.1	62.2	13.6	95.0
Barents Sea:				
7120/7-1		22.5		22.5
7120/7-2 Askeladd Sentral	9.9			9.9
7120/8-1 Askeladd		49.8		49.8
7120/9-1 Albatross		41.7		41.7
7121/4-1 Snøhvit	6.7	83.0	9.2	101.7
7121/4-2 Snøhvit Nord		3.3		3.3
7121/5-2 Beta		4.3		4.3
7121/7-2 Albatross Sør	10.8			10.8
7122/6-1		11.0		11.0
7124/3-1		2.1		2.1
Sum	6.7	238.4	9.2	257.1
Total	139.7	489.5	27.8	665.2

1) Norwegian share only

discoveries made in 1994, which have their own resource classes.

The 54 discoveries are listed in this category because the Norwegian Petroleum Directorate considers them not to have sufficiently firm development plans, or because the operators' activity level is low with regard to these discoveries. The total resources volume represents 0.67 billion Sm³ o.e. Out of this, 0.31 billion Sm³ are in the North Sea and 0.1 billion Sm³ in the Norwegian Sea and a considerable volume, approximately 0.26 billion Sm³ o.e., in the Barents Sea.

Table 2.12.1.g
Petroleum resources in discoveries in relinquished areas, in small technical discoveries and new discoveries in 1994

	OIL 10^6 Sm³	GAS 10^9 Sm³	NGL 10^6 tons	O.E. 10^6 Sm³
Relinquished discoveries	11	110		121
Small, technical discoveries and new discoveries	80	70		150
Sum	91	180		271

Resources in discoveries in relinquished areas

In addition to the discoveries mentioned in the paragraphs above, the Norwegian Petroleum Directorate data base also contains 16 discoveries in relinquished areas. A number of these are small, technical discoveries but this category also comprises discoveries of a certain size such as 35/3-2 Agat, 35/8-1, 35/8-2, 7120/12-2Alke Sør and 7226/11-1. These are mainly gas discoveries. In total the resources in discoveries in relinquished areas represent 11 million Sm³ oil and 110 billion Sm³ gas, see Table 1.12.1.g.

Resources in small, technical discoveries and in new discoveries, 1994

A total of 42 discoveries are registered in this category. The new discoveries have not been fully evaluated, and are therefore not placed in the respective classes mentioned above.

The small, technical discoveries comprise discoveries with poor formation tests and discoveries which were not tested. The Norwegian Petroleum Directorate's resources data base contains 28 such discoveries.

14 new discoveries were made in 1994 (see above). Among the largest are 34/11-1, 25/8-5 S and 6204/11-1. Some of the new discoveries will be added to existing fields as incremental resources. There is great uncertainty attached to the resource estimate in this discovery category, but the Norwegian Petroleum Directorate estimates a total expected value of approximately 80 million Sm³ oil and about 70 billion Sm³ gas.

2.12.2 REVISIONS IN RESOURCE ESTIMATES SINCE LAST ANNUAL REPORT

2.12.2.1 Fields in production/decided to be developed

For fields in production the Norwegian Petroleum Directorate generally utilizes the operator's estimates of reserves in its published figures. A number of reassessments of the reserves estimates have been made in 1994, as shown in Table 2.12.2. The reasons for the most important changes are as follows:

Table 2.12.2
Changes in reserve/resource estimates, annual reports 1993-1994

	Annual report 1993			Annual report 1994			Changes 1993 to 1994		
	OIL 10^6 Sm^3	GAS 10^9 Sm^3	NGL 10^6 tons	OIL 10^6 Sm^3	GAS 10^9 Sm^3	NGL 10^6 tons	OIL 10^6 Sm^3	GAS 10^9 Sm^3	NGL 10^6 tons
Fields having ceased production									
Odin		26.9			26.6			-0.3	
Mime	0.6	0.1		0.4	0.1		-0.2	0.0	
Fields in production									
Albuskjell	8.8	20.8	1.3	7.4	15.8	1.0	-1.4	-5.0	-0.3
Brage	46.2	1.7	1.0	46.2	2.0	0.8		0.3	-0.2
Edda	4.7	2.0	0.2	4.8	2.1	0.2	0.1	0.1	
Ekofisk	355.0	159.0	14.7	359.7	150.8	14.1	4.7	-8.2	-0.6
Eldfisk	77.0	54.0	4.8	70.7	44.9	3.7	-6.3	-9.1	-1.1
Embla	4.1	1.4	0.2	5.0	3.0	0.3	0.9	1.6	0.1
Frigg	112.0	0.4		110.9	0.4		-1.1		
Gullfaks	253.0	17.8	2.1	281.0	21.5	2.2	28.0	3.7	0.1
Gullfaks Vest	3.7	0.4		2.9	0.3		-0.8	-0.1	
Gyda	30.6	4.0	1.9	30.6	3.9	1.7		-0.1	-0.2
Heimdal	6.1	37.4		6.5	38.6		0.4	1.2	
Hod	7.9	2.3	0.4	7.9	2.0	0.3		-0.3	-0.1
Loke	1.8	5.8	0.5	1.4	5.8	0.7	-0.4		0.2
Murchison	12.7	0.4	0.4	12.0	0.4	0.3	-0.7	0.0	-0.1
Oseberg	300.0	81.0		310.0	88.9		10.0	7.9	
Sleipner Øst	27.1	47.0	15.2		47.8	30.4	-27.1	0.8	15.2
Snorre	142.0	7.6	5.4	173.3	6.9	3.6	31.3	-0.7	-1.8
Statfjord	498.0	53.0	15.5	530.0	57.0	16.0	32.0	4.0	0.5
Statfjord Øst	13.3	1.9		19.4	2.4	0.7	6.1	0.5	0.7
Tommeliten Gamma	3.4	8.2	0.5	3.8	9.7	0.5	0.4	1.5	
Tor	23.4	11.5	1.2	21.3	10.8	1.1	-2.1	-0.7	-0.1
Tordis	18.8	1.2	0.5	29.0	2.0	1.0	10.2	0.8	0.5
Ula	69.0	4.7	3.2	69.1	4.7	2.7	0.1		-0.5
Valhall	94.0	25.3	4.8	100.7	26.3	4.1	6.7	1.0	-0.7
Veslefrikk	45.0	3.6	1.5	52.8	2.3	0.9	7.8	-1.3	-0.6
Vest Ekofisk	12.4	28.0	1.5	12.2	27.2	1.4	-0.2	-0.8	-0.1
Øst Frigg	8.6			8.8	0.1		0.2	0.1	
30/6 Gamma Nord	0.9	6.2	0.4	1.3	6.2		0.4		-0.4
Draugen	92.0	4.4		92.0				-4.4	
Fields with approved dev. plan									
Frøy	14.0	3.0		13.9	3.0	0.2	-0.1		0.2
Gyda Sør	1.5	0.9	0.1	1.5	0.9	0.2			0.1
Sleipner Vest	29.5	122.0	10.0		126.9	33.7	-29.5	4.9	23.7
Statfjord Nord	31.0	2.5		29.0	2.4		-2.0	-0.1	
Troll Vest (Phase 2) oil	61.0			71.0	17.5		10.0	17.5	
Troll Øst (Phase 1)		825.0	19.2		825.0	20.0			0.8
Vigdis	33.1	2.3		33.9	2.4		0.8	0.1	
Discoveries with firm dev. plans									
15/12-4 Beta	13.2	2.3		12.3			-0.9	-2.3	
15/5-1 Dagny	2.0	6.0			6.1	1.4	-2.0	0.1	1.4
15/9-15 My	5.0	11.0			4.4	1.9	-5.0	-6.6	1.9
30/9-6	2.7			2.0	0.2		-0.7	0.2	
34/8-1 Visund	45.0	46.0		47.0	51.0		2.0	5.0	
9/2-1 Yme	3.4			5.8			2.4		
6506/12-1 Smørbukk	37.0	95.0			95.0	35.0	-37.0		35.0
6608/10-2 Norne	70.0	13.0		76.2	15.6		6.2	2.6	
Discoveries without firm dev. plans									
1/3-3	3.3	0.1		1.2	0.3		-2.1	0.2	
1/3-6	1.2	2.8		3.3	5.8		2.1	3.0	
1/9-1 Tommeliten Alpha	3.5	7.8	0.5	2.5	2.7	0.5	-1.0	-5.1	
15/8-1 Alpha	5.0	11.0			4.3	3.6	-5.0	-6.7	3.6
15/9-19 SR	4.6	0.7		6.5			1.9	-0.7	
25/2-5 Lille Frøy	5.3	1.9		1.2	1.5	0.3	-4.1	-0.4	0.3
25/4-6 S Vale	3.1	2.3		1.3	1.0	0.3	-1.8	-1.3	0.3
25/5-3 Skirne	0.3	2.3			3.3	0.3	-0.3	1.0	0.3
25/6-1	4.1	0.9		2.0			-2.2	-0.9	
3/7-4 Trym	0.7	3.9		1.1	4.1		0.4	0.2	
30/9-13 S	7.2	2.2		7.5	1.7		0.3	-0.5	
30/9-9	5.2				1.7		-5.2	1.7	
35/11-2	5.4	5.6		4.6	4.9		-0.8	-0.7	
35/11-4 R	18.0	10.8		9.0	8.6		-9.0	-2.2	
35/11-7	20.7	15.4		9.0	4.0		-11.7	-11.4	
6/3-1 Pi	0.9	1.0		0.8			-0.1	-1.0	
6407/1-2 Tyrihans Sør	5.1	11.5			11.5	5.1	-5.1		5.1
6407/1-3 Tyrihans Nord	4.5	15.0		2.5	15.4	2.0	-2.0	0.4	2.0
6407/6-3 Mikkel	3.8	18.0			18.2	3.7	-3.8	0.2	3.7
6506/11-2	6.3	3.6			1.6	2.8	-6.3	-2.0	2.8
6507/3-1	1.1	7.1			11.0		-1.1	3.9	
6507/8-4	11.8	2.5		7.3	1.9		-4.5	-0.6	
7120/8-1 Askeladd		59.7			49.8			-9.9	
Sum							-17.2	-19.9	91.7

Albuskjell
Updated simulation model has led to reduced reserves estimate.

Draugen
Marketable gas has been set to 0, as no sales agreement for gas from Draugen has been concluded, and the produced gas is being injected into a water-bearing structure.

Eldfisk
The change in reserves figures are due to updated reservoir-simulation model.

Gullfaks
The increased reserves estimate is in part due to the mapping of larger in-place reserves and in part to improved recovery.

Gullfaks Vest
The estimate of recoverable oil is reduced based on new mapping and information from production drilling.

Oseberg
The reserves estimate has been increased as a result of a stable gas front, delayed gas breakthrough, improved drainage and successful horizontal wells.

Sleipner Øst
The reduction in reserves estimate for oil/NGL is due to changes in PVT properties leading to "drier" production, which produces less liquid than assumed earlier. All liquid production is now given as NGL.

Snorre
The increased reserves estimate is mainly due to the inclusion of the Lunde formation in the reserves.

Statfjord
The upward adjustment of the reserves estimate is based on results from a new long-term plan for the field which Statoil has prepared in co-operation with the licensees.

Statfjord Øst
The upward adjustment of the reserves estimate is based on results from production wells which show that the rock volume is greater than assumed earlier.

Tordis
The upward adjustment of the reserves is related to a new geological model, new mapping and new reservoir simulation.

Troll Vest (Phase 2) oil
In addition to Troll oil province (19 wells) this field now includes the approved well cluster (H cluster) with 6 wells in the Troll Vest gas province.

Valhall
The upward adjustment of the reserves is due to new mapping by means of 3D data.

Veslefrikk
The upward adjustment of the oil reserves is in part due to the results of new mapping, and in part to the fact that the resources in the Statfjord formation and the upper Brent group have been included. The reduction in the gas and NGL reserves is due to gas re-injection.

2.12.2.2 Discoveries
The changes in resources estimates from 1993 to 1994 are reported in Table 2.12.2. Discoveries for which a major change was made are discussed specifically.

1/3-3
The reason for the change in the resource estimate is that the Norwegian Petroleum Directorate now uses the operator's figures.

1/3-6
The reserves estimate is adjusted upward due to new mapping.

1/9-1 Tommeliten Alpha
The change in the resource estimate is due to new mapping and a change in the reservoir zonation in the geological model. In addition, a new analysis of PVT data and of water saturation has been carried out.

9/2-1 Yme
The upward adjustment of the resources is due to increased information, due to the drilling of an appraisal well and in addition the use of water injection has been decided.

15/8-1 Alpha
The reason for the change in the resource estimate is that the Norwegian Petroleum Directorate now uses the operator's figures.

15/9-15 My
The reason for the change in the resource estimate is that the Norwegian Petroleum Directorate now uses the operator's figures.

25/2-5
New mapping constitutes the basis for the downward adjustment of resource figures.

25/4-6 S Vale
New studies constitute the basis for the downward adjustment of resource figures.

25/5-3 Skirne
New resource figures are based on a new study. New simulation study does not exist, and the Norwegian Petroleum Directorate's previous recovery factor for gas/NGL has therefore been used in the calculation of reserves.

25/6-1
The downward adjustment of the resources is a result of new mapping.

30/9-9
The reason for the change in the resource estimate is that the Norwegian Petroleum Directorate now uses the operator's figures.

34/8-1 Visund
Reinterpretation of the last wells and new interpretation of the latest simulation models have led to an increase in the resource estimates.

35/11-4 R
The resource estimate is reduced due to new resource evaluation based on 3D seismic.

35/11-7
The resource estimate is reduced due to new resource evaluation based on 3D seismic.

6506/11-2
New mapping of the discovery is the reason for the reduction in the resource estimate.

6506/12-1 Smørbukk
The liquid resources in 6506/12-1 Smørbukk are now given as NGL. At the same time, an adjustment upwards has been made of recoverable NGL which presupposes that part of the produced gas is re-injected into the reservoir. Previous estimates presupposed depressurisation as driving force.

6507/3-1
The upward adjustment of the resources is due to new mapping by means of 3D data.

6507/8-4 Heidrun Nord
The downward adjustment of the resources is a result of new mapping/modelling.

6508/10-2 Norne
The reason for the upward adjustment of the resources is that the Norwegian Petroleum Directorate this year has carried out its own calculations where the recovery factor is based on water injection. Last year's resources were the operator's calculations, based on combined gas/water injection.

7120/8-1 Askeladd
The previous resource figure for Askeladd (59.7 billion Sm^3 gas) is split between the discoveries 7120/8-1 Askeladd (49.8 billion Sm^3 gas) and 7120/8-2 Askeladd Sentral (9.9 billion Sm^3 gas).

2.12.2.3 Name changes in 1994
In this Annual Report, the Norwegian Petroleum Directorate has carried out changes in relation to previous years' Annual Reports, of the designations of a number of discocveries. From now on, the Norwegian Petroleum Directorate will designate all discoveries, i.e. accumulations which do not have an approved plan for development and operation, with the discovery well in conjunction with an approved or unofficial name if such name exists. All changes due only to this alteration of practice are reflected in the tables under subsection 2.12.1, and are not mentioned here.Those name changes which have been approved on application from the operators in 1994 are:

Present name	Previous designation
Gyda Sør	2/1-9 Gyda Sør
2/4-17 Tjalve	2/4-17 Nordvest Tor
9/2-1 Yme	9/2-1 Gamma
34/10-17 Rimfaks	34/10-17 Beta

2.12.3 IMPROVED OIL RECOVERY
Out of 26 oil fields either in production or which have been decided to be developed per December 1994, 20 have reservoir in sandstone, and the reserves for these fields have been estimated to 1,887 million Sm^3 oil. This corresponds to an expected average recovery factor of approximately 43 %. The oil reserves in 6 oil fields with reservoir in chalk rock are estimated to 565 million Sm^3 with an expected average recovery factor of approximately 29 %. This means that average recovery factor for all Norwegian oil fields now is approximately 39 %.

The Norwegian Petroleum Directorate has previously defined the following objectives for their work for improved oil recovery:

The Norwegian Petroleum Directorate's long-term objective for improved oil recovery is to realise as much as possible of the identified potential and the upside potential in profitable projects.

By the year 2000, the planned recovery factor for those fields which were in production or were decided to be developed in 1991, shall be increased so as to correspond to increased reserves of at least 400 million Sm^3 compared with the reserves estimates from 1991.

Table 2.12.3
Changes in recoverable oil in mill. Sm^3 and in recovery factor from 1991 to 1994

Year	1991	1994
Recoverable oil	2 017	2 402
Recovery factor	33.9 %	38.9 %

Out of the increase of 385 million Sm^3, about 297 million Sm^3 are a result of increased recovery factor and the rest an increase in the estimates for in-place oil.. This means that a sum of nearly 300 out of the goal of 400 million Sm^3 by the year 2000 has been achieved before 1995.

Fig. 2.12.4.a
Undiscovered petroleum resources on the Norwegian continental shelf

	OIL (mill Sm³)			GAS (bill Sm³)		
	P95	Exp.	P05	P95	Exp.	P05
North Sea	450	740	1122	390	615	915
Norwegian Sea	110	455	1125	220	890	2205
Barents Sea	65	240	695	230	585	1260
Norwegian Shelf	830	1435	2280	1110	2090	3590

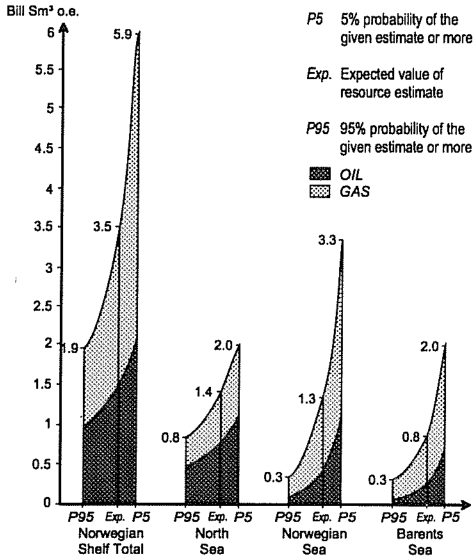
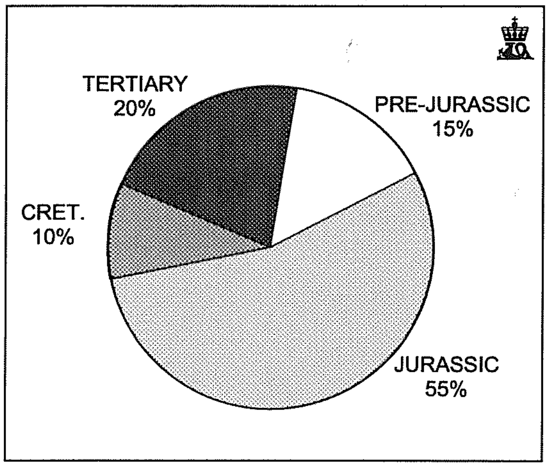


Fig. 2.12.4.b
Stratigraphic distribution of undiscovered petroleum resources on the Norwegian Shelf



During the last few years, a number of studies have been carried out, both by the operators and by the Norwegian Petroleum Directorate, with view to estimate the potential for increasing the recovery factor for oil. These studies vary from preliminary screening studies, which often include a number of fields, to detailed full-field simulation studies for individual fields or for parts of the reservoir. The studies also comprise many different methods, from measures to improve reservoir control and to reduce operating costs to the use of advanced recovery methods. Research is in progress on such methods in various connections, e.g. in the research programmes RUTH and PROFIT, described in sections 5.1.4 and 5.1.5.

The latest estimate of the Norwegian Petroleum Directorate for future improved oil recovery potential, based on the Norwegian Petroleum Directorate's official reserves figures per November 1994, is about 500 million Sm³. This corresponds to an increase of the average recovery factor for oil fields to approximately 47 %, i.e. an increase somewhat in excess of 8 percentage points in relation to current recovery factor. Out of the total potential, somewhat in excess of 60 % originates from sandstone fields and the rest from chalk fields. The potential represented by the five largest fields (Ekofisk, Gullfaks, Oseberg, Snorre, Statfjord) constitutes about half the total potential.

2.12.4 Undiscovered resources on the Norwegian continental shelf

The undiscovered petroleum resources on the Norwegian continental shelf are estimated to have an expected value of 3.53 billion Sm³ o.e., split into 1.44 billion Sm³ o.e. oil and 2.09 billion Sm³ o.e. gas.

This corresponds to approximately 50 % of the petroleum resources discovered until today.The estimates of undiscovered resources are subject to considerable uncertainty. The statistical calculations show that these estimates represent an uncertainty area ranging from about 2.0 to about 6.0 billion Sm³ o.e.

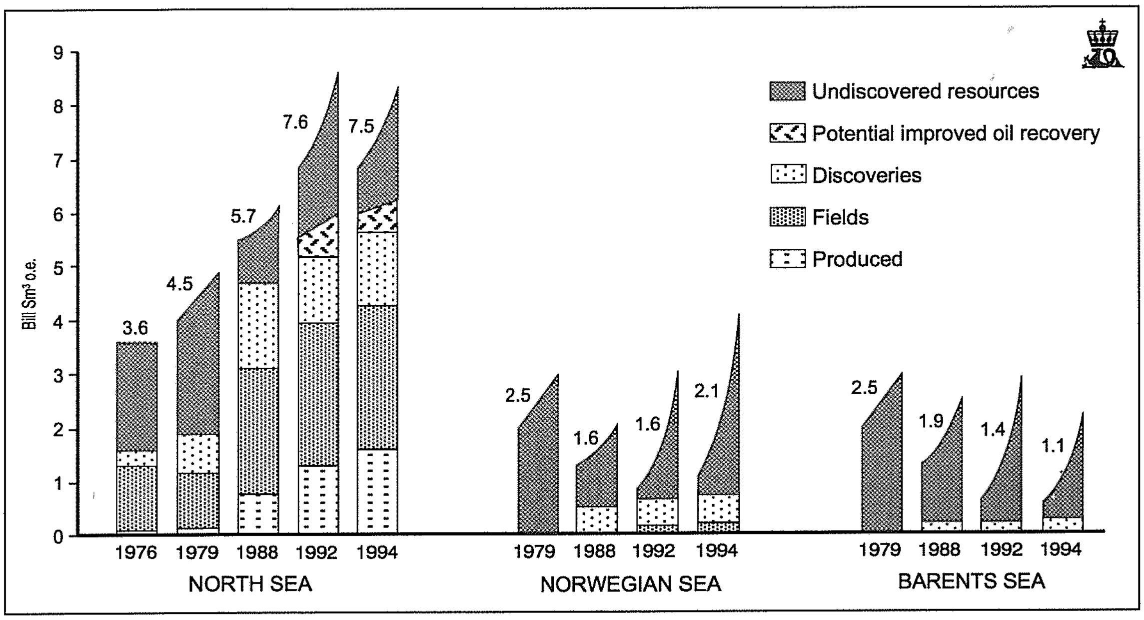
The expected value of the undiscovered resources is subdivided as follows: 38 % in the North Sea, 38 % in the Norwegian Sea and 24 % in the Barents Sea, cf. Figure 2.12.4.a.

If we look at the stratigraphic distribution, Figure 2.12.4.b, play models in Jurassic rock types are expected to contribute with 55 % of the expected undiscovered resources. Tertiary play models are expected to contribute with 20 %, while Pre-Jurassic and Cretaceous play models are expected to contribute with 15 % and 10 % each, respectively.

In calculating the undiscovered resource potential on the Norwegian continental shelf, basically the same method as used for the 91/92 analysis has been used. In addition, greater emphasis has in this analysis been placed on using statistical base data from exploration history for the various play models, as well as relevant parameters from existing discoveries and fields. For comparison with estimates from the previous analysis, it must be pointed out that earlier, a constant recovery factor of 40 % has been used for all potential oil deposits. In the current analyses, a uniform distribution from 30 % to 60 % in the North Sea and the Norwegian Sea has been used. This results in an average recovery factor of 45 %. For potential gas deposits, a constant recovery factor of 75 % has been chosen.

Comparison with resource estimates of previous years
The estimates of total resources on the Norwegian continental shelf have changed considerably over the years. This is the case both for discovered and for undiscovered resources. Figure 2.12.4.c shows a comparison of the Norwegian Petroleum Directorate's estimates of the total pe-

Fig. 2.12.4.c
Total estimates of petroleum resources made by the Directorate from 1976 to the present day.



troleum resources on the Norwegian continental shelf from 1976 until today.

The first rough estimates were made in 1976 and 1979 respectively, and only took into account well information from the North Sea. The estimates were made prior to drilling of blocks from the 4th licensing round (Oseberg, Troll, Veslefrikk, Brage, Huldra etc.). This was also before areas north of the 62nd parallel had been opened up for licencing and exploration drilling. In 1979 the Norwegian Petroleum Directorate estimated that the total petroleum resources in the North Sea would be about 4.5 billion Sm^3 oil equivalents. The range of uncertainty was estimated to be between 4.0 and 5.0 billion Sm^3 oil equivalents. Based on a very rough regional seismic set of data it was then estimated that the petroleum potential north of the 62nd parallel would be about equivalent to the North Sea, divided about evenly between the Norwegian Sea and the Barents Sea.

It was not until 1988 that the Norwegian Petroleum Directorate carried out a complete evaluation of the total undiscovered petroleum potential on the Norwegian continental shelf. The discovered resources in 1988 were 2.44 billion Sm^3 o.e. oil and 3.09 billion Sm^3 o.e. gas. The undiscovered resources were calculated to be approximately 3.75 billion Sm^3 o.e., split into 1.19 billion Sm^3 o.e. oil and 2.56 billion Sm^3 o.e. gas. The total resource potential was thus extimated to be somewhat less than 9.3 billion Sm^3 o.e., but in 1988 the potential for improved oil recovery was not taken into account.

During the years 1991/92 the Norwegian Petroleum Directorate carried out a new assessment of the undiscovered resources on the Norwegian continental shelf. For the first time the estimates were carried out by means of a statistical software programme. The undiscovered resources were then calculated to be approximately 3.89 billion Sm^3 o.e. split into 1.48 billion Sm^3 o.e. oil and 2.41 billion Sm^3 o.e. gas. At the end of 1992, the discovered resources were 3.02 billion Sm^3 o.e. oil/NGL and 3.13 billion Sm^3 o.e. gas. When in addition to this, an expected potential for increased oil recovery of 0.57 billion Sm^3 o.e. was included, the total petroleum resources were estimated to be approximately 10.6 billion Sm^3 o.e. with an oil/gas ratio of approximately 48/52.

During 1994 the Norwegian Petroleum Directorate has updated the estimates of undiscovered resources on the Norwegian continental shelf. The expected value of the new estimates is 3.53 billion Sm^3 o.e. , split into 1.44 billion Sm^3 o.e. oil and 2.09 billion Sm^3 o.e. gas. At the turn of the year 1994/95 the discovered resources were approximately 6.72 billion Sm^3 o.e., split into 3.43 billion Sm^3 o.e. oil/NGL and 3.29 billion Sm^3 o.e. gas. The total petroleum resources on the Norwegian continental shelf are now estimated to be approximately 10.75 billion Sm^3 o.e. when an expected potential for increased oil recovery of 0.5 billion Sm^3 o.e. oil is included.

During the period from the last published analysis (1992) until today, the expected *undiscovered* resource potential on the Norwegian continental shelf has been somewhat reduced. In the North Sea, the reduction is in part a result of new discoveries, and in part lower expectations. These lower expectations are linked with Upper Jurassic stratigraphic traps in the northern part of the North Sea and with deep pre-Jurassic and Jurassic traps in Sentral Graben, and are due to negative drilling results from these play models. Expectation to the Norwegian Sea has increased in the same period, due to better mapping an new geological information. In the Barents Sea, expectations are reduced, partly due to negative drilling results and partly to better mapping.

On the Norwegian continental shelf a total of 53 play models have been defined, where 25 fall within the category confirmed play models, while 28 are unconfirmed

Fig. 2.12.4.d
The main structural elements in the North Sea

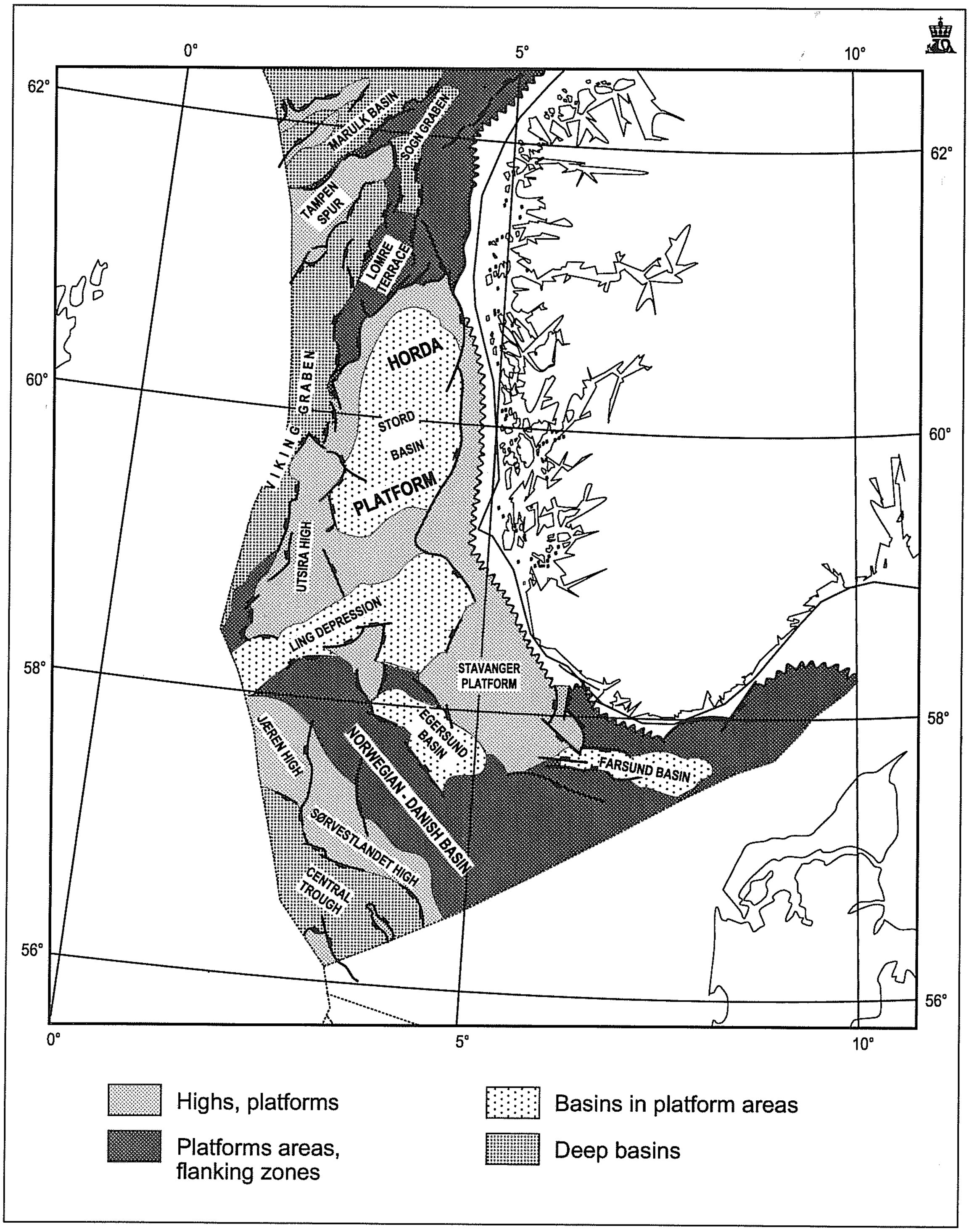


Fig. 2.12.4.e
Stratigraphic distribution of undiscovered resources in the North Sea

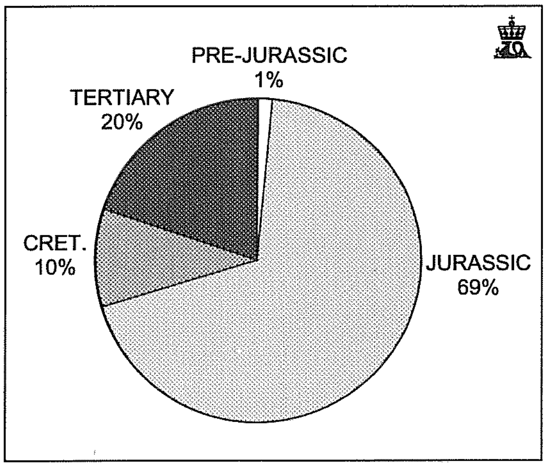


Fig. 2.12.4.f
Expected growth in resources for Late, Middle and Early Jurrasic plays in the North Sea

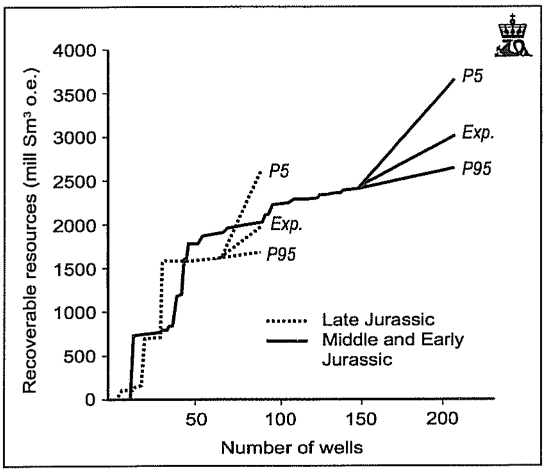
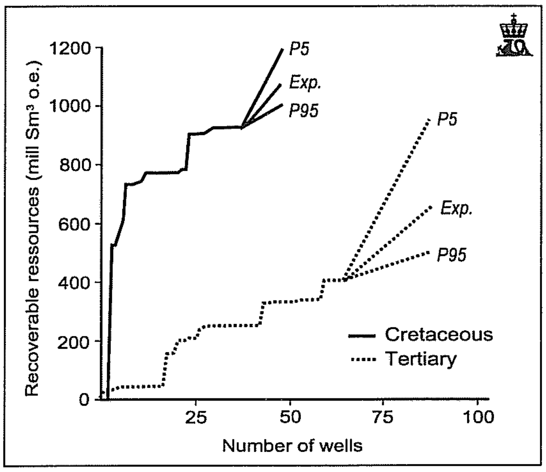


Fig. 2.12.4.g
Expected growth in resources for Tertiary and Createous plays in the North Sea



play models. In the North Sea there are 14 confirmed play models. In the Norwegian Sea, 6 confirmed play models and 13 unconfirmed play models are defined. In the Barents Sea, 5 confirmed play models and 15 unconfirmed play models are defined. In the Norwegian Sea the confirmed play models constitute 45 % of the undiscovered resource potential, while they constitute 40 % in the Barents Sea.

Definitions

A play model is defined by the existence of a particular reservoir rock and a mature source rock, and migration ways from the source into the hydrocarbon traps. Play models may be divided into confirmed and unconfirmed play models. Confirmed play models contain at least one discovery of producible quantities of hydrocarbons, and consequently it is confirmed that the critical factors exist *simultaneously* in these play models. In unconfirmed play models, petroleum deposits have not yet been proven, and these are consequently subject to a considerable degree of uncertainty. When oil companies have decided to drill a prospect, the decision is based on a number of factors which together desribe the properties of the prospect. Numerically this description is expressed in the form of an expected size and a discovery probability. If we add together all the resources in prospects in a given area statistically weighted with the probabilities of discovery, we obtain the risk-weighted resource potential of the area. In play model analyses, risk-weighting consists of two factors, a play model probability and a prospect probability which together constitute the probability of discovery. The play model probability is an expression of the probability of the assumed reservoir and source rock being present, and of the probability of the geological traps being effectively sealed.

The prospect probability is an expression of the probability that individual prospects have a minimum porosity, that the geological traps have been correctly mapped and that hydrocarbons have migrated into, and have been preserved in, the individual traps.

The North Sea

The expected value of undiscovered resources in the North Sea is 1,355 million Sm³ o.e., split into 740 million Sm³ o.e. of oil and 615 million Sm³ o.e. of gas. Even in a mature exploration area such as the North Sea, uncertainties in the calculations are significant, ranging from a figure of 840 million Sm³ o.e. to 2.040 million Sm³ o.e.

The main geological structural elements are shown in Figure 2.12.4.d. A total of 14 confirmed play models have been defined in the North Sea.

Play models of Early and Middle Jurassic age are subdivided geographically and defined in the Central Trough in the southernmost parts of the North Sea, in the Egersund, Farsund and Stord basins in the easterly areas, and in the northern parts of the North Sea. For the northern parts of the North Sea, Late Triassic rocks are also included in the play model. For all play models, rotated fault blocks are the most common trap type. The most important source rocks are shales of Late Jurassic age and shales and coal of Middle Jurassic age.

Fig. 2.12.4.h
The main structural elements in the Norwegian Sea

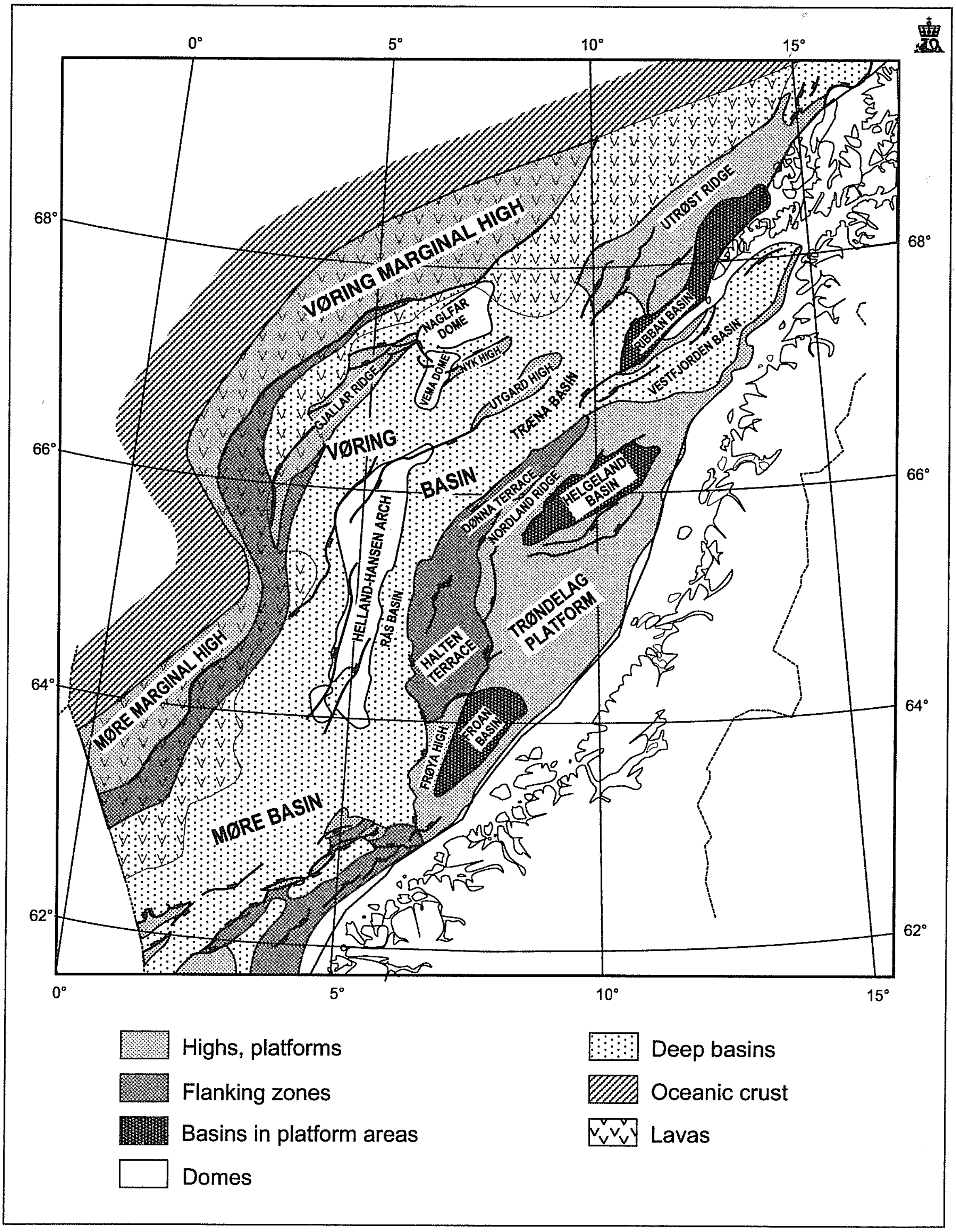


Fig. 2.12.4.i
The stratigraphic distribution of undiscovered resources in the Norwegian Sea

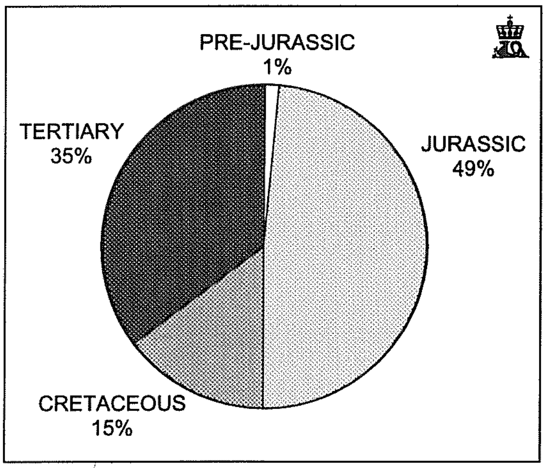
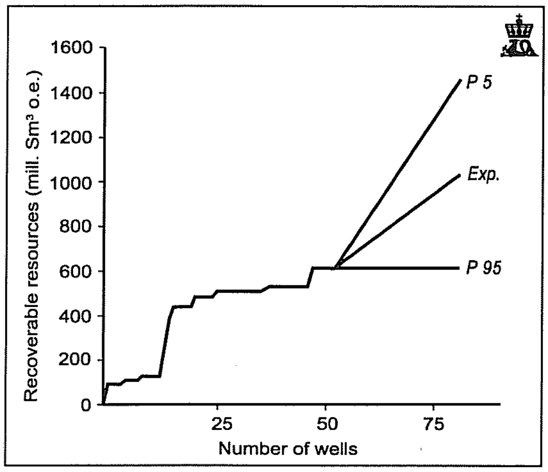


Fig. 2.12.4.j
The expected growth in resources for the Middle Jurrasic play on Haltenbanken in the Norwegian Sea



Play models of Late Jurassic age are subdivided into three geographical areas; the north-eastern part of the North Sea (equivalent to the deposits in the Troll field), the Tampen area in the northwest and the southern part of the North Sea. Both stratigraphic and structural traps are encountered. The most important source rock is shale of Late Jurassic age. In some areas there is also a possibility of older source rocks.

A Late Cretaceous play model has been defined in the Central Trough in southern parts of the North Sea. The potential in stratigraphic traps with reservoirs of reworked Cretaceous sediments is of particular interest in this play. Remaining undrilled dome structures are also possible traps, but will in volume represent a modest contribution. The source rock is Late Jurassic shale.

Tertiary play models are located largely in western parts of the North Sea and are subdivided according to potential reservoir levels in the Tertiary. Both structural and stratigraphic traps are encountered. The most likely source rocks in these play models are shales and coals of Jurassic age.

The stratigraphic distribution of expected, undiscovered resources shows that 60 % of the oil and 80 % of the gas potential is in Jurassic play models, and that the remaining resource potential is chiefly in Tertiary and Late Cretaceous play models, see Figure 2.12.4.e.

In the play analysis, a statistical forecast of the distribution of both the sizes and numbers of discoveries has been calculated for each play model. These distributions are based on the resource estimates for each play model. There is a considerable spead in the resource estimates, leading to considerable uncertainty both with regard to the statistical distribution of discovery sizes and the most probable number of future discoveries.

Approximately 90 % of the undiscovered resources in the North Sea are located in deposits which are larger than 5 million Sm^3 o.e.

Play models in Jurassic rocks are expected to contribute with the largest discoveries also in the future. The largest undiscovered accumulations are statistically calculated to be approximately 60 million Sm^3 o.e., with a spread from 15 to 200 million Sm^3 o.e. Corresponding calculations for play models of Tertiary age show that the expected largest accumulations statistically will be approximately 30 million Sm^3 o.e., with a spread ranging from 20 to 45 million Sm^3 o.e.

The growth in resources for each exploration well is a measure of the efficiency of exploration activities. The figures 2.12.4.f and 2.12.4.g illustrate the historical growth in resources as a function of the number of exploration wells drilled for play models of Jurassic, Cretaceous and Tertiary age respectively, in the North Sea. The figures also show future trends based on expected value and the associated range of uncertainty.

With regard to play models of Jurassic age, the expected growth in resources for each exploration well shows that the historical trend is expected to continue.

The prognosed trend for Cretaceous play models is linked to the future investigation of stratigraphic hydrocarbon traps with a different size distribution than in previously drilled structures (Ekofisk, Valhall etc.). The situation is somewhat more complex for Tertiary play models, covering play models of varying exploration history duration and varying expectations to prospect definition.

The Norwegian Petroleum Directorate's prospect data base contains records of more than 250 mapped prospects in the North Sea. These prospects represent approximately 45 % of the total expected undiscovered resources in the North Sea.

An areal subdivision of the play models between areas with and areas without exploration licences in the North Sea has been performed in connection with the resource analysis. About 2/3 of the undiscovered resources are located in areas without exploration licences.

The Norwegian Sea

The expected value of undiscovered resources in the Norwegian Sea is 1 345 million Sm^3 o.e., comprising 455 million Sm^3 o.e. of oil and 890 million Sm^3 o.e. of gas. The level of uncertainty in the calculations is substantial, ranging from 330 million Sm^3 o.e. to 3 330 million Sm^3 o e.

Fig. 2.12.4.k
Major elements of the geological structure in the Barents Sea

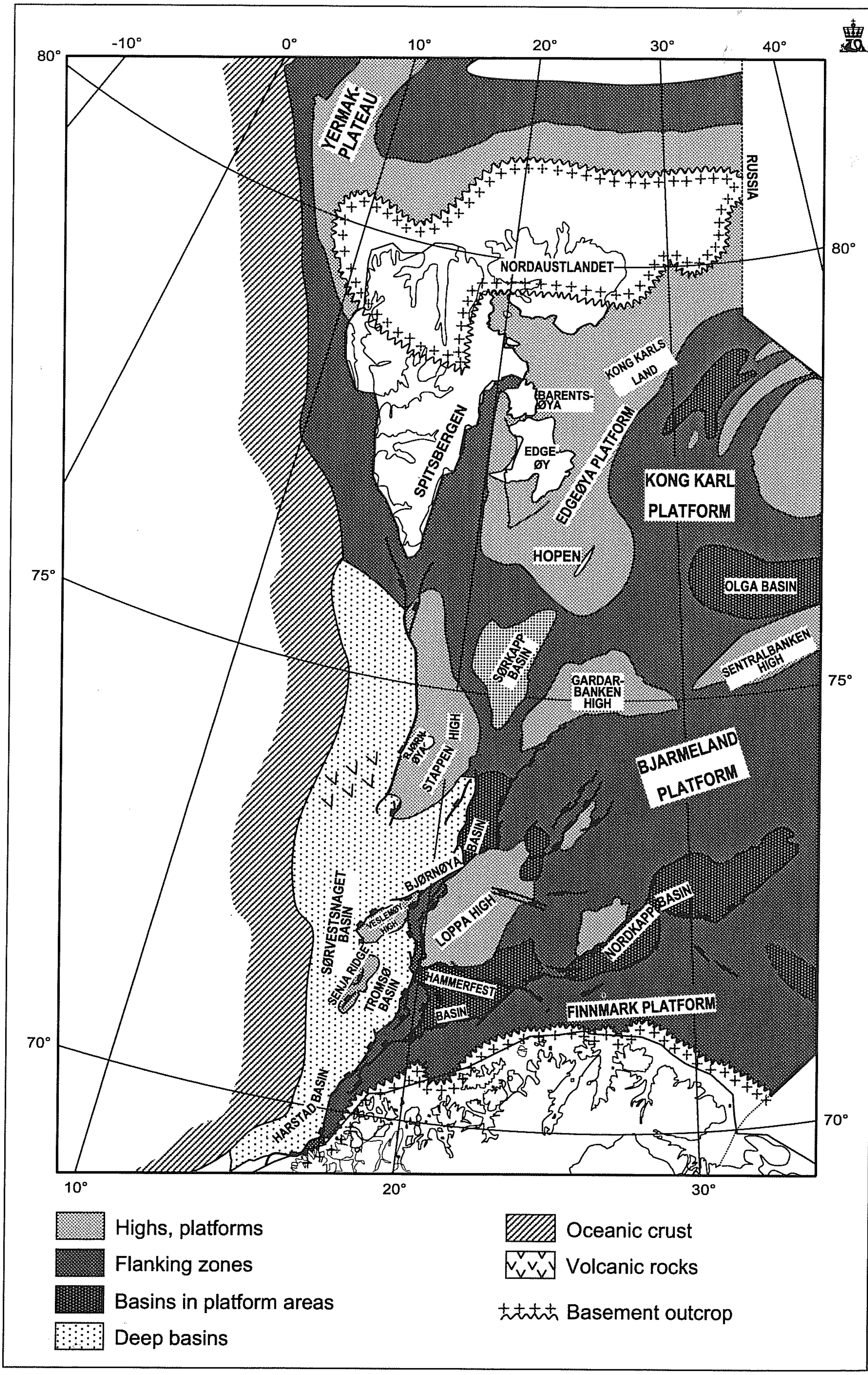
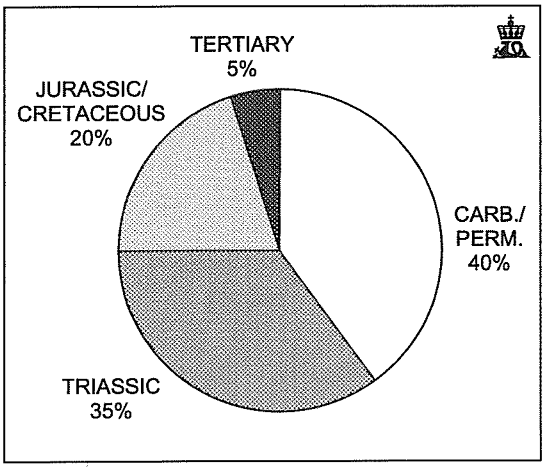


Fig. 2.12.4.l
Stratigraphic distribution of the undiscovered resources in the Barents Sea



The great uncertainty in the estimates underlines the need for a cost effective exploration strategy in the Norwegian Sea. This entails the need for a gradual exploration of new areas. Available geological information must be used effectively to explore the unconfirmed play models. This again requires very thorough mapping and evaluation prior to drilling.

The principal geological structural elements are shown in Figure 2.12.4.h.

Six confirmed and 13 unconfirmed play models have been defined in the Norwegian Sea.

Two unconfirmed play models of pre-Jurassic age have been defined near the coast on the Trøndelag Platform, and in the Træna and Ribban Basins. Trap type is rotated fault blocks. For the southerly play model, the source rock is assumed to be of Permian age. With regard to the northerly play model, source rocks are thought to be of Early and Late Jurassic age.

The three play models of Early and Middle Jurassic age are geographically subdivided. The confirmed play model is defined on Haltenbanken extending northwards into the Nordland II area. An unconfirmed play model is defined in the areas south and west of Lofoten, another on the Vøring and Møre Marginal Highs in the west. For all these play models, rotated fault blocks form the most likely trap type, with shales and coals of Early Jurassic age and shales of Late Jurassic age the most likely source rocks. In areas adjacent to the coast, it is also possible that a source rock of Permian age may contribute.

Two play models have been defined in sediments of Late Jurassic age, one confirmed play model on the Frøya High and the Trøndelag Platform (the Draugen field), and an unconfirmed play model on the flanks below these highs. Both exhibit stratigraphic trap types and have source rocks of Jurassic age.

Two confirmed play models have been defined in rocks of Early Cretaceous age. The traps are stratigraphic and the source rocks assumed to be of Jurassic age

Five play models have been defined in Late Cretaceous rocks. Three of the play models are classified according to stratigraphic level, and two of these are confirmed.

The play models have been defined on the Halten and Dønna Terraces and in areas near the northern coast approaching Lofoten. The trap types are stratigraphic, and shales of Late Jurassic age are the most important source rocks. The other two play models are unconfirmed, and are defined in the Vøring Basin. Both stratigraphic and structural traps are anticipated, and the likely source rocks are thought to be shales of Late Cretaceous age.

Three unconfirmed play models have been defined in sediments of Early Tertiary age. These are subdivided geographically, in the area south and southwest of Lofoten, and in the Møre and Vøring Basisns, respectively. Traps are thought to be stratigraphic. In areas near Lofoten, possible source rocks are Late Jurassic shales, whereas non-proven Late Cretaceous and Tertiary shales are potential source rocks for the Tertiary play models in the Møre and Vøring Basins.

The stratigraphic distribution of expected undiscovered resources, Figure 2.12.4.i, demonstrates that 70 % of the oil resources will be found in Jurassic play models. The gas resources are split 40 % in Jurassic and 40 % in Tertiary play models.

The statistical distribution of the sizes of future discoveries can be calculated only for confirmed play models. In the Norwegian Sea, the resources in the confirmed play models constitute 55 % of the expected oil resources and 30 % of the expected gas resources. An example of a statistical distribution of sizes of discoveries has been taken from a Middle Jurassic play model on Haltenbanken, see Figure 2.12.4.j. In this play model, the statistical distribution shows that about 95 % of the resources are expected to be found in accumulations larger than 5 million Sm^3 o.e. The largest accumulations in this play model are calculated to be approximately 50 Sm^3 o.e., with a spread from 20 to 110 Sm^3 o.e.

Measured in terms of exploration wells, the Norwegian Sea has had a relatively short exploration history. Consequently, only the Middle Jurassic play model on Haltenbanken provides sufficient statistical data to support a comparison between historic and future exploration efficiency. The historical, compared with the prognosed growth in resourcs for each exploration well, illustrates the expectations in exploration efficiency for this play model.

The Barents Sea

The expected value of undiscovered resources in the Barents Sea is 825 million Sm^3 o.e., comprising 240 million Sm^3 o.e. of oil and 585 million Sm^3 o.e. of gas. Uncertainty in the calculations is considerable, and ranges from 295 million Sm^3 o.e. to 1 955 million Sm^3 o.e.

The uncertainty of the estimates and the exploration results over the last few years indicate the need for a very cost effective future exploration in the Barents Sea. The authorities have therefore, in cooperation with the oil companies, drawn up a concept for a future allocation of exploration licences in this area (cf. Report to the Storting, No. 26, 1993-94). The framework conditions applicable to the Barents Sea will in a number of ways be adapted and made less stringent. In addition, the oil companies are encouraged to engage in a comprehensive co-operative mapping effort prior to the allocation of new licences.

The main geological structural elements are shown in Figure 2.12.4.k.

A total of 5 confirmed and 15 unconfirmed play models have been defined in the Barents Sea.

Two unconfirmed play models have been defined in sandstones of Early Carboniferous age on the Finnmark Platform and Loppa High, and on the Kong Karl Platform. Trap types are both structural and stratigraphic. Likely source rocks are shales and coals of Carboniferous age.

One confirmed and two unconfirmed play models are defined in Late Carboniferous and Permian dolomites and limestones. The play models are defined on the Finnmark Platform, the Loppa High and in the north-easterly platform areas. Trap types are both structural and stratigraphic. Permian and Carboniferous shales and coals are potential source rocks. The confirmed play model is defined on the Finnmark Platform with spiculites (fossilised siliceous sponge spicules) as the reservoir.

A total of 8 Triassic play models have been defined, two of which have been confirmed. The models are classified partly in terms of stratigraphy and partly geography. Together the play models cover the majority of the eastern platform areas, and their associated basins. Both stratigraphic and structural trap types are anticipated, and possible source rocks are shales of Triassic, Permian and Carboniferous age. Two play models of Early and Middle Jurassic age have been defined. One confirmed play model is defined in the Hammerfest Basin. One unconfirmed play model is defined in the western areas. In both cases rotated fault blocks constitute the trap type, and Late Jurassic or Triassic shales are potential source rocks.

Play models of Late Jurassic and Early Cretaceous age have been defined in the same areas.

Two unconfirmed play models of Tertiary age have been defined in the marginal western areas and on the Yermak Plateau. Likely trap types may be both structural and stratigraphic, and possible source rocks may be shales of Jurassic, Cretaceous and Tertiary age.

The stratigraphic distribution of expected undiscovered resources, Figure 2.12.4.l, shows that Permo-Carboniferous play models are expected to contain 40 % of the total resources, and also that there is an interesting gas potential in Triassic and Jurassic/Cretaceous play models. Within the established areas, the greatest expectations centre around the Finnmark Platform. The sparsely studied areas of the northern Barents Sea are expected to have a significant potential for gas, as well as an interesting oil potential.

2.13 PETROLEUM ECONOMY

2.13.1 EXPLORATION AND PLANNING ACTIVITIES

In 1994, 21 exploration wells were spudded, while the number of exploration wells in 1993 was 27. In 1994, 18 wildcats and 3 appraisal wells were spudded. The corresponding figures for 1993 were 21 and 6, respectively. On

Fig. 12.13.1.a
Annual exploration and planning costs

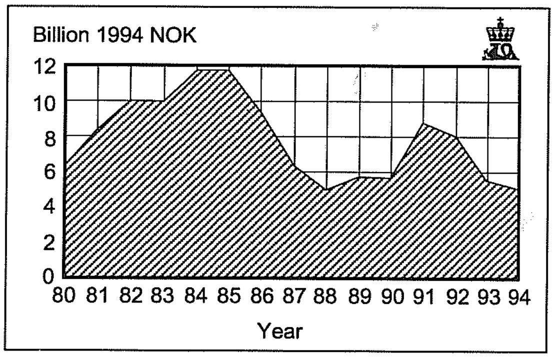
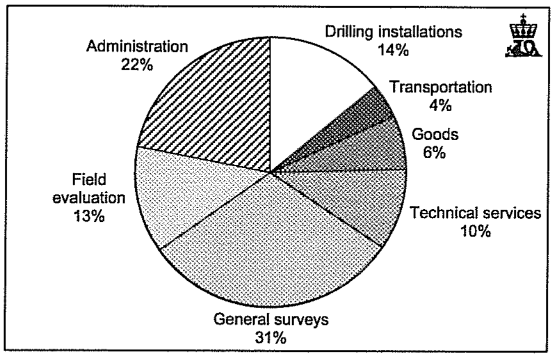


Fig. 2.13.1.b
Exploration and planning costs for 1994 by expenditure type



average for the period 1966 to 1994, the number of spudded wildcat wells and appraisal wells has been 20 and 8, respectively.

Figure 2.13.1.a illustrates the costs of exploration and planning activities from 1980 onwards. These costs include exploration drilling, general surveys, field evaluation and administration. According to figures reported to the Norwegian Petroleum Directorate, total exploration costs for the period 1980 to 1994 amount to approximately 1994-NOK 117 billion.

Shown below are the exploration and planning costs for 1994 broken down by goods and service categories. The amounts reflect data reported by the operating companies. The same statistics are basis for the chart in Figure 2.13.1.b, which shows the percentage breakdown between the different expenditure types.

Exploration and planning costs		NOK million
Exploration drilling		1725
- Drilling installations	702	
- Transportation costs	213	
- Goods	312	
- Technical services	493	
General surveys		1537
Field evaluations		654
Administration 1)		1093
Total		5009

1) Administration costs include area fees.

Fig. 2.13.1.c
Drilling costs per well

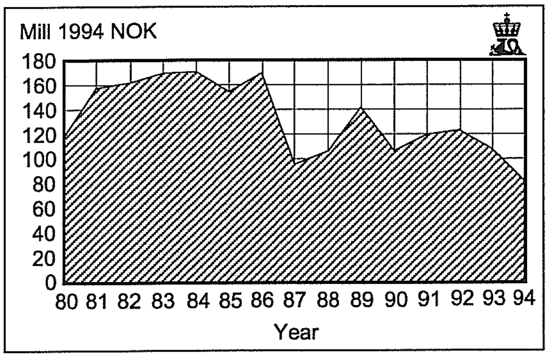
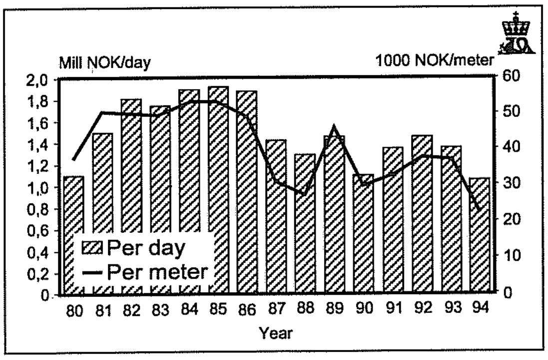


Fig. 2.13.1.d
Drilling costs 1980-1994



Expenses in connection with exploration drilling are significantly lower than in 1993, and the decrease is greatest for technical services and drilling installations. The costs for general surveys are on approximately the same level as in 1993, and now make up about 31 % of the total exploration and planning expenses. In 1993, general surveys constituted about 21 % of the total exploration and planning expenses. General surveys comprise, inter alia, collection of seismic data. Expenses in connection with seismic data compilation have shown a significant increase compared with a few years ago.

Figure 2.13.1.c gives the mean drilling costs per exploration well. i.e. wildcats and appraisal wells. Drilling costs in 1994 were roughly NOK 1.7 billion, and the costs per well are estimated to somewhat in excess of NOK 80 million. This is 20 % lower than the drilling costs in 1993.

Figure 2.13.1.d shows the mean drilling costs per day and per meter drilled in the years 1980 to 1994.

2.13.2. ACTIVITY LEVEL TOWARDS YEAR 2010

The Norwegian Petroleum Directorate has taken a closer look at the overall activity level on the Norwegian continental shelf towards the year 2010. The estimated total petroleum production is shown in Figure 2.13.2.a. The figure indicates that production is expected to increase towards a total of approximately 230 million Sm³ o.e. in 1998, decreasing in the following years towards the current level in 2005, and approximately 180 million Sm³ in the year 2010. Some uncertainty is attached to the

Fig. 2.13.2.a
Total production - Norwegian continental shelf 1970-2010

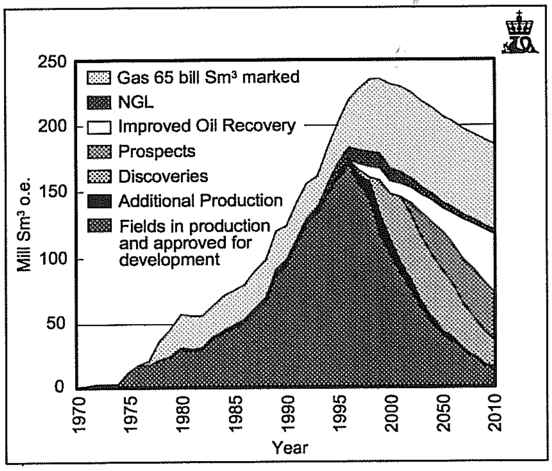
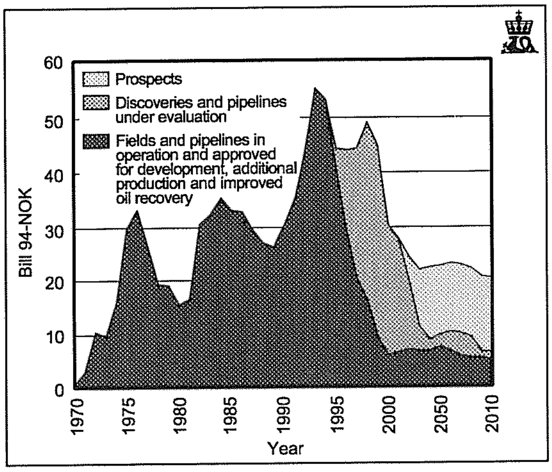


Fig- 2.13.2.b
Investments - Norwegian continental shelf 1970-2010



expected production in the years ahead.In particular the future oil and gas price development will materially affect the long term production trend.

The estimated total investment level in the period 1970-2010 is shown in Figure 2.13.2.b. The level of investments is expected to stay relatively stable in the period 1995-1999, then to decrease from over NOK 45 billion to approximately NOK 20 billion in 2010. Investments in discoveries and pipelines considered for development, improved recovery and prospects constitute the bulk of the forecast investment budget towards 2010. Future oil and gas price changes will materially affect the future investment level estimates.

Figure 2.13.2.c shows the development in operating costs on the Norwegian continental shelf towards the year 2010. Operating costs, including carbon dioxide tax and insurance cover, are expected to increase evenly until the turn of the century, then to show a decrease. Later the operating costs are reduced from about NOK 30 billion to approximately NOK 27 billion in 2010.

Fig. 2.13.2.c
Operating costs - Norwegian continental shelf 1970-2010

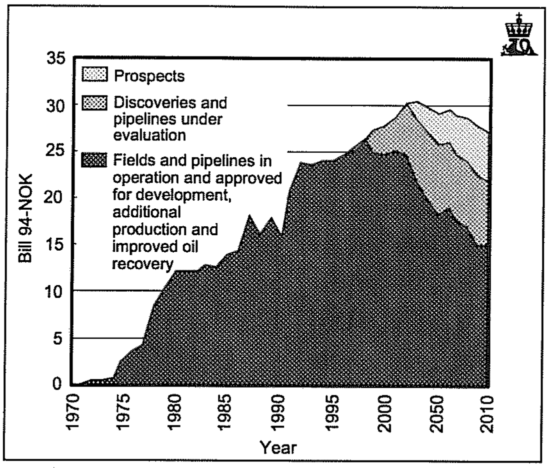


Fig. 2.13.2.d
Operating costs per unit produced for fields in production

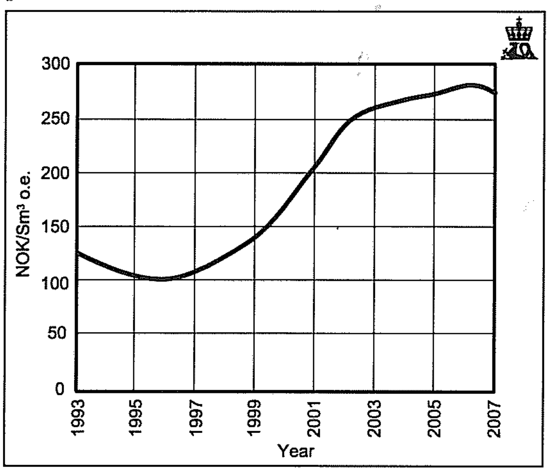


Figure 2.13.2.d shows the forecast development of operating costs for each unit produced from fields in production. As production from the fields is reduced, operating costs per unit will increase, as a large proportion of the operating costs are fixed costs. The figure shows that the operating costs for each unit produced will more than double from 1995 to 2005. Additional recovery and reduced operating costs constitute important challenges in order to reduce unit costs on the Norwegian continental shelf.

2.13.3 STATE'S DIRECT FINANCIAL INTEREST

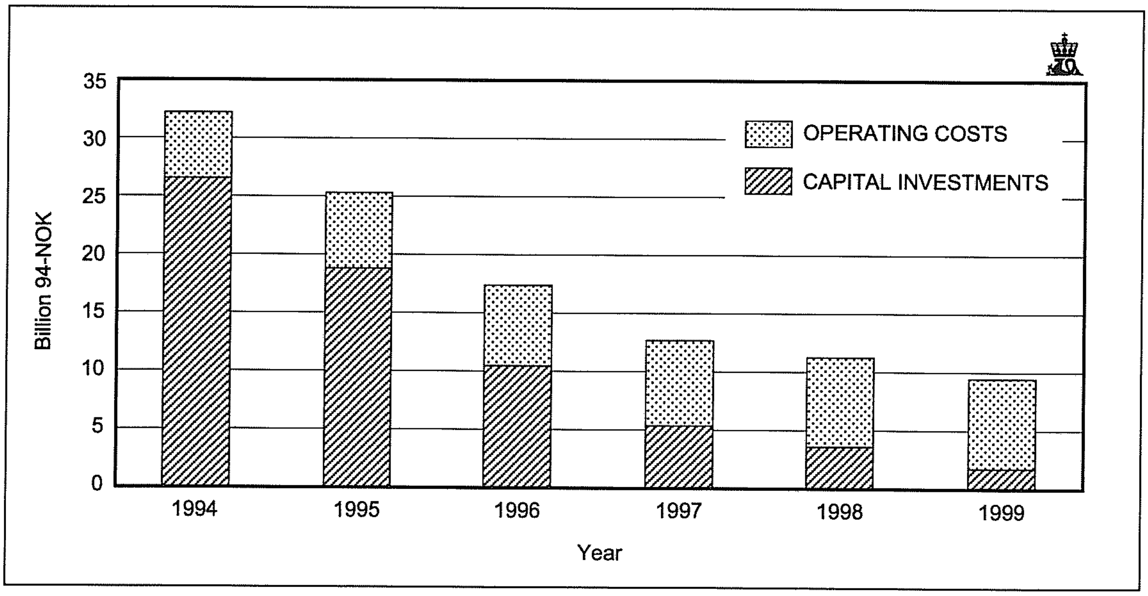
The State's Direct Financial Interest (SDFI) was established with effect from 1985. With few but important exceptions, the cash flows linked to the total state participation in production licences were divided into one Statoil share (20 %) and one SDFI share (30 %). Statoil is responsible for operational and financial administration of the State's Direct Financial Interest.

The SDFI is the largest investor on the Norwegian continental shelf and is represented with a significant volume in the exploration, development and operational phases.

The overall investment costs on the Norwegian continental shelf for the period 1994-1999 have been estimated at NOK 154 billion (non-discounted fixed 1994-NOK). This includes investments in fields in production, additional recovery and fields approved to be developed, as well as pipelines in operation and approved to be developed. The SDFI share is about 43 %.

The overall operating costs for this period are estimated at NOK 147 billion. Costs include operating costs incurred and CO_2 fees, but exclude tariffs. The SDFI share is about 28 %. The SDFI 's share of total anticipated production is expected to represent approximately 37 % of

Fig. 2.13.3
SDFI's share of total costs



the oil production (including condensate) while the eastimate for gas is 31 % in the same period.

The SDFI 's total share of these investment and operating costs amounts to approximately NOK 110.7 billion. See Figure 2.13.3 for the breakdown over time.

For a few more years the SDFI will continue to make big investments, resulting in a build-up of real capital in the petroleum sector. The yield from these investments depends in part on the future development of prices as well as the escalation of costs and any fluctuations in production for the fields concerned.

One of the main objectives of the licensing and taxation system is to apportion costs and income between private licensees (companies) and the State. Through the SDFI and framework conditions such as taxes, fees, the carrying and use of a sliding scale in favour of the SDFI, the State has collected a maximum share of the net present value of fields. The SDFI has achieved the goal set in 1985, which included ensuring the highest possible direct share for the State in future revenues from production of hydrocarbons.

2.13.4 THE ROLE OF PETROLEUM IN THE NATIONAL ECONOMY

Gross national product

The petroleum sector makes a significant contribution to the overall creation of value in Norway today. In 1975, the gross product in the petroleum sector constituted some 3 % of the gross national budget. In 1985, this share had increased to 19 %, then dropping back due to the fall in oil prices in 1985-86. More recently, the share has been in the region of 16 %. The development of the petroleum sector's contribution to Norway's Gross National Product is shown in Table 2.13.4.

Foreign economy

The petroleum sector also represents a relatively large proportion of Norway's export revenues. There was an increase in export share from approximately 6 % in 1975 to 38 % in 1985. The export share of the petroeum sector then fell to about 24 % in 1988. In recent years the share of the petroleum sector has represented approximately 33 % of the Norwegian export revenues. Table 2.13.4 shows details.

State's tax revenues

The State's total tax revenues from the petroleum activities comprise corporate wealth and income tax, special tax, royalty, and acreage fees. Tax revenues reached a preliminary high of 71.1 billion 1994-NOK in 1985, before dropping to about 14.5 billion 1994-NOK in 1988. In the course of the last few years there has again been an increase in the State's tax revenues. In 1994, tax revenues from the petroleum activities were NOK 21.9 billion. The development in tax revenues is shown in Table 2.13.4.

Employment

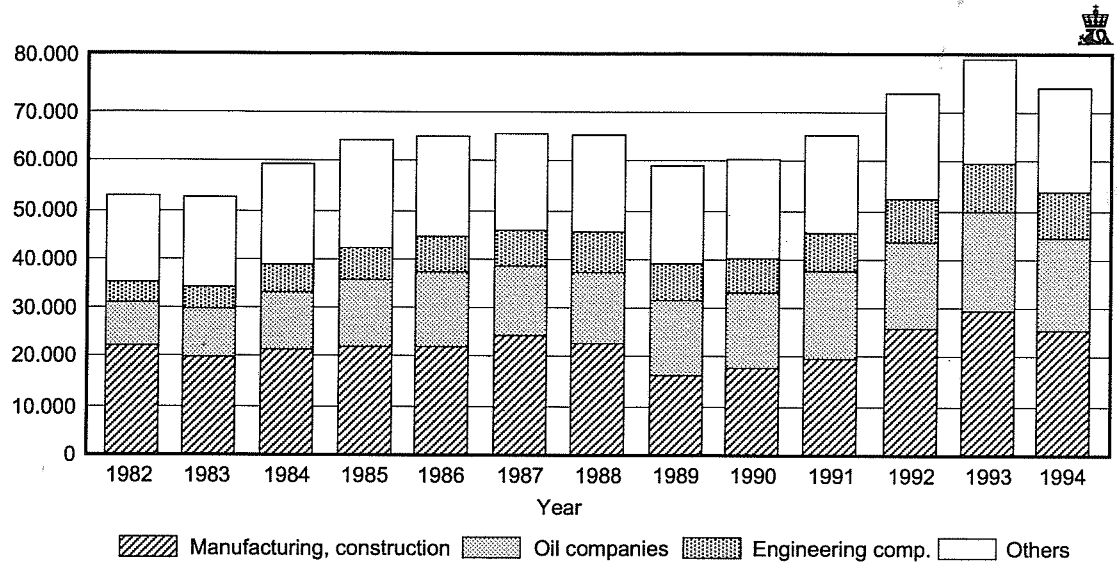
The activity level on the Norwegian continental shelf involves employment both onshore and offshore. In 1994, 73,986 people were employed as a result of the petroleum activities in Norway. Figure 2.13.4 illustrates employment as a result of the petroleum activities, broken down by type of company. Some 35 % of the employees in the petroleum sector work in industry, building and construction; 26 % in the oil companies and 11 % work in engineering consulting firms. The rest work in services, transportation, for shipowners and drilling contractors, in catering, landing facility and refinery operation, public administration, research and training.

Table 2.13.4
Development of share of GNP, share of Norwegian total exports and the State's revenues.

	1975	1980	1985	1988	1990	1991	1992	1993[4])	1994
The petroleum sector's share of GNP [1])	3 %	16 %	19 %	9 %	15 %	15 %	16 %	16 %	17 % [4])
The petroleum sector's share of total exports [2]).	6 %	33 %	38 %	24 %	31 %	32 %	33 %	33 %	34 % [4])
The State's revenues derived from petroleum activities [3]). (Bill. 1994 NOK)	0.7	45.2	71.1	14.5	29.3	34.0	25.0	25.0	21.9 [4])

Source: Central Bureau of Statistics
1) Includes production of crude oil and natural gas, drilling and operation of pipelines.
2) Includes export of crude oil, natural gas and pipeline transportation services.
3) Includes ordinary corporate tax, special tax, area fees and royalties.
4) Preliminary figures/estimates.

Fig. 2.13.4
Employees in the petroleum industry, by kind of company



Others include service-companies, transportation and shipping activities, operation of pipelines and refineries, drilling companies, catering, public administration, research and education, bases and other commodities and services
Source: Directorate of labour

2.13.5 CRUDE OIL MARKET

Global oil production (excluding NGL) is for 1994 estimated to be approximately 60.4 million barrels a day (Source: Oil and Gas Journal (OGJ) December 1994). This corresponds to approximately 3.5 billion Sm^3 per annum, and represents an increase of 1.0 % from 1993 to 1994. The largest increase was in the North Sea, whereas the largest reduction was in the former Soviet Union.

Norwegian oil output in 1994 accounted for in excess of 4 % of the global production. Norwegian oil production increased by 11 % in 1994, and was about level with the UK production, which showed a major increase in 1994.

The global proven oil resources at year end 1994 were according to OGJ just under 160 billion Sm^3, i.e. about the same as in 1993. This constitutes just over 47 years of production at 1994 level. Based on estimates the largest future oil producing areas will be OPEC and the Middle East.

At the turn of the year 1993/94 the price of Brent Blend crude was around 14 dollars per barrel. Prices fell in the beginning of 1994, but rose again to as much as nearly 19 dollars in the beginning of August. There could be several possible causes for this rise: Low stocks, strike among petroleum workers in Nigeria and stable OPEC production. During the autumn, however, the prices fell again, to around 16 dollars at the year end.

The average price of Norwegian produced crude in 1994 was just under 16 dollars per barrel, which corresponds to about NOK 111. In comparison the prices in 1993 were on average about NOK 123 per barrel (about 17 dollars).

2.13.6 NATURAL GAS MARKET

Today all Norwegian gas exports go to Western Europe. In 1994, Norway exported gas to the UK, Germany, the Netherlands, Belgium and France. The UK was the largest client up to 1990, while Germany is now the largest buyer. Figure 2.13.8 shows the distribution of gas sales to the various buying countries.

In 1994, Norwegian exports amounted to 26.6 billion Sm^3, an increase of 2 billion Sm^3 gas over the year before.

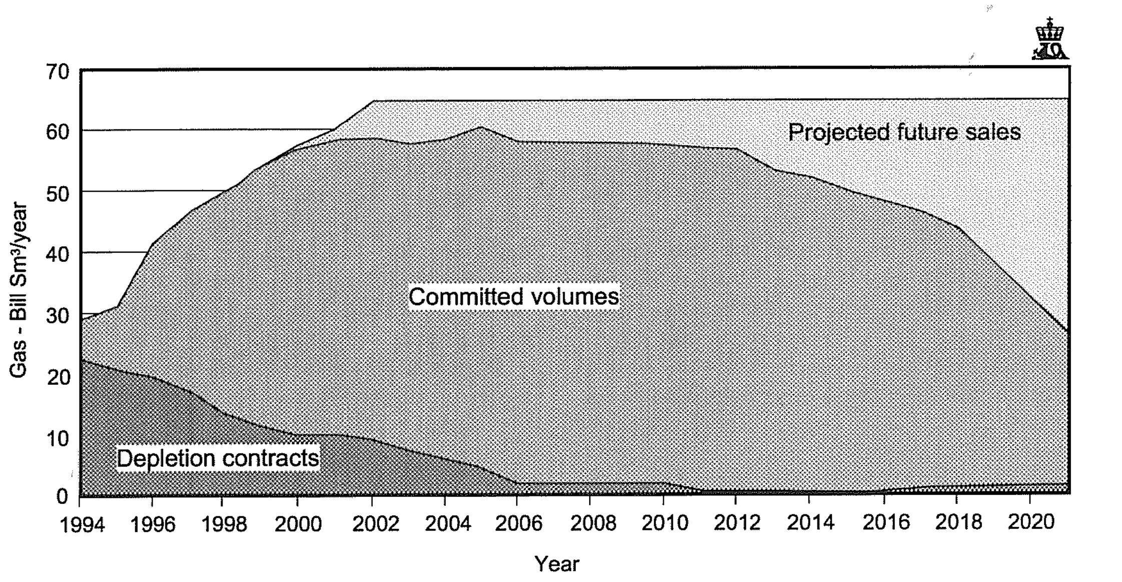
The first gas volumes sold were generally based on depletion of available reserves in specific fields. On 1 October 1993, Norway entered a new gas sales era when deliveries under the Troll gas sales agreements (TGSA) got underway. These contracts offer the buyers fixed annual volumes and permit other fields in addition to Troll to source deliveries. In connection with the Troll agreements, the authorities, by establishing the Troll Commercial Model, have opened up an avenue for the sale of associated gas and small gas accumulations.

Organisation of Norwegian gas sales

In recent years the sales of Norwegian gas have been coordinated by the Joint Gas Negotiations Committee (GFU) under the chairmanship of Statoil , and with representatives from Norsk Hydro and Saga.

The GFU negotiates contracts with buyers of Norwegian natural gas. However, the partners in a production licence have the option to sell the gas by their own efforts. Within the framework of the existing gas organisation, the authorities set up the Gas Supply Committee in 1993. This committee, which is made up of the ten leading resource

Fig. 2.13.6
Committed and projected future sales



owners on the Norwegian continental shelf, has an advisory function towards the Ministry of Industry and Energy in matters pertaining to development and exploitation of gas fields and gas transport systems.

The Ministry of Industry and Energy and the Norwegian Petroleum Directorate both sit on the Committee as observers.

2.13.6.1 Existing commitments
Field contracts

The fields currently supplying gas under field contracts are Statfjord, Gullfaks, and fields in the Frigg and Ekofisk areas. Production from these fields is now in the declining phase, but they will nevertheless deliver gas for many years to come. Gas deliveries from the Ekofisk and Frigg areas started in 1977, from Statfjord in 1985, from Heimdal in 1986, and from Gullfaks in 1987. The gas from the Frigg area is delivered to the UK, while the other fields deliver to buyers on the Continent.

Troll gas sales agreements of 1986 (TGSA)

The TGSA agreements were signed in 1986 by the Troll licensees and buyers on the Continent. The buying countries are Germany, the Netherlands, Austria, France, Belgium and Spain. The Troll agreements consist of basic gas deliveries of 23.7 billion Sm^3 per annum, with the addition of 30 % and 50 % options, which entitle buyers to receive deliveries in excess of their basic volumes, without committing them to do so. At peak level these sales to the Continent will amount to 40.8 billion Sm^3 per year at plateau.

New commitments

The Electrabel contract (Belgium) was signed in 1992. In 1993 two new contracts were signed - for sale of additional volumes to Ruhrgas and to VNG (Germany). In 1994, contracts were signed with MEEG (Germany) and GdF (France). In aggregate these five contracts represent 12.7 billion Sm^3 per year at peak delivery rate. New sales to the UK have also been negotiated, but these are subject to a new Frigg Treaty.

2.13.6.2 New sales

During 1994, negotiations and discussions have been in progress with potential buyers from many countries. Talks have also been in progress with Eastern European countries. Together with France, Italy and Spain the possibilities for sale of Norwegian gas seem to be the best here.

Sale of Norwegian natural gas to the Scandinavian markets has to date not proved economically interesting. The same applies to the sale of Liquified Natural Gas (LNG).

The Norwegian Petroleum Directorate anticipates that Norway's total sales of natural gas will ultimately increase to 60-70 billion Sm^3 per annum. Figure 2.13.6 shows commitments and potential new sales.

2.13.6.3 Use of gas in Norway

The most important Norwegian gas market is to be found on the continental shelf. The largest buyers are Oseberg and Ekofisk. In 1994, Troll (TOGI) and 30/6 Gamma Nord sold in total approximately 4 billion Sm^3 of gas to Oseberg. At Oseberg the gas is injected in order to achieve improved oil recovery. Over 4 billion Sm^3 gas from several fields was purchased for Ekofisk in 1994, for fuel and other purposes. Other fields use smaller quantities of gas to improve recovery of oil and NGL. In addition, gas is the most important source of energy for operation of fields and transportation systems. Primarily it is gas produced from the individual fields themselves which is used for this purpose.

Gas has been landed in Norway since Statpipe was taken into use in 1985. Plans have also been approved to land gas at Tjeldbergodden in 1995, and Kollsnes in 1996.

In February 1992 the Storting gave its approval for delivery of about 0.7 billion Sm^3 gas a year from the Heidrun field to a methanol plant at Tjeld-bergodden starting in 1996. In North Rogaland, an agreement has been signed for smaller annual deliveries to Gasnor, a distribution company. Gasnor at Kårstø was established with the purpose to distribute gas to industrial activities in North Rogaland.

Over a period of time, resources have been used for research, reports and pilot projects for use of gas on-shore in Norway. The State Programme for Exploitation of Natural Gas (SPUNG) has received the bulk of the research funds. Support has been granted to research projects in the transportation sector (buses, ferries). At Kollsnes, small quantities of gas have been offered to local buyers at favourable prices, without this having resulted in sales. Other uses of the gas, e.g. a bioprotein plant, may be feasible at one of the three landing sites. In any case it will be a question of very small quantities of gas compared with the quantities being exported.

Statkraft, Statoil and Norsk Hydro have since the middle of the 1980s considered several different alternatives for gas power in Norway. For various reasons these have not materialised. A joint venture company, Naturkraft, was established in 1994 by Statkraft, Statoil and Norsk Hydro. The purpose of Naturkraft is to utilise natural gas from the continental shelf for production of electric power to Nordic markets.

2.13.7 SALE OF PETROLEUM FROM THE NORWEGIAN CONTINENTAL SHELF

In 1994, total sales of crude oil from the Norwegian continental shelf amounted to 124.3 million tonnes. This represented an increase of 12.8 % compared to 1993. Norway was the largest recepient with 22.2 % of the shipments, The United Kingdom received 19.1 %, the Netherlands 16.2 %, Germany 10.5 % and France 8.0 %. In 1994, Norway's own share was 20.3 %. This is a slight increase compared with 1993.

Figure 2.13.7.a shows the sale of crude oil by country for the period 1982-94. Up to 1988, both Belgium and Canada were reported under the heading 'Others'.

The sale of Natural Gas Liquids, (including condensate), from the Norwegian continental shelf reached 5.5 million tonnes in 1994. This is 2.4 million tonnes more than in 1993.

Figure 2.13.7.b shows the sale of crude oil and NGL in 1994 by licensee.

Norway exported 24.6 billion Sm^3 of gas in 1994. This represents an increase of 7.7 % compared to 1993.

Fig. 2.13.7.a
Sale of crude oil from the Norwegian continental shelf

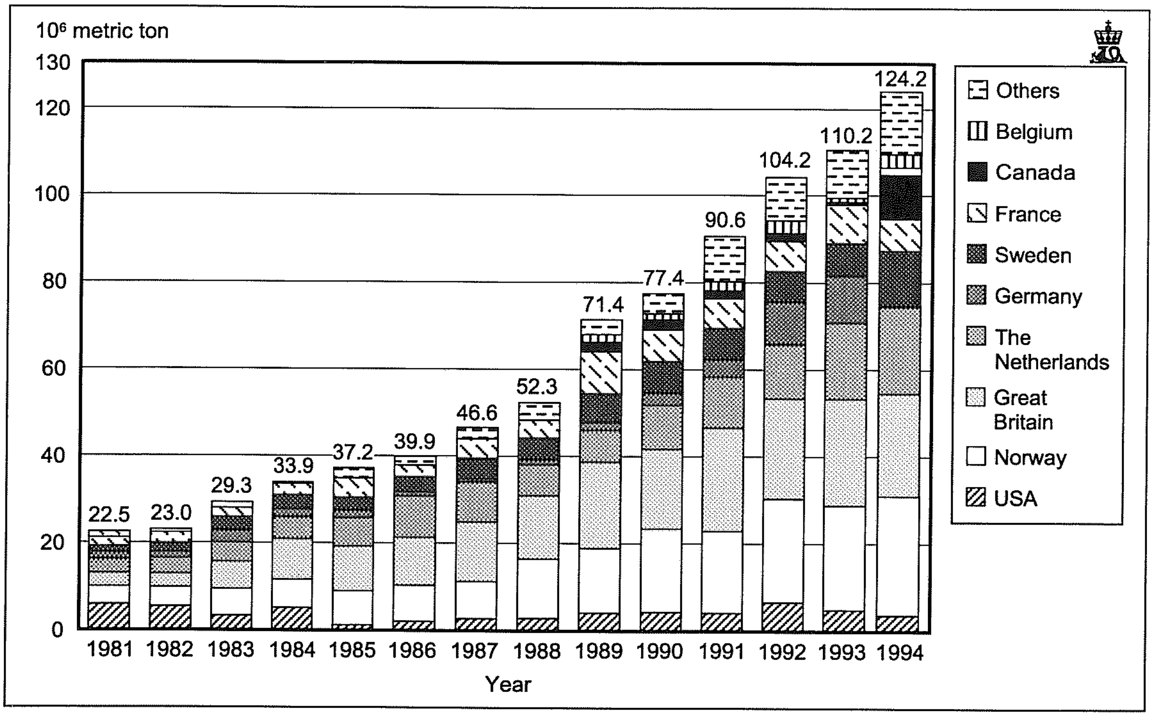


Fig. 2.13.7.b
Sales quantities of oil/NGL (excl. condensate) per licensee in 1994

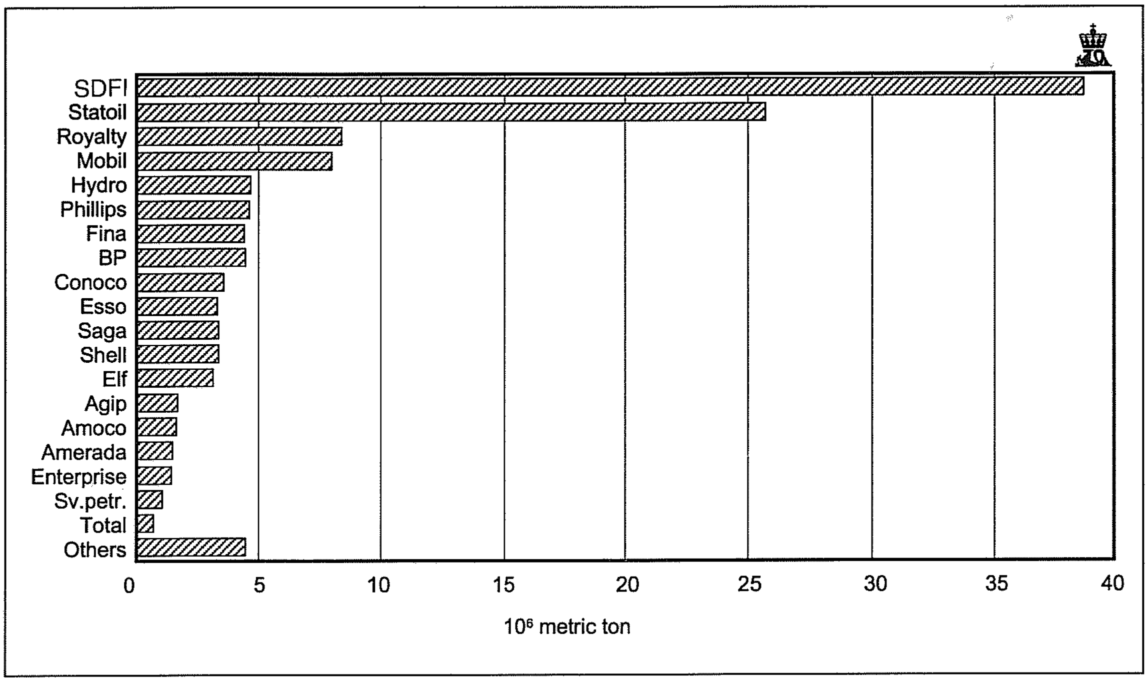


Fig. 2.13.7.c
Sales quantities of gas per country

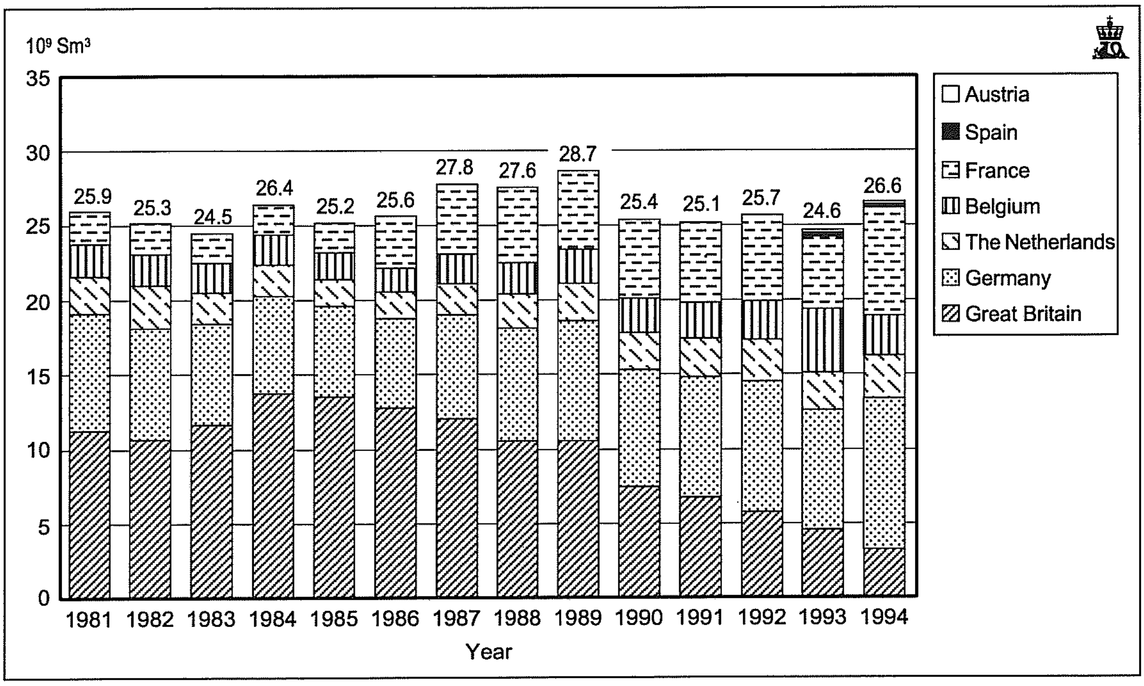
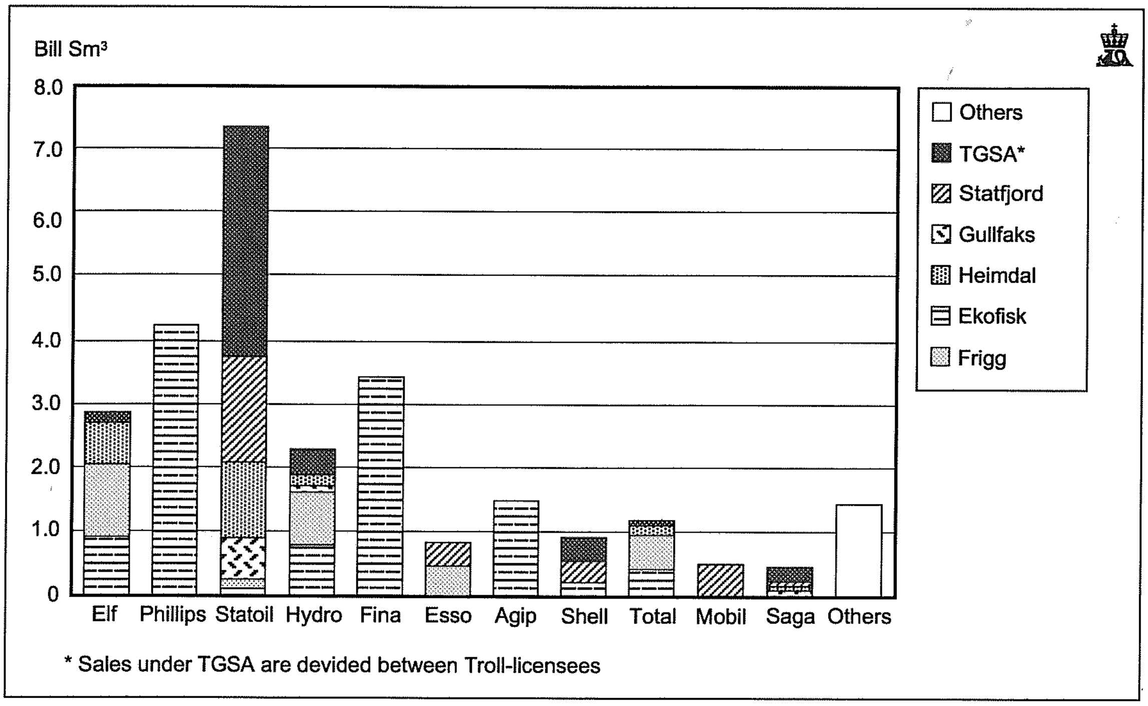


Fig. 2.13.7.d
Sales quantities of gas per licensee in 1994



A total of 9.9 billion Sm³ was sold to Germany, 3.0 billion Sm³ to the UK, 6.9 billion Sm³ to France, 2.8 billion Sm³ to the Netherlands, 2.6 billion Sm³ to Belgium, 1.1 billion Sm³ to Spain, and 0.3 billion Sm³ to Austria, cf. Figure 2.13.7.c.

Figure 2.13.7.d shows the gas sale by licensee. Sales under the TGSA agreements are distributed to the Troll owners.

The column 'Others' is not split up into companies, as it contains figures for many small fields and it would be very inaccurate to specify them.

2.13.8 ROYALTY

The Norwegian Petroleum Directorate has been delegated the responsibility for collection of royalty from petroleum production.

Production royalty is calculated according to the provisions of the Act relating to Petroleum Activitites, which entered into force on 1 July 1985. The formula for calculating the royalty is the value of petroleum production passing each field's loading point. As it is not customary to calculate the price of petroleum products at the loading point, in practice the formula applied is the difference between the gross sales value and the costs incurred between the taxation point and the point of sale.

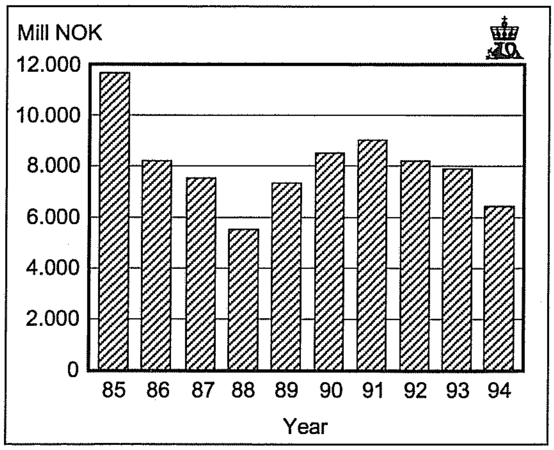
In Odelsting Proposition no. 64 (1986-87), Act regarding certain amendments to the Petroleum Act, it was provided that royalties would not be charged for production from areas for which the development plans were approved after 1 January 1986.

The interpretation and enforcement of the current statutory rules and regulations for royalty calculation involve problems of a legal, economic, processing and measurement nature.

From 1 January 1992 the royalty rate for gas was set to nil, confer Royal Decree of 27 March 1992 and The Crown Prince Regent's Decree of 22 May 1992. This means that from now on, royalty will only be levied on oil.

Since on some fields the oil and NGL are one single product at the loading point, as the NGL is only separated out later, then for those fields royalty will be paid on the NGL. On the other hand, NGL is not payable for fields where NGL at the loading point constitutes a part of the gas.

Fig. 2.13.8
Royalties paid 1985-1994



For some fields the costs of transportation have at times been higher than the gross sales value of the specific petroleum product. This occurred most frequently before 1992, when royalty was still levied on gas. Under such circumstances the petroleum product in question has no value at the taxation point, and no royalty is charged.

2.13.8.1 Total royalty

The licensees on the Norwegian continental shelf have in 1994 paid in NOK 6,595,851,967 in royalties to the Norwegian Petroleum Directorate. Table 2.13.8.1 shows the breakdown for the various petroleum products for 1993 and 1994. Figure 2.13.8 shows royalty revenues for the period 1985-94.

Table 2.13.8.1
Royalty paid in 1993 and 1994 (mill NOK)

Product	Field/area	1993	1994
Oil	Ekofisk area, Ula and Valhall	1 624.7	1 307.5
«	Statfjord	4 186.9	3 273.4
«	Murchison	18.5	17.0
«	Heimdal	*-2.0	0.0
«	Oseberg	1 034.6	985.6
«	Gullfaks	972.7	896.7
NGL	Ekofisk area	4.6	18.1
«	Valhall	6.4	1.9
«	Ula	6.3	101.6
«	Murchison	0.9	0.3
«	Heimdal	**-1.8	**-6.2
TOTAL		7 851.8	6 595.9

* Related to refund of transport costs for royalty oil
** Refund of area fees etc. for previous periods

2.13.8.2 Royalty on oil

In 1994, a total of NOK 6,480,144,810 was collected in royalties on oil production from the Ekofisk area, Ula, Valhall, Statfjord, Murchison, Oseberg, and Gullfaks, see Table 2.13.8.2. Royalty on oil is usually taken out in kind, but the Ministry of Industry and Energy has determined that royalty on oil from Heimdal is to be taken out in cash as from 1 April 1993. The sale of the State's royalty oil is the responsibility of Statoil. Payment from Statoil to the Directorate is on a monthly basis. Settlement is at the nominal rate (norm price) fixed from time to time by the Petroleum Price Council. A significant part of the considerable decrease in production royalties from oil from 1993 to 1994 is due to lower oil prices.

Table 2.13.8.2
Royalty paid on oil

Field/area	1st half	2nd half	Total 1994
Ekofisk area, Ula and Valhall	696 797 605	610 656 1691	307 453 774
Statfjord	1 665 070 553	1 608 273 516	3 273 344 069
Murchison	7 465 904	9 523 346	16 989 250
Heimdal	0	0	0
Oseberg	431 417 947	554 201 694	985 619 641
Gullfaks	457 650 730	439 087 346	896 738 076
TOTAL	3 258 402 739	3 221 742 071	6 480 144 810

2.13.8.3 Royalty on NGL

In 1994, a total of NOK 115,707,157 was collected in royalties on NGL. Table 2.13.8.3 shows the breakdown of the revenues on company/group on a six month basis.

The settlement of royalties paid in cash, is on a six month basis, with a three month term for payment. Even though the royalty on gas was set to nil effective 1 January 1992, the receipts for NGL in 1994 will also include certain adjustments in respect of royalties from gas in previous years. Settlement for NGL was made at contract prices which vary with the individual fields/groups.

The delivery of gas to Dyno/Methanor was discontinued effective from 1 July 1984. The receipts from Dyno/Methanor relate to the transportation and processing of gas already received and paid for.

Table 2.13.8.3
Royalty paid on NGL

Field/area	1st half	2nd half	Total 1994
Ekofisk area			
Phillipsgroup	11 074 427	10 764 781	21 839 208
Amocogroup (Tor)	*-23 784	26 029	2 245
Shell (Albuskjell)	0	**-3 994 072	-3 994 072
Dyno/Methanor	13 066	222 593	235 659
Total Ekofisk area	11 063 709	7 019 331	18 083 040
Valhall	1 009 761	914 469	1 924 230
Ula	98 579 781	3 032 350	101612 131
Murchison	211 668	39 036	250 704
Heimdal	0	**-6 162 948	-6 162 948
Total all fields	110 864 919	4 842 238	115 707 157

* Adjustment due to final NGL prices
** Refund of area fees etc. for previous periods

2.13.9 AREA FEES IN PRODUCTION LICENCES
The Norwegian Petroleum Directorate collected NOK 227,094,598 in area fees in 1994. With reference to production licence year, the breakdown of this amount is shown in Table 2.13.9.

The Norwegian Petroleum Directorate has refunded NOK 89,381,553 in area fees in 1994. This represents the deductible portion of the area fees in the royalty settlement for production licences 006, 018, 019A, 033, 037, 050, 053, and 079.

The area fees on some of the production licences are deducted directly in the royalty settlement. For 1994, such deductions amounted to NOK 4,706,363 as is reflected in the royalty receipts.

Figure 2.13.9.a shows the net area fee receipts for the years 1973-94. 1994 shows a reduction compared

Fig. 2.13.9.a
Area fees 1973-1994

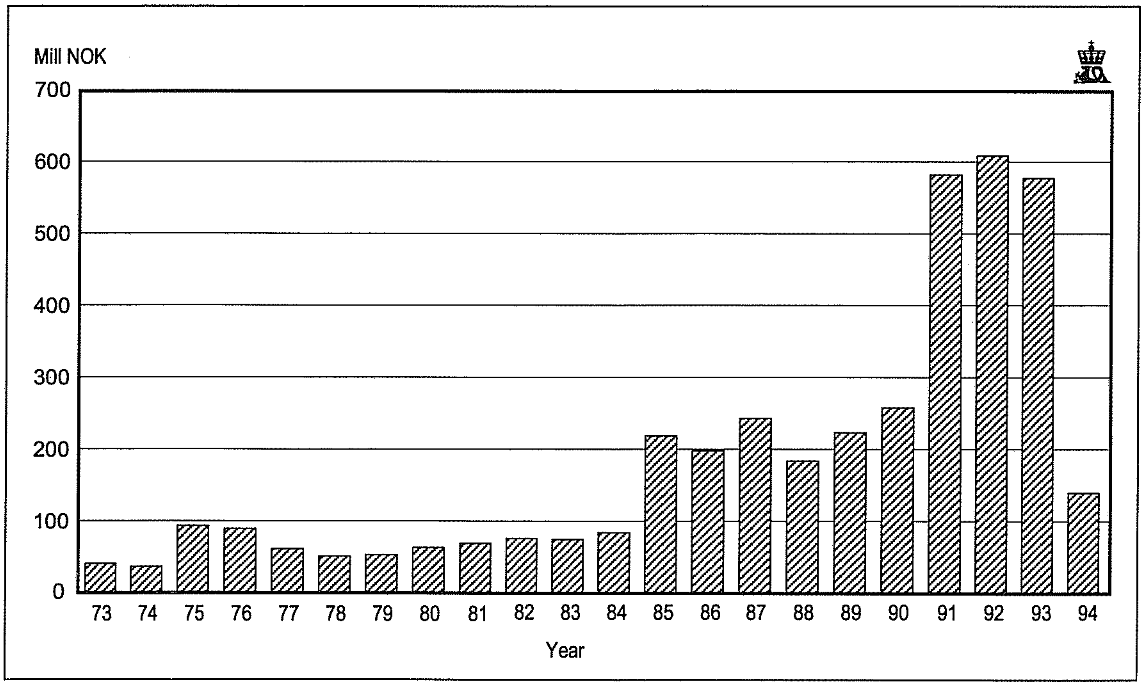


Fig. 2.13.9.b
Total tax and royalties

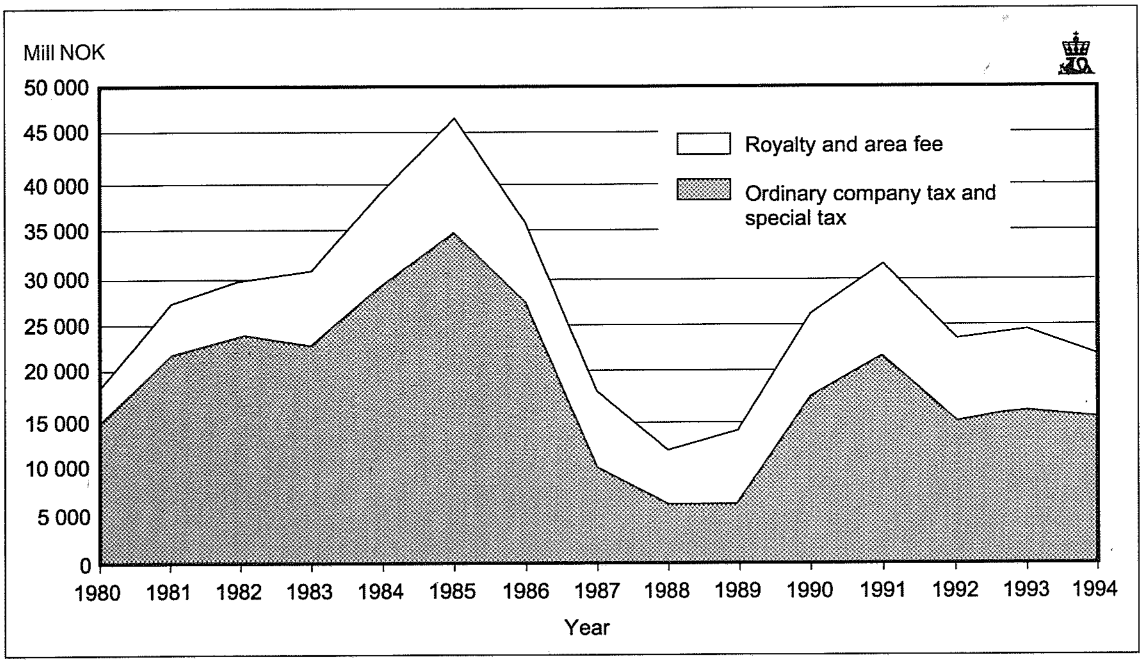


Table 2.13.9
Area fees on production licenses

Production licenses year granted	NOK
1965	75 918765
1969	61 352 559
1977	12 978 000
1979	33 941 559
1981	2 196 000
1982	-3 445 954
1984	8 449 429
1985	7 613 890
1986	8 615 474
1987	4 740 000
1988	14 469 033
1991	130 000
1992	135 843
Total	227 094 598

with 1993 of more than 400 million NOK. The reason for this is that production licences awarded according to the 1972 resolution on account of a public holiday had the due date moved to 2 January 1995.

Production royalties and area fees in 1994 amounted to 31% of all taxes and duties from the petroleum activities. The proportion of these fees and royalties has varied over the years. It was greatest in 1989 at 53 %. Figure 2.13.9.b is a summary of the total paid-up taxes and duties in 1980-94.

2.13.10 CARBON DIOXIDE TAX

The Act of 21 December 1990 No. 72 relating to tax on discharge of CO_2 in the petroleum activities on the continental shelf, entered into force on 1 January 1991. The Norwegian Petroleum Directorate is given the authority of collecting the carbon dioxide tax and of making the administrative decisions necessary to enforce the Act. The tax is calculated on petroleum flared and natural gas released to the atmosphere from platforms, installations and plants used in connection with production or transportation of petroleum. This tax is also levied on Norwegian petroleum transport systems extending outside the continental shelf. For fields extending across the median line in relation to another state, the CO_2 tax is only calculated on the Norwegian ownership share.

1993 and 1994, the CO_2 tax was stipulated to 0.80 and 0.82 NOK per Sm^3 of gas and to 0.80 and 0.82 NOK per litre of diesel oil. The tax, payable on a six month basis with three months to pay (at 1 October and 1 April in the following year, respectively), is levied on the operators of the individual fields and installation. Table 2.13.10 is a list of the total tax receipts in 1994. The tax revenues are broken down by individual field and transport systems. Corrections in previous six month periods have been taken into account. The total received in 1994 was NOK 2,557,248,267.

Table 2.13.10
CO_2 - tax for the 1. and 2. half 1994 (NOK)

Field/area:	1. half	2. half	Total 1994
Ekofisk area	366 281 051	360 539 228	726 820 279
Frigg area	19 989 664	26 447 401	46 437 065
Gullfaks A+B+C	144 595 466	151 846 383	296 441 849
Tordis		737 305	737 305
Gyda	18 051 870	19 059 245	37 111 115
Heimdal	21 345 027	18 890 616	40 235 643
Hod	6 850 680	6 105 598	12 956 278
Murchison	7 830 846	7 081 737	14 912 583
Odin	2 741 665	2 806 418	5 548 083
Oseberg A+B+C	129 313 600	132 845 188	262 158 788
Brage	14 496 000	22 366 320	36 862 320
Sleipner	74 025 472	67 499 627	141 525 099
Statfjord A+B+C	205 727 045	207 100 711	412 827 756
Ula	32 226 533	29 180 839	61 407 372
Valhall	26 511 464	27 088 128	53 599 592
Veslefrikk	25 899 760	30 335 736	56 235 496
Snorre	53 491 190	50 301 158	103 792 348
Draugen	9 743 337	27 042 305	36 785 642
Transport systems:			
Norpipe	96 603 560	109 131 409	205 734 969
Statpipe	2 383 371	2 735 314	5 118 685
Sum	**1 258 107 601**	**1 299 140 666**	**2 557 248 267**

3. Safety and working environment administration

3.1 INTRODUCTION

The Norwegian Petroleum Directorate's performance of its administrative duties in connection with safety and working environment is based on a system of close co-operation in matters of safety, working environment and resource administration, internally in the Directorate as well as externally in relation to other authorities and institutions. The Norwegian Petroleum Directorate has a co-ordinating role in relation to other public authorities which have an individual supervisory responsibility according to the Petroleum Act. Furthermore, expert assistance is called upon from other administrative agencies where the Norwegian Petroleum Directorate does not possess its own expertise.

From 1993, the Working Environment Act was also made applicable to mobile units in the petroleum activities and to manned underwater operations carried out from vessel or installation. The supervisory authority was delegated to the Norwegian Petroleum Directorate. In this way provision was made for a comprehensive and co-ordinated supervision of the petroleum activities also in the area of the working environment, as embodied in Royal Decree of 28 June 1985 concerning the regulatory supervision. The new duties assigned to the Norwegian Petroleum Directorate are clearly reflected in the account of work carried out in 1994.

Administration of safety and working environment is based on the principle of internal control. This means that the statutory legislation and supervision must be designed and implemented in such a way as to support the perception of the participants of their responsibility to ensure prudent operations in accordance with the formal framework applicable to the petroleum activities.

This means that supervision is aimed at the duty of the industry to carry out internal control, i.e. that the supervisory activities of the Norwegian Petroleum Directorate are first and foremost aimed at the licensees' control systems and decisionmaking processes which have an impact on safety and the working environment. Conclusions from supervision are directed at improvements in the control systems of the enterprises.

The system oriented supervision consists of system audits supported by verifications. The purpose of system audits is to determine if control systems have been established and see that they function. The purpose of verifications is to evaluate the effect of the control systems by examining the actual standard of safety and working environment in the enterprise. The Norwegian Petroleum Directorate's supervisory activities are in addition to the internal audits and inspection activities of the companies which are required in order to ensure compliance with the requirements of the authorities and own requirements at all times.

3.2 REVISION AND DEVELOPMENT OF LEGISLATION

In 1992, the Norwegian Petroleum Directorate completed an extensive revision of the legislation under the Safety Regulations (the technology legislation). The new legislation is functionally designed, and provides for application of different solutions inasmuch as the requirements express purpose, rather than dictate specific solutions.

At the end of 1994 this legislation has been in force for more than two years, and a picture is beginning to form of the way this legislation functions. It is the Norwegian Petroleum Directorate's opinion that the new legislation in general has been well received by the industry, even if the industry as well as the authorities have been faced with certain new challenges as a result of this legislation.

In certain areas, however, the legislation has received a somewhat more mixed reaction. Work has been initiated to map out the issues, and this will be followed up on the part of the Norwegian Petroleum Directorate in 1995.

Similarly, in connection with the work with the report on the competitive situation of the Norwegian continental shelf (NORSOK), prepared by a working group established by the Ministry of Industry and Energy, certain specific initiatives have been put forward with regard to improvements to the legislation. These will also be followed up in 1995.

In preparing the new technology legislation, one objective was to provide a basis that would allow the detailed technical standards, which the authorities traditionally set out in the legislation itself, instead to derive from industry specifications or through preparation of agreed industry standards. The Norwegian Petroleum Directorate has also in 1994 given priority to participation in standardisation work believed to be of particular importance to safety and the working environment in the petroleum activities.

The Directorate's goal is in a more long-term perspective to be able to transfer parts of the more technical elements of the regulatory legislation to the standardisation organisations, with a view to publishing this as national standards. A trend in this direction would further simplify the statutory framework of the Norwegian Petroleum Directorate, and would thereby also contribute to reducing the need to maintain and update it.

3.2.1 REGULATIONS UNDER THE WORKING ENVIRONMENT ACT

In 1991 the Norwegian Petroleum Directorate initiated work to identify the needs for, and developing frameworks for, regulations concerning the working environment in the petroleum activities. This preparatory work, together with experience from the Directorate's supervisory activities, indicated that there was no need to develop new working environment requirements, but that there was a need to highlight requirements already in existence by reference to norms and standards, precedents set by individual administrative decisions etc. and to make the changes required as a consequence of the European Economic Area (EEA) agreement.

The work on preparing draft regulations was started in 1992. The regulations will be issued pursuant to the Working Environment Act of 1977 and Royal Decree of 27 November 1992 on regulations relating to worker protection and working environment in the petroleum activities, and are intended to elaborate on these. The regulations have been named «Regulations relating to systematic follow-up of the working environment in the petroleum activities», and will be supplemented by guidelines.

The purpose in preparing the new regulations has been to:
- contribute to a structured and comprehensive regulation of working environment matters in petroleum activities;
- prepare legislation under the Working Environment Act conforming with the structure and strategies used as basis for the «Technology legislation» under the Safety Regulations;
- contribute, in co-operation with the authorities concerned, to the development of national regulations that are as uniform as possible, while at the same time reducing the numbers of «competing» sets of regulations and guidelines;
- implement the EEA agreement in the area of working environment.

The regulations seek to ensure a working environment which is in conformity with the intentions of the law. This is sought to be achieved e.g. by specification of requirements in the Working Environment Act, and by providing for regulatory supervision by the authorities to include also this area. The regulations will provide for control of the activities based on the licensees' duty to perform internal control.

The regulations will demand a systematic approach to planning and implementation of all phases of the petroleum activities and will stress the active participation of all parties in fulfilling the intentions of the Working Environment Act. The regulations also aspire to simplify and improve the authorities' administrative procedures.

In conjunction with its associated guidelines, the regulations will address matters that were previously dealt with in regulations that will be repealed when the new regulations enter into force. The regulations will also clarify interfaces with other national legislation, as well as with national and international recognized standards in this area of working environment.

Draft regulations were circulated in 1994 to external bodies and interested parties, and were at the end of the year submitted to the Ministry of Local Government and Labour with request for the Ministry's consent.

3.3 SUPERVISORY ACTIVITIES

The supervisory duties in safety and working environment matters in the petroleum activities were essentially carried out in accordance with the designated priority commitment areas for 1994. A number of universal supervisory duties were performed, by which is meant supervision aimed at a number of operating companies, and concentrating on the same issue. This is intended to provide a better basis for assessing the general situation within the individual areas.

3.3.1 CONSENTS

The system of consents is one of the tools the Norwegian Petroleum Directorate uses in its statutory supervision of the operating companies to see that they are in control in relation to central decision milestones in their activities. Application for consent to commence an activity, implies a commitment on the part of the operating company with regard to compliance with regulation requirements to the control systems in general, and to the relevant activity in particular.

The consent of the Norwegian Petroleum Directorate to commence the activity applied for, is a formalised expression of the NPD's confidence in the operator's ability to implement the activity in accordance with the requirements of the authorities.

In 1994, a total of 81 consents were awarded, with a breakdown on the various types of consent as follows:

2 consents for exploratory survey
17 consents for exploration drilling
3 consents for detail engineering
6 consents for fabrication
14 consents for installation
18 consents for use of installation
8 consents for rebuilding or changes in operation of installation
1 consent for removal
12 consents for use of service vessel.

3.3.2 COMMITMENT AREAS IN STATUTORY SUPERVISION

In 1994, the Norwegian Petroleum Directorate gave priority to supervisory activities associated with:

- new concepts in development and operation
- handling of major accident risk due to changes in operation of installations
- measures to protect the external environment
- maintenance management
- safety and working environment on mobile installations
- limitation of hydrocarbon leaks
- drilling and maintenance of high pressure and high temperature wells
- drilling in environmentally vulnerable areas

New concepts in development and operation

In this commitment area, supervision has been carried out to examine how the operating companies comply with the safety and working environment requirements in connection with economies measures, including measures that entail changes in manning. During a series of meetings in the spring, three of the operating companies gave an account of how they exercise control of processes connected with cost reductions. The meetings left an impression of considerable variation in the degree of systematic approach and thoroughness exercised by the operators in such matters. There are also marked differences in the relationship and climate of co-operation between employers and employees.

Based on the experience gained from these meetings, system audits were carried out directed at two of the operating companies in this area. Preliminary conclusions indicate a reasonably good climate of co-operation between the operating companies and the employees. It appears the parties are working systematically and with determination to achieve continuous improvement, also in the area of cost optimisation, and that considerations with regard to safety and working environment are satisfactorily included in these processes. Further audits directed at other operating companies are planned in this area for 1995.

Handling of major accident risk due to changes in operation of installations

Major modifications and changes in operation of installations represent particular challenges as regards compliance with requirements set out in the regulations relating to risk analyses and emergency preparedness, particularly in order to avoid the introduction of new risk elements with a major accident potential as a result of such modifications. The existing solutions were built according to previous detailed regulations, and any associated analyses are generally not very suitable as basis for evaluation in relation to the existing legislation.

As the first phase of this work, a base document has been prepared describing the issues and the statutory requirements, and clarifying the concepts major rebuilding and changes in operation in Section 11 of the Safety Regulations. This document has been used as basis for the selection of objects for supervision and planning of the actual supervisory activities.

Measures to protect the external environment

The basis for this commitment area is, inter alia, the fact that the volume of water produced together with the oil, increases greatly towards the end of a field's lifetime. The water produced must be purified to meet the requirements stipulated in the discharge permit. Increasing volumes of water requiring treatment entail correspondingly increased requirements to capacity and functional reliability of the water purification system.

Supervisory activities focusing on the companies' intended measures to deal with this challenge were planned.

The State Pollution Control Authority will be an important collaborator in the execution of these tasks. These activities, however, had to be postponed until 1995 as a result of capacity problems.

Maintenance management

Supervisory activities directed at the operating companies' systems for maintenance management show a number of positive aspects. This area will represent a great challenge in the years to come, particularly for the companies that operate installations nearing the final phase of production.

The Norwegian Petroleum Directorate also makes efforts to ensure that the companies even at the early stages in the engineering phase of new developments adopt clear strategies and establish adequate systems for future maintenance. A number of decisions in the earlier phases have a crucial effect on the possibilities for prudent and cost effective operation throughout the operational phase.

Through the supervisory activities carried out in 1994, the Norwegian Petroleum Directorate has highlighted items for improvement e.g. in the communication between the maintenance organisation on shore and the units responsible for implementation of the maintenance on the individual installations. Examples are such matters as inadequate specification of how the company's overall objectives relating to safety and working environment are to be realised with regard to maintenance, inadequate control parameters for purpose oriented maintenance, and lack of participation from the safety department of the company in evaluations of critical safety of systems and equipment.

The Norwegian Petroleum Directorate has also made an evaluation of aspects related to arrears in maintenance activities. It was demonstrated that figures showing the extent of arrears in relation to planned maintenance, are not immediately comparable between the various operating companies. The reason for this is that the companies work with different definitions, priorities and evaluations of safety criticality. The Norwegian Petroleum Directorate will follow up on this in 1995, with a view to establish as uniform a basis as possible for supervisory activities directed at the maintenance management of the companies.

Safety and working environment on mobile installations

Since the Working Environment Act was made applicable also to installations in the petroleum activities, effective from 1 January 1993, the Norwegian Petroleum Directorate now expects the operators to establish requirements to the working environment in connection with the use of mobile installations, and that such requirements are complied with and followed up.

The supervision of how requirements relating to the working environment are complied with on mobile installations has been continued in 1994, and has confirmed the previous impression with regard to inadequate mapping of working environment, inadequate requirement specifications, inappropriate workplace design and the lack of action plan.

The Norwegian Petroleum Directorate notes however as a positive element that the supervisory activities which have been carried out, seem to have contributed to initiating processes with licensees and contractors which demonstrate that these issues are taken seriously. Among visible effects to now are stronger management involvement and improved control in areas such as working hours, organisation of the safety service and principal enterprise responsibility.

Limitation of hydrocarbon leaks

There has in later years been an increasing trend in the number of hydrocarbon leaks reported. Some of this increase can probably be attributed to better reporting routines as a result of the Norwegian Petroleum Directorate's and the industry's own increased focus on this question. Nevertheless the Directorate finds cause for concern and has followed up on these matters with reference to the very severe damage potential in the event of accidents that may be caused by a hydrocarbon leak.

The supervisory activities in this area have been directed at the measures taken by the operators to ensure the maximum possible reduction in the number of and the extent of gas leaks. Relevant measures comprise both technical and operational aspects and also measures to contribute, through systematic risk analysis activities, to seeing that hydrocarbon leaks which may nevertheless occur, do not entail unacceptable consequences.

In 1994 the Norwegian Petroleum Directorate has continued supervision commenced in 1993 directed at several operating companies, so that at present, a total of four companies have been subject to system audits in this area. Through this supervision the Norwegian Petroleum Directorate has acquired detailed insight into the companies' systems and measures to prevent accidental releases of hydrocarbons, and has only had minor comments to these. Experience gained from these activities will be carried further in connection with supervision directed at the companies' activities to examine the handling of major accident risk.

Drilling and maintenance of high pressure and high temperature wells

Over a three-year period, five operators have been subject to audits particularly directed at control of activities in connection with high pressure and high temperature wells (HPHT). The result of an audit carried out in 1994 was basically positive, and demonstrated that the company in this case has implemented particular measures in specific areas which significantly exceed what is common practice in exploration drilling under traditional pressure and temperature conditions.

It was also demonstrated, however, that certain aspects can be improved, mainly in areas applicable to all drilling activities. Such aspects may include updating the governing documentation, stipulating requirements to personnel qualifications, understanding the management line responsibility for quality assurance, etc. The Norwegian Petroleum Directorate wishes to emphasise that such items for improvement should be particularly focused in connection with drilling of high pressure and high temperature wells, since the consequences of failure in wells of this type may be greater than usual.

The Norwegian Petroleum Directorate has noted that the industry has made considerable efforts to be able to handle the particular challenges connected with this type of well activities, inter alia through seminars, conferences and special projects.

The Norwegian Petroleum Directorate has noted that the industry has made considerable efforts to be able to handle the particular challenges connected with this type of well activities, inter alia through seminars, conferences and special projects. In this connection should be mentioned in particular a HTHT programme under the direction of Statoil, in which 12 operating companies cooperated on projects relevant to these questions.

Drilling in environmentally vulnerable areas

The work in this commitment area is in a fact-finding phase. An audit was carried out in 1994, in connection with exploration drilling on Møre I outside Runde, where the purpose of the audit was primarily the mapping of relevant issues. In connection with the planning of supervisory activities in the near future, the Norwegian Petroleum Directorate has made use of external consultancy assistance to clarify what requirements should be stipulated with regard to how the companies' risk and emergency preparedness analyses should address the considerations relating to environmental vulnerability in their planning of drilling operations with a view to arriving at preventive preparedness measures for drilling.

3.4 SUPERVISORY ASSISTANCE

According to Royal Decree of 28 June 1985 concerning regulatory supervisory activities with the safety etc., the Norwegian Petroleum Directorate, in supervising the safety and working environment in the petroleum activities, is expected to draw on professional expertise from other authorities, public bodies and institutions in areas where the Directorate does not have its own expertise. In relation to the various public authorities with independent supervisory responsibility, the Norwegian Petroleum Directorate has a co-ordinating function.

Co-operation with the relevant authorities, public bodies etc. has been satisfactory in all significant areas and represents a contribution to efficiency and consistency in the supervision of the activities.

With reference to several occurrences in 1993 where measuring instruments which contain radioactive sources have been lost during well operations, a draft agreement has also been drawn up in 1994 relating to co-ordination aspects between the Norwegian Radiation Protection Authority and the Norwegian Petroleum Directorate.

3.5 PERSONAL INJURIES

3.5.1 GENERAL

The Norwegian Petroleum Directorate receives information about personal injuries and fatalities in connection with petroleum activities on fixed and mobile installations on the Norwegian continental shelf. This information can be subdivided into two main categories:

Notification

In case of fatality or serious personal injury the Norwegian Petroleum Directorate shall be notified immediately. This notification forms the basis for an assessment of what is further required on the part of the Norwegian Petroleum Directorate. Follow-up activities may include on-scene inquiries, if applicable in co-operation with the police, or monitoring of the company's own investigation of the accident.

Report

In addition to notification of serious injuries and fatalities, the Norwegian Petroleum Directorate also receives reports of personal injury resulting in absence from work extending into the following 12-hour shift, and of injury requiring medical treatment. The reports serve as basis for statistics, such as presented in the Norwegian Petroleum Directorate's Annual Report. Reporting is a responsibility resting on the employer, but operators are required to have knowledge of events on their installations. The statistical base material registered in the Directorate is compared each year with information from the oil companies, enabling correction of any underreporting or registration errors. The injury frequencies are based on comparisons of personal injuries and working hours reported for each quarter from the individual installations and fields.

Such an extensive reporting system will have a number of possible sources of error, and the Directorate has noted a somewhat varying understanding and knowledge of reporting criteria and routines. The statistical summaries presented in the Annual Report should nevertheless provide a reasonably accurate picture of the injury situation in the petroleum activities.

3.5.2 TYPES AND CAUSES OF PERSONAL INJURY

In the light of the accounts of events and causes given on the standard injury reporting forms in 1994, the Norwegian Petroleum Directorate makes the following summary of injuries and causes:

- Wounds and crushing injuries to hands and fingers are still the most frequent type of injury. Such injuries are often a result of an inappropriate posture on the part of the injured person in relation to the equipment being operated, and must also be seen in connection with an increase in the number of occupational accidents registered where problems of access and unfavourable conditions from an ergonomic point of view are part of the overall picture of causes. The wrong use of tools and equipment is still an important factor in the cause analysis of injuries of this kind, but this is less pronounced in the recordings from 1994 than was the case in 1993. Wounds and crushing injuries as a result of equipment and tools handled not being in regulation order, however, have increased.

- Eye injuries constituted 14.6 % of the total number of injuries in 1994, as compared to 21.8 % in 1993. This is a considerable reduction, although the eyes remain one of the most vulnerable parts of the body.

  Most eye injuries are caused by air-borne particles, particularly in connection with grinding and welding work. Air-borne particles were among the most frequently recorded injury causes in 1993, but this cause factor has shown a decrease both in a total context and for eye injuries in particular.

  Handling of chemicals, painting, etc. as a cause of eye injuries has however increased greatly during the last three years, from about 8 % in 1992 to 18 % in 1994.

- Head and face injuries have also increased somewhat in 1994 as compared to the previous year. Many of these are dental injuries caused by careless handling of tools and equipment.

- There has also been an increase in acute musculoskeletal injuries due to inappropriate posture in the work situation, inappropriate lifting and also in connection with sliding and stepping on surface irregularities. In this category most of the injuries were to feet/ankles, although back, arms and shoulders are also vulnerable.

3.5.3 PERSONAL INJURIES ON FIXED INSTALLATIONS

No significant change has been recorded in the total personal injury frequency from 1993 to 1994, after correction of the 1993 figures for injuries reported late. In 1994 the Norwegian Petroleum Directorate recorded 541 personal injuries in connection with drilling for and production of oil and gas on fixed installations on the Norwegian continental shelf, one of which was fatal.

On Odin, a roustabout was killed when he was hit by production tubing in connection with shut-down of the activities on the installation. The length of pipe, suspended in a winch wire with lifting gear, was to be taken out and placed outside the drill floor. The lifting gear included among other items a swivel. The bolt through the swivel was secured by a securing pin. As the pipe was moved out, the bolt probably caught on to the derrick. This caused the securing pin to break, the bolt came loose and the pipe fell down over the drill floor. After this incident, the Norwegian Petroleum Directorate sent a circular letter to all the operating companies, making it clear that use of swivel with this type of bolt connection constitutes a violation of the applicable regulations and must not occur. Such bolt connections are to be designed with double security against failure. The accident is still being investigated by the police.

Injuries which occurred outside working hours on the installations (off-duty injuries) are not included in the statistics. In 1994, 13 off-duty injuries were recorded on fixed installations, compared to 23 in 1993. Off-duty injuries are most often wounds and cuts in soft tissue areas, and sprains in connection with physical fitness activities.

There was a reduction of roughly 15 % in the total number of hours worked on fixed installations from 1993 to 1994. The Ekofisk field accounts for most of this reduction. In addition, there has been a reduction in hours worked as a result of normal operations on Sleipner, Brage and Draugen. Also on Gullfaks the number of

Table 3.5.3.a
Injuries/deaths per 1000 man-years (1976-94) on fixed installations

Year	Hours worked	Hours per man-year	Man-year	Injuries and deaths	Injuries and death per 1000 man-years	Deaths	Deaths per 1000 man-years
1976	4.876.316	1852	2633	213	80.9	2	0.76
1977	8.146.948	1852	4399	282	64.1	2	0.45
1978	14.932.296	1752	8523	624	73.2	6	0.70
1979	14.986.608	1752	8554	575	67.2	0	0.00
1980	12.237.720	1752	6985	451	64.6	0	0.00
1981	15.612.072	1752	8911	415	46.6	0	0.00
1982	14.790.384	1752	8442	526	62.3	0	0.00
1983	11.473.848	1752	6549	334	51.0	0	0.00
1984	14.643.216	1752	8358	491	58.7	1	0.12
1985	15.014.640	1752	8570	599	69.9	1	0.12
1986	17.108.280	1752	9765	606	62.1	0	0.00
1987	22.169.458	1612	13753	832	60.5	0	0.00
1988	19.878.727	1612	12332	638	51.7	0	0.00
1989	19.935.637	1612	12367	596	48.2	1	0.08
1990	19.852.093	1612	12315	571	46.4	1	0.08
1991	22.263.572	1612	13811	589	42.6	0	0.00
1992	22.203.641	1612	13774	583	42.3	0	0.00
1993	25.411.735	1612	15764	639	40.5	2	0.13
1994	21.542.463	1612	13364	541	40.5	1	0.07
Total/average	317.079.654		189169	10105	53.4	17	0.09

Fig. 3.5.3.a
Personal injury frequency on fixed installations (1979-94)

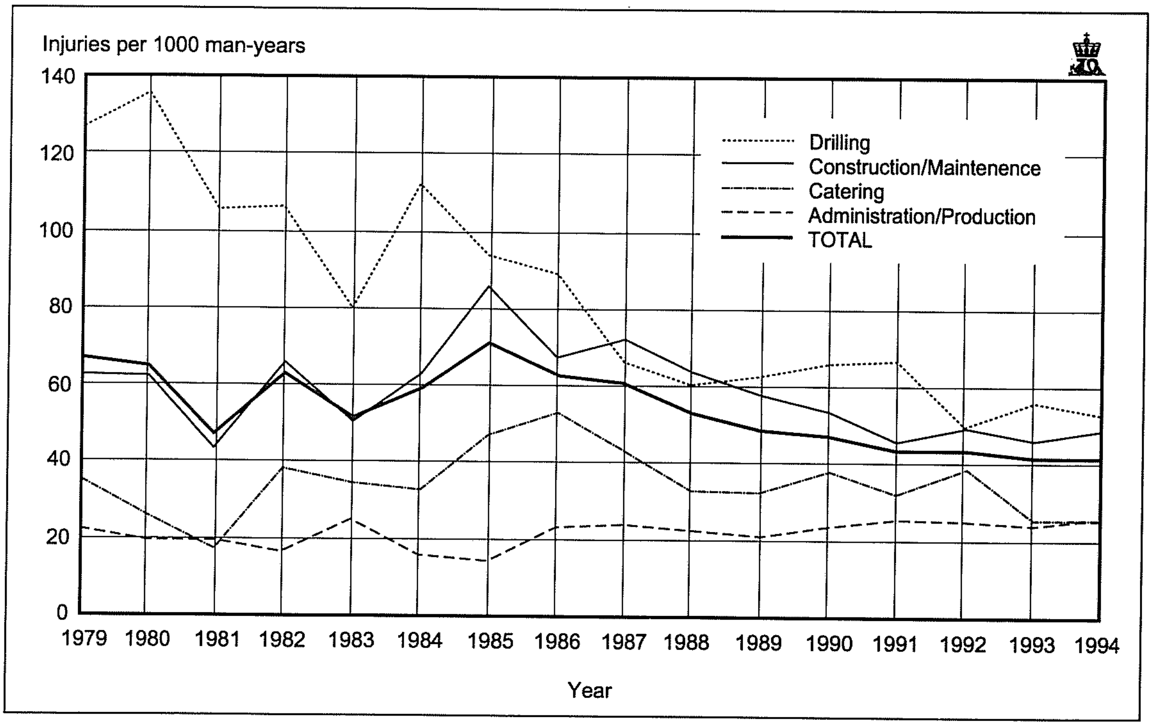
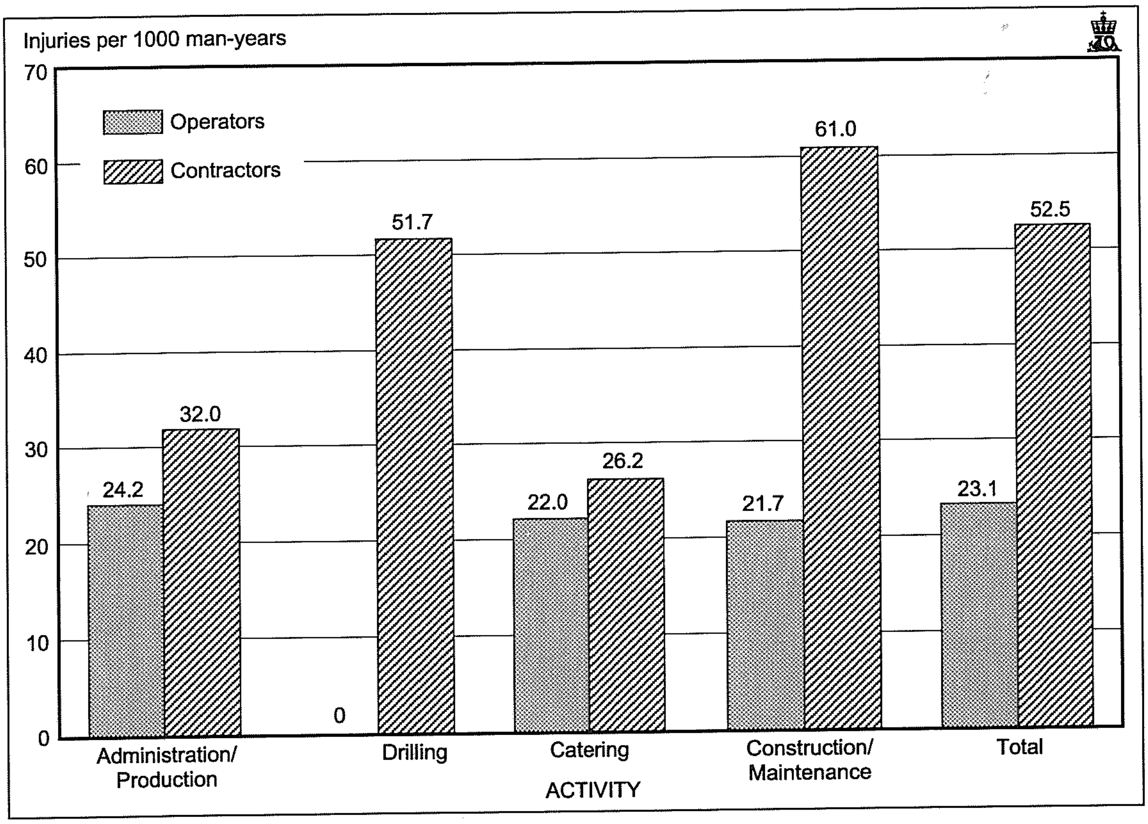


Fig. 3.5.3.b
Personal injury frequency by operators and contractors - 1994 on fixed installations



working hours has decreased considerably over the last few years.

Tables and figures - fixed installations

Table 3.5.3.a provides a summary of personal injuries per 1000 years worked on fixed installations from 1976 to 1994 including the mobile production vessel «Petrojarl 1», which was active on the Norwegian continental shelf in 1991. For 1994 also the operations with Mærsk Giant on Hod and Mærsk Gallant on Frøy are included in the figures for fixed installations. The overall injury frequency in 1994 is equivalent to 25 injuries per million hours worked. The injury frequency for 1993 has been corrected for 4 injuries notified in late reports.

Figure 3.5.3.a shows the development of personal injury frequency during the period 1979-94 for the various main activities. From 1993 to 1994 there has been a decrease in the injury frequency from 54.4 to 51.7 injuries per 1000 years worked. In the category construction/maintenance there has been an increase in the injury frequency from 45.2 to 47.9 injuries per 1000 years worked.

Catering accounts for the smallest portion of the total work volume on fixed installations with only about 9.7 % of the total number of hours worked. In 1994 the catering activities represented 5.9 % of all injuries. Expressed in injury frequency, this is 24.8 injuries per 1000 years worked in catering activities, which is the same as the previous year.

Wounds caused by equipment handling dominate the picture, although soft tissue injuries in connection with falls and contact with stationary objects are also frequent.

The big reduction in construction activities has led to a total reduction of the work volume on fixed installations. Construction and maintenance accounted for 54.7 % of the total hours worked in 1993, decreasing to 44.4 % in 1994. The proportion of injuries in construction and maintenance activities has also declined from 61.0 % to 52.5 % respectively, but the injury frequency for this group has nevertheless increased.

The biggest increase was found among the employees of the operators, but this must be seen in the light of the fact that the injury frequency for 1993 was the lowest ever. Also for contractor employees the injury frequency increased from 1993 to 1994. The most common injuries are still cuts, bruises and impact injuries and injuries resulting from blows to the hands and head. Furthermore there are still a number of eye injuries, even if the proportion of such injuries has declined.

The increase in work volume for the administration/production category makes up for some of the decrease in construction/maintenance. Also for this category there has been an increase in injury frequency of almost 2 injuries per 1000 years worked. This increase applies to operator employees as well as contractor employees.

Table 3.5.3.b

Distribution of injuries and man-years on operator and contractor employees on fixed installations (1985-1994)

FUNCTION		1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	
Administration Production	Man-years	1575	1293	1692	1985	2099	2259	2366	2499	2607	3021	Operator
		80	213	603	454	294	500	424	369	482	468	Contractor
	Injuries	19	34	44	47	43	49	53	54	58	73	o
		4	0	9	6	6	12	14	15	14	15	c
	Injuries/1000 man-years	12.1	26.3	26.0	23.7	20.5	21.7	22.4	21.6	22.2	24.2	o
		50.0	0.0	14.9	13.2	20.4	24.0	33.0	40.7	29.1	32.0	c
Drilling	Man-years	0	0	0	0	0	0	0	0	0	0	o (operator)
		1384	1371	1567	1883	2128	2027	2239	2340	2590	2648	c (contractor)
	Injuries	0	0	0	0	0	0	0	0	0	0	o
		130	122	103	110	131	132	147	117	141	137	c
	Injuries/1000 man-years	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	o
		93.9	89.0	65.7	58.4	61.6	65.1	65.7	50.0	54.4	51.7	c
Catering	Man-years	0	39	94	209	340	396	447	464	498	454	o (operator)
		685	817	1073	882	888	868	953	887	956	839	c (contractor)
	Injuries	0	5	5	4	3	13	13	17	11	10	o
		32	40	45	29	36	34	31	34	25	22	c
	Injuries/1000 man-years	0.0	128.2	53.2	19.1	8.8	32.8	29.1	36.6	22.1	22.0	o
		46.7	49.0	41.9	32.9	40.5	39.2	32.5	38.3	26.1	26.2	c
Construction/ Maintenance	Man-years	1544	2063	2441	2399	2381	2364	2482	2536	2694	1985	o (operator)
		3301	3969	6283	4520	4237	3901	4900	4679	5937	3949	c (contractor)
	Injuries	61	51	49	50	70	61	65	79	39	43	o
		353	354	577	391	307	267	266	267	351	241	c
	Injuries/1000 man-years	39.5	24.7	20.1	20.8	29.4	25.8	26.2	31.2	14.5	21.7	o
		106.9	89.2	91.8	86.5	72.8	68.4	54.3	57.1	59.1	61.0	c
TOTAL	Man-years	3119	3395	4227	4593	4820	5019	5295	5499	5798	5459	o (operator)
		5450	6370	9526	7739	7547	7296	8516	8275	9966	7904	c (contractor)
	Injuries	80	90	98	101	116	123	131	150	108	126	o
		519	516	734	536	480	445	458	433	531	415	c
	Injuries/1000 man-years	25.6	26.5	23.2	22.0	24.1	24.5	24.7	24.3	18.6	23.1	o
		95.2	81.0	77.1	69.3	63.6	61.0	53.8	52.3	53.3	52.5	c

Figure 3.5.3.b shows the injury frequency for operator employees and contractor employees in the main activity categories for 1994.

Table 3.5.3.b shows the distribution of injuries, years worked and injury frequency for operator and contractor employees from 1985 to 1994. In 1994, contractors contributed 59.2 % of the total hours worked on fixed installations, the lowest ever, against 63.2 % in 1993. 76.7 % of the injuries were sustained by contractor employees in 1994, against 83.1 % in 1993. The total injury frequency for contractor employees was slightly reduced, while for operator employees the frequency increased by 4.5 injuries per 1000 years worked as compared with 1993.

Table 3.5.3.c shows the distribution of accident types in each particular occupational category. The figures are cumulative for the period 1979-1994.

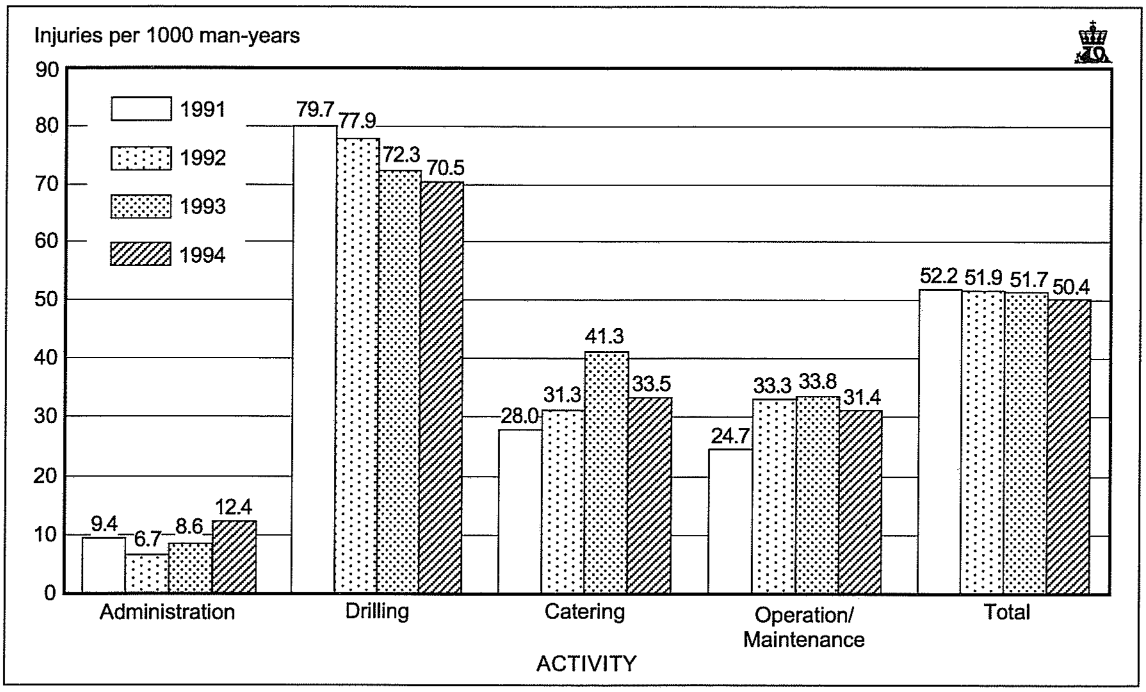
Table 3.5.3.c
Work accidents 1979-94 on fixed installations. Injury incident/occupation.

Occupation / Injury/incident	Administration	Drillfloor worker	Driller	Electrician	Caterer	Assistant	Instrument technician	Crane operator	Painter/Gritblaster	Mechanic/Motorman	Operator	Plateworker/Insulator	Pipeworker/Plumber	Service technician	Scaffolder	Welder	Derrickman	Other, unspecified	TOTAL	%
Other contact with objects/ machinery in motion	43	301	38	70	74	385	29	19	50	139	51	75	83	70	104	53	93	4	1681	18.7
Fire, Explosion etc.		1		3		8			1	5	2	4	4			3			31	0.3
Fall to lower level	17	30	12	49	15	111	21	15	57	49	33	38	43	23	35	34	20	3	606	6.7
Fall at same level	34	30	6	57	60	122	23	10	42	42	37	44	63	31	71	46	12	8	738	8.2
Stepping on uneven surface or tripping	32	25	10	70	39	110	23	15	53	48	49	36	63	36	64	61	14	8	755	8.4
Falling objects	11	48	11	13	14	79	7	1	17	38	7	40	35	25	66	29	6	2	449	5.0
Other contact with objects at rest	27	24	7	61	39	90	33	10	66	65	33	77	57	28	77	43	12	5	754	8.4
Handling accidents	27	91	12	91	122	236	32	18	56	168	47	123	125	53	94	99	33	3	1400	15.6
Contact with chem. or physic. compound	6	17		15	36	70	10	4	102	22	28	23	26	23	10	30	9	1	432	4.8
Muscular strain	30	49	8	48	37	123	12	12	43	65	48	35	66	29	79	28	20	4	736	8.2
Splinter and splashes	18	34	9	40	22	103	7	3	161	75	33	150	169	21	30	296	7	4	1182	13.2
Electrical current		2		28		1	1	1		1		2			1	1			38	0.4
Extreme temperature	1			5	49	6	1		1	8	8	8	11	1	4	19		1	123	1.4
Fall into sea						1			1							1		1	4	0.0
Other	4	3		5	4	11	1	2	3	4	3	6	6		2	4			57	0.6
TOTAL	250	655	113	555	511	1426	200	110	653	729	379	660	751	339	637	747	226	44	8985	100
%	2.8	7.3	1.3	6.2	5.7	15.9	2.2	1.2	7.3	8.1	4.2	7.3	8.4	3.8	7.1	8.3	2.5	0.5	100	

Table 3.5.4.a
Injuries/deaths per 100 man-years on mobile installations (1976-94).

Year	Hours worked	Hours per man-year	Man-year	Injuries and deaths	Injuries and deaths per 1000 man-years	Deaths	Deaths per 1000 man-year
1989	3.584.740	1612	2224	92	41.4	2	0.90
1990	4.328.907	1612	2685	139	51.8	1	0.37
1991	4.878.152	1612	3026	157	51.9	0	0.00
1992	4.380.013	1612	2717	140	51.5	0	0.00
1993	4.205.431	1612	2609	135	51.7	1	0.38
1994	3.517.938	1612	2182	110	50.4	0	0.00
Total/average	24.895.180		15444	773	50.1	4	0.26

Fig. 3.5.4.a
Personal injury frequency on mobile drilling units (1991-1994)



3.5.4 PERSONAL INJURIES ON MOBILE UNITS

In 1994 there have been 17 mobile units in action on the Norwegian continental shelf, the same number as in 1993. The operations of Mærsk Giant on Hod and Mærsk Gallant on Frøy are not included here, but are comprised in the figures for fixed installations. In connection with exploration and development drilling from mobile units, the Norwegian Petroleum Directorate has registered 110 personal injuries, a decrease of 25 from 1993. Seen in connection with a reduction of about 16 % of the hours worked, this represents a reduction of the total injury frequency from 1993 to 1994 of 1.3 injuries per 1000 years worked. There have been no fatalities on mobile units in 1994. The Norwegian Petroleum Directorate has registered 3 off-duty injuries in 1994, against 4 in 1993.

Accident reporting for mobile units is subject to the same criteria as for fixed installations. The Norwegian Petroleum Directorate has nevertheless noted a relatively greater proportion of reporting irregularities for mobile units, inter alia as a result of misinterpretation of reporting criteria. Also, it has been more difficult to achieve the same degree of retrospective reporting of incidents, because charterers of the units change , units are laid up, or cease operations on the Norwegian continental shelf. These factors also make it difficult to achieve the same degree of accuracy in figures for hours worked on mobile units.

In the past few years the Directorate has therefore placed emphasis on control of these figures. The working hours reported by the operators have been collated with the rig days registered by the Directorate and adjusted in consultation with the operators, thus producing a reasonably accurate estimate of the average number of personnel on the units. The Norwegian Petroleum Directorate therefore feels that the figures over the latest years offer a reasonably correct picture of the situation on mobile units.

Table 3.5.4.b
Work accidents 1989-94 on mobile installations. Injury incident/occupation.

Occupation / Injury incident		Administration	Drillfloor worker	Driller	Electrician	Caterer	Assistant	Crane operator	Painter/Gritblaster	Mechanic/Motorman	Operator	Plateworker/Insulator	Pipeworker/Plumber	Service technician	Scaffolder	Welder	Derrickman	Other/unspecified	TOTAL	%
Other contact with objects/ machinery in motion		4	88	16	1	5	73	4	1	9	4			22		4	18	3	252	32.7
Fire, Explosion etc.																			1	0.1
Fall to lower level		1	5	2	1	2	8	2		2		1		5		4	2		35	4.5
Fall at same level		3	9	1	1	2	8	2		1				3			2	1	33	4.3
Stepping on uneven surface or tripping		4	14	6	1	3	14	3		3			1	11			10	1	71	9.2
Falling objects			21	4		2	10	2		1				5	1	2	4		52	6.8
Other contact with objects at rest			11	5	1	7	7			2	1	1		7		1	7		50	6.5
Handling accidents		5	48	3	1	12	11	2		9		1		14		4	8		118	15.3
Contact with chem. or physic. compound		1	7	1	1	1	3			1			1	2	1	2	4		25	3.2
Muscular strain		4	21	6	1	4	12	2		1	1			9			7		68	8.8
Splinter and splashes		2	16	1	3	2	7	1	1	5				3		8	5	1	55	7.1
Electrical current														1			1		2	0.3
Extreme temperature			1			4				1			1						7	0.9
Other				1															1	0.1
TOTAL		24	241	46	11	44	154	18	2	35	6	3	3	82	2	25	68	6	770	100
%		3.1	31.3	6.0	1.4	5.7	20.0	2.3	0.3	4.5	0.8	0.4	0.4	10.6	0.3	3.2	8.8	0.8	100	

Tables and figures - mobile units

Table 3.5.4.a presents a summary of personal injuries per 1000 years worked on mobile units from 1989 to 1994. The injury frequency in 1994 represents about 31.3 injuries per million man hours.

Figure 3.5.4.a shows the comparative injury frequency for each main activity category on mobile units in the past four years. Drilling and well operations make up 55.2 % of the hours worked, but as much as 77.3 % of the injuries. The injury rate is therefore relatively higher than for corresponding activities on fixed installations. The absolutely predominant types of injury in drilling and well operations are cuts, bruises and impact injuries in connection with lifting operations and handling of equipment on the drill floor. The body parts most likely to be injured are the hands, the head/face and the feet.

The number of injuries for the functions administration, catering, operation and maintenance is low, in total 25 injuries. Both in catering and in operation and maintenance there has been a decrease in injury frequency in 1994, with the largest reduction in catering.

A comparison of operator employees and contractor employees on mobile units shows that operator employees account for only 6.1 % of man hours worked, substantially work of an administrative nature. Only one operator employee was injured in connection with work on mobile units in 1994.

Table 3.5.4.b is a matrix of the types of accidents in the various occupational categories. The table shows the cumulative values for the period 1989 to 1994.

3.5.5 SUMMARY

Also in 1994 a fatal accident occurred in the petroleum activities on the Norwegian continental shelf, when a roustabout was killed after being hit by a falling length of pipe from production tubing. There was no significant reduction in the total injury frequency compared with 1993. Nevertheless it would seem that the proportion of personal injuries considered serious, is lower both for fixed and for mobile installations. For fixed installations, the proportion of personal injuries registered serious is the lowest ever. However, also in 1994 mobile installations show a relatively higher number of serious incidents than the fixed installations. An injury is defined as serious if in all probability it will result, or has resulted, in permanent injury (such as amputation) or extended absence from work. The classification is not based on a medical evaluation in retrospect, but on the account given in the accident report.

The injury frequency in the drilling and well operations function on fixed installations has again been somewhat reduced and seems to have leveled off just under 60 injuries per 1000 years worked. The extensive construction and maintenance activities in connection with installation of new production installations were terminated in 1994, but the injury frequency for this function has nevertheless increased. Catering accounts for a relatively small proportion of hours worked and injuries sustained, with the same injury frequency in 1994 as the year before. Administration/production has shown stable figures for injury frequency since 1986, with a minor increase of 2 injuries per 1000 years worked in 1994. The injury frequency for mobile installations is also for 1994 in excess of 50 injuries per 1000 years worked.

A study of the injuries registered for 1994 showed that there must be a fairly marked uncertainty with regard to criteria and routines for reporting to the Norwegian Petroleum Directorate. Based on experience gained through supervisory activities, the Directorate cannot disregard the possibility that this in part may be due to an inappropriate focus on and use of injury frequencies. In the Norwegian Petroleum Directorate's opinion it is important to focus on the intentions behind the regulation requirements relating to registration and reporting of situations of hazard and accident. The purpose of these requirements is that the participants should develop a tool which can be used to discover areas where the employees are subjected to risk, demonstrate cause connections and identify preventive measures. Injury frequencies alone with focus on aims and comparisons will undermine the value of the reporting systems, also as a suitable indicator of risk and safety levels.

Despite the limitations one must expect in such a comprehensive reporting system, the Directorate still believes that these statistical summaries, at an overall level, provide a reasonably accurate picture of the situation in the petroleum industry. Although there has been no reduction in the total injury frequency on fixed installations, it cannot on the other hand be said that the figures for 1994 represent a clear indication that the favourable trend of recent years has been broken.

3.5.6 INJURIES IN DIVING ACTIVITIES

Figures 3.5.6.a and 3.5.6.b show an overview of the number of incidents reported to the Norwegian Petroleum Directorate for the years 1985 to 1994, in connection with diving activities. The incidents are subdivided into the categories near accident, accident and fatal accident. Accident is in this connection defined as all occurrences which have entailed personal injury in one form or another. Infections such as inflammation of the external auditory canal, are consequently registered as accident.

From Figure 3.5.6.a can be seen that the number of accidents with personal injury during saturation diving is basically unchanged in 1994 compared with 1993, even though the activity level is reduced by 50%. The reason for this is that there remains a relatively large number of cases of inflammation of the external auditory canal.

Table 3.5.6 shows how accidents with personal injury subdivide into different types of injury. In 1994 there has been no cases reported of decompression sickness during diving in the petroleum activities. In addition to the incidents mentioned in the tables, a bacterial epidemic occurred on the Frigg field which also spread to a diving vessel, which in turn resulted in the vessel being demobilised.

Table 3.5.6
Accidents related to type of injury

Type of injury	Saturation diving	Surface oriented diving
Outer ear infection	17	1
Thermal injury		
Decomp. sickness		
Wounds		
Pain in muscle/joint		
Cold injury		
Fracture		
Infection		
Hypoxia/Anexia		
Unconsciousness		
Barotraume - comp.		1
Barotraume - decomp.		
Other illness/injury	4	
Total	21	2

Fig. 3.5.6.a
Incidents in saturation diving

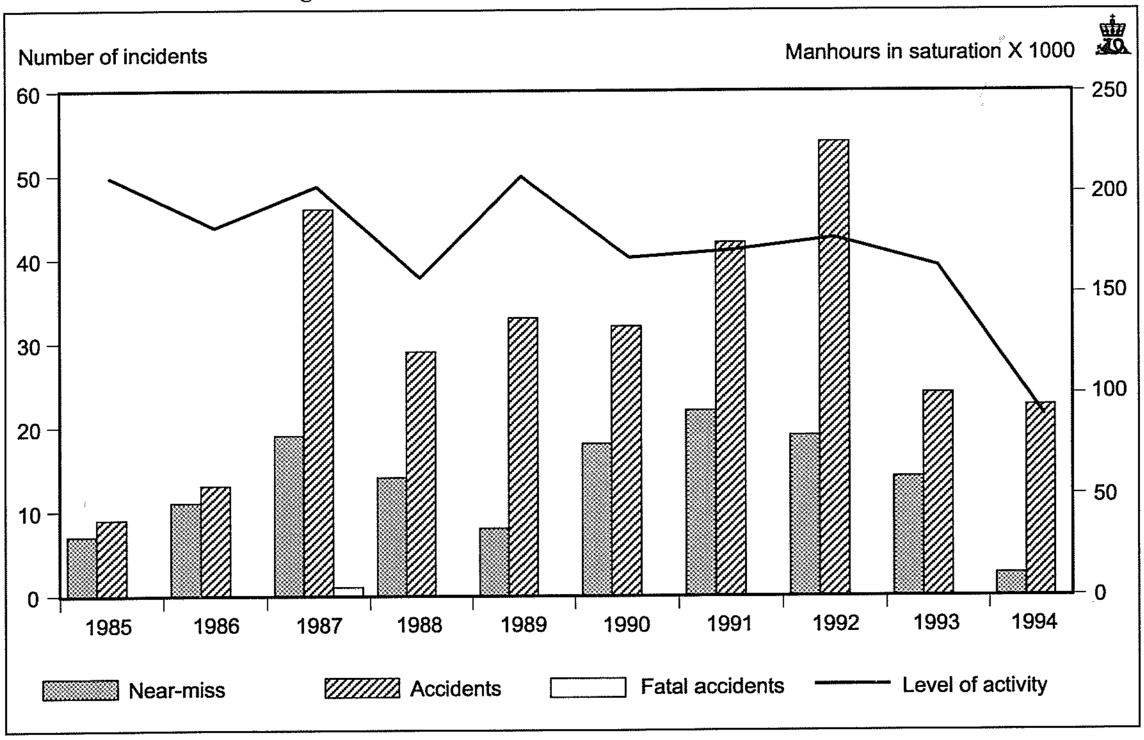
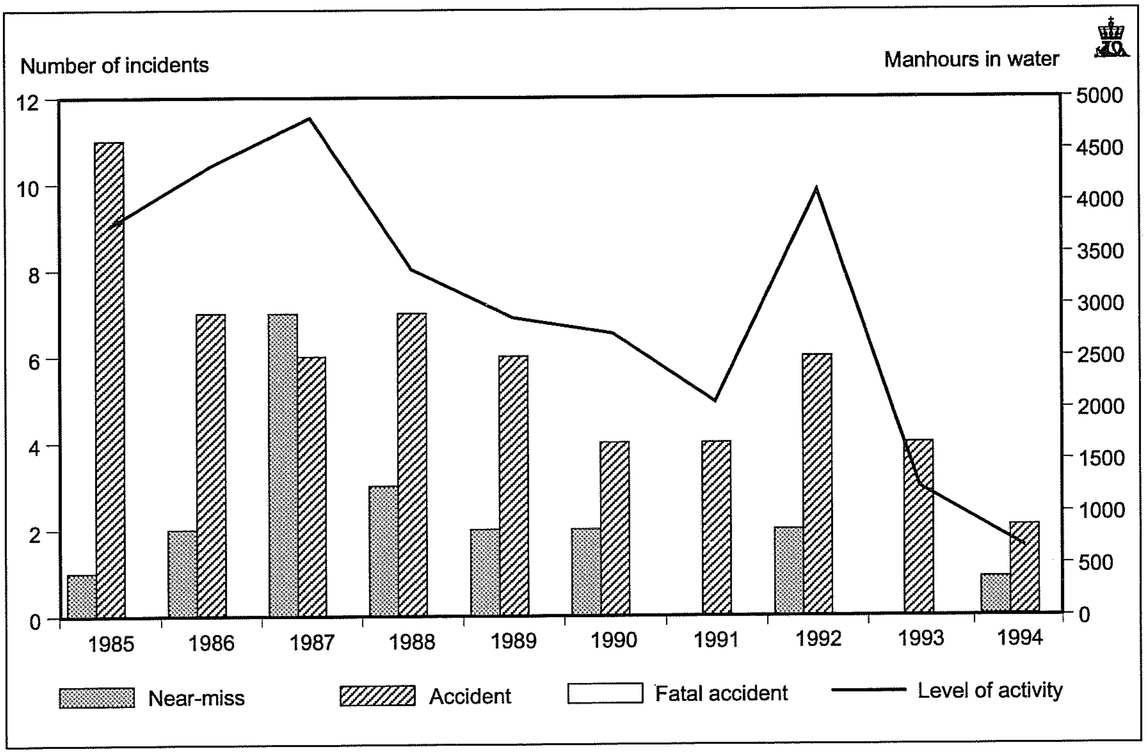


Fig. 3.5.6.b
Incidents in surface oriented diving



3.6 WORK-RELATED DISEASES

The Norwegian Petroleum Directorate has continued to focus on the Working Environment Act's requirement that diseases that may be ascribed to work shall be reported to the supervising authority, and notes with satisfaction that this report duty is being followed up more and more actively by the companies.

The occurrence of work-related diseases can be an indicator of the quality of the working environment. It is therefore an objective to see that companies establish this as a working environment indicator , and use it actively in their preventive safety and environment work.

A total of 343 reports of work-related diseases were received. This is an increase of almost 70 % from 1993, and corresponds to a reporting frequency of 2.3 % per year worked. This frequency is substantially more than the reported frequencies for mainland industry in Norway, but even so, there is reason to believe that underreporting still occurs, as there continues to be few reports received from certain companies with a large number of employees on the continental shelf. In addition to the individual reports mentioned above, the Norwegian Petroleum Directorate also received summary reports of 35 cases of loss of hearing.

In 1992, the Directorate has established a special data base to systematise the incoming work-related disease reports. This was modified last year, with assistance among others from the Danish Labour Inspection (Arbejdstilsynet). Recordings in this data base include the patient's present and former employer, type of work, relevant work processes, working environment factors supposed to have caused the disease(s), as well as the associated diagnosis.

Figure 3.6 shows the distribution of work-related diseases registered in 1994 by diagnostic group (according to the ICD classification). The figures for 1993 are shown for comparison. Cases of noise-induced loss of hearing have not been included in the figure, since these are reported both in summary and individual reports. In total, 131 cases of hearing loss were reported in 1994, of which 96 were reported individually.

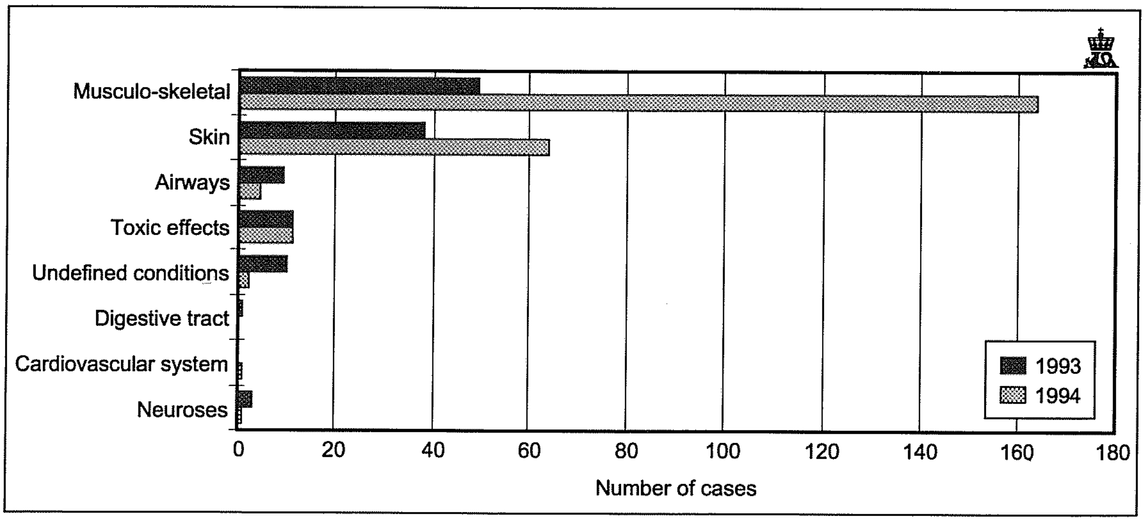
In addition to loss of hearing due to noise, the picture is as in previous years dominated by musculo-skeletal complaints (including disorders of connective tissue), usually called muscular strain injuries. Typical causes are repetitive, monotonous work, work in uncomfortable posture and heavy manual work. Other factors causing illness in this group are pace of work and static muscular strain. New in 1994 were several cases of degenerative changes of knees and hip joints attributed to walking on hard surfaces or in stairways.

The third dominating group of disease is skin complaints. These are cases of eczema due to exposure to various chemicals. This group is dominated by employees with hand eczema after contact with oil-based drilling mud. Other cases may be due to contact with other organic substances, including epoxy, and in addition a certain number may be due to contact with inorganic substances, such as certain metals. Some cases of eczema are caused by ether based drilling mud. This type of drilling mud has also caused other problems for employees, such as respiratory irritation, nausea and headache. A number of cases of eczema among employees in catering are attributed to being exposed to detergents and other chemicals used by this category of employees.

Respiratory diseases are asthma and bronchitis, and cases of respiratory irritation due to atmospheric irritants (as mentioned above), while the diagnoses grouped as toxic effects refer to a range of different symptoms following exposure to chemicals. The category includes cases of teflon fever.

Undiagnosed conditions refer to various symptoms resulting from exposure to poor working environment factors, which are, however, difficult to classify as disease. The mental illness category includes cases of neuroses conditional on psychological stress in the working environment.

Fig. 3.6
Distribution of work-related diseases on diagnosis groups 1993 and 1994



3.7 WORKING ENVIRONMENT

3.7.1 OCCUPATIONAL HYGIENE

Noise

Noise emerges as a relatively extensive working environment problem in the petroleum activities.

In order to avoid unacceptable noise conditions, a thorough follow-up is required during the design of installations. Good design solutions with regard to noise levels, e.g. in connection with ventilation noise, will generally entail only insignificant cost increase, if included as part of the design. The same applies in the case of major modifications to installations. In the Norwegian Petroleum Directorate's experience, systematic work is done in relation to noise issues during the design of new installations, but it is also felt that the possibilities for cost effective noise prevention in this phase might have still been utilised more effectively.

Furthermore it is the experience of the Norwegian Petroleum Directorate that noise measurements carried out after the installation has been taken into use, in some cases are not representative to the normal operational situation. This is particularly true of mobile installations. Confusion with regard to the specific requirements to noise level for the relevant activity often leads to insufficient assessment of the need for measures to be taken. Even if hearing protection normally is used with high noise levels, the Norwegian Petroleum Directorate has in some cases pointed out that it must be specified clearly in the company's governing documentation that the use of hearing protection is mandatory in areas where the noise level is liable to damage hearing.

Chemicals

Proper and safe use of chemicals is dependent on necessary information about the health hazard of the products, on the implementation of technical measures to the extent possible, and on the use of necessary personal protective equipment. Making use of the available possibilities to choose the least health hazardous product is also a central element.

With regard to information about the health hazard of the products, internal requirements in the operating companies are applicable to quality control of occupational hygiene related product data sheets in connection with the purchase of chemicals. In practice, chemicals are often used without any assessment of whether the supplier's data sheet information is adequate and without any consideration to choosing the least health hazardous product. The fact that several almost identical products are used, and that the supplier changes the composition of the product or the information on the data sheet, contributes to creating difficulties on the installation with regard to obtaining the correct product information. The Norwegian Petroleum Directorate has observed that the supplier's data sheet is often inadequate and in a number of instances it is not in compliance with the health hazard marking of the product.

A continuous and rapid development is taking place with regard to drilling mud types. It happens that use of drilling mud causes health problems to drilling personnel, as a result of skin contact and inhalation. The Norwegian Petroleum Directorate has observed that the operating companies have varying practices with regard to carrying out evaluations of the different mud types in relation to the health hazard they represent. A consequence of this may in turn be insufficient basis for choices and priorities in relation to preventive measures. The Norwegian Petroleum Directorate wishes to emphasize that technical and operational measures should primarily be implemented, and that personal protective equipment can only be accepted as a temporary or secondary solution to safeguard the health of the employees.

Radiation

The Norwegian Petroleum Directorate has in collaboration with the Norwegian Radiation Protection Authority collected information about natural radioactivity in connection with the operating companies' operation of production installations on the Norwegian continental shelf, particularly connected with deposits in production equipment. The information is, inter alia, intended to be used in connection with a project aimed at preparing more specific guidelines in this area.

3.7.2 ERGONOMICS

Strain injuries (muscular and skeletal complaints) is the health problem which contributes most to absence from work, and therefore represents considerable expenses for the individual enterprise and for society. Unsatisfactory ergonomic arrangement of work and workplace is an important cause for such complaints. Furthermore, poor ergonomic conditions may lead to reduced safety and work efficiency. There are great benefits to be gained by a stronger focus on ergonomics.

In the opinion of the Norwegian Petroleum Directorate, efforts in relation to ergonomics have not been given sufficient attention. The Directorate's supervision has disclosed that expertise with competence in ergonomics has been made use of only to a small extent, even though most enterprises have access to such expertise through their own or through hired corporate health service. Other contributing factors are inadequate ergonomic requirement specifications in connection with purchases of equipment and design of workplaces, and inadequate administrative control systems for mapping and follow-up of ergonomics related issues in the operations and design phase.

Inadequate preparation and arrangement in connection with handling and transport of materials, difficult access to equipment, heavy manual work, work in uncomfortable postures, inadequate individual adaption of fixed workplaces and unsatisfactory design of technical equipment with view to man-machine interaction, are common issues.

In the autumn of 1990, the Norwegian Petroleum Directorate, in co-operation with the Norwegian Oil Industry Association (OLF), initiated a project with the purpose to develop ergonomic guidelines for the offshore industry. These guidelines are now available through

OLF. The purpose of the guidelines is to reduce the occurrence of work-related strain injuries on the continental shelf by stipulating specific requirements to design of the workplaces, workload, ergonomic mapping, job analyses and to health monitoring. The Norwegian Petroleum Directorate has expectations that these guidelines will contribute to improving the efforts related to ergonomic issues. In order to achieve the desired effects, it is essential that these requirements are made known to the industry and that they are incorporated into the internal control systems of the individual enterprises.

3.7.3 ORGANISATIONAL FACTORS

Climate of co-operation

The Norwegian Petroleum Directorate has in the reporting period noted as a positive trend that several operating companies carry out good work in following up on psycho-social aspects. The effect of co-operation aspects on safety and working environment is increasingly emphasised.

There has been a certain reduction of workforce on the continental shelf. There are great variations between the operating companies with regard to the manner in which reorganisation processes, which for example may entail workforce reductions, are carried out. In some operating companies the climate of co-operation is poor in relation to these issues, and the parties often do not succeed in reaching mutually agreed solutions. The cases are then referred to the authorities for evaluation of the safety and working environment related consequences of proposed changes in workforce. Other operating companies on the other hand are able to implement major reorganisation processes in an orderly and mutually agreed manner.

The formal institution established to ensure employee participation in the preventive work on safety and working environment issues, including working environment committees and the safety delegate system, has been found largely to function according to intentions. On certain mobile installations, however, deficiencies have been pointed out which have entailed comments from the Directorate.

Decision in cases connected with working environment committee resolutions

If a working environment committee deems it necessary in order to protect life or health of the employees, the committee may pass a resolution, by virtue of the Working Environment Act, to the effect that the employer shall effect specific measures to restore the working environment. If the employer for various reasons finds he cannot comply with the resolution passed by the working environment committee, the question may, according to the provisions of the Working Environment Act, be referred to the Norwegian Petroleum Directorate for a decision.

The Norwegian Petroleum Directorate has dealt with several cases of this nature in 1994. These cases have primarily been related to disagreement concerning the number of employees on the installations. The Directorate has considered these cases thoroughly, obtaining information from both parties. The planning, implementation and follow-up phases have been studied and improved to ensure employee participation and safeguard the life and health of employees. Based on such specific considerations in each individual case, the Directorate has concluded that there has not been grounds for ordering the employers to halt planned workforce reductions.

Quality assurance function

The Norwegian Petroleum Directorate has in 1994 continued the work of evaluating the quality assurance function in the operating companies, focusing on the quality assurance unit and the interaction between this unit and the line management organisation. Experience from 1994 indicates improvement in priorities, planning and implementation of internal supervision in the companies. With regard to the line management's measures to follow up results from supervision, there is still a potential for improvement. Governing documentation is still not sufficiently updated, so that it reflects the actual control systems. Due to extensive reorganisations among other things, the updating and improvement of governing documentation is regarded as a continuous process. The Norwegian Petroleum Directorate notes, however, that the companies invest a considerable amount of work in this area.

Working hours

There has been a positive trend with regard to compliance with the provisions on working hours for operator and contractor employees on the continental shelf. The systems for planning, recording and control of working hours are largely adequate. The Directorate has, however, registered breach of the working hours provisions relating to maximum number of hours per working period, to time off after completed duty period and to permissible accumulated working hours and overtime. The Norwegian Petroleum Directorate has also disclosed inconsistencies in different lists of working hours covering the same work period. The Directorate takes a serious view of the fact that different lists giving contradictory information are used.

It has been disclosed that certain employees have been classified as having a managerial/particularly independent position when this is not in accordance with the classification criteria. The Directorate has repeatedly been required to remind employers of the stringent criteria that are applicable in order to exempt employees from the working hours provisions. It is, for example, not an acceptable criterion for exemption that the employees have individual wage agreements.

3.8 EMERGENCY PREPAREDNESS

3.8.1. SEMINAR ON THE EMERGENCY PREPAREDNESS REGULATIONS

Regulations relating to emergency preparedness in the petroleum activities, which entered into force in 1992, represented a marked change in the direction of system oriented requirements, in accordance with the overall principles on which the Norwegian Petroleum Directorate's other thematic regulations are based. Different circumstances have existed for the various operating companies and they have used differing procedures in order to comply with the regulation requirements relating to emergency preparedness administration.

The Norwegian Petroleum Directorate has received several messages signalling difficulties experienced in relation to the new regulations, and with this in mind arranged a seminar where the industry and the authorities exchanged experience with the new regulations. In addition to providing the Norwegian Petroleum Directorate with an opportunity to give information on the authorities' expectations, the seminar provided valuable feedback from the industry. Conclusions from the seminar will constitute an important contribution to a planned review of the emergency preparedness regulations, with a view to assessing the need for a possible revision. A seminar report has been prepared, which contains a copy of all presentations given during the seminar.

3.8.2 ACTIONS IN CONNECTION WITH DRIFTING OBJECTS

On 13 February 1994 a burning vessel of about 1000 tons was adrift in the direction of the Sleipner A installation. The vessel was at that time abandoned by the crew. The situation was deemed critical, and the relevant bodies were alerted and put into a state of preparedness. Several possible solutions were considered, and the situation was brought under control when a vessel from the Coast Guard succeeded in getting a towline on board the disabled ship.

Based on this incident, a revision was carried out of routines for alert, responsibilities and procedures for handling drifting objects. This work ties in with restructuring of the authorities' engagement in emergency preparedness situations as a result of the fact that the Governmental Action Control Group (AKU) will cease to exist in 1995. A revised concept for handling of situations with drifting objects is intended to be presented in the course of 1995.

3.9 DRILLING

3.9.1 SUMMARY OF DRILLING AND WELL OPERATIONS

During 1994 there were a total of 21 exploration wells drilled on the Norwegian continental shelf, as compared to 27 in 1993. This is the lowest number of exploration wells since 1978. Geographically, 16 of the new exploration wells are located in the North Sea and 5 in the Norwegian Sea. No exploration wells were spudded in the Barents Sea in 1994.

A total of 120 production wells were drilled on the Norwegian continental shelf in 1994. This is 15 more than in 1993, and the highest number ever. Out of these, 38 were drilled from mobile installations, against 34 the year before. Thus, the overall level of activities for mobile drilling installations has been approximately as high as in 1993.

Partly as a consequence of the increasing age of many wells, there has been an increase in activities related to maintenance and recompletion, so that the total activity level in the category drilling and well activities in 1994 has been somewhat higher than in 1993.

3.9.2 DRILLING IN DEEP WATER

In 1994 the Vøring plateau was opened for exploration drilling, and it is expected that production licences will be awarded in this area in connection with the 15th licensing round in 1995. It will then probably be possible to start exploration drilling during 1996/97. The Vøring plateau is characterised inter alia by deep waters - ranging from 800 to 2500 meters. This means that the participants are faced with great challenges, with regard to operational and technical aspects as well as safety and working environment issues.

The Norwegian Petroleum Directorate has in the period 1992 to 1994 carried out a series of projects to study and clarify the range of problems connected with drilling in deep water. The conclusion of this project series is that there seems to be no technical reasons why the industry should not be able to implement exploration drilling on the Vøring plateau in a prudent manner. However, drilling in deep waters requires an extensive planning process. The industry is furthermore conducting further studies to throw light on specific technical questions connected with drilling in deep water.

3.9.3 SLIM HOLE DRILLING

Slim hole drilling is a drilling technique which entails drilling the well with a smaller hole diameter than what has been usual in the petroleum activities until now. The Norwegian Petroleum Directorate has carried out a project in 1994, to study issues related to slim hole drilling on Svalbard and otherwise on the Norwegian continental shelf.

When drilling on shore, there are advantages insofar as this technique allows the use of a smaller and lighter drilling rig, which in turn requires less transportation activities, less consumables, reduced volumes of waste and less personnel. This contributes to lower costs, and in addition it represents advantages in reduced impact on and pollution of nature.

Use of this technique does however require a high degree of well control. Decisive factors will be the ability to establish a satisfactory interaction of activities such as well planning, casing programme, drilling fluid programme, system for detection of kicks, training and procedures for well control.

Also for drilling operations offshore work is in progress to reduce the dimensions of the borehole. Drilling with drill string consisting of coil tubing instead of traditional drillpipe has already been carried out from conventional installations. The industry is in the process of considering the practical implications of using modified exploration installations and drilling vessels designed specially for slim hole drilling.

3.9.4 HIGH-DEVIATION DRILLING

The proportion of wells classified as high-angle wells

Table 3.9.4
Number of wells with maximum deviation 60° - 90°

Year / <	60° - 65°	65° -70°	70° - 75°	75° - 80°	80° - 90°
1984	2				
1985	3	4			
1986	4	4			
1987	7				
1988	4	1	1	1	
1989	13	1		1	2
1990	8	4	1		3
1991	8	5	5	2	9
1992	9	4	3	3	13
1993	8	4	5	3	31
1994	3	4	1	5	44

continued to increase in 1994. Since 1984 a total of 233 wells have been drilled with a maximum borehole angle exceeding 60 degrees, as many as 57 of these in 1994. Table 3.9.4 illustrates this trend. This illustration shows that the number of wells that are deviated more than 80 degrees, i.e. completely or virtually horizontal wells, is increasing rapidly.

Basis for this new trend is extensive research and development of new technology as well as refinement of existing equipment and techniques.

Wells that are drilled at a high deviation angle offer significant economic rewards, principally because larger parts of the reservoir can be reached from a single production installation. The force behind the trend is thus primarily economic, but through research and development the industry also acquires competence which has a positive effect on the safety of drilling and well operations. This area of technological advance is therefore a good example of how improved safety can go hand in hand with improved profitability.

3.10 NATURAL ENVIRONMENT DATA

Acquisition of natural environment data (current, waves, wind etc.) from Ekofisk, Sleipner, Frigg, Statfjord, Draugen, Ross Rig, Deep Sea Bergen and Polar Pioner has been satisfactory in 1994. With assistance from the Norwegian Meteorological Institute, the Norwegian Petroleum Directorate has supervised the collection of data on these installations. The arrangement has functioned very satisfactorily and contributes to enhanced quality of this supervision.

Further preparations were made in 1994 to commence acquisition of natural environment data from the Heidrun field when this unit is installed during the summer 1995. Furthermore, collection of natural environment data was in 1994 ordered from Yme and Norne, when production starts from these fields in 1995 and 1996.

3.11 STRUCTURES AND PIPELINES

3.11.1 INTERNATIONAL STANDARDISATION

A committee was set up in 1990 under the auspices of the Norwegian Building Standards Council (Norsk Byggstandardiseringsbyrå) with the task of revising Norwegian Standard NS 3479 on Design of Structures and Design Loads. The Norwegian Petroleum Directorate was represented on the committee. After the committee started its work, work also started on a European standard (CEN) concerning the same subject matter. After that the work of the committee has been for the Norwegian committee to be a consultative body for the (CEN) standard. Several parts of this standard have been adopted in 1994. The most important parts relevant to offshore petroleum activities are the parts concerning specific gravities, variable loads and wind loads.

In 1991, the Norwegian Engineering Standards Association (NVS) set up national reference committees for new ISO standards on 'Offshore Structures', 'Pipeline Transportation System for the Petroleum and Natural Gas Industries', and 'Line Pipe'. The Norwegian Petroleum Directorate has been represented both on national committees and has been the Norwegian representative in international work. ISO 13636 - Part 1 on Offshore Structures was adopted in 1994. Work on Part 3 concerning steel structures is in progress for the second year running. It will to a considerable extent be based on the American standard API-RP-2A-LRDF. The work on Part 4 concerning concrete structures started in 1994. This will to a considerable extent be based on the Norwegian standards NS 3420 and NS 3473. Work on Part 5 concerning mobile installations will start in 1995.

3.11.2 FLARE STACK VIBRATION

Several cracks have been discovered in flare stacks on the production installations on Statfjord, Heimdal, Gullfaks B, Odin and Valhall. The cracks must have been caused by wind eddies causing certain beams and large trusses in the stacks to resonate together.

It has been necessary to make an evaluation of whether the industrial practice is good enough. As a result of this, the first step was to make an amendment to the Norwegian Petroleum Directorate's legislation, so that now reference is made to Deutsche Industrie Norm DIN 4133, which is regarded to be a more suitable reference in this area than the previous reference. Eurocode 1 will be issued in 1995. This carries the German standard further and is expected to become an even better reference. Concurrently with this, the Norwegian Petroleum Directorate has, in co-operation with Statoil, continued the work with further adaptation of these standards to offshore use.

3.11.3 "RINGING"

Ringing on structures has in 1994 presented challenges in connection with the design of the Troll A installation and the evaluation of the water leaks occurring on the Draugen installation.

The phenomenon referred to as "ringing" has the form of impulse loads, i.e. sudden blows to the structure. The blows create resonant vibrations, which are dampened over a number of vibration periods. The effects are primarily due to extremely high waves, but even small wave heights may through "ringing" contribute to fatigue. These effects are found on structures with natural oscillation frequency lower than the wave frequency (about 15 seconds). This in practice will comprise all installations fixed on the sea bed and all tension leg installations, which have oscillation frequencies on the range 1 - 5 seconds. Semi-submersible installations have oscillation frequencies in excess of 18 seconds and are consequently not subjected to these effects.

A major research project was initiated in 1992, with SINTEF and Det norske Veritas as executive institutions. The project was financed by several oil companies, Norwegian Contractors, Health and Safety Executive in the UK and the Norwegian Petroleum Directorate. The purpose of the project was to determine the predictability of the "ringing" effect and if possible develop a calculation tool to calculate the loads. When the project was terminated in 1994, methods had been developed to enable the prediction of the extent of "ringing" on slim, sea-bed fixed structures. With regard to tension leg structures, methods have not been found which will analytically predict the magnitude of the load effects. For this type of structures it will be necessary to carry out model tests in order to calculate the load effects.

3.11.4 COLLISIONS

One collision was reported in 1994 between vessel and installation, when a supply vessel collided with the Brage installation during a discharging operation. The cause was linked with failure in the vessel's dynamic positioning system.

In the last 14 years, a total of 30 collisions have been registered between installations and vessels. The collision frequency indicates that an installation will be subject to a collision about once every 30 years.

Four of the collision registered are between tankers and loading buoys. Their cause has been connected with the use of one particular type of dynamic positioning system. This system was taken out of use in 1994.

A study to compare and standardise calculation of collision risk was initiated in 1994, in co-operation with British and Dutch authorities.

3.11.5 WAVE HEIGHTS

It is of great importance to the industry to have an accurate data basis for calculation of wave heights. Particularly in connection with the subsidence problems at Ekofisk, the height of waves is a very crucial factor for decisions and implementation of measures to maintain an adequate level of safety on the installations.

If wave heights are estimated in excess, it may lead to high expenditure on the part of the licensees. Too low estimates may mean that the installations will be subject to damage in connection with adverse weather conditions, which in addition to causing human lives to be endangered, also may have serious consequences on the regularity of operations.

Calculating wave heights and the effects of waves is however very complicated. The form and size of waves depend on a number of factors. In addition to the wave height itself, also the form and direction of the waves are important to the effect on structures hit by the waves.

Wave heights in the Ekofisk area have in 1994 been subject to several independent evaluations, from several operators as well as from the Norwegian Petroleum Directorate. For most parameters describing the size and form of waves, the results correspond reasonably well. There are, however, differing views with regard to wave crest height with hundred years return period. The explanation for this difference is to be found in the choice of data source (buoy or radar), the choice of distributions and the statistical treatment of the data.

3.12 PROCESS EQUIPMENT

3.12.1 OPTIMISING MAINTENANCE

The operators are in the process of carrying out extensive alterations in maintenance of the process equipment. The changes include frequency of maintenance activities, methods and criteria for acceptance of condition. The Norwegian Petroleum Directorate has in 1994 carried out supervision to see that safety considerations are adequately taken into account in such alterations, and will continue to follow up on this in the future.

3.12.2 QUALITY ASSURANCE OF FABRICATION

Some operators have experienced that a thorough follow-up of the fabrication of equipment and components of significance to safety and production regularity is required. In connection with a quality audit of a delivery of process equipment, one operator concluded that in the future it will be necessary to specify requirements to the product in greater detail, and that there is a need for closer follow-up during the fabrication phase in order to ensure that the specified quality is achieved.

This trend to a certain extent contradicts the general trend in the industry towards increased use of functional requirements to equipment suppliers. The Norwegian Petroleum Directorate will consider the experience acquired in this area more closely, to ensure that the efforts of the industry to achieve cost reductions are implemented in a way that does not adversely affect safety.

3.13 LIFTING GEAR

The Norwegian Petroleum Directorate has in 1994 registered several, partly serious, incidents in connection with operation of lifting gear. The direct causes of these incidents have been inadequate control of lifting equipment, wrong use of equipment and failure of communication between crane operators and signalers/slingers.

The Norwegian Petroleum Directorate has in 1994 carried out survey of the operators' control of measures to ensure that lifting gear and its use is safe, both in the drilling area and in other areas on the installations. The operating companies have carried out training and campaigns to reduce accidents and incidents due to use of lifting gear. The accidents and incidents in 1994 however demonstrate that there is still a need for efforts in this area.

Fig. 3.14.1.a
Classification of reported gas leaks by degree of seriousness

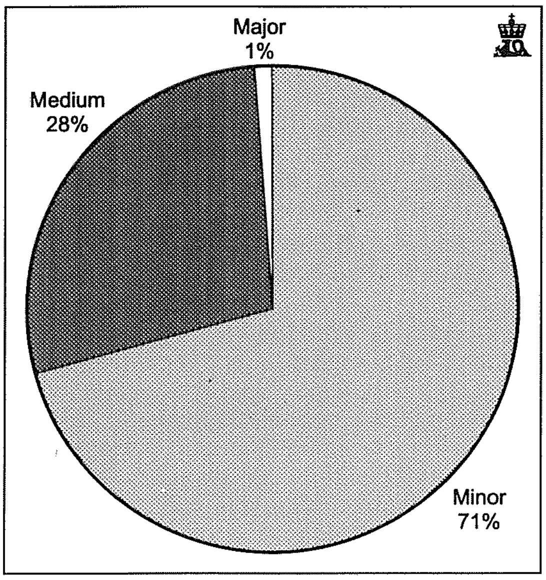


Fig. 3.14.1.b
Causes of gas leaks - operational errors

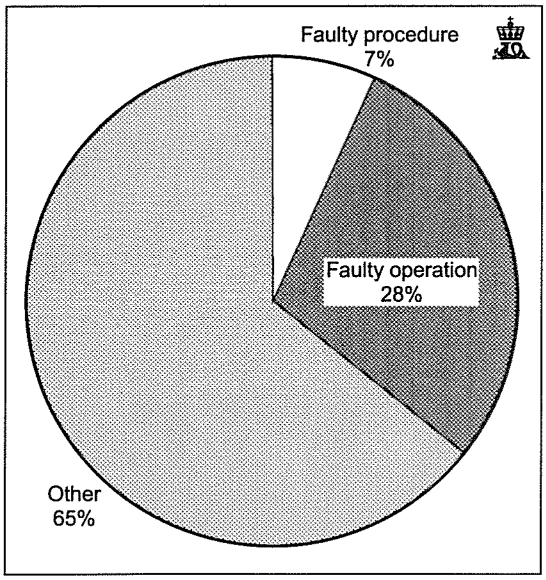


Table 3.14.1
Gas leaks detected by gas detection systems

Severity	Number of leaks	Detected by gas detection system	Reading in % LEL 20%	Reading in % LEL 60%
Minor	88	16	13	3
Medium	35	14	8	6
Major	1	1	0	1

(LEL = Lower explosion limit)

3.14 HYDROCARBON LEAKS, FIRES AND OUTBREAKS

3.14.1 HYDROCARBON LEAKS

During 1994, 124 hydrocarbon leaks were reported to the Norwegian Petroleum Directorate, compared to 96 in 1993. Out of these there was an increase of small and medium size leaks, but only one large hydrocarbon leak.

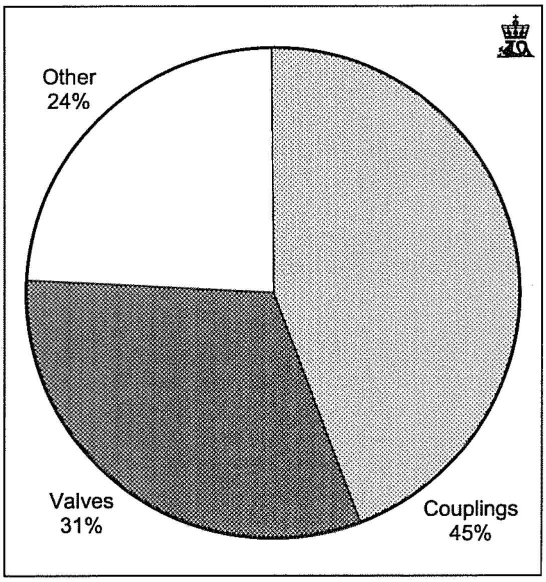
The increase in small leaks can be interpreted in a positive sense inasmuch as it reflects a greater willingness to report incidents which again provides greater possibilities for interpretation of causes. The increase in medium size leaks is a matter of concern to the Norwegian Petroleum Directorate, and leads to the conclusion that the efforts in a continued effective supervision of the operating companies must be upheld. Some of the increase is explained by altered reporting routines in some companies.

Main conclusions from the supervision show that previous commitment areas should be maintained and that it is important to combine technical measures with organisational and motivational measures by placing more emphasis on the administrative and job organisational aspects. The Norwegian Petroleum Directorate regards this as an opportunity to create a favourable climate of co-operation between employees and company, which is considered to be particularly important in getting to grips with the problem.

Operators are showing engagement and institute systematic measures to reduce the number of leaks. Their experience will be utilised in the Directorate's further supervisory work. Figure 3.14.1.a shows distribution of hydrocarbon leaks according to their degree of seriousness.

Table 3.14.1 gives the number of hydrocarbon leaks detected by gas detection systems. The table shows that detection systems only detect a small number of leaks out of the total, and most of those detected were large and medium size leaks.

Fig. 3.14.1.c
Causes of gas leaks - faulty technical equipment



Figures 3.14.1.b and c give an indication of the causes of the leaks. Often the causes behind a leak are complex. The subdivisions reflect the Norwegian Petroleum Directorate's assessment of the factors that were most paramount in each particular incident.

3.14.2 GAS LEAK ON GULLFAKS A

On 31 July 1994 an extensive gas leak occurred on Gullfaks A during preparations for annual shutdown for necessary maintenance purposes.

The leak occurred during pressure relief to the flare system from a high-pressure gas system. The restriction orifice which was to ensure the pressure drop was missing. The consequence of this was that the pipe on the low pressure side was ruptured, and large quantities of gas escaped. The leak lasted about 12 minutes, and the volume escaped gas has been estimated to approximately 20,000 m³ .

With reference to this incident, the Norwegian Petroleum Directorate issued a safety notice to emphasise to the industry the importance of correct assembly, control/inspection and maintenance of orifice plates.

Table 3.14.3
Causes and extent of fires reported in 1994

Cause	Extent		
	Minor	Medium	Major
Welding	6	1	
Hot surfaces, overheating	9	6	
Electrical	6	4	
Other causes	3	3	
Total	24	14	0

3.14.3 FIRES AND OUTBREAKS

The Norwegian Petroleum Directorate registered 38 fires in 1994, compared with 56 in 1993. High temperature surfaces and overheating emerge as the principal cause of ignition.

Table 3.14.3 summarises the scope and causes of fires and outbreaks reported to the Directorate in 1994. None of the reported fires have been classified as major fires (class C). The Norwegian Petroleum Directorate notes that the fire statistics reveal a decreasing trend and this may be interpreted to indicate the start of a positive trend.

3.15 DIVING

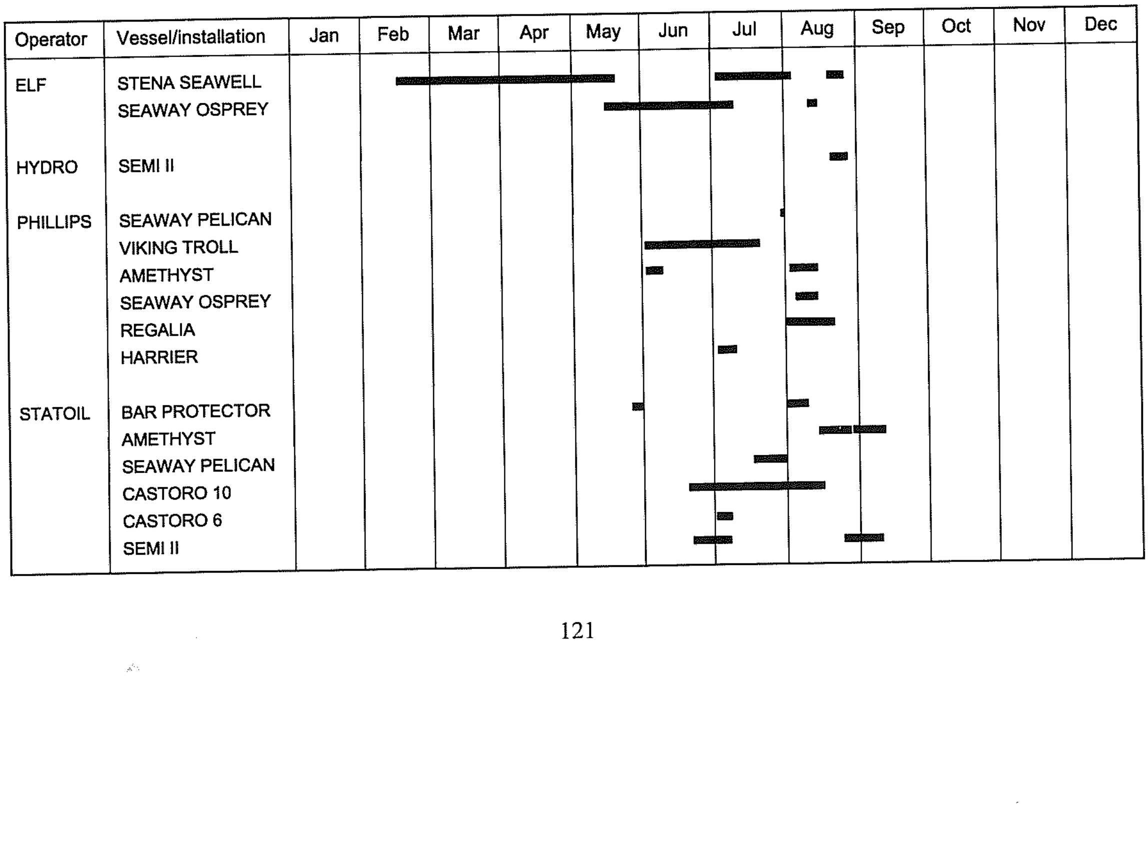
3.15.1 DIVING OPERATIONS

In 1994, 326 surface oriented dives, 703 bell runs (in saturation), and 88,630 man hours in saturation were carried out on the Norwegian continental shelf and on Norwegian pipelines on foreign shelf under Norwegian jurisdiction. This was about half the activity in surface oriented and saturation dives as compared with the previous year. The mean bell run time for saturation diving was 6.3 hours and the mean saturation period 13.9 days. The figures represent an increase in mean bell run time of 0.9 hours, but a decrease in mean saturation period of 1.1 days compared to 1993. The mean immersion time for surface oriented divers was 1.7 hours. The dives were carried out from ten different vessels/installations, cf. Figure 3.15.1.

Diving operations generally fell into the categories inspection, maintenance and structural contracts for fields operated by, Elf, Norsk Hydro, Phillips and Statoil.

Diving in connection with construction work made up a large part of the operations. This work has essentially been in connection with hook-up of flowlines and

Fig. 3.15.1
Diving operations in 1994



risers and to give assistance with the emplacement of various structures.

With regard to personal injuries in connection with diving activities, reference is made to summary in section 3.5.6.

3.15.2 DIVING RESEARCH

In 1989, the Norwegian Petroleum Directorate joined with Statoil and Norsk Hydro in launching a joint Programme for Research and Development in Diving Technology and Diving Medicine (FUDT). In 1990, Saga Petroleum joined the programme. Other oil companies have from time to time made contributions in specific fields, either on an independent basis or through the Norwegian Oil Industry Association (OLF). The research activities established through the FUDT programme (diving technology and diving physiology/medicine) were continued in 1994 through the research programmes ALFA and OMEGA, which represent basic research and applied research, respectively.

The Directorate is pleased to note that the oil companies cooperate to arrive at common solutions to relevant offshore diving issues

The Norwegian Petroleum Directorate is a member of the Board of the OMEGA project, and also of the various steering committees established for sub-projects under that project. These duties enable the Directorate to keep up to date on current research and development in the technical fields involved and to maintain close ties with the industry. In recent years the Directorate has noted with satisfaction improvements in organisation and quality of R&D activities related to technical and health aspects of manned subsea operations.

3.15.3 NEW CONTRACT STRUCTURE

A change in the operators' contracts for manned subsea operations has taken effect in the recent time. Contracts are now very much of shorter duration than before, often lasting only one or two weeks. Vessels and personnel employed work alternately in Norwegian and foreign sectors and are often in action on a foreign shelf up to the moment a job is commenced on the Norwegian shelf. This puts a great strain on company management systems and follow-up of operations. Experience from supervision carried out by the Norwegian Board of Health and the Norwegian Petroleum Directorate in 1994 demonstrated among other things significant deficiencies in the operators' follow-up in relation to contractors.

3.15.4 APPROXIMATION OF DIVING LEGISLATION

In connection with approximation of diving standards, the European Diving Technology Committee (EDTC) arranged an international meeting in Luxembourg in April 1994, with financial support from the EU Commission. The meeting considered subjects related to technical, operational, medical and educational aspects of occupational diving. A positive attitude was expressed with regard to approximation of statutory requirements applicable to the diving industry. In the technical and the medical areas a high degree of consensus was achieved on a draft standard which is in line with the intentions contained in the Norwegian legislation.

The report prepared after the meeting will be able to serve as basis for future European standardisation of legislation applicable to diving.

4. Environmental Measures in the Petroleum Activities

4.1 INTRODUCTION

Environmental issues have in recent years acquired a central position in the formation of energy policy. To the petroleum industry, this means that considerable efforts must be made to prevent and contain environmental damage resulting from the activities. The costs involved in environmental measures can be expected to increase and contribute to reduced profitability on the Norwegian continental shelf, unless the industry as well as the authorities address the issues in a systematic and reflected manner.

Consideration for the environment is an integral part of the Norwegian Petroleum Directorate's total efforts to contribute to a sound management of the Norwegian petroleum resources. The Norwegian Petroleum Directorate's efforts in environmental protection thus concentrate on precautionary measures designed to prevent and contain pollution damage.

The main components of this work are preparation of statutory legislation and a general framework for the activities, reports, supervision, co-operation with other authorities and information. These duties in sum make up a substantial part of the Directorate's total resource commitment.

4.2 ENVIRONMENTAL FRAMEWORK

In 1994, the Norwegian Petroleum Directorate continued to implement activities in many areas that impose constraints in order to protect the external environment.

These activities include following up the conditions stipulated with respect to the environment in propositions and reports to the Storting (Parliament), in connection with opening new areas for petroleum activities and with matters relating to development in connection with applications for consent. The Norwegian Petroleum Directorate has also taken active part in the work following up the report to the Storting (Stortingsmelding) No. 26 (1993-94), opening of new areas for exploration activities in the Norwegian Sea.

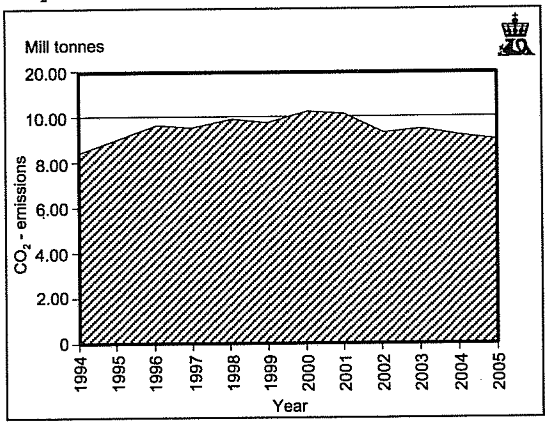
The Norwegian Petroleum Directorate has in co-operation with the State Pollution Control Authority assisted the Ministry of Industry and Energy in its work drafting national action plans for reduction of acid precipitation and climatic gas emissions. The Norwegian Petroleum Directorate and the State Pollution Control Authority have jointly been responsible for preparing and evaluating various measures directed at the petroleum activities. Such measures have included possibilities for reducing air polluting emissions from energy production, flaring, cold venting, buoy loading and terminal loading as well as formation testing. The work on the national action plans is not yet completed, and will continue in 1995.

New prognoses for emissions of CO_2, NOx, VOC (volatile organic compounds) and methane from the petroleum activities have been prepared, in co-operation with the State Pollution Control Authority. Prognoses constitute important instruments in monitoring measures to ensure compliance with national and international environment obligations.. In addition, the preparation of prognoses constitutes an important part of the work with national action plans for reduction of acid precipitation and climatic gas emissions. Figure 4.2 shows the Norwegian Petroleum Directorate's prognosis for CO_2 emissions from the petroleum activities for the period 1994 to 2005. Emissions from activities which today are not subject to tax are also included in the prognosis.

In connection with the report work on the competitive situation of the Norwegian continental shelf (NORSOK), the Norwegian Petroleum Directorate has participated as observer in certain working groups aimed at the external environment. In addition, the Norwegian Petroleum Directorate has contributed with supporting material for this work. The Directorate was also represented by an observer in the reference group for the NORSOK work on health, environment and safety matters.

The Norwegian Petroleum Directorate has participated, jointly with the Ministry of Industry and Energy, in discussions with the operating companies in connection with consequence analyses, plans for development and operation, and plans for construction and operation. In its consideration of plans for development and operation for new developments, the Norwegian Petroleum Directorate has to a greater extent than before focused on the possibilities of employing technology that will contribute to reduced discharge.

Fig. 4.2
CO_2 - emission forecast for the petroleum activities



4.3 SUPERVISION OF OPERATING COMPANIES

Much of the Norwegian Petroleum Directorate's supervision of the operating companies' activities that were related to environmental measures, was performed as an integral part of the Directorate's supervision of safety and the working environment. This supervision targets the companies' internal control mechanisms, which are intended to provide a systematic means of ensuring that company operations during all phases are planned and executed in conformity with the authorities' requirements and the companies' own objectives and acceptance criteria.

The Norwegian Petroleum Directorate also carried out supervision particularly aimed at operators' precautionary measures when drilling in environmentally sensitive areas. Consequently, an audit was carried out in 1994 of Statoil's exploration drilling on Møre I outside Runde. Furthermore, work has been initiated in order to specify requirements that should be imposed to ensure that the environmental concerns are taken into account in the companies' risk and preparedness analyses when planning drilling operations, with a view to arriving at precautionary measures and emergency preparedness measures for drilling.

In 1990 the Norwegian Petroleum Directorate issued regulations relating to implementation and use of risk analyses in the petroleum activities. An important principle in these regulations is the duty of the operating companies themselves to define safety objectives and acceptance criteria for risk. The Norwegian Petroleum Directorate has in 1994 continued the work of monitoring the activities in the industry aimed at developing acceptance criteria for environmental risk.

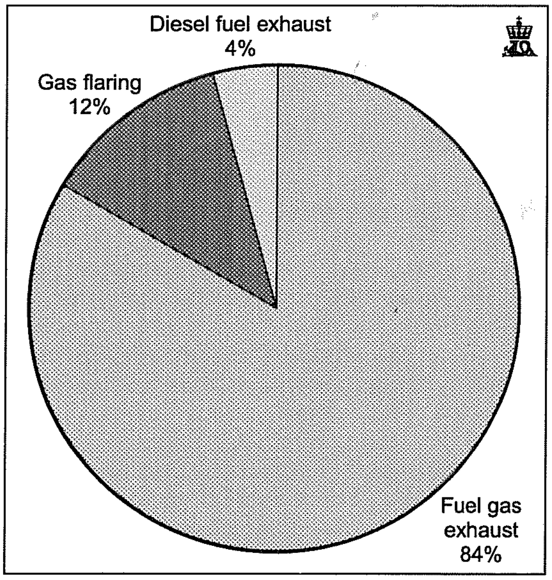
4.4 CARBON DIOXIDE TAX

Since I January 1991, the Norwegian Petroleum Directorate has been assigned responsibility on behalf of the Ministry of Finance for enforcement of the Act relating to carbon dioxide tax on the Norwegian continental shelf. Apart from administrating the actual collection of the tax, the Directorate also supervises the metering systems for fuel and flare gas metering.

The Norwegian Petroleum Directorate also considers complaints and other judicial problems in connection with the CO_2 tax. Furthermore the Directorate considers the ongoing effects of the tax. This latter work is organised in the form of annual meetings with the operating companies and analyses of the statistics reported by the companies to the authorities.

In 1994, the tax was levied at a rate of NOK 0.82 per Sm^3 of natural gas and NOK 0.82 per liter of oil or condensate. The total CO_2 emissions from activities subject to tax in 1994 were 7.3 million tonnes. This represents an increase in CO_2 emissions of 0.3 million tonnes compared to 1993. Figure 4.4 shows how the emissions can be grouped related to sources. There has been an increase in use of natural gas both for flaring and for fuel, and the consumption of diesel oil also increased. The increase in CO_2 emissions was however less than the increase in

Fig. 4.4
CO_2- emission sources



petroleum production, and this shows a trend towards a more energy-efficient production of oil and gas.

4.5 TECHNOLOGY DEVELOPMENT

The Petroleum Act and the regulations derived from it contain requirements relating to technical solutions and activities, but there is also a requirement relating to the constant development of safety and technology, in accordance with general advances in technology and development otherwise in society. The Norwegian Petroleum Directorate follows up on this in many areas. In 1994 attention was focused on:

- development of improved cleansing methods for produced water and development of new measuring methods for discharge of produced water in accordance with international standards;
- development of technology to reduce NOx emissions from combustion;
- research and development of more energy efficient technology for oil and gas production;
- reduction of need for gas flaring during production and in connection with well testing;
- development and use of new types of drilling mud, and work to obviate or minimise the use of oil-based drilling mud;
- various methods for handling and storage of oily cuttings;
- more efficient drainage systems;
- new fire-fighting agents in connection with phasing out halons;
- use and handling of biocides, heavy metals and low activity isotopes;
- composition of sacrificial anodes for corrosion protection.

4.6 OTHER ENVIRONMENT WORK

The Norwegian Petroleum Directorate takes part in a range of national and international forums working with protection of the environment. These activities are intended to influence these forums and bodies in the desired direction, and also to build up the competence the Directorate needs in order to carry out its responsibilities in this field. In 1994, the following were among those the Norwegian Petroleum Directorate participated in:

- Governmental Action Control Group (AKU)
- International Maritime Organization (IMO)
- North Sea Offshore Authorities Forum (NSOAF)
- Standardisation organisations CEN and ISO.

Since 1992, the Norwegian Petroleum Directorate been a member of the technical committee of the Norwegian Research Council's research programme MUST. This is a programme for environment friendly and profitable development of small petroleum fields.

In addition to sitting on the technical committee, the Directorate is also active in the capacity of advisor in the evaluation of projects that may be of interest to the programme. The programme will last for a five year period and has an overall expenditure budget of NOK 111 million.

The Directorate also administers and operates an annual scrap recovery programme in the North Sea. In 1994 this activity had an operating budget of about NOK 4.6 million.

4.7 CO-OPERATION WITH THE STATE POLLUTION CONTROL AUTHORITY

As provided in the premises of the regulatory supervision for the petroleum activities, the Norwegian Petroleum Directorate co-ordinates the practical implementation of supervision carried out both by the Norwegian Petroleum Directorate and by the State Pollution Control Authority (SFT), under the Pollution Control Act and the Petroleum Act respectively, including co-ordination of duties in connection with the issue of consents and discharge permits. The Norwegian Petroleum Directorate carries out supervision of the operators' systematic efforts to meet the requirements of the Regulations relating to the licensee 's internal control, as well as the Regulations for implementation and use of risk analysis and the Regulations for emergency preparedness, which are all laid down jointly by the two agencies.

In its coordination role the Directorate must evaluate the cost and safety aspects of actions contemplated by the pollution control authorities insofar as they may be of significance to the petroleum activities.

Also the Norwegian Petroleum Directorate works jointly with the State Pollution Control Authority to prevail on the industry to participate in environmental experience exchange programmes. The aim is to contribute to the development of solutions which are effective and at the same time as economic as possible.

The Norwegian Petroleum Directorate and the State Pollution Control Authority have carried out several supervisory duties based on a common legislation, and the Directorate has assisted the State Pollution Control Authority in connection with oil pollution control exercises.

5. Special Reports and Projects

In 1994, the Norwegian Petroleum Directorate appropriated a total of NOK 14,976,706 for special projects, of which NOK 10,216,842 was budgeted for projects in the Resource Management Division and NOK 4,370,772 for projects in the Safety and Working Environment Division.

In addition NOK 4,721,768 was committed to the North Sea Seabed Clearance project and NOK 3,537,715 was made available for collection of meteorological and oceanographic data in the Barents Sea.

5.1 RESOURCE MANAGEMENT

5.1.1 EXPLORATION

Project title	Executive institution
Play analysis data base	Geoknowledge, Opheim Data
Processing of satellite data, Lofoten	University of Oslo
Arctic correlation of Permian-Carboniferous strata	University of Tromsø
Porosity development in Late Paleozoic carbonate buildup in Spitzbergen and in the Barents Sea	University of Tromsø
The Norwegian Petroleum Directorate's oil sample store	Rogaland Research, Institute of Energy Technology
Norwegian geochemical standard samples bank	Norwegian Petroleum Directorate Norwegian oil companies, IKO, Geolab N
Thermal effects on source rocks	Norwegian Petroleum Directorate Commissioner of Mines for Svalbard

Play analysis data base
Keeping the resource account is one of the main tasks of the Exploration Department. This account also includes estimates of the undiscovered resources.

This project has aimed to develop and implement software for a data base of play models and their resource estimates.

This data base is connected to a resource estimation programme and is now used in the Norwegian Petroleum Directorate's play model analyses which form the basis for the resource account. The software makes the mapping of resources and the use of resource data more effective, and enables a quick updating of the undiscovered resources for the entire shelf or parts of it.

Processing of satellite data, Lofoten
The purpose of the project has been to process digital satellite data to obtain better image of geological structures in parts of Lofoten and Vesterålen. These results are used to map the fault tectonics continuously from shore and out on the continental shelf. This can make it possible to study the fault systems at different erosion levels.

Arctic correlation of Permian-Carboniferous strata
The project compares the Late Paleozoic strata based on well information in the Barents Sea South and outcrop on Svalbard, Greenland and Arctic Canada. The study has made use of modern sequential stratigraphic principles to be able to assess well results for evaluation of this play model.

Porosity development in Late Paleozoic carbonate buildup in Spitzbergen and in the Barents Sea
This is a three-year project (1994-96) under the administration of the University of Tromsø. The project receives support from the Norwegian Research Council, Amoco., Elf, Norske Shell, Norsk Hydro, Phillips, Saga Petroleum, Statoil and the Norwegian Petroleum Directorate. The study has focused on diagenetic issues in the Late Paleozoic carbonate rocks in central Spitzbergen.

The Norwegian Petroleum Directorate's oil sample store
The Norwegian Petroleum Directorate's oil sample store was established in 1990. The samples are released by the Release Committee for various geochemical analyses, and are intended as an instrument to help further exploration activities on the Norwegian continental shelf. The samples were moved from deepfreezer boxes to the Norwegian Petroleum Directorate's new deepfreezer storage room during 1994. At the year end 1994 the oil sample store contains 510 oil samples (primarily DST samples) from 267 wells. Only 10 samples were delivered in 1994, while 40 samples were released for analyses. The Norwegian Petroleum Directorate has carried out two special studies in connection with the oil sample store:

1. Distribution of heavy metals in oils and source rocks. The analyses were carried out by Rogaland Research.
2. Use of radiogenic isotopes of strontium and neodymium as tracers. This is an R&D joint venture with the Institute of Energy Technology.

Norwegian geochemical standard samples bank
The Norwegian Petroleum Directorate decided in 1993 to establish standard samples for geochemical analyses of oils and source rocks. The purpose is to achieve a higher quality standard of geochemical analyses of such material, and to increase the comparability of analyses carried out in different laboratories. The companies and consultants who have prepared «The Norwegian Industry Guide to Organic Geochemical Analyses, 3rd Edition, 1993» have been active participants in selecting suitable samples. As oil standard was selected oil from the Oseberg field where Norsk Hydro is the operator, and as source rock standard was selected a Triassic shale (Botneheia formation) from Teistberget on Spitzbergen. The collection and processing of the sample material is financed by equal contributions from the Norwegian Petroleum Directorate, Norsk Hydro, Saga Petroleum and Statoil.

About 1000 liters of the oil standard sample was collected by the operator in June 1994 and is stored in the Norwegian Petroleum Directorate's cold storage facility. About 900 kg source rock samples from Teistberget was collected by Norsk Hydro in August 1994. Preliminary analyses show that the source rock sample is not optimal for all methods of analysis, and it has been decided to collect an additional sample from England in January 1995. 37 laboratories from all parts of the world are to analyse organic components, heavy metals and stable and radiogenic isotopes in the oil samples as well as in the source rock samples. The oil standard sample has bees designated North Sea Oil - 1 (NSO-1), and was distributed to the laboratories in October 1994. Both standard samples of the source rock are planned to be processed and distributed early in 1995. Completed calibration of all samples as standards is expected by the year end 1995.

Thermal effects on source rocks
In several of the sedimentation basins on the Norwegian continental shelf, magmatic activity in the form of intrusions and volcanism has led to important geological events. Examples of such geological events comprise the Møre basin, the Vøring basin and the Vestbakken volcano province. On Svalbard, analogue magmatic rocks and ambient hydrocarbon bearing source rocks are available for field studies. In 1994 consequently, the Norwegian Petroleum Directorate, jointly with the Commissioner of Mines for Svalbard carried out a systematic collection of samples of source rocks from specifically selected locations. These samples are to be analysed using different geochemical methods. The purpose is to acquire more knowledge of the effects of magmatic activity on the petroleum potential in the relevant areas on the Norwegian continental shelf.

5.1.2 DEVELOPMENT AND OPERATION

Project title	Executive institution
Continental shelf analysis model	Bechtel Ltd
Conditions for utilisation of infrastructure on the UK continental shelf - consequences for the development of small fields	Wood MacKenzie
Lithostratigraphic and structural geological names on the Norwegian continental shelf	Norges geologiske undersøkelse (NGU)
Raw water programme	Capcis

Costs related to tie-in of pipelines and modifications of a gas processing terminal	Kværner Engineering A/S
Decisive parameters in the choice of development concepts in future developments on the Norwegian continental shelf	Granherne Limited
Seismic interpretation of Heidrun	Petec a.s
Well problems in overlying strata in the Ekofisk area	Network Stratigraphical consultants
Reservoir studies	Professor Doctor B. Sellwood, University of Reading
Magnetostratigraphic examinations of core material from the Lunde formation in the Snorre Phase II area	CB MAGNETO A/S
Ekofisk subsidence	Mervyn Jones, Dr. SDR, University College, London
Geophysical interpretation on the Ekofisk and Eldfisk field	Petrolet A/S
Production below the boiling point pressure	Rogaland Research
Improved oil recovery Gullfaks	Rogaland Research
Pipe simulation model - PIPESIM	Baker Jardine and Associates Limited
Reservoir technical evaluation of multiple hole horizontal wells	Petec a.s
Albuskjell reservoir model	Geomatic
Eldfisk reservoir model	Petec a.s
Modelling fluid transport in cracks	Prof. R. Bruhn, University of Utah
Costs of alternative development concepts in the Norwegian Sea	Kværner Engineering A/S
Reservoir technology, Norne	Petec a.s
PVT evaluation of Smørbukk	Scandpower a.s
Seismic interpretation of Gullfaks Sør	Badleys Earth Sciences Limited
Petrophysical assistance in evaluation of Smørbukk	Petec a.s

Continental shelf analysis model

SARA is a multiperiodic investment analysis model. The model has been developed as a supplementary tool for decisions relating to development of petroleum resources on the Norwegian continental shelf. The model is used particularly in the work of gas allocation on the Norwegian continental shelf.

Conditions for utilisation of infrastructure on the UK continental shelf - consequences for the development of small fields

Wood MacKenzie have carried out an analysis of how the principles applicable to the stipulation of tariffs for transport and processing services on the UK continental shelf may affect development of small fields, and the choice of development concept. Development on the UK continental shelf is compared with the development on the Norwegian continental shelf.

Lithostratigraphic and structural geological names on the Norwegian continental shelf

The project is the Norwegian Petroleum Directorate's contribution to Norwegian Geological Council to establish a data base of lithostratigraphic and structural geological names on Norwegian territory. The data base is located at NGU (Norges geologiske undersøkelse) in Trondheim. The data base provides information on named formations existing within a geographic/geolological area, how they are defined, where they are defined in the literature, whether a name has been used previously, whether the unit has a revised definition, what formations are defined in a group, etc. All data stored in the data base are publicly available.

Raw water programme

This project aims to clarify the effects of injection of untreated sea water into a reservoir. The study is carried out by Capcis at the University of Manchester, and is controlled by representatives from the oil companies and the authorities in Norway and the United Kingdom. It was initiated in 1994 and will be completed in 1996.

Costs related to tie-in of pipelines and modifications of a gas processing terminal

The project has verified and costed a plant which can extract wet components from a gas flow and deliver stabilised condensate and gas of marketing quality. The composition of the gas flow is varied in order to cover relevant feedflows from fields on Haltenbanken and from the northern North Sea.

Decisive parameters in the choice of development concepts in future developments on the Norwegian continental shelf

The project aimed at defining those parameters that will influence the choice of development concept in future developments on the Norwegian continental shelf. Based on this, limit values were defined for those areas where the individual concepts are competitive.

Seismic interpretation of Heidrun

The purpose of the project has been to determine erosion limits and the extent of the field. This constitutes part of the Norwegian Petroleum Directorate's evaluation of the field prior to production start.

Well problems in overlying strata in the Ekofisk area

In many chalk fields problems are encountered due to breaking and deformation of the casing in production wells in the sediment layers above the reservoir. In order to examine the sediments above reservoir level, biostratigraphic analyses (dating and zonation) of cuttings material from eight wells in three chalk fields were carried out. The study was commenced in 1993 and will be completed in 1995.

Reservoir studies

Sedimentological and biostratigraphic studies have been carried out of 40 meters of core material collected from the Ekofisk and Tor formations in a well drilled in a new structure. The discovery confirmed a new play model type, and the results from the study are important in understanding the geological model.

Magnetostratigraphic examinations of core material from the Lunde formation in the Snorre Phase II area

The project was carried out in two phases. First, an examination was carried out of two wells in the north-eastern part of Snorre. The project was then extended to comprise another two wells. The purpose of the project was to establish a stratigraphic framework as support for well to well correlations and reservoir modelling in an area where geometry and extent of sandstones are difficult to predict, and traditional biostratigraphic analysis methods do not provide sufficient resolution for reservoir geological modelling.

Ekofisk subsidence

This project aimed to evaluate observations of seabed subsidence at Ekofisk. A central aspect of this project was the relationship between net reservoir outtake and seabed subsidence. The effect of different fluid properties in the determination of rock compressibilitiy has also been examined.

Geophysical interpretation on the Ekofisk and Eldfisk field

This project involved interpretation of 3D seismic across the Ekofisk and Eldfisk fields. On the Ekofisk field, the southern part was given particular attention.

Pilot project - Production below the boiling point pressure

The project is intended to provide more knowledge of issues related to production below the boiling point pressure. The project aims primarily to achieve a physical understanding of the process and to arrive at laboratory measuring methods and a mathematical description to be able to quantify the reduction in flow properties and production rate of oil, and to determine to what extent they may be restored when the well pressure varies around the boiling point.

The pilot project studied issues and procedures specifically. Information from producing fields where these issues are relevant was acquired.

Improved oil recovery Gullfaks

This project is a continuation of the 1993 project. The project aims to acquire a better understanding of WAG injection combined with foam in the Cook formation on the Gullfaks field. The separate-simultaneous WAG injection technology (SSWG) is to be difined for possible implementation with different types of wells.

Pipe simulation model - PIPESIM

The project is about acquisition of a simulation model for dimensioning of pipe systems, analyses of flow regimes, pressure and temperature development etc. This tool will among other things be used in connection with concept evaluations, including phase-in of small fields to existing installations.

Reservoir technical evaluation of multiple hole horizontal wells
Horizontal wells branching out in several directions have to date not been drilled on the Norwegian continental shelf. This type of wells has, however, been used with a good result in other countries. A limited study has been carried out which examines reservoir technical analyses of multiple hole horizontal wells. In particular the utilisation of this type of wells for Troll Vest has been considered.

Albuskjell reservoir model
A reservoir geological model has been designed for the Ekofisk formation in the western part of the Albuskjell field. The model will be included in a reservoir simulation model which will analyse potential production alternatives in connection with different choices of vertical and horizontal wells in this relatively dense formation. Geomatic have been engaged as consultants in designing the geological model.

Eldfisk reservoir model
The Norwegian Petroleum Directorate has received reservoir simulation models for Eldfisk Alpha and Eldfisk Bravo, produced by Petec a.s for Norsk Agip A/S, Elf Petroleum Norge A/S and Norsk Hydro a.s. A consultant has been engaged in order to adapt the models to the Norwegian Petroleum Directorate's own interpretations and the results from new wells. The simulation model will be history adapted and used for predictions of production schedules in connection with different choices of development strategies.

Modelling fluid transport in fractures
Professor R Bruhn of the University of Utah has continued the work of developing a numerical model to simulate permeability through fractured chalk reservoirs. The project has drawn on mapped fracture data from chalk mines at Lägerdorf in Germany, and compared them with core data from wells on the Ekofisk field to simulate verious three-dimensional flow models.

Costs of alternative development concepts in the Norwegian Sea
In this project estimates for dimensions, weights, investments and project implementation time were prepared for various development concepts for the fields Smørbukk, Smørbukk Sør and Midgard. The costs include both investments and operating costs. The results from this project have been included as a part of the Haltenbanken area study.

Reservoir technology, Norne
The consultancy company Petec a.s has been engaged in connection with reservoir technology studies of the Norne discovery. The work included among other things production of a simulation model based on the Norwegian Petroleum Directorate's mapping of the discovery. The purpose of the project was to evaluate alternative development strategies for the discovery, and to assess central reservoir input data. The results from the study were used for the Norwegian Petroleum Directorate's consideration of the plan for development and operation for this discovery.

PVT evaluation of Smørbukk
The consultants firm Scandpower a.s has carried out an analysis of PVT data from the Smørbukk discovery. The work included an evaluation of representativity to fluid and gas samples, subdivision of the field in different fluid regimes as well as generation of input data for compositional reservoir simulation.

Seismic interpretation of Gullfaks Sør
Reprocessing of 3D seismic data on Gullfaks Sør showed a marked data quality improvement. New seismic mapping has been carried out based on the reprocessed 3D seismic data. Seismic data are correlated to the wells in the area, and the velocities from the wells have formed the basis for a velocity model for depth conversion. The final result is a depth map of the top and bottom of the reservoirs. Rock volumes of gas and oil filled reservoirs are estimated. Structural geological issues in connection with the discovery are described.

Petrophysical assistance in evaluation of Smørbukk
Petec has assisted the Norwegian Petroleum Directorate in collection of data and petrophysical interpretation of the Smørbukk discovery, and in permeability estimation in using the programme Horizon. The field is complicated with barriers between the strata, varying fluid contacts and in addition the logs are affected by cave-in of the borehole. The work has been carried out in the Norwegian Petroleum Directorate's premises and by means of the Norwegian Petroleum Directorate's interpretation tools. The result is intended to be used in the Norwegian Petroleum Directorate's mapping and resource estimation of the field.

5.1.3 DATA MANAGEMENT

Project title	Executive institution
Services well data release	Petec a.s, Allservice, TK-Service, Tape Technology Norge
Petrophysical quality control	Petec a.s, Simon Petroleum Technology
Geodata project	See below: 5.1.8
Wet sample handling	Geco-Prakla
Well Data Summary Sheets	Norwegian Petroleum Directorate
Software maintenance	See below
Software procurement and development	See below
Evaluation of a production data computer model	Tape Technology Norge/Geco-Prakla
Quality control and reformatting of the NPD seismic data	Tape Technology Norge/Geco-Prakla

Services well data release
This project covers a range of activities associated with the reprocessing and preparation of materials for release. External contractors were also employed for copying of digital data compilations and printing of catalogues and publications.

Petrophysical quality control
In connection with implementation of the High Quality Log Data (HQLD) project to provide a total quality upgrade for all log data from Norwegian exploration wells, the services of external consultants were employed. The Norwegian Petroleum Directorate has recovered all paper logs and associated magnetic tapes for all exploration wells. Based on detailed specification requirements, they have been checked for quality of contents and well trajectory identification and sent to a consultant for compilation of a complete digital version. At year end about 600 of the 780 exploration wells have been dealt with and the result distributed to the oil companies who have funded the quality upgrade. The project continues in 1995.

Wet sample handling
In 1992 the Norwegian Petroleum Directorate received about 20,000 extra wet samples from Statoil, from wells for which the Directorate's backup stocks for scientific analysis were running low. External consultants were used to pack and mark the samples according to regulations, so that storage and retrieval can take place efficiently. The project was started in 1992, and the last 4,000 samples were processed, packaged and registered as prescribed in 1994.

Well Data Summary Sheets
WDSS publication No. 19, containing key data from wells released per 1 January 1994, was published in June 1994. All exploration wells more than 5 years old are consequently covered by the WDSS series published by the Norwegian Petroleum Directorate.

Software maintenance
To ensure that the Norwegian Petroleum Directorate's around 50 different computer software systems used by the Resource Management Division are always operative and available for technical and administrative tasks, maintenance contracts have been signed with the following companies: OIS Contracting, Andersen Consulting, Geodata, Intera, Calcep, Sintef, Rogaland Research Institute, Geomatic, Geco-Prakla, Advanced Technology, Platte River, Seres, Z&S Consultants, SSI, Hyprotec and Simon Petroleum Technology.

Software procurement and development
To increase the availability of effective, modern software applications, new programmes were purchased or developed in 1994, from the following firms: Geomatic, Current Software, ISI, Delfi Data, Baker Jardine, Geodata and Opheim Data.

During the year 1994, the Resource Management Division completed conversion of most of its older format systems from Norsk Data formats to Unix and MS Windows based systems.

Evaluation of a production data computer model
The Norwegian Petroleum Directorate has initiated a process to design a new Petroleum Production Reporting System (PPRS). The project comprises an evaluation of the question whether to base this system on the Petrotechnical Open Software Corporation (POSC) standard for software related to exploration and production of petroleum.

The project will also constitute the basis for the Norwegian Petroleum Directorate's introduction of a new transmission format for production data based on the POSC standard. The aim is to provide specific advice to a project for standardisation of reporting format initiated by the Norwegian Petroleum Directorate, and to recommend a computer model to the project group for the new PPRS.

Quality control and reformatting of the NPD seismic data
The project entails commissioning a consultancy firm to perform quality control and reformatting of the Norwegian Petroleum Directorate's processed seismic data to a digital work station format, of various types for which there is a demand from the oil companies. For the Norwe-

gian Petroleum Directorate first to carry out reformat-ting and then copying the finished data to the oil companies, will make the data more easily available than if each individual company were to generate its own work station formats. In 1994, the Norwegian Petroleum Directorate has been able to offer 18 of its seismic data packages both in Charisma, GeoQuest and Landmark formats.

5.1.4 RUTH

RUTH (Reservoir Utilization through advanced Technological Help), is a research programme under the direction of the Research Council of Norway, with the Norwegian Petroleum Directorate taking care of the programme administration. The programme aims primarily to promote improved oil recovery, but also to a strengthening and further development of the Norwegian research establishment. The overall budget will be roughly NOK 105 million, of which the State (the Research Council) will provide NOK 55 million. The balance comes from 18 participating oil companies. The programme will run for four years (1992-95).

RUTH is organised into six sub-programmes as shown in the table below, representing six recovery methods which may contribute to improved oil recovery from the Norwegian continental shelf. Rogaland Research and IKU Petroleum Research (IKU Petroleumsforskning) have been given main responsibility for the sub-programmes, though links are in place with many other research centres. Each sub-programme contains multiple subprojects. In 1994 approximately NOK 27 million was spent in the programme, on 27 individual subprojects.

In connection with the programme, international links have been established with research institutions in France, England and Russia. Co-operation is also in place with operating companies for the planning and evaluation of field-scale pilot projects to qualify new technology. This includes use of foam, polymer gels and alternating water/gas injection (WAG). As part of this joint project the use of foam was tested on Oseberg during the summer 1994, and this test was successful. In addition, two projects have highlighted environmental issues associated with the various methods.

Project title	Executive institute
Use of surfactants	RF - Rogaland Research
Use of polymer-gel	RF - Rogaland Research
Microbial methods	RF - Rogaland Research
Combined gas/water injection	IKU Petroleum Research
Use of foam	RF, IKU
Gas flooding	IKU Petroleum Research

The annual RUTH-Seminar was arranged in the Norwegian Petroleum Directorate in September, where roughly 120 delegates from eight countries were gathered. Several international workshops within specific technical subject themes were also held in 1994. A separate information brochure has been prepared for the RUTH programme.

5.1.5 PROFIT

The research programme PROFIT (Program for Research On Field Oriented Improved Recovery Technology) was estalished in 1990, and research was terminated in 1994. This too is a programme aimed at improved oil recovery, e.g. through improved methods and improved modelling and prediction tools.

The Norwegian Petroleum Directorate has taken part on an equal footing with 12 oil companies in funding and managing the activity. The Norwegian Petroleum Directorate has in addition seen to the programme administration. The research is carried out mainly by Norwegian research institutes.

PROFIT had a total budget of NOK 68 mill. and has included two main projects:

Reservoir Characterization	NOK 45 mill. 13 sub-projects
Near Well Flow	NOK 23 mill. 11 sub-projects

In 1994 research for approx. NOK 15 million was performed. Results from previous years' research were presented at a seminar held at the NPD in February 1994.

Within Reservoir Characterization, important subtopics have included the study of fractures and faults, improved mapping by means of seismic data, homogenization of petrophysical data and description of reservoir uncertainties. Near Well Flow is divided into three subtopics: Fracturing around injection wells, induced barriers (gel) and horizontal wells.

The great majority of the projects have achieved the goals defined for them, and the research carried out as well as the reports rendered reflect a high professional standard. Without doubt a good number of interesting results have emerged which will find application for fields on the Norwegian continental shelf.

The implementation of PROFIT illustrates very well how the companies and the Norwegian Petroleum Directorate can get a considerably higher return on investments through a joint effort than if the parties were to carry out and finance projects individually. The technical discussions in the various working groups following up the projects have been very useful, both to the Norwegian Petroleum Directorate, the companies and the research environments alike.

The research results from PROFIT were originally only available to the participating parties. The Board has however approved publication of a number of technical articles for international conferences and in periodicals. Also at the close of the project, work is in progress on a book which will give a summary of the main results from each project. This book will be publicly available and will be on sale through the Norwegian Petroleum Directorate.

PROFIT will be terminated by a seminar at the Norwegian Petroleum Directorate 25 - 26 April 1995, where the participating parties are presented with the results of the five-year research programme.

5.1.6 SAFARI

SAFARI, an acronym for the name *Cooperation on Field Analogues and Reservoir Information* in Norwegian (Samarbeid om Feltanaloger og Reservoarinformasjon), is a co-operative project between Norsk Hydro, Saga Petroleum, Statoil and the Norwegian Petroleum Directorate. The project has collected quantitative, geological data from sediments onshore that are analogous to reservoir rocks on the Norwegian continental shelf. The aim of the project is to build up a data base of quantified information on sedimentary and tectonic reservoir heterogeneities. The data collected are used as the base data for geo-mathematical modelling tools and reference datum for conceptual geological modelling, and contribute substantially in reducing uncertainties in well-to-well correlations. The objective has been to achieve improved reservoir descriptions, a fundamental prerequisite for success in using improved oil recovery methods. The project has been organised with a steering committee and two working groups with responsibility for sedimentary and tectonic heterogeneities, respectively.

Data acquisition for sedimentary heterogeneities is made on the basis of requirements surveys, which aim to clarify the need for analogue studies of different types of deposit, and to specify the reservoir problems. In the choice of field analogues for relevant reservoir formations, the emphasis has been on finding formations that are well exposed and which have the greatest possible similarity with respect to sedimentological processes and depositional environment. Data have been collected from shallow marine, tidal deposits that are analogous to the Cook, Fensfjord, Sognefjord and Tilje formations. Data have also been collected from shallow marine analogues of Brent, and from fluvial deposits that are analogous to the Lunde and Statfjord formations.

Data have also been acquired from modern systems based on analysis of satellite scans, in order to provide information on horizontal heterogeneities as a supplement the vertical heterogeneities that we are familiar with from vertical exploration. The aim has been to achieve better three dimensional modelling of heterogeneities in sediments. Studies of modern systems have been carried out in fluvial and deltaic settings.

Data on tectonic heterogeneities have been collected from areas having the same structural features as the Tampen area. The work concentrated on spatial distribution of the fault plane at seismic resolutions, and the relations between the former plane and larger, block-limited faults.

The financial administration of SAFARI is the responsibility of the Norwegian Petroleum Directorate, which is also responsible for co-ordinating the demand analyses.

5.1.7 «JOINT CHALK RESEARCH»

This programme, which is a joint chalk research programme, was launched in 1982 on the initiative of Norwegian and Danish authorities. The aim was to gain increased knowledge of the reservoir behaviour during production from the chalk fields in the North Sea. During the period 1982 to 1992, three phases of the programme were completed and NOK 43 million has been applied.

A fourth, three-year phase (1994-1996), was commenced in 1994 based on an agreement signed by the Norwegian Petroleum Directorate, the Danish Energy Agency and seven oil companies. This phase has a budget of NOK 17.5 million, and will particularly target the following themes:

- Characterisation of chalk rocks and cracks
- Mechanical properties of chalk rocks
- Effects of water injection.

In one of the seven projects there will be produced an overview of the results from the three previous phases of the programme. The implementation of this project is headed by the Norwegian Petroleum Directorate.

The programme is administered by Amoco, and the steering committee is headed alternately by the Danish Energy Agency and the Norwegian Petroleum Directorate. The Norwegian Petroleum Directorate took over the leadership of the committee in October 1994. A separate information brochure on the programme has been published.

5.1.8 GEODATA PROJECT DISKOS

The Norwegian Petroleum Directorate has instituted a joint initiative with Saga Petroleum, Norsk Hydro and Statoil for system development and operation of a common data base for geodata. The object is for the four parties to have direct access to for example seismic data from the common data base, where the Norwegian Petroleum Directorate and company data will be stored. Modern high capacity storage media and transmission highways will be employed and the system will be updated with base data and company raw data. Access to data will be controlled by the rules and agreements for usage rights entered into, and costs will be split between the users of the system. Towards year end 1994 an agreement was signed also with Mobil Exploration Norway to join in the project.

The scheme is headed by the Norwegian Petroleum Directorate which in December 1993 signed a contract for development of the system with IBM EPAC in Stavanger. The system should be operative by the beginning of 1995. From then on, also other oil companies and research institutes will be able to access the system to store their own data or retrieve data from other owners for which they have usage rights.

In November 1994 an agreement was entered into with the newly established company PetroData, which for a period of at least five years is to manage the operation of the common data base. PetroData is established in Stavanger, and at the turn of the year the company is in the process of improving the operation by preparing procedures and installing modern high capacity storage robot and computers. In the course of 1995 the aim is to store six TB of data.

5.1.9 NEWSLETTER ON IMPROVED OIL RECOVERY

In December 1994 the Norwegian Petroleum Directorate published the first issue of a quarterly newsletter on improved oil recovery. («The Norwegian Petroleum Directorate Newsletter on Improved Oil Recovery»). This is a part of the Norwegian Petroleum Directorate's strategy for dispersion of information on and active contribution in efforts to realise commercial projects for improved oil recovery. The newsletter will contain information e.g. about ongoing research and research results, pilot projects on the fields to test new methods and field activities in general which contribute to increased recovery factor. A particularly relevant target group for the publication is decisionmakers in the operating companies, as it will contain factual information as well as the Norwegian Petroleum Directorate's views on what may be considered the right strategies and important commitment areas.

5.2 SAFETY AND WORKING ENVIRONMENT

Project title	Executive institution
Petroleum Operations North of 74°30'N	Smedvig, Saga Petroleum
Register of work related diseases	The Labour Inspection in Denmark / The Norwegian Petroleum Directorate
Drilling in deep water	Scanlift as
Safety and working environment in a cold climate	University of Tromsø
Professorship in hyperbaric medicine	University of Bergen / The Norwegian Petroleum Directorate
Operational recommendations for drilling of high pressure and high temperature wells	Rogaland Research Institute (RF)
The emergency preparedness regulations: Experience gained	Technica
Test procedure for jet fire	Sintef - NBL (Norwegian Building Research Laboratory)
Membership of Norwegian Electrical Engineering Committee (NEK)	NEK (Norwegian Electrical Engineering Committee)
Gas safety programme 1993-96	CMI (Christian Michelsen Institute)
Perceived risk and safety	University of Trondheim
Working environment for divers	NUTEC
Technical and operational aspects of manned underwater operations	Sintef
Research and development in diving technology	NUTEC, Sintef
Reduction of leak frequency in flanged connectors in process facilities	Veritec, Sintef
Membership of Welding Institute	The Welding Institute, UK
Membership of Marine Technology Directorate	The Marine Technology Directorate, UK
Ductility of high-strength concrete	Sintef - FCB

Reliability based design methods for pipelines	Snamprogetti, Sintef
High-strength steels in offshore engineering	Cranfield Institute, UK
Corrosion protective coating	Sintef - Corrosion Centre
Residual strength in damaged and corroded pipelines	DnV - Veritec
Ringing vibrations in offshore installations	DnV, NTH
Reinforcement bar corrosion under dynamic load	Veritec
Geotechnical site surveys for projected pipelines	Norges Geotekniske Institutt
Corrosion in transportation pipelines	British Gas
Evaluation of possibilities offered by use of new information technology	The Norwegian Petroleum Directorate
Continued development of the drilling data base - DDRS	Pride as
Brochure on the regulation of safety and working environment on the continental shelf	The Norwegian Petroleum Directorate
International standardisation in the petroleum sector	NVS and others
Maintenance management	Framatome, Sintef
Requalification of steel structures - Phase 2	Sintef
Comparison of standards for steel structures	DnV Industri
Use of certificates in the petroleum activities	Sintef

Petroleum operations north of 74°30'N
This project has in 1994 been divided into two independent substudies. One deals with slim hole drilling on Svalbard, and the project has discussed various types of slim hole technology which may be possible to use in connection with exploration drilling on Svalbard. The other one has discussed the potential for the use of slim hole technology in drilling operations offshore. Such technology may prove to be more economic than traditional methods, and particular interest is attached to possible savings which may be achieved by using such drilling technology in deep water.

Drilling in deep water
In this project a comparison has been made of the Norwegian Petroleum Directorate's drilling regulations with associated guidelines and general industry practice with regard to drilling in deep water. Furthermore, there has been carried out a mapping of which particular areas within deep water drilling that equipment and/or procedures differ from conventional drilling. The results from this project will be used in the Norwegian Petroleum Directorate's future supervision of exploration drilling in deep water, and the report will thus be used as a reference document for administrative procedures in connection with drilling operations, including the Vøring plateau.

Register of work-releated diseases
The Norwegian Petroleum Directorate's data base of work-related diseases was established to provide a systematic framework for incoming reports. One of the uses of the register will be to help identify commitment areas and supervision priorities. In a register of this kind, the most important elements will be to ensure a good system for registration and classification of working environment factors. A collaborative project has been in progress between the Norwegian Petroleum Directorate and the Danish Labour Inspection aimed at further developing the Norwegian Petroleum Directorate's existing data base. The background for this co-operation was to be able to draw on Danish experience with a well es-tablished system and to gain insight into the work done in this field in the European Union, where Denmark plays a central role. This work has resulted in a new and improved data base in the Norwegian Petroleum Directorate.

Safety and working environment in a cold climate
The Norwegian Petroleum Directorate has via the Nor-

wegian Research Council contributed to the funding of a research programme at the University of Tromsø, dealing with work in a cold climate. The programme projects look at both the basic research side and the more clinical and applied issues, with close links between basic research and solving practical problem related to effects of cold temperatures. By supporting the project the Directorate has contributed to enhancing the national and international competence in cold climate research. Such knowledge may prove useful in planning and implementation of petroleum activities as well as for activities on shore.

Professorship in hyperbaric medicine

The Norwegian Petroleum Directorate is funding a part-time position for one of its employees as Professor II at the University of Bergen, linked to a research project in the area of physiology. The project focuses on issues such as fluid balance, hyperbaric physiology, temperature regulation and sleep, which constitute issues with clear relevance to safety and working environment in the petroleum activities. The project is planned to last through 1998, and the results are published in annual status reports as well as in Norwegian and international professional periodicals.

Operational recommendations for drilling of high pressure and high temperature wells

Drilling of high pressure and high temperature wells entails particular operational and safety related challenges. The project aims to increase the understanding of these issues, in order that safety during drilling of such wells can be improved. Through previous projects in this area, a great amount of data have been collected. In this project the data material has been analysed and operational recommendations have been prepared for the implementation of drilling operations at high pressures and temperatures. The recommendations could be a contribution to improving the Norwegian Petroleum Directorate's guidelines to the drilling regulations within this area.

The emergency preparedness regulations: Experience gained

The emergency preparedness regulations which entered into force in 1992, entailed a marked change in the direction of system oriented requirements, in accordance with generally applied principles which also constitute the basis for the other thematic regulations issued by the Norwegian Petroleum Directorate. Different premises have existed and different procedures have been employed by the various operating companies in order to comply with the regulation requirements to emergency preparedness administration.

The project has consisted of planning and implementation of a seminar where the industry and the authorities have exchanged experience with the new regulations. In addition to providing the Norwegian Petroleum Directorate with an opportunity to give information on the authorities' expectations, the seminar provided valuable feedback from the industry. Conclusions from the seminar will constitute an important contribution to a planned review of the emergency preparedness regulations, with a view to assessing the need for a possible revision. A seminar report has been prepared, which contains a copy of all presentations given during the seminar.

Test procedure for jet fire

Ignition of a gas leakage from a system under pressure may cause a so-called jet fire, which can contribute to a particularly dramatic development of a fire, as in the case of the Piper A accident on the British continental shelf in 1988. Following an initiative by the Health and Safety Executive in the UK, the Norwegian Petroleum Directorate was in 1992 invited to take part in a working group charged with the task of drawing up a procedure for determining the resistance of passive fire barriers to jet fires. A procedure established by SINTEF/NBL (Norwegian Building Research Laboratory) with support from the Norwegian Petroleum Directorate, constituted part of the basis for this work. The work resulted in a common British-Norwegian procedure for testing of such materials in a jet fire. Practical tests have been carried out in the project in 1994 to verify the procedure.

Membership of the Norwegian Electrical Engineering Committee (NEK)

By joining the Norwegian Electrical Engineering Committee (NEK), the Norwegian Petroleum Directorate seeks to ensure that regulations in the electrical engineering field are continually under review and keep pace with advances in technology, international practices, and practical experience. The importance of this is emphasised by Norway's efforts to comply with commitments under the Agreement on Technical Barriers to Trade within EFTA and the EU.

The Norwegian Petroleum Directorate also takes part in national and international co-operation with regard to preparing a new statutory framework. This work is headed by NEK.

Gas safety programme 1993-96

The Christian Michelsen Institute (CMI) in Bergen has over a number of years, in co-operation with oil companies and government agencies in a number of countries, carried out research on the gas explosion risk in modules on offshore installations. The project, started in 1990 and terminated in 1993, incurred total costs of about NOK 34 million. Among other things the project led to the development of a new and improved version of the FLACS code, a model which describes flame acceleration for estimation of explosion overpressure in modules. A PC-programme for such estimates (MicroFLACS) and a Gas Blast Handbook have also been developed.

The project also demonstrated areas where there is a need for further research, and the new four-year programme is to continue working on issues related to gas explosions in modules on petroleum installations. In 1994, the project has developed further the FLACS code in order to enable estimation of pressure propagation in modules. Furthermore, the project has commenced work on modelling the effect of sprinkler and pressure water-spraying systems and gas rarefaction.

Perceived risk and safety

This project is a follow-up of a study carried out in 1990 on the employees' own perceptions of security against injury as a result of potential sources of risk on the installations and in the performance of their work. In 1994, a study was carried out to map any possible changes in the employees' evaluation of risk and safety during this period of time.

A large number of persons on the installations have participated in the study, which has provided a valuable basis for continued efforts by the industry and by the Directorate in considering specific measures and if applicable further follow-up of recommendations from the project. The work will be continued in 1995, including a comparison of results from a corresponding study on the British continental shelf.

Working environment for divers

Projects over many years have produced results of considerable practical importance in relation to the working environment for divers. In 1994, the project has focused on arriving at a new cleaning agent suitable for the removal of impurities in breathing gas pipes. Three alternative agents will be examined in 1995 with regard to toxicity and corrosion properties.

Technical and operational aspects of manned underwater operations

From experience we know that there are still technical and operational aspects of manned underwater operations which could be improved. The project has already highlighted problems such as diving bell battery emergency capacity, emergency training for diving personnel and depth monitoring of divers, decompression tables for surface oriented dives and loss of body fluids (dehydration).

In 1994 the project has focused on issues in connection with decompression for surface oriented dives with diving bell. The results will form the basis for stipulation of requirements to technical equipment, personnel qualifications and operational procedures for this type of diving activities.

Research and development in diving technology

The Norwegian Petroleum Directorate has earlier participated in the research programme "Research and development in diving technology". This programme is now continued in the ALFA and OMEGA programmes, for basic research and applied research and development, respectively, in the area diving technology and diving medicine.

The Norwegian Petroleum Directorate has in 1994 participated in the OMEGA programme, which has comprised a number of sub-projects in areas such as working environment, pressure changes, tools/equipment and implementation of research results. Participation in this programme gives the Norwegian Petroleum Directorate access to results and a possibility to exercise influence on significant parts of R&D activities in Norway in the area diving technology and diving physiology.

Reduction of leak frequency in flanged connectors in process facilities

This project is a continuation of work started in 1992 with a view to improve flanged connectors, above all to help reduce the number of unintentional hydrocarbon leaks. The project aims to produce proposals for improvement of design calculations as well as practical work on flanged connectors. In 1994 the project carried out analyses based on the requirements of relevant standards relating to bolt tightening. The calculations show that the standards in general allow tensions that are too low to ensure the flanged connectors will remain tight if subjected to the loads to which the connection is intended to be able to tolerate.

Membership of Welding Institute

The Norwegian Petroleum Directorate has been a member of the Welding Institute (TWI) in the United Kingdom since 1981. This is the leading welding institute in the offshore field and is very active within research, training and consultancy services. Membership gives access to consultancy assistance, project participation and current information on the latest development within materials and welding technology.

Membership of Marine Technology Directorate

Since 1980, the Norwegian Petroleum Directorate has been a member of the British Offshore and Underwater Engineering Group (UEG), a subdivision of the British Construction Industry Research and Information Association (CIRIA). The group merged with the Marine Technology Directorate (MTD) in 1989. The projects administrated by the organisation are very pertinent to the Norwegian Petroleum Directorate's duties in this sphere. Co-operation and availability of information have been very useful for safety reports, drafting of regulations and competence building. The Norwegian Petroleum Directorate participates in projects on guidelines for design and analyses of floating installations, and on guidelines for risk analyses for offshore installations.

Ductility of high-strength concrete

This project is a continuation of work to develop high-strength, high-ductility concrete for applications in structures which may experience particular stresses, such as impact, pressure shock, earthquake, heat and cold. The development of specifications for design and structural shaping of high-strength concrete exposed to particular stresses was also included in the project. In 1994, the project has focused on loads connected with ships collisions and falling objects, and a suggested design formula for falling objects has been drawn up.

Reliability based design methods for pipelines

The criteria in existing design codes may embody safety margins that in certain cases are unnecessarily conservative, causing safety levels for pipelines to be inconsistent in relation to such factors as water depth, seabed uniformity and erosion resistance, fluid carried, and potential accidental loads. A pilot project was carried out in 1992, and the main project is scheduled to last until 1995. The Norwegian Petroleum Directorate is a member of the steering group for the project, which is sponsored by the industry with a total budget of NOK 5 million in 1994.

High-strength steels in offshore engineering
This project is carried out at the Cranfield Institute of Technology in the UK and is a major collaborative venture with participation by many countries.The project initially studied on a broad basis the properties of modern high-strength steels in practical applications in the offshore petroleum activities. The programme has been going on since 1992, with total costs of nearly NOK 5 million. The programme was completed in 1994 with an evaluation of results achieved and preparation of final reports.

Corrosion protective coating
The design lifetime of installations in the petroleum activities is steadily increasing, and the right combination of materials and coatings is decisive in order to achieve the desired lifetime. As yet, little attention has been given to conditions affecting cathodic debonding and the effects of various forms of surface treatment before the application of paint. Nor does there exist any effective method for accelerated testing of how these factors influence the final result.

This project, which seeks to provide answers to these questions, is planned to run until 1998, with considerable support from the operators and coating manufacturers.

Residual strength in damaged and corroded pipelines
The Norwegian Petroleum Directorate has helped support this industry sponsored project aiming to develop methods for estimating the residual strength of pipelines, marine risers and tension legs once damage has been sustained or internal corrosion has set in. The project in its first phase focused in particular on ANSI/ASME-B31G, and studied possible optimisation of the estimation methods described there. The work has provided useful competence in pipeline design. The experience may also be of value in the development of statutory legislation in this area, and in the Directorate's supervision activities when such damage has occurred.

Ringing vibrations in offshore installations
The Norwegian Petroleum Directorate has initiated and helped fund this industry sponsored project which has an overall budget of NOK 5.3 million. The project aims to develop design models to describe the so-called "ringing" effects observed in model tests with concrete gravity bases, so as to estimate the effects in a predictable and standardised manner. The project was concluded in 1994 without resulting in a method for calculation of "ringing" effects. A follow-up project to commence in 1995 will however be considered.

Reinforcement bar corrosion under dynamic load
The Norwegian Petroleum Directorate has supported this project which is sponsored by the industry and the authorities. The project was commenced in 1993, and aimed to clarify the properties of light-weight concrete with respect to corrosion protection and corrosion resistance in a marine environment. Improved knowledge in this field is necessary if we are to draw full benefit from the increasing popularity of light-weight concrete in offshore structures, since until now there has been only limited understanding of the long term properties of light-weight concrete in a marine environment. Results from this project have led to initiation of particular supervision activities by the Norwegian Petroleum Directorate in this area.

Geotechnical site surveys for projected pipelines
The aim of this project has been to explore various geotechnical factors related to design, construction and operation of pipeline systems. The project has among other things looked at methods for soil investigations, the thermal properties of soil, requirements to backfilling materials, problems connected with local depressions and ice scouring marks as well as various stresses affecting the stability of pipelines.

Corrosion in transportation pipelines
The latest years have seen several cases of unexpected, in part severe, corrosion to transportation pipelines both for oil and for gas. The existing design models for evaluation of the effects of corrosion to pipelines are developed for steel with a low yield strength. With regard to more recent pipelines made of high strength steel , existing design models may be too conservative.

The project will carry out a thorough analysis of existing evaluation tools, and if applicable develop new design models capable of better evaluation of the effects of corrosion on the strenght of pipelines. Reliable calculations will contribute to ensuring maximum capacity utilization in transportation systems affected by corrosion. The project is supported by the industry and by authorities in the UK, USA, the Netherlands and Norway, and will have a duration of three years with a total budget of about NOK 12.5 million.

Evaluation of possibilities offered by use of new information technology
The Norwegian Petroleum Directorate has chosen an information technology strategy which entails a change over from terminals to powerful PCs. This change has provided the employees with simpler access to internal information data bases, and has contributed to enabling the information to be presented in a suitable way. The project contributes to a continuous promotion of competence on available information technology, with a view to meet the internal demands for information systems that will constitute part of the basis for revision and development of statutory legislation, for supervision and for information activities within the administrative area safety and working environment. The project also contributes to higher efficiency in the Directorate's activi-

ties through optimalisation of the use of information technology in administrative procedures.

Continued development of the drilling data base - DDRS

The Norwegian Petroleum Directorate's drilling data base, DDRS, contains systematically arranged experience data from drilling activities on the Norwegian continental shelf since 1984. Use of this material contributes greatly to priority decisions in respect of tasks connected with supervision and development of statutory legislation. The data base volume as well as the advances in information technology have however necessitated conversion of the data base to the new hardware and software architecture (UNIX and PC). In 1994, a new computer model for DDRS has been prepared using external consultancy assistance. Full conversion is expected to be finalised in 1995.

Brochure on the regulation of safety and working environment on the continental shelf

The project has prepared a brochure which gives a brief survey of the principles of the statutory legislation and the regulatory supervisory activities in the petroleum activities. The project funds have been used for printing costs. The brochure is available in both official Norwegian languages and in English.

International standardisation in the petroleum sector

The Norwegian Petroleum Directorate's philosophy on statutory legislation allows for a large part of the normative work to be taken care of by the industry itself in the form of industry standards. To the extent possible, Norwegian petroleum activities are to be based on international standards. The Norwegian Petroleum Directorate's engagement in standardisation work primarily takes place through several sub-projects, partly in the form of support to standardisation organisations, primarily Norsk Verkstedindustris Standardiseringssentral (Norwegian Engineering Standards Association) and Norsk Elektroteknisk Komitė (Norwegian Electrotechnical Committee), and in part by participation in committees preparing standards of particular importance to the offshore petroleum activities.

Extreme wind velocities in Norway

Under the direction of the European standardisation organisation CEN, a European standard (Eurocode) has been drawn up inter alia for estimation of wind load effects on structures. The standard is basically a common standard for all of Europe. The extreme values for wind velocity are however very much linked to the location in queston, and consequently appendices are prepared for the individual countries, which will indicate wind velocities applicable both to locations on shore and offshore. The project in Norway has received support from a number of public institutions and companies, and had in 1994 a budget of NOK 1.8 million. The Norwegian Petroleum Directorate intends to make reference to the new standard in guidelines relating to loads and load effects.

Maintenance Management

The purpose of this project is to establish suitable methods of supervision using result indicators which can be used as basis for evaluating results from supervision carried out of the operating companies' maintenance planning and management. Among other things the project has looked at the question whether the petroleum activities may make use of the principles governing and the experience gained from maintenance management in the nuclear industry, and in other types of activities where there are stringent requirements to reliability in a long-term perspective.

Requalification of steel structures - Phase 2

This project has developed a method for evaluating the strength of load-bearing members in steel jackets that have been subjected to a load exceeding their original design load. The method may be used in situations where an installation has sustained damage where repair may be questionable, or has been exposed to environmental loads exceeding the design assumptions. Relevant issues are changed weather criteria, subsidence of the sea bed and accidental loads. The project was started in 1993 with a budget of NOK 3.5 million.

Comparison of standards for steel structures

A new European standard (Eurocode 3) for calculation and engineering design of steel structures has recently been issued. In the Norwegian Petroleum Directorate's regulations relating to loadbearing structures the Directorate makes reference to NS 3472, and therefore work has been initiated to consider to what extent European standards are suitable for use in the offshore petroleum activities.

Use of certificates in the petroleum activities

This project has produced an overview of various types of standards, certification and accreditation systems in Norway and in the EU/EEA area that are related to the petroleum activities, and how and to what extent these are in use. The purpose is to throw light on how such documents and systems may be of significance to the future supervisory activities of the Norwegian Petroleum Directorate. The project has excluded maritime certificates, as there is an established practice in respect of the use of such certificates in the petroleum activities.

5.3 SEABED CLEARANCE

Seabed clearance

The Norwegian Petroleum Directorate's seabed clearance project in 1994 concentrated on an area of 1,370 km² on Kanten, north of Vestrebakken, 100 km directly to the west of Marstein lighthouse. The area is fishery intensive and was chosen on the basis of recommendations from the fishery organisations and the fishery authorities. The commission for compensation for loss of fishing gear has dealt with several cases relating to loss and damage to equipment in these waters.

Wires, anchors, fishing gear and various chains were recovered from the seabed. The exact locations of 4 shipwrecks and one mine field have been determined, which is of great importance to fishermen.

The Norwegian Hydrographic Service's survey vessel, M/S «Lance», was used to chart the bottom by sonar. The clearance contract was awarded to Stolt Comex Seaway A/S, of Haugesund.

The clearance project executive committee was made up of representatives from the Norwegian Petroleum Directorate, the Directorate of Fisheries, the Norwegian Hydrographic Service, the Association of Fishermen and the Oil Industry Association.

6. International Co-operation

6.1 AID TO FOREIGN COUNTRIES

6.1.1 CO-OPERATION THROUGH NORAD

In 1994 the Norwegian Petroleum Directorate engaged in development co-operation in Tanzania, Mozambique, Namibia, the Seychelles, Bangladesh and Nicaragua. The Norwegian Petroleum Directorate has also continued co-operation with the Coordinating Committee for Coastal and Offshore Geoscience Programmes in East and South-east Asia (CCOP) in connection with the implementation of a petroleum resource management project.

The Norwegian Petroleum Directorate's total work commitment in 1994 was 4.4 man-labour years. In addition to providing assistance and reports within the area of responsibility of the Norwegian Petroleum Directorate, the work duties also included overseeing consultants for such services as seismic data acquisition, processing and data reformatting; maintenance of computer hardware and software; and follow-up of consultants for technical advice, contract evaluation, and support in negotations in connection with field developments. The main efforts in 1994 focused on the following countries:

a) Bangladesh

Co-operatioin with the Bangladesh Petroleum Institute (BPI) has continued in 1994 on the project BGD 023, which according to plan is to run until the summer 1995. Assistance has amounted to about 3 man-labour months. On request from the BPI, the Norwegian Petroleum Directorate carried out a study on the BPI's future role in the Bangladesh petroleum sector, during the period November 1993 to February 1994. The Bangladesh authorities, i.e. the Ministry of Energy and Mineral Resources (MOEMR), has postponed its decision on the future role of the BPI following the completion of the project, until the Asiatic Development Bank has carried out a study containing a recommendation for reorganisation of the petroleum sector, particularly concentrating on downstream activities. This study is planned to start early in 1995 and is expected to be completed towards year end 1995.

For 1994, a work volume corresponding to 10 man-labour months had been envisaged. Problems in gaining access to necessary data, however, continued also in 1994. These problems are linked with the organisation of the petroleum sector, and a solution to this must be provided by the authorities. As such solution cannot be expected until the end of 1995, and seeing at the same time that the data problems had not been solved, NORAD on their part decided in May to reduce the support to such minimum as would be required to maintain BPI as an institution, and at the same time ensure maintenance of acquired equipment at the institute. At the same time it was also was decided to carry out a revision of the project with view to consider possible alterations of the final phase of the project. In this connection the Norwegian Petroleum Directorate, together with a representative from the evaluation group, took part in meetings with the Asiatic Development Bank, the BPI and MOEMR in Dhaka in October, to discuss the contents and extent of a possible future study for MOEMR relating to procedures and principles for statutory control and follow-up of exploration activities for petroleum in Bangladesh.

b) Namibia

The Norwegian Petroleum Directorate has continued the work in association with the National Petroleum Corporation of Namibia (NAMCOR) and the Ministry of Mines and Energy. The time employed in 1994 corresponds to just under 6 man-labour months.

Also in 1994 the work has been mainly related to development of regulations and regulatory framework for petroleum activities. At the request of NAMCOR the Norwegian Petroleum Directorate has considered the possibilities of a course on a joint venture basis with the State Pollution Control Authority (SFT), for Government Action Control Group (GACG) in Namibia. A course structure has been suggested to NAMCOR. In connection with the establishment of a geophysical data base and the introduction of a filing system for geodata at NAMCOR, the Norwegian Petroleum Directorate has visited NAMCOR and introduced routines for this work. The Norwegian Petroleum Directorate has been requested to assist in the training programme for a later planned introduction of new software for data storage. The Norwegian Petroleum Directorate has furthermore followed up on the work in previous years related to the introduction of a filing system and routines at NAMCOR, which now functions satisfactorily. A suitable PC based programme has been installed for this purpose. The Norwegian Petroleum Directorate has on behalf of NAMCOR followed up the processing of seismic data collected by NOPEC and NAMCOR in the Walvis basin in Namibia.

c) Tanzania

The work of the Norwegian Petroleum Directorate in co-operation with the Tanzania Petroleum Development Corporation (TPDC) and the Ministry of Water, Energy and Minerals (MWEM) in 1994 represented 8.7 man-labour months. The activities have concentrated on following up the reformatting, reprocessing and storage of seismic tapes and on following up the assistance from Norwegian consultants (Petroteam a.s, Novatech a.s, Statoil) to MWEM in connection with negotiations with the operator of the development of the gas field Songo Songo for transport of gas by pipeline to Dar es Salaam for production of electric power for domestic consumption.

The project has been supported and in part initiated by the World Bank. Furthermore, the Norwegian Petroleum Directorate has placed experts and equipment at the disposal of professional experts from TPDC, who during a 3 week stay at the NPD received illustrations of microfossils for an atlas on fossils which is being prepared. This work was originally initiated during the petroleum programme in Southern African Development Community (SADC), which also receives support from NORAD. There is now a good possibility that the work can be completed as planned. In connection with World Petroleum Congress the Norwegian Petroleum Directorate received a visit by a delegation from Tanzania headed by the Petroleum Minister.

d) Mozambique

The Norwegian Petroleum Directorate has in 1994 employed 14.5 man-labour months to assist Empresa Nacional de Hidrocarbonetos de Mocambique (ENH) . The work has concentrated on studies to prepare the Pande gas field in Mozambique for development, and to assist the ENH and the National Directorate of Copal and Hydrocarbons (NDCH) in reorganising the petroleum sector management.

The work has comprised follow-up of seismic processing, preparation of seismic data for further interpretation at the work station in the NPD, interpretation and re-mapping of the Pande field in connection with the visit by experts from the ENH to the Norwegian Petroleum Directorate, reserves estimates, counselling in connection with location of 2-4 appraisal wells on Pande.

The Norwegian Petroleum Directorate has also assisted the ENH during meetings with the World Bank in Washington, Maputo, London and Stavanger. A representative for the Norwegian Petroleum Directorate takes part in the so-called Project Management Unit, a support group for the ENH administration in connection with implementation of the studies that are planned to prepare the Pande field for development - a project initiated by the World Bank. Several of these studies will be financed by Norway and carried out by Norwegian companies. The Norwegian Petroleum Directorate has considered tenders from firms/consultants for assignments defined under the Norwegian support to the petroleum sector in Mozambique. Furthermore, the Norwegian Petroleum Directorate was on a fact-finding trip to Maputo and Pretoria in December 1994, in connection with support to the authorities' organisation and control of the petroleum sector. This has become very relevant in connection with a possible development of the Pande field where the ENH will be a participating party. The control authority must in the future be placed with the NDCH.

e) **Nicaragua**

The Norwegian Petroleum Directorate has employed 5.9 man months assisting the Nicaraguan national energy office, Instituto Nicaraguense de Energia (INE). The assistance was related to the preparation of a campaign for exploration for hydrocarbons on the Nicaraguan continental shelf. The campaign will be launched when the new petroleum act has been adopted. This is expected at year end 1995.

The work has been concentrated on support in connection with copying seismic data and well data to data packages to be used in the campaign. The copying of the data has been done in Stavanger and much of the work has been carried out by INE personnel who have been staying at the NPD. Experts from the NPD have further evaluated the possibilities for reprocessing of older seismic data from the east coast and test processing has been carried out internally in the NPD. The INE has had PC-based software installed for registration of geophysical data. An employee of the NPD has been trained to use the programme, and has implemented the installation in the INE as well as the training of personnel in using the programme. Furthermore, a reformatting of the older seismic data has been planned, to allow them to be moved and stored with the INE. This work is planned to start in 1995.

f) CCOP

The Norwegian Petroleum Directorate has also in 1994 acted as the technical advisor to the Committee for Coordination of Joint Prospecting for Mineral Resources in Asian Offshore Areas (CCOP), which has now changed name to Committee for Coastal and Offshore Geoscience Programmes (CCOP). This has been the last year of the three-year project Oil and Gas Resource Management (OGRM), which has been run by the Norwegian company Geoknowledge a.s. through SINTEF, also with support from the Norwegian petroleum advisor at the CCOP who has been provided and partly financially sponsored by Statoil and from the Norwegian Petroleum Directorate, which has participated as technical expert at a workshop in Bangkok. Furthermore the Norwegian Petroleum Directorate has co-operated with the CCOP in preparing a suggestion for a new project in the CCOP, Resource Evaluation Programme (REP), with emphasis on professional training of personnel from Cambodia, Vietnam and the Philipines, implementation of a Petrad seminar in China and further development of the decisionmaking process based on Resource Assessment methods which have been introduced in the previous programme.

g) Miscellaneous advisory services and administration

A total of 13.2 man-months have been employed in administration and various advisory services during 1994. Advisory services have been in relation to:

- consideration of possible Norwegian support to the petroleum sector in the SOPAC countries (South Pacific Applied Geoscience Commission) based on request from SOPAC after the advisor financed by the UK left in 1993;
- consideration of possible need for professional support to the authorities in Eritrea in their administration and control of petroleum activities in the country after liberation;
- participation jointly with NORAD at the ESMAP meeting in Washington concerning support within the petroleum sector;

- participation jointly with NORAD at a seminar in Addis Abeba arranged by the World Bank, relating to utilisation of gas in Africa south of the Sahara;
- giving professional advice to the group of experts in SADC in connection with the study on gas utilisation in the south of Africa.

After consultations and meetings with the Directorate General of Hydrocarbons (DGH) in India at the end of 1993, a proposal was presented for an institutional co-operation project between the Norwegian Petroleum Directorate and the DGH, with a draft programme for the first year of a three-year project. The project was also discussed in connection with a visit from the Petroleum Minister of India to the NPD during the World Petroleum Congress in May. The project proposal could not be approved until funding was clarified in late November. At that time the go-ahead was given for a smaller project of about 1 year's duration. The necessary clarification will be given early in 1995.

A delegation from Angola, header by the Minister for Petroleum, also visited the Norwegian Petroleum Directorate in connection with the WPC. Possible support from the Norwegian Petroleum Directorate to the Ministry of Petroleum (MINPET) was discussed and a Memorandum of Understanding was signed where a fact-finding trip was suggested for later in the year. No such trip was found to be possible and it was jointly planned that in connection with the consideration of whether support should continue to be given to the Angolan petroleum sector, a review of previous petroleum sector projects should also be carried out. This was planned to start early in 1995.

The Norwegian Petroleum Directorate also received a visit from the Chairman of the Energy and Mining Committee in the parliament of South Africa.

Administration involvement has been in connection with co-ordination and preparation of activities within the Norwegian Petroleum Directorate itself, between the NPD and NORAD and between the NPD and the co-operating institutions. Included is also the task of quarterly reporting and invoicing of the costs of the NPD's services to NORAD and the other co-operating institutions.

6.1.2 PETRAD - INTERNATIONAL PROGRAMME FOR PETROLEUM MANAGEMENT AND ADMINISTRATION

From 1 January 1989 until 31 December 1993, the Norwegian Petroleum Directorate undertook a test project for Norad aimed at examining the feasibility of setting up a training scheme in Norway for petroleum administration and management executives. The target group is executives in public petroleum administration and the national oil companies in the developing countries. Later the target group has been extended to include also executives from Russia and countries in the former Soviet Union.

The project became known as the International Programme for Petroleum Management and Administration (PETRAD).

Based on the good results from the initial trial period, the Government decided to recommend establishing PETRAD on a permanent basis as a foundation, effective from and including 1994. Founders are the Norwegian Petroleum Directorate and Norad.

The following have been appointed to the Board of Directors of PETRAD:

- Mr Vidkunn Hveding (chairman), former Minister for Petroleum and Energy
- Mr Fredrik Hagemann, Director General, Norwegian Petroleum Directorate
- Mr Sven A Holmsen, Assistant Director Norad
- Mr Johan Nic Vold, Senior Executive Vice President, Statoil
- Ms Eva R Karal, Managing Director, Technological Institute.

Special advisor Reidar G Trædal of the Norwegian Petroleum Directorate was appointed secretary to the Board of Directors.

Based on information concerning the need for executive training in the petroleum sector in Africa, Asia, Latin America and Russia/SUS, PETRAD has, since the start in 1989, organised 51 seminars and courses of a duration varying from one day to eight weeks. These have been arranged in Africa as well as Asia, Russia/SUS and Norway. A total of about 2,500 executives from 57 countries have participated.

For the development and implementation of the project, Petrad has sought to draw on all aspects of Norwegian competence in the petroleum sector. Some 270 representatives from 50 Norwegian institutions have contributed as resource persons and lecturers. PETRAD has also engaged a score or so lecturers from developing countries as well as experts from a wide range of international organisations. The programme has sought to cover a broad spectrum of issues concerning management and administration of petroleum activities, both upstream and downstream. The training has been organised in four categories:

- The role of petroleum in a sustainable development
- Petroleum resource management and administration
- Safety and environmental management and administration
- Management and administration of import, sale, distribution and use of petroleum products.

In the light of its experience with courses and seminars, PETRAD has developed two eight-week instruction programmes:

- Petroleum policy and management
- Management of petroleum operations.

These programmes were developed with the aid of 50 experts from Norwegian teaching establishments, consultants and operating companies.

The courses were first offered between 9 September and 1 November 1991, and have been repeated each autumn. The two courses are arranged in the premises of the Norwegian Petroleum Directorate, attracting 45 participants from around 20 countries, among them Norway. The courses have since the beginning had about 180 participants in all, and they have been in great demand. Participants came from high levels in their respective national oil companies and from national authorities.

PETRAD has in 1994 in addition organised the following seminars:

- 'Safety Management' (the Philippines, 2 days, 80 participants)
- 'Exploration Promotion Forum' (incl. exhibition at the WPC, Stavanger, 130 participants from 16 countries in Asia/Russia/SUS
- 'Petroleum Policy for Sustainable Development' (Tanzania, 70 participants from 9 countries)
- 'Petroleum Policy and Management' (Kazakhstan, 2 days, 98 participants)
- 'Safety and Environmental Management' (incl. visits to companies, Stavanger, 7 participants from Petroleum Authority of Thailand)
- 'Oil Price Forecasting' (Malaysia, 2 days, 38 participants from 6 countries)
- 'Principles and Mechanisms of Efficient Management in Petroleum Licencing and Exploration' (Russia, 26 participants)
- 'Offshore Gas Field Development' (Russia, 20 participants)

Feedback from the PETRAD programmes has been good and there is reason to believe that this special type of tailor-made seminars and the effects that seminar results produce lead to immediate and tangible economic benefits in the countries concerned.

The demand for PETRAD courses and seminars has grown so large that the organisation has no chance of satisfying the demand. At year end 1994-95 PETRAD has received applications for 44 courses and seminars from authorities and national petroleum companies in Africa, Asia and Russia/SUS, which are being considered.

The scope of the contacts that PETRAD has built up during the trial period is unique. The Norwegian authorities and Norwegian industry have gradually seen the significance of PETRAD's effective way to create a high-level network of international contacts and the opportunities this network offers.

6.1.3 BORIS - DEVELOPMENT OF SAFETY REGULATIONS FOR OFFSHORE PETROLEUM ACTIVITIES IN RUSSIA

The Boris project (Bilateral Co-operation on Development of Russian Regulations Concerning Industrial Safety) was started in 1994. This is a co-operation project between the Russian Gosgortekhnadzor (Supervision Directorate), which is responsible for supervising safety within most sectors of the Russian industry, and the Norwegian Petroleum Directorate. The project will extend over a 3-year period. The Norwegian part of the project is funded by the Ministry of Foreign Affairs.

In the Boris project, the Norwegian Petroleum Directorate will assist the Gosgortekhnadzor in preparing and planning the development of a safety legislation for the Russian offshore petroleum industry. Such legislation is today non-existent. Based on its own experience in legislation development, the Norwegian Petroleum Directorate will give advice and guidance with regard to detailing and analysis of issues that will be governing the legislation development. The reforms at present being implemented in Russia contribute to making the task of developing a relevant framework of statutory legislation, suitable to a future Russian petroleum industry, a complicated one.

The nature of the project requires a high level of confidence and good communication to be established between the Norwegian and Russian partners in the project. In order to contribute to this end, the Norwegian Petroleum Directorate has employed two persons to work on the projects, who among other qualifications also master the Russian language. This has proved to have a positive effect on the co-operation aspect.

The benefit of the project for the Norwegian side is primarily linked with the realisation that by contributing to the development of an effective safety legislation for the petroleum activities in the Russian areas of the North, the danger of major catastrophes or accidents occurring in waters near the Norwegian coast and offshore areas is reduced. However, the project also represents a practical opportunity to strengthen relations and co-operation between Norway and Russia, which could present interesting possibilities to Norwegian industry in general.

6.2 INTERNATIONAL COOPERATION IN RESOURCE MANAGEMENT

6.2.1 RESEARCH CO-OPERATION ON IMPROVED OIL RECOVERY

Norway has participated in international research co-operation on Enhanced Oil Recovery (EOR) under the direction of the International Energy Agency (IEA) since 1979. Currently there are nine nations taking part, and co-operation is largely a matter of a commitment to undertake a certain volume of research in stipulated areas, and to share results. On the Norwegian side the co-operation is now taken care of by RUTH, a state research programme administered by the Norwegian Petroleum Directorate, and the Norwegian Petroleum Directorate is represented in the international steering committee for this IEA-co-operation. RUTH is described in more detail in section 5.1.4.

The participating countries in this international research programme have on an alternating basis undertaken to arrange an annual conference where the research results are presented. In 1994 it was Norway's turn to arrange this conference, which was held in Bergen 28 to 31 September. During three days, research results from the world's top research scientists in the field improved oil recovery were presented and discussed. The conference assembled around 40 participants, it was implemented under the direction of the RUTH programme and arranged by the Norwegian Petroleum Directorate.

6.2.2 CO-OPERATION WITH GOVERNMENT AGENCIES OF THE NORTH SEA COUNTRIES

6.2.2.1 Annual meetings with Danish and British authorities

As oil and gas province the North Sea is basically shared between the UK, Norway and Denmark. Even though the individual fields are very different, there are many aspects of resemblance between the fields in the North Sea area. The issues encountered by the government agencies in the management of the petroleum resources are therefore in many ways common to the three countries.

The Norwegian Petroleum Directorate has consequently through many years engaged in regular meetings with British and Danish resource management authorities, who with regard to their continental shelf largely have the same areas of responsibility as is the case for the Norwegian Petroleum Directorate on the Norwegian continental shelf. With regard to the UK continental shelf, it is the technical part of Oil and Gas Division within the DTI (Department of Trade and Industry) which is responsible for the resource related part of exploration, development and operations activities. With regard to the Danish continental shelf, the corresponding responsibility is delegated to the Danish Energy Agency (Energistyrelsen).

The purpose of these meetings is mainly to exchange views and experience from the respective activities. The British are a few years ahead of Norway in their activities. It has therefore been very valuable for Norway to be able to draw on their experience with regard to improved recovery, development of small fields and co-ordination. The Danes have particular sets of problems related to chalk fields. First hand information about their experience has therefore been valuable. Data management is another area where the exchange of experience has been useful. Extensive co-operation is envisaged also in this connection.

The annual meeting with our Danish counterparts was held in Stavanger 18-19 April. Besides general update on experience and future plans, the topic well technology was in particular discussed.

With our British counterparts there were two meetings held during 1994: In Stavanger 2-3 June, and in London 9-10 December. The topics this time were concentrated on ways of co-operation, experience gained from a number of years of activities, and on the ongoing efforts to increase efficiency in the activities in general, and particularly relation to reducing cost levels.

6.2.3 ANNUAL MEETINGS WITH OTHER COUNTRIES' AUTHORITIES - EXPLORATION PHASE

Since 1983, annual meetings on technical issues have taken place between the Norwegian Petroleum Directorate and units of the State administration of other North and West European countries with responsibility for exploration for oil and gas. At first England, Ireland, Denmark, Germany, the Netherlands and Norway took part in these meetings. Later, France and the Isle of Man have joined. The arrangement duties alternate between the different countries. Norway has hosted the meetings once before (in 1988), and will be hosts again in 1995. The Faroe Islands and Iceland will then be invited for the first time.

The meetings mainly discuss geo-technical problems, exploration technology and data management issues and challenges facing the different countries in their efforts to discover new oil and gas resources effectively.

The aggregate of expertise and experience gathered at these meetings is very considerable, and the supply of information is important to each participating country with a view to preparing optimal exploration strategies.

6.2.4 ANNUAL MEETINGS WITH OTHER COUNTRIES' AUTHORITIES - METERING

A certain volume of petroleum from the Norwegian continental shelf is produced from fields located on the borderline with the UK (Statfjord, Murchison and Frigg). This has necessitated a common understanding between the two countries as to how the volumes produced and exported are to be determined.

In addition to joint verifications of equipment and procedures for fiscal metering technology, an annual cooperation meeting is arranged between the competent Norwegian and the British authorities.

Norwegian gas is marketed via large gas metering stations in Emden (Germany), Zeebrugge (Belgium) and St. Fergus (UK). Procedures for operation and maintenance of the metering stations have been prepared by the respective operating company in consultation with the competent authorities in the host country and the Norwegian Petroleum Directorate.

The competent authorities for fiscal metering in Germany, Belgium and the UK carry out their duties in respect of their installations according to requirements set out in national legislation. The Norwegian Petroleum Directorate exercises the corresponding duties according to Norwegian legislation.

Co-operation meetings are arranged annually between the Norwegian Petroleum Directorate and the competent authorities responsible for fiscal metering technology in Germany, Belgium and the UK, to coordinate questions of common interest related to the gas metering stations.

6.2.4.1 International standardisation in metering

International standards are utilised for the analysis and metering of oil and gas. The Norwegian Petroleum Directorate participates in the international work to revise existing standards and establish new ones.

The European Standardisation Organisation (CEN), is responsible for standardisation work in Europe. A document known as the Vienna Agreement, signed by CEN and ISO, the International Standardisation Organisation, ensures that CEN adopts ISO standards where they exist. The Norwegian Petroleum Directorate is also directly involved in the standardisation work in CEN. In Norway, the Norwegian Engineering Standards Association (NVS) has organised working groups that monitor the standardisation work at the international level. NVS also provides the secretariat function. The Norwegian Petroleum Directorate is actively involved also in these working groups, e.g. with the chairman function of K141 which follows up the ISO TC193 «Natural Gas». Effective from 1 January 1995, the NVS will change its name to Norsk Teknologistandardisering, NTS (Norwegian Technological Standardisation).

6.3 SAFETY AND THE WORKING ENVIRONMENT

The Norwegian Petroleum Directorate enjoys extensive contacts and co-operation with international professional organisations and government agencies, both directly and indirectly through other Norwegian government agencies. The purpose of this co-operation is as follows:

- to help ensure that safety and the working environment in the petroleum activities at least meet the accepted international standards;
- to ensure the supply of relevant information for competence building and for revision and development of legislation;
- to contribute with insight and experience in international forums in order to promote the positive development of safety and working environment issues.

Generally the co-operation has involved taking part in inter-governmental forums in Europe and the United Nations, supplemented by direct co-operation with various kinds of international and regional professional bodies. A list of the most important partners in 1994 is given below:

- NSOAF - North Sea Offshore Authorities Forum;
- EU Commission, in collaboration with Norway's Ministry of Local Government and Labour, on safety and the working environment;
- the United Nations International Maritime Organisation,IMO, and the International Labour Organisation ILO, concerning safety at sea and the working environment, respectively;
- European Diving Technology Committee (EDTC) and Association of Offshore Diving Contractors (AODC), on diving safety;
- the Marine Technology Directorate (MTD) in the United Kingdom, on inspection and maintenance of installations;
- the Welding Institute (WI) in the United Kingdom, on research and development of materials and welding;
- the American Petroleum Institute (API), to attend annual conferences on technical petroleum topics and standardisation;
- the National Association of Corrosion Engineers (NACE) in the USA, to attend annual conference on corrosion and surface treatment;
- CENELEC; co-operation on electrical engineering standardisation in Europe, through the Norwegian Electrical EngineeringCommittee (Norsk Elektroteknisk Komité -NEK).

6.3.1 NSOAF - NORTH SEA OFFSHORE AUTHORITIES FORUM

In the field of safety management the Norwegian Petroleum Directorate participates in the North Sea Offshore Authorities Forum (NSOAF), where all North Sea countries are represented.

In May 1992 the NSOAF established two working groups in which the Norwegian Petroleum Directorate is represented. One of the groups is to consider the question of establishing a NSOAF plan aimed at mutual acceptance of methods for documentation of compliance with national legislation requirements, such as «Safety Case», which are specific to the individual mobile installation. The chairman of this group is Norwegian.

The other group, under a Danish chairman, will seek to approximate safety training requirements in the various North Sea countries.

6.3.2 THE EU COMMISSION

Since 1982, Norway, represented by the Norwegian Petroleum Directorate, has held observer status in the EU proceedings on safety and the working environment in the offshore petroleum activities.

This work comes under the EU's "Safety and Health Commission for the Mining and Other Extractive Industries" (SHCMOEI) and was until early 1993 implemented by a working group called the «Working Party on Oil, Gas and Other Minerals Extracted by Borehole». The activities under SHCMOEI were reorganised in 1993 and the working group is now known as "the Committee on Borehole Operations" - the Borehole Committee.

During 1994, the Borehole Committee's mandate and tasks were reviewed in preparation for further consideration in 1995 by the appropriate superior administrative bodies in the EU, which will include defining the structure of the future work of the Committee.

6.3.3 ELECTROTECHNICAL STANDARDS AND REGULATIONS

The Norwegian Petroleum Directorate is a member of the following electrotechnical committees:

a) Comité Européen de Normalisation Electro-technique (CENELEC), Working Group 12, Regulations for Installation of Explosion-proof Materials,

b) Norsk Elektroteknisk Komité (NEK) (Norwegian Electrotechnical Committee), Standards Committee (NK) 18, Shipboard Installations,

c) NEK, Standards Committee (NK) NK 31, Electrical Equipment for Explosion-Hazard Areas
d) International Electrotechnical Commission (IEC), Technical Committee 18, Electrical Installations of Ships and of Mobile and Fixed Offshore Units.

The Norwegian Petroleum Directorate's representative is the chairman of Working Group 18, which will prepare a new international standard - «Electrical Installations of Mobile and Fixed Offshore Units.

6.4 LECTURES

Also In 1994 the Norwegian Petroleum Directorate has been engaged to lecture and chair meetings at a number of conferences, courses and similar concerning issues falling within the Directorate's field of interest in Norway and abroad. This activity is considered an essential channel in the mutual exchange of information and influence, not least in the light of the trend of increasing internationalisation with regard to regulations and other statutory instruments.

7. Statistics and summaries

7.1 SUMMARY OF SEISMIC DATA SOLD AND RELEASED

Table 7.1.a
Summary of seismic data packages sold (NPD seismic data)

NO	NAME	1994	Total
001	MØRE-TRØNDELAG-REGIONAL-PK-1		34
002	MØRE-TRØNDELAG-REGIONAL-PK-2		27
003	TAMPEN-SPUR		22
004	MØRE-SOUTH-84		22
005	TRØNDELAG-REGIONAL		25
006	HALTENBANKEN-VEST-84		24
007	FRØYABANKEN-84		27
008	MØRE-TRØNDELAG-PAKKE-2#)		22
009	MØRE-TRØNDELAG-PAKKE-3#)		28
010	TRÆNABANKEN		30
011	REG-DATA-NORDLAND-RYGGEN		22
012	NORDLAND-IV-85	1	13
013	REG-DATA-MIDT-N-SOKKEL		21
014	NORDLAND-II-83		23
015	NORDLAND-III-84	1	16
016	TROMS-II		12
017	REGIONAL-DATA-TROMS-ØST		18
018	FINNMARK-VEST-83		19
019	FINNMARK-VEST-84		20
020	NORDLAND-III-85		15
021	MØRE-SØR-TEST-84#)		5
022	STOREGGA-85	3	10
023	VØRINGPLATÅET	2	14
024	VØRING-BASSENGET-85/86	2	14
025	LOFOTEN-VEST-86	3	16
026	JAN-MAYEN-85		1
028	VØRING-BASSENGET-87	2	14
029	NORDLAND-VI-87	2	17
030	NORDLAND-VII-87		13
031	NORDLAND-V-87	1	12
032	NORDLAND-VI-88	2	17
033	NORDLAND-VII-88		13
034	NORDLAND-V-73-79	1	12
035	NORDLAND-VI-73-79	3	17
036	NORDLAND-VI-89	3	17
037	NORDLAND-VII-89		13
038	NORDLAND-VII-74/75		13
039	NORDSJØEN-SØR-TEST-89#)		1
040	VØRING-BASSENGET-88	3	14
041	VØRING-BASSENGET-MERLIN-89	3	14
042	VØRING-BASSENGET-WESTERN-89	3	14
043	MØRE-BASSENGET-88	5	11
044	TYPEPROFILER-BARENTSHAVET#)		2
045	VØRINGBASSENGET-I-90	3	14
046	STOREGGA-90	4	8
047	VIKINGGRABEN-SØR-TEST-91#)		1
048	VIKINGBANKEN-TEST-91#)		3
049	NORSKEHAVET-74/79		1
050	VØRINGBASSENGET-II-ENSIGN-91	3	9
051	VØRINGBASSENGET-II-DIGICON-91	4	9
052	MØREBASSENGET-91	6	10
053	JAN-MAYEN-88		1
054	VØRINGBASSENGET-II-92	4	9
055	MØREBASSENGET-ENSIGN-92	7	10
056	MØREBASSENGET-DIGICON-92	7	10

NO	NAME	1994	Total
057	VESTFJORDEN	2	2
058	VESTFJORDEN-77/78	2	2
100	TROMS-HOVEDPAKKE		35
101	REG-DATA-TROMS-BAR.HAVET-73		22
102	TROMS-III-83/84		17
103	TROMS-III-85		17
105	TROMS-I-ØST-77		20
106	TROMS-NORD-82-PAKKE-1		24
107	TROMS-NORD-83-PAKKE-3		23
108	TROMS-NORD-82-PAKKE-2		17
109	TROMS-NORD-83-PAKKE-4		17
200	BJØRNØYA-PAKKE-1		21
201	BJØRNØYA-SØR-84		21
202	BJØRNØYA-ØST-REGIONAL-84		18
203	BJØRNØYA-ØST-84		17
204	BJØRNØYA-TILLEGG-NORD		17
205	BJØRNØYA-VEST-REGIONAL-84		15
206	LOPPARYGGEN-ØST-REGIONAL-84		19
207	LOPPARYGGEN-ØST-85-SSL-DIAG		19
208	LOPPARYGGEN-ØST-85-NORD		19
209	LOPPARYGGEN-ØST-85-GECO-DIAG		19
210	LOPPARYGGEN-ØST-85-GRID		19
211	BJØRNØYA-ØST-TEST-85#)		1
212	BJØRNØYA-VEST-86-DIAG		13
213	BJØRNØYA-VEST-86-HIGH		13
214	BJØRNØYA-VEST-86-MARGIN		12
215	BJØRNØYA-VEST-86-SWATH#)		1
216	BJØRNØYA-VEST-87		13
300	BARENTSHAVET-SØR-ØST-HOVEDPK		22
301	BARENTSHAVET-SØR-ØST-PAKKE-2		21
302	NORDKAPP-BASS-85-GECO-DIAG		20
303	NORDKAPP-BASSENGET-85-NORD		20
304	NORDKAPP-BASSENGET-85-GRID		21
305	NORDKAPP-BASSENGET-86-DIAG		20
306	NORDKAPP-BASSENGET-86-SØR		21
307	NORDKAPP-BASSENGET-86-NORD		14
308	FINNMARK-ØST-86-REGIONAL		19
309	FINNMARK-ØST-86-DIAG		18
310	FINNMARK-ØST-86-GSI		19
312	NORDKAPP-TEST-87#)		1
400	BARENTSHAVETNORDVESTREGIONAL		2
500	BARENTSHAVETNORDØSTREGIONAL		2

#) Not compulsory

Table 7.1.b
Released seismic surveys (company seismic)

Package		Survey	Area	Kilometer in package
1	A	NH-8007	BL. 7/11	231,328
2	A	SG-8048	BL. 7/11	689,619
3	A	NH-8302	BL. 7/11	350,404
4	A	NHCN-82	BL. 7/8,11	1400,587
5	A	SH-82	BL. 2/5	872,699
6	A	SG-8052	BL. 2/2	541,722
7	A	BP80-019	BL. 2/1,7/12	985,315
8	A	EL-8180	BL. 2/6,2/9	1023,510
9	A	ST-501	BL. 33/2	696,000
10	A	ST-502	BL. 33/3	1182,771
11	A	ST-503	BL. 33/5,6	1307,000
12	A	NH-754	BL. 33/5	174,000
13	A	NAG-80	BL. 33/6	498,000
14	A	ANO-77	BL. 34/2	195,921
15	A	ANO-77-1	QUAD 30,31	357,787
16	A	ANO-77-2	BL. 24/6	9,000

Package		Survey	Area	Kilometer in package
17	A	ANO-79	BL. 34/2	923,155
18	A	ANO-80	BL. 34/2	72,566
19	A	SA-530	BL. 35/3	1229,439
20	A	SAG-78	BL. 35/3	186,660
21	A	SG-8130	BL. 35/3	783,153
22	A	GULF-79-2	BL. 35/8,9	1000,323
23	A	GULF-80-1	BL. 35/8	1396,503
24	A	ANO-74	BL. 36/1	1515,589
25	A	SG-8252	BL. 2/2,3	1115,433
26	A	PSL-84-1	BL. 8/10	562,258
27	A	ST-8007	QUAD 31	395,000
27	A	SH-8007	QUAD 31/32	2495,000
28	A	TO-8513	BL. 29/3	25,287
29	A	TO-8510	BL. 29/3	261,665
30	A	SG-85	BL. 34/4	27,474
31	A	NH-8504	BL. 30/6	421,850

Package	Survey	Area	Kilometer in package
32 A	MN-85	BL. 35/11	587,980
33 A	NH-8502	BL. 30/9	1269,787
34 A	NH-8503	BL. 29/3,33/12	24,073
35 A	NH-8202	QUAD 31,32	2072,594
36 A	SG-8127	QUAD 35,36	813,636
37 A	SG-8133	BL. 34/11	350,377
38 A	SG-8425	BL. 31/2,3	275,184
39 A	NH-8104	QUAD 32,36	1921,288
40 A	ST-8109	QUAD 35,36	1318,896
41 A	81-007	QUAD 31	339,599
42 A	EL-8307	BL. 34/8	2372,612
43 A	ST-8006	BL. 30/2,3,6	1948,741
44 A	BP-85	BL. 16/8	423,043
45 A	ST-8116	QUAD 31,32	2194,671
46 A	G-81	BL. 35/8,9	519,484
47 A	GU-82	BL. 35/8	681,716
48 A	GU-81	BL. 35/8	376,311
49 A	ST-8313	BL. 34/10	276,587
50 A	ST-8112	BL. 30/2,3	368,311
51 A	ST-8111	BL. 30/6,9	347,830
52 A	G-8101	BL. 35/8,9	848,026
53 A	BP81-043	BL. 29/6,30/4	1375,896
54 A	NH-8502-3D	BL. 30/9	22431,769
55 A	NS-79	SYD 62	3710,355
56 A	NS-78	SYD 62	4638,521
57 A	PGE-82	BL. 2/7,10	700,213
58 A	NH-8201	BL. 2/8,11	1103,320
59 A	PGO-2/10-77	BL. 2/10	204,562
60 A	ANO-78-2	BL. 2/6,8&3/4	1540,000
61 A	ANO-78-3	VALHAL/HOD	363,927
62 A	ANO-79-1	BL. 2/5	90,834
63 A	PGE-80	BL. 2/4,7	716,189
64 A	PSL-84-2	BL. 2/7	235,360
65 A	ANO-83	VALHALL	393,692
66 A	ST-8421	BL. 2/9,12	592,346
67 A	NS-76	SYD 62	3569,609
68 A	ANO-80-1	BL. 2/5,8	199,091
69 A	CSSC-78-4	BL. 2/2	93,062
70 A	ST-404	BL. 1/9	454,590
71 A	EL-8201	BL. 3/7	592,000
72 A	SH-72	BL. 1/9	83,507
73 A	EL-8186	BL. 1/3	1743,788
74 A	PG-2/7-73	BL. 2/7	115,142
75 A	EL-8083	BL. 3/7	124,002
76 A	GULF-79	BL. 2/2,3	420,961
77 A	ST-809	BL. 1/9,2/7	28,406
78 A	PGE-80-GE	BL. 2/4	25,995
79 A	ST-8013-81	BL. 1/9	121,976
80 A	CSSC-78-2	BL. 2/2,3	62,829
81 A	ANO-78-1	BL. 2/2,5	793,394
82 A	EL-980	BL. 2/6	356,736
83 A	PSL-84-3	BL. 2/4	440,268
84 A	EL-686	BL. 2/6	207,568
85 A	PG-2/4-73	BL. 2/4	101,000
86 A	ANO-76	BL. 2/4,5	251,148
87 A	ST-601	BL. 1/5	110,379
87 A	ST-602	BL. 1/2	406,030
87 A	ST-603	BL. 7/11	419,115
88 A	N2-70	BL. 2/1	226,399
89 A	SH-79-1	BL. 1/3,2/1	598,979
90 A	PGE-79	BL. 2/4,5	120,029
91 A	A-79	BL. 1/6&2/4	344,734
92 A	ANO-80-2	BL. 3/4	117,580
93 A	SH-74-1	QUAD 1	437,325
94 A	EL-8186-82	BL. 1/3	158,842
95 A	CSSC-78-3	BL. 3/4	52,681
96 A	CN2-73	BL. 2/1	639,479
97 A	CN2-76	BL. 2/1	430,723
98 A	SSL-7172	56-58 DEG	3274,995
99 A	CN2-77	BL. 2/2	357,822
100 A	SH-79-3	BL. 2/2	86,895
101 A	UN-80	BL. 2/2	153,508
102 A	C3-74	BL. 3/2	173,007

Package	Survey	Area	Kilometer in package
103 A	CN7-76	BL. 7/12	1124,482
105 A	C3-71	BL. 3/2	47,294
106 A	N7-71	BL. 7/9,12	202,283
107 A	MOB-79	QUAD 10	177,163
108 A	CN7-73	BL. 7/12	478,447
109 A	PG-8/10-73	BL. 8/8,10,11	180,508
110 A	MOB-81-2	BL. 8/12	103,075
111 A	PW-8303	BL. 1/2	132,028
112 A	SH-72-5	BL. 3/5,8	54,340
113 A	A-80	ALBUSKJELL	76,730
114 A	ST-805	REG 57-62	2682,502
115 A	NERC-83	QUAD 8,9	135,554
116 A	ANO-81	HOD	248,398
117 A	EL-8084	BL. 1/3,7/12	140,533
118 A	TO-8401	BL. 25/4,24/6	168,103
119 A	TO-8605	BL. 30/10	563,399
120 A	ST-8410	BL. 8/3	592,514
121 A	ST-8629	QUAD 12	1033,074
122 A	SH-84-1	QUAD 25-31	957,388
123 A	SG-8603	BL. 25/6	1406,246
124 A	NH-8603	BL. 25/1	338,168
125 A	EL-8603	BL. 25/2	139,030
126 A	BN16-86	BL. 15/6	331,105
127 A	ST-8516	BL. 31/11	570,020
128 A	ST-8502	BL. 15/12	505,055
129 A	SBP-85	BL. 26/4	565,747
130 A	NA-85	BL. 16/10	460,576
131 A	M85-16	BL. 15/2,3	20,000
132 A	EL-8504	BL. 25/4	962,803
133 A	EL-8503	BL. 25/2,5	1654,389
134 A	BP-85-1	BL. 34/8	293,181
135 A	PSL-84	BL. 16/11	612,945
136 A	ST-8315	BL. 16/10	699,141
137 A	SH-83-2	BL. 30/11	252,862
138 A	EL-8302	BL. 16/6	529,731
139 A	E-83	BL. 16/7	454,945
140 A	ST-8215	BL. 15/9	99,800
141 A	NH-8204	BL. 15/5	154,004
142 A	ST-8004	BL. 15/6,9,12	293,107
143 A	ST-8107-GE	QUAD 17	2109,984
144 A	ST-8104	BL. 15/8	50,779
145 A	SH-81	BL. 30/11	577,033
146 A	P-1712-81	BL. 17/12	519,839
150 A	EL-8602	BL. 30/10	110,000
151 A	TO-8506	BL. 24/6,25/4	265,000
152 A	BVI-85	BL. 15/2	302,479
153 A	NH-8408	BL. 16/10	477,000
154 A	EL-8303	BL. 25/4	559,219
155 A	ST-8202	QUAD 26,27	259,170
156 A	ST-8201	QUAD 26,27	5200,253
157 A	ST-8108	QUAD 7	1566,000
158 A	SH-82-2	BL. 30/11	353,459
159 A	ST-8122	BL. 15/9,16/47	1020,340
160 A	E-82	BL. 16/7	308,573
161 A	EL-8206	BL. 15/3	1539,390
162 A	MOB-81-3	BL. 17/3,4,11	511,656
163 A	ST-8209	BL. 15/8	389,000
164 A	NH-8006	BL. 15/2	470,649
165 A	ST-8236	BL. 15/12	49,494
166 A	SH-82-1	BL. 31/2	69,438
167 A	CN-8525	BL. 25/7	1157,936
168 A	ST-508	BL. 15/5	289,799
169 A	NH-753	BL. 15/5	633,000
170 A	ST-8114	BL. 30/6,9	31,448
171 A	NH-8406	BL. 30/9	109,613
172 A	ST-507	BL. 15/2	245,119
173 A	EL-580	BL. 15/3	1120,380
174 A	ST-8107-WE	QUAD 16,17	937,803
175 A	ST-8118	BL. 8/3	356,812
176 A	ST-8619	BL. 8/3	78,531
177 A	SH-74-2	BL. 17/11	450,270
178 A	PSE-78-1	BL. 17/12	381,374
179 A	SB-81	STORD BASIN	2314,596

Package		Survey	Area	Kilometer in package
182	A	A35-10-83	BL. 35/10	374,051
183	A	EL-8184	BL. 25/7,10	471,882
184	A	EL-8202	BL. 25/1	431,191
185	A	EL-8304	BL. 34/7	522,899
186	A	EL-8284	BL. 25/7,10	375,177
187	A	G-8102-82	BL. 35/10	36,054
188	A	M-82	QUAD 9,10,16	426,240
189	A	NH-8107	BL. 31/4	47,109
190	A	MOB-81-1	QUAD 24,25	334,000
191	A	MOB-81-4	BL. 31/8	69,000
192	A	MOB-81-5	QUAD 35,36	306,724
193	A	SH-8107	BL. 31/2	168,000
194	A	NSE-81	SYD 62	1253,738
195	A	SG-8232	BL. 34/8	1603,171
196	A	ST-8125	QUAD 26,31,32	252,670
197	A	SG-8278	SYD 62	496,000
198	A	UH-81	UTSIRAHIGH	883,824
199	A	SH-76-1	BL. 25/12	257,552
200	A	SH-76	BL. 30/11	305,872
201	A	SH-84-2	QUAD 34	970,211
202	A	AN30-77	BL. 30/2,3,6	835,608
203	A	CSSC-77	BL. 30/10	503,680
204	A	EL-780	BL. 25/4	366,661
205	A	EL-781	BL. 25/3,4,5	231,475
205	A	EL-782	BL. 25/3,4,5	231,475
206	A	EL-783	BL. 15/3	68,766
207	A	NH-752	BL. 30/7	656,000
208	A	ST-8121	BL. 30/6	20,031
209	A	ST-8123	QUAD 30,31,32	47,116
210	A	ST-8105	BL. 15/12	49,057
211	A	NH-760	BL. 15/8	72,192
212	A	CSSC-78	BL. 34/5,7,8	436,887
213	A	SH-77	BL. 25/5	135,781
214	A	SH-77-2	BL. 34/2,5	119,943
215	A	SH-77-1	QUAD 30,31	177,785
216	A	EL-580-78	BL. 30/7	22,136
217	A	NH-852	BL. 30/7	428,000
218	A	PSE-78	BL. 8/3	46,340
219	A	ST-810	BL. 24/12	29,328
220	A	MOB-79-1	QUAD 16,17	268,560
221	A	PG-1611-77	BL. 16/11	202,116
222	A	SH-79-2	BL. 30/11	235,517
223	A	SH-79-4	BL. 31/2	599,478
224	A	NH-954	QUAD 30,31	1059,640
225	A	ST-906	BL. 9/2,3	490,372
226	A	ST-908	BL. 25/7	454,177
227	A	ST-909	QUAD 31,32	1061,465
228	A	ST-910	QUAD 34,35	586,466
229	A	ST-913	BL. 30/6,9	274,831
230	A	BP80-043	BL. 29/6,30/4	108,000
231	A	EL-8082	QUAD 26	1231,765
232	A	NH-80-04	BL. 31/8,9	137,838
233	A	NH-80-05	BL. 35/10,12	967,005
234	A	NH-8002	BL. 33/5	28,000
235	A	NH-8004	BL. 31/8,9	128,322
236	A	NH-8005	BL. 35/10,12	92,234
237	A	NH-8008	BL. 16/7	654,888
238	A	NSE-80	SYD 62	1504,247
239	A	SH-8007-ORG	QUAD 31/32	3952,116
240	A	CNST-82	SOUTH OF 60	2589,000
241	A	TLGS-80	SOUTH OF 62	3938,069
242	A	CGT-81	CENT.GRABEN	2803,000
243	A	NH-8415	BL. 30/7	266,264
244	A	ST-8404	BL. 6/3,7/1	1005,516
245	A	SH-87-2	BL. 30/5,6	75,502
246	A	SG-8710	BL. 6507/6	827,280
247	A	SG-8820	BL. 34/4	296,559

Package		Survey	Area	Kilometer in package
248	A	EL-8305	FRIGG	363,701
249	A	F-83	BL. 24/6	417,816
250	A	MN-83	BL. 34/7,11	555,260
251	A	MN-83-1	BL. 24/6	157,837
252	A	NH-8366	BL. 31/3	118,578
253	A	SH-7982-83	BL. 31/2	38,931
254	A	SH-83	BL. 34/7	570,624
255	A	SH-83-1	BL. 25/2,5	111,646
256	A	ST-8312	BL. 30/2,3	65,564
257	A	ST-8317	BL. 24/6,25/4	57,897
258	A	SG-8330	BL. 35/3	71,108
259	A	T-8301	BL. 34/7	278,035
260	A	EL-8402	BL. 25/1,2	391,908
261	A	MN-84	BL. 35/11	161,652
262	A	MN-84-1	BL. 25/5,7	299,278
263	A	MN-84-2	BL. 34/8,9,10	686,339
264	A	NAG-84	BL. 34/8	225,564
265	A	NH-8405	BL. 34/8	227,801
266	A	ST-8401	BL. 25/7	656,345
267	A	ST-8405	BL. 34/8,10	241,127
268	A	SG-8595	BL. 30/12	772,232
269	A	ST-8609	BL. 8/3	71,365
270	A	ST-8626	BL. 9/2	489,488
271	A	NH-8702-3D	BL. 2/12	25566,00
273	A	ST-608	BL. 15/5	298,667
274	A	SVT-83	VIKINGTHROUHG	5764,000
275	A	NSDP-84	REG 56-62	725,000
276	A	SF-77	STATFJORD	549,000
277	A	ST-606	BL. 34/4	1114,000
1	B	SH-84	BL. 6407/9	1238,985
2	B	CN-8502	HALTENBANKEN	1002,000
3	B	NH-8102	TRÆNABANKEN	4699,883
4	B	BP-83	HALTENBANKEN	923,962
5	B	SG-8158	BL. 6507/11,12	236,813
6	B	SG-8258	BL. 6507/11,12	436,561
7	B	SG-8271	BL. 6407/2	638,185
8	B	ST-8110	TRØNDELAG VEST	280,384
9	B	ST-8306	HALTENBANKEN	325,840
10	B	EL-8204	TRÆNABANKEN	2934,451
11	B	ST-8217	TRÆNABANKEN	464,058
12	B	ST-8407	BL. 6609/5	422,139
13	B	EL-8502	NORDLAND 2	652,803
14	B	PW-83	BL. 6609/7	1056,637
15	B	SG-8445	BL. 6507/12	93,613
16	B	SG-8458	BL. 6507/11	162,952
17	B	SG-8558	BL. 6507/11	144,511
18	B	SG-8558-1	BL. 6507/11	92,074
19	B	SG-8658	BL. 6507/11	173,572
20	B	ST-8002	BL. 6507/7,8,9	214,532
21	B	ST-8102	BL. 6507/7,8,9	893,371
22	B	ST-8616	BL. 6407/4	202,161
23	B	ST-8634	BL. 6406/6	240,648
24	B	MN-84-3	BL. 6407/7	647,282
25	B	NH-8411	FRØYABANKEN	289,429
26	B	ST-8403	HALTENBANKEN	926,372
27	B	MN-85-1	NORDLAND2	574,398
28	B	SH-85-1	HALTENVEST	558,463
29	B	NH-8609	BL. 6407/7	171,704
30	B	SH-86-2	BL. 6407/9	154,269
31	B	NE-85A	BL. 6607/08	779,96
32	B	AE-86	BL. 6607/5	679,728
33	B	NH-8409	HALTENBANKEN	423,178
34	B	SG-8710	BL. 6507/6	827,000
35	B	UB-8204	TRÆNABANKEN	1348,000
36	B	UIO-JM-86	JANMAYEN	3186,000
37	B	SH-87-9	BL. 6407/8	236,000
38	B	MG-86	BL. 6407/5	156,000

7.2 SUMMARY OF DISTRIBUTION OF RELEASED DATA AND DATA COMPILATIONS

The well archives have received and dealt with 212 orders during the year, of which 151 were for film/paper copies of logs. A total of 5,391 logs from 751 wells were ordered.

In addition, 18 orders were received for digital core analyses from 168 wells and well deviation data from two wells. All in all the well archives released data from 1,020 wells in 1994. The Data Management Department's distribution of digital data compilations has increased considerably in 1994. 125 digital data compilations have been sold either directly from the Norwegian Petroleum Directorate or from sub-contractors, as compared with 63 in 1993. The most usual ones are well lists (exploration and development wells), production licences (existing and historic), exploration areas and blocks, pipelines, installations, field contours, lists of commercially available seismic data and other compilations given in the Norwegian Petroleum Directorate's Publication List. In addition, several compilations have been especially made to order.

The Norwegian Petroleum Directorate's map of the continental shelf was published in two versions in 1994. A smaller version was handed out at the ONS Conference and Exhibition. The maps were interactively produced for the first time from the Norwegian Petroleum Directorate's ILGI data base. This has opened up new possibilities for production of maps by the Norwegian Petroleum Directorate. There has been a great demand for maps of various versions both internally in the Directorate and from petroleum related industry.

Table 7.2.a
Regional spread of spudded exploration and development wells

Year spudded	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90	91	92	93	94	Sum
North Sea																														
Wildcat	2	6	10	12	11	11	11	17	12	18	20	12	14	18	23	19	27	20	22	13	14	9	9	15	18	23	21	14	13	434
Appraisal			2	1	6	5	3	5	6	8	3	8	5	10	10	15	13	7	11	14	5	8	10	6	9	13	14	5	3	205
Norwegian Sea																														
Wildcat															1	2	5	7	6	10	10	10	5	2	7	8	5	4	5	87
Appraisal																			1	6	5	4	1	1	1			2		21
Barents Sea																														
Wildcat															2	3	4	5	7	7	2	5	4	4	1	3	3	2		52
Appraisal																		1												1
Total exploration drilling																														
Wildcat	2	6	10	12	11	11	11	17	12	18	20	12	14	18	26	24	36	32	35	30	26	24	18	21	26	34	29	20	18	573
Appraisal			2	1	6	5	3	5	6	8	3	8	5	10	10	15	13	8	12	20	10	12	11	7	10	13	14	7	3	227
Exploration wells	2	6	12	13	17	16	14	22	18	26	23	20	19	28	36	39	49	40	47	50	36	36	29	28	36	47	43	27	21	800
Development wells							1	18	24	7	34	50	36	27	16	22	23	33	47	47	48	55	66	60	64	86	105	120	989	
Total	2	6	12	13	17	16	14	23	36	50	30	54	69	64	63	55	71	63	80	97	83	84	84	94	96	111	129	132	141	1789

7.3 EXPLORATION DRILLING STATISTICS

Per 31 December 1994, a total of 800 exploration wells had been started on the Norwegian continental shelf since the first was spudded in 1966. Of this number, 573 were wildcats and 227 appraisal wells. By the same date, 758 exploration wells had been terminated, while 39 were suspended for various reasons. Some have been suspended for deferred testing, possible completion as development wells, continued drilling, or subsequent plugging.

The most northerly exploration well to date on the Norwegian continental shelf is 7316/5-1, which was drilled in 1992 under Hydro as operator. The furthest east is 7229/11-1, drilled by Shell in 1993, and the westernmost well is 6301/11-2, drilled by Statoil in 1991.

The exploration wells have been drilled by 20 different operating companies. The regional numbers drilled per operator are shown in Figure 7.3.a. Number of days of operation per company in 1994 are shown in Figure 7.3.b. Figure 7.3.c shows the Norwegian operating companies' share of drilling operations. Per 31 November 1994, the total length of exploration drilling had reached 2,577,818 meters, of which 72,205 meters were drilled in 1994. The average total depth of the exploration wells reaching their prospective total depth in 1994 was 3371 meters.

Exploration well 1/6-6, drilled to prospective total depth in 1992, is the deepest well to date on the Norwegian continental shelf. Shell was the operator, and the total depth for this well was 5,567 meters RKB (5,542 meters msl.)

The longest exploration borehole to date is 2/12-2 S, drilled by Norsk Hydro in 1990. The borehole length was 5,757 meters, but the well was drilled at an angle and did not reach the same depth below the sea bed as well 1/6-6.

The average water depth for exploration wells drilled in 1994 was 185 meters. The greatest water depth to date drilled in the Norwegian sector is 523 meters. The exploration well was 6607/5-2 and was drilled in 1991 with Esso as operator.

Figure 7.3.d shows the average water depths for exploration wells drilled during the period 1966-1994. 76 different drilling units have been employed in drilling operations on the Norwegian continental shelf, nine of them under two different names. Out of these, 52 were of the type semi-submersibles, 15 jackups, 5 drill ships and 4 were fixed installations. In 1994, 12 different drilling units have been active in exploration drilling on the Norwegian continental shelf.

Tables 7.3.a to 7.3.e contain statistics for exploration drilling on the Norwegian continental shelf.

Fig. 7.3.a
Regional spread of exploration wells per operator

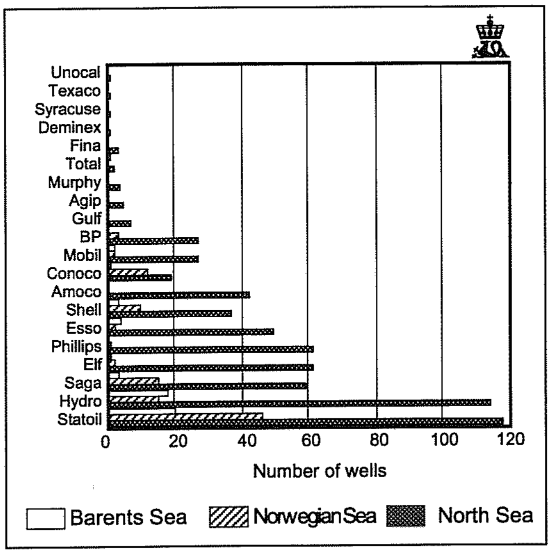


Fig. 7.3.b
Rigdays per operator

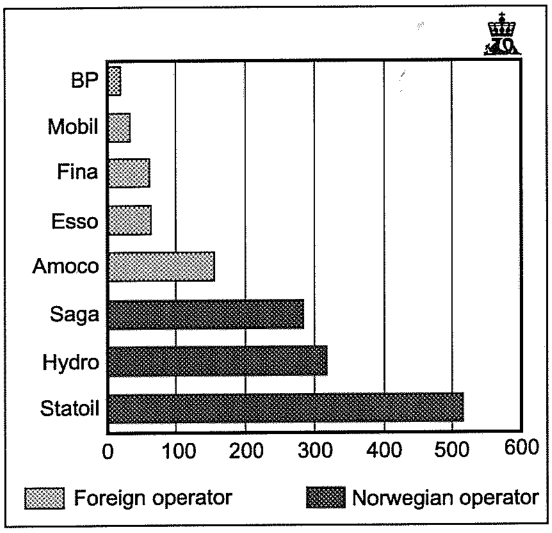


Table 7.3.b
Exploration wells by operating company and region

Operator	North Sea			Norwegian Sea			Barents Sea			Total		
	W	A	E	W	A	E	W	A	E	W	A	E
Statoil	68	50	118	40	6	46	19	1	20	127	57	184
Hydro	77	37	114	13	2	15	18		18	108	39	147
Phillips	41	20	61	1		1				42	20	62
Elf	44	17	61	2		2	1		1	47	17	64
Saga	48	11	59	15		15	3		3	66	11	77
Esso	29	20	49	2		2	4		4	35	20	55
Shell	26	11	37	5	5	10	3		3	34	16	50
Amoco	28	14	42							28	14	42
Conoco	19		19	4	8	12	1		1	24	8	32
Mobil	18	9	27	2		2	2		2	22	9	31
BP	13	14	27	3		3				16	14	30
Gulf	7		7							7		7
Murphy	3	1	4							3	1	4
Total	2		2				1		1	3		3
Agip	5		5							5		5
Deminex	1		1							1		1
Syracuse	1		1							1		1
Texaco	1		1							1		1
Unocal	1		1							1		1
Fina	2	1	3							2	1	3
Wildcat	434			87			52			573		
Appraisal		205			21			1			227	
Exploration			639			108			53			800

W = Wildcat
A = Appraisal
E = Exploration

Table 7.3.c
Exploration wells by operating company and region in 1994

Operator	North Sea			Norwegian Sea			Barents Sea			Total		
	W	A	E	W	A	E	W	A	E	W	A	E
Statoil	4		4	2		2				6		6
Hydro	3	1	4	1		1				4	1	5
Phillips												
Elf												
Saga	2	1	3							3	1	4
Esso	1		1							1		1
Shell												
Amoco	2		2							2		2
Conoco												
Mobil	1		1							1		1
BP				1		1				1		1
Gulf												
Murphy												
Total												
Agip												
Deminex												
Syracuse												
Texaco												
Unocal												
Fina		1	1							1		1
Wildcat	13			5						18		
Appraisal		3									3	
Exploration			16			5						21

W = Wildcat
A = Appraisal
E = Exploration

Fig. 7.3.c
Participation of Norwegian operators in exploration drilling activity

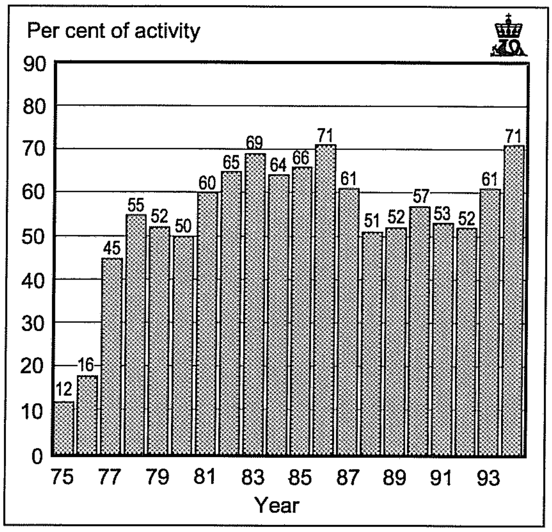


Table 7.3.d
Average water depth and drilling depth

Year	Average water depth (m)	Average total depth (m)
1966	94	3 015
1967	100	2 682
1968	81	3 303
1969	74	3 276
1970	92	2 860
1971	79	3 187
1972	78	3 742
1973	85	3 075
1974	106	3 163
1975	106	3 173
1976	108	3 314
1977	104	3 450
1978	110	3 432
1979	157	3 444
1980	179	3 209
1981	164	3 243
1982	163	3 457
1983	192	3 287
1984	212	3 247
1985	224	3 367
1986	234	3 248
1987	236	3 386
1988	248	3 598
1989	188	3 331
1990	156	3 619
1991	194	3 639
1992	225	3 560
1993	185	3 474
1994	185	3 371

Table 7.3.e
Drilling rigs active on the Norwegian continental shelf as of 31 December 1994

Rig name	Number of wells	Number of re-entries	Type of rig
Aladdin	1		Semi-submersible
Arcade Frontier (was Norjarl)	7		«
Borgny Dolphin (was Fernstar)	27	8	«
Borgsten Dolphin (was Haakon Magnus)	9		«
Bucentaur		1	Drill-ship
Byford Dolphin (was Deepsea Driller)	27		Semi-submersible
Chris Chenery	2		«
Deepsea Bergen	41	3	«
Deepsea Saga	16	3	«
Drillmaster	5	1	«
Drillship	1		Drill-ship
Dyvi Beta	6	1	Jack-up
Dyvi Gamma	1		«
Dyvi Stena	22	1	Semi-submersible
Endeavour	2		Jack-up
Glomar Biscay II (was Norskald)	39	1	Semi-submersible
Glomar Grand Isle	11	3	Drill-ship
Glomar Moray Firth I	2		Jack-up
Gulftide	3		«
Henry Goodrich	2		Semi-submersible
Hunter (was Treasure Hunter)	6	3	«
Kolskaya		1	Jack-up
Le Pelerin	1		Drill-ship
Mærsk Explorer	7		Jack-up
Mærsk Gallant	2		«
Mærsk Giant	1		«
Mærsk Guardian	3	1	«
Mærsk Jutlander	4	1	Semi-submersible
Neddrill Trigon	3	1	Jack-up
Neptune 7 (was Pentagone 81)	13		Semi-submersible
Nordraug	12		«
Nortrym	32	3	«
Ocean Tide	5		Jack-up
Ocean Traveller	9		Semi-submersible
Ocean Victory	1		«
Ocean Viking	28	1	«
Ocean Voyager	2		«
Odin Drill	3		«
Orion	7		Jack-up
Pentagone 84	2	1	Semi-submersible
Polar Pioneer	31	6	«
Polyglomar Driller	11		«
Ross Isle	31	8	«
Ross Rig	29		«
Ross Rig (new)	26	3	«
Saipem II	1		Drill-ship
Scarabeo 5	1		Semi-submersible
Sedco 135 G	3		«
Sedco 703	3	1	«
Sedco 704	3		«
Sedco 707	8		«
Sedco H	2		«
Sedneth I	3		«
Sovereign Explorer	3	1	«
Transocean 8	15	2	«
Transworld Rig 61	2		«
Treasure Prospect	1	1	«
Treasure Saga	47	4	«
Treasure Scout	23		«
Treasure Seeker	24	5	«
Vildkat Explorer	27	5	«
Vinni	5		«
Waage Drill I	2		«
West Alpha (was Dyvi Alpha)	22	2	«
West Delta (was Dyvi Delta)	37	5	«
West Vanguard	33	11	«
West Venture	12	2	«
West Vision	1		«
Yatzy	1		«
Zapata Explorer	13		Jack-up
Zapata Nordic	5		«
Zapata Ugland	5	1	Semi-submersible
	795	91	
In addition 5 wells have been drilled from fixed installations:			
Cod platform	1	1	
Ekofisk B	1		
Sleipner A	1		
Veslefrikk A	2		
	800	92	

Table 7.3.f
Spudded and/or completed exploration wells in 1994
R = re-entry, X = junked due to technical problems, S = side drilled, A, B, C = sidedrilled new wells

Exploration well	Perm. no Prod. lic. number		Position north east	Spudded Completed	Operator Drilling rig	Well class. Completion status	Water depth (in metres) KBE in metres	Total depth Geological period
2/07-29	765	L	56 18 43.62	93.09.18	BP	Wildcat	72	4900
	145		03 04 55.28	94.01.06	Mærsk Guardian	Oil	41	Permian
24/09-05	778	L	59 29 06.52	93.12.07	Fina	Wildcat	123	2860
	150		01 55 10.82	94.01.26	West Delta	Oil	29	Creataceous
30/09-15	773	L	60 22 18.63	93.12.07	Hydro	Wildcat	104	2764
	104		02 55 24.80	94.01.05	West Vanguard	Oil	23	Jurassic
34/08-11	780	L	61 21 46.94	93.12.10	Hydro	Appraisal	332	3140
	120		02 27 37.54	94.02.08	Polar Pioneer	Oil/Gas	23	Jurassic
6608/10-04	776	L	66 02 25.26	93.12.15	Statoil	Wildcat	379	2800
	128		08 09 41.74	94.03.06	Ross Isle	Oil/Gas	23	E. Jurassic
7128/04-01	779	L	71 32 27.33	93.12.17	Statoil	Wildcat	370	2530
	180		28 04 54.08	94.02.26	Ross Rig	Oil/Gas	24	Pre-Cambr.
9/02-04 S	775	L	57 49 07.48	93.12.25	Statoil	Appraisal	92	4417
	114		04 31 10.74	94.04.11	Deepsea Bergen	Suspended	23	M.Jurassic
30/03-06 S	777	L	60 46 57.87	93.12.26	Statoil	Wildcat	175	6085
	052		02 53 51.96	94.04.20	Veslefrikk A	Suspended	34	E. Jurassic
30/12-01	774	L	60 08 44.30	94.01.06	Hydro	Wildcat	113	3641
	171		02 51 06.54	94.03.07	West Vanguard	Dry well	22	Jurassic
3/04-01	781	L	56 40 53.56	94.01.11	Amoco	Wildcat	44	3107
	006		04 15 39.09	94.02.26	Mærsk Gallant	Dry well	45	Perm
24/09-06	782	L	59 29 01.50	94.02.01	Fina	Appraisal	123	2255
	150		01 57 27.14	94.03.07	West Delta	Oil	29	Tertiary
15/09-20 S	787	L	58 22 01.89	94.02.16	Statoil	Wildcat	82	3624
	046		01 54 31.98	94.04.03	Sleipner A	Reclass. to prod.	78	
2/04-18 R	762	L	56 41 57.72	94.02.19	Saga	Wildcat	68	5301
	146		03 09 44.24	94.07.10	Mærsk Guardian	Hydrocarbons	42	Jurassic
34/07-23 S	783	L	61 20 24.89	94.02.22	Saga	Wildcat	246	2889
	089		02 04 31.54	94.04.03	Vildkat Explorer	Oil	25	Jurassic
2/11-10 S	784	L	56 10 35.49	94.02.28	Amoco	Wildcat	72	4090
	033		03 27 36.57	94.06.14	Mærsk Giant	Reclass. to prod.	47	Creataceous
6507/02-03	785	L	65 51 59.90	94.03.14	Hydro	Wildcat	355	3972
	122		07 39 58.88	94.05.05	West Vanguard	Oil shows	22	Jurassic
33/09-17	786	L	61 27 18.58	94.04.02	Mobil	Wildcat	227	3233
	172		01 50 45.79	94.05.04	Treasure Saga	Dry well	26	M.Jurassic
34/07-23 A	788	L	61 20 24.89	94.04.03	Saga	Appraisal	246	3412
	089		02 04 31.54	94.05.20	Vildkat Explorer	Oil/Gas	24	Jurassic
30/06-19 R	511	L	60 42 58.03	94.05.15	Hydro	Appraisal	136	3304
	053		02 54 54.18	94.05.25	West Vanguard	Oil/Gas	25	Jurassic
34/04-08	790	L	61 35 04.02	94.05.22	Saga	Wildcat	363	3110
	057		02 10 09.73	94.06.21	Vildkat Explorer	Dry well	25	Trias
30/06-22 R	578	L	60 43 57.26	94.05.27	Hydro	Appraisal	179	3336
	053		02 58 53.12	94.06.02	West Vanguard	Oil	25	E. Jurassic
30/06-21 R	537	L	60 38 34.88	94.06.04	Hydro	Appraisal	112	3100
	053		02 43 47.60	94.06.12	West Vanguard	Oil/Gas	25	E. Jurassic
30/09-16	789	L	60 15 10.35	94.06.14	Hydro	Wildcat	101	3550
	104		02 45 00.84	94.08.08	West Vanguard	Oil/Gas	22	E. Jurassic
6306/06-01	791	L	63 30 01.45	94.06.22	Statoil	Wildcat	283	1317
	198		06 49 14.42	94.07.05	Ross Rig	Dry well	22	Basement
34/07-16 R2	640	L	61 23 13.06	94.06.23	Saga	Wildcat	287	2980
	089		02 06 58.84	94.07.05	Vildkat Explorer	Oil	25	Trias
34/07-19 R	698	L	61 23 38.96	94.07.06	Saga	Appraisal	286	2800
	089		02 05 31.46	94.07.12	Vildkat Explorer	Oil	24	E. Jurassic
34/11-01	792	L	61 04 44.46	94.07.07	Stavanger	Wildcat	191	4580
	193		02 30 22.74	94.10.25	Ross Rig	Gas/Condensate	24	E. Jurassic
25/08-05 S	793	L	59 27 27.10	94.07.21	Esso	Wildcat	128	3420
	027		02 21 52.15	94.09.21	Dyvi Stena	Suspended Oil	25	Trias
25/11-18	794	L	59 09 08.45	94.08.10	Hydro	Appraisal	128	1875
	169		02 28 28.79	94.10.24	West Vanguard	Oil	22	Creataceous
6204/11-01	795	L	62 11 16.70	94.10.12	Statoil	Wildcat	199	2966
	175		04 23 57.80	94.11.14	Deepsea Bergen	Oil/Gas	23	Trias
6407/08-02	796	L	64 17 00.63	94.10.19	BP	Wildcat	318	1950
	158		07 31 25.28	94.11.25	Dyvi Stena	Oil/Gas	25	Trias
6406/02-01	798	L	64 52 15.16	94.10.30	Saga	Wildcat	278	
	199		06 36 21.40	00.00.00	Ross Rig		24	
30/08-01S	797	L	60 27 46.96	94.11.01	Hydro	Wildcat	96	
	190		02 38 06.53	00.00.00	Treasure Saga		26	
33/09-18	799	L	61 15 40.78	94.11.16	Statoil	Wildcat	145	3253
	037		01 56 07.73	94.12.20	Deepsea Bergen	Dry well	23	
33/09-18 A	800	L	61 15 40.78	94.12.12	Statoil	Wildcat	145	
	037		01 56 07.73	00.00.00	Deepsea Bergen		23	

Table 7.3.g
Drilling activity on Svalbard

Exploration (location)	Position North East	Spudded	P&A	Drilling days	Operator Licensee Drilling contractor	Total depth metres	KB msl metres
7714/2-1 Grønnfjorden I (Nordenskiøld Land)	77 57 34 14 20 36	09.06.63 13.06.64 26.06.65 26.06.67	05.09.63 26.08.64 08.09.65 12.08.67	287	Norsk Polar Navigasjon	971,60	7,50
7715/3-1 Ishøgda I (Van Mijenfjorden)	77 50 22 15 58 00	01.08.65	15.03.66	277	Amoseas Ltd Caltex-gruppen Peter Bowden Drilling	3304,00	18,00
7714/3-1 Bellsund I (Fridtjofsbreen) Berzelivsdalen	77 47 00 14 46 00	23.08.67 29.06.68 07.07.69 10.07.74 16.07.75 22.08.80 01.07.81	02.09.67 21.08.68 16.08.69 18.09.74 20.09.75 05.09.80 10.08.81	299*	Norsk Polar Navigasjon	405,00	
7625/7-1 Hopen I (Hopen)	76 26 57 25 01 45	11.08.71	29.09.71	50	Norske Fina A/S Fina-gruppen Forasol	908,00	9,10
7722 /3-1 Raddedalen (Edgeøya)	77 54 10 22 41 50	02.04.72	12.07.72	100	Total Caltex-gruppen Forasol	2823,00	84,00
7721/6-1 Plurdalen (Edgeøya)	77 44 33 21 50 00	29.06.72	12.10.72	108	Norske Fina a/s Fina-gruppen Westburne International Drilling Ltd	2351,00	144,60
7811/2-1 Kvadehuken I (Brøggerhalvøya)	78 57 03 11 23 23	01.09.72 21.04.73	10.11.72 19.06.73	112	Norsk Polar Navigasjon Terratest a.s/ Parker Drilling Co.	479,00	
7625/5-1 Hopen II (Hopen)	76 41 15 25 28 00	20.06.73	20.10.73	123	Norsk Fina A/S Fina-gruppen Westburne International Drilling Ltd	2840,30	314,70
7811/2-2 Kvadehuken II (Brøggerhalvøya)	78 55 32 11 33 11	18.08.73 22.03.74	19.11.73 16.06.74	186	Norsk Polar Navigasjon Terratest a.s.	394,00	
7811/5-1 Sarstangen (Forlandsrevet)	78 43 36 11 28 40	15.08.74	01.12.74	109	Norsk Polar Navigasjon Terratest a.s	1113,50	5,00
7815/10-1 Colesbukta (Nordenskiøld Land)	78 07 00 15 02 00	13.11.74	01.12.75	373	Trust Arktikugol « «	3180,00	12,00

Exploration (location)	Position North East	Spudded	P&At	Drilling days	Operator Licensee Drilling contractor	Total depth meters	KB msl meters
7617/1-1 Tromsøbreen I (Haketangen)	76 52 30 17 05 30	11.09.76 13.06.77	22.09.76 19.09.77	109	Norsk Polar Navisasjon Terratest a.s	990,00	6,70
7617/1-2 Tromsøbreen II (Haketangen)	76 52 31 17 05 38	20.07.87 13.06.88	30.10.87 24.08.88	175	Tundra A/S/Polargas Prospektering KB Norsk Polar Navigasjon Deutag Drilling	2337,00	6,70
7715/1-1 Vassdalen II (Van Mijenfjord)	77 49 57 15 11 15	22.01.85	1)		Trust Arktikugol « «	2481,00	15,13
7715/1-2 Vassdalen III (Van Mijenfjorden)	77 49 57 15 11 15	30.03.88	01.11.89		Trust Arktikugol « «	2352,00	15,13
7816/12-1 Reindalspasset-1 (Spitsbergen)	78 03 28 16 56 31	17.01.91	18.04.91		Norsk Hydro a.s Store Norske Spitsbergen Kullkompani Deutag/Aker Drilling	2315,00	182,50
7814/12-1 Kapp Laila 1 (Noprdenskiøld Land)	78 06 52 14 43 38	22.02.94	08.05.94		Store Norske Spitsbergen Kullkompani Trust Arktikugol SNSK	503,50	15,00

1) Drilling abandoned due to technical problems
*) Drilling not concluded

7.4 DEVELOPMENT DRILLING STATISTICS

Since 1973, a total of 989 development wells have been commenced on the Norwegian shelf. 451 of these are production wells and 163 are water or gas injection wells. 357 are out of service, suspended for later completion or closed down for other reasons. The wells have been drilled from 49 installations.

Drilling was in progress on 18 development wells per 31 December 1994. Figure 7.4 shows development wells commenced each year for the period 1973-1994.

Per 31 December 1994, production/injection is in progress from 31 fields, comprising 45 installations. Four new fields started production in 1994. They were: Gullfaks Vest, Lille-Frigg, Statfjord Øst and Tordis. Three fields have completed production: Nordøst Frigg, Odin and Mime. In addition, the F installation on Albuskjell is closed down.

The distribution of development wells by field is shown in Figure 7.4.b. Figure 7.4.c. shows the distribution of development wells by operating companies.

The first development wells on the Troll field and Statfjord Nord were commenced in 1994.

During 1994, a total of 120 development wells had been spudded on 20 fields by year end. Out of these, 38 were drilled from 9 different mobile units.

Development wells broken down by installations are shown in Figure 7.4.d. More information on development wells is presented in the Tables 7.4.a, 7.4.b and 7.4.c. Figure 7.4.e. is a summary of development wells drilled from mobile drilling units.

Fig. 7.4.a
Development wells on the Norwegian continental shelf 1973-1994

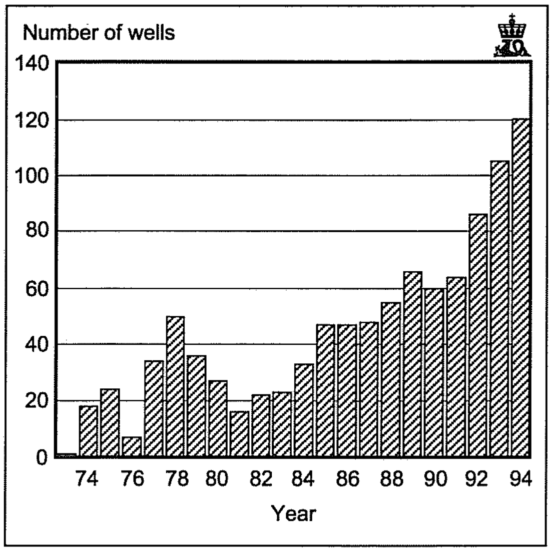


Fig. 7.4.b
Development wells per field

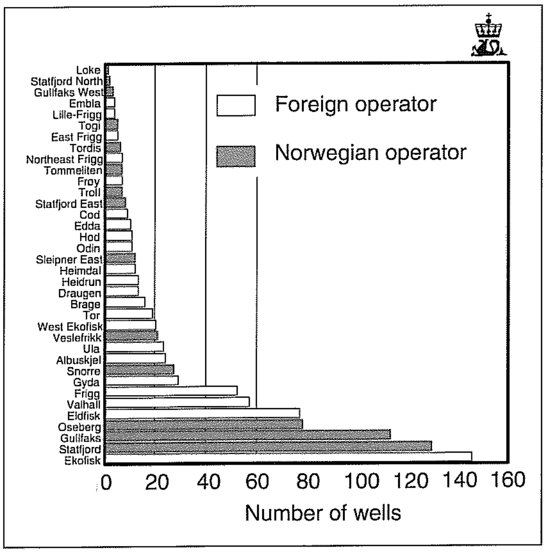


Fig. 7.4.c
Development wells per operator

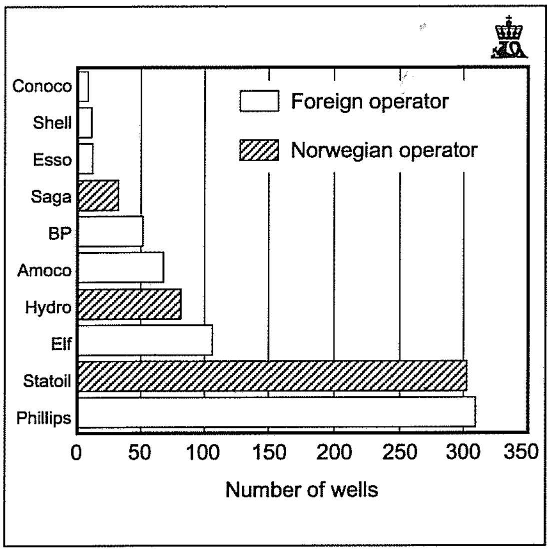


Fig. 7.4.d
Development wells drilled 1994 by installations

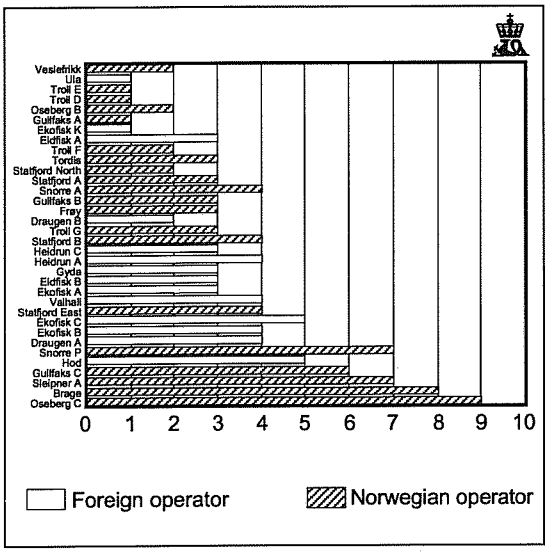


Fig. 7.4.e
Development drilling by mobile installations

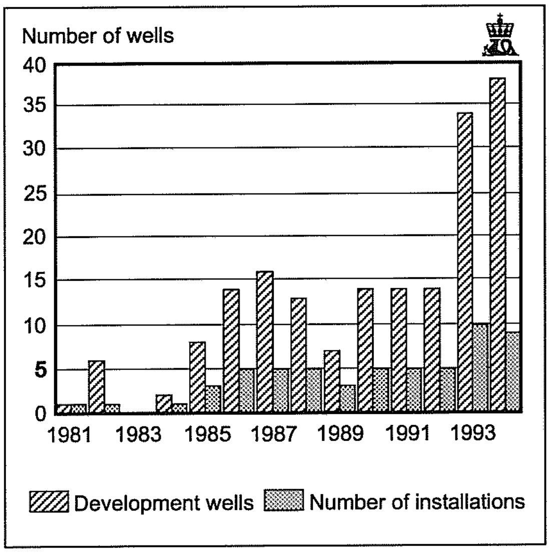


Table 7.4.a
Development drilling as of 31.12.1994

Field	Drilled	1994	Producing Oil	Producing Cond.	Producing Gas	Inj/Obs	Drilling	Closed/Susp.
Albuskjell A	11			7				4
Albuskjell F	13							13
Brage	16	8	8			3	1	4
Cod	9			3				6
Draugen A	8	4	4			1		3
Draugen B	3	2				2		1
Draugen C	2					2		
Edda	10		5					5
Ekofisk A	34	3	22					12
Ekofisk B	41	4	23			2		16
Ekofisk C	33	5	19			3	1	10
Ekofisk K	29	1				27	1	1
Ekofisk W	8					8		
Eldfisk A	40	2	21				1	18
Eldfisk B	37	3	19					18
Embla	4		4					
Frigg (UK)	24							24
Frigg	28				15			13
Frøy	7	3					1	6
Gullfaks A	52	1	28			13		11
Gullfaks B	35	3	18			9	1	7
Gullfaks C	26	6	15			5	1	5
Gullfaks Vest	3		1					2
Gyda	29	3	14			9	1	5
Heidrun A	10	4					1	9
Heidrun C	3	3						3
Heimdal	12			5				7
Hod	11	5	5					6
Lille-Frigg	4		3					1
Loke	1				1			
N-Ø Frigg	7							7
Odin	11							11
Oseberg B	47	3	20			8	1	18
Oseberg C	32	9	12			7	1	12
Sleipner A	10	7			7	2	1	
Sleipner D	2				2			
Snorre A	10	4	4			3	1	2
Snorre P	18	7	8			6	1	3
Statfjord A	50	3	25			13		12
Statfjord B	44	4	28			12	1	3
Statfjord C	35		20			11		4
Statfjord Nord	2	2					1	1
Statfjord Øst	8	4		4				4
TOGI	5				5			
Tommeliten	7			6				1
Tor	19		10			2		7
Tordis	6	3	3				1	2
Troll D	1	1						1
Troll E	1	1						1
Troll F	2	2					1	1
Troll G	3	3						3
Ula	23	1	8			7		8
Valhall	57	4	27			1		29
V. Ekofisk	20			7				13
Veslefrikk	21	2	11			7		3
Øst Frigg A	3				3			
Øst Frigg B	2				1			1
	989	**120**	**385**	**32**	**34**	**163**	**18**	**357**

Table 7.4.b
Development wells spudded or completed in 1994

Perm. no	Development well	Spudded	Completed	Operator	Field/installation
697 P	25/02-C-01 H	92.02.25	94.05.07	ELF	MÆRSK JUTLANDER
748 P	25/02-C-02 H	92.10.19	94.03.25	ELF	MÆRSK JUTLANDER
813 P	25/05-A-01	93.05.16	94.03.26	ELF	TREASURE SAGA
824 P	33/09-M-01 H	93.07.07	94.07.05	STATOIL	TREASURE PROSPECT
831 P	33/09-M-02 H	93.08.13	94.08.01	STATOIL	TREASURE PROSPECT
828 P	2/08-A-10 B	93.09.22	94.01.07	AMOCO	VALHALL
843 P	34/07-P-17	93.09.29	94.01.15	SAGA	SNORRE P
839 P	34/07-I-01 H	93.10.15	94.06.01	SAGA	VILDKAT EXPLORER
845 P	33/09-A-27 A	93.10.21	94.03.09	STATOIL	STATFJORD A
855 P	6407/09-C-02 H	93.10.24	94.01.07	SHELL	DYVI STENA
847 P	2/04-C-13 A	93.11.03	94.01.01	PHILLIPS	EKOFISK C
856 P	15/09-A-28	93.11.05	94.01.01	STATOIL	SLEIPNER A
859 P	30/03-A-19	93.11.09	94.01.02	STATOIL	VESLEFRIKK A
857 P	34/07-A-10 H	93.11.09	94.01.01	SAGA	SCARABEO 5
861 P	6407/09-C-01 H	93.11.11	94.01.20	SHELL	DYVI STENA
863 P	33/12-B-16 A	93.11.20	94.01.10	STATOIL	STATFJORD B
865 P	2/01-A-30 A	93.11.21	94.05.16	BP	GYDA
853 P	2/04-B-21 A	93.12.02	94.01.07	PHILLIPS	EKOFISK B
868 P	30/09-B-30	93.12.03	94.09.17	HYDRO	OSEBERG B
867 P	30/06-C-22	93.12.04	94.01.19	HYDRO	OSEBERG C
869 P	6507/07-A-35	93.12.13	94.01.11	CONOCO	TRANSOCEAN 8
837 P	34/10-C-18	93.12.15	94.02.19	STATOIL	GULLFAKS C
875 P	30/09-B-48	93.12.22	94.06.08	HYDRO	OSEBERG B
864 P	25/05-A-04	93.12.23	94.03.03	ELF	TREASURE SAGA
877 P	31/04-A-23	93.12.26	94.02.19	HYDRO	BRAGE
871 P	34/07-I-03 H	93.12.26	94.07.19	SAGA	VILDKAT EXPLORER
878 P	34/10-B-29 B	93.12.26	94.05.03	STATOIL	GULLFAKS B
872 P	15/09-A-26	94.01.04	94.02.15	STATOIL	SLEIPNER A
879 P	34/07-A-03 H	94.01.04	94.03.23	SAGA	SCARABEO 5
880 P	33/09-K-03 H	94.01.06	94.04.05	STATOIL	TREASURE PROSPECT
882 P	34/10-B-30	94.01.07	94.06.17	STATOIL	GULLFAKS B
885 P	6507/07-A-17	94.01.11	94.02.19	CONOCO	TRANSOCEAN 8
870 P	33/12-B-15	94.01.12	94.03.19	STATOIL	STATFJORD B
866 P	34/07-P-12	94.01.18	94.04.08	SAGA	SNORRE P
873 P	2/04-C-12 A	94.01.18	94.03.08	PHILLIPS	EKOFISK C
874 P	2/07-B-19 A	94.01.23	94.04.17	PHILLIPS	EKOFISK B
881 P	30/06-C-24	94.01.25	94.03.27	HYDRO	OSEBERG C
883 P	2/04-B-24 A	94.01.28	94.05.05	PHILLIPS	EKOFISK B
630 P	2/01-A-13	94.01.31	00.00.00	BP	GYDA
884 P	33/09-K-02 H	94.02.04	94.03.30	STATOIL	TREASURE PROSPECT
887 P	2/08-A-07 B	94.02.04	94.05.09	AMOCO	VALHALL
891 P	34/10-C-21	94.02.19	94.07.11	STATOIL	GULLFAKS C
890 P	31/04-A-07	94.02.19	94.04.15	HYDRO	BRAGE
889 P	6507/07-A-50	94.02.19	94.03.16	CONOCO	TRANSOCEAN 8
930 P	2/11-A-05	94.02.28	94.08.02	AMOCO	MÆRSK GIANT
902 P	34/10-C-22	94.03.01	94.04.04	STATOIL	GULLFAKS C
876 P	6407/09-A-01	94.03.07	94.05.23	SHELL	DRAUGEN
900 P	31/02-G-04 H	94.03.18	00.00.00	HYDRO	POLAR PIONEER
897 P	30/03-A-21	94.03.19	94.11.11	STATOIL	VESLEFRIKK A
888 P	6407/09-B-02 H	94.03.22	94.04.08	SHELL	DYVI STENA
896 P	34/07-A-02 H	94.03.24	94.04.29	SAGA	SCARABEO 5
893 P	33/09-A-02 A	94.03.24	94.05.27	STATOIL	STATFJORD A
904 P	15/09-A-24	94.03.27	94.05.21	STATOIL	SLEIPNER A
898 P	2/04-C-08 A	94.03.28	94.04.29	PHILLIPS	EKOFISK C
892 P	30/06-C-24 A	94.03.28	94.04.25	HYDRO	OSEBERG C
901 P	6507/07-A-38	94.03.30	94.04.27	CONOCO	TRANSOCEAN 8
905 P	33/12-B-12	94.04.02	94.05.25	STATOIL	STATFJORD B
894 P	34/10-C-20	94.04.05	94.09.26	STATOIL	GULLFAKS C
903 P	33/09-K-01 H	94.04.07	94.04.25	STATOIL	TREASURE PROSPECT
908 P	6407/09-B-05 H	94.04.10	94.05.15	SHELL	DYVI STENA
895 P	34/07-P-07	94.04.11	94.06.13	SAGA	SNORRE P
906 P	7/12-A-08 A	94.04.13	94.06.24	BP	ULA
899 P	2/04-A-06 A	94.04.16	94.05.20	PHILLIPS	EKOFISK A
909 P	31/04-A-13	94.04.16	94.06.12	HYDRO	BRAGE
911 P	31/02-F-06 H	94.04.19	94.05.14	HYDRO	POLAR PIONEER
912 P	33/09-K-01 A H	94.04.25	94.05.30	STATOIL	TREASURE PROSPECT

Perm. no	Dev. well	Spudded	Completed	Operator	Field/installation
913 P	2/11-A-07	94.04.28	94.06.14	AMOCO	MÆRSK GIANT
910 P	30/06-C-23	94.05.02	94.06.06	HYDRO	OSEBERG C
916 P	31/02-G-03 H	94.05.15	94.08.01	HYDRO	POLAR PIONEER
917 P	2/01-A-32	94.05.20	94.08.21	BP	GYDA
915 P	15/09-A-09	94.05.23	94.06.12	STATOIL	SLEIPNER A
920 P	6407/09-A-06	94.05.24	94.07.25	SHELL	DRAUGEN
919 P	6507/07-C-02 H	94.05.27	94.06.18	CONOCO	TRANSOCEAN 8
907 P	2/04-B-22 A	94.05.29	94.07.01	PHILLIPS	EKOFISK B
914 P	2/04-C-11 A	94.06.01	94.06.25	PHILLIPS	EKOFISK C
886 P	15/09-A-22	94.06.01	94.06.13	STATOIL	SLEIPNER A
921 P	34/10-A-42	94.06.06	94.09.15	STATOIL	GULLFAK A
924 P	30/06-C-17	94.06.06	94.07.01	HYDRO	OSEBERG C
918 P	2/07-B-08 A	94.06.10	94.09.20	PHILLIPS	ELDFISK B
928 P	2/11-A-07 A	94.06.14	94.07.01	AMOCO	MÆRSK GIANT
922 P	34/07-P-14	94.06.16	94.07.14	SAGA	SNORRE P
926 P	31/04-A-08	94.06.17	94.08.07	HYDRO	BRAGE
929 P	34/07-I-05 A H	94.06.18	94.10.13	SAGA	SCARABEO 5
932 P	6507/07-C-03 H	94.06.19	94.07.15	CONOCO	TRANSOCEAN 8
923 P	2/08-A-30 A	94.06.21	94.08.24	AMOCO	VALHALL
925 P	33/09-A-31 A	94.06.23	94.10.24	STATOIL	STATFJORD A
939 P	30/06-C-17 A	94.07.01	94.07.14	HYDRO	OSEBERG C
935 P	15/09-A-27	94.07.02	94.08.27	STATOIL	SLEIPNER A
938 P	2/11-A-01 B	94.07.09	94.07.25	AMOCO	HOD
934 P	2/04-A-11 B	94.07.12	94.08.05	PHILLIPS	EKOFISK A
941 P	30/06-C-17 B	94.07.14	94.08.29	HYDRO	OSEBERG C
940 P	34/07-P-38	94.07.14	94.08.26	SAGA	SNORRE P
936 P	6507/07-C-01 H	94.07.15	94.07.30	CONOCO	TRANSOCEAN 8
933 P	33/12-B-42	94.08.02	94.11.02	STATOIL	STATFJORD B
943 P	2/11-A-05 A	94.08.02	94.09.16	AMOCO	MÆRSK GIANT
931 P	31/02-G-04 A H	94.08.02	94.12.20	HYDRO	POLAR PIONEER
946 P	31/04-A-08 A	94.08.07	94.08.29	HYDRO	BRAGE
952 P	2/08-A-30 B	94.08.24	94.09.27	AMOCO	VALHALL
951 P	2/01-A-11	94.08.25	94.10.16	BP	GYDA
949 P	2/04-A-15 B	94.08.26	94.09.21	PHILLIPS	EKOFISK A
945 P	2/04-B-18 A	94.08.27	94.09.20	PHILLIPS	EKOFISK B
957 P	15/09-A-05	94.08.28	94.11.11	STATOIL	SLEIPNER A
947 P	30/06-C-02	94.08.30	94.09.22	HYDRO	OSEBERG C
955 P	31/04-A-26	94.08.31	94.09.24	HYDRO	BRAGE
956 P	31/02-B-03 H	94.09.02	00.00.00	HYDRO	POLAR PIONEER
960 P	33/09-E-01 H	94.09.12	94.10.27	STATOIL	TREASURE PROSPECT
950 P	34/10-B-31	94.09.15	94.12.14	STATOIL	GULLFAKS B
944 P	6407/09-A-02	94.09.18	94.11.04	SHELL	DRAUGEN
964 P	31/04-A-25	94.09.25	94.10.15	HYDRO	BRAGE
948 P	30/09-B-06	94.09.25	94.11.27	HYDRO	OSEBERG B
961 P	25/05-A-05	94.09.28	94.11.01	ELF	MÆRSK GALLANT
962 P	31/02-E-06 H	94.09.29	94.10.25	HYDRO	POLAR PIONEER
927 P	2/04-C-09 A	94.09.29	94.11.02	PHILLIPS	EKOFISK C
959 P	30/06-C-26	94.09.30	94.12.18	HYDRO	OSEBERG C
942 P	2/07-B-15 A	94.10.04	94.12.14	PHILLIPS	ELDFISK B
937 P	34/10-C-23	94.10.05	94.11.01	STATOIL	GULLFAKS C
958 P	2/04-A-02 A	94.10.08	94.12.28	PHILLIPS	EKOFISK A
966 P	34/07-P-14 A	94.10.09	94.11.21	SAGA	SNORRE P
970 P	31/04-A-14	94.10.18	94.11.25	HYDRO	BRAGE
953 P	34/07-I-04 H	94.10.21	94.11.21	SAGA	VILDKAT EXPLORER
969 P	31/02-D-06 H	94.10.26	94.12.09	HYDRO	POLAR PIONEER
972 P	34/07-A-07 H	94.10.26	94.11.20	SAGA	SCARABEO 5
968 P	33/09-E-02 H	94.10.28	00.00.00	STATOIL	TREASURE PROSPECT
967 P	2/07-A-13 A	94.11.02	94.12.19	PHILLIPS	MÆRSK GUARDIAN
965 P	2/08-A-16 D	94.11.02	94.12.07	AMOCO	VALHALL
973 P	25/05-A-06	94.11.02	94.12.21	ELF	MÆRSK GALLANT
977 P	34/10-C-23 A	94.11.02	94.11.23	STATOIL	GULLFAKS C
974 P	6407/09-A-02 A	94.11.05	94.12.01	SHELL	DRAUGEN
954 P	15/09-A-21	94.11.11	00.00.00	STATOIL	SLEIPNER A
975 P	2/04-C-06 B	94.11.16	00.00.00	PHILLIPS	EKOFISK C
976 P	30/03-A-06 A	94.11.21	94.12.25	STATOIL	VESLEFRIKK A
984 P	34/07-A-08 H	94.11.21	00.00.00	SAGA	SCARABEO 5
981 P	34/07-I-02 H	94.11.22	00.00.00	SAGA	VILDKAT EXPLORER
980 P	34/10-C-24	94.11.24	00.00.00	STATOIL	GULLFAKS C
985 P	34/07-P-31	94.11.27	94.12.31	SAGA	SNORRE P

Perm. no	Dev. well	Spudded	Completed	Operator	Field/installation
986 P	31/04-A-18	94.11.27	00.00.00	HYDRO	BRAGE
979 P	30/09-B-06 A	94.11.28	94.12.25	HYDRO	OSEBERG B
971 P	33/09-A-21	94.12.02	94.12.21	STATOIL	STATFJORD A
982 P	33/12-B-33	94.12.06	00.00.00	STATOIL	STATFJORD B
983 P	6507/07-A-14	94.12.15	00.00.00	CONOCO	TRANSOCEAN 8
978 P	34/10-B-32	94.12.15	00.00.00	STATOIL	GULLFAKS B
987 P	2/04-K-06	94.12.19	00.00.00	PHILLIPS	EKOFISK K
990 P	30/06-C-26 A	94.12.20	00.00.00	HYDRO	OSEBERG C
994 P	25/05-A-06 A	94.12.22	00.00.00	ELF	MÆRSK GALLANT
992 P	2/07-A-07 B	94.12.27	00.00.00	PHILLIPS	MÆRSK GUARDIAN
991 P	30/09-B-34	94.12.25	00.00.00	HYDRO	OSEBERG B
996 P	34/07-P-31 A	94.12.31	00.00.00	SAGA	SNORRE P

Table 7.4.c
Development wells drilled from mobile units 1994

Perm. no	Dev. well	Spudded	Completed	Operator	Field/installation
879 P	34/07-A-3 H	94.01.04	94.03.23	SAGA	SCARABEO 5
880 P	33/09-K-03 H	94.01.06	94.04.05	STATOIL	TREASURE PROSPECT
885 P	6507/07-A-17	94.01.11	94.02.19	CONOCO	TRANSOCEAN 8
884 P	33/09-K-02 H	94.02.04	94.03.30	STATOIL	TREASURE PROSPECT
889 P	6507/07-A-50	94.02.19	94.03.16	CONOCO	TRANSOCEAN 8
930 P	2/11-A-05	94.02.28	94.08.02	AMOCO	MÆRSK GIANT
900 P	31/02-G-04 H	94.03.18	94.12.20	HYDRO	POLAR PIONEER
888 P	6407/09-B-02 H	94.03.22	94.04.08	SHELL	DYVI STENA
896 P	34/07-A-02 H	94.03.24	94.04.29	SAGA	SCARABEO 5
901 P	6507/07-A-38	94.03.30	94.04.27	CONOCO	TRANSOCEAN 8
903 P	33/09-K-01 H	94.04.07	94.04.25	STATOIL	TREASURE PROSPECT
908 P	6407/09-B-05 H	94.04.10	94.05.15	SHELL	DYVI STENA
911 P	31/02-F-06 H	94.04.19	94.05.14	HYDRO	POLAR PIONEER
912 P	33/09-K-01 A H	94.04.25	94.05.30	STATOIL	TREASURE PROSPECT
913 P	2/11-A-07	94.04.28	94.06.14	AMOCO	MÆRSK GIANT
916 P	31/02-G-03 H	94.05.15	94.08.01	HYDRO	POLAR PIONEER
919 P	6507/07-C-02 H	94.05.27	94.06.18	CONOCO	TRANSOCEAN 8
928 P	2/11-A-07 A	94.06.14	94.07.01	AMOCO	MÆRSK GIANT
929 P	34/07-I-05 A H	94.06.18	94.10.13	SAGA	SCARABEO 5
932 P	6507/07-C-03 H	94.06.19	94.07.15	CONOCO	TRANSOCEAN 8
936 P	6507/07-C-01 H	94.07.15	94.07.30	CONOCO	TRANSOCEAN 8
943 P	2/11-A-05 A	94.08.02	94.09.16	AMOCO	MÆRSK GIANT
931 P	31/02-G-04 A H	94.08.02	94.09.01	HYDRO	POLAR PIONEER
956 P	31/02-B-03 H	94.09.02	00.00.00	HYDRO	POLAR PIONEER
960 P	33/09-E-01 H	94.09.12	94.10.27	STATOIL	TREASURE PROSPECT
961 P	25/05-A-05	94.09.28	94.11.01	ELF	MÆRSK GALLANT
962 P	31/02-E-06 H	94.09.29	94.10.25	HYDRO	POLAR PIONEER
953 P	34/07-I-04 H	94.10.21	94.11.21	SAGA	VILDKAT EXPLORER
969 P	31/02-D-06 H	94.10.26	94.12.09	HYDRO	POLAR PIONEER
972 P	34/07-A-07 H	94.10.26	94.11.20	SAGA	SCARABEO 5
968 P	33/09-E-02 H	94.10.28	00.00.00	STATOIL	TREASURE PROSPECT
967 P	2/07-A-13 A	94.11.02	94.12.19	PHILLIPS	MÆRSK GUARDIAN
973 P	25/05-A-06	94.11.02	94.12.21	ELF	MÆRSK GALLANT
984 P	34/07-A-08 H	94.11.21	00.00.00	SAGA	SCARABEO 5
981 P	34/07-I-02 H	94.11.22	00.00.00	SAGA	VILDKAT EXPLORER
982 P	6507/07-A-14 H	94.12.15	00.00.00	CONOCO	TRANSOCEAN 8
994 P	25/05-A-06 A	94.12.22	00.00.00	ELF	MÆRSK GALLANT
992 P	2/07-A-07 B	94.12.27	00.00.00	PHILLIPS	MÆRSK GUARDIAN

7.5 UNITS OF MEASUREMENT FOR OIL AND GAS

Oil and gas are often measured in volumetric units valid under certain defined ISO standard conditions (temperature 15 degrees Celsius, pressure 1.01325 bar). Oil volumes are stated in million standard cubic meters, (10^6 Sm^3), and gas volumes in billion standard cubic meters (10^9 Sm^3).

Conversion from volume units to oil equivalents for oil and gas quantities is done in cases of aggregating and comparing gas and oil volumes, and when exact quantities are not required.

Previously the Norwegian Petroleum Directorate has stated (cf. the NPD Annual Reports 1975-93) that for a large variety of oil and gas compositions on the Norwegian continental shelf the energy in one tonne of oil will roughly correspond to that in 1000 Sm^3 gas. Up to and including 1993 the Norwegian Petroleum Directorate therefore stated the aggregate resource estimates in tonnes oil equivalents (t.o.e.), so that 1 t.o.e. would correspond to 1 tonne of oil or 1,000 Sm^3 of gas.

The conversion to *oil equivalents* is based on the quantity of energy which is released during combustion of oil and gas. Based on a closer study of the combustion values of known oil and gas compositions on the Norwegian continental shelf, the Norwegian Petroleum Directorate has arrived at the conclusion that the quantity of energy on average corresponds to the quantity of energy in 1 Sm^3 of oil.

As from 1 January 1995, the Norwegian Petroleum Directorate has therefore chosen to use *Sm^3 oil equivalents* (Sm^3 o.e.) in the presentation of the aggregate petroleum resources. Consequently, when adding up or comparing volumes of oil and gas, the following formulae will be used as from 1 January 1995:

- 1000 Sm^3 gas equals: 1 Sm^3 o.e.
- 1 Sm^3 oil equals: 1 Sm^3 o.e.

Conversion from unit of weight NGL to Sm^3 oil equivalents is however somewhat more complicated, as composition of the light hydrocarbon components may vary considerably from one field to another. The NPD has chosen to use a constant conversion factor of 1.3 from tonnes NGL/condensate to Sm^3 o.e. This is based on a quantity of energy in 1 tonne of an average NGL/condensate mixture from the Norwegian continental shelf corresponding to the quantity of energy in 0.769 Sm^3 oil.

This new calculation procedure for conversion of oil and gas to *Sm^3 oil equivalents* represents clear advantages. Firstly the stated numerical values for oil (million Sm^3) and gas (billion Sm^3) can be added directly. The NGL estimates must be converted, but in general this is only applicable to fields. Secondly it will facilitate comparison of the Norwegian Petroleum Directorate's total resource estimates with other estimates.

7.6 PRODUCTION OF OIL AND GAS

The production of oil and natural gas on the Norwegian continental shelf was 180.4 x 10^6 Sm^3 o.e. in 1994. Production in 1993 was 160.8 x 10^6 Sm^3 o.e.

Tables 7.6.a-7.6.y and Figures 7.6.a and 7.6.b illustrate production in more detail.

The data in Table 7.6.a summarise the Norwegian share of production in Statfjord, Frigg, and Murchison. In the oil figures, NGL is included for Brage, the Ekofisk area, Embla, Gullfaks, Gyda, Hod, Murchison, Sleipner Øst, Snorre, Statfjord, Statfjord Øst, Tommeliten Gamma, Tordis, Ula, Valhall and Veslefrikk.

The data for gas in Table 7.6.a indicate the volumes sold for all fields.

Condensate is included in the field statistics for Brage, the Frigg area, Gullfaks, Heimdal, Sleipner, Snorre, Statfjord, Statfjord Øst, Tordis and Veslefrikk.

Table 7.6.a
Production in million Sm^3 oil equivalent (Sm^3 o.e.)

1994	Oil/NGL	Gas/cond.	Total
Brage	5.463	0.200	5.663
Draugen	3.887	0.000	3.887
Ekofisk area	13.782	7.169	20.951
Embla	1.478	0.428	1.906
Frigg area	0.388	3.202	3.590
Gamma Nord	0.155	0.000	0.155
Gullfaks	30.564	2.088	32.652
Gullfaks Vest	0.472	0.000	0.472
Gyda	4.069	0.475	4.544
Heimdal	0.000	3.742	3.742
Hod	0.642	0.139	0.781
Murchison	0.233	0.004	0.237
Oseberg	29.056	0.000	29.056
Sleipner Øst (incl. Loke)	1.232	6.247	7.479
Snorre	10.244	0.514	10.758
Statfjord	32.591	3.323	35.914
Statfjord Øst	0.619	0.034	0.653
Tommeliten Gamma	0.337	0.993	1.330
Tordis	1.581	0.097	1.678
Troll	0.061	0.000	0.061
Ula	5.698	0.349	6.047
Valhall	3.266	0.667	3.933
Veslefrikk	4.611	0.268	4.879
Total 1994	150.429	29.939	180.368
Total 1993	134.757	26.080	160.837
Total 1992	126.545	26.679	153.224
Total 1991	111.050	25.826	136.876
Total 1990	97.169	26.309	123.478
Total 1989	88.567	29.519	118.086
Total 1988	67.197	29.202	96.404
Total 1987	59.004	28.963	87.967
Total 1986	50.845	26.673	77.518
Total 1985	46.665	26.259	72.924

Fig. 7.6.a
Oil and gas production on the Norwegian shelf 1971-1994

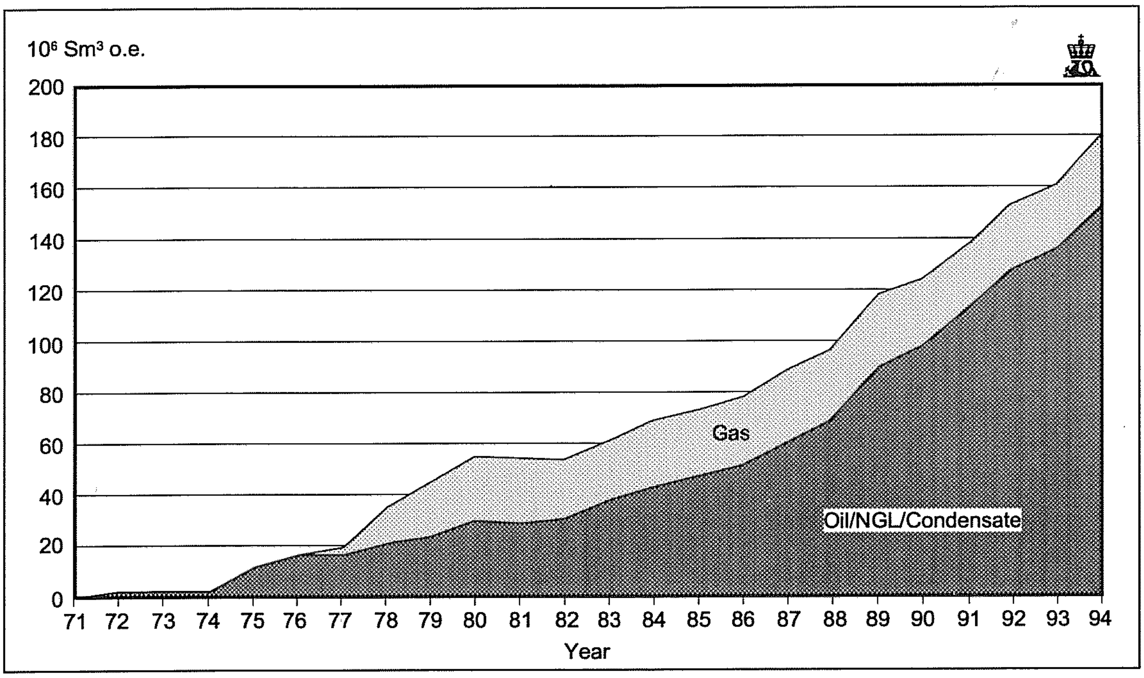


Fig. 7.6.b
Oil and gas production on the Norwegian shelf 1977-1994

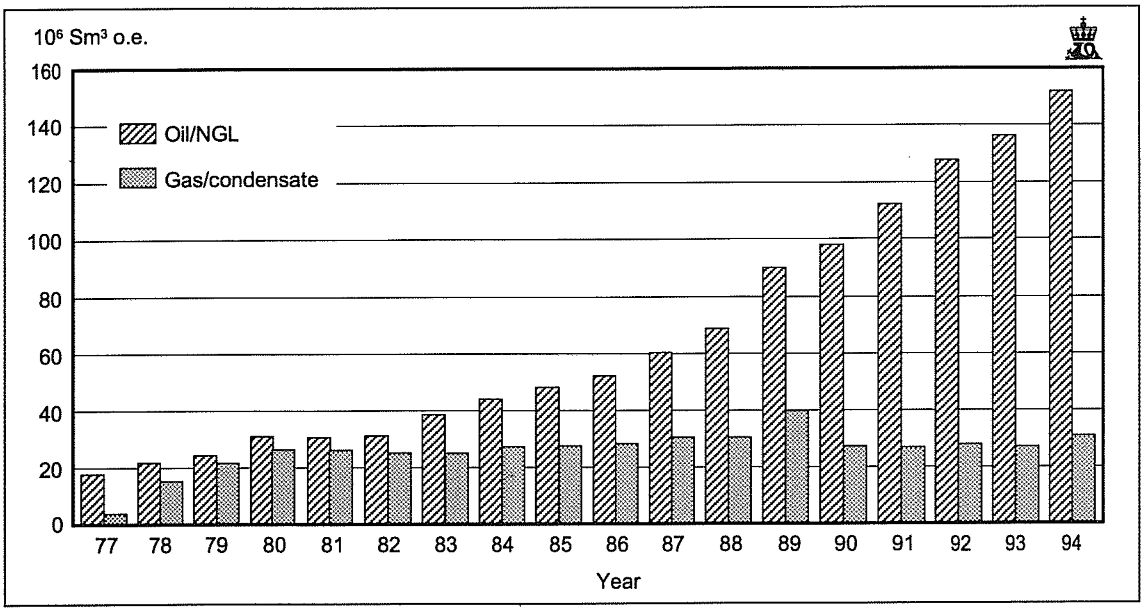


Table 7.6.b.
Monthly oil and gas production allocated to the Ekofisk area

1994	Unstabilised oil prod.	Gas prod.	Gas flared	Gas fuel	Stabilised oil Teesside	NGL Teesside	Gas sold Emden
	10^3 Sm³	10^6 Sm³	10^6 Sm³	10^6 Sm³	10^3 Sm³	10^3 Sm³	10^6 Sm³
JAN	1169	817	1.0	99	1066	109	596
FEB	1046	715	0.5	88	955	96	538
MAR	1136	761	1.2	97	1040	104	546
APR	1113	740	1.0	88	1020	99	553
MAY	1176	769	0.5	87	1085	102	520
JUN	1145	738	1.0	87	1050	98	596
JUL	1167	771	1.2	85	1086	86	614
AUG	788	468	1.7	47	738	52	364
SEP	1302	814	1.8	84	1199	106	668
OCT	1364	857	1.1	92	1272	116	727
NOV	1353	826	0.4	93	1252	115	717
DEC	1373	839	1.0	94	1267	117	729
YEAR TOTAL	14132	9115	12.1	1041	13030	1200	7168

Table 7.6.c.
Monthly gas and condensate production in the Frigg area

1994	Gas prod.	Condensate prod.	Gas flared	Gas fuel	Gas St.Fergus	Stabilised oil Sture	Condensate St.Fergus
	10^6 Sm³	10^3 Sm³	10^6 Sm³	10^6 Sm³	10^6 Sm³	10^3 Sm³	10^3 Sm³
JAN	376	1	0	8	377		2
FEB	353	1	0	8	351		2
MAR	386	1	0	9	382		2
APR	391	1	0	9	389		2
MAY	379	36	1	9	377	26	2
JUN	268	58	1	9	255	59	2
JUL	212	54	1	8	200	55	1
AUG	53	2	0	1	58	2	0
SEP	244	51	2	1	237	52	1
OCT	145	62	2	1	129	64	1
NOV	229	66	2	1	230	68	1
DEC	204	61	1	1	201	63	0
YEAR TOTAL	3240	394	10	65	3186	389	16

Figures are for the Norwegian share of Frigg, which is 60.82 per cent, plus 100 per cent of Odin, Øst Frigg and Lille-Frigg.

Table 7.6.d.
Monthly oil and gas production on 30/6 Gamma Nord

1994	Stabilised. oil prod.	Gas prod.	Gas flared	Gas fuel	Stabilised oil Sture
	10^3 Sm³	10^6 Sm³	10^6 Sm³	10^6 Sm³	10^3 Sm³
JAN	19	56	0.1	0.1	18
FEB	16	49	0.1	0.1	15
MAR	17	52	0.1	0.3	16
APR	17	55	0.2	0.1	16
MAY	10	29	0.1	0.9	10
JUN	16	48	0.2	0.3	15
JUL	17	55	0.1	0.3	16
AUG	17	59	0.1	0.0	16
SEP	4	14	0.1	0.0	4
OCT	3	5	0.0	0.0	2
NOV	17	50	0.1	0.4	16
DEC	14	44	0.2	0.2	13
YEAR TOTAL	167	516	1.4	2.7	157

Table 7.6.e.
Monthly oil and gas production on Gullfaks

1994	Stabilised oil prod.	Gas prod.	Gas flared	Gas fuel	NGL/cond. Kårstø	Gas Sale
	10^3 Sm³	10^6 Sm³	10^6 Sm³	10^6 Sm³	10^3 Sm³	10^6 Sm³
JAN	2639	277	7	25	41	209
FEB	2436	255	6	24	38	194
MAR	2697	286	4	26	47	195
APR	2702	284	7	26	42	213
MAY	2795	298	5	26	45	215
JUN	2593	288	5	24	38	133
JUL	2657	290	9	25	39	148
AUG	1369	143	18	12	19	78
SEP	2534	256	5	24	35	163
OCT	2732	280	7	24	36	160
NOV	2547	265	4	23	36	155
DEC	2611	278	4	24	34	155
YEAR TOTAL	30312	3200	81	283	450	2018

NGL/cond. from Kårstø and Gas sale figures are inclusive figures from Gullfaks Vest.

Table 7.6.f
Monthly oil and gas production on Gyda

1994	Unstabilised oil prod.	Gas prod.	Gas flared	Gas fuel	Stabilised oil Teesside	NGL Teesside	Gass Emden
	10^3 Sm³	10^6 Sm³	10^6 Sm³	10^6 Sm³	10^3 Sm³	10^3 Sm³	10^6 Sm³
JAN	314	45	0.4	3	293	33	37
FEB	270	39	0.3	3	252	28	33
MAR	276	40	0.1	4	258	28	33
APR	282	42	0.1	4	262	28	34
MAY	337	47	0.2	4	312	33	40
JUN	390	53	0.1	4	362	39	44
JUL	382	52	0.2	4	355	35	45
AUG	199	26	0.3	1	184	17	22
SEP	403	53	0.3	3	368	41	45
OCT	443	58	0.5	3	409	46	50
NOV	412	55	0.2	4	380	43	47
DEC	408	55	0.2	4	374	42	46
YEAR TOTAL	4116	565	3.0	41	3809	413	476

Table 7.6.g
Monthly gas and condensate production on Heimdal

1994	Gas prod.	Condensate prod.	Gas flared	Gas fuel	Gas Sale	Condensate Kinneil
	10^6 Sm³	10^3 Sm³	10^6 Sm³	10^6 Sm³	10^6 Sm³	10^3 Sm³
JAN	357	57	0.1	4	344	48
FEB	329	53	0.0	4	315	45
MAR	318	51	0.0	4	300	47
APR	283	46	0.1	4	304	41
MAY	205	33	0.0	3	222	31
JUN	204	33	0.0	3	251	30
JUL	206	33	0.1	3	222	31
AUG	104	17	0.2	2	136	15
SEP	204	33	0.0	3	270	32
OCT	244	40	0.0	3	296	36
NOV	280	45	0.0	3	286	40
DEC	315	51	0.0	4	324	45
YEAR TOTAL	3049	492	0.5	40	3270	441

Table 7.6.h
Monthly oil and gas production on Hod

1994	Unstabilised oil prod.	Gas prod.	Gas flared	Gas fuel	Stabilised oil Teesside	NGL Teesside	Gas Emden
	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3	10^3 Sm^3	10^6 Sm^3
JAN	64	15	0.2	1	61	4	14
FEB	47	9	0.1	1	45	3	10
MAR	59	14	0.1	1	56	3	13
APR	56	14	0.1	1	53	3	13
MAY	55	14	0.0	1	52	3	13
JUN	55	13	0.0	1	52	3	12
JUL	60	13	0.1	1	57	3	12
AUG	35	5	0.1	1	33	2	4
SEP	57	15	0.1	1	53	4	15
OCT	59	11	0.1	1	56	4	12
NOV	53	12	0.1	1	50	3	11
DEC	52	12	0.1	1	49	3	11
YEAR TOTAL	652	147	1.1	12	617	38	140

Table 7.6.i
Monthly oil and gas production on Gullfaks Vest

1994	Stabilised oil prod.	Gas prod.
	10^3 Sm^3	10^6 Sm^3
JAN		
FEB		
MAR		
APR		
MAY	39	4
JUN	58	6
JUL	61	7
AUG	25	2
SEP	65	6
OCT	73	7
NOV	73	7
DEC	77	8
YEAR TOTAL	471	47

Table 7.6.j
Monthly oil and gas production on Murchison

1994	Unstabilised oil prod.	Gas prod.	Gas flared	Gas fuel	Stabilised oil Sullom Voe	NGL S.Voe/St.Fer	Gas St.Fergus
	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3	10^3 Sm^3	10^6 Sm^3
JAN	25	4	0.2	1.2	24	1	1
FEB	23	3	0.1	1.2	22	1	0
MAR	32	4	0.4	1.2	31	1	1
APR	20	3	0.3	0.9	19	0	0
MAY	23	3	0.1	1.2	21	0	0
JUN	10	2	0.5	0.3	9	0	0
JUL	19	3	1.1	0.4	18	0	0
AUG	12	2	0.7	0.3	11	0	0
SEP	18	3	0.9	0.5	17	0	0
OCT	22	3	0.4	0.9	20	0	0
NOV	21	3	0.1	1.1	19	0	1
DEC	19	2	0.4	0.9	19	0	1
YEAR TOTAL	244	35	5.1	9.9	230	3	4

These figures are for the Norwegian share of Murchison.

Table 7.6.k
Monthly oil and gas production on Oseberg

1994	Unstabilised oil prod.	Gas prod.	Gas flared	Gas fuel	Stabilised oil Sture
	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3
JAN	2478	346	1	21	2471
FEB	2252	322	1	20	2244
MAR	2440	373	3	20	2434
APR	2334	381	2	20	2321
MAY	2496	399	3	20	2496
JUN	2407	402	2	21	2402
JUL	2488	438	2	21	2479
AUG	2487	427	2	21	2482
SEP	2411	444	3	20	2400
OCT	2457	461	6	20	2450
NOV	2398	409	2	19	2394
DEC	2491	398	2	22	2485
YEAR TOTAL	29139	4800	29	245	29058

Table 7.6.l
Monthly oil and gas production on Snorre

1994	Unstabilised oil prod.	Gas prod.	Gas flared	Gas fuel	Stabilised oil prod.	Gas Sale	NGL/cond. Kårstø
	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3	10^6 Sm^3	10^3 Sm^3
JAN	770	80	5	5	762	55	52
FEB	842	88	2	6	837	62	53
MAR	1031	114	2	7	1019	51	62
APR	815	89	6	6	812	19	50
MAY	1046	115	2	7	1044	7	60
JUN	849	87	7	6	849	29	47
JUL	661	62	6	5	653	31	39
AUG	605	60	5	4	601	17	38
SEP	403	40	2	3	400	23	21
OCT	1010	108	5	6	1002	57	66
NOV	878	93	3	6	881	46	55
DEC	1003	109	5	7	1012	57	68
YEAR TOTAL	9913	1045	50	68	9872	454	611

Table 7.6.m
Monthly oil and gas production on Statfjord

1994	Stabilised oil prod.	Gas prod.	Gas flared	Gas fuel	NGL/cond. Kårstø	Gas Sale
	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3	10^6 Sm^3
JAN	2760	634	6	38	118	281
FEB	2672	618	5	35	110	252
MAR	2904	689	5	38	131	301
APR	2491	588	6	32	109	264
MAY	2655	632	8	35	106	241
JUN	2822	665	6	34	119	251
JUL	2911	669	7	36	110	257
AUG	2746	636	8	34	113	219
SEP	2327	529	8	28	104	198
OCT	2590	623	8	36	113	249
NOV	2409	580	9	34	122	275
DEC	2498	619	8	36	138	356
YEAR TOTAL	31785	7482	84	416	1393	3144

These figures are for the Norwegian share of Statfjord.

Table 7.6.n
Monthly oil and gas production on Tommeliten Gamma

1994	Unstabilised oil prod.	Gas prod.	Stabilised oil Teesside	NGL Teesside	Gas Emden
	10^3 Sm^3	10^6 Sm^3	10^3 Sm^3	10^3 Sm^3	10^6 Sm^3
JAN	45	113	29	12	104
FEB	39	98	25	10	90
MAR	43	106	28	11	98
APR	39	101	25	10	93
MAY	39	97	25	10	90
JUN	32	86	20	9	79
JUL	29	80	19	7	74
AUG	17	45	11	4	41
SEP	29	77	19	8	71
OCT	33	90	22	9	83
NOV	36	91	23	10	84
DEC	35	94	22	10	86
YEAR TOTAL	416	1078	268	110	993

Table 7.6.o
Monthly gas and condensate production on Troll

1994	Gas prod.	Condensate prod.	Gas flared	Gas fuel	Stabilised oil Sture
	10^6 Sm^3	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3
JAN	272	5	0.0	3	5
FEB	318	6	0.0	4	6
MAR	204	4	0.1	2	3
APR	304	6	0.5	4	5
MAY	327	7	0.0	4	7
JUN	324	7	0.0	4	6
JUL	319	7	0.0	4	6
AUG	321	7	0.0	4	6
SEP	312	6	0.0	4	6
OCT	258	6	0.0	4	5
NOV	296	6	0.0	4	5
DEC	54	1	0.0	1	1
YEAR TOTAL	3309	68	0.6	42	61

Table 7.6.p
Monthly oil and gas production on Ula

1994	Unstabilised oil prod.	Gas prod.	Gas flared	Gas fuel	Stabilised Teesside	NGL Teesside	Gas Emden
	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3	10^3 Sm^3	10^6 Sm^3
JAN	596	48	0.4	6	570	40	37
FEB	511	41	0.6	5	489	35	31
MAR	472	38	0.3	5	449	33	29
APR	553	45	0.3	5	527	37	35
MAY	539	43	0.6	6	514	36	33
JUN	544	45	0.2	5	523	36	34
JUL	520	43	0.4	5	501	30	34
AUG	201	16	0.4	2	193	11	12
SEP	451	37	0.8	5	430	29	28
OCT	427	35	3.8	5	411	28	23
NOV	448	37	0.5	5	428	29	28
DEC	443	37	0.4	5	421	29	27
YEAR TOTAL	5705	465	8.7	59	5456	373	351

Table 7.6.q
Monthly oil and gas production on Valhall

1994	Unstabilised oil prod.	Gas prod.	Gas flared	Gas fuel	Stabilised oil Teesside	NGL Teesside	Gas Emden
	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3	10^3 Sm^3	10^6 Sm^3
JAN	285	64	0.7	5	272	14	59
FEB	254	56	0.5	5	243	13	51
MAR	277	58	0.3	5	264	14	54
APR	254	54	0.4	5	241	13	50
MAY	297	64	0.3	5	284	14	60
JUN	277	62	0.2	5	265	13	57
JUL	281	64	0.6	5	269	13	59
AUG	162	31	0.8	3	155	8	28
SEP	285	57	0.4	5	271	13	53
OCT	308	68	0.4	5	295	15	63
NOV	320	71	0.3	6	305	17	66
DEC	308	71	0.4	5	292	16	66
YEAR TOTAL	3308	720	5.3	59	3156	163	666

Table 7.6.r
Monthly oil and gas production on Veslefrikk

1994	Unstabilised oil prod.	Gas prod.	Gas flared	Gas fuel	NGL/cond. Kårstø	Gas Sale	Stabilised oil Sture
	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3	10^6 Sm^3	10^3 Sm^3
JAN	363	51	1	3	24	35	365
FEB	343	48	1	4	22	33	342
MAR	368	45	1	4	22	28	368
APR	343	45	2	4	20	20	341
MAY	384	56	2	4	24	4	388
JUN	400	49	0	4	22	15	403
JUL	367	45	2	4	20	14	366
AUG	256	31	1	2	15	10	256
SEP	411	50	1	4	21	15	413
OCT	407	49	2	4	22	26	407
NOV	381	47	1	4	22	27	380
DEC	417	50	1	4	23	26	415
YEAR TOTAL	4440	566	15	45	257	253	4444

Table 7.6.s
Monthly oil and gas production on Brage

1994	Unstabilised oil prod.	Gas prod.	Gas flared	Gas fuel	NGL/cond. Kårstø	Gas Sale	Stabilised oil Sture
	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3	10^6 Sm^3	10^3 Sm^3
JAN	415	25	1	3	12	17	408
FEB	388	25	0	4	13	16	386
MAR	424	27	1	4	14	18	419
APR	409	26	0	4	13	14	402
MAY	467	29	1	4	14	15	463
JUN	464	29	0	4	15	14	459
JUL	482	34	1	4	17	16	477
AUG	480	32	0	4	16	14	474
SEP	467	32	0	4	15	15	462
OCT	477	33	1	4	16	19	473
NOV	465	32	0	4	17	18	459
DEC	478	30	2	4	14	18	469
YEAR TOTAL	5416	354	7	47	164	194	5351

Table 7.6.t
Monthly oil and gas production on Embla

1994	Unstabilised oil prod.	Gas prod.	Gas flared	Gas fuel	NGL Teesside	Gas Sale	Stabilised oil Teesside
	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3	10^6 Sm^3	10^3 Sm^3
JAN	155	47	0	0	10	44	148
FEB	140	43	0	0	9	40	132
MAR	147	44	0	0	10	41	139
APR	134	42	0	0	9	39	127
MAY	128	37	0	0	8	34	121
JUN	122	39	0	0	8	36	116
JUL	120	39	0	0	7	37	115
AUG	26	8	0	0	1	7	25
SEP	123	38	0	0	7	35	118
OCT	129	40	0	0	9	38	123
NOV	133	42	0	0	9	39	127
DEC	131	42	0	0	9	39	124
YEAR TOTAL	1488	461	0	0	96	429	1415

Table 7.6.u
Monthly oil and gas production on Draugen

1994	Stabilised oil prod.	Gas prod.	Gas flared	Gas fuel
	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3
JAN	139	6	4	1
FEB	35	1	1	1
MAR	66	2	1	1
APR	165	7	2	3
MAY	127	5	1	2
JUN	316	14	1	3
JUL	341	18	1	4
AUG	525	29	0	4
SEP	518	29	0	4
OCT	526	29	1	5
NOV	525	27	1	3
DEC	604	31	0	3
YEAR TOTAL	3887	198	13	34

Table 7.6.v
Monthly gas and condensat production on Sleipner Øst

1994	Condensate prod.	Gas prod.	Gas flared	Gas fuel	NGL/Cond. Kårstø	Gas Sale
	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3	10^6 Sm^3
JAN	285	266	3	9	334	316
FEB	264	249	4	7	283	273
MAR	244	230	5	7	264	253
APR	229	212	4	6	256	248
MAY	323	298	3	9	358	281
JUN	365	335	5	9	402	307
JUL	281	253	2	7	314	264
AUG	198	180	2	5	212	195
SEP	480	426	2	11	485	288
OCT	572	522	1	10	580	484
NOV	559	510	1	10	559	510
DEC	550	500	1	10	544	533
YEAR TOTAL	4350	3981	33	100	4591	3952

NGL/Cond. from Kårstø and gas sale figures are inclusive Loke.

Tabel 7.6.w
Monthly gas and condensate production on Loke

1994	Condensate prod.	Gas prod.	Gas flared	Gas fuel
	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3
JAN	47	51	0	2
FEB	24	25	0	1
MAR	24	26	1	1
APR	29	31	1	1
MAY	43	46	1	1
JUN	39	42	1	1
JUL	30	34	0	1
AUG	23	25	0	1
SEP	27	31	0	1
OCT	29	32	0	1
NOV	28	31	0	1
DEC	22	24	0	0
YEAR TOTAL	365	398	4	12

Table 7.6.x
Monthly oil and gas production on Tordis

1994	Stabilised oil prod.	Gas prod.	Gas flared	Gas fuel	NGL/cond. Kårstø	Gas Sale
	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3	10^6 Sm^3
JAN						
FEB						
MAR						
APR						
MAY						
JUN	103	11		1		
JUL	135	13		1		7
AUG	82	8		1		6
SEP	229	23		2		6
OCT	309	31	1	2	12	23
NOV	338	33	1	2	13	25
DEC	361	34	1	3	15	26
YEAR TOTAL	1557	153	3	12	40	93

Table 7.6.y
Monthly oil and gas production on Statfjord Øst

1994	Stabilised oil prod.	Gas prod.	NGL/Cond. Kårstø	Gas Sale
	10^3 Sm^3	10^6 Sm^3	10^3 Sm^3	10^6 Sm^3
JAN				
FEB				
MAR				
APR				
MAY				
JUN				
JUL				
AUG				
SEP	6	1		
OCT	129	19	5	10
NOV	214	31	5	11
DEC	262	38	5	11
YEAR TOTAL	611	89	15	32

7.7 LICENSEES IN ACTIVE PRODUCTION LICENSES

Table 7.7.
Licensees in active production licenses per 31 December 1994

PROD. LIC.	AWARDED EXPIRES	BLOCKS	(O = operator)	LICENSEES	SHARES
001	65/09/01 11/09/01	25/11	O	ESSO EXPL. & PROD. NORWAY A/S	100.000000 %
001 P	65/09/01 11/09/01	16/1		ENTERPRISE OIL NORWEGIAN A/S	50.000000 %
			O	ESSO EXPL. & PROD. NORWAY A/S	50.000000 %
006	65/09/01 11/09/01	2/5 2/8 3/4		AMERADA HESS NORGE A/S	28.333000 %
			O	AMOCO NORWAY OIL COMPANY	28.333000 %
				ELF PETROLEUM NORGE A/S.	15.000000 %
				ENTERPRISE OIL NORWEGIAN A/S	28.333000 %
008	65/09/01 11/09/01	2/6 18/10	O	SAGA PETROLEUM A.S.	100.000000 %
009	65/09/01 11/09/01	9/5	O	ELF PETROLEUM NORGE A/S.	60.392000 %
				ELF REX NORGE A/S	3.420000 %
				NORSK AGIP A/S	5.220000 %
				PHILLIPS PETROLEUM COMPANY NORWAY	14.780000 %
				TOTAL NORGE A.S	16.188000 %
011	65/09/01 11/09/01	1/3 1/6	O	A/S NORSKE SHELL	100.000000 %
018	65/09/01 11/09/01	1/5 2/4 2/7 7/11		DEN NORSKE STATS OLJESELSKAP A.S	1.000000 %
				ELF PETROLEUM NORGE A/S.	7.594000 %
				ELF REX NORGE A/S	0.855000 %
				NORMINOL A/S	0.304000 %
				NORSK AGIP A/S	13.040000 %
				NORSK HYDRO PRODUKSJON A.S	6.700000 %
				NORSKE FINA A/S	30.000000 %
			O	PHILLIPS PETROLEUM COMPANY NORWAY	36.960000 %
				TOTAL NORGE A.S	3.547000 %
019	65/09/01 11/09/01	7/12	O	BP PETROLEUM DEV. OF NORWAY AS	57.500000 %
				CONOCO NORWAY INC.	10.000000 %
				DEN NORSKE STATS OLJESELSKAP A.S	12.500000 %
				KS PELICAN & CO A/S	5.000000 %
				SVENSKA PETROLEUM EXPLORATION A/S	15.000000 %
019 B	77/09/12 11/09/01	2/1 7/12 7/12	O	BP PETROLEUM DEV. OF NORWAY AS	26.625000 %
				CONOCO NORWAY INC.	9.375000 %
				DEN NORSKE STATS OLJESELSKAP A.S	50.000000 %
				KS PELICAN & CO A/S	4.000000 %
				NORSKE AEDC A/S	5.000000 %
				NORSKE MOECO A/S	5.000000 %
024	69/05/23 15/05/23	25/1		DEN NORSKE STATS OLJESELSKAP A.S	20.000000 %
			O	ELF PETROLEUM NORGE A/S.	26.420000 %
				NORSK HYDRO PRODUKSJON A.S	32.870000 %
				TOTAL NORGE A.S	20.710000 %
025	69/05/23 15/05/23	15/3	O	ELF PETROLEUM NORGE A/S.	53.200000 %
				NORSK HYDRO PRODUKSJON A.S	10.000000 %
				TOTAL NORGE A.S	36.800000 %

PROD. LIC.	AWARDED EXPIRES	BLOCKS		LICENSEES (O = operator)	SHARES	
026	69/05/23 15/05/23	25/2		DEN NORSKE STATS OLJESELSKAP A.S	5.000000	%
			O	ELF PETROLEUM NORGE A/S.	41.420000	%
				NORSK HYDRO PRODUKSJON A.S	32.870000	%
				TOTAL NORGE A.S	20.710000	%
027	69/05/23 15/05/23	25/8	O	ESSO EXPL. & PROD. NORWAY A/S	100.000000	%
027 P	69/05/23 15/05/23	25/8		ENTERPRISE OIL NORWEGIAN A/S	50.000000	%
			O	ESSO EXPL. & PROD. NORWAY A/S	50.000000	%
028	69/05/23 15/05/23	25/10	O	ESSO EXPL. & PROD. NORWAY A/S	100.000000	%
028 P	69/05/23 23/05/15	25/10		ENTERPRISE OIL NORWEGIAN A/S	50.000000	%
			O	ESSO EXPL. & PROD. NORWAY A/S	50.000000	%
029	69/05/23 15/05/23	15/6	O	ESSO EXPL. & PROD. NORWAY A/S	100.000000	%
030	69/05/23 15/05/23	30/10	O	ESSO EXPL. & PROD. NORWAY A/S	100.000000	%
031	69/05/23 15/05/23	2/10		NORSK AGIP A/S	18.260000	%
				NORSKE FINA A/S	30.000000	%
			O	PHILLIPS PETROLEUM COMPANY NORWAY	51.740000	%
032	69/05/30 15/05/30	2/9		AMERADA HESS NORGE A/S	25.000000	%
			O	AMOCO NORWAY OIL COMPANY	25.000000	%
				ELF PETROLEUM NORGE A/S.	15.000000	%
				ENTERPRISE OIL NORWEGIAN A/S	25.000000	%
				SVENSKA PETROLEUM EXPLORATION A/S	10.000000	%
033	69/05/30 15/05/30	2/11		AMERADA HESS NORGE A/S	25.000000	%
			O	AMOCO NORWAY OIL COMPANY	25.000000	%
				ELF PETROLEUM NORGE A/S.	25.000000	%
				ENTERPRISE OIL NORWEGIAN A/S	25.000000	%
034	69/11/14 15/11/14	30/5	O	A/S NORSKE SHELL	100.000000	%
035	69/11/14 15/11/14	30/11 30/11	O	A/S NORSKE SHELL	100.000000	%
036	71/06/11 21/07/11	25/4	O	ELF PETROLEUM NORGE A/S.	33.702000	%
				MARATHON PETROLEUM NORGE A/S	46.904000	%
				NORSK HYDRO PRODUKSJON A.S	6.920000	%
				SAGA PETROLEUM A.S.	6.611000	%
				TOTAL NORGE A.S	5.541000	%
				UGLAND CONSTRUCTION COMPANY A/S	0.322000	%
037	73/08/10 09/08/10	33/9		A/S NORSKE SHELL	10.000000	%
		33/9		AMERADA HESS NORGE A/S	1.042000	%
		33/12	O	DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
				ENTERPRISE OIL NORWEGIAN A/S	1.042000	%
				ESSO EXPL. & PROD. NORWAY A/S	10.000000	%
				MOBIL DEVELOPMENT NORWAY A.S.	15.000000	%
				NORSKE CONOCO A/S	11.042000	%
				SAGA PETROLEUM A.S.	1.875000	%
038	75/04/01 11/04/01	15/12	O	DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
		15/12		SAGA PETROLEUM A.S.	50.000000	%
040	75/04/01 11/04/01	29/9		DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
		30/7		ELF PETROLEUM NORGE A/S.	28.800000	%
		30/7	O	NORSK HYDRO PRODUKSJON A.S	6.800000	%
				TOTAL NORGE A.S	14.400000	%

PROD. LIC.	AWARDED EXPIRES	BLOCKS		LICENSEES (O = operator)	SHARES	
043	76/08/06	29/6		DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
	12/08/06	30/4	O	TOTAL NORGE A.S	50.000000	%
044	76/08/27	1/9	O	DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
	12/08/27			NORSK AGIP A/S	9.130000	%
				NORSKE FINA A/S	15.000000	%
				PHILLIPS PETROLEUM NORSK A/S	25.870000	%
046	76/12/03	15/8	O	DEN NORSKE STATS OLJESELSKAP A.S	49.600000	%
	14/09/03	15/8		ELF PETROLEUM NORGE A/S.	9.000000	%
		15/9		ESSO EXPL. & PROD. NORWAY A/S	30.400000	%
				NORSK HYDRO PRODUKSJON A.S	10.000000	%
				TOTAL NORGE A.S	1.000000	%
048	77/02/18	15/5		BP PETROLEUM DEV. OF NORWAY AS	10.900000	%
	13/02/18			DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
				ELF PETROLEUM NORGE A/S.	21.800000	%
			O	NORSK HYDRO PRODUKSJON A.S	17.300000	%
050	78/06/16	34/10	O	DEN NORSKE STATS OLJESELSKAP A.S	85.000000	%
	16/06/30			NORSK HYDRO PRODUKSJON A.S	9.000000	%
				SAGA PETROLEUM A.S.	6.000000	%
051	79/04/06	30/2	O	DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
	15/04/06			NORSKE CONOCO A/S	25.000000	%
				TOTAL NORGE A.S	25.000000	%
052	79/04/06	30/3		DEMINEX (NORGE) A/S	11.250000	%
	15/04/06	30/3	O	DEN NORSKE STATS OLJESELSKAP A.S	55.000000	%
				NORSK HYDRO PRODUKSJON A.S	9.000000	%
				NORSKE DEMINEX A/S	2.250000	%
				SVENSKA PETROLEUM EXPLORATION A/S	4.500000	%
				TOTAL NORGE A.S	18.000000	%
053	79/04/06	30/6		DEN NORSKE STATS OLJESELSKAP A.S	59.400000	%
	17/04/06	30/6		ELF PETROLEUM NORGE A/S.	9.333000	%
				MOBIL DEVELOPMENT NORWAY A.S.	7.000000	%
			O	NORSK HYDRO PRODUKSJON A.S	12.250000	%
				SAGA PETROLEUM A.S.	7.350000	%
				TOTAL NORGE A.S	4.667000	%
054	79/04/06	31/2	O	A/S NORSKE SHELL	25.900000	%
	30/09/01			DEN NORSKE STATS OLJESELSKAP A.S	58.800000	%
				ELF PETROLEUM NORGE A/S.	3.105000	%
				NORSK HYDRO PRODUKSJON A.S	4.900000	%
				NORSKE CONOCO A/S	5.190520	%
				TOTAL NORGE A.S	2.104480	%
055	79/04/06	31/4		DEN NORSKE STATS OLJESELSKAP A.S	46.000000	%
	17/04/06			ESSO EXPL. & PROD. NORWAY A/S	17.600000	%
				NESTE PETROLEUM A/S	13.200000	%
			O	NORSK HYDRO PRODUKSJON A.S	23.200000	%
057	79/04/06	34/4		AMERADA HESS NORGE A/S	4.900000	%
	15/04/06			DEMINEX (NORGE) A/S	24.500000	%
				DEN NORSKE STATS OLJESELSKAP A.S	41.400000	%
				ENTERPRISE OIL NORWEGIAN A/S	4.900000	%
				IDEMITSU PETROLEUM NORGE A.S.	9.600000	%
			O	SAGA PETROLEUM A.S.	14.700000	%
062	81/03/27	6507/11		DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
	21/03/27			NESTE PETROLEUM A/S	10.000000	%
				NORSK HYDRO PRODUKSJON A.S	5.000000	%
			O	SAGA PETROLEUM A.S.	10.000000	%
				TOTAL NORGE A.S	25.000000	%

PROD. LIC.	AWARDED EXPIRES	BLOCKS		LICENSEES (O = operator)	SHARES	
064	81/03/27	7120/8	O	DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
	17/03/27			ELF PETROLEUM NORGE A/S.	5.000000	%
				ESSO EXPL. & PROD. NORWAY A/S	25.000000	%
				NORSK HYDRO PRODUKSJON A.S	15.000000	%
				PHILLIPS PETROLEUM NORSK A/S	5.000000	%
065	81/08/21	1/3		A/S NORSKE SHELL	15.000000	%
	22/01/01	1/3		BP PETROLEUM DEV. OF NORWAY AS	8.333000	%
				DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
			O	ELF PETROLEUM NORGE A/S.	16.667000	%
				ENTERPRISE OIL NORWEGIAN A/S	10.000000	%
066	81/08/21	2/2		DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
	20/01/01		O	SAGA PETROLEUM A.S.	50.000000	%
067	81/08/21	2/5		DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
	18/01/01		O	NORSK AGIP A/S	40.000000	%
				PHILLIPS PETROLEU NORSK A/S	10.000000	%
069	81/08/21	7/8		DEMINEX (NORGE) A/S	5.000000	%
	18/01/01			DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
				DNO OLJE A/S	5.000000	%
				NORSK HYDRO PRODUKSJON A.S	15.000000	%
			O	NORSKE CONOCO A/S	25.000000	%
070	81/08/21	7/11		AMOCO NORWAY OIL COMPANY	14.700000	%
	18/01/01	7/11		DEN NORSKE STATS OLJESELSKAP A.S	51.000000	%
			O	NORSK HYDRO PRODUKSJON A.S	24.500000	%
				SAGA PETROLEUM A.S.	9.800000	%
072	81/08/21	16/7		DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
	18/01/01		O	ESSO EXPL. & PROD. NORWAY A/S	40.000000	%
				NORSK HYDRO PRODUKSJON A.S	10.000000	%
073	82/04/23	6407/1	O	DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
	18/04/23			NORSK HYDRO PRODUKSJON A.S	16.667000	%
				TOTAL NORGE A.S	33.333000	%
074	82/04/23	6407/2		DEMINEX (NORGE) A/S	10.000000	%
	18/04/23			DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
				NESTE PETROLEUM A/S	15.000000	%
				NORSK AGIP A/S	15.000000	%
			O	SAGA PETROLEUM A.S.	10.000000	%
077	82/04/23	7120/7	O	DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
	18/04/23			NORSK HYDRO PRODUKSJON A.S	15.000000	%
				PHILLIPS PETROLEUM NORSK A/S	10.000000	%
				SAGA PETROLEUM A.S.	5.000000	%
				TEXACO EXPLORATION NORWAY A/S	10.000000	%
				TOTAL NORGE A.S	10.000000	%
078	82/04/23	7120/9		DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
	18/04/23			ELF PETROLEUM NORGE A/S.	15.000000	%
			O	NORSK HYDRO PRODUKSJON A.S	25.000000	%
				TOTAL NORGE A.S	10.000000	%
079	82/08/20	30/9		DEN NORSKE STATS OLJESELSKAP A.S	73.500000	%
	18/08/20		O	NORSK HYDRO PRODUKSJON A.S	16.000000	%
				SAGA PETROLEUM A.S.	10.500000	%
085	83/07/08	31/3	O	DEN NORSKE STATS OLJESELSKAP A.S	82.000000	%
	30/09/01	31/5		ELF PETROLEUM NORGE A/S.	2.000000	%
		31/6	O	NORSK HYDRO PRODUKSJON A.S	9.000000	%
			O	SAGA PETROLEUM A.S.	6.000000	%
				TOTAL NORGE A.S	1.000000	%

PROD. LIC.	AWARDED EXPIRES	BLOCKS		LICENSEES (O = operator)	SHARES
085 B	92/09/11	31/9	O	DEN NORSKE STATS OLJESELSKAP A.S	82.000000 %
	95/09/11	32/4		ELF PETROLEUM NORGE A/S.	2.000000 %
			O	NORSK HYDRO PRODUKSJON A.S	9.000000 %
			O	SAGA PETROLEUM A.S.	6.000000 %
				TOTAL NORGE A.S	1.000000 %
086	84/03/09	6/3		AMERADA HESS NORGE A/S	10.000000 %
	20/03/09		O	DEN NORSKE STATS OLJESELSKAP A.S	50.000000 %
				NORSK HYDRO PRODUKSJON A.S	10.000000 %
				NORSKE CONOCO A/S	30.000000 %
088	84/03/09	24/6		DEN NORSKE STATS OLJESELSKAP A.S	50.000000 %
	22/03/09		O	TOTAL NORGE A.S	50.000000 %
089	84/03/09	34/7		DEMINEX (NORGE) A/S	2.800000 %
	24/03/09			DEN NORSKE STAT OLJESELSKAP A.S	55.400000 %
				DNO OLJE A/S	0.700000 %
				ELF PETROLEUM NORGE A/S.	5.600000 %
				ESSO EXPL. & PROD. NORWAY A/S	10.500000 %
				IDEMITSU PETROLEUM NORGE A.S.	9.600000 %
				NORSK HYDRO PRODUKSJON A.S	8.400000 %
			O	SAGA PETROLEUM A.S.	7.000000 %
090	84/03/09	35/11		DEN NORSKE STATS OLJESELSKAP A.S	50.000000 %
	24/02/09			MOBIL DEVELOPMENT NORWAY A.S.	40.000000 %
				NORSK HYDRO PRODUKSJON A.S	10.000000 %
091	84/03/09	6406/3	O	DEN NORSKE STATS OLJESELSKAP A.S	50.000000 %
	20/03/09			MOBIL DEVELOPMENT NORWAY A.S.	45.000000 %
				SAGA PETROLEUM A.S.	5.000000 %
092	84/03/09	6407/6		BRITOIL NORGE A/S	2.000000 %
	20/03/09		O	DEN NORSKE STATS OLJESELSKAP A.S	50.000000 %
				DNO OLJE A/S	8.000000 %
				MOBIL DEVELOPMENT NORWAY A.S.	40.000000 %
093	84/03/09	6407/9	O	A/S NORSKE SHELL	21.000000 %
	24/03/09			BP PETROLEUM DEV. OF NORWAY AS	14.000000 %
				DEN NORSKE STATS OLJESELSKAP A.S	65.000000 %
094	84/03/09	6506/12	O	DEN NORSKE STATS OLJESELSKAP A.S	51.000000 %
	24/03/09			MOBIL DEVELOPMENT NORWAY A.S.	14.700000 %
				NESTE PETROLEUM A/S	9.800000 %
				NORSK AGIP A/S	9.800000 %
				NORSK HYDRO PRODUKSJON A.S	4.900000 %
				TOTAL NORGE A.S	9.800000 %
095	84/03/09	6507/7		DEN NORSKE STATS OLJESELSKAP A.S	75.000000 %
	24/03/09			NESTE PETROLEUM A/S	5.000000 %
			O	NORSKE CONOCO A/S	20.000000 %
097	84/03/09	7120/6		AMERADA HESS NORGE A/S	11.250000 %
	20/03/09	7120/6		DEMINEX (NORGE) A/S	10.000000 %
				DEN NORSKE STATS OLJESELSKAP A.S	56.250000 %
			O	NORSK HYDRO PRODUKSJON A.S	22.500000 %
099	84/03/09	7121/4	O	DEN NORSKE STATS OLJESELSKAP A.S	50.000000 %
	20/03/09			NORSK HYDRO PRODUKSJON A.S	12.500000 %
				TOTAL NORGE A.S	37.500000 %
100	84/03/09	7121/7		DEMINEX (NORGE) A/S	4.000000 %
	20/03/09		O	DEN NORSKE STATS OLJESELSKAP A.S	50.000000 %
				DNO OLJE A/S	1.000000 %
				ELF PETROLEUM NORGE A/S.	35.000000 %
				SVENSKA PETROLEUM EXPLORATION A/S	10.000000 %

PROD. LIC.	AWARDED EXPIRES	BLOCKS		LICENSEES (O = operator)	SHARES	
101	85/03/01	16/10		DEMINEX (NORGE) A/S	5.000000	%
	22/03/01			DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
			O	NORSK AGIP A/S	45.000000	%
102	85/03/01	25/5		DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
	95/03/01		O	ELF PETROLEUM NORGE A/S.	30.000000	%
				TOTAL NORGE A.S	20.000000	%
103	85/03/01	25/7		AMERADA HESS NORGE A/S	10.000000	%
	21/03/01			BRITOIL NORGE A/S	10.000000	%
				DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
			0	NORSKE CONOCO A/S	30.000000	%
104	85/03/01	30/9		DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
	95/03/01			DNO OLJE A/S	5.000000	%
				NORSK AGIP A/S	5.000000	%
			O	NORSK HYDRO PRODUKSJON A.S	30.000000	%
				NORSKE CONOCO A/S	5.000000	%
				SAGA PETROLEUM A.S.	5.000000	%
107	85/03/01	6407/7		NORSK AGIP A/S	10.000000	%
	21/03/01			DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
				A/S NORSKE SHELL	20.000000	%
			O	NORSK HYDRO PRODUKSJON A.S	20.000000	%
108	85/03/01	7120/1	O	A/S NORSKE SHELL	40.000000	%
	22/03/01			DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
				ELF PETROLEUM NORGE A/S.	5.000000	%
				NORSK HYDRO PRODUKSJON A.S	5.000000	%
109	85/03/01	7120/2		DEN NORSKE STATS OLJESELSKAP A.S	55.000000	%
	22/03/01	7120/3		MOBIL DEVELOPMENT NORWAY A.S.	15.000000	%
			O	NORSK HYDRO PRODUKSJON A.S	20.000000	%
				NORSKE CONOCO A/S	10.000000	%
110	85/03/01	7120/5		AMERADA HESS NORGE A/S	8.330000	%
	21/03/01	7121/5	O	DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
	7121/5			ELF PETROLEUM NORGE A/S.	20.000000	%
				NORSK HYDRO PRODUKSJON A.S	16.670000	%
				NORSKE FINA A/S	5.000000	%
112	85/07/26	25/2		DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
	21/07/26		O	ELF PETROLEUM NORGE A/S.	21.800000	%
				NORSK HYDRO PRODUKSJON A.S	17.300000	%
				TOTAL NORGE A.S	10.900000	%
113	85/08/23	2/12	O	AMERADA HESS NORGE A/S	50.000000	%
	21/08/23			DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
114	85/08/23	9/2		DEMINEX (NORGE) A/S	10.000000	%
	22/08/23		O	DEN NORSKE STATS OLJESELSKAP A.S	65.000000	%
				PETROSAGA AS	10.000000	%
				SAGA PETROLEUM A.S.	15.000000	%
115	85/08/23	9/3		DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
	21/08/23			DNO OLJE A/S	5.000000	%
				NORSKE CONOCO A/S	15.000000	%
			O	TOTAL NORGE A.S	30.000000	%
116	85/08/23	15/12		AMERADA HESS NORGE A/S	10.000000	%
	22/08/23	15/12	O	DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
				NORSK HYDRO PRODUKSJON A.S	10.000000	%
				NORSKE CONOCO A/S	30.000000	%

PROD. LIC.	AWARDED EXPIRES	BLOCKS		LICENSEES (O = operator)	SHARES
117	85/08/23	25/6		DEN NORSKE STATS OLJESELSKAP A.S	50.000000 %
	22/08/23			AMERADA HESS NORGE A/S	10.000000 %
				NORSKE FINA A/S	15.000000 %
			O	SAGA PETROLEUM A.S.	25.000000 %
120	85/08/23	34/7		DEN NORSKE STATS OLJESELSKAP A.S	50.000000 %
	23/08/23	34/8		ELF PETROLEUM NORGE A/S.	13.000000 %
			O	NORSK HYDRO PRODUKSJON A.S	18.000000 %
				NORSKE CONOCO A/S	13.000000 %
				SAGA PETROLEUM A.S.	6.000000 %
121	86/02/28	6407/5		BRITOIL NORGE A/S	2.000000 %
	22/02/28		O	DEN NORSKE STATS OLJESELSKAP A.S	50.000000 %
				DNO OLJE A/S	8.000000 %
				MOBIL DEVELOPMENT NORWAY A.S.	20.000000 %
				NORSK HYDRO PRODUKSJON A.S	20.000000 %
122	86/02/28	6507/2		AMERADA HESS NORGE A/S	10.000000 %
	25/02/28			DEN NORSKE STATS OLJESELSKAP A.S	50.000000 %
				ESSO EXPL. & PROD. NORWAY A/S	10.000000 %
				MOBIL DEVELOPMENT NORWAY A.S.	10.000000 %
			O	NORSK HYDRO PRODUKSJON A.S	20.000000 %
124	86/02/28	6507/8	O	DEN NORSKE STATS OLJESELSKAP A.S	60.000000 %
	25/02/28			DNO OLJE A/S	5.000000 %
				NESTE PETROLEUM A/S	10.000000 %
				NORSKE CONOCO A/S	25.000000 %
127	86/02/28	6607/12		DEN NORSKE STATS OLJESELSKAP A.S	50.000000 %
	23/02/28		O	ELF PETROLEUM NORGE A/S.	35.000000 %
				NORSKE FINA A/S	15.000000 %
128	86/02/28	6608/10	O	DEN NORSKE STATS OLJESELSKAP A.S	50.000000 %
	96/02/28	6608/11		ENTERPRISE OIL NORWEGIAN A/S	10.000000 %
				NORSK AGIP A/S	10.000000 %
				NORSK HYDRO PRODUKSJON A.S	15.000000 %
				SAGA PETROLEUM A.S.	15.000000 %
132	87/04/10	6407/10		NORSK AGIP A/S	10.000000 %
	23/04/10			A/S NORSKE SHELL	10.000000 %
				DEMINEX (NORGE) A/S	10.000000 %
				DEN NORSKE STATS OLJESELSKAP A.S	50.000000 %
			O	NORSK HYDRO PRODUKSJON A.S	20.000000 %
134	87/04/10	6506/11	O	DEN NORSKE STATS OLJESELSKAP A.S	50.000000 %
	95/04/10			ENTERPRISE OIL NORWEGIAN A/S	10.000000 %
				NORSK AGIP A/S	30.000000 %
				TOTAL NORGE A.S	10.000000 %
135	87/04/10	7124/3		AMERADA HESS NORGE A/S	35.000000 %
	23/04/10	7124/3		DEN NORSKE STATS OLJESELSKAP A.S	50.000000 %
		7125/1	O	SAGA PETROLEUM A.S.	15.000000 %
		7125/1			
138	87/05/29	7122/6		AMERADA HESS NORGE A/S	8.000000 %
	23/05/29			DEN NORSKE STATS OLJESELSKAP A.S	50.000000 %
				NORSK HYDRO PRODUKSJON A.S	10.000000 %
			O	TOTAL NORGE A.S	32.000000 %
142	87/05/29	29/9		DEN NORSKE STATS OLJESELSKAP A.S	50.000000 %
	95/05/29	30/7	O	ELF PETROLEUM NORGE A/S.	40.000000 %
		30/10		SAGA PETROLEUM A.S.	10.000000 %

PROD. LIC.	AWARDED EXPIRES	BLOCKS		LICENSEES (O = operator)	SHARES	
143	88/07/08	1/2		DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
	95/07/08			ENTERPRISE OIL NORWEGIAN A/S	15.000000	%
			O	PHILLIPS PETROLEUM NORSK A/S	25.000000	%
				AMOCO NORWAY A/S	10.000000	%
144	88/07/08	1/5		BP PETROLEUM DEV. OF NORWAY AS	25.000000	%
	95/07/08	1/6		DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
		1/6	O	NORSKE CONOCO A/S	25.000000	%
145	88/07/08	1/9	O	BP PETROLEUM DEV. OF NORWAY AS	30.000000	%
	24/07/08	2/7		DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
				NORSK AGIP A/S	10.000000	%
				NORSK HYDRO PRODUKSJON A.S	10.000000	%
146	88/07/08	2/4		AMERADA HESS NORGE A/S	10.000000	%
	95/07/08			DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
				ELF PETROLEUM NORGE A/S.	20.000000	%
			O	SAGA PETROLEUM A.S.	20.000000	%
147	88/07/08	3/7	O	A/S NORSKE SHELL	50.000000	%
	95/07/08	3/8		DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
148	88/07/08	7/4		AMERADA HESS NORGE A/S	25.000000	%
	24/07/08	7/7		AMOCO NORWAY A/S	10.000000	%
			O	DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
				TOTAL NORGE A.S	15.000000	%
150	88/07/08	24/9		DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
	24/07/08			ENTERPRISE OIL NORWEGIAN A/S	30.000000	%
			O	NORSKE FINA A/S	10.000000	%
				SAGA PETROLEUM A.S.	10.000000	%
152	88/07/08	33/12		BP PETROLEUM DEV. OF NORWAY AS	30.000000	%
	95/07/08		O	DEN NORSKE MSTATS OLJESELSKAP A.S	50.000000	%
				IDEMITSU PETROLEUM NORGE A.S.	10.000000	%
				SAGA PETROLEUM A.S.	10.000000	%
153	88/07/08	35/9		A/S NORSKE SHELL	12.000000	%
	95/07/08	36/7		DEMINEX (NORGE)A/S	8.000000	%
				DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
			O	NORSK HYDRO PRODUKSJON A.S	20.000000	%
				PETROSAGA AS	10.000000	%
154	89/03/03	6205/3		AMOCO NORWAY A/S	10.000000	%
	95/03/03	6305/12		DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
				ELF PETROLEUM NORGE A/S.	10.000000	%
			O	NORSK HYDRO PRODUKSJON A.S	30.000000	%
156	89/03/03	6406/11		AMERADA HESS NORGE A/S	10.000000	%
	95/03/03			DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
				MOBIL DEVELOPMENT NORWAY A.S.	20.000000	%
			O	SAGA PETROLEUM A.S.	20.000000	%
157	89/03/03	6406/12	O	DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
	95/03/03			DNO OLJE A/S	15.000000	%
				NORSKE CONOCO A/S	10.000000	%
				PETROSAGA AS	10.000000	%
				PHILLIPS PETROLEUM NORSK A/S	15.000000	%
158	89/03/03	6407/8	O	BP PETROLEU DEV. OF NORWAY AS	36.000000	%
	96/03/03			BRITOIL NORGE A/S	4.000000	%
				DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
				TOTAL NORGE A.S	10.000000	%

PROD. LIC.	AWARDED EXPIRES	BLOCKS		LICENSEES (O = operator)	SHARES	
159	89/03/03	6507/3	O	DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
	96/03/03			NORSK HYDRO PRODUKSJON A.S	20.000000	%
				SAGA PETROLEUM A.S.	10.000000	%
				TOTAL NORGE A.S	20.000000	%
163	91/03/01	2/10		AMERADA HESS NORGE A/S	10.000000	%
	97/03/01	2/10		DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
				NORSK AGIP A/S	10.000000	%
			O	SAGA PETROLEUM A.S.	30.000000	%
164	91/03/01	2/1	O	BP PETROLEUM DEV. OF NORWAY AS	30.000000	%
	97/03/01	7/12		DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
		7/12		NORSKE CONOCO A/S	10.000000	%
		8/10		SVENSKA PETROLEUM EXPLORATION A/S	10.000000	%
166	91/03/01	15/6		A/S NORSKE SHELL	10.000000	%
	97/03/01		O	DEMINEX (NORGE) A/S	30.000000	%
				DEN NORSKE STATS OLJESELSKAP A.S	60.000000	%
167	91/03/01	16/1		AMOCO NORWAY A/S	10.000000	%
	97/03/01		O	DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
				NORSK HYDRO PRODUKSJON A.S	30.000000	%
				PHILLIPS PETROLEUM NORSK A/S	10.000000	%
168	91/03/01	25/10		AMERADA HESS NORGE A/S	20.000000	%
	96/03/01			BP PETROLEUM DEV. OF NORWAY AS	15.000000	%
			O	DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
				NORSKE FINA A/S	15.000000	%
169	91/03/01	25/8		DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
	97/03/01	25/11		ESSO EXPL. & PROD. NORWAY A/S	10.000000	%
			O	NORSK HYDRO PRODUKSJON A.S	30.000000	%
				NORSKE CONOCO A/S	10.000000	%
170	91/03/01	30/6		DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
	25/03/01		O	NORSK HYDRO PRODUKSJON A.S	30.000000	%
				TOTAL NORGE A.S	20.000000	%
171	91/03/01	30/12		DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
	97/03/01		O	NORSK HYDRO PRODUKSJON A.S	30.000000	%
				SAGA PETROLEUM A.S.	20.000000	%
172	91/03/01	33/9		AMERADA HESS NORGE A/S	10.000000	%
	25/03/01	33/9		DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
			O	MOBIL DEVELOPMENT NORWAY A.S.	25.000000	%
				NORSKE CONOCO A/S	15.000000	%
173	91/03/01	35/10	O	DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
	97/03/01			ELF PETROLEUM NORGE A/S.	15.000000	%
				MOBIL DEVELOPMENT NORWAY A.S.	20.000000	%
				NORSK HYDRO PRODUKSJON A.S	15.000000	%
174	91/03/01	35/12		DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
	96/03/01			ESSO EXPL. & PROD. NORWAY A/S	10.000000	%
				MOBIL DEVELOPMENT NORWAY A.S.	10.000000	%
			O	SAGA PETROLEUM A.S.	30.000000	%
175	91/03/01	6204/10	O	DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
	97/03/01	6204/11		ENTERPRISE OIL NORWEGIAN A/S	10.000000	%
				NESTE PETROLEUM A/S	10.000000	%
				PHILLIPS PETROLEUM NORSK A/S	20.000000	%
				SAGA PETROLEUM A.S.	10.000000	%
176	91/03/01	6407/11	O	A/S NORSKE SHELL	30.000000	%
	97/03/01	6407/12		DEN NORSKE STATS OLJESELSKAP A.S	50.000000	%
				NORSK HYDRO PRODUKSJON A.S	10.000000	%
				NORSKE FINA A/S	10.000000	%

PROD. LIC.	AWARDED EXPIRES	BLOCKS		LICENSEES (O = operator)	SHARES
177	91/03/01	6610/2		BP PETROLEUM DEV. OF NORWAY AS	30.000000 %
	97/03/01	6610/3	O	DEN NORSKE STATS OLJESELSKAP A.S	50.000000 %
				SAGA PETROLEUM A.S.	20.000000 %
180	91/03/01	7128/4		BP PETROLEUM DEV. OF NORWAY AS	20.000000 %
	97/03/01		O	DEN NORSKE STATS OLJESELSKAP A.S	50.000000 %
				NORSK AGIP A/S	20.000000 %
				TOTAL NORGE A.S	10.000000 %
181	91/03/01	7128/6		AMOCO NORWAY A/S	15.000000 %
	97/03/01	7128/9		DEN NORSKE STATS OLJESELSKAP A.S	50.000000 %
		7129/4		ELF PETROLEUM NORGE A/S.	10.000000 %
			O	NORSKE CONOCO A/S	25.000000 %
182	91/03/01	7219/7		DEN NORSKE STATS OLJESELSKAP A.S	50.000000 %
	97/03/01	7219/8		ENTERPRISE OIL NORWEGIAN A/S	20.000000 %
			O	SAGA PETROLEUM A.S.	30.000000 %
183	91/03/01	7229/11	O	A/S NORSKE SHELL	30.000000 %
	97/03/01	7229/12		AMERADA HESS NORGE A/S	10.000000 %
				AMOCO NORWAY A/S	10.000000 %
				DEN NORSKE STATS OLJESELSKAP A.S	50.000000 %
185	91/09/13	31/7		DEN NORSKE STATS OLJESELSKAP A.S	46.000000 %
	95/04/06			ESSO EXPL. & PROD. NORWAY A/S	17.600000 %
				NESTE PETROLEUM A/S	13.200000 %
			O	NORSK HYDRO PRODUKSJON A.S	23.200000 %
186	93/09/10	7/10	O	AMOCO NORWAY A/S	25.000000 %
	99/09/10	7/11		DEN NORSKE STATS OLJESELSKAP A.S	50.000000 %
				SAGA PETROLEUM A.S.	10.000000 %
				TOTAL NORGE A.S	15.000000 %
187	93/09/10	15/2	O	AMOCO NORWAY A/S	25.000000 %
	99/09/10	15/3		DEN NORSKE STATS OLJESELSKAP A.S	55.000000 %
		15/3		NORSK HYDRO PRODUKSJON A.S	20.000000 %
188	93/09/10	17/3		AMERADA HESS NORGE A/S	15.000000 %
	99/09/10			DEN NORSKE STATS OLJESELSKAP A.S	40.000000 %
			O	ELF PETROLEUM NORGE A/S.	25.000000 %
				NORSK AGIP A/S	20.000000 %
189	93/09/10	25/8	O	AMERADA HESS NORGE A/S	20.000000 %
	99/09/10	25/9		DEN NORSKE STATS OLJESELSKAP A.S	55.000000 %
				PHILLIPS PETROLEUM NORSK A/S	15.000000 %
				SAGA PETROLEUM A.S.	10.000000 %
190	93/09/10	30/8		DEN NORSKE STATS OLJESELSKAP A.S	60.000000 %
	99/09/10			ENTERPRISE OIL NORWEGIAN A/S	15.000000 %
			O	NORSK HYDRO PRODUKSJON A.S	25.000000 %
191	93/09/10	31/1		DEN NORSKE STATS OLJESELSKAP A.S	60.000000 %
	99/09/10	31/2		MOBIL DEVELOPMENT NORWAY A.S.	10.000000 %
		31/4		NESTE PETROLEUM A/S	10.000000 %
		31/5	O	NORSK HYDRO PRODUKSJON A.S	20.000000 %
192	93/09/10	34/5		DEN NORSKE STATS OLJESELSKAP A.S	55.000000 %
	99/09/10		O	MOBIL DEVELOPMENT NORWAY A.S.	25.000000 %
				NORSKE CONOCO A/S	20.000000 %
193	93/09/10	34/11		BP PETROLEUM DEV. OF NORWAY AS	15.000000 %
	99/09/10		O	DEN NORSKE STATS OLJESELSKAP A.S	65.000000 %
				NORSK HYDRO PRODUKSJON A.S	20.000000 %

PROD. LIC.	AWARDED EXPIRES	BLOCKS		LICENSEES (O = operator)	SHARES
194	93/09/10	35/4		DEN NORSKE STATS OLJESELSKAP A.S	55.000000 %
	99/09/10	35/5		ELF PETROLEUM NORGE A/S.	10.000000 %
			O	NORSK HYDRO PRODUKSJON A.S	25.000000 %
				SAGA PETROLEUM A.S.	10.000000 %
195	93/09/10	35/8	O	BP PETROLEUM DEV. OF NORWAY AS	25.000000 %
	99/09/10			DEN NORSKE STATS OLJESELSKAP A.S	45.000000 %
				NORSK HYDRO PRODUKSJON A.S	15.000000 %
				NORSKE CONOCO A/S	15.000000 %
196	93/09/10	35/6	O	BP PETROLEUM DEV. OF NORWAY AS	25.000000 %
	99/09/10	36/4		DEN NORSKE STATS OLJESELSKAP A.S	45.000000 %
				IDEMITSU PETROLEUM NORGE A.S.	10.000000 %
				NORSK HYDRO PRODUKSJON A.S	20.000000 %
197	93/09/10	6306/2		AMERADA HESS NORGE A/S	15.000000 %
	99/09/10	6306/5		AMOCO NORWAY A/S	15.000000 %
				DEN NORSKE STATS OLJESELSKAP A.S	45.000000 %
			O	NORSKE CONOCO A/S	25.000000 %
198	93/09/10	6306/6	O	DEN NORSKE STATS OLJESELSKAP A.S	65.000000 %
	99/09/10			ELF PETROLEUM NORGE A/S.	15.000000 %
				NORSK HYDRO PRODUKSJON A.S	20.000000 %
199	93/09/10	6406/2		DEN NORSKE STATS OLJESELSKAP A.S	60.000000 %
	99/09/10			MOBIL DEVELOPMENT NORWAY A.S.	15.000000 %
			O	SAGA PETROLEUM A.S.	25.000000 %
200	93/09/10	6608/7	O	DEN NORSKE STATS OLJESELSKAP A.S	65.000000 %
	99/09/10	6608/8		NESTE PETROLEUM A/S	15.000000 %
				PHILLIPS PETROLEUM NORSK A/S	20.000000 %
201	93/09/10	7018/3		DEN NORSKE STATS OLJESELSKAP A.S	40.000000 %
	99/09/10	7019/1		ENTERPRISE OIL NORWEGIAN A/S	20.000000 %
				NESTE PETROLEUM A/S	10.000000 %
			O	NORSK AGIP A/S	30.000000 %
202	93/09/10	7227/11		AMERADA HESS NORGE A/S	25.000000 %
	99/09/10	7227/12	O	DEN NORSKE STATS OLJESELSKAP A.S	55.000000 %
		7228/7		SAGA PETROLEUM A.S.	20.000000 %
		7228/10			

7.8 NORWEGIAN PETROLEUM DIRECTORATE PUBLICATIONS IN 1994

ACTS, REGULATIONS AND GUIDELINES

- Acts, regulations and provisions for the petroleum activities in 1994.
  An updated compendium of the statutory framework of acts, regulations and guidelines applicable to the Norwegian continental shelf. Issued 1 January 1994.
- Regulations relating to drilling and well activities and geological
  data collection in the petroleum activities, with guidelines
- Regulations relating to lifting appliances and lifting gear in the petroleum activities, with guidelines
- Regulations relating to loadbearing structures in the petroleum activities, with guidelines
- Regulations to Act relating to petroleum activities
- Act relating to petroleum activities
- Act relating to worker protection and working environment etc.
- Regulations relating to extension of the scope of various regulations on exploration and exploration drilling in the petroleum activities on the Norwegian continental shelf
- Regulations relating to the collection of environmental data etc., with guidelines
- Regulations relating to emergency preparedness in the petroleum activities, with guidelines
- Regulations relating to process and auxiliary facilities in the petroleum activities, with guidelines
- Regulations relating to safety and communication systems on installations in the petroleum activities, with guidelines
- Regulations relating to explosion and fire protection of installations in the petroleum activities, with guidelines
- Delimitation interfaces related to the Norwegian continental shelf legislation

STUDIES - REPORTS

- Kroppens væskebalanse under hyperbare forhold (Physiological Fluid balance in hyperbaric conditions). *Norwegian text.*
- Rapport fra seminaret «Erfaringer med beredskapsforskriften» (Report from the seminar «Experience gained with the Emergency Preparedness Regulations. *Norwegian text.*

OTHER PUBLICATIONS

- List of publications from the Norwegian Petroleum Directorate
- Well Data Summary Sheets, Vol. 19
- NPD - Contribution No. 38. En stratigrafisk undersøkelse av øvre del av brønn 7316/5-1 (Bjørnøya Vest). (A stratigraphic examination of the upper part of well 7316/5-1 (Bjørnøya Vest). *Norwegian text.*
- The Norwegian Petroleum Directorate Annual Report 1993.
- Licenses, Areas, Area-coordinates, Exploration Wells.
- Borehole list.
- Borehole list - Exploration Drilling
- Opprydding av havbunnen i Nordsjøen 1993. (Seabed clearance in the North Sea 1993). *Norwegian text.*
- Opprydding av havbunnen i Nordsjøen 1994. (Seabed clearance in the North Sea 1994). *Norwegian text.*
- Development Wells
- Newsletter
- Safety and working environment legislation applicable to the petroleum activities
- The regulation of safety and working environment on the continental shelf
- Rapport om standard dekompresjonstabeller for overflateorientert dykking (Report on standard decompression tables for surface oriented diving). *Norwegian text.*
- Report from the Dive data base - DSYS 1993.
- Well Data Published by NPD.
- Securing Petroleum Supplies in Eastern Africa.

7.9 ORGANISATION CHART