Norwegian Petroleum Directorate

ANNUAL REPORT 1988

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Unofficial translation

«The objectives of the Norwegian Petroleum Directorate are actively to contribute to a sound administration of the Norwegian petroleum resources through a balanced evaluation of the natural, safety-related, technological and economic aspects of the activity within an overall framework.»

Contents

Report of The Board of Directors

In 1988 the Norwegian Petroleum Directorate could look back on fifteen years' activity. The working day began on 1 April 1973 in Stavanger, and since then the petroleum activity in Norway has entered upon a more mature phase. Even now, however, unexpected and dramatic events show that the petroleum industry must display flexibility and adaptability.

The most dramatic event in 1988 was the tragic accident onboard the Piper Alpha installation in the British sector of the North Sea, in which 167 people lost their lives. The disaster shows how necessary it is to set and reach safety and environmental goals, as well as endeavour to satisfy demands for improved profitability and effectiveness.

The nature and extent of the Piper Alpha accident made it necessary for the Norwegian Petroleum Directorate to evaluate the immediate consequences the catastrophe may have for the activity and its safety on the Norwegian continental shelf. In this connection regular meetings were held between the Norwegian Petroleum Directorate, the operator companies and the labour organisations for exchange of information, which was something the accident revealed a great need for.

In the light of the accident the Norwegian Petroleum Directorate enjoined the operator companies for Norwegian oil and gas fields once more to go through the safety studies made in their time for the newest installations in the North Sea, and to let older platforms be subjected to the same safety assessments in the light inter alia of new regulations and operational experience. The Norwegian Petroleum Directorate has so far not found it necessary to take any steps over and above these.

The Piper Alpha catastrophe also caused a major and sometimes intense debate on Norwegian safety thinking and working environment development on the Shelf even though the safety on the Norwegian shelf has been consciously worked on and improved over the years.

The Board is of the opinion that this development, in which the Norwegian Petroleum Directorate as an active participant, must continue. There is reason to emphasise the comprehensive work done in the course of the year on modernisation of the safety rules. The objective is a further improvement of the working environment through emphasis on the operator's responsibility vis-à-vis the Working Environment Act. This includes the relationship to chemical health hazards.

A number of new preconditions for the activity on the Shelf will affect precisely the working environment in the coming years. 1988 saw the beginning of such a development, inter alia through reduction of manning levels in parts of the Ekofisk complex (drilling), a discussion that provoked vigorous participation from the employees.

The development of new, simpler, technology forced on us by lower oil prices will make great demands on innovation and safety planning within the standards laid down for the Norwegian continental shelf. In 1988 the oil industry has also moved the technological boundaries on the Shelf. This applies for example to the development of East Frigg and Tommeliten, the first subsea production systems in Norway. In 1988 the Norwegian Petroleum Directorate has considered the plans for development of the Hod field, which will be the first unmanned, remote-controlled wellhead platform on the Norwegian shelf.

The Norwegian Petroleum Directorate sees clearly that developments along these lines will be more and more marked, and within its area of responsibility it will contribute to finding solutions.

Also in other areas of the Shelf activity, developments in 1988 have contributed to reinforcing the perception that vital framework conditions can change dramatically. The price assumptions employed in the mid-Eighties have far from been realised. We may be facing a long period with uncertain prices.

The Norwegian Petroleum Directorate's perspective analysis for 1988, "Norwegian Petroleum Resources in a Historical and Global Perspective", has for the first time since the beginning of the oil activity in Norway in 1966 gone through the most important aspects of the industry and attempted to place Norway's resource basis and development potential in a global perspective.

Norway has proven petroleum resources for 28 years' oil production and 98 years' gas production at today's levels. It is this resource situation the Perspective Analysis places in a historical perspective. The aim has been to demonstrate that the growth of resources on the Norwegian shelf cannot proceed at the same tempo and the the same extent as hitherto.

Whereas the 1987 petroleum accounts showed that Norway took more oil out of the Shelf than was found in new deposits, the situation at the end of 1988 is the reverse – growth is greater than depletion. This is due particularly to the upwards adjustment of oil resources on fields in production, but new, albeit small, oil finds also contribute to these positive accounts.

No new gas finds have been made in 1988, but scaling-up of the existing resources in older fields mean that the gas accounts are also positive.

On the Norwegian shelf, therefore, we must be able to develop relatively demanding resources on a technically and economically sound basis. This does not, however, have to mean that Norway's competitive situation vis-à-vis other oil-producing countries outside OPEC has necessarily to develop negatively, even if production drilling in the last two years has failed to hit any jackpots. Three finds have been made, all in the North Sea. Exploration results off Mid-Norway have not been up to the expectation, and no new finds have been made in the Barents Sea either.

As in the previous licensing round, the philosophy of the 12th Round also reflects something of the resource situation in question. The 12th Round was divided into an A and a B phase. Phase A comprised 18 blocks or parts of blocks in the North Sea. Twenty-three companies applied, and in all 11 new production licences were awarded, of which four had Norwegian operators. Fina, which had not previously been an operator on the Norwegian shelf, was this time given an operatorship.

Most of the blocks allocated in the 12th Round phase A are near existing fields in production. One of the objectives is to prove new oil resources that will be commercially profitable to develop in connection with existing fields. In addition it is the objective to obtain an overview over possible resources extending over the boundary to other countries' continental shelves.

Phase B of the 12th Round comprises the areas north of Stad. Three blocks in Møre 1 were advertised, two on Haltenbanken and eight new key blocks divided between three areas in the Barents Sea. In addition, previously non-allocated blocks were advertised. All in all it was possible to apply for 106 blocks north of Stad. The application deadline was 15 November 1988 with allocation over New Year. Twenty-one companies applied.

Interest in Svalbard has been stable for the past year. In 1988 the Soviet company Trust Arktikugol began a new drilling in Vassdalen, while the Swedish company Polargas Prospektering finished off the hole begun at Haketangen in 1987. Minor quantities of gas were tested here.

For the Barents Sea an agreement has been made between Soviet and Norwegian authorities on co-operation on rescue services in the Barents Sea. Through the agreement has been established contact between Norwegian and Soviet rescue centres, which is expected to facilitate rescue work considerably.

The Petroleum Act has had a powerful coordination effect on the Norwegian Petroleum Directorate's tasks within resources, safety and working environment. The Board emphasises that the expertise, experience and inter-disciplinary insight represented by the Norwegian Petroleum Directorate should be retained and developed further so as to be able to meet constant fresh challenges on the Shelf.

Stavanger, 26 January 1989
Members of the Board of Directors
of the Norwegian Petroleum Directorate

Martin Buvik

Andreas Lønning *Per Sævik* *Liv Hatland*

Kåre D. Nielsen *Jan B. M. Strømme*

Odd Raustein *Anna Aabø*

Fredrik Hagemann
Director General

Bjørn Bratbak
Head of Branch
Secretary of the Board

1. The Directorate's tasks, board of directors and administration

1.1 THE DIRECTORATE'S TERMS OF REFERENCE

The objectives and tasks of the Norwegian Petroleum Directorate are provided for in special instructions. These were last amended on 29 March 1979. These tasks have subsequently been altered by delegrations,which follow directly from Acts and Regulations or by separate delegation decisions from superior authorities. The delegations apply to parts of:

a) The Petroleum Act of 23 March 1985 No. 11, with Regulations
b) The Working Environment Act of 9 February 1977 No. 4 with Regulations
c) Act for Protection against Tobacco Injuries of 9 March 1973 § 6, eighth subsection, plus Regulations laid down by Royal Decree 8 July 1988
d) Regulations of 29 March 1988 on safety for surveying and exploration drilling for petroleum deposits on Svalbard.
e) Regulations regarding scientific surveys of natural deposits on the Norwegian continental shelf etc of 31 January 1969.
f) Temporary regulations of 26 October 1979 on littering and pollution from the petroleum activity on the Norwegian continental shelf.

1.2 THE DIRECTORATE'S OBJECTIVES

On the basis inter alia of the terms of reference, the following objectives for the Directorate have been laid down:

"The objectives of the Norwegian Petroleum Directorate are actively to contribute to a sound administration of the Norwegian petroleum resources through a balanced evaluation of the natural, safety-related, technological and economic aspects of the activity within an overall framework."

1.3 THE BOARD OF DIRECTORS AND THE ADMINISTRATION

1.3.1 The Board of Directors

The composition of the Board in the report period was:

1. Mr Martin Buvik, County Governor, Tromsø (Chairperson)
2. Mr Andreas Lønning, Group Director, Oslo
3. Ms Bjørg Simonsen, Researcher, Mo i Rana
4. Ms Liv Hatland, Managing Director, Oslo
5. Mr Kåre D. Nielsen, Director, Oslo
6. Mr Ole Knapp, Secretary, Oslo
7. Mr Odd Raustein, Section Manager, Stavanger
8. Ms Anne-Lise Jensen, Principal Engineer, Stavanger

Deputies:

For1–4:
1. Mr Per Sævik, Mayor, Remøy
2. Ms Sylvi Enevold, Deputy County Council Chairman
3. Ms Marit Greve, Editor, Bærum

For 5:
Mr Halvor Ø Vaage, Managing Director, Stavanger

For 6:
Mr Jan Strømme, Oil Secretary, Oslo

For 7–8:
Ms Anna Aabø, Special Advisor, Stavanger
Mr Bjørn Kvant, Chief Archivist, Stavanger

Mr. Ole Knapp was released from his membership of the Board on 12 February 1988. From the same date Mr. Jan B.M. Strømme, Oil Secretary, took a seat on the Board and Mr. Bjørn Kolby, Attorney, Oslo, was appointed personal deputy.

On 19 February 1988 Ms. Bjørg Simonsen was appointed State Secretary in the Ministry of Transport and Communications. From the same date Mayor Per Sævik took a seat on the Board.

On 18 July 1988 Chief Engineer Anne-Lise Jensen resigned her post with the Norwegian Petroleum Directorate. From the same date Special Advisor Anna Aabø took a seat on the Board.

During the report period the Board held eight meetings. In May the Board was on a study trip to the Shell Group in the Netherlands, where among other things Shell's laboratory in Rijsviik was visited, as was the Groningen gas field. In October the Board visited the NPD's branch office in Harstad.

1.3.2 Organisation

The organisational changes that have taken place in recent years were formally concluded with a protocol made between the management and the staff organisations on 5 April 1988.

In practice it remains to appoint a head of section in the newly established Section for Informatics and Documents in the Administration Branch.

A cooperation agreement has been made between the NPD and NORAD for creation of a new administrative entity subordinate to the Directorate. This entity shall establish petroleum training for managers and key personnel associated with the petroleum sector in the developing countries. The cooperation agreement is temporary and runs from 1 January 1989 to the end of 1991. To begin with the new administrative entity will consist of two managers seconded from the NPD and Statoil and one secretarial post.

1.3.3 Personnel

At the end of the report period there were 335 authorised positions in the Directorate. The Norwegian Petroleum Directorate was given no new posts in 1988. In connection with a government research program for enhanced recovery (the SPOR project) directly under the auspices of the Ministry of Petroleum and Energy, a temporary four-year position has been set up to head the project. In addition there are three positions salaried by the Directorate for Development Aid (NORAD). At the end of 1988 the Directorate employed 336 persons, plus 13 on leave. Staff members include 37.3 per cent women. Figure 1.3.3 shows the proportions of men and women in the various job categories within the Directorate. Also working at the Directorate during the entire report period was one of NORAD's special advisors on oil matters in developing countries.

In 1988 the Directorate dealt with 73 vacancies and took on 21 new members of staff. Of the newcomers, six have relocated to Stavanger, one comes from oil-related activities and three are newly qualified.

Thirty-nine members of staff left their positions. This constitutes 11.6 per cent of the total number of authorised positions.

Departures in 1988 are fairly evenly distributed over the various Divisions and branches, and quite similar to the previous years, apart from last year, when the wastage was less than usual.

Equal Opportunities Work

The Directorate has a special agreement on equal opportunities and a separate Equal Opportunities Committee. This committee consists of four members, two from management and two from the staff unions. Last year the committee has been working inter alia on a system to show up any differences in salary grading and salary development between the sexes. Preparation of an action plan for equal opportunities is one of the committee's tasks.

Co-determination

Cooperation with the staff unions has followed the same pattern as in previous years, with monthly meetings between the employee delegates and general management.

Eleven meetings were held which considered 50 items. The following current items can be mentioned:

- Budget proposals
- Introduction of Rehabilitation and AKAN Committee
- Use of Neo-Norwegian (nynorsk) in the NPD
- The welfare budget
- Framework description for the Safety Division
- Withdrawal of pay powers
- Criteria for promotion to Chief Engineer
- Activity plans for 1988
- Annual Report for 1987.

In line with practice in previous years, the Board held a two-way briefing with representatives of the seven staff unions.

Training

The training budget in 1988 was NOK 3,290,000. These funds have been used in accordance with earlier practice, and large amounts have as previously been allocated to travelling and overnight expenses. In addition, greater weight has been assigned to internal training, which has proved to yield an efficient use of resources. In this connection a course catalogue of internal training facilities was prepared, and a course package in management training. The training was begun in 1988 and will continue in 1989. As in the previous report period there are several staff members who have participated in on-the-job (OTJ) training with the oil companies. These courses were well-organised by the companies and the training periods have been well worth while for all attending.

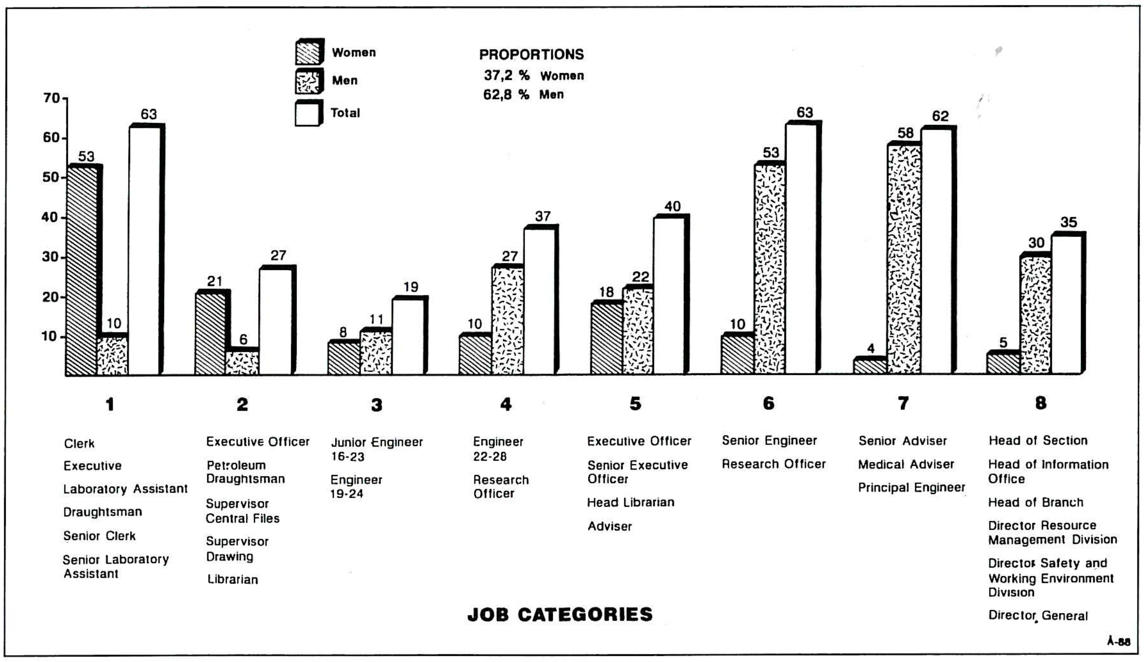
1.3.4 Budget/finance

In all NOK 225,766,843 was used for the Directorate's various functions in 1987. The figure can be broken down as follows:

Table 1.3.3. Personnel leaving in 1988 with indication of job category

Division/ Branch	Managers	Sen. Advisors	Princ. Eng.	Sen. Eng.	Sen. Geol. Geol.	Branch Eng/ Eng	Advisers	Junior Exec/ Sen Exec	Secr. etc	Total	Wastage in %
R Div	2	0	2	2	1	2	1	3	1	14	10.5
S Div	0	3	2	5	0	6	0	0	0	16	15.5
J Branch	0	1	0	0	0	0	0	0	0	1	10.0
A Branch	0	0	0	0	0	0	1	2	5	8	11.5
Total	2	4	4	7	1	8	2	5	6	39	11.6

Fig. 1.3.3
Job categories as of 31 December 1988



Operating budget NOK 156,311,420
Inspection costs NOK 8,845,358
Geological and geophysical surveys
NOK 56,604,308
Safety and emergency preparedness research
NOK 4,005,757

Total appropriation budget for 1986
NOK 225,776,843

NOK 90,411,377 of the operating budget was allocated to salaries and NOK 5,657,023 to the running of buildings and renting of premises. The remaining NOK 60,243,020 of the operating budget represents other expenses such as external consultancy services, operation of a weather ship, research and development projects, travel, training, electronic data processing (EDP) operations, investment in new equipment, etc.

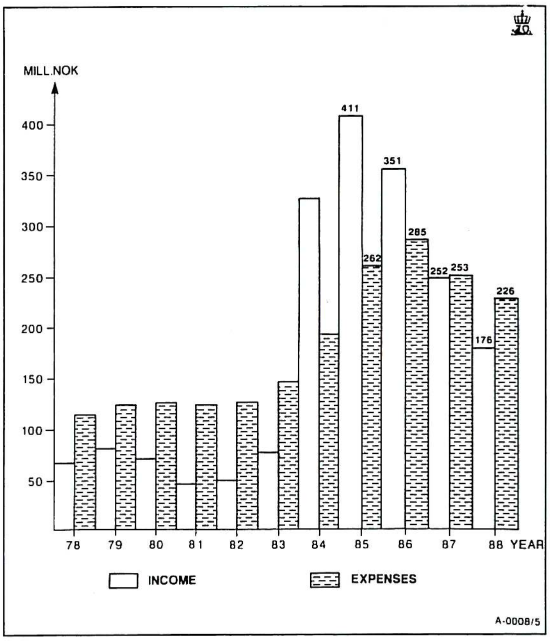
The NPD has been given a number of special tasks as follows:

Clean-up of seabed NOK 4,396,155
Research and development in enhanced oil recovery (SPOR) NOK 17,670,642
World Petroleum Congress 1995 NOK 17,371

Its budget situation causes the Directorate to face an ever greater challenge regarding priorities. Efforts therefore focus on developing better planning and management systems.

Revenues and income
In addition to revenues in the form of royalties and acreage fees (Chapter 5), the Directorate received income totalling NOK 176,192,178. Income in 1988 was distributed as follows:

Fig. 1.3.4
NPD's operating budget 1978–1988



Sales of publications	NOK	3,294,099
Sales of released sample material	NOK	1,419,302
Survey fees	NOK	1,900,000
Refunded inspection costs	NOK	28,341,744
Refunded for environmental data acquisition	NOK	3,500,000
Sales of seismic survey results	NOK	130,129,418
Credit interest on bank deposits	NOK	2,730,374
Miscellaneous income	NOK	2,730,178
	NOK	176,192,178

The Directorate's operating budget and income development for the period 1976–88 are shown in Figure 1.3.4.

1.3.5 Information

During this report period there has been a brisk demand for information both from Norwegian and foreign institutions, the media, companies and individuals. Representatives of foreign mass media, singly or in groups, have visited the Directorate to acquaint themselves with the NPD and the oil activity. For their part, Norwegian Petroleum Directorate staff have frequently participated as speakers in various fora.

The Norwegian Petroleum Directorate's Annual Report is a central feature of our information activities. The 1987 Annual Report became available in August.The 1988 Perspective Analysis, entitled "Norwegian Petroleum Resources in a Historical and Global Perspective", was published in connection with the NPD's participation in ONS-88.

During 1988 were issued 49 press bulletins, inter alia in connection with the conclusion of exploration wells, where the Norwegian Petroleum Directorate attempts to provide maximum information.

1.3.6 The Library

Library activity was again considerable in 1988, with a nine per cent increase in enquiries for literature and information. The increase was due to increased internal demand for material. External use of the Library has fallen somewhat. External users include Norwegian and foreign libraries, students, researchers, oil companies and other firms within the petroleum sector.

Library staff have given tours of the Library and briefings on the Library's services to oil companies, public services and other libraries.

The Library actively participates in the publication of the Norwegian Petroleum Directorate's bibliographical reference work Oljeindeks (Oil Index) and the reference data base OIL. Demand for bibliographical references in the Oil Index and OIL is still considerable.

1.3.7 The INFOIL secretariat

Use of the computer-based information services show constant subscriber figures for both the OIL and Infoil databases and for the printed editions Oljeindeks and Oil Index.

Orders for original publications from the OIL service to the Directorate's library show an increase in use of this service of over seven per cent from previous years.

A diskette version has been prepared and offered for sale to users of personal computers.

A revised plan for the research base Infoil 2 has been submitted in collaboration with NTNF and the British Department of Energy. The plan is for exchange of data with the EEC Commission and cooperation with their database facilities from the Datacentralen in Copenhagen.

The secretariat service for the Petroleum Documentation Forum (FoP) has experienced the same level of activity as in previous years. As planned the NPD's support to the FoP ceased from 31 December 1988.

2. Activity on the Norwegian Continental Shelf

2.1 EXPLORATION AND PRODUCTION LICENCES

2.1.1 New exploration licences

As of 31 December 1988, 164 commercial exploration licences had been granted. Each licence has a term of three years.

The following licences were issued in 1988:

	Licence No.
A/S Norske Shell	158
Conoco Norway Inc	159
Western Geophysical Company	160
Nopec a.s	161
Britoil	162
Chevron Exploration North Sea Ltd	163
Horizon Exploration Ltd	164

2.1.2 Licensing rounds and new production licences

In Phase A of the 12th licensing round, 21 blocks were advertised in the North Sea, of which 15 blocks had previously been allocated. The blocks were advertised 12 August 1987 with an application deadline of 19 February 1988. Twenty-three companies applied, and all blocks were applied for. On 8 July 1988 16 blocks were allocated, covered all together by 11 production licences.

Table 2.1.2.a contains information about the production licences issued in 1988, whilst Table 2.1.2.b gives information about all production licences issued since 1965. Table 2.1.2 c shows Norwegian and foreign interests in the individual licensing rounds.

In Phase B of the 12th licensing round, on 1 September 1988, three blocks were advertised in the area Møre I, two blocks in Trøndelag II and eight key blocks in the Barents Sea. There was also opportunity to apply for blocks advertised in previous licensing rounds but not allocated. The application deadline was 15 November 1988. Twenty-one companies applied for in all 18 blocks. Allocation will probably occur in early 1989.

2.1.3 Transfer of interests

In the course of 1988, the following transfers have been approved in accordance with Section 61 of the Act of 22 March 1985 No. 11 concerning Petroleum Activities:

Production Licence No. 018

Coparex Norge A/S	0.399 %
Den norske stats oljeselskap a.s	1.000 %
Elf Aquitaine Norge A/S	7.594 %
Eurafrep Norge A/S	0.456 %
Norexplor A/S	0.304 %
Norsk Agip A/S	13.040 %
Norsk Hydro Produksjon A.S	6.700 %
Norske Fina A/S	30.000 %
Phillips Petroleum Co Norway	36.960 %
Total Marine Norsk A/S	3.547 %

Production Licence No. 019B

Conoco has sold 10 % to Norsk AEDC A/S and Norsk Moeco A/S, 5 % to each. The distribution in Production Licence 019B is subsequently:

Statoil	30.000 %
BP Petroleum Development (Norway) Ltd	26.625 %
Conoco	9.375 %
KS/AS Pelican	4.000 %
Norsk AEDC A/S	5.000 %
Norsk Moeco A/S	5.000 %

Production Licence 046

Statoil has transferred 10 % of its share, 9 % to Elf and 1 % to Total. The distribution in Production Licence 046 is subsequently:

Den norske stats oljeselskap a.s	49.6 %
Esso Norge A/S	30.4 %
Norsk Hydro a.s.	10.0 %
Elf Aquitaine Norge A/S	9.0 %
Total Marine Norsk A/S	1.0 %

Production Licence 054

Statoil has sold 3 % of its interest, 2 % to Elf and 1 % to Total. Mobil has sold 2.595 % of its share to Conoco and the rest, 1.1045 %, to Elf. The distribution in Production Licence 054 is subsequently:

A/S Norske Shell	25.9000 %
Conoco Norway Inc	6.2955 %
Den norske stats oljeselskap a.s.	58.8000 %
Elf Aquitaine Norge A/S	3.1045 %
Norsk Hydro a.s	4.9000 %
Total Marine Norsk A/S	1.0000 %

Production Licence 057

After the operator's declaration of commerciality 30.5.88 and after Amoco has sold its share to Deminex, the distribution in Production Licence 057 is subsequently:

Den norske stats oljeselskap a.s.	62.0 %
Saga Petroleum a.s	9.0 %
Esso Norge A/S	7.3 %

Deminex (Norge) A/S	8.7 %
Norsk Hydro a.s	5.8 %
Elf Aquitaine Norge A/S	3.9 %
Amerada Hess Norge A/S	1.4 %
Texaco	1.4 %
Den norske oljeselskap a.s	0.5 %

Production Licence 085

Statoil has transferred 3 % of its share, 2 % to Elf and 1 % to Total. The distribution in Production Licence 085 is subsequently:

Den norske stats oljeselskap a.s.	82.0 %
Elf Aquitaine Norge A/S	2.0 %
Norsk Hydro a.s	9.0 %
Saga Petroleum a.s	6.0 %
Total Marine Norsk A/S	1.0 %

Table 2.1.2.a
Allocations: Licensing Round 12A

Lic. No.	Field/Block	% Share		Licensee (O=Operator)
143	1/2	25.000	O	Phillips Petroleum Norsk A/S
		50.000		Den norske stats oljeselskap a.s
		15.000		Texas Eastern Norway A/S
		10.000		ØMV Norge A/S
144	1/5 and 1/6	25.000	O	Norske Conoco A/S
		25.000		BP Petroleum Development of Norway A.s
		50.000		Den norske stats oljeselskap a.s
145	1/9 and 2/7	30.000	O	BP Petroleum Development of Norway A.s
		10.000		Norsk Agip A/S
		10.000		Norsk Hydro Produksjon a.s
		50.000		Den norske stats oljeselskap a.s
146	2/4	20.000	O	Saga Petroleum a.s.
		10.000		Amerada Hess Norge A/S
		20.000		Elf Aquitaine Norge A/S
		50.000		Den norske stats oljeselskap a.s
147	3/7 and 3/8	35.000	O	A/S Norske Shell
		50.000		Den norske stats oljeselskap a.s
		15.000		Total Marine Norsk A.S
148	7/4 7/7	50.000	O	Den norske stats oljeselskap a.s
		25.000		Amerada Hess Norge A/S
		10.000		Amoco Norway A/S
		15.000		Total Marine Norsk A.S
149	16/3	40.000	O	Esso Norge a.s
		10.000		Idemitsu Oil Exploration (Norsk) a.s.
		50.000		Den norske stats oljeselskap a.s
150	24/9	30.000	O	Norske Fina A/S
		10.000		Saga Petroleum a.s.
		50.000		Den norske stats oljeselskap a.s
		10.000		Texas Eastern Norway A/S
151	25/3	20.000	O	Elf Aquitaine Norge A/S
		8.000		Det Norske Oljeselskap as
		10.000		Esso Norge a.s
		12.000		Norsk Hydro Produksjon a.s
		50.000		Den norske stats oljeselskap a.s
152	33/12	50.000	O	Den norske stats oljeselskap a.s
		30.000		BP Petroleum Development of Norway A.s
		10.000		Idemitsu Oil Exploration (Norsk) a.s.
		10.000		Saga Petroleum a.s.
153	35/9 and 36/7	20.000	O	Norsk Hydro Produksjon a.s
		8.000		Deminex (Norge) A/S
		10.000		Petrobras Norge A/S
		12.000		A/S Norske Shell
		50.000		Den norske stats oljeselskap a.s

Table 2.1.2.b
Production Licences and areas as of 1 January 1989

Lic. Round	Allocated	Prod. Lic. No.	Number of blocks Alloc.*	Relinq.*	Area allocated km²	Area relinquished km²	Area in prod. lic. km²
1.	01.Sep.1965	001–021	74	54	39842.475	35363.535	4478.940
	07.Dec. 1965	022	4	4	2263.565	2263.565	–
	12.Sep.1977	019 (2)	2	0	617.890	–	617.890
2.	23.May 1969	023–031	9	1	4107.833	2233.366	1874.467
	30.May 1969	032–033	2	0	746.285	376.906	369.379
	14.Nov. 1969	034–035	2	0	1024.529	564.837	459.692
	11.Jun 1971	036	1	0	523.937	262.047	261.890
ut.	10.Aug. 1973	037	2	0	586.834	295.157	291.677
3.	01.Apr. 1975	038–040 and 042	7	4	1840.547	1389.779	450.768
	01.Jun 1975	041	1	0	488.659	244.048	244.611
	06.Aug. 1976	043	2	0	604.558	303.217	301.341
	27.Aug. 1976	044	1	0	193.076	90.417	102.659
	03.Dec. 1976	045–046	4	2	1270.682	814.708	455.974
	07.Jan. 1977	047	2	1	368.363	304.160	64.203
	18.Feb.1977	048	2	1	321.500	107.019	214.481
	23.Dec. 1977	049	1	1	485.802	485.802	–
ut.	16.Jun. 1978	050	1	0	500.509	151.962	348.547
4.	06.Apr. 1979	051–058	8	1	4007.887	1938.064	2069.823
ut.	20.Aug. 1982	079	1	0	102.167	–	102.167
5.	18.Jan. 1980	059–061	3	2	1108.078	998.675	109.403
	27.Mar 1981	062–064	3	1	1099.522	499.780	599.742
	23.Apr. 1982	073–078	6	2	2311.912	1444.153	867.759
6.	21.Aug. 1981	065–072	9	1	3218.945	1362.539	1856.406
7.	10.Dec 1982	080–084	5	5	2082.966	2082.966	–
ut.	08.Jul 1983	085	3	0	1521.160		1521.160
8.	09.Mar 1984	086–100	17	0	6346.604		6346.604
9.	14.Mar 1985	101–111	13	0	5293.053		5293.053
ut.	26.Jul 1985	112	1		260.215		260.215
10a	23.Aug. 1985	113–120	9		3075.433		3075.433
10b	28.Feb.1986	121–128	9		3828.257		3828.257
ut.	11.Jul 1986	129	1		225.393		225.393
11.	10.Apr. 1987	130–142	22		7139.517		7139.517
12a	8.Jul. 1988	143–153	16		4701.018		4701.018
			243	83	102109.172	53576.697	48532.475

* whole or parts of blocks
ut. = allocated outside of licensing rounds

Table 2.1.2.c
Licensing rounds. Norwegian and foreign interests as of 1 October 1988

Licensing Round	Year	Number of Blocks	Interest % Norwegian	Interest % Foreign	Operator % Norwegian	Operator % Foreign
1	1965	78	9	91	0	100
2	1969 – 71	14	15	85	0	100
Statfjord	1973	2	52	48	0	100
3	1974 – 78	22	58	42	63	37
Ula (19 B)	1977	2	50	50	0	100
Gullfaks	1978	1	100	0	100	0
4	1979	8	58	42	68	32
5	1980 – 82	12	66	34	92	8
6	1981	9	64	34	50	50
Utv.t 079	1982	1	100	0	100	0
7	1982	5	60	40	80	20
Utv.t 085	1983	3	100	0	100	0
8	1984	17	60	40	60	40
9	1985	13	43	57	62	38
Utv.t 112	1985	1	67	33	0	100
10A	1985	9	64	36	67	33
10B	1986	9	65	36	56	44
Utv.t 129	1986	1	67	33	100	0
11	1987	22	59	41	62	38
12A	1988	16	58.2	41.8	36.4	63.6

2.1.4 Relinquishments/surrenders

Seventeen production licences have been relinquished / surrendered in 1988. In the case of eight production licences, the whole area has been relinquished. This can be seen from Table 2.1.4.

Table 2.1.4
Relinquishments/surrenders

Prod. Lic.	Operator	Block	Original area in km²	Relin./surr. area in km²	Area in prod. lic.
016	Phillips	16/11,17/12	2203.126 1)	169.391	424:871
051	Statoil	30/2	504.440 2)	50.292	201.776
067	Shell	2/5B	183.915	89.186	94.729
069	Conoco	7/8	558.364	336.591	221.773
070	Norsk Hydro	7/11	415.775	222.640	193.135
071	Statoil	8/3	366.771	366.771	0
072	Esso	16/7	543.172	347.371	195.801
073	Statoil	6407/1	440.392	268.786	171.606
074	Saga	6407/2	440.392	229.216	211.176
075	BP	6507/10	436.310	436.310	0
076	Norsk Hydro	7119/7	331.606	331.606	0
078	Norsk Hydro	7120/9	331.606	178.235	153.371
080	Statoil	6609/5	411.636	411.636	0
081	Phillips	6609/7	415.770	415.770	0
082	Saga	6609/10	419.895	419.895	0
083	Norsk Hydro	6609/11	419.895	419.895	0
084	Statoil	6610/7	415.770	415.770	0

1) Area of production licence before last surrender 594,262
2) Area of production licence before last surrender 252,068

2.2 SURVEYING AND EXPLORATION DRILLING

2.2.1 Geophysical and geological surveys

A total of 122,436 km of seismics were gathered on the Norwegian continental shelf in 1988. This means that activity has been on about the same level as in 1987 (120,794 km).

2.2.1.1 The Norwegian Petroleum Directorate's geophysical surveys in 1988

The Norwegian Petroleum Directorate assembled 11,614 km of seismics in the course of 1988 (Figure 2.2.1.b). This includes 976 seismics gathered on the Jan Mayen Ridge. Data were gathered from the areas indicated in Figure 2.2.1.c, d and e.

Fig. 2.2.1.a
Seismic surveys on the Norwegian continental shelf 1962–1988

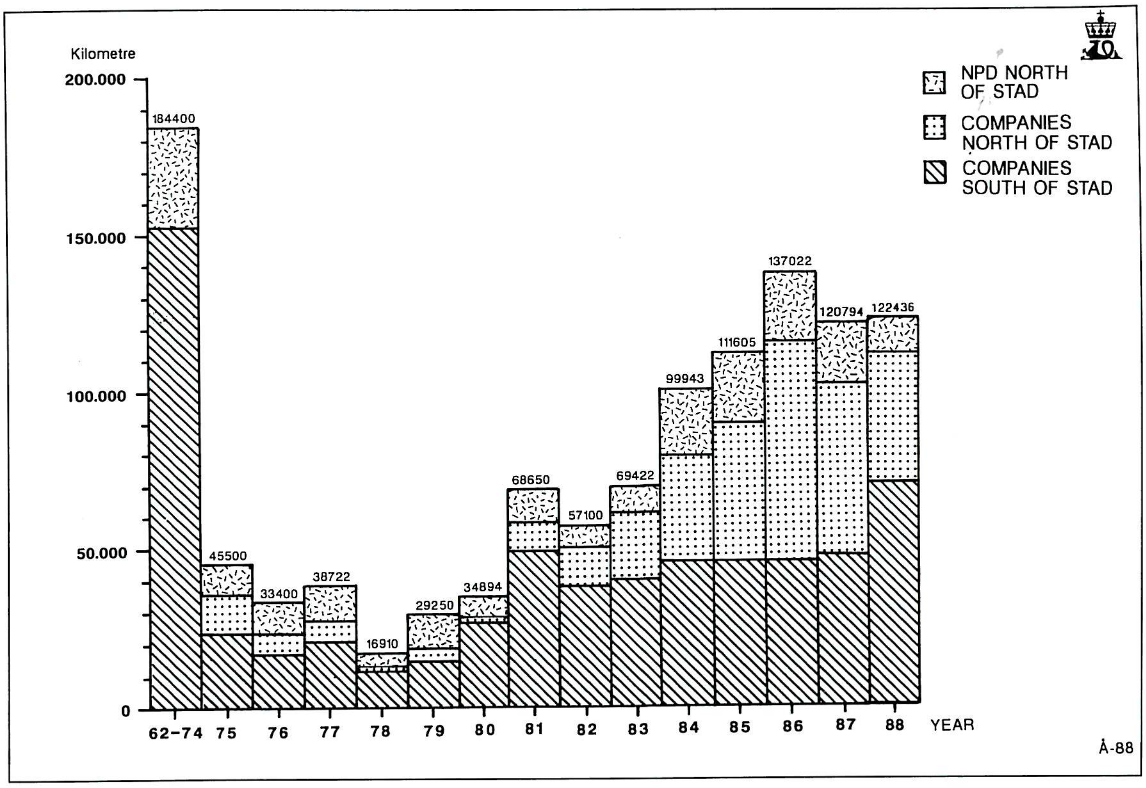


Fig. 2.2.1.b
Seismic surveys north of Stad conducted by the Norwegian Petroleum Directorate.

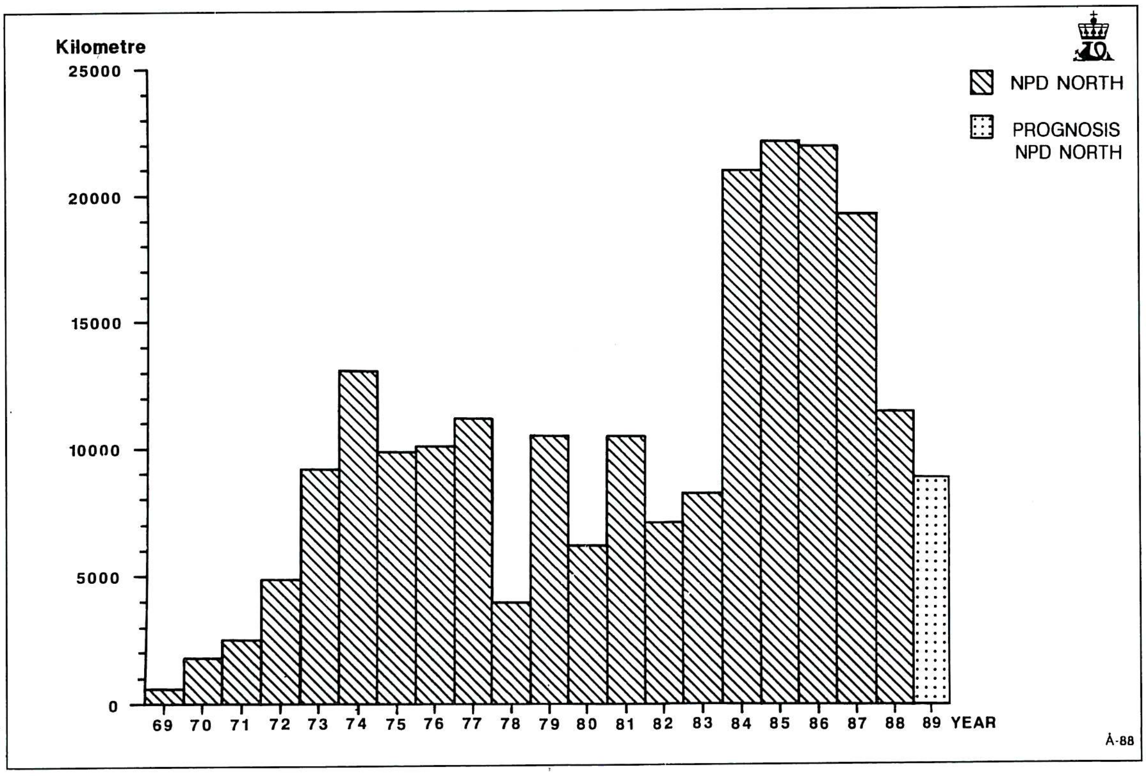


Fig. 2.2.1.c
Seismic surveys on the Mid-Norwegian shelf in 1988

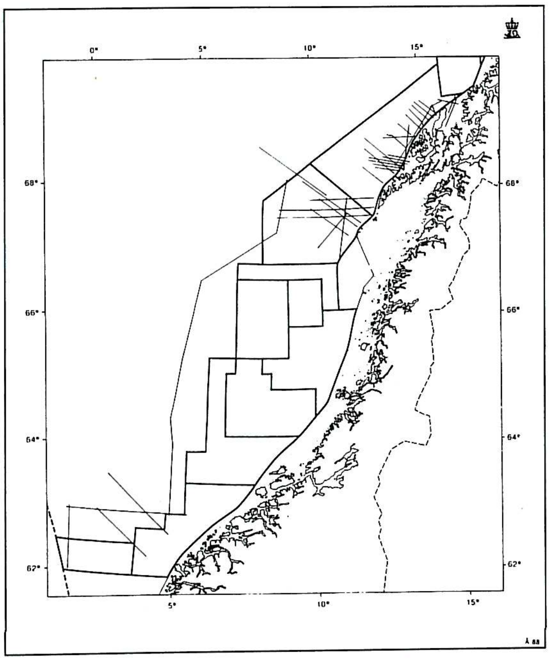


Fig. 2.2.1.d
Seismic surveys in the Barents sea in 1988

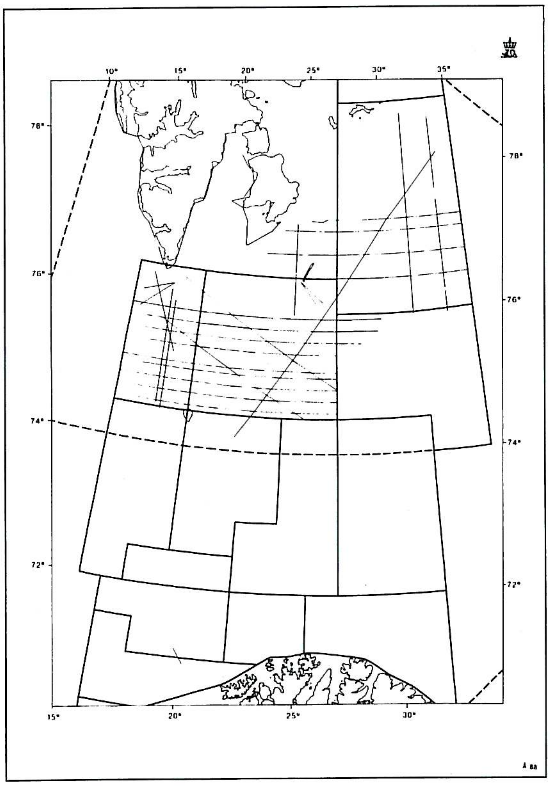
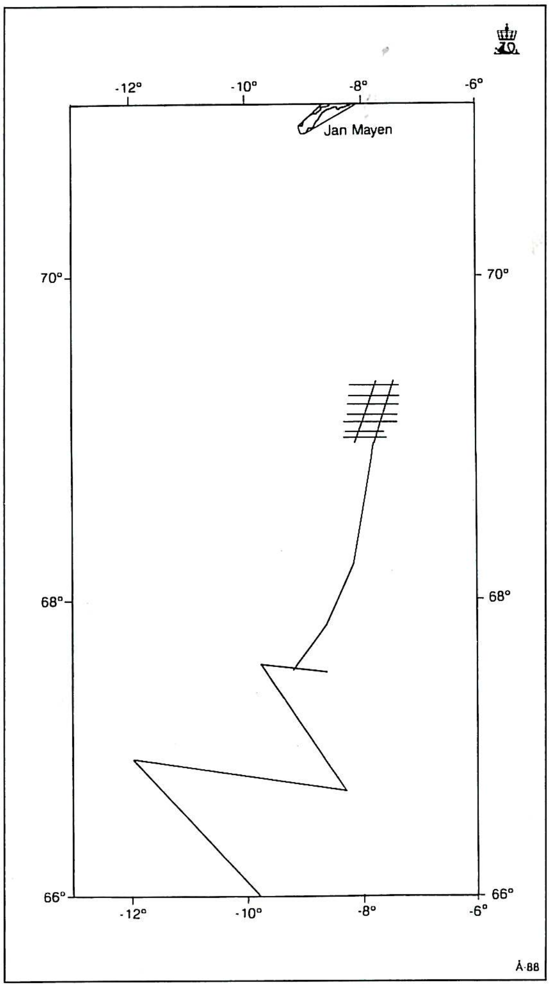


Fig. 2.2.1.e
Seismic surveys on the Jan Mayen shelf in 1988



All the Norwegian Petroleum Directorate's 1988 data were gathered with the vessel "Geco Echo", apart from two test lines on Troms, which were taken by "Western Challenger". The data on Jan Mayen were collected by the University of Bergen vessel "Håkon Mosby".

The Møre Basin
In order to obtain a better understanding of the deeper basin outside of the areas opened up on Møre, 600 km regional lines were collected off the Møre coast (Figure 2.2.1.c). These data were gathered with 15-second registration and will be processed by the Norwegian company Geoteam a.s in Oslo.

The Vøring Basin
In order to chart the deeper reflectors outside the opened-up areas, 677 km regional data were gathered from the Vøring basin. These were collected by deep registration (see above) in the deeper areas off Mid-Norway from Møre to Lofoten West.

The data are being processed by Horizon Exploration in London.

Lofoten West
2,087 km semi-regional data were gathered off Lofoten (Figure 2.2.1.c). In planning of any shallow drillings there will be a need for shallow seismics, and shallow seismic data were therefore also gathered in parallel with the aid of a shallow high-resolution air gun and a shallow 500-m mini-cable. The data are being processed by SSL and Ensign (for parts of the shallow seismics) in London.

A number of test lines were also gathered off Lofoten. These lines were gathered by deep registration, and they stretch out in the deeper areas where there are penetration problems because of lava areas. Deep sources were used with time delays on the individual guns to achieve a special low-frequency signature, and also large "arrays" with a volume of 8,716 cubic inches and 100 meters width. In addition two cables with horizontal separation of 150 metres were used. The purpose of using two cables is to achieve better penetration on account of noise reduction. These lines are being processed by Geco and GSI in Stavanger.

Troms I
Two lines with different "source arrays" were gathered with the vessel "Western Challenger". The lines go through two wells in Troms I, as the purpose of the test was to try to obtain better data quality, inter alia by using data from wells. The data are being processed by Western in London.

Hopen test lines
A number of test lines were gathered in the area just off Hopen. The data quality is very poor in this area. Normal parameters for deep seismics were used, and in addition high-resolution parameters for charting of the shallow strata. The data are being processed by GSI in Stavanger.

Barents Sea North
6,667 km of regional lines were gathered in the northern Barents Sea (Figure 2.2.1.d). There can be great problems with the data quality in this area. The problems are due inter alia to hard seabed, which generates strong multiples and also noise on account of diffraction from the shallow strata. It is therefore useful to try out new methods with regard to "source and receiver arrays" and new software for removal of multiples.

Two of the longest lines were gathered with 15-second registration for mapping of the very deep reflections. The other data were by and large collected with a shallow gun for high resolution and a large "source array" for the deep data. Registration was done with three cables: two long cables towed broadside (150–175 m) and a shallow 500-metre long cable in the middle. Data were gathered to about 78° 50' N. Conditions were very difficult during the data-gathering in the northern Barents Sea, with many icebergs and often dense fog. Wind conditions were, however, very favourable, and a very high production rate was maintained. The data were processed by Western, Merlin, GSI and Geco (shallow seismics).

Jan Mayen
In September 1988 the Norwegian Petroleum Directorate collected 976 km of seismics over the Jan Mayen Ridge between Jan Mayen and Iceland (see Figure 2.2.1.e). The survey was done by "Håkon Mosby", which belongs to the University of Bergen. The survey was done in connection with the border agreement for the area between Norway and Iceland. This enjoins the Directorate to carry out geological/geophysical mapping of the area in collaboration with Orkustofnun, Iceland's national energy agency. The work was a follow-up of a major survey done in 1985. Orkustofnun will be responsible for processing the data.

2.2.1.2 Opening-up of new exploration areas
West Bear Island was opened for seismic surveys under the direction of the companies in the winter of 1988.

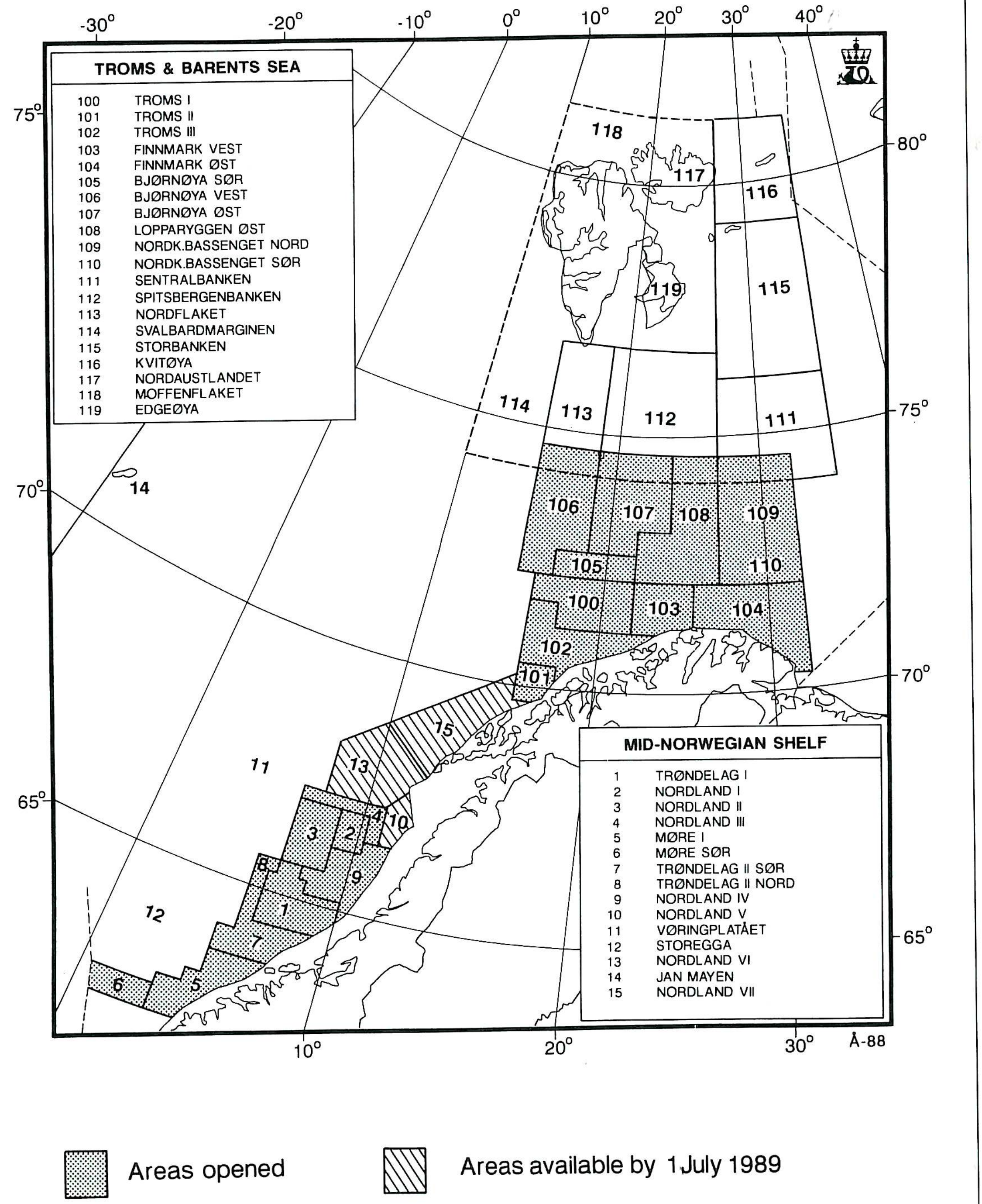
In the course of 1988 the Petroleum Directorate cleared most of the area off Lofoten for opening for company seismic surveys. After some further studies in the course of May/June 1989, it is planned to open the areas Nordland V, VI and VII on 1 July 1989 (Figure 2.2.1.f).

2.2.1.3 Geophysical surveys by the companies
In 1988, 110,822 km of seismics were shot on the Norwegian continental shelf under the direction of oil companies, contractors or universities. Of these, 47,593 km are 3D seismics. 70,539 km were shot in the North Sea and 40,283 north of Stad. It appears from the figures above that the activity in the North Sea increased considerably from 1987 to 1988, while the activity north of Stad was correspondingly reduced. Norwegian oil companies shot 66,102 km, foreign oil companies 44,593 km and scientific institutions 127 km of seismics in 1988. 19,722 km of wildcat seismics were gathered by GECO, NOPEC and GSI.

2.2.1.4 Sale of seismic data
In 1988, the Norwegian Petroleum Directorate has booked income from the sale of seismic data packages at NOK 130.1 million (NOK 207.4 million in 1987). Cf. Table 2.2.1.4.

Companies which have purchased all the Petroleum Directorate's seismic data packages in the various areas are as follows:

Fig. 2.2.1.f
Areas which are, or in the near future will be opened for seismic surveys by companies. Area designations north of Stad.



Trøndelag I
Agip, Amerada, Amoco, Arco, BP, Britoil, Conoco, Deminex, DNO, Elf, Esso, Fina, Hydro, Idemitsu, Mobil, Occidental, Petrobras, Phillips, Saga, Shell, Statoil, Svenska Petroleum, Tenneco, Texas Eastern, Total and Unocal.

Nordland I
Agip, Amerada, Amoco, Arco, BP, Britoil, Chevron, Conoco, Deminex, Elf, Esso, Fina, Getty, Gulf, Hispanoil, Hydro, Japan Oil, Mobil, Phillips, Saga, Shell, Statoil, Superior, Svenska Petroleum, Tenneco, Texaco, Texas Eastern, Total, Unocal and ØMV.

Nordland II
Agip, Amerada, Arco, BP, Britoil, Conoco, Elf, Esso, Fina, Hydro, Mobil, Phillips, Saga, Shell, Statoil, Tenneco, Texas Eastern, Total and Unocal.

Nordland III
Agip, BP, Elf, Esso, Hydro, Mobil, Saga, Shell, Statoil and Total.

Møre I
Agip, Amerada, Amoco, Arco, BP, Britoil, Conoco, Deminex, DNO, Elf, Esso, Fina, Hydro, Idemitsu, Mobil, Occidental, Petrobras, Phillips, Saga, Shell, Statoil, Svenska Petroleum, Tenneco, Texas Eastern, Total and Unocal.

Møre South
Agip, Amerada, Amoco, BP, Britoil, Conoco, Deminex, DNO, Elf, Esso, Fina, Hydro, Mobil, Occidental, Petrobras, Phillips, Saga, Shell, Statoil, Texas Eastern and Total.

Trøndelag II South
Agip, Amerada, Amoco, Arco, BP, Britoil, Conoco, Deminex, DNO, Elf, Esso, Fina, Hydro, Idemitsu, Mobil, Phillips, Saga, Shell, Statoil, Svenska Petroleum, Tenneco, Texas Eastern, Total and Unocal.

Trøndelag II North
Agip, Amerada, Arco, BP, Britoil, Conoco, Deminex, DNO, Elf, Esso, Fina, Hydro, Mobil, Petrobras, Phillips, Saga, Shell, Statoil, Svenska Petroleum, Tenneco, Texas Eastern and Total.

Nordland IV
Agip, Elf, Esso, Hydro, Mobil, Saga, Shell, Statoil and Total.

Troms I
Agip, Amerada, Conoco, Elf, Esso, Hydro, Mobil, Phillips, Saga, Shell and Statoil.

Troms II
Agip, Elf, Esso, Hydro, Mobil, Saga, Shell, Statoil and Total.

Troms III
Agip, Elf, Esso, Mobil, Saga, Shell, Statoil and Total.

Finnmark West
Agip, Amerada, Amoco, Arco, BP, Conoco, Elf, Esso, Fina, Hydro, Mobil, Phillips, Saga, Shell, Statoil, Tenneco and Total.

Finnmark East
Agip, Amoco, Arco, BP, Conoco, Deminex, Elf, Esso, Hydro, Mobil, Saga, Shell, Statoil, Texas Eastern and Total.

Bear Island South
Agip, Amerada, Amoco, Arco, BP, Britoil, Conoco, Deminex, Elf, Esso, Fina, Hydro, Mobil, Phillips, Saga, Shell, Statoil, Svenska Petroleum, Tenneco, Texas Eastern and Total.

Bear Island West
Amoco, Conoco, Elf, Hydro, Mobil, Shell, Statoil and Total.

Bear Island East
Agip, Amoco, Arco, BP, Conoco, Deminex, Elf, Esso, Fina, Hydro, Mobil, Saga, Shell, Statoil, Tenneco and Total.

Loppa Ridge East
Agip, Amerada, Amoco, Arco, BP, Conoco, Deminex, Elf, Esso, Fina, Hydro, Mobil, Phillips, Saga, Shell, Statoil, Tenneco, Texas Eastern and Total.

North Cape Basin North
Agip, Amoco, Arco, BP, Conoco, Elf, Esso, Hydro, Mobil, Saga, Shell, Statoil, Texas Eastern and Total.

North Cape Basin South
Agip, Amoco, Arco, BP, Conoco, Deminex, Elf, Esso, Hydro, Mobil, Petrobras, Phillips, Saga, Shell, Statoil, Svenska Petroleum, Texas Eastern and Total.

2.2.1.5 Release of data and material from the shelf
In connection with the Norwegian Petroleum Directorate's monitoring of oil operations on the Norwegian continental shelf, the Norwegian Petroleum Directorate receives copies of well logs and continuous, representative samples of drilling shale and cores.

Tests of drilling shale are taken every 10 metres throughout the well, and every third metre in formations which may contain hydrocarbons. As regards wet samples, which should have a weight of at least 1/2 kg, the same sampling frequency applies.

Of drilling cores, the Norwegian Petroleum Directorate receives a complete length section comprising at least one fourth of the core in exploration

Table 2.2.1.4
Summary of number of seismic data packages sold in 1988

Pack	Name	1988	Total
001	MØRE-TRØNDELAG-REGIONAL-PAKKE-1	1	33
002	MØRE-TRØNDELAG-REGIONAL-PAKKE-2	1	26
003	TAMPEN-SPUR		21
004	MØRE-SØR-84		21
005	TRØNDELAG-REGIONAL	1	25
006	HALTENBANKEN-VEST-84		23
007	FRØYABANKEN-84	1	25
008	MØRE-TRØNDELAG-PAKKE-2		22
009	MØRE-TRØNDELAG-PAKKE-3		28
010	TRÆNABANKEN		30
011	REG-DATA-NORDLAND-RYGGEN		20
012	NORDLAND-IV-85	1	9
013	REG-DATA-MID-N-SOKKEL		19
014	NORDLAND-II-83		21
015	NORDLAND-III-84	1	10
016	TROMS-II		9
017	REGIONAL-DATA-TROMS-ØST	1	18
018	FINNMARK-VEST-83	1	19
019	FINNMARK-VEST-84	1	20
020	NORDLAND-III-85	1	10
021	MØRE-SØR-TEST-84		5
022	STOREGGA-85	1	5
023	VØRINGPLATÅET	2	6
024	VØRING-BASS.-85/86	3	6
025	LOFOTEN-VEST-86	2	6
026	JAN-MAYEN-85		1
028	VØRING-BASS.-87	3	3
029	NORDLAND-VI-87	6	6
030	NORDLAND-VII-87	6	6
100	TROMS-HOVED-PAKKE		34
101	REG-DATA-TROMS-BAR.HAVET-73	1	20
102	TROMS-III-83/84		11
103	TROMS-III-85		8
105	TROMS-I-ØST-77	1	19
106	TROMS-NORD-82-PAKKE-1		23
107	TROMS-NORD-83-PAKKE-3		22
108	TROMS-NORD-82-PAKKE-2		15
109	TROMS-NORD-83-PAKKE-4		15
200	BJØRNØYA-PAKKE-1		21
201	BJØRNØYA-SØR-84		21
202	BJØRNØYA-ØST-REGIONAL-84		17
203	BJØRNØYA-ØST-84	1	17
204	BJØRNØYA-TILLEGG-NORD	1	16
205	BJØRNØYA-VEST-REGIONAL-84	4	14
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	5	11
213	BJØRNØYA-VEST-86-HIGH	5	11
214	BJØRNØYA-VEST-86-MARGIN	4	9
215	BJØRNØYA-VEST-86-SWATH	1	1
216	BJØRNØYA-VEST-87	9	9
300	BARENTS-HAVET-SØR-ØST-HOVED	2	22
301	BARENTS-HAVET-SØR-ØST-PAKKE-2	1	20
302	NORDKAPP-BASS.-85-GECO-DIAG	1	19
303	NORDKAPP-BASS.-85-NORD	1	18
304	NORDKAPP-BASS.-85-GRID	2	21
305	NORDKAPP-BASS.-86-DIAG	1	19
306	NORDKAPP-BASS.-86-SØR	2	20
307	NORDKAPP-BASS.-86-NORD		14
308	FINNMARK-ØST-86-REGIONAL	2	18
309	FINNMARK-ØST-86-DIAG	1	16
310	FINNMARK-ØST-86-GSI	3	18
312	NORDKAPP-TEST-87	1	1

wells and one half of the core in production wells. As of 31 December 1988, the Norwegian Petroleum Directorate has stored 55,292 m of core material from 594 wells, 319,535 samples of washed drilling shales from 795 wells and 324,391 wet samples from 868 wells on the Norwegian continental shelf. This includes production wells. In total, material from 1,143 wells is available.

The Norwegian Petroleum Directorate is responsible for publishing data and releasing material for educational and research purposes. Data is released 5 years after completion of the well. The licensees' interpretations are not released.

Well Data Summary Sheets (WDSS) are published annually, and summarise wells which have become more than five years old during the calendar year. The purpose of this series is to show which wells have been released and which core and log material is available from the different wells. Furthermore, some technical data and test results are given, as well as a composite log with lithological description for each well at 1:4000 scale.

Core material, drilling shale and wet tests may be studied in the Norwegian Petroleum Directorate's core study room. In special cases, it is possible to release material for studies and analysis outside of the Directorate. The five-year rule for release of material applies also in this instance.

Figure 2.2.1.5 shows the demand for test material distributed between the disciplines organic geochemistry, biostratigraphy and sedimentology/petrophysics. Up to 1985 biostratigraphy was the field that applied for the most tests. In later years, however, the greatest bulk of applications has come from projects in the fields of sedimentology and petrophysics.

Seismics are released in one-block packages, and may only be released from blocks which are or which have been subject to production licences, or after the seismics are older than five years.

As of 1 January 1989, 98 blocks had been released, making 80,158 profile km. Figure 2.2.1.g shows a map with indications of from which blocks data have been released.

2.2.1.6 Scientific studies

As of 31 December 1988, a total of 267 licences for scientific surveys had been issued on the Norwegian continental shelf. As appears from Table 2.2.1.6, 14 such licences were issued in 1988; four were issued by the Norwegian Petroleum Directorate in Stavanger and ten by the Petroleum Directorate's regional office in Harstad.

From 1 July 1987, the handling of applications for and issuing of licences concerning scientific surveys for the areas north of 65°N was delegated to the Norwegian Petroleum Directorate regional office in Harstad. In the instances when such applications comprise areas both north and south of 65°N, the consideration and issue is done from the main office in Stavanger.

2.2.2 Exploration drilling

At the turn of the year 1987/1988, six exploration

Fig. 2.2.1.5
Applications for sample material by subject

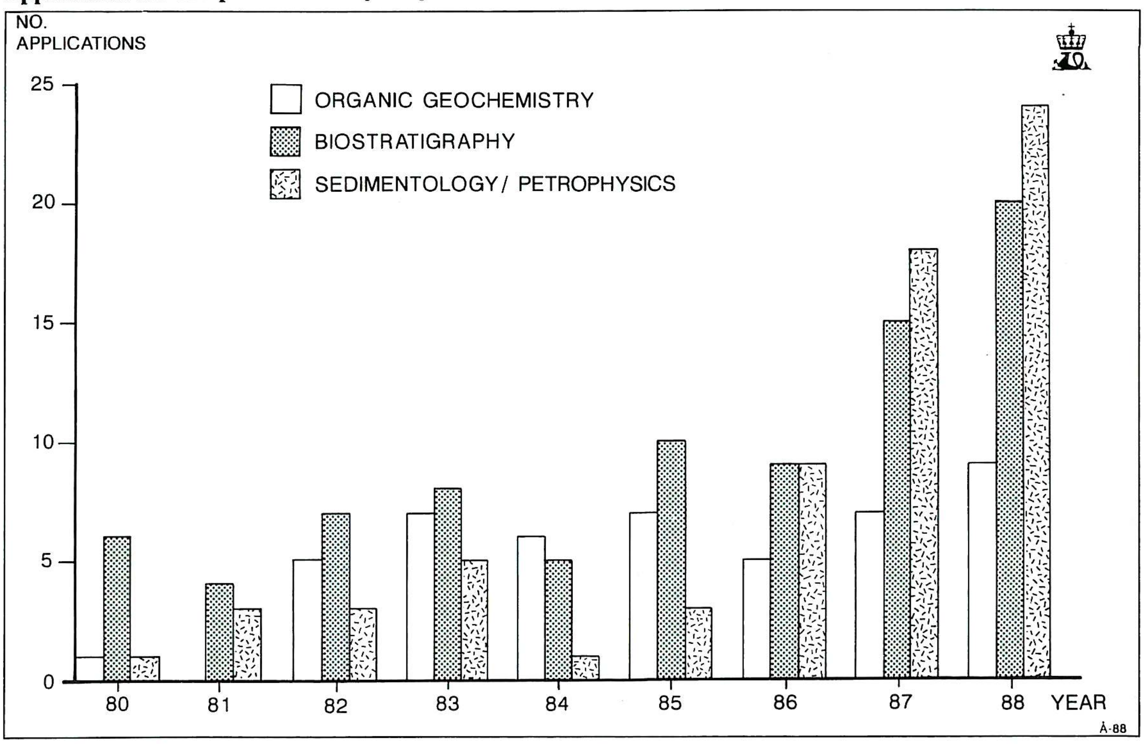


Table 2.2.1.6
Permits for scientific surveys for natural deposits

Permit	Name	Discipline Geo-physics	Geo-logy	Bio-logy	Area
252	Norwegian Geological Survey, Trondheim		X		Sveio, Hordaland
253	Nederlands Instituut vor Onderzoek der Zee Netherlands		X		Skagerrak, Norwegian Trench
254	Alfred-Wegener Institut für Polar- und Meeresforschung Bremerhaven, BRD		X		Norwegian Sea Greenland See
255	Institut für Meereskunde Universität Hamburg, BRD		X		Skagerrak, Ytre Oslofjord
3/88-H	Institut für Meereskunde Universität Hamburg, BRD	X			Greenland Sea
4/88-H	Institut für Meereskunde Universität Hamburg, BRD	X	X		East of Bear Island
5/88-H	Rijks Geologische Dienst Ad Harlem Netherlands	X	X		North-west of Spitsbergen, Isfjorden
6/88-H	Institut für Meereskunde Universität Hamburg, BRD		X	X	Norwegian Sea Greenland Sea
7/88-H	Institut für Meereskunde Universität Hamburg, BRD		X	X	Norwegian Sea
8/88-H	Institut für Meereskunde Universität Hamburg, BRD		X	X	Greenland Sea
9/88-H	University of Tromsø, Institute of Biology and Geology, Tromsø	X	X		Finnmark coast and western Barents Sea
10/88-H	University of Bergen Earthquake Station, Bergen	X			West of Lofoten
11/88-H	Institut Français de Recherche pour l'Exploitation de la Mer Paris, France	X			Around Jan Mayen
12/88-H	University of Tromsø Geological Department Tromsø	X	X		Finnmark coast and southern Barents Sea

wells were being drilled. They were all completed in 1988. In 1988, 29 new exploration wells were initiated, divided between 18 wildcats and 11 appraisal wells. This is seven exploration wells less than in 1987, see Figure 2.2.2.a. One wildcat well did not reach the prospective depths. Thirty-one exploration wells were finished during the year, six were suspended and four were still being drilled at the end of the year. At the end of 1988, a total of 598 exploration wells had been spudded on the Norwegian continental shelf (429 wildcat wells and 169 appraisal wells).

Drilling activity in 1988 resulted in 19 wells in the North Sea, six off Mid-Norway and four in the Barents Sea.

A total of 27 exploration wells had been temporarily abandoned on the Norwegian shelf at the end of the year.

Suspended wells on the Norwegian shelf with equipment placed on the seafloor are:

1/09–01	7/12–07	30/06–22
1/09–04	15/09–17	30/09–2 R
1/09–06 S	25/01–07 R	34/10–03
2/05–08	25/01–08 SR	34/10–05
2/07–14	30/02–01	6407/09–03
2/07–19	30/03–04	6407/09–05
2/07/20	30/06–09	6407/09–06
2/11–06 S	30/06–16	6407/07–03
7/11–07 R	30/06–19	6506/12–08

Fig. 2.2.1.g
Blocks in which seismic data have been released

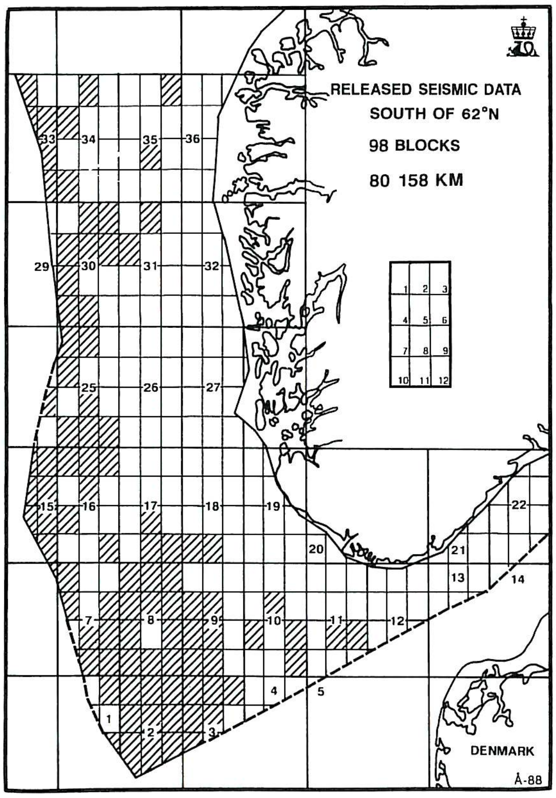


Figure 2.2.2.b, c and d shows the wells which had been spudded in the three areas on the Norwegian shelf (North Sea, Mid-Norway and Barents Sea). The Norwegian companies Saga, Norsk Hydro and Statoil have in 1988 had the operatorship for 18 (62 %) of the spudded drillings. The other 11 are divided between Elf, Conoco, Mobil, Shell, Amoco, Gulf/ Chevron and BP. This can be seen from Table 2.2.2.a.

2.2.2.1 Classification of prospect types

Exploration activity in 1988 was mainly directed towards Jurassic sandstone prospects. Twenty-seven of the 29 exploration wells had Jurassic as the main target. The two others were Cretaceous and Triassic. Some wells had Triassic and Permian/Carboniferous as secondary prospects.

2.2.2.2 New finds in 1988

The number of exploration wells drilled on the Norwegian shelf in 1988 is the lowest since 1977. This is due to several factors, including the low oil prices. Certain mobile drilling rigs have been occupied in production drilling, where activity has been greater than ever. There have been an unusual number of problematic drillings, so that a number of wells that should have been spudded in the course of the year have been put back to 1989. Of 29 spudded exploration wells, 17 were classified as wildcats, 11 as appraisal, and one was interrupted for technical rea-

Fig. 2.2.2.a
Exploration drilling on the Norwegian continental shelf. Numbers of wells per year 1966–1988

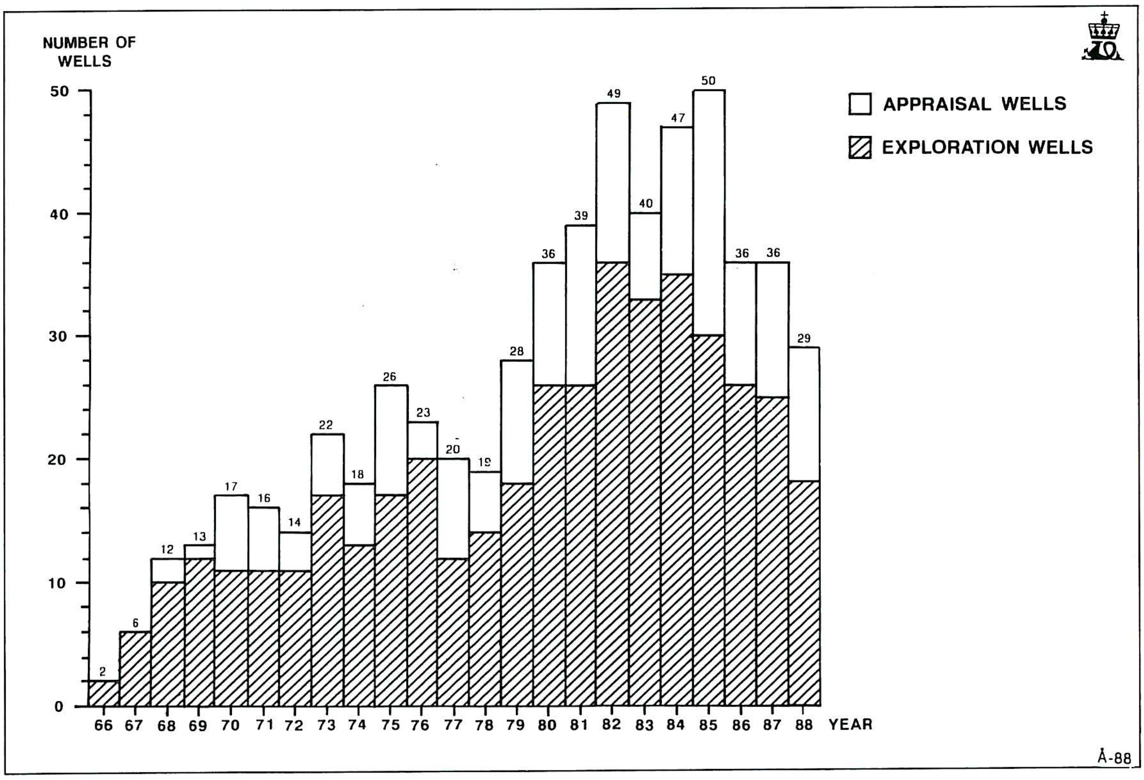
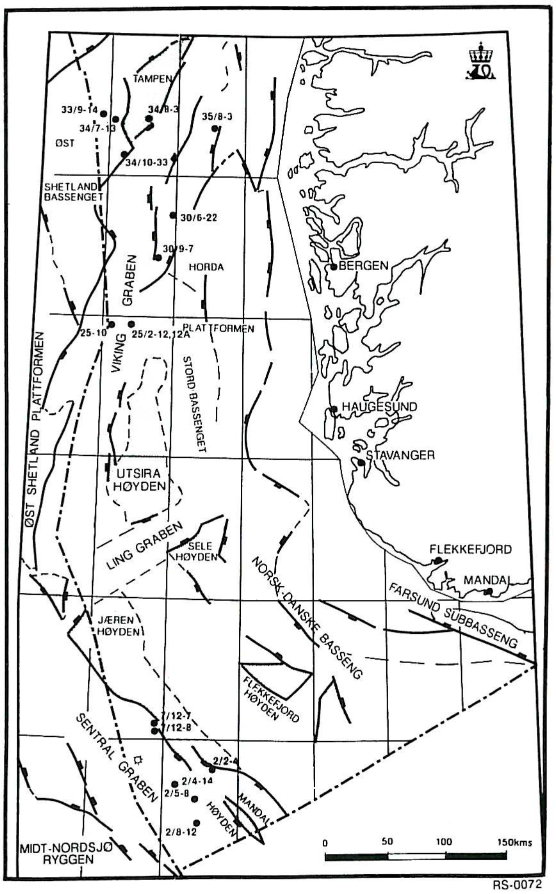


Table 2.2.2.a
Spudded and/or completed wildcats (U) and appraisal wells (A) in 1988 (as of 1 January 1989)
R = reopened x = has not reached prospective depths = deviation drilled

Exploration wells	Lic. No. Prod. Lic.	Position North East	Drilling Spudded Completed	Operator Rig	Well type Completion classification	Water depth KBE	Total depth Geological period
2/02–04	574	56 47 40.88	88.04.16	Saga	Wildcat	59	4020
	066	03 39 34.46	88.06.07	Treasure Saga	Dry hole	26	Triassic
2/04–13 X	588	56 41 03.98	88.09.04	Saga	Wildcat	69	2518
	146	03 08 44.53	88.10.06	Treasure Saga	Abandoned	26	
2/04–14	593	56 41 05.60	88.10.06	Saga	Wildcat	69	
	146	03 08 43.10	00.00.00	Treasure Saga		26	
2/05–08	585	56 35 16.49	88.09.18	Amoco	Appraisal	66	3367
	006	03 25 22.19	88.11.05	Dyvi Stena	Suspended	25	Creteaceous
2/07–20	566	56 19 58.22	87.10.15	Phillips	Wildcat	70	4512
	006	03 14 47.62	88.06.25	Dyvi Stena	Susp. Oil	25	
2/08–12	595	56 23 48.40	88.11.07	Amoco	Wildcat	69	
	006	03 26 15.20	00.00.00	Dyvi Stena		25	
7/12–07	583	57 06 31.92	88.06.20	BP	Appraisal	70	3852
	019	02 52 47.27	88.07.26	Vildkat	Suspended	25	Jurassic
7/12–08	590	57 05 01.28	88.10.03	BP	Appraisal	79	
	019	02 53 52.26	00.00.00	Vildkat		25	
25/01–07 R2	455	59 55 08.28	88.05.03	Elf	Appraisal	101	2722
	024	02 06 09.79	88.05.10	West Vanguard	Suspended	22	Creteaceous
25/01–08 SR2	466	59 54 03.28	88.05.12	Elf	Appraisal	102	2650
	024	02 06 09.79	88.05.15	West Vanguard	Suspended	22	Paleocene
25/01–10	570	59 57 08.58	88.04.19	Elf	Wildcat	99	4739
	024	02 05 48.11	88.09.14	Vinni	Dry hole	27	M. Jurassic
25/02–12	584	59 57 48.34	88.07.17	Elf	Appraisal	115	4100
	026	02 23 40.78	88.11.12	West Vanguard	Gas/condensate	22	U. Jurassic
25/02–12 A	596	59 57 49.89	88.11.12	Elf	Appraisal	115	
	026	02 23 21.64	00.00.00	West Vanguard		22	
30/06–22	578	60 43 57.26	88.05.21	Hydro	Appraisal	179	3336
	053	02 58 53.12	88.07.13	Polar Pioneer	Suspended Oil	23	U. Jurassic
30/09–07	592	60 25 04.73	88.11.02	Hydro	Wildcat	98	3565
	104	02 45 07.03	88.12.24	Polar Pioneer	Oil	23	U. Jurassic
33/09–14	571	61 26 00.26	88.02.17	Statoil	Appraisal	248	2982
	037	01 54 04.48	88.04.09	Deepsea Bergen	Oil	23	U. Jurassic
34/07–13	572	61 24 19.23	88.02.19	Saga	Wildcat	289	2994
	089	02 03 12.49	88.04.13	Treasure Saga	Oil	26	Triassic
34/08–03	581	61 24 28.04	88.07.14	Hydro	Wilcat	382	3328
	120	02 32 45.06	88.09.14	Polar Pioneer	Oil/Gas	23	U. Jurassic
34/08–03 A	589	61 24 28.04	88.09.14	Hydro	Appraisal	382	3230
	120	02 32 45.06	88.10.31	Polar Pioneer	Oil/Gas	23	M. Jurassic
34/10–33	591	61 07 34.44	88.09.25	Statoil	Appraisal	134	3870
	050	02 12 57.10	88.12.15	West Delta	Oil	29	L. Jurassic
34/10–33 A	591	61 07 34.44	88.12.15	Statoil	Appraisal	134	
	050	02 12 57.10	00.00.00	West Delta		29	
35/08–03	580	61 21 05.35	88.07.05	Gulf	Wildcat	373	3947
	058	03 32 02.63	88.10.15	Treasure Scout	Dry hole	23	M. Jurassic
6406/03–05	576	64 58 20.07	88.04.03	Statoil	Wildcat	302	4283
	091	06 58 33.65	88.06.02	West Delta	Dry hole	29	L. Jurassic
6406/08–01	560	64 21 55.01	87.09.15	Elf	Wildcat	348	4914
	131	06 26 48.16	88.04.11	Vinni	Gas/oil indications	23	L. Jurassic
6407/07–03	573	64 16 44.34	88.03.02	Hydro	Wildcat	333	3222
	107	07 09 00.13	88.05.19	Polar Pioneer	Suspended/Oil	23	Triassic
6407/05–01	562	64 36 22.40	87.12.11	Mobil	Wildcat	4306	
	121	07 28 26.54	88.03.04	Treasure Scout	Dry hole	25	M. Jurassic
6407/09–07	577	64 29 48.05	88.04.26	Shell	Wildcat	242	2561
	093	07 51 44.90	88.05.25	Treasure Scout	Dry hole	23	Triassic
6408/04–01	586	64 40 00.22	88.09.18	Conoco	Wildcat	209	2725
	133	08 15 27.84	88.10.18	Vinni	Dry hole	27	Triassic
6506/11–01	569	65 11 04.49	87.12.30	Statoil	Wildcat	246	4679
	134	06 39 53.88	88.03.31	Dyvi Delta	Gas indication	29	L. Jurassic
6506/12–08	579	65 00 59.32	88.06.04	Statoil	Appraisal	296	4335
	094	06 56 58.75	88.08.30	West Delta	Suspended	29	L. Jurassic
6507/08–03	587	65 27 34.61	88.09.03	Statoil	Wildcat	309	2075
	124	07 38 29.29	88.09.20	West Delta	Dry hole	29	Triassic
7125/01–01	597	71 53 24.20	88.11.30	Saga	Wildcat	250	2200
	135	25 11 15.40	88.12.29	Ross Rig	Oil	23	Triassic
7219/09–01	568	72 24 00.78	87.11.17	Hydro	Wildcat	356	4300
	136	19 57 11.68	88.02.25	Polar Pioneer	Dry hole	23	

Exploration wells	Lic. No. Prod. Lic.	Position North East	Drilling Spudded Completed	Operator Rig	Well type Completion classification	Water depth KBE	Total depth Geological period
7224/07–01	575	72 17 06.34	88.04.13	Statoil	Wildcat	268	3067
	137	24 18 02.98	88.06.19	Ross Rig	Oil	23	Triassic
7226/11–01	561	72 14 18.16	87.10.22	Statoil	Wildcat	238	5200
	139	26 28 44.78	88.04.11	Ross Rig	Gas	23	
7321/07–01	582	73 25 55.57	88.06.26	Mobil	Wildcat	475	3550
	140	21 04 31.75	88.10.22	Ross Rig	Dry hole	23	U. Triassic
7321/09–01	594	73 16 07.34	88.10.25	Hydro	Wildcat	459	
	141	21 41 00.86	88.11.28	Ross Rig	Traces of hydrocarbons	23	

Fig. 2.2.2.b
Wells drilled in 1988 in relation to structural main features of the North sea and Møre South



sons without having reached the prospect.

Fourteen of the 17 wildcat wells were drilled on new, previously undrilled structures. Sufficient quantities of hydrocarbons have been found to justify designating only four wells as finds, whereas eight were dry and two had not reached the prospect strata at the end of the year. The last three wildcat wells, which all discovered hydrocarbons, were drilled in separate parts of structures where finds had previously been made.

As concerns exploration drilling in general, the level of activity was highest in the North Sea, with 19 spudded wells. This is a small increase in relation to the preceding couple of years, whereas the areas off Mid-Norway suffered a clear decline in activity levels, with only six spudded wells. In the Barents Sea, activity has been constant, with one rig operating all year and four spudded wells.

Block 2/7
Phillips has drilled well 2/7–20 on the South Eldfisk structure in Production Licence 018. The well has proven oil in Jurassic sandstone at depths of 4,000 metres plus. A test was performed, in which maximum production rate was 556 Sm^3 oil and 224,000 Sm^3 gas per day through a choke of 9.5 mm.

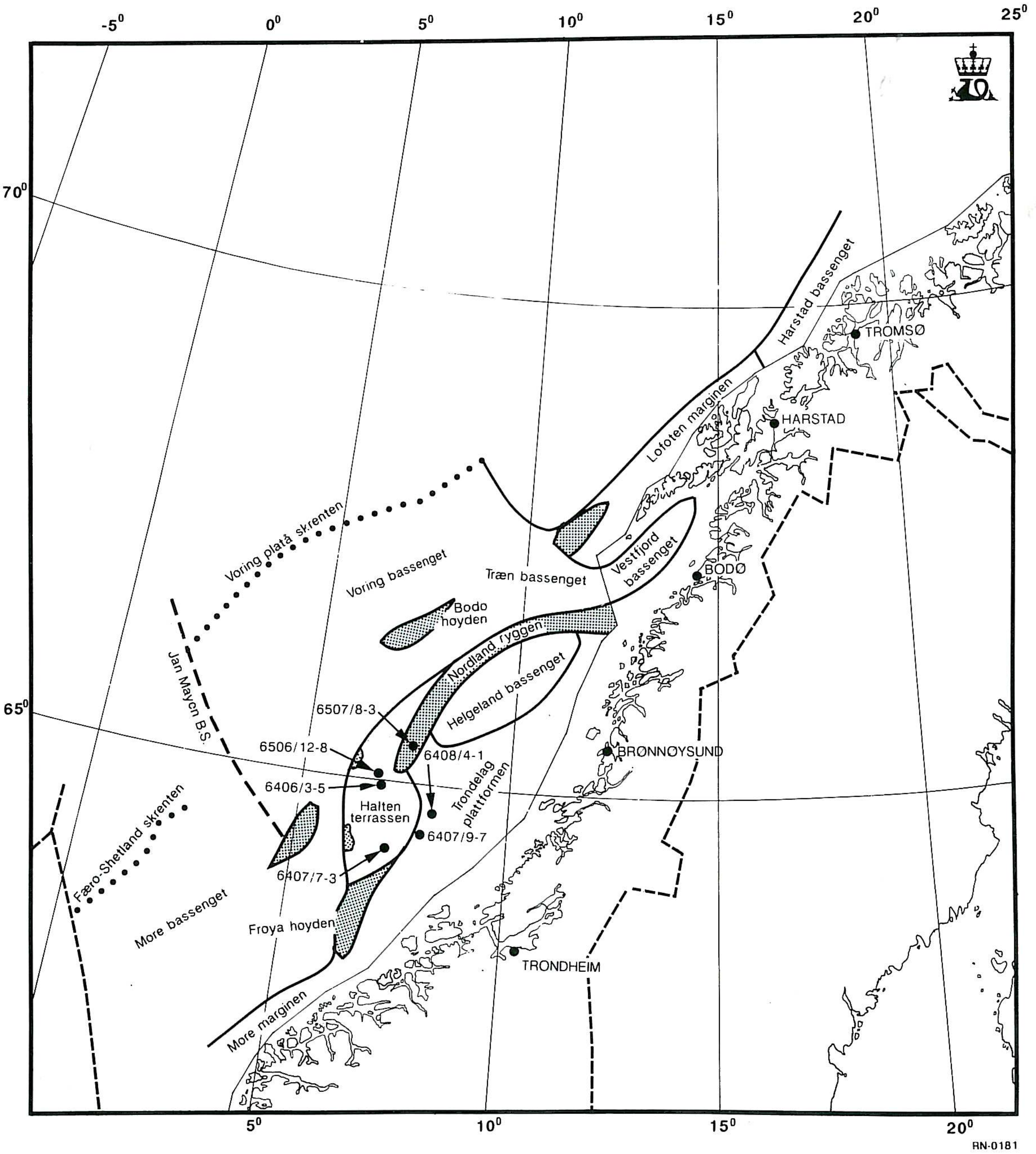
Block 34/7
Well 34/7–13 has been drilled by Saga in Production Licence 089 into a separate structure south of the Snorre field. Oil was discovered in Middle Jurassic sandstones. A test was performed, and maximum production was 1,350 Sm^3 oil per day through a choke of 16 mm. The gas/oil ratio was 51 Sm^3 per Sm^3. The reservoir's production characteristics are good.

These finds in Blocks 2/7–20 and 34/7–13 are of particular interest because they lie near existing and planned fields, and because provisional calculations show that they may be of such a size as to justify future development. It is, however, necessary to make further studies before the final extent of the finds can be determined.

Block 30/9
Norsk Hydro drilled wildcat well 30/9–7 in Production Licence 104 on a separate fault block on the south-western flank of the Oseberg field. Oil was discovered in Middle Jurassic sandstone strata. The best test produced 1,032 Sm^3 of oil per day through a choke of 19 mm. The oil's best density is 0.85 g per cm^3. Proven resources are relatively modest, but it is assumed that the discovery can be exploited in conjunction with the development of the Oseberg field.

Block 34/8
Norsk Hydro has in Production Licence 120 drilled wildcat 34/8–3 and appraisal well 34/8–3A centrally on the northern part of the A structure. Well 34/8–

Fig. 2.2.2.c
Wells drilled in 1988 in relation to structural main features on the Mid-Norwegian shelf

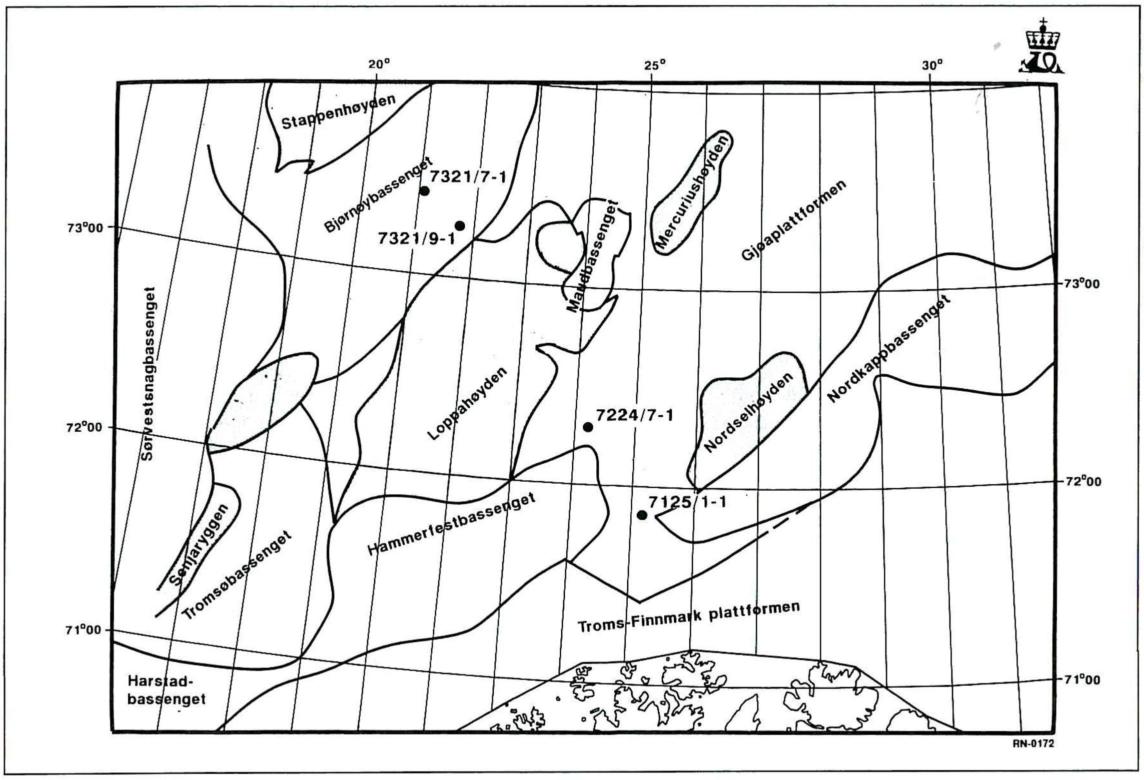


3 found gas and oil in Middle Jurassic rocks without finding the oil/water interface. Three production tests were performed, in which both the oil and the gas zone were tested. Maximum production from the oil zone was 67 Sm³ oil and 18,400 Sm³ gas per day through a 4.8 mm choke. Maximum production from the gas zone was 1.5 million Sm³ gas and 570 Sm³ condensate per day through a 25.4mm choke. In 34/8–3A, deviation-drilled out from 34/8–3, the structure's oil/water interface was found. Two production tests were carried out in the oil zone. Maximum production was measured as 1,450 Sm³ oil and 268,000 Sm³ gas per day through a 15.9 mm choke.

2.2.2.3 Further description of the various drillings
Block 2/2

Saga has drilled wildcat 2/2–4 on the Alpha structure, Production Licence 066, without finding any trace of hydrocarbons. A well was previously drilled on the same structure, in which oil was found in Ju-

Fig. 2.2.2.d
Wells drilled in 1988 in relation to structural main features of the Barents sea



rassic sandstones. Proven resources have now been considerably reduced, and are at present not thought commercially exploitable.

Block 2/5
In Production Licence 066 Amoco has drilled the other appraisal well 2/5–8 on South East Tor. The result of the drilling is most disappointing, in that the find showed only insignificant traces of hydrocarbons in the upper part of the Tor formation. Resources for South East Tor have therefore been reduced.

Block 7/12
As operator for Production Licence 019, BP has drilled two appraisal wells on the Ula field. The results have been highly positive and have increased the field's known, recoverable reserves considerably. 7/12–7 showed that the oil/water interface on the east flank of the Ula field lay deeper than previously supposed. The well was not production-tested. Well 7/12–8 was drilled to evaluate the reservoir characteristics of the field's south-eastern part. Here, too, a deeper oil/ water interface was found. A production test and a water injection test were performed. The highest production rate was 280 Sm^3 oil per day through a 16 mm choke. The Petroleum Directorate's provisional resource estimate is 52.5 x 10^6 Sm^3 oil and 3.3 x 10^9 Sm^3 gas.

Block 25/1
Elf has drilled 25/1–10 in Production Licence 024 on a separate Jurassic structure beneath the Frigg field itself. No hydrocarbons were found.

Block 25/2
As operator for Production Licence No. 026, Elf has drilled and tested wildcat well 25/2–12. The well was drilled on a separate structure north of East Frigg, where 25/2–4 had previously discovered gas and oil. Well 25/2–11 discovered gas in Jurassic sandstones. As several reservoir factors have not yet been clarified, and test attempts were unsuccessful on account of sand production, it was decided to do deviation drilling to obtain more information about the reservoir. At the end of the year, 25/2–12A had not yet reached the reservoir.

Block 30/6
In Production Licence 053 Norsk Hydro drilled appraisal well 30/6–22 on the Beta structure north-east of the Oseberg field. Oil was discovered in Middle Jurassic sandstone strata. Two production tests were performed, in which the best test rate produced 485 Sm^3 oil and 31,500 Sm^3 gas per day through a 12.7 mm choke. The density of the oil is 0.83 g/cm^3. The drilling confirms the extent of the field to the north.

Block 33/9
As operator for Production Licence No. 037, Statoil has drilled an appraisal well in the block. Well 33/9–14 was drilled in the west of the Statfjord North field. Oil was discovered in Middle Jurassic sandstones. Two tests were performed, and the best test produced 1,420 Sm^3 of oil per day through a 14 mm choke.

Block 34/10
In Production Licence 050 Statoil has drilled 34/10–33, which is an appraisal well on the northern part of South Gullfaks. Well 34/10–33 showed a much thicker oil zone than expected and the oil/water interface was not encountered. The discovery was tested and maximum production was 1,350 Sm^3 oil and 215,000 Sm^3 gas per day through a 12.7 mm choke. Well 34/10–33A was deviationally drilled from 34/10–33 to determine the oil/water interface.

Block 35/8
As operator for Production Licence 058 Gulf has drilled 35/8–3 on a new structure in Block 35/8. The result of the drilling was disappointing, as the reservoir carried water.

Block 6406/3
Statoil has drilled appraisal well 6406/3–5 in Production Licence 091, on the Lambda structure in the north-east of the block. Only a little oil was found at the top of the reservoir, which has very poor reservoir characteristics. The hole was not tested, and the total resources are very limited and can probably not be exploited commercially.

Block 6406/8
In Production Licence 131 Elf has drilled 6406/8–1 on a deep structure west of the Njord field. Traces of hydrocarbons were found and two tests performed. The results were disappointing, as the first test produced small quantities of water and the other test showed that the reservoir was non-permeable.

Block 6407/7
Norsk Hydro drilled wildcat well 6407/7–3 in Production Licence 107 on a separate part of the Njord structure north-west of the first well and found oil in Jurassic rocks. The reservoir was tested in three zones and maximum production was measured at 936 Sm^3 oil and 380,000 Sm^3 gas per day through a 16 mm choke. The results are positive and new resource estimates are being prepared by the Norwegian Petroleum Directorate.

Block 6407/9
Norske Shell has drilled 6407/9–7 on a separate structure north-west of the Draugen field, in Production Licence 093. No hydrocarbons were found.

Block 6408/4
In Production Licence 133 Conoco has drilled 6408/4 on a structure north-west of Draugen. No hydrocarbons were found here either.

Block 6506/12
Appraisal well 6506/12–8 has been drilled on Smørbukk South, in Production Licence 094. As in previous wells, oil and gas was found in Middle and Lower Jurassic sandstones. Two tests were performed, and the highest oil production was measured at 1,475 Sm^3 and highest gas at 550,000 Sm^3 per day through a 31.7 mm choke.

Block 6507/8
In Production Licence 124 Statoil has drilled 6507/8–3 in the north-eastern corner of Block 6507/8. Insignificant quantities of gas were proven in Middle Jurassic rocks. The hole was not production tested.

Block 7125/1
Saga has as operator for Production Licence 135 drilled wildcat well 7125/1–1 on an east-west structure in the middle of the block. The well proved a thin oil zone in sandstones 400 m under the seabed, and insignificant quantities of gas were found in deeper Triassic sandstones. The hole was not production-tested.

Block 7224/7
As operator for Production Licence 137, Statoil has drilled wildcat 7224/7–1 in Key Area II. Only traces of hydrocarbons were found and the well was not production-tested.

Block 7321/7
As operator for Production Licence 140, Mobil has drilled wildcat 7321/7–1 in Key Area III. Only traces of hydrocarbons were found, and the well was not production-tested.

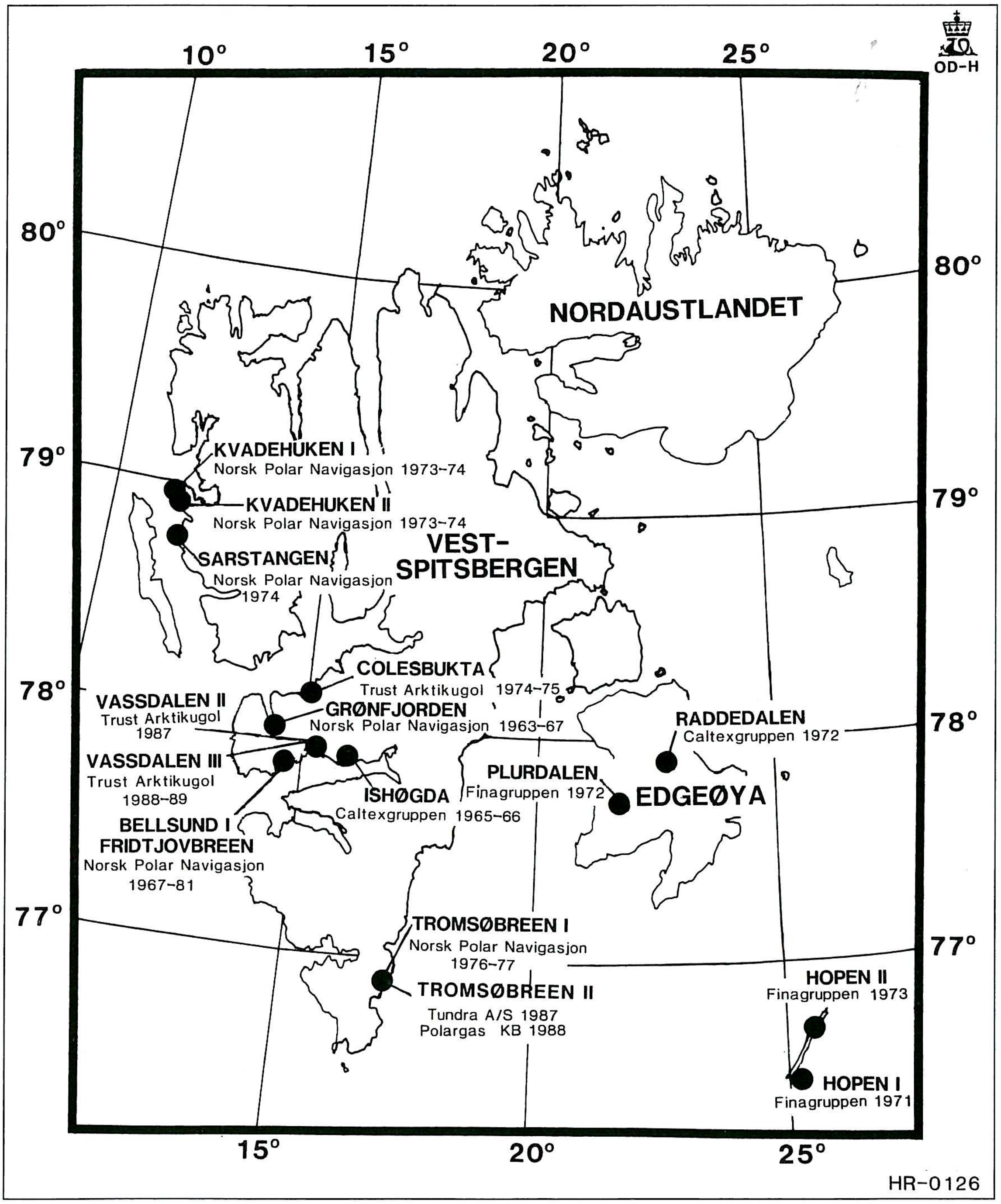
Block 7321/9
Norsk Hydro, as operator for Production Licence 141, drilled wildcat 7321/9–1. Only traces of hydrocarbons were found in Jurassic rocks , and the well was not production-tested.

2.2.2.4 Svalbard
In collaboration with Store Norske Spitsbergen Kullkompani, Norsk Hydro has shot 280 km land seismics in the area between Sassendalen, Reindalen and east to Nordmannsfjorden. In addition, Statoil has shot 710 km marine seismics in Isfjorden, Spitsbergen.

In 1988 one new drilling operation was started on Svalbard, and one drilling operation was resumed after demobilisation for the winter.

The Russian company Trust Arktikugol began drilling its second well in Vassdalen, after the first drilling was stopped in 1986 because of technical

Fig. 2.2.2.4
Well locations on Svalbard



problems. Drilling permission for the hole was given 30 March 1988. At the end of the year the hole had reached 2,342 metres, and the operation is continuing in 1989.

The Swedish operation Polargas Prospektering KB resumed its drilling operation on Haketangen by agreement with the previous year's operators Tundra, Nordisk Polarinvest and the licensees for the concession area. After two weeks' mobilisation the drilling operation began on 13 June 1988. In 1987 the hole was drilled to 1,732 metres and in 1988 it was drilled a further 605 metres to a depth of 2,337 metres. In addition to three tests made in 1987, ten tests were performed in 1988, the tests revealing minor quantities of gas. The hole was completed 22 August 1988 and the rig was dismantled for storage over the winter. Polargas Prospektering KB is working on plans to use the rig to drill a hole at Kvalvågen in 1989.

Figure 2.2.2.4 shows the drilling sites on Svalbard, and Table 2.2.2.4 shows the drilling permits given for Svalbard in connection with drilling for oil and gas.

2.3 FIELDS UNDER CONSIDERATION

2.3.1 The North Sea

Fields around Ula

Block 1/3 is adjacent to the Gyda field to the west, and Elf Aquitaine is the operator. A minor oil discovery has been made, which probably extends into Block 2/1. There is no connection between the Gyda field and the 1/3–3 structure.

Block 2/2 is adjacent to Gyda eastwards, with

Table 2.2.2.4
Drilling activity on Svalbard

Exploration well location	Position North East	Spudded	Completed	Drilling days	Operator Licensee	Total depth metres	KB elev. over MSL in m
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 Navig. Norsk Polar Navig.	971,6	7,5
7715/3–1 Ishøgda I (Spitsbergen)	77 50 22 15 58 00	01.08.65	15.03.66	277	Texaco Caltex group	3304	18
7714/3/1 Bellsund I (Fridtjofsbreen)	77 47 14 46	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 Navig. Norsk Polar Navig.	405	
7625/7–1 Hopen I (Hopen)	76 26 57 25 01 45	11.08.71	29.09.71	50	Forasol Fina group	908	9,1
7722/3–1 Raddedalen (Edgeøya)	77 54 10 22 41 50	02.04.72	12.07.72	100	Total Caltex group	2823	84
7721/6–1 Plurdalen (Edgeøya)	77 44 33 21 50 00	29.06.72	12.10.72	108	Fina Fina group	2351	144,6
7811/2–1 Kvadehuken I (Brøggerhalvøya)	78 57 03 11 23 33	01.09.72 21.04.73	10.11.72 19.06.73	112	Terratest a/s Norsk Polar Navig.	479	
7625/5–1 Hopen II (Hopen)	76 41 15 25 28 00	20.06.73	20.10.73	123	Westburne Int. Ltd Fina group	2840,3	314,7
7811/2–2 Kvadehuken II (Brøggerhalvøya)	78 55 32 11 33 11	13.08.73 22.03.74	19.11.73 16.06.74	186	Terratest a/s Norsk Polar Navig.	394	
7811/5–1 Sarstangen (Forlandsrevet)	78 43 36 11 28 40	15.08.74	01.12.74	109	Terratest a/s Norsk Polar Navig.	1113,5	5
7815/10–1 Colesbukta (Nordenskiøld Land)	78 07 15 02	13.11.74	01.12.75	373	Trust Arktikugol	3180	12
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	Terratest a/s Norsk Polar Navig.	990	6,7
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	Deutag Tundra A/S	2337	6,7
7715/1–1 Vassdalen II (Van Mijenfjorden)	77 49 57 15 11 15	22.01.85	1)		Trust Arktikugol	2481	15,13
7715/1–2 Vassdalen III (Van Mijenfjorden)	77 49 57 15 11 15	30.03.88			Trust Arktikugol		15,13

1) Drilling concluded because of technical drilling problems.

Saga as operator. A minor oil discovery has been made here also. The water depth is very moderate, 60 m.

In the block adjacent to the Ula field to the west, 7/11, an oil find has been made, and work has been done on plans for test production. The plans are to transfer the wellstream to the Cod installation for processing in its test separator, and to lead the oil and gas, together with the Cod oil and gas, to Ekofisk.

A minor oilfield has also been found in Block 7/8 to the north west of Ula.

Any development of these smaller finds should be considered in connection with the development of the infrastructure in the area.

Gullfaks South, 34/10-Beta and 34/10-Gamma

Block 34/10 was allocated in 1978 with Statoil as operator, cf. the description of Gullfaks, Chapter 2.5.12. Gullfaks South is located in the middle of the block (about 9 km south of the Gullfaks field). Beta is located to the west of Gullfaks South and extends into 33/12. Gamma is located in the south-eastern corner of the block.

Gullfaks South is structurally difficult. Several independent gas/oil, gas/water and oil/water interfaces have been observed in the field. Hydrocarbons have been discovered in Middle and Lower Jurassic and Triassic sandstones. Up to now, six wells have been drilled on Gullfaks South, one on Beta and one on Gamma. Well 34/10–33 was drilled in the last quarter of 1988 on the northern part of Gullfaks South. Oil and gas has been discovered in Middle Jurassic sandstone. Well 34/10–33 proved far more oil in Brent than previously estimated.

Production tests have been made in the oil zone. The new 3D seismics collected over Gullfaks South are ready for processing and interpretation in 1989.

Results from reinterpretation of old seismics and from 34/10–33 indicate that there is more oil and less gas in Gullfaks South than previously thought. When 34/10–33 was planned, the plans included drilling of a horizontal part in the oil zone in the Brent reservoir. This was to be tested in order to prove whether it was possible to increase recovery in the Brent reservoir. Because the well proved a considerably larger oil column than expected, it is now more uncertain whether test production will be implemented.

Gullfaks South contains both oil, condensate and unassociated gas. The operator is considering both parallel oil and gas production and sequential production (first oil, later gas).

In September of 1987, Statoil presented a feasibility study for Gullfaks South. The study shows five alternative platform concepts. It is envisaged that Gullfaks A will be used for both processing and storage of oil. Gas transportation both to Great Britain and the Continent is under consideration. The date of presentation of a plan for development and operation is uncertain.

The Oseberg area

This is one of the richest prospective areas on the Norwegian shelf. Finds of various sizes have been made in the fields Oseberg, Brage, Veslefrikk, Huldra, 30/ 6 Beta, 30/ 6 Beta Saddle, 30/6 Kappa, 30/6 Gamma North, 30/9 Omega and 30/9–06.

The Oseberg field itself came on stream in December 1988. In addition to Oseberg it has been decided to develop the fields Veslefrikk and 30/6 Gamma North.

Brage

The Brage field is located in Block 31/4, which was allocated as Production Licence No. 055 in 1979. Norsk Hydro is the operator. Plans for development and operation were presented to the authorities in December of 1987. Final approval of the plan was postponed by up to five years by Storting Proposition No. 56 (1987–1988).

Oil has been discovered in three formations: Statfjord, Fensfjord and Sognefjord. The operator has estimated recoverable reserves at 46.2 x 10^6 Sm^3 oil and 3.5 x 10^9 Sm^3 gas.

It is planned to develop the field with an integrated production, drilling and accommodation installation. The installation will have an average processing capacity of 12,300 Sm^3 per day.

Brage 30/6 Beta and 30/6 Beta Saddle

30/6 Beta and Beta Saddle consist of two structural elements separated from each other by a sealing fault. Both structural elements lie in Production Licence 053. Norsk Hydro is operator. In both structures oil has been found in sandstones in the Brent group. A probable resource estimate for the two structures is in the area of magnitude 40 x 10^6 Sm^3 oil recoverable.

There are several alternatives for the development of the Beta area. One likely alternative is a production installation in steel or concrete with a process capacity in the order of magnitude of 12,700 Sm^3 oil per day and coordination between 30/6 Beta and the Oseberg field. Produced oil from the Beta area will be transportable through the pipeline from Oseberg to Sture.

30/9 Omega

30/9 Omega is to the west of the Oseberg Field Centre. The main bulk of the resources are in Production Licence 079, but the structure stretches also south-east into production licence 104. Norsk Hydro is the operator.

Oil and gas have been found in the Ness and Tarbert formations. Resource estimates for the find are highly uncertain, and at least one new appraisal well must be drilled on the structure before development is an option.

Some of the Omega structure is within the extraction radius for the Oseberg Field Centre, and can therefore be produced with the help of wells on the installation. The other resources on Omega can be depleted either by seabed wells or a simple wellhead installation connected to Oseberg.

Statfjord North

Statfjord North consists of two separate reservoirs, of Upper and Middle Jurassic age respectively. The lower reservoir may possibly extend into Block 34/7. Three wells have been drilled on Statfjord North. Well 33/9–14 was drilled to the south-west of the structure in the spring of 1988. Hydrocarbons of the Upper Jurassic were discovered and tested. The well yielded small adjustments of the resource basis, and the operator's estimates for recoverable reserves is 22.6 x 10^6 Sm^3 oil and 1.2 x 10^9 Sm^3 gas.

Statoil has considered developing the field with seabed wells or, alternatively, simplified installation solutions. Production start is scheduled for 1993.

The Norwegian Petroleum Directorate is engaged in a new mapping of Statfjord North, and an updated reserves estimate will be available in 1989.

Statfjord East

Statfjord East is about 7 km north-east of the installation on Statfjord C. The structure stretches into Block 34/7. Three holes have been drilled on the Statfjord East structure, two in 33/9 and one in 34/7 with hydrocarbons proven and tested in all three holes. No new wells were drilled in 1988.

The Norwegian Petroleum Directorate's estimate of recoverable reserves is 19.0 x 10^6 Sm^3 oil and 2.5 x 10^9 Sm^3 gas. These deposits are in the Brent group, and the operator's reserves estimates presuppose pressure-maintenance by means of water injection. The operator has considered developing the field by means of seabed wells or, alternatively, simplified installations. Production start is planned for 1994.

In 1988 the Petroleum Directorate made a reservoir study of Statfjord East, and updated reservoir estimates will be available in 1989.

Frøy

Hydrocarbons were proven in the Sleipner formation via 25/5–1 in 1987. The field is mostly in Production Licence 102, which was allocated in the ninth licensing round with Elf as operator.

The operator is planning an appraisal well in 1989 for further determination of the resource basis. Elf has estimated the recoverable resources at 18 x 10^6 Sm^3 oil and 3 x 10^9 Sm^3 gas.

In the course of 1988 Elf has carried out concrete field studies on Frøy. No decision as to final development concept has yet been taken. The operator's objective is to submit a commerciality declaration and prepare a development and operation plan in the course of 1989. Operation of the field is, however, largely dependent on the outcome of an appraisal well on the field planned in the course of the first six months of 1989.

Balder

Block 25/11 was allocated in 1965, under Production Licence No. 001, with Esso as operator. Esso was also granted Blocks 25/8 and 25/10 in 1969, under Production Licences Nos. 027 and 028.

The field was discovered in 1974 with drilling of exploration well 25/11–5, where oil was discovered in Palaeocene sandstones. In Block 25/8, minor quantities of oil have also been discovered in corresponding sandstone strata.

No decision has been made so far concerning the development of the field, and no drilling has been done on this field since 1981. The Norwegian Petroleum Directorate's estimate of recoverable oil reserves is 35 x 10^6 Sm^3.

The landing application was submitted in December 1980, but a marked downwards adjustment of the reserves weakened the economics of the project, and the application was withdrawn. The operator company has the field under evaluation.

2.3.2 Haltenbanken

Heidrun

Eight exploration and appraisal wells have been drilled on the field, which contains heavy oil with a superadjacent gas cap. The reservoir is heavily faulted, and contains a number of reservoir formations. For reasons of reservoir conditions, the gas cap should be produced after the main part of the oil has been produced. The Norwegian Petroleum Directorate has downgraded the resource estimate to 87 x 10^6 Sm^3 oil and 43 x 10^9 Sm^3 gas. The Directorate would especially point to the uncertainty regarding the resources on the Heidrun field.

The first production phase from the field should, according to the plan, begin in the second half of 1990 with the aid of a production ship. Such an early production phase will provide information on the reservoir that may be useful in later phases of the development. An updated plan for the early production phase was submitted to the authorities and approved in the autumn of 1988. The operator, however, broke the contract for the building of the ship in December 1988, and the further operation of the Heidrun field is therefore uncertain.

The operator is planning to start main production in a subsequent phase. It is thought that the development solution for this phase will be a tension-leg platform with concrete base. There will in addition be a need for seabed wells connected to the main installation.

Midgard

A total of four exploration wells have been drilled on the Midgard field. The structure is divided into three parts by two transverse faults. The field consists mainly of gas, and the reservoir properties are good.

In one of the fault blocks, a thin oil zone has been discovered which it may be difficult to produce, since it is located between a large gas cap and a water zone. The Norwegian Petroleum Directorate has estimated recoverable reserves at 80 x 10^9 Sm^3 gas and 15 x 10^6 Sm^3 oil.

Production rate and production start will be dependent on the gas market. For development solutions are being considered both a fixed seabed platform and a floating installation. It is also being considered whether to develop parts of the field with seabed wells connected to Heidrun.

Njord

Three exploration wells have now been drilled on 6407/7, and all have proven oil. One hole was drilled in 6407/10 that did not find oil. It is nevertheless considered that the field stretches into Block 6707/10.

The last hole, the northernmost on Block 6707/7, found oil in a downfaulted block. The Directorate's estimate for recoverable resources on the Njord field is 25 x 10^6 Sm^3 and 4 x 10^9 Sm^3 gas. These figures do not include oil resources proven in 1988. The field has been mapped with 3D seismics.

Smørbukk and 6506/12-Beta, Block 6505/12

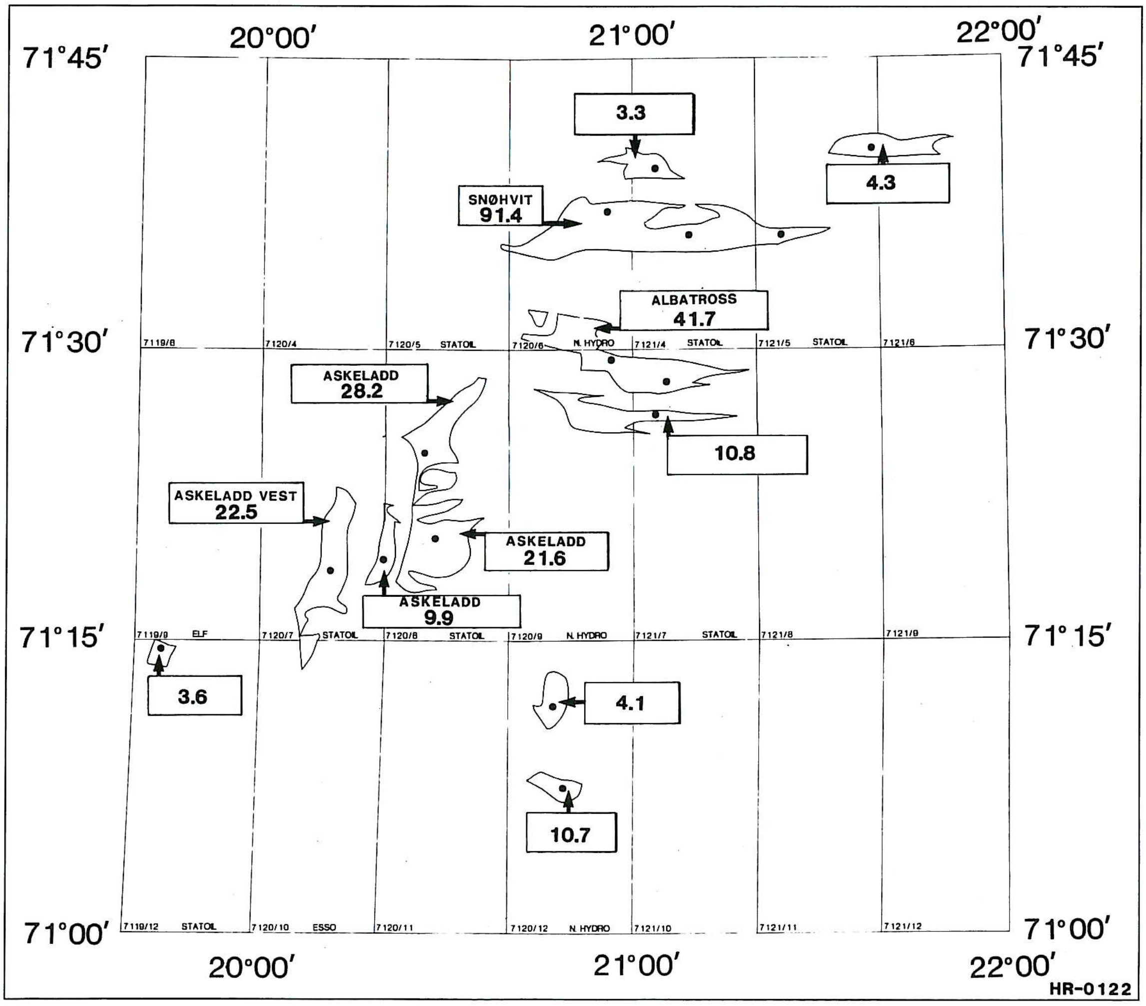
A total of eight wells have been drilled on the block. In 1988, one well was drilled into the 6506/12-Beta structure, and work is being done on test production from this well.

The Norwegian Petroleum Directorate has begun to map 6506/12-Beta based on 3D seismics, and the work will be finished in 1989.

The Directorate's resource estimate for the main Smørbukk structure is 20 x 10^6 Sm^3 condensate and 65 x 10^9 Sm^3 gas. The estimate for the resources in 6506/12-Beta is 22 x 10^6 Sm^3 condensate and 11 x 10^9 Sm^3 gas.

Fig. 2.3.3
Troms I. The resource basis. Recoverable gas indicated in $10^9 Sm^3$

OD-H



Among the two discoveries of the block, 6507/12-Beta is the better surveyed and most mature for development. The time for development and the selection of development solution for the discoveries in this block will depend on the market development for gas from Haltenbanken. A phased development may also be assessed for adaptation to the gas market. As concerns the processing and transportation of gas from the Smørbrukk field, it will be natural to consider this in light of other development projects in this area.

Tyrihans
Two wildcat wells have been drilled on the field, which consists of two structures, one with gas/condensate and one with a thin oil zone and a gas cap. The resources are 16 x 10^6 Sm^3 oil/condensate and 40 x 10^9 Sm^3 gas.

6403/3
Exploration well number two in this block hit reservoir sandstone which was oil-filled. In 1987 a new well was drilled in the continuation of this structure. This hole hit non-permeable sandstone.

2.3.3 Troms
The proven gas resources on Troms I is estimated to be 252 x 10^9 Sm^3 (Figure 2.3.3).

In the last two years the licensees on the Snøhvit field have submitted new development solutions. According to the licensees, the most financially and technically promising solutions are the following:

Two semi-submersible gas processing installations with seabed-completed wells. Gas and condensate sent through separate pipes to LNG terminal plant on shore.

Fixed gravity-based concrete installation (GBS-PDQ) with completed wells for the installation. The gas is transported in pipelines to shore LNG terminal, while the condensate is stabilised, stored and loaded on the field.

LNG production on the field from one or two specially-built ships.

For all concepts the annual gas production rate will be 6 x 10^9 Sm^3, which indicates a sales volume of about 5 x 10^9 Sm^3 per year.

Market analyses do not appear to allow for sales of LNG from Troms I to the USA before 1995. The licensees are now considering alternative use of this gas, and the operator will submit a major field development study in January 1989.

2.4 FIELDS APPROVED FOR DEVELOPMENT
2.4.1 Veslefrikk
Production Licence 052

Licensees

Den norske stats oljeselskap a.s. (Statoil)	50.0 %
Unocal Norge A/S	20.0 %
Norsk Hydro Produksjon a.s.	10.0 %
Deminex (Norge) A/S	12.5 %
Norske Deminex A/S	2.5 %
Svenska Petroleum Exploration A/S	5.0 %

The field is in the south-east of Block 30/3, which was allocated in 1979 with Statoil as operator. Four wildcats have been drilled in the block and two exploration wells on the Veslefrikk structure itself. In both these wells oil was proven at two different levels in the sandstones of the Brent and Cook formations.

The commerciality report was submitted to the partners in November 1986. A development and operations plan was submitted in February 1987 and approved by Storting Proposition No. 73 (1986–1987). The operator has estimated the total oil recovery from the field at 36.4 x 10^6 Sm^3, and total production of associated gas at 3 x 10^9 Sm^3. Production will be by water injection. In addition the first predrilled production wells proved resources in the Statfjord and Tarbert reservoirs.

The field is to be developed by a fixed wellhead installation with steel base installed over a frame with six predrilled wells.

The semi-submersible drilling vessel "West Vision", which is being rebuilt as a floating production installation, will be anchored and coupled to the fixed wellhead installation.

Fig. 2.4.1
Planned installations on Veslefrikk

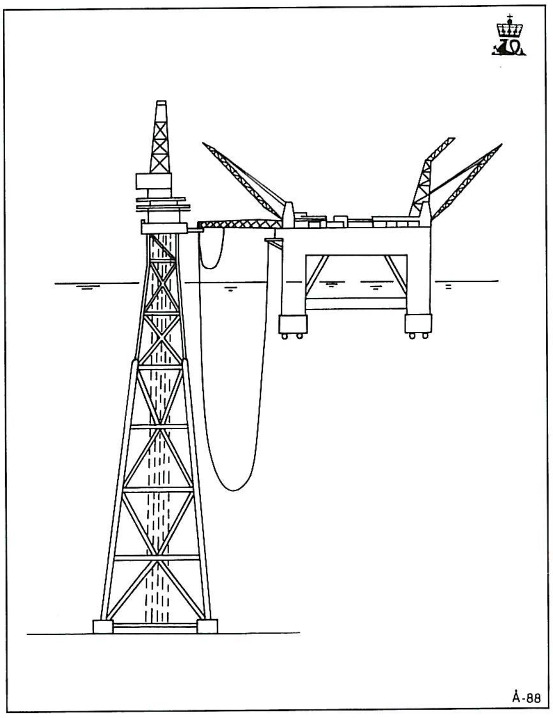


Figure 2.4.1 shows the planned installations.

It is planned to connect an oil pipeline to the Oseberg transport system for transport to the Sture terminal. Gas can be transported via the Statpipe system. The gas has not yet been sold.

The development is estimated to cost NOK (1988) 6.5 billion including well costs. The low costs and the short construction time means that the field is profitable even at today's oil prices. On the operator's plans the field will be ready to produce in October 1989.

Preparedness

The Norwegian Petroleum Directorate is following the work on this development closely, as it raises new problems on the preparedness side, given the design of a fixed manned wellhead installation and a mobile production and accommodation installation. The Norwegian Petroleum Directorate has been particularly concerned about the accessibility of rescue and evacuation aids.

Metering system

The metering stations for oil and gas are being supplied from yards in 1988. Fitting on the Veslefrikk B installation will take place at the beginning of 1989.

2.4.2 30/6 Gamma North

Licensees

The State share has been increased for Production Licence 053 after exercise of the sliding scale vis-à-vis the foreign companies. The last increase was from 1 April 1989 in connection with the approval of the revised plan for development and operation of Oseberg.

The owner interests in Production Licence 053 (from 1 April 1988) are:

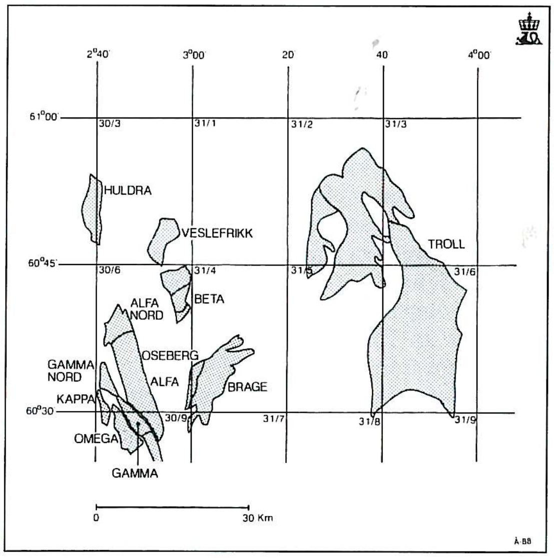
Den norske stats oljeselskap a.s. (Statoil)	59.04 %
Norsk Hydro Produksjon a.s.	12.25 %
Saga Petroleum a.s	7.35 %
Elf Aquitaine Norge A/S	9.33 %
Mobil Development Norway A/S	7.00 %
Total Marine Norsk A/S	4.67 %

In order to meet the need for extra injection gas in connection with the putting forward of Oseberg Phase II, approval was given by Royal Decree of 23 December 1988 for the Gamma North structure in Block 30/6 to be developed. This structure is in Production Licence 053 outside the "Oseberg Unit" (the unitised Oseberg field).

Gamma North contains gas with an underlying thin oil zone. In order to produce the oil, a horizontal well is to be drilled, which will produce from the oil zone at the same time as it produces the gas necessary for injection in Oseberg. Production start is October 1991.

Production will be from a seabed-completed well operated from Oseberg C. Investments in the horizontal well are estimated an NOK (1988) 419 mil-

Fig. 2.4.3
The Oseberg and Troll area



lion. Experience from the first well can determine whether another one will be drilled.

More information on 30/6 Gamma North can be found in the section on Oseberg.

2.4.3 Troll

Production Licences 054 and 085

Licensees in Production Licence 054

Norske Conoco A/S	5.000 %
Norsk Hydro Produksjon a.s.	5.000 %
Mobil Development Norway	5.000 %
A/S Norske Shell	35.000 %
Den norske stats oljeselskap a.s (Statoil)	47.000 %
Total Marine Norsk A.S	1.000 %
Elf Aquitaine Norge A/S	2.000 %

Licensees in Production Licence 085

Norsk Hydro Produksjon a.s.	9.000 %
Elf Aquitaine Norge A/S	2.000 %
Total Marine Norsk A.S	1.000 %
Saga Petroleum a.s.	6.000 %
Den norske stats oljeselskap a.s (Statoil)	82.000 %

The Troll field covers parts of Blocks 31/2, 31/3, 31/5 and 31/6 (Figure 2.4.3). Allocation of Block 31/2 was made in 1979, while the other three blocks were allocated in July 1983. Block 31/2 belongs to Production Licence 054 with Norske Shell as operator. Blocks 31/3, 31/5 and 31/6 belong to Production Licence 085. Operatorship is here split between Statoil, Saga and Norsk Hydro. Unitisation of the two production licences has been completed.

The reservoir extends through three geological formations, all Upper Jurassic. The uppermost (Sognefjord) is dominated by medium to coarse grained sandstone with good reservoir characteristics. This formation, the predominant one in the reservoir, overlies the middle (Heather) formation consisting of silt and fine grained sandstone with relatively high mica content. Flow properties in this formation are therefore poor in comparison with the overlying one. The bottom formation consists of sandstone with variable reservoir characteristics.

At the top of Troll West in Block 31/2 and at the top of Troll East in Block 31/6 and 31/3 there is a gas column of 200 metres plus. The column varies over the field and is considerably smaller in the western parts. This western part of Troll, largely covered by Block 31/2, has a 22–27 metre oil column underlying the gas, compared with 10–17 metres further east in the block. In Troll East the proven oil layer varies in thickness from zero to a few metres.

The resources in Troll as estimated by the Directorate are 1,288 x 10^9 Sm^3 gas and 41 x 10^6 Sm^3 oil. In its estimates the Directorate has not yet included oil in those parts of the field with a 10–17 metre oil column, though the feasibility of producing from this part of the field is still being considered.

A/S Norske Shell, the operator of the first gas development on Troll, presented its plan for development and operation of Gas Phase I in September 1986. The plan was considered by the Storting in December 1986. Development will consist of one concrete base platform with a production capacity of 90 million Sm^3 gas per day with all process trains installed. The plan will be updated and considered by the authorities in the course of 1989. In addition to the main gas development, it has been decided to build a subsea production system (the Troll module) for gas to be used for gas injection on the Oseberg field from 1991. Norsk Hydro is operator for this project. The plans call for production of about 2.2 x 10^9 Sm^3 of gas a year.

The initial oil development on the field is expected to be development of the southern part of the thick oil zone.

Costs

Total development costs for Troll Phase I are estimated at about NOK (1988) 26.1 billion. Total operating costs to the year 2010 are estimated at about NOK (1988) 18.0 billion.

2.4.4 Snorre

The Snorre field is located in Blocks 34/4 and 34/7. Block 34/4 was allocated as Production Licence No. 057 in 1979. Block 34/7 was allocated as Production Licence No. 089 in 1984. Saga is operator for both blocks.

Licensees in Production Licence 057

Saga Petroleum a.s	15.00 %
Den norske stats oljeselskap a.s (Statoil)	50.00 %
Amerada Hess Norge A/S	5.00 %
Texas Eastern Norway Inc.	5.00 %
Deminex (Norge) A/S	25.00 %

Licensees in Production Licence 089

Saga Petroleum a.s	10.00 %
Den norske stats oljeselskap a.s (Statoil)	50.00 %
Esso Exploration and Production Norway A/S	15.00 %
Norsk Hydro Produksjon a.s	12.00 %
Elf Aquitaine Norge A/S	8.00 %
Deminex (Norge) A/S	4.00 %
Det Norske Oljeselskap a.s	1.00 %

Ownership distribution after unitisation

The licensees have estimated a distribution of the reserves in Snorre of 30 % in Block 34/4 and 70 % in Block 34/7. The ownership interests in the unitised Snorre field are:

Saga Petroleum a.s	11.26 %
Den norske stats oljeselskap a.s (Statoil)	51.00 %
Amerada Hess Norge Inc.	1.46 %
Texas Eastern Norway Inc.	1.46 %
Deminex (Norge) A/S	10.03 %
Esso Exploration and Production Norway A/S	10.33 %
Norsk Hydro Produksjon a.s	8.27 %
Elf Aquitaine Norge A/S	5.51 %
Det Norske Oljeselskap a.s	0.69 %

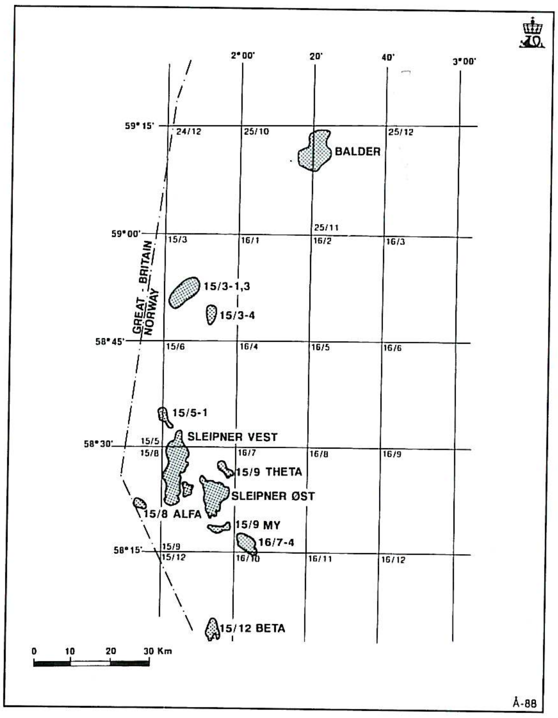
Plans for the development and operation of the Snorre field were submitted to the authorities on 1 September 1987. The Storting approved the development plan in 1988.

Snorre is a large oilfield. Commercially recoverable reserves have been estimated by the operator at about 120 x 10^6 Sm^3 oil and 7 x 10^9 Sm^3 associated gas. The Norwegian Petroleum Directorate's reserves estimate is 108 x 10^6 Sm^3 oil and 6.6 x 10^9 Sm^3 associated gas. The Directorate would point to the uncertainty associated with the reserves on the Snorre field, which contains a number of supplementary reserves in both the Snorre structure itself and outside the field (separate structures).

The oil, which is strongly undersaturated, is divided between two reservoirs: the Statfjord reservoir and the Lunde reservoir. The reservoirs have been well surveyed, and the volumetric control is relatively good. There is uncertainty as concerns the extent of the sand units and the communication in the Lunde reservoir. This may be of importance for how it will develop during production. The depth of the reservoir is about 2,500 m. Drilling and testing has discovered three different oil/water interfaces, the deepest in the western part of the field.

The water depth varies over the field from 300 m in the south to 370 m in the north. It is planned for the field to be developed in two phases, Phase 1 consisting of a floating tension-leg platform in the south and a seafloor installation in the central part of the field. The oil will be processed in two steps on the Snorre platform, and will afterwards be transported to Statfjord for final processing. Estimated development costs for Phase I are about NOK

Fig. 2.4.5
The Sleipner and Balder area



(1988) 22 billion. Phase II of the development concerns the depletion of the central and northern part of the field and involves two development options. One possibility is the moving of the platform, the other is a further development with installations on the seafloor.

2.4.5 Sleipner East

Production Licence 046

Licensees

Esso Exploration and Production Norway A/S	30.4 %
Norsk Hydro Produksjon A/S	10.0 %
Den norske stats oljeselskap a.s (Statoil)	59.6 %

The production licence was allocated in 1976 and covers Blocks 15/8 and 15/9. Statoil is operator for Sleipner East (see Figure 2.4.5). Under the sliding scale provision, Statoil has increased its interest in the licence from 50 % at Esso's expense.

The Norwegian Petroleum Directorate's reserves estimate for Sleipner East is 51 x 10^9 Sm^3 gas, 17 x 10 ^{6} Sm^3 oil and 10 x 10^6 tonnes NGL.

Development

It has been decided to develop Sleipner East using a fully integrated process, drilling and accommodation platform with four-shafted concrete gravity base, plus a 508 mm diameter fluid pipeline to Ula.

The plans call for condensate to be sent on to Teesside in England through the Ula-Ekofisk-Teesside pipeline system. Gas will pass by pipeline to Zeebrügge in Belgium and through the Statpipe-Norpipe system to Emden in West Germany.

Preparedness/working environment

The preparedness situation has been followed up by the Directorate via participation in the main audit and through meetings. The Directorate is satisfied with the collaboration established and its results so far.

As regards working environment, on the main audit in the spring of 1987 the Directorate found deficient practising of working environment requirements in an early phase of the project. This area has been subject to active follow-up by the operator in the subsequent phase.

Costs

Total development costs and total operating costs are estimated at NOK (1988) 15.1 and 12.4 billion respectively.

2.4.6 Gyda

The Gyda field is in Block 2/1, about 28 km southeast of Ula and is covered by Production Licence 019B.

Licensees

Den norske stats oljeselskap a.s. (Statoil)	50.000 %
BP Petroleum Development of Norway A/S	26.625 %
Norske Conoco A/S	9.375 %
K/S A/S Pelican & Co	4.000 %
AEDC	5.000 %
MOECO	5.000 %

BP is the operator for the field, which was declared commercial on 22 January 1987. The licensees submitted their development and operation plan on 11 March 1987, and these plans were approved by the Storting in the spring of 1987.

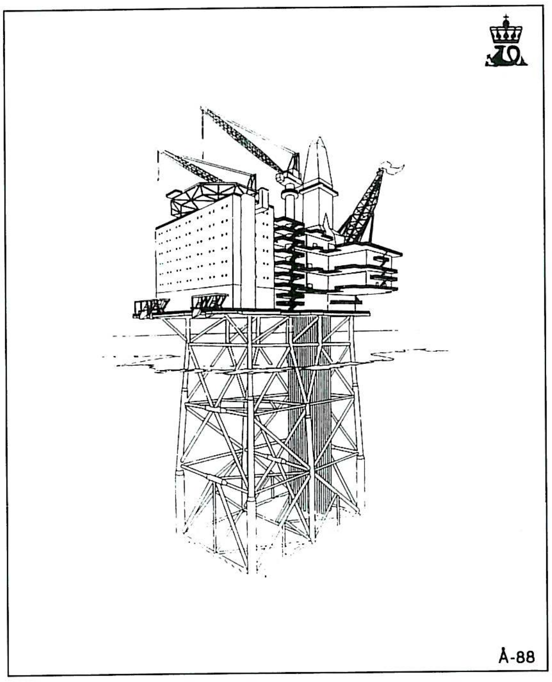
Development

It has been decided to develop the field with a fixed installation for accommodation, drilling and processing of oil and gas, see Figure 2.4.6. The oil is to be transported to Ekofisk via the oil pipeline from Ula to Ekofisk and on to Teesside. Gas is to be carried in a new pipeline direct to Ekofisk and used there as fuel gas.

The predrilling frame has been placed on the field and five production wells have been drilled. The platform is under construction. Emplacement and hook-up will occur in the third and fourth quarter of 1989. Under the new plan, production is planned to start on 1 July 1990.

It is planned to produce the field with water injection as drive mechanism. Nineteen production wells are planned and 11 water injection wells. Eight production wells will be predrilled.

Fig. 2.4.6
Planned installation on Gyda



The operator's reserves estimate is 31.8 x 10^6 Sm^3 oil, while the Norwegian Petroleum Directorate's reserves estimate is 30.5 x 10^6 Sm^3 oil. Gas production is expected to be 3 x 10^9 Sm^3 gas.

By means of eight predrilled wells, a plateau production can be reached from production start. Plateau production is planned at 9,500 Sm^3 oil and 1.1 x 10^9 Sm^3 gas per day, and will last for two years. Production will thereafter gradually decline, and is expected to cease in the year 2010.

Costs

Total development costs are estimated at NOK (1988) 8.4 billion, and total operating costs at about NOK (1988) 9.8 billion.

2.4.7 Hod

Licensees

Amoco Norway Company (operator)	25 %
Amerada Hess Norge A/S	25 %
Texas Eastern Norwegian Inc.	25 %
Norwegian Oil Consortium A/S & Co.	25 %

Block 2/11 was allocated in 1969 as Production Licence 033 with Amoco as operator. The field is about 12 km south of Valhall. Parts of the block have subsequently been relinquished, and parts of the relinquished areas have been incorporated in Production Licence 068. Hod consists of two minor structures, West Hod and East Hod (Figure 2.5.1.a). All in all five exploration and appraisal wells have been drilled. One well on West Hod and two on East Hod proved and tested oil with associated gas in chalk reservoirs of late Cretaceous and Lower Tertiary period.

The licensees submitted a development and operation plan in the spring of 1988. The plan has been approved by the authorities.

Development

The field is to be developed with an unmanned wellhead installation installed over a seabed frame with eight well slots. Five production wells are planned, but the number may be greater. Production of oil will occur by pressure release.

In its development plan for Hod, Amoco proposed a hundred-year wave of 22.0 metres, whereas the Norwegian Petroleum Directorate had previously concluded that plans should not be based on a wave lower than 23.8 m in this area. After further consideration Amoco increased the value to 22.6. The Directorate's studies of available data from this area show that an expected hundred-year value is about 25.0 metres. The value of 23.8 metres is, however, within the prevailing uncertainty range. Hod is planned to be an unmanned installation, and a breakdown will therefore normally have small consequences for personnel and pollution, and limited consequences for operational availability and social economics. In the light of these facts the Norwegian Petroleum Directorate elected to accept the values Amoco proposed.

Production

Produced quantities will be transported to Valhall as two-phase stream. The operator has set production start for summer 1990.

The Norwegian Petroleum Directorate has used the operator's figures for recoverable reserves, 4 x 10^6 Sm^3 oil, 0.9 x 10^9 Sm^3 gas, and 0.5 x 10^6 tonnes NGL. The operator has estimated the development costs at about NOK (1988) 600 million.

2.4.8 Draugen

The Draugen field, which lies in Block 6407/9, was allocated in 1984 as Production Licence 093.

Licensees

Den norske stats oljeselskap a.s	50.00 %
A/S Norske Shell	30.00 %
BP Petroleum Development of Norway A/S	20.00 %

Norske Shell is field operator. Production start is planned for summer 1993.

Field history

The operator declared the field commercial in September 1987 and the plan for development and operation was submitted to the authorities in September 1987. In August 1988 the operator submitted an updated plan for development and operation, which was approved by the Storting in December 1988. Draugen is the first field on Haltenbanken ready for development.

Reservoir

The Norwegian Petroleum Directorate's estimate of recoverable reserves is 68 x 10^6 Sm^3 oil and 4.8 x 10^9 Sm^3 associated gas. The Draugen reservoir is of very high quality and consists of two formations. Frøya contains the bulk of the reserves and the Haltenbank formation has a small part of the oil. There are several minor faults in the reservoir, which may allow for communication between the formations. There may also be communication in areas where the slate layer is thin. It is planned to drill the water injectors after plateau production is attained. On the basis of the test results a high delivery rate and injectability is expected from the wells.

Development solution

It is planned to develop the field with a fixed seabed concrete installation with integrated deck. Six or seven production wells are planned, and six wells for water injection. Seven of the wells will be seabed-completed. The installation has ten well slots and in all 34 J-pipes. An average plateau rate of 14,300 Sm^3 oil per day is planned.

Transport

It is proposed to export the oil via a loosely anchored floating loading buoy (FLP). The gas will be injected until a use for it is found.

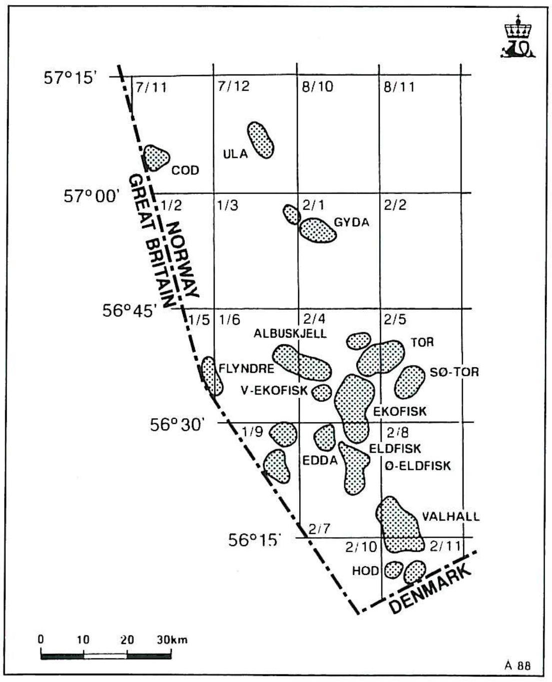
Alternative use for gas

The operator has considered a number of alternatives for the associated gas. The main plan is to inject it into the Middle Drake horizon (water zone) for three years. It is also possible to produce the Frøya South formation early, so that gas injection can be continued in this formation for a period of two years. It is assumed that a after 1999 a solution for gas transport or other use of Haltenbanken gas will have been achieved.

Costs

Total investment costs run to NOK (1988) 10,037 million, including gas injection costs for the Middle Drake formation. Operating costs are NOK (1988) 697 million per year.

Fig. 2.5.1.a
The Ekofisk area



2.5 FIELDS IN PRODUCTION

2.5.1 Valhall

Production Licence 006

Licensees

Amoco Norway Oil Company A/S	28.33 %
Amerada Hess Norge A/S	28.33 %
Texas Eastern Norwegian Inc	28.33 %
Norwegian Oil Consortium A/S & Co	15.00 %

Block 2/8 was allocated in 1965 with Amoco as the operator. The Valhall field lies mainly within Block 2/8 (Figure 2.5.1.a). The southern part of the block reaches into Block 2/11, Production Licence 033. In this licence, each of the companies mentioned above have a 25 per cent interest.

Recovery of reserves

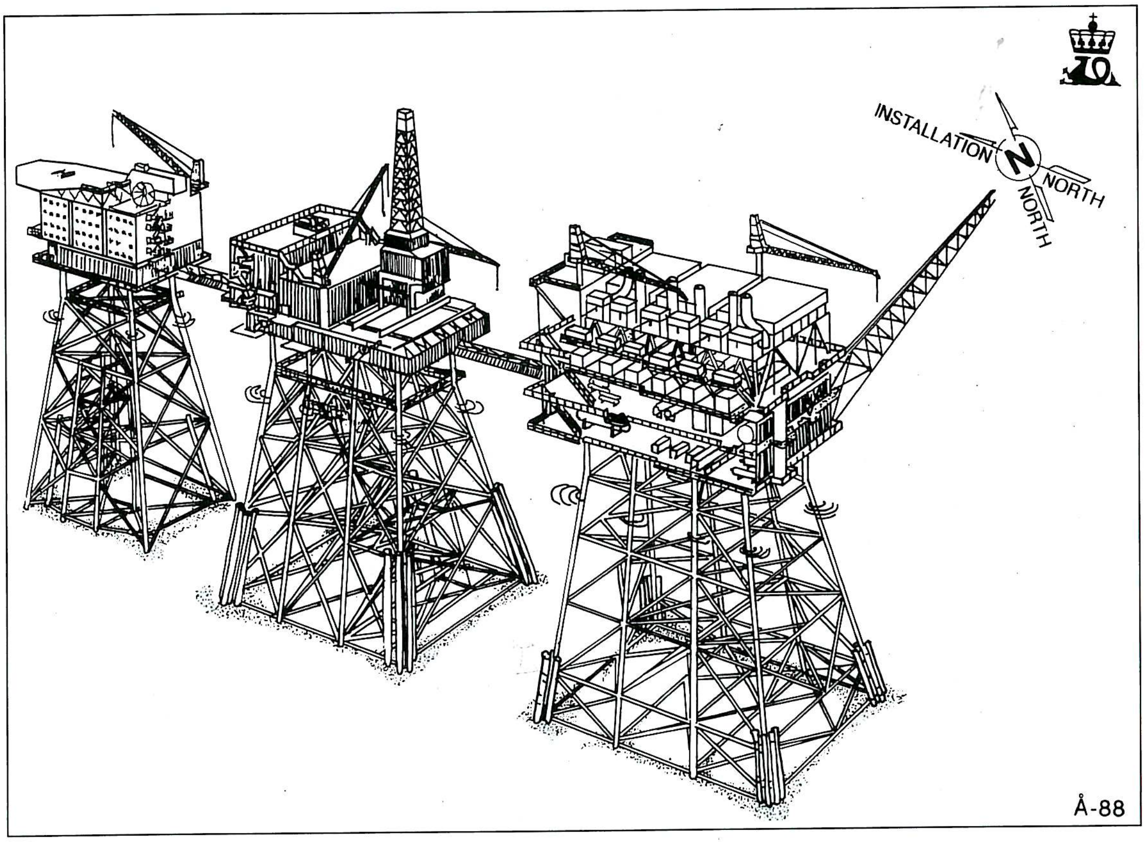
Valhall can be compared to the fields in the Ekofisk area as regards reservoir properties and geology. The fields produce from fractured chalk which is tight in comparison with other reservoir rocks on the Norwegian shelf. This means that the field will have a long lifetime and a comparatively small degree of production. Valhall produces most from the Tor structure (about two-thirds of the reserves) and to a smaller extent from Hod. The Ekofisk structure, which is the most important in some of the fields in the Ekofisk area, is not present on Valhall.

Production started in November 1982 and at the end of 1988 there were 22 production wells on the field. The operator appears to have been successful with a new completion technique that avoids the problem of flow of reservoir rocks into the production wells.

There has been great uncertainty about the Valhall geology on account of a cloud of gas over the reservoir that has made seismics unusable as a survey tool. After a good deal of work by the operators and partners, a geological model for the field has been worked out that has proved useful in the drilling of new wells.

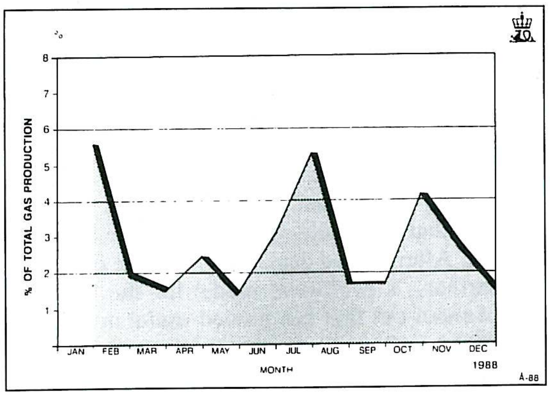
The subsidence of Valhall does not now appear to

Fig. 2.5.1.b
Installations on Valhall



be such a great problem as previously feared. A subsidence rate of 17 cm per year has been measured. This means that the sort of modification used on Ekofisk is hardly likely on Valhall. Conditions linked to subsidence, as for example well deformation, loss of productivity and differential settlement, have not been studied in detail.

Fig. 2.5.1.c
Gas flared on Valhall



Production facilities
Development includes an accommodation, a drilling, a production and a marine riser pipe platform. The three first-mentioned platforms are placed on the Valhall field and interlinked with bridge connections. Figure 2.5.1.b shows these installations. The marine riser platform, for which Phillips Petroleum Company Norway has the operatorship, is connected to the Ekofisk Tank.
The oil is separated on Valhall using two separation units, before being pumped to the Ekofisk facility, where it is metered and led on into the Teesside pipeline. The gas is compressed, dried and its dewpoint checked on the production platform before being despatched by pipeline to the Ekofisk installation, where it is metered and sent on via the Emden pipeline. Denser gas fractions of NGL are separated out on Valhall using a fractionating column, and then injected partly into the oil and partly into the gas.

Transport
The oil and gas are transported in the same system as the production from the Ekofisk area.

Flaring of gas
The reported gas quantities flared on the field in 1988 Valhall were on average 55,000 Sm^3 per day, corresponding to 2.8 per cent of the total gas production (Figure 2.5.1.c) and 36 % of the maximum permitted.

Costs
Total investment costs on the Valhall field up to 2011 are predicted to reach about NOK (1988) 11.17 billion. Total operating costs up to 2011 are estimated at about NOK (1988) 23.6 billion.

2.5.2 The Ekofisk area
Production Licence 018

Licensees

Phillips Petroleum Company Norway	36.960 %
Norske Fina A/S	30.000 %
Norsk Agip A/S	13.040 %
Norsk Hydro Produksjon A/S	6.700 %
Elf Aquitaine Norge A/S	7.594 %
Total Marine Norsk A/S	3.547 %
Den norske stats oljeselskap a.s (Statoil)	1.000 %
Eurafrep Norge A/S	0.456 %
Norexplor A/S	0.304 %
Coparex Norge A/S	0.399 %

The above companies (the "Phillips Group") hold the licences to the Ekofisk, Cod, Edda, Eldfisk, Ekofisk and West Ekofisk fields. Cod is in Block 7/11, Edda and Eldfisk in Block 2/7 and Ekofisk and West Ekofisk in Block 2/4.

Albuskjell is split between Production Licences 018 and 011, and the Tor field between Production Licences 018 and 006. Albuskjell lies in Blocks 1/6 and 2/4 and the Tor field in Blocks 2/4 and 2/5.

The distribution is as follows:

Albuskjell:

"Phillips group":	50 %
A/S Norske Shell:	50 %

Tor:

"Phillips group":	75.3612 %
"Amoco group":	24.6388 %

(the licensees on Valhall)

Development
The Ekofisk area,which is operated by Phillips, consists of seven fields: Albuskjell, Cod, Edda, Ekofisk, Eldfisk, Tor and West Ekofisk. The first of these, Cod, was discovered in 1968. This is the only one producing from a sandstone reservoir in the Ekofisk area, the others in the area produce from Cretaceous rocks. The Ekofisk field was discovered in 1969, and declared commercial as early as 1970. Other fields in the area were discovered in the period from 1969–72. The Ekofisk field is easily the largest in the Ekofisk area, with a hydrocarbon pore volume about 30 % greater than the Statfjord field. Eldfisk is the next biggest. Figure 2.5.1.a shows the fields' location.

Recovery of reserves
Development has taken place in four phases. From June 1971 to May 1974 oil was produced from four wells commissioned on the seabed of the Ekofisk field. The fields Cod, Tor and West Ekofisk were developed and linked to Ekofisk Centre at the same time as an oil pipeline was laid from Teesside and a gas pipeline to Emden. The lines were taken into operation in October 1975 and September 1977 respectively. Before the gas pipeline was completed, the produced gas was injected into the Ekofisk field.

The next stage in the development consisted of the connection of the fields Albuskjell, Edda and Eldfisk to Ekofisk Centre.

From December 1987, water was injected into the Tor formation in the northern part of the Ekofisk field, to enhance the recovery of oil and gas. In the course of 1988 it was decided that the water injection project should be extended to include injection of water also in the Ekofisk formation as well as the southern part of the Tor formation.

The operator is now studying the effect of injecting nitrogen into the Ekofisk field.

These measures will substantially increase the recovery rate from the Ekofisk field. While water injection involves increased oil depletion, any nitrogen injection project will be directed towards increased depletion of gas.

Similar measures are now under consideration for the next biggest field in the area, Eldfisk.

In the course of 1988 gas lifting equipment was installed on the Tor field, which has given positive results so far. Gas lifting will contribute to a considerably longer economic lifetime for the field.

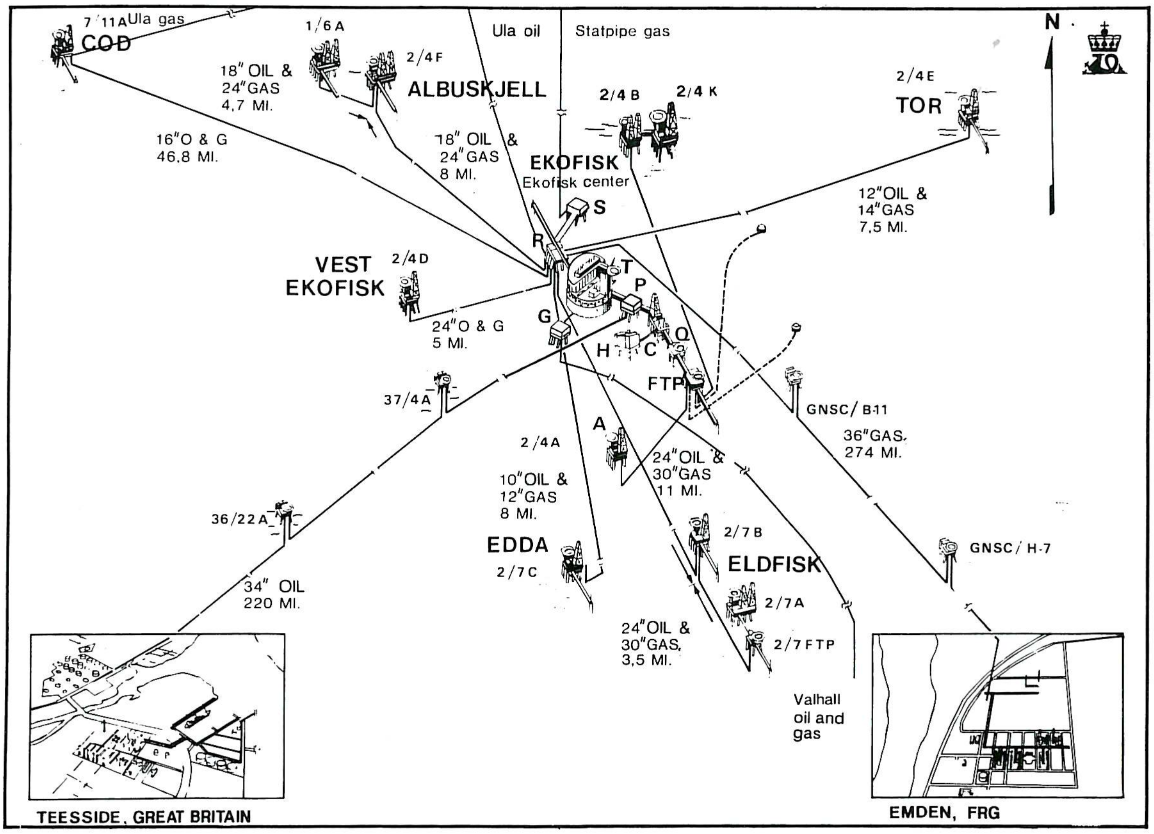
On the Albuskjell field the operator made a successful test on the Ekofisk formation, which is very tight in this area. Further plans for testing of this formation are being prepared. The operator is also considering automating Albuskjell.

On the Edda field modification work is under way so as to receive production from the Tommeliten field. This means that the installation on the Edda field can be kept operating longer than previously supposed. Figure 2.5.2.a shows the installations in the Ekofisk area.

Subsidence
In November 1984 it was discovered that the seabed at the Ekofisk Centre had subsided. Measurements since performed indicate the total subsidence as of 1 December 1988 to be about 4.3 metres.

The rate of subsidence in the period 1980–86 was 0.4 to 0.5 metres a year, with some lessening towards the end of the period. The annual rate in 1987 and 1988 has been measured as about 0.3 metres per year.

Fig. 2.5.2.a
Installations in the Ekofisk area



Several measurement methods have been used to determine the rate of subsidence. In 1984/85 analyses of wave data were made. The analyses indicated only the earlier subsidence rate. For this reason the operator made a number of measurements in 1985 of the distance from the sea surface to horizontal struts in the platform base. The method was of limited accuracy. Today the subsidence is measured with the aid of pressure sensors mounted on the seabed, in addition to regular satellite measurements.

Ekofisk field subsidence is the result of the oil and gas-bearing rock three kilometres under the seabed being relatively loose and being compacted as the pore pressure lessens. It was always expected that the reservoir volume would contract, but no one expected this to show on the surface. It is still uncertain how the shrinking of the reservoir accounts for the subsidence, or whether other factors are at work.

The only way to prevent further subsidence and other problems related to pressure relief is to limit the fall in pressure. This can be done by injection of fluids such as natural gas, nitrogen gas and/ or water.

Subsidence is not confined to Ekofisk Centre. It has been calculated that there will be a need for modification of the installations on the north and south of the field in the course of the second half of the 1990s.

In the summer of 1987 the steel installations of the Ekofisk Centre were jacked up to cope with the subsidence. This was done to protect them against any wave stress (the hundred year's wave). It was not technologically possible to use this method to protect the Ekofisk tank, and so to give it equivalent protection the Phillips Group decided to build a concrete wall round the tank. Construction began in 1988. The concrete wall will be towed out to Ekofisk in two halves and joined together there. Installation is scheduled for summer 1989.

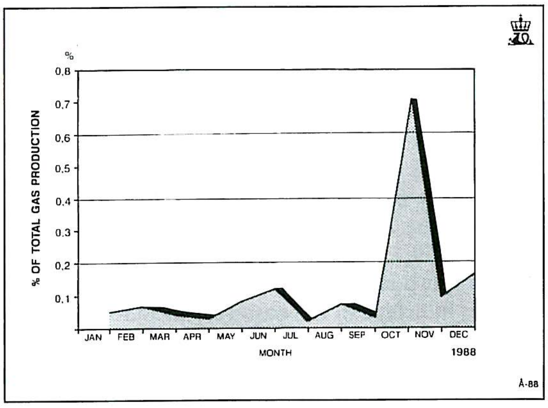
Maintenance on Ekofisk

Some equipment on Ekofisk essential for safety is now being upgraded.

On 2/4 Q the fire pump room is being rebuilt to satisfy modern requirements for such rooms. The fire pump room on 2/4 FTP will later be rebuilt.

Replacement of nitrogen accumulators to the emergency shut-down valves is under way on 2/4 T. Nitrogen accumulators are to be replaced on all the Ekofisk installations.

Fig. 2.5.2.b
Gas flared in the Ekofisk area



A nitrogen accumulator is an emergency power source capable of operating shut-down valves for oil and gas, if the main power fails in an emergency. The nitrogen accumulators have, therefore, an important function on the installations.

Metering systems
Verifications were conducted of selected oil and gas metering systems in the Ekofisk area. Regular inspections were also make of sales metering stations at Teesside and Emden.

Transport
The gas is transported by pipeline to Emden, and the oil to Teesside.

Flaring of gas
Gas reported flared on the field in 1988 was an average of 21,000 Sm^3 per day. This corresponds to 0.07 per cent of the total gas production (see Figure 2.5.2.b) and 36 % of the maximum permitted.

Costs
As of 31 December 1988 about NOK (1988) 68 billion has been invested in the seven fields constituting the Ekofisk area. Total operating costs so far are about NOK (1988) 58 billion.

2.5.3 Tommeliten
Production Licence 044

Licensees

Den norske stats oljeselskap a.s. (Statoil)	70.64 %
Norske Fina A/S	20.23 %
Norske Agip A/S	9.13 %

Production Licence 044 was allocated on 27 August 1976 and includes Block 1/9, southwest of the Ekofisk area. The field was discovered by drilling exploration well 1/9–1 in December 1976 and is Statoil's first oil find.

The plan for development and operation was approved by the Storting in June 1986. Start-up took place on 3 October 1988. A gas sales contract has been signed with the Phillips Group for deliveries up to and including 1991. The remaining gas has not been sold.

Recovery of reserves
Tommeliten consists of two structures, Alpha to the south and Gamma to the north. Gas and condensate have been proven in both structures. Hydrocarbon-bearing rocks are represented by the Ekofisk and Tor formations. Total recoverable reserves are estimated at 18 x 10^9 Sm^3 dry gas and 8.5 x 10^6 Sm^3 condensate. Recovery of gas is calculated to last 20 years with a plateau rate of about 1 x 10^9 Sm^3 per year. The recovery strategy for the field will be production with the help of the reservoir's natural drive mechanism.

Production facilities
The field will be developed with subsea completion wells and full well transfer and hook up to the Edda platform.

Development is planned in four phases. Phase 1, which includes the development of the Gamma structure and consists of a seabed frame with six wells, has been completed and was put into production 3 October 1988.

No decision has been made as to when the Alpha structure will be developed. This will depend on when the sales agreement for the rest of the gas can be signed.

Metering system
Existing metering systems on the Edda installation have been rebuilt and upgraded, so that separate measurement can be made of of gas and oil/condensate from both the Edda field and Tommeliten, in addition to metering of gas consumption on the platform.

Transport
After first-stage separation and metering on the Edda installation, gas from Tommeliten will be transferred in a 304 mm pipe to Ekofisk Centre for further processing, before the dry gas is compressed and sent through Norpipe's gas pipeline to Emden.

Tommeliten condensate will be transferred from Edda to Ekofisk Centre in a 203 mm oil pipeline together with the Edda products (oil and gas). After second-stage processing on Ekofisk Centre, the fluid will be pumped into the Ekofisk-Teesside pipeline for further stabilisation, storage and sale in Teesside.

Flaring of gas
The gas quantity permitted burnt on Tommeliten is included in the quantity permitted for the Ekofisk field all together. To maintain reliability during un-

foreseen operational stoppages that demand that pipeline between the underground well frame and the Edda installation must be pressure-relived, additional permission has been given for flaring of gas corresponding to up to 200,000 Sm^3 per day.

Costs
Total investments for Phase 1 are NOK (1988) 2.6 billion. Development of Phase 2 is calculated at about the same figure.

2.5.4 Ula
Production Licence 019 A

Licensees

BP Petroleum Development of Norway A/S	57.5 %
K/S A/S Pelican & Co	5.0 %
Norske Conoco A/S	10.0 %
Den norske stats oljeselskap a.s (Statoil)	12.5 %
Svenska Petroleum Exploration A/S	15.0 %

The field lies in Block 7/12 some 70 kilometers northwest of Ekofisk (Figure 2.5.1.a). It was discovered in 1976 and declared commercial in December 1979. The field development plan was approved in 1980, but the same year it became clear that the development would not be profitable. A new field development plan with a new development option was submitted in April 1983 and approved in January 1984. BP is the operator for the production licence.

Recovery of reserves
The Ula field is Upper Jurassic sandstone, lying on the Ula trend,which is an oil province along the faulted north-eastern margin of the Central Channel. The field is a salt dome structure and the reservoir has very good production characteristics.

In 1988 the operator increased his reserves estimate from 39.7 x 10^6 Sm^3 oil to 52.5 x 10 ^{6} Sm^3. The increase was due mostly to the discovery of a deeper oil/water interface in the eastern and southern parts of the field.

The operator is now studying the consequences of the reserves increase for the further development of the field and the production behaviour that can now be expected.

As of December 1988 six wells are producing and two injecting water. One well, however, is an observation well to register rising of the oil/water interface in the western part of the field. In the course of the year two appraisal wells have been drilled on the field to determine the oil/water interface in the eastern and southern parts.

Fig. 2.5.4.a
Installations on Ula

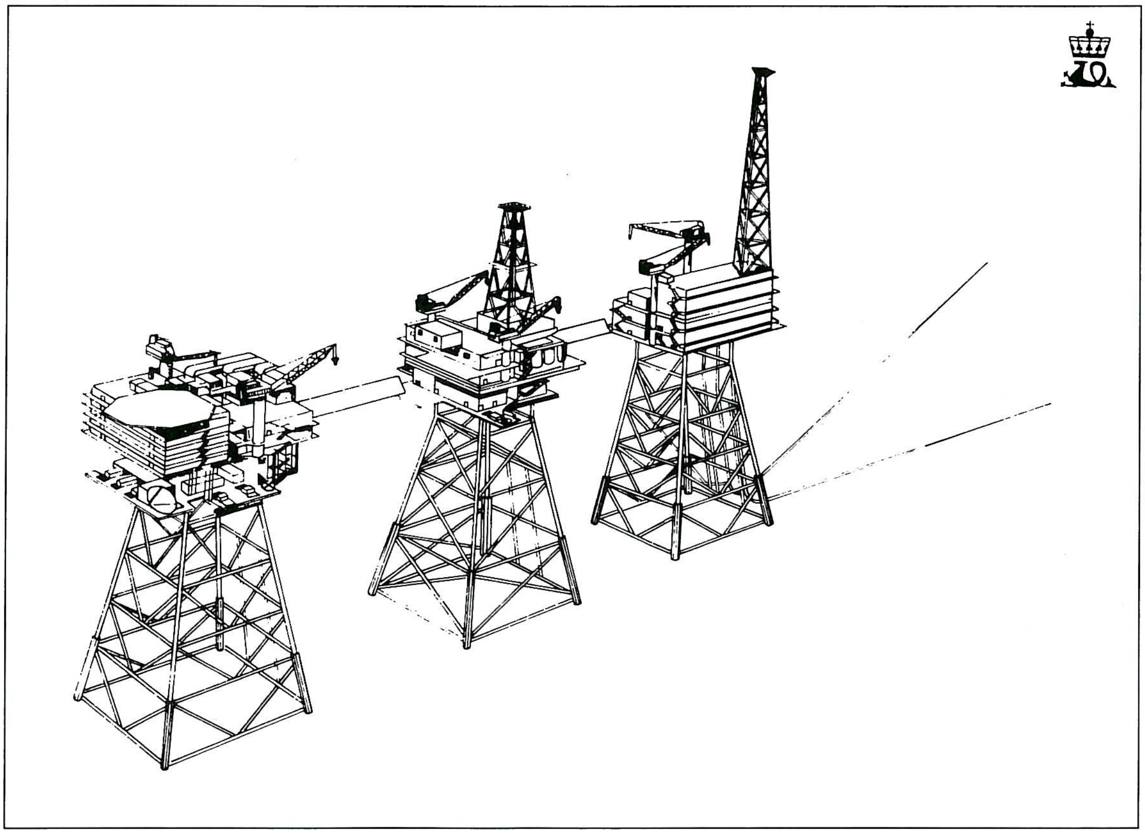
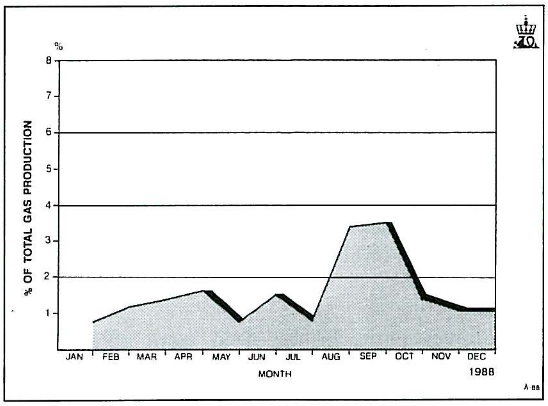


Fig. 2.5.4.b
Gas flared on Ula



Production facilities

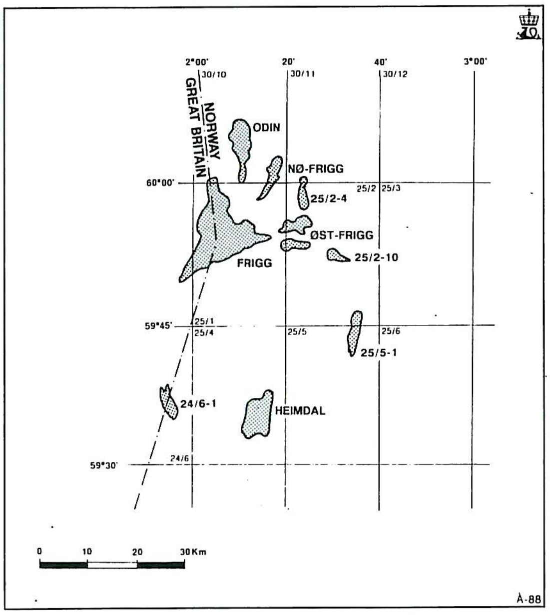
The development concept involves three conventional steel platforms (Figure 2.5.4.a) for production, drilling and accommodation. Steel bases for the platforms were installed in summer 1985 and the offshore hook-up work took place October 1985 to August-September 1986. The oil pipeline to Ekofisk was laid in the summer of 1984 and the Ula-Cod gas pipeline in the spring of 1985.

This year, too, considerable quantities of asphalt were found in the separators. Some of the asphalt got into the metering systems and has led to problems with these.

The Norwegian Petroleum Directorate has closely followed up the previous problems with compartments that with the aid of overpressure are to prevent penetration of gas, and it now appears that the systems work satisfactorily.

On the operator company's monthly testing of the downhole safety valves, it was discovered that these valves did not function as they should. The reason was that the material in some of the packings had swollen, so that the valves did not close as they were supposed to. Other material is now being tried out in the packings.

Fig. 2.5.5.a
The Frigg area



Transport

Oil is carried by pipeline via the Ekofisk Centre to Teesside. Statoil is the operator for the pipeline. The pipeline to the Ekofisk Centre was installed on the seabed in the summer of 1984. Its diameter is 508 mm and its length is about 70 kilometres. The gas is transported by pipeline via Cod to Emden. Ula-Cod was installed and tested in the spring of 1985.

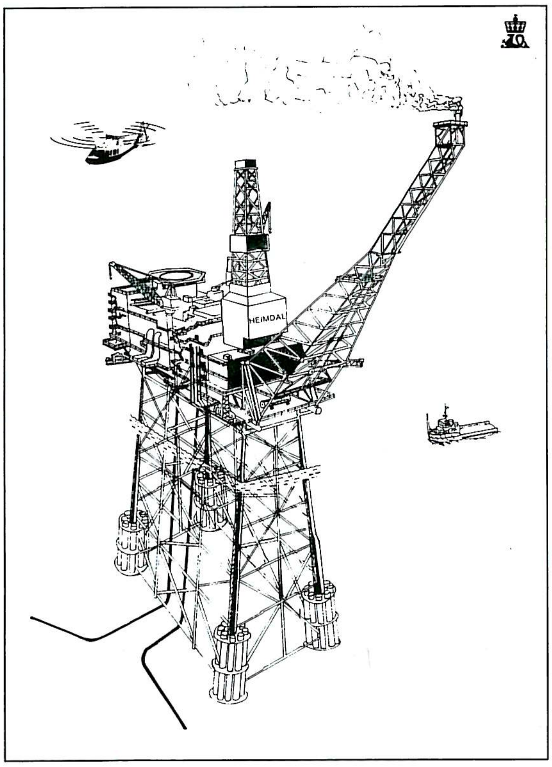
Flaring of gas

The gas reported as flared on the field in 1988 is 20,000 Sm^3 per day. This corresponds to 1.6 % of gas production (Figure 2.5.4.b) and 22 % of the maximum permitted.

Costs

Total investment costs as of 31 December 1988 are

Fig. 2.5.5.b
Installation on Heimdal



about 8.8 billion 1988 NOK. Since production start in October 1986 about NOK (1988) 1 billion has been incurred in operating costs.

2.5.5 Heimdal

Production Licence 036 was allocated in 1971 and includes Block 25/4, about 180 km north-west of Stavanger (Figure 2.5.5.a). Elf Aquitaine Norge A/S is the operator for Heimdal. For that part of the production licence which covers Heimdal, the State has exercised its option, and the ownership structure is now as follows:

Licensees

Den norske stats oljeselskap a.s (Statoil)	40.000 %
Marathon Petroleum Norge A/S	23.798 %
Elf Aquitaine Norge A/S	17,639 %
Norsk Hydro Produksjon A/S	6.228 %
Total Marine Norsk A/S	4.820 %
Sunningdale Norge A/S	3.875 %
Saga Petroleum a.s	3.471 %
A/S Uglands Rederi	0.169 %

The field was discovered in 1972 by the drilling of exploration well 25/4–1, and was declared commercially viable in April 1974. The commerciality declaration was withdrawn in 1976 due to low gas prices.

During 1980, the gas market picked up and Heimdal became the centre of discussion for a landing solution for Statfjord gas. The landing application for gas to the Continent was submitted in January 1981 and approved by the Storting on 10 June 1981. The landing application for condensate was approved in January 1983.

Recovery of reserves

The reservoir lies some 2,100 metres below sea level in Paleocene sand. Total recoverable reserves are estimated at 33 x 10^9 Sm^3 gas and 5 x 10^6 Sm^3 oil.

Production drilling on Heimdal started in April 1985. As of December 1988, ten platform wells had been drilled, nine for production and one observation/injection well. One production well was, however, closed down in 1987 because of leakage problems.

Production has so far proceeded without any problems worth mentioning. Because of the field's powerful water drive, both pressure development and water rise are being followed closely.

Production is now up to plateau rates. Regularity is good, and there is little need for flaring of gas.

Production facilities

The Heimdal field has been developed with an integrated steel installation with drilling, production and accommodation functions (Figure 2.5.5.b). Production began in December 1985, and deliveries of gas via Emden started up in February 1986.

Metering system

The Norwegian Petroleum Directorate inspects the metering systems for gas and condensate. The condensate metering system is inspected in collaboration with the British Department of Energy, in that the condensate is carried via the Forties pipeline system from the Brae field in the British sector to Cruden Bay in Scotland. From Heimdal to the Brae field the condensate is carried in its own pipeline.

Transport

Gas from the Heimdal field is transported via Statpipe, and the Heimdal line is tied in to Statpipe at riser platform 16/11-S.

Costs

Total investments in the field were about NOK (1988) 11.3 billion, and total operating costs are expected to be NOK (1988) 4.2 billion.

2.5.6 The Frigg area

2.5.6.1 Frigg

Licensees

Norwegian share (60.82 %) (Production Licence 024);

Elf Aquitaine Norge A/S	25.19 %
Norsk Hydro Produksjon A/S	19.99 %
Total Marine Norsk A/S	12.60 %
Den norske stats oljeselskap a.s (Statoil)	3.04 %

British share (39.18 %);

Elf Aquitaine UK Ltd	25.97 %
Total Oil Marine Ltd	12.98 %
BP Ltd	0.23 %

Elf Aquitaine Norge A/S is the operator for the Frigg field, while Total Oil Marine Ltd is the operator for the pipeline system and the St Fergus terminal in Scotland.

Frigg lies in Block 25/1 on the Norwegian continental shelf and Blocks 10/1 and 9/5 on the British shelf (Figure 2.5.5.a). The field has been unitised, and by agreement 60.82 % of the gas reserves are regarded as belonging to the Norwegian licensees. The remaining 39.18 per cent to the British licensees. The agreement governing distribution of the reserves may be renegotiated every four years, or as new reservoir knowledge may dictate.

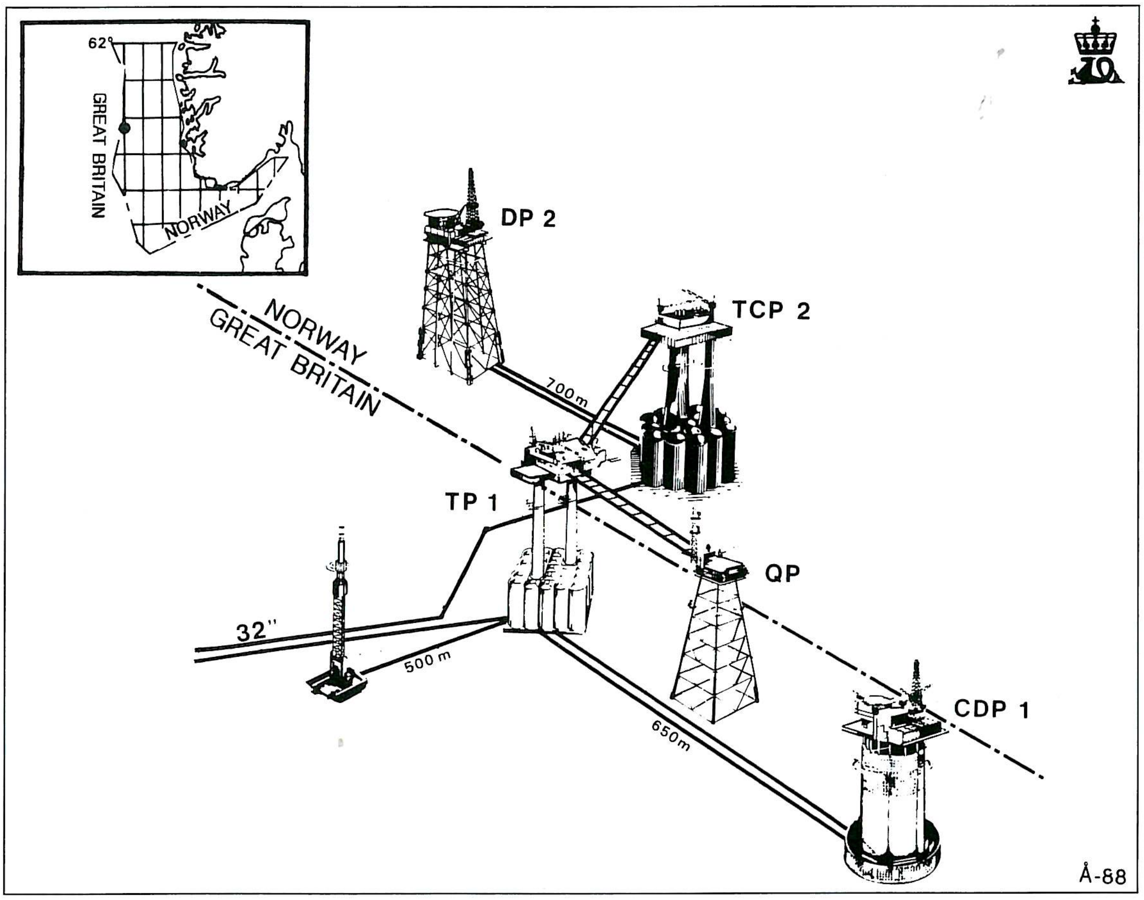
Recovery of reserves

In 1984 substantial and uneven water rise was observed on the field. Several wells were drilled or deepened, and much work was done to clarify the situation. It was found that the water was penetrating the reservoir in the south-east on account of an imperfectly continuous slate barrier there, and flowing laterally northwards. This fact, and the studies made, meant that the reservoir estimate was reduced.

At the end of 1988 formation water was observed in a number of production wells on CDP1.

No water breakthrough is expected in the produc-

Fig. 2.5.6.a
Installations on Frigg



tion wells on DP2 before 1989. The field is expected to produce until 1993.

A deep wildcat was drilled in 1988 to check the depletion in the north. In addition two inspection wells in the north are opened regularly to follow the water rise there. The water rise varies from about 2 to 20 metres per year from north to south on the field. North of DP2 there is probably an undepleted zone, and supplementary wells are being considered for production of the remaining gas, which is estimated at about 6 to 10 billion Sm^3.

Production facilities

The Frigg field was discovered in spring 1971 and declared commercial on 25 April 1972. Frigg was developed in three phases, the first of which consisted of one production, one processing and one processing platform in the British sector plus an accommodation platform (CDP1, TP1 and QP). Production from these platforms started on 13 September 1977.

Phase 2 consisted of one production and one processing platform on the Norwegian side (DP2 and TCP2). Production from the Phase 2 platforms began in summer 1978. Figure 2.5.6.a depicts the Frigg installations.

Phase 3 of the development included the installation of three turbine-driven compressors on platform TCP2. The booster facility is necessary to compensate for the reduced reservoir pressure. The unit started operation in autumn 1981.

Gas from North East Frigg and Odin is processed and metered at Frigg. New modules for processing of the gas and condensate from these fields have been installed on TCP2. Transport of gas from the Alwyn North field on the British side goes via TP1.

Metering system – Frigg

Inspections in connection with the metering systems on Frigg, MCP-01, Alwyn North and in St Fergus have been performed in cooperation with the British Department of Energy. The collaboration also includes the Norwegian fields North East Frigg and Odin, as the sum of these two fields' production is deducted from the total metered quantity entering the pipeline to St Fergus. This makes it possible to determine the Frigg field's contribution. New equipment for East Frigg was inspected in cooperation with the Department of Energy before start-up.

Transport

The gas is transported the 355 km to St Fergus in Scotland through two 813 mm diameter pipelines. To increase the capacity of the transport system, two 38,000 horsepower turbo-compressors have been installed on Booster Platform MCP-01, which stands midway between Frigg and Scotland. The increase in capacity was necessary to move the gas from the Odin field. For the same reason, the St Fergus terminal has been expanded from five to six process lines. The terminal will also be subject to modification, as the new fields will yield increased supplies of petroleum in liquid phase.

Costs

Total investments in the Norwegian part of the Frigg field were about NOK (1988) 20.8 billion. Investments in the transport system are additional to this. Total operational costs over the field's lifetime are estimated at about NOK (1988) 7.6 billion.

2.5.6.2 East Frigg

Production Licences 024 (Block 25/1) and 026 (Block 25/2) See Figure 2.5.5.a.

Licensees

Elf Aquitaine Norge A/S	41.42 %
Norsk Hydro Produksjon A/S	32.87 %
Total Marine Norsk A/S	20.71 %
Den norske stats oljeselskap a.s (Statoil)	5.00 %

Production Licence 112 (previously relinquished part of Block 25/2, reallocated in 1985)

Licensees

Elf Aquitaine Norge A/S	21.80 %
Norsk Hydro Produksjon A/S	17.30 %
Total Marine Norsk A/S	10.90 %
Den norske stats oljeselskap a.s (Statoil)	50.00 %

East Frigg Alpha was discovered in 1973 and East Frigg Beta in 1974. Both fields stretch into Blocks 25/1 and 25/2 and a little bit into the previously relinquished area. The reserves are divided 95.129 % for Production Licences 024 and 026, 4.871 % on Production Licence 112. The field was declared commercial in August 1984, and the landing application was considered by the Storting on 14 December 1984. A development plan with four wells was approved by the partners.

The Norwegian Petroleum Directorate gave consent for production start in the autumn of 1988.

Recovery of reserves

The East Frigg field consists of two structures, Alpha and Beta, previously called East Frigg and South-east Frigg respectively. They are part of the same pressure system as the Frigg field, and the gas is therefore sold to the British Gas Corporation within the existing sales agreement. Recoverable gas reserves were originally estimated at 8 x 10^9 Sm^3 on East Frigg Alpha and 5 x 10^9 Sm^3 on East Frigg Beta, in all 13 x 10^9 Sm^3.

Production on Frigg has, however, lead to considerable pressure reduction and sloping liquid interfaces on East Frigg plus a gas leakage of about 6.4 x 10^9 Sm^3 from Alpha. The Beta structure's deep saddle to the west has prevented gas leakage over to Frigg. In both structures there is a good deal of gas locked into the zones already depleted, and the reserves estimate is now reduced to 8 x 10^9 Sm^3: 4 x 10^9 Sm^3 in each structure.

Because of these problems a third well has been drilled on the Alpha structure, which will be put in production in May 1989. Production from the first four wells began in August 1988, and sales began 1 October 1988.

The last production year is expected to be 1996, instead of 2002 as originally planned. This is due not only to the reduction of the reserves, but also an increase in the field's production rate.

Production facilities

Development will be based on subsea technology. Two seabed frames for the production stations and a central manifold station tying the systems together were emplaced on the seafloor in the summer of 1987.

These subsea production systems are remotely controlled from Frigg. From the manifold goes a gas and service line to TCP2, where the gas is to be produced and fed to the Frigg field transportation system.

The individual modules and parts of the underwater systems are more or less complete, and the station control module is being tested. Trial hookup of the subsea production systems is in progress.

Besides the construction of a subsea production system and pipeline, modifications to the Frigg field have been made before production start to enable it to receive the gas.

Costs

Total investments on the field were about NOK (1988) 1.9 billion, and total operating costs over the field's lifetime are estimated at NOK (1988) 1.1 billion.

2.5.6.3 North East Frigg

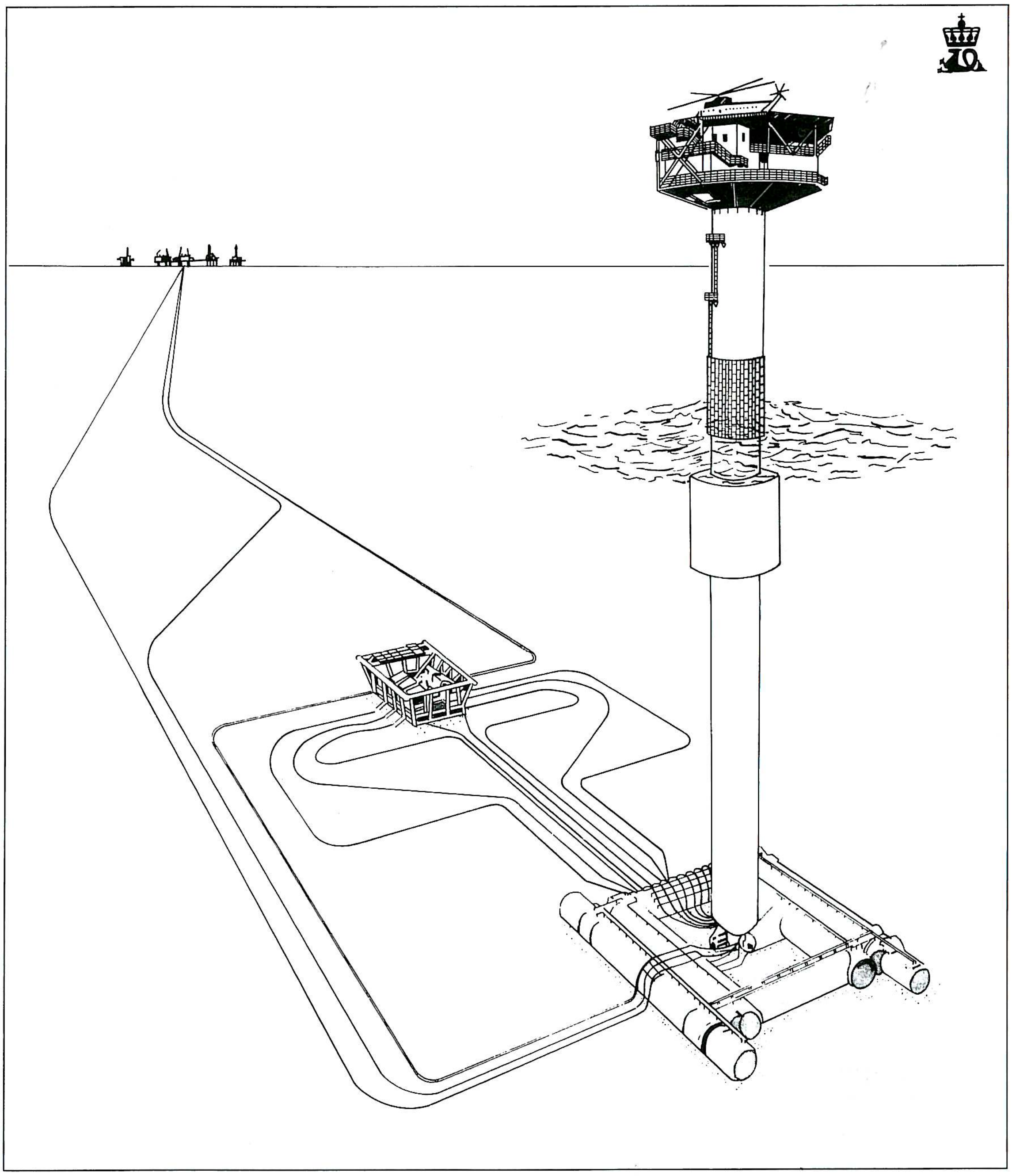
Production licence 024 (Block 25/1)

Licensees

Elf Aquitaine Norge A/S	41.42 %
Norsk Hydro Produksjon A/S	32.87 %
Total Marine Norsk A/S	20.71 %
Den norske stats oljeselskap a.s (Statoil)	5.00 %

Production licence 030 (Block 30/10)

Fig. 2.5.6.b
Installations on North-East Frigg



Licensees
Esso Exploration & Production
Norway Inc 100.00 %

Statoil is entitled to 17.5 per cent of the net profits before tax.

The North East Frigg field lies in Blocks 25/1 and 30/10 (Figure 2.5.5.a) and redistribution of the gas reserves in August 1984 gave 42 per cent and 58 per cent, respectively, in each of the blocks. Elf Aquitaine Norge A/S is the operator for the development.

Recovery of reserves
The sale of gas from North East Frigg started in October 1980, by means of advance deliveries from Frigg. Since production start in December 1983, North East Frigg has reimbursed this gas, plus deliv-

ered gas on behalf of Frigg in addition to contractual quantities. In order to obtain a lengthier sales profile, sales were to continue by means of delivery from Frigg after production stop on North East Frigg. The uncertainty regarding Frigg's production life, however, has led to plans for balancing-out by 1 October 1989.

Pressure measurements made before production start showed that the reservoir pressure decreased as a result of communication with the Frigg field through the underlying saddle. About 70 % of the field's recoverable reserves have now been produced. The low production rate maintained now so as to be able to sell gas reimbursed from Frigg is contributing to reduction of the water coning problem in the reservoir. The field is expected to produce until 1993.

Production facilities

The North East Frigg gas field was proven in 1974 and the final development plan approved in 1980. The field was developed with six wells drilled through a frame structure on the seabed (Figure 2.5.6.b). In May 1986 one well had to be plugged because of leakage problems.

The frame structure has, in addition to the wellheads and valvetrees, a manifold for collecting the gas from the six wells. The gas is led through a 406 mm pipeline to the Frigg field for processing. Each of the six valvetrees is controlled via separate service and control lines from the control station (an articulated column) placed 150 metres from the wellheads. The control station was installed in July 1983 and is remote-controlled from the Frigg field.

Costs

Total investments on the field were estimated at about NOK (1988) 2.6 billion. Total operating costs are expected to be about NOK (1988) 0.6 billion.

2.5.6.4 Odin

Production licence 030

Licensee

Esso Exploration & Production Norway Inc 100 %

Statoil is entitled to 17.5 per cent of the net profit before tax. Odin lies in Block 30/10 (Figure 2.5.5.a), with development operated by Esso. The Odin gas field field was proven in 1974, and the development plan was approved in 1980.

Recovery of reserves

Gas sales from Odin began in October 1983 by means of advance delivery from Frigg. Since production start in April 1984 Odin has reimbursed this, in addition to delivery of its own contractual quantities.

Fig. 2.5.6.c
Installation on Odin

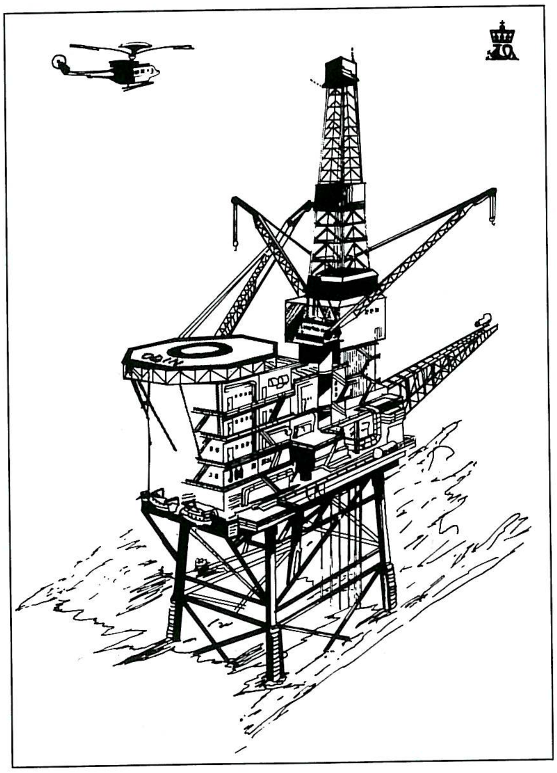
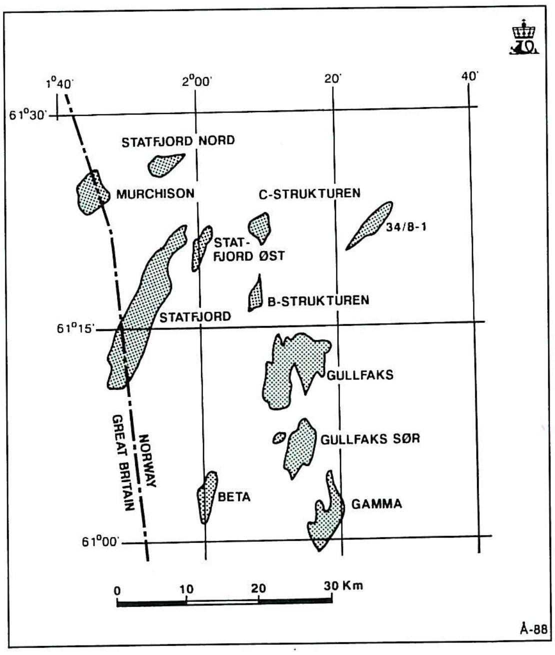


Fig. 2.5.7.a
The Gullfaks and Statfjord area



Pressure measurements before production start showed pressure communication with the Frigg field via the underlying water zone. The Odin reservoir has a quicker pressure reduction than the other fields in the Frigg area on account of very limited water drive.

In spring 1985 the operator increased his reserve estimates for Odin on the basis of new well data and mapping. For the additional reserves of 11.8 x 10^9 Sm^3 there is now a transport and processing agreement with the Frigg Norwegian Association (FNA) Group. On account of the additional reserves, production time is being extended by four years, that is, up to 1997.

Production facilities

The field has been developed with one small steel platform with simplified processing and drilling equipment and relatively small accommodation quarters (Figure 2.5.6.c). Such a development was possible because an auxiliary vessel was used for a two-year period, for installation work as well as production drilling.

On the Odin platform water is separated from the gas and methanol is injected for hydrate control. Subsequently the gas is dispatched by pipeline to the TCP2 platform on Frigg for further processing before delivery through the Norwegian Frigg pipeline to St Fergus.

Metering system

Inspection of the metering system installed on Frigg is performed in collaboration with the British Department of Energy.

Costs

Total investment costs were about NOK (1988) 3.8 billion. Total operating costs are calculated at about NOK (1988) 2.6 billion.

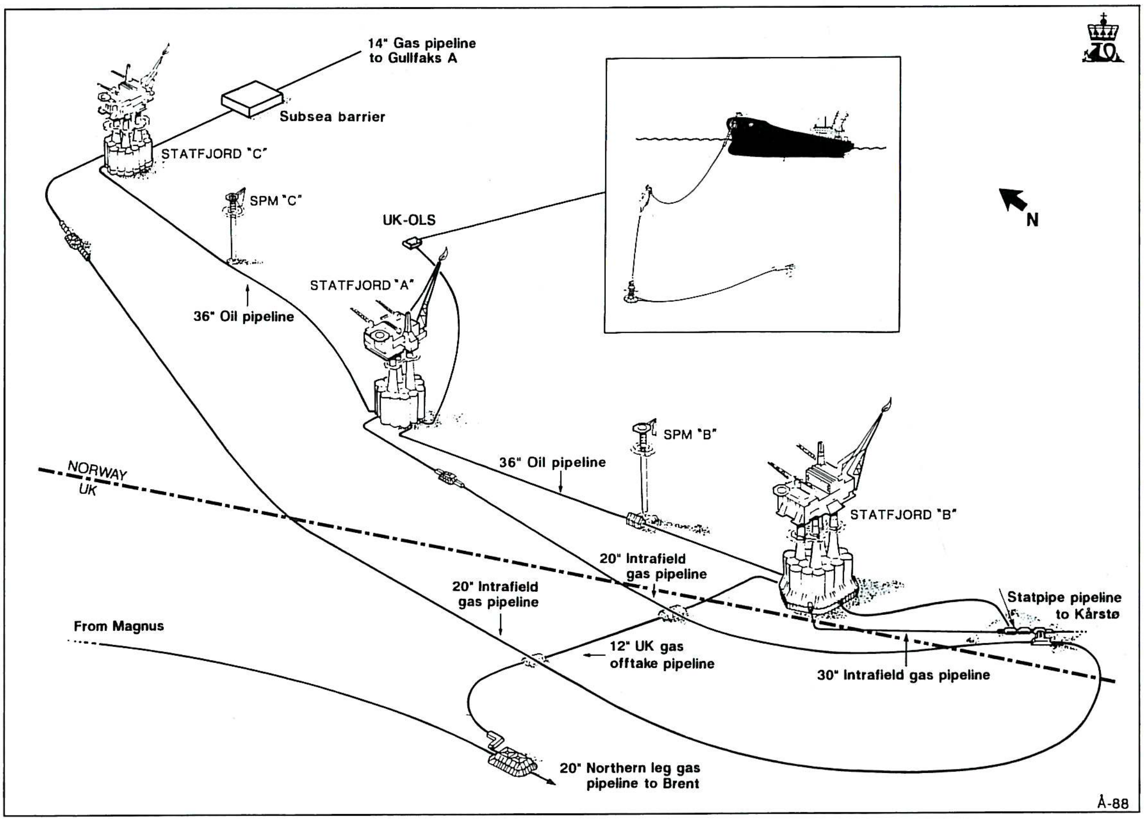
2.5.7 Statfjord

Production Licence 037

Licensees

Norwegian share (84.09322 %);	
Mobil Exploration Norway Inc	12.61400 %
Den norske stats oljeselskap a.s (Statoil)	42.04661 %
Norske Conoco A/S	8.40932 %
Esso Exploration and Production Norway A/S	8.40932 %
A/S Norske Shell	8.40932 %
Saga Petroleum a.s	1 .57674 %
Amoco Norway Oil Company A/S	0.87597 %

Fig. 2.5.7.b
Installations on the Statfjord field



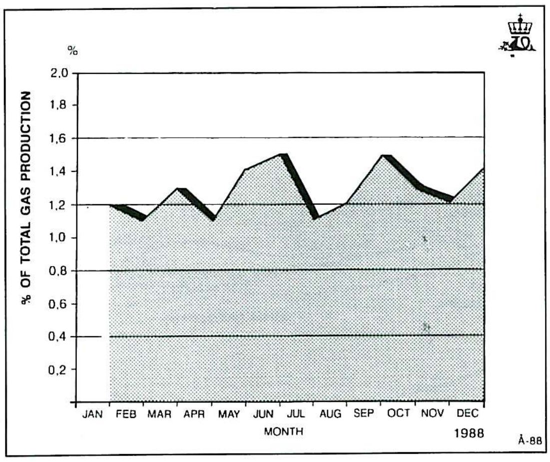
Amerada Hess Norge A/S	0.87597 %
Texas Eastern Norway	0.87597 %
British share (15.90678 %);	
Conoco (UK) Ltd	5.30226 %
Britoil PLC	5.30226 %
Chevron USA Inc/Gulf Oil (UK) Ltd	5.30226 %

Production Licence 037 was allocated in 1973, including Blocks 33/9 and 33/12 (Figure 2.5.7.a). Statfjord extends onto the British side where Conoco is the operator. The Statfjord field itself was discovered in the spring of 1974 and declared commercial the same year. Mobil was operator until 1 January 1987, when Statoil assumed the operatorship. The operator has followed the original field development plan, and we have now come to a phase in the field's lifetime when this must be developed further.

The recovery factor for the installations on the Statfjord field has now peaked. After the approval of the Snorre development with connection to Statfjord A in 1988, the plant on this installation will achieve a higher utilization factor from 1992 than would otherwise have been the case. It is planned to develop the Statfjord satellites North and East as underwater installations with processing on Statfjord C. This will enhance the utilization rate on this installation from the beginning of 1993.

Recovery of reserves
The Norwegian Petroleum Directorate expects a recovery factor of about 50 per cent for the field as a whole. It has calculated the total recoverable quantities of oil in the Brent and Statfjord formations at 445.7 x 10^6 Sm^3. The amount of recoverable associated gas has been estimated at 58.6 x 10^9 Sm^3 dry gas, and 18.4 x 10^6 tonnes of NGL. The production strategy being followed is based on maximising production rates and recovery factors by controlling the

Fig. 2.5.7.c
Gas flared in the Statfjord area



pressure conditions in the reservoir. This is done by injection of water into the Brent Group and injection of gas into the Statfjord reservoir.

The reserves distribution approved by the authorities in 1979 assigns 15.9068 per cent to the British side, and 84.0932 per cent to the Norwegian. The second renegotiation round began in June 1985 and is expected to be concluded in 1989.

Production facilities
The field has been developed in three phases with fully integrated installations, A, B and C (Figure 2.5.7.b).

Statfjord A
The Statfjord A platform is located near the centre of the field, and is a fully-integrated installation with concrete base consisting of 14 storage cells and three shafts. The deck is of steel. Production capacity is 55,000 Sm^3 a day through two production lines. In 1988 capacity of the water treatment system was increased to be able to deal with the increasing quantities of water from the various wells. The platform started production on 24 November 1979 and is equipped with 36 wells, of which 22 are oil producers, 10 water injectors and four gas injectors.

Statfjord B
Statfjord B, sited in the southern part of the field, is fully-integrated with concrete base consisting of 24 cells and four shafts. The deck is of steel. Production capacity is 39,800 Sm^3 a day. On Statfjord B, too,it has proved necessary to increase the capacity of the water treatment system so as to handle the increasing quantities of water from the different wells. Production started on 5 November 1982, and the platform is equipped with 30 wells, of which 20 are oil producers, eight water injectors and two gas injectors.

Statfjord C
Statfjord C is emplaced in the northern part of the field and is a fully-integrated installation, identical in design to Statfjord B. It, too, has been given increased capacity in its water treatment system in 1988. Production started on 26 June 1985, and the platform has in all 24 wells, of which 14 are oil producers, eight water injectors and two gas injectors.

Metering system
The metering systems for fiscal oil metering on Statfjord A, B and C have been characterised by stable operation through 1988. This year Statoil took delivery of a new type of equipment for calibrating pipe norms. This equipment uses Norwegian Primary Standard as reference, whereas the previous reference was British Primary Standard.

The new sampling system intended to start operation on Statfjord A in 1988 has been postponed to 1989.

Fig 2.5.8.a
Installation on Murchison

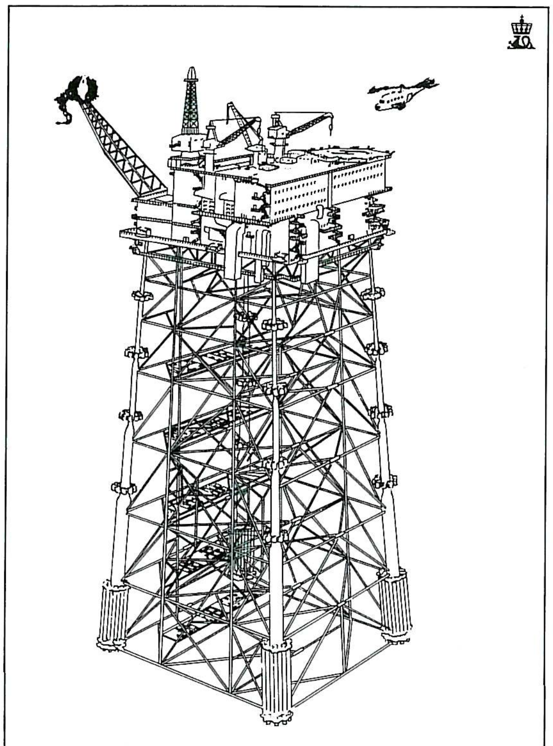
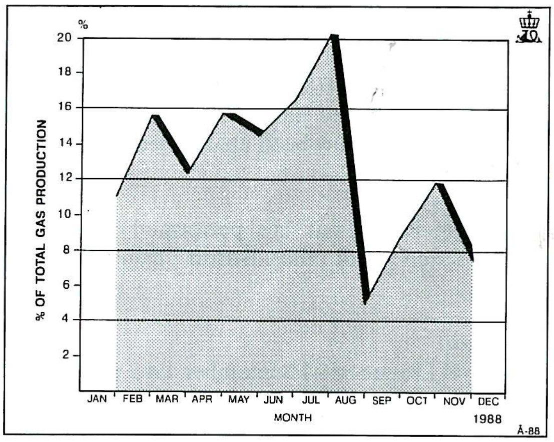


Fig. 2.5.8.b
Gas flared on Murchison



The fiscal metering system for gas from the Statfjord field has, like the oil metering systems, enjoyed stable operation in 1988.

In several years on Statfjord B and C, liquid has been observed in the gas phase being metered, which causes underestimation of the gas stream. This state of affairs has now been corrected, thanks to physical process modifications and chemical injection.

Transport systems
Gas is transported via the Statpipe line. Stabilised oil is stored for further transport by tanker.

Flaring of gas
The amount of gas flared on the Statfjord field in 1988 was on average 260,000 Sm^3 per day, corresponding to 1.2 % of total gas production and 30 % of the maximum permitted (see Figure 2.5.7.c).

Preparedness
During the casework for the removal of the flotel "Kosmos", the operator has decided that rescue sleeves shall be installed on the field.

Costs
The total investment costs on Statfjord up to 2010 are expected to run to about NOK (1988) 59 billion. Total operating costs up to 2010 are estimated at NOK (1988) 69 billion. The figures apply to the Norwegian share (84.09322 %).

2.5.8 Murchison
Licensees

British share (77.8 %);	
Conoco (UK) Ltd	25.9334 %
Britoil PLC	25.9333 %
Chevron USA Inc	25.9333 %
Norwegian share (22.2 %)	
Mobil Exploration Norway Inc	3.3300 %
Den norske stats oljeselskap a.s (Statoil)	11.1000 %
Norske Conoco A/S	2.2200 %
Esso Exploration and Production Norway A/S	2.2200 %
A/S Norske Shell	2.2200 %
Saga Petroleum a.s	0.4162 %
Amoco Norway Oil Company A/S	0.2313 %
Amerada Hess Norge a.s	0.2313 %
Texas Eastern Norway A/S	0.2312 %

The Murchison field was proven in August 1975. It lies in Block 211/19 on the British side and Block 33/9 on the Norwegian (Figure 2.5.7.a). The Norwegian share is 22.2 per cent. Development of the Murchison field was started in 1976 by the British licensees. The field was declared commercial in summer 1977, and Statoil joined the declaration in summer 1978.

Recovery of reserves
The recoverable reserves in the whole field are 53 x 10^6 Sm^3 oil and 1.2 x 10^9 Sm^3 gas. Murchison has been producing at almost maximum processing capacity since 1981. 1984 was the last year of plateau production. There is now water penetration in all production wells.

Production facilities
Field development uses an integrated steel platform

with production capacity 26,200 Sm³ a day (Figure 2.5.8.a). On 28 September 1980, oil production started from the two subsea completion wells. Current production is roughly 11,000 Sm³ crude oil a day. The platform has in all 27 well slots. Twenty-seven wells have been completed, so far of which 18 are production wells and nine water injection. The satellite wells have now been abandoned.

Metering system
Operating inspections are performed annually in collaboration with the British Department of Energy.

Transport
By Royal Decree of 24 September 1982 the Government consented to landing of the Norwegian share of the Murchison gas via the Northern Leg Gas Pipeline (NLGP) on the Brent field in the British sector, and on to St. Fergus in Scotland via the Far North Liquefied and Associated Gas Gathering System (FLAGS). Gas deliveries through the NLGP began on 20 July 1983. Murchison oil is sent by pipeline to Sullom Voe on Shetland.

Flaring of gas
The flared gas reported last year was 136,000 Sm³ per day (about 26,500 Sm³ for the Norwegian share), see Figure 2.5.8.b. This corresponds to about 13 per cent of gas production. The reason for the relatively great gas flaring in certain periods of 1988 is leakages in the transport pipelines. These are being repaired.

Costs
Total investments on Murchison up to 1998 are expected to reach about NOK (1988) 4 billion. Total operating costs are estimated at about NOK (1988) 1.7 billion. The figures apply to the Norwegian share (22.2 %).

2.5.12 Gullfaks
Production licence 050 (Block 34/10)

Licensees

Den norske stats oljeselskap a.s (Statoil)	85.0 %
Norsk Hydro Produksjon a.s	9.0 %
Saga Petroleum a.s	6.0 %

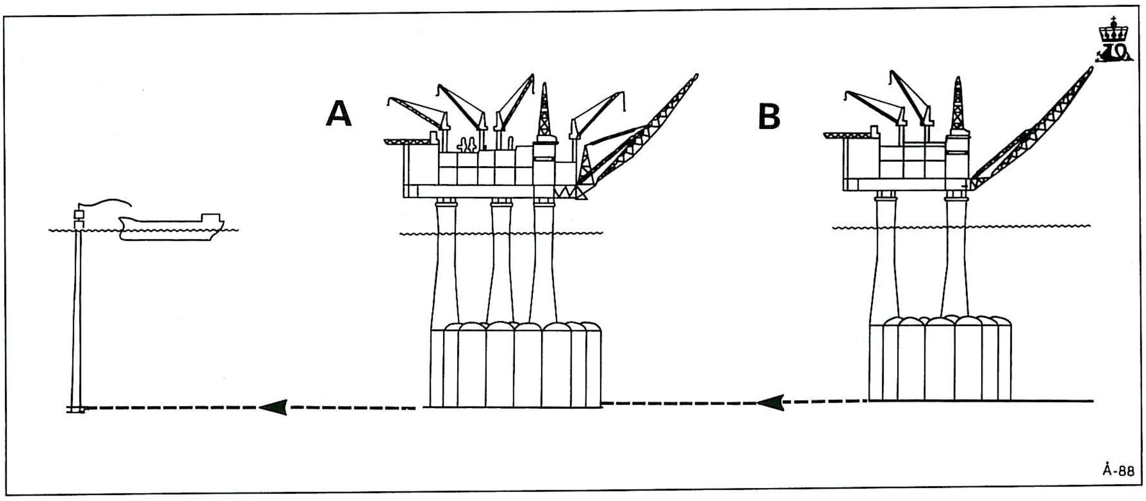
Statoil is the operator. Esso was the technical assistant during the exploration phase. Conoco has been engaged as technical assistant for the development phase.

Recovery of reserves
The field is in the north-east part of Block 34/10 and covers an area of about 200 km². Proven reserves are entirely within the block. Figure 2.5.7.a shows the location of the field.

The field was discovered in 1978. In 1981 the development plan for Gullfaks Delta East was considered by the Norwegian Storting and the Government was given authority to approve the first phase of the development, following approval of the development plan by the Norwegian Petroleum Directorate and the Ministry of Petroleum and Energy.

The Gullfaks field is relatively shallow, divided by north-south faults into several angled and rotated segments of Jurassic strata. The segments, or blocks, have variable declinations with an unclear structure. The area is highly dissected by faults and in places heavily eroded. The structural details of the eastern part are more difficult to plot due to poor seismic data. The field is bounded in the south, east and northeast by faults with vertical displacements exceeding 100 metres. Gullfaks is the most

Fig. 2.5.9.a
Installations on Gullfaks phase 1



geologically complex field so far developed on the Norwegian continental shelf. The operator's resources estimate is 210.3 x 10^6 Sm^3 oil, 13.7 x 10^9 Sm^3 gas and 2.1 x 10^6 tonnes NGL. The Norwegian Petroleum Directorate is here using the operator's figures.

Oil and a little dissolved gas has been proven in the Brent group and the Cook and Statfjord formations. In the easternmost part of the field oil has also been found in Triassic strata. The reservoir rock is quite like that found in Statfjord and Murchison, that is, sandstone with high permeability and comparatively high porosity. Under the oil there is a water zone of variable volume, which is, however, not enough to maintain pressure in the reservoir as the oil is depleted. It has therefore been decided to inject water into the reservoir to maintain pressure and effectively force out the oil. Gas injection has also been considered as a recovery method, but this gives poorer results than water injection.

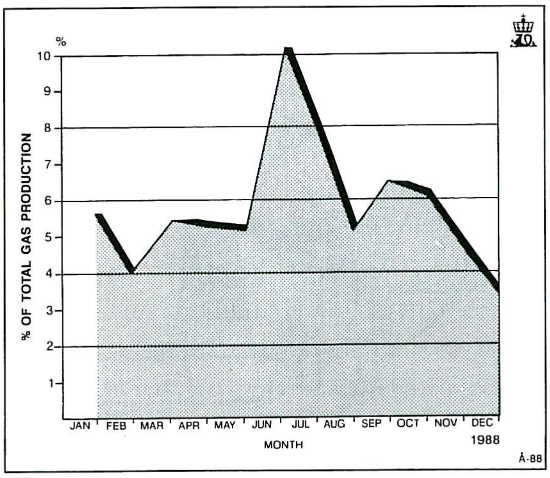
The field's complicated geology has been confirmed during production drilling in Phase 1, with some major surprises as regards the fault pattern. The faults are, however, less sealed than first thought, which means less need for pressure support in the first part of the production period. The reservoir characteristics in Phase 1 appear to be good and in part better than previously supposed. This applies in particular to the upper part of the Brent group, which has very high-productive sand bodies.

Oil reserves have been discovered in the Cook formation in Phase 1 and the reserves are now so considerable that a separate depletion strategy for this reservoir is being considered.

Production facilities

Phase I consists of two platforms, the A and B installations shown in Figure 2.5.9.a. They are Condeeps, with concrete base and steel deckframe.

Fig. 2.5.9.b
Gas flared on Gullfaks



The A installation is emplaced in the southern part of the field, the B on the north-western part.

The A platform was put into production 21 December 1986 and the B on 29 February 1988. The A platform is a fully-integrated drilling, processing and accommodation installation, whereas the B platform is a simplified drilling, processing and accommodation installation with only first-stage separation. Further processing and storage of stabilised oil is done on the A platform.

Because of good well capacity, production capacity will be limited by the treatment capacity on the A installation. This capacity has been increased to 51,180 Sm^3 stabilised oil per day.

At the end of the year in all 14 wells will have been completed on the A platform. In addition five seabed wells are linked to the platform. There are 12 production wells, five water injection wells and two wells for shallow gas production. Two-thirds of the production comes from the A installation's wells, a third from the B's.

At the end of the year the B platform will have five wells, four production and one water injection.

Oil from the field is off-loaded to tankers.

Gas from the field will be transported through the Statpipe system to Kårstø/Emden.

Gullfaks Phase II

Phase II includes the area east of the main fault between exploration wells 34/10–4 and 34/10–9. The ocean depth in this area is considerably greater than in Phase I.

Resources Phase II

Thanks to the complicated field boundaries to the east and southeast, estimates of resources are very unreliable. The operator's estimates of recoverable reserves are about 75.2 x 10^6 Sm^3 oil and 10.5 x 10^9 Sm^3 gas for Delta East, Phase II. These estimates were made after drilling of well 34/10–19. The Norwegian Petroleum Directorate is using the operator's figures. Development of the area received Storting approval on 1 June 1985. The reduction in the estimated reserves in the Phase II area led to selection of a development concept comprising a full processing platform. This will be a copy of the Gullfaks A platform.

The Gullfaks C platform will be located in the middle part of the field where the water is 220 metres deep. The plan is to produce all reservoirs using water injection, and subsea completion wells will be used to the extent necessary to ensure good depletion of the reservoir.

In addition, partially processed crude oil is expected to be dispatched through a 205 mm pipeline from Gullfaks B to Gullfaks C, where final processing can begin in 1990. Stabilised crude oil produced on Gullfaks C will be transported to a loading buoy (single point mooring, SPM2) via a 414 mm pipeline.

The gas will pass along a 254 mm pipeline from Gullfaks C to Gullfaks A and from there into the Statpipe system.

Development
Phase 2. Gullfaks C will be towed out to the field in the spring of 1989. The official date for production start is the middle of 1990, but in the light of previous experience we can expect an earlier date for production start on Gullfaks C too.

Metering systems
Production from Gullfaks A and B is processed on Gullfaks A and then metered before shipment of oil and gas. The fiscal metering systems for oil and gas have been in normal operation in accordance with the regulations of the Norwegian Petroleum Directorate.

Flaring of gas
The quantity of gas reported flared off on the field in 1988 was 140,000 Sm^3 per day (Figure 2.5.9.b). This corresponds to 5.7 % of the gas production and 49 % of the maximum permitted.

Preparedness
The operator has decided to equip Gullfaks C with rescue sleeves to improve the evacuation facilities on the platform.

Costs
Total development costs are expected to run to about NOK (1988) 61.2 billion. At the end of the year about 78 % of these had been incurred (inflation-adjusted).

Total operating costs over the field's lifetime are expected to be about NOK (1988) 50 billion. In addition come transport costs for oil, gas and NGL, which are estimated to amount in all to about NOK (1988) 20 billion.

2.5.10 Oseberg
The Oseberg field extends into two production licences, Licence 053 on Block 30/6 which was allocated in 1979, and Licence 079 on Block 30/9 which was allocated in 1982 (Figure 2.4.3).

Ownership distribution for Oseberg
That part of the production licences including the Oseberg field is unitised between the two licences. The licensees have indicated a provisional distribution of the reserves of 60 % to Block 30/6 and 40 % to Block 30/9. Statoil's ownership share in Oseberg has been increased after exercise of the sliding scale vis-à-vis the foreign companies. The last increase occurred from 1 April 1988 in connection with the approval of the revised plan for development and operation.

From 1 April 1988 the ownership interests in the unitised Oseberg field are:

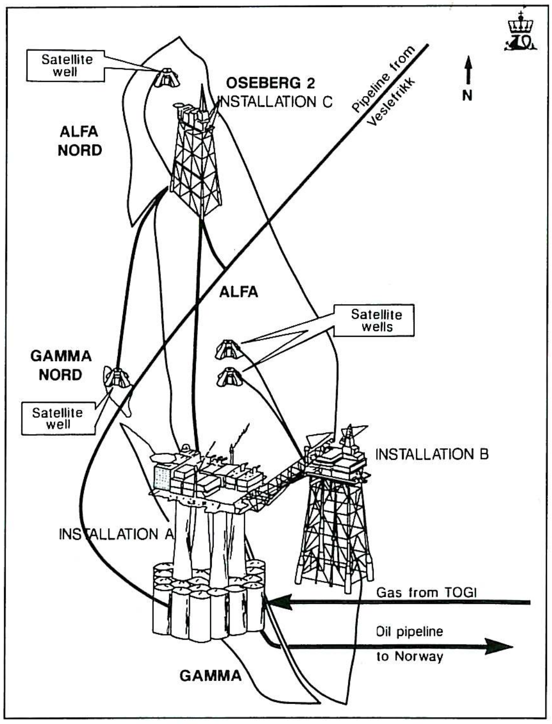
Den norske stats oljeselskap a.s. (Statoil)	65.04 %
Norsk Hydro Produksjon A/S	13.75 %
Saga Petroleum a.s	8.61 %
Elf Aquitaine Norge A/S	5.60 %
Mobil Development Norway A/S	4.20 %
Total Marine Norsk A/S	2.80 %

Recovery of reserves
The initial discovery was made in 1979 and proved gas. Subsequent discoveries have shown that the reservoir consists of an oil-bearing layer topped by a gas cap. A declaration of commerciality was presented in June 1983. The Norwegian Storting considered the development application in the spring of 1984 and a revised development and operations plan was approved in January 1988. It's main content was a bring-forward of the development of the northern part of the field (Phase 2) and an increase in the production rate from the field centre in the south.

In the plan for development and operation (PUD) of 1984, development of the northern part of Oseberg was to be carried out with a simple installation (Oseberg C) equipped for partial stabilisation of the wellstream. Oil and gas was then to be transferred to the A platform for further processing. The C installation was to be ready for production in 1995.

Gas injection was to be used to recover the oil from the main parts of the field, and water injection for a separate reservoir in the north.

Fig. 2.5.10
Existing and planned installations on Oseberg

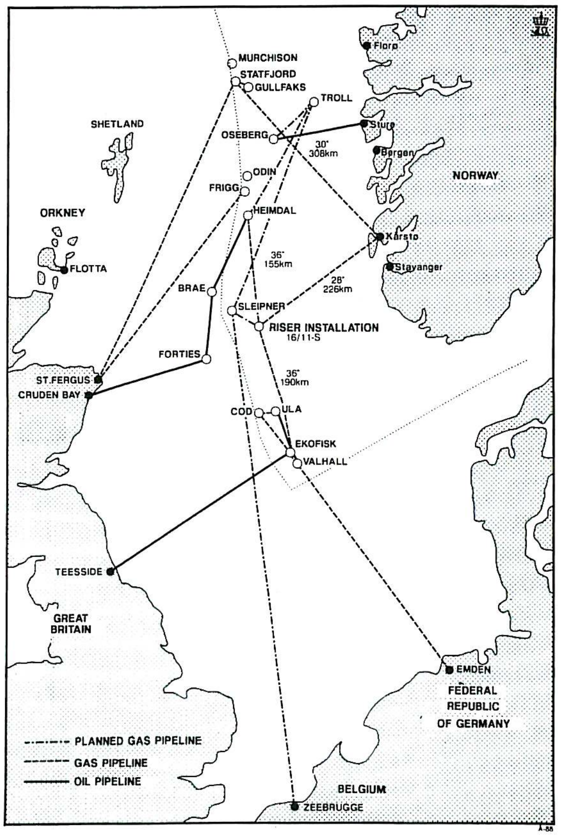


There is insufficient gas in Oseberg for pressure maintenance injection. A subsea production unit on the Troll field (TOGI) will therefore be built, with a line from Troll to the Oseberg field centre. The plant will deliver about 25 x 10^9 Sm^3 gas during the 12 year period starting in 1991. In connection with the acceleration of Oseberg 2 the operator plans to fetch further injection gas from a satellite field on the west flank of Oseberg, Gamma North. From this structure about 4 x 10^9 Sm^3 gas will be injected over a six-year period from the start-up of the C platform. Most of the injected gas can be recovered during the gas production phase on Oseberg, which is expected to last from 2002 to about 2020.

Chemical flooding

In connection with the plans for water injection as a drive mechanism for the main reservoir on the Alpha structure, a project was started to investigate the possibility for enhancing recovery by adding surfactants to the injection water. This project continued after gas injection was chosen for the Alpha structure, having in mind the Alpha North reservoir, where the oil is to be recovered by water injection. Some positive results have been achieved on the analysis side, and the project is continuing in 1989. A decision is expected by the end of 1989 as to whether the project is to be extended by a pilot experiment on the field.

Fig. 2.6
Pipelines for oil and gas from Norwegian fields in the North Sea



Long-range testing

In order to gain a better understanding of the reservoir properties, a long running test program was initiated in autumn 1986 using "Petrojarl I", a production and test ship. The production tests were concluded in 1988. They have been performed in two wells divided between several reservoir zones. The first test hole is in Gamma and the other in the Alpha structure.

Experience from the tests has been good. They have yielded important information, particularly as regards the limited reservoirs in the Ness and Tarbert formations, and about volume, oil/ water interface, productivity, rate-dependence and other reservoir behaviour during production.

In all there was produced 1.6 x 10^6 Sm^3 oil and about 230 x 10^6 Sm^3 gas in the test period of slightly less than two years. The oil produced was sold and the gas burnt. The value of the oil was greater than the investments and operating costs, so that the project turned a profit.

Production facilities

Oseberg is to be developed in two phases. Phase 1 includes a field centre in the south with two platforms: Oseberg A, a processing and accommodation platform with concrete base; and Oseberg B, a drilling and water injection installation with steel base. The middle part of the field is to be depleted by two subsea-completed wells linked to the field centre. production start for Oseberg field centre has been accelerated from 1 April 1989 to 1 December 1988. Average oil treatment capacity is 38,000 Sm^3 per day.

Phase 2 embraces development of the northern part of the field. In the revised Oseberg plan, the C installation is upgraded from a satellite platform to an integrated production, drilling and accommodation platform (PDQ) with use of support vessel in the drilling phase. The date of production start has been put forward from 1995 to October 1991. Average oil treatment capacity is 14,300 Sm^3 per day.

The installations are shown in Figure 2.5.10.

Metering system

The oil metering system on Oseberg A and the Sture I export metering station have been calibrated and tested in accordance with current regulations.

Installation of the Sture II export metering station was in progress at the end of 1988, and an oil metering station for Oseberg C is under construction.

A gas metering station for purchase of injection gas from Troll is under construction, and it is planned to install it on Oseberg A in February 1989.

Transport systems

A pipeline to transport stabilised oil from Oseberg to Sture was laid in summer 1987. Gas export from Oseberg will according to the present plans begin in 2002. The gas has not been sold, and no decision has been made as to how it is to be transported.

Costs

Total development costs for Oseberg A, B and C including Gamma North are about NOK (1988) 43 billion. Total operating costs over the lifetime of the field are estimated at about NOK (1988) 46 billion, excluding the Oseberg Transport System.

2.6 TRANSPORT SYSTEMS FOR GAS AND OIL

2.6.1. Existing transport systems

There are two landing pipelines for oil and three for gas on the Norwegian shelf. From Heimdal goes a condensate pipeline, mostly on the British side of the North Sea. A sketch-map of the oil and gas transport system on the Norwegian side of the North Sea may be found in Figure 2.6.

The oil pipeline from the Ekofisk area (including Ula and Valhall) goes to Teesside in Great Britain. Oil transport from Oseberg began at the end of 1988 and goes to Sture. Condensate from Heimdal is transported to Cruden Bay in Scotland. The gas pipelines Statpipe and Norpipe were linked together in 1986 and end up at Emden in West Germany. Frigg gas is transported to St. Fergus.

Gas transport, Statpipe

The Statpipe gas transport system was founded with the following partners:

Den norske stats oljeselskap a.s (Statoil)	60 %
Elf Aquitaine Norge A/S	10 %
Norsk Hydro Produksjon A/S	8 %
Mobil Development Norway A/S	7 %
Esso Exploration and Production A/S	5 %
A/S Norske Shell	5 %
Total Marine Norsk A/S	3 %
Saga Petroleum a.s	2 %

Statoil is operator for construction and operation of the pipeline.

The transport system includes:

- a rich gas pipeline from Statfjord to Kårstø
- a separation and fractionating facility on Kårstø, including storage farm and loading facility
- dry gas lines from Heimdal and Kårstø to a riser platform in Block 16/11, and a pipeline to the marine riser platform at the Ekofisk Centre.

Kårstø

The first North Sea gas was landed at Kårstø in March 1985. Transport capacity from Statfjord to Kårstø is 8 x 10^9 Sm^3 wet gas per year. Kårstø has a processing capacity of 5 x 10^9 Sm^3 wet gas per year, the dry gas pipeline to the Ekofisk Centre has a transport capacity of 17 x 10^9 Sm^3 a year. This exceeds the capacity requirements for Statfjord, Gullfaks and Heimdal and has been provided to allow later tie-in of other fields. If it becomes necessary to increase transport capacity in the Statpipe system, a compressor platform will need to be erected next to the marine riser platform 16/11-S. A blanket agreement with Norpipe A/S and the Phillips group has been made concerning the use of the Ekofisk Centre and the pipeline to Emden.

The licensees on Statfjord, Heimdal and Gullfaks have also entered into sales agreements for the gas with buyers on the Continent.

K Lab, commissioned in 1988, is a plant for full-scale testing and development of fiscal gas metering equipment built in connection with Kårstø. It is owned two-thirds by Statoil and one-third by Total.

Metering system

Metering of gas supplied from the Kårstø terminal was performed according to current standards in 1988. For LNG export the metering results are based on ship metering through most of 1988.

Gas transport, Norpipe A/S

The pipeline system for transport of natural gas from Ekofisk to Emden in West Germany is owned by Norpipe A/S, a share company owned 50/50 by Statoil and the Phillips Petroleum Norway group, with the Phillips Group as operator. In 1988 there was a swap between Statoil and Elf/Total, giving new ownership:

Den norske stats oljeselskap a.s (Statoil)	50 %
Phillips Petroleum Norway group	50 %
Phillips Petroleum Co. Norway	18.480 %
Norske Fina A/S	15.000 %
Norske Agip A/S	6.520 %
Norsk Hydro Produksjon A/S	3.350 %
Elf Aquitaine A/S	3.547 %
Total Marine Norsk A/S	1.524 %
Eufrarep Norge A/S	0.228 %
Coparex Norge A/S	0.200 %
Cofranord A/S	0.152 %
Statoil	1.000 %

Emden

The owner of the installations at the Emden terminal is Norsea Gas A/S. landing rights to the Emden area are held by Norsea Gas GmbH. Norsea Gas A/S and Norsea Gas GmbH are owned by the Phillips Petroleum Norway group. Phillips Petroleum Norsk A/S is the operator on behalf of the Group.

Gas transport, Ula

Licensees

BP Petroleum Development (Norway) Ltd	57.5 %
K/S A/S Pelican	5.0 %
Conoco Norway Inc	10.0 %
Den norske stats oljeselskap a.s (Statoil)	12.5 %
Svenska Petroleum Exploration	15.0 %

Gas transport, Frigg
The Norwegian Frigg pipeline is owned by the Norwegian Frigg partners. Ownership was changed in 1988 and is now:

Elf Aquitaine Norge A/S	26.42 %
Norsk Hydro Produksjon A/S	32.87 %
Total Marine Norsk A/S	16.71 %
Den norske stats oljeselskap a.s (Statoil)	24.00 %

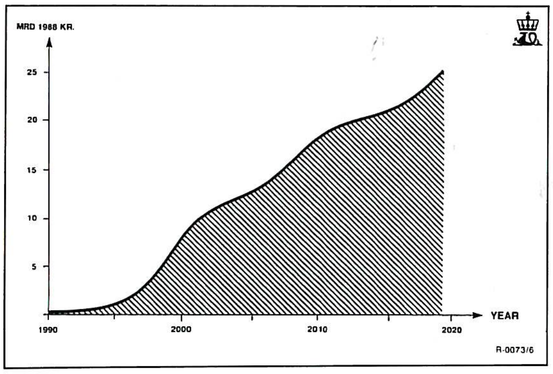
Total Oil Marine UK is operator.

The MCP-01 installation, midway between Frigg and St. Fergus,is 50 % Norwegian-owned, while the compression plant on the platform installed because of the Odin production is 100 % Norwegian-owned. Total investments for the Norwegian part of the transport system were about NOK (1988) 10.7 billion.

St. Fergus
The terminal is owned by the Norwegian and the British Frigg partners (Elf UK 66⅔, Total UK 33⅓). The various processing modules on the terminal are owned only by one of these groups or by both. Total Oil Marine UK is operator.

Oil transport, Norpipe A/S
The pipeline for transport of oil from the Ekofisk fields, Ula and Valhall to Teesside in Great Britain is owned by Norpipe A/S, a share company owned

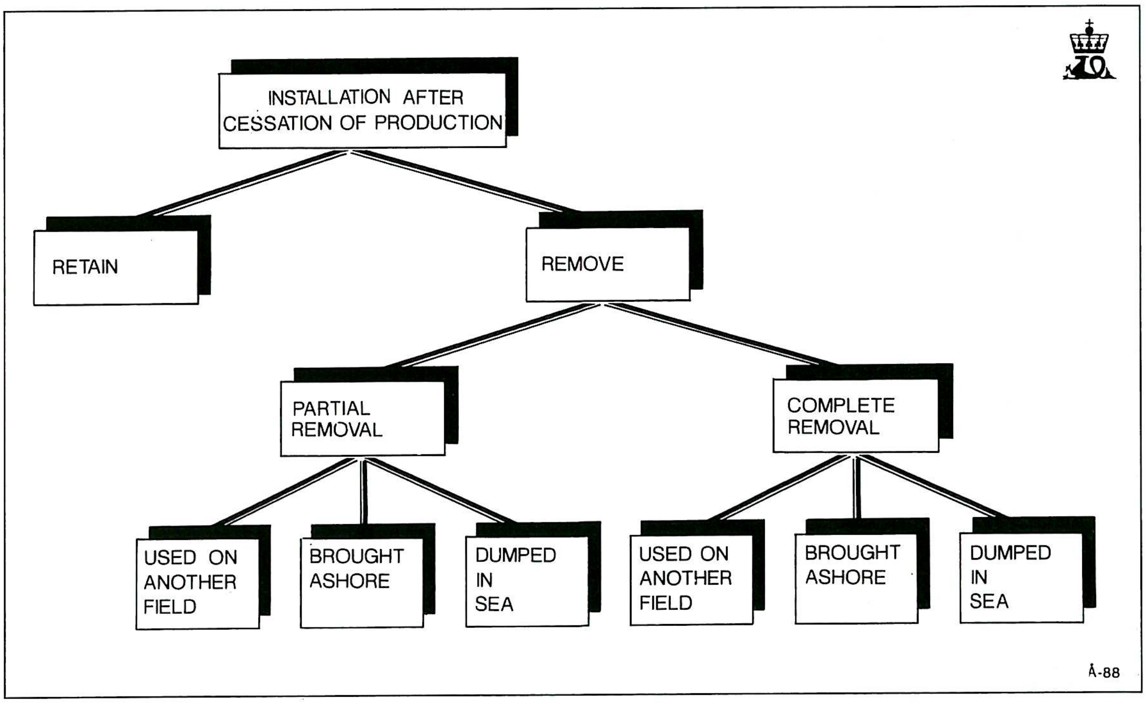
Fig. 2.7.a
Estimate of accumulated removal costs on the Norwegian shelf until 2020 given all installations be removed.



50/50 by Statoil and the Phillips Petroleum Norway Group, the ownership being the same as for the gas pipeline. Phillips Petroleum Company Norway is operator.

Teesside
The ownership of the installations at the Teesside terminal is divided between Norpipe A/S and the Phillips Petroleum Norway group, via Norpipe Petroleum UK Ltd and Norsea Pipeline Ltd. Phillips Petroleum Company UK Ltd is operator on behalf of Norpipe A/S and the Phillips Petroleum Norway

Fig. 2.7.b
Final production and removal



group. Norpipe Petroleum UK Ltd is a share company owned 50/50 by Statoil and the Phillips Petroleum Norway Group.

Oil transport, Ula

Statoil owns 100 % of the pipeline from Ula to Ekofisk.

Oil transport, Oseberg

The pipeline has a diameter of 711 mm and a capacity of 95,000 Sm^3 per day. Maximum water depth is about 350 metres.

The installation, including the Sture terminal, is owned and run by a separate unit interest company called A/S Oseberg Transport System (OTS). Unit holders in the venture are the Oseberg licensees and the operator for the pipeline and terminal is Norsk Hydro. The Oseberg Transport System began operation with the start-up of Oseberg.

The Oseberg Transport System consists of the following main components:

- pipeline equipment on Oseberg (platform A)
- seafloor pipeline
- landing site
- land pipeline
- terminal.

2.6.2 Zeepipe

In connection with the Troll contract, in the autumn of 1986 it was also decided to establish a gas pipeline, Zeepipe, from Troll via Sleipner to Zeebrügge in Belgium. Development will be in several phases, the first phase from Sleipner to Zeebrügge is scheduled for completion in 1993. The Troll-Sleipner connection is planned for completion in 1996. A connection from Troll to Heimdal is also planned.

In the autumn of 1988 it was decided that the dimension of the pipeline for Phase I was to be 1,016 mm. Initial capacity can later be increased by the installation of compressor stations, and maximum capacity for Phase I is calculated at about 18 billion Sm^3 per year. Dimensioning and design of the system north of Sleipner has not been determined.

Total costs of the Zeepipe project are expected to be about NOK 16.5 billion.

2.7 FINAL PRODUCTION AND REMOVAL

Since 1986 the International Maritime Organisation has been working on international guidelines for removal of installations on the continental shelf. The Ministry of Petroleum and Energy and the Norwegian Petroleum Directorate have been responsible for Norwegian participation in this project.

The question of to what extent a coastal state shall be made to remove its installations on the continental shelf after their use has finally ceased is of great import for Norway. Removal of the platforms on the Norwegian shelf will with few exceptions be considerably more expensive and technically complicated than elsewhere in the world. Norway has at present about 50 installations either producing petroleum, under construction or in the planning stage.

The costs of complete removal of all platforms is estimated at about NOK 38 billion. This figure is subject to great uncertainty. If we look at removal costs up to 2020, we find them estimated at about NOK 20 billion (Figure 2.7.a). The Removal Costs Distribution Act means that the State must meet about 80 per cent of the costs.

Within IMO Norway has, as indicated above, worked to ensure maximum flexibility in any international regulations.

Since December 1987 representatives of the USA, Great Britain and Norway have been negotiating for a compromise. The results of the negotiations are principally as follows:

- All installations whose use has finally ceased and which are in ocean depths less than 75 metres and have a base (jacket) weighing less than 4,000 tonnes, shall be removed.
- All installations emplaced after 1 January 1998, whose use has finally ceased and which are in ocean depths less than 100 metres and have a base (jacket) weighing less than 4,000 tonnes, shall be removed.
- For other installations, the question of removal will depend on a concrete evaluation on the part of the individual coastal state. In this evaluation, account shall be taken of, inter alia, safety of maritime traffic and other users of the sea, the effect on the environment and living resources, the costs and safety risks associated with removal, alternative uses and other reasonable grounds for letting the installation stand, wholly or in part.
- If a coastal state decides that an installation should be removed to below the surface of the sea, there shall be a free water column to the surface of at least 55 metres.
- If a coastal state decides that an installation shall be left standing, wholly or in part, so that it protrudes from the surface of the sea, proper maintenance shall be conducted to prevent it falling apart.
- After 1 January 1988, no installations may be emplaced which it is technically impossible to remove.

In April 1988 the IMO Maritime Safety Committee approved international guidelines for removal,based on the results of negotiations. These have now been sent to the United Nations Food and Agriculture Organisation, the United Nations Environment Program and the signatories to the London Dumping Convention for comments. Final consideration is expected to occur in IMO's supreme organ, the Assembly, in the autumn of 1989.

The international guidelines for removal of installations now being circulated for comments (the IMO rules) show up the need to develop further internal removal regulations in Norway. It should be noted here that the rules the IMO will adopt will be guidelines and not legally binding on the states. On the other hand, they will have considerable moral force, and it will be politically difficult for states not to follow them.

The question of removal is on the road to becoming very pressing on the Norwegian continental shelf. Norwegian authorities must take a position on a number of technical, economic and legal questions. Several of these questions will probably be suitable subjects for legislation or statutory regulation.

3. Petroleum resources

3.1 RESOURCE INVENTORY

Petroleum resources belong to the group of non-renewable energy resources, and comprise all technically recoverable oil and gas quantities.

Petroleum reserves are the part of the proven resources which can be extracted under given technical/economic conditions, and which the licensees have declared to be commercial.

The resource inventory comprises a summary of remaining commercial petroleum resources on the Norwegian continental shelf. Changes in the resource inventory from one year to another are caused by new discoveries, adjustment of the estimates for existing discoveries and reductions in consequence of production.

From 1987 to 1988, the Norwegian Petroleum Directorate's inventory for existing resources shows a net increase as compared with the preceding year. This increase is of 76 x 10^6 Sm^3 oil, including NGL, and 52 x 10^9 Sm^3 gas. The reason for this increase is a considerable upwards adjustment of resources in fields in production, upwards adjustment of gas estimates for old previous finds in the Barents Sea and additions from new finds in late 1987 and 1988. The balance between production and discovery rates for the last two years shows, however, that oil and NGL

Fig. 3.1.a
Resource account for the Norwegian continental shelf

		DISCOVERED						UNDISCOVERED	
	OIL/NGL x 10^6 Sm^3 GAS $10^9 Sm^3$	PROVED		PROBABLE		POSSIBLE		HYPOTHETICAL	SPECULATIVE
		OIL NGL	GAS	OIL NGL	GAS	OIL NGL	GAS		
PROGRESS	PRODUCING	955	365						
PROGRESS	DECIDED DEVELOPED			292	902				
PROGRESS	PLANNED DEVELOPED			261	648				
TECHNICAL ECONOMICAL CONFIDENCE	POSSIBLY DEVELOPED			247	721	219	148		
TECHNICAL ECONOMICAL CONFIDENCE	UNDER EVALUATION					17	17		
TECHNICAL ECONOMICAL CONFIDENCE	SUB. MARGINAL					9	24		
		PROD. WELLS		APPRAISAL WELLS		EXPLORATION WELLS		DEFINED PROSPECT	UNDEFINED PROSPECT
		DECREASING WELL CONTROL						DECREASING SEISMIC CONTROL	
		DECREASING GEOLOGICAL CONTROL							

PRODUCED	**486 x $10^6 Sm^3$ oil including NGL** **266 x $10^9 Sm^3$ gas**

Å-88

production equals the amount in new deposits found. In consequence of priority being given to oil exploration instead of gas, the gas balance is negative. For 1988 the additional reserves from older finds are, however, are so large that total resource balance for oil and gas is nevertheless positive.

The resource inventory for the Norwegian continental shelf is shown in Figure 3.1.a, and the geographical distribution of the resources is shown in Figure 3.1.b.

For the purpose of presentation in the annual report, the resources on the Norwegian continental shelf are shown in three tables:

I Reserves associated with development projects for which a development decision has been taken, or which are under development or in production south of Stad (Table 3.2).
II Other resources south of Stad (Table 3.3)
III Resources north of Stad (Table 3.4).

3.2 RESERVES BASIS FOR APPROVED FIELDS
As of 31 December 1988, decisions have been taken to go through with 27 development projects on the Norwegian continental shelf. This is an increase of four compared with 1987. The new fields approved for development are Draugen, Hod, Snorre and 30/6 Gamma. In total, these fields contain 0.17 x 10^9 t.o.e. Moreover, a decision has been taken to advance the development of Oseberg phase 2.

The petroleum quantities for fields with an approved development and operations plan south of Stad are shown in Table 3.2. Reserves figures for Draugen are given in Table 3.4.

In all, 0.66 x 10^9 t.o.e. have been produced up to 1 November 1988.

3.3 OTHER PROVEN RESERVES SOUTH OF STAD
Table 3.3 shows other resources which have been discovered south of Stad. Of these, the fields Brage, Statfjord North, Statfjord East, Sleipner West and Troll West have been declared commercial. The resource quantity in these five fields amounts to a total of 0.75 x 10^9 t.o.e.

3.4 PROVEN RESERVES NORTH OF STAD
So far, 0.75 x 10^9 t.o.e. have been discovered by drilling north of Stad. Of these, 0.48 x 10^9 are on Haltenbanken and 0.27 x 10^9 t.o.e. in the Barents Sea. On Haltenbanken it has been decided to develop Draugen.

3.5 CHANGES IN RESOURCE ESTIMATES FROM THE PREVIOUS ANNUAL REPORT
3.5.1 Fields in production
In the case of fields in production, the Norwegian Petroleum Directorate mainly employs the operator's forecast figures for its resource summaries. There are only small changes in the estimates compared with the annual report for 1987. For Ekofisk, Eldfisk, Tor, Ula, Valhall and East Frigg great changes have been made in the resource estimates from 1987 to 1988 (Table 3.5).

Fig. 3.1.b
Geographical distribution of the resources on the Norwegian continental shelf

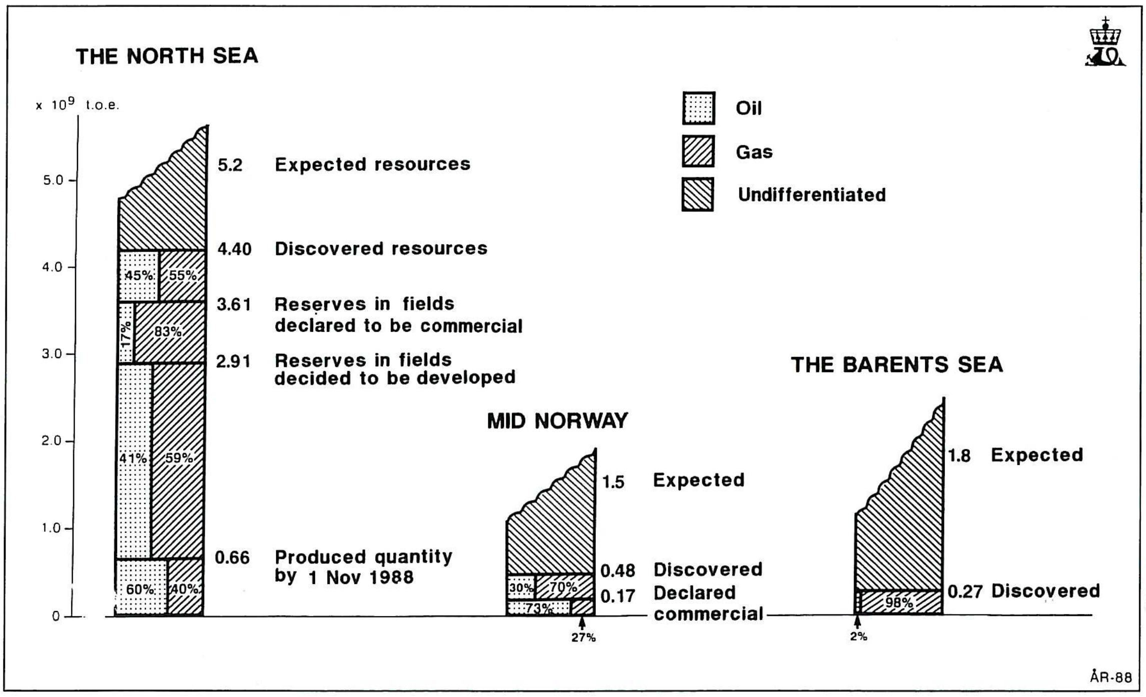


Table 3.2
Proven petroleum resources in fields with approved development and operation plan south of Stad

	ORIGINAL SALEABLE				REMAINING		
	OIL $10^6 Sm^3$	GAS $10^9 Sm^3$	NGL 10^6 tons	O EQV 10^6 tons	OIL $10^6 Sm^3$	GAS $10^9 Sm^3$	NGL 10^6 tons
Albuskjell[1)]	8.1	18.3	1.2	26.8	1.5	5.4	0.3
Cod[1)]	2.8	7.1	0.5	10.2	0.3	1.4	0.1
Edda[1)]	4.5	1.8	0.2	5.8	1.0	0.1	
Ekofisk	266.0	143.0	13.0	376.6	125.2	83.5	8.1
Eldfisk[1)]	73.0	48.4	4.5	114.8	36.2	34.7	3.0
Frigg[1)2)]	0.4	105.0		105.3		8.8	
Gullfaks[1)]	210.3	14.3	2.2	196.8	198.9	13.7	1.8
Gyda	30.5	3.0	2.5	32.1	30.5	3.0	2.5
Heimdal[1)]	4.5	33.2		36.3	2.9	24.6	
Hod[1)]	4.0	0.9	0.5	5.1	4.0	0.9	0.5
Murchison[1)3)]	12.0	0.3	0.4	11.1	1.5		
North East Frigg[1)]	0.1	11.0		11.1		3.7	
Odin[1)]	0.1	33.3		33.4		17.9	
Oseberg[1)4)]	242.0	79.0		285.0	240.4	79.0	
Sleipner East	17.0	51.0	10.0	79.1	17.0	51.0	10.0
Snorre	108.0	6.6		96.2	108.0	6.6	
Statfjord[5)]	374.8	48.2	14.6	383.5	183.0	38.9	12.3
Tommeliten[1)]	6.4	18.4	1.0	25.3	6.3	18.3	1.0
Tor[1)]	26.9	17.0	1.9	42.2	10.0	7.8	0.9
Troll East		825.0		825.0		825.0	
Ula	52.5	3.3	5.1	54.7	42.8	2.6	4.6
Valhall[1)]	48.7	12.7	3.5	57.8	32.9	9.9	2.7
Veslefrikk[1)]	36.4	3.0		33.2	36.4	3.0	
West Ekofisk[1)]	13.1	29.4	1.6	42.8	1.9	7.0	0.4
East Frigg		8.0		8.0		7.8	
30/6 Gamma North	1.4	7.5		8.6	1.4	7.5	
Total	1543.5	1528.7	62.7	2906.8	1082.1	1262.1	48.2

1) Operator's estimate
2) This is Norwegian share: 60.82 %
3) This is Norwegian share: 22.2 %
4) Includes Alpha, Alpha North and the Gamma structure
5) This is Norwegian share: 84.09 %

Ekofisk
The decision to increase the water injection and a favourable pressure development in the field have caused the resource estimate for Ekofisk to be increased by 12 per cent compared with the figure in the 1987 annual report.

Eldfisk
At Eldfisk the infilling of new production wells and a favourable pressure development have caused the oil resource estimate to be adjusted upwards by 19 per cent compared with the figure in the annual report for 1987.

Tor
Changes in well management and gas risers have increased the production rate of Tor. The resource estimate has been adjusted upwards by 14 per cent compared with the figure in the annual report for 1987.

Ula
A new appraisal well has shown that a fault passing through the field acts as a seal. The oil/water interface lies considerably lower than previously thought. This has led to the Ula resources being adjusted upwards by 43 per cent compared with the figures in the annual report for 1987.

Valhall
New information about drive mechanisms of the field and inclusion of several production wells have resulted in increased recovery rate on the field. The resource estimates for Valhall have been adjusted upwards by 17 per cent compared with 1987.

East Frigg
The reduced estimate for recoverable gas from East Frigg is due to leakage of gas to the main Frigg field. The 1988 estimate has been reduced by 38 per cent compared with 1987.

3.5.2 Other finds south of Stad
The changes in estimates for deposits south of Stad not yet in production include adjustments of old finds as well as new discoveries which previously have not had their forecast included in the annual report (Table 3.5).

The estimates for Frøy, Hod, North Statfjord and South-East Tor have been reduced, whilst for Brage

Table 3.3
Proven petroleum resources south of Stad for which no development decision has been taken

	Oil 10^6Sm^3	Gas 10^9Sm^3	NGL 10^6tons	O EQV 10^6tons
Agat[1]		43.0		43.0
Balder	35.0			31.6
Brage	46.2	3.5		42.3
Frøy	11.0	3.0		12.0
Gullfaks South	45.0	88.0		127.6
Hild[1]	1.2	8.8		9.8
Huldra[1]	5.4	16.4		20.8
Sleipner satellites[2]	16.0	35.0		47.2
Sleipner West[3]	27.0	135.0	9.0	169.2
Snorre West[1]	7.0			5.7
Statfjord North[1]	22.6	1.2		19.7
Statfjord East	19.0	2.5		18.3
SE-Tor	2.5	2.0		4.0
Troll West	41.0	463.0		499.9
1/3–3	3.3	0.1		2.8
2/7–20	33.0			27.0
2/12–1[1]	8.4			6.9
6/3 PI	0.9	1.0		1.7
7/11 A[1]	3.7			3.0
9/2 Gamma[1]	24.0	1.0		20.9
15/3–1,3	2.0	29.0		30.6
15/3–4[1]	12.0	5.0		15.0
15/5–1	2.0	6.0		7.5
15/12 Beta[1]	16.0	1.3		14.4
16/7–4[1]	1.4	8.0		9.0
24/6–1[1]	1.8	6.0		7.5
24/9	3.0			2.4
25/2–4	4.0	12.0		15.3
30/6 Beta	20.0			17.0
30/6 Beta Sadel	20.0			17.0
30/6 Kappa[1]	5.0	5.0		9.1
30/9 Omega[1]	9.3	3.0		10.6
30/9–6[1]	2.7			2.2
34/7 B[1]	25.5			20.9
34/7 C[1]	4.0			3.3
34/8–1[1]	22.5	75.0		93.5
34/10 Beta[1]	8.0	22.5		29.0
34/10 Gamma	2.2	28.0		29.8
35/8–1	1.9	13.5		15.0
35/8–2	2.6	7.0		9.1
35/11–2[1]	10.3	10.9		19.4
Total	528.4	1035.7	9.0	1491.0

1) Operator's estimate
2) Includes 15/8 Alpha, 15/9 Mu and 15/9 Theta
3) Includes Alpha, Beta, Epsilon and Delta

and 34/8–1 petroleum resource estimates have been considerably increased.

At Oseberg, the estimate of oil resources has been increased by almost 20 %. The most important finds not previously quantified in the annual report are 34/7-B from 1987 and 2/7–20 from 1988.

Brage
The Norwegian Petroleum Directorate has mapped Brage anew, based on three-dimensional seismics, leading to an increase of 24 per cent in the oil and gas resource estimates in comparison with the 1987 annual report.

Frøy
A new survey of the structure has led to a reduction of the oil and gas resources by 31 per cent compared with the operator's estimate of the 1987 annual report.

Hod
The Norwegian Petroleum Directorate here makes use of the operator's resource estimate, which is a reduction by 56 per cent compared with the Directorate's previous estimate in the 1987 annual report.

Snorre West
This is a new find from 1988, which might become a valuable supplementary resource for the Snorre development.

Statfjord North
The NPD resource figures in the 1987 annual report

Table 3.4
Proven petroleum resources north of Stad

		Oil $10^6 Sm^3$	Gas $10^9 Sm^3$	O EQV 10^6tons
Haltenbanken	Draugen	68.0	4.8	60.3
	Heidrun	87.2	42.7	114.2
	Midgard	15.0	80.0	91.6
	Njord	25.0	4.0	24.5
	Smørbukk	20.0	65.0	81.4
	Tyrihans	16.0	40.0	53.1
	6406/3 Alfa[1)]	9.0		7.0
	6407/6–3[1)]	5.7	14.3	19.0
	6506/12 Beta[1)]	22.0	11.0	29.0
	Sum	267.9	261.8	480.1
The Barents Sea	Albatross		41.7	41.7
	Albatross South		10.8	10.8
	Askeladd		59.7	59.7
	Snøhvit	6.5	91.4	96.7
	Snøhvit North		3.3	3.3
	7119/12[1)]		3.6	3.6
	7120/07		22.5	22.5
	7120/12		14.8	14.8
	7121/5 Beta		4.3	4.3
	7122/06–1[1)]		11.0	11.0
	7124/03–1[1)]		2.1	2.1
	Sum	6.5	265.2	270.5
	Total	274.4	527.0	750.6

1) Operator's estimate

are old, and have not included any new reports from appraisal wells. For this reason the 1988 annual report makes use of the operator estimates, which lead to a reduction of oil and gas estimates by 43 per cent compared with the 1987 annual report.

South-East Tor
Disappointing results from a new appraisal well have led to oil and gas estimates being reduced by 40 per cent.

2/12–1
This is a 1987 find not previously included in the annual report. The discovery is of particular interest because it opens up for a new exploration concept in deeper Jurassic strata in the southern part of the North Sea.

2/7–20
2/7–20 is the biggest new oil and gas discovery made in 1988 on the Norwegian continental shelf. The find confirms possibilities of new discoveries in the deep Jurassic formations in the southern part of the North Sea.

7/11 A
The operator has made a new survey, reducing the resource estimate. The Norwegian Petroleum Directorate has no resource data of its own for this structure and is using the operator's resource estimate in its resource summary.

34/8–1
A new appraisal well has been drilled in a separate part of the structure (34/8–3). The bore showed that the fault between the two structure parts is a sealing one, and after the last drilling the resource estimate for the whole structure has been increased by 30 per cent compared with the 1987 annual report.

34/7 B
This is an oil discovery from December 1987 for which the resources have not previously been listed in the annual report. The find is of interest as a supplementary resource for Snorre.

34/7-C
This is a minor oil discovery from 1986 which has not previously been included in the annual report.

35/11–2
This is an oil and gas discovery from December 1987 which has not previously been included in the annual report.

3.5.3 Haltenbanken
No new discoveries have been made on Haltenbanken in 1988, but a find from 1987 in Block 6407/6 not before listed in the annual report has been included in the resource summary (Table 3.4).

Heidrun
Mapping based on new and improved 3D seismics as well as up-dated technical reservoir studies have led the Norwegian Petroleum Directorate to adjust downwards its oil and gas resource estimates on

Heidrun by about 13 per cent compared with the 1987 annual report.

6407/6–3
This is a 1987 find for which the resource estimates have not previously been listed in the annual report. The find is located on the same place where "West Vanguard" had a blow-out of shallow gas in 1985.

3.5.4 The Barents Sea
No significant finds have been made in 1988. The Norwegian Petroleum Directorate has, however, made a new survey of the structures in the Hammerfest basin, leading to an 8 per cent increase in the gas resource estimates compared with 1987. In 1988 an estimate of technically recoverable oil from a thin oil zone in Snøhvit has been indluded in the resource accounts. Changes in each find are presented in Table 3.5.

Table 3.5
Changes in resources estimates in annual reports 1987–1988

	Annual report 1987			Annual report 1988		
	Oil 10^6Sm^3	Gas 10^9Sm^3	NGL 10^6tons	Oil 10^6Sm^3	Gas 10^9Sm^3	NGL 10^6tons
Fields in production and fields approved for development						
Albuskjell	8.0	18.0	1.2	8.1	18.3	1.2
Cod	2.9	7.1	0.5	2.8	7.1	0.5
Edda	4.7	1.9	0.2	4.5	1.8	0.2
Ekofisk	237.0	126.0	13.5	266.0	143.0	13.0
Eldfisk	63.5	39.4	3.4	73.0	48.4	4.5
Gullfaks	210.3	13.8	2.1	210.3	14.3	2.2
Hod	7.2	5.4		4.0	0.9	0.5
Oseberg	247.0	79.0		242.0	79.0	
Statfjord	375.0	49.0	15.4	374.8	48.2	14.6
Tor	24.0	14.6	1.6	26.9	17.0	1.9
Ula	33.0	1.6	1.4	52.5	3.3	5.1
Valhall	41.0	11.9	2.8	48.7	12.7	3.5
West Ekofisk	12.4	26.9	1.5	13.1	29.4	1.6
East Frigg		13.0			8.0	
Other fields						
Brage	38.0	3.0		46.2	3.5	
Frøy	15.0	5.0		11.0	3.0	
Heidrun	113.0	38.0		87.2	42.7	
Snorre West	–	–		7.0		
Statfjord North	39.0	2.0		22.6	1.2	
SE-Tor	4.0	3.0		2.5	2.0	
2/12–1	–	–		8.4		
2/7–20	–	–		33.0		
7/11 A	6.5			3.7		
34/8–1	8.0	65.0		22.5	75.0	
34/7 B	–	–		25.5		
34/7 C	–	–		4.0		
35/11–2	–	–		10.3	10.9	
6407/6–3	–	–		5.7	14.3	
Albatross		34.3			41.7	
Albatross South		8.2			10.8	
Askeladd		52.0			59.7	
Snøhvit	0.0	86.1		6.5	91.4	
7120/07		24.3			22.5	
7121/5 Beta		5.6			4.3	

4 Safety and Working Environment in the Petroleum Activity

4.1 INTRODUCTION

In the report period, the Norwegian Petroleum Directorate has continued its work on increasing the efficiency of its own activities. The Directorate has worked on developing a goal structure in order to have a planning tool that complies with the requirement for goal-oriented public activities.

4.1.1 Guidance to participants in the industry

In the for Safety and Working Environment Division, a service has been established which receives and and answers or coordinates requests concerning the present supervisory system and gives advice about the technical aspects of the regulations. In principle, the same guidance which is offered to operator companies is to be provided to all other participants in the petroleum industry, including owners of installations, vessels and equipment. The interest in this service indicates a great need for information in the industry.

4.1.2 R&D activity in S Division

A total of 37 R&D projects have been accomplished, and the total project amount is approx. NOK 4 million. A short presentation of each project is given in Chapter 6.2, which shows that the projects cover a wide range, from working environment conditions to high-tech problems.

In addition to providing answers to specific questions, the R&D work also entails a significant development of competence in the division.

Financing of the projects varies from projects financed by the Norwegian Petroleum Directorate to extensive joint projects where the Norwegian Petroleum Directorate bears a minor part of the costs. A requirement for the latter type of project is that the Directorate be given the same access to information and participation with regard to projects as the other participants.

4.2 LEGISLATION – WORK ON REGULATIONS

4.2.1 Methodical development of legislation for safety and working environment

When the new petroleum legislation and the introduction of a new supervisory system became effective in 1985, one of the objectives was to be able to develop a collective and uniform legislation for safety and working environment for industrial activities on the Norwegian Continental Shelf.

The Directorate started working on methodical development of legislation in January 1987. The objective is to modernize and update the existing detailed regulations.

The work, which comprises both the form and contents of legislation, is described in further detail in the Norwegian Petroleum Directorate's Annual Report for 1987.

In the report period, the Directorate has concluded the review and preparatory part of the work, and has made the following decisions concerning:

a) strategies with regard to formulating future detailed regulations
b) internal procedures with regard to the implementation of work on regulations

The Directorate has also developed an overall audit plan for existing detailed regulations. The plan is valid until the end of 1990.

The results of the study comparing the prevailing legislation for the Continental Shelf with adjoining flag state legislation for mobile installations (the equality study) has been published in the period.

The results will clarify the use of maritime certificates as documentation for compliance with shelf legislation requirements, and will contribute toward reducing the need for documentation in the petroleum industry.

In formulating the legislation the Directorate has been directed to consider the formulation with regard to a possible harmonisation with the legislation of the EEC.

The Directorate has prepared for this directive through the organising of, and procedures for, the implementation of legislation.

4.2.2 Work on regulations

On 10 February 1988 the Directorate issued the regulation on the scope of certain regulations for surveys and exploration drilling in petroleum activities on the Norwegian Continental Shelf.

The regulation entails that the detailed regulations for mobile installations used for exploration drilling and well activities, will now, with a few amplifications, be applicable to the same installation when completing production drilling and well activities.

The regulation will lead to a considerable simplification compared with previous regulations.

The Directorate has prepared an overall audit plan for detailed regulations that are prepared pursuant to the safety regulation.

The audit plan comprises the preparation of 13 thematic regulations before the end of 1990. The previous distinction in the detailed regulations between permanently sited installations and mobile installations will no longer exist.

The Directorate has worked on the following regulations in the report period:

a) regulation for drilling and well technology and data acquisition w/explanatory guidelines (planned completion 3rd quarter 1989)
b) regulation concerning planning, preparation and implementation of manned underwater operations in petroleum activities w/explanatory guidelines (external comments completed autumn 1988)
c) regulation for pipeline systems in petroleum activities w/explanatory guidelines (planned completion 3rd quarter 1989)
d) regulation for electric equipment in petroleum activities w/explanatory guidelines (planned completion 2nd quarter 1989)
e) regulation concerning natural data in petroleum activities w/explanatory guidelines (planned completion 3rd quarter 1989)
f) regulation for implementation of analyses of safety in petroleum activities w/explanatory guidelines (planned completion 4th quarter 1989)
g) regulations for cranes and lifting equipment on installations in petroleum activities w/explanatory guideline (planned completion 3rd quarter 1990)
h) regulation relating to emergency preparedness w/explanatory guidelines (planned completion 3rd quarter 1990).

In addition, the Directorate has worked on guidelines to the Norwegian Petroleum Directorate's regulation for loadbearing structures etc. The guidelines deal with the following areas:

a) soil mechanics
b) floating structures
c) steel materials
d) steel calculations

4.3 SUPERVISORY ACTIVITIES

Supervisory activities in the report period were implemented in accordance with an overall plan that reflected priority areas of concentration. Experience from completed supervisory activities comprised a substantial part of the plan foundation.

The Norwegian Petroleum Directorate's supervision shall motivate the participants in petroleum activities and contribute to secure that the participants comply with the regulations through the internal control principle, thus contributing to maintain the Norwegian Petroleum Directorate's objectives in relation to safety and working environment in the best possible manner.

The Norwegian Petroleum Directorate makes sure that the operator has a control system which ensures that the operations are planned, organized and maintained in accordance with the requirements of laws and regulations. This is undertaken by the study of how the control systems are followed up and maintained (system audit) and through spot checks to confirm that activities and products are in accordance with specified requirements (verification).

4.3.1 Consents and licences

At a number of milestones defined in the safety regulations, approval from the Norwegian Petroleum Directorate is necessary in order to initiate petroleum activities.

In the report period, 71 consents were given, broken down as follows:

5 consents for exploration
18 consents for exploration drilling
5 consents for detailed planning
5 consents for fabrication
8 consents for emplacement
10 consents for use
5 consents for rebuilding or change of use of installation
1 consent for removal of installation
14 consents for the use of service vessels.

In addition to this, 62 licences have been given for production drilling, 30 licences for exploration drilling and 44 licences for shallow drilling.

4.3.2 Priorities and objectives

Supervisory activities gave priority to the following concentration areas in the report period:

a) Compliance with the intentions of the Working Environment Act
b) Early phase
c) Older installations

Objectives and priorities for supervisory activities were concretised in the supervision plan. The plan was prepared in accordance with the following main lines:

a) supervisory activities directed toward the individual operator shall be adapted to the experience which the Norwegian Petroleum Directorate has with the operator's compliance with the internal control duty and the extent of his activities on the Norwegian Continental Shelf
b) all supervisory activities shall have reference to the operator's compliance with the internal control duty
c) there shall be correlation and systematism in all supervisory activities directed toward the operator
d) there shall be a balance between system audits,

verifications and other supervisory activities that provide achievement of objectives with the least possible use of resources

e) there shall be an active use of contributory agencies

4.3.3 Experience

Experience from the implementation of supervision in the report period shows a rather good achievement of objectives for supervisory activities. At the same time the implementation shows that the Norwegian Petroleum Directorate is faced with new challenges, and that planning and implementation of supervision can be improved.

Based on experience and increased understanding and knowledge, both in the Norwegian Petroleum Directorate and in the industry, the supervision methodology of the Norwegian Petroleum Directorate is being further developed with a view towards making it more efficient and correct. The Norwegian Petroleum Directorate feels that this continued development has contributed to the industry also making their systems more efficient, so that the internal control systems in the petroleum industry are further developed and made more efficient.

Supervisory activities in the report period have gone in the direction of more system audits at the expense of verifications in relation to previous years. In the assessment of the Norwegian Petroleum Directorate there is now a relatively good balance in supervision, even if there is still room for improvement with a view to the achieving of objectives with the least possible use of resources.

The contributory agencies have participated actively in supervisory activities, but the Norwegian Petroleum Directorate has not achieved a satisfactory involvement by the contributory agencies with regard to these agencies being participants in the Norwegian Petroleum Directorate's total supervision. As participants in the supervision, the contributory agencies shall implement supervisory activities in a manner consistent with the principles for internal control. The Norwegian Petroleum Directorate sees corresponding supervisory activities as a clear challenge.

4.3.3.1 Compliance with requirements in the Working Environment Act

In the report period, the Norwegian Petroleum Directorate has given priority to supervision directed at the companies' compliance with conditions governed by the Working Environment Act. The results of the supervision show that the operators to an increasing degree place emphasis on complying with these conditions, but there is still a fair way to go before the requirements and objectives of the act are obtained. In a negative direction the Directorate would especially mention conditions related to the organised safety delegate service and the relationship between the employee and employer.

4.3.3.2 Early phase

The Norwegian Petroleum Directorate emphasises that security and working environment be maintained in early phases of a project. By clarifying at an early date what requirements are expected to be met, the Directorate contributes to more optimum solutions.

Follow-up of projects in an early phase (plan for development and operations and detail planning) was given priority in the report period. The results of these supervisory activities will not be seen until the projects are completed and the installations have been put into operation. It can still be concluded though, on the basis of experience from follow-up in the early phase, that the Norwegian Petroleum Directorate has gained increasing influence on conditions of importance for the working environment, safety and emergency preparedness, and for choosing new cost-efficient development solutions.

4.3.3.3 Older installations

The Norwegian Petroleum Directorate has in the report period also given priority to the follow-up of the operator's maintenance of older installations. This supervisory activity has disclosed in part major flaws in the operator's maintenance systems and, to a certain extent, a lag in the implementation of planned maintenance. Flaws and lag can lead to equipment not always having the necessary standard. An increase in reporting of unintentional gas discharges on the older installations has been registered particularly in the last half of 1988. The Norwegian Petroleum Directorate has for the moment not been able to establish whether this increase is solely due to the Norwegian Petroleum Directorate's enjoining of the reporting routines, or whether there has been an actual increase in unintentional gas discharges. Work has been initiated to clarify the circumstances surrounding this increase and to evaluate what measures must be implemented vis-à-vis the industry. Statistics for gas leakage in 1988 have been included in Table 4.13.4.

4.4 REMOVAL OF FLOTEL FROM STATFJORD B

The operator, Statoil, applied in September 1988 to have the flotel removed from Statfjord B, as the operator felt that the requirement for additional living quarters was no longer present.

The employee's organisation became strongly involved in the matter, and after consultation with the organisation Statoil decided to install additional evacuation systems on the Statfjord installations. There was strong disagreement between Statoil and the employees on when the flotel was to be moved. The employees did not wish that the flotel be moved until additional evacuation systems had been installed, as they felt that the safety level would be lowered to below what was acceptable.

Statoil, on its part, felt that studies had documented that the safety level was also acceptable without the flotel in the period prior to installation of the additional system. The Norwegian Petroleum Directorate gave its approval for Statoil to remove the flotel.

4.5 MANNING REDUCTIONS

The employee organisations reacted strongly to less personnel and manning reduction measures on the installations in the Ekofisk area. The size of the drilling teams has been reduced from 30 to 25 persons, and the operator, Phillips Petroleum Company Norway, wished to reduce the number of personnel in the radio rooms on most of the installations in the Ekofisk area. In this connection the operator has implemented a trial project with reduced manning of the radio room at Eldfisk 2/7 B, and has postponed the implementation of reduced manning of the radio rooms. Elf Aquitaine has reduced the manning in the radio rooms on the DP-2 and HMP-1 installations.

There are no regulations in the petroleum industry that stipulate the extent of manning. It is regarded as being up to the operator to determine the extent, based on the requirements of the concrete situation. Disagreement between the parties on the extent of manning is subject to negotiations.

The Norwegian Petroleum Directorate's decision regarding manning reduction was appealed by employee representatives in coordinating field work environmental committees. The basis of the complaints was that safety was reduced.

The complaint regarding the decision on reduced drilling teams was withdrawn by the complainants before the factual aspects were considered by the Ministry of Local Government and Labour.

In the matter regarding reduced manning of the radio rooms, the ministry agreed with the evaluation of the Norwegian Petroleum Directorate.

It is the aim of the Norwegian petroleum Directorate that matters of this nature be solved in accordance with the Working Environment Act's objective regarding negotiations between the parties.

4.6 INDUSTRY EXPERIENCE WITH INTERNAL CONTROL

In 1986 the Norwegian Petroleum Directorate completed a study on the experience of operators and project groups in implementing internal control and quality assurance. This study showed great variation in the degree of implementation, practice and requirements for the industry regarding internal control and quality assurance. The Norwegian Petroleum Directorate therefore initiated a study to obtain an overview of the oil-related industry's experience with requirements and practice of operators and project groups regarding internal control and quality assurance, and how this effected their activities. The study was completed in the spring of 1988, and the results were published in a separate report.

Approx. 100 persons in senior positions in about 60 groups and companies stated their opinions on quality assurance and its implementation in connection with contracts, the use of standards, follow-up and audit activities, degree of acceptance, costs and the industry's impression of the Norwegian Petroleum Directorate's follow-up.

As the report has been made public, the industry can utilise the results in its work on efficiency in quality assurance.

In connection with the planning of measures for maintaining and further developing the Norwegian Petroleum Directorate's total expertise, the Directorate has evaluated the viewpoints expressed regarding the quality of the Directorate's supervisory activities. The Norwegian Petroleum Directorate invited representatives from the operators to an open discussion of experience with internal control and the Norwegian Petroleum Directorate's supervisory activities in this connection.

4.7 PERSONAL INJURIES

4.7.1 Injuries in connection with drilling

The Norwegian Petroleum Directorate receives reports on personal injuries in connection with drilling operations, and the reports are evaluated with a view to establishing whether follow-up shall be implemented on the part of the Norwegian Petroleum Directorate.

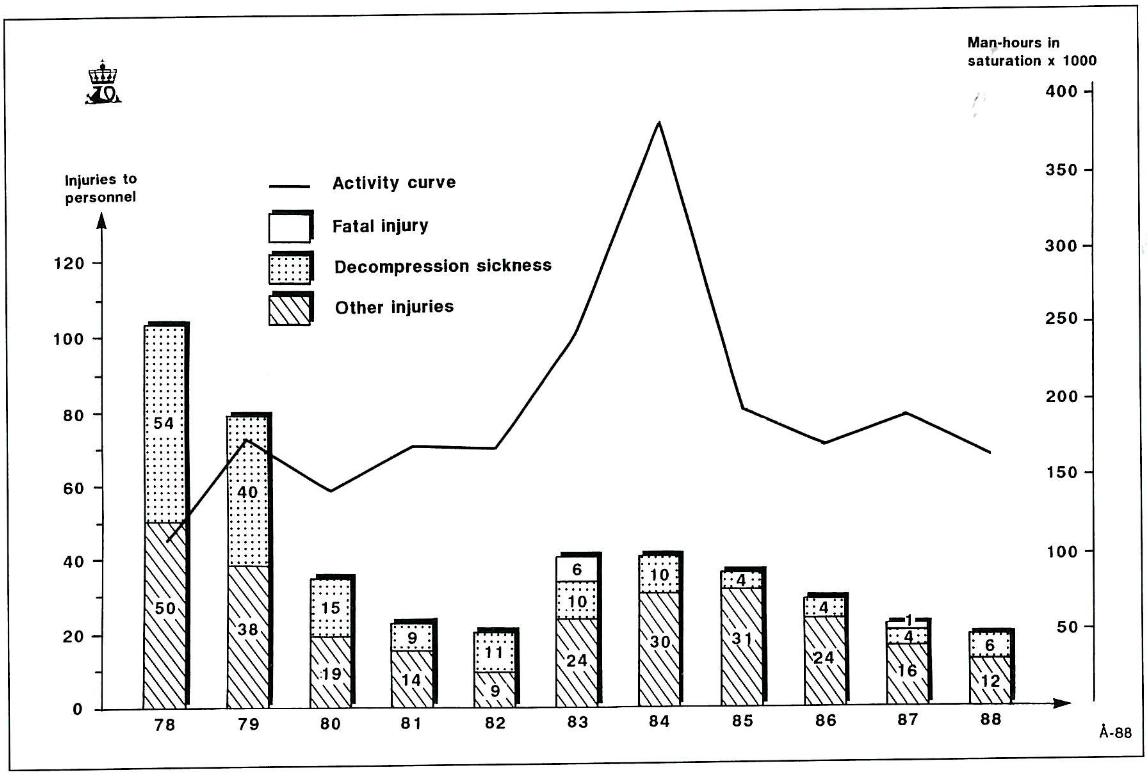
In some instances the Directorate has sent out safety reports and/ or letters, or called a meeting to discuss special problems with operators and drilling contractors.

Personal injuries in connection with drilling occur, however, where clear causal connections are hard to see. The Norwegian Petroleum Directorate therefore felt the need for further dialogue with the industry so that together we can find measures to prevent such injuries. On this basis the industry was was invited to a meeting at the Directorate in August 1988.

The purpose of the meeting was to find a common platform where the industry and the Directorate together cooperate on an action plan in order to reduce injuries connected with drilling. The meeting arrived at conclusions regarding measures in the areas of:

a) Supervision and planning of the work
   Management's attitude toward safety
   Planning of the work
   Operating philosophy
   Preparation of the work
   Management's follow-up
   Safety meetings
b) Training and motivation
   Motivation measures
   Development opportunities and job content
   Training in injury investigation

Fig. 4.7.2
Total number of personal injuries in connection with diving on the Norwegian Continental Shelf – 1978–88.



Training in ergonomics
Sponsors for new employees

c) Transfer of experience
The role of the Norwegian Petroleum Directorate
The role of the industry
Reward systems

d) Protective gear
Design of protective gear
Tidiness and cleaning
Cooperation and communication

In 1989 the Norwegian Petroleum Directorate will follow up the injury-preventive work in drilling that was initiated in 1988. The role of the Directorate with regard to establishing a safety forum must especially be clarified.

4.7.2 Injury statistics for diving operations

Figure 4.7.2 provides a summary of the number of personal injuries which have been reported to the Norwegian Petroleum Directorate in the years 1978–88 in connection with diving activities on the Norwegian continental shelf. Personal injuries have been divided into the categories of deaths, other injuries and decompression sickness.

Four cases of decompression sickness occurred during saturation diving and two during surface diving.

Infections and near accidents have not been included in the summary. In the report period there were 16 reported cases of infection of the outer auditory canal of the divers. There were also 16 reported near accidents. These are primarily undesired decompression, malfunction in the fastening system for the diving helmet, malfunction in the breathing mixture supply and incidents where objects lowered from the surface were placed at a reckless proximity from the diver without the diver being informed.

4.7.3 Injury statistics for production activities

635 incidents of personal injury have been reported in connection with the production of oil and gas in the report period, none of which have caused loss of lives. This is 196 less than the year before, i.e. a reduction of about 23 %. At the same time, 12,564 man-years were reported, compared with 13,753 the year before; a reduction of about 9 %. This reduction in man-years is caused mainly by the conclusion of the jack-up operations at Ekofisk in 1987.

The injury rate varies considerably from operator to operator. This is caused by the major differences in activity levels, the type of installations and the different phases of the field development.

The tables

Table 4.7.3.a shows a summary of personal injury

cases per 1000 man-years in the period 1978–88 in the production operations. The tables for 1987 have been corrected due to the revised number of hours per man-year, which means that the conclusion of the last report must be substantially revised. The total injury rate in 1987 has been corrected to the reduced 60.4 injuries per 1,000 man-years. The injury rate in 1988 has been calculated at 50.5. This implies a considerable reduction in the calculated injury rate, a change that is significant statistically.

Injuries sustained on the installations outside of working hours (leisure time injuries) have not been included. There were 32 reports of such injuries in 1988, compared with 24 the year before. Leisure time injuries primarily consist of sprain/ strain injuries in connection with climbing stairs etc. and in

Fig 4.7.3.a
Personal injury cases in the period 1978–88

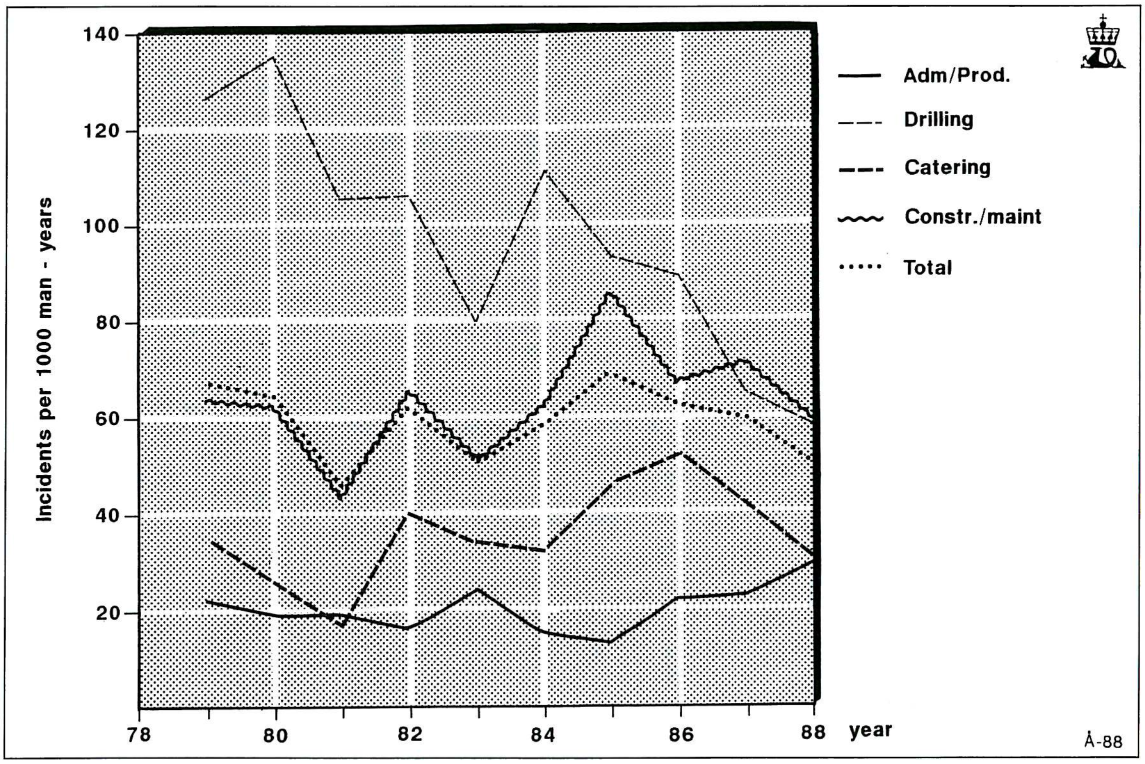


Table 4.7.3.a
Occupational accidents/fatalities/1,000 man years (1976–88). Production installations

Year	Hours worked	Hours per man year	Man years	Number of injuries (incl dead)	Number of injuries per 1,000 man years	Number of deaths	Number of deaths per 1,000 man years
1976	4876316	1852	2633	213	80,9	2	0,76
1977	8146948	1852	4399	282	64,1	2	0,45
1978	14932296	1752	8523	624	73,2	6	0,70
1979	14986608	1752	8554	575	67,2	0	0,00
1980	12237720	1752	6985	451	64,6	0	0,00
1981	15612072	1752	8911	415	46,6	0	0,00
1982	14790384	1752	8442	528	62,5	0	0,00
1983	11473848	1752	6549	334	51,0	0	0,00
1984	14643216	1752	8358	491	58,7	1	0,12
1985	15014640	1752	8570	598	69,8	1	0,12
1986	17108280	1752	9765	605	62,0	0	0,00
1987	22169458	1612	13753	831	60,4	0	0,00
1988	20253470	1612	12564	635	50,5	0	0,00
Total	186245256		108006	6582	60,9	12	0,11

connection with leisure activities, in addition to injuries as a result of falls from top bunks.

Table 4.7.b shows the distribution of the injury rate for the various main activities in the period 1979–88. With the exception of administration/ production which has increased, the summary shows a clear reduction in the injury rate. Drilling, and construction and maintenance represent the most vulnerable workplaces. It is therefore gratifying to ascertain that the decrease in the injury rate for drilling and well operations continue, and that the development in construction and maintenance now seems to be headed in a positive direction. There has also been a considerable reduction in the injury rate for catering, compared with 1987.

In 1988 drilling and well operations accounted for

Fig 4.7.3.b
Injury frequency 1984–1988 by function

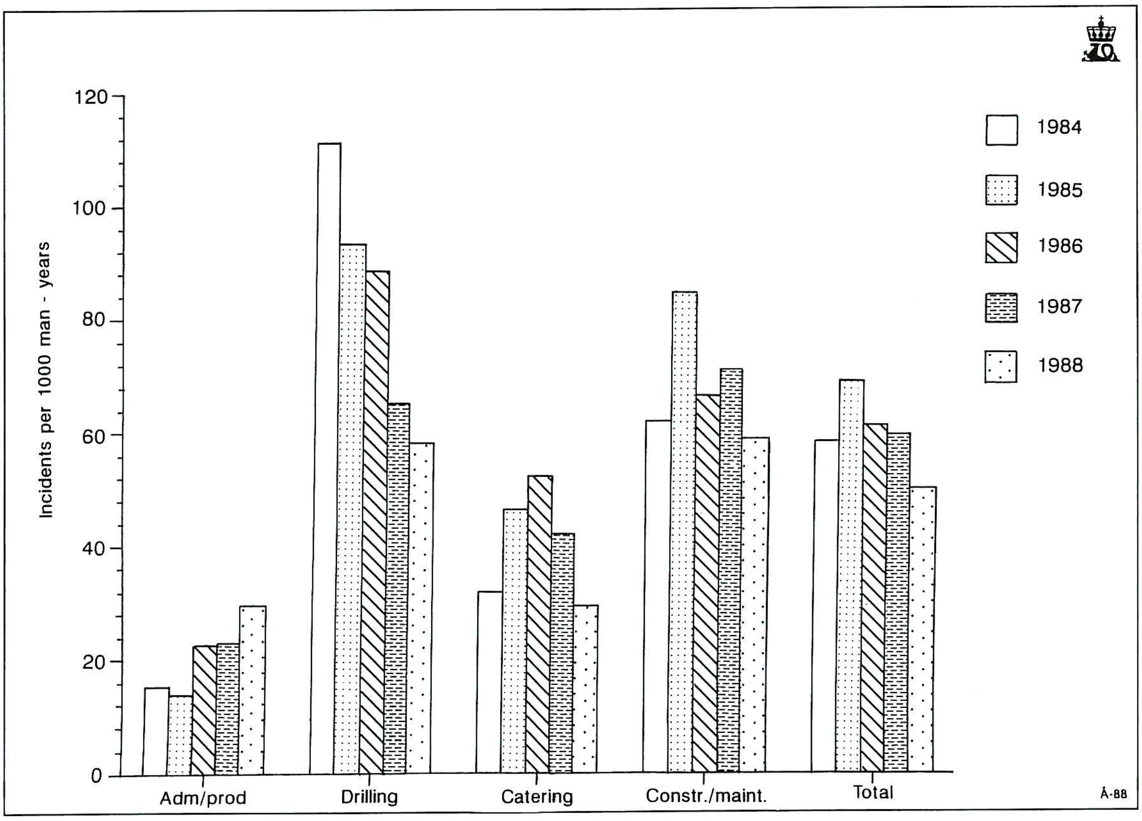


Table 4.7.3.b
Occupational accidents per 1,000 man years, distributed on fuctions (1979–88). Production installations

FUNCTION		1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
Administration/	Man years	1098	1174	1144	1306	1182	1614	1656	1507	2295	2627
production	Injuries	25	23	22	21	29	25	23	34	53	78
	Injuries/1000 man years	22,8	19,6	19,2	16,1	24,5	15,5	13,9	22,6	23,1	29,7
	Man years	1467	1095	1098	1289	1300	1324	1384	1371	1567	1883
Drilling	Injuries	186	148	116	137	104	148	130	122	103	110
	Injuries/1000 man years	126,8	135,2	105,6	106,3	80,0	111,8	93,9	89,0	65,7	58,4
	Man years	507	383	411	548	525	681	685	856	1167	1098
Catering	Injuries	18	10	7	22	18	22	32	45	50	33
	Injuries/1000 man years	35,5	26,1	17,0	40,1	34,3	32,3	46,7	52,6	42,8	30,0
Building/	Man years	5482	4333	6258	5299	3542	4739	4845	6031	8724	6956
maintenance	Injuries	346	270	270	348	183	296	413	404	625	414
	Injuries/1000 man years	63,1	62,3	43,1	65,7	51,7	62,5	85,2	67,0	71,6	59,5
	Man years	8554	6985	8911	8442	6549	8358	8570	9765	13753	12564
Total	Injuries	575	451	415	528	334	491	598	605	831	635
	Injuries/1000 man years	67,2	64,6	46,6	62,5	51,0	58,7	69,8	62,0	60,4	50,5

Table 4.7.3.c
Distribution of injuries and man years among operator and contractor employees

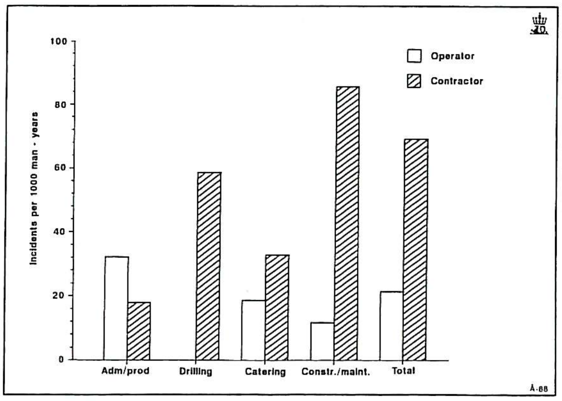
FUNCTION		1985	1986	1987	1988		
Administration/ production	Man years	1575	1293	1692	2173	o	(operator)
		80	213	603	454	c	(contractor)
	Injuries	19	34	44	70	o	
		4	0	9	8	c	
	Injuries/1000 man years	12,0	26,3	26,0	32,2	o	
		49,6	0	14,9	17,6	c	
Drilling	Man years	0	0	0	0	o	(operator)
		1384	1371	1567	1883	c	(contractor)
	Injuries	0	0	0	0	o	
		1 30	122	103	110	c	
	Injuries/1000 man years	0	0	0	0	o	
		93,9	89,0	65,7	58,4	c	
Catering	Man years	0	39	94	217	o	(operator)
		685	817	1073	882	c	(contractor)
	Injuries	0	5	5	4	o	
		32	40	45	29	c	
	Injuries/1000 man years	0	129,3	53,3	18,4	o	
		46,7	49,0	41,9	32,8	c	
Building/ maintenance	Man years	1544	2063	2441	2436	o	(operator)
		3301	3969	6283	4520	c	(contractor)
	Injuries	61	51	49	78	o	
		352	353	576	386	c	
	Injuries/1000 man years	39,5	24,7	20,1	11,5	o	
		106,6	88,9	91,7	85,4	c	
Total	Man years	3120	3394	4227	4825	o	(operator)
		5450	6370	9526	7739	c	(contractor)
	Injuries	80	90	98	102	o	
		518	515	733	533	c	
	Injuries/1000 man years	25,6	26,5	23,2	21,1	o	
		95,0	80,8	76,9	68,9	c	

man-years for the period 1985 to 1988 between the employees of the operator companies and the contractors. In 1988, the contractor companies contributed with 61.6 per cent of the total man-hours on the production installations, compared with 69.3 per cent the year before. 84 per cent of the injuries in 1988 took place within this group, compared with 88.2 per cent the year before. For operator employees the injury rate was 21.1 in 1988, compared with 23.2 in 1987.

Table 4.7.d-g shows the distribution of personal injuries within the different variables.

Table 4.7.h shows the distribution of personal injuries according to the assumed degree of seriousness. An injury is here defined as serious if it has led to or probably will lead to injury of a permanent character (e.g. amputation) or long-term absence from work. The evaluation has been made on the basis of information given in the injury form, and is therefore not based on a future medical and professional evaluation .

Fig 4.7.3.c
Injury frequency 1988 operator/contractor employees



The figures

Figure 4.7.b shows the development of the calculated injury rate in the period 1984–88 according to function

Figure 4.11.b shows the distribution of the injury rate between operator and contractor employees and main activities in 1988.

Figure 4.7.d shows the development of personal injuries in the period 1979–1988.

4.7.4 Injury statistics in connection with exploration and production drilling from mobile installations

This is the second year the Directorate presents a

Table 4.7.3.d
Occupational accidents 1987–88. Production installations. Injury incident/occupation

Injury incident / Occupation	Admin. stration	Drillfloor worker	Driller	Electrician	Catering	Assistent worker	Instrument technician	Crane operator	Painter/ Sandblaster	Mechanic/ Motorman	Operator	Plateworker insulator	Pipeworker Plumber	Service-technician	Scaffolder	Welder	Derrickman	Unspecified	Total	%	Year
Other contact with objects/machinery in motion	1	8	2	7	4	17	2	1	7	9	5	9	5	3	11	7	2	0	100	12.0	87
	1	12	2	2	3	15	0	2	3	5	7	3	4	10	3	0	4	0	76	12.0	88
Fire Explosion etc	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	1	0.1	87
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	88
Fall to lower level	4	1	0	5	2	6	0	2	3	5	2	3	4	2	4	3	0	0	46	5.5	87
	0	1	0	1	1	6	2	2	6	2	3	3	2	0	3	1	1	0	34	5.4	88
Fall to same level	2	0	0	6	6	12	0	0	6	2	1	5	7	1	15	3	1	2	69	8.3	87
	2	3	1	4	3	11	4	0	2	1	2	2	0	2	7	2	1	0	47	7.4	88
Stepping on uneven surface, mis-step	2	2	1	7	8	10	3	2	9	4	8	6	4	1	15	15	1	1	99	11.9	87
	0	3	0	5	2	4	0	2	7	4	7	5	7	3	9	3	2	0	63	9.9	88
Falling objects	0	0	1	1	0	9	0	0	1	5	0	7	3	1	5	4	1	0	38	4.6	87
	0	8	1	0	2	1	0	0	0	7	2	3	4	0	4	2	0	0	34	5.4	88
Other contact with objects at rest	0	0	0	8	1	12	1	2	5	6	2	8	11	4	11	4	0	0	75	9.0	87
	2	2	1	2	1	6	1	0	8	4	2	2	0	0	3	0	0	0	34	5.4	88
Handling accidents	3	8	0	10	16	23	1	1	4	20	6	14	13	6	14	12	0	0	151	18.2	87
	2	8	1	10	11	14	3	1	6	15	11	14	8	3	10	8	1	0	126	19.8	88
Contact with chemical/ physio-compound	1	2	0	1	6	2	3	1	6	2	4	0	3	1	0	4	0	0	36	4.3	87
	0	3	0	1	1	4	0	0	10	1	2	3	0	0	0	0	1	0	26	4.1	88
Overloading of part of body	0	4	1	4	2	11	0	3	1	3	3	4	10	3	15	3	2	0	69	8.3	87
	1	2	0	7	3	8	0	0	10	4	6	6	5	4	9	4	1	0	70	11.0	88
Splinters, splashes	0	0	0	5	2	11	0	0	11	8	1	29	15	0	6	40	0	1	129	15.5	87
	1	3	0	4	3	11	0	0	25	9	4	18	11	0	2	21	2	0	114	18.0	88
Electric current	0	0	0	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	0.4	87
	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0.3	88
Extreme temperature	1	0	0	0	3	1	0	0	0	0	1	1	0	0	0	4	0	0	11	1.3	87
	0	0	0	0	5	0	0	0	0	0	0	0	3	0	0	1	0	0	9	1.4	88
Fall into sea	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	87
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	88
Other	0	0	0	0	1	2	0	0	0	0	1	0	0	0	0	0	0	0	4	0.5	87
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	88
Total	14	25	5	57	51	116	10	12	54	64	34	86	75	22	96	99	7	4	831	100	87
	9	45	6	38	35	80	10	7	77	52	46	59	44	22	50	42	13	0	635	100	88
%	1.7	3.0	0.6	6.9	6.1	14.0	1.2	1.4	6.5	7.7	4.1	10.3	9.0	2.6	11.6	11.9	0.8	0.5	100		87
	1.4	7.1	0.9	6.0	5.5	12.6	1.6	1.1	12.1	8.2	7.2	9.3	6.9	3.5	7.9	6.6	2.0	0.0	100		88

Talbe 4.7.3.e

Occupational accidents 1987-88. Production installations. Injury incident/Injured part of the body

Injury incident \ Injured part of the body	Eye	Back	Toe/foot	Hip/leg	Stomach/chest	Arm/ shoulder	Head/ face	Tooth	Hand/ finger	Other	Total	%	Year
Other contact with objects/machinery in motion	3	0	17	10	2	7	13	7	41	0	100	12.0	87
	1	0	9	4	0	5	13	8	36	0	76	12.0	88
Fall to lower level	0	9	3	4	2	11	10	0	3	4	46	5.5	87
	0	7	5	5	4	3	6	1	3	0	34	5.4	88
Fire Explosion etc	0	0	0	0	0	0	1	0	0	0	1	.1	87
	0	0	0	0	0	0	0	0	0	0	0	.0	88
Fall to same level	0	16	8	10	2	8	4	1	20	0	69	8.3	87
	0	5	5	13	3	6	6	2	6	1	47	7.4	88
Stepping on uneven surface, mis-step	0	9	67	13	2	3	2	0	3	0	99	11.9	87
	0	4	48	4	2	2	0	1	1	1	63	9.9	88
Falling objects	1	0	11	1	0	3	6	0	16	0	38	4.6	87
	0	1	9	3	1	7	1	3	8	1	34	5.4	88
Other contact with objects at rest	0	5	4	10	7	9	18	9	13	0	75	9.0	87
	0	2	1	4	2	9	6	5	5	0	34	5.4	88
Handling accidents	4	1	7	9	2	3	8	10	107	0	151	18.2	87
	1	0	8	2	2	4	6	16	86	1	126	19.8	88
Contact with chemical/ physio-compound	27	0	0	0	3	0	3	0	0	3	36	4.3	87
	17	0	0	0	1	1	4	0	1	2	26	4.1	88
Overloading of part of body	0	35	4	6	5	12	0	1	6	0	69	8.3	87
	0	36	1	9	8	8	0	4	4	0	70	11.0	88
Splinters, splashes	116	0	0	0	1	2	7	0	2	1	129	15.5	87
	89	0	4	4	0	4	9	1	1	2	114	18.0	88
Electric current	0	0	0	0	0	0	2	0	1	0	3	.4	87
	0	0	0	0	0	0	1	0	1	0	2	.3	88
Extreme temperature	0	0	3	2	1	2	2	0	1	0	11	1.3	87
	0	0	0	0	1	1	1	1	6	0	9	1.4	88
Fall into sea	0	0	0	0	0	0	0	0	0	0	0	.0	87
	0	0	0	0	0	0	0	0	0	0	0	.0	88
Other	0	0	1	0	0	0	1	2	0	0	4	.5	87
	0	0	0	0	0	0	0	0	0	0	0	.0	88
Total	151	75	125	65	27	60	77	30	213	8	831	100	87
	108	55	90	48	24	50	53	41	158	8	635	100	88
%	18.2	9.0	15.0	7.8	3.2	7.2	9.3	3.6	25.6	1.0	100		87
	17.0	8.7	14.2	7.6	3.8	7.9	8.3	6.5	24.9	1.3	100		88

Table 4.7.3.f
Occupational accidents 1987–88. Production installations. Injury indicent/Contributing factor

Injury incident \ Contributing factor	Chemical/physio/ biological factors	Cold pressure/ heat ventilation	Materials/ packaging	Electrical equipment	Other machinery	Drill strings	Handtools/machines/ implements	Loose/fixed fittings on strueture	Lifting transp. gear	Other	Total	%	Year
Other contact with objects/machinery in motion	0	0	20	1	11	6	7	32	23	0	100	12.0	87
	0	0	12	0	16	5	7	15	21	0	76	12.0	88
Fall to lower level	0	0	1	0	1	0	0	42	2	0	46	5.5	87
	0	0	3	0	0	0	0	30	1	0	34	5.4	88
Fire Explosion etc.	0	0	0	0	0	0	1	0	0	0	1	0.1	87
	0	0	0	0	0	0	0	0	0	0	0	0.0	88
Fall to same level	0	0	11	0	0	0	2	52	2	2	69	8.3	87
	4	1	7	0	0	0	0	34	0	1	47	7.4	88
Stepping on uneven surface, move-step	0	0	12	0	0	0	1	86	0	0	99	11.9	87
	0	0	11	0	1	0	2	49	0	0	63	9.9	88
Falling objects	0	0	19	0	2	0	5	9	3	0	38	4.6	87
	0	0	15	0	1	1	5	6	6	0	34	5.4	88
Other contact with objects at rest	0	1	4	0	2	0	1	63	3	1	75	9.0	87
	0	0	5	0	2	0	1	26	0	0	34	5.4	88
Handling accidents	1	0	39	0	6	3	88	9	5	0	151	18.2	87
	0	0	25	2	1	2	74	13	9	0	126	19.8	88
Contact with chemical/ physio compound	24	2	0	0	0	0	10	0	0	0	36	4.3	87
	12	0	2	0	1	0	11	0	0	0	26	4.1	88
Overloading of part of body	0	0	20	1	6	1	9	20	10	2	69	8.3	87
	0	1	29	1	4	1	7	19	0	8	70	11.0	88
Splinters, splashes	6	1	20	1	0	0	94	0	0	7	129	15.5	87
	15	4	16	0	5	1	67	2	0	4	114	18.0	88
Electric current	0	0	0	3	0	0	0	0	0	0	3	0.4	87
	0	0	0	2	0	0	0	0	0	0	2	0.3	88
Extreme temperature	0	1	7	0	0	0	3	0	0	0	11	1.3	87
	3	0	1	0	2	0	3	0	0	0	9	1.4	88
Fall into sea	0	0	0	0	0	0	0	0	0	0	0	0.0	87
	0	0	0	0	0	0	0	0	0	0	0	0.0	88
Other	0	0	2	0	0	0	0	0	0	2	4	0.5	87
	0	0	0	0	0	0	0	0	0	0	0	0.0	88
Total	31	5	155	6	28	10	221	313	48	14	831	100	87
	34	6	126	5	33	10	177	194	37	13	635	100	88
%	3.7	0.6	18.7	0.7	3.4	1.2	26.6	37.7	5.8	1.7	100		87
	5.4	0.9	19.8	0.8	5.2	1.6	27.9	30.6	5.8	2.0	100		88

Table 4.7.3.g
Occupation accidents 1979-88. Production installations. Injury incident/Occupation.

Injury incident \ Occupation	Admini-stration	Drillfloor worker	Driller	Electrician	Catering	Assistent worker	Instrument technician	Crane operator	Painter Sandblaster	Mechanic Motormen	Operator	Plateworker insulator	Pipeworker plumber	Services technician	Scaffolder	Welder	Derrickman	Unspecified	Total	%
Other contact with objects/machinery in motion	23	198	19	40	37	243	15	12	29	70	29	48	49	40	56	25	73	1	1007	18.4
Fall to lower level	15	21	9	33	7	83	17	8	36	35	16	25	33	15	27	30	18	1	429	7.9
Fire Explosion etc	0	0	0	2	0	5	0	0	1	2	0	1	2	0	0	1	0	0	14	0.3
Fall to same level	21	20	4	46	32	90	17	7	34	31	25	36	55	21	60	35	10	9	553	10.1
Stepping on uneven surface, mis-step	17	14	2	51	21	67	13	10	36	23	28	25	44	16	45	47	12	3	474	8.7
Falling objects	7	26	8	6	4	45	3	1	6	25	4	29	30	13	33	16	5	0	261	4.8
Other contact with objects in rest	9	15	3	31	20	52	16	4	41	31	11	50	34	12	42	20	6	2	399	7.3
Handling accident	9	62	7	56	65	134	20	7	35	105	33	73	88	25	58	63	21	0	861	15.8
Contact with chemical/ physio-compound	2	13	0	12	23	44	8	2	81	14	17	12	21	14	6	16	6	0	291	5.3
Overloading of part of body	6	32	5	38	15	85	2	7	32	32	20	24	50	15	53	22	15	1	454	8.3
Splinters, splashes	8	11	4	19	7	51	2	1	68	39	13	79	89	6	14	144	4	1	560	10.3
Electric current	0	1	0	25	0	1	1	1	0	1	0	2	0	0	0	0	0	0	32	0.6
Extreme temperature	1	0	0	2	25	5	1	0	0	4	4	6	8	1	1	14	0	0	72	1.3
Fall into sea	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0.0
Other	4	3	0	5	3	11	1	2	3	4	3	5	6	0	1	3	0	0	54	1.0
Total	122	416	61	366	259	916	116	62	402	416	203	415	509	178	396	436	170	19	5462	100
%	2.2	7.6	1.1	6.7	4.7	16.8	2.1	1.1	7.4	7.6	3.7	7.6	9.3	3.3	7.3	8.0	3.1	0.3	100	

Table 4.7.3.h
Distribution of injuries after degree of severity. Production installations.

	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	TOTAL
Fatal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Serious	0.13	0.07	0.04	0.09	0.04	0.05	0.03	0.04	0.04	0.02	0.05
Minor	0.63	0.69	0.69	0.68	0.70	0.70	0.86	0.92	0.93	0.96	0.80
Unspec.	0.24	0.24	0.27	0.22	0.26	0.24	0.10	0.04	0.03	0.02	0.15
Total	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Table 4.7.3.i
Occupational accidents in 1988 in connection with exploration drilling. Injury incident/Occupation

Injury incident \ Occupation	Admini-stration	Drillfloor worker	Driller	Operator	Catering	Assistent worker	Crane Operator	Mechanic/ Motorman	Services/ mechanics	Welder	Derrickman	Total	%
Other contact with objects/machinery in motion	1	13	2	0	10	1	0	0	4	0	4	35	32.1
Fire Explosion etc	0	0	0	0	0	0	0	0	1	0	0	1	0.9
Fall to lower level	0	3	0	0	2	0	0	0	0	0	0	5	4.6
Fall to same level	0	3	0	1	4	0	1	0	3	0	1	13	11.9
Stepping on uneven surface, mis-step	0	1	0	1	1	0	0	0	0	0	1	4	3.7
Falling objects	0	4	1	0	5	0	1	0	4	0	0	15	13.8
Other contact with objects at rest	0	0	0	1	1	0	0	0	1	0	0	3	2.8
Handling accident	0	7	1	1	8	0	0	0	1	0	2	20	18.3
Contact with chemical/ physio-compound	0	1	0	0	1	0	0	0	0	0	1	3	2.8
Overloading of part of body	0	3	0	0	2	0	0	1	1	0	0	7	6.4
Splinters, splashes	0	0	0	0	0	0	0	0	1	1	0	2	1.8
Temperature	0	0	0	0	0	0	0	0	1	0	0	1	0.9
Total	1	35	4	4	34	1	2	1	17	1	9	109	100
%	0.9	32.1	3.7	3.7	31.2	0.9	1.8	0.9	15.6	0.9	8.3	100	

Table 4.7.3.j
Occupational accidents in 1988 in connection with exploration drilling. Injury incident/contributing factor

Injury incident \ Contributing factor	Handtools/machines/ implements	Other machinery	Drill strings	Materials/ packaging	Loose/fixed fittings onstructure	Lifting transp. gear	Electrical equipment	Cold pressure/ heat ventilation	Chemical/physio/ biological factors	Total	%
Other contact with objects/machinery in motion	3	5	3	5	6	13	0	0	0	35	32.1
Fire Explosion etc	1	0	0	0	0	0	0	0	0	1	0.9
Fall to lower level	0	0	0	0	3	2	0	0	0	5	4.6
Fall to same level	0	0	0	2	11	0	0	0	0	13	11.9
Stepping on uneven surface, mis-step	0	0	0	2	2	0	0	0	0	4	3.7
Falling objects	2	1	1	5	2	3	1	0	0	15	13.8
Other contact with objects at rest	0	0	0	1	1	1	0	0	0	3	2.8
Handling accident	9	2	4	1	2	2	0	0	0	20	18.3
Contact with chemical/ physio-compound	0	0	0	2	0	0	0	0	1	3	2.8
Overloading of part of body	1	1	0	3	1	1	0	0	0	7	6.4
Splinters, splashes	1	0	0	0	0	0	0	1	0	2	1.8
Temperature	1	0	0	0	0	0	0	0	0	1	0.9
Total	18	9	8	21	28	22	1	1	1	109	100
%	16.5	8.3	7.3	19.3	25.7	20.2	0.9	0.9	0.9	100	

15 per cent of the quantity of work performed and 17.3 per cent of the injuries, primarily consisting of crushing, sprains and cuts.

In 1988 construction and maintenance operations accounted for 65.4 per cent of the man-hours and 65.2 per cent of the injuries.

Construction and maintenance workers are a non-uniform group. There are therefore several job categories that have a considerably higher injury rate than average. This especially applies to personnel involved in heavy welding and maintenance work. 48 per cent of the injuries occurred in connection with stepping wrongly, handling of tools and materials, and splinters and spatter from welding and grinding equipment. The corresponding figure for 1987 was 45.6 per cent. The proportion of these types of injuries seems to increase for each year, which is surprising in the light of in part clear causal connections and the possibility of taking preventive measures, e.g. effective eye protection.

Table 4.7.c shows the distribution of injuries and summary of industrial accidents in connection with exploration drilling. Reporting is done in accordance with the same criteria as for production operations. Only personal injuries which occurred while the installation was engaged in petroleum activities, i.e. while in the drilling position, have been included in the summary. There were 109 reported personal injuries in 1988, compared with 130 the year before. Reporting control of personal injuries from exploration activities has not been as comprehensive as that from production activities. The same applies to reporting of the man-hours presented for the first time. A somewhat greater uncertainty is therefore attached to these specifications. No personal injuries resulting in death have been reported. Fourteen mobile installations for exploration and production drilling have been in activity on the continental shelf in 1988, as last year. The number of rig-days in 1988 is estimated at 3,544, compared with 3,471 the previous year. The injury rate measured in the number of personal injuries per 1,000 rig-days was 30.8 in 1988, compared with 37.5 in 1987.

On the basis of submitted reports over man-hours on these installations in 1988, the number of man-years has been calculated at 1,900, of which 1,740 were for contractors and 160 were for operators. The total injury rate measured in personal injuries per 1,000 man-years (like for production installations) was calculated at 57.4 in 1988.

Table 4.7.i shows the distribution of incidents causing injury among the various function groups.

Tables 4.7.j shows the distribution of incidents causing injury among contributory factors.

Conclusion

The summary for all activities on the production installations shows there has been a considerable improvement in the injury rate in 1988 compared with the year before, from 60.4 to 50.5 injuries per 1,000 man-years. This improvement is greater than the assumed uncertainty of the figures.

The reduction has occurred in the main activities drilling, catering, and construction and maintenance. With regard to administration/ production, there has been a steady increase in the injury rate in the period 1979 – 1988. The decrease in the injury rate for personnel involved in drilling and well operations continues, a development which is distinct from 1985. A marked improvement in the injury rate for construction and maintenance has taken place the last year, but these are still the activities most exposed to risk, together with drilling.

Even though the figures used by the Directorate for statistics for personal injuries are encumbered with some uncertainty, the Directorate is of the opinion that the development these past years has headed in a positive direction.

The injury rate on mobile installations for exploration and production drilling has been reduced from 37.5 personal injuries per 1,000 rig-days in 1987 to 30.8 in 1988.

In spite of the limitations that must be expected in such a comprehensive reporting system for personal injuries and man-hours, the Directorate feels that the statistical summaries give a correct picture of the situation for the petroleum activities on the continental shelf.

4.8 WORKING ENVIRONMENT

4.8.1 Design of new installations

The key to a good working environment in the operating phase lies in the conceptual development and design phase. Interdisciplinary expertise, operating experience and special evaluations concerning working environment in the operating phase must be taken into account already in these phases. Budgetary conditions in the operating phase often place great restrictions on the possibilities for subsequent revisions and modifications.

Even if working environment conditions are primarily regarded as an operating responsibility, the Norwegian Petroleum Directorate views the increased consciousness among the operators positively with regard to the necessity of securing the transfer of experience from operations to new projects. But a lot remains before the utilisation and integration of operating experience and specialist expertise in the projects can be said to be satisfactory.

The Norwegian Petroleum Directorate's experience is that the companies have only to a limited extent specified working environment requirements and integrated these in their planning and quality assurance systems at the start of detail planning. Therefore, there is a need for improved control with the formulation and implementation of the working environment programme in the various phases.

Superior control documentation which is to secure the working environment of the installation has in certain instances proved not to be comprehensive with regard to changes in contract practice; for instance when changing over to contract forms that comprise "total packages" of services (EPC contracts).

4.8.2 The operator companies' main employer responsibility – the contractor companies' employer responsibility

In the report period the Norwegian Petroleum Directorate has completed several supervisory activities directed toward the operators' upholding of the main employer responsibility. The conclusion of this responsibility is that the follow-up on the part of the operators varies somewhat, dependent on the extent of the work. Those companies that often have tasks that require many employees, are better followed up by the operator than those having only one or two persons per task. In general, it is the Norwegian Petroleum Directorate's impression that the exchange of information between the operator and the contractor company in many cases could have been better.

During the same supervisory activities an evaluation has also been made of how the individual contractor company upholds its independent employer responsibility. Certain contractor companies proved to have little knowledge of the working environment legislation, and the implementation of working environment measures was to a great degree characterised by circumstance. Through its audits the Norwegian Petroleum Directorate has wished to make the contractor companies conscious of the provisions of the Working Environment Act.

4.8.3 Documentation of chemical health hazards – product data sheet

The Norwegian Petroleum Directorate has implemented audits to clarify how the operators secure the quality of documentation of chemical health hazards, and what quality requirements are made. This is an area where the internal control principle has little tradition, both in the industry and on the part of the authorities.

By linking the internal control principle to the Working Environment Act, the Norwegian Petroleum Directorate has been able to follow the products through verifications at all stages back to the manufacturer, whether he be located in Norway or abroad.

The Norwegian Petroleum Directorate's experience from these audits has primarily been that the customer has not appreciably defined the needs for documentation of chemical health hazards in connection with contract negotiations and entering into contracts.

The Directorate also registered that control of revisions and updating of information on chemical health hazards was not very systemised.

By using the internal control principle the authorities and the industry need not require that manufacturers surrender information, but refer to the right of access to, for example, audits of and visits to the manufacturer. This access has proved to be relatively easy to obtain in the audits done by the Norwegian Petroleum Directorate, also in the case of national and international manufacturers of chemicals.

4.8.4 Asbestos

For dismantling/demolition work on older installations the operator must ascertain in advance whether products containing asbestos have been used, and implement any necessary protective measures.

During a major demolition job in 1988 it was found that the materials contained asbestos, but not until the demolition work had been completed. The incident was reported to the police by the Norwegian Petroleum Directorate, but was subsequently dismissed by the police after an evaluation of the degree of negligence shown by the operator.

With regard to packings and brake linings, asbestos-free products should be used when this is technically possible. In the Norwegian Petroleum Directorate's assessment there are now asbestos-free packings and brake linings for all areas of application on the continental shelf. In the report period the Norwegian Petroleum Directorate has registered a somewhat varying practice among operators in this area, and has intensified its supervision with regard to compliance with these matters.

4.8.5 Epoxy-based paint products

In the report period the Norwegian Petroleum Directorate has looked at the use of epoxy products for maintenance of the installations. Epoxy-based paint products represent a health hazard due to organic solvents and pigments, and because these products contain substances that entail a danger of developing allergic contact eczema. The solvents and pigments are also often found in other paint products.

It is apparent that training of personnel in the use of epoxy products should be better. Some personnel, however, seem to understand the significance of using personal protective gear against the allergy risk, but are not aware of the danger of solvents. Others seem to have received inadequate training in what protective gear is necessary when working with epoxy products. The uncertainty that has prevailed in connection with health hazards and application procedures in the use of epoxy-based paint products, has been an unnecessary strain on the employees involved.

4.8.6 Mercury exposure

Since 1979 the Norwegian Petroleum Directorate has been strongly engaged in the use of mercury when transferring bottom hole and separator samples to portable containers. Work is being done to direct the development toward the use of substances and products that are less hazardous to health; and in this case the introduction of equipment where transfer of formation fluids is done without the use of mercury.

Testing of new types of mercury-free sampling equipment has shown positive results in the report period. Reliable and appropriate mercury-free equipment for transfer of formation fluid is available today, in the opinion of the Norwegian Petroleum Directorate.

4.8.7 Hydrogen sulphide

Hydrogen sulphide (H_2S) can be formed both in the reservoir and in equipment on the installations. During a leakage on Statfjord A from a ballast water tank in the utility shaft, H_2S concentrations occurred that irritated the eyes and respiratory passages. With the exception of emergency personnel the crew was evacuated to the flotel adjacent to Statfjord A. No life-threatening concentrations of H_2S were measured, however, in any part of the installation.

In the report period a working party in the Norwegian Petroleum Directorate has taken a closer look at whether there is a reservoir acidification taking place on the Norwegian continental shelf. A number of fields on the British continental shelf, fields which had a very low content of H_2S initially, have had a pronounced increase in the content of H_2S. Seawater is injected into all these fields. The probable cause of the reservoir acidification with the forming of H_2S, is that sulphate-reducing bacteria break down sulphate found in the injected seawater and form sulphide. There is reason to believe that biocidal treatment of injected seawater reduces the risk of H_2S development in the reservoir, but such water treatment is no guarantee against acidification of the reservoir.

Statfjord is the first field on the Norwegian continental shelf that started with seawater injection. There has been an increase of H_2S in gas from Statfjord over the last year, but no reservoir acidification seems to be in progress at the moment. The increase seems to be related to the forming of H_2S in the process equipment as a result of bacterial activity, in addition to an increase in produced water from the reservoir. The H_2S level must be maintained within safe limits due to the danger of corrosion. This involves chemical treatment which can lead to safety and environmental problems.

4.8.8 Unmanned installations

During the report period the Norwegian Petroleum Directorate has considered Amoco's application for approval of planning, development and operation of an unmanned installation on the Hod field. Several unmanned installations on the Norwegian continental shelf are now being planned.

Unmanned installations are usually manned periodically. The Norwegian Petroleum Directorate therefore expects the operators to make the necessary assessments pertaining to safety and working environment when planning such installations. This will include, inter alia, assessments of accommodation facilities for overnight stays and catering services, in addition to maintenance functions that must be carried out in an operating phase, such as conditions related to the design of the installation, choice of equipment and materials, operating safety and maintenance facilitation, in addition to personnel expertise and the organising of work.

4.8.9 Multi-skills and multi-disciplines

There are no existing plans for substantially reduced manning on new installations. Multi-skills and multi-disciplines of personnel is being evaluated as a means to achieve reduced manning.

Multi-skills and multi-disciplines are also mentioned as a possible means to make the operating of existing installations more efficient.

The Norwegian Petroleum Directorate's supervision philosophy and requirements in the working environment act and in the internal control regulation entail that the operator is responsible for ensuring that personnel given jobs to look after have the necessary qualifications.

This responsibility implies that the operator be given the opportunity to adapt the qualification requirements to the work to be performed, so that flexibility is achieved in accommodating qualification requirements to technological development.

The Norwegian Petroleum Directorate views with interest the development in the direction of greater elements of multi-skill and/ or multi-discipline personnel on the continental shelf. It is, however, important to emphasise how important it is that the operators maintain a dialogue with the employees' organisations and with the authorities and educational institutions during the planning and implementation of such a system.

4.8.10 Working hours

Supervisory activities carried out by the Norwegian Petroleum Directorate in the report period have shown that most of the operators have satisfactory systems for registering working hours for their own employees. With regard to employees of contractor firms, several violations of the working hours provisions have been registered, and the systems for registration of working hours have in many cases been inadequate.

4.8.11 Reduced working hours

The Norwegian Petroleum Directorate received an application from two medics at the Statfjord field concerning reduced working hours. The two medics applied to share a full-time position, in order to attend to the care of their child through this arrangement. The Norwegian Petroleum Directorate supported their claim to share a position. Statoil appealed the case to the Ministry of Local Government and Labour, but the ministry sustained the decision regarding the right to reduced working hours.

4.8.12 Working Environment Committees on the Shelf

The interface between the working environment committees of the individual companies and coordinating working environment committees has been further clarified in the report period. It is expected that the working environment committees of the individual companies will function better as they now gain more experience in preparing action plans for safety and environmental work, and the training of safety delegates and members of the working environment committees is followed up more thoroughly. When the working environment committees of the individual companies function better, and the effect of increased training starts to show, this will also strengthen the coordinating working environment committees.

4.8.13 Mobile installations

The Norwegian Petroleum Directorate has, in the report period, conducted limited supervision of working environment conditions on mobile installations, in keeping with the limitations set by the legislation. The Working Environment Act does not apply to mobile installations. A consequence of this is that the Norwegian Petroleum Directorate's supervision of working environment conditions on mobile installations is based on judging whether conditions can be said to be of significance to safety. The scope of the Working Environment Act thus complicates efficient supervision of working environment conditions on the part of the authorities.

4.9 PREPAREDNESS

4.9.1 Alternative evacuation systems

From the beginning the Norwegian Petroleum Directorate has followed the development of an escape sleeve that is to be a supplement to existing rescue equipment. A project has been planned for 1989 to further develop the rescue system to a dry evacuation system. The Norwegian Petroleum Directorate views the development of alternative evacuation systems as a considerable contribution to the improvement of total preparedness on the continental shelf.

4.9.2 Drifting objects

The Norwegian Petroleum Directorate is represented in North Sea Offshore Authorities Forum (NSOAF), a body that has representatives from all the North Sea countries. NSOAF has appointed a group that is to consider measures against drifting objects that can threaten petroleum installations. The group is under the leadership of the Director of the Safety and Working Environment Division of the Norwegian Petroleum Directorate.

Initially the group will look at conditions regarding towing of objects connected with the petroleum industry. The objective is to harmonise and make the legislation regarding such towing more efficient, so that towing can be implemented more safely. The group will present its report to NSOAF in June 1989.

4.9.3 Collision between German submarine and the Oseberg B installation

During a German military exercise in the North Sea, the submarine "U-27" collided with the fixed installation at Oseberg B. The submarine was at a depth of 30 metres and had a speed of 8.8 knots when it collided.

The collision caused a strong shock to the installation, and until the submarine submerged there was uncertainty as to the cause. The activities on the platform were stopped and the personnel were evacuated to the flotel "Polyconfidence".

Considerable damage had been done to the B installation and the submarine. The damages to the installation alone were estimated at NOK 80–100 million. The damages were repaired in the autumn of 1988. Among other things, a cross-stay was replaced.

An inquiry was held in Kiel on 1 December 1988. It was established that the master on board "U-27" had acted with negligence as he had not made use of all navigational facilities for a safe passing. He had also acted reprehensibly by not taking into consideration discrepancies in navigation.

Due to military reasons no further explanation was given about the use of sonar; only that passive sonar had been used and that no signals (interference) from the installation had been picked up.

The Norwegian Petroleum Directorate has for the time being not drawn any conclusion with regard to implementing any future measures which can contribute to preventing similar accidents.

4.9.4 Experience from exploration drilling in the Barents Sea – preparedness factors

As mentioned in the Norwegian Petroleum Directorate's annual report for 1987, the Directorate asked the operators to submit a report on experience in connection with preparedness following the conclusion of each well. The Norwegian Petroleum Directorate placed special emphasis on the following areas:

a) the functional capacity of mechanical standby equipment
b) drills and training
c) operational limitations on the installation and standby vessel
d) warning systems
e) communication

f) weather forecast service
g) supply service
h) helicopter service

The conclusion so far, having received the reports, is that the activities have not revealed any special problem areas.

4.9.5 Helicopters stationed in Hammerfest
In addition to extra fuel tanks on the two Super Puma helicopters in Hammerfest, they have also been equipped with a deicing system.

4.9.6 Fuel transfer vessel – helicopter
A project is currently in progress under the direction of the Norwegian Oil Industry Association concerning fuel transfer from supply or standby vessel to helicopter, with a view to both national rescue services and civilian helicopter preparedness.

Such fuel transfer would increase the operating time of the helicopters in areas with great distances and greatly restricted possibilities for refueling.

4.9.7 Barents Sea rescue agreement between the Soviet Union and Norway
As a continuation and replacement of a previous agreement of 19 October 1956 regarding cooperation between the Soviet Union and Norway on the rescue of persons in distress and searching for missing persons in the Barents Sea, a new agreement was made between the two countries on 15 January 1988.

The responsibility for organising and coordinating the work of searching for missing persons and rescuing persons in distress in the Barents Sea lies with:

a) in Norway: the Main Rescue Centre Northern Norway in Bodø
b) in the Soviet Union: Murmansk Shipping Company in Murmansk

The Norwegian Petroleum Directorate regards the agreement as being very positive, as this means greater assistance resources in connection with activities in the Barents Sea.

4.9.8 Preparedness research
Experience from supervision activities in the report period has shown that research and concentration on development of preparedness technology are not as substantial as would be desired. This will lead to greater activity in 1989 on the part of the Norwegian Petroleum Directorate in order to transmit to the operator the expectations of the Directorate with regard to concentration on safety.

4.9.9 Safety zones
The Directorate has in the report period used, in part, considerable resources on following up the Regulation concerning safety zones etc., issued 9 October 1987. The work has involved the following elements:

a) a general briefing to ensure common understanding of the provision of the regulation
b) revision of § 14 of the regulation concerning the seizure of vessels
c) an elaboration of the regulation's provisions concerning special area with restrictions for underwater production installations.

4.10 DRILLING

4.10.1 Exploration drilling in the northern areas
The Norwegian Petroleum Directorate has closely followed the exploration drilling in the Barents Sea that started in the summer of 1987, and which has continued in 1988. The activity has been somewhat lower in 1988 than in the second half of 1987, as only one installation ("Ross Rig") has been in operation in the area in the last 10 months of the year. Four exploration wells have been spudded in the Barents Sea in 1988, and six wells have been completed.

4.10.2 Coordination of drilling activities
Two installations have been in activity in the Barents Sea in the report period. "Polar Pioneer" spent the first two months of the year completing exploration well 7219/9–1 for Norsk Hydro. "Polar Pioneer" then went south for new assignments for Norsk Hydro. "Ross Rig" was in operation for Statoil in the Barents Sea in the first half of 1988. Mobil then used the installation for four months and thus completed coordination sequence 1 for "Ross Rig". A new coordination agreement was entered into by the operators Hydro, Saga, Shell and Statoil on the use of "Ross Rig" for drilling three new exploration wells. As of 31 December 1988 the following exploration wells were either completed or spudded in 1988:

Operator	Production license	Explor. well	Spudded	Completed	Installation
HYDRO	136	7219/9–1	11/87	2/88	POLAR PIONEER
HYDRO	141	7321/9–1	10/88	11/88	ROSS RIG
MOBIL	140	7321/7–1	6/88	10/88	ROSS RIG
SAGA	135	7125/1–1	11/88	12/88	ROSS RIG
STATOIL	139	7226/11–1	10/87	4/88	ROSS RIG
STATOIL	137	7224/7–1	4/88	6/88	ROSS RIG

4.10.3 Consequence analysis for opening of Barents Sea South, Troms II, Troms III and southerly parts of Finnmark West for petroleum activity

On the instructions of the Ministry of Petroleum and Energy, a consequence analysis for opening of Barents Sea South, Troms II, Troms III and southerly parts of Finnmark West was sent out for comments in the summer of 1988.

With regard to the safety aspects of drilling operations, the analysis deals, inter alia, with probabilities of having a blowout resulting in oil pollution. The analysis concludes that this probability is minor, and not greater than for drilling in areas already opened. This is in line with the Norwegian Petroleum Directorate's report "The Probability of Oil Blowouts" from 1985.

4.10.4 Development of safety valve for drilling of tophole sections

The probability of a kick developing to a blowout in connection with drilling of tophole sections cannot be discounted. Human lives, wells and drilling equipment have been lost and led to large losses for operators and society.

After the accident on "West Vanguard" the Norwegian Petroleum Directorate has identified areas where resources must be placed to reduce the risk of a gas discharge. One of these areas is the barrier problem.

Drilling of topholes up to the present date has generally been done with drilling mud as the only barrier. The remaining part of the well is always drilled with two barriers.

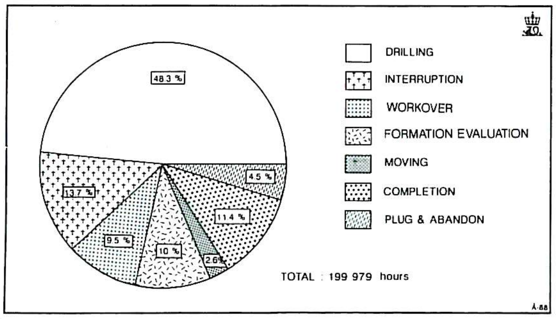
Under certain conditions it can be possible to to introduce an extra barrier when drilling topholes, in the form of an annular preventer over the wellhead.

Another possibility lies in the further development of a downhole blowout preventer. Such a safety valve, developed by Smedvig with financial support from Statoil, has been tested. It has been the opinion of the Norwegian Petroleum Directorate that such a valve can be developed to close the downhole annulus when drilling tophole sections.

The Royal Norwegian Council for Scientific and Industrial Research (NTNF) granted funds for a pre-project where the Norwegian Petroleum Directorate, in cooperation with Smedvig, was to analyse the application characteristics of downhole safety valves when drilling tophole sections. On the basis of the pre-project the Norwegian Petroleum Directorate initiated an industrial project together with the industry, where the intention was to determine whether this safety valve was suitable for a barrier.

The valve has now been constructed and tested in the factory, and has also been subject to functional testing at the Rogaland Research Institute with convincing results. During the first weeks of 1989 the valve will undergo more comprehensive tests at the Rogaland Research Institute before it will be ready for testing and use in the field.

Fig. 4.10.5
Daily Drilling Report System 1988. Main operations:



4.10.5 Drilling data base – DDRS

The duties of the Safety and Working Environment Division entail professional evaluations in the following areas:

a) drilling site survey
b) drilling phase
c) testing phase
d) completion phase
e) production phase
f) well maintenance
g) replugging
h) concept evaluation

There is great need for a suitable analysis tool in this work area.

To meet this need the Norwegian Petroleum Directorate's data base DDRS (Daily Drilling Report System) was established in 1984. The objective of the data base is that all information on drilling activities shall be systematised, so that it is available and applicable in the Directorate's supervisory activities.

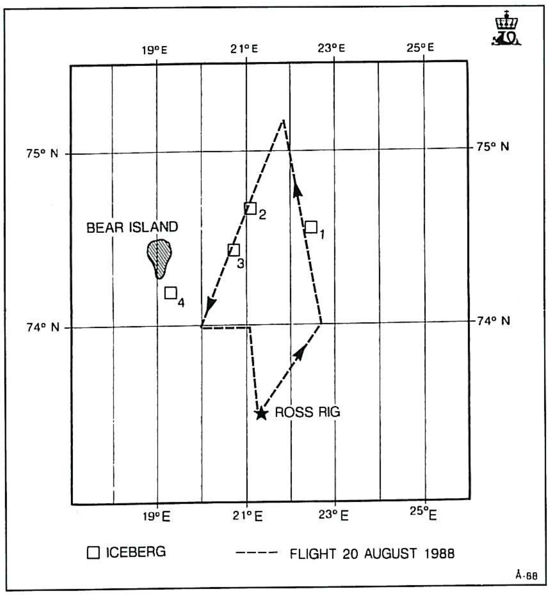
The use of the drilling data base so far seems to prove it is also useful to the operators, who have access to data they themselves have reported.

The operators use a common format for daily reporting. Reporting is done in one of two possible ways:

a) direct terminal connection to the Norwegian Petroleum Directorate's computer system for manual registration
b) "automatic" transmission of drilling reports after selection of specified DDRS data from one's own data bases.

All new drilling reports are entered in the central DDRS data base daily. This contains information from all wells spudded after 1 April 1984. Altogether the DDRS now comprises information from:

Fig. 4.11.2
Iceberg observations



a) approx. 800 wells
b) approx. 33 000 daily status reports
c) approx. 207 000 operations

In the DDRS this comprehensive data foundation has been developed in a structured form with a high degree of consistency. This means that DDRS has a large potential for further use. The system can be used in several connections where the use of empirical data is relevant.

Several programmes or routines have been developed for using the DDRS. These can be divided into 3 main groups:

a) daily follow-up of the well, operator etc.
b) graphic presentation (Figure 4.10.5 shows main operations in 1988)
c) further analyses

In addition to this several programmes have been developed that enable retrieval or return of data from DDRS to interested operators and partners. Several external users currently make use of this possibility to update their own data bases.

A separate operating system has been developed for the DDRS, which includes several programmes for daily operations, error recovery, distribution of data etc. As a result of this the Directorate has been able to reduce considerably the use of resources for daily operation of the drilling data base from the start in 1984 and up to today, despite an exceedingly increasing amount of data.

The drilling data base has proved to have a very large potential as an analysis tool. By comparing and classifying approximately identical operations (weather parameters, equipment, lithology etc.), it is easy to see which operators on the Norwegian continental shelf are successful and who have problems.

With this base the Norwegian Petroleum Directorate has received a tool to control supervisory activities in the area of drilling. A controlled transfer of experience can also be done which can raise the level of safety for drilling operations on the Shelf.

The system, or parts of the system, can/ should be made accessible in the future to the actors in the North Sea. It can provide a good basis for a useful discussion in the industry and, in the next place, lead to an optimisation of drilling operations with regard to safety and economics.

In the short term it will be of great significance that a user environment, as broadly composed as possible, be established, also internationally.

The Directorate has started work on developing a procedure for improved systematising of equipment faults in connection with drilling, among other things on the basis of interest from operators and institutions.

By connecting information on equipment faults to other information in the data base, a basis for decision can be produced which can contribute to raising the safety level in connection with the use of the various types of equipment.

4.11 NATURAL ENVIRONMENT

4.11.1 Collection of natural data

Gathering of natural data (current, wind, waves, etc.) from Ekofisk, Frigg and Statfjord has functioned satisfactorily in the report period. With the assistance of the Norwegian Institute of Meteorology (DNMI), the Directorate has supervised the collection of data from these three fields. By using DNMI, the Directorate has obtained greater professional expertise in the supervisory work. The system under which assistance has been provided has functioned very satisfactorily.

In 1988, the Norwegian Petroleum Directorate has instructed that meteorological data be collected during exploration drilling in the Barents Sea, as the notification service for the Barents Sea is less reliable than in the North Sea. For drilling at Bear Island South, the Directorate has instructed the operators to have a notification system for possible iceberg movements.

The Norwegian Petroleum Directorate has been engaged in the gathering of natural data from the Barents Sea in cooperation with the Oceanographic Data Acquisition Project (ODAP). The Norwegian Petroleum Directorate's financial contribution amounted to NOK 4.5 million in 1988. The total financial framework of the project was NOK 14.5 million. Data on wave height and direction, current, in addition to meteorology, tides and icing have been collected. The contract with the research vessel M/S "Endre Dyrøy" has been terminated effective 1 May 1988. From this date and throughout the year, four trips were made by vessels on short-term contracts to perform maintenance and inspection of the buoys.

The measurement programme has been implemented through the purchasing of services from Oceanor in Trondheim.

4.11.2 Icebergs and sea ice

During Mobil's drilling operations with "Ross Rig" in August 1988, icebergs were discovered 90–130 km north of the drilling site, see Figure 4.11.2. Since then Mobil has kept the icebergs under observation to see whether they would move and thus cause dangerous situations. In November 1988 a small iceberg was discovered on block 7321/9, while Norsk Hydro was in the process of completing drilling operations.

The Norwegian Petroleum Directorate has, in the report period, made a comparison of all known iceberg observations in the Barents Sea south of the 74th parallel. The comparison shows that icebergs occur regularly in the area south of Bear Island and further east, at Sentralbanken. In May – June 1929 a number of icebergs came in to the coast of East Finnmark and the Kola peninsula. The western boundary was at the Porsanger fjord and in the east at the White Sea. This comparison shows that icebergs must be taken into consideration within a vast area of the Barents Sea when planning installations.

The extent of sea ice in the Barents Sea proves to have large seasonal and yearly variations. The largest known extent was in 1870–71, when the sea ice extended all the way in to the coast of Berlevåg and Båtsfjord.

4.12 STRUCTURES AND PIPELINES

4.12.1 Data base for damage to and non-conformance of installations, risers and pipelines

Injuries have been registered in the data base since 1981. A total of 2 026 incidents of damage and non-conformance have been registered on fixed installations, 1 231 on risers and 101 on pipelines. Entry of all previously reported damages, as of installation date, is now in progress.

The data base is being revised in order to better utilise the registered data. Standardised report forms are being tested by certain operators, so that a uniform reporting can be achieved.

This is the first step toward EDP transmission of this type of damages and non-conformance.

4.12.1 Structural steel

Through the follow-up of development projects, legislative work, participation in research projects and committee work, the Norwegian Petroleum Directorate is following the development and experiences made in the area of material technology.

The Norwegian Petroleum Directorate has a permanent survey programme for steel which is used for development projects on the Shelf. Steel is elected which is used for the most exposed parts of the load-bearing structure. The survey employs two testing methods: Welding simulation technology and so-called CTOD (Crack Tip Opening Displacement) testing with surface notch. These methods provide a basis for a simple evaluation of the microstructure of the steel in connection with welding and breaking tensile strength properties in the heat-affected zone of the weld. A total of 17 steels from various development projects have been examined in 1988. The testing methodology has been developed by SINTEF, which also does the testing for the Norwegian Petroleum Directorate.

The interest in using high tensile strength steel in structures is increasing. Several development projects which have been initiated or which are in the design phase will make use of a certain amount of high tensile strength steel. It seems, however, that high tensile strength steel with tensile strength of up to 500 MPa will be the most relevant. There is still a certain uncertainty connected with the use of steel with a higher tensile strength, especially with regard to fatigue-stressed weld connections.

The use of castings and forgings for load-bearing structures has increased over the past years. Several steel jackets now under construction have cast nodes. The advantage of using these compared with a welded structure is that the fabrication is simplified and the fatigue lifetime is increased.

4.12.2.1 Pipelines and risers

The new development concepts on the Norwegian continental shelf make new requirements for pipelines and risers.

Due to the transport of unprocessed hydrocarbons from subsea installations, conventional pipeline materials cannot be used on some projects, in part due to the corrosive environment the materials are exposed to. In the pipelines between Tommeliten and the Edda installation for instance, steel of stainless quality (duplex steel) has been used.

Flexible pipelines have increasingly been used over the past years. Due to technical and economic reasons these pipelines are often better suited than conventional steel pipelines for connecting subsea installations to fixed production installations. Flexible risers are a prerequisite for mobile production installations. This type of riser will probably be used to an increasing extent on the Norwegian continental shelf.

Tension leg installations will entail that new technology must be employed for risers. On the Snorre installation for instance, the export risers will consist of connected risers.

4.13 ELECTRICAL PLANT AND SAFETY SYSTEMS

4.13.1 Electrical plant and equipment

Reference is made to the annual report for 1987 regarding the work on reducing short circuit current.

The results of this work can be seen today.

During the past two years the Norwegian Petroleum Directorate has received reports of three total trips of the electrical plants on three different installations in the North Sea. In each case the UPS (Uninterrupted Power Supplies) system proved not to be dependable. Ways of improving these systems have been sought. One recommendation entails using more direct current.

4.13.2 Gas leakage through drain systems

Following several gas leakages in the summer of 1988, a working party was appointed in the Norwegian Petroleum Directorate. The working party was to deal with the problems concerning gas escaping through the drain systems. The objective of the work was to:

a) analyse known incidents where gas had escaped through the drain systems.

b) propose measures for procedures and/or regulations or measures of a technical nature in order to avoid similar incidents.

The working party has prepared two sectional reports which formed the basis for a meeting with the operators. The participants in the meeting discussed the recommendations and viewpoints presented by the working party, and useful experience concerning drain systems was exchanged among the operators. A final report will now be prepared, and letters will be sent to all Norwegian operators.

4.13.3 Fires

Fires on mobile and fixed installations reported by the operator companies are listed in Table 4.13.3. The table shows injury/ damage, number of fires and cause of fire. Fires on mobile installations have previously not been registered by the Norwegian Petroleum Directorate.

Table 4.13.3

Injury/ damage	Constr. phase	Permanent installations			Mobile installations		
		A	B	C	A	B	C
Personal injuries and material damage							
Personal injuries and minor or no material damage		2				1	
No personal injuries, but major material damage		1					
No personal injuries and minor or no material damage		13	9	5		4	
Total 35 fires	0	16	9	5		5	

Cause of fire:
A: Due to technical failure during operations.
B: Welding, grinding etc., defined as hot work.
C: Other causes.

The Norwegian Petroleum Directorate has registered a total of 35 fires in 1988, compared with 43 fires in 1987.

Three of the fires mentioned under other causes (C), were caused by lightning.

4.13.4 Gas leakages

Gas leakages on fixed installations, reported be the operators in the report period, are listed in table 4.13.4. The table shows injuries, number of leakages and cause of leakage.

This is the first time the Norwegian Petroleum Directorate publishes figures for gas leakages on fixed installations.

4.14 DIVING

In the course of the report period, 1767 surface-orientated dives and 163,560 man-hours in saturation were registered on the Norwegian continental shelf. This is a decrease in diving activities compared with 1987.

4.14.1 Research in diving

With the assistance of external consultants con-

Table 4.13.4

Injury/ damage	General gas leakages			Gas leakages via drain systems		
	A	B	C	A	B	C
Personal injuries and major gas leakages	1					
No personal injuries, but major gas leakages	2	1	1	5		
No personal injuries, but minor gas leakages	1	6	2	1	2	3
Total 24 gas leakages	4	7	3	6	2	3

Cause of gas leakages:
A: Due to insufficient (and missing) procedures
B: Due to mistakes made during inspection routines
C: Due to lack of maintenance, corrosion etc.

nected with the "Deep Diving" and "Working Environment for Divers" projects, a number of studies have been made regarding divers and their working conditions. Reports concerning toxicology and the evaluation of applied disinfectants have been well received by the industry, and will be useful in method development and technical solutions. Follow-up, first of all of microbic contamination and mechanical skin injuries, is in progress and will continue in 1989.

The Norwegian Petroleum Directorate has held a two-day conference on the topics "Health Examination of Divers" and "Decompression Use of Oxygen". The conference gathered about 70 participants from Europe and the USA. A two-day conference was also held in collaboration with Statoil, entitled "Hyperbaric Communication". The participants came from Sweden, Great Britain and Norway.

Manned subsea operations at a depth of 218 metres will take place during installation of Gullfaks C in 1989. The development of procedures and materials to be used in the operations has been subject to a thorough follow-up on the part of the Norwegian Petroleum Directorate, as continuous diving to this depth represents a new challenge on the Norwegian continental shelf.

4.14.2 Joint use of diving services

Statoil, Norsk Hydro and Phillips Petroleum Company Norway, which have long-term contracts for the use of diving services, have entered into an agreement on joint use of diving vessels as needed. This will take place on the basis of mutual approval of the individual company's quality system, and is thus a step in the right direction in relation to previous practice. A comprehensive approval programme was then initiated each time a diving vessel was awarded a contract to supply diving services to an operator.

It is the view of the Norwegian Petroleum Directorate that this system can contribute to increased efficiency (with a corresponding financial profit) and provide a wider empirical basis (which leads to improved qualifications), in addition to leading to increased standardisation in manned subsea operations. This will also be a natural and necessary step in connection with field development requiring installation of equipment at greater water depths. Operators should prepare plans for an efficient solution of problems that may arise in connection with unexpected situations during diving operations at great depths.

4.14.3 Safety Delegate system

The fact that the safety delegate system and the establishing of elected representatives seem to have been accepted in the diving industry is regarded as very positive by the Norwegian Petroleum Directorate. Personnel participating in diving operations on the Norwegian continental shelf now have their elected representatives to look after their interests.

4.15 MECHANICAL EQUIPMENT

4.15.1 Unmanned wellhead installations

It has been decided to develop the Hod field. This is a marginal field that has led to rethinking in the choice of a concept solution. Unmanned wellhead installation will be used for the first time on the Norwegian continental shelf. It is planned that the installation will be remote-controlled from the Valhall field.

The operator has also elected to drill wells with a jack-up installation, so that the drilling operation takes place directly over the wellhead installation from a cantilevered jacket. This operation method has not been used previously on the Norwegian continental shelf.

4.15.2 Composite materials

For several years the Norwegian Petroleum Directorate has followed the development of composite materials (plastic) used in piping systems on production installations. "West Vision", which will be used as a mobile production installation in the Veslefrikk field, has been planned with limited use of piping systems of plastic in order to reduce weight and limit maintenance. In this connection, special evaluations concerning fire and smoke emission have been made.

Flexible pipes (hoses) are also planned for use in the Veslefrikk field between the wellhead installation and the production installation "West Vision".

4.16 THE NPD's FOLLOW-UP OF ACCIDENTS OUTSIDE NORWAY

4.16.1 "Piper Alpha"

The explosion of the British production installation "Piper Alpha" on 6 July 1988 led to a chain of fires and explosions that completely destroyed the installation. Of the 226 persons on board, 165 lost their lives, in addition 2 rescue team members lost their lives.

As a result of the catastrophe, the Norwegian Petroleum Directorate appointed a group consisting of representatives from all affected disciplines in the Safety and Working Environment Division. The group was to attempt to clarify the cause of the accident and propose relevant measures for the Norwegian continental shelf on the basis of experience from the catastrophe.

The Norwegian Petroleum Directorate has instructed the operators to re-evaluate all concept safety studies that have been made, on the basis of this accident and any other experience. For older installations where such studies have not been made, the operators have been instructed to do studies.

In addition to the order to do concept safety studies, it is expected that the operators identify conditions where relatively simple measures will improve safety on the installations without great costs.

The Norwegian Petroleum Directorate presently sees no need for immediate measures beyond this. The follow-up of problems disclosed on the basis of Piper Alpha will be one of the main concentration areas of the Safety and Working Environment Division's supervisory activities in 1989. The concentration area comprises matters such as shutdown facilities for pipelines, separate living quarters, general layouts, design requirements, fire and explosion protection, use of standby vessels, evacuation equipment, simultaneous activities, securing of wells, platform organisation and the work order system.

4.16.2 "Viking Explorer"

The drilling vessel "Viking Explorer" was drilling a well for Total east of Borneo at a water depth of 77 metres, when a gas pocket was encountered. A large concentration of gas in the cooling water inlet to the air compressor is the probable cause of the complete power supply shutdown during the blowout. The brakes on the four anchor winches could not be released in order to move the vessel, and in a matter of short time it capsized and sank. One crew member lost his life.

Even if accidents in connection with shallow gas have been avoided on the Norwegian continental shelf in the report period, shallow gas has been encountered in several wells. Certain aspects of the accident on "Viking Explorer" thus have parallels to Norwegian conditions, and the Norwegian Petroleum Directorate has given the accident due attention in order to better handle the problems of shallow gas on the Norwegian continental shelf.

4.16.3 "Ocean Odyssey"

The installation "Ocean Odyssey" was drilling a well for Arco on site 22/30 b-3 on the British continental shelf when a leakage occurred during circulation bottom up, so that gas flowed up under the rig and was ignited. The rig was evacuated and everybody was saved except one. Three of the anchor chains were blasted off later, and the rig drifted away from the well. The gas flow from the well stopped by itself after a while.

The Department of Energy has prohibited the use of flexible hoses in the BOP system when drilling wells with expected well pressure higher than 690 bar (10 000 psi).

The Norwegian Petroleum Directorate has appointed a working party to obtain detailed information on the course of events and evaluate relevant measures for the Norwegian continental shelf. The working party's report is expected to be completed in the first half of 1989.

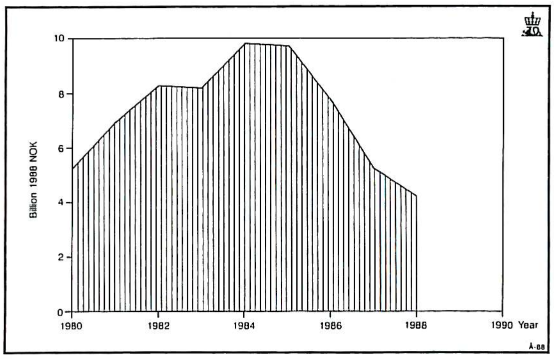
5 Petroleum Economy

5.1 EXPLORATION, GOODS AND SERVICES SUPPLIED

Exploration drilling activity showed a relatively steady increase from 1966 to 1985, when a total of 50 new exploration wells were spudded. Since 1986 there has been a decline in the amount of activity, with 36 exploration wells in 1986 and 1987 and 29 wells in 1988.

Figure 5.1.a shows the costs of exploration activity since and including 1980. The costs include exploration drilling, general surveys, field evaluation and administration.

Fig. 5.1.a
Exploration costs per year 1980–1988. Billion 1988 NOK



The table below shows the exploration costs for 1988 divided into groups of goods and services. The amounts represent preliminary estimates based on data reports from the operating companies. The same figures form the basis of figure 5.1.b which shows the distribution by percentage between the different types of costs.

Exploration costs	Mill kr	Mill kr
– Exploration drilling		2 370
– Drilling rigs	730	
– Transport	280	
– Goods	410	
– Services	950	
– General surveys		550
– Field evaluation		720
– Administration[1]		560
Total		4 200

1) Administration costs include acreage fees.

Fig 5.1.c shows average drilling costs per well, that is exploration and appraisal wells.

Fig. 5.1.b
Oil and gas exploration costs in 1988 by category of goods and services

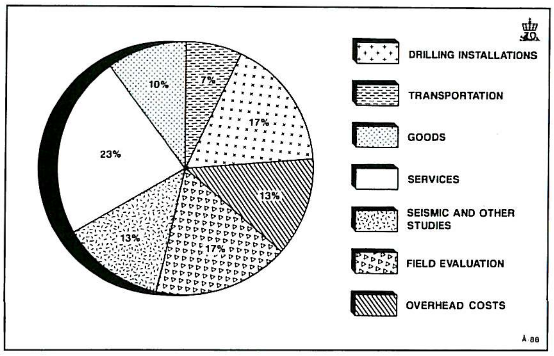
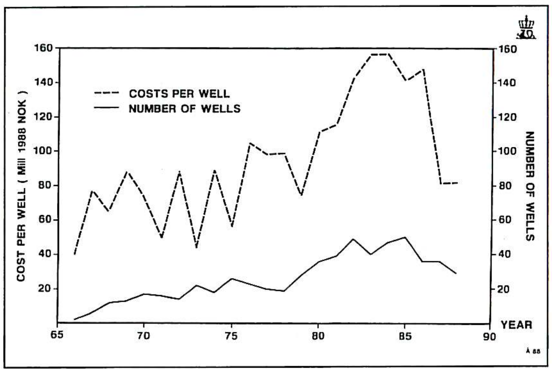


Fig. 5.1.c
Number of exploration and delineation wells and drilling costs per well



5.2 COSTS ASSOCIATED WITH DEVELOPMENT AND OPERATION ON THE NORWEGIAN CONTINENTAL SHELF

The Norwegian Petroleum Directorate has calculated the annual costs associated with development of fields, including production drilling, for the period 1970–2010. The cost figures apply to fields in production, fields under development and fields for which there are approved development plans as of 31 December 1988. For fields on both sides of the sector line between Norway and Great Britain, only the Norwegian share is included. The following fields and transport systems are included in the calculation:

- Frigg
- Albuskjell
- Ekofisk
- North-east Frigg
- East Frigg
- Gullfaks
- Heimdal
- Murchison
- Odin
- Oseberg Transport
- Oseberg
- Statfjord
- Tommeliten
- Tor
- Ula
- Valhall
- Norpipe
- Statpipe
- Ula Pipeline
- Veslefrikk
- Troll-Oseberg Gas Injection
- Gyda
- Troll – phase 1
- Sleipner East
- Zeepipe
- Snorre
- Hod
- Draugen
- Gamma North

No decision had been made concerning early production on the Heidrun field at the end of 1988, so Heidrun has not been included in the calculations. All costs are calculated in fixed 1988 NOK.

Past and approved investments for field development and transport plant for petroleum can be seen from Figure 5.2.a. Investments increased steadily until 1976, when they reached their highest point until then. The decline in investment in subsequent years was replaced by a new rise from 1981 on, and in 1984 investments on the Norwegian shelf totalled NOK (1988) 28.8 billion. At the beginning of the nineties we shall again have investments approaching NOK (1988) 30 billion, but if no more developments are decided upon, there will be a sharp decline in the investment level towards the year 2000. As early as 1996 the investment level will be as low as NOK (1988) 2.5 billion.

Fig. 5.2.a
Investments in fields and pipelines on the Norwegian shelf 1970–2010. Fixed 1988-NOK

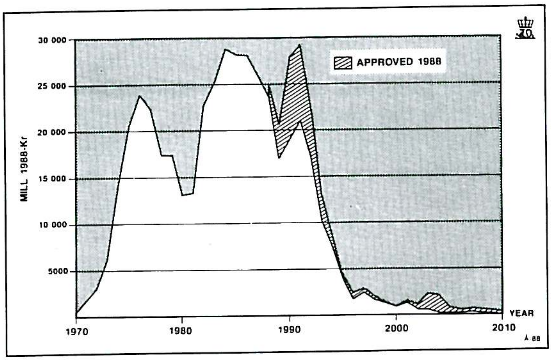
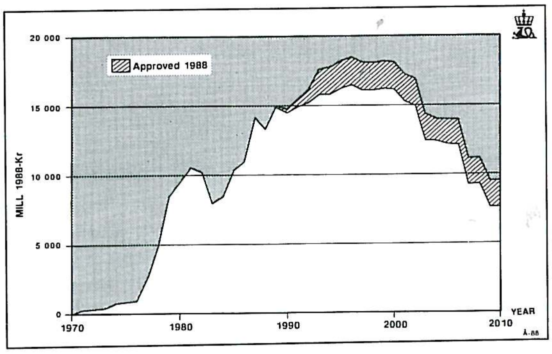


Fig. 5.2.b
Operating costs for fields and pipelines on the Norwegian shelf 1970–2010. Fixed 1988-NOK



Annual operating costs, including pipeline operation costs, can be seen from Figure 5.2.b. The level of demand for goods and services for operational purposes has risen steadily, and will continue to rise as more fields come into production. Operating costs will thus probably be the most significant cost component in the future. It will be important to try to reduce these in the time ahead.

5.3 ROYALTY

The Norwegian Petroleum Directorate is responsible for collecting royalties.

Royalties are calculated according to the provisions of the Petroleum Act, which came into force 1 July 1985. The calculation base for royalty is the value of the produced petroleum quantities at the shipment point of the individual production area.

On 26 May 1988 the Storting passed an Amendment of the Petroleum Act in the form of § 67 no. 3b which states that the Ministry may deviate from the rules in the first subsection of § 15 pertaining to the shipment point of the production area for production licences granted in accordance with the 1965 resolution.

In practice the calculation base for royalty will be the difference between gross sales value and costs which accrue between the royalty point and the sales point.

In some fields the cost deductions are higher than the corresponding sales value of the petroleum product in question (this applies particularly to gas). In these cases production royalty shall not be paid.

In Odelsting Proposition No. 64 (1986–87), pertaining to amendments in the the Petroleum Act, it is resolved that royalty shall not be paid on petroleum produced from accumulations where a development plan was approved after 1 January 1986.

Interpretation and practice of the applicable acts and regulations for calculation of royalties involve legal, financial, process technological and measurement problems.

5.3.1 Total royalty

In 1988 NOK 5,480,914,764 was paid in royalties. Table 5.3.1. shows royalties divided by different petroleum products for 1987 and 1988.

Fig. 5.3.1.a
Royalties 1973–1988

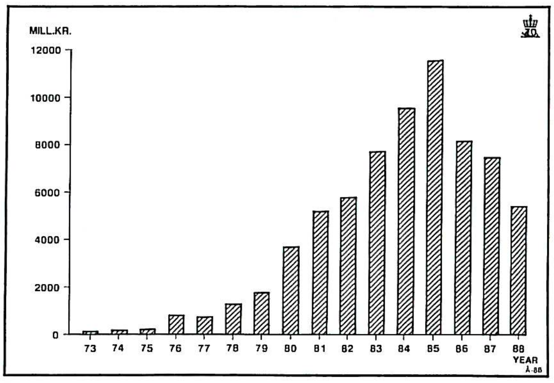


Figure 5.3.1.a shows royalties 1973 – 1988

5.3.2 Royalty oil

In 1988 the Norwegian Petroleum Directorate received NOK 4,550,311,347 in royalties on oil from Murchison, Ekofisk, Valhall, Ula, Statfjord, Heimdal, Oseberg and Gullfaks, see Table 5.3.2. Royalty for oil was taken in the form of oil. Sale of the State's royalties oil is conducted by Statoil. From 1987 payment from Statoil to the Norwegian Petroleum Directorate is monthly. Calculation is on the basis partly of norm prices fixed by the Petroleum Price Council and partly of calculation prices laid down by the Ministry of Petroleum and Energy (Oseberg).

5.3.3 Royalty gas and NGL

In 1988 the Norwegian Petroleum Directorate received NOK 930,603,417 in royalty on gas and NGL. Table 5.3.3 shows payment by half year and company/group.

By Royal Decree 27 May 1988 the regulations governing payment instalments for royalties paid in cash were changed to half-yearly installments with a 3-month deadline for payment. This means that payment is only received for one quarter (2nd quarter 1988) in the second half year, as opposed to two quarters previously. On Statfjord, Gullfaks and Ula no royalty on gas was paid because cost deductions are greater than gross royalty in all quarters.

Calculation for gas has been undertaken on the

Table 5.3.1
Royalties in 1987 and 1988 (NOK million)

		1987	1988
OIL	EKOFISK/VALHALL/ULA	1,190.8	1,029.1
	STATFJORD	4,832.6	3,321.9
	MURCHISON	14.5	21.5
	HEIMDAL	−12.4	−0.3
	OSEBERG	33.0	12.9
	GULLFAKS	82.5	165.2
GAS/NGL	EKOFISK FIELDS	545.3	415.7
	VALHALL	14.7	0.4
	ULA	−2.6	−1.2
	FRIGG,NE FRIGG,ODIN	785.0	521.4
	STATFJORD	5.6	0.0
	MURCHISON	−0.3	0.2
	HEIMDAL	27.8	−6.0
	GULLFAKS	0.0	0.0
TOTAL ALL FIELDS		7,516.7	5,480.9

Table 5.3.2
Royalties on oil

AREA/FIELD	1st half year	2nd half year	Total 1988
EKOFISK, ULA AND VALHALL	565,901,142	463,226,982	1,029,128,124
STATFJORD	1,896,925,508	1,424,941,346	3,321,866,854
MURCHISON	7,538,895	14,002,022	21,540,917
HEIMDAL	−115,484	−198,375	−313,859
OSEBERG	13,294,624	−400,181	12,894,443
GULLFAKS	61,533,598	103,661,270	165,194,868
TOTAL	2,545,078,283	2,005,233,064	4,550,311,347

basis of the contract price, which varies from group to group.

Deliveries of gas from Dyno/Methanor ceased from 1 July 1984. Sums refunded to Dyno/Methanor are related to transport and treatment of already received and paid gas.

Table 5.3.3
Royalties on gas and NGL

	1st half year	2nd half year	Total 1988
EKOFISK AREA			
Phillips gr.	226,177,056	181,294,875	407,471,931
Amoco gr. (Tor)	2,469,443	0	2,469,443
Shell (Albuskjell)	5,759,854	38,283	5,798,137
Dyno/Methanor	398,971	−463,018	−64,047
Total Ekofisk area	234,805,324	180,870,140	415,675,464
FRIGG AREA			
Petronord gr.	315,209,281	118,201,404	433,410,685
Esso (NE-Frigg)	21,153,459	7,351,272	28,504,731
Esso (Odin)	43,391,866	16,119,572	59,511,438
Total Frigg area	379,754,606	141,672,248	521,426,854
VALHALL	108,296	309,800	418,096
ULA	*) −1,172,107	0	−1,172,107
STATFJORD	0	0	0
MURCHISON	248,059	**) −15,480	232,579
HEIMDAL	**) −5,977,469	0	−5,977,469
GULLFAKS	0	0	0
TOTAL ALL FIELDS	607,766,709	322,836,708	930,603,417

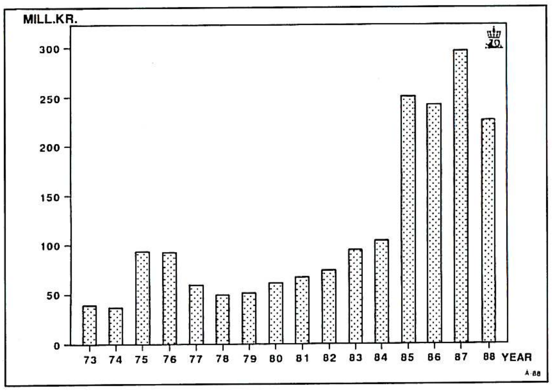
*) The amount is for cash refunds of oil royalties paid in excess.
**) Repayment of royalties paid in excess in previous settlement.

5.4 ACREAGE FEE ON PRODUCTION LICENCES

In 1988 the Norwegian Petroleum Directorate has collected NOK 183,756,652 in acreage fees. The sum is divided between production licences as follows:

Production licences issued in 1965:	NOK 108,220,000
Production licences issued in 1969:	NOK 56,763,000
Production licences issued in 1971:	NOK 5,502,000
Production licences issued in 1975:	NOK 8,037,739
Production licences issued in 1977:	NOK 5,672,440
Production licences issued in 1979:	NOK 15,053,072
Production licences issued in 1980:	NOK 809,885
Production licences issued in 1981:	NOK 6,166,124
Production licences issued in 1982:	NOK 4,058,124
Production licences issued in 1988:	NOK 14,106,000
	NOK 224,388,384

Fig. 5.4
Acreage fees 1973–1988



The Norwegian Petroleum Directorate has refunded NOK 40,631,732 in acreage fees in 1988.

This represents the tax-deductible part of the acreage fee in the royalty settlement for production licences 006, 018, 019a, 033, 037, 050 and 053.

For some individual production licences the acreage fee will be deducted direct in the royalty settlement. This sum is not included in the NOK 40,631,732.

Figure 5.4 shows paid acreage fee, 1973–88.

5.5 THE PETROLEUM MARKET

5.5.1 The crude oil market

The fall in price of crude oil in 1988 has once more shown how difficult it is to predict the course of oil prices in the short term. On the basis of the big fall in prices in 1986 and the effects of this on the economies of OPEC countries, it was anticipated that the OPEC countries would stake a lot to defend a price in the region of 18 USD per barrel. At this point it seemed as if they would manage this.

However, there were considerable uncertainties. Several OPEC countries needed quick money on account of their large foreign debts. The war between Iran and Iraq seemed to be drawing to an end and this was expected to result in both a lower and higher supply of oil. Non-OPEC countries increased their production capacity and this would harm OPEC's share of the market if OPEC itself limited production too much.

All in all this uncertainty led to an increase in production in most OPEC countries. In the case of some production almost reached capacity level. Nor was Saudi Arabia willing to play the role of market swinger any longer and increased its production.

This has been the state of affairs for most of 1988. In March–May there was a small rise in prices to around 16 USD per barrel due to increased demand as a result of reduced stocks earlier in the year. After this prices fell steadily until the OPEC meeting in November.

The fall in prices resulting from increased production has on the whole been so great that there has been only a small increase in total revenues. Thus near the end of 1988 OPEC has once more decided to resume a quota regulation with a total framework of 18 million barrels per day. It is hoped that this level of production will bring the price of oil up to a level of about 15 USD per barrel during 1989. This would enable most OPEC members to improve their financial situation. The individual quotas are set at a much higher level than previously. This is a result of difficulties in reaching an agreement involving a considerable reduction in production on all sides and the anticipation of a higher level of consumption.

The fall in oil prices has also had consequences for Norwegian economy. Compared to the revenues reckoned from the basis for calculating the 1988 national budget, the loss up to now may amount to as much as NOK 2 billion.

However, the fall in price does not seem to have had much effect on oil companies' exploration activities on the Norwegian continental shelf. The announcement of concession round 12B for blocks in the North Sea, Møre and the Barents Sea resulted in a large number of applications and there has been substantial interest in blocks in all these areas.

5.5.2 The gas market

Gas consumption in western Europe rose by 6.6 % or from 218.1 to 232.4 billion Sm^3 per year from 1986 to 1987. In percentage terms Sweden, Finland and Denmark showed the greatest increase, whereas in terms of volume West Germany, Italy and the Netherlands increased most. All these countries increased their import and this increase was covered by the Netherlands, the Soviet Union, Algeria and Norway in that order.

Norwegian sales to the continental gas market have increased beyond this in 1988. In April 1988 an agreement was signed with the Spanish Enagas for deliveries of between 1.5 and 2.1 billion Sm^3 per year between 1996 and 2025. The gas is to be delivered through France. Negotiations with potential transporters are still in progress and a pipeline route through the Pyrenees has not been decided on either. The agreement is of particular interest as Spain is a market with development potential and may in addition open the way for deliveries to Portugal.

A letter of intent was made in 1988 with the Netherlands for the delivery of 2 billion Sm^3 per year between 1995 and 2015. This agreement is trailblazing in that it was a direct agreement between two Dutch power producers and not with the state-owned gas company. It is also unusual in that the price of gas is linked to coal as an index regulator and not to oil, as coal is the alternative fuel in Dutch power stations.

Continuous negotiations are in progress between Norway and Sweden over the sale of Norwegian gas, but Sweden is also negotiating with the Soviet Union. From the Norwegian point of view it is important to sell a quqntity which is sufficiently large to make the development of a conveyor system a paying proposition.

Negotiations are also being carried out with potential buyers of Norwegian gas. The total market potential for Norway is viewed as too small at the momemt to make a separate pipeline profitable. Only a common solution whereby Sweden buys a substantial quantity is considered economically viable today.

After the British government in 1986 was not able to approve the sale of Norwegian gas to British Gas (BG) as compensation for reduced deliveries from Frigg, there was for a long time no question of new Norwegian initiatives. This year, however, negotiations have been opened with British buyers. Reorganisation in the British gas market has resulted in the "common carrier" principle (that the owner of the pipeline systems must carry gas for others) being introduced. Today there are negotiations both with BG and directly with major consumers such as power stations. BG's monopoly has also been broken in other ways so new possibilities have been opened up in this market, but at the same time the market is more complex from the seller's point of view.

The "common carrier" principle seems to be gaining support in other EEC countries too. A more easily accessible carrier system for gas in Europe may benefit Norway as a seller of gas by dint of simplified contractual conditions. Today it is usual for a carrier in a third country to own the gas as it passes through its pipelines. The "common carrier" principle may, however, involve greater competition; Soviet gas may, for example, have easier access to countries such as Spain and Great Britain, and LNG from Algeria and Nigeria will be able to be un-loaded and stored in countries which find it easier than others to accept the safety and pollution risks represented by systems such as these, before it is transported further to other markets. Major oil companies have a strong belief today that the EEC commission will go in for the introduction of the principle and that this will also mean that a pipeline for gas will soon be laid across the English Channel.

Until recently Soviet gas has had a substantial position in energy supplies in many European countries. However, the share of gas in the supply systems of individual countries has been limited for political reasons, normally to about 30 %. Growing confidence in detente and the Soviet need for money to carry out its economic reforms may change this. Competition with Soviet gas with its low production costs will present a considerable challenge to Norwegian offshore technology. The need felt by most countries to diversify their gas deliveries may, nevertheless, mean a large share of the market for Norwegian gas.

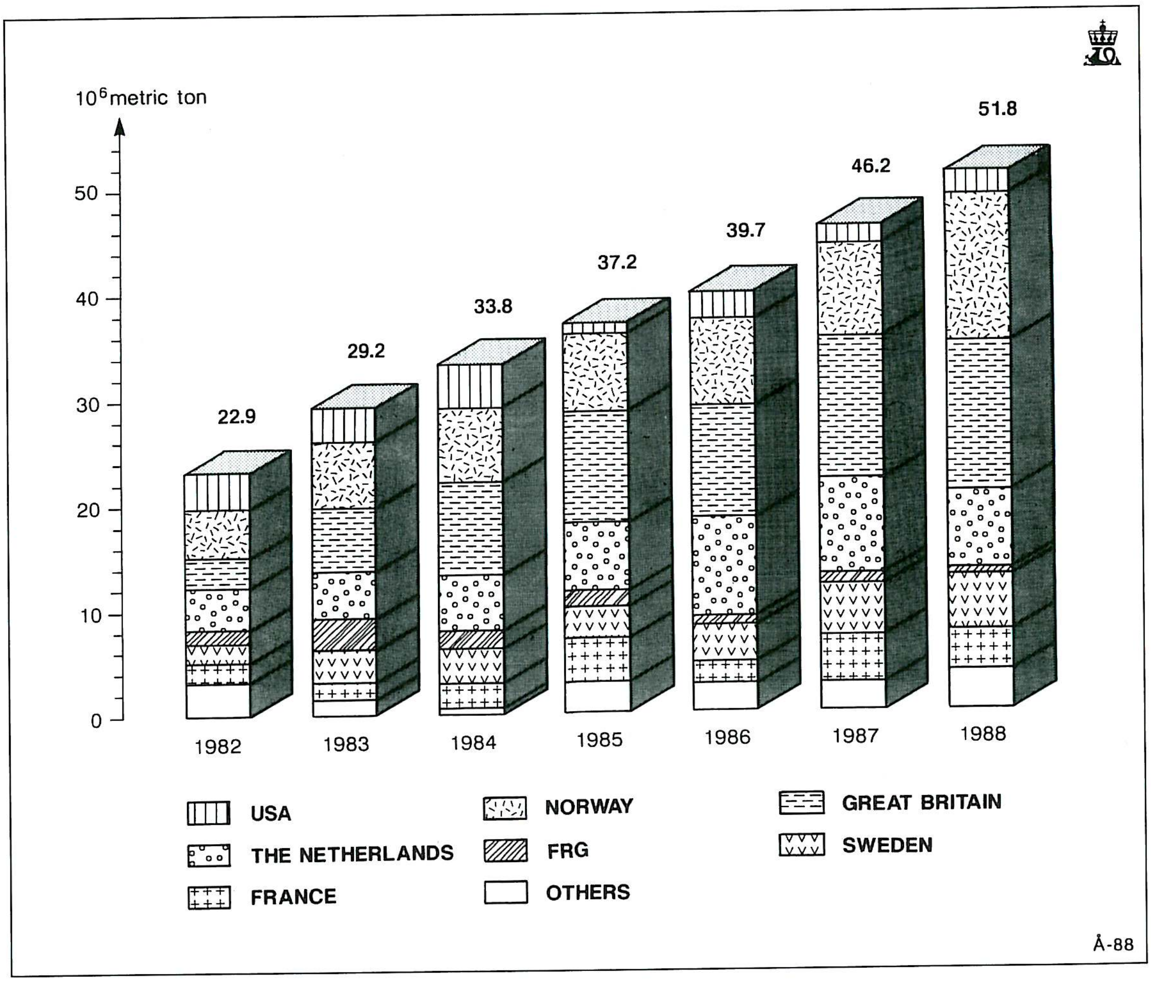
In the above circumstances LNG may become an important competitor for Norwegian gas delivered from the North Sea through pipelines. It is first and foremost Algeria which has big gas reserves and capacity to deliver. Nigeria will also enter the arena soon. Great Britain, among others, may feel under obligation to buy large quantities of gas from Nigeria, which is a Commonwealth country, at the same time as this will contribute to increased diversification on the part of suppliers.

In considering Norwegian LNG export to overseas markets, we shall have to take account of the relatively low production costs which can be achieved by these two competitors.

5.5.3 Sale of petroleum from the Norwegian continental shelf

In 1988 51.8 x 10^6 tons crude oil were sold from the Norwegian continental shelf. This represents an increase of 12.10 per cent in relation to 1986. Last year as in recent years Great Britain was the largest recipient, with 28 per cent of the shipments. The Netherlands took 14 per cent and Norway 26 per

Fig. 5.5.3.a
Sale of crude oil from the Norwegian continental shelf



cent. In 1987 Norway took 18.5 per cent, so there has been a relatively big increase in 1988.

Figure 5.5.3.a shows sales of crude oil divided by countries in the 1982–88 period.

In 1988 sales of NGL from the Norwegian shelf reached 2.4 x 10^6 tons, an increase of 24 per cent in relation to 1987.

Figure 5.5.3.c shows the sales of crude oil and NGL in 1988 divided by licensees.

Norway exported 27.7 x $10^9 Sm^3$ of gas in 1988. This is small decrease in relation to 1987. 7.6 x 10^9 Sm^3 were sold to West Germany. 10.6 x 10^9 Sm^3 were sold to Great Britain, 2.3 x 10^9 Sm^3 to the Netherlands, 5.1 x 10^9 Sm^3 to France and 2.1 x 10^9 Sm^3 to Belgium, see Figure 5.5.3.b.

Figure 5.5.3.d shows gas sales divided by licensees. In the column headed "others", companies have not been treated individually as it contains figures from several small fields, and it would be very inaccurate to plot these in.

Fig. 5.5.3.b
Sales quantities of gas per country

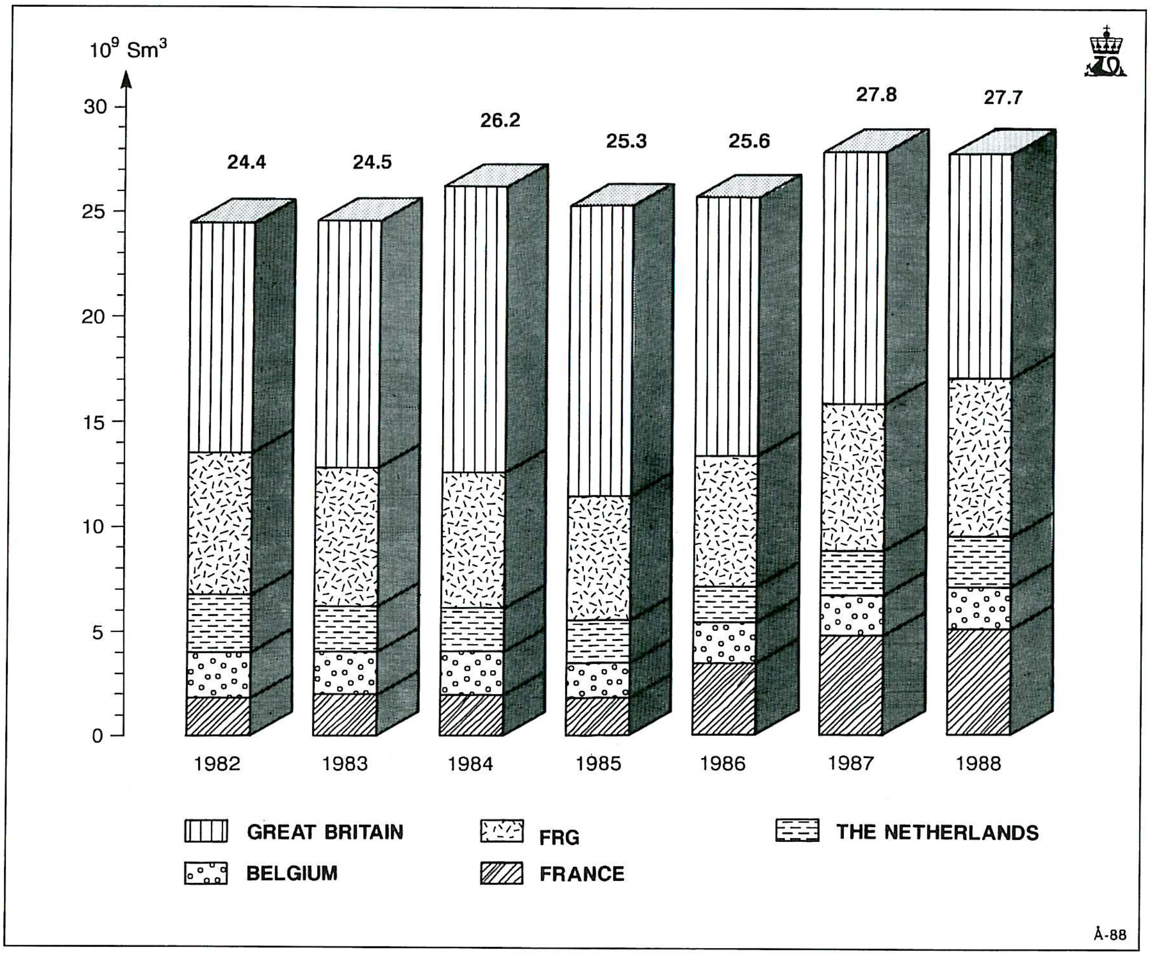


Fig. 5.5.3.c
Sales quantities of oil/NGL per licensee in 1988

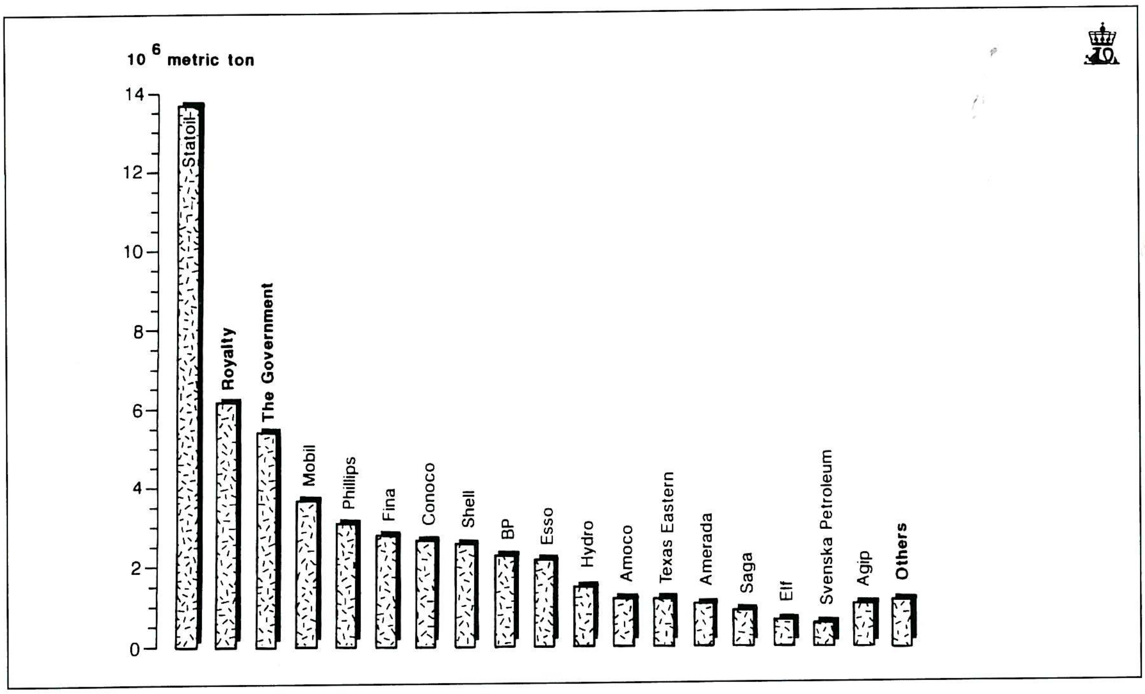
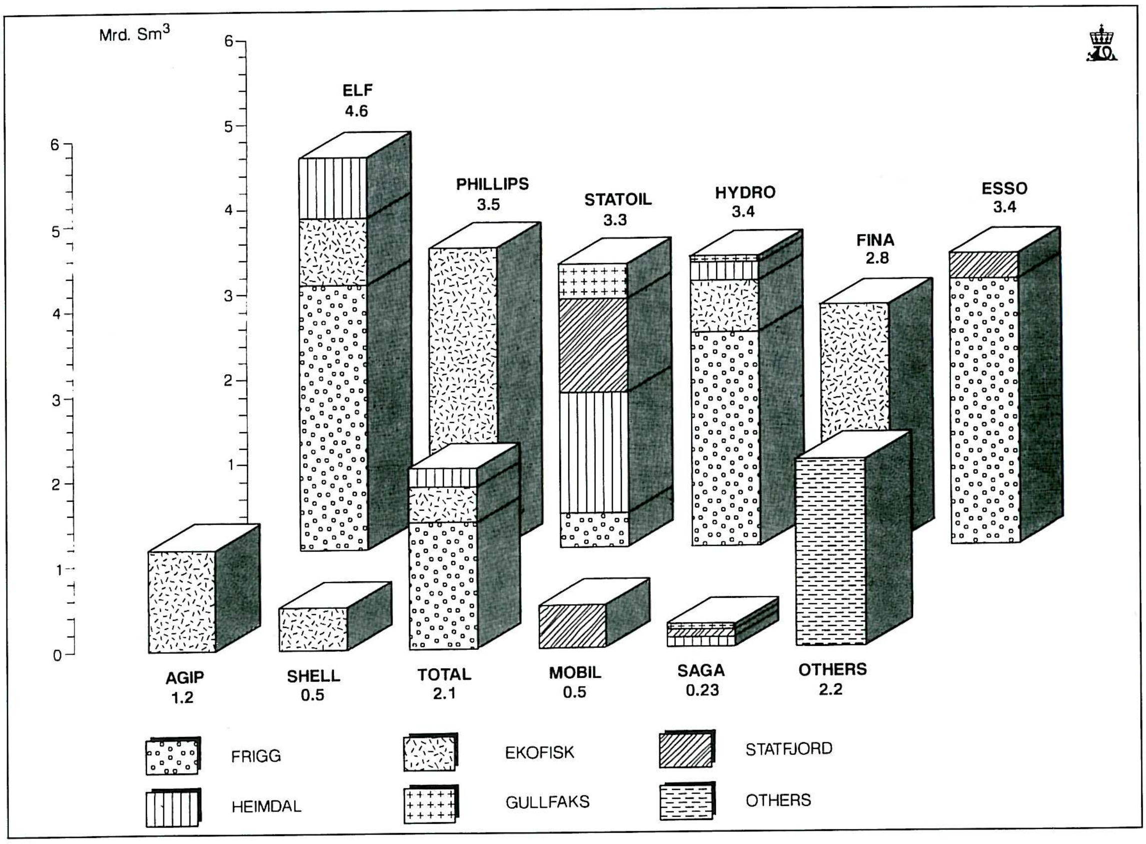


Fig. 5.5.3.d
Sales quantities of gas per licensee in 1988



6 Special Reports and Projects

In 1988 the Norwegian Petroleum Directorate granted a total of NOK 16,203,413 for special projects. This is divided between NOK 3,930,082 for projects of the Safety and Working Environment Division and NOK 11,549,938 for the Resource Management Division.

In addition NOK 4,396,155 was granted for the North Sea seabed clearance project.The weather ship project in the Barents Sea, administered by the Norwegian Petroleum Directorate, received NOK 11,960,882. The SPOR program (a state-funded research and development program) has also been granted NOK 17.7 million in 1988.

Some of the project titles with implementing institutions are listed below.

6.1 RESOURCE MANAGEMENT DIVISION

6.1.1 Exploration Branch

PROJECT TITLE	PROJECT IMPLEMENTATION AGENCY
Publication of lithostratigraphic nomenclature north of 62°N	Norwegian Petroleum Directorate
Publication of regional geological map of area 56–69°N	NGU/Norwegian Petroleum Directorate
Well Data Summary Sheets	Norwegian Petroleum Directorate
Analysis of pore and crack geometry in heterogenous reservoirs	Frakton
Purchase of petrophysical software for use in log interpretation	IPEC
Uncertainty provision related to log interpretation	Schlumberger
Study of different faults to decide whether they are sealing or not	University of Leeds and Rogaland Research Institute
Porosity and migration history in sandstones on the Gullfaks field	University of Oslo
Detailed sedimentological interpretation of induction dipmetre in wells 34/10-bl and 34/10-al4 on the Gullfaks field	Z og S Geologi A/S
Petrophysical mineral analysis and studies of pore geometry on Smørbukk	IKU, Rogaland Research Institute and Norsk Regnesentral
2D-fault modelling	Rogaland Research Institute
Further development of Norwegian Petroleum Directorate's program package for basin modelling	Rogaland Research Institute
Further development of program package for resource calculation	Christian Michelsens Institute

PROJECT TITLE	PROJECT IMPLEMENTATION AGENCY
Development of south-west part of Barents Sea in tertiary period based on foraminifera stratigraphy	University of Tromsø
A biostratigraphic analysis of tertiary sediments in the western Barents Sea	IFE
Depth conversion in Hammerfest basin	Read
Post-Caledonian tectonics on Svalbard	University of Tromsø

Publication of lithostratigraphic nomenclature north of 62°N
Work on a uniform lithostratigraphic nomenclature north of Stad is a collaborative project involving Hydro, Saga, Statoil and the Norwegian Petroleum Directorate. The results of this work have been published and are on sale as NPD-Bulletin no. 4.

Publication of regional geological map of the area 59–69°N
The Petroleum Directorate in collaboration with NGU has put together a map of cretaceous sedimentation in the North Sea and Central Norway. This is a recapitulation of several years' work and is a substantial contribution to the general geological charting of the shelf. The map will be published by the NPD.

Well Data Summary Sheets
The Norwegian Petroleum Directorate releases uninterpreted data from the continental shelf when these are older than five years.

Uninterpreted logs and log tapes are released for sale when the well is presented in "Well Data Summary Sheets".

The purpose of "WDSS" is to show which wells have been released and what core and drilling samples and log/tape material is available from the various wells.

In addition they give a certain amount of technical data, well history, shallow gas information and results of tests, as well as the Petroleum Directorate's compiled log for each well.

Analysis of pore and crack geometry in heterogeneous reservoirs
The present geological descriptions of reservoirs is often not very compatible with the reservoir model used in simulation. This means that geological information is not used at all effectively. This project has developed a method to increase the relevance of geological information for the purpose of simulation.

A quantitive study of cores has been carried out from the complex Tilje reservoir on Heidrun. This study has shown that the distribution of shale in the reservoir follows a fractal distribution in one dimension. Studies of aerial photos and satellite pictures of recent sedimentation systems of the same type show a fractal surface pattern of sedimentation environments. It is therefore highly probable that the spacial distribution of shale deposits is fractal. A sedimentologiocal process response model has been made which can explain this. An analysis of porperm measurements from the core is underway, and will be linked to the shale distribution.

The project has also shown that styolites and probably faults follow a three-dimesional fractal pattern.

Purchase of petrophysical software for use in interpretation of logs
In order to carry out independent log interpretations, the Petroleum Directorate bought the EPIC computer program in 1989. This program also makes possible the storing of raw data and results. The program has been installed in Nord computers both in the Stavanger and Harstad offices.

Uncertainty provision related to log interpretation
The interpretation of well logs is associated with uncertainty as regards measuring instruments, invasion effect, mineral model and empirical saturation equations. This project has mapped these uncertainties and combined then into a model which allows them to be quantified.

Study of different faults to decide whether they are sealing or not
Methods are being developed through this project which make it possible to decide whether faults are sealing or not. The results will be of great significance to a number of fields on the Norwegian shelf.

Porosity and migration history in sandstones on the Gullfaks field
The project has resulted in a greater understanding

of the reservoir and the way it is filled. By using core material, different petroleum populations are described and characterised. The analyses contain geochemical, sedimentological and diagenetic surveys. In this manner factors which may control filling of a reservoir with hydrocarbons are identified. Correlation between core material and well logs may enable extrapolation to areas without core material.

Detailed sedimentological interpretation of induction dipmetre in wells 34/10-bl and 34/10-a14 on the Gullfaks field

The project has resulted in increased understanding of individual reservoirs on the Gullfaks field. Using interpretation of induction dipmetre logs in two of the wells on the field, compared to a corresponding analysis of an earlier well, we have reached a better understanding of the extent, geometry and reservoir properties of the reservoir.

Petrophysical mineral analysis and study of pore geometry on the Smørbukk field

In individual reservoirs on the Norwegian shelf it has been shown that conventional logging does not permit an interpretation which separates the oil zone from the water zone; this applies inter alia to one of the reservoirs on the Smørbukk field. New methods have been developed through this project which permit this differentiation.

Probable effective microporosity often constitutes 15–20 per cent of total porosity. If the water in the micropores makes a network, which is fully possible with these values, the rock may get a "false" resistivity, where the log results apparently show water, even if the macropores contain oil.

2D-fault modelling

A data program has been made which models faults based on interpreted seismic cross-sections. This year's project has built on the routines worked out by the Rogaland Research Institute last year. The programme provides important entry data for the Petroleum Directorate's basin modelling program and is related to this. There is now a first version available which is adapted for work station use.

Further development of the Petroleum Directorate's program package for basin modelling

The Petroleum Directorate is working on building up expertise within the field of basin modelling. A program package has been developed for internal basin modelling at the Petroleum Directorate, which will permit the Directorate to make a quantitative assessment of the hydrocarbon volumes made by the sinking together and maturing of source rocks in the sediment basin. This project has developed and improved this package, particularly towards the development of a profile model (2D) and towards a better control of the use of temperature data.

Further development of a program package for resource calculation

The project has meant that the Petroleum Directorate now has a good program for calculating the probable distribution of resources in reservoirs consisting of several layers.

Development of south west Barents Sea throughout tertiary period based on foraminifera stratigraphy

The project has contributed to a better understanding of developments in the Barents sea throughout the tertiary period. This is important when determining the basic resources in the Barents sea. The work has included chronology, sedimentology, paleoecology, sea level and paleo-oceanography studies.

A biostratigraphic analysis of tertiary sediments in the western Barents sea

The project has produced a more precise dating of the sediments in three wells which penetrate the proximal part of a huge sedimental fan which constitutes the continental slope between the Barents sea and the Norwegian basin. This is important for the understanding of sand development in this area.

Depth conversion in the Hammerfest basin

Depth conversion is a big problem in the Barents sea. This project has led to the development of a new and improved method of depth conversion in the Hammerfest basin.

Post-caledonian tectonics on Svalbard

In 1988 the Petroleum Directorate has compared well data from exploration wells on Svalbard and participated in Mobil's expedition to the group of islands to enable it to make profile descriptions and interpretations off different parts of the stratigraphy.

This has led to new insight into and understanding of the geological developments on Svalbard and the shelf area around. The project is important for the supervisory work of the Petroleum Directorate on Svalbard.

6.1.2 Development Branch

PROJECT TITLE	PROJECT IMPLEMENTATION AGENCY
Transport of compressed natural gas	Kværner Engineering A/S
Seabed installations	NovaTech A/S
"Offshore Process Technology Study"	The Ralph M. Parsons Company Limited
Cost data bank	Kværner Engineering A/S
Area evaluation of the Sleipner area	Kværner Engineering A/S
OLE, prospect evaluation model	Chr Michelsens Institute
Gas transport study	SINTEF
Reservoir study of Heidrun	Restek
Gas injection	Restek/D Waldren

Transport of compressed natural gas
The purpose of the project was to assess the transport of gas in compressed form by ship as an alternative to exploitation of minor oil fields or small marginal gas fields. The consultant documented that this method is possible. Preliminary financial calculations have been made on the basis of cost figures in the report which show that the idea may be of interest.

Seabed installations
Subsea developments on the Norwegian shelf have proved more expensive than corresponding systems in other countries. During this project a survey and classification have been made of technical and cost-related data for seabed installations on the Norwegian shelf. The results will be used in cost analyses in the future with a view to making a survey of potential cost reductions.

"Offshore Process Technology Study"
The solving of problems within the field of process technology may result in weight and cost savings on a production installation. In this project the focus was on the consequences for weight and costs of the size of the installation, reserve philosophy and regularity, and of production with different water undercuttings and gas/oil conditions.

Cost data bank
A new data bank has been prepared for weight and cost data related to development projects. The purpose of this is to prepare the ground for analysis work and also to simplify the looking up of facts.

Area evaluation of the Sleipner area
A survey has been made of possible development models for the Sleipner area at different levels of gas production from the area. The results will be used in connection with an assessment of potential gas sources in any new gas sales.

OLE – Prospectus evaluation model
The Petroleum Directorate has developed a new tool for financial prospectus evaluation, the OLE model, which is used inter alia in financial assessments in connection with the awarding stages. The project assesses the possibility of changing the OLE model to a model which can tackle several prospectuses at the same time and not just single ones as now.

Gas transport study
In connection with the Petroleum Directorate's work regarding choice of source and transport solutions for the Norwegian and European gas market, a major analysis has been made using an economic phasing-in model/"portfolio model".

Reservoir study of Heidrun
A full-field model was made to undertake separate reservoir assessments of the Heidrun field. The model is based on 3D-seismic. The model will be useful for interpreting the first production experiences. In addition it has provided some information about uncertainties in the interpretatioon of the field. The objectives of the project have been fulfilled on the whole.

Gas injection
The aim of the project is to obtain independent expert opinions and assessment of the reservoir measurements and evaluation methods which ought to be used for making decisions about gas injection/storage on the best possible basis.

6.1.3 Production Branch

PROJECT TITLE	PROJECT IMPLEMENTATION AGENCY
Reservoir Technology Section	
Lopap	CAP-GEMINI
Eclipse maintenance	ECL
WIPER + RADPACK	IPEC
RDRS-IFE	IFE
SCORPIO	ERC
UNIRAS	UNIRAS
SIOS	IFE
RDRS further development	CAP-GEMINI
FRAGOR/GENISYS test installation	FRANLAB
Blow-out further development	Ole Vignes
RDRS – entry	CAP-GEMINI
Water analyses, Ring test	Aquateam
Requirements for reservoir monitoring	READ
Block partition	Norsk Regnesentral
Direction for rock mechanics tests	SDF
Production Economics Section	
Technical/economic aspects of removing	Opcon
System for royalty calculation	Rogaland Reseach Institute
Incentives in the operating phase – The overhead system	Furset Consulting
Measurement Section	
Program development and maintenance PPRS-2	Rogaland Research Institute
Expert support in micro-computer technology	Cresttec
Design criteria for test separator	MB and R
Fabrication requirements for orifice plates	NEL

LOPAP
The program system is used in the preparation of the national budget report in June and December. CAP-GEMINI has carried out some maintenance work and adjustments to new plotters, more fields as well as having made the system easier to use.

ECLIPSE maintenance
A maintenance contract has been signed with the British firm ECL (Exploration Consultants Limited). In addition some adjustments have been made to the Norwegian Petroleum Directorate's new plotters and machines. An additional agreement has also been signed in order to have the program on two computers simultaneously in a changeover period.

WIPER, RADPAC
Wiper and Radpack are two program systems bought by the Norwegian Petroleum Directorate from the British company IPEC. Wiper is a system for interpretation of pressure development tests and Radpack is a partly analytic reservoir analysis system especially adjusted to situations with little reservoir information. Internal courses have been arranged about the use of these systems, and continuous maintenance/updating and adjustments. A maintenance contract has been negotiated for the two systems, which is cheaper than the two previous single contracts.

SIOS
This is a small project where the Norwegian Petroleum Directorate buys its right to use existing software for further development under its own direction within the RDRS-application program. (Reservoir Data Reporting System)

IFE-RDRS
For a period the Directorate had a maintenance agreement with IFE (the Institute of Energy Technology) on work in connection with changes and adjustments of the RDRS application programs. This agreement came to an end in June 1988.

SCORPIO

Scorpio is an EOR-simulation model bought by the Norwegian Petroleum Directorate from the British firm ERC in 1987. The model was developed by the Department of Energy and is used by SPOR (a state program for increased production and reservoir technology), among others. The Directorate has a maintenance contract with the ERC with a view to up-dating and adjustments on a fixed price basis.

RDRS further development

RDRS (Reservoir Data Reporting System) is a comprehensive system which takes care of both collection and reporting of reservoir data and inspection of companies' quality control of measurement results. The system is very well adapted to collecting data for internal and external analyses with help from other software. The program has been further developed by consultants from the firm CAP-GEMINI, first and foremost by making it easier to use from the point of view of presentation. The system is now very efficient for correlation and validity control of data.

Blow-out further development

The consultant has carried out the following work in 1988:

1. Entry of SPE-preferred SI-units
2. Plotting of various information
3. New integration of pressure loss and automatic decision. Calculation length through the use of 3-order and 2-order Runge-Kutta techniques.
4. Gas productivity is descibed in two new ways
5. Program testing

FRAGNOR/GENISYS Test installation

The Norwegian Petroleum Directorate has carried out a study to find a program system suitable for reservoir simulation of cracked reservoirs, in addition to fields with complicated liquid properties. The conclusion was a wish to test the program FRAGNOR from the firm FRANLAB. An agreement has been signed for 60 days' use on the Directorate's computer, and installation costs have been paid for such testing.

RSRS – entry

Assistance from consultants is necessary to keep the data base in RDRS (Reservoir Data Reporting System) operational and to enter the data sent by the companies on magnet tapes. The quality of the data must be checked and detailed procedures must be followed in order to avoid errors in the data base.

Water analyses – ring test

Previous water analysis projects have proven possible sources of error with testing and analysis of formation water. The purpose of this project was to evaluate the method used offshore and onshore for analyses of formation water and seawater, as well as obtaining better knowledge about accuracy and uncertainties by use of different analysis techniques.

Identical sets of water samples were sent to 10 laboratories for extensive analysis. The analysis results with information were processed and evaluated by Aquateam to decide possible types of errors and the reasons for these. Methods and laboratories were compared and the accuracy assessed. The results of the tests were presented at a meeting with the participants on 28 September and a report was prepared before the turn of the year.

The project was carried out without major problems. The test did not reveal any major disagreements in the analysis results, but it was made clear what parameters and methods could cause problems. The necessity of such a test with subsequent discussion was clearly present.

Reservoir monitoring requirements

An external consultant has been used to go through all reservoir data collected on three selected fields. This has been compared with the reservoir monitoring program which is imposed on the operators. The quality of the measurements has been assessed in addition to how carefully the requirements from the authorities have been followed with a view to reservoir monitoring.

Guidelines for rock mechanics tests

To follow up the work that has been done regarding the establishment of a data bank for the companies' results from rock mechanics tests and preparation of guidelines for execution of such tests, in addition to reporting, the Norwegian Petroleum Directorate has used an external consultant. This consultant has also made surveys and experimental studies to find the connection between pressure velocity and compaction and how knowledge about the lime reservoirs can be used for the sandstone reservoirs.

Technical and economic aspects of removing installations on the Norwegian continental shelf

This project is intended to assess the technical alternatives and constraints inherent in today's technology, as well as looking at the economics of removal of concrete installations. More specifically, the project focused on the following:

- Identification of parameters needing consideration when fully or partly removing concrete installations
- Examination of likely removal methods
- Assessment of costs of alternative removal operations

In addition, one has assessed measures needing to be implemented on installations which will remain in place after production has ceased. The project is part of the work the Norwegian Petroleum Directorate's "Final Phase Group" is conducting. The work is planned to end in 1989.

System for royalty calculation
The aim of this project is to go through present routines for royalty calculation and control. The intention is to organise the work in a better way with regard to efficiency and control, among other things by establishing a larger degree of data processsing of the tax routines.

During the first six months of 1988 a preliminary project was carried out for surveys of present routines of the mentioned areas. Rogaland Research Institute was used in the preliminary project.

Continuation of the project is being prepared with storage and reporting of historical data in addition to computerized automation.

Incentives in the operating phase – The overhead system
The aim of this project was to look at the incentive effects of the overhead system on the operator. A description has been given of how the overhead system can influence the incentives of the operator in various decision situations.

The costs of development and operation of petroleum fields include "overhead" to the operator. Overhead is coverage of costs for administration etc.

The project also illuminated whether the overhead system contributes to deviation from the partners', the state's and society's economic adaption.

Program development and maintenance of PPRS-2
A new menu system has been developed for the petroleum production report system (PPRS) in order to make the system easier to use.

Expert support within micro-computer technology
In connection with a review of regulations for fiscal measurements there was a need for support in the area of micro-cumputer technology. Since the regulations are an important work tool in connection with inspection operations, an external consultant with special expertise was brought in. The project has come up to our expectations.

Design criteria for test separators
In connection with the development of minor fields related to older installations, a proposal has been presented based on test separator fiscal measurements (Hod, Statfjord satellites). The Norwegian Petroleum Directorate has found it necessary to develop attitudes and guidelines for this type of measurement. This is to ensure a uniform treatment in the future. The project has been carried out to be used as a basis for the development of such guidelines. The results have come up to our expectations. A project report has been prepared.

Fabrication requirements for orifice plates
This is a multi-client project at the National Engineering Laboratory in Scotland in connection with fabrication requirements for orifice plates. The project includes the following:
- examination of edge sharpness upstream and downstream
- examination of trace in upstream surface
- examination of effect of local damage in upstream edge

The final report has not been received.

6.1.4 Planning Branch

PROJECT TITLE	PROJECT IMPLEMENTATION AGENCY
Phase-in of development projects under uncertainty	SINTEF
Market potential for Norwegian LNG in the US	ECON
The British gas market in the light of institutional changes	Coopers & Lybrand
Delivery pattern related to offshore activity	Novatek A/S
Macro-economic consequences in connection with changed delivery patterns relating to offshore activity	Asplan Stavanger A/S Asplan Analyse A/S
World Hydrocarbon Resource Project	Nopec A/S
Cost data for global resources	Chr. Michelsens Institute

Phase-in of development projects under uncertainty
Planning of operations on the Norwegian continental shelf must take account of many uncertainty factors which require careful consideration of the planning concept, attention to goal formulation, and realizing that decisions in practice will follow upon one another in time. This project was designed to create a decision tool of assistance in such planning – a model that, instead of generating a set of decisions for the entire timespan of the plan, says what decisions should be made later in the light of information not available now, but available then. Development of the model may be termed dynamic programming using stochastic state variables. The work will be completed in 1989.

Market potential for Norwegian LNG in the USA
In 1987 work was started on surveys of the possibilities of LNG exports to the USA. The work was implemented by using a Norwegian researcher for the study which is being carried out under the direction of the Energy Modelling Forum at Stanford University (EMF9) to examine the American gas market.

The study has covered institutional conditions and analyses of the supply and demand situation for natural gas. From a Norwegian point of view it was particularly interesting to illuminate the cost situation for Norwegian LNG compared with competitors in the market. The study was carried out in close cooperation with the Ministry of Petroleum and Energy.

The British gas market in the light of institutional changes
The intention of the study was to determine the importance for future gas sales of major institutional changes which taken place, and which are being planned in the UK. This includes privatisation of British Gas (BG), planned privatisation of the electric power sector and certain changes in the rules for BG. The study was carried out in close cooperation with the Ministry of Petroleum and Energy.

Delivery patterns in connection with offshore operation
The study intended to assess the demand for main components which future development paths may create. The need to assess this on the basis of expected technological and cost development was stressed.

The study showed, among other things, that a change from today's traditional modules to larger modules and integrated decks can be expected. Floating platform bases may constitute a significant part of the base market in the future at the expense of fixed platform bases of concrete or steel.

World Hydrocarbon Resource Project
The aim of the project is to determine the oil resources in the various geographical regions of the world and particularly cost classification for future oil fields. Such a survey will enable us to make certain conclusions about the potential long-term oil supply at different oil price developments. The analysis will also give certain indications of the future cost competion situation for new Norwegian oil discoveries. This knowledge will be a useful contribution to the planning of a future exploration strategy on the Norwegian continental shelf.

6.1.5 SPOR

PROJECT TITLE	PROJECT IMPLEMENTATION AGENCY
Water injection (SPOR-WATER)	Rogaland Research Institute
Gas injection (SPOR-GAS)	Institute for continental shelf surveys and petroleum technology (IKU)
Optimizing of reservoir data (SPOR-OPT)	Institute of Energy Technology IFE)

Large activities were shown in the SPOR program in 1988, a state research and development program which started in 1985. Through expertise building up, research and development of new technology SPOR is intened to provide the basis for increased oil production.

Up to now the program has used NOK 60 million. The funds are granted from the budget of the Ministry of Petroleum and Energy. In 1988 the Norwegian Petroleum Directorate and other affected bodies proposed to extend the program period from 5 to 7 years in order to obtain the efforts and results which were the prerequisites at the start of the program.

The implementation of the SPOR program has given major positive side effects for the work with increased oil production both in the Norwegian Petroleum Directorate and in companies involved on the Norwegian continental shelf. Results from SPOR also form the basis of Norwegian participation in international cooperation, for example International Energy Agency (IEA), and for cooperation with individual countries, for example the US.

6.2 SAFETY AND WORKING ENVIRONMENT DIVISION

PROJECT TITLE	PROJECT IMPLEMENTATION AGENCY
Norwegian Electrotechnical Committee (NEK) – membership	Norwegian Electrotechnical Committee
CIRIA-UEG (SFM)	CIRIA-UEG
Systematic development of regulations (SS)	Norwegian Petroleum Directorate
WOAD – Worldwide offshore accident data bank	Det norske Veritas
Total safety assessments	SikteC a/s
Welding Institute	Welding Institute
Arctic drilling onshore	Norwegian Petroleum Directorate
Deep diving	Norwegian Petroleum Directorate
Manned underwater operations international cooperation	Norwegian Petroleum Directorate
Working environment for divers	Norwegian Petroleum Directorate
Analysis and follow-up of damage/ accident data	Norwegian Petroleum Directorate
Improvement of reliability of instrumentation for establishment of gas in mud	Norwegian Petroleum Directorate
Consequences of shallow gas discharges in the sea	Veritec
Assessment of new equipment and new technology for drilling and well-related activities	Norwegian Petroleum Directorate
Influence of welding on materials' performance offshore	Cranfield Institute
Fiber optics systems	Veritas/SINTEF
Toughness requirements for offshore steel structures	Norwegian Petroleum Directorate Department of Energy/ Netherlands IndCouncil for Oceanology
Expert system for assessment of corrosion risk of pipeline designs	Cranfield Institute
Acceptance criteria for documentation of chemical health hazards	Nordcal
Future accommodation quarters	Norwegian Rig Consultants
Administrative standards for 12-hour shifts	SINTEF

PROJECT TITLE	PROJECT IMPLEMENTATION AGENCY
Criteria for establishment of safety zones	SINTEF
Material technology offshore	SINTEF/NTH
Automatisation of drilling operations	Rogaland Research Institute
Experienced risk and safety	Norwegian Petroleum Directorate
Survey of hurricanes on the continental shelf	Norwegian Petroleum Directorate
Reliability of structures	NGI, Veritas
Data base for malfunction of safety systems	SINTEF
Design criteria for corrosion risks	SINTEF/Siktec a/s
Internal inspection and quality assurance	Norwegian Petroleum Directorate
Design curve for fatigue of cathodic protected structures	SINTEF
New materials in pipelines	Norwegian Petroleum Directorate
High tensile steel – welding properties	SINTEF
Precision of fracture mechanics testing methods	SINTEF/Nordtest
Data imports – data analysis expertise exports	Norwegian Petroleum Directorate
Further development of the Technical and working environment Branch	Norwegian Petroleum Directorate
Guidelines for emergency preparedness	Scandpower

Norwegian Electrotechnical Committee (NEK) – membership
The Norwegian Petroleum Directorate's membership in NEK shall among other things ensure that the regulations in this area at all times are developed in step with technical developments and international practice and experience. The importance of this is stressed by the Norwegian efforts to satisfy the commitments according to the agreement for technical trade obstacles within EFTA.

CIRIA/UEG
The Construction Industry Research and Information Association (CIRIA) is a British industry association for consultants, contractors, companies in the construction industry and public authorities. The objective of the association is to encourage research, provide information and give advice to the members and the construction industry in general.

The Norwegian Petroleum Directorate has since 1980 been a member of the subgroup Offshore and Underwater Engineering Group (UEG). The projects being managed by the UEG are highly relevant for the work tasks of the Norwegian Petroleum Directorate in this area. The professional collaboration which has been established and the source of information represented by CIRIA has been of great help in formulating reports and regulations. The Directorate participates in a project on operation inspection for subsea structures and installations.

Systematic development of regulations
The project has been referred to under 4.2.2.

WOAD – Worldwide offshore accident data bank
The Norwegian Petroleum Directorate subscribes to this data bank which is operated by Veritec a/s. Background data from this bank will be of great value in connection with evaluation of safety studies and such conducted by the operator companies in the different project phases for priority of inspection areas and for regulation work.

Total safety assessments
The aim of the project is to consider systems and methods for treatment and control of total safety assessments which the Norwegian Petroleum Directorate has been delegated authority to make, in order to satisfy quality assessments, use of resources and goal achievements in this work. The project initially looked at the treatment of individual decisions towards the licencees and advice to the authorities in the various phases of activities, as well as development of remedies in this connection.

Welding Institute
The Norwegian Petroleum Directorate has been a member of the Welding Institute in Great Britain since 1981. This welding institute is a leader in offshore areas and is very actively involved in research, education and consultancy services. Membership gives access to consultancy assistance, project participation and current information on the newest developments of materials and welding technology.

Arctic drilling on shore
The project shall make surveys and systematize experience from arctic drilling on shore. The results will be used to attend to the Directorate's inspection responsibility in relation to drilling operations on Svalbard.

Deep diving
The project embraces assessment of health surveys in connection with deep diving and long-term effects, as well as criteria for selection of divers. The project shall also follow up development of new technology in the area, in particular the use of hydrogen as inert gas in breathing gas.

Manned subsea operations – international cooperation
The project continues the work with standardization, primarily of qualification requirements, procedures and technical solutions for improvement of the total safety when carrying out manned underwater operations.

Working environment for divers
The project will be continued with a view to collecting and formulating proposals or guidelines on how the most important stress factors for divers in saturation can be reduced or eliminated.

Analysis and follow-up of damage/accident data
A system for active use of the existing damage/accident registration system is to be established, both internally in the Norwegian Petroleum Directorate and externally towards industry and in research circles.

Improvement of reliability of instrumentation for establishment of gas in mud
The project aims at a general improvement in the reliability of instrumentation for showing gas in mud and includes quantity measurements of mud return, improvement of data presentation, as well as development of an expert system for the drilling process and mud system.

Consequences of shallow gas discharges in the sea
The project is a continuation of the Norwegian Petroleum Directorate's shallow gas program. The intention is to determine whether shallow gas in the sea can be released and lead to gas concentrations on installations, and thus represent fire and explosion risks.

Assessment of new equipment and new technology for drilling and well-related activities
Through the project the Norwegian Petroleum Directorate aims to further develop areas of rapid technological development, such as well inspection, well maintenance, extended reach drilling, horizontal drilling, "hot tapping" in addition to subsea completion, maintenance and abandoning.

Influence of welding on material properties offshore
The Norwegian Petroleum Directorate is participatin in the project "The Influence of Welding on Materials Performance Offshore", phase 2, directed by the Cranfield Institute in Great Britain. Phase 2 will examine the weldability and similar qualities of new high tensile, low-alloy steel, HSLA-steel, steel with accelerated cooling, combinations between these and cast as well as forged components. Focus will be on possibilities of improving weldability and cost reductions.

Fibre optics systems
The aim of the project is to establish guidelines for use of fibre optics in censors and communications systems offshore, and includes, among other things, a survey of environmental conditions, construction principles, system arrangements, instrumentation systems, installation, maintenance and repair. The implementation of the project is in collaboration with industry which provides major financial support.

Toughness requirments for offshore steel structures
The project is a cooperation between the Norwegian Petroleum Directorate, the Department of Energy, Netherlands Industrial Council for Oceanology in addition to 7 oil companies. Through collection and processing of data from toughness or fracture mechanics testing, the aim is to find the best suited test methods and which values from the testing are of structural importance. This will then form a basis of simpler, more uniform and generally accepted toughness requirements.

Expert system for assessment of corrosion risk on pipeline designs
The project is carried out at the British Cranfield Institute of Technology, and financed by British oil companies, the Department of Energy and the Norwegian Petroleum Directorate. The objective is a practical expert system for assessment of corrosion risks in pipelines, which can be used in evaluation of documentation by the licencees in this area both in the construction and the operating phase. Through the project the Directorate also expects to increase its own expertise in an area in which computer use is increasing rapidly.

Acceptance critieria for documention of chemical health hazards
The project shall make surveys of systems and practice for development and distribution of toxicological knowledge about chemicals used offhore. This will form the basis of determination of quality requirements for information about chemical health hazards and will be used as a basis for legislation development in this area.

Future accommodation quarters
The Norwegian Petroleum Directorate's provisional regulations for accommodation quarters date back to 1979. The industry has started to use new methods and is gaining experience from accommodation solutions where new departments have become involved in planning or transfer of experience. Surveys will be made of progess and development of accommodation quarters on offshore installations.

Administrative standards for 12-hour shifts
The aim of the project is to develop guidelines on how to assess 12-hour shifts compared with 8-hour standards with a view to exposure to chemicals.

Criteria for establishment of safety zones
The aim of this project is to establish a decision-making tool for determination of safety zones with uncontrolled blow-outs. The intention is that available rescue resources shall operate as efficiently as possible, at the same time as the usual traffic and activities are not obstructed by unnecessary safety zone size.

Materials technology offshore
The Norwegian Petroleum Directorate is participating in the pre-project of SINTEF/NTH's project "MATOFF 2000", which intends to coordinate and increase efficency of all ongoing and future research activities in Norway concerning all types of materials for use in petroleum activities offshore.

Automation of drilling operations
Mechanization of drilling operations has so far not brought the desired effects with a view to reductions in damage. A real decline in drilling related accidents can only be reached by making methods and equipment in drilling activities conform with modern technology. The project aims to devlop an automatic drilling installation which will be a model for future drilling machines.

Experienced risk and safety
The project shall make surveys of the risk connected to the experienced risk, by examining whether there is a connection between risk and damage or wrong actions. It is expected that the results will trigger the operators to take steps within the problems which are revealed. Furthermore the Norwegian Petroleum Directorate will strengthen its own expertise in this area.

Survey of hurricanes on the continental shelf
The project shall extend the basis of documentation for wave measurements on the continental shelf from the present basis which is limited to 5–10 years, to include other documentation from the last century, for example by means of observations from the lighthouse service. The purpose is to obtain a better basis for determinating the "hundred-year wave", which is an important construction criterion on the continental shelf.

Reliability of structures
The Norwegian Petroleum Directorate is participating in a project under the direction of the Norwegian Geotechnical Institute (NGI) and Veritas Research, aiming to develop a calculation tool for calculation of reliability of different structures, in addition to "calibration" of the load and material factor in the regulations of the Directorate on load-bearing structures.

Data-base for malfunction of safety systems
The project aims to establish a data base for failure of components, systems and operative errors of the safety systems which have resulted in damage, risk of damage, stoppage or reduction of production. The data base is expected to be a valuable tool both for internal and external users in the safety analysis of offshore production installations.

Design criteria for collision risks
Design criteria for collision risks have not been satisfactorily taken care of by the existing regulations. The intention is to obtain a model which will give an acceptable probability of accuracy regarding collision risk on the continental shelf.

Internal inspection and quality assurance
The intention of the project is a further development of the Norwegian Petroleum Directorate's own expertise in special fields. Contact will be established with research circles in the area, literature searches and literature studies will be made in international data bases, in addition to study visits to Swedish and French nuclear power industries.

Design curve for fatigue of cathodic protected structures
The Norwegian Petroleum Directorate is participating in a project under the auspices of SINTEF with support from the oil industry. The aim is to determine the effect of cathodic protection on the fatigue lifetime of welded pipe joints. The design curve for cathodic protected constructions in the Regulation for load-bearing structures etc, will be assessed and revised on the background of the results from the project.

New materials in pipelines
The project is intended to gain knowledge of the limitations of new pipeline materials concerning inspection possibilities, fatigue resistance, heat resistance, tensile yield strength etc. Such knowledge will be a prerequisite for a satisfactory treatment of new projects to be presented to the Directorate.

High tensile steel – welding properties
The Norwegian Petroleum Directorate will contribute to a SINTEF project aiming to clarify the possibilities of reducing the use of preheating in the welding of low-alloy high tensile steel, as well as establishing recommendations for choice of admixing materials for the welding of high tensile steel. At the same time the Norwegian Petroleum Directorate will contact other countries' authorities and other institutions to make surveys and recommendations which can be used in the legislation work.

Precision of fracture mechanics testing methods
The Norwegian Petroleum Directorate is contributing to SINTEF/Nordtest's project aiming to specify the weaknesses of present fracture mechanics test methods and present proposals for improvements. The result will be of importance to the Petroleum Directorate's legislation for load-bearing structures.

Data import – data analysis – expertise exports
The project is intended to contribute to the establishment of a harmonized system for data collection, data analysis, in addition to internal and external use of data within the frameworks of the Norwegian Petroleum Directorate's safety and working environment inspections on the continental shelf.

Further development of The Technical and Working Environment Branch
The project aims to reveal whether the branch's organisation, resources, coordination and expertise way covers the assigments. This is a natural continuation and follow-up of the re-organisation carried out in 1986 in the Safety and Working Environment Division. The result will be used for further development of personnel and organisation.

Guidelines for emergency preparedness
The project was completed at the end of 1987. The report was presented to the parties concerned and other interested groups at a one-day seminar at the Directorate in January 1988. So many visitors came to the seminar that the number of participants had to be limited.

6.3 ADMINISTRATION BRANCH

PROJECT TITLE	PROJECT IMPLEMENTATION AGENCY
North Sea seabed clearance	Norwegian Petroleum Directorate

Seabed clearance
The Norwegian Petroleum Directorate's clearance of the seabed in 1988 north east of the Viking Bank concentrated on an area south east of the Gullfaks field, bordering in the south on the area where clearance was carried out in 1986. The area was chosen on the recommendations of fishing organsiations and fishery authorities. Following a survey using lateral sonar, obstacles were singled out for identification by a remote controlled submersible vehicle. Dynamically positioned vessels and remote controlled submersible vehicles were then used to lift the objects considered most likely to hamper efficient fishing in the area.

Following completion of the clean-up, the remaining budget was used to continue the the work already initiated of retrieving piping from the Egersund Bank. This involves a large accumulation of steel pipes, very likely a deck cargo lost overboard in rough sea. These pipes were located during the official clearance operation in 1985, when 21 pipes were recovered. In 1986 55 pipes were removed, in 1987, 127, and the year after 75. Systematic search in the area did not recover any more pipes.

As in 1987 the pipes have been given free of charge to the National Highways Authority. Previously the highways authority has received over 120 pipes and most of these have been used by the authority for various purposes such as road construction, drain pipes etc.

A large iron structure which was previously located on the Egersund Bank, at a depth of 290 metres, was removed in 1988 by a rented supply vessel.

A further strenghtening of the collaboration with the Norwegian Hydrographic Service has been effected through the use of the organisation's vessel M/S "Lance" in 1988 in the sonar surveying of the seabed. The clearance assignment was awarded to Bergen Underwater Services A/S, Bergen.

The Clearance Steering Committee has consisted of representatives from the Norwegian Petroleum Directorate, the Fishery Directorate, the Norwegian Hydrographic Service, the Norwegian Union of Fishermen, and the Norwegian Industry Association for Oil Companies (NIFO).

The official clearance operations continue to command the keen attention of fishermen and the media. The clearance has been mentioned in the British fishery press, which again has resulted in inquiries from British organisations. During a visit to Norway, Canadian authorities were informed about the clearance.

7 International cooperation

7.1 ASSISTANCE TO FOREIGN STATES

In 1988 the Norwegian Petroleum Directorate's involvement in the Norwegian Development Aid, NORAD, was concentrated on the following countries: Tanzania, Mozambique, Bangladesh, Nicaragua, Costa Rica, Angola and the Seycelles.

In these countries the Norwegian Petroleum Directorate was concerned with (1) general data processing, (2) processing and storage of seismic data tapes, (3) data interpretation, (4) guidance to consultants conducting interpretational and seismic processing work, (5) help in building a biostratigraphic laboratory (Tanzania), (6) support in follow-up drilling activities (Mosambique), (7) and guidance to NORAD-supported consultants in Mozambique and Tanzania.

The Norwegian Petroleum Directorate has continued the work of establishing a training facility for supervisors in developing countries. The trial period for the project, which will be under the adminstration of the Norwegian Petroleum Directorate, will start at the beginning of 1989.

The Norwegian Petroleum Directorate's main efforts have been in the following countries:

a) Tanzania

Assistance to TPDC for planning and collection of seismic data on shore. Development of a biostratigraphic laboratory, in addition to strengthening the exploration division of TPDC through active participation in evaluation of various sedimentation basins in the country. The follow-up of a filing system for geophysical data in TPDC has been continued.

b) Bangladesh

As part of the development of the Bangladesh Petroleum Institute (BPI), the Norwegian Petroleum Directorate has actively contributed to organising potential projects which BPI will be involved in, and has contributed to arranging courses in geochemistry in Dacca in the autumn of 1988.

c) Central America

The Norwegian Petroleum Directorate has participated in assessments of projects in the petroleum sector in Costa Rica and Nicaragua. A preliminary evaluation of existing data from the west coast of Nicaragua has been prepared with a view to future involvement.

7.2 SAFETY AND WORKING ENVIRONMENT

7.2.1 Introduction

The Norwegian Petroleum Directorate has a comprehensive collaboration with international professional institutions and political/ technical bodies, either directly or indirectly through other Norwegian authorities.

The object of this collaboration is:

a) To contribute to ensuring that safety and working environment conditions in the petroleum activity as a minimum requirement satisfy recognised international standards.
b) to ensure access to relevant information for expertise development and legislation development.
c) to contribute our insight and expertise to the outside world and exert a positive influence on safety and working environment.

In the main, collaboration has consisted of participation in international cooperation with authorities in Europe and in UN contexts, plus more direct cooperation with various types of international and regional professional instituations. The most important partners hitherto have been:

a) The Common Market Commission, in collaboration with the Ministry of Local Government and Labour on safety and working environment
b) The UN organisations IMO and ILO on maritime safety and working environment respectively, from 1979/1980.
c) EDTC and AODC on diving safety, from 1983
d) CIRIA/ UEG (UK) on inspection and maintenance of installations, from 1980
e) Welding Institute (UK) on research and development of materials and welding, from 1981
f) API (USA), participation in annual conferences on petroleum subjects in addition to standardisation, from 1979
g) NACE (USA), participation in annual conferences on corrosion and surface treatment, from 1984
h) CENELEC, cooperation on electrical technology standardisation in Europe via the Norwegian Electrotechnology Committee (NEK).
i) CCOP/ASCOPE/ NECOR, participation in the UN cooperation on safety questions for a group of East Asian countries, from 1985.

Further descriptions of the institutions and the content of the cooperation is to be found also in previous annual reports of the Norwegian Petroleum Directorate.

It is particularly within the fields of diving, drilling, production, electronics, materials technology and operational inspection that the Safety and Working environment Division has enjoyed considerable professional collaboration with foreign bodies. Also within other of the Division's areas of responsibility, however, there has been considerable international contact, with exchange and transfer of experience and discussion of problems.

7.2.2 The EEC (the European Economic Community)

From 1982 Norway has had observer status in the organised EEC conference activity with the main emphasis on "Safety and Health in the Oil and Gas Extraction Industries". The Norwegian Petroleum Directorate has taken part in Norwegian delegations to meetings and has in particular followed the work of harmonising of safety requirements etc related to petroleum activity at sea, where experience has been discussed and exchanged with regard to industrial injury statistics, training requirements etc. This EEC-orchestrated activity also includes a number of matters previously dealt with by the North-West European Cooperation.

In 1987 the Ministry of Local Government and Labour started formal cooperation with the EEC Safety and Health at Work Commission. The cooperation embraces exchange of experience with a view to harmonisation of provisions in regulations and standards. The Norwegian Petroleum Directorate participates as an observer in the annual meetings, but can also raise questions of interest as a part of the ongoing collaboration within the agreement between the Ministry and the Commission.

In the EEC's new system for regulations harmonisation, which came into force in 1987, a formalised cooperation with the EFTA countries is included, and this is likely to embrace the petroleum sector, too. This formal partnership with the EEC Commission through the Ministry of Local Government and Labour will therefore be of significance for the Norwegian Petroleum Directorate's own development of regulations.

7.2.3 The International Maritime Organization IMO

The IMO is a special agency in the UN system whose primary task is to work for better safety and measures against pollution at sea. The main thrust of IMO's activities is directed at vessels and shipping, but some of its activities are also of relevance to the offshore petroleum activities.

The petroleum-related part of the IMO's business is transacted mainly in the Maritime Safety Committee and its technical subcommittees. As a member of the Norwegian delegation to the IMO, the Norwegian Petroleum Directorate has taken part in the committee work of three of the subcommittees in the fields of personnel training, diving, construction of mobile installations and removal of permanent installations.

In 1988 the Norwegian Petroleum Directorate participated in the work on revision of the IMO standard for mobile drilling installations and in a committee in which removal of permanent installations has been discussed.

The Norwegian Petroleum Directorate also participates in the work of developing an IMO standard for training of key maritime personnel on mobile installations. The work is to be finished in 1989.

Furthermore, the Directorate has participated in the work on detailed formulation of international guidelines for safety zones around installations for petroleum activites offshore. A separate work group has been established and the work is expected to be finished in 1989.

7.2.4 CCOP/ASCOPE/NECOR

The Petroleum Directorate participates in a program for development of safety regulations for petroleum activities under the auspices of the United Nations' system of agencies. This particular program is directed at East Asian countries (Thailand, Malaysia, Indonesia, the Philippines and China) and is administered by CCOP/ASCOPE/NECOR.

NECOR is the Norwegian subdivision of ECOR, the Engineering Committee on Oceanic Resources, the UN advisory subcommittee for exploitation of subsea resources. Norwegian authorities contributed roughly one million kroner to the program in 1988.

A work program extending over five years from 1985 was set up in which individual countries develop laws and regulations in the areas of highest priority. The Petroleum Directorate will take part in this activity using specialists in the individual fields so as to assist the implementation of the program.

7.2.5 EDTC – European Diving Technology Committee

The Petroleum Directorate has worked actively in this group, in which most European nations participate. The objectives of the organization are to make recommendations to member countries in questions regarding diver safety. Work is done to improve harmonization and standardization designed to improve safety of diving operations.

7.2.6 Electrical norms and regulations

The Norwegian Petroleum Directorate is participating in the work to establish new legislation of electrical equipment in explosive areas. The work is carried out under the auspices of CENELEC – the Comité Europeén de Normalisation Electrotechnique.

7.3 ISO – THE INTERNATIONAL STANDARDISATION ORGANISATION

The Petroleum Directorate is participating in the work of standardization of technical measurement performed by the International Standardisation Organisation ISO. International standards apply for metering of oil and gas. To assist the further development of international standards, the Directorate sits on the technical committees working with oil and gas measurement.

In order to make Norwegian work in this area more efficient, a national measurement technology forum has been set up in which the Directorate participates.

8 Statistics and Summaries

8.1 UNITS OF MEASUREMENT

The Norwegian Petroleum Directorate normally utilises the units of the International System of Units, the SI system, which are also recommended for use by the oil companies operating on the continental shelf. For historical reasons, however, the use of other units than those allowed by SI is strongly entrenched in the petroleum industry.

Certain terms and abbreviated expressions occurring in connection with production data for oil and gas related to the units of measurement are briefly commented on below.

Measurement – oil

An exact measurement of an oil quantity by volume must refer to a more closely defined measuring state characterised by pressure and temperature. This is necessary because the volume of an oil quantity varies both with temperature and pressure. The temperature and pressure the petroleum volume is referred to, is called the volume's reference state. The most common reference states are: a) 60 °F, 0 psig, and b) 15 °C, 1.01325 bar.

Other pressure and temperature reference states may also occur. It should be noted that expressions like "standard state" , "barrels at standard conditions" etc. are ambiguous unless standard pressure and temperature conditions are defined.

Reference condition b) is recommended for use by the International Standardisation Organisation, ISO, and in 1979 these standard conditions were introduced as Norsk Standard NS 5024. The Norwegian Petroleum Directorate is making efforts to establish the use of this reference condition in the petroleum industry.

The exact conversion of an oil volume from one condition to another requires the use of special tables. As a first approximation, however, a factor of one can be used for conversion from 60 °F, 0 psig to 15 °C, 1.01325 bar.

Commonly used abbreviations:

Sm^3 = Standard cubic metre. Temperature and pressure must be stated to make the unit unambiguous.

Barrels at standard conditions = Barrels at standard conditions, generally 60 °F, 0 psig. (Traditional US unit).

Conversion:

1 Sm^3 corresponds to approx 6.29 barrels at standard conditions.

Measurement – gas

To an even greater extent than for oil volumes, the numerical value of a gas volume will depend on the pressure and temperature the volume is referred to. Four reference states are normally employed: a) (60 °F, 14.73 psia), b) (60 °F, 14.696 psia), c) (15 °C, 1.01325 bar), d) (0 °C, 1.01325 bar). The reference states a), b) and c) are usually termed "standard conditions", d) "normal conditions".

It is not possible to convert one volume to another without knowing the physical characteristics of the gas. For estimates, however, one can consider a volume of a given gas quantity approximately equal in states a), b) and c), and about five per cent less in state d).

Commonly used abbreviations:

SCM or Sm^3 =	Standard cubic metre.
Nm^3 =	Normal cubic metre.
Scf =	Standard cubic foot.

Temperature and pressure must be specified to make the units unambiguous.

Conversion:

1 Sm^3 corresponds to approximately 0.95 Nm^3.
1 Sm^3 corresponds to approximately 35.3 Scf.

Quality measurement – oil and gas

Density or relative density is often used to describe the composition of an oil or gas. A low density value indicates that the oil or gas is made up of light components.

Oil:

(a) "Specific gravity " 60/60 °F:
The relative density of oil related to water.
Oil and water at a temperature of 60 °F and pressure corresponding to the atmospheric pressure of the site of measurement. The figure is undenominated.

(b) "API-Gravity" at 60 °F:
Specific Gravity expressed on an enlarged scale, in °API units. Converted by using the following formula:

$$\text{API Gravity at } 60°\text{F} = \frac{141.5}{\text{Specific Gravity at } 60/60°\text{F}} - 131.5$$

(c) Density at 15 °C:
Absolute density at a temperature of 15 °C and pressure equal to atmospheric pressure at the measuring site.

Gas:

(a) "Specific Gravity":

The relative density of gas in proportion to air. The meaning of the term is not exactly defined unless temperature and pressure are stated. Very often, however, no temperature and pressure references are given for Specific Gravity, but this is of little importance for rough estimates, since the difference is small between commonly used standard conditions.

Expression of oil and gas in oil equivalents

Oil and gas are often measured in tons oil equivalents in contexts where exact registration of amount or quality is not required. The conversion is based on the amount of energy liberated in the combustion of the oil or gas. In many cases the energy content of one ton of oil and gas is close to that of one thousand Sm^3 of gas. This conversion factor is very simple to employ, all the time the quality differences between oil and gas are so great during processing, storage, distribution and use that it would not be correct to use many digits when reporting the converted figures. Common practice is therefore:

One ton oil equivalent (t.o.e) corresponds to one ton of oil or one thousand Sm^3 of gas.

8.2 EXPLORATION DRILLING STATISTICS

A total of 598 exploration wells have been spudded on the Norwegian shelf since exploratory drilling started in 1968 in the Norwegian sector of the North Sea. 594 exploration wells were concluded as of 1 January 1989, of which 429 were exploration wells and 169 appraisal wells. 27 wells were suspended for different reasons. Some were suspended for later testing, possible completion as a production well or later extension or plugging. At year's end four exploration wells were being drilled. The northernmost exploration well on the Norwegian shelf is 7321/7–1, being drilled in 1988 with Mobil as operator.

The exploration wells were drilled by eighteen different operating companies. Fig. 8.2.a shows the distribution of the number of exploration wells for each operator, Fig. 8.2.b shows the Norwegian operator companies' share of the drilling activities, and seasonal fluctuations in the drilling activities are shown in Fig. 8.2.c.

As of 1 January 1989 598 exploration wells had been drilled with a total length of 1,903,503 metres. During 1988 110,324 metres were drilled, corresponding to an average depth of 3,335 metres for the 29 exploration wells concluded this year. The deepest bore on the Norwegian shelf, Well 30/4–1, was drilled by BP as the operator and completed in 1979 with a total depth of 5,455 metres. A summary of the average total depth of wells drilled during the years 1966–1988 is presented in Fig. 8.2.d.

In 1988 the exploration wells were drilled at an average water depth of 200 metres. The maximum

Fig. 8.2.a
Operators on the Norwegian continental shelf. 598 exploration wells drilled as of 31 December 1988

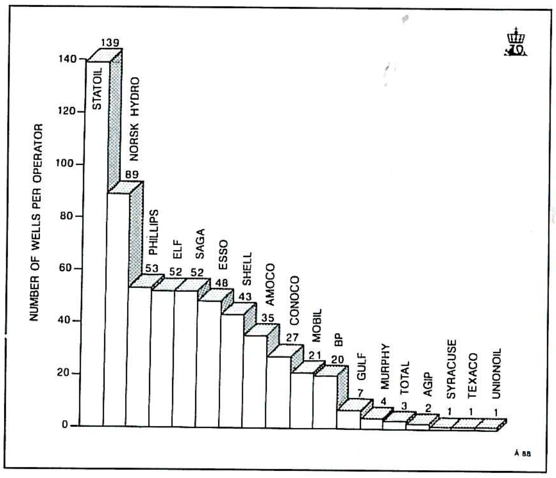


Fig. 8.2.b
Participation of Norwegian operator companies in drilling activity. Per cent of operating days. 1975–88

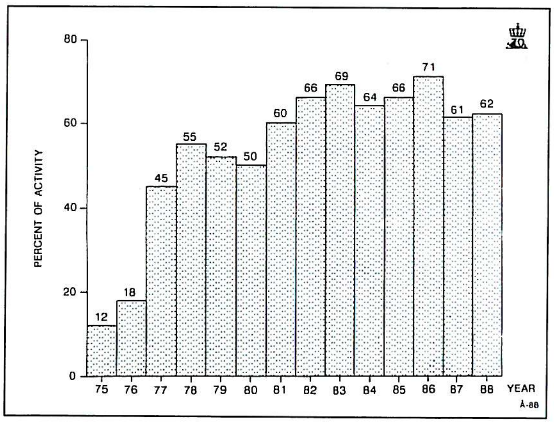


Fig. 8.2.c
Seasonal variations in exploration drilling activity 1966–1988

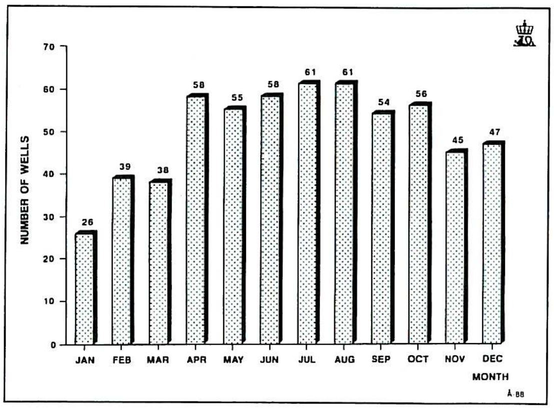


Fig. 8.2.d
Average total depth per year. Exploration drilling 1966–88

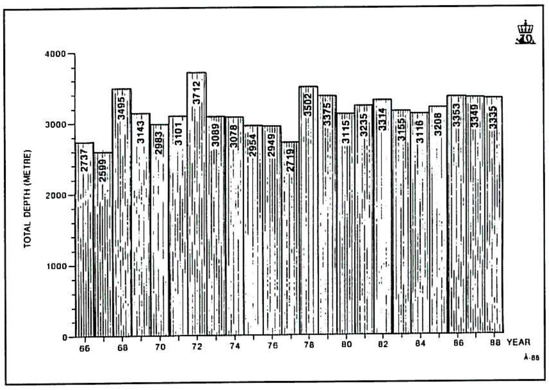
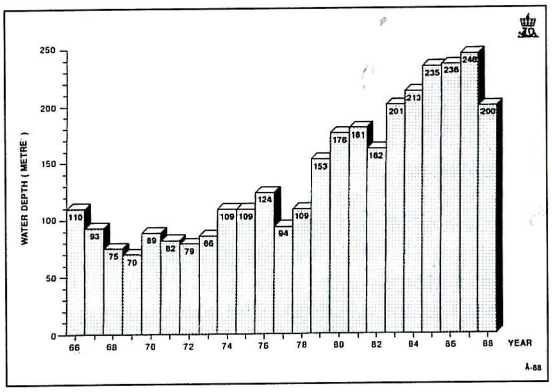


Fig. 8.2.e
Average water depth per year. Exploration wells 1966–88



depth until now is 468 metres for the exploration well 7321/8–1, being drilled in 1987 with Norsk Hydro as operator. Fig. 8.2.e shows the increase in the average water depth of wells drilled during 1966–1988.

63 different drilling platforms have been used on the Norwegian shelf, six of them under two different names. 45 were semi-submersibles, 11 jack-ups, 5 drillships and 2 fixed installations.

The tables 8.2.a to 8.2.e present exploration drilling statistics on the Norwegian continental shelf.

8.3 PRODUCTION DRILLING STATISTICS

Since drilling of production wells began in the Norwegian sector of the North Sea in 1973, 488 wells in all have been spudded. Of these wells, 313 are production (oil, gas and condensate), 53 are water or gas injection, four are observation/production wells,

Table 8.2.a
Exploration wells spudded as of 1.1.1989

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	Total
Exploration	2	6	10	12	11	11	11	17	13	17	20	12	14	18	26	26	36	33	35	30	26	25	18	429
Appraisal			2	1	6	5	3	5	5	9	3	8	5	10	10	13	13	7	12	20	10	11	11	169
Sum	2	6	12	13	17	16	14	22	18	26	23	20	19	28	36	39	49	40	47	50	36	36	29	598
Production								1	18	24	7	34	50	36	28	16	22	23	33	47	46	48	55	488
Total	2	6	12	13	17	16	14	23	36	50	30	54	69	64	64	55	71	63	80	97	82	84	84	1086

Table 8.2.b
Exploration wells by operator as of 1.1.1989

Statoil	139	exploration wells
Norsk Hydro	89	"
Phillips	53	"
Saga	52	"
Elf	52	"
Esso	48	"
Shell	43	"
Amoco	35	"
Conoco	27	"
Mobil	21	"
BP	20	"
Gulf	7	"
Murphy	4	"
Total	3	"
Agip	2	"
Syracuse	1	"
Texaco	1	"
Unocal	1	"
	598	exploration wells

Table 8.2.c
Exploration wells spudded in 1988

Statoil	7	exploration wells
Norsk Hydro	6	"
Saga	5	"
Elf	3	"
Conoco	1	"
Mobil	1	"
Shell	1	"
Amoco	2	"
Gulf/Chevron	1	"
BP	2	"
	29	exploration wells

Table 8.2.d
Average water depth and total depth

Year	Average water depth (m)	Average total depth (m)
1966	110	2 737
1967	93	2 599
1968	75	3 495
1969	70	3 143
1970	89	2 983
1971	82	3 101
1972	79	3 712
1973	86	3 089
1974	109	3 078
1975	109	2 954
1976	124	2 949
1977	94	2 719
1978	109	3 502
1979	153	3 375
1980	176	3 115
1981	181	3 235
1982	162	3 314
1983	201	3 155
1984	213	3 116
1985	235	3 208
1986	236	3 353
1987	246	3 349
1988	200	3 335

one is a observation/injection well, 80 are temporarily out of commission, suspended for completion later or for other reasons and 23 are dry. Ten production wells were being drilled at the end of the year. Information on these production wells is set up in Table 8.3.a.

As of 1 January 1989 18 fields are producing, with 24 production platforms and three seabottom completions (North-East Frigg, East Frigg and Tommeliten). Three new fields came on stream in 1988 (Oseberg, East Frigg and Tommeliten).

55 production wells were begun in the year, as shown in Table 8.3.b.

Table 8.2.e
Drilling rigs that have been operating on the Norwegian continental shelf as of 1.1.1989

Name of drilling rig	No of wells	No of re-entries	Type of rig
Aladdin	1		Semi-submersible
Borgny Dolphin (prev. Fernstar)	25	7	"
Borgsten Dolphin (prev. Haakon Magnus)	6		"
Bucentaur		1	Drillship
Byford Dolphin (prev. Deepsea Driller)	15		Semi-submersible
Chris Chenery	2		"
Deepsea Bergen	14	2	"
Deepsea Driller (now Byford Dolphin)	8		"
Deepsea Saga	17	3	"
Drillmaster	6	1	"
Drillship	1		Drillship
Dyvi Alpha	17	2	Semi-submersible
Dyvi Beta	7	1	Jack-up
Dyvi Gamma	1		"
Dyvi Delta (now West Delta)	20	1	Semi-submersible
Dyvi Stena	9		"
Endeavour	2		Jack-up
Fernstar (now Borgny Dolphin)	3		Semi-submersible
Gulftide	3		Jack-up
Glomar Biscay II (prev. Norskald)	12	1	Semi-submersible
Glomar Grand Isle	11	3	Drillship
Glomar Moray Firth I	2		Jack-up
Haakon Magnus (now Borgsten Dolphin)	2		Semi-submersible
Henry Goodrich	2		"
Maersk Explorer	7		Jack-up
Neddrill Trigon	3		"
Neptune 7 (prev. Pentagone 81)	12		Semi-submersible
Nordraug	10		"
Norjarl	3		"
Norskald (now Glomar Biscay II)	26		"
Nortrym	33	3	"
Ocean Tide	5		Jack-up
Ocean Traveler	9		Jack-up
Ocean Victory	1		"

Name of drilling rig	No of wells	No of re-entries	Type of rig
Ocean Viking	29	1	Semi-submersible
Ocean Voyager	2		"
Odin Drill	3		"
Orion	7		Jack-up
Pelerin	1		Drillship
Pentagone 81 (now Neptune 7)	1		Semi-submersible
Pentagone 84	3	1	"
Polar Pioneer	16		"
Polyglomar Driller	11		"
Ross Isle	16	3	"
Ross Rig	34		"
Saipem II	1		Drillship
Sedco H	2		Semi-submersible
Sedco 135 F	2		"
Sedco 135 g	1		"
Sedco 703	3	1	"
Sedco 704	3		"
Sedco 707	6		Semi-submersible
Sedneth I	3		"
Transworld Rig 61	2		"
Treasure Hunter	5	3	"
Treasure Saga	29	1	"
Treasure Scout	23		"
Treasure Seeker	27	4	"
Vildkat	7		"
Vinni	4		"
Waage Drill I	2		"
West Delta (prev. Dyvi Delta)	5		"
West Vanguard	18	4	"
West Venture	11	2	"
West Vision	1		"
Zapata Explorer	13		Jack-up
Zapata Nordic	5		"
Zapata Ugland	5	1	Semi-submersible
	596	44	
In addition 2 exploration wells have been drilled from fixed installations			
Cod Platform	1	1	
Ekofisk B	1		
	598	45	

Table 8.3.a
Production drilling

Field	Total drilled	Spudded 1988	Producing	Injection/ (Observ.)	Drilling in progress	Suspend./ plugged/ compl.
ALBUSKJELL A +	11		8			3
ALBUSKJELL F +	13		7			6
COD +	9		6			3
EDDA +	10		7			3
EKOFISK A +	18		15			3
EKOFISK B +	26	2	17	(1)*		8
EKOFISK C +	17	4	7	4**	1	5
EKOFISK K +	17	6		10	2	5
ELDFISK A +	31	2	18		1	12
ELDFISK B +	24	3	16			8
FRIGG (UK) +	24		22			2
FRIGG +	26		21	(3)*		2
GULLFAKS A +	21	7	14	5	1	1
GULLFAKS B	5	4	4		1	
GYDA	6	5				6
HEIMDAL +	11		9	(1)***		1
N.E.FRIGG +	7		6			1
ODIN +	11		11			
OSEBERG B +	13	2	1			12
OSEBERG C	2	2			1	1
STATFJORD A +	38		22	13		3
STATFJORD B +	30	1	20	10		
STATFJORD C +	25	1	15	9		1
TOMMELITEN +	7	1	6			1
TOR +	15	1	10			5
ULA +	10	4	6	2(1)*	1	
VALHALL +	34	5	23		1	10
W. EKOFISK +	16	2	13			3
VESLEFRIKK	6	2			1	5
EAST FRIGG +	5	1	5			
	488	55	309	49	10	110

\+ FIELD PRODUCING
* OBSERVATION/PRODUCTION WELL(S)
** PRODUCTION/INJECTION WELLS, DEPENDING ON GAS SALES
*** OBSERVATION/INJECTION WELL(S)

309 wells producing (201 oil, 43 condensate and 65 gas)
49 wells are shut down/plugged
54 wells are injection wells (whereof 4 inj./prod.)
4 wells are observation/production wells
1 well is an observation/injection well
10 wells are drilling
1 well is shut down (10/1-A-12) and drilled deeper with British license no. and new designation (10/1-A-25)
31 wells are suspended at TD
1 well is suspended after setting of 9 5/8"
1 well is suspended after setting of 13 3/8"
1 well is suspended after setting og 20"
2 wells are suspended after setting of 30"
1 well is suspended with fish in 30" open hole
23 wells have never produced

488

Table 8.3.b.
Production wells spudded in 1988 (as of 1.1.1989)

Lic. No.	Production well no.	Spudded	Completed	Operator	Field
362	33/12-B-40	88.07.02	88.10.25	Statoil	Statfjord B
429	2/04-K-27	88.01.08	88.07.14	Phillips	Ekofisk
436	2/01-A-07 H	88.01.13	88.03.11	BP	Gyda
437	2/08-A-10 A	88.02.13	88.03.23	Amoco	Valhall
438	2/04-C-04	88.02.15	88.04.20	Phillips	Ekofisk
439	2/07-B-04	88.11.06	88.12.29	Phillips	Eldfisk
440	25/02-A-03	88.03.06	88.04.12	Elf	East Frigg
441	7/12-A-01	88.02.27	88.05.13	BP	Ula
442	1/09-A-06 H	88.02.20	88.04.18	Statoil	Tommeliten
443	2/01-A-05 H	88.03.18	88.05.05	BP	Gyda
444	34/10-A-14	88.02.25	88.04.14	Statoil	Gullfaks
445	2/04-D-08 A	88.03.18	88.04.15	Phillips	West Ekofisk
446	2/04-E-02 A	88.03.17	88.05.17	Phillips	Tor
447	2/08-A-23	88.03.23	88.07.05	Amoco	Valhall
448	2/07-B-13 A	88.04.04	88.06.30	Phillips	Eldfisk
449	34/10-B-02	88.03.25	88.06.15	Statoil	Gullfaks
450	34/10-A-15	88.04.17	88.10.05	Statoil	Gullfaks
451	2/04-C-07	88.04.24	88.07.15	Phillips	Ekofisk
452	2/07-A-04	88.05.07	88.06.24	Phillips	Eldfisk
453	2/01-A-04 H	88.05.05	88.06.18	BP	Gyda
454	7/12-A-05	88.05.15	00.00.00	BP	Ula
455	2/08-A-20	88.06.16	88.08.18	Amoco	Valhall
456	7/12-A-12	88.05.21	88.07.24	BP	Ula
457	2/04-K-21	88.05.26	88.07.03	Phillips	Ekofisk
458	34/10-B-03	88.06.03	88.07.30	Statoil	Gullfaks
459	34/10-A-16	88.06.08	88.11.10	Statoil	Gullfaks
460	2/04-D-15	88.06.23	88.09.01	Phillips	West Ekofisk
461	2/07-A-13	88.06.27	00.00.00	Phillips	Eldfisk
462	2/04-B-02 A	88.05.24	88.08.21	Phillips	Ekofisk
464	30/09-B-07	88.07.21	88.08.05	Hydro	Oseberg
465	30/09-B-42	88.08.06	88.08.23	Hydro	Oseberg
467	2/04-K-11	88.07.04	88.10.10	Phillips	Ekofisk
468	2/07-B-16	88.09.07	88.11.05	Phillips	Eldfisk
469	34/10-A-17	88.07.23	88.10.08	Statoil	Gullfaks
470	2/04-C-15 A	88.07.16	88.11.23	Phillips	Ekofisk
471	34/10-B-04	88.07.25	88.09.13	Statoil	Gullfaks
473	2/01-A-06 H	88.07.28	88.09.25	BP	Gyda
474	2/04-K-24	88.08.03	88.08.31	Phillips	Ekofisk
475	2/08-A-24	88.09.16	88.11.07	Amoco	Valhall
476	30/03-A-05	88.08.15	88.11.27	Statoil	Veslefrikk
477	7/12-A-04	88.09.01	88.11.11	BP	Ula
478	2/08-A-07 A	88.11.07	00.00.00	Amoco	Valhall
479	34/10-A-18	88.09.27	88.11.16	Statoil	Gullfaks
480	2/01-A-03 H	88.09.26	88.10.01	BP	Gyda
481	2/04-B-03 A	88.10.06	88.11.22	Phillips	Ekofisk
482	30/06-C-11	88.10.13	88.11.20	Hydro	Oseberg
483	2/04-K-05	88.10.11	88.11.28	Phillips	Ekofisk
484	34/10-B-05	88.10.25	00.00.00	Statoil	Gullfaks
485	33/09-C-15	88.10.25	88.12.18	Statoil	Statfjord
486	34/10-A-19	88.11.04	88.12.20	Statoil	Gullfaks
487	30/03-A-06	88.11.27	00.00.00	Statoil	Veslefrikk
489	2/04-C-06 A	88.12.28	00.00.00	Phillips	Ekofisk C
493	30/06-C-10	88.12.20	00.00.00	Hydro	Oseberg C
494	34/10-A-20	88.12.13	00.00.00	Statoil	Gullfaks A
492	2/04-K-10	88.12.12	00.00.00	Phillips	Ekofisk K

8.4 PRODUCTION OF OIL AND GAS

Production of oil and gas on the Norwegian continental shelf in 1988 was 85.1 x 10^6 toe. Production in 1987 was 77.8 x 10^6 toe.

Production on the Norwegian continental shelf is presented in more detail in Tables 8.4.a to 8.4.i and Figures 8.4.a and b.

The data in Table 8.4.a show the Norwegian share of Statfjord, Frigg and Murchison. NGL for the Ekofisk area, Murchison, Valhall and Statfjord are included in the figures for oil.

The figures for gas in Table 8.4.a indicate the amounts sold for all fields.

Condensate is included in the figures for the Frigg area.

Table 8.4.a
Production in mill. t.o.e.

1988	Oil	Gas	Total
Ekofisk area	9.513	8.393	17.905
Statfjord	29.668	3.365	33.031
Frigg area	0.000	11.314	11.314
Valhall	3.281	0.709	3.927
Murchison	0.393	0.022	0.415
Heimdal	0.000	4.076	4.036
Ula	4.423	0.361	4.784
Oseberg	0.961	0.000	0.961
Gullfaks	7.623	0.593	8.216
Tommeliten	0.188	0.255	0.443
Total 1988	55.953	29.088	85.041
Total 1987	49.025	28.795	77.820

Table 8.4.b
Monthly oil and gas production Vallhall

1988	Unstabilized oil	Prod. gas	Flared gas	Gas consumed fuel	Stable oil Teesside	NGL Teesside	Gas Emden
	1000 Sm³	Mill. Sm³	Mill. Sm³	Mill Sm³	1000 Sm³	1000 tons	Mill Sm³
JAN	344.	65.	3.	8.	317.	15.	57.
FEB	322.	65.	1.	8.	296.	14.	55.
MAR	339.	68.	1.	9.	313.	15.	59.
APR	329.	54.	1.	9.	302.	15.	65.
MAY	335.	74.	1.	9.	310.	14.	58.
JUN	302.	59.	1.	8.	277.	14.	50.
JUL	334.	68.	4.	9.	307.	14.	57.
AUG	341.	68.	1.	9.	314.	15.	59.
SEP	328.	66.	1.	9.	301.	15.	57.
OCT	341.	70.	2.	9.	314.	14.	61.
NOV	338.	61.	1.	8.	313.	14.	63.
DEC	360.	75.	1.	8.	335.	13.	68.
Year's total	4014.	793.	7.	104.	3698.	174.	709.

Table 8.4.c
Monthly gas and condensate production from the Frigg area

1988	Gas produced	Condensate produced	Gas flared	Gas fuel	Gas St. Fergus	Condensate St. Fergus
	Mill. Sm³	Sm³	Mill. Sm³	Mill. Sm³	Mill. Sm³	Sm³
JAN	1207.	2529.	0.	1.	1196.	5745.
FEB	1225.	2450.	0.	1.	1215.	3933.
MAR	1246.	2333.	0.	2.	1235.	5211.
APR	1225.	2513.	0.	1.	1215.	5465.
MAY	911.	1919.	0.	1.	925.	5061.
JUN	783.	1557.	0.	1.	792.	3709.
JUL	665.	1323.	0.	1.	647.	945.
AUG	604.	982.	0.	1.	605.	2302.
SEP	571.	1187.	0.	1.	569.	2959.
OCT	751.	1743.	0.	1.	743.	3467.
NOV	1061.	2253.	0.	1.	1058.	3993.
DEC	1082.	2473.	0.	1.	1076.	4422.
Year's total	11331.	23262.	2.	12	11276.	47213.

Figures are Norwegian share of Frigg, 60.82%, NE Frigg, Odin and East Frigg 100%.

Fig. 8.4.a
Oil and gas production on the Norwegian shelf 1971–1988

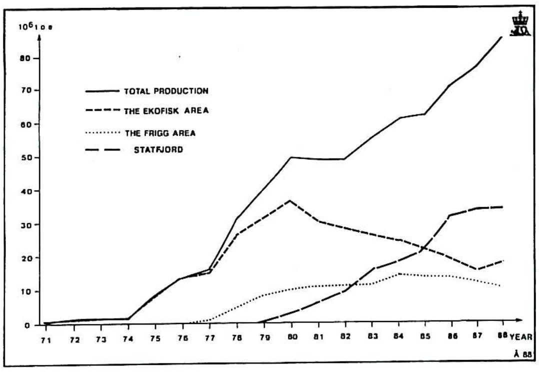


Fig. 8.4.b
Oil/NGL and gas production on the Norwegian shelf 1977–1988

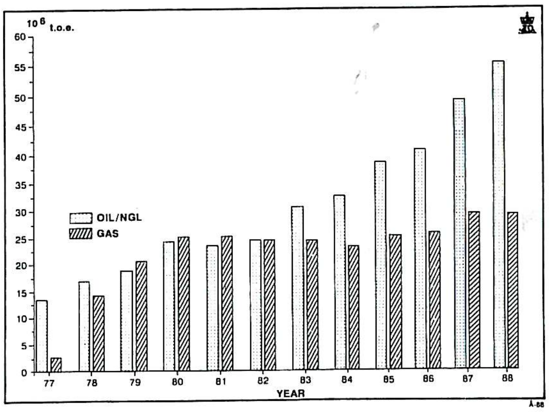


Table 8.4.d
Monthly oil and gas production from Gullfaks, total

1988	Prod. oil stabilized	Prod. gas	Flared gas	Gas consumed fuel	Gas Emden	NGL/condensate Kårstø
	1000 Sm³	Mill. Sm³	Mill. Sm³	Mill. Sm³	Mill. Sm³	Tons
88-01	541.	51.	3.	10.	33.	1464
88-02	534.	51.	2.	9.	35.	2111
88-03	731.	69.	4.	11.	47.	2961
88-04	720.	68.	4.	10.	47.	3340
88-05	542.	53.	3.	11.	29.	1905
88-06	366.	38.	4.	10.	20.	1367
88-07	821.	85.	7.	12.	52.	4467
88-08	891.	94.	5.	13.	56.	4466
88-09	922.	102.	7.	12.	72.	6157
88-10	1043.	109.	7.	13.	77.	4841
88-11	1035.	107.	5.	13.	76.	6874
88-12	492.	60.	2.	8.	37.	5208
Year's total	8639.	879.	50.	132.	582.	45161

Table 8.4.e
Monthly gas and condensate production from Heimdal

1988	Gas prod	Condensate produced	Flared gas	Gas fuel	Gas sold Emden	Condensate Kinneil
	Mill. Sm³	Sm³	Mill. Sm³	Mill. Sm³	Mill. Sm³	Sm³
JAN	336	53843	0	5	320	49250.
FEB	285	45876	0	5	271	45584.
MAR	302	48499	0	5	287	46673.
APR	310	49751	0	5	293	48281.
MAY	295	47590	0	5	282	48290.
JUN	307	48777	0	5	293	45867.
JUL	337	54305	0	5	321	53766.
AUG	320	51716	0	5	304	48619.
SEP	299	48264	0	5	285	45549.
OCT	325	52236	0	5	309	49712.
NOV	322	51712	0	5	308	48605.
DEC	336	53998	0	5	320	47722
Year's total	3773	606569	2	61	3595	577918

Table 8.4.f
Monthly oil and gas production from Murchison

1988	Prod. oil Unstabilized	Prod. gas	Flared gas	Gas consumed fuel	Stable oil Sullom Voe	Gas St. Fergus	NGL S.Voe/St.Fergus
	1000 Sm^3	Mill. Sm^3	Mill. Sm^3	Mill. Sm^3	1000 Sm^3	Mill. Sm^3	1000 tons
JAN	28	6	1	1.	27.	2	0
FEB	26	6	1	1.	25.	2	0
MAR	28	6	1	1.	27.	2	0
APR	28	6	1	1.	27.	2	0
MAY	28	6	1	1.	27.	2	0
JUN	27	6	1	1.	25.	1	2
JUL	55	6	1	1.	52.	1	0
AUG	72	7	1	1.	67.	2	1
SEP	71	8	1	1.	65.	3	1
OCT	69	8	1	1.	63.	2	1
NOV	65	8	1	1.	59.	3	1
DEC	65	8	1	1.	59.	2	1
Year's total	564	80	9	11	523	24	9

Figures show Norwegian share of Murchison.

Table 8.4.g
Monthly oil and gas production from Statfjord total

1988	Prod. oil stabilized	Prod. gas	NGL/condensate Kårstø	Flared gas	Gas consumed fuel	Gas Emden
	1000 Sm^3	Mill. Sm^3	1000 tons	Mill. Sm^3	Mill. Sm^3	Mill. Sm^3
JAN	3114.	667.	74.	8.	38.	343.
FEB	2896.	622.	91.	7.	35.	295.
MAR	3087.	651.	81.	9.	38.	260.
APR	3016.	645.	73.	7.	38.	239.
MAY	3029.	648.	75.	9.	38.	245.
JUN	2363.	507.	82.	8.	31.	262.
JUL	2934.	622.	74.	7.	38.	241.
AUG	2384.	486.	68.	6.	30.	217.
SEP	2888.	609.	65.	9.	36.	224.
OCT	3023.	655.	77.	8.	37.	245.
NOV	2840.	613.	84.	7.	35.	278.
DEC	3010.	664.	140.	10.	37.	353.
Year's total	34586.	7390.	985.	94.	431.	3203.

Figures are Norwegian share of Statfjord: 84.09322 %

Table 8.4.h
Monthly oil and gas production from Ula

1988	Unstabilized oil	Prod. gas	Flared gas	Gas consumed fuel	Stable oil Teesside	NGL Teesside	Gas sold Emden
	1000 Sm^3	Mill. Sm^3	Mill. Sm^3	Mill. Sm^3	1000 Sm^3	1000 tons	Mill. Sm^3
JAN	489.	42.	0.	4.	458.	22.	35.
FEB	449.	38.	0.	3.	419.	22.	30.
MAR	486.	41.	0.	4.	452.	24.	32.
APR	473.	40.	0.	4.	441.	24.	31.
MAY	457.	38.	0.	4.	430.	20.	30.
JUN	340.	28.	0.	3.	317.	16.	22.
JUL	494.	41.	0.	4.	461.	23.	33.
AUG	474.	40.	1.	4.	444.	22.	31.
SEP	457.	38.	1.	3.	429.	21.	30.
OCT	452.	38.	1.	3.	419.	22.	30.
NOV	468.	40.	0.	4.	436.	23.	31.
DEC	382.	32.	0.	4.	356.	19.	25.
Year's total	5421.	455.	7.	42.	5061.	257.	361.

Table 8.4.i
Monthly oil and gas production allocated to the Ekofisk fields

1988	Unstabilized oil	Prod. gas	Gas flared	Gas consumed fuel	Stabilized oil Teesside	NGL Teesside	Gas sold Emden
	1000 Sm^3	Mill. Sm^3	Mill. Sm^3	Mill. Sm^3	1000 Sm^3	1000 tons	Mill. Sm^3
JAN	971	886	0	62	668	80	724
FEB	902	851	1	58	616	79	728
MAR	1000	934	0	63	685	87	779
APR	1000	935	0	63	685	86	701
MAY	1017	954	1	66	702	80	673
JUN	866	841	1	56	594	77	653
JUL	1124	978	0	69	788	91	678
AUG	1073	961	1	68	743	90	711
SEP	1064	970	0	67	762	90	703
OCT	1087	978	1	69	757	90	704
NOV	1076	926	1	70	749	88	640
DEC	1108	947	2	72	733	91	698
Year's total	12288	11159	8	781	8482	1030	8393

8.5 PUBLICATIONS BY THE NORWEGIAN PETROLEUM DIRECTORATE IN 1988

Regulations

- Regulations compendium: "Regelverksamling for petroleums-virksomheten 1988" (Acts, regulations and provisions for the petroleum activity 1986): up-to-date compendium with the legislation, the regulations and guidelines which apply to the shelf. Updated to 1 January 1988.
- Regulations on workers protection and environment.
- Regulations on extension of the areas on the Norwegian continental shelf for which certain regulations on survey and exploration drilling for petroleum activities apply.
- Safety regulations on survey and exploration drilling for petroleum deposits in Svalbard.
- Equality studies – methodical regulations development.
- Shelf legislation interfaces.

Research reports

- Determination of the mechanical properties of reservoir rocks using the triaxial test.
- Environmental data collection in the Barents Sea in 1985.

Other publications

- Well Data Summary Sheets, vol. 13. Boreholes completed in 1982.
- NPD Bulletin No. 4.
  A lithostratigraphic scheme for the Mesozoic and Cenozoic succession off Mid-Norway and Northern Norway.
- NPD contribution No. 26.
  Perspectives for oil and gas in the Barents Sea.
- Oljedirektoratets Årsberetning 1987 (Norwegian Petroleum Directorate Annual Report 1987) (Norwegian edition)
- NPD Annual Report 1987 (English edition of the above)
- Perspektivanalysen 1988
- Petroleum Outlook 1988 (English edition of the above)
- Petroleum thesaurus for the information bases OIL and INFOIL.
- Litter on the seabed – clearance by the state.
- Industrial experience with quality assurance in offshore-related projects.
- Health examination of divers – Fitness to dive – Decompression – Use of oxygen.
- Clearance of the seabed 1988.

8.6 ORGANISATION CHART