Norwegian Petroleum Directorate

ANNUAL REPORT 1990

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"The objectives of the Norwegian Petroleum Directorate are to promote the sound management of the Norwegian petroleum resources having a balanced regard for the environmental, safety, technological and economic aspects of the petroleum activity in a coordinated, socially-oriented evaluation."

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Report of the Directors

There was intensive exploration activity on the Norwegian continental shelf in 1990, indeed, such a high activity level has not been seen since 1985. By year end 36 exploration and appraisal wells had been spudded; and there were 12 exploration rigs in action, again, the largest number since 1985.

Additionally 60 production wells were put down in 1990, making a grand total of 96 wells in the Norwegian sector during the year, which is all but identical with the record year 1985, with its grand total of 97 wells of all kinds.

This intensive exploration activity has also produced results: 10 discoveries were made during the year. Seven of them are in the North Sea and three offshore Mid-Norway. Statistically this means oil or gas was encountered in four of 10 boreholes in the Norwegian sector in 1990. With this rate of success, the Norwegian continental shelf is among the prime exploration areas in the world.

It is too early to measure the growth in reserves due to this year's discoveries. Eventually the new discoveries will almost certainly overcompensate for the depletion due to production of oil and gas in 1990. Concurrently there was a marked upswing in the logged resources in fields in operation and fields for which the declaration has been filed. This upswing alone more than compensates for the year's petroleum production.

At the present level of petroleum takeoff, Norway's discovered resources are sufficient for 20 years of production of oil, and over a century of gas production. If one includes predicted resources in future discoveries, Norway's reserves are sufficient for 40 years of oil production and about 200 years of gas production.

The interest manifest in the 13th licensing round serves to confirm that the Norwegian sector is still of major interest to the exploration arms of the international oil industry.

The 13th licensing round was announced on 15 March with the closing date for applications on 14 September 1990. The announcement covered 52 blocks or parts of blocks, plus reannouncement of 103 blocks offshore Mid-Norway and in the Barents Sea for which no allocations were made at the time of announcement. By closing date 24 companies had filed to take part in the new production licences. All companies applied for North Sea acreage, nine for Mid-Norway blocks, and 17 for blocks in the Barents Sea.

The year witnessed no petroleum exploration drilling on Svalbard. On the other hand, Norsk Hydro joined with Store Norske Spitsbergen Kullkompani in mobilising drilling equipment and machinery for the purpose of starting drilling in Reindalen in January 1991.

At year end the Directorate was delegated authority by the Ministry of Petroleum and Energy to collect the new Environment Tax on carbon dioxide emissions in the Norwegian sector.

The Directorate also supervises the estimation and calculation of the tax, and pursues its effects; for example documenting whether the tax brings about a reduction in emissions, any change-over to other forms of energy, or technological developments which serve to conserve resources and the environment.

In connection with the introduction of the new environment tax offshore, calculations were made to estimate how much gas is used on the platforms, and the magnitude of the associated carbon dioxide emission. It should be remembered that the Norwegian authorities have always had a very restrictive attitude to gas flaring on the continental shelf. In fact, the Norwegian sector is among the oil and gas producing areas in the world which flare off least gas.

In the course of the year two new fields came on stream on the Norwegian shelf: Gyda and Hod. This brings the total of oil and gas fields in permanent production to 21, which compares very favourably with the total of 12 five years ago. The Directorate also considered plans for development and operation (PDOs) for Heidrun and Statfjord North and Statfjord East and Embla, and the plan for construction and operation (PCO) for Haltenpipe.

The Directorate also considered an update to the PDO for Troll, phase 1. In this version one recommends that the gas processing stage be removed from the offshore platform to a land terminal at Kollsnes in Øygarden, near Bergen.

This will provide a flexible, cost-efficient and safe development solution for Norway's largest gas field. There is reason to suppose that in later field developments, too, one will be able to exploit the advantages of transporting untreated oil and gas over long distances in order to build future processing plants on shore.

On the Troll West field test production of oil was performed from a horizontal well. The result was very encouraging and shows that there is great potential for deployment of horizontal wells on the Norwegian shelf.

Horizontal recovery is also planned for other fields. On Statfjord three horizontal wells were drilled during the year as one step in the efforts to enhance recovery from the reservoirs.

On Valhall a trial project has been launched to examine whether water injection can enhance oil recovery in a limestone reservoir. Similar measures are being considered for other fields, too; and such activities will confront the industry and the Directorate with demanding, but interesting, challenges to raise the petroleum potential in the Norwegian sector.

International events again served to bring the Norwegian shelf into the limelight. Particularly the Middle East situation after Iraq's occupation of Kuwait, which triggered fluctuations in the oil price which have had no equal since 1979.

In the North Sea itself the publication of the Cullen Commission's report after investigation of the Piper Alpha disaster caused Norwegian safety philosophy and supervision practices to be carefully examined. The Directorate's Safety Director was extensively questioned as an expert witness in the Cullen hearings in Aberdeen in January.

Following the publication of the commission's report and the political handling its 106 recommendations received, there is reason to suppose that UK supervision philosophy will assimilate several aspects of Norway's.

The Piper Alpha lessons caused the Directorate almost immediately to order Norwegian operators to review all existing installations in the Norwegian sector in the light of the new regulations, operating experience and technological development. The result was keener attention to older installations. Thanks to measures already implemented, their technical standard has in many cases been significantly upgraded.

The process also turned up deficiencies in the companies' internal control systems in the maintenance field.

Pursuance of the requirements in the Working Environment Act and the dictates of the Internal Control principle were two priority areas in 1990. Supervision was largely directed to the requirements for performing working environment analyses and the incorporation – as early as the design stage – of working environment requirements.

Supervision in the operating/production phase concentrated on manning cuts, lines of responsibility and communications, and personnel qualifications.

Regrettably two lives were lost in the offshore petroleum industry in 1990. Accidents and other serious incidents meant considerable involvement by the Directorate, for direct follow-up and to assist the police and public prosecutor with their enquiries.

The drilling of high-pressure wells was another commitment area in the year, aimed at avoiding a situation such as occurred in well 2/4–14 last year. Operations procedures have been changed, drilling programmes have been changed, drilling rigs have been upgraded, and the latest experiential data known to the Directorate are fed back to the operators on a current basis.

The Directorate's new regulations will mean significant improvement in safety supervision. The new regulations permit the necessary adjustments to be made depending on the demands and special features of each activity. This is expected to produce dividends of cost-efficiency and simultaneously allow safety levels to improve.

The Directorate has been in close consultation with the industry and its organisations during the drafting of the detailed regulations. This has helped ensure their quality, and will serve to smoothen implementation, as a more consistent understanding of how to apply and enforce the rules has been formed. The implementation of the new rules will be a major challenge for the Directorate in the future in its own organisation and in relation to the industry. It will be essential to engage in extensive information activities inside the organisation and without, so as to ensure compliance with the new structural frameworks.

The Directorate was one of the bodies consulted in connection with the scope of the Working Environment Act in the offshore industry, and an opinion was submitted. The Directorate noted the committee's suggestion to coordinate, by and large, the fields covered by the Working Environment Act and the Petroleum Act.

The Directorate has started work on drawing up plans for detailed regulations under the WEA as it will apply to the offshore industry.

The work of devising strategies for how the Directorate should participate in the future standardisation efforts in Norway and Europe was another priority area. The Directorate was also ordered to evaluate its own regulatory efforts against the similar activities being conducted in the European Community. Hitherto the Directorate has been almost unaffected by the EC's regulatory drafting, though we attended as observer at the EC's Safety and Health Commission which is preparing the draft for a special directive for safety and health for jobs in the petroleum industry.

On 10 November 1990, Director General Fredrik Hagemann's third period as Petroleum Director expired. By Crown Prince Regent's decree of 27 July 1990, Mr Gunnar Berge, member of the Norwegian parliament, was appointed to the office for a service period of six years, Fredrik Hagemann being constituted as Director General until such time as Gunnar Berge can take over.

Stavanger, 27 February 1991

Members of the Board of Directors of the Norwegian Petroleum Directorate

Arve Berg

Andreas Lønning

Oddny Aleksandersen

Liv Hatland

Peter J Tronslin

Jan B M Strømme

Arne H. Nilsen

Elisabet Stephansen

Fredrik Hagemann
Director General

Bjørn Bratbak
Head of Branch
Secretary of the Board

1. Duties, Directors and Administration

1.1 TERMS OF REFERENCE

The objectives and tasks of the Norwegian Petroleum Directorate are given by special instructions, amended most recently on 29 March 1979. Its tasks have since been revised by delegations which follow directly from acts of parliament, regulations or delegation resolutions from a superior authority. The delegations derive from:

a) *Petroleum Act*, of 22 March 1985 no. 11, with regulations
b) *Working Environment Act*, of 4 February 1977 no. 4, with regulations
c) *Tobacco Restrictions Act*, of 9 March 1973 no. 14, section 6, eighth paragraph, and Regulations, given by Royal Decree of 8 July 1988
d) Regulations for *Safe Practices* for Surveying and Exploration Drilling for Petroleum Deposits on Svalbard etc, of 29 March 1988
e) Regulations for *Scientific Research* into Natural Resources on the Norwegian Continental Shelf etc, of 31 January 1969
f) Provisional Regulations for *Litter and Pollution* caused by Petroleum Activities on the Norwegian Continental Shelf, of 26 October 1979.

1.2 OBJECTIVES

On the basis of the above terms of reference and the Norwegian Petroleum Directorate's guiding instructions the following objective has been laid down for the Directorate:

"The objectives of the Norwegian Petroleum Directorate are to promote the sound management of the Norwegian petroleum resources having a balanced regard for the environmental, safety, technological and economic aspects of the petroleum activity in a coordinated, socially-oriented evaluation."

1.3 BOARD OF DIRECTORS AND ADMINISTRATION

1.3.1 Board of Directors

The composition of the Board of Directors during the report period was:

1. Mr Arve Berg, Regional Employment Director, Ålesund (Chairman)
2. Mr Andreas Lønning, Group Director, Oslo (Deputy Chairman)
3. Ms Liv Hatland, Managing Director, Oslo
4. Ms Oddny Aleksandersen, Executive Officer, Tromsø
5. Mr Jan B.M. Strømme, Trade Union Secretary for Oil, Drøbak
6. Mr Peter J. Tronslin, Managing Director, Stavanger
7. Mr Arne H. Nilsen, Senior Engineer, Stavanger
8. Ms Elisabet Stephansen, Head of Section, Stavanger.

Deputies:

For 1–4:
Mr Per Sævik, Member of Parliament, Remøy
Ms Sylvi Enevold, County Council Deputy Chairwoman, Hammerfest
Ms Marit Greve, Editor, Bærum

For 5:
Mr Bjørn Kolby, Department Manager, Oslo

For 6:
Mr Gunnar Flaat, Negotiations Director, Oslo

For 7–8:
Mr Tor Inge Ottosen, Executive Officer, Stavanger
Ms Susanne Larsen, Senior Engineer, Stavanger.

Senior Engineer Susanne Larsen retired from her post on 6 June 1990 and thus also her office as deputy board member. No new deputy was appointed.

During the year the Board held nine meetings, seven of them in Stavanger. The May meeting was held in Pau in Southern France in connection with the year's study visit to oil companies Total and Elf Aquitaine. The October meeting was held at the Harstad office, and the board took the opportunity to visit the North Norway Training Centre for oil personnel in Tjeldsund.

1.3.2 Organisation

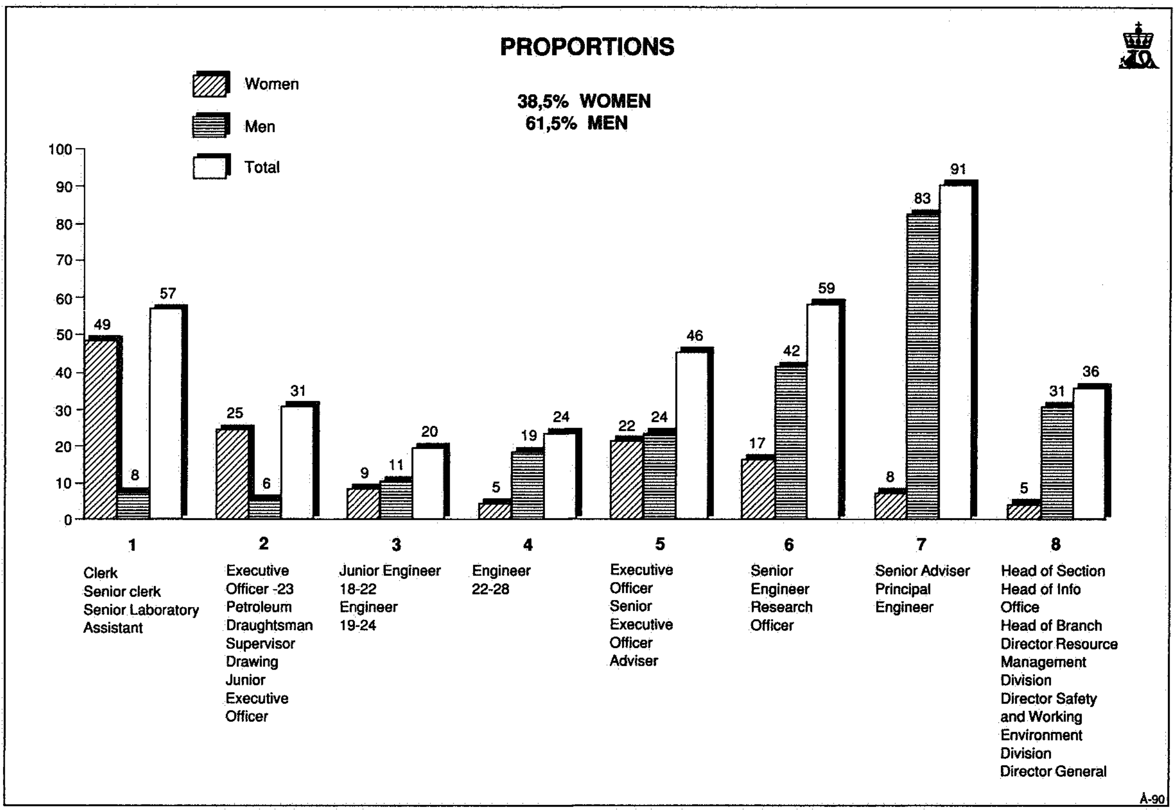
No structural changes were made in the Directorate's organisation in 1990.

As Director General Fredrik Hagemann's third term as Petroleum Director expired on 10 November 1990, the position was advertised. By Crown Prince Regent's decree of 27 July 1990, Mr Gunnar Berge was appointed Petroleum Director for a service period of six years, Fredrik Hagemann being constituted as Director General until such time as Gunnar Berge can assume the position.

1.3.3 Staff

At the end of the period the Directorate had 339 authorised positions. No new positions were authorised during the year. Three more positions are funded by NORAD. At year end there were 352 employees in service, 15 on leave. Of Directorate employees, 38.5 per cent are women. Figure 1.3.3 shows the breakdown of men and women in the

Fig. 1.3.3
Job categories as of december 1990



various position categories. One of NORAD's special advisors for oil matters in developing countries worked in the Directorate for the entire report period.

In 1990, the Directorate considered applications for 51 vacancies and 13 new employees were taken on in permanent positions. Of the new employees three have relocated from elsewhere, seven have joined us from other oil-related activities, and three were newly qualified.

Employees leaving were 24 in number, representing 7 per cent of the total authorised positions.

Codetermination

Thirteen meetings were held during the year between management and the staff representatives. Among the subjects of particular interest considered were the following:

- Analysis of Directorate's organisation
- Conversion of vacancies
- Transfer of positions and staff between units
- Job rotation system
- Reversal of wages authorities
- Employment terms for supervision leaders
- Introduction of computerised planning system
- New routine for evaluation of vacancies
- Distribution of welfare funds.

Training

The training budget was Nkr 3,450,000 in 1990. The budget also covers travel and accommodation in connection with training. To get the most out of the resources, most emphasis was on courses and seminars organised internally. To this end course catalogues were printed listing the inhouse training options. Inhouse training also covers management training under a specially developed course programme. The Directorate also derived great benefit from courses held by the oil companies.

Equal opportunity

The Directorate is bound by a special agreement on equal opportunity and has its own Equal Opportunity Committee. This committee is four in number, with two representatives from management and two from the staff unions. Each year an Equal Opportunity Action Plan is drawn up. The main concern of the committee in 1990 was an equality survey of the Directorate, the results of which have been presented to employees and management.

1.3.4 Budget and economy

The Directorate employed Nkr 232,667,517 for its various tasks in 1990.

The amount was appropriated as follows:

– Operating budget	Nkr 165,531,031
– Inspection costs	8,256,404
– Geological and geophysical surveys	52,954,904
– Safety and working environment	5,925,178
Total	232,667,517

Of the operating budget, payroll costs account for Nkr 104,722,297 and hire and operation of buildings Nkr 6,045,109. The remainder, Nkr 54,763,625, covers costs of consultants, operation of weather ship, external assistance, travel, training, computer systems operation, new investments in equipment, etc.

Other tasks:

– Clearance of seabed	Nkr 4,666,457
– Research and development for enhanced oil recovery (SPOR)	14,978,785
– World Petroleum Congress 1995	108,437

Revenues

In addition to the paid-up royalties on production and acreage fees, Nkr 8,729,244,293, the Directorate received Nkr 106,882,917 from various sources of revenue as follows:

– Sale of publications	Nkr 3,297,246
– Sale of released test material	1,503,355
– Exploration fees	1,500,000
– Refund of inspection outlays	37,269,296
– Sale of seismic survey results	57,338,084
– Credit interest, bank	5,882,218
– Miscellaneous	92,718
Total	106,882,917

1.3.5 Information

During the report period great interest was shown in the Directorate's information services on the part of Norwegian and foreign institutions, the press and media, companies and individuals. One confirmation of this is the visits by foreign media representatives, individually or in groups, in order to familiarise themselves with the Directorate and the oil activity. For their part, Directorate employees have been energetic as visiting lecturers in the various forums.

The Norwegian Petroleum Directorate Annual Report plays a central role in the Directorate's information activities. The 1989 Annual Report was presented to the press in April.

The Directorate joined with the Ministry of Petroleum and Energy and the Ministry of Local Government to present a government stand at the Offshore Northern Seas exhibition, ONS-90.

The number of press releases issued in 1990 was 54, most of which were in connection with termination of exploration wells.

1.3.6 Document and data records management

Almost 100,000 documents were entered in the file catalogue, Library, and Infoil in 1990. In the same period some 20,000 enquiries and orders were received.

Three inhouse courses introduced users to the Directorate's document records databases, and search instructions for the file directory *Journal* and literature directory *Odin* were prepared.

Cancellation rules for documents have been worked out, and the filing system has been revised.

Activity in the library was again intense in 1990, and the number of enquiries for literature and information was 8.5 per cent up on last year.

Use of the information bases OIL and Infoil 2 and their printed lists was as popular as in previous years.

One new development in 1990 was the issue of OIL in electronic form for use on a personal computer. Several subscriptions have already come in for this PC version.

An agreement has been struck with the EC regarding coordination and combination of the Infoil, Infoil 2 and Sesame databases into Infoil-Sesame.

2. Activity on the Norwegian Continental Shelf

2.1 EXPLORATION AND PRODUCTION LICENCES

2.1.1 New exploration licences

As of 31 December 1990, 185 commercial exploration licences had been granted. Each licence is valid for three years.

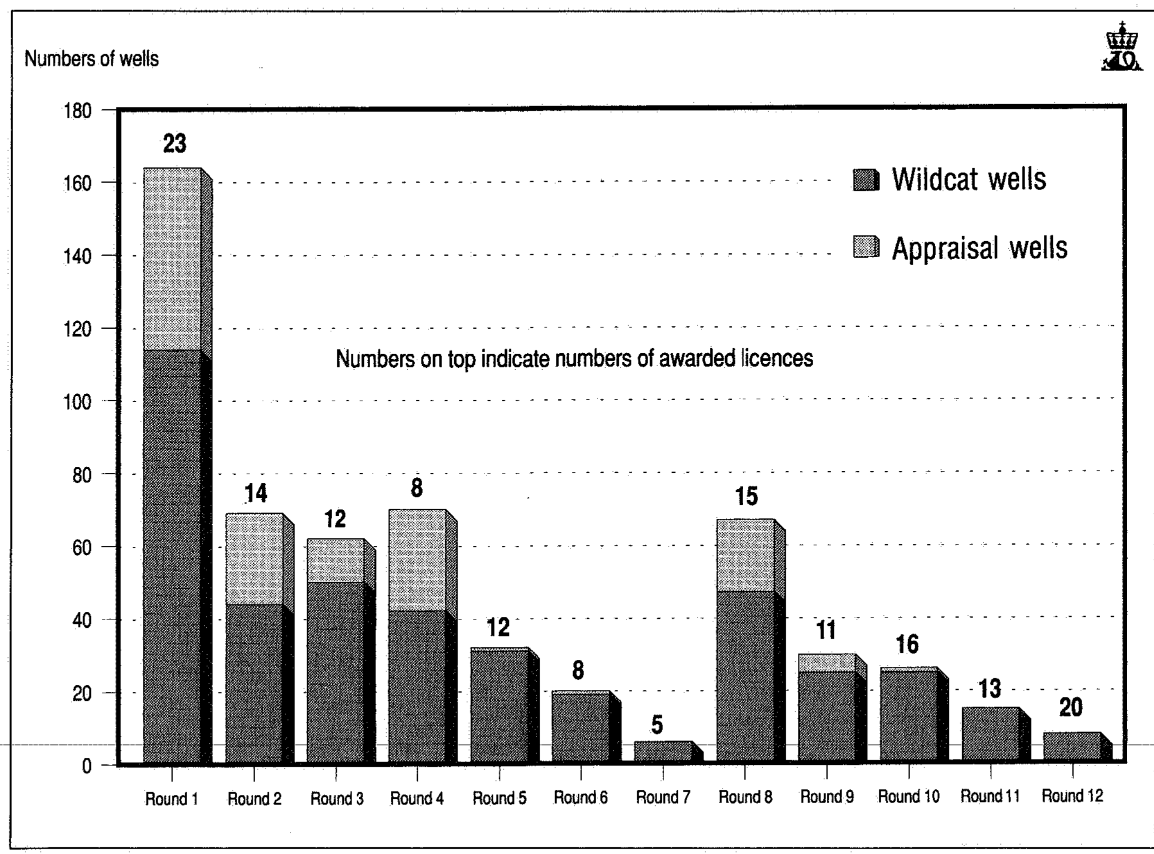
The following licences were awarded in 1990:

Company	*Licence no.*
Geophysical Company of Norway A/S	172
Mobil Development Norway A.S	173
Esso Norge A.S	174
Saga Petroleum a.s	175
Continental Shelf Institute (IKU)	176
Amoco Norway Oil Company	177
Geoteam A/S	178
Norsk Agip A/S	179
Amerada Hess Norge A/S	180
Mærsk Olie og Gass A/S	181
Norsk Hydro Produksjon a.s	182
Norske Fina A/S	183
Marathon Petroleum Norge A/S	184
Hoff International Offshore Service Team Inc.	185

2.1.2 Licensing rounds and new production licences

Licensing round 13, announced on 6 March 1990, invited applications for 52 blocks and parts thereof distributed over the entire continental shelf; 22 of them in the North Sea, five off Mid-Norway, and 25 in the Barents Sea. In addition, interested parties had the opportunity to apply for all acreage announced previously, but for which no production licence had been granted, off Mid-Norway and in the Barents Sea – in all 103 blocks or parts thereof. The application deadline was 14 September 1990. Twenty-four companies applied for 30 of the 52 blocks announced, and 99 of the blocks off Mid-Norway and in the Barents Sea. Of the 99 blocks, 62 had been announced earlier, but had not been allocated. Allocation is expected to take place early in 1991. Up to 31 December 1990, 162 production licences have been allocated in all, see Table 2.1.2.a and b, and Figure 2.1.2.

Fig. 2.1.2
Exploration wells drilled in each licensing round



Tabell 2.1.2.a Production licences and acreages as of 31 December 1990

Lic. round	Allocated	Production licence no.	No of blocks: Blocks allocated	No of blocks: Blocks relinquished	Area km² allocated	Area km² relinquished	Area km² in licence
1.	01.09.65	001–021	74	55	39842.476	35466.252	4376.244
	07.12.65	022	4	4	2263.565	2263.565	0.0
	12.09.77	019 (2)	2	0	617.891	0.0	617.891
2.	23.05.69	023–031	9	1	4107.833	2233.346	1874.487
	30.05.69	032–033	2	0	746.285	376.906	369.379
	14.11.69	034–035	2	0	1024.529	564.837	459.692
	11.06.71	036	1	0	523.937	262.047	261.890
Plus	10.08.73	037	2	0	586.834	295.157	291.677
3.	01.04.75	038–040 og 042	7	4	1840.547	1389.780	450.767
	01.06.75	041	1	1	488.659	488.659	0.0
	06.08.76	043	2	0	604.558	303.217	301.341
	27.08.76	044	1	0	193.076	90.417	102.659
	03.12.76	045–046	4	2	1270.682	814.708	455.974
	07.01.77	047	2	1	368.363	304.160	64.203
	18.02.77	048	2	1	321.500	107.019	214.481
	23.12.77	049	1	1	485.802	485.802	0.0
Plus	16.06.78	050	1	0	500.509	151.962	348.547
4.	06.04.79	051–058	8	1	4007.887	2434.633	1573.254
Plus	20.08.82	079	1	0	102.167		102.167
5.	18.01.80	059–061	3	2	1108.078	998.675	109.403
	27.03.81	062–064	3	1	1099.522	499.780	599.742
	23.04.82	073–078	6	2	2311.912	1668.413	643.499
6.	21.08.81	065–072	9	1	3218.945	1746.972	1471.973
7.	10.12.82	080–084	5	5	2082.966	2082.966	0.0
Plus	08.07.83	085	3	0	1521.160	725.816	795.344
8.	09.03.84	086–100	17	1	6338.273	2035.279	4302.994
9.	14.03.85	101–111	13	0	5293.054		5293.054
ut.	26.07.85	112	1		260.215		260.215
10a	23.08.85	113–120	9		3075.433		3075.433
10b	28.02.86	121–128	9	1	3828.258	428.120	3400.138
Plus	11.07.86	129	1		225.393		225.393
11.	10.04.87	130–137	11	1	4163.711	628.856	3534.855
	29.05.87	138–142	11		2975.807		2975.807
12a	08.07.88	143–153	16		4701.021		4701.021
12b	09.03.89	154–162	13		5031.262		5031.262
			256	85	107132.130	58847.344	48284.786

Blocks relinquished includes whole and partial blocks. Plus indicates allocations made outside licensing rounds.

2.1.3 Transfer of interests

In the course of 1990 the following transfers of interests were approved in accordance with § 61 in the Act no. 11 of 22 March 1985 regarding the Petroleum Activity:

Production licence 025
Operator: Elf Aquitaine Norge A/S

Total Marine Norsk A/S has taken over 15.00 per cent from Lasmo Norge A/S. The distribution in the production licence after this is as follows:

Elf Aquitaine Norge A/S	53.200 %
Total Marine Norsk A/S	36.800 %
Norsk Hydro Produksjon a.s	10.000 %

Table 2.1.2.b Allocation rounds. Norwegian and foreign shares and operatorships as of 31 December 1990

Licensing round	Year	Number of blocks	Norwegian share %	Foreign share %	Norwegian operator %	Foreign operator %
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
Prod. lic 079	1982	1	100	0	100	0
7	1982	5	60	40	80	20
Prod. lic 085	1983	3	100	0	100	0
8	1984	17	60	40	60	40
9	1985	13	43	57	62	38
Prod. lic 112	1985	1	67	33	0	100
10A	1985	9	64	36	67	33
10B	1986	9	65	36	56	44
Prod. lic 129	1986	1	67	33	100	0
11	1987	22	59	41	62	38
12A	1988	16	58	43	38	63
12B	1989	13	64	36	67	33

Total Marine Norsk A/S has taken over Unocal Norge A/S's interests in four production licences: 25.00 per cent in PL 051, 18.00 per cent in PL 052, 20.00 per cent in PL 088, and 10.00 per cent in PL 158.

After this, the distribution in the production licences is as follows:

Production licence 051
Operator: Den norske stats oljeselskap a.s (Statoil)

Den norske stats oljeselskap a.s (Statoil)	50.000 %
Conoco Petroleum Norge a/s	25.000 %
Total Marine Norsk A/S	25.000 %

Production licence 052
Operator: Den norske stats oljeselskap a.s (Statoil)

Den norske stats oljeselskap a.s (Statoil)	55.000 %
Total Marine Norsk A/S	18.000 %
Deminex (Norge) A/S	11.250 %
Norsk Hydro Produksjon a.s	9.000 %
Svenska Petroleum Exploration a/s	4.500 %
Norske Deminex A/S	2.250 %

Production licence 088
Operator: Total Marine Norsk A/S

Den norske stats oljeselskap a.s (Statoil)	50.000 %
Total Marine Norsk A/S	50.000 %

Production licence 158
Operator: BP Norway Limited U.A

Den norske stats oljeselskap a.s (Statoil)	50.000 %
BP Norway Limited U.A	30.000 %
Det Norske Oljeselskap A/S	10.000 %
Total Marine Norsk A/S	10.000 %

Neste Oy (Neste Petroleum A/S) has taken over Arco Norway Inc's shares in seven production licences: 9.80 per cent in PL 055, 10.00 per cent in PL 062, 15.00 per cent in PL 074, 10.00 per cent in PL 094, 10.00 per cent in PL 095, 10.00 per cent in PL 124, and 15.00 per cent in PL 135.

After this, the distribution in the production licence is as follows:

Production licence 055
Operator: Norsk Hydro Produksjon a.s

Den norske stats oljeselskap a.s (Statoil)	51.000 %
Esso Norge a.s	19.600 %
Norsk Hydro Produksjon a.s	14.700 %
Neste Oy (Neste Petroleum A/S)	9.800 %
BP Norway Limited U.A	4.900 %

Production licence 062
Operator: Saga Petroleum a.s

Den norske stats oljeselskap a.s (Statoil)	50.000 %
A/S Norske Shell	25.000 %
Neste Oy (Neste Petroleum A/S)	10.000 %
Saga Petroleum a.s	10.000 %
Norsk Hydro Produksjon a.s	5.000 %

Production licence 074
Operator: Saga Petroleum a.s

Den norske stats oljeselskap a.s (Statoil)	50.000 %
Norsk Agip A/S	15.000 %
Neste Oy (Neste Petroleum A/S)	15.000 %
Deminex (Norge) A/S	10.000 %
Saga Petroleum a.s	10.000 %

Production licence 094
Operator: Den norske stats oljeselskap a.s (Statoil)

Den norske stats oljeselskap a.s (Statoil)	50.000 %
Mobil Development Norway A/S	15.000 %
Norsk Agip A/S	10.000 %
Conoco Petroleum Norge A/S	10.000 %
Neste Oy (Neste Petroleum A/S)	10.000 %
Norsk Hydro Produksjon a.s	5.000 %

Production licence 095
Operator: Norske Conoco A/S

Den norske stats oljeselskap a.s (Statoil)	50.000 %
Norske Conoco A/S	30.000 %
Conoco Petroleum Norge A/S	10.000 %
Neste Oy (Neste Petroleum A/S)	10.000 %

Production licence 124
Operator: Den norske stats oljeselskap a.s (Statoil)

Den norske stats oljeselskap a.s (Statoil)	50.000 %
Norske Conoco A/S	15.000 %
Conoco Petroleum Norge A/S	10.000 %
Norsk Hydro Produksjon a.s	10.000 %
Neste Oy (Neste Petroleum A/S)	10.000 %
Det Norske Oljeselskap A/S	5.000 %

Production licence 135
Operator: Saga Petroleum a.s

Den norske stats oljeselskap a.s (Statoil)	50.000 %
Neste Oy (Neste Petroleum A/S)	15.000 %
Saga Petroleum a.s	15.000 %
Total Marine Norsk A/S	15.000 %
Amerada Hess Norge A/S	5.000 %

Production licence 057
Operator: Saga Petroleum a.s

Idemitsu Oil Norwegian A/S has taken over 9.60 per cent from Den norske stats oljeselskap a.s.

After this, the distribution in the production licence is as follows:

Den norske stats oljeselskap a.s (Statoil)	41.400 %
Deminex (Norge) A/S	24.500 %
Saga Petroleum a.s	14.700 %
Idemitsu Oil Exploration (Norsk) A.S	9.600 %
Amerada Hess Norge A/S	4.900 %
Enterprise Oil Norwegian A/S	4.900 %

Production licence 065
Operator: Elf Aquitaine Norge A/S

Enterprise Oil Norwegian A/S has taken over 10 per cent from Texaco Exploration Norway A/S.

After this, the distribution in the production licence is as follows:

Den norske stats oljeselskap a.s (Statoil)	50.000 %
Elf Aquitaine Norge A/S	16.667 %
A/S Norske Shell	15.000 %
Enterprise Oil Norwegian A/S	10.000 %
Total Marine Norsk A/S	8.333 %

Production licence 066
Operator: Saga Petroleum a.s

Mobil Development Norway A/S and Saga Petroleum a.s have taken over Arco Norway Inc's share with 3.60 per cent and 1.40 per cent, respectively.

After this, the distribution in the production licence is as follows:

Den norske stats oljeselskap a.s (Statoil)	50.000 %
Mobil Development Norway A/S	28.600 %
Saga Petroleum a.s	11.400 %
Norsk Hydro Produksjon a.s	10.000 %

Production licence 089
Operator: Saga Petroleum a.s

Idemitsu Oil Norwegian A/S has taken over 9.60 per cent from Den norske stats oljeselskap a.s (Statoil).

After this, the distribution in the production licence is as follows:

Den norske stats oljeselskap a.s (Statoil)	51.400 %
Esso Norge A.S	14.700 %
Norsk Hydro Produksjon a.s	11.760 %
Saga Petroleum a.s	9.800 %
Idemitsu Oil Exploration (Norsk) A.S	9.600 %
Elf Aquitaine Norge a/s	7.840 %
Deminex (Norge) A/S	3.920 %
Det Norske Oljeselskap A/S	0.980 %

Production licence 130
Operator: Den norske stats oljeselskap a.s (Statoil)

Den norske stats oljeselskap a.s (Statoil) and Enterprise Oil Norwegian A/S have taken over 7.500 per cent each of the 15.000 per cent that Petrobras A/S had in production licence 130.

After this, the distribution in the production licence is as follows:

Den norske stats oljeselskap a.s (Statoil)	57.500 %
A/S Norske Shell	27.500 %
Enterprise Oil Norwegian A/S	15.000 %

Arco Norway Inc and Lasmo Norge A/S are now without any interests on the Norwegian continental shelf. Neste Oy (Neste Petroleum A/S) is the only new licensee in 1990.

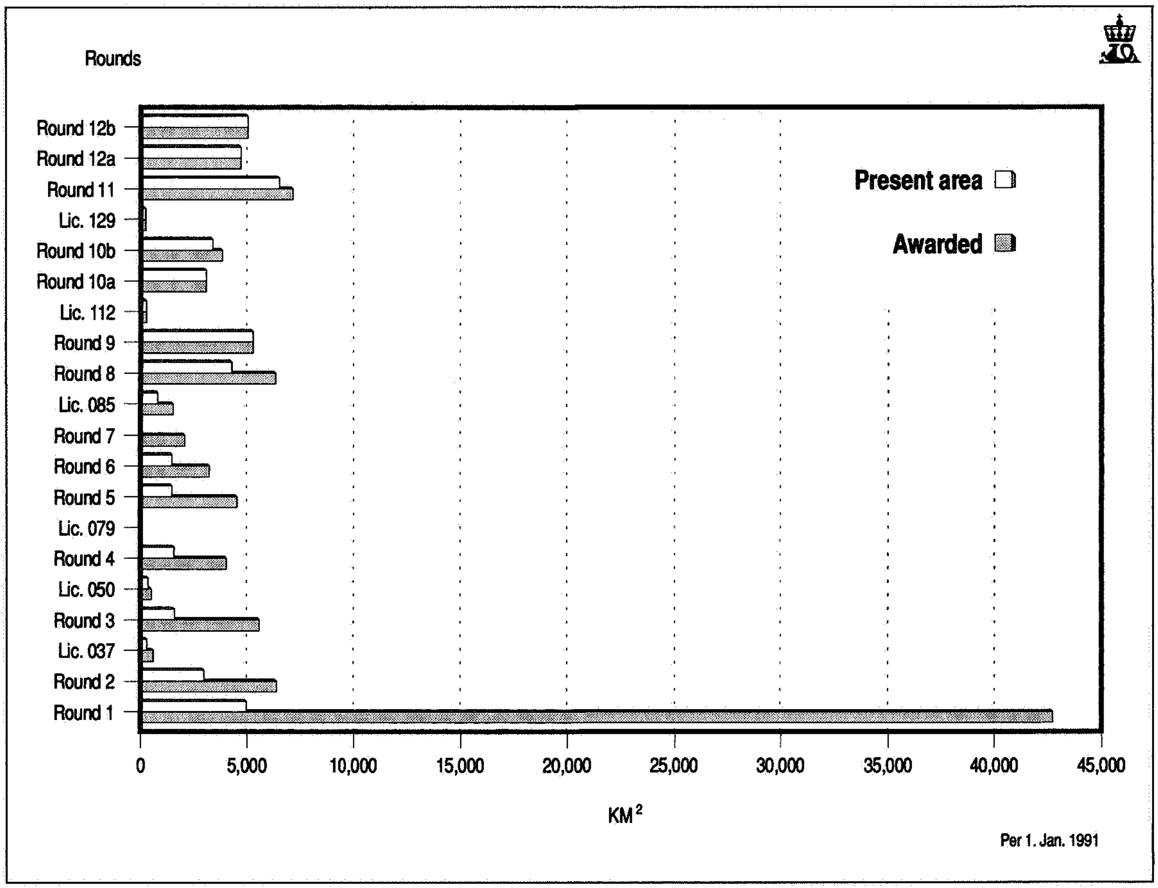
2.1.4 Relinquishments and surrenders

Relinquishment or surrender of acreage occurred in 11 production licences in 1990. In four cases the entire area was relinquished. See Table 2.1.4 for details. The allocated and present acreage is shown in Figure 2.1.4.

Table 2.1.4 Relinquishments

Production licence	Operator	Block	Original area km^2	Relinquished area km^2	Area in licence km^2
007	Elf	16/6	2152.548	2152.548	.000
066	Saga	2/2	565.894	484.432	181.461
077	Statoil	7120/7	331.606	224.260	107.346
086	Statoil	6/3	594.788	538.067	56.721
091	Statoil	6406/3	440.392	262.697	177.695
092	Statoil	6407/6	444.465	263.687	180.778
096	Elf	7119/9	331.606	331.606	.000
097	Hydro	7120/6	327.322	181.910	145.412
099	Statoil	7121/4	327.322	226.962	100.360
100	Statoil	7121/7	331.606	230.349	101.257
125	Shell	6508/5	428.120	428.120	.000
137	Statoil	7224/7 and 7224/8	628.856	628.856	.000

Fig. 2.1.4
Awarded and present area in licenses



2.2 SURVEYING AND EXPLORATION DRILLING

2.2.1 Geophysical and geological surveys

Some 119,409 km of seismics were shot on the Norwegian continental shelf in 1990, see Figure 2.2.1.a. This reflects an activity level 11.8 per cent higher than in 1989.

2.2.1.1 Directorate's geophysical surveys 1990

The Norwegian Petroleum Directorate commissioned 8567 km of seismics in 1990, see Figure 2.2.1.b. Data were collected 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

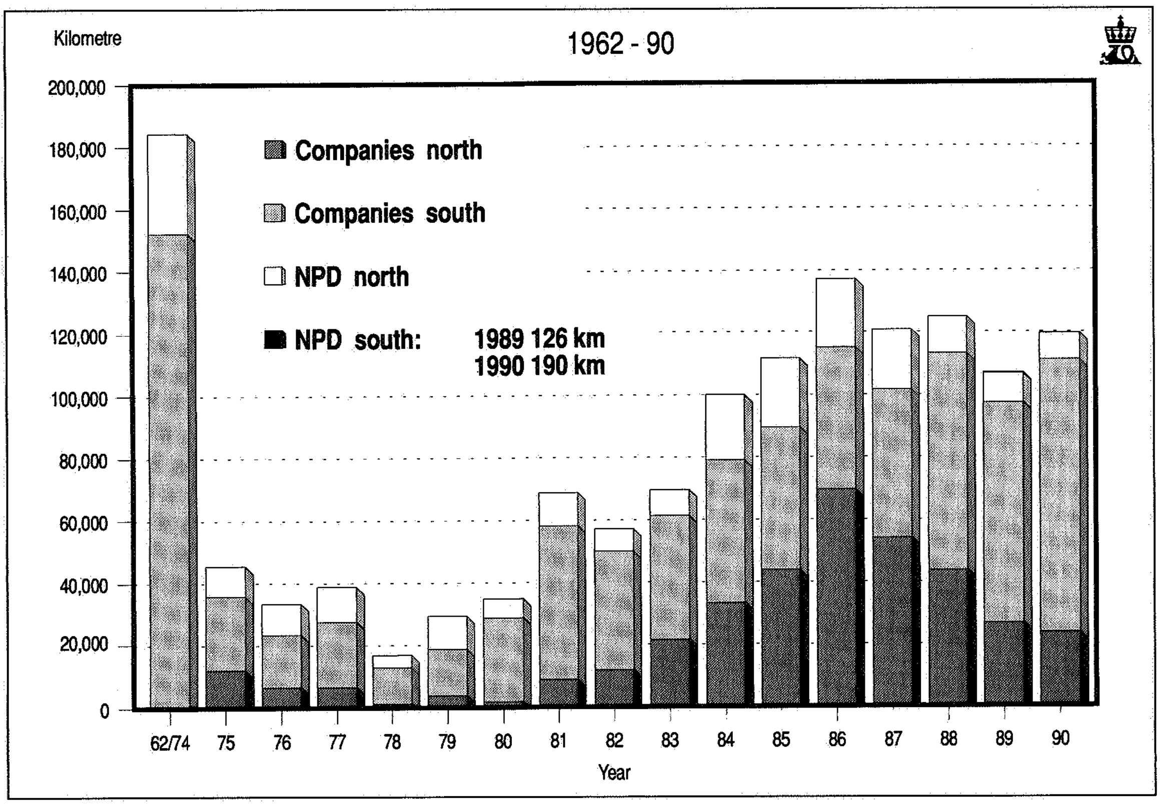


Fig. 2.2.1.b
Seismic surveys conducted by the Norwegian Petroleum Directorate

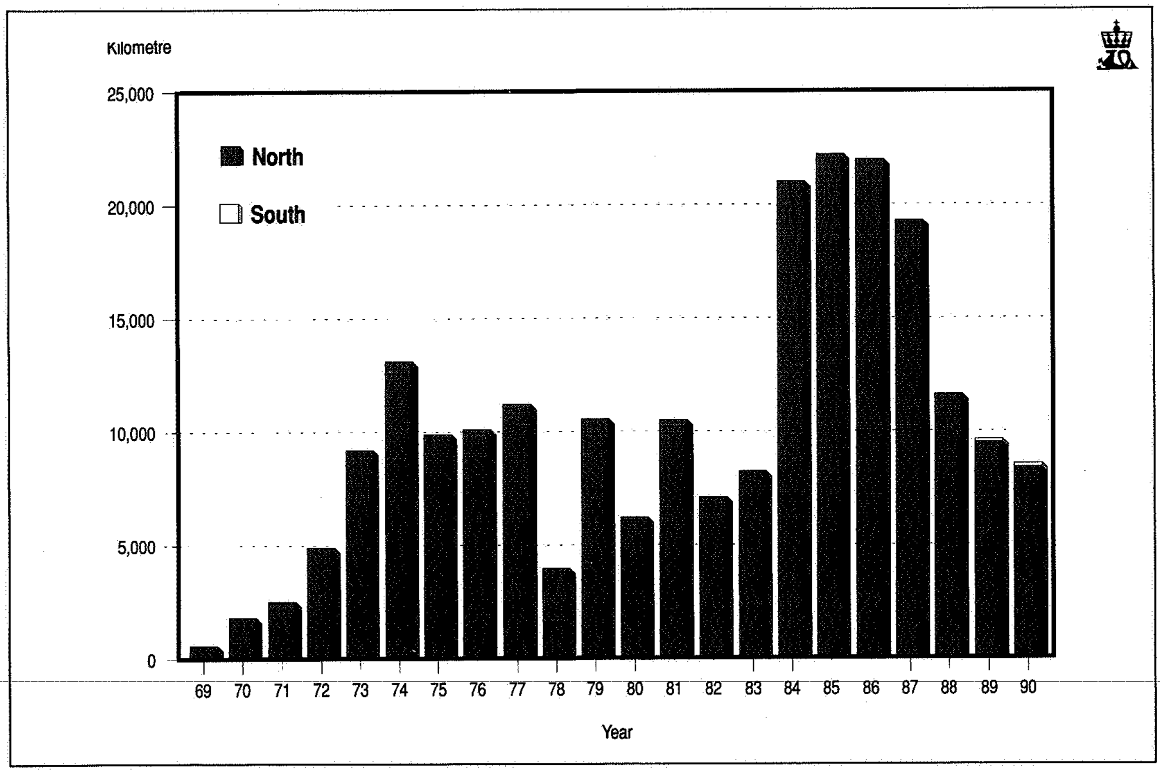


Fig. 2.2.1.c
Seismic test lines in the North Sea

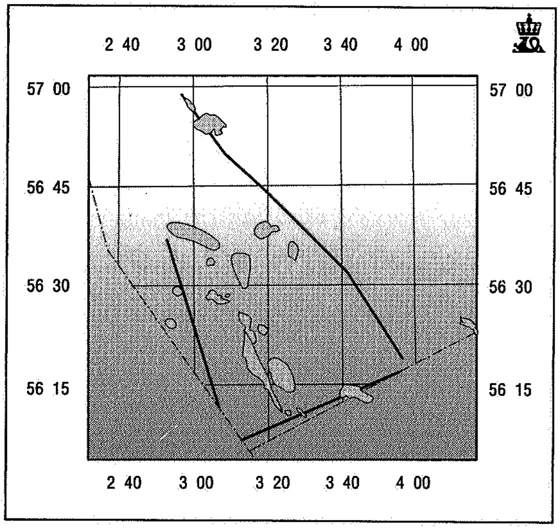


Fig. 2.2.1.e
Geophysical surveys in the northern Barents Sea

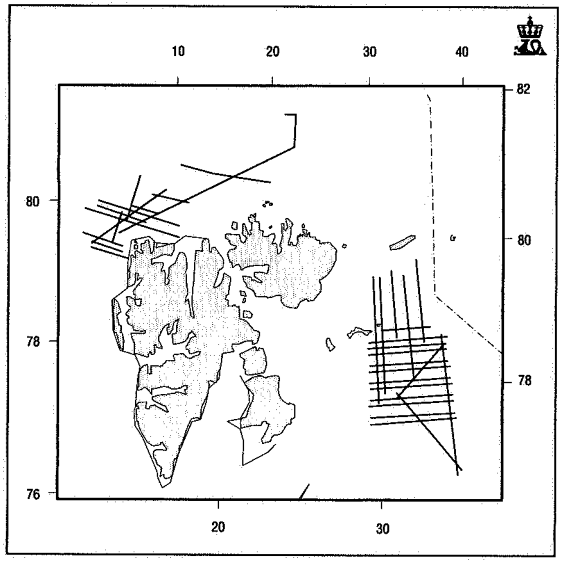
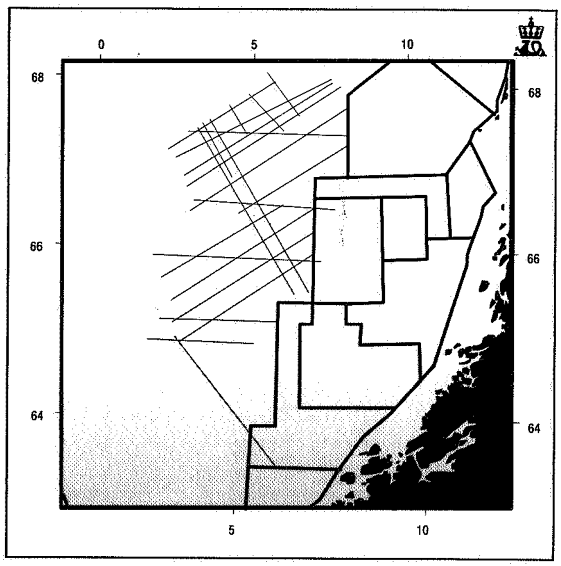


Fig. 2.2.1.d
Geophysical surveys offshore Mid-Norway



North Sea

Three test lines totalling 190 km in length were surveyed in the southern North Sea. The data were compiled by the newly established Norwegian company Master Seismic using the vessel *Skandi Pioneer*. The company is planning to make the processed data available to the industry. The data will be processed by CGG.

Vøring Plateau

Some 4044 km of seismics were collected in the Vøring Plateau basin. The majority were taken from the northern part of the area, although some of the lines extend into the Møre basin. These data were also compiled using the *Skandi Pioneer* vessel.

The seismic method employed was by sleeve guns, the data duration being ten seconds due to the great water depth and great sediment thickness in the area.

The data are being processed by Western Geophysical in London. The Norwegian Petroleum Directorate is planning to complete the compilation of data in the northern part of the Vøring basin in the course of 1991, and parts of the area may subsequently be opened for surveying under the companies' direction.

Barents Sea

Some 4333 km of seismics were shot in the northern Barents Sea using the Norwegian *Geco Echo* vessel. Although the surveys this year were heavily delayed, data were nevertheless gathered very far to the north due to highly favourable ice conditions. Most of the data were collected on Storbanken and all the way up to Kvitøya. Three cables were used in this survey, one of which was a relatively short, shallow cable specially intended for shallow seismics.

After completing surveys on Storbanken the vessel proceeded through the strait of Hinlopen and continued its surveying operations north and northwest of Svalbard. In the small hours of 5 October the vessel reached 82 degrees North (82°00'09"N, 22°59'08"E). As far as we know, high quality seismics have never been shot so far north before. This kind of work, close to the ice edge and with water temperatures around the freezing point, puts a heavy strain on the equipment. Also, few good charts are available for this area. The Storbanken data are being processed by Digicon and Geco (shallow seismics), whereas the data from Moffenflaket are being processed by CGG.

Navigation

Various types of navigation systems were used during the surveys. Although in the northern part of the area ground-based navigation systems were not available, navigation by means of the US global military satellite positioning system Navstar GPS could be used successfully. This system is about to reach continuous coverage as more and more satellites are entering service, and it is expected to be much used in the oil industry in future.

The primary system used during the surveys off Mid-Norway and partly in the Barents Sea, however, was the land-based Geoloc operated by Geoteam a.s.

Shallow drilling operations

In 1990, three shallow drilling operations were carried out in the northern Barents Sea under NPD direction and with the Continental Shelf Institute (IKU) as operator. These drilling operations were carried out at Gardabankhøgda and in the Olga basin in areas that have not yet been opened for exploration drilling. The intention was to supplement the seismic maps with geological information for further planning. Core samples were taken from the mesozoic strata series, and the results will not be made available to the oil companies for the time being.

The following drilling operations were performed:

7427/03-U-1

Coordinates	27°45′42.3″E 74°54′56.0″N
Depth below seabed	93.30 meters
Lithology at total depth	Claystone/siltstone
Age at total depth	Middle Triassic

7532/02-U-1

Coordinates	32°32′28.4″E 75°45′00.9″N
Depth below seabed	19.92 meters
Lithology at total depth	Claystone/siltstone
Age at total depth	Middle Triassic

7533/03-U-1

Coordinates	33°44′59.1″E 75°56′16.9″N
Depth below seabed	120.55 meters
Lithology at total depth	Claystone
Age at total depth	Middle Jurassic

In all holes the quaternary thickness was less than five meters.

2.2.1.2 Opening-up of new exploration areas

No new areas were opened for exploration drilling in 1990. Figure 2.2.1.2 shows areas which are open for seismic surveys by the industry.

2.2.1.3 Companies' geophysical surveys

In 1990, some 110,843 km of seismics were shot on the Norwegian continental shelf under the direction of the oil companies and contractors. Of the total, 88,700 km are three-dimensional surveys. All told, some 87,200 km were taken from the North Sea and 23,600 km off Mid-Norway and in the Barents Sea. As the figures show, the activity level increased by 16,250 km compared to 1989. The activity off Mid-Norway and in the Barents Sea increased by 6200 km compared to 1989. Norwegian oil companies shot some 27,665 km of seismics, which is a reduction of 4000 km from the year before. Foreign companies shot 71,000 km, or 32,000 more than in 1989. Geco, Geoteam and Nopec shot 12,100 km of speculative seismics, which is 14,000 km less than the year before.

2.2.1.4 Sale of seismic data

In 1990, the Norwegian Petroleum Directorate recorded income from the sale of seismic data packages amounting to Nkr 57.3 million (compare Nkr 43.1 million in 1989). See Table 2.2.1.4.

Companies having purchased all the Directorate's seismic data packages for the individual regions are listed below:

Møre South

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

Møre I

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

Trøndelag I

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

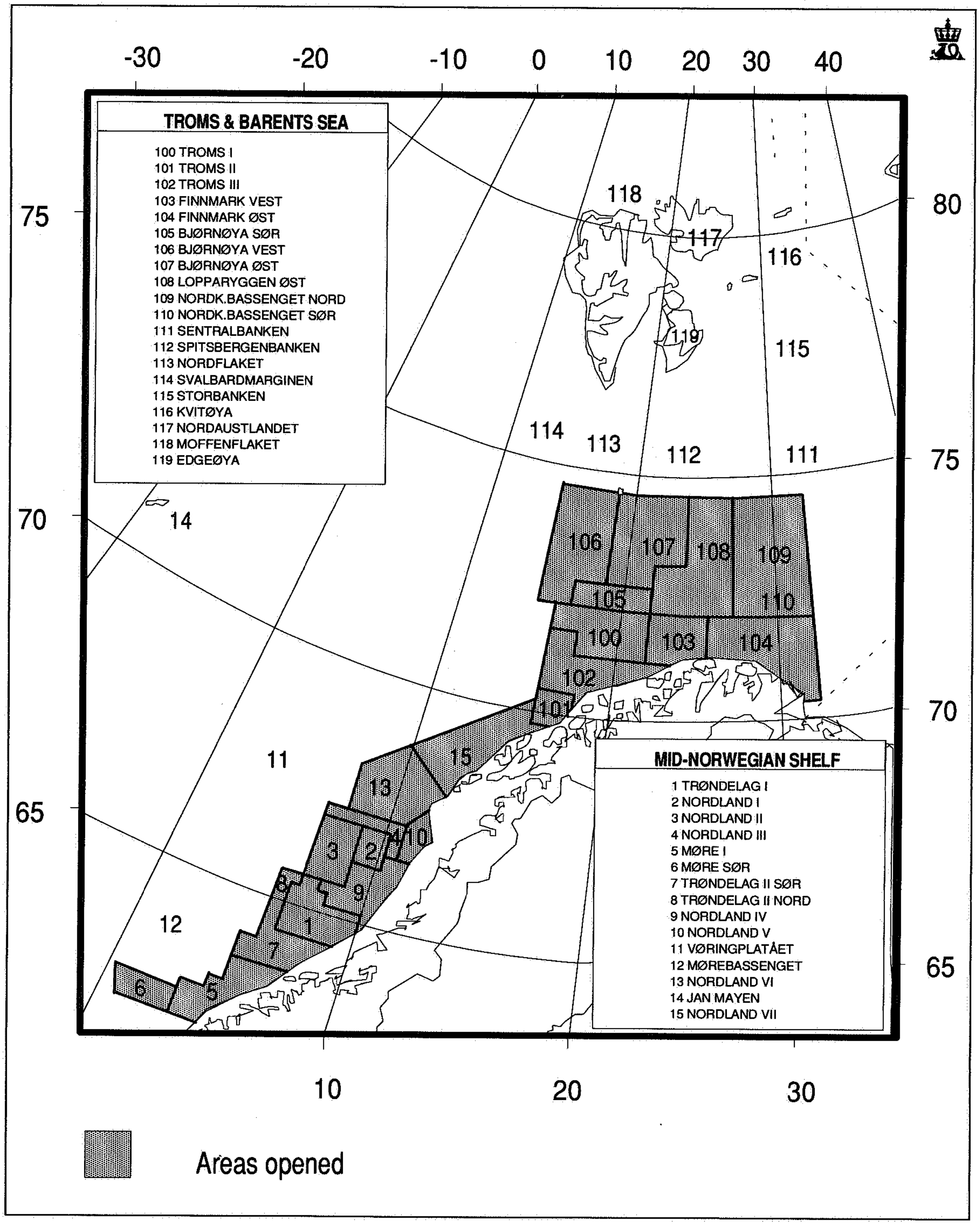
Trøndelag II, north of 64°15″

Agip, Amoco, Arco, BP, Britoil, Conoco, Deminex, DNO, Elf, Enterprise, Esso, Fina, Hydro, Mobil, Petrobras, Phillips, Saga, Shell, Statoil, Svenska Petroleum, Tenneco, and Total.

Trøndelag II, south of 64°15″

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

Fig. 2.2.1.2
Areas which are opened for seismic surveys by companies.
Area designations offshore Mid-Norway and in the Barents Sea



Nordland I

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

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

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

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

Nordland V
Conoco, Elf, Hydro, Mobil, Shell, Statoil, and Total.

Nordland VI
BP, Conoco, Elf, Enterprise, Esso, Mobil, Shell, Statoil, and Total.

Nordland VII
BP, Conoco, Elf, Enterprise, Hydro, Mobil, Shell, Statoil, and Total.

Troms I, east of 19°
Agip, Amerada, Amoco, Arco, BP, Conoco, Elf, Enterprise, Esso, Fina, Hydro, Mobil, Phillips, Saga, Shell, Statoil, and Total.

Troms I, west of 19°
Agip, Amerada, BP, Conoco, Elf, Enterprise, Esso, Hydro, Mobil, Phillips, Saga, Shell, Statoil, Tenneco, and Total.

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

Troms III
Agip, BP, Conoco, Elf, Enterprise, Esso, Hydro, Mobil, Phillips, Saga, Shell, Statoil, and Total.

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

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

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

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

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

Lopparyggen East
Agip, Amerada, Amoco, Arco, BP, Conoco, Deminex, Elf, Enterprise, Esso, Fina, Hydro, Mobil, Phillips, Saga, Shell, Statoil, Tenneco, and Total.

North Cape Basin, north of 73°15″
Agip, Amoco, Arco, BP, Conoco, Elf, Enterprise, Esso, Hydro, Mobil, Saga, Shell, Statoil, and Total.

North Cape Basin, south of 73°15″
Agip, Amerada, Amoco, Arco, BP, Conoco, Deminex, Elf, Enterprise, Esso, Fina, Hydro, Mobil, Petrobras, Phillips, Saga, Shell, Statoil, Svenska Petroleum, and Total.

Table 2.2.1.4 Survey of seismic data packages

Package		1990	Total
001	MØRE-TRØNDELAG-REGIONAL-PK-1		33
002	MØRE-TRØNDELAG-REGIONAL-PK-2		26
003	TAMPEN-SPUR		21
004	MØRE-SØR-84		21
005	TRØNDELAG-REGIONAL		25
006	HALTENBANKEN-VEST-84		23
007	FRØYABANKEN-84		26
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		9
013	REG-DATA-MIDT-N-SOKKEL		19
014	NORDLAND-II-83		21
015	NORDLAND-III-84	1	13
016	TROMS-II	1	12

Package		1990	Total
017	REGIONAL-DATA-TROMS-ØST		18
018	FINNMARK-VEST-83		19
019	FINNMARK-VEST-84		20
020	NORDLAND-III-85	1	13
021	MØRE-SØR-TEST-84 #)		5
022	STOREGGA-85		5
023	VØRINGPLATÅET	3	10
024	VØRING-BASSENGET-85/86	2	8
025	LOFOTEN-VEST-86	3	10
026	JAN-MAYEN-85		1
028	VØRING-BASSENGET-87	4	7
029	NORDLAND-VI-87	3	10
030	NORDLAND-VII-87	3	10
031	NORDLAND-V-87	5	8
032	NORDLAND-VI-88	5	9
033	NORDLAND-VII-88	6	9
034	NORDLAND-V-73–79	4	7
035	NORDLAND-VI-73–79	6	11
036	NORDLAND-VI-89	7	9
037	NORDLAND-VII-89	7	9
038	NORDLAND-VII-74/75	6	9
039	NORDSJØEN-SØR-TEST-89 #)	1	1
040	VØRING-BASSENGET-88	5	5
041	VØRING-BASSENGET-MERLIN-89	5	5
042	VØRING-BASSENGET-WESTERN-89	5	5
043	MØRE-BASSENGET-88	3	3
100	TROMS-HOVEDPAKKE		34
101	REG-DATA-TROMS-BAR.HAVET-73		21
102	TROMS-III-83/84	1	14
103	TROMS-III-85	3	13
105	TROMS-I-ØST-77	1	20
106	TROMS-NORD-82-PAKKE-1	1	24
107	TROMS-NORD-83-PAKKE-3	1	23
108	TROMS-NORD-82-PAKKE-2	1	16
109	TROMS-NORD-83-PAKKE-4	1	16
200	BJØRNØYA-PAKKE-1		21
201	BJØRNØYA-SØR-84		21
202	BJØRNØYA-ØST-REGIONAL-84		18
203	BJØRNØYA-ØST-84		17
204	BJØRNØYA-TILLEGG-NORD	17	
205	BJØRNØYA-VEST-REGIONAL-84	1	15
206	LOPPARYGGEN-ØST-REGIONAL-84		19
207	LOPPARYGGEN-ØST-85-SSL-DIAG		19
208	LOPPARYGGEN-ØST-85-NORD		19
209	LOPPARYGGEN-ØST-85-GECO-DIAG		19
210	LOPPARYGGEN-ØST-85-GRID		19
211	BJØRNØYA-ØST-TEST-85 #)		1
212	BJØRNØYA-VEST-86-DIAG	1	13
213	BJØRNØYA-VEST-86-HIGH	1	13
214	BJØRNØYA-VEST-86-MARGIN	1	12
215	BJØRNØYA-VEST-86-SWATH #)		1
216	BJØRNØYA-VEST-87	2	13
300	BARENTSHAVET-SØR-ØST-HOVEDPK		22
301	BARENTSHAVET-SØR-ØST-PAKKE-2		21
302	NORDKAPP-BASS-85-GECO-DIAG	1	20
303	NORDKAPP-BASSENGET-85-NORD	2	20
304	NORDKAPP-BASSENGET-85-GRID		21
305	NORDKAPP-BASSENGET-86-DIAG	1	20
306	NORDKAPP-BASSENGET-86-SØR	1	21
307	NORDKAPP-BASSENGET-86-NORD		14
308	FINNMARK-ØST-86-REGIONAL		19
309	FINNMARK-ØST-86-DIAG		18
310	FINNMARK-ØST-86-GSI		19
312	NORDKAPP-TEST-87 #)		1

2.2.1.5 Release of data and material from the continental shelf

In connection with the Norwegian Petroleum Directorate's monitoring of the oil activities on the Norwegian continental shelf the Directorate receives copies of well bore logs and continual, representative selections of drill cuttings and cores.

Cuttings samples are recovered every 10 meters downhole and every three meters if the formation potentially contains hydrocarbons. For wet samples, which should weigh at least half a kilo, the same sampling frequency is observed.

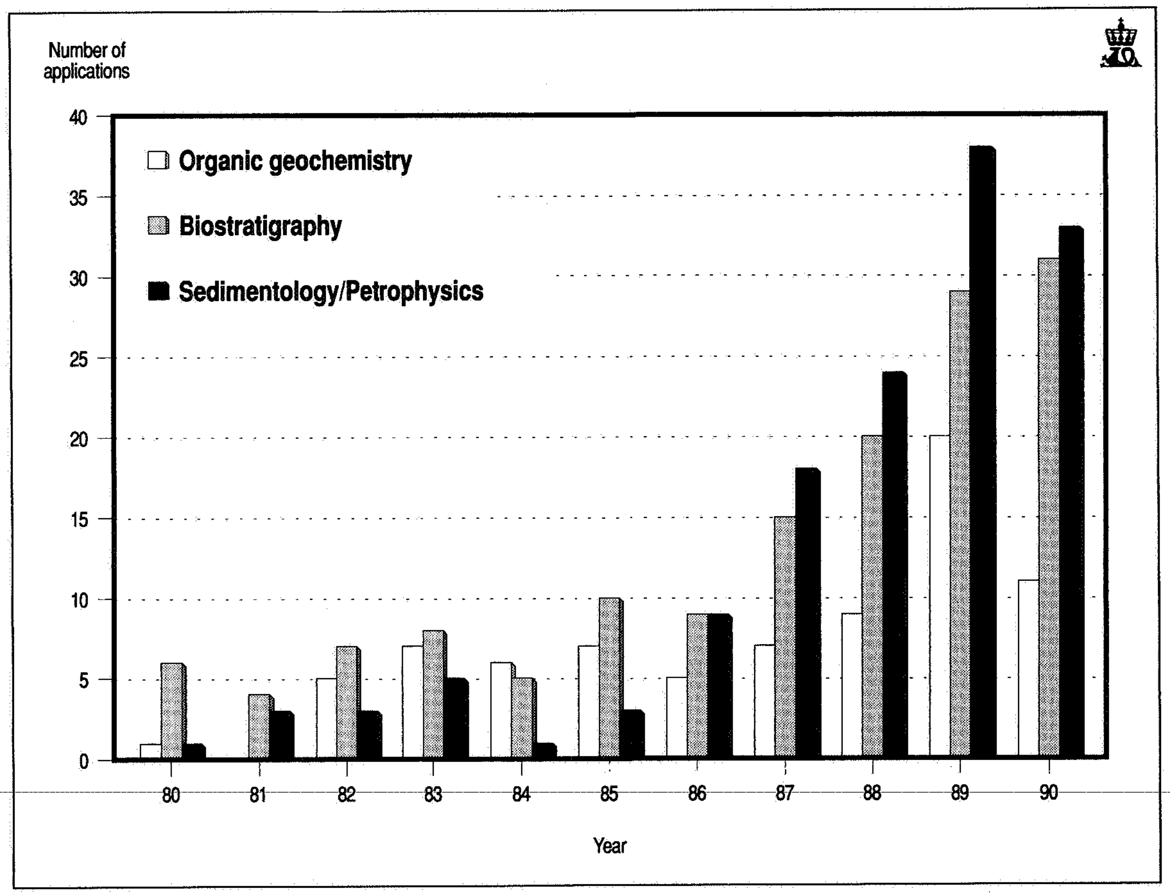
The Directorate receives a complete longitudinal section of core samples including minimum a quarter of cores in exploration wells and minimum half in production wells. As of 31 December 1990 the Norwegian Petroleum Directorate had stocks totalling 63,362 meters core material from 702 well holes, 338,857 samples of washed cuttings from 881 well holes, and 367,024 wet samples from 1035 holes. This includes production wells and material from 80 foreign well holes, mainly from the UK sector of the North Sea, but also including Svalbard, Andøya, Hopen, Tanzania, and Mozambique.

The Norwegian Petroleum Directorate is responsible for the publishing of data and release of material specimens for purposes of education and research. Data are released five years after the well is completed. The licensees' interpretations are not released. The NPD's *Well Data Summary Sheets* are issued once a year and provide a survey of wells five years old in the year of publication. The series aims to show which holes have been released and what core and log materials are available from the respective holes. Some technical data and test results are also issued as well as a composite log with lithographic specifications of each well hole to scale 1:4000.

In addition to its WDSS summaries the Norwegian Petroleum Directorate issues two publication series: *Licences, Areas, Area Coordinates, Exploration Wells* and *Borehole List, Exploration Drilling*. Both are published annually. The list of production licences contains a summary of each production licence on the Norwegian continental shelf, stating licence number, allocation date, operator, allocated area, present area, partners and units, geographical coordinate points for area in the production licence, some data about each well hole drilled in the licence, and a map of each licence area with the wells plotted in. Also included are some historical details and lists and tables presenting the drilling activity. The wellbore list is an extended version of the Directorate's previous wellbore lists. Exploration wells are sorted according to five different criteria: well number, spudding date, completion date, operator, and licence number.

In the Norwegian Petroleum Directorate's core study room it is possible to examine the core materials, drill cuttings and wet samples, and in special cases it may be possible to be issued material from

Fig. 2.2.1.5.a
Applications for sample material by subject



the collection in order to study and analyse it outside the confines of the Directorate. The five-year cut-off rule for release qualification also applies in this case. Figure 2.2.1.5.a shows the demand for specimens broken down by discipline: organic geochemistry; biostratigraphy; sedimentology and petrophysics.

From 1986 to 1989, the number of applications for release of material, and therefore also the number of studies based on released material, has risen sharply. In 1990, however, the number of organic geochemical and sedimentological or petrophysical applications has decreased by 24 per cent compared to the year before, whereas the number of applications for biostratigraphical examinations shows a continuing increase.

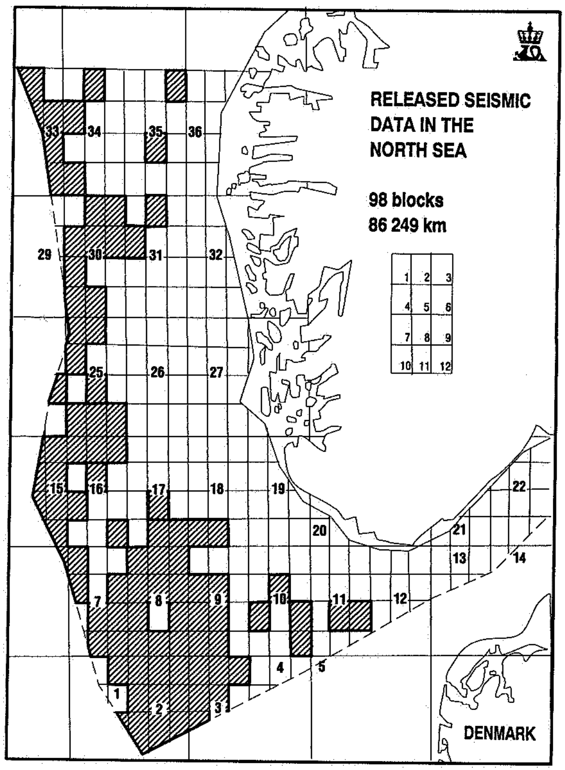
Figure 2.2.1.5.a shows that studies based on organic geochemistry constitute a minority of projects for which the Directorate has released material. On the other hand, this discipline accounts for the greatest volume of material released in the period 1986–90.

Figure 2.2.1.5.b shows a map identifying the North Sea blocks for which seismic data have been released. The routines for release of seismic data are currently under revision and will be explained in more detail in our 1991 annual report.

2.2.1.6 Scientific research

As of 31 December 1990, a total of 279 licences for scientific research had been awarded on the Norwegian continental shelf. As Table 2.2.1.6 shows, in 1990 seven such licences were awarded, one by the Norwegian Petroleum Directorate in Stavanger and the other six by the NPD Regional Office in Harstad.

Fig. 2.2.1.5.b
Blocks in which seismic data have been released



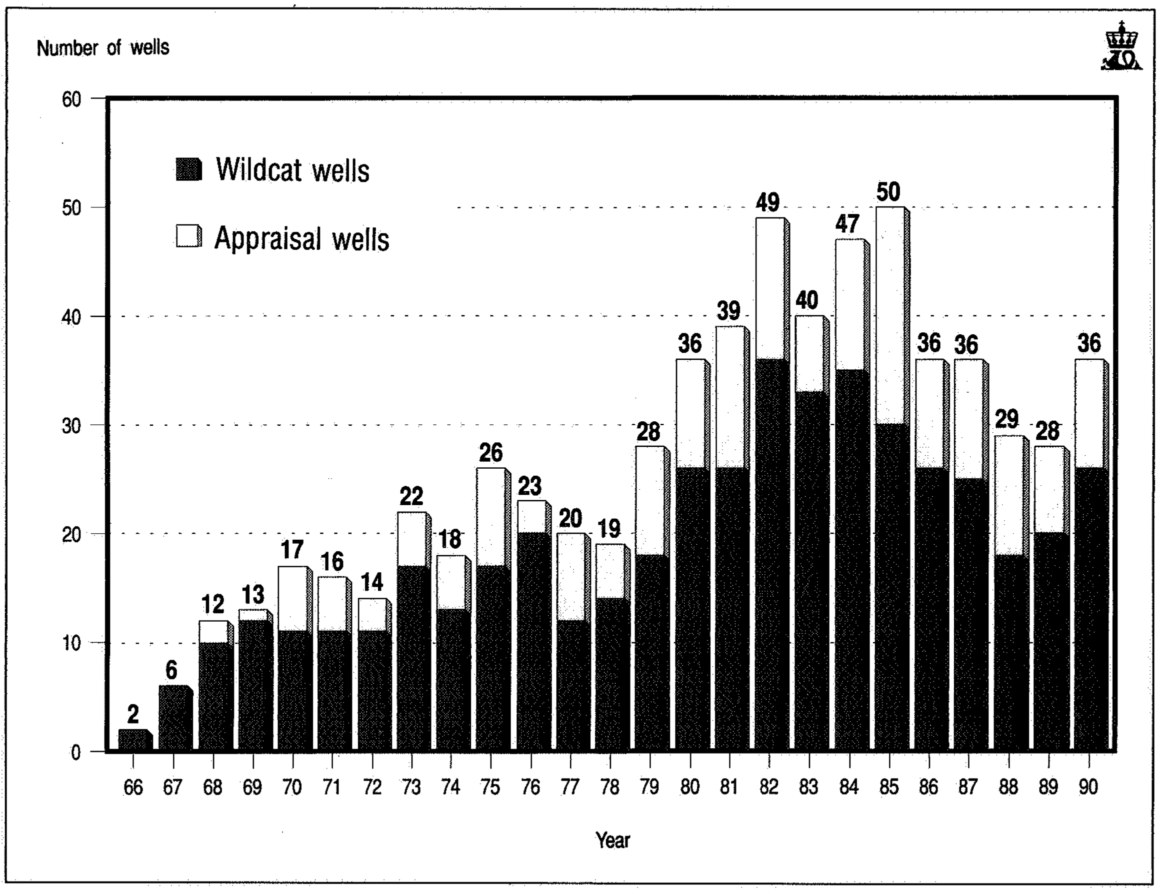
2.2.2 Exploration drilling

There were nine exploration wells being drilled at year end 1989. Of these, four were terminated, one was abandoned and four were suspended in 1990. Also in 1990, 36 new exploration wells were spudded, 26 wildcats and ten appraisal wells.

Table 2.2.1.6
Permits for scientific exploration for natural resources

Permit	Institution	Geo-physical survey	Geology	Biology	Area
257/90	Nederlands Instituut voor Onderzoek der Zee Nederland		X		Skagerrak, The Norwegian trench
17/90-H	Universität Hamburg Forbundsrepublikken Tyskland		X	X	Norwegian Sea Barents Sea
18/90-H	Murmansk Sevmorgeologija USSR	X			Svalbard and associated sea areas
19/90-H	Universität Hamburg Forbundsrepublikken Tyskland	X	X		Coast of Finnmark and southern Barents Sea
20/90-H	P.P. Sjirsjov Institutt for Oceanografi USSR		X		Northwestern part of Barents Sea
21/90-H	Norsk Polarinstitutt Oslo	X	X		West coast of Svalbard
22/90-H	Universitetet i Bergen Jordskjelvstasjonen Bergen		X		West coast of Svalbard

Fig. 2.2.2.a
Exploration drilling on the Norwegian continental shelf
Number of wells per year 1966–1990



Drilling activity in 1990 broke down with 27 wells in the North Sea, eight offshore Mid-Norway and one in the Barents Sea. In addition, ten suspended exploration wells were reopened in the course of the year. Twenty-five exploration wells were terminated and plugged in 1990, nine suspended, one abandoned and one converted to a production well. Nine exploration wells were being drilled as at 31 December 1990. By year end a total of 662 exploration wells had been spudded in the Norwegian sector, of which 475 were wildcat and 187 appraisal wells. See Figure 2.2.2.a. In all, 34 exploration wells had been abandoned on the Norwegian continental shelf at the end of the year.

Suspended exploration wells on the Norwegian continental shelf for which equipment has been installed on the seabed are as follows:

1/09–04	25/02–09	30/09–10
1/09–06 S	25/02–13	31/02–16 S
2/04–15 S	25/11–14 S	34/04–07
2/07–20	30/02–01	34/10–05
2/07–21 S	30/03–04	34/10–32 R
2/07–23 S	30/06–16	35/11–04

2/12–02 S	30/06–19	6407/07–03
7/11–10 SR	30/06–21	6407/07–04
15/09–17	30/06–22	6407/09–03
15/12–06 S	30/09–02 R	6407/09–05
25/01–08 SR3	30/09–09	6407/09–06
		6506/12–08

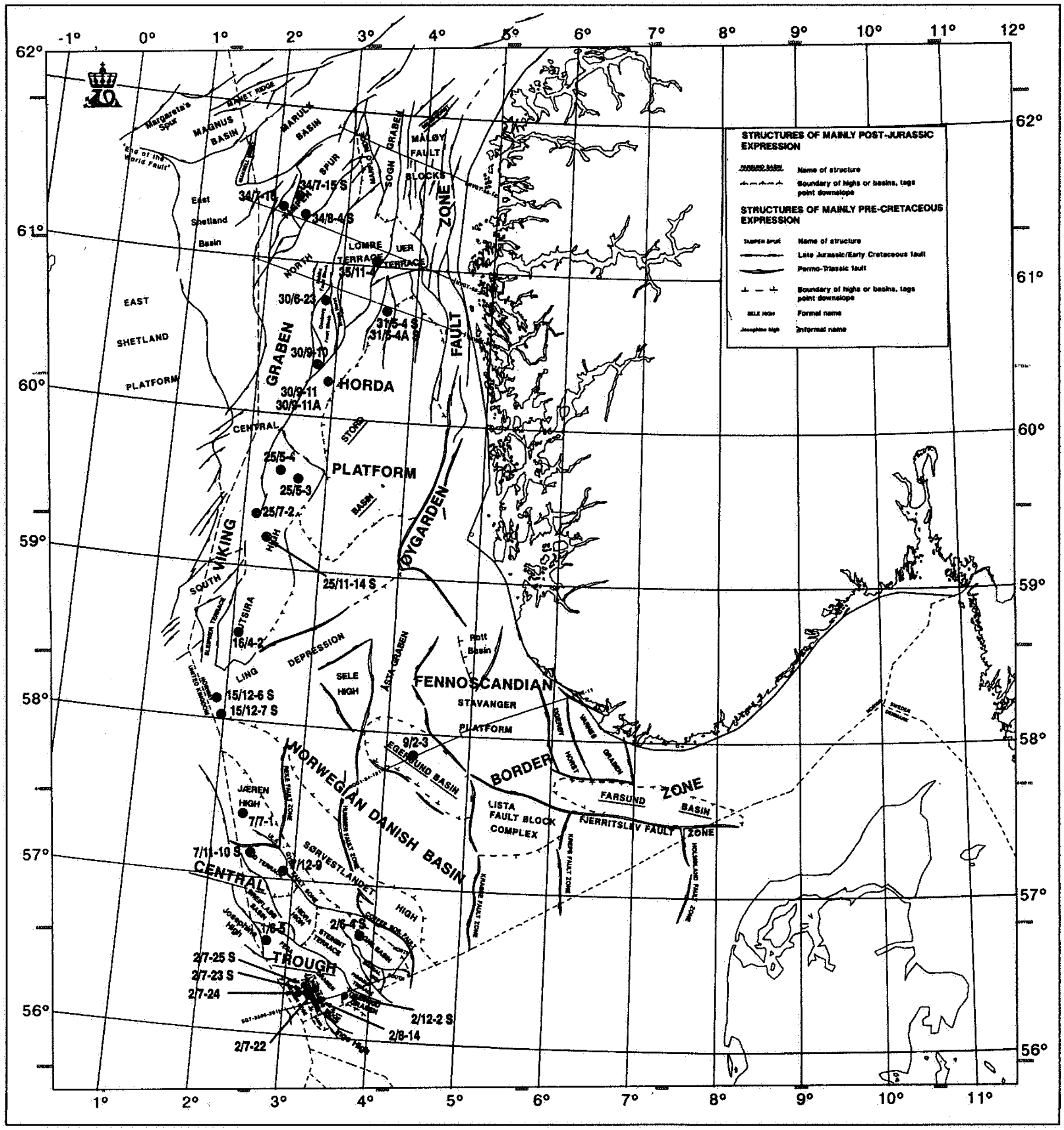
Figures 2.2.2.b, c and d show the wells spudded in the three regions of the Norwegian continental shelf (North Sea, Mid-Norway and Barents Sea) in relation to structural main features.

The Norwegian companies Saga, Norsk Hydro and Statoil operated 20 of the spudded wells in 1990, corresponding to 55.6 per cent. The remaining 16 wells were operated by Elf, Conoco, BP, Phillips, Esso, Amoco, Mobil, and Shell. See Table 8.2.c for details.

2.2.2.1 Distribution of prospect types

Exploration activity in 1990 was very largely directed to jurassic sandstone prospects. Of the 36 exploration wells spudded as of 31 December 1990, 29 had jurassic strata as their main prospect. Of the other main prospects, four were in palaeocene sand-

Fig. 2.2.2.b
Wells drilled in 1990 in the North Sea



stone, one in cretaceous, one in triassic and two in devonian sandstone. Of the secondary prospects, three were in tertiary, three in cretaceous, two in jurassic, two in triassic, and one in permian strata.

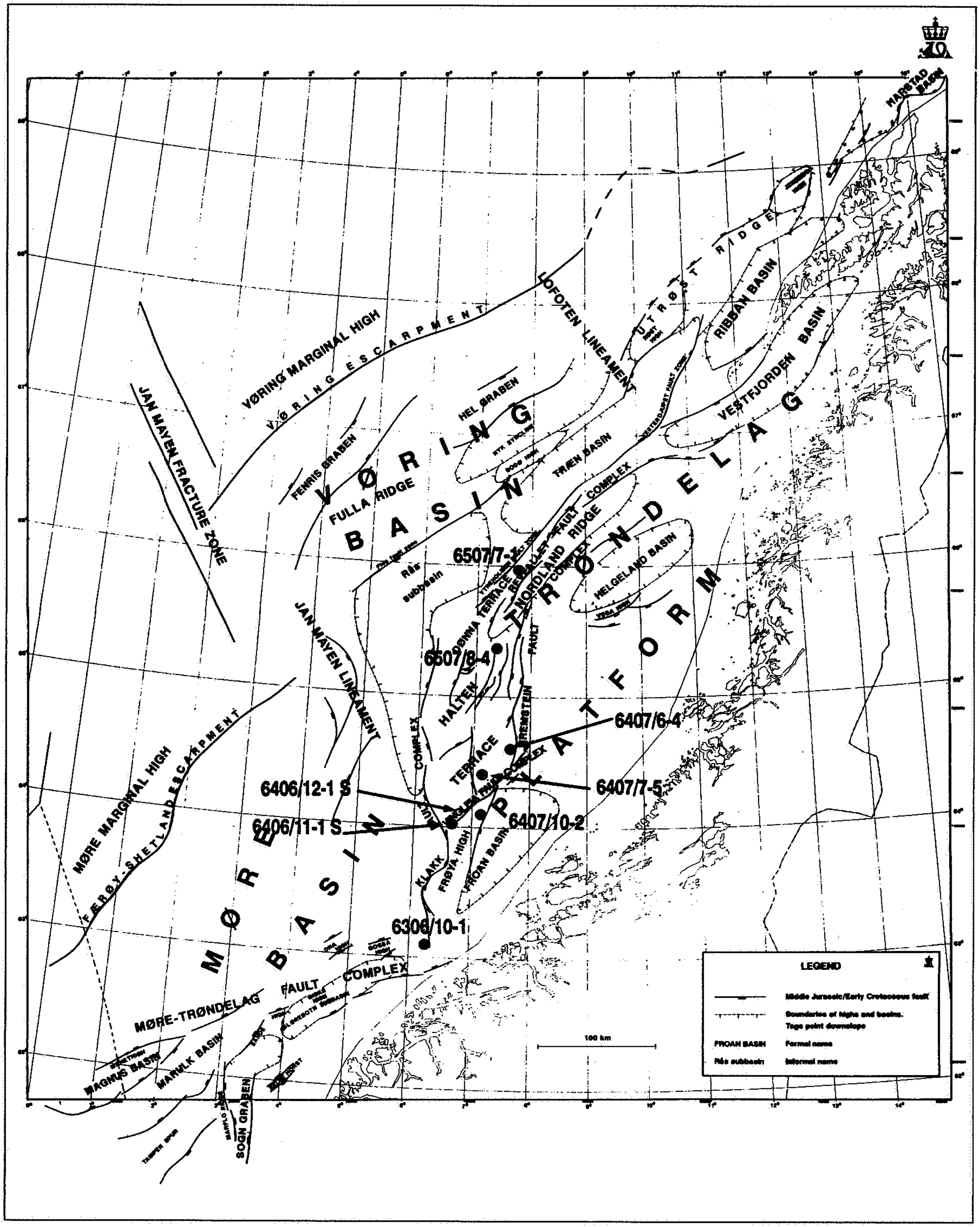
2.2.2.2 New discoveries in 1990

Thirty-six exploration wells were spudded on the Norwegian continental shelf in 1990 (Table 2.2.2.a), eight more than the year before. Twenty-six of the wells are classified as wildcat wells, ten as appraisal wells.

Fifteen of the 26 wildcat wells were drilled into new, previously unpenetrated structures. Ten new discoveries were tested in 1990. Well 9/2–3 was spudded in 1989, but because it was tested for production in 1990, it was assigned to this year. Eight of the 26 wildcat wells were dry, while nine had not reached down to prospective strata by year end.

As regards exploration drilling in general in 1990, activity was greatest in the North Sea with 27 holes spudded. Eight wells were spudded off Mid-Norway, while only one well was started in the Barents Sea.

Fig. 2.2.2.c
Wells drilled in 1990 on the Mid-Norwegian shelf



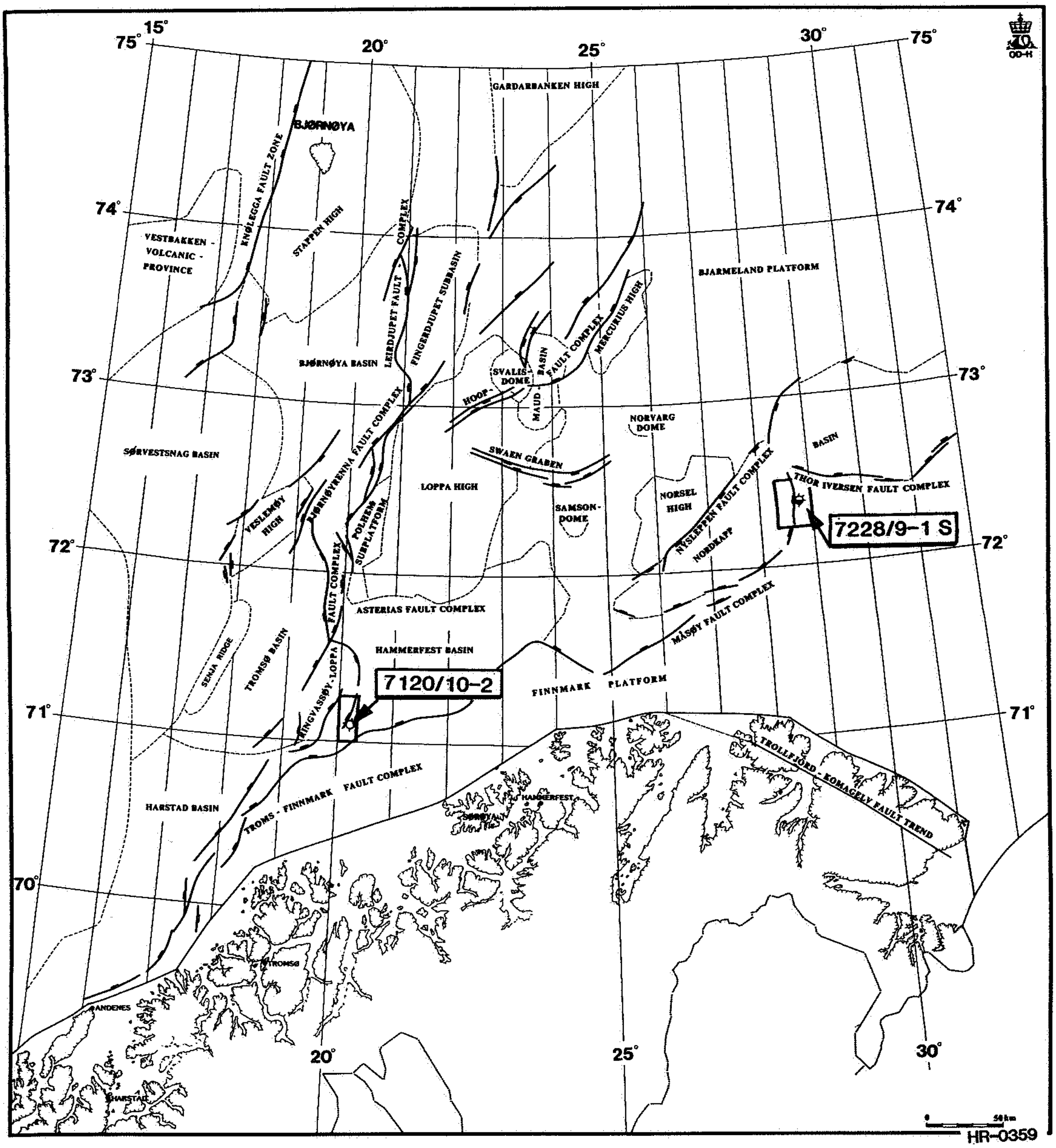
Block 2/7

BP as operator of production licence 145 drilled wildcat well 2/7–22 in a previously unpenetrated structure west of the Valhall field.

The well was drilled down to 4727 meters below sea level and hydrocarbons were proven in pre-cretaceous rock. The reservoir age is uncertain, but could possibly be triassic or permian.

A production test gave 226,000 scm gas a day, 207 scm condensate a day, and 334 scm formation water

Fig. 2.2.2.d
Wells drilled in 1990 in the Barents Sea



a day through a 12.7 mm choke. Gas density is 0.78 relative to air, while condensate density is 0.79 g/cc. Preliminary estimates indicate that the discovery is too small to be included in the Norwegian Petroleum Directorate's resources accounts.

Block 9/2

Statoil as operator of production licence 114 drilled the 9/2–3 wildcat. The drilled structure is located in the southwestern part of the block. The well was drilled to 3399 meters below sea level and terminated in middle jurassic rock. Hydrocarbons were proven during the drilling operation, and the well was tested for production. The aim of the test was primarily to find out whether one had struck residual or mobile hydrocarbons, which could not be finally determined on the basis of the logs and cores. The recoverable resources of oil are too small to be included in the resources accounts.

Block 15/12

Statoil as operator of production licence 038 drilled the 15/12–6-S wildcat. The well was drilled in a separate fault segment in the northwestern part of the

Table 2.2.2.a
Spudded and terminated exploration wells in 1990 as of 31 December

Exploration Well	Prod Licence No	Position North East	Spudded Terminated	Operator Drill rig	Well type/ Completion	Water depth KBE in metres	Total depth Geol period
2/07–19 R	262	56 20 18.36	90.01.15	Phillips	Wildcat	73	4873
	018	03 06 13.61	90.03.14	Ross Isle	Oil	22	Perm
2/11–06 SR	305	56 10 35.50	90.07.19	Amoco	Appraisal	72	4076
	033	03 27 36.72	90.08.13	Kolskaya	Oil	0	
30/06–09 R	339	60 30 03.46	90.05.09	Hydro	Wildcat	107	3476
	053	02 46 52.62	90.05.12	Polar Pioneer	Oil/Gas	23	Trias
25/01–07 R4	455	59 55 08.28	90.03.30	Elf	Appraisal	101	2722
	024	02 06 09.79	90.04.06	West Vanguard	Gas	22	Cret.
6407/07–02 R	532	64 15 26.39	90.03.07	Hydro	Wildcat	338	3320
	107	07 10 42.65	90.04.30	Vildkat	Oil	25	
2/04–14 R	593	56 41 05.49	89.05.08	Saga	Wildcat	68	4734
	146	03 08 43.06	90.04.06	Neddrill Trigon	Suspended	26	
2/04–14 R2	593	56 41 05.49	90.04.06	Saga	Wildcat	68	4264
	146	03 08 43.06	90.04.14	Treasure Saga	Junked	26	
2/04–15 S	602	56 40 27.25	89.01.31	Saga	Wildcat	68	4962
	146	03 08 38.79	90.03.16	Treasure Saga	Suspended	26	
2/07–21 S	610	56 19 59.63	89.06.21	Phillips	Appraisal	71	5044
	018	03 14 53.75	90.01.09	Ross Isle	Suspended	22	
34/10–33 CR	614	61 07 34.44	90.02.24	Statoil	Appraisal	134	3753
	050	02 12 57.10	90.04.27	Deepsea Bergen	Oil	23	
25/02–13	617	59 47 37.69	89.09.06	Elf	Appraisal	116	3909
	026	02 27 12.52	90.01.26	West Vanguard	Suspended	22	Trias
3/07–04	619	56 24 15.60	89.09.20	Shell	Wildcat	67	3723
	147	04 14 22.24	90.01.23	Hunter	Oil/Gas	25	Perm
6205/03–01	623	62 57 08.62	89.10.24	Hydro	Wildcat	157	4300
	154	05 56 38.11	90.02.11	Mærsk Jutlander	Suspended	22	
6205/03–01 R	623	62 57 08.62	90.09.20	Hydro	Wildcat	157	
	153	05 56 38.11	90.11.30	Mærsk Jutlander		23	
9/02–03	624	57 45 20.20	89.12.04	Statoil	Wildcat	79	3424
	114	04 22 13.50	90.02.08	Vildkat	Oil	25	Jura
7228/09–01 S	625	72 23 48.36	89.12.22	Hydro	Wildcat	279	4576
	161	28 43 08.67	90.05.07	Ross Rig	Oil/Gas	23	Paleozoic
7/07–01	626	57 24 56.88	89.12.30	Statoil	Wildcat	82	3500
	148	02 15 59.74	90.02.20	Deepsea Bergen	Dry hole	23	Trias
25/05–03	627	59 35 08.01	90.01.27	Elf	Wildcat	118	2878
	102	02 37 46.94	90.03.14	West Vanguard	Gas/Condensate	22	
25/07–02	628	59 16 28.59	90.02.08	Conoco	Wildcat	124	4850
	103	02 12 26.09	90.07.18	Dyvi Stena	Gas/Condensate	25	M.Jura
2/12–02 S	629	56 13 54.28	90.02.15	Hydro	Wildcat	70	5757
	113	03 42 16.63	90.09.14	Mærsk Jutlander	Suspended	22	Pre-Jura.
7/12–09	630	57 04 21.52	90.03.18	BP	Appraisal	70	3820
	019	02 52 56.51	90.05.14	Ross Isle	Oil/Gas	23	
6507/08–04	631	65 23 17.18	90.06.14	Statoil	Wildcat	354	2560
	124	07 23 59.65	90.08.13	Deepsea Bergen	Oil/Gas	23	Trias
2/06–04 S	632	56 38 59.29	90.04.08	Elf	Wildcat	55	3617
	008	03 47 23.27	90.06.02	West Vanguard	Dry hole	22	Perm
6407/10–02	633	64 13 44.34	90.05.03	Hydro	Wildcat	334	3825
	132	07 16 54.02	90.06.23	Vildkat	Traces of hydrocarb.	25	L.Jura
30/06–23	634	60 40 58.01	90.04.29	Hydro	Appraisal	151	3209
	053	02 55 58.97	90.07.01	Transocean 8	Oil/Gas	23	L.Jura
6507/03–01	635	65 58 29.85	90.05.12	Statoil	Wildcat	369	4757
	159	07 49 31.52	90.10.26	Ross Rig	Gas/Condensate	23	L.Jura
2/07–23 S	636	56 19 57.79	90.05.15	Phillips	Appraisal	71	
	018	03 14 53.64	90.11.21	West Delta		29	
2/07–22	637	56 17 46.25	90.05.17	BP	Wildcat	69	4750
	145	03 09 32.01	90.10.15	Ross Isle	Gas/Condensate	23	Pre-Cret.
34/07–15 S	638	61 24 38.59	90.05.23	Saga	Wildcat	306	4646
	089	02 12 53.22	90.09.04	Treasure Saga	Traces of hydrocarb.	26	L.Jura
16/04–02	639	58 35 47.03	90.06.29	Hydro	Wildcat	93	3117
	087	02 01 48.03	90.07.29	Vildkat	Dry hole	25	Jura
34/07–16	640	61 23 13.05	90.06.27	Saga	Wildcat	287	2700
	089	02 06 59.13	90.08.13	Scarabeo 5	Susp. after 9 5/8"	25	
34/07–16 R	640	61 23 13.05	90.09.04	Saga	Wildcat	287	2980
	089	02 06 59.13	90.10.15	Treasure Saga	Oil	25	Trias
7/11–10 S	641	57 07 12.51	90.07.05	Hydro	Appraisal	78	4566
	070	02 29 10.56	90.09.10	Transocean 8	Suspended	23	

Exploration Well	Prod Licence No	Position North East	Spudded Terminated	Operator Drill rig	Well type/ Completion	Water depth KBE in metres	Total depth Geol period
7/11–10 SR	641	57 07 12.51	90.09.25	Hydro	Appraisal	78	4566
	070	02 29 10.56	90.10.24	Vildkat	Susp. Oil	25	
35/11–04	642	61 01 59.93	90.08.18	Mobil	Wildcat	355	
	090	03 32 53.58	90.12.29	Yatzy		17	
7120/10–02	643	71 05 34.80	90.07.20	Esso	Wildcat	186	2500
	098	20 14 28.31	90.09.05	Byford Dolphin	Dry hole	25	Jura
15/12–06 S	644	58 04 40.30	90.08.19	Statoil	Wildcat	84	3050
	038	01 53 25.41	90.11.04	Deepsea Bergen	Susp. Oil	23	Trias
1/06–05	645	56 32 21.57	90.07.20	Conoco	Wildcat	70	1855
	144	02 48 04.77	90.09.02	Dyvi Stena	Traces of hydrocarb.	25	Perm
30/09–10	646	60 23 23.20	90.07.31	Hydro	Wildcat	95	3649
	104	02 47 13.16	90.09.21	Vildkat	Susp. Oil	25	L.Jura
2/08–14	647	56 15 48.93	90.08.14	Amoco	Wildcat	67	
	006	03 21 23.11	00.00.00	West Vanguard		22	
25/11–14 S	648	59 11 17.31	90.09.13	Esso	Appraisal	127	
	001	02 22 11.64	90.12.31	Byford Dolphin		25	
6306/10–01	649	63 09 26.32	90.09.07	Shell	Wildcat	83	
	155	06 19 41.45	90.12.17	Dyvi Stena		25	
31/05–04 S	650	60 43 16.19	90.09.13	Hydro	Appraisal	317	
	085	03 33 43.06	90.10.10	Transocean 8		23	
6406/11–01 S	651	64 02 46.02	90.10.19	Saga	Wildcat	315	
	156	06 36 14.16	00.00.00	Treasure Saga		25	
30/09–11	652	60 19 27.89	90.10.27	Hydro	Wildcat	108	
	104	02 55 44.00	90.11.19	Vildkat		25	
2/07–24	653	56 18 33.00	90.11.07	Phillips	Wildcat		
	018	03 19 23.56	00.00.00	Ross Isle		22	
6407/06–04	654	64 37 36.77	90.10.31	Mobil	Wildcat		
	092	07 40 56.25	90.12.13	Ross Rig		25	
15/12–07 S	655	58 00 49.93	90.11.06	Statoil	Wildcat		
	116	01 58 35.54	00.00.00	Deepsea Bergen		23	
31/05–04 AS	656	60 43 16.19	90.10.10	Hydro	Appraisal	317	
	085	03 33 43.06	90.12.13	Transocean 8		25	
30/09–11 A	658	60 19 27.89	90.11.19	Hydro	Appraisal	108	
	104	02 55 44.00	90.12.29	Vildkat		25	
2/07–25 S	657	56 19 59.69	90.11.29	Phillips	Appraisal	68	
	018	03 14 53.90	00.00.00	West Delta		20	
34/08–04 S	659	61 19 29.35	90.12.06	Hydro	Wildcat	309	
	120	02 25 19.14	00.00.00	Mærsk Jutlander		23	
6406/12–01 S	662	64 04 11.14	90.12.15	Statoil	Wildcat	330	
	157	06 43 56.91	00.00.00	Ross Rig		23	
6407/07–05	660	64 18 24.56	90.12.17	Hydro	Appraisal	327	
	107	07 10 51.42	00.00.00	Transocean 8		24	
25/05–04	661	59 36 33.22	90.12.22	Elf	Wildcat	123	
	102	02 28 32.07	00.00.00	Dyvi Stena		25	

KBE = Kelly Bushing Elevation, R = Reentry, X = Prospective depth not reached, S = Directionally drilled

Beta West structure centrally in block 15/12. The hole was drilled to 3027 meters below sea level and terminated in triassic rock. Hydrocarbons were found in late jurassic sandstone, and the well was production tested. Peak production was measured to 1100 scm oil and 67,100 scm gas a day through a 15.9 mm choke. Measured oil density was 0.85 g/cc. Evaluation of the discovery is currently ongoing so that it is still to early to say anything certain about the size of it. However, it has been ascertained that the results from the drilling operation and the test did not meet pre-drilling expectations.

Block 25/5

Elf as operator of production licence 102 drilled wildcat 25/5–3. The drilled structure lies some 15 km east-southeast of Frøy. The well was drilled to 2878 meters below sea level and terminated in triassic rock. Hydrocarbons were proven when drilling in middle jurassic sandstone, and a production test was run. The maximum measured production rate was 585,000 scm gas and 115 scm condensate a day through a 15.6 mm choke. The condensate density was 0.7 g/cc. The discovery has contributed to increased resources in the block and is encouraging with a view to future opportunities for discoveries in remaining prospects.

Block 25/7

Conoco as operator of production licence 103 drilled wildcat 25/7–2. The well was drilled down to 4812 meters below sea level and terminated in middle jurassic rock. Hydrocarbons were proven in late jurassic sandstone, and a production test was run. The maximum measured production was 255,000 scm gas and 230 scm condensate a day through a 15.9 mm choke. Condensate density was 0.77 g/cc. The drilling results are considered to be positive as the exploration model for the block was tested and confirmed. However, studies showed that the reservoir quality in the area close to the well is poor with respect to production. Evaluation is currently ongoing so that it is too early to say anything certain about the size of the discovery.

Block 30/9

In production licence 104 Hydro drilled wildcat 30/9–10. The drilled structure lies southeast of the Oseberg field, centrally in block 30/9. The well was drilled to 3624 meters below sea level and terminated in early jurassic rock. Hydrocarbons were proven in middle jurassic sandstone during the drilling operation, and a production test was made. The measured peak output was 970 scm oil and 77,600 scm gas a day through a 19.1 mm choke. Measured oil density was 0.866 g/cc. The well was temporarily plugged with future production or injection in mind. The discovery is currently being evaluated, and it is clear that it will lead to an increase in the resources in the Oseberg area.

Block 34/7

Saga as operator of production licence 089 drilled wildcat 34/7–16 in a structure south of the Snorre field. It was drilled to a total depth of 2980 meters below sea level and terminated in triassic rock. Oil was proven in jurassic rock, and two production tests were run. The maximum measured production rate was 1300 scm oil a day through a 12.7 mm choke and a gas-oil ratio of 47. Measured oil density was 0.836 g/cc. This is considered to be a significant oil discovery in an oil province that is already very important. Two new wells are to be drilled in 1991 on the continuation of the same structure to determine the size of the discovery.

Block 6306/10

Norske Shell as operator of production licence 155 drilled wildcat 6306/10–1, which is the second well drilled in the Møre I area. The well was drilled to a total depth of 3161 meters below sea level and terminated in bedrock. Two production tests were carried out, but it turned out that only small amounts of gas and oil could be produced due to impervious reservoir rock. One is nonetheless optimistic about further exploration drilling in this area. Norske Shell is now planning a major seismic survey in the block.

Block 6507/3

Statoil as operator of production licence 159 drilled wildcat 6507/3–1 in a structure in the northern part of the block. The well was drilled to a total depth of 4734 meters below sea level and terminated in early jurassic rock. Hydrocarbons were proven in jurassic rock, and a production test gave 1.07 mcm gas and 320 scm condensate a day through a 25 mm choke.

This was the first hydrocarbon discovery and the first production test in the Nordland II area. This structure is believed to extend into the adjacent block in the north, and the discovery will be explored further in 1991. The discovery was particularly satisfying as up to that point only dry holes had been drilled in this area, showing only traces of hydrocarbons.

Block 6507/8

Statoil as operator of production licence 124 drilled wildcat 6507/8–4 in a structure just northeast of the Heidrun field. This well was drilled to a total depth of 2560 meters below sea level and terminated in triassic rock. Hydrocarbons were proven in jurassic rock, and four production tests were run. The maximum measured production rate was 1700 scm oil and 770,000 scm gas a day through 25 mm and 16 mm chokes. The measured density was 0.908 g/cc for oil and 0.648 g/cc for gas. This oil and gas discovery is regarded with optimism and it will be re-explored in 1991.

2.2.2.3 Further details of drilling operations

Block 1/6

Conoco as operator of production licence 144 drilled wildcat 1/6–5 in a previously undrilled structure in the southern part of the block, about 15 km southwest of the Albuskjell field.

The well was drilled down to 1829 meters below sea level and terminated in permian rock. Although traces of hydrocarbons were proven in rock of presumed palaeocene age, a production test in the interval only resulted in production of formation water. The measured average production rate was 209 scm salt water a day through a 9.55 mm choke.

Block 2/4

Saga's well 2/4–14 was brought under control by means of relief well 2/4–15-S on 12 December 1989. The efforts to bring 2/4–14 under control had then been going on for nearly 11 months. The work of plugging the well properly went on for the first few months of 1990. Both 2/4–14 and 2/4–15 have now been plugged permanently and abandoned.

Saga has regularly carried out shallow seismic surveys in the surrounding area to get an idea of the extent of gas in shallow sand strata. These sand strata acted as recipients of hydrocarbons during the subterranean blowout. The shallow seismic surveys are also critical with regard to new drilling operations in the block.

Block 2/6

Elf as operator of production licence 008 drilled wildcat 2/6–4-S in a previously undrilled structure centrally in the block. The well was drilled to a depth of 3562 meters below sea level and terminated in permian rock. No hydrocarbons were proven during the drilling operation.

Block 2/7
Phillips as operator of production licence 018 tested wildcat 2/7–19-R which was temporarily plugged and abandoned in 1981.

Well 2/7–19-R is the only one that has been drilled in the structure and the production test was made in pre-cretaceous sandstone. Maximum measured production was 34.8 scm oil a day and 15,631 scm gas a day through a 11.9 mm choke. The gas-oil ratio was 449 scm/scm. The specific gravity of the oil was 0.807 g/cc, while gas density was 0.82 relative to air.

The low production rates indicate that the reservoir is relatively impervious, although serious problems involving loss of drilling fluid to the formation during drilling operations may also have resulted in poorer production properties. The structure is still considered interesting.

As operator of production licence 018, Phillips is drilling the 2/7–24 wildcat in a prospect in the southern part of blocks 2/7 and 2/8. The target reservoir had not been reached at the end of the year.

Embla appraisal wells
2/7–21-S, 2/7–23-S, 2/7–25-S
Phillips as operator of production licence 018 has engaged in appraisal drilling on the Embla field south of Eldfisk. The plan for development and operation for the field was approved in December 1990. Reservoir age is uncertain but is assumed to be older than jurassic, perhaps triassic. The two appraisal wells completed in 1990 did not lead to any change in the resources estimates.

Appraisal well 2/7–21-S was drilled to a depth of 4713 meters below sea level in a southerly direction. The drilling was a positive appraisal, and three production tests were run. The maximum measured production was 1236 scm oil a day and 447,140 scm gas a day through a 19.1 mm choke. The gas-oil ratio was 362 scm/scm, and the specific gravity of the oil was 0.808 g/cc, while gas density was 0.76 relative to air.

Well 2/7–23-S was drilled to delineate the Embla field in a northerly direction and reached a depth of 4436 meters below sea level. Hydrocarbons were proven but the well was not tested due to technical problems. The well will be side-drilled at a later date to allow a production test to be run.

Well 2/7–25-S was drilled to delineate the Embla field in a southeasterly direction. At year end the well had not reached the target reservoir level.

Block 2/8
Amoco as operator of production licence 006 drilled wildcat 2/8–14 in the same prospect as 2/7–24 is being drilled into. The drilling operation had not been completed at the end of the year.

Block 2/12
Hydro as operator of production licence 113 drilled the 2/12–2-S wildcat. The well was drilled west of the Mjølner field situated on the borderline between the Norwegian and Danish continental shelves. On the Danish side the field is called Gert.

The well was drilled to a depth of 5313 meters below sea level and terminated in pre-jurassic rock. Well 2/12-S contained only traces of hydrocarbons in early cretaceous rock and was therefore not tested. The result of the drilling operation led to reduced resources estimates for Mjølner.

Block 7/7
Statoil as operator of production licence 148 drilled 7/7–1. The well was drilled in a previously unpenetrated prospect to a depth of 3477 meters below sea level and terminated in triassic rock. No hydrocarbons were proven.

Block 7/11
Hydro as operator of production licence 070 drilled appraisal well 7/11–10-SR on the Mime field situated north of the Cod field.

The well was drilled down to 4227 meters below sea level and terminated in triassic rock. It proved hydrocarbons in jurassic rock. A production test was run showing 560 scm oil a day and 106,500 scm gas a day through a 12.7 mm choke. The specific gravity of the oil was 0.82 g/cc and gas density was 0.77 relative to air. The gas-oil ratio is 190 scm/scm. The well is currently being tested on a long-term basis with production to the Cod installation.

Block 7/12
BP as operator of production licence 019 drilled appraisal well 7/12–9 in the southern part of the Ula field. The well was drilled to a depth of 3798 meters below sea level and terminated in triassic rock.

Oil was proven in late jurassic sandstone. A production test and a water injection test were run. During the former 149 scm oil a day and 12,225 scm gas a day were produced through a 12.7 mm choke. The measured gas-oil ratio was 87 scm/scm. The specific gravity of the oil was between 0.821 and 0.825 g/cc, and gas density was between 0.90 and 0.93 relative to air. The water injection rate was 2067 scm a day. The drilling results led to a hike in the reserves estimates for the Ula field.

Block 15/12
Statoil as operator of production licence 116 drilled the 15/12–7-S wildcat. The intention was to test the hydrocarbon potential in a structure southeast in the block. The well was drilled to a depth of 3529 meters below sea level and terminated in triassic rock without striking hydrocarbons.

Block 16/4
Hydro as operator of production licence 087 drilled the 16/4–2 wildcat in a structure in the western part of the block. The well was drilled to a depth of 3092 meters below sea level. Since no hydrocarbons were

proven the well was permanently plugged and abandoned.

Block 25/11
Esso as operator of production licence 001 drilled appraisal well 25/11–14-S on the Balder field. The well will be tested over an extended period of time in spring 1991.

Block 30/6
Hydro as operator of production licence 053 drilled appraisal well 30/6–23 in the southern part of the Beta structure, northeast in the block. This section of Beta was proven in 1981 through the drilling of wildcat well 30/6–5 but was not tested due to the presence of hydrogen sulphide, H_2S. When drilling the shallow section a minor gas blowout occurred. However, the situation was quickly brought under control. The shallow seismics did not signal any presence of shallow gas.

The well was drilled to a depth of 3186 meters below sea level and terminated in early jurassic rock. The drilling results coincided nicely with the prognoses. Hydrocarbons were proven in middle jurassic sandstone, and three production tests were run. The maximum measured production was 1575 scm oil and 74,250 scm gas a day through a 25.4 mm choke. Oil density was 0.84 g/cc, and measurements of the amount of hydrogen sulphide showed 4–5 ppm. The drilling operation provided new and important information about the reservoir in this part of the Beta structure and will also form the basis for more accurate resources estimates. However, the well was plugged with a possible future long-term test in mind.

Block 30/9
Hydro as operator of production licence 104 drilled wildcat well 30/9–11 and appraisal well 30/9–11-A, the former being drilled in a structure southeast of the Oseberg field. The drilling operations were terminated in early jurassic rock at a depth of 2545 meters below sea level without hydrocarbons having been proven. The well was subsequently plugged back to a depth of 910 meters at which depth the drilling of 30/9–11-A started, the aim being to test the hydrocarbon potential in a structure west of well 30/9–11. Well 30/9–11-A was drilled down to 2710 meters below sea level and terminated in early jurassic rock. Only traces of hydrocarbons were proven in middle jurassic sandstone, and no production test was run.

Block 31/5
Hydro as operator of production licence 085 drilled the second horizontal well on Troll Vest, the 31/5–4-AS, the main objective being to perform a long-term test in the 13 meter high oil zone in the late jurassic Fensfjord formation. The well will be included in the TOGI project. The length of the horizontal section is about 800 meters, and the well is currently being used for test production from the thin oil zone on Troll West.

Block 34/7
Saga Petroleum as operator of production licence 089 drilled the 34/7–15-S wildcat in a structure east of the main fault. The well was drilled at an angle to a vertical depth of 4299 meters below sea level and terminated in early jurassic rock. Only traces of hydrocarbons were proven and the well was not tested.

Block 35/11
Mobil as operator of production licence 090 is in the process of drilling wildcat 35/11–4 in a structure in the extreme south of block 35/11. The well reached down to lower jurassic rock, and zones containing hydrocarbons were proven, and will later be tested for production.

Block 6205/3
Norsk Hydro as operator of production licence 154 drilled the first wildcat well in the Møre I area. It was drilled in two stages, first as 6205/3–1 up until 15 February, at which time it was temporarily abandoned. In the period from 15 February to 1 June there is a ban on drilling operations in this area. The well was reopened in the autumn as 6205/3–1-R and drilled to a total depth of 5241 meters below sea level and terminated in rock that was difficult to date, but presumably jurassic. The location of the well is in the northeastern part of the structure. A production test was run but it then turned out that the proven hydrocarbons could not be produced due to the impervious rock. One is nevertheless optimistic in regard to further exploration drilling in this area.

Block 6406/11
Saga Petroleum as operator of production licence 156 is in the process of drilling the first wildcat well, 6406/11–1-S, in a structure in the southeastern section of the block, the aim of which is to explore the potential for hydrocarbons in middle jurassic sandstone.

Block 6407/6
Mobil as operator of production licence 121 (block 6407/5) drilled the 6407/6–4 wildcat in the southeasterly extension of the Mikkel structure. The well was allowed to be placed in the neighbouring block 6407/6 operated by Statoil, and was drilled to a depth of 3101 meters below sea level and terminated in early jurassic rock. Only traces of hydrocarbons were proven and the well was not tested.

Block 6407/10
Norsk Hydro as operator of production licence 132 drilled the 6407/10-2 wildcat just southeast of the Njord field. The well was drilled in a separate structure and completed in early jurassic rock at a depth

of 3800 meters. Only minor traces of hydrocarbons were proven, and the well was not tested.

Block 7228/9
Norsk Hydro as operator of production licence 161 drilled the 7228/9-1-S wildcat in a structure just east of the North Cape Basin. Only traces of oil and gas were proven in jurassic and triassic sandstone. The well was not tested for production.

Block 7120/10
Esso as operator of production licence 098 drilled the 7120/10-2 wildcat. The production licence was allocated in the eighth licensing round. The block is located in the southern part of the Hammerfest Basin, and the well was drilled in order to test cretaceous sandstone in a fan-shaped feature. No hydrocarbons were proven.

2.2.2.4 Svalbard
There was no drilling activity for petroleum deposits at Svalbard in 1990. However, Norsk Hydro, in collaboration with Store Norske Spitsbergen Kullkompani, has mobilised drilling installations and equipment to commence drilling operations in Reindalen in January 1991. Figure 2.2.2.4 shows the drilling locations at Svalbard, while Table 2.2.2.4 shows drilling licences awarded for Svalbard in connection with oil and gas drilling.

2.3 FIELDS UNDER CONSIDERATION
2.3.1 North Sea

Ekofisk area

Mjølner
Mjølner lies in block 2/12 in production licence 113, allocated in 1985, with Norsk Hydro as operator. The field straddles the borderline between the Norwegian and Danish continental shelves. The distribution of resources has not been negotiated between the Norwegian and Danish sectors, nor has one decided on a development concept.

Southeast Tor
This field is located in block 2/5 in production licence 006, allocated in 1965, with Amoco as operator. The Norwegian Petroleum Directorate estimates the recoverable oil resources to be some 2–3 mcm and the gas resources to be 2 bcm. The development concept has not been chosen.

Trym
The Trym field was proven by the drilling of well 3/7–4 and lies in production licence 147, where Shell is operator. The field, which is a gas condensate field, extends into the Danish sector. It has not been decided what development concept to opt for.

Fields around Ula
Block 1/3 is the neighbouring block to the Gyda field in the west, with Elf as operator. A small oil discovery has been proven in the field which probably extends into block 2/1. There is no communication between the Gyda field and the 1/3–3 structure.

On block 2/2, the neighbour to Gyda in the east where Saga is operator, another small oil discovery has been proven. The water depth here is only moderate, 60 meters.

In block 7/8 northwest of Ula under Conoco's operatorship yet another small oil discovery has been made.

The development of these discoveries, if implemented, needs to be considered in connection with development of the infrastructure in the immediate vicinity.

In block 7/11 between Cod and Ula, Hydro made an oil discovery, Mime. In June 1989 Hydro applied for permission to run test production on the field. The Ministry of Petroleum and Energy gave its permission in August 1989. Test production started in October 1990 and will continue for 1 1/2 years, or until 0.21 mcm oil has been produced, whichever occurs first. Production will be from one well, the well flow from which will be routed to the Cod installation for processing in the test separator. The oil and gas will be mixed with the Cod-produced oil and gas before transportation to the Ekofisk field for end processing.

Sleipner area
In the latter half of 1990 the operator of production licence 046 applied to develop the Sleipner satellite field 15/9 Theta, which has pressure communication with Sleipner East. The operator plans to drain the field by means of a single well, but prefers to use a subsea template with four slots, where the plan is to use the remaining slots to drain Theta Triassic, Theta West Heimdal, and any other satellites.

Furthermore, discoveries have been made on the British side of the 15/5 block which extend into the Norwegian sector. The operator of production licence 048 plans to drill the structure in the first half of 1991, as exploration well 15/5–4. Preliminary thoughts on development concept tend toward phasing the field into the Sleipner A installation or into the British Brae or Miller installations.

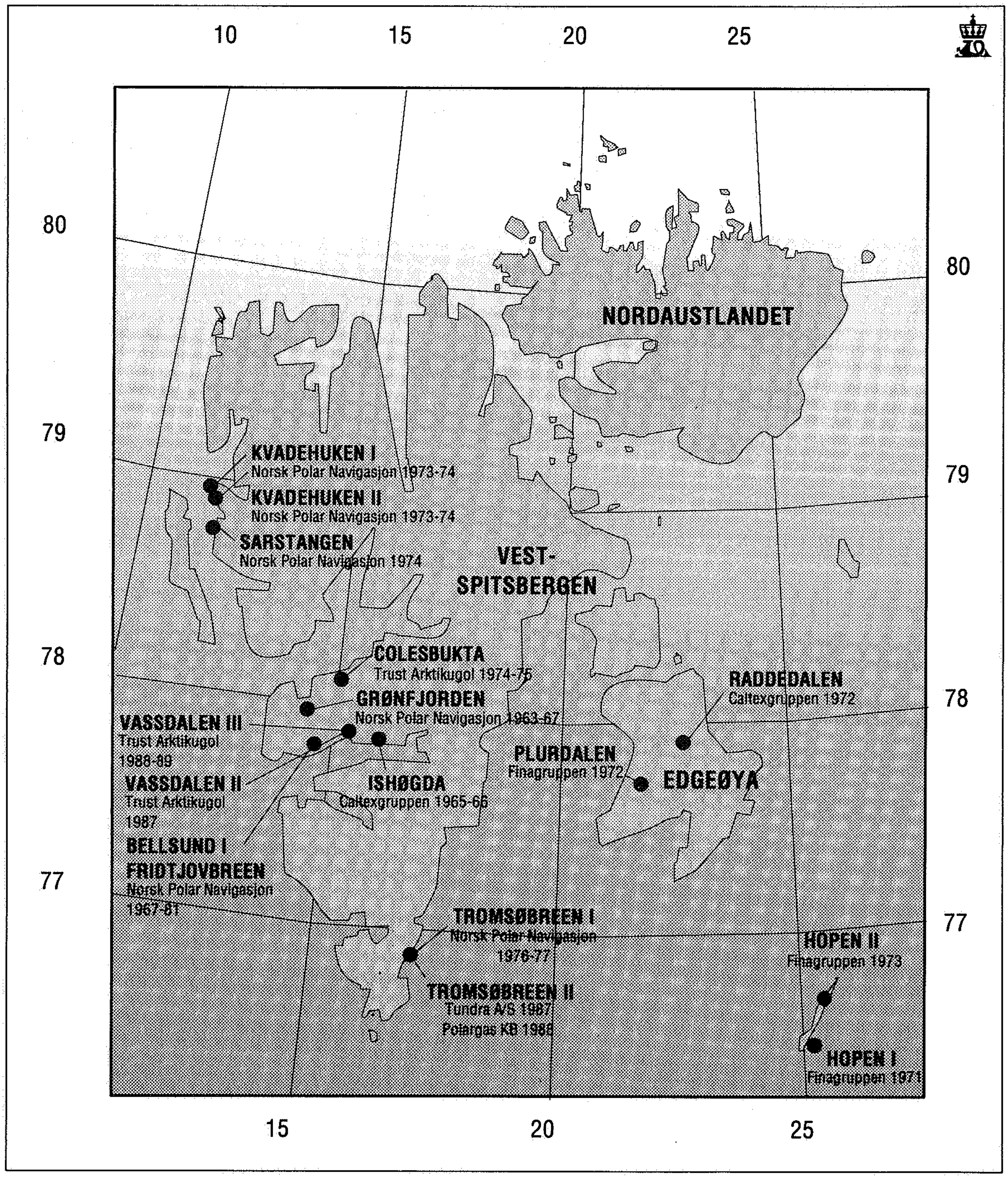
Frigg area

Balder
Balder was proven in 1974 by exploration well 25/11–5 in sandstone dating from the palaeocene. Later, hydrocarbons were also proven in eocene sand. The field is situated in blocks 25/10 and 25/11 in production licences 001 and 028 where Esso is the operator.

The Norwegian Petroleum Directorate estimates the recoverable reserves at 35 mcm oil.

Esso drilled and tested well 25/11–14 in 1990. However, the well has been temporarily abandoned pending test production from Petrojarl I in the first

Fig. 2.2.2.4
Well locations on Svalbard



half of 1991. The outcome of this test will decide the subsequent progress on the field.

25/5–3

Well 25/5–3 lies in block 25/5, production licence 102, allocated in 1985 with Elf as operator. The discovery was proven by well 25/5–3 in 1990 in the Brent group, in middle jurassic sandstone.

The operator's estimates for recoverable resources are 9.1 bcm gas and 1.7 mcm condensate. These figures are identical to the Directorate's figures.

The operator engaged in reservoir studies for the field in 1990, and the plan for development and operation is expected at the end of 1991, in which case production can be expected to commence at the end

Table 2.2.2.4
Drilling activity on Svalbard

Exploration well/ Location	Position North East	Spudded	Terminated	Days drilling	Operator Licensee	Total depth m	KB over MSL 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-gruppen	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-gruppen	908	9.1
7722/3–1 Raddedalen (Edgeøya)	77 54 10 22 41 50	02.04.72	12.07.72	100	Total Caltex-gruppen	2823	84
7721/6–1 Plurdalen (Edgeøya)	77 44 33 21 50 00	29.06.72	12.10.72	108	Fina Fina-gruppen	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-gruppen	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	01.11.89		Trust Arktikugol	2352	15.13

1) Drilling abandoned due to technical difficulties.
* KBE over MSL = Kelly Bushing Elevation over Mean Sea Level.

of 1994. A probable development solution will be a subsea installation connected directly with Frigg or Heimdal, or indirectly via Frøy.

Frøy

Frøy was proven by well 25/2–6, production licence 026, in 1977. The field lies essentially in production licence 102, allocated in the ninth licensing round, with Elf as operator. Drilling of well 25/5–1 in 1987 proved hydrocarbons in the Sleipner formation.

The operator's estimates for recoverable resources are 16.5 mcm oil, 1.4 mcm NGL and 3.5 bcm gas. The Norwegian Petroleum Directorate is currently updating the resources estimates for the field.

In 1990, the operator submitted its commerciality declaration, and the plan for development and operation is expected in the first half of 1991. The development solution, which is likely to be a wellhead installation, will be operated from Frigg or Heimdal. A development involving five production wells and four water injection wells is planned.

The operator will drill an appraisal well 25/2–14 in a separate structure on the field early in 1991, and the results from this well may influence the choice of development solution for Frøy.

Lille Frigg

Lille Frigg is situated in block 25/2, production licence 026, allocated in 1969 with Elf as operator. The field was proven by well 25/2–4 in 1975 in the Brent group of middle jurassic sandstone. Drilling of well 25/2–12 in 1988 was followed by work to submit a commerciality declaration.

The operator's estimates for recoverable resources are 7 bcm gas and 3.7 mcm condensate, which are identical to the Directorate's figures.

In 1990, the operator submitted an evaluation program for the field, and the plan for development and operation is expected in 1991, in which case production start-up can be anticipated at the end of 1993. A likely development solution will consist of a subsea installation with three to five production wells.

Oseberg area

Several fields are being considered in this area in addition to those already in production (Oseberg and Veslefrikk) or those that have been resolved to be developed (Brage and 30/6 Gamma Nord). Fields currently being considered include 30/9 Omega, Hild, 30/6 Kappa, 30/6 Beta, and Huldra.

30/9 Omega

30/9 Omega is situated to the west of the Oseberg field center in production licences 079 and 104. The structure is divided into Omega Nord and Omega Sør. In Omega Nord, gas and oil have been proven in the Ness and Tarbert formations, and oil has been proven in Tarbert in Omega Sør. It is uncertain whether there is communication between the northern and southern parts of Omega.

Omega Nord can be reached through wells from the Oseberg field center and can be produced from there. The development concept for the southern part is uncertain and will depend on the size of other discoveries in the area, such as 30/9–6 and 30/9–9.

Hild

Hild straddles two production licences, 040 covering blocks 29/9 and 30/7, and 043 covering blocks 20/6 and 30/4. Norsk Hydro is operator for production licence 040, while BP is operator for production licence 043. These blocks were allocated in 1974 and 1976, respectively. If Hild is developed, unitisation negotiations must be conducted between the two production licences.

In 1990, neither of the production licences were drilled. A well with short-term testing is planned on the field in 1992, and the plan for development and operation is also scheduled for 1992.

Preliminary plans involve field development using subsea installations and transfer of the well flow to the Frigg field.

30/6 Kappa

30/6 lies west of the Oseberg field center, with most of the structure located in production licence 053 and the southern part extending into production licence 079 in block 30/9. Oil and gas have been proven in the Statfjord formation. Development plans for the field have not been determined, but it is included in the fields considered in Hydro's plans for the Oseberg area.

30/6 Beta

30/6 Beta consists of two structural elements which are separated from one another by a sealing fault. Both elements are covered by production licence 053 where Hydro is the operator. Oil has been proven in several formations in the Brent group. The reservoirs are complicated and there are several different oil-water contacts and relatively low permeability. The recoverable resources are estimated at some 19 mcm oil.

Hydro's plans are for development involving an installation with partial processing and transfer of gas and oil to the Oseberg field center or Oseberg C for further treatment. The plan for development and operation will probably be submitted in autumn 1991, and production start-up is projected for 1996.

Huldra

Huldra is a gas field located northwest of Veslefrikk. The bulk of the field lies in block 30/2 in production licence 051, although the field probably also extends into production licence 052 in block 30/3. Statoil is operator for both production licences.

Gas has been proven in the Brent group, and Statoil's estimates of the recoverable resources are some 22 bcm gas and 9 mcm condensate. The operator is contemplating field development employing a wellhead or subsea installation with transport to Statfjord B for processing. Preliminary plans assume production start-up in autumn 1994.

Gullfaks area

Gullfaks Sør, 34/10 Beta and 34/10 Gamma

Block 34/10 was allocated in 1978 with Statoil as operator, see history of Gullfaks in section 2.5.11. Gullfaks Sør lies in the middle of the block, about 9 km south of the Gullfaks field. The Beta field lies to the west of Gullfaks Sør and extends into 33/12. Gamma lies in the southeastern corner of the block.

Gullfaks Sør is structurally complex: several unconnected gas-oil, gas-water and oil-water contacts have been detected. Hydrocarbons have been proven in sandstone dating from the mid and early jurassic period and triassic period.

So far, nine wells have been drilled to reservoir level on Gullfaks Sør in addition to one on Beta and one on Gamma.

In 1989, Statoil carried out a test production in which some 60,000 scm oil was produced in the course of one month.

The test production in the oil zone was performed to obtain important information on the production conditions in the reservoir.

Together with new 3D seismics the test results form the basis for remapping and new resources estimates, such estimates being highly speculative as far as Gullfaks Sør is concerned.

Statoil is currently preparing the plan for development and operation of Gullfaks Sør, which is likely to be presented to the authorities in spring 1991. The plan will contain a stepwise development of Gullfaks Sør with test production as in phase 1. Test production is likely to take place from five wells over a period of about two years. Production will be from a wellhead installation or a subsea installation. The well flow will be transported to Gullfaks for processing.

Tordis

Tordis comes under production licence 089 and was proven by the drilling of well 34/7–12 in 1987. An appraisal well, 34/7–14, was drilled on the field in autumn 1989. Based on these two wells the field was declared commercial, and the plan for development and operation was submitted in December 1990.

The Directorate estimates the recoverable resources to be 18.8 mcm oil, almost the same as the operator's estimates.

The plan is to develop the field with seabed completion wells, with drainage from five production wells and two water injection wells. The well flow will be phased into Gullfaks C for processing, metering and onward transportation. According to the operator's plans production will start in autumn 1994.

Visund

At year end 1990 Hydro started drilling of the fourth wildcat well in block 34/8 covered by production licence 120. The purpose of this well is to test the southern extension of the field. Hydro has previously drilled three wildcat wells and one appraisal well in this block. The two wildcat wells in the so-called A structure proved considerable quantities of oil and gas. In the course of 1990 new seismic surveys were shot over parts of the field. Together with the results from the ongoing drilling operation the seismic surveys will provide valuable information on the resource potential of the block, which is believed to be relatively great. Plans for 1991 include shooting more seismics over the field and drilling two wells. One of the wells is to delineate Visund further, and the other is to be drilled in another previously undrilled prospect in the block.

2.3.2 Off Mid-Norway

Njord

Five exploration wells have now been drilled in 6407/7 and four of these have proven oil. Although the two wells drilled in 6407/10 did not prove oil, it is nevertheless assumed that the field extends into block 6407/10. The Norwegian Petroleum Directorate puts the field's in-place resources at 25 mcm recoverable oil and 4 bcm recoverable gas.

Tyrihans

Two wells have been drilled on Tyrihans which consists of two structures, one holding gas and condensate and the other having a thin oil zone and gas dome. The resources estimates are 16 mcm recoverable oil and condensate and 40 bcm recoverable gas. Figure 2.3.2 shows the area off Mid-Norway.

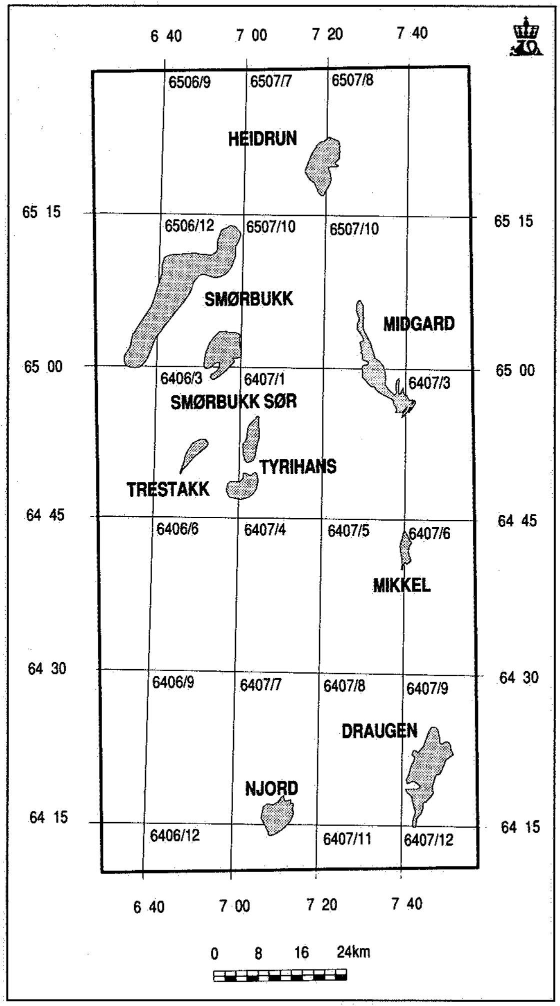
Midgard

Four exploration wells in all have been drilled on the Midgard field, a structure which is divided into three parts by two transverse faults. The field predominantly contains gas and the reservoir properties are good.

In one of the fault blocks a thin oil zone has been proven which may be troublesome to produce since it is situated between a large gas dome and an aquifier. The Directorate assumes recoverable resources of 80 bcm gas and 15 mcm oil.

Production start-up and output will depend on the gas market. The development options being considered for the field are a fixed platform or a floating installation.

Fig. 2.3.2
Fields offshore Mid-Norway



Smørbukk and 6506/12 Beta

A total of eight wells have been drilled in this block. The two fields contain partially gas condensate and partially oil with a relatively high gas-to-oil ratio.

The Directorate's resources estimates for Smørbukk are 20 mcm recoverable oil and condensate and 65 bcm recoverable gas.

The estimated resources for 6506/12 Beta are 22 mcm oil and condensate and 11 bcm gas.

Of the two discoveries in the block, 6506/12 Beta is the most mature and likely to be developed since its liquids potential is held to be greater than for Smørbukk. The Beta structure might be recoverable using gas recirculation, thereby displacing sale of the gas some years into the future.

Heidrun

The operator declared the field commercial in December 1986, and the plan for development and operation was submitted to the authorities in November 1987. In December 1989, the operator presented a revised plan for development and operation of the field. The revised plan was considered by the Norwegian Petroleum Directorate in March 1990, but had not been fully considered by the Ministry by the end of the year.

Eight wildcats and appraisal wells have been drilled on Heidrun, a field which contains oil with an overlying gas dome. The reservoir is heavily faulted and contains several geological formations. In order to get the most from the reservoir the gas dome should be produced after most of the oil has been recovered.

The resources in the Heidrun field give rise to considerable speculation. The Norwegian Petroleum Directorate estimates the field resources at 87 mcm recoverable oil and 38 bcm marketable gas, while the operator puts recoverable oil resources at 119 mcm and marketable gas at 47 bcm.

The operator is currently planning to develop the field using a tension leg concrete platform, installed over a subsea template with 58 well slots.

The operator has examined several strategies for uses of associated gas, including reinjection of the gas into the reservoir, injection of the gas into a water-flooded structure in the vicinity, or landing for use in Mid-Norway.

2.3.3 Barents Sea

On Troms I about 250 bcm recoverable gas have been proven, see Figure 2.3.3. In addition, there is a thin oil zone on Snøhvit.

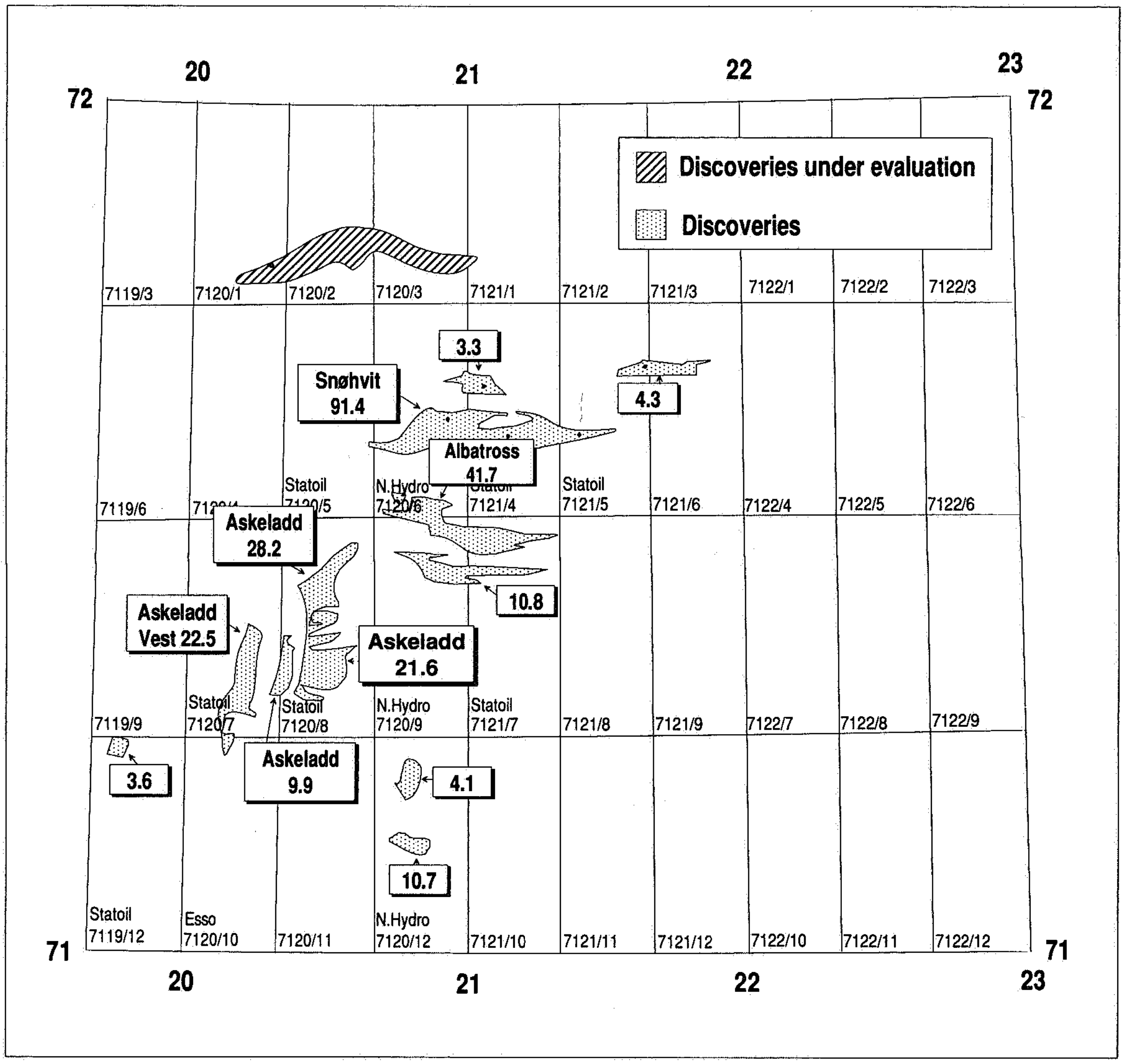
Snøhvit

For several years now the licensees have studied possible development concepts for the Snøhvit gas. Pipeline transportation of the gas has been found commercially inviable due to the long distance to potential gas markets. Thus, any field development must include a facility whereby the gas can be cooled to LNG. This will require additional investments compared to a traditional development of a gas field. In the last few years the development studies have therefore concentrated on finding simple and inexpensive solutions that are commercially sound. The following concepts are considered to be the most interesting:

- A semi-submersible floater with production from wells arrayed in templates on the seabed, involving processing of the gas on the floater before transportation to a land-based LNG terminal;
- Subsea production system, with well flow to be carried directly to an LNG terminal onshore. When the reservoir pressure becomes low the subsea unit must be connected to an installation in order to pump the gas to shore.

Two alternative production rates are being considered: 4.5 bcm a year and 9.0 bcm a year. This corresponds to a gas sales volume of 3.85 and 7.70 bcm a

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



year after separating out condensate. In the event the high rate is chosen development will include the Askeladd and Albatross fields.

The Norwegian Petroleum Directorate considers a satisfactory sales contract for gas to be decisive for any development of Snøhvit and other gas fields on Troms I. The relevant markets appear to be Italy, the USA, and Canada. Sales negotiations are currently being conducted, and these negotiations, together with further technological evaluations, will determine whether the Troms fields can be developed.

In addition to gas the Snøhvit field also contains thin oil zones. The thickness of these zones and average to poor reservoir characteristics make the oil difficult to recover. The Norwegian Petroleum Directorate nevertheless feels one should consider the possibilities for production of the oil employing horizontal wells, especially in the light of the positive results obtained with horizontal wells on the Troll field.

2.4 FIELDS DECLARED COMMERCIAL

2.4.1 Embla

Embla lies in block 2/7 and was allocated under production licence 018 in 1965.

Licensees

Phillips Petroleum Company Norway (operator)	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 %

Eurofrep Norge A/S	0.456 %
Coparex Norge A/S	0.399 %
Cofranord A/S	0.304 %

Field history
The first well was drilled in 1973–74 and proved hydrocarbons. Since then two new wells have been drilled (1988 and 1989). In 1990, the plan for development and operation of Embla was submitted, and adopted in December 1990.

Reservoir
The Directorate's estimates of recoverable reserves are 33 mcm oil. The geological and reservoir characteristics of the field are highly uncertain.

Development concept
The field is to be developed in several stages, where phase 1 will be a wellhead installation in the northern part of the field. This installation may have up to 18 wells. Phase 2 will comprise an installation further south on the field, while phase 3 will secure enhanced recovery by means of gas or water injection. It has not been determined how and when phases 2 and 3 are to be implemented.

Transportation
After processing on Eldfisk FTP, both the oil and gas will be carried to Ekofisk and from there onward to Teesside and Emden, respectively.

Costs
Estimated investment costs run to some 1.8 billion 1990 kroner, with annual operating costs amounting to about 52 million 1990 kroner.

2.4.2 Sleipner Øst
Production licence 046

Licensees

Den norske stats oljeselskap a.s (Statoil)	49.6 %
Esso Exploration & Production Norge a.s	30.4 %
Norsk Hydro Produksjon a.s	10.0 %
Elf Aquitaine Norge A/S	9.0 %
Total Marine Norsk A/S	1.0 %

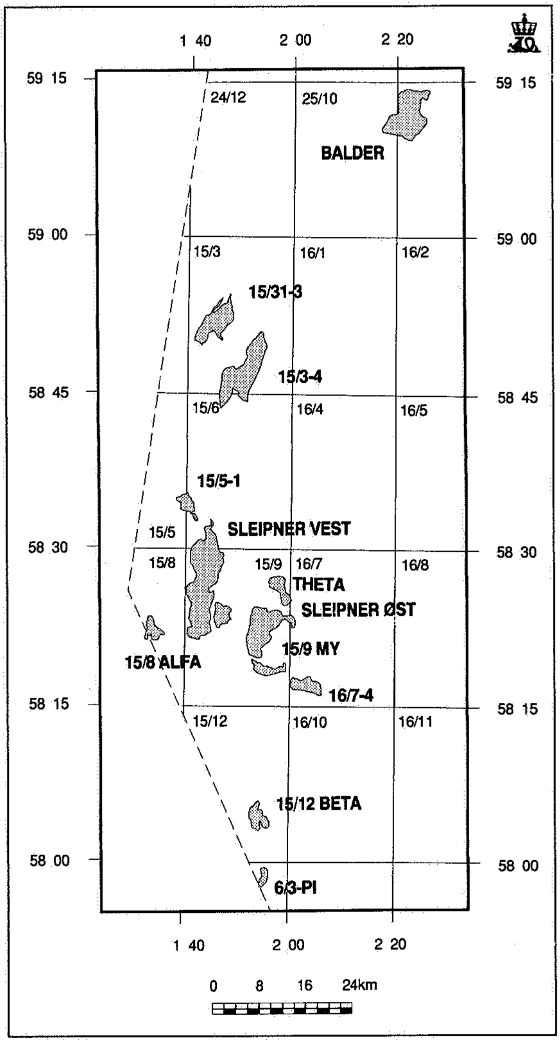
The production licence was allocated in 1976 and embraces blocks 15/8 and 15/9. Statoil is the operator for the Sleipner Øst field, see Figure 2.4.2.

The Norwegian Petroleum Directorate's estimated reserves in place in Sleipner Øst are 51 bcm gas, 19 mcm oil and 10 mtoe NGL.

Development
The decision to go ahead with Sleipner Øst development involves a fully integrated process, drilling and accommodation platform with quadripod concrete gravity base.

Condensate will be landed to Kårstø after laying a new 508 mm pipeline from Sleipner A to Kårstø.

Fig. 2.4.2
The Sleipner and Balder area



The gas will be transported partially by pipeline to Zeebrügge in Belgium and partially through the Statpipe-Norpipe system to Emden in West Germany. Sleipner Øst is planned to be ready for production start-up on 1 October 1993.

Costs
The estimated total development costs are 18.3 billion 1990 kroner, inclusive a condensate pipeline from the Sleipner A installation to Kårstø. Total operating costs are estimated at 8 billion 1990 kroner, exclusive transportation costs.

2.4.3 Brage
The bulk of the Brage field is situated in block 31/4 and was allocated in 1979 as production licence 055. The field also extends into block 30/6, production licence 053, and into a non-allocated area in block 31/7. This section of block 31/7 will be allocated as a separate production licence.

Licensees in production licence 055

Den norske stats oljeselskap a.s (Statoil)	51.00 %
Esso Norge a.s	19.60 %
Norsk Hydro Produksjon a.s	14.70 %
Neste Petroleum a.s	9.80 %
BP Norway Limited U.A	4.90 %

Norsk Hydro is the operator for the field and the plan for development and operation was adopted by the Storting in spring 1990. Oil has been proven, providing the basis for development of two formations on Brage: Statfjord and Fensfjord. In the Sognefjord formation minor quantities of oil and gas have been proven, and this reservoir is so far not included in the development plan. A new appraisal well in the northeastern part of the field, ordered when the plan for development and operation was adopted, will provide more information on the reserves in the Sognefjord and parts of the Fensfjord reservoir outside the drainage area of the installation.

The Norwegian Petroleum Directorate has put the recoverable reserves at 46.2 mcm oil and 3.5 bcm gas, while the operator's estimates are 38.5 mcm oil and 2.8 bcm gas.

Development concept

The field is to be developed with an integrated production, drilling and quarters installation with steel jacket. Production start-up is planned for January 1994, and the plateau production of 13,000 scm oil a day is expected to be reached in the course of the first year since four production wells are to be predrilled.

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

Costs

Estimated total development costs are 9.1 billion 1990 kroner, and total operating costs 8.2 billion 1990 kroner over a 14-year period.

2.4.4 Troll

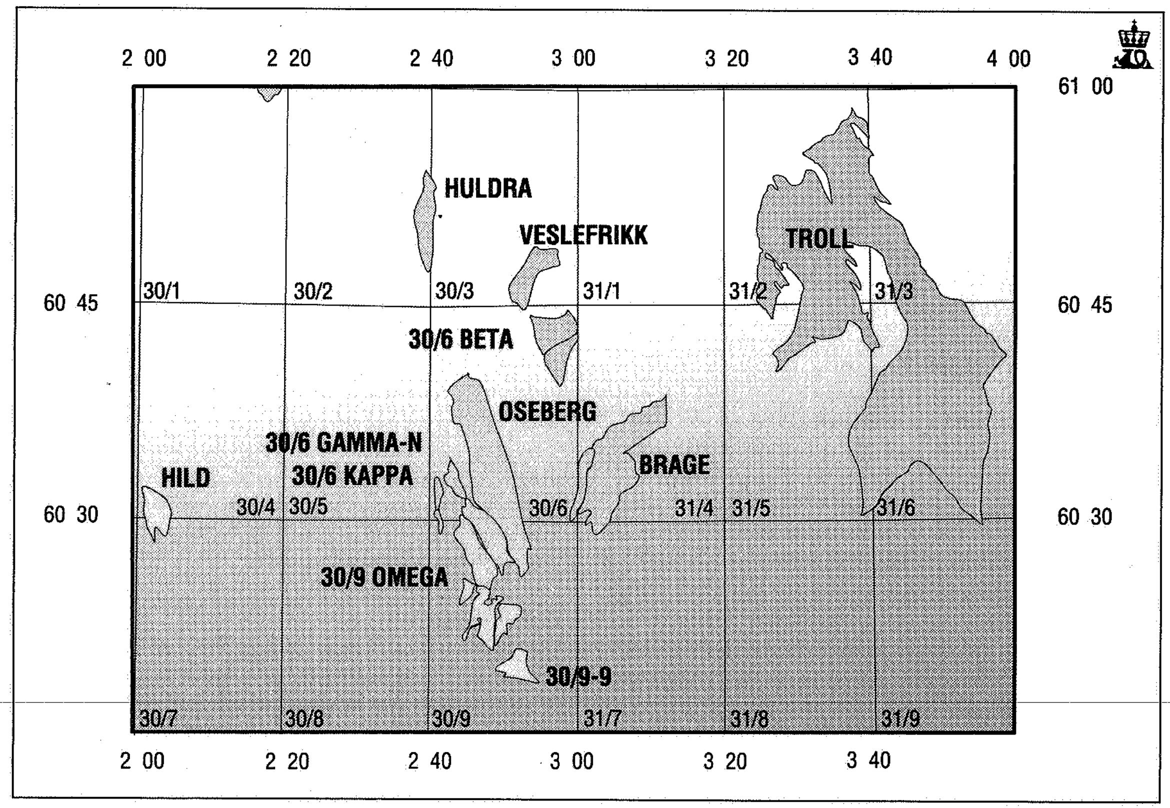
Production licences 054 and 085

Licensees after unitisation

Den norske stats oljeselskap a.s	74.576 %
A/S Norske Shell	8.288 %
Norsk Hydro Produksjon A/S	7.688 %
Saga Petroleum A/S	4.080 %
Elf Aquitaine Norge A/S	2.353 %
Conoco Norway Inc	2.015 %
Total Marine Norsk A/S	1.000 %

The Troll field covers parts of blocks 31/2, 31/3, 31/5 and 31/6, see Figure 2.4.4.a. Allocation of 31/2

Fig. 2.4.4.a
The Oseberg and Troll area



was made in 1979 while the other three blocks were allocated in July 1983. Unitisation of the two production licences has been completed.

The Directorate's estimates for recoverable gas in the entire Troll field are 1288 bcm.

The Directorate's estimates for recoverable oil are 41 mcm. This estimate was made before testing of horizontal wells on the field and only includes the oil in the thick oil zone. New resources estimates will be carried out in the course of 1991. The Norwegian Petroleum Directorate deems the opportunities for profitable production of both thick and thin oil zones to be good.

Reservoir

The reservoir is situated in three geological formations of late jurassic age. The upper formation (Sognefjord) is dominated by medium to coarse grade sandstone with good reservoir characteristics. Sognefjord contains the bulk of the gas and oil in the field and gradually fades into the Heather and Fensfjord formations, which show variable reservoir properties.

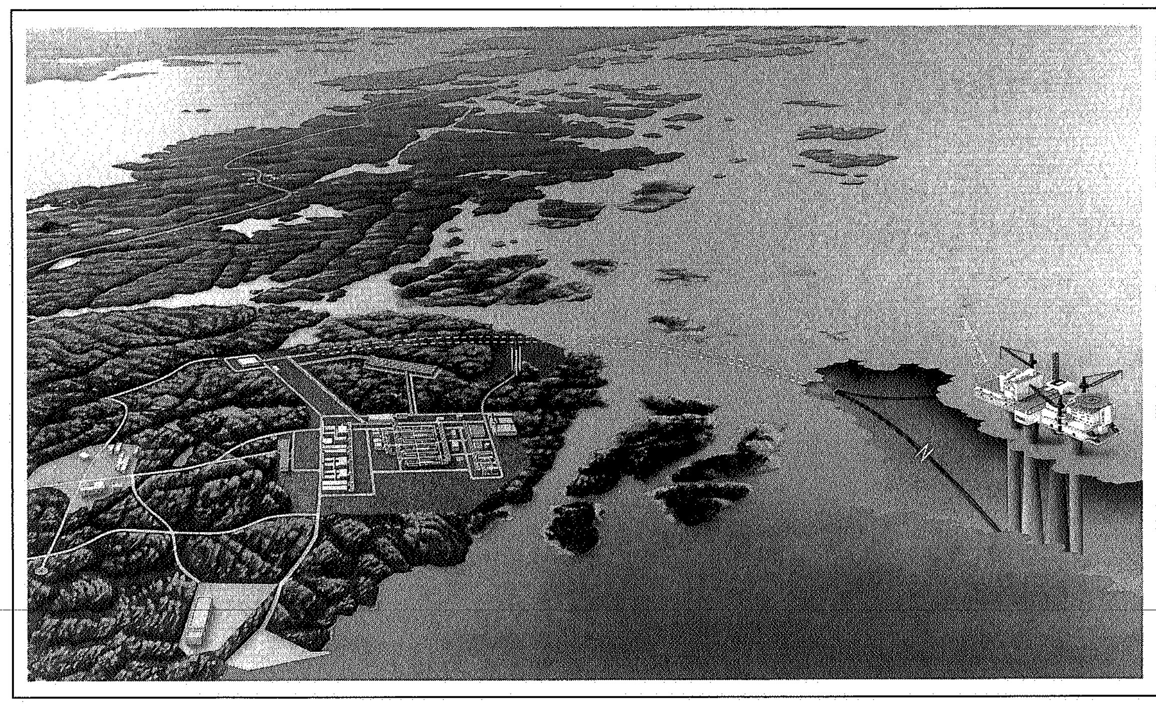
At the top of Troll Øst and Troll Vest is a gas column over 200 meters high. This gas column varies across the field. The western part of the field, lying predominantly in block 31/2, features an oil column 22 to 27 meters high under the gas, compared to 10 to 17 meters further east in the block. In Troll East the proven oil strata vary from zero to four meters in thickness.

Development concept

Norske Shell, as operator of the first development on Troll, submitted the partners' plan for development and operation of gas phase 1 to the authorities in September 1986. The Storting considered and adopted the PDO in December 1986. The development plan called for a fully integrated platform with initial processing capacity of 21.3 bcm a year. The operator was asked to submit a revised plan with a more detailed description of the installation and processing equipment. A revised plan was submitted by the operator and adopted by the authorities in 1990. This new plan comprises a wellhead installation, pipeline to shore, and an onshore terminal for separation, drying and compression of gas. From the onshore terminal the gas will be exported to the Continent. Upon completion the facility will have a capacity of 23.7 bcm a year, which is equivalent to some 93 per cent of Norway's overall gas export in 1990. Total investments have been estimated at some 27 billion 1990 kroner, with estimated annual operating costs running to 800–1100 million 1990 kroner. The Norwegian Petroleum Directorate considers the new development concept to be safer, more flexible and more cost-efficient than the original solution. See Figure 2.4.4.b for the planned Troll installation.

In addition to the principal gas development project a subsea production system (Troll-Oseberg Gas Injection) for gas required for injection on Oseberg is being built. TOGI will be ready for gas deliveries

Fig. 2.4.4.b
Planned installation on Troll



in 1991. Norsk Hydro is operator for development and operation of TOGI. Estimated investments are about 3.0 billion 1990 kroner. The Directorate considers TOGI to be decisive for enhanced oil recovery from Oseberg and important for further development of subsea technology on the Norwegian continental shelf.

The Troll partners are also in the process of making plans and engaging in studies in connection with Troll phase 2. Both the thick and the thin Troll Vest oil zones are being considered for possible development. Norsk Hydro, the operator for Troll phase 2, in 1990 drilled a horizontal well in the south in the thick oil zone and carried out a long-term test using the test ship *Petrojarl I*. The test gave positive results regarding the chances of producing the oil in Troll Vest by means of horizontal wells. Norsk Hydro has drilled a new horizontal well in the thin oil zone, and this will be tested in the course of spring 1991.

2.4.5 Statfjord Nord and Statfjord Øst

Production licence 037 covers blocks 33/9 and 33/12 and was allocated in 1973. The partners in the licence are given below.

Licensees in production licence 037

Den norske stats oljeselskap a.s (Statoil) (operator)	50.000 %
Mobil Development Norway A/S	15.000 %
A/S Norske Shell	10.000 %
Esso Exploration & Production Norge a.s	10.000 %
Norske Conoco A/S	10.000 %
Saga Petroleum A/S	1.880 %
Amerada Hess Norge A/S	1.040 %
Amoco Norway A/S	1.040 %
Enterprise Oil Norwegian A/S	1.040 %

Production licence 089 was allocated in 1984. When the Snorre field was declared commercial, 1 per cent of the equity was transferred to the Norwegian State through Statoil from the other licensees in the production licence. Statoil's economic share is 10 per cent after the company sold 9.6 per cent to Idemitsu in 1989.

The partners in production licence 089 apart from the Snorre field before and after the application of the sliding scale are as follows:

	Before sliding scale	After sliding scale
Det norske stats oljeselskap a.s (Statoil)	41.400 %	55.400 %
Esso Exploration and Production Norway	14.700 %	10.500 %
Norsk Hydro Produksjon A/S	11.760 %	8.400 %
Saga Petroleum A/S (operator)	9.800 %	7.000 %
Idemitsu Petroleum Norge A/S	9.600 %	9.600 %
Elf Aquitaine Norge A/S	7.840 %	5.600 %
Deminex (Norge) A/S	3.920 %	2.800 %
Det Norske Oljeselskap A/S	0.980 %	0.700 %

Development

The fields will be developed with subsea installations connected to the Statfjord C platform. The subsea installations will consist of three templates, two for production and one for water injection. The well flow consisting of oil, gas and water, will be carried in two pipelines to Statfjord C for processing, storage and onward transportation. The plan is to drain the fields using six production wells and four water injection wells.

Production

Production from Statfjord Nord is scheduled to start in the second quarter of 1994 and last to the year 2009. According to Statoil's calculations, the total recovery will be some 27.7 mcm oil, whereas the Directorate's estimates for recoverable reserves in Statfjord Nord are about 32 mcm oil. This estimate for the reserves assumes the drilling of eight production wells and will mean that oil production lasts until the year 2014. Any decision to drill two extra wells will not be made until after the field has come on stream.

Statfjord Øst is scheduled to come on stream in the fourth quarter of 1994 and last until 2007. The field will reach its peak production 2–3 years after production start-up with some 65,000 barrels, or 3.5 mcm, a day. Present plans involve drilling up to six production and water injection wells on the Statfjord Øst field. Two of the water injection wells are planned to be drilled from Statfjord C. Following new updated studies from the Statfjord field it turns out that Statfjord does not have any available well slots for Statfjord Øst. Now the plan is to drill all water injection wells from the template. According to Statoil's calculations the recoverable oil reserves amount to some 19.4 mcm. The Directorate's estimates for recoverable oil reserves in Statfjord Øst are 13.3 mcm, which is about 30 per cent lower than Statoil's estimates. Differences in geological models account for most of the disparity. The Directorate recommends a maximum annual recovery rate of 2.4 mcm oil. The Ministry has approved the production profile which justifies the licensees' development application for Statfjord Øst. The production profile will be reconsidered after the first production and injection wells have been drilled. If the reserves base in the field turns out to be lower than predicted by the licensees, the recovery rate may be adjusted downward.

Costs

Investment costs for Statfjord Nord and Statfjord Øst are 3.34 and 2.91 billion 1990 kroner, respectively. In the production phase the annual operating costs for Statfjord Nord and Statfjord Øst have been estimated at 71 and 67 million 1990 kroner, respectively. The estimated costs for processing of oil and gas on Statfjord C are some 2.6 billion 1990 kroner for Statfjord Nord and for Statfjord Øst about 1.4 billion 1990 kroner. The operating costs given by the operator are associated with some measure of uncertainty since the strategies for maintenance and compilation of data have not been finalised. In the Directorate's opinion the operating costs appear to be somewhat low.

2.4.6 Snorre

The Snorre field is situated in blocks 34/4 and 34/7. Block 34/4 was allocated under production licence 057 in 1979, block 34/7 under production licence 089 in 1984. Saga operates both blocks.

Licensees in production licence 057

Den norske stats oljeselskap a.s (Statoil)	41.40 %
Deminex (Norge) A/S	24.50 %
Saga Petroleum a.s	14.70 %
Idemitsu Oil Exploration A/S	9.60 %
Amerada Hess Norge A/S	4.90 %
Enterprise Oil Norway A/S	4.90 %

Licensees in production licence 089

Den norske stats oljeselskap a.s (Statoil)	41.40 %
Esso Exploration & Production Norge a.s	14.70 %
Norsk Hydro Produksjon a.s	11.76 %
Saga Petroleum a.s	9.80 %
Idemitsu Oil Exploration A/S	9.60 %
Elf Aquitaine Norge A/S	7.84 %
Deminex (Norge) A/S	3.92 %
Det Norske Oljeselskap A/S	0.98 %

Ownership interests after unitisation

The partners have adopted a distribution of the reserves in Snorre which puts 30 per cent in block 34/4 and 70 per cent in block 34/7. The ownership interests in the unitised Snorre field are:

Den norske stats oljeselskap a.s (Statoil)	41.40 %
Saga Petroleum a.s	11.26 %
Esso Exploration & Production Norge a.s	10.33 %
Deminex (Norge) A/S	10.03 %
Idemitsu Oil Exploration A/S	9.60 %
Norsk Hydro Produksjon a.s	8.27 %
Elf Aquitaine Norge A/S	5.51 %
Amerada Hess Norge A/S	1.46 %
Enterprise Oil Norway A/S	1.46 %
Det Norske Oljeselskap A/S	0.69 %

Field history

The plan for development and operation of the Snorre field was adopted by the Storting in 1988.

Pre-drilling of wells on the field started in autumn 1990, with production start-up scheduled for autumn 1992.

Reservoir

Snorre is a large oil field: the commercially recoverable reserves according to the operator's estimate are about 120 mcm oil and 7 bcm associated gas. The Norwegian Petroleum Directorate estimates the reserves at 106 mcm oil and 5.7 bcm associated gas. The Norwegian Petroleum Directorate notes the uncertainty surrounding the Snorre field reserves. Snorre contains numerous additional reserves in the field itself and also outside the field limits (separate structures).

The oil, which is heavily undersaturated, is divided between two reservoirs: Statfjord and Lunde. These are well surveyed and the volumes are reasonably certain. There is some uncertainty regarding the extent of the sand formations and communication in the Lunde reservoir. This may affect reservoir performance. The depth of the reservoir is about 2500 meters. Drilling and test operations have proven three different oil-water contacts, the deepest being in the western part of the field.

Development concept

The water depth over the field varies from 300 meters in the south to 370 meters in the north. According to plan the field will be developed in two phases: phase 1 consists of a floating tension leg platform in the south and a subsea installation in the central part of the field. Production will be driven by water injection. The oil will be separated in two stages on the Snorre platform, then transported to Statfjord for end processing. The estimated development costs for phase 1 are about 21 billion 1990 kroner. Phase 2 of the development involves depletion of the central and northern parts of the field and entails two development options. One is the relocation of the tension leg platform, the other to continue the development with another production unit on the seafloor.

2.4.7 Draugen

The Draugen field, situated in block 6407/9, was allocated in 1984 as production licence 093.

Licensees

Den norske stats oljeselskap a.s (Statoil)	50.00 %
A/S Norske Shell	30.00 %
BP Norway Limited U.A.	20.00 %

Shell is operator for the field. Production is scheduled to come on stream in autumn 1993.

Field history

The operator declared the field commercial in September 1987 and submitted the partners' plan for development and operation to the authorities that same month. In August 1988, the operator presented an updated PDO for the field, which the Storting approved in December 1988. Draugen is the first field on Haltenbanken to be approved for development.

Reservoir

The Norwegian Petroleum Directorate estimates the in-place reserves on Draugen to be around 68 mcm oil and 3.0 bcm marketable gas. The Draugen reservoir is of excellent quality and consists of two formations: Rogn which contains the major part of the reserves, and Garn which contains a small part of the oil. There are several minor faults in the reservoir which may allow communication between the formations. There may also be communication in areas where the slate strata are thin. On the evidence of the test results the wells are expected to provide high delivery capacity and high injection capability.

Development concept

The field development plan assumes a fixed concrete installation with an integrated deck. Six or seven production wells are planned plus six water injection wells. Seven of the wells will be completed subsea. The installation will have ten well slots and 34 J tubes when complete. A mean plateau rate of 14,300 scm oil a day is conjectured.

Transportation

It is proposed to export the crude via a floating loading platform, FLP, with compliant moorings. The gas will be reinjected until a use has been found for it.

Alternative gas applications

The operator has considered numerous alternative uses for the associated gas. The principal plan is to reinject it into the Ile formation (water zone) for three years. It would also be possible to produce the Rogn South formation early on, making it possible to continue gas injection into this formation for a three-year period. After 1999 it is expected that a gas transportation solution or some other use for the gas will have been found on Haltenbanken.

Costs

The estimated total investment costs are 11.3 billion 1990 kroner. This includes gas injection plant for the Ile formation. Estimated annual operating costs are 576 million 1990 kroner.

2.5 FIELDS IN PRODUCTION

2.5.1 Hod

Production licence 033

Licensees

Amoco Norway Oil Company (operator)	25 %
Amerada Hess Norge A/S	25 %
Enterprise Oil Norway A/S	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 located about 12 km south of the Valhall field. Parts of the block have later been relinquished, and parts of the relinquished acreage have been included in production licence 068. The Hod field consists of two minor, separate structures: West Hod and East Hod. See Figure 2.5.4.a.

Production

The Hod field can to some extent be compared to the other cretaceous fields in Central Graben in terms of geology and reservoir parameters. The main differences with regard to the reservoir, as compared to the Valhall field, can be summarised as follows: in the Hod field the Ekofisk formation is present in some wells, the reservoir zone HO (Supra Hod) and possible additional reservoirs in lower cretaceous do not exist in the Valhall field.

It is very hard to interpret the geophysics of the West Hod structure since there is gas in the overlying rock. This cloud of gas distorts and attenuates the signals on which the interpretation relies. In this structure there are just two data points, 2/11–2 located centrally in the structure, and 2/11–5 found outside the supposed oil-water contact. The East Hod structure does not contain an overlying gas cloud, which indicates that it is easier to interpret it geophysically. In addition, well control is better. Three exploration and two production wells have been drilled in this structure. As in the early phase of the Valhall field, the first two production wells in the East Hod structure have produced great surprises.

The reservoir zone, which embraces the Ekofisk, Tor and Supra Hod formation, is considerably richer than expected. An increase in the Directorate's reserves estimates can be anticipated for the Hod field in 1991. The operator's reserves estimates are unchanged at 4 mcm oil, 0.9 bcm gas and 0.3 mtoe NGL. The two production wells in the East Hod structure indicate a possible additional reservoir in the lower cretaceous. This formation will be tested towards the end of 1990.

The production from Hod started from one well (2/11-A-6) in October 1990. The rate of production has topped about 2000 cubic meters per day, which is more than expected. This is due to greater richness of the reservoir and better reservoir quality.

Furthermore, three production wells are planned to be drilled from a subsea template. The capacity is eight slots. Oil will be produced by means of natural pressure drive. Secondary production methods such as water and possibly gas injection are not planned.

Production installations

Development includes a remotely controlled production installation. Oil and gas are separated by means of a separation unit and then metered before being piped to Valhall for further processing.

Transportation

Oil and gas are transported in a single pipeline to Valhall and from there through the existing transportation system to the riser platform and Emden and Teesside.

Metering system
Oil and gas are metered to fiscal standard at Hod. The metering system is included in the Valhall-Hod system for the distribution of hydrocarbons.

Flaring
No separate reports for Hod were received, as the flaring is included in the quota limit for Valhall.

Costs
Total investments for the Hod field up to and including year 2004 are estimated to be about 634 million 1990 kroner. Total operation costs through 2004 are estimated to be about 1.2 billion 1990 kroner.

2.5.2 Valhall
Production licence 006

Licensees

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

Block 2/8 was allocated in 1965 with Amoco as operator. In 1989, Texas Eastern Norwegian Inc's interest was sold to Enterprise Oil Norway A/S. Most of the Valhall field is in block 2/8 (see Figure 2.5.4.a) although the southern part extends into block 2/11, production licence 033, in which each of the 006 partners owns 25 per cent.

Production
Valhall, in terms of geology and reservoir characteristics, is similar to the Ekofisk area fields, which produce from crumbled limestone which is relatively tight compared to other reservoir rocks on the Norwegian continental shelf. This gives the fields very low recovery, only about 17 per cent, although the factor can be enhanced by employing new production techniques.

In 1990 a pilot project was initiated whereby water was injected into a well in the Tor formation. The intention was to test how much water could be injected into the well and see what response the water would give in the reservoir. The results so far have been positive with regard to injectivity, but the reservoir response remains to be seen. The final decision on full-scale water injection will be made in summer 1991. Other methods to be evaluated in the course of 1991 include gas injection. A big problem with the geological model used today is that it is not predictable when considering full-field water injection, which may be a reality from the end of 1991.

The Directorate ordered the operator to carry out a dipmeter study in the course of 1990. The results from this study will provide a better understanding of the development of the geological field structure, the sedimentary directions of transportation of resedimented material, the present stress conditions in the field, plus information on fissures, such as fissure orientation and slope.

Valhall came on stream in October 1982. By year end 1990 the field was producing from 24 wells. The operator seems to have succeeded with a new completion technology which avoids the problem of eroded reservoir rock migrating into the production wells.

The subsidence of Valhall does not seem as much of a problem as was once feared. Several methods of measurement are being used to establish the rate of collapse. What are considered the most reliable results show a subsidence rate of about 0.18 meters a year.

Production installations
The development of Valhall comprises quarters, drilling, production and riser platforms, the three first-mentioned being on the field and connected to each other by flying gangways. See Figure 2.5.2 for details. The riser platform – for which Phillips is the operator – is connected to the Ekofisk tank.

Oil is separated from the Valhall gas using two separation trains before being pumped to Ekofisk where it is metered and then fed into the Teesside pipeline. The gas is compressed, dried and checked for dew point on the production platform before being piped to the Ekofisk installation for metering and export through the Emden pipeline. The heavier gas fractions, natural gas liquids (NGL), are separated on Valhall in a fractioning column and then reinjected, mainly into the oil.

Metering system
Oil and gas from Valhall and Hod are metered on the riser platform. The fiscal metering systems are included in the Ekofisk system for hydrocarbon distribution.

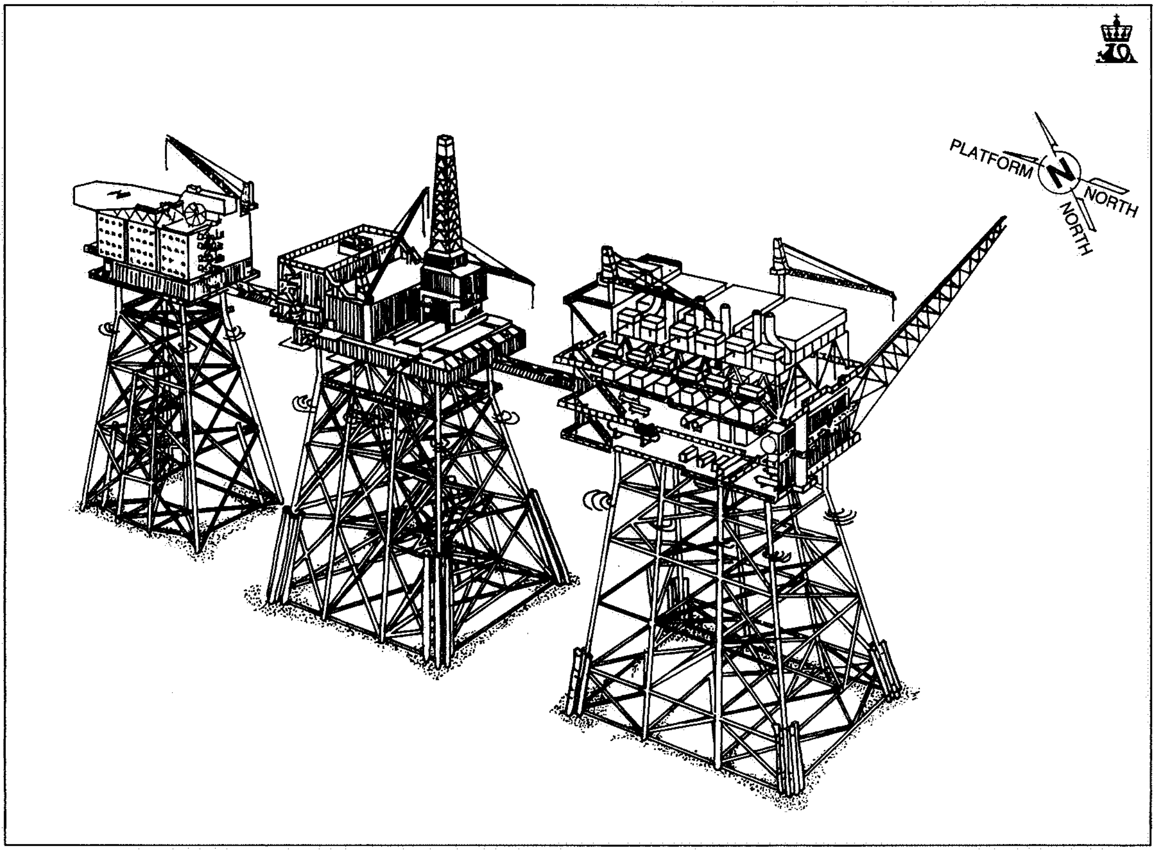
Transportation
From the riser platform the Valhall gas is transported to Emden, and the oil is transported to Teesside.

Flaring
The reported average volume of gas flared on the field in 1990 is 25,000 scm a day, equivalent to 0.8 per cent of gas production, and 25 per cent of the permitted maximum.

Costs
The total investments on the Valhall field up to year 2011 are expected to be roughly 12.3 billion 1990 kroner. The total operating costs to the same date have been calculated at around 19.9 billion 1990 kroner.

2.5.3 Tommeliten
Production licence 044

Fig. 2.5.2
Installations on Valhall



Licensees

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

Production licence 044 was allocated on 27 August 1976 and embraces block 1/9 southwest of the Ekofisk area. The field was discovered by the drilling of exploration well 1/9–1 in December 1976 and was Statoil's first discovery in the oil activity.

The plan for development and operation was approved by the Norwegian Storting in June 1986. Phase 1 of the development, comprising the Gamma structure, came on stream on 3 October 1988. A gas sales contract has been concluded with the Phillips Group for supplies up to 1 October 1991. The remaining gas remains unsold at the beginning of 1991.

Two options for gas sales are being considered, either sales to Phillips or sales to Ruhrgas. The latter may involve a temporary shut down of Tommeliten for two years.

Tommeliten comprises two structures, Alpha in the south and Gamma in the north. Both structures have proven gas and condensate. The hydrocarbon-bearing strata are the Ekofisk and Tor formations. Furthermore, underlying sandstone formations have been located, which are considered to hold promise and will be explored in greater detail.

Gas from Tommeliten is processed on the Edda installation. A minor portion of the gas is used as gas lift for Edda oil wells and thus extends the economic lifetime of the Edda field.

Production installations

The Tommeliten field has been developed using subsea completion wells. As mentioned, only the Gamma structure has been developed. The next phase, which is the Alpha structure, will also be developed using a subsea template with subsea completion wells. This development will not be implemented before a gas sales agreement has been obtained.

The produced fluid is processed on Edda. Phillips Petroleum Company Norway A/S, which undertakes the processing, will continue to use the Tommeliten gas for artificial lift of Edda wells.

Metering system

The existing metering system for oil and gas on the Edda installation has been rebuilt and upgraded to development projects had been examined. The test method was developed by SINTEF, the Foundation for Scientific and Industrial Research at the University of Trondheim, who also perform the actual tests on the Directorate's behalf.

Enthusiasm for using high strength steel in structures is growing: Several development projects already started or being engineered will employ high strength steel in some areas. Steel with strength up to 500 MPa seems most suited. There are still some questions to be answered before steel of higher strengths can be used, notably in connection with weld joints subject to fatigue.

4.13.3 Instrumental status assessment

Since 1978 the Directorate has been looking for alternatives to the traditional methods of assessing the status of a structure. With the development and utilisation of ever more complex structures, with long service lives and little opportunity to inspect them properly, the Directorate has initiated a project to examine instrumental status assessment (ITK). The aim of the project is to show what systems and devices are currently available, how suitable they are for use on fixed and floating installations in the next decade or so, and the prospects of using new and existing installations, if their projected lives are already long or can be extended. The results will be used to update our guidelines for status assessment of load-bearing structures and will be available to user groups.

ITK is expected to provide user groups with supplementary information on the state of structures beyond that provided by traditional methods.

4.13.4 Pipelines and risers

Due to the coming need to expand the gas export capacity to continental Europe, in June 1989 Norpipe applied to increase the capacity of the gas line from Ekofisk to Emden by upgrading pressure to more than the design rating. Following a careful review in consultation with German and Danish authorities, the Directorate determined that such permission could not be given for plans which called for an increase in the maximum operating pressure of the pipeline.

The company's calculations relied on analyses which were based on data from the internal inspection of the pipeline, using inspection tools from British Gas. In the view of the authorities consulted, these tools have not been shown to provide data of sufficient quality to support an analysis based on fracture mechanical computations.

As a result the company has shelved its upgrade plans, although work is continuing to verify the inspection tools' capability to detect weld flaws, among other things. The work is continuing with a possible future upgrade of the pipeline in mind.

The Zeepipe project has reached the fabrication stage. The pipes are being made in Japan, Germany and France, whereafter corrosion protection and concrete sheathing is applied in the Netherlands and Scotland. Work is going on to prepare and plan their installation, which will begin in April 1991.

4.13.5 Subsidence on Ekofisk

The subsidence of the seabed in the vicinity of the Ekofisk Center has been going on since the late seventies. The reasons for the subsidence are a combination of structurally weak reservoir rocks and diminishing reservoir pressure as gas and oil are extracted.

Although in the early eighties subsidence was about 50 cm a year, the subsidence rate has now slowed to about half as much.

The total collapse to date is rather less than five meters, and the total expected is about 6.5 meters.

The seabed above the Vest Ekofisk field is also collapsing, by about 20 cm a year. The rate is expected to slow down in the years to come. The present level is about 2.5 meters below the starting point.

Three modes of measurement have been employed: pressure detectors, satellite ranging, and direct measurements of water level against the legs of installations. Phillips has put in a great deal of work to analyse the measurement readings so as to gain the best possible overview of the subsidence problem.

4.13.6 Extreme ice sightings

Historically we know that icebergs reached the North Norway coast in eastern Finnmark in 1881, 1929 and 1939. Iceberg observations this far south, therefore, are a rare occurrence. The actual probability, per annum, of collision with an installation in this coastal region has been estimated to be greater than 1 in 10,000. This is more than once in every 10,000 years for each installation.

The largest iceberg, observed off Gamvik in 1881, was about one kilometre in length, had three peaks, and towered 25–30 meters above the sea. Its weight must have been over a million tons, and its average speed of drift 0.1 meters per second.

In the region between Bear Island and Hopen, several hundred icebergs have been observed in recent years. The probability of collision with any installation in the vicinity is therefore very significant.

Icebergs have also been observed south of Bear Island. In order to estimate the magnitude of the risk of collision to the south, the Directorate asked the Norwegian Hydrotechnology Laboratory for help. It turns out that the annual risk of such a collision is greater than 1 in 10,000 south to about 73 degrees North. Bergs between Bear Island and Hopen are on average about 560,000 tons in weight.

The winter of 1880–81 witnessed the most extreme icing conditions recorded during the past century and a half. In order to determine just what conditions were like, the Directorate has made a careful ditions were like, the Directorate has made a careful review of the available source material. At the end of May 1881 drift ice was arrayed at about 71 degrees 30 minutes North from Tromsø Patch to east Finnmark. A northerly storm then pushed parts of the ice towards the shore. As late as about 10 June, drift ice was observed some 20 km north of Berlevåg in east Finnmark.

4.13.7 Soil surveys

In connection with evaluation of the foundations of installations and the appraisal of pipeline routes in the Norwegian sector, for many years soil studies have been going on. Details of such studies, where they are made and the results obtained, are communicated to the oil companies concerned.

In 1990 the Directorate compiled a catalogue of studies completed and the general stratigraphy at each survey point.

4.14 ELECTRICAL SYSTEMS

4.14.1 Power supply on Draugen

The Draugen project group have developed an electrical power supply system based on a concept for integrated power production. The system comprises three gas turbine generator sets which supply dedicated high and low voltage systems. Each generator is at the same time a main generator and a stand-by, and each of the three systems is connected to an electrically powered combination firewater and seawater pump. Each such pump is capable of meeting the installation's firewater demands.

There is an additional fourth electric fire pump which again is sufficient to meet the entire needs of the installation. It is powered by a separate diesel generator set and is therefore independent of the other electrical systems. A special system enables this stand-alone generator to serve as a power source to start up the main generator, without impairing fire pump capacity.

4.14.2 Magnetic bearings in rotary plant

Magnetic bearings which are fitted to rotating machinery are now also finding application offshore. Sleipner A will be receiving turbo-expanders made in Switzerland equipped with magnetic bearings of French manufacture.

As yet, there are no international regulations or guidelines regarding explosion proofing of such systems. The Directorate therefore endeavours to keep up to date on technical appraisals made by the operator.

4.14.3 Professional cooperation and assistance

The Norwegian Water Courses and Energy Board (NVE) and the Directorate are collaborating on new regulations to be published for electrical systems in Norway. The NVE office concerned with regulations, the Electricity Inspection, was split off as an autonomous division and moved from the Ministry of Petroleum and Energy to the Ministry of Local Government. This change of address will make even closer cooperation possible.

Attention is also being given to an assistance and cooperation agreement between the Electricity Inspection and the Petroleum Directorate. Such an agreement may be effective from 1991.

4.15 GAS LEAKAGES, FIRES AND OUTBREAKS

4.15.1 Piper Alpha follow-up

The public inquiry commission appointed in the UK following the Piper Alpha burnout has now discharged its mandate under the direction of Lord Cullen.

The report was published in 1990 and it contains many recommendations, some of which are of great significance for inspection strategies in the UK sector. If these recommendations are pursued, the British inspection strategy will be more like its Norwegian counterpart.

The Directorate has studied the report and its implications, and concludes in this instance that no changes in the supervisory methods in the Norwegian sector seem to be called for. Nonetheless, the report identifies organisational and technical problem areas, and this knowledge will provide a useful fund for the Directorate to draw on in its inspection activities. The Directorate has appointed an ad hoc group to ensure that the recommendations of the Cullen Commission are duly addressed, and put into effect within the various technical disciplines as appropriate.

4.15.2 Gas leakages

The Directorate has received reports on 48 gas leaks on fixed installations during the reporting period. This is three more than in 1989.

The Directorate's statistical base has been improved during the period and this enhancement will be drawn on in the 1991 inspection activities.

The Oil Industry Association (OLF) and Amalgamated Oil Workers Union (OFS) have compiled a report on all gas leaks during 1988 and 1989. The Directorate has received the report and noted the large discrepancy in the number of cited gas leaks: 272 in the industry report versus 69 in the Directorate's report. Some of the difference can be traced to the distinction drawn by the Directorate between controlled and uncontrolled gas leaks. Operators are only required to report the latter.

Figure 4.15.2.a breaks down the reported gas leakages in order of severity. The divisions in the figure are based on the Directorate's appraisal of the course of events and the risks the gas leakage entailed. The figure shows that most of the gas leakages were small and quickly brought under control.

Table 4.15.2 shows gas leakages in the given severity categories as detected by the gas detector systems.

Figure 4.15.2.b serves to illustrate the causes of

Fig. 4.15.2.a
Classification of reported gas leaks according to degree of seriousness

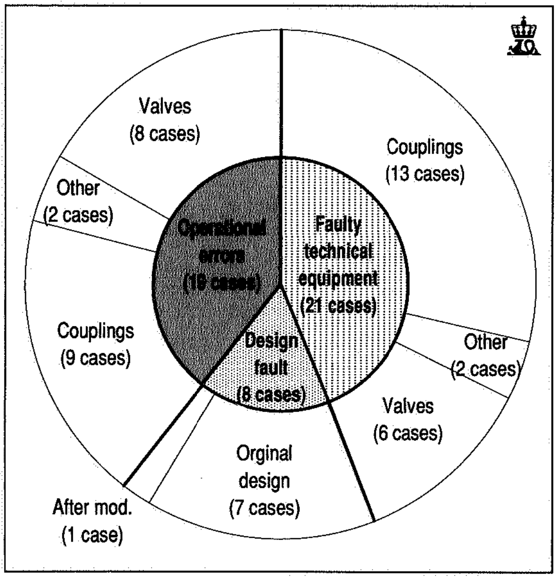
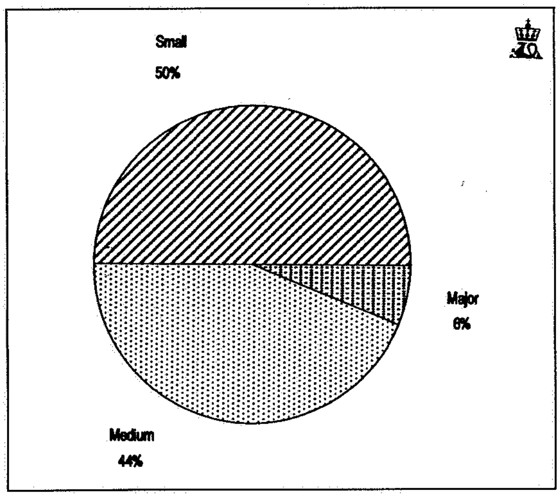


Fig. 4.15.2.b
Gas leaks – classification of causal relationship



the gas leakages. The causes behind a gas leakage are often several and coincidental. The figure assigns the causal factors on the basis of the Directorate's analysis of reports received. Human error is one causal subcategory in the operational error category. In turn a human error may have many underlying causal elements, such as poor preparation of work, lack of training, lack of information, muddled lines of communication, and the stress factor.

The statistics show that gas leakages of a more serious nature are often the result of operational error.

4.15.3 Fires and outbreaks

The Directorate has records of 41 fires in all in 1990, versus 51 in 1989. This seems to indicate a positive trend.

Table 4.15.3 summarises the extent and causes of fires and outbreaks reported to the Directorate in 1990.

4.16 DIVING

4.16.1 Diving operations

In the current period 1513 surface oriented dives, 1429 bell runs, 167,744 manhours in saturation, and zero monobaric dives were registered on the Norwegian continental shelf. This was a decrease relative to 1989. The dives were carried out from 10 tenders.

Diving operations in the Norwegian sector are as in previous years concerned with long-term inspection and maintenance contracts on Ekofisk, fields operated by Statoil, the Frigg field, and shorter installation jobs on various other fields. Diving in connection with installation jobs was generally to hook up pipelines and give assistance with the emplacement of other types of structures.

4.16.2 Diving accident survey

Figure 4.16.2.a provides a summary of the personal injuries reported to the Directorate in the years 1978–90 in connection with diving operations on the Norwegian continental shelf.

Personal injuries are subdivided into categories for fatality, other injury, and decompression sickness (bends). One of the bends cases occurred during saturation diving and two during surface oriented operations. Infections and incidents are not

Table 4.15.2
Gas leakages detected by gas detection systems

Significance	Total number	Number detected automatically	Reading in % LEL	
			20 %	60 %
Minor	24	7	7	
Medium	21	13	5	8
Major	3	3		3

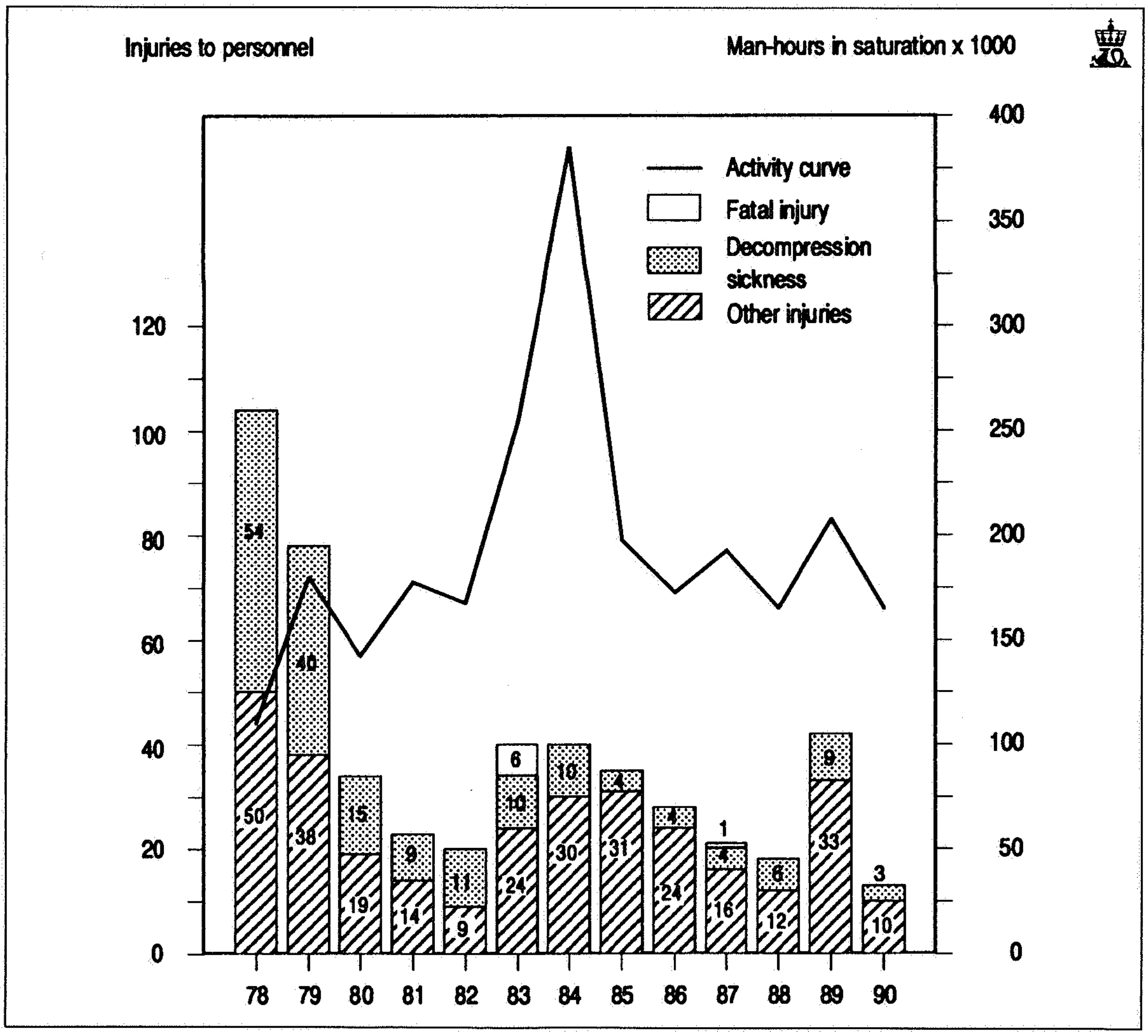
(LEL = Lower Explosion Limit)

Table 4.15.3
Summary of fires on mobile and fixed production installations

Causes for fires and fire outbreaks	Construction phase			Fixed installations Operating phase			Mobile installations Operating phase		
	S	M	L	S	M	L	S	M	L
Welding				7	2				
Spontaneous ignition (possibly overheating)		1		12	2				
Electrical shortcircuiting				4	2	3			
Other causes	1			6			1		
Total	1	1		29	6	3	1		

S = small, M = medium, L = large

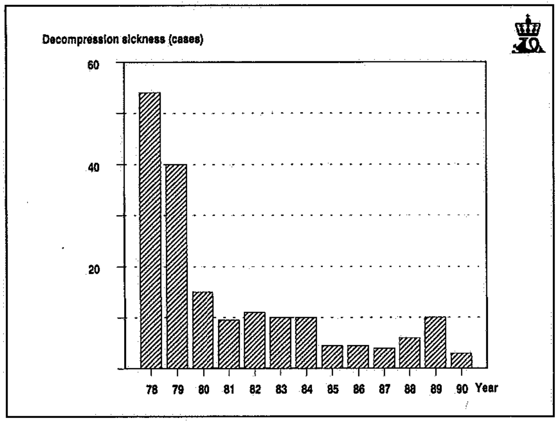
Fig. 4.16.2.a
Injuries to personnel engaged in diving activities on the Norwegian continental shelf 1978–90



included in the summary. During the current period 15 cases of outer ear infection and five cases of other infections were reported among divers. Also, 19 incidents were reported.

The reduction in the number of decompression cases compared to 1988 and 1989 is noteworthy. See Figure 4.16.2.b.

Fig. 4.16.2.b
Decompression sickness in connection with diving on the Norwegian continental shelf 1978–90



4.16.3 Diving research

In 1989 the Directorate launched a common research and development programme for diving technology (FUDT) in cooperation with Statoil and Hydro. In 1990 Saga joined the programme and yet other oil companies have made contributions in certain fields, either on an independent basis or through the Oil Industry Association.

The programme concentrated on the following key areas of manned subsea operations:

- Technical and operational aspects
- Safety and the working environment
- Implementation, organisation and training.

The Directorate is very pleased that the oil companies can work together to reach common solutions to pressing offshore diving issues.

In 1990 the Directorate carried out a project whose purpose was to standardise decompression procedures. The project also looked at compression, living at habitat depth, and excursions from habitat depth. All Norwegian diving contractors who are active in the offshore industry took part as did representatives from the oil companies and employee organisations. The outcome of the project was a recommended standard for diving to depths of 180 meters.

4.17 MECHANICAL EQUIPMENT

4.17.1 New water injection technology

Traditional water treatment plant for water flooding of oil reservoirs comprises heavy machinery which takes up a lot of space. For its Snorre installation, Saga has chosen a design developed in Norway which offers weight savings of 600 tons, and halves the space factor compared to conventional systems.

The new system filters the injection water to 98 per cent of particles larger than 2 microns. Oxygen is removed by means of nitrogen absorption in a closed cycle which reduces the oxygen content to less than 10 parts per billion.

4.17.2 Valves influencing safety

Based in part on the reports of larger numbers of gas leaks in recent years, the Directorate has imposed stricter controls on the operators' fitting and use of valves which may prejudice safety.

The Directorate notes that there is room for improvement in areas such as experience interchange when purchasing, procedures for fitting, corrosion protection, use and maintenance, drawing documentation and markings, and level of skill of the valve systems operator and maintenance personnel.

The Directorate will continue its scrutiny in 1991 to ensure that the industry tackles the issue credibly.

4.17.3 Mercury in wellstream

In 1990 small quantities of mercury were detected in the wellflow from certain reservoirs in the Norwegian sector. The concentrations, though extremely small, may be enriched in the gas phase during separation and compression stages. On one installation certain monel alloy components were ruined by a type of brittle fracture as a result. Metallic mercury can destroy the alloys of copper, aluminium and several other metals.

The phenomenon is already known from oil and gas production in other countries and should not result in insurmountable problems for Norwegian operations.

It is essential, nonetheless, to identify the reservoirs which produce mercury, and the alloys that may fail due to this type of brittle fracture.

4.17.4 Mechanical pipe joints

Once again in 1990, pipe joints have been subject to careful study. The focus was on the installation and use of flange joints in process trains, both for plant already in operation and plant still on the drawing board. It may even be interesting to evaluate alternative or new designs for mechanical joints which are aimed more specifically at joint stability.

During the year the need for better maintenance of flanged joints was identified. Bolts and gaskets on older installations have proven ripe for replacement. The matter will be pursued in 1991.

4.18 DATABASES

The Directorate draws on many databases in its work to oversee the safety and working environment offshore. These bases have been compiled in view of the internal demand for systematic experiential data to substantiate regulatory drafting tasks and serve as a guide when deciding supervisory priorities. Work is going on to assess the level of demand inside the Directorate and possible closer links between the bases. Work has also been initiated to establish the level of demand outside the Directorate, with a view to deciding whether to make the data available to the industry, and if so, to what degree.

DDRS, the Daily Drilling Report System, was started in 1984. This database is designed to collate all information about drilling activities, making it available and useful for supervision purposes. The systematic approach has also enabled the data to be used for other purposes, for example, reliability and risk analyses. The entry of data started in 1984 and the base now contains data from the about 820 exploration and production wells either drilled or worked over since 1 April 1984.

CODAM, the COrrosion DAMages database, contains information on damage to and non-conformance of load-bearing structures and pipeline systems. The base was started in 1982.

DSYS, for Diving SYStems, is a compilation of information on diving operations, including such details as injury statistics, certificates, and activity reports. The base was opened in 1984 and contains data from 1978 onward.

UPS (*Ulykker På Sokkelen*), which is the database compiled of accidents on the continental shelf, was started in 1982 to facilitate analysis of personal injury reports. More than 7500 personal injuries have been reported from 1979 on.

Reports on manhours spent on various activities offshore are recorded in a special database. The information is used to calculate personal injury frequencies per time unit.

Reports on fires and gas leaks have been recorded in a special database since 1989.

5. Petroleum Economy

5.1 EXPLORATION ACTIVITY, GOODS AND SERVICES

The exploration drilling activities increased steadily between 1966 and 1985, when 50 new exploration wells were commenced. 1990 saw the commencement of 36 new wells, which could be compared to activity in 1986 and 1987, but was a marked increase over both 1988 and 1989.

Figure 5.1.a shows the costs of exploration from 1980 onwards. These costs include exploration drilling, general exploration costs, field evaluation and administration.

Shown below are the exploration costs for 1990 split over goods and services. The amounts represent provisional estimates from data received from the operating companies. The same statistics are the basis for Figure 5.1.b, which shows the percentage breakdown between the different expenditure types.

Exploration costs		Nkr million
Exploration drilling		3490
of which:		
– Drilling installations	1010	
– Transportation costs	490	
– Goods	730	
– Technical services	1260	
General surveys		520
Field evaluations		440
Administration (incl acreage fees)		580
Total		5030

Figure 5.1.c shows the mean drilling costs per exploration well. Exploration wells are wildcats and appraisal (or delineation) wells.

Fig. 5.1.a
Exploration costs per year 1980–1990

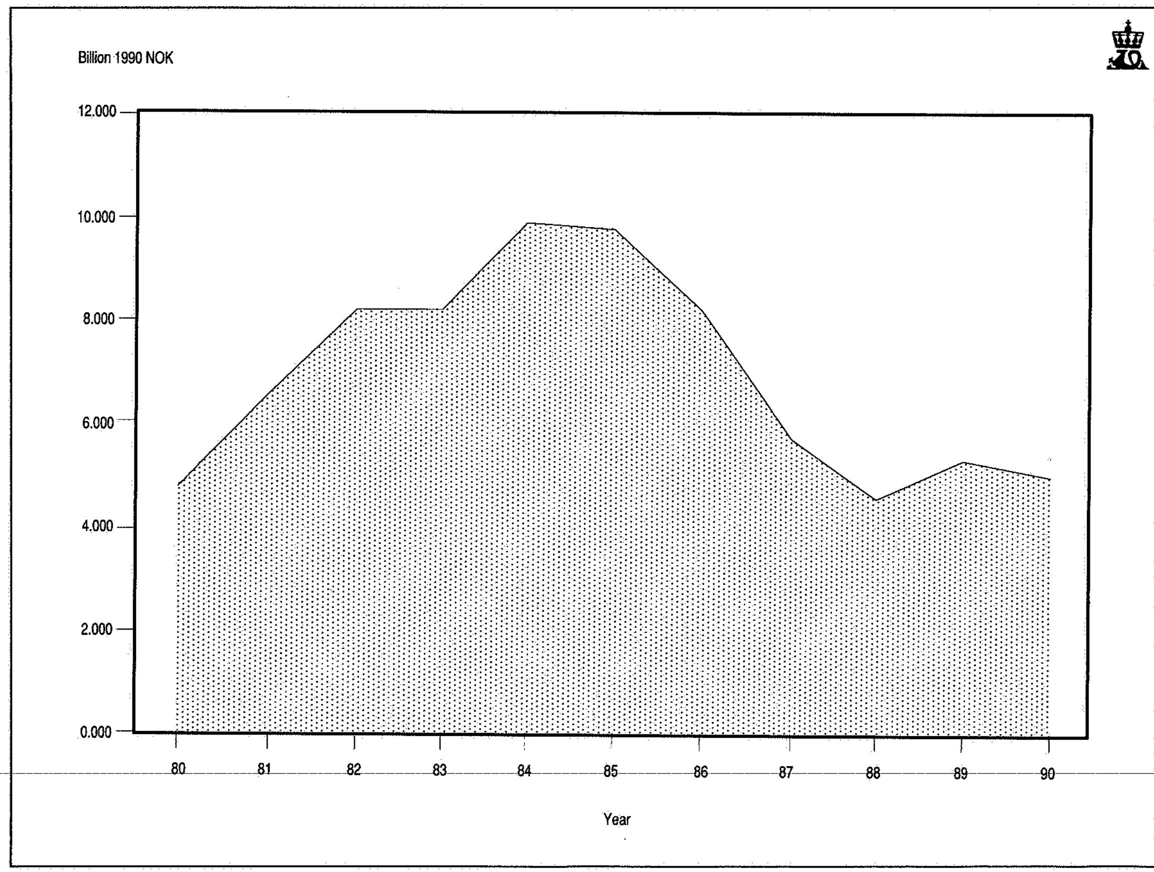
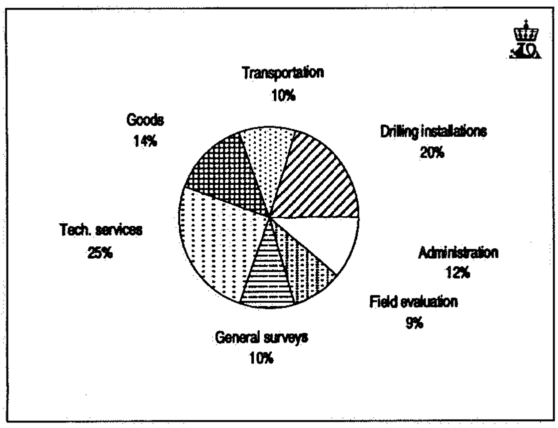


Fig. 5.1.b
Oil and gas exploration costs in 1990



5.2 COSTS OF DEVELOPMENT AND OPERATION ON NCS

The Norwegian Petroleum Directorate has calculated annual costs in connection with the development of fields, including production drilling, for the period 1970–2013. The costs include fields in production, under development and those which have been approved for development as at 31 December 1990. Where fields straddle the sector dividing line between Norway and the UK, only the Norwegian parts have been included. The following fields and transport systems are included in the calculations:

- Frigg (including pipeline to St.Fergus)
- Ekofisk complex
- Nordøst Frigg
- Øst Frigg
- Gullfaks
- Heimdal
- Murchison
- Odin
- Oseberg Transport System
- Oseberg
- Statfjord
- Tommeliten
- Ula
- Valhall
- Norpipe
- Statpipe
- Veslefrikk
- Troll-Oseberg Gas Injection
- Gyda
- Troll Phase 1
- Sleipner Øst
- Zeepipe
- Snorre
- Hod

Fig. 5.1.c
Number of exploration wells and drilling costs per well

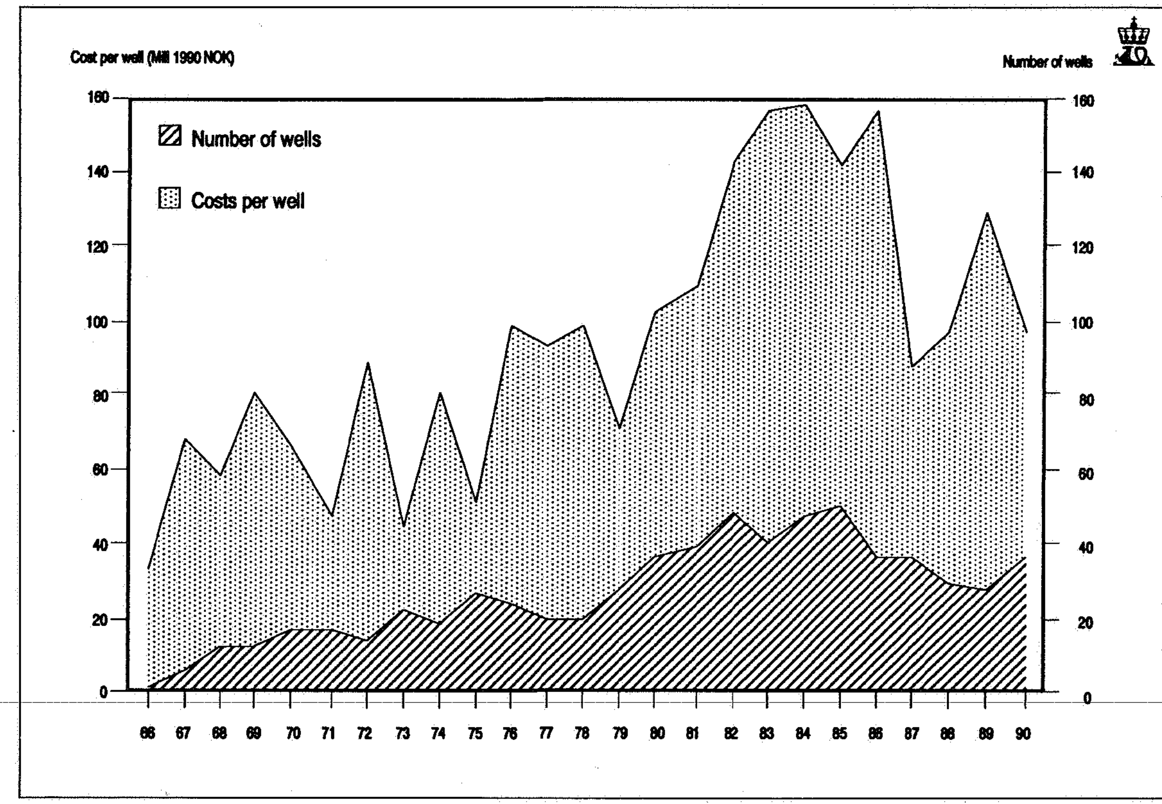
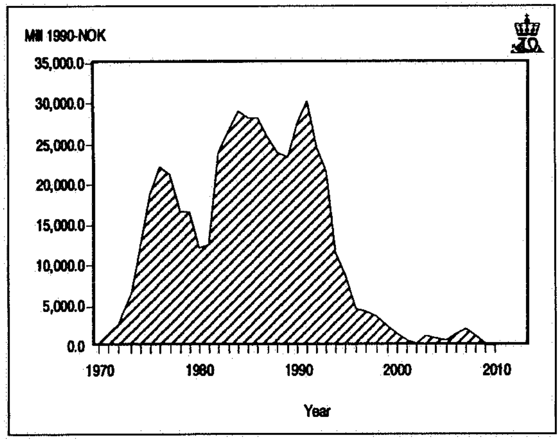


Fig. 5.2.a
Investments in fields and pipelines on the Norwegian shelf



- Draugen
- Gamma Nord
- Gyda pipeline
- Ula pipeline
- Statfjord Nord
- Statfjord Øst
- Brage
- Embla

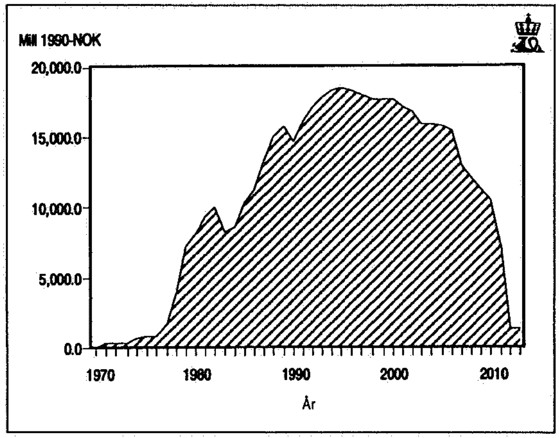
Historical and approved investments for field development and transport systems for petroleum are shown in Figure 5.2.a. All amounts are given in fixed 1990 kroner. Investments increased steadily until 1976, then slowed during the following years until a new increase occurred from 1981. A temporary peak was reached in 1984, when 29.1 billion 1990-value kroner was invested in the Norwegian continental shelf. In the light of the decisions taken, this will give an investment value of some 30 billion 1990 kroner early in the 1990s.

In 1990 the decision was made to bring the following fields on stream:
- Statfjord Nord
- Statfjord Øst
- Brage
- Embla.

During 1991 the Storting will evaluate further plans for development and operation. If these become actual the investment curve will show a much gentler rise during the 1990s.

The annual operation costs, including pipeline operating costs, are shown in Figure 5.2.b. The level of demand for operational goods and services have increased considerably, and will continue to increase as more fields enter production. Operation costs therefore appear to be the most important cost component of the future, so it will be of paramount importance to try to reduce these costs during the coming years.

Fig. 5.2.b
Operating costs for fields and pipelines on the Norwegian shelf



5.3 ROYALTY

The Norwegian Petroleum Directorate has been delegated the responsibility for collecting the production royalty.

The production royalty is calculated as specified in the Petroleum Act, which came into effect from 1 July 1985. The formula for calculating the royalty is the value of petroleum production passing each field's loading point.

In practice the formula for the calculation is the difference between the gross sales value and the costs incurred between the taxation point and the point of sale.

For some fields the cost of transport is higher than the gross sales value for the specific petroleum product. This applies especially to gas. Under such circumstances no royalty is charged.

When Odelsting Proposition no. 64 for 1986–87, regarding certain revisions to the Petroleum Act, was under discussion it was decided that royalties would not be charged for production from areas where the development plans were approved after 1 January 1986.

The interpretation and application of existing laws and regulations in connection with the calculation of royalty, incorporates legal, economic, technical processing, and technical measuring problems.

5.3.1 Total royalty

The total of royalties collected in 1990 was Nkr 8,471,352,890. Table 5.3.1 shows the breakdown over the different petroleum products for 1989 and 1990.

Figure 5.3 shows collected royalties for the period 1973–90.

5.3.2 Royalty on oil

In 1990 royalty of Nkr 7,519,750,914 was collected for oil production from the Ekofisk, Valhall, Ula, Statfjord, Murchison, Heimdal, Oseberg and Gullfaks fields. See Table 5.3.2. Royalty for oil was taken out in kind. The sale of this, the State's, royalty oil is the responsibility of Statoil, and payment for the sale is made from Statoil to the Norwegian Petroleum Directorate on a monthly basis. Settlement is at the norm rate fixed by the Petroleum Price Council.

Figure 5.3 shows the royalty paid up from 1973 to 1990.

5.3.3 Royalty on gas and NGL

The royalty collected for gas and NGL in 1990 amounted to Nkr 951,601,976. Table 5.3.3 shows the payments on a half-yearly basis by company and groups of companies.

The settlement, which is in cash, is on a six-monthly basis, with a three-monthly term for payment.

No gas royalty was paid for the Statfjord, Gullfaks and Ula fields for 1990, due to the high transport costs.

The settlement for gas is related to gas contract prices, which vary for the different groups.

The delivery of gas to Dyno-Methanor terminated from 1 July 1984. The payments from, and refunds to Dyno-Methanor relate to the transportation and processing of gas already received and paid for.

Fig. 5.3
Royalties 1973–1990

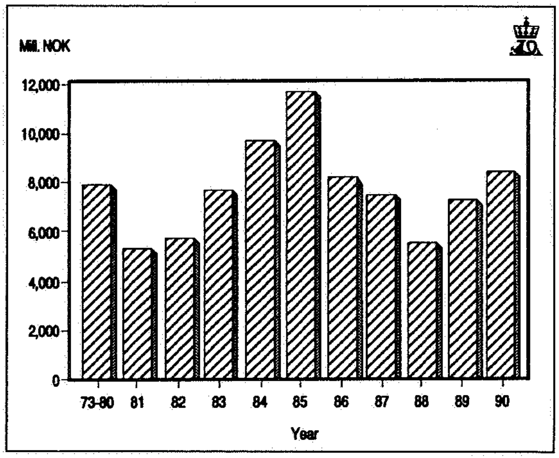


Table 5.3.1
Paid-up royalty in 1989 and 1990 (million kroner)

		1989	1990
OIL	EKOFISK/VALHALL/ULA	1 416.8	1 808.4
"	STATFJORD	4 095.5	4 591.7
"	MURCHISON	28.1	23.3
"	HEIMDAL	3.2	11.1
"	OSEBERG	351.0	589.9
"	GULLFAKS	431.6	495.4
GAS/NGL	EKOFISK FIELDS	448.2	408.7
"	VALHALL	8.8	29.2
"	ULA	0.0	0.0
"	FRIGG,NØ-FRIGG,ODIN	463.6	440.4
"	STATFJORD	0.0	0.0
"	MURCHISON	0.2	0.7
"	HEIMDAL	41.3	72.6
"	GULLFAKS	0.0	0.0
TOTAL ALL FIELDS		7 288.3	8 471.4

TablE 5.3.2
Paid-up royalty on oil in 1990

Field/Area	1st half	2nd half	Total 1990
EKOFISK, ULA AND VALHALL	755 796 834	1 052 542 831	1 808 339 665
STATFJORD	2 070 305 277	2 521 366 043	4 591 671 320
MURCHISON	14 981 104	8 324 827	23 305 931
HEIMDAL	1 334 186	9 755 071	11 089 257
OSEBERG	216 696 674	373 224 761	589 921 435
GULLFAKS	217 204 809	278 218 497	495 423 306
TOTAL	3 276 318 884	4 243 432 030	7 519 750 914

Table 5.3.3
Paid-up royalty on gas and NGL in 1990

Field/area	1st half	2nd half	Total 1990
EKOFISK AREA			
Phillipsgruppen	117 865 168	285 448 733	403 313 901
Amoco-gr. (Tor)	665 462	1 283 784	1 949 246
Shell (Albuskj.)	463 768	874 835	1 338 603
Dyno/Methanor	1 372 072	702 918	2 074 990
Total Ekofisk area	120 366 470	288 310 270	408 676 740
FRIGG AREA			
Petronord-gruppen	192 529 363	190 633 020	383 162 383
Esso (NØ-Frigg)	7 387 930	6 628 158	14 016 088
Esso (Odin)	20 201 369	23 046 404	43 247 773
Total Frigg area	220 118 662	220 307 582	440 426 244
VALHALL	6 402 171	22 759 011	29 161 182
ULA	0	0	0
STATFJORD	0	0	0
MURCHISON	570 873	131 408	702 281
HEIMDAL	30 860 695	41 774 834	72 635 529
GULLFAKS	0	0	0
TOTAL ALL FIELDS	378 318 871	573 283 105	951 601 976

5.4 ACREAGE FEES IN PRODUCTION LICENCES

The Norwegian Petroleum Directorate collected Nkr 326,949,270 in 1990 in acreage fees. With reference to production licence year the receipts were as follows:

Award of production licence	kroner
1965	104,879,250
1969	56,763,000
1971	5,502,000
1973	26,280,000
1975	19,627,767
1976	29,267,621
1977	8,998,833
1978	8,470,660
1979	25,794,700
1980	1,604,539
1981	13,104,062
1982	6,228,215
1983	4,565,260
1989	15,863,363
Total	326,949,270

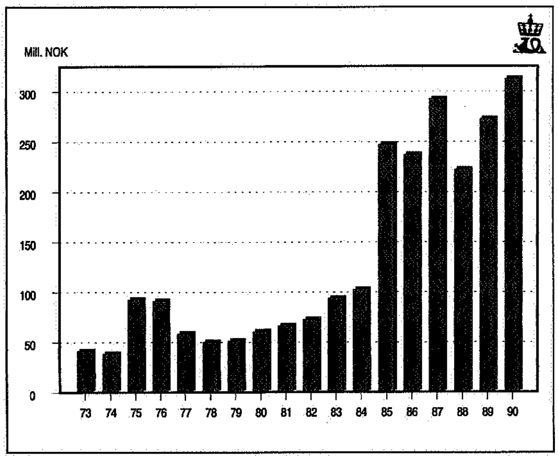
The Norwegian Petroleum Directorate refunded Nkr 69,057,866 in acreage fees in 1990.

This represents the deductible portion of the acreage fees in the royalty settlement for production licences 006, 018, 019A, 033, 037, 050, 053, and 079.

The acreage fees for some of the production licences are deducted directly in the royalty settlement. This amount was Nkr 25,236,593, which is therefore reflected in the royalty payments.

Figure 5.4 shows the acreage fees payments for 1973–90.

Fig. 5.4
Acreage fees 1973–1990



5.5 PETROLEUM MARKET

5.5.1 Crude oil market

The event which influenced the crude oil market most in 1990 was the Iraqi invasion, occupation, and later annexation of Kuwait. The UN decision for a total worldwide trade blockade against Iraq resulted in, amongst other things, a shortfall of some 4 million barrels of oil daily from the world market. This led to an increase in production by the other Gulf states, and considerable uncertainty regarding the price development for oil. The price varied from the commencement of the conflict considerably, and followed the tension level in the Middle East.

At the beginning of the year there was a high demand for oil in the world market, not least due to the exceptionally cold weather in the USA. It was expected that the demand would exceed that of 1989, and exceed the previous peak year in 1979. Several of the OPEC countries, particularly in the Middle East, announced plans to increase their production capacity. Assuming that the demand would increase, this action was necessary, particularly as production in several large non-OPEC countries was on the decrease. But already by the end of the first quarter it was obvious that oil demand would not reach the level of expectation; this being partly due to the fact that a mild winter had followed the intense cold of December 1989.

The oil storage tanks around the world were relatively full, due to the low withdrawal from stock in the first quarter. The OPEC countries' combined production exceeded the agreed production ceiling of 22 million barrels daily. In May OPEC convened a crisis meeting because of the drop in oil prices. The fall had been 30 per cent, equivalent to six US dollars, since the top price level in January 1990. A production reduction was agreed, in an attempt to stabilise the price.

In July Iraq stated that they wanted the production quotas to remain in effect until a price of about US$ 25 per barrel was achieved, and they threatened to "do something effective" if the Gulf states did not assist in this aim.

On 2 August Iraq invaded Kuwait, and by so doing gained control over Kuwait's 100 billion barrel oil resources, and 2.5 million barrels daily oil production capacity. This gave Iraq approximately the same resource size as Saudi Arabia.

The immediate result of the invasion was the disappearance from the world market of oil from Kuwait and Iraq, a loss of around 4 million barrels daily.

The conflict in the Gulf caused the International Energy Agency to review a crisis plan in connection with the distribution of oil. In November it became apparent that it was unnecessary to draw from oil reserves to meet demand, which had gradually been reduced, and that production in some OPEC countries had increased so much that it had now become a question of introducing production restrictions.

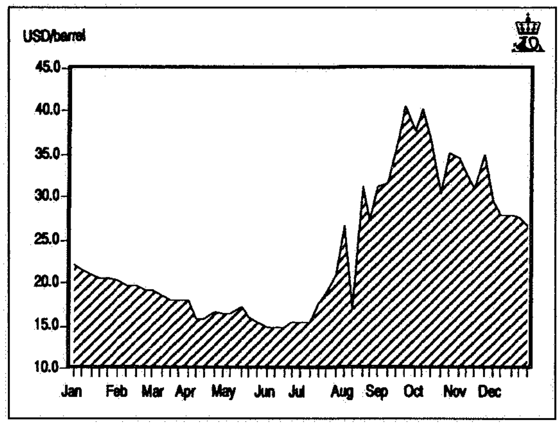
There has been a relative strong increase in the world oil consumption over the last few years, which has been partly due to the low relative price of oil. But the probably most important reason has been increased oil consumption in the newly industrialised countries.

The average OPEC production in 1990 was some 23.2 million barrels daily. That was an increase of 8.5 per cent over 1989.

1990 has been a year with falling production amongst some of the larger non-OPEC countries. The world's largest producer of oil, the Soviet Union, experienced a reduction of 5.3 per cent over 1989.

Oil production in the USA and Canada also de-

Fig. 5.5.1
Spot price Brent blend in 1990



creased in 1990, by 5.2 per cent in the USA and 3.2 per cent in Canada.

The production of oil in Western Europe increased by 5.6 per cent, due to the relatively large increase from both the British and Norwegian fields. During October the combined North Sea production reached 4 million barrels daily for the first time.

From 1 July 1990, Norway cancelled its self-imposed 5 per cent production reduction. The reduction, which had been introduced in 1987, was a contribution towards reducing the pressure on the sliding oil prices at that time. By comparison with 1989, the 1990 oil production on the Norwegian shelf increased by about 10 per cent.

5.5.2 Gas market

The world consumption of natural gas is increasing. In 1989 gas accounted for 21.3 per cent of the primary energy consumption.

The use of gas on a world percentage share basis is higher than for Western Europe, where gas in 1989 accounted for approximately 16 per cent of the total energy consumption. However it is expected that gas will show a steep share increase in the total energy consumption in the coming years, due primarily to the ecological advantages.

Gas production in Western Europe increased by 2.8 per cent from 1988 to 1989. Three countries experienced a fall in production: the previous West Germany, the United Kingdom, and France. Both the Netherlands and Norway showed strong increases in production, with the result that the total production for Western Europe showed an overall increase. The main countries which supply Western Europe with gas are the Soviet Union, the Netherlands, Norway and Algeria.

In 1990 the UK was again the largest recipient of Norwegian gas. However, under the existing contracts the delivery of gas from Norway is on a declining scale, and will terminate in the mid 1990s.

Norway has already sold some 30 billion cubic meters of gas for peak delivery under the Troll and SEP agreements. Deliveries under the Troll contracts will commence in 1993, and plateau production will occur just after the turn of the century. Deliveries under the SEP contracts will commence in 1995. On 1 July 1990 the deadline expired for German buyers to exercise their option for an additional volume of some 2.05 bcm of gas. In fact, the whole of this option was exercised. In addition Ruhrgas have already confirmed that they will exercise their 30 per cent share option in the original Troll contract. The deadline for this option is 1 July 1991. Ruhrgas has also entered into an agreement to purchase 1 bcm of gas in addition to the volume in the Troll contract. The French buyers have agreed to purchase 2 bcm of gas under the Troll contract conditions. If all of the Troll options are exercised Norway will be contracted to sell 40.8 bcm of gas to Continental purchasers from the year 2005. In addition to the extra quantities for Germany under the Troll agreement, the Ekofisk contract was re-negotiated in 1990. The result of this re-negotiation was an increase in delivery rate. An agreement has also been reached with Spain whereby deliveries will be advanced from 1996 to 1993, and the time to reach plateau delivery level is reduced.

The Italian market for gas is the third largest in Western Europe, and is expected to continue to expand. Discussions are taking place between the Gas Sales Committee and several Italian purchasers regarding the sale of Norwegian gas.

The Norwegian Gas Sales Committee had hoped to sign a sales contract for Norwegian gas with Sweden during 1990. Discussions were based on a delivery date in late 1995, when it was expected that Sweden will run down its first two atomic energy reactors. The decision regarding the run-down date has been postponed, and gas negotiations were suspended during the autumn 1990.

A large increase in Finnish gas requirements is expected, and Neste has shown an interest in purchasing Norwegian gas. A volumetric quantity of between 2 and 3 bcm has been mentioned. By the end of 1991 Finland must make a decision whether to expand their atomic energy reactors, or increase their reliance on gas. The Norwegian delivery of gas to Finland could be reliant on the possible export of Norwegian gas to Sweden.

Several countries have, in 1990, expressed interest for possible future imports of gas from Norway. The Eastern European countries, who traditionally have imported their gas from the Soviet Union, have particularly shown interest. This is because they wish to diversify their gas imports now that they have changed to a market-based economy.

Fig. 5.5.3.a
Sale of crude oil from the Norwegian continental shelf

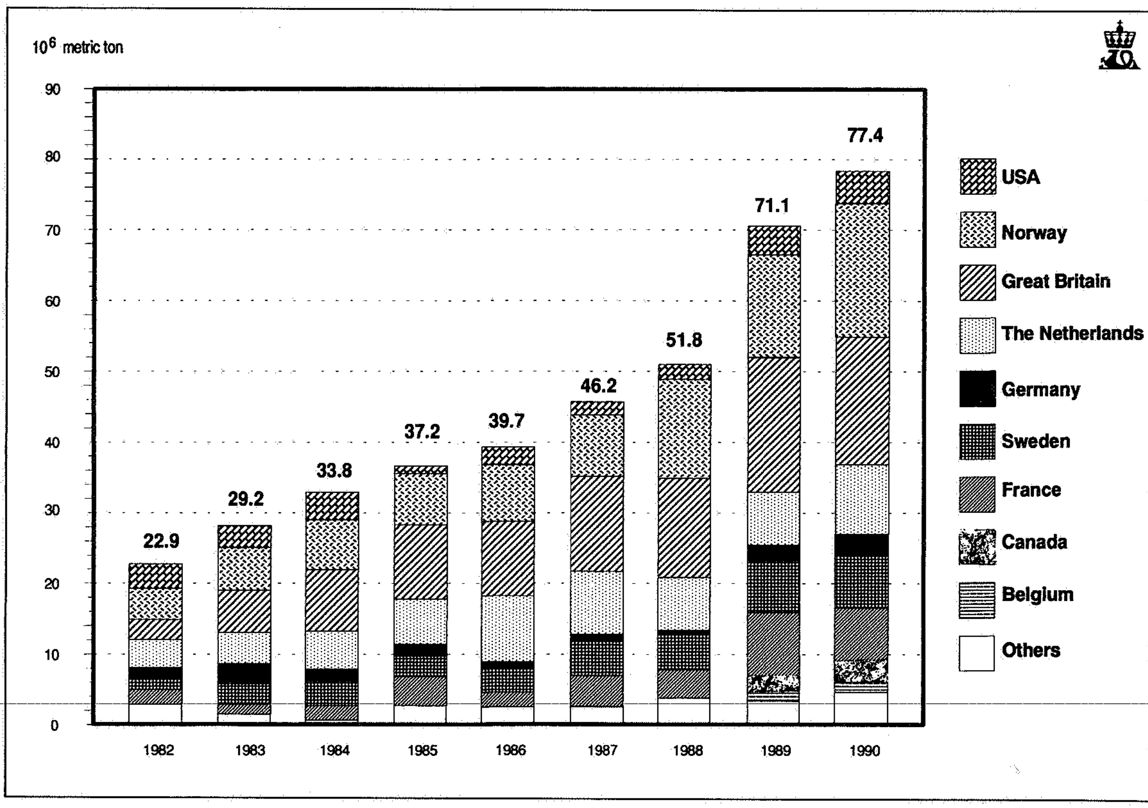


Fig. 5.5.3.b
Sales quantities of gas per country

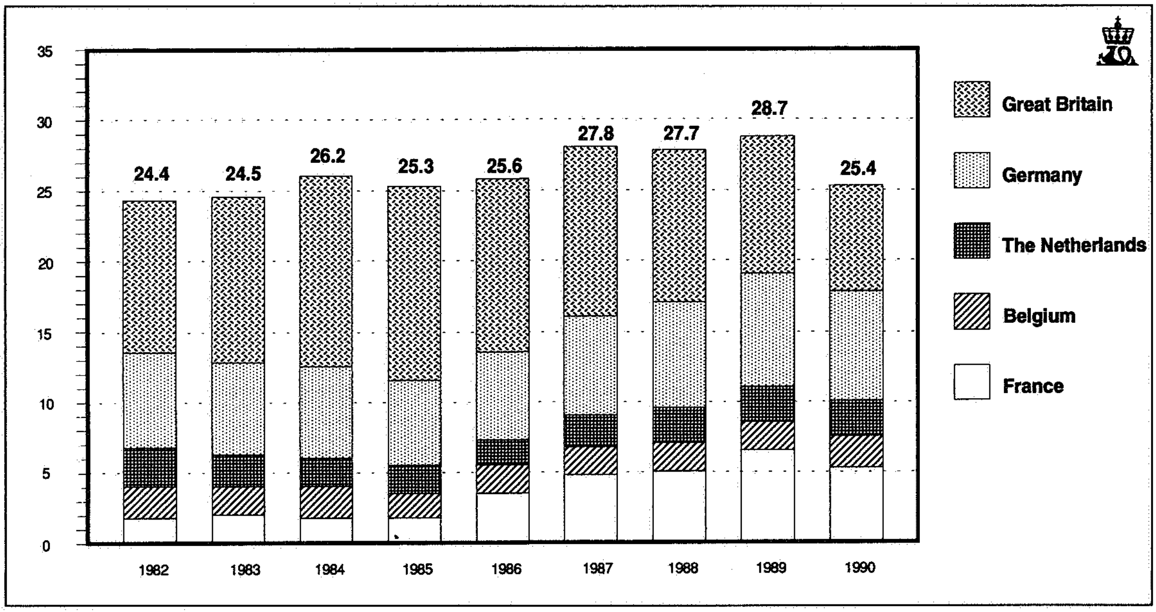


Fig. 5.5.3.c
Sales quantities of oil/NGL per licensee in 1990

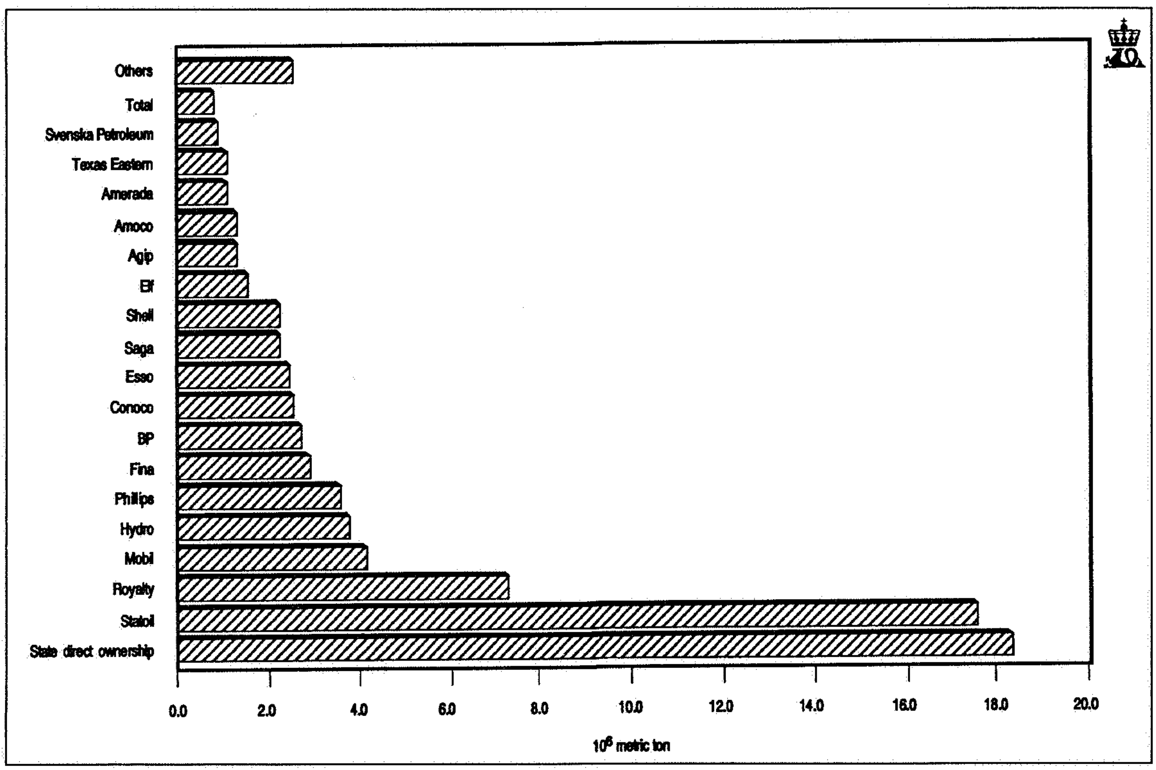
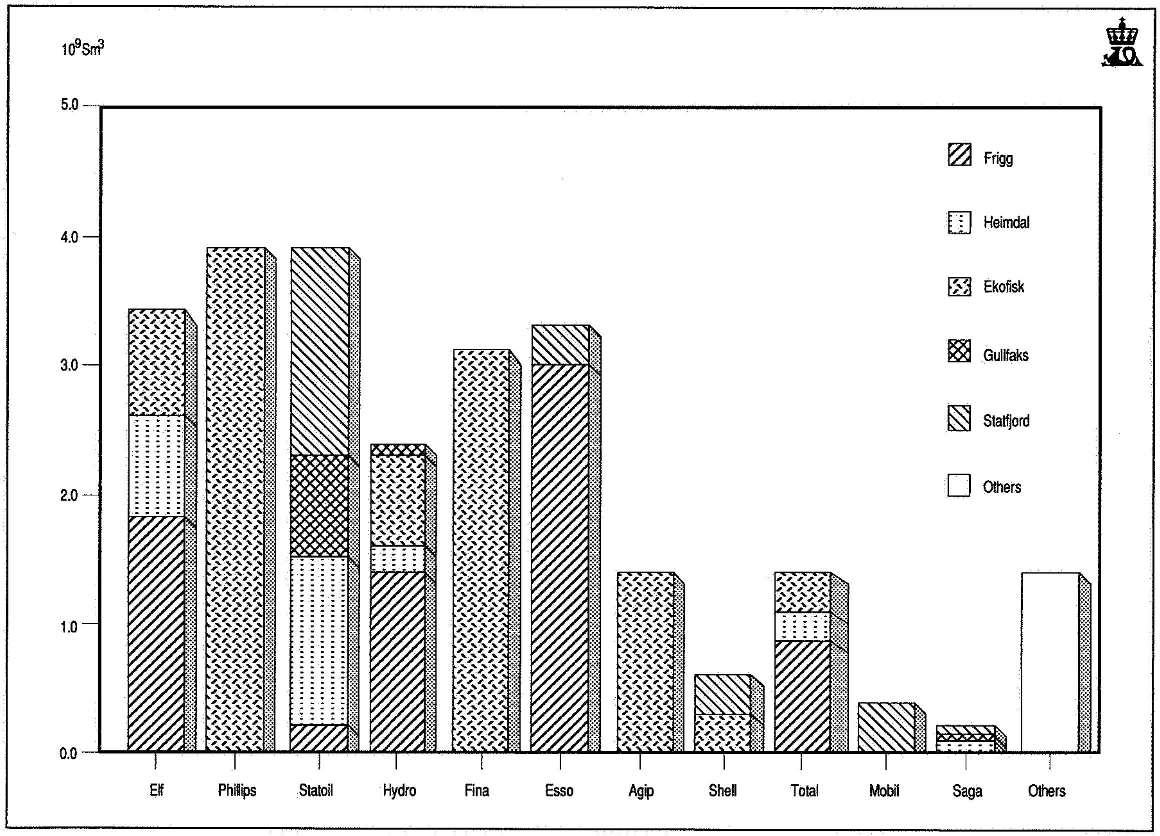


Fig. 5.5.3.d
Sales quantities of gas per licensee in 1990



5.5.3 Sale of petroleum from NCS

In 1990 total sales of crude oil from the Norwegian continental shelf amounted to 77.4 million tons. This was an increase of 7.5 per cent compared to 1989. Norway was the largest recipient with 24.5 per cent of the shipments; the UK received 23.5 per cent, the Netherlands received 13 per cent, and France and Sweden 9.3 per cent each. In 1989 Norway received 21 per cent of the total, so a small percentage increase was recorded in 1990. Figure 5.5.3.a shows the sale of crude oil by country for the period 1982–90.

Up until 1988 both Belgium and Canada were shown under the heading "Others". The sale of Natural Gas Liquids from the Norwegian continental shelf in 1990 was 2.4 million tons. That was the same result as for 1989. Figure 5.5.3.c shows the sale of crude oil and NGL in 1990 by licensee. Norway exported 25.4 bcm gas in 1990, which was a reduction of 11.5 per cent compared to 1989. A total of 7.9 bcm was sold to Germany (West), 7.4 bcm to the UK, 5.3 bcm to France, 2.5 bcm to the Netherlands and 2.3 bcm to Belgium, as is shown in Figure 5.5.3.b. Figure 5.5.3.d shows the gas sale by licensee for 1990. Under the column "Others" the oil companies are not shown separately, due to the fact that there are too many small fields included, which would make it too confusing to try to show them in detail.

6. Special Reports and Projects

In 1990 the Norwegian Petroleum Directorate appropriated a total of Nkr 19,572,650 for special projects. Of this amount Nkr 5,925,178 was budgeted for projects in the Safety and Working Environment Division and Nkr 13,647,472 for projects in the Resource Management Division.

Another Nkr 4,666,457 was committed to the North Sea Seabed Clearance project.

Nkr 5,858,796 was made available for collection of meteorological and oceanographic data in the Barents Sea, under the auspices of the Directorate; while the SPOR enhanced recovery project received Nkr 14,978,785.

The titles of the projects and the various institutions carrying them out are reviewed for each division below.

6.1 RESOURCE MANAGEMENT DIVISION
6.1.1 Exploration Branch

Project title	Executive institution
Processing of Deep Seismic Data in Skagerrak	University of Oslo
Satellite gravity map 62–72°N	Institute of Earth Geophysics, University of Bergen
Nomenclature of Structural Elements offshore Mid-Norway	Norwegian Petroleum Directorate
Evaluation of Exploration Activity	Christian Michelsen's Institute
Geological Projects	
Upgrading of the Resources Base	Christian Michelsen's Institute
Glaciation, Erosion and Sedimentation in the Norwegian Trench	Geological Institute, University of Bergen
Neo-Tectonics	Geological Institute, University of Bergen and State Mapping Authority
Seismics in Jæren (region of Norway)	NPD/Norwegian Geological Survey
Analysis of Fission Traces	University of South Carolina
Bio-Stratigraphy	CB Magneto
Well Data Summary Sheets	NPD
Well Data Log Splicing	Tape Technology, Norway
Miocene and Pliocene Sedimentation and Paleonic Environs on Vøring Plateau	University of Oslo
Field Studies of Carbonate Deposition on Bear Island	Continental Shelf Institute (IKU) and NPD

Processing of Deep Seismic Data in Skagerrak
This project involved the reprocessing of deep seismic lines shot by *Mobil Search*. The renewed processing has succeeded in identifying interesting crust reflections which can be correlated, for example with the Oslo fault. The results will be of significance for the understanding of Skagerrak's geological history.

Satellite Gravity Map 62–72°N
The aim of this project was to construct a gravity field anomalies map based on satellite altimeter readings. This is comparable to ordinary gravimetric maps and will provide information on density variations below the surface. Such information is useful for regional geological surveys. By employing satellite data, information is also obtained from areas not covered by the marine gravimetry scans.

Nomenclature of Structural Elements offshore Mid-Norway
The work to name geological structures and elements on the Mid-Norway shelf is a joint project involving Hydro, Saga, Statoil and the Directorate. The results of the project will be published and offered for sale in the NPD Bulletin no. 6, part II.

Evaluation of Exploration Activity
This project aims to produce a methodic summary of technical and economic lines of argument regarding exploration scope within geographical areas and problems confronting exploration in given areas, in a given block or an identified structure. The project intends to summarise the results of previous studies and existing literature.

Geological projects
In 1990 the Directorate chose to give priority to implementing projects concerning development of computerised tools and basin modelling skills. The purpose is to develop programme systems that can predict how much oil and gas is formed in sediment basins which can migrate to the structural traps identified. In connection with this, stress is also given to projects looking at the influence of the ice age on oil and gas accumulations. Basin evaluation includes an assessment of methods of calculating paleo temperature, for example fission tracer analysis.

Bio-Stratigraphic Consulting Services
These projects all concern dating work for which the Directorate lacks the necessary expertise, such as magnetic stratigraphs of core samples.

Well Data Summary Sheets
This is an annual undertaking which deals with released well data from the continental shelf. This year's publication is the sixteenth in the series and deals with wells put down in 1985.

Well Data Log Splicing
Much of the well data from the older wells is at present stored on multiple magnetic tapes. This project intends to splice the tapes, as it were, thereby collecting entire well logs on single tapes. The products will be released as they reach five years of age.

Miocene and Pliocene Sedimentation and Paleonic Environs on Vøring Plateau
This project aims to provide detailed zoning of the late tertiary sediments on the Vøring Plateau. The dates are important principally in connection with the land rise issue and its correlation with the Barents Sea.

Field Studies of Carbonate Deposition on Bear Island
This project continues where the *Study of Permian and Carboniferous Carbonates in Barents Sea* left off.

Studies have been made into the sedimentology and diagenetics of the strata sequence on Bear Island as a step towards increasing our regional understanding of carbonate development in the Arctic area.

6.1.2 Development Branch

Project title	Executive institution
Reservoir Study of 6506/12 Beta	READ
RUDI Resources Development and Operational Information System	Cap Gemini
Dipmeter Studies on Gullfaks Sør	Z&S Geologi
Gas Injection 1990	Restek
Microbial Enhanced Oil Recovery	Rogaland Research Institute
Petroleum Geo-Chemistry Study of Njord Field and Regional Adjacent Prospects	Karlsen Keros Consulting
Log Interpretation Njord	Scientific Software-Intercomp
Compliant Towers	Aker Engineering A/S
Further Development of INVERS Cost Databank	Andersen Consulting A/S
Novel Cash Flow Model	Arthur Andersen & Co

Reservoir Study of 6506/12 Beta
A full-field simulation of the 6506/12 Beta structure was performed. The study included a compositional description of the fluid systems and evaluation of the various depletion strategies. The results will be used in connection with the evaluation of the field's plan for development and operation (PDO).

RUDI Resources Development and Operational Information System
RUDI is the Directorate's central database for petroleum fields. The purpose of the system is to simplify the generation of reports, improve the chances of running historical analyses, and reduce the array of information sources for basic data.

Dipmeter Studies on Gullfaks Sør
The Directorate has collaborated with Z&S Geologi, of Stavanger, to conduct a study of dipmeter data from Gullfaks Sør. Besides complementing the older database, the work produced a report which describes how the various fault blocks have rotated in time and space. This has contributed important new information regarding the field's structural development, particularly in the eastern parts.

Gas Injection 1990
This project is a part of the collaboration programme between Statoil, Hydro, Saga and the Directorate for the evaluation of the chances of enhancing oil recovery by various approaches. In 1990 the project particularly targeted combined water and gas injection. The project aimed to study if combination injection results in better recovery than pure waterflood for certain predetermined fields.

Microbial Enhanced Oil Recovery
This project was a review of the literature concerning employment of micro-organisms to enhance the production of oil; and examine the salient factors determining how applicable such a method might be in the North Sea context. The method may present an alternative to other advanced methods of increasing production, such as surfactant injection and similar strategies.

Petroleum Geo-Chemistry Study of Njord Field and Regional Adjacent Prospects
Phase 1 of this project was carried out in 1990 by the engineering firm of Karlsen Keros Consulting. The task was to conduct relatively exhaustive analyses of fluid samples from 27 wellbore tests. The analysis results are designed to elucidate the filling history of the fields in this region.

Log Interpretation Njord
Former interpretations concerned three Njord wells (in 1988). Scientific Software-Intercomp ran a petrophysical analysis of a fourth well in the report period. In addition to log interpretation, the study also addressed the determination of cutoff values for all four wells. The results will be used by the Directorate for volume estimation.

Compliant Towers
A study of compliant tower structures has been carried out in order to establish whether, and if so how much, this type of platform base can save costs for the development of small fields and satellites. Compliant towers have been considered for use as wellhead structures tied in to process plant located close by.

The project was conducted in cooperation with the oil companies with Aker Engineering responsible for execution.

Further development of INVERS cost databank
The Directorate has joined with the industry in the task of standardising code structures for cost data for North Sea development projects. The aim is to structure empirical data from the activities. The Directorate has embodied the results of the work in the cost databank INVERS.

Novel Cash Flow Model
Jointly with the Ministry of Petroleum and Energy the Directorate has developed a new cash flow model for use with project and company accounts analysis. Development and maintenance will be easier and less costly than with the older model. The model is also more user-friendly, and is already installed in the Ministry and the Directorate.

6.1.3 Production Branch

Project title	Executive institution
SAFARI Data Acquisition	Norwegian Computer Center, University of Barcelona, Colorado State University, Rogaland Research Institute, University of Bergen
Laegerdorf	GeoRecon A/S
NPD's Involvement in Reservoir Descriptions for SPOR Enhanced Recovery Project	Rogaland Research Institute, Institute of Energy Technology (IFE), Continental Shelf Institute (IKU)
Sealing Faults	GeoRecon A/S
Study of Geological Factors of Significance for Migration Mechanisms in Gullfaks Area	University of Oslo
Modelling and Simulation of Statfjord Formations, Statfjord Field	Norwegian Computer Center, Institute of Energy Technology (IFE)
Identification of Uncertainties of Petrophysical Analysis of Wellhole Logs	Schlumberger
Economics of Personal Safety	SikteC
Safety, Taxes and Incentives	SREA
Multi-phase Measurement	National Engineering Laboratories (NEL)
Gas Flaring Criteria	Novatech a.s
Feedback of Operating Experience to Design Phase	Novatech a.s
Reservoir Souring	Capcis, Manchester
Database Operating Costs	Arthur Andersen
Coriolis Mass Flowmeter Project	National Engineering Laboratories (NEL)
Flowmeter for Simultaneous Measurement of Oil, Gas and Water	Christian Michelsen's Institute
Sampling of Water Content of Oil	National Engineering Laboratories (NEL)
Prognosis Subproject for RUDI	Cap Gemini
ECLIPSE-200	ECL
Geotechnical Support	Mervyn Jones
Enhanced Recovery on Eldfisk, Reservoir Study	READ
Reservoir Studies on Ekofisk	Ali Saidi, Continental Shelf Institute (IKU)
Use of Tracers in Norwegian Sector	Restek, Institute of Energy Technology (IFE)

SAFARI

This is a cooperation project involving Saga, Statoil, Hydro and the Directorate. The project covers collection of quantitative, geological data from sediments which are uncovered on land and which are analogous to sediments in the North Sea reservoirs. The project is compiling a database for quantified information on sedimentary reservoir heterogenities. The aim is to reduce the uncertainties of reservoir descriptions and reservoir simulations for fields in the Norwegian sector.

Laegerdorf

This cooperation project between eight companies was launched in 1990 and will be concluded in summer 1992. Consultants Geo-Recon Group A/S have been engaged to implement the project which is intended to compile a three-dimensional database (using data collected from the Laegerdorf chalk quarry in Germany) embracing such parameters as fracture, fault and flow figures. This type of reservoir description will provide the oil industry with a better understanding of the chalk fields in the North Sea.

NPD's Involvement in Reservoir Descriptions for SPOR Enhanced Recovery Project

The Directorate is responsible for assistance to the SPOR programme in the reservoir descriptive field. This is done by closely following up research projects at home and abroad. It is also important to the Directorate's own work in the discipline of reservoir description.

Sealing Faults

This project has sought to examine how slate in the plane of the fault influences sealing potential. A knowledge of how slate influences permeability across the fault plane will be crucial for many fields in the Norwegian sector.

Study of Geological Factors of Significance for Migration Mechanisms in Gullfaks Area

This project seeks to increase our fund of knowledge and degree of comprehension of hydrocarbon migration in the Gullfaks area, thereby improving our understanding of the reservoir and its production characteristics. The potential for correlation and extrapolation of reservoir characteristics to areas where there is little or no well control will be enhanced.

Modelling and Simulation of Statfjord Formations, Statfjord Field

A detailed geological charting operation with a view to identifying slate incidence and continuity has been performed. This was then modelled using stochastic methods. A key element in the study is reservoir simulation of the production history of the field, which is a means of evaluating how exactly the simulation fits the data. The best fit is then used to predict production to come.

Identification of Uncertainties of Petrophysical Analysis of Wellhole Logs

The interpretation of well logs is frustrated by considerable uncertainty in the instrumental measurements and the mathematical models used to interpret the readings. In 1988 the Directorate initiated a project which aimed to shed light on and quantify these uncertainty factors.

The programme was expanded in 1990 and was of great assistance in the petrophysical interpretation of wells on the Ekofisk, Troll and Heidrun fields.

Economics of Personal Safety

The aim of this project was to combine a theoretical problem approach with case studies by identifying one minor and one not-so-minor accident, then identifying and specifying the costs associated with human injury.

Safety, Taxes and Incentives

This project aimed to clarify the safety incentives inherent in various types of organisational system, such as the tax system and insurance schemes.

The project combines a theoretical approach with a few case studies so as to reveal how capital investments and operating costs earmarked to improve safety are dealt with in the tax system; and what incentives are built into today's insurance and taxation systems which reward investment in insurance, as opposed to rewarding investment in accident preventive systems.

Multi-phase Measurement

The project group for multi-phase measurement consists of a multiple client consortium in which eight operating companies participate. The aim is to develop a concept for measurement of multi-phase flow based on known technology.

The work involves three phases:

1) Design and testing of equipment
2) Fabrication of prototype
3) Field testing of prototype.

So far the project has completed phase 1. Interim reports for some of the tests have been submitted.

Gas Flaring Criteria

The project has identified the problems associated with flaring of gas in connection with startup of new fields. The reasons gas flaring may be necessary in connection with commissioning of equipment have been catalogued. Likewise a summary of completion tasks which must be concluded before hydrocarbons can be introduced into the given system has been given. In the final part of the project, factors limiting the plant's turndown capacity will be pinpointed and analysed. Opportunities to upgrade this turndown capacity will also be suggested.

Feedback of Operating Experience to Design Phase
This project is a preliminary study to find out what is available in the way of useful databases, what information they contain, and how appropriate the information is for the engineering design of installations having improved operating economy. An itinerary for further work has also been proposed.

Reservoir Souring
This project was carried out to define the causes of reservoir acidification in the North Sea. The work which was done by Capcis at the University of Manchester was completed in 1989.

Based on the results obtained, the Directorate commissioned Capcis to run another study, *Reservoir Souring and Chalk Rock Properties*. The results may provide some indication of whether to expect souring of such reservoirs if waterflooded. The study should be completed by early 1991.

Database Operating Costs
This project is intended to develop a database which will accommodate operating costs data and technical key figures. Also, data reports have been prepared for different methods of presentation of the data in the bases. Reporting of data is scheduled for 1991.

Coriolis Mass Flowmeter Project
This project, combining the forces of Statoil, Total, Phillips, Norwegian Petroleum Directorate, Kodak and UK authorities, will test metering devices from many instrument suppliers which capitalise on the measurement of the coriolis effect. The instruments are carefully examined for accuracy, installation effects, maintenance routines, etc.

Flowmeter for Simultaneous Measurement of Oil, Gas and Water
This project involves the development testing of an instrument with which to monitor water, oil and gas flowrates at the same time. Again, this is a multi-client project involving BP, Saga, Hydro, Elf, Phillips and the Directorate.

Sampling of Water Content of Oil
The Norwegian Petroleum Directorate and the UK Department of Energy have cooperated for several years with 12 oil companies in a research programme aimed at drafting common guidelines for the design and operation of sampling devices. The results will subsequently be used for preparation of international standards in this technical field. The tests are performed under the direction of the National Engineering Laboratories (NEL) in Scotland, where a test station has been built specially for the purpose.

Prognosis Subproject for RUDI
RUDI, the resources development and operations system, is aimed at replacing the present LOPAP, a single-user, non-user-friendly system. The subproject hopes to create a prognosis programme which is a part of the RUDI database, where it rightfully belongs.

ECLIPSE-200
The Directorate purchased an extended version of this programme which is in use at present. The purpose is to simulate structures with horizontal wellbores more viably.

Geotechnical Support
The Directorate feels the need to seek expert assistance for the special problems which arise in connection with production of hydrocarbons from chalk reservoirs (subsidence, chalk production, sidewall cave-in). As of yet these problems have not been resolved satisfactorily and the task is being tackled by the companies and the authorities in Denmark and Norway. Project funds will be used to commission expert opinions and conduct special studies (lab tests).

Enhanced Recovery on Eldfisk, Reservoir Study
This project aims to quantify how much additional oil and gas can be coaxed from the Eldfisk field by means of novel recovery methods such as water or gas injection, or a combination of both. The initial part of the project was to collate the PVT analysis data from oil samples on the field to determine representative figures for further reservoir studies.

Reservoir Studies on Ekofisk
This project was designed to construct a numerical reservoir simulation model for Ekofisk and simulate the alternative production strategies (water and gas injection). The modelling method is new for Ekofisk in the sense that the fracture pattern in the rock is modelled in a new, unconventional manner.

Use of Tracers in Norwegian Sector
Tracers have a considerable potential in the North Sea, principally since the information such tests produce, is difficult to obtain in any other way. Also, the costs are very modest by comparison with the sheer volume of information obtainable. The Directorate in this project has sought to shed light on the difficulties facing users of tracers. The project has also sought to identify the potential for using trace substances in connection with enhanced recovery.

6.1.4 Planning Branch

Project title	Executive institution
Petroleum Assets and Uncertainty	Christian Michelsen's Institute
Assistance with Methodology Questions	Kurt Ossian Jørnsten Consulting
Portfolio Model, Graphics, Documentation	SINTEF
Reliability Database	SINTEF
Energy Consumption in Europe	Norwegian School of Management (BI, Oslo)
Market for Natural Gas in Italy	Arthur D. Little
World Hydrocarbon Resource Project	Colin Campbell, Cap Gemini
British Gas Market	Coopers & Lybrand

Petroleum Assets and Uncertainty
Oil and gas resources are a key element in Norway's total assets. A crucial task for the Directorate is to promote the best possible management of these resources, our "Petroleum Assets". Both when managing and when drawing on these assets, it is essential to understand the factors that determine their size. In conjunction with the Ministry of Finance, the Directorate has therefore commissioned an analysis to optimise estimation of the magnitude of various types of resources (see resources accounts, Chapter 3). Crucial to the analysis is price uncertainty and its impact, not just on the evaluation of the assets as a whole, but also the viability of the various investment projects.

The report's conclusions suggest that the Directorate will be reconsidering certain of the underlying home truths of current economic analyses and recommendations.

Assistance with Methodology Questions
This project considered issues surrounding the phasing in of fields, and also questions relating to exploration economy.

Reliability Database
The Directorate has commissioned a Safety and Reliability project with SINTEF, designed to update, document and enhance estimation of reliability factors when evaluating alternative development options in North Sea fields. A computer tool has been developed which performs this task easier and more accurately.

Energy Consumption in Europe
This project aims to highlight how demand for Norwegian gas may be affected by development of the electrical power market in Europe. Conditions in certain key European countries were assessed. A discussion of the general conditions influencing energy consumption were a core area of the study.

Market for Natural Gas in Italy
Italy's demand for natural gas has intensified very fast and further development is predicted, particularly considering the price advantage of gas compared to oil, and its relatively low pollution level. If demand continues to grow, this will have important commercial implications for Norwegian gas export. The project was conducted jointly by the Directorate and the Ministry of Petroleum and Energy.

World Hydrocarbon Resource Project
In 1990 work continued on compiling a database for information about the world's resources and production of petroleum. The oil statistics obtained have been collated and appraised with a view to constructing a realistic picture of the resources potential of the world's oil producing countries.

British Gas Market
In 1988 a study was made of the British gas market. In the light of organisational changes in this market, in 1990 a renewed study was made, which had as its main objective to chart the new opportunities for Norwegian gas export to the UK. The project was conducted by the Directorate and Ministry of Petroleum in cooperation.

6.1.5 SPOR Enhanced Recovery Programme

Project title	Executive institution
Water Injection (SPOR Water)	Rogaland Research Institute
Gas Injection (SPOR Gas)	Continental Shelf Institute (IKU)
Optimisation of Reservoir Data (SPOR Opt)	Institute of Energy Technology (IFE)

Again in 1990 there was much activity within the SPOR enhanced recovery programme, a government research and development programme initiated in 1985. The programme seeks through build-up of expertise, and through research and development of novel technology, to provide a foundation for enhanced oil recovery from the Norwegian continental shelf.

To date Nkr 90 million has been spent on the programme and these funds have been appropriated over the Ministry of Petroleum and Energy's budget. SPOR, a limited period research and development programme, is scheduled to terminate in 1991. Attempts to extend the programme are under way.

Implementation of the SPOR programme has produced tangible spinoffs for the work on enhanced oil recovery in the Directorate and the companies engaging in offshore activities in the Norwegian sector. The results from the SPOR programme also provide a platform for Norwegian participation in international cooperation such as the International Energy Agency (IEA) and bilateral cooperation, as with the USA.

6.1.6 PROFIT

A new five-year programme for research into *Field Oriented Improved Recovery Technology* was launched in 1990. In it the Directorate takes part on an equal footing with 13 oil companies to finance and manage the activities, which in certain areas will develop the results of the SPOR programme. The research will be largely undertaken at Norwegian institutes.

PROFIT has a budget of Nkr 90 million, and to date work has started in two main projects:

- Reservoir specification
- Near-well flow.

6.2 SAFETY AND WORKING ENVIRONMENT DIVISION

Project title	Executive institution
Membership of Welding Institute	Welding Institute
Membership of Marine Technology Directorate (MTD)	MTD
Membership of Norwegian Electro-Engineering Committee (NEK)	NEK
Petroleum Operations North of 74°30′N	NPD
Manned Underwater Operations – International Co-operation	NPD
Working Environment for Divers	SINTEF
Plastics Composite Tubing, Use in Fire-Fighting Systems	SINTEF, Norwegian Building Laboratory (NBL)
Ergonomic Requirements and Criteria	Novatech A/S
Jack-up Site Assessment Procedures	Noble Denton
Use of Oil-Based Drilling Mud	Petreco

Project title	Executive institution
Planning and Criteria for Relief Wells	Neal Adams
Heavy Lift Criteria	Brown & Root Vickers Ltd, London
Design Data for Bolt Materials – Influence of Hydrogen	SINTEF
Design Codes for Plastics Materials	SINTEF
Gas Kick in Oil-Based Drilling Mud	Rogaland Research Institute
World Offshore Accident Databank, WOAD	Det norske Veritas (DnV)
Perceived Risk and Safety	SINTEF
Hydrostatic and Dynamic Pressure Modelling for High-Pressure, High-Temperature Deep Wells	Rogaland Research Institute
Coiled Tubing HAZOP	Proffshore
Partial Safety Coefficients for Geo-Engineering Analyses	Noteby
Iceberg Frequency off Troms and Finnmark Coast	NPD
Release of Deluge Systems on Gas Alert	NPD
Gas Safety Programme 1990–92	Christian Michelsen's Institute
Technical and Operational Aspects of Manned Underwater Operations	Oceaneering
Internal Quality Control of Documentation of Chemical Health and Environmental Hazards	Novatech A/S
Correlation between Demanning and Accident Frequency	SINTEF, SikteC
Well Control in Horizontal Wells	Target Drilling
Instrumental Status Control, ITK	Det norske Veritas (DnV)
Russian-Norwegian Petroleum Dictionary	Knut Finne
Internal Control of Activities in Norway	SINTEF
Influence of Welding on Materials Performance Offshore	Cranfield Institute, UK
EXPRES – Expert System for Evaluation of Corrosion Risk	Cranfield Institute, UK
Design Curves for Fatigue of Cathodic Protected Structures	SINTEF
Corrosion Rate in Crevices in High-Alloy Steel in Seawater	SINTEF

Project title	Executive institution
Multi-phase Pipeline Transport	Veritec
Hydrate Problems with Pipeline Transport	Petreco
Application of Statistical Analysis Tools to Accident Data	SaS Institute A/S
Maintenance Planning Tool, Formula PS	Norsk Data
Implementation of Drawings in Database, CODAM	EB Industrier Offshore
Data Communication, Alternative Solution for NPD	Norwegian Telecom Business Division (TBK)

Membership of Welding Institute
The Norwegian Petroleum Directorate has been a member of the Welding Institute in Great Britain since 1981. WI is the leading authority in the offshore field and is very energetic in research, training and consultancy. Membership qualifies for consultancy services, project participation and current information on the latest developments in materials technology and welding engineering.

Membership of Marine Technology Directorate (MTD)
Since 1980 the Norwegian Petroleum Directorate has been a member of the British Offshore and Underwater Engineering Group (UEG) which was a subdivision of the British Construction Industry Research and Information Association (CIRIA). The group has now joined the Marine Technology Directorate. The projects administrated by the organisation are very pertinent to the Norwegian Petroleum Directorate's work tasks in this sphere. Cooperation and availability of information have been of tremendous assistance for safety reports, regulatory drafting, and competence build-up. The Norwegian Petroleum Directorate is a member of a project concerned with operative inspection of structures and installations underwater.

Membership of Norwegian Electro-Engineering Committee (NEK)
Among the Directorate's justifications for joining the NEK was to ensure that regulations in the electrical engineering field are continually under revision and keep pace with technological advance, international practices, and experience. The importance of these factors is underscored by Norway's efforts to meet the prescriptions of the agreement concerning technical barriers to trade in EFTA and the EC.

The Directorate also takes part in national and international cooperation for preparation of new regulations. This work is headed by NEK.

Petroleum Operations North of 74°30′N
This project is designed to elucidate the controlling factors for petroleum operations in areas having similar climate to Barents Sea North. Special attention is given to other governments' regulations and requirements, particularly those of the US and Canada.

The project also seeks to estimate the chances of collision with icebergs in the region between Bear Island and King Charles' Land, based on the methods given in the Sintef report: *Platform and Foundation Behaviour during Combined Hydrodynamic and Ice Loading – Location A and B*, of February 1990.

Manned Underwater Operations – International Cooperation
This project has aimed to continue and expand the established international cooperation in the fields of safety and the working environment, standardisation of regulatory requirements, and guidelines for and enhancements to technical systems for manned underwater operations. The project which has lasted several years and produced invaluable results, is of great significance for current and future underwater operations.

Working Environment for Divers
Former projects under the auspices of the Directorate, using only modest resources, produced valuable results of considerable practical importance in the field of working environment for divers.

In 1990 the project went on to look at microbial contamination of diving bell atmospheres, considered procedures for decontamination of diving bells, and evaluated various disinfectants for use in hyperbaric habitats.

The project also examined the bell atmospheres in diving systems which have clocked up several saturation runs using the same bell gas, in order to detect any enrichment of contaminants.

Plastics Composite Tubing, Use in Fire-Fighting Systems

This project aimed to examine whether or not plastics composite tubing is suitable for firewater and other systems critical to safety. The serious setbacks encountered with metal pipe systems persuaded the researchers to look for more suitable materials. The report identifies the criteria that must be met if glassfibre reinforced plastics and epoxy pipes are to provide an alternative, and highlights problem areas still to be satisfactorily addressed.

Ergonomic Requirements and Criteria

This project served to obtain a summary of standards and guidelines which apply within the occupational hygiene and ergonomics field today.

Relying on the compiled data, regulations are being planned under the authority of the Working Environment Act which will govern the design of work places. As the rules stand at present, only very general requirements are imposed for the work place. The Directorate's inspections have revealed a conspicuous need for specified function requirements and references to accepted standards. The situation is particularly critical at the design phase.

Jack-Up Site Assessment Procedure

Noble Denton Associates have highlighted major discrepancies in the calculation methods (use of parameters) and philosophies used when Shell, the American Bureau of Shipping, and NDA assess jack-up rigs. In this project the overall target is to arrive at international procedures for this sort of assessment which are acceptable to all concerned. International standards should introduce greater predictability for the industry and the authorities. The project agenda has hitherto been concerned with compiling and evaluating background materials. The project will continue in 1991.

Use of Oil-Based Drilling Mud

In the wake of the sharpening of the ecological requirements for discharge of oily cuttings, it has become necessary to reconsider the arguments for using oil-based drilling mud. This project examines the criteria that should be met if the use of oil-based drilling mud is to be acceptable.

Planning and Criteria for Relief Wells

This project analyses the need for criteria by which to evaluate projected relief holes, for exploration and production wells alike.

Heavy Lift Criteria

This project is based on a preliminary study made by Brown & Root Vickers Ltd on behalf of BP for review of installation criteria used offshore. The study determined that there was a need for a detailed review of installation criteria, and a cost saving potential in certain areas. The project has identified common lifting criteria to suit the particular module, weight and weather.

Design Data for Bolt Materials – Influence of Hydrogen

In this project the sensitivity to hydrogen of various materials and bolted joints was demonstrated, with cathodic protection in the sea and through static and dynamic experiment. Comparisons were also made of different test methods by which to rank materials. Also, SN curves for bolts have been determined which are typical as far as materials and shape go. In the light of experiments and literature searches, design curves and design data for bolted joints have been proposed.

Design Codes for Plastics Materials

Glassfibre reinforced plastics are already employed offshore, and this project has enabled researchers to review the content of regulations due for revision.

The project also summarises the standards and codes available today, which the Directorate can refer to in its guide to revised regulations for production and utility systems. The standards will cover strength, production, installation, testing, quality control, operational inspection and maintenance of GRP materials.

Gas Kick in Oil-Based Drilling Mud

This project examines the problems peculiar to gas kicks in oil-based drilling mud. The project has produced a user-friendly application which will enable operators to simulate circulation of a gas kick in oil-based drilling mud.

World Offshore Accident Databank (WOAD)

This project is an annual subscription to the WOAD database, which is a systematic directory of accidents from petroleum operations worldwide. The root base is managed by Veritec which assembles and updates data on accident events on a current basis. WOAD is implemented on the Directorate's computer system.

Perceived Risk and Safety

This project was started in 1988 and completed in 1990 under the direction of the Directorate.

The results are based on an extensive questionnaire which identified feelings of safety and patterns of injury among personnel. Clear links between causes and effects were identified for employees' physical work strain, perceived safety, and numbers of accidents and incidents. The results are presented in a special NPD publication.

Hydrostatic and Dynamic Pressure Modelling for High-Pressure, High-Temperature Deep Wells

This project is a continuation of the examination of deep wells made in 1989.

Based on thermodynamic data (pressure, volume and temperature) and HPHT rheology data for the various well fluids, an exact model will be developed to calculate downhole pressure on the basis of well tightness and rheology. A preliminary project was completed in 1990.

Coiled Tubing HAZOP

Hazop techniques are applied in this project to a coiled tubing operation on a mobile installation.

Partial Safety Coefficients for Geo-Engineering Analyses

Different methods of stability calculation give different answers to how safe a foundation is. This project has determined why such differences exist. Armed with this information, it is possible to decide between the materials coefficients in the regulations for *Structural Design of Load-bearing Structures*, depending on the analysis approach.

Iceberg Frequency off Troms and Finnmark Coast

Studies of the literature have looked at iceberg sightings close to the coast. Three observations are known of icebergs close to the Norwegian coast, in 1881 at Kvaløya in North Troms, in 1929 between the North Cape and Kirkenes, and in 1939 at Gamvik. The sizes of these bergs have been estimated, as has the iceberg risk potential for operations in the Barents Sea South.

Release of Deluge Systems on Gas Alert

Following the Piper Alpha burnout and the operator's subsequent safety appraisals, there appears to be general confusion as to whether or not it is a good thing to release deluge systems in the hope of preventing ignition of gas leaks.

This project, which is a preliminary one, has identified the factors taken into account by the operators, and provides a summary of research done and its results. The pre-project has also produced a foundation for recommendations for further work in this particular subject.

Gas Safety Programme 1990–92

Christian Michelsen's Institute in Bergen has been doing much research in recent years into explosions in certain offshore modules. The work continued in 1990 with the support of several oil companies and public authorities. The work has three parts:

- Experimental test programme
- Improvement of FLACS computer programme for estimating blast pressure
- Application of safety technology.

The project will last three years and have a budget framework of Nkr 30 million.

Technical and Operational Aspects of Manned Underwater Operations

From experience we know that there are still technical and operational aspects of manned underwater operations which require further effort if a responsible level of safety is to be secured.

The project highlights problem aspects of emergency systems for divers, and analyses matters such as excursions (temporary pressure change) during shallow saturation dives. Keywords apart from emergency systems for divers are hyperbaric rescue units and shallow saturation dives.

Internal Quality Control of Documentation of Chemical Health and Environmental Hazards

This project identifies the systems and practices for development and distribution of toxicological information on chemicals employed by the petroleum industry offshore. The findings will provide a basis for formulation of quality requirements for chemical hazard data, and will be incorporated in regulations in this field. The project is a major undertaking by the Directorate which heavily stresses the principle of internal control.

Correlation between Demanning and Accident Frequency

Manning and demanning of offshore installations is a recurring theme in the Directorate's supervision. In 1989 the Directorate initiated a project to make a survey of safety and working environment factors which may be susceptible to demanning schemes.

Factors which are of significance for determining the size of installation crews, and thus also any changes therein, include prevailing technology, work tasks, and organisational structure.

Armed with this information the principal project has explored relevant issues and developed a method by which to evaluate safety and working environment consequences of changes in crew size.

Well Control in Horizontal Wells

The advantages of horizontal wells can seem obvious. Earlier reservations were founded on supposed technical difficulties and costs.

Recent years' developments have shown that for many fields, horizontal wells are an attractive solution to the drainage problem.

The project has concentrated on particular conditions which will influence well control while drilling horizontal wells. The project has given the Directorate an insight into the particular factors which will influence well control, and the rapid detection of well kick while drilling long horizontal sections. In particular, the call for oil-based drilling mud will create problems of kick detection due to the high solubility of gas in the oil medium.

Instrumental Status Control, ITK
Investigation of installations' capability to meet design criteria for strength and fatigue fracture has largely been using traditional inspection methods: visual and non-destructive testing. These methods are generally used by divers performing underwater inspection, and diving tasks associated with complex subsea operations hold a certain inherent risk.

Accordingly a project has been carried out to obtain an overall evaluation of ITK. The result of the project helps shape the expectations the Directorate has for use of ITK. Also, the project has provided the necessary anchor for the Directorate's new *Guidelines for Inspection of Primary and Secondary Structures* etc.

Russian-Norwegian-English Petroleum Dictionary
This project has compiled a Russian-Norwegian-English technical petroleum dictionary to aid the Norwegian authorities, for instance in connection with Soviet petroleum operations on Svalbard.

Internal Control of Activities in Norway
The Internal Control project has achieved the following:

- Determine if internal control has had a generally positive effect, and identify any difficulties it has encountered
- Offer documentation of solutions to problems in selected companies
- Referral of good and bad experience back to the companies
- Develop evaluation tools to enable companies to evaluate their inhouse introduction of internal control
- Provide substance for supervisory agencies' follow-up of implementation and enforcement of internal control system in the industry.

Influence of Welding on Materials Performance Offshore
The Directorate has participated in this project, phase 2, headed by the Cranfield Institute in England. Phase 2 examined the weldability and analogous properties of new high-strength low-alloy steels, accelerated cooling steels, combinations of either, and both cast and forged components.

EXPRES – Expert System for Evaluation of Corrosion Risk
This project is also carried out by the Cranfield Institute of Technology in England and is financed by British oil companies, the UK Department of Energy, and the Norwegian Petroleum Directorate. The aim is to develop a practical expert system that can evaluate the corrosion risk in pipelines, and which can be used to assess the licensee's documentation in the subject, during both the design and the operating phase. Through this project the Directorate also expects to upgrade its expertise in a field where advanced computing methods are under intense development.

Design Curves for Fatigue of Cathodic Protected Structures
The Directorate is one of the participants in a SINTEF project backed by the oil industry. The objective is to determine the effects of cathodic protection on the fatigue lifetime of welded tubular nodes. The design curve for cathodic protected structures in the Directorate's *Regulations for Structural Design of Load-Bearing Structures* will be reviewed, and if necessary redrawn, in the light of the project results.

Corrosion Rate in Crevices in High-Alloy Steel in Seawater
The Directorate is a partner in this SINTEF project together with representatives from the oil industry and steel manufacturers. The object of the project is to investigate the onset of crevice corrosion in the best qualities of high alloy stainless steel in salt water environments with time, and how the rates depend on the material composition, method of manufacture, and welding. Project staff have also determined how to protect stainless steel effectively from crevice corrosion using cathodic protection under all conditions.

Multi-phase Pipeline Transport
This project has succeeded in the following:

- Identifying and specifying key parameters for safety and reliability of systems for multi-phase transportation
- Listing existing systems for multi-phase transport and lessons learned from them
- Describing current technological status, including known R&D projects at home and abroad
- Evaluating the necessity and scope of status monitoring and necessity for barriers in multi-phase pipelines.

Hydrate Problems with Pipeline Transport
This project aimed to examine if and to what extent hydrate problems represent a heavy safety risk in the petroleum industry. Data from previous incidents have been collected and evaluated. A report was written making recommendations for action and sent to all operators in the Norwegian sector.

Application of Statistical Analysis Tools to Accident Data
This project will structure the use of the statistical analysis tool SaS with the Norwegian Petroleum Directorate's database for accident records. The project will secure significant competence build-up around an analysis tool which will find broad application throughout the Directorate's sphere of responsibility.

Maintenance Planning Tool, Formula PS
A planning tool has been developed which will provide management with the necessary overview of planned activities and their interdependence. The tool should also rationalise the allocation and utilisation of human resources in the supervisory and other tasks of the Directorate.

In 1990 the planning system was maintained with the assistance of outside expertise.

Implementation of Drawings in Database, CODAM
This pilot project aims to link inspection drawings to the database for damage to fixed installations and pipelines.

Implementation of the drawings archive is a necessary supplement to an enhanced version of the accident database CODAM. Accident data are a necessary tool to pursue the operators' internal control activities, the Directorate's supervisory activities, to evaluate any extended lifetimes, and in the case of risk and reliability analysis. It will also be possible to transfer general data to the industry without going through the operator, since the Oil Industry Association (OLF), Operating Technology Committee, supports the use of data for purposes which will benefit the industry (special terms).

Data Communication, Alternative Solution for NPD
Several of the Directorate's databases currently receive data directly from the oil companies via data links. One machine communicates directly with the other.

Nonetheless, breathtaking developments are taking place in the field of data communications. This project examined the pros and cons of alternative new solutions.

6.3 ADMINISTRATION BRANCH

Project title	Executive institution
North Sea Seabed Clearance	NPD

North Sea Seabed Clearance
The Norwegian Petroleum Directorate's seabed clearance project was concentrated in 1990 on the area north of Patch Bank, 59°N, directly West of Haugesund. The area, covering 1320 square kilometers, was chosen on the advice of fishery organisations and fishery authorities. Once the area had been charted with side-beam sonar, the obstacles discovered were identified more closely using a remote control underwater vehicle. Dynamically positioned tenders and remote rovers were then used to recover the objects which were considered to be in the way of effective fishing in the area.

Five wrecks were pinpointed, including an old aircraft, but not raised. Various chains, wires of assorted sizes, one container platform, an anchor and fishery implements were recovered.

Again in 1990, the Norwegian Hydrographic Service's survey vessel, *M/S Lance*, was used to sonar scan the bottom. The clearance contract was given to Stolt-Nielsen Seaway A/S, of Haugesund.

The clearance project executive committee was made up of representatives from the Norwegian Petroleum Directorate, Directorate of Fisheries, Norwegian Hydrographic Service, Association of Fishermen and Oil Industry Association.

Once the clearance was completed, the Norwegian Petroleum Directorate issued a press release with the following content:

We are pleased that the oil industry now seems to be dumping less trash than hitherto. However, we still encounter objects which can be traced back to the oil industry, but which it has proved difficult to persuade any companies to claim responsibility for. The authorities have now intensified their search to identify who has caused the trashing. It is to be hoped this will further reinforce the preventive effect of the government's clearance project. Hopefully it will also encourage seafarers in their duty to report lost implements which may present an obstacle to fishing and shipping.

7. International Cooperation

7.1 AID TO FOREIGN COUNTRIES

7.1.1 Aid through NORAD

In 1990, the Norwegian Petroleum Directorate's activities through NORAD, the Norwegian Directorate for Development Cooperation, were channelled to Tanzania, Namibia, Mozambique, Bangladesh, and Nicaragua.

In these countries the Norwegian Petroleum Directorate has engaged in general computer processing services, processing and storage of seismic data tapes, interpretation of data, follow-up of consultants in connection with seismic processing, assistance for development of a biostratigraphic laboratory in Tanzania, support to NORAD-funded advisors in Tanzania and Mozambique, and advisory services to Nicaragua in connection with evaluation of petroleum potential.

The Norwegian Petroleum Directorate's major commitment areas in 1990 were in the following countries:

a) Tanzania

The most important input areas in 1990 were within biostratigraphy, basin modelling, compilation and processing of seismic data, and general exploration strategy. Worthy of special mention is the work associated with the development of a biostratigraphic reference collection for East Africa in general and Tanzania in particular.

b) Namibia

Namibia is a new aid partner for Norway. The Norwegian Petroleum Directorate was engaged in the gathering of preliminary information in general and geo-data in particular.

On behalf of the Namibian administration the Directorate, through a consultant, initiated a project for the mapping of the entire Namibian continental shelf in connection with the country's first licensing round in 1991. The Directorate was also engaged as advisor in connection with the general implementation of this licensing round. For a brief period of time in 1990 the Directorate had a geo-physicist on location to be in charge of cartographic training.

c) Bangladesh

The Directorate acted as advisor in connection with the purchase of hardware and software for processing, mapping, and digitalisation of seismic data for Bangladesh Petroleum Institute (BPI).

d) Nicaragua

In 1990, the Norwegian Petroleum Directorate was involved in advisory services to the national energy office called *Instituto Nicaraguense de Energia* (INE) in respect of evaluation of the petroleum potential on the Pacific continental shelf and planning of possible renewed exploration activity. In all, 1700 km of seismics were reprocessed, and reprocessing of further data has been initiated. The Directorate contributed with quality control in connection with the compilation, processing, and interpretation of new seismic data from the Pacific continental shelf within the framework of a regional agreement between Norway, Costa Rica, and Nicaragua, in which Statoil was responsible for work performance.

7.1.2 Aid through PETRAD

In 1989, the Norwegian Directorate for Development Cooperation, NORAD, established an international programme for PETRoleum ADministration and management aimed at activities in developing countries.

The programme was initiated because NORAD received many requests for assistance in this sector. The programme, initially to be carried out as a test project of three years' duration, is under Norwegian Petroleum Directorate administration.

The project was named PETRAD, being the International Programme for Petroleum Management and Administration.

PETRAD is managed by a project group consisting of three persons reporting directly to the Director General of Petroleum.

An expert board with five members has been appointed to assist PETRAD.

The project has concentrated on organising seminars with central leaders in the upstream and downstream sectors alike in accordance with the needs of specific countries and regions.

Seminars have been given in Norway and abroad, attracting participants from a total of more than 30 countries. The participants have represented the whole range of responsibilities in the mid-level and top-level management of national oil companies and government authorities. Four participants were government ministers. Norway has supplied senior representatives from some twenty institutions and enterprises who have contributed as lecturers and resource persons.

One of the main activities in the latter half of 1990 was the planning and development of two eight-week courses in *Petroleum Policy and Management* and the *Management of Petroleum Operations* to be held in Stavanger in September-October 1991.

7.2 SAFETY AND WORKING ENVIRONMENT

The Norwegian Petroleum Directorate cooperates and has extensive contacts with international professional organisations and political and professional bodies, either directly or through other official Norwegian bodies.

The purpose of this cooperation is as follows:

a) To help ensure that safety and the working environment at minimum meet the accepted international standards
b) To secure the inflow of relevant information for expertise build-up and regulatory revision
c) To improve our understanding of and experience in international relations and influence safety and working environment issues in the right direction.

Generally the cooperation has involved taking part in inter-governmental forums in Europe and the United Nations, supplemented by direct cooperation with various kinds of national and regional technical bodies. A list of the most important cooperation partners is given below followed by further details of the areas covered:

a) EC Commission, in collaboration with Norway's Ministry of Local Government, on safety and the working environment
b) The United Nations' International Maritime Organisation, IMO, and International Labour Organisation, ILO, concerning safety at sea and the working environment, respectively
c) European Diving Technology Committee, EDTC, and Association of Offshore Diving, AODC, for safety while diving
d) Marine Technology Directorate, MTD, UK, on inspection and maintenance of installations
e) Welding Institute in UK on research and development of materials and welding
f) American Petroleum Institute, API, attendance at annual conferences on petroleum subjects and standardisation
g) National Association of Corrosion Engineers, NACE, in USA, participation at annual conferences on corrosion and surface treatment
h) CENELEC, the *Comité Européen de Normalisation Electrotechnique*, concerning electrical engineering standardisation in Europe, through the Norwegian Electrical Engineering Committee, NEK
i) In 1990, the Norwegian Petroleum Directorate together with the State Pollution Control Authority participated in the Paris Commission's taskforce for oil pollution.

7.2.1 The European Community (EC)

Since 1982 Norway, represented by the Norwegian Petroleum Directorate, has held observer status in the EC work on safety and the working environment in the offshore petroleum activity. This work comes under the EC's Safety and Health Commission for the Mining and other Extractive Industries and is implemented by the Working Party on Oil, Gas and Other Minerals Extracted by Borehole.

The Working Party considered a proposal for harmonising of safety requirements, particularly with respect to guidelines on training and occupational injury statistics. Generally emphasis was placed on exchange of findings and information. This activity under the auspices of the EC embraces subjects which were previously the business of the Northwest European cooperation.

The activities of the Working Party received higher priority in 1990 as a result of the decision on the part of the EC to prepare directives which also cover the working environment and safety in the offshore petroleum industry. Accompanying technical appendices have also been prepared.

Preliminary time schedules indicate that the work will be considered by the Commission in the course of 1991, the aim being for the directives to enter into force at year end 1992.

7.2.2 Electro-engineering standards and regulations

The Norwegian Petroleum Directorate sits on the following committees:

a) *Comité Européen de Normalisation Electrotechnique* (CENELEC), Working Group 12, Regulations for Installation of Explosion-proof Materials
b) The Norwegian Electrical Engineering Committee (NEK), Standards Committee (NK) 18, Installations onboard Ships
c) The Norwegian Electrical Engineering Committee (NEK), Standards Committee (NK) 31, Electrical Equipment for Explosion-Hazard Areas
d) International Electrotechnical Commission (IEC) Technical Committee 18, Electrical Installations on Ships and on Mobile and Fixed Offshore Units. The Directorate's participant acts as secretary of the European part of Working Group 18, who, together with a North-American group, is to prepare new IEC publications for mobile and fixed installations.

7.2.3 Piper Alpha follow-up

In January 1990, the NPD Safety Director attended the official British hearing on the Piper Alpha accident. Witnesses were heard and questions posed by the parties involved in the hearing were answered.

Based on the recommendations given in the inquiry commission's report (Cullen Report), it looks as if some of the principles of Norwegian inspection practice will influence developments in Britain in this respect. For further details, see section 4.15.1.

7.2.4 Lectures

In 1990, as previously, the Norwegian Petroleum Directorate was engaged to lecture and chair meetings at a number of courses and conferences on issues relating to safety and the working environment, in Norway and abroad. This activity is considered a very important factor in the mutual exchange of information and influence, not least in the light of the increasingly international flavour of regulations and similar documents.

7.3 INTERNATIONAL STANDARDISATION ORGANISATION (ISO)

International standards are utilised for the analysis and measurement of oil and gas, and the Norwegian Petroleum Directorate joins in the international work to revise existing standards and establish new ones in these twin areas.

When the EC Internal Market is established as from 1993, the EC will place greater emphasis on the requirement to employ standardised procedures also in connection with the measurement and analysis of oil and gas. The standardisation work in ISO is therefore of the utmost importance.

National work groups have been set up to follow up the efforts made in ISO for measurement of oil and gas, the aim of these groups being to look after national interests. The Norwegian Petroleum Directorate is actively involved in this work.

8. Statistics and Summaries

8.1 UNITS OF MEASUREMENT

The Norwegian Petroleum Directorate generally prefers the *Système International d'Unités*, or SI, system of units, and this system is recommended for use by the oil companies engaged in operations on the Norwegian continental shelf. However, there are many other units which have won a place in the petroleum and offshore industry by virtue of long tradition.

There are several units and expressions used to describe production statistics for oil and gas which are based on measurement units. Some of these are described in brief below.

Quantity of oil

An exact statement of a quantity of oil, expressed as volume, must be with reference to a given set of standard conditions, or state, defined in terms of temperature and pressure. This is necessary because the volume of a given quantity of oil varies with pressure and temperature. The standard conditions in each case are the reference conditions for the measurement in question. The two most common reference conditions are a) 60 degrees Fahrenheit, 0 pounds per square inch gauge and b) 15 degrees Centigrade, 1.01325 bar.

Other pressure and temperature references are also found. Note that expressions such as "standard conditions", "barrels at standard conditions" are ambiguous so long as the pressure and temperature references are not identified.

The International Standardisation Organisation recommends the use of the reference state given under b) above, and this reference state was incorporated in Norwegian Standard NS 5024 in 1979. The Norwegian Petroleum Directorate is making efforts to get this reference state more generally accepted in the offshore industry.

An exact conversion of an oil volume under given conditions to its equivalent under other given conditions requires the use of special tables; for rough estimates only it can be assumed that the volume under conditions a) is approximately the same as under conditions b).

Common abbreviations (oil)

The Standard Cubic Meter is written SCM, scm, Sm3 or, more properly, Sm^3. Also cm is sometimes seen. For larger quantities it is useful to write mcm (million cubic meters) and bcm (billion cubic meters). A million is sometimes written 106, and a billion (a thousand million), 109. Note the caution above regarding standard conditions: if the temperature and pressure references are not specified, the units are ambiguous.

The traditional American unit is Barrels at Standard Conditions, the conditions usually being as under a) above (60 degrees F and 0 psig).

The conversion formula is 1 scm equals approx 6.29 barrels at standard conditions.

Quantity of gas

Even more than for oil the volume of gas will depend on the temperature and pressure conditions assumed for the measurement. Four sets of reference conditions are common: a) 60 degrees F, 14.73 psi absolute; b) 60 degrees F, 14.696 psia; c) 15 degrees C, 1.01325 bar; d) 0 degrees C, 1.01325 bar. The first three are usually termed "standard conditions", while alternative d) is usually called "normal conditions".

It is not possible to convert volumes from one set of conditions to another without knowing the physical properties of the particular gas. For rough estimates it is sufficient, nonetheless, to say that conditions a), b) and c) produce nearly identical results; while alternative d) gives a volume approx 5 per cent lower for a given quantity of gas.

Common abbreviations (gas)

The abbreviations for gas are the same as given for oil above with the addition of the following: Nm^3 or, more properly, Nm^3 indicates normal cubic meters; Scf indicates standard cubic feet. Once again the reference conditions have to be specified if the quantity is to be expressed exactly.

For conversion 1 scm is about equal to 0.95 Nm^3, or to about 35.3 Scf.

Quality indication – oil and gas

A commonly used method of indicating the composition of oil or gas is to note its specific gravity or relative density. A low value in either case means the oil or gas is made up of low molecular weight components.

Oil

a) Specific gravity 60/60°F
   This is the relative density of oil to water. Oil and water are both at 60°F temperature and atmospheric pressure at the point of measurement. The quantity has no units.

b) API gravity at 60°F
This is the specific gravity 60/60°F expressed on an expanded scale. The units are called °API and conversion is by this formula: API gravity at 60°F equals (141.5/specific gravity 60/60°F) minus 131.5.

c) Density at 15°C
Absolute density at 15°C temperature and atmospheric pressure at the point of measurement.

Gas
a) Specific gravity
This is the relative density of gas compared to air. The expression is not exactly defined unless the temperature and pressure are stated. Very often, however, no reference temperature or pressure are given. For rough estimates this is not critical as the differences between the most commonly used reference states are small.

Indication of oil and gas quantities in oil units
Oil and gas quantities are often expressed in tons of oil equivalent (toe) where an exact statement of the quantity or volume is not called for. The conversion is based on the quantity of energy (thermal value) released by combustion of the oil or gas. For many oils and gases the energy in one ton of oil will be very close to the energy in 1000 scm gas. As this factor is so easy to apply, and the qualitative differences between oil and gas are so very pronounced during treatment, storage, distribution and application, it would not be useful to state the conversion factor to more decimals. It is therefore usual to assume the following: 1 toe equals 1 ton oil or 1000 scm gas. Useful units for larger volumes are therefore mtoe and btoe, for million and billion tons.

8.2 EXPLORATION DRILLING STATISTICS

By year end 1990 a total of 662 exploration wells had been started on the Norwegian continental shelf since the first was spudded in 1966. Of the wells started, 475 were wildcats and 187 appraisal wells. By the same date 613 exploration wells had been terminated, while 34 were suspended for various reasons, including deferred testing, possible completion as production wells, or continued drilling, or subsequent plugging.

The northernmost well so far on the Norwegian continental shelf is 7321/7–1 which was drilled in 1988 with Mobil as operator. The easternmost is 7228/2–1 S, again drilled by Mobil, this time in 1989; and the westernmost 6201/11–1, drilled by Statoil in 1987. Exploration wells have been drilled by 18 different operating companies. The regional numbers drilled per operator are shown in Figure 8.2.a and

Fig. 8.2.a
Regional distribution of exploration drilling

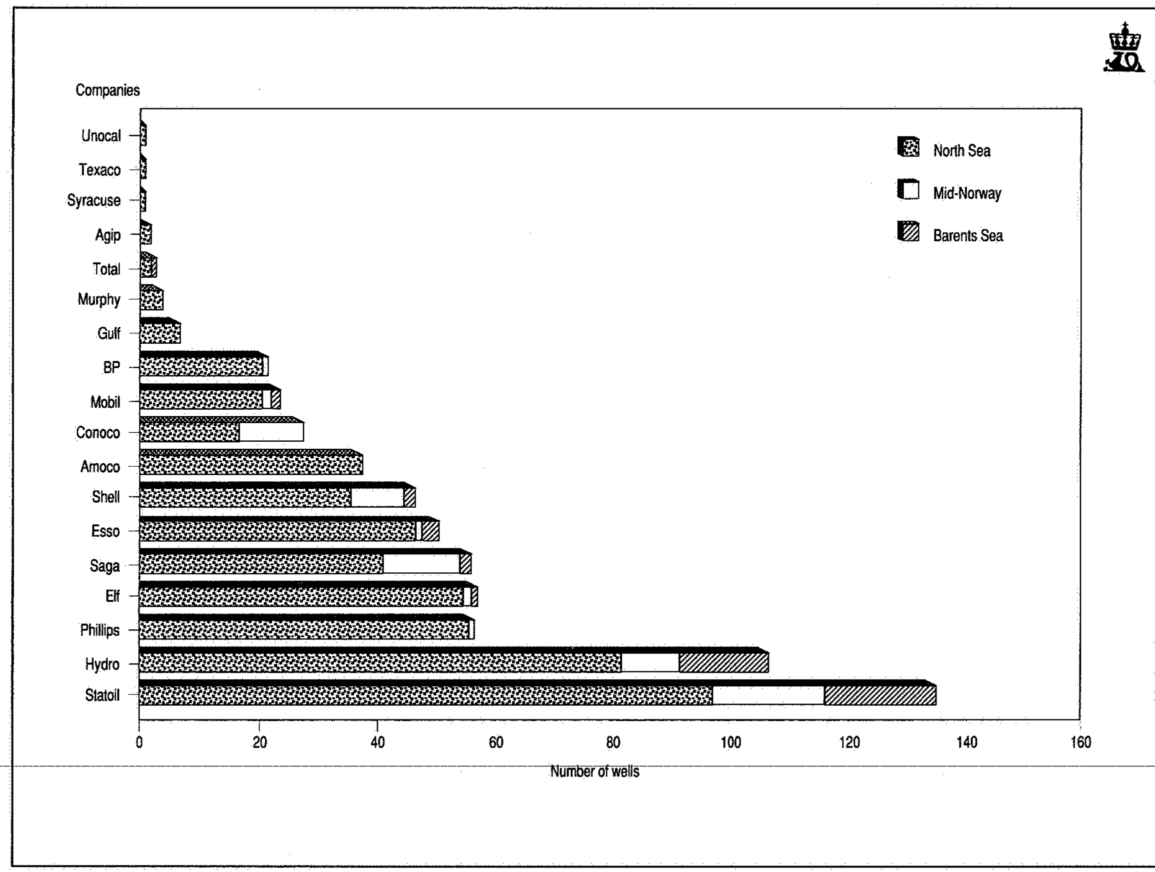


Fig. 8.2.b
Operation days per operator in 1990

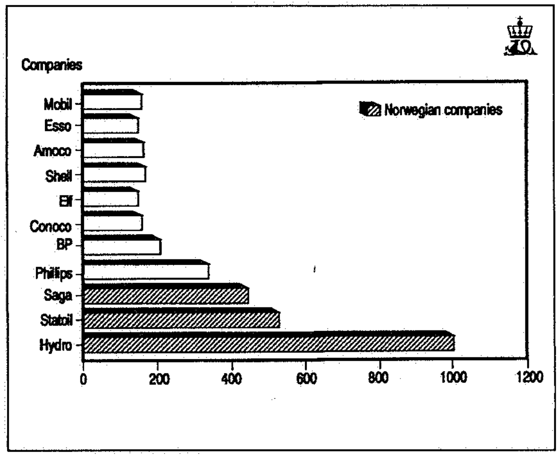


Fig. 8.2.c
Participation of Norwegian operator companies in exploration drilling

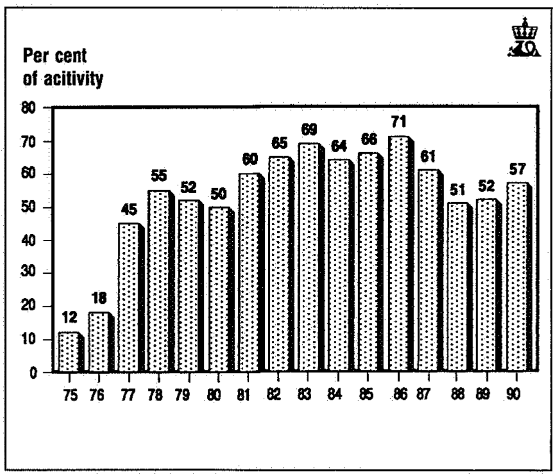


Fig. 8.2.d
Seasonal variations in exploration drilling activity 1966–1990

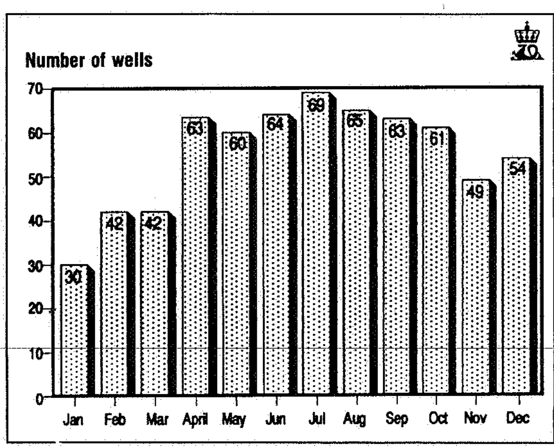


Fig. 8.2.e
Average total depth per year exploration drilling 1966–1990

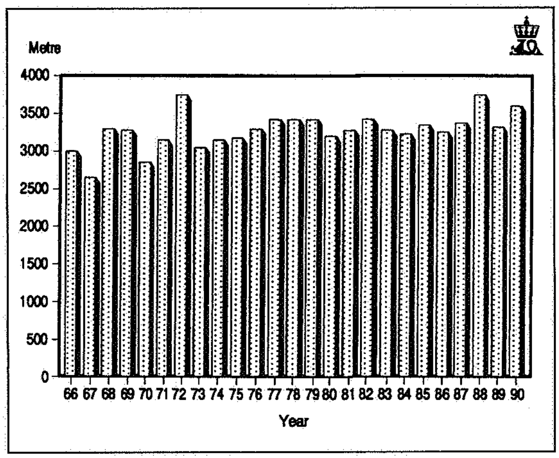


Fig. 8.2.f
Average water depth per year exploration wells 1966–90

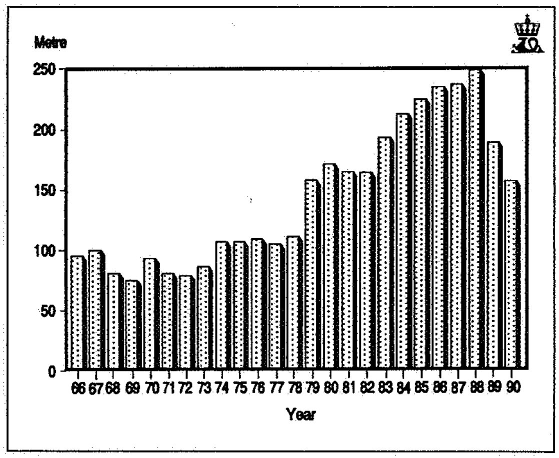


Table 8.2.b. The number of days of operation per company in 1990 is shown in Figure 8.2.b. Figure 8.2.c shows the Norwegian operating companies' share of the drilling activities. Seasonal variations in drilling activity are shown in Figure 8.2.d.

By year end 1990 the total length of exploration hole had reached 2,117,035 meters. Of the total, 127,365 meters were drilled in 1990. The average total depth of the 36 exploration wells reaching bottom in 1990 was 3619 meters. Exploration well 30/4–1, terminated in 1979, is the deepest well so far drilled in the Norwegian sector. Here BP was the operator and the total depth 5455 meters. The longest well drilled so far is 2/12–2-S, by Norsk Hydro in 1990. The length of the well was 5757 meters, but as it was drilled at an angle it did not reach the same depth below the seabed as 30/4–1. A summary of average total depths of exploration wells drilled between 1966 and 1990 is given in Figure 8.2.e.

Table 8.2.a
Wells spudded as of 31 December 1990

Year spudded	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90	Total
Wildcat	2	6	10	12	11	11	11	17	13	17	20	12	14	18	26	26	36	33	35	30	26	25	18	20	26	475
Appraisal			2	1	6	5	3	5	5	9	3	8	5	10	10	13	13	7	12	20	10	11	11	8	10	187
Total	2	6	12	13	17	16	14	22	18	26	23	20	19	28	36	39	49	40	47	50	36	36	29	28	36	662
Production								1	18	24	7	34	50	36	27	16	22	23	33	47	47	48	55	66	60	614
Total	2	6	12	13	17	16	14	23	36	50	30	54	69	64	62	55	71	63	80	97	83	84	84	94	96	1276

Table 8.2.b
Exploration wells by operating company and region as of 31 December 1990

Operator	North Sea			Mid-Norway			Barents Sea			Total		
	W	A	E	W	A	E	W	A	E	W	A	E
Statoil	52	46	98	30	4	34	18	1	19	100	51	151
Norsk Hydro	63	20	83	8	2	10	15		15	86	22	108
Phillips	40	17	57	1		1				41	17	58
Elf	40	15	55	2		2	1		1	43	15	58
Saga	36	6	42	13		13	2		2	51	6	57
Esso	28	19	47	1		1	2		2	32	19	51
Shell	24	11	35	4	5	9	2		2	30	16	46
Amoco	24	14	38							24	14	38
Conoco	18		18	3	8	11				21	8	29
Mobil	13	8	21	2		2	2		2	17	8	25
BP	11	10	21	1		1				12	10	22
Gulf	7		7							7		7
Murphy	3	1	4							3	1	4
Total	2		2				1		1	3		3
Agip	2		2							2		2
Syracuse	1		1							1		1
Texaco	1		1							1		1
Unocal	1		1							1		1
Wildcat	366			65			44			475		
Appraisal		167			19			1			187	
Exploration			533			84			45			662

W = Wildcat
A = Appraisal
E = Exploration

Table 8.2.c
Exploration wells spudded in 1990 by operating company and region as of 31 December 1990

Operator	North Sea			Mid-Norway			Barents Sea			Total		
	W	A	E	W	A	E	W	A	E	W	A	E
Statoil	2		2	3		3				5		5
Norsk Hydro	5	5	10	1	1	2				6	6	12
Phillips	1	2	3							1	2	3
Elf	3		3							3		3
Saga	2		2	1		1				3		3
Esso		1	1				1		1	1	1	2
Shell				1		1				1		1
Amoco	1		1							1		1
Conoco	2		2							2		2
Mobil	1		1	1		1				2		2
BP	1	1	2							1	1	2
Wildcat	18			7			1			26		
Appraisal		9			1						10	
Exploration			27			8			1			36

W = Wildcat
A = Appraisal
E = Exploration

Table 8.2.d
Mean water depths and total depths

Year	Mean water depth (m)	Mean total depth (m)
1966	94	3 015
1967	100	2 682
1968	81	3 303
1969	74	3 276
1970	92	2 860
1971	79	3 187
1972	78	3 742
1973	85	3 075
1974	106	3 163
1975	106	3 173
1976	108	3 314
1977	104	3 450
1978	110	3 432
1979	157	3 444
1980	170	3 209
1981	164	3 243
1982	163	3 457
1983	192	3 287
1984	212	3 247
1985	224	3 367
1986	234	3 248
1987	236	3 383
1988	248	3 760
1989	188	3 331
1990	156	3 619

The average water depth in which exploration wells were drilled in 1990 was 156 meters. The greatest water depth in which a well has been drilled to date in the Norwegian sector is 475 meters: The well was 7321/7–1, drilled in 1988 with Mobil as operator. Figure 8.2.f shows the average water depths in which exploration wells were drilled from 1966 to 1990. For the drilling operations on the Norwegian continental shelf 69 different drilling installations were employed, seven of them under two different names. Of the total, 51 were semi-submersibles, 11 jack-ups, five drilling ships and two fixed installations. Tables 8.2.a to 8.2.e give the statistics for exploration drilling on the Norwegian continental shelf.

Table 8.2.e
Drilling rigs active on Norwegian continental shelf as of 31 December 1990

Rig name	Number of wells	Number of reentries	Type of rig
Aladdin	1		Semi-submersible
Borgny Dolphin (formerly Fernstar)	24	8	"
Borgsten Dolphin (formerly Haakon Magnus)	7		"
Bucentaur		1	Drill ship
Byford Dolphin (formerly Deepsea Driller)	16		Semi-submersible
Chris Chenery	2		"
Deepsea Bergen	23	3	"
Deepsea Driller (now Byford Dolphin)	9		"
Deepsea Saga	16	3	"
Drillmaster	5	1	"
Drillship	1		Drillship
Dyvi Alpha	17	2	Semi-submersible
Dyvi Beta	6	1	Jack-up
Dyvi Delta (now West Delta)	21	1	Semi-submersible
Dyvi Gamma	1		"
Dyvi Stena	16		"
Endeavour	2		Jack-up
Fernstar (now Borgny Dolphin)	3		Semi-submersible
Glomar Biscay II (formerly Norskald)	13	1	"
Glomar Grand Isle	11	3	Drillship
Glomar Moray Firth I	2		Jack-up
Gulftide	3		"
Haakon Magnus (now Borgsten Dolphin)	2		Semi-submersible
Henry Goodrich	2		"
Hunter (formerly Treasure Hunter)	1		"
Kolskaya		1	"
Le Pelerin	1		Drillship
Maersk Explorer	7		Jack-up
Mærsk Jutlander	3	1	Semi-submersible
Neddrill Trigon	3	1	Jack-up
Neptune 7 (formerly Pentagone 81)	12		Semi-submersible
Nordraug	12		"
Norjarl	3		"
Norskald (now Glomar Biscay II)	26		"

Rig name	Number of wells	Number of reentries	Type of rig
Nortrym	32	3	"
Ocean Tide	5		Jack-up
Ocean Traveler	9		Semi-submersible
Ocean Victory	1		"
Ocean Viking	28	1	"
Ocean Voyager	2		"
Odin Drill	3		"
Orion	7		Jack-up
Pentagone 81 (now Neptune 7)	1		Semi-submersible
Pentagone 84	2	1	"
Polar Pioneer	20	2	"
Polyglomar Driller	11		"
Ross Isle	21	7	"
Ross Rig	33		"
Ross Rig (new)	10		"
Saipem II	1		Drillship
Scarabeo	1		Semi-submersible
Sedco 135 G	3		"
Sedco 703	3	1	"
Sedco 704	3		"
Sedco 707	8		"
Sedco H	2		"
Sedneth I	3		"
Transocean 8	5		"
Transworld Rig 61	2		"
Treasure Hunter (now Hunter)	5	3	"
Treasure Saga	32	3	"
Treasure Scout	23		"
Treasure Seeker	24	5	"
Vildkat	15	4	"
Vinni	5		"
Waage Drill I	2		"
West Delta (formerly Dyvi Delta)	7		"
West Vanguard	23	5	"
West Venture	12	2	"
West Vision	1		"
Yatzy	1		"
Zapata Explorer	13		Jack-up
Zapata Nordic	5		"
Zapata Ugland	5	1	Semi-submersible
	650	65	
In addition two wells were drilled from fixed installations:			
Cod	1	1	
Ekofisk B	1		
	652	66	

8.3 PRODUCTION DRILLING STATISTICS

Since 1973, a total of 614 production wells have been commenced in the Norwegian sector of the North Sea; 322 are producers of oil, gas or condensate, 86 are water or gas injectors, one is an observation and production well, and one is an observation and injection well. Of the total 191 are out of service; being either closed down, suspended for later completion or for some other reason, or, in 25 cases, having never produced. Thirteen production wells were being drilled at year end 1990.

A summary of production wells is given in Table 8.3.a. Figure 8.3.a shows production wells started each year during the period 1973 to 1990. At year end production or injection was underway from 21 fields and 29 installations, three of which – on Nordøst Frigg, Øst Frigg and Tommeliten – are subsea installations. Two new fields, Gyda and Hod, came on stream in 1990.

The distribution of production wells by field is shown in Figure 8.3 b. Figure 8.3.c shows production wells broken down by operating company. In 1990, 66 production wells were started in ten fields. Thirteen of them were drilled from mobile drilling rigs. Production wells broken down by installation are shown in Figure 8.3.d. Information on the production wells is set out in Tables 8.3.a to 8.3.c.

In addition, 32 pre-drilling operations were carried out in 1990, in which 20-inch or 18 5/8-inch casing was set. This was done on the fields Ekofisk, Valhall, and Hod. Seven of the pre-drilling operations were made from mobile installations.

The longest well to date on the Norwegian continental shelf, 33/9-C-10, was concluded in 1990. Drilled by Statoil from the Statfjord C platform, the well reached a depth of 5886 meters below the seabed. The vertical depth was 2741 meters and the well had a bottom position 4550 meters from the vertical.

Fig. 8.3.a
Production drilling on the Norwegian continental shelf 1973–90

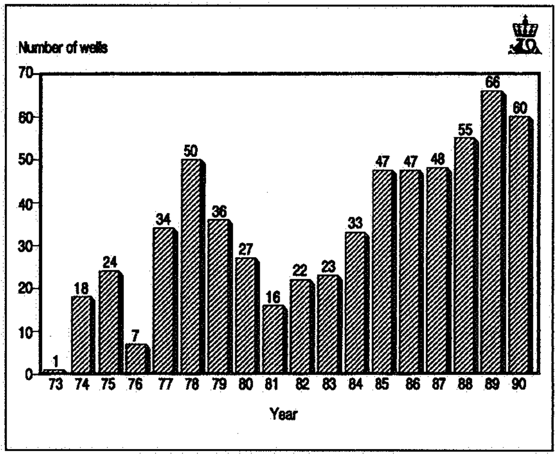


Fig. 8.3.b
Production wells per field

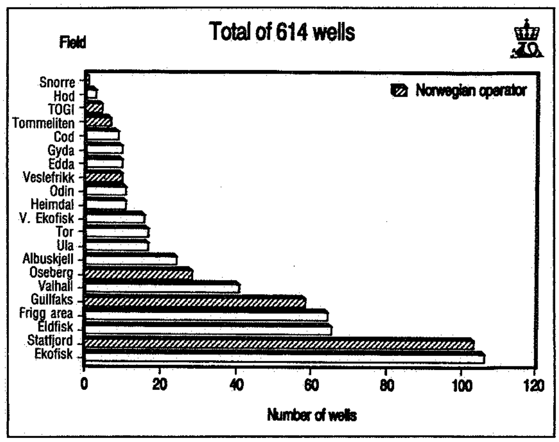


Fig. 8.3.c
Production wells by operator

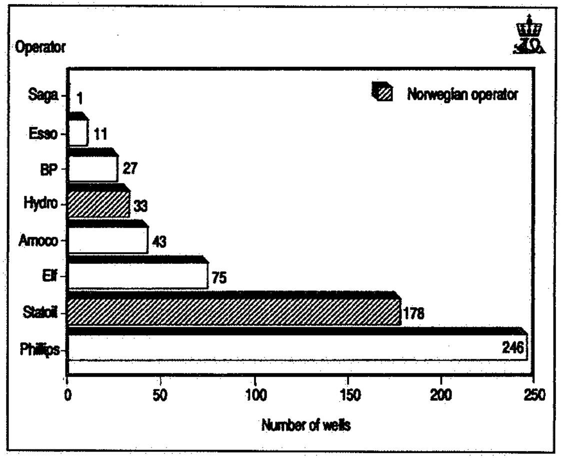


Fig. 8.3.d
Production wells drilled in 1990 by installation

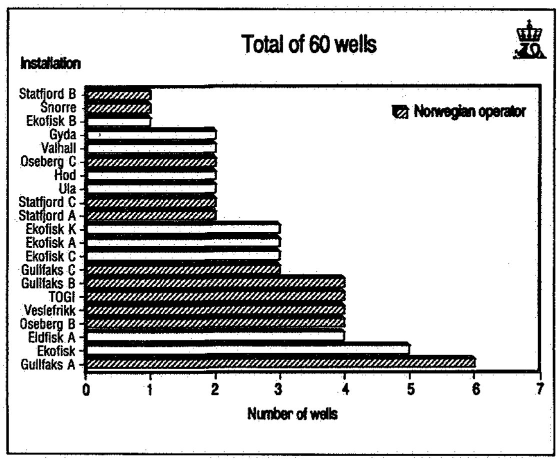


Table 8.3.a
Production drilling as of 31 December 1990

Field	Hydro-carbon	Total drilled	Spudded 1990	Producing	Injection, observation	Drilling	Suspended plugged, completed
Albuskjell A +	cond	11		7			4
Albuskjell F +	cond	13					13
Cod +	cond	9		5			4
Edda +	oil	10		6			4
Ekofisk A +	oil	22	3	17			5
Ekofisk B +	oil	31	1	20	1(1)*	1	8
Ekofisk C +	oil	21	3	11	5**	1	4
Ekofisk K +	w.inj.	26	3		21	1	4
Ekofisk W +	w.inj.	5	5		3	1	1
Eldfisk A +	oil	38	4	22		1	15
Eldfisk B +	oil	27		20			7
Frigg (UK) +	gas	24					24
Frigg +	gas	28		11			17
Gullfaks A +	oil	36	6	20	8	1	7
Gullfaks B +	oil	17	4	10	5	1	1
Gullfaks C +	oil	5	3	3		1	1
Gyda +	oil	10	2	7		1	2
Heimdal +	cond	11		8	(1)***		2
Hod +	oil	2	2	1		1	
N.Ø.Frigg +	gas	7		4			3
Odin +	gas	11		10			1
Oseberg B +	oil	20	4	13	3		4
Oseberg C	oil	8	2				8
Snorre	oil	1	1				1
Statfjord A +	oil	40	2	22	14		4
Statfjord B +	oil	33	1	21	10		2
Statfjord C +	oil	30	2	18	10		2
Togi	gas	5	4			1	4
Tommeliten +	cond	7		4			3
Tor +	oil	17		11			6
Ula +	oil	17	2	7	6		4
Valhall +	oil	41	2	23		1	17
V. Ekofisk +	cond	16		9			7
Veslefrikk +	oil	10	4	7		1	2
Øst Frigg +	gas	5		5			
		614	60	322	86	13	191

\+ Field producing/injecting
* Observation/production well/wells
** Production/injection wells depending on gas sales
*** Observation/injection well/wells

322	wells	are producing (258 oil, 33 condensate and 31 gas)
135	wells	are shut down/plugged
86	wells	are injection wells (of which 5 inj./prod.)
1	well	is an observation/production well
1	well	is an observation/injection well
13	wells	are under drilling (2/1-A-17, 2/4-B-17 A, 2/4-C-18, 2/4-K-16, 2/4-W-2, 2/7-A-23 B, 2/8-A-12 B, 2/11-A-2, 31/5-B-5 H, 30/3-A-10, 34/10-A-31, 34/10-B-14 A, 34/10-C-5)
23	wells	are susp. on TD: (2/1-A-6 A, 2/4-K-2, 2/4-K-7, 2/4-K-15, 2/4-W-6, 2/7-A-7 A, 30/3-A-7, 30/6-C-5, 30/6-C-6, 30/6-C-7, 30/6-C-8, 30/6-C-9, 30/6-C-10, 30/6-C-11, 30/6-C-12, 30/9-B-2, 30/9-B-7, 31/5-B-2 H, 31/5-B-3 H, 31/5-B-4 H, 31/5-B-6 H, 34/7-P-28, 34/10-C-4
1	well	is suspended at 9 5/8": (30/9-B-19)
4	wells	are suspended at 13 3/8": (2/7-A-15, 2/7-A-22, 30/3-A-9, 30/9-B-42)
2	wells	are suspended at 20": (25/4-A-1, 33/9-C-3)
1	well	is suspended with a fish in the 36" open hole: (2/4-K-3)
25	wells	never produced
614		

Table 8.3.b
Production wells spudded or terminated in 1990

A,B = Directionally drilled from another well. H = Subsea completion

Lic. no.	Prod. well no.	Spudded	Terminated	Operator	Field
323	2/04-K-02	85.10.15	90.10.02	PHILLIPS	EKOFISK K
430	2/01-A-08	87.11.18	90.11.09	BP	GYDA
436	2/01-A-07	88.01.13	90.09.30	BP	GYDA
464	30/09-B-07	88.07.21	90.11.07	HYDRO	OSEBERG B
480	2/01-A-03	88.09.26	90.09.19	BP	GYDA
488	2/04-K-07	90.09.23	00.00.00	PHILLIPS	EKOFISK K
500	2/01-A-02	89.02.21	90.08.29	BP	GYDA
512	2/01-A-01	89.05.08	90.10.13	BP	GYDA
535	30/09-B-31	89.08.15	90.02.05	HYDRO	OSEBERG B
536	2/07-A-01	90.05.10	90.08.16	PHILLIPS	ELDFISK A
543	33/09-C-10	89.10.18	90.01.25	STATOIL	STATFJORD C
544	34/10-C-01	89.10.01	90.01.08	STATOIL	GULLFAKS C
549	2/04-B-23 A	89.11.28	90.02.02	PHILLIPS	EKOFISK B
550	33/12-B-19	89.12.28	90.02.19	STATOIL	STATFJORD B
551	34/10-B-12	89.11.07	90.01.14	STATOIL	GULLFAKS B
552	31/05-B-06 H	89.11.19	90.10.09	HYDRO	TOGI
553	2/07-A-08 A	89.11.22	90.01.17	PHILLIPS	ELDFISK A
554	2/04-C-19	89.11.18	90.03.14	PHILLIPS	EKOFISK C
555	34/10-A-27	89.12.04	90.01.15	STATOIL	GULLFAKS A
556	30/06-C-09	89.12.11	90.02.05	HYDRO	OSEBERG C
557	34/10-C-02	89.12.31	90.04.25	STATOIL	GULLFAKS C
558	7/12-A-03 A	90.01.28	90.03.28	BP	ULA
559	2/04-K-26	89.12.28	90.02.22	PHILLIPS	EKOFISK K
560	2/04-A-12 B	90.02.21	90.05.13	PHILLIPS	EKOFISK A
561	31/05-B-04 H	90.01.15	00.00.00	HYDRO	TOGI
562	30/09-B-40	90.02.05	90.05.03	HYDRO	OSEBERG B
563	34/10-A-28	90.01.30	90.04.11	STATOIL	GULLFAKS A
564	30/06-C-07	90.02.06	90.03.13	HYDRO	OSEBERG C
565	34/10-B-13	90.02.13	90.04.17	STATOIL	GULLFAKS B
566	2/04-C-16	90.07.20	90.10.19	PHILLIPS	EKOFISK C
567	2/07-A-18 A	90.02.21	90.05.14	PHILLIPS	ELDFISK A
568	34/10-C-03	90.03.03	90.06.22	STATOIL	GULLFAKS C
569	31/05-B-05 H	90.02.26	90.10.28	HYDRO	OSEBERG C
570	2/04-W-08	90.03.19	90.05.22	PHILLIPS	EKOFISK W
571	31/05-B-02 H	90.03.12	90.08.11	HYDRO	TOGI
572	30/06-C-06	90.03.14	90.04.28	HYDRO	OSEBERG C
573	2/04-A-20	90.06.25	90.09.23	PHILLIPS	EKOFISK A
574	33/09-A-37 A	90.04.21	90.07.08	STATOIL	STATFJORD A
575	33/12-B-28 A	90.05.02	90.06.23	STATOIL	STATFJORD B
576	7/12-A-12 A	90.04.15	90.06.14	BP	ULA
577	31/05-B-03 H	90.03.26	90.06.24	HYDRO	TOGI
578	2/04-K-15	90.04.28	90.07.15	PHILLIPS	EKOFISK K
579	34/10-B-14 X	90.04.20	90.11.12	STATOIL	GULLFAKS B
580	2/04-C-01 A	90.04.09	90.06.06	PHILLIPS	EKOFISK C
581	34/10-A-27 A	90.04.12	90.05.19	STATOIL	GULLFAKS A
582	30/03-A-07	90.06.03	90.07.16	STATOIL	VESLEFRIKK A
583	30/09-B-15	90.05.01	90.07.15	HYDRO	OSEBERG B
584	34/10-A-24 A	90.06.04	90.07.26	STATOIL	GULLFAKS A
585	2/04-W-05	90.06.15	90.08.05	PHILLIPS	EKOFISK W
586	34/10-B-15	90.06.06	90.09.14	STATOIL	GULLFAKS B
587	2/08-A-16 B	90.06.21	90.07.31	AMOCO	VALHALL
588	33/09-C-11	90.07.23	90.09.22	STATOIL	STATFJORD C
589	2/07-A-19 A	90.09.14	90.11.20	PHILLIPS	ELDFISK A
590	34/10-C-04	90.06.22	90.10.22	STATOIL	GULLFAKS C
591	33/09-A-20 A	90.08.01	90.08.28	STATOIL	STATFJORD A
592	30/09-B-12	90.07.15	90.09.14	HYDRO	OSEBERG B
593	30/03-A-08	90.07.17	90.10.22	STATOIL	VESLEFRIKK A
594	2/04-W-04	90.08.05	90.10.11	PHILLIPS	EKOFISK W
595	2/11-A-06	90.08.13	90.09.22	AMOCO	HOD
596	34/10-A-29	90.08.22	90.10.01	STATOIL	GULLFAKS A
597	2/04-A-22	90.09.24	90.12.05	PHILLIPS	EKOFISK A
598	2/11-A-02	90.09.30	00.00.00	AMOCO	HOD
599	2/04-B-17 A	90.12.17	00.00.00	PHILLIPS	EKOFISK B
600	34/10-C-05	90.09.02	00.00.00	STATOIL	GULLFAKS B
601	34/07-P-28	90.09.12	00.00.00	SAGA	SNORRE
602	34/10-A-30	90.10.02	90.11.05	STATOIL	GULLFAKS A
603	2/04-W-06	90.10.12	90.11.27	PHILLIPS	EKOFISK W
604	30/03-A-09	90.10.29	90.11.13	STATOIL	VESLEFRIKK A

Lic. no.	Prod. well no.	Spudded	Terminated	Operator	Field
605	2/04-C-18	90.10.21	00.00.00	PHILLIPS	EKOFISK C
606	2/01-A-06 A	90.11.09	90.12.02	BP	GYDA
608	2/01-A-17	90.12.06	00.00.00	BP	GYDA
610	33/09-C-03	90.11.07	90.12.04	STATOIL	STATFJORD C
611	30/09-B-02	90.11.07	90.12.18	HYDRO	OSEBERG B
612	30/03-A-10	90.11.15	00.00.00	STATOIL	VESLEFRIKK A
613	2/07-A-23 B	90.11.23	00.00.00	PHILLIPS	ELDFISK A
614	2/08-A-12 B	90.12.01	00.00.00	AMOCO	VALHALL
615	2/04-W-02	90.11.25	00.00.00	PHILLIPS	EKOFISK W
616	2/4-K-16	90.12.26	00.00.00	PHILLIPS	EKOFISK K
619	34/10-B-14 A	90.12.24	00.00.00	STATOIL	GULLFAKS B
620	34/10-A-31	90.12.07	00.00.00	STATOIL	GULLFAKS A

Table 8.3.c
Production wells drilled from mobile drilling rigs
H = Subsea completion

Per 31.12.1990

Lic. no.	Prod. well no.	Spudded	Terminated	Operator	Drilling rig
552	31/05-B-06 H	89.11.19	90.10.09	HYDRO	POLAR PIONEER
556	30/06-C-09	89.12.11	90.02.05	HYDRO	TRANSOCEAN 8
561	31/05-B-04 H	90.01.15	00.00.00	HYDRO	POLAR PIONEER
564	30/06-C-07	90.02.06	90.03.13	HYDRO	TRANSOCEAN 8
569	31/05-B-05 H	90.02.26	90.10.28	HYDRO	POLAR PIONEER
570	2/04-W-08	90.03.19	90.05.22	PHILLIPS	MÆRSK GUARDIAN
571	31/05-B-02 H	90.03.12	90.08.11	HYDRO	POLAR PIONEER
572	30/06-C-06	90.03.14	90.04.28	HYDRO	TRANSOCEAN 8
577	31/05-B-03 H	90.03.26	90.06.24	HYDRO	POLAR PIONEER
585	2/04-W-05	90.06.15	90.08.05	PHILLIPS	MÆRSK GUARDIAN
594	2/04-W-04	90.08.05	90.10.11	PHILLIPS	MÆRSK GUARDIAN
595	2/11-A-06	90.08.13	90.09.22	AMOCO	KOLSKAYA
598	2/11-A-02	90.09.30	00.00.00	AMOCO	KOLSKAYA
601	34/07-P-28	90.09.12	00.00.00	SAGA	SCARABEO 5
603	2/04-W-06	90.10.12	00.00.00	PHILLIPS	MÆRSK GUARDIAN
615	2/04-4-02	90.11.25	00.00.00	PHILLIPS	MÆRSK GUARDIAN

8.4 PRODUCTION OF OIL AND GAS

The total production of oil and gas on the Norwegian continental shelf was 107.3 mtoe in 1990. Production in 1989 was 103.6 mtoe. In Tables 8.4.a-p and Figures 8.4.a-b, production is set out in more detail.

The figures in Table 8.4.a show the Norwegian share of Statfjord, Frigg, and Murchison. In the tables for oil, NGL is included for the Ekofisk area, Statfjord, Valhall, Murchison, Ula, Gullfaks, Tommeliten, Hod, and Mime.

The figures for gas in Table 8.4.a indicate the quantities sold for all fields. In the figures for Statfjord, Frigg area, Heimdal and Gullfaks, the condensate is included.

Table 8.4.a
Production in million tonnes oil equivalent (mtoe)

1990	Oil	Gas	Total
Ekofisk area	10.915	7.876	18.791
Statfjord	28.466	3.125	31.591
Frigg area	0.000	7.591	7.591
Valhall	3.618	0.919	4.537
Murchison	0.405	0.008	0.413
Heimdal	0.000	3.750	3.750
Ula	4.797	0.376	5.173
Oseberg	14.658	0.000	14.658
Gullfaks	13.079	0.937	14.016
Tommeliten	0.659	1.250	1.909
Veslefrikk	2.432	0.000	2.432
Gyda	1.322	0.159	1.481
Troll Vest (test production)	0.929	0.000	0.929
Hod	0.133	0.021	0.154
Mime (test production)	0.022	0.006	0.028
Total 1990	81.368	26.018	107.386
Total 1989	74.280	29.364	103.644

Fig. 8.4.a
Oil and gas production on the Norwegian shelf 1971–1990

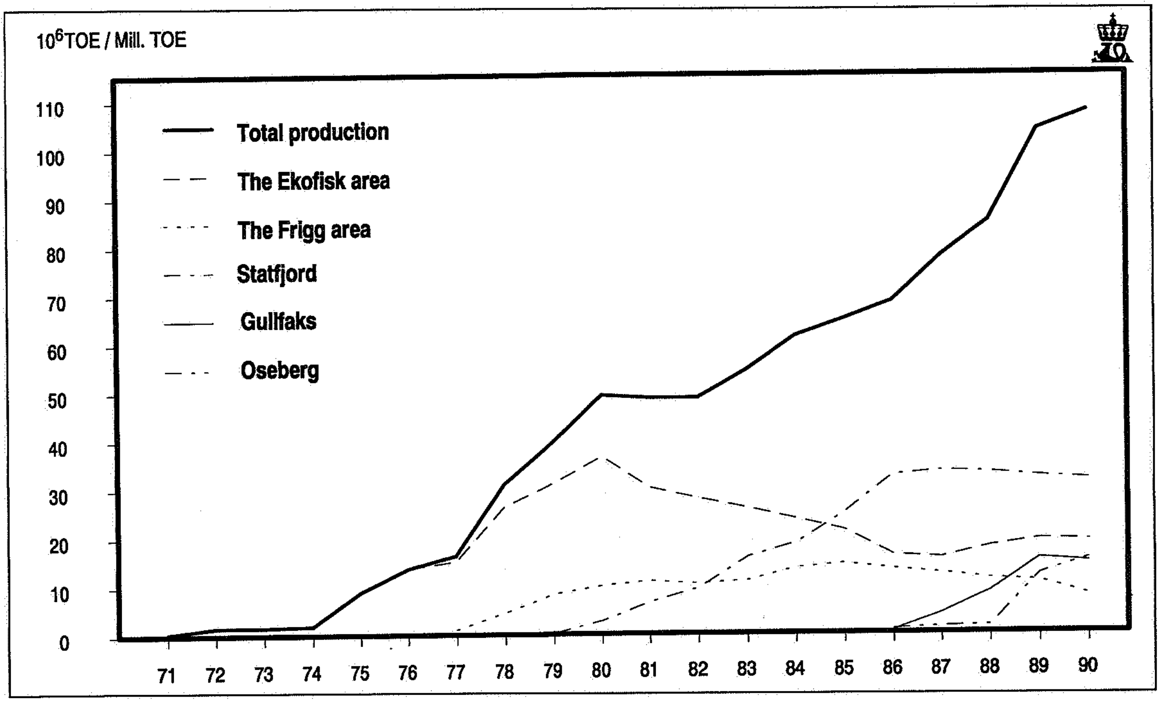


Fig. 8.4.b
Oil and gas production on the Norwegian shelf 1977–1990

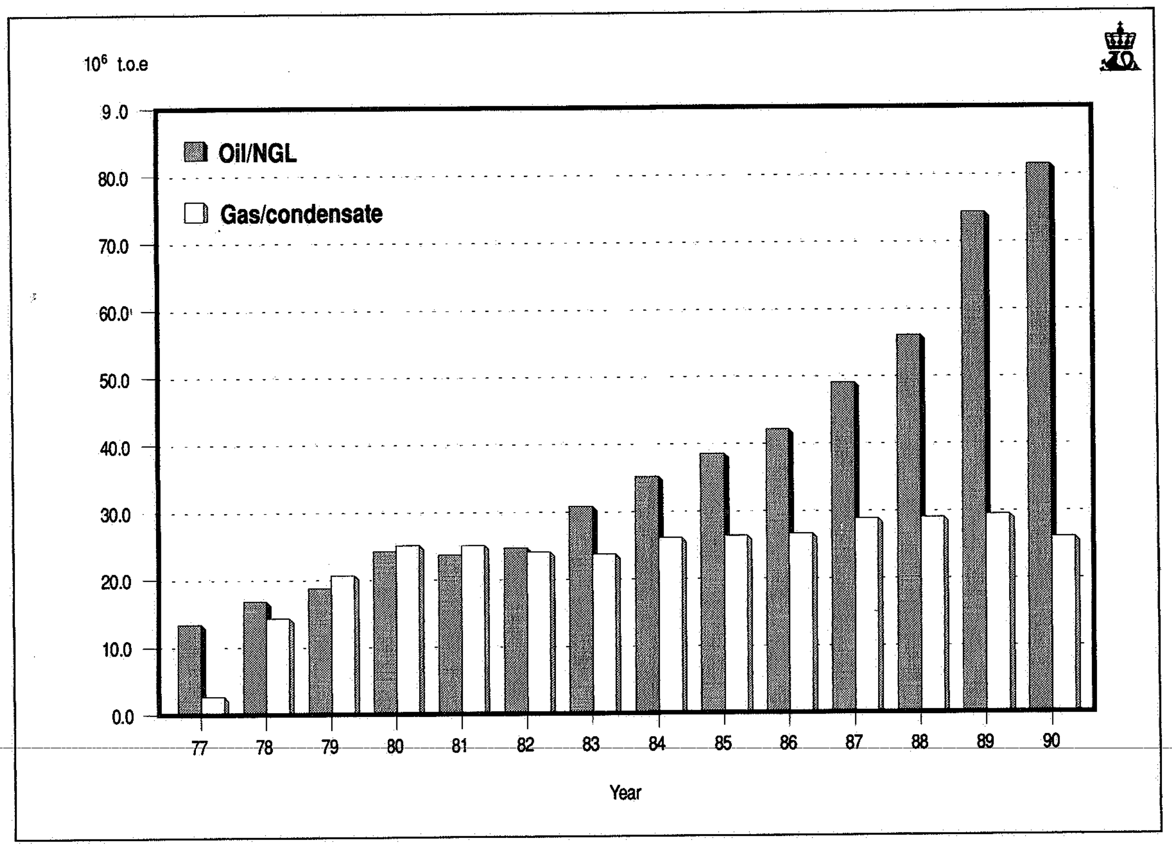


Table 8.4.b
Monthly oil and gas production on Valhall

1990	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Teesside	NGL Teesside	Gas Emden
	1000 Sm³	Mill Sm³	Mill Sm³	Mill Sm³	1000 Sm³	1000 Sm³	Mill Sm³
JAN	424.	91.	.5	8.	390.	36.	84.
FEB	375.	81.	1.3	7.	345.	33.	73.
MAR	393.	86.	.8	8.	362.	33.	78.
APR	376.	83.	.5	8.	347.	33.	75.
MAY	378.	84.	.6	8.	348.	34.	78.
JUN	356.	79.	.5	8.	325.	34.	72.
JUL	326.	69.	1.1	7.	306.	25.	62.
AUG	393.	89.	.8	8.	364.	32.	82.
SEP	373.	85.	.6	8.	344.	31.	78.
OCT	366.	86.	.9	7.	342.	29.	79.
NOV	356.	78.	.4	7.	331.	27.	76.
DEC	374.	87.	.4	8.	352.	28.	81
YEAR TOTAL	4491.	997.	8.4	92.	4156.	375.	919.

Table 8.4.c
Monthly gas and condensate production in Frigg area

1990	Gas prod	Condensate prod	Gas flared	Gas fuel	Gas St Fergus	Condensate St Fergus
	Mill Sm³	1000 Sm³	Mill Sm³	Mill Sm³	Mill Sm³	1000 Sm³
JAN	982.	2.8	66.	.9	977.	5.
FEB	871.	2.4	207.	.8	871.	4.
MAR	913.	2.5	129.	1.0	912.	4.
APR	441.	1.5	93.	.9	441.	3.
MAY	508.	1.7	74.	.9	401.	2.
JUN	421.	1.4	140.	.9	420.	3.
JUL	453.	1.5	107.	.9	448.	3.
AUG	589.	2.1	136.	.9	567.	4.
SEP	607.	2.1	2716.	.9	593.	3.
OCT	540.	2.0	79.	.8	527.	5.
NOV	700.	2.5	68.	.9	675.	5.
DEC	797.	2.5	86.	.9	721.	4.
YEAR TOTAL	7822.	25.0	3905.	10.7	7553.	45.

Figures are for the Norwegian share of Frigg, which is 60.82 per cent, plus 100 per cent of Nordøst Frigg, Odin and Øst Frigg.

Table 8.4.d
Monthly oil and gas production on Gullfaks

1990	Stabilized oil prod	Gas prod	Gas flared	Gas fuel	Gas Emden	NGL/cond Kårstø
	1000 Sm³	Mill Sm³	Mill Sm³	Mill Sm³	Mill Sm³	1000 Sm³
JAN	1210.	116.	17.	17.	72.	5.
FEB	1080.	105.	9.	14.	70.	8.
MAR	1221.	118.	12.	17.	76.	10.
APR	1213.	119.	9.	18.	78.	10.
MAY	1318.	134.	10.	20.	90.	13.
JUN	1308.	131.	5.	20.	85.	13.
JUL	1049.	106.	8.	16.	70.	10.
AUG	821.	86.	11.	13.	48.	8.
SEP	1278.	133.	7.	19.	70.	14.
OCT	1452.	152.	14.	20.	80.	16.
NOV	1432.	147.	7.	20.	84.	16.
DEC	1448.	157.	8.	20.	89.	23.
YEAR TOTAL	14830.	1504.	117.	214.	912.	146.

Table 8.4.e
Monthly gas and condensate production on Heimdal

1990	Gas prod	Condensate prod	Gas flared	Gas fuel	Gass sold Emden	Condensate Kinneil
	Mill Sm³	1000 Sm³	1000 Sm³	Mill Sm³	Mill Sm³	1000 Sm³
JAN	326.	52.	112.	5.	310.	44.
FEB	297.	47.	48.	4.	282.	46.
MAR	288.	46.	57.	4.	274.	44.
APR	274.	44.	105.	4.	261.	43.
MAY	241.	39.	2.	4.	251.	36.
JUN	200.	32.	237.	4.	211.	31.
JUL	216.	35.	322.	4.	225.	30.
AUG	281.	45.	130.	4.	288.	45.
SEP	297.	48.	37.	5.	286.	49.
OCT	303.	49.	58.	5.	319.	45.
NOV	296.	48.	26.	5.	308.	46.
DEC	289.	50.	1.	5.	320.	46.
YEAR TOTAL	3308.	535.	1135.	53.	3335.	505.

Table 8.4.f
Monthly oil and gas production on Murchison

1990	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Sullom Voe	Gas St Fergus	NGL S Voe/ St Fergus
	1000 Sm³	Mill Sm³	Mill Sm³	Mill Sm³	1000 Sm³	Mill Sm³	1000 Sm³
JAN	45.	6.	.4	1.3	41.	.3	1.
FEB	38.	5.	.1	1.3	35.	1.3	1.
MAR	40.	5.	.2	1.2	36.	1.4	1.
APR	39.	5.	.2	1.2	35.	1.4	2.
MAY	44.	6.	.4	1.3	40.	1.6	1.
JUN	51.	6.	.8	1.2	47.	1.6	2.
JUL	54.	9.	2.7	1.3	49.	0.0	1.
AUG	53.	8.	2.5	1.3	47.	0.0	1.
SEP	47.	7.	2.3	1.2	42.	0.0	1.
OCT	38.	6.	1.7	1.1	34.	0.0	1.
NOV	39.	6.	2.0	.9	35.	0.0	1.
DEC	42.	7.	2.1	1.2	39.	0.0	1.
YEAR TOTAL	530.	76.	15.5	14.5	480.	7.6	14.

These figures are for the Norwegian share of Murchison.

Table 8.4.g
Monthly oil and gas production on Statfjord

1990	Stabilized oil prod	Gas prod	Gas flared	Gas fuel	Gas Emden	NGL/cond Kårstø
	1000 Sm³	Mill Sm³	Mill Sm³	Mill Sm³	Mill Sm³	1000 Sm³
JAN	2877.	687.	9.	38.	327.	92.
FEB	2638.	636.	6.	35.	256.	139.
MAR	2983.	693.	7.	38.	285.	145.
APR	2834.	652.	15.	38.	249.	139.
MAY	3065.	704.	8.	39.	196.	107.
JUN	2922.	671.	6.	37.	246.	135.
JUL	2420.	550.	12.	33.	190.	105.
AUG	2319.	535.	10.	29.	247.	133.
SEP	2131.	476.	4.	27.	187.	89.
OCT	3091.	667.	8.	38.	249.	142.
NOV	3028.	636.	8.	37.	267.	156.
DEC	3006.	647.	6.	39.	274.	221.
YEAR TOTAL	33314.	7554.	99.	428.	2973.	1603.

These figures are for the Norwegian share of Statfjord.

Table 8.4.h
Monthly oil and gas production on Ula

1990	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Teesside	NGL Teesside	Gas sold Emden
	1000 Sm³	Mill Sm³	Mill Sm³	Mill Sm³	1000 Sm³	1000 Sm³	Mill Sm³
JAN	495.	41.	1.0	4.	462.	45.	31.
FEB	446.	37.	.2	4.	415.	42.	29.
MAR	489.	41.	.7	4.	452.	46.	32.
APR	479.	40.	1.0	4.	448.	45.	31.
MAY	352.	29.	.5	3.	328.	33.	23.
JUN	488.	40.	2.3	4.	459.	49.	30.
JUL	464.	38.	1.6	4.	439.	37.	29.
AUG	525.	44.	2.9	4.	492.	45.	33.
SEP	484.	41.	.5	5.	454.	41.	31.
OCT	537.	47.	.8	5.	508.	45.	37.
NOV	548.	46.	.4	5.	520.	43.	36.
DEC	553.	45.	.6	5.	526.	43.	35.
YEAR TOTAL	5860.	489.	12.5	51.	5503.	514.	377.

Table 8.4.i
Monthly oil and gas production allocated to Ekofisk fields

1990	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Teesside	NGL Teesside	Gas sold Emden
	1000 Sm³	Mill Sm³	Mill Sm³	Mill Sm³	1000 Sm³	1000 Sm³	Mill Sm³
JAN	1189.	966.	1.	77.	1023.	175.	739.
FEB	1071.	864.	2.	69.	859.	153.	694.
MAR	1165.	924.	2.	77.	973.	164.	722.
APR	1137.	900.	1.	79.	1041.	162.	594.
MAY	1166.	921.	1.	76.	1079.	160.	672.
JUN	1139.	882.	2.	77.	973.	159.	528.
JUL	1033.	771.	2.	69.	902.	122.	479.
AUG	1202.	915.	1.	80.	1081.	156.	585.
SEP	1169.	916.	1.	77.	1024.	149.	645.
OCT	1222.	946.	1.	83.	1082.	150.	724.
NOV	1176.	909.	1.	77.	1042.	136.	732.
DEC	1182.	911.	2.	78.	1071.	136.	762.
YEAR TOTAL	13851.	10825.	17.	919.	12150.	1822.	7876.

Table 8.4.j
Monthly oil and gas production on Tommeliten

1990	Unstabilized oil prod	Gas prod	Stabilized oil Teesside	NGL Teesside	Gas sold Emden
	1000 Sm³	Mill Sm³	1000 Sm³	1000 Sm³	Mill Sm³
JAN	87.	125.	69.	18.	115.
FEB	76.	108.	61.	16.	100.
MAR	86.	125.	67.	19.	117.
APR	82.	121.	65.	17.	112.
MAY	65.	93.	51.	14.	87.
JUN	73.	113.	57.	16.	106.
JUL	59.	90.	47.	11.	83.
AUG	77.	117.	59.	17.	110.
SEP	67.	107.	52.	14.	99.
OCT	70.	116.	54.	15.	108.
NOV	68.	113.	53.	14.	105.
DEC	71.	118.	56.	14.	109.
YEAR TOTAL	881.	1346.	691.	185.	1251.

Table 8.4.k
Monthly oil and gas production on Oseberg

1990	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Sture
	1000 Sm³	Mill Sm³	Mill Sm³	Mill Sm³	1000 Sm³
JAN	1485.	210.	2.	10.	1495.
FEB	1338.	188.	4.	8.	1335.
MAR	1524.	212.	4.	10.	1522.
APR	1516.	208.	2.	9.	1514.
MAY	1580.	217.	4.	9.	1577.
JUN	1051.	146.	2.	6.	1045.
JUL	1359.	189.	5.	8.	1355.
AUG	1259.	173.	5.	8.	1255.
SEP	1611.	225.	3.	10.	1606.
OCT	1625.	227.	5.	10.	1620.
NOV	1586.	221.	3.	10.	1581.
DEC	1410.	197.	6.	9.	1403.
YEAR TOTAL	17344.	2413.	45.	107.	17308.

Table 8.4.l
Monthly oil and gas production on Veslefrikk

1990	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Sture
	1000 Sm³	Mill Sm³	Mill Sm³	Mill Sm³	1000 Sm³
JAN	85.	11.	11.	0.0	70.
FEB	114.	15.	15.	0.0	115.
MAR	153.	21.	21.	0.0	154.
APR	153.	20.	20.	0.0	153.
MAY	258.	35.	10.	0.0	259.
JUN	283.	38.	9.	0.0	286.
JUL	254.	34.	9.	2.0	256.
AUG	257.	35.	5.	2.0	259.
SEP	325.	44.	6.	2.0	328.
OCT	341.	44.	3.	3.0	342.
NOV	320.	41.	2.	3.0	322.
DEC	325.	41.	4.	3.0	328.
YEAR TOTAL	2868.	379.	45.	15.0	2872.

Table 8.4.m
Monthly oil and gas production on Gyda

1990	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Teesside	Gas Emden	NGL Teesside
	1000 Sm³	Mill Sm³	Mill Sm³	Mill Sm³	1000 Sm³	Mill Sm³	1000 Sm³
JAN	.	.	.	.	.	.	.
FEB	.	.	.	.	.	.	.
MAR	.	.	.	.	.	.	.
APR	.	.	.	.	.	.	.
MAY	.	.	.	.	.	.	.
JUN	26.	4.	4.	0.	16.	0.	2.
JUL	139.	20.	8.	1.	129.	9.	14.
AUG	172.	24.	5.	2.	158.	16.	20.
SEP	259.	37.	6.	1.	238.	26.	31.
OCT	324.	48.	16.	2.	300.	28.	35.
NOV	361.	56.	9.	2.	334.	41.	41.
DEC	347.	53.	9.	2.	323.	38.	38.
YEAR TOTAL	1628.	242.	57.	10.	1498.	158.	181.

Table 8.4.n
Monthly oil and gas test production on Troll Vest

1990	Stabilized oil prod	Gas prod	Gas flared	Gas fuel
	1000 Sm^3	Mill Sm^3	Mill Sm^3	Mill Sm^3
JAN	82.	5.6	4.2	1.4
FEB	80.	7.0	5.0	2.0
MAR	121.	7.7	5.3	2.4
APR	123.	7.0	5.2	1.8
MAY	83.	7.4	5.7	1.7
JUN	123.	6.8	5.2	1.6
JUL	83.	6.8	4.8	2.0
AUG	83.	5.7	4.3	1.4
SEP	81.	5.5	4.1	1.4
OCT	83.	16.5	14.9	1.6
NOV	80.	5.2	4.4	.8
DEC	41.	2.2	1.9	.3
YEAR TOTAL	1053.	83.4	65.0	18.4

Table 8.4.o
Monthly oil and gas production on Hod

1990	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Teesside	Gas Emden	NGL Teesside
	1000 Sm^3	Mill Sm^3	Mill Sm^3	Mill Sm^3	1000 Sm^3	Mill Sm^3	1000 Sm^3
JAN	.	.	.	.	.	.	.
FEB	.	.	.	.	.	.	.
MAR	.	.	.	.	.	.	.
APR	.	.	.	.	.	.	.
MAY	.	.	.	.	.	.	.
JUN	.	.	.	.	.	.	.
JUL	.	.	.	.	.	.	.
AUG	.	.	.	.	.	.	.
SEP	.	.	.	.	.	.	.
OCT	56.	6.	.	.	53.	6.	3.
NOV	58.	7.	.	.	54.	7.	4.
DEC	51.	7.	.	.	48.	7.	3.
YEAR TOTAL	165	21.	0.0	0.0	155.	21.	10.

Table 8.4.p
Monthly oil and gas test production on Mime

1990	Unstabilized oil prod	Gas prod	Stabilized oil Teesside	Gas Emden	NGL Teesside
	1000 Sm^3	Mill Sm^3	1000 Sm^3	Mill Sm^3	1000 Sm^3
JAN	.	.	.	.	.
FEB	.	.	.	.	.
MAR	.	.	.	.	.
APR	.	.	.	.	.
MAY	.	.	.	.	.
JUN	.	.	.	.	.
JUL	.	.	.	.	.
AUG	.	.	.	.	.
SEP	.	.	.	.	.
OCT	2.	0.	2.	0.	0.
NOV	13.	3.	12.	3.	1.
DEC	12.	3.	12.	3.	1.
YEAR TOTAL	27.	6.	26.	6.	2.

8.5 PUBLICATIONS BY THE NPD IN 1990

Regulations and guidelines

- *Acts, Regulations and Provisions* for the Petroleum Activity 1990. A compendium of the laws etc applying to the offshore industry issued each year and up to date on 1 January 1990 (Norw and Engl).
- Regulations concerning *Manned Underwater Operations* in the Petroleum Activities (Norw and Engl)
- Regulations on *Environmental Data* in the Petroleum Activities (Norw and Engl)
- Regulations concerning *Pipeline Systems* in the Petroleum Activities (Norw and Engl)
- Regulations concerning *Implementation and Use of Risk Analyses* in the Petroleum Activities (Norw and Engl)
- Guidelines on *Qualifications for Personnel Engaged in Manned Underwater Operations* in the Petroleum Activity (Norw and Engl)
- Guidelines for *Design and Analysis of Steel Structures* in the Petroleum Activities (Norw and Engl)
- Guidelines for *Arrangement and Contents of Plan for Development and Operation* of Petroleum Deposits (Norw and Engl).

Study reports

- *Application of Multivariate Analysis to Carbon-13 Nuclear Magnetic Resonance Spectra of Mixtures* (Engl)
- *Drifting Objects that may cause a Threat to Petroleum Installations/ Units* (Engl)
- Three reports on *Perceived Risk and Safety*, Summary Report, Result Report, Technical Documentation Report (Norw).

Other publications

- Well Data Summary Sheets, vol 15, *Wells Completed 1984* (Engl)
- NPD Bulletin No 6, *Structural Elements of the Norwegian Continental Shelf* (Engl)
- *Norwegian Petroleum Directorate Annual Report 1989* (Norw and Engl)
- *Licences, Areas, Area Coordinates, Exploration Wells* (Engl)
- *Borehole Lists* (Engl).

Fig. 8.6 Organisation chart