Norwegian Petroleum Directorate

ANNUAL REPORT 1991

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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."

Contents

Report of the Directors

Drilling operations on the Norwegian continental shelf reached in 1991 the highest level since exploration for oil and gas commenced in 1966. No less than 47 exploration wells were spudded, 34 being classified as wildcats and 13 as appraisal wells. A further 64 wells were drilled for production. The total for the year was thus 111 wells, 14 more than the previous record in 1985.

This extensive exploration activity produced satisfactory results. Eleven discoveries were made during the year, ten in the North Sea and one off the coast of Mid-Norway. Hydrocarbons were also proven in three other wells which were pending testing at year-end.

The discovery rate is high and puts the Norwegian continental shelf among the most attractive exploration areas in the world. One particularly pleasing result of the exploration drilling was a new oil discovery in the vicinity of Balder in the North Sea.

Continued exploration for oil and gas offshore Norway presupposes steadily improving data quality, resulting in an accelerating effort to collect seismic data. In 1991, well in excess of 300,000 kilometres of lines were shot, three times as much as in 1990. Most of the data is three-dimensional, as the added detail this gives goes some way to compensate for the growing geological complexity of the exploration phase.

While there remains some uncertainty regarding the magnitude of the proven new discoveries, tentative estimates put the year's increment due to exploration equal to the year's depletion due to production.

At the present rate of production, Norway has sufficient reserves for about 20 years of oil extraction and about 100 years of gas extraction, assuming the rate is sustained. If one makes allowance for predicted discoveries, the time scales can be extended by as much again.

The 13th licensing round, in which oil companies were invited to apply for 52 new blocks or parts of blocks, and 103 previously announced, but unallocated, blocks, was concluded in 1991. It resulted in 22 production licences being awarded on 36 blocks; 12 in the North Sea, three off Mid-Norway, and seven in the Barents Sea.

No less than 24 companies declared their interest in the 13th round allocations, which serves to confirm the great attraction that Norwegian prospects hold.

One new exploration well was put down on Svalbard, where Norsk Hydro and Store Norske Spitsbergen Kullkompani jointly conducted a project in Reindalen. Although neither oil nor gas was proven, the bore furnished valuable geological and operational insights for potential future operations on the island.

On the field development side, 1991 will also go down as an energetic year. During the period the Directorate considered Plans for Development and Operation of the Loke, Tordis and Lille-Frigg fields, and the updated PDO for Heidrun. The Plan for Construction and Operation of Europipe was considered on two occasions. A similar plan for gas transportation on Haltenbanken, the Haltenpipe, was also up for consideration in the Directorate, and likewise an overall strategy for the application of gas from that region.

In the North Sea the Directorate prepared area studies designed to look at the new development projects in a comprehensive light, in respect of which special emphasis was given to exploring the implicit merits of shared systems of processing and transportation.

The Directors would like to record their appreciation for the professional zeal shown by the Directorate staff in connection with the redistribution of the Statfjord field reserves, which are of immense importance to Norway. The final verdict of the experts was a 1.14547 per cent increment in favour of Norway, bringing the total Norwegian content of the Statfjord field to 85.23869 per cent.

The total loss of the Sleipner A platform gravity base in Gandsfjorden in August 1991 produced a whole new set of problems, relating to investigation of the causes and checking that similar failures cannot occur on existing or new installations. This work can be expected to continue for some time. The immediate, principal repercussions of the Sleipner loss on the Directorate's regulatory systems were stricter requirements for independent verification of concrete structures, and the running of elementary calculations to augment the advanced computer programmes during the building phase.

On the resources side the Directorate was forced to look for alternative sources of gas following the loss of Sleipner A.

In 1991, production tests were performed on Mime and Balder, and in the thin oil zone on Troll. The results were analysed by the Directorate in the course of the year.

In connection with Troll it should be mentioned that horizontal drilling produced very promising results in 1991. We can see excellent opportunities for optimal, cost-effective tapping of minor fields and complex geological structures.

Regarding the general prospects of enhanced recovery, the Ekofisk area was central to the Directorate's activities in 1991. The Ekofisk fields possess great potential for improving recovery beyond the operators' assumptions. The Directorate has therefore solicited plans for enhanced recovery on Ekofisk, Eldfisk, Tor and Valhall; which the respective operators are now in the process of drafting.

The gradual subsidence of some fields is a matter of concern to the Directorate. The Ekofisk field in particular is sinking faster than anyone hitherto had reason to suspect, and the process will require careful monitoring for a long time to come. Any alterations to our overall response will require a reassessment of resources and safety in the region.

Another matter which is of great principal significance is the shut-down of the Frigg area installations. On 1 September the Directorate received Elf's plans to decommission and dismantle Nordøst-Frigg. The whole issue is the first of its kind in the Norwegian sector.

From 1 January 1991 the Directorate was responsible for administration of the new carbon dioxide tax on the continental shelf. Wide powers were delegated under the legislation, and reporting procedures and a suitable chart of accounts were established. During the first six months, the tax generated revenues of Nkr 810 million.

Apart from its tasks in connection with this emissions tax, the Directorate also investigated several other environmental issues in 1991. Notable initiatives included emission forecasts for various greenhouse gases, the use of carbon dioxide or machinery exhaust for field injection purposes, and follow-up of the Oil Industry Association's ecology programme. These issues were the subject of reports to the Ministry of Petroleum and Energy.

In the Government's Environmental (Green) Budget, the Directorate committed Nkr 62.25 million of its 1991 operating costs to direct environmental measures or related expenditures. The projects included acquisition of environmental data in the Barents Sea, scrap removal from the North Sea seabed, direct assistance to the State Pollution Control Authority, SFT, and partial funding of pollution control exercises. The environment-related expenditures also cover the Directorate's general commitments in the fields of safety and resources on the continental shelf.

On the environmental side, many companies have worked with the Directorate to remove oily drill cuttings as a potential source of pollution. Tests have been carried out to see if it is feasible to discard oily drill cuttings in non-producing well zones. Further tests will be watched closely to determine whether the long-term consequences might be detrimental to well performance.

Work in the Directorate on the new Safety Regulations was finally concluded. With their completion, the Directorate feels that the authorities and the companies have acquired a useful tool which will facilitate the continuing improvement of the established safety levels, at the same time as cost-effective solutions in the industry are permitted. The use of function-oriented requirements combined with requirements to set safety targets and apply risk analyses is a great challenge. Considerable resources were therefore used on measures to improve the industry's general understanding of the new regulations.

The new regulations also pave the way for harmonisation with international regulations and standards. During 1991 the Directorate was pleased to take part in several ongoing standardisation projects which will affect the domestic offshore petroleum industry.

Both the constraints and the time-table for the development of new Working Environment Regulations in the Directorate's field of responsibility have been finalised. Drafting of the regulations will commence in 1992. The experience of working closely with the parties involved during formulation of the Safety Regulations has convinced the Directorate that the new project should be run along the same lines.

The Government has decreed that the Working Environment Act will apply to mobile installations engaging in petroleum operations; and the overall responsibility for the working environment on mobile installations now rests with the Ministry of Local Government, although details of how supervision of the Ministry's authority will be effected have yet to be decided.

In the light of the recommendations made by the Inquiry Commission into the Piper Alpha burn-out in 1988, the UK authorities implemented major changes in the organisation of safety supervision in their sector. The changes mean greater similarities in the UK and Norwegian supervisory systems. Excellent relations have been established between the Norwegian Petroleum Directorate and the new UK supervisory authority, and our best efforts will go toward continuing this close communication.

The Directorate's supervision of offshore operations went generally according to plan in 1991, although a certain degree of priority shuffling was called for. The main disruption was problems encountered while drilling deep, high-pressure bores. One critical event caused the Directorate to order all drilling of high-pressure wells to cease for a brief period while the causes and effects were elucidated.

The experiences with supervisory control and the evidence of the accident and absence statistics persuaded the Directorate to step up its supervision of contractor companies. Control of major drilling contractors having already been performed, control measures in 1991 were concentrated on smaller contractors, such as the well service companies. Control included the operators' criteria for contractor selection, contract provisions, and control of the working environment. The Directorate's investigations uncovered areas of unclear division of responsibility between operator and contractor, inadequate reporting systems for working hours, and several cases where working hour regulations had been disregarded. As a result, the Directorate has issued orders to all operating companies.

In 1991, inspections were made of the operators' internal control systems for reporting and investigating accidents, while work commenced simultaneously to review the Directorate's own systems for collecting and conditioning these statistics. Generally, the deficiencies identified seem to stem from a lack of understanding of the Directorate's rules and criteria for reporting of accidents and hazard situations. For example, deficiencies were identified in procedures and training. Ongoing supervision of these matters and review of the Directorate's own systems will continue in 1992.

Regrettably, petroleum operations cost the lives of three people in 1991. During a routine maintenance operation on Ekofisk, a helicopter collided with the flare stack and crashed. All three people on board the helicopter were killed in the accident.

Finally the Directors would like to refer to two important programmes administered by the Directorate on a daily basis which have now reached conclusion.

The first was the government-backed SPOR project, which looked at enhanced recovery and reservoir technology, and which was concluded after seven years of input by Norwegian research and development teams. It is with great satisfaction that the Directors can report that the programme's objectives were attained, and that Norwegian know-how in the field is currently second to none. The Directorate was responsible for programme administration.

The second was the Programme for Petroleum Administration, PETRAD, which was concluded after a three-year trial. This programme was conducted by the Norwegian Petroleum Directorate on behalf of NORAD, the Norwegian Directorate for Development Cooperation, in collaboration with leading institutions in Norway and abroad. No less than 850 persons from 38 countries attended the 32 seminars which sought to train leading personnel for petroleum operations in developing countries. The possible continuation of the project is presently under review by NORAD.

Stavanger, 31 January 1992

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

Leiv Gidskehaug

Liv Nielsen

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 in special instructions, as last amended 29 March 1979. These tasks have been revised and supplemented by delegations which follow directly from Acts of Parliament, regulations, and superior authorities, as follows:

a) *Petroleum Act*, of 22 March 1985 no. 11, embracing
   - *Petroleum Regulations*, by Royal Decree of 14 June 1985
   - *Safety Regulations*, by Royal Decree of 28 June 1985
   - *Internal Control Regulations*, by Royal Decree of 28 June 1985
   - *Safety Zone Regulations*, by Royal Decree of 9 October 1987

b) *Working Environment Act*, of 4 February 1977 no. 4, embracing
   - *Working Environment Regulations*, by Royal Decree of 1 June 1979
   - (See also WER section 15 with comments)

c) *Carbon Dioxide Act*, of 21 December 1990, no. 72

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

e) *Svalbard Act*, of 17 July 1925, no. 11, embracing
   - Regulations for *Safe Practices* for Exploration and Exploration Drilling for Petroleum Deposits on Svalbard etc, by Royal Decree of 25 March 1988

f) Act relating to *Scientific Research* for, Exploration for and Exploitation of Subsea Natural Resources Other than Petroleum Resources, of 21 June 1963 no. 12, embracing
   - Regulations for *Scientific Research* for Natural Resources on the Norwegian Continental Shelf etc, by Royal Decree of 31 January 1969
   - Provisional Regulations for *Littering and Pollution* caused by Petroleum Activities on the Norwegian Continental Shelf, by Royal Decree 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 formulated:

"The objective of the Norwegian Petroleum Directorate is 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."

1.3 DIRECTORS AND ADMINISTRATION

1.3.1 Board of Directors

The composition of the Board of Directors up to 15 April 1991 was:

1. Mr Arve Berg, Regional Employment Director, Ålesund (Chairman)
2. Mr Andreas Lønning, Corporate Director, Oslo (Deputy Chairman)
3. Ms Liv Hatland, Managing Director, Bergen
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, Principal 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, Branch Supervisor, Oslo
For 6:
Mr Gunnar Flaat, Negotiations Director, Oslo
For 7–8:
Mr Tor Inge Ottosen, Executive Officer, Stavanger.

By letter of 23 April 1991 the Ministry of Petroleum and Energy extended the directors' term of office by one year on the following grounds:

"Pending the report of a Commission to examine the role, mandates and composition of directors in public office (the Public Board Review Commission), the Directors of the Norwegian Petroleum Directorate are reappointed for a period of one year ending 15 April 1992."

Directors elected from among the employees will be replaced as indicated by the election results.

The composition of the board of directors until 15 April 1992 is therefore:

1. Mr Arve Berg, Regional Employment Director, Ålesund (Chairman)

2. Mr Andreas Lønning, Corporate Director, Oslo (Deputy Chairman)
3. Ms Liv Hatland, Managing Director, Bergen
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 Leif Gidskehaug, Senior Engineer, Stavanger
8. Mr Ole Preben Berget, Head of Section, Stavanger.

Deputies:
For 1–4:
Ms Sylvi Enevold, County Council Deputy Chairwoman, Hammerfest
Ms Marit Greve, Editor, Bærum
For 5:
Mr Bjørn Kolby, Branch Supervisor, Oslo
For 6:
Mr Gunnar Flaat, Negotiations Director, Oslo
For 7–8:
Ms Liv Nielsen, Head of Supervisory Activities, Stavanger
Mr Sverre Øxnevad, Advisor, Sandnes.

Mr Ole Preben Berget, head of section, left his position effective 22 December 1991 and was no longer eligible to serve. The employee representatives' first deputy, Ms Liv Nielsen, therefore moved onto the board.

During the report period the board held ten meetings. In connection with the May meeting the directors made a study visit to Germany where Ruhrgas and Veba/Deminex were among the hosts. The August meeting was held in Oslo where the board met with the two Secretaries of State, Finn Kristensen and Kjell Borgen, who oversee the Directorate's operations, and representatives of the senior civil servants at the Ministries. The November meeting was held in Hammerfest, where the directors met with county and local authority officers. Statoil hosted an introduction to the Plan for Development and Operation of the Snøhvit field, and the directors inspected the Hammerfest oil base facility.

1.3.2 Organisation

The year saw certain organisational changes to the Regional Office in Harstad, where the two technical sections were amalgamated into a single Section for Resource and Safety Management.

Changes were also announced in the Resource Management Division from 1 January 1992. A new Data Management Branch was established, resulting in the transfer of geophysical and well data archives from their former home in the Administration Branch. The Planning Branch was wound up, the tasks of the Exploration Branch were broken down by geographical region, and the Production Evaluation and Production Geology Sections were combined into a single Production Section.

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 the Norwegian Directorate for Development Cooperation, NORAD. At year end there were 340 employees in service and 20 on leave. The latter comprised 11 on parental leave, one seconded to an organisational project, one engaging in development aid, two pursuing further education, and five on leave for various other reasons.

Of employees at the Directorate, 37.3 per cent are women. Figure 1.3.3 shows the breakdown of men and women in the various position categories. One of NORAD's special advisors for oil matters in developing countries worked in the Directorate during parts of 1991.

In the year the Directorate took on 17 new employees in permanent positions, of whom five come from oil-related activities, four from the public sector, four from private enterprise, and four of whom were newly qualified.

Employees leaving were 31 in number, representing 9 per cent of the total authorised positions.

Competence building

In order to streamline and strengthen operations in the Directorate, team building projects were initiated in 1991 at different levels of management. During the report period the Directorate also implemented a seminar for all managers.

The Safety and Working Environment Division is analysing jobs at all levels with the objective of elucidating the division's future competence requirements.

To utilise our resources as best possible, support for internal courses and seminars has been arranged whenever this is deemed propitious.

The Directorate has also benefited greatly from staff participation in technical courses hosted by the operating companies.

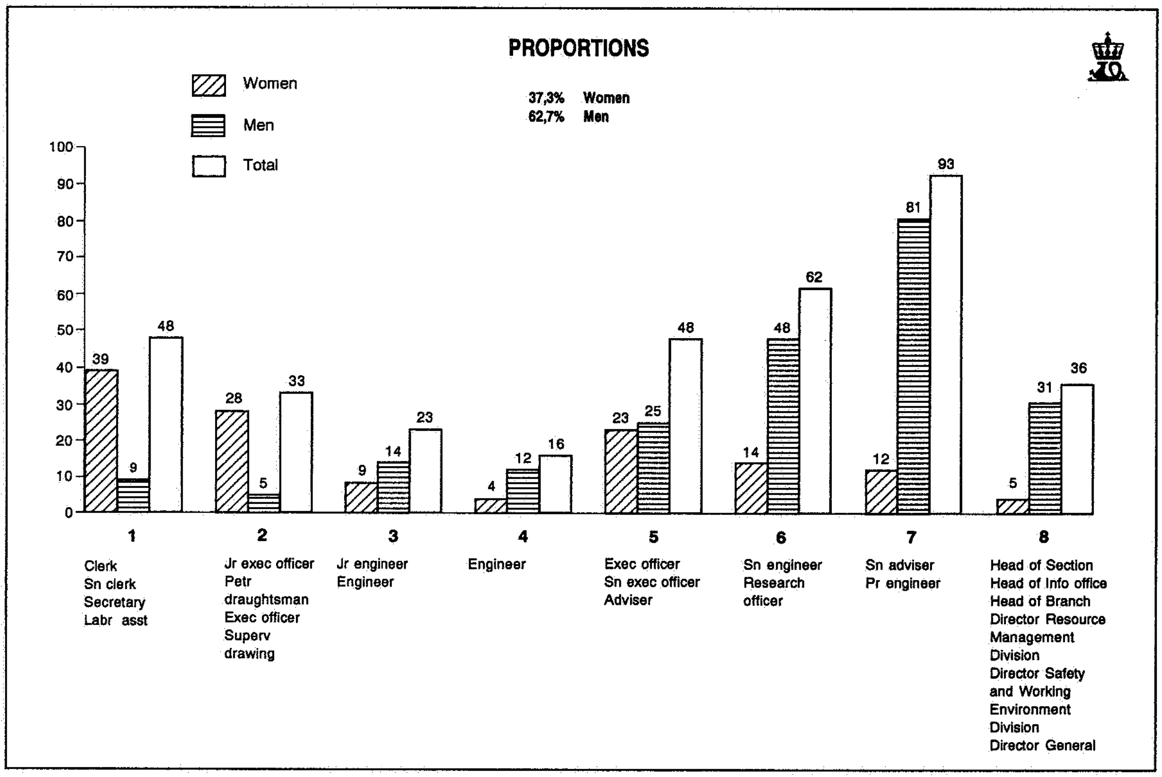
Equal opportunity

The Directorate is bound by a specific agreement on equality and has its own Equal Opportunity Committee. This committee of four people comprises two representatives from management and two from the staff unions. Each year an Equal Opportunity Action Plan is drawn up. In 1991 the Committee's work included the publication of a booklet on equality in the Directorate and the performance of an equality survey.

1.3.4 Budget and economy

The Directorate employed Nkr 217,727,462 for its various tasks in 1991.

Fig. 1.3.3
Job categories per 31.12. 1991



The amount was appropriated as follows:

– Operating budget	Nkr 161,218,428
– Inspection costs	7,884,107
– Geological and geophysical surveys	43,012,745
– Safety and working environment	5,612,182
Total	217,727,462

Of the operating budget, payroll costs account for Nkr 102,548,618 and lease and operation of buildings Nkr 6,006,992. The remainder, Nkr 52,662,818, covers costs of consultants, operation of weather ship, external assistance, travel, training, computer systems operation, new investments in equipment, etc.

The Directorate is required to carry out certain special tasks as follows:

– Clearance of seabed	Nkr 4,381,575
– Research and development for enhanced oil recovery, SPOR	9,827,066
– World Petroleum Congress	460,000

As the budget situation increasingly taxes the Directorate's priorities, the development of planning tools is a commitment area.

Revenues

In addition to production royalties, acreage fees and carbon dioxide tax in the amount of Nkr 10,332,833,849, the Directorate received Nkr 98,419,726 from various other sources of revenue as follows:

– Sale of publications	Nkr 4,132,203
– Sale of released test material	1,228,437
– Exploration fees	1,560,000
– Reimbursed inspection outlays	33,406,934
– Sale of seismic survey results	50,570,230
– Credit interest, bank	7,482,549
– Miscellaneous	39,373
Total	98,419,726

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 electronic 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 staff 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 1990 Annual Report was presented to the press in May.

The Directorate's *Map of the Continental Shelf* showing production licences at 27 March 1991 came off the press in June.

There were 76 press releases issued in 1991, most of them in connection with termination of exploration wells.

1.3.6 Document and data records management

Almost 75,000 document units were entered in the file catalogue, Library, and Infoil in 1991. During the same period some 15,000 enquiries and orders were logged and fielded by the section, representing a decline since 1990.

A plan has been developed for information and data records management, and work on requirement specifications for a new filing and library system has started. Much effort has gone into improving archival routines. One result is the much quicker distribution of daily registered mail to the addressees. Assistance with the development of records management functions was also furnished to NAMCOR in Namibia.

Library activity was intense in 1991: a summary of periodicals and journals in the Library was prepared and a quality manual for the library was printed. Despite these advances, enquiries for literature and information lagged 20 per cent behind 1990, particularly in the case of internal users.

Work particularly targeted sales efforts for the Oil and Infoil-Sesame databases, where especially the PC version has been well received. Infoil and Sesame are now available on an English language CD-ROM containing petroleum data. Norway's National Computing Centre took over as host for both databases in autumn 1991, and Infoil and Sesame came on line from the German database host, STN, in Karlsruhe.

2. Activity on the Norwegian Continental Shelf

2.1 EXPLORATION AND PRODUCTION LICENCES

2.1.1 New exploration licences

As of 31 December 1991, 193 commercial exploration licences had been granted. Each licence is valid for three years.

The following licences were awarded in 1991:

Company	*Licence no.*
Nopec	186
A/S Norske Shell	187
Conoco Norway Inc	188
Western Geophysical Company	189
Oryx UK Energy Company	190
Deminex (Norge) A/S	191
Amarok A.S	192
Norwegian Exploration Services A/S	193

2.1.2 Scientific exploration licences

As at 31 December 1991, a total of 285 licences had been granted for scientific explorations on the Norwegian continental shelf. As Table 2.1.2 shows, six such licences were granted in 1991, two being issued by the Directorate in Stavanger, and four by the Directorate's Regional Office in Harstad.

Table 2.1.2
Permits for scientific exploration for natural resources

Permit	Institution	Subject Geo-physics	 Geo-logy	 Bio-logy	Area
258/91	Norwegian Exploration Services A/S		X		North Sea
259/91	Universitetet i Oslo	X			Skagerrak
23/91-H	Amarok a.s	X			East of Svalbard
24/91-H	Universitetet i Tromsø		X		Off North-Andøy
25/91-H	Universitetet i Tromsø	X	X		Coast of Finnmark and southern Barents Sea
26/91-H	Universitetet i Tromsø	X	X		Coastal areas in Troms

2.1.3 New production licences

The 13th licensing round was announced on 6 March 1990 and allocations made on 1 March 1991. The allocations embraced 22 production licences covering 36 blocks or parts thereof, 12 production licences on 15 blocks in the North Sea, three production licences on six blocks off Mid-Norway, and seven production licences on 15 blocks in the Barents Sea. Nine companies were awarded operatorships, of which Statoil was awarded six, Hydro five, Saga three, Esso and Shell two each, and Mobil, BP, Conoco, and Deminex one each. Deminex is the only new operator on the Norwegian continental shelf.

Furthermore, a minor portion of block 31/7 was awarded in September 1991, with Norsk Hydro as operator. This area covers the Brage field's extension into block 31/7.

Table 2.1.3.a shows production licences awarded in 1991. Table 2.1.3.b shows production licences and acreages, Table 2.1.3.c licensing rounds, and Figure 2.1.3 exploration wells drilled in each licensing round.

Table 2.1.3.a
Allocations: Licensing round 13 and prod. lic. 185

License no.	Field/block	Share in %		Licensee (O=operator)
163	2/10	10.000		Norsk Agip A/S
		10.000		Amerada Hess Norge A/S
		30.000	O	Saga Petroleum a.s.
		50.000		Den norske stats oljeselskap a.s (Statoil)
164	2/1, 7/12 and 8/10	30.000	O	BP Petroleum Development of Norway A.S
		10.000		Norske Conoco A/S
		50.000		Den norske stats oljeselskap a.s (Statoil)
		10.000		Svenska Petroleum Exploration A/S
165	19/7	10.000		Enterprise Oil Norwegian A/S
		25.000	O	Esso Norge a.s
		15.000		Mobil Development Norway A/S
		50.000		Den norske stats oljeselskap a.s (Statoil)
166	15/6	10.000		BP Petroleum Development of Norway A.S
		30.000	O	Deminex (Norge) A/S
		10.000		A/S Norske Shell
		50.000		Den norske stats oljeselskap a.s (Statoil)
167	16/1	10.000		Amoco Norway A/S
		30.000		Norsk Hydro Produksjon a.s
		10.000		Phillips Petroleum Norsk A/S
		50.000	O	Den norske stats oljeselskap a.s (Statoil)
168	25/10	20.000		Amerada Hess Norge A/S
		15.000		BP Petroleum Development of Norway A.S
		15.000		Norske Fina A/S
		50.000	O	Den norske stats oljeselskap a.s (Statoil)
169	25/8 and 25/11	10.000		Norske Conoco A/S
		10.000		Esso Norge a.s
		30.000	O	Norsk Hydro Produksjon a.s
		50.000		Den norske stats oljeselskap a.s (Statoil)
170	30/6	30.000	O	Norsk Hydro Produksjon a.s
		50.000		Den norske stats oljeselskap a.s (Statoil)
		20.000		Total Norge A/S
171	30/12	30.000	O	Norsk Hydro Produksjon a.s
		10.000		Saga Petroleum a.s.
		50.000		Den norske stats oljeselskap a.s (Statoil)
		10.000		Total Norge A/S
172	33/9	10.000		Amerada Hess Norge A/S
		15.000		Norske Conoco A/S
		25.000	O	Mobil Development Norway A/S
		50.000		Den norske stats oljeselskap a.s (Statoil)
173	35/10	15.000		Elf Aquitaine Norge A/S
		15.000		Norsk Hydro Produksjon a.s
		20.000		Mobil Development Norway A/S
		50.000	O	Den norske stats oljeselskap a.s (Statoil)
174	35/12	10.000		Esso Norge a.s
		10.000		Mobil Development Norway A/S
		30.000	O	Saga Petroleum a.s.
		50.000		Den norske stats oljeselskap a.s (Statoil)
175	6204/10 and 6204/11	10.000		Enterprise Oil Norwegian A/S
		10.000		Neste Petroleum A/S
		20.000		Phillips Petroleum Norsk A/S
		10.000		Saga Petroleum a.s.
		50.000	O	Den norske stats oljeselskap a.s (Statoil)
176	6407/11 and 6407/12	10.000		Norske Fina A/S
		10.000		Norsk Hydro Produksjon A/S
		30.000	O	A/S Norske Shell
		50.000		Den norske stats oljeselskap a.s (Statoil)

License no.	Field/block	Share in %		Licensee (O=operator)
177	6610/2 and	30.000		BP Petroleum Development of Norway A.S
	6610/3	20.000		Saga Petroleum a.s.
		50.000	O	Den norske stats oljeselskap a.s (Statoil)
178	7122/1 and	30.000	O	Esso Norge a.s
	7122/4	20.000		Norsk Hydro Produksjon a.s
		50.000		Den norske stats oljeselskap a.s (Statoil)
179	7122/2 and	10.000		Esso Norge a.s
	7122/3	30.000	O	Norsk Hydro Produksjon A/S
		10.000		Saga Petroleum a.s.
		50.000		Den norske stats oljeselskap a.s (Statoil)
180	7128/4	20.000		Norsk Agip A/S
		20.000		BP Petroleum Development of Norway A.S
		50.000	O	Den norske stats oljeselskap a.s (Statoil)
		10.000		Total Norge A/S
181	7128/6,	15.000		Amoco Norway A/S
	7128/9 and	25.000	O	Norske Conoco A/S
	7129/4	10.000		Elf Aquitaine Norge A/S
		50.000		Den norske stats oljeselskap (Statoil)
182	7218/7 and	20.000		Enterprise Oil Norwegian A/S
	7219/8	30.000	O	Saga Petroleum a.s.
		50.000		Den norske stats oljeselskap a.s (Statoil)
183	7229/11 and	10.000		Amerada Hess Norge A/S
	7229/12	10.000		Amoco Norway A/S
		30.000	O	A/S Norske Shell
		50.000		Den norske stats oljeselskap a.s (Statoil)
184	7316/4,	10.000		Norske Conoco A/S
	7316/5 and	10.000		Deminex (Norge) A/S
	7316/8	20.000	O	Norsk Hydro Produksjon a.s
		10.000		Mobil Development Norway A/S
		50.000		Den norske stats oljeselskap a.s (Statoil)
185	31/7	17.600		Esso Norge a.s
		13.200	O	Norsk Hydro produksjon a.s
		13.200		Neste Petroleum A/S
		56.000		Den norske stats oljeselskap (Statoil)

Table 2.1.3.b
Production licenses and acreages as of 31.12.1991

Lic. round	Allocated	Prod. lic. no.	No. of blocks* allo-cated	No. of blocks* re-linquished	Area allocated km²	Area relinquished km²	Area in license km²
1.	01.09.65	001–021	74	58	39842.476	35946.860	3895.636
	07.12.65	022	4	4	2263.565	2263.565	0.0
	12.09.77	019 (2)	2		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		746.285	376.906	369.379
	14.11.69	034–035	2		1024.529	564.837	459.692
	11.06.71	036	1		523.937	262.047	261.890
plus	10.08.73	037	2		586.834	295.157	291.677
3.	01.04.75	038–040 and 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		604.558	555.553	49.005
	27.08.76	044	1		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		500.509	151.962	348.547

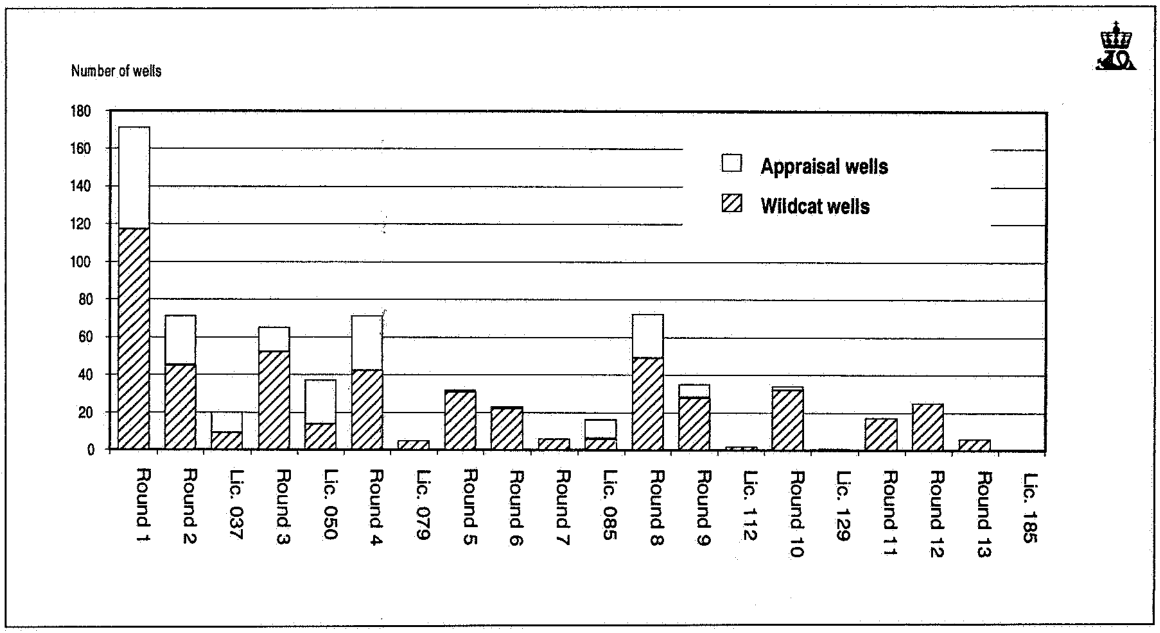
Lic. round	Allocated	Prod. lic. no.	No. of blocks* allo-cated	re-linquished	Area allocated km²	Area relinquished km²	Area in license km²
4.	06.04.79	051–058	8	2	4007.887	2434.633	1573.254
plus	20.08.82	079	1		102.167		102.167
5.	18.01.80	059–061	3	2	1108.078	998.675	109.403
	27.03.81	062–064	3	1	1099.522	867.542	231.981
	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		1521.160	725.816	795.344
8.	09.03.84	086–100	17	2	6338.273	2643.394	3693.879
9.	14.03.85	101–111	13		5293.054	1791.686	3501.368
plus	26.07.85	112	1		260.215	129.958	130.257
10a	23.08.85	113–120	9	2	3075.433	1070.258	2005.175
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	2	4163.711	628.856	3534.855
	29.05.87	138–142	11	4	2975.807	1188.588	1787.219
12a	08.07.88	143–153	16		4701.021		4701.021
12b	09.03.89	154–162	13	2	5031.262	602.953	4428.309
13	01.03.91	163–184	36		12076.889		12076.889
plus	13.09.91	185	1		25.535		25.535
			256	99	119234.554	65340.608	53893.946

* whole and partial blocks plus= allocations made outside licensing rounds

Table 2.1.3.c
Licensing rounds. Norwegian and foreign shares as of 31.12.1991

Licensing round	Year	Number of blocks	Share % Norwegian	Share % foreign	Operator % Norwegian	Operator % foreign
1	1965	78	9	91	0	100
2	1969 – 71	14	15	85	0	100
Statfjord	1973	2	52	48	0	100
3	1974 – 78	22	58	42	63	37
Ula (19 B)	1977	2	50	50	0	100
Gullfaks	1978	1	100	0	100	0
4	1979	8	58	42	68	32
5	1980 – 82	12	66	34	92	8
6	1981	9	64	34	50	50
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	42	38	62
12B	1989	13	64	36	67	33
13	1991	36	66	34	64	36
Prod. lic. 185	1991	1	69	31	100	0

Fig. 2.1.3
Exploration wells drilled in each licensing round



2.1.4 Transfer of interests
In the course of 1991 the following transfers of interests were approved in accordance with Section 61 of the Petroleum Act, no. 11 of 22 March 1985:

Production licence 043
Operator: Total Norge A/S

Total Norge A/S has taken over 50 per cent from BP Petroleum Development of Norway A.S. Total also took over operatorship of the production licence. The distribution in the production licence after this is as follows:

Den norske stats oljeselskap a.s	50.0000 %
Total Norge A/S	50.0000 %

Production licence 048
Operator: Norsk Hydro Produksjon a.s

Petroleum Development of Norway A.S has taken over 10.9 per cent from Total Norge A/S. The distribution in the production licence after this is as follows:

Den norske stats oljeselskap a.s	50.0000 %
Elf Aquitaine Norge A/S	21.8000 %
Norsk Hydro Produksjon a.s	17.3000 %
BP Petroleum Development of Norway A.S	10.9000 %

Production licence 062
Operator: Saga Petroleum a.s

Total Norge A/S has taken over 25 per cent from A/S Norske Shell. The distribution in the production licence after this is as follows:

Den norske stats oljeselskap a.s	50.0000 %
Total Norge A/S	25.0000 %
Neste Petroleum A/S	10.0000 %
Saga Petroleum a.s	10.0000 %
Norsk Hydro Produksjon a.s	5.0000 %

Production licence 067
Operator: Norsk Agip A/S

Norsk Agip A/S has taken over 30 per cent from A/S Norske Shell. At the same time Norsk Agip A/S took over as operator for the production licence. The distribution in the production licence after this is as follows:

Den norske stats oljeselskap a.s	50.0000 %
Norsk Agip A/S	40.0000 %
Phillips Petroleum Norsk A/S	10.0000 %

Production licence 078
Operator: Norsk Hydro Produksjon a.s

Total Norge A/S has taken over 10 per cent from A/S Norske Shell. The distribution in the production licence after this is as follows:

Den norske stats oljeselskap a.s	50.0000 %
Norsk Hydro Produksjon a.s	25.0000 %
Elf Aquitaine Norge A/S	15.0000 %
Total Norge A/S	10.0000 %

Production licence 102
Operator: Elf Aquitaine Norge A/S

Total Norge A/S has taken over 20 per cent from A/S Norske Shell. The distribution in the production licence after this is as follows:

Den norske stats oljeselskap a.s	50.0000 %
Elf Aquitaine Norge A/S	30.0000 %
Total Norge A/S	20.0000 %

Production licence 114
Operator: Den norske stats oljeselskap a.s (Statoil)

Den norske stats oljeselskap a.s has taken over 15 per cent from A/S Norske Shell. The distribution in the production licence after this is as follows:

Den norske stats oljeselskap a.s	65.0000 %
Saga Petroleum a.s	15.0000 %
Deminex (Norge) A/S	10.0000 %
Petrobras Norge A/S	10.0000 %

Production licence 115
Operator: Total Norge A/S

Total Norge A/S has taken over 30 per cent from A/S Norske Shell. At the same time Total has taken over as operator for the production licence. The distribution in the production licence after this is as follows:

Den norske stats oljeselskap a.s	50.0000 %
Total Norge A/S	30.0000 %
Conoco Norway Inc	15.0000 %
Det Norske Oljeselskap A/S	5.0000 %

Production licence 126
Operator: Esso Norge a.s

Mobil Development Norway A.S has taken over 10 per cent and Enterprise Oil Norwegian A/S 20 per cent from Esso Norge a.s. The distribution in the production licence after this is as follows:

Den norske stats oljeselskap a.s	50.0000 %
Mobil Development Norway A/S	25.0000 %
Enterprise Norge A/S	20.0000 %
Esso Norge a.s	5.0000 %

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

Den norske stats oljeselskap a.s and Enterprise Oil Norwegian A/S have taken over 7.5 per cent each from Petrobras Norge A/S. Furthermore, Total has taken over 15 per cent from A/S Norske Shell. The distribution in the production licence after this is as follows:

Den norske stats oljeselskap a.s	57.5000 %
Enterprise Norge A/S	27.5000 %
Total Norge A/S	15.0000 %

Production licence 147
Operator: A/S Norske Shell

A/S Norske Shell has taken over 15 per cent from Total Norge A/S. The distribution in the production licence after this is as follows:

A/S Norske Shell	50.0000 %
Den norske stats oljeselskap a.s	50.0000 %

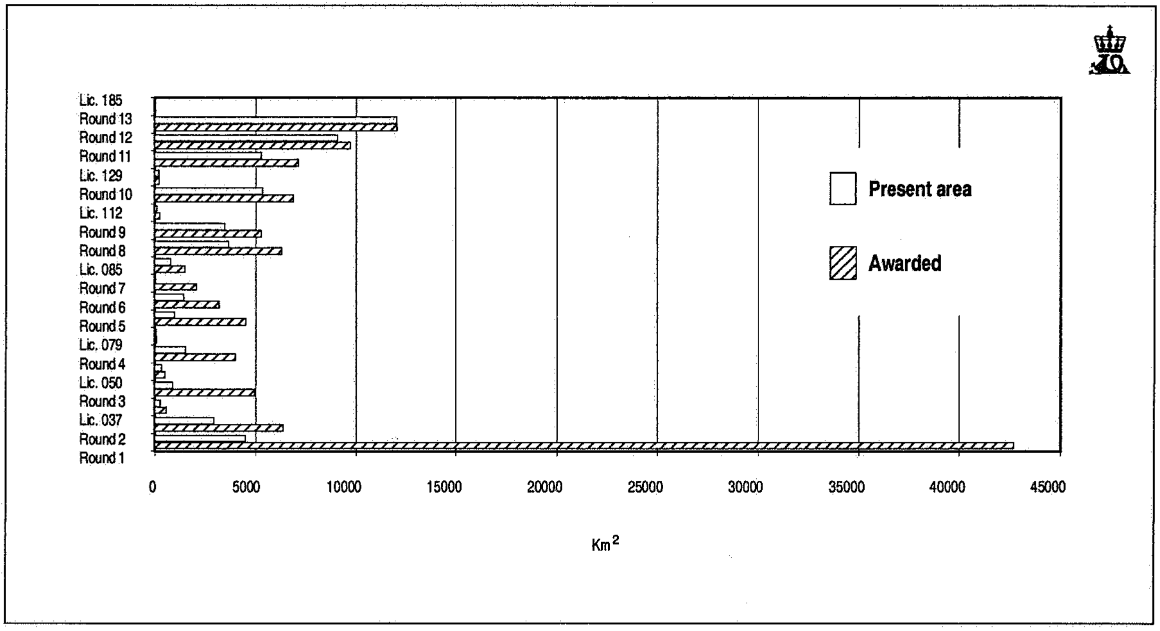
2.1.5 Relinquishments and surrenders

Relinquishment or surrender of acreage occurred in 17 production licences in 1991. In seven cases the entire area was relinquished. See Table 2.1.5 for details. The originally allocated and present acreages are shown in Figure 2.1.5.

Table 2.1.5
Relinquishments

Prod. lic.	Operator	Block	Original area km^2	Relinquished area km^2	Area in license km^2
017	Phillips	8/8, 8/10 and 8/11	1682.634	1682.634	0.000
043	Total	29/6 and 30/4	604.558	555.553	49.005
062	Saga	6507/11	436.310	367.762	68.548
087	Hydro	16/4	539.346	273.231	266.115
098	Esso	7120/10	335.884	335.884	0.000
103	Conoco	25/7	527.805	263.829	263.976
105	Statoil	6406/6	444.465	444.465	0.000
106	Statoil	6407/4	444.465	239.991	204.474
107	Hydro	6407/7	448.529	227.011	221.518
110	Statoil	7120/5 and 7121/5	654.644	444.642	210.002
111	Esso	7121/1	323.030	171.748	151.282
112	Elf	25/2	260.215	129.958	130.257
115	Total	9/3	550.790	376.048	174.742
118	BP	26/4	523.937	523.937	0.000
119	Total	29/3	170.273	170.273	0.000
141	Hydro	7321/8 and 7321/9	594.294	594.294	0.000
162	Statoil	7324/10 and 7324/11	602.952	602.952	0.000

Fig. 2.1.5
Allocated and present areas in each licensing round



2.2 SURVEYING AND EXPLORATION DRILLING

2.2.1 Geophysical and geological surveys

Some 329,369 kilometres of seismics were shot on the Norwegian continental shelf in 1991. This means there was a marked increase in seismic activity last year. The bulk of the increase is due to the greater volume of 3D seismics. The number of kilometres refers to the total "line kilometres". Using several sources and cables on the same vessel enables one to shoot many line kilometres simultaneously. The new seismic vessels often have several cables, and by using for example two sources it is possible to shoot six to eight lines at the same time. It is also possible to shoot several lines by using two vessels. Figure 2.2.1.a shows the development in recent years with respect to the number of "vessel kilometres".

2.2.1.1 Directorate's geophysical surveys

The Directorate commissioned 6614 vessel kilometres of seismic lines in 1991, see Figure 2.2.1.b. Data were collected from the areas indicated in Figures 2.2.1.c, d and e.

North Sea

A total of 270 km of test lines were surveyed in two areas; quadrants 24 and 30. The data were compiled using the new vessel *Geco Sapphire*, employing different configurations for sources and receivers.

In the southern area a large source and two 4500 m long cables were used, towed at 100 m horizontal separation.

In the northern area, a spread of three cables 3000 m in length with 100 m horizontal separation and two sources 75 m apart was used. One line was reshot using a large source.

The data will be processed by HGS in Stavanger, and the Directorate is planning to make the processed data available to the industry.

Mid-Norway

Some 2731 km of deep, regional lines were shot in the southern part of the Vøring basin and in the Møre basin. The data were compiled using the *Master Odin* vessel (ex *Skandi Pioneer*). The seismic method employed utilised sleeve guns, the data duration being ten seconds due to the great water depth and thickness of the sediment in the area. The data are being processed by Ensign and Digicon.

Barents Sea

Some 3613 km of seismics were shot in the northern Barents Sea using *Master Odin*. Most of the data were collected in the areas Storbanken (771 km), Spitsbergenbanken (1736 km), and Nordflaket (1107 km). The data are being processed by CGG, Geco-Prakla, and Spectrum.

Processing

The Directorate has concluded the processing of the data compiled in the course of 1991. Some reconditioning of older data has also been performed. The northern part of the Barents Sea offers great challenges in this connection so that there will be a need for further reconditioning efforts in this area in the next few years. In the course of 1991 the Directorate has conducted test processing, giving interesting results with selected contractors.

Fig. 2.2.1.a
Seismic surveys on the Norwegian continental shelf 1962–1991

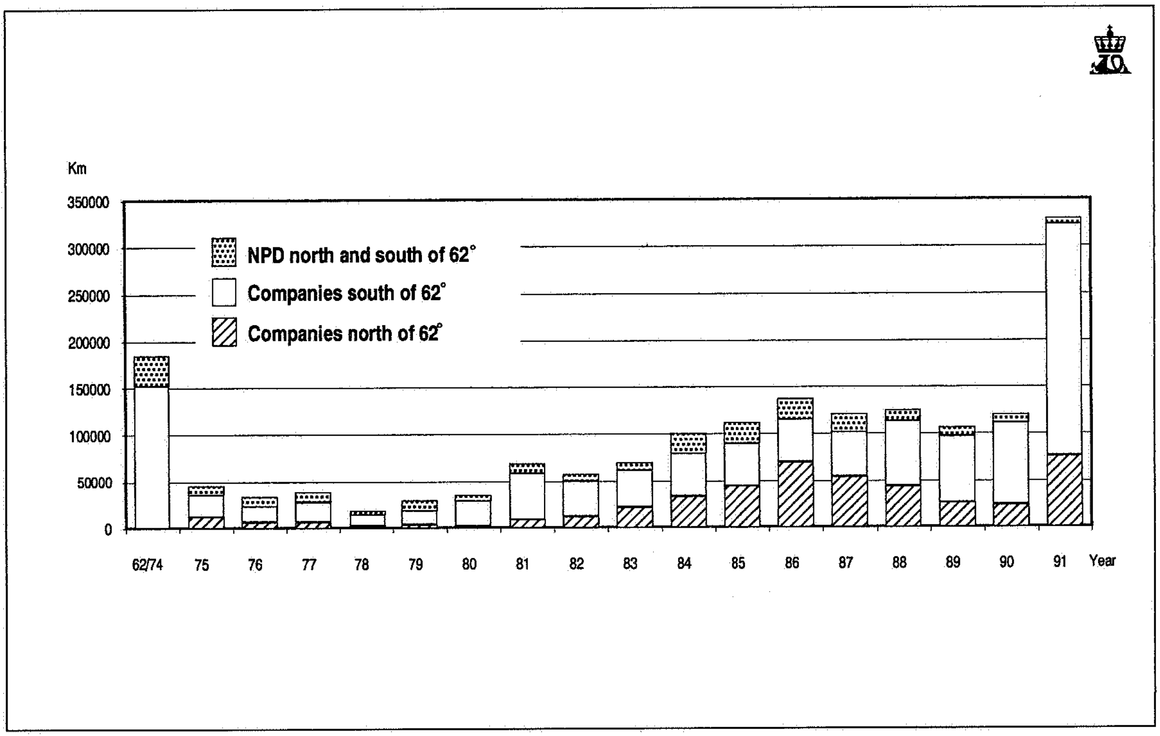


Fig. 2.2.1.b
Seismic surveys conducted by the Norwegian Petroleum Directorate

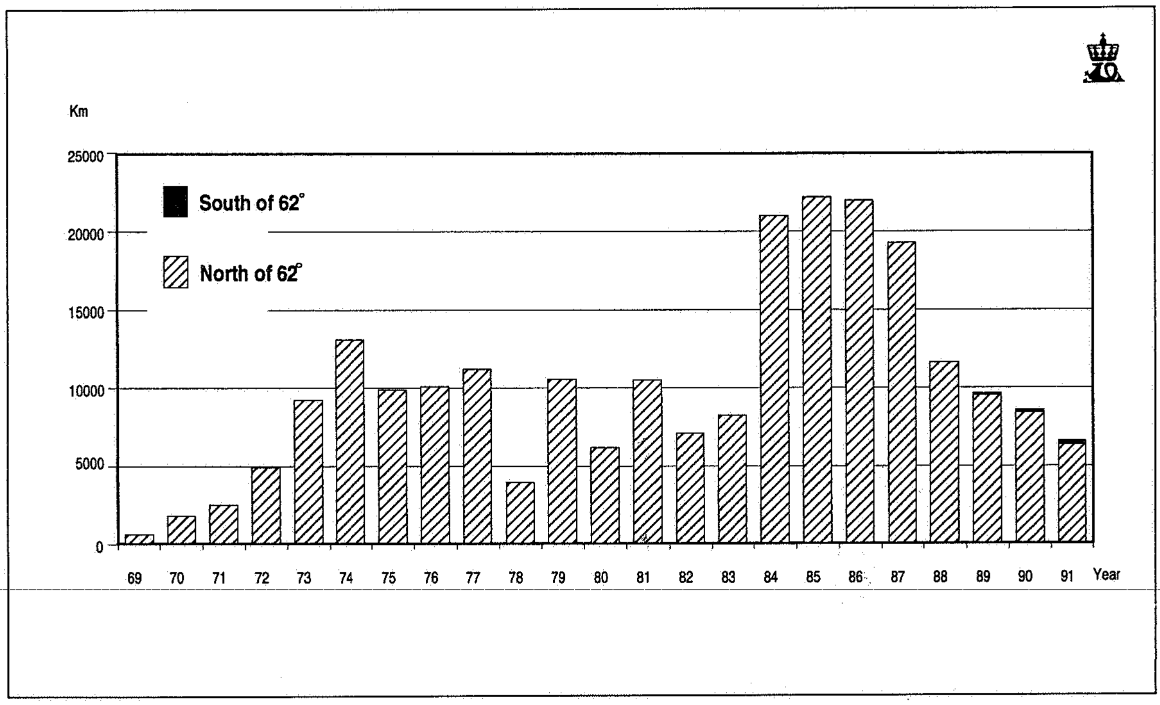


Fig. 2.2.1.c
Seismic surveys in the North Sea

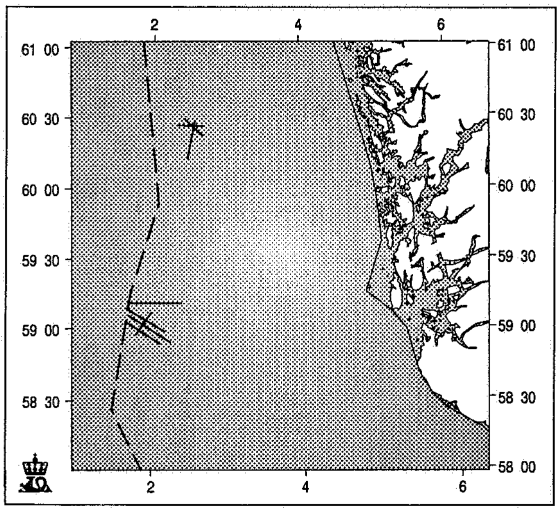


Fig. 2.2.1.d
Seismic surveys off Mid-Norway

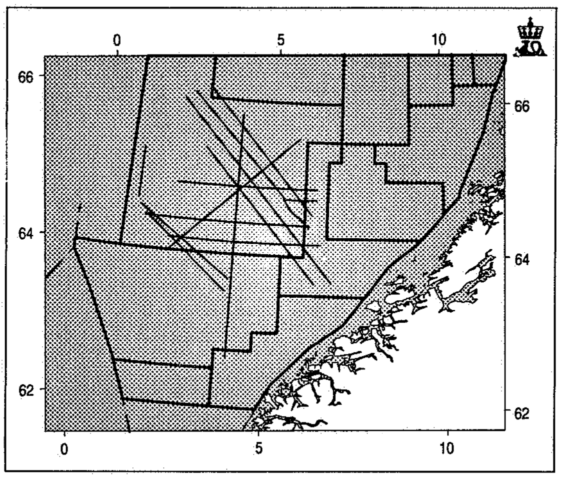
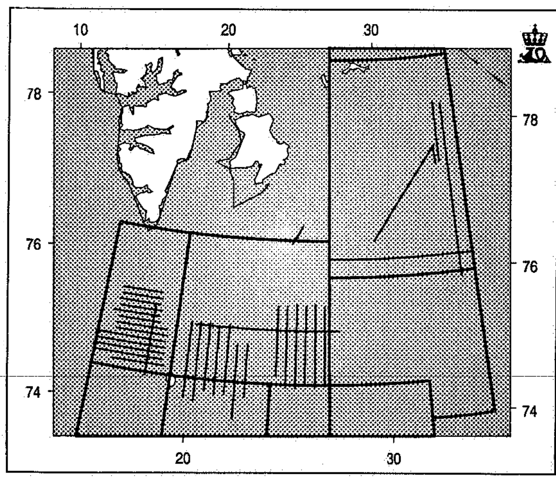


Fig. 2.2.1.e
Seismic surveys in the northern Barents Sea



In addition, the Directorate has upgraded its own processing software and hardware. We are now using interactive software from Seres and Geco-Prakla on workstations.

2.2.1.2 Opening of new exploration areas

The northern part of the Vøring basin has been prepared to be opened up for seismic surveys from 1 January 1992, see Figure 2.2.1.2.

The Directorate is planning to complete the compilation of seismic data off Mid-Norway in the course of 1992.

2.2.1.3 Companies' geophysical surveys

In 1991, some 322,755 km of seismics were shot on the Norwegian continental shelf under the direction of the oil companies and seismic survey operators. Of the total, 257,370 km are three-dimensional surveys. All told, some 247,025 km were taken from the North Sea and 75,730 km off Mid-Norway and in the Barents Sea. As the figures show, the activity level increased by 159,825 km compared to 1990. The activity off Mid-Norway and in the Barents Sea increased by 52,130 km compared to 1990.

This shows that the activity level in 1991 was almost three times as great as in 1990.

Norwegian oil companies shot some 107,702 km of seismics, which is an increase of 80,037 km from the year before. Foreign companies shot 161,393 km, or 90,393 more than in 1990.

A total of 52,839 km of commercial seismics were shot by Geco, Geoteam, HGS, and Nopec, which is an increase of 40,739 km compared to the previous year.

2.2.1.4 Sale of seismic data

In 1991, the Directorate recorded income from the sale of seismic data packages amounting to Nkr 50.6 million (compare Nkr 57.3 million in 1990). See Table 2.2.1.4.

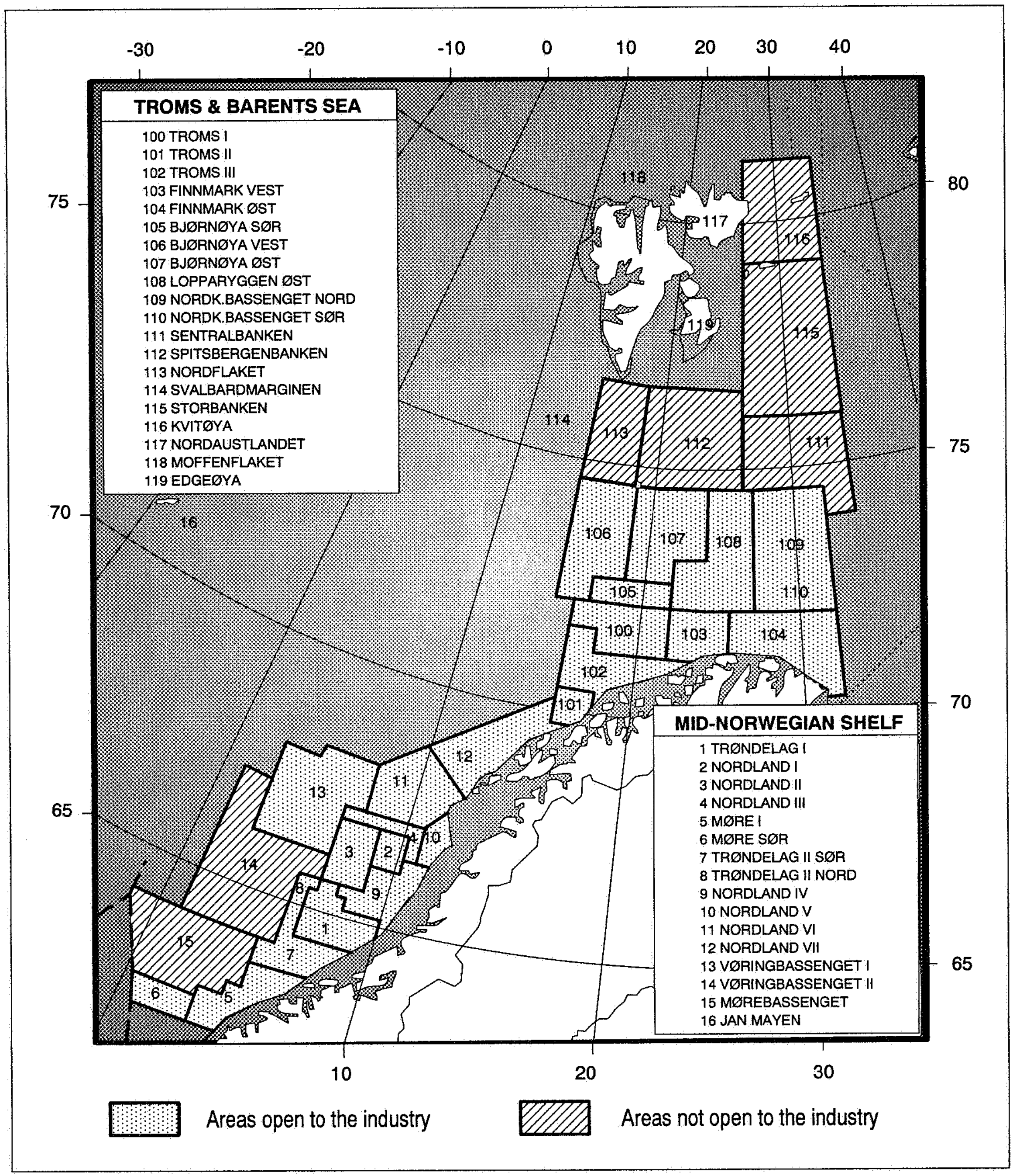
Companies having purchased all of the Directorate's seismic data packages for the individual regions are listed below:

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

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

Trøndelag I
Agip, Amerada, Amoco, BP, Britoil, Conoco, Deminex, DNO, Elf, Enterprise, Esso, Fina, Hydro,

Fig. 2.2.1.2
Area status for seismic acquisition offshore Mid-Norway and in the Barents Sea



Idemitsu, Mobil, Neste, Occidental, Pelican, Petrobras, Phillips, Saga, Shell, Statoil, Svenska Petroleum, Tenneco, Total, and Unocal.

Trøndelag II, north of 64°15′
Agip, Amoco, BP, Britoil, Conoco, Deminex, DNO, Elf, Enterprise, Esso, Fina, Hydro, Mobil, Neste, Petrobras, Phillips, Saga, Shell, Statoil, Svenska Petroleum, Tenneco, and Total.

Trøndelag II, south of 64°15′
Agip, Amerada, Amoco, BP, Britoil, Conoco, Deminex, DNO, Elf, Enterprise, Esso, Fina, Hydro, Idemitsu, Mobil, Neste, Occidental, Pelican, Petrobras, Phillips, Saga, Shell, Statoil, Svenska Petroleum, Tenneco, Total, and Unocal.

Vøring Basin I
Phillips and Statoil.

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

Nordland II
Agip, Amerada, BP, Britoil, Conoco, Elf, Enterprise, Esso, Fina, Hydro, Mobil, Neste, Phillips, Saga, Shell, Statoil, Svenska Petroleum, 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
BP, Conoco, Elf, Hydro, Mobil, Saga, Shell, Statoil, and Total.

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

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

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

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

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

Bjørnøya Sør
Agip, Amerada, Amoco, BP, Britoil, Conoco, Deminex, Elf, Enterprise, Esso, Fina, Hydro, Mobil, Neste, Phillips, Saga, Shell, Statoil, Svenska Petroleum, Tenneco, and Total.

Bjørnøya Vest
Amoco, Conoco, Deminex, Elf, Enterprise, Hydro, Mobil, Saga, Shell, Statoil, and Total.

Bjørnøya Øst
Agip, Amoco, BP, Conoco, Deminex, Elf, Enterprise, Esso, Fina, Hydro, Mobil, Neste, Saga, Shell, Statoil, Tenneco, and Total.

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

Nordkapp Basin, north of 73°15′
Agip, Amoco, BP, Conoco, Elf, Enterprise, Esso, Hydro, Mobil, Neste, Saga, Shell, Statoil, and Total.

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

Table 2.2.1.4
Survey of sold seismic data packages

Package		1991	Total
001	MØRE-TRØNDELAG-REGIONAL-PK-1	1	34
002	MØRE-TRØNDELAG-REGIONAL-PK-2	1	27
003	TAMPEN-SPUR	1	22
004	MØRE-SØR-84	1	22
005	TRØNDELAG-REGIONAL		25
006	HALTENBANKEN-VEST-84		23
007	FRØYABANKEN-84	1	27
008	MØRE-TRØNDELAG-PAKKE-2 #)		22
009	MØRE-TRØNDELAG-PAKKE-3 #)		28
010	TRÆNABANKEN		30
011	REG-DATA-NORDLAND-RYGGEN	1	21
012	NORDLAND-IV-85		9

Package		1991	Total
013	REG-DATA-MIDT-N-SOKKEL	1	20
014	NORDLAND-II-83	1	22
015	NORDLAND-III-84		13
016	TROMS-II		12
017	REGIONAL-DATA-TROMS-ØST		18
018	FINNMARK-VEST-83		19
019	FINNMARK-VEST-84		20
020	NORDLAND-III-85		13
021	MØRE-SØR-TEST-84 #)		5
022	STOREGGA-85		5
023	VØRINGPLATÅET	1	11
024	VØRING-BASSENGET-85/86	1	9
025	LOFOTEN-VEST-86		10
026	JAN-MAYEN-85		1
027	JAN-MAYEN-79/85		0
028	VØRING-BASSENGET-87	2	9
029	NORDLAND-VI-87	1	11
030	NORDLAND-VII-87	1	11
031	NORDLAND-V-87	1	9
032	NORDLAND-VI-88	1	10
033	NORDLAND-VII-88	2	11
034	NORDLAND-V-73–79	2	9
035	NORDLAND-VI-73–79		11
036	NORDLAND-VI-89	1	10
037	NORDLAND-VII-89	1	10
038	NORDLAND-VII-74/75	1	10
039	NORDSJØEN-SØR-TEST-89 #)		1
040	VØRING-BASSENGET-88	2	7
041	VØRING-BASSENGET-MERLIN-89	2	7
042	VØRING-BASSENGET-WESTERN-89	2	7
043	MØRE-BASSENGET-88	1	4
044	TYPEPROFILER-BARENTSHAVET #)	2	2
045	VØRINGBASSENGET-I-90	2	2
046	STOREGGA-90	1	1
100	TROMS-HOVEDPAKKE	1	35
101	REG-DATA-TROMS-BAR.HAVET-73	1	21
102	TROMS-III-83/84	3	17
103	TROMS-III-85	4	17
105	TROMS-I-ØST-77		20
106	TROMS-NORD-82-PAKKE-1		24
107	TROMS-NORD-83-PAKKE-3		23
108	TROMS-NORD-82-PAKKE-2	1	17
109	TROMS-NORD-83-PAKKE-4	1	17
200	BJØRNØYA-PAKKE-1		21
201	BJØRNØYA-SØR-84		21
202	BJØRNØYA-ØST-REGIONAL-84		18
203	BJØRNØYA-ØST-84		17
204	BJØRNØYA-TILLEGG-NORD		17
205	BJØRNØYA-VEST-REGIONAL-84		15
206	LOPPARYGGEN-ØST-REGIONAL-84		19
207	LOPPARYGGEN-ØST-85-SSL-DIAG		19
208	LOPPARYGGEN-ØST-85-NORD		19
209	LOPPARYGGEN-ØST-85-GECO-DIAG		19
210	LOPPARYGGEN-ØST-85-GRID		19
211	BJØRNØYA-ØST-TEST-85 #)		1
212	BJØRNØYA-VEST-86-DIAG		13
213	BJØRNØYA-VEST-86-HIGH		13
214	BJØRNØYA-VEST-86-MARGIN		12
215	BJØRNØYA-VEST-86-SWATH #)		1
216	BJØRNØYA-VEST-87		13
300	BARENTSHAVET-SØR-ØST-HOVEDPK		22
301	BARENTSHAVET-SØR-ØST-PAKKE-2		21
302	NORDKAPP-BASS-85-GECO-DIAG		20
303	NORDKAPP-BASSENGET-85-NORD		20
304	NORDKAPP-BASSENGET-85-GRID		21
305	NORDKAPP-BASSENGET-86-DIAG		20
306	NORDKAPP-BASSENGET-86-SØR		21
307	NORDKAPP-BASSENGET-86-NORD		14
308	FINNMARK-ØST-86-REGIONAL		19
309	FINNMARK-ØST-86-DIAG		18
310	FINNMARK-ØST-86-GSI		19
312	NORDKAPP-TEST-87 #)		1

2.2.1.5 Release of data and material from the continental shelf

In connection with resources supervision of the petroleum activities offshore Norway, the Directorate is supplied with copies of well bore logs and representative selections of drill cuttings and cores.

Cuttings samples are recovered every 10 metres downhole and every three metres 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 1991 the Directorate had stocks totalling 70,452 metres of core material from 779 wells, 351,757 samples of washed cuttings from 930 wells, and 387,084 wet samples from 1104 wells. This includes production wells and material from 86 foreign bores, mainly from the UK sector of the North Sea, but also including Svalbard, Andøya, Hopen, Tanzania, and Mozambique.

The Directorate is responsible for the publishing of data and release of material specimens for purposes of education and research. The licensees' interpretations are not released.

The Directorate'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 exploration wells have been released and what core and log materials are available from the various exploration wells. Some technical data and test results are also issued as well as a composite log with lithology specifications of each exploration well to scale 1:4000.

In addition to its WDSS summaries, the Directorate issues two publication series: *Licences, Areas, Area Coordinates, Exploration Wells* and *Borehole List, Exploration Drilling*, which also provides information on released material. 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 acreage, present acreage, partners and units, geographical coordinates for area, some data about wells drilled in the production 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 well bore list is an extended version of the Directorate's previous well bore list. Exploration wells are sorted according to five different criteria: well number, spudding date, completion date, operator, and production licence number.

In the Directorate's core study room it is possible to examine the core materials, drill cuttings and wet samples, and in special cases permission may be granted to be issued sediment samples and oil samples in order to study and analyse them outside the confines of the Directorate.

Figure 2.2.1.5 shows the demand for specimens broken down by discipline: organic geo-chemistry; biostratigraphy; sedimentology and petrophysics.

In 1991, the routines for release of geological samples were amended in connection with applications for such release. Applications for release of material are now considered three times a year, with application deadlines on 1 April, 1 August, and 1 December.

Fig. 2.2.1.5
Applications for sample material by subject

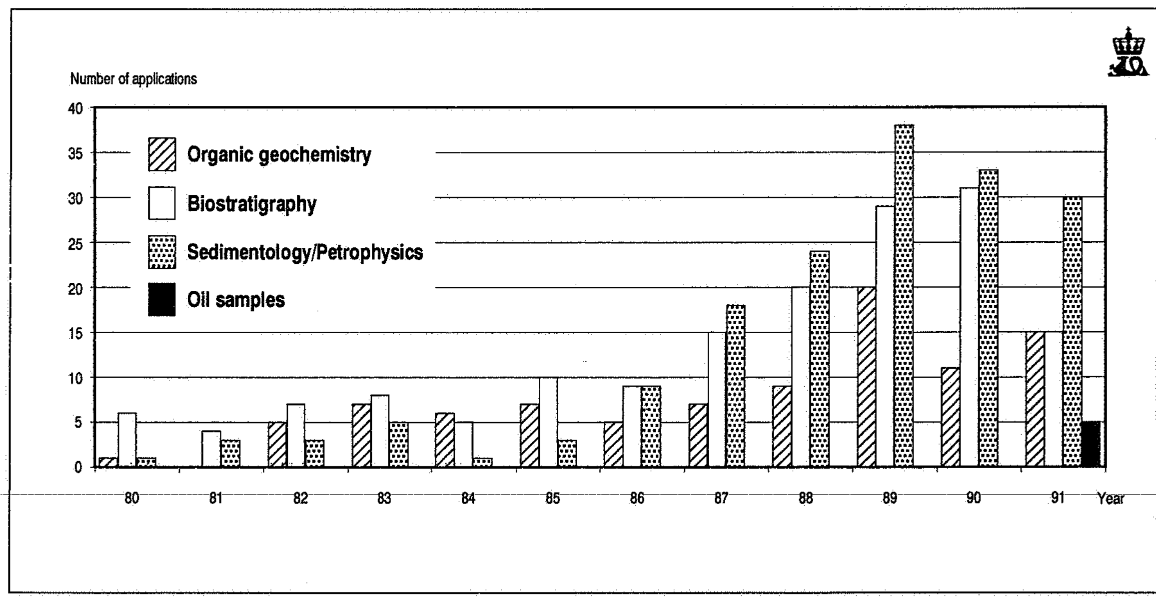


Table 2.2.1.5
Released seismic data

No	Package name	Lenght (km)	Area	No	Package name	Length (km)	Area
A 1	NH-8007	231,328	0007/11	A 51	ST-8111	347,830	30/6 & 9
A 2	SG-8048	689,619	7/11	A 52	G-8101	848,026	35/8 & 9
A 3	NH-8302	350,404	0007/11	A 53	BP81–043	1375,896	29/6&30/4
A 4	NHCN-82	1400,587	0007/08,11	A 54	NH-8502–3D	22431,769	0030/09
A 5	SH-82	872,699	0002/05	A 55	NS-79	3710,355	SYD 62
A 6	SG-8052	541,722	0002/02	A 56	NS-78	4638,521	SYD 62
A 7	BP80–019	985,315	2/1 & 7/12	A 57	PGE-82	700,213	0002/07,10
A 8	EL-8180	1023,510	2/6 & 2/9	A 58	NH-8201	1103,320	0002/08,11
A 9	ST-501	696,000	0033/02	A 59	PGO-2/10–77	204,562	0002/10
A 10	ST-502	1182,771	0033/03	A 60	ANO-78–2	1540,000	2/6,8,93/4
A 11	ST-503	1307,000	0033/05,06	A 61	ANO-78–3	363,927	VALHAL/HOD
A 12	NH-754	174,000	0033/05	A 62	ANO-79–1	90,834	0002/05
A 13	NAG-80	498,000	0033/06	A 63	PGE-80	716,189	2/4 & 7
A 14	ANO-77	195,921	0034/02	A 64	PSL-84–2	235,360	0002/07
A 15	ANO-77–1	357,787	30/ &31/4	A 65	ANO-83	393,692	VALHALL
A 16	ANO-77–2	9,000	0024/06	A 66	ST-8421	592,346	2/9,12
A 17	ANO-79	923,155	0034/02	A 67	NS-76	3569,609	SYD 62
A 18	ANO-80	72,566	0034/02	A 68	ANO-80–1	199,091	0002/05,08
A 19	SA-530	1229,439	0035/3	A 70	ST-404	454,590	0001/09
A 20	SAG-78	186,660	35/3	A 71	EL-8201	592,000	0003/07
A 21	SG-8130	783,153	BL:35/3	A 72	SH-72	83,507	0001/09
A 22	GULF-79–2	1000,323	35/8&9	A 73	EL-8186	1743,788	0001/03
A 23	GULF-80–1	1396,503	35/8	A 74	PG-2/7–73	115,142	0002/07
A 24	ANO-74	1515,589	0036/01	A 75	EL-8Ø83	124,002	3/7
A 25	SG-8252	1115,433	2/2,3	A 76	GULF-79	420,961	0002/02,03
A 26	PSL-84–1	562,258	0008/10	A 77	ST-809	28,406	1/9 & 2/7
A 27	ST-8007	395,000	0031/	A 78	PGE-80-GE	25,995	0002/04
A 27	SH-8007	2495,000	31 & 32	A 79	ST-8013–81	121,976	0001/09
A 28	TO-8513	25,287	0029/03	A 80	CSSC-78–2	62,829	0002/2,03
A 29	TO-8510	261,665	0029/03	A 81	ANO-78–1	793,394	0002/02,05
A 30	SG-85	27,474	0034/04	A 82	EL-980	356,736	0002/06
A 31	NH-8504	421,850	0030/06	A 83	PSL-84–3	440,268	0002/04
A 32	MN-85	587,980	0035/11	A 84	EL-686	207,568	0002/06
A 33	NH-8502	1269,787	0030/09	A 85	PG-2/4–73	101,000	0002/04
A 34	NH-8503	24,073	29/3&33/12	A 86	ANO-76	251,148	0002/04,05
A 35	NH-8202	2072,594	31 & 32	A 87	ST-601	110,379	0001/05
A 36	SG-8127	813,636	35/36	A 88	N2–70	226,399	0002/01
A 37	SG-8133	350,377	34/11	A 89	SH-79–1	598,979	0001/3,2/1
A 38	SG-8425	275,184	0031/02,3	A 90	PGE-79	120,029	BL:2/4,5
A 39	NH-8104	1921,288	32,34–36	A 91	A-79	344,734	1/6 & 2/4
A 40	ST-8109	1318,896	35,36	A 92	ANO-80–2	117,580	0003/04
A 41	81–007	339,599	0031	A 93	SH-74–1	437,325	0001/
A 42	EL-8307	2372,612	34/8	A 94	EL-8186–82	158,842	0001/03
A 43	ST-8006	1948,741	0030/2,3,6	B 1	SH-84	1238,985	6407/9
A 44	BP-85	423,043	0016/08	B 2	CN-8502	1002,000	HALTENBANKEN
A 45	ST-8116	2194,671	31 &32	B 3	SSL-7172	3274,995	56–58 DEG
A 46	G-81	519,484	35/8&9	B 4	BP-83	923,962	HALTENBANKEN
A 47	GU-82	681,716	35/8	B 5	SG-8158	236,813	6507/11,12
A 48	GU-81	376,311	35/8	B 6	SG-8258	436,561	6507/11&12
A 49	ST-8313	276,587	BL:34/10	B 7	SG-8271	638,185	6407/2
A 50	ST-811	368,311	0030/02,03	B 8	ST-8110	280,384	TRØND WEST
				B 9	ST-8306	325,840	HALTENBANKEN

In 1991 the Directorate released a total of 100,518 line kilometres of seismics in 103 data packages. The released seismics included 94 packages south of 62°N and nine packages off Mid-Norway.

Table 2.2.1.5 gives a summary of seismic data released.

2.2.2 Exploration drilling

Of the nine exploration wells being drilled at year end 1990, five were terminated, one was abandoned and three were suspended in 1991.

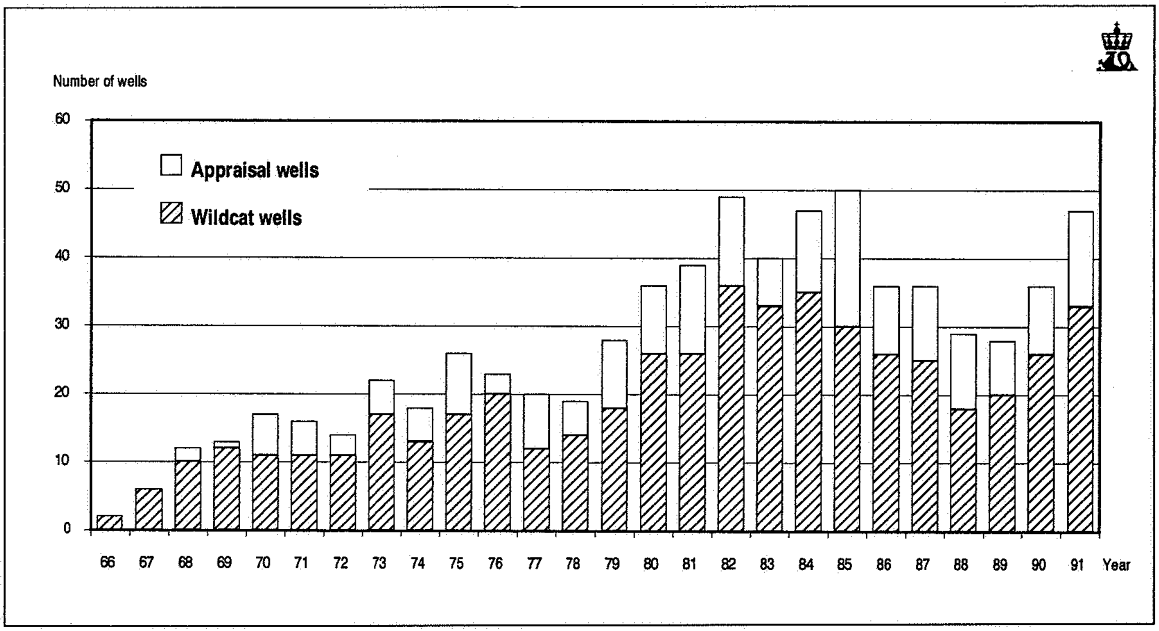
In 1991, 47 new exploration wells were spudded, of which 34 were wildcats and 13 appraisal wells. Drilling activity in 1991 comprised 36 exploration wells in the North Sea, eight offshore Mid-Norway, and three in the Barents Sea. In addition to the 47 exploration wells spudded, ten suspended exploration wells were reopened in the course of 1991. Of these 57 exploration wells, 32 had been terminated, 13 suspended, and 12 were still being drilled at 31 December 1991. All told by the same date, 709 exploration wells had been spudded in the Norwegian sector, of which 509 were wildcats and 200 appraisal wells. See Figure 2.2.2.a. Table 2.2.2 summarises the exploration wells spudded and/or terminated in 1991. In all, 40 exploration wells had been tempo-

Table 2.2.2
Spudded and terminated exploration wells in 1991
R = reentry, X = prospective depth not reached, S = deviated

Exploraiton well	Lic. no. Prod. lic. no.	Position north east	Drilling Spudded Terminated	Operator Drill rig	Well type Completion classification	Water depth (in metres) KBE in metres	Total depth (in metres) Geol period
2/08–14 X	647	56 15 48.93	90.08.14	Amoco	Wildcat	67	4392
	006	03 21 23.11	91.01.22	West Vanguard	Suspended	22	
6406/11–01 S	651	64 02 46.02	90.10.19	Saga	Wildcat	315	4185
	156	06 36 14.16	91.02.22	Treasure Saga	Dry hole	25	L.Trias
15/12–07 S	655	58 00 49.93	90.11.06	Statoil	Wildcat	85	3529
	116	01 58 35.54	91.01.07	Deepsea Bergen	Dry hole	23	Trias
2/07–24	653	56 18 33.00	90.11.07	Phillips	Wildcat	71	4985
	018	03 19 23.56	91.04.13	Ross Isle	Dry hole	22	U.Jura
2/07–25 S	657	56 19 59.69	90.11.29	Phillips	Appraisal	68	5177
	018	03 14 53.90	91.03.31	West Delta	Suspended. Dry hole	29	
34/08–04 S	659	61 19 29.58	90.12.06	Hydro	Wildcat	310	4150
	120	02 25 18.67	91.06.09	Mærsk Jutlander	Suspended	23	
6406/12–01 S	662	64 04 11.14	90.12.15	Statoil	Wildcat	330	3965
	157	06 43 56.91	91.02.28	Ross Rig	Dry hole	23	M.Jura
6407/07–05	660	64 18 24.34	90.12.17	Hydro	Appraisal	327	3724
	107	07 10 50.58	91.02.15	Transocean 8	Hydrocarbons	24	L.Jura
25/05–04	661	59 36 33.22	90.12.22	Elf	Wildcat	120	3185
	102	02 28 32.07	91.03.07	Dyvi Stena	Susp. Gas/Condensate	25	L.Jura
35/09–02	663	61 20 08.69	91.01.01	Hydro	Wildcat	367	2885
	153	03 56 16.59	91.04.03	Vildkat Explorer	Gas/Condensate	25	Bedrock
6201/11–02	664	62 01 07.62	91.01.12	Statoil	Wildcat	373	3778
	130	01 25 16.78	91.03.11	Deepsea Bergen	Dry hole	23	Trias
25/02–14	666	59 45 53.52	91.01.25	Elf	Appraisal	117	3623
	026	02 35 23.04	91.03.30	West Vanguard	Dry hole	22	L.Jura
7120/02–02	665	71 50 24.00	91.01.27	Hydro	Wildcat	337	2800
	109	20 36 03.60	91.03.23	Polar Pioneer	Hydrocarbons	23	M.Jura
34/08–05	667	61 19 29.94	91.02.18	Hydro	Appraisal	296	3540
	120	02 20 57.94	91.04.01	Transocean 8	Hydrocarbons	24	Trias
34/07–17	668	61 20 50.69	91.02.25	Saga	Appraisal	259	3115
	089	02 05 42.31	91.04.07	Treasure Saga	Dry hole	26	Trias
6507/08–05	670	65 20 36.75	91.03.02	Statoil	Wildcat	332	2000
	124	07 38 04.70	91.03.16	Ross Rig	Dry hole	23	Jura
1/03–06	669	56 56 14.92	91.03.11	Elf	Wildcat	72	3586
	065	02 42 20.81	91.06.22	Dyvi Stena	Gas/Condensate	25	Cret.
2/07–26 S	674	56 19 59.60	91.03.30	Phillips	Appraisal	70	4849
	018	03 14 53.73	91.09.13	West Delta	Suspended	29	
2/11–08	673	56 08 08.60	91.04.03	Hydro	Wildcat	66	4584
	068	03 20 46.64	91.07.11	Polar Pioneer	Dry hole	23	Prejura
25/01–08 S4R	466	59 54 03.29	91.04.03	Elf	Wildcat	102	2650
	024	02 06 09.80	91.04.14	West Vanguard	Gas	25	Paleocen
1/09–06 SR	318	56 29 03.85	91.04.06	Statoil	Appraisal	75	3880
	044	02 56 00.14	91.04.20	Ross Rig	Gas/Condensate	25	U.Cret.
30/09–12	671	60 25 57.09	91.04.07	Hydro	Appraisal	104	2994
	104	02 51 34.90	91.05.09	Vildkat Explorer	Oil	25	L.Jura
34/07–17 A	677	61 20 50.69	91.04.07	Saga	Appraisal	259	2650
	089	02 05 42.31	91.05.04	Treasure Saga	Oil/gas	26	M.Jura
34/10–34	672	61 13 04.19	91.04.10	Statoil	Wildcat	139	2410
	050	02 08 04.69	91.05.31	Deepsea Bergen	Oil/gas	23	L.Jura
2/01–09	676	56 51 37.77	91.04.15	BP	Appraisal	66	4289
	019	03 05 04.77	91.07.06	Ross Isle	Susp. Oil/gas	23	Perm
25/04–06 S	678	59 42 35.43	91.04.15	Elf	Wildcat	114	4170
	036	02 19 04.45	91.08.24	West Vanguard	Susp. Oil/gas	22	
24/09–04	675	59 23 21.95	91.04.17	Fina	Wildcat	119	2208
	150	01 47 20.29	91.06.17	Byford Dolphin	Traces of oil	25	Tert.
1/09–04 R	182	56 29 03.76	91.04.21	Statoil	Wildcat	75	3710
	044	02 56 00.29	91.04.26	Ross Rig	Gas/Condensate	25	Perm
6507/06–02	679	65 44 26.42	91.04.27	Saga	Wildcat	315	4354
	123	07 41 06.55	91.07.16	West Alpha	Oil	18	U.Trias
15/09–17 R	356	58 26 44.19	91.04.28	Statoil	Wildcat	86	3120
	046	01 56 53.58	91.05.04	Ross Rig	Gas/Condensate	25	Trias
2/04–16	680	56 40 37.23	91.05.07	Saga	Wildcat	68	4996
	146	03 09 02.07	91.11.04	Treasure Saga	Suspended	26	
6506/11–02	681	65 03 25.32	91.05.08	Statoil	Wildcat	296	4810
	134	06 37 22.39	91.10.26	Ross Rig	Oil/gas	23	L.Jura
30/09–12 A	683	60 25 57.09	91.05.09	Hydro	Appraisal	104	2927
	104	02 51 34.90	91.06.04	Vildkat Explorer	Suspended.Oil	25	L.Jura

Exploraiton well	Lic. no. Prod. lic. no.	Position north east	Drilling Spudded Terminated	Operator Drill rig	Well type Completion classification	Water depth (in metres) KBE in metres	Total depth (in metres) Geol period
15/12–08	684	58 03 01.85	91.06.05	Statoil	Wildcat	87	3053
	038	01 58 03.41	91.07.14	Deepsea Bergen	Gas/Condensate	23	Trias
15/05–04	682	58 38 28.40	91.06.06	Hydro	Appraisal	112	2300
	048	01 33 08.87	91.07.03	Vildkat Explorer	Traces of oil	25	U.Paleocen
16/10–02	685	58 08 26.58	91.06.20	Agip	Wildcat	79	3150
	101	02 02 14.91	91.08.01	Byford Dolphin	Dry hole	25	Trias
31/02–16 SR	622	60 46 00.00	91.06.26	Hydro	Appraisal	354	2390
	054	03 25 27.55	91.07.08	Transocean 8	Suspended	25	U.Jura
35/11–05	687	61 05 45.58	91.06.27	Mobil	Wildcat	355	3769
	090	03 23 53.49	91.11.03	Sovereign Explorer	Hydrocarbons	25	L.Jura
30/09–13 S	688	60 21 37.69	91.07.05	Hydro	Wildcat	106	3964
	104	02 43 17.78	91.10.11	Vildkat Explorer	Susp. Oil/Gas	25	L.Jura
7/12–10	686	57 10 57.37	91.07.08	BP	Appraisal	71	3667
	019	02 48 18.47	91.08.29	Ross Isle	Dry hole	23	Trias
31/05–04 AR	656	60 43 16.19	91.07.09	Hydro	Appraisal	317	2605
	085	03 33 43.06	91.07.18	Transocean 8	Susp. Oil/Gas	25	U.Jura
15/12–08 A	691	58 03 01.85	91.07.14	Statoil	Wildcat	87	2940
	038	01 58 03.41	91.07.29	Deepsea Bergen	Gas/Condensate	23	Trias
34/07–18	690	61 19 10.75	91.07.20	Saga	Wildcat	243	2443
	089	02 06 40.26	91.09.17	West Alpha	Oil	18	L.Jura
2/04–17	689	56 41 02.60	91.07.21	Phillips	Wildcat	68	5258
	018	03 13 45.20	00.00.00	Mærsk Guardian		43	
6305/12–01	693	63 01 25.73	91.07.29	Hydro	Wildcat	176	4301
	154	05 47 23.94	91.09.21	Transocean 8	Dry hole	24	Bedrock
35/10–01	692	61 07 02.05	91.08.01	Statoil	Wildcat	362	3986
	173	03 13 34.87	00.00.00	Deepsea Bergen		23	
6607/05–02	694	66 41 03.38	91.08.07	Esso	Wildcat	523	4684
	126	07 21 22.52	91.11.17	Dyvi Stena	Dry hole	25	
7128/06–01	695	71 31 04.99	91.08.11	Conoco	Wildcat	336	2543
	181	28 49 03.41	91.11.08	Arcade Frontier	Dry hole	23	Pre-Devon
7/12–11	696	57 07 10.71	91.08.31	BP	Wildcat	67	3868
	164	02 58 33.19	91.11.06	Ross Isle	Dry hole	23	Trias
2/05–09	697	56 32 07.18	91.09.10	Amoco	Wildcat	69	
	006	03 33 13.06	00.00.00	West Vanguard		22	
2/07–21 SR	610	56 19 59.63	91.09.13	Phillips	Appraisal	71	5044
	018	03 14 53.75	91.10.14	West Delta	Susp. Oil	29	
34/08–06	699	61 25 31.00	91.09.21	Hydro	Wildcat	377	3950
	120	02 28 33.00	91.11.03	Transocean 8	Dry hole	23	Jura
34/07–19	698	61 23 38.96	91.09.23	Saga	Appraisal	286	2803
	089	02 05 31.46	91.12.26	West Alpha	Suspended	18	L.Jura
30/06–24 S	700	60 42 02.74	91.10.13	Hydro	Wildcat	144	3985
	170	02 41 34.28	91.12.07	Vildkat Explorer	Hydrocarbons	24	Trias
2/07–20 R	566	56 19 59.70	91.10.14	Phillips	Wildcat	71	4512
	018	03 12 53.86	91.11.01	West Delta	Suspended	22	Trias
6507/02–02	702	65 55 01.68	91.10.21	Hydro	Wildcat	369	
	122	07 30 54.56	00.00.00	Polar Pioneer		23	
6608/10–02	701	66 00 49.35	91.10.28	Statoil	Wildcat	374	3678
	128	08 04 26.48	00.00.00	Ross Rig	Oil/gas	23	
2/02–05	705	56 50 05.80	91.11.07	Saga	Wildcat	63	
	066	03 27 22.90	00.00.00	Treasure Saga		26	
2/01–10	703	56 57 53.61	91.11.09	BP	Wildcat	66	
	164	03 01 19.70	00.00.00	Ross Isle		23	
2/07–27 S	707	56 19 59.81	91.11.09	Phillips	Appraisal	71	
	018	03 14 53.77	00.00.00	West Delta		29	
25/11–15	704	59 11 03.50	91.11.10	Hydro	Wildcat	127	2035
	169	02 29 03.82	91.12.24	Transocean 8	Oil	24	L.Jura
7122/04–01	706	71 44 50.47	91.11.13	Esso	Wildcat	343	
	178	22 05 06.39	00.00.00	Arcade Frontier		25	
35/11–04 R	642	61 01 59.93	91.11.16	Mobil	Wildcat	355	3127
	090	03 32 53.58	00.00.00	Sovereign Explorer		25	L.Jura
25/11–14 SR	648	59 11 17.31	91.11.24	Esso	Appraisal	127	1908
	001	02 22 11.64	91.12.02	Dyvi Stena		25	Paleocen
3/07–05	708	56 28 47.00	91.12.06	Shell	Wildcat	67	
	147	04 18 17.60	00.00.00	Dyvi Stena		25	
31/2–17 S	709	60 52 57.08	91.12.28	Hydro	Appraisal	340	
	054	03 27 05.79	00.00.00	Transocean 8		24	

Fig. 2.2.2.a
Exploration drilling on the Norwegian continental shelf.
Number of wells per year 1966–1991



rarily 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:

2/02–09	25/04–06S	31/05–04AR
2/04–15S	25/05–04	34/04–07
2/04–16	30/02–01	34/07–19
2/07–20R	30/03–04	34/08–04S
2/07–21SR	30/06–16	34/10–05
2/07–23S	30/06–19	34/10–32R
2/07–25S	30/06–21	6407/07–03
2/07–26S	30/06–22	6407/07–04
2/12–02S	30/09–02R	6407/09–03
7/11–10SR	30/09–09	6407/09–05
15/09–17	30/09–10	6407/09–06
15/12–06S	30/09–12A	6506/12–08
25/02–09	30/09–13S	
25/02–13	31/02–16SR	

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

The Norwegian companies Saga, Norsk Hydro and Statoil operated 29 of the spudded wells as at 31 December 1991, corresponding to 61.7 per cent. The remaining 18 wells were operated by Elf, Conoco, BP, Phillips, Esso, Amoco, Mobil, Agip, Shell, and Fina. See Table 8.2.c for details.

2.2.2.1 Distribution of prospect types

Exploration activity in 1991 was very largely targeted at Jurassic sandstone prospects. Of the 47 exploration wells spudded, 40 had Jurassic strata as their main prospect. Of the other main prospects, three were in Tertiary, one in Cretaceous, one in Triassic, one in pre-Jurassic, and one in Permian strata. Of the secondary prospects, two were in Tertiary, two in Cretaceous, ten in Jurassic, three in Triassic, and one in Permian strata.

2.2.2.2 New discoveries in 1991

Of the exploration wells terminated in 1991 the following are classed as discoveries:

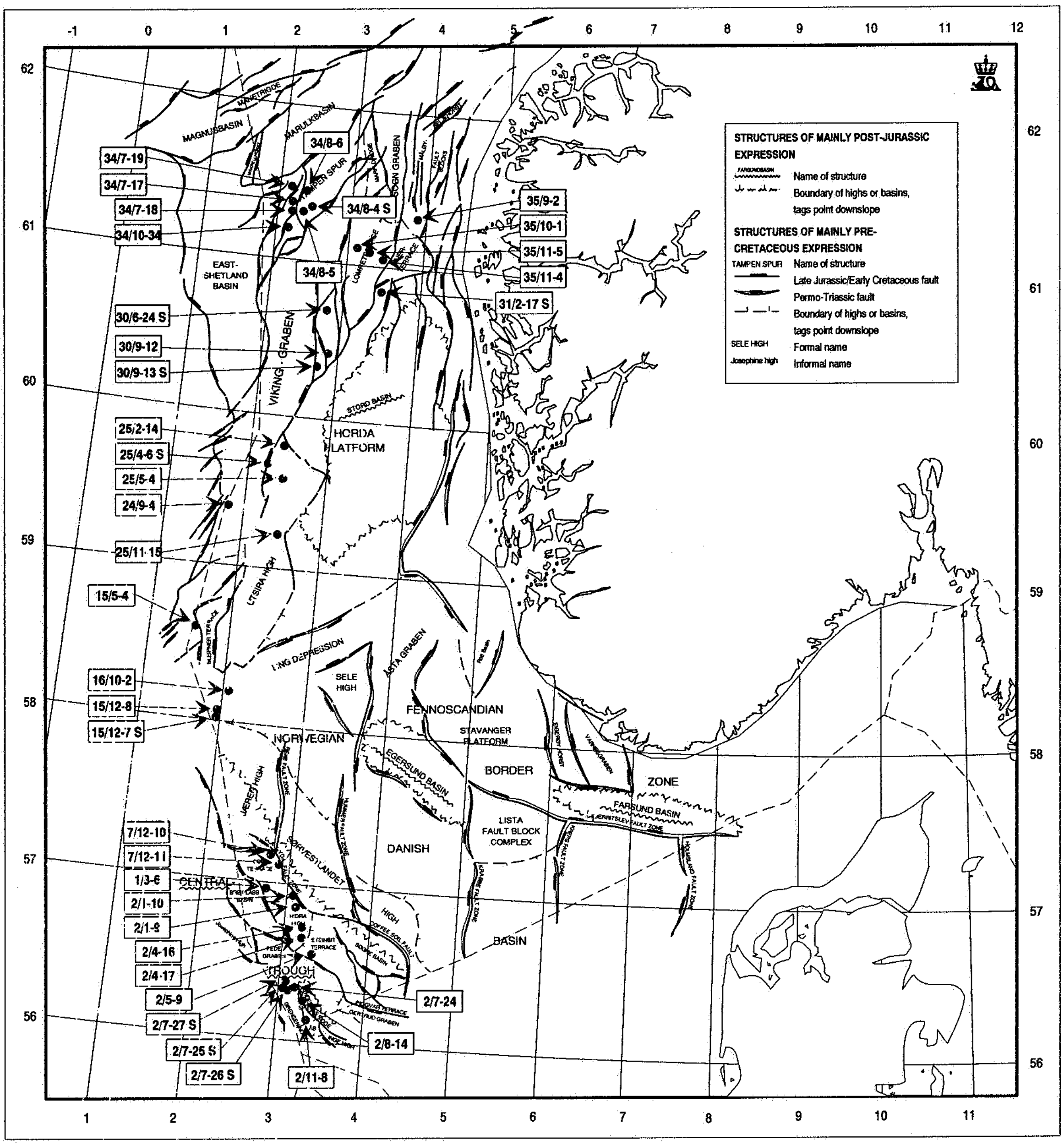
Well	Operator	Hydrocarbons
1/3–6	Elf	Gas and condensate
15/12–8	Statoil	Gas and condensate
25/4–6S	Elf	Gas and oil
25/5–4	Elf	Gas and condensate
25/11–15	Hydro	Oil
30/9–13S	Hydro	Oil and gas
34/7–18	Saga	Oil
34/8–4S	Hydro	Gas and condensate
34/10–34	Statoil	Oil and gas
35/11–4R	Mobil	Oil and gas
6506/11–2	Statoil	Oil, condensate and gas

Block 1/3

Elf Aquitaine Norge A/S as operator of production licence 065 drilled wildcat 1/3–6 in the northwestern part of the block. The well was drilled to a total depth of 3561 metres below sea level and terminated in Cretaceous rock.

Hydrocarbons were proven in Palaeocene sand-

Fig. 2.2.2.b
Exploration wells drilled in 1991 in the North Sea



stone and two production tests were run. The highest rate was measured at 0.17 mcm gas a day, with a gas-to-condensate ratio of 1100 scm/scm through a 19.05 mm choke, while condensate density was 0.78 g/cc. The discovery has been evaluated and is now included in the resources accounts.

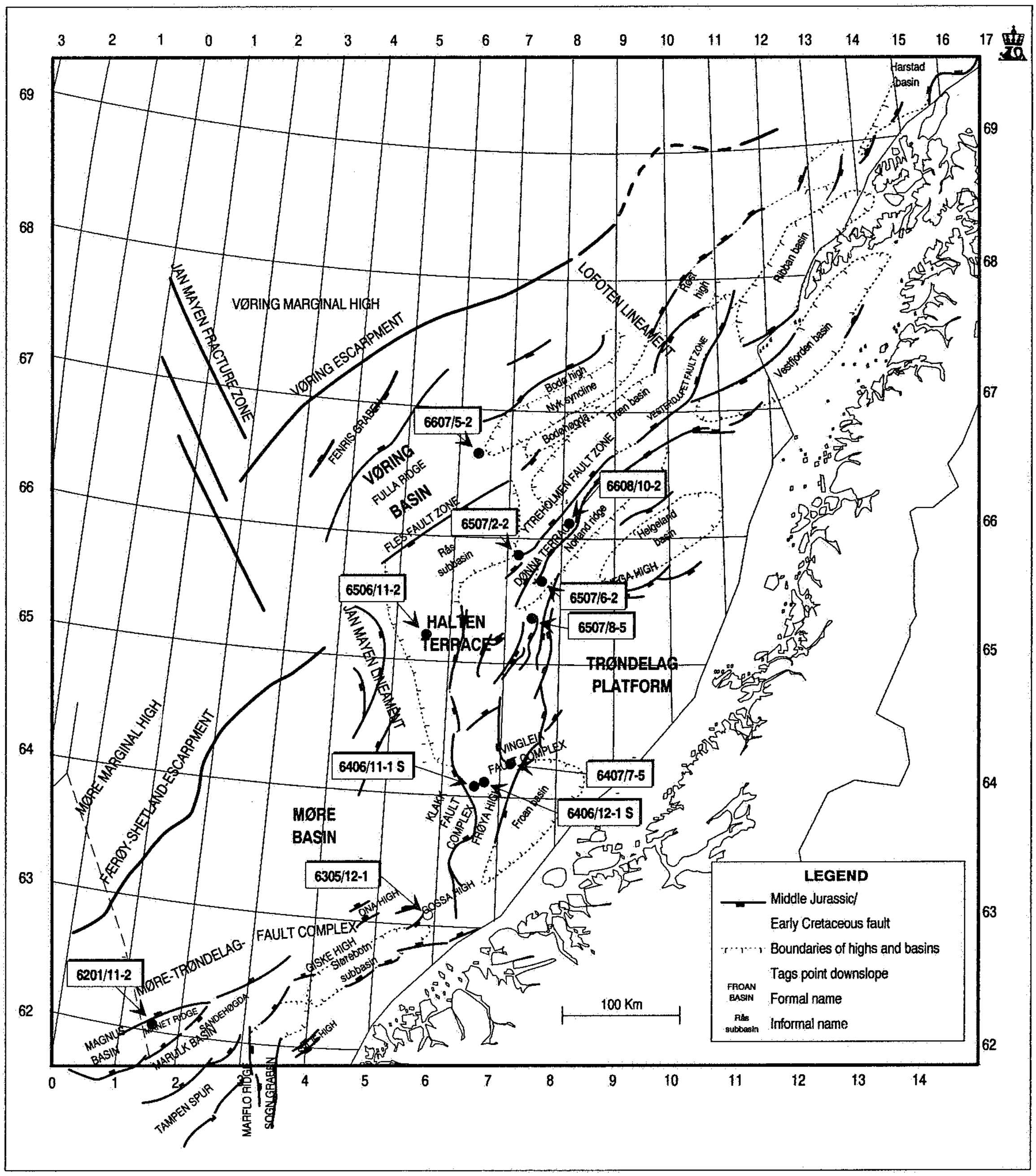
Block 15/12

Statoil as operator of production licence 038 drilled the 15/12–8/8-A wildcat in a structure in the southeastern part of the block. The well was drilled to a depth of 3031 metres below sea level and terminated in Triassic rock. Hydrocarbons were proven in Jurassic and Triassic sandstone, and the well was production tested. Peak production was measured to 0.55 mcm gas and 420 scm condensate a day through a 15.9 mm choke. Measured condensate density was 0.74 g/cc. The deviation drilling of 15/12–8-A was carried out in order to take core samples of the reservoir zone. The discovery has been evaluated and is now included in the resources accounts.

Block 25/4

Elf Aquitaine as operator of production licence 036 drilled the 25/4–6-S wildcat in the northeastern corner of the block. The well was drilled to 4148 metres

Fig. 2.2.2.c
Exploration wells drilled in 1991 on the Mid-Norwegian shelf

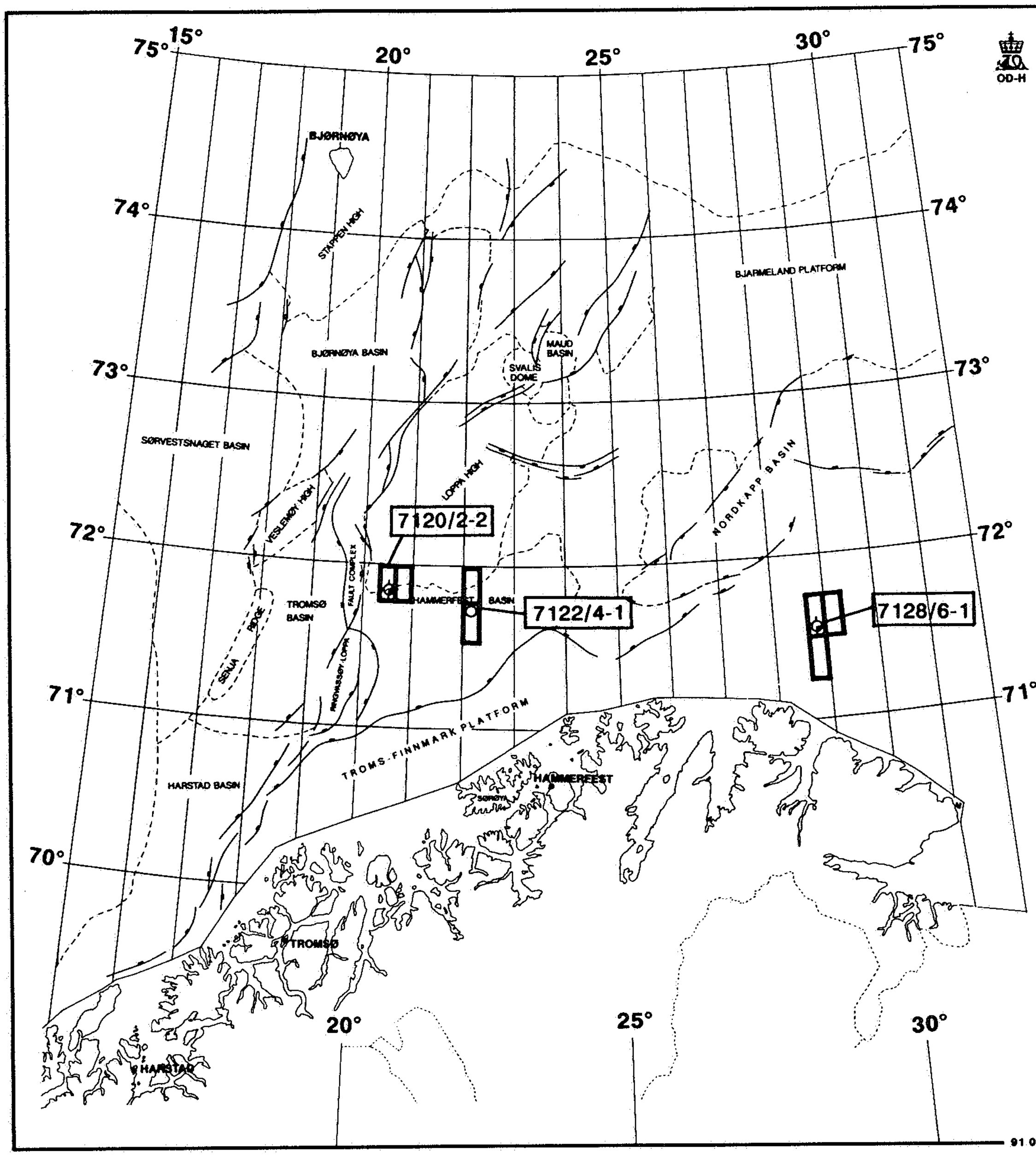


below sea level and terminated in early Jurassic rock. Hydrocarbons were proven in middle Jurassic sandstone, and the well was production tested. Peak production was 0.46 mcm gas and 688 scm oil a day through a 20.64 mm choke. It is as yet to early to say anything about the magnitude of the discovery although drilling results and the test are considered interesting.

Block 25/5

Elf Aquitaine as operator of production licence 102 drilled wildcat 25/5–4 in a structure centrally located in the block. The well was drilled to 3168 metres below sea level and terminated in early Jurassic rock. Hydrocarbons were proven in middle Jurassic sandstone, and a production test was run. The maximum measured production rate was 0.74 mcm gas a day through a 20.3 mm choke. The gas-to-condensate ratio was measured to 3100 scm/scm. The condensate density was 0.7 g/cc. The discovery has now been evaluated by the Directorate and is included in the resources accounts. The discovery has been named Byggve.

Fig. 2.2.2.d
Exploration wells drilled in 1991 in the Barents Sea



Block 25/11

Norsk Hydro as operator of production licence 169 drilled the 25/11–15 wildcat in a structure east of Balder. The well was drilled to 2011 metres below sea level and terminated in early Jurassic rock. Oil was proven in Palaeocene sandstone strata in the Heimdal formation and a production test was run. Peak production rate was measured at 540 scm oil a day through a 25.4 mm choke. The measured gas-to-oil ratio was 15 scm/scm, while oil density was 0,945 g/cc. The discovery has been evaluated and is now included in the resources accounts.

Block 30/9

Norsk Hydro as operator of production licence 104 drilled wildcat 30/9–13-S in the Gamma Øst structure southwest of the Oseberg field. The well was drilled to 3939 metres below sea level and terminated in early Jurassic rock. Hydrocarbons were proven in middle and late Jurassic sandstone, and three production tests were run, two oil tests and one gas test. The measured peak production rate from the oil zone was 824 scm oil a day through a 19.05 mm choke. The gas-to-oil ratio was 148 scm/scm. Measured oil density was 0.845 g/cc. The measured peak production rate from the gas zone was 0.46 mcm gas a day through a 28.6 mm choke. The gas-to-oil ratio was here 5200 scm/scm, and the density of the gas relative to air was 0.72. The drilling results are interesting when considering future exploration activity in the Oseberg field area.

Block 34/7
Saga as operator of production licence 089 drilled wildcat 34/7–18 in a structure south of the Snorre field. It was drilled to a total depth of 2421 metres below sea level and terminated in early Jurassic rock. Only small quantities of hydrocarbons were proven in middle Jurassic strata, which is disappointing. However, hydrocarbons were proven in Palaeocene sand, where a production test was run. The test gave a production rate of about 44 scm oil a day through an 8 mm choke, and oil density was 0.89 g/cc.

This is the first time oil has been proven and tested from this level in the area so that the discovery is considered interesting despite the low test rates.

Block 34/8
Norsk Hydro as operator of production licence 120 drilled wildcat 34/8–4-S in the southeastern part of the Visund discovery. The well was drilled to a total depth of 3779 metres below sea level and terminated in Triassic rock. Hydrocarbons were proven in late Triassic sandstone. A total of four production tests were run and the measured peak production rate was 988 scm condensate a day and 0.792 mcm gas a day through a 20.64 mm choke. Condensate density was 0.785 g/cc, while gas density was 0.739 relative to air.

Block 34/10
Statoil as operator of production licence 050 drilled the 34/10–34 wildcat in a previously undrilled structure to the west of the Gullfaks field. The well was taken to a total depth of 2397 metres below sea level and terminated in early Jurassic rock. Hydrocarbons were proven in middle Jurassic sandstone, and a test was run. The measured peak production was 606 scm oil a day and 0.1413 mcm gas a day through a 19.05 mm choke. This result must be regarded as positive considering the close proximity to Gullfaks.

Block 35/11
Mobil as operator of production licence 090 performed a production test of wildcat 35/11–4-R. The well was first drilled in 1990 in a separate structure in the southeastern part of the block. It was drilled to a total depth of 3110 metres below sea level and terminated in early Jurassic rock. Hydrocarbons were proven in Jurassic sandstone.

The well was reentered in fall 1991 and was being production tested at the end of the year. A total of four tests were performed where the maximum stable production rate was measured at 683 scm oil a day. The gas-to-oil ratio was then 96 scm/scm. Oil density was 0.831 g/cc, while gas density was 0.670 relative to air. This result is considered positive and encouraging for the block. The well, which is counted as a discovery made in 1991, has been evaluated and is now included in the resources accounts.

Block 6506/11
Statoil as operator of production licence 134 drilled wildcat 6506/11–2 in the southeastern part of the block.

The aim was to delineate the Smørbukk structure extending from the neighbouring block 6506/12 to the east. Gas and oil have previously been proven in this structure. The drilling operation was terminated at a depth of 4787 metres below sea level in early Jurassic rock. Gas, condensate and oil were proven in Jurassic and Cretaceous sandstone.

Six production tests were run and the best test gave 720 scm condensate and 1 mcm gas a day through a 25 mm choke. The gas-to-oil ratio was measured to 1440. Gas density was 0.734 relative to air, while condensate density was 0.783 g/cc.

The results from this drilling operation confirm that the hydrocarbon column in the Smørbukk structure extends into block 6506/11. Another positive characteristic was that hydrocarbons were proven in Cretaceous sandstone.

2.2.2.3 Further details of other drilling operations
Block 2/1
BP as operator of production licence 019B drilled appraisal well 2/1–9. The well was drilled to 4266 metres below sea level and terminated in Permian rock. Hydrocarbons were proven in late Jurassic sandstone. This is a possible extension of the Gyda field to the south but further evaluation is required before the size and reach can be ascertained. A production test was run, giving a measured production rate of 165 scm oil, 0.091 mcm gas and 120 cubic metres of water a day through a 17.5 mm choke.

BP as operator of production licence 164 is drilling wildcat 2/1–10 in a prospect in the northwestern part of the block. The drilling operation had not been terminated at the end of the year.

Block 2/2
Saga Petroleum as operator of production licence 066 is drilling wildcat 2/2–5. The drilling operation had not been terminated at the end of the year.

Block 2/4
Saga Petroleum as operator of production licence 146 drilled the 2/4–16 wildcat in the same structure as 2/4–14. Control was lost of the well, resulting in a long and costly normalisation process, and the anticipated reservoir sand was not encountered. When the well had reached 4970 metres below sea level there was a gas kick up the drill string onto the drill floor. It is uncertain whether the gas derived from a

new reservoir or evidenced gas from coal benches sucked into the well. The well was plugged using the shear ram. The situation was in some ways similar to what happened on 2/4–14.

However, the starting point for regaining control was better than for 2/4–14. After about two months the well had been killed and most of the drill string fished out. The well was then plugged temporarily.

Phillips Petroleum as the operator of production licence 018 is drilling wildcat 2/4–17 in the Nordøst Tor prospect. Hydrocarbons were proven in Jurassic and possibly also Triassic sandstone. The reservoir zones are going to be production tested. Drilling operations had not yet been terminated at the end of the year.

Block 2/5
Amoco as operator of production licence 006 is drilling the 2/5–9 wildcat in the Magne prospect. Drilling operations had not yet been terminated at the end of the year.

Block 2/7
Phillips as operator of production licence 018 drilled wildcat 2/7–24 west of the Valhall field. The well was drilled to 4963 metres below sea level and terminated in late Jurassic rock. The hole was a duster.

Embla appraisal wells in block 2/7
Phillips as operator of production licence 018 has engaged in appraisal drilling on the Embla field. The wells were sidetracked through a seabed template positioned over 2/7–20.

Appraisal well 2/7–25-S was drilled to 4529 metres below sea level but the expected reservoir was not proven. The well was drilled to an Upper Jurassic interval before being terminated in rock of unknown age. No significant hydrocarbon traces were found.

Appraisal well 2/7–26-S was drilled to 4820 metres below sea level and terminated in pre-Jurassic sandstone. The well proved two independent hydrocarbon-bearing sandstone strata of unknown age. Two production tests were run. In the first, the production rate was 53 scm oil and 10,109 scm gas a day through a 6.35 mm choke with a measured gas-to-oil ratio of 191 scm/scm. In the second test the production rate was 223 scm oil and 62,141 scm gas a day through a 6.35 mm choke with a measured gas-to-oil ratio of 279 scm/scm.

Appraisal well 2/7–27-S was sidetracked with a trajectory as close to 2/7–23-S as possible in order to test the reservoir zone in the northern part of the Embla field. Drilling operations had not yet been terminated at the end of the year.

Block 2/8
Amoco as operator of production licence 006 drilled wildcat 2/8–14 northwest of the Valhall field. The well was drilled to a total depth of 4370 metres below sea level and terminated in late Jurassic rock. It was terminated 1230 metres over the projected total depth due to unexpectedly high pore pressure. Hydrocarbon traces were observed during the drilling operation.

Block 2/11
Norsk Hydro as operator of production licence 068 drilled wildcat 2/11–8. The well was drilled to a total depth of 4561 metres below sea level and terminated in pre-Jurassic rock. The hole was dry.

Block 3/7
Norske Shell as operator of production licence 147 is drilling wildcat 3/7–5 in the Lemen prospect. The drilling operation had not yet been terminated at the end of the year.

Block 7/12
BP as operator of production licence 019A drilled wildcat 7/12–10. The well was drilled to 3632 metres below sea level and terminated in Triassic rock. The anticipated reservoir levels were dry. Only traces of hydrocarbons were proven in Cretaceous rock. The well was not production tested.

BP as operator of production licence 164 drilled wildcat 7/12–11 just east of the Ula field. The well was drilled to 3842 metres below sea level and terminated in Triassic rock. Well 7/12–11, the first in production licence 164, failed to prove hydrocarbons.

Block 15/5
Norsk Hydro as operator of production licence 048 drilled appraisal well 15/5–4 in a structure in which hydrocarbons have been proven in the British sector and which was assumed to extend into the Norwegian sector. The well was drilled to a depth of 2275 metres below sea level and terminated in late Palaeocene rock. The wells showed weak indications of hydrocarbons, and a production test was run. Only small volumes of water were produced during the test.

Block 15/12
Statoil as operator of production licence 116 drilled the 15/12–7-S wildcat in a structure in the southeastern corner of the block. The well was drilled to a depth of 3506 metres below sea level and terminated in Triassic rock without striking hydrocarbons.

Block 16/10
Agip as operator of production licence 101 drilled the 16/10–2 wildcat in a structure in the western part of the block. The well was drilled to a depth of 3125 metres below sea level and terminated in Triassic rock. No hydrocarbons were encountered in the well.

Block 24/9
Fina as operator of production licence 150 drilled the 24/9–4 wildcat in a stratigraphic trap in the western part of the block. The well was drilled to a depth of 2183 metres below sea level and terminated in

early Tertiary rock. Only traces of oil were proven and the well was not production tested.

Block 25/2
Elf Aquitaine as operator of production licence 026 drilled appraisal well 25/2–14. The well was drilled in a separate fault segment just north of Frøy to a depth of 3601 metres below sea level and terminated in early Jurassic rock. No hydrocarbons were proven in the well.

Block 30/6
Norsk Hydro as operator of production licence 170 drilled wildcat 30/6–24-S in a structure in the northwestern part of the block. The well was drilled to a total depth of 3961 metres below sea level and terminated in Triassic rock. Only traces of hydrocarbons were proven in the well.

Block 30/9
Norsk Hydro as operator of production licences 104 and 079 drilled appraisal wells 30/9–12 and 30/9–12-A in the Alfa-Sør structure southeast of the Oseberg field. Well 30/9–12 was drilled to a total depth of 2969 metres below sea level and terminated in early Jurassic rock. Oil was proven in middle Jurassic sandstone but no production test was made of the discovery. The lower portion of the well was plugged back and subsequently drilled directionally as a further delineation of the Alfa-Sør structure.

Well 30/9–12-A was drilled to a total depth of 2902 metres below sea level and terminated in early Jurassic rock. Oil was proven in late Jurassic sandstone. The well was not production tested and has been temporarily plugged back for reuse at a later date. The results of these appraisal drilling operations in this part of the Oseberg field must be considered disappointing.

Block 31/2
Norsk Hydro as operator of the Troll oil field development is drilling appraisal well 31/2–17-S in Troll Vest. The drilling operation had not yet been terminated at the end of the year.

Block 31/5
Norsk Hydro as operator of the Troll oil field development, is drilling appraisal well 31/5–4-AR in Troll Vest. The well was first drilled to a total depth of 1884 meters below sea level and terminated in late Jurassic rock. It was subsequently sidetracked in the northeasterly direction where the last part of the well was drilled 800 metres horizontally to a total depth of 2580 metres below sea level (vertical depth 1556 m). Production testing was performed in the horizontal part of the well, giving 345 scm oil, 20,350 scm gas, and 575 cubic metres of water a day through a 19.05 mm choke.

Block 34/7
Saga Petroleum as operator of production licence 089 drilled three appraisal wells in the block in 1991. Well 34/7–17, drilled to test the reach of a discovery made in 1990 by 34/7–16, attained a total depth of 2855 metres below sea level before terminating in Triassic rock. No hydrocarbons were proven in the hole and it was decided to sidetrack a new bore, 34/7–17-A, higher up in the structure.

The sidetrack, 34/7–17-A, was drilled to a total depth of 2380 metres below sea level where hydrocarbons were proven in middle Jurassic rock. A production test was run, giving a production rate of 719 scm oil and 0.036 mcm gas a day through a 15.6 mm choke.

The third appraisal well, 34/7–19, tested the northern segment in the former C+ structure, now part of the Vigdis field. The well was drilled to a total depth of 2785 metres below sea level and terminated in early Jurassic rock. Hydrocarbons were proven in middle Jurassic rock and two production tests were run; one for water and one for oil. The measured peak production rate in the oil test was 1150 scm oil a day through a 14.3 mm choke. The gas-to-oil ratio was 40 scm/scm and the oil density 0.835 g/cc. These results are considered to be positive and will probably justify an increase in the reserves estimates for the Vigdis field.

Block 34/8
Norsk Hydro as operator of production licence 120 drilled appraisal well 34/8–5 in the southern part of the Visund discovery. The well was drilled to a total depth of 3516.5 metres below sea level and terminated in Triassic rock. The result was disappointing as only traces of hydrocarbons were found. Norsk Hydro also drilled the 34/8–6 wildcat in a separate prospect northwest of Visund. The well was drilled to a total depth of 3927 metres below sea level and terminated in Jurassic rock. No hydrocarbons were found in the well.

Block 35/9
Norsk Hydro as operator of production licence 153 drilled the 35/9–2 wildcat. This well, drilled to a total depth of 2852 metres below sea level, terminated in bedrock. Hydrocarbons were proven in Jurassic sandstone, and four production tests were run. The measured production rate in the oil zone was 458 scm oil a day with a gas-to-oil ratio of 423 scm/scm through a 12.7 mm choke. The oil density was 0.819 g/cc, while the gas density was 0.631 relative to air. The production rate in the gas zone was measured at 755 mcm gas a day with a gas-to-condensate ratio of 4741 scm/scm through a 25.4 mm choke. Here the gas density was 0.665 relative to air, and the condensate density 0.732 g/cc.

Block 35/10
Statoil as operator of production licence 173 drilled the 35/10–1 wildcat in a structure in the eastern part of the block. The well was drilled to a total depth of 3963 metres below sea level and terminated in early

Jurassic rock. Only traces of hydrocarbons were found and no production tests were performed. The results were disappointing in light of the expectations associated with this well.

Block 35/11
Mobil as operator of production licence 090 drilled the 35/11–5 wildcat in a structure in the southwestern part of the block. The well was drilled to a total depth of 3743 metres below sea level and terminated in early Jurassic rock. Hydrocarbon traces were proven in Jurassic sandstone. No production test was performed.

Block 6201/11
Statoil as operator of production licence 130 drilled the 6201/11–2 wildcat in the southwestern part of the block in an Upper Jurassic prospect. The drilling operation was terminated in Triassic rock at a depth of 3755 metres below sea level. No hydrocarbons were proven and the well was not production tested.

Block 6305/12
Norsk Hydro as operator of production licence 154, blocks 6205/3 and 6305/12, drilled the 6305/12–1 wildcat in a middle Jurassic prospect in the southern part of the block. The drilling operation was terminated in bedrock at a depth of 4279 metres below sea level. No hydrocarbons were proven and the well was not tested.

Block 6406/11
Saga Petroleum as operator of production licence 156 drilled the 6406/11–1-S wildcat in a middle Jurassic prospect in the southeastern part of the block. The drilling operation was terminated in Triassic rock at a depth of 4159 metres below sea level. Hydrocarbons were proven in early to middle Jurassic rock, and three zones were tested. The tests showed that the hydrocarbons could not be produced.

Block 6406/12
Statoil as operator of production licence 157 drilled the 6406/12–1-S wildcat in an Upper Jurassic sand wedge prospect in the southwestern part of the block. The drilling operation was terminated in Upper Jurassic rock at a depth of 3942 metres below sea level. Only traces of hydrocarbons were proven and the well was not tested.

Block 6407/7
Norsk Hydro as operator of production licence 107 drilled appraisal well 6407/7–5 in the Nord II segment, which was a possible northern extension of the Njord discovery. The drilling operation was terminated in early Jurassic rock at a depth of 3702 metres below sea level. No hydrocarbons were proven and the well was not tested.

Block 6507/2
Norsk Hydro as operator of production licence 122 is in the process of drilling the 6507/2–2 wildcat in a middle Jurassic prospect in the eastern part of the block. The well is located 15 km west of well 6507/3–1 where Statoil made a gas and condensate discovery in 1990. The drilling operation had not yet been terminated at the end of the year.

Block 6507/6
Saga Petroleum as operator of production licence 123 drilled the 6507/6–2 wildcat in a middle Jurassic prospect in the northwestern corner of the block. The drilling operation was terminated in Triassic rock at a depth of 4336 metres below sea level. Only small volumes of hydrocarbons were proven in Cretaceous sand strata, but the well was not production tested.

Block 6507/8
Statoil as operator of production licence 124 drilled the 6507/8–5 wildcat in a middle Jurassic prospect in the eastern part of the block. It was located about 10 km southeast of well 6507/8–4 where Statoil found oil and gas in 1990. The drilling operation was terminated in early Jurassic rock at a depth of 1977 metres below sea level. No hydrocarbons were proven.

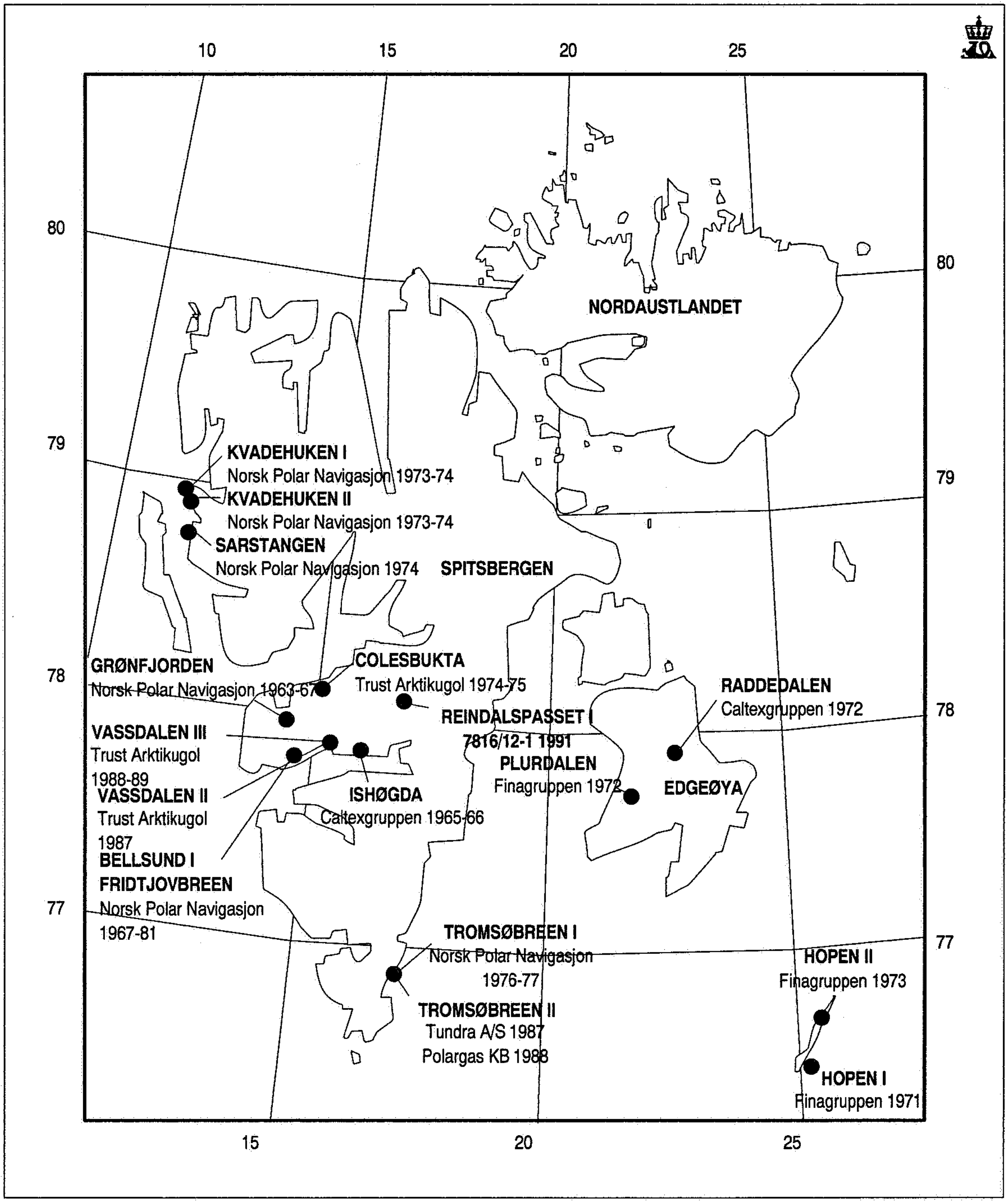
Block 6607/5
Esso as operator of production licence 126 drilled the 6607/5–2 wildcat in the northwestern part of the block. The prospect was assumed to be Jurassic sandstone. The drilling operation was terminated in middle Cretaceous rock at a depth of 4659 metres below sea level. No hydrocarbons were proven, but rich Cretaceous sand strata were discovered.

Block 6608/10
Statoil as operator of production licence 128 is in the process of drilling the 6608/10–2 wildcat in a middle Jurassic prospect in the southwestern corner of the block. The distance to well 6507/3–1 where Statoil proved gas and condensate in 1990 is 12 km. The drilling operation is currently ongoing, and oil and gas have been proven in Jurassic sandstone. Production tests had not yet been terminated at the end of the year.

Block 7120/2
Norsk Hydro as operator of production licence 109 drilled the 7120/2–2 wildcat in a structure in the flank of Loppahøgda. The well was drilled to test sandstone in a Cretaceous fan. The drilling operation was terminated in middle Jurassic rock at a depth of 2777 metres below sea level. Oil traces were found in the fan, but no production test was performed.

Block 7128/6
Conoco as operator of production licence 181 drilled the 7128/6–1 wildcat in a carbonate build-up in the Finnmark Øst area. The well was terminated in pre-Devonian bedrock at a depth of 2520 metres below

Fig. 2.2.2.4
Well locations on Svalbard



sea level. Traces of oil were found in late Permian carbonates, but nothing was produced to the surface during the test.

Block 7122/4

Esso as operator of production licence 178 started drilling of the 7122/4–1 wildcat in a structure in the Hammerfest basin. The well had not been terminated at the end of the year.

2.2.2.4 Svalbard

Norsk Hydro, in cooperation with Store Norske Spitsbergen Kullkompani and Petro Arctic AB, drilled the 7816/12–1 wildcat known as Reindalspasset-1. The purpose of the enterprise was to test the hydrocarbon potential in the Permian-Carboniferous strata series. Drilling was terminated in Carboniferous rock at a depth of 2315 metres below the drill floor. Only traces of gas were found. See Table

Table 2.2.2.4
Drilling activity on Svalbard

Exploration well/ location	Position north east	Spudded	Terminated	Days drilling	Operator Licensee	Total depth metres	KB elev. over msl metres
7714/2–1 Grønnfjorden I (Nordenskiøld Land)	77 57 34 14 20 36	09.06.63 13.06.64 26.06.65 26.06.67	05.09.63 26.08.64 08.09.65 12.08.67	287	Norsk Polar 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 23	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	18.08.73 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 II (Van Mijenfjorden)	77 49 57 15 11 15	30.03.88	01.11.89		Trust Arktikugol	2352	15.13
7816/12–1 Reindalspasset-I (Spitsbergen)	78 03 28 16 56 31	17.01.91	18.04.91		Norsk Hydro	2315	182.5

1) Drilling abandoned due to technical problems.
*) Drilling not concluded.

2.2.2.4 for drilling activities on Svalbard, and Figure 2.2.2.4 for drilling locations on the island.

2.3 FIELDS AND DISCOVERIES UNDER CONSIDERATION

2.3.1 Ekofisk area

This is the area on the Norwegian continental shelf which has been in production for the longest period of time, see Figure 2.5.4.a. The fields in production are primarily Cretaceous, while the exploration activity is focused on making discoveries in sandstone. A number of small discoveries have been made in the area and the plan is to produce them as satellites to existing installations.

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. Recoverable resources lie in a segment 100 per cent within the Norwegian sector, estimated by Norsk Hydro to be 1.7 mcm oil. A possible development concept is a wellhead installation with minimum manning and one production well and pipeline for further processing and transport.

Trym

The Trym field was proven by the drilling of the 3/7–4 wildcat and lies in production licence 147, where Shell is operator. According to Shell's estimates, recoverable resources are 10–14 bcm dry gas and 2.0–2.6 mcm condensate. Of this, 60 per cent is in the Norwegian sector. It has not yet been decided what development concept to opt for. Since Total sold its equity in the licence to Shell, only Shell and Statoil remain as licensees.

Sørøst Tor

This field is located in block 2/5 in production licence 006, allocated in 1965, with Amoco as operator. The Directorate estimates the recoverable oil resources to be 2.5 mcm and the gas resources to be 2 bcm. The development concept has not been chosen.

Mime

Mime is a small oil field seven kilometres north of Cod. Hydro as operator of production licence 070 is currently conducting long-term test production from the field. Production takes place via a seabed completion well with transfer to the Cod installation. The well stream from Mime uses the Cod test separator for measurement. The oil and gas are mixed with oil and gas from the Cod production and transferred to the Ekofisk field for final processing.

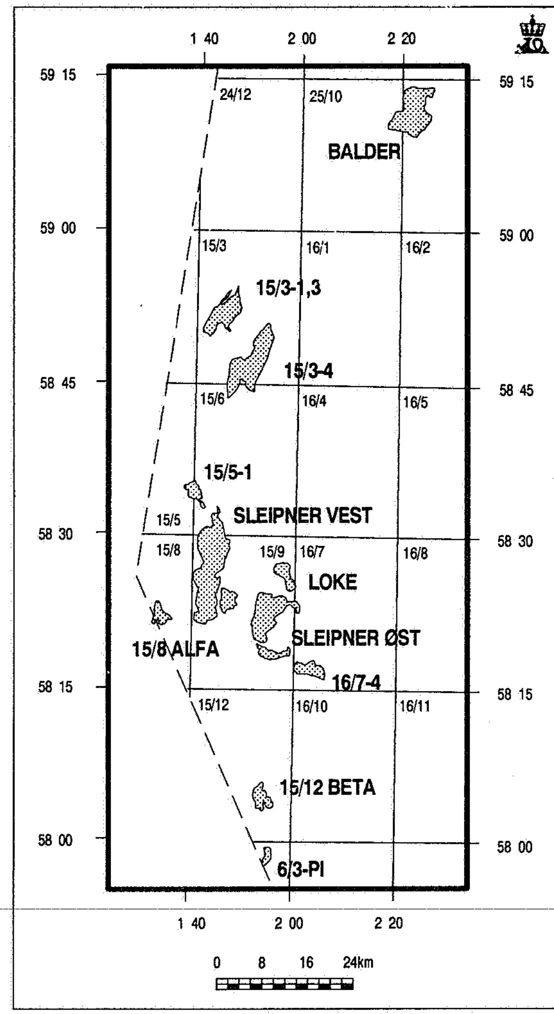
The test period started on 25 October 1990 and a permit was granted for the production of maximum 0.21 mcm oil, or for one and a half years. Production so far indicates that the limiting volume will be reached in March 1992. Hydro applied for an extension of the permit until the end of April 1992, which was granted on condition that the plan for development and operation is submitted to the authorities by the end of February 1992.

Drilling of the test well and the production history have led to a reduction in the Mime reserves, which in turn has brought about a reduction in further investments. The operator is currently looking into the option of lowering the operating pressure to the Cod test separator so as to increase production from Mime. Later, when the well rate becomes so low as to be uneconomical, it can be sidetracked down into a neighbouring segment.

9/2 Gamma

9/2 Gamma is located in block 9/2 on production licence 114, which was allocated in 1985 with Statoil as operator. The discovery lies in the Egersund basin and was proven by well 9/2–1. There is no existing infrastructure in the area. The operator's estimate of recoverable resources is 6.4 mcm oil.

Fig. 2.3.2
The Sleipner and Balder area



2.3.2 Sleipner and Balder area

In addition to Sleipner Øst, Loke, Sleipner Vest and 15/12 Beta discussed below, the Sleipner area consists of a number of other discoveries and prospects, see Figure 2.3.2.

Sleipner Vest

Sleipner Vest lies in block 15/6, allocated in 1969, and blocks 15/9 and 15/8, allocated in 1976. Unitisation negotiations are currently being conducted between the respective production licences 029 and 046. Esso is operator of production licence 029 and Statoil of 046. The Directorate estimates the field's reserves to be 135 bcm gas (including carbon dioxide), 27 mcm oil and 9 million tonnes NGL. The Sleipner Vest gas contains up to 9 per cent carbon dioxide. The plan for development and operation was submitted in December 1991.

The development concept consists of a wellhead installation, Sleipner B, located in the southern part of the Sleipner Vest field, with transfer of the well flow to the Sleipner T installation located next to Sleipner A for removal of carbon dioxide and processing. Further development of the northern reaches of Sleipner Vest will, according to plan, be performed using two subsea templates or wellhead installations with transfer of the well flow to Sleipner B.

Sleipner Vest should be ready for production in 1996 and the gas is planned to be injected into Sleipner Øst in order to increase the production of oil and NGL from the latter. The partners expect to be awarded the gas sale in connection with the 1991 contracts when the buyers exercise their 30 per cent options under the Troll gas sales agreement. This sale is expected to commence in the year 2001.

15/12 Beta

The discovery is located in block 15/12 allocated in production licence 038 in 1974 with Statoil as operator and Esso as partner. The operator estimates the recoverable resources to be between 15 and 20 mcm oil. The licensees are evaluating various development concepts at the same time as the geological data are being processed further. The preliminary plans are to start production in 1995–96.

Other discoveries and prospects

Two discoveries have been made in block 15/3; a gas-condensate discovery 15/3–1,3 in 1974, and a gas-oil discovery 15/3–4 in 1984. The Directorate's estimates for recoverable resources in 15/3–1,3 are about 10 bcm gas and 5 mcm oil. Both discoveries are still in the early phase and there are no proposed development concepts.

In a structure in block 15/5, on the boundary to the British sector, a discovery has been made on the UK side. The discovery was first assumed to extend into the Norwegian continental shelf, but exploration drilling in 1991 in the Norwegian sector gave a negative result. Norsk Hydro as operator has therefore suspended all field development work except for further geological studies.

Among the prospects in the Sleipner area, Theta Vest Heimdal, located about four kilometres west of Loke, is probably the most critical timewise, if resources are not to be lost when Sleipner Øst comes on stream. The plan is for the template installed to produce Loke to be used also to drain any discovery in Theta Vest Heimdal. If it exists, it will probably, like Loke, have pressure communication with the Heimdal reservoir in Sleipner Øst. Any development of Sleipner Øst would be contingent on careful evaluation of such communicating discoveries and prospects to avoid losing petroleum.

Balder

Balder was proven in 1974 by exploration well 25/11–5 in Palaeocene sandstone. The discovery is situated in blocks 25/10 and 25/11 in production licences 001 and 028 where Esso is the operator. Esso owns 100 per cent of production licence 001.

The Directorate estimates the recoverable reserves at 35 mcm oil. The Balder discovery contains relatively viscous oil. Hydrocarbons have been proven in Lower Eocene and Palaeocene sandstone. The reservoir sandstone has relatively poor consolidation but the reservoir parameters are otherwise good. Oil has been proven in four different sand units.

Well 25/11–14-S was drilled at the end of 1990 and underwent long-term testing from May to the end of September 1991. The well provided useful geological information. Test production from *Petrojarl I* amounted to 128,500 scm oil. Test production results will determine further progress for Balder but as yet there is no conclusion.

2.3.3 Frigg area

This is an area where gas fields have been in production since 1977, see Figure 2.5.8.a. Recently, several small discoveries have been made in the area and the plan is to tie them into the existing infrastructure. For some of the new discoveries the reservoir pressure is relatively high. Oil has also been found in the area.

Frøy

Frøy is situated in block 25/2 in production licence 026, and in block 25/5 in production licence 102. Elf is the operator of both licences. In summer 1991 Total Norge took over Shell's interest in production licence 102.

The operator's reserves estimates have been reduced from 16.5 to 15 mcm oil, from 3.5 to 2.95 bcm gas, and increased from 0.77 to 0.89 million tonnes NGL. In autumn 1991 the Directorate made reserve estimates for Frøy which are somewhat lower than those of the operator.

Appraisal well 25/2–14 was drilled early in 1991 in a separate structure in the northern part of the field. This well did not prove any hydrocarbons.

In the course of 1991 the geological model for the field was reevaluated. The plan for development and operation was submitted in December 1991 where the planned development concept is a wellhead installation with first stage separation and transfer of oil and gas to Frigg. Development plans are for five production wells and four water injection wells. Production start is planned for early 1995.

Skirne

This field is situated in block 25/5 in production licence 102 allocated in 1985 with Elf as operator. The field was proven by well 25/5–3 in the Brent group, middle Jurassic sandstone in 1990. The operator's reserves estimates are 5.0 bcm gas and 0.7 mcm condensate. The Directorate's estimates are about half of the operator's.

Three-dimensional seismics will be shot in the structure in 1992. The plan for development and operation is expected in the second quarter of 1992, which may give production start late in 1995 if the gas is sold.

A probable development concept is a subsea installation with transfer of the well flow to Frøy and thence to Frigg. From 1997 onward the plan is to combine the well flows from Skirne and Byggve before multiphase transportation to Frigg. The development is closely associated with Byggve.

Byggve

This field is situated in block 25/5 in production licence 102 allocated in 1985 and operated by Elf. The field was proven by well 25/5–4 in the Brent group in 1991.

The operator's estimates of recoverable reserves are 3.4 bcm gas and 0.7 mcm condensate, while the Directorate's estimates are somewhat lower.

Three-dimensional seismics will be shot over the structure in 1992 and better mapping of the field is anticipated. The need to drill a well in the southern part of the structure will be evaluated based on the 3D seismics. The drilling results will form the basis for a plan for development and operation in 1994. Byggve will feature in the Skirne development plan as these fields have to be seen in conjunction.

Production is planned to start in late 1997, provided the gas is sold. The assumed development concept is a subsea installation with transfer of the well flow to Frøy, where it joins with the Skirne well flow for transportation to Frigg.

Peik

Peik was proven by well 24/6–1 in 1985. The field is situated in production licence 088 allocated in 1984 with Total Norge as operator. In 1987 the 9/15–1 wildcat in the UK sector proved hydrocarbons.

The operator's estimate of recoverable resources is 9.6 bcm gas, of which about 66 per cent is in the Norwegian sector.

Three-dimensional seismics will be shot over the structure in 1992 to improve reservoir mapping. New maps are expected to be available in the early summer of 1993.

In 1991, the operator evaluated various development concepts and prepared a plan for development and operation. This plan is expected to be submitted after the results from the 3D seismics become available, but any development is contingent on gas sale. The probable development concept would be a wellhead installation with minimum manning tied up to Frigg.

Hild

Hild is situated in production licences 040 and 043 operated by Norsk Hydro and Total Norge, respectively, see Figure 2.4.6.a. On 1 January 1991 Total took over BP's interest and operatorship in production licence 043. Production licence 040 in blocks 29/9 and 30/7 was allocated in 1975. Production licence 043 was allocated in 1976 covering blocks 29/6 and 30/4. If the field is developed unitisation talks must be conducted between the production licences.

The two operators have different interpretations of the reservoir as well as different estimates of recoverable resources.

In 1991, three-dimensional seismics were shot in the area, the interpretation of which is expected to be ready towards the end of 1992. Among other things the results will be used to determine the location of a test well.

Further reservoir and conceptual studies have been postponed until the results from the 3D seismics become available. The plan for development and operation can be submitted in 1994 at the earliest, meaning production start-up in 1996–97. The most probable development concept is a subsea installation with transfer of the well flow to Frigg.

25/2–5

This discovery is located in block 25/2 in production licence 026 and was allocated in 1969 with Elf as operator. The discovery was proven in 1976. At present there are no concrete plans to develop the field, but a drilling operation scheduled in 1992 may change this. If developed, the field will probably be tied up to Frøy.

25/4–6-S

This discovery is situated in block 25/4 in production licence 036 and was allocated in 1981 with Elf as operator. It was proven in the summer of 1991. There is still some doubt whether the reservoir consists of light oil or gas with a lot of condensate. No resources estimates are available. Further work is required to determine if the discovery is commercial. Any field development will probably involve tie-in to Frigg or Heimdal.

2.3.4 Oseberg and Troll area

Oseberg area

Several fields and discoveries are being considered in this area in addition to those already in production (Oseberg, Veslefrikk and 30/6 Gamma Nord) and those already resolved for development (Brage), see Figure 2.4.6.a. Fields planned to be developed are Oseberg Øst and Huldra. Other discoveries in the area include 30/6 Kappa, 30/9 Omega, and several discoveries in production licence 104 in block 30/9.

Oseberg Øst

Oseberg Øst comprises two structures divided by a sealing fault. Both structures are situated in production licence 053 operated by Norsk Hydro. Oil has been proven in several formations in the Brent group. The reservoirs are complicated, with several different oil-water contacts and relatively low permeability. The reserves are estimated at 19 mcm oil.

Hydro is planning a development using an installation equipped for partial processing and transfer of gas and oil to the Oseberg field centre for further processing. The plan for development and operation was scheduled for autumn 1991 but has now been postponed for about one year. The reason is that Oseberg is probably retaining its plateau rate much longer than assumed and first oil from Oseberg Øst should therefore be postponed until about 1997.

30/9 Omega

30/9 Omega is situated to the southwest of the Oseberg field centre 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 centre 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, 30/9–9 and 30/9–13.

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 also extends into production licence 052 in block 30/3. Statoil operates both production licences.

The field was declared commercial in summer 1991 and unitisation talks are currently ongoing between the two production licences.

Gas has been proven in the Brent group, and Statoil estimates reserves to be 17 bcm gas and 4.5 mcm condensate. The operator is contemplating several alternative development concepts. A new appraisal well will be drilled in the field in the course of 1992. The plan for development and operation is scheduled to be submitted in or about the new year 1993. Production start-up will be autumn 1996 at the earliest.

30/6 Kappa

Block 30/6 lies west of the Oseberg field centre, 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 discovery have not been determined, but it is included in the resources base considered in Hydro's plans for the Oseberg area.

2.3.5 Gullfaks, Statfjord and Snorre area

This is a high activity area where several fields are in operation, in the process of being developed and under consideration, see Figure 2.5.11.a. The area is very prospective and a number of interesting discoveries have been made.

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 nine kilometres 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 Jurassic and Triassic sandstone.

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

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.

The licensees had scheduled to submit the plan for development and operation of the Gullfaks Sør oil phase in 1991. However, this has now been postponed, the current plan being to prepare a commerciality declaration for both the oil and gas phases. Earlier gas production will improve field economy. Further work in the production licence will include an evaluation of coordination with other fields and discoveries in the area, among them 34/10 Gamma. According to plan an appraisal well will be drilled on 34/10 Gamma in 1992.

Vigdis

The Vigdis field is situated in block 34/7 and comes under production licence 089. Vigdis comprises several discoveries and structures where Saga Petroleum is the field operator. One appraisal well was drilled in the field in 1991. Well 34/7–19 tested a northern segment in the C+ structure.

The well was drilled to a total depth of 2782 metres below sea level and terminated in early Jurassic rock. Hydrocarbons were found in middle Jurassic reservoirs, and two production tests were run.

The water depth in the area is 230 to 300 metres. Preliminary plans involve development of Vigdis using subsea completion wells tied either to a production ship or existing process facilities in the area. The plan for development and operation is expected to be submitted in December 1992, which means production start-up in 1996.

Visund

The Visund discovery lies in block 34/8 which comes under production licence 120 operated by Norsk Hydro. The first discovery was made in the Brent group with well 34/8–1 in 1986. Well 34/8–3 followed in 1988 and proved hydrocarbons in a Brent segment further north. In 1991, three wells were drilled in the production licence, two of which were in connection with existing discoveries. Well 34/8–4-S struck hydrocarbons in the Lunde formation, while well 34/8–5 delineated the Brent reservoir in the south.

Visund has proven resources in the Brent group and in the Lunde formation. An exploration well will be drilled in the stratigraphically intermediate Statfjord formation early in 1992. The Brent group contains relatively thin oil zones which extend over a large area under extensive gas caps. The plan is to produce this oil by means of horizontal wells.

Three-dimensional seismics have been shot over the entire area. Once the maps become available a comprehensive delineation plan will be prepared. This is especially the case for the northern Brent segment where the bulk of the resources are located.

The water depth in the area is 310–380 metres. The preliminary plans involve field development using a floating installation. The gas will probably be processed on the installation and transferred to an existing transportation system. The oil can either be exported via offshore loading buoys or transferred to an existing process centre in the vicinity. Production start-up is expected in autumn 1997.

2.3.6 Fields and discoveries off Mid-Norway

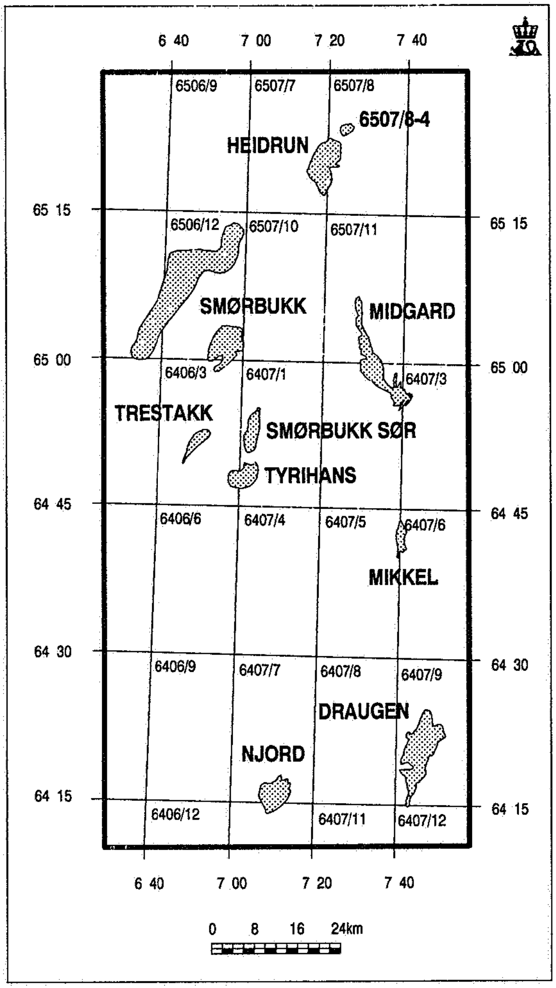
Haltenbanken

A total of 75 wildcat and appraisal wells have been drilled on Haltenbanken and the area can therefore be characterised as a petroleum province which is relatively well explored. All told, ten fields and discoveries have been proven, embracing total recoverable resources in the order of 310 mcm oil and 280 bcm gas, see Figure 2.3.6. At present, two of the fields have been resolved to be developed. There are good chances of making further discoveries in the area.

Trestakk

Trestakk is an oil discovery in block 6406/3. Statoil operates the production licence, which was allocated in 1984. The operator estimates recoverable resources to be 9 mcm oil. According to plan, produced gas will be reinjected into the reservoir to enhance oil recovery. It is assumed that the reservoir can be drained by means of three horizontal production wells. No decision has yet been made concerning development concept.

Fig. 2.3.6
Fields and discoveries offshore Mid-Norway



Tyrihans

Tyrihans lies in blocks 6406/3 and 6407/1 and consists of two structures; Tyrihans Sør and Tyrihans Nord, which probably have pressure communication through a common water zone. Statoil is the operator. The southern structure is classed as a gas-condensate structure, while Tyrihans Nord contains an oil zone with an overlying gas cap. The magnitude of the oil zone in the north is uncertain since no oil-water contact has been found. The Directorate's estimates for recoverable resources are 16 mcm oil-condensate and 40 bcm gas. No decision has yet been made concerning the development concept.

Njord

Njord is an oil discovery in blocks 6407/7 and 6407/10 where Norsk Hydro operates production licences 107 and 132 allocated in 1985 and 1987. A total of seven exploration wells have been drilled in the two blocks, four of which proved oil. The structure features a complex fault pattern which will probably have a major impact on oil recovery. The Directorate's estimates of recoverable resources are 35 mcm oil and 7.2 bcm commercial gas.

Midgard

The Midgard field is situated in blocks 6507/11 and 6407/2 under production licences 062 and 074, with Saga the operator. A total of seven exploration wells have been drilled in the area, four of them into the structure. The field, discovered in 1981 by the drilling of well 6507/11–1, is divided into four structural segments: Alfa, Beta, Gamma, and Delta. The field was declared commercial by the operator in autumn 1991.

Reservoir properties are good, and the Directorate's reserves estimates are 87 bcm gas, 1.3 mcm oil, and 13 million tonnes NGL. These figures are approximately 20 per cent lower than the operator's estimates.

Field development is planned using a fixed, gravity base platform with integrated deck. Twelve production wells are planned for gas, and two horizontal producers for draining of the underlying oil zone. The plateau production rate will correspond to dry gas sales of 8 bcm. The operator assumes that the gas will be processed on the field and transported to the market via a direct dry gas pipeline.

Smørbukk

The bulk of this discovery lies in block 6506/12 covered by production licence 094 allocated in 1984. The southern part lies in block 6506/11 in production licence 134. Statoil operates both production licences. The discovery contains gas, condensate and oil with a relatively high gas-to-oil ratio. It is located about 200 km from relevant onshore tie-in points, in 250 metres of water. A total of eight wells have been drilled in block 6506/12. One wildcat has also been drilled in the southern part of the Smørbukk structure, in block 6506/11. The Directorate's resources estimates are 20 mcm recoverable oil-condensate and 65 bcm recoverable gas. Some 7 mcm recoverable oil has been discovered in the northeastern part of the field, and the operator is contemplating developing this part as a satellite to Smørbukk Sør. Gas production from Smørbukk must be seen in conjunction with a general gas transport solution for Haltenbanken. The discovery has not as yet been defined as mature for development.

Smørbukk Sør

This field, situated in the southern part of block 6506/12, was proven in 1985 by the wildcat 6506/12–3, and later confirmed by two appraisal wells. The field lies about 10 km from Smørbukk in 300 metres of water. The Directorate's reserves estimates for Smørbukk Sør are 31 mcm oil and condensate and 24 bcm gas. Statoil is the operator.

The licensees have opted for field development and the operator is expecting to submit the plan for development and operation in June 1992. The operator anticipates first oil will be feasible in January 1996. According to the development plan the oil in the field will be produced first while associated gas is reinjected into the field for later production. In this way one also improves the recovery factor.

Field development is planned using subsea completion wells and a production ship. Eight oil production wells and three gas injection wells are planned. Oil production will last for 15 years, with a peak rate of 11,000 scm a day. The oil is assumed to be transported from the field by tanker. Smørbukk Sør is conveniently situated as a possible field centre for other neighbouring discoveries. Gas sales from the field would be feasible from about the year 2010.

6507/8–4

This discovery is covered by production licence 124 where Statoil is the operator and is situated about four kilometres northeast of the Heidrun field. In August 1990, the discovery well, 6507/8–4, proved oil with an overlying gas cap in the Åre formation. The operator's estimates of recoverable resources are 20 mcm oil and 2 bcm gas.

No decision has yet been made concerning development concept.

2.3.7 Barents Sea

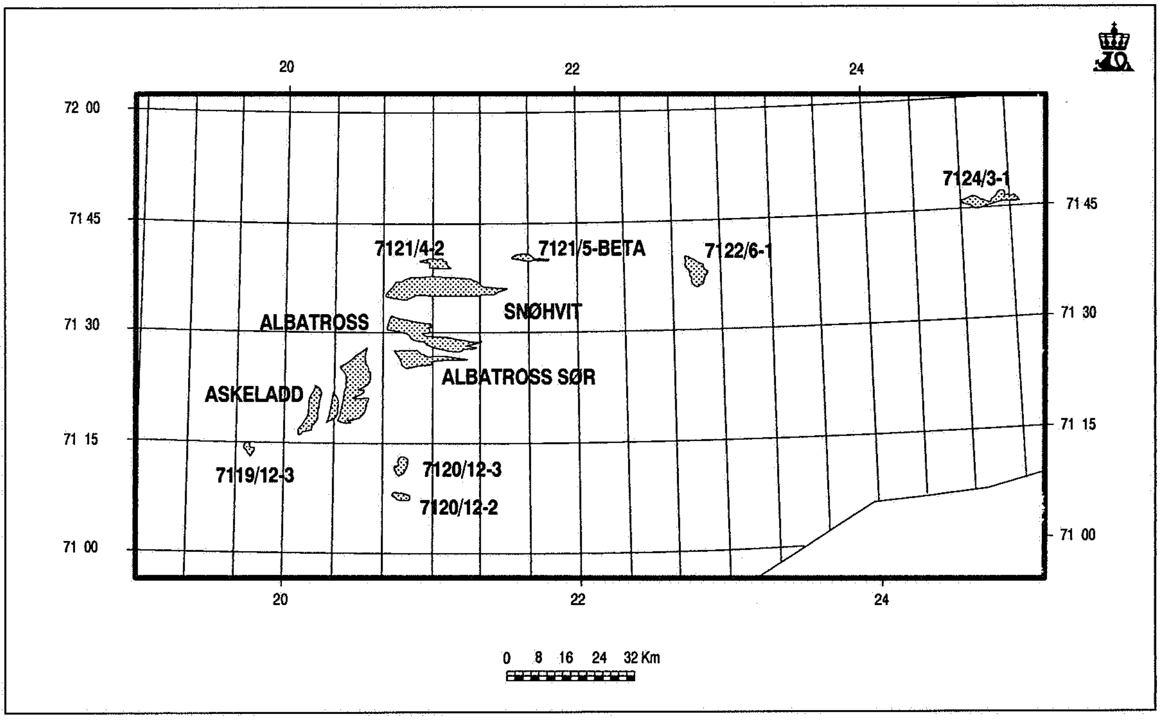
About 250 bcm recoverable gas has been proven in the Troms area, see Figure 2.3.7. In addition, there is a thin oil zone on Snøhvit. The Directorate is currently reevaluating the resources base in the Snøhvit discovery.

Snøhvit

For several years now the licensees have studied possible development concepts for the Snøhvit gas. Pipeline transportation of the gas has been found uneconomic 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 the most interesting:

- Semi-submersible platform with production from wells arrayed in templates on the seabed, involving processing of the gas on the platform before transportation to an LNG terminal onshore;
- Subsea production system, with well flow to be carried directly to an LNG terminal onshore. When the reservoir pressure depletes the subsea unit must be connected to a booster installation to pump the gas to shore.

Fig. 2.3.7
The Troms area



Two alternative production rates are being considered: 4.5 bcm a year and 9.0 bcm a year. These correspond to gas sales volumes of 3.85 and 7.70 bcm a year after separating out condensate. In the event the higher rate is chosen, development will include the Askeladden and Albatross fields.

The Directorate considers a satisfactory sales contract for gas to be decisive for any development of Snøhvit and the other gas fields on Troms I. The most interesting markets seem to be Italy, the USA, and Canada. Sales negotiations are currently being conducted, which, 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 Directorate nevertheless feels one should consider the feasibility of combined production of oil and gas from some of the gas wells.

2.4 FIELDS APPROVED DEVELOPED

2.4.1 Embla

Embla lies in block 2/7 and was allocated under production licence 018 in 1965, see Figure 2.5.4.a.

Licensees

Phillips Petroleum Company Norway (operator)	36.9600 %
Norske Fina A/S	30.0000 %
Norsk Agip A/S	13.0400 %
Elf Aquitaine Norge A/S	7.5940 %
Norsk Hydro Produksjon a.s	6.7000 %
Total Norge A/S	3.5470 %
Den norske stats oljeselskap a.s	1.0000 %
Eurofrep Norge A/S	0.4560 %
Coparex Norge A/S	0.3990 %
Norminol A/S	0.3040 %

Field history

The first well was drilled in 1974 and proved hydrocarbons in what was initially held to be Jurassic rock but which later turned out to be older. High reservoir pressure led to postponement of any further exploration. The discovery was not confirmed until 1988 by a new exploration well. Once it was ascertained that the reservoir was pre-Jurassic, this fact led to a new exploration model in the southern part of the North Sea. The plan for development and operation of Embla was submitted in 1990 and adopted in December of the same year. In addition to the discovery wells, a total of four combined appraisal and production wells have been drilled, one of which was dry.

Reservoir

Great drilling depths and high reservoir pressures have led to some technical difficulties during the pre-drilling programme. At the same time, complex geology has brought surprises during development of the field. For this reason the operator has elected to reduce the reserves base. There is still a great deal of uncertainty linked to field geology and reservoir characteristics.

Development concept

The original plan was to develop Embla in several stages, phase 1 including a wellhead installation with slots for up to 18 wells. Due to the great surprises in geology and reservoir conditions, further plans for development will be evaluated in autumn 1992.

Transportation

After processing on Eldfisk FTP, both the oil and gas will be carried to Ekofisk. From here they will be routed to Teesside and Emden, respectively.

Costs

Estimated investment costs for phase 1 run to some 2.1 billion 1991 kroner, with annual operating costs amounting to about 23 million 1991 kroner.

2.4.2 Sleipner Øst

Production licence 046

Licensees

Den norske stats oljeselskap a.s	49.6000 %
Esso Norge a.s	30.4000 %
Norsk Hydro Produksjon a.s	10.0000 %
Elf Aquitaine Norge A/S	9.0000 %
Total Norge A/S	1.0000 %

The production licence was allocated in 1976 and embraces blocks 15/8 and 15/9, see Figure 2.3.2. Statoil is the operator for the Sleipner Øst field.

The Directorate's estimated reserves in place in Sleipner Øst are 51 bcm gas, 20 mcm oil and 10 mtoe NGL. If it is decided to inject gas from Sleipner Vest or other fields into Sleipner Øst, one will achieve considerably higher oil and NGL recovery from Sleipner Øst.

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

After the concrete gravity base for the Sleipner A installation sank in the Gandsfjord the licensees have extensively revised the plans for development of Sleipner Øst with a view to meeting the field's gas sales obligations under the Troll gas sales agreements. The two most important changes in the development concept seem to be a new riser installation and a new subsea production system in order to drain the northern part of the Sleipner Øst field.

Costs

The estimated total development costs are some 18 billion 1991 kroner, inclusive a condensate pipeline from the Sleipner A installation to Kårstø. Total operating costs are estimated at 8.2 billion 1991 kroner, exclusive transportation costs.

Estimated investment costs will be higher due to the loss of the concrete gravity base structure.

2.4.3 Loke

The production licence, licensees and allocation year are the same as for Sleipner Øst. Development of Loke was approved in 1991. Two reservoir strata have been proven, Heimdal and Triassic, corresponding to the reservoir strata in Sleipner Øst. The Heimdal reservoir in Loke has pressure communication with the Heimdal reservoir in Sleipner Øst. Production of Sleipner Øst will therefore influence the pressure in the Heimdal reservoir Loke. Development of Loke will therefore stop large volumes of hydrocarbons from being trapped in the water zone between Loke and Sleipner Øst. The Directorate's and operator's reserves estimates for the Heimdal reservoir coincide, being 2.9 bcm gas and 2.1 mcm oil. For the Triassic reservoir, which has not yet been resolved to be developed, the reserves estimates are 5.1 bcm gas and 2.0 mcm oil.

Development concept

Loke will be produced by means of a subsea production system with transfer of the well flow to the Sleipner A installation. The original plan was to drain Loke with just one well, but after the loss of the Sleipner A base, the partners are considering draining Loke using two wells. The gas is planned to be sold under the Troll gas sales agreement in the same way as the gas from Sleipner Øst. According to plan Loke will be ready for production at the same time as Sleipner Øst.

Costs

Estimated investment costs are some 0.7 billion 1991 kroner. Total operating costs are estimated at 31 million 1991 kroner over the lifetime of the field.

2.4.4 Lille-Frigg

Lille-Frigg is situated in block 25/2 covered by production licence 026, see Figure 2.5.8.a.

Licensees

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

Field history

The production licence was allocated in 1969 with Elf as operator. The 25/2–4 wildcat proved hydrocarbons in 1975. The work of producing a commerciality declaration started after drilling of well 25/2–12 in 1988. The plan for development and operation was submitted in February 1991 but was not approved. An updated plan was approved in September 1991.

Reservoir

Lille-Frigg is a combined gas-condensate field. The reservoir lies in the Brent group in a fault block which is an extension of the Heimdal ridge. The operator's estimates for recoverable reserves are 7 bcm gas and 2.7 million tonnes NGL.

Development concept

Lille-Frigg will be developed using a subsea installation remotely controlled from Frigg. Development is based on three production wells with pressure relief as the production mechanism. It will be possible to tie in two extra wells. The untreated wellflow will be transferred under high pressure directly to Frigg for treatment. Gas and NGL will be forwarded to St Fergus in the existing pipeline. According to plan, stabilised condensate will be transported by pipeline to Oseberg. Production start is scheduled for 1 October 1993.

Costs

Estimated investment costs are 1875 million 1991 kroner and total operating costs 1762 million 1991 kroner.

2.4.5 Brage

The bulk of the Brage field is situated in block 31/4 and was allocated in 1979 as production licence 055, see Figure 2.4.6.a. The field also extends into block 30/6, production licence 053, and into the northern part of block 31/7. In 1991, this section of block 31/7 was allocated to the licensees of production licence 055 as production licence 185. Unitisation negotiations were conducted between production licences 055 and 053 in 1991 but no agreement was reached.

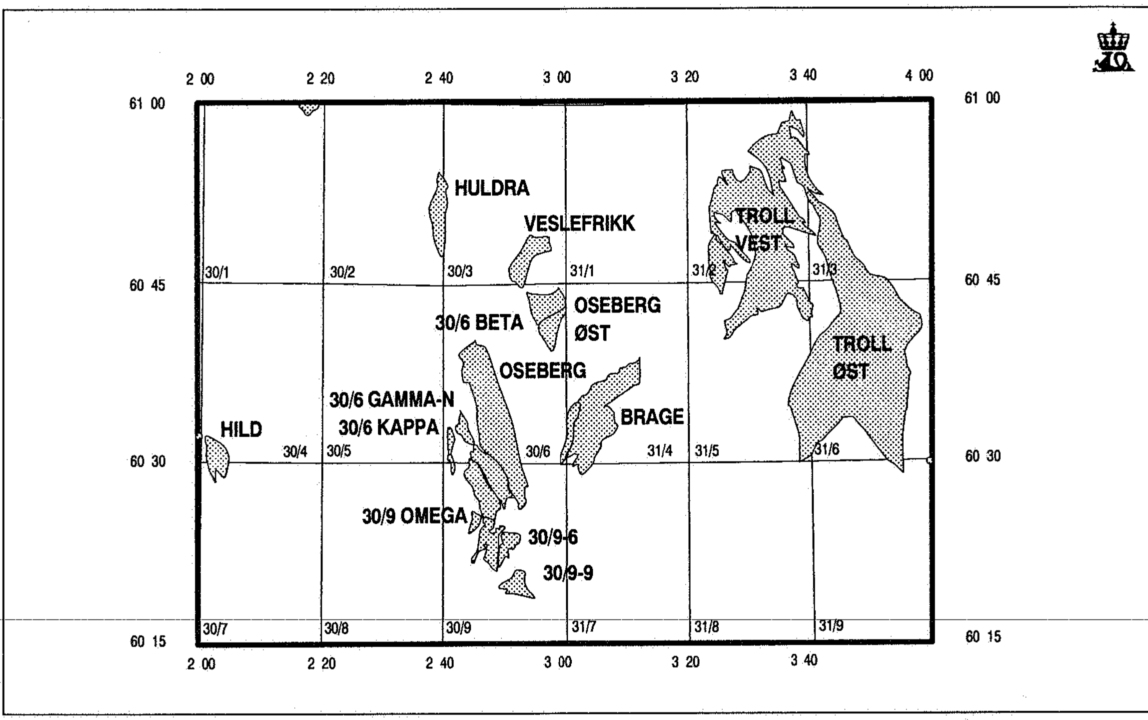
Licensees in production licences 055 and 185

Den norske stats oljeselskap a.s	56.0000 %
Esso Norge a.s	17.6000 %
Norsk Hydro Produksjon a.s	13.2000 %
Neste Petroleum a.s	13.2000 %

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. The authorities ordered the operator to drill an appraisal well in the northeastern part of the field in connection with the approval of the plan for development and operation. This well must be drilled maximum three years after production start and will provide more information on the resources in the Sognefjord and parts of the Fensfjord reservoir outside the drainage area of the installation.

The Directorate has put the recoverable reserves at 46.2 mcm oil and 1.7 bcm gas, while the operator's estimates are 38.5 mcm oil and 1.6 bcm gas.

Fig. 2.4.6.a
The Oseberg and Troll area



Development concept

The field will be developed with an integrated production, drilling and quarters installation on a steel jacket. Production start-up is scheduled 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. Six production wells are to be pre-drilled and pre-drilling started in December 1991. The oil will 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 10.6 billion 1991 kroner, and total operating costs 520 million 1991 kroner a year.

2.4.6 Troll

Production licences 054 and 085
Licensees after unitisation

Den norske stats oljeselskap a.s	74.5800 %
A/S Norske Shell	8.2880 %
Norsk Hydro Produksjon a/s	7.6880 %
Saga Petroleum a/s	4.0800 %
Elf Aquitaine Norge A/S	2.3530 %
Conoco Norway Inc	2.0150 %
Total Norge A/S	1.0000 %

The Troll field covers parts of blocks 31/2, 31/3, 31/5 and 31/6, see Figure 2.4.6.a. Block 31/2 was allocated 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 64 mcm. This estimate is based on 17 horizontal wells in the Troll Vest oil province and six horizontal wells in the Troll Vest gas province. Development of the gas province is being considered by the licensees and a decision to increase the number of wells in the gas province can mean an upward adjustment of the reserves estimates for oil.

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. Underneath Sognefjord lies the Heather formation, which shows poor reservoir properties, and the Fensfjord formation with variable reservoir characteristics.

At the top of Troll Øst and Troll Vest is a gas column over 200 metres high. This gas column varies across the field. The western part of the field (Troll Vest oil province), lying predominantly in block 31/2, features an oil column 22 to 27 metres tall under the gas, compared to 11 to 17 metres further east in the block (Troll Vest gas province). In Troll Øst the proven oil strata vary from zero to four metres in thickness.

Troll phase 1

Norske Shell, as operator of the first development on Troll, submitted the partners' plan for development and operation of Troll 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 almost equivalent to Norway's overall gas export in 1991. Total investment costs have been estimated at some 27.8 billion 1991 kroner, with estimated annual operating costs running to 830–1150 million 1991 kroner.

The Directorate considers the selected development concept (see Figure 2.4.6.b) to be safer, more flexible and more cost-efficient than the original solution.

TOGI

In addition to the principal gas development project a subsea production system (Troll-Oseberg Gas Injection, TOGI) for gas required for injection on Oseberg has been built. TOGI started production of gas from Troll Øst in February 1991 and currently delivers some 3 mcm gas a day to Oseberg. Norsk Hydro is operator for development and operation of TOGI, where investments to date amount to approx 3.0 billion 1991 kroner.

The Directorate considers TOGI to be decisive for enhanced oil recovery from Oseberg and crucial to further development of subsea technology on the Norwegian continental shelf.

Troll phase 2

In December 1991, Norsk Hydro as operator of Troll phase 2 submitted a plan for development and operation of Troll phase 2, currently being considered by the authorities.

The plan recommends production from 17 horizontal wells in the Troll Vest oil province. A concrete floater is the recommended installation for processing and export of the oil, after floating and fixed installations as well as ships have been considered. The licensees also considered an installation capable of handling both oil and later gas production from Troll Vest. The planned plateau production is 25,000 scm oil a day. Up to 5 mcm gas a day can be exported to the Troll phase 1 installation. To-

Fig. 2.4.6.b
Planlagt innretning for Troll fase 1

tal investments are estimated at 14.3 billion 1991 kroner.

The licensees wish to continue to evaluate the oil recovery potential from the gas province. The results from drilling and production from test well 31/5-T1 in the southern part of the gas province were promising but the well produced more water than expected. Parts of the gas province are considered to be profitable although the uncertainty associated with the production estimates is believed to be significant on account of geological unknowns. In its estimates of oil reserves the Directorate has included production from the most promising area of the gas province.

Further phases on Troll

No decision has been made for further development of the Troll field. The licensees are engaged in studies to prepare for development and operation of the Troll Vest gas resources. It has not yet been determined when gas production can start. This depends on future developments in the gas market and the rate of oil production in Troll Vest.

The Directorate considers large-scale gas production from Troll Vest to be unsound resources policy until such time as the bulk of the oil reserves in Troll Vest have been produced.

2.4.7 Tordis

Tordis is situated in block 34/7 (see Figure 2.5.11.a) and comes under production licence 089 allocated in 1984 with Saga as operator.

Licensees

Production licence 089 was allocated in 1984. The sliding scale has been exercised in the production licence, giving the following distribution:

Den norske stats oljeselskap a.s	55.4000 %
Esso Norge a.s	10.5000 %
Idemitsu Petroleum Norge A/S	9.6000 %
Norsk Hydro Produksjon a/s	8.4000 %
Saga Petroleum a/s (operator)	7.0000 %
Elf Aquitaine Norge A/S	5.6000 %
Deminex (Norge) A/S	2.8000 %
Det Norske Oljeselskap A/S	0.7000 %

Field history

Tordis 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 plan was adopted by the Storting in May 1991.

Reservoir

The Directorate estimates the recoverable resources to be 18.8 mcm oil, 1.2 bcm gas and 0.5 million tonnes NGL. These estimates are almost identical with those of the operator. The production mechanism for the field is pressure maintenance by means of water injection. The oil is undersaturated and is found in the two reservoirs Upper and Lower Brent. Reservoir depths are around 2150 metres.

Development concept

The plan is to develop the field with subsea completion wells: five producers and two water injectors. The well flow will be phased into Gullfaks C for processing, metering and forwarding. According to the operator's plans, production will start in autumn 1994. The gas will be sold under the Troll gas sales agreement.

Costs

Total investments are estimated at some 3.4 billion 1991 kroner, including wells and modification costs on Gullfaks C. Estimated total operating costs are 3 billion 1991 kroner, including processing tariffs on Gullfaks C.

2.4.8 Statfjord Øst

Statfjord Øst is situated in production licences 037 and 089, see Figure 2.5.11.a. Production licence 037 covers blocks 33/9 and 33/12 and was allocated in 1973. The licence partners are listed below.

Licensees in production licence 037	
Den norske stats oljeselskap a.s (operator)	50.0000 %
Mobil Development Norway A/S	15.0000 %
A/S Norske Shell	10.0000 %
Esso Norge a.s	10.0000 %
Norske Conoco A/S	10.0000 %
Saga Petroleum a/s	1.8800 %
Amerada Hess Norge A/S	1.0400 %
Amoco Norway A/S	1.0400 %
Enterprise Oil Norwegian A/S	1.0400 %

Production licence 089 was allocated in 1984. Statoil's share is 40.4 per cent after the company sold 9.6000 per cent to Idemitsu in 1989.

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

Licensees in pl 089	Before	After
Den norske stats oljeselskap a.s	41.40 %	55.40 %
Esso Norge a.s	14.70 %	10.50 %
Norsk Hydro Produksjon A/S	11.76 %	8.40 %
Saga Petroleum a/s (operator)	9.80 %	7.00 %
Idemitsu Petroleum Norge A/S	9.60 %	9.60 %
Elf Aquitaine Norge A/S	7.84 %	5.60 %
Deminex (Norge) A/S	3.92 %	2.80 %
Det Norske Oljeselskap A/S	0.98 %	0.70 %

Field history

The plan for development and operation of Statfjord Øst was adopted by the Storting on 9 November 1990. Statoil operates the field. A unitisation agreement for Statfjord Øst was signed in June 1991 and splits the reserves with 50 per cent to each of the two production licences. On 19 November 1991, the Ministry of Petroleum and Energy approved a coordination agreement for Statfjord Øst, which means that Statfjord Nord and Statfjord Øst will have a common project organisation and use the same equipment on Statfjord C.

Reservoir

Production from Statfjord Øst is scheduled to start in the fourth quarter of 1994 and last until the year 2007. The field will reach peak production two to three years after production start-up. The plan is to drill up to ten production and water injection wells at Statfjord Øst. According to Statoil's estimates the oil reserves are approximately 19.4 mcm. The Directorate's estimates for oil reserves in Statfjord Øst are 13.4 mcm, which is about 30 per cent lower than Statoil's estimates. Differences in geological model account for most of the deviations in the reserves estimates. The Ministry of Petroleum and Energy has approved the production profile which the licensees relied on in their development application for Statfjord Øst. The production profile will be reconsidered once the first production and injection wells have been drilled. If the field reserves turn out to be lower than the licensees' estimates, the recovery rate may be adjusted downward.

Development concept

The field will be developed with subsea installations connected to the Statfjord C platform. The subsea installations will consist of three templates, two for production and one for water injection. The well flow comprising 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. A scheme has been approved for conversion of two water injection wells drilled from Statfjord C into subsea completion wells, which constitutes a change in the plan for development and operation of the field.

Costs

Estimated investment costs for Statfjord Øst are 3.37 billion 1991 kroner. In the production phase the annual operating costs for Statfjord Øst have been estimated at 70 million 1991 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.

2.4.9 Statfjord Nord

Statfjord Nord is situated in production licence 037 covering blocks 33/9 and 33/12 and was allocated in 1973, see Figure 2.5.11.a. The partners in the licence are given below.

Licensees in production licence 037

Den norske stats oljeselskap a.s (operator)	50.0000 %
Mobil Development Norway A/S	15.0000 %
A/S Norske Shell	10.0000 %
Esso Norge a.s	10.0000 %
Norske Conoco A/S	10.0000 %
Saga Petroleum a/s	1.8750 %
Amerada Hess Norge A/S	1.0420 %
Amoco Norway A/S	1.0420 %
Enterprise Oil Norwegian A/S	1.0420 %

Field history

The plan for development and operation of Statfjord Nord was adopted by the Storting on 9 November 1990. Statoil operates the field.

Reservoir

Production from Statfjord Nord is scheduled to start in the second quarter of 1994 and last until the year 2009. According to Statoil's estimates, total production from the field will be 27.7 mcm oil. The Directorate's estimates for oil reserves in Statfjord Nord are about 31 mcm. This estimate assumes that eight production wells will be drilled and that oil production is not terminated until the year 2014. Any decision to drill two extra wells will be deferred until after production start-up.

Development concept

The field will be developed with subsea installations connected to the Statfjord C platform. The subsea installations will consist of three templates, two for production and one for water injection. The well flow comprising 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. Statfjord Nord and Statfjord Øst will have a common project organisation and use the same equipment at Statfjord C.

Costs

Investment costs for Statfjord Nord run to 3.65 billion 1991 kroner. In the production phase the annual operating costs for Statfjord Nord have been estimated at 75 million 1991 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.

2.4.10 Snorre

The Snorre field is situated in blocks 34/4 and 34/7, with Saga as operator, see Figure 2.5.11.a. Block 34/4 was allocated under production licence 057 in 1979, block 34/7 under production licence 089 in 1984.

Licensees in production licence 057

Den norske stats oljeselskap a.s	41.4000 %
Deminex (Norge) A/S	24.5000 %
Saga Petroleum a.s	14.7000 %
Idemitsu Oil Exploration A/S	9.6000 %
Amerada Hess Norge A/S	4.9000 %
Enterprise Oil Norway A/S	4.9000 %

Licensees in production licence 089

Den norske stats oljeselskap a.s	41.4000 %
Esso Norge a.s	14.7000 %
Norsk Hydro Produksjon a.s	11.7600 %
Saga Petroleum a.s	9.8000 %
Idemitsu Oil Exploration A/S	9.6000 %
Elf Aquitaine Norge A/S	7.8400 %
Deminex (Norge) A/S	3.9200 %
Det Norske Oljeselskap A/S	0.9800 %

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	41.4000 %
Saga Petroleum a.s	11.2559 %
Esso Norge a.s	10.3323 %
Deminex (Norge) A/S	10.0348 %
Idemitsu Oil Exploration A/S	9.6000 %
Norsk Hydro Produksjon a.s	8.2658 %
Elf Aquitaine Norge A/S	5.5106 %
Amerada Hess Norge A/S	1.4559 %
Enterprise Oil Norway A/S	1.4559 %
Det Norske Oljeselskap A/S	0.6888 %

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 August 1992. The plan is to pre-drill four production wells and two injection wells before the platform is placed on the field in April-May 1992.

Reservoir

Snorre is a large oil field: the recoverable reserves according to the operator's estimate are about 120 mcm oil and 7 bcm associated gas. The Directorate estimates the reserves at 106 mcm oil and 6.7 bcm associated gas. The Directorate notes the uncertainty surrounding the Snorre field reserves. Snorre contains numerous additional resources.

The oil, which is heavily undersaturated, has collected in two reservoirs: Statfjord and Lunde. These are amply surveyed and the volumes are reasonably definite; although there is some uncertainty regarding the extent of the sand formations and communication in the Lunde reservoir, which may affect reservoir performance during production. The depth of the reservoir is about 2500 metres.

Development concept

The water depth over the field varies from 300 metres in the south to 370 metres in the north. In the plan the field will be developed in two phases.

Phase 1 comprises a floating tension leg platform in the south and a subsea installation in the central part of the field, where production will be driven by water injection and 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, including drilling, are about 23.5 billion 1991 kroner. Annual operating costs are variously estimated at from 1100 to 1600 million 1991 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.

2.4.11 Draugen

The Draugen field, situated in block 6407/9, was allocated in 1984 as production licence 093, see Figure 2.3.6.

Licensees

Den norske stats oljeselskap a.s	50.0000 %
A/S Norske Shell	30.0000 %
BP Petroleum Development of Norway A.S	20.0000 %

Shell operates the field, where 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 adopted for development.

Reservoir

The Directorate estimates the in-place reserves on Draugen to be around 68 mcm oil and 3 bcm gas. The Draugen reservoir is of excellent quality and consists of two formations: Rogn which contains the major part of the reserves, and Garn. There are several minor faults in the reservoir which may allow communication between the formations. There may also be communication in areas where the intervening slate strata are thin. On the evidence of the test results the wells are expected to provide high delivery capacity.

Development concept

The field development plan assumes a fixed concrete gravity base with integral (as opposed to modular) topsides. Six or seven production wells are planned, plus six water injection wells and one gas injection well. Seven of the wells will have subsea completion. The installation will have ten well slots and 34 J tubes when complete. A 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.

Gas application

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 feasible to produce the Rogn South formation early on, enabling the partners 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 11.8 billion 1991 kroner. Estimated annual operating costs are 700 million 1991 kroner.

2.4.12 Heidrun

Heidrun is situated in blocks 6507/7 and 6507/8, see Figure 2.3.6, the former being allocated in 1984 under production licence 095, and the latter in 1986 under production licence 124.

Licensees after unitisation

Den norske stats oljeselskap a.s	75.0000 %
Conoco Norway Inc (operator)	18.1250 %
Neste Petroleum a.s	5.0000 %
Norsk Hydro Produksjon a.s	1.2500 %
Det Norske Oljeselskap a.s	0.6250 %

Statoil will take over the Heidrun operatorship from Conoco from the operating phase. Production startup is scheduled for autumn 1995.

Field history

Heidrun was discovered in 1985 and declared commercial in December 1986. The plan for production and operation of the field was submitted in November 1987, including early production. The plan was approved but the partners discontinued their efforts to implement it, and the operator submitted a revised plan in December 1989. This plan was adopted by the Storting in May 1991. However, the decision of what to do with the associated gas was postponed. In November 1991, the Government presented a proposition recommending landing of the associated gas for methanol production.

Reservoir
The field contains oil with an overlying gas cap. The reservoir is faulted and consists of several geological formations. For optimal resource exploitation the gas cap should be produced after the bulk of the oil. The reserves estimates for Heidrun have given rise to much uncertainty, the Directorate's estimates being 87 mcm oil and 38 bcm gas, while the operator's estimates are 119 mcm oil and 45 bcm gas.

Development concept
Heidrun will be developed using a concrete tension leg platform installed over a subsea template with 56 well slots. According to the plan, 35 production wells, 11 water injection wells and two gas injection wells will be drilled. Six of the water injection wells will have subsea completion. The projected production capacity for oil is 35,000 scm a day, while maximum treatment capacity for water and gas will be 24,700 cubic metres and 4,7 mcm a day, respectively. Likely concepts for storage of produced oil might involve tankers and a concrete offshore loading platform. The oil storage capacity will be about 240,000 scm.

Costs
Estimated total investment costs are 25.6 billion 1991 kroner, while annual operating costs are estimated at 1.2 billion 1991 kroner.

Gas application
A number of alternatives for the sale of associated gas from the field have been considered, amongst others reinjection into the reservoir, injection into an adjacent water-filled structure, and landing in Mid-Norway. In November 1991, the Government presented a proposition recommending landing of the associated gas to Tjeldbergodden for methanol production.

2.5 FIELDS IN PRODUCTION

2.5.1 Hod

Production licence 033
Licensees

Amoco Norway Oil Company (operator)	25.0000 %
Amerada Hess Norge A/S	25.0000 %
Enterprise Oil Norway A/S	25.0000 %
Norwegian Oil Consortium A/S & Co	25.0000 %

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 separate structures: Vest Hod and Øst Hod. See Figure 2.5.4.a.

Production
The Hod field is a typical Cretaceous field in Central Graben. The Ekofisk formation is thin where it exists at all. The Tor formation is an excellent reservoir zone in the eastern structure. The H4 formation is best in the western structure, while varying parts of the Hod formation form a good reservoir in the eastern structure. Some oil has been proven in impervious, chalk-rich lower Cretaceous rock, but production here is not profitable at present.

Geophysical interpretation of the western structure is difficult due to gas in the rock overlying the reservoir. Three-dimensional seismics have been shot this year and the interpretation process will be concluded by the operator and partners in the first part of 1992. The eastern structure on the other hand has no interfering gas cloud and is therefore easier to understand. There are also more wells in this part of the structure.

The plan for development and operation of the Hod field was adopted by the Storting on 26 June 1988, while production started from one well in October 1990. In the course of one year or so, production has reached about 5000 scm a day from five subsea wells. Some 95 per cent of the production flows from the eastern structure, which has significantly better reservoir properties than that in the west. The plan calls for at least one more well to be drilled in the field, probably in the western structure.

Primary production will be by means of natural pressure relief, while secondary production methods such as water flooding or gas injection are also being considered.

Production installations
Development features an unmanned production installation, where oil and gas are separated by means of a separation unit and 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 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
All gas flaring takes place at Valhall as there is no separate flaring permit for Hod.

Costs
Total investments for the Hod field up to and including year 2005, and total operating costs through 2005, are estimated to be 954.3 and 818.1 million 1991 kroner, respectively.

2.5.2 Valhall

Production licence 006

Licensees

Amoco Norway Oil Company	28.3300 %
Amerada Hess Norge A/S	28.3300 %
Enterprise Oil Norway A/S	28.3300 %
Norwegian Oil Consortium A/S & Co	15.0000 %

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 impervious compared to other reservoir rocks on the Norwegian continental shelf. This gives the fields relatively low recovery, about 23 per cent, although the factor can be enhanced by employing new production techniques. The plan for development and operation was adopted by the Storting in spring 1977, with production start-up in 1980.

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 elicit from the reservoir.

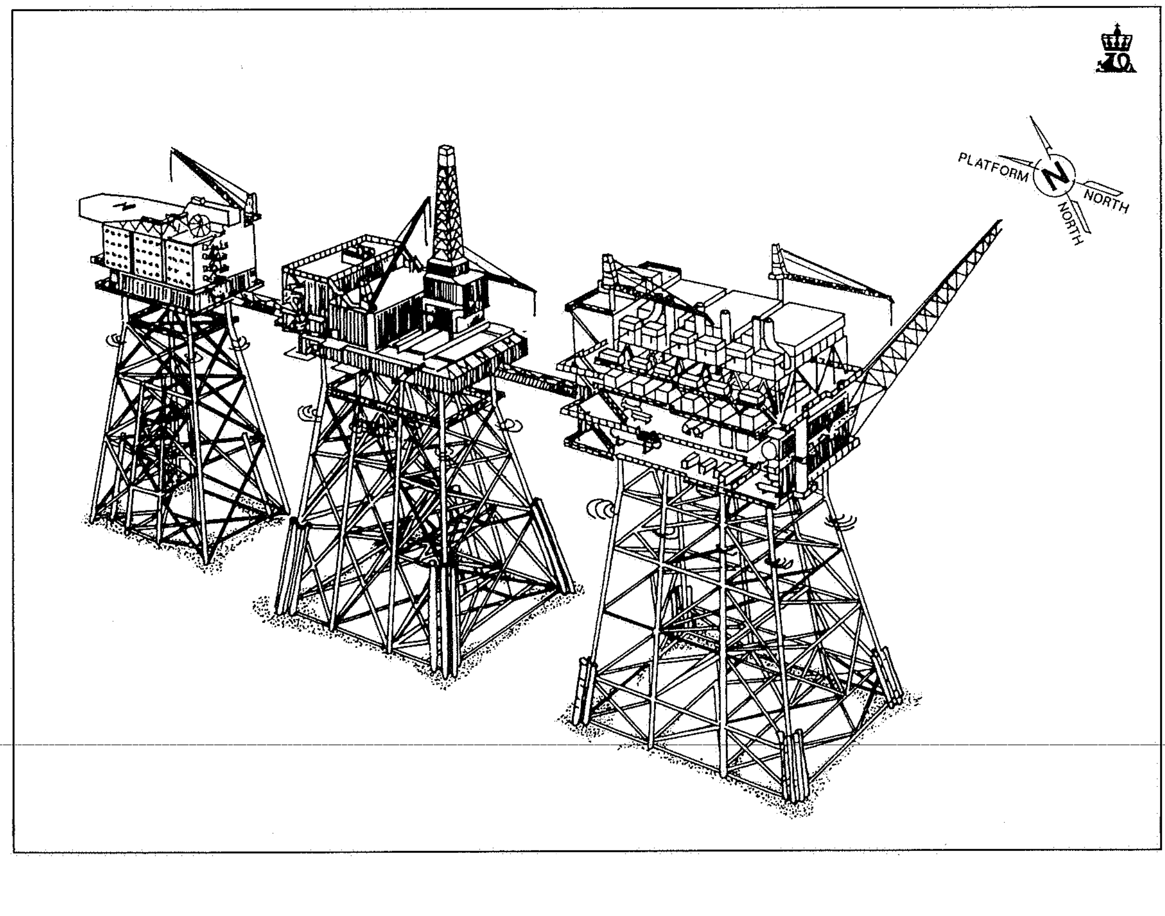
The results so far have been positive both with regard to injectivity and displacement efficiency. About 600,000 cubic metres of water were injected into the pilot well before water broke out in one of the neighbouring wells. According to plan the pilot experiment will continue until 1992. Simultaneously with the pilot project, studies have been made into water injection and gas injection on a full-field scale. The operator is expected to reassess the overall production strategy in the course of spring 1992.

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

Fig. 2.5.2
Installations on Valhall



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.

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

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

Flaring
The reported average gas flare volume on the field in 1991 was 35,000 scm a day, equivalent to 1.3 per cent of gas production, and 35 per cent of the permitted maximum.

Costs
The total investments on the Valhall field up to year 2011 are expected to be roughly 12.7 billion 1991 kroner. The total operating costs to the same date have been calculated at 16.7 billion 1991 kroner.

2.5.3 Tommeliten

Production licence 044
Licensees

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

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 offshore petroleum discovery.

Production
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.

Tommeliten comprises two structures, Alfa in the south and Gamma in the north. 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 duty cycle of the Edda field.

In 1992, a revised plan for development and production of the Tommeliten Alfa structure will be submitted. The most important change compared to the original plans is that one will now use horizontal wells to drain the structure, which will give an increase in recoverable reserves with a smaller number of wells.

Production installations
The Gamma structure has been developed using subsea completion wells and the Alfa structure will probably be developed using the same method. The produced fluid and gas are processed on the Edda installation.

Transportation
Following the first stage separation and metering on Edda, the Tommeliten gas is taken by pipeline to the Ekofisk Centre for further processing, while the dry gas is used by Phillips as fuel.

Tommeliten crude is transported from Edda to the Ekofisk Centre and thence by pipeline to Teesside for sale.

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

Flaring
The volume of gas which the operator is permitted to flare off on Tommeliten is included in the aggregate volume permitted for the Ekofisk field as a whole.

Costs
The total investments for the Tommeliten field up to and including the year 2005 are expected to reach about 4.2 billion 1991 kroner. The total operating costs up to the same date are expected to be about 1.3 billion 1991 kroner.

2.5.4 Ekofisk area

Production licence 018
Licensees

Phillips Petroleum Co Norway A/S	36.9600 %
Norsk Fina A/S	30.0000 %
Norsk Agip A/S	13.0400 %
Elf Aquitaine Norge A/S	7.5940 %
Norsk Hydro Produksjon A/S	6.7000 %
Total Norge A/S	3.5470 %
Den norske stats oljeselskap a.s	1.0000 %
Eurafrep Norge A/S	0.4560 %
Coparex Norge A/S	0.3990 %
Norminol	0.3040 %

This group, called the Phillips Group, owns the rights to the Cod, Edda, Eldfisk, Ekofisk and Vest Ekofisk fields. Cod lies in block 7/11, Edda and Eldfisk in block 2/7, and Ekofisk and Vest Ekofisk in block 2/4.

The Albuskjell field is split between production licences 018 and 011; the Tor field between production licences 018 and 006. Albuskjell lies in blocks 1/6 and 2/4; Tor in blocks 2/4 and 2/5.

The field interests are split as follows:

Albuskjell	
Phillips Group	50.0000 %
A/S Norske Shell	50.0000 %
Tor	
Phillips Group	75.3612 %
Amoco Group	24.6388 %
(Valhall licensees)	

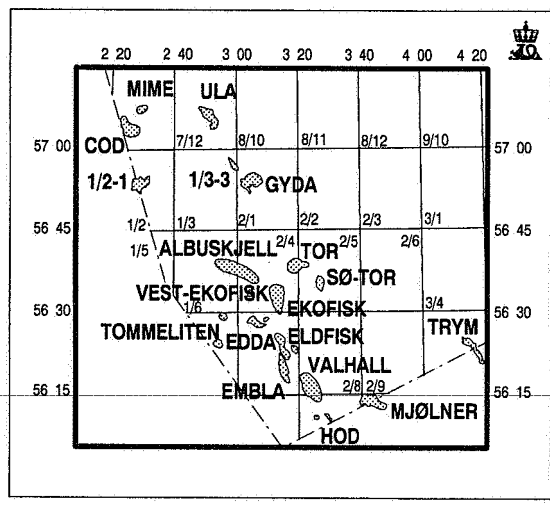
The Ekofisk area, operated by Phillips, consists of seven fields: Albuskjell, Cod, Edda, Ekofisk, Eldfisk, Tor and Vest Ekofisk. Cod was discovered in 1968 and is the only field producing from a sandstone reservoir in the Ekofisk licence. The other fields in the area all produce from chalk. Ekofisk itself was discovered in 1969 and declared commercial the year after. The other fields were discovered between 1969 and 1972. Ekofisk, easily the largest field in the area, has a hydrocarbon pore volume about 30 per cent larger than the Statfjord field. Eldfisk is the second in line as far as size goes. See Figure 2.5.4.a for field locations.

Production

The Ekofisk area has been developed in several stages.

From June 1971 to May 1974, oil was recovered from four wells which had been completed on the seafloor on the Ekofisk field. The fields Cod, Tor and Vest Ekofisk were developed and tied in with the Ekofisk Centre at the same time as the oil pipeline was laid to Teesside and the gas pipeline to Emden. These pipelines came on stream in October 1975 and September 1977, respectively. Before the gas line was commissioned the gas had been re-injected into the Ekofisk field.

Fig. 2.5.4.a
The Ekofisk area



The second development stage involved the tie-in of Albuskjell, Edda and Eldfisk to the Ekofisk Centre.

The fields, which are produced by means of depressurisation, have a relatively low oil recovery factor of about 20 per cent. The recovery factor can be increased by injecting water or gas into the reservoirs. In addition, greater use of horizontal wells both as producers and injectors can contribute to increased recovery. In 1991, the Directorate ordered the operator to perform studies of Ekofisk, Eldfisk and Tor. The purpose of these studies was to evaluate the feasibility of optimising recovery from the fields.

On the Ekofisk field, where water flooding has been performed on a field scale since 1987, the recovery factor will probably increase to about 30 per cent. In 1991, the water injection equipment was upgraded to an injection capacity of about 500,000 barrels of water a day. This upgrading permitted injection of water into the Tor formation and the lower part of the Ekofisk formation across the entire field. The operator is currently evaluating the future production strategy for the rest of the Ekofisk formation.

On Eldfisk, the second largest field in the area, the operator is also considering increasing the recovery by means of water flooding or gas injection. To this end a pilot project was performed in 1991 in which limited volumes of water were injected into a single well with positive results.

On the Tor field, also, the operator is evaluating the potential for water flooding or gas injection. Drilling of the first horizontal well in the area was initiated in 1991. The drilling of further horizontal wells in the area will be considered based on experience from this well.

The uppermost reservoir in the Albuskjell field, the Ekofisk formation, consists of relatively impervious rock with poor production properties. However, a new stimulation method has given rise to greater optimism with respect to production from this reservoir. Also horizontal wells will be considered to drain the Ekofisk formation. Figure 2.5.4.b shows the installations in the Ekofisk area.

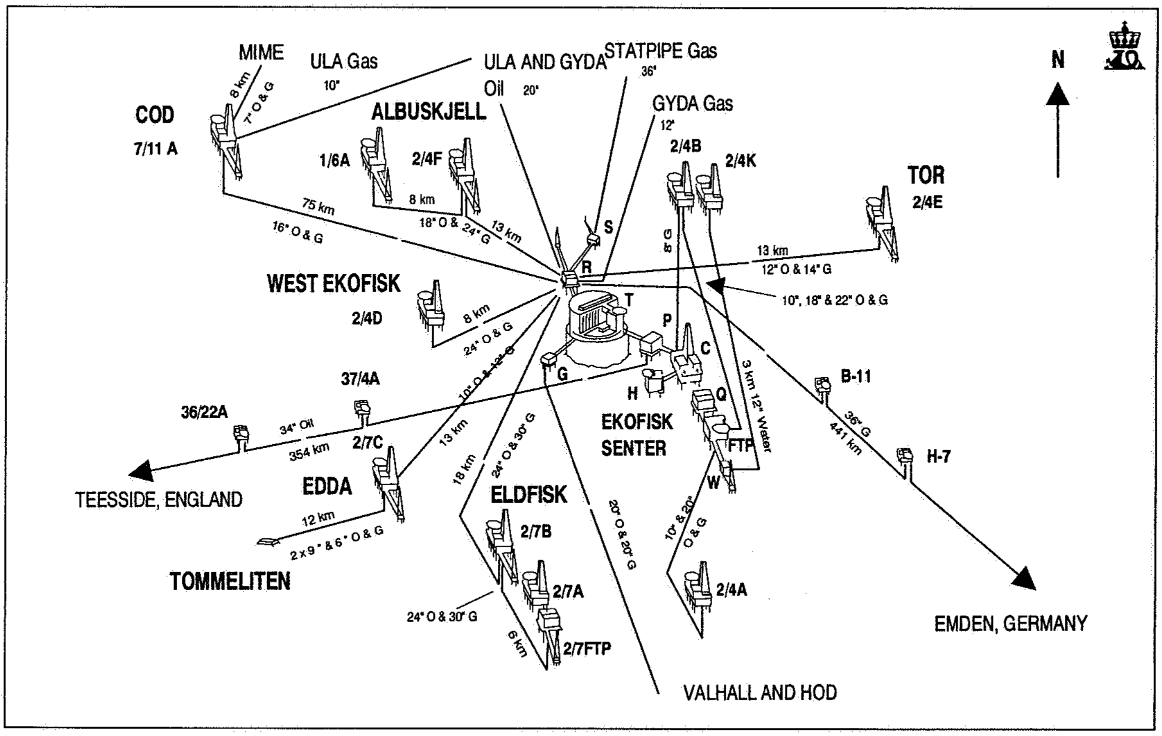
Subsidence

In November 1984 it was observed that the seabed beneath the Ekofisk Centre had subsided. Since then, measurements have shown that the total depth of the subsidence was about 5.21 metres as at 15 November 1991.

The rate of collapse from 1980 to 1986 was about 0.4 to 0.5 metres a year, although slightly less towards the end of the period. During 1987 and 1988 the measured rate of subsidence was about 0.3 metres a year. In 1991 the rate of subsidence increased compared to what was expected.

Several monitoring methods have been used to estimate the rate of subsidence. In 1984–85, analyses were made of wave data, though these could only in-

Fig. 2.5.4.b
Installations in the Ekofisk area



dicate the previous subsidence rate. This prompted the operator in 1985 to take many measurements of the distance from the sea surface to certain horizontal braces in the platform steel jackets. This method was of limited precision. Nowadays the subsidence is measured using pressure sensitive detectors on the seabed in addition to regular satellite passes.

The cause of the subsidence is the compaction of the reservoir rocks, permitted by the reduction in reservoir pressure from 7200 psi originally to about 3800 psi today. There is still some doubt about the mechanism by which the reservoir volume reduction causes subsidence and if perhaps there are also other factors contributing to the phenomenon.

The only way to prevent further compaction and other problems related to depressurisation is to limit the reduction in pressure. This can be done by injection of natural gas and/or water.

Subsidence is not peculiar to the Ekofisk Centre and it is reckoned there will be a need to modify installations in the northern and southern parts of the field during the 1990s.

In summer 1987 the steel platforms on Ekofisk were all jacked up due to the subsidence. This was done to lift them above the effects of the waves (100 year wave). This engineering feat was impossible for the concrete Ekofisk tank, so the Phillips Group decided to emplace a concrete barrier around it. Construction started in 1988 and the protective barrier was towed out to Ekofisk in two halves and mated on site in 1989.

Transportation
The gas is transported by pipeline to Emden. The capacity is fully exploited and the plan is therefore to include new coolers which will provide extra transportation capacity for next year.

The oil, containing the NGL fraction, is transported by pipeline to Teesside. Here the transport capacity is increased by increasing the operating pressure. As a further measure, anti-friction chemicals are added, giving a total current transportation capacity of over 600,000 barrels a day.

Metering systems
Total oil and gas deliveries to the Teesside and Emden pipelines from the area are metered on the Ekofisk tank. In addition, oil and gas production from the individual platforms is metered before transportation by pipeline to Ekofisk Centre. The exceptions are Vest Ekofisk and Ekofisk itself, which are metered on the Ekofisk tank.

All metering systems are in accordance with the fiscal standard and included in the operator's system for hydrocarbon distribution. Modernisation work is currently being undertaken in Teesside and Emden and there are plans for modernisation of the Ekofisk tank.

The annual cooperation meeting concerning gas metering in Emden was held with the German authorities as usual.

Flaring
The field gas flaring reports for 1991 record that a daily average of 40,000 scm gas was flared, equivalent to 0.19 per cent of gas produced and 40 per cent of the maximum permitted daily flare limit.

Costs
By year end 1991, over 70 billion 1991 kroner had been invested in the seven fields making up the Ekofisk area.

2.5.5 Gyda

Production licence 019B
Licensees

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

The Gyda field is located in block 2/1, about 28 km southeast of Ula, along the Ula Trend (Figure 2.5.4.a). The field was proven in 1980 by exploration well 2/1–3, and by 1985 three appraisal wells had also been drilled in the structure.

The Gyda field was declared commercial on 22 January 1987. The partners submitted their plan for development and operation on 11 March 1987, and the plan received Storting approval in spring 1987. Gyda came on stream on 21 June 1990.

Production
The reservoir from which production takes place consists of Upper Jurassic sandstone. Estimates for recoverable oil and gas are 32 mcm and 4 bcm, respectively, of which 2 bcm is sales gas, and 2 million tonnes is NGL.

The field is produced using water injection as the drive mechanism. There are plans for 17 production wells and eight injection wells, although the number can be increased if necessary. All in all there are 32 available slots.

Eight wells were pre-drilled in the period 1988–89, seven of which were tied in to the installation and their production initiated on a continuous basis in the course of the second half of 1990. One well had to be sidetracked and another three production wells were being drilled at the end of 1991.

Two injection wells were drilled in 1991. In addition, water is injected into two earlier production wells on the periphery of the field. The water injection capacity on the installation will be upgraded in the course of 1992.

The field has turned out to be more complicated than first assumed. Partly sealing faults pose a challenge with regard to draining strategy.

An exploration well south of Gyda proved a small accumulation of oil which will probably be produced by means of single-well depressurisation via tie-back to the Gyda installation.

Average production is about 10,500 scm oil and 1.6 mcm gas a day. The plateau rate can be maintained for three to four years, after which time production will gradually decrease and probably be terminated in 2012.

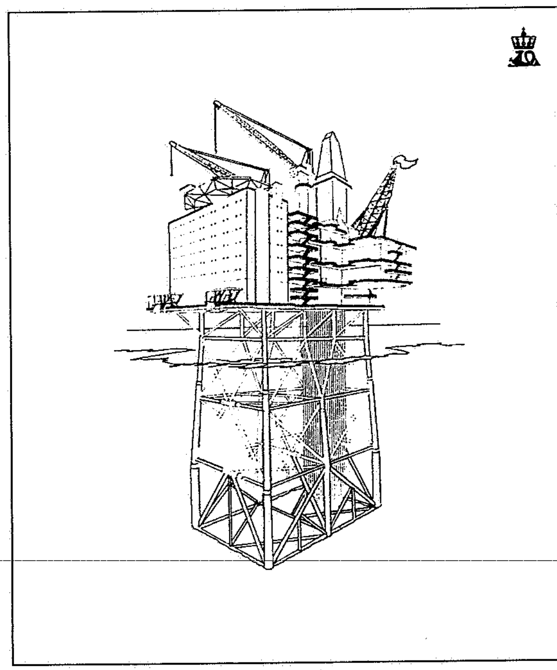
Production installations
The development concept for the field comprises a combined drilling, quarters and processing installation on a steel jacket, see Figure 2.5.5. The installation was prefabricated in large assemblies which were generally finally inspected and tested in the yard before being towed offshore in winter 1989–90. The high degree of completion before tow-out cut costs and reduced the manhours spent on offshore hook-up operations.

Oil production commenced on 21 June 1990, eight months ahead of schedule. Present production capacity is 11,000 scm oil and 1.6 mcm gas a day.

Transportation
Gyda crude is transported to Ekofisk via the Ula-Ekofisk oil pipeline and thence to Teesside, whereas the gas is transported in a separate pipeline to Ekofisk from where it flows to Emden.

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

Fig. 2.5.5
Installation on Gyda



Flaring

For 1991 the average reported volume of flared gas was 47,000 scm a day. This corresponds to 3.4 per cent of total gas production and constitutes 24 per cent of the maximum volume permitted.

Costs

Total investments up to 2012 amount to 8.3 billion 1991 kroner, whereas total operating costs come to 12.1 billion 1991 kroner.

2.5.6 Ula

Production licence 019A

Licensees

BP Petroleum Development of Norway A.S (operator)	57.500 %
Svenska Petroleum Exploration A/S	15.000 %
Den norske stats oljeselskap a.s	12.500 %
Norske Conoco A/S	10.000 %
K/S A/S Pelican & Co	5.000 %

The Ula field, situated in block 7/12 about 70 km northwest of Ekofisk (Figure 2.5.4.a), was discovered in 1976 and declared commercial in December 1979. Although the field development plan received approval in 1980, it became clear that same year that the development would not be profitable after all. A new field development plan was therefore submitted for a revised development concept in April 1983 and approved in January 1984. Production from Ula started in October 1986.

Production

The Ula field is an Upper Jurassic sandstone sediment. It lies on the Ula Trend which is an oil province along the faulted northeast margin of the Central Graben. The field is a salt dome structure with a reservoir having excellent production properties.

In 1990, an appraisal well was drilled in the southern part of the field, the results of which formed the basis for production also from this area.

In 1991, a long-range production well was drilled whose location was less than ideal on account of technical difficulties. According to plan the appraisal well will double as a water injector at a later date.

A further production well was drilled centrally in the field in 1991.

By year end the cumulative production was 27.5 mcm oil, and the cumulative injection 22.5 million cubic metres of water. Eight wells were simultaneously producing and six injecting. Water breakthrough is expected in 1992, after which time oil production will gradually decline until termination in 2009.

In the underlying Triassic reservoir recoverable volumes of oil have been proven only in the northern part of the block. Oil-water contact is uncertain, and the estimate for oil in place is in the region of 15 mcm, but a low recovery factor can be expected due to poor reservoir properties.

Production installations

The development concept involves three conventional steel jacketed platforms for production, drilling and quarters (Figure 2.5.6). The jackets were installed in summer 1985 and offshore hookup took place from October 1985 to August-September 1986.

In 1991, the production capacity was upgraded from 15,900 to 21,700 scm oil a day. The water injection capacity was increased from 19,100 to 28,600 cubic metres a day in 1990.

Transportation

The Ula crude is carried by pipeline via the Ekofisk Centre to Teesside. Statoil is operator for the link to Ekofisk, which was installed on the seabed in summer 1984. The Ekofisk link is about 70 km long and has a diameter of 508 mm. The Ula gas is carried by a gas line via Cod to Emden. The Ula-Cod link was installed and tested in spring 1985.

Metering system

The oil is continuously metered for tax purposes before being exported by pipeline to Ekofisk. Similarly, fiscal metering of the Ula gas takes place before the gas is injected into the gas line to Cod and Emden. The metering systems are part of the Ekofisk hydrocarbon distribution system.

Flaring

The reported daily average quantity of gas flared on Ula in 1991 was 20,000 scm, equivalent to 1.3 per cent of gas production and 20 per cent of the permitted flare limit.

Costs

Estimated total investments up to year end 2006 are about 11.5 billion 1991 kroner, while total operating costs up to the same date are expected to be 11.1 billion 1991 kroner.

2.5.7 Heimdal

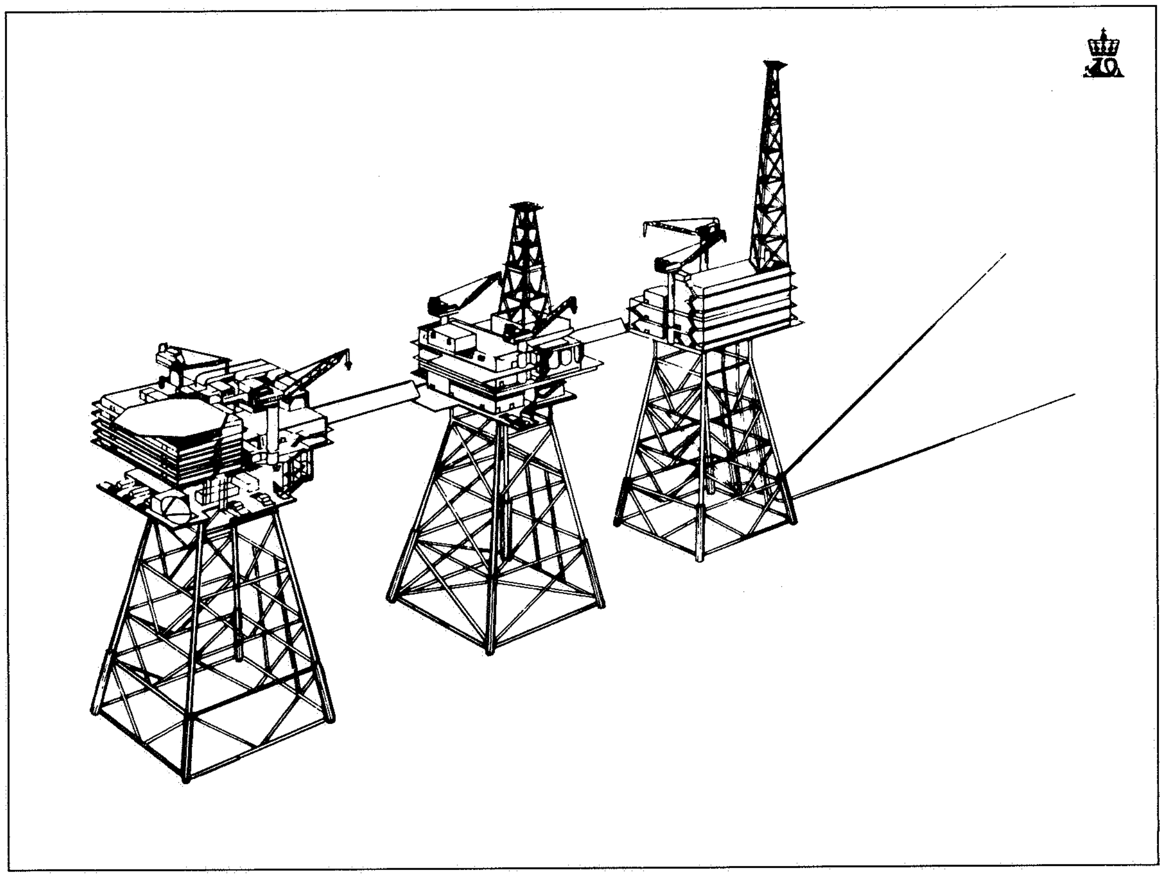
Production licence 036 was allocated in 1971 and covers block 25/4, lying about 180 km west-northwest of Stavanger (Figure 2.5.8.a), where Elf is operator. On that part of the field which embraces Heimdal, the Norwegian State has exercised its option through Statoil, and the field ownership is now as follows:

Licensees

Den norske stats oljeselskap a.s	40.000 %
Marathon Petroleum Company (Norway)	23.798 %
Elf Aquitaine Norge A/S	21.514 %
Norsk Hydro Produksjon a.s	6.228 %
Total Norge A/S	4.820 %
Saga Petroleum a.s	3.471 %
Ugland Construction Company A/S	0.169 %

The field was discovered in 1972 by the drilling of exploration well 25/4–1 and declared commercial in

Fig. 2.5.6
Installations on Ula



April 1974. This declaration was withdrawn in 1976 due to the low gas price.

In 1980 the gas market swung around and Heimdal became the key element in the debate about a landing option for the Statfjord gas. The application to land the gas on the Continent was submitted in January 1981 and received Storting approval on 10 June 1981. The landing application for condensate was approved in January 1983.

Production

The estimated total reserves in place in Heimdal are 36 bcm gas and 6 mcm condensate.

Production drilling on Heimdal started in April 1985. From the installation, 10 wells, nine production wells and one observation and injection well, have been drilled, although one producer had to be closed down in 1987 due to leakage problems.

Production so far has not met with any serious setbacks, though because of the powerful water drive in the field, pressure development and water ascent are both carefully monitored.

Production has reached plateau level, availability is good, and there is little occasion to flare off field gas.

Production installations

Heimdal has been developed with an integrated steel jacket structure combining drilling, production and quarters functions (Figure 2.5.7). Production start-up was in December 1985 and delivery of gas to Emden began in February 1986.

Transportation

The gas from the Heimdal field is transported through Statpipe, and the pipeline from Heimdal meets the pipeline from Kårstø to Ekofisk at the 16/11-S riser platform.

Metering system

The Norwegian Petroleum Directorate inspects the metering systems for gas and condensate. In the case of the condensate system, the inspection is done in collaboration with the British Department of Energy, as the condensate is transported via the Forties gathering system from the Brae field in the UK sector to Cruden Bay in Scotland. The condensate travels in a dedicated pipeline from Heimdal to Brae.

Costs

The total investments in the Heimdal field are in the region of 11.7 billion 1991 kroner. The total operat-

Fig. 2.5.7
Installation on Heimdal

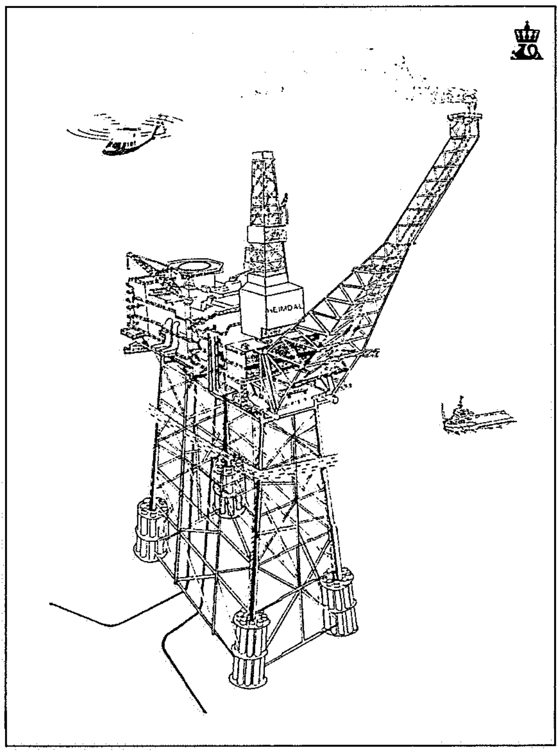
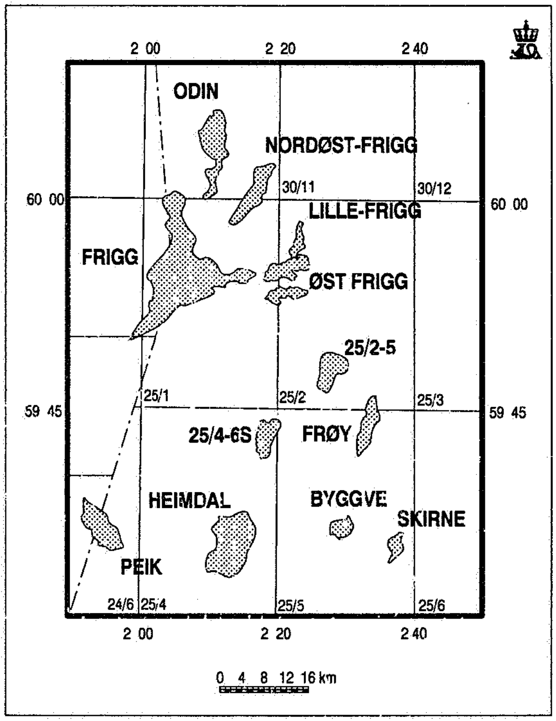


Fig. 2.5.8.a
The Frigg area



ing costs over the lifetime of the field are expected to reach 5.4 billion 1991 kroner.

2.5.8 Frigg area

2.5.8.1 Frigg

Licensees

Norwegian share (60.82 %) (production licence 024)

Elf Aquitaine Norge A/S	25.1910 %
Norsk Hydro Produksjon A/S	19.9920 %
Total Norge A/S	12.5960 %
Den norske stats oljeselskap a.s	3.0410 %

British share (39.18 %)

Elf Aquitaine UK Ltd	26.1190 %
Total Oil Marine Ltd	13.0600 %

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

The Frigg field is situated in blocks 25/1 and 30/10 in the Norwegian sector and blocks 10/1, 9/5 and 9/10 in the UK sector (Figure 2.5.8.a). The field has been unitised with 60.82 per cent of gas reserves in place being deemed to belong to the Norwegian partners. By the same agreement, the remaining 39.18 per cent belong to the UK partners.

Production

The Norwegian share of the total recoverable reserves is believed to be 110 bcm gas.

In 1984 considerable, though uneven, water ascent was observed in parts of the field. Several wells were drilled or deepened, and a lot of effort was made to clarify the situation. It transpired that the water is entering the reservoir from the southeast on account of a discontinuous slate barrier there, and flows laterally northward. This realisation, coupled with certain other studies, caused the estimated reserves to be scaled down.

North of the DP2 installation is an undrained zone into which an additional well has been drilled so as to produce the remaining gas. Another well has been drilled from DP2 into that part of the reservoir which is situated under CDP1 in order to deplete the remaining gas once CDP1 has shut down.

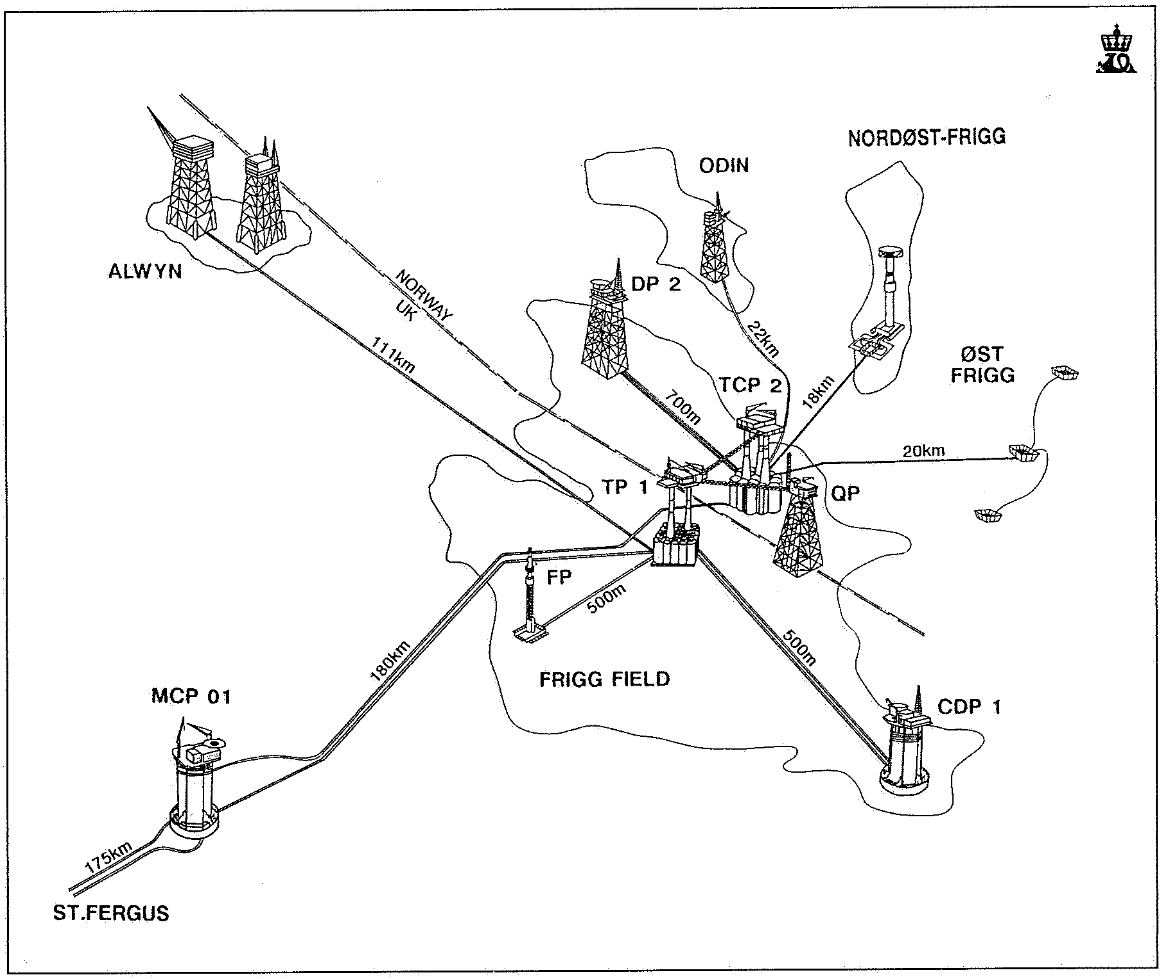
Production installations

Frigg was discovered in spring 1971 and declared commercial a year later on 25 April 1972. The field was developed in three phases, phase 1 comprising production and processing installations in the UK sector and a quarters platform (CDP1, TP1 and QP). Production from these installations started on 13 September 1977.

Phase 2 comprises production and processing platforms (DP2 and TCP2) in the Norwegian part of the field. Production from these came on stream in summer 1978. See Figure 2.5.8.b for a map of the Frigg installations.

Phase 3 of the Frigg development comprises the installation of a trio of turbine driven compressors on TCP2, which are necessary to compensate for the

Fig. 2.5.8.b
Installations in the Frigg area



falling reservoir pressure. Commissioning of the compressor plant was accomplished in autumn 1981.

Gas from Nordøst-Frigg, Odin and Øst-Frigg is processed and metered on Frigg. New modules for processing of gas and condensate from these satellite fields have been emplaced on TCP2. Export of gas from Alwyn North in the UK sector flows through TP1.

TP1 has been converted from a processing facility to a riser platform. TCP2 has been modified to adapt the compressor plant to changing pressure conditions and reduced gas volumes. In addition, one of three process trains on TCP2 has entered service.

Transportation

The gas is transported 355 km to St Fergus in Scotland through twin 813 mm diameter pipelines. In order to increase line capacity, two compressor turbines, each rated at 38,000 bhp, were installed on the compressor platform MCP-01 in 1983, halfway between Frigg and Scotland in a capacity upgrade that was necessary to make room for the Odin field gas. Now, because the requirement for transportation capacity is reduced, the compressors have been retired.

Metering system – Frigg area

Supervision of the metering systems on Frigg, Alwyn North and St Fergus is carried out in conjunction with the UK Department of Energy. This combined supervision extends to the Norwegian fields: Nordøst-Frigg, Øst-Frigg and Odin; the sum of these fields' production being deducted from the total measured quantity flowing into the St Fergus pipeline. The aim is to determine the quantity originating from the Frigg field.

Costs

The estimated total investments in the Norwegian sector of the Frigg field are about 19.5 billion 1991 kroner over the lifetime of the field. Investments in the transportation system come on top of this figure. The estimated total operating costs over the lifetime of the field are in the region of 9.7 billion 1991 kroner.

2.5.8.2 Øst-Frigg

Production licence 024 (block 25/1) and production licence 026 (block 25/2), see Figure 2.5.8.a:

Licensees	
Elf Aquitaine Norge A/S	41.4200 %
Norsk Hydro Produksjon a/s	32.8700 %
Total Norge A/S	20.7100 %
Den norske stats oljeselskap a.s	5.0000 %

Production licence 112 (previously relinquished part of block 25/2, re-allocated in 1985):

Licensees	
Den norske stats oljeselskap a.s	50.0000 %
Elf Aquitaine Norge A/S	21.8000 %
Norsk Hydro Produksjon a.s	17.3000 %
Total Norge A/S	10.9000 %

Øst-Frigg Alfa was discovered in 1973 and Øst-Frigg Beta the year after. Both structures extend into blocks 25/1 and 25/2 and marginally into the area previously relinquished. The reserves are split with 95.129 per cent in production licences 024 and 026, and 4.871 per cent in production licence 112. The field was declared commercial in August 1984 and the landing application considered by the Norwegian Storting on 14 December the same year. Production commenced in August 1988 and the sale of gas on 1 October 1988.

Production

The Øst-Frigg field consists of the two principal structures, Alfa and Beta, formerly known as Øst-Frigg and Sørøst-Frigg, respectively. They are part of the same pressure system as the Frigg field, and the gas is therefore sold to the British Gas Corporation (BGC) under the existing sales agreement.

The recoverable gas reserves were originally estimated at 8 bcm in Alfa and 5 bcm in Beta, or 13 bcm in all. However, production on Frigg has brought about substantial reduction in pressure and receding liquid contacts on Øst-Frigg, plus gas leakage amounting to about 6.4 bcm from the Alfa structure. On the other hand the deep saddle in the western part of the Beta structure has prevented gas migration from there to Frigg. In both structures, some gas is trapped in zones already drained, and the reserve estimates have therefore been revised downward to 8.2 bcm (total); with 5.1 bcm in Alfa and 3.1 bcm in Beta.

It is because of these problems that a third well was drilled on the Alfa structure, coming on stream in 1989.

The forecasted final year of production is now 1994, compared with the year 2002 originally planned. The reason is not just the decline in estimated reserves, but also the greater rate of production on the field.

Production installations

The Øst-Frigg development is based on subsea completion technology: Two templates for the production stations and a central manifold station tying the systems together were emplaced on the seabed in summer 1987.

These subsea production systems are remotely controlled from the Frigg control room. From the manifold a gas and service line runs to TCP2 where the gas is processed and fed into the Frigg field transportation system.

In connection with this development, modifications also had to be made on the Frigg field before start-up in order to support receipt of the gas.

Costs

The estimated total investments in the field are about 2.6 billion 1991 kroner. The estimated total operating costs over the lifetime of the field are 531 million 1991 kroner.

2.5.8.3 Nordøst-Frigg

Production licence 024 (block 25/1)

Licensees	
Elf Aquitaine Norge A/S	41.4200 %
Norsk Hydro Produksjon a.s	32.8700 %
Total Norge A/S	20.7100 %
Den norske stats oljeselskap a.s	5.0000 %

Production licence 030 (block 30/10)

Licensees	
Esso Norge a.s	100 %

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

The Nordøst-Frigg field lies in blocks 25/1 and 30/10 (Figure 2.5.8.a) where a redistribution of the gas reserves in August 1984 assigned 42 per cent to the former and 58 per cent to the latter. Elf Aquitaine Norge A/S operates the field.

Production

The total recoverable reserves in place on Nordøst-Frigg are believed to be 11.8 bcm gas.

Sale of gas from Nordøst-Frigg started on 1 October 1980 by virtue of pre-delivery from Frigg. Since production started up in December 1983 Nordøst-Frigg has been reinstating this gas in addition to volumes delivered on behalf of Frigg and own contract volumes. In order to achieve a longer-range sales profile it was proposed to continue deliveries from Frigg after production shutdown on Nordøst-Frigg.

Pressure measurements made before production start-up showed that the reservoir communicates with the Frigg field via the underlying aquifer. Although the field is expected to cease production in 1992–93, sales will continue until 30 September 1993.

Production installations

The Nordøst-Frigg gas field was discovered in 1974 and the final development plan passed in 1980. The field has been developed with six wells drilled through a subsea template (Figure 2.5.8.b).

The template also supports a manifold in addition to the wellheads and valve trees the purpose of which is to gather the gas from the six wells. The gas is led through a 406 mm diameter pipeline to the Frigg field for processing. Each of the valve trees is controlled by discrete service and control lines from the Frigg control station, an articulated column structure located 150 metres from the wellheads. The control station was installed in July 1983 and is remotely controlled from Frigg itself. The plan for removal of the Nordøst-Frigg installation was submitted to the authorities on 30 August 1991.

Costs

The estimated total field investments are roughly 2.7 billion 1991 kroner, while total operating costs are expected to run to about 646 million 1991 kroner.

2.5.8.4 Odin

Production licence 030

Licensees

Esso Norge a.s	100 %

Statoil is entitled to 17.5 per cent of net profit before tax. The Odin field lies in block 30/10 (Figure 2.5.8.a) and is operated by Esso. This gas field was proven in 1974 and the field development plan adopted in 1980.

Production

The estimated total recoverable reserves in place are 29.3 bcm gas.

Gas sales from Odin were initiated on 1 October 1983 through the pre-delivery arrangement with Frigg. Since production start-up in April 1984, Odin has been reinstating the pre-delivered volumes in addition to delivering own contract quantities.

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

In spring 1990, the operator detected water penetration in the field's southernmost well. It was expected that water penetration would occur in this well first, but it happened rather earlier than anticipated. New studies show that both the remaining reserves and the lifetime of the field will be somewhat curtailed.

Production installations

The field development concept involves a small steel jacket structure with relatively modest processing and drilling facilities and comparatively small quarters (Figure 2.5.8.b). This concept was feasible because a standby vessel was employed for two years in connection with installation work and production drilling operations.

The Odin facilities separate the water from the gas and inject methanol for hydrate control purposes. The gas is then sent by pipeline to the TCP2 platform on Frigg for further processing before being exported through the Norwegian Frigg line to St Fergus.

Costs

The estimated total investments in the field are about 3.9 billion 1991 kroner. The total operating costs over the lifetime of the field are estimated to be about 2.4 billion 1991 kroner.

2.5.9 Oseberg area

2.5.9.1 Oseberg

The Oseberg field extends into two blocks: block 30/6 in production licence 053 allocated in 1979, and block 30/9 in production licence 079 which was allocated in 1982. See Figure 2.4.4.a.

Licensees

Those parts of the production licences which cover Oseberg have been unitised over the two licences. The partners have assumed a provisional apportionment of the reserves with 60 per cent in block 30/6 and 40 per cent in block 30/9. Statoil's equity in Oseberg increased relative to the foreign partners when the sliding scale was exercised. The latest increase was on 1 April 1988 in connection with approval of the revised plan for development and operation.

The partners in the unitised Oseberg field are as follows (from 1 April 1988):

Den norske stats oljeselskap a.s	65.0400 %
Norsk Hydro Produksjon a.s	13.7500 %
Saga Petroleum a.s	8.6100 %
Elf Aquitaine Norge A/S	5.6000 %
Mobil Development Norway A/S	4.2000 %
Total Norge A/S	2.8000 %

Production

The first discovery on Oseberg was made in 1979 which proved gas. Later evidence showed that the reservoir is an oil bearing stratum with a gas cap. The commerciality declaration was submitted to the Ministry in June 1983 and the Storting dealt with the development application in the spring session 1984. A revised plan for development and operation was approved in January 1988, its main revision being the accelerated development of the northern part of the field (phase 2) and an increased output from the field centre in the south.

In November 1987, Hydro submitted a revised plan for development and operation of Oseberg. The Oseberg C installation has been upgraded from a satellite unit to an integrated production, drilling and quarters (PDQ) platform making use of a support vessel during the drilling phase. Production start-up was brought forward from 1995 to December 1990. During 1988 it became obvious that this plan was too ambitious and production start-up on Oseberg C was put back to October 1991.

Increased reserves in the northern part of the field have occasioned plans to lay a multi-phase flowline from the C platform to the field centre. This line will result in optimal production and improved exploitation of the processing capacity at the field centre.

In order to understand the Oseberg reservoir better, a long-term test program was initiated in autumn 1986 using the production testing vessel *Petrojarl I*. These production tests were terminated in spring 1988.

Ordinary production started to flow in December 1988 through a total of 10 wells (of which eight were producers and two gas injectors) from the field centre. As all 10 wells had been pre-drilled full production was soon reached, although teething troubles caused much of the initial gas to be flared off. These setbacks were largely overcome during the year and flaring assumed a normal level towards the end of 1989.

Estimated total oil recovery from the field is about 226 mcm. This gives a mean recovery factor close to 50 per cent. Even though the factor is already relatively high, there are good opportunities for increasing oil production from the field even further.

Oseberg does not contain sufficient gas for the operator to maintain pressure by reinjection of the gas. Therefore a subsea production unit, Troll-Oseberg Gas Injection, has been fabricated and installed on the Troll field with a pipeline from Troll to the Oseberg field centre. The TOGI unit will supply some 25 bcm gas over a 12 year period starting in 1991. In connection with the acceleration of the Oseberg 2 development, the operator is planning to obtain further injection gas from a satellite field, Gamma Nord, on the western flank of Oseberg. From this structure about 4 bcm gas will be injected over an eight-year period from start-up of the Oseberg C platform. Most of the injected gas can be recovered during the gas production phase on Oseberg which is expected to last from year 2003 to about 2017.

Chemical flooding

On account of the plans for water injection to provide the drive mechanism for the main Alfa structure reservoir, it was decided to implement a project aimed to examine the viability of enhancing recovery by the addition of surfactants to the injection water. This project has continued despite the selection of gas injection for the Alfa enhancement, though now with the Alfa-Nord reservoir as the target where water injection is the preferred driver.

In 1991, the project directed a lot of energy to defining the optimum surfactant system and to identifying what opportunities exist for running a pilot injection project on a limited portion of the reservoir.

The plans are first to run a simple single-well test using both chemicals and tracers in order to gain experience with the field before initiating a major pilot project. Such a test was scheduled for execution in 1991 but has been postponed until spring 1992.

Production installations

Oseberg developed involves two phases. Phase 1 was developed with a field centre in the south comprising two installations, Oseberg A which is a process and quarters platform on a gravity base, and Oseberg B which is a drilling and waterflood platform on a steel jacket. The middle portion of the field will be depleted using two subsea completion wells tied in to the field centre. Production start-up occurred on 1 December 1988 on the Oseberg field centre, which has a mean crude processing capacity of about 50,000 scm a day.

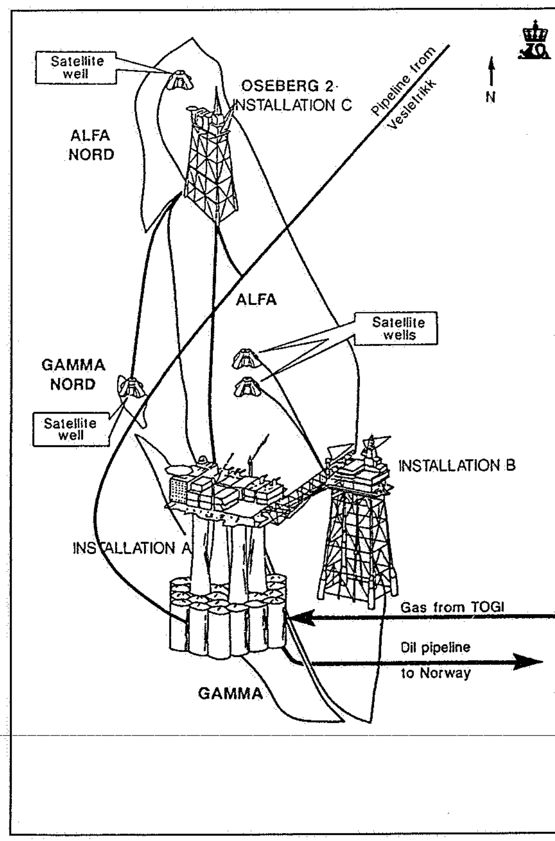
Phase 2 involves development of the northern part of the field. In the revised Oseberg plan the C installation has been upgraded from a satellite unit to an integrated production, drilling and quarters (PDQ) platform employing the services of a support vessel during the drilling phase. Production start for Oseberg C was 2 September 1991. The mean crude processing capacity is 14,300 scm a day.

For a diagram of the installations, see Figure 2.5.9.

Transportation

A pipeline for transportation of stabilised oil from Oseberg to Sture, north of Bergen, was laid in summer 1987. This 711 mm diameter line has a capacity

Fig. 2.5.9
Existing and planned installations on Oseberg



of 95,000 scm oil a day. The greatest water depth this line reaches is about 350 metres.

The plant including the Sture terminal is owned and operated by a joint venture, I/S Oseberg Transport System, whose partners are identical with the Oseberg partners. The pipeline operator is Hydro, who also operates the terminal. The OTS entered service when Oseberg came on stream and comprises the following main elements:

- Pipeline support functions on Oseberg A
- Subsea pipeline
- Landing point
- Onshore pipeline
- Terminal.

In the present plans the gas export from Oseberg will commence in year 2002. The gas has not been sold and no decision has been made how to export it from Sture.

Metering system

The oil metering system on Oseberg A and the Sture I export metering station were commissioned in December 1988. The Sture II export metering system has been in operation since mid-year 1989.

All three metering systems were calibrated in the course of 1991. The metering system for Oseberg C was tested and entered service at the time of production start-up in the middle of September 1991.

The gas metering system for injection gas purchased from Troll's TOGI system was tested in December 1990 and commissioned by the time of production start-up in early 1991.

Flaring

The volume of flared gas on Oseberg A is about 120,000 scm a day on average. This corresponds to some 1.6 per cent of the associated gas produced and constitutes about 60 per cent of the maximum volume permitted to be flared off.

Costs

By year end 1991 some 37 billion 1991 kroner had been invested in the Oseberg field. The final total is expected to be about 41.9 billion 1991 kroner. The total operating budget is expected to reach about 41.2 billion 1991 kroner by year end 2011. These costs do not include the Oseberg Transport System (see below).

Costs for Oseberg Transport System

The total investment in OTS is about 4.6 billion 1991 kroner. Predicted operating costs are about 3.7 billion 1991 kroner up to the end of year 2000.

2.5.9.2 Gamma Nord

Gamma Nord is situated in block 30/6 covered by production licence 053 allocated in 1979. The field is included in the revised development plan for the northern part of the Oseberg field.

Production licence 053

Licensees

Den norske stats oljeselskap a.s	59.4000 %
Norsk Hydro Produksjon a.s	12.2500 %
Elf Aquitaine Norge A/S	9.3330 %
Saga Petroleum A/S	7.3500 %
Mobil Development Norway A/S	7.0000 %
Total Norge A/S	4.6670 %

Production

The Gamma Nord structure is situated west of the Oseberg field and is an inclined fault block whose hydrocarbon bearing strata are part of the Statfjord formation. A layer of rich, coal bearing slate divides the Statfjord formation into an upper and a lower reservoir zone. Two wells have been drilled in Gamma Nord, one exploration well and one horizontal production well where a pilot hole was drilled before the horizontal section was drilled. The pilot hole also proved hydrocarbons in the lower reservoir zone. Hydrocarbons were proven in 1984 and the field entered production in October 1991.

Gamma Nord is a gas field, though with a thin oil zone. A horizontal well was selected in order to recover as much of the oil as possible before depleting the gas. All of the gas will be used as injection gas for the Oseberg field. Oil production is estimated at some 0.53 mcm while gas production is some 3.85 bcm.

The drilling of one further well on Gamma Nord is being considered and a revised plan for development and operation will be available early in 1992.

Production installations

Gamma Nord is developed by means of a seabed completion well feeding to Oseberg C for processing.

Metering system

The oil and gas metering system entered service simultaneously with production start-up in the middle of October 1991.

2.5.10 Veslefrikk

Production licence 052

Licensees

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

Veslefrikk lies in the southeast of block 30/3 which was allocated in 1979, with Statoil as operator. Four exploration wells have been drilled in the block and two in the Veslefrikk structure itself.

The commerciality declaration was submitted to the partners in November 1986; while the plan for development and operation was submitted in February 1987 and approved by the Storting in 1987. An updated field report, written after pre-drilling of six production wells, was submitted in September 1989. The field started production on 26 December 1989.

Production

The Veslefrikk field makes up the highest part of a slightly arched structure with downfaulted areas on all sides. Commercially recoverable reserves are found in two levels, in the Brent group (lower and middle part) and Intra Dunlin Sand. The estimated total recoverable reserves in place in Veslefrikk are 36.4 mcm crude oil and 3.1 bcm associated dry gas. Additional resources have been proven in the upper Brent (Tarbert) and Statfjord formations, but these resources have so far not been declared commercial. Both in Intra Dunlin Sand and the lower Brent (Oseberg) formation, calcite cementation occurs to a varying degree. Faults break the field into four regions.

Production from the field is by means of water injection. However, delayed start-up of water injection and problems of availability have resulted in somewhat lower than anticipated production since February 1991. Enhanced injection capacity and plans to upgrade show signs of giving positive pressure development and stable production. Water alternating gas injection has also been considered. Simulations show that WAG injection can materially boost production. However, the peak effect is highly sensitive to the pressure conditions in the reservoir.

Reservations about the field reservoir are closely linked to geological uncertainties. Lack of control of the distribution of carbonate cementing gives cause for uncertainty with regard to injectivity in various areas of the field. It is also uncertain to what extent cemented horizons form vertical barriers. In addition, there is doubt whether there is any communication across faults and between individual reservoir zones in middle Brent.

Production installations

The field has been developed with a fixed wellhead installation with a steel jacket and a semi-submersible platform containing the processing facilities and living quarters. The wellhead unit is emplaced above a template with six pre-drilled wells. The semi-submersible, formerly the *West Vision* drilling rig, is moored and hooked up to the fixed wellhead unit.

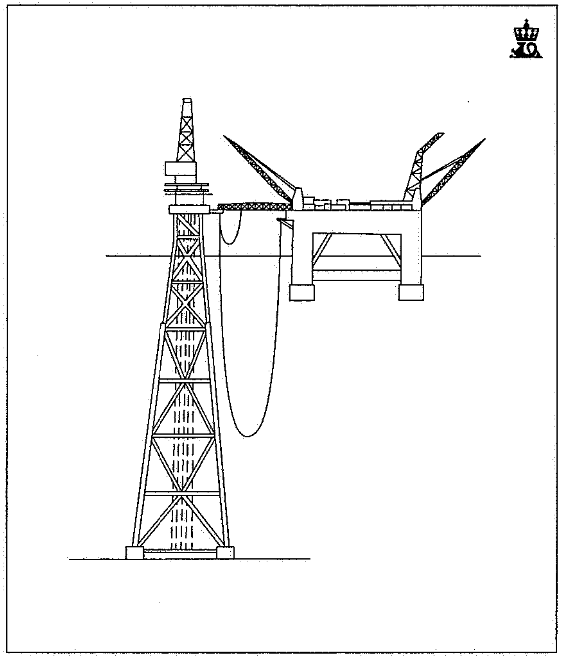
The Veslefrikk production facilities have returned 95 per cent availability. Water injection was initiated in spring 1991.

See Figure 2.5.10 for Veslefrikk installations.

Transportation

An oil pipeline is connected to the Oseberg Transport System for transport of the Veslefrikk oil to the Sture terminal. Gas is carried through the Statpipe system. The gas has not yet been sold, although an interim agreement has been struck with Heimdal for intermediate storage of produced gas from Veslefrikk.

Fig. 2.5.10
Installations on Veslefrikk



Metering system

The metering station for oil entered service on Veslefrikk at year end 1989. Gas metering commenced in May 1990.

Costs

Estimated total investment and operating costs over the lifetime of the field are 8.0 billion and 11.8 billion 1991 kroner, respectively.

2.5.11 Gullfaks

Production licence 050

Licensees

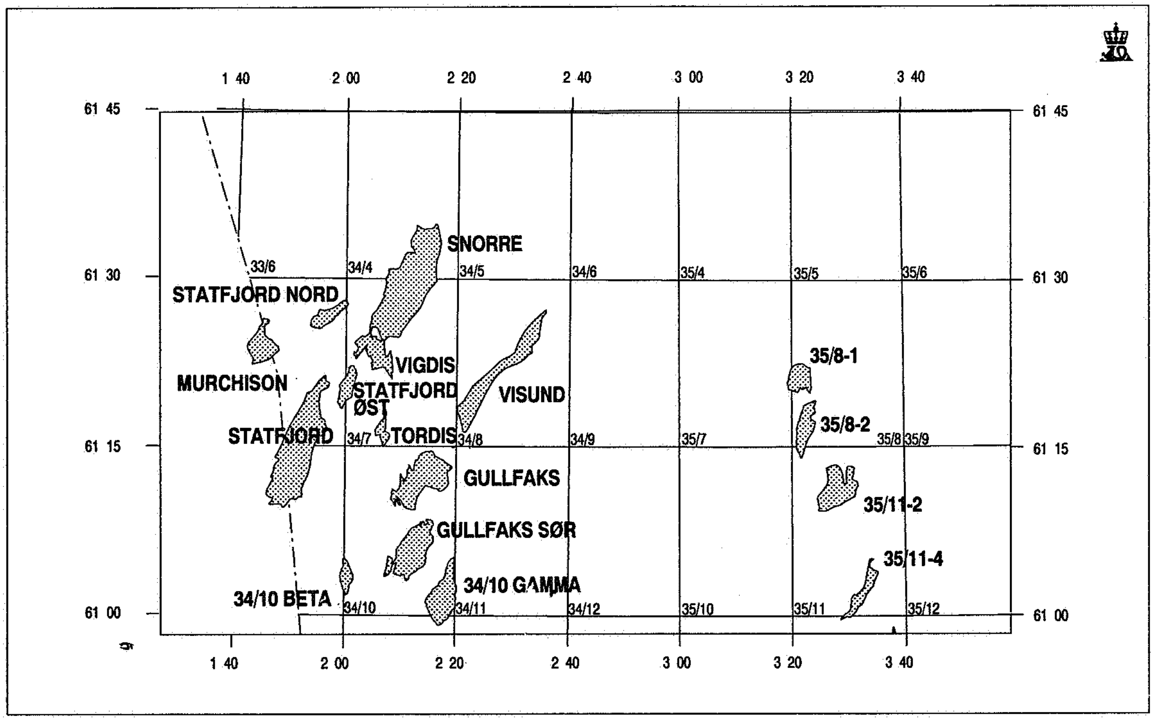
Den norske stats oljeselskap a.s	85.0000 %
Norsk Hydro Produksjon a.s	9.0000 %
Saga Petroleum a.s	6.0000 %

Gullfaks lies in the northeastern part of block 34/10 and covers an area of about 200 square kilometres. Figure 2.5.11.a shows the location. Gullfaks was discovered in 1978. Due to the phased development concept, separate field development plans for phase 1 and 2 were adopted in 1981 and 1985, respectively. The phase 1 development embraces the A and B installations, while the C installation covers phase 2. Production from the field started to flow in December 1986.

Production

Gullfaks is a relatively shallow accumulation and has fault groups in several angled and rotated fault blocks. The reservoir rock is Jurassic sandstone. The blocks vary in slope and are in some places heavily

Fig. 2.5.11.a
The Gullfaks, Statfjord and Snorre area



eroded. The structural features in the eastern section are difficult to identify due to the poor seismic readings obtained. The complex geological makeup of the field was confirmed during the production drilling, when several quite surprising fault patterns turned up. However, these faults are not as sealing as first supposed.

The reservoir phases 1 and 2 are segregated by a north-south fault. A certain degree of communication has been proven in the northern part. Fault lines more than 1000 metres apart limit the field in the south, east and northeast.

The reserves are dispersed in the Brent group, Cook formation and Statfjord formation, although over 80 per cent are in Brent. The operator re-estimated the reserves in 1991, resulting in a small decrease in oil in place and different distribution in the various accumulations. However, the estimated total recoverable volume of oil is still 230 mcm, 61 per cent of which is in phase 1 and 39 per cent in phase 2. Phase 2 production started in December 1989.

By year end 1991 the cumulative production was 63.18 mcm oil and the cumulative injection 70.29 million cubic metres of water. Currently, about 69,000 scm oil is lifted from the field on a daily basis. The 1991 production was somewhat higher than forecast, mainly as a result of more wells, high regularity, successful intervention and active follow-up of well control criteria. Problems with water and sand production are still a limiting factor. The field as a whole is expected to produce at plateau rate in the years 1992–94, later to be stepped down gradually until production ceases in 2006.

The drive mechanism in the field is primarily water injection, although alternative methods of increasing the recovery factor are also being considered and tested. Pilot studies employing WAG (water alternating gas) injection and a one-well test with tenside injection as well as the drilling of horizontal wells started in 1991. The injection of thin gel is also considered a plausible recovery strategy on Gullfaks. New well completion and stimulation methods have been tested with encouraging results.

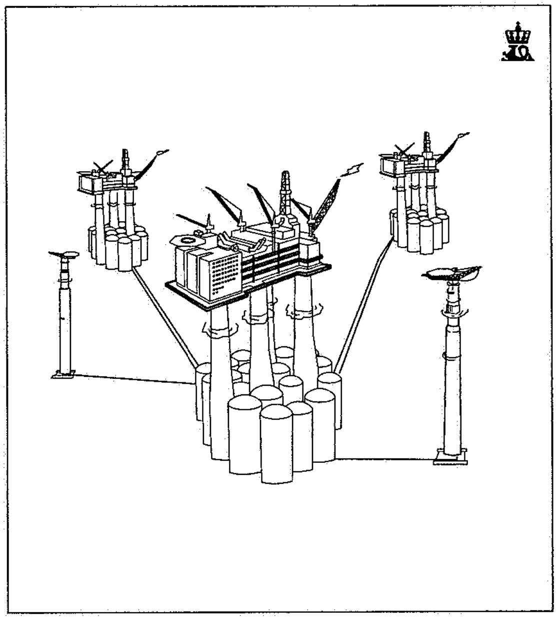
Production installations

Phase 1 comprises two installations, Gullfaks A and B, which are both Condeep type gravity base platforms with steel frame topsides. See Figure 2.5.11.b. The C installation in phase 2 is essentially a copy of Gullfaks A. All three are fully integrated process, drilling and quarters platforms, although Gullfaks B has a simplified process train with only first-stage separation.

Gullfaks A is located in the southern part of the field where production commenced on 21 December 1986. The process capacity is 52,000 scm oil and 70,000 cubic metres water a day from early 1992. Gullfaks A water injection capacity is 75,000 cubic metres a day. At year end the platform counted 25 production wells and eight water injection wells, of which six were completed subsea.

Gullfaks B is located in the northwestern part of

Fig. 2.5.11.b
Installations on Gullfaks



the field and came on stream on 29 February 1988. Its process capacity is 31,000 scm oil and 30,000 cubic metres water a day. Oil from Gullfaks B is transferred to Gullfaks A and C for further processing and storage. A separate water injection system was installed on Gullfaks B in 1991, with a capacity of 30,000 cubic metres a day. In addition, injection water can be transferred from Gullfaks C. At year end, 11 production wells and seven water injection wells had been linked up to Gullfaks B.

Gullfaks C is located in the eastern part of the field and will produce the Gullfaks field's phase 2 resources. Operations started with oil transferred from Gullfaks B on 4 November 1989. Production from its own well started around year end 1989. Process capacity on the installation is 39,000 scm oil and 30,000 cubic metres water a day, and up to 60,000 cubic metres water can be injected on a daily basis. At year end the installation had six production wells and two water injection wells.

Metering system and transportation
Both Gullfaks A and C have storage cells in which to store the stabilised oil, which is metered and exported via loading buoy to tankers. Processed gas is subject to continual fiscal metering on A and C before being exported into the Statpipe system.

Flaring
The Gullfaks gas flaring reports for 1991 show that 260,000 scm were discharged a day. This is 4.5 per cent of gas production and 66 per cent of the permitted flare limit.

Costs
Estimated total investment costs and operating costs over the lifetime of the field are 62.5 billion and 52.0 billion 1991 kroner, respectively.

2.5.12 Statfjord
Production licence 037
Licensees

Norwegian share (85.23869 %)	
Den norske stats oljeselskap a.s	42.619345 %
Mobil Exploration Norway Inc	12.785804 %
Norske Conoco A/S	8.523869 %
Esso Norge a.s	8.523869 %
A/S Norske Shell	8.523869 %
Saga Petroleum a.s	1.598225 %
Amoco Norway Oil Company	0.887903 %
Amerada Hess Norge A/S	0.887903 %
Enterprise Oil Norway A/S	0.887903 %
British share (14.76131 %)	
Conoco (UK) Ltd	4.920437 %
BP Petroleum Development of Norway A.S	5.920437 %
Chevron UK Ltd	5.920437 %

Production licence 037 was allocated in 1973 and covers blocks 33/9 and 33/12 (Figure 2.5.7.a). The Statfjord field extends into the UK sector where Conoco is the operator. The field was discovered in spring 1974 and declared commercial the same year. Mobil was operator on the field until 1 January 1987 when Statoil assumed operatorship. Statfjord is Norway's largest oil field.

The Statfjord field partners have now concluded the protracted process of redistributing the field between Norway and the UK. Pursuant to existing agreements, disputes regarding the interpretation of certain points should be settled by an independent expert. The final expert decision on redistribution of the field was available in August 1991, resulting in an increase in the Norwegian share by 1.14547 per cent to 85.23869 per cent. However, the new distribution figures have not yet been approved by the authorities of the two countries.

Production
The total recoverable reserves of oil were upgraded in 1990 to an estimated 531.5 mcm, the comparable figure for associated dry gas being 60.0 bcm, and for NGL 18.6 million tons. The recovery strategy pursued is based on maximising the production rates and recovery factor by manipulating the pressure conditions in the reservoirs. This is achieved by injection of water in the Brent group and gas into the upper part of the Statfjord reservoir. A gas cap has now developed at the top of the Statfjord reservoir, which has resulted in an increase in the gas-to-oil ratio in many producers in this reservoir. In the lower part of the Statfjord reservoir the operator is now planning for water injection.

In order to better exploit the remaining reserves in place the operator has formulated a revised production strategy for the field in so far as utilisation of the wells is concerned. The strategy involves more wells than originally planned, plus extensive re-use of the wells in several reservoir zones. Using horizontal and long-range high-deviation bores is also part of the strategy. So far, a couple of horizontal wells have been drilled in the Statfjord reservoir and long-range high-deviation or horizontal wells have been drilled in the geologically more complex parts of the field in the east and north.

Studies were performed in 1991 to examine how modifications to the installation, such as increased water treatment capacity, can improve reservoir exploitation. Furthermore, a plan for exploitation of the Dunlin reservoir has been under preparation. This reservoir has a limited volume of resources compared to the Brent and Statfjord reservoirs.

A study programme into relevant advanced oil recovery methods is currently ongoing and may lead to a pilot project on the field.

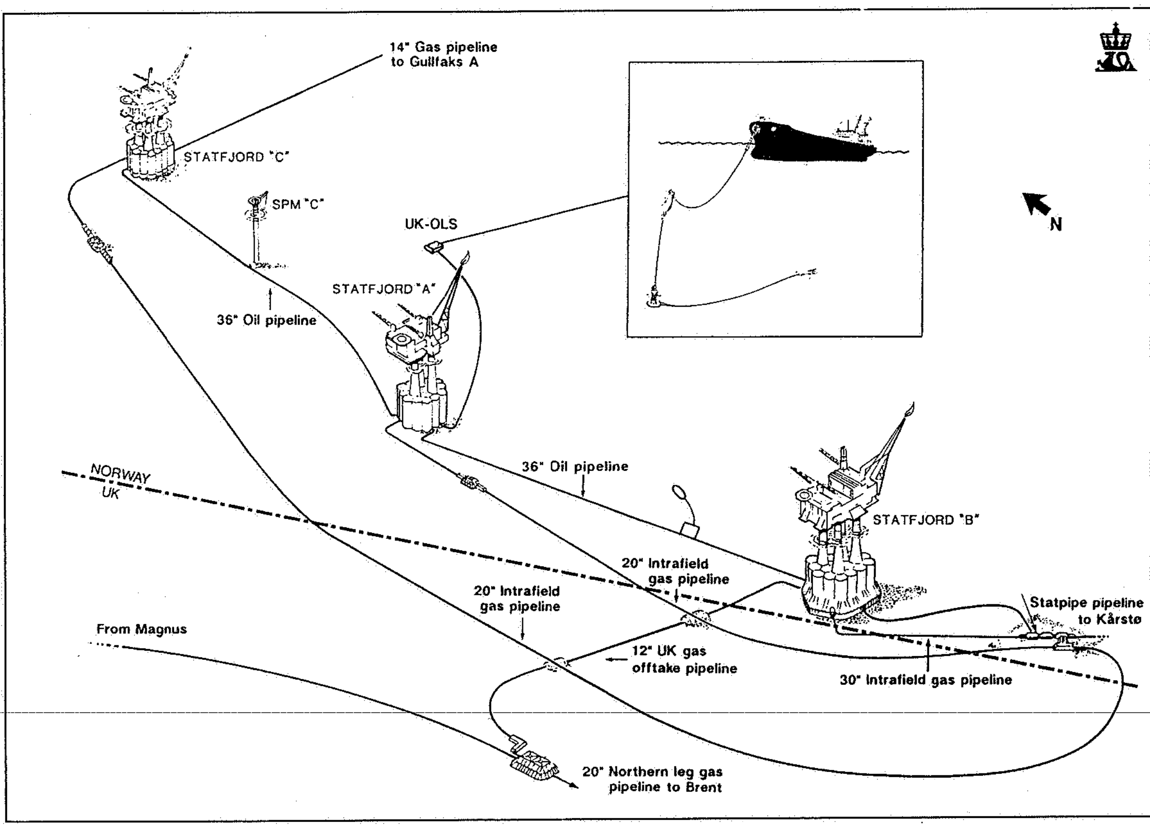
Production installations

The Statfjord field has been developed in three phases using three fully integrated platforms, Statfjord A, B and C. See Figure 2.5.12.

Statfjord A

The Statfjord A installation is situated near the centre of the Statfjord field. It is a fully integrated platform with concrete gravity base consisting of 14 storage cells and three columns. The topsides are of steel. The production capacity is 55,000 scm a day split between two production trains. In 1988, the water treatment system capacity was upgraded in order to handle the increasing produced water volumes from the various wells. The water treatment capacity will be upgraded even further in the near future. The platform started production on 24 November 1979 and has been developed with 37 wells, 23 being oil producers, 10 water injection wells and four gas injection wells. In 1986, a new type of offshore loading buoy was installed for Statfjord after the original one had to be decommissioned and removed due to extensive mechanical malfunctioning. The new buoy has an offloading capacity of about 5000 scm an hour compared to the former buoy's approx 8000 scm an hour. As the Snorre development was resolved in 1988 with connections to Statfjord A, this means that the facilities on this installation will be better utilised from 1992 than would otherwise have been the case.

Fig. 2.5.12
Installations on the Statfjord field



Statfjord B

The Statfjord B platform is located in the southern part of the Statfjord field. Again it is a fully integrated platform with concrete gravity base, this time combining 24 storage cells and four columns. Again, too, the topsides are of steel. Production capacity is 39,800 scm a day from one production train. Here too, it has been necessary to upgrade the water treatment capacity in order to deal with the increasing water cut from the various wells. Statfjord B came on stream on 5 November 1982 and has been developed with 32 wells: 22 oil producers, eight water injection wells and two gas injection wells. In 1988, serious mechanical problems were discovered on the original Statfjord B loading buoy, and in 1989 it was decided to replace it with a new version similar to the Statfjord A successor. This new offshore loading buoy entered service in autumn 1990. It has the same capacity (8000 scm an hour) as the buoy it replaced.

Statfjord C

The Statfjord C platform, situated in the northern part of the Statfjord field, is another fully integrated installation, structurally identical to Statfjord B. Statfjord C's water treatment capacity was also upgraded in 1988. A further increase in water treatment capacity will be required also here. The platform came on stream on 26 June 1985 and has 38 wells: 28 oil producers, eight for water injection and two gas injection wells. It has been decided to develop the Statfjord Nord and Statfjord Sør satellites as subsea installations with associated processing on Statfjord C. This means that the treatment capacity for the facilities on this platform can also be used from the end of 1993.

Transportation

Statfjord gas is transported via the Statpipe pipeline. The UK takes off its part of the gas through the Northern Leg Gas Pipeline via a 305 mm link from Statfjord B. Stabilised oil is stored in storage cells before being shipped into shuttle tankers.

Metering system

The fiscal oil and gas metering systems for Statfjord A, B and C operated steadily throughout the year.

For several years observations on Statfjord B and C have shown that there are liquids in the gas phase being measured, which causes the instruments to underestimate the gas flow. The difficulty has now been rectified by physical modification of the process and chemicals injection systems.

During the last year liquids have been observed in the gas phase passing through the metering station at Statfjord A. The same measures as were taken on B and C are now being planned to rectify the situation on Statfjord A.

Flaring

The gas volume exhausted through the flare stacks on Statfjord in 1991 was 250,000 scm a day on average. This is equivalent to 1.0 per cent of gas production and represents 63 per cent of the maximum permitted flare volume.

Costs

The total investments in Statfjord up to year 2010 are estimated at about 62.5 billion 1991 kroner. The estimated total operating costs up to the same date have been put at 73.6 billion 1991 kroner. These figures refer to the Norwegian share.

2.5.13 Murchison

Licensees

British share (77.8 %)	
Conoco (UK) Ltd	25.9334 %
Oryx UK Energy Company	25.9333 %
Chevron UK Ltd	25.9333 %
Norwegian share (22.2 %)	
Den norske stats oljeselskap a.s	11.1000 %
Mobil Exploration Norway Inc	3.3300 %
Norske Conoco A/S	2.2200 %
Esso Norge a.s	2.2200 %
A/S Norske Shell	2.2200 %
Saga Petroleum a.s	0.4162 %
Amoco Norway Oil Company	0.2313 %
Amerada Hess Norge A/S	0.2313 %
Enterprise Oil Norway A/S	0.2312 %

The Murchison field, proven in August 1975, is situated in block 211/19 in the UK sector and block 33/9 in the Norwegian sector (Figure 2.5.11.a). The Norwegian share is 22.2 per cent. The development of the Murchison field was initiated in 1976 by the UK partners. In 1979, the British and Norwegian partners entered into an agreement for joint exploitation of the Murchison field. Production started in 1980.

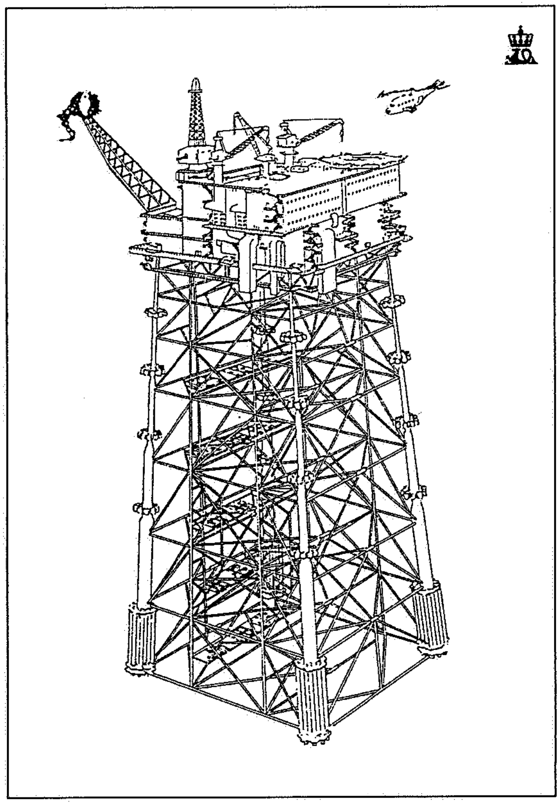
Production

The estimated recoverable reserves for the field as a whole are 57 mcm oil and 1.2 bcm gas in the Brent group. The field has been flowing at almost maximum fluid processing capacity since 1981, and the water treatment capacity has been upgraded several times. 1984 was the last year of plateau production. Water break-through has occurred in all of the original production wells, with a high cut of water. According to a plan prepared in 1987 several new wells have been drilled in recent years, including long-range high-deviation wells towards the flanks of the field. Studies have also been made into re-use of existing wells in various reservoir zones. These measures help improve resource exploitation.

Production installations

Murchison was developed with an integrated steel jacket structure with a production capacity of 26,200 scm a day (Figure 2.5.13). The installation came on stream on 28 September 1980 and initially produced from two subsea completion wells. Present production is around 6000 scm oil a day.

Fig. 2.5.13
Installation on Murchison



Transportation

The Norwegian government by Royal Decree of 24 September 1982 gave the go-ahead for landing of the Norwegian part of the Murchison gas via the Northern Leg Gas Pipeline to the Brent field in the UK sector, and thence to St Fergus in Scotland through the Far North Liquified and Associated Gas Gathering System, FLAGS. Gas deliveries started flowing through the NLGP on 20 July 1983. The Murchison crude oil is carried by pipeline to Sullom Voe in the Shetland Isles. Murchison has been shut down for long periods of time in the last couple of years due to various forms of maintenance work on the transportation systems.

Metering system

Inspection of the metering system operation is carried out each year jointly with the UK Department of Energy.

Flaring

The quantity of gas reported diverted through the Murchison flare stack was roughly 124,000 scm a day in 1991, approx 27,000 scm being the Norwegian share.

Costs

The predicted total investment in the Murchison field up to 2005 is roughly 4.1 billion 1991 kroner. The equivalent total operating costs are estimated at approx 2.6 billion 1991 kroner. These figures refer to the Norwegian share (22.2 per cent).

2.6 TRANSPORTATION SYSTEMS FOR GAS AND OIL

2.6.1 Existing transportation systems

There are three oil pipelines and four gas pipelines which carry oil and gas from the Norwegian continental shelf to shore. See the sketch of the transport systems for oil and gas in the Norwegian sector of the North Sea in Figure 2.6.

The UK share of gas from Statfjord is carried via the NLGP to St Fergus. The oil pipeline from the Ekofisk area, including the Ula and Valhall lines, runs to Teesside in the UK. Oil transportation from Oseberg started late in 1988 and comes to Sture. Condensate from Heimdal is taken to Cruden Bay in the UK. This pipeline, which runs via Brae and Forties, is primarily for British oil and condensate. The Statpipe and Norpipe gas pipelines were tied together in 1986 and both lead to Emden in Germany. Gas from Frigg is transported to St Fergus.

Gas transportation systems – Statpipe

The Statpipe gas transportation system involves the following partners:

Den norske stats oljeselskap a.s	58.2500 %
Elf Aquitaine Norge A/S	10.0000 %
Norsk Hydro Produksjon a.s	8.0000 %
Mobil Development Norway A/S	7.0000 %
Esso Norge a.s	5.0000 %
A/S Norske Shell	5.0000 %
Total Norge A/S	3.0000 %
Saga Petroleum a.s	2.0000 %
Norske Conoco A/S	1.7500 %

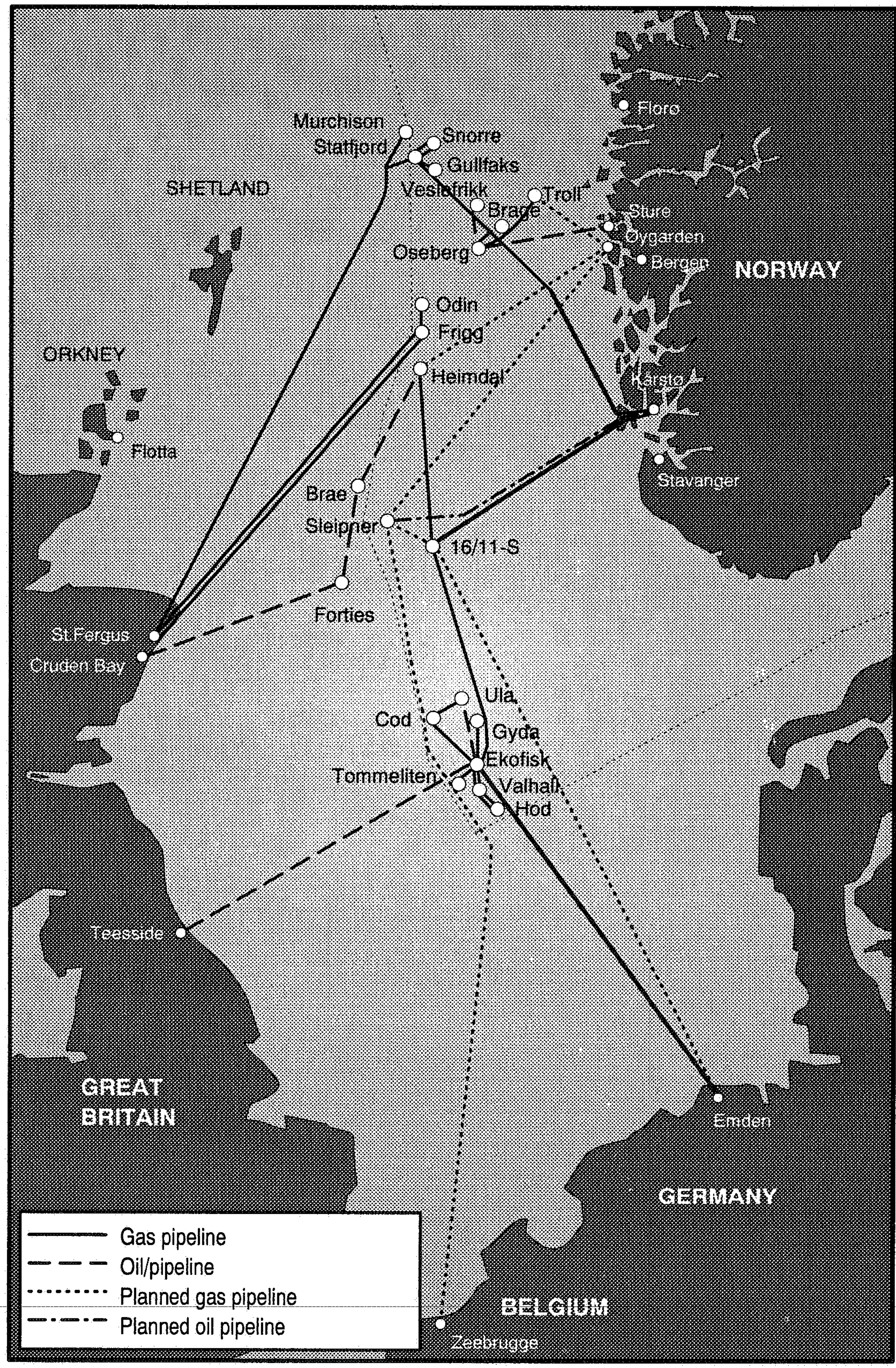
Statoil was responsible for construction and is the operator of the system which comprises:

- Wet gas pipeline from Statfjord to Kårstø
- Separation and fractioning plant at Kårstø, plus storage farm and loading facility
- Dry gas pipeline from Heimdal; dry gas pipeline from Kårstø to riser platform in block 16/11; and pipeline to riser platform at Ekofisk Centre.

Kårstø

The first North Sea gas was landed to Kårstø in March 1985. The transport capacity from Statfjord to Kårstø is 8 bcm wet gas a year. The Kårstø processing plant's capacity has been upgraded to handle this volume. The dry gas pipeline to the Ekofisk Centre is capable of transporting 17 bcm annually, which is more than is required for Statfjord, Gullfaks and Heimdal, and allows for possible tie-in of other fields at a later date. If an increase in the Statpipe system is desired, a new compressor unit must be installed beside the 16/11-S riser platform. A framework contract has been signed with Norpipe A/S and the Phillips Group regarding use of the Ekofisk Centre and pipeline to Emden.

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



The Statfjord, Heimdal and Gullfaks partners have also concluded sales agreements for the gas with buyers on the Continent.

K-lab is a facility for full-scale testing and development of fiscal gas metering equipment. In 1991, the laboratory performed various tests of metering equipment using natural gas under high pressure as the test medium.

Metering system

Metering of the gas delivered from the Kårstø terminal was undertaken in compliance with the current rules for gas metering.

Propane measurements are based on a dynamic metering system. For butanes and naphtha dynamic metering was introduced in summer 1990.

Gas transportation systems – Norpipe A/S

The pipeline transportation system for natural gas from the Ekofisk Centre to Emden in Germany is owned by Norpipe A/S, a limited company owned 50 per cent by Statoil and 50 per cent by the Phillips Group.

Emden

The Emden terminal is owned by Norsea Gas A/S, and the right to land in the Emden area by Norsea Gas GmbH. Both these companies are owned by the Phillips Group, on whose behalf Phillips Petroleum Norsk A/S acts as operator. The metering station in Emden will be modernised in 1992.

Etzel gas terminal

Licensees	
Den norske stats oljeselskap a.s	67.0000 %
Norsk Hydro Produksjon a.s	8.0000 %
A/S Norske Shell	8.0000 %
Esso Norge a.s	8.0000 %
Saga Petroleum a.s	4.0000 %
Elf Aquitaine Norge A/S	2.2985 %
Norske Conoco A/S	1.7015 %
Total Norge A/S	1.0000 %

Under the Troll gas sales agreement the sellers have covenanted to deliver gas for up to 14 days in the event of a shutdown for "non-technical reasons". In addition to ensuring this requirement can be met, the terminal's storage capacity will offer operational advantages with respect to delivery availability, gas quality equalisation, seasonal fluctuations from associated fields, and deliveries that can be upheld during inspection and maintenance shutdowns. Quantities to and from the store will be measured by a new fiscal metering station operated by Phillips in Emden. The store will be ready for gas filling around the new year 1993 and will be operative in autumn 1993.

Gas transportation systems – Ula

Licensees	
BP Petroleum Development of Norway A.S	57.5000 %
Svenska Petroleum Exploration	15.0000 %
Den norske stats oljeselskap a.s	12.5000 %
Conoco Norway Inc	10.0000 %
K/S A/S Pelican	5.0000 %

Gas deliveries go via the Cod field to the Ekofisk Centre. Oil from Gyda and Ula flow in a separate pipeline to the Ekofisk Centre.

Gas transportation systems – Frigg

The Norwegian Frigg pipeline is owned by the Norwegian Frigg partners. Their ownership interests were revised in 1988 and are now:

Norsk Hydro Produksjon a.s	32.8700 %
Elf Aquitaine Norge A/S	26.4200 %
Den norske stats oljeselskap a.s	24.0000 %
Total Norge A/S	16.7100 %

The operator is Total Oil Marine UK.

The compressor platform MCP-01, midway between Frigg and St Fergus, is owned 50 per cent by Norwegian interests. The compressors have been removed from service since there is no longer any need for them with the lower production from Frigg. The partners are therefore planning to withdraw all personnel from MCP-01 in order to cut operating costs. This will have consequences for fiscal metering. Instead of measuring the overall quantity from British fields that supply gas to the Frigg pipeline at MCP-01, the apportionment will have to be based on field metering.

St Fergus

This terminal is owned by the Norwegian Frigg partners and UK Frigg partners (Elf UK 66 2/3 and Total UK 33 1/3 per cent). The various processing modules on the terminal are owned either by one partner group or by both. Total Oil Marine UK is the operator.

Oil transportation systems – Norpipe A/S

The pipeline system for transportation of oil from the Ekofisk Centre, Ula and Valhall to Teesside in the UK is owned by Norpipe A/S, a limited company owned 50 per cent each by Statoil and the Phillips Group.

Teesside

Ownership of the Teesside terminal facilities is split between Norpipe A/S and the Phillips Group through Norpipe Petroleum UK Ltd and Norsea Pipeline Ltd. The operator is Phillips Petroleum Company UK Ltd on behalf of Norpipe A/S and the Phillips Group. Norpipe Petroleum UK Ltd is owned 50 per cent each by Statoil and the Phillips Group. Norsea Pipeline Ltd is owned by the Phillips Group.

Oil transportation systems – Oseberg

The pipeline and the terminal facilities at Sture are owned and operated by a joint venture formed for the purpose and called I/S Oseberg Transport System. The venturers are the Oseberg partners. Hydro operates the pipeline and terminal. The OTS came on stream simultaneously with the Oseberg field, and comprises the following elements:

- Pipeline support functions on Oseberg A
- Subsea pipeline
- Landing point
- Onshore pipeline
- Terminal.

The pipeline, of 711 mm diameter and capacity 95,000 scm a day, lies in water depths of up to 350 metres.

The OTS entered service in December 1988 and the first export oil cargo was shipped on 20 December 1988.

Oil transportation systems – Veslefrikk

The oil pipeline from Veslefrikk to Oseberg A is 37 km long and 406 mm in diameter. It connects the Veslefrikk field with the Oseberg Transportation System thereby allowing Veslefrikk crude to be exported from the Sture terminal.

In order to sell the Veslefrikk gas a 24 km pipeline of 255 mm diameter has been laid which ties in with the Statpipe system at a tee-junction east of Oseberg.

2.6.2 Projected transportation systems

Zeepipe

Licensees

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

Zeepipe is a gas transportation system which will carry gas from Kollsnes in Øygarden to the Continent. Phase 1 of the project has been approved, which includes a 966.4 mm pipeline from Sleipner to Zeebrügge in Belgium and a 725 mm pipeline from Sleipner to the 16/11-S riser platform. Phase 1 including the terminal in Zeebrügge is under construction and will be ready to transport gas in 1993. Capacity without compression will be 13 bcm gas a year.

Phase 2 studies are currently being performed. A plan for the construction and operation for phase 2 is expected to be submitted in 1992. Phase 2 will include a pipeline to carry gas from Kollsnes to Sleipner and the 16/11-S riser platform. The size and route for phase 2 have not yet been decided.

Europipe

Licensees

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

The general plan for the building of a third pipeline to the Continent has been passed by the Storting. The plan for construction and operation of Europipe, however, which sets out the details, has not been approved. Statoil's plans are to build a 966.4 mm pipeline running about 600 km from a new riser platform 16/11-E (near 16/11-S) to Emden in Germany. The system will be able to accommodate compression facilities about half way between 16/11-E and Emden. Without compression the capacity will be 13 bcm gas a year. With compression the capacity can be upgraded to about 18 bcm gas a year. According to plan Europipe will be operational from autumn 1995.

Haltenpipe

The Heidrun partners have updated their plans for the likely alternatives for application of the gas from this field. The partners recommend methanol production as the best application alternative.

On the basis of the plans submitted previously and the most recent recommendations from the companies, the Ministry of Petroleum and Energy submitted a Storting Report in autumn 1991 for landing of gas from Heidrun, and possibly Draugen, and the establishment of a methanol plant in Møre og Romsdal. These plans will be presented to the Storting early in 1992.

The plans assume a 483 mm pipeline from Heidrun to Tjeldbergodden, with a carrying capacity of 3.5–4.5 bcm gas a year. Depending on other application alternatives for the gas, other fields on Haltenbanken may be tied in to the pipeline at a later date. According to plan the pipeline will be operational in the second half of 1996.

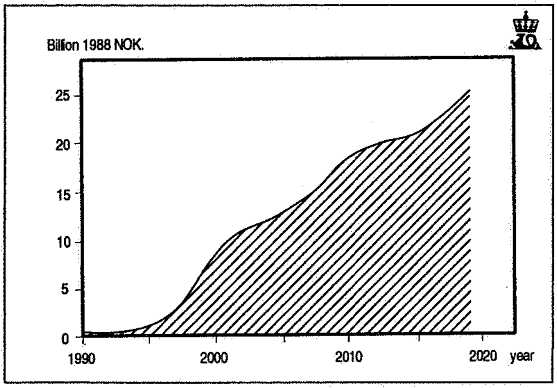
2.7 DECOMMISSIONING AND REMOVAL

The International Maritime Organization (IMO) in autumn 1989 resolved international guidelines for removal of installations on the continental shelf.

The question of if and when a coastal state should be ordered to remove its installations from the continental shelf once their useful life expires is of enormous importance to Norway. Removal of the installations on the Norwegian continental shelf will inevitably be in almost all cases much more expensive and technically complex than in other parts of the world. At present, Norway has about 50 installations already producing petroleum or under planning or construction.

The estimated cost of complete removal of all installations is roughly Nkr 38 billion, see Figures 2.7.a and b, although of course this figure is highly speculative. Under the legislation for removal of installations the State has to bear a considerable portion of the costs of removal.

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



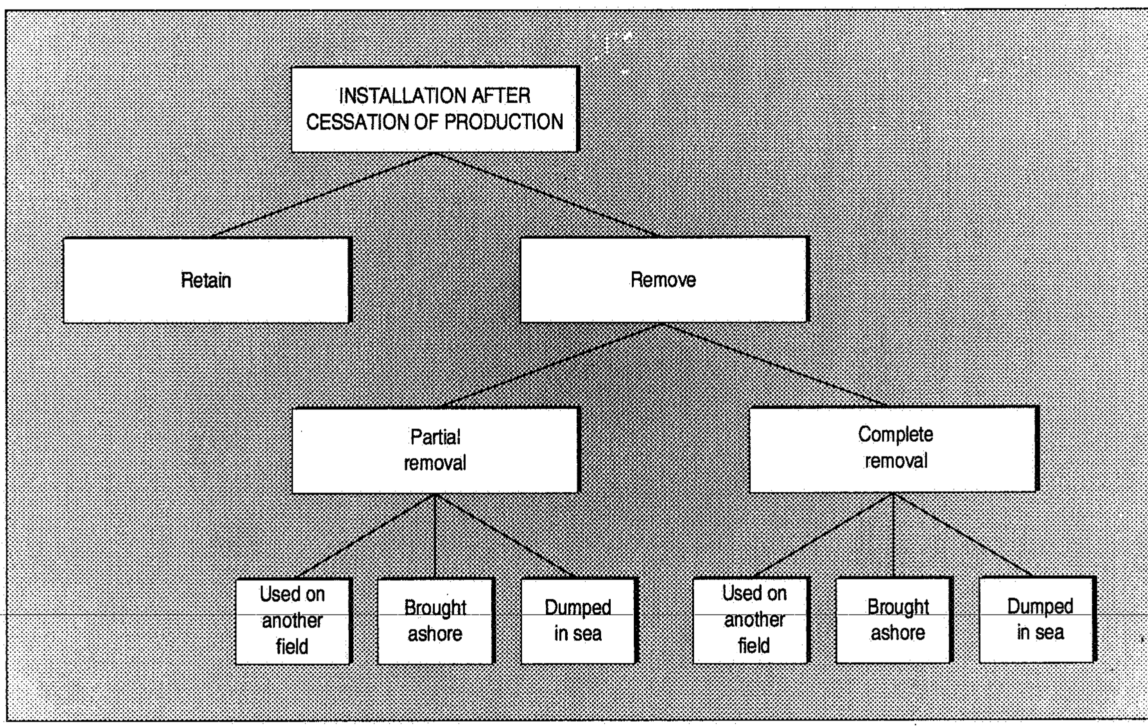
These are the main points in the IMO rules as adopted:

- All installations whose use is finally over and which are at a sea depth of less than 75 metres and have a base (jacket) weighing less than 4000 tons shall be removed;
- All installations deployed after 1 January 1998 whose use is finally over and which are at a sea depth of less than 100 metres and have a base (jacket) weighing less than 4000 tons shall be removed;
- For other installations the question of removal will be determined on the basis of the individual coastal state's evaluation in each case. Said evaluation shall weigh considerations of safety at sea, other users of the sea, environmental impact and life resources, the costs and safety hazards of removal, alternative uses and other reasonable grounds to allow the installation to remain in place, wholly or in part;
- Should a coastal state determine that an installation shall be removed to below the sea surface, a free height of minimum 55 metres water shall be left below the sea surface;
- Should a coastal state determine that an installation shall remain in place wholly or in part such that it protrudes from the sea surface, satisfactory maintenance shall be carried out to prevent disintegration of the installation;
- After 1 January 1998 no installations shall be emplaced which it is technically impossible to remove.

The IMO's international guidelines for removal of installations highlight the need to draft further national rules of law addressing the removal question in Norway. It must be emphasised that the IMO rules should be considered more like guidelines – they will not be legally binding on the states involved. On the other hand, the rules will have considerable moral force and it would be politically reckless to ignore them.

The removal issue is becoming especially relevant on the Norwegian continental shelf. In this connection the Petroleum Act Committee has been requested to study and develop a national set of rules for decommissioning and removal of installations on the Norwegian continental shelf.

Fig. 2.7.b
Final production and removal



3. Petroleum Resources

3.1 RESOURCES ACCOUNTING

Petroleum resources are non-renewable energy resources comprising all technically recoverable oil and gas quantities.

Resources accounts are summaries of the original marketable petroleum quantities on the Norwegian continental shelf and the amounts remaining to date. Changes in the accounts from one year to the next result from new discoveries, adjustments to estimates for existing discoveries, and reductions due to production.

In 1991 the Directorate introduced a new system of classifying resources. The new system is published in NPD Contribution no. 31 and distinguishes between discovered and undiscovered resources, as shown in Figure 3.1.a.

Discovered resources include fields and discoveries. Fields includes resources and reserves in fields in production, adopted for development, or planned for development. Reserves are the quantities of petroleum which one plans to produce under the declaration of commerciality. Additional resources are the quantities that can be produced using one or several enhanced recovery techniques not included in the production plan.

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

			OIL $10^6 Sm^3$ Most likely	GAS $10^9 Sm^3$ Most likely	NGL 10^6 tonnes Most likely	T.O.E. Most likely
DISCOVERED	FIELDS PRODUCING (ORIGINALLY)	CURRENT PLAN	1607	674	64	2064
		IMPROVED RECOVERY				
	FIELDS APPROVED DEVELOPED	CURRENT PLAN	404	950	37	1318
		IMPROVED RECOVERY				
	FIELDS DECLARED DEVELOPED	CURRENT PLAN	188	735	33	925
		IMPROVED RECOVERY				
	DISCOVERIES UNDER EVALUATION		398	730	9	1079
	FIELDS AND DISCOVERIES TOTAL		2597	3089	143	5386
UNDISCOVERED	PROSPECTS AND AREAS		10^6 T.O.E. Most likely			
			~3500			

SOLD PER: 31/12-91	OIL	GAS	NGL	TOE
	756	349	24	1000

RESERVES
RESOURCES

Discoveries are proven and tested resources in separate structures or separate stratigraphic levels. This category includes recent discoveries being evaluated, and discoveries which under present conditions are not considered commercial. A field may contain several discoveries.

The undiscovered resources include predicted resources in surveyed, undrilled structures, and predicted resources in areas where exploration models have been defined, but no prospects identified.

New discoveries

Eleven new discoveries were made in 1991. These were 1/3–6, 15/12–8, 25/4–6 S, 25/5–4 (Byggve), 25/11–15, 30/9–13 S, 34/7–18, 34/8–4 S, 34/10–34, 35/11–4 R and 6506/11–2. Hydrocarbons were also encountered in 2/4–17, 6507/2–2 and 6608/10–2, though testing is not due until 1992.

The work of evaluating the discoveries is ongoing. It is therefore too early to say anything for certain as to their size, although they will probably exceed the lifting of resources that took place in 1991.

Of the year's discoveries, 1/3–6, 15/12–8, 25/5–4 (Byggve), 25/11–15, 34/10–34 and 35/11–4 R have been evaluated and are included in the resources accounts. The growth in resources attributable to these new discoveries is 83.4 mcm oil and 19.3 bcm gas.

Past discoveries newly recorded

In addition to this year's discoveries already mentioned, wells 7/8–3, 30/9–10, 34/7–16 R, 35/9–1,2, 6507/3–1 and 6507/8–4 are now included in the resources accounts. The growth in resources attributable to these past discoveries newly recorded is 53.6 mcm oil and 21.0 bcm gas.

Adjustment of resources estimate for existing fields and discoveries

For fields in production, approved developed and declared commercial, and existing discoveries, the present resources accounts show that, relative to 1990, oil reserves have decreased by 24.0 mcm and gas reserves by 32.9 bcm. Natural Gas Liquids increased by 21.8 mton. For details of revisions, see Table 3.2.

Production

Lifting of petroleum on the Norwegian continental shelf amounted to 107.2 mcm oil, 24.6 bcm gas, and 2.3 mton NGL in 1991.

Resources status

The Directorate's accounts for 1990 and 1991 show that the additions of oil are greater than the depletion. For gas the situation is the opposite. The increase in oil was 5.8 mcm, whereas gas has been reduced by 17.2 bcm. There was also an increase in NGL of 19.5 mton. All in all, the figures represent an increase of 3.5 mtoe.

At the present rate of depletion of petroleum, Norway has proven resources sufficient for 17 years of oil production and 111 years of gas production.

The resources status on the Norwegian continental shelf is illustrated in Figure 3.1.a and the geographical distribution of the resources in Figure 3.1.b.

The resources on the Norwegian continental shelf are presented in four tables showing:

1. Petroleum reserves in producing fields, Table 3.1.a
2. Petroleum reserves in fields approved developed, Table 3.1.b
3. Petroleum reserves in fields declared commercial, Table 3.1.c
4. Petroleum resources in discoveries south of Stad under evaluation, Table 3.1.d.

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

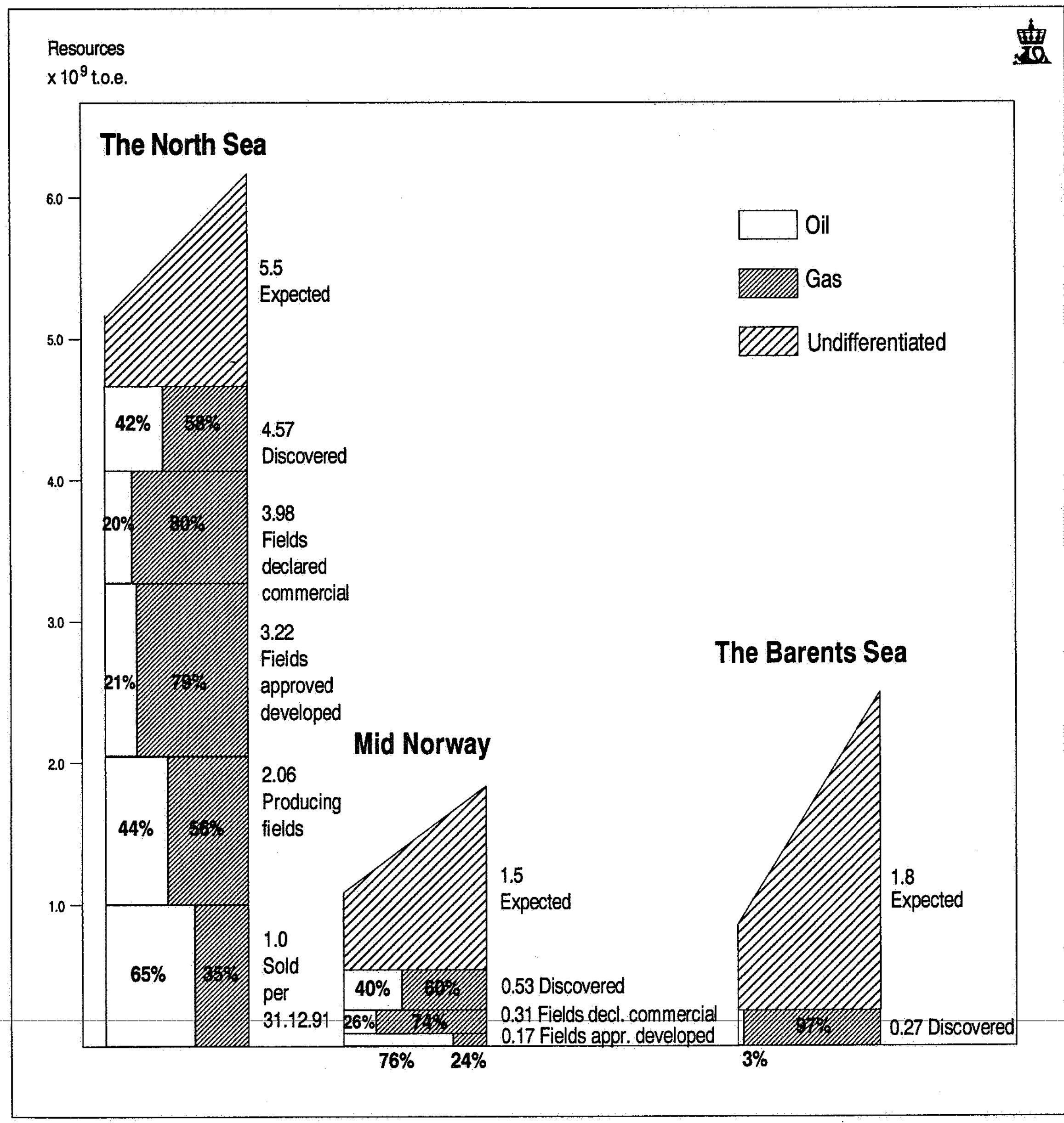


Table 3.1.a
Petroleum reserves in producing fields

	Initial produceable reserves				Remaining produceable reserves		
	Oil $10^6 Sm^3$	Gas $10^9 Sm^3$	NGL 10^6 tonnes	TOE	Oil $10^6 Sm^3$	Gas $10^9 Sm^3$	NGL 10^6 tonnes
Albuskjell[1]	10.0	22.0	1.5	31.6	3.1	8.0	0.5
Cod[1]	2.8	7.0	0.5	9.8	0.2	0.7	
Edda[1]	5.2	2.1	0.2	6.4	1.2	0.3	
Ekofisk[1]	330.0	151.0	15.0	430.0	165.5	75.8	8.3
Eldfisk[1]	77.0	59.0	5.3	126.7	28.7	40.0	3.1
Frigg[1] [2]		110.0	0.4	110.4		4.0	
Gullfaks[1]	230.0	16.5	1.9	213.9	166.9	12.9	1.6
Gyda	32.0	4.2	1.9	32.3	27.3	3.6	1.6
Heimdal[1]		35.6	4.1	39.7		16.3	1.7
Hod[1]	5.7	1.2	0.4	6.4	4.0	1.0	0.3
Murchison[1] [3]	12.0	0.3	0.4	10.8	1.5		
Nord Øst-Frigg[1]		11.8	0.1	11.9		0.7	
Odin[1]	0.2	29.3		29.5		6.4	
Oseberg[1] [4]	226.0	70.0	3.0	265.1	172.1	70.0	3.0
Statfjord[1] [5]	453.0	51.6	15.9	443.5	152.5	32.8	11.1
Tommeliten[1]	7.5	16.5	1.0	22.7	5.3	12.9	0.7
Tor[1]	27.2	15.9	1.8	40.0	8.8	5.9	0.7
Ula	69.2	4.7	3.5	64.9	41.3	2.8	2.2
Valhall[1]	68.8	17.7	4.1	77.5	40.2	12.2	2.8
Veslefrikk[1]	36.0	3.0	1.3	33.8	29.6	3.0	1.1
Vest Ekofisk[1]	13.3	28.9	1.7	41.5	1.6	4.7	0.4
Øst Frigg		8.2		8.2		3.3	
30/6 Gamma Nord[1]	1.3	7.1		8.2	1.2	7.1	
Sum	1607.2	673.6	64.0	2064.8	851.0	324.4	39.1

Table 3.1.b
Petroleum reserves in fields approved developed

		Oil $10^6 Sm^3$	Gas $10^9 Sm^3$	NGL 10^6tonnes	TOE
North Sea	Brage	46.2	1.7	1.0	41.5
	Embla[1]	9.2	3.4	0.5	11.4
	Lille-Frigg[1]		7.0	2.7	9.7
	Loke[1] [6]	4.1	8.0		11.1
	Sleipner Øst	19.9	51.0	10.3	76.4
	Snorre	106.0	6.7	3.2	97.9
	Statfjord Nord	31.0	2.5		27.9
	Statfjord Øst	13.4	2.0		13.1
	Tordis	18.8	1.2	0.5	17.1
	Troll Øst[7]		825.0	19.2	844.2
	Sum	248.6	908.5	37.4	1150.3
Off Mid-Norway	Draugen	68.0	3.0		58.8
	Heidrun	87.3	37.8		109.4
	Sum	155.3	40.8		168.2
	Total	403.9	949.3	37.4	1318.5

Reserves in fields approved developed
By year end, 35 development projects had been adopted on the Norwegian continental shelf, four more than one year previously. The four newcomers are Heidrun, Lille-Frigg, Loke and Tordis. As yet only Draugen and Heidrun have been approved north of Stad.

Up to end-91 total sales were 1.0 btoe. This is 29 per cent of discovered oil and 11 per cent of discovered gas on the Norwegian continental shelf.

Reserves in fields declared commercial
By year end, under the new classification system, there were 11 fields which had been declared commercial, see Table 3.1.c. The amount of petroleum reserves is 0.92 btoe.

Table 3.1.c
Petroleum reserves in fields declared commercial

		Oil 10^6Sm^3	Gas 10^9Sm^3	NGL 10^6tonnes	TOE
North Sea	Byggve	0.6	2.6		3.1
	Frøy	12.5	2.7		13.0
	Huldra[1]	4.5	17.0		20.7
	Mime[1]	0.9	0.2		0.9
	Oseberg Øst	19.0	1.0		16.5
	Skirne	0.3	2.3		2.5
	Sleipner Vest[8]	27.0	135.0	9.0	164.5
	Troll Vest[7]	64.0	463.0	10.8	531.0
	Vigdis[1]	27.1			22.2
	Sum	155.9	623.8	19.8	774.4
Off Mid-Norway	Midgard	1.3	87.0	13.0	101.0
	Smørbukk Sør	31.0	24.0		49.7
	Sum	32.3	111.0	13.0	150.7
	Total	188.2	734.8	32.8	925.1

1) Operator's estimate
2) Norwegian share only, i.e. 60.82 % of total
3) Norwegian share only, e.e. 22.2 % of total
4) Includes Alpha, Alpha North and Gamma structure
5) Norwegian share only, i.e. 85.24 % of total
6) Resource figure includes Heimdal reservoir and Trias. Only Heimdal reservoir is approved developed.
7) Condensate incl. in NGL.
8) Includes Alpha, Beta, Epsilon and Delta

Table 3.1.d
Petroleum resources in discoveries south of Stad under evaluation

	Oil 10^6Sm^3	Gas 10^9Sm^3	NGL 10^6tonnes	TOE
Agat[1]		43.0		43.0
Balder	35.0			31.6
Gullfaks Sør	25.6	56.1	3.0	81.6
Hild[1]	1.9	12.1		11.8
Mjølner[1]	1.7			1.4
Peik[1] [2]	1.8	6.0		7.5
SØ-Tor	2.5	2.0		4.0
Trym[2]	2.1	8.7		10.4
Visund[1]	16.2	47.6		60.9
1/2–1[2]	3.0			2.4
1/3–3	3.3	0.1		2.8
1/3–6	1.2	2.8		3.7
6/3 PI	0.9	1.0		1.7
7/8–3[1]	6.2			5.4
9/2 Gamma[1]	6.4			5.3
15/3–1,3[1]	5.2	10.5		14.7
15/3–4[1]	2.2	1.3		3.1
15/5–1	2.0	6.0		7.5
15/8 Alfa	5.0	11.0		14.8
15/9 My	5.0	11.0		14.8
15/12 Beta[1]	16.0	1.3		14.4
15/12–8[1]	0.6	1.3		1.7
16/7–4[1]	1.4	8.0		9.0
25/2–5[1]	5.3	1.9		6.2
25/11–15	60.0	1.8		58.8
30/6 Kappa[1]	1.0	3.6		4.4
30/9 Omega	16.6	8.0		21.6
30/9–6[1]	2.7			2.2
30/9–9[1]	5.2			4.3
30/9–10[1]	3.2			2.8
34/10 Beta[1]	8.0	22.5		29.0
34/10 Gamma	2.2	28.0		29.8
34/10–34[1]	3.0			2.6
35/8–1	1.9	13.5		15.0
35/8–2	2.6	7.0		9.1
35/9–1,2[1]	5.0	11.5		15.6
35/11–2	5.4	5.6		10.0
35/11–4R	18.0	10.8		25.6
Total	285.3	344.0	3.0	590.2

1) Operator's estimate 2) Norwegian share.

Resources in discoveries being evaluated
Table 3.1.d is a summary of discoveries south of Stad being evaluated. The quantities here amount to 0.59 btoe in all. Resources in discoveries being evaluated north of Stad amount to 0.48 btoe; of which 0.22 btoe off Mid-Norway and 0.26 btoe in the Barents Sea. See Table 3.1.e.

Table 3.1.e
Petroleum resources in discoveries off Mid-Norway and in the Barents Sea under evaluation

		Oil 10^6Sm^3	Gas 10^9Sm^3	NGL 10^6tonnes	TOE
Off Mid-Norway	Njord	35.0	7.2		36.0
	Mikkel[1)]	5.7	14.3		19.0
	Smørbukk	20.0	65.0		81.4
	Trestakk[1)]	9.0			7.0
	Tyrihans	16.0	40.0		53.1
	6507/3–1[1)]	1.1	7.1		8.0
	6507/8–4[1)]	19.8	2.4		20.2
	Sum	106.6	136.0		224.7
Barents Sea	Albatross		41.7		41.7
	Albatross Sør		10.8		10.8
	Askeladd		59.7		59.7
	Snøhvit	6.5	76.0	5.7	90.7
	Snøhvit Nord		3.3		3.3
	7119/12–3[1)]		3.6		3.6
	7120/07–1		22.5		22.5
	7120/12–2		14.8		14.8
	7121/5–2 Beta		4.3		4.3
	7122/06–1[1)]		11.0		11.0
	7124/03–1[1)]		2.1		2.1
	Sum	6.5	249.8	5.7	264.5
	Total	113.1	385.8	5.7	489.2

1) Operator's estimate

3.2 REVISION OF RESOURCES BASE SINCE LAST YEAR

3.2.1 Fields in production, approved developed and decleared commerical

For fields in production the Directorate generally accepts the operator's projections of future reserves. On many fields only moderate changes were made in the forecasts compared to the figures given in the 1990 Annual Report. Fields where a substantial revision has occurred are dealt with specifically below. For changes in resources statistics from 1990 to 1991, see Table 3.2.

Ekofisk
Estimates were increased due to a new historical approach to the reservoir simulation model.

Embla
The new interpretation of reconditioned seismic data and predrilling of production wells has proven earlier geological models of the field to be incorrect, leading to a relatively large decrease in projected reserves.

Frigg
A small upward adjustment of the gas reserves on Frigg was made. The liquid component, previously reported as oil, is now sold as NGL.

Heimdal
The liquid component on Heimdal, previously reported as oil, is now sold as NGL.

Lille-Frigg
The liquid component of the Lille-Frigg reserves has been reclassified from oil to NGL.

Loke
The Directorate has used the operator's figures in the resources summary, entailing a reduction relative to the Directorate's own estimate.

Midgard
The Directorate has reevaluated this field, the most important change being that most of the liquids are now reported as NGL.

Mime
New surveys and the results of test production have led to a downward adjustment of reserves on Mime.

Skirne
The Directorate's analysis of the figures shows last year's estimate to be too high. The new estimate is based on the Directorate's analysis.

Smørbukk Sør
New surveys and new field simulation led to increases in oil and gas reserves on Smørbukk Sør.

Statfjord
The Norwegian component increased following redistribution, giving an increase in the Norwegian reserves.

Troll Vest
New simulations and the decision to deploy horizontal wells prompted an upward adjustment of the oil reserves.

Valhall
The increase in reserves on Valhall was due to five new wells which are planned to be drilled and higher pore compressibility in the reservoir model.

3.2.2 Discoveries
The changes in resources estimates from 1990 to 1991 are reported in Table 3.2. Discoveries for which a major change was made are discussed specifically.

Gullfaks Sør
The Directorate performed a new survey and field simulation, leading to a reduction in resources relative to previous estimates.

Mjølner
New surveys and new reservoir geology data led to a reduction in resources.

Njord
New surveys and new field simulation led to an increase in reserves for this discovery.

Visund
The resource estimate was reduced to match the operator's new projection.

9/2 Gamma
New surveys based on 3D seismics and new resource estimates led to a heavy reduction in resources relative to earlier estimates.

24/9
This discovery is not reported this year due to the results of drilling well 24/9-4 in 1991.

30/6 Kappa
The resource estimate was reduced to match the operator's new projection.

30/9 Omega
The Directorate upgraded these resources on the evidence of its own surveys and resources estimates of the discovery.

35/11-2
The Directorate reduced the resources on the basis of own surveys and resources estimates of the discovery.

Table 3.2
Changes in estimated resources annual reports 1990–1991

	Annual Report 1990			Annual Report 1991		
	Oil 10^6Sm^3	Gas 10^9Sm^3	NGL 10^6tonnes	Oil 10^6Sm^3	Gas 10^9Sm^3	NGL 10^6tonnes
Fields in production						
Ekofisk	315.0	145.0	15.0	330.0	151.0	15.0
Eldfisk	74.0	57.0	5.4	77.0	59.0	5.3
Frigg	0.4	107.0			110.0	0.4
Gullfaks	230.0	16.0	2.2	230.0	16.5	1.9
Gyda	31.0	3.0	2.5	32.0	4.2	1.9
Heimdal	5.7	35.6			35.6	4.1
Hod	4.0	0.9	0.3	5.7	1.2	0.4
N-Ø-Frigg	0.1	11.0			11.8	0.1
Odin	0.1	27.3		0.2	29.3	
Oseberg	228.0	70.0	6.0	226.0	70.0	3.0
Statfjord	447.0	49.0	15.6	453.0	51.6	15.9
Tommeliten	6.4	18.4	1.0	7.5	16.5	1.0
Tor	25.0	17.0	2.0	27.2	15.9	1.8
Ula	67.0	4.6	3.4	69.2	4.7	3.5
Valhall	62.0	12.5	3.3	68.8	17.7	4.1
Vest Ekofisk	13.0	28.0	1.5	13.3	28.9	1.7
Øst Frigg		7.5			8.2	
Fields approved developed						
Brage	46.2	1.7		46.2	1.7	1.0
Embla	33.0	10.5	1.6	9.2	3.4	0.5
Lille-Frigg	3.7	7.0			7.0	2.7
Sleipner Øst	19.0	51.0	10.0	19.9	51.0	10.3

	Annual Report 1990			Annual Report 1991		
	Oil $10^6 Sm^3$	Gas $10^9 Sm^3$	NGL 10^6tonnes	Oil $10^6 Sm^3$	Gas $10^9 Sm^3$	NGL 10^6tonnes
Snorre	106.0	5.8	2.7	106.0	6.7	3.2
Tordis	18.8	1.2		18.8	1.2	0.5
Loke	6.0	13.0		4.1	8.0	
Fields under evaluation						
Byggve[1)]				0.6	2.6	
Frøy	11.0	3.0		12.5	2.7	
Huldra	5.4	16.4		4.5	17.0	
Midgard	15.0	80.0		1.3	87.0	13.0
Mime	3.0			0.9	0.2	
Skirne	1.7	9.1		0.3	2.3	
Smørbukk Sør	22.0	11.0		31.0	24.0	
Snorre Vest	6.2			5.7		
Troll Vest	41.0	463.0	10.8	64.0	463.0	10.8
34/7 C	4.0			3.1		
34/7–16R[1)]				18.3		
Discoveries						
Gullfaks Sør	45.0	88.0		25.6	56.1	3.0
Hild	1.2	8.8		1.9	12.1	
Mjølner	5.3	0.9		1.7		
Njord	25.0	4.0		35.0	7.2	
Trym	2.0	10.0		2.1	8.7	
Visund	22.5	75.0		16.2	47.6	
1/3–6[1)]				1.2	2.8	
7/8–3[1)]				6.2		
9/2 Gamma	24.0	1.0		6.4		
15/12–8[1)]				0.6	1.3	
24/9	3.0					
25/11–15[1)]				60.0	1.8	
30/6 Kappa	5.0	5.0		1.0	3.6	
30/9 Omega	9.3	3.0		16.6	8.0	
30/9–10[1)]				3.2		
34/10–34[1)]				3.0		
35/9–1,2[1)]				5.0	11.5	
35/11–2	10.3	10.9		5.4	5.6	
35/11–4R[1)]				18.0	10.8	
6507/3–1[1)]				1.1	7.1	
6507/8–4[1)]				19.8	2.4	

1) Discoveries not reported previously.

3.3 NAME CHANGES IN 1991

Nine new names came into use in 1991: Byggve (previously 25/5–4), Loke (Sleipner satellite 15/9 Theta), Oseberg Øst (30/6 Beta and 30/6 Beta Sadel), Peik (24/6–1), Skirne (25/5–3), Smørbukk Sør (6506/12 Beta), Vigdis (Snorre Vest, 34/7 C, 34/7–16 R and 34/7–19). 15/9 My (a Sleipner satellite) and 15/8 Alfa (a Sleipner satellite).

4. Safety and the Working Environment

4.1 INTRODUCTION

The formal authorities which underpin the Norwegian Petroleum Directorate's supervisory and regulatory duties are summarised below.

a) Frameworks given in governing legislation:
   - *Petroleum Act*, of 22 March 1985 no. 11
   - *Working Environment Act*, of 4 February 1977 no. 4
   - *Svalbard Act*, of 17 July 1925 no. 11
   - *Scientific Research Act*, of 21 March 1963 no. 12
   - *Tobacco Injuries Act*, of 9 March 1973 no. 14.

b) Regulations and instructions given by the Ministry of Local Government:
   - Regulatory supervisory activities. with the safety etc, by Royal Decree of 28 June 1985
   - Authority of 28 June 1985 whereby the Directorate is delegated certain powers, including to:
     - Issue regulations for the activity
     - Conduct overall safety evaluations
     - Decide consents, orders, dispensations and approvals.

The Directorate's supervisory activities are based on close cooperation on safety, the working environment and resources, both inside the organisation and externally with other government agencies and institutions. The Directorate plays a coordinating role relative to the other government departments which under the Petroleum Act exercise an autonomous control responsibility in their own right; and draws on the professional expertise of other departments where it has no comparable skills inhouse.

The scope of the offshore petroleum industry continued to widen in 1991, and once again it was imperative to focus on sharpening our organisational efficiency and thus maintain a responsible level of supervision, even though no new positions have been authorised since 1987. An analysis of the expertise available and future demands has been made, which will guide the work to exploit resources optimally.

4.2 REGULATORY DRAFTING AND REVISION

The work of drafting new *Technology Regulations* was finalised for the Directorate's part in 1991. The new regulations reflect the intentions inherent in the petroleum legislation of 1985 and the supervisory arrangements which were implemented as a result.

The work has continued unabated since 1987 and addresses both the form and the content of the regulations. The new regulations represent a marked turn in the direction of functional requirements where a large part of the detailed standards to be developed will be left to the industry in collaboration with employees and standardisation institutions.

In the European Community the body of directives and standards which may impact on Norwegian offshore activities continues to grow. The Directorate seeks to influence the direction these drafts take, notably through its comments at the consultative stage, and by keeping abreast of and participating in key standardisation bodies wherever possible.

4.2.1 Regulatory status

By year end the status of the regulatory development work was as follows:

Regulations issued

- Regulations on *Environmental Data* etc, issued 1 February 1989
- Regulations conc *Pipeline Systems* etc, issued 30 April 1990
- Regulations conc *Manned Underwater Operations* etc, issued by NPD and Directorate of Health, 11 June 1990
- Regulations conc *Implemention and Use of Risk Analyses* etc, issued by NPD and Ministry of the Environment, 4 December 1990.
- Regulations conc *Electrical Installations* etc, issued by NPD, 8 January 1991.

Drafts submitted to Ministry of Local Government for approval

- Regulations conc *Drilling and well activities and geological data collection* etc
- Regulations conc *Explosion and fire protection* etc
- Regulations conc *Safety and Communications Systems* etc
- Regulations conc *Marking of Installations* etc
- Regulations conc *Lifting appliances and Lifting Gear* etc
- Regulations conc *Emergency Preparedness* etc.
- Regulations conc *Process and auxiliary facilities* etc
- Regulations conc *Loadbearing structures* etc.

The Regulations conc Electrical Installations, issued in 1991, are discussed below. The other regulations have all been discussed in earlier reports.

4.2.2 Regulations for Electrical Installations

The purpose of the *Electrical Installations Regulations* is to provide rules for the planning, engineering, construction and use of electrical systems for the offshore industry and to facilitate the application of the Directorate's supervisory activities to such operations. The emphasis has been on harmonising the regulations with the requirements given in other rules administered by other government departments, notably the Electricity Inspection and Maritime Directorate, and international electrical standards.

The new regulations introduce no new technical requirements additional to the existing rules given by other authorities, but present requirements relating to the supervisory system which has been established for the offshore petroleum industry.

4.2.3 Regulations under Working Environment Act

In spring 1991 the Directorate instigated work to examine the need and propose the framework for future rules covering the working environment in the petroleum industry.

The purpose of developing such rules is to establish a structured, comprehensive regulation of the working environment of employees offshore.

The rules will support the adopted objectives and current strategies for detailed regulation design under the *Safety Regulations*. Active cooperation with the other authorities concerned, particularly the Labour Inspection, seeks to produce a set of rules which are as nation-wide as possible, thereby reducing the numbers of competing regulations and guidelines.

In 1991 the preparatory survey was carried out which aimed to prepare a full summary of national and international standards, other national regulations, etc, which either already or in the future can be expected to influence future regulations in the Directorate's sphere of responsibility. A proposal for regulatory strategy and structure has also been developed in the light of this survey. A plan for future regulatory work has also been developed.

4.3 SUPERVISORY DUTIES

The Directorate's supervisory duties during the year were conducted according to a plan which reflects the objectives adopted and priority commitment areas.

Some degree of re-ranking of priorities was called for, nevertheless, largely due to problems encountered with the drilling of deep, high-pressure wells, which made strict control of such activities necessary. The loss of the Sleipner A gravity base also triggered considerable, non-planned activity.

In addition to supervisory operations directed at particular operating companies, the Directorate conducted extensive audits of a specified problem area which is common to many companies. This strategy produced many benefits which will be drawn on in the new year.

In connection with the Directorate's project to implement the new regulations, the industry was asked for its views on possible areas where supervision could be improved. Activities were also initiated to improve the Directorate's handling of its coordinatory role.

4.3.1 Consents and permits

The year saw the award of 111 consents and permits, compared to 80 in 1990. These were as follows (1990 in brackets):

– Exploratory survey	9 (5)
– Exploration drilling	40 (32)
– Detailed engineering	8 (3)
– Fabrication	10 (5)
– Installation	6 (9)
– Use of installation	20 (9)
– Rebuild or redefinition of purpose of installation	8 (3)
– Use of service vessel	10 (14)

Drilling permits were awarded as follows: 70 (61) for production drilling, 46 (40) for exploration drilling, and 32 (30) for shallow drilling.

The general increase in the figures reflects the continuing increase in total activity on the continental shelf.

4.3.2 Priority commitment areas

In 1991 the Directorate gave priority to supervisory activities associated with:

- Early phase of field development
- Older installations
- Compliance with Working Environment Act
- Transition from engineering to operation, and specific challenges in operating phase.

4.3.2.1 Early phase of field development

Supervision of the early phases of field development projects was carried out in 1991 on the basis of the new Risk Analysis Regulations. The early phase means phases in the project leading up to the Plan for Development and Operation.

The year's activities concentrated on three operators, where it is clear that the level of employee input on decisions in these phases varies from one company to the next. The same can be said of experience transfer from partners.

The operators are all in the implementation phase of the Risk Analysis Regulations. Work is ongoing to define a format which meets the intentions of the regulations and ensures that all relevant parties have a say in the decision process.

4.3.2.2 Older installations

Supervision here revealed problems of maintaining the technical standard of installations and equipment to the level required under the new regulations. The problems are linked in some cases with deficiencies in the operators' systems for maintenance management.

Maintenance management is a key tool for optimising the total costs of operations and maintenance. Cost optimisation of this type also produces a safety dividend since the evaluation of equipment criticality can help rank priorities. The application of new maintenance technology and selection of equipment on the basis of life-cycle costs are important tools for the optimisation of safety and costs.

The lessons of Piper Alpha on the UK sector in 1988 helped persuade operators to implement major modifications on older installations to improve installation safety.

Following from the conclusions and recommendations in an updated safety study for Statfjord A, major modification work was implemented there. Similar updates of the safety studies for Statfjord B and C were made in 1991, and modification work on these installations will commence in 1992.

Safety studies for the various Ekofisk installations show that, except for the Ekofisk tank (2/4 T), they meet the acceptance criteria given in the Directorate's former guidelines for safety evaluation of platform designs, now replaced by the Risk Analysis Regulations. In the case of the Ekofisk tank, deficiencies were noted in connection with design and personnel safety. Also, fires and gas leaks are on the increase, which is causing concern. Supervisory operations on Ekofisk will therefore concentrate very largely on 2/4 T from now on.

4.3.2.3 Compliance with Working Environment Act

Most supervisory operations in this field in 1991 were concerned with contractor employees in the offshore industry and their working conditions. Supervisory control revealed deficiencies in:

- Health, environmental and safety (HMS) targets
- Company health service
- Working environment committee
- HMS training
- Registration of sick leave.

In connection with this supervision it was noted that employees in well service companies work hours longer than are normally acceptable in the offshore industry. In December 1991, operators were therefore ordered to ensure that a system of monitoring the working hours of leading personnel and people in particularly independent positions in well service operations should be established. The operators were also ordered to ensure that the criteria under which personnel are classified as leading or particularly independent match those given in Odelsting Proposition no. 41 1975–76 concerning Working Hours, Dismissal Protection, Factory Inspection, etc.

4.3.2.4 Transition from engineering to operation

Supervision under this commitment area revealed varying degrees of experience feed-back between these important project phases. The involvement of operating personnel in the engineering phase is nevertheless an approach used by the operators. The time and degree of such involvement is what varies from company to company. In connection with implementation of the new regulations, the companies are working to define a format which will adequately involve the employee side in the decision process.

4.4 INTERNAL CONTROL EXPERIENCE

One common lesson of the total supervision activity is that there are very often deficiencies in the companies' systems for document management and deviation handling. As the responsibility for safety and quality assurance becomes more conscious in the line organisation, it is often the case that line managers do not always possess the necessary competence to get the processes to function in practice.

The organisational units which are set to supervise the company's internal control activities are not always given adequate resources and organisational freedom to fill the role they are supposed to fill under the regulations.

Another lesson is that people's respect for important governing documentation is not always as great as might be wished.

4.5 INTER-DISCIPLINARY COOPERATION

Again in 1991 the Directorate engaged the services of other government agencies as permitted under the existing inter-departmental assistance contracts.

The Electricity Inspection was split off from the Norwegian Water Courses and Energy Authority on 1 January 1991 and the responsible department became the Ministry of Local Government. It had previously been the Ministry of Petroleum and Energy.

The efforts to draw up a contract for assistance and cooperation which had already started were completed and the contract became effective 1 May 1991. Cooperation with the Electricity Inspection has been most productive, particularly in the field of common rules for electrical systems.

The development concept chosen for the Troll field requires offshore installations to be linked to land installations for product processing and power supply. Close ties have therefore been established with the Directorate for Fire and Explosion Safety and the Electricity Inspection so as to coordinate and divide the supervisory responsibilities for the Troll project.

4.6 INTER-GOVERNMENTAL COOPERATION

Formal cooperation with other countries with whom treaties have been signed for joint supervision of pipelines etc continued to perform successfully in 1991.

The Directorate has long enjoyed excellent relations with the UK authorities. In 1991 a notable event was the transfer of responsibility for safety supervision in the UK sector from the Department of Energy to the Health and Safety Executive (HSE) on 1 April, in line with the recommendations of the public inquiry commission report into the Piper Alpha accident in 1988. For the same reasons the UK authorities are in the process of restructuring their supervision systems, which will bring the Norwegian and UK systems closer to each other. During 1991 good relations were established with the HSE. Formal contacts have already been established between the two agencies for the exchange of information on accidents and incidents.

Closer cooperation was also initiated with the Danish Ministry of Energy, which oversees supervisory control in the Danish sector. Activities have been planned which will mean even closer ties in 1992.

4.7 ACCIDENT REPORTS AND FOLLOW-UP

In 1991 the Directorate performed system audits of seven operating companies and five contractors, the theme of which was the reporting and follow-up of accidents, including preventive measures. These audits came as the result of several areas of difficulty experienced by the Directorate regarding reporting and follow-up of accidents, incidents, fires and gas leaks.

The main impression gleaned from these audits is that the operators' reporting and follow-up systems for accidents and hazard situations are inadequately ingrained in the quality assurance systems, and that the systems are often suboptimal when it comes to defining responsibilities and reporting criteria. Furthermore, there was a general lack of understanding with responsible personnel of the current regulations and criteria for accident and incident reporting.

Measures implemented as the result of accidents are most often aimed at removing hazardous actions and dangerous conditions at the accident site. The Directorate feels that a systematic approach in which all relevant parts of the organisation are mobilised to remove the underlying causes of accidents and incidents is all too rarely implemented.

4.8 PERSONAL INJURIES

4.8.1 General

The Directorate receives reports and notices about personal injuries in connection with offshore activities. These reports are under continual review and details are input into the Directorate's database. Notices of serious events are analysed to see whether immediate intervention is called for, in which case the Directorate oversees the company's house investigation, often in parallel with police inquiries. Supervision often takes the form of orders to the operator or contractor.

As already noted in section 4.7, the Directorate concentrated thorough supervisory activities on several operating and contract companies, examining their reporting and follow-up systems for accidents and hazard situations. These showed, not least, a lack of understanding of the Directorate's reporting criteria, which led to under-reporting. Certain operators were therefore ordered to submit personal injury reports in retrospect. Some of these late reports will therefore not be included in the statistics until 1992. Supervision will continue in 1992. A project has also been initiated aimed at developing and improving the Directorate's systems for registering, analysing, and utilising accident and hazard situation reports.

4.8.2 Helicopter crash on Ekofisk 2/4 S

On 10 August 1991 a Bell helicopter, flown by Helikopterservice, crashed while working on the Ekofisk 2/4-S riser platform. The whole crew of three perished in the accident. The accident occurred while the helicopter was assisting with a lift operation, when it struck the flare stack and crashed onto the platform. The accident is being investigated by the police and the Civil Aviation Inquiry Commission. As the accident is reported in the Civil Aviation Authority's statistics it is therefore omitted from the offshore fatality figures.

4.8.3 Causes of personal injury

On the basis of the empirical data reported as personal injury statistics for 1991 the Directorate sees the need to continue to focus on situations that can cause accidents and incidents, particularly:

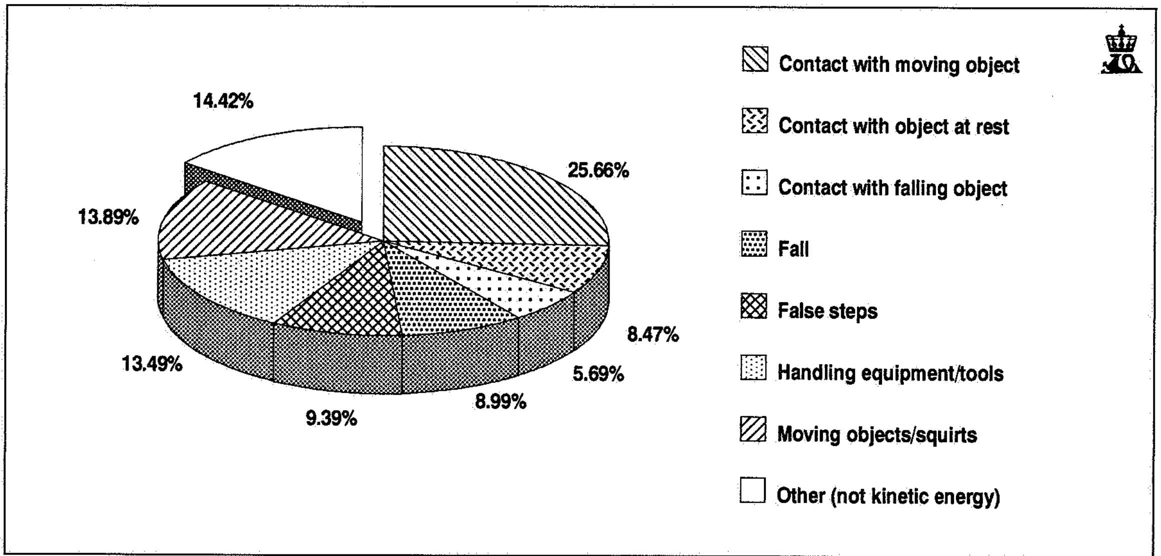
a) Work on systems which have been pressurised
b) Work on systems and equipment of poor design standard which can cause injury by crushing, cuts, blows, falls and impact
c) Areas having poor safety planning or poor safety organisation of work.

The Directorate will continue discussions with the industry for possible measures by which to reduce the continuing large numbers of accidents caused by objects and appliances in motion, falling objects, splinters, as well as falls, etc, see Table 4.8.5.d. For follow up purposes such injuries will be termed kinetic energy injuries, which still make up about 85 per cent of the total, see Figure 4.8.3. The figure shows the types of events that involve kinetic energy.

In 1990 the Directorate embarked on a programme of systematic registration of hazardous actions and conditions (symptoms) based on the descriptions of causal events given on the injury report forms. By continual assessment and analysis of personal injury statistics in 1990–91 the Directorate has identified the following specific areas as having the greatest symptom incidence:

a) Inappropriate position or work posture relative to tools or equipment
b) Inadequate protective equipment
c) Slippery and uneven surfaces, untidy workplace
d) Equipment in poor repair or used wrongly
e) Air-borne particles causing eye injury
f) Cluttered access to workplace and/or poor design of equipment or workplace.

Fig. 4.8.3
Accidents caused by lack of control of kinetic energy, 1991



Accidents caused by someone assuming an inappropriate posture for the tools or equipment concerned often produce serious injury, such as crushing, falls, and contact with falling objects or objects moving horizontally. The Directorate has noticed that category (a) can be identified in almost all descriptions of serious personal injury, or events where the injury potential was high. The underlying causes of such events can be split into two rough divisions:

- Layout workplace and work task: Equipment and components may be so arranged that operators are forced to take up an unsuitable posture. Often personnel must violate hazard zones simply due to poor task organisation, or due to limitations with the equipment or tools used.
- Individual factors: Certain individuals may lack the necessary insight to do the job. For example, inadequate understanding of the risks involved can lead to an unsound working posture. And even where the employer has dutifully informed personnel of risks, it may still happen that personnel take risks due to an inappropriate safety attitude.

4.8.4 Incidents

Through research in Norway and overseas it has been established that the number of incidents (near-misses) will always far exceed the number of accidents. The low number of incidents reported in 1990 (48), was partially the result of the Directorate's requirement that only serious incidents should be reported. In 1991, however, the Directorate encouraged companies to include in their reports all incidents which have a useful lesson to teach. This led to an increase in incident reports to 172 in 1991. Since the need for information in connection with accident prevention is very large, the Directorate will continue to work to encourage incident reporting. The Directorate has also noted with satisfaction the operators' greater commitment to reporting, registration, and follow-up of incidents.

4.8.5 Personal injuries in production activity

Reported injuries in connection with production of oil and gas totalled 574 in 1991, six more than in 1990. There were no fatal accidents in production. The number of manhours worked was 13,811 in 1991, compared to 12,315 in 1990. This means that the accident frequency declined from 46.1 injuries per 1000 manhours in 1990 to 41.6 in 1991.

Tables and figures – production installations

Personal injuries are reportable to the Directorate under two criteria: Lost time during next 12-hour shift, and/or Medical treatment.

Accidents suffered during time off are not included in the tables. 29 such injuries were reported in 1990, plus six retrospective reports, or 35 injuries in all. In 1991 the reported recreational accidents were 25 in number, a reduction of ten.

Table 4.8.5.a includes a summary of the personal injuries per 1000 man-years worked in production from 1976 to 1991 – including the production ship *Petrojarl 1*. Since 1987 the number of hours worked a year has been cut from 1752 to 1612. The overall injury frequency and personal injury statistics for 1990 have been adjusted from 45.6 to 46.1 for late reports and verification of the database. For the same reason the personal injury statistic rose from 562 to 568.

The calculated injury rate in 1991 was 41.6 per 1000 years worked. This is equivalent to an injury frequency of 25.8 per million hours.

Table 4.8.5.a
Injuries and deaths per 1000 man-years on production installations 1976–91

Year	Hours worked	Hours per man-year	Man-years	Injuries and deaths	Injuries and deaths per 1000 man-years	Deaths	Deaths per 1000 man-years
1976	4876316	1852	2633	213	80.9	2	0.76
1977	8146948	1852	4399	282	64.1	2	0.45
1978	14932296	1752	8523	624	73.2	6	0.70
1979	14986608	1752	8554	575	67.2	0	0.00
1980	12237720	1752	6985	451	64.6	0	0.00
1981	15612072	1752	8911	415	46.6	0	0.00
1982	14790384	1752	8442	526	62.3	0	0.00
1983	11473848	1752	6549	334	51.0	0	0.00
1984	14643216	1752	8358	491	58.7	1	0.12
1985	15014640	1752	8570	599	69.9	1	0.12
1986	17108280	1752	9765	606	62.1	0	0.00
1987	22169458	1612	13753	832	60.5	0	0.00
1988	19878727	1612	12332	637	51.7	0	0.00
1989	19935637	1612	12367	596	48.2	1	0.08
1990	19852093	1612	12315	568	46.1	1	0.08
1991	22263572	1612	13811	574	41.6	0	0.00
Total	247921815		146267	8323	56.9	14	0.10

Figure 4.8.5.a shows the development of personal injury frequency during the period 1979–91.

Table 4.8.5.b shows the distribution of accident frequency for the various main activities during the same period. This summary shows a distinct reduction in accident frequency for the drilling function although this has levelled off in the past two years. The construction and maintenance statistic has been falling for four years. The overall injury frequency has been declining since 1985.

The accident frequency for the administration and production function has been stable since 1980.

Construction and maintenance accounted for 50.9 per cent of the work performed and 57.7 per cent of the injuries suffered in 1990. In 1991 this function accounted for 53.5 per cent of the work performed, while the share of injuries fell off to 56.4 per cent.

Table 4.8.5.c shows the distribution of injuries and years worked for operator and contractor employees from 1985 to 1991. In 1990 contractors con-

Fig. 4.8.5.a
Injuries to personnel 1979–91. Production installations

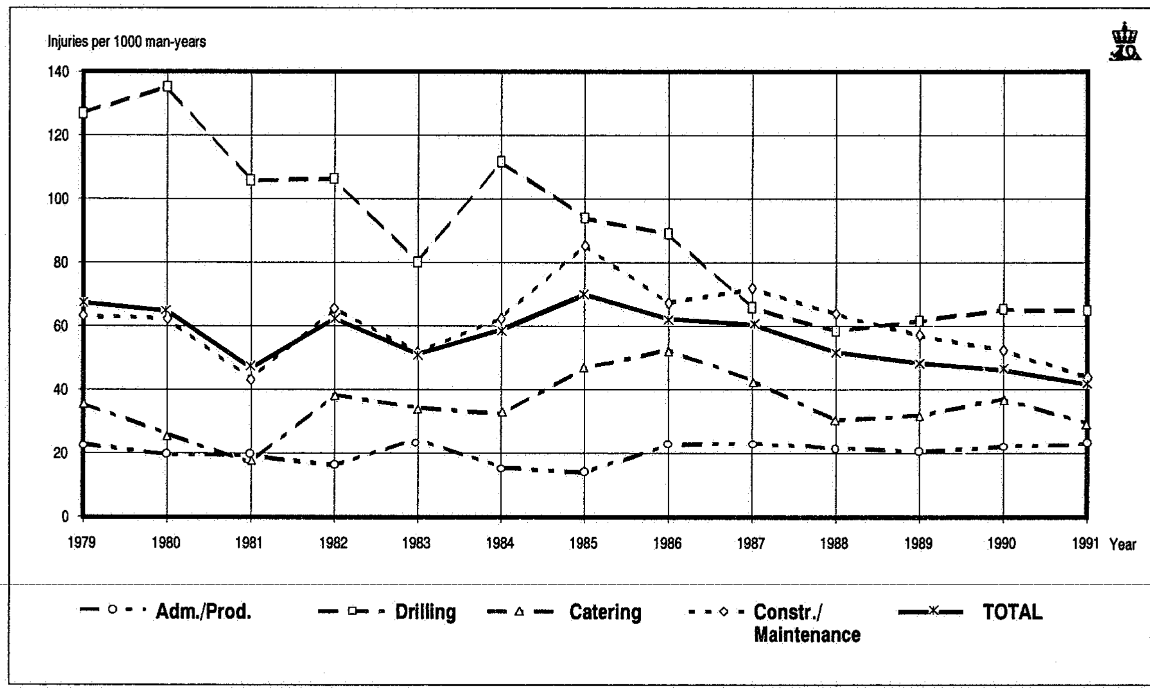


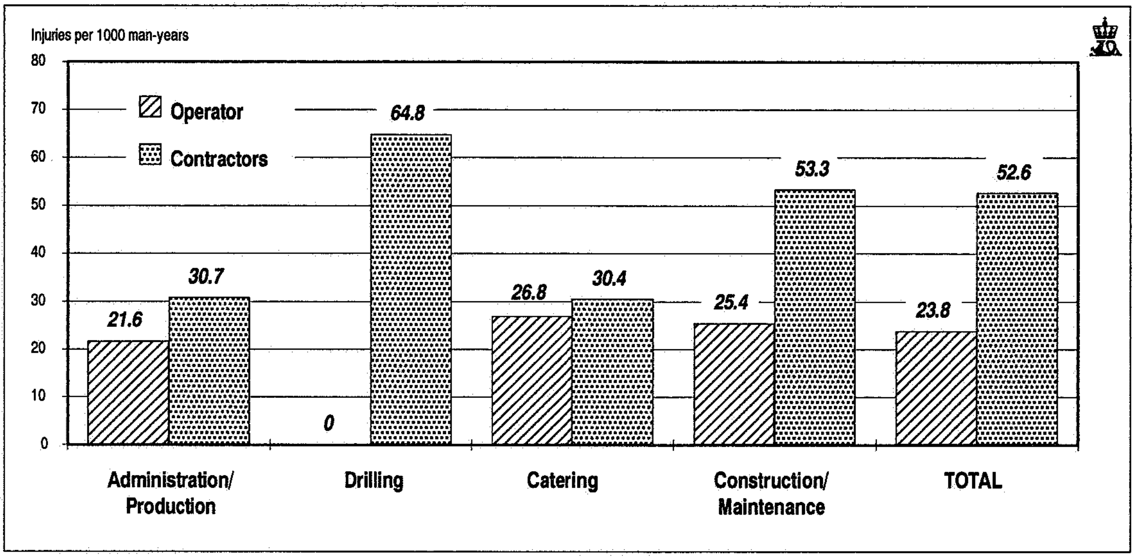
Table 4.8.5.b
Injuries per 1000 man-years by function on production installations 1979–91

FUNCTION		1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
Administration/ Production	Man-years	1098	1174	1144	1306	1182	1614	1656	1507	2295	2440	2393	2759	2790
	Injuries	25	23	22	21	29	25	23	34	53	53	49	61	64
	Injuries/1000 man-years	22.8	19.6	19.2	16.1	24.5	15.5	13.9	22.6	23.1	21.7	20.5	22.1	**22.9**
Drilling	Man-years	1467	1095	1098	1289	1300	1324	1384	1371	1567	1883	2128	2027	2239
	Injuries	186	148	116	137	104	148	130	122	103	110	131	132	145
	Injuries/1000 man-years	126.8	135.2	105.6	106.3	80.0	111.8	93.9	89.0	65.7	58.4	61.6	65.1	**64.8**
Catering	Man-years	507	383	411	548	525	681	685	856	1167	1091	1227	1264	1400.5
	Injuries	18	10	7	21	18	22	32	45	50	33	39	47	41
	Injuries/1000 man-years	35.5	26.1	17.0	38.3	34.3	32.3	46.7	52.6	42.8	30.2	31.8	37.2	**29.3**
Construction/ Maintenance	Man-years	5482	4333	6258	5299	3542	4739	4845	6031	8724	6919	6619	6265	7382.2
	Injuries	346	270	270	347	183	296	414	405	626	441	377	328	324
	Injuries/1000 man-years	63.1	62.3	43.1	65.5	51.7	62.5	85.4	67.2	71.8	63.7	57.0	52.4	**43.9**
TOTAL	Man-years	8554	6985	8911	8442	6549	8358	8570	9765	9421.8	7423.7	7053	6645.4	7750.1
	Injuries	575	451	415	526	334	491	599	606	832	637	596	568	574
	Injuries/1000 man-years	67.2	64.6	46.6	62.3	51.0	58.7	69.9	62.1	60.5	51.7	48.2	46.1	**41.6**

Table 4.8.5.c
Break down of injuries and man-years by operator and contractor employees on production installations

FUNCTION		1985	1986	1987	1988	1989	1990	1991	
Administration/ Production	Man-years	1575	1293	1692	1985	2099	2259	2366	Operator
		80	213	603	454	294	500	424	Contractor
	Injuries	19	34	44	47	43	49	51	o
	Injuries/	4	0	9	6	6	12	13	c
		12.1	26.3	26.0	23.7	20.5	21.7	21.6	o
	1000 man-years	50.0	0.0	14.9	13.2	20.4	24.0	30.7	c
Drilling	Man-years	0	0	0	0	0	0	0	o (operator)
		1384	1371	1567	1883	2128	2027	2239	c (contractor)
	Injuries	0	0	0	0	0	0	0	o
	Injuries/	130	122	103	110	131	132	145	c
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	o
	1000 man-years	93.9	89.0	65.7	58.4	61.6	65.1	64.8	c
Catering	Man-years	0	39	94	209	340	396	447	o (operator)
		685	817	1073	882	888	868	953	c (contractor)
	Injuries	0	5	5	4	3	13	12	o
	Injuries/	32	40	45	29	36	34	29	c
		0.0	128.2	53.2	19.1	8.8	32.8	26.8	o
	1000 man-years	46.7	49.0	41.9	32.9	40.5	39.2	30.4	c
Construction/ Maintenance	Man-years	1544	2063	2441	2399	2381	2364	2482	o (operator)
		3301	3969	6283	4520	4237	3901	4900	c (contractor)
	Injuries	61	51	49	50	70	61	63	o
	Injuries/	353	354	577	391	307	267	261	c
		39.5	24.7	20.1	20.8	29.4	25.8	25.4	o
	1000 man-years	106.9	89.2	91.8	86.5	72.5	68.4	53.3	c
TOTAL	Man-years	3119	3395	4227	4593	4820	5019	5295	o (operator)
		5450	6370	9526	7739	7547	7296	8516	c (contractor)
	Injuries	80	90	98	101	116	123	126	o
	Injuries/	519	516	734	536	480	445	448	c
		25.6	26.5	23.2	22.0	24.1	24.5	23.8	o
	1000 man-years	95.2	81.0	77.1	69.3	63.6	61.0	52.6	c

Fig. 4.8.5.b
Injuries to personnel employed by operators and contractors on production installations, 1991



tributed 59.2 per cent of the total hours worked on production installations and 78.3 per cent of injuries. In 1991 the contractors' share of hours worked rose to 61.7 per cent, while their share of injuries declined to 78 per cent. The discrepancy between share of manhours and share of accidents therefore declined from 19.1 to 16.3 per cent for contractors and operators combined.

Figure 4.8.5.b shows the injury frequency broken down by operator and contractor personnel and main activity functions.

Tables 4.8.5.d-g show the distribution of injury events by work group, part of body injured and contributory causes.

Table 4.8.5.h shows the distribution of personal injuries by assumed seriousness. An injury is defined as serious here if it results (or will probably result) in permanent injury (for example amputation) or extended absence from work. The evaluation is made solely on the basis of the information in the accident report.

4.8.6 Personal injuries in exploration and production drilling on mobile rigs

There were no fatal accidents on mobile rigs in 1991.

Accident reporting from mobile exploration and production rigs is subject to the same criteria as for production activity. The summary only embraces personal injuries on the installations while engaging in petroleum activities, i.e. while positioned for drilling. In 1991 there were 159 accident reports compared to 139 in 1990 (corrected from 133 to allow for retrospective reports). This represents an accident frequency (in injuries per 1000 man-years, as for production installations) of 52.5 in 1991, compared to 51.8 in 1990, which is a slight increase.

It proved difficult to obtain accurate reports for manhours worked on mobile installations, and the Directorate has therefore collated the hours reported by the operators with details of rig days worked in the Directorate's databases. The figures are consistent in 1991, presumably due to energetic follow-up by the Directorate. However, there is reason to suppose that the manhour figures reported for 1990 and 1989 are less reliable, for which reason these figures will be reviewed anew.

Table 4.8.5.d
Work accidents 1990–91 on production istallations, showing type of incident and occupation

Occupation / Injury incident	Administration	Drillfloor worker	Driller	Electrician	Cook	Caterer	Assistant	Instrument technician	Crane operator	Painter, gritblaster	Mechanic, motorman	Operator	Plateworker insulator	Pipeworker plumber	Servicetechnician	Scaffolder	Welder	Derrickman	Other, unspecified	TOTAL	%	YEAR
Other contact with object/machinery in motion	2	16	1	10	3	5	14	3	2	3	11	6	7	6	5	6	2	3	0	105	18.5	90
	5	21	5	3	3	4	29	1	1	6	11	3	7	8	4	8	6	5	0	130	22.6	91
Fire Explosion etc	0	0	0	1	0	0	0	0	0	0	0	1	1	0	0	0	1	0	0	4	0.7	90
	0	1	0	0	0	0	0	0	0	0	0	0	0	2	0	0	1	0	0	4	0.7	91
Fall to lower level	0	3	1	3	0	2	1	1	0	2	4	3	5	2	0	0	1	1	0	29	5.1	90
	0	1	1	1	1	2	7	0	0	2	1	2	2	1	3	2	1	0	0	27	4.7	91
Fall at same level	2	0	1	4	2	7	10	2	0	1	0	2	1	1	3	1	3	2	1	43	7.6	90
	4	1	0	0	0	1	6	1	0	1	1	2	2	0	1	2	1	0	0	23	4.0	91
Stepping on uneven surface or tripped	1	0	2	3	0	5	4	1	0	4	3	6	3	3	2	5	1	1	1	45	7.9	90
	3	1	1	1	1	2	12	3	1	4	5	3	3	2	5	4	0	0	0	51	8.9	91
Falling objects	1	4	1	1	0	0	5	1	0	1	2	0	2	0	2	10	1	0	0	31	5.5	90
	1	4	0	1	0	1	9	1	0	7	1	1	1	1	4	3	1	0	1	37	6.4	91
Other contact with object at rest	2	2	0	2	1	2	4	3	2	5	6	3	2	2	3	4	2	0	0	45	7.9	90
	4	0	1	5	0	3	6	2	0	5	5	2	6	2	2	4	3	3	0	53	9.2	91
Handling accident	6	6	1	5	4	3	15	2	0	3	7	1	8	7	5	5	4	2	0	84	14.8	90
	2	6	0	4	4	6	10	3	0	2	12	4	4	4	5	3	4	1	0	74	12.9	91
Contact with chemical or physical compound	0	0	0	0	0	2	6	0	0	1	1	2	3	0	1	0	3	0	0	19	3.3	90
	1	1	0	2	0	3	2	0	0	3	1	1	3	2	0	2	2	1	0	24	4.2	91
Muscular strain	2	2	0	5	0	3	5	1	0	3	5	3	1	0	4	6	1	2	1	44	7.7	90
	7	2	2	0	2	2	10	4	0	2	3	6	3	3	0	2	0	0	1	49	8.5	91
Splinters, splashes	1	6	0	2	0	1	8	3	0	15	7	7	18	15	2	5	17	1	1	109	19.2	90
	1	5	1	1	0	2	11	0	0	6	6	0	7	12	7	3	33	0	0	95	16.6	91
Electrical current	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	3	0.5	90
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	91
Extreme temperature	0	0	0	0	4	2	0	0	0	0	0	0	0	0	0	0	0	0	0	6	1.1	90
	0	0	0	0	2	2	0	0	0	0	0	1	0	0	0	1	0	0	1	7	1.2	91
Fall into sea	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	1	0.2	90
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	91
Total	17	40	7	37	14	32	73	17	4	38	46	34	51	36	27	42	37	12	4	568	100	90
	28	43	11	18	13	28	102	15	2	38	46	25	38	37	31	34	52	10	3	574	100	91
%	3.0	7.0	1.2	6.5	2.5	5.6	12.9	3.0	0.7	6.7	8.1	6.0	9.0	6.3	4.8	7.4	6.5	2.1	0.7	100		90
	4.9	7.5	1.9	3.1	2.3	4.9	17.8	2.6	0.3	6.6	8.0	4.4	6.6	6.4	5.4	5.9	9.1	1.7	0.5	100		91

Table 4.8.5.e
Work accidents 1990–91 on production installations, showing type of incident and part of body injured

Injury incident / Injured part of body	Eye	Back	Arm, shoulder	Head, face	Teeth	Hip, leg	Hand, finger	Stomach, chest	Toe, foot	Other	TOTAL	%	YEAR
Other contact with object/ machinery in motion	2	3	2	10	12	4	54	3	15	0	105	18.5	90
	2	1	3	16	8	11	69	4	16	0	130	22.6	91
Fire Explosion etc.	0	0	0	0	0	0	3	0	0	1	4	0.7	90
	0	0	1	2	0	0	0	0	0	1	4	0.7	91
Fall to lower level	0	6	5	1	1	3	4	4	4	1	29	5.1	90
	0	9	3	1	1	3	4	1	4	1	27	4.7	91
Fall at same level	0	5	6	4	2	8	7	2	8	1	43	7.6	90
	0	3	4	3	1	5	3	3	0	1	23	4.0	91
Stepped on uneven surface or tripped	0	3	0	0	1	6	2	1	32	0	45	7.9	90
	0	4	4	2	2	4	1	1	33	0	51	8.9	91
Falling objects	0	0	4	6	1	2	7	0	11	0	31	5.5	90
	0	2	4	2	3	6	8	0	12	0	37	6.4	91
Other contact with object at rest	1	3	1	11	4	9	14	1	1	0	45	7.9	90
	0	5	6	11	6	8	13	1	3	0	53	9.2	91
Handling accident	2	0	1	3	4	7	65	1	1	0	84	14.8	90
	2	0	2	6	7	2	53	0	2	0	74	12.9	91
Contact with chemical or physical compound	12	0	0	0	0	0	1	0	1	5	19	3.3	90
	12	0	1	1	0	1	2	0	0	7	24	4.2	91
Muscular strain	0	12	10	0	9	3	4	4	1	1	44	7.7	90
	0	22	5	0	7	5	5	3	2	0	49	8.5	91
Splinters, splashes	94	1	2	3	2	2	2	1	2	0	109	19.2	90
	85	0	0	4	0	0	3	1	2	0	95	16.6	91
Electrical current	1	1	1	0	0	0	0	0	0	0	3	0.5	90
	0	0	0	0	0	0	0	0	0	0	0	0.0	91
Extreme temperature	0	0	0	1	0	0	2	0	3	0	6	1.1	90
	0	0	3	0	0	0	2	0	2	0	7	1.2	91
Fall into sea	0	0	0	1	0	0	0	0	0	0	1	0.2	90
	0	0	0	0	0	0	0	0	0	0	0	0.0	91
Total	112	34	32	40	36	44	165	17	79	9	568	100.0	90
	101	46	36	48	35	45	163	14	76	10	574	100.0	91
%	19.7	6.0	5.6	7.0	6.3	7.7	29.0	3.0	13.9	1.6	100.0		90
	17.6	8.0	6.3	8.4	6.1	7.8	28.4	2.4	13.2	1.7	100.0		91

Table 4.8.5.f
Work accidents 1990–91 on production installations etc showing injury and contributory factors

Contributory factors / Injury incident	Other mechanical equipment	Drill tongs	Electrical equipment	Hand tools, machinery, implements	Loose fittings, fixtures on structure	Chemical, physio-, biological factors	Cold, pressure, heat, ventilation	Lifting, transport gear	Materials, goods, packaging	Other	TOTAL	%	YEAR
Other contact with object/machinery in motion	8	4	1	26	27	0	1	30	8	0	105	18.5	90
	7	7	1	35	16	0	0	40	23	1	130	22.6	91
Fire Explosion etc.	0	0	1	2	0	1	0	0	0	0	4	0.7	90
	0	0	0	3	1	0	0	0	0	0	4	0.7	91
Fall to lower level	0	0	0	1	23	0	1	3	1	0	29	5.1	90
	1	1	1	3	18	0	0	2	1	0	27	4.7	91
Fall at same level	0	0	0	1	31	0	0	4	4	3	43	7.6	90
	0	0	0	2	17	0	0	1	3	0	23	4.0	91
Stepped on uneven surface or tripped	0	0	0	4	29	0	1	0	10	1	45	7.9	90
	0	0	0	5	33	0	0	6	7	0	51	8.9	91
Falling objects	1	0	2	4	4	0	0	5	15	0	31	5.5	90
	4	0	2	11	6	0	0	2	12	0	37	6.4	91
Other contact with object at rest	2	0	2	9	22	0	0	5	5	0	45	7.9	90
	4	0	1	10	30	0	0	3	5	0	53	9.2	91
Handling accident	0	3	0	60	5	0	0	2	14	0	84	14.8	90
	1	2	0	61	3	0	0	1	5	1	74	12.9	91
Contact with chemical or physical compound	1	0	0	11	0	5	0	0	2	0	19	3.3	90
	0	0	2	16	0	5	0	0	1	0	24	4.2	91
Muscular strain	3	0	1	4	13	0	0	4	15	4	44	7.7	90
	2	1	1	5	17	0	0	8	14	1	49	8.5	91
Splinters, splashes	2	0	1	66	2	8	8	2	17	3	109	19.2	90
	2	0	0	60	4	13	2	0	12	2	95	16.6	91
Electrical current	0	0	1	2	0	0	0	0	0	0	3	0.5	90
	0	0	0	0	0	0	0	0	0		0	0.0	91
Extreme temperature	1	0	0	1	0	2	1	0	1	0	6	1.1	90
	1	0	0	3	0	3	0	0	0	0	7	1.2	91
Fall into sea	0	0	0	0	0	0	0	1	0	0	1	0.2	90
	0	0	0	0	0	0	0	0	0	0	0	0.0	91
Total	18	7	9	191	156	16	12	56	92	11	568	100.0	90
	22	11	8	214	145	21	2	63	83	5	574	100.0	91
%	3.2	1.2	1.6	33.6	27.5	2.8	2.1	9.9	16.2	1.9	100.0		90
	3.8	1.9	1.4	37.3	25.3	3.7	0.3	11.0	14.5	0.9	100.0		91

Table 4.8.5.g
Working accidents 1979-91 on production installations etc showing injury incident and occupation

Injury incident \ Occupation	Administration	Drillfloor worker	Driller	Electrician	Caterer	Assistant	Instrument technician	Crane operator	Painter, gritblaster	Mechanic, motorman	Operator	Plateworker, insulator	Pipeworker, plumber	Service technician	Scaffolder	Welder	Derrickman	Other, unspecified	TOTAL	%
Other contact with object/ machinery in motion	32	247	31	58	57	314	23	15	40	108	39	64	70	52	79	39	86	3	1357	18.8
Fire Explosion etc	0	1	0	3	0	7	0	0	1	2	2	2	4	0	0	3	0	0	25	0.3
Fall to lower level	14	26	11	39	15	96	19	10	44	43	23	33	37	19	29	32	19	3	512	7.1
Fall at same level	32	24	6	52	46	113	20	8	38	36	32	41	58	26	65	39	12	8	656	9.1
Stepped on uneven surface or tripped	25	17	6	58	33	93	20	12	45	34	41	33	55	26	56	51	14	8	627	8.7
Falling objects	9	38	9	9	7	66	6	1	14	30	5	34	34	19	53	20	5	2	361	5.0
Other contact with object at rest	18	18	4	40	30	71	23	6	54	45	17	62	42	20	57	31	9	4	551	7.6
Handling accident	21	80	8	70	89	174	26	6	41	136	39	102	105	41	72	75	26	3	1114	15.5
Contact with chemical or physical compound	5	15	0	14	30	57	8	2	92	16	20	22	23	15	8	22	8	0	357	5.0
Muscular strain	22	39	7	42	24	110	9	7	40	46	33	30	57	20	66	24	18	4	598	8.3
Splinters, splashes	12	24	6	27	12	77	5	1	105	56	23	118	131	17	23	215	5	3	860	11.9
Electrical current	0	2	0	27	0	1	1	1	0	1	0	2	0	0	0	1	0	0	36	0.5
Extreme temerature	1	0	0	2	38	5	1	0	0	4	5	6	9	1	3	14	0	1	90	1.2
Fall into sea	0	0	0	0	0	1	0	0	1	0	0	0	0	0	0	1	0	1	4	0.1
Other	4	3	0	5	3	11	1	2	3	4	3	5	6	0	2	4	0	0	56	0.8
TOTAL	195	534	88	446	384	1196	162	71	518	561	282	554	631	256	513	571	202	40	7204	100
%	2.7	7.4	1.2	6.2	5.3	16.6	2.2	1.0	7.2	7.8	3.9	7.7	8.8	3.6	7.1	7.9	2.8	0.6	100.0	

Table 4.8.5.h
Break down of injuries on production installations by severity

SEVERITY	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	TOTAL
FATAL							1				1	1		4
SERIOUS	75	33	18	48	12	26	19	24	31	12	28	22	22	370
MINOR	363	309	287	360	235	345	517	559	777	610	566	545	551	6024
UNSPECIFIED	137	109	110	118	87	119	62	23	24	15	1		1	806
TOTAL	575	451	415	526	334	491	599	606	832	637	596	568	574	7204

Tables and figures – mobile installations
Table 4.8.6.a presents a summary of personal injuries per 1000 man-years from 1989 to 1991 in connection with drilling on mobile installations.

Figure 4.8.6.a shows the injury frequency distributed by main functions.

Table 4.8.6.b shows the injury events distributed by occupational groups.

Table 4.8.6.c shows the injury events distributed by contributing factors.

4.8.7 Development of injury frequency on production installations
There was a clear decline in accident frequencies for the catering function last year. The frequency for construction and maintenance also declined. In drilling the frequency was more or less unchanged from 1990. In administration and production there was a slight increase. In all the main functions showed a decline in accident frequencies on fixed installations.

The accident frequency overall on production installations is 41.6, the lowest figure reported since statistics were first compiled in 1976. Despite the statistics, the Directorate is inclined to believe that the actual figure is rather higher, due to under-reporting as discussed above.

In spite of the limitations of the system and possible systematic under-reporting, the Directorate feels that the summaries provide a reasonably accurate view of personal injury development in the offshore industry; and that there is therefore still reason to claim that injury development is headed in the right direction.

4.9 WORKING ENVIRONMENT

4.9.1 Conditions for contractor employees
In 1991 the Directorate performed system audits of seven operators and ten contractors with a view to investigating the working environment of contractor employees. The audits concentrated mostly on well service companies.

The audits examined the following problem areas in particular:

Table 4.8.6.a
Injuries and deaths per 1000 man-years in connection with drilling from mobile installations in 1989–91

Year	Hours worked	Hours per man-year	Man-years	Injuries and deaths	Injuries and deaths per 1000 man-years	Deaths	Deaths per 1000 man-years
1989	3584740	1612	2224	87	39.1	2	0.90
1990	4328907	1612	2685	139	51.8	1	0.37
1991	4878152	1612	3026	159	52.5	0	0.00
Total	12791799		7935	385	48.5	3	0.38

Fig. 4.8.6.a
Injuries per 1000 man-years in connection with drilling from mobile installations in 1991

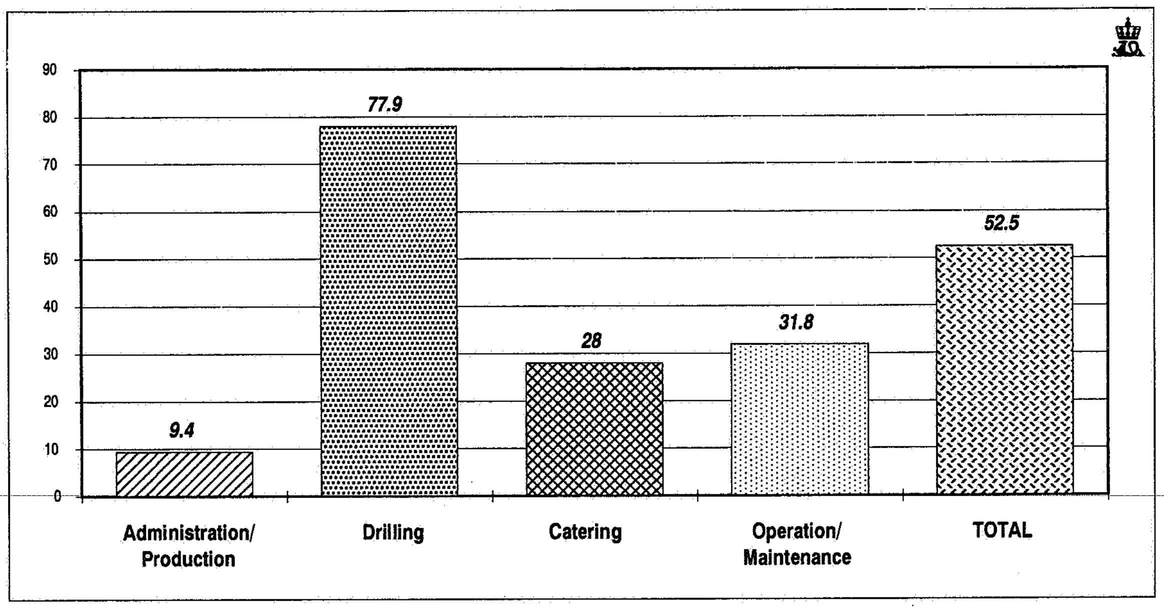


Table 4.8.6.b
Work accidents in connection with drilling from mobile installations in 1990–91 showing type of incident and occupation

Injury incident / Occupation	Administration	Drillfloor worker	Driller	Electrician	Cook	Caterer	Assistant	Crane operator	Painter, gritblaster	Mechanic, motorman	Operator	Plateworker, insulator	Service technician	Welder	Derrickman	Other, unspecified	TOTAL	%	YEAR
Other contact with object/machinery in motion	0	13	2	0	0	2	12	1	0	0	1	0	5	1	4	0	41	29.5	90
	0	28	4	0	0	0	15	1	0	0	0	0	4	1	3	2	58	36.5	91
Fall to lower level	0	0	1	0	0	1	0	1	0	0	0	0	3	0	0	0	6	4.3	90
	0	2	1	0	0	1	2	0	0	0	0	1	1	0	1	0	9	5.7	91
Fall at same level	0	2	0	0	0	0	0	0	0	0	0	0	0	0	1	1	4	2.9	90
	0	1	0	1	0	0	2	0	0	0	0	0	1	0	0	0	5	3.1	91
Stepped on uneven surface or tripped	0	2	1	1	0	0	6	1	0	1	0	0	0	0	2	1	15	10.8	90
	1	3	2	0	1	0	2	0	0	1	0	0	3	0	1	0	14	8.8	91
Falling objects	0	4	1	0	0	0	3	0	0	0	0	0	0	0	1	0	9	6.5	90
	0	4	0	0	0	0	2	0	0	0	0	0	0	0	0	0	6	3.8	91
Other contact with objects at rest	0	5	2	0	0	2	3	0	0	1	0	0	1	1	0	0	15	10.8	90
	0	2	2	0	1	0	1	0	0	1	0	0	2	0	1	0	10	6.3	91
Handling accident	1	4	0	0	0	0	2	0	0	2	0	0	3	1	2	0	15	10.8	90
	1	11	2	1	0	2	0	1	0	1	0	0	3	1	2	0	25	15.7	91
Contact with chemical or physical compound	0	1	1	0	0	0	0	0	0	0	0	0	0	2	1	0	5	3.6	90
	1	4	0	0	0	1	0	0	0	0	0	0	0	0	1	1	8	5.0	91
Muscular strain	2	5	1	0	1	1	2	0	0	0	1	0	1	0	0	0	14	10.1	90
	1	3	1	0	0	0	4	0	0	0	0	0	2	0	1	0	12	7.5	91
Splinters, splashes	0	5	0	0	0	0	0	0	0	1	0	0	1	3	3	1	14	10.1	90
	0	2	1	1	0	0	3	0	1	1	0	0	0	0	0	0	9	5.7	91
Electrical current	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	1	0.7	90
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	91
Extreme temperature	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	90
	0	1	0	0	1	1	0	0	0	0	0	0	0	0	0	0	3	1.9	91
Total	3	41	9	1	1	6	28	3	0	5	2	0	15	8	14	3	139	100	90
	4	61	13	3	3	5	31	2	1	4	0	1	16	2	10	3	159	100	91
%	2.2	29.5	6.5	0.7	0.7	4.3	20.1	2.2	0.0	3.6	1.4	0.0	10.8	5.8	10.1	2.2	100		90
	2.9	38.4	8.2	1.9	1.9	3.1	19.5	1.3	0.6	2.5	0.0	0.6	10.1	1.3	6.3	1.9	100		91

- Criteria for selection of contractor
- Responsibilities and communication between operator and contractor in connection with compliance with regulations
- Working environment of contractor employees, stressing occupational hygiene, ergonomics, personnel qualifications and organisational factors, including working hours.

The audits showed that operators frequently specify requirements for contractors in the field of safety, but less frequently in connection with health monitoring, personnel qualifications, environmental studies, safety delegate systems and working environment committees.

Confusion was also shown between operator and contractor regarding who was responsible for examining the working environment, implementing improvement measures, monitoring health, inspecting time sheets, etc.

Technical assessments and information to employees about health hazards when using chemicals is generally defective.

Measures to reduce the problems of noise in cement units have received little attention.

Ergonomic factors for well service personnel are less than satisfactory and seem clearly to have attracted too little attention. Heavy lifting operations, cramped space, time pressure, cold and draughts, combined with the design of the equipment, contribute to muscular strain injuries and sickness absence.

Table 4.8.6.c
Work accidents in connection with drilling from mobile installations in 1990–91 showing type of incident and contributory factor.

Injury incident / Contributory factor	Other mechanical equipment	Drill tongs	Electric equipment	Hand tools, machinery, implements	Loose fittings, fixtures on structure	Chemical, physio-, biological factors	Lifting, transport gear	Materials, goods, packaging	Other	TOTAL	%	YEAR
Other contact with objects/machinery in motion	5	3	0	6	6	0	17	4	0	41	29.5	90
	1	4	0	14	3	0	30	5	1	58	36.5	91
Fall to lower level	0	0	0	1	4	0	1	0	0	6	4.3	90
	0	0	0	0	6	0	3	0	0	9	5.7	91
Fall at same level	0	0	0	1	2	0	1	0	0	4	2.9	90
	0	0	0	0	4	0	0	1	0	5	3.1	91
Stepped on uneven surface or tripped	1	0	0	0	8	1	2	3	0	15	10.8	90
	0	0	0	2	9	0	0	3	0	14	8.8	91
Falling objects	0	1	0	1		0	4	3	0	9	6.5	90
	0	1	0	1	1	0	2	1	0	6	3.8	91
Other contact with object at rest	1	1	0	1	6	0	3	3	0	15	10.8	90
	2	1	0	0	7	0	0	0	0	10	6.3	91
Handling accident	0	2	0	6	0	0	4	3	0	15	10.8	90
	1	1	0	18	2	0	2	1	0	25	15.7	91
Contact with chemical or physical compound	0	0	0	4	0	1	0	0	0	5	3.6	90
	0	0	0	4	1	1	1	1	0	8	5.0	91
Muscular strain	1	2	0	2	2	0	2	4	1	14	10.1	90
	0	0	0	1	1	0	5	3	2	12	7.5	91
Splinters, splashes	0	0	0	8	1	0	0	5	0	14	10.1	90
	0	0	0	4	0	2	0	2	1	9	5.7	91
Electrical current	0	0	1	0	0	0	0	0	0	1	0.7	90
	0	0	0	0	0	0	0	0	0	0	0.0	91
Extreme temperature	0	0	0	0	0	0	0	0	0	0	0.0	90
	1	0	0	1	0	0	0	1	0	3	1.9	91
Total	8	9	1	30	29	2	34	25	1	139	100	90
	5	7	0	45	34	3	43	18	4	159	100	91
%	5.8	6.5	0.7	21.6	20.9	1.4	24.5	18.0	0.7	100		90
	3.1	4.4	0.0	28.3	21.4	1.9	27.0	11.3	2.5	100		91

Well service personnel are usually so few on each installation that they do not have a special safety delegate. It seems often to be the case that the drilling contractor's or operator's safety delegate responsible for the area is not aware of his responsibility for contractor personnel, for which reason well service personnel often fall outside the delegate system. Another difficulty is that the safety delegate is not always adequately qualified to look after the working environment of well service personnel.

The Directorate's audits revealed many violations of working hour provisions. In some cases well service operators have worked for longer than 24 hours without an off-duty period. It is not unusual in some operating companies for employees who are reported as holding a leading or particularly independent position to work more than 16 hours without rest which qualifies as such. There were large differences between companies regarding the definition of personnel who held leading or particularly independent positions.

Employees who often work long duty periods without adequate rest represent a threat to safety. The Directorate considers it irresponsible for personnel working with wells under pressure, pressure testing, explosives, radioactive isotopes, chemicals, etc, to work hours longer than are normally accepted in the industry. The provisions in the Working Environment Act concerning offshore working hours ought also, the Directorate feels, provide the standard for well service employees having leading or particularly independent positions.

4.9.2 Installation manning

The size and composition of installation crews is determined by prevailing conditions, such as the type and scope of activities on the installation, the choice of technical solutions, the age of the installation, personnel qualifications, organisation and management. Any assessment of installation manning must therefore build on a detailed understanding of each particular installation.

In 1991 the Directorate looked in particular at Elf's plans to reduce crews in connection with declining activity on DP2 and Phillips' plans for various rationalisation measures on Ekofisk field installations.

4.9.3 Accommodation

Living quarters – flotel

During the entire year there was a heavy demand for accommodation on Ekofisk due to the high level of activities, particularly in connection with the upgrading work on the Ekofisk tank. In February Phillips hired the *Safe Lancia* flotel, a vessel with 358 beds, hooking it to the field centre by footbridge. As Phillips was planning work requiring another 200–300 beds, the *Rigmar 301* jack-up was also hired, with 336 beds. This installation is being refurbished and a new living quarters module with 256 beds has been constructed. This upgrade took longer than projected and the application for consent to use was not submitted to the Directorate until December. The application concerns three years with an option to extend. Phillips is also considering more permanent solutions to increase accommodation capacity on Ekofisk.

Oseberg C which entered service in 1991 is equipped with living quarters for 122 persons. The *Polyconfidence* flotel is linked to the Oseberg field centre. The Directorate have also consented to the use of the mobile *Borgila Dolphin*, which will act as support vessel and flotel for a period of three years.

Older installations

As production declines and revenues decrease, several operators are looking at the options for demanning and remotely controlling older installations. Phillips has applied to remotely control Vest Ekofisk (2/4 D), in which case the living quarters will be converted to emergency quarters for maintenance personnel, who will otherwise commute back and forth, being on the platform only by day.

Elf has implemented a reduction in crew on DP2 in connection with which parts of the quarters have been closed down, and other functions have been reduced to match the smaller crew.

The Edda installation quarters are not up to regulatory standard. In 1986 Statoil was awarded consent to develop the Tommeliten field, and consent to hook up the subsea installation to Edda, where Phillips is the operator. The Directorate gave Phillips dispensation from the *Provisional Regulations for Living Quarters on Production Installations* etc until the end of 1991; however, Phillips has been advised that this dispensation will not be extended and that the living quarters on Edda will need to be upgraded to meet regulation standards.

Statoil was awarded consent to erect a new accommodation and office module on Statfjord C, which will supplement existing facilities and be installed in 1992.

Remote control installations

During the year permission was given to start fabrication work on the Embla installation. Phillips is the operator for this installation which will be controlled remotely from Eldfisk 2/7 FTP and maintained by a commuting maintenance crew. Embla has emergency quarters with overnight capacity for 12 persons should the weather prevent disembarkation. The Directorate expects other fields to be developed according to the same pattern in the future.

4.10 CONTINGENCY PREPAREDNESS

4.10.1 Helicopter operations on Norwegian sector

In 1989 the Civil Aviation Authority presented a concept for operations in the Norwegian sector of the North Sea.

This concept contains certain recommendations, including the formalisation of the Helicopter Flight Information Service for helicopter pilots. This means that the personnel advising and routing information to the pilots are given a course of training and take a final exam, receiving certification as for personnel in charge of similar services to aircraft at land stations.

The HFIS has been established in the Ekofisk, Gullfaks and Oseberg areas in order to cover the southern and middle parts of the North Sea.

Several of the recommendations of the air operations concept of 1989 have been implemented or are in the process of being implemented. In 1991, however, a revision of the concept was instigated aimed at further safeguarding helicopter flights up to year 2000. This revised concept seeks to improve navigation services, alarm services, and helicopter routines on deck. Finalisation of the concept is expected by the end of 1992.

4.10.2 Removal of man-overboard boats

In 1991 Elf applied to the Directorate for dispensation from the regulatory requirement to hold fast MOB boats on its Frigg and Heimdal installations. The company wanted instead to upgrade its response to man-overboard situations on standby vessels.

This matter was considered at great length in the Directorate, particularly regarding whether or not it was acceptable to concentrate all man-overboard resources in one place (on the standby vessel).

The Directorate was unable to recommend dispensation, and Elf appealed the decision to the Ministry of Local Government, who rejected the appeal.

4.10.3 Preparedness on Eldfisk 2/7 A and FTP
The Directorate looked at emergency services on these installations in connection with supervision in the early summer 1991. Several aspects of preparedness were so seriously out of line that the operator decided to shut down operations for a brief period.

The report from the inspection sparked off many activities in Phillips, directed both at the installations mentioned and at the company's general follow up of preparedness on its installations.

4.10.4 Helideck on Ekofisk tank
Phillips and the Directorate have been assessing the risks of using the helideck on the Ekofisk tank (2/4 T) for a long time. The deck is fitted with one of the two hangars on the Ekofisk field centre.

This hangar was required for maintenance of one of the two shuttle and SAR helicopters on Ekofisk; the other uses the hangar on the hotel platform 2/4 H.

In order to reduce the sources of risk on 2/4 T as far as possible, Phillips decreed that all flights to the helideck will cease effective 1 November 1991.

Phillips has an agreement with Amoco to use the helideck and hangar on Valhall until such time as a hangar can be provided on Ekofisk.

4.10.5 Saga's preparedness on 2/4–16
The audit following the *Treasure Saga* accident on 2/4–16 revealed several deficiencies in Saga's governing documents and their use.

On the preparedness side there are three things that stand out:

- Compliance with Oil Industry Association guidelines for safety and preparedness training
- Implementation and use of emergency drills
- Internal alert systems on installation.

4.10.6 Foreign rigs without letters of compliance
Mobil chose the UK registered *Sovereign Explorer* to run two wells on blocks 35/11 and 33/9.

When using foreign installations in the Norwegian sector, operators have usually obtained a Letter of Compliance from the maritime authorities in Norway. This has provided a yardstick by which to evaluate the installation's compliance with Norwegian maritime legislation. In this case the rig owner chose Det norske Veritas as consultants to evaluate compliance.

Mobil assured itself through its quality assurance system that the installation satisfied the requirements in force for mobile installations operating in the Norwegian sector.

The Directorate's experiences with this type of approach have been most satisfactory.

4.10.7 Exercises
Once again, in 1991 the Directorate took part in many emergency drills in cooperation with the operators and major national and international preparedness exercises. Operating companies often hold one such major exercise each year, when the Directorate has a role to play in our own command centre. These drills provide a forum for inhouse training of Directorate staff, and simultaneously provide a good insight into operating companies' emergency response systems.

The major national and international exercises where the Directorate takes part are *Sosex* and *Bright Eye*. The first of these involves mobilising the Governmental Action Control Group, of which the Directorate is a part. The second is an international Search and Rescue exercise, with full participation by SAR groups from countries around the North Sea. The exercises include SAR sorties in connection with offshore petroleum operations.

These comprehensive exercises provide invaluable information on the total resources available and their capabilities.

4.10.8 Personnel qualifications
There has long been a general requirement in the regulations for special qualifications for all personnel intended to perform specific tasks in an emergency situation.

On fixed installations the Oil Industry Association's guidelines for safety and preparedness training have long been the accepted standard for such training.

The Directorate has been concerned that similar training for personnel on mobile installations should be upgraded. In 1991 the Oil Industry Association and Norwegian Shipowners Association reached agreement on a new curriculum for training, which builds on basic training and refresher courses at four-year intervals. The Directorate is very pleased with this development.

4.11 DRILLING
The Directorate's activities in 1991 in the services of drilling and well technology were marked by the rapid technological development which characterises this field. Development is driven by the large risks connected to drilling and well operations, the ever-increasing emphasis on the global environment, and the fact that activities offshore Norway are likely to enter areas where improved technology and methods are crucial.

4.11.1 Exploration drilling in North
In 1991, three wildcats were drilled in the Barents Sea, for which two mobile rigs were contracted, *Polar Pioneer* and *Sonat Arcade Frontier*. The latter needed to enclose its production test equipment before permission could be granted to operate in the area. No untoward problems were reported in connection with the external environment.

4.11.2 High-pressure wells
Partly as a result of advanced techniques which will

become appropriate for future field development projects, and partly due to critical operational incidents in recent years, the Directorate was particularly concerned with the following disciplines in drilling and well technology:

- Effects of relatively narrow kick margins applying in high-pressure wells
- Effects and consequences of high pressure
- Effects and consequences of high temperature.

Also the problems that arose while drilling well 2/4–16, causing the drill string to be cut on account of escaping gas, led the Directorate to commit considerable energy to examining the incident.

The Directorate's follow-up sought to identify as broadly as possible the various factors which triggered the incident. It was particularly essential to clarify the course of events, causalities, and possible consequences for future drilling operations.

4.11.3 Horizontal wells

The trend in recent years toward increasing numbers of high-deviation wells was further reinforced in 1991. As Table 4.11.3 shows, the number of highly deviated wells increased markedly, as did the proportion of wells where the deviation is so pronounced that they can usefully be defined as horizontal.

Highly deviated and horizontal wells make a useful contribution to the economics of many development projects since they enable one installation to drain a much larger area. Recent years have brought notable technical advances in the field and there is all reason to suppose that the progress shown in the table will continue for years to come.

Table 4.11.3
Number of wells with maximum deviation 60° – 90°

Year/<	60°–65°	65°–70°	70°–75°	75°–80°	80°–90°
1984	2				
1985	3	4			
1986	4	4			
1987	7				
1988	4	1	1	1	
1989	13	1		1	2
1990	8	4	1		3
1991	8	5	5	2	9

4.11.4 Deepwater drilling

During the present decade one expects blocks to be allocated in areas where the ocean is very deep (1000–2000 m, Vøringplatået). As one approaches water depths of 2000 m, one simultaneously approaches the limits of modern technology.

The Directorate has endeavoured to identify the drilling problems that are likely to be encountered on this type of operation well in advance of any such allocation, to that any adjustment of the regulations can be considered in advance.

4.11.5 Subsea production systems

Field developments in the years ahead will increasingly draw on subsea production systems. The Directorate considers it important to analyse the technical and safety aspects of the available technology as best possible, to provide the basis for regulatory adaptation and supervisory control.

For development concepts utilising tension-leg platforms (TLP), studies will be necessary to examine the safety aspects of tie-back systems. To begin with potential weak spots between the production tree on the installation and the wellhead on the seabed (mudline) will be examined. Later it will be necessary to carefully study the applications of the flexible flow lines which will be used.

An important target of the studies will be to examine the risk of flowline rupture and identify the most appropriate backup systems to contain any resulting damage as best possible.

4.11.6 Cuttings reinjection

Following from the growing environmental awareness of those involved on the Norwegian continental shelf and increasingly stringent government requirements, the industry has made active efforts to develop methods to solve the problems associated with oily drill cuttings. To date the normal course is to dispose of the cuttings on the seabed close to the installation.

Several operators have now conducted tests to bury the cuttings in the well, and results of these tests were so promising that one can speak of a breakthrough for this type of technology.

The method involves finely grinding the cuttings which come to the surface while drilling, and reinjecting the slurry in a suitable well. The injection takes place into the annulus between two layers of casing via the wellhead on the drilling installation.

Drilling of an ordinary well produces about 500 tons of oily cuttings. From 1 January 1993 the cleansing requirements for oily cuttings will be so strict that the only practicable alternative will be shipping the waste back to land for disposal. Apart from the high costs of storage, loading and shipment this involves, there are also well recognised environmental drawbacks to land disposal.

There is therefore all reason to believe that the reinjection of cuttings slurry into available annuli will be the preferred disposal method in future.

4.11.7 Daily drilling report system, DDRS

As the volume of data and staff experience with data usage builds up, the Directorate is drawing more and more benefit from its Daily Drilling Report System database.

Many enquiries have come in from operators, contractors and research institutes regarding data in the base. Wherever possible the Directorate has responded with the information on hand.

Figures 4.11.7.a and b illustrate the times spent on various activities in connection with production and exploration drilling in 1991, as taken from the database.

4.12 NATURAL ENVIRONMENT DATA

The acquisition of natural environment data such as information on currents, wind strengths, wave heights etc from Ekofisk, Frigg, Statfjord and the mobile rig *Polar Pioneer* continued satisfactorily in 1991. On the other hand there were certain difficulties obtaining the projected data quantities from monitoring systems on *Deepsea Bergen* and *Ross Rig*. With the help of the Norwegian Meteorological Institute the Directorate supervised the collection of data from these installations. This assistance scheme worked extremely well and is a powerful contributory factor to the good quality of control in this field.

In 1991 further efforts were made to initiate environmental data acquisition from Draugen once the

Fig. 4.11.7.a
Daily drilling report system 1991 – Production

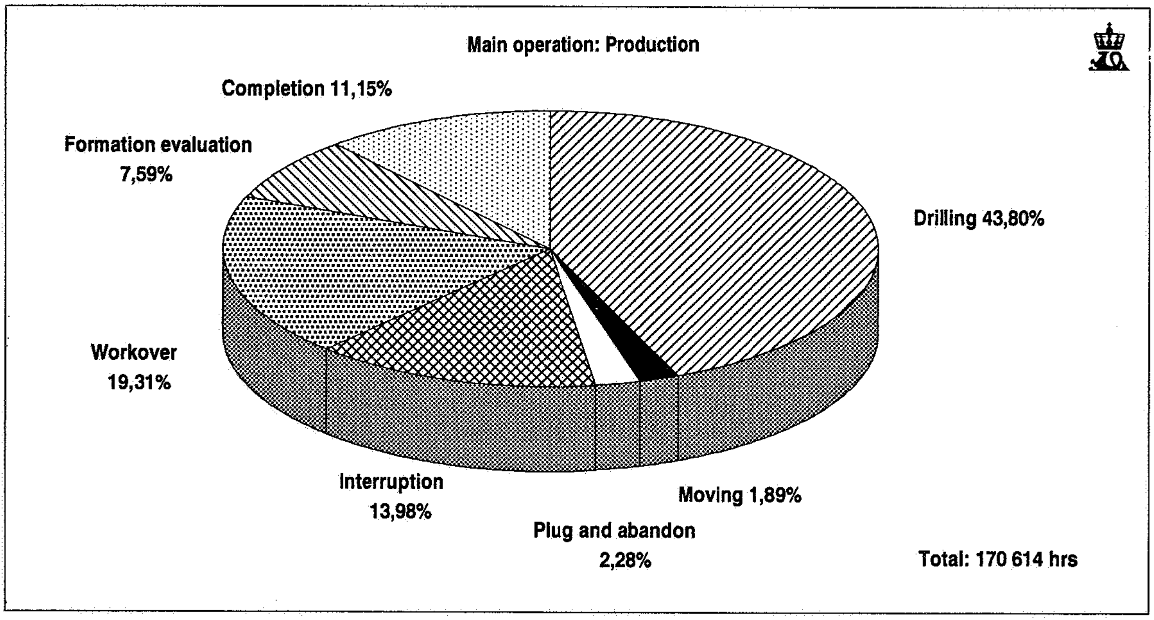
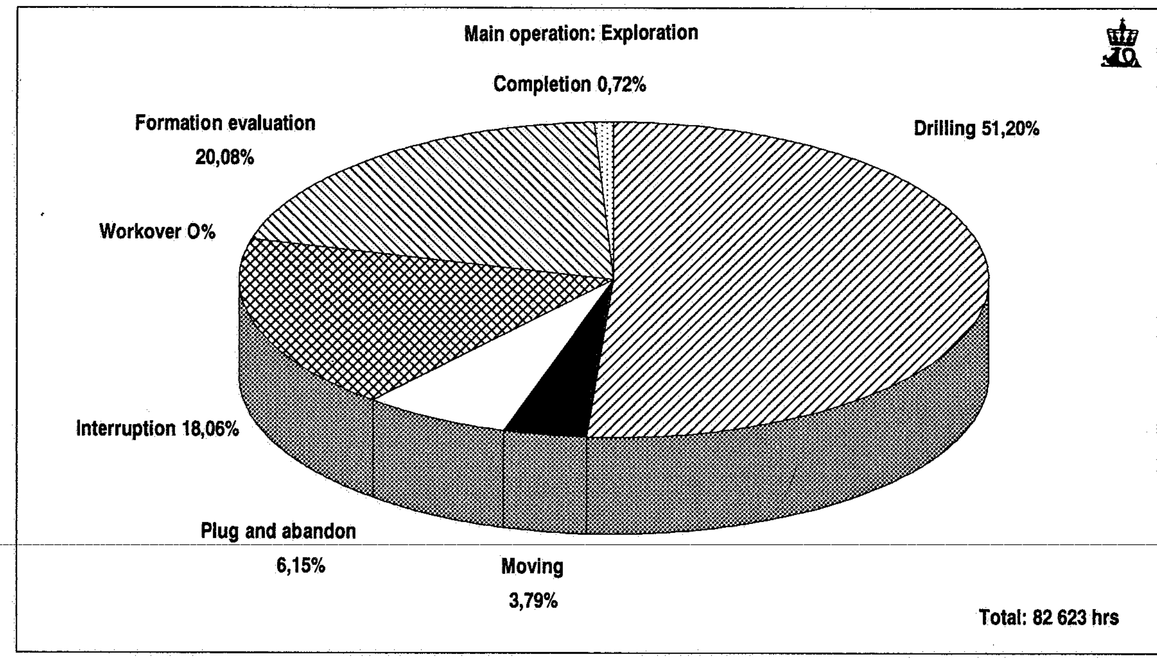


Fig. 4.11.7.b
Daily drilling report system 1991 – Exploration



installation is in place. The operator, Conoco, has also been ordered to collect environmental data on Heidrun. All told this will mean six permanent monitoring stations off the Norwegian coast.

Again in 1991 the Directorate collected natural data from the Barents Sea (Nordkappbanken), Vøringplatået, and the weather ship *Polarfront*. For two years now Coast Guard ships have been recruited to set out and collect monitoring equipment. In 1991 four sorties were undertaken with the assistance of the Coast Guard in a programme that means economic savings.

In 1991 the natural data project had an overall budget of about Nkr 5.9 million. Data were collected on wave heights and wave set, current velocity and current set, and meteorology. The measurement programme was put out on contract to Oceanor.

4.13 STRUCTURES AND PIPELINES

4.13.1 Subsidence on Ekofisk

The gradual subsidence of the seabed around the Ekofisk centre and Vest Ekofisk has been continuing since the late 1970s. The causes are a combination of weak reservoir rock and declining pressure in the reservoir, the latter being the result of depletion of the oil and gas coupled with inadequate pressure maintenance.

During the first half of the 1980s the subsidence rate at the Ekofisk centre was about 0.5 metres a year. Towards the end of the decade it had slowed to about half, but increased again to 0.35 metres a year in 1990 and 1991. The total subsidence of the Ekofisk field centre is 5.2 metres. At 2/4 A and B and Vest Ekofisk 2/4 D the rate is slightly less, the totals to date being 2.6 and 2.9 metres, respectively.

It was anticipated that subsidence rates would slacken off as the reservoir collapsed. The increase in rate in 1990–91 tends to indicate that there are other causes at work and an explanation using simple models is difficult to find.

The subsidence means that the clearance of the deck structures above a 100-year wave is less than intended. Installations at the field centre were therefore jacked up in 1987 to maintain the necessary clearance. For the 2/4 A, B and D installations Phillips is considering what measures to take to compensate for the lower safety margin. For the time being special procedures have been implemented to shut down production if extreme weather conditions are forecast.

Phillips has employed three types of systems to measure subsidence: pressure sensors, satellite ranging, and direct measurements of installation clearance above sealevel.

Phillips has also performed analyses of environmental loads, which include measurements taken over a 10-year period. The results will provide the basis for future engineering and usage parameters for the Ekofisk area.

Phillips has made strenuous efforts to analyse measurements and examine suitable measurement methods so as to produce the best possible synopsis of the subsidence question.

4.13.2 Flare stack crack formation

Several cracks were discovered in the Statfjord B flare stack in 1991, which in conjunction with earlier observations persuaded the Directorate of the necessity to reassess whether the regulations are adequate in respect of the problem.

The cracks are above and below the bracings, which would seem to indicate that the bracings have moved laterally to the prevailing wind. The cracks must have formed by the influence of wind eddies on certain braces and heavier framing, causing resonant movements. On Heimdal and Statfjord A visual observations had previously been made of flare stack sections which experienced vibration. These factors seen in conjunction with each other provide a reliable basis on which to determine the causes and effects.

The results of the Directorate's reassessment are that DIN 4133 would seem to be preferable as the reference in the Regulations for Structural Design, so the old reference will be removed.

4.13.3 Storm damage

During the past decade storm damage has occurred to fixed installations on several occasions. The Ekofisk area has been particularly exposed. Major damage occurred in November 1981, January 1984 and February 1988, culminating in the largest damage to date in December 1990. The reasons Ekofisk is particularly damage prone are to be found in the combination of aging installations, freak waves which are characteristic of the area, and reservoir collapse which has reduced installation clearance above the wavetops.

Very many cracks have been reported in secondary bracing on steel jackets, particularly in the splash zone, where wave impact is heaviest in bad weather. The number of cracks is greater on the upper sides of braces. Such damage is the result of waves crashing down on the brace from above. The cracks as they stand are not considered to represent an immediate safety problem.

4.13.4 Collisions

In 1991 two collisions were reported between vessels and installations. In one case a vessel collided with the Gyda jacket. In the other a tanker bumped the Gullfaks offshore loading buoy. In another accident, a helicopter crashed onto Ekofisk 2/4 S without causing damage to the installation.

In the last decade 13 collisions of ships with installations have been recorded. The rate is thus about two collisions per 100 working years. A number of dents in steel jackets have also been observed, which would indicate that unreported collisions may have occurred. Three of the reported collisions were between tankers and loading buoys, which would indicate that there is no difference between big and small vessels when it comes to collision frequency. This supports the Directorate's view that if vessels are to be permitted to enter the safety zone around an installation, the installation must be designed with collision in mind.

4.13.5 International standardisation

A committee was set up under the auspices of the Norwegian Building Standards Council in 1990 with the job of revising Norwegian Standard NS 3479 for structural loads. The Directorate was represented on the committee. After the committee started its work, work also started on an European Community standard concerning the same subject matter, from which time therefore the Norwegian committee has become a consultative body for the EC standard.

In 1991 the Norwegian Engineering Standards Association (NVS) set up Norwegian reference committees for a new ISO standard concerning Offshore Structures, Pipeline Transportation Systems for the Petroleum and Natural Gas Industries, and Line Pipe. The Directorate was represented on the committees which all met for the first time in 1991.

4.13.6 Pipeline and structural damage reports, CODAM

The CODAM, for COrrosion DAMage, database covers damage and non-conformance of pipeline systems and structures. Standard reporting forms have been designed, and operators can choose between reporting in writing or employing a specified data transfer format, depending on report volume. The Directorate hopes this will simplify the reporting routines. The Directorate is also concerned that operators and the industry as a whole should draw benefit from the systematic experiential data that the database can provide.

The database which has been in existence since 1982, is presently undergoing extensive restructuring to enable drawings to also be integrated and linked to damage. The system is expected to become fully operative in 1992.

4.13.7 Structural steel

Evolution in steel production has led to the types now used for structural components possessing excellent weldability, while mechanical properties and especially fracture toughness are good. This evolution is reflected in the operating phase, where faults that can be sourced to the structural steel are few and insignificant. In the Directorate's view the Norwegian offshore industry has been an important source of momentum in the development of the structural steel qualities currently in use.

Enthusiasm for using high strength steels in parts or all of the load-bearing structure is also growing steadily. At the moment steels of strengths up to 500 MPa seem to be producing the best returns.

The Directorate is pursuing developments and experience in the material technology field, following up field development projects and taking part in research projects and standardisation committees.

4.13.8 Loss of Sleipner A gravity base

On 23 August 1991 the Sleipner A gravity base sank at its moorings during submersion testing in Gandsfjorden. Despite the very short time it took for the accident to happen, nobody was injured.

Statoil immediately established an Inquiry Group comprising personnel from the company who had not been involved in the Sleipner project. Representatives from Norsk Hydro, Elf and Esso were members of the group on behalf of the partners. The Directorate held observer status in the group.

The Inquiry Group's mandate was to find the cause or causes of the base sinking and make the necessary recommendations in connection with a decision to construct a new base.

Underwater wreckage

Just as soon as it was possible to do so, a search was initiated for wreckage using an unmanned submarine. In all probability the concrete cells were crushed as the gravity base sank, leaving the whole structure to hit the bottom at high speed, and causing it to crumble into thousands of pieces spread over a wide area. The bottom of the fjord is also covered by a layer of mud up to 20 metres thick, so that not all the wreckage is visible. The observations of the wreckage were therefore unable to give any clue as to the cause of the accident.

Causal relationships

The Inquiry Group has formed the view on the basis of witness reports that the leak must have started in the concrete wall between the T-23 tricell and cell D-3. A tricell is the triangular space formed where three circular cells meet. Further work concentrated on analysing the base's structural strength in this region.

The following main conclusions were formed as the result of this analysis:

- The global analysis originally performed was incorrect, leading to under-dimensioning of the areas in question
- The reinforcement steel was inappropriate and in places incorrectly detailed
- Nodes are designed as a continuation of the cell walls between the cells, not as a support point.

The Inquiry Group has formed the opinion that all the structures in the supposed area of failure should have been right first time. The errors that in fact were made, should at the very least have been detected by the companies in their internal control routines before construction work commenced. The group reviewed the internal management systems in the project to see how errors of this type could be ignored. Several points were found, the key ones being:

- Experience transfer from the early project was inadequately supported
- Verification requirements incorporated in Norwegian Contractors' contract with Statoil were waived with Statoil's consent
- The verification carried out by Statoil should have been more extensive and deeper-going
- The product of considerable audit activity inhouse and in respect of NC was very small.

There is a tendency for more and more design work to be done with the aid of computer programmes. These often produce results that are not easily verified. On Sleipner A this tendency was very pronounced.

Conclusions and recommendations

The Inquiry Group concluded that it has no hesitation in recommending a new, concrete gravity base for Sleipner A, provided the group's recommendations are followed.

On the basis of the accident and the Inquiry Group's findings, the Directorate has planned supervisory activities in 1992 which will be implemented for operators who wish to use concrete for their field development projects, in order to check that the lessons of the accident are incorporated in their projects. The experiences drawn from the Sleipner inquiry process have also led the Directorate to plan a review of internal control's role, responsibility and organisational location with the operating companies.

Experience from the accident has also led to a revision of the guidelines for concrete structures in the Regulations for Structural Design, which will be issued early in 1992.

4.14 GAS LEAKS, FIRES AND OUTBREAKS

As discussed in section 4.7 above, the Directorate conducted system audits of the oil companies' systems for accident reporting in 1991.

The audit revealed large differences between operators regarding the criteria underlying reporting of gas leaks and fires to the Directorate.

Uniform reporting routines and criteria are important if such data are to be useful in any systematic approach to the Directorate's supervisory activities and regulatory drafting. The Directorate feels therefore that current practices are inadequate and has initiated cooperation with the Oil Industry Association to see if uniform reporting routines and criteria can be developed.

4.14.1 Gas leaks

During the year 55 gas leaks were reported on fixed and mobile installations, seven more than in 1990.

Figure 4.14.1.a breaks down the reported gas leakages by severity. The divisions in the figure are based on the Directorate's appraisal of the course of events and the risks the gas leak entailed. The figure shows that most of the leaks were small and quickly brought under control.

Fig. 4.14.1.a
Classification of reported gas leaks according to severity.

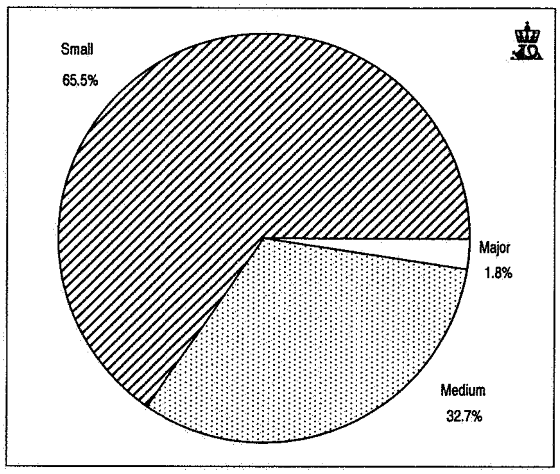


Table 4.14.1 shows gas leakages in the given severity categories as detected by the gas detector systems.

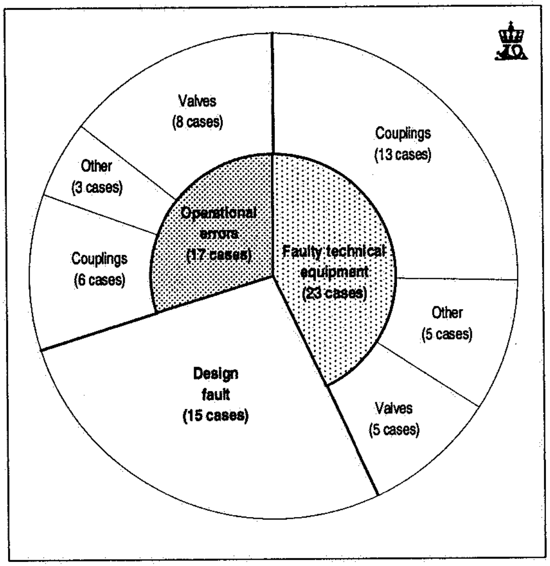
Figure 4.14.1.b serves to illustrate the causes of the gas leakages. The causes behind a gas leakage are often several and coincidental. The figure assigns the causal factors on the basis of the Directorate's analysis of reports received. Human error is one causal subcategory in the operational error category. In turn a human error may have many underlying causal elements, such as poor preparation of work, lack of training, lack of information, crossed communications, and the stress factor.

Table 4.14.1.a
Gas leakages detected by gas detection systems

Severity	Total number	Number detected automatically	Reading in % LEL	
			20%	60%
Minor	36	11	9	2
Medium	18	9	3	6
Major	1	0	0	0

(LEL=Lower explosion limit)

Fig. 4.14.1.b
Gas leaks – classification of causal relationship



The statistics show that gas leakages of a more serious nature are often the result of faulty connections and faulty valve operation.

4.14.2 Fires and outbreaks

The Directorate has records of 52 fires in 1991, versus 41 in 1990.

Fires in connection with welding operations account for most of the increase in the number of fires.

Table 4.14.2 summarises the scope and causes of fires and outbreaks reported to the Directorate in 1991 and it will be seen that none of the reported fires are classified as large fires (class L).

4.14.3 Halon usage

During the year the State Pollution Control Authority (SFT) circulated a consultative document proposing a revision of the Regulations for Production, Import, Export and Use of Chlorofluorocarbons (CFCs) and Halons.

The revisions seek to include halon also for fire-fighting purposes. The SFT's intentions in this respect have been known to the industry for some time, and operators have displayed commendable ability to adapt to the new regulations on new and planned installations. Considering the announced transitional arrangements, the Directorate does not feel that the new regulations will represent a safety risk to the petroleum industry.

4.15 DIVING

4.15.1 Diving operations

In the current period 1360 surface oriented dives, 1310 bell runs (in saturation), 170,200 manhours in saturation, and zero monobaric dives were made on the Norwegian continental shelf. This was about the same level of activity as in 1990. The dives were carried out from nine different support vessels, as shown in Figure 4.15.1.

Diving operations in the Norwegian sector were as in previous years concerned with inspection, maintenance and structural contracts on Ekofisk, Frigg, and fields operated by Statoil and Norsk Hydro. Diving in connection with construction work was generally to hook up flowlines and risers and give assistance with the emplacement of other types of structures.

4.15.2 Diving accident survey

Figures 4.15.2.a and b provide a summary of the events reported to the Directorate in the years 1985–91 in connection with diving operations. The incidents are broken down into the following categories: near-miss, accident, fatal accident.

In 1991, no cases of decompression sickness were reported in connection with saturation diving. Once case was reported in connection with surface oriented diving. Figures 4.15.2.c and d show how accidents involving personal injury were divided between the various injury categories.

Table 4.14.2
Summary of fires on mobile and fixed production installations

	Construction phase			Fixed installations operating phase			Mobile installations operating phase		
	S	M	L	S	M	L	S	M	L
Welding				17	3		1		
Spontaneous ignition		1		10	7			1	
Electrical short circuiting				6				1	
Other causes				5					
Total		1		38	10		1	2	

S=Small, M=Medium, L=Large

Fig. 4.15.1
Diving operations in 1991

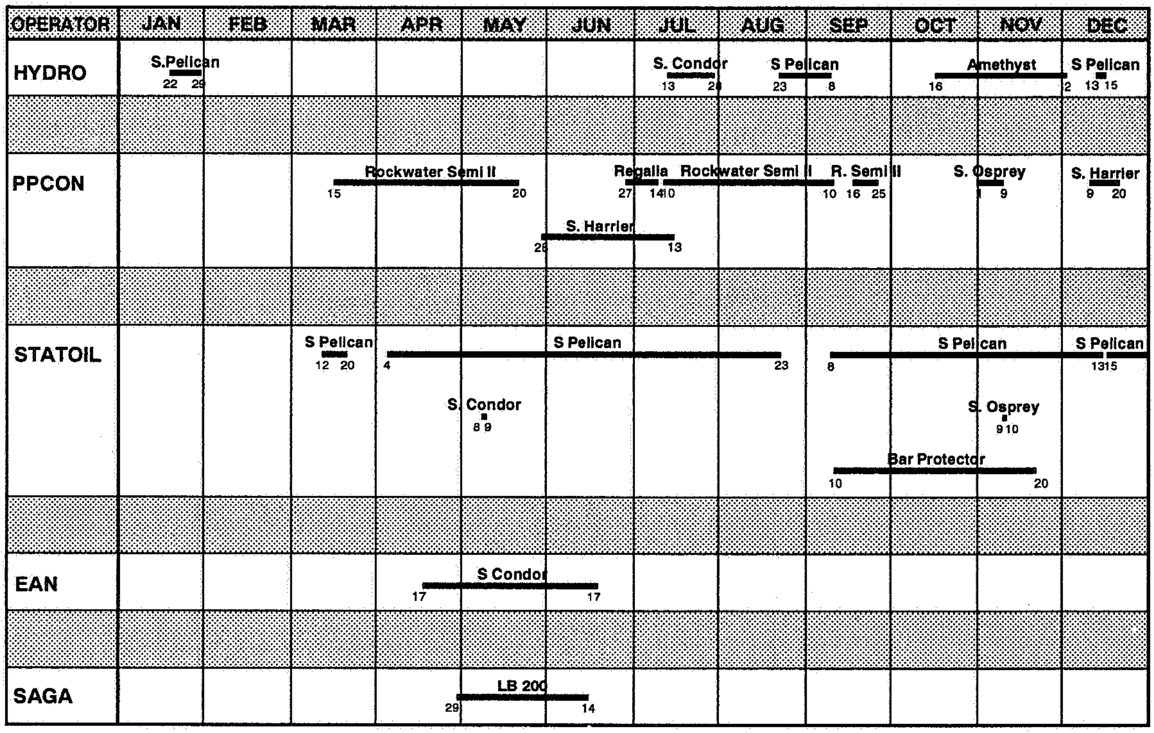


Fig. 4.15.2.a
Incidents in saturation diving

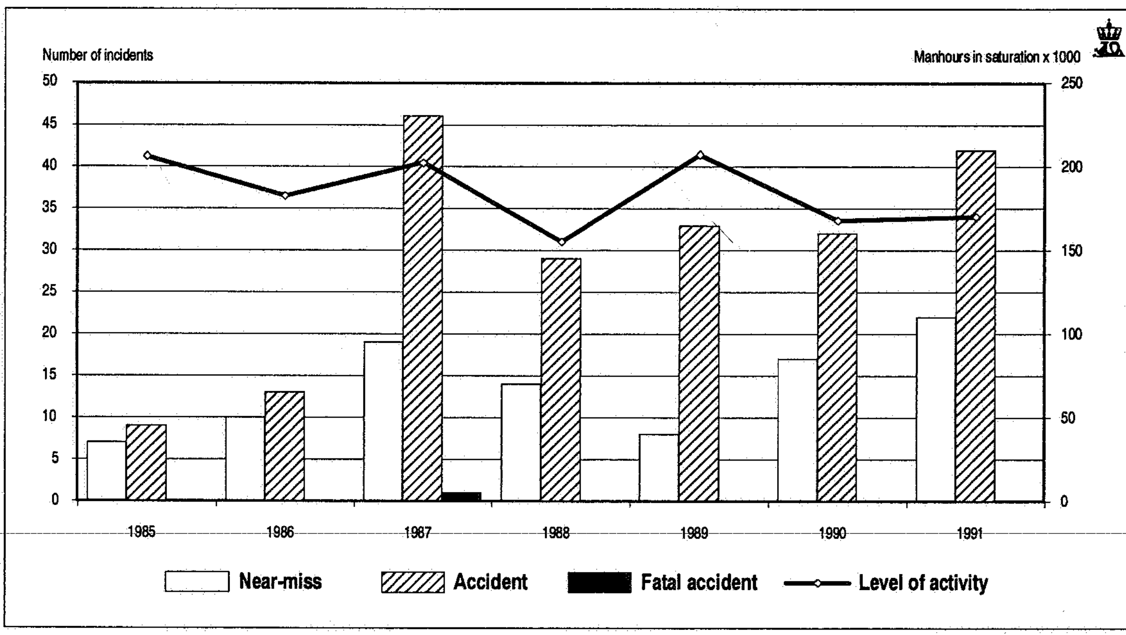


Fig. 4.15.2.b
Incidents in surface oriented diving

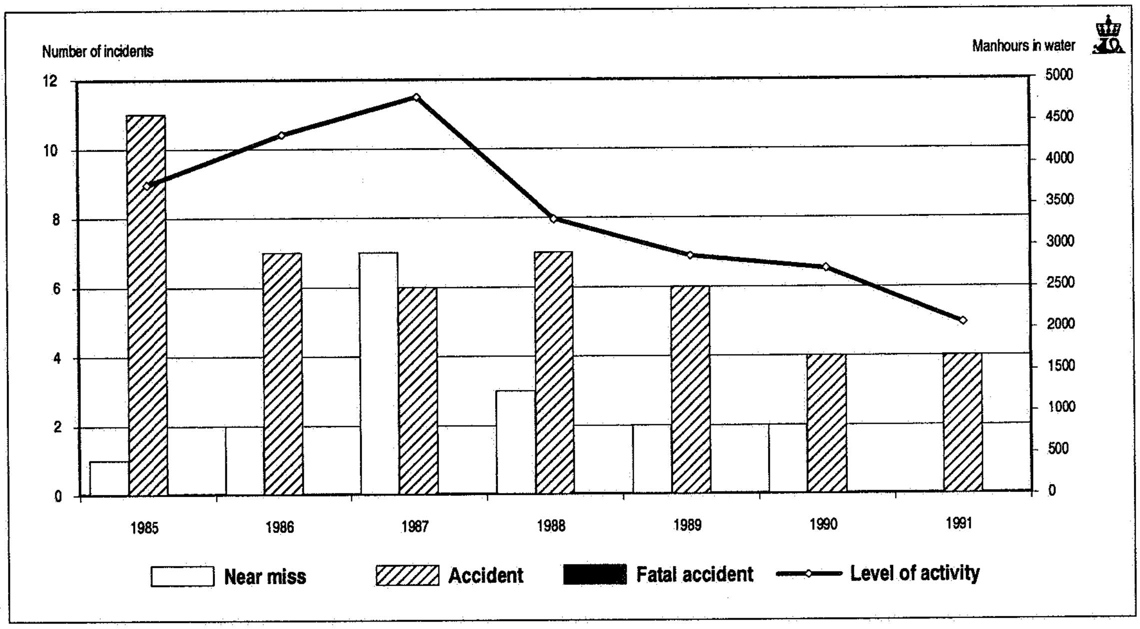
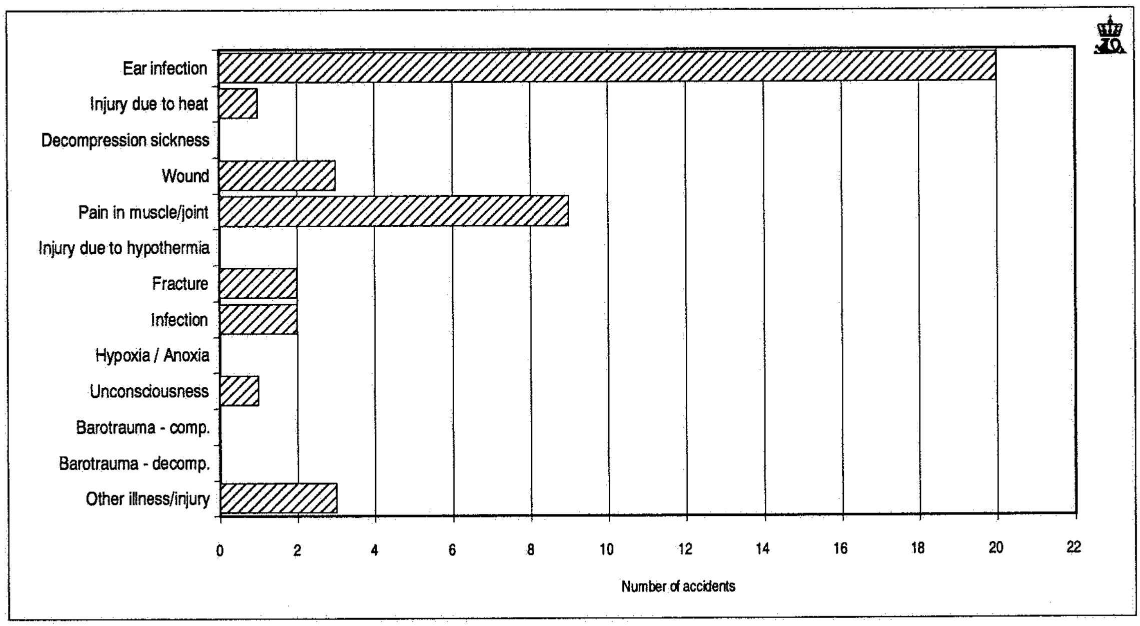


Fig. 4.15.2.c
Accidents in saturation diving – 1991



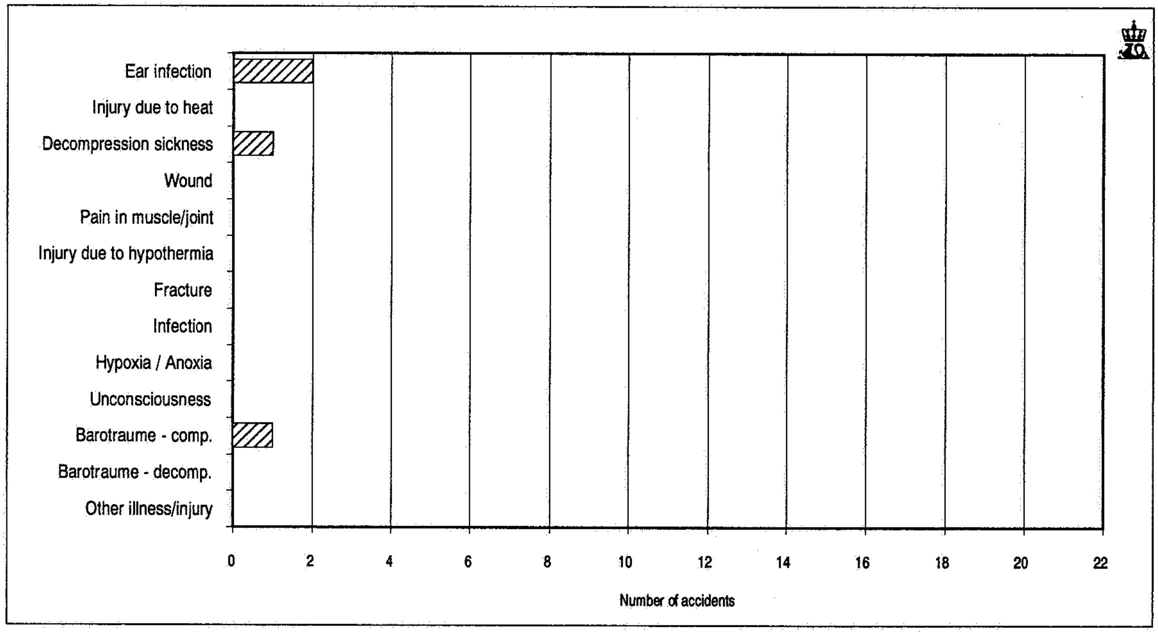
4.15.3 Diving research

In 1989 the Directorate launched a common research and development programme for diving technology (FUDT) with Statoil and Norsk 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 Directorate is very pleased that the oil companies can work together to reach common solutions to pressing offshore diving issues.

In 1991, the Directorate provided an observer to the steering committee for the HADES project, which is a research programme looking into decompression, financed by Phillips. The project, started in 1990, is planned to finish in 1995.

Fig. 4.15.2.d
Accidents in surface oriented diving – 1991



In 1990, the Directorate carried out a project aimed at standardising 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 is a recommended standard for diving to depths of 180 meters.

It now seems that most operators choose to specify this table in their contract criteria, which the Directorate notes with satisfaction.

In 1991, the Directorate also implemented a project aiming to produce standard impurity thresholds for hyperbaric environments. Representatives from the diving industry and employee organisations took part in this work which was led by an external project supervisor.

By way of following up an extended survey of the effects of diving on the nervous system, the Directorate carried out a project to analyse data from this long-term study, though limited to divers who have received their certificate since 1980.

4.15.4 Regulatory drafting

In 1991 the Directorate issued guidelines for evaluation of breathing apparatus for use in manned underwater operations in the offshore industry. These guidelines were prepared in conjunction with the UK authorities. The Directorate has suggested to the Norwegian Standardisation Organisation that the guidelines should be put forward as an international standard.

Now that the Regulations for Manned Subsea Operations have been in effect for a year, the Directorate is beginning to see the positive effects of its use. Although some work remains before the regulations can be said to be fully effective in the industry, things are moving in the right direction. Areas which require further effort if the regulations' intentions are to be fulfilled, are such factors as ergonomics in the control room, chamber facilities and diving bells.

The Directorate has noted that operators have been slow to apply their skills in risk analysis to the problems of manned subsea operations. The Directorate is convinced companies could apply such methods to good advantage also in the underwater context.

Through supervisory activities in conjunction with the Norwegian Directorate of Health, the Directorate has noted that it is difficult to attain the established goals for health matters. One significant reason for this is employment conditions in the industry.

4.15.5 Database development

In 1990 the Directorate was concerned to identify information needs and develop databases in manned subsea operations and mechanical equipment. The work was continued in 1991, when it formed part of a general programme for information management in the Directorate.

During 1991 a new version of the manned subsea operations database was established, and as a trial a new reporting form for accidents and incidents was used which is an annex to the RTV form.

5. Petroleum Economy

5.1 EXPLORATION ACTIVITY, GOODS AND SERVICES

The exploration drilling activities increased relatively steadily between 1966 and 1985, when 50 new exploration wells were commenced. 1991 saw the commencement of 47 new exploration wells, a level identical to 1984.

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

Shown below are the exploration costs for 1991 split by goods and services. The amounts represent provisional estimates from data reported by the operating companies. The same statistics produced the piechart in Figure 5.1.b, which shows the percentage breakdown between the different expenditure types.

Exploration costs		Nkr million
Exploration drilling		5586
of which:		
– Drilling installations	2011	
– Transportation costs	722	
– Goods	1006	
– Technical services	1847	
General surveys		1138
Field evaluations		812
Administration (incl acreage fees)		1017
Total		8553

Fig. 5.1.a
Exploration costs per year 1980–1991

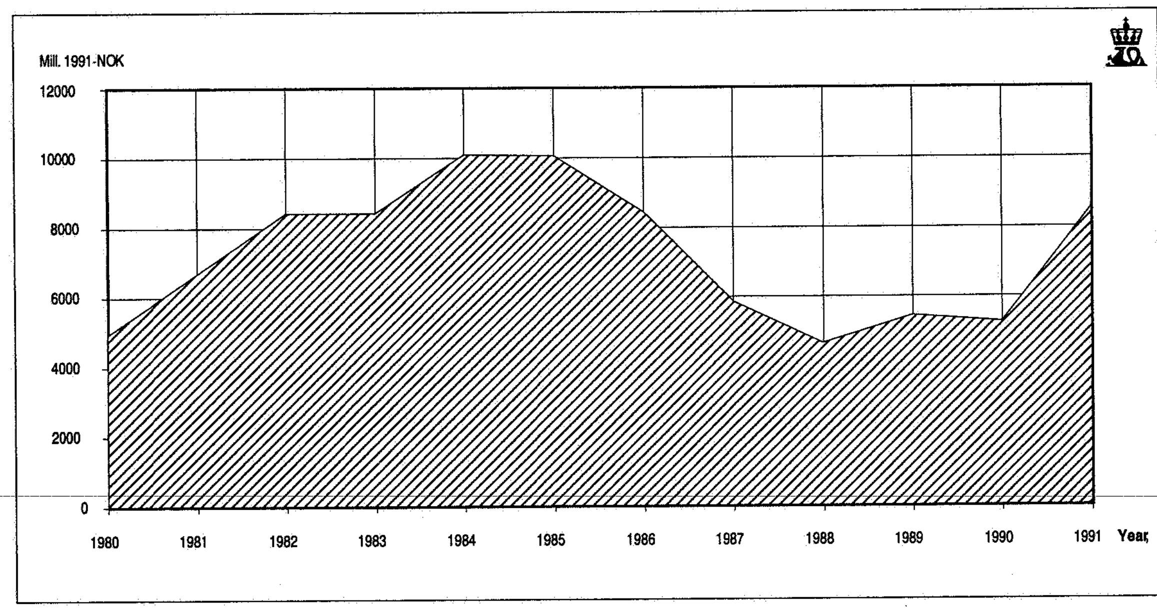


Fig. 5.1.b
Oil and gas exploration costs in 1991

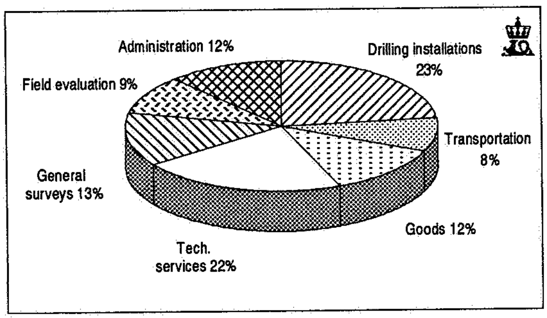
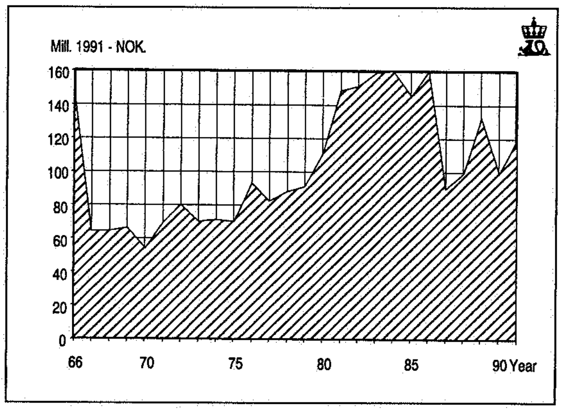


Figure 5.1.c shows the mean drilling costs per exploration well. Exploration wells are wildcats and appraisal wells. Drilling costs in 1991 were almost Nkr 5,600 million.

5.2 COSTS OF DEVELOPMENT AND OPERATION

The Directorate has calculated annual costs in connection with the development of offshore fields, including production drilling, for the period 1970–2013. The costs include fields in production, fields under development, and fields for which the development plans had been approved at 31 December 1991. Where fields straddle the sector dividing line

Fig. 5.1.c
Drilling costs per well



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)
- Albuskjell
- Ekofisk area (Vest-Ekofisk, Cod, Edda, Eldfisk, Ekofisk)
- Nordøst-Frigg
- Øst-Frigg
- Gullfaks
- Heimdal
- Murchison
- Odin
- Oseberg Transport System
- Oseberg
- Statfjord
- Tommeliten
- Tor
- Ula
- Valhall
- Norpipe
- Statpipe
- Veslefrikk
- Troll-Oseberg Gas Injection
- Gyda
- Troll Phase 1
- Sleipner Øst
- Zeepipe
- Snorre
- Hod
- Draugen
- Gamma Nord
- Ula Transport System
- Statfjord Nord
- Statfjord Øst
- Brage
- Embla
- Heidrun
- Tordis
- Lille-Frigg
- Loke.

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 1991 kroner. Investments increased steadily until 1976 when they reached a provisional high, then slowed in the years thereafter until a new increase occurred from 1981 on. A temporary peak was reached in 1984, when 28.3 billion 1991-value kroner was invested on the Norwegian continental shelf. Taking new decisions into account, the investment level will approach 40 billion 1991 kroner in the first half of the present decade.

In 1991 the following fields were approved for development:

- Heidrun
- Tordis
- Lille-Frigg
- Loke.

During 1992 the Storting will evaluate other plans for development and operation. If these are approved the investment curve will show a much gentler gradient later in the decade.

The annual operating costs, including pipeline operating costs, are shown in Figure 5.2.b. The level of demand for goods and services for operations has increased considerably, and will continue to increase for some years as more fields come on stream. Operating costs therefore appear to be the most serious cost component henceforth, and it will be essential to seek to reduce such costs from now on.

5.3 ROYALTY

The Directorate has been delegated the responsibility for collection of royalty from petroleum production.

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

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

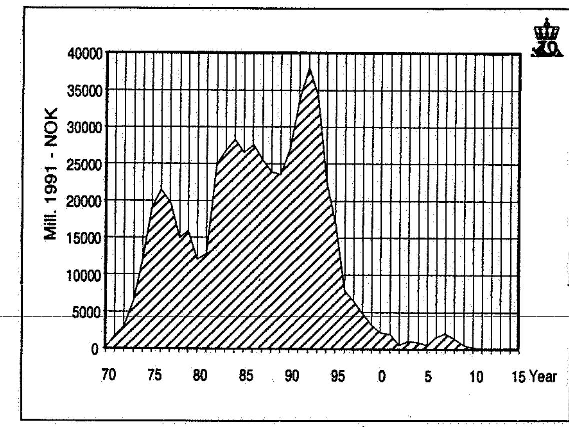
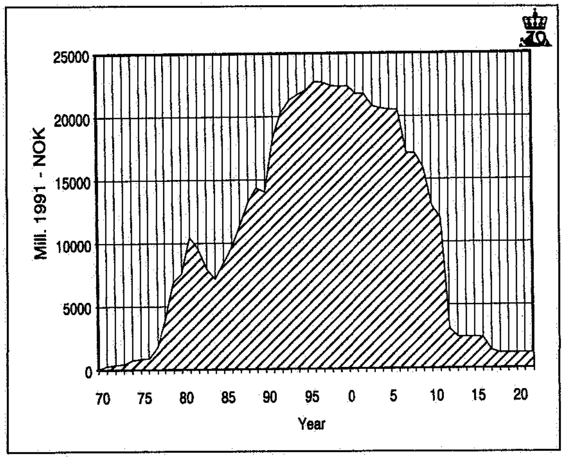


Fig. 5.2.b
Operating costs for fields and pipelines on the Norwegian shelf



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.

The interpretation and enforcement of the current rules and regulations for royalty calculation involve problems of a legal, economic, processing and measurement nature.

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.

A case is currently before the courts concerning setting off the tax bases for oil and gas. The Statfjord licensees, except Statoil, have claimed that the tax base for gas royalty, which is negative due to low gas rates and high transport costs, should be deductible from the tax base for oil, which is positive. The Norwegian State contests this claim. The Oslo City Court in judgment of 26 April 1991 found for the State, hence separate calculations must be made for oil and gas royalty. The licensees have appealed this decision, however, and the Supreme Court will examine the matter directly. The amounts concerned are quite considerable.

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

In Odelsting Proposition no. 12 for 1991–92, an Act regarding certain revisions to the Petroleum Taxation Act, it states that the Ministry of Petroleum and Energy intend to set the royalty to zero for gas produced from fields which under today's rules must pay royalty. This means that from now on, royalty will only be claimed on oil.

5.3.1 Total royalty

The total of royalties collected in 1991 was Nkr 8,940,235,918. Table 5.3.1 shows the breakdown over the different petroleum products for 1990 and 1991.

Figure 5.3 shows royalty receipts for the period 1973–91.

5.3.2 Royalty on oil

In 1991 royalty of Nkr 8,049,393,092 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 is 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 Directorate on a monthly basis. Settlement is at the norm rate fixed by the Petroleum Price Council.

Table 5.3.1
Paid-up royalty in 1990 and 1991 (mill Nkr)

		1990	1991
OIL	EKOFISK/VALHALL/ULA	1 808.4	1 790.9
«	STATFJORD	4 591.7	4 866.9
«	MURCHISON	23.3	29.1
«	HEIMDAL	11.1	9.9
«	OSEBERG	589.9	692.0
«	GULLFAKS	495.4	660.6
GAS/NGL	EKOFISK FIELDS	408.7	471.6
«	VALHALL	29.2	23.3
«	ULA	0.0	0.2
«	FRIGG,NØ-FRIGG,ODIN	440.4	329.8
«	STATFJORD	0.0	0.0
«	MURCHISON	0.7	1.3
«	HEIMDAL	72.6	64.6
«	OSEBERG	0.0	0.0
«	GULLFAKS	0.0	0.0
TOTAL		8 471.4	8 940.2

Fig. 5.3
Royalties paid 1973–1991

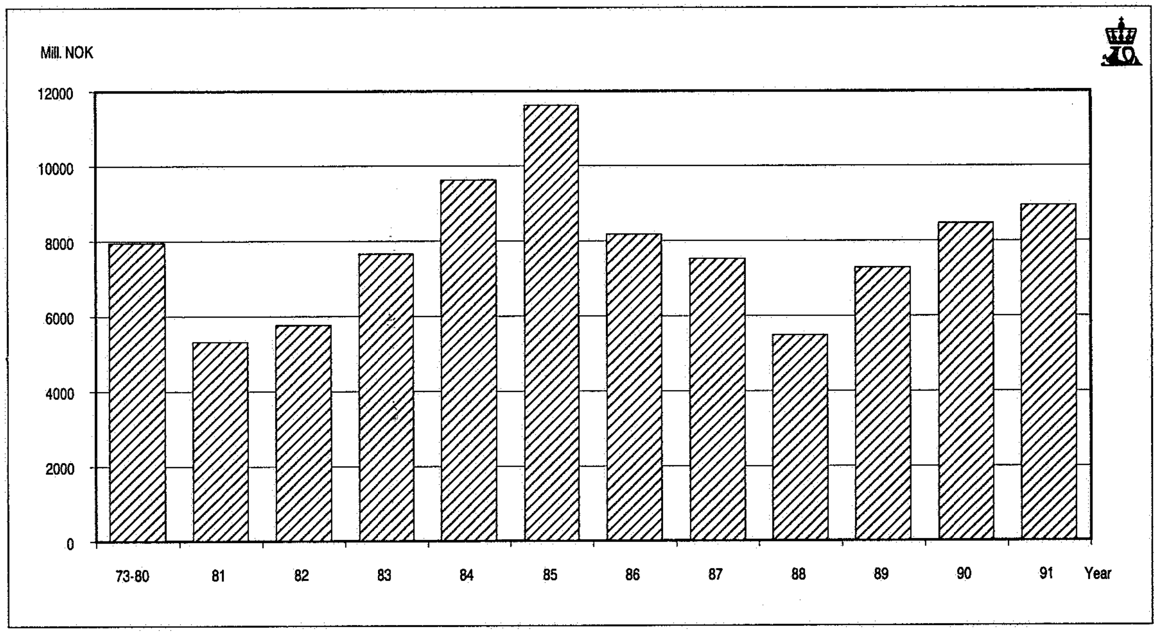


Table 5.3.2
Paid-up royalty on oil, 1991

Area/field	1st half	2nd half	Total 1991
EKOFISK, ULA AND VALHALL	877 513 299	913 362 092	1 790 875 391
STATFJORD	2 577 636 614	2 289 271 429	4 866 908 043
MURCHISON	9 566 763	19 575 924	29 142 687
HEIMDAL	4 441 636	5 463 619	9 905 255
OSEBERG	288 080 149	403 889 691	691 969 840
GULLFAKS	262 441 260	398 150 616	660 591 876
TOTAL	4 019 679 721	4 029 713 371	8 049 393 092

Table 5.3.3
Paid-up royalty on gas and NGL in 1991

	1st half	2nd half	Total 1991
EKOFISK AREA			
Phillips-group	147 618 105	318 060 002	465 678 107
Amoco-gr.(Tor)	915 310	−87 070	828 240
Shell (Albuskj.)	1 803 271	1 970 085	3 773 356
Dyno/Methanor	782 040	559 430	1 341 470
Total Ekofisk area	151 118 726	320 502 447	471 621 173
FRIGG AREA			
Petronord-group	111 092 958	125 585 977	236 678 935
Esso (NØ-Frigg)	6 774 663	12 394 708	19 169 371
Esso (Odin)	35 270 404	38 649 654	73 920 058
Total Frigg area	153 138 025	176 630 339	329 768 364
VALHALL	13 113 943	10 228 574	23 342 517
ULA	91 527	98 561	190 088
STATFJORD	0	0	0
MURCHISON	875 060	458 870	1 333 930
HEIMDAL	22 266 518	42 320 236	64 586 754
OSEBERG	0	0	0
GULLFAKS	0	0	0
TOTAL ALL FIELDS	340 603 799	550 239 027	890 842 826

5.3.3 Royalty on gas and NGL

The royalty collected for gas and NGL in 1991 amounted to Nkr 890,842,826. Table 5.3.3 shows the receipts on a half-yearly basis by company and partner groups.

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, Oseberg and Gullfaks fields for 1991, 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 was discontinued from 1 July 1984. The receipts from, and refunds to, Dyno-Methanor relate to the transportation and processing of gas already received and paid for.

5.4 ACREAGE FEES IN PRODUCTION LICENCES

The Directorate collected Nkr 659,040,113 in 1991 in acreage fees. With reference to licence year the receipts were as follows:

Licence awarded	Nkr
1965	98,140,000
1969	56,768,198
1971	5,502,000
1973	69,434,798
1975	70,688,946
1976	73,686,930
1977	13,916,349
1978	31,034,739
1979	83,284,352
1980	2,940,926
1981	23,874,028
1982	13,003,160
1983	6,868,029
1984	26,807,767
1985	34,644,465
1991	48,445,426
Total	659,040,113

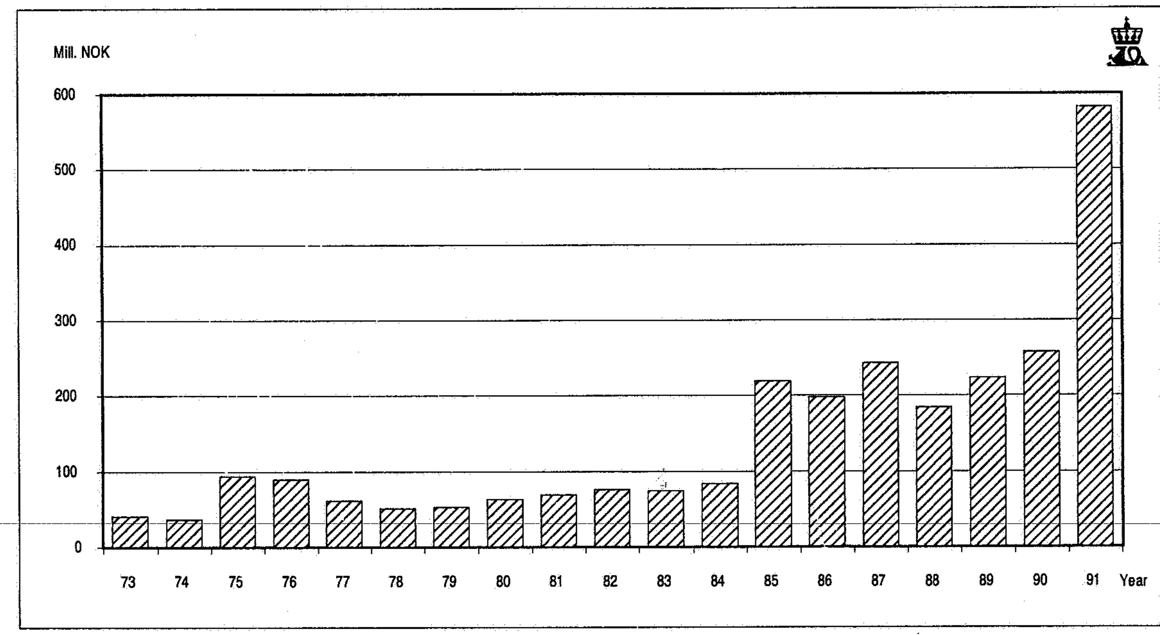
The Directorate refunded Nkr 76,929,324 in acreage fees in 1991. Figure 5.4 shows the net receipts of acreage fees (claims less refunds).

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, Nkr 26,499,765, is therefore reflected in the royalty receipts.

Figure 5.4 shows the acreage fee receipts for the years 1973–91.

Fig. 5.4
Acreage fees 1973–1991



5.5 CARBON DIOXIDE TAX

The new Act relating to Carbon Dioxide Emissions in the Offshore Petroleum Activity passed by the Storting on 20 November 1990 became effective on 1 January 1991. The Directorate was given the responsibility of collecting the emission tax. The tax is calculated on petroleum flared and natural gas released to the atmosphere from platforms, installations and plant used in connection with production or transportation of petroleum. This tax is also levied on Norwegian petroleum transport systems which cross the continental shelf. Where fields straddle a sector boundary, the emission tax is only calculated on the Norwegian share.

In 1991 the emission tax was Nkr 0.60 per standard cubic metre of gas, and the same figure for one litre of diesel oil. It is payable on a six month basis with three months to pay from field and installation operators. Table 5.5 is a list of the total tax receipts broken down by field and transport system for the first half of 1991. The incoming amount in 1991 was Nkr 810,487,141. A similar amount is expected in respect of the second half of 1991, bringing the total to a projected Nkr 1,600 million in emission tax for the year.

Table 5.5
Paid-up CO_2-tax 1991 (mill Nkr)

Paid-up CO_2-tax for 1st half 1991	
Field:	
BALDER	1 807 433
EKOFISK	255 543 449
FRIGG	14 915 896
GULLFAKS	99 789 240
GYDA	16 913 570
HEIMDAL	16 546 866
HOD	1 751 616
MIME	767 021
MURCHISON	7 430 448
ODIN	2 090 402
OSEBERG	62 602 800
STATFJORD	159 834 055
TROLL VEST	13 507 800
ULA	23 470 307
VALHALL	30 116 393
VESLEFRIKK	23 260 020
Transport systems:	
FRIGG TRANSPORT	801 224
NORPIPE	77 687 766
STATPIPE	1 650 835
TOTAL	810 487 141

5.6 PETROLEUM MARKET

5.6.1 Crude oil market

Global oil production slipped by about 1 per cent from 1990 to 1991 to about 60 million barrels a day. The decline was particularly obvious in the former Soviet Union and Eastern Europe. In the Middle East the decline was also pronounced due to little production from Kuwait and Iraq. Nevertheless, OPEC's share of production increased, though only slightly, largely due to increasing output from Saudi Arabia, the Emirates, and Venezuela. Production from the rest of South America, Africa and Asia also increased.

Production in the United States nudged upward for the first time since the middle of the 1980s, though this is not expected to last.

Norwegian oil production accounted for about 3.1 per cent of world crude in 1991, compared to 2.7 per cent in 1990. Norway's output of oil also passed that of the United Kingdom, which declined from 1990 to 1991.

The price of oil, high at the beginning of the year, sank once Iraq was driven from Kuwait. The mean price during the first nine months for Norwegian crude was over US$ 20 a barrel. During the autumn the price of oil slid, ending at about $ 18 a barrel by year end.

Kuwait's production is in the process of building up, and increasing production from there and perhaps also Iraq, coupled with increasing production from other parts of the world, would put growing pressure on oil prices. This might be counter-balanced by the continuing decline in oil exported from the former Soviet Union and Eastern Europe.

The world's estimated oil reserves are believed to have shrunk by about 1 per cent from 1990 to 1991 (provisional figures). Production ran at about 2 per cent of reserves. Due to the smaller output, the ratio of proven reserves to production was more or less unchanged, and reserves equivalent to 45 years or more of production at the 1991 level are believed to exist. This is substantially longer than the view held earlier, for example in the early 1980s.

5.6.2 Natural gas market

As anticipated, world consumption of natural gas continued to grow. Natural gas's share of global energy sales was 21.6 per cent in 1990 compared to 21.3 per cent the year before. World-wide gas consumption increased by almost 2 per cent; and the total production of gas was about 1,980 bcm in 1990.

For Norway, of course, the European market is the interesting one. In Western Europe (including what used to be East Germany), gas consumption increased by 1.7 per cent from 1989 to 1990. Gas's share of the total energy consumption in Western Europe was 15.8 per cent in 1990, or slightly less than the world average.

In the years ahead natural gas is expected to corner a larger part of the energy market on account of its environmental advantages. Gas competitivity on the other hand will depend not least on how energy is taxed in Norway's potential markets.

The total sales of Norwegian gas declined from 25.4 to 25.2 bcm from 1990 to 1991. The decline in production, though greatest for the Frigg field, was largely compensated by slight increases from other fields. Gas from Frigg is transported to the UK. Frigg's declining output has meant that Germany has now passed Britain as Norway's largest taker of natural gas. Figure 5.6.3.c shows the distribution of gas sales to the various buyer countries.

It is planned that Norwegian gas sales should increase again from 1993 when the Troll agreements come on stream. This time schedule seems to hold good despite the loss of the Sleipner Øst gravity base in August.

In 1991 the other buyers confirmed their intention to exercise the so-called 30 per cent options in the Troll agreement, increasing Norway's annual maximum sales under the Troll and SEP agreements by about 2.5 bcm to about 33 bcm. No final decision has been made regarding which fields will supply these gas volumes. If all options are exercised, Norway will be committed to supply 40.8 bcm a year to continental buyers from year 2005 under the Troll and SEP agreements.

In 1991 a contract was signed with National Power, Britain's major electricity producer, for supply of natural gas. The contract may involve 2 bcm or so of gas a year, with deliveries starting in the mid-1990s. Another contract awarded in 1991 covers sale of gas from Lille-Frigg to British Gas.

Negotiations with British Gas were also conducted for substantially larger deliveries, and also with other UK interests; although the British government's wish to curtail British Gas's role as a gas supplier may have reduced the chances of a major gas agreement being signed with the latter. This does not necessarily mean the total demand for Norwegian gas will be any less.

On the Continent talks are also going on with several potential buyers, including German Verbundnetz Gas, in which Statoil owns a small share. As in the UK, considerable shifts in the market structure can occur on the Continent which would be liable to influence future sales of gas from Norway. There remain, too, uncertainties connected with landing of Norwegian gas to the Continent.

Talks with Swedish and Finnish interests concerning possible purchase of Norwegian gas which took place in 1991, seem for the moment to have come to a standstill.

All Norwegian gas is exported by pipeline at present, and in the foreseeable future this delivery method is likely to predominate. Export of liquid natural gas (LNG) is most likely from the far north areas, particularly Tromsøflaket (Snøhvit). Here, Italy seems to be the most interesting market.

In 1991 the Norwegian government submitted a proposal to land gas from Heidrun for a methanol plant in Mid-Norway for the Storting's consideration. The projected annual gas consumption is about 0.7 bcm. It will be the first major industrial application for dry gas from the continental shelf in Norway. Lesser quantities of gas may also be used for various purposes close to the landing terminals (Kårstø, Øygarden, Snøhvit terminal if realised).

The most important Norwegian market for gas, however, is offshore. Substantial injection of gas into petroleum reservoirs is already made to increase oil recovery. In January 1991, gas injection started from Troll into Oseberg under the Troll-Oseberg Gas Injection project. The planned delivery rate from TOGI is about 3 bcm a year; and most of the injected gas will be available for production and sale from Oseberg at a later date.

The Directorate sees great potential to improve oil recovery using gas injection, not least from Sleipner Øst and the Ekofisk area. However, there is a considerable challenge in realising injection projects which are economic.

New contracts and expectations of further gas sales for either export or injection can be a major parameter of development patterns on the continental shelf; not least for fields on Haltenbanken where gas sales are a prerequisite. These are matters which the Directorate has been energetically involved in throughout 1991. The Directorate is also concerned to find sales outlets for associated gas from oil fields.

5.6.3 Sale of petroleum

In 1991 total sales of crude oil from the Norwegian continental shelf amounted to 90.6 million tons. This was an increase of 17 per cent compared to 1990. Britain was the largest recipient with 26.1 per cent of the shipments; Norway received 20.7 per cent, the Netherlands 12.9 per cent, Sweden 7.9 per cent and France 7.4 per cent. In 1990, Norway took 24.5 per cent of the total, so a small percentage decrease was recorded in 1991. Figure 5.6.3.a shows the sale of crude oil by country for the period 1981–91.

Up until 1988 both Belgium and Canada were reported under the heading "Others". The sale of Natural Gas Liquids from the Norwegian continental shelf reached 2.3 million tons in 1991, or 0.1 mton less than in 1990. Figure 5.6.3.b shows the sale of crude oil and NGL in 1991 by licensee. Norway exported 25.2 bcm gas in 1991, a reduction of 0.8 per cent compared to 1990. A total of 8.1 bcm was sold to Germany, 6.7 bcm to the UK, 5.4 bcm to France, 2.6 bcm to the Netherlands and 2.4 bcm to Belgium, as charted in Figure 5.6.3.c. Figure 5.6.3.d shows the gas sale by licensee for 1991. The column "Others" contains figures for many small fields.

Fig. 5.6.3.a
Sale of crude oil from the Norwegian continental shelf

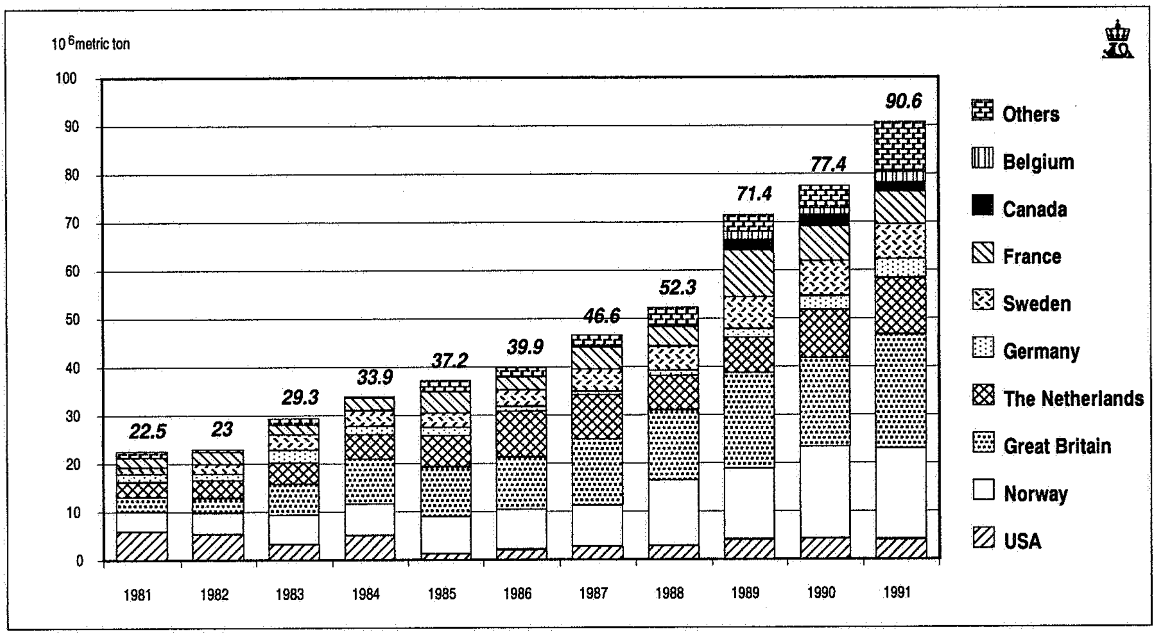


Fig. 5.6.3.b
Sales quantities of oil/NGL per licensee in 1991

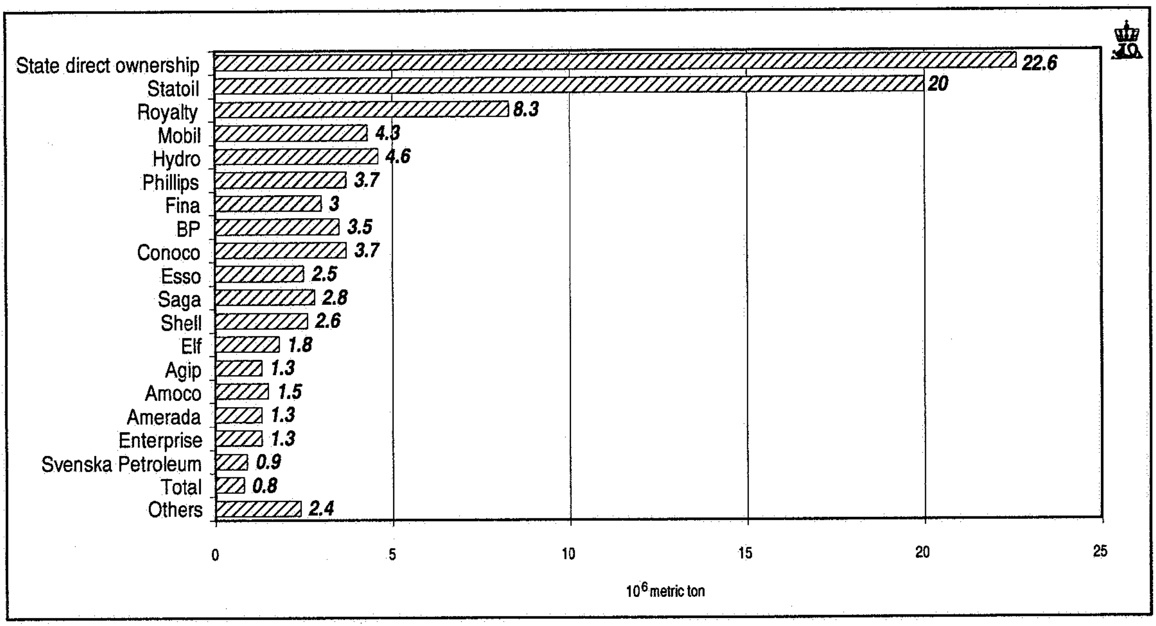


Fig. 5.6.3.c
Sales quantities of gas per country

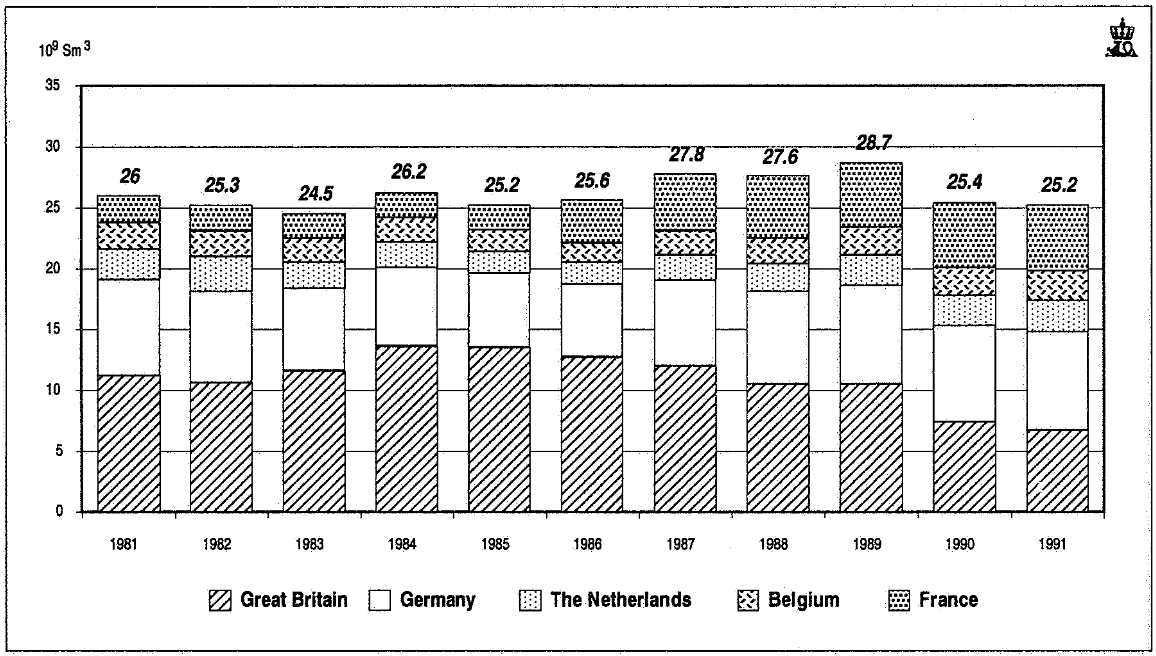
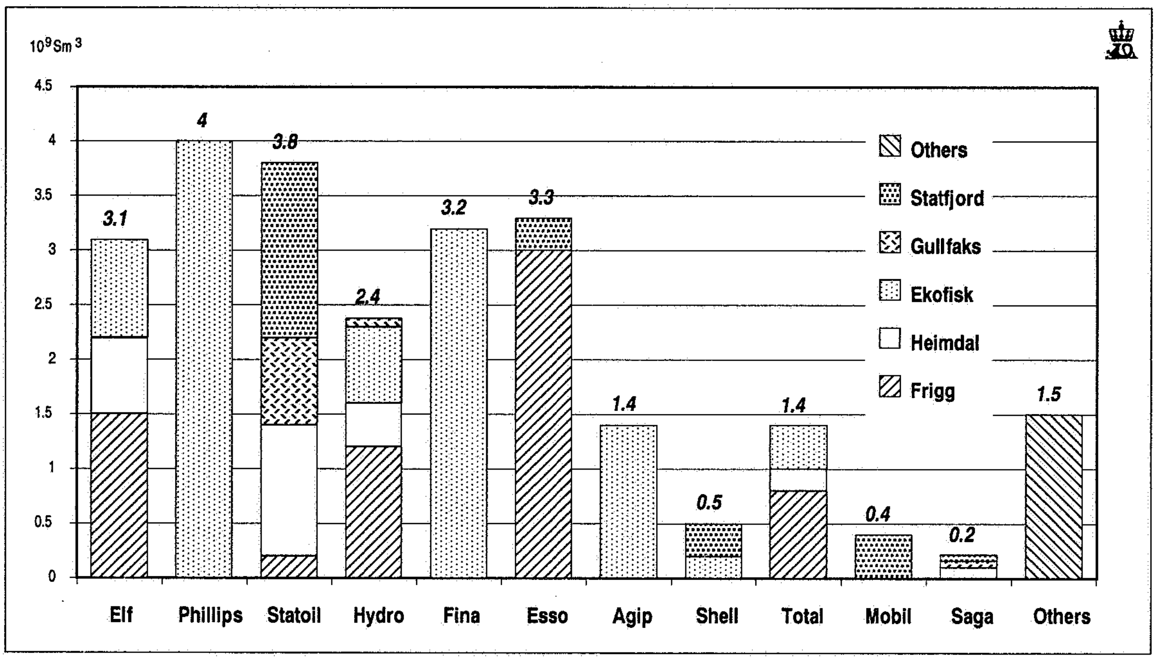


Fig. 5.6.3.d
Sales quantities of gas per licensee in 1991



6. Special Reports and Projects

In 1991 the Norwegian Petroleum Directorate appropriated a total of Nkr 22,586,005 for special projects. Of this amount, Nkr 5,612,182 was budgeted for projects in the Safety and Working Environment Division and Nkr 17,786,934 for projects in the Resource Management Division.

Another Nkr 4,381,575 was committed to the North Sea Seabed Clearance project.

Nkr 5,345,501 was made available for collection of meteorological and oceanographic data in the Barents Sea, under the auspices of the Directorate; while the SPOR enhanced oilfield recovery project received Nkr 9,827,066.

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

6.1 RESOURCE MANAGEMENT DIVISION

6.1.1 Exploration Branch

PROJECT TITLE	EXECUTIVE INSTITUTION
Well Data Summary Sheets	NPD
Bio-Stratigraphy, Additional Datings	CB Magneto, University of Bergen, Institute of Energy Technology (IFE), Continental Shelf Institute (IKU), and K. Perch-Nilsen
Database for Pore Pressure and Rock Mechanics	Proffshore
Resources Database	NPD and Opheim Data
Sealing Faults	Geo Recon A/S
Late Palaeozoic Carbonates in Central Spitsbergen	NPD
Regional Correlations in Barents Sea	Continental Shelf Institute (IKU)
Polar North-Atlantic Margin, PONAM	Norwegian Polar Research Institute
Miocene and Pliocene Sedimentation and Paleonic Environs on Vøringplatået	University of Bergen
Measuring Land Rise	State Mapping Authority

Well Data Summary Sheets
This is an annual publication listing released well data from the continental shelf. This year's edition is the seventeenth in the series and deals with wells put down in 1986.

Bio-Stratigraphy, Additional Datings
This project seeks to cover some of the dating methods for which the Directorate lacks the necessary expertise, such as magnetic stratigraphs and nanofossiles.

Database for Pore Pressure and Rock Mechanics
The reason for compiling this database is the desire to improve accessibility to geological and technical well data of significance for planning bores into high-pressure, high-temperature zones.

Resources Database
One of the Directorate's key objectives is to keep the accounts for Norway's discovered and undiscovered petroleum resources. This project intends to streamline the existing resources databases allowing the full resources accounts to be handled as a single database.

Sealing Faults
The Directorate keeps running track of ways to assess the risks inherent in prospect evaluation. For this reason a database of sealing faults has been de-

veloped, allowing information on sealing mechanisms to be plugged into risk calculations for prospects which depend for their production on a good seal.

Late Palaeozoic Carbonates in Central Spitsbergen
These field studies are a continuation of the *Study of Permian and Carboniferous Carbonates in the Barents Sea* and examine the sedimentology of the strata sequence on Central Spitsbergen as a step towards increasing our regional understanding of carbonate evolution in the Arctic area.

Regional Correlations in Barents Sea
Geochemical and biostratigraphic studies were carried out in the Barents Sea as a way to increase regional understanding of the Triassic rock as a source and reservoir rock. The study correlates the southern Barents Sea with the Directorate's shallow drillings in the northern Barents Sea.

Polar North-Atlantic Margin, PONAM
The Late Cenozoic Evaluation of the Polar North-Atlantic Margin is a broad collaboration project between European institutions aimed at studying the geological evolution of these regions. The Norwegian Polar Research Institute is in charge of Norway's contribution to the project. The Directorate has provided support with field work on Svalbard and geological studies of the effects of the last ice-advance in the northern Barents Sea and on Svalbard.

Miocene and Pliocene Sedimentation and Paleonic Environs on Vøringplatået
This project aims to study the sediments in deep-sea cores, looking at oxygen isotopes and ice-dropped matter. The primary emphasis is on matter dating 10–16 million years back. Data from the studies are important for dating and understanding late Tertiary rise of the continent and continental shelf areas. Studies of younger sediments have already been published.

Measuring Land Rise
Measurements were made of water level marks chiselled in the rock at sealevel by the Norwegian Geological Survey a century or so ago. Over a three-year period all the marks it was possible to identify in North Norway were remeasured, and the project is thus completed. From the data, the present rate of land rise was calculated. These land rise data are important in the calculation of the properties of the earth's crust and in order to study fault movements.

6.1.2 Development Branch

PROJECT TITLE	EXECUTIVE INSTITUTION
Field Simulation Njord	Restek A/S
Log Interpretation Oseberg Øst	Logware A/S
Log Interpretation Oseberg Øst, Phase 2	Logware A/S
Optimal Selection and Use of Acoustic Logs	Schlumberger
Tests of Predrilled Wells	Smedvig IPR
Reservoir Evaluation Oseberg Øst	Tape Technology Norway A/S
Integrated Interpretation of 34/7 C, 34/7 C+ and Snorre Vest	Badly Ashton
Reservoir Simulation Troll Vest	Scandpower A/S
INVERS – Update of Cost Bank	Andersen Consulting AS
INVERS – Analysis Tool for Cost Bank	NIT – Landbruk A/S
Evaluation of LNG Plant	Novatech a.s and Foundation for Scientific and Industrial Research at University of Trondheim (Sintef)
Geochemical Survey of Njord	University of Oslo and Brekkes Kjemometriske
New Cash Flow Model	NPD and Ministry of Petroleum and Energy

Field Simulation Njord
A full field reservoir simulation was performed for Njord, the main purpose of which was to study different recovery approaches, such as gas injection, water injection, or a combination of the two. The results will be employed in connection with the evaluation of the Plan for Development and Operation of Njord.

Log Interpretation Oseberg Øst
Logware A/S ran a petrophysical analysis of Oseberg Øst including log interpretation of four wells and determination of cut-off criteria. Calculations were also performed of water saturation factors (J function) from capillary pressure readings. The work will be included in the Directorate's resource mapping and resource calculations.

Log Interpretation Oseberg Øst, Phase 2
Logware A/S also estimated the water saturation reaction (J function) based on log interpretations made earlier in 1991. The object was to examine the uncertainty in the estimated oil in place based on different input parameters for calculation of water saturation.

Optimal Selection and Use of Acoustic Logs
This project aimed to elucidate the working range of various acoustic logging systems. Different ways of conditioning data already compiled were tested. Alternative collection methods and conditioning techniques were evaluated. Six sets of data including wells from limestone fields and sandstone fields underlay the study. The project was a collaboration venture between Schlumberger and the Directorate.

Tests of Predrilled Wells
The background for this project was the different practices used for testing predrilled wells. The feasibility of production testing predrilled wells immediately after drilling was examined, and experience from the few wells for which this was done was reviewed. Different solutions were outlined for temporarily abandoning a well after the well test.

Reservoir Evaluation Oseberg Øst
The consulting engineers digitised the charts and assisted with development of a reservoir model for volume calculation by IRAP.

Integrated Interpretation of 34/7 C, 34/7 C+ and Snorre Vest
Three-dimensional seismics covering 34/7 C, 34/7 C+, and Snorre Vest were interpreted. These discoveries will henceforth be called the Vigdis field. The seismics were correlated with the well bores in the region and velocities from the boreholes formed the basis for a velocity model. The final result was a depth chart showing the top and bottom of the reservoirs, on the basis of which the migration routes and degree of fault sealing were discussed. The depth charts will be factored into the Directorate's resource calculations.

Reservoir Simulation Troll Vest
In connection with an analysis of the feasibility of recovering oil from Troll Vest, a reservoir simulation study was performed. Single well models of horizontal wells adapted to the results from test production from the two horizontal wells on the field were used to study oil production from individual wells. A full field model which includes both oil and gas wells was used to study the effects of gas production from Troll Øst and Troll Vest on oil production.

INVERS – Update of Cost Bank
The Directorate conferred with the industry on a standardised code structure for cost data for North Sea development projects. The databank has now been updated on the basis of reported data and discussions with oilfield development operators.

INVERS – Analysis Tool for Cost Bank
A statistical analysis tool has now been developed for using historical data in the databank as basic data for evaluation of new applications for plans for development and operation and plans for construction and operation which are submitted to the Directorate.

Evaluation of LNG Plant
A plant for the liquefaction of Liquified Natural Gas may be interesting in connection with exploitation of large quantities of natural gas in Snøhvit. A study of the correlations has been performed which considers technical, costing and energy aspects of such a plant. The project was a collaborative one between Novatech and Sintef's Division for Cryogenic Engineering.

Geochemical Survey of Njord
This project is a petroleum geochemical study of Njord and selected regionally adjacent prospects. The purpose was to obtain information regarding the historical filling of Njord and to correlate its hydrocarbons with any liquid inclusions using DST. The analysis results are of high quality and the results of the studies help increase our understanding of the generation of hydrocarbons in the area, their migration, phase separation, and filling history.

New Cash Flow Model
In collaboration with the Ministry of Petroleum and Energy the Directorate has developed and installed a new cash flow model. This is used in economic analyses for projects and company-based calculations. The model was refined in 1991.

6.1.3 Production Branch

PROJECT TITLE	EXECUTIVE INSTITUTION
SAFARI Data Acquisition	Norwegian Computer Centre, University of Bergen, Rice University, Louisiana State University
Laegerdorf	Geo Recon A/S
NPD Involvement in Reservoir Descriptions for SPOR	Rogaland Research Institute, Institute of Energy Technology (IFE), and Continental Shelf Institute (IKU)
Modelling and Simulation of Statfjord	Norwegian Computer Centre and Institute of Energy Technology (IFE)
Cut-off Criteria	Atlas Wireline Services
Multi-phase Measurement	National Engineering Laboratories (NEL)
Gas Flaring Criteria for Onstream Fields	Novatech a.s
Environmental Technology	NPD
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 (CMI)
Sampling of Water Content of Oil	National Engineering Laboratories (NEL)
Production at below Boiling Point Pressure	Restek a.s
ECLIPSE	ECL
Reservoir Data Reporting System, RDRS	Cap Gemini
Simulation Study of Statfjord	Scientific Software (UK) Limited
Well Technology	Smedvig IPR A/S
Chalk Research	NPD
Geotechnical Support	Mervyn Jones and University College, London
Reservoir Studies of Ekofisk	Restek a.s
Fracture Studies of Eldfisk	Ali M Saidi
Reservoir Studies of Eldfisk	Restek a.s

SAFARI Data Acquisition

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 the Directorate and eight interested companies was launched in 1990 and will be concluded in 1992. Consultants Geo Recon A/S have been engaged to implement the project which is intended to compile a three-dimensional fracture database using data collected from the Laegerdorf chalk quarry in Germany. The project aims to provide a better understanding and description of fracture geometry in the chalk fields in the North Sea.

NPD Involvement in Reservoir Descriptions for SPOR
The Directorate is responsible for assistance to the SPOR Enhanced Recovery Project 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.

Modelling and Simulation of Statfjord
A detailed geological charting operation with a view to identifying slate incidence and continuity has been performed. The results were 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 snugly the simulation fits the data. The best fit is then used to predict production to come.

Cut-off Criteria
Since several of the fields proven to date are marginal in terms of resources, it turns out that cut-off values based on petrotypical parameters can materially influence the definition of productive rock. This project examines alternative methods of improving the determination of cut-off values based on static and dynamic data.

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 for Onstream Fields
This project picks up where last year's *Gas Flaring Criteria*, which examined problems in connection with starting up new fields, left off. The work has identified critical factors deciding flare demand on onstream fields and the opportunities to reduce such demand. The limiting factors for minimum oil production were also identified and discussed.

Environmental Technology
This project has built up expertise in environmental technology so as to provide advice when called upon to do so to the Ministry of Petroleum and Energy in respect of environmental technology issues. The technology available in the United States for reduction of pollution from the petroleum industry was studied with the main emphasis on technology designed to reduce atmospheric emissions.

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 water flooded. The study should be completed early in 1992.

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 1992.

Coriolis Mass Flowmeter Project
This project, combining the forces of Statoil, Total, Phillips, the Norwegian Petroleum Directorate, Kodak and the 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 tests to develop 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 specifically for the purpose.

Production at below Boiling Point Pressure
This project was designed to elucidate what happens in the reservoir and on the surface when production takes place at bottom-hole flow pressures lower than the boiling point pressure of the oil. The study included a theoretical review of the issues and an evaluation of two actual cases, one of which was simulated.

ECLIPSE
In the course of the year two projects were carried out for the ECLIPSE reservoir simulation package: one for maintenance, where the Directorate received a new version of the software, and one for procurement of new modules for the software package.

Reservoir Data Reporting System, RDRS
Two projects linked to the RDRS database were implemented in 1991: one for maintenance of the system and one for continuing development. Development this year was mainly a validification programme which the operating companies use before the final data are submitted to the Directorate.

Simulation Study of Statfjord
During 1990 and 1991 a composite section simulation of the Statfjord formation was performed, which examined possible future strategies for optimal recovery of the residual oil in the reservoir.

Well Technology
This study analysed possible methods for optimal use of wells which penetrate several independent reservoirs or reservoir zones.

Chalk Research
The Norwegian Petroleum Directorate joined with Denmark's Ministry of Energy to initiate this chalk research programme, which eleven oil companies are financing and implementing jointly. The programme aims to improve our understanding of chalk fields and use this understanding to improve recovery. The project chair which was held for much of 1991 by the Directorate has now passed on to the Ministry of Energy. The Directorate sits on the six technical committees and the steering committee.

Geotechnical Support
In connection with the problems of subsidence in the Ekofisk region the Directorate has sought the counsel of Dr. Mervyn Jones of University College, London. Dr. Jones, who is an expert on rock mechanics, acted as consultant for technical evaluations and performance of tests.

Reservoir Studies of Ekofisk
Restek a.s was engaged to construct a phenomenological model which will provide the foundation for subsequent reservoir simulations of the Ekofisk field. Future simulations will aim to evaluate various production strategies, such as gas and water injection in the upper part of the field.

Fracture Studies of Eldfisk
Dr. Ali M Saidi assisted the Directorate with the task of developing a reservoir simulation model of Eldfisk. His experience is drawn from crumbled reservoirs in other regions of the world and he has acted as consultant in connection with the Directorate's evaluation of future production strategies for crumbled fields, such as Eldfisk.

Reservoir Studies of Eldfisk
This project was a continuation of the 1990 project. Reservoir simulations of the northern structure in the field were performed, and different recovery mechanisms, such as depressurisation, gas injection and water flooding were simulated. The results indicate that there are good opportunities for enhancing recovery from the field.

6.1.4 Planning Branch

PROJECT TITLE	EXECUTIVE INSTITUTION
Portfolio Model, Continuation	Sintef
Market Data for Gas: Soviet Role in European Gas Market	Fridtjof Nansen's Institute

Portfolio Model, Continuation
The portfolio model is an economic analysis tool used especially for area evaluations and rough estimates of gas supplies. The model was developed for the Directorate by Sintef and in 1991 its evolution continued. Several oil companies have expressed an interest in the model.

Market Data for Gas: Soviet Role in European Gas Market
This project, which looked specifically at strategic and operational perspectives, was started by the Gas Negotiations Committee in conjunction with the Ministry of Petroleum and Energy and this Directorate in 1989. Its purpose was to gather information

about developments in the Soviet Union and Eastern Europe, as it then was, which might ultimately influence Norwegian gas exports. To date the project has provided sponsors with continuous assessments of political and economic matters of importance in the gas market. This work will continue in 1992.

6.1.5 SPOR Programme

PROJECT TITLE	EXECUTIVE INSTITUTION
Water Injection (SPOR Water)	Rogaland Research Institute
Gas Injection (SPOR Gas)	Continental Shelf and Petroleum Technology Institute (IKU)
Optimisation of Reservoir Data (SPOR Opt)	Institute of Energy Technology (IFE)

Again in 1991 there was much activity within the SPOR enhanced recovery programme, a government research and development programme initiated in 1985 and brought to a conclusion on 31 December 1991. The programme sought through competence building, and through research and development of novel technology, to provide a foundation for enhanced oil recovery from the Norwegian continental shelf.

In all Nkr 101 million was spent on the programme and these funds were appropriated over the Ministry of Petroleum and Energy's budget. Extension of certain parts of the programme will be realised through RUTH, a programme run by the Royal Norwegian Council for Scientific and Industrial Research (NTNF) which starts in 1992.

Implementation of the SPOR programme produced tangible spinoffs in connection with the work on enhanced oil recovery, both in the Directorate and in the companies engaging in offshore activities on 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, such as with the USA.

A SPOR monography has been prepared which summarises the status in the field. This report, called *Recent Advances in Improved Oil Recovery Methods for North Sea Sandstone Reservoirs*, can be ordered from the Directorate.

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 further develop the results of the SPOR programme. The research will be largely undertaken at Norwegian institutes.

Profit has a maximum budget of Nkr 90 million. Due to limited participation, only two projects have been initiated so far, with a budget of Nkr 68 million for the five-year period, to examine:

- Reservoir specification
- Near-well flow.

The plans for 1992 will involve research to the value of about Nkr 18 million.

6.2 SAFETY AND WORKING ENVIRONMENT DIVISION

PROJECT TITLE	EXECUTIVE INSTITUTION
Membership of Welding Institute	Welding Institute (WI)
Membership of Marine Technology Directorate	Marine Technology Directorate (MTD)
Membership of Norwegian Electro-Engineering Committee	Norwegian Electro-Engineering Committee (NEK)
Petroleum Operations North of 74°30′N	NPD
Manned Underwater Operations, International Co-operation	NPD
Working Environment for Divers	Sintef
Jack-up Site Assessment Procedures	Noble Denton Associates (NDA)
Planning and Criteria for Relief Wells	Neal Adams

PROJECT TITLE	EXECUTIVE INSTITUTION
Gas Kick in Oil-Based Drilling Mud	Rogaland Research Institute
Worldwide Offshore Accident Databank, WOAD	Det norske Veritas (DnV)
Design Criteria for Collision Risk, COLLIDE	SikteC
Hydrostatic and Dynamic Pressure Modelling for High-Pressure, High-Temperature Deep Wells	Rogaland Research Institute
Gas Safety Programme	Christian Michelsen's Institute (CMI)
Technical and Operational Aspects of Manned Underwater Operations	Oceaneering
Internal Control of Documentation of Chemical Health and Environmental Hazards	Novatech A/S
Internal Control of Activities in Norway	Sintef
Influence of Welding on Materials Performance Offshore	Cranfield Institute, UK
Expert System for Evaluation of Corrosion Risk, EXPRES	Cranfield Institute, UK
Design Curves for Fatigue of Cathodic Protected Structures	Sintef
Application of Statistical Analysis Tools to Accident Data	SaS Institute A/S
Maintenance of Formula PS Planning Tool	Norsk Data
Implementation of Drawings in Damage Database, CODAM	EB Industrier Offshore
Pressure Testing of Blowout Preventer (BOP)	Sintef
Specific Preparedness Requirements	Novatech
Methods for Testing Materials and Structures for Jet Fires	Sintef
Foam and Deluge Systems for Engineroom and Electrical Fires	Royal Norwegian Navy
Kick Tests with Horizontal Wells	Rogaland Research Institute
Maintenance Management	Sintef
Ductility of High-Strength Concrete	Sintef
Qualification of Welding Joints	Sintef
Cathodic Protection of Thermally Insulated Pipelines	Corrocean
Light Aggregate Concrete	Sintef
High-Strength Concrete, Phase 3	Sintef
Corrosion and Erosion in Piping for Process and Support Systems	Sintef

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
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 (MTD). 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
The Directorate's membership of the Norwegian Electro-Engineering Committee (NEK) is designed 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 on 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 looking at the risk of encountering drift ice at seven selected positions in the Barents Sea. Also, the distance to the ice edge and the length of ice-free periods is being analysed. For four of the positions the collision risk and probable size of ice-bergs in the area are also evaluated.

Manned Underwater Operations, International Cooperation
This project aims 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 been continuing for 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 1991 the project looked more closely at microbial contamination of diving bell atmospheres, considered procedures for decontamination of diving bells, and evaluated various disinfectants for use in hyperbaric habitats. The quality of bell atmospheres in various diving systems was also improved.

Jack-Up Site Assessment Procedure
Noble Denton Associates (NDA) have identified major discrepancies in the calculation methods (use of parameters) and philosophies of the various companies and institutions for assessing 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 1992.

Planning and Criteria for Relief Wells
This project analyses the need for requirements for relief wells during exploration and production drilling. The project started in 1990.

Gas Kick in Oil-Based Drilling Mud
This project examines the problems peculiar to gas kicks in oil-based drilling mud. So far the project has produced a user-friendly application which will enable operators to simulate circulation out of a gas kick in oil-based drilling mud. This project started in 1990.

Worldwide 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.

Design Criteria for Collision Risk, COLLIDE
This project was started in 1988 and aims to improve design criteria to reduce the collision risk between merchant shipping and offshore installations. In earlier phases of the project a basic model for calculation of the collision risk and procedures for working out rough estimates were developed. In the last phase the risk picture for the entire North Sea was input into the data programme developed.

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. The project continues in 1992.

Gas Safety Programme

In recent years Christian Michelsen's Institute in Bergen has been doing much research into explosions in certain offshore modules. The work continued in 1991 with the support of several oil companies and government agencies. 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 has 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 the sought-for level of safety is to be secured. The project highlights problem aspects of emergency systems for divers, and analyses matters such as excursions involving temporary pressure changes during shallow saturation dives. Keywords apart from emergency systems for divers are hyperbaric rescue units and shallow saturation dives. This project will continue in 1992.

Internal Control of Documentation of Chemical Health and Environmental Hazards

This project identifies how quality assurance principles are reflected in the distribution of toxicological and occupational health information on chemicals. In 1991 the project looked at manufacturers and importers in order to reach quality assurance guidelines which can be used by these organisations for development and distribution of such information.

Internal Control of Activities in Norway

So far the Internal Control project has achieved the following:

- Determined if internal control has had a generally positive effect, and identified any difficulties it has encountered
- Offered documentation of solutions to problems in selected companies
- Referred good and bad experiences back to the companies
- Developed evaluation tools to enable companies to evaluate their inhouse introduction of internal control
- Provided substance for supervisory agencies' follow-up of implementation and enforcement of internal control systems in the industry.

The project is a major collaborative effort with the Confederation of Industry (NHO) and NTNF, and will continue in 1992.

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 comparable properties of the new high-strength low-alloy steels, accelerated cooling steels, combinations of the two, and castings and forgings. The risk of hydrogen brittleness was particularly examined.

Expert System for Evaluation of Corrosion Risk, EXPRES

This project, also carried out by the Cranfield Institute of Technology in England, 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 in the light of the project results.

Application of Statistical Analysis Tools to Accident Data

This project will structure the use of the statistical analysis tool SaS with the Directorate's database for accident records. The project will secure significant competence building for an analysis tool which will find broad application throughout the Directorate's sphere of responsibility.

Maintenance of Formula PS Planning Tool

A computer-based planning tool has been developed which will provide management with the necessary overview of planned activities and their interdependence. The tool will also rationalise the allocation and utilisation of human resources for the Directorate's supervisory and other tasks. In 1991 the planning system was maintained with the assistance of outside expertise.

Implementation of Drawings in Damage Database, CODAM

This pilot project aims to link inspection drawings to the Fixed Installation and Pipeline Damage Database.

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 installation lifetimes, and in the case of risk and reliability analysis. It will also be possible to transfer general data to the industry. On certain conditions the Norwegian Oil Industry Association (OLF) supports the release of data for purposes which will benefit the industry.

Pressure Testing of Blowout Preventer (BOP)

In the new *Drilling Regulations* the Directorate sets out requirements for new test intervals and test pressures for blowout preventers. The new aspect is that functional testing of such valves is acceptable. Previous tests of so-called "wet" systems produced positive results; this time, "dry" systems were examined. The project, which started in 1989, was completed in 1991.

Specific Preparedness Requirements

The new *Emergency Preparedness Regulations* require operators to define their activities' specific requirements for emergency preparedness. The project report illustrates how the method can be used to develop such requirements. This project was performed in the second half of 1991 and was limited to emergency measures requiring the involvement of the emergency response organisation.

Methods for Testing Materials and Structures for Jet Fires

The special conditions which prevail in the offshore petroleum industry are not always reflected in international or domestic standards. A case in point is the incidence of jet fires and their effects. This phenomenon was impossible to ignore after the Piper Alpha burn-out on the UK sector. The resistance of materials and structures to the ravages of a jet fire will need to be documented from now on. The project has developed a method for doing so.

Foam and Deluge Systems for Engineroom and Electrical Fires

Based on work by the Royal Norwegian Navy Logistics Command to replace halons as fire-fighting agents, this project was carried out concerning the use of foam and sprinklers as extinguishing agents. The project showed the relevance of such methods for engineroom fires and electrical panel rooms.

Kick Tests with Horizontal Wells

The numbers of horizontal wells drilled in Norwegian waters are expected to grow, and one difficulty with such bores is how to deal with a gas kick. This project staged a full-scale test which produced answers to many of the issues that were raised in connection with well behaviour during a well kick and methods of detecting and tackling such eventualities.

Maintenance Management

Maintenance is very important in the safety context. The increasing age of many installations in the North Sea is bringing the problem ever closer.

The Directorate's supervision shows that there sometimes exist serious defects in the maintenance systems of some operators. They also show that the petroleum industry is not a leader when it comes to utilising new maintenance technology, compared for example with land-based industry where maintenance is a prerequisite for safe operation and sound economy.

The need to improve management of maintenance has led us to look at new maintenance technology, including the identification of critical equipment for several operators.

The Directorate's objective for this project is to develop the competence required in the maintenance discipline, principles of cost-efficient engineering, and furtherance and implementation of maintenance systems. The project aims also to contribute technical expertise for regulatory drafting intended to amplify the Directorate's requirements and expectations for maintenance management.

Ductility of High-Strength Concrete

This project helped develop high-strength, high-ductility concrete for applications in structures which may experience particular stresses, such as impact, pressure shock, earthquake, heat and cold. The development of specifications for design and structural shaping of high-strength concrete exposed to particular stresses was also examined. The following were involved with the Directorate: NTNF, Norwegian Contractors, Norske Shell and the Norwegian Army Construction Service.

Qualification of Welding Joints

This project developed new standards for fabrication specifications, qualification routines and quality control of welded seams. The project also collated requirements which the authorities (the Directorate) and clients (the operating companies) prescribe on materials technology and welding technology grounds.

The new European standards for welding procedures, mechanical testing of weld seams, and accreditation of workshops and welders were incorporated as references. The project helps continue the standardisation work in welding and materials technology already started.

The Norwegian Welding Technology Association and Sintef's Welding Centre took the initiative for the project which, besides NTNF and the Directorate, attracted input from shipyards and workshops, engineering consultants, and offshore operators. The project is planned to last three years.

Cathodic Protection of Thermally Insulated Pipelines
The Directorate was approached by some operating companies who need more information about the regulatory requirements for corrosion protection on thermally insulated pipelines. This project was a systematic study of experience won with existing plant of this type. A preliminary project was undertaken in 1991, and the plans are to continue the work in 1992. In the next phase, practical trials will be staged in which the industry will be invited to participate.

Light Aggregate Concrete
Concrete containing light-weight aggregate weighs only 1500 kg per cubic metre and therefore possesses tremendous potential for fixed and mobile installations. On the other hand, light aggregate concrete possesses properties which are entirely different from concretes mixed using traditional aggregates. This project developed types of concrete using lightweight aggregate and suitable other materials to secure properties suitable for floating installations. Started in 1989, is carried out by Sintef's FCB section in Trondheim.

High-Strength Concrete, Phase 3
This project is a continuation of the preliminary project in 1986, phase 1 in 1986–88 and phase 2 in 1989–90. In 1991 the project compared the data obtained in phases 1 and 2 with high-quality data available from other parts of the world. The project also included additional experiments aimed to fill existing holes and remove various uncertainties.

The results of phases 1 and 2 comprised a major part of the documentation which underlies the rules in the new Norwegian Standard NS 3473 for concrete. This standard is currently considered the most advanced standard for high-strength concrete in the world.

The project was carried out by Sintef's FCB section in Trondheim and attracted considerable support from the industry. The 1991 budget was Nkr 4.5 million.

Corrosion and Erosion in Piping for Process and Support Systems
This project developed a summary of internal and external corrosion and erosion problems in piping systems. The need to develop better corrosion protection was also examined. The project will examine such issues as when and where corrosion and erosion arise, and how the associated problems can best be handled. The project which will last two years should be concluded in 1992. A continuation programme may be called for if the industry is prepared to assist with financing.

6.3 ADMINISTRATION BRANCH

PROJECT TITLE	EXECUTIVE INSTITUTION
North Sea Seabed Clearance	NPD

North Sea Seabed Clearance
The Directorate's seabed clearance project concentrated in 1991 on the Kanten area at 60°N, south of the Brage field and directly west of Bergen. The area, covering 1021 square kilometres, 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 deemed to be in the way of effective fishing in the area.

Three wrecks were accurately positioned, but not raised. Various chains, wires of assorted sizes, anchors and fishing implements were recovered from the seabed with a total weight of 100 tons.

Again in 1991, the Norwegian Hydrographic Service's survey vessel, *M/S Lance*, was used to chart the bottom by sonar. 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.

7. International Cooperation

7.1 AID TO FOREIGN COUNTRIES

7.1.1 Aid through NORAD

Through a cooperation agreement with NORAD, the Norwegian Directorate for Development Cooperation, the Norwegian Petroleum Directorate assisted with development aid to Tanzania, Namibia, Mozambique, the Seychelles, Yemen, Bangladesh, Nicaragua and Costa Rica in 1991. Assistance was also given to the Committee for Coordination of Joint Prospecting for Mineral Resources in Asian Offshore Areas (CCOP), an organisation covering 11 countries.

Tasks in these areas comprised consultation in connection with planning and implementation of licensing rounds, follow-up of consultants in connection with seismic processing, seismic interpretation and installation of computer equipment, transfer of seismic data, storage of seismic data, and training of personnel.

The Norwegian Petroleum Directorate's major commitments in 1991 were in the following countries:

a) Bangladesh

The Directorate acted as advisor in connection with the purchase and installation of hardware and software for processing and digitalisation of seismic data for the Bangladesh Petroleum Institute (BPI). The Directorate also acted as advisor for several studies of reconditioning of seismic data, regional geological charting, density studies of sedimentary basins, and mapping and appraisal of a small oil field. These are steps in the project process to build up the institution.

b) Namibia

Aid to Namibia is directed to the National Petroleum Corporation of Namibia (NAMCOR) and was largely connected to the planning and implementation of Namibia's first licensing round. The Directorate followed up seismic interpretation studies undertaken by consulting engineers and collated data from several explorations. Advice was also given regarding the choice of consultant to undertake a market analysis for the Kudu gas field. The Directorate also examined the filing system in Namcor and has proposed a project which will develop a new records management system for 1992 suitable for the increasing volume of petroleum business. An engineer from Namcor was seconded to Norway for a short period to examine the Directorate's systems for storage and filing of geological specimens.

c) Nicaragua

As part of an advice programme to the Nicaraguan national energy office, *Instituto Nicaraguense de Energia* (INE), the Directorate assisted with the reconditioning of seismics from the Pacific continental shelf. Initiation and follow-up of a project undertaken by a firm of consultants aiming towards a petroleum exploration campaign on the Nicaraguan continental shelf was also on the agenda. Two Nicaraguan geologists spent a short term with the Directorate in Norway in connection with the conclusion of a project under a Norad bursary at the Norwegian Institute of Technology (NTH).

d) Tanzania

This project is approaching a conclusion and in 1991 the Directorate concentrated on two main areas: collection and processing of seismic data; and storage of seismic data. In respect of collection of seismic data in the Pemba-Zanzibar region, assistance was given to the Tanzania Petroleum Development Corporation (TPDC) involving advice on choice of gathering parameters. The Directorate also helped with follow-up and control of data processing. Tanzania's seismic data are stored in Norway. In view of the future storage of these materials in Tanzania, they were transferred from ordinary tape to a more compact format. The Directorate assisted in this process with advice and a helping hand.

e) Yemen

In connection with the signing of a bilateral cooperation agreement between Norway and Yemen, the Directorate assisted with the direction and control of the oil activity. Two representatives from the Ministry of Energy and Mineral Resources, Exploration and Production Board, spent three months in the Directorate for instructional purposes. The Directorate also joined with Norway's State Pollution Control Authority (SFT) to make a study trip to Yemen in connection with a proposed programme for environmental and safety-related control of the oil activity.

f) Seychelles

The chief executive of the Seychelles National Oil Company Ltd (SNOC) spent five weeks in Norway to gain an insight into Directorate routines for control and administration of the oil industry.

In connection with the drafting of environmental legislation for the islands, a representative of the Department of the Environment, Republic of Seychelles, spent a brief period in the Directorate doing information searches and engaging in discussions.

7.1.2 Aid through PETRAD

From 1 January 1989 until 31 December 1991 the Directorate undertook a test project for Norad aimed at examining the feasibility of setting up a training scheme in Norway for petroleum administration and management executives. The target group is executives in petroleum administration and the national oil companies in the developing countries.

The project, called the International Programme for Petroleum Management and Administration (PETRAD), was the direct responsibility of the Director General of Petroleum.

Based on information regarding the need for executive training in the petroleum sector in Africa, Asia and Latin America, Petrad organised 29 courses and seminars, lasting from two days to eight weeks. Training was given in Africa, Asia and Norway. No less than 845 executives from 40 countries attended the seminars. The budget for the trial period was Nkr 21 million.

For the design and implementation of the training Petrad sought to draw on all aspects of Norwegian competence in the petroleum sector. Some 32 representatives of Norwegian institutions took turns as resource persons and lecturers. Petrad also engaged a score or so lecturers from developing countries as well as many experts from various international organisations.

The programme aimed to cover a broad spectrum of management and administration of petroleum activities, both upstream and downstream, and training was organised in four categories:

- The Role of Petroleum in Sustainable Development
- Petroleum Resource Management
- Safety and Environmental Management
- Managing Petroleum Procurement and Use.

The experiences of these courses and seminars allowed Petrad to develop two eight-week instruction programmes:

- Petroleum Policy and Management
- Management of Petroleum Operations.

These programmes were developed with the aid of 50 experts from Norwegian teaching environments, consultants and operating companies.

The courses were first offered between 9 September and 1 November 1991, attracting 40 participants from 19 countries, among them Norway.

Experience from the trial project was extremely rewarding and shows what a great need the developing countries have to train their executives in petroleum management and administration.

Norad has therefore asked the Directorate to undertake the continuation of the programme in 1992 for an interim period while an evaluation and, hopefully, a decision to set up Petrad on a permanent basis from 1993, can be made.

7.2 SAFETY AND THE WORKING ENVIRONMENT

The Directorate cooperates and enjoys extensive contacts with international professional organisations and political and technical bodies, both directly and indirectly through other Norwegian agencies.

The purpose of this cooperation is as follows:

a) To help ensure that safety and the working environment at least meet the accepted international standards
b) To secure the supply of relevant information for competence building and regulatory development
c) To improve our understanding of and experience in international relations so as to usefully influence safety and working environment issues.

Generally the cooperation has involved taking part in inter-governmental fora in Europe and the United Nations, supplemented by direct cooperation with various kinds of international and regional professional bodies. A list of the most important partners in 1991 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) in UK on inspection and maintenance of installations
e) Welding Institute (WI) in UK on research and development of materials and welding
f) American Petroleum Institute (API), attendance at annual conferences on technical petroleum subjects and standardisation
g) National Association of Corrosion Engineers (NACE) in USA, participation at annual conferences on corrosion and surface treatment
h) Comité Européen de Normalisation Electrotechnique (CENELEC), concerning electrical engineering standardisation in Europe, through the Norwegian Electrical Engineering Committee (NEK).

7.2.1 The EC Committee

Since 1982 Norway, represented by the Norwegian Petroleum Directorate, has held observer status in the EC processes concerning 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 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.

The draft directive in 1991 was examined by the European Parliament, whose comments were considered by the EC Safety and Health Commission mentioned above, and a new consultative document is being planned for circulation in the EC. The intended date of implementation of the directive is the new year 1993.

7.2.2 Electro-engineering standards and regulations

The Norwegian Petroleum Directorate sits on the following committees:

a) CENELEC, Working Group 12, Regulations for Installation of Explosion-proof Materials
b) NEK, Standards Committee (NK) 18, Shipboard Installations
c) 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, which, together with a North-American group, will prepare new IEC publications for mobile and fixed installations.

7.2.3 Lectures

In 1991, as previously, the Directorate was engaged to lecture and chair meetings at a number of courses and conferences concerning 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

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

When the EC Internal Market is established 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 is therefore of the utmost importance.

National work groups have been set up to review the International Standardisation Organisation (ISO)'s activities regarding oil and gas measurement for the purpose of protecting national interests. The Directorate is also actively involved in this work.

8. Statistics and Summaries

8.1 UNITS OF MEASUREMENT

The Norwegian Petroleum Directorate generally advocates the *Système International d'Unités*, or SI, system of units, and use of this system is recommended for 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 b) given above, and this reference state was incorporated in Norwegian Standard NS 5024 in 1979. The 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 Metre 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 metres) and bcm (billion cubic metres). A million is sometimes written 10^6, and a billion (a thousand million), 10^9. 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: Nm3 or, more properly, Nm^3, indicates normal cubic metres; Scf indicates standard cubic feet. Once again the reference conditions have to be specified if an exact expression is required.

For conversion 1 scm is about equal to 0.95 Nm3, 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 equivalents

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 nearly equal to the energy in 1000 scm gas. As this factor is so easy to apply, and the qualitative differences of oil and gas during treatment, storage, distribution and application are very considerable, 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 toe. By analogy, mton and bton would indicate million and billion tons. Tons are in all cases metric tonnes (1000 kg).

8.2 EXPLORATION DRILLING STATISTICS

By year end 1991 a total of 709 exploration wells had been started on the Norwegian continental shelf since the first was spudded in 1966. Of this number, 509 were wildcats and 200 appraisal wells. Table 8.2.a gives details. By the same date, 658 exploration wells had been terminated, while 40 were suspended for various reasons.

The reasons include deferred testing, possible completion as production wells, continued drilling, or subsequent plugging.

The most northerly exploration well to date on the Norwegian continental shelf is 7321/7–1 which was drilled in 1988 with Mobil as operator. The furthest east is 7228/6–1, drilled by Conoco in 1991; and the westernmost 6201/11–2, drilled by Statoil in 1991. The furthest south is 2/10–1-S, drilled by Phillips in 1976.

Exploration wells have been drilled by 19 different operating companies. The regional numbers drilled per operator are shown in Figure 8.2.a and Tables 8.2.b-c. The number of days of operation per company in 1991 is shown in Figure 8.2.b. Figure 8.2.c shows the Norwegian operating companies' share of drilling operations.

By year end 1991, the total length of exploration hole had reached 2,287,562 metres. Of the total, 170,627 metres were drilled in 1991. The average total depth of the exploration wells reaching total depth in 1991 was 3639 metres.

Exploration well 30/4–1, terminated in 1979, is the deepest well to date on the Norwegian side. Here, BP was the operator and the total vertical depth

Fig. 8.2.a
Regional spread of exploration wells per operator

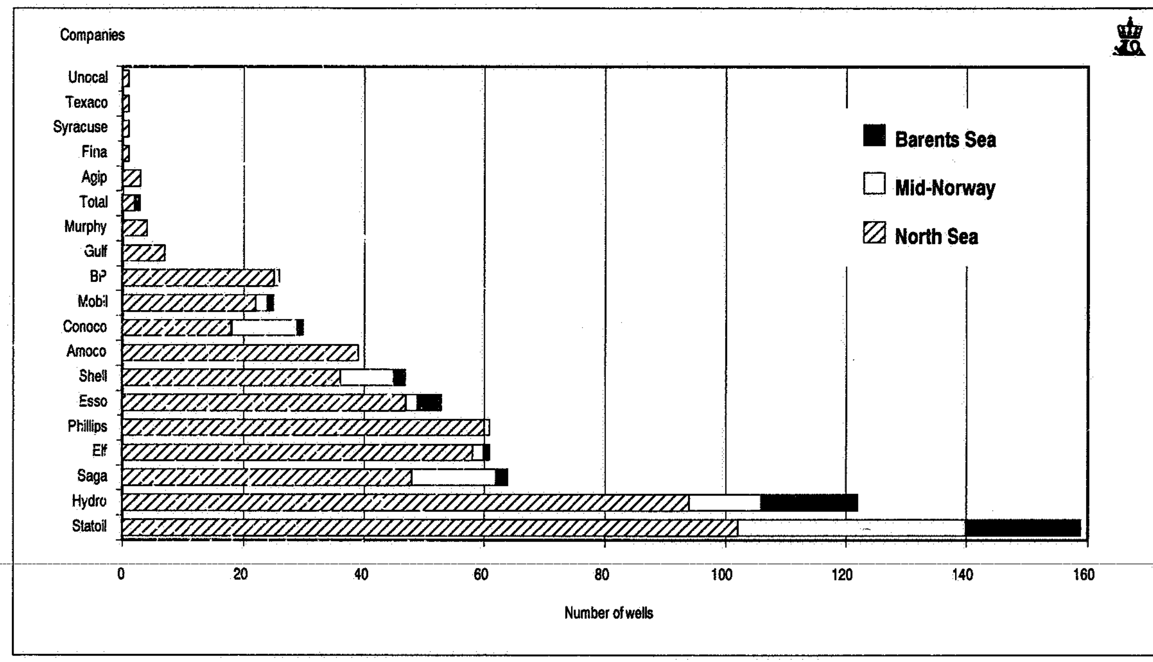


Table 8.2.a
Wells spudded as of 31 December 1991

Year spudded	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90	91	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	34	509
Appraisal			2	1	6	5	3	5	5	9	3	8	5	10	10	13	13	7	12	20	10	11	11	8	10	13	200
Exploration	2	6	12	13	17	16	14	22	18	26	23	20	19	28	36	39	49	40	47	50	36	36	29	28	36	47	709
Development								1	18	24	7	34	50	36	27	16	22	23	33	47	47	48	55	66	60	64	678
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	111	1387

Table 8.2.b
Exploration wells by operating company and region

Operator	North Sea			Off Mid-Norway			Barents Sea			Total		
	W	A	E	W	A	E	W	A	E	W	A	E
Statoil	56	46	102	34	4	38	18	1	19	108	51	159
Norsk Hydro	69	25	94	10	2	12	16		16	95	27	122
Saga	39	9	48	14		14	2		2	55	9	64
Elf	42	16	58	2		2	1		1	45	16	61
Phillips	41	19	60	1		1				42	19	61
Esso	28	19	47	2		2	4		4	34	19	53
Shell	25	11	36	4	5	9	2		2	31	16	47
Amoco	25	14	39							25	14	39
Conoco	18		18	3	8	11	1		1	22	8	30
Mobil	14	8	22	2		2	2		2	18	8	26
BP	13	12	25	1		1				14	12	27
Gulf	7		7							7		7
Murphy	3	1	4							3	1	4
Total	2		2				1		1	3		3
Agip	2		2							2	2	
Fina	1		1							1		1
Syracuse	1		1							1		1
Texaco	1		1							1		1
Unocal	1		1							1		1
Wildcat	389			73			47			509		
Appraisal		180			19			1			200	
Exploration			569			92			48			709

W = Wildcat
A = Appraisal
E = Exploration

Table 8.2.c
Exploration wells spudded in 1991 by operating company and region

Operator	North Sea			Off Mid-Norway			Barents Sea			Total		
	W	A	E	W	A	E	W	A	E	W	A	E
Statoil	4		4	4		4				8		8
Norsk Hydro	6	5	11	2		2	1		1	9	5	14
Phillips	1	2	3							1	2	3
Elf	2	1	3							2	1	3
Saga	3	3	6	1		1				4	3	7
Esso				1		1	1		1	2		2
Shell	1		1							1		1
Amoco	1		1							1		1
Conoco							1		1	1		1
Mobil	1		1							1		1
BP	2	2	4							2	2	4
Fina	1		1							1		1
Agip	1		1							1	1	
Wildcat	23			8			3			34		
Appraisal		13									13	
Exploration			36			8			3			47

W = Wildcat
A = Appraisal
E = Exploration

Fig. 8.2.b
Rigdays per operator in 1991

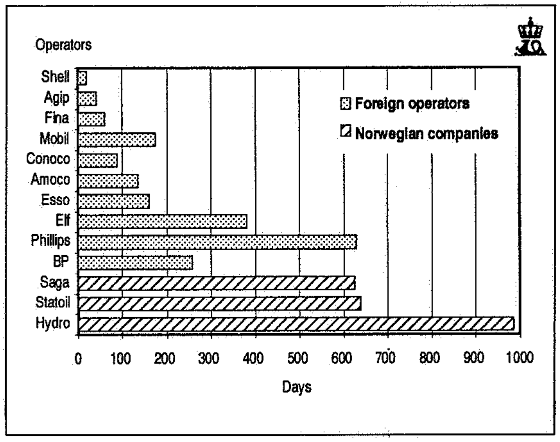


Fig. 8.2.d
Average waterdepth for exploration wells 1966–1991

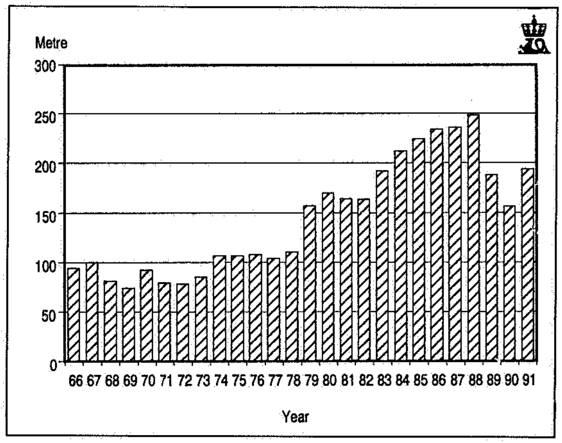
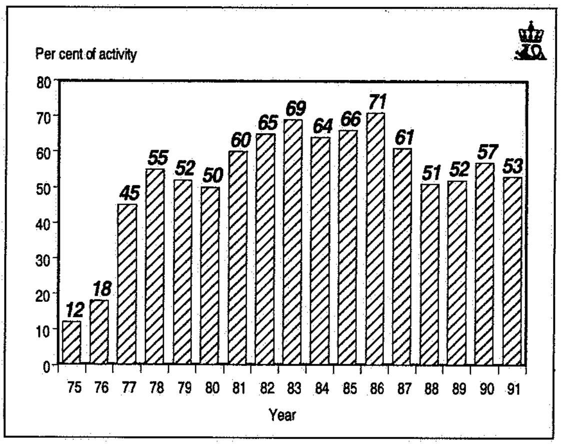


Fig. 8.2.c
Participation of Norwegian operators in exploration drilling activity



5455 metres. The longest borehole so far is 2/12–2-S, drilled by Norsk Hydro in 1990. The length of the well is 5757 metres, but as it was drilled at an angle it did not reach the same total depth as 30/4–1.

The greatest water depth in which a well has been drilled to date in the Norwegian sector is 523 metres: The well, 6607/5–2, was drilled in 1991 with Esso as operator. The average water depth in which exploration wells were drilled in 1991 was 194 metres. Figure 8.2.d shows the average water depths in which exploration wells were drilled from 1966 to 1991.

For the drilling operations to date on the Norwegian continental shelf, 70 different drilling rigs have been employed, nine of them under two different names. Of the total, 52 were semi-submersibles, 11 jack-ups, five drill ships and two fixed installations. In 1991 there were 17 different drilling rigs in action in Norway's offshore regions.

All drilling rigs engaged at one time or another in the Norwegian sector are listed in Table 8.2.d.

Table 8.2.d
Drilling rigs active on Norwegian continental shelf as of 31 December 1991

Rig name	Number of wells	Number of reentries	Type of rig
Aladdin	1		Semi-submersible
Arcade Frontier (formerly Norjarl)	5		«
Borgny Dolphin (formerly Fernstar)	27	8	«
Borgsten Dolphin (formerly Haakon Magnus)	9		«
Bucentaur		1	Drill ship
Byford Dolphin (formerly Deepsea Driller)	27		Semi-submersible
Chris Chenery	2		«
Deepsea Bergen	28	3	«
Deepsea Saga	16	3	«
Drillmaster	5	1	«
Drillship	1		Drill ship
Dyvi Beta	6	1	Jack-up
Dyvi Gamma	1		«
Dyvi Stena	19	1	«
Endeavour	2		«
Glomar Biscay II (formerly Norskald)	39	1	«

Rig name	Number of wells	Number of reentries	Type of rig
Glomar Grand Isle	11	3	Drill ship
Glomar Moray Firth I	2		Jack-up
Gulftide	3		«
Henry Goodrich	2		«
Hunter (formerly Treasure Hunter)	6	3	«
Kolskaya		1	«
Le Pelerin	1		Drill ship
Mærsk Explorer	7		Jack-up
Mærsk Guardian	1		«
Mærsk Jutlander	3	1	Semi-submersible
Neddrill Trigon	3	1	Jack-up
Neptune 7 (formerly Pentagone 81)	13		Semi-submersible
Nordraug	12		«
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 84	2	1	Semi-submersible
Polar Pioneer	23	2	«
Polyglomar Driller	11		«
Ross Isle	25	7	«
Ross Rig	29		«
Ross Rig (new)	17	3	«
Saipem II	1		Drill ship
Scarabeo	1		Semi-submersible
Sedco 135 G	3		«
Sedco 703	3	1	«
Sedco 704	3		«
Sedco 707	8		«
Sedco H	2		«
Sedneth I	3		«
Sovereign Explorer	1	1	«
Transocean 8	10	2	«
Transworld Rig 61	2		«
Treasure Saga	36	3	«
Treasure Scout	23		«
Treasure Seeker	24	5	«
Vildkat Explorer	21	4	«
Vinni	5		«
Waage Drill I	2		«
West Alpha (formerly Dyvi Alpha)	20	2	«
West Delta (formerly Dyvi Delta)	31	2	«
West Vanguard	25	6	«
West Venture	12	2	«
West Vision	1		«
Yatzy	1		«
Zapata Explorer	13		Jack-up
Zapata Nordic	5		«
Zapata Ugland	5	1	Semi-submersible
	707	74	
In addition two wells have been drilled from fixed instllations			
Cod	1	1	
Ekofisk B	1		
	709	75	

8.3 DEVELOPMENT DRILLING STATISTICS

Since 1973, a total of 678 development wells have been commenced in the Norwegian sector of the North Sea, and these are tabulated in Figure 8.2.a for each year up to 1991.

Of these wells, 349 are producers of oil, gas or condensate, 107 are water or gas injectors, one is an observation and production well, and one is an observation and injection well. Of the total, 207 are out of service; being either closed down, suspended for later completion, or suspended for some other reason. Thirteen production wells were being drilled at year end 1991.

A summary of development wells is given in Table

8.3.a. Figure 8.3.a shows development wells started each year during the period 1973 to 1991.

At year end production or injection was underway from 22 fields and 32 installations, four of which – Nordøst-Frigg, Øst-Frigg, TOGI and Tommeliten – are subsea installations.

The distribution of development wells by field is shown in Figure 8.3.b, while Figure 8.3.c shows the wells broken down by operating company. The first production well on the Brage field was spudded just before the new year using the *Vildkat Explorer* semi-submersible.

In 1991, 64 development wells were started in 14 fields. Fourteen of them were drilled from mobile drilling rigs.

Development wells broken down by installation are shown in Figure 8.3.d. Wells spudded or terminated in 1991 are listed in Table 8.3.b; while Figure

Fig. 8.3.a
Development drilling on the Norwegian continental shelf 1973–1991

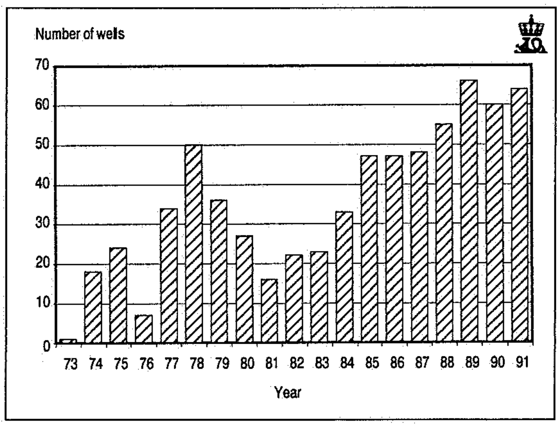


Fig. 8.3.b
Development wells per field

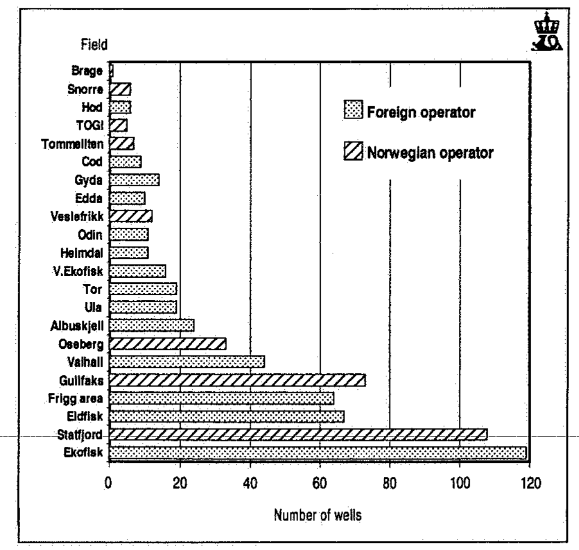


Fig. 8.3.c
Development wells per operator

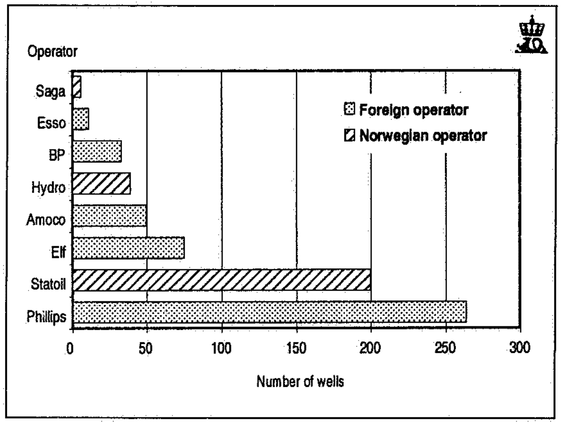


Fig. 8.3.d
Development wells drilled 1991 by installations

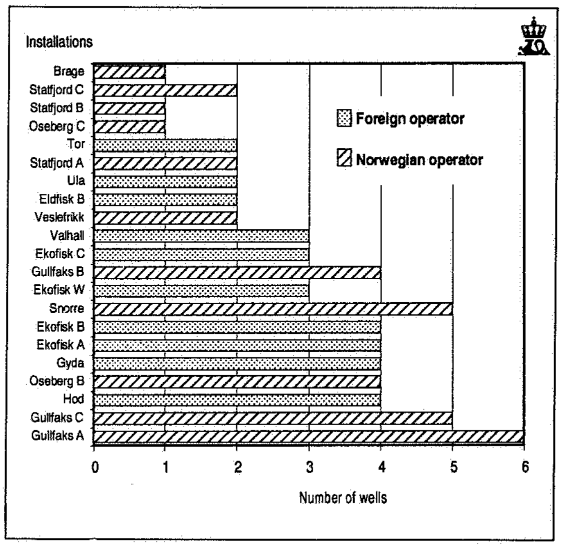


Fig. 8.3.e
Development drilling by mobile installations

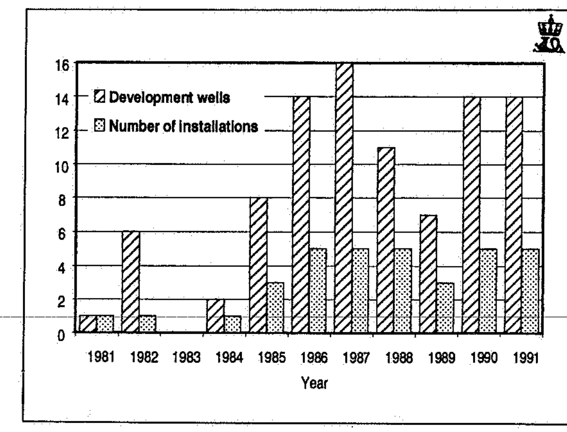


Table 8.3.a
Development drilling as of 31 December 1991

Field	Hycro-carbon	Total drilled	Spudded 1990	Produc-ing	Injection/ (observation)	Drilling	Plugged/ Shut-down/ Suspended
Albuskjell A +	cond	11		7			4
Albuskjell F	cond	13					13
Brage	oil	1	1			1	
Cod +	cond	9		3			6
Edda +	oil	10		6			4
Ekofisk A +	oil	26	4	21			5
Ekofisk B +	oil	35	4	20	1*		14
Ekofisk C +	oil	24	3	15	5**		4
Ekofisk K +	w.inj.	26			23	1	2
Ekofisk W +	w.inj.	8	3		8		
Eldfisk A +	oil	38		23			15
Eldfisk B +	oil	29	2	19		1	9
Frigg (UK)	gas	24					24
Frigg +	gas	28		10			18
Gullfaks A +	oil	42	6	24	7	1	10
Gullfaks B +	oil	21	4	11	6	1	3
Gullfaks C +	oil	10	5	6	2	1	1
Gyda +	oil	14	4	8	4	1	1
Heimdal +	cond	11		8	(1)***		2
Hod +	oil	6	4	5			1
N.Ø.Frigg +	gas	7		3			4
Odin +	gas	11		10			1
Oseberg B +	oil	24	4	9	7	1	7
Oseberg C +	oil	9	1	6			3
Snorre	oil	6	5			1	5
Statfjord A +	oil	42	2	22	14	1	5
Statfjord B +	oil	34	1	22	10	1	1
Statfjord C +	oil	32	2	21	10	1	
Togi +	gas	5		5			
Tommeliten +	cond	7		6			1
Tor +	oil	19	2	10		1	8
Ula +	oil	19	2	10	6		3
Valhall +	oil	44	3	20			24
V. Ekofisk +	cond	16		7			9
Veslefrikk +	oil	12	2	7	5		
Øst Frigg +	gas	5		5			
		678	64	349	102	13	207

+	Field producing/injecting	(1)*
*	Observation/production well(s)	5**
**	Prod./inj. wells depending on gas sales	(1)***
***	Observation/injection well(s)	

349 wells are producing (285 oil, 31 condensate and 33 gas)
163 wells are shut down/plugged
107 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-16, 2/4-E-6 A, 2/4-K-16, 2/7-B-3 A, 30/9-B-46, 31/4-A-1, 33/9-A-24, 33/9-C-27, 33/12-B-2, 33/7-P-13, 34/10-A-35, 34/10-B-19, 34/10-C-9)
12 wells are suspended at total depth: (2/1-A-9, 2/4-K-15, 2/7-A-7 A, 30/6-C-5, 30/6-C-8, 33/9-A-27, 33/9-C-39, 34/7-P-18, 34/7-P-28, 34/7-P-33, 34/7-P-29, 34/10-B-18)
1 well is susp. at 9 5/8": (34/10-C-10)
3 wells are susp. at 13 3/8": (2/7-A-15, 2/7-A-22, 30/9-B-42)
1 well is susp. at 18 5/8": (34/7-P-25)
1 well is susp. at 20": (25/4-A-1)
1 well is suspended with a fish in the 36" open hole: (2/4-K-3)
25 wells never produced

678 wells

8.3.e and Table 8.3.c provide summaries of wells drilled from mobile rigs.

The longest borehole to date on the Norwegian continental shelf, 33/9-C-3, was concluded in 1991. Drilled by Statoil from the Statfjord C platform, the well reached a measured depth of 7250 metres. With a vertical depth of 2695 metres the well reached out to a bottom position 6085 metres from the platform centreline.

Table 8.3.b
Development wells spudded or terminated in 1991

Lic. no.	Prod. well no.	Spudded	Terminated	Operator	Field
482	30/06-C-11	88.10.14	91.09.15	HYDRO	OSEBERG C
488	2/04-K-07	90.09.23	91.04.20	PHILLIPS	EKOFISK K
552	31/05-B-06 H	89.11.19	91.10.15	HYDRO	TOGI
561	31/05-B-04 H	90.01.15	91.01.01	HYDRO	TOGI
571	31/05-B-02 H	90.03.12	91.01.14	HYDRO	TOGI
590	34/10-C-04	90.06.22	91.02.09	STATOIL	GULLFAKS C
598	2/11-A-02	90.09.30	91.01.04	AMOCO	HOD
599	2/04-B-17 A	90.12.17	91.03.02	PHILLIPS	EKOFISK B
600	34/10-C-05	90.09.02	91.01.03	STATOIL	GULLFAKS C
604	30/03-A-09	90.10.29	91.05.22	STATOIL	VESLEFRIKK A
605	2/04-C-18	90.10.20	91.01.12	PHILLIPS	EKOFISK C
606	2/01-A-06 A	90.11.09	91.04.15	BP	GYDA
607	2/04-C-22	91.01.16	91.03.25	PHILLIPS	EKOFISK C
608	2/01-A-17	90.12.06	91.02.01	BP	GYDA
609	33/09-A-27	91.01.01	91.08.12	STATOIL	STATFJORD A
610	33/09-C-03	90.11.09	91.05.04	STATOIL	STATFJORD C
611	30/09-B-02	90.11.08	91.01.14	HYDRO	OSEBERG B
612	30/03-A-10	90.11.13	91.01.06	STATOIL	VESLEFRIKK A
613	2/07-A-23 B	90.11.23	91.03.14	PHILLIPS	ELDFISK A
614	2/08-A-12 B	90.12.01	91.03.21	AMOCO	VALHALL
615	2/04-W-02	90.11.25	91.01.26	PHILLIPS	EKOFISK W
616	2/04-K-16	90.12.26	00.00.00	PHILLIPS	EKOFISK K
617	2/11-A-01	91.01.01	91.03.06	AMOCO	KOLSKAYA
618	34/07-P-29	91.01.01	91.03.08	SAGA	SNORRE
619	34/10-B-14 A	90.12.24	91.03.08	STATOIL	GULLFAKS B
620	34/10-A-31	90.12.07	91.03.17	STATOIL	GULLFAKS A
621	2/04-W-07	91.01.27	91.03.22	PHILLIPS	EKOFISK W
622	30/09-B-12 A	91.01.17	91.03.13	HYDRO	OSEBERG B
623	2/04-B-16 B	91.03.02	91.04.17	PHILLIPS	EKOFISK B
624	34/10-A-20 A	91.01.23	91.02.24	STATOIL	GULLFAKS A
625	34/10-C-06	91.02.11	91.04.18	STATOIL	GULLFAKS C
626	30/09-B-08	91.02.03	91.04.27	HYDRO	OSEBERG B
629	2/04-B-16 C	91.04.17	91.06.05	PHILLIPS	EKOFISK B
631	34/07-P-25	91.03.09	91.03.15	SAGA	SNORRE
632	2/04-W-01	91.03.19	91.05.06	PHILLIPS	EKOFISK W
633	2/11-A-01 A	91.03.06	91.04.11	AMOCO	HOD
634	7/12-A-17	91.04.05	91.10.02	BP	ULA
635	2/07-B-11 A	91.06.10	91.09.07	PHILLIPS	ELDFISK B
636	2/01-A-23	91.04.17	91.07.08	BP	GYDA
637	34/10-A-32	91.03.17	91.05.09	STATOIL	GULLFAKS A
638	2/04-A-17	91.03.27	91.05.20	PHILLIPS	EKOFISK A
639	2/04-C-17	91.03.28	91.05.18	PHILLIPS	EKOFISK C
640	30/06-C-27 H	91.04.02	91.06.25	HYDRO	OSEBERG C
641	30/03-A-11	91.05.25	91.07.02	STATOIL	VESLEFRIKK A
642	2/11-A-03	91.04.12	91.07.23	AMOCO	HOD
643	30/09-B-39	91.04.27	91.10.15	HYDRO	OSEBERG B
644	2/08-A-25	91.04.17	91.07.17	AMOCO	VALHALL
645	34/10-C-07	91.04.18	91.06.26	STATOIL	GULLFAKS C
646	34/10-B-16	91.04.26	91.06.26	STATOIL	GULLFAKS B
650	34/10-A-33	91.05.09	91.09.13	STATOIL	GULLFAKS A
651	2/04-C-23	91.05.19	91.07.10	PHILLIPS	EKOFISK C
652	2/04-E-06	91.07.10	91.11.14	PHILLIPS	TOR
653	2/04-E-06 A	91.11.14	00.00.00	PHILLIPS	TOR
654	2/11-A-04	91.07.24	91.09.09	AMOCO	HOD
655	2/08-A-27	91.07.18	91.09.03	AMOCO	VALHALL
656	34/10-B-17	91.07.02	91.08.11	STATOIL	GULLFAKS B
657	33/09-C-39	91.06.25	91.10.01	STATOIL	STATFJORD C
658	2/04-A-16	91.07.30	91.09.17	PHILLIPS	EKOFISK A
659	34/10-C-08	91.06.26	91.08.19	STATOIL	GULLFAKS C
660	33/09-A-24	91.08.14	91.09.11	STATOIL	STATFJORD A
661	30/03-A-12	91.07.03	91.08.22	STATOIL	VESLEFRIKK A
662	2/01-A-09	91.07.09	91.09.03	BP	GYDA
663	2/07-B-03 A	91.09.28	91.11.17	PHILLIPS	ELDFISK B
664	34/10-A-34	91.07.14	91.10.09	STATOIL	GULLFAKS A
665	33/12-B-02	91.08.17	00.00.00	STATOIL	STATFJORD B
666	34/10-B-18	91.08.11	91.11.14	STATOIL	GULLFAKS B
667	34/10-C-09	91.08.19	00.00.00	STATOIL	GULLFAKS C
668	2/04-B-13	91.10.15	91.12.22	PHILLIPS	EKOFISK B
669	2/01-A-22	91.09.04	91.10.24	BP	GYDA
670	34/07-P-18	91.09.11	91.11.09	SAGA	SNORRE
671	7/12-A-01 A	91.10.03	91.11.14	BP	ULA

Lic. no.	Prod. well no.	Spudded	Terminated	Operator	Field
672	2/04-A-18	91.09.22	91.11.11	PHILLIPS	EKOFISK A
673	30/09-B-46	91.10.16	00.00.00	HYDRO	OSEBERG B
674	34/10-A-34 A	91.10.09	91.11.16	STATOIL	GULLFAKS A
675	2/08-A-16 C	91.10.03	91.12.16	AMOCO	VALHALL
676	2/01-A-16	91.10.26	00.00.00	BP	GYDA
677	34/10-B-19	91.11.22	00.00.00	STATOIL	GULLFAKS B
678	34/10-C-10	91.10.22	91.11.29	STATOIL	GULLFAKS C
679	34/10-A-35	91.11.17	00.00.00	STATOIL	GULLFAKS A
680	34/07-P-33	91.11.10	91.12.28	SAGA	SNORRE
682	33/09-C-27	91.11.27	00.00.00	STATOIL	STATFJORD C
689	34/07-P-13	91.12.29	00.00.00	SAGA	SNORRE
683	31/04-A-01	91.12.30	00.00.00	HYDRO	BRAGE

Table 8.3.c
Production wells drilled from mobile drilling rigs **Per 31.12.1991**

Lic. no.	Prod. well no.	Spudded	Terminated	Operator	Drilling rig
561	31/05-B-04 H	90.01.15	91.01.01	HYDRO	POLAR PIONEER
571	1/05-B-02 H	90.03.12	91.01.14	HYDRO	POLAR PIONEER
598	2/11-A-02	90.09.30	91.01.04	AMOCO	KOLSKAYA
615	2/04-W-02	90.11.25	91.01.26	PHILLIPS	MÆRSK GUARDIAN
617	2/11-A-01	91.01.01	91.03.06	AMOCO	KOLSKAYA
618	34/07-P-29	91.01.01	91.03.08	SAGA	SCARABEO 5
621	2/04-W-07	91.01.27	91.03.22	PHILLIPS	MÆRSK GUARDIAN
633	2/11-A-01 A	91.03.06	91.04.11	AMOCO	KOLSKAYA
631	34/07-P-25	91.03.09	91.03.15	SAGA	SCARABEO 5
632	2/04-W-01	91.03.19	91.05.06	PHILLIPS	MÆRSK GUARDIAN
640	30/06-C-27 H	91.04.02	91.06.25	HYDRO	TRANSOCEAN 8
642	2/11-A-03	91.04.12	91.07.23	AMOCO	KOLSKAYA
647	2/04-W-03	91.05.07	91.07.07	PHILLIPS	MÆRSK GUARDIAN
654	2/11-A-04	91.07.24	91.09.09	AMOCO	KOLSKAYA
670	34/07-P-18	91.09.11	91.11.09	SAGA	SCARABEO 5
680	34/07-P-33	91.11.10	91.12.28	SAGA	SCARABEO 5
689	34/07-P-13	91.12.29	00.00.00	SAGA	SCARABEO 5
683	31/04-A-01	91.12.30	00.00.00	HYDRO	VILDKAT EXPLORER

8.4 PRODUCTION OF OIL AND GAS

The total production of oil and gas on the Norwegian continental shelf was 118.4 mtoe in 1991. Production in 1990 was 107.3 mtoe. Tables 8.4.a-s which look at each producing field in turn and Figures 8.4.a-b which give period summaries, set out production in more detail.

The data in Table 8.4.a summarise the Norwegian shares in Statfjord, Frigg, and Murchison. In the tables for oil, NGL is included for the Ekofisk area, Statfjord, Valhall, Murchison, Ula, Gullfaks, Tommeliten, Hod, Mime and Veslefrikk.

The data for gas in Table 8.4.a indicate the net quantities produced in all fields. For the fields Statfjord, Frigg area, Heimdal and Gullfaks, condensate is included.

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

1991	Oil	Gas	Total
Ekofisk area	10.898	7.879	18.777
Statfjord	29.734	2.969	32.703
Frigg area	0.000	6.711	6.711
Valhall	3.206	0.818	4.024
Murchison	0.332	0.003	0.335
Heimdal	0.000	3.825	3.825
Ula	5.843	0.424	6.267
Oseberg	17.617	0.000	17.617
Gullfaks	17.512	0.936	18.448
Tommeliten	0.443	1.001	1.444
Veslefrikk	3.068	0.000	3.068
Gyda	2.754	0.416	3.170
Troll-Vest/Togi	0.133	0.000	0.133
Hod	1.301	0.202	1.503
Mime	0.139	0.037	0.176
Balder	0.117	0.000	0.117
Gamma Nord	0.091	0.000	0.091
Total 1991	93.123	25.231	118.354
Total 1990	81.368	26.018	107.386
Total 1989	74.280	29.364	103.644
Total 1988	56.001	29.023	85.024
Total 1987	49.016	28.797	77.813
Total 1986	42.052	26.561	68.613
Total 1985	38.479	26.276	64.755

Fig. 8.4.a
Oil and gas production on the Norwegian shelf 1971–1991

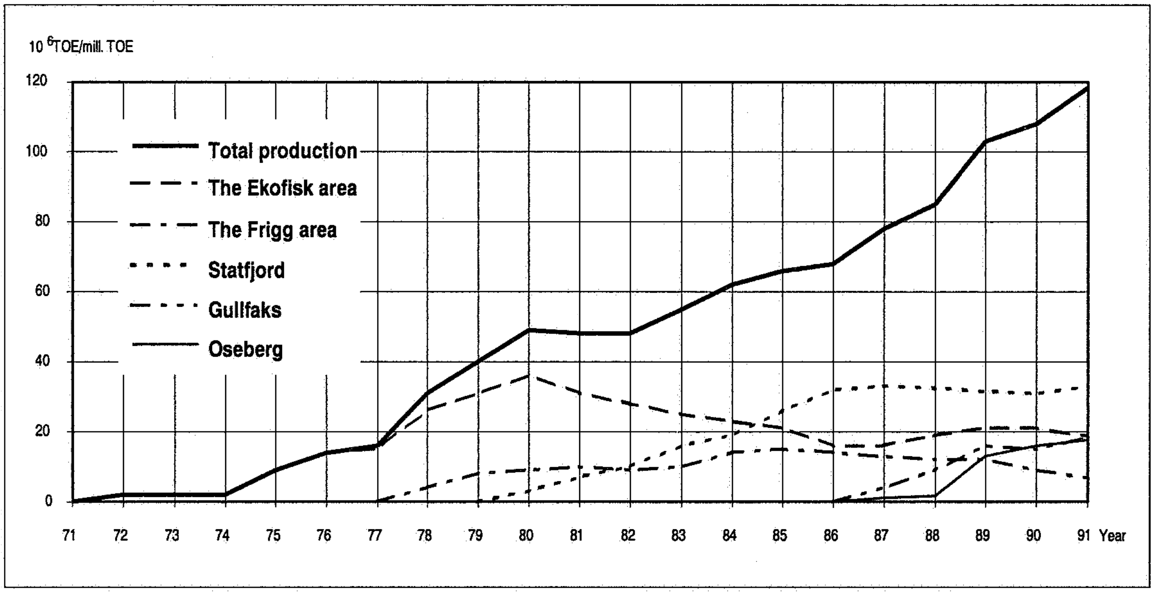


Fig. 8.4.b
Oil and gas production on the Norwegian shelf 1977–1991

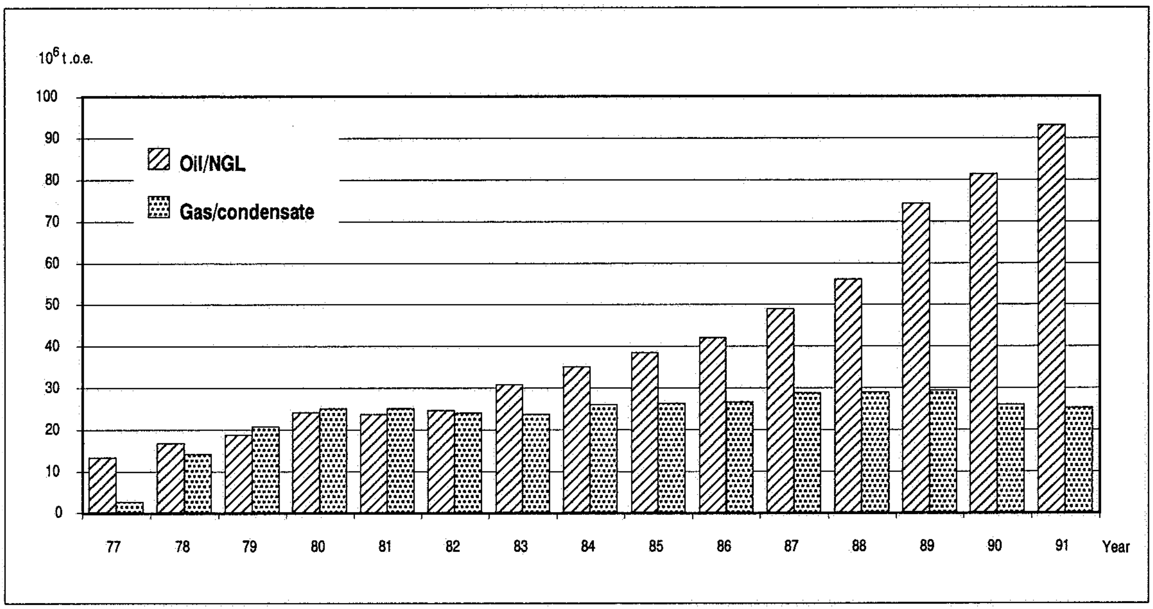


Table 8.4.b
Monthly oil and gas production from Valhall

1991	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Teesside	NGL Teesside	Gas Emden
	1000 Sm^3	Mill Sm^3	Mill Sm^3	Mill Sm^3	1000 Sm^3	1000 Sm^3	Mill Sm^3
JAN	362.	82.	.4	7.	340.	27.	72.
FEB	298.	70.	.6	6.	283.	20.	61.
MAR	328.	76.	.8	6.	310.	23.	66.
APR	348.	80.	.5	6.	329.	24.	70.
MAY	361.	80.	.3	6.	341.	24.	70.
JUN	341.	76.	.4	6.	325.	22.	66.
JUL	331.	75.	.7	5.	317.	20.	65.
AUG	142.	28.	1.4	2.	136.	6.	22.
SEP	364.	77.	.6	5.	346.	22.	68.
OCT	363.	78.	.4	5.	348.	22.	70.
NOV	338.	72.	1.8	5.	324.	20.	63.
DEC	360.	81.	2.1	5.	345.	20.	70.
YEAR TOTAL	3936.	876.	10.1	65.	3744.	249.	763.

Table 8.4.c
Monthly gas and condensate production from Frigg

1991	Gas prod	Condensate prod	Gas flared	Gas fuel	Gas St Fergus	Condensate St Fergus
	Mill Sm^3	1000 Sm^3	1000 Sm^3	Mill Sm^3	Mill Sm^3	1000 Sm^3
JAN	689.	2.	85.	7.	708.	3.
FEB	643.	2.	85.	6.	668.	5.
MAR	660.	2.	92.	6.	699.	4.
APR	656.	2.	147.	9.	685.	5.
MAY	719.	2.	133.	6.	659.	3.
JUN	497.	2.	151.	5.	476.	3.
JUL	404.	1.	2007.	7.	312.	3.
AUG	385.	1.	1041.	7.	311.	5.
SEP	388.	1.	78.	6.	404.	1.
OCT	531.	2.	73.	5.	544.	4.
NOV	599.	2.	48.	6.	600.	4.
DEC	620.	2.	64.	5.	658.	5.
YEAR TOTAL	6792.	21.	4004.	75.	6722.	45.

Figures are for the Norwegian share of Frigg, NØ-Frigg, Odin and Øst-Frigg 100%.

Table 8.4.d
Monthly oil and gas production from Gullfaks

1991	Stabilized oil prod	Gas prod	Gas flared	Gas fuel	Gas Emden	NGL/cond Kårstø
	1000 Sm^3	Mill Sm^3	Mill Sm^3	Mill Sm^3	Mill Sm^3	1000 Sm^3
JAN	1576.	166.	7.	19.	90.	10.
FEB	1417.	150.	4.	19.	82.	16.
MAR	1481.	154.	11.	21.	91.	14.
APR	1547.	158.	6.	21.	78.	16.
MAY	1774.	191.	5.	23.	80.	19.
JUN	1743.	190.	6.	21.	72.	22.
JUL	1799.	197.	6.	24.	72.	25.
AUG	1041.	105.	25.	14.	25.	4.
SEP	1850.	196.	5.	23.	71.	22.
OCT	1970.	210.	6.	24.	85.	28.
NOV	1797.	188.	5.	24.	86.	27.
DEC	1912.	196.	5.	25.	90.	34.
YEAR TOTAL	19907.	2101.	91.	258.	922.	237.

Table 8.4.e
Monthly gas and condensate production from Heimdal

1991	Gas prod	Condensate prod	Gas flared	Gas fuel	Gas sold Emden	Condensate Kinneil
	Mill Sm³	1000 Sm³	1000 Sm³	Mill Sm³	Mill Sm³	1000 Sm³
JAN	216.	34.	63.	4.	321.	27.
FEB	285.	46.	34.	5.	286.	31.
MAR	355.	57.	82.	5.	296.	60.
APR	296.	47.	53.	4.	303.	47.
MAY	338.	55.	11.	5.	291.	55.
JUN	274.	44.	4.	4.	260.	48.
JUL	292.	47.	38.	4.	288.	42.
AUG	70.	11.	189.	1.	96.	13.
SEP	250.	41.	21.	4.	411.	39.
OCT	306.	50.	8.	4.	252.	46.
NOV	294.	48.	60.	4.	307.	44.
DEC	299.	48.	23.	4.	323.	45.
YEAR TOTAL	3275.	528.	586.	48.	3434.	497.

Table 8.4.f
Monthly oil and gas production from Murchison

1991	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	47.	8.	1.2	2.3	45.	.0	.1
FEB	41.	6.	0.8	2.0	37.	.0	.2
MAR	36.	5.	1.1	0.6	35.	.2	.7
APR	0.	0.	0.0	0.0	2.	.0	.0
MAY	14.	2.	0.3	0.6	7.	.2	.2
JUN	40.	5.	1.2	0.4	41.	.3	1.3
JUL	2.	0.3	0.1	0.0	2.	.3	.2
AUG	15.	2.	0.1	1.1	13.	.0	.2
SEP	67.	8.	1.2	0.9	61.	.5	2.0
OCT	58.	7.	1.3	0.4	53.	.5	2.0
NOV	49.	6.	1.1	1.1	45.	.3	1.5
DEC	59.	7.	1.3	0.4	53.	.5	1.6
YEAR TOTAL	428.	56.3	9.7	9.8	394.	2.8	10.0

These figures are for the Norwegian share of Murchison.

Table 8.4.g
Monthly oil and gas production from Statfjord

1991	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	3094.	652.	6.	39.	284.	91.
FEB	2904.	597.	6.	35.	260.	140.
MAR	3168.	684.	9.	39.	287.	139.
APR	3027.	650.	9.	39.	243.	128.
MAY	3288.	721.	6.	41.	254.	119.
JUN	2392.	534.	6.	28.	231.	114.
JUL	2787.	593.	8.	35.	235.	105.
AUG	3138.	642.	5.	40.	75.	26.
SEP	3385.	676.	5.	38.	229.	111.
OCT	2378.	474.	4.	27.	272.	166.
NOV	2425.	472.	10.	27.	272.	155.
DEC	2872.	567.	9.	32.	286.	211.
YEAR TOTAL	34858.	7262.	84.	420.	2927.	1505.

These figures are for the Norwegian share of Statfjord.

Table 8.4.h
Monthly oil and gas production from Ula

1991	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Teesside	NGL Teesside	Gas sold Emden
	1000 Sm^3	Mill Sm^3	Mill Sm^3	Mill Sm^3	1000 Sm^3	1000 Sm^3	Mill Sm^3
JAN	581.	48.	.2	5.	553.	44.	37.
FEB	523.	43.	.3	5.	500.	38.	33.
MAR	597.	48.	.5	6.	567.	45.	36.
APR	593.	48.	.2	6.	562.	46.	36.
MAY	619.	50.	.4	6.	588.	47.	38.
JUN	577.	46.	.3	6.	552.	43.	34.
JUL	628.	49.	.4	6.	598.	46.	37.
AUG	284.	22.	3.1	3.	272.	15.	14.
SEP	666.	52.	.7	6.	632.	53.	39.
OCT	684.	54.	.4	6.	651.	52.	41.
NOV	665.	52.	.5	6.	634.	49.	39.
DEC	707.	54.	.5	6.	673.	52.	42.
YEAR TOTAL	7124.	566.	7.5	67.	6782.	530.	424.

Table 8.4.i
Monthly oil and gas production allocated to Ekofisk fields

1991	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Teesside	NGL Teesside	Gas Emden
	1000 Sm^3	Mill Sm^3	Mill Sm^3	Mill Sm^3	1000 Sm^3	1000 Sm^3	Mill Sm^3
JAN	1228.	946.	.7	80.	1075.	142.	778.
FEB	1090.	844.	1.7	95.	982.	124.	723.
MAR	1216.	942.	1.6	98.	1095.	139.	774.
APR	1177.	924.	.3	95.	1030.	141.	703.
MAY	1221.	965.	.6	103.	1097.	141.	735.
JUN	1209.	968.	.5	101.	1084.	144.	665.
JUL	1216.	1004.	1.5	101.	1046.	127.	687.
AUG	539.	402.	1.5	40.	497.	35.	257.
SEP	1245.	967.	1.4	102.	1148.	148.	597.
OCT	1259.	998.	2.6	104.	1121.	142.	782.
NOV	1185.	952.	.8	98.	1058.	133.	821.
DEC	1234.	977.	.6	104.	1101.	135.	835.
YEAR TOTAL	13819.	10889.	13.9	1121.	12334.	1554.	8357.

Table 8.4.j
Monthly oil and gas production from Tommeliten

1991	Unstabilized oil prod	Gas prod	Stabilized oil Teesside	NGL Teesside	Gas Emden
	1000 Sm^3	Mill Sm^3	1000 Sm^3	1000 Sm^3	Mill Sm^3
JAN	73.	119.	57.	14.	110.
FEB	60.	103.	46.	12.	95.
MAR	71.	124.	55.	15.	115.
APR	52.	95.	40.	11.	88.
MAY	54.	96.	42.	11.	88.
JUN	54.	93.	42.	11.	86.
JUL	36.	63.	28.	7.	59.
AUG	2.	4.	2.	0.	3.
SEP	31.	56.	23.	7.	52.
OCT	62.	115.	47.	13.	107.
NOV	53.	100.	40.	11.	93.
DEC	58.	112.	44.	12.	104.
YEAR TOTAL	606.	1080.	466.	124.	1001.

Table 8.4.k
Monthly oil and gas production from Oseberg

1991	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Sture
	1000 Sm³	Mill Sm³	Mill. Sm³	Mill. Sm³	1000 Sm³
JAN	1611.	223.	6.	10.	1609.
FEB	1398.	205.	4.	11.	1396.
MAR	1632.	228.	3.	11.	1632.
APR	1550.	209.	3.	9.	1550.
MAY	1637.	220.	4.	8.	1633.
JUN	1569.	211.	5.	10.	1566.
JUL	1586.	222.	1.	11.	1584.
AUG	1662.	235.	3.	9.	1656.
SEP	1916.	269.	20.	12.	1907.
OCT	2058.	297.	9.	11.	2051.
NOV	2048.	586.	3.	14.	2041.
DEC	2219.	325.	2.	17.	2209.
YEAR TOTAL	20886.	2930.	63.	133.	20834.

Table 8.4.l
Monthly oil and gas production from Veslefrikk

1991	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Sture	NGL/cond Kårstø
	1000 Sm³	Mill Sm³	Mill Sm³	Mill Sm³	1000 Sm³	1000 Sm³
JAN	313.	40.	4.	2.	313.	13.
FEB	290.	36.	1.	4.	293.	18.
MAR	310.	39.	3.	3.	312.	19.
APR	287.	36.	3.	3.	290.	18.
MAY	301.	38.	2.	3.	305.	19.
JUN	296.	37.	1.	3.	298.	19.
JUL	283.	36.	4.	3.	285.	17.
AUG	74.	9.	2.	1.	75.	3.
SEP	321.	40.	2.	3.	324.	20.
OCT	336.	43.	3.	4.	339.	23.
NOV	323.	42.	3.	3.	325.	20.
DEC	327.	42.	4.	3.	329.	30.
YEAR TOTAL	3461.	438.	32.	35.	3488.	219.

Table 8.4.m
Monthly oil and gas production from Gyda

1991	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	367.	56.	3.9	2.	341.	45.	40.
FEB	289.	44.	5.5	2.	268.	34.	31.
MAR	289.	45.	2.0	3.	269.	37.	33.
APR	300.	47.	.4	3.	279.	39.	35.
MAY	307.	48.	.6	3.	286.	40.	36.
JUN	251.	39.	.3	2.	235.	32.	28.
JUL	220.	32.	.5	2.	206.	26.	23.
AUG	123.	19.	2.4	1.	116.	13.	10.
SEP	276.	42.	.6	3.	258.	35.	32.
OCT	287.	43.	.2	3.	268.	36.	31.
NOV	316.	45.	.4	3.	296.	38.	34.
DEC	330.	48.	.4	3.	308.	41.	35.
YEAR TOTAL	3355.	508.	17.2	30.	3130.	416.	368.

Table 8.4.n
Monthly oil and gas test production on Troll Vest

1991	Stabilized oil prod	Gas prod	Gas flared	Gas fuel
	1000 Sm^3	Mill Sm^3	Mill Sm^3	Mill Sm^3
JAN	26.	2.	2.1	0.0
FEB	26.	2.	1.4	0.2
MAR	26.	2.	1.4	0.6
APR	25.	14.	12.1	1.4
MAY	25.	1.	0.8	0.0
JUN	.	.	.	.
JUL	.	.	.	.
AUG	.	.	.	.
SEP	.	.	.	.
OCT	.	.	.	.
NOV	.	.	.	.
DEC	.	.	.	.
YEAR TOTAL	128.	20.	17.8	2.2

Table 8.4.o
Monthly oil and gas production from Hod

1991	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	115.	15.	0.1	1.	110.	15.	6.
FEB	128.	15.	0.1	1.	121.	15.	8.
MAR	133.	16.	0.2	2.	126.	17.	8.
APR	131.	15.	0.1	1.	124.	16.	8.
MAY	130.	14.	0.1	1.	123.	15.	8.
JUN	135.	18.	0.1	1.	130.	18.	8.
JUL	143.	19.	0.2	1.	137.	19.	8.
AUG	67.	8.	0.4	1.	64.	8.	3.
SEP	156.	20.	0.2	1.	149.	20.	8.
OCT	166.	20.	0.1	2.	159.	21.	8.
NOV	157.	20.	0.6	2.	151.	21.	8.
DEC	136.	16.	0.5	1.	131.	16.	7.
YEAR TOTAL	1597.	196.	2.7	17.	1526.	202.	88.

Table 8.4.p
Monthly oil and gas test production on Mime

1991	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	17.	4.	16.	4.	1.
FEB	15.	3.	15.	3.	1.
MAR	17.	4.	16.	4.	1.
APR	16.	3.	15.	3.	1.
MAY	16.	3.	15.	3.	1.
JUN	15.	3.	14.	3.	1.
JUL	14.	3.	14.	3.	1.
AUG	5.	1.	5.	1.	0.
SEP	15.	3.	14.	3.	1.
OCT	14.	3.	14.	3.	1.
NOV	13.	3.	12.	3.	1.
DEC	13.	3.	12.	3.	1.
YEAR TOTAL	170.	36.	162.	36.	11.

Table 8.4.q
Monthly oil and gas test production on Balder

1991	Stabilized oil prod	Gas prod	Gas flared	Gas fuel
	1000 Sm³	Mill Sm³	Mill Sm³	Mill Sm³
JAN	.	.	.	.
FEB	.	.	.	.
MAR	.	.	.	.
APR	.	.	.	.
MAY	19.	1.0	0.5	0.5
JUN	27.	1.4	0.7	0.7
JUL	32.	1.6	0.7	0.9
AUG	21.	1.0	0.8	0.2
SEP	29.	1.4	0.7	0.7
OCT	.	.	.	.
NOV	.	.	.	.
DEC	.	.	.	.
YEAR TOTAL	128.	6.4	3.4	3.0

Table 8.4.r
Monthly oil and gas production from Gamma Nord

1991	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Sture
	1000 Sm³	Mill Sm³	Mill. Sm³	Mill. Sm³	1000 Sm³
JAN	.	.	.	.	.
FEB	.	.	.	.	.
MAR	.	.	.	.	.
APR	.	.	.	.	.
MAY	.	.	.	.	.
JUN	.	.	.	.	.
JUL	.	.	.	.	.
AUG	.	.	.	.	.
SEP	.	.	.	.	.
OCT	25.	2.9	0.1	0.01	25.
NOV	41.	5.0	0.2	0.25	40.
DEC	44.	8.8	0.1	0.02	42.
YEAR TOTAL	110.	16.7	0.4	0.28	107.

Table 8.4.s
Monthly oil and gas production from TOGI

1991	Gas prod	Condensate prod	Gas flared	Gas fuel	Stabilized oil Sture
	Mill. Sm³	1000 Sm³	Mill. Sm³	Mill. Sm³	1000 Sm³
JAN	29.	1.	0.1	0.0	0.
FEB	136.	3.	0.2	0.8	0.
MAR	213.	5.	0.1	3.0	0.
APR	267.	5.	0.1	3.5	0.
MAY	274.	6.	0.0	4.0	0.
JUN	294.	6.	0.0	4.2	0.
JUL	172.	4.	0.8	2.4	0.
AUG	155.	3.	0.5	2.1	3.
SEP	254.	5.	1.5	3.7	4.
OCT	130.	3.	0.1	1.5	2.
NOV	357.	6.	0.0	4.7	6.
DEC	365.	7.	0.0	4.7	6.
YEAR TOTAL	2646.	53.	3.4	34.6	21.

8.5 NPD PUBLICATIONS IN 1991

Acts, regulations and guidelines

- *Acts, Regulations and Provisions* for the Petroleum Activity 1991. A compendium of the laws etc applying to the offshore industry issued each year and up to date on 1 January 1991 (Norw and Engl)
- *Working Environment Act* of 4 February 1977, as last amended 21 December 1990
- Regulations for *Collection of Fees* for Regulatory Supervision of the Petroleum Activities
- Regulations for a *Fishery Expert* to be Carried by Seismic Exploration Vessels on the Norwegian Continental Shelf
- Regulations for *Electrical Installations* in the Petroleum Activities
- Regulations for *Fiscal Metering* of Oil and Gas in the Petroleum Activities
- Regulations for *Evaluation of Breathing Apparatus* for use in Manned Subsea Operations in the Petroleum Activities

Studies and reports

- *Vurderinger av kriterier for bruk av oljebasert boreslam*
  Evaluation of Criteria for Use of Oil-Based Drilling Mud (Norw)

Other publications

- NPD Contribution no. 28
  En biostratigrafisk analyse av sedimenter over og under basal pleistocen, regionale vinkeldiskordans i nordøstlige deler av Nordsjøen
  A biostratigraphic analysis of sediments above and below the Basal Pleistocene, regional angle discordance in north-eastern parts of the North Sea (Norw)
- NPD Contribution no. 29
  En biostratigrafisk analyse av tertiære sedimenter på kontinentalmarginen av Midt-Norge, med hovedvekt på øvre pliocen vifteavsetninger
  A biostratigraphic analysis of Tertiary sediments on the continental margin of Mid-Norway, concentrating on Upper Pliocene fan sediments (Norw)
- NPD Contribution no. 30
  Behov for geologer og geofysikere i Norge
  Demand for geologists and geophysicists in Norway (Norw)
- NPD Contribution no. 31
  Oljedirektoratets ressursklassifikasjonssystem
  NPD's resource classification system (Norw)
- *Oljedirektoratets årsberetning 1990* (Norw)
- *NPD Annual Report 1990* (Engl)
- *Licences, Areas, Area Coordinates, Exploration Wells* (Engl)
- *Borehole List* (Engl)
- *Opprydding av havbunnen i Nordsjøen 1990*
  North Sea seabed clearance 1990 (Norw)
- *The Role of Petroleum in Sustainable Development*, Petrad publication no. 1 (Engl)
- *Management of Petroleum Operations*, Petrad publication no. 2, vol I and II (Engl)
- *Petroleum Policy and Management*, Petrad publication no. 3, vol I and II (Engl)
- *Petroleum Management and Administration*, Petrad publication no. 4 (Engl)
- SPOR Monograph: *Recent Advances in Improved Oil Recovery* (Engl)
- *Methods for North Sea Sandstone Reservoirs* (Engl)
- *Kart over den norske kontinentalsokkel*
  Map of the Norwegian continental shelf (Norw).

8.6 ORGANISATION CHART