Annual Report 1981

Unofficial translation

Oljedirektoratet

911

ISBN 82-7257-093-9

Annual Report 1981

Unofficial translation

Oljedirektoratet

May 1982

CONTENTS

F O R E W O R D

In accordance with § 4 (f) of the instructions to the Norwegian Petroleum Directorate, the Board of Directors shall prepare a report on the Directorate´s activities. The Board of Directors hereby presents the Annual Report for 1981.

Stavanger, 24 February 1982

Martin Buvik

Andreas Lønning Bjørg Simonsen Liv Hatland

Kåre D Nielsen Ole Knapp

Øystein Kristiansen Inge Døskeland

Fredrik Hagemann Bjørn Bratbak

Report by the Board of Directors

This year´s petroleum finds on Tromsøflaket and Haltenbanken must be viewed as a milestone in the development of activities on the shelf.

In both areas gas was demonstrated with indications that oil has been formed in the lower parts of the basins. Even though it has not been possible to demonstrate commercial amounts of petroleum so far, the results have nevertheless strengthened the hope that such finds may be made. At the same time, results of drillings in the North Sea during the report period have confirmed last year´s increase in proven reserves. This year´s drilling results have also increased confidence in the validity of the Directorate´s earlier evaluation of the total expected reserves in the North Sea area. However, it is still too early to take possible reserves in the Haltenbanken and Troms into account in our overall estimates.

The increases in the reserves, the varied types of prospects proven and the spread through differing geological areas will without doubt provide the Norwegian Petroleum Directorate with new challenges. Moreover, the new areas will increase the work load of the Directorate.

Depending on the finds made and the commercial basis of possible development in Northern areas, it may be necessary to perform demanding tasks of review and planning to adjust these activities to an overall national strategy for activities on the shelf. This raises anew crucial questions, both as regards the total activity level it is wished to maintain during the various phases of petroleum activity, and its division between the various geographical areas. We are probably now faced with a situation where the question of evenness in the activity should be viewed both from a regional and a national angle.

The finds on Haltenbanken and Tromsøflaket have also provided valuable information of significance for the evaluation of neighbouring geological areas.

The results are assessed continually with a view to future development when this comes to be considered necessary as a step in an overall strategy. The Norwegian Petroleum Directorate´s seismic surveying scheduled for 1982 takes account of possible development of the areas opened up.

The Board has emphasized in its previous reports the importance of further efforts to increase the recovery factor of reserves on the shelf. The Directorate´s work to find new methods to increase the recovery from existing and planned fields during the report period has particularly included water injection in the Ekofisk area, gas injection at Valhall and increased recovery from new fields. The pilot project for water injection mentioned by the Board in last year´s report was started in the spring of 1981 and has so far shown positive results. The decision whether to undertake full scale water injection will be made in the summer of 1982.

The Board wishes to emphasize the strong connection between the level of activities on the shelf and the growth of the Norwegian Petroleum Directorate's requirements for qualified personnel and aids for carrying out its tasks. Within the field of safety inspection, tasks have increased significantly in 1981 at the same time as the staffing situation has been difficult. Because of this, the Norwegian Petroleum Directorate has not been in a position to carry out its control program as planned. The Board has on several occasions dealt with and expressed concern at the Directorate's difficult staffing and budget situation. The chairman of the Board therefore, in a special meeting with the heads of the Ministry of Petroleum and Energy and the Ministry of Local Government and Labour, took up questions related to the Norwegian Petroleum Directorate's working situation. This led among other things to the government setting up a special committee to evaluate wage conditions at the Directorate, at the same time as funds were made available for increased further education in 1981. Retirement from the Directorate in 1981 has been somewhat less that in 1980, but has affected specialist personnel to a greater extent, particularly in the Department for Safety Inspection. Among other things, this has led to it being necessary to make temporary arrangements to maintain sufficient capacity, i.a. in the Drilling Section.

The supply of qualified specialists in the Norwegian Petroleum Directorate may constitute a capacity limitation for activities. Experience shows that the Directorate's opportunities for controlling the oil companies decrease even before the companies themselves experience their most acute capacity problems.

When a level of activities is planned which will bring great pressure to bear on the labour market, responsible control depends for one thing upon the Norwegian Petroleum Directorate having framework conditions which enable it to retain and engage sufficient qualified specialists in the increasingly competitive climate. This is a highly critical point if the Directorate is to have any possibility of carrying out the tasks assigned to it.

The huge development tasks on the continental shelf with their corresponding investments in the petroleum sector indicate that the work of consolidating petroeconomic expertise in the Norwegian Petroleum Directorate must be carried further.

On the basis of our national objectives, assessment of the economic consequences of petroleum activities is crucial in the years to come. During the report period the Directorate has continued the work of establishing models and tools for use within its professional area. However, there still remains important development work, including the establishment of a cost data bank for use in cost assessment and for following up specific development projects.

In 1981 approx. NOK 5,300 million was paid in royalty, while the corresponding figure for 1973 was approx. NOK 16 million.

Not only magnitude but also complexity has made it necessary for the activities of the Directorate in this field to be strengthened. At the proposal of the Board, approval was obtained in the report period for the establishment from 1 January 1981 of a Section for Tax Calculation. This section is to supervise the estimation and collection of royalty and acreage fees, amongst other things.

At the end of 1981 the Norwegian Petroleum Directorate finalised its two research programs in the fields of safety and preparedness. Development, execution and finalisation of the programs has taken place within the framework of the original four year plan. In addition to the results of the individual projects, the Directorate notes the positive advantages of the basis which has been built up in research circles for further creative efforts within safety and preparedness. In addition to the research results, the activity has also involved development of expertise, which is available to the industry and the community at large.

In the report period the Ministry of Local Government and Labour sent out for comments a draft of revised regulations on safety in exploration for and production of petroleum reserves. The draft represents a simplification and adjustment of the present regulations. The Ministry has set up a working group in which the Norwegian Petroleum Directorate is represented to evaluate present control arrangements and make recommendations on future systems of control on the Norwegian continental shelf. The Board is particularly interested in this work as the new regulations and the control system to be set up will determine the future scope of the Directorate´s safety work.

The Norwegian Petroleum Directorate´s accident statistics show that accidents involving personal injury occur particularly in drilling and construction work. During the period the Directorate has set forth new drilling regulations which contain requirements as to the mechanisation of work on the drill floor. As regards construction activities, the Directorate has been concerned in the report period to define the problem areas with a view to implementing measures which can reduce the number of personal injuries.

Also in 1981, there occurred labour conflicts on the shelf which led to reduction in production and some changes in the scheduled drilling programs. Production in the period fell by about 1 million tons oil equivalent to a gross production value of approx. NOK 1.3 billion.

The coming years will be characterized by extensive development on the Norwegian shelf. This will be of great significance for the Norwegian economy and will have obvious effects for the whole Norwegian community. Therefore it will be necessary to make stringent requirements as regards planning on the part of the authorities. A proper dimensioning of development rate will require insight and an understanding of the consequences which different paths of development may give rise to.

Future development will make requirements of our understanding of the connection between the resource, economic, employment and social consequences of the various measures and alternative development strategies.

The Norwegian Petroleum Directorate, within its area of responsibility, must seek to meet these challenges.

The Board has found that it is time the information activities of the Directorate were reinforced and will recommend the establishment of a separate information manager position.

The Board has noted with satisfaction that the Government in its inaugural declaration expressed the need to strengthen the position of the Directorate, and that this view has received the full support of the Storting.

1. THE DIRECTORATE'S TASKS, BOARD OF DIRECTORS AND MANAGEMENT

1.1. Instructions to the Norwegian Petroleum Directorate

The objectives and tasks of the Norwegian Petroleum Directorate are provided in special instructions. These were most recently amended by resolution of the Ministry of Petroleum and Energy on 29 March 1979. The instructions' § 1 relating to the objectives and § 2 relating to the tasks are worded as follows:

§ 1 Objectives

The Norwegian Petroleum Directorate is located in Stavanger and reports to the Royal Norwegian Ministry of Petroleum and Energy. In matters relating to working environment, safety and emergency preparedness, it reports to the Royal Norwegian Ministry of Labour and Municipal Affairs. The Norwegian Petroleum Directorate is authorised to determine matters relating to exploration for and exploitation of petroleum resources on the sea floor and its substrata, to the extent that the matter is not determined by the King, relevant Ministry or other public authority. The Norwegian Petroleum Directorate exercises this authority in inner Norwegian waters, Norwegian sea territory, on that part of the continental shelf which is subject to Norwegian sovereignty, and in other areas where Norwegian jurisdiction follows from agreements with foreign states or from international law in general. In addition, the Norwegian Petroleum Directorate shall enforce safety regulations, etc., in the areas defined by Article 1 of the Svalbard Treaty of 9 February 1920 and Section 1 of the Svalbard Act of 27 July 1925, and in the territorial waters of these areas.

§ 2 Tasks

The tasks of the Norwegian Petroleum Directorate within its area of authority are:

a) To undertake regulatory and economic control to ensure compliance with applicable legislation, regulations, decisions, concession terms, agreements, etc. in the exploration for and exploitation of petroleum, cf. § 1
b) To ensure that applicable safety regulations are complied with.
c) To ensure that the exploration for and exploitation of petroleum resources does not lead to unnecessary damage or cause inconvenience to other activities.
d) To ensure that the exploration for and exploitation of petroleum resources at all times takes place in compliance with the guidelines stipulated by the relevant Ministry.
e) To collect and process geological, geophysical and technical material relating to subsea natural resources, including their evaluation and the possibilities thereby provided for the formulation of national petroleum policy and negotiation plans, as well as to plan and have executed geological and geophysical petroleum surveys.

f) To undertake current financial controls of exploration for and exploitation of petroleum resources.
g) To issue exploration licences and assist the relevant Ministry, upon request, in the processing of applications for other licences, the formulation of regulations, etc.
h) To maintain links with scientific institutions and ensure that material is made available to interested companies, scientific institutions, etc., to the extent that this is possible in view of the rules which apply concerning confidential treatment of material submitted by licencees and in general pursuant to the decision of the relevant Ministry.
i) To keep the Ministries informed at all times about the activities given in § 1, and to present the issues dealt with by the Directorate which do not come under § 2 a-h, to the Ministry in question.
j) To prepare and present for decision to the relevant Ministry matters of importance to plant and animal life or matters which may otherwise affect important environmental preservation interests in the areas mentioned in § 1, final sentence.
k) To present to the relevant Ministry regulations and individual decisions made concerning proper and sound exploitation of petroleum resources (conservation).
l) To act as advisory body to the Ministries in matters relating to exploration for and exploitation of subsea natural resources.

Even if a matter is subject to the authority of the Directorate pursuant to § 2 a-h, it shall be presented to the appropriate Ministry if it is of special importance or of interest in principle.

1.2.1. The Board of Directors

At the start of the report period, the Board consisted of:

1 Martin Buvik, County Governor, TromsØ
2 Andreas LØnning, Director, Oslo
3 BjØrg Simonsen, Mayor, Mo i Rana
4 Liv Hatland, Municipal Director, Trondheim
5 Kåre D. Nielsen, Director, Oslo
6 Ole Knapp, Secretary, Oslo
7 Hallvard Tunheim, Senior Engineer, Stavanger
8 Inge DØskeland, Section Manager, Stavanger

Deputies:

For 1-4	Olav Marås, Farmer, SæbØvåg
	Ragna B JØrgensen, Consumer Advisor, BodØ
	Marit Greve, Editor, Oslo
For 5	Odd Henrik Robberstad, Director
For 6	BjØrn Kolby, Attorney-at-Law
For 7-8	Kåre A TjØnneland, section Manager
	Aase Moe, Department Engineer

The term of this Board of Directors ended 1 April 1981 and a new Board of Directors was appointed by Crown Prince Regent´s Decree of 27 March 1981.

The new Board consisted of:

1 Martin Buvik, County Governor, Tromsø (Chairmann)
2 Andreas Lønning, Director, Oslo
3 Bjørg Simonsen, Mayor, Mo i Rana
4 Liv Hatland, Municipal Director, Trondheim
5 Kåre D. Nielsen, Director, Oslo
6 Ole Knapp, Secretary, Oslo
7 Øystein Kristiansen, Chief Consultant, Stavanger
8 Inge Døskeland, Section Manager, Stavanger

Deputies:

For 1-4	Olav Marås, Farmer, Sæbøvåg
	Astrid Nistad, Executive Committee Secretary
	Marit Greve, Editor, Oslo
For 5	Odd Henrik Robberstad, Director
For 6	Bjørn Kolby, Attorney-at-Law
For 7-8	Aase Moe, Department Engineer, Stavanger
	Kristen Karlsen, Section Manager, Stavanger

The Board has held ten meetings in the period covered by the report. At the invitation of the Sør-Trøndelag County Municipality and the Municipality of Trondheim, the Board held a meeting in Trondheim, including a visit and inspection to the County Council and the Otter Group.

In connection with the Board meeting in Tromsø in August, the Board made a tour of inspection to the drilling rig "Treasure Seeker" which was then drilling for Norsk Hydro at 7120/12-2.

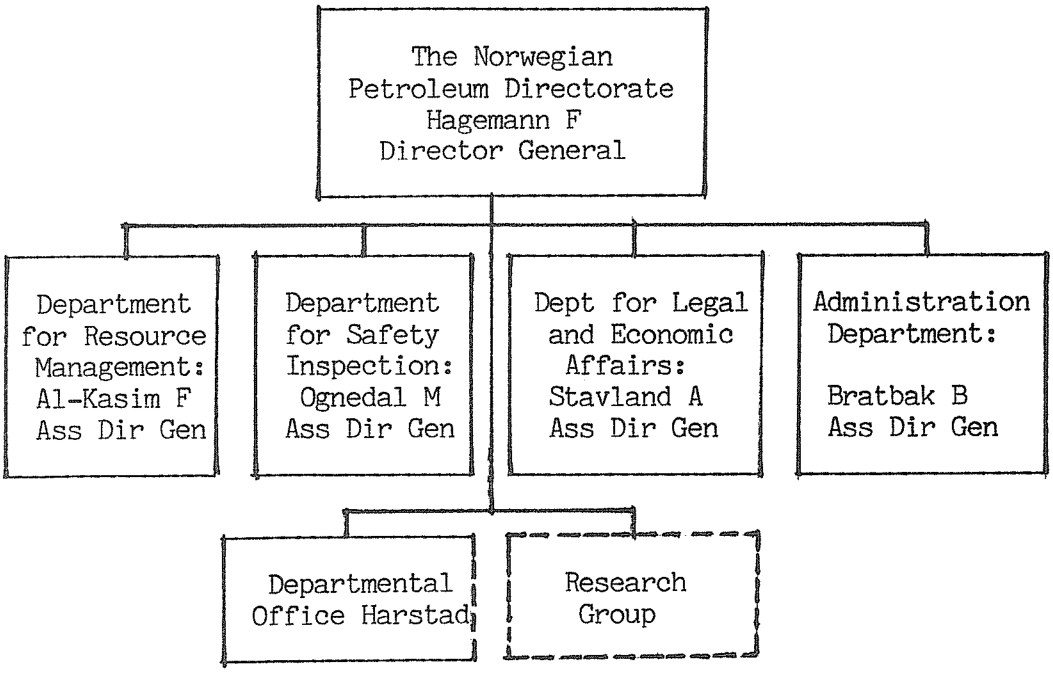
1.2.2. The Organization

No organizational changes were made in the period covered by the report.

Scaling down of the temporarily established research group continued in 1981. The group was dissolved at the end of the report period.

At its meeting in November, the Board dealt with the Directorate´s information activities, among other things, and found that now was the time to strengthen the information section, by i.a. establishing a new position as information manager. The proposal for the position will be included in the budget for 1983.

FIGURE 1 Organizational Table



1.2.3. **Personnel**

In the budget for 1981, eight new positions were established. With these, the Directorate will have 235 permanent positions. In addition there are 48 contract positions, of which one is salaried by the Norwegian Directorate for Development Aid (NORAD). Nine positions have been made available to persons who are paid through the budgets of other agencies, either persons with vocational limitations or unemployed young persons. Two retired state employees are working on retirement terms, and three scholarship holders from Tanzania have for parts of the year been in training at the Directorate on NORAD scholarships.

There were 265 employees in service at the end of the period covered by the report and 39 persons have terminated their employment in the period, cf. Table 1. This constitutes approx. 14 % of the total number of positions, as opposed to approx. 17 % in 1980. Table 2 shows the retirements by department and position category.

Table 1.2.3.a indicates that approx. 70 % of those who terminated their employment in 1981 have moved to the oil industry. Of the total number of persons who have resigned since 1973, approx. 55 % have gone to the oil industry.

While most persons who leave the Directorate go to the oil industry, only very few move in the opposite direction - in 1981 there were only two new employees.

Approx. 70 % of the new employees in the period covered by the report come from the Stavanger region, while 8 % are foreigners. About 30 % of the new employees are women, while only 16 % of those who terminated their employment were women. At the end of the period covered by the report, approx. 29 % of the employees were women.

By the second quarter of the report period, the Department for Safety Inspection had experienced as many terminations as the total number of resignations received in for 1980, and these terminations were particularly noticeable in the Drilling Section. The Board has considered the personnel situation at several meetings, and the Chairman of the Board raised the matter of the difficult staffing situation at a separate meeting with the Ministry of Petroleum and Energy and the Ministry of Labour and Municipal Affairs in June.

Following negotiations between the civil servant unions and the Ministry of Petroleum and Energy, the Ministry of Consumer Affairs and Government Administration, special standardization and adjustment measures were implemented for employees of the Norwegian Petroleum Directorate at the end of 1980. These measures have not had the expected effect on the personnel situation in the Directorate in 1981.

Working conditions in the Norwegian Petroleum Directorate have therefore received considerable attention within the Directorate. The Government has also appointed a public servant committee to evaluate, among other things, the personnel situation at the Directorate. No clarification with regard to necessary measures was presented by the end of the report period.

The agreement concerning compensation to those of the Directorate employees who receive assignments on the continental shelf has been improved during the period.

The question of reorganizating temporary positions into permanent ones has long been an important issue in the Directorate. The matter now seems to have been solved in that the Storting has adopted the 1982 budget and thereby approved the alteration of 37 contract positions into permanent positions.

The Directorate was given authority by the Ministry of Consumer Affairs and Government Administration on 18 February to decide matters relating to resettlement compensation for new employees. This has already had a positive effect on recruitment.

During the period covered by the report, separate guidelines were prepared for the allocation of houses and loans, and a separate housing and loans committee has been established. The committee consists of three representatives of the management and three employee representatives. During the period it has allocated 17 housing units and recommended 32 loans.

Codetermination

The General Tariff Agreement for State Employees, Part 2, Codetermination, deals with the rights and duties of employees in connection with codetermination at the work place.

On 23 December 1980, a "Special Agreement on Extended Codetermination in the Norwegian Petroleum Directorate" was entered into as a supplement to the General Tariff. During the period covered by the report, 20 meetings were held with the elected representatives in connection with this. Issues such as the staffing situation, budget proposals, training funds, etc., were discussed.

The Working Environment Committee

In 1981, the Working Environment Committee held three meetings dealing with such questions as safety training, offshore survival suits, office facilities, etc.

On 28 April 1981 new members and deputies were appointed:

- Chief Safety Delegate: Arne B. Wermundsen, Senior Secretary
- Safety Delegate for Inspectors: Tom Terjesen, Senior Engineer.

Table 1.2.3.a

Personnel who left the Norwegian Petroleum Directorate in 1981 with indication of new place of work.

Department	Oil industry	Other private activities	Other public activities	Sundry	Education	TOTAL
Resource Management	6	1	0	1	0	8
Safety Inspection	17	0	1	0	0	18
Legal/Economic	1	0	0	0	0	1
Administration	4	1	2	3	2	12
TOTAL	28 (104)	2 (26)	3 (33)	4 (27)	2 (12)	39 (193)

The numbers in parenthesis refer to the period 1973-81.

TABLE 1.2.3.b

Personnel who left the Norwegian Petroleum Directorate in 1981 with indication of type of position.

Department	Superv.	Chief eng.	Head eng.	Geol.	Div. eng.		Lab. pers.	Office pers.	TOTAL
Resource Management	0	0	2	2	2	-	2	-	8
Safety Inspection	4	2	10	-	2	-	0	-	18
Legal/Economic	0	-	0	-	1	0	-	-	1
Administr.	1	-	0	-	0	2	-	9	12
TOTAL	5	2	12	2	5	2	2	9	39

1.2.4. Training

The Petroleum Directorate wishes to give the individual employee the opportunity of further education to improve vocational skills and for personal development.

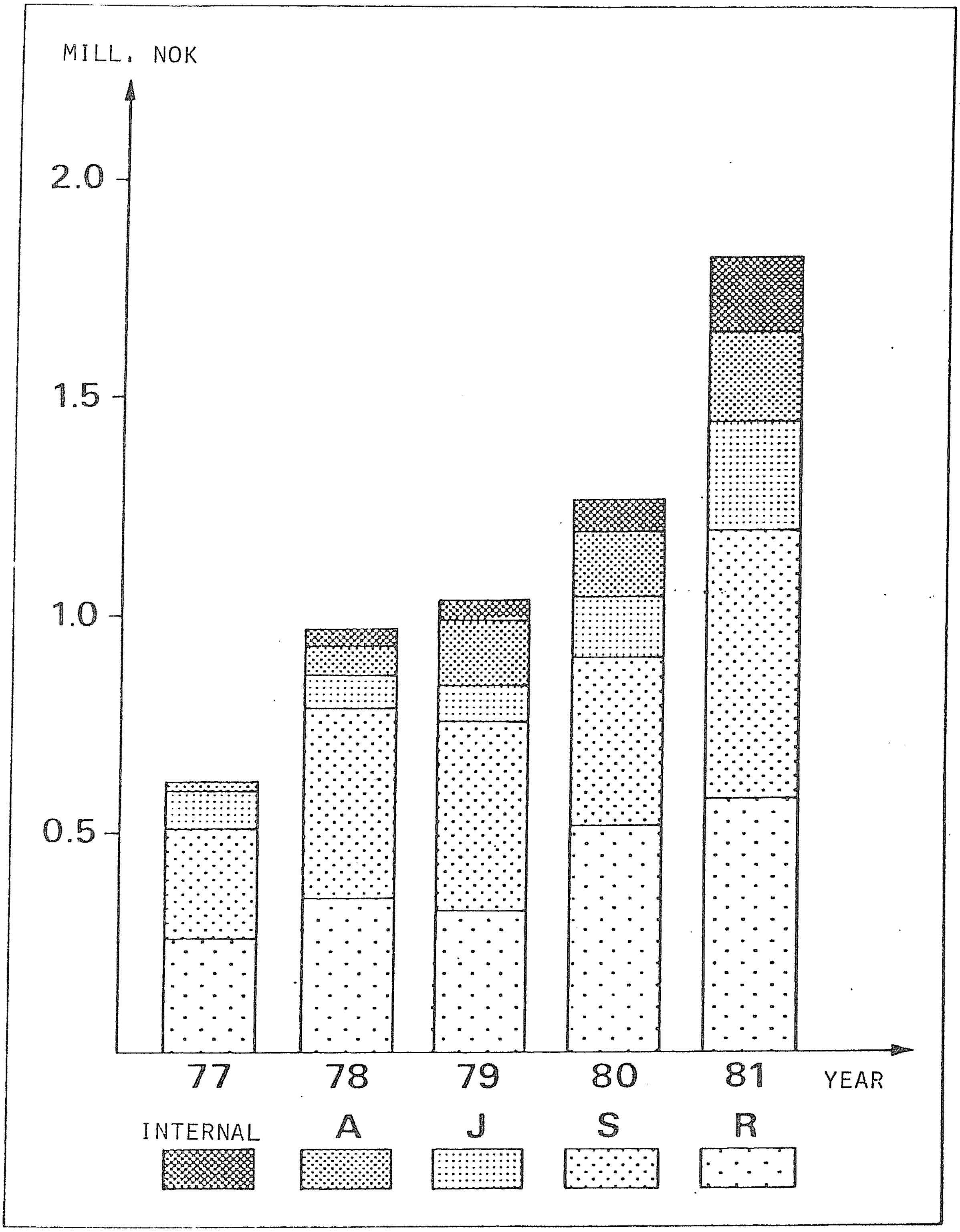
Due to the increased demand, approval was given in late summer for the Directorate to utilize up to an additional NOK 1 million of unassigned salary funds for training programs. The sum for training programs in 1981 therefore amounted to NOK 2.2 million. Figure 1.2.4 shows the development and distribution of the training budget for 1977-1981.

The number of course days per employee increased in 1981. The trend towards greater numbers of courses at home in Norway rather than abroad is also positive. This results particularly from the fact that the oil companies held more of their courses in Stavanger than previously.

Approximately 75 % of the total number of oil company course days occured Stavanger. Of the total number of courses within the country, 67 % were held in Stavanger.

By agreement with the oil companies, four personnel members have completed on-the-job training programs lasting from two to six months.

As in previous years, for courses in administrative subjects the program offered by the Ministry of Consumer Affairs and Government Administration was followed. Two of these courses have been arranged internally.


MILL. NOK
2.0
1.5
1.0
0.5
77
78
79
80
81
YEAR
INTERNAL
A
J
S
R

1.2.5. Budget/Economy

In 1981, a total of NOK 123,489,000.- was allocated to the various Directorate tasks. The amount was distributed as follows:

- Ordinary budget	NOK	80,809,000.-
- Geological and geophysical surveys, etc.	NOK	35,000,000.-
- Safety and emergency preparedness research	NOK	7,680,000.-
	NOK	123,489,000.-

NOK 25 million from the ordinary budget goes to inspection costs. These costs have been wholly refunded by the licensees. Furthermore, NOK 33,769,000.- goes to salaries, NOK 6,200,000.- to the operation of buildings, and NOK 2,000,000.- to project costs for new buildings. The remaining portion of the budget, NOK 13,840,000.-, represents the Directorate´s budget for conducting normal business.

The budget situation confronts the Norwegian Petroleum Directorate with great challenges regarding priorities. Much emphasis is put on the continuing development of improved planning and control systems as a means of assigning the proper priorities to the large number of resource-intensive measures.

Income

In addition to royalties and acreage fees paid (Ch. 7), the Directorate received NOK 40,594,000 in income.

For 1981, the income was made up as follows (NOK thousands):

Account no:	4801 01 00	Exploration fees	NOK	480
	4801 03 00	Refunds of inspection costs	NOK	26,066
	4801 05 00	Incoming fees from test material released	NOK	606
	4801 06 00	Sale of publications	NOK	480
	4840 01 00	Sale of seismic data	NOK	12,947
	5309 29 00	Sundry income	NOK	15
			NOK	40,594

TABLE 1.2.5

Income development in the period 1973-81

	1973	1974	1975	1976	1977	1978	1979	1980	1981	TOTAL
Sale of publications	-	-	-	30	135	197	291	387	480	1 520
Sale of released samples	-	-	-	2	33	46	282	235	606	1 204
Survey fee	345	340	220	210	280	380	420	400	480	3 075
Insp. expenses	5 525	16 539	19 721	26 717	42 037	45 189	47 358	33 673	26 066	262 825
Sale of data packs.	-	-	-	1 300	3 170	14 847	31 275	35 304	12 947	98 843
Subletting halls	-	288	463	375	76	71	-	-	-	1 273
TOTAL	5 860	17 177	20 404	28 634	45 731	60 730	79 626	69 999	40 579	368 740
NDP's total budget	28 067	45 380	61 101	79 855	101 160	114 730	123 565	125 949	123 489	

1.2.6. Information

Also in this report period, there has been a brisk demand for information from both Norwegian and foreign public institutions, mass media, companies and persons. The Norwegian Petroleum Directorate was visited in the course of the year by a number of official delegations from other countries. Moreover, many foreign journalists have visited the Directorate, individually or in groups, to obtain information about the Directorate and the oil industry.

The annual report of the Norwegian Petroleum Directorate holds a central position in its information activities. The annual report for 1980 was available in March. In conjunction with this, representatives of the press were invited to the Norwegian Petroleum Directorate to meet the Directorate management, who made themselves were available for additional comment on the report.

In collaboration with the Maritime Directorate, the Norwegian Petroleum Directorate participated in the "NORSHIPPING" exhibition held in Oslo in May.

The number of press releases issued in 1981 shows a continued increase in relation to previous years. The increase reflects the growth in activity. In the course of the year, 63 press releases were issued. Among these can be mentioned a monthly activity report which is also available in English.

1.2.7. The Office in Northern Norway

The regional office of the Norwegian Petroleum Directorate in Harstad has been in operation since 20 June 1980. Since its establishment, the staff has consisted of a local representative and a part-time office clerk.

The service district of the office is the three northernmost counties.

Within the Norwegian Petroleum Directorate´s field of work, the regional office has been the Directorate´s link with regional and local authorities and industry in Northern Norway. Furthermore, the office has maintained contact with the press and broadcasting, and assisted the mass media by making information available. The regional office has also distributed information in that part of the country by lecturing, taking part in meetings, etc.

Contact with fisheries organizations is an important aspect of the office´s area of work. Two contact conferences between the oil and fishing industries in Central Norway and Northern Norway have been held. These inititiatives resulted in the establishment of a contact body between the operating companies in the north and the three northern fishery cooperatives, i.e. between the users of Tromsøflaket.

The office acts also a service body for main office employees on service assignments in Northern Norway. A current evaluation of a possible extension of the office´s area of work is being made in conjunction with possible major surveys in Northern Norway.

1.2.8. Library

In the course of the year, the entire library catalogue apparatus (ODIN) was computerized. This implies that the library staff is able to offer a far more efficient service than previously from its own collection, which now includes 6,000 volumes.

The use of the library by employees and other interested parties remains considerable. One third of all enquiries come from external users. These include Norwegian libraries, oil companies, other companies in the petroleum industry and private persons. Information on petroleum documentation, the library´s computer based catalogue and library services has been distributed to several local oil companies and other companies and institutions.

1.2.9. The INFOIL secretariat

The Norwegian Petroleum Directorate has also been responsible in 1981 for the issue of the reference publication Olje-indeks (Norwegian version), Oil-index (English version) and the associated data base OIL on the Nordic Scannet data network. A total of approx. 160 copies of the indexes is distributed. In 1981, the data base was used for more than 40 hours by clients in the Nordic countries.

The INFOIL II project, initiated by the Directorate in 1980, includes the development of a publicly available data base on Scannet concerning current research projects in petroleum subjects in Great Britain and Norway. In 1981, INFOIL II was established as an online service. So far, all projects of the Norwegian Petroleum Directorate have been included in the data base. The British Department of Energy, the Continental Shelf Committee of the Norwegian Research Council of Technology and Natural Science, the Secretariat for Safety on the Shelf and the Norwegian Petroleum Directorate are collaborating in this joint British-Norwegian task. The Norwegian Center for Informatics serves as the operating center of the service.

A new initiative towards joint Norwegian financing of the American Petroleum Institute literature service has been taken, but as yet without success. The API service is considered a very central source of information for the Norwegian oil industry, and the work of funding a link-up with it will continue.

1.2.10. Rationalization and effectivization

Computer equipment

At the end of the previous period, the Norwegian Petroleum Directorate was installing a major computer system of the NORD-100 type. This system is now in operation and is linked up with approx. 20 terminals, graphics displays and drawing equipment.

In addition, a separate NORD-100 system was installed in the period to be used for storage and processing of geological information in connection with a major computer project (ILGI) developed for the Norwegian Petroleum Directorate by Rogaland Research.

At the end of the period, negotiations are under way to acquire a bigger NORD-500 system for major calculations within reservoir simulation and seismic processing, and a NORD-100 system for measures to improve the efficiency of controlling eligibility for drilling licences, qualifications of diving personnel, processing of data pertaining to causes of work accidents and the study of risk-related operations in order to facilitate rapid implementation of counter-measures.

Computer personnel

In the course of 1980 and 1981, a separate group was set up in the Administration Department whose main responsibility is to operate of the Directorate´s computer equipment

Use of computers in the Administration Department

The Administration Department of the Norwegian Petroleum Directorate has previously employed a number of small computer systems to improve the efficiency of accounting, personnel handling and literature retrieval (library), amongst other tasks.

Experience with the facilities has shown that it is possible to achieve considerable savings with regard to greater availability, wider horizons and simpler processing routines.

In 1981, the Directorate extended this activity and employed computers for major and extensive office and management tasks.

Filing system

The Rationalization Directorate´s EKSARD filing system was introduced into the Directorate as a test project in 1981.

The object is computer storage of details of all post and information.

The system automatically generates remainder lists and surveys case progress.

The filing staff are now able to search for case details and documents more quickly and efficiently than formerly.

Word processing

In the course of 1981, several word processing work stations have been installed by the secretary and typing service.

The equipment has provided significant benefits for the production of major reports and regulations.

Computer usage in the technical departments

A large proportion of the work performed by the technical departments of the Norwegian Petroleum Directorate involves the processing of complex batches of information.

The majority of such tasks can only be solved by computers with extensive calculation and storage capacity. Formerly, the Directorate hired external computer competence for this purpose.

However, by acquiring its own computers, savings and improvements have been achieved in the working results of the technical departments.

The Division for Resource Surveys has introduced computers for storage and processing of geological information, including production of maps and interpretation of well data.

At the end of the period, the Directorate was working on a system for improving the preparation of petroleum activity prognoses.

The Department for Safety Inspection has introduced computers in connection with work concerning personnel qualifications and diving certificates.

Other Efficiency Measures

Since 1978, the Norwegian Petroleum Directorate has published the regulations compendium "Faste installasjoner I-III (Fixed Installations I-III)". The arrangement with a loose-leaf folder has proved to be cumbersome and labour intensive, and in 1981 efforts were made to find a more rational method. From 1982 therefore, the collection will be issued as a separate booklet to be updated at the end of each year.

2. ACTIVITY ON THE NORWEGIAN CONTINENTAL SHELF

2.1. Exploration and production licences

2.1.1. Exploration licences

At 31 December 1981, a total of 95 commercial exploration licences had been granted. The following licences were granted in 1981:

Licence no. 090 - Norsk Hydro A/S
" " 091 - Tenneco Oil Company Norway A/S
" " 092 - The British National Oil Corporation
" " 093 - Geophysical Company of Norway A/S
" " 094 - Chevron Oil Company of Denmark
" " 095 - Deminex UK Oil and Gas Limited

2.1.2. Production licences

In 1981, 12 new production licences were granted. Production licences 062-064 constitute the 2nd part of the 5th allocation round. Production licences 065-072 comprise the 6th allocation round and concern allocation of areas previously relinquished.

TABLE 2.1.2.a Fifth round blocks granted by Royal Decree of 27 March 1981

Production licences	Licencees		Percentage share
062 BLOCK 6507/11	Saga Petroleum A/S	Operator	10
	A/S Norske Shell	Tech. ass.	25
	Den norske stats oljeselskap a.s		50
	Arco Norge A/S		10
	Norsk Hydro Produksjon A/S		5
063 BLOCK 7119/9	Norsk Hydro Produksjon A/S	Operator	20
	BP Petroleum Development of Norway A/S	Tech. ass.	20
	Den norske stats oljeselskap a.s		50
	Total Marine Norsk A/S		5
	Saga Petroleum A/S		5
064 BLOCK 7120/8	Den norske stats oljeselskap a.s	Operator	50
	Esso Exploration and Production Norway	Tech. ass.	25
	Norsk Hydro Produksjon A/S		15
	Elf Aquitaine Norge A/S		5
	Phillips Petroleum Norsk A/S		5

TABLE 2.1.2.b Sixth round blocks granted by Royal Decree of 21 August 1981

Production licences	Licencees		Percentage share
065 BLOCK 1/3	Elf Aquitaine Norge A/S	(operator)	16 2/3
	Texaco North Sea Norway A/S		10
	Total Marine Norsk A/S		8 1/3
	A/S Norske Shell		15
	Den norske stats oljeselskap a.s		50
066 BLOCK 2/7	Mobil Development of Norway A/S		25
	Saga Petroleum A/S	(operator)	10
	Norsk Hydro Produksjon A/S		10
	Arco Norge A/S		5
	Den norske stats oljeselskap a.s		50

TABLE 2.1.2.b (Cont´d)

Production licences	Licencees		Percentage shares
067 BLOCK 2/5	Norsk Agip A/S		10
	A/S Norske Shell	(operator)	30
	Phillips Petroleum Norsk A/S		10
	Den norske stats oljeselskap a.s		50
068 BLOCK 2/8	Mobil Development of Norway A/S		7 1/2
	Saga Petroleum A/S		10
	Norske Conoco A/S		7 1/2
	Norske Hydro Produksjon A/S	(operator)	25
	Den norske stats oljeselskap a.s		50
BLOCK 2/11	Mobil Development of Norway A/S		7 1/2
	Saga Petroleum A/S		10
	Norske Conoco A/S		7 1/2
	Norsk Hydro Produksjon A/S	(operator)	25
	Den norske stats oljeselskap a.s		50
069 BLOCK 7/8	Norske Conoco A/S	(operator)	25
	Norsk Hydro Produksjon A/S		15
	Deminex (Norge) A/S		5
	BP Petroleum Development of Norway A/S		5
	Den norske stats oljeselskap a.s		50
070 BLOCK 7/11	Mobil Development of Norway A/S		7 1/2
	Saga Petroleum A/S		10
	Norske Conoco A/S		7 1/2
	Norsk Hydro Produksjon A/S	(operator)	25
	Den norske stats oljeselskap a.s		50
071 BLOCK 8/3	A/S Norske Shell		35
	Volvo Petroleum Norge A/S		7 1/2
	Petroswede		7 1/2
	Den norske stats oljeselskap a.s	(operator)	50

TABLE 2.1.2.c Licenced area as of 31 December 1981

Production licence granted	Original km^2	Relinquished area as of 31 Dec. 1981	Area granted production licence in km^2	Area granted production licence in percent	Distributed in number of blocks
1965	42 106,041	36 169,546	5 936,495	14,10	27
1969	5 878,647	3 004,025	2 874,622	48,90	13
1971	523,937	262,047	261,890	49,99	1
1973	586,834	295,157	291,677	49,70	2
1975	2 329,206	1 212,779	1 116,427	47,92	5
1976	2 068,318	-	2 068,318	100,00	7
1977	1 175,665	-	1 175,665	100,00	5
1978	500,509	-	500,509	100,00	1
1979	4 007,887	-	4 007,887	100,00	8
1980	1 108,078	-	1 108,078	100,00	3
1981	3 318,467	-	4 318,467	100,00	12
	64 603,589	40 943,554	23 660,035	32,62	84

TABLE 2.1.2.d Production licences as of 31 December 1981

Notified with effect from	Production licence no.	Total area km^2	Number of blocks
1 Sep 1965	001-021	39 842,476	74
7 Dec 1965	022	2 263,565	4
23 May 1969	023-031	4 107,833	9
30 May 1969	032-033	746,285	2
14 Nov 1969	034-035	1 024,529	2
11 June 1971	036	523,937	1
10 Aug 1973	037	586,834	2
1 April 1975	038-040,42	1 840,547	7
1 June 1975	041	488,659	1
6 Aug 1976	043	604,559	2
27 Aug 1976	044	193,077	1
3 Dec 1976	045-046	1 270,682	4
7 Jan 1977	047	368,363	2
18 Feb 1977	048	321,500	2
23 Dec 1977	049	485,802	1
16 June 1978	050	500,509	1
6 April 1979	051-058	4 007,887	8
18 Jan 1980	059-061	1 108,078	3
27 March 1981	062-064	1 099,522	3
21 Aug 1981	065-072	3 218,945	9
		64 603,589	138

2.1.3. Transfer of shares

No transfers of shares were made in 1981.

2.1.4. Relinquishments

In 1981, there have been relinquishments of licenced areas on four production licences. These are shown in Table 2.1.4.

TABLE 2.1.4 Relinquishments

Production licence	Block	Operator
036	25/4	Elf Aquitaine
038	6/3, 15/11 and 15/12	Statoil
039	24/9	Conoco
040	29/9 and 30/7	Norsk Hydro

Production licence 036, block 25/4, with Elf Aquitaine Norge A/S as listed operator: Relinquishment was made according to the relinquishment rules of 1965. As per 1 July 1981, the relinquishment constitutes 50.01 % of the original area covered by the production licence.

Production licence 038, block 6/3, 15/11 and 15/12, with Statoil as listed operator: Relinquishment was made according to the rules of 1972. Blocks 6/3 and 15/11 have been relinquished at 49.01 %. Due to the terms of the production licence, the total relinquishment for this licence was 55.66 % at 1 April 1981.

Production licence 039, block 24/9, with Norske Conoco A/S as listed operator: Relinquishment was made according to the rules of 1972. At 1 April, 52.83 % of production licence 039 had been relinquished.

Production licence 040, block 29/9 and 30/7, with Norsk Hydro Produksjon A/S as listed operator: Relinquishment was made according to the rules of 1972. Blocks 29/9 and 30/7 were relinquished at 33.96 % and 53.19 % respectively. For production licence 040 this amounts to a total relinquishment of 52.34 % as of 1 April 1981.

2.2. Surveys and exploration drilling

2.2.1. Geophysical and geological surveys

2.2.1.1. The Norwegian Petroleum Directorate's geophysical surveys

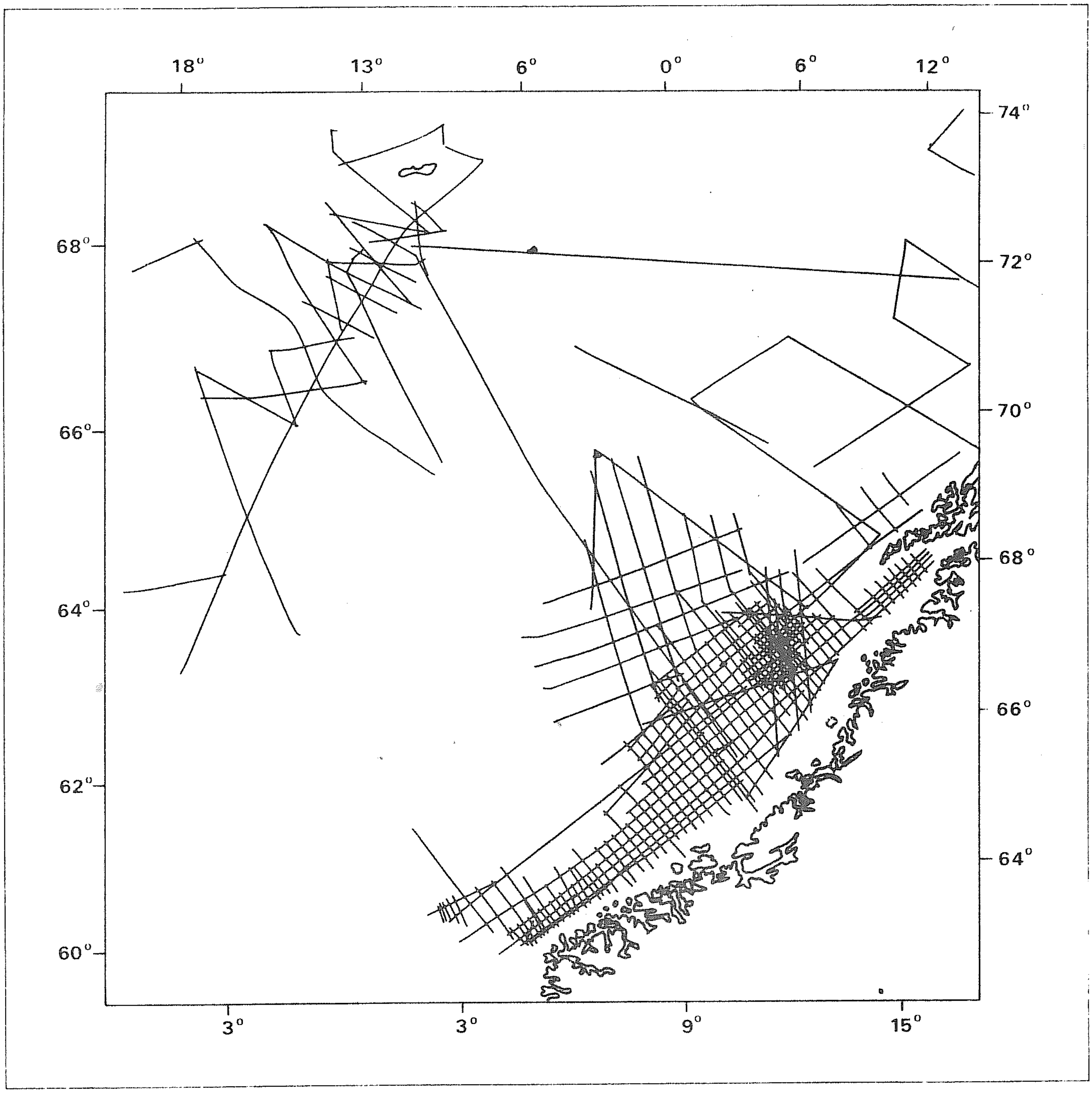
The major part of the regional geophysical surveys in 1981 was carried out in the Barents Sea (Figure 2.2.1.a). In addition, a survey was made on Vøringsplatået (Figure 2.2.1.b). In all, data were collects over a line distance of approx. 10,500 km, with 7,800 km in the Barents Sea and 2,700 km on Vøringsplatået. Along all lines, gravimetric and shallow seismic data (analogue sparker) were collected in addition to the deep seismic data. As in 1980, GECO A/S was the main contractor, while A/S Geoteam was responsible for sparker recordings. Figure 2.2.1.c gives a numerical presentation of the surveys (number of km of seismic lines) performed in the north by NTNF and the Norwegian Petroleum Directorate. A total of approx. 94,500 km of seismic data has been registered under government direction since 1969.

Collection methods

In the Barents Sea, as has been done in the last few years, a very long energy source (approx. 250 meters) was used in order to achieve optimum reduction of the noise types which are most disturbing in this area. But the Vøringplatå survey was carried out with a conventional energy source, due to the considerably different noise conditions occuring there.

In the years 1978, 1980 and 1981, the identical line off Mid-Norway has been shot with three different energy sources: the first approx. 250 m in length, the second approx. 110 m wide and the last a (fairly) conventional point source. As far as the reduction of signal-generated noise is concerned, it seems clear that a long energy source is the most effective. The effect of widening the source was difficult to measure from the actual data, but it is possible that some noise reduction may be achieved without reducing the degree of resolution.

2.2.1.a



REGIONAL SEISMIC SURVEYS IN THE NORWEGIAN SEA

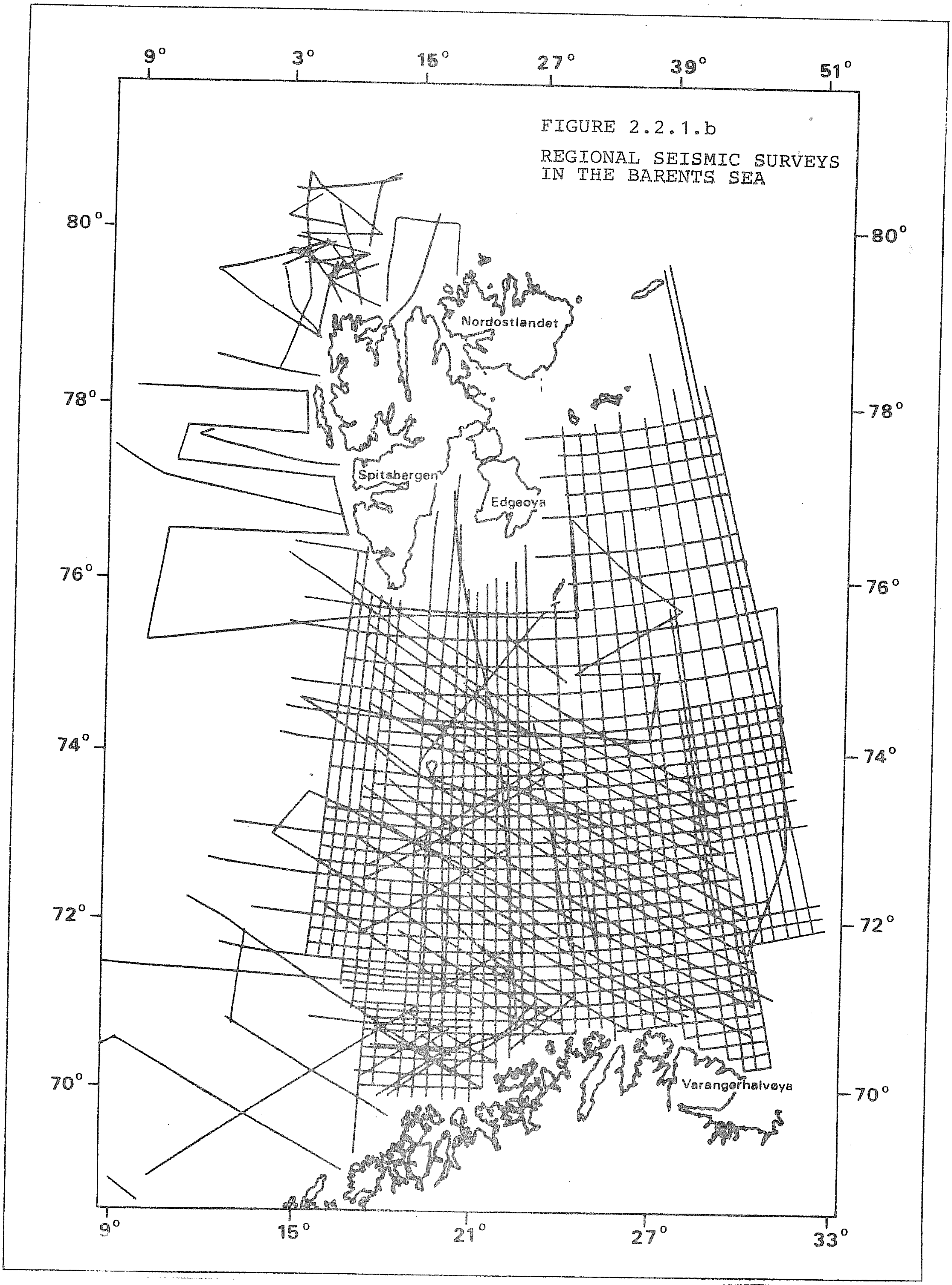
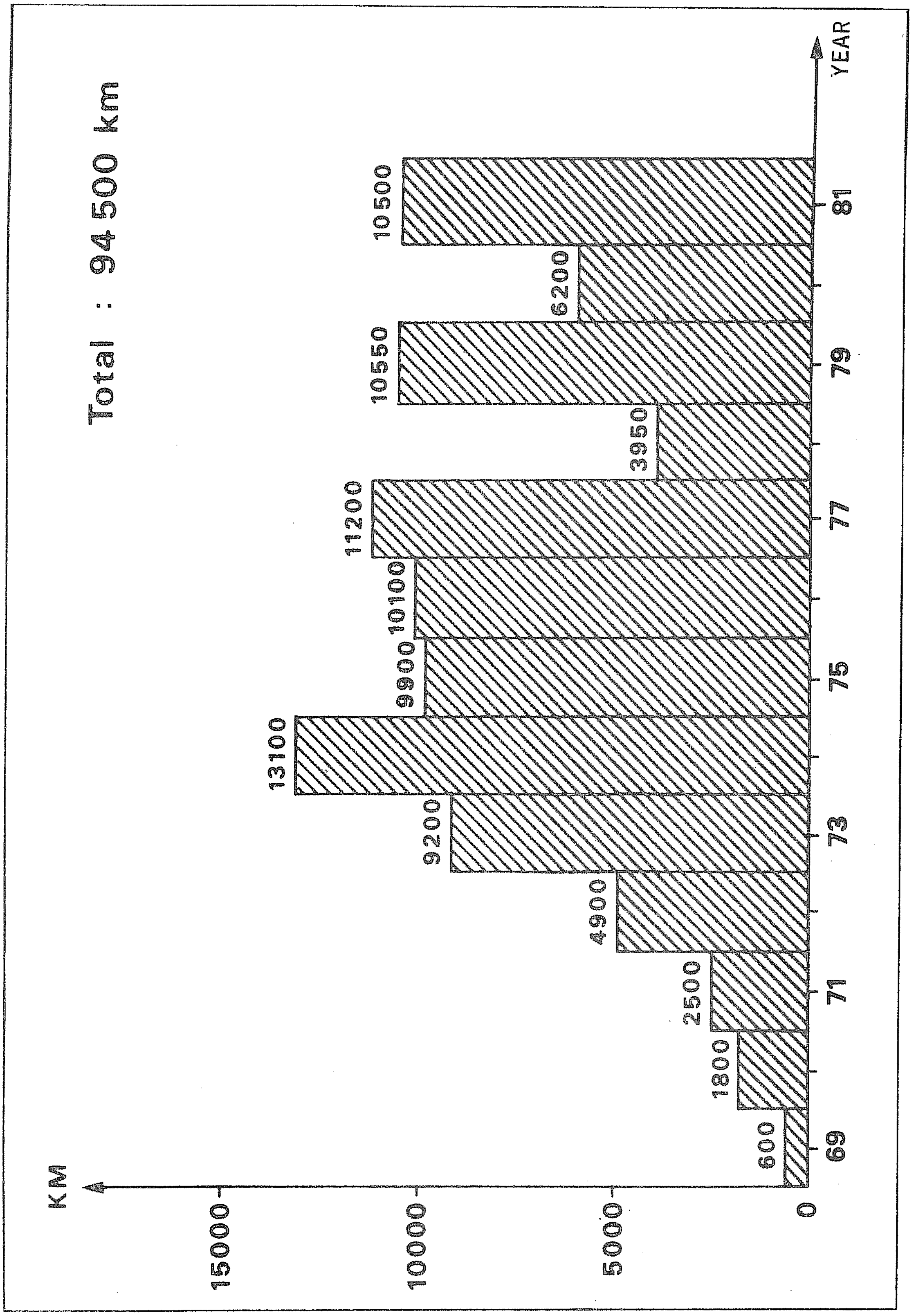


FIGURE 2.2.1.b

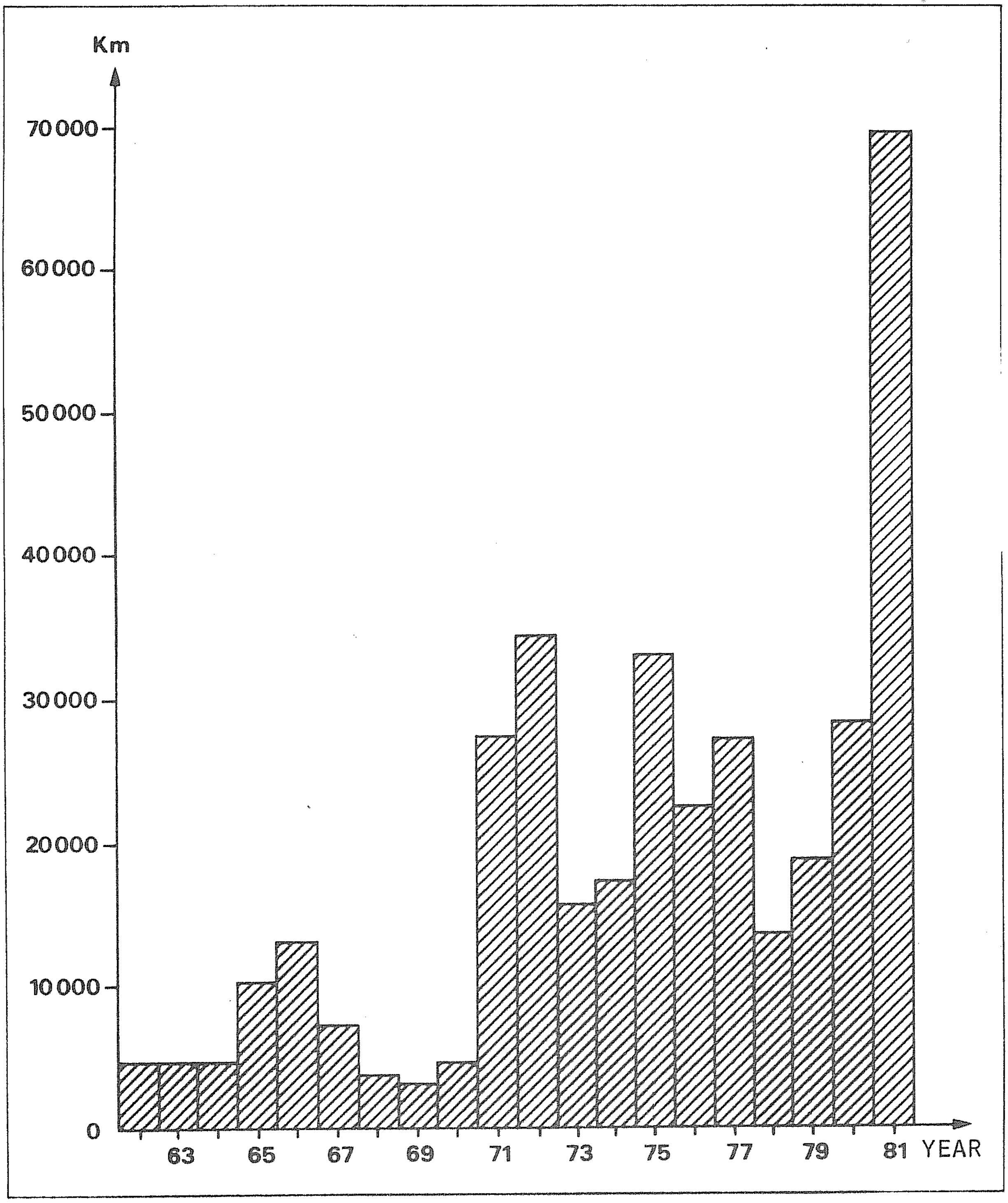
REGIONAL SEISMIC SURVEYS IN THE BARENTS SEA

FIGURE 2.2.1.c



GOVERNMENTALLY CONDUCTED SEISMIC SURVEYS NORTH OF STADT

FIGURE 2.2.1.d



GEOPHYSICAL SURVEYS CARRIED OUT ON THE WHOLE NORWEGIAN SHELF

2.2.1.2. Geophysical surveys under company direction

In 1981, 49,300 km of seismic survey were fired under company direction on the Norwegian continental shelf in the North Sea.

North of Stadt, approx. 8,850 km of seismic surveys were made in the report period. Figure 2.2.1.d shows the total number of kilometers of seismic surveys on the Norwegian continental shelf.

2.2.1.3. Costs of seismic surveys

The total costs of seismic surveys for 1981 amounted to approx. NOK 260 million.

2.2.1.4. Sale of seismic data

In 1981, the following three companies purchased the Norwegian Petroleum Directorate´s seismic data package including Trænabanken: ØMV-Norge A/S, Norse Getty Exploration A/S and Superior Oil Norge A/S. As of 31 December 1981, 25 companies had purchased the package.

In addition, Saga and Norsk Hydro bought regional seismic data for Troms and the Barents Sea.

The Norwegian Petroleum Directorate sold seismic data to the total amount of approx. NOK 7 million in 1981.

In all, the Norwegian Petroleum Directorate has sold seismic data for approx. NOK 125 million. (Table 2.2.1.4)

TABLE 2.2.1.4 Buyers of data north of Stadt
Status as of 31 Dec. 1981

COMPANIES	TRANA-PACK	MØRE-LOFOTEN I	MØRE-LOFOTEN II	MØRE-LOFOTEN III	TROMS MAIN PACK	TROMS REGIONAL DATA BARENTS SEA	TROMS ØST
1. SAGA	X	X	X	X	X	XX	X
2. HYDRO	X	X	X	X	X	XX	X
3. ESSO	X	X	X	X	X		X
4. CONOCO	X	X	X	X	X	X	X
5. PHILLIPS	X			X	X	X	X
6. MOBIL	X	X	X	X	X	XX	X
7. FINA	X	X		X	X		
8. SHELL	X	X	X	X	X	XX	X
9. ELF	X	X	X	X	X	XX	X
10. BP	X	X	X	X	X		
11. AGIP	X	X		X	X		
12. PETROSWEDE				X	X		
13. TEXACO	X		X	X	X		
14. UNIONOIL	X	X	X	X	X		X
15. AMOCO	X	X		X	X		
16. TOTAL	X	X	X	X	X	X	X
17. DEMINEX	X	X	X	X	X		
18. ARCO	X	X	X	X	X	X	X
19. GULF	X	X		X	X		
20. CITIES		X		X	X		
21. STATOIL	X				X		X
22. HUDBAY					X		
23. SUN OIL					X		
24. TEXAS EASTERN		X	X	X	X		
25. HISPANOIL	X	X	X	X	X		
26. SUPERIOR	X	X	X	X	X		
27. PETRO CANADA		X		X	X		
28. CHEVRON	X	X	X	X	X		
	X	X	X	X	X		
				X			
31. SVENSKA [illegible]		X					
32. VOLVO PETR.				X	X		
33. ØMV	X						
TOTALT PK	25	24	18	28	30	9	12

XX = WHOLE PACK
X = PARTS OF THE PACK

2.2.1.5. Release of data

The Norwegian Petroleum Directorate can release geological material and uninterpreted data from the continental shelf when such material is more than five years old.

Uninterpreted logs are released for sale when the well is presented in the "Well Data Summary Sheets" series, published by the Norwegian Petroleum Directorate.

All wells completed before 1977, a total of 166, have been presented in the seven volumes of the series. Volume 7, published in 1981, describes the following 27 wells drilled in 1976:

1/6-4	10/5-1	24/9-1
2/4-19B	11/9-1	25/2-5
2/8-8	15/6-4	30/7-3
2/8-9	15/12-2	33/9-5
2/8-10	16/1-2	33/9-6
2/8-11	16/3-1	33/9-7
2/10-1	16/3-2	33/12-5
7/12-2	16/8-1	33/12-6
8/9-1	17/11-2	35/3-1

A more detailed geological description of the various wells is presented in the series "NPD Papers" from the Norwegian Petroleum Directorate.

In the course of 1981, three booklets covering a total of 20 wells were published. At the end of 1981, details of 59 holes had been published in 30 booklets.

The outline below lists the booklets issued and the wells covered by them.

Seismic data is released in major packages for relinquished blocks.

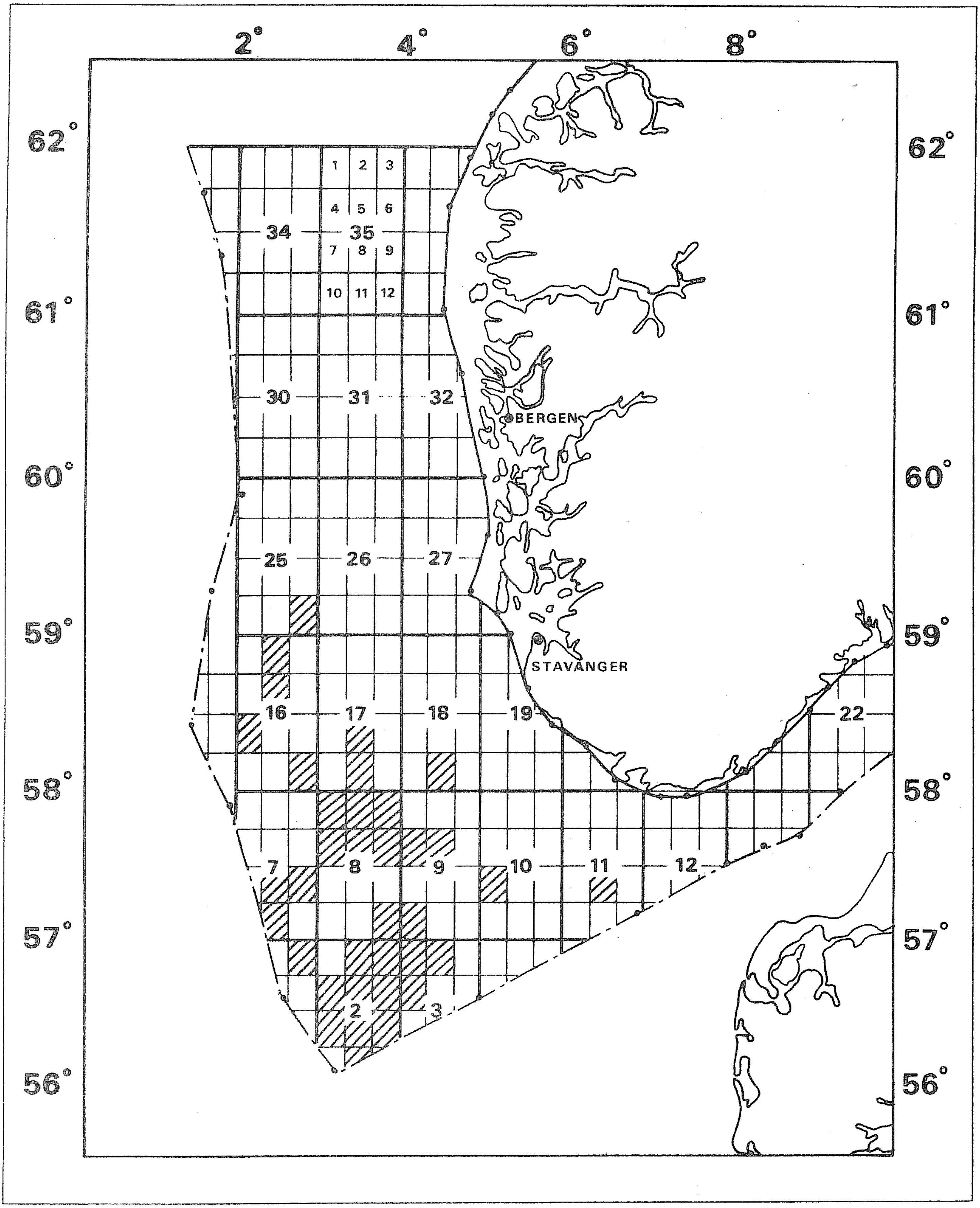
At the time of writing, approx. 16,320 km of seismic lines are available for 36 relinquished blocks or parts of blocks. The price is the cost of copying, plus an additional charge for administration costs and postage.

Figure 2.2.1.e is an outline map specifying the blocks where seismic data has been released. The individual blocks are as follows:

1/3, 2/2, 2/3, 2/4, 2/5, 2/6, 2/7, 2/8, 2/9, 2/11, 3/1, 3/2, 3/4, 7/8, 7/9, 7/11, 8/1, 8/2, 8/3, 8/4, 8/5, 8/6, 8/12, 9/4, 9/5, 9/10, 10/7, 11/8, 16/2, 16/5, 16/7, 16/12, 17/8, 17/11, 18/11 and 25/12.

Att. no.	Well	Att. no.	Well	Att. no.	Well
No 1	8/3-1	11	16/9-1	21	17/10-1
No 2	25/11-1	12	17/11-1	22	8/10-1
No 3	16/2-1	13	2/8-2	23	11/10-1
No 4	16/11-1	14	17/4-1	24	9/4-1, 2, 3
No 5	9/8-1	15	1/3-1, 2	25	2/4-1, 2, 3, 4
No 6	16/1-1	16	7/12-1	26	10/8-1
No 7	2/11-1, 2/8-1	17	2/3-1, 2, 3	27	9/12-1
No 8	16/1-1	18	7/8-1	28	25/11-2, 3, 4
No 9	16/6-1	19	2/6-1		25/10-1, 2, 3
No 10	7/11-1, 2, 3, 4	20	7/3-1		25/8-1
				29	25/4-1, 2, 3, 4
				30	2/7-1, 2, 3,6,7,8,9

FIGURE 2.2.1.e



BLOCKS WHERE SEISMIC DATE HAVE BEEN RELEASED

2.2.1.6. Assignments to scientific institutions

Partly on the inititative of research institutions and partly on the initiative of the Norwegian Petroleum Directorate, geological and geophysical research institutions carry out surveys with financial support from the Norwegian Petroleum Directorate. These surveys are clearly linked to the tasks of the Norwegian Petroleum Directorate, and form an integral part of the petroleum-related surveys of the continental shelf.

In 1981, 16 different projects received support from the Norwegian Petroleum Directorate to the total amount of NOK 1.1 million (NOK 1,133,684.-).

PROJECT	RESEARCH INSTITUTION
Bedrock tectonics on the Norwegian Continental Shelf	Institute for Petroleum Technology and Applied Geophysics, State Institute of Technology, Trondheim
Studies of seismic data for correlation of logs and presentation of synthetic logs	Institute for Geology, University in Oslo
Sedimentological studies of mesozoic rock from the Norwegian-Danish basin, North Sea	Institute for Geology, University in Oslo
Paleontological and sedimentological surveys in the jurasic layer in north-eastern North Sea	Institute for Geology, University in Oslo

PROJECT	RESEARCH INSTITUTION
Tertiary (eocene-pliocene) sediments' textural mineral-ogical and geochemical com-position	Institute for Geology, University in Oslo
The North Sea and the Nor-wegian continental margin's tertiary deposits	Institute for Geology, University in Oslo
Marine-geophysical research	Institute for Geology, University in Oslo
Catalog, dinophlagellate cysts	Institute for Geology, University in Oslo
IGCP-Project 124, NW Euro-pean Tertiary Basin	Institute for Geology, University in Oslo
Palynological surveys of tertiary dinophlagel-lates and sub/mid juras-sic pollen and traces from the North Sea area	Institute for Geology, University in Oslo
Processing seismic data from Antartic	Earthquake station, University in Bergen
Continental shelf surveys 1981	Earthquake station, University in Bergen
The Continental Boundary Project	Earthquake Station, University in Bergen

PROJECT	RESEARCH INSTITUTION
Processing of geophysical and geological data from the Barents Sea	Norwegian Polar Institute
Petroleum-related testing of sedimentary rock types along the Hornsund-Sørkapp heights, Svalbard	Geological Institute, Dept. A, University in Bergen
The Per-Trias project	Geological Institute, Dept. A, University in Bergen

2.2.1.7. Scientific surveys

As per 31 December 1981, a total of 140 permits for scientific surveys on the Norwegian continental shelf had been granted. As can be seen from Table 2.2.1.7, a total of 13 such permits was granted for 1981.

The surveys concern mostly the geology and geophysics of the Norwegian continental shelf.

TABLE 2.2.1.7 Licences for scientific research for natural resources

Licence Name		Work Field			Area
		Geoph.	Geol.	Biol.	
128	Natural Environment Research Council Wales		x		Norwegian Sea - North to Svalbard's continental shelf
129	DAFS, Marine Laboratory Scotland		x		North Sea between 61° and 56°N
130	Institute for Continental Shelf Surveys	x	x		Haltenbanken, Trænabanken, Sklinnabanken
131	Gøteborg University Sweden		x		Skagerrak
132	University at Tromsø	x			Andsfjorden, Malangdjupet, Malangen
133	Gøteborg University Sweden		x		Skagerrak
134	Natural Environment Research Council Wales	x			Boundry area toward English sector
135	Institute for Continental Shelf Surveys		x		Helgeland coast (postponed until summer 1982
136	Natural Environment Research Council, Wales	x			Boundry area toward the English sector between 58° and 59°N
137	Deutsches Hydrographisches Institut, West-Germany	x	x		Skagerrak
138	Natural Environment Research Council, Wales	x			Norwegian Continental Shelf
139	University at Bergen	x			Svalbard - continental shelf margine from 76°N
140	DAFS, Marine Lab., Scotland			x	Area around Brent, Beryl and Forties

2.2.2. Exploration and appraisal wells

At the turn of the year 1980-81, ten exploration wells and two appraisal wells were being drilled. All of these wells were completed in 1981.

The three wells which had been temporarily abandoned at the end of last year: 25/10-4 (Esso), 31/2-1 and 5 (Shell), were completed in the course of 1981. The remaining work consisted of testing strata containing hydrocarbons. Well 30/7-8 was being drilled at the end of last year, but was temporarily abandoned in April 1981. The work has now been taken up, and is expected to be finished early in 1982.

In the course of 1981, 39 new wells were commenced, of which 25 were for exploration and 14 for appraisal. Of the wells started, 27 were completed during the year (Figure 2.2.2.a).

No wells have been abandoned due to technical difficulties this year.

At the end of the year, two wells had been temporarily abandoned: 31/2-4 and 30/3-1. Well 31/2-4 will be tested in 1982. Well 30/3-1, which was stopped due to high formation pressure, requires drilling rigs with 15,000 psi equipment to do the remaining part of the drilling, and was not completed on schedule in 1981. The well is expected to be completed in 1982.

At the end of the year, a total of 311 wells had been commenced on the Norwegian shelf. These include 226 exploration wells and 85 appraisal wells.

DRILLING ACTIVITY ON THE NORWEGIAN CONTINENTAL SHELF

(NUMBER OF WELLS PER YEAR)

2.2.2.a

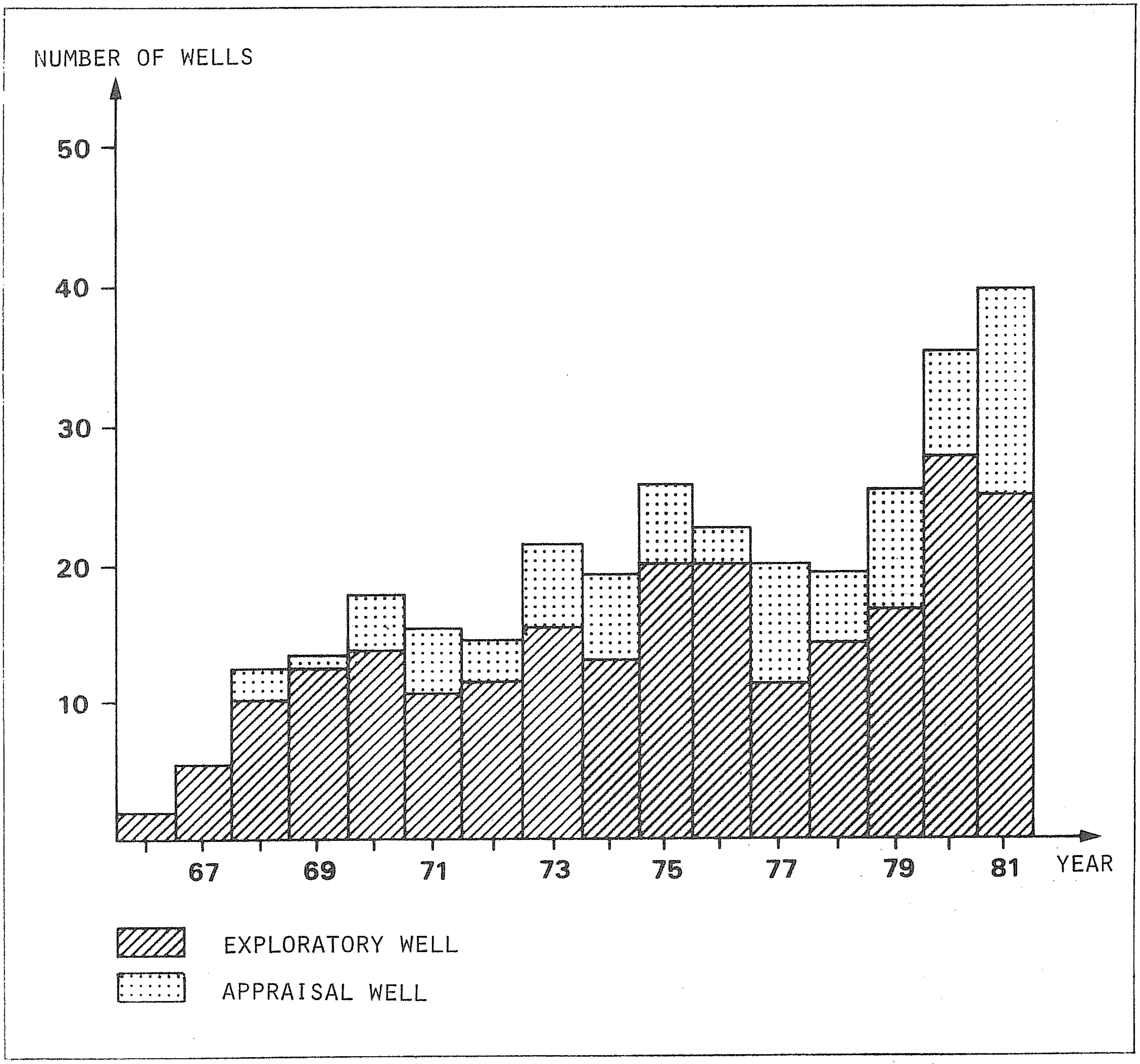


Table 2.2.2 gives an summary of the exploration and appraisal wells which were commenced and/or completed in 1981.

1980 introduced a new era in Norwegian oil exploration, as the areas north of the 62nd parallel were opened for drilling (5th round of concessions).

In 1980, drilling was undertaken on three different blocks, two on Tromsøflaket and one on Haltenbanken, all with Norwegian operators.

In 1981, three additional blocks were allocated, two on Tromsøflaket and one on Haltenbanken. These were also allocated to Norwegian operators.

The results of the year's drilling were good. Gas was detected on both Tromsøflaket and Haltenbanken, in both cases in sandstone layers from the Jura period. The three Norwegian operators have made one strike each, of which Statoil's in block 7120/8 is clearly the biggest.

Two of the wells, that of Norsk Hydro on Tromsøflaket and that of Saga on Haltenbanken, were drilled very deep, approx. 5,000 m, as required by the government work program.

These deep wells have contributed valuable information to our understanding of the geology in the area.

The results of the year's drilling have confirmed the correctness of the strategy followed, which was formulated for new and unknown areas. It involves the exploration of shallow, relatively simple structures in the first place. Subsequently, the degree of complexity may be increased gradually until more knowledge of the areas has been obtained. This strategy has proved to be prudent from a safety point of view. Although in 1980 no unusually high pressures were registered during drilling, higher than normal pressures were experienced in some wells in 1981.

TABLE 2.2.2 Spudded and/or completed exploration wells (U) and delination wells (A) in 1981.

R = reentry S = sidetrack

Lic. no.	Well no.	Drill. start. compl.	Operator concess. holder	Drilling vessel ctry.reg.	Well type	Water depth (KB)	Total depth (MSB)
219	0031/02-01 R	26.10.81 09.11.81	Shell Stat/Shell Gr.	Borgny Dolphin Norge	U	324 24	2409
254							
256							
258							
261							
262							
263	0031/02-05 R	12.06.81 20.07.81	Shell Stat/Shell/Conoco	Borgny Dolphin Norge	U	333 25	2500
264							
267							
268							
269	0030/07-08 R	23.09.81	N. Hydro Stat/Petronord	Treasure Seeker Norge	U	103 25	
270	0025/10-04 R	01.06.81 13.06.81	Esso Esso	Glomar Biscay II USA	A	126 25	2324
271							
273	0003/07-02	30.03.81 20.06.81	Elf Petronord Gr.	Dyvi Alpha Norge	U	087 25	4305
274	0025/11-10	20.01.81 17.02.81	Esso Esso	Glomar Biscay II USA	A	125 25	1973
275	0024/09-03	28.01.81 15.04.81	Conoco Stat/Con/Hydro	Sedco 704 USA	U	120 26	3025
276	0007/12-05	06.02.81 07.06.81	BP Statoil/BP	Borgsten Dolphin Norge	U	073 25	4415
277	0030/06-04	17.02.81 11.05.81	Statoil Stat/Petronord	Deepsea Saga Norge	U	110 25	2917
278	0025/11-11	19.02.81 19.03.81	Esso Esso	Glomar Biscay II USA	A	126 25	1935
279	0015/09-08	04.03.81 25.05.81	Statoil Stat/Esso/Hydro	Nortrym Norge	A	106 25	3705
280	0025/08-03	20.03.81 17.04.81	Esso Esso	Glomar Biscay II USA	U	130 25	1843
281	0025/11-12	18.04.81 07.05.81	Esso Esso	Glomar Biscay II USA	A	127 25	1893
282	0007/12-06	10.04.81 24.07.81	BP BP/Conoco	Sedco 707 USA	A	069 25	3675
283	7119/12-02	16.04.81 26.06.81	Statoil Stat/Esso/Hydro	Ross Rig Norge	U	182 25	1877
284	7120/12-02	15.04.81 10.09.81	N. Hydro Stat/Con/Hydro	Treasure Seeker Norge	U	164 25	4655
285	0015/09-09	04.05.81 14.07.81	Statoil Stat/Esso/Hydro	Nordraug Norge	U	083 25	3019
286	0034/02-03	15.05.81 13.08.81	Amoco Stat/Amoco	Sedco 703 USA	U	338 25	3716
287	0025/11-13	11.05.81 29.05.81	Esso Esso	Glomar Biscay II USA	A	127 25	1907
288	0031/04-05	27.05.81 29.07.81	N. Hydro Stat/Hydro/Esso	Nortrym Norge	U	148 25	2905
289	6507/12-02	09.06.81 24.11.81	Saga Elf/Saga/Volvo	Byford Dolphin Norge	U	261 25	4983
290	0030/06-05	11.06.81 15.08.81	Statoil Stat/Petronord	Deepsea Saga Norge	U	156 25	3525
291	0025/10-05	15.06.81 17.07.81	Esso Esso	Glomar Biscay II USA	A	125 25	1986

TABLE 2.2.2 Continued

Spudded and/or completed exploration wells (U) and delination wells (A) in 1981. R = reentry S = sidetrack

Lic. no.	Well no.	Drill. start. compl.	Operator concess. holder	Drilling vessel ctry.reg.	Well type	Water depth (KB)	Total depth (MSB)
292	7120/08-01	28.06.81 10.09.81	Statoil Stat/Esso/Hydro	Ross Rig Norge	U	270 25	2585
293	0003/07-03	21.06.81 31.08.81	Elf Petronord	Dyvi Alpha Norge	U	067 25	3517
294	0024/12-02	22.06.81	Statoil Stat/Texaco/Hydro	Dyvi Delta Norge	U	119 32	
295	0034/10-12	16.07.81 12.09.81	Statoil Stat/Hydro/Saga	Nordraug Norge	U	138 25	
296	0031/02-06	21.07.81 17.10.81	Shell Stat/Shell/Conoco	Borgny Dolphin Norge	A	343 25	1735
297	0033/05-02	31.07.81 18.11.81	N. Hydro Stat/Hydro/Elf	Nortrym Norge	U	308 25	4495
298	0015/08-01	18.07.81	Statoil Stat/Esso/Hydro	Glomar Biscay II USA	U	112 25	4275
299	0035/08-02	11.09.81	Gulf Stat/Gulf/Getty	Sedco 704 USA	U	381 26	
300	0034/10-13	24.08.81	Statoil Stat/Esso/Hydro	Deepsea Saga Norge	A	214 25	3366
301	6507/11-01	13.09.81 10.12.81	Saga Stat/Shell/Saga	West Venture Norge	U	298 33	3106
302	0015/09-10	15.09.81 07.11.81	Statoil Stat/Esso/Hydro	Nordraug Norge	A	098 25	3264
303	0015/09-11	18.09.81 23.12.81	Statoil Stat/Esso/Hydro	Ross Rig Norge	A	088 25	2925
304	0015/03-04	03.10.81	Elf Petronord Gr.	Borgsten Dolphin Norge	U	107 25	
305	0002/11-06	03.09.81	Amoco Amoco/Noco Gr.	Sedco 703 USA	A	072 25	
306	0034/04-03	16.10.81	Saga Stat/Saga/Amoco	Dyvi Alpha Norge	U	366 25	
307	0029/06-01	12.10.81	BP Statoil/BP	Sedco 707 USA	U	124 25	
309	0015/09-12	26.11.81	Statoil Stat/Esso/Hydro	Nordraug Norge	A	107 25	
310	0015/02-01	26.11.81	N. Hydro Stat/Elf/Hydro	Nortrym Norge	U	109 25	
312	0034/10-14	24.12.81	Statoil Stat/Hydro/Saga	Ross Rig Norge	A	227 25	
313	0035/03-05	22.12.81	Saga Stat/BP/Saga	West Venture Norge	A	270 25	

In addition to new block allocations north of the 62nd parallel (5th round of concessions), a number of production licences have been granted in the southern part of the North Sea (6th round of concessions) in 1981. The blocks in this round of concessions have all been allocated previously, but have been relinquished to the State as the law allows. Renewed interest has been attached to these blocks due to improved geological understanding.

Because of the high level of activity experienced in 1981, it was decided at this block allocation to delay drilling until after 1 January 1982.

At the end of the year, various kinds of work were being performed at 13 wells, as illustrated in Table 2.2.2. The activity was high throughout the season with a peak at the end of the year and as many as 15 drilling rigs in operation at the same time.

Drilling activity in 1981 is compared with previous years in the schematic outline, Figure 2.2.2.a.

As may be seen, there is a notable increase in activity level compared to previous years, despite the loss of working hours as a consequence of the labour dispute onboard drilling rigs at the end of the year, and despite the fact that four of the wells drilled in 1981 were abandoned at shallow depth for technical reasons.

The increased activity is the result of several circumstances. One important reason is the fourth round of allocations, following which several interesting finds were made. This stimulated the companies to increase exploration efforts. The appraisal of occasional major finds in complex geological areas requires many wells. Also, most blocks allocated in the third, fourth and fifth concession round are encumbered with comprehensive work committments within the licence period of 6 years. This implies a high level of activity.

Activity has also been great in blocks from the first and third round of concessions. High activity levels in blocks from the third concession round result from the fact that these are subject to relinquishment in 1981 and 1982. The operating companies therefore work intensively to meet their work commitments and to determine the areas they would like to keep.

Naturally, the opening of areas north of the 62nd parallel is also a factor which contributes to the high level of activity.

Figure 2.2.2.b illustrates the geographical distribution of wells drilled in the North Sea in 1981, and their location in relation to the main structural elements.

Figures 2.2.2.c and 2.2.2.d show the wells on Haltenbanken and Tromsøflaket and their locateion in relation to block partitions and main structural elements. Figure 2.2.2.e shows the drilling localities on Svalbard.

As can be seen from the figures, activity took place all over the shelf. Extraordinary efforts were however made in the Sleipner area, where eight new wells were commenced, and on the Balder field, where six new wells were started this year. This represents more than a third of all drilling operations started in 1981.

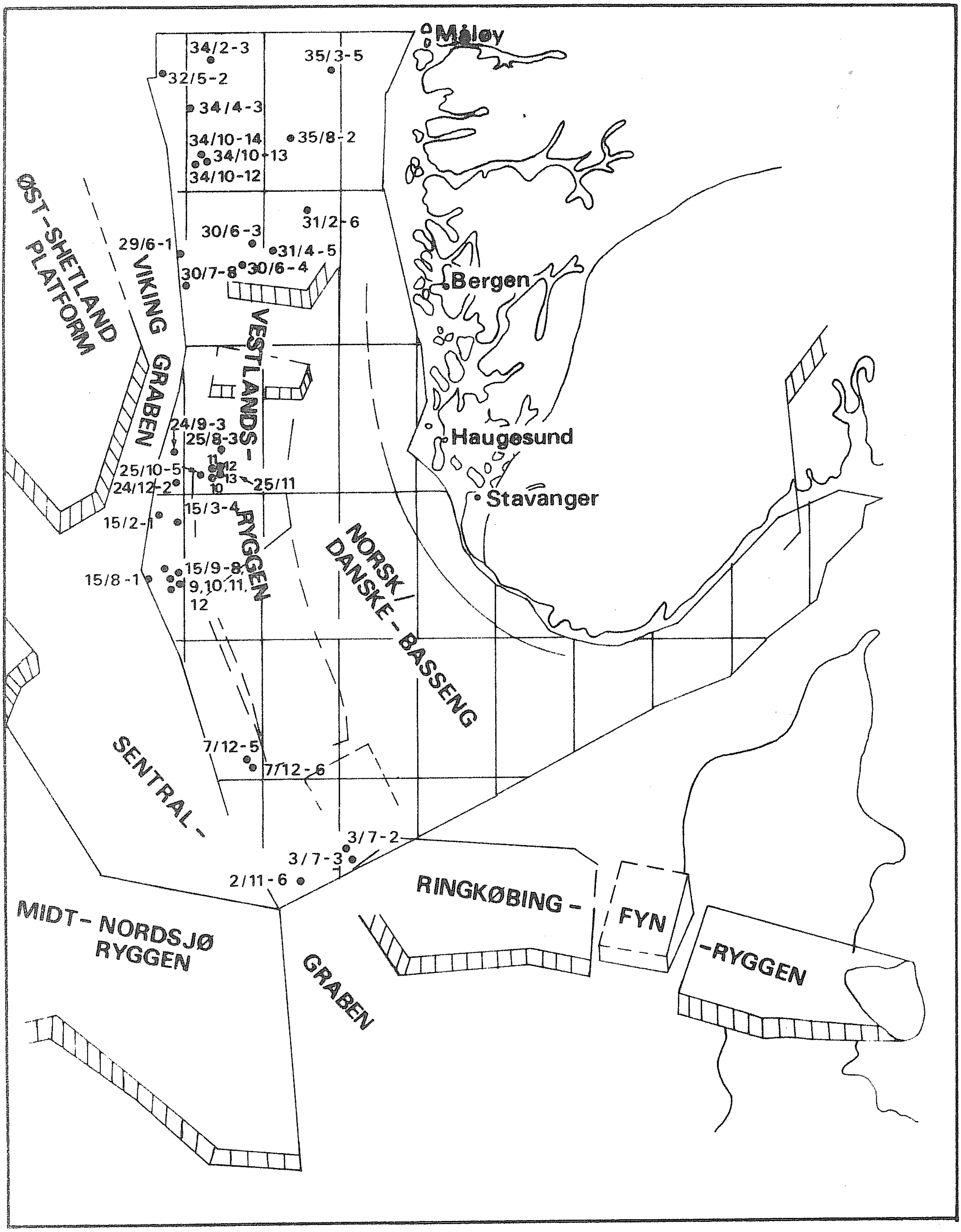
High levels of drilling activity also took place in blocks 30/6, 31/2 and 34/10.

In 1981, the Norwegian companies Saga, Norsk Hydro and Statoil had operator responsibility for more than half the drilling operations started (22), while the remaining 17 were distributed among seven different international companies. Statoil alone drilled 14 wells.

Since commencement in 1966, a total of 16 different companies have acted as operator on the Norwegian continental shelf. Phillips has drilled most wells (50), closely followed by Statoil with 47. During this period, 45 different drilling vessels have seen operation on the Norwegian continental shelf.

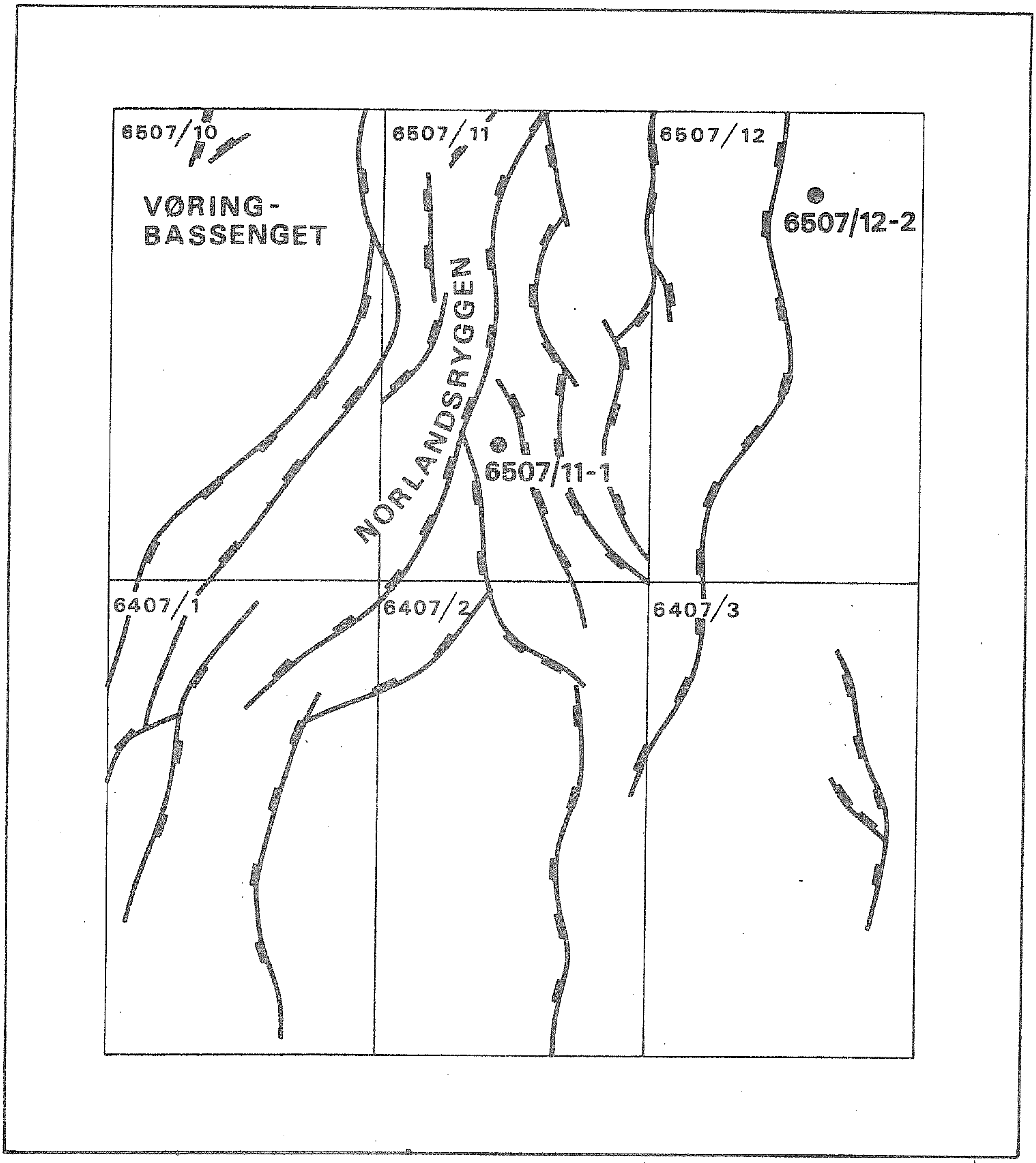
The greatest water depth at which drilling has taken place, is 391 m by Amoco at well 34/2-3 in 1981. BP is still in possession of the total depth record in the North Sea: 5430 m below sealevel in the drilling of well 30/4-1. The 311 wells started account for a drilled distance of almost 1,000 km (976,502 m), or an average of 3154 m per well.

FIGURE 2.2.2.b



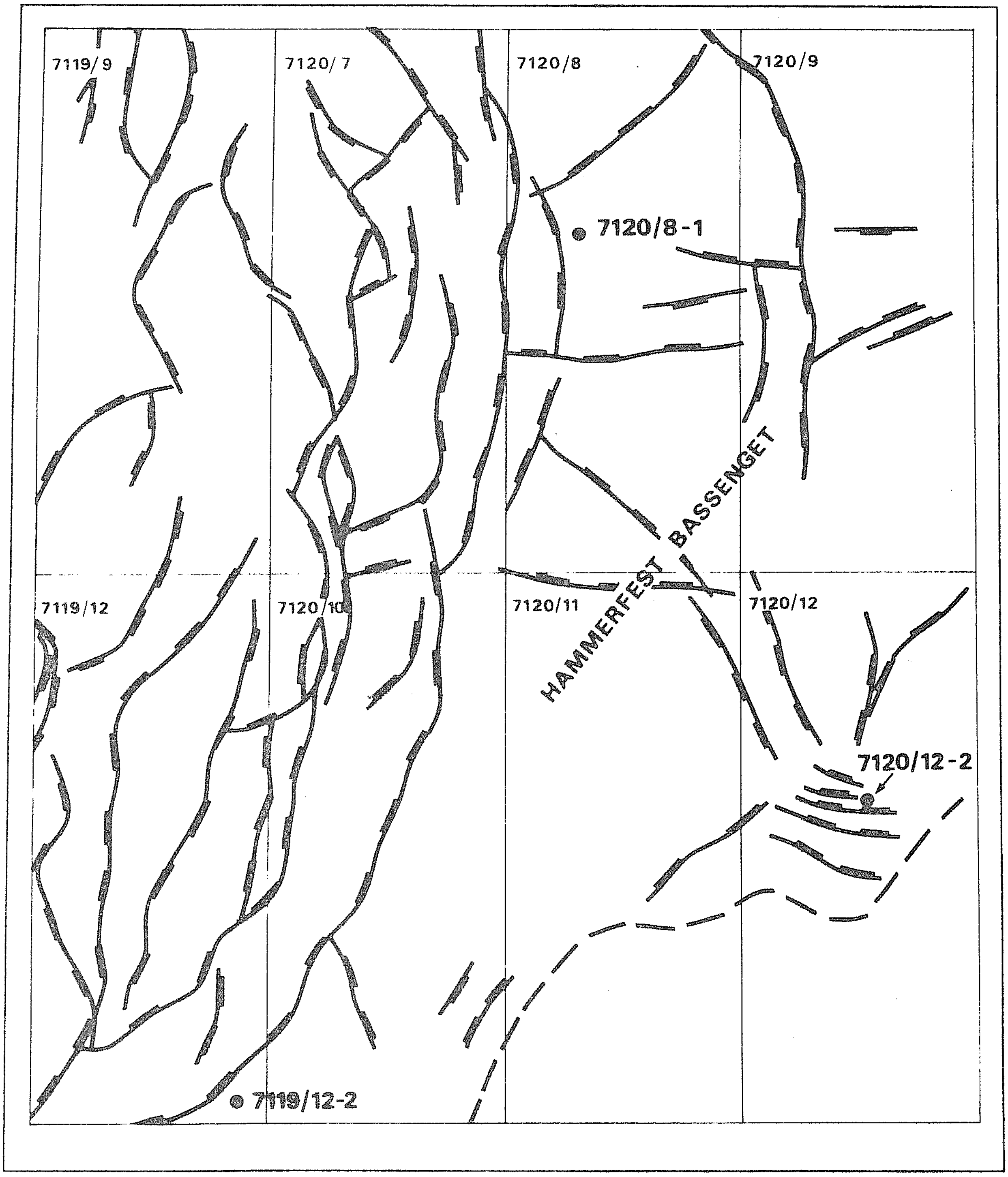
WELLS DRILLED IN 1981 IN RELATION TO MAIN STRUCTURAL ELEMENTS

FIGURE 2.2.2.c



WELLS DRILLED IN 1981 IN RELATION TO MAIN STRUCTURAL ELEMENTS ON HALTENBANKEN

FIGURE 2.2.2.d



WELLS DRILLED IN 1981 IN RELATION TO MAIN STRUCTURAL ELEMENTS IN THE EASTERN PART OF THE TROMS I AREA

FIGURE 2.2.2.e

WELL LOCATIONS ON SVALBARD

2.2.2.1. Distribution by prospect type

Also in 1981, exploration activity focused mainly on Jurassic sandstone reservoirs. Of the total of commenced and reopened wells, 29 (74 %) have had as their main objective the exploration of various Jurassic sandstone prospects. Several of these wells have also included secondary prospective zones at other levels.

Drilling into prospects of the Tertiary period (Eocene and Paleocene) accounts for eight wells, six on Balder, one on Sleipner and one in block 24/9.

The remaining two wells tested prospects of the Cretaceous period. Well 2/11-6 is an appraisal well for oil finds in limestone rocks of the Upper Cretaceous, while 35/3-5 is expected to contain gas in reservoir sands from the Lower Cretaceous period.

As regards the wells which were being drilled at the end of the previous year, and where the primary prospects had not been reached at the time (eight wells), these show approximately the same pattern as this year´s drillings (five Jura, two Lower Cretaceous and one Tertiary).

2.2.2.2. Svalbard

Norsk Polarnavigasjon A/S continued its work this season in Berzeliusdalen on Fridtjovbreen site no. 15. This well, Bellsund no. 1, was first commenced in 1974. Drilling continued in 1975, but after having drilled to a depth of approx. 500 m, the drill string jammed and the well was abandoned.

Work on the well, temporarily plugged since 1975, was taken up again in 1980. Directional drilling succeeded in by-passing parts of the stuck drill string. In the course of a months and a half´s work last autumn, the well was drilled even deeper, but without managing to penetrate the prospective layers. The well has not been logged. Drilling is expected to continue next season.

Store Norske Spitsbergen Kulkompani A/S made a relatively shallow drilling in Adventdalen to examine the gas potential of sandstone layers from the Lower Cretaceous period in which gas had previously been detected (1967). This well reached a total depth of 160 m.

Some gas was registered, but not in the same quantities as in the previous well. The results from the well must be further evaluated before any definite conclusions can be drawn.

Store Norske drilled another shallow well (200 m) in the same area in 1981. Drilling took place in the vicinity of pit 7, primarily to produce water, secondarily to examine the possibility of gas pockets. Although more gas was registered in connection with this drilling than the first one, it is too early to say what significance this has.

2.2.2.3. Experience from this year's drilling season

1981 has been a year of considerable exploration activity on the Norwegian continental shelf. Despite the high level of activity, no problems arose in connection with the drilling operations which it was not considered possible to solve.

In 1981, drilling was carried out by two drilling rigs on Tromsøflaket from 15 April to 1 October. On Haltenbanken, the drilling season commenced on 15 April 1981 with one drilling rig, and was scheduled to close on 1 December 1981. Late in the drilling season, another drilling rig was brought in. The rigs ceased operations on 25 November and 15 December 1981.

The safety and contingency aspects of exploration activity in 1981 off Northern and Mid-Norway were satisfactory.

During the drilling of well 6507/12-2 on Haltenbanken, an uncontrolled blow-out of gas occured. The incident brought about a thorough review of Saga's procedures in particular, and a detailed assessment of the problem by Norwegian operators in general.

2.2.2.4. Year-round drilling north of Stadt

In 1981, the Ministry of Local Government and Labour set up a work group for a more detailed evaluation of the safety and contingency criteria for a possible switch to year-round drilling. Group participants included the Maritime Directorate, Saga, Norsk Hydro and Statoil and the chair was held by the Norwegian Petroleum Directorate. Norsk Skipsforskningsinstitutt (Norwegian Ship Research Institute) provided the secretariat. The first report was made available in October. The report only takes up matters of importance to semi-submersible drilling rigs.

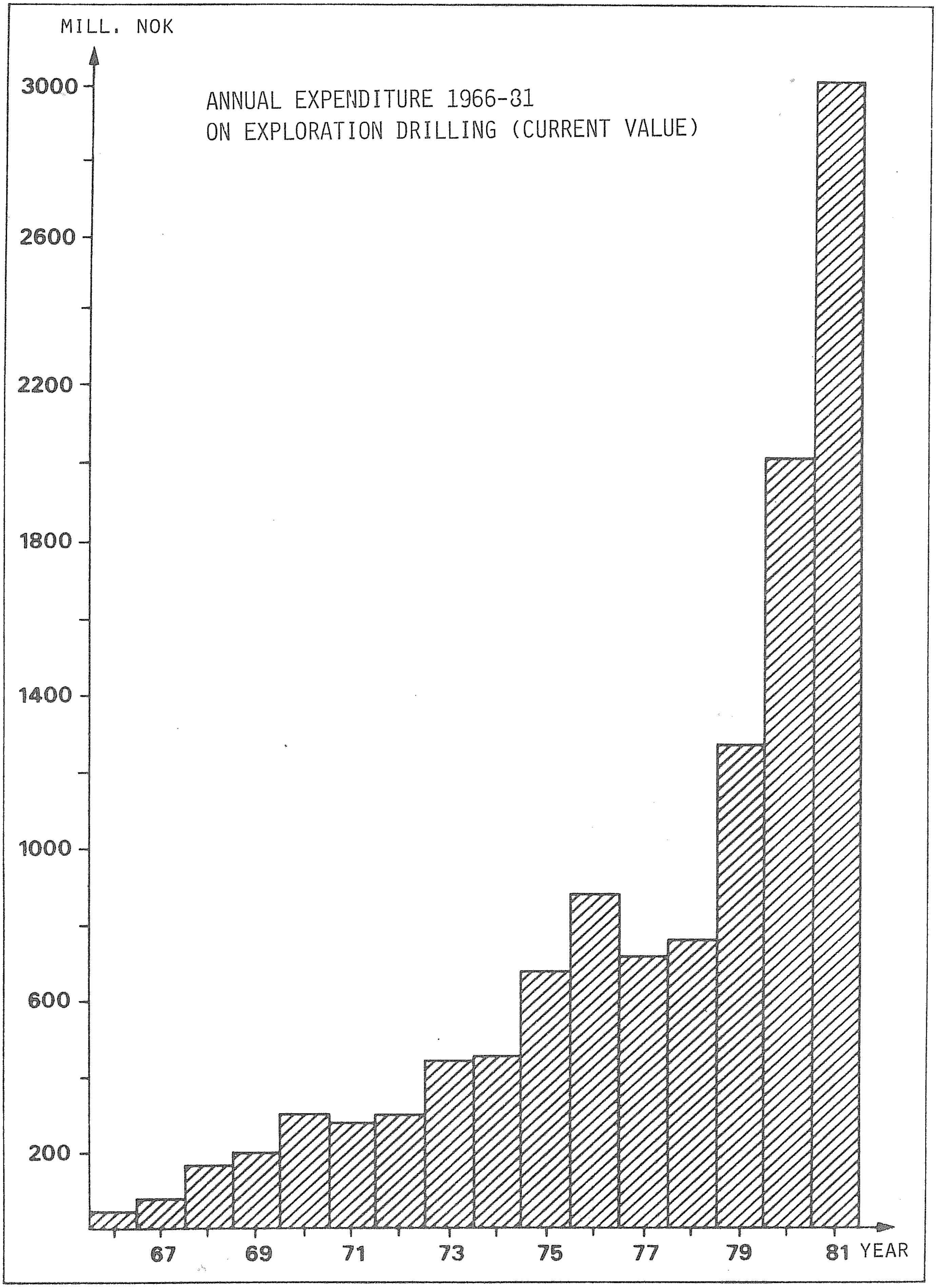
The report is being continued, and criteria are being evaluated for supply services and personnel transport for carrying out drilling operations in northern waters during the winter months.

2.2.2.5. Expenditure on exploration drilling

The total expenditure on exploration drilling in 1981 will amount to just over NOK 3,000 million. The corresponding figure for 1980 was NOK 2,200 million. The expenditure figures include the total costs of all exploration and appraisal wells which were started in the course of the year. Final expenditure on drilling operations which started in the second half of 1981 was not available early in 1982. For this reason, the expenditure estimate for 1981 is a provisional one. The main reason for the relatively heavy increase in expenditure is that in 1981, 39 new well drillings were started compared with 36 in 1980. (Moreover, four of these wells were abandoned at shallow depth for technical reasons). Measured in operating days for mobile rigs, the activity in 1981 has thus increased by roughly 24 % compared to 1980. In addition to the general price increase, the day rate for mobile rigs was considerably higher in 1981. The average rate in 1980 amounted to approx. NOK 200,000 per day compared with approx. NOK 360,000 in 1981. Some contracts have been entered into at a day rate of approx. NOK 550,000. In 1981, the average cost per well amounted to just under NOK 80 million. The corresponding figure for 1980 was approx. NOK 62 million.

Figure 2.2.2.f shows the annual expenditure on exploration drilling in the period 1966-1981, which is the period in which exploration drilling has taken place on the Norwegian continental shelf. It is seen from the figure that exploration drilling on the Norwegian continental shelf has represented a rapidly growing market, especially during the last three years. The total expenditure on exploration drilling amounts to NOK 11,800 million (current prices) for the period 1966-1981.

FIGURE 2.2.2.f


MILL. NOK
ANNUAL EXPENDITURE 1966-81
ON EXPLORATION DRILLING (CURRENT VALUE)
3000
2600
2200
1800
1400
1000
600
200
67
69
71
73
75
77
79
81
YEAR

2.2.3. Finds and fields being evaluated

2.2.3.1. Finds in 1981

At the turn of the year 1980/81, 12 exploration and appraisal wells were being drilled which led to six finds in 1980 and four in 1981. Two wells were dry. Of the 39 exploration and appraisal wells started in 1981, finds of hydrocarbons were made in 23, while ten were dry and six had not reached prospective layers.

A total of 24 undrilled structures were drilled in the course of 1981. Finds of hydrocarbons were made in 13 of these structures. This represents a strike frequency of just over 50 %, which is very high in terms of exploration drilling.

Tests

Eighteen wells were tested in 1981. Tests of 31/2-4 were postponed to 1982. Wells 30/7-8 and 2/11-6 will not be tested until after the end of the year. Well 7/12-5 could not be tested for technical reasons, and 30/6-5 was not tested due to the unexpected hydrogen sulphide content of the gas.

2.2.3.2. New finds

Block 24/9

Block 24/9 was allocated in 1974 with Conoco as operator.

Well 24/9-3 was drilled on a shallow structure on the boarder of the British sector. During the drilling, oil was detected in sandstone layers from the Eocene period. The oil column rises approx. 90 m. Net oil bearing sand extends approx. 36 m. The reservoir was tested at a maximum production of 86 Sm3 heavy oil per day. The density is 0.92 g/cm3 (23^{o}API). Oil/water contact occurs 1780 m below sealevel. Recoverable reserves on the Norwegian side have been estimated at 3 billion Sm3.

Block 30/3

The block was allocated in 1979 with Statoil as operator.

There are two structures of interest in this block. One, which lies relatively deep on the border with block 30/2, is expected to have high formation pressures. Drilling on this structure was commenced in 1980, but completion was postponed until 1982. The other structure lies in the south-west of the block and extends into neighbouring block 30/6. This structure lies at a more shallow depth. Formation testing (RFT) in well 30/3-2 detected oil in three sandstone layers of the jurassic period. The Brent formation consists of two separate sandstone layers, and oil/water contact has been demonstrated in both. This implies that there are two separate reservoirs. The upper sand layer of the Brent formation is 17 m thick, of which 10 m is oil bearing. The lower layer is 80 m thick, of which 55 m is oil bearing. The reservoir characteristics are favourable. The density of the oil was shown by measurement to be 0.83 g/cm3.

Compared with Statfjord and the 34/10 wells for example, the production results from this well are considerably less. 370 Sm3 and 31,500 Sm3 per day were produced through a 13 mm choke from the best zone.

Blocks 29/6, 29/9, 30/4 and 30/7

Blocks 29/9 and 30/7 were allocated in 1974 with Norsk Hydro as operator, and blocks 29/6 and 30/4 were allocated in 1976 with BP as operator.

Gas/condensate has been detected in Mid-jurassic sandstone in a complicated structural complex in blocks 29/6, 29/9, 30/4 and 30/7. The proven recoverable reserves are estimated to contain 50 billion Sm3 gas. The reservoir rocks lie at different levels in the various wells, which may vary in depth between 3,800 and 4,300 m. In the best well, a high pressure gas column of approx. 100 m was demonstrated.

Status for exploration drilling

Norsk Hydro has drilled a new well 30/7-8 on a separate structure west of the gas find in 30/7-6 and 30/4-2. The well was abandoned due to a number of technical problems, as well as rig reassignment. Drilling was taken up in September, and is expected to be completed in the course of January 1982. Gas has been proven in several separate sandstone layers. Total net sand containing hydrocarbons is approx. 40 m.

At the end of 1981, BP started a new well in block 29/6 (29/6-1).

Block 31/4

The block was allocated in 1979 with Norsk Hydro as operator.

Norsk Hydro has once again detected oil in block 31/4. Well 31/4-5 lies in the same structural complex as 31/4-3, where two separate layers of the upper jurassic were tested for gas and oil respectively. In 31/4-5, the upper layer contains water, while the lower, approx. 40 m thick, contains oil.

Three tests have been carried out in the well. The first did not produce anything as the formation was too dense. The best test produced 400 Sm3 oil and 33,200 Sm3 gas per day.

The density of the oil is 0.845 g/cm3, while the density of the gas relative to air is 0.73.

The test results are more favourable than in the neighbouring well 31/4-3, but poorer than the Statfjord wells for example.

By drilling 31/4-4, Norsk Hydro intended to explore a stratigaphic trap of lower cretaceous age, a new type of project in the area, but did not succeed in finding any reservoir rock at the first attempt.

Preliminary reservoir estimates are 3 million Sm3 oil and 12 billion Sm3 gas.

Block 35/3

The block was allocated in 1975 with Saga as operator.

Exploration Drilling

Four wells have been drilled in this block, but the third well 35/3-3 had to be abandoned at shallow depth due to technical problems, and was replaced by 35/3-4. This well has been drilled structurally higher than 35/3-2 in the eastern part of the block. As in 35/3-2, gas was detected in sandstone layers from the lower cretaceous period. The reservoir is divided into two parts by slate zone. The lower part turned out to be non-productive.

The reservoir properties are better in the upper part, which produced 730,000 Sm3 gas and 835 Sm3 condensate per day through a 14.3 mm choke. The density of the gas in relation to air was measured at 0.62, and the condensate density was 50.3^{o} API. The test results are very favourable.

The geology in this block is very complex at reservoir level. A number of thin sand layers of various ages make up the reservoir rock, which apparently covers major parts of the block. Several wells will be required before it is possible to say anything about the size and extent of the find. A new well in the south-east of the block was commenced at the end of the year.

It is too early at present therefore to say whether the field will be commercial or when investment and production start can take place.

Block 35/8

The block was allocated in 1979 with Gulf as operator.

Well 35/8-1 was drilled in the western part of the block, on a minor structure which extends just into the neighbouring block 35/7. Light oil/condensate was detected in sandstone from the Mid-jurassic period. In advance, great expectations had been attached to the upper jurassic. Only 2 thin sand layers were found however, 5 and 7 m thick (the Heather formation), both containing hydrocarbons.

The Mid-jurassic sand (Brent formation) is massive, 198 m in all. Oil/condensate was detected in the upper 141 m of the reservoir, but only 70 m can be considered productive reservoir.

Two production tests were made in the Mid-jurassic reservoir. The best zone produced 0.92 million Sm3 gas and 229 Sm3 oil per day through a 19 mm choke. The density of the gas in relation to air was 0.647, and the density of the condensate 0.80 g/cm3 (45.7^{o} API). The test results must be considered very positive.

Preliminary reserves have been estimated to be 10 billion Sm3 gas with small amounts of condensate. A new well 35/8-2 is being drilled on a separate structure in the south-west of the block. The well had not reached prospective layers by the end of the year.

Block 6507/11

The block was allocated in 1981 with Saga as operator.

Well 6507/11-1 was drilled on a structure in the central part of the block. Two dry wells had previously been drilled in block 6507/12, to the east of this block.

In 6507/11-1, Saga discovered gas in two separate sandstone layers of the jurassic period. The upper zone has a gross thickness of 58 m, of which 40 m has reservoir properties.

The entire reservoir was filled with gas down to the slate below, so that no gas/water - or gas/oil contact was established.

The other zone is 27 m thick, of which 20 m has reservoir properties. In this zone, a gas/water contact has been detected approx. 2,500 m below sealevel.

A production test of the upper sand zone gave the following result: 760,000 Sm3 gas and 138 Sm3 condensate through a 20 mm choke. The well has recoverable reserves proven so far amounting to 10 billion Sm3 gas.

Block 7120/8

The block was allocated in 1981 with Statoil as operator.

Dry gas was detected in sandstone layers from the jurassic period in the first, and so far only, well in the block. The gross gas column is 85 m. The reservoir properties are very favourable. The structure into which the well was drilled is flat and covers the major part of the block.

Gas/water contact occurs at approx. 2,150 m below sealevel. Three tests have been carried out of the gas zone, the best of which produced 1.04 million Sm3 gas and 475 Sm3 condensate per day through a 25 mm choke. This result equals the very best registered in the North Sea. Preliminary estimates of the proven recoverable reserves are 50 billion Sm3 gas. The structure is very large however, and further drilling will probably increase the reservoir estimate. If the structure is full, the total recoverable reserves are expected to be between 100-150 billion Sm3.

Block 7120/12

The block was allocated in 1980 with Norsk Hydro as operator.

While drilling the second well in the block, a gas reservoir assumed to date from the lower jurassic period was found. The reservoir properties vary a good deal, and of the total gas column of 93 m, approx. 70 m is considered productive reservoir.

Furthermore, high gas readings have been registered throughout the entire triassic, but only two thin layers are expected to be productive. Both the triassic and the jurassic reservoirs have been tested.

From a 12 m thick layer of triassic sand, 416,000 m3 condensate were produced per day through a 13 mm choke.

This result is remarkably good.

The density of the gas is 0.62 in relation to air and the density of the condensate is 55.8^{o} API. No hydrogen sulphide, carbon dioxide or water was produced.

In the main reservoir, which dates from the jurassic period, tests on three different intervals were performed. The result of the best test was 732,000 Sm3 gas and 52 Sm3 oil per day through a 24 mm choke.

The well was drilled on a minor element in a large structural complex. Provisional reserves recoverable amount to 5 billion Sm3 gas. Several wells will have to be drilled to estimate the total reserves in the structural complex.

Well 7120/12-1 which was dry, lies a little south of 7210/12-2, separated by a fault.

2.2.3.3. Fields being evaluated

Block 1/9

The block was allocated in 1976 with Statoil as operator.

Production licence 044.

Statoil has undertaken a field analysis which is planned to form the basis of a commerciality declaration. In the analysis, consideration has been given to the technical and economic aspects of the following alternatives:

- complete and partial processing on block 1/9
- plateau production at 7.5% and 15% of the total recoverable reserves
- conventional development concepts together with a development concept for final positioning of seafloor wells at Gamma
- two-phase pipeline or separate oil and gas pipelines between Alpha and Gamma
- steel and concrete platforms

Recoverable reserves are provisionally estimated at 9 billion Sm3 oil and 24 billion Sm3 gas.

South-East Tor

The field lies in block 2/5 which was allocated in 1965 with Amoco as operator (Figure 2.3.2.a).

The field is an oil field with dissolved gas. Separated by a denser chalk zone are two reservoirs in chalk rocks belonging to the Ekofisk and Tor formations.

Amoca, the operator, has no definite plans for development. The reserve basis is under evaluation at this time.

Ekofisk-South

Block 2/7 was allocated in 1965 with Phillips as operator.

Exploratory well 2/2-14 showed in 1979 that the Ekofisk field stretches further south than earlier estimated. It seems clear however, that a part of the reserves are being tapped by the existing wells on the field, but there is uncertainty as to the extent of this.

Evaluation of whether well 2/7-14 should be reassigned to production is taking place, and the well is at present temporarily abandoned. There is uncertainty as to whether the well is in such condition that it may be brought on-line.

Hod

Block 2/11 was allocated in 1969 with Amoco as operator.

The Hod field consists of two separate structures, East Hod and West Hod.

The Norwegian Petroleum Directorate´s estimates for commercial reserves are respectively 9.0 million Sm3 oil and 7.0 billion Sm3 gas. The operator is working with two alternative concepts for development of the field. Selection of concept will depend on a more detailed survey of the reserves at East Hod.

During 1981, well 2/11-6 was drilled from a steel frame positioned over the Hod structure. This well will be abandoned temporarily and will later be reworked as production well for the Hod field. 60 m of oil bearing chalkstone were drilled through. The results from 2/11-6 are encouraging, but it is too early to tell whether the occurence can be exploited commercially. According to the operator, one more well must be drilled to obtain more certain figures as to the reserves on the Hod field.

The platforms at Valhall are planned so that any production from Hod can be processed at Valhall A.

The Sleipner area

The Sleipner area includes blocks 15/5, 15/6, 15/8 and 15/9. Block 15/5 was allocated in 1977 with Hydro as operator. Block 15/6 was allocated in 1969 with Esso as operator. Blocks 15/8 and 15/9 were allocated in 1976 with Statoil as operator.

The first find in the area was made by Esso in 1974 in block 15/6. At the end of 1981, there were a total of 17 finished wells, of which 11 were in block 15/9. In the course of 1981, five wells were completed in the area, one in block 15/8 and four in block 15/9.

Well 15/8 in the Alpha structure is the first one to be drilled in this block. Three separate hydrocarbon-bearing zones were encountered in rocks of jurassic age. The highest zone, presumed to be sandstone of callovian age, is 58 m thick, of which 42 m is net hydrocarbon-bearing sand.

In the underlying Sleipner formation, hydrocarbon-bearing sand layers were also discovered. The top layer lies a good 200 m under the upper reservoir, and is only 16 m thick. The bottom reservoir lies an additional 250 m deeper and is approx. 30 m thick.

Three different zones were tested. The best test gave the following result: 668,000 Sm3 gas and 380 Sm3 condensate per day through a 22 mm choke. The carbon dioxide content was 10%.

Well 15/9, which was drilled on the edge of the Epsilon structure, is the first well in this structure. Gas-bearing mid-jurassic sand of good quality was demonstrated. Drilling penetrated approx. 165 m of gross sand above gas/water contact, of which the top 70 m were of very high quality.

The well was tested in three different zones. The best test result was 915 000 Sm3 gas and 245 Sm3 condensate per day through a 25 mm choke. The carbon dioxide content was 7%, which is normal for the area.

Well 15/9-8 is the second well in the Delta structure, which lies to the east of the Beta and Epsilon structures and is separated from these by a fault. There does not seem to be any direct connection between Delta and the other structures. The well has been drilled near the top of the structure and 119 m gross of gas-bearing sand of middle jurassic age were demonstrated above gas/water contact. Only the upper approx. 50 m are of good quality, while the rest is alternately sand and slate. An interval in the top zone was tested which produced 8.1 million Sm3 gas and 285 Sm3 condensate per day through an 18 mm choke. The carbon dioxide content was 7% here.

Well 15/9-10 was drilled on the Eta structure. The well was found to be dry.

New finds in the Sleipner area - 15/9 Gamma

Well 15/9-9 is the first on the Gamma structure, a separate structure approx. 5 km south east of the Delta structure.

Quite unexpectedly, gas-bearing sand was encountered here dating from the paleocene period (Heimdal formation). This is the first find of gas in sand of paleocene age in this block. Drilling penetrated 82 m net of gas-bearing sand of good quality with porosity over 20%. The whole reservoir in the block bore gas, so no gas/water contact was registered. The reservoir was tested with the following result: 583,400 Sm3 gas and 295 Sm3 condensate per day through a 25 mm choke. This gas was almost free from carbon dioxide, which contrasts with the high carbon dioxide content usual for jurassic reservoirs in the Sleipner area.

The well was drilled further through jurassic sandstone and terminated in rocks of permian age. Traces of hydrocarbons however, were only noted in the jurassic.

Well 15/9-11 is an appraisal well on the north-west flank of the gas-bearing paleocene structure which was discovered in 15/9-9. Here, drilling penetrated 52.5 m net of gas-bearing sand above the gas/water contact then established.

The test gave 8.92 million Sm3 gas and 387 Sm3 condensate per day through a 32 mm choke. The carbon dioxide content was less than 1%. The total height of the gas column from the top of the structure to the gas/water contact is about 120 m.

The well was drilled on through a 30 m thick sandstone reservoir of presumed triassic age which contains gas. The reservoir was tested with the following favourable result: 566,400 Sm3 gas and 246 Sm3 condensate per day through a 17 mm choke. The carbon dioxide content is low here too, between 0.5 and 1%. The extent and geometry of this reservoir have not yet been finally established.

Reserve estimates

Recoverable gas reserves in the 15/5 structure and the main structures Alpha, Beta, Delta and Epsilon in blocks 15/6 and 15/9 amount to approx. 140 billion Sm3 with a carbon dioxide content in the latter four varying between 4.8 and 9%. Recoverable reserves of condensate in these structures amount to approx. 12 million Sm3. Provisional reserve estimates for 15/8-1 are considered to be 10 billion Sm3 gas. The provisional reserves in 15/9-Gamma are estimated at 80 billion Sm3 gas. This last reserve estimate is highly uncertain.

Balder

Block 25/11 was allocated in 1965. The blocks 25/8 and 25/10 were allocated in 1969. Esso is the operator for all blocks.

The Balder field includes blocks 25/10 and 25/11. The field was discovered in 1974 by drilling 25/11-5. Oil was found in sandstones of paleocene age. In block 25/8, north east of Balder, small amounts of oil in corresponding sandstone have been demonstrated.

A landing application was submitted in December 1980. Because of uncertainty regarding the size of the reserves following drilling of 25/11-9 and 25/10-4, the landing application was retracted. No decision to develop the field has yet been taken.

In 1981, six wells were drilled in the Balder area. In addition, well 25/10-4, which had been started in 1980, was completed in 1981.

Well 25/8-3 was drilled to examine a separate structure north east of Balder. An oil-bearing sand layer approx. 10 m thick was found, but the well was not tested.

Well 25/10-4 was drilled in the western part of Balder. The top of the reservoir was encountered approx. 40 deeper than expected. 19 m of oil bearing sand was detected.

In well 25/10-4, finds were made in sandstone of eocene age. The well was tested, and the best test gave a good result: 515 Sm3 oil per day through a 25 mm choke.

Well 25/11-10 was found to be dry.

Well 25/11-11 was drilled more towards the centre of the field. 45 m gross and 30 m net of oil-bearing sand was detected. Well 25/11-12 was shown to be dry. Well 25/11-13 was drilled in the eastern part of Balder field. The well revealed approx. 13 m of oil-bearing sand. The negative results from 25/11-12 and 25/11-13 reduce the recoverable reserves to 35 million Sm3 oil.

Block 30/6

The block was allocated in 1979 with Statoil as operator.

So far there have been four wells drilled on the Alpha structure in the western half of the block, and one well (30/6-5) on a lesser structure (the Beta structure) in the north east of the block. The Alpha structure extends into block 30/9. Gas has been demonstrated in three wells in the Alpha structure, with good reservoir properties and high production rates in the gas zone. In the fourth well, oil was detected. The whole reservoir in the well was oil-bearing. Oil/water contact was not established, but gas/oil contact was estimated from the test results of the four wells. The total hydrocarbon column is over 500 m, approx. 400 m bears gas and a little over 100 m bears oil.

New find - 30/6-Beta

Well 30/6-5 was drilled on the Beta structure, which is a small structure in the north east of the block. Oil had previously been demonstrated further north in the same structural complex during the drilling of 30/3-2. The oil/water contact in these two finds is different. Therefore, there is probably no connection between the two reservoirs. In the drilling of 30/6-5, hydrogen sulphide gas (H2S) was encountered for the first time on the Norwegian shelf. This means that special test equipment is required, and tests were not taken. The block contains three structures which have not yet been drilled.

Reserve estimates:

Reserves in the Beta structure are being evaluated.

The Norwegian Petroleum Directorate has estimated the recoverable resources in the Alpha structure to 117 million Sm3 oil and 60 billion Sm3 gas.

Reservoir characteristics are extremely good, and because there exists a large gas head over the oil which gives the reservoir great driving power, the indication is that everything points towards to a high degree of oil recovery.

Block 31/2

The block was allocated in 1979 with Shell as operator.

The field was discovered in 1979 and contains large amounts of gas. Considerable quantities of oil exist in a thin but not uniformly thin zone below the gas. The find extends into the neighbouring blocks 31/3, 31/5 and 31/6.

At present there are six wells drilled in the structure.

The Norwegian Petroleum Directorate estimates the recoverable reserves to be: 480 billion Sm3 gas and 120 million Sm3 oil.

The expected reserves in the undrilled parts are of the order of 1100 billion Sm3 gas, but these are somewhat uncertain.

One new well has been drilled in 1981 (31/2-6), and tests have been made in a further two wells, 31/2-1 and 31/2-5.

31/2-1

This well has been temporarily plugged and abandoned for over two years. The oil zone in it is present in poor (mica rich) sand, and hydrocarbon saturation was therefore registered under the established oil/water contact for the field, which is some 1560 m below sea level. Tests were performed in two intervals below this level. The results were negative. After two minutes flow, production stopped. A total of approx. 1 cubic meter formation liquid was produced.

31/2-5

31/2-5 was drilled in 1980, but testing was postponed to 1981.

The object of the oil test was to obtain information as to how great an oil production could be obtained without recovering large amounts of gas from the layers above and water from the underlying layers together with the oil. The oil zone in this well was approx. 21 m thick. In the other wells further east, the oil zone is only half this thickness (10-12 m).

A uniform production of 906 Sm3 per day was measured over a ten day period with a gas/oil ratio of approx. 53 Sm3/Sm3.

The well was brought to a top production of approx. 1240 Sm3 oil per day over a period of two days. The gas/oil ratio then increased to 224 Sm3/Sm3.

Water production during the whole test period was approx. 3%.

The oil has a density of 0.88 (29° API) and was produced through a choke of 25 mm. The results of test production must be considered encouraging.

31/2-6

Wekk 31/2-6 lies right on the boundry with block 31/3 on the north east part of the structure. Gas and oil were demonstrated in sandstone layers of jurassic age as in the other wells in the block. The gas zone is 80 m thick and the oil zone approx 10 m.

Shell has completed quite an extensive test program. The gas was tested with a maximum production of up to 1.7 million Sm3 gas per day through four chokes, each of 49 mm. The gas has a relatively low condensate content. The density of the gas relative to air is 0.6. The oil zone was also tested, and a uniform production of 127 Sm3 per day was measured through an 8 mm choke over a five day period. During this time, the gas/oil ratio rose from 60 Sm3/Sm3 to 295 Sm3/Sm3 due to seepage from the overlying gas reservoir. The oil has a density of 0.89 (28^{o} API).

Recovery prospects

Because of the reservoir depth and the thickness of the oil zone, the oil is difficult to recover. Therefore, active research is being undertaken by the operator to determine the technical and economic possibilites of producing oil alone or in some combination with simultaneous gas production. Before the decision can be made, it is also necessary to study the geological and reservoir properties more closely.

Additional new wells are to be drilled in the western section of the block in 1982. On the basis of these drillings and the test results of the trial production mentioned in 1981, the well which is best suited for a more longterm (2-4 month) test production of oil will be selected. For this, a semi-submersible drilling vessel will be employed as drilling platform with loading directly onto the tanker. This will presumably take place in the summer of 1983.

Any full-scale pilot project will be decided upon when the results of the longterm oil test have been assessed.

34/10 Delta East Phase II

The block was allocated in 1978 with Statoil as operator.

The first find in the block was made in 1978. The commerciality assessment was presented in November 1980. On 10 June 1981, development of 34/10 Delta East was dealt with in the Storting and the government received authority to approve the first phase of the development following approval by the Norwegian Petroleum Directorate and the Ministry of Petroleum and Energy of the development plan. The revised development plan for Phase I, west of the main fault, was finally approved on 9 October 1981.

Phase II of the development includes the area east of the main fault between wells 34/10-4 and 34/10-9. The depth of water in this area is considerably greater than in the area covered by Phase I.

So far five wells have been drilled in that part of the Delta structure which is included in Phase II development. In addition, there is a sixth well, 34/10-14, being drilled. In 1982 a further well in this part of the Delta structure is planned.

Reserves

The Norwegian Petroleum Directorate estimates that 53% of the proven reserves in the Delta structure lie to the east of the main fault.

The Directorate estimates the recoverable reserves in Phase II to be 102 million Sm3 oil and 12 billion Sm3 gas.

2.2.3.4. New fields declared commercial

No commerciality declarations were submitted i 1981.

2.3. Fields being planned, developed or in production

At the end of 1981, production was taking place on the following fields: Statfjord, seven fields in the Ekofisk area, Frigg and Murchison.

Valhall, North-East Frigg, Odin and Statfjord were under development and 34/10, Heimdal and Ula were being planned.

Sixteen production wells were started in 1981. The greatest drilling activity has occured on Statfjord A, Eldfisk and Albuskjell. At the end of the year, the total number of drilled or initiated production wells on the Norwegian shelf was 213. Of these, 24 drain the British sector of the Frigg field. See Table 2.3.

There were a total of 12 drilling units in operation with production drilling. Totally, there was a decided increase in heavier maintenance operations, particularly in the Ekofisk area. This is mainly due to the fact that some of the production equipment in the well is now coming to reflect its long period in operation.

The costs for this drilling reached a total of approx. NOK 920 million, which gives a mean cost of approx. NOK 60 million per well.

TABLE 2.3 Production wells by field

Field	For 1981	Total	Well maintenance
Valhall	1	1	-
Ekofisk	-	46	8
Eldfisk	4	35	4
Albuskjell	4	23	3
Tor	1	14	1
Edda	-	10	-
Hod	-	8	1
West Ekofisk	-	12	6
Frigg	-	48 (24 on Norw side)	-
North-East Frigg	1	1	-
Statfjord	5	15	-
	16	213	23

Ekofisk

No new wells have been drilled on Ekofisk in 1981. In all, 46 wells have been drilled on the field, 14 at the A platform, 20 at the B platform and 12 at the C platform. Of these, 37 are in production, five are being used for gas injection and one for water injection. One previous gas injection well has been closed down, and two wells are not producable. Of the approved drilling program, one well remains (2/4-b-12). This will be drilled in 1982.

Eldfisk

On Eldfisk, four new wells were started in 1981, three at the B platform and one at the A platform. In all, 31 wells have been drilled to full depth on the field, 22 at the A platform and nine at the B platform. Of these, 25 are in production, four are not producable and two are temporarily abandoned. One well is being drilled from each platform.

Albuskjell

On Albuskjell in 1981, four new wells were started, one at the A platform and three at the F platform. In all, 22 wells have been drilled on the field, ten at the A platform and 12 at the F platform. Of these, 18 are in production, one is not producing and three have been temporarily abandoned. One well is being drilled from the F platform. According to the present program, production drilling has been completed for the A platform, while the final F platform well is being drilled.

Tor

One well has been drilled on Tor in 1981. In all, 14 wells have been drilled on the field and 11 of these are in production. One well was given up at shallow depth, and one is temporarily abandoned. The final well approved by the drilling program is now being drilled.

Valhall

At Valhall, 23 of the 726 mm conductor pipes have been placed, and drilling was started on 14 November 1981 to set the 20" casing pipes. Drilling of the first production well started at the end of the year.

Statfjord A

There were three wells drilled at Statfjord A in 1981. In all, 14 wells have been drilled on the field, six in the north and seven in the south shaft. There are nine wells in production, and there are also four gas-injection wells and one with water injection. At year´s end, one well was being drilled.

Statfjord B

On 4 November 1981, drilling was started to set conductor pipes at Statfjord B.

North-East Frigg

Production drilling was started in December 1981. The wells are to be drilled through a bottom template from the mobile drilling vessel "Byford Dolphin".

Murchison

This platform lies on the English side of the boundary line and drilling licences etc. are therefore awarded by the English authorities. Of the reserves in the field, 16.25% lie on the Norwegian side of the boundary.

2.3.1. **Valhall**

Production licence 006.

Concession holders

Amoco Norway Oil Company A/S	28.33 %
Amerada Petroleum Corporation of Norway A/S	28.33 %
Texas Eastern Norway Inc.	28.33 %
Norwegian Oil Consortium A/S & Co.	15.00 %

The Valhall field lies mainly in block 2/8. The southern part of the field stretches into block 2/11, production licence 033. In this production licence, all the above-mentioned companies have a 25% share. Amoco/Noco applied for landing permits for petroleum from Valhall and Hod (block 2/11) in the autumn of 1976. Development during the first stage includes one accomodation platform, one drilling platform, one production platform and one riser pipe platform The first three platforms mentioned stand on the Valhall field and are connected to eachother by bridges. Figure 3.2.1 shows these installations. The riser pipe platform is connected to the Ekofisk tank.

The work of projecting has been done by Valhall Engineering Joint Venture. This company consists of A/S Aker Mekanisk Verksted, Brownaker Offshore A/S and Kverner Bruk A/S. Amoco is operator for the development.

Production facilities

At the end of 1980, only the steel base of the accomodation platform had been positioned on the field. During 1981, there has been extensive activity on the field with these main tasks:

- placing of steel base of platform
- placing of steel base of production platform
- installation and connection of deck and modules to drilling plarform
- connection to accomodation platform
- installation of deck and modules on the production platform

In addition to these tasks, both the steel base and the deck of the riser pipe platform have been installed at the Ekofisk tank and connected to it by bridge.

In the course of the year, both the accomodation platform and the drilling platform were completed. Drilling of the first production well was started in December after 23 of the conductor pipes and 6508 mm casing pipe had been set.

During November and December, Amoco carried out an extensive lifting program including installation of the deck and modules for the production platform. Considering the season, this work was carried out extremely quickly and will make it possible to start connecting up at the beginning of January 1982. According to the operator, this work will take approx. ten months. Production from the Valhall field will be able to start on about 1 November 1982, according to the same source.

At the end of 1981, something over 90% of the total work in connection with the first stage of the Valhall development had been completed.

Recovery of reserves

Valhall´s geology and reservoir are similar to the fields in the Ekofisk area. The total recoverable amounts in the Valhall field are estimated to be 61 million Sm3 oil and 47 billion Sm3 gas.

Considerable efforts were made in 1981 to evaluate the effect of gas injection at Valhall. In the spring of 1981, the concession holder presented reservoir studies which showed marked gains in oil produced if gas is injected. The Norwegian Petroleum Directorate has made estimates for the production prospects with and without gas injection. Without gas injection, it is expected that only approx. 32 million Sm3 oil will be recoverable from Valhall A. This represents about 14% of the reserves which are covered by the Valhall A development. Gas injection will increase the recovery ratio to approx. 16%.

If the other parts of the Valhall field are not developed, the recovery ratio for the field as a whole will only be about 9% (without gas injection). This is the poorest result for any field on the Norwegian continental shelf. It is therefore important to evaluate thoroughly both the development of periferal parts of the field, and the choice of development strategy.

The Amoco/Noco group has itself selected to focus on water injection as a method of increasing recovery at Valhall. Reservoir data indicate however, that conditions are not so suitable for water injection at Valhall as for example at Ekofisk. It is therefore not to be assumed that water injection can replace gas injection as the method of assisted recovery at Valhall. The Valhall platforms have been planned so that any production from Hod may be processed on Valhall A.

The operator´s estimated times of start for drilling and production were originally October 1980 and September 1981 respectively. Drilling of the first 508 mm conductor pipe well was undertaken in December 1981, some 13-14 months behind schedule. Present progress indicates that production start will be subject to a corresponding delay.

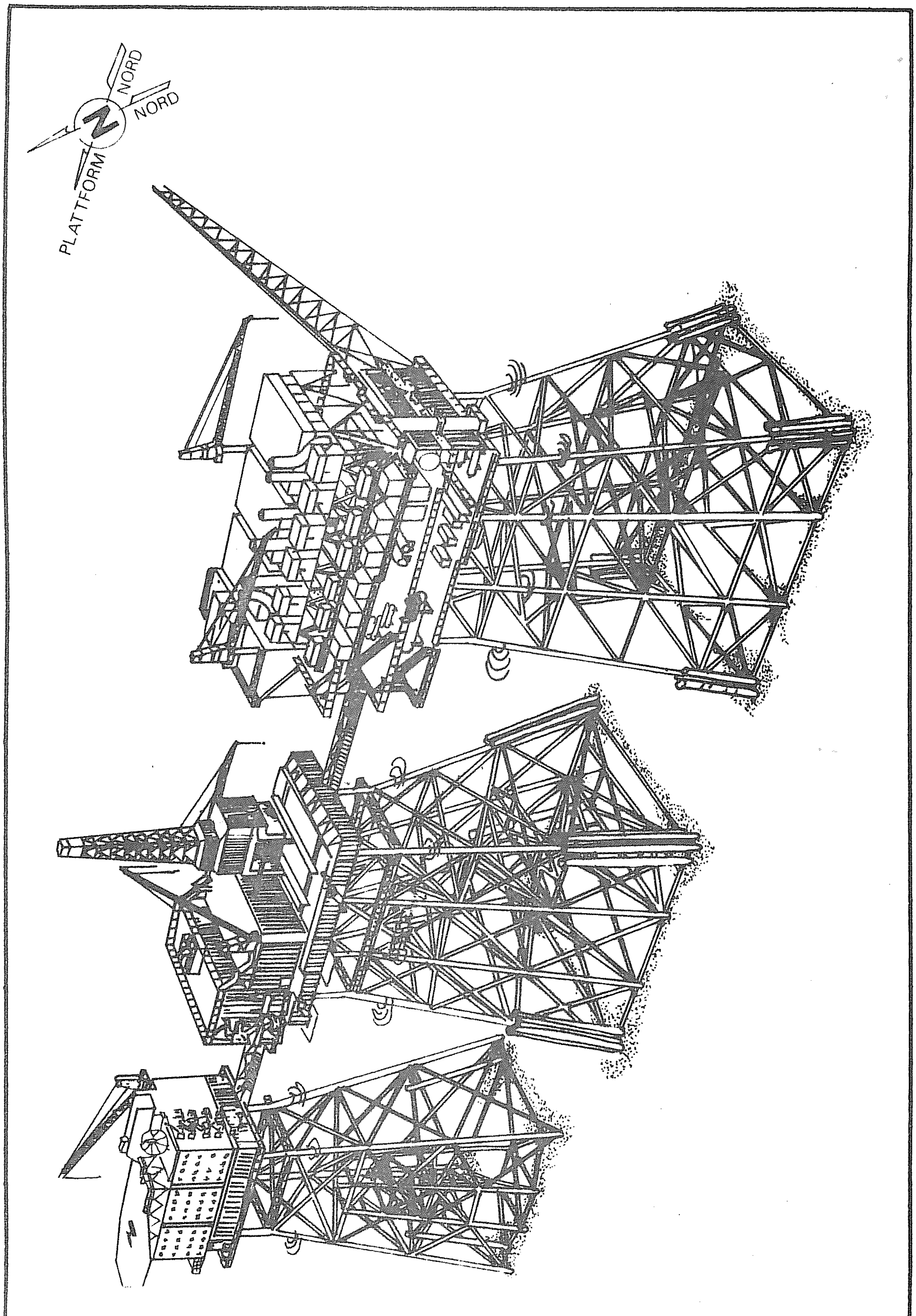
Metering system

The metering system for Valhall oil and gas has been approved so far and the next phase will be control of start up and operations out on the field.

Costs

The cost estimate for development was NOK 3660 million (NOK/$ 5.50). At the same exchange rate the development costs were estimated at NOK 4530 million. Including the costs of production drilling and drilling modules, the total cost for development will amount to NOK 6070 million. The cost estimate for production drilling has been adjusted upwards from NOK 600 million to approx. NOK 1300 million. All figures are stated at current monetary value.

FIGURE 2.3.1



INSTALLATIONS ON VALHALL

2.3.2. The Ekofisk area

Production licence 018

Concession holders

Phillips Petroleum Co Norway A/S	36.960 %
Norske Fina A/S	30.000 %
Norsk Agip A/S	13.040 %
Norsk Hydro Produksjon A/S	6.700 %
Elf Aquitaine Norge A/S	8.094 %
Total Marine Norsk A/S	4.047 %
Eurafrep Norge A/S	0.456 %
Coparex Norge A/S	0.399 %
Cofranord A/S	0.304 %

The above-mentioned companies ("The Phillips Group") hold the licences to the fields Ekofisk, West-Ekofisk, Cod, Eldfisk and Edda (Fig. 2.3.2.a). The two fields mentioned first lie in block 2/4. Cod lies in block 7/11, and Eldfisk and Edda in block 2/7.

The fields Albuskjell and Tor have been divided between licence 018, and licence 011 and licence 006, respectively. Albuskjell lies in block 1/6 and 2/4, and the Tor field in block 2/4 and 2/5.

Albuskjell:

Licence 018:	"The Phillips Group"	50 %
Licence 011:	A/S Norske Shell Exploration and Production	50 %

Tor:

Licence 018:	"The Phillips group"	70.8230 %
Licence 006:	"The Amoco Group"	29.1770 %

Licence 006 ("The Amoco Group") consists of:

Amoco Norway Oil Company A/S	28.33 %
Amerada Petroleum Corporation Norway A/S	28.33 %
Texas Eastern Norway Inc.	28.33 %
Norwegian Oil Consortium A/S & Co	15.00 %

The Ekofisk area thus consists of seven fields: Ekofisk, West-Ekofisk, Cod, Tor, Eldfisk, Edda, and Albuskjell. The first field, the Cod field, was discovered in 1968. In 1969, the Ekofisk field was discovered, and as early as 1970 the field was declared to be commercial. The other fields in the area were discovered in the period 1969-1972. The Cod field which lies 80 km from Ekofisk is not commercial as a separate unit, but it was decided that it should be developed as it could be connected to the Ekofisk facilities. Phillips is the operator of all seven fields.

THE EKOFISK AREA

FIGURE 2.3.2.a

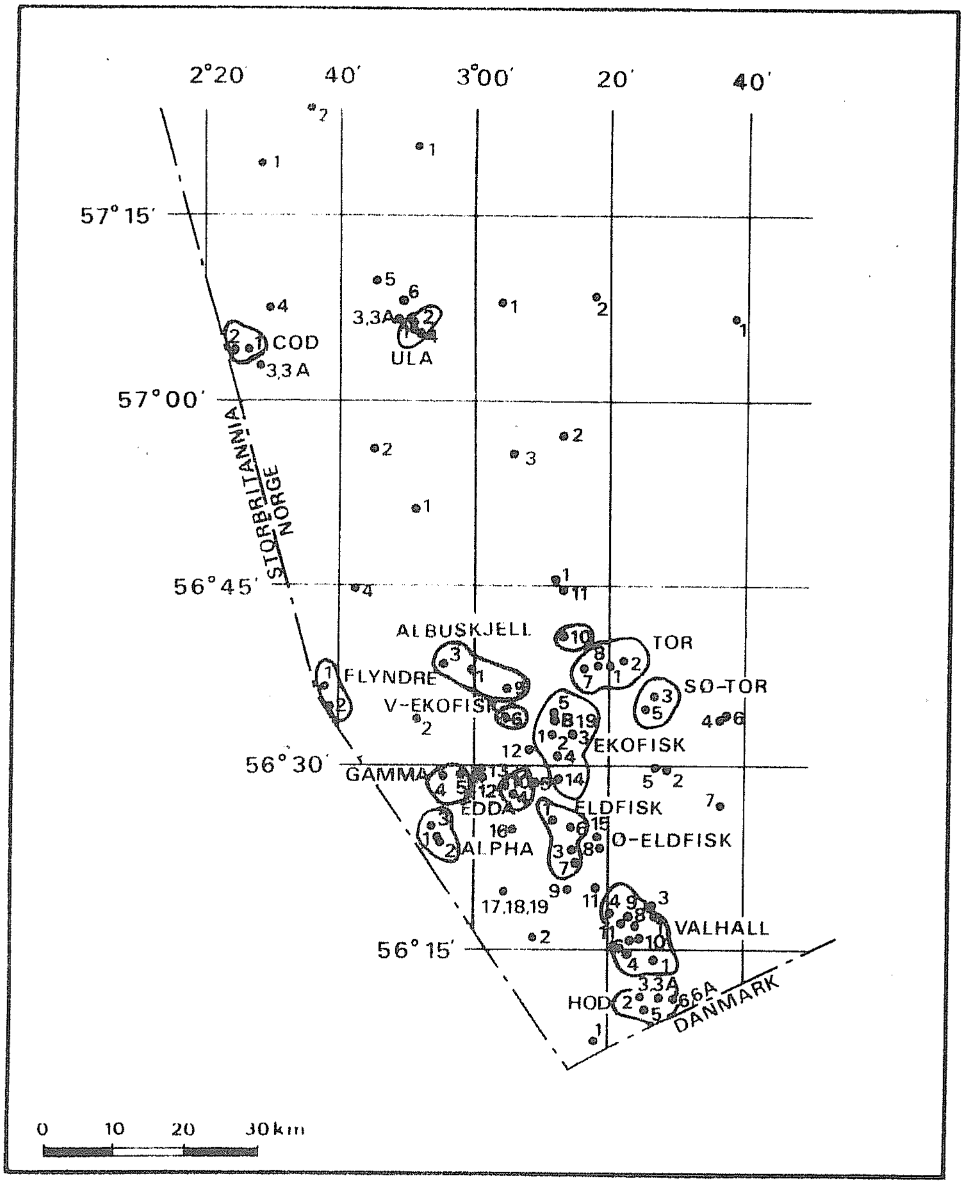
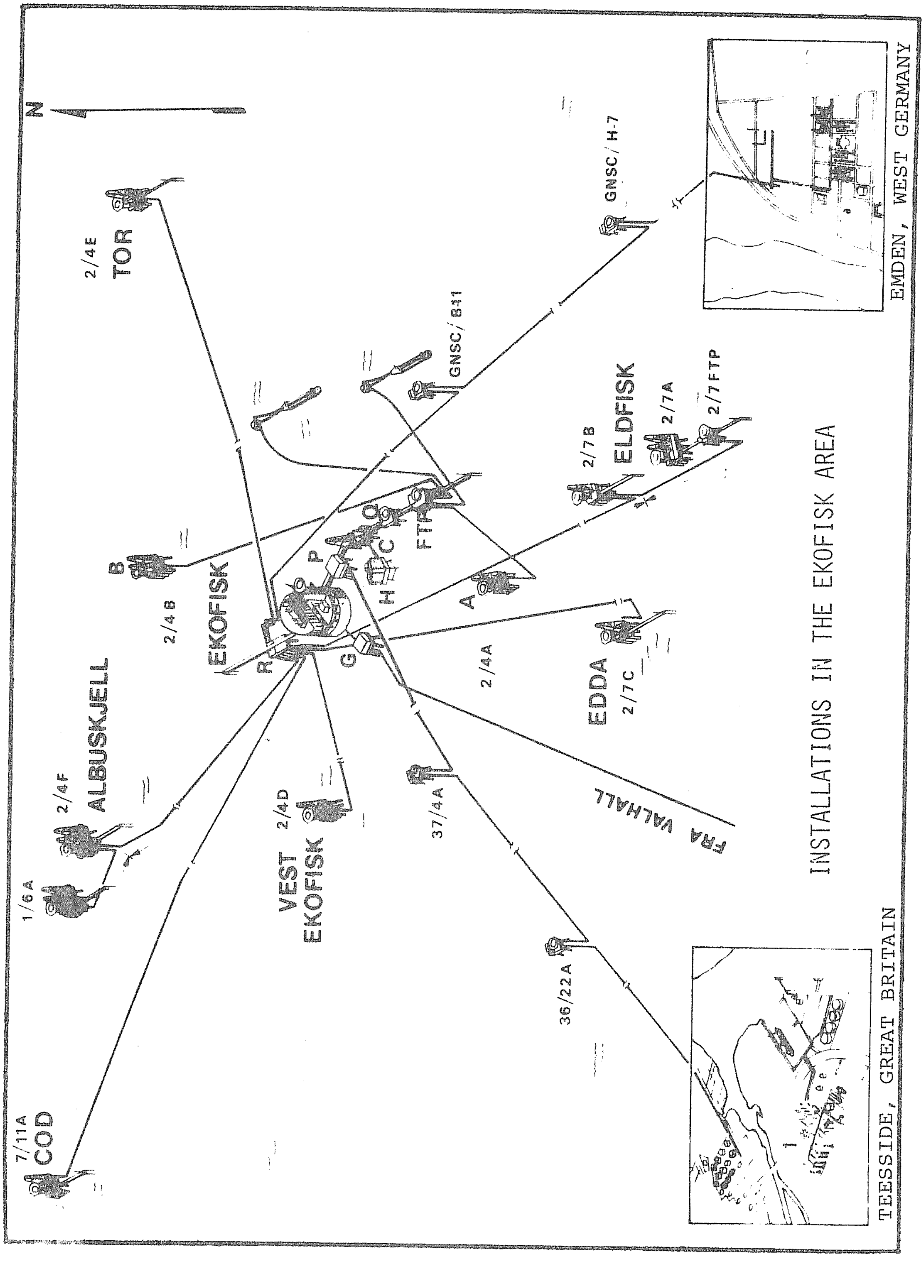


FIGURE 2.3.2.b



INSTALLATIONS IN THE EKOFISK AREA

The fields have been developed in four phases:

Phase 1: Test production on the Ekofisk field from four completion wells on the sea floor. This phase lasted from June 1971 - May 1974

Phase 2: Construction of the platforms at Ekofisk.

Phase 3: The development and connection of the fields West-Ekofisk, Cod, and Tor to the Ekofisk center, and the laying of an oil pipeline to Teesside and a gas pipeline to Emden. The lines were entered into operation in October 1975 and September 1977, respectively.

Phase 4: Development and connection of the Eldfisk, Edda and Albuskjell fields to the Ekofisk center.

A fifth phase is now being planned. This phase will consist of an extensive water injection project if the preliminary project at platform 2/4 B is successful.

Figure 2.3.2.b shows an outline of the installation in the Ekofisk area.

Transport

Oil and gas from the Ekofisk area will be brought to shore through pipelines to Teesside and Emden, respectively.

The oil pipeline to Teesside, England, is 354 km long and has a diameter of 860 mm. In 1981, the average flow rate was 57,290 Sm3 of oil per day.
The gas pipeline to Emden, West-Germany, is 442 km long and has a diameter of 915 mm. During 1981 an average of 38.4 million Sm3 gas per day was transported.

Production facilities

All of the seven fields in the Ekofisk area are completely developed and in production. In 1981, however, a good deal of construction work remaining was carried out. The main activities were:

- commissioning of the newest platforms
- connection of water injection equipment on platform 2/4 B
- connection of new generators on the riser platform 2/4 R

At the end of the year practically all this work had been completed.

In 1981 there were no significant technical production problems. However, all fields, with the exception of Ekofisk, were shut down for the period 4 August - 22 August 1981. During this period the production from Ekofisk was limited by the gas injection capacity. In the period 9-11 August 1981, the Ekofisk field was also shut down as a result of maintenance work at the Teesside terminal.

The shutdowns were planned well in advance. This explains why a considerable amount of maintenance work requiring plant shutdown could be carried out.

Examples of the work done:

- replacement of the two flare stacks on the Ekofisk center
- repair of valves on the pumping platforms on the gas pipeline to Emden,
- visual internal control of pressure vessels and separators, etc.

A similar shutdown last occured in the autumn of 1979.

In the month of March, a routine underwater inspection of the West-Ekofisk platform revealed cracks on the conductor template. Calculations were carried out which showed that the cracks were not dangerous to the installation in the short term. The cracks were repaired during the summer.

In July, damage was discovered on the inlet riser pipe to pump platform B-11. The damage had probably been caused during installation of the corrosion protection jacket. The operational pressure was reduced for a short period of time until it had been verified that the damage was not serious.

Recovery of reserves

Both the operator of the Ekofisk area, Phillips, and the Norwegian Petroleum Directorate have been occupied with the possibility of increasing oil recovery from the fields by water injection. The preliminary project on the Ekofisk field, where water is injected in one of the wells, was started in March. During the year approx. 0.5 million m3 of water has been injected.

A separate program has been set up for the collection of data from this preliminary project in order to make it possible to clarify with some degree of certainty just how much oil recovery may be increased by water injection.

A detailed plan of full scale water injection at the Ekofisk field is being prepared in parallel with the preliminary project, in order to avoid wasting time in the event of decision to adopt such a plan. It would be possible to make such a decision sometime during 1982, and this would entail the construction of at least one new, large platform. Water injection on a large scale may be commenced in 1986 at the earliest. The total investment (incl. drilling of wells) for a platform would amount to approx. 5 billion 1981-kroner.

In 1981, Phillips has also made detailed evaluations of water injection at the Tor field. The data basis for this field is more uncertain. In the autumn it was therefore decided to postpone the project pending the results of the preliminary project on the Ekofisk field.

Increased oil recovery from the Ekofisk-field as a result of gas injection has been dealt with in previous annual reports. As a result of the contracted gas delivery obligations, the quantities of gas available for injection into the field will diminish in time. In 1981, approx. 1.0 billion Sm3 of gas was injected. This increased oil recovery by an estimated 1.2 billion Sm3. The Norwegian Petroleum Directorate still retains the goal of limiting production from those parts of the reservoir which contain the most gas, thereby attaining the greatest possible recovery factor.

Flaring of gas in the Ekofisk area

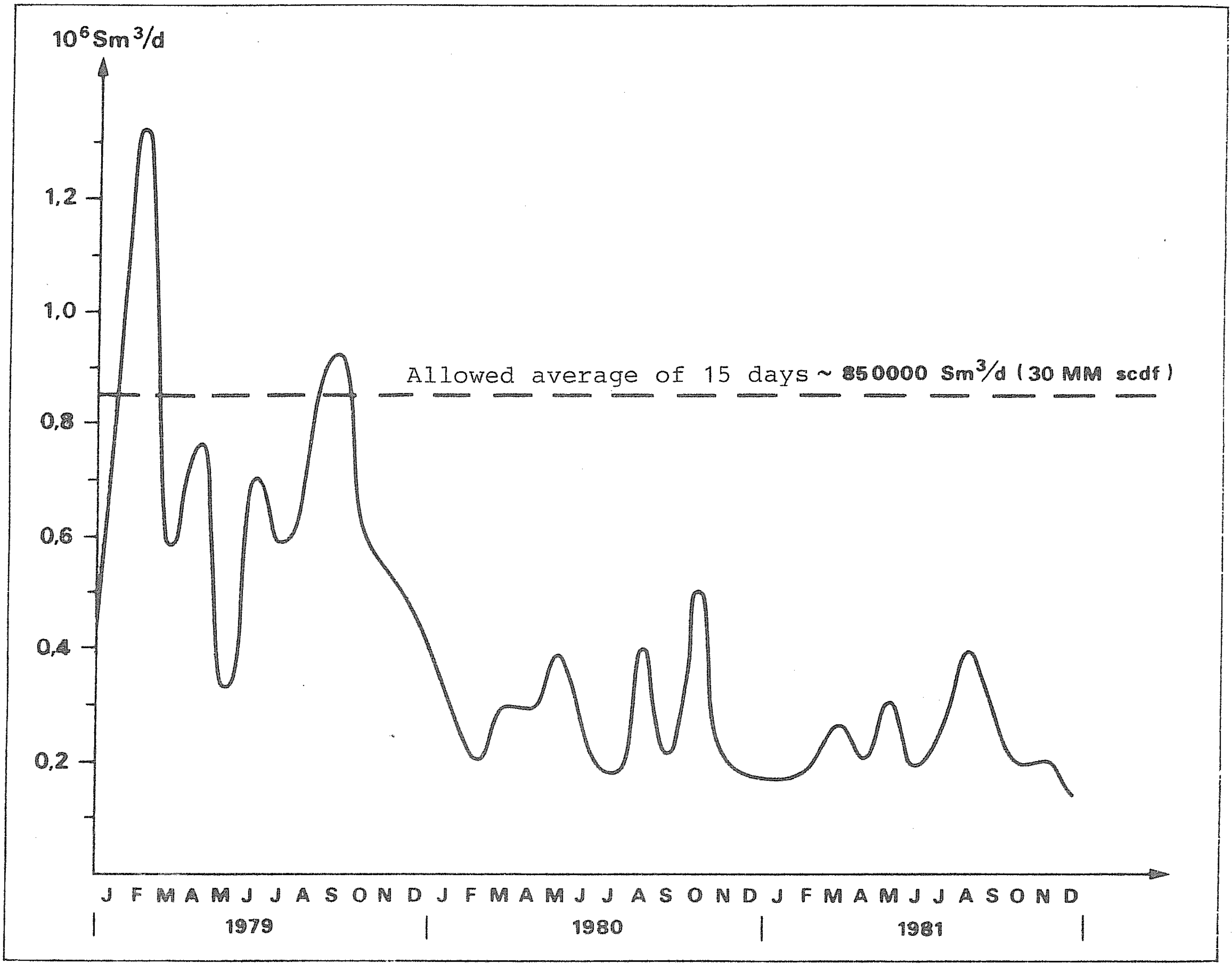
The amount of gas which has been flared can be read from Figure 2.3.2.c. During Phase I of the Ekofisk development from 1971 to 1974, test production was carried out utilising buoy loading, and all gas was flared. From 1977, the gas has been landed and sold through the Emden pipeline, any surplus gas being injected. Since inauguration of the Emden pipeline, the amount of gas flared has been substantially reduced, and 1981 has shown that the flaring rate now seems to have been stabilized at less than 1 % of the total production. Figure 2.3.2.d shows the gas flared as a percentage of total gas production.

Metering system

Working inspections of the metering equipment in the Ekofisk area continued until 1981, during which time the Norwegian Petroleum Directorate had an inspector present on the field at all times. Due to personnel retirement, the extent of this inspection was reduced in 1981. Inspection of the metering system at the sales site for the gas in Emden has been performed as in previous years, which is to say by monthly survey.

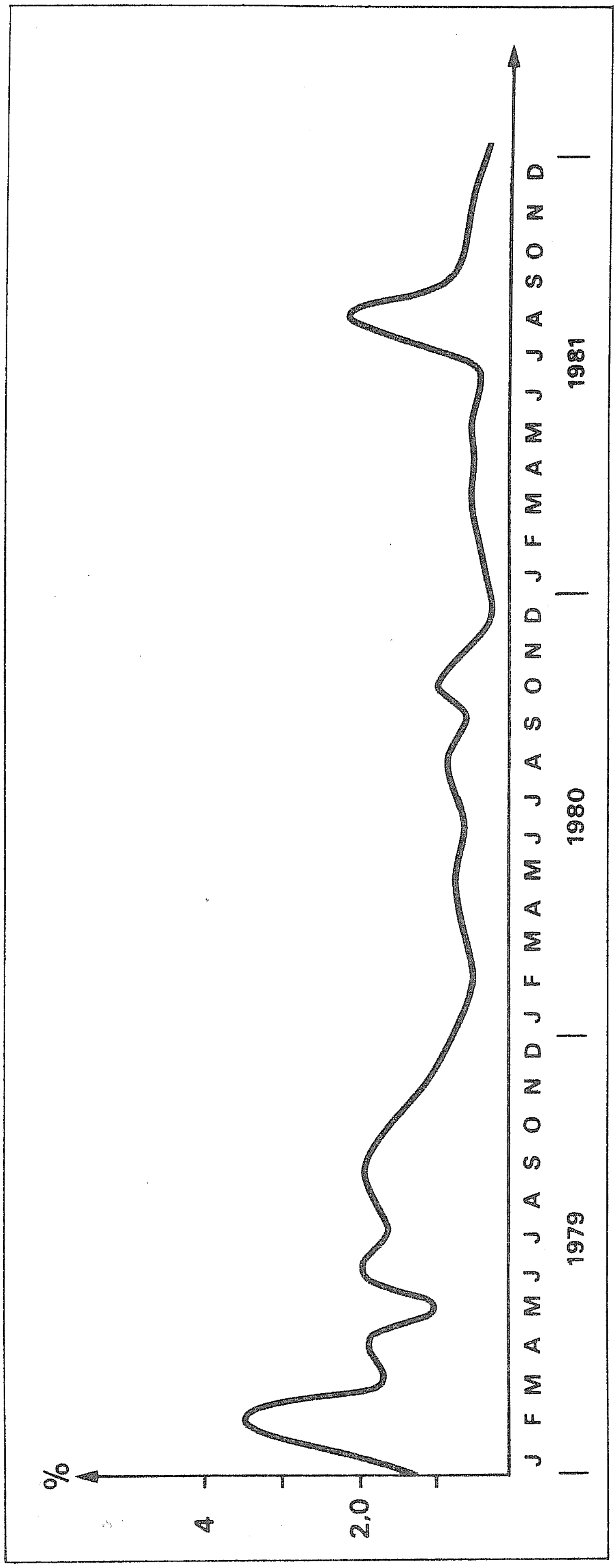
Pending a formal clarification of the right to make inspections at Teesside, no inspection arrangement has been established for the sales metering systems for oil and wet gas at this location.

FIGURE 2.3.2.c



AVERAGE QUANTITY OF GAS FLARED IN THE EKOFISK AREA

FIGURE 2.3.2.d



PERCENTAGE AVERAGE FLARED GAS OUT OF TOTAL PRODUCTION IN THE EKOFISK AREA

Costs

Development of the fields in the Ekofisk area has cost approx. NOK 32 billion in current money value. This amount also includes production drilling, landing systems and terminals.

Safety and working environment

The accomodation standard in the Ekofisk area

The accomodation of employees in living quarters offshore provided by the employer is regulated by the authorities in the Royal Decree of 9 July 1976 (The Safety Regulations) and other regulations issued pursuant to it. However, before the regulations mentioned were made applicable, a letter of 3 September 1975 notified that the requirement for accomodation of a maximum of two persons per room would be made applicable for all installations from the time of starting of drilling.

The Ekofisk fields were partly planned and developed before the above-mentioned resolution entered into force. That the accomodation standard of the Ekofisk fields was not in accordance with all requirements stipulated by legislation and regulations has thus been an ever-recurring problem.

Without doubt, the greatest drawback has been that the capacity of the living quarters is not consistent to the level of activities at the installations. The reason for this is probably an underestimate of the need for accomodation in the planning phase. At the same time, the authorities have, with the increasing amount of experience gained, allowed several activities to be carried out at once (drilling, production, construction, etc.).

In order to maintain the high level of activities, it has been difficult to comply with the requirement that bunkrooms be furnished for a maximum of two persons. During the years, vast resources have been spent, both by the operating company and by the Directorate, on discussions, reports and dealing with issues in connection with the handling of applications for dispensation from this requirement.

In the autumn of 1980, the accomodation situation was considerably worsened, among other things as a result of the unexpectedly large number of activities relating to safety and maintenance. At the same time, there were substantial changes on the rig market which caused great problems in providing additional living quarters in the form of flotels.

In order to relieve the situation, ships were brought in to function as flotels. They were poorly suited to this purpose. The employees became increasingly dissatisfied with the conditions while the operating company showed little desire to bring about a reduction in or a solution to the problems of accomodation. In a letter from the operator to the Directorate in late autumn 1980, it was stated that these accomodation problems ought to be resolved by the authorities by the granting of an exemption from the requirement in the regulations for two persons per room when this was necessary in order to maintain the level of activities.

The Norwegian Petroleum Directorate did not find that it could grant such a general exemption from the regulations unless the high level of activities was related to safety, i.e. that it was necessary to perform the work tasks in order to maintain the level of safety.

With a view to bringing about an improved correlation between the level of activities and the accomodation capacity, the Directorate considered implementing alternative measures:

- to limit the possibility of carrying out several activities simultaneously,
- to order the company to increase the accomodation capacity,
- to modify the regulations so that it would be permissible to accomodate four persons per room.

The consequences will be significant regardless of which solution is chosen. The Directorate, therefore, did not find it proper, administratively speaking, to require the operating company to carry out one specific solution, but to let the company itself find and propose a solution which would provide satisfactory results and which would not entail unacceptable consequences.

In order to contribute to the solution of this acute problem, the Directorate informed the company that it would be willing to grant exemptions from the regulations, providing the company would aim for a permanent solution to the accomodation problem.

Independently of the work carried out by the Directorate, the company had initiated discussions and negotiations between company management and the elected employee representatives with the object of finding a solution to the accomodation problem.

Based on the above situation, the operator decided in the spring of 1981, to provide a permanent solution to the living quarter problem by implementing an extensive renovation program, the cost of which was estimated at approx. NOK 900 million in current money value. Until this program has been completed, it will still be necessary to seek dispensation for deviations from the requirement of the regulations that accomodation be for two persons per room. Pursuant to the Guidelines for Licensee´s Internal Control, the company will administer the use of the existing living quarters independently, according to directives specified in greater detail. A special procedure has been elaborated for this purpose to ensure sound accomodation and to ensure that the accomodation of more personnel per room than is permitted by the regulatory requirement shall only take place with the approval of the personnel. A separate report form has been prepared for submission to the Directorate, to enable the Directorate to make sure, at any time, that the living quarters are administered according to the procedure.

Testing of down hole safety valves (DHSV)

In 1979, a down hole safety valve loosened in well 2/4-B-21 at Ekofisk. Phillips was ordered to present an evaluation of the reasons for this and the measures implemented, at a meeting with the Norwegian Petroleum Directorate. Originally, the operator was of the opinion that this was an accident which could happen to anyone, but a total of eight valves have worked loose so far.

The types of safety valves employed at Ekofisk have insufficient intrinsic safety and have therefore placed great demands on the operators. The follow-up and control of operations carried out by Phillips has previously been inadequate. However, the Norwegian Petroleum Directorate now feels that the measures effected by Phillips have raised the safety factor to a provisionally acceptable level. Using the newly developed equipment for the control of nipples and production tubing, Phillips can keep a satisfactory check on the state of the lock nipples.

Gas compressors (flash) 2/4 Ekofisk tank

The operator has had some problems with the shaft packings on the compressors. In the course of 1981, as many as 13 packings have been replaced. The cause seems to be the design of the packing itself. The damage has been small, but the Norwegian Petroleum Directorate regards this as a serious problem which can have wide-reaching consequences.

Production separators 2/4 Ekofisk FTP

In 1981, corrosion damage was discovered on the 2-step separators. The separators were taken off-line and opened for inspection. In one case, extensive damage was revealed, particularly in the oil/water interface area. The cause was galvanic corrosion. Anodes have now been mounted. The separators will be inspected again after one year of operation. Ultrasonic tests will be made from the outside every four months. Due to the low well pressure, the separators operate at a pressure well below the original design value.

Diesel engines for fire pumps, Ekofisk area

These have broken down a number of times because of overheating following cooling water failure. The cooling water systems have now been rebuilt and improved.

2.3.3. Ula

Production licence 019

Concession holders

BP Petroleum Development of Norway A/S	57.5 %
K/S Pelican A/S	5.0 %
Norsk Conoco A/S	25.0 %
Den norske stats oljeselskap A/S (Statoil)	12.5 %

The field lies in block 7/12 approx. 70 km northwest of Ekofisk. It was discovered in 1976 and declared commercial in December 1979. Statoil conceded the declaration in September 1980. BP is the operator of the production licence.

The recoverable reserves are estimated by the Norwegian Petroleum Directorate at approx. 29 million Sm3 oil and approx. 2 billion Sm3 gas. The operator has a somewhat lower estimate (approx. 24 million Sm3 and 1.6 billion Sm3). In 1981 two wells were drilled: 7/12-5 and 7/12-6.

In December 1980, after about six months of investigative work, it became clear that the chosen concept (a processing/accomodation platform and a wellhead platform) would be significantly more expensive (approx. 50%) than previously estimated. Development would not be profitable based on the figures submitted.

In April 1981, the licensees decided to prepare analyses of alternative concepts. At the end of the period covered by this report, the licensees had not presented revised development plans.

2.3.4. Heimdal

Production licence 036

Concession holders

Statoil A/S	40.000 %
Marathon Petroleum Norge A/S	23.798 %
Elf Aquitaine Norge A/S	9.639 %
Bow Valley Exploration Norge A/S	8.000 %
Norsk Hydro Produksjon A/S	6.228 %
Total Marine Norsk A/S	4.820 %
Sunningdale Norge A/S	3.875 %
Saga Petroleum A/S & Co.	3.471 %
A/S Uglands Rederi	0.169 %

Production licence 036 was awarded in 1971 and covers block 25/4, which is located approx. 32 km south of Frigg and approx. 215 km northwest of Stavanger. For that part of the concession which includes Heimdal, the State has been given a 40 % ownership share. Elf Aquitaine Norge A/S is the operator of Heimdal.

The field was discovered in 1972 by the drilling of well 25/4-1 and was declared commercial in April 1974. Due to low gas prices, the declaration that the field was commercial was withdrawn in 1976.

During 1980, the gas market changed, and Heimdal become a central topic of discussion on a solution for the landing of Statfjord gas. The application for landing of gas on the continent was submitted in January 1981, and was approved by the Storting on 10 June 1981. The gas from Heimdal has been sold to buyers on the continent. It remains to be decided where the condensate from Heimdal is to be landed. The Norwegian authorities hold the option on the Heimdal condensate.

The reservoir lies approx. 2100 m below the surface of the sea, in sand of paleocenic age. The sand in the Heimdal formation is of a relatively good quality.

Development

The Heimdal field contains 48.1 billion Sm3 rich gas. Of this, it is estimated that approx. 70 % is recoverable. The reservoirs may be reached from an installation. It has been decided to develop Heimdal with an integrated steel platform with drilling, production, and accomodation functions (Figure 2.3.4).

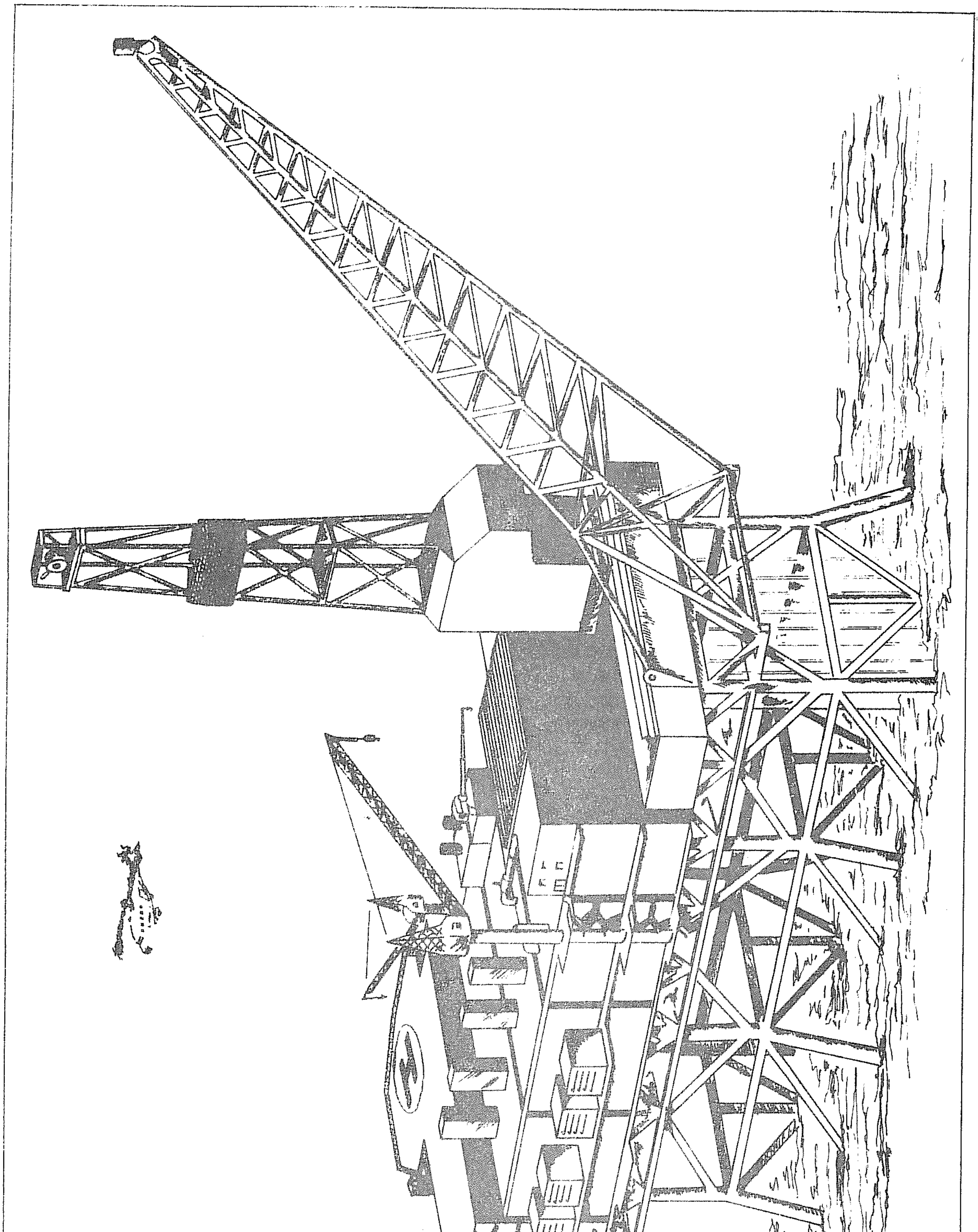
Transportation

For gas transport, the Heimdal field will be connected to the Statpipe system near the Sleipner field. Transportation of condensate will take place either by offshore loading or by pipeline to the Brae field for further connection to St. Fergus in Scotland.

Costs

Total investments have been calculated at NOK 7,825 million in current money value, provided that the landing of condensate takes place through the BRAE-system.

FIGURE 2.3.4



PLANNED INSTALLATION ON HEIMDAL

2.3.5. The Frigg area (Frigg, NE Frigg and Odin)

2.3.5.1. Frigg

Concession holders

Norwegian share (60.82 %) (production licence 024)	
Elf Aquitaine N A/S	25.19 %
Norsk Hydro A/S	19.99 %
Total Marine N A/S	12.60 %
Statoil A/S	3.04 %
British share (39.18 %)	
Elf Aquitaine UK Ltd	25.97 %
Total Oil Marine Ltd	12.98 %
BP Ltd	0.23 %

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

The Frigg field lies in block 25/1 on the Norwegian shelf and in block 10/1 and 9/5 on the British Shelf (Figure 2.3.5.a). The field is unitized. By agreement, 60.82 % of the gas reserves are regarded to belong to the Norwegian licensees and the remaining 39.18 % to the British ones. The agreement on distribution of reserves may be brought up for discussion every four years, the next time being 1 January 1983, or whenever additional reserves are proven which are believed to communicate with the Frigg reservoir. In 1982, it was agreed by the British group and BP that 0.588 % of the British Frigg reserves lie in block 9/5, in which BP has a 100 % share. BP´s interest in the Frigg field is being taken care of by Total Oil Marine.

Production facilities

The Frigg field was discovered in the spring of 1971 and was declared commercial on 25 April 1972. The field has been developed in three phases. Phase 1 consists of a production platform and a processing platform on the British part of the field, and an accomodation platform (CDP1, TP1 and QP). Production from the Phase 1 platforms started on 13 September 1977.

Phase 2 consists of a production platform and a processing platform located in the Norwegian part of the field (DP2 and TCP2). Production from the Phase 2 platforms started in the summer of 1978. Figure 2.3.5.b shows the installation at the Frigg field.

Phase 3 of the development included the installation of three turbine operated compressors of 38,000 HP each on the TCP2 platform. The compressor facility is required to compensate for reduced reservoir pressure. The facility entered into production in the autumn of 1981. The final cost of the Phase 3 development will be approx. NOK 1.293 billion. This is approx. 53 % higher than the estimate which was presented in the spring of 1976, which amounted to NOK 846 million, and which was the first estimate based on a technical solution which was largely similar to the final solution. A substantial share of the cost increase may be explained by the fact that significant alterations were made to the required specifications after project start. Norwegian workshops were utilized to do the work.

Preliminary work is currently being carried out to prepare TCP2 to receive gas from NE-Frigg and Odin.

THE FRIGG AREA

FIGURE 2.3.5.a

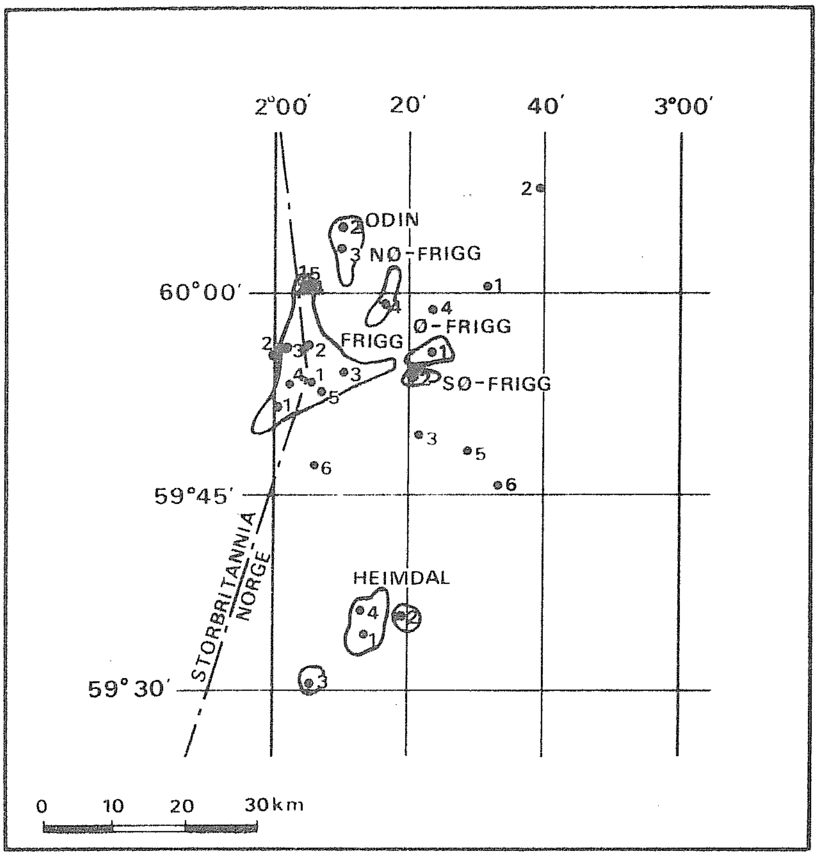
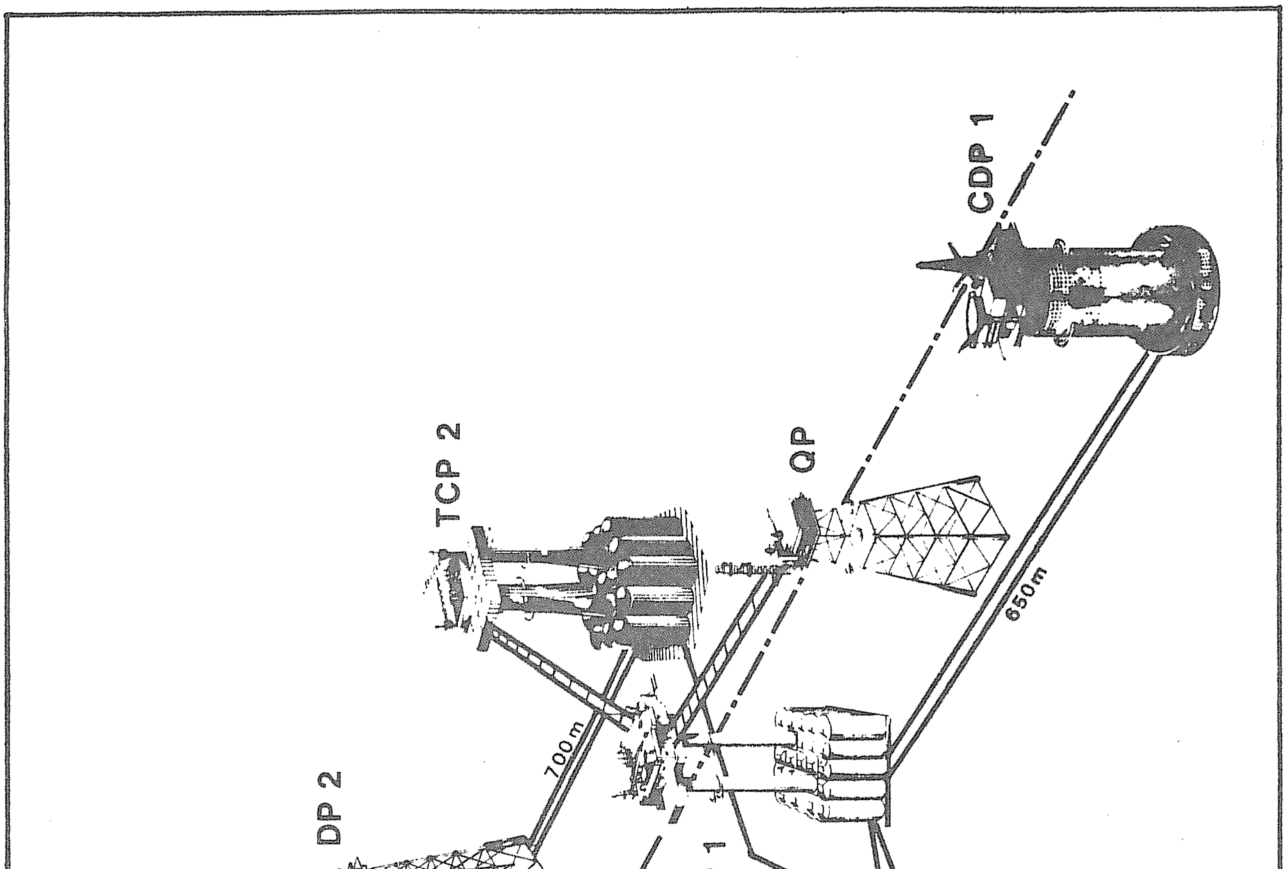


FIGURE 2.3.5.b


CDP 1
QP
TCP 2
DP 2
TP 1
650m
700m
500m
32"
NORGE
STORBRITANNIA
62°
STORBRIT
NORGE

Transportation

The gas is transported to St. Fergus in Scotland through two 813 mm pipelines. In order to increase the capacity of the transport system, two turbocompressors, each rated at 38,000 HP, will be installed on manifold platform MCP 01, which lies midway between Frigg and Scotland. The capacity increase is necessary to enable trasportation of gas from the Odin field. For the same reason, an expansion of the terminal at St. Fergus from five to six processing lines is also being prepared.

The recovery of reserves

In 1981, no new information has been presented about NE-Frigg or the Odin reservoirs in 1981 to alter opinion concerning yield or behavior of the reservoirs.

Oil/water and gas/oil contact in the Frigg field is monitored several times a year. The movement of the fluid interface has been somewhat unstable in 1981. This may indicate that the field is slightly more complicated than previously assumed, with layers of slate which partially prevent the oil and water from moving in the reservoir. However, the "irregularities" are so small that they alone do not provide a reason for reevaluating field reservoir behavoir. Revision of the reservoir model will only be made when new seismic data and results from the production drilling on NE-Frigg have been presented in 1982.

Costs

Total development cost is approx. NOK 16.8 billion in current money value. The Norwegian share represents approx. NOK 10.2 billion.

Safety and working environment

During the inspection in 1981, cracks were again noted in the pressure vessel on the TCP-2 platform. Cracks had also been registered in 1979 and 1980, but these were ground out.

Production on TCP-2 was closed down on 13 June and a thorough investigation was commenced. The Norwegian Petroleum Directorate granted Elf the right to start-up with reduced working pressure after the vessels had undergone pressure testing and subsequent inspection.

The cause of these cracks proved in some cases to be poor welding procedures.

The status at the turn of the year is that the vessels operate with a reduced working pressure, which makes it possible to maintain delivery from Frigg. Work is being done on calculations and tests which may make it possible to return one of the vessels to the original working pressure.

2.3.5.2. NE Frigg

Concession holders

Production licence 024 (Block 25/1)

Elf Aquitaine Norge A/S	41.42 %
Norsk Hydro A/S	32.87 %
Total Marine Norsk A/S	20.71 %
Statoil A/S	5.00 %

Production licence 030 (Block 30/10)

Esso Exploration & Production Norway Inc	100 %

Statoil has rights to 17.5 % of net profit before taxes.

The NE Frigg field is situated in blocks 25/1 and 30/10. Gas reserves are distributed with 60% and 40% respectively in the two blocks. Elf Aquitaine Norge A/S is operator for the development.

Production facilities

Gas was proven in the NE Frigg field in 1974. It is part of the same pressure system as the Frigg field. The final development plan was carried in 1980. The field will be developed with six wells completed on the sea floor. The six wells will be drilled from a semi-submersible drilling rig through a template on the sea floor. The drilling rig will also be used for the work of completion and to install the six underwater christmas trees, and later for any well maintenance. The template was installed on the sea floor in the summer of 1981. Drilling of the first well was started on 24 December, approx. two months later than planned. Aside from the well heads and christmas trees, the frame structure will be equipped with a manifold to gather gas from the six wells. The gas will be transfered to the Frigg field for processing through a 406 mm pipeline. Each of the six christmas trees will be controlled by separate service and control lines from the control station (an articulated column) placed 150 meters from the well heads. The control station will be remotely controlled from the Frigg field.

The sale of gas from NE Frigg started on 1 October 1981, i.e. before any of the production wells had been drilled. This was possible because the Frigg field delivers gas care of NE Frigg until NE Frigg starts producing. Frigg will likewise deliver gas care of NE Frigg after production on NE Frigg has stopped. "Repayment" will take place by NE Frigg, in its short production period, delivering gas care of Frigg in addition to the NE Frigg contract amount.

Thus, a more normal long-term sales profile for the gas from NE Frigg will be achieved, even with its short production period.

The pipelines between NE Frigg and Frigg are prefabricated, and Brown & Root plans to start the work of pipelaying in March 1982. In all, the project at year-end was approx. one month behind a schedule aiming at production start on 1 January 1984.

Use of drilling rigs as floating production facilities

In 1981, Elf Aquitaine Norge A/S applied for a user permit for the semi-submersible Norwegian registered vessel "Byford Dolphin", to undertake production drilling and completion of six production wells on 25/1-B-1, NE Frigg. The drilling was to be carried out with the aid of a template which had previously been placed on the sea floor. With Elf´s application for user rights to "Byford Dolphin", the Petroleum Directorate had to make decisions for the first time on the actual and formal problems concerning the use of mobile drilling vessels as floating production facilities on the Norwegian shelf.

Particularly at the formal/legal level, the Directorate was confronted with a new problem. The current regulations have not taken this new type of activity adequately into account. The Petroleum Directorate therefore had to strike a balance between the legislation pertaining to the continental shelf, shipping and the working environment.

With regard to shelf legislation, the Petroleum Directorate stated that the activity envisaged for "Byford Dolphin" on NE Frigg would be covered by the regulations for fixed installations, cf. Royal Decree of 9 July 1976 on Safety Regulations for Production etc. "Byford Dolphin" was therefore defined as a production facility and its operator would therefore be bound by the rules formulated pursuant to the safety regulations for fixed installations. However, these regulations cannot be applied in full for the practical reason that "Byford Dolphin" is designed as a mobile drilling rig, equipped for exploration drilling. This was expressed in this actual case by the utilisation of a so-called "letter of compliance", which was issued, at the request of the Petroleum Directorate, by the Maritime Directorate. It makes up a part of the documentation which the Petroleum Directorate uses as a basis in the issue of user permits.

The Petroleum Directorate considered in this particular case that the activity of "Byford Dolphin" during operation at NE Frigg, was, as far as concerns the working environment, subject to Norwegian maritime legislation, except for the personnel on board not covered by this legislation. The Petroleum Directorate regards the procedure as a special case, which will not necessarily set a precedent for future, similar solutions.

Cost

The cost of development is estimated at approx. NOK 2 billion at current value.

2.3.5.3. Odin

Production licence 030

Concession holders

Esso Exploration & Production Norway Inc 100%

Statoil has rights to 17.5% and Esso is operator for the development.

Production facilities

Gas was proven in the Odin field in 1974 and the development plan was carried in 1980. The chosen solution for development consisted of a platform on a steel base with four legs and an integral deck. A semi-submersible drilling rig will be used as an auxiliary platform during the drilling phase. The production platform will only to a limited degree be equipped with processing equipment, since the gas will be sent unprocessed to the Frigg field through a 508 mm pipeline.

The platform is designed for 12 wells.

There are nine production wells planned, of which one is a reserve.

The accommodation section is designed for 20 persons.

The construction contract for the steel base has been awarded to the Spanish firm of Dragados y Construcciones, and construction work will be get properly started in January 1982. Contracts for construction of the module frame and main module will be awarded at the beginning of 1982.

The drilling vessel "Treasure Supporter" will be rebuilt and used as an auxiliary platform.

Brown & Root will be laying the pipeline to Frigg, and work will start in March 1982. The pipelaying program is coordinated with Elf and the same pipelaying vessel will lay both the Odin and NE Frigg pipelines. Esso plans production start in October 1984.

Cost

The development is estimated at year-end to cost approx. NOK 2.8 billion at current value.

2.3.6. 34/10 Delta East Phase I

Production licence 050

Concession holders

Den norske stats oljesselskap A/S	85%
Norsk Hydro Produksjon A/S	9%
Saga Petroleum A/S & Co	6%

Statoil is operator and Esso the technical assistant during the exploration phase. Negotiations to determine who will provide technical assistance for the development phase, are presently going on.

Production facilities

The first find in the block was made in 1978. On 10 June 1981, the development plan for 34/10 Delta East was taken up in the Storting and the government was granted full authority to approve the first phase of the development following approval by the Petroleum Directorate and the Ministry of Petroleum and Energy for the development plan. The Petroleum Directorate considers that, with the development solution that has been chosen, the development has been divided into phases that are independent in time. Phase II, the eastern part of the Delta structure, may be postponed indefinitely. The water depth in the east is somewhat greater than in the west, and at least two platforms will be needed in Phase II.

Phase I will include two platforms (Figure 2.3.6). Platform A will be an integrated drilling-processing-accommodation platform with a capacity of approx. 39,000 Sm3 per day. The platform will be located at the south-western part of the structure where the depth of water is approx. 135 m. The platform will have a Condeep base and a T-formed deck frame of steel. A loading buoy will be installed in connection with this platform.

Platform B will be a drilling and accommodation platform, possibly also equipped with limited processing equipment. This platform will be located at the north-western part of the Delta structure where the sea depth is also approx. 135 m. The specifications for platform B are not yet complete.

Phase I will also include of a reserve loading buoy, possibly with a simpler design than the first one.

Gas from the field will be transported through the Statpipe pipeline (cf. discussion of the Statpipe system under Statfjord). It has not been decided whether the link-up is to take place through Statpipe or directly by underwater connection.

Preliminary project planning of platform A is scheduled for completion in July 1982.

Construction of the concrete structure will start in 1982, and part of the other construction and connection contracts will be awarded in 1982.

The operator estimates that platform A will be ready for production by 1 July 1987, and platform B is scheduled to come into operation two years later.

Recovery of reserves

The field is located in the north-eastern part of block 34/10 and covers an area of about 200 sq.km. The proven reserves lie entirely within the block. Figure 2.3.7.a. shows where the field is located in the Statfjord area.

The Delta structure is a relatively shallow field, split by north-south faults in several diagonal and rotated segments of layers of jurassic age. The segments, or blocks, have varying degrees of inclination, ranging from 7° to 20°, but tilt quite consistently westwards. In the east the field structure is more unclear, the area is greatly broken up by faults and is in part greatly eroded. The structural conditions in the eastern area are difficult to map because of poor seismic data. Faults, which vary more than 100 m in height, limit the field in the south, east and north-east. 34/10 Delta is decidedly the most complicated field so far considered in terms of development on the Norwegian continental shelf.

Oil has been demonstrated with little gas, in three jurasic formations: Brent, Cook and Statfjord. Moreover, in the easternmost part of the field, oil has been found in layers of triasic age. The reservoir rock is quite similar to that found in Statfjord and Murchison, i.e. sandstone with high permeability and relatively high porosity. Some of the wells extend down to the water zone, but due to complicated fault patterns, it is doubtful whether the water zone is large enough to maintain pressure in the reservoir as oil is taken out. It will therefore be necessary to inject water right from the start of production. Gas injection has also been considered as a means of recovery. However, this method gives considerably poorer results than water injection, not least because the field contains so little gas that it should be regarded in the main as a pure oil field.

Cost

The operator estimates the total development cost for Phase I to be NOK 40 billion at current value.

2.3.7. The Statfjord area

The Statfjord area consists of the Statfjord field, the 33/9-Alpha, 33/9-Beta and 33/9-Delta fields.

Concession holders

Norwegian share (84.09322 %) (Production licence 037)

Mobil Development of Norway A/S	12.61400 %
Den norske stats oljeselskap A/S	42.04661 %
Norske Conoco A/S	8.40932 %
Esso Exploration and Production Norway	8.40932 %
A/S Norske Shell	8.40932 %
Saga Petroleum A/S & Co	1.57674 %
Amoco Norway Oil Co A/S	0.87597 %
Amerada Hess Norwegian Exporation A/S	0.87597 %
Texas Eastern Norway Inc	0.87597 %

British share (15.90678 %)

Conoco North Sea Inc	5.30226 %
BNOC (Exploration) Ltd	5.30226 %
Gulf Oil Corporation	2.65113 %
Gulf UK Offshore Investments Ltd	2.65113 %

On 10 August 1973 the concession holders in the Statfjord field were granted production licence 037. This covers the 33/9 and 33/12 blocks. Mobil is operator (Figure 2.3.7.a.). So far, it has been decided to develop only the Statfjord field.

The Statfjord field itself was found in the spring of 1974 and was declared commercial the same year. The Statfjord field extends to Field 221 on the British side, where Conoco is operator. The first field development report was submitted to the authorities in the spring of 1976. Since then, more field development reports have been submitted. It has been decided to develop the field in three phases with fully-integrated platforms A, B and C (Figure 2.3.7.b). The Statfjord A platform rests in the center of the field, while B is located in the south and C will be placed in the northern part of the field.

The concession holder originally estimated the total existing amounts of oil and gas in the field to be 1033 million Sm3 oil and 180 billion Sm3 gass. Later estimates made by the Directorate indicate 811 million Sm3 oil and 142 billion Sm3 gas. By injecting water into the Brent reservoir and gas into the Statfjord reservoir, a recovery factor of approx. 50% is expected to be obtained. This means that the total amount of oil recoverable is 405 million Sm3 (including the British share). The amount of associated gas recoverable is estimated at 48 billion Sm3 dry gas and 15 million tons NGL. The allocation of reserves in the field, officially approved in 1979, is 15.9068 % on the British side and 84.0932 % on the Norwegian side. The next opportunity for re-allocation of reserves will be 1 January 1983.

Production facilities

Statfjord A

The Statfjord A platform (Condeep, PDQ), is centrally located in the field and has three concrete columns and 14 concrete cells. The deck is of steel. Total production capacity is 47,600 Sm3 per day. The platform started production on 24 November 1979 and, according to the operator, will have 26 production wells, four gas injection wells and 12 wells designated for water injection. So far, the highest production rate achieved was on 22 November 1981, giving 39,559 Sm3 of oil. Total investment in connection with the Statfjord A project was NOK 7,417 million.

Statfjord B

Statfjord B (Condeep, PDQ), which is situated in the southern part of the field, has four columns and 24 cells of concrete. The production capacity is 28,600 Sm3 per day. The operator expects to start production by year´s end 1982. The drilling program, with a total of 38 wells, will be divided as follows: 22 oil producing wells, three gas injection wells and 12 water injection wells. Some unforseen offshore work requiring in all 2.5 million person-hours, will give a cost increase of NOK 835 million. The total estimate for the Statfjord B platform is NOK 11,297 million (at 5.57 rate of exchange).

Statfjord C

The third and last phase in the development of the Statfjord field is now being completed with the building of the C platform. This is being built as an integrated Condeep with four concrete columns, 24 concrete cells and a steel deck. The equipment necessary to make possible the production and storage of oil, equipment for gas injection, dehydration facilities and water injection will be available. Statfjord C will have 42 well slots, and at the same time will make it possible to connect nine wells pre-positioned on the ocean floor. The cost of the Statfjord C platform has increased by approx. NOK 1,700 million compared to original estimates. The total cost for the Statfjord C project is estimated at approx. NOK 13.4 billion. This also includes rate of exchange adjustments at 320 million dollars. A good 50 % of the above cost increase is due to price increases that are 2-3 % higher than Mobil accounted for in its assessments in the first quarter of 1980. Approx. 25 percent of the cost increase is due to design alterations, particularly those of a safety and environmental nature. The remainder may be attributed to changes in the level of background experience following work on Statfjord B. According to the work schedule, the platform will be towed out to the field in August 1984, with the planned production start set for February 1986.

Recovery of reserves

The drilling of production and injection wells in 1981 has not provided any major surprises with regard to reserves or reservoir behaviour. The productivity of the wells is still high. The gas injection facility has come into normal operation, and throughout

1981, about 92 % of the produced gas has been transfered back to the Statfjord reservoir.

The water injection facility is ready for operation, and by year-end 1981, the first water injection well will be almost ready. Therefore, water will be injected into the Brent reservoir early in 1982.

Three of the wells in the Statfjord field produce as much as 10 % water. Water production has been stable at this level for most of 1981, without having to limit oil production. From similar fields in the North Sea, it is known that water production can be a considerable problem, causing reduced oil production.

The landing of gas from the Statfjord field has received great attention also in 1981. On 10 June 1981 the Storting gave its approval for landing the gas through the Statpipe system to Emden, by way of Kårstø. Until the facility is operational, the gas has to be injected into the field. Gas injection in the Statfjord reservoir will have a positive effect on oil development. Meanwhile, the room for gas in this reservoir is limited. The Directorate therefore emphasized that the Brent reservoir be developed in such a way that gas can also be injected here if necessary.

The effects of injecting gas into the Statfjord field are still uncertain. If gas is shown to displace oil effectively, it may be prudent in terms of resources to continue with gas injection also after the gas pipelines have become operative.

Flaring of gas on Statfjord A

The amount of gas flared is indicated in Figure 2.2.7.c. When the Statfjord A platform was ready for production in November 1979, the injection system for associated gas was not yet completed and, in the beginning, the gas was flared. When injection started in June 1980, the operator had certain problems with the injection compressors, which resulted in a relatively high rate of flaring in the second half of 1980. In 1981, the operator improved the technical details of the injection equipment, so that reliability is considerably improved. This has resulted in a flaring rate of 0.35 million Sm3 per day, while the Petroleum Directorate´s maximum limit is set at 0.5 million Sm3 per day. Figure 2.3.7.a shows flared gas in relation to total production. In 1981, approx. 8 % of the produced gas was flared.

Metering system

A permanent inspection arrangement for Statfjord A was established at the end of 1981. The metering system in operation on the field is now subject to regular, monthly inspections. The metering systems for oil from Statfjord B and C have been tested by the manufacturers and will not be subject to further control before the starting up period. Control of the design of the gas metering system for Statfjord C has begun.

Cost

The total cost, including platforms, production drilling, leasing of accommodation platform, MSV vessels, internal pipelines etc. will be approx. NOK 49.7 billion at current value. The Norwegian share constitutes approx. NOK 42 billion.

THE STADTFJORD AREA

FIGURE 2.3.7.a

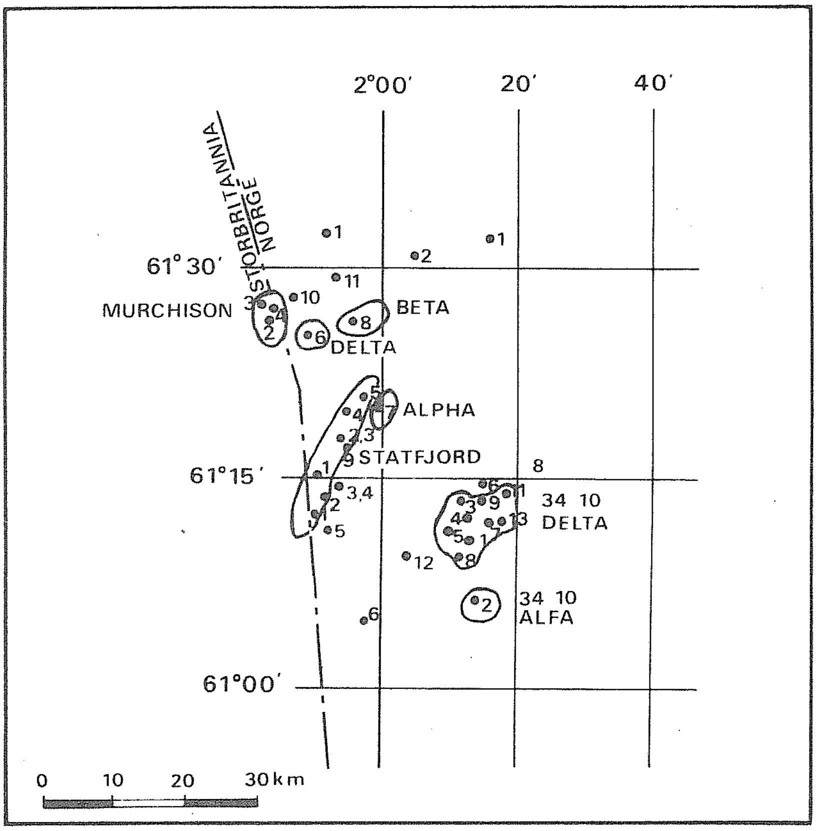
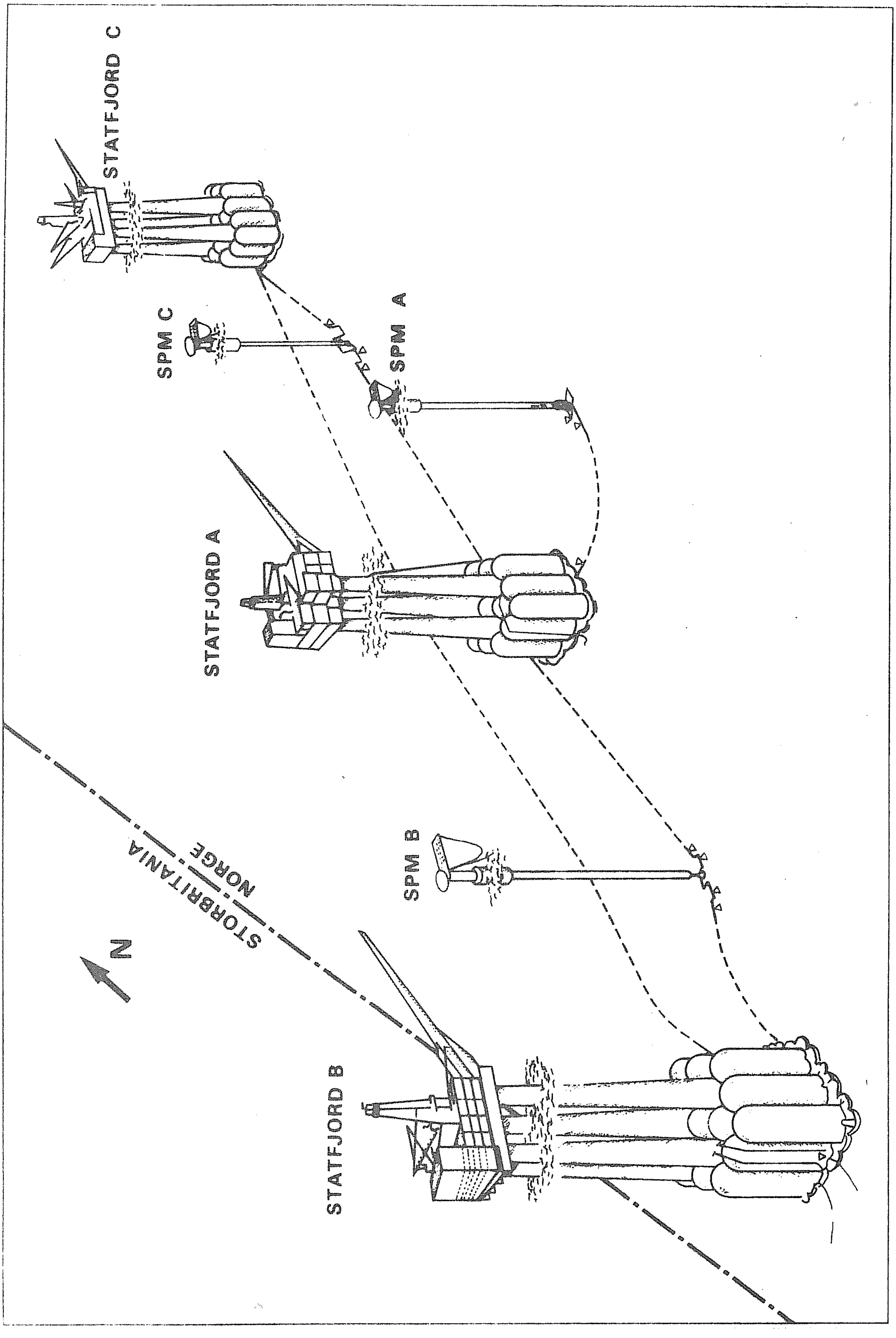


FIGURE 2.3.7.b



EXISTING AND PLANNED INSTALLATIONS ON THE STATFJORD FIELD

FIGURE 2.3.7.c

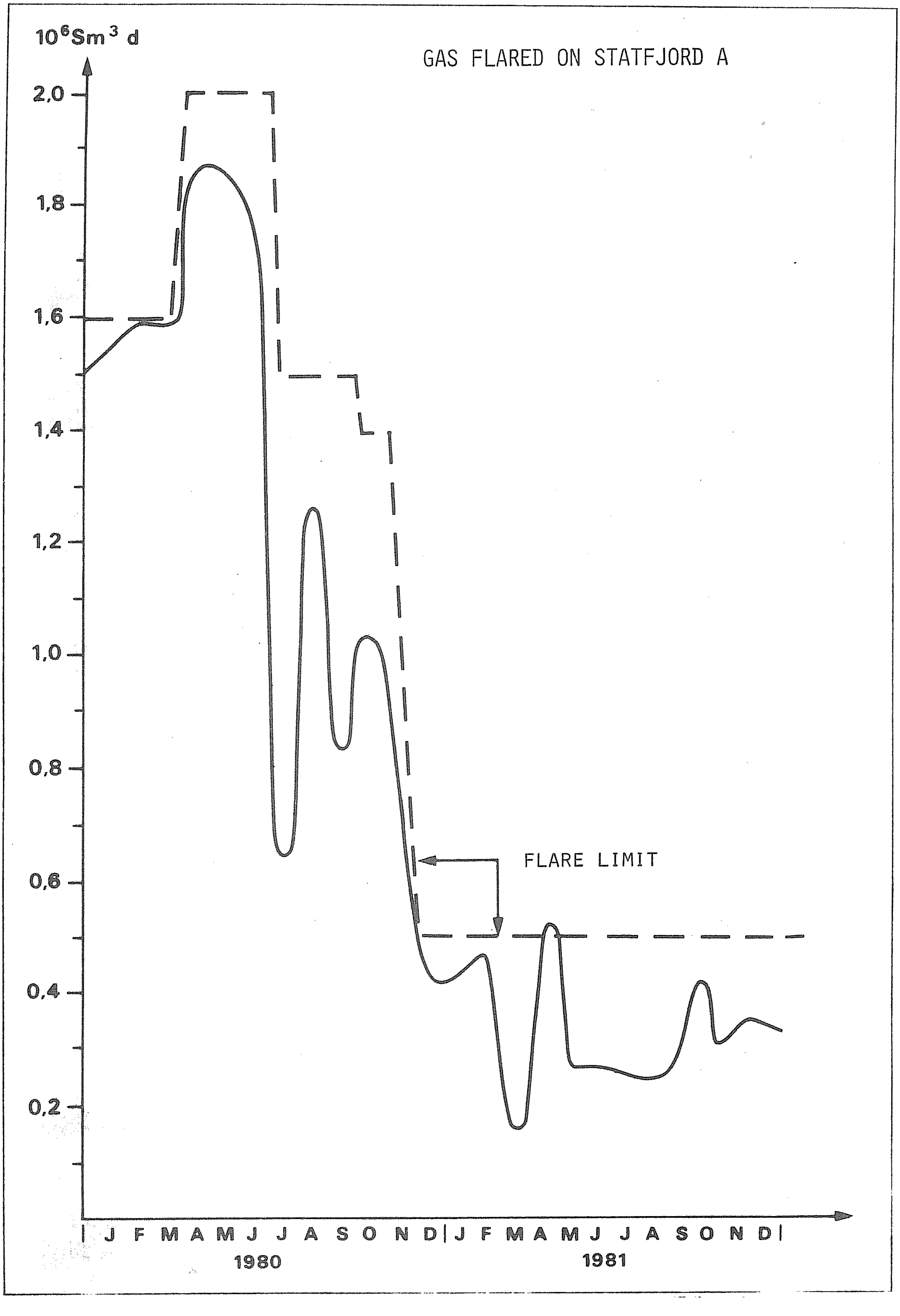
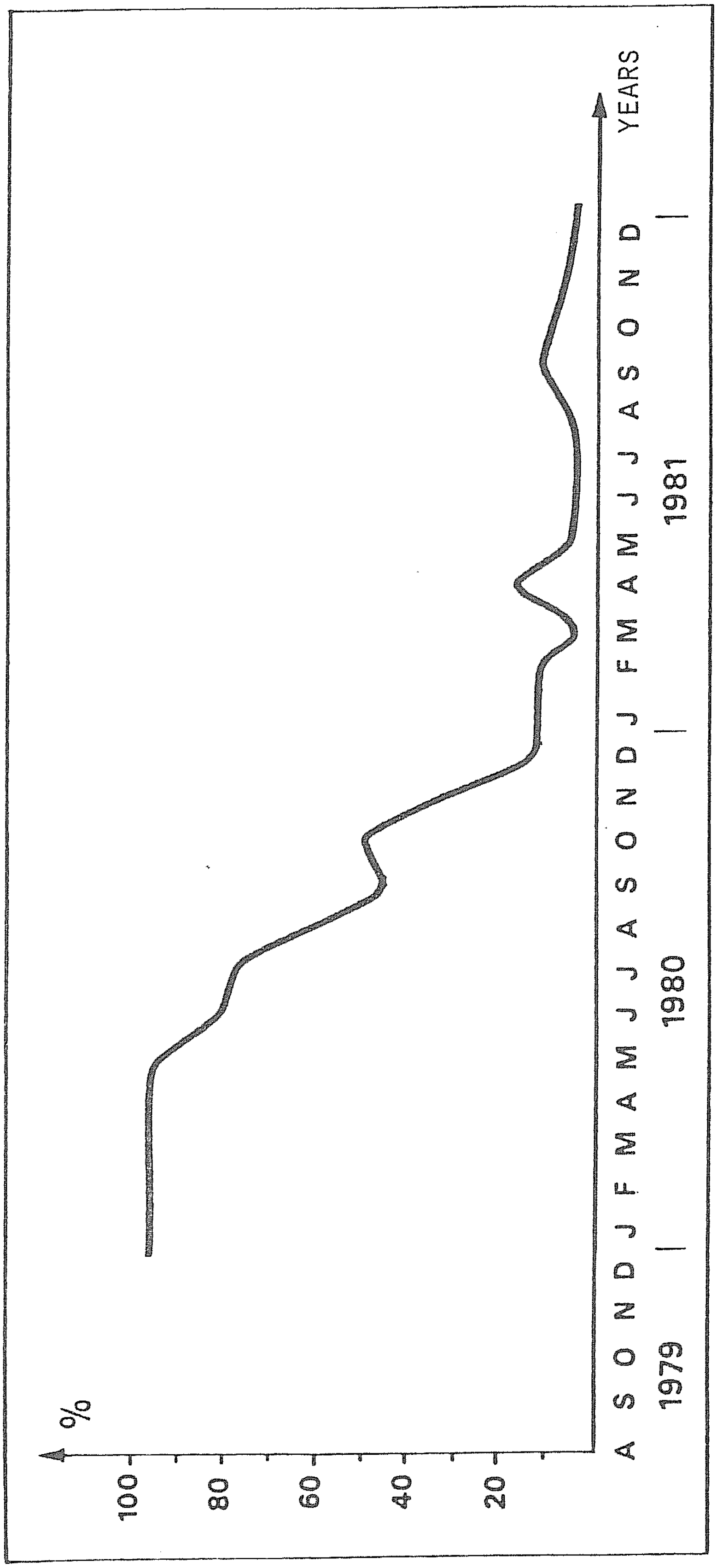

$10^6 Sm^3$ d
GAS FLARED ON STATFJORD A
2,0
1,8
1,6
1,4
1,2
1,0
0,8
0,6
0,4
0,2
FLARE LIMIT
J F M A M J J A S O N D J F M A M J J A S O N D
1980
1981

FIGURE 2.3.7.d



PERCENT AVERAGE FLARED GAS OUT OF TOTAL GAS PRODUCTION ON STATFJORD A

Gas transport (Statpipe)

The pipeline company Statpipe has been founded with the following concession holders:

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

Statoil is operator for Statpipe.

The transport system will include:

- a trunkline from Statfjord to Kårstø
- separation and fractioning facilities at Kårstø, as well as storage and loading facilities
- pipeline from Heimdal and pipeline from Kårstø to a riser platform south-east of Sleipner, pipeline to a riser platform at Ekofisk with main equipment.

A framework agreement has been made between Norpipe A/S and the Phillips group for the use of the Ekofisk Centre and the pipeline to Emden, and with the terminal company in Emden. The concession holders in production licence 050 (block 34/10) have also recommended that the produced gas quantity from the Delta East field be landed via the Statpipe system.

Figure 2.3.7.e shows a diagram of Statpipe with the length and diameter of the pipelines.

The transport capacity from Statfjord to Kårstø is 8 billion Sm3 per year. The capacity from Kårstø to the riser platform south-east of Sleipner is approx. 7 billion Sm3 per year provided that approx. 10 billion Sm3 per year are produced from Heimdal.

This will give a maximum transport capacity of approx. 17 billion Sm3 per year to Ekofisk. If there is an unfavourable division of gas flow from Kårstø and Heimdal, the total transport capacity will be reduced. The maximum amount of gas that can be producted from Heimdal, if no gas is delivered form Kårstø, will be 14 billion Sm3 per year.

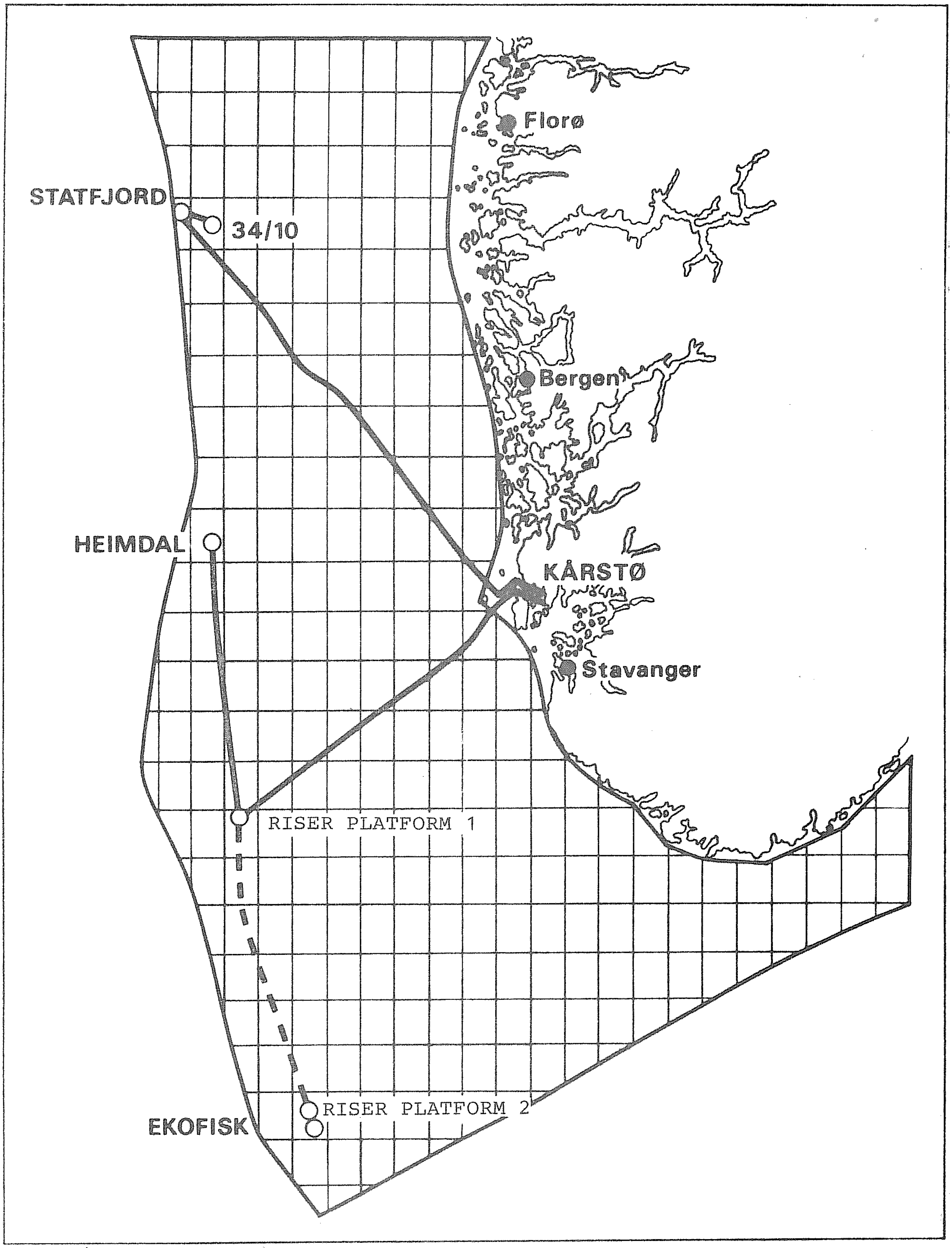
If it is desired to increase the transport capacity of the Statpipe system, a new compressor platform must be built beside the riser platform that is to be placed south-east of Sleipner.

Cost

The total investment for the Statpipe pipeline system is estimated at NOK 17,600 million at current value, based on a 10 % escalation factor and a 5.50/$ rate of exchange.

THE STATPIPE PROJECT

FIGURE 2.3.7.e



2.3.8. Murchison

Concession holders

British share (83.75 %)

Conoco North Sea, Inc	27.916 %
BNOC (Exploration) Ltd	27.916 %
Gulf Oil Corporation	13.958 %
Gulf Offshore Investment Ltd.	13.958 %

Norwegian share (16.25 %) (Production licence 037)

Mobil Development Norway A/S	2.438 %
Den norske stats oljeselskap A/S	8.125 %
Norske Conoco A/S	1.625 %
Esso Exploration and Production Norway	1.625 %
A/S Norske Shell	1.625 %
Saga Petroleum A/S & Co	0.305 %
Amoco Norway Oil Co A/S	0.169 %
Amerada Hess Norwegian Exploration A/S	0.169 %
Texas Eastern Norway Inc	0.169 %

The above concession holders are the same as for the Statfjord field. The Murchison field was found in August 1975. The field is situated in block 211/19 on the British side and in block 33/9 on the Norwegian side. The Norwegian share of the block is temporarily stipulated at 16.25 % of produceable reserves, and the British share at 83.75 %.

The development of the Murchison field was initiated in 1976 by the British concession holders. The 037-Group declared the field profitable in the summer of 1977 and Statoil conceded with the declaration in the summer of 1978. The field was developed with an integrated platform of steel with a production capacity of 23,900 Sm3 per day (Figure 2.3.8).

The steel base was placed in the field on 20 August 1979. The deck frame was installed in September 1979. On 28 September 1980, oil production from the completed underwater wells started at a rate of 1,590 Sm3 per day. Five years had then passed since the the find was made, and four years since the development plan was submitted.

Drilling of the wells in the Murchison field proceeded more quickly than planned, and production is already at peak level. Mainly water injection wells have been drilled in 1981, and the injection capacity is now so great that the reservoir pressure is on the point of being stabilized.

Gas injection started in August. Only one well is used for injection, and this has such a low capacity that three-quarters of the gas is still being flared. However, the equipment on the platform has a considerably greater capacity, so that a second injection well would considerably reduce the gas flaring.

According to plan, the gas from Murchison would be transported through a British leg gas system ("North Leg Gas System"). This has been delayed and in any event, the gas will be directed for a short period via the FLAGS pipeline. This will probably come into operation at about the end of 1982 and, until then, most of the gas will be flared on the field.

The oil from Murchison will be sent by pipeline to Sullom Voe in Shetland. The fractioning facility for wet gas in Sullom Voe has been delayed two years, and before it is ready the oil must be stabilized in the field. The wet gas which is thereby removed, must be flared. The fractioning facility will start receiving oil of high vapour pressure in the first half of 1982.

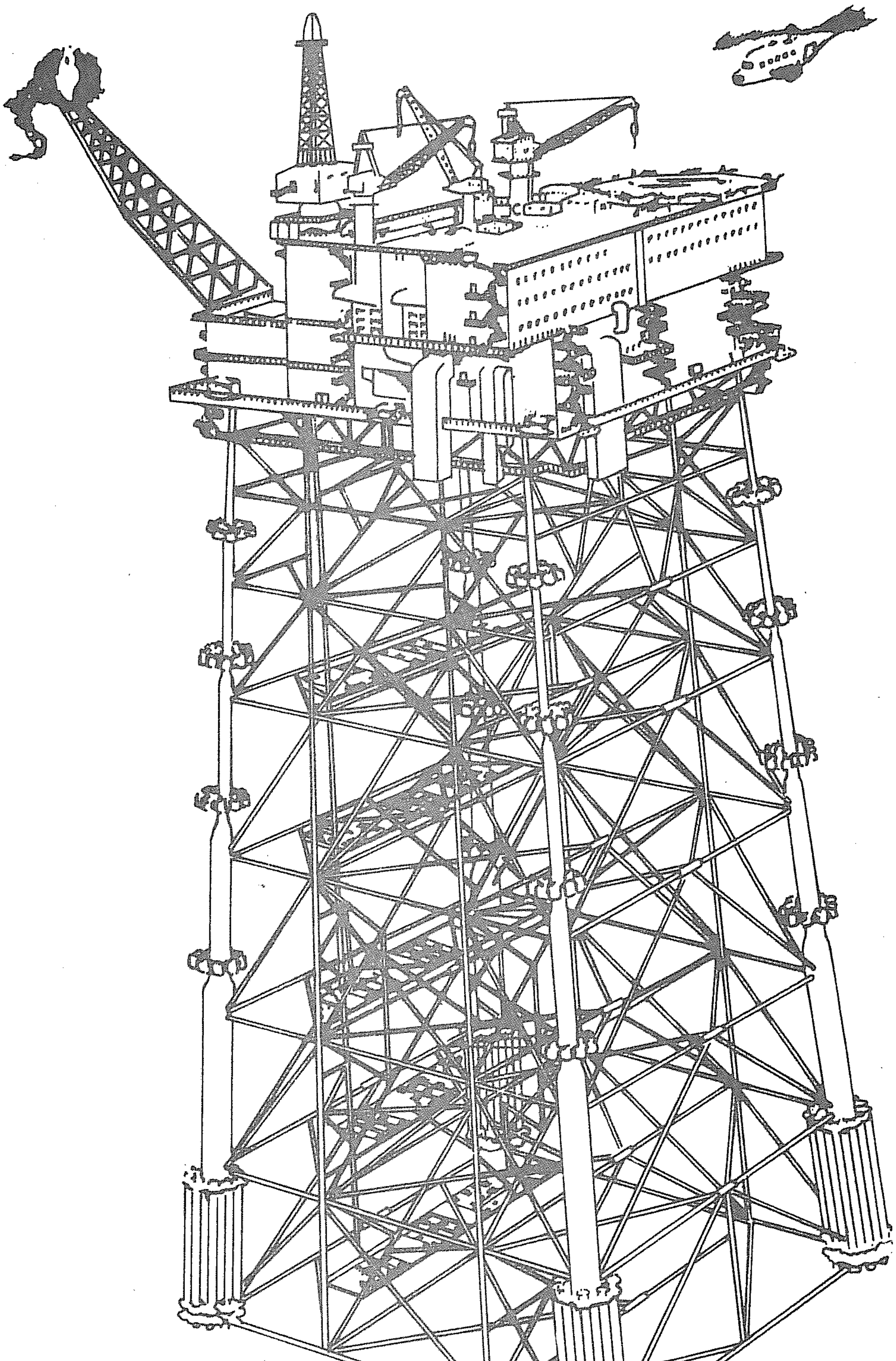
Metering system

Control and testing of the metering system before production start and approval of operation and maintenance procedures have not been carried out. This is partially attributable to the special formal circumstances which apply regarding the right to establish control routines on this field.

Cost

The total development cost is estimated at at least NOK 7 billion at current value, based on a 5.50/$ rate of exchange and including 10 % inflation. The Norwegian share constitutes approx. NOK 1.1 billion.

FIGURE 2.3.8



INSTALLATION ON MURCHISON

3. SAFETY CONTROL

The work tasks within safety control have increased considerably in 1981. This, in addition to being understaffed, has resulted in the Petroleum Directorate not being able to to carry through its control program as planned. This, among other things, has resulted in a reduced number of operating inspections, longer procedure time and the assignment of strict priorities to tasks etc.

The operator companies are bound by the authorities to practice an internal control policy. Included in this duty , among other things, is the establishment of a system in the companies´ organization to ensure that the activity is carried out within the framework stipulated by the authorities. During the reporting period the Petroleum Directorate has given priority to carrying out active controls in connection with the establishment and follow-up of internal controls, together with revising and stipulating "Guidelines for Owner´s Internal Control" of 15 May 1981. Until now, experience has shown a positive trend, though as expected, there has and will be a need for necessary improvements and adjustments. The work of internal control and following it up must continually be given high priority.

During the reporting period there have been no technical accidents of any size. Corrosion and maintenance problems have in the course of time reduced the installations´ original quality level somewhat. The demands on the companies´ control and maintenance work will therefore increase.

3.1. Complying with the Directorate´s orders

The Petroleum Directorate uses various methods to obtain an impression of how an operator company´s internal control system is functioning. A common method is to carry out a spot test control of the company´s installations in the North Sea. If, during the control, conditions are uncovered which are not in compliance with regulations, this would be an indication that the company´s internal control system is not functioning satisfactorily.

The Petroleum Directorate has clear authority to demand that the companies correct conditions in the activity that are not in accordance with current laws and regulations. The company is informed of this requirement in writing where the Directorate´s issues orders for the company to follow. The condition must be put in order and a report sent to the Petroleum Directorate within a given time limit.

In practice, it has been shown to be difficult to arrive at routines that ensure a systematic compliance of all orders issued by the Directorate.

The Directorate uses disproportionately much time in checking the reply reports. This pertains particularly to controlling that the companies have kept the deadlines stipulated for reporting back that the orders have been carried out.

In 1981 the Petroleum Directorate frequently had to remind companies that deadlines for carrying out orders had been exceeded. The Petroleum Directorate has repeatedly found it necessary to order companies to put in more resources in order to bring this condition under control.

Certain companies seem to have such extensive routines and procedures for the approval of purchases or work orders that the time limit for complying with orders from the Directorate, in certain cases, runs out before the company has approved the purchase or work order.

The company´s own systems for internal control are made responsible for monitoring and ensuring that official orders are followed, and this will be emphasized and followed up in the future.

With regard to the Directorate´s own controls of orders being carried out within the stipulated time limits, it is aiming toward making this more efficient by utilizing computer-based routines. The Directorate will here - in collaboration with the operator companies - look at the possibilities of arriving at suitable administrative routines.

3.2. Qualification requirements

During the course of 1981 the Petroleum Directorate has phased out the arrangement concerning dispensations from the qualification requirements for all categories of drilling personnel except toolpushers and assistant toolpushers. For these positions, a number of temporary permissions to continue working until the end of 1982 have been granted, on the condition that they complete toolpusher training through part-time courses. This type of toolpusher course was initiated in January 1982, and by year-end 1982-83 approx. 120 pupils will have completed these part-time courses in public and private schools.

Corresponding part-time courses for English-speaking drilling personnel will be initiated in January 1982.

The education offered to drilling personnel is flexible, and covers the requirements of the trade. As new platforms come into operation the requirement for necessary experience will be difficult to fill. However, practical experience constitutes a considerable part of the training.

Increased global activity has an effect on the influx of personnel to the Norwegian shelf. This applies particularly to drilling supervisors. There is still a shortage of leading operative personnel and onshore engineering personnel.

3.3. Contingency planning

Contingency plans for the fixed installations

In the course of 1981, all operator companies except one have revised and updated their plans for the fixed installations. The plans have been considerably simplified and are more straightforward.

Contingency plans for mobile platforms

Throughout 1981 work has been going on to standardize these plans. There has been a collaboration between the Maratime Directorate, the Norwegian Ship Research Institute, the Norwegian Industry Federation for Operating Companies, the Norwegian Offshore Association and the Petroleum Directorate in this area. Standard contingency plans for the mobile drilling vessels are divided into four parts concerning:

Part 1 The platform
Part 2 The operator
Part 3 The authorities
Part 4 The contractor

A standart draft is sought within the individual parts. The advantage of standard plans is that there is no need to rework the whole plan when the drilling vessels change operator etc. Evaluation of an application for drilling licence, for example, will be simplified a good deal, together with the fact that the plans will have a better continuity and guarantee for their being adequate. Standard contingency plans will be put into use in 1982.

Contingency scheme for organizations on land

In 1981, improvements were made in contigency planning on land. Most operator companies have strengthened their contingency schemes in the form of better plans and organization, together with the fact that fixtures and technical equipment in connection with crisis and contingency rooms have been improved. This also applies to the Petroleum Directorate, which has been linked to the operator companies and the Main Rescue Centre by permanent telephone lines using its private manual emergency exchange. Together, all of these measures contribute to raise the level of preparedness.

Exercises

Besides the huge simulated catastrophy exercise (SIKAS 1981), the operators have completed internal contingency exercises. During these exercises, the Petroleum Directorate has been notified in accordance with the warning plans and has, to a varying extent, participated in the exercises. SIKAS 81 was a large joint exercise which involved an operator company and most of the relevant authorities. The completed exercises have contributed to improving the contingency schemes.

3.4. Drilling

A total of 40 drilling licences were granted in 1981. There has been greater activity in 1981 compared with previous years.

The activity level has varied from 12 to 15 mobile drilling vessels in continual operation. Further, 12 units are in operation with production drilling and well maintenance. At the same time, there are a large number of production platform concepts and new mobile platforms in the planning and construction stage, and these are also subject to control.

In the course of 1981, new drilling regulations have entered into force. These contain stricter requirements for certain equipment and are expected in future to provide the basis for noticeably improved work conditions on the drill floor.

3.5. Electrical installations

Personal safety with regard to electrical installations has been receiving special attention. Operational considerations have made it increasingly necessary to work on or in the proximity of high tension facilities. This places huge demands on both fitters and the relevant work routines. It is very important that current safety rules are followed, and that the fitters receive the working aids necessary to carry out their work in a secure manner.

Unfortunately, it seems that increased competition from manufacturers has resulted in factory-produced electrical panels with a lower personal safety rating than desirable.

In this context it is natural to mention that the users of the facilities should have been more involved in the design and construction phase than is the case at present.

Monitoring of power plants has also been the subject of special attention during the report period. Development in this field makes it necessary to intensify the work. Plants have become so huge and complex, with such enormous consequences in the event of a short circuit, that there are worries about the effects of a possible failure in vital sections. The development rate is so fast that it is difficult to provide equipment that can carry out its designated task in a satisfactory manner. The safety margins seem to becoming increasingly smaller, at the same time as dependability and accessibility are becoming increasingly important. In this situation it is of course important that the personnel who are going to operate the plants are given necessary training and that adequate consideration is given to the choice of equipment and relay protection. The Petroleum Directorate is watching this development closely.

Beyond that, it seems that the power plants offshore generally have a poor selectivity. This often results in an unnecessary high degree of failures in the power production. The consequences of this are most likely to be unstable operation and en extra heavy load on vital parts of the processing plants.

The Petroleum Directorate sees it as an important task, during the time ahead, to point out and inform of the above problems. The Petroleum Directorate will also intensify its control work to the highest possible degree in these areas, but the lack of qualified experts seems to make this difficult.

The Petroleum Directorate, in collaboration with the Norwegian Water Resources and Electricity Board and British authorities, worked with revisions of existing regulations and guidelines concerning electrical facilities. Particular mention may be given to the collaboration with British authorities concerning common guidelines for use of electricity under water and concerning requirements and better security systems on the hoist during drilling operations. Collaboration in this and other areas has been of mutual benefit and has yielded positive results.

3.6. Corrosion and structural damage

With regard to operational experience from fixed steel platforms, bulges in the structures in the wash zone seem to be a recurring problem. The bulges can result in a weakening of the structural integrity, and has in some cases resulted in somewhat difficult repair work. The damages inflicted on the structures are in most cases caused by incautious operation by surrounding vessels etc.

Further, it seems that cracks in crane pedestals are a problem. An abnormally large number of cracks have been discovered and repaired.

Pitting near joints in heat affected zones has been revealed to be a problem. Potential measurements in the area however, show that the protection level is satisfactory. There are many indications that pitting starts immediately after installation before the platform is satisfactorily polarized. Even though the protection level in the pitting area is adequate, pitting might be a starting factor for cracks.

"Guidelines for inspection of primary and secondary structures for production and shipping facilities together with underwater pipeline systems" has been under revision in 1981. The revised issue is expected to be ready by the first half of 1982.

3.7. Internal inspection of pipelines

The Petroleum Directorate has a requirement in its "Guidelines for inspection of primary and secondary structures for production and shipping facilities together with underwater pipeline systems" for internal inspection of pipelines. Accessible equipment places a number of restrictions on the shape of the pipe system. These can be solved at an early stage during the formation of the transport system. Further, the equipment available is limited with regard to the length of pipe that can by inspected.

In 1981 an inspection in one of the parts of the Norwegian Frigg pipeline was carried out. The results from this inspection have caused the Petroleum Directorate to view optimistically the possibilities for further development of equipment for inspecting larger pipelines such as those included in the Statpipe system, for example.

3.8. Diving

In 1981 there was an increase in diving activity on the Norwegian shelf. On a yearly basis, approx. 1,500 surface-based dives have been carried out, i.e. dives from the surface without the use of a diving bell. Divers have spent approx. 180,000 hours in saturation.

In addition, the atmosphere systems MANTIS and JIM have been utilized. These are one-man systems with cable connections to the surface. These have been in use mainly from mobile drilling vessels for assignments that were previously carried out by divers.

In 1981 there were no fatal accidents or serious personal injuries in connection with diving operations on the Norwegian shelf.

As a step in improving the safety for divers the Petroleum Directorate is working continually with evaluations of existing and future equipment. As diving is carried out in increasing depths, it will also be neccessary to make requirements of the most important of all equipment used by the divers, personal breathing apparatus. Specialists on such equipment have gathered under the direction of the Petroleum Directorate, and have carried out the fundamental work of establishing criteria and test procedures for personal breathing apparatus. In order for such criteria and test procedures to have any significance, they must be accepted internationally.

Furthermore, the Petroleum Directorate, together with the Maritime Directorate, have furthermore participated in a project under IMCO, the Intergovernmental Maritime Consultative Organization, which is a UN body working to improve safety within shipping.

The purpose of the project is to work out a code for the diving system on board ships and floating installations. Such a code will result in a raising of standards for the diving systems and will simplify the control tasks of the individual shelf countries.

Through participation in the European Diving Technology Committee, the Petroleum Directorate has contributed to the issue of recommendations on harmonization in many important areas.

The resolution that bell divers on the Norwegian shelf must have a licence, was stipulated on 1 September 1980. It must be said that the arrangement is a step forward and that it has worked satisfatorily for all parties. As of 31 December 1981, 1,520 licences had been issued for bell divers.

The Petroleum Directorate´s revised regulations for diving, which will be ready for publication at the end of 1982, will cover both monobar and hyperbar diving.

The revised regulations will emphasize requirements for safe functioning. Underwater technology is developing rapidly and functional requirements will yield a greater opportunity for transfer of this technology to practical diving.

The development of new fields in deeper water will increase the requirements as to equipment and training of personnel used in underwater operations. In order to best meet these challenges, the Petroleum Directorate is scrupulously following up the experimental diving being conducted nationally and internationally.

3.9. Worker protection and work environment

General

Maintaining a high standard within worker protection and work environment places particularly great demands on the responsible operator companies´ organization.

The complicated tasks connected to building, operation and maintenance of installations are contingent upon, among other things, the companies having effective administrative systems.

This is particularly applicable when a field is developed with many installations and/or when the activity level is high. Further, the activity involves extensive use of contracting firms, thus placing additional demands on cooperation, coordination and follow-up for and among all concerned.

The Petroleum Directorate´s control within worker protection and work environment has shown that current laws and regulations are largely enforced satisfactorily, but that a number of problems still remain to be solved.

Occupational hygiene

In 1981, the Directorate has been particularly busy in getting companies to develop and utilize routines that ensure control of unhealthy and toxic materials used in the offshore environment.

In this connection, the Petroleum Directorate has emphasized measures that may contribute to a responsible registration and labeling of dangerous materials, the establishment of data for evaluating chemical products and materials (particularly for components and drilling mud) as to health hazard, and the establishment of company files and product data sheets.

In collaboration with operator and contractor companies, a survey of products used in drillinig and production of oil and gas has therefore been carried out. Many of these chemicals are often highly specialized, and therefore little used in industry in general. Knowledge of the health hazards these represent, and the access to such knowledge is therefore often lacking. This has been reflected in the varying quality of the data sheets.

Among other things, data sheets must be a source of information for employees on the toxic characteristics of the different products. Often equally important is information on the risk involved in using the products. However, this requires a certain amount of fundamental knowledge of occupational hygiene, the terms and strategy that form the foundation for evaluations, the purpose of the products in question and the measures required to reduce potential hazards. This is difficult to put across on data sheets. That is why informational material geared toward the user is of great benefit.

New products are constantly being offered in this field, and the requirements for knowledge, control and monitoring are becoming more stringent. Access to information on how to relate to these problems has hardly been systematic.

The Petroleum Directorate therefore sees a clear necessity to develop a tool for providing greater capability in carrying out systematic assessments of new products and new technology with regard to health hazards.

In addition, the stricter requirements for information on long term effects of chemicals imply the need for monitoring the work-place and keeping track of employees exposed to such chemicals.

The Petroleum Directorate has also in 1982 poured considerable resources into inducing operator companies to comply with the Worker Protection Act Section 11 on internal company files.

Although they are now largely completed, the individual product data sheets vary greatly in quality. This is often attributed to the manufacturer´s calling for extreme demands on confidentiality in order to protect product formulas.

Meanwhile, the Petroleum Directorate has full authority to obtain detailed product formulas, as well as to outlaw the use or sale of products where the importer or manufacturer has neglected its duty to provide information. The Directorate has on many occasions in 1981 used this authority to aid the operator companies in connection with obtaining the necessary product information.

In order for nurses to carry out their work in a satisfactory way, medically correct procedures for first-aid and medical treatment for accidents or poisoning are required. Presently, nurses often have to place their trust in random directions

In its continuing work, the Directorate will emphasize information activity. Good information provided in the right way will give employees a better capability of understanding occupational hygienic problems, and will thereby strengthen the technical basis of the protection service.

A correct occupational hygiene evaluation with particular attention to health hazards from exposure, as well as instruction on preventive measures, will reduce the risks of over-exposure. In addition, proper information will contribute to reduce some of the insecurity that often spreads among employees.

Here it should be mentioned that it was due to such insecurity that a safety representative, by power of his authority, chose to stop work on one of the installations in 1981.

Further, it should be mentioned that the operator companies have given high priority to the problem of exposure to mercury fumes, and have finally managed to initiate effective procedures for safety in work with mercury, as well as for the health control of the personnel who participate in such work.

Seen in the light of the troubling developments in 1980, the analysis results of health checks in 1981 show a clear reduction in the number of employees experiencing an exposure level above the stipulated protection and occupational hygiene norms.

This development is to a large degree also a result of improvements in the equipment which the contracting firms have developed for transfering well samples during production testing. Further, an operator company has developed a new type of transfer container utilized in taking samples from sample separators. This container is designed so that nitrogen gas may be used instead of mercury. In this manner, the company has also satisfied an important principle for development of working environment offshore, namely that materials hazardous to health should be replaced by materials that are less dangerous where possible.

For the time being, this new type of sampling container is only used for analyses of crude oil, but evaluations are now being made for using it to take samples for PVT analyses (pressure, volume, temperature). The Petroleum Directorate wants great attention paid to this development also in the future.

The Petroleum Directorate, in its work towards improving occupational hygiene in the work environment offshore, has as a clear goal: to direct development toward the use of materials and products less hazardous to health.

Individual consequences of work environment conditions

The widened work environment concept, as expressed in the Working Environment Act, places special demands upon employers as well as the regulatory bodies responsible for undertaking control of the activity.

Concerning development within the physical and technical aspect of the work environment on installations in the North Sea, the Petroleum Directorate has built up extensive professional expertise in this area during the last few years.

The general change in working conditions and the overall increase in the standard of living in the community may have consequences for the demands that will be made of all working environments. It is therefore reasonable to expect an increased interest in questions concerning the psychological and social aspects of the work environment in the future - also with regard to the North Sea.

The oilworkers´ work situation is in many ways special compared to other vocational groups, with regard to both working hours, work environment and time off. It is natural to believe that the individual employee´s adjustment and attitude toward the work environment will have consequences for the interplay with family as well as local environment. In other words, the offshore workers´ adjustment to society on land and the situation at home will have a natural correlation to his/her degree of adaptation to and well-being in the work environment offshore.

It will be necessary for the Petroleum Directorate to get a general view of the opportunities and limitations existing in the oil workers´ work situation, family and society. To the extent that marked developmental characteristics are uncovered that necessitate the involvement of the Petroleum Directorate, these will form the basis for a high priority effort on the work environment question.

In order to illuminate the special conditions in this activity which have consequences for an individual´s adjustment to family and the local community, the Directorate has taken the initiative for collaboration with responsible professional circles concerning the problem of "the oil worker, family and society". In collaboration with the Work Research Institutes, Rogaland Research and Family Counseling Offices in Stavanger and Kristiansand S, preparations have been started for carrying out regional conferences on this problem, where participants are recruited from among employees in the North Sea and their spouses. It is hoped that such conferences will contribute to an increased insight into and understanding of the wellfare and adjustment problems of the offshore environment.

Drug problem

In 1981, it became publicly known that there exists, also in the North Sea, a drug problem which includes the use of narcotics.

The Directorate is of the opinion that we may here be faced with a serious safety problem.

On this background, the Directorate has taken initiatives to establish a collaboration with other responsible authorities on the narcotics question. The question of representation in the Regional or County Contact Commission for Narcotics Cases has been taken up with the Directorate of Health. The Director of Health has given an affirmative answer and formal collaboration will start early in 1982.

The situation seems to reflect the fact that the oil workers´ work situation also involves unsolved social and psycho-social problems. The Directorate has a clear responsibility to follow up on these matters. On questions tied to the work environment and health, there has long existed a natural cooperation with the Directorate of Health´s Continental Shelf Office, which is also responisble for follow-up within the problem area.

Acknowledgement of the fact that there exists a drug problem on the Norwegian part of the continental shelf has had the positive result that both the employer and employee sides have initiated activities and measures directed at the problem. This seems to have contributed to promoting increased engagement and making the public aware of such questions.

Blocking of escape routes

Inspections of the installations´ general safety level as well as reported incidents and injuries in 1981 show that the operator companies still have problems maintaing a tidy work place. The

Directorate is aware of the fact that conditions from time to time will vary a great deal due to repair, maintenance or construction activities.

Meanwhile, it is clear that poor habits in cleaning and gathering up scraps, materials, tools, machines, scaffolds, containers, pipes etc. cannot be accepted at the expense of the general level of safety, the requirements for uncluttered escape routes etc.

The Directorate has seen it as especially serious, that large objects such as containers have been placed in escape routes. This often happens because all storage space has been taken up.

It is the Directorate´s view that effective measures must be implemented to bring these conditions under control. Emphasis must be placed on:

- clarifying responsibility with regard to tidiness and free escape routes
- working out routines for control and follow-up of conditions
- widening and increasing storage room capacity
- making the management of storage and transport functions more efficient.

In 1982, the Petroleum Directorate will follow these conditions closely.

3.10. Registering accidents

In Table 3.10.a the injuries statistics for 1976-1981 are given. The figures for 1980 have been corrected in accordance with reports from the operator companies. The summary includes work injuries on the fixed installations on the Norwegain continental shelf, as well as the pumping platforms linked with the pipelines to Teesside and Emden.

As indicated by the table, there was a marked decrease in the number of work injuries per 1000 person-years for 1981.

It is difficult at present to draw any sound conclusions as to whether the material for 1981 is encumbered with systematic errors, or whether the working places in the North Sea have become safer. During 1981, the Petroleum Directorate has repeatedly impressed on the companies their obligation as principal firms to ensure that the company as well as the contractors report accidents and work injuries in accordance with current regulations, and that report deadlines are kept.

It is nevertheless the Petroleum Directorate´s opinion that the accident statistics for 1981 seem encouraging. At the same time, the statistics must commit the individual employee as well as the employer, the organized protection and environment personnel, and the authorities, so that this positive development may be maintained and carried further. Although the material may be interpreted to mean that the working places on fixed installations in the North Sea have become safer, there still occur too many "unnecessary" injuries.

TABLE 3.10.a Occupational accidents/fatalities/1000 man years (1976-81), fixed installations

YEAR	WORK HOURS	HOURS PER MAN YEAR	MAN YEARS	ACC.	ACC./1000MAN YEARS	FAT.	FAT./1000 MAN YEARS
1976	4.876.316	1852	2633	213	80,9	2	0,76
1977	7.926.742	1802	4399	282	64,1	2	0,45
1978	14.932.154	1752	8523	624	73,2	6	0,70
1979	14.588.728	1752	8327	603	72,4	0	0,00
1980	10.524.510	1752	6007	460	76,6	0	0,00
1981	13.849.131	1752	7905	427	54,0	0	0,00
TOTAL	66.130.869		37.470	2.609	69,6	10	0,27

TABLE 3.10.b Occupational accidents 1980-81, fixed installations, cause of injury/occupation

Injury Cause / Profession	Management	Builder of scaffolds	Painter/Sand blaster	Pipe worker	Construction worker	Welder	Electrician	Instrument mechanic	Production personnel	Catering	Driller	Derrick man	Roughneck	Roustabout	Others	Total	%	Year
Engine Generator Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00	-80
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00	-81
Working machine Splinters, etc., from same	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00	-80
	0	0	0	0	1	0	0	0	0	0	0	0	1	1	0	3	0.70	-81
Lift, crane, lifting devices, transporters	0	1	0	1	0	0	0	1	0	0	0	1	1	1	0	6	1.30	-80
	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	1	0.23	-81
Vehicles Vessels airplanes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00	-80
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00	-81
Hand tools, splinters, etc., from same	2	0	0	5	2	7	5	3	2	3	1	0	3	4	1	38	8.26	-80
	0	4	2	17	5	7	5	6	1	0	0	3	4	6	3	63	14.75	-81
Hot or cold substances, solid, liquid or gaseous	0	0	0	2	3	3	2	1	2	1	0	0	1	3	3	21	4.57	-80
	0	0	0	1	0	1	0	0	1	2	0	0	0	1	1	7	1.64	-81
Electric currents	0	0	0	1	0	0	3	0	0	0	0	1	0	0	0	5	1.09	-80
	0	0	0	1	0	0	2	0	0	0	0	0	1	0	1	5	1.17	-81
Explosion, blasting, fire, etc.	0	0	0	0	0	0	1	0	1	0	0	1	0	0	1	4	0.87	-80
	0	0	2	0	0	0	0	2	3	0	0	0	0	1	0	8	1.87	-81
Toxic and/or corrosive substances, radiation	0	0	3	1	1	2	0	1	0	1	0	0	3	4	6	22	4.78	-80
	0	0	7	0	0	0	0	0	3	0	0	1	0	1	3	15	3.51	-81
Falling (person to lower level)	4	3	3	5	3	2	3	3	0	2	1	3	6	7	13	58	12.61	-80
	1	6	1	7	6	5	7	2	2	0	2	2	1	7	4	53	12.41	-81
Falling (person to same level)	5	2	0	7	2	4	12	6	4	3	2	2	4	4	6	63	13.70	-80
	3	9	1	7	4	7	5	3	5	1	1	1	4	5	10	66	15.46	-81
Falling object not handled by the injured	1	4	2	3	2	2	2	2	0	1	2	0	4	7	6	38	8.26	-80
	1	2	1	5	1	1	3	2	2	0	1	0	2	4	0	25	5.85	-81
Stepping on, shove by or against an object, squeezing	8	8	5	12	7	8	12	6	3	2	1	11	25	35	11	154	33.48	-80
	2	8	1	6	11	9	7	9	1	2	5	9	16	24	8	118	27.63	-81
Lifting, carrying performed by the injured	1	3	0	5	0	3	3	3	0	1	0	0	3	4	4	30	6.52	-80
	0	1	4	6	5	5	3	1	0	0	0	1	5	6	6	43	10.07	-81
Other causes	2	0	2	4	0	2	1	1	0	0	0	0	3	2	4	21	4.57	-80
	1	2	0	4	1	2	1	3	0	0	0	0	1	0	5	20	4.68	-81
Occupational diseases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00	-80
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00	-81
SUM	23	21	15	46	20	33	44	27	12	14	7	19	53	71	55	460		-80
	8	32	19	54	34	37	33	28	18	15	9	17	36	56	41	427		-81
%	5.00	4.57	3.26	10.00	4.35	6.96	9.57	6.09	2.61	3.04	1.52	4.13	11.52	15.43	11.96		100	
	1.87	7.99	4.45	12.65	7.96	8.67	7.73	6.56	4.22	1.17	2.11	3.98	8.43	13.11	9.60			

ABLE 3.10.c Occupational accidents 1980-81, fixed installations, cause of injury/activity

Injury cause \ Activity	Construction	Drilling	Production	Transport	To and from work	Other	TOTAL	%	Year
Engine Generator Transmission	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0.00 0.00	-80 -81
Working machine Splinters, etc., from same	0 1	0 1	0 1	0 0	0 0	0 0	0 3	0.00 0.70	-80 -81
Lift, crane, lifting device transporter	1 0	2 0	3 1	0 0	0 0	0 0	6 1	1.30 0.23	-80 -81
Vehicle Vessel Airplane	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0.00 0.00	-80 -81
Hand tool splinters,etc., from same	13 18	7 5	17 40	0 0	0 0	1 0	38 63	8.26 14.75	-80 -81
Hot or cold substances Solid, liquid gaseous	7 2	2 1	12 4	0 0	0 0	0 0	21 7	4.57 1.64	-80 -81
Electric current	1 3	1 0	3 2	0 0	0 0	0 0	5 5	1.09 1.17	-80 -81
Explosion, blasting fire, etc.	0 3	1 0	3 5	0 0	0 0	0 0	4 8	0.87 1.87	-80 -81
Toxic and/or corrosive substances, radiation	1 0	6 0	15 15	0 0	0 0	0 0	22 15	4.78 3.51	-80 -81
Falling (person to lower level)	12 19	15 7	25 23	0 0	5 4	1 0	58 53	12.61 12.41	-80 -81
Falling (person to same level)	11 17	9 5	22 37	0 2	10 5	2 0	63 66	13.70 15.46	-80 -81
Falling objects not handled by the injured	10 8	12 3	15 14	0 0	0 0	1 0	38 25	8.26 5.85	-80 -81
Stepping on, shove by or against an object, squeezing	24 24	58 35	55 58	0 0	16 1	1 0	154 118	33.48 27.63	-80 -81
Lifting, carrying performed by the injured	6 21	8 5	13 17	0 0	0 0	3 0	30 43	6.52 10.07	-80 -81
Other causes	2 8	4 1	14 11	0 0	0 0	1 0	21 20	4.57 4.68	-80 -81
Occupational diseases	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0.00 0.00	-80 -81
TOTAL	88 124	125 63	197 228	0 2	40 10	10 0	460 427		
%	19.13 29.04	27.17 14.75	42.83 53.40	0 0.47	8.70 2.34	2.17 0.00		100	

TABLE 3.10.d Occupational accidents 1910-81, fixed installations, cause of injury/injured part of the body

Injured part of body / Injury cause	Head	Eye	Stomach Chest	Back	Hand Finger	Arm Shoulder	Toe Ancle	Foot Leg	Dead	Other	Total	%	Year
Engine Generator Transmission	0	0	0	0	0	0	0	0	0	0	0	0,00	80
	0	0	0	0	0	0	0	0	0	0	0	0,00	81
Working machine splinters, etc., from same	0	0	0	0	0	0	0	0	0	0	0	0,00	80
	1	1	0	0	1	0	0	0	0	0	3	0,70	81
Lift, crane, lifting device transporter	1	0	0	0	1	1	0	3	0	0	6	1,30	80
	0	0	0	0	1	0	0	0	0	0	1	0,23	81
Vehicle Vessel Airplane	0	0	0	0	0	0	0	0	0	0	0	0,00	80
	0	0	0	0	0	0	0	0	0	0	0	0,00	81
Hand tool splinters, etc., from same	4	10	2	0	19	1	1	1	0	0	38	8,26	80
	12	21	0	0	26	2	0	2	0	0	63	14,75	81
Hot or cold substances Solid, liquid gaseous	2	13	0	0	4	1	0	0	0	1	21	4,57	80
	1	3	0	0	2	0	0	1	0	0	7	1,64	81
Electric current	0	2	0	0	1	1	0	0	0	1	5	1,09	80
	0	2	0	0	2	0	0	0	0	1	5	1,17	81
Explosion, blasting fire, etc.	1	0	2	0	1	0	0	0	0	0	4	0,87	80
	0	3	0	0	0	3	1	1	0	0	8	1,87	81
Toxic and/or corrosive substances, radiation	0	14	0	0	0	0	0	2	9	6	22	4,78	80
	0	13	0	0	1	0	0	0	0	1	15	3,51	81
Falling (person to lower level)	7	0	2	9	3	5	6	15	0	11	58	12,61	80
	5	1	7	10	11	7	7	3	0	2	53	12,41	81
Falling (person to same level)	10	0	7	8	6	4	3	22	0	3	63	13,70	80
	8	0	2	9	9	11	12	15	0	0	66	15,46	81
Falling objects not handled by the injured	5	0	0	1	18	0	3	8	0	3	38	8,26	80
	4	0	0	2	7	2	2	8	0	0	25	5,85	81
Stepping on, shove by or against an object, squeezing	21	0	7	4	65	8	11	33	0	5	154	33,41	80
	11	0	3	5	61	8	7	23	0	0	118	27,63	81
Lifting, carrying performed by the injured	0	0	1	23	2	1	0	3	0	0	30	6,52	80
	0	0	3	24	4	11	0	1	0	0	43	10,07	81
Other causes	1	3	0	5	4	2	0	4	0	2	21	4,57	80
	1	9	3	1	3	1	0	1	0	1	20	4,68	81
Occupational diseases	0	0	0	0	0	0	0	0	0	0	0	0,00	80
	0	0	0	0	0	0	0	0	0	0	0	0,00	81
TOTAL	52	42	21	50	124	24	24	91	0	32	460	100	
	43	53	18	51	128	45	29	55	0	5	427	100	
	11,30	9,13	4,57	10,87	26,9	5,22	5,22	19,78	0,00	6,96		100	
	10,07	12,41	4,22	11,94	29,98	10,54	6,79	12,88	0,00	1,17			

TABLE 3.10.e Occupational accidents 1976-81, fixed installations, cause of injury/injured part of the body

Injured part of body / Injury cause	Head	Eye	Stomach Chest	Back	Hand Finger	Arm Shoulder	Toe Ancle	Foot Leg	Dead	Other	Total	%
Engine Generator Transmission	1	0	0	0	4	1	0	1	0	1	8	0.30
Working machine Splinters, etc., from same	3	3	0	1	8	0	0	3	0	0	18	0.69
Lift, crane, lifting device transporter	4	0	2	3	22	2	4	5	1	3	46	1.70
Vehicle Vessel Airplane	0	0	0	0	1	0	0	0	0	0	1	0.04
Hand tool splinters,etc., from same	33	155	6	2	128	10	5	14	0	2	355	13.61
Hot or cold substances Solid, liquid gaseous	7	93	1	0	14	6	0	4	0	4	129	4.91
Electric current	0	5	0	0	11	1	0	0	0	6	23	0.88
Explosion, blasting fire, etc.	6	5	2	0	4	3	1	2	5	3	31	1.19
Toxic and/or corrosive substances, radiation	4	52	0	0	2	1	0	1	0	17	78	2.99
Falling (person to lower level)	24	1	31	60	28	38	31	68	3	53	337	12.92
Falling (person to same level)	29	1	28	47	44	33	59	88	0	13	342	13.11
Falling objects not handled by the injured	28	3	1	6	60	8	18	63	1	7	195	7.47
Stepping on, shove by or against an object, squeezing	73	4	25	27	306	47	67	154	0	14	717	27.48
Lifting, carrying performed by the injured	1	0	10	129	48	30	5	12	0	1	237	2.08
Other causes	4	33	4	15	13	7	1	9	0	6	92	3.58
Occupational diseases	0	0	0	0	0	0	0	0	0	0	0	0.00
TOTAL	217	355	110	290	693	187	191	426	10	130	2609	
%	8.32	13.61	4.22	11.12	26.56	7.17	7.32	16.33	0.38	4.98		100

Work injuries

Tables 3.10.b-e are a summary of work injuries that have been reported to the Petroleum Directorate for 1976-81, and that resulted in absence from work, or death. The summaries to not take duration of absence into consideration, and therefore do not provide a basis for comparison with statistics from other activities.

Types of injuries

With the injury statistics and information from the operator companies concerning routines, procedures, experience etc. as a point of departure, the Petroleum Directorate has particularly contrentrated on certain types of injuries and work operations in 1981.

Falls

The Directorate´s experience data shows that during the building phase, work accidents of a relatively serious nature often occur. This applies particularly to fall accidents, which may be explained by the fact that during the construction phase, problems may arise in erecting guard rails or cordons where there is a risk of falling.

On this basis, the Petroleum Directorate has, in 1981, tightened control with regard to security measures on installations during the construction phase or where large construction work has been going on. This tightened control activity has also contributed to certain operator companies´ laying down a huge amount of work in preparing special requirements for - and improving procedures for - the safety of employees. In spite of these efforts, the Directorate found it necessary on two occasions in 1981 to stop all activity on a facility because physical protection from falls at exposed work areas had not been erected.

Drill floor injuries

The number of injuries on drill floors is high. A large proportion of these are injuries due to being squeezed by spinner tongs and rig tongs. Increased mechanization and automation on the drill floor are being incorporated in new installations. This will, among other things, be conducive toward reducting the number of injuries on the drill floor.

Some of the drill floor injuries have been spray in the eyes and sloshing of drilling mud or completion chemicals which have an etching effect on the skin and eyes.

The drilling companies have measures and routines built into their drilling procedures to lessen the occurrence of such accidents. The daily supervision of the drilling operations is responsible for ensuring that these procedures are followed.

When such injuries nevertheless occur, the daily compliance with these procedures must questioned. Moreover, an important causal factor which has been shown to be of considerable significance in other areas, is the tempo of the different drilling activities.

The Petroleum Directorate is now under way comparing the number of injuries and possible distortion of the injury picture on drill floors with the degree of mechanization and automation of drilling equipment.

Use of hand tools

The use of sledgehammers and spanners on nuts and bolts is a frequent cause of finger injuries.

This is the result of three main factors:
- lack of accessible modern equipment, e.g. pneumatic and hydraulic screwdrivers
- irresponsible use of existing tools
- inadequate planning or adjustment of work.

These factors contribute to the strong increase in the number of injuries within the "use of hand tools" category, from 1980 to 1981.

Future formulation of injury statistics

The Petroleum Directorate´s intentions and work recording injuries, has been to chart the hazards involved in different work operations. This hazard is the basis for evaluating counter-measures, the extent of measures to be initiated, and method of application.

It presupposes a general perspective of the significance of the different factors in each injury occurrence. Charting of this type requires the development of injury statistics that are better defined than those used by the Petroleum Directorate at present.

Three main factors must be evaluated:

- Formulation of an injury report form:
  The form shall in a concise way provide space for an adequate and well-defined description of all factors in an injury case.

- Description of injury cases:
  The description of injury cases is frequently unsatisfactory. The reasons for this are currently being researched and recommendations are being prepared for improvements.

- Development of a code system:
  The Petroleum Directorate will continue to work to improve the existing system for recording causes and contributory causal factors in the string of events. Efforts are being made to evolve a code system which can transform such an injury description into statistical data in a way which minimizes information loss.

3.11. Fire injuries

Fires, as reported to the Petroleum Directorate in accordance with the Attorney General´s provisions, are shown in Table 3.11. The reporting procedure that has been established is so comprehensive that it should include virtually every small fire.

All fixed production facilities have been in the operation phase in 1981, except Statfjord B and Valhall.

In 1981, the Petroleum Directorate registered a total of 35 fires as against 25 in 1980.

Two of the fires resulted in injury, while the others involved insignificant or no injuries.

TABLE 3.11 Fire damages on fixed installations 1981

DAMAGES FROM FIRE	CONSTR. PHASE	OPERATION PHASE A	B	C
Personal injuries and extensive material damages	0	0	0	0
Personal injuries and small or no material damages	0	0	0	0
No personal injury, but extensive material damages	0	2	0	0
No personal injuries and minimal or no material damages	2	13	17	1
TOTAL	2	15	17	1

A - cause of fire: due to operation/operation accident
B - cause of fire: construction work
C - cause of fire: other causes

4. PETROLEUM ECONOMICS

4.1. Petroleum economic planning

The Norwegian Petroleum Directorate in the period has been working actively to develop tools for use amongst other things in connection with the planning of shelf activities for perspective analysis. In what follows, a summary is given of the project.

The company model

The aim of the work with a company model was to develop an analytic tool which takes account of the company's total activity, because tax legislation does not consider fields, but companies, as tax objects. With a model apparatus which focuses on companies, data and information will be capable of storage in data banks and of utilization in the analysis of: the company's future financial state, the effect on profitability and liquidity of new engagements, the fields' economy in terms of company combinations, the effects of changes in tax laws on national tax revenue, company cash flow and field economy.

A major feature of the calculation is therefore that it enables analysis of a field project in the context of the company's other portfolios. The criteria (internal interest, net present value ...) and other economic parameters which such an economic analysis provides, form the relevant decision-making criteria regarding company participation in any one project.

Costs and consequences connected with oil activities

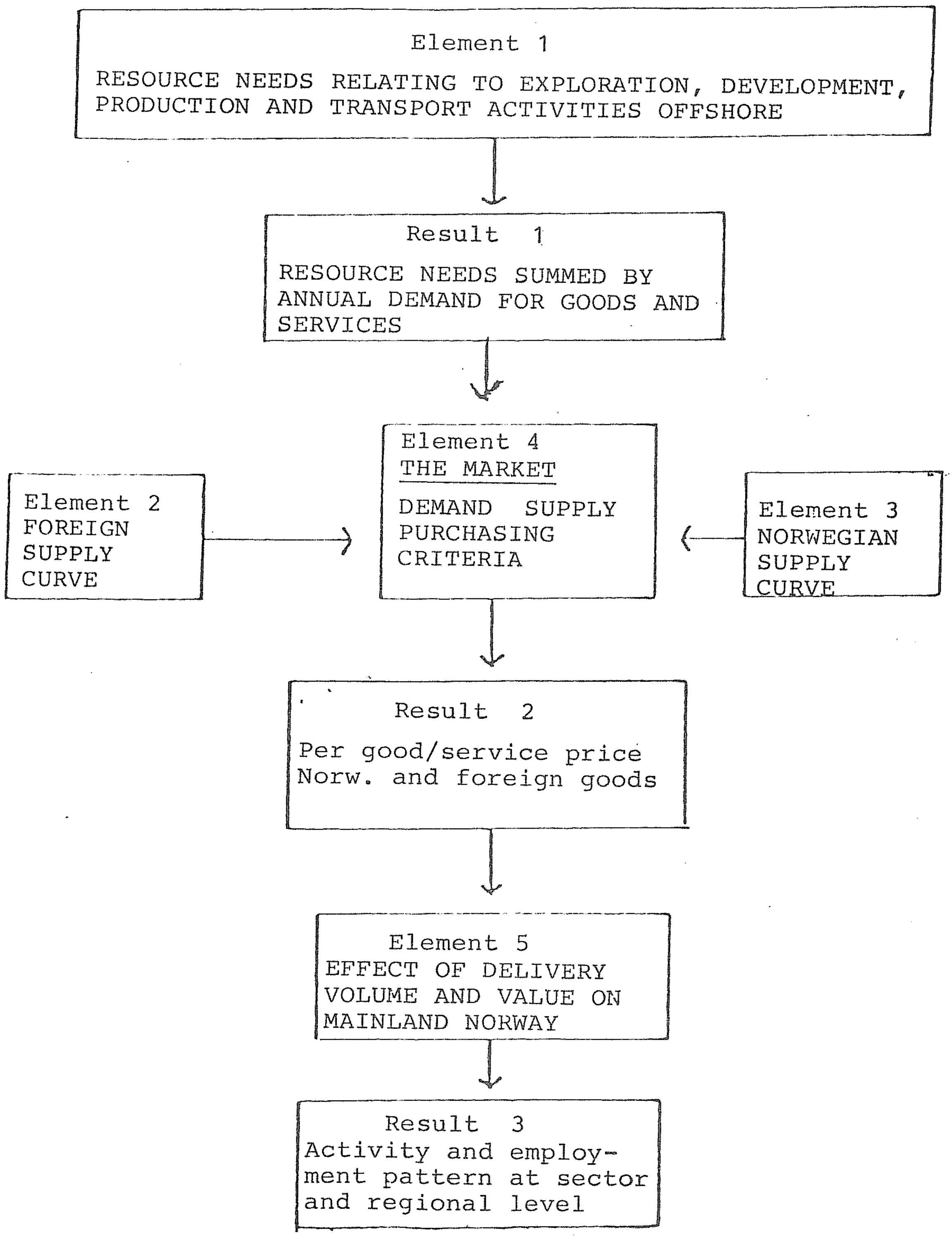
The project was carried out with a controlling body, of which the Ministry of Petroleum and Energy was one member. The object of the project was to clarify the relationship between levels of activity and cost levels in the petroleum sector, Norwegian deliveries of goods and services, and the consequences for mainland Norway. Moreover, to develop a data and analytic tool for continual assessment of exploration, development, production and transport decisions as they apply to shelf activities. In the course of the project, various official bodies, operator companies and other private institutions have been contacted.

The project is divided into three areas:

A Estimation of resource consumption on the shelf
B Estimation of Norwegian market shares in shelf markets: the Market Model.
C Estimation of delivery capacity and implications for activities and employment ashore: the Mainland Model.

The relationship between these project tasks is illustrated in the figure below.

MODEL ELEMENTS AND CONTEXT



A Estimation of resource consumption on the shelf

One aim has been to develop a task-orientated analogue tool which is also client-suited. Therefore, it has been decided to divide the analogue model into five independent submodels. The following have been implemented:

1. Model for test drilling
2. Model for field development
3. Model for development of transport systems
4. Model for development of terminal facilities
5. Model for operation and maintenance of facilities.

The submodels may be used independently of eachother and will fit together on the principle of building bricks. This provides the analogue tool with many degrees of freedom and makes it easy to apply.

B The market model

The aim of this model is to study the connection between and effects on the cost level, delivery size, Norwegian deliveries and employment levels of alternative development strategies for the fields offshore.

The present model will require greater amounts of collected data and further development before it can be applied as intended.

C The mainland model

On the basis of the National Bureau of Statistics effect tables, the Norwegian Petroleum Directorate has had a calculation program developed called VIRKMOD. For the time being it has been decided to see how changes in the seven input variables affect the 31 output variables. The inputs are production and investment variables, such as gross investment in production and drilling, gross investment in oil and gas transport, production within development and drilling for oil and gas, etc.

As regards the output variables, examples include: gross national product, private consumption, export, gross product in shielded industries, gross product in services, etc. in addition to which the model notes the effects on employment of changes in the input variables. The calculation program will readily provide indications of how changes in activities within the petroleum sector (input variables) lead to changes in certain social economic variables (output variables).

The last-named models developed in the period are prototypes, and several of them reveal clearly characteristics which reflect their early stage of development. The Norwegian Petroleum Directorate will continue working with parts of these in coming periods to make possible in time the supply of expert prognoses of the consequences of various shelf development strategies. A step in this direction is the establishment of a data base for goods, services and expenditure as applied to shelf activities.

4.2. Economic assessment of safety and working environment measures

One of the Norwegian Petroleum Directorate´s main tasks is to see that activities on the continental shelf take place in a proper fashion in accordance with current legislation and regulations. As regards control tasks related to safety and working environment, the Norwegian Petroleum Directorate is answerable to the Ministry of Local Government and Labour. This ministry has issued a note to its control bodies which includes the directive that: "considerable emphasis must be placed on the economic aspects of measures to do with working environment and safety before they are finally decided upon". The Norwegian Petroleum Directorate has, before and particularly since this directive, prepared economic consequence analyses of measures prior to their introduction. The aim of such analyses of individual measures and regulations is that the benefits may be weighed against the cost. In this way, it will be possible to judge whether an individual measure involves a sensible utilisation of community resources. The economic documentation is included as a necessary part of the decision-making basis and does not by itself determine whether a measure shall be implemented or not.

In individual cases, there may be several alternative solutions to a current problem. By carrying out economic analyses, it will be possible, having made a total evaluation, to select the most economic alternative on the condition that this gives the desired effect.

When evaluating divers measures on the shelf, it is important to be clear what characteristics such activities possess as opposed to land-based activity. Roughly speaking, it may be stated that the following factors are different:

- climatic conditions
- a high degree of complexity
- lower efficiency
- the consequences in the event of accident
- often at the "borders of technology"
- high taxation level

The factors mentioned above contribute in greater or lesser degree to the much larger magnitude of expenditure for activities on the continental shelf as compared with land-based industry. The tax system also causes a large part of the costs to fall to the state. For additional investments in measures for working environment and safety and various other investments, the state defrays up to 120% of the investment costs in the form of reduced tax revenues. Expressed at current value with a 10% discount interest rate, this amounts to as much as 80% of the investment cost. Company tax status is of importance here.

To be able to understand the companies´ behavior and argumentation, a closer look should be taken at the distributional consequences of the measures. It might be thought that the tax system would affect the companies in different ways. The fact that the costs to a large degree are defrayed by the state means that the companies may more easily invest in measures which promote working environment and other risk reducing measures. This may be a positive result of the tax system in this context. One negative effect may be that the companies in some cases may perhaps tend to invest in measures which, upon further investigation, appear to lack a proper relationship between costs and usefulness. Thus it may be claimed that there is the risk of an "overdose" of certain safety measures.

Other factors also affect a company when it is about to make a decision concerning a given risk-reducing measure. What consequences might the measure have for this and other companies' activities both on and off the Norwegian continental shelf? Consequences in this context might mean a requirement by the authorities and the employees for corresponding measures.

Before a company takes a stand regarding its decision to participate in the field development of a project additional to an existing field development, the company carries out a calculation of the economic benefits and weighs against these the estimated risks of the project. In the risk analysis, consideration is taken of the following factors, among others:

- the loss of "goodwill" nationally and globally caused by accidents
- how loss of production or income from the project will affect the company's integral system
- their economic liability for personal injury, damage to materials and the environment

By taking out insurance, companies may reduce their own economic risk, but cannot in any sense eliminate the total risk.

The individual company managements will therefore make their decision on participation on the basis of a total evaluation which includes considerations of economics, safety, politics and ethics. In addition to the above, both the company's financial status and the supply situation for crude oil to the integrated company will influence it in its decision-making process. If the company for example is in a position which indicates that new, reliable supplies of crude oil are of great value, this may perhaps lead it to be willing to take on greater risks to secure the supplies.

On the basis of the above, it will be apparent that the companies may take different stands regarding investments in working environment and risk-reducing measures.

The applies even if the measures are judged by social economic assessment to show a sound balance between cost and utility.

In its work of assessing economic consequences, it is important to the Directorate that the company's situation regarding finance and supply is known. In this way, it is easier to evaluate company arguments when the authorities submit proposals for measures.

4.3. Exploration drilling, deliveries of goods and services

The exploration drilling market has increased considerably since the start in 1966. This applies both as regards volume and value. Figure 2.2.2.a shows the number of wells started per year in the period 1966-1981. In Figure 4.3.a, the increase in value of the market has been presented both in terms of current and fixed prices. In 1966, the first year of exploratory drilling on the Norwegian continental shelf, goods and services for NOK 65 million were employed. Ten years later, deliveries amounted to NOK 860 million. They then reached a provisional peak in 1981 at approx. NOK 3 billion (NOK current). In the same period, the number of wells initiated annually has increased from zero to 39.

A market exhibiting such strong growth has increased the possiblities for Norwegian suppliers and has thus also created new work places. An example of this is the establishment of new bases along the coast, drill crews, service company employees, etc. As the activities have expanded northwards, it is worth pointing out their consequences for the regions. Among other things, drilling personnel and catering staff are being recruited from a greater number of counties.

Which categories of goods and services are represented in this market? A detailed presentation would be going too far here, but we can look a little more closely at the way the NOK 3 billion which is expected to have been used in 1981 is divided among some of the groups of goods and services. Figure 4.3.b shows a rough division into hire charges for mobile drilling vessels, supplies of goods and services, and sundry expenses. In Table 4.3, further subdivision of the goods and services categories is provided within the main groups.

FIG 4.3.a Annual expenditure on exploration drilling in current (L) and fixed (F) value

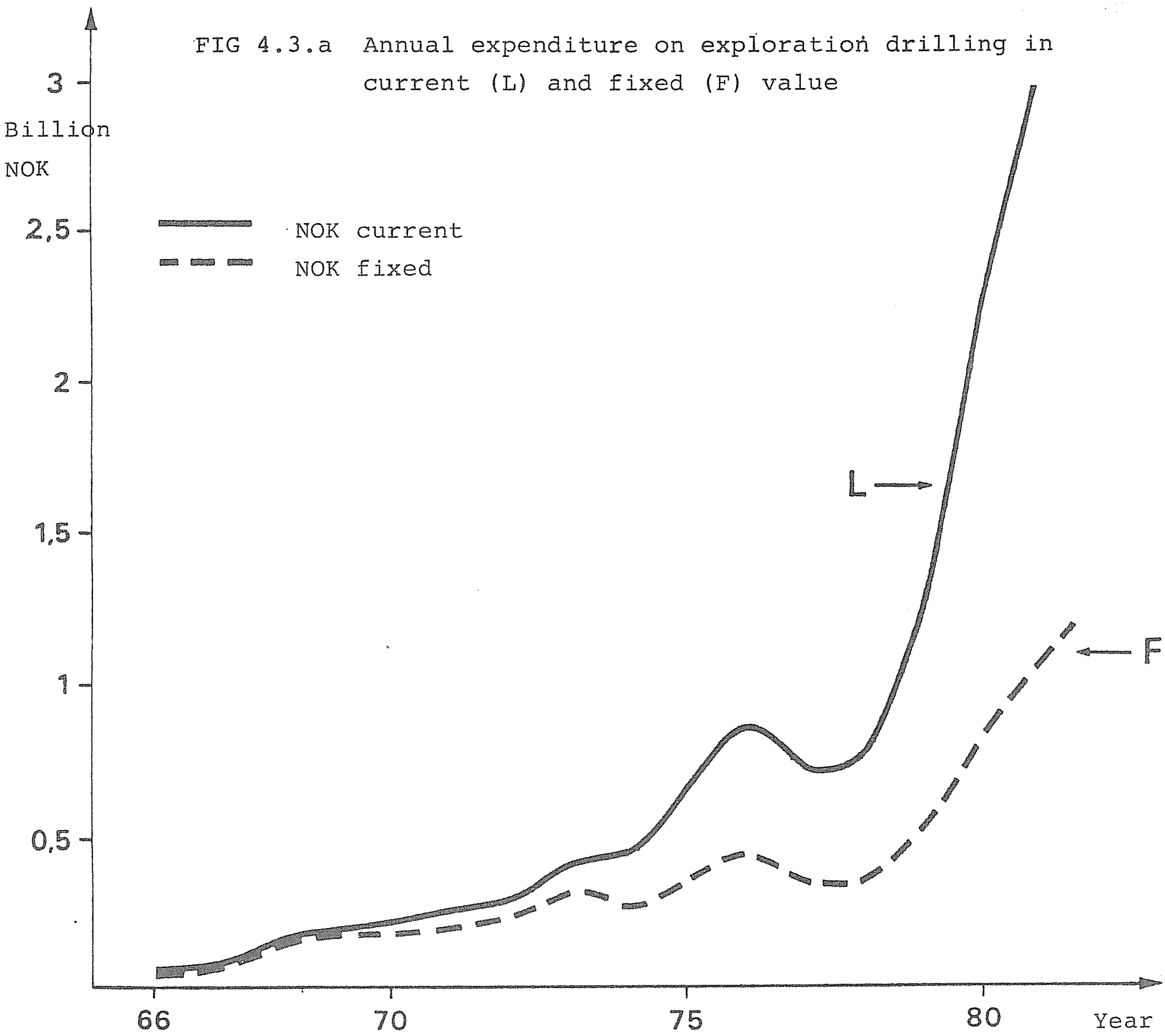


FIG 4.3.b Exploration expenditures in 1981 per main cost categories

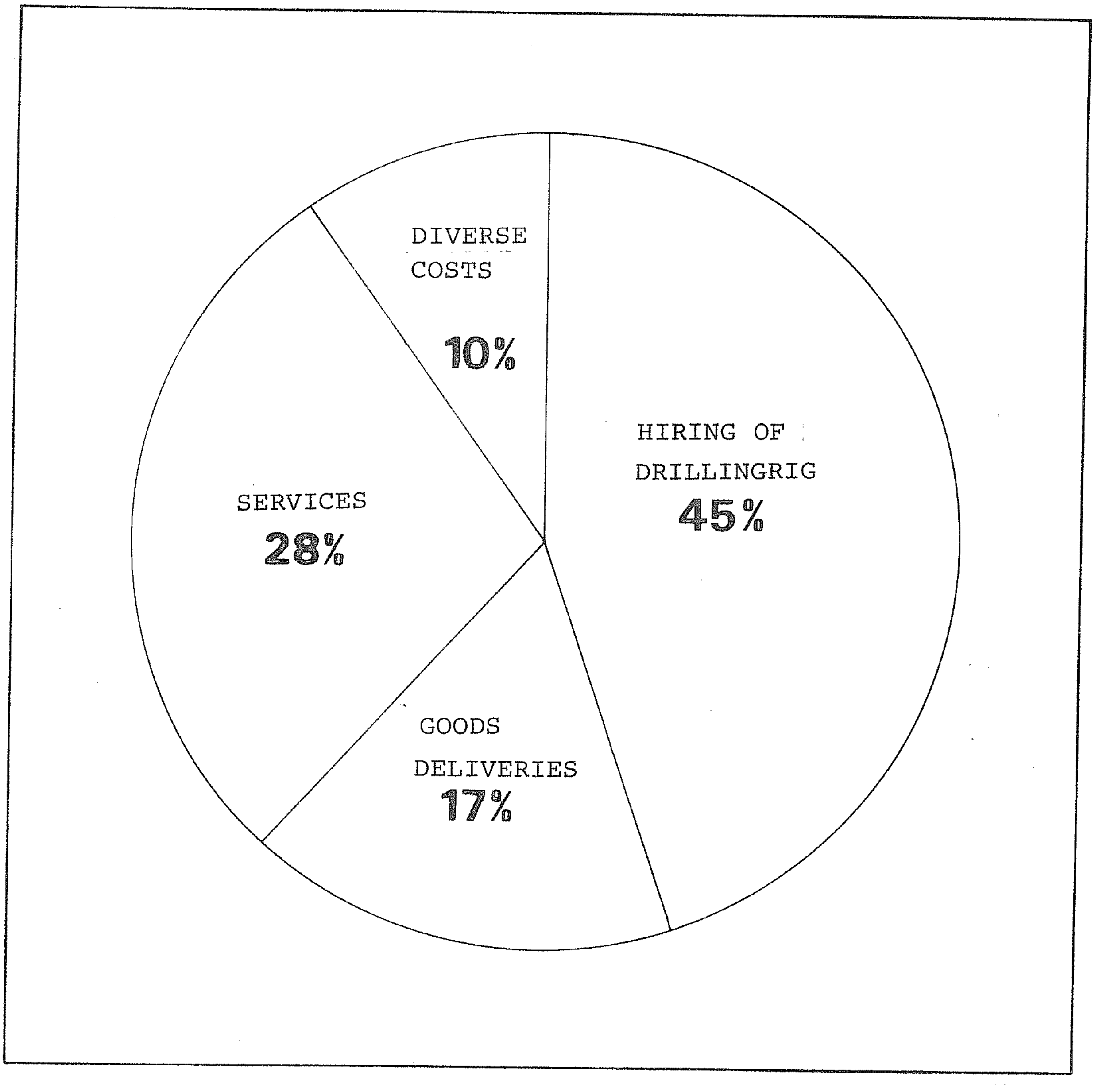


TABLE 4.3 Deliveries of goods and services in 1981 to the exploration drilling market

Category		Million NOK	Percentage
Hire of drilling platform		1 360	45
Goods supplied		495	17
Pipes	140		
Drilling mud	85		
Cement	40		
Fuel and lubrication oil	120		
Drill bits and drilling tools	50		
Sundry deliveries of goods	60		
Services supplied		855	29
Supply ships	260		
Helicopter	100		
Logging	165		
Testing	100		
Core samples	10		
Communication and navigation	15		
Sundry services	205		
Sundry costs		290	10
Drilling platform modifications and repair	70		
Base costs	60		
Administration	115		
Sundry costs	45		
		3 000	100

The figures are based on data submitted by the companies and reflect the costs of all wells which were started in 1981. For drilling which started at the end of the year, the total cost and cost distribution has been estimated by the Norwegian Petroleum Directorate.

It should be pointed out that the above figures involve some measure of uncertainty. Nonetheless, they should provide a good idea of the importance of the individual categories of goods and services as compared with the total cost.

In addition to the exploration drilling market, many of the same categories of goods and services play a part in the drilling of production wells. In 1981, this market amounted to approx. NOK 1 billion.

4.4. Costs connected with activity on the Norwegian continental shelf

The Norwegian Petroleum Directorate has estimated the annual costs connected with the activity on the Norwegian continental shelf for the period up to 1982. The costs have been estimated for exploration for petroleum, investment in field development and operational costs for developed fields, fields being developed and fields for which development plans have been approved at 31 December 1981. In addition, estimates have been prepared for the same items for the years up to 1992. The figures are based on the operators´ submitted figures.

For fields which lie on both sides of the boundary line between Norway and Britain, only the Norwegian share has been included.

The following fields (Norwegian share) are included in the calculations:

- the Ekofisk area
- Valhall
- Ula
- Frigg (60.82 %)
- North East Frigg
- Odin
- Statfjord (84.09 %)
- Murchison (16.25 %)
- Heimdal
- 34/10 Delta East

In addition, the Norwegian pipeline from Frigg to St. Fergus, the Norpipe pipeline from Ekofisk to Emden and Teesside and the Statpipe pipeline from Statfjord to Kårstø and on to Ekofisk are included. In the Statpipe system, there is also a pipeline from Heimdal which connects this field with the pipeline from Ekofisk.

All figures are in Norwegian kroner at current monetary value. From 1982-1992, the profiles have escalated by 10% per annum. In the cases where the numerical material has been prepared in US$, the $ has been converted at the actual exchange rate up to 1982, thereafter according to the ratio: NOK/$ = 5.50.

With the assumptions made, the Norwegian Petroleum Directorate´s presentation may differ from calculations already given in other official publications.

As will be apparent from Figure 4.4.a, the total volume of investments in field development, production drilling and in the operation of fields increased in terms of current prices from approx. NOK 8 billion in 1975 to approx. NOK 16.7 billion in 1981, not including exploration drilling. The total volume of costs including exploration drilling was NOK 20 billion in 1981.

The total cost volume will increase strongly into the 1980s due to the projects resolved in 1981 (Heimdal, 34/10 Delta Phase I and Statpipe).

Investment in field development and production drilling

Figure 4.4.b shows the annual investments in field development up to the end of 1981, with estimates up to 1992. As mentioned, only projects for which start-up had been resolved at 31 December 1981 are included in the estimates. In 1981, approx. NOK 9 billion were invested in field development. The investment level will increase rapidly in 1982-1984, but will fall quickly to a level corresponding to that for 1981. In the final part of the 1980s, activities will fall off rapidly if no new projects are initiated. It should be mentioned that the activity level in 1983-1984 will be unusually high, particularly due to extensive development of 34/10 and the Statpipe project.

Figure 4.4.c shows the costs of production drilling. As the figure shows, the level will rise until the end of the 1980s, and will then fall.

FIG 4.4.a Total investments, production drilling costs and operating costs 1970-1992

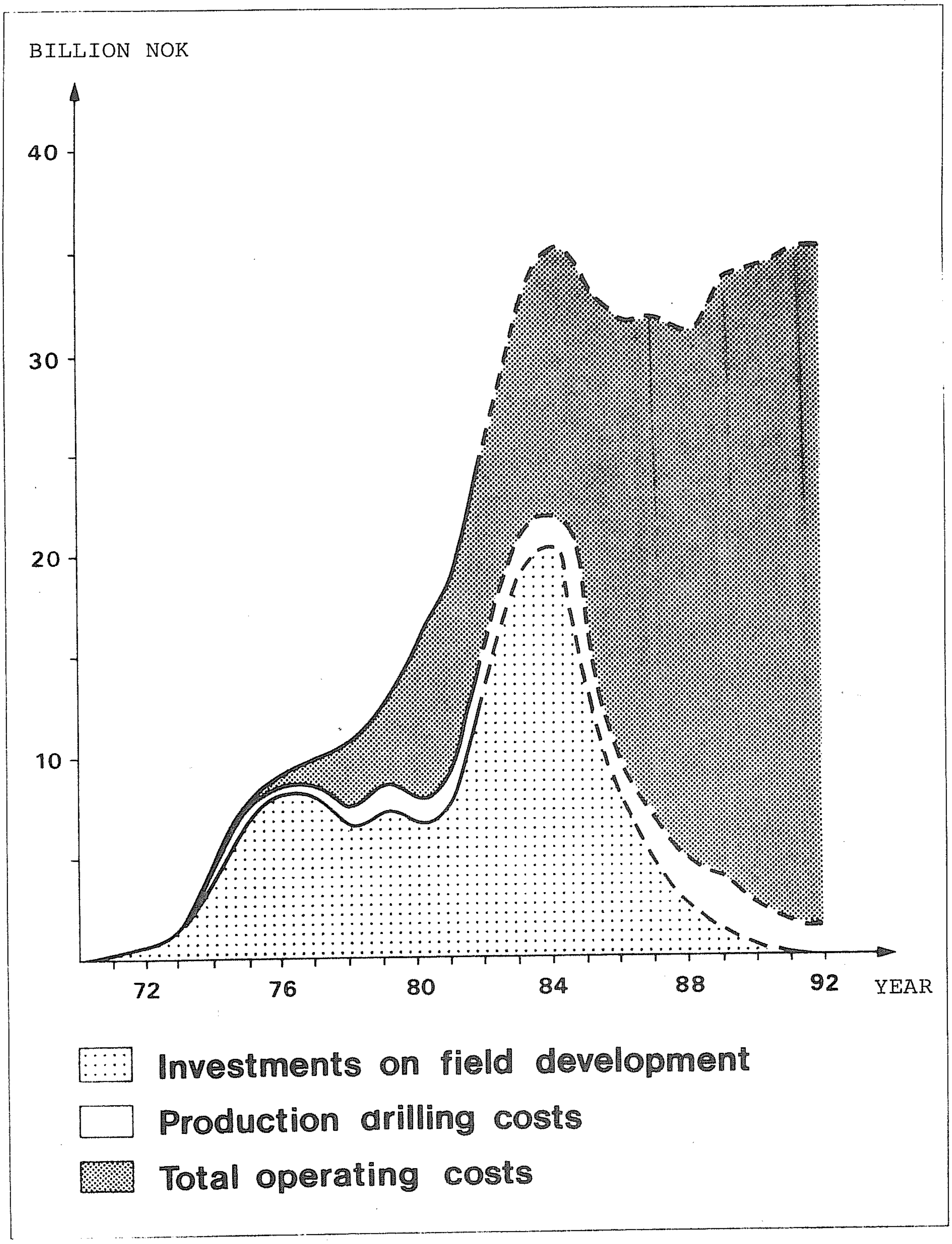


FIG 4.4.b Field investments (excl. production drilling) 1970-1991

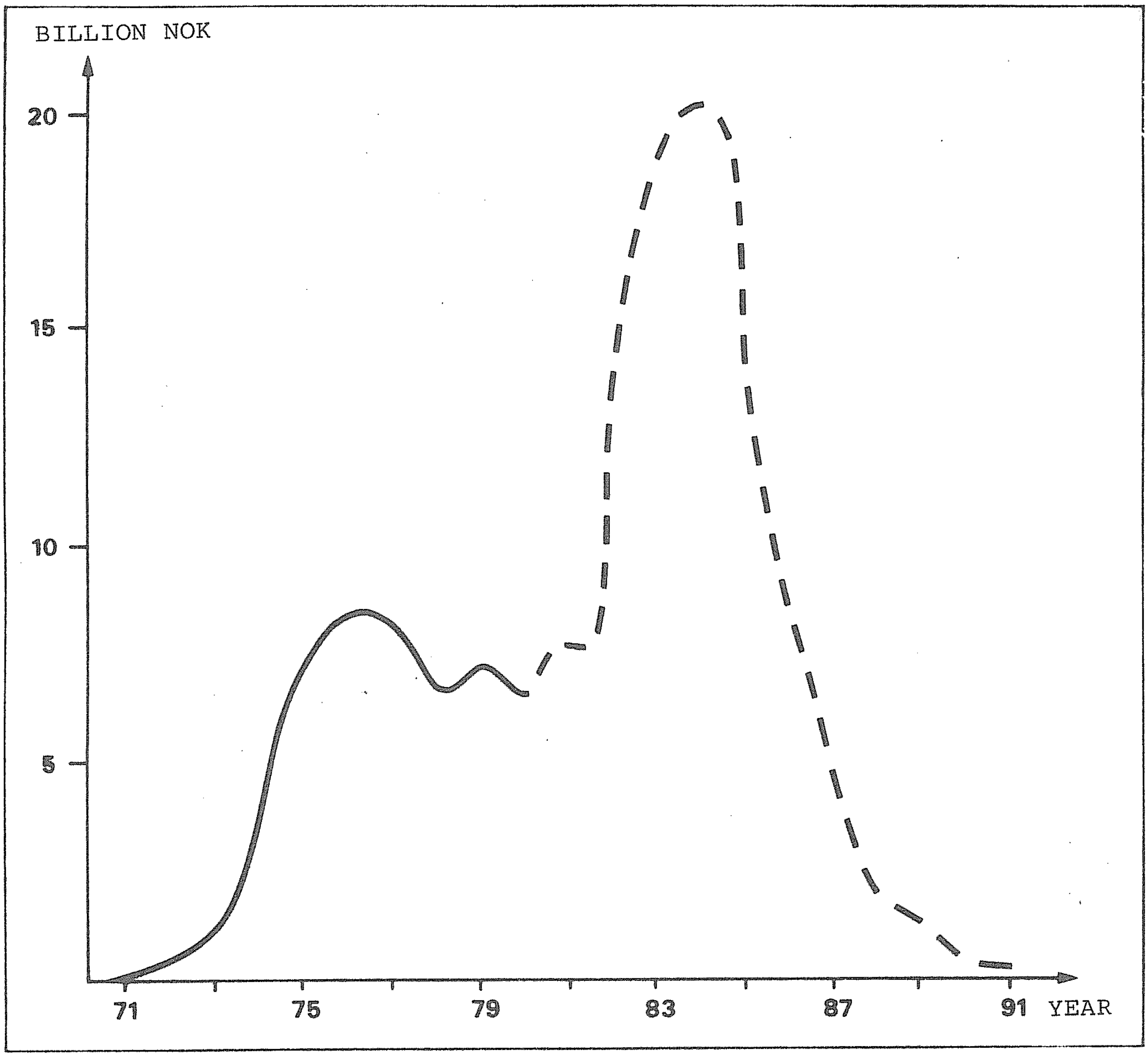
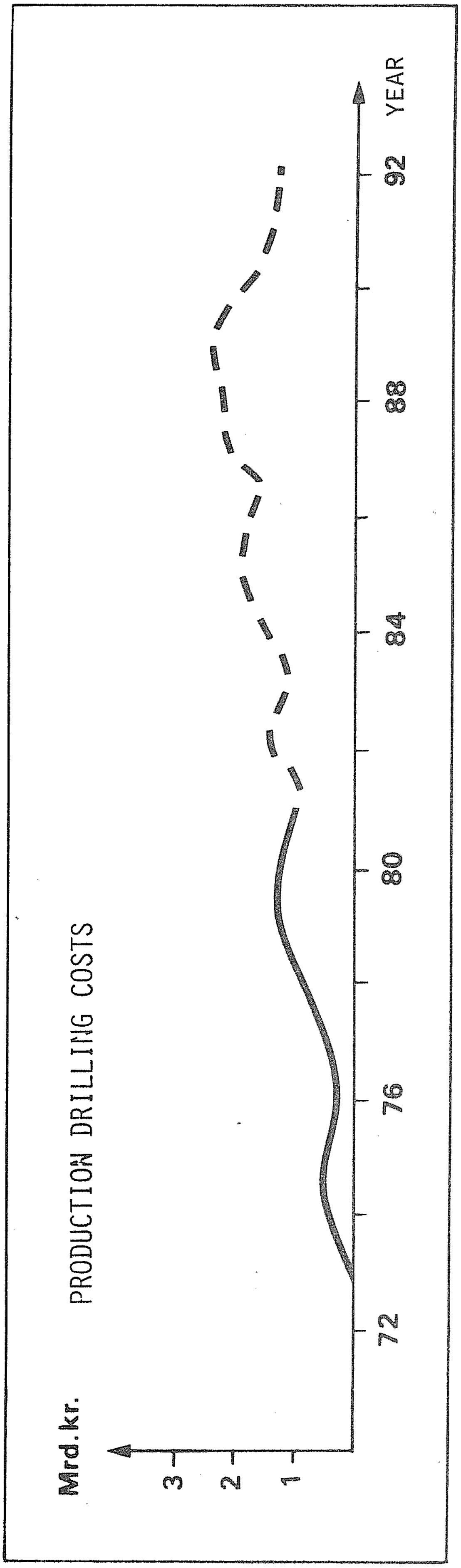


FIGURE 4.4.c



<u>Norwegian companies´ share of the total field investments including production drilling</u>

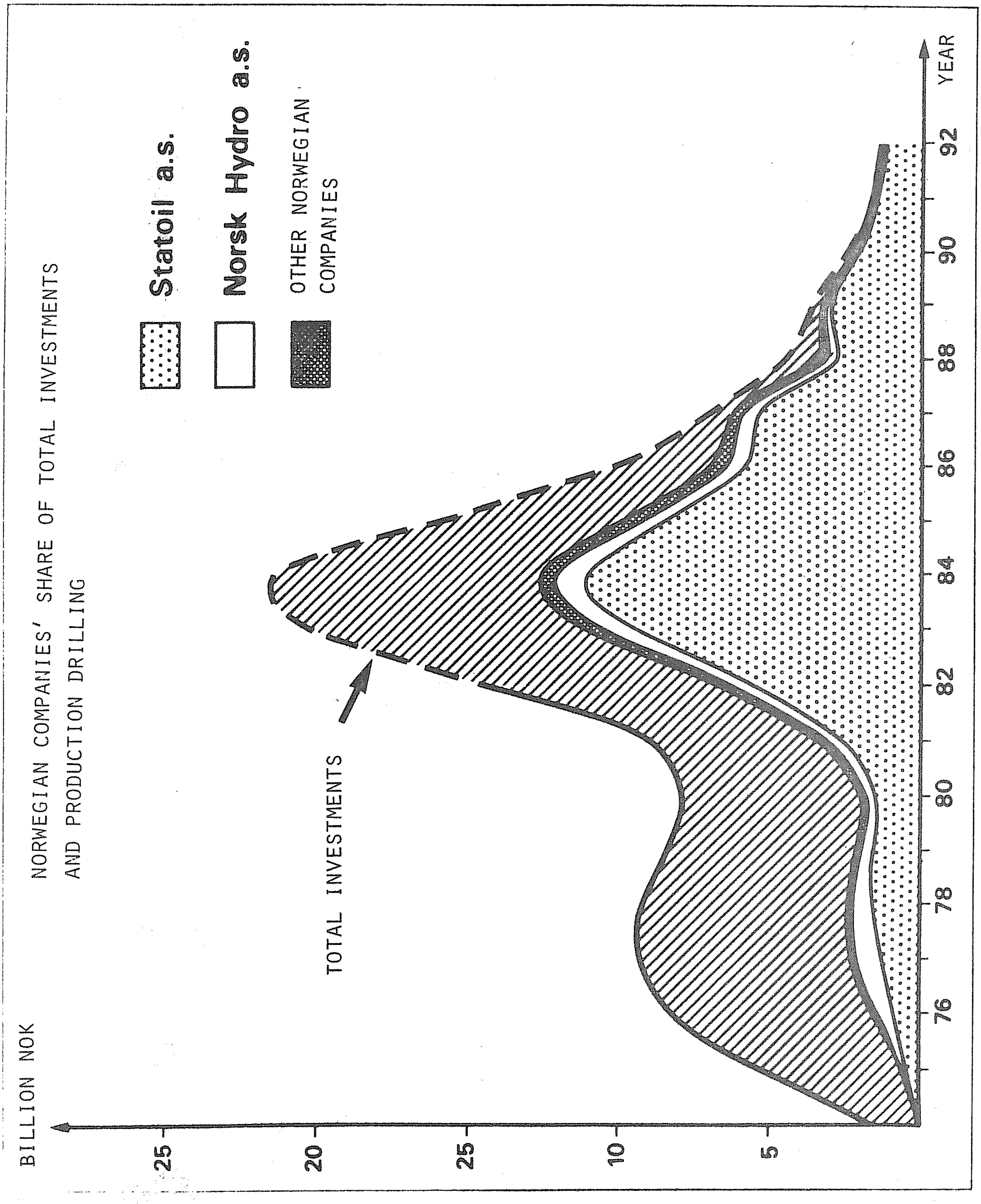
Figure 4.4.d shows the Norwegian companies´ share of the total field investment including production drilling for developed fields, fields being developed and fields declared for recovery as of 31 December 1981.

The Norwegian companies´ share was approx. 34% in 1981, but shows a strong increase later in the 1980s, and in 1983-84 the share will be approx. 57% on average. Statoil´s share will rise from 29% in 1981 to approx. 50% in 1983-84.

1983 and 1984 are the years for which the level of activity will be particularly high. Towards the end of the 1980s, the Norwegian share will be approx. 80%, with Statoil´s share at approx. 60-70%.

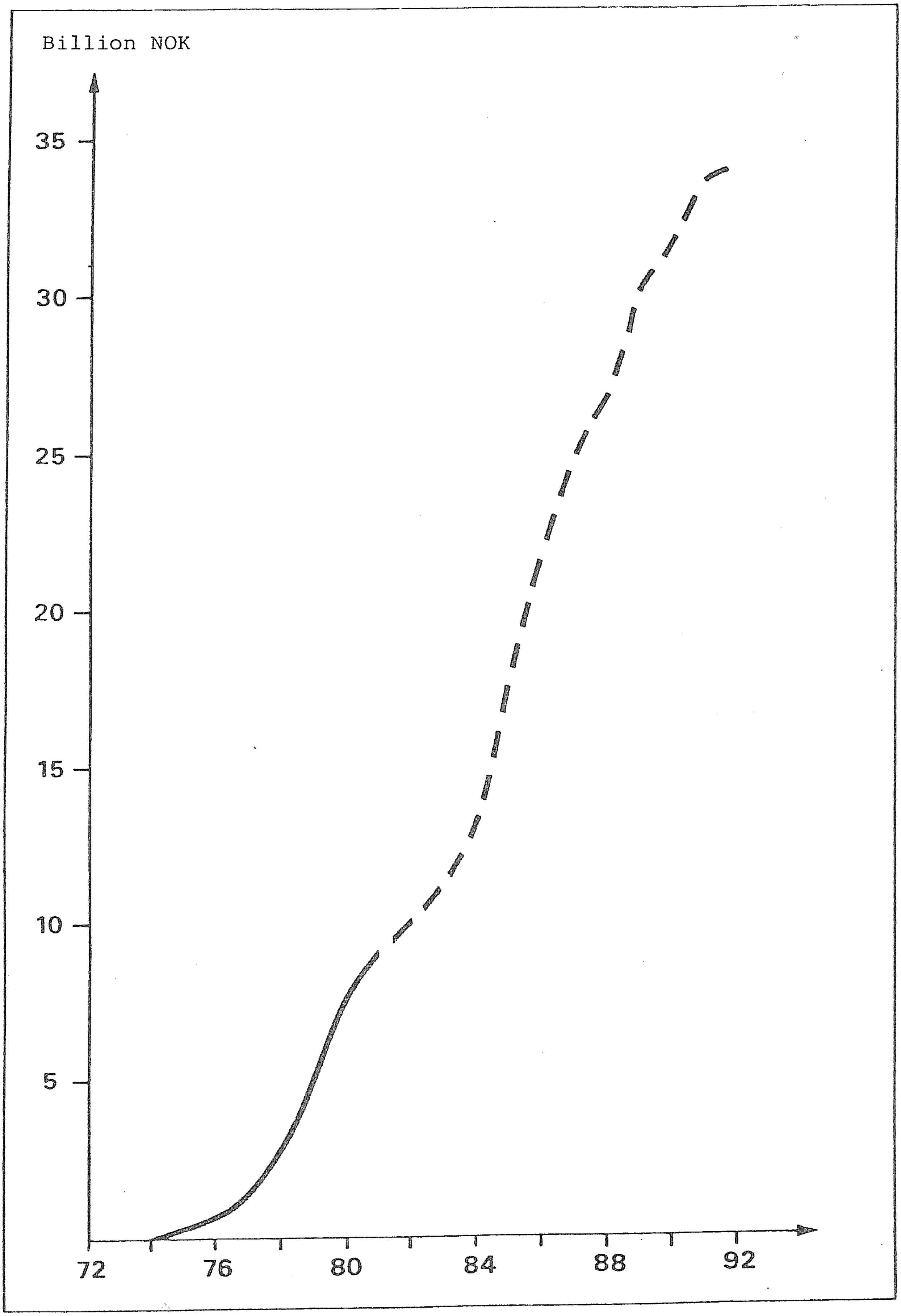
<u>Operations costs</u>

Figure 4.4.e shows the annual operations and maintenance costs of the fields declared for recovery. The total costs of operation, maintenance and transport amounted in 1981 to approx. NOK 7.8 billion. In connection with the new projects, the total volume of costs will show a strong increase towards the end of the 1980s, and represents a rapidly increasing share of the total offshore market.



NORWEGIAN COMPANIES' SHARE OF TOTAL INVESTMENTS
AND PRODUCTION DRILLING
BILLION NOK
25
20
25
10
5
TOTAL INVESTMENTS
Statoil a.s.
Norsk Hydro a.s.
OTHER NORWEGIAN COMPANIES
76
78
80
82
84
86
88
90
92
YEAR

FIG 4.4.e Total operating costs 1972-1992 in current value and fixed 1981 value



5. RECOVERY OF PETROLEUM DEPOSITS AND FUTURE PROSPECTS

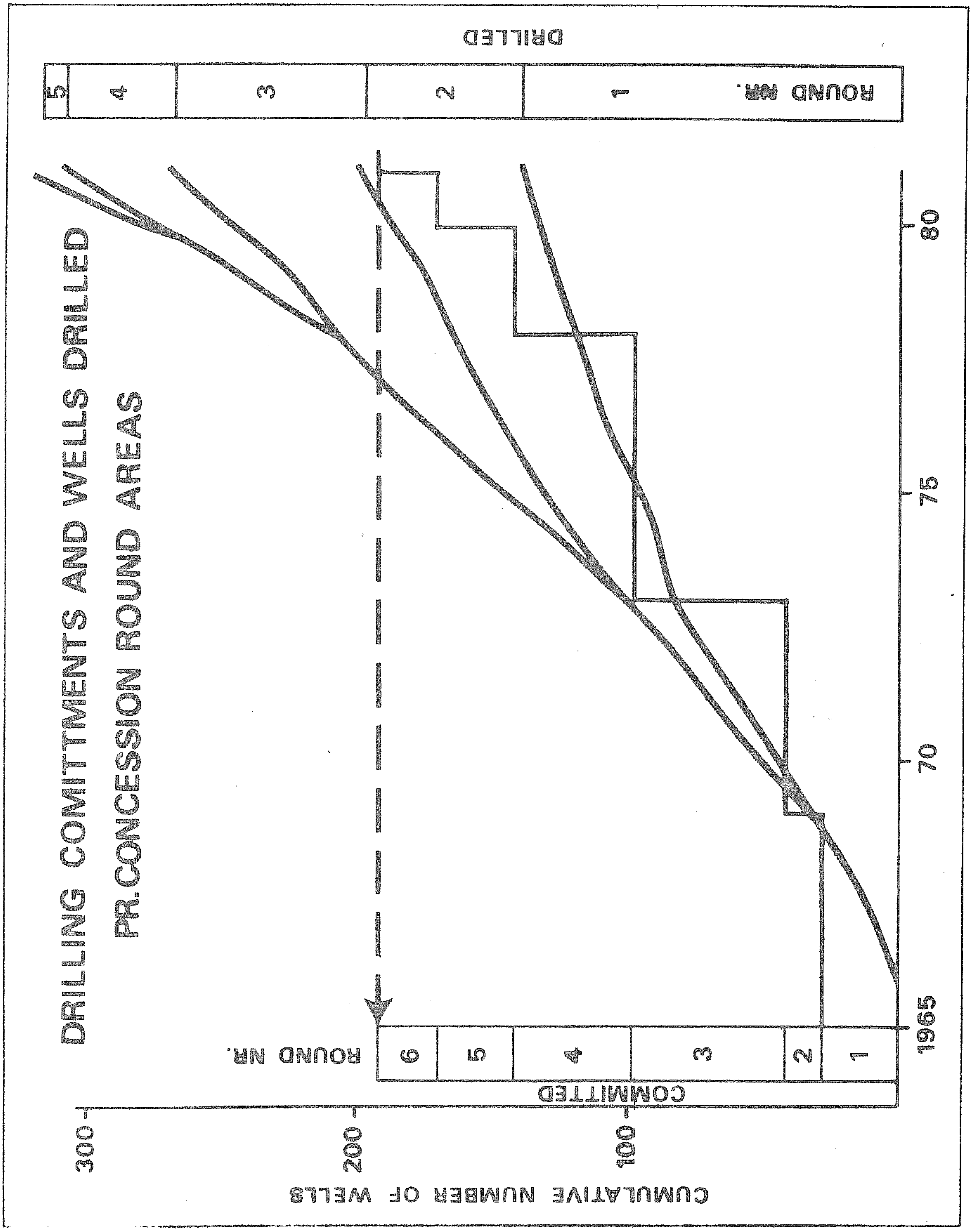
When the prospects for activities on the continental shelf are evaluated, this must be done on the basis of the market prospects for oil and gas respectively.

5.1. Reserves basis

Experience confirms that concession allocation is the most effective means of controlling the tempo of activities on the continental shelf. The immediate consequence of a round of concessions is increased drilling activity. Figure 5.1.a illustrates this by comparing the drilling obligations the concession holder undertakes in a concession round, and the total number of exploratory wells actually drilled within the blocks allocated. As is apparent from the figure, many more wells have been drilled in the old concessions than drilling obligations would indicate. This is also expected to take place for new concessions. Now the latest work program has been fixed on the basis of a better understanding of the geological conditions and improved preliminary studies than was the case for the previous ones. This means that the work programs of recent years are probably better suited to the natural conditions than was the case earlier. The drilling activity which results form the work program not only provides an important basis for clarifying known prospects, but will also give an opportunity to make finds not previously acknowledged. In addition, the finds made will require appraisal drilling before they can be developed. This matter is not covered by the drilling obligations. Also, in the more recent concessions, it may be seen that the magnitude of drilling activities will far exceed that given by the obligations.

As is apparent from Figure 5.1.a, the number of wells which are required to be drilled has increased on average since 1965. The same applies to the number of wells which have been drilled annually. (This is also apparent from Figure 2.2.2.a). It ought to be possible to allocate production licences frequently and still maintain a satisfactory negotiating position in each concession round. If the negotiating position is to be satisfactory, this will require in the first place that the concessions to be allocated are sufficiently numerous and interesting for several categories of concession holders to want to compete for them. Secondly, variations are required in block prospects so that the authorities can establish a well-balanced survey of all interesting areas, not only the most interesting ones. By making the allocations frequently, subsequent activities such as drilling, development and production will have a constant supply of new tasks and thus also a more uniform work tempo.

FIGURE 5.1.a


DRILLING COMITTMENTS AND WELLS DRILLED
PR.CONCESSION ROUND AREAS
CUMULATIVE NUMBER OF WELLS
300
200
100
1965
70
75
80
COMMITTED
ROUND NR.
1
2
3
4
5
6
DRILLED
ROUND NR.
1
2
3
4
5

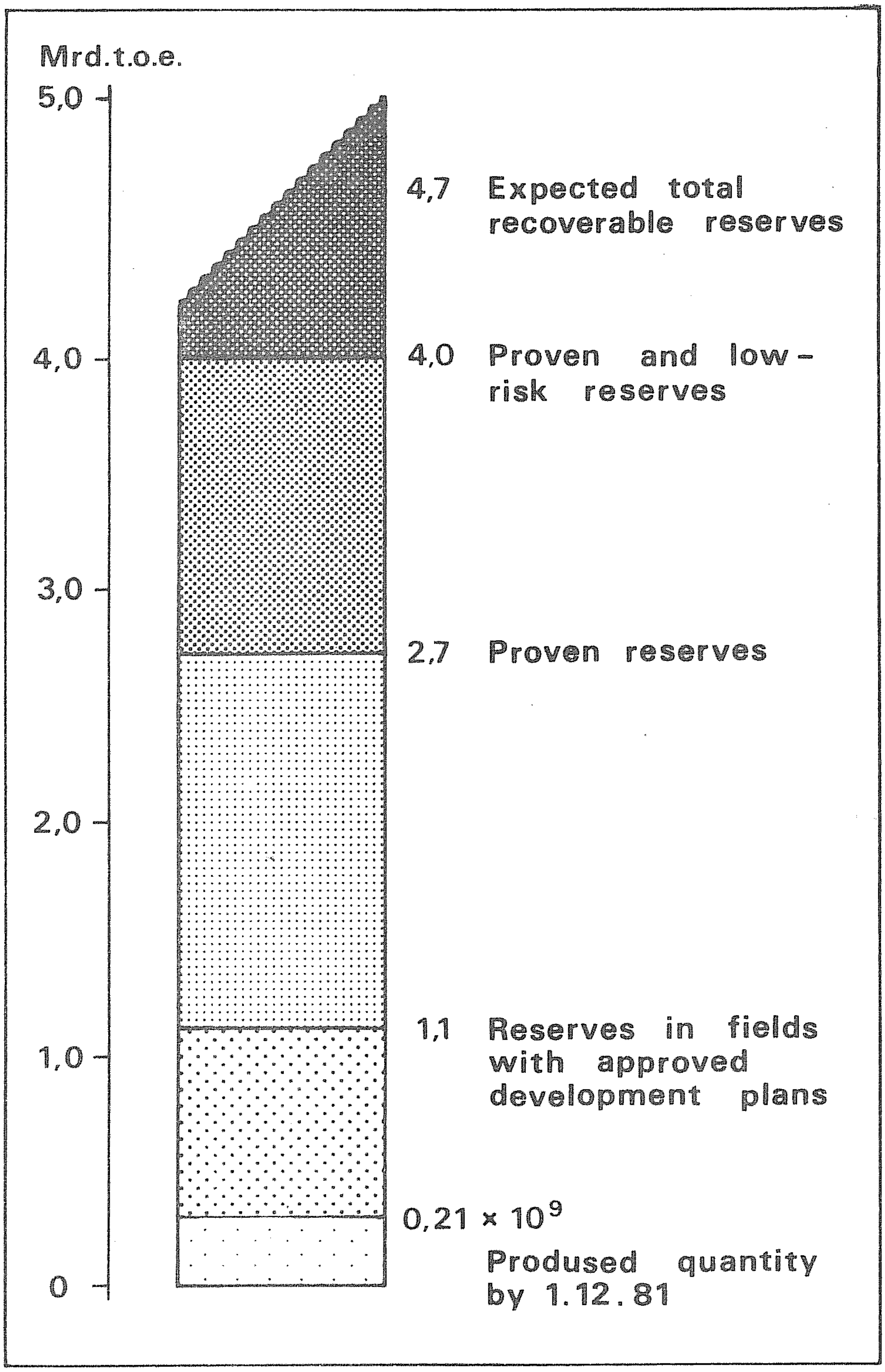
The acceleration which has taken place in drilling activities has, together with a deliberate allocation of good concession areas, accelerated the rate of determination of in-place petroleum quantities, as Figure 5.1.c shows. It follows from Figure 5.1.b that the total recoverable reserves in the North Sea are expected to be up to 5 billion ton oil equivalents. This is unchanged from last year's annual report. Of these, 0.21 billion toe have been produced, approx. 1.1 billion toe have firm plans for recovery and approx. 2.7 billion toe have been proven.

These reserves have been proven by drilling. In addition, the seismic data reveal that the gas and oil deposits which were demonstrated in block 31/2 extend over a large area into 31/3, 31/5 and 31/6. Even though the gas exists continuously throughout the whole of this area, the area is so large that it is difficult to extrapolate well information from block 31/2 with any great certainty to the greater part of the other three blocks. There are probably large reserves in the areas which have not been drilled. It is estimated that there are approx. 40 million Sm3 oil and 1100 billion Sm3 gas. This cannot however be considered to be proven as yet, but the reserves deserve to be considered low-risk.

Figure 5.1.c shows the growth in proven reserves and in reserves which have been declared for recovery. The growth, according to present estimates, is shown respectively for the year of discovery and the year of recovery declaration. In practice, it takes at least two years and often much longer to appraise a reserve, and to conclude the assessment of it after its existence is first demonstrated. During this period, the reserve estimates will therefore change frequently. At present, some ten new finds are being evaluated. These are considered perhaps to amount to something like 300 million ton oil equivalents.

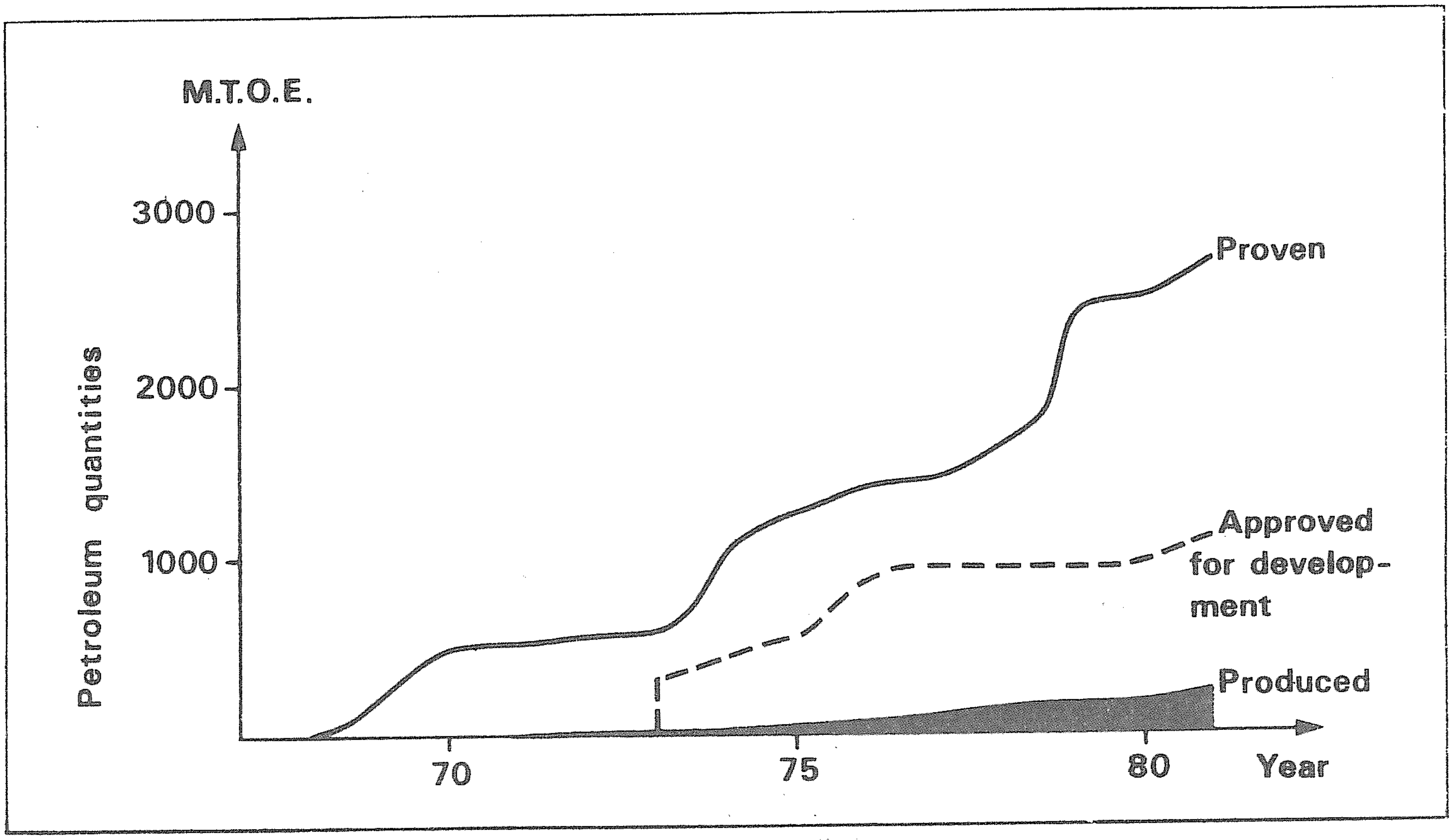
The amounts of petroleum which have been proven so far are sufficient to maintain production, development and operational activities for several years ahead with alternate courses of activity.

FIGURE 5.1.b



Reserves south of Stadt

FIGURE 5.1.c



PROVEN, DECLARED COMMERCIAL AND PRODUCED RESERVES SOUTH OF STADT

5.2. Prognosis of activity for projects declared for development

Figure 5.2.a shows how production has been, and how it is expected to be, from the reserves which have been declared for development. In addition, it shows the present gas export capacity and the processing capacity which it has been decided to install.

The historical course of production has become significantly different from the original expectation. This is apparent from Figure 5.2.b, in which the production prognosis for 1976 has been compared with actual production. Here it may be seen that the operators greatly over-estimated the production prospects. The same may be said of the Norwegian Petroleum Directorate, though not to the same degree. The reasons for this are shown in Figure 5.2.c. Until 1979, the over-estimates of production were due to a too optimistic view of when the development constructions would be ready, and how quickly production could be build up. From 1979 onwards, the early over-estimates of the reserves and course of production also contributed to the divergence from the prognosis, and comprise at present the most important reason for the disparity. A typical feature of this development is that changes in reserves and the course of production give a more long-term result and are notified earlier than changes in the schedule for development.

Delays in the development work are shown in Figure 5.2.d. To emphasize that such delays are not limited to projects on the Norwegian continental shelf, delays are also shown for a selection of projects in the Mexican Gulf. It is apparent that no development project has been completed before time and that the projects on the Norwegian continental shelf were on average expected to be completed in 70% of the time actually required.

In the years 1973 to 1977, it was resolved to undertake several large developments. As is apparent from Figure 5.2.e, activities started after 1973 have grown rapidly, and the rate of investment reached a level of approx. NOK 13 billion (1981 kroner) as early as during the latter half of the 1970s.

The projects if fact took much longer than predicted, and required so much more resources that it was necessary to set up an official committee to investigate the matter. Several of the reasons for cost increase which are mentioned in the Cost Analysis - Norwegian Continental Shelf, may be traced back to a rapid development of activities carried out on a poor experience base. The most important are:

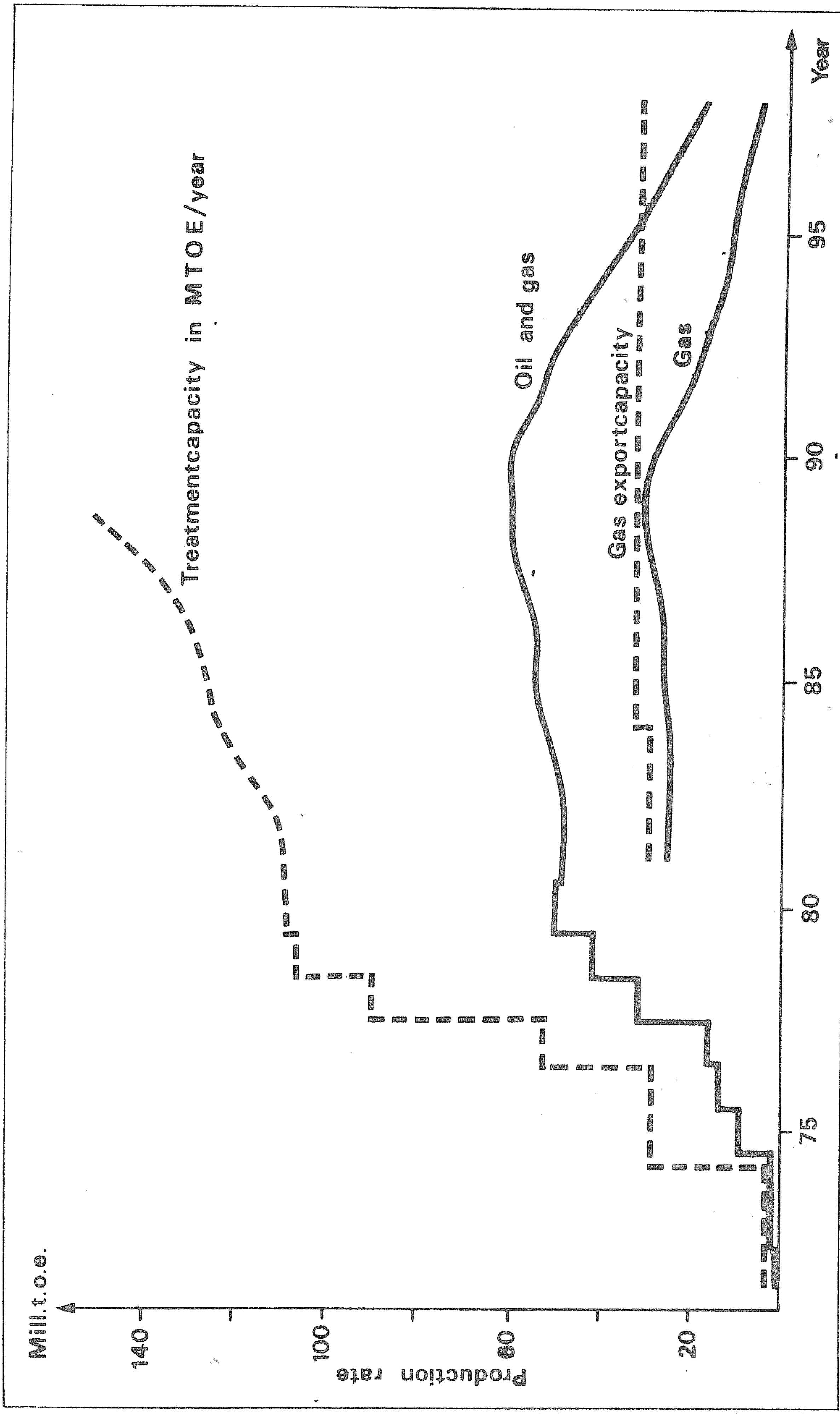
- original under-estimation of the scope of the project
- weak control of the operator
- incomplete planning prior to start of construction work
- poor cost conciousness and cost control
- expensive technical solutions
- high costs during connection due to deficient prefabrication by vendors
- tight North Sea market as a result of the level of activity
- development of safety requirements and regulations for working environment, worker protection and the natural environment, at the same time as development projects were being carried out.

Since 1976, no new developments had been submitted to Storting until the developments of Ula, Odin and North-East Frigg were presented following the price increase in 1979 and 1980. The lack of opportunity for starting new projects led to a fall in investment level, and the impossibility of continuing to increase oil production beyond 1980. In the years 1980 and particularly 1981, the investment picture was fundamentally altered. Investments approved in 1980 were stated to be approx. 1980-NOK 5.9 billion for Ula and North-East Frigg. Investment estimates for Odin are not included in this figure. The total investments in the three projects are at present stated by the operators to be approx 1981-NOK 15 million. This is due among other things to the investment estimates for Ula having been adjusted strongly upwards in relation to the estimate presented to the Storting. (As a result of this, the concession holders are evaluating to what extent the development shall be carried through.) Investments which were approved in 1981 were stated by the operators to amount to approx. NOK 40 billion. In all, these decisions will provide the basis of a course of investment which the Norwegian Petroleum Directorate predicts will resemble Figure 5.2.e.

In the investments approved in 1981, the Statpipe system is included. This will create an infrastructure for the transport of gas which will also help to increase the value of gas reserves in fields other that those for which the pipeline is being constructed.

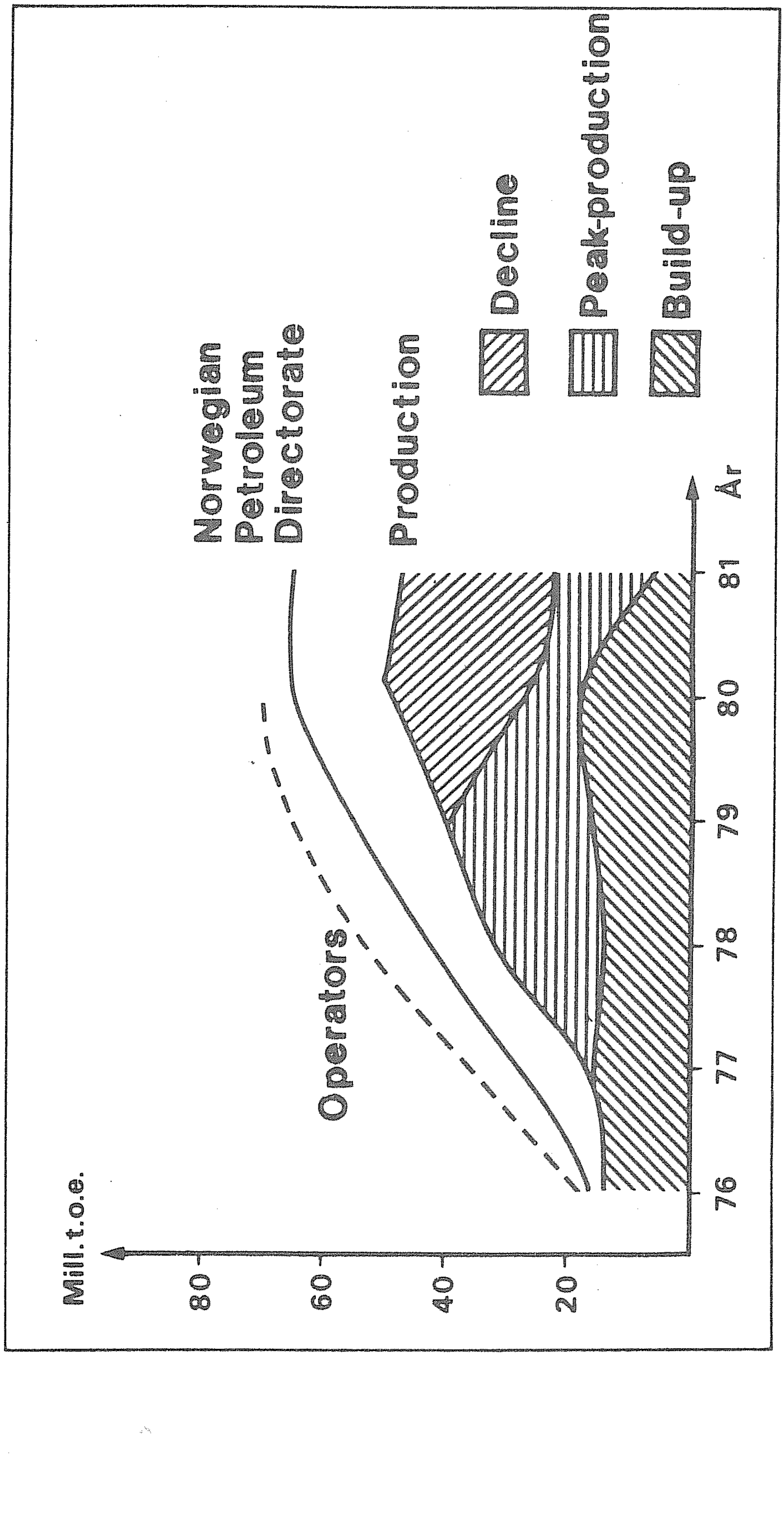
As these facilities are completed and taken into use, operational activities start up. Their significance increased strongly from 1977, when the costs only accounted for some hundred million 1981-NOK annually, to the present, when they amount to close on 8 billion 1981-NOK. The costs are expected to continue to rise, both as regards the facilities already in operation and as a result of new facilities being brought into use. To the extent that the same resources are used for development and operation, the operations activities, which of course are extremely stable over time, contribute to lessen the effect of fluctuations in the development activities.

FIGURE 5.4.c



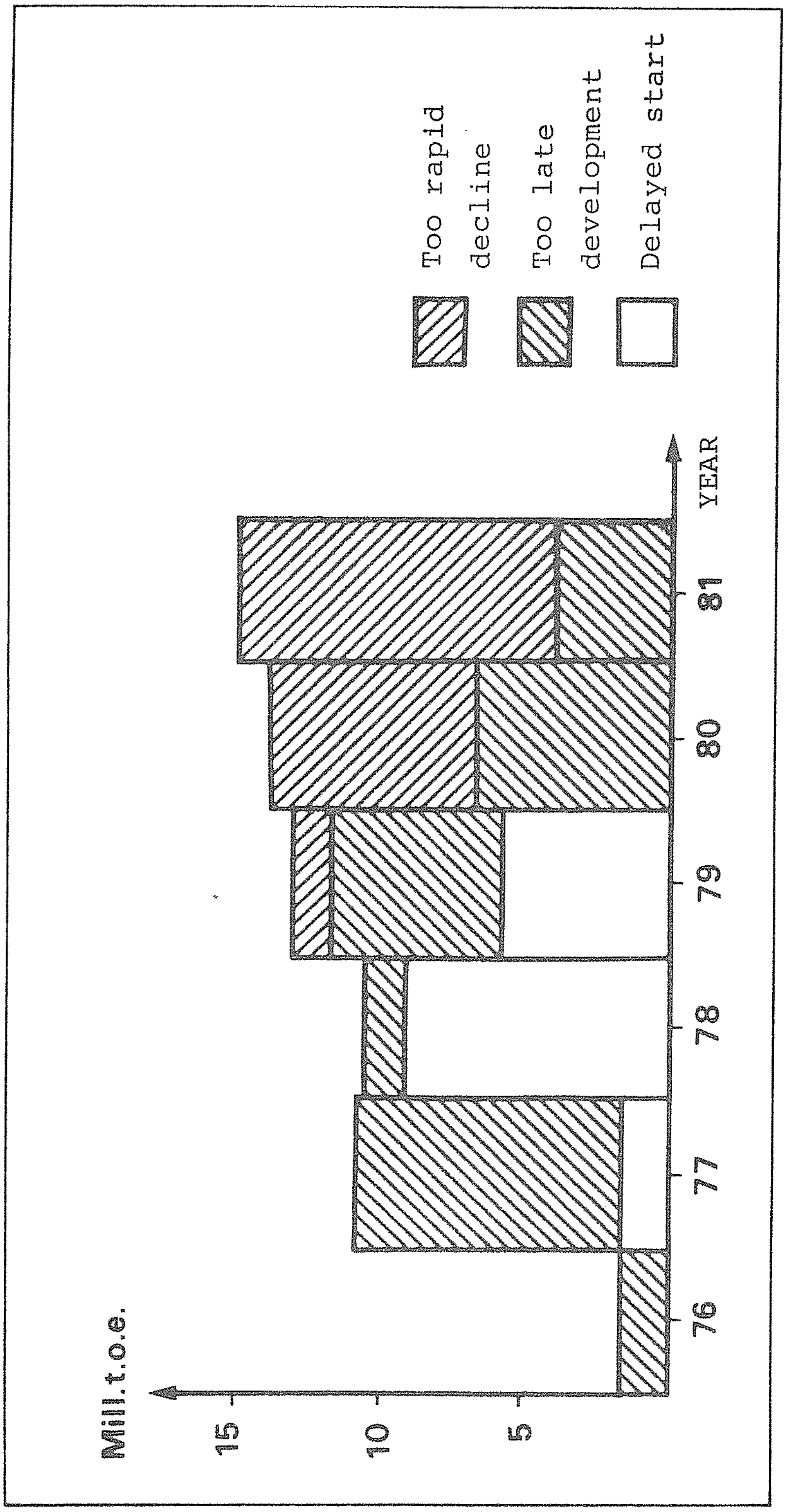
PRODUCTION, PROCESSING CAPACITY AND GAS EXPORT CAPACITY

FIGURE 5.2.b



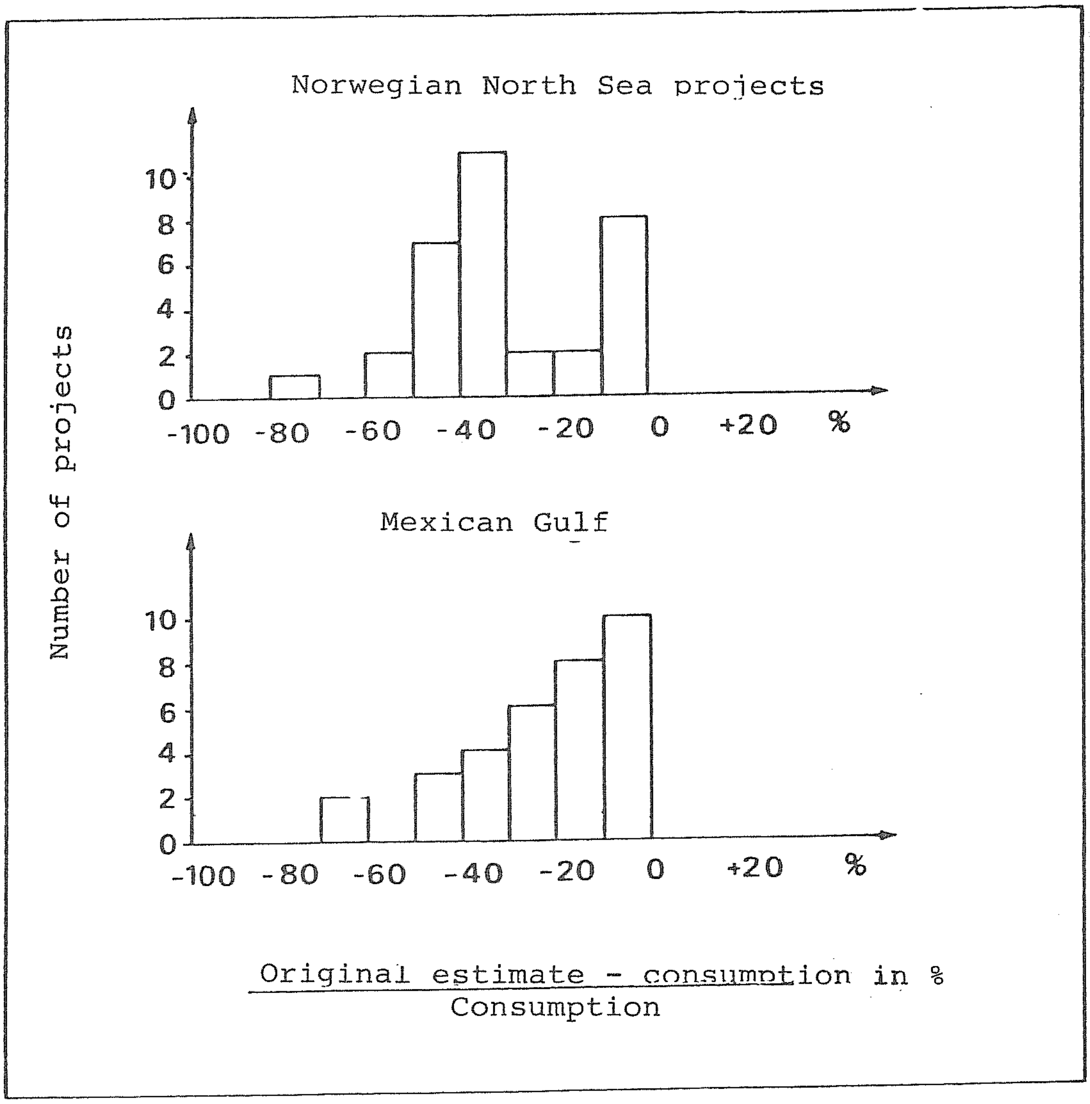
Comparison between 1976 prognosis and actual production

FIGURE 5.2.c



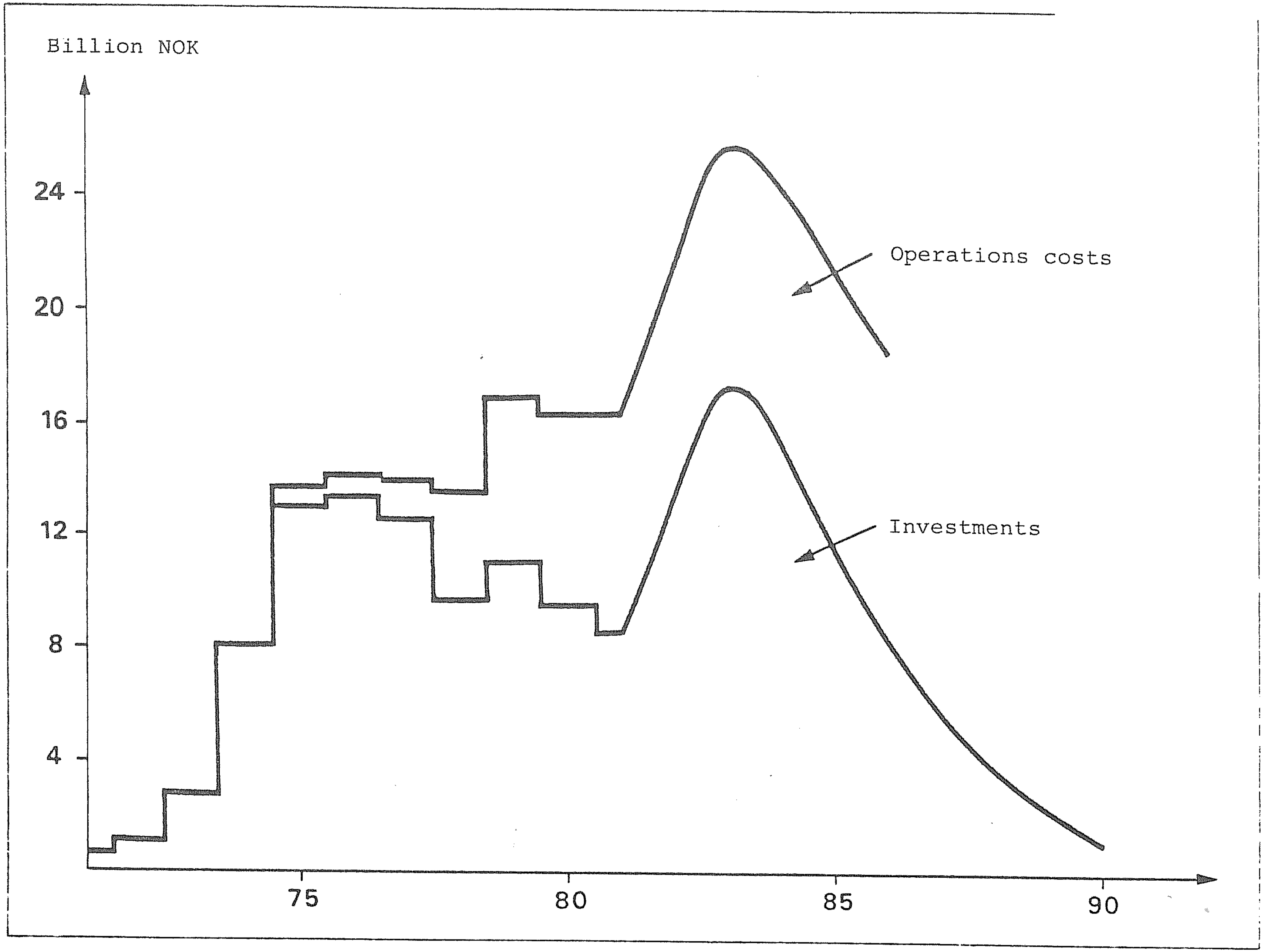
Explanation for differences between expected and actual production

FIG 5.2.d



Time taken for large development projects

FIG 5.2.e



Investments and operations costs in fixed 1981-kroner

5.3. Future development prospects

One precondition for field development on the shelf is that the prices at all times justify the relatively high costs connected with activities on it. To the extent that oil prices continue to increase in real value, in relation to costs, the precondition will continue to hold good for further development. Both the oil prices and cost development in recent times however, give grounds for some uncertainty in planning. Unstable oil prices, particularly in combination with a relative increase in development costs, may for some periods disturb rational development in the long term. This may take the form of a reduction in the number of options to an unsuitable minimum which does not provide an optimal solution totally.

As regards development of gas finds, these will to a greater degree than for oil, depend on the achievement of longterm security regarding price and supply expectations. This is something that buyers and manufacturers may help to create jointly. Such security will lead among other things to development of the infrastructure necessary for production and transport, which will in turn improve finances within the individual fields, particularly small ones.

Experience gained from developments on the Norwegian shelf till now illustrate clearly how necessary it is to plan supplements to the production profile at least ten years before the need for such supplements arises. This is due to several factors. In the first place: it takes at least two years, in many cases three, from the time a find is made until the reserve has been sufficiently surveyed. In the second place: experience indicates that it takes at least six years from the time the commerciality declaration is given until the production actually starts. When account is taken of the fact that it takes at last two to five years to build up production to the plateau level, and at the same time of the increase in geological complexity and greater depths of water for future reserves, it is reasonable to expect that development time in the future will extend beyond its historical mean value of eight years from find to plateau production per development unit.

Nonetheless, it should be emphasized that till now on the shelf, we have been confronted with a situation where choice of development projects has been extremely limited. The situation at present will however be characterised to some extent by real choice options between such development alternatives. This points in the direction of the need to acknowledge the requirement for a planning horizon which is not less than eight to ten years. A concrete view of the prospects for the future as presented in Figure 5.2.a reveals that, even with a modest production rate of 60 million top annually, it will be necessary to produce from new reserves by 1991. This means in other words that the decision to undertake new development must come before 1984. With such a resolution, it would also be possible to maintain the investment level (cf. Figure 5.2.e).

However, here a distinction must be drawn between gas projects and oil projects, specially to the extent that development of a gas occurrence is dependent on a new infrastructure or a considerable change in existing facilities. Preparations for such changes in the infrastructure may take longer than average. The same is the case for fields where a considerable technological breakthough is necessary.

How the development, operations and production activities will stand in relation to eachother in the future depends both of the finds which it is decided to produce, and the method of their recovery. In the next paragraph, it is noted that it will be desirable to prepare for a more effective use of capacity (cf Figure 5.2.a). This will help to reduce both investment and operations cost levels in relation to the production level. On the other hand, we are confronted with having to utilise more high-cost reserves in the future than has been the case till now. Reserves which may be recovered by water injection on the Ekofisk area belong in this category, as does the find in the 31/2 field and the finds in North Norway. The same is the case for large infrastructure facilities for transportation and processing of gas. Development of these may push the investment and operational costs upwards in relation to the production level. These are circumstances which must be presented as they are clarified.

With large decisions at long intervals we have seen that the level of activities fluctuates strongly. Here, as during concession allocation, a more uniform tempo may be obtained by more even decision-making, with emphasis directed the whole time towards adjusting the investment level to production ambitions.

The Norwegian Petroleum Directorate´s task in the further planning will be to clarify the consequences of the options which may realistically be selected by the deciding authorities. This will be done on a factual basis, development by development, in the perspective analysis which is now being prepared and which should be ready in August 1982.

5.4. Recovery of resources

The Norwegian Petroleum Directorate has worked to achieve a reasonable recovery of resources on the continental shelf since it was established in 1972. The work has been done according to the general guidelines laid down in the provisional regulations for proper exploitation of petroleum reserves of 17 October 1978.

Previous annual reports indicate that the work of proper exploitation of petroleum reserves has always received high priority.

Exploitation of petroleum reserves has been given top priority until now, followed by the exploitation of the investments made to recover the reserves. In recent times it has also become more and more important to evaluate how effective operational activities may become.

Recovery of petroleum reserves

Figures 5.4.a and 5.4.b show how oil and gas respectively are distributed among the various reserves. In addition to the amounts in place, the figures show the amounts which are expected to be recovered with the development plans so far declared. A complete summary of the reserves is given in Tables 5.4.a, 5.4.b and 5.4.c.

FIG 5.4.a Oil in place and oil with firm plans for recovery in Norwegian accumulations

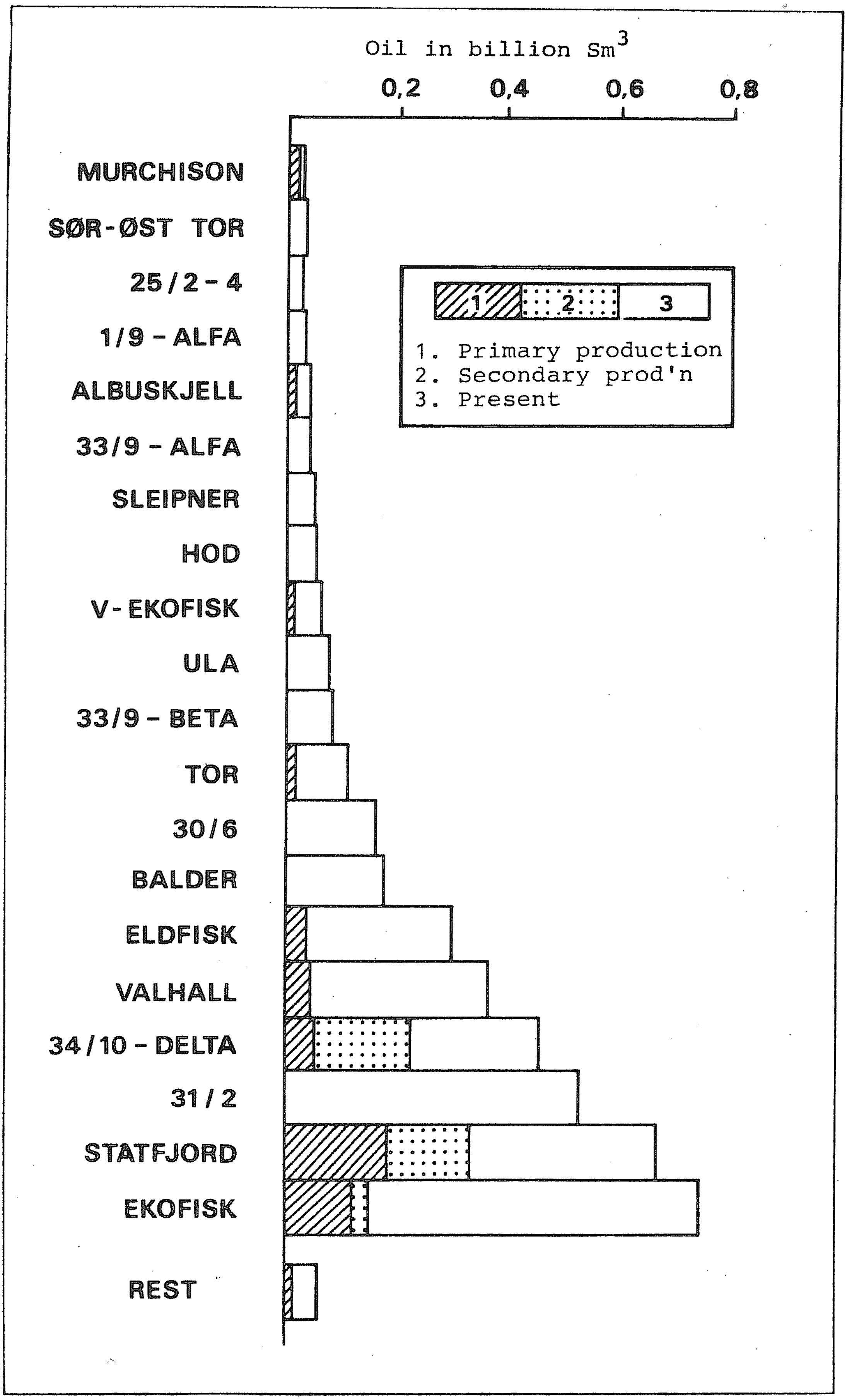


FIG 5.4.b Gas in place and gas with firm plans for recovery in Norwegian accumulations

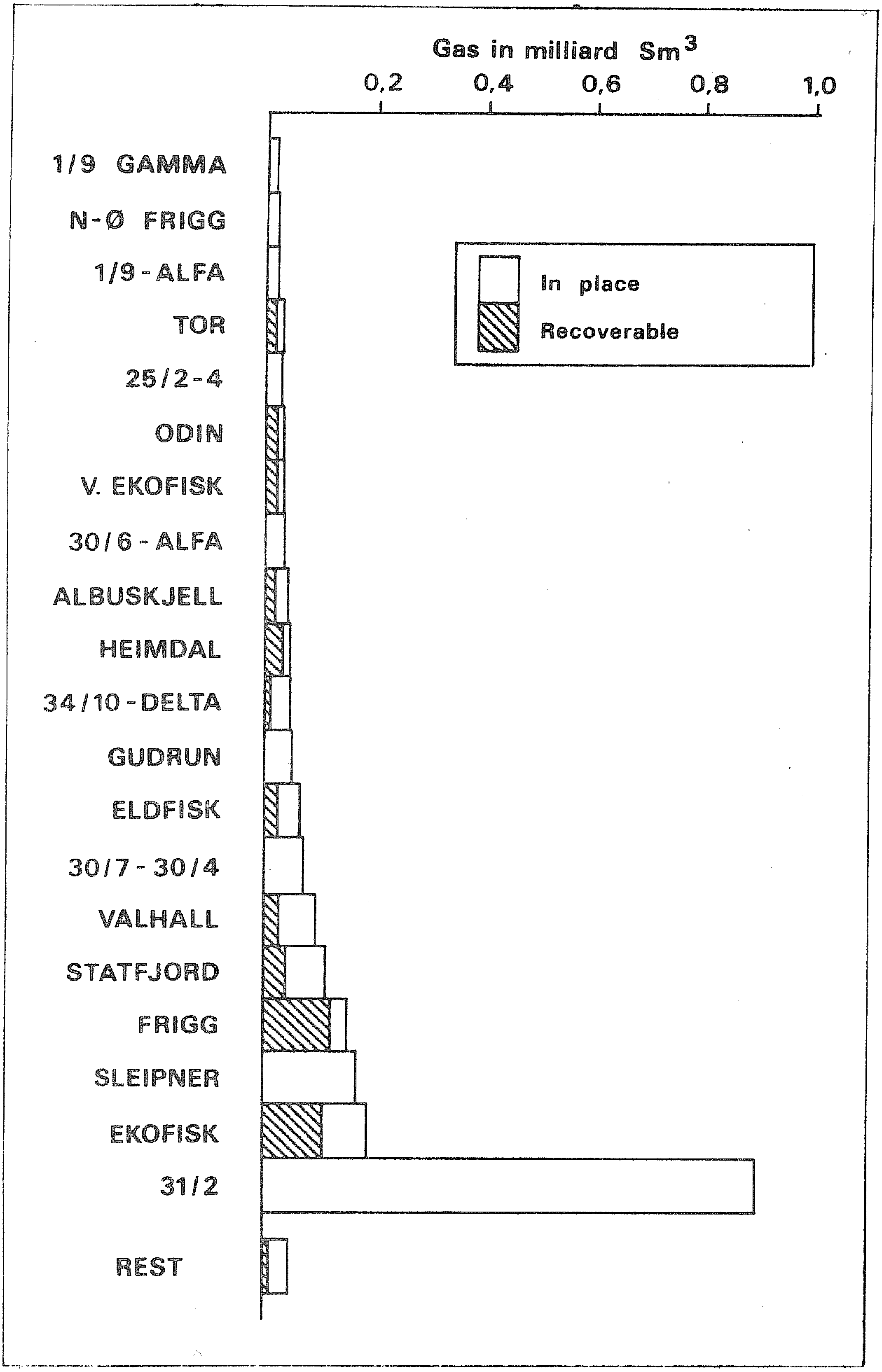


TABLE 5.4.a Proven in place and recoverable hydrocarbon reserves in fields declared commercial as of 31.12.81

Field	Originally present amount petroleum		Originally recoverable amt. petroleum		Recovered petroleum		Remaining non-recoverable amt. petroleum	
	Oil $10^6 Sm^3$	Gas $10^9 Sm^3$	Oil $10^6 Sm^3$	Gas $10^9 Sm^3$	Oil $10^6 Sm^3$	Gas $10^9 Sm^3$	Oil $10^6 Sm^3$	Gas $10^9 Sm^3$
Albuskjell 1)	35	38	11	16	4	5	7	11
Cod 1)	8	9	2	5	1	2	1	3
Edda 1)	14	3	3	2	2	0.8	1	1
Ekofisk 1)	828	191	162	112	100	25	62	87
Eldfisk 1)	235	77	40	38	13	4	27	34
Frigg 1)	-	158	1	127	0.10	34	1	93
Heimdal	3	48	3	31	-	-	3	31
Murchison 3)	19	1	9	-	0.80	-	8	-
NE Frigg	-	10	-	5	-	0.50	-	4
Odin	-	30	-	22	-	-	-	22
Statfjord 4)	682	119	367	40	11	-	356	40
Tor 1)	144	25	18	12	12	4	6	8
Ula	70	8	29	2	-	-	29	2
Valhall A	243	61	36	28	-	-	36	28
W Ekofisk 1)	60	31	12	22	9	14	3	8
34/10 Delta Phase 1	221	20	89	9	-	-	89	9
Total	2562	829	782	474	153	89	629	384

1) Including NGL in oil
2) This is the Norwegian share: 60.82%
3) This is the Norwegian share: 16.25%
4) This is the Norwegian share: 89.09%

TABLE 5.4.b Proven in place and recoverable hydrocarbon reserves in fields declared commercial as of 31 December 1981

	In place amounts		Recoverable amounts	
	Oil mill Sm3	Gas bill Sm3	Oil mill Sm3	Gas bill Sm3
Balder 1)	131	-	35	-
Bream	<1	<1	<1	-
Brisling	<1	<1	<1	-
Flyndre	<1	<1	<1	<1
SE Frigg	-	1	-	1
E Frigg	-	6	-	5
15/3-1	-	49	2	29
Hod	45	11	9	7
Murphy	-	2	-	2
Sleipner 2)	45	196	12	140
SE Tor	21	6	4	3
Valhall 3)	126	31	25	19
1/9 Alpha	26	19	5	11
1/9 Gamma	18	18	4	13
25/2-4	23	25	4	12
30/6-Alpha *	234	75	117	60
30/7-30/4 *	-	73	-	51
31/2 *	830	690	120	480
33/9-Alpha	37	4	18	2
33/9-Beta	78	3	39	2
34/10-Alpha	17	6	8	4
34/10-Delta Phase II	254	23	102	12
New finds **	253	289	71	175
	2138	1521	575	1028

1) Being evaluated. Estimate includes whole field.
2) Includes several structures, but not 15/9-Gamma, which is being evaluated
3) That part of the field which is not included in the Valhall A development
*) Fields marked thus also include reservoirs which extend into the neighbouring blocks.
**) Includes 2/1, 15/9-Gamma, 24/9, 30/3, 31/4, 35/8, 6507/11, 7120/8, 7120/12 (see Table 5.4.c).

TABLE 5.4.c Proven in place and recoverable hydrocarbon reserves in new fields which are only partly evaluated

	In place amounts		Recoverable amounts	
	Oil mill Sm3	Gas bill Sm3	Oil mill Sm3	Gas bill Sm3
2/1	17	2	5	-
15/8-Alpha		15	-	10
15/9-Gamma	-	115	-	80
24/9	11	-	3	-
30/3	60	20	24	8
31/4	165	46	38	12
35/8	-	15	1	10
6507/11	-	14	-	10
7120/8	-	70	-	50
7120/12	-	7	-	5
Sum	253	304	71	185

The greater part of the reserves are concentrated in relatively few finds. How great the reserves are on the Norwegian shelf, and how well they are utilised, will therefore depend to a large extent on how large these finds are and how they are recovered. They also allow the possibility that dispersed and diversified production activities may be built up which contribute to stabilise fluctuations within most sections of petroleum activity.

It is the degree of recovery which in particular is influenced by the way the recovery is arranged. The importance of achieving a high recovery factor is clearly apparent from the reserves tables. The mean recovery factor for the fields declared commercial is 30%. For every percent this increases, 26 million Sm3 oil are gained, amounting at present prices to a value of approx. NOK 35 billion.

The average recovery factor for gas is approx. 55%. Because this recovery factor is greater that the recovery factor for oil, it is also more difficult to raise. Nevertheless, it is clear that great amounts are gained by any increase. A one percent rise will represent an increase of approx. 8 billion Sm3, which is not much short of equalling Norway´s annual consumption of petroleum.

The recovery factor of petroleum resources on the Norwegian shelf is not determined by technical reservoir considerations alone. Also of great importance for commerciality are the value of the resources. The value will be determined both by the market prices and by the efficiency with which petroleum products may be produced, transported, refined and marketed. The reason that the Norwegian Petroleum Directorate has found it necessary to take an interest in the resources which are put into the construction and operation of facilities on the continental shelf, is not only its interest in employing these particular resources effectively. An efficient facilities and transport pattern also provides the best basis for ensuring that a larger part of the petroleum resources can be declared commercial.

Utilisation of facilities

The production capacity which is installed on the Norwegian shelf is expensive. Figure 5.4.c indicates that the investments for the facilities which it has been decided to build vary in the region of 500-3000 1981-NOK per million ton oil equivalents which the facilities can process annually. Despite the fact that the major part of the reserves developed have had low capacity costs, in recent times it has also been decided to build facilities in the mid-cost area. The most interesting developments which are now being evaluated for execution are more evenly distributed over the cost spectrum. It is therefore reasonable to expect that the average cost for new capacity will increase from a level of between NOK 1000 and NOK 1500 per year-ton which applied some years ago, to a level between NOK 1500 and NOK 2000 per year-ton in a few years.

Figure 5.4.d shows how large a production capacity has been installed in relation to the recoverable reserves. The diagram gives a main variation in capacity in the region of 5 to 20% of the reserves per year.

The high values result as a rule from the reserves being over-estimated at the outset. In some exceptional cases, it has been decided to develop high capacity to achieve rapid profits, and thus more favourable project finance.

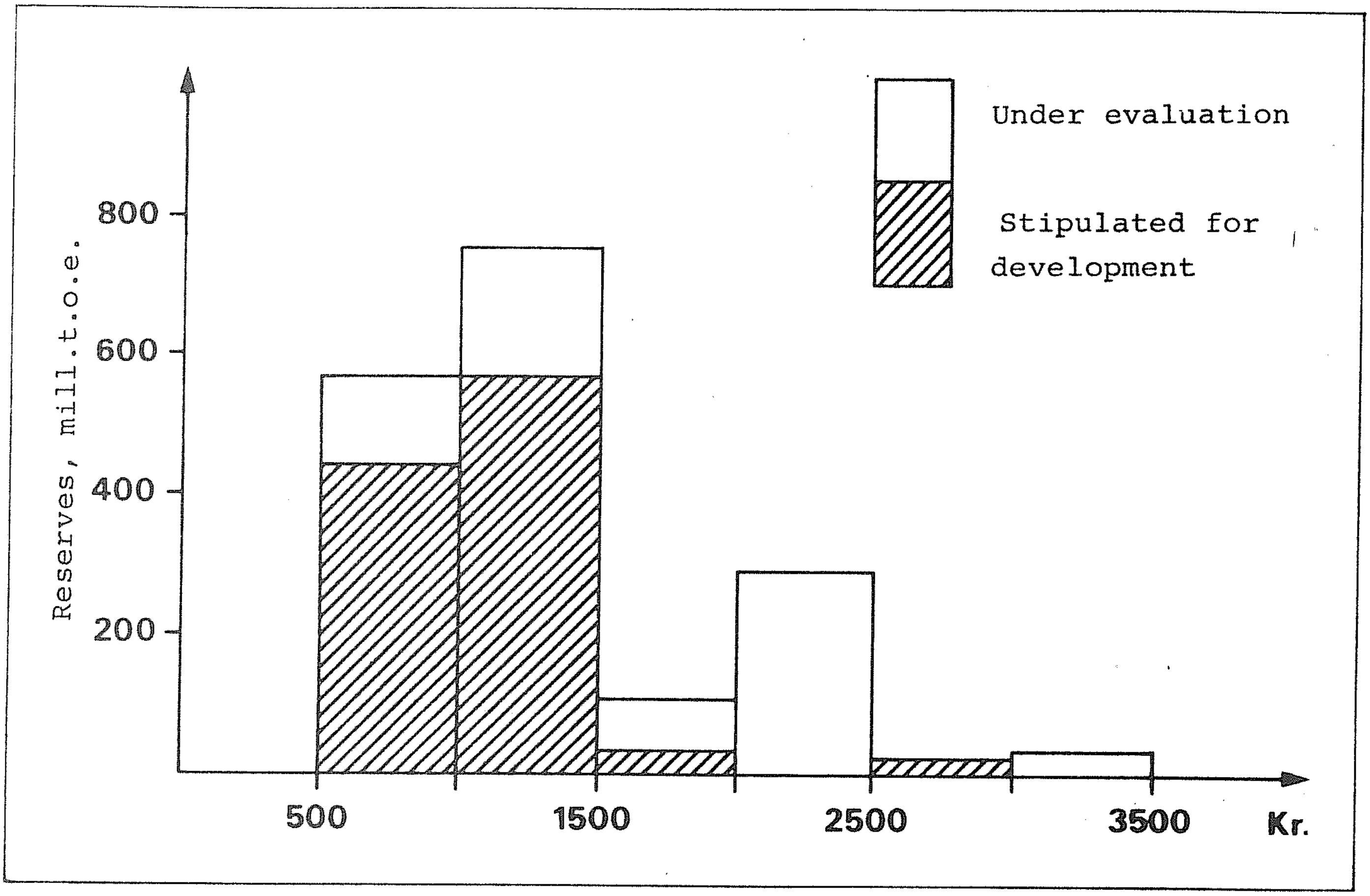
The facilities which are being built may be expected to be in use for 30-40 years, which corresponds to the concession validity period. If they were utilised wholly in this time, they would be able to process much larger amounts of petroleum than the reserves they have been built to exploit. A facility with the capacity to process 10% of the reserves annually would on average over a 40-year period appear to be only 25% utilised. Installation of such high capacity follows from the fact that the production rate from the fields declines rapidly after the first productive period. In some cases, a part of the capacity which is released will not be available due to high water or gas production, reduced pressure or other factors. In most cases however, the facilities would be able to process larger amounts of petroleum if such were available.

In Figure 5.2.a, the development of nominal production and processing capacity is compared with the actual production. Here it may be seen that gas export capacity is relatively well utilised. The same thing cannot be said of the production and processing capacity. Of a total processing capacity of approx. 110 million ton oil equivalents annually, only approx. 50 are utilised today. This unemployed capacity would make it possible to save on new investments to the extent of many billion kroner if it could be made use of.

In practice, it has been difficult to effect collaborative utilisation of existing capacity to the extent that this might be desirable on the basis of a total evaluation. An exception is the Frigg development however, where joint utilisation not only of the facilities, but also of the reservoirs, has secured low development costs and a reliable supply from the satellite fields.

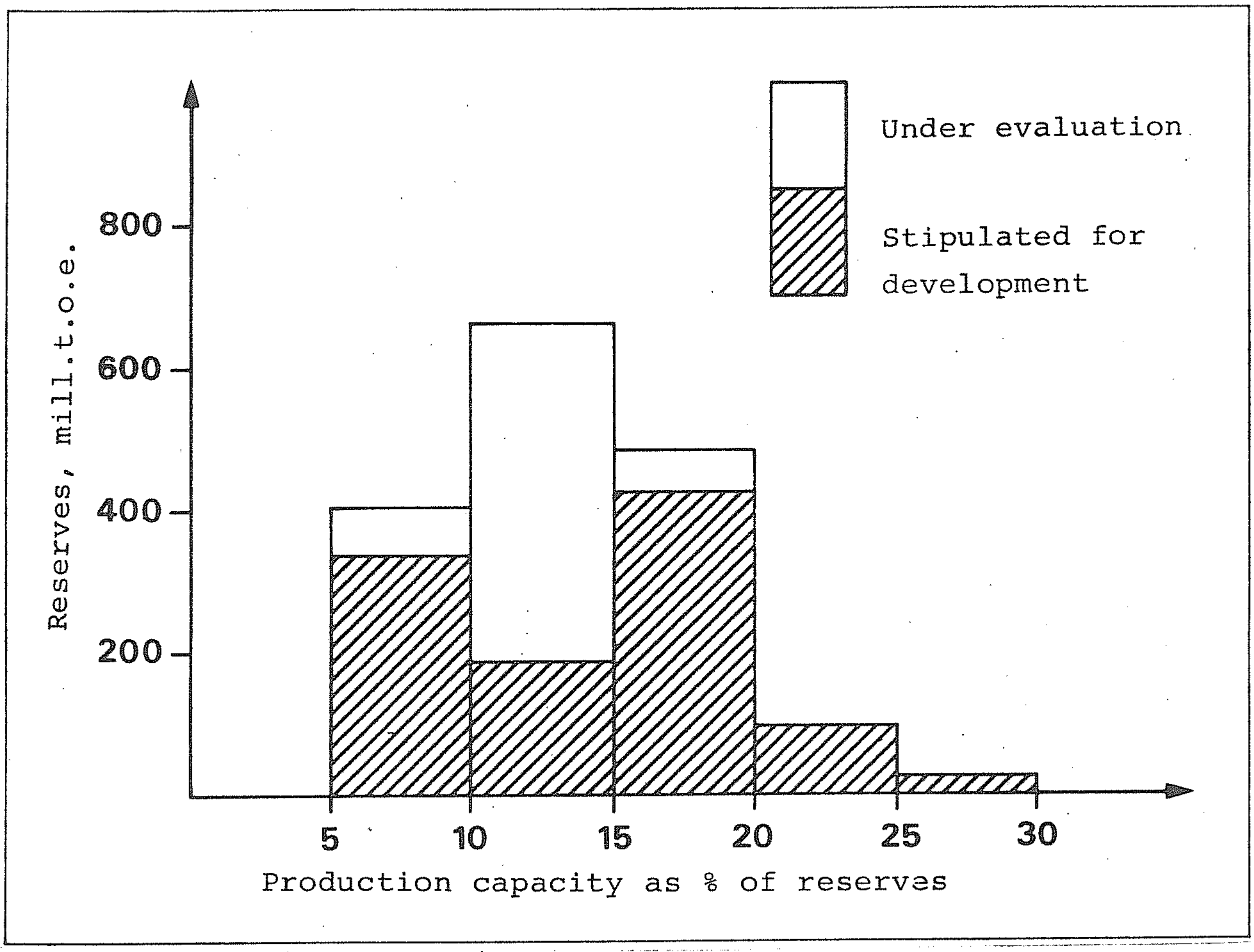
If the degree of utilisation of the facilities is to be increased, it will be necessary for one thing to plan this purposefully, and to ensure that new reserves are coupled with old capacity soon enough.

FIG 5.4.c



EXTRA COSTS FOR FIELDS STIPULATED FOR DEVELOPMENT AND FOR THE MOST INTERESTING FIELDS UNDER EVALUATION

FIG 5.4.d



RESERVES IN MILLIONS OF TONS OF OIL EQUIVALENT, GROUPED ACCORDING TO THE SIZE OF THE PRODUCTION CAPACITY AS A % OF THE EXTRACTABLE RESERVES IN THE FIELD

6. SAFETY AND PREPAREDNESS RESEARCH

Introduction

At the outset of 1981 the Norwegian Petroleum Directorate completed its two research programs within preventive safety (the SPO program) and preparedness (the SSB program). The structuring, execution and completion have been carried within the framework of the original four-year plan.

The results of the individual projects will be discussed specifically in the final reports on the individual programs. These will be ready in 1982. In what follows, individual projects will be presented to the extent that they contribute to illuminate the most central matters considered and to exemplify principles.

Results of good individual projects have their own independent utilitarian value. In addition, the Petroleum Directorate can see the value of the milieu that have been built up in the research institutes by the individual projects. These milieu represent accessible competence for trade and industry and the authorities. They they also form a foundation for further research and development (R&D) activities within safety and preparedness.

Point of departure

Through the SPO and SSB programs, as well as other R&D programs concerning safety under the direction of the Norwegian Technical Scientific Research Council, safety receives highly exclusive treatment with considerable economic funds and great administrative emphasis. This has the clear goal of lifting this area of research up to the same level as all other research. The programs were time-limited on the grounds that R&D activity in connection with safety would later have to find its place within a technological and administrative whole. This is in keeping with the views that the government had sketched in the long-term program (Storting Report no. 79 for 1980-81) and the research report (St. Rep. no. 35 for 1975-76 and St. Rep. no. 119 for 1980-81).

Goals and division into specialist areas

In its introduction, Storting Proposition no. 1, Supplement 2 (1977-78), on "Increase in allocations for safety and preparedness research in connection with the petroleum activity on the continental shelf" gives the following major goals for this research:

- to obtain better knowledge and understanding of safety and preparedness conditions pertaining to the petroleum activity

- to intensify research and preparation activity in this area in order to improve safety and preparedness

- to localize and define specialist areas that are vital to safety on the continental shelf

- to coordinate and direct the research effort and thereby ensure that it is aimed at improving safety

The division of specialist areas between NTNF´s and the Petroleum Directorate´s research programs was as follows:

- NTNF has covered the basic professional problems within the technical and method-orientated as well as sociological areas

- the Petroleum Directorate has covered the conditions within preventive safety which are of particular importance for the Petroleum Directorate´s regulatory responsibility (the SPO program)

- the Petroleum Directorate has covered all questions regarding the preparedness system (the SSB program)

From the major goals and the specialist divisions, the individual programs have formulated more detailed strategic goals, and at the same time have prepared project plans for the operative execution of the individual programs.

Results

The central result of safety research is the evolution of system understanding, in which preventive safety and preparedness are closely tied to the technical system. Concerning the results from individual areas, the following will be emphasized here:

- improved understanding of the preparedness system.

- project planning of the new main rescue station at Sola.

- training arrangements with simulation programs

- evacuation
  - system comprehension
  - free-fall lifeboats
  - improvement of existing concepts

- contributions toward improving preparedness for divers through a large number of individual projects

- contributions toward increased understanding in connection with prevention/limitation of uncontrolled blow-outs

- establishment of criteria in connection with fire preparedness

- evaluation of technical systems within:
  - fire and gas detection
  - safety valves
  - lightning conductors
  - leak detection
  - monitoring of the condition of process equipment
  - monitoring the the condition of structures

- analysis of personal injuries in a particularly accident prone area (drill floor)

- work conferences for protection and environment work
- development of a well control simulator for training and research
- preparation of guidelines for evaluation of platform concepts
- proposals for inspection systems for technical equipment
- contributions toward evaluation of maintenance practice on oil installations in the North Sea, by surveying the maintenance systems within:
  - the European oil and petrochemical industry
  - the energy industry
  - the aircraft industry
- development of information systems for
  - drilling activity on the Norwegian continental shelf
  - oil and petrochemical related R&D projects
  - offshore security systems
- contributions toward improving safety for divers, particularly concerning physiological limitations and long-term effects

In evaluating the results, it is important to keep in view the fact that exclusive safety research involves taking individual subjects out of context. This creates a special need for subsequent integration with technological research as a whole.

Direction

The principles for direction of SPO and SSB programs are laid down in the respective committees´ mandates and the contracts for the individual projects. Emphasis has been placed by the Petroleum Directorate on using the two steering committees as advisory bodies with sound representation as regards both the individual and the institution represented.

Important aspects of the quality of the Petroleum Directorate´s management lay in the quality of the committees. This principle is continued to include the steering groups for the individual specialist areas and projects. Use has been made in particular of key experts from public regulation, the operator companies and research institutions.

Economy

The funding of the research programs has consisted of annual allocations by the national budget of approx. NOK 8 million. In addition, other sources (primarily industry) have contributed considerable sums. In the tables below, the overall distribution is given for each individual year for the two programs. The amounts are given in millions of NOK.

The SSB program

	1978	1979	1980	1981	Sum
Norw. Petroleum Directorate	0.9	4.4	3.3	4.0	12.6
Others	-	2.0	4.7	5.0	11.7
Total	0.9	6.4	8.0	9.0	24.3

The SPO program

	1978	1979	1980	1981	Sum
Norw. Petroleum Directorate	4.5	2.9	3.4	2.7	13.5
Others	-	-	2.4	0.7	3.1
Total	4.5	2.9	5.8	3.4	16.6

The above figures do not cover costs tied to the Norwegian Petroleum Directorate´s engagement in management or regulation, or the activities of the steering committees or steering groups for the individual projects, except as regards secretarial functions.

Moreover, the operator companies, partly jointly (through the Norwegian Industrial Association for Operator Companies, NIFO) and partly individually, have taken on the continuation of projects and project areas. Two examples may be mentioned here: diving (NIFO) and well control (Statoil).

Contacts

Through project descriptions, project reports etc. the Petroleum Directorate has concrete reference points for establishing contacts. This has also formed the basis for the exchange of ideas, statistical information, reports etc.

With regard to operator companies, contacts are established both through individual projects and technical areas. Among other things, the Petroleum Directorate, through the SSB program, has been able to test definitions, contingency plans, training programs, exercises etc., and has thus achieved mutual understanding of the content and coherence of the preparedness system.

Contacts with other national authorities concern primarily the Department of Energy in England. We on our side have been able to gain particular benefit from their contacts within maintenance and they, on their side, have been able to make particular use of our contacts within preparedness.

Links with other official services within state management concern primarily the State Pollution Authority (STF) and the State Explosives Inspection (SSI). In this connection, reference is made to contacts with SSI concerning blast research.

Internal administration

The secretariat built up by the Research Group was intended, on a background of goal descriptions and an activity plan, to undertake all the administrative tasks of carrying through the programs. It was also to provide financial means supplementary to the funds allocated by the national budget, if this was necessary for performance of the planned activities within the stipulated time.

A separate secretariat is necessary for carrying out, in a controlled way, research programs of the magnitude of SSB and SPO.

Information

The basic principle for spreading information results for the SSB and SPO projects, is that the executing institution is requested to do the marketing of competence gained through the projects for industry and the authorities. The marketing is thereby tied directly to those who will further build upon and make a living from the services that are offered on the professional basis which is built up. The result has thereby been that the good projects, which the executing institutions believe in, obtain a profile suitable for marketing and carrying the work forward.

The Petroleum Directorate has assisted in this process by binding the executing institutions by contract to supply information to the partners. Another important element for spreading information and results is based on the administrative apparatus for the programs and projects. Members of the management have been appointed from among representatives of the authorities, workers´ organizations and research institutes. The best possible direct contact with the users is thereby achieved. Further, project reports are issued, seminars and informational meetings are arranged and annual program reports are published. The final reports from the two programs will be the final information documents in this series. The final reports will also be published in English.

The forms of information that will be available after the programs have ceased, result from SPO Project 3.3, "Infoil II". From the desire for a general information system for running research projects related to the shelf activity, a system of current subscriptions to project information has been built up. The basis for this system is built on elements that have, to a considerable degree, previously been under the direction of the Petroleum Directorate. Infoil II has also aroused interest beyond shelf-related activities and outside Norway. In this connection, it may be shown that the British Department of Energy has agreed to contribute one third of the cost of continuing the project into 1982. The preliminary extent and responsibility for the permanent operation of Infoil II will probably be clarified in 1982.

Completion of the research programs

The programs were planned and directed on the understanding that keeping within the deadline for completion would be a real and high priority goal.

In order to take care of the continuation of the central project areas, the Petroleum Directorate has collaborated with NTNF´s management. A committee laid down by NTNF (the Øverås Committee) concluded by stating that safety research for the continental shelf activity should be continued with the same volume of public funding as at present, but that the matter be further administered by NTNF´s standing committees. The Petroleum Directorate will retain a part of this allocation to cover its reporting requirements within this sector. There is wide consensus for this line. Moreover, in the subsequent direction, emphasis will be placed on building up the individual projects and administering them in such a way that, to the greatest possible extent, they are made generally accessible to other industries and other regulatory bodies.

Experience

Safety in technical systems is a compound problem for which only one of many component problems can be solved technically. Safety is also an administrative, social and emotional problem.

The management of research concerning safety and its control is a problem which may easily receive a wrong emphasis because a holistic understanding is required to balance the individual components. This is because the most exact and detailed basic data are obtained where one has the best insight into the problems and the mutual connection between the individual components. Thus, the areas where quantative analyses can be carried out with meaningful accuracy, are the very areas for which the best preconditions for control already exist. By placing particular emphasis on such analyses, one may easily create a wrong total impression.

The Petroleum Directorate has greatly emphasised projects concerning people and their work place. Within the "Preparedness system", the regard to the human factor is basic, especially concerning human reaction patterns under extreme duress.

Control of safety is difficult for three main reasons:

- safety is a peripheral condition for a larger system having another main function
- safety is largely controlled on "negative premises"
- safety is not an answer or a condition, but a dynamic process where technical, administrative and human factors constitute the whole.

The aspects of safety which are most easily controllable are the technical systems and the administrative conditions surrounding them. For particularly complicated technical systems, it is important to augment the control on this point by administrative control systems, quality assurance systems, etc. However, it is also equally important to ensure that the whole is taken care of.

The authorities' control of safety within the different activities in society is built upon a number of factors: legislation, accident commissions, etc. This system has been constructed and developed somewhat in parallel in the industrialized countries. In this context, Norway does not stand out particularly, except that we formulated concrete requirements for safety at an early stage in the planning phase, we have formalised safety work on the employee side and we have come quite a long way with regard to integrating preventive safety and preparedness into a holistic safety evaluation. Research and development are important in this process. Safety research can contribute to concrete improvements within individual areas, and may provide a better understanding of major and minor correlations.

7. INTERNATIONAL COOPERATION

7.1. North-West European cooperation

The second North-West European conference on "Safety and pollution safeguards in the development of North-West European mineral resources" was held in the Haag on 13-17 November 1978. The participating countries in the international harmonizing work are as follows: Belgium, Denmark, Ireland, France, the Netherlands, Norway, Great Britain, Sweden and the German Federal Republic.

The final reports of the three working groups were dated as follows:

- Working Group I June 1980
- Working Group II May 1980
- Working Group III July 1980

The third North-West European conference will be held in Oslo on 10-13 May 1982.

7.2. The Inter-Governmental Maritime Consultative Organization IMCO

The Norwegian Petroleum Directorate was represented in 1981 by two representatives appointed as members of the Norwegian delegation to IMCO´s "Sub-committee on standards of training and watchkeeping," 14th session. The above sub-committee hears questions concerning manning and personnel qualifications on mobile drilling vessels.

The Petroleum Directorate has also been represented in the Norwegian delegation to IMCO´s "Sub-committee on ship design and equipment" in connection with questions used for regulations and supervision of diving systems on ships, etc.

7.3. The International Labour Organization (ILO)

With the meeting of experts in the International Labour Organization (ILO) as a point of departure and subsequent work, ILO´s governing Body, during its 215th session in February-March 1981, has approved "Guidelines for safety and health questions during construction of fixed installations in the petroleum activity at sea". (Cf. Norwegian Petroleum Directorate annual report 1980, page 93).

ILO´s guidelines are meant to be of help to authorities, companies and employers in collaboration with the employees to improve their own rules/instructions and experience during such work. The guidelines are not binding for ILO member countries and neither are they supposed to act as a check on national laws and accepted standards. Meanwhile, it is ILO´s hope that the guidelines will be of help in harmonizing national attitudes with regard to safety and health questions within this industry, by which the employees may achieve the same standards and protection everywhere within petroleum activities at sea.

Concerning the activity on the Norwegian continental shelf, the guidelines do not entail anything directly new in addition to matters already covered in the Working Environment Act and the safety regulations, etc.

Increased international familiarity with and practice of the guidelines will however clearly contribute to improving the level of safety and the understanding of traditional Norwegian worker protection and working environment legislation.

7.4. Aid to foreign countries

The Norwegian Petroleum Directorate's aid to other countries through NORAD has continued in 1981 to an even larger degree than in previous years. The Petroleum Directorate has participated in petroleum-related projects, mainly for Tanzania and Mozambique, but has also carried out evaluations for countries such as Portugal, Pakistan, Guyana and the Seychells. In Tanzania the tasks have concerned seismic surveys in open concession areas, evaluation of finds and the training of two scholarship holders.

The Petroleum Directorate has also assisted in the engagement of advisors to some countries. Furthermore, the Petroleum Directorate has aided a number of other countries to some extent through the Ministry of Petroleum and Energy and the Ministry of Foreign Affairs.

8. TECHNICAL ARTICLES

8.1. Economic field evaluation

Introduction

When a group of concession holders or a company is faced with the decision of whether or not to develop a field, the material basis for the decision includes key factors such as expected investment costs, production profile, transport and operational costs and prices.

Geological and technical reservoir conditions, reservoir depth and the number of drilling rigs on the platform, are decisive factors determining how many production wells will be drilled and how quickly they can be drilled. The production profiles can be drawn up when in addition the processing capacity for oil/gas is known. Designs for platforms, transport systems, terminals and thus also processing capacity, are selected after being weighed against estimates of the profitability of the development. It is generally the rule that oil fields have a short period in which production builds up, a short peak period and a long period of decline. Production from pure gas fields is built up and phased down over short periods, while the peak production period is long.

For the investment decision, an initial investment estimate is usually prepared with a confidence interval of 20-50%, based on a provisional project plan for the production equipment. An estimate is also made of how the investments are to be distributed over a period of time. In such introductory investment analyses, annual operational costs are often calculated in relation to the total investments. Usually, rates are employed that lie somewhere between 5 and 10 %.

Operational costs are made up of the following main components: operation and maintenance of facilities, transport services, catering, base services, preparedness, insurance and administration.

The transport costs per unit of oil and gas vary according to the transport distance and mode of transport, i.e. whether by buoy loading or through a pipeline to land. Generally, the transport cost as a percentage of the sales price is larger for gas than for oil. The cost for gas per unit may be twice as high as the cost for oil per unit. As Figure 8.1.a shows, great uncertainty must be attached to the predicted development of oil prices when one looks at the trend of the last few years. Long-term agreements are made for the sale of gas, and until these are ready, it will be difficult to estimate prices exactly. They may vary greatly from agreement to agreement, depending on market conditions. However, gas prices are often linked to the oil price development by formulas laid down, and may thereby vary with time.

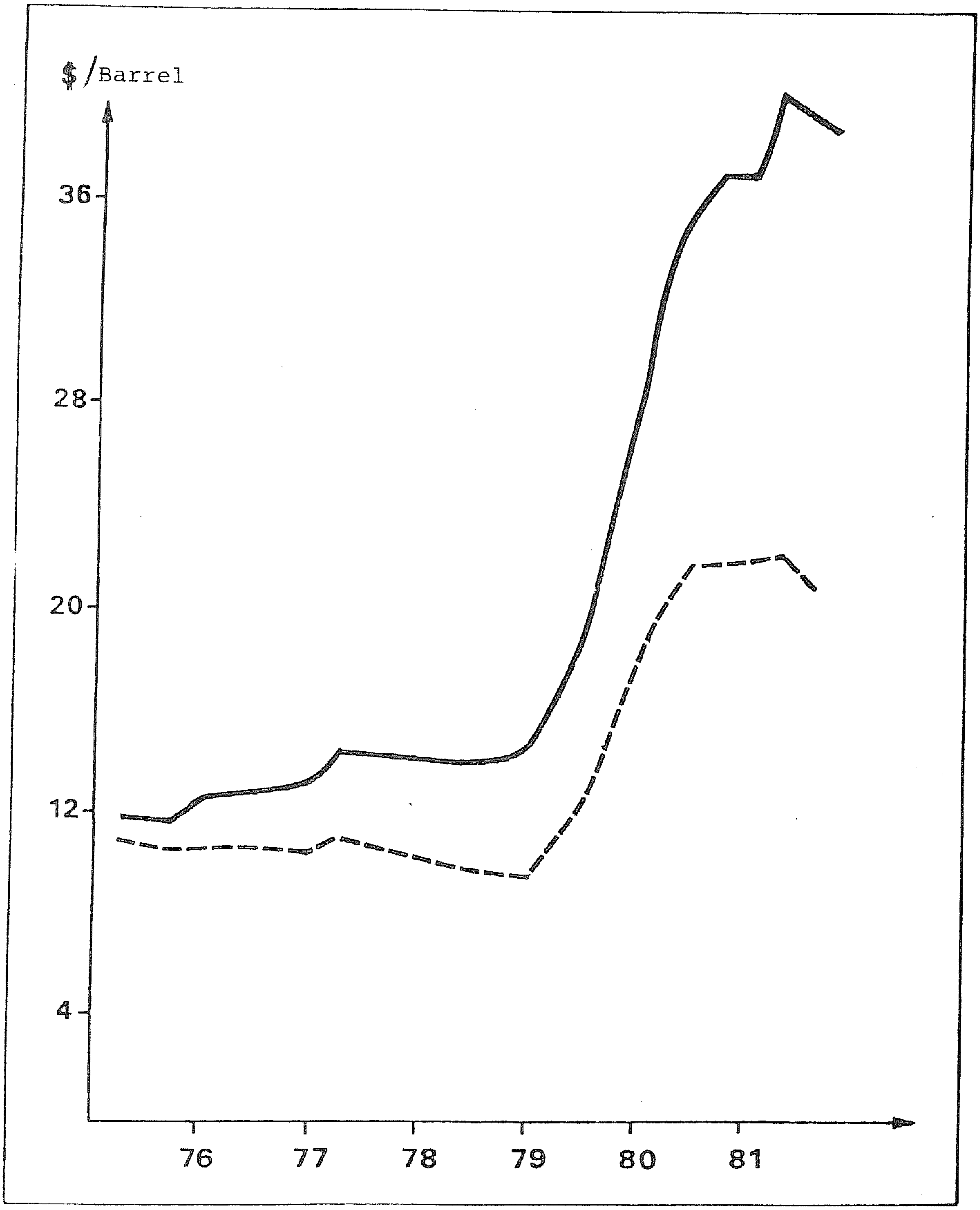


FIG 8.1.a Current (-) and fixed (---) prices of Ekofisk-oil (norm prices)

Tax system

The following presentation illustrates the main items included in an ordinary statement of results:

Gross production value
- Royalty
- Operational costs
- Transport costs
- Depreciation (over 6 years, may be longer for oil and gas pipelines: depreciation over 10-20 years)
- Interest

Result before taxes
- Income tax
- Special tax (uplift)

Result after taxes

Below are presented the main characteristics of the system of taxes and fees on the Norwegian contintental shelf:

Royalty

The gross production value is obtained by multiplying the produced amount by a norm price for oil and a contract price for gas and NGL. The gross production worth with deductions for certain transport costs is used as a basis for calculation of royalty.

The following rates apply:

	Gas	Oil	
Production licences before 1972	10 %	10 %	
Production licences after 1972	12.5 %	8-16 %	(1)

Note (1) Depends on producted amount.

Income tax

State income tax which replaces municipal tax and common tax: 23 %. Ordinary state tax for companies with deduction rights on profits: 27.8 %.

Special tax (uplift)

Result before taxes
- Free income (100% of investment divided over 15 years)
= Tax basis

Tax rate: 35 %.

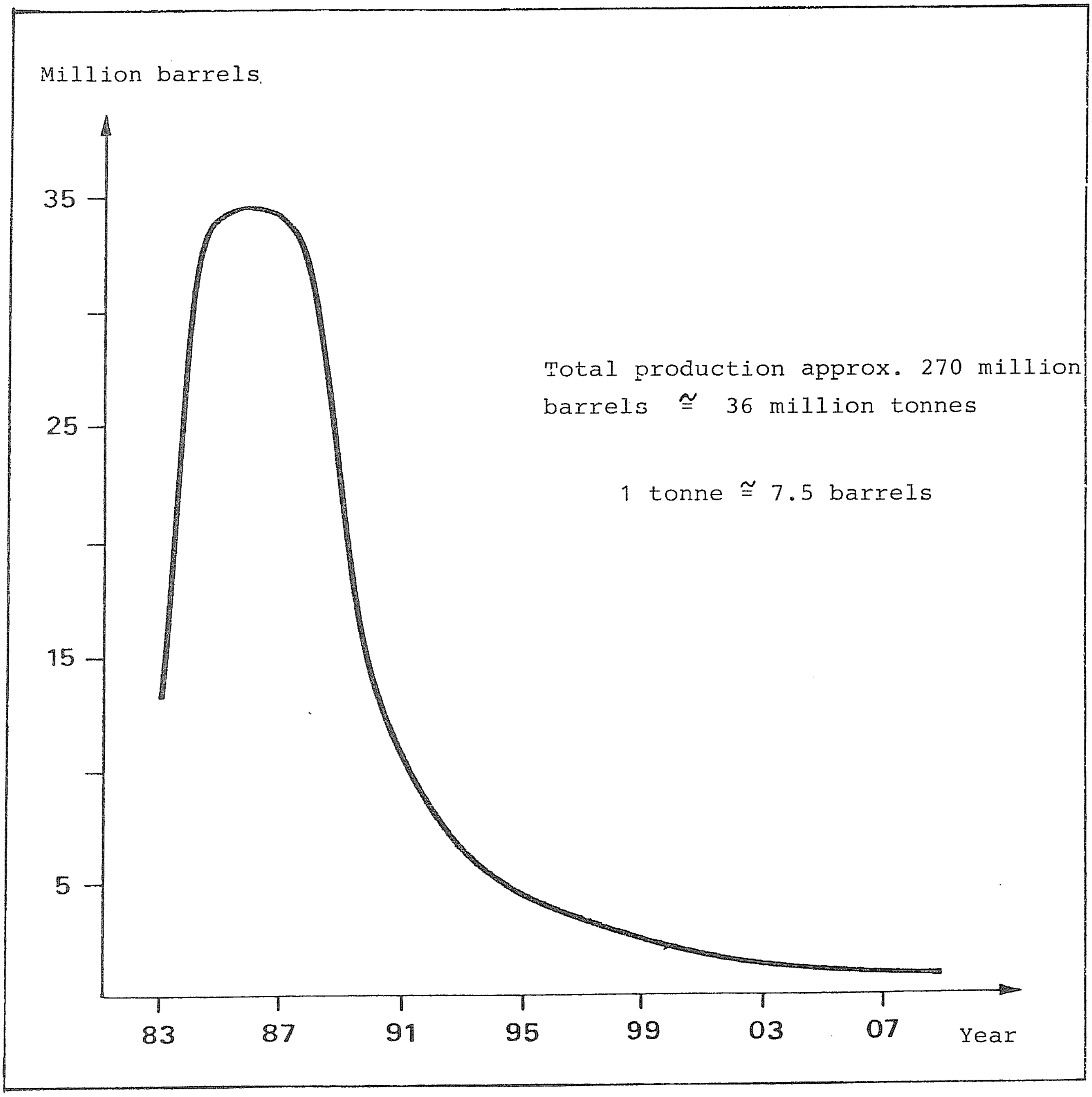
General property tax - 0.7 % (usually ignored in such analyses)

A hypothetical development

Information about the field

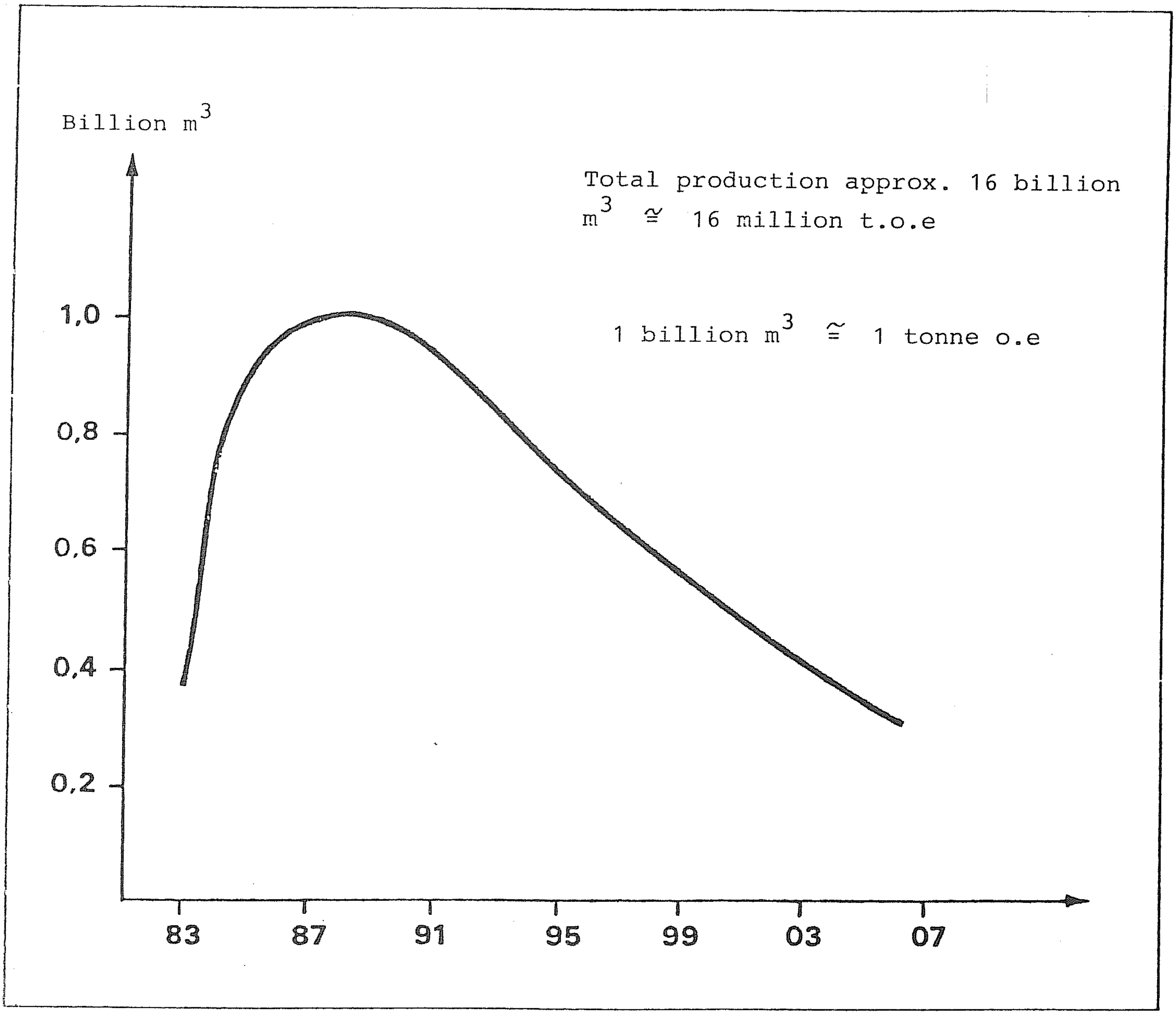
A hypothetical development of a gas/oil field for which investment is assumed to have started in 1979, is estimated to cost approx. 1981-NOK 6 billion. The production profiles upon which the example is based are reproduced in Figures 8.1.b and 8.1.c. Production start is assumed to take place in 1983. At an oil price of NOK 206 per barrel and a gas price of NOK 1.04 per cubic meter (37.50 $/barrel and 0.19 $/m3), measured in fixed 1981-NOK, the total sales income or the gross production value during the course of the field's lifetime will be approx. NOK 72 billion. Total state revenues, assuming a basis of 100% equity funding, amount to approx. NOK 42.8 billion, and the total expenditure in connection with development, operation and transport runs to NOK 18.7 billion (cf. Figure 8.1.d). We have accounted only for field-related taxation, i.e. the owners are assumed not to have incomes and costs in connection with other activities. Investment started in 1979 and amounts to a total of approx. 1981-NOK 5.5 billion. The year of evaluation 1981. Profitability assessments after investment start are relevant in cases where decisions must be made on possible future additional projects, such as water or gas injection for example.

FIG 8.1.b



Oil production from and oil-/gasfield in the North Sea

FIG 8.1.c



Gas production from and oil-/gasfield in the North Sea

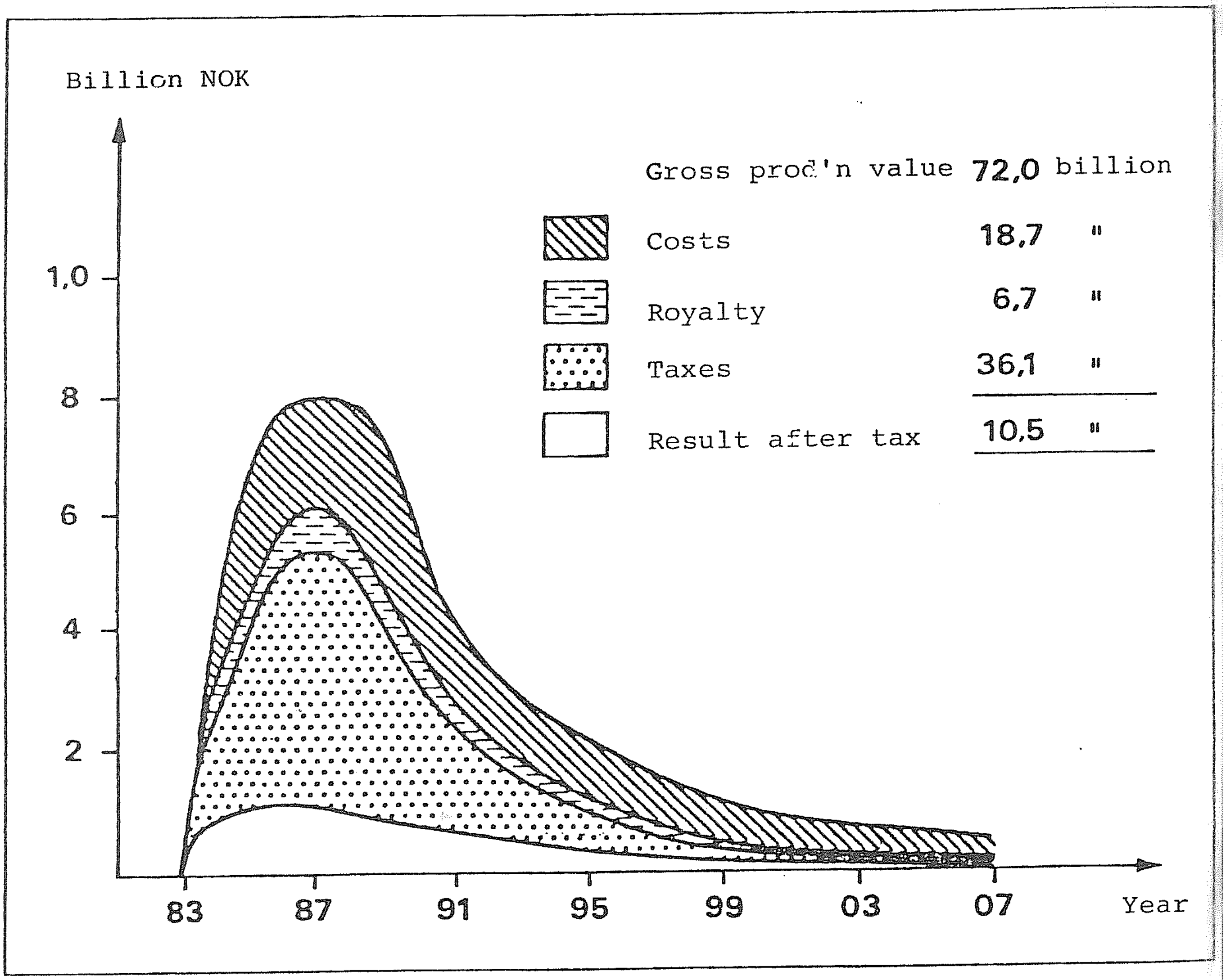


FIG 8.1.d

Distribution of accumulated cash flows as per main item

Cash flow and profitability assessment

When evaluating the state's, lenders' and concession holders' share of income, respectively, the cash flow yielded by the field is used as a point of departure.

The state's cash flow consists of total taxes and fees.

The lenders' cash flow during the investment phase consists of the investment amounts contributed by the lenders. In other words, there is a negative flow. As the installments and interest are paid, the total cash flow will go from negative to positive.

In the same manner, the concession holders' cash flow during the first years consists of their share of the investment cost which they themselves contribute (equity funding). When production is under way, the cash flow may be found as follows:

Result after tax
+ Depreciation
- Any loan installments
- Any investment costs covered by equity.

100 % equity funding

If one envisions that the concession holders fund the project themselves, the relationship between the part which falls to the state and the part which falls to the concession holders (equity) will be as shown in Figure 8.1.e.

The figure shows the total net cash flow over the lifetime of the field. Curves A and B indicate the total net cash flow respectively for the field as a whole and for the equity funds, reading from the x-axis. The cash flow to the state is always positive, and in Figure 8.1.e may be found from the separation between curves A and B. Curve B represents in other words the zero point marking. Of the total net cash flow of approx. NOK 53.3 billion which the field yields, the state collects approx. 80% in taxes and fees. The concession holders' share constitues approx. NOK 10.5 billion, and as Figure 8.1.f shows, this cash flow yields a real profit of approx. 19%. The curve labelled "equity" gives the net present value of equity at different discount rates. A discount rate is a percentage which is used to refer future incoming and outgoing payments back to the year of evaluation (1981). At a rate of 19% the total value of the project will be zero, i.e. a net present value of zero. (1). When the net present value is zero, discount rate represents the income of the project, also called the internal interest. The curve for "State" will not intersect the axis and it is not possible to define any internal interest (i.e. it is infinite). This is because the state has no payments to make.

Note (1): Downward discount at 19 %

$$\sum_{t=0}^{n} \frac{C}{1.19^t}$$

1981 (time of evaluation) = 0;
2007 (last production year) = n;
C = cash flow; t = 0 ... n;

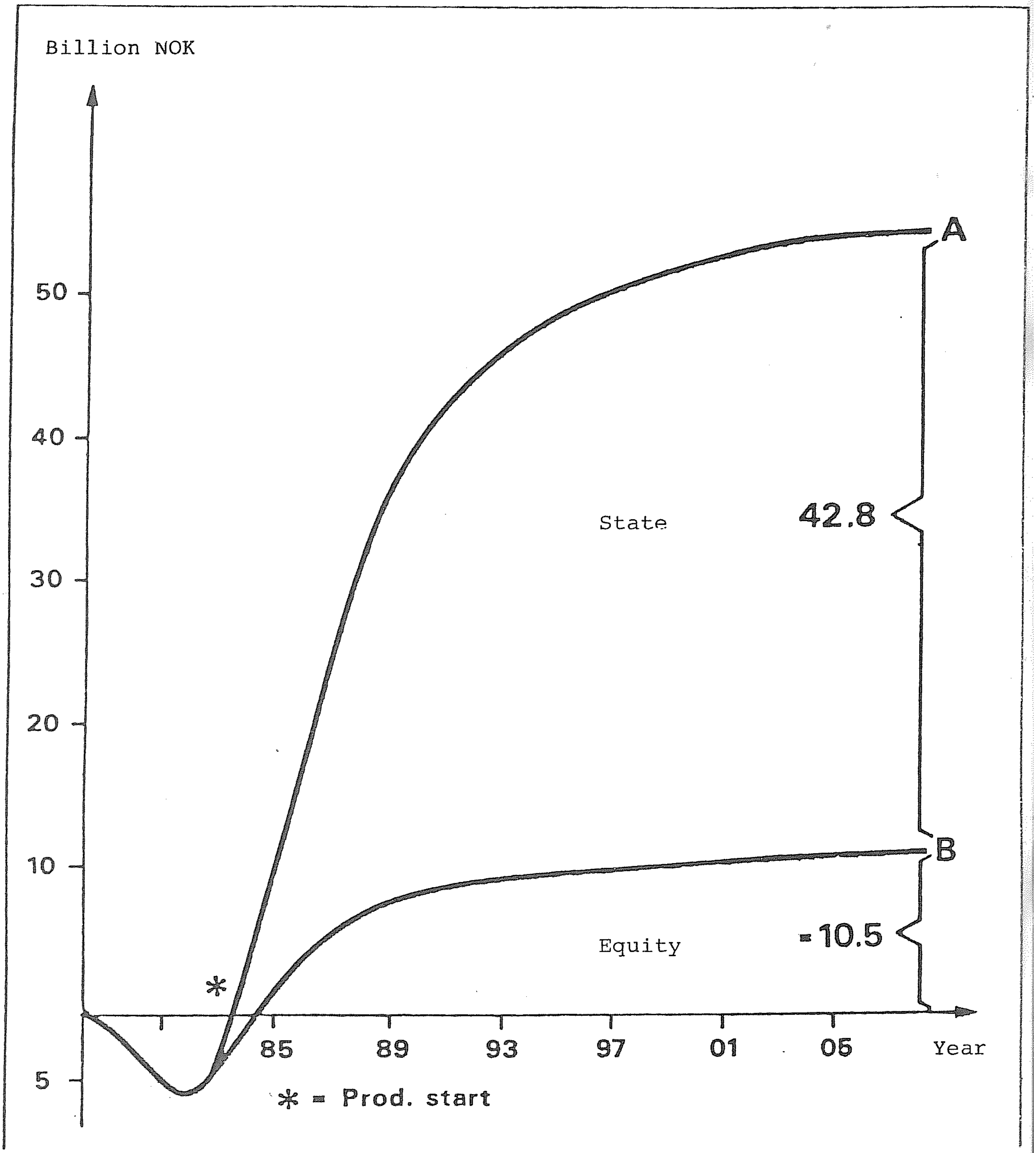


FIG 8.1.e Cumulative cash flows (1981-kroner).
Funding - 100% equity

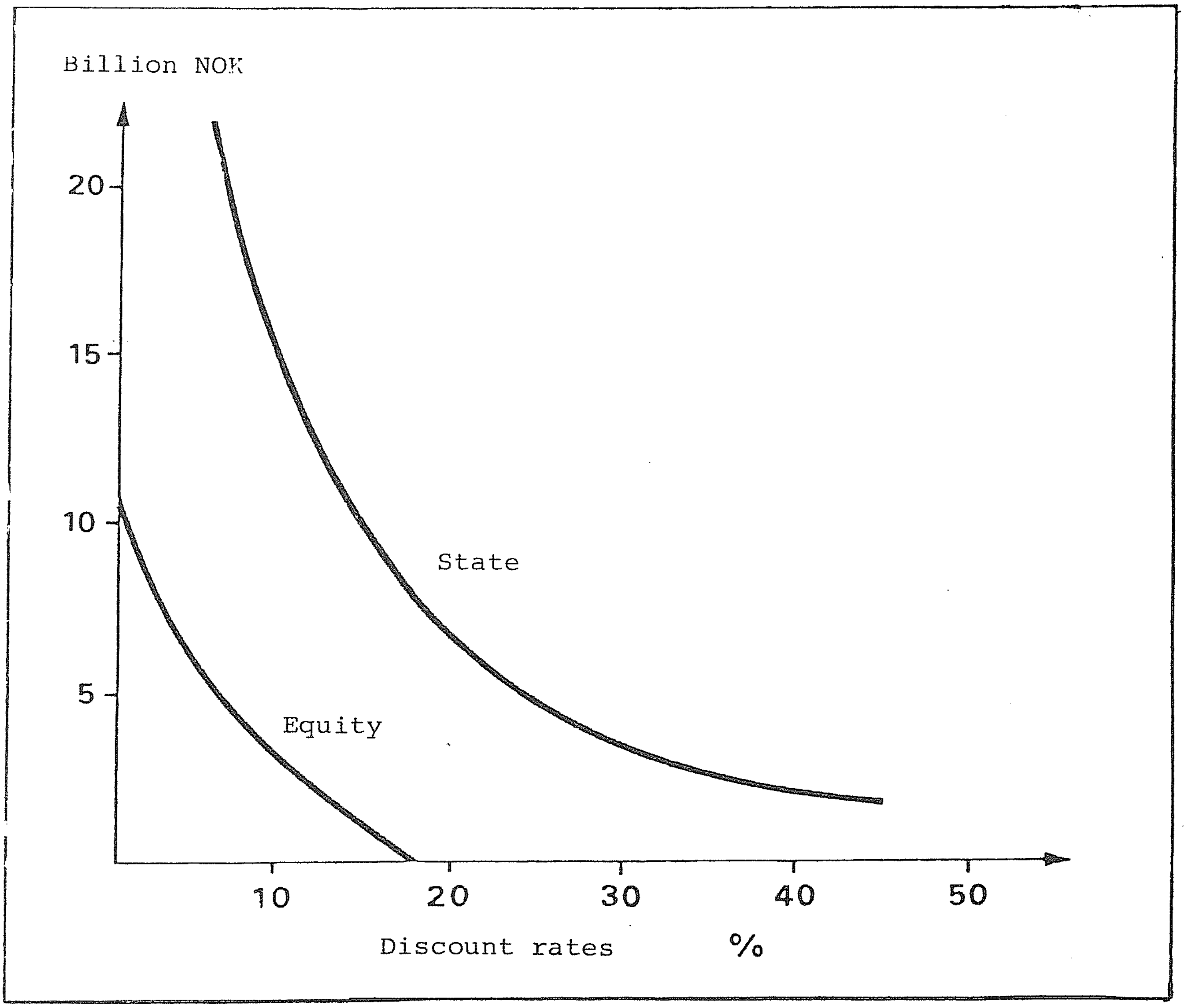


FIG 8.1.f Net present value at different discount rates.
Funding - 100% equity

75 % loan funding

The assumption that a field development is 100% financed by equity is unrealistic. The lenders´ share, loan capital, usually constitutes a considerable part of the project funding. In this example it is assumed that the loan share makes up 75%, that the interest is 12% and that there are no installments the first five years and that repayment occurs during the five subsequent years. The effect on equity income will be an increase from approx. 19% to approx. 35%. The reason is that the income from the loan, which equals the interest, is less than the income without loan funding. In other words, when the loan is repayed at 12% interest, a relatively greater portion will remain than with 100 % equity funding, when seen in relation to the investments covered by the equity. Figures 8.1.g and 8.1.h depict these conditions. Curve B is the zero point marking for the loan. The reason for the reduction in state revenues is that the tax basis is reduced by deductions for interest expenditure.

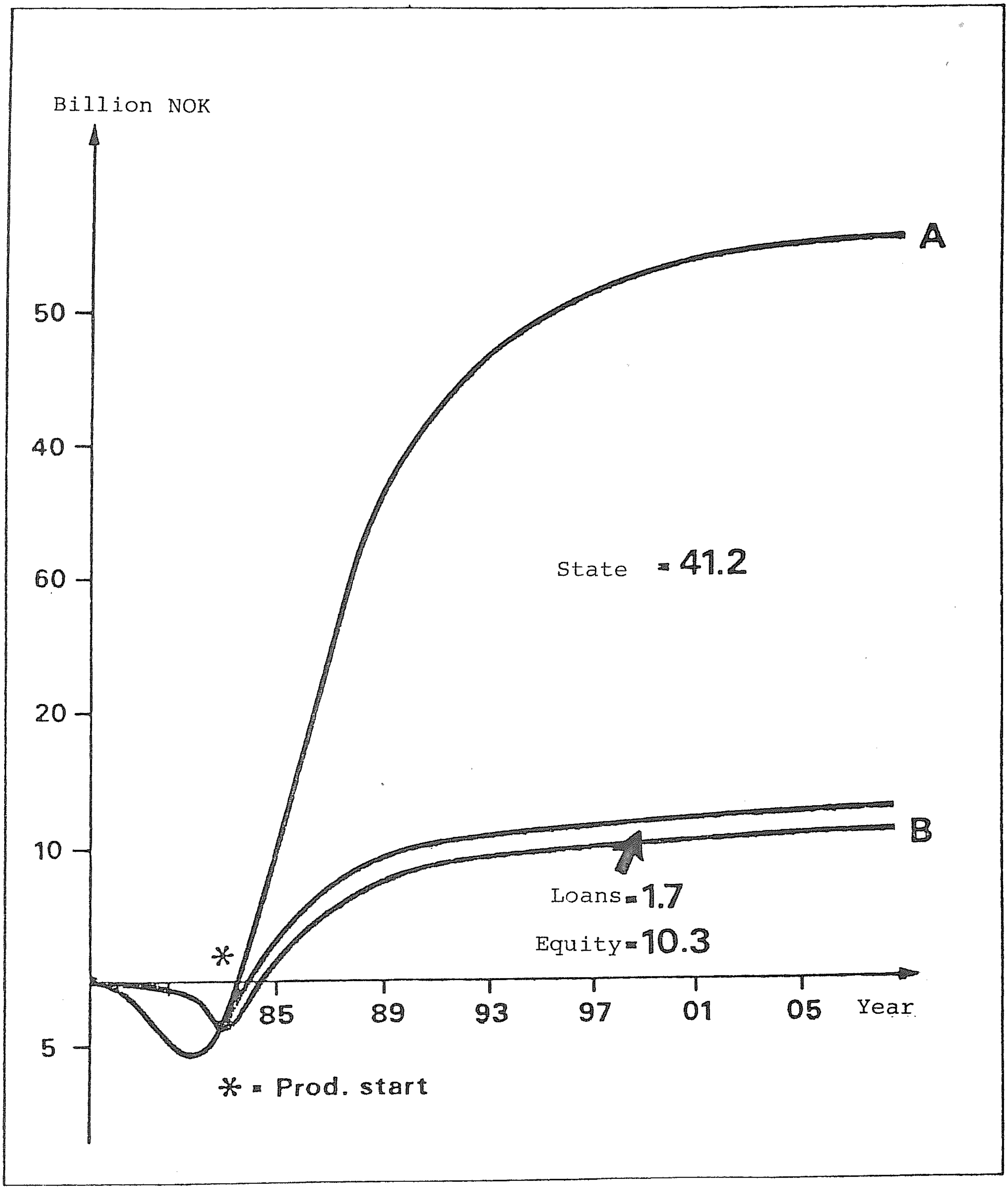


FIG 8.1.g Cumulative cash flows
Funding - 75% loans and 25% equity

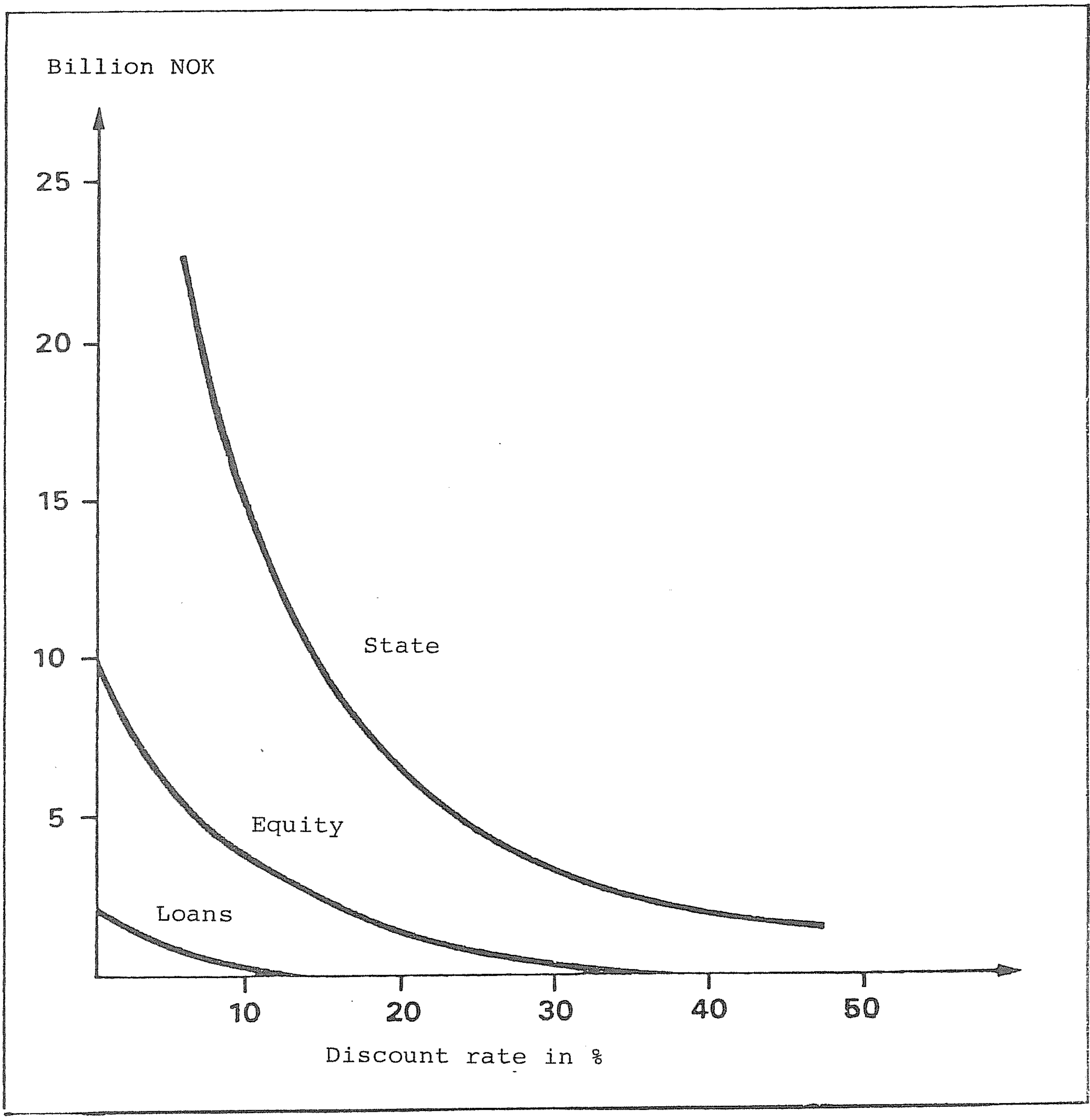


FIG 8.1.h Net present value at different discount rates.
Funding - 75% loans, 25% equity.

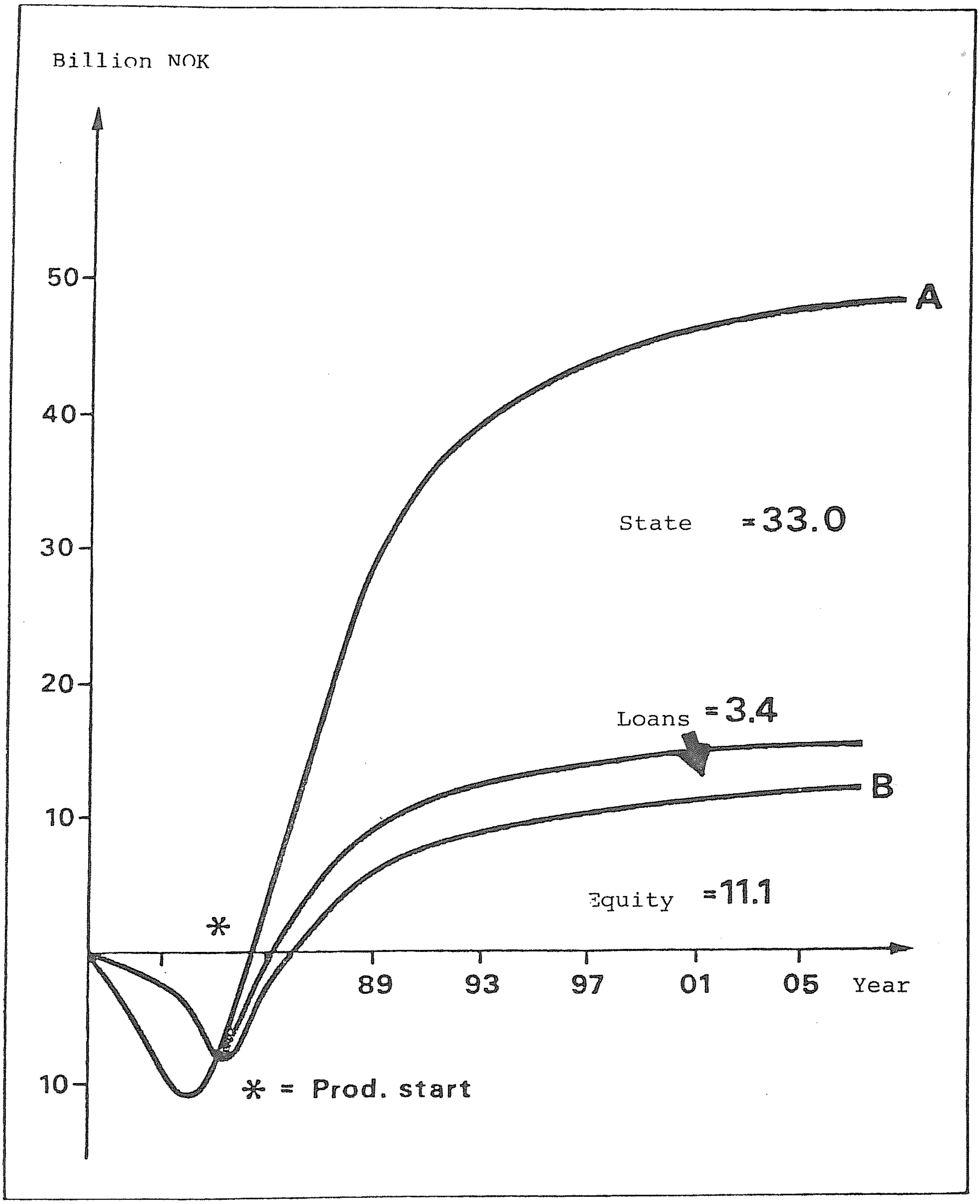


FIG 8.1.i Cumulative cash flows. 100% capex over-run.
Funding - 75% loans, 25% equity

Cost overruns

It appears that most development projects in the North Sea are more expensive than calculated during the project planning phase. The overrun, for the first 7-8 years, was approx. 100%. By assuming a 100% overrun on investment costs in our case, the distribution for the state, lenders and owners will be as shown in Figure 8.1.i. The overrun causes the tax basis to be reduced due to greater depreciation. The special tax (uplift) is reduced in that there is a higher free income. The increased interest expenses also result in lower taxes. From the curves in Figure 8.1.j it may be seen that the internal interest on the equity has declined in spite of the fact that the non-discounted value of the equity income has increased.

Total non-discounted cash flow to equity amounted to approx. NOK 10.3 billion before the cost overrun, while it amounted to approx. NOK 11.1 billion afterwards (cf. Figure 8.1.i). The main reason for this is that the taxes, due to the increased depreciation and interest expenses, are reduced by more than 100% in relation to the cost overrun. The reason that the internal interest on equity nevertheless declines (cf. Figures 8.1.h and 8.1.j), is that discount rates over approx. 5% give a negative net present value for this additional cash flow. Increased investment means that the early negative cash flows increase, and these will receive greater emphasis the greater the rate of discount. Positive cash flows in the form of reduced taxes come over a long period of time late in the lifetime of the project and receive relatively less emphasis. The internal interest for the equity is therefore reduced by approx. 15 percentage units, from approx. 35% to approx. 20%.

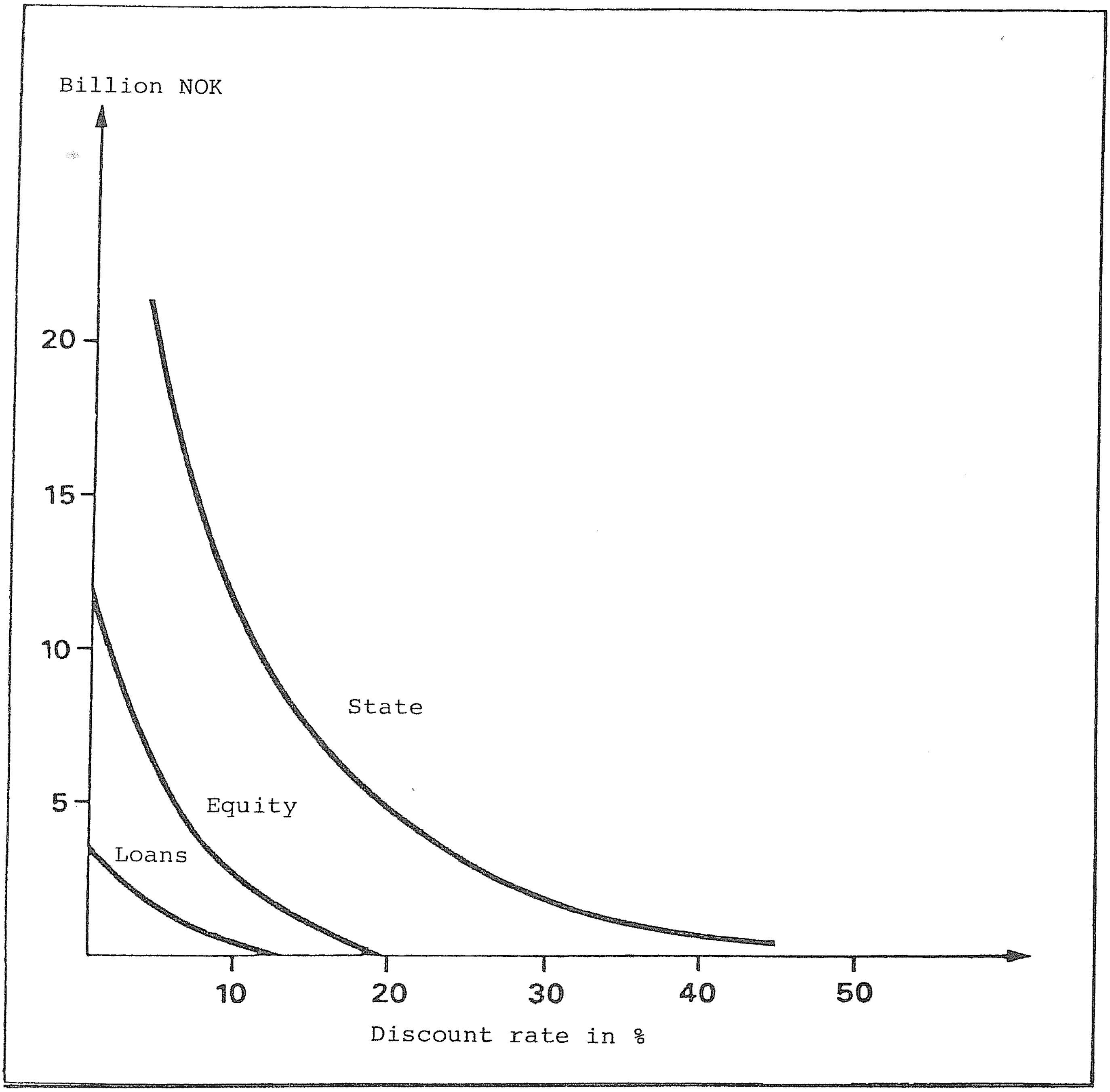


FIG 8.1.j Net present value at different discount rates.
100% capex over-run.

Effects of cost overruns

A greatly simplified presentation of the effects of a cost overrun of e.g. NOK 100 million may be given in the following way: It is assumed that there is 100% equity funding, that the overrun occurs at the end of a year (year 0) and that the effects in the form of reduced taxes come at the end of the following years (year 1 - year 15). The effects on general property tax are not taken into account.

C = Cost overruns
R = Discount factor (Percent rate/100)
t = Number of years

During the first 6 years, the tax basis is reduced through both increased ordinary deductions and through increased free income in connection with special tax. The remaining free income amounts become relevant during the final nine years.

The total tax reduction, due to cost overrun C, thus amounts to:

$$\sum_{t=1}^{6} \frac{0.508\ C/6 + 0.35\ C/6 + 0.35\ C/15}{(1 + R)^t}$$

$$\sum_{t=7}^{15} \frac{0.35\ C/15}{(1 + R)^t}$$

The reduced tax, at non-discounted value, amounts to NOK 120.8 million over the 15 years, and is discounted down to 100 at a rate of approx. 4%. In other words, R = approx. 4%.

For the cost overrun in connection with our hypothetical development, the same principle applies, but of course giving a presentation corresponding to the one above would be more complicated. Among other things, it would be of significance that the overrun does not occur during the course of one year, but over many years. Moreover, the assumption of 75 % loan funding also enters the picture, so that the effects with regard to interest expenses must thus be taken into account.

Criteria for decision

Internal interest

The internal interest is an important factor in the decision whether or not to develop a field. The internal interest is an indication of a field´s profitability and it can be measured from fixed or current prices and costs. In other words, the conditions used as a basis may vary. The important thing is that the conditions are consistent from project to project so that comparisons can be made. Requirements as to the size of the internal interest in connection with the decision to develop vary from company to company. For each individual company, they may also fluctuate with time, depending on any alternative projects that are of interest.

If calculations in connection with a field development indicate that the company would achieve a real yield of approx. 20% of its own capital (equity), as in the case of our hypothetical development, this would normally represent a very satisfactory basis upon which to continue the project.

Net present value

In the same manner, the present value at fixed discount rates receives great emphasis. The net present value represents in other words the difference between incoming and outgoing payments for different dicount rates, measured at the time of evaluation. From the magnitudes of their net present value it is possible to set up projects in order of priority. Two projects providing equal internal interest can have different net present values for a given rate of discount. Figure 8.1.k illustrates this. The reason that the difference in the present value falls as the discount rate increases, is that the earning phase for project A is most prevalent later than that for project B. Sums that come late in time will be multiplied by a factor which falls increasingly as the discount rate increases. The factor is given as 1/(1 + R)exp.t. In the same manner, two different projects for which comparisons are made, as illustrated in Figure 8.1.1, can have equal present values for a fixed discount rate. If the rate increases, A is preferable to B, but if it decreases, the order of priority is reversed.

Repayment time

Another criterium which is used as a basis is the repayment time for the project. It indicates long it will take before the invested capital is recovered. This criterium indicates the risk connected with the project. The shorter the repayment time, the greater the probability for realizing the project. This is because the capital owners may then more quickly recover invested funds and reinvest them in new projects.

Net cash flow/investment

In addition, emphasis is placed on how much a project will yield in net cash flow in relation to the investments. A high ratio here indicates that the investment is recovered a corresponding number of times. Possible uncertainties pertaining to geological and technical reservoir factors will in this case not contribute to a critical reduction in income. A low figure indicates the opposite - that relatively small deviations from the original assumptions will have a large effect on income.

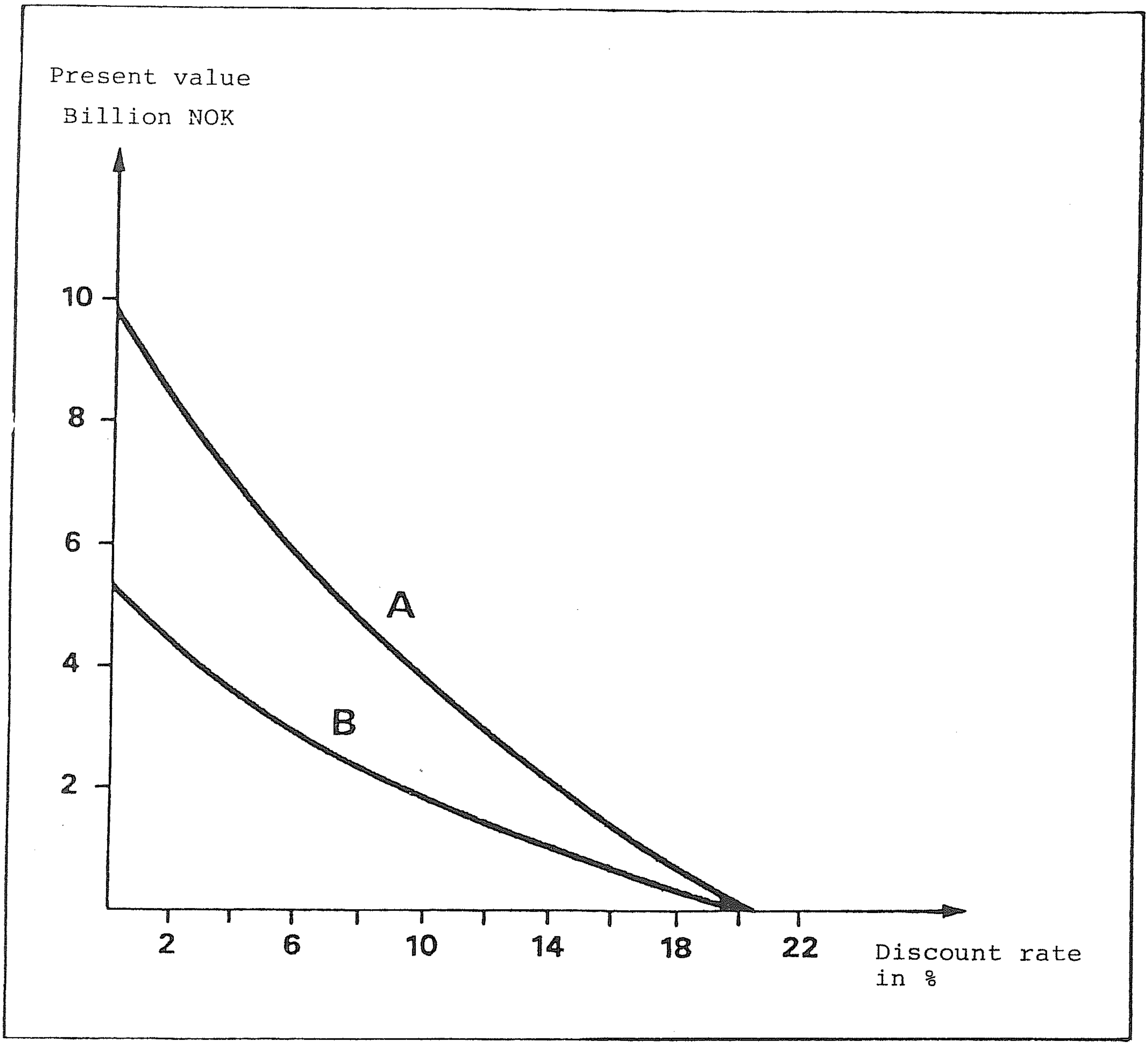


FIG 8.1.k Net present value at different discount rates. Projects with most of revenue generated at different points of time.

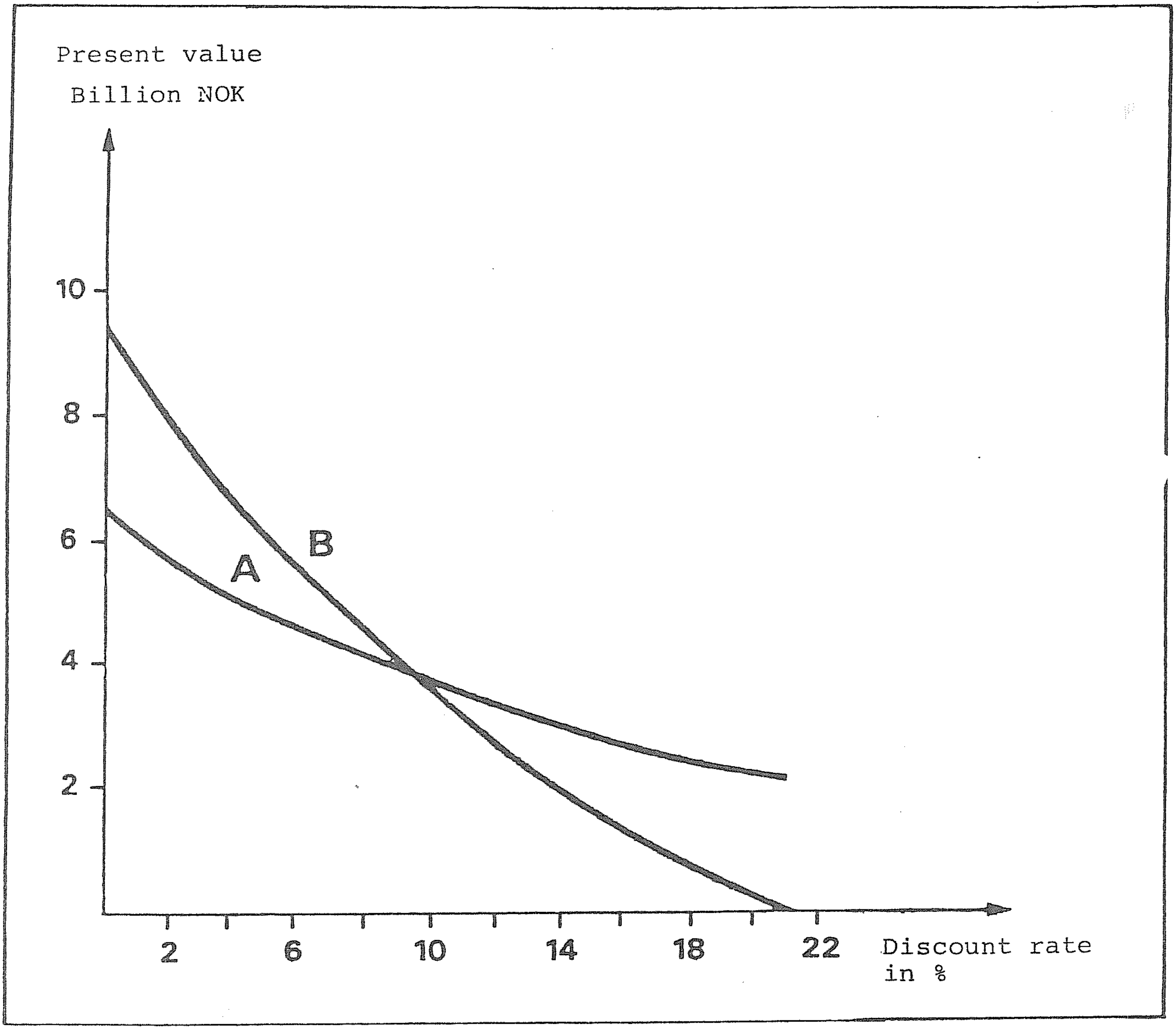


FIG 8.1.1 Projects with different priority at different discount rates

8.2. Noise on offshore facilities

Introduction

The Norwegian Petroleum Directorate took the initiative in the autumn of 1980 to start a research project to clarify the noise conditions on facilities offshore.

The main aim of the project is to obtain basic material for the design of relevant noise regulations for offshore facilities.

The project is run as a collaborative venture between the Norwegian Petroleum Directorate and the State Technological Institute.

As a resource and a professional corrective for the project managers, a resource group has been established in conjunction with the project. This is composed of representatives for the employees, employers and the industry´s interest organisations. Thus, the resource group includes members with insight, experience and competence in the various professional areas concerned with the problem complex (noise, process technology, work organisation, occupational medicine, occupational hygiene, etc).

The establishment of a resource group was also intended to facilitate conditions for exchange of information, progress and attitudes and opinions developing during the collaboration. But it is also expected that the members of the resource group in its meetings will present the views of the various interested parties as to the principle conditions which may be affected by the progress of the project.

Training and information

A significant task for the project managers has been to find and implement effective measures to transfer the experience gained in the project, its insight and results to the employees concerned, companies, institutions and professional environments as well as to the relevant authorities.

As a step in this work, the noise project was introduced with an introductory course about noise and noise measurement. The main aim of this course has been the clarification of central noise concepts and terminology. In addition, the plan was for the companies to carry out the necessary studies and clarify the working environment with regard to noise for the project, and the course was therefore also intended to put the company representatives in a position to perform such tasks, as well as ensuring the use of more or less similar methods. During the course, the main emphasis was put on:

- basic concepts of acoustics
- measurement units
- measurement techniques
- air noise
- structure noise
- health and noise

- regulations

The plan further calls for two additional courses to be held before project termination in May/June 1982. Emphasis here will be placed on the subjects of vibration and noise prevention, as well as exchange of project experiences and insight.

Data searches and literature studies

During the spring of 1981, thorough literature searches were made in national and international collections of articles and periodicals.

The Norwegian Petroleum Directorate encouraged the operator companies at an early stage to make available to the project any material they might have from measurements and surveys of noise conditions on offshore facilities. In particular, project interest was directed at:

- noise measurement data
- noise reduction measures implemented
- information on low-noise equipment
- noise loads for individual workers in the course of a shift
- noise loads within the individual zones of the platform

and possibly:

- sick leave statistics for the various professions/work tasks
- data on persons who resign or transfer to different work.

Concerning information on sick leave and persons resigning, this is not systemised or catalogued in the companies or therefore easily available to the project managers. Even though these matters are important in an evaluation of possible advantages in the introduction of basic regulations for noise, the motivation in the resource group to arrive at relevant noise regulations seems to be so great that the gain would hardly bear a reasonable relationship to the large resources which would have to be applied to make this information available.

Otherwise the project management has received a series of reports concerning noise measurements on offshore facilities. Many of these have been performed on the orders of the trade institutes, but some companies have also submitted reports of high quality which the company´s own personnel have prepared. The resource group´s meetings have also provided valuable information on noise conditions offshore, put into system by the project managers.

A provisional summary of noise conditions on offshore installations

Experience from the project so far shows that there are a number of circumstances which make noise conditions on offshore installations special as compared with similar industries ashore:

- "compact" facilities and constructions which give high noise concentrations
- most facilities are built of modules with steel plates both inside and out, giving high values for sound reflection
- the installations consist in the main of steel structures, even though the base may be of concrete. This gives good opportunity for

structural sound transfer from noise-generating activities and noise zones to control rooms, offices and accomodation quarters.
- employees are often exposed to high sound levels in the surroundings over long periods (12-hour shifts)
- sound implantation may occur to a large extent via the ventilation systems
- lack of space and "dense" constructions may make it difficult to make use of large sound absorbers or enclosures.

The generator/motor room

Measurements undertaken for the project show a noise level in the generator room of between 90-96 dB(A) on fixed installations. Measurements of diesel motors/generators show noise levels as high as 100-120 dB(A). On mobile platforms, the noise levels are largely similar.

The noise levels will depend on the type of equipment, the applied power and the number of units in operation. If, during the design and construction phases, emphasis had been put on noise reduction measures, this could have brought about to a considerable reduction in noise levels in the individual rooms.

Compressor room

The noise levels in the compressor room were measured at from 100-106 dB(A) for as many as four gas compressors simultaneously in operation. These levels correspond with the literature levels and measurement data obtained under the operator companies´ direction.

Pumps and pump rooms, valves and pipes

Pumps constitute a significant part of the equipment of production platforms, as well as fixed and mobile drilling rigs. In particular, it appears that mud pumps, and in some cases, injection pumps, generate relatively large amounts of noise.

Results of measurements on the Norwegian shelf show noise levels in the region of 93-96 dB(A) in the mud pump room. Corresponding levels have been recorded in the vicinity of pumps for the oil line.

Calculations have shown that by using absorbant and radiation inhibiting coverings on walls and ceilings, noise traps and enclosure of pumps, noise levels in these areas may be reduced to less than 90 dB(A).

The drill floor

On the drill floor, activities take place which exhibit highly variable noise levels. Characteristic for this area is the fact that there is often small distance between noise sources (lifting gear, rotation table, spinning wrench) and the individual worker: the distance varies from 1 to 3 meters.

A total evaluation of collected data for the activities on the drill floor provides mean noise levels in excess of 90 dB(A) for a normal drilling operation.

During the placing of conductor pipes, casing pipes and cementing operations, noise levels may increase significantlty.

The wellhead area

Measurements undertaken in the vicinity of the wellhead on a production platform show small variations in noise level, 84-87 dB(A).

Crane cabs

The Norwegian Petroleum Directorate has, in the relevant set of regulations, stipulated maximum noise levels of 75 dB(A) at the crane driver. With few exceptions, it has been difficult to fulfil this requirement on the Norwegian shelf. Depending on the load, noise levels in the crane cab lie between 83-85 dB(A) on the majority of installations in the North Sea.

Control rooms

Noise levels in control rooms vary greatly with their location, sound insulation, etc. In an acousticly unsuitable control room on a mobile platform, a noise level of 85 dB(A) was recorded.

Corresponding surveys of fixed installations show the noise level to vary between 60-70 dB(A).

The most important sources of noise in the control rooms are the compressed air systems, cooling fans and ventilation. In addition, external sources of noise may contribute significantly.

Offices

As for control rooms, noise levels in offices depend on their location and activity. Typical levels lie at about 55 dB(A), but vary by as much as 15 dB(A).

Living environment

Experience shows that noise levels in bunkrooms and other furnishings must be considered a problem area. The Directorate has, in the course of the years, received many complaints about this. Noise conditions in bunkrooms have a special importance in the cases where they cause sleep disturbance or insomnia. On the basis of a total evaluation of the available measurement data, it seems reasonable to fix 50 dB(A) as a typical average noise level in sleeping quarters on offshore facilities.

Summary: Estimated noise levels on offshore facilities

In the table below, a summary is given of the noise levels for various activities and items of equipment on production platforms and mobile drilling rigs. The data have been collected in part from own measurements, in part from measurements undertaken by institutions on order from the operator companies, together with literature data from English and American sources.

The various data often give little information of the type of measurement procedure followed, but it seems reasonable to assume that the level of precision corresponds to NS 4814.

Location	Typical noise level in dB(A)	Variation range in dB(A)
Machine rooms containing generators, diesel motors, turbines, compressors, pumps, etc:	100	+/- 5
Drill floor and work operations near drilling:	90	+/- 10
Wellhead, etc:	90	+/- 10
Workshops/laboratories:	70	+/- 20
Control rooms:	65	+/- 10
Offices:	55	+/- 15
Bunkrooms/living quarters:	50	+/- 20

Effects of noise

It is a well known fact that noise can damage hearing. Hearing damage can occur in two ways: as instantaneous damage at high impulse noise loads (hammer blows, shots, etc), and as gradual fatigue damage due to several years' noise load.

Because of large individual differences in sensitivity to noise, unequivocable load levels for the occurence of injurious effects cannot be given.

It is usual to assume that for impulse noise loads over 110 dB(A), the probability of instantaneous hearing damage will be considerable.

If the average noise load (equivalent level) does not exceed approx. 80 dB(A), there is very little probability of noise damage to hearing, even after 20-30 years of occupational life.

Noise damage to hearing occurs in the inner ear by destruction of the hair cells which transport pressure signals to nerve impulses in the brain. Research shows that for instantaneous loss of hearing, mechanical damage occurs to the hair cells, while the longterm results of noise are effects to cell metabolism, with whole or partial destruction as a result.

When noise limits are to be stipulated to protect against loss of hearing, the following arguments must be looked at amongst others:

- what is loss of hearing?
- how large a part of the personnel should we aim to protect?
- how and to what extent should the individual´s susceptability to hearing damage be taken into account?

These factors lie in the main outside the realm of acoustics experts and must therefore be the subject of policy evaluations based on what is technically and economically justified.

Noise and sleep

Everyone has experienced the fact that we sleep more or less deeply. ECG-assisted surveys have shown that sleep may be divided into five phases.

Phase 1 represents the most shallow sleep and Phase 4 the deepest. The fifth phase is called REM sleep (Rapid Eye Movement) and occurs when we dream.

Many surveys have been made to clarify the effects of noise on sleep. The results indicate that there are differences both of age and sex, in addition to large individual variations.

In general, the surveys show that old people sleep more lightly than the young, and are therefore more readily woken. Women seem to react more towards noise during sleep that men of corresponding age.

A survey with recordings of noise from motor lorries showed that 10% of the persons tested experienced a change in sleep phase (not necessarily waking) when the noise level was 40 dB(A). At 50 dB(A), half of them experienced a change, while at 70 dB(A), 75% experienced a change in sleep phase. Of these, about 30% woke up.

Other surveys have shown that there is a threshold value for waking up of 60 dB(A).

Examinations of acclimatisation to noise show varying results, even though most of them indicate that such adaption does not occur.

Poor sleep during the night effects working ability the day after. Tests of both awareness and numerical ability show reduced performance following nights with many noise-induced changes in sleep phase. Performance appears to approach normal values towards the end of the day.

Speech comprehensibility

The most noticable effect of noise is disturbance of speech comprehension, both as regards normal conversation, telephone conversation and messages given by public address system.

One way of representing the disturbing effects of noise is to calculate so-called PSIL values (Preferred Speech Interference Level). PSIL values are calculated as the arithmetic mean of noise levels in the octave bands 500, 1000, 2000 and 4000 Hz. A rough estimate of PSIL values is obtained by putting:

PSIL = dB(A) - 7 dB(A)

In the table below, PSIL values are noted with the corresponding distances at which conversation is possible:

PSIL in dB (preferred speech interference level)	Maximum distance in meters at which conversation is possible	
	Normal voice	Raised voice
35	7.5	15
40	4.2	8.4
45	2.3	4.6
50	1.3	2.6
55	0.75	1.5
60	0.42	0.85
65	0.25	0.50
70	0.13	0.26

A background noise level of 60 dB(A) will have a PSIL value of approx. 53 dB. The table shows that conversations may readily take place when the distance separating the conversants is approx. 1 meter. With raised voice, conversation may be readily understood at separations of 2-3 meters.

Messages over the public address system may often be difficult to comprehend. This may sometimes relate to the factor mentioned above, that the level of the loudspeaker voice is not sufficient compared to the background noise level, but in most cases there are other reasons.

If the loudspeaker system is not powerful enough, sound will be distorted. The distortion will get worse the further the system is pushed beyond its proper operating level. It is no good the sound level of the loudspeaker being way above the background level if only incomprehensible noises emerge from it.

In many cases, it would help to reduce the amplification of the system and to speak clearly into the microphone.

Alarms

The requirement for comprehensibility is simpler here, as it is sufficient to be aware that the alarm is sounding, and to recognise the alarm signal so that the necessary actions may be taken.

The first requirement relates to the sound level an alarm must have to be heard, and the second is the need for clear distinctions between alarms. The sound level for the alarms in the individual 1/3 octave bands ought to be 15 dB above the background noise in the band, while tone pitch (frequency) may be placed at a position in the sound spectrum where background noise is slight.

Because the individual worker may have reduced hearing (due to noise damage), the alarm ought not to have a frequency greater than 2000 Hz.

Factors which should be evaluated in the preparation of noise regulations

Terminology/standards of measurement

In the Norwegian Petroleum Directorate´s present noise regulations, the maximum allowed noise levels are noted in both dB(A) and NR (Noise Rating). Even though the difference between these values is not normally very great, some noise spectra may show discrepancies which may be significant as regards boundary levels.

The NR tables require an octave analysis of the noise. Therefore, more complicated measurement apparatus is required than for a simple dB(A) reading, without the result being significantly better. It will therefore be recommended that the noise regulations offshore be based upon dB(A) equivalent levels and maximum levels.

Boundary levels

Regarding hearing protection, there appears, as far as can be seen, to be little reason to depart from the requirements made on land. With a 12-hour shift arrangement, the maximum allowed equivalent noise level ought to lie at 83 dB(A).

A noise limit in control rooms of 60 dB(A) seems to be satisfactory. Lower values in control rooms with many persons should perhaps be considered to improve conversational comprehension.

For bunkrooms, the limit of 45 dB(A) seems a little high, but it would presumably be technically difficult to fix a lower boundary level. Some persons may have trouble with deep sleep at such levels. In any case, a number of the bunkrooms should have a lower noise level.

Sound insulation

Sound insulation between bunkrooms in the present regulations is given in terms of Ia number. The Ia number refers only to air insulation. Experience from a recently installed accomodation module indicates that requirements should also be made of structural sound insulation.

Control of hearing

Automatic implementation of the rules ashore would indicate audiometric control of all persons experiencing an equivalent noise level of 78 dB(A) for 12 hours.

Research concerning provisional threshold changes indicates a restitution period of over 12 hours. This means possibly that the audiometric control should be applied at a lower 12-hour equivalent level, for example 75 dB(A).

Form of the regulations

The Working Environment Act describes a number of ideal requirements to the working environment which should, amongst other things, ensure full security from physical as well as psychological damage. Further, the aim of the Act is that the working environment´s safety technology, occupational hygiene and welfare standard shall at all times accord with technological and social development in the community, a dynamic aim in the sense that working environment shall be subject to continuing efforts at improvement. This means that special demands must be made of the set of regulations and rules which govern the activity.

Regulations regarding noise conditions on offshore installations must therefore be formulated and must express the requirements of the authorities in a way which supports and contributes to progress in accordance with the stipulations of the Working Environment Act.

There are alternative methods of performing a longterm noise reduction program, The regulations which regulate the noise situation will greatly influence which measures are employed, how the work is carried out and, not least, what the result will be.

Experience shows that regulations which only contain clearly stipulated boundary levels for allowed noise on an offshore facility will give rise to efforts which by design and noise reduction measures will limit noise to the "allowed" level.

A development program with an eye to noise reduction as the Working Environment Act demands, where standards shall conform to technological and social progress in the community, may later be followed up by regular revision of the regulations and lowering the maximum allowed threshold levels for noise.

Such detail regulations are fairly readily prepared and the business of controlling the extent to which the requirements of the regulations are followed up is correspondingly easy.

As greater insight has been gained into noise and the effect noise has as a factor in the working environment, it appears nevertheless that such regulations do not necessarily tend to promote the result desired.

An example can illustrate this: If the maximum allowed boundary level for noise is fixed in the regulations at 45 dB(A), awareness will be directed to the extent to which the bunkroom satisfies this requirement. This can be determined by measurements and, depending on the results of these, the following may occur:

- if the measurement is 44 dB(A), the noise level will be accepted

- if the measurement is 45-46 dB(A) or above, the noise level will not be accepted and noise reducing measures must be implemented, or the requirements of the regulations must be waived.

In the latter case however, the experience is that a question mark is placed regarding the extent to which the measuring instrument or method was correct in the sense that the measured value might be higher than the actual noise. This has in turn led to purchase of more advanced measuring apparatus or to the engagement of a firm of consultants to perform new and more reliable measurements.

In any case, such detailed regulations or activities do not necessarily ensure a development of the working environment as explained in the Working Environment Act: When all insight and experience regarding noise as a working environment problem indicates that human reaction to noise is individual, a generalisation of the noise problem cannot be in accordance with the object of the Working Environment Act to fix standards in relation to developments in society.

Insight into the effects of noise tells us that it will probably be fully possible and justifyable to allow some persons to sleep in a living environment with a noise level of 47 dB(A), while others will not get a wink of sleep if the noise level exceeds 43 dB(A).

These are the conditions a modern regulation must seek to fulfil: In addition to the fact that provisions in the regulations must contribute to it being continually interesting and necessary to work for reduction of noise levels in working and recreation environments, it must contribute in greater degree to legitimising consideration of the individual´s ability and possibility of adapting to this factor in the working environment.

This does not mean that we should fix 43 dB(A) in our example as the maximum limit for allowed noise in the living quarters.

But it is clear that in all living quarters there will be bunkrooms with greater or lesser amounts of disturbing noise, and consideration must be taken of this fact in the allocation of sleeping quarters to each person. The regulations must stimulate this type of management of the working environment without at the same time facilitating conditions leading to an increased tendency to select, when taking on new employees, persons who individually might be considered to be specially robust with respect to environmental factors.

The Norwegian Petroleum Directorate considers it to be a significant step forward that the new noise regulations are formed in such a way that they stimulate purposeful management of the working environment as described above.

Conclusion

The work of the project so far has revealed the need for clarification of the boarderlines between areas where several authorities have regulatory responsibility.

In particular, this applies to the combating of noise in connection with drilling activities on mobile rigs, where both the Norwegian Petroleum Directorate and the Norwegian Maritime Directorate have authority.

The resource group has made a clear recommendation to the project managers to take contact with the Norwegian Maritime Directorate to clarify these circumstances. The discussion between the two directorates so far concludes that:

- New regulations for offshore personnel on fixed and mobile installations in the North Sea must be harmonised.

- Noise limits fixed on the basis of project work as described for fixed installations must be so relevant that the Norwegian Maritime Directorate can easily transfer them to mobile installations (cf. accomodation regulations).

9. STATISTICS AND SUMMARIES

9.1. Units of measurement

In line with common Norwegian practice for measuring units, the Norwegian Petroleum Directorate would normally use the units from the SI-system. This system is also recommended for use by the oil companies operating on the continental shelf.

However, other units than those whose use is allowed in the SI-system have a very strong position in the petroleum industry due to tradition and practical conditions.

In Table 9.1, physical entities have been tabulated along with the units from the SI-system most often used for these. Moreover, formulas to be used for conversion from other units into the corresponding unit in the SI-system have been tabulated.

Furthermore, there are some concepts and expressions for abbreviations which are often used in connection with production data for oil and gas, and which are related to the measuring units. Some of these have been briefly dealt with below.

Measurement - oil

An exact measurement of an oil quantity in volume (barrels or m^3) must refer to a further given condition characterized by pressure and temperature. This is necessary because the volume of an oil quantity is affected both by pressure and temperature. The pressure and temperature which the oil volume refers to, is normally termed the "standard condition" or "reference condition" of the volume. The two most common reference conditions are a) 60^oF, 0 psig and b) 15^oC, 1.01325 bar.

Other pressure and temperature references than these may also occur. One should note that expressions like "standard condition", "barrels at standard condition", etc. are not unambiguous unless pressure and temperature references have been defined.

Reference condition (b) is recommended for use by the International Standardization Organisasjon. Moreover, this reference condition was introduced as Norsk Standard in 1979. The Norwegian Petroleum Directorate is working to establish this reference condition both for internal use and for reports from the oil companies.

Exact conversion of an oil volume from one condition into another implies the use of special tables. For calculations of estimates, however, the volume at 60^oF, 0 psig may approximately correspond to the volume at 15^oC, 1.01325 bar.

Normal units/abbreviations:

Sm^3 = standard cubic meter. Temperature and pressure references must be given for the unit to have an unambiguous meaning.

Barrels at standard conditions = Traditional American unit. Reference condition normally $60^{o}F$ and 0 psig.

Conversion

1 Sm^3 corresponds to approx. 6.29 barrels at standard conditions.

Measurement - gas

To an even greater extent than for oil volumes, the numeric value of a gas volume will be related to the pressure and the temperature to which the volume refers. Four reference conditions are normally used: a) ($60^{o}F$, 14.73 psia), b) ($60^{o}F$, 14.696 psia), c) ($15^{o}C$, 1.01325 bar), d) ($0^{o}C$, 1.01325 bar). Reference conditions a), b) and c) are usually termed as "standard conditions", d) as "normal conditions".

A volume cannot be converted exactly from one condition into another without knowing the physical properties of the gas. For calculation of estimates, a volume of the same gas quantity can, however, be considered approximately equal in conditions (a), (b) and (c), and the volume of this quantity is 5% less than in condition (d).

Normal abbreviations:

SCM or Sm^3 = Standard cubic meter. Please note that the temperature and pressure reference must be given for the unit to have an unambiguous meaning.

Nm^3 = Normal cubic meter.

Scf (Scuft) = Standard cubic feet. Temperature and pressure reference must be given for the unit to have any meaning.

Conversion

1 Sm^3 corresponds to approx. 0.95 Nm^3
1 Sm^3 corresponds to approx. 35.3 Scf.

Quality measurement - oil and gas

Density or relative density is often used to characterize the composition of an oil or gas. A low value for this property indicates that the oil/gas is made up of light components.

Oil:

(a) Specific Gravity 60/60^{O}F
Relative density of oil in relation to water. Oil and water at temperature 60^{O}F and pressure corresponding to atmospheric at the place of measurement. The figure is undenominated.

(b) API-Gravity at 60^{O}F:
Specific Gravity 60/60^{O}F expressed on an enlarged scale. Units are ^{O}API. Conversion by this formula:

$$\text{API-gravity at } 60^{O}\text{F} = \frac{141.5}{\text{Specific Gravity } 60/60^{O}\text{F}} - 131.5$$

(c) Density at 15^{O}C:
Absolute density at temperature 15^{O}C and pressure corresponding to atmospheric at the place of measurement. Units usually kg/l.

Gas:

(a) Specific Gravity
The relative density of gas in relation to air. The content of this concept is not exactly defined unless the temperature and pressure at which the densities for gas and air have been measured, are given. Very often however, no temperature or pressure references are given for specific gravity. For rough calculations this is not very important, as the differences between the values which may be measured/calculated for the most usually used reference states are very small.

Registration of oil and gas in oil equivalents

Oil and gas are often spoken of in the form of tons oil equivalent in contexts where an exact registration of amount or quality is not required. Conversion is based on the amount of energy liberated in the combustion of oil and gas. For many oils and gases, the energy quantity in a ton of oil will be close to the quantity of energy in 1000 Sm^3 gas. This conversion factor is very easy to use, at the same time as the difference in quality between oil and gas is so large both during processing, storage, distribution and application that it would not be correct to note the conversion to more figures. Normal practice is therefore:

1 ton oil equivalent corresponds to 1 ton oil or 1000 Sm^3 gas

TABLE 9.1 Some units from the SI-system with conversion formulas to other units (Ref. ISO R - 1000, Api Publ. 2563)

Size	Unit from the SI-system	Abbreviation	Conversion formula	Comments
Length	meter	m	Inches x 0.0254 Feet x 0.3048 Yards x 0.91440 Miles(US st.) x 1609.344	
Mass	Kilogrammes	kg	Pound-mass(lbs avoirdupois) x 0.45359237 Long tons x 1016.047 Short tons x 907.1847 Tonn x 1000 (permissible in the SI-syst.)	
Temperature	Kelvin	K	°Celcius + 273.15 Rankine x 5/9	
	°Celcius		(°F-32) x 5/9	
Amount of substance	Mol	Mol		Elementary units (atoms, molecules, etc.) must be stated
Area	Square meter	m^2	Acre x 4046.856 Foot x 0.09290304 Inch x 0.0006451600	
Volume	Cubic meter	m^3	Barrel x 0.1589873 $Foot^3$ x 0.02831685 Acre ft x 1233.5 US Gallon x 0.0037854	Note! Accurate statement of volume, oil or gas includes information about pressure and temperature reference. Approximate conversion of oil and gas volume is: To Sm^3 oil:Barrels x 0.159 To Sm^3 gas:Nm^3 gas x 1.055 Scuft x 0.0283
Density	Kilogramme per cubic meter	kg/m^3	$\frac{141.5}{°API + 131.5}$ x 1000, lb/gallon x 119.83 lb/barrel x 2.8530, lb/cuft x 16.018	
Force	Newton	N	Pound-force (lbf avoirdupois) x 4.448221615260 kp x 9.806650	
Pressure	Pascal	Pa	Bar x 100000 (Bar permissible in SI-syst.)	1 Normal atmosphere=1.01325 bar 1 Techn. atmosphere=0.9806650 " $1kp/cm^2$ corresp. to 1 technical atmosph. $1kg/cm^2$ corresp. to 1 technical atmosph.
	Bar	-	mm Hg x 0.00133322 psi x 0.06894757	
Energy	Joule	J	Calories x 4.19 (approximately) Btu x 1060 (approximately)	The calorie and Btu units must be more accurately specified for accurate conversion
Effect	Watt	W	hp x 735.499	English/American horse power is not unambiguous. Normally approx. 745 w. Watt is defined as Joule pr. second
Dynamic viscosity	Pascal-second	Pa-s	Poise x 0.1, lbm/ft - sec x 1.4882	
Chimeatic viscosity	meters squared per second	m^2/s	Stoke x 10^{-4}	Defined as dynamic viscosity divided by density

See text for further description of constants.

9.2. Exploration and appraisal drilling on the Norwegian continental shelf

Since exploratory activities for petroleum started in 1966 in the Norwegian sector of the North Sea, a total of 311 exploration and appraisal wells have been started as of 31 December 1981. Of these, 299 were completed at the same date.

Information from these wells has been presented statistically to illustrate some aspects of the activities.

A total of 976,502 meters has been drilled in the wells which are included, of which 135,054 meters was drilled in 1981. The average depth of the 38 wells completed in 1981 is 3,235 meters. The average cost of the 49 wells which were started in 1981 is estimated at approx. NOK 80 million.

The deepest well in the Norwegian part of the North Sea is 30/4-1 with British Petroleum as operator. Drilling was started in November 1978 and completed in March 1979 at a depth of 5,430 meters.

The greatest depth of water drilled in so far is 388 meters. The well was 34/2-3 which was drilled in 1981 with Amoco as operator.

For drilling of the wells covered by the statistics, 44 different drilling rigs have been employed. Of these, 35 are of the semi-submersible type, 9 are jack-ups and 3 drilling ships.

- Table 9.2.a shows "rig months" per quarter up to and including 1981.
- Table 9.2.b shows seasonal variations in well activities from 1963 to 1981 inclusive.
- Table 9.2.c shows the average water depth and total depth.
- Table 9.2.d shows the drilling rigs that have been active on the Norwegian shelf.

TABLE 9.2.a Rig months per quarter 1966-1981.

Year	First quarter	Second quarter	Third quarter	Fourth quarter	Total per year
1966			2	3	5
1967	3	3	5	6	17
1968	5	11	9	8	33
1969	6	7	9	6	28
1970	5	8	16	15	44
1971	12	12	14	9	47
1972	9	13	18	13	53
1973	5	7	10	17	39
1974	19	15	8	12	54
1975	9	16	17	13	55
1976	17	8	13	8	46
1977	5	10	17	18	52
1978	10	14	14	11	49
1979	15	14	20	25	74
1980	32	29	34	35	130
1981	34	31	32	39	136
Total per quarter	188	198	238	238	862

TABLE 9.2.b
Seasonal variations in activity 1966-1981

Month	Number of wells started
January	15
February	18
March	16
April	27
May	24
June	33
July	37
August	37
September	29
October	27
November	22
December	26

TABLE 9.2.c Average water depth and total depth

Year	Average water depth (m)	Average total depth (m)
1966	110	2737
1967	93	2599
1968	75	3495
1969	70	3143
1970	89	2983
1971	82	3101
1972	79	5313
1973	86	3089
1974	109	3078
1975	109	2954
1976	124	2949
1977	94	2719
1978	109	3502
1979	153	3375
1980	176	3115
1981	181	3235

TABLE 9.2.d Drilling rigs that have been active on the Norwegian shelf

Name	Number	Rig type
Ocean Viking	29	Semi-submersible
Neptune 7 (prev. Pentagone 81)	12	Semi-submersible
Zapata Explorer	13	Jack-up
Nordskald (now Glomar Biscay II)	29	Semi-submersible
Glomar Grand Isle	11	Drilling ship
Ross Rig	26	Semi-submersible
Ocean Traveler	9	Semi-submersible
Deepsea Driller (now Byford Dolphin)	8	Semi-submersible
Orion	7	Jack-up
Polyglomar Driller	11	Semi-submersible
Zapata Nordic	5	Jack-up
Ocean Tide	5	Jack-up
Maersk Explorer	7	Jack-up
Deepsea Saga	14	Semi-submersible
Drillmaster	6	Semi-submersible
Sedneth 1	3	Semi-submersible
Gulftide	3	Jack-up
Dyvi Alpha	12	Semi-submersible
Endeavour	2	Jack-up
Transworld Rig 61	2	Semi-submersible
Ocean Voyager	2	Semi-submersible
Ocean Victory	1	Semi-submersible
Chris Chenery	2	Semi-submersible
Drillship	1	Drilling ship
Waage Drill	2	Semi-submersible
Sedco 135 G	3	Semi-submersible
Norjarl	3	Semi-submersible
Odin Drill	3	Semi-submersible
Saipem II	1	Drilling ship
Borgny Dolphin (prev. Fernstar)	8	Semi-submersible
Treasure Seeker	10	Semi-submersible
Dyvi Beta	7	Jack-up
Dyvi Gamma	1	Jack-up
Sedco H	2	Semi-submersible
Sedco 707	4	Semi-submersible
Haakon Magnus (now Borgsten Dolphin)	2	Semi-submersible
Byford Dolphin (prev. Deepsea Driller)	7	Semi-submersible
Pentagone 84	3	Semi-submersible
Fernstar (now Borgny Dolphin)	3	Semi-submersible
Nortrym	8	Semi-submersible
West Venture	3	Semi-submersible
Nordraug	4	Semi-submersible
Sedco 704	3	Semi-submersible
Sedco 703	2	Semi-submersible
Borgsten Dolphin (prev. Haakon Magnus)	4	Semi-submersible
Dyvi Delta	1	Semi-submersible
Glomar Biscay II (prev. Nordskald)	8	Semi-submersible
Ekofisk B	1	Fixed install'n
Pentagone 81 (now Neptune 7)	1	Semi-submersible

9.3. Production of oil and gas in 1981

The production of oil and gas on the Norwegian shelf in 1981 was 48.8 million ton oil equivalents, production in 1980 was 49.5 million toe. In Table 9.3.a and Figures 9.3.a and 9.3.b, the production on the Norwegian shelf is presented more closely.

TABLE 9.3.a Production of oil and gas

Million toe 1981	Oil (incl. NGL)	Gas	Total
Ekofisk area	16.4	14.0	30.4
Frigg area		11.2	11.2
Statfjord	6.5		6.5
Murchison	0.6		0.6
Total 1981	23.5	25.2	48.8
Total 1980	24.4	25.1	49.5

FIGURE 9.3.a Oil and gas production from the Norwegian shelf in million ton oil equivalents

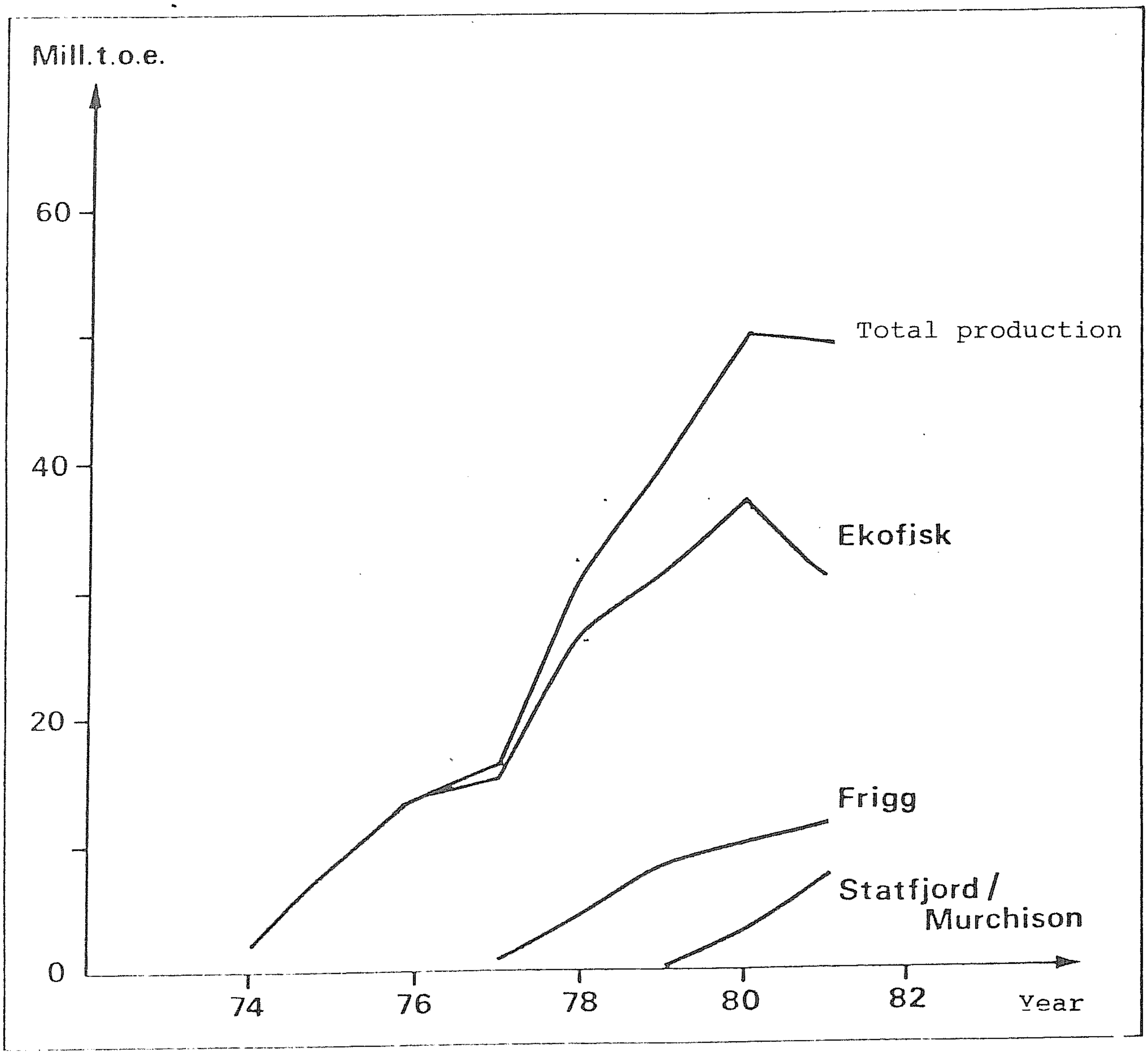


FIG 9.3.a Oil and gas production from the Norwegian shelf in million ton oil equivalents

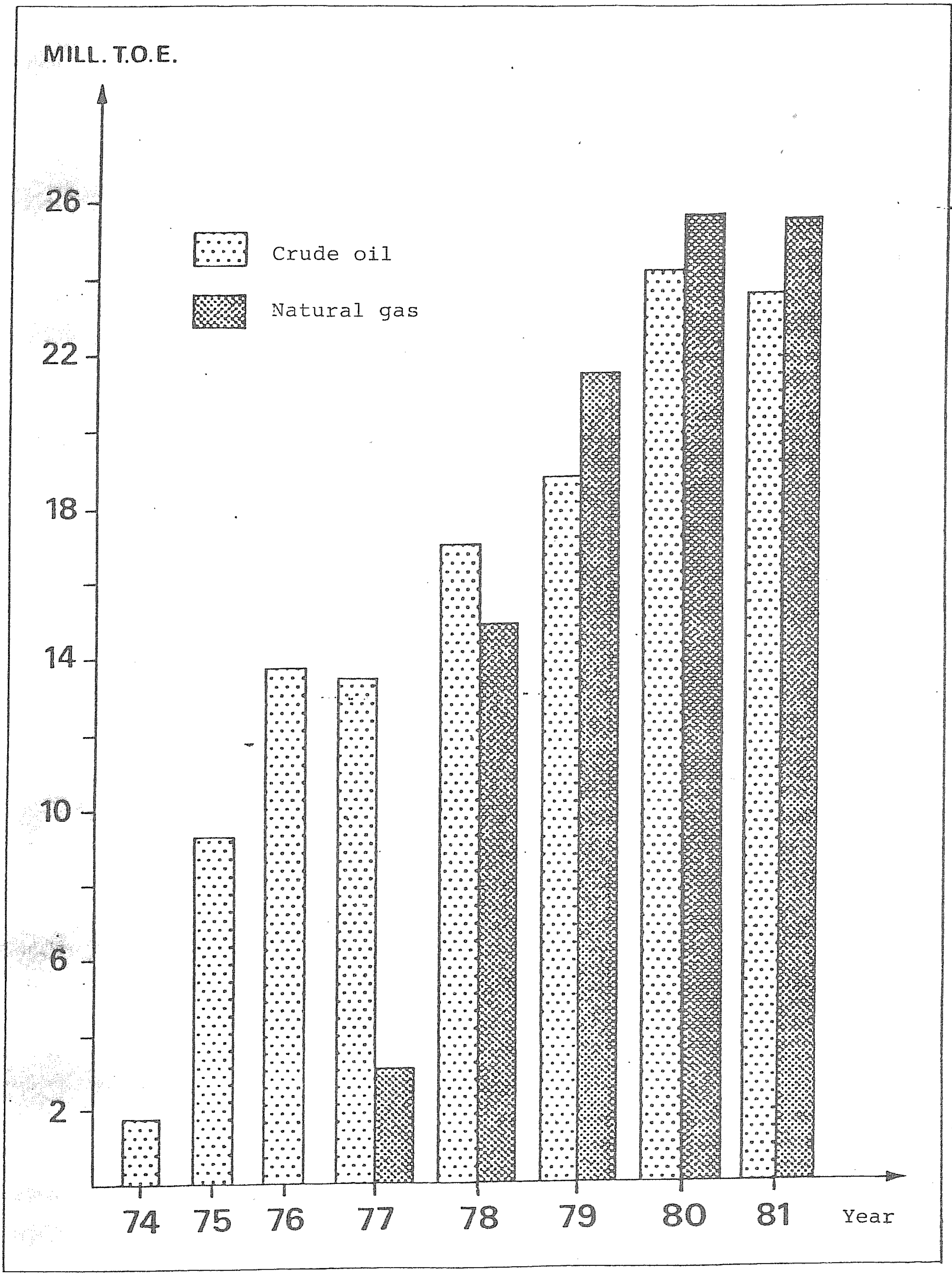


FIG 9.3.b Oil and gas production from the Norwegian shelf 1974–1981

TABLE 9.3.c MONTHLY OIL AND GAS PRODUCTION FROM THE MURCHISON FIELD

1981	OIL PROD. STABILE OIL	GAS PROD	GAS INJ	GAS FLARED	GAS FUEL	[illegible]
	1000 SM3	MILL. SM3	MILL. SM3	MILL. SM3	MILL. SM3	[illegible]
JANUARY	42	4	0	4	0	[illegible]
FEBRUARY	49	5	0	5	0	[illegible]
MARCH	47	5	0	5	0	47
APRIL	59	6	0	5	0	[illegible]
MAY	67	6	0	6	0	[illegible]
JUNE	51	5	0	5	0	64
JULY	70	7	0	6	0	62
AUGUST	65	6	0	6	0	62
SEPTEMBER	69	7	1	5	1	67
OCTOBER	60	6	1	5	0	53
NOVEMBER	71	7	2	5	0	67
DECEMBER	74	7	2	5	1	72
TOTAL	726	70	5	62	4	[illegible]

FIGURES ARE NORWEGIAN SHARE OF MURCHISON : 16.25 %

TABLE 9.3.b MONTHLY OIL- AND GAS PRODUCTION FROM THE STATFJORD FIELD

1981	OIL PROD. STABILE OIL	GAS PROD	GAS INJ	GAS FLARED	GAS FUEL	GAS SOLD EMDEN
	1000 SM3	MILL. SM3	MILL. SM3	MILL. SM3	MILL. SM3	MILL. SM3
JANUARY	503	84	66	11	7	0
FEBRUARY	504	84	66	11	7	0
MARCH	601	100	87	5	8	0
APRIL	459	77	58	13	6	0
MAY	671	115	101	7	7	0
JUNE	912	142	126	8	8	0
JULY	768	125	120	6	8	0
AUGUST	743	134	119	7	7	0
SEPTEMBER	560	100	84	11	6	0
OCTOBER	592	104	90	8	6	0
NOVEMBER	825	146	129	9	8	0
DECEMBER	852	155	141	6	8	0
TOTAL	7928	1376	1139	101	86	0

FIGURES ARE NORWEGIAN SHARE OF STATFJORD : 84.09322 %

TABLE 9.3.d MONTHLY OIL AND GAS PRODUCTION FROM THE EKOFISK AREA

1981	OIL PROD (INCL NGL)	GAS PROD	GAS INJ	GAS FLARED	GAS FUEL	STABLE OIL TEESSIDE	GAS SOLD EMDEN
	1000 SM3	MILL. SM3	MILL. SM3	MILL. SM3	MILL. SM3	1000 SM3	MILL. SM3
JANUARY	2078	1544	162	5	226	1347	1295
FEBRUARY	1840	1342	73	4	84	1648	1139
MARCH	1900	1439	13	8	88	1707	1052
APRIL	1921	1447	57	7	89	1695	1232
MAY	2003	1542	145	9	93	1842	1215
JUNE	1959	1443	203	6	92	1674	1171
JULY	1896	1468	186	7	92	1718	1213
AUGUST	871	593	133	12	43	777	407
SEPTEMBER	1799	1370	22	6	62	1644	1266
OCTOBER	1463	1164	0	4	67	1324	1104
NOVEMBER	1627	1242	24	6	76	1477	1121
DECEMBER	1639	1342	7	5	83	1461	1258
TOTAL	20910	15941	1026	79	1115	18836	14019

TABLE 9.3.e MONTHLY GAS AND CONDENSATE PRODUCTION FROM THE FRIGG FIELD

1981	GAS PRODUCED	GAS FLARED	GAS FUEL	GAS SOLD ST.FERGUS	CONDENSATE ST.FERGUS
	MILL. SM3	MILL. SM3	MILL. SM3	MILL. SM3	TON
JANUARY	1121		3	1125	4228
FEBRUARY	1009		3	1024	4292
MARCH	1112		3	1130	3998
APRIL	998		2	1000	3573
MAY	635		2	659	2420
JUNE	639		2	702	2371
JULY	652		2	654	2101
AUGUST	675		2	683	2701
SEPTEMBER	724		2	738	2214
OCTOBER	1046		2	1082	3501
NOVEMBER	1102		3	1150	3090
DECEMBER	1172		3	1224	3493
TOTAL	10936	2	30	11212	[illegible]

FIGURES ARE NORWEGIAN SHARE OF FRIGG 60.82% AND NE FRIGG 100%

9.4. Royalty

In 1981 a total of NOK 5,308,296,964.- was paid in as royalty. Table 9.4.a shows the total royalties on the Norwegian shelf in 1980 and 1981 divided as to oil, gas, NGL and condensate.

Figure 9.4.a shows the total royalties in 1980 and 1981 as columns. Figure 9.4.b shows the royalty paid in from 1973-1981.

TABLE 9.4.a Royalties 1980-1981

		1980	1981
Oil Ekofisk	NOK	2 326 668 960.-	2 647 725 781.-
Oil Statfjord		257 972 003.-	1 085 598 769.-
Oil Murchison			62 270 657.-
Gas Ekofisk		701 597 893.-	963 852 359.-
Gas Frigg		333 172 126.-	505 861 255.-
NGL Ekofisk		13 928 658.-	37 019 877.-
Condensate Frigg		6 152 112.-	5 968 265.-
	NOK	3 639 491 752.-	5 308 396 963.-

FIGURE 9.4.a Royalties 1980 and 1981

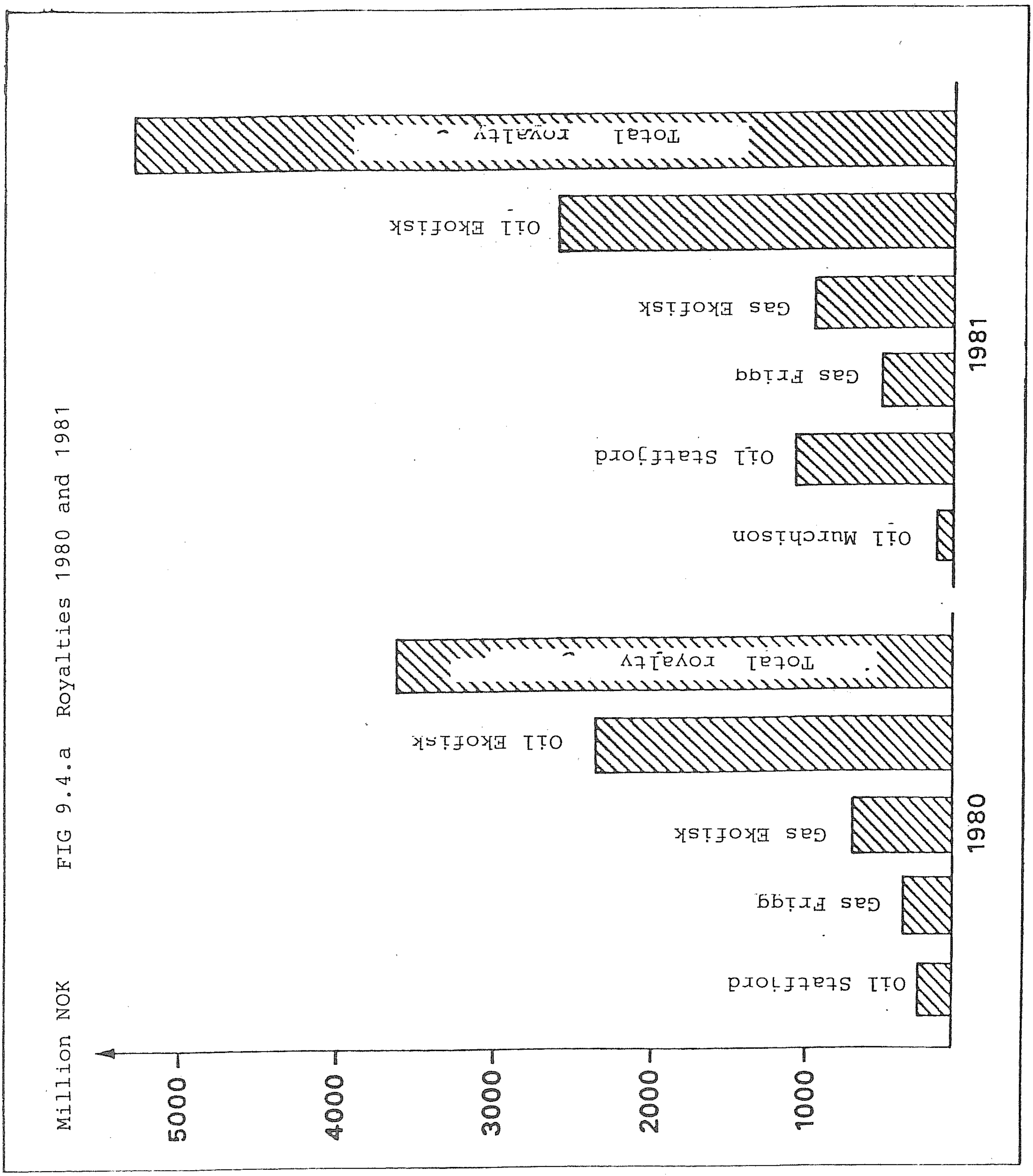
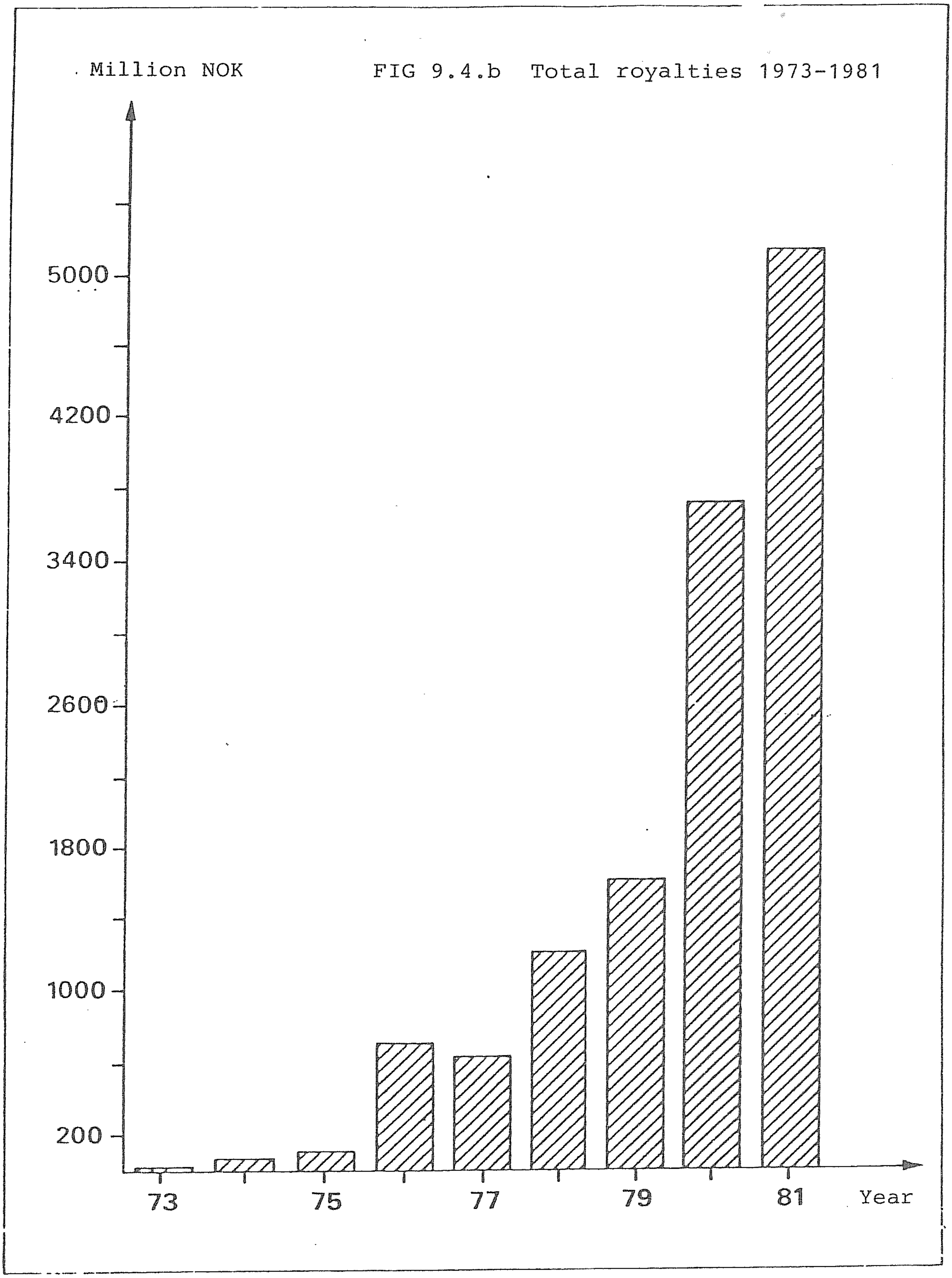


FIGURE 9.4.b Total royalties 1973-1981



Oil royalties

The Norwegian Petroleum Directorate has received royalties amounting to NOK 2,647,725,781.- in 1981 for crude oil from the Ekofisk area, NOK 1,085,598,769.- for crude oil from Statfjord and NOK 62,270,657.- for crude oil from Murchison.

Assessments for crude oil for 1981 have been made in accordance with the price norm. Royalties have been collected quarterly in the following way:

Ekofisk

1981		Royalties paid
Provisional statement 4. quarter 1980	NOK	712 881 798.-
Price adjustment 3. & 4. quarter 1980		40 671 850.-
Provisional statement 1. quarter 1981		549 194 089.-
Provisional statement 2. quarter 1981		564 692 915.-
Price adjustment 1. & 2. quarter 1981		217 338 635.-
Provisional statement 3. quarter 1981		562 946 494.-
	NOK	2 647 725 781.-

Statfjord

1981		Royalties paid
Provisional statement 4. quarter 1980	NOK	148 856 265.-
Price adjustment 3. & 4. quarter 1980		9 605 931.-
Provisional statement 1. quarter 1981		196 660 180.-
Provisional statement 2. quarter 1981		265 492 258.-
Price adjustment 1. & 2. quarter 1981		84 593 169.-
Provisional statement 3. quarter 1981		380 390 966.-
	NOK	1 085 598 769.-

Murchison

1981		Royalties paid
Provisional statement 4. quarter 1980	NOK	12 159 492.-
Provisional statement 1. quarter 1981		14 465 373.-
Provisional statement 2. quarter 1981		14 779 010.-
Price adjustment 1. & 2. quarter 1981		4 312 374.-
Provisional statement 3. quarter 1981		16 554 408.-
	NOK	62 270 657.-

Gas royalties - Ekofisk

The Norwegian Petroleum Directorate has received NOK 963,852,359.- in royalties in 1981 for gas in the Ekofisk area. Table 9.4.b shows the receipts distributed according to company/group and quarter.

TABLE 9.4.b Royalties on gas from the Ekofisk area 1981

	4.qu.1980	1.qu.1981	2.qu.1981	3.qu.1981	TOTAL
Phillips group	146,851,752	125,680,560	109,461,335	81,265,126	463,258,773
refunded by NPD -	1,466,464	5,301,170	6,101,234	6,834,882	19,703,750
	145,385,288	120,379,390	103,360,101	74,430,244	443,555,023
Dyno/Methanor	27,458,524	66,362,724	67,712,167	60,250,934	221,784,349
Sydvaranger/Norddeutsche Ferrowerke	9,356,451	40,655,884	61,516,134	54,776,527	166,304,996
Shell	14,602,509	14,599,058	18,410,682	16,375,134	63,987,385
Amoco/Noco	8,863,853	3,541,721	4,231,173	2,835,864	19,472,611
	205,666,625	245,538,777	255,230,257	208,668,703	915,104,262

Assessments of gas have been made according to contract price. This differs for the various groups.

Payments from Dyno/Methanor and Sydvaranger/Norddeutsche Ferrowerke are amounts for that part of the royalty which has been taken out in the form of produced petroleum. The companies have, in addition to the quarterly payments made above, also paid NOK 51,286,200 in 1981 to cover the balance for the fourth quarter 1981.

In 1981, the Norwegian Petroleum Directorate has refunded approx. NOK 22 million to Phillips Petroleum Company Norway to cover costs on Ekofisk which have been incurred on that part of state royalties which has been taken out in the form of produced petroleum.

Gas royalties - Frigg

In 1981, the Norwegian Petroleum Directorate has received NOK 505,861,255.- in royalties for gas in the Frigg area. Table 9.4.c shows the payments of royalty distributed by company and quarter.

TABLE 9.4.c Royalties on gas from the Frigg field in 1981

	4.qu.1980	1.qu.1981	2.qu.1981	3.qu.1981	TOTAL
Petronord group (NE Frigg)	1,808,818	2,104,788	1,454,431	1,093,616	6,461,653
Petronord group (Frigg)	114,868,165	160,268,449	118,084,239	103,347,205	496,568,058
Petronord group (total)	116,676,983	162,373,237	119,538,670	104,440,821	503,029,711
Esso Exploration	717,710	966,803	658,758	488,273	2,831,544
	117,394,693	163,340,040	120,197,428	104,929,094	505,861,255

NGL royalties - Ekofisk

In 1981 the Norwegian Petroleum Directorate has received NOK 37,019,877.- in royalty for NGL from the Ekofisk area. Table 9.4.d shows the payments of royalties distributed by company and quarter.

TABLE 9.4.d Royalties on NGL from the Ekofisk area 1981

	4.qu.1980	1.qu.1981	2.qu.1981	3.qu.1981	TOTAL
Shell	(209,230)	(339,469)	512,680	765,988	729,969
Amoco/Noco group	812,775	749,873	160,638	(11,296)	1,711,990
Phillips group	2,788,018	14,139,028	14,011,928	3,638,944	34,577,918
	3,391,563	14,549,432	14,685,246	4,393,636	37,019,877

As is apparent from the presentation, the net paid royalty constitutes approx. 1% of the total paid royalty for the Ekofisk area in 1981. The statements for Shell and the Amoco/Noco group have been partly negative. The negative result has moreover been deducted from the companies´ statement for gas. There are two major reasons for obtaining a negative result, a relatively low positive result or both in the NGL statements:

1. Low prices for sale to Rafnes.
2. High processing costs at Teesside.

Condensate royalty - Frigg

The Norwegian Petroleum Directorate in 1981 has received NOK 5,968,265.- in royalty for condensate from the Frigg area. Table 9.4.e shows the royalty payments made distributed by company and quarter.

TABLE 9.4.e Royalties on condensate from the Frigg field 1981

	4.qu.1980	1.qu.1981	2.qu.1981	3.qu.1981	TOTAL
Petronord group	1,187,126	2,065,273	3,287,790	(571,924)	5,968,265

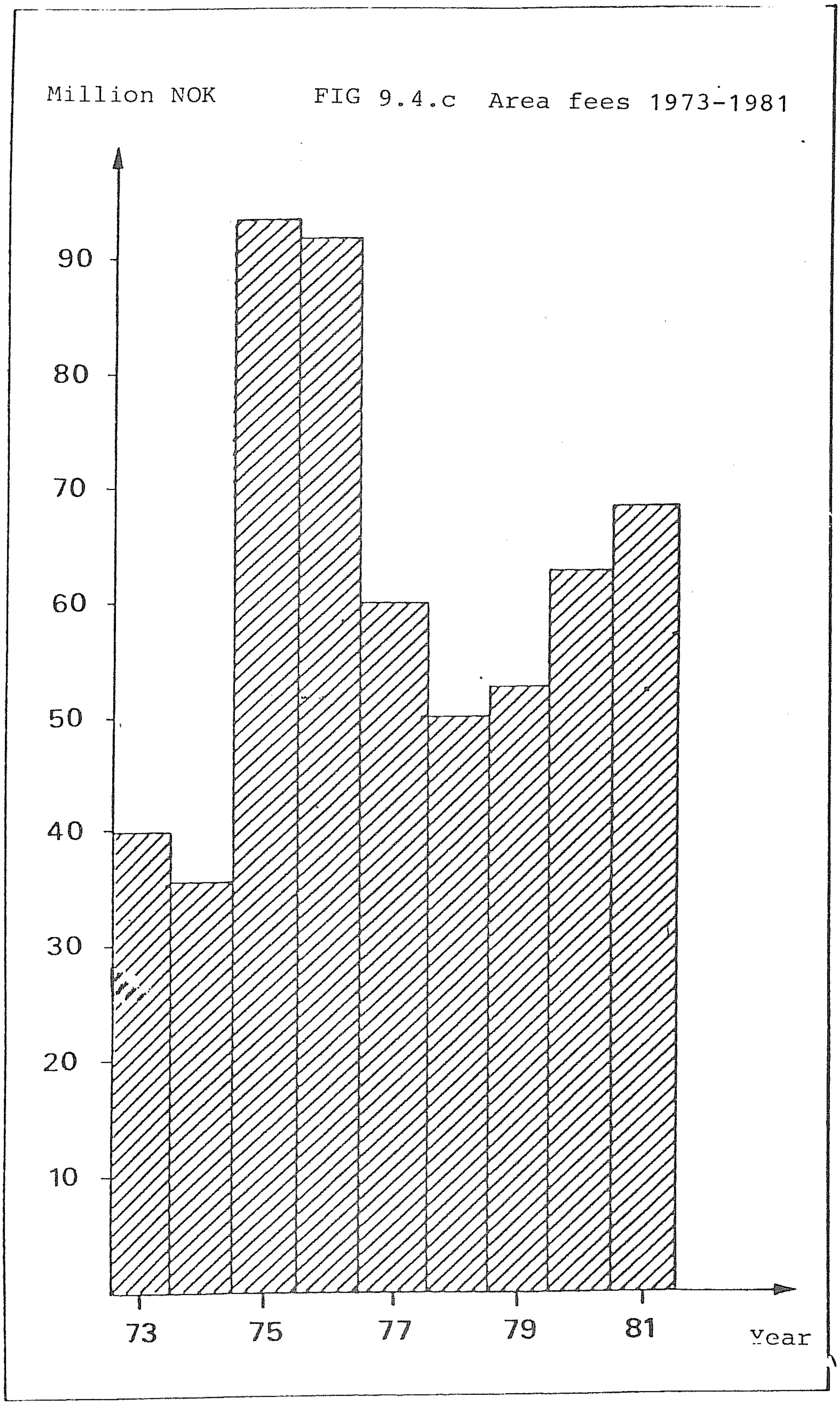
Acreage fees from areas covered by production licences

In the course of 1981, the Norwegian Petroleum Directorate has received NOK 69,098,837.- in acreage fees. The amount is made up of production licences as follows:

Production licences awarded in 1965:	NOK	55 212 550.-
Production licences awarded in 1969:		18 753 352.-
Production licences awarded in 1971:		1 205 200.-
Production licences awarded in 1973:		730 000.-
Production licences awarded in 1975:		2 010 600.-
Production licences awarded in 1981:		3 379 220.-
	NOK	81 290 922.-
Repaid in 1981		12 192 085.-
	NOK	69 098 837.-

The Norwegian Petroleum Directorate has refunded NOK 12,192,085.- in acreage fees in 1981. This represents the deductable part of the acreage fees for production licences 006, 018 and 037 in the period 1 October 1980 to 1 October 1981, together with a corrected amount of approx. NOK 375,000.- to the Amoco/Noco group (production licence 006) for the period 1 October 1979 to 1 October 1980 due to changes in ownership of the Tor field. Figure 9.4.c shows the payments of acreage fees for 1973-1981.

FIGURE 9.4.c Area fees 1973-1981



9.5. Petroleum markets

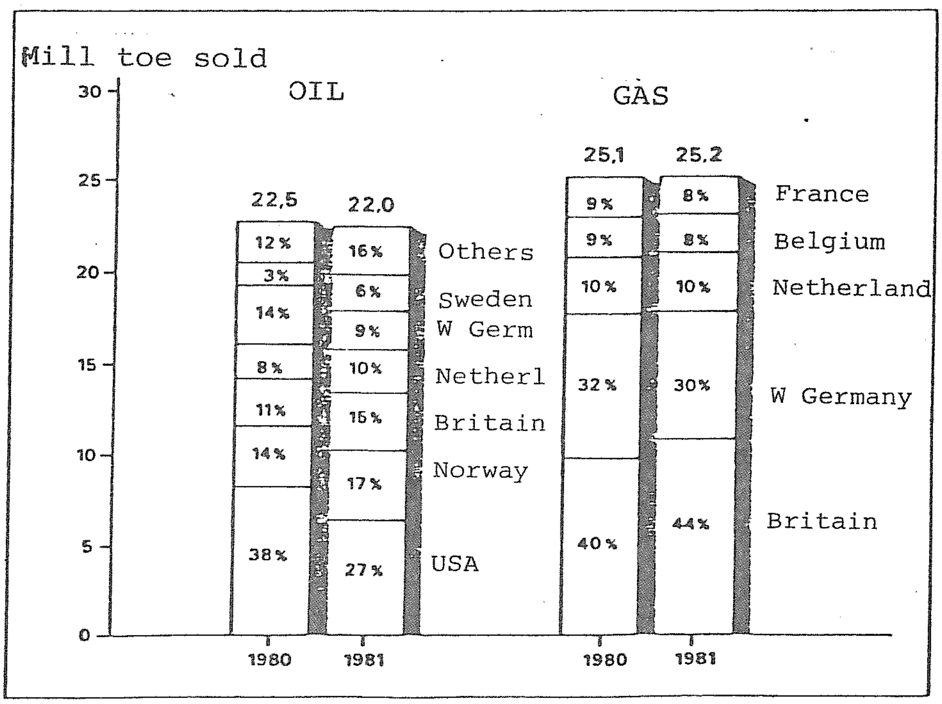
The total shipments of Norwegian crude from Teesside, Statfjord and Murchison were 22.0 million tons in 1981, as shown in Figure 9.5. The decline in the percentage of the amount of shipped crude to USA was 11 %, but USA is still the largest market for Norwegian crude oil.

The deliveries of Norwegian natural gas to the Continent and buyer countries West Germany, the Netherlands, Belgium and France were 14.0 billion in 1981. Sm^3, a reduction of 1.1 billion Sm^3 from 1980. The gas deliveries to Great Britain increased during the same period from 9.9 to 11.2 billion Sm^3.

The Norwegian gas share of the West-European gas market on the Continent in 1981, as seen in relation to a total consumption of approx. 136 billion Sm3, was at least 10 percent. With a total consumption in Great Britain of approx. 50 billion Sm3, the Norwegian gas share of the British gas market was a good 22 percent in 1981.

FIGURE 9.5 Sales quantities of gas and oil from the Norwegian shelf as per country

FIG 9.5 Sales quantities of gas and oil from the Norwegian shelf as per country



9.6. Prices and tariffs

From the norm price development for Norwegian crude, Table 7.6.a, it may be seen that the average market price for Norwegian crude oil during the period 1975-81 rose from NOK 60 to NOK 220 per barrel, an increase of at least 270 percent. Furthermore, it can be seen that the norm price in the first and second quarters of 1981, expressed in dollars, sank from 40 to 39.30 USD per barrel, at the same time as the norm price in NOK increased from NOK 214 to 223.35 per barrel due to developments in monetary exchange.

In a description of the price development for Norwegian crude, it is of interest to eliminate the general price rise in order to get a picture of how the real price development has been. This can be done with the aid of the wholesale price index (statistical monthly pamphlet, 1975 = 100).

Corrected for the general price rise, Figure 9.6.a indicates that the general crude oil price stayed nearly constant in the period 1975-78, that it rose by approx. 100 % during the period 1979 - 2nd half of 1980, and that the real price until the 2nd half of 1981 remained nearly constant.

The prices of Norwegian natural gas are determined by price formulas that tie the contract price to the index for oil product prices in the European inland markets. This entails a certain time displacement in the period between the accumulated price rise for oil products and the contract-related adjustment of gas prices.

Figure 9.6.b shows the price level for Norwegian natural gas during the period 1977-81 in NOK per Sm3 as a weighed average of the contract prices for Frigg gas and for gas from the Ekofisk area.

Together with the prices per oil and gas unit, the cost tariffs for transport and processing determine the economic profitability levels and the choices between alternative solutions for development. In Table 9.6.b, the average tariffs are calculated for 1981 based on the cost calculations for the annual production fees statement. The tariff figures indicate, among other things, that it costs more per barrel to transport crude from the loading platform at Statfjord by ship, and further, that the processing costs at the terminal are higher per barrel NGL than per barrel crude oil.

TABLE 9.6.a Quarterly normprice 1975-1981

Year and quarter (qu)		Price per barrel kroner (NOK)	Price per barrel dollars (USD)
1975 1. qu.	Teesside	59.62	11.90
2.		58.35	11.80
3.		63.38	11.70
4.		69.12	12.60
1976 1. qu.	Teesside	70.40	12.70
2.		70.50	12.79
3.		71.00	12.89
4.		69.25	13.15
1977 1.		75.50	14.33
2.		76.00	14.39
3.		76.25	14.26
4.		75.75	14.04
1978 1.		73.25	13.98
2.		75.25	13.94
3.		74.00	14.02
4.		71.75	14.29
1979 1.		81.65	16.05
2.		103.50	20.05
3.		120.45	24.00
4.		137.20	27.50
1980 1.	Teesside	166.95	33.75
2.		177.95	36.00
1.	Statfjord	166.70	33.70
2.		177.70	35.95
3.	Teesside	179.35	37.05
4.		186.50	37.10
3.	Statfjord	180.35	37.25
4.		187.50	37.30
1981 1.	Teesside	214.00	40.50
2.		223.35	39.30
1.	Statfjord	215.10	40.20
2.		224.50	39.50
1.	Murchison	210.00	39.25
2.		218.80	38.50

TABLE 9.6.b Transport and processing tariffs 1981

1981	Pipeline transport tariff	Ship transport tariff	Terminal tariff
OIL NOK/barrel:			
Ekofisk area	6		7
Statfjord		3	
NGL NOK/barrel			
Ekofisk area		8	55
GAS NOK/Sm^3			
Ekofisk area	0.10		0.02
Frigg			0.07

FIGURE 9.6.a Development of oil price. Nominal and real price, 1975 = 100

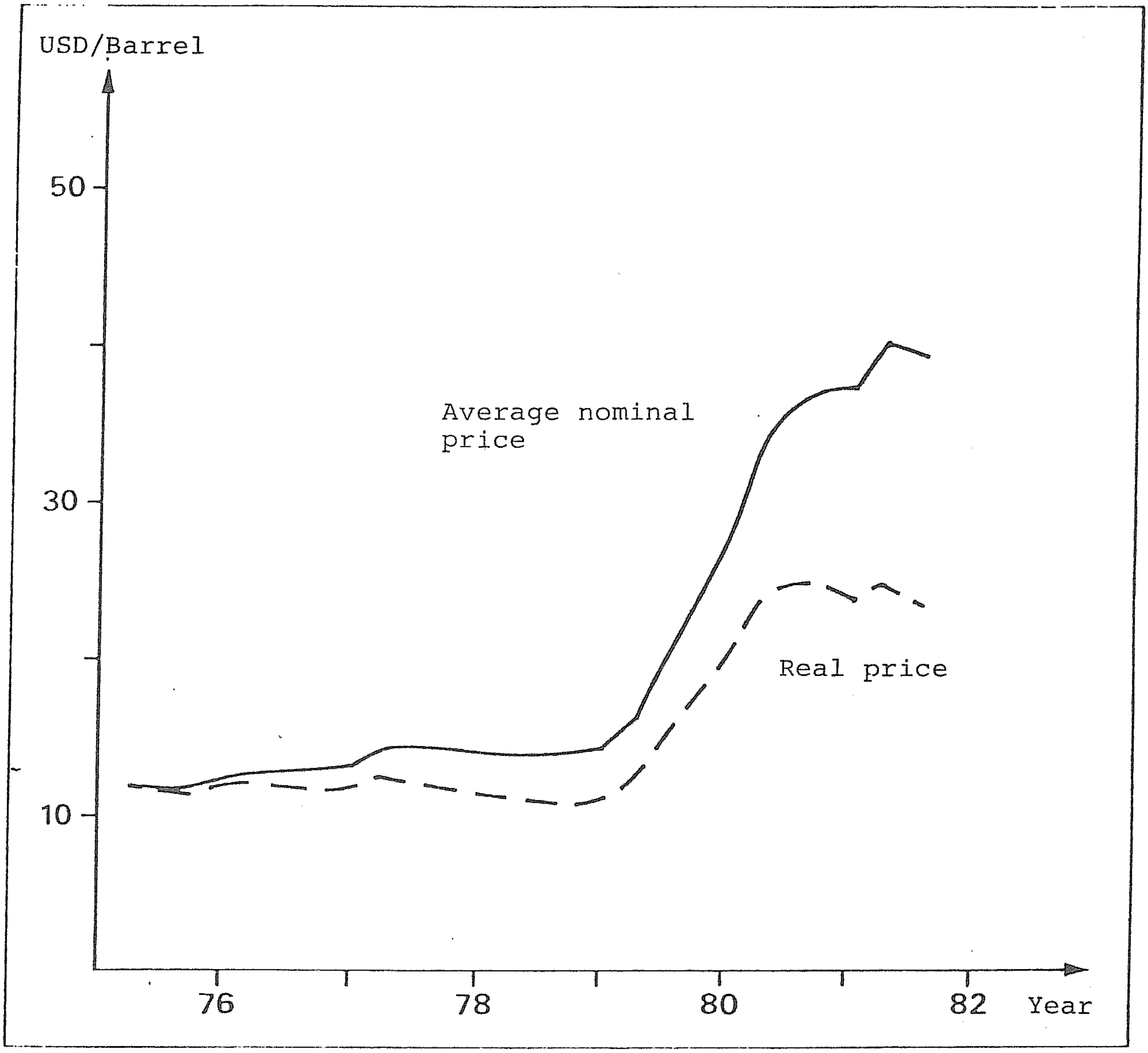


FIG 9.6.a Development of oil price for Norwegian crude. Nominal and real price, 1975 = 100

FIGURE 9.6.b Average sales price on gas from the Norwegian shelf, NOK/Sm3

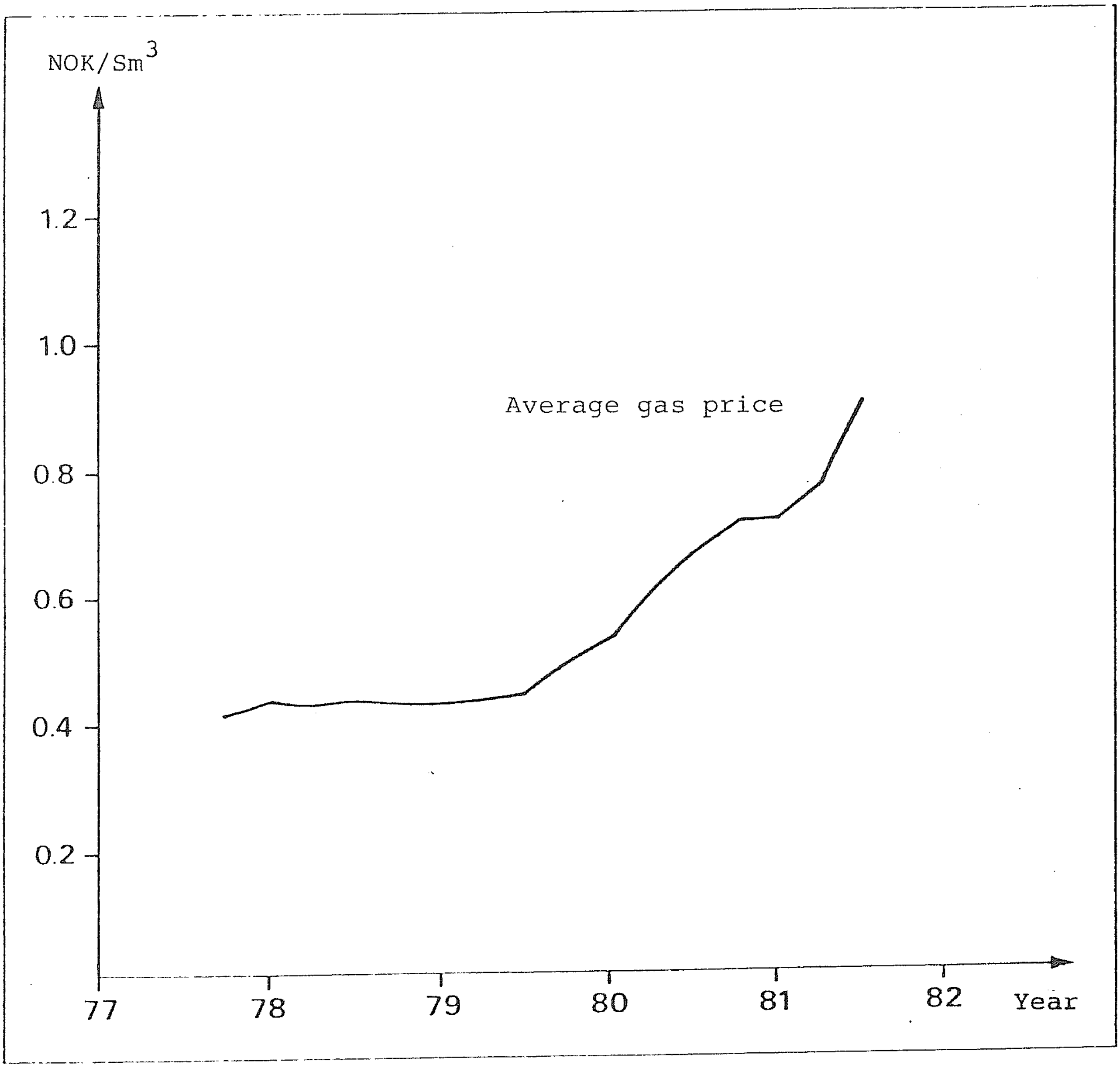


FIG 9.6.b Average sales price on gas from the Norwegian shelf, NOK/Sm^3

9.7. Publications issued by the Norwegian Petroleum Directorate in 1981

Regulations

Regulations compendium: "Fixed installations":
An up-to-date compendium of the regulations and guidelines stipulated by the Norwegian Petroleum Directorate or by other control institutions. Up-dated to 1 January 1982.

Regulations on collection of fees to the state treasury for inspection and control of temporary and fixed facilities: Stipulated by the Ministry of Industrial Affairs on 11 November 1977 with subsequent amendments, latest 23 December 1980.

Guidelines for concession holder´s internal control: Stipulated by the Norwegian Petroleum Directorate on 15 May 1981.

Guidelines for safety-related evaluation of platform concepts: Stipulated by the Norwegian Petroleum Directorate on 1 September 1981.

Regulations for drilling etc. for petroleum resources in inner Norwegian waters, Norwegian territorial waters and the part of the continental shelf subject to Norwegian sovereignty: Stipulated by the Norwegian Petroleum Directorate on 23 September 1981.

Regulations for technical drilling installations and equipment on mobile drilling platforms that are registered or will be registered in Norwegian ship registries: Stipulated by the Norwegian Petroleum Directorate on 23 September 1981.

Research reports

Feasibility of Leak Detection in Process Plant on Offshore Installations.

A State of the Art Review of Integrity Monitoring Systems being offered or under Development for Use on Offshore Structures.

Investigation into Maintenance, Methods and Procedures.

Brann i elektriske kabelanlegg (Fires in electrical cable facilities).

Beskyttelse av oljeplattformer mot skader ved lynnedslag (Protection of oil platforms against damage by lightning).

Environmental conditions at Tromsøflaket 71°30´N 19°00´E
Current and Waves. Four reports, 4-7.

Geological publications

Well Data Summary Sheets, Vol. 6.

NPD PAPER No 28, The Balder Area
NPD PAPER No 29, The Heimdal Area
NPD PAPER No 30, The Eldfisk Area

Petroleum documentation

Petroleumstesaurus (Petroleum Thesaurus), Norwegian vocabulary prepared for use with indexing and searching in literature bases ODIN and Oljeindex (Oil Index) on Scannet.

Other publications

Behovet for geofagekspertise og geoforskning innen petroleumssektoren i Norge (The need for geo-expertise and geo-research within the petroleum sector in Norway).

Prøveprosjekt - opprydding av havbunnen i Nordsjøen 1980 (Test project - cleaning up the sea floor in the North Sea 1980).

Optimal utnyttelse av ressurser og anlegg på norsk kontinentalsokkel (Optimal use of resources and facilities on the Norwegian continental shelf).

Strategies for the Management of Petroleum Resources.

Exploration Strategies - a Norwegian Lesson.

Kan mer olje utvinnes fra feltene i Nordsjøen? (Can more oil be recovered from the fields in the North Sea?)

Resurskartlegging og ressursplanlegging nord for Stadt (Resource mapping and resource planning North of Stadt).