Norwegian Petroleum Directorate

ANNUAL REPORT 1993

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Petroleum Directorate

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

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Director General's Statement

Once again the resource account on the Norwegian continental shelf showed a positive return. The figures indicate significantly greater additions from fields and discoveries than was depleted in 1993. But despite this increment, offshore activities will continue to offer major challenges with regard to exploration activities and to develop commercial projects from the large numbers of small and medium size discoveries. But though the challenges are many, we now possess a reasonably clear picture of what is involved and how the issues confronting us are interrelated.

The Directorate's most recent resource study was published in February and thus provides a fair account of the way forward, not only for the discovered resources; but also the undiscovered resources. The study reports an aggregate expectation that there are resources totalling roughly 10 billion tonnes oil equivalent, of which about 12 per cent has already been depleted. As might be expected, the undiscovered figures involve major imponderables, but it cannot be denied that the potential may be even greater than 10 btoe.

Our statistics from 1992 to 1993 reveal a growth in oil and gas that exceeds the depletion. In the case of the crude, the addition is 92.3 million cubic metres; and for natural gas 47.8 billion cubic metres.

The increments come generally as the result of improved understanding of the reservoir conditions, improvements in the technology of oil recovery, and the increasingly popular deployment of long reach and horizontal wellbores.

Assuming the same production rate as at present, the discovered resources of oil and gas will last us another 20 years and 115 years, respectively.

Although this time scale may appear long to us, we cannot sit back and let the future take care of itself. We must act. And it is important to emphasise that as time goes on, petroleum exploration on our continental shelf will become increasingly difficult; which is to say, the element of challenge will increase. Stricter data quality requirements, more advanced interpretation techniques and cost effective exploration are three key areas. We have already seen that these challenges have spurred greater efforts in compiling three dimensional seismic coupled with the introduction of new drilling technologies and advanced downhole logging methods.

Norway's offshore operations generate vast volumes of data and the amount increases from one year to the next. Part of the reason is the large volume of digital data generated by the new technologies, where 3D surveys are a prime example. Storage and maintenance of the data therefore require substantial resources. Increased efficiency here would offer major savings since storage and reproduction outlays could be reduced while increasing access. Greater efficiencies will involve state of the art storage media and streamlined data highways enabling operators to store their data collectively.

The Directorate has accepted this challenge and made arrangements with Statoil, Norsk Hydro and Saga Petroleum for the development and operation of a joint data bank for geodata. The project is one example of the means by which the Directorate can contribute in enhancing cost effectiveness within the industry.

The positive return reported in the 1993 resource account was very much a result of upgraded figures for reserves in fields already decided to be developed. The fields that provided the biggest increases in the resource account were Draugen, Gullfaks, Huldra, Oseberg, Snorre, Statfjord, Valhall and Vigdis. Notable among the discoveries augmenting Norway's resources were Hild, Norne, Visund and 34/10–23 Gamma.

The last decade's enormous efforts by offshore operators and official agencies to develop methods and technologies for Improved Oil Recovery seem at last to be bringing in dividends. The potential, though, remains huge.

The Directorate has estimated that the technical IOR potential is 530 mcm, equivalent to increasing the average recovery factor from its present 37 per cent to roughly 45 per cent. In the longer term we are hoping that the expectations for recovery from producing and fields decided to be developed will be upgraded by at least 400 mcm before the beginning of the year 2000.

To achieve this it is vital for the industry and the authorities to work very closely together, both in regular operations and in forward looking planning that embraces research and development.

It should be noted that the contribution from new discoveries was less in 1993 than in previous years: only three new discoveries were proven, all in the North Sea. None the less, the general activity level by drilling operators in 1993 was roughly compatible with the 1992 level. While the number of exploration wells spudded fell from 43 in 1992 to 27 in 1993, the number of production wells increased from 86 to 105.

The fourteenth licensing round completed in 1993 reaffirmed the continuing keen interest operating companies hold for the Norwegian shelf, especially the North Sea and Norwegian Sea provinces. Interest in the Barents Sea was less tangible.

Of the 50 blocks announced: 25 in the North Sea, 13 in the Norwegian Sea, and twelve in the Barents Sea; 31 were allocated. Seventeen licences were awarded and ten companies were duly rewarded with operatorships. The numbers of blocks awarded were 19 in the

North Sea, six in the Norwegian Sea, and six in the Barents Sea.

The Directorate applied much energy to issues connected with the future operation of the Ekofisk area fields. The slow collapse of the seabed coupled with the gradual ageing of the installations raised safety concerns, in particular for the Ekofisk tank itself. Since substantial volumes of recoverable oil and gas remain in place, the issues needed to be illuminated in a broad light. Careful scrutiny of the operator's plans for a long term solution involved the commitment of resource and safety personnel in the Directorate. A milestone was attained near the end of the year when the licensees submitted their revised plan for development and operation.

Apart from the inherent challenge of realising the new plans in a timely way, there is still the task of ensuring safe operation until the new concepts come on line.

The year witnessed three tragic accidents in which four offshore personnel lost their lives. Although the statistics for other injuries and accidents remained virtually unchanged from last year, the Directorate carefully investigates all accidents resulting in fatalities. Only by carefully tracking the chain of events can the appropriate measures be implemented to lessen the chances of repetition.

The new set of safety regulations pursuant to the Petroleum Act have been in effect now for more than a year, and the Directorate is well satisfied with the results so far. It is particularly pleasing that the industry has also expressed general satisfaction with the new regime. The phase we have now entered is one in which the rules will be subject to continual review and, where necessary, revision. The philosophy is to match the rules to advances in technology and keep pace with developments in society as a whole.

The year saw a further extension of our area of authority when the Working Environment Act became effective on mobile installations engaged in petroleum activities; and the supervisory authority was vested in the Norwegian Petroleum Directorate. The initial reaction is that large variations exist in the way in which the WEA is complied with on floaters, and thus both the industry and the Directorate can look forward to a good deal of hard work to secure compliance.

In connection with the safety of exploration drilling, the Directorate was particularly concerned about operations in ecologically sensitive areas, specifically the Barents Sea. The Norwegian Storting made it a condition of drilling in the far north that safety must be compatible with levels in the North Sea. Since the environmental impact of an oil spill in Arctic regions may have even bigger repercussions, the Directorate was even more searching in its oversight of the operator's preventive actions than usual.

The Directorate notes that there still occur many gas leaks on offshore installations. These occurences are especially disturbing on account of the large accident potential such uncontrolled leaks entail. Supervision of the operators' measures to tackle the problem have shown that while technical advances are important, it is equally essential to look closely at organisational factors and attitudes to the danger.

The increasing interest shown internationally in the details of the administrative framework that the Norwegian authorities have adopted with a Directorate is most gratifying; as is the interest in the Norwegian regulatory model with its tenet of internal control. Countries are increasingly seeking to draw up regulations which use functional requirements to set clear targets for the activity regulated. Norway's organisation of the governmental supervisory function is a further point of interest.

On an internal note, the Directorate was delighted to receive two accolades in its twentieth year of operation: the Norwegian State's Administrative Excellence Award; and the Safety Shield, given each year by the Safety Conference at Sola. This is confirmation that we are doing our job to the satisfaction of the wider community.

Let me also, to give some idea of the range of our activities, say that Petrad, the International Programme for Petroleum Management and Administration, has now achieved permanent status. Constituted as a foundation by Government decision in August, it will seek as before to develop and implement training programmes in petroleum management and petroleum administration, aimed primarily at the leaders and executives of developing countries. The foundation is owned by this Directorate and Norad, the Norwegian Directorate for Development Cooperation, and will become operative in its new form in 1994.

The task of setting up a special day care centre and play group for the children of Directorate staff was brought to a successful conclusion in 1993, when on 1 September cabinet minister Ms Oddny Aleksandersen officially inaugurated the *Havhesten*, or Seahorse, kindergarten.

Let me finally express my deep gratitude to all Directorate staff for their consummate work in the year past during a period of large and complex tasks needing prudent resolution.

Stavanger, 25 March 1994

Fredrik Hage

Fredrik Hagemann
Director General

1. Duties and Administration

1.1 TERMS OF REFERENCE

The objectives and duties of the Norwegian Petroleum Directorate are given in special instructions of 1 October 1992. These duties have been revised and supplemented by powers delegated through Acts of Parliament, regulations and administrative directives, as follows:

a) *Petroleum Act*, of 23 March 1985 no. 11, embracing
   - *Petroleum Regulations*, by Royal Decree of 14 June 1985
   - *Safety Regulations*, by Royal Decree of 28 June 1985
   - *Internal Control Regulations*, by Royal Decree of 28 June 1985
   - *Safety Zone Regulations*, by Royal Decree of 9 October 1987
   - *Anchoring and Fishing Prohibition Regulations*, by Royal Decree for each specific field (see details in Compendium of Acts, Regulations and Provisions for the petroleum activity, 1994)
   - Regulations for the *Government Action Control Group* in the event of Pollution Accidents etc, by Royal Decree of 19 November 1982

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

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

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

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

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

g) Provisional Regulations for *Littering and Pollution* caused by Petroleum Activities on the Norwegian Continental Shelf, by Royal Decree of 26 October 1979.

1.2 OBJECTIVE

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

1.3 ADMINISTRATION

1.3.1 Organisation

After several years of effort to set up a day care centre for children of staff, the *Havhesten* (Seahorse) kindergarten opened on 1 August 1993. The centre comes under the Administration Department and has 14 employees. Currently there are 51 children in two 0–3 year and two 3–7 year departments.

1.3.2 Staff

At the end of the period the Directorate had 353 authorised positions. Three more positions are funded by Norad, the Norwegian Directorate for Development Cooperation. Fourteen new positions were authorised in 1993 to provide kindergarten staff. At year end there were 367 members of staff in service and 19 on leave.

In the year the Directorate took on 33 new members of staff in permanent positions, of whom twelve come from oil-related activities, twelve from the public sector, and three from private enterprise, and of whom six were newly qualified.

Staff leaving were 13 in number, representing 3.7 per cent of the total authorised positions.

1.3.3 Budget and economy

The Directorate employed Nkr 266,407,050 for its various duties in 1993. The amount was appropriated as follows:

Outlays	
– Operating budget	Nkr 200,875,303
– Supervision costs	10,554,709
– Geological and geophysical surveys	48,807,466
– Projects conc safety and working environment	6,169,570
Total	266,407,050

Of the operating budget, payroll costs account for Nkr

118,353,726; lease and operation of buildings Nkr 23,995,449. The remainder, Nkr 59,245,690, covers costs of consultants, operation of a weather ship, external assistance, travel, training, computer systems operation, new investments in equipment, etc.

The Directorate is required to carry out certain specific tasks, including seabed clearance and administration of two research programmes:

– Clearance of seabed	Nkr 4,653,490
– Administration of Ruth/Profit	Nkr 1,874,316

Increasingly, the budget situation compels the Directorate to enforce strict priorities. Much work is therefore done to refine the available planning tools.

Revenues

In addition to production royalties, area fees and carbon dioxide tax totalling Nkr 10,675,608,718, the Directorate received Nkr 111,276,528 from various other sources of revenue as follows:

– Exploration fees	Nkr 1,860,000
– Commission fees	1,950,896
– Reimbursed inspection outlays	40,269,904
– Sale of released test material	3,689,277
– Sale of publications	5,231,435
– Kindergarten fees	1,013,763
– Reimbursed for job schemes	483,708
– Reimbursed from other agencies	3,206,842
– Sale of seismic data	48,476,802
– Credit interest, bank	5,043,888
– Miscellaneous	50,009
Total	111,276,528

1.3.4 Information

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

The *NPD Annual Report* plays a central role in the Directorate's information activities. The 1992 Annual Report was presented to the press in April.

The Directorate's internal magazine *Oss Direkte* was published in four issues in 1993, as planned.

There were 47 press releases issued in 1993, the majority in connection with the completion of exploration wells.

1.3.5 Document and data records management

Public records have been on display at the Press Centre in the Government building in Oslo since August, since when the number of petitions to inspect documents has significantly increased. It seems to be the case that commercial information people are increasingly turning to this public service which remains free of charge, despite the work it involves for branches of the administration. The Directorate is therefore keeping statistics on the number of insight petitions to see how the service developments.

New archival software entered service in December which complies with Norway's official NoArk requirements for filing systems. The system is a key element in efforts by the Directorate to harmonise document management. Our inhouse use of the Central File was up 35 per cent in 1993.

Library utilisation continued to expand, moderately in the case of external users, but more than 10 per cent by internal patrons. Orders for reprints of OIL, the Oil Index data bank, were up 6 per cent; while subscribers seem to have stabilised at just below 200.

Another data bank, the Infoil and Sesame systems containing details of current and completed petroleum-oriented research projects, received a large influx of new projects in the year. In Norway the bank is only offered on floppy disk. Users abroad can choose a CD-ROM version or access the German host base in Karlsruhe. From 1994 the Directorate will be offering Infoil and Sesame searches for fee-paying third parties.

Again in 1993, assistance was furnished to Namibia for the development of archival functions in Namcor, their national oil corporation.

1.3.6 Premises

September saw the commissioning of the expanded geological store (800 square metres), new geophysical archive rooms, show rooms for core samples, and a crude oil samples store (1035 sq.m). The building works were performed by the government building office, Statsbygg, at a total cost of Nkr 21,700,000.

The *Havhesten* day care centre for staff children entered service on 1 August. The building covers 560 sq.m and cost Nkr 6,120,000 to build. Statsbygg acted as the landlord. The four departments of the kindergarten can between them look after about 54 to 72 children, depending on the ages represented.

A new tenancy scheme was implemented in the year whereby Statsbygg rents premises to the Directorate. Under this new system the Directorate is required to pay an annual rental of Nkr 18,900,000 (1993) for its main office buildings in Stavanger.

A dispute between the Norwegian Broadcasting Service (NRK) and the State relating to final settlement for the land now used by the Directorate was resolved by a judgment in the Stavanger City Court in August 1993. The court ruled that a fair price is Nkr 200 per square metre.

2. Resources Management on the Norwegian shelf

2.1 INTRODUCTION

The objective of the Norwegian Petroleum Directorate is to contribute actively to the sound management of the petroleum resources in order to maximise the value obtained from the Norwegian continental shelf, and to act as the key advisory and executive body for the Ministry of Industry and Energy in offshore matters. The objective can only be achieved if the Directorate at all times has a broad overview of the petroleum resources and is in a position to evaluate alternatives for prudent exploration, development and recovery of our resources. Given this overview and evaluative capacity the Directorate is well equipped to advise the central authorities with respect to prudent management of the petroleum resources.

The formal basis for the Directorate's mandate to administrate the resources is as follows:

- Act of 22 March 1985 no. 11 relating to *Petroleum Activities* (Petroleum Act)
- Act of 21 December 1990 no. 72 relating to *Carbon Dioxide Tax* in the Petroleum Activities
- Act of 21 June 1963 no. 12 relating to *Scientific Research* and Exploration for and Exploitation of Subsea Natural Resources Other than Petroleum Resources.

The resources management activity on the Norwegian continental shelf was again high in 1993, within exploration, development, and operation.

The Resources Division was reorganised towards the end of 1993. The background for this move was an increasing need for integration of the development and operating phases, at the same time as there was a need for higher efficiency in staff and planning work. The Resources Division will retain the phased, product-geared basic organisation. One adaptation has been made, however, in the joining of the two phases development and operation to form one Development and Operations Department, while the staff and planning work has been combined in a new Strategy and Planning Department. The new organisation entered into force from the new year.

2.2 DEVELOPMENT OF REGULATIONS

In late 1991 and early 1992, the Directorate was involved in methodic development of regulations in the field of resources management (the MR project). This project is a continuation of corresponding development of regulations in the field of safety and working environment, see chapter 3. The work is a collaboration with the Ministry of Industry and Energy (MIE).

The object of the project is to efficiently and pragmatically consider the development and structure of the frameworks governing the petroleum activity, hereunder:

- Ensure controlled and coordinated development of rules and regulations for resources management, and evaluate the potential for streamlining
- Evaluate the potential to simplify, systematise, and unify administrative practices in certain areas
- Promote systematic and consistent use of administrative measures so the industry knows what to expect
- Clarify interfaces between the Directorate and other competent authorities.

In the course of 1992, the Directorate and the Ministry explored the frameworks and reviewed the documents that are important for resources management. The potential for improvement was also mapped.

In 1993, the two authorities, based on the material produced in 1992, defined areas that it will be useful to reexamine with a view to possible amendments of the Petroleum Act and its regulations. The Ministry will prepare a draft for possible such amendments in 1994.

One of the duties within the Directorate has been involvement in the introduction of REGAL, the data base for rules and regulations, concerning resources management.

2.3 PERFORMANCE MANAGEMENT

As a step in the work to introduce techniques of performance management in public administration, an initiative has been taken to launch a project under the guidance of the Ministry which examines the suitability of such ideas for Directorate activities.

Statskonsult has expressed its willingness to participate in a joint project also involving the Ministry of Industry and Energy, represented by the Oil and Gas Office; the Directorate; and the Ministry of Finance, represented by the Financial Office.

The project aims to apply performance management ideas to the oil and gas area, with special emphasis on addressing the need for management and performance benchmarks that are relevant for attainment of the Directorate's objectives. The project will focus on the need to develop the managerial aspect of the relations between the Directorate and the competent Ministry.

2.4 EXPLORATION LICENCES AND PRODUCTION LICENCES

2.4.1 New exploration licences

By year end 1993, a total of 214 exploration licences had been granted. Each licence is valid for three years. This is the breakdown of licences awarded in 1993:

Company	*Licence no.*
Amerada Hess Norge A/S	202
Amoco Norway Oil Company	203
Mobil Exploration Norway Inc	204
Esso Norge A/S	205
Norsk Hydro Produksjon a.s	206
Geoteam Exploration	207
Geco A/S	208
Institutt for kontinentalsokkelundersøkelser	209
Saga Petroleum a.s	210
Norske Fina A/S	211
Simon Petroleum Technology Ltd	212
Norsk Agip A/S	213
Compagnie Generale de Geophysique	214

2.4.2 Scientific exploration licences

As of 31 December 1993, a total of 276 licences had been granted for scientific exploration on the Norwegian continental shelf. As Table 2.4.2 shows, six such licences were granted in 1993.

2.4.3 New production licences

The fourteenth licensing round was announced on 19 June 1992 and advertised on 22 December 1992 by the Ministry of Petroleum and Energy (MPE), as it then was. Allocation of blocks took place on 10 September 1993. Of the 50 blocks or parts that were advertised, 25

Table 2.4.2
Permits for scientific exploration for natural resources

Permit	Institution	Subject: Geophysics	Subject: Geology	Subject: Biology	Area
271/93	Universitetet i Tromsø	X			Balsfjord
272/93	Norges geologiske undersøkelse	X			North Sea
273/93	Ocean Drilling Program Texas A&M University		X		Sea areas around Svalbard
274/93	Universitetet i Tromsø	X	X		Western Barents Sea/northeastern Norwegian Sea and sea areas north of Svalbard
275/93	Universitetet i Tromsø	X	X		Estuary of Tana river/Tana fjord
276/93	Universitetet i Oslo	X	X		Areas off Kragerø, Risør, Lyngør and areas in outer Oslo fjord

Fig. 2.4.3
Exploration wells drilled in each licensing round

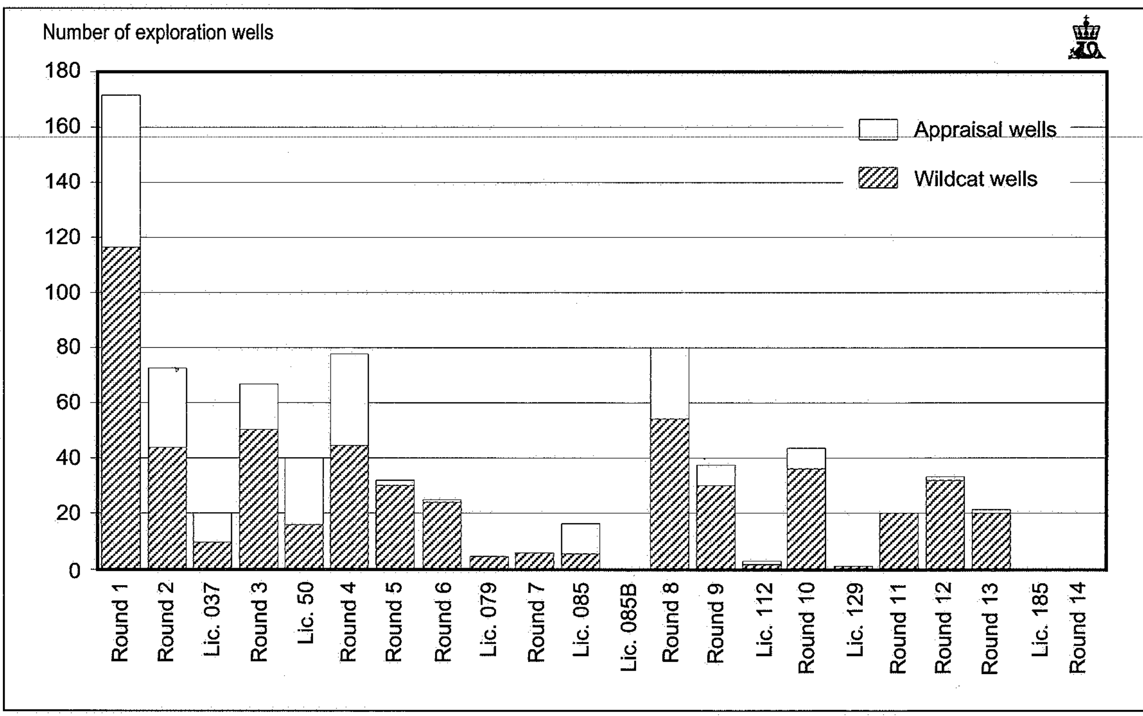


Table 2.4.3.a
Production licenses allocated in the 14th licensing round

License no.	Field/block	Share		Licensee (O = operator)
186	7/10, 7/11	25.000	O	Amoco Norway A/S
		10.000		Saga Petroleum a.s.
		50.000		Den norske stats oljeselskap a.s
		15.000		Total Norge A/S
187	15/2, 15/3	25.000	O	Amoco Norway A/S
		20.000		Norsk Hydro Produksjon a.s
		55.000		Den norske stats oljeselskap a.s
188	17/3	15.000		Amerada Hess Norge A/S
		40.000		Den norske stats oljeselskap a.s
		25.000	O	Elf Petroleum Norge AS
		20,000		Norsk Agip A/S
189	25/8, 25/9	20.000	O	Amerada Hess Norge A/S
		55.000		Den norske stats oljeselskap a.s
		15.000		Phillips Petroleum Norsk A/S
		10.000		Saga Petroleum a.s.
190	30/8	65.000		Den norske stats oljeselskap a.s
		10.000		Enterprise Oil Norwegian A/S
		25.000	O	Norsk Hydro Produksjon a.s
191	31/1, 31/2, 31/4, 31/5	60.000		Den norske stats oljeselskap a.s
		10.000		Mobil Development Norway A/S
		10.000		Neste Petroleum A/S
		20.000	O	Norsk Hydro Produksjon a.s
192	34/5	20.000		Norske Conoco A/S
		55.000		Den norske stats oljeselskap a.s
		25.000	O	Mobil Development Norway A/S
193	34/11	15.000		BP Petroleum Dev. of Norway AS
		65.000	O	Den norske stats oljeselskap a.s
		20.000		Norsk Hydro Produksjon a.s
194	35/4, 35/5	55.000		Den norske stats oljeselskap a.s
		10.000		Elf Petroleum Norge AS
		25.000	O	Norsk Hydro Produksjon a.s
		10.000		Saga Petroleum a.s.
195	35/8	25.000	O	BP Petroleum Dev. of Norway AS
		15.000		Norske Conoco A/S
		45.000		Den norske stats oljeselskap a.s
		15.000		Norsk Hydro Produksjon a.s
196	35/6, 36/4	25.000	O	BP Petroleum Dev. of Norway AS
		45.000		Den norske stats oljeselskap a.s
		10.000		Idemitsu Petroleum Norge a.s.
		20.000		Norsk Hydro Produksjon A/S
197	6306/2, 6306/5	15.000		Amerada Hess Norge A/S
		15.000		Amoco Norway A/S
		45.000		Den norske stats oljeselskap a.s
		25.000	O	Norske Conoco A/S
198	6306/6	65.000	O	Den norske stats oljeselskap a.s
		15.000		Elf Petroleum Norge AS
		20.000		Norsk Hydro Produksjon a.s
199	6406/2	60.000		Den norske stats oljeselskap a.s
		15.000		Mobil Development Norway A/S
		25.000	O	Saga Petroleum a.s.
200	6608/7, 6608/8	65.000	O	Den norske stats oljeselskap a.s
		15.000		Neste Petroleum A/S
		20.000		Phillips Petroleum Norsk A/S
201	7018/3, 7019/1	40.000		Den norske stats oljeselskap a.s
		20.000		Enterprise Oil Norwegian A/S
		10.000		Neste Petroleum A/S
		30.000	O	Norsk Agip A/S
202	7227/11, 7227/12, 7228/7, 7228/10	25.000		Amerada Hess Norge A/S
		55.000	O	Den norske stats oljeselskap a.s
		20.000		Saga Petroleum a.s.

Table 2.4.3.b
Production licenses and acreages as of 31.12.1993

Lic. round	Allocated	Prod. lic. no.	No. of blocks* allo-cated	No. of blocks* re-linquished	Area allocated km²	Area relinquished km²	Area in license km²
1.	1.9.1965	001–021	74	58	39842.476	35946.84	3895.636
	7.12.1965	022	4	4	2263.565	2263.565	
	12.9.1965	019B	2		617.891		617.891
2.	23.5.1969	023–031	9	1	4107.833	2233.366	1874.467
	30.5.1969	032–033	2		746.285	376.906	369.379
	14.11.1969	034–035	2		1024.529	564.837	459.692
	11.6.1971	036	1		523.937	262.047	261.89
plus.	10.8.1973	037	2		586.834	295.157	291.677
3.	1.4.1975	038–040 og 042	7	5	1840.547	1389.78	450.767
	1.6.1975	041	1	1	488.659	488.659	
	6.8.1976	043	2		604.558	555.553	49.005
	27.8.1976	044	1		193.076	90.417	102.659
	3.12.1976	045–046	4	2	1270.682	814.708	455.974
	7.01.1977	047	2	2	368.363	368.363	
	18.2.1977	048	2	1	321.5	203.498	118.002
	23.12.1977	049	1	1	485.802	485.802	
plus.	16.6.1978	050	1		500.509	151.962	348.547
4.	6.4.1979	051–058	8	2	4007.887	2434.633	1573.254
5.	18.1.1980	059–061	3	3	1108.078	1108.078	
	27.3.1981	062–064	3	1	1099.522	867.542	231.98
	23.4.1982	073–078	6	2	2311.912	1751.343	560.569
6.	21.8.1981	065–072	9	3	3218.945	2149.358	1069.587
plus.	20.8.1982	079	1		102.167		102.167
7.	10.12.1982	080–084	5	5	2082.966	2082.966	
plus.	8.7.1983	085	3		1521.16	725.816	795.344
plus.	11.9.1992	085B	2		27.166		27.166
8.	9.3.1984	086–100	17	2	6338.273	2948.467	3389.806
9.	1.3.1985	101–111	13	1	5293.054	2905.553	2387.501
plus.	26.7.1985	112	1		260.215	129.958	130.257
10a	23.8.1985	113–120	9	2	3075.433	2260.563	814.87
10b	28.2.1986	121–128	9	3	3828.258	1699.343	2128.915
plus.	11.7.1986	129	1		225.393	119.417	105.976
11.	10.4.1987	130–137	11	7	4163.711	3335.546	828.165
	29.5.1987	138–142	11	7	2975.807	2370.757	605.05
12a	8.7.1988	143–153	16		4701.021		4701.021
12b	9.3.1989	154–162	13	7	5031.262	2312.12	2719.142
13.	1.3.1991	163–184	36	2	12076.889	650.352	11426.537
plus.	13.9.1991	185	1		25.535		25.535
14.	10.9.1993	186–202	31		10509.919		10509.919
			326	122	129771.619	76343.272	53428.347

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

were in the North Sea, 13 in the Norwegian Sea and twelve in the Barents Sea.

A total of 17 production licences were awarded, comprising 31 blocks. Of these, eleven production licences comprising 19 blocks were awarded in the North Sea, four production licences comprising six blocks were awarded in the Norwegian Sea, and two

Table 2.4.3.c
Licensing rounds. Norwegian and foreign shares as of 31.12.1993

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

production licences also comprising six blocks were awarded in the Barents Sea.

Ten applicants were awarded operatorships, the breakdown being four to Statoil, three to Norsk Hydro, two each to BP and Amoco; and one each to Agip, Saga Petroleum, Conoco, Mobil, Elf, and Amerada Hess. This was the first operatorship awarded to Amerada Hess in Norway.

Table 2.4.3.a shows production licences awarded in the fourteenth licensing round.

Table 2.4.3.b shows the production licences and acreages, Table 2.4.3.c Norwegian and foreign shares in licensing rounds, and Figure 2.4.3 exploration wells drilled in each licensing round.

2.4.4 Transfer of interests

In the course of 1993, the following transfers of interests were approved in accordance with Section 61 of the Petroleum Act, no. 11 of 22 March 1985:

Production licence 070
Operator: Den norske stats oljeselskap a.s

With effect from 7 January 1993, Amoco Norway Oil Company took over a 7.350 per cent share from Mobil Development Norway A/S. The change resulted in the following equity distribution in the licence:

Amoco Norway Oil Company	7.350 %
Norske Conoco A/S	7.350 %
Norsk Hydro Produksjon a.s	24.500 %
Saga Petroleum a.s	9.800 %
Den norske stats oljeselskap a.s	51.000 %

Production licence 138
Operator: Total Norge A/S

Effective 29 May 1993, Total Norge A/S and Amerada Hess Norge A/S took over a 15.000 per cent share from A/S Norske Shell. The change resulted in the following equity distribution in the licence:

Amerada Hess Norge A/S	8.000 %
Norsk Hydro Produksjon a.s	10.000 %
Den norske stats oljeselskap a.s	50.000 %
Total Norge A/S	32.000 %

Production licence 099
Operator: Den norske stats oljeselskap a.s

Effective 15 February 1993, Norsk Hydro Produksjon a.s took over 2.500 per cent from Norske Conoco A/S. The distribution in the production licence after this is as follows:

Norske Conoco A/S	7.500 %
Norsk Hydro Produksjon a.s	12.500 %
Den norske stats oljeselskap a.s	50.000 %
Total Norge A/S	30.000 %

Production licence 110
Operator: Den norske stats oljeselskap a.s

Effective 15 January 1993, Norsk Hydro Produksjon a.s and Amerada Hess Norge A/S took over shares of 6.760 per cent and 3.330 per cent, respectively, from Norske Conoco A/S. The change resulted in the following equity distribution in the production licence:

Amerada Hess Norge A/S	8.330 %
Elf Petroleum Norge A/S	20.000 %
Norske Fina A/S	5.000 %
Norsk Hydro Produksjon a.s	16.670 %
Den norske stats oljeselskap a.s	50.000 %

Production licence 135

Effective 10 April 1993, Amerada Hess Norge A/S took over shares from Total Norge A/S and Neste Petroleum A/S, each of 15.000 per cent, in production licence 135, as the licence entered the 30-year period. The change resulted in the following new equity distribution in the production licence:

Amerada Hess Norge A/S	35.000 %
Saga Petroleum a.s	15.000 %
Den norske stats oljeselskap a.s	50.000 %

Effective 1 April 1993, Total Norge A/S took over entire shares or parts thereof in five production licences from Norske Conoco A/S, Conoco Petroleum Norge A/S, and Conoco Norway Inc. The production licences are 054, 073, 094, 099, and 134.

Production licence 054

Operator: A/S Norske Shell

The change resulted in the following new equity distribution in the production licence:

Norske Conoco A/S	5.19052 %
Elf Petroleum Norge AS	3.10500 %
Norsk Hydro Produksjon a.s	4.90000 %
A/S Norske Shell	25.90000 %
Den norske stats oljeselskap a.s	58.80000 %
Total Norge A/S	2.10448 %

This results in Total Norge A/S's share in the unitised Troll field increasing by 0.35343 per cent. The field as unitised comprises parts of production licences 054 and 085 in block 31/2, 31/3, 31/5, and 31/6. The present distribution in the unitised Troll field is as follows:

Norske Conoco A/S	1.66157 %
Elf Petroleum Norge A/S	2.35300 %
Norsk Hydro Produksjon a.s	7.68800 %
Saga Petroleum a.s	4.08000 %
A/S Norske Shell	8.28800 %
Den norske stats oljeselskap a.s	74.57600 %
Total Norge A/S	1.35343 %

Production licence 073

Operator: Den norske stats oljeselskap a.s

The new equity distribution in the field after this is as follows:

Amoco Norway A/S	20.000 %
Norsk Hydro Produksjon a.s	10.000 %
Den norske stats oljeselskap a.s	50.000 %
Total Norge A/S	20.000 %

Production licence 094

Operator: Den norske stats oljeselskap a.s

The change resulted in the following new equity distribution in the production licence:

Norsk Agip A/S	9.800 %
Norsk Hydro Produksjon a.s	4.900 %
Mobil Development Norway A/S	14.700 %
Neste Petroleum A/S	9.800 %
Den norske stats oljeselskap a.s	51.000 %
Total Norge A/S	9.800 %

This transfer also applies to a 9.800 per cent share in the fields Smørbukk and Smørbukk Sør.

Production licence 099

Operator: Den norske stats oljeselskap

The change resulted in the following new equity distribution in the production licence:

Norsk Hydro Produksjon a.s	12.500 %
Den norske stats oljeselskap a.s	50.000 %
Total Norge A/S	37.500 %

This transfer also applies to the Snøhvit discovery.

Production licence 134

Operator: Den norske stats oljeselskap a.s

The change resulted in the following new equity distribution in the production licence:

Norsk Agip A/S	30.000 %
Enterprise Oil Norwegian A/S	10.000 %
Den norske stats oljeselskap a.s	50.000 %
Total Norge A/S	10.000 %

Production licence 150

Operator: Norske Fina A/S

Effective 3 June 1993, Norske Fina A/S transferred 20 per cent of its 30 per cent share to Enterprise Oil Norwegian A/S. The distribution in the production licence after this is as follows:

Enterprise Oil Norwegian A/S	30.000 %
Norske Fina A/S	10.000 %
Saga Petroleum a.s	10.000 %
Den norske stats oljeselskap a.s	50.000 %

Production licence 066

Operator: Saga Petroleum a.s

Effective 25 January 1993, Saga Petroleum a.s took over a 10.000 per cent share in this licence from Norsk Hydro Produksjon a.s. The change resulted in the following new equity distribution in the production licence:

Mobil Development Norway A/S	28.600 %
Saga Petroleum a.s	21.400 %
Den norske stats oljeselskap a.s	50.000 %

Effective 8 December 1993, Saga Petroleum a.s took over a 28.600 per cent share in this licence from Mobil

Table 2.4.5
Relinquishments

Prod. lic.	Operator	Block	Original area km²	Relinquished area km²	Area in license km²
047	Hydro	33/5	64.203	64.203	0.000
048	Hydro	15/5	214.481	96.479	118.002
061	Hydro	7120/12	109.403	109.403	0.000
106	Statoil	6407/4	204.474	204.474	0.000
108	Shell	7120/4	160.621	80.543	80.078
120	Hydro	34/7, 34/8	546.309	274.705	271.604
127	Elf	6607/12	419.895	209.560	210.335
130	Statoil	6201/11	478.061	478.061	0.000
132	Hydro	6407/10	452.564	380.440	72.124
135	Saga	7124/3, 7125/1	646.039	326.328	319.711
136	Hydro	7219/9, 7220/7	628.935	628.935	0.000
138	Total	7122/6	327.333	234.567	92.766
139	Statoil	7226/8, 7226/9, 7226/11	947.638	947.638	0.000
155	Shell	6306/10	468.712	468.712	0.000
160	Mobil	7228/1, 7228/2	610.600	610.600	0.000
161	Hydro	7228/8, 7228/9	628.856	628.856	0.000
178	Esso	7122/1, 7122/4	650.352	650.352	0.000

Development A/S. The change resulted in the following equity distribution in the production licence:

Saga Petroleum a.s	50.000 %
Den norske stats oljeselskap a.s	50.000 %

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

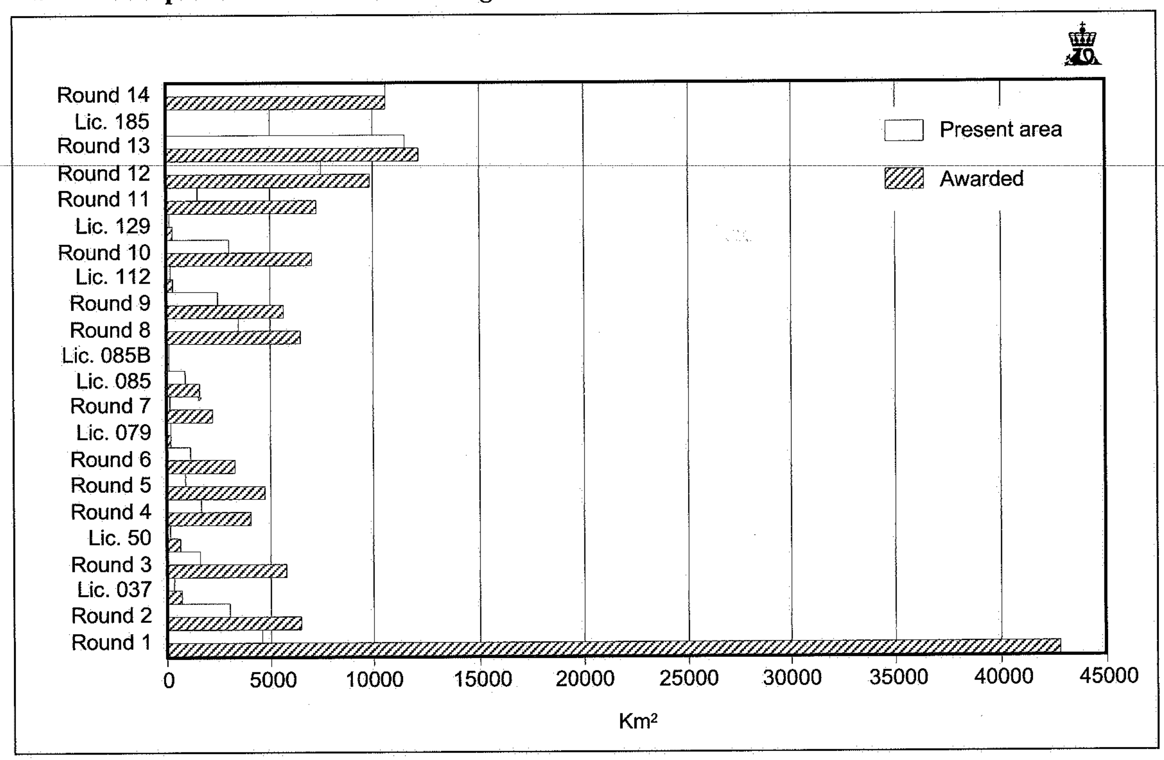
Effective 1 July 1993, Den norske stats oljeselskap a.s took over the operatorship for production licence 121 from Mobil Development Norway A/S.

With effect from 6 July 1993, Saga Petroleum a.s acquired 100 per cent of the shares in DNO Olje A/S, which holds equity in six production licences: 086, comprising the fields Tordis, Snorre, Vigdis, and Statfjord Øst; and 100, 104, 115, 151, and 158. DNO Olje A/S will not be merged with Saga Petroleum a.s, but will retain its status as a fully owned subsidiary.

With effect from 21 December 1992, Norminol A/S became a fully owned subsidiary of Saga Petroleum a.s. Norminol holds shares in the following five production licences: 008, 009, 016, 018, and 124.

By letter of 13 December 1993, the Ministry of Industry and Energy authorised Den norske stats oljesel-

Fig. 2.4.5
Awarded and present areas in each licensing round



skap a.s to convey 10.000 per cent of its shares in production licences 055 and 185 to Norsk Hydro Produksjon a.s; and Norsk Hydro to convey its 10.000 per cent share in production licence 124 to Den norske stats oljeselskap a.s. Norsk Hydro also conveyed its 1.250 per cent unit in the unitised Heidrun field to Den norske stats oljeselskap a.s. The unitised Heidrun field comprises parts of production licences 095 and 124 in blocks 6507/7 and 6507/8.

Production licence 055
Operator: Norsk Hydro Produksjon a.s

The change resulted in the following new equity distribution in the production licence:

Esso Norge A/S	17.600 %
Neste Petroleum A/S	13.200 %
Norsk Hydro Produksjon a.s	23.200 %
Den norske stats oljeselskap a.s	46.000 %

Production licence 185
Operator: Norsk Hydro Produksjon a.s

The distribution in the production licence after this is as follows:

Esso Norge A/S	17.600 %
Neste Petroleum A/S	13.200 %
Norsk Hydro Produksjon a.s	23.200 %
Den norske stats oljeselskap a.s	46.000 %

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

The change resulted in the following new equity distribution in the production licence:

Norske Conoco A/S	15.000 %
Conoco Petroleum Norge A/S	10.000 %
Neste Petroleum A/S	10.000 %
Norminol A/S	5.000 %
Den norske stats oljeselskap a.s	60.000 %

Production licences 095 and 124 (unitised Heidrun field)
Operator: Norske Conoco A/S

The distribution in the unitised Heidrun field after this is as follows:

Norske Conoco A/S	18.125 %
Neste Petroleum A/S	5.000 %
Norminol A/S	0.625 %
Den norske stats oljeselskap a.s	76.250 %

With effect from 8 December 1993, Esso Exploration and Production Norway Inc merged with Esso Exploration and Production Norway A/S. The former corporation is being wound up, and therefore all of its shares in production licences 001, 027, 028, 029, and 030 are being taken over by the Norwegian firm. The latter has also taken over all the shares held by Esso Norge A/S in production licences 122, 149, 151, 165, 169, 174, 178, 179, and 185.

Fig. 2.5.1
Seismic surveys on the Norwegian continental shelf 1962–1993

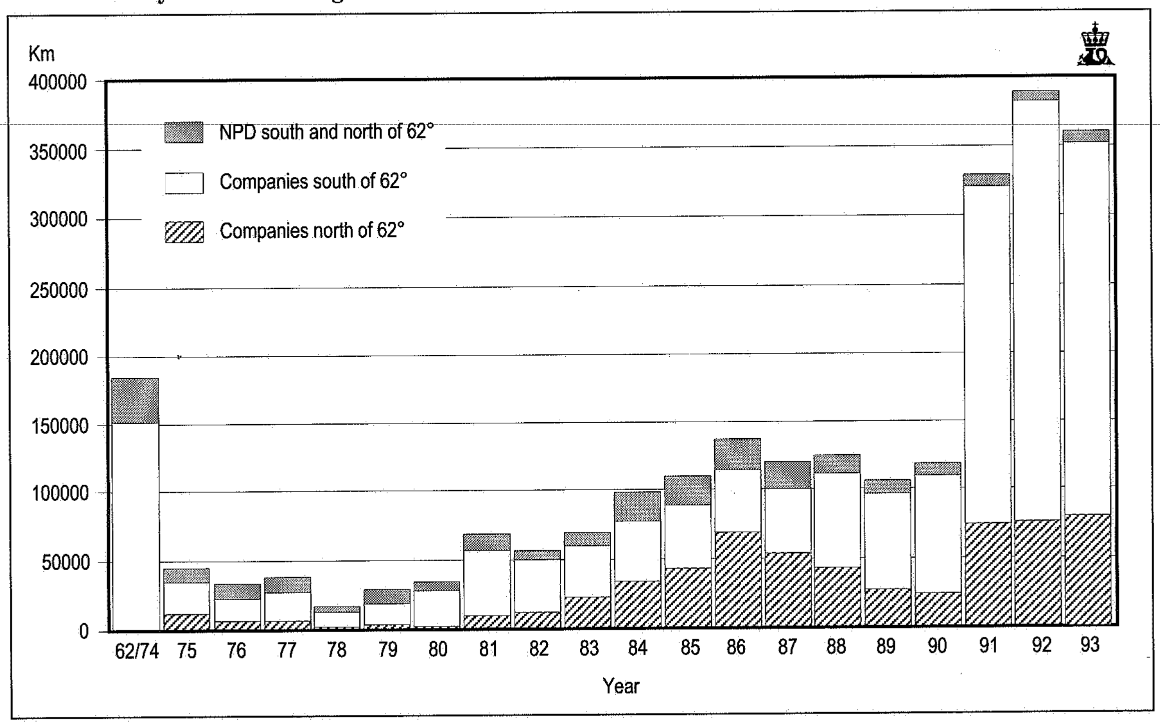
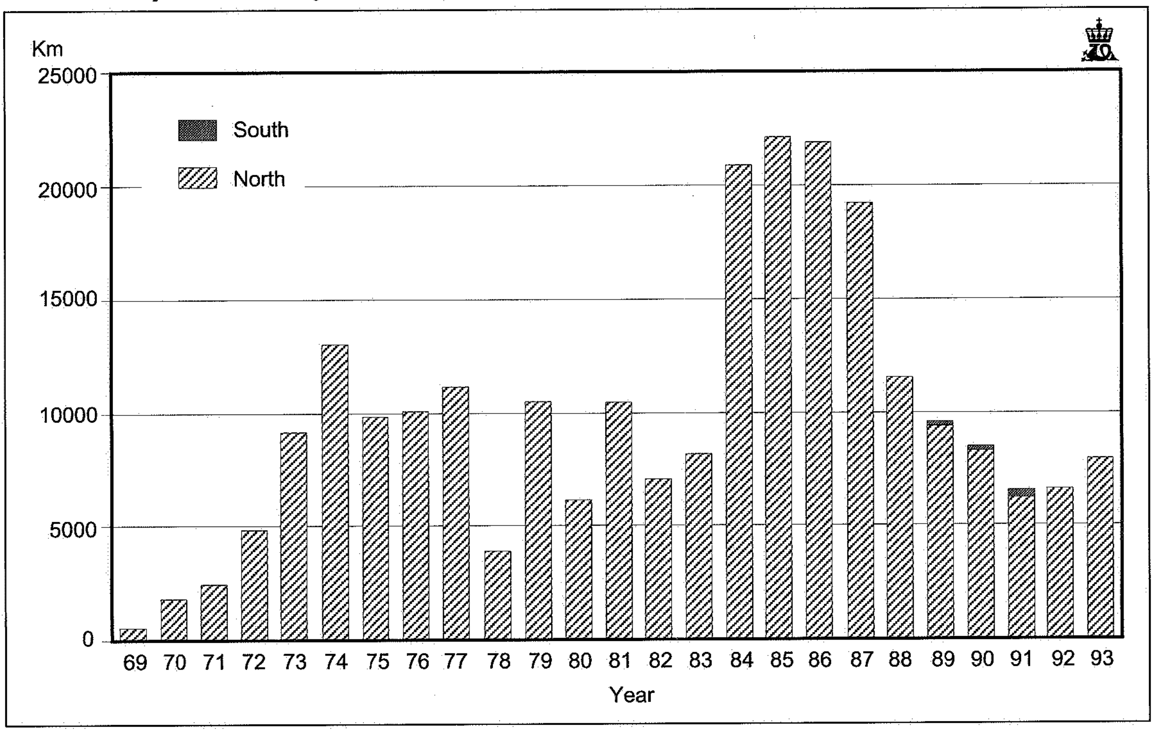


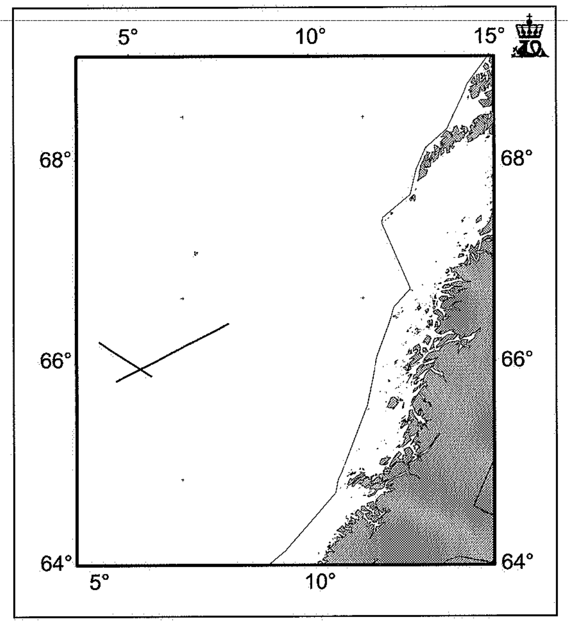
Fig. 2.5.1.1.a
Seismic surveys conducted by the Norwegian Petroleum Directorate



2.4.5 Relinquishments and surrenders

Relinquishment or surrender of acreage occurred in 17 production licences in 1993. In ten cases the entire area was relinquished. See Table 2.4.5 for details. The originally allocated and present acreages are shown in Figure 2.4.5.

Fig. 2.5.1.1.b
Geophysical surveys in the Norwegian Sea



2.5 SURVEYS AND EXPLORATION DRILLING

2.5.1 Geophysical and geological surveys

Some 360,728 kilometres of seismics were shot on the Norwegian continental shelf in 1993. The number of kilometres refers to the total line kilometres. Figure 2.5.1 shows the development in recent years based on the number of line kilometres compiled.

2.5.1.1 Directorate's geophysical surveys in 1993

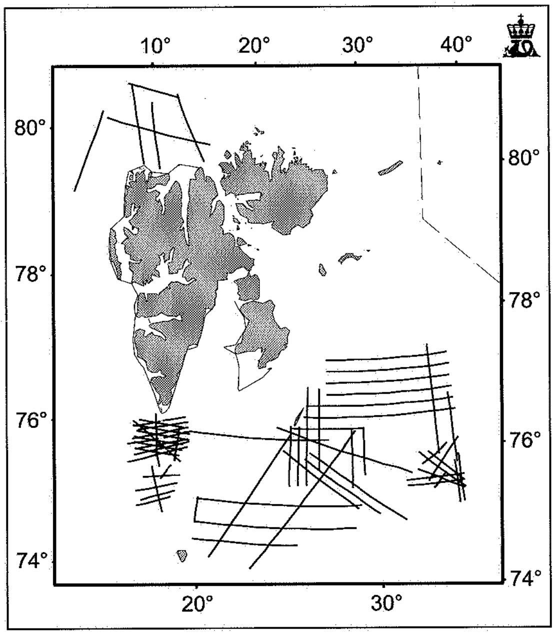
The Directorate commissioned 8083 km of seismic lines in 1993, see Figure 2.5.1.1.a; and also 231 km of shallow seismic lines. Data were collected from the areas indicated in Figures 2.5.1.1.b and c.

Test lines

Two test lines totalling 209 km were acquired in the Vøring basin II (Figure 2.5.1.1.c). Data were shot in October using the vessel *Ocean Explorer*. Due to the great water depth and sediment thickness two long cables (5100 metres) and long record length (12 seconds) were used. The purpose of these test lines was mainly to improve the deep data in an area with severe noise problems. The data will be processed in 1994.

In connection with the surveys in the northern Barents Sea, the plan was to acquire refraction data by means of measuring equipment on the seabed. In the event, however, the project had to be cancelled due to severe weather. In order to test the method, a set of data was later acquired in the Tordis field in the North Sea, using three-component geophones on the seabed.

Fig. 2.5.1.1.c
Geophysical surveys in the Barents Sea



The project was carried out in cooperation with Saga Petroleum and Read Well Services.

Barents Sea
It was planned to acquire a great deal of shallow seismic in Nordflaket as a preliminary study for shallow stratigraphic drilling operations in this area. The vessel *Sea Searcher* from Gardline was chosen for the purpose. Due to extremely difficult ice conditions it proved impossible to enter the area in question within the time permitted, and therefore only a few test lines totalling 184 km were acquired around Bear Island.

Deep seismic were acquired using two vessels from PGS, specifically *Ocean Explorer* from Geoteam Exploration and *Master Odin* from Geoteam AS.

Master Odin shot 3128 km of seismic in August-September, of which 776 km in Moffenflaket north of Spitzbergen, 1467 km at Storbanken, and 885 km in Sentralbanken. A wide source array and a 3000 metre long cable were used. The ice conditions were reasonably benign in Moffenflaket this year, but the survey did not succeed in reaching as far north as planned in Storbanken. The data from Moffenflaket, Storbanken, and Sentralbanken are being processed by Ensign, Digital, and Geoteam AS, respectively.

Ocean Explorer is a more advanced vessel, and several acquisition techniques were used. Initially, 47 km of shallow seismic was shot in the southern part of Nordflaket. Subsequently 1627 km of seismic was shot in Nordflaket using two long cables (4050 metres long, 100 metres horizontally apart) in an array with a shorter (1050 metre), shallower cable in the middle.

The data are being processed by Spectrum and Geco-Prakla. The shallow seismic is being processed by Spectrum.

Two 318 km lines were shot through Nordflaket and Spitsbergenbanken using a long cable of 5100 metres. Then 2801 km of seismic was shot in the most complicated areas in Spitsbergenbanken and Sentralbanken, using a wide and powerful source and four parallel cables each of 3000 metres and a total width of 300 metres.

Processing
The Directorate has finalized the processing of the data acquired in the course of 1992. A good deal of reprocessing of data from the northern Barents Sea was also performed. Major improvements have been achieved for some data from the mid 1970s. Some work has also been done on data from 1987–88, though here improved quality has been harder to achieve. Moreover, the data for large parts of the area are highly complex, and there still seems to be a need for reprocessing.

Gravimetric data
Gravimetric data were acquired in connection with seismic surveys in the Barents Sea. The data will be processed by Amarok a.s in 1994.

2.5.1.2 Companies' geophysical surveys
In 1993, some 352,645 line kilometres of seismic was shot on the Norwegian continental shelf under the direction of the oil companies and seismic acquisition contractors. Of the total shot, 318,838 km are 3D seismic surveys. Roughly 270,875 km were acquired in the North Sea and 81,770 km in the Norwegian Sea and the Barents Sea. As the figures show, the activity level in the North Sea decreased by some 37,029 km compared to 1992. The activity in the Norwegian Sea and the Barents Sea increased by 5546 km.

Norwegian oil companies shot some 179,528 line kilometres of seismics, which is a decrease of 28,541 km from the year before. Foreign companies shot 83,870 km, or 44,431 km less than in 1992.

A total of 89,247 line kilometres of commercial seismic was shot by Geco-Prakla, CGG, Geoteam Exploration, Simon, and Nopec, which is an increase of 41,463 km compared to the previous year.

2.5.1.3 Sale of seismic data
In 1993, the Directorate recorded income from the sale of seismic data packages amounting to Nkr 48.5 million (compare Nkr 37.0 million in 1992). For data packages, see Table 7.2.a.

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

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

Møre I
Agip, Amerada, Amoco, BP, Britoil, Conoco, Deminex, DNO, Elf, Enterprise, Esso, Fina, Hydro, Ide-

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

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

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

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

Vøring basin I
BP, Conoco, Elf, Esso, Hydro, Mobil, Phillips, Saga, Shell, Statoil, and Total.

Vøring basin II
Hydro, Saga, and Statoil.

Møre basin
Hydro and Saga.

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

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

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

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

Nordland V
BP, Conoco, Elf, Enterprise, Hydro, Mobil, Phillips, Saga, Shell, Statoil, and Total.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

2.5.1.4 Release of data and material from the continental shelf

In connection with resources supervision of the petroleum activities offshore Norway, the Directorate is supplied with copies of borehole logs and measurement data from all wells; plus continuous, representative samples of drill cuttings and cores. Cuttings samples are recovered every ten metres downhole and every three metres if the formation potentially contains hydrocarbons. For wet samples, which should weigh at least half a kilo, the same sampling frequency is observed. The Directorate receives a complete longitudinal section of core samples including minimum a quarter of cores in exploration wells and minimum half in development wells.

As of 31 December 1993, the Directorate had stocks totalling 82,143 metres of core material from 905 wells, 375,994 samples of washed cuttings from 1020 wells, and 445,822 wet samples from 1245 wells. This includes material from foreign wells, mainly from the UK sector of the North Sea, but also including Svalbard, Andøya, Hopen, Tanzania, and Mozambique.

The Directorate is responsible for the publishing of data and release of material specimens for purposes of education and research. Data are released five years after well completion, or in special cases after two years at the Directorate's discretion. The licensees' interpretations are not released.

The Directorate's *Well Data Summary Sheets* are issued once a year and provide a survey of wells five years old in the year of publication. The series aims to show which wells have been released and what core and log materials are available from the various holes. Some technical data and test results are also issued as well as a composite log with lithology specifications of each well to scale 1: 4000.

In addition to its WDSS summaries, the Directorate issues two publication series: *Licences, Areas, Area Coordinates, Exploration Wells* and *Borehole List, Exploration Drilling*, which also provide information on released material. Both are published annually.

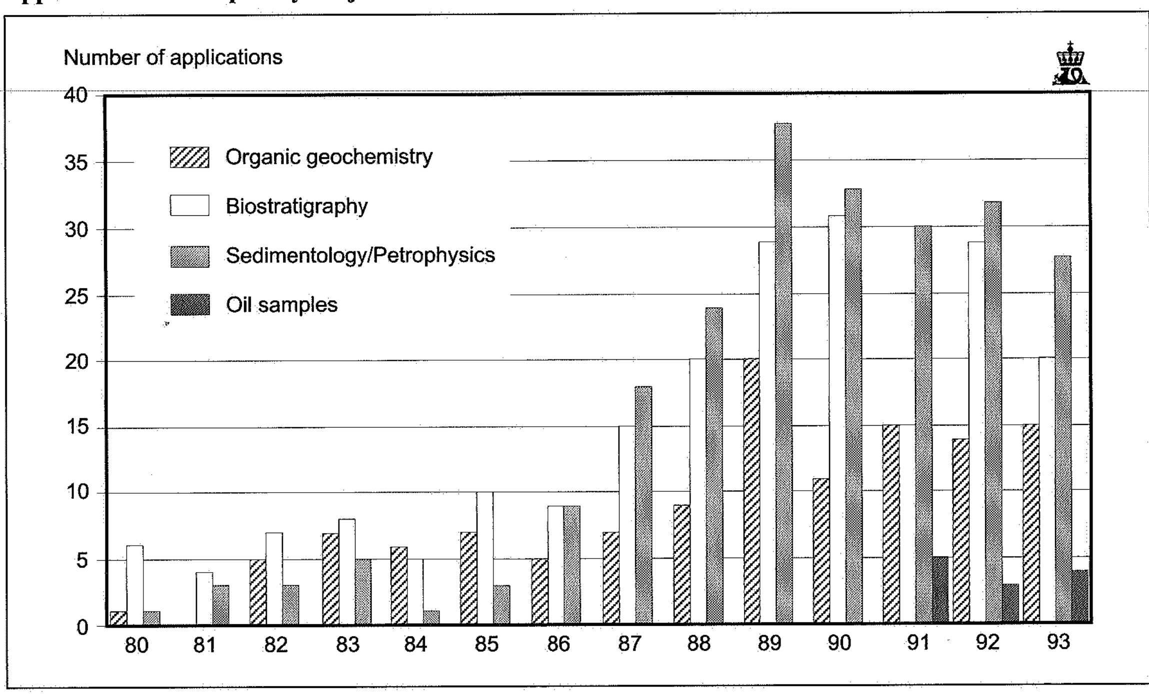
The list of production licences contains a summary of each production licence on the Norwegian continental shelf, stating licence number, allocation date, operator, allocated acreage, present acreage, licensees and their license share, geographical coordinates for area, some data about each well drilled in the production licence, and a map of each licence area with the exploration wells plotted in. Also included are some historical details and tables presenting the drilling activity.

The borehole list is an extended version of the Directorate's previous one. In it, exploration wells are sorted according to five different criteria: well number, spudding date, completion date, operator, and production licence number. Information of this type is also available in digital format.

Other digital correlations of released data are also available. Reference is made to the annual *Publications List* issued by the Directorate.

In the Directorate's core study room it is possible to examine the core materials, drill cuttings and wet samples, and in special cases permission may be granted to remove sediment samples and oil samples for study and analysis outside the confines of the Directorate. The five-year rule for release applies here also. In 1992, the Directorate introduced a fee for use of the core study room.

Fig. 2.5.1.4
Applications for samples by subject



As released samples often cannot be returned after use, the Directorate will evaluate the usefulness of the analysis and whether corresponding analyses have been carried out on the same material on earlier occasions before approving any release. Also if stocks drop to below a minimum level, an application for release may be denied. Applications for the release of geological samples should be addressed to the Release Committee at the Directorate. Applications are now considered three times a year, with submission deadlines on 1 April, 1 August, and 1 December.

In 1993, of the 67 applications considered, 15 were for organic geo-chemistry studies, 20 concerned bio-stratigraphy, 28 sought to examine sedimentology and petrophysics, and four targeted oil-condensate samples. All told, applications were received for the release of about 600 kg of sample material.

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

As of 31 December 1993, the Directorate had released a total of 206,765.937 line kilometres of seismics in 278 data packages. These are surveys performed by oil companies and other commercial enterprises. The released seismics included 247 packages in the North Sea and 31 packages in the Norwegian Sea. Table 7.2.b shows a list of released seismic data.

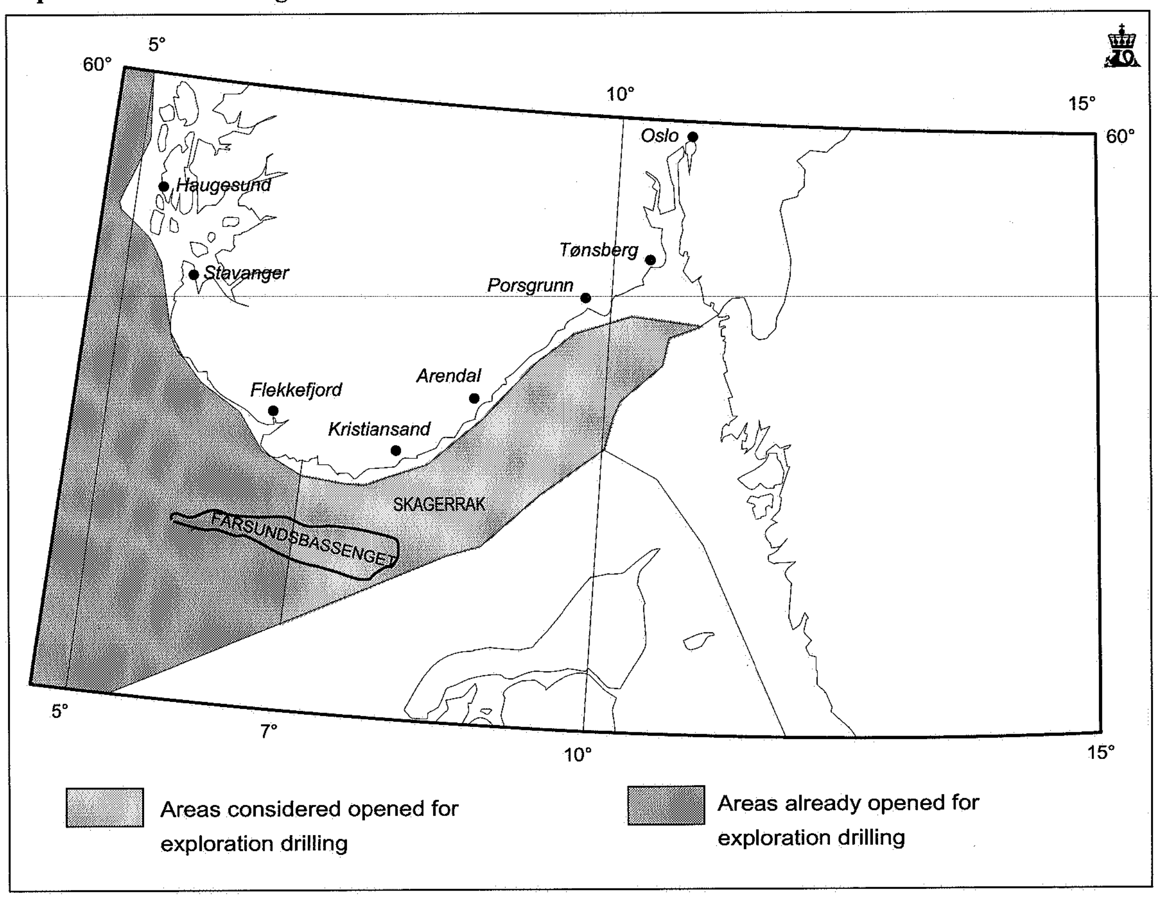
A list of the released surveys is found in *Released Seismic Surveys*, Volumes A and B. Volume A contains seismic survey packages for the North Sea, while Volume B contains packages for the Norwegian Sea.

2.5.2 Opening up of new areas for exploration

Under the guidance of the Ministry of Industry and Energy, in-depth studies of the environmental impact of exploration activities in hitherto unopened areas of the Norwegian Sea and the Skagerrak, and their consequences for natural resources and the community, were carried out. These consequence analyses are available to the public and were submitted for comments to various consultative bodies in September 1993. The areas in question are shown in Figures 2.5.2.a and b.

– North Sea	
Skagerrak east of 7°E	14,770 km^2
– Norwegian Sea	
Trøndelag I east	6,979 km^2
Nordland IV	15,436 km^2
Nordland V	5,723 km^2
Nordland VI	23,702 km^2

Fig. 2.5.2.a
Exploration areas in Skagerrak



Nordland VII	23,790 km²
Vøring basin I	41,338 km²
Vøring basin II	59,923 km²
Møre basin	39,403 km²

The Directorate has mapped the various areas based on available data and evaluated the geological evidence for petroleum potential in the areas. The three most important conditions that must be satisfied in order for hydrocarbons to be present are:

- Presence of a reservoir rock,
- Presence of a mature source rock that can generate hydrocarbons, and
- Presence of hydrocarbon traps that were formed at the right time and place in relation to the source rock location and time of maturity. A general account of the Directorate's findings is given below.

Skagerrak

The unopened area of Skagerrak lies east of 7° East. The area has been open to the industry for seismic surveys since the first licensing round. It is now covered by a seismic grid of between 2 x 2 to 4 x 4 kilometres

Fig. 2.5.2.b
Exploration areas in the Norwegian Sea

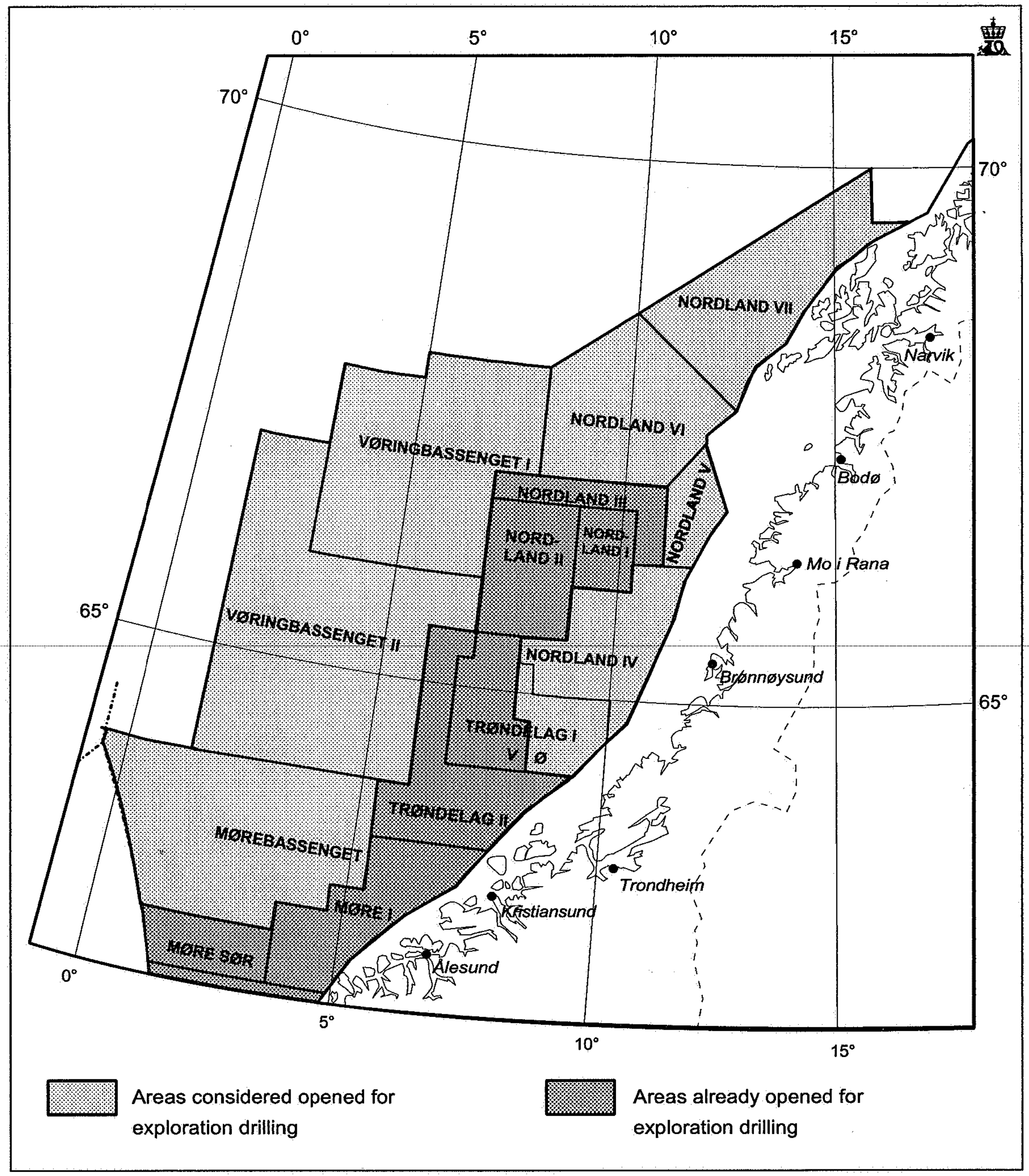
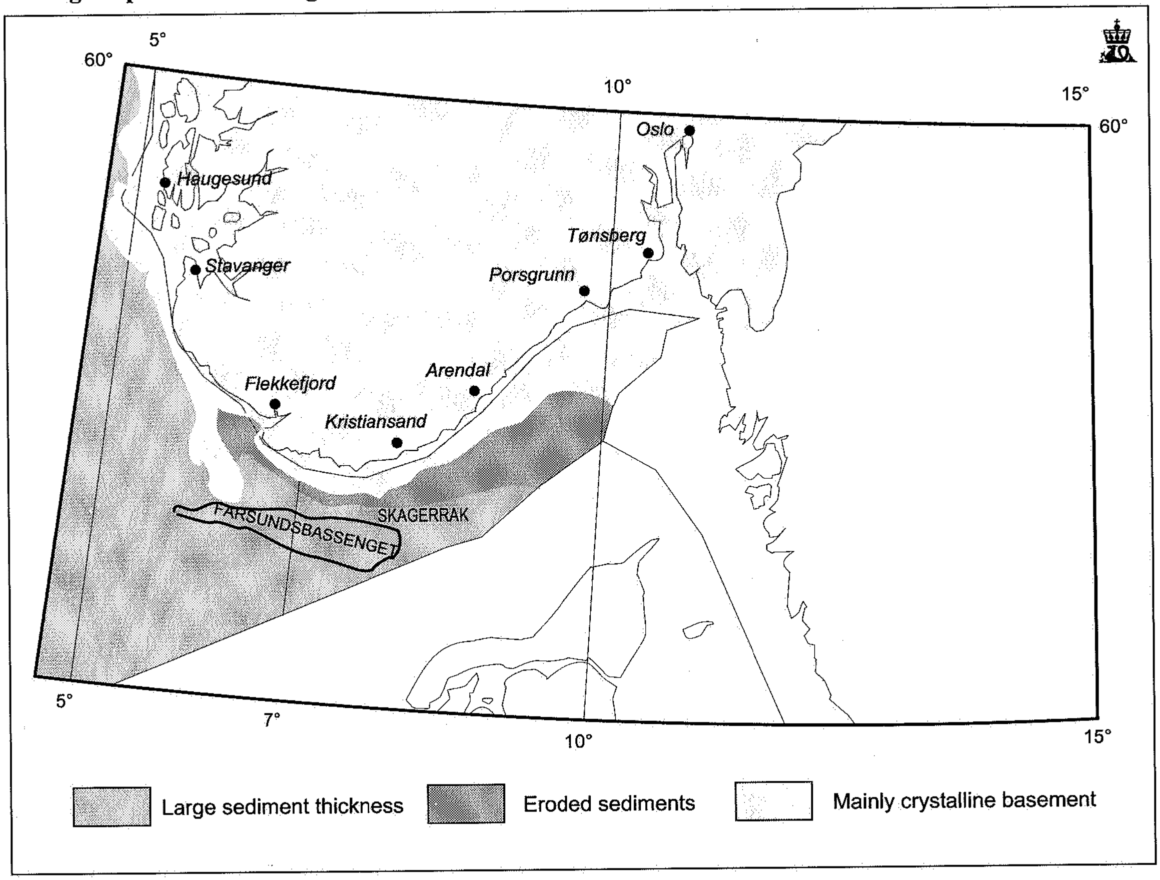


Fig. 2.5.2.c
Geological provinces in Skagerrak



west of Kristiansand and a grid of approx 10 x 10 kilometres further east. No exploration wells have been drilled within this area, but in the Danish sector four wells have been drilled 10–20 kilometres from the sector line between 7° and 9° East, although no discoveries have been made. In 1989, rock samples were taken in a shallow drilling programme covering four boreholes in the Norwegian sector, of which the deepest ran to 300 metres below the seabed. This programme was carried out by the Continental Shelf and Petroleum Technology Institute (IKU) and funded by several oil companies.

The unopened area can be divided into two geological main provinces: the coastal bedrock areas in the north, and the areas with unmetamorphosed sedimentary rocks in the south. In the northern province the crystalline underlying rocks extend right up to the seabed.

The southern province can be subdivided into two further zones: one in the northeast and one in the southwest. In the northeastern zone the sedimentary rocks are largely eroded, and the strata that are known to potentially contain hydrocarbons have partly disappeared. This, together with the inclination of the strata, increases the chances that possible hydrocarbons may have leaked out, but the area is never the less interesting with a view to finding oil or gas.

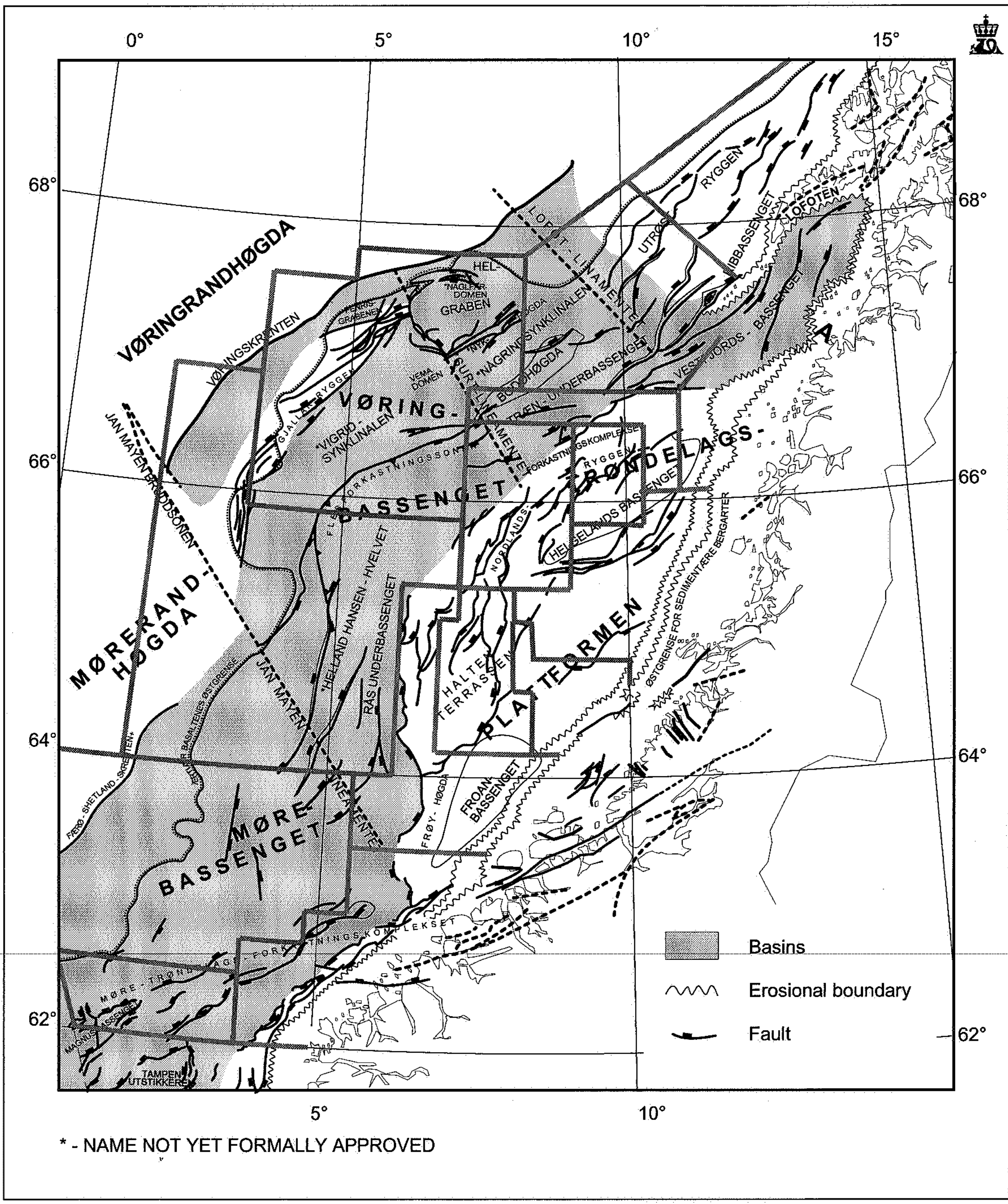
In the southwestern zone the erosion has not gone so deep (it decreases steadily from shore) and the most important rocks are present (Jurassic and Cretaceous). It is possible that the traditional plays from the rest of the North Sea can be used within this zone, too. The area that distinguishes itself as the most interesting at present is the flanks of the Farsund basin; see Figure 2.5.2.c. Chances are good that this basin contains a mature source rock that may have leaked hydrocarbons to surrounding structures.

Norwegian Sea

The analysed area consists of the sub-areas Trøndelag I (East), Nordland IV, Nordland V, Nordland VI, Nordland VII, Vøring basin I, Vøring basin II, and Møre basin; see Figure 2.5.2.b. All of this area is now open to the industry for seismic surveys. The eastern areas have the best coverage, while the three newly opened basin areas in the west are presently lagging behind. In the eastern areas Trøndelag I and Nordland IV and V, the IKU has been commissioned by the industry to carry out several sampling projects using shallow drilling excursions. Other than that, the geology here is reasonably well known from the various exploration wells in adjacent areas that have been opened up in this part of the shelf.

The IKU and the industry have also engaged in a

Fig. 2.5.2.d
Geological provinces in the Norwegian Sea



shallow drilling programme in Nordland VI and VII and in Vøring basin I. Also undertaken were high resolution, aero-magnetic surveys and surface geo-chemical surveys in the Vøring basin I under company direction. Earlier, scientific shallow boreholes had also been drilled in the western basin areas under projects for the international Ocean Drilling Programme and Deep Sea Drilling Programme. The exploration wells in the adjacent areas provide little information of value in the western basin, apart from the two wells in block 6607/5 called Bodøhøgda.

Broadly speaking, it is in a central zone between the mainland and the deep ocean areas that exploration activity is most attractive. This includes the areas that have already been opened and large parts of the areas studied in the consequence analysis. In the east there is a zone along the coast where the crystalline underlying rocks are virtually exposed at the seabed, which means any exploration drilling would be a fruitless enterprise; see Figure 2.5.2.d. In another parallel thin zone to the west the sedimentary rocks are inclined and deeply eroded, so that parts of the most important rocks have disappeared. This may have led any hydrocarbons to have leaked out already, but the possibility of striking hydrocarbons in this area cannot be wholly ruled out.

To the west of the Vøringrand and Mørerand ridges the area is limited by a geologically young ocean crust supporting a relatively thin layer of sediment. To the east and within the ocean crust lies a wide zone of laval origin superimposed on the limestone sediments. The lava rocks compromise the integrity of the seismic data and make seismic mapping of the underlying rocks difficult. Since it is the underlying rocks that are of most interest to reservoir geologists, new and improved data acquisition is required.

The areas that it is relevant to open up for exploration drilling can be divided into three geological provinces: an eastern province (Trøndelag I and Nordland IV and V), a northern province (Nordland VI and VII), and a western province (Vøring basin I and II and Møre basin).

In the eastern province the geology very much resembles what we find within the areas already opened up on Haltenbanken, where discoveries have been made. One important difference from the opened areas is that in the east the known source rock is less mature, except for the areas north in Nordland V. Future exploration activity in this area therefore depends very much on the identification of an older, deeper and better source rock that may have leaked hydrocarbons. There are certain indications that this may have happened, but it has not yet been clarified.

In the northern province a great deal of the most important rocks are deeply eroded in the west. The greatest sediment thicknesses are found along the shore parallel with the coast. This area is believed to have an interesting potential, and one expects to be able to use many of the same plays that have proved fruitful in the opened areas further south.

In the western province the geological conditions differ significantly from the other areas. This province consists of large basin areas with generally enormous thicknesses of limestone rocks. Exploration activities must largely rely on new and unproved plays. The area has a great, but uncertain potential. Various geological interpretations and models indicate that the most critical factor is the existence or non-existence of effective and mature source rocks in the area.

2.5.3 Exploration drilling

Of the eight exploration wells being drilled at the beginning of 1993, one was a reentry.

In 1993, 27 new exploration wells were spudded, of which 21 were wildcats and six appraisal wells. Drilling activity in 1993 comprised 19 exploration wells in the North Sea: 14 wildcats and five appraisal wells; six in the Norwegian Sea: four wildcats and two appraisal wells; and two in the Barents Sea, both of them wildcats. In addition, eight of the suspended exploration wells were reentered for further work. At year end 1993, eight exploration wells were in progress.

As of 31 December 1993, a total of 779 exploration wells had been spudded on the Norwegian continental

Fig. 2.5.3.a
Exploration wells drilled on the Norwegian continental shelf

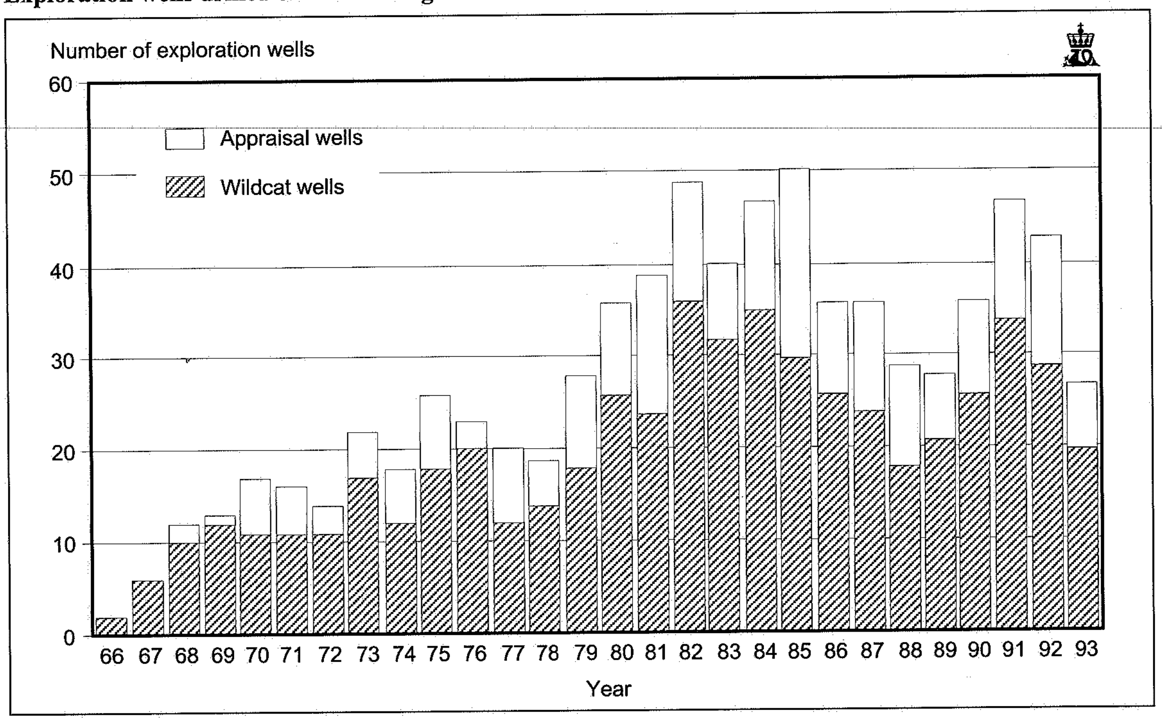
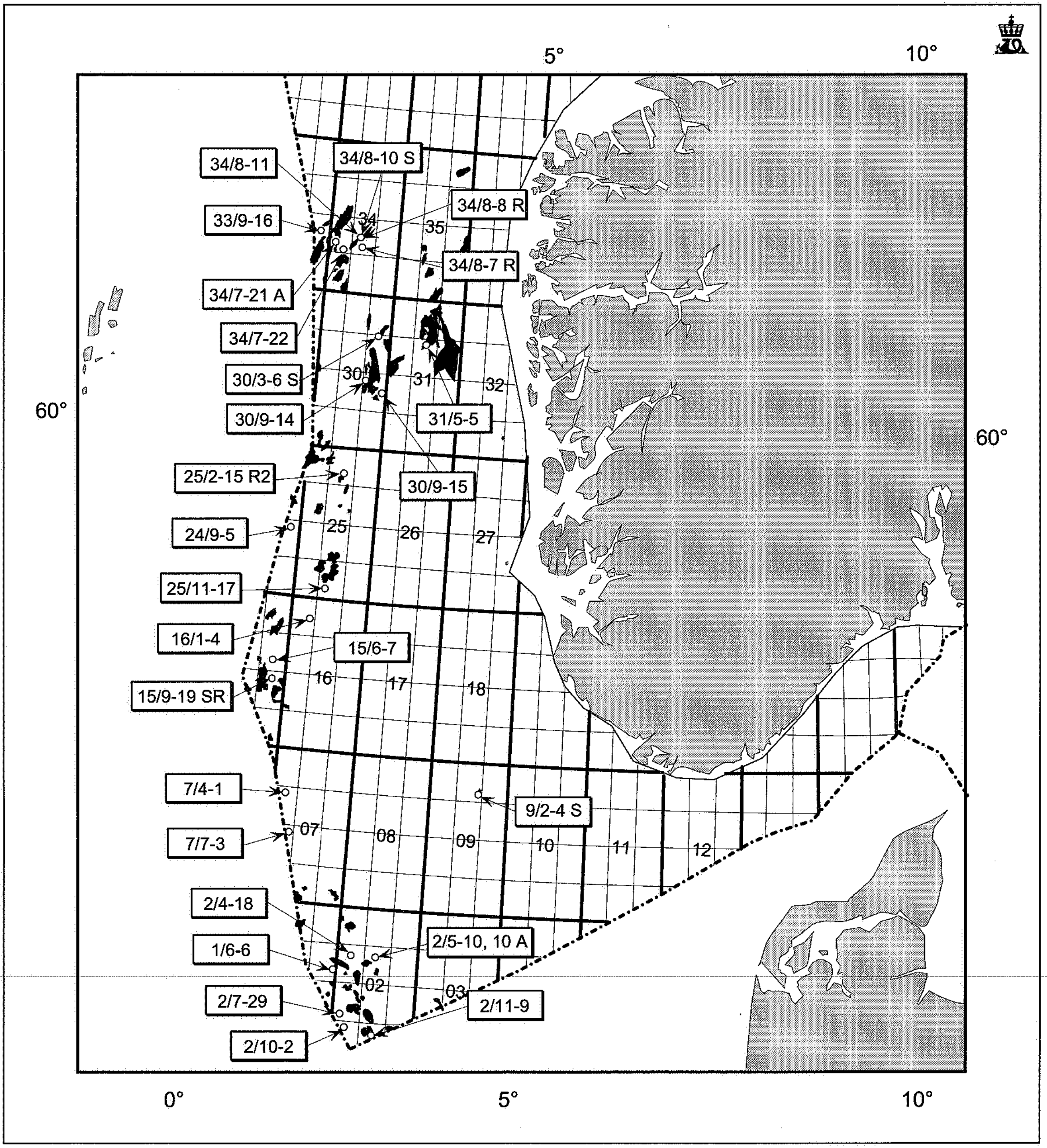


Fig. 2.5.3.b
Exploration wells drilled in the North Sea in 1993



shelf: 555 wildcats and 224 appraisal wells. See Figure 2.5.3.a. The Norwegian operators were responsible for 50.4 per cent of the total over the years.

In 1993, 26 exploration wells were completed on the Norwegian continental shelf: 18 wildcats and eight appraisal wells. The geographical distribution of the wells is as follows: 13 wildcats and six appraisal wells in the North Sea; four wildcats and two appraisal wells in the Norwegian Sea; and one wildcat in the Barents Sea.

The operators for the completed drilling operations were as follows: Statoil eight, Norsk Hydro five, Saga Petroleum four, Shell two, Agip two, and Elf, Amoco, Conoco, Mobil, and Deminex one each.

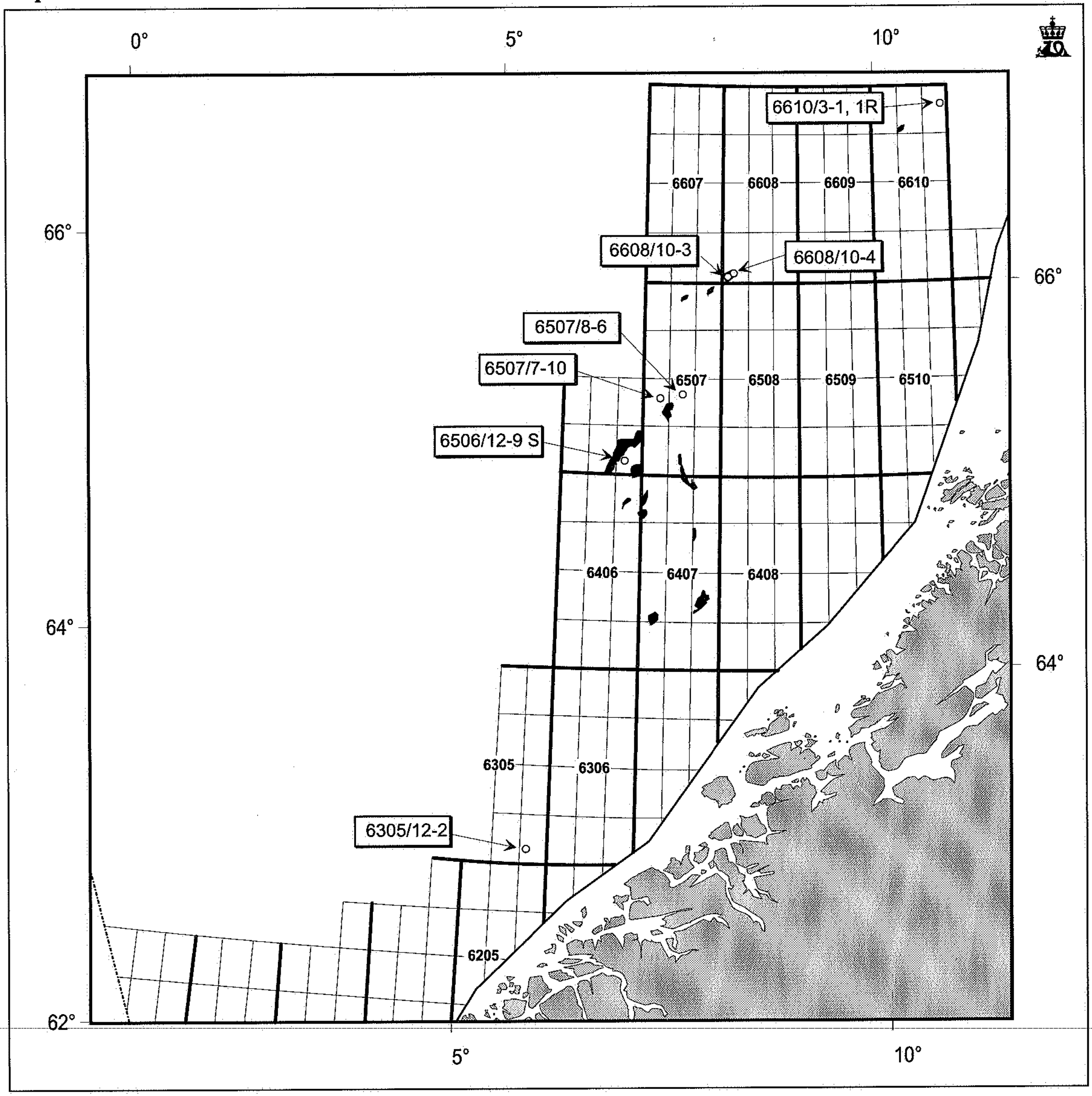
As of 31 December 1993, 771 exploration wells had been completed or suspended on the Norwegian continental shelf, comprising 549 wildcats and 222 appraisal wells.

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

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

Suspended exploration wells on the Norwegian

Fig. 2.5.3.c
Exploration wells drilled in the Norwegian Sea in 1992



continental shelf for which equipment has been installed on the seabed are as follows:

2/01–09A	25/02–13	31/02–16SR
2/04–15S	25/04–06S	31/02–18A
2/04–17	25/05–04	31/05–04AR
2/04–18	25/11–16	31/05–05
2/07–20R	30/02–01	34/04–07
2/07–21SR	30/03–04	34/07–16R
2/07–23S	30/06–19	34/07–19
2/07–25S	30/06–21	34/08–04A
2/10–02	30/06–22	34/10–34
2/12–02S	30/09–07	6407/07–02R
7/11–10SR	30/09–08R	6407/07–04
7/12–08	30/09–09	6506/12–08
7/12–09	30/09–10	6507/08–04
15/09–19SR	30/09–12A	6608/10–03
15/12–06S	30/09–13S	
15/12–09S		

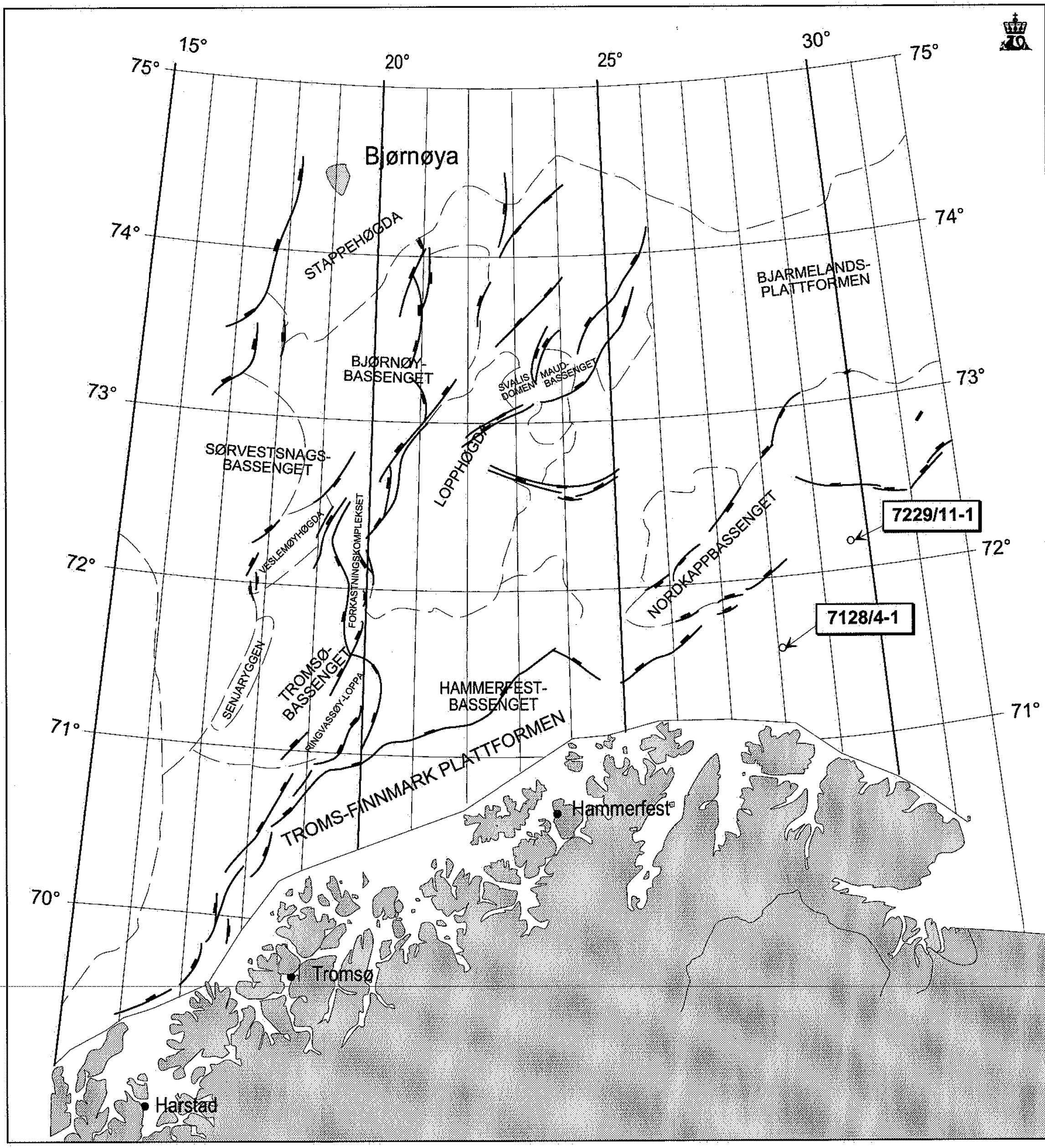
Figures 2.5.3.b, c and d show the wells being drilled in the three provinces of the Norwegian continental shelf (North Sea, Norwegian Sea and Barents Sea) in 1993.

The Norwegian companies Statoil, Norsk Hydro and Saga Petroleum operated 19 of the spudded wells, corresponding to 70 per cent. The remaining eight wells were operated by Agip, Shell, Amoco, Conoco, BP, Fina, and Deminex. See Table 7.3.c for details.

2.5.3.1 Distribution of prospect types

Exploration activity in 1993 was very largely targeted at Jurassic sandstone prospects. Of the 27 exploration wells spudded, 21 had Jurassic strata as their main prospect. Of the other main prospects, two were in Cretaceous, one in Triassic, two in Permian, and one in Devonian strata.

Fig. 2.5.3.d
Exploration wells drilled in the Barents Sea in 1993



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

2.5.3.2 New discoveries in 1993

Of the exploration wells completed in 1993, three were confirmed through production testing. There were also hydrocarbon shows in 2/7–29 and 30/9–15, though it was decided not to run production tests on these wells due to the quality of the reservoir and anticipated volume. The last two drilling operations had not been completed by year end.

Exploration well	*Operator*	*Hydrocarbons*
15/9–19SR	Statoil	Oil
34/7–22	Saga Petroleum	Oil
34/8–7R	Norsk Hydro	Gas

Block 15/9

Statoil as operator of production licence 046, parts of blocks 15/8 and 15/9, drilled the 15/9–19SR wildcat into a structure west of the Loke field and made a new discovery. The well was drilled to a vertical depth of 3108 metres below sea level and terminated in Triassic rocks. Oil was found in Early Jurassic sandstones, and the well was production tested. The peak measured production rate was 1340 scm oil a day with a gas-oil ratio (GOR) of 100. The choke size was 22.7 mm, and measured oil density was 0.87 g/cc. The resources estimate for this discovery is 4.6 mcm oil and 0.7 bcm gas.

The drilling results are encouraging for further exploration in the Jurassic level in the area.

Block 34/7

Saga Petroleum, as operator of production licence 089 in block 34/7, drilled the 34/7–22 wildcat in the southeastern part of the block. The well was drilled to a depth of 2478 metres below sea level and terminated in Early Jurassic rocks. It proved oil bearing strata in sandstones belonging to the Brent group. The well was production tested and the main stream gave a steady rate of 1220 scm oil a day through a 14.3 mm choke. Oil density was 0.83 g/cc with a gas-oil ratio of 65 scm/scm.

The results are considered to be good. The discovery is relatively small, but interesting by virtue of its location close to known discoveries and fields.

Block 34/8

Norsk Hydro as operator of production licence 120 ran a production test on wildcat reentrant 34/8–7R in a separate structure southeast of the Visund field.

Well 34/8–7 was drilled to a total depth of 5437 metres below sea level and terminated in Triassic rock. Hydrocarbons gave shows in Jurassic sandstones, and the well was temporarily abandoned in summer 1992.

Two production tests were run in 34/8–7R. The maximum well flow rate was 16,000 scm gas a day through a 12.7 mm choke. The discovery is relatively small and the acreage was later relinquished.

2.5.3.3 Further details of other drilling operations

Block 1/6

A/S Norske Shell as operator of production licence 011, block 1/6, drilled the 1/6–6 wildcat in order to test the hydrocarbon potential in Jurassic sandstones under the Albuskjell field. The well was classified as a high-pressure, high-temperature well.

The well was drilled to a total depth of 5540 metres below sea level and terminated in rocks probably of Jurassic period. So far, this is the deepest well ever drilled on the Norwegian continental shelf. Shows of hydrocarbons were obtained from Jurassic sandstones, and the well was production tested. Only water and small volumes of gas were produced to the surface during the test. The pressure and temperature conditions forecast were confirmed by this drilling operation. Based on the test results 1/6–6 is not considered a new discovery.

Block 2/4

Saga Petroleum as operator of production licence 146 drilled the 2/4–18 pilot hole. The well was drilled to 596 metres below sea level in order to find out if there is any shallow gas in place where appraisal reentrant 2/4–18R will be sited in January 1994.

Block 2/5

Norsk Agip as operator of production licence 067 drilled the 2/5–10 and 2/5–10A wildcats. Well 2/5–10 was drilled to 4678 metres below sea level and terminated in Triassic rock. Traces of hydrocarbons were found in Jurassic reservoir rocks. Well 2/5–10A was deviated from the original well 2/5–10 in order to explore another part of the same structure. This well was drilled to a vertical depth of 4651 metres below sea level and terminated in Triassic rocks. Also in this well traces of hydrocarbons were found in Jurassic reservoir rocks. The results from these wells did not warrant further testing.

Block 2/7

BP Norway as operator of production licence 145 drilled wildcat 2/7–29. The bore was drilled to 4852 metres below sea level and terminated in Permian rock. A minor oil discovery was made in the topmost Jurassic prospect. Traces of hydrocarbons were present in the bottom Jurassic prospect, while the Permian prospect turned out to be water bearing. The well was not production tested, but an extensive amount of data was compiled in the form of core samples, pressure tests, and liquid samples.

Block 2/10

Saga Petroleum as operator of production licence 163 drilled the 2/10–2 wildcat near the UK sector line. The purpose was to test the hydrocarbon potential in Jurassic sandstones. The well was drilled to 4138 metres below sea level and terminated in Permian rock.

Traces of hydrocarbons were proven in Cretaceous strata, but the anticipated Jurassic reservoir was missing. The results from this well show that the geology of the area is complex. Further mapping activity in the area will therefore be required to determine the resource potential.

Block 2/11

Amoco Norway as operator of production licence 033 drilled the 2/11–9 wildcat well close to the sector line that divides the Norwegian and Danish continental shelves. The drilling operation was a cooperation between the Norwegian production licence 033 and the Danish production licence 2/89. The well was drilled to 4362 metres below sea level and terminated in Early Carboniferous rock. No hydrocarbons were discovered.

Block 7/4

Statoil as operator of production licence 148, blocks 7/7 and 7/4, drilled the 7/4–1 wildcat. The well reached a total depth of 3110 metres below sea level and terminated in Permian rock. No hydrocarbons were proven in this well.

Block 7/7

Statoil as operator of production licence 148 drilled the 7/7–3 appraisal well, aimed at determining the extent of an oil discovery identified by well 7/7–2 in 1992. The appraisal well was drilled to 3561 metres below sea level where it terminated in Permian rock. The results of the drilling operation were disappointing as there were no shows. Therefore the resource estimate for the discovery will have to be downgraded.

Block 9/2
Statoil as operator of production licence 114, block 9/2, is in the process of sidetracking wildcat 9/2–4S into the southern part of the 9/2–1 Gamma field. The well had not been completed by year end.

Block 15/6
Deminex Norge A/S as operator of production licence 166, block 15/6, drilled the 15/6–7 wildcat in a structure north of Sleipner Vest. The well was drilled to 3515 metres below sea level and terminated in Triassic rock. No hydrocarbons were found in this well.

Block 16/1
Statoil as operator of production licence 167, block 16/1, completed the drilling of wildcat 16/1–4 midway between the Sleipner field and the Balder discovery. The well was driven to 1986 metres below sea level and terminated in Permian-Devonian rock. Only small volumes of gas were found and production from the well was not tested.

Block 24/9
Norske Fina A/S as operator of production licence 150, block 24/9, is in the process of drilling wildcat 24/9–5 in a structure in the northern part of the block. The object is to test the hydrocarbon potential in Tertiary sandstones. The drilling operation had not been concluded at the end of the year.

Block 25/2
Elf Petroleum Norge AS, as operator of production licence 026, block 25/2, drilled wildcat 25/2–15R2 in a structure in the southern part of the block. The well was drilled to 3920 metres below sea level and terminated in Early Jurassic rock. Only traces of hydrocarbons were proven in this well.

Block 25/11
Norsk Hydro as operator of production licence 169, blocks 25/8 and 25/11, drilled the 25/11–17 wildcat in a structure south of the 25/11–15 discovery. The well was drilled to 2227 metres below sea level and terminated in bedrock. The reservoir was struck as forecast, but proved to be water bearing.

Block 30/3
Statoil as operator of production licence 052, block 30/3, is in the process of drilling the 30/3–6S wildcat in a prospect just southwest of the Veslefrikk field. The drilling operation had not been completed by the end of the year.

Block 30/9
Norsk Hydro as operator of production licence 104, block 30/9, drilled the 30/9–14 appraisal well, located in a structure just southwest of the Oseberg field. The well was drilled to a total depth of 3657 metres below sea level and terminated in Jurassic rock.

As anticipated, oil and gas were proven in Jurassic sandstone strata. Two production tests were run, one in the oil zone and one in the water zone. The maximum measured production rate from the oil zone was 979 scm oil a day through a 25.4 mm choke. The gas-oil ratio was 152 scm/scm, while oil density was 0.84 g/cc. The maximum production rate in the water zone was measured at 650 cubic metres of water a day through a 22.2 mm choke.

In the same production licence Norsk Hydro also drilled the 30/9–15 wildcat in a structure just southeast of the Oseberg field.

The well was drilled to 2741 metres below sea level and terminated in Jurassic rock. Oil was proven in Middle Jurassic sandstones. The discovery is relatively small and was not production tested. Its central location is interesting and the findings justify an upgrade in the resources for the area as a whole. The well had not been completed at the end of the year.

Block 31/5
Norsk Hydro as operator of production licence 085, blocks 31/3, 31/5 and 31/6, completed the drilling of appraisal well 31/5–5 located in the western part of the Troll field.

The well was drilled to 1901 metres below sea level and terminated in Jurassic rock. As anticipated, oil and gas were proven in Late Jurassic sandstone strata.

Block 33/9
Mobil as operator of production licence 172 drilled the 33/9–16 appraisal well aiming to determine whether there were commercial quantities of oil in a Late Jurassic sand body proven in well 33/9–15. The well was drilled to 2848 metres below sea level and terminated in Middle Jurassic rock. Only traces of hydrocarbons were found and the well was therefore not production tested. The results were disappointing in the light of the results from the first drilling operation in this structure.

Block 34/7
Saga Petroleum as operator of production licence 089 deviated the 34/7–21A appraisal well from 34/7–21 where a discovery had been made in Late Jurassic sandstone in a structure in the western part of the block. The well was drilled to 2847 metres below sea level and terminated in Middle Jurassic rocks. It confirmed the discovery by proving hydrocarbons in Upper Jurassic sandstone, but was not production tested. The drilling operation showed that the lateral development and extent of the reservoir sand is difficult to map, making it hard to say anything for certain about the size of the discovery until new appraisal wells have been drilled.

Block 34/8
Norsk Hydro as operator of production licence 120 ran a production test on appraisal well 34/8–8 centrally in the Visund field. The well was drilled to 3602 metres below sea level and terminated in Triassic rock. In

1992, the well was suspended without any production test having been performed. The well was reentered, designated 34/8–8R, and production tested in 1993. Two production tests were run, achieving a measured maximum flow rate of 964 scm oil and 154,200 scm gas a day through a 19 mm choke. The results from the drilling operation and production test are encouraging, confirming the resource expectations in this part of the Visund structure.

Norsk Hydro also sidetracked an appraisal well, 34/8–10S, centrally in the Visund discovery, which sought to determine the resource basis and examine reservoir continuity in two of the Visund segments. Oil was proven in several strata of Jurassic and Triassic origin; and a production test performed in rocks belonging to the Statfjord formation gave a maximum flow reading of 1200 scm oil and 410,000 scm gas a day through a 17.5 mm choke.

The test results are considered good, and the well confirmed the partners' expectations in the two southern segments where new data was sought. In the two northern segments the results were unexpected, most probably because the string passed through the Brent group in a heavily tectonified area. The well was deviated to 3447 metres below sea level, equivalent to a vertical depth of 3293 metres, and terminated in Triassic rock.

Norsk Hydro is drilling one further appraisal well, 34/8–11, in the Visund discovery. It is located between wells 34/8–8 and 34/8–10S and is intended to explore reservoir continuity and determine the resources in place in this segment of the Visund structure. The drilling operation had not been completed by the end of the year.

Block 6305/12

Norsk Hydro as operator of production licence 154, blocks 6205/3 and 6305/12, drilled the far west 6305/12–2 wildcat in the perimeter of the block. The principal prospect was presumed Early Cretaceous sandstones deposited from the Gossehøgda high, while the secondary prospect was possibly eroded and fractured bedrock. The well was drilled to a total depth of 3139 metres below sea level. Traces of hydrocarbons were proven at several levels, but did not warrant production testing.

Block 6506/12

Statoil as operator of production licence 094 drilled the 6506/12–9S appraisal well in the Smørbukk discovery. The well was sidetracked on the eastern part of the structure and was located far down on the flank in order to be able to delimit the oil and gas potential in the Middle and Early Jurassic reservoir zones. It was continued to a total vertical depth of 4903 metres below sea level and terminated in Early Jurassic rock.

The well proved oil, condensate and gas in Jurassic sandstones, and a total of five production tests were performed.

The results from the three deepest tests were highly encouraging. In the deepest test, for the first time oil and gas were produced from the Åre formation in the Smørbukk discovery. The results of the last two tests were disappointing as they showed tight reservoir zones. The same reservoir zones in previous wells were among the best in the area.

The best single test gave 900 scm oil and 250,000 scm gas a day through a 22 mm choke with a recorded gas-oil ratio of 270 scm/scm. Oil density was 0.855 g/cc and gas density 0.832 relative to air.

The results of the drilling operation were surprising and confirm that the Smørbukk discovery is one of the most complicated on the Norwegian continental shelf in terms of pressure regimes and reservoir properties. The results justify a renewed evaluation of Smørbukk that also takes into account the deeper reservoir zones.

Block 6507/7

Conoco as operator of production licence 095 drilled the 6507/7–10 wildcat in a structure just north of the Heidrun field. It was drilled to a total depth of 3285.5 metres below sea level and terminated in Triassic rock. The well was dry, though traces of hydrocarbons were recorded.

Block 6507/8

Statoil as operator of production licence 124 drilled wildcat 6507/8–6 in a structure to the northeast of the 6507/8–4 discovery. The well was drilled to a total depth of 2827 metres below sea level and terminated in Triassic rock.

No hydrocarbons were found during the drilling operation. The results were disappointing considering the well's promising location relative to previous discoveries and fields.

Block 6608/10

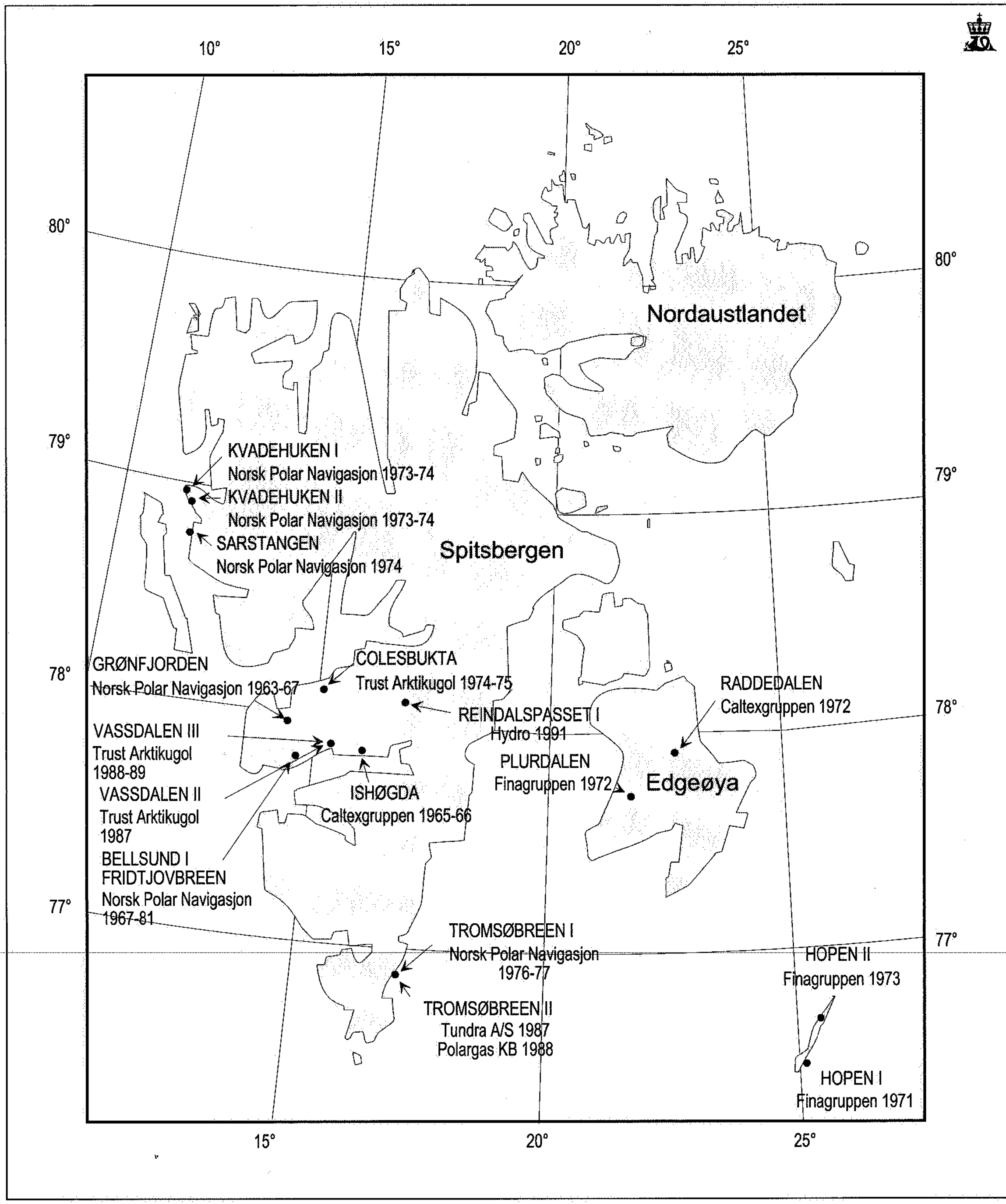
Statoil as operator of production licence 128, blocks 6608/10 and 6608/11, drilled the 6608/10–3 appraisal well in a fault segment adjacent to well 6608/10–2 in the north where the Norne discovery was made in 1991.

It was drilled to 2896 metres below sea level and terminated in Early Jurassic rock. The well proved oil and gas in Jurassic sandstones, and a production test giving 1250 scm oil a day through a 23.8 mm choke was run. The gas-oil ratio recorded was 90 scm/scm and the oil density 0.850 g/cc.

This confirms that the Norne field extends further north, and the drilling results mean an increase in the resources estimate.

The discovery was recently mapped by means of 3D seismic, and the need for further drilling led to the spudding of wildcat 6608/10–4 on 15 December 1993. This well is located in a segment northeast to the discovery well 6608/10–2. The prime purpose of this drilling is to prove additional Norne resources in Middle Jurassic sandstones in this part of the block. At the end of the year the drilling operation had not yet been completed.

Fig. 2.5.3.4
Well locations on Svalbard



Block 6610/3

Statoil as operator of production licence 177, blocks 6610/2 and 6610/3, completed the first wildcat well, 6610/3–1. The well was drilled in two stages, 6610/3–1 and 6610/3–1R. The parent well was spudded in 1992 and temporarily suspended on 17 February 1993 as there is a ban on drilling through oil-bearing strata in this area in the period 15 February to 1 March. The well was reentered as 6610/3–1R on 16 September.

This wildcat was drilled in a structure in the northern part of the block in order to study the prospectivity of Lower Jurassic sandstones. It was drilled to 4177 metres below sea level and terminated in Triassic rock. Abundant shows of hydrocarbons were proven in several stratigraphic levels, and two production tests were performed in Cretaceous reservoir zones. The results were disappointing, however, as no hydrocarbons were produced to the surface.

Block 7229/11

A/S Norske Shell as operator of production licence 183 drilled the 7229/11–1 wildcat in the eastern part of the Finnmark platform. It is the easternmost well on the Norwegian continental shelf. The purpose of the well was to test the hydrocarbon potential in Permian-Carboniferous limestone deposits. It was drilled to 4606 metres below sea level and terminated in Middle Carboniferous rock. The presumed reservoir rocks were tight and no hydrocarbons were discovered.

Block 7128/4

Statoil as operator of production licence 180 started drilling the 7128/4–1 wildcat in the southwestern part of the Finnmark platform to test the hydrocarbon potential in Early Carboniferous sandstones. The well had not reached reservoir level at the end of the year.

2.5.3.4 Svalbard

No seismic data were acquired and there was no drilling for hydrocarbons on Svalbard in 1993. Store Norske Spitsbergen Kullkompani is planning to drill a well in Trust Arktikugol's claim at Cap Laila near Coles Bay. According to plan the well will be drilled to 1000 metres below ground using an upgraded but conventional coal drilling rig. Estimated operation start-up is the first half of February 1994. Table 7.3.g and Figure 2.5.3.4 summarise wells on Svalbard.

2.5.3.5 Jan Mayen

The Jan Mayen ridge is a bathometric high extending southward from the Jan Mayen island toward Iceland. This ridge is believed to represent a continental crust fragment which potentially contains both Mesozoic and Cenozoic rocks.

The Directorate, in collaboration with the Icelandic energy authorities, *Orkustofnun*, carried out three different seismic surveys in this area. The Jan Mayen-79 and Jan Mayen-85 surveys are both major regional surveys made available to the industry in 1987. In 1993, the Jan Mayen-88 survey was offered to the industry together with regional lines extending from Jan Mayen to Vøring I and Troms I. The Jan Mayen-88 survey covers an area which must be regarded as interesting even though its hydrocarbon potential is uncertain and more surveys have to be carried out for proper evaluation.

2.6 DISCOVERIES UNDER CONSIDERATION AND FIELDS PLANNED TO BE DEVELOPED

2.6.1 Ekofisk area

This is the area on the Norwegian continental shelf which has been in production for the longest period of time; see Figure 2.8.4.a. Whereas the producing fields are primarily chalk, the exploration activity is now focused on sandstone prospects. A number of small discoveries have been made in the area and the plan is to produce them as satellites to existing installations.

Mjølner

Mjølner lies in block 2/12 in production licence 113, allocated in 1985. The field straddles the borderline between the Norwegian and Danish sectors. Norsk Hydro operates Mjølner, and Mærsk operates the Gert field on the Danish side. The A segment, from which production is planned to take place, lies, according to the Norwegian operator, 100 per cent within the Norwegian sector. The resources in the segment are estimated by Norsk Hydro to be 1.5 mcm oil and 0.7 bcm gas.

Norsk Hydro, in cooperation with the operator in the Danish sector, is reprocessing the 3D seismic. Hydro intends to submit a plan for development and operation in 1995 at the earliest. A plausible development concept involves a non-permanently manned wellhead platform and a production well and pipeline to existing installations for further processing.

Trym

The Trym field lies in block 3/7 on production licence 147, allocated in 1988 with Shell as operator. A gas-condensate discovery was made with well 3/7–4. The discovery is in a structure that straddles the borderline between the Danish and Norwegian sectors. The structure was originally called Trym. In 1992 a well on the southern part of the same structure in the Danish sector proved oil and the discovery was named Lulita.

Shell's latest interpretation of the 3D seismic for the entire structure divide it into three segments, two of them in the Norwegian sector. Trym is held to be 100 per cent Norwegian. The Lulita discovery is believed to extend into the Norwegian sector, and is operated by Statoil-Denmark on the Danish side.

The resources have been reduced as Trym and Lulita are two separate accumulations, all be it with possible communication through the aquifer. Estimates of recoverable resources in Trym are 3.9 bcm gas and 0.7 mcm condensate according to the operator, Shell. In 1994 development studies will be undertaken for Trym and Lulita in a joint programme with the Danish operator.

2/5–3 Sørøst Tor

This field is located in block 2/5 in production licence 006, allocated in 1965, where Amoco is operator. The Directorate estimates the recoverable oil resources to be 2.5 mcm and the gas resources to be 2 bcm. No development concept has been finalised as yet.

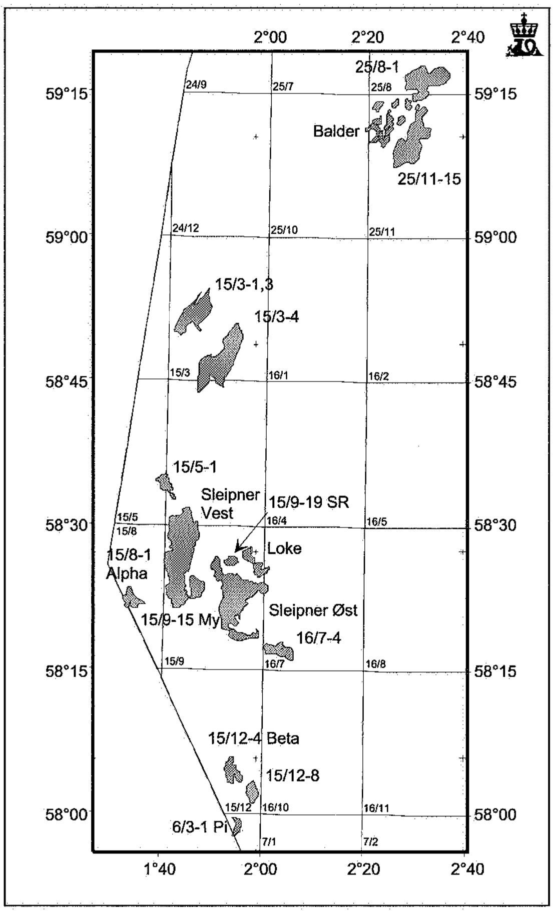
2/4–17 Nordvest Tor

This discovery was located in 1992 in production licence 018, allocated in 1965 under Phillips as operator. So far the plans are to use the discovery well as a producer by hooking up to an existing installation. The plan for development and operation should be submitted in 1994 if all goes as planned bringing the discovery on stream in 1997.

9/2–1 Gamma

This discovery is located in block 9/2 on production licence 114, which was allocated in 1985 with Statoil as operator. The field lies in the Egersund basin and was proven by well 9/2–1. There is no existing infras-

Fig. 2.6.2
Fields and discoveries in the Sleipner and Balder area



tructure in the area. The operator's estimate of recoverable reserves is 3.4 mcm oil. The proposed development concept is based on a jack-up rig with a storage tanker and offshore loading buoy that will feed shuttle tankers. The partners submitted a plan for development and operation to the authorities in December 1993. Well 9/2–4S was started on the structure in the same month, see Figure 2.5.3.b, and production is due to commence in mid 1995.

2.6.2 Sleipner and Balder area

In addition to Sleipner Øst, Loke, Sleipner Vest and 15/12–4 Beta which is discussed below, the Sleipner area consists of a number of other discoveries; see Figure 2.6.2. Sleipner Øst and Loke came into production on 1 October 1993 and are discussed in more detail in section 2.8 below. Sleipner Vest has already been declared commercial and is further discussed in section 2.7.2 below.

15/12–4 Beta

This discovery is located in block 15/12, allocated in production licence 038 in 1974, where Statoil is operator. The operator estimates the recoverable resources to be 13.2 mcm oil and 2.3 bcm gas. The licensees are evaluating various development concepts at the same time as the geological data are being squeezed for more information. The preliminary plans are to start production in 1997 at the earliest.

15/5–1

On the boundary line between block 15/5 and block 15/6, a gas-condensate discovery was made in 1974 by the drilling of well 15/6–2 and in 1978 by the drilling of well 15/5–1. Norsk Hydro operates 15/5 and Esso 15/6. The Directorate has estimated the recoverable resources at 6 bcm gas and 2 mcm oil. The licensees expect to submit their plan for development and operation in 1995.

Balder

Balder was proven in 1967 by exploration well 25/11–1. The discovery extends into blocks 25/10 and 25/11 in production licences 001 and 028, both operated by Esso. Esso holds 100 per cent of production licence 001. The recoverable resources have been estimated by the Directorate at 32.2 mcm oil, which in Balder's case is relatively viscous. Hydrocarbons have also been proven in sandstones of early Eocene and Palaeocene age in four diverse sand units. The reservoir sandstone is not very well consolidated, though other reservoir parameters are good. An extended test that was carried out in summer 1991 using the production ship *Petrojarl I* gathered valuable geological and production information. The operator has not yet decided what to do next on Balder, and the plans will be considered in conjunction with a neighbouring discovery, 25/11–15, described below.

25/11–15

Norsk Hydro discovered oil in 25/11–15 east of Balder in 1991. The discovery is in the Heimdal formation which is of Palaeocene age. The Directorate estimates the recoverable resources at 60 mcm oil and 1.8 bcm gas. Three dimensional seismics have been shot across the area and an appraisal well has been planned for 1994.

Other discoveries under consideration

Two discoveries have been made in block 15/3: a gas-condensate discovery 15/3–1,3 in 1975; and a gas-oil discovery 15/3–4 in 1982. The Directorate's estimates of recoverable resources in 15/3–1,3 are 10.5 bcm gas and 5.2 mcm oil. At year end 3D seismics are being collected over the block in order to assist further mapping.

On block 15/9 Statoil discovered oil in the 15/9–19SR sidetracked reentry well in rocks dating from the Jurassic-Triassic period just north of Sleipner Øst. The operator estimates the resources in place are 4.6 mcm oil and 0.7 bcm gas.

2.6.3 Frigg area

This is a vicinity where gas fields have been in production since 1977; see Figure 2.8.10.a. Recently, several small discoveries have been made in the area, including oil. The most attractive of the planned developments are Skirne and Vale.

Skirne

This field is situated in block 25/5 in production licence 102 allocated in 1985 with Elf as operator. The field was proven by well 25/5–3 in the Brent group in 1990. The Directorate's reserves estimates are 2.3 bcm gas and 0.3 mcm condensate. The operator estimates the reserves at 5.0 bcm gas and 0.7 mcm condensate.

A three dimensional seismic survey was shot over the field in 1992 and new maps were prepared in 1993. They suggest few changes in field estimates. A probable development concept is a subsea installation with the wellflow conducted either to Frøy and thence to Frigg, or directly to Frigg. A plan for development and operation will be available in 1994 at the earliest. This may allow for production start-up in 1997. However, field development presupposes sale of the gas.

Byggve

This field is situated in block 25/5 in production licence 102 allocated in 1985 and operated by Elf. The field was proven by well 25/5–4 in the Brent group in 1991. The Directorate's reserves estimates of 2.6 bcm gas and 0.6 mcm condensate are rather less expansive than the operator's.

Based on 3D seismic the accepted interpretation of the field has had to be modified slightly, and more clarification is needed before a plan for development and operation can be adopted. It may be possible to achieve synergies if Skirne is also developed. In any case, development is contingent on sale of the gas.

Peik

Peik was proven by well 24/6–1 in 1985. The field is situated in production licence 088 allocated in 1984 with Total as operator. In 1987, the 9/15–1 wildcat in the UK sector proved hydrocarbons. The operator has reduced the reserve estimate considerably since new 3D seismic results became available.

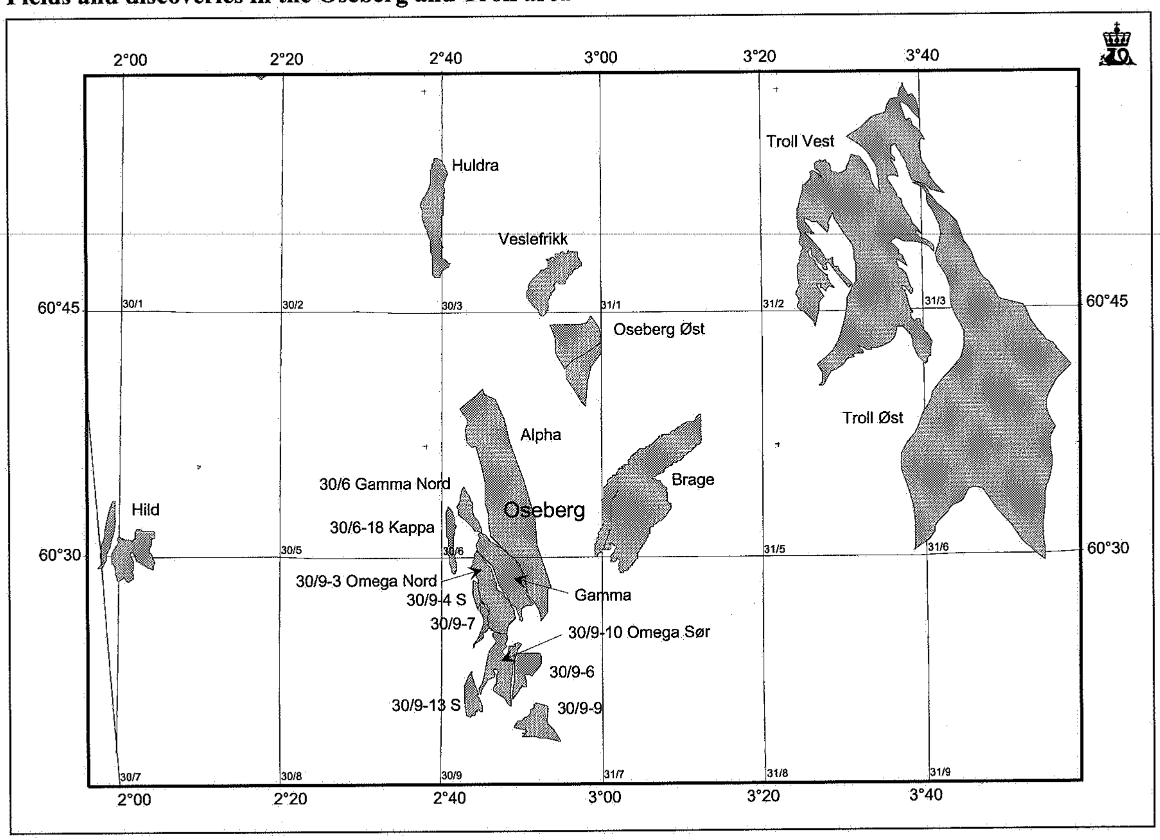
Vale

This discovery is located in block 25/4 in production licence 036 which was allocated in 1981 with Elf as operator. Gas rich in condensate was proven in summer 1991. The licensees are currently working towards a commerciality declaration, and the plan for development and operation may be submitted in 1994. The most probable development concept is a subsea installation with tie-in to either Frigg or Heimdal. The operator estimates resources at 2.3 bcm gas and 3.1 mcm condensate.

25/2–5

This discovery is located in block 25/2 in production licence 026 allocated in 1969 with Elf the operator. The discovery well 25/2-5 was drilled in 1976 and

Fig. 2.6.4
Fields and discoveries in the Oseberg and Troll area



contains oil. There are no definite development plans as well 25/2–15 produced only negative results.

Hild

Hild is situated in two production licences: 040, in blocks 29/9 and 30/7, which was allocated in 1975; and 043, in blocks 29/6 and 30/4, which was allocated in 1976; see Figure 2.6.4. The operators of the respective licences are Norsk Hydro and Total Norge. The gas discovery was proven by reentry well 30/7–6R in 1978. From 1 January 1991, Total took over BP's interest and operatorship in production licence 043. If the field is developed, unitisation talks must be conducted between the two licences.

A three dimensional survey was shot in the area in 1991 and interpretation has now been completed. Based on the results the resources estimates have been upgraded. However, more wells are needed before a development decision can be taken.

2.6.4 Oseberg and Troll area

Oseberg area

Several oil and gas fields in this area are in production or being developed. There are also a number of discoveries that have been made in the area which are planned to be produced as satellites to existing installations; see Figure 2.6.4.

Oseberg Øst

Oseberg Øst is in production licence 053 in block 30/6, about 14 kilometres from Oseberg C. The field comprises two structures divided by a sealing fault. Four wells have been drilled on the field. Both structures contain several oil bearing strata of variable porosities and permeabilities in the Brent group, and there are a number of different oil-water contacts. The recoverable resources are estimated by the Directorate at 19 mcm oil and 1.0 bcm gas.

Norsk Hydro, the field operator, declared the field commercial in June 1991. Possible development concepts under evaluation are a subsea installation and wellhead platform with hook up to Oseberg C. The partners plan to maintain pressure by means of water or water alternating gas (WAG) injection. The plan for development and operation is expected to be submitted to the authorities in mid 1995 at the earliest.

Oseberg Sør area

South of the Oseberg field a number of discoveries of oil and gas have been made in production licences 079 and 104. These are 30/9–3 Omega Nord, 30/9–10 Omega Sør, 30/9–13S, 30/9–4S, 30/9–7, 30/9–9, and 30/9–6. The operator estimates the recoverable resources are 35.3 mcm oil and 9.3 bcm gas. The area which is very complex offers considerable uncertainty regarding its upside potential.

Several development solutions are being evaluated and most of the interesting concepts are based on using the Oseberg field centre for processing and onward transportation. Even with very long horizontal wells, at least two drilling sites will be required. Most of 30/9–3 Omega Nord can be reached using wells from the Oseberg field centre and produced from the centre, provided sufficient well slots are available. Omega Nord will most likely be the first component of a phased field development. The Directorate estimates recoverable reserves on 30/9–3 Omega Nord to be 16.6 mcm oil and 8.0 bcm gas. The partners are expected to present their commerciality declaration and submit a plan for development and operation in 1995.

Other discoveries under evaluation

Three discoveries are located west of the Oseberg field centre, mainly in production licence 053. They are: 30/6-C-27H in the Lower Statfjord formation in Gamma Nord, 30/6–18 Kappa, and 30/6–17R Alpha Cook on the western flank of the Oseberg Alpha structure.

Well 30/6-C-27H was drilled as a pilot hole in the Lower Statfjord reservoir in connection with the horizontal producer for 30/6 Gamma Nord. Further appraisal wells are being considered. The existing production well could be sidetracked to the lower Statfjord formation, but a very long deviated well from Oseberg is an alternative being looked at. For the other discoveries, no firm development plans exist to date.

Huldra

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

The field was declared commercial in summer 1991. Gas has been proven in the Brent group, and Statoil's reserves estimates are 22.3 bcm gas and 7.9 mcm condensate. The operator is contemplating a number of development concepts. Both a stand-alone installation with processing capacity and a wellhead unit tied in to existing processing facilities in the area are considered feasible. The operator will continue with technical studies in 1994.

The plan for development and operation may be submitted to the authorities in the middle of 1994, and the field could come on stream in 1998 provided gas sales allocations fall into place.

2.6.5 Gullfaks, Statfjord and Snorre area

This is a high activity area where there are numerous fields either in production or in the process of being developed, and discoveries under consideration; see Figure 2.8.13.a. The area is still considered very prospective.

Gullfaks Sør

Gullfaks Sør lies in the middle of block 34/10, about nine kilometres south of the Gullfaks field. Block 34/10 was allocated in 1978 with Statoil as operator; see description of Gullfaks in section 2.8.13.

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

In 1993 the operator reprocessed the 3D seismic acquired over the field in 1987 and as a result the data quality was enhanced. The operator has therefore now initiated a new interpretation of the field. The Directorate already has results from its own mapping of Gullfaks Sør, which put the estimated reserves at 25.6 mcm recoverable oil and 56.1 bcm recoverable gas, though these estimates are highly speculative.

Gullfaks Sør was declared commercial in November 1993 and the declaration outlines a number of alternative development strategies. The two main options are dry gas processing, contra rich gas processing. The various concepts are being considered by the partners.

The development concepts presented are based on simultaneous oil and gas production from the Brent group, while gas from the Statfjord formation is recirculated to maintain reservoir pressure. The Directorate was keen to examine whether recirculation of the gas in the Brent group would also bring about increased reservoir fluids production, and therefore in 1993 carried out studies to examine the effect of recirculating gas in Brent. Further work on the field will depend on gas sales.

34/10–17 Beta

This discovery straddles the boundary line between block 34/10 and 33/12, about 15 kilometres southwest of the Gullfaks field. Statoil operates both production licences. The discovery was proven in 1983 by the wildcat 34/10–17, the only drilling so far into the structure. In 1993 the operator undertook a field development study for the discovery.

The operator estimates recoverable reserves at 13 mcm oil and 10 bcm gas based on full pressure maintenance by means of gas injection. The operator is contemplating developing 34/10–17 Beta using subsea completion wells tied in to Gullfaks A. The water is 135 metres deep. Based on current plans production cannot start before 1998. Plans for an appraisal well in the structure in 1994 are being prepared.

34/10–23 Gamma

This discovery is situated in block 34/10 in production licence 050 where Statoil is the operator. It is about 14 kilometres south of the Gullfaks field.

Proof of the discovery was obtained in 1985 by well 34/10–23 which revealed gas in Middle Jurassic sandstone. Appraisal well 34/10–35 was drilled into the northern part of the structure in 1992 and similarly proved gas in Jurassic sandstone. In 1993 the 3D seismic was reinterpreted based on the new well results. The Directorate estimates that recoverable resources are 69 bcm gas and 6 mcm condensate.

Vigdis

The Vigdis field is situated in block 34/7 and comes under production licence 089 operated by Saga Petroleum. The Vigdis reservoir is made up of Brent group sandstones. Faults split the field into two segments. The oil-water contacts in these two segments are not identical. Three exploration wells, 34/7–13, 34/7–16 and 34/7–19, were drilled on the field, but there were no appraisal wells drilled in 1993. The Directorate has estimated recoverable resources at 33.1 mcm oil and 2.3 bcm gas. There is a chance that additional resources will be discovered in adjacent structures.

Water depths in the area are 230 to 300 metres and the operator is considering developing Vigdis with subsea wells tied up to existing installations in the vicinity.

The operator tendered his commerciality declaration on 29 December 1992. The plan for development and operation is expected to be submitted to the authorities in mid 1994. Based on the development concepts examined by the partners, production may commence in 1998 at the earliest.

Visund

The Visund discoveries lie in block 34/8, which is in production licence 120 allocated in 1985 and operated by Norsk Hydro. The first discovery was made in the Brent group by well 34/8–1 in 1986. Well 34/8–3 followed in 1988 and proved hydrocarbons in a Brent segment further north. In 1991, three wells were drilled in the production licence, two of them in the Visund structure.

In 1992, three wells were drilled in the structure. Well 34/8–4A proved oil in the Statfjord formation, while well 34/8–8 proved oil in the Brent group in 1992 and tested that reservoir early in 1993. In the same year, well 34/8–10S proved hydrocarbons in several reservoir levels. To improve the definition of the oil reservoir in the Brent group, well 34/8–11 was spudded in 1993. Three dimensional seismic has been shot over the entire structure.

Visund proved resources in the Brent group, and in the Amundsen, Statfjord and Lunde formations. The operator's estimates of recoverable resources are 38 mcm oil, 7.0 mcm condensate, and 46 bcm gas.

The water depth in the area is 310–380 metres. The preliminary plans involve field development in two phases. The plan for development and operation may be submitted in 1994 which might entail production start-up in 1998.

Block 35/11

Block 35/11 was allocated in 1984 as production licence 090. Mobil operates the block and seven wells have been drilled of which three proved hydrocarbons.

Well 35/11–2 penetrated the north of the block in 1987 where the Directorate estimates the recoverable resources are 5.4 mcm oil and 5.6 bcm gas. Reentrant 35/11–4R was drilled in 1991, and 35/11–7 just east of it the year after. For these two wells, the resources estimates are 18 mcm and 20.7 mcm oil, and 10.8 bcm and 15.4 bcm gas, respectively.

In 1994 the operator plans three appraisal wells for the 34/11–4R and 35/11–7 discoveries, and is aiming to submit the plan for development and operation in 1996 and come on stream in 1999–2000.

2.6.6 Fields and discoveries in the Norwegian Sea

To date 15 fields and discoveries have been proven in the Norwegian Sea; see Figure 2.6.6. At present one of them is in production and another has been declared commercial. The Directorate is of the opinion that there is potential for making further discoveries in the area.

Midgard

The Midgard field is situated in blocks 6507/11 and 6407/2 under production licences 062 and 074, with Saga as operator. The field was discovered in 1981 by the drilling of well 6507/11–1 and was declared commercial by the operator in autumn 1991.

All in all, seven exploration wells have been drilled in the area, four of which were drilled on the structure, which is split into four structural segments. The field is mainly a gas field with some condensate and a thin oil zone. Reservoir properties are good, and the Directorate's reserves estimates are 87 bcm gas, 1.3 mcm oil, and 13 million tonnes NGL.

Field development in 250–270 metres of water is planned using an integrated, fixed, gravity base platform. It is planned to produce the reservoir using depressurisation as the driving force. Development is based on a total of twelve production wells for gas, and two horizontal oil producers. The plateau rate will correspond to dry gas sales of 8 bcm per annum. The operator assumes that the gas will be processed on the field and transported to the market via a dry gas pipeline.

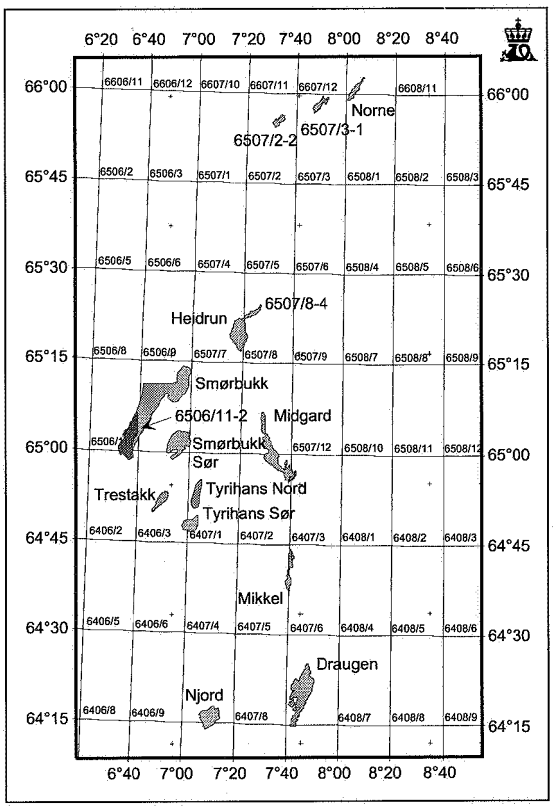
Smørbukk

The bulk of this discovery lies in block 6506/12 in production licence 094 allocated in 1984. The southern part lies in block 6506/11 in production licence 134 allocated in 1987. Statoil operates both licences. The discovery contains gas, condensate and oil with a relatively high gas-oil ratio.

It is located about 200 kilometres from prospective landing sites, in 290 metres of water. A total of eight wells have been drilled in block 6506/12. One wildcat was also drilled in the southern part of the Smørbukk structure, in block 6506/11. The Directorate estimates resources to be 37 mcm recoverable oil and condensate and 95 bcm recoverable gas.

The estimated recoverable volumes of oil and condensate presuppose depressurisation as the driving force. If pressure is maintained fully or in part, improved recovery of oil and condensate can be expected. The operator is evaluating the situation. In any event, gas production from Smørbukk must be seen in conjunction with a general gas transport solution for Haltenbanken.

Fig. 2.6.6
Fields and discoveries in the Norwegian Sea



The licensees are now considering joint development of Smørbukk and Smørbukk Sør and talks have been initiated with the Midgard licensees to examine the options for coordinated development of the trio of fields so as to sell oil and gas from the beginning of year 2000.

Smørbukk Sør

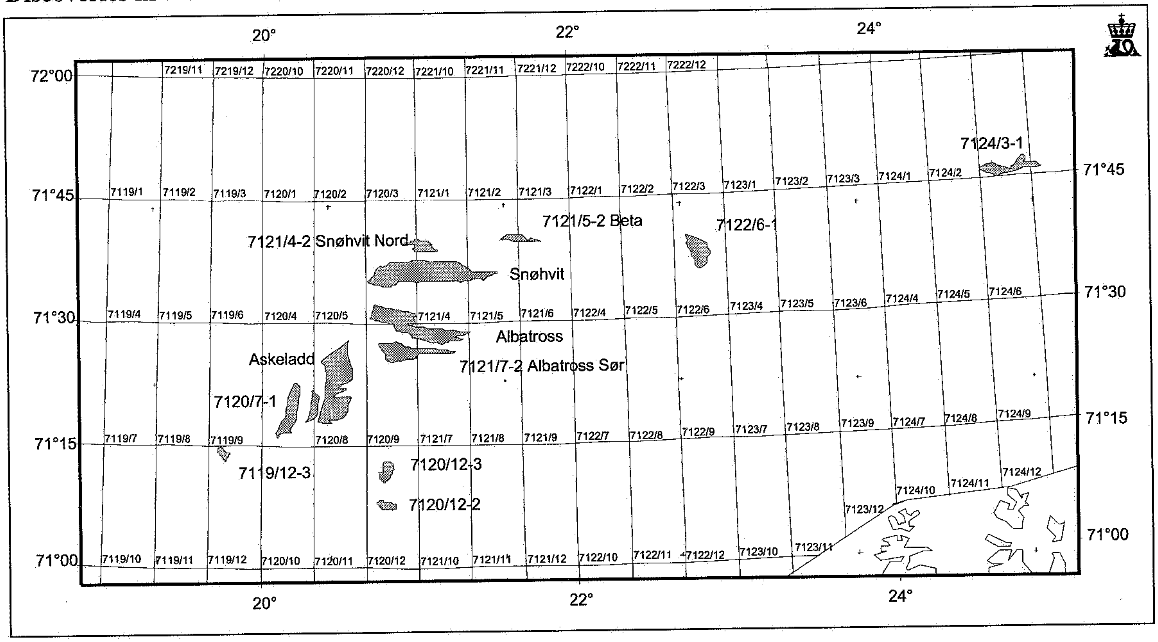
This field, situated in the southern part of block 6506/12, was proven in 1985 by the wildcat 6506/12–3, and later confirmed by two appraisal wells. Statoil is the operator. The field lies about ten kilometres from Smørbukk in 300 metres of water. The reserves in Smørbukk Sør are estimated by the Directorate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

The field was declared commercial in January 1992. The licensees are now considering a separate development of Smørbukk Sør to sell the oil and inject the associated gas if Smørbukk is put on hold pending an overall gas solution on Haltenbanken.

Trestakk

Trestakk is an oil discovery in block 6406/3. Statoil operates the production licence, which was allocated in 1984. The operator estimates recoverable resources to be 4.8 mcm oil. The plan calls for produced gas to be reinjected into the reservoir to improve oil recovery. It is assumed that the reservoir can be drained by means of three horizontal production wells.

Fig. 2.6.7
Discoveries in the Barents Sea



Tyrihans Sør and Tyrihans Nord

These discoveries lie in blocks 6406/3 and 6407/1, where Statoil operates the production licence. There is probably pressure communication through a common aquifer. Tyrihans Sør is classed as a gas-condensate discovery, while Tyrihans Nord contains an oil zone with an overlying gas cap. The magnitude of the oil zone in Tyrihans Nord is uncertain since no oil-water contact has been proven. The operator's estimates for total recoverable resources are 9.6 mcm oil-condensate and 26.5 bcm gas.

Njord

Njord is an oil discovery in the two blocks 6407/7 and 6407/10, where Norsk Hydro operates production licences 107 and 132, allocated in 1985 and 1987. A total of seven exploration wells have been drilled in the blocks, four of which proved oil. The structure features a complex fault pattern which will probably be a major factor in oil recovery. The Directorate's estimates of recoverable resources are 35 mcm oil and 7.2 bcm associated gas. The licensees are working to submit a plan for development and operation in 1994.

6507/8–4

This discovery, covered by production licence 124 under Statoil's operatorship, is situated about four kilometres northeast of the Heidrun field. In August 1990, the discovery well, 6507/8–4, proved oil with an overlying gas cap in the Åre formation. The operator's estimates of recoverable resources are 12 mcm oil and 2.5 bcm gas.

Norne

The Norne field is situated in block 6608/10, some 85 kilometres north of Heidrun and 200 kilometres off the Nordland coast. Production licence 128 was awarded in 1986 and Statoil operates the field, which lies in 360–380 metres of water and was proven in January 1992. The operator estimates recoverable resources at 70 mcm oil and 13 bcm gas. A plan for development and operation is being worked out, and is planned to be submitted to the authorities in the second half of 1994. The most likely development concept is a production ship with subsea production units and loading of the crude into shuttle tankers. Production start-up under this scenario is feasible during 1997.

2.6.7 Discoveries in the Barents Sea

About 250 bcm recoverable gas has been proven in the Barents Sea; see Figure 2.6.7. In addition there is a thin oil column in the Snøhvit discovery.

Snøhvit

Snøhvit is situated in the following blocks and production licences: 7120/6–097; 7121/4–099; 7121/5 and 7120/5–110. Norsk Hydro is the operator of production licence 097, whereas Statoil is the operator of production licences 099 and 110. Production licences 097 and 099 were allocated in 1984, while production licence 110 was allocated in 1985. There is no existing infrastructure in the area.

The operator's estimates for recoverable resources are 101 bcm gas and 11 million tonnes NGL, while the Directorate's estimates for recoverable resources are 83 bcm gas, 6.7 mcm oil and 9.2 million tonnes NGL. Due to the long distance to potential gas markets, pipeline transportation of the gas is uneconomic. Any development of the discovery would therefore probably include a refrigeration plant to produce liquified natural gas, LNG.

In the Directorate's view, a satisfactory gas sales contract is crucial for any development of Snøhvit and the other gas discoveries on Troms I. Snøhvit also contains a thin oil zone. The narrowness of the zone and the average to poor reservoir characteristics render the oil difficult to produce. The operator considers integrated oil and gas production to be feasible if a concept involving full processing on the field is chosen.

Askeladd

This discovery is situated in blocks 7120/7 and 7120/8 where Statoil is the operator. The discoveries date from 1981–84 and comprise gas and condensate. The Directorate estimates the recoverable resources are 59.7 bcm gas. Askeladd is a likely production satellite for Snøhvit (discussed above) if the latter is developed.

Albatross

Albatross lies in blocks 7120/6, 7120/9 and 7121/7 and embraces discoveries in Albatross and 7121/7–2 Albatross Sør. The operators are Norsk Hydro and Statoil. Both discoveries contain gas found in 1982 and 1986. The Directorate estimates resources to be 52.5 bcm gas altogether. Also Albatross is a likely satellite field if Snøhvit is developed.

2.7 FIELDS DECIDED TO BE DEVELOPED

2.7.1 2/1–9 Gyda Sør

Production licence 019B

Licensees

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

Field 2/1–9 Gyda Sør is situated in block 2/1 and is an extension of the Gyda field towards the southeast; see Figure 2.8.4.a. Gyda Sør was declared commercial on 5 February 1993 and their plan for development and operation was adopted five months later on 4 July 1993.

Field history

Two wells have been driven into the structure. The first, well 2/1–9, was drilled in 1991 and penetrated an 89 metre tall oil column on the structural flank. Only the lower portion of the column was of good reservoir quality. In 1992 the well was sidetracked to target central regions of the structure, when a 160 metre thick oil column was proven in Upper Jurassic sandstone.

Reservoir

No pressure communication has been observed between Gyda Sør and Gyda. That there may be communication via the aquifer is none the less possible. The seismic shows that Gyda Sør is a structure subdivided by faults into a number of segments. The recovery factor will depend on whether these faults are sealing or not.

The plan is to produce the reservoir from a long range well drilled from the Gyda installation. It may be necessary to sidetrack the well or drill a new well to drain off any isolated structures. The operator estimates recoverable reserves in Gyda Sør to be 1.5 mcm oil, 0.9 bcm gas, and 0.1 million tonnes NGL.

The partners plan to initiate production from Gyda Sør in 1994 and the field is expected to remain on stream until sometime in 1999.

Development concept

The planned production well from the Gyda platform to Gyda Sør will extend about 5700 metres in the horizontal direction. Processing will utilise the existing installations on Gyda. The capacities of gas treatment systems and the special gas export compressor may limit oil production from the Gyda Sør structure.

Transportation

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

Costs

The estimated investment costs for Gyda Sør up to 1999 are anticipated to be about 0.2 billion 1993 kroner.

2.7.2 Sleipner Vest

Production licences 046 and 029

Licensees

Den norske stats oljeselskap a.s (Statoil)	52.6000 %
Esso Norge a.s	28.0000 %
Norsk Hydro Produksjon a.s	9.4000 %
Elf Petroleum Norge A/S	9.0000 %
Total Norge A/S	1.0000 %

Field history

Sleipner Vest lies in blocks 15/6, 15/9 and 15/8, allocated in 1969 and 1976. See Figure 2.6.2. Statoil is operator of production licence 046 and Esso of production licence 029. The field was discovered by wildcat 15/6–3 in 1974 and the discovery was later confirmed between 1977 and 1982 by three wells in block 15/6 and nine in 15/9. The field was adopted for development in December 1992.

Reservoir

Sleipner Vest is a gas-condensate field, and the reservoir comprises Hugin formation sandstone laid down in the Jurassic. The Directorate estimates field reserves to be 135 bcm gas (including carbon dioxide), 27 mcm oil, and 9 million tonnes NGL. The Sleipner Vest gas contains up to 9 per cent carbon dioxide.

Development concept

The first phase of the development concept consists of a wellhead installation, Sleipner B, and an installation for processing and carbon dioxide removal, Sleipner T. See Figure 2.8.8. Sleipner B will be located in the southern part of the Sleipner Vest field, with transfer of the well flow to the Sleipner T installation located next to Sleipner A so as to exploit common utility systems. Further development of the northern reaches of Sleipner Vest is planned using subsea templates or wellhead installations with transfer of the well flow to Sleipner B.

The plan is to get Sleipner Vest ready to produce in October 1996, when the produced gas will be injected into Sleipner Øst in order to increase the production of crude oil and NGL from the latter. Sleipner Vest has been awarded the gas sale in connection with the 1991 contracts when the buyers exercise their 30 per cent options under the Troll gas sales agreements.

Costs
The estimated total development costs are 14.1 billion 1993 kroner for the first phase of the development and 19.5 billion 1993 kroner for development of the entire field. The total operating costs are estimated at 22.9 billion 1993 kroner including pipeline tariffs.

2.7.3 Frøy
Frøy is located in blocks 25/2 and 25/5 in production licences 026 and 102.

Licensees

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

Field history
Production licences 026 and 102 were allocated in 1969 and 1985, respectively, and are both operated by Elf. The field was proven in 1987 by well 25/5–1 and declared commercial in November 1990. The partners' plan for development and operation of Frøy was officially adopted in May 1992.

Reservoir
Frøy is an oil field and the Directorate's reserves estimates are 14 mcm oil and 3 bcm gas.

Development concept
The field is to be developed using a wellhead platform with single-stage separation. Oil and gas will be transported in separate flowlines to Frigg for further processing. Onward transportation will take place in the existing transport system for gas to Great Britain and in a new oil pipeline, Frostpipe, to Oseberg. The field will be drained with five production wells and four water injection wells. Production start is planned in summer 1995.

Costs
The estimated investment costs are 5.9 billion 1993 kroner, while the total operating costs have been estimated at 5.7 billion 1993 kroner exclusive of tariffs.

2.7.4 Lille-Frigg
Lille-Frigg is situated in block 25/2 covered by production licence 026; see Figure 2.8.10.a.

Licensees

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

Field history
The production licence was allocated in 1969 with Elf as operator. The 25/2–4 wildcat proved hydrocarbons in 1975. The plan for development and operation was adopted in September 1991.

Reservoir
Lille-Frigg is a combined gas-condensate field. The reservoir lies in the Brent group in a fault block which is an extension of the Heimdal ridge. The operator's estimates for recoverable reserves are 7 bcm gas and 3.6 million tonnes condensate.

Development concept
The Lille-Frigg field will be developed using a subsea template remotely controlled from Frigg. Development is based on three production wells with pressure loss as the drive mechanism. It will be possible to tie in two extra wells. The raw wellflow will be conducted under high pressure directly to Frigg for treatment. Gas will be transported to St Fergus in the existing pipeline. Stabilised condensate will be carried in a new line, Frostpipe, to Oseberg. Production start-up on Lille-Frigg, originally scheduled for 1 October 1993, has been delayed until the end of April 1994.

Costs
The estimated investment costs are now 3.6 billion 1993 kroner and the total operating costs roughly 1.5 billion 1993 kroner exclusive of tariffs.

2.7.5 Troll
The rights associated with Troll were allocated in 1979 under production licence 054 (block 31/2) and again in 1983 under production licence 085 (blocks 31/3, 31/5 and 31/6). Troll was proven in 1979 when the operator on block 31/2, A/S Norske Shell, drilled the 31/2–1 exploration well in Troll Vest.

In November 1983, A/S Norske Shell declared the section of the Troll field inside the block commercial. The licensees acceded to the declaration in December 1984 after 15 wells had been drilled in the block to delineate its extent.

The gas resources in Troll Øst were proven by well 31/6–1. Subsequent drilling formed the basis for unitisation of the field between the 054 and 085 licence partners in 1986.

The present rights in the Troll field are distributed as follows:

Troll Unit licensees

Den norske stats oljeselskap a.s (Statoil)	74.67600 %
A/S Norske Shell	8.28800 %
Norsk Hydro Produksjon A/S	7.68800 %
Saga Petroleum a.s	4.08000 %

Elf Petroleum Norge A/S	2.35344 %
Norske Conoco A/S	1.66113 %
Total Norge A/S	1.35343 %

The Troll field covers parts of blocks 31/2, 31/3, 31/5 and 31/6; see Figure 2.6.4. Development will take place in the following phases:

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

No decision has been reached regarding the development of Troll III.

Reservoir

The reservoir is situated in three geological formations of Late Jurassic age. The topmost formation, Sognefjord, is dominated by medium to coarse grade sandstone with good reservoir properties. This formation contains the bulk of the gas and oil in the field. Below the Sognefjord lies the Heather formation, which has inferior reservoir properties, and the Fensfjord formation with variable reservoir properties.

At the top of Troll Øst and Troll Vest is a gas column over 200 metres thick. The western part of the field (Troll Vest oil province), lying predominantly in block 31/2, features an oil column 22 to 26 metres thick, compared to 11 to 13 metres in the Troll Vest gas province. In Troll Øst the proven oil strata vary from zero to four metres in thickness.

At the bidding of Norsk Hydro the partners remapped the Troll Vest provinces in 1993 using 3D seismic. By doing so their understanding of the extent of the Troll reservoir sands was markedly improved.

The Directorate estimates the Troll reserves to comprise:

	Reserves			Resources in place
	Oil mcm	Gas bcm	NGL mton	Oil mcm
Troll phase I (Troll Øst)		825	19.2	
Troll phase II (Troll Vest oil province)	61			184
Troll phase III (Troll Vest gas province)		463	10.8	421

Troll phase I: Development of gas reserves in Troll Øst

Shell is the development operator for Troll phase I, but it has been agreed that Statoil will take over the operatorship when the field comes on stream.

Led by the operator, A/S Norske Shell, the licensees submitted their plan for development and operation of the gas reserves in Troll Øst (Troll phase I) to the authorities in September 1986. The Storting adopted the plan for development and operation in December 1986. The plan called for a fully integrated platform with initial processing capacity of 23.7 bcm gas a year. The operator was asked to submit a revised plan with a more detailed description of the installation and processing equipment. Such a revised plan was submitted by the licensees in May 1990 and adopted by the authorities in December the same year.

This new development plan for Troll phase I entails drainage of the gas reserves in Troll Øst from a fixed wellhead installation with a concrete base. The platform location is about 80 kilometres northwest of Bergen in 303 metres of water. The wellflow from up to 40 wells will be transferred from the installation via two 915 millimetre diameter multiphase pipelines to the landing site at Kollsnes in the Øygarden local district.

Condensate will be separated from the gas in the onshore processing facility and will be transported via a 203 mm pipeline to the terminal at Sture for the market. The dry gas will be compressed and exported from the onshore terminal to the Continent through new pipelines. When completed in 1996, the Kollsnes facility as now planned will have a capacity of 89 mcm gas a day. The licensees are simultaneously looking at options for greater additional capacity.

Some of the gas from the field has been sold under the Troll gas sales agreements (TGSA) finalised in 1986 with buyer groups in Germany, the Netherlands, Belgium, France, and Austria. Since 1986, further gas sales agreements have been negotiated with other buyers, where Troll, or other fields, will supply the gas. Under the agreements the initial gas will be delivered from Sleipner from 1 October 1993 pending production start-up of the Troll field in 1996.

Total investment costs for Troll phase I have been estimated at 33.4 billion 1993 kroner, with estimated total operating costs of 27 billion 1993 kroner.

Troll phase II: Development of oil reserves in Troll Vest

Troll phase II involves development of the 22–26 metre thick oil column in the Troll Vest oil province. Norsk Hydro operates both the development and operating phases.

The plan for development and operation of Troll phase II was submitted to the authorities in December 1991 and adopted by the Storting in May 1992. In connection with the adoption of Troll phase II it was decided that Statoil will be the operator for further planning, development and operation of the residual gas in the Troll field. Norsk Hydro, though subject to Statoil's overall coordination, will be the operator for any development, or for modification and operation of the Troll phase II installation, if this is also used to treat part of the residual gas in the Troll field.

The original plan for drainage of Troll Vest oil reserves called for oil production from 17 horizontal wells. A concrete floater was recommended for the processing and storage of the oil before export, after studies had been made of concepts using floaters, fixed installations, and ships. An installation capable of handling both oil and subsequent gas production from Troll Vest was also considered by the licensees.

The planned plateau production is 25,000 scm oil a day, corresponding to about 157,000 barrels a day. Between 5 and 6 mcm gas a day can be exported to the Troll phase I installation for landing at Kollsnes together with gas and condensate from Troll phase I.

The licensees decided in 1992 to carry out gas injection through a separate injection well in the southern part of the reservoir in the Troll Vest oil province. This will increase the recovery factor for oil and is considered by the Directorate to be an improved production strategy for the southern part of the oil province. In addition, it was decided to increase the number of production wells in the Troll North oil province from five to six. According to the present plans, Troll II will therefore be developed with 18 oil producers and a single gas injector, deployed in four subsea stations, which in turn are tied in to the parent installation. In addition, the installation will have capacity for hook-up of another five subsea stations from the Troll Vest gas province.

Norsk Hydro, which operates Troll phase II, has drilled two appraisal wells in order to clarify the potential for production from the oil column in the Troll Vest gas province. Based on the new mapping the licensees are planning oil production from the first cluster of wells in the south of the Troll Vest gas province. A plan for development and operation is expected to go to the authorities in the first quarter 1994. The total investments in Troll phase II are estimated at 16.8 billion 1993 kroner and the total operating costs on the field at 14 billion 1993 kroner.

Further development of the time-critical oil resources in the gas province is being examined. The Directorate estimates recoverable oil reserves to be 30–40 mcm.

Troll phase III: Development of gas reserves in Troll Vest

A future development of the gas reserves in the Troll Vest gas province will constitute phase III of the Troll field development. Various development concepts, dates of production start-up, and coordination concepts involving other infrastructure on the Troll field are being examined and are contingent in part on future gas sales scenarios.

TOGI

In addition to the principal gas development project in Troll Øst (Troll phase I), a subsea production system (Troll Oseberg Gas Injection, TOGI) has been built with Norsk Hydro being the operator for development and operation.

The TOGI template, which is located in Troll Øst, is controlled from the Oseberg field centre and supplies gas for injection in the Oseberg field. The production and delivery of TOGI gas from Troll Øst started in February 1991.

TOGI investments are in the region of 3 billion 1993 kroner, while total operating costs up to 1999 inclusive are an estimated 1.1 billion 1993 kroner.

2.7.6 Tordis

Tordis is situated in block 34/7; see Figure 2.8.13.a. Production licence 089 was allocated in 1984 with Saga as operator. The sliding scale was exercised in the production licence giving the following equity distribution:

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

Landing Troll oil

When the Storting adopted the development of Troll phase II in May 1992, the transport solution for the oil from the field had not been clarified. In autumn 1992, the licensees decided to land the oil by pipeline to the Mongstad terminal. The development and operation of the transport system will be carried out by a Statoil operated partnership in which all licensees in the Troll field are represented. Statoil submitted a plan for construction and operation (PCO) of a landing pipeline from the Troll phase II installation to Mongstad on 12 May 1993. As additional documentation was needed, Statoil prepared an additional PCO that was submitted on 10 September 1993 and adopted by the authorities in December 1993.

The total investments in the Troll oil pipeline are an estimated roughly 1 billion 1993 kroner with annual operating costs of 11 million 1993 kroner.

Field history

Tordis was proven by drilling the 34/7–12 wildcat in 1987. An appraisal well, 34/7–14, was drilled on the field in autumn 1989. Based on these two wells the field was declared commercial, and the plan for development and operation was adopted by the Storting in May 1991.

Reservoir

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

Development concept

The plan is to develop the field with subsea completion wells: five producers and two water injectors. The well flow will be carried to Gullfaks C for processing, metering and forwarding. Production was originally planned to start in autumn 1994 but has been advanced a couple of months. The gas will be sold under the Troll gas sales agreements.

Costs

Total investments are estimated at about 3.7 billion 1993 kroner, including wells and modification costs on Gullfaks C. The estimated total operating costs are 1.7 billion 1993 kroner.

2.7.7 Statfjord Øst

Statfjord Øst is situated in production licences 037 and 089; see Figure 2.8.13.a. Production licence 037 covers blocks 33/9 and 33/12 and was allocated in 1973, while production licence 089 covers block 34/7 and was allocated in 1984.

The sliding scale has been exercised in the two licences, giving the following licensees in the unitised field:

Licensees after unitisation

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

Field history

The plan for development and operation of Statfjord Øst was adopted by the Cabinet on 9 November 1990. Statoil operates the field. A unitisation agreement for Statfjord Øst was signed in June 1991 which splits the reserves with 50 per cent to each of the two licences, 037 and 089. On 19 November 1991, the Ministry of Petroleum and Energy approved a unitisation agreement for Statfjord Øst, whereby Statfjord Nord and Statfjord Øst will have a common project organisation and share the same equipment on Statfjord C. Production from Statfjord Øst is planned to start in the fourth quarter of 1994 and will continue until the year 2007.

Reservoir

According to Statoil's estimates the oil reserves are 19.4 mcm. The Directorate's estimate is only 13.3 mcm, which is about 30 per cent lower. Differences in geological model account for most of the discrepancy. Results from production wells drilled in autumn 1993 show that the reservoir rock volume is greater than hitherto supposed.

Development concept

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

Costs

The estimated investment costs for Statfjord Øst are 3.7 billion 1993 kroner. The total operating costs for Statfjord Øst are estimated at 1.1 billion 1993 kroner. The work to modify the Statfjord C platform is now believed to be more extensive than first supposed.

2.7.8 Statfjord Nord

Statfjord Nord is situated in block 33/9 covered by production licence 037 and was allocated in 1973; see Figure 2.8.13.a.

Licensees

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

Field history

The plan for development and operation of Statfjord Nord was adopted by the Cabinet on 9 November 1990. Statoil operates the field. The original plan was for production from Statfjord Nord to start in 1994, but due to lack of treatment capacity on Statfjord C, the start has been delayed. There is a unitisation agreement binding Statfjord Nord and Statfjord Øst.

Reservoir

According to Statoil's estimates, there are 31 mcm oil reserves and 2.5 bcm gas reserves in place. This estimate assumes that eight production wells will be drilled and that oil production is not terminated until the year 2014. Any decision to drill two extra wells will be deferred until after production start-up.

Development concept

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

Costs

Investment costs for Statfjord Nord run to 3.9 billion 1993 kroner; operating costs for Statfjord Nord have been estimated at 1.2 billion 1993 kroner. The operating costs given by the operator involve some measure of uncertainty since the strategies for maintenance and compilation of data have not been finalised.

2.7.9 Heidrun

Heidrun is situated in blocks 6507/7 and 6507/8, see Figure 2.6.6, the former being allocated in 1984 under production licence 095, and the latter in 1986 under production licence 124.

Licensees after unitisation

Den norske stats oljeselskap a.s (Statoil)	75.0000 %
Norske Conoco A/S (operator)	18.1250 %
Neste Petroleum a.s	5.0000 %
Norsk Hydro Produksjon a.s	1.2500 %
DNO Olje a.s	0.6250 %

Statoil will take over the Heidrun operatorship from Conoco in the operating phase. Production start-up is scheduled for autumn 1995.

Field history

The Heidrun field was discovered in 1985 and declared commercial in December 1986. The plan for production and operation of the field was submitted in November 1987, including early production. The plan was adopted but the partners discontinued their efforts to implement it, and the operator submitted a revised plan in December 1989. This plan was adopted by the Storting in May 1991. However, the decision about what to do with the associated gas was postponed. In November 1991, the Government presented a proposition recommending landing of the associated gas for methanol production, a solution which was adopted by the Storting in February 1992.

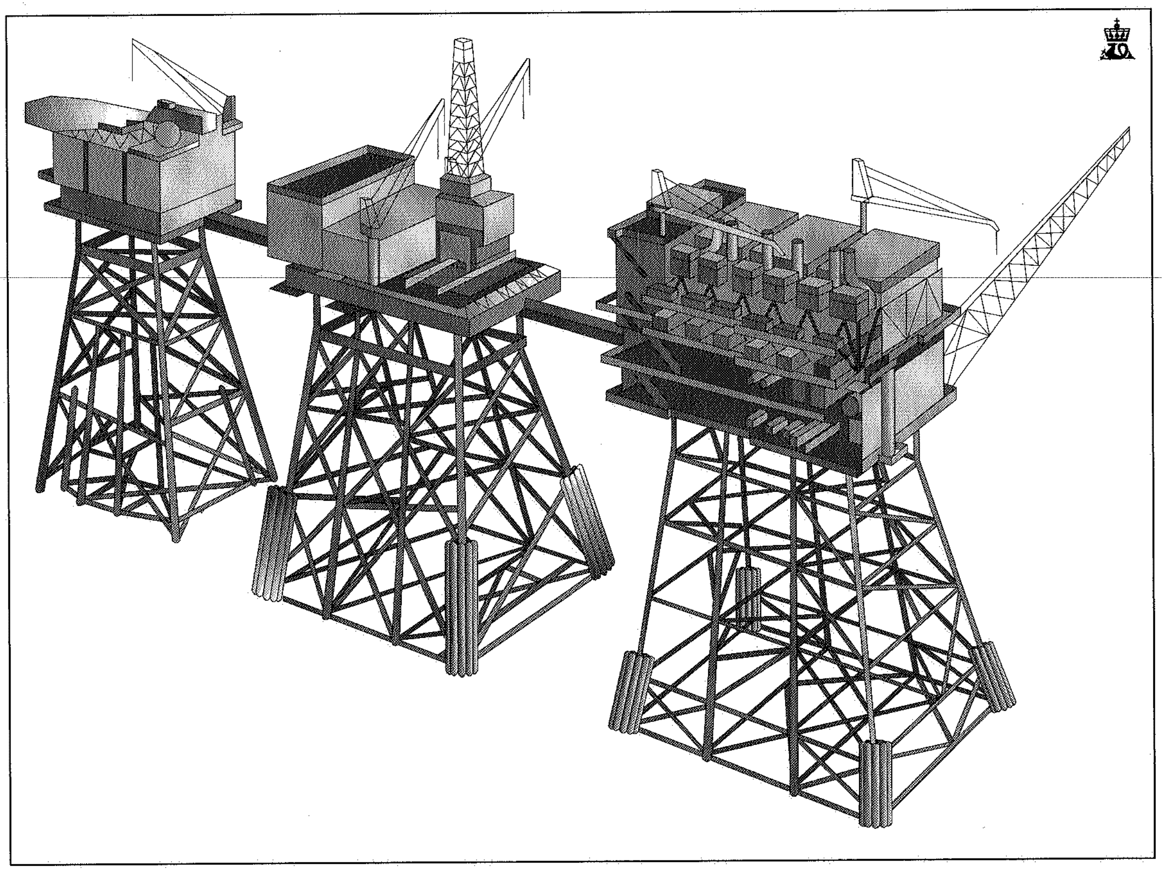
Reservoir

The field contains oil with a overlaying gas cap. The reservoir is faulted and comprises several geological formations. For optimal resource exploitation the gas cap should be produced after the bulk of the oil. The reserves estimates for Heidrun have given rise to much uncertainty, the Directorate's estimates being 87 mcm oil and 38 bcm gas, while the operator estimates 119 mcm oil and 45 bcm gas. The variations in reserves estimates are primarily due to differences in geological models.

Development concept

Heidrun has sea depths of roughly 350 metres and will be developed using a concrete floater installed over a subsea template with 56 well slots. The plan calls for

Fig. 2.8.2
Installations on Valhall



35 production wells, 11 water injection wells and two gas injection wells to be drilled. Six of the water injectors will have subsea completion. The projected production capacity for oil is 35,000 scm a day; while maximum treatment capacity for water will be 24,700 cubic metres a day, and for gas 4,7 mcm a day. Oil will be exported by means of a new concept based on direct shipboard loading (DSL), which is tanker transport without the use of offshore oil storage.

Costs

The estimated total investment costs are 28 billion 1993 kroner. In the production phase, annual operating costs are estimated at about 700 million 1993 kroner.

Gas application

Associated gas will be reinjected into the reservoir in the period 1995–96 and subsequently landed to Tjeldbergodden for methanol production from the fourth quarter 1996. Production of the gas cap is not feasible until the end of the oil production period.

2.8 FIELDS IN PRODUCTION

2.8.1 Hod

Production licence 033

Licensees

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

Hod lies in block 2/11 and was allocated in 1969. The field is located about 12 kilometres south of the Valhall field. Parts of the block have later been relinquished, and parts of the relinquished acreage have been included in production licence 068. The Hod field consists of two separate structures. See Figure 2.8.4.a.

The plan for development and operation of Hod was adopted by the Storting in June 1988, and production from the field started to flow in October 1990.

Production

Hod is a chalk field in the Central Graben producing from several formations. Production is enabled from two wells in the western structure and three wells in the eastern structure. About 95 per cent of the production comes from the eastern structure. A renewed evaluation of the potential for improved oil recovery was completed in September 1993, resulting in the estimated recovery factor for oil being increased from 17 per cent to 22 per cent. Estimated total reserves are 7.8 mcm oil, 2.3 bcm gas, and 0.4 million tonnes NGL.

Production installations

The development features an unmanned production installation, where oil and gas are separated and metered before being piped to Valhall for further processing.

Transportation

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

Metering system

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

Costs

The total investments in the Hod field from 1988 to 2011 are estimated at approx 1 billion 1993 kroner. The operating costs for 1993 were roughly 110 million kroner.

2.8.2 Valhall

Production licences 006 and 033

Licensees

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

Block 2/8 was allocated in 1965. In 1989, the interest held by Texas Eastern Norwegian Inc was sold to Enterprise Oil Norwegian A/S. In 1991, Norwegian Oil Consortium A/S & Co was sold to Elf. Valhall is located primarily in block 2/8, which contains 92.8 per cent of the reserves (production licence 006). The remaining 7.2 per cent lie in block 2/11 (production licence 033), in which each partner owns 25 per cent. See Figure 2.8.4.a. The field development plan was adopted by the Storting in 1977, and production started in autumn 1982.

Production

Valhall produces from fragmented chalk. The recovery factor at present is estimated at 30 per cent. Estimated total reserves are 94.0 mcm oil, 25.3 bcm gas, and 4.8 million tonnes NGL. In summer 1990, a pilot project was initiated whereby water was injected into the Tor formation from a well on the field. The intention was to test the efficacy of water injection to improve drainage. Water break-through occurred in one of the adjacent wells after injection of some 600,000 cubic metres of water. The results so far have been positive both with regard to injectivity and improved drainage. There have been no indications of water break-through in other producers. The water pilot was completed in September 1993.

The Ministry of Petroleum and Energy ordered the operator to perform an extended field study (UFS) of the Valhall reservoirs in 1991, the purpose of which was to evaluate feasible measures to increase field recovery, including both gas and water injection. It is expected that this study will be completed in January 1994.

Production installations

The development of Valhall comprises quarters, drilling, production and riser platforms, the three first-mentioned being on the field and connected to each other by gangways. See Figure 2.8.2 for details. The riser platform – for which Phillips is the operator – is connected to the Ekofisk tank.

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

Transportation
The crude oil including NGL is transported by pipeline to Ekofisk for Teesside, while the gas is carried in a separate pipeline to Ekofisk for Emden.

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

Costs
The total investment costs on the Valhall field from August 1977 through year 2011 are expected to reach 20 billion 1993 kroner, while the operating costs in 1993 have been estimated at about 1 billion kroner.

2.8.3 Tommeliten Gamma and Tommeliten Alpha

Production licence 044
Licensees

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

Production licence 044, allocated in 1976, embraces block 1/9 southwest of the Ekofisk area; see Figure 2.8.4.a. Tommeliten Alpha was the first discovery made by Statoil, in December 1976. Tommeliten Gamma followed just over a year later in January 1978.

The partners' plan for development and operation of Tommeliten Gamma was adopted by the Storting in June 1986. Production started on 3 October 1988.

Production
Production from Tommeliten Gamma is processed on the Edda installation. A portion of the gas is used as gas lift for wells on Edda and thus extends the economic duty cycle of the Edda field. Total reserves for Tommeliten Gamma are estimated at 3.4 mcm oil, 8.2 bcm gas, and 0.5 million tonnes NGL.

At the end of 1993 no plan for development and operation of Tommeliten Alpha had been submitted.

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

Transportation
Following the first stage separation on Edda, the Tommeliten gas is taken by pipeline to the Ekofisk field centre for further drying, while the dry gas is entrained in Phillips's gas export system for delivery to Emden.

Tommeliten crude is transported from Edda to the Ekofisk field centre and from there it flows by pipeline to Teesside.

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

Costs
The total investments in Tommeliten Gamma from 1986 to 1997 will amount to about 3 billion 1993 kroner. The operating costs in 1993 were roughly 50 million kroner.

2.8.4 Ekofisk area

Production licence 018
Licensees

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

This group, called the Phillips Group, owns the rights to the Cod, Edda, Ekofisk, Eldfisk, Embla, and Vest Ekofisk fields. Cod lies in block 7/11; Edda, Embla and Eldfisk in block 2/7; and Ekofisk and Vest Ekofisk in block 2/4. See Figure 2.8.4.a.
The Albuskjell field, located in blocks 1/6 and 2/4, is split between production licences 018 and 011. The Albuskjell field interests are split as follows:

Phillips Group	50.0000 %
A/S Norske Shell	50.0000 %

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

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

The Ekofisk area consists of eight fields in production: Albuskjell, Cod, Edda, Ekofisk, Eldfisk, Embla, Tor and Vest Ekofisk. See Figure 2.8.4.b. Cod was discovered in 1968. Ekofisk was discovered in 1969 and declared commercial the year after. The other fields in the area were discovered between 1969 and 1974. Production from the area started in June 1971. The last field to come on stream in the area was Embla, which started producing in May 1993.

For a number of reasons the authorities on 16 June 1993 demanded the submission of a revised plan for development and operation for production licence 018.

On 31 December 1993, the plan was submitted to the authorities, describing two plausible future solutions for the Ekofisk area. It will be considered in spring 1994.

The fields Cod and Embla produce from sandstone strata, while the other fields in the area produce from chalk. The Ekofisk field is the largest in the area with a hydrocarbon pore volume about 30 per cent greater than Statfjord. The recoverable oil reserves from the field are estimated at 355 mcm. Eldfisk is the next largest field in the area with 77 mcm recoverable oil.

Production

The Ekofisk area has been developed in several stages. From June 1971 to May 1974, oil was recovered from four wells which had been completed on the seafloor on the Ekofisk field. The fields Cod, Tor and Vest Ekofisk were developed and tied in with the Ekofisk field centre at the same time as the oil pipeline was laid to Teesside and the gas pipeline to Emden. These pipelines came on stream in October 1975 and Sep-

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

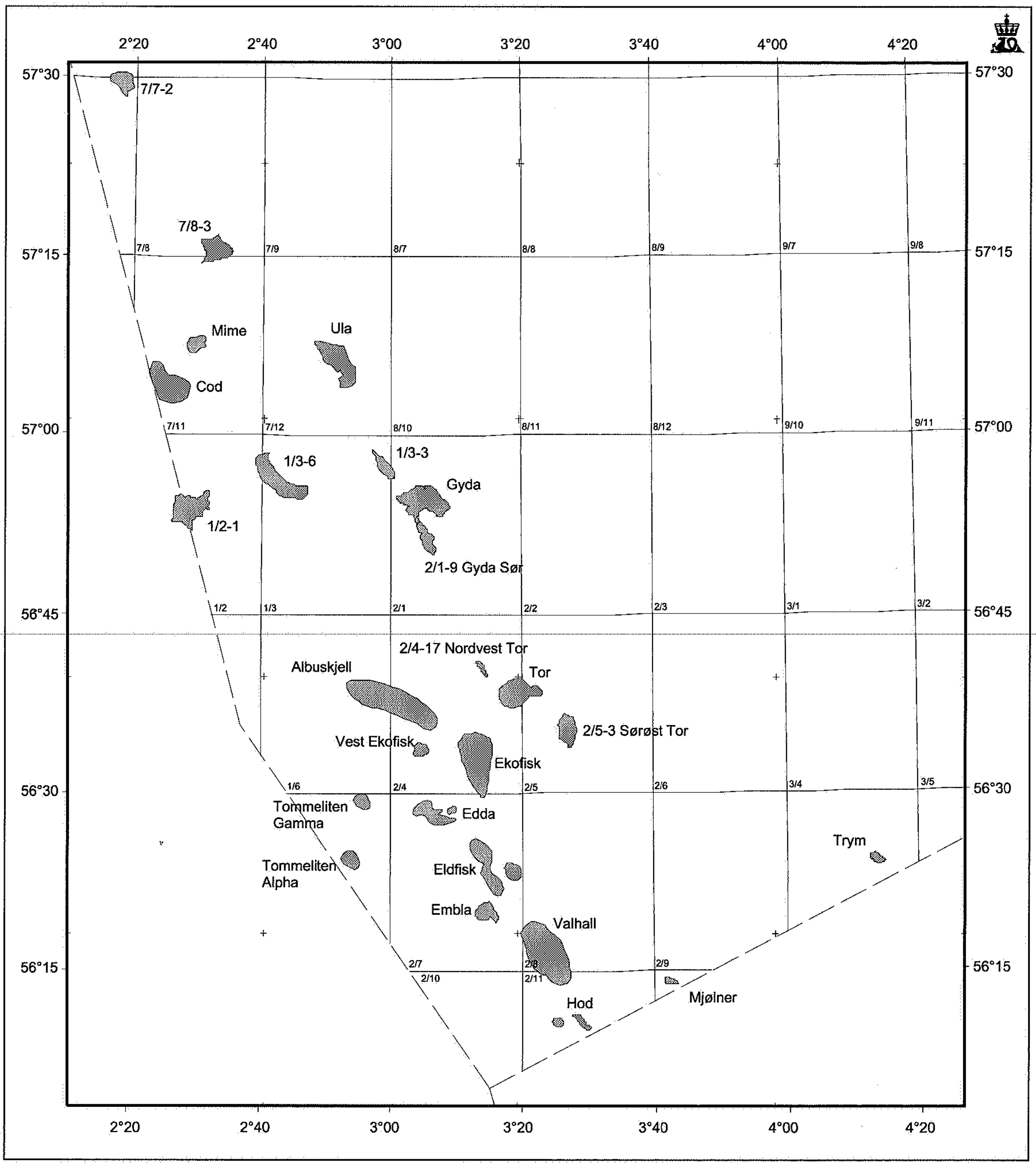
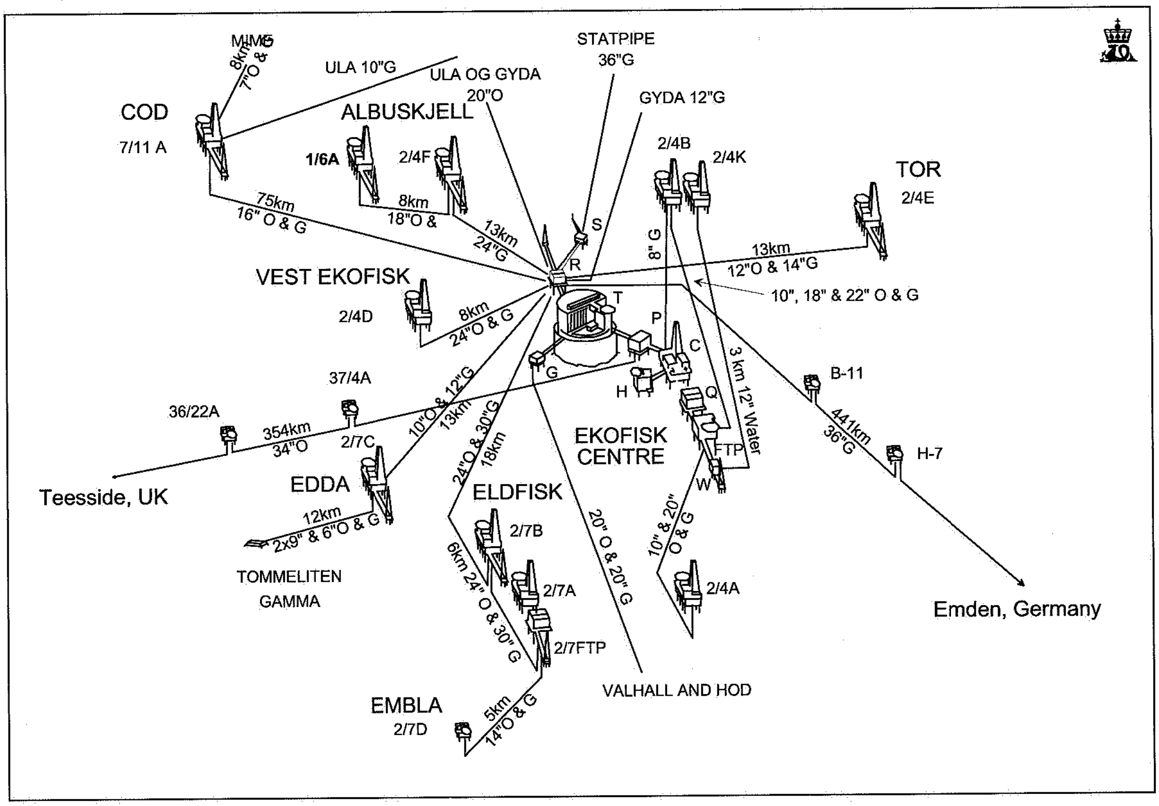


Fig. 2.8.4.b
Installations in the Ekofisk area



tember 1977, respectively. Before the gas line was commissioned the gas had been re-injected into the Ekofisk field. The second development stage involved the tie-in of Albuskjell, Edda and Eldfisk to the Ekofisk field centre. Embla was developed using a sporadically manned wellhead installation remotely controlled from Eldfisk Alpha.

All the fields in the area were originally developed with depressurisation as the drive mechanism. The oil recovery factor from the fields in the area is therefore expected to be relatively low, about 30 per cent. The possibility of improving the recovery factor, however, remains considerable.

Limited gas injection, implementation of full-scale water injection, and improved understanding of the reservoir have all greatly helped increase the recovery factor on the Ekofisk field. Estimates show that it has increased from originally 18 per cent to over 35 per cent today. Production flows from two formations on the field, namely the Tor formation and the overlying Ekofisk formation. There is a varying degree of communication between the formations. A waterflood project started in 1981 with field trials in the Tor formation. Injection on a larger scale commenced in 1987. The area under injection has gradually been expanded, first to the lower part and in 1993 also to the upper part of the Ekofisk formation.

The first horizontal well on the field was drilled and came on stream in 1993. Preliminary evaluations of the production are promising with regard to future drainage of the flank areas. In 1993, the operator submitted an updated extended field study (UFS) for the Ekofisk field. Both the current and extended study describe the status after 20 years of field experience and look at future enhanced recovery and reservoir management scenarios.

The Eldfisk field produces from three separate structures. The recovery factor for oil is low, approx 21 per cent. Various improved oil recovery methods are described in the operator's extended field study, including optimising continued depressurisation, gas injection, water injection, as well as more advanced methods.

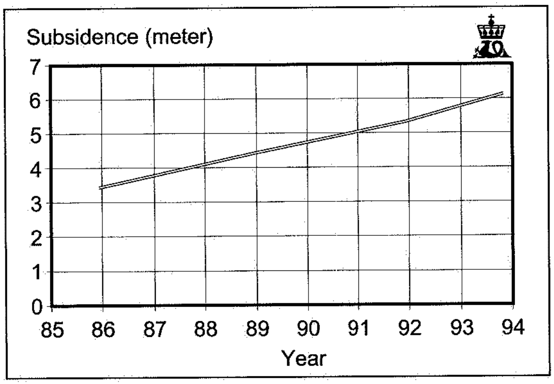
On the Tor field, water injection started from a single well in 1992. The operator is evaluating the additional potential for water flooding or gas injection. The first horizontal well spudded came on stream in 1992 on the Tor field. An extended field study describing future possibilities on Tor will be submitted to the Directorate in 1994.

The original plan for Embla calls for development in several phases, where phase 1 entails a wellhead installation accommodating up to 18 wells. By September 1993 a total of four wells had come on stream. A revised plan for development and operation is to be prepared by 1 June 1994.

Subsidence

Subsidence of the seabed has been observed on the Ekofisk, Eldfisk, and Vest Ekofisk fields. It was only

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



in November 1984 that the phenomenon was noticed at the Ekofisk field centre. Since then, measurements have shown that the total subsidence was 5.98 metres as of 15 December 1993. Figure 2.8.4.c shows subsidence readings at 2/4-H in the period 1985–93. The rate of collapse in 1993 was more than 40 cm (about 16 inches) a year.

The subsidence of the seabed is caused by the highly porous reservoir rock being squeezed together due to depletion of the reservoir. There is still some doubt about the mechanism by which the reservoir volume reduction takes place and causes subsidence. In order to limit further subsidence and other problems related to compaction of the reservoir the net reservoir recovery must be limited. An attempt was made using a combination of water and gas injection in the Ekofisk field. In 1993, the operator employed unconventional methods to increase the water flood capacity, when mud pumps on 2/4-K and an injection module on the *Neddrill Kolskaya* jack-up were used to augment the capacity already in place on 2/4-K. Some 80,000 cubic metres of water and almost 4 mcm of gas were injected on a daily basis in order to limit the net reservoir depletion.

In summer 1987, the steel platforms at the Ekofisk field centre were all jacked up to offset the subsidence. In order to protect the Ekofisk tank a concrete barrier was built and placed around the tank in 1989.

Transportation
The gas is transported by pipeline to Emden. The capacity is usually fully exploited. The oil, containing the NGL fraction, is carried by pipeline to Teesside. Here the transport capacity is augmented by boosting the operating pressure. As a further measure, anti-friction additives (drag reducers) are added, giving a total current transportation capacity of over 95,000 scm a day.

Metering systems
Sales metering of oil, NGL and natural gas takes place at the terminals in Teesside and Emden. Total oil and gas deliveries to the Teesside and Emden pipelines from the area are metered and analysed on the Ekofisk tank. In addition, oil and gas production are metered on the individual satellite platforms before being transferred by pipeline to the Ekofisk field centre. The exceptions are Vest Ekofisk and Ekofisk itself, which are metered on the Ekofisk tank. All metering systems are made to fiscal standard and make up part of the operator's system for hydrocarbon distribution. Modernisation work is currently being undertaken in Teesside, Emden and the Ekofisk area.

Costs
Future investment costs depend on the choice of concept for redevelopment and operation.

2.8.5 Gyda
Production licence 019B
Licensees

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

The Gyda field is located in block 2/1; see Figure 2.8.4.a. The field was proven in 1985 and declared commercial in January 1987. The plan for development and operation was adopted by the Storting in spring 1987. Gyda came on stream on 21 June 1990.

Production
The reservoir is in Upper Jurassic sandstone. In 1993, the operator made a minor downward adjustment in the reserves estimates from 32.1 mcm oil and 4.2 bcm gas to 30.6 mcm oil and 4.0 bcm gas. NGL reserves remain unchanged and stand at 1.9 million tonnes.

At the end of 1993, the field had production from twelve wells and injection in seven. Two wells have been shut down due to a high water cut. Production of oil in 1993 was higher than forecast. From 1994 onward the oil production will decline and the last year of production is expected to be 2009.

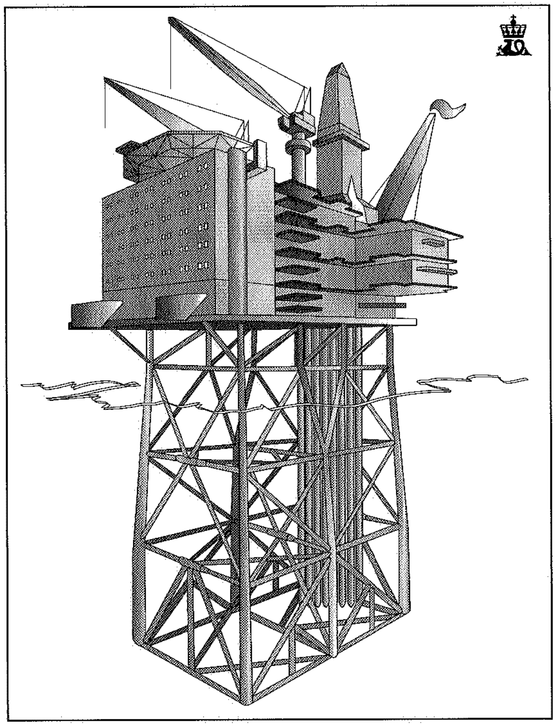
Production installations
The development concept for the field comprises a combined drilling, quarters and processing installation with a steel jacket; see Figure 2.8.5.

Current production capacity is 11,000 scm oil and 1.6 mcm gas a day. The water injection capacity was doubled in 1992, and the plan is to double the field's treatment capacity for produced water in 1994. In connection with production from Gyda Sør an increase in the maximum export capacity by modification of the existing gas export compressor is contemplated.

Transportation
The Gyda crude is transported to Ekofisk via the Ula pipeline and thence to Teesside, whereas the gas is transported in a separate pipeline to Ekofisk and from there to Emden.

Metering system
Oil and gas production is metered to fiscal standard before being piped to Ekofisk. The metering systems

Fig. 2.8.5
Installation on Gyda



are included in the Ekofisk system for distribution of hydrocarbons.

Costs
Total investments from 1987 to 2012 are expected to be 8.6 billion 1993 kroner, whereas operating costs in 1993 came to roughly 510 million kroner.

2.8.6 Ula

Production licence 019A
Licensees

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

The Ula field, situated in block 7/12, see Figure 2.8.4.a, was discovered in 1976. It was declared commercial in December 1979. The plan for development and operation was adopted in January 1984.

Production
The Ula field is in Upper Jurassic sandstones from which production started in October 1986. At the end of 1993, eight wells were producing while six injected water. Three oil producers had to be shut down due to a high water cut. The water front is now advancing from the north and east towards the central parts of the field, and production will decline gradually until it ceases altogether in 2007.

In 1992, the operator was ordered to prepare an extended field study (UFS) for the Ula field so that the licensees would have a basis for deciding on measures to improve oil recovery.

In the underlying Triassic reservoir, recoverable volumes of oil have been proven only in the northern part of the field. The operator's reserves estimates for the Triassic reservoir are in the order of 0.1 to 2.4 mcm oil. The operator is planning production from the Triassic reservoir to start in 1994–95.

Production installations
The development concept involves three conventional steel jacketed platforms for production, drilling and quarters; see Figure 2.8.6.

Current production capacity is 21,700 scm oil and 1.63 mcm gas a day. The water injection capacity was upgraded to 30,900 cubic metres a day in 1992. The plan is to increase the treatment capacity for produced water in 1994 from 6500 to approximately 15,900 cubic metres a day.

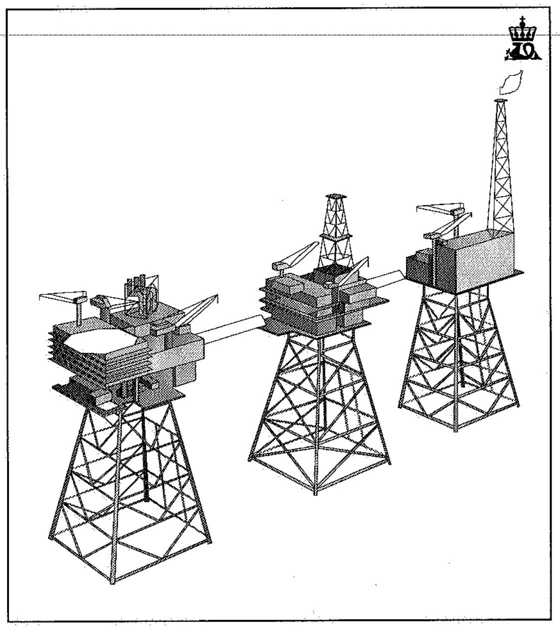
All 18 well slots are now in use, and new wells will be deviated from existing wells.

Transportation
The Ula crude is carried by pipeline via Ekofisk to Teesside. Statoil operates the pipeline. The Ula gas is piped via Cod to Ekofisk and then Emden.

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

Costs
The estimated total investments in the period 1983 to 2007 will be about 12 billion 1993 kroner, while the

Fig. 2.8.6
Installations on Ula



total operating costs in 1993 amounted to roughly 560 million kroner.

2.8.7 Mime

Production licence 070

Licensees

Den norske stats oljeselskap a.s (Statoil)	51.0000 %
Norsk Hydro Produksjon A/S (operator)	24.5000 %
Saga Petroleum a.s	9.8000 %
Norske Conoco A/S	7.3500 %
Amoco Norway Oil Company	7.3500 %

Mime is a small oil field seven kilometres north of Cod, in block 7/11 allocated in 1987; see Figure 2.8.4.a. The field was discovered in 1982 and test production started on 25 October 1990. The plan for development and operation of Mime was adopted by the authorities on 6 November 1992.

Production

The reservoir consists of Upper Jurassic sandstone in the Ula formation. Mime is produced from one well, located centrally in the structure. In November 1993 production from Mime was temporarily suspended due to the precipitation of asphaltenes in the well. Total production depends on the actual lifetime of the Cod platform.

Production installations

Production is by means of a subsea completion well with transfer of the well flow to the Cod installation.

Transportation

The oil and gas from Mime are mixed with gas and condensate from the Cod production and transferred to the Ekofisk field for final processing and allocation. Whereas the oil is forwarded to Teesside, the gas is used locally at the Ekofisk field centre.

Metering system

The test separator on the Cod installation is used to meter the well flow from Mime.

Costs

The estimated total investment costs in the period 1989 to 1997 are about 0.4 billion 1993 kroner, while the operating costs for 1993 amounted to about 10 million kroner.

2.8.8 Sleipner Øst

Production licence 046

Licensees

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

The production licence was allocated in 1976 and embraces blocks 15/8 and 15/9; see Figure 2.6.2. The plan for development and operation was adopted in 1986, and the field came on stream on 24 August 1993.

Production

Two reservoir strata have been proven in Sleipner Øst, one a Tertiary reservoir called the Heimdal formation and one a Jurassic-Triassic reservoir called the Hugin formation. The estimate for total reserves is 47.0 bcm gas, 27.1 mcm oil, and 15.2 million tonnes NGL. So far, three wells have been drilled from the Sleipner A installation: two gas producers and one gas injector. In addition to this, two production wells have been drilled from the template at Sleipner Øst. In the plan, new wells will be drilled from the Sleipner A installation continuously until 1997, comprising both production and injection wells. It has been decided to reinject gas into Sleipner Øst to enhance condensate recovery from the field. New 3D seismic will be compiled in 1994 to provide field data at the Jurassic level.

Production installations

Sleipner Øst has been developed using an integrated process, drilling and accommodation platform with a quadripod concrete gravity base; see Figure 2.8.8. After the concrete gravity base for the Sleipner A installation sank in the Gandsfjord in August 1991, the licensees have extensively revised their plans for development of Sleipner Øst with a view to meeting the field's gas sales obligations under the Troll gas sales agreements. The two most important changes in the development concept are a new riser installation and a new subsea production system in order to drain the northern part of the Sleipner Øst field.

Transportation

The condensate will be landed to Kårstø through a new 250 kilometre long, 508 mm diameter pipeline from the Sleipner A installation, while the gas will be piped partly to Zeebrügge in Belgium and partly through the Statpipe-Norpipe system to Emden in Germany.

Metering system

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

Costs

The estimated total development costs will be about 20 billion 1993 kroner in the period 1987 to 1996. The operating costs for 1993, including Loke, were about 600 million kroner, while the operating costs for 1994, which is expected to be a normal year of operation, are estimated at about 800 million kroner (including Loke, described below).

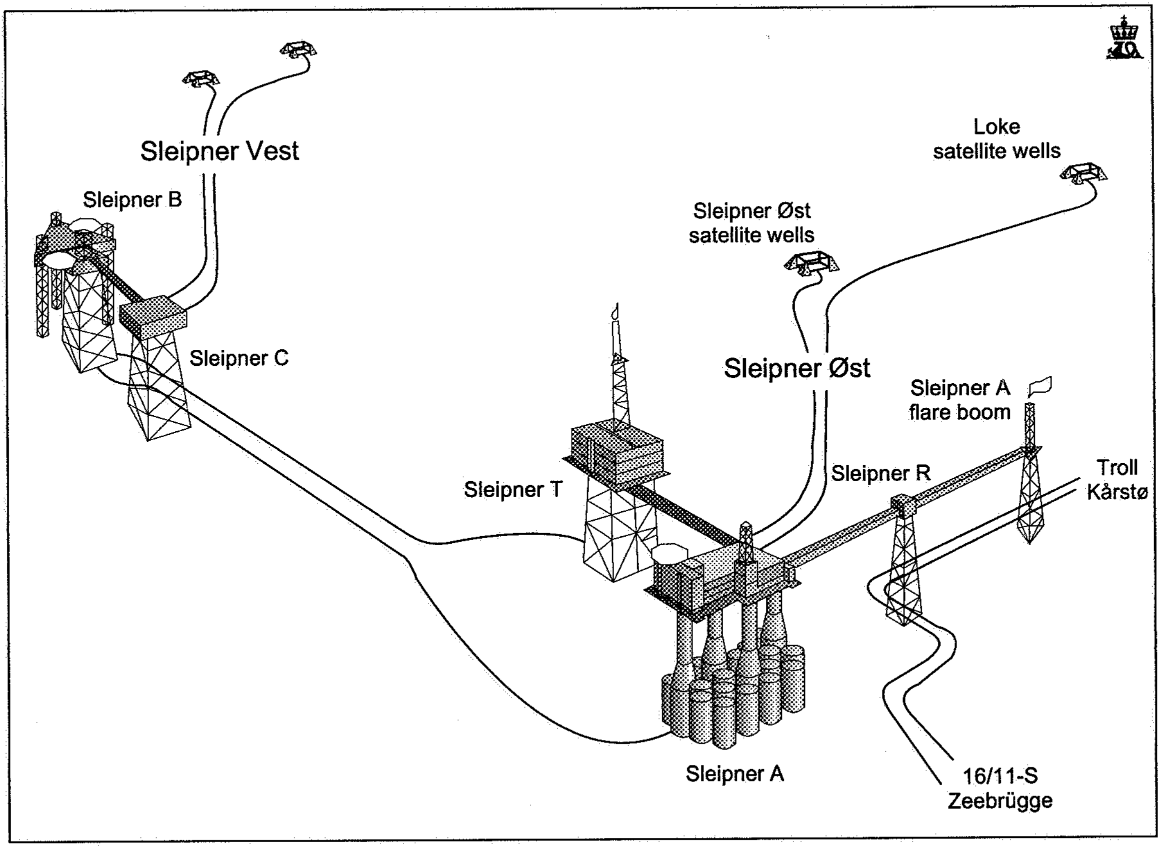
2.8.8.1 Loke

Production licence 046

Licensees

Den norske stats oljeselskap a.s (Statoil) (operator)	49.6000 %
Esso Norge a.s	30.4000 %

Fig. 2.8.8
Existing and projected installations in the Sleipner area



Norsk Hydro Produksjon a.s	10.0000 %
Elf Petroleum Norge A/S	9.0000 %
Total Norge A/S	1.0000 %

The production licence was allocated in 1976 and is the same as for Sleipner Øst. The field was proven by well 15/9–17 in 1983; see Figure 2.6.2. The plan for development and operation was adopted by the Storting in 1991 and Loke came on stream on 11 September 1993.

Production
Two reservoir strata corresponding to the reservoir strata in Sleipner Øst have been proven, but it is only the reservoir in the Heimdal formation that is being drained. The Heimdal formation in Loke has pressure communication with the Heimdal formation in Sleipner Øst. Depletion of Sleipner Øst will therefore influence the pressure in Loke. Prior development of Loke will therefore prevent large volumes of hydrocarbons from being trapped in the aquifer between Loke and Sleipner Øst. Loke will be drained from one well. The total estimated reserves for the Heimdal formation are 0.7 bcm gas, 0.39 mcm oil and 0.18 million tonnes NGL. One exploration well has been drilled from the Loke template into a prospect west of Loke, where a new oil discovery was made in 1993 in Early Jurassic sandstone.

Production installations
Loke will be produced by means of a subsea production system with transfer of the well flow to the Sleipner A installation; see Figure 2.8.8.

Costs
The total estimated investment costs for the field in the period 1991–93 are about 0.6 billion 1993 kroner. The operating costs are included in the operating costs for Sleipner Øst.

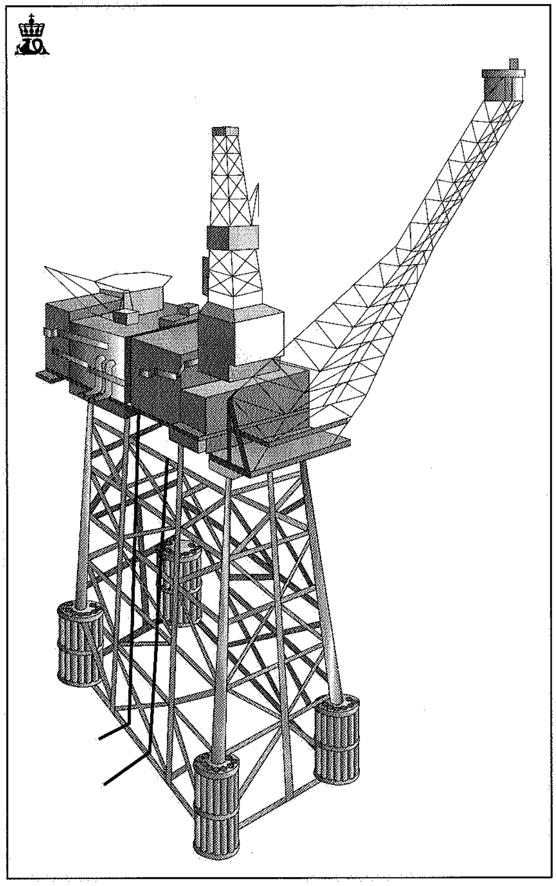
2.8.9 Heimdal
Production licence 036
Licensees

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

Production licence 036 was allocated in 1971 and covers block 25/4; see Figure 2.8.10.a. On that part of the license which embraces Heimdal, the Norwegian State has exercised its option.

The field was proven in 1972 with exploration well 25/4–1 and declared commercial in April 1974. Landing of the gas to the Continent was approved on 10

Fig. 2.8.9
Installation on Heimdal



June 1981, and the landing concept for condensate received Storting approval in January 1983. Production drilling on the Heimdal field started in April 1985.

Production
The field produces from the Heimdal formation, which consists of Palaeocene sand. The estimated total reserves in place in Heimdal are 35.6 bcm gas and 5.7 mcm oil and condensate.

Ten wells – nine producers and one observation and injection well – have been drilled from the field installation, although one producer had to be shut down in 1987 due to leakage problems. Because of the powerful water drive in the field, pressure decline and water ascent are both carefully monitored. Production has reached plateau level.

In October 1992, development of a Jurassic deposit located beneath the main reservoir received approval. The reservoir turned out to have smaller reserves than first assumed, making further plans for drainage of the deposit uncertain.

Production installations
Heimdal has been developed with an integrated steel jacket structure combining drilling, production and quarters functions; see Figure 2.8.9. Production start-up was in December 1985 and delivery of gas via Emden began in February 1986.

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

Metering system
Both the gas and condensate are metered to fiscal standard on the Heimdal installation. In the case of the condensate system, the accreditation is done in collaboration with the British Department of Trade and Industry.

Costs
The total investments in the Heimdal field are in the region of 13 billion 1993 kroner in the period from 1981 to 1997. The operating costs for 1993 amounted to approx 441 million kroner.

2.8.10 Frigg area
2.8.10.1 Frigg
Licensees

Norwegian share (60.8200 %) (PL 024)	
Elf Petroleum Norge A/S	25.1910 %
Norsk Hydro Produksjon A/S	19.9920 %
Total Norge A/S	12.5960 %
Den norske stats oljeselskap a.s (Statoil)	3.0410 %
British share (39.1800 %)	
Elf Exploration UK Ltd	26.1200 %
Total Oil Marine Ltd	13.0600 %

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

The Frigg field is situated in blocks 25/1 and 30/10

Fig. 2.8.10.a
Fields and discoveries in the Frigg area

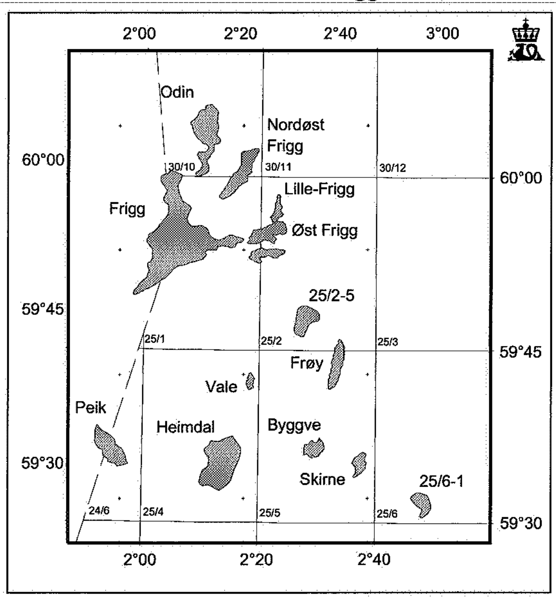
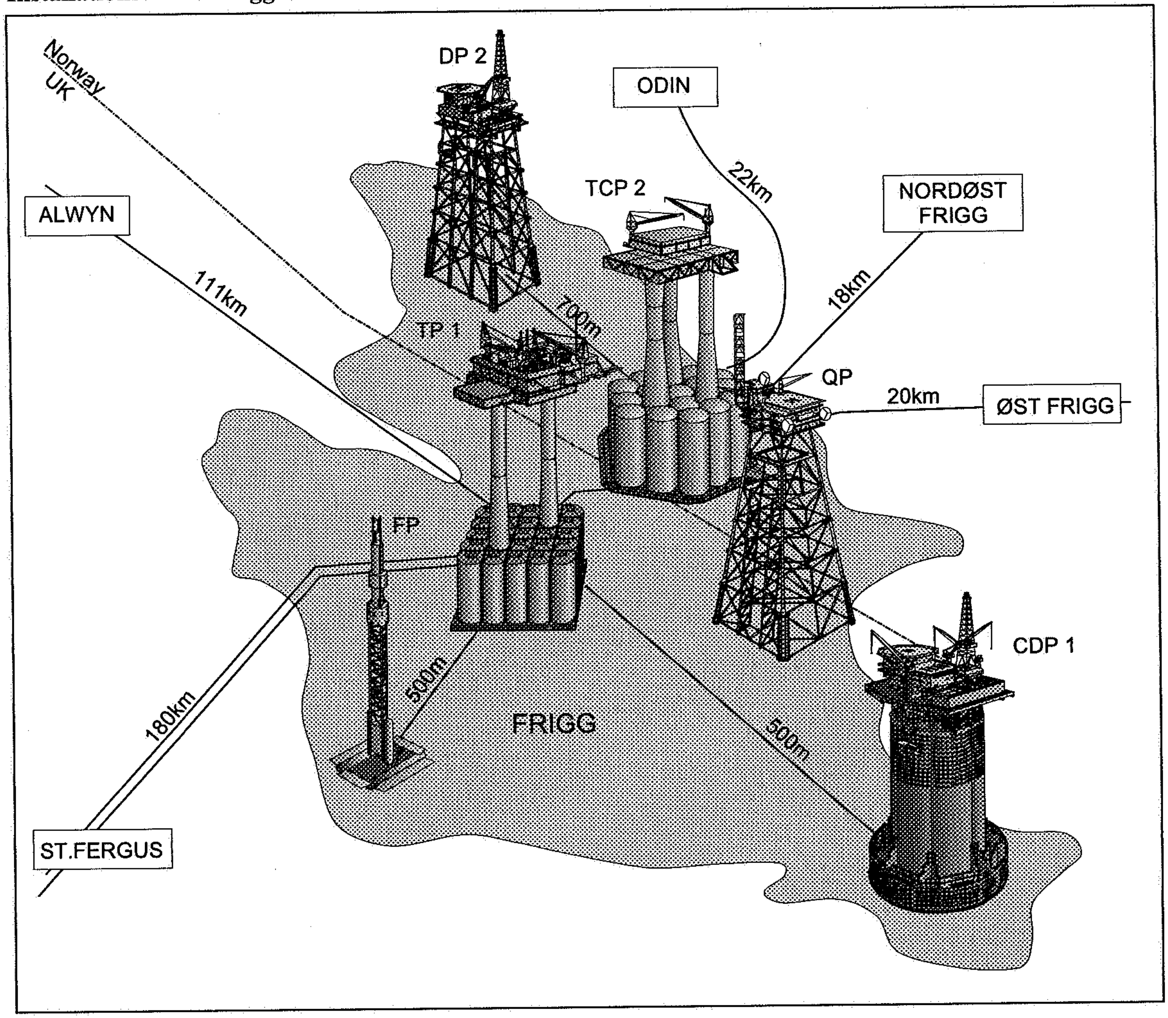


Fig. 2.8.10.b
Installations in the Frigg area



in the Norwegian sector and blocks 10/1, 9/5 and 9/10 in the UK sector; see Figure 2.8.10.a. The field has been unitised with 60.82 per cent of gas reserves in place being deemed by agreement to belong to the Norwegian partners.

Frigg was discovered in spring 1971 and declared commercial on 25 April 1972. The resolution to go ahead with development was passed in spring 1974.

Production

The field produces from the Frigg formation, which consists of Eocene sand. The total estimated reserves are 184 bcm gas. On CDP1 all production wells have been permanently plugged, whereas on DP2 there are 16 wells available for production, 15 of which have reduced production potential due to water influx in the wells. Future water encroachment will be decisive for shutdown of the field.

Production installations

The field was developed in three phases, phase 1 comprising production and processing installations in the UK sector and a quarters platform (CDP1, TP1 and QP). Production from these installations started on 13 September 1977.

Phase 2 comprises the production and processing platforms DP2 and TCP2 in the Norwegian part of the field. Production from these came on stream in summer 1978. Figure 2.8.10.b shows the Frigg installations.

Phase 3 of the Frigg development comprises the installation of three turbine driven compressors on TCP2, which are necessary to compensate for the declining reservoir pressure. Commissioning of the compressor plant was finished in autumn 1981.

Gas from Nordøst Frigg (until 8 May 1993), Odin and Øst Frigg is processed and metered on Frigg. New modules for processing of gas and condensate from these satellite fields have been installed on TCP2. Export of gas from Alwyn North in the UK sector flows through TP1.

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

Modification work has been done on TCP2 in order to process gas from Lille-Frigg and Frøy. This work will continue in 1994.

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

Metering system – Frigg area
Gas export via the pipeline to St Fergus is metered to fiscal standard collectively for the Norwegian Frigg fields. The contribution from the Frigg field proper is determined by deducting the contributions from Nordøst Frigg, Øst Frigg and Odin from the total gas export. Condensate that has been separated out is metered separately and injected into the gas pipeline for transport to St Fergus.

Costs
The estimated total investments in the Norwegian part of the Frigg field are about 24 billion 1993 kroner over the lifetime of the field. Investments in the transportation system come on top of this figure. The operating costs for 1993 were roughly 500 million kroner.

2.8.10.2 Øst Frigg
This field is in production licence 024 (block 25/1), production licence 026 (block 25/2), and production licence 112 (previously relinquished part of block 25/2, reallocated in 1985); see Figure 2.8.10.a.

Licensees in the unitised Øst Frigg field

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

Øst Frigg consists of two structures located in blocks 25/1 and 25/2. The reserves are split with 21.593 per cent in production licence 024, 77.536 per cent in 026, and 4.871 per cent in 112. The field was declared commercial in August 1984 and the landing application approved by the Norwegian Storting on 14 December the same year. Production commenced in August 1988 and the sale of gas on 1 October 1988.

Production
The two principal structures, Alpha and Beta, were discovered in 1973 and 1974. They are part of the same pressure system as the Frigg field, and the gas is therefore sold to the British Gas Corporation (BGC) under the existing sales agreement.

Following updating of the simulation model the gas reserves have now been estimated at 8.6 bcm, with 5.4 bcm in the Alpha structure and 3.2 bcm in Beta.

Production installations
The Øst Frigg development concept is based on subsea completion: Two templates for the production stations and a central manifold station tying the systems together were installed on the seabed in summer 1987. The subsea production systems are remotely controlled from the Frigg control room. From the manifold a gas and service line runs to TCP2, where the gas is processed and fed into the Frigg field transportation system. Before starting up on Øst Frigg, it was also necessary to make modifications on Frigg in order to accept the gas.

Costs
The estimated total investments in the field are about 2.8 billion 1993 kroner. The operating costs for 1993 amounted to 51 million kroner.

2.8.10.3 Nordøst Frigg
Production licences 024 and 030
Licensees in the unitised Nordøst Frigg field

Elf Petroleum Norge A/S (operator)	11.0964 %
Norsk Hydro Produksjon a.s	13.8054 %
Total Norge A/S	8.6982 %
Den norske stats oljeselskap a.s (Statoil)	8.4000 %
Esso Norge a.s	58.0000 %

The Nordøst Frigg field lies in blocks 25/1 and 30/10, see Figure 2.8.10.a, where a redistribution of the gas reserves in August 1984 assigned 42 per cent to the former and 58 per cent to the latter.

The gas field Nordøst Frigg was proven in 1974 and the final development plan was adopted in 1980. Production from the field ceased on 8 May 1993.

Production
The Nordøst Frigg reservoir belongs to the same sedimentation system as the Frigg field. The total recoverable reserves in place in Nordøst Frigg are believed to be 11.8 bcm gas.

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

Pressure measurements made before production start-up showed that the reservoir communicates with the Frigg field via the underlying aquifer.

Production installations
The field was developed with six wells drilled through a subsea template. The plan for removal of the Nordøst Frigg installation was submitted to the authorities on 30 August 1991, and a decision is expected in 1994.

Costs
The estimated total field investments were roughly 3.2 billion 1993 kroner, while the operating costs for 1993 amounted to about 36 million kroner.

2.8.10.4 Odin

Production licence 030
Licensees

Esso Norge a.s	100 %

Statoil is entitled to 17.5 per cent of net profit before tax. The Odin field lies in block 30/10; see Figure 2.8.10.a. This gas field was proven in 1974 and the field development plan adopted in 1980.

Production
Odin produces from the same sedimentation system as the Frigg field. The estimated total reserves in place are 26.9 bcm gas. Gas sales from Odin were initiated on 1 October 1983 in the pre-delivery arrangement with Frigg. Since production start-up in April 1984, Odin has been reinstating the pre-delivered volumes in addition to delivering its own contract quantities.

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

In spring 1990, the operator detected water breakthrough in the field's southernmost well. It was expected that water would break through in this well first, but it occurred rather earlier than anticipated. New studies show that the residual reserves are less than assumed and that the lifetime of the field will be somewhat curtailed.

Production installations
The field development concept involved a small steel jacket structure with relatively modest processing and drilling facilities and comparatively small quarters. This concept was feasible because a standby vessel was chartered for two years in connection with installation work and production drilling.

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

Costs
The estimated total investments in the field are about 4.5 billion 1993 kroner. The operating costs for 1993 amounted to about 180 million kroner.

2.8.11 Oseberg area

2.8.11.1 Oseberg

Production licences 053 and 079
Licensees in the unitised Oseberg field

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

The Oseberg field extends into two blocks: block 30/6 in production licence 053 allocated in 1979, and block 30/9 in production licence 079 which was allocated in 1982. See Figure 2.6.4.

Those parts of the two production licences which cover Oseberg have now been unitised. In 1993, the partners made a new unitisation accord for blocks 30/6 and 30/9. The accord assigned the equity units as follows from 1 January 1994:

Unitised Oseberg field

Production licence 053	61.8171 %
Production licence 079	38.1829 %

The plan for development and operation was adopted in 1984. Production start-up for the Oseberg field centre took place on 1 December 1988, while the Oseberg C installation came on stream on 2 September 1991.

Production
The first discovery on Oseberg was made in 1979 which proved gas. Later evidence showed that the reservoir is an oil bearing stratum with a gas cap. The field consists of several reservoirs in the Brent group in multiple structures. The main reservoirs are found in the Oseberg formation in the Alpha and Gamma structures.

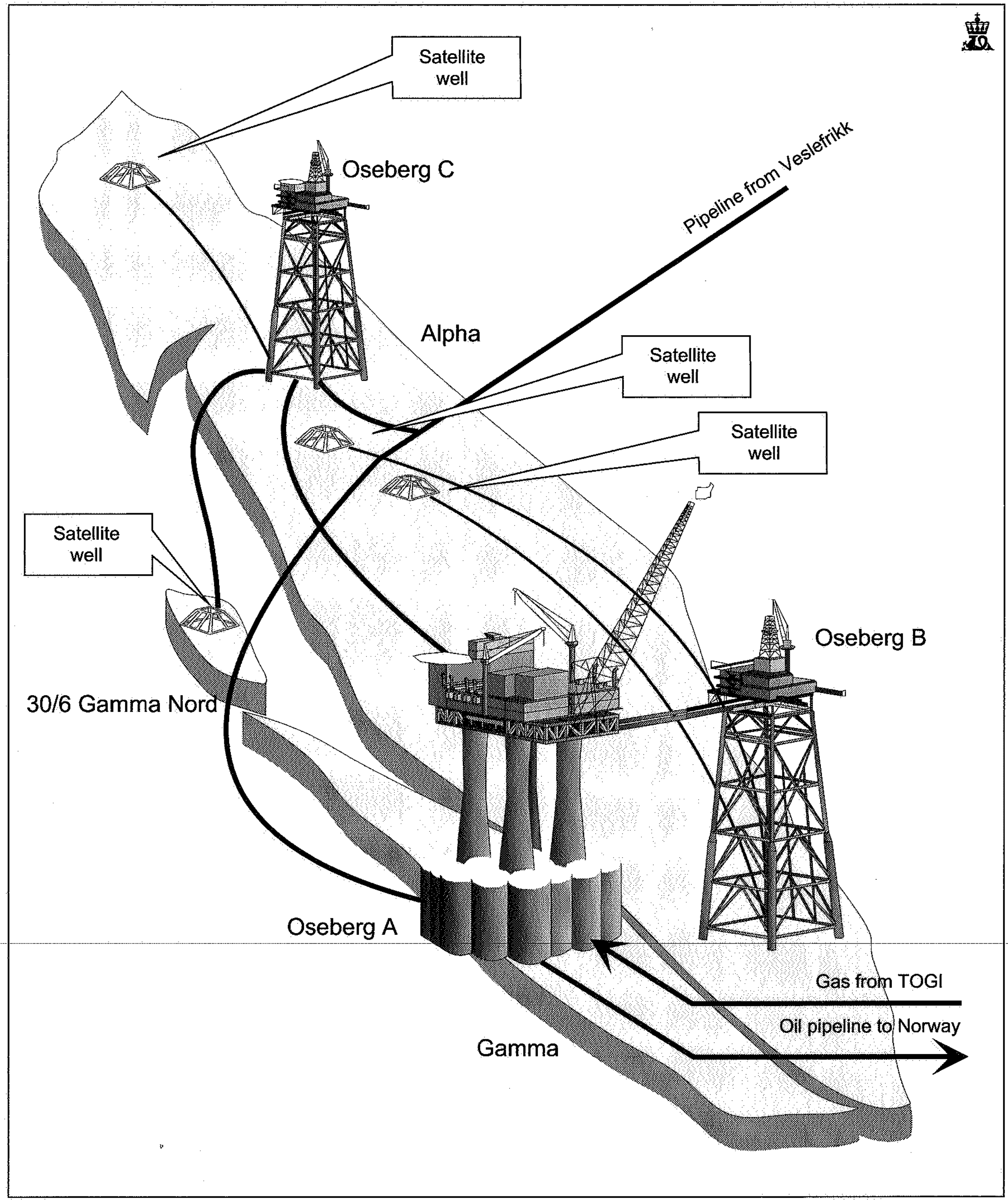
The estimated total reserves in the field are about 300 mcm oil, including approx 13 million tonnes NGL. This gives a mean recovery factor for oil close to 55 per cent. Although the original plans did not call for horizontal wells, the majority of recent producers have been drilled horizontally with excellent results. A test using foam to retard gas breakthrough in a producer is planned in 1994.

The gas reserves in Oseberg are estimated at about 106 bcm, including the recoverable part of injected gas from TOGI and 30/6 Gamma Nord. It has not yet been determined when gas export from Oseberg will start.

Production installations
The Oseberg field was developed in two phases. Phase 1 was developed with a field centre in the south comprising two installations, Oseberg A which is a process and quarters platform with a gravity base, and Oseberg B which is a drilling and waterflood platform with a steel jacket. The central part of the field will be depleted using two subsea completion wells tied in to the field centre. The mean crude processing capacity is about 55,000 scm a day.

Phase 2 involves development of the northern part of the field. In the revised Oseberg plan the C installation has been upgraded from a satellite unit to an integrated production, drilling and quarters (PDQ) platform employing the services of a support vessel during the drilling phase. The mean crude processing capacity is some 20,000 scm a day.

Fig. 2.8.11
Installations on Oseberg



For a diagram of the installations; see Figure 2.8.11.

Metering system

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

Costs

By year end 1993, about 43 billion 1993 kroner had been invested in the Oseberg field. The total from 1983 to 2001 is expected to be about 53 billion 1993 kroner. The operating costs in 1993 were roughly 1900 million kroner. These costs do not include the Oseberg Transport System described below.

2.8.11.2 30/6 Gamma Nord

Production licence 053

Licensees

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

The Gamma Nord field is situated in block 30/6 and was allocated in 1979; see Figure 2.6.4. It is included in the revised development plan for the northern part of Oseberg and came on stream in October 1991.

Production

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

The estimated total reserves are 0.9 mcm oil, 6.2 bcm gas, and 0.4 mcm NGL.

Metering system

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

Costs

Total investments are estimated at 0.6 billion 1993 kroner from 1988 to 1994, while the operating costs for 1993 are estimated at 20 million kroner.

2.8.12 Veslefrikk

Production licence 052

Licensees

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

Veslefrikk lies in the southeast of block 30/3, allocated in 1979; see Figure 2.6.4. The plan for development and operation was adopted by the Storting in April 1987. An updated reservoir management report, prepared after pre-drilling of six production wells, was submitted in September 1989. The field started production on 26 December 1989. After 13 production wells had been drilled, yet another revised plan for reservoir management was prepared in February 1992.

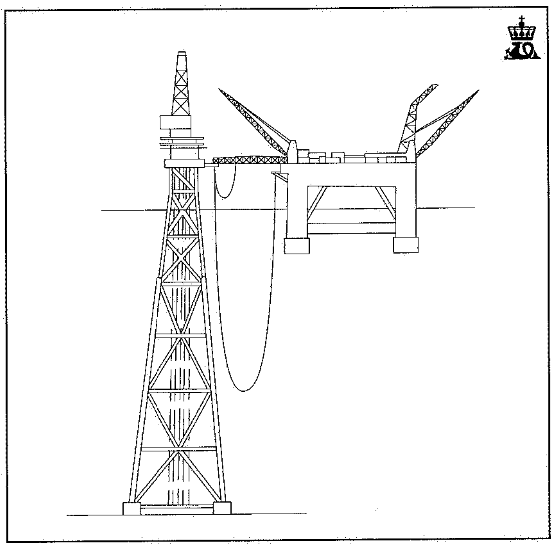
Production

The Veslefrikk field produces from reservoirs in the Brent group and Dunlin group (Intra Dunlin Sand). Effective October 1993, the reserves were upgraded by about 25 per cent compared to the estimate at the time of production start-up. The upgrade is due to greater rock volume, since the reservoirs in several fields have come in higher than anticipated. Moreover, the recovery factor has increased as the production history indicates better lateral communication across faults than originally projected. The drilling of exploration well 30/3–5 in June 1992 proved resources in the G area, a downfaulted segment along the southeastern flank of the field. This segment turned out to have pressure communication with the main field and has now been phased into the production. Production from the G area is slightly poorer than from the main field due to less favourable reservoir characteristics and weak natural water drive. The reserves estimates are now 45.3 mcm oil and 3.6 bcm associated gas. The resources in isolated pressure regimes in Upper Brent were not included in the latest calculations.

Production from the field is by means of water injection. In addition, water alternating gas (WAG) injection will be used to enhance recovery.

Resources are also found in a deeper reservoir in the Statfjord formation. This reservoir has a gas cap and a higher content of associated gas than the Brent and Dunlin reservoirs. These resources were not declared to be commercial in connection with the PDO, essentially due to the market price of gas. The potential demand for gas in connection with the WAG project as well as improved recovery technology later led to increased interest in gas from the Statfjord formation, and these resources could be declared commercial in December 1993. The PDO for this reservoir

Fig. 2.8.12
Installations on Veslefrikk



should be presented in the course of the first six months 1994. Resources in place are estimated at 5.2 mcm oil, 1.9 bcm associated gas, 1.9 bcm free gas, and 1.9 mcm condensate from the gas cap.

Production installations

The field has been developed with a fixed wellhead installation with a steel jacket and a semi-submersible platform containing the processing facilities and living quarters; see Figure 2.8.12. The wellhead unit is installed above a template with six pre-drilled wells. There are now twelve producing wells and seven water injection wells. A semi-submersible, formerly the *West Vision* drilling rig, is moored and hooked up to the fixed wellhead unit.

The Veslefrikk production facilities have returned 92.8 per cent availability. Water injection was initiated in spring 1991.

Transportation

An oil pipeline is connected to the Oseberg Transport System for transportation to the Sture terminal. Gas is carried through the Statpipe system. An interim agreement has been struck with the Heimdal partners for intermediate storage of the Veslefrikk produced gas in Heimdal.

Metering system

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

Costs

The estimated total investments from 1987 to 2009 are 9 billion 1993 kroner, while the operating costs for 1993 are estimated at 640 million kroner.

2.8.13 Gullfaks and Gullfaks Vest

Production licence 050

Licensees

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

Gullfaks lies in the northeastern part of block 34/10 and covers an area of about 200 square kilometres. Figure 2.8.13.a shows the location. Gullfaks was discovered in 1978. Due to the phased development, separate field development plans for phases 1 and 2 were adopted in 1981 and 1985, respectively. The phase 1 concept embraces the A and B installations, while the C installation represents phase 2. Production from the field started to flow in December 1986. The Gullfaks field produces oil with associated gas.

Fig. 2.8.13.a
Fields and discoveries in the Gullfaks, Statfjord and Snorre area

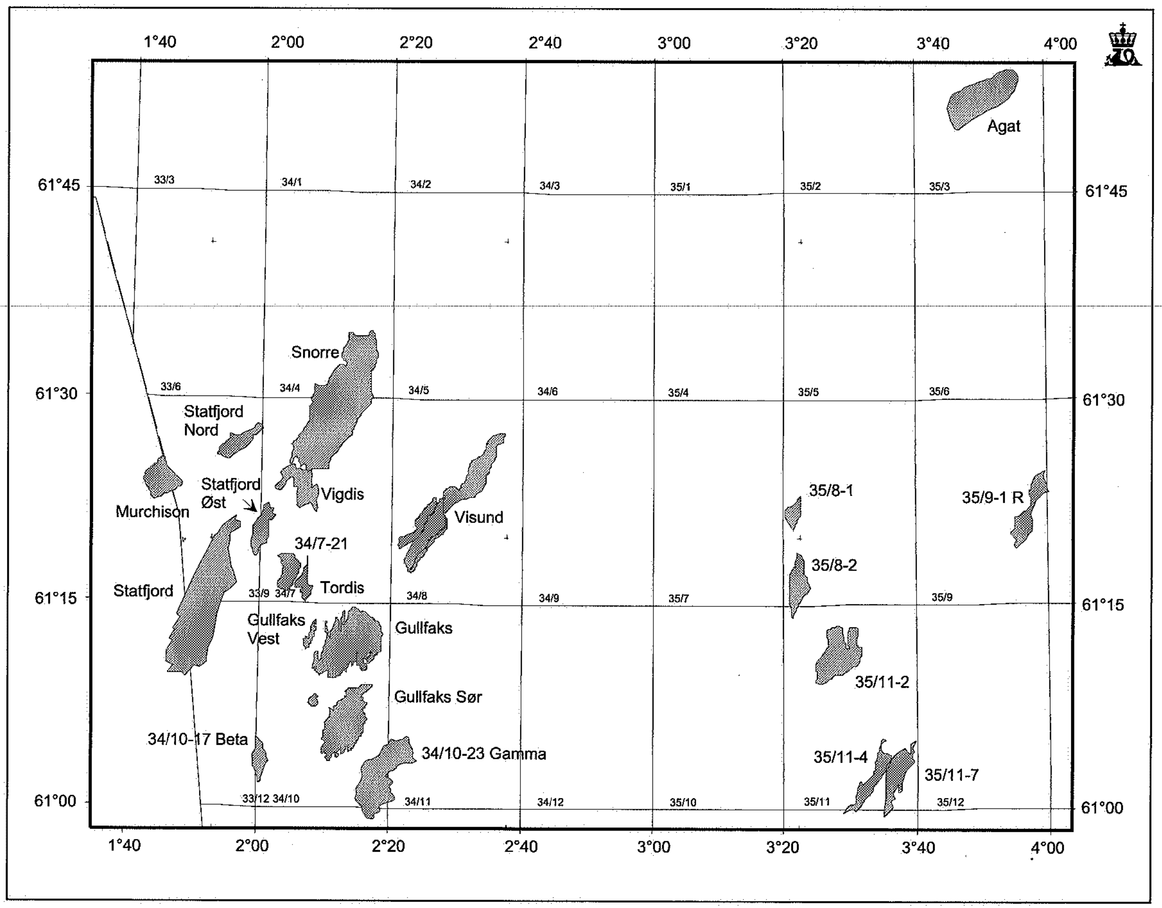
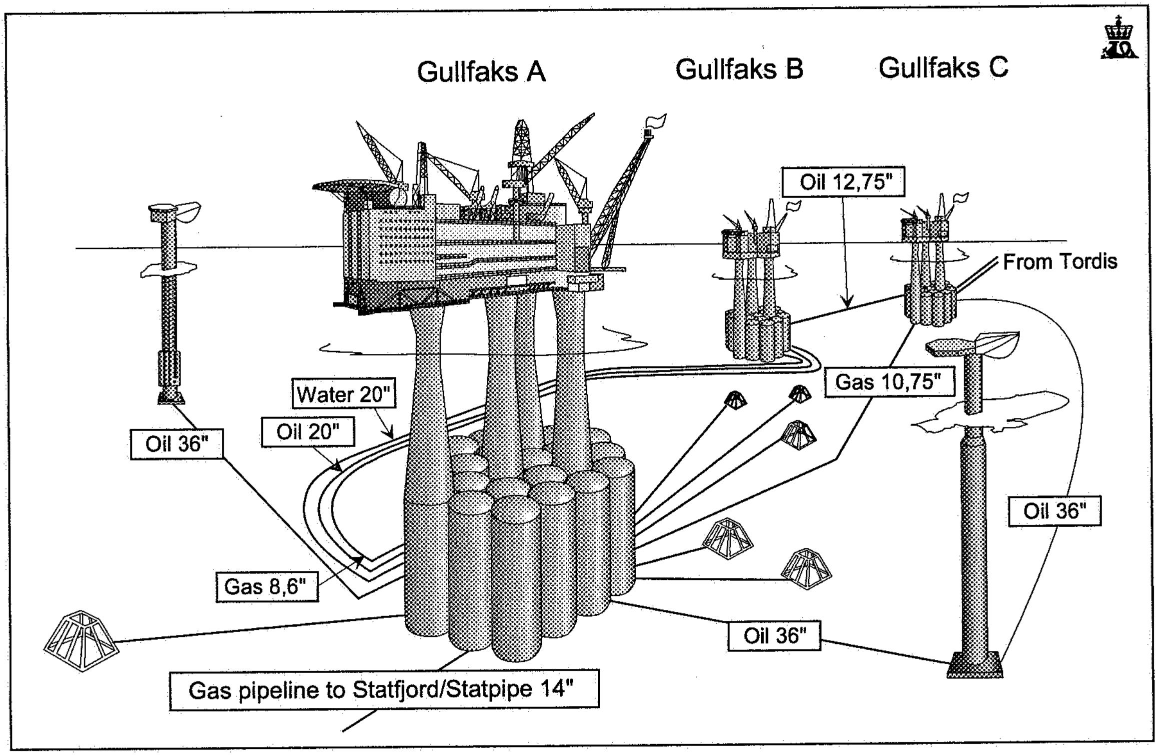


Fig. 2.8.13.b
Installations on Gullfaks



Production

The Gullfaks field contains oil in Jurassic sandstone. Gullfaks is a relatively shallow accumulation having fault groups in several angled and rotated fault blocks. The blocks vary in slope and are in some places heavily eroded. The structural features in the eastern section are difficult to identify due to poor seismic data quality. The geological complexity of the field was confirmed during the production drilling, when several quite unexpected fault patterns were encountered. However, these faults are not as sealing as first supposed.

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

The reserves are distributed in the Brent group, Cook formation and Statfjord formation. The estimated total recoverable volume of oil was upgraded from 230 mcm to 253 mcm in December 1993.

The increase in recoverable reserves has not led to a longer projected lifetime for the Gullfaks field. The reserves estimate is still based on production ending in 2006.

The drive mechanism in the field is primarily pressure maintenance by means of water injection, although alternative methods of increasing the recovery factor are also being considered and are tried out from time to time. New completion and stimulation methods have been tested on the wells with encouraging results. Water alternating gas (WAG) injection has been tried and will be continued where suitable. The same applies to horizontal wells. A more extensive test involving surfactant injection is being considered. The injection of thin gel is also believed to be a feasible recovery strategy on Gullfaks, and a test using polymer gel (sodium silicate) was performed in 1993, the results of which are still being appraised.

Production installations

Phase 1 comprises two installations, Gullfaks A and B, which are both Condeep type gravity base platforms with steel frame topsides. See Figure 2.8.13.b. The C installation in phase 2 is essentially a copy of Gullfaks A. All three are fully integrated process, drilling and quarters platforms, though Gullfaks B has a simplified process train with only first-stage separation. The water depth varies between about 140 metres (phase 1) and 217 metres (phase 2).

Gullfaks A is located in the southern part of the field where production commenced on 21 December 1986. The process capacity is 52,000 scm oil and 35,000 cubic metres of water a day. Gullfaks A has a water injection capacity of 75,000 cubic metres a day and is also fitted for gas injection. The platform has 30 producers and nine water injectors, six of which were completed subsea (of a total of 39 wells). Now, however, three of the subsea completions have been shut down, two of them due to the evolution of hydrogen sulphide (reservoir souring). Drilling from Gullfaks A has been suspended for the time being.

Gullfaks B is located in the northwestern part of the field and came on stream on 29 February 1988. Its process capacity is 30,000 scm oil and 30,000 cubic metres of water a day. Oil from Gullfaks B flows to Gullfaks A and C for further processing and storage. Water injection capacity is also 30,000 cubic metres a day and alternative injection water can also be sourced from Gullfaks A. Gullfaks B has 19 producers and nine water injectors to date.

Gullfaks C is located in the eastern part of the field and will produce the Gullfaks field's phase 2 reserves. Operations started with oil transferred from Gullfaks B on 4 November 1989. Production from its own well started around year end 1989. Process capacity on the installation is 50,000 scm oil and 30,000 cubic metres of water a day, and up to 60,000 cubic metres of water can be injected on a daily basis. Gullfaks C has twelve producers and four water injectors. From 1994 onwards production from Tordis will also be treated on Gullfaks C.

Gullfaks Vest

Gullfaks Vest is an oil field located in block 34/10, northwest of Gullfaks. It was proven by exploration well 34/10–34 in summer 1991. Based on the results of that well, Gullfaks Vest is believed to contain recoverable oil reserves in the order of 3.7 mcm.

Production from this field will be by means of two horizontal production wells with natural water drive. The first production well was being drilled at year end. The wells will be drilled from Gullfaks B, where scheduled production start is February 1994 and production is expected to last for twelve years.

Metering system and transportation

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

Costs

The estimated total investment costs over the lifetime of the field are 70 billion 1993 kroner. For Gullfaks Vest the estimate is 0.2 billion 1993 kroner. The operating costs for 1993 are estimated at about 2700 million kroner, including Gullfaks Vest.

2.8.14 Brage

Production licences 053, 055 and 185

Licensees in the unitised Brage field

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

The bulk of the Brage field is situated in block 31/4 and was allocated in 1979 as production licence 055; see Figure 2.6.4. The field also extends into block 30/6, production licence 053, and into the northern part of block 31/7. In 1991, this section of block 31/7 was allocated to the licensees of production licence 055 as production licence 185. Unitisation negotiations were conducted between the two licences in 1993 when a distribution of 92.86 per cent for 055 and 7.14 per cent for 053 was agreed.

With effect from 1 January 1993, 10 per cent of the equity interests in production licences 055 and 185 was transferred from Statoil and the Norwegian State to Norsk Hydro.

The plan for development and operation received Storting approval in spring 1990 and Brage entered production in September 1993.

Production

Crude oil has been proven in Brage, providing the basis for development of two formations: Statfjord and Fensfjord. In the Sognefjord formation small volumes of oil and gas were proven, but the reservoir has not yet been incorporated in the development plans. The authorities ordered the operator to drill an appraisal well in the northeastern part of the field in connection with the adoption of the plan for development and operation. This well must be drilled maximum three years after production start and will provide further data on the resources in the Sognefjord reservoir and parts of the Fensfjord reservoir outside the drainage footprint of the installation.

Five production wells and one water injection well were pre-drilled. Production takes place from the Statfjord and Fensfjord reservoirs. The Directorate has put the field reserves at 46.2 mcm oil, whereas the operator's estimates are 38.5 mcm oil. These estimates will be updated following interpretation of the results of the pre-drilled wells; the results of further drilling of wells from the installation; and the production experience gradually obtained.

Production installations

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

Transportation

The oil is transported by pipeline to Oseberg and from there through the Oseberg line to Sture. A gas pipeline is tied to the Statpipe line. The engineering and commissioning were successful largely due to the transfer of experience from Oseberg C.

Metering system

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

Costs

The estimated total development costs from 1990 to 1998 are about 10 billion 1993 kroner, while the estimated operating costs for 1993 are 420 million kroner.

2.8.15 Statfjord

Production licence 037

Licensees: Norwegian share (85.23869 %)

Mobil Development Norway A/S	12.785804 %
Den norske stats oljeselskap a.s (Statoil) (operator)	42.619345 %
Norske Conoco A/S	8.523869 %
Esso Norge A/S	8.523869 %
A/S Norske Shell	8.523869 %
Saga Petroleum a.s	1.598225 %
Amoco Norway A/S	0.887903 %
Amerada Hess Norge A/S	0.887903 %
Enterprise Oil Norwegian A/S	0.887903 %

British share (14.76131 %)

Conoco North Sea Inc	4.920437 %
BP Petroleum Development Ltd	4.920437 %
Chevron UK Ltd	4.920437 %

Production licence 037 was allocated in 1973 and covers blocks 33/9 and 33/12; see Figure 2.8.13.a. The Statfjord field extends into the UK sector. The field was discovered in spring 1974 and declared commercial by the licensees the same year. In 1976 the authorities adopted the field for development, and it came on stream in 1979. Mobil operated the field until 1 January 1987 when Statoil acquired the operatorship. Statfjord is Norway's largest oil field.

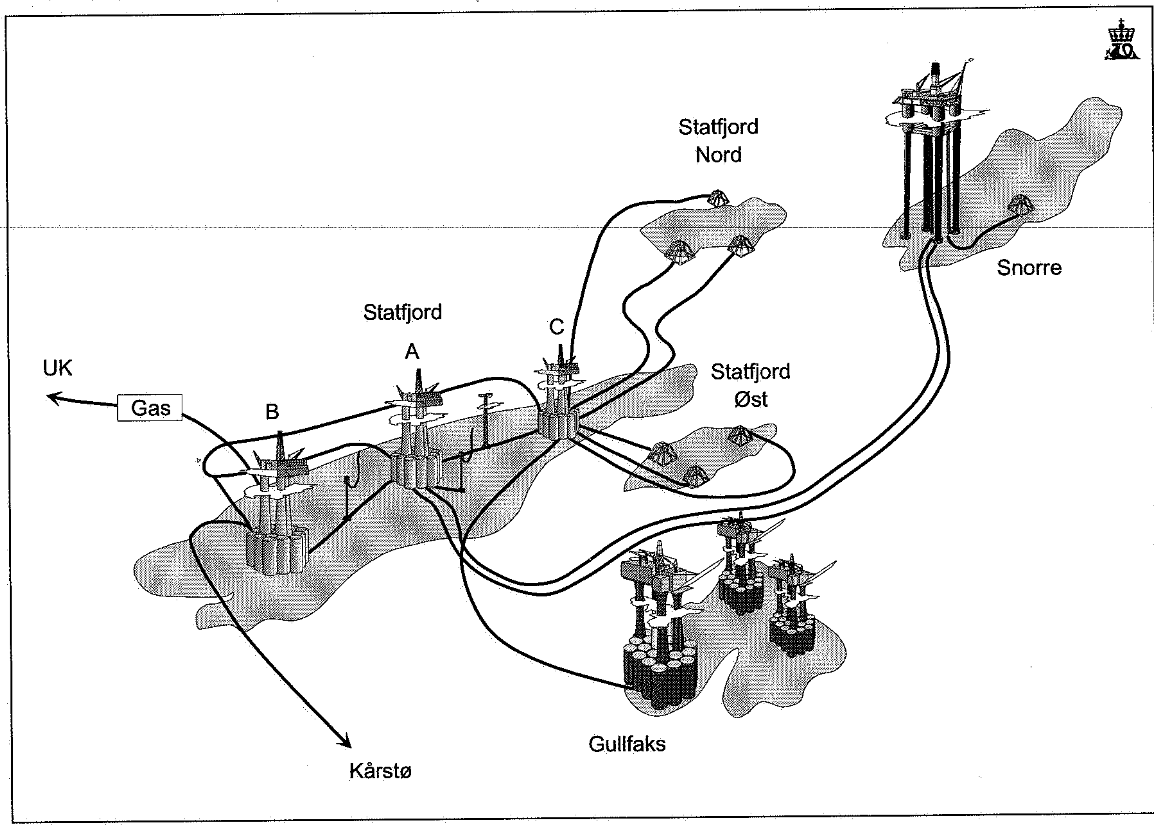
Production

The total recoverable reserves of oil were upgraded in 1993 to an estimated 585 mcm, the comparable figure for associated dry gas being 63 bcm, and for NGL 18.6 million tonnes. NGL is extracted from the gas at Kårstø. The recovery strategy pursued is based on maximising the production rates and recovery factor by manipulating the pressure conditions in the reservoirs. This is achieved by injection of water into the Brent group and gas into the upper part of the Statfjord reservoir. A gas cap has now developed at the top of the Statfjord reservoir, which has resulted in an increase in the gas-oil ratio in many producers in this reservoir. In the lower part of the Statfjord reservoir the operator is now preparing for water injection, but water alternating gas (WAG) injection is currently also being considered as a possible strategy.

In order to better exploit the remaining reserves in place the operator is continually refining the recovery strategy for the field. The strategy involves using more wells than originally planned, plus extensive re-use of the wells in multiple reservoir zones. Using horizontal and long-range high-deviation wells is another element of the strategy.

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

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



A production strategy for exploitation of the Dunlin reservoir has been prepared by the operator which was endorsed by the licensees. Production from Dunlin is set for January 1994. The Dunlin reservoir has a limited volume of resources by comparison with the Brent and Statfjord reservoirs.

Production installations

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

Statfjord A

The Statfjord A installation is situated near the centre of the Statfjord field. It is a fully integrated platform with a concrete gravity base consisting of 14 storage cells and three columns. The topsides are of steel. The crude oil processing capacity is currently 60,000 scm a day split between two production trains. The water treatment capacity is in the region of 25,000 cubic metres a day. The platform started production on 24 November 1979 and has been developed with 25 producers, ten water injectors and four gas injectors. Oil is loaded via one of the three offshore loading systems on the field. The storage capacity for oil on the platform is 175,000 scm.

The Snorre field came on stream on 3 August 1992. Snorre production is received at Statfjord A following second stage separation at Snorre TLP. This means that Statfjord A is now producing close to its peak processing capacity. In 1993, Statfjord A produced, on average, about 31,000 scm of its own oil a day.

Statfjord B

The Statfjord B platform is located in the southern part of the Statfjord field. Again it is a fully integrated platform with a concrete gravity base, this time combining 24 storage cells and four columns. Again, too, the topsides are of steel. Production capacity is about 40,000 scm a day from one production train. The Statfjord B water treatment capacity has been upgraded to roughly 26,000 cubic metres a day. Statfjord B came on stream on 5 November 1982 and has been developed with 24 producers, nine water injectors and two gas injectors. Oil production in 1993 reached about 35,000 scm a day, which was achieved by using a test separator as a production separator for limited periods of time.

The platform's integral crude storage capacity is 302,000 scm.

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

Statfjord C

The Statfjord C platform, situated in the northern part of the Statfjord field, is another fully integrated installation, structurally identical to Statfjord B. The production capacity is 43,500 scm through a single production train. Statfjord C's water treatment capacity has been upgraded to 23,000 cubic metres in the same way as for Statfjord B. The platform came on stream on 26 June 1985 and has 24 producers, eight water injectors and two gas injectors. The work of preparing Statfjord C to receive production from the Statfjord satellites is ongoing. The anticipated date for production start-up for Statfjord Øst is some time in 1994. Statfjord C produced on average about 37,500 scm of oil a day in 1993.

Transportation

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

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

Metering system

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

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

Costs

The total investments in Statfjord up to year 2010 are estimated at about 73 billion 1993 kroner. The total operating costs for 1993 came to about 3.5 billion kroner. These figures refer to the Norwegian share.

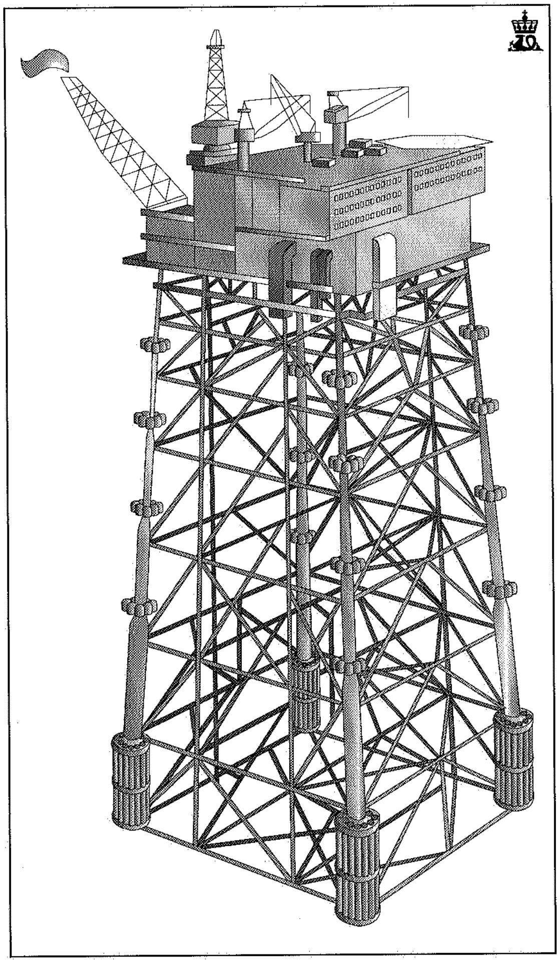
2.8.16 Murchison

Production licence 037

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

The field was proven in August 1975 and is situated in block 211/19 in the British sector and block 33/9 in the

Fig. 2.8.16
Installation on Murchison



Norwegian sector; see Figure 2.8.13.a. The Norwegian share is 22.2 per cent. The development of the Murchison field was initiated in 1976 by the UK partners. In 1979, the British and Norwegian partners entered into an agreement for joint exploitation of the Murchison field. Production started in 1980.

Production

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

Production installations

Murchison was developed with an integrated steel jacket structure with a production capacity of 26,200 scm oil a day; see Figure 2.8.16. Present production is around 3500 scm oil a day.

Transportation

The Norwegian part of the Murchison gas is landed via the Northern Leg Gas Pipeline to the Brent field in the UK sector, and thence to St Fergus in Scotland via the Far North Liquified and Associated Gas Gathering System, FLAGS. Gas deliveries started to flow through the NLGP on 20 July 1983. The Murchison crude is carried by pipeline to Sullom Voe in the Shetland Isles.

Metering system

Produced oil and gas are metered to fiscal standard on the installation. Accreditation of the metering system is carried out each year jointly with inspectors from the British Department of Trade and Industry.

Costs

The predicted total investment in the Murchison field up to year 2001 is roughly 4.8 billion 1993 kroner, while the operating costs for 1993 amounted to roughly 150 million kroner. These figures refer to the Norwegian share (22.2 per cent).

2.8.17 Snorre

Production licences 057 and 089
Licensees in the unitised Snorre field

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

The Snorre field is situated in blocks 34/4 and 34/7, with Saga as operator; see Figure 2.8.13.a. Block 34/4 was allocated under production licence 057 in 1979; block 34/7 under production licence 089 in 1984. The partners have adopted a distribution of the reserves in Snorre which puts 30 per cent in block 34/4 and 70 per cent in block 34/7.

The plan for development and operation of Snorre was adopted by the Storting in 1988. Pre-drilling of wells started in autumn 1990 and the field came on stream on 3 August 1992.

Production

The Snorre field consists of several large fault segments which are not believed to be in general communication with each other. The reservoir rocks are fluvial sandstones in the Statfjord formation (Lower Jurassic) and in the Lunde formation (Upper Triassic). In

Fig. 2.8.17
Installations on Snorre

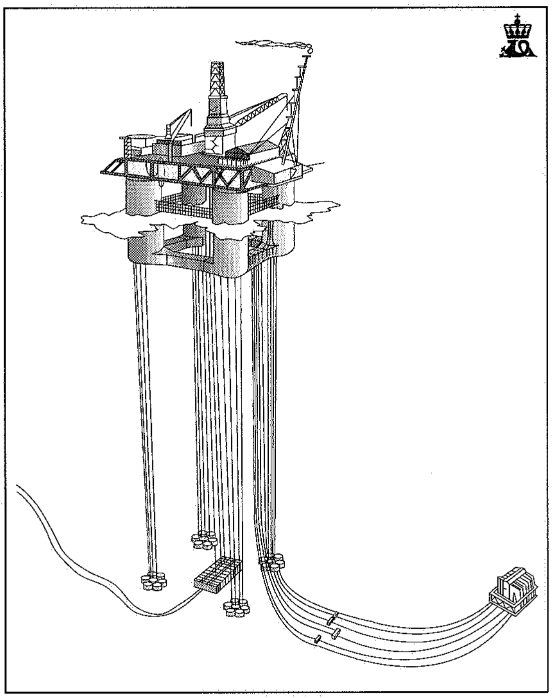
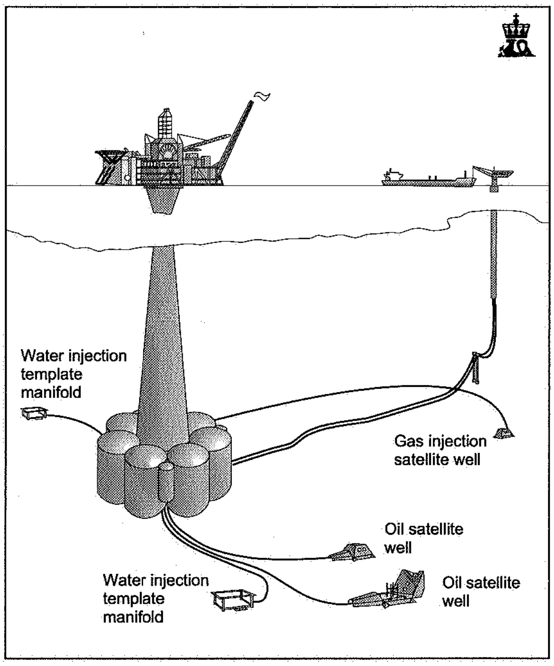


Fig. 2.8.18
Installations on Draugen



both formations the richest reservoir intervals are believed to represent continuous channel belts, whose extent and overall geometry are regarded as well understood. The thinner reservoir intervals are generally believed to represent smaller channel belts and individual channels, and here the uncertainties of extent and geometry are much greater.

After the plan for development and operation had been submitted, the reserves in Snorre were raised to 142 mcm oil and 7.6 bcm gas. The upgrade in the oil estimate was mainly in response to revisions in the geological model and reservoir model based on new well data and reprocessed seismics. Water alternating gas injection (WAG) is being considered which it is hoped will net an additional 3 mcm oil. Experience gained in the pilot project will be decisive for further work on WAG injection.

Production installations

The water depth over the field varies from 300 metres in the south to 370 metres in the north. In the plan the field will be developed in two phases. Phase 1 is for a floating Tension Leg Platform in the south and a subsea installation in the central part of the field; see Figure 2.8.17. Oil and gas are separated in two stages at the Snorre TLP before flowing on via an oil and a gas pipeline to Statfjord A for further processing.

In 1993, the average daily production of oil was roughly 19,500 scm. The oil treatment capacity on the Snorre installation is roughly 34,000 scm a day.

Phase 2 of the development involves depletion of the central and northern parts of the field, but the final decision regarding development of phase 2 has not yet been made.

Transportation

Snorre crude will be sold via a loading system on Statfjord A, while the gas will be sold through the Statpipe system via Statfjord A.

Metering system

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

Costs

According to the operator's reports, the approximate total development investments for phases 1 and 2 will be 34 billion 1993 kroner. The figures are based on deployment of subsea production facilities in phase 2. The corresponding operating costs for this concept have been similarly reported to be about 800 million 1993 kroner.

2.8.18 Draugen

Production licence 093

Licensees

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

The Draugen field, situated in block 6407/9, was allocated in 1984; see Figure 2.6.6. It was declared commercial in September 1987 whereupon the plan for development and operation was adopted in December 1988. Oil production from the Draugen field started on 19 October 1993 which made it the first field on Haltenbanken to come on stream.

Production

In 1993, the operator adjusted the oil reserves from 68 mcm to 92 mcm. The volume of associated gas is 4.4

bcm. The field will produce until the year 2021 by means of water injection. It is not expected that either injected water or reinjected gas will have any influence on oil production until about ten years have passed.

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

The operator has considered a number of alternative applications of the associated gas. In April 1993, the operator's plan to reinject associated gas into a nearby water-bearing structure was adopted by the Ministry of Industry and Energy. The adopted gas solution for the Draugen field may be reconsidered if a concept promising better socio-economic profitability than injection in the aquifer is presented.

Production installations

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

The main reservoir will be depleted using six producers, two of which feature subsea completion and which produced the oil in 1993. The rest of the producers will come on stream in the course of 1994. In the plan, the Middle Jurassic reservoir will start production in 1998 through the seventh well that is drilled from the installation.

Pressure support for the production will be by means of five or six subsea completed water injection wells, five of which will be in operation in 1994. One well is used for the gas injection.

Transportation

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

Metering system

An oil metering station has been installed on the Draugen field.

Costs

The total investments on the Draugen field from 1988 to 1994, inclusive, are estimated to be 13.3 billion 1993 kroner, while the operating costs for 1993 amounted to about 617 million kroner.

2.9 TRANSPORTATION SYSTEMS FOR OIL AND GAS

2.9.1 Existing transportation systems

There are four oil-condensate landing lines and four gas landing lines which carry gas from the Norwegian continental shelf to shore. See the sketch of the transport systems for oil-condensate and gas in the Norwegian sector of the North Sea in Figure 2.9. The UK share of gas from Statfjord is carried via the NLGP to Shell's terminal in St Fergus. The oil pipeline from the Ekofisk area runs to Teesside in the UK. Oil transportation from Oseberg comes to Sture at Øygarden. Condensate from Heimdal is taken via the UK Brae and Forties systems to the BP operated Kinneil terminal near Edinburgh. This pipeline mainly transports British oil and condensate. Condensate from Sleipner is transported to Kårstø. The Statpipe and Norpipe gas pipelines were tied together in 1985 and both lead to Emden in Germany. Gas from Frigg is piped to Total's terminal at St Fergus in Scotland. The Zeepipe gas pipeline ends in Zeebrügge in Belgium. As of yet only Zeepipe phase 1, which is the pipeline running south from Sleipner, has entered service.

Gas transportation systems – Statpipe

Partners

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

Statoil is the operator of the system which comprises:

- Wet gas pipeline from Statfjord to Kårstø
- Separation and fractioning plant at Kårstø, plus storage farm and loading facility
- Dry gas pipeline from Heimdal; dry gas pipeline from Kårstø to riser platform in block 16/11; and pipeline to the 2/4-S riser platform at the Ekofisk field centre.

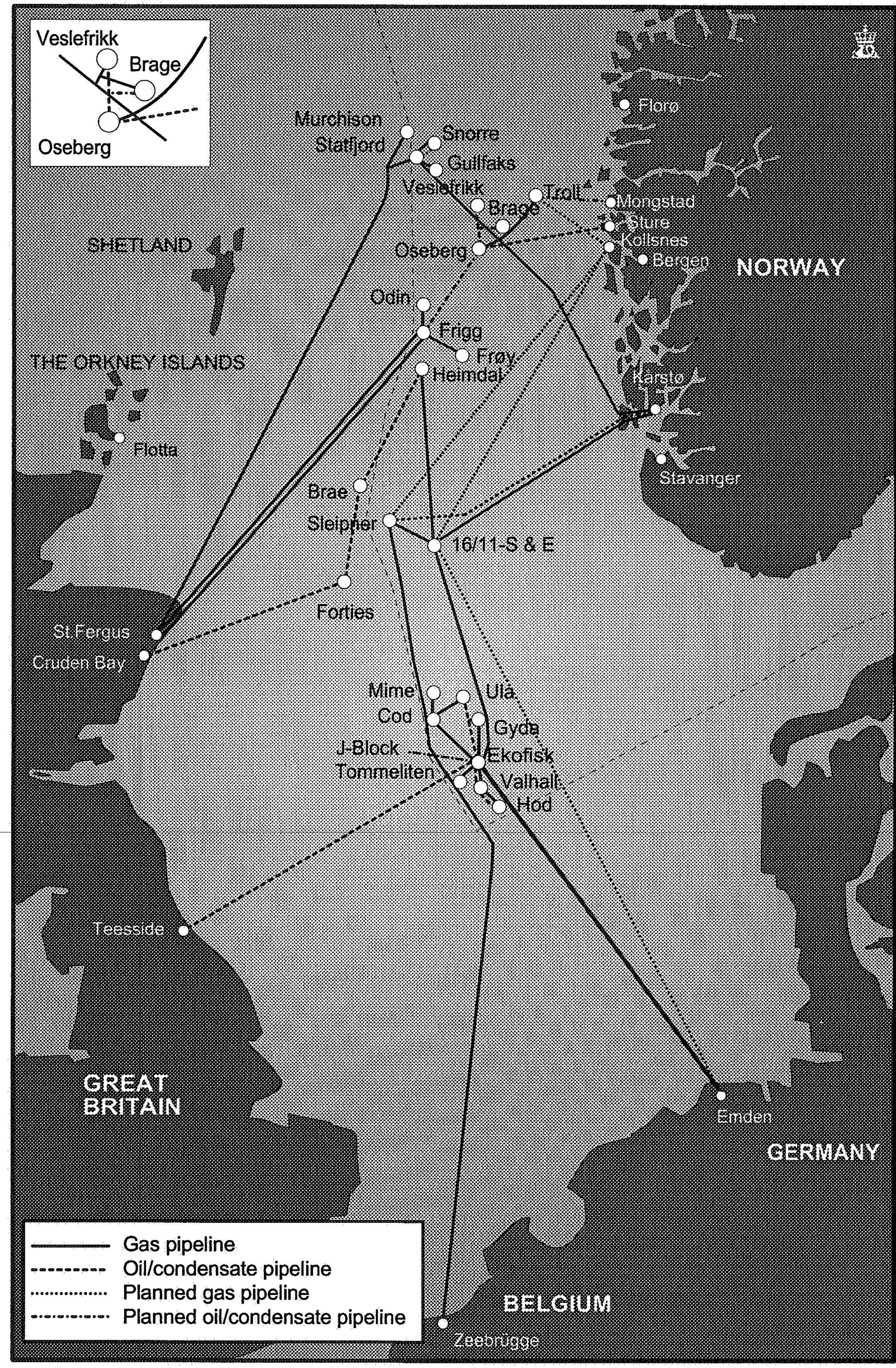
After production start-up the Gullfaks, Veslefikk, Snorre and Brage fields were tied in to the Statpipe system upstream of the Kårstø facility.

Kårstø

The first North Sea gas was landed to Kårstø in March 1985. Delivery of dry gas from the terminal started in October 1985. The transport capacity from Statfjord to Kårstø is 25 mcm a day. This capacity will be fully exploited in 1995–96. In order to process and forward this volume of gas the Kårstø terminal is being modified, including the laying of a bypass line from the wet gas side to the dry gas side of the plant. The gas compressors at Kårstø are being upgraded to cope with the changed transportation requirements after the tie-in of Statpipe and Zeepipe.

In connection with the Sleipner development a new facility for treatment of the condensate piped from that field has been built at the Kårstø terminal. Propane and butane will be separated from the condensate and

Fig. 2.9
Transportation systems for oil and gas from Norwegian North Sea fields



stored in common tanks with LPG products from Statpipe before being sold. The processed condensate is stored in separate tanks pending shipment from the terminal.

Metering system

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

Propane, butane and naphtha measurements are based on a dynamic metering system. A new loading jetty with a special dynamic metering station has been erected for Sleipner condensate.

Gas transportation systems – Norpipe

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

At present, the laying of a new pipeline from Statpipe to the compression booster platform B11 in the German sector is being considered.

Emden

The Emden terminal is owned by Norsea Gas A/S, while Norsea Gas GmbH owns the land on which the terminal is erected. Both these companies are owned by the Phillips Group, and Statoil holds a 2 per cent interest (1 per cent in the Phillips group linked to Ekofisk). Phillips Petroleum Norsk A/S operates the terminal on behalf of the Phillips group.

The entire computer system for the sales gas metering station was replaced in 1993.

Etzel gas terminal

Partners

Den norske stats oljeselskap a.s (Statoil)	67.0000 %
Norsk Hydro Produksjon a.s	8.0000 %
A/S Norske Shell	8.0000 %
Esso Norge a.s	8.0000 %
Saga Petroleum a.s	4.0000 %
Elf Petroleum Norge A/S	2.2985 %
Norske Conoco A/S	1.4030 %
Total Norge A/S	1.2985 %

A minor change in the equity held by Conoco and Total was effected as of 1 April 1993.

Under the Troll gas sales agreements the vendors are committed to the delivery of gas for up to 14 days in the event of a shutdown for non-technical reasons. In addition to ensuring this requirement can be met, the terminal's storage capacity will offer operational advantages with respect to delivery availability, gas quality equalisation, and deliveries that can be upheld during operational and maintenance shutdowns.

Volumes to and from the terminal will be metered to fiscal standard by a metering station installed on site at the existing Phillips terminal at Emden. Input and output are located upstream of the sales gas metering station.

The official start-up day for filling of the storage terminal was 19 April 1993.

Gas transportation systems – Frigg

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

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

The compressor platform MCP-01, midway between Frigg and St Fergus, is owned 50 per cent by the Norwegian interests. The compressors have now been removed and the installation is unmanned. Some UK fields are connected to the Norwegian Frigg pipeline via MCP-01. As long as the installations were manned, their volumes were determined by metering on MCP-01. Following the removal of all manpower the volumes from the British fields are metered on the individual installations.

St Fergus

This terminal is owned by the Norwegian Frigg partners and UK Frigg partners (Elf UK 66.6667 and Total UK 33.3333 per cent). The various processing modules on the terminal are owned either by one partner group or by both. Total Oil Marine UK is the operator. The computer system for sales gas metering was replaced in 1993.

Oil transportation systems – Norpipe A/S

The pipeline system for transportation of oil from the Ekofisk field centre to Teesside in the UK is owned by Norpipe A/S. Oil from the Ekofisk area, which in addition to the eight fields operated by Phillips, comprises Valhall, Hod, Ula, Gyda, Mime and Tommeliten, is delivered to Norpipe. There is also an agreement to transport oil from the British Judy and Joanne fields. Norpipe A/S is a limited company owned 50 per cent each by Statoil and the Phillips Group. Phillips Petroleum Company Norway is the technical operator of the pipeline, while Statoil looks after the economic and administrative functions.

Teesside

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

Transportation systems – Oseberg

A pipeline for transportation of stabilised oil from Oseberg to Sture, north of Bergen, was laid in summer 1987. This 711 mm diameter line has a capacity of 95,000 scm oil a day. However, by adding drag reducers it is possible to increase the capacity to about 112,000 scm a day. The greatest water depth the line reaches is about 350 metres.

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

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

Costs for Oseberg Transport System

By the end of 1993, a total of about 9 billion 1993 kroner had been invested in the OTS. The operating costs for 1993 are estimated at 367 million kroner.

Zeepipe

Partners

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

Zeepipe is a gas transportation system which will carry gas from Kollsnes in Øygarden to the Continent. Phase 1 of the project is a 966.4 mm diameter, roughly 800 kilometre long pipeline from Sleipner to Zeebrügge in Belgium and a 725 mm diameter, roughly 40 kilometre long pipeline from Sleipner to the 16/11-S riser platform. Phase 1, incorporating the terminal in Zeebrügge, was commissioned in 1993. Contracted gas volumes have been exported since 1 October 1993 as planned, at a rate of 12.5 mcm a day.

Capacity without compression will be 13 bcm gas a year.

Costs

Investments in Zeepipe phase 1 amounted to 10.5 billion 1993 kroner in the period 1988 to 1993.

2.9.2 Projected transportation systems

Zeepipe

Partners

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

According to plan the Zeepipe transport system for gas from Troll and Sleipner will be further developed. Phases under consideration are IIA, IIB and IV.

Development of phase IIA has been adopted and involves a roughly 300 kilometre long pipeline of diameter 906 mm from Kollsnes to Sleipner. The plan calls for the pipeline to enter service in 1996.

Phase IIB studies are currently being performed. A plan for construction and operation in phase IIB is expected to be submitted in 1994. This phase will include a pipeline to transport gas from Kollsnes to Heimdal or to a new marine riser platform 16/11-E near 16/11-S. The route for the 906 mm diameter pipeline has not yet been decided. According to plan the pipeline will enter service in autumn 1997.

Phase IV studies are currently being performed. A plan for construction and operation of phase IV is expected to be submitted in 1994. Several alternative concepts, such as installing a compressor on Zeepipe or Europipe, or a fourth pipeline to the continent, are under consideration. The plan is for phase IV to enter service in autumn 1998.

Costs

The total development costs are estimated at 3.9 billion 1993 kroner for Zeepipe phase IIA.

Europipe

Partners

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

Europipe is a third pipeline to the Continent. The work of building the 906 mm diameter and roughly 600 kilometre long pipeline is well underway. It starts from the new riser platform 16/11-E and will end up in Emden in Germany. The system will be able to accommodate compression units between 16/11-E and Emden. Uncompressed, the capacity will be about 12 bcm gas a year. With compression the capacity can be lifted to about 18 bcm gas a year. Problems associated with approval of the landing site in Germany have led to delays for parts of the facility. It is never the less expected that the pipeline system will be operational from autumn 1995.

Costs

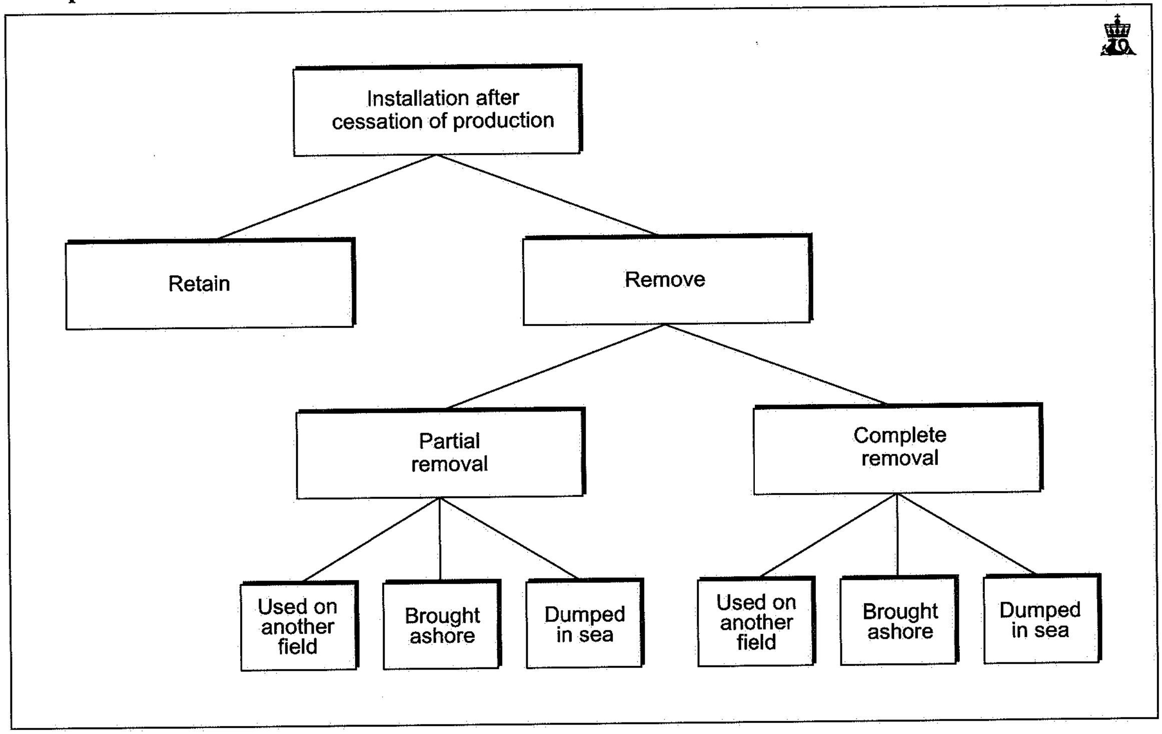
Total development costs have been estimated at about 13.6 billion 1993 kroner.

Frostpipe

Partners

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

Fig. 2.10
Final production and removal



Development
Frostpipe is a pipeline roughly 80 kilometres in length for transportation of stabilised crude and condensate from Frigg to Oseberg with a capacity of 16,000 scm a day. The plan for construction and operation was adopted by the Government in April 1992.

The transportation system is primarily built to carry fluids from Lille-Frigg and Frøy and will enter service simultaneously with production start-up on Lille-Frigg in spring 1994.

Costs
Total investment costs for the pipeline are 0.7 billion 1993 kroner.

2.10 DECOMMISSIONING AND REMOVAL

The question of if and when a coastal state should be ordered to remove its installations from the continental shelf once their useful life expires is of enormous importance to Norway. Removal of the installations on the Norwegian continental shelf will inevitably be in almost all cases much more expensive and technically complex than in other parts of the world. At present, Norway has about 70 installations already producing petroleum or under planning or construction. Several possible solutions exist for disused installations; see Figure 2.10.

The estimated cost of complete removal of all installations is roughly Nkr 50 billion, although of course this figure is highly speculative. Under the legislation for removal of installations the State has to bear a considerable portion of the costs of removal.

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

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

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

Fig. 2.11.1.a
Resource account for the Norwegian continental shelf

			OIL 10^6 Sm^3 most likely	GAS 10^9 Sm^3 most likely	NGL 10^6 tonnes most likely	O.EKV. 10^6 tonnes most likely
Discovered resources	Fields producing and ceased production (orginally)	Current plan	2119	754	78	2598
		Improved recovery	486			405
	Fields decided developed	Current plan	264	1002	30	1251
		Improved recovery	44			36
	Fields planned developed	Current plan	128	672	24	803
		Improved recovery				
	Discoveries under evaluation		534	777	9	1238
	Fields and discoveries total		3575	3205	141	6331
Undiscovered resources			1480	2410		3670
Sold 31.12.93			Oil	Gas	NGL	t.o.e.
			1010	400	32	1273

Reserves — Discovered resources

placed which it is technically impossible to remove.

It must be emphasised that the IMO rules should be looked on more as guidelines – they will not be legally binding on the states involved. On the other hand, the rules will have considerable moral force and it would be politically difficult to ignore them.

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

The Committee suggests amendments in the form of a new chapter in the Petroleum Act, where the new provisions in part will be a continuation of current rules and in part new schemes.

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

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

Production from the Nordøst Frigg field was terminated in May 1993, prompting the question of installation removal on the Norwegian continental shelf.

2.11. PETROLEUM RESOURCES

2.11.1 Resource accounting

Petroleum resources are defined as non-renewable energy resources comprising all technically recoverable oil and gas volumes.

The Norwegian Petroleum Directorate's resource account is a summary of the original marketable petroleum quantities on the Norwegian continental shelf and the amounts remaining to date. Changes in the account from one year to the next result from new discoveries, adjustments to estimates for existing fields and discoveries, and depletion due to production.

The Directorate utilises a system of classifying resources that is set out in NPD Contribution no. 37, *Description of the NPD's Resource Classification System*, published in English and Norwegian in 1993. It distinguishes between discovered and undiscovered resources, as shown in Figure 2.11.1.a.

Discovered resources are of four categories: fields in production, fields decided to be developed, fields planned to be developed, and discoveries under consideration. There are also a number of discoveries not yet evaluated, and some small discoveries that in the present situation do not qualify as under consideration. No resource estimates are published by the Directorate for the latter.

Reserves is the term used for that portion of the discovered resources which are recoverable under given technical and economic conditions, and which the licensees have declared commercial. By this definition, reserves are the first three of the four categories defined above.

Additional resources are the quantities that can be produced using various improved and enhanced recovery techniques (see section 2.11.3, below) not included in adopted plans.

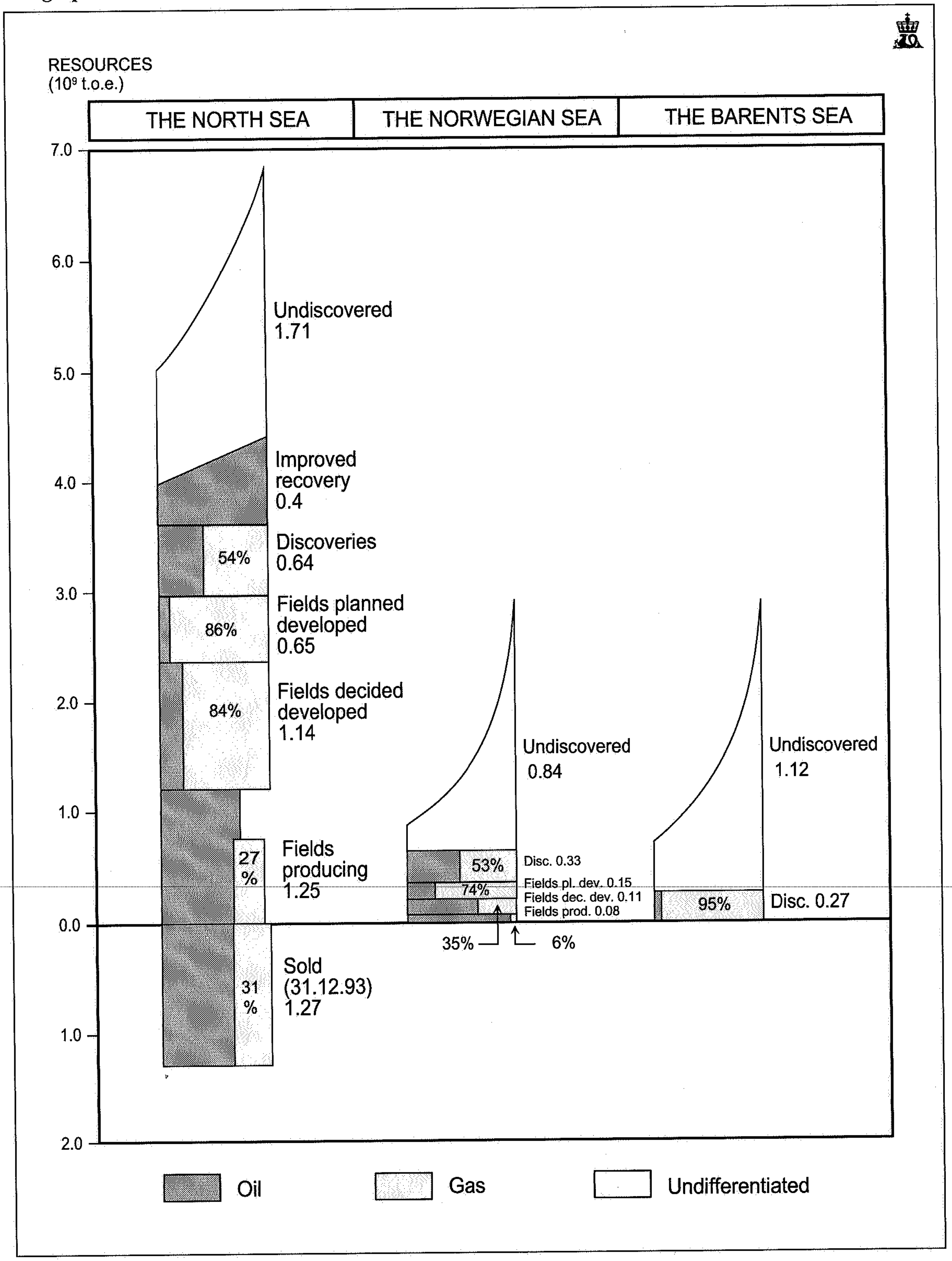
By definition, any discovery and any field has only one discovery well. This means that wildcats which prove resources which are included, or will be included, in the resources figure for an existing discovery or field, are not reckoned as new discoveries. The discovery year is the year the well is completed following testing.

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

Undiscovered resources

In the case of these undiscovered resources, the Directorate utilises its own 1992 analysis figures (see Figure 2.11.1.a-b). These estimates were published in the 1992

Fig. 2.11.1.b
Geographical distribution of resources on the Norwegian continental shelf



Annual Report and a detailed booklet called *Petroleum Resources – Norwegian Continental Shelf*, issued in Norwegian and English editions in February 1993.

Discoveries made in 1993

Three new discoveries were made in 1993. These were 15/9–19SR, 34/7–22 and 34/8–7R. Shows of hydrocarbons were also encountered in 2/7–29 and 30/9–15, though these wells had not been tested or completed by the end of the year.

Poor reservoir characteristics in 34/8–7R mean it does not add to the resources accounts. The sidetrack reentry 15/9–19SR added 4.6 mcm oil and 0.7 bcm gas to the estimated resources. Although discovery 34/7–22 has yet to be evaluated, it is believed to represent a growth in resources of about 3–7 mtoe.

Table 2.11.1.a
Original reserves in fields which have ceased production

ORIGINAL RECOVERABLE				
	OIL 10^6 Sm^3	GAS 10^9 Sm^3	NGL mton	mtoe
Nordøst Frigg		11.8	0.1	11.9
Sum		11.8	0.1	11.9

Past discoveries newly posted

In addition to this year's discoveries already mentioned, the following past discoveries are now included in the resources accounts: 2/1–9 Gyda Sør, 2/4–17, 30/9–4S, 30/9–7, 34/7–21 and 35/11–7. The incremental resources attributable to these past discoveries newly posted is 38.0 mcm oil, 18.6 bcm gas and 0.1 million tonnes Natural Gas Liquids (NGL).

Table 2.11.1.b
Discovered reserves in fields in production

	ORIGINAL RECOVERABLE				REMAINING		
	OIL 10^6 Sm^3	GAS 10^9 Sm^3	NGL mton	mtoe	OIL 10^6 Sm^3	GAS 10^9 Sm^3	NGL mton
North Sea:							
Albuskjell	8.8	20.8	1.3	29.0	1.7	6.3	0.4
Brage	46.2	1.7	1.0	41.5	45.2	1.7	1.0
Cod	2.9	7.3	0.5	10.0	0.2	0.7	
Edda	4.7	2.0	0.2	6.1	0.5	0.2	
Ekofisk	355.0	159.0	14.7	471.8	172.8	73.3	7.1
Eldfisk	77.0	54.0	4.8	121.5	23.5	31.5	2.4
Embla	4.1	1.4	0.2	5.0	3.4	1.2	0.2
Frigg [1]		112.0	0.4	112.4		3.0	
Gullfaks	253.0	17.8	2.1	235.0	136.4	9.9	1.3
Gyda	30.6	4.0	1.9	31.0	18.7	2.5	1.2
Heimdal [2]	6.1	37.4		42.5	2.3	11.1	
Hod	7.9	2.3	0.4	9.3	4.1	1.6	0.3
Loke [3] [6]	1.8	5.8	0.5	7.7	1.8	5.8	0.5
Mime	0.6	0.1		0.6	0.2		
Murchison [4]	12.7	0.4	0.4	11.4	1.4	0.1	0.1
Odin		26.9		26.9		0.2	
Oseberg [5]	300.0	81.0		336.0	192.1	81.0	
Sleipner Øst [6]	27.1	47.0	15.2	83.1	26.7	46.2	15.0
Snorre	142.0	7.6	5.4	130.9	133.5	7.4	5.1
Statfjord [7]	498.0	53.0	15.5	482.0	128.5	28.3	8.2
Tommeliten Gamma	3.4	8.2	0.5	11.5	0.4	2.1	0.1
Tor	23.4	11.5	1.2	31.9	4.4	1.3	0.1
Ula	69.0	4.7	3.2	64.6	26.5	1.9	1.4
Valhall	94.0	25.3	4.8	106.2	57.9	18.2	3.3
Veslefrikk	45.0	3.6	1.5	42.7	30.8	3.5	1.4
Vest Ekofisk	12.4	28.0	1.5	39.5	0.5	3.1	0.1
Øst Frigg		8.6		8.6		1.4	
30/6 Gamma Nord	0.9	6.2	0.4	7.4	0.3	6.2	0.4
Sum	2026.6	737.6	77.6	2506.1	1013.8	349.7	49.6
Norwegian Sea:							
Draugen	92.0	4.4		79.8	91.9	4.4	
Sum	92.0	4.4		79.8	91.9	4.4	
Total	2118.6	742.0	77.6	2585.9	1105.7	354.1	49.6

[1]) Norwegian share only: 60.83 per cent.
[2]) Resource estimate includes Heimdal formation (in production) and Jura reservoir (decided developed). NGL sold as oil.
[3]) Resource estimate includes Heimdal formation (in production) and reservoir of Jurassic and Triassic period (decided developed).
[4]) Norwegian share only: 22.2 per cent.
[5]) Includes Alpha, Alpha Nord and Gamma structure.
[6]) Sale from Sleipner Øst and Loke together. So far produced quantities are from Sleipner Øst. Condensate included in NGL.
[7]) Norwegian share only: 85.24 per cent.

Table 2.11.1.c
Discovered reserves in fields decided to be developed

		OIL 10^6 Sm^3	GAS 10^9 Sm^3	NGL mton	mtoe
North Sea	Frøy	14.0	3.0		14.5
	Gullfaks Vest	3.7	0.4		3.4
	Lille-Frigg	3.6	7.0		9.9
	Sleipner Vest [1]	29.5	122.0	10.0	154.4
	Statfjord Nord	31.0	2.5		27.9
	Statfjord Øst	13.3	1.9		12.9
	Tordis	18.8	1.2	0.5	17.1
	Troll Øst [2]		825.0	19.2	844.2
	Troll Vest olje	61.0			54.9
	2/1−9 Gyda Sør	1.5	0.9	0.1	2.2
	Sum	176.4	963.9	29.8	1141.4
Norwegian Sea	Heidrun	87.3	37.8		109.4
	Sum	87.3	37.8		109.4
	Total	263.7	1001.7	29.8	1250.8

[1]) Includes Alpha, Beta, Epsilon and Delta.
[2]) Condensate included in NGL.

Adjustment of resources estimates for fields and discoveries

For fields in production, fields decided to be developed, fields planned to be developed, and discoveries, the present resource account shows that, relative to the *Annual Report 1992*, oil resources have increased by 223.7 mcm and gas resources by 72.6 bcm. NGL was up by 0.3 million tonnes. For details of adjustments, see Table 2.11.2.

Resources status

The Directorate's accounts for 1992 and 1993 show that the additions of oil and gas are greater than the depletion. The increase in oil was 92.3 mcm and gas increased by 47.8 bcm. NGL resources decreased by 3.3 million tonnes.

At the present rate of depletion of hydrocarbons, Norway has discovered resources sufficient for 20 years of crude oil production and 115 years of natural gas production. These figures take improved and

Production

Recovery of petroleum on the Norwegian continental shelf in 1993 amounted to 131.4 mcm oil, 24.8 bcm gas, and 3.6 million tonnes NGL (including condensate).

Table 2.11.1.d
Discovered reserves in fields planned to be developed

		OIL 10^6 Sm^3	GAS 10^9 Sm^3	NGL mton	mtoe
North Sea	Byggve	0.6	2.6		3.1
	Gullfaks Sør	25.6	56.1		78.6
	Huldra	7.9	22.3		28.8
	Mjølner	1.5	0.7		1.9
	Oseberg Øst	19.0	1.0		16.6
	Peik [2]	0.9	3.1		3.8
	Skirne	0.3	2.3		2.5
	Tommeliten Alpha	3.5	7.8	0.5	11.2
	Troll Vest gass [1]		463.0	10.8	473.8
	Vigdis	33.1	2.3		29.5
	9/2−1 Gamma	3.4			2.8
	Sum	95.8	561.2	11.3	652.6
Norwegian Sea	Midgard	1.3	87.0	13.0	101.0
	Smørbukk Sør	31.0	24.0		49.7
	Sum	32.3	111.0	13.0	150.7
	Total	128.1	672.2	24.3	803.3

[1]) Condensate included in NGL.
[2]) Norwegian share of discovered reserves: 60 per cent (not unitised).

Table 2.11.1.e
Discovered resources in discoveries under consideration

	OIL 10^6 Sm^3	GAS 10^9 Sm^3	NGL mton	mtoe
Agat		43.0		43.0
Balder	32.2			29.3
Hild	6.6	27.6		33.0
Trym	0.7	3.9		4.5
Vale	3.1	2.3		4.8
Visund	45.0	46.0		82.9
1/2–1 [1]	3.0			2.4
1/3–3	3.3	0.1		2.8
1/3–6	1.2	2.8		3.7
2/4–17 Nordvest Tor	1.0	2.1		2.9
2/5–3 Sørøst Tor	2.5	2.0		4.1
6/3–1 PI	0.9	1.0		1.7
7/7–2	2.7	0.1		2.5
7/8–3	6.2			5.4
15/3–1,3	5.2	10.5		14.7
15/3–4	2.2	1.3		3.1
15/5–1	2.0	6.0		7.5
15/8–1 Alpha	5.0	11.0		14.8
15/9–15 My	5.0	11.0		14.8
15/9–19 SR	4.6	0.7		4.8
15/12–4 Beta	13.2	2.3		13.4
15/12–8	0.6	1.3		1.7
16/7–4	1.4	8.0		9.1
25/2–5	5.3	1.9		6.2
25/6–1	4.1	0.9		4.3
25/8–1	7.0			6.0
25/11–15	60.0	1.8		58.8
30/6–18 Kappa	1.0	3.6		4.4
30/9–3 Omega Nord	16.6	8.0		21.6
30/9–4 S	0.3	0.2		0.4
30/9–6	2.7			2.2
30/9–7	0.9			0.7
30/9–9	5.2			4.3
30/9–10 Omega Sør	3.2			2.8
30/9–13 S	7.2	2.2		8.3
34/7–21	13.6			11.2
34/10–17 Beta	13.0	10.0		20.7
34/10–23 Gamma	6.0	69.0		74.0
35/8–1	1.9	13.5		15.1
35/8–2	2.6	7.0		9.1
35/9–1 R	5.0	11.5		15.6
35/11–2	5.4	5.6		10.0
35/11–4 R	18.0	10.8		25.6
35/11–7	20.7	15.4		32.4
Sum	347.3	344.4		640.6

[1]) Norwegian share

enhanced oil recovery into account, as explained in Section 2.11.3.

Change in resources 1992–93	Oil mcm	Gas bcm	NGL mton	Total mton
New discoveries posted	4.6	0.7	0.0	4.8
Past discoveries now posted	38.0	18.6	0.1	49.9
Adjustments for fields and discoveries	181.1	53.3	0.2	204.0
Production 1993	– 131.4	– 24.8	– 3.6	– 138.9
Sum change 1992–93	92.3	47.8	– 3.3	119.8

The resource account for the Norwegian continental shelf is illustrated in Figure 2.11.1.a and the geographical distribution of the resources in Figure 2.11.1.b.

The resources on the Norwegian continental shelf are set out in tables showing:

- Original reserves in fields which have ceased production, Table 2.11.1.a
- Discovered reserves in fields in production, Table 2.11.1.b
- Discovered reserves in fields decided to be developed, Table 2.11.1.c
- Discovered reserves in fields planned to be developed, Table 2.11.1.d
- Discovered resources in discoveries under consideration, Table 2.11.1.e-f.

Fields which have ceased production

In 1993 production ceased from the Nordøst Frigg field as the first field on the Norwegian continental shelf.

Reserves in fields in production and decided to be developed

By year end, 41 development projects had been adopted on the Norwegian continental shelf, two more than one year previously. The two newcomers are Gullfaks Vest and 2/1–9 Gyda Sør. By end 1993, five new fields had entered production: Brage, Draugen, Embla, Loke and Sleipner Øst. Draugen is the first field north of Stad to come on stream; and Heidrun is so far the only other field declared for development north of Stad (see Table 2.11.1.b and 2.11.1.c).

By the end of the year 1993, the total production from Norwegian fields was 1273 mtoe. This is 28 per cent of discovered oil and 12 per cent of discovered gas on the Norwegian continental shelf. The figures take account of improved oil recovery.

Reserves in fields planned to be developed

By year end there were 13 fields which had been declared commercial and therefore are classified as fields, see Table 2.11.1.d. The quantity of petroleum in place in these fields is 0.8 btoe.

Resources in discoveries under consideration

Table 2.11.1.e is a summary of discoveries under consideration south of Stad. The quantity here amounts to 0.64 btoe in total. Resources in discoveries under consideration north of Stad amount to 0.60 btoe; of which 0.33 btoe is in the Norwegian Sea and 0.27 btoe in the Barents Sea. See Table 2.11.1.f.

2.11.2 Revisions since last year

2.11.2.1 Fields in production, decided, and planned to be developed

For fields in production the Directorate generally utilizes the operator's estimates of future reserves. On many fields only moderate changes were made compared to the figures given in the 1992 Annual Report. Fields where a substantial revision has occurred are dealt with specifically below. For changes in reserves figures from 1992 to 1993, see Table 2.11.2.

Table 2.11.1.f
Discovered resources under consideration in discoveries in the Norwegian Sea and the Barents Sea

		OIL 10^6 Sm^3	GAS 10^9 Sm^3	NGL mton	mtoe
Norwegian Sea	Mikkel	3.8	18.0		21.1
	Njord	35.0	7.2		35.9
	Norne	70.0	13.0		72.5
	Smørbukk	37.0	95.0		125.3
	Trestakk	4.8			3.9
	Tyrihans Nord	4.5	15.0		18.9
	Tyrihans Sør	5.1	11.5		15.5
	6506/11-2	6.3	3.6		8.8
	6507/2-2	0.5	2.6		3.0
	6507/3-1	1.1	7.1		8.0
	6507/8-4	11.8	2.5		13.2
	Sum	179.9	175.5		326.1
Barents Sea	Albatross		41.7		41.7
	Askeladd		59.7		59.7
	Snøhvit	6.7	83.0	9.2	97.7
	7119/12-3		3.6		3.6
	7120/7-1		22.5		22.5
	7120/12-2		10.7		10.7
	7120/12-3		4.1		4.1
	7121/4-2 Snøhvit Nord		3.3		3.3
	7121/5-2 Beta		4.3		4.3
	7121/7-2 Albatross Sør		10.8		10.8
	7122/6-1		11.0		11.0
	7124/3-1		2.1		2.1
	Sum	6.7	256.8	9.2	271.5
	Total	186.6	432.3	9.2	597.6

Draugen
The operator increased his estimated reserves based on remapping and new reservoir simulations.

Ekofisk
Reservoir changes are due to new adjustments to the reservoir simulation model.

Embla
New resource mapping and simulation led to a reduction in estimated reserves.

Gullfaks
The reserves were adjusted upward based on new field mapping and a new geological model.

Heimdal
The reserves were adjusted upward as the Tertiary and Jurassic reservoirs are reported collectively.

Hod
Upward adjustment of the reserves resulted from new mapping and a new field model.

Huldra
The operator adjusted the reserves upward after a new resource estimate based in part on new mapping and the acquisition of new well data.

Loke
The reserve estimates were adjusted downward based on new mapping and improved depth control.

Odin
The reserve estimates were adjusted downward when water broke through earlier than forecast.

Oseberg
Positive production results and added horizontal wells led to an increase in estimated reserves. Former NGL volumes are now reported collectively with the oil estimate.

Peik
New mapping based on 3D seismic resulted in a downward adjustment of reserves.

Sleipner Vest
The updated reservoir model resulted in an increase in oil reserves and reduction in gas reserves.

Sleipner Øst
New fluid data and optimised injection studies led to adjustment of the reserves estimate upward.

Snorre
The reserves increased based on new information about hydrocarbon contact levels.

Statfjord
New reservoir simulations have justified an increase in estimated reserves.

Tor
The updating of the reservoir simulation model led to a reduction in estimated reserves.

Valhall
An updated reservoir model led to an increase in estimated reserves.

Table 2.11.2
Changes in reserve/resource estimates annual reports 1992–1993

	Annual report 1992			Annual report 1993			Changes from 1992 to 1993		
	OIL 10^6 Sm^3	GAS 10^9 Sm^3	NGL mton	OIL 10^6 Sm^3	GAS 10^9 Sm^3	NGL mton	OIL 10^6 Sm^3	GAS 10^9 Sm^3	NGL mton
Fields in production									
Albuskjell	9.0	20.0	1.3	8.8	20.8	1.3	-0.2	0.8	
Cod	2.9	7.4	0.5	2.9	7.3	0.5		-0.1	
Draugen	68.0	3.0		92.0	4.4		24.0	1.4	
Edda	5.0	2.1	0.2	4.7	2.0	0.2	-0.3	-0.1	
Ekofisk	360.0	151.0	14.4	355.0	159.0	14.7	-5.0	8.0	0.3
Eldfisk	79.0	56.5	4.7	77.0	54.0	4.8	-2.0	-2.5	0.1
Embla	5.6	2.1	0.2	4.1	1.4	0.2	-1.5	-0.7	
Frigg		110.0	0.4		112.0	0.4		2.0	
Gullfaks	230.0	16.0	1.8	253.0	17.8	2.1	23.0	1.8	0.3
Gyda	32.0	4.2	1.9	30.6	4.0	1.9	-1.4	-0.2	
Heimdal		35.6	4.2	6.1	37.4		6.1	1.8	-4.2
Hod	6.7	1.3	0.3	7.9	2.3	0.4	1.2	1.0	0.1
Loke	4.1	8.0		1.8	5.8	0.5	-2.3	-2.2	0.5
Mime	0.7	0.2		0.6	0.1		-0.1	-0.1	
Murchison	12.7	0.3	0.4	12.7	0.4	0.4		0.1	
Odin		29.3	0.2		26.9			-2.4	-0.2
Oseberg	277.0	81.0	11.6	300.0	81.0		23.0		-11.6
Sleipner Øst	19.0	50.0	11.3	27.1	47.0	15.2	8.1	-3.0	3.9
Snorre	130.0	6.7	3.3	142.0	7.6	5.4	12.0	0.9	2.1
Statfjord	486.0	52.0	15.4	498.0	53.0	15.5	12.0	1.0	0.1
Tommeliten Gamma	3.6	8.5	0.6	3.4	8.2	0.5	-0.2	-0.3	-0.1
Tor	25.7	14.3	1.5	23.4	11.5	1.2	-2.3	-2.8	-0.3
Ula	69.0	4.3	2.8	69.0	4.7	3.2		0.4	0.4
Valhall	76.0	19.0	3.6	94.0	25.3	4.8	18.0	6.3	1.2
Veslefrikk	43.8	3.5	1.4	45.0	3.6	1.5	1.2	0.1	0.1
Vest Ekofisk	12.7	28.6	1.5	12.4	28.0	1.5	-0.3	-0.6	
Øst Frigg		8.2			8.6			0.4	
Fields decided developed									
Gullfaks Vest	3.3			3.7	0.4		0.4	0.4	
Lille-Frigg		7.0	2.7	3.6	7.0		3.6		-2.7
Sleipner Vest	27.0	135.0	9.0	29.5	122.0	10.0	2.5	-13.0	1.0
Statfjord Øst	13.4	2.0		13.3	1.9		-0.1	-0.1	
Troll Vest olje	64.0			61.0			-3.0		
2/1–9 Gyda Sør				1.5	0.9	0.1	1.5	0.9	0.1
Fields planned developed									
Huldra	4.5	17.0		7.9	22.3		3.4	5.3	
Peik	1.8	6.0		0.9	3.1		-0.9	-2.9	
Vigdis	27.1			33.1	2.3		6.0	2.3	
9/2–1 Gamma	3.7			3.4			-0.3		
Discoveries									
Hild	1.9	12.1		6.6	27.6		4.7	15.5	
Norne	30.3	1.5		70.0	13.0		39.7	11.5	
Snøhvit	6.7	83.0		6.7	83.0	9.2			9.2
Trym	2.1	8.7		0.7	3.9		-1.4	-4.8	
Visund	16.2	47.6		45.0	46.0		28.8	-1.6	
2/4–17 Nordvest Tor				1.0	2.1		1.0	2.1	
7/7–2	16.0	0.5		2.7	0.1		-13.3	-0.4	
15/9–19 SR				4.6	0.7		4.6	0.7	
15/12–4 Beta	16.0	1.3		13.2	2.3		-2.8	1.0	
30/9–4 S				0.3	0.2		0.3	0.2	
30/9–7				0.9			0.9		
34/7–21				13.6			13.6		
34/10–17 Beta	8.0	22.5		13.0	10.0		5.0	-12.5	
34/10–23 Gamma	2.2	28.0		6.0	69.0		3.8	41.0	
35/9–1 R	5.0	11.0		5.0	11.5			0.5	
35/11–7				20.7	15.4		20.7	15.4	
6507/8–4	19.8	2.4		11.8	2.5		-8.0	0.1	
Sum							223.7	72.6	0.3

Vigdis
The Directorate carried out a new mapping operation and field simulation resulting in the upward adjustment of the reserves.

2.11.2.2 Discoveries
The changes in resources estimates from 1992 to 1993 are reported in Table 2.11.2. Discoveries for which a major change was made are discussed specifically.

Hild
The operator of production licence 043 undertook new mapping based on the 3D seismic data. Estimated resources were increased as a result.

Norne
The increase in estimated resources was based on the operator's mapping and evaluation of Norne following new well data.

Snøhvit
The increase here is due to the inclusion of NGL in the resource estimate.

Trym
The reduced resources are due to the inclusion by the operator of only the northernmost part of the structure in the discovery. The rest is now assigned to Lulita, a discovery on the Danish shelf.

Visund
The increase in resources is because the Directorate has elected to make use of the operator's estimates until the Directorate's new estimates are available in spring 1994.

7/7–2
The operator has reduced his estimated resources following new mapping and evaluation based on new well information.

34/10–17 Beta
This resource estimate was reduced based on the operator's remapping.

34/10–23 Gamma
The Directorate has increased its estimated resources based on the operator's mapping activity.

6507/8–4
The estimated resources here were reduced after a new reservoir simulation.

2.11.2.3 Name changes in 1993
The following name changes were effected in the year passed:

Present name	*Previous name*
Heimdal	Heimdal and 25/4–1 Heimdal Jura
Norne	6608/10–2
Tyrihans Sør	Tyrihans

2.11.3 Improved oil recovery
The Directorate and central oil companies have in recent years turned their attention increasingly towards the feasibility of improving the recovery factor from fields already producing. A growing appreciation of the potential has gradually developed. Many practical

Improved Oil Recovery (IOR)

Improved Oil Recovery is used about actual measures resulting in an increased oil recovery factor from a reservoir as compared with the expected value at a certain reference point in time.

Improved oil recovery may be achieved by using conventional methods including improved reservoir management and cost reducing measures, or by using advanced methods (EOR).

Conventional methods may for instance include:
- Injection of water and/or gas
- Infill drilling
- Horizontal wells for drainage of thin oil zones or remaining oil pockets
- Long-reach wells for drainage of oil in the outer flanks of the reservoir
- Upgrading of treatment capacity for produced water and/or gas
- Reduced wellhead pressure or artificial lift in the wells
- Change of completion strategy.

Enhanced Oil Recovery (EOR)

Enhanced Oil Recovery is used about advanced recovery techniques going beyond what are considered conventional methods at a given reference point in time.

Typical features of advanced recovery techniques are that they involve the injection of fluids other than water and/or hydrocarbon gas, and/or require a technical feasibility qualification, such as a pilot project.

Advanced methods may include:
- Water alternating gas (WAG) injection
- Chemical methods: surfactant, foam, polymer, gel, etc
- Injection of non-hydrocarbon gases: carbon dioxide, nitrogen
- Microbial methods
- Thermal methods.

steps have already been taken and more are planned that should help augment Norway's reserves.

Using today's technology and production plans about one third of the crude oil originally in place in the Norwegian fields will be recovered. Improving on this figure is a major challenge for future operations on the shelf. In 1993 the Directorate updated the latest estimates of improved recovery potential, issuing in connection with the work a status report: *Improved Oil Recovery – Norwegian Continental Shelf*, published in both languages in November 1993. The account below is a summary of this report.

Definition of improved oil recovery (IOR)

This concept has many definitions. Over the years it has become customary to use Improved Oil Recovery (IOR) to designate all methods of increasing oil recovery, including so-called enhanced methods; and to use Enhanced Oil Recovery (EOR) as a high-technology subset of the IOR method portfolio.

Just what each term embraces will vary from year to year and field to field. Water injection might qualify as IOR in a chalk field, but in a sandstone field it is so commonplace that it counts as a standard oil recovery method. A few years back, horizontal wells were an advanced technique, but today they are very much the known art.

For all these reasons the Directorate has opted to use the definitions given in the highlight boxes on IOR and EOR.

Estimates of in place and recoverable oil are always speculative, and will normally change over time in most oil fields as more data comes in. The reasons for the changes can be quite complex: for instance remapping of the field may alter not only the estimated volume in place, but also the perceived reservoir properties. These two factors in combination will alter the recoverable volume and the recovery factor. But also adjustments in reservoir management following from improved understanding of the reservoir and the various steps taken by the engineers could lead to the same result, an increase in recovery factor. On the other hand, better understanding of the reservoir might mean that the estimates for recoverable volume and recovery factor have to be scaled down.

In real life therefore it is often difficult to consistently distinguish between changes in recoverable reserves and recovery factor due to actual measures implemented, and changes that are due to improved predictions following from new knowledge about the reservoir.

The Directorate seeks to keep accounts for field developments, and will highlight the changes in estimates of recoverable reserves and recovery factor. Wherever possible, the Directorate will also try to identify the factors that brought about the changes.

Potential for improved oil recovery

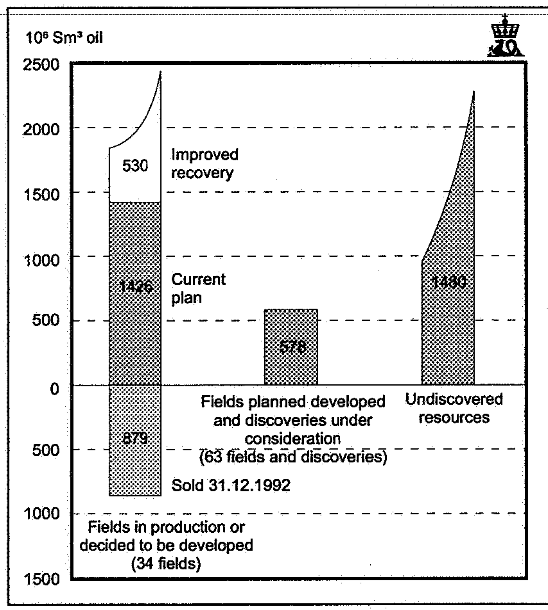
On the Norwegian shelf per May 1993, the last reference date for which data is available, there were 19 oil fields and nine gas and condensate fields in production. Another twelve fields were declared. The reservoirs in sandstone oil fields contain reserves of 1669 mcm oil and have an average recovery factor of roughly 39 per cent. For oil reserves in chalk reservoirs the average recovery factor is roughly 29 per cent and the volume of reserves 550 mcm. Over all the average recovery factor is 36 per cent. There is also some oil and natural gas liquids in gas-condensate fields.

Table 2.11.3
Estimated potential for improved oil recovery from Norwegian fields in production or decided to be developed

Method	Proved through studies	Partly proved	Total
	10^6 Sm³ oil	10^6 Sm³ oil	10^6 Sm³ oil
Water injection	78	32	110
Gas injection	13	0	13
Combined water and gas injection	46	16	62
Chemical flooding	71	0	71
Well-related techniques	65	25	90
Miscellaneous*	-	185	185
Total	273	258	530

** Combination of several methods*

Fig. 2.11.3
The potential for improved oil recovery compared with the total oil resources in oil and condensate fields and discoveries (per May 1993)



In recent years many studies have been carried out by operators and Directorate researchers to estimate the potential for improving oil recovery. The studies vary from screening studies, often embracing many fields, to detailed full field simulations of specific target reservoirs.

The most recent figures for potential based on the Directorate's official reserves statistics of May 1993 indicate that about 530 mcm could be obtained by improved methods. This is equivalent to increasing the average recovery from oil fields to roughly 45 per cent, or over 8 per cent above present day reserves. Of the 530 mcm that could be added, over half comes from sandstone fields, the rest from chalk fields. The potential in the five largest Norwegian fields: Ekofisk, Gullfaks, Oseberg, Snorre and Statfjord; makes up about half of the total.

Table 2.11.3 shows how this is split on the different recovery methods. As shown in the table, the estimates are based partly on documented studies and partly on more approximate assessments which only to some extent are based on documented evaluations. The latter column has a relatively large miscellaneous category of about 185 million Sm^3, which indicates a potential that can be achieved by a combination of several measures, e.g. a combination of water injection and more infill drilling in chalk fields. When the potential is to be estimated for each individual field, different methods for improved oil recovery may be in competition with each other. The proportion of the potential for the different methods could therefore change over time, depending on what has been realized and what is considered most probable or most profitable.

Without doubt uncertainties are attached to such estimates, and to evaluate one particular field project, significantly more thorough studies are required. In addition the price of oil and other economic framework conditions will constitute uncertainty factors. The NPD has not specified the potential as a function of economic framework conditions, however certain economic considerations have nevertheless been assumed. Another point is that the potential connected to use of gel, foam and microbial methods has yet to be studied. If this is included, the total potential will in all probability increase. This together with the possibilities for technological advances indicates that there is an upside potential compared with the current estimates. In addition there will also be possibilities for increasing the estimated recovery factor for those fields where no development plans have yet been adopted (mentioned below). The NPD therefore considers the uncertainty of the estimate to be greatest upwards, and assumes there is a realizable potential for improved oil recovery in the region of **400–1000 million Sm^3.**

Improved oil recovery seen in relation to exploration and new developments

In the petroleum activities it would seem natural to compare improved oil recovery as a value adding activity with the activities related to exploration and development of new fields.

The potential for improved oil recovery totalling 530 million Sm^3 (about 440 million t.o.e.) from 21 fields corresponds to 36 % of the estimate for the undiscovered oil resources and 12 % of the estimate for the total undiscovered oil and gas resources. The estimate both for improved oil recovery and for undiscovered oil resources has an upside potential, estimated to 1000 million Sm^3 and about 2300 million Sm^3 oil, respectively. This leads to the conclusion that both improved oil recovery and exploration should play an important role in the further activities on the Norwegian continental shelf.

In the further exploration activities the expectation is discovery of a few large, but mostly small discoveries. In order to discover a certain resource volume, it is expected that a more extensive exploration effort than earlier will be needed, in the form of number of wells and investments. The investments needed to qualify and produce incremental reserves in developed fields will in many cases be lower than what is required to find and then develop new fields. Projects for improved oil recovery have the advantage of certainty of the discovered resources in place and usually well mapped reservoirs. The time at disposal for utilization of these resources is however limited. The return from projects for improved oil recovery may in the 10–15 years ahead prove to be of the same order of magnitude as the return from activities connected with exploration for new resources.

If we look at the estimate for oil resources in discovered fields which until now have not been decided to be developed, this amounts to 578 million Sm^3 in a total of 63 fields and discoveries. Here there will be an uncertainty both as regards volumes in place and in recovery factor. The estimate assumes, however, an average recovery factor of about 30 %. Here there will also be a potential for increase. If, for example, the recovery factor can be increased to an average of 35 %, this corresponds to an increase in resources of 90 million Sm^3.

In order to compare IOR with development of new fields, both the potential for improved oil recovery and the total discovered oil resources are shown in Figure 2.11.3. The IOR potential (530 million Sm^3) is on the same level as the total oil resources in the 63 discovered fields with oil resources which are planned to be deveoped or which are being considered for development (578 million Sm^3). This illustrates the fact that a large number of new fields must be developed in order to achieve an increase in reserves of the same magnitude as that which can be achieved through projects for improved oil recovery. Many projects for improved oil recovery can also match the profitability achieved from development of new fields.

Pilot project

Prior to any large-scale field application of methods with which there is limited experience, there will in many cases be a need for implementation of a field test on a small scale. Even if extensive research related to the method has been carried out and the operators have conducted thorough studies with a view to application at a specific field, the implementation of a larger field project may be associated with significant uncertainty. This applies particularly to advanced methods. Prior to testing there will always be uncertainty attached to whether the effects measured in the laboratories and estimated in reservoir simulation will be the same in the actual reservoir. The purpose of a pilot project is therefore to obtain actual data from the reservoir which can be used to confirm the effect of the method, qualitatively as well as quantitatively. This requires thorough planning, implementation and evaluation. Even if a good number of field tests with a particular method have been carried out for example in the USA, the reservoir conditions in Norwegian fields will differ to such extent that this does not eliminate the need for pilot projects in Norwegian fields. The qualitative results from pilot projects in Norwegian fields will, however, to a large extent be transferable to other Norwegian fields with similar reservoir properties.

The simplest field tests will be single well tests, with all data coming from one and the same well. These may be of relatively limited duration and cost. For most methods however, an adequate pilot project will imply injection into a well followed by measuring of the effect on production in one or more other wells. This means a more comprehensive and time consuming programme. Both with regard to single well tests and larger pilot projects the application and further development of tracer techniques constitutes an important part of the activity in order to be able to interpret the results in the best way possible.

Field tests can in some cases be profitable projects, but in other cases they could represent an expense. The NPD expects the oil companies to be willing to take on such an expense and a certain financial risk when there is a potential for a more comprehensive and profitable project which can be qualified through the field test. The extent of and costs connected with a pilot project can vary considerably, but the total costs of planning and implementation could in some cases be of the same order of magnitude as the costs associated with an exploration well. In exploration drilling, significant costs and the risk of a negative result are accepted. Correspondingly, a pilot project need not be profitable as an isolated activity, but it may nevertheless represent an expected profitability when the probability of one or more large and profitable field applications is taken into account. Seen in this perspective the return on a pilot project may well exceed the return on many exploration wells. When exploration drilling and pilot projects are compared from a decision-making point of view, risk and profitability calculations should be handled consistently.

The results from the pilot projects carried out on the Norwegian continental shelf have generally speaking been very positive, and have in most cases led to either a field application or to furhter plans for continued testing. Thus we are currently going through an exciting phase where the NPD both sees a need for and expects a continuation of the pilot activities connected with those methods where large-scale field application is still considered uncertain.

Summary

The analyses carried out by the Directorate indicate that the opportunities that exist to increase the recovery factor from oil fields represent a significant potential. To help realise this potential, the Directorate has formulated a target for improved oil recovery (IOR) on the Norwegian continental shelf:

- The Norwegian Petroleum Directorate's long term objective for improved oil recovery (IOR) is to realise as much as possible of the identified potential and the upside potential in profitable projects.

By the year 2000, the planned recovery factor for those fields which were in production or were decided to be developed in 1991, shall be increased so as to correspond to the increased reserves of at least 400 million Sm^3 compared with the reserves estimates from 1991.

The Directorate's latest figure for IOR is 530 mcm. Moreover, the Directorate finds there is a significant upside potential in light of the technological advances being made and the new fields being found. The total potential may therefore be as much as 1000 mcm oil.

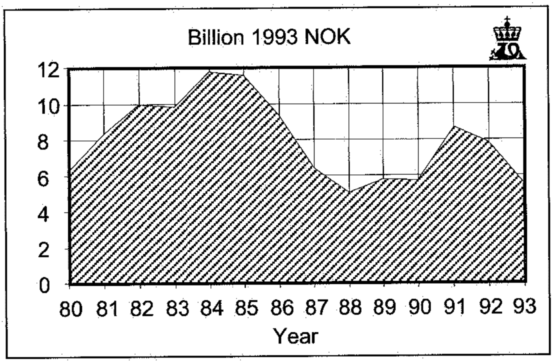
Some of the expected increase in reserves has already been realised, since the reserves in the fields referred to in the target have increased by 167 mcm since the last count. About 125 mcm resulted from improvements in oil recovery factor.

The most important oil field measures in attaining the stated target will be:

- Reduction of costs
- Utilisation of infrastructure
- Conventional reservoir development measures, including optimisation of reservoir management
- Improved oil recovery using advanced methods (so-called enhanced oil recovery, EOR).

The potential for improved oil recovery is a time critical resource which must be utilized within the production period for the individual field. Consequently strategies must be adopted to utilize this resource during the next 10 to 15 years. There is currently increased focus on such projects among the oil companies, and interesting results and further plans exist for a good number of fields. Investments in projects for improved oil recovery represents a considerable additional value in the years ahead. The return from projects for improved oil recovery may during the next 10 to 15 years

Fig. 2.12.1.a
Exploration costs per year 1980–1993



be of the same order of magnitude as the return from exploring for new resources, and many projects for improved oil recovery may be equally profitable as development of new fields. The potential for improved oil recovery is approximately equal to the total oil resources in the remaining fields where development is planned or under consideration.

The potential estimated by the NPD assumes implementation of both conventional technology and more advanced recovery methods. Use of advanced methods is studied and further developed in ongoing research programmes (Joint Chalk Reseach, PROFIT and RUTH), where collaboration between the authorities and the oil companies has been established.The authorities consider it vital that the oil companies which are to play a central role on the Norwegian continental shelf possess and maintain high competence in technical areas of importance to an optimal resource utilization. The NPD considers it important that plans for development and operation (PDO) for new fields contain the best possible analysis of the prospects for improved oil recovery, and that such possibilities are followed up during the production phase. The initial plans adopted will necessarily have to be based on a limited amount of data about the reservoir itself. Knowledge about the reservoir is multiplied many times when a field has been in production for a period of time. It is only at a more mature stage that the right basis exists for an evaluation of what strategies during the latter half of the life span of a field may contribute to the best possible resource utilization. The NPD has taken the consequences of this fact in requesting a so-called extended field study (EFS) for the more mature fields in production. The NPD assumes that the companies also regard such comprehensive studies as a useful instrument in defining an updated, long-term recovery strategy.

Commercial agreements on processing and transport of petroleum will affect the profitability of the various projects. The NPD will focus on the task of seeing that such agreements do not impede an optimal resource utilization for the benefit of the society at large. Furthermore, the general framework conditions will affect the long-term strategy of the oil companies. Considering these conditions will therefore also be an important concern to the NPD.

The NPD intends to contribute actively to see that the technical and economic possibilities for improved oil recovery are studied and realized. The NPD will therefore continue to participate in relevant research programmes and will in addition carry out its own field related studies, area studies and continental shelf analyses. In addition to this, the NPD considers a positive and open communication with the oil companies to be of great importance.

2.12. PETROLEUM ECONOMY

2.12.1 Exploration activity, goods and services

The level of exploration drilling activities declined in 1993 compared with previous years. The year saw the commencement of 27 new exploration wells, against 43 in 1992. In all, 21 wildcats and six appraisal wells were spudded, while the corresponding figures for 1992 were 29 and 14, respectively. On average for the period 1966 to 1993, the number of spudded wildcat wells and appraisal wells has been 20 and eight, respectively.

Figure 2.12.1.a illustrates the costs of exploration from 1980 onwards. These costs include exploration drilling, general surveys, field evaluation, and administration. According to figures reported to the Directorate, total exploration costs for the period 1980 to 1993 were equivalent to about 110 billion 1993 kroner.

Fig. 2.12.1.b
Oil and gas exploration costs in 1993

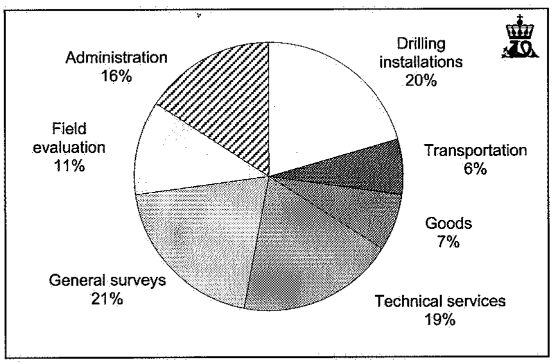


Fig. 2.12.1.c
Drilling costs per well

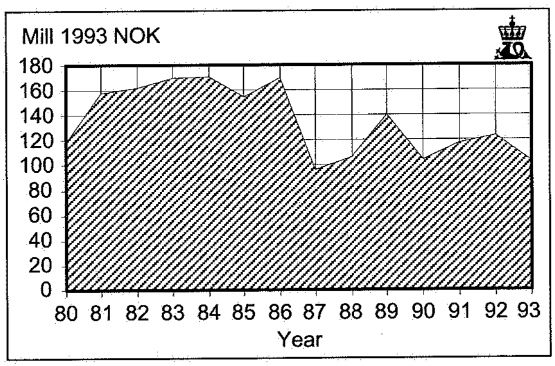
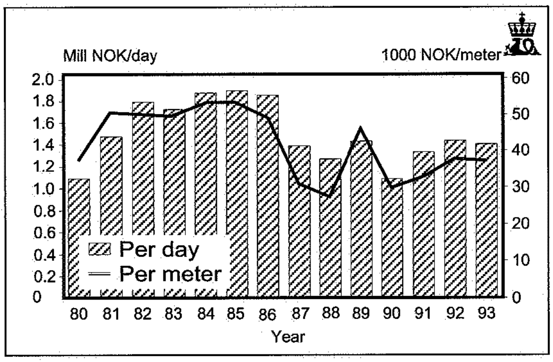


Fig. 2.12.1.d
Drilling costs 1980–1993



Shown below are the exploration costs for the year broken down by goods and service categories. The amounts reflect data reported by the operating companies. The same statistics produced the chart in Figure 2.12.1.b, which shows the percentage breakdown between the different expenditure types.

Exploration costs		*Nkr million*
Exploration drilling		2 869
of which:		
– Drilling installations	1 108	
– Transportation costs	345	
– Goods	407	
– Technical services	1 009	
General surveys		1 135
Field evaluations		584
Administration (incl area fees)		845
Total		5 433

Fig. 2.12.2.a
Investments in fields and pipelines in operation on the Norwegian shelf 1970–2010 (Billion 1993 NOK). Investments in fields decided to be developed and pipelines approved for construction are also included.

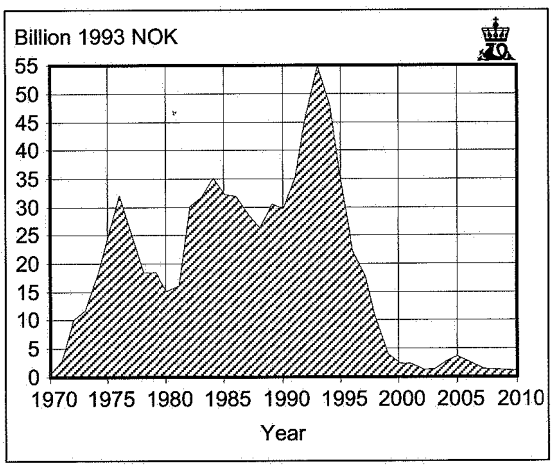
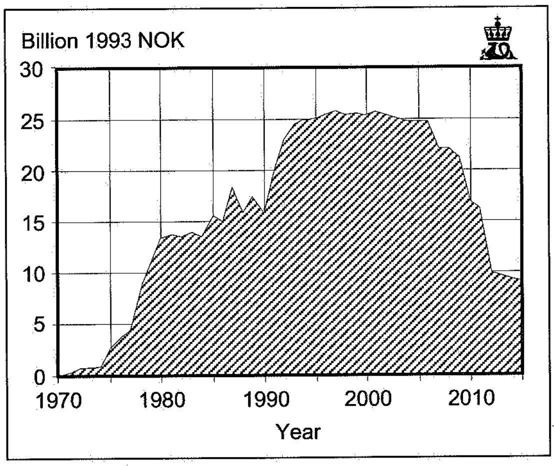


Fig. 2.12.2.b
Operating costs on fields and pipelines in operation on the Norwegian shelf 1970–2015.
Operating costs for fields decided to be developed and pipelines approved for construction are also included



Expenses in connection with field evaluations are significantly higher than in 1992, while the general survey expenses are slightly higher. General surveys include, among other things, the compilation of seismic data. Expenses associated with seismic data compilation have shown a considerable increase relative to figures from just a few years back.

Figure 2.12.1.c gives the mean drilling costs per exploration well. Exploration wells are wildcats and appraisal wells. Drilling costs in 1993 were roughly Nkr 2.7 billion, broken down as follows (approximate figures): drilling installations 39 per cent, transport 12 per cent, goods 14 per cent, and technical services 35 per cent.

Figure 2.12.1.d shows the mean drilling costs per day and per metre in the years 1980 to 1993.

2.12.2 Costs of development and operation on the Norwegian continental shelf

The Directorate has calculated the annual costs in connection with the development of offshore fields, including production drilling, for the period 1970–2015. The costs include fields in production, fields for which the development plans had been approved at 31 December 1993, and pipeline systems. Where fields straddle the sector dividing line between Norway and the UK, only the Norwegian parts have been included.

Historical and approved investments for field developments and transport systems for petroleum are shown in Figure 2.12.2.a. All amounts are given in fixed 1993 kroner. Investments increased steadily, reaching a peak in 1976, then sliding for several years until a new surge occurred from 1981 on. Another peak occurred in 1984, when the equivalent of roughly 34.7 billion 1993 kroner was invested in projects on the Norwegian continental shelf. Taking new decisions into account, the investment level will approach 55 billion 1993 kroner in the first half of the present decade before falling off rapidly towards the year 2000.

In 1993 the following fields and pipeline systems were adopted for development:

- Gyda Sør
- Gullfaks Vest
- Troll oil pipeline.

During 1994, it is expected that several plans for development and operation will be considered. If these are adopted, the investment curve will show a gentler drop than outlined above.

The annual field operating costs, including pipeline operating costs, are shown in Figure 2.12.2.b. The level of demand for goods and services for operations has increased heavily, and will continue to increase for some years as more fields come on stream. Operating costs therefore appear to be the most serious cost component henceforth, and it will be essential to seek to reduce such costs from now on.

2.12.3 Activity level up to 2005

The Directorate has taken a closer look at the overall activity level on the Norwegian continental shelf up to the year 2005.

The total petroleum production is shown in Figure 2.12.3.a, which indicates that production is expected to build slowly to roughly 180 mtoe in about the year 2000, thereafter sliding until the end of the period forecast in 2005, when the level may have approached today's. Fields in production and adopted for development will gradually produce less in the period. The contour for *other fields* is a mix of the production forecast from fields planned to be developed, certain mature discoveries, and improved recovery. There is some uncertainty in relation to the forecast production, especially in the *other fields* category. It is important

Fig. 2.12.3.b
Estimated total investments on the Norwegian shelf 1993–2005. Other fields include discoveries, fields planned to be developed and improved oil recovery. (Billion 1993-NOK)

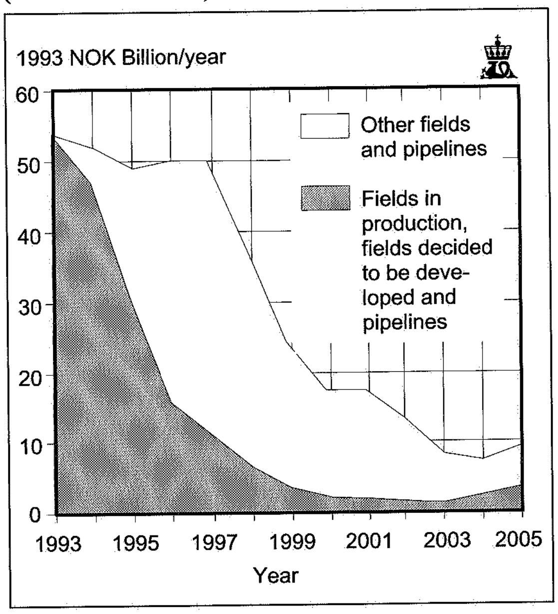


Fig. 2.12.3.a
Estimated total production on the Norwegian shelf 1993–2005. Other fields include discoveries, fields planned to be developed and improved oil recovery. (Million t.o.e.)

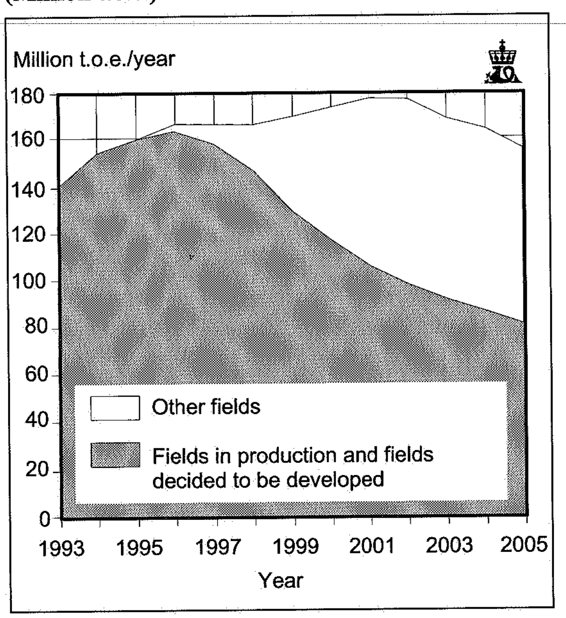


Fig. 2.12.3.c
Estimated total operating costs on the Norwegian shelf 1993–2005. Other fields include discoveries, fields planned to be developed and improved oil recovery (Billion 1993-NOK)

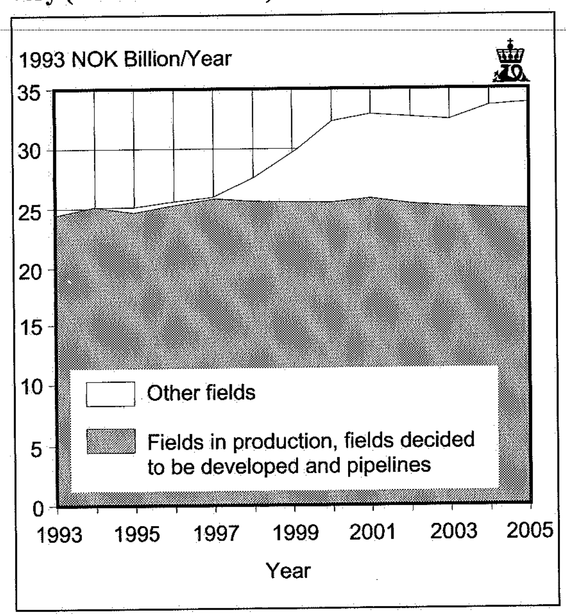
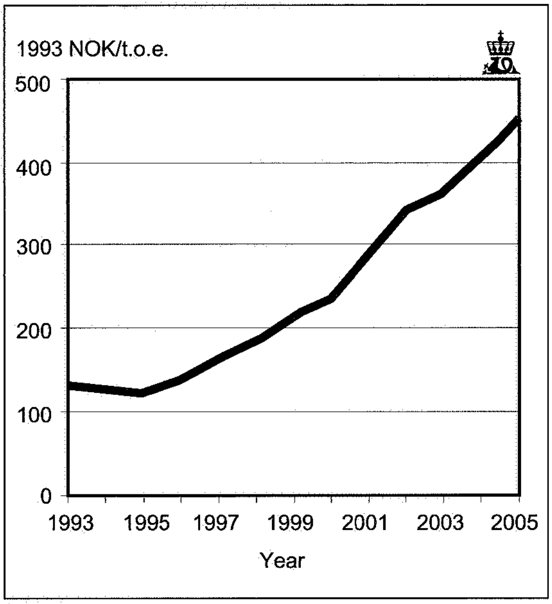


Fig. 2.12.3.d
Estimated development for operation costs per t.o.e. for fields in production on the Norwegian shelf 1993–2005. Operation costs includes insurances and CO_2-taxes. Tariffs are not included. (1993 NOK per t.o.e.)



to note that future oil and gas price development will materially affect the long term production trend.

The estimated total investment level in the period 1992–2000 is shown in Figure 2.12.3.b. The level of investments is expected to stay relatively stable until 1997, then sliding to about 10 billion 1993 kroner in 2005. The fields in production and fields adopted for development are expected to report a steady reduction in investment levels throughout the period. Investments in discoveries and fields planned for development, and presumptions about investments in improved recovery from existing fields, make up the bulk of the forecast investment budget to 2005.

Figure 2.12.3.c shows costs in connection with the operation of fields and pipelines on the Norwegian continental shelf to 2005. Operating costs, including carbon dioxide tax and insurance cover, are expected to increase evenly until 2000, then level off. The increase is given by discoveries and fields planned for development coming on stream, coupled with the operating costs for improved recovery from existing fields. From 2000 to 2005 the total annual demand for goods and services for operations on the Norwegian continental shelf is expected to be about 35 billion 1993 kroner.

Figure 2.12.3.d shows the forecast development of operating costs for each unit produced from fields in production. It shows that the anticipated unit cost on producing fields will more than double from 1993 to 2005. One reason is that operating costs are generally fixed and do not lend themselves to reduction as production tails off. Improved and enhanced recovery and reduced operating costs will never the less be key areas where unit costs can be usefully tackled.

2.12.4 State's direct economic involvement, SDØE

The State's direct economic involvement in the petroleum activity, SDØE, was established with effect from 1985 such that cash flows linked to most of Statoil's stakes were divided in two, with one part to Statoil and the other to the State (SDØE). The latter participates in 128 production licences of the total of 202.

At present, the State's involvement is notable for the very substantial volumes now in the exploration, development and operating phases. SDØE as the largest investor on the Norwegian continental shelf has secured for the State a high stake in present and future reserves in the petroleum activity. Thus, this scheme has fulfilled the partial objective identified in 1985: to secure for the State the greatest possible share of future revenues from the recovery of hydrocarbons.

The total average State participation is broken down by field categories is as follows:

– Fields in production	37.55 %
– Fields decided to be developed	47.65 %
– Fields planned to be developed	38.46 %
– Pipelines	49.85 %

The SDØE's share in fields planned to be developed (declared commercial by the licensees) will increase if the sliding scale provisions which regulate State participation are exercised when the development is adopted by the Storting.

The overall investment costs on the Norwegian continental shelf for the period 1993–2005 have been estimated at Nkr 355 billion (non-discounted fixed 1993 kroner). This includes investments in fields planned and adopted for development and fields in production, and in pipelines. The SDØE share is about 39 per cent.

Fig. 2.12.4
SDØE: Capital investments and operating cost for fields planned and decided to be developed, and fields in producting, as well as pipelines

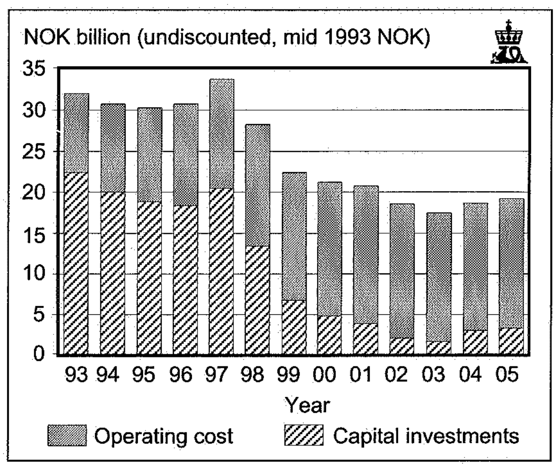


Table 2.12.5
The role of petroleum in the national economy

	1975	1980	1985	1988	1990	1991	1992	1993
The petroleum sector's share of GNP1).	3 %	16 %	19 %	9 %	15 %	15 %	16 %4)	17 %4)
The petroleum sector's share of total exports2).	6 %	33 %	38 %	24 %	31 %	32 %	33 %	33 %4)
The State's revenues derived from petroleum activities3). (Bill. 1993-NOK)	0.7	44.0	69.2	14.1	28.5	33.1	24.3	24.34)

Source: Central Bureau of Statistics

1) Includes production of crude oil and natural gas, drilling and operation of pipelines.
2) Includes export of crude oil, natural gas and pipeline transportation services.
3) Includes ordinary corporate tax, special tax, area fees and royalties.
4) Preliminary figures/estimates.

The overall operating costs during the same period are estimated at Nkr 637 billion which includes goods and services, carbon dioxide tax, and user tariffs. Here, the SDØE share is about 29 per cent; which is roughly the same as the SDØE's anticipated share of oil production during the same period.

The SDØE's net share of these investment and operating costs tops Nkr 320 billion. See Figure 2.12.4 for the breakdown over time.

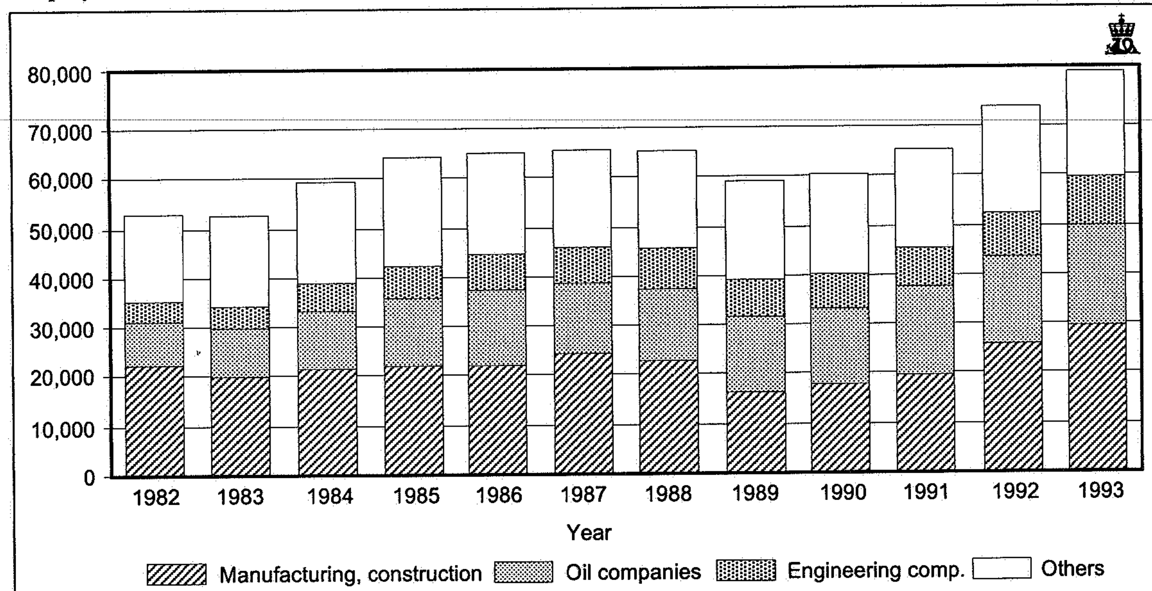
For a few more years the SDØE will continue to make big investments, resulting in a build-up of real capital in the petroleum sector. The yield from these investments depends in part on the future development of prices as well as the escalation of costs and any fluctuations in production on the fields concerned.

2.12.5 The role of petroleum in the national economy

Gross national product

The petroleum sector makes a significant contribution to the overall economy in Norway today. In 1975, the gross value added in the petroleum sector constituted some 3 per cent of the GNP. In 1985, its share had increased to 19 per cent, then dropping back due to the fall in oil prices in 1985–86. More recently, the share has been in the region of 16 per cent. The development

Fig. 2.12.5
Employees in the petroleum-industry, by kind of company



Others include service-companies, transportation and shipping activities, operation of pipelines and refineries, drillingcompanies, catering, public administration, research and education, bases and other commodities and services.

of the petroleum sector's contribution to Norway's Gross National Product is shown in Table 2.12.5.

Foreign economy

The petroleum sector also earns a relatively large portion of Norway's export revenues, with an increase in export share from approximately 6 per cent in 1975 to 38 per cent in 1985, after which time it fell to about 24 per cent in 1988. In recent years there has again been a slight upturn in the contribution from the petroleum sector; see Table 2.12.5 for details.

State's tax revenues

The State's total tax revenues from the petroleum activity comprise corporate wealth and income tax, special tax, royalty, and acreage fees. Tax revenues reached a preliminary high of 69 billion 1993 kroner in 1985, before dropping to about 14 billion in 1988. In the course of the last few years there has been an increase in the State's tax revenues. In 1992, tax revenues from the petroleum activity were 24.3 billion 1992 kroner, or some 17 per cent of the State's total receipts from direct and indirect taxes. The yearly development in tax revenues is shown in Table 2.12.5.

Employment

The activity level on the Norwegian continental shelf involves employment both onshore and offshore. In 1993, some 79,000 people were employed as a result of the petroleum activity in Norway. Figure 2.12.5 illustrates employment as a result of the petroleum activity, broken down by type of company. Some 35 per cent of employees in the petroleum sector work in industry, building and construction; 26 per cent in the operating companies; and 12 per cent in engineering consulting firms. The remaining 27 per cent work in services, transportation, shipowners and rig operators, drilling contractors, catering, landing facility and refinery operation, public administration, and research and training.

2.12.6 Crude oil market

Global oil production slipped by about 0.1 per cent from 1992 to 1993 to about 67 million barrels a day, according to the IEA.

Norwegian oil output again accounted for about 3.5 per cent of world crude production in 1993. Compared with last year Norway's output was up 6.7 per cent in absolute units and remains ahead of UK production.

In 1993, there was an increase in estimated oil reserves in most parts of the world. Statistics show an overall increase in reserves of 0.2 per cent from 1992 to 1993. Based on these estimates the largest future oil producing areas will be OPEC and the Middle East. Production ran at over 2 per cent of reserves. The ratio of proven reserves to output did not alter significantly from 1992. Current global oil reserves are equivalent to 47 years of production at the 1993 level.

The average price of oil in the year was roughly US$ 17 per barrel. OPEC member countries decided at the February 1993 meeting to fix production quotas at 23.6 million barrels a day, which led to a temporary rise in price to about US$ 19. From June it fell again, to below US$ 17 a barrel, due to over-production relative to the adopted quotas. The general lack of determination to limit output in the third quarter and growing expectations that Iraq would again enter the world stage as an albeit limited exporting country combined to drive the price below US$ 17. Until September this was the prevailing level, though early in that month it dipped below US$ 16. The average price attained for a barrel of Norwegian crude in 1993 was roughly US$ 17, or something over Nkr 122.

2.12.7 Natural gas market

Today all Norwegian gas exports go to Western Europe. In 1993, Norway exported gas to the UK, Germany, the Netherlands, Belgium, France, Austria and Spain. The UK was the largest client up to 1990 but Germany has now taken over this role. Figure 2.12.8.b shows the distribution of gas sales to the various countries buying Norwegian gas.

In 1993, Norwegian exports amounted to 24.6 bcm, which was 1.1 bcm down on the year before.

The first gas volumes sold from the Norwegian shelf were generally based on depletion of reserves in specific fields. On 1 October 1993, however, Norway entered a new gas sales era when deliveries under the Troll gas sales agreements got underway. These contracts offer the buyers a fixed annual volume and permit other fields, not just Troll, to source the delivery. In connection with these agreements, the authorities, by establishing the Troll Commercial Model, have opened up an avenue for the sale of associated gas and small gas accumulations.

Organisation of Norwegian gas sales

In recent years the sales of Norwegian gas have been coordinated by the Joint Gas Negotiations Committee (GFU) under the chairmanship of Statoil and with representatives from operators Norsk Hydro and Saga Petroleum. The job of the Committee is to negotiate contracts with buyers of Norwegian natural gas. However, the partners in a licence have the option to sell the gas by their own efforts. Subject to the constraints of the existing gas organisation, the authorities set up the Gas Supply Committee in 1993. This committee is made up of the ten leading resource owners in the Norwegian sector and has an advisory function towards the Ministry of Industry and Energy in matters pertaining to development and exploitation of gas fields and gas transport systems.

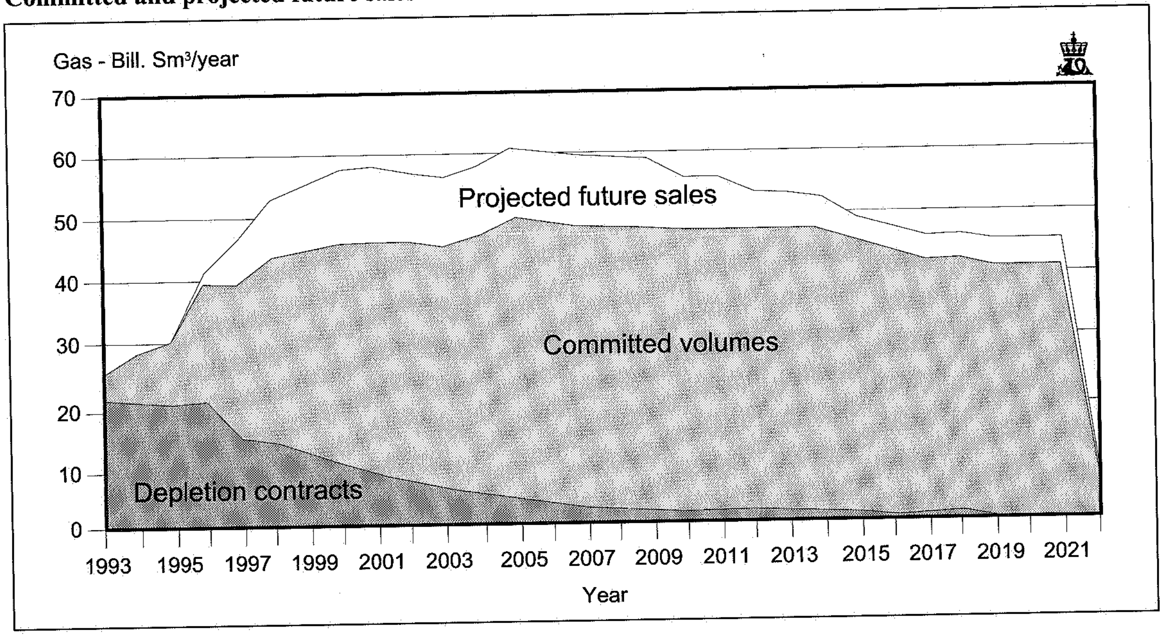
The Ministry and this Directorate sit on the latter Committee as observers only.

2.12.7.1 Existing commitments

Field contracts

The fields currently supplying gas under field contracts are Statfjord, Gullfaks, and fields in the Frigg and Ekofisk areas. Gas production from these sites,

Fig. 2.12.7
Committed and projected future sales



which commenced in 1977 from Ekofisk and Frigg, in 1985 from Statfjord, in 1986 from Heimdal, and in 1987 from Gullfaks, will begin to decline in just a few years. Whereas the Frigg area gas is piped to the UK, all other fields deliver gas to Continental buyers.

Troll gas sales agreements of 1986

These so-called TGSA agreements were signed by the Troll partners and Continental buyer consortiums. The countries making up the buyer side are Germany, the Netherlands, Austria, France, Belgium and Spain. The agreements are for basic gas deliveries of 23.66 bcm per annum, with the addition of 30 and 50 per cent options, which entitle buyers to receive deliveries in excess of their basic volume, without committing them to do so. At peak level the TGSA sales will amount to 40.82 bcm of natural gas delivered per year.

New commitments

The Electrabel contract, with Belgium, was signed in 1992. In 1993 two new contracts were signed for additional volumes to Ruhrgas and VNG, both in Germany. In aggregate these three contracts commit 7.3 bcm per year at peak delivery rate. New sales to the UK were also negotiated, but are subject to a new Frigg Treaty.

2.12.7.2 New sales

The year saw negotiations and discussions with many potential buyers from many countries. Talks have also been initiated with Eastern European countries. Sales of Norwegian natural gas to the Scandinavian markets have found little interest to date, and the same must be said of Liquified Natural Gas.

This Directorate anticipates that sales of Norwegian natural gas will ultimately expand to 60–70 bcm per annum. Figure 2.12.7 shows the commitments and the potential.

2.12.7.3 Use of gas in Norway

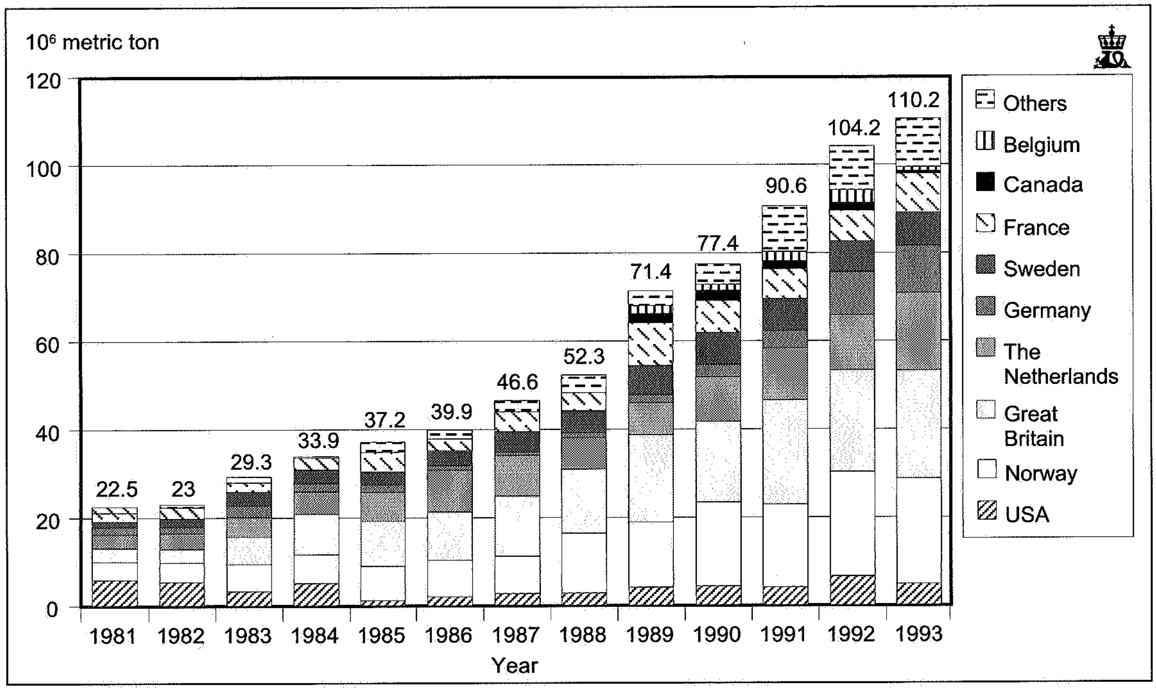
The Norwegian Storting gave in February 1992 its approval for delivery of roughly 0.7 bcm gas a year from the Heidrun field to a methanol plant at Tjeldbergodden starting in 1996. Elsewhere, in North Rogaland, an agreement has been signed for smaller annual deliveries to Gasnor, a distribution company. Despite these developments, the most important gas market is on the continental shelf itself. Here, the largest buyer is Oseberg, taking off about 3.5 bcm gas a year from Troll. The gas is used to enhance oil recovery from Oseberg. On Ekofisk, about 4 bcm gas is used every year for fuel and injection. In Sleipner Øst, too, considerable gas volumes will be injected into the reservoir in order to improve the production of wet gas (condensate). Most of the injected gas can be produced again at a later date and sold.

2.12.8 Sale of petroleum from the Norwegian continental shelf

In 1993, total sales of crude oil from the Norwegian continental shelf amounted to 110.2 million tonnes. This was an increase of 6.0 per cent compared to 1992. The United Kingdom was the largest recipient with 23.6 per cent of shipments; the Netherlands took 14.3 per cent, Germany 11 per cent, and Sweden 6.2 per cent. Norway's own share was 20.3 per cent, slightly down on the 1992 result.

Figure 2.12.8.a shows the sale of crude oil by country for the period 1982–93. Note that up to 1988, both Belgium and Canada were reported under the heading *Others*.

Fig. 2.12.8.a
Sale of crude oil from the Norwegian continental shelf



The sale of Natural Gas Liquids, inclusive condensate, from the Norwegian continental shelf reached 3.1 million tonnes in 1993, or 0.5 million tonnes more than in 1992. Figure 2.12.8.b shows the sale of crude oil and NGL in 1993 by licensee.

Norway exported 24.6 bcm gas in the year, a decrease of 4.3 per cent compared to 1992. A total of 8.9 bcm was sold to Germany, 4.5 bcm to the UK, 5.7 bcm to France, 2.7 bcm to the Netherlands, 2.5 bcm to Belgium, 0.2 bcm to Spain, and 0.1 bcm to Austria, as charted in Figure 2.12.8.c.

Figure 2.12.8.d shows the gas sale by licensee. Here, the column *Others* contains aggregates for many small fields.

Fig. 2.12.8.b
Sales quantities of oil/NGL (excl. condensate) per licensee in 1993

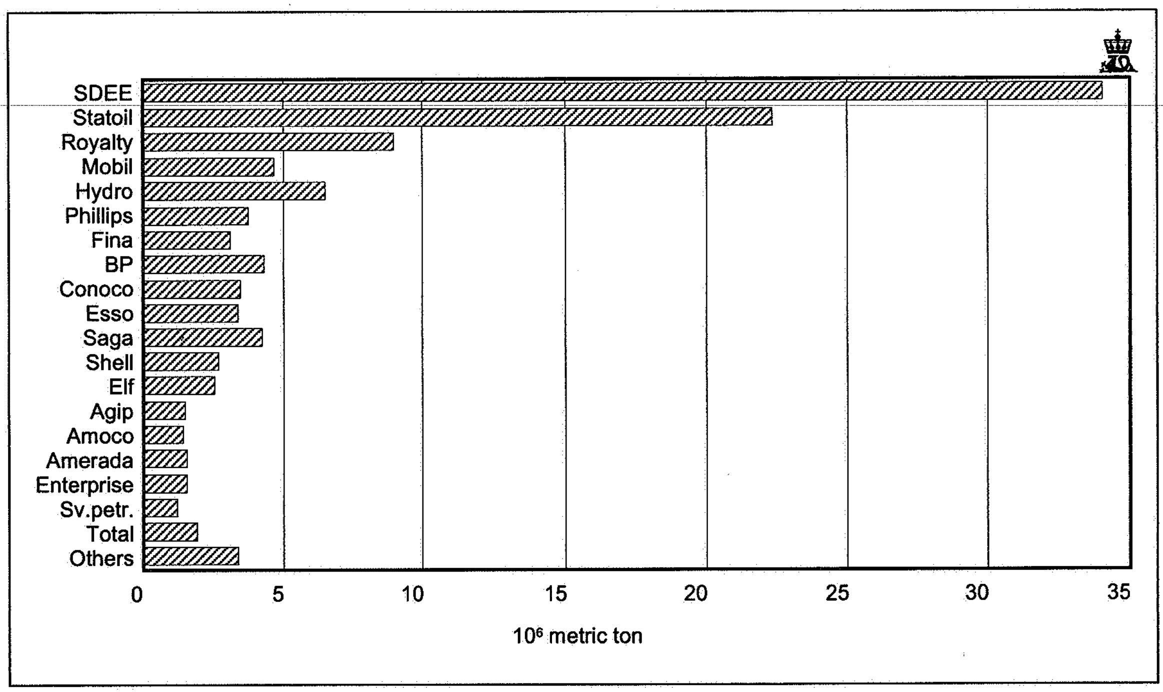
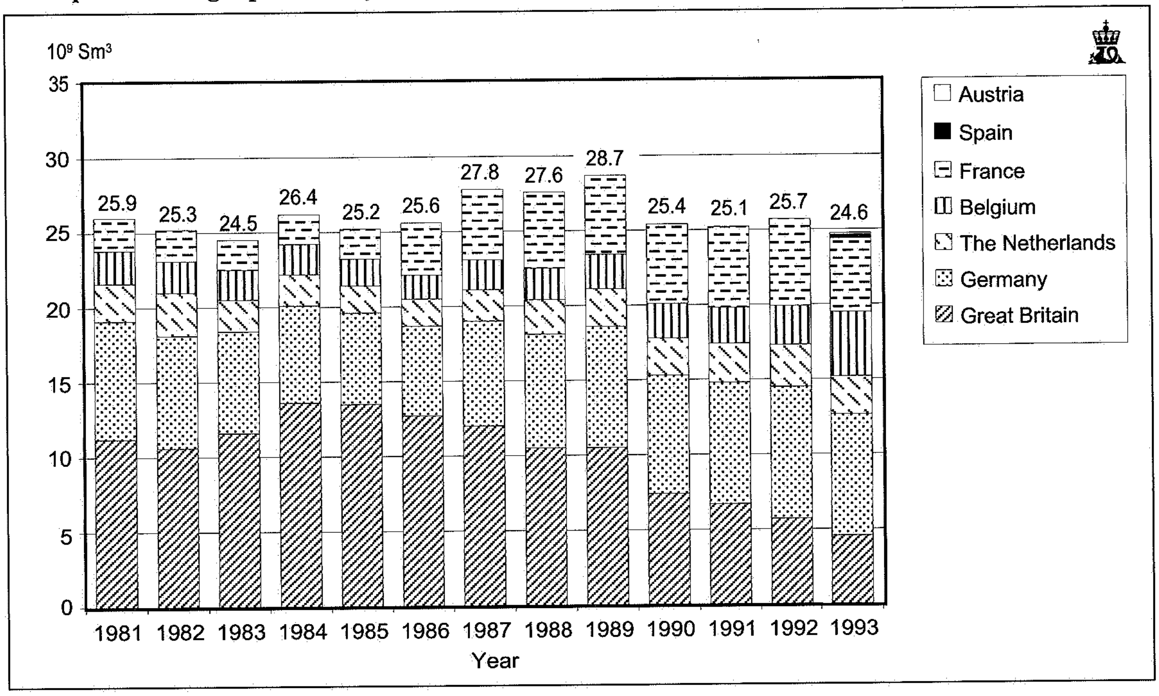


Fig. 2.12.8.c
Sales quantities of gas per country

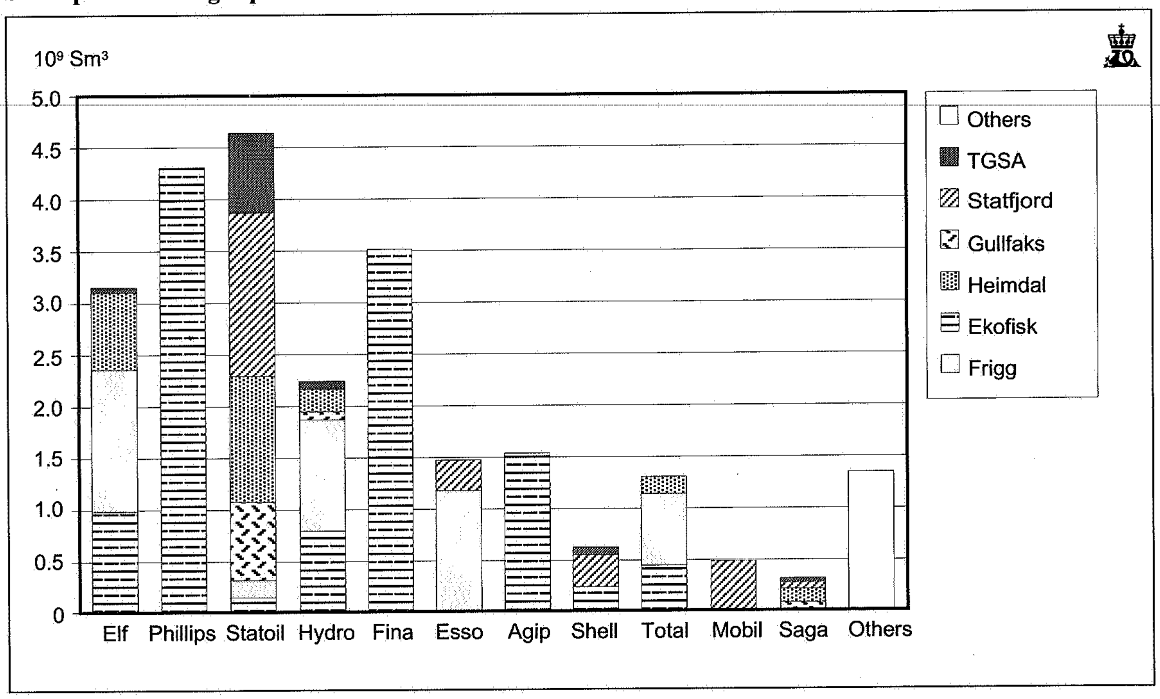


2.12.9 Royalty

The Directorate has been delegated the responsibility for collection of royalty from petroleum production.

Production royalty is calculated as specified in the Petroleum Act, which came into effect on 1 July 1985. The formula for calculating the royalty is the value of petroleum production passing each field's loading point. As it is not customary to calculate the price of petroleum products at the loading point, in practice the formula applied is the difference between the gross sales value and the costs incurred between the taxation point and the point of sale.

Fig. 2.12.8.d
Sales quantities of gas per licensee in 1993



In Odelsting Proposition no. 64 for 1986–87, an Act regarding certain amendments to the Petroleum Act, it was provided that royalties would not be charged for production from areas for which the development plans were approved after 1 January 1986.

The interpretation and enforcement of the current rules and regulations for royalty calculation involve problems of a legal, economic, processing and measurement nature.

From 1 January 1992 the royalty rate for gas was set to nil, confer Royal Decree of 27 March 1992 and Crown Prince Regent Decree of 22 May 1992. This means that from now on, royalty will only be levied on oil.

Since on some fields the oil and NGL are a single product at the loading point, the NGL only being separated out later, then for those fields royalty will be paid on the NGL. On the other hand, NGL is not payable on fields where it is combined with the gas phase at the loading point.

For some fields the cost of transportation has at times been higher than the gross sales value of the specific petroleum product. This applies especially to gas. Under such circumstances the product has no value at the taxation point, and no royalty is charged.

On 25 June 1993 the Supreme Court upheld the Oslo City Court's judgment of 26 April 1991 which found as the State had argued, that separate reckonings must be done for oil and gas royalty. The Statfjord licensees, except Statoil, had claimed that the tax base for gas royalty, which they calculated was negative due to low gas rates and high transportation costs, should be deductible from the tax base for oil, which was positive. The Norwegian State contested this claim. The same licensees then appealed against the City Court judgment and the appeal was handled directly by the Supreme Court. The amounts at issue were very substantial.

Fig. 2.12.9
Royalties paid 1984–1993

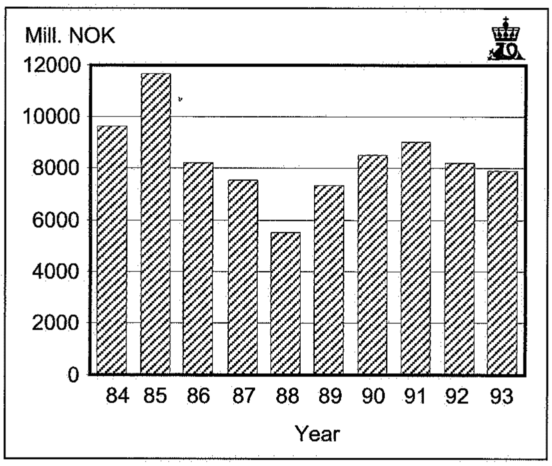


Table 2.12.9.1
Paid-up royalty in 1992 and 1993 (mill Nkr)

Product	Field/area	1992	1993
Oil	Ekofisk area, Ula and Valhall	1 695.6	1 624.7
"	Statfjord	4 356.6	4 186.9
"	Murchison	23.7	18.5
"	Heimdal	4.1	*-2.0
"	Oseberg	964.6	1 034.6
"	Gullfaks	738.2	972.7
Gas/NGL	Ekofisk area	205.5	4.6
"	Valhall	13.0	6.4
"	Ula	0.0	6.3
"	Frigg, Nordøst Frigg, Odin	132.5	0.0
"	Statfjord	**-31.1	0.0
"	Murchison	0.7	0.9
"	Heimdal	25.8	**-1.8
SUM		8 129.2	7 851.8

* Related to refund of transport costs for royalty oil
** Repayed royalty in prevoius period

2.12.9.1 Total royalty

The total royalties collected by the Directorate from licensees on the Norwegian continental shelf in 1993 were Nkr 7,851,771,286. Table 2.12.9.1 shows the breakdown for the various petroleum products for 1992 and 1993.

Figure 2.12.9 shows royalty receipts for the period 1984–93.

2.12.9.2 Royalty on oil

In 1993, royalty of Nkr 7,835,337,764 was collected on oil production from the Ekofisk, Valhall, Ula, Statfjord, Murchison, Heimdal, Oseberg, and Gullfaks fields; see Table 2.12.9.2. Royalty on oil is usually taken out in kind, but the Ministry of Industry and Energy has determined that royalty on oil from Heimdal will be taken out in cash from 1 April 1993. The sale of the State's royalty oil is the responsibility of Statoil, and payment for the sale is made from Statoil to the Directorate on a monthly basis. Settlement is at the nominal rate fixed from time to time by the Petroleum Price Council.

2.12.9.3 Royalty on gas and NGL

The royalty collected for gas and NGL in 1993 amounted to Nkr 16,433,522. Table 2.12.9.3 shows the receipts on a semi-annual basis by company and partner group.

The settlement, which is in cash, is on a six month basis, with a three month term for payment. As the royalty on gas was set to nil effective 1 January 1992, any receipts for gas in 1993 will just be adjustments in respect of previous years. Settlement for NGL was made at contract prices which varied from one licence group to the next.

The delivery of gas to Dyno-Methanor was discontinued from 1 July 1984. The receipts from Dyno-Methanor relate to the transportation and processing of gas already received and paid for.

Table 2.12.9.2
Paid-up royalty on oil

Field/area	1st half	2nd half	Total 1993
Ekofisk area, Ula and Valhall	827 311 794	797 349 129	1 624 660 923
Statfjord	2 186 351 747	2 000 535 970	4 186 887 717
Murchison	17 126 961	1 396 484	18 523 445
Heimdal	* -3 471 497	1 436 427	*-2 035 070
Oseberg	459 927 166	574 654 331	1 034 581 497
Gullfaks	516 942 528	455 776 724	972 719 252
SUM	4 004 188 699	3 831 149 065	7 835 337 764

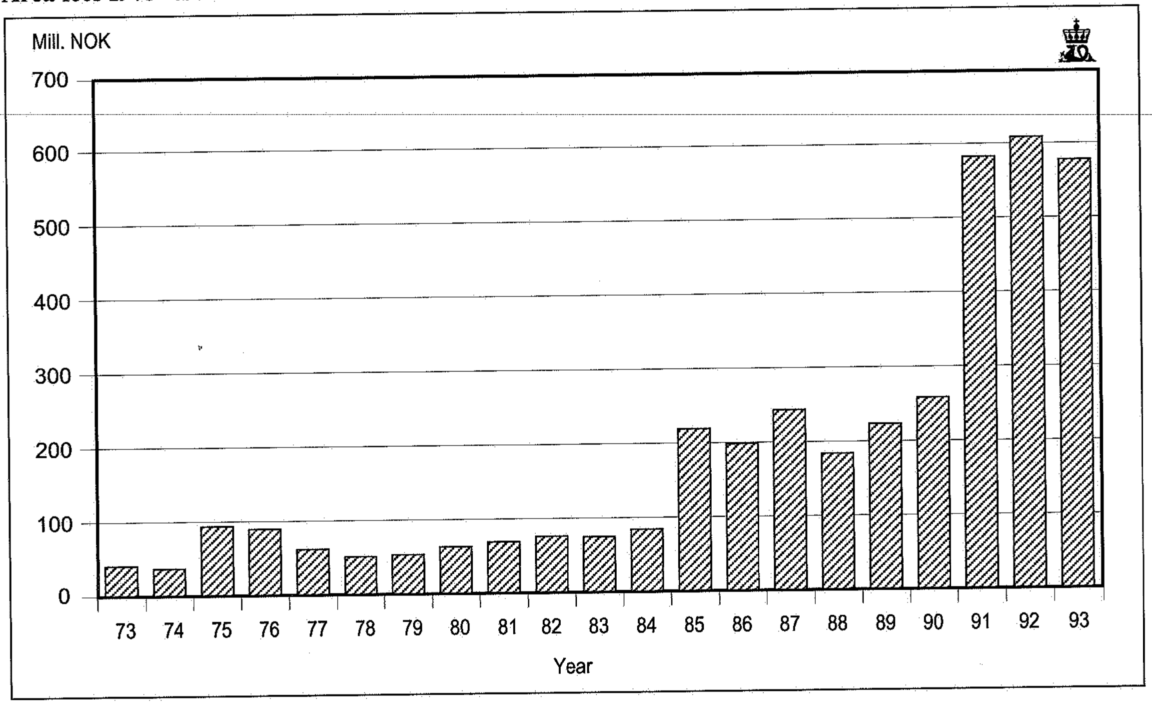
* Relates to refund of transport costs for royalty oil

Table 2.12.9.3
Paid-up royalty on gas and NGL

Field/area	1st half	2nd half	Total 1993
Ekofisk area			
Phillipsgroup	15 479 338	*-8 007 237	7 472 101
Amoco-gr. (Tor)	143 582	99 129	242 711
Shell (Albuskj.)	0	-3 105 397	*-3 105 397
Dyno/Methanor	170 276	*-158 064	12 212
Sum Ekofisk area	15 793 196	-11 171 569	4 621 627
Valhall	3 189 349	3 193 229	6 382 578
Ula	0	6 340 086	6 340 086
Murchison	140 501	703 891	844 392
Heimdal	165 878	-1 921 039	*-1 755 161
Total all fields	19 288 924	-2 855 402	16 433 522

* Repayed for excess paid-up royalty in previous years.

Fig. 2.12.10.a
Area fees 1973–1993



2.12.10 Area fees in production licences

The Directorate collected Nkr 666,173,692 in 1993 in acreage fees. With reference to licence year the receipts were as follows:

Licence awarded	*Kroner*
1965	82,015,815
1969	56,766,875
1971	5,502,000
1973	35,478,000
1975	54,796,500
1976	73,872,000
1977	27,315,000
1978	32,800,742
1979	47,051,548
1981	40,493,762
1982	22,271,887
1983	19,176,925
1984	52,887,690
1985	47,865,039
1986	14,569,827
1987	11,093,658
1991	130,000
1993	42,086,424
Total	666,173,692

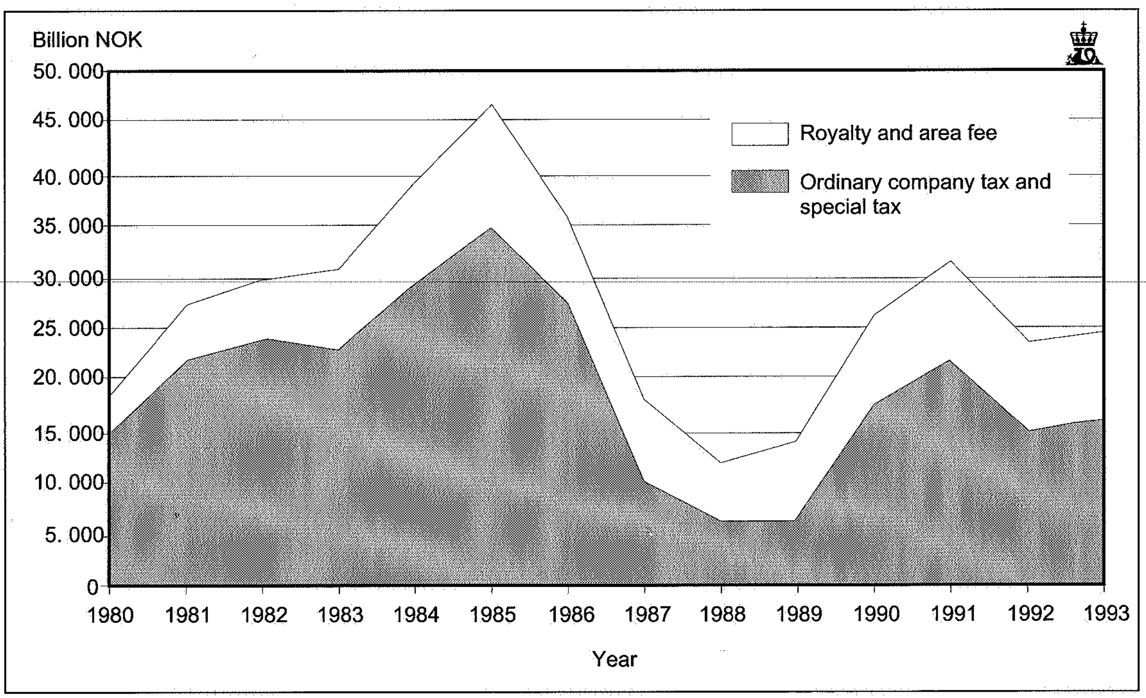
The Directorate refunded Nkr 89,636,779 in area fees in 1993. This represents the deductible portion of the area fees in the royalty settlement for production licences 006, 018, 019A, 033, 037, 050, 053, and 079.

The area fees on some of the production licences are deducted directly in the royalty settlement. For 1993, such deductions amounted to Nkr 239,909 as is reflected in the royalty receipts, which are reported net.

Figure 2.12.10.a shows the area fee receipts for the years 1973–93.

Production royalty and area fees in 1993 accounted for 35 per cent of all taxes and duties from the petroleum activity. The proportion has varied over the years and was greatest in 1989 at 53 per cent. Figure 2.12.10.b is a summary of the total paid-up taxes and duties in 1980–93.

Fig. 2.12.10.b
Total tax and royalties



2.12.11 Carbon dioxide tax

The Act of 21 December 1992 no. 72 relating to *Carbon Dioxide Tax in the Petroleum Activities* became effective on 1 January 1991. The Directorate was given the responsibility of collecting the carbon dioxide tax and passing the resolutions necessary to enforce the Act. The tax is calculated on petroleum flared and natural gas released to the atmosphere from platforms, installations and plant used in connection with production or transportation of petroleum. This tax is also levied on Norwegian petroleum transport systems which cross the continental shelf. Where fields straddle a sector boundary, the carbon dioxide tax is only calculated on the Norwegian share.

In 1992 and 1993, the carbon dioxide tax was Nkr 0.80 per standard cubic metre of gas and per litre of diesel oil. The tax, payable on a six month basis with three months to pay (at 1 October and 1 April in the following year, respectively), is levied on field and installation operators. Table 2.12.11 is a list of the total tax receipts broken down by field and transport system for the second half of 1992 and the first half of 1993. Corrections in previous six month periods have been taken into account. The gross receipts in 1993 were Nkr 2,270,685,386.

Table 2.12.11
Paid-up Carbon Dioxide tax for 2nd half 1992 and 1st half 1993

Field/area:	2nd half 1992	1st half 1993	Total 1993
Ekofisk area	350 898 599	335 615 901	686 514 500
Frigg area	20 639 925	12 651 921	33 291 846
Gullfaks	163 120 011	155 872 769	318 992 780
Gyda	16 487 784	18 983 446	35 471 230
Heimdal	18 941 306	20 979 669	39 920 975
Hod	9 198 354	7 122 800	16 321 154
Murchison	8 156 665	7 998 956	16 155 621
Odin	2 674 690	2 961 994	5 636 684
Oseberg	127 526 400	121 456 800	248 983 200
Statfjord	197 487 398	197 691 243	395 178 641
Ula	31 030 387	31 959 573	62 989 960
Valhall	29 657 049	27 964 575	57 621 624
Veslefrikk	26 166 080	25 865 520	52 031 600
Snorre	31 467 055	29 700 161	61 167 216
Transport systems			
Norpipe	121 325 817	114 404 170	235 729 987
Statpipe	2 252 056	2 426 312	4 678 368
Sum	1 157 029 576	1 113 655 810	2 270 685 386

3. Safety and Working Environment

3.1 INTRODUCTION

The formal authorities underpinning the Norwegian Petroleum Directorate's supervisory and regulatory duties related to safety and working environment in 1993 were as follows:

a) Frameworks given in governing legislation:
   - *Petroleum Act*, of 22 March 1985 no. 11
   - *Working Environment Act*, of 4 February 1977 no. 4
   - *Svalbard Act*, of 17 July 1925 no. 11
   - *Scientific Research Act*, of 21 June 1963 no. 12, relating to research and exploitation of other subsea natural resources
   - *Tobacco Injuries Act*, of 9 March 1973 no. 14.

b) Regulations and instructions given by the Ministry of Local Government and Labour:
   - Regulatory Supervisory Activities with the Safety in the Petroleum Activities etc, by Royal Decree of 28 June 1985
     - Authority of 28 June 1985 whereby the Directorate is delegated certain powers, including to:
     - Stipulate regulations for the activity
     - Conduct overall safety evaluations
     - Decide consents, orders, exemptions and approvals.

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

From 1 January 1993, the Working Environment Act applied also to mobile units engaging in petroleum activities and manned subsea operations from motherships or installations. The Ministry of Local Government and Labour resolved to vest the supervisory authority in the Directorate. Thus, the working environment is another sphere that has been provided with a coordinated, unified supervisory regime, embodied in the Royal Decree of 28 June 1985 concerning Regulatory Supervisory Activities with the Safety etc. The challenge to the Directorate lies in the added supervision duties the decision entails, the development of detailed regulations in the field, and the resolution of general delimitation issues, etc.

3.2 DEVELOPMENT OF REGULATIONS

As explained in the Annual Report for 1992, the new set of *Technology Regulations*, as they are called, under the *Safety Regulations* (enacted by another Royal Decree of 28 June 1985) have entered into force with full effect. The Directorate has formed the impression that the new rules are perceived by all parties as being both modern and serviceable, although the industry has been forced to confront new ways of working. 1993 was a running-in year, with much dialogue between the authorities and the industry regarding interpretation and implementation of specific provisions.

As a consequence of the new Technology Regulations and the general development in regulatory philosophy, more of the detailed standards, which traditionally were set out in government rulebooks, will now derive from industry specifications or industry-wide norms. The Directorate therefore focused on standardisation work in 1993 that we believe will be particularly important for safety and the working environment in the offshore industry.

The Directorate's goal is to transfer the more technical elements of regulatory drafting to the standardisation organisations, in the hope that the results will be published as or incorporated in national or international standards. A trend in this direction would further simplify the Directorate's regulations, thereby also removing some of the need to maintain and update them.

3.2.1 Regulations under WEA

In 1991 the Directorate set about identifying needs and developing frameworks for regulations concerning the working environment in the petroleum activity. This exploratory work and our supervisory experience both indicated that, although there was no need to develop new working environment requirements, there was a need to highlight those already in existence: for instance in national rules and standards, precedents, individual decisions, etc; and to make the changes necessary as a result of the European Economic Area (EEA) agreement.

The work on developing draft regulations was started in 1992. Tentatively called the Regulations relating to *Systematic Follow-up* of the Working Environment in the Petroleum Activity, with Detailed Guidelines, they are due to be issued under the Working Environment Act of 1977, and under the Royal Decree of 27 November 1992 relating to Regulations for *Worker Protection and the Working Environment* in the Petroleum Activity. The Systematic Follow-up Regulations are intended to amplify the Act and Royal

Decree just mentioned. The aims in preparing the new Regulations are to:

- Contribute to the regulation of working environment matters in petroleum activities in a structured and comprehensive manner
- Devise rules under the Working Environment Act conforming with the aims and strategies that underpin the Technology Rules under the Safety Regulations
- Contribute, in association with the interested authorities, to development of national regulations that are as uniform as possible, while at the same time reducing the numbers of "competing" sets of regulations and guidelines.

The Systematic Follow-up Regulations seek to ensure that the working environment is in conformity with the intentions of the legislation. One seeks to achieve this in part by focusing on the requirements in the WEA and by expediting the insight of the authorities in this field. The Regulations will facilitate control of the activities based on the licensees' duty to maintain an internal control scheme.

The Regulations will demand a systematic approach to planning and implementation of all phases of the activity and will stress the active participation of all parties in fulfilling the intentions of the WEA. One seeks also, through the Regulations, to simplify and streamline the paperwork done by the authorities.

In conjunction with its associated guidelines, the Regulations will address matters that were previously dealt with in regulations that will be repealed when the new ones enter into force. The Regulations will also clarify links to other national regulations, and national and international accepted standards in the working environment sphere.

In December 1993 the consultative draft for the Systematic Follow-up Regulations (with detailed guidelines) was circulated to external bodies with the consent of the Ministry for Local Government and Labour. The consultative bodies were given three months in which to make their opinions known.

In working on the draft regulations and guidelines the Directorate had formal talks with interested parties through the External Reference Group for Regulatory Development (ERR).

3.3 SUPERVISORY DUTIES

The Directorate's supervisory duties in safety and working environment matters during the year were generally conducted according to a plan which reflects the objectives adopted and the *priority commitment areas* detailed below. As in 1992, however, the safety ramifications of Ekofisk 2/4-T, the Ekofisk tank, were a central concern.

A number of across-board supervisory activities were performed, by which is meant that a number of operators were scrutinised in the same fields. Supervisory audits of this type additionally allow the Directorate to compare the companies against a common baseline in each particular sphere.

3.3.1 Consents awarded

The year saw the award of 107 consents, compared to 118 in 1992. The breakdown was as follows (1992 in brackets):

- Exploratory survey 4 (8)
- Exploration drilling 29 (36)
- Detail engineering 4 (13)
- Fabrication 14 (15)
- Installation 13 (10)
- Use of installation 17 (16)
- Rebuild, or redefine purpose of, installation 10 (6)
- Removal 1 (0)
- Use of service vessel 15 (14).

3.3.2 Priority commitment areas

In 1993, the Directorate gave priority to supervisory activities associated with:

- Introduction of new technology
- Operator's and employer's preventive safety and environment work
- High-temperature, high-pressure wells
- Major modifications and tie-ins with existing installations
- Operator's measures to protect the external environment
- Systems of maintenance management
- Follow-up of Ekofisk tank.

3.3.2.1 Introduction of new technology

The long-range plans for Directorate supervision assume that technological diversity will increase and stricter constraints will engender cost effective solutions. Through a set of rules rooted in functional requirements the industry has been given a free hand to introduce new solutions and new technology, assuming always that safety and working environment concerns are safeguarded at least as adequately as provided in the regulations and guidelines.

Although the Directorate seeks in this way to stimulate innovative ideas and technological advance, new and untried concepts will often contain an element of uncertainty in regard to safety and the working environment. The Directorate has therefore given special scrutiny to the operators' handling of these factors when new concepts, equipment and methods are at the planning stage.

Our findings from this scrutiny are by and large positive, which shows that the operators are making systematic efforts even during the early stages of a development project to adequately qualify the concepts they plan to commission.

3.3.2.2 Operator's and employer's preventive safety and environment work

The Directorate's duties in this commitment area were broadened by the coming into effect, on 1 January 1993, of the WEA for mobile installations. The plans were therefore adjusted to permit wide supervision of many operators, shipowners and contractors. The activities focused on the following, in part:

- Operator's fulfilment of his special obligation to carry out internal control

- Operator's systems for chartering rigs, evaluation, and oversight
- Principal enterprise's coordination of contractors' safety and environment work
- Employer's obligations under WEA
- Mapping of the working environment, including occupational hygiene, ergonomic factors, work organisation, working hours, layout, lighting, noise, etc
- Employee participation, including the safety delegate system and Working Environment Committee.

The overriding impression we got was positive. Even though the results show variations when it comes to implementation of and compliance with WEA requirements on mobile installations, things are moving in the right direction.

Not only the contractors have a duty to ensure that laws and regulations are observed; the operating companies have a special responsibility to ensure that people doing work on their behalf observe the rules. When submitting an application that involves hire of a mobile rig, operators are required to explain how working environment requirements will be met. Our scrutiny showed in a number of cases that the status reported by the operator did not reflect the situation on the ground.

The operators' house systems for evaluating mobile installations and shipowners before a rig is chartered proved in some cases to be defective. Descriptions of routines to be followed when hiring rigs did not, for example, always contain references to the requirements in the WEA and its regulations.

It seems, moreover, that the responsibilities, powers and tasks that the so-called *principal enterprise* must address in connection with each contractor's safety and working environment efforts were not always sufficiently defined. Thus it is to be welcomed that the Norwegian Oil Industry Association (OLF) and the Employers Association for Ships and Offshore Installations (ASO) are now working to devise a model agreement that will regulate the relations of principal enterprises with their various contractors.

The greatest challenge facing the industry in this area is to make active efforts in preventive safety and environment work. Considerable potential for improvement was evidenced in employers' routines for mapping the working environment on mobile installations in order to avoid health injury in both the short and long term.

The transition from the Safety and Environment Committee under the Maritime Act to the Working Environment Committee (WEC) under the Working Environment Act (WEA) took rather longer than anticipated. Having notified the industry of the new regime and explained the current rules, the Directorate audited the models so far established for organising WECs on mobile installations. This supervision revealed a number of violations.

In order to make sure that all employees, regardless of the conditions of their employment, are represented on the WEC for each installation, the Directorate has issued an order to operators that they must set up a common, local WEC. The new rules being prepared under the WEA will stipulate such a requirement. We have noted with satisfaction that the industry is working actively to constitute such committees.

The safety delegate system on mobile installations was also examined, and by and large it was found to function as intended.

3.3.2.3 High-temperature, high-pressure wells

During the year, three wells were drilled in the high-pressure, high-temperature category. The supervisory work done in 1993 showed that extensive planning is undertaken prior to drilling, and that drilling was conducted in a sound manner. Certain deficiencies were still found in updating and observance of governing documentation. On account of the special strictures of HTHP wells, the Directorate is especially keen to make sure that governing systems are fully in place, allowing future wells in similar conditions to proceed safely.

3.3.2.4 Major modifications and hook-ups with existing installations

In 1993 the Directorate continued its examination of operators' observance of regulatory requirements for major modifications, for instance when new field developments are tied in to existing installations for processing or transportation.

The Directorate was particularly seeking to examine how operators govern simultaneous operations while maintaining proper safety and a fully sound working environment at all times. The supervision showed that there are still large variations between operators when it comes to clear assignment of responsibility, coordination, good communications, and full documentation during simultaneous operations.

It is evident that, in addition to direct effects on safety and the working environment, such weaknesses in the governing systems often result in the underestimation of the extent of the task, and sometimes considerable cost overruns.

This commitment area also involved supervision of operators' observance both of inhouse requirements and the authorities' requirements for ergonomically correct control room layout. Our supervision showed that some operators only to a limited extent carry out a systematic evaluation, implementation and follow-up of matters concerning occupational physiology in general, and design of control rooms in particular.

3.3.2.5 Operator's measures to protect the external environment

In the year the Directorate performed one supervisory activity of an operator's observance of regulatory requirements to cut back on the use of oil-based drilling mud, reinject oily cuttings, and elucidate the working environment aspects of oil-based mud. The general impression from this supervision was positive, though the Directorate is reluctant to make any definite conclusion until more data has been collected.

3.3.2.6 Systems of maintenance management

Supervision in this commitment area continues the work of previons years. One major audit of a single operator's maintenance management system gave a positive impression.

In general it remains the elderly installations that present the biggest challenge to maintenance regimes. As the equipment nears its planned retirement age, fault frequencies escalate. Leakage of hydrocarbons is a sort of fault that frequently occurs in connection with ageing hardware, and which is particularly worrying due to the massive risk potential involved.

The companies are seeking to break the trend by improving maintenance and inspection methods. One fundamental requirement is the careful registration and monitoring of the equipment, which requires in turn that technical documentation and drawings are up to date. On most elderly installations, a history of minor modifications, equipment replacements, etc, has been the rule, and as these events are not always fully documented, the work to update drawings and other technical documents is a daunting task.

The lower price of oil means that cost reductions and lower operating and maintenance expenditures are ever more crucial. This fact has encouraged operators to implement new, cost-effective modes of operation and maintenance. Such methods presuppose that the operator simultaneously upgrades his administrative systems for maintenance management.

3.3.2.7 Follow-up of Ekofisk tank

The Directorate applied considerable energy in 1993 to following up the order issued on 18 November 1992 whereby safety standards on Ekofisk 2/4-T were required to be maintained. This follow-up of operator Phillips' activities was mostly directed to evaluating and following up the necessary risk-reducing measures in the interim until a new long term solution is on the table, and evaluating the long term solutions presented by the partners.

In the case of short-term risk-reducing measures, the Directorate's efforts were focused on measures such as upgrading escape routes and fire protection in essential rooms, measures to upgrade the emergency shutdown system and certain administrative measures to do with managing work orders and managing safety in general.

Also, Phillips imposed strict restrictions regarding the number of hot work permits that could be issued on the Ekofisk Tank. One positive factor in 1993 was the registration of fewer fire outbreaks and serious gas leaks than in previous years.

The licensees' plans for a long range solution have been evaluated by the Directorate. As 1993 drew to a close, two different concepts were presented, one requiring the construction of a new Field Centre, the other based on continuing use of the existing installations. Both the licensees and the Directorate consider the alternative with a new Field Centre to be the better option from a safety perspective.

3.4 INTERNAL CONTROL EXPERIENCE

In 1993, the Directorate continued to target quality assurance functions in the operating companies, focusing on the quality assurance units' responsibilities and duties and the interaction of the quality units with their company line organisations.

The experience so far supports the conclusions voiced in 1992, namely that governing documentation does not adequately keep pace with the actual control systems. The reason may be that most operators elected to base much of their governing documentation on the existing organisational structure. Frequent reorganisation, as has occurred in most operating companies, has inevitably brought a need to revise the governing documents. It does not appear that the operators have devoted adequate time and energy to keeping papers up to date as changes took effect.

Also, governing documentation has in many cases proven defective in describing how regulatory requirements should be observed in the organisation.

The Directorate also misses a more active approach from line managers to give priority to internal control in the company, and there seems to be a clear potential for improved relations between line management and the quality staff. Line management is often content to stay in the wings not using this control option actively as required in the regulations. The quality units for their part are occasionally passive, awaiting impetus from the line managers.

3.5 INTER-DEPARTEMENTAL COOPERATION

Under the Royal Decree of 28 June 1985 concerning Regulatory Supervisory Activities with the Safety etc. the Directorate, in supervising the safety and working environment in the petroleum activities, is expected to draw on the competence of other government agencies in fields where the Directorate has none. In cases where the other agency has an autonomous supervisory authority of its own, the Directorate's role is to coordinate.

Cooperation with such agencies has largely been very satisfactory and the arrangement ensures efficient and unified supervision of the activities.

3.6 PERSONAL INJURIES

3.6.1 General

The Directorate receives reports and notices about personal injuries and fatalities in connection with offshore activities on fixed and mobile installations on the Norwegian continental shelf. These reports generally belong to one of two categories: Notices or Reports.

Notices

In case of fatality or serious personal injury the Directorate is notified immediately. Notices trigger an assessment process and are followed up by the Directorate. Follow-up is usually by an on-scene inquiry in cooperation with the Police or by monitoring of the company's own accident investigations.

Reports

Subsidiarily to and separately from notices of serious injuries and fatalities, the Directorate also receives reports of personal injury resulting in lost time in the following 12-hour shift or requiring medical treatment. The reports serve as the basis for statistics such as those presented in this Annual Report. Although reporting is the employer's responsibility, operators are required to maintain familiarity with events on their installations. The statistics registered in the Directorate are compared each year with oil company figures, enabling both parties to check and correct any under-reporting or registration errors. The injury frequencies are based on comparisons of the injuries reported and the working hours reported each quarter from each particular installation and field.

While it is to be expected that such a broad reporting programme sometimes turns up erroneous data, the Directorate feels that relatively stable reporting practices have evolved within most operating companies. And while the injury frequencies vary a good deal from one operator to the next, the statistical summaries presented in this Annual Report should provide a reasonably accurate picture of the injury situation in Norway's offshore industry.

3.6.2 Types and causes of personal injury

In the light of the causal accounts given on the standard injury reporting forms in 1993, the Directorate intends to focus on roughly the same hazardous conditions and actions as were targeted last year in response to the 1992 statistics:

– Crushing injuries and wounds to hands and fingers. These were the most frequent injuries. The reason was most commonly inappropriate posture for the equipment being operated, coupled with wrongly used tools and equipment. Also crushing and wounds due to unserviceable tools and equipment seem to have been on the increase.
– Eye injuries. These increased from 16.0 per cent in 1992 to 21.8 per cent in 1993. The increase may be related to one of the most frequent hazardous conditions registered in the Directorate in 1993, namely inadequate personal safety equipment. However, it does seem that eye injury caused by air-borne particles is less prevalent. On the other hand, relatively more eye injuries occurred in connection with handling of chemicals, painting, etc.
– Sprains injuries. 1993 was predominanted by leg injuries due to slipping on a slippery or uneven surface. Sprains of hands, arms and shoulders were only 9 per cent of sprains in 1993, compared with 26 per cent in 1992.
– Head and face injuries. These were slightly less common in 1993 than in the year before. The slight decline also extended to dental injuries caused by careless handling of hand tools.

3.6.3 Personal injuries on fixed installations

The total personal injury frequency declined by roughly two injuries per 1000 years worked from 1992 to 1993, including 1992 injuries that were reported late. The Directorate recorded 635 personal injuries on

Table 3.6.3.a
Injuries/deaths per 1000 man-years on fixed installations (1976–93)

Year	Hours worked	Hours per man-year	Man-years	Injuries and deaths	Injuries and deaths per 1000 man-years	Deaths	Deaths per 1000 man-years
1976	4876316	1852	2633	213	80.9	2	0.76
1977	8146948	1852	4399	282	64.1	2	0.45
1978	14932296	1752	8523	624	73.2	6	0.70
1979	14986608	1752	8554	575	67.2	0	0.00
1980	12237720	1752	6985	451	64.6	0	0.00
1981	15612072	1752	8911	415	46.6	0	0.00
1982	14790384	1752	8442	526	62.3	0	0.00
1983	11473848	1752	6549	334	51.0	0	0.00
1984	14643216	1752	8358	491	58.7	1	0.12
1985	15014640	1752	8570	599	69.9	1	0.12
1986	17108280	1752	9765	606	62.1	0	0.00
1987	22169458	1612	13753	832	60.5	0	0.00
1988	19878727	1612	12332	637	51.7	0	0.00
1989	19935637	1612	12367	596	48.2	1	0.08
1990	19852093	1612	12315	571	46.4	1	0.08
1991	22263572	1612	13811	589	42.6	0	0.00
1992	22203641	1612	13774	583	42.3	0	0.00
1993	25411735	1612	15764	635	40.3	2	0.13
Total/average	295537191		175805	9559	54.4	16	0.10

Fig. 3.6.3.a
Injuries to personnel 1979–93 on fixed installations

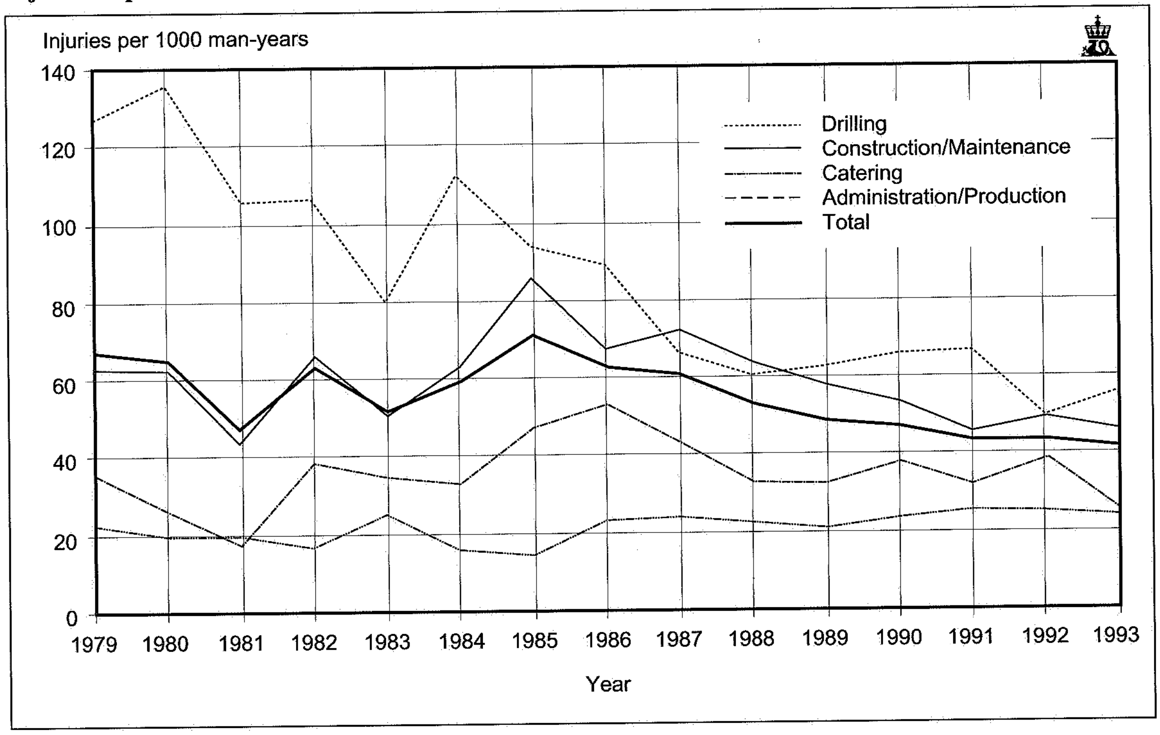
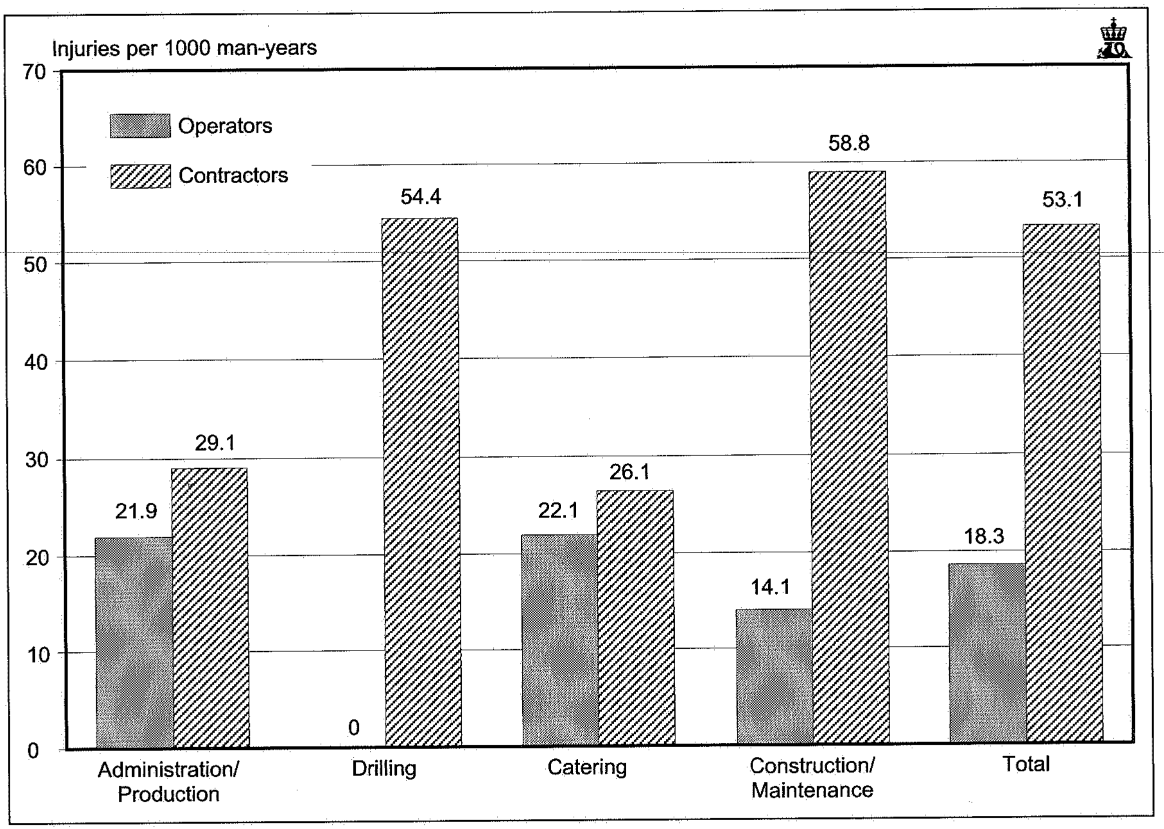


Fig. 3.6.3.b
Injuries to personnel employed by operators and contractors – 1993 on fixed installations



fixed installations on the Norwegian continental shelf in 1993, two of them fatal.

– On Statfjord C, two persons died when a lifeboat fell into the sea during maintenance. The direct cause of the accident was incorrect connection of the safety chains. The investigation did not show any mechanical fault on the equipment, but inappropriate colour coding may have confused the repairmen regarding how to attach the safety chain. In light of this occurrence the Directorate has issued a warning to all operators urging a review of the routines for using support straps when lifeboats are being worked on.

Offshore injuries which occurred outside working hours (in off-duty periods) are not included in the statistics. In 1993 there were 23 off-duty injuries, compared to 29 in 1992. Off-duty injuries are most often cuts and wounds, dental injuries, and sprains.

There was an increase of roughly 13 per cent in the total hours worked on fixed installations from 1992 to 1993. The increase parallels the increase in accident reports from the three new fixed installations on the Norwegian continental shelf; Sleipner, where Statoil is the operator, Brage, where Norsk Hydro is the operator, and Draugen, where Shell is the operator. Also Elf doubled its number of hours worked on fixed installations due to the hook-up of Lille Frigg and the drilling operations on Heimdal. These account for about 3 per cent of man hours worked on the shelf. On other fixed installations relatively small changes in hours worked occurred.

Tables and figures for production installations

Table 3.6.3.a provides a summary of the personal injuries per 1000 years worked on fixed installations from 1976 to 1993 including the mobile production vessel *Petrojarl 1*, which was active in production in 1991.

The overall injury frequency in 1993 is equivalent to 25 injuries per million hours worked. The reported injury frequency for 1992 has been corrected for twelve injuries notified in late reports.

Figure 3.6.3.a shows the development of personal injury frequency during the period 1979–93 for the various main functions. The marked improvement in the drilling and well operations function from 1991 to 1992 has levelled off in 1993, though injury frequencies continue to be well below the pre-1992 level. Drilling and well operations traditionally constitute the most risk-exposed function. Here the injury frequency rose from 49.1 to 54.4 injuries per 1000 years worked last year. This function has also produced the most striking long term reduction in injury frequency.

Table 3.6.3.b.
Distribution of injuries and man-years on operator and contractor employee on fixed installations (1985–1993)

Function		1985	1986	1987	1988	1989	1990	1991	1992	1993	
Administration/ Production	Man-years	1575	1293	1692	1985	2099	2259	2366	2499	2607	Operator
		80	213	603	454	294	500	424	369	482	Contractor
	Injuries	19	34	44	47	43	50	53	54	57	o
	Injuries/	4	0	9	6	6	12	14	15	14	c
	1000 man-years	12.1	26.3	26.0	23.7	20.5	21.7	22.4	21.6	21.9	o
		50,5	0.0	14.9	13.2	20.7	24.0	33.0	40.7	29.1	c
Drilling	Man-years	0	0	0	0	0	0	0	0	0	o (operator)
		1384	1371	1567	1883	2128	2027	2239	2340	2590	c (contractor)
	Injuries	0	0	0	0	0	0	0	0	0	o
	Injuries/	130	122	103	112	132	132	147	115	141	c
	1000 man-years	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	o
		93.9	89.0	65.7	58.4	61.6	65.1	65.7	49.1	54.4	c
Catering	Man-years	0	39	94	209	340	396	447	464	498	o (operator)
		685	817	1073	882	888	868	953	887	956	c (contractor)
	Injuries	0	5	5	4	3	13	13	17	11	o
	Injuries/	32	40	45	31	36	34	31	34	25	c
	1000 man-years	0.0	128.2	53.2	19.1	8.8	32.8	29.1	36.6	22.1	o
		46.7	49.0	41.9	32.9	40.5	39.2	32.5	38.3	26.1	c
Construction/ Maintenance	Man-years	1544	2063	2441	2399	2381	2364	2482	2536	2694	o (operator)
		3301	3969	6283	4520	4237	3901	4900	4679	5937	c (contractor)
	Injuries	61	51	49	51	70	63	65	79	38	o
	Injuries/	353	354	577	387	306	267	266	269	349	c
	1000 man-years	39.5	24.7	20.1	20.8	29.4	25.8	26.2	31.2	14.1	o
		106.9	89.2	91.8	86.5	72.5	68.4	54.3	57.5	58.8	c
TOTAL	Man-years	3119	3395	4227	4593	4820	5019	5295	5499	5798	o (operator)
		5450	6370	9526	7739	7547	7296	8516	8275	9966	c (contractor)
	Injuries	80	90	98	102	116	126	131	150	106	o
	Injuries/	519	516	734	536	480	445	458	433	529	c
	1000 man-years	25.6	26.5	23.2	22.2	24.1	25.1	24.7	27.3	18.3	o
		95.2	81.0	77.1	69.3	63.6	61.0	53.7	52.3	53.1	c

Table 3.6.3.c.
Work accidents 1979–93 on fixed installations. Injury incident/occupation

Occupation / Injury incident	Administration	Drillfloor worker	Driller	Electrician	Caterer	Assistant	Instrument technician	Crane operator	Painter gritblaster	Mechanic, motorman	Operator	Plateworker insulator	Pipeworker plumber	Service technician	Schaffolder	Welder	Derrickman	Other, unspecified	TOTAL	%
Other contact with object/machinery in motion	38	285	36	63	69	361	27	18	47	130	46	75	78	62	100	52	91	3	1581	8.7
Fire Explosion etc	0	1	0	3	0	7	0	0	1	5	2	2	4	0	0	3	0	0	28	0.3
Fall to lower level	16	28	12	48	16	107	21	15	54	49	30	36	41	21	34	34	19	3	584	6.9
Fall at same level	34	27	6	56	57	119	21	9	41	38	33	44	62	29	69	42	12	8	707	8.4
Stepping on uneven surface or tripped	31	23	8	67	36	107	22	15	51	42	46	36	61	31	60	60	14	8	718	8.5
Falling objects	9	43	11	11	13	77	6	1	16	32	7	38	35	22	62	26	5	2	416	4.9
Other contact with object at rest	26	22	5	55	36	83	33	9	64	58	25	72	54	25	73	41	12	4	697	8.3
Handling accident	24	85	10	84	109	195	30	15	55	155	45	116	117	48	86	91	32	3	1300	15.4
Contact with chemical or physical compound	6	17	0	15	34	68	10	2	100	21	25	23	26	21	9	30	8	0	415	4.9
Muscular strain	27	46	7	46	35	120	12	10	42	55	41	34	62	26	73	27	19	4	686	8.1
Splinters, splashes	17	29	8	35	19	97	6	3	147	68	31	146	160	20	28	274	7	3	1098	13.0
Electrical current	0	2	0	28	0	1	1	1	0	1	0	2	0	0	1	1	0	0	38	0.5
Extreme temperature	1	0	0	4	47	5	1	0	1	6	8	8	9	1	4	16	0	1	112	1.3
Fall into sea	0	0	0	0	0	1	0	0	1	0	0	0	0	0	0	1	0	1	4	0.0
Total	4	3	0	5	3	11	1	2	3	4	3	5	6	0	2	4	0	0	56	0.7
Total	233	611	103	520	474	1359	191	100	623	664	342	637	715	306	601	702	219	40	8440	100
%	2.8	7.2	1.2	6.2	5.6	16.1	2.3	1.2	7.4	7.9	4.1	7.5	8.5	3.6	7.1	8.3	2.6	0.5	100.0	

Catering, which accounts for the smallest volume of work with only about 9.2 per cent of total hours, was responsible for 5.7 per cent of all injuries in 1993 compared to 8.7 per cent in 1992. The injuries reported were mostly cuts and bruises caused by equipment handling, though burns were also reported. Catering injury statistics have fluctuated considerably in recent years and were notably less in 1993 than the year before.

Construction and maintenance accounted for 54.7 per cent of the work performed, up from 52.4 per cent in 1992; and 60.9 per cent of the injuries suffered in 1993, up from 59.7 per cent in 1992. The injury frequency, though, declined, also for this group. The decline is due to the operator employees, as the frequency for contractor employees in construction and maintenance increased by 1.3 injuries per 1000 years worked. The typical injuries were cuts, bruises and impact to the hands and head, and eye injuries caused by splinters and splashing in the absence of required safety equipment.

The injury statistics for the administration and production function still remain stable. In 1993 the frequency decreased by 1.1 injuries per 1000 years worked, which was due more than anything else to the notable decrease in injury frequency among contractor employees.

Figure 3.6.3.b shows the distribution of injuries for operator and contractor employees for 1993 in each of the main functions.

Table 3.6.4.a.
Injuries/deaths per 1000 man-years on mobile units (1989–93)

Year	Hours worked	Hours per man-year	Man-years	Injuries incl. deaths	Injuries per 1000 man-years	Deaths	Deaths per 1000 man-years
1989	3584740	1612	2224	87	39,1	2	0,90
1990	4328907	1612	2685	139	51,8	1	0,37
1991	4878152	1612	3026	159	52,5	0	0,00
1992	4380013	1612	2717	140	51,5	0	0,00
1993	4205431	1612	2609	135	51,7	2	0,77
Total/average	21377243		13261	660	49,8	5	0,38

Table 3.6.3.b shows the distribution of injuries and years worked for operator and contractor employees from 1985 to 1993. In 1993, contractors contributed 63.2 per cent of the total hours worked on fixed installations, against 60.1 per cent the year before; and 83.3 per cent of injuries, against 74.3 per cent in 1992. The disproportion of share of man hours and share of accidents is therefore on the rise again. The injury frequency for operator employees was significantly reduced in 1993 – it has never been lower – while for contractor employees the frequency increased to above the 1992 level.

Table 3.6.3.c is a cross-reference to the distribution of accident types in each particular occupational category. The figures are cumulative for the period 1979–1993.

3.6.4 Personal injuries on mobile units

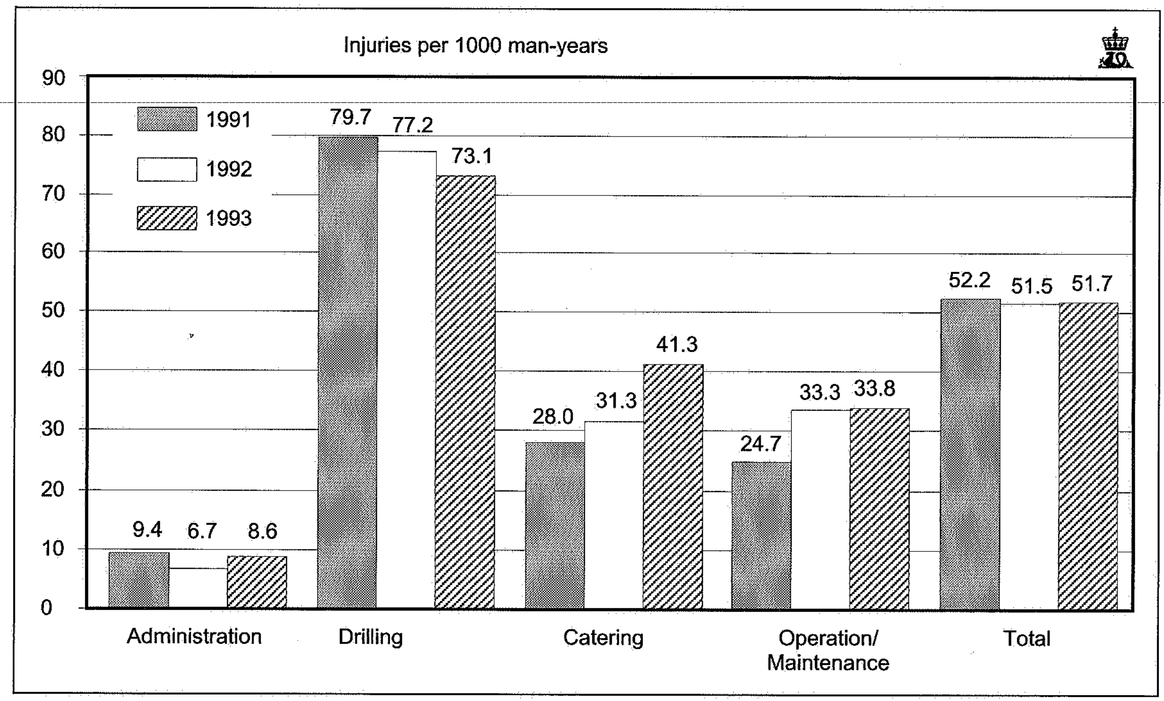
In the reporting period, 17 mobile units were in action on the Norwegian continental shelf, the same number as in 1992. According to the Directorate's records for exploration and development drilling, there were 135 personal injuries in connection with the function, a decrease of five from 1992, although as the hours worked fell slightly the injury rate remained more or less the same for the two years. Four off-duty injuries were reported, compared to one in 1992.

There were two fatal injuries on mobile units in 1993.

– A roustabout on *Vildkat Explorer* was killed instantaneously when the pipe tongs traversed without warning, striking him in the head. The accident was a result of faulty hydraulic controls. The inquiry revealed a number of unfortunate circumstances regarding procedures for work of this nature and actions to facilitate the work in hand. As a result of the accident the Directorate urged all operators to reassess their procedures for this type of work operation.

– On *Ross Rig* a roustabout was killed when he fell twelve metres onto the cellar deck. The casualty walked through a door that usually opens onto a

Fig. 3.6.4.a
Injuries to personnel 1991–93. Mobile drilling units



moveable gangway. At the time of the accident the gangway had been removed, although no warning sign or barrier had been erected. Inadequate evaluation of risk elements in connection with removal of the gangway and inadequate follow-up and control by leading personnel contributed to the accident. It also seems likely that the casualty was not aware that the gangway could be rolled away from the door.

Accident reporting for mobile units is subject to the same criteria as for fixed installations. The Directorate has noted a relatively wider discrepancy between the reports submitted to the Directorate and the summaries compiled by the operators for mobile units than for fixed installations. Also, it has been harder to achieve the same degree of retrospective reporting of incidents, since the units tend to work for different clients, be laid up, or cease operations in Norwegian waters. All these factors render it difficult to compile as accurate figures for working hours on mobile units.

In the past few years the Directorate has therefore been at pains to cross-check the numbers. The working hours reported by the operators have been collated with the rig days registered by the Directorate and adjusted in talks with the operators, thus producing a reasonably accurate estimate of the average number of personnel on the units. The Directorate feels therefore that the latest years' figures offer a true and fair picture of the situation on the mobile units.

Tables and figures for mobile units

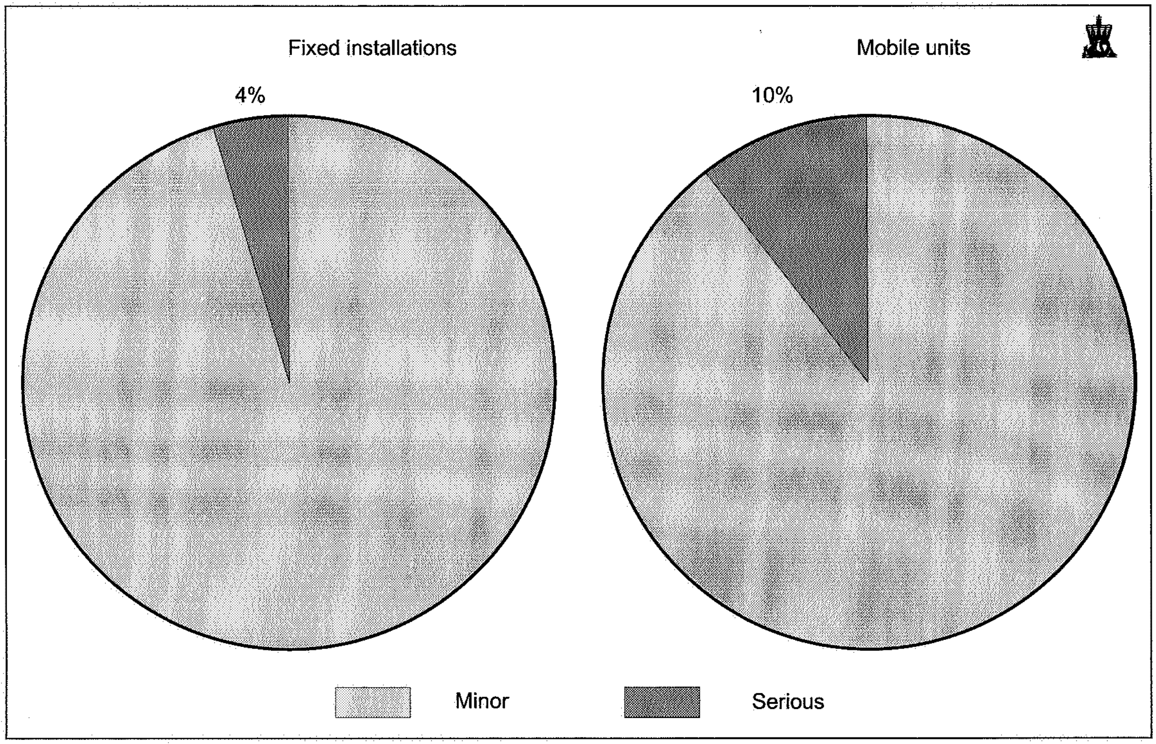
Table 3.6.4.a presents a summary of personal injuries per 1000 years worked on mobile units from 1989 to 1993. The injury frequency in 1993 is roughly the same as in 1992 and equivalent to about 32 injuries per million man hours.

Figure 3.6.4.a shows the comparative injury fre-

Table 3.6.4.b.
Work accidents 1989–93 on mobile units. Injury incident/occupation

Occupation / Injury incident	Administration	Drillfloor worker	Driller	Electrician	Caterer	Assistant	Crane operator	Painter, gritblaster	Mechanic, motorman	Operator	Plateworker, insulator	Plumber	Service technician	Scaffolder	Welder	Derrickman	Other, unspecified	TOTAL	%
Other contact with object/machinery in motion	2	75	13	1	4	67	4	1	7	4	0	0	20	0	3	14	2	217	32.9
Fire Explosion etc	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	1	0.2
Fall to lower level	0	4	2	0	2	7	2	0	2	0	1	0	5	0	1	2	0	28	4.2
Fall at same level	1	9	1	1	1	7	2	0	0	0	0	0	3	0	0	2	0	27	4.1
Stepped on uneven surface or tripped	3	14	5	1	3	12	3	0	3	0	0	1	9	0	0	6	1	61	9.2
Falling objects	0	19	3	0	1	10	1	0	1	0	0	0	4	1	1	3	0	44	6.7
Other contact with objects at rest	0	10	5	1	6	7	0	0	2	1	1	0	5	0	1	5	0	44	6.7
Handling accident	5	42	3	1	11	8	2	0	7	0	1	0	12	0	4	8	1	105	15.9
Contact with chemical or physical compound	1	5	1	1	1	2	0	0	1	0	0	1	2	1	2	4	0	22	3.3
Muscular strain	4	18	4	1	2	10	2	0	1	1	0	0	9	0	0	6	0	58	8.8
Splinters, splashes	2	13	1	1	1	7	0	1	4	0	0	0	3	0	7	5	1	46	7.0
Electrical current	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	1	0.2
Extreme temperature	0	1	0	0	4	0	0	0	1	0	0	0	0	0	0	0	0	6	0.9
Total	18	210	38	8	36	138	16	2	29	6	3	2	73	2	19	55	5	660	100
%	2.7	31.8	5.8	1.2	5.5	20.9	2.4	0.3	4.4	0.9	0.5	0.3	11.1	0.3	2.9	8.3	0.8	100.0	

Fig. 3.6.5.a
Injuries by severity 1993



quency for each main function on mobile units in the past three years. Drilling and well operations make up 53.5 per cent of the hours worked, but no less than 76 per cent of the injuries. The injury rate is therefore relatively high compared to similar functions on fixed installations. The absolutely predominant type of injury in drilling and well operations in 1993 was cuts, bruises and impact injuries in connection with lifting operations and handling of equipment on the drill floor. The body parts most likely to be injured are the hands, head and face, and feet. In only 5 per cent of cases was the mechanical roughneck (tongs) involved in the causal chain in 1993, compared to 10 per cent in 1992.

The catering function and the operations and maintenance function both showed an increase in injury frequency, though this fact is overshadowed by the relatively large number of injuries in drilling and well operations.

In the administration and production function the injury frequency remains below ten per 1000 years worked. The number of injuries in the function is in any case small.

A comparison of operator personnel and contractor personnel on mobile units indicates that the former account for only 6.2 per cent of man hours worked, and this substantially in administration. One operator employee was injured in 1993, during off-duty time.

Table 3.6.4.b is a matrix of the types of accidents in each occupational category, showing cumulative values from 1989 to 1993.

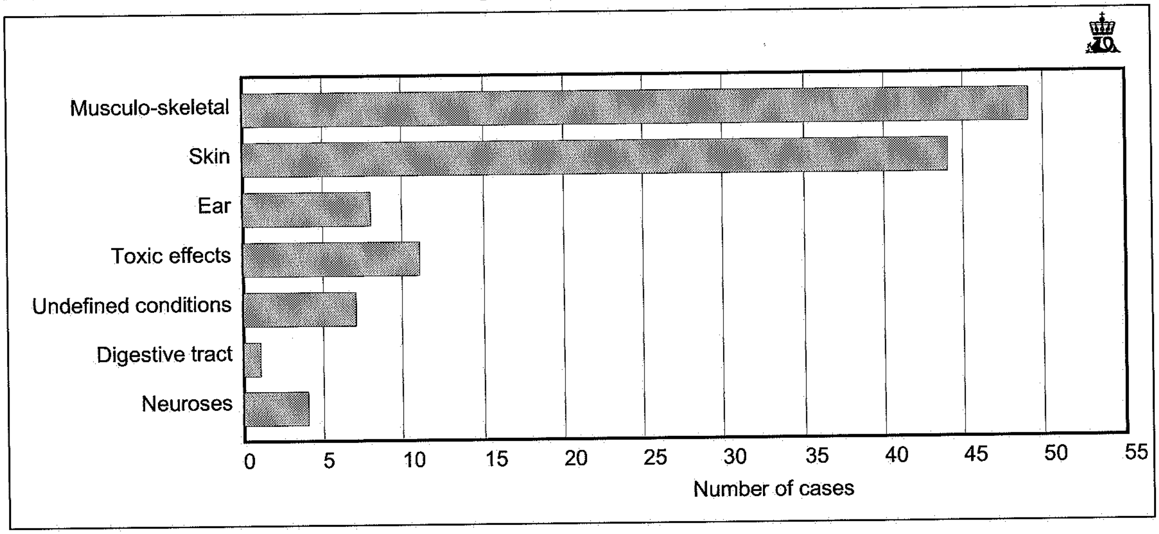
3.6.5 Summary

In 1993 and despite the overall reduction in personal injury frequency, three accidents resulting in the deaths of four people occurred. The Directorate is seriously concerned about the occurrences which will therefore be carefully investigated with a view to uncovering the chain of events in as much detail as possible.

The injury frequency in the drilling and well operations function increased marginally in 1993. Even so, it remains well below the level for years up to 1991, which may be a sign that the slowly rising trend of those years has been reversed. Despite activity levels for construction and maintenance having increased due to the deployment of new production installations since 1991, the injury frequency was only marginally above 1991, which was the second lowest injury frequency ever following a marked decline in previous years. Catering remains a small contributor to hours worked and injuries sustained, with an average of 30–40 injuries per 1000 years worked in the past five years. In 1993 the decrease was very substantial, from 37.7 per cent to 25.2 per cent. The injury frequencies in the administration and production function have been stable since 1986, with a slight dip in 1993.

On mobile units it may be that reporting and registration have become more consistent. The data here are scarcer than for fixed installations, and conclusions must be more circumspect. The injury frequency for the last three years was over 50 injuries per 1000 years worked.

Fig. 3.7.1
Distribution of work-related diseases on diagnosis groups 1993



In terms of the severity of the personal injuries suffered, it seems that on mobile units there are relatively greater numbers of serious accidents than on the fixed installations. An injury is defined as serious if in all probability it will result, or has resulted, in permanent injury (such as amputation) or extended absence from work. The classification is not based on a medical evaluation in retrospect, but on the account given in the accident report. The percentages are given in Figure 3.6.5.a.

Despite the limitations of such a comprehensive reporting system, the Directorate believes that these statistical summaries provide a reasonably fair idea of the situation in the petroleum industry. Although the reduction in injury frequency on fixed installations was not as marked in 1993 as in previous years, the Directorate is encouraged that the favourable trend of recent years does not seem to have been broken.

3.7 WORK-RELATED DISEASES

The Directorate has continued to focus on the Working Environment Act's requirement that diseases that may be ascribed to working conditions shall be reported to the supervisory authority.

The occurrence of work-related diseases is one indicator of the quality of a workplace and it is intended therefore that companies shall establish such an indicator which they use actively in their preventive safety and environment work.

As a means to improve reporting, the Directorate called the industry to a meeting in June, where people from each company's line management, the health, safety and working environment staff, safety delegates and union representatives were informed about the reporting duty, how reported data can be used in preventive work, and regulatory work in progress in the area.

Some 202 reports of work-related diseases came in, or almost twice the number for 1992. The figure corresponds to a frequency of 1.1 per cent per man year, which is substantially more than the reported frequencies for mainland industry in Norway. Even so, there are grounds to believe that work-related diseases are underreported, since we still get few or no reports from the major operators. In addition to its individual reports, the Directorate also received summary reports of 235 cases of hearing loss.

In 1992, the Directorate has established a special data base to bring the incoming work-related disease reports into order. This base records the patient's present and former employer, type of work, work factors supposed to have triggered the symptoms, and the diagnosis.

Figure 3.7 shows the distribution of reported work-related diseases in 1993 by ICD diagnostic group. Hearing loss due to noise is not shown as it is reported both as individual and as summary reports. In all, 313 instances of hearing loss were reported, of which 78 were reported individually.

In addition to hearing loss, the main emphasis is on muscular and skeletal complaints (including tendons and cartilage), usually called muscular strain injuries. Typical causes are repetitive, monotonous movement and uncomfortable posture. Other factors are pace of work and static muscular strain.

The third major group is skin disease. This is eczema due to exposure to various chemicals. The group is dominated by employees with hand eczema after contact with oil-based drilling mud. Other cases may be due to contact with other organic substances, including epoxy, and also some may be due to inorganic substances, such as certain metals. A new development in 1993 was reports of eczema due to ether-based drilling mud, which also caused other problems for employees in the form of respiratory irritation, nausea, and headache.

Respiratory diseases include asthma and bronchitis, and cases of respiratory distress due to atmospheric irritants; while toxic diagnoses refer to a range of symptoms following exposure to chemicals. The category includes so-called teflon-fever.

Undiagnosed conditions include various symptoms seeming to result from exposure to a poor working environment, though their disease classification is difficult. The mental illness category includes neuroses that are believed to be related to psychological stress at the workplace.

Ageing of offshore personnel
In recent years concern has been expressed in a number of quarters that very many offshore workers have to leave their job for health reasons before reaching retirement age. In order to shed light on the phenomenon, the Directorate joined with the Health Directorate in organising a seminar on the *Ageing of Offshore Personnel*. After the seminar a report was published with the text of all presentations and a summary of the measures suggested.

3.8 WORKING ENVIRONMENT

3.8.1 Working environment on mobile units

Since the Working Environment Act became effective on mobile units engaging in petroleum activities, the Directorate has implemented a comprehensive supervisory scheme to investigate the working environment on mobile units as described in section 3.3.2.2, above. The activities were intended to promote development of a working environment on mobile units that measures up to standards in other parts of the offshore industry.

Mapping the working environment
The degree to which the working environment on mobile units has been investigated on a systematic basis has apparently varied, for which reason the quality of the mapping efforts has been uneven. There is also some ambivalency regarding whether contractors should carry out such mapping by virtue of their own responsibilities as an employer, or by virtue of the responsibilities imposed on them by the *principal enterprise*.

Chemical health risk
On all mobile units the chemical data records and material data sheets were generally good. When it comes to assessing the health risk and selecting the least hazardous product as required by the WEA, section 11, however, the routines sometimes left something to be desired.

Ergonomics
Strain injuries caused by bad work preparation and inauspicious workplace design are a major vector of sickness absence. The Directorate's verifications revealed many unsuccessful workplace layouts. Elsewhere there exists a potential for improvement in the design of living spaces and living quarters in general, which could help address the problem.

Noise
Noise is a major environmental concern on mobile units. They are so constructed that any modifications to reduce the nuisance to an acceptable level are very difficult to implement. And even though some noise surveys have been undertaken, there are few reliable studies to show whether the rules are observed in the various parts of the units. Specific noise requirements, such as employee exposure times, have been established in varying degrees.

Work-related diseases
The systems whereby work-related diseases are recorded and reported have proven less than adequate. Many employers do not have a system, procedure or even personnel competent to carry out these duties. Therefore it is with some satisfaction that the Directorate has noted that work-related diseases are beginning to turn up on the agendas of some companies.

3.8.2 Compliance with working hour provisions

In the year the Directorate has noted a positive trend in relation to compliance with the working hour provisions for operator and contractor employees on fixed and mobile units alike. The systems used in planning, logging and inspecting working hours are generally good.

In the case of marine crews, violation of the *Working Environment Regulations'* requirement: that total working hours including overtime shall not exceed 16 hours a day, has been uncovered.

For employees in oil service companies, violations were found of the rule that time off between two offshore tours shall last at least one-third of the duration of the last tour. They concerned in particular employees in oil service companies whose work is performed sometimes on fixed and sometimes on mobile units, and sometimes also onshore.

The Directorate has been presented with disputes regarding how to classify personnel under the WEA's working hours provisions, which recognises leading and particularly independent positions. The oil service contractors were concerned that different firms would be treated differently under a classification scheme. Accordingly the Directorate has supported the Oil Service Companies Association (OSSL) in its work to ensure uniform classifications in member companies.

3.8.3 Accommodation

Several operators have from time to time needed to increase their accommodation beyond the rated capacity of the platform living quarters. They therefore applied for exemptions from the provisional *Living Quarters Regulations* on production platforms. The applications were granted where there were special grounds to do so; when compensatory measures were implemented; and when the Directorate after weighing all aspects of the matter considered the manning increase justified.

Those cases where exemption was sought were connected with critical activities for the installation of new installations, modifications to existing ones in connection with hook-up of new installations, repairs and modifications to safety systems, and work required in connection with annual shutdowns. The criteria for granting exemption were an adequately documented need, the due prior performance of studies and risk analyses, and an evaluation and implementation of compensatory measures. The Directorate also stressed the inclusion of employees in the deviation process.

In one case where the Directorate had granted dispensation from the *Living Quarters Regulations* in connection with the annual maintenance shutdown, the employees, whose representatives had also opposed the exemption at the WEC meeting handling the matter, appealed against the decision. The Ministry of Local Government and Labour upheld the appeal, thereby reversing the Directorate's decision.

For future applications for exemption the Directorate will emphasise that ordinary operational functions such as maintenance, maintenance shutdowns, modifications, and so forth will not be considered sufficient justification. This position was stressed in a draft for new regulations under the WEA.

3.8.4 Supervision of Tobacco Injuries Act

From 1 January 1993 the Directorate took over responsibility for supervision of the *Tobacco Injuries Act* on mobile units. The Directorate has investigated compliance with the Act in connection with its reviews of compliance with the WEA on such units. Conditions were found that do not satisfy the Act's criteria for installation layout and allocation of rooms for smokers and non-smokers. The internal routines for enforcing the Act were also defective. The Directorate has since urged the industry to report back on the organisational and technical changes that must be effected to ensure compliance.

3.8.5 Loss of isotopes

In the second half of the year there occurred two incidents where measuring instruments containing radioactive sources were lost or destroyed down hole. The events attracted follow-up investigations by the State Pollution Control Authority (SFT), the State Radiation Protection Authority, and the Directorate.

In the Directorate's case the object is to pinpoint any flaws in the control systems, which in other circumstances might lead to more serious incidents. In the two instances that occurred in 1993, the quantities of radioactive substance that came out of control were insignificant.

3.8.6 Ether-based drilling mud

In response to reports that indicate that the use of ether-based drilling mud may be a problem factor in the working environment, the Directorate obtained data from the operators about their environmental record when using such mud.

Most of the operators with any experience of the mud recorded cases of health complaints that seem to be related to the use of ether-based drilling mud. The complaints include irritation of the respiratory system and skin, for instance. Most of the cases seem to come from skin exposure.

As a result the Directorate has recommended that, when using ether-based drilling mud, preventive working environment measures are implemented like those that apply for use of oil-based drilling mud. The measures include ventilation systems to mitigate respiratory exposure and routines to protect the skin.

3.9 CONTINGENCY PREPAREDNESS

3.9.1 Reorganisation of Governmental Action Control Group (AKU)

The Governmental Action Control Group (AKU) was established in 1982 with a mandate to ensure clear lines and smooth cooperation between the agencies concerned in the management of major disasters, where material damage and great pollution might arise or has arisen. The Group has the following members: Director General, State Pollution Control Authority (SFT); Safety Director, Norwegian Petroleum Directorate; Director General of Shipping; Police Commissioners from Bodø and Sola Main Rescue Coordination Centres; and a senior officer from the Defence forces. They are assisted by a large staff.

The Action Control Group filled a clear need until new regulations were established under the Petroleum Act. Through the structural changes that came about when the new act was drawn up, considerable clarification was achieved regarding the lines of responsibility in each government agency; and the agencies were simultaneously given more powerful means of handling likely catastrophe events. In part due to this development, the Action Control Group never found it appropriate to actually step in and take control of any action.

In 1990 the Group set up a working party to look at the arrangements between authorities and the experience won with the Group's role, and based on them decide whether there remains any need to coordinate the branches of government in the event of disasters exceeding the individual departments' general administrative responsibilities.

In 1992 the working party presented a report that concluded that there does exist a need for coordination of the role of government agencies, but that it differs from that envisaged for the Action Control Group today. As a result, the ministries concerned have started efforts to recast the Group in a new mould. For one thing, a distinction will now be drawn between petroleum accidents and maritime (shipping) accidents. Supervision of the operator's handling of a petroleum accident will take place based on a revised coordination instruction that links the efforts of the State Pollution Control Authority and the Norwegian Petroleum Directorate.

3.9.2 Release of standby vessel

Norsk Hydro asked for permission to release one of the vessels standing by on the Oseberg field, allowing it to take up position midway between the Oseberg A and Oseberg C installations. The Directorate decided that permission could be granted. The change complies with the intentions stated in the plan for development and operation whereby the long range aim was to have just the one standby vessel for both the Oseberg and Brage fields.

Statoil also dismissed one of its standby vessels from Gullfaks, so that from now on there is one vessel standing by the three production platforms and two offshore loading buoys at Gullfaks. The standby vessel also carries out service functions in connection with hooking up tankers to the loading buoy systems. The Directorate has initiated an evaluation of Statoil's justification for its decision.

3.9.3 International rescue coordination

The North Sea Offshore Authorities Forum (NSOAF) continued its work to harmonise the safety and rescue training in all North Sea basin countries in 1993.

The working party that is examining the issues was given a new mandate in May 1993 whereby it would encourage the relevant interests in the petroleum industry to refine the concept drafted by the party. In September the working party held a seminar in which its conclusions in the report were reviewed.

At the seminar it was decided to continue the work in the industry itself, whereupon the Exploration and Production (E&P) Forum took on the task. The job is to draw up a provisional report to summarise the proposals put forward by the industry, which should be ready in time for the NSOAF plenary session in May 1994.

3.9.4 Exempted from mobilisation

Norway's national defence concept is based on total defence, meaning that the full resources of the country are brought to bear in any war or emergency situation.

An exemption and deferral procedure allows public authorities and private firms to exempt key personnel in time of mobilisation for war or other emergency for a limited period. The idea is to ensure that vital interests, such as the oil industry, can maintain some level of activity even after the situation has arisen.

In 1990 the Directorate assumed governmental responsibility for overseeing this procedure within the petroleum industry. In the operating companies, the procedure is generally administered by the personnel departments in consultation with the emergency and safety departments, who report status changes to the Directorate.

Considerable emphasis has been given to ensure close relations between the operators and the Directorate in practising the procedure. During the years it has been in force, general and specific information meetings have been held to increase the level of knowledge and understanding about exemption and deferral.

3.10 DRILLING OPERATIONS

3.10.1 Summary of drilling and well operations

During 1993 there were a total of 105 production wells drilled on the Norwegian continental shelf, or 19 more than in 1992. In the case of exploration wells, on the other hand, there was a marked decrease, with only 27 exploration wells being commenced, compared to 43 in 1992.

In geographical terms, 19 of the exploration wells were in the North Sea, six in the Norwegian Sea, and two in the Barents Sea.

Other activities associated with well workover and completion of production wells were also noticeably up on 1992. One contributory reason is that the need to work over wells is increasing as they get older.

Altogether, therefore, there was a considerable increase in activities in drilling and well operations in 1993, although exploration activity itself actually declined.

3.10.2 Shallow gas

In the reporting year the Directorate was careful to follow up companies that have used jack-up rigs to drill exploration wells. Particular focus was given to the problems surrounding possible pockets of shallow gas, and supervision looked at all phases of each project, all the way from planning until the well was drilled home, including plug back if necessary.

It was important for the Directorate in this context to effect some reduction in the uncertainty regarding the feasibility of controlling a kick of shallow gas into the wellbore.

In this connection the Directorate has accepted two solutions for drilling the tophole section that differ in principle. One is based on drilling a pilot hole. The size of the pilot hole will be based on theoretical calculations and simulations, which must prove that it will be possible to control any gas kick by circulating heavy drilling mud. The other involves the use of a down hole blowout preventer comprising a packer which sits on the drill string just above the bit, and which can be inflated using drilling mud so as to close off the space between the string and the borehole wall.

3.10.3 High-pressure wells

In its supervision of drilling and well operations that may encounter high pressures and high temperatures, the Directorate directed considerable attention to the selection of equipment and components used for the job. Key equipment categories for this type of work include elastomers, well control systems, hoses, measuring while drilling (MWD) systems, and production liners.

The Directorate's supervision was generally concentrated on the operator's systems for specifying equipment requirements and personnel qualifications.

3.10.4 Reduction of discharges from drilling

All forms of planned discharge of oily cuttings have now ceased on the Norwegian continental shelf. Each

Table 3.10.5
Number of wells with maximum deviation 60°–90°

Year/<	60°-65°	65°-70°	70°-75°	75°-80°	80°-90°
1984	2				
1985	3	4			
1986	4	4			
1987	7				
1988	4	1	1	1	
1989	13	1		1	2
1990	8	4	1		3
1991	8	5	5	2	9
1992	9	4	3	3	13
1993	8	4	5	3	31

company must now adhere to national and international rules which make strict requirements for cleansing oily cuttings.

One of the consequences is that each company must decide whether to ship its cuttings ashore for treatment there, or return them to the well for injection into suitable geological formations. The latter method has gained considerable popularity in recent years. The method offers good results both in terms of ecological benefit and cost friendliness.

3.10.5 High-deviation drilling

The share of wells classified as high-angle wells continued to increase in 1993. Since 1984 a total of 176 wells have been drilled with a maximum angle exceeding 60 degrees, no less than 51 of them in 1993. Table 3.10.5 shows the trend. Also of note is the striking increase in wells that are deviated more than 80 degrees; these virtually horizontal wells are also listed in the table.

Driving the new trend is extensive research and development of new technology and the refinement of existing equipment and techniques.

Wells that are put down at a high angle offer significant economic rewards, principally because larger parts of the reservoir can be reached from a single production installation. The force behind the trend is thus primarily economic, but research and development brings the industry added expertise with which to improve the safety of other drilling and well operations. This field of technological advance is thus an example of good safety and profitable economics going hand in hand.

3.10.6 Temporary abandonment

Whenever an exploration well is considered a potential producer if the field is developed, or the licensee for whatever reason wishes to keep his reentry option open, then the wellhead must be abandoned when the rig goes off station.

In 1993, eight wells were temporarily abandoned in this way, while the total abandoned wells in the Norwegian sector at year end was 45. To protect fishery interests, the Directorate is restrictive in permitting temporary abandonment. The result has been a reduction in the numbers that operators leave on a temporary basis.

3.11 NATURAL ENVIRONMENT DATA

In 1993 data acquisition started from Sleipner and Draugen, with statistics of currents, waves and wind, etc. There are now four fixed measuring stations in the North Sea and one in the Norwegian Sea. In the far north the operators' need for weather data is looked after by ordering mobile exploration units to keep weather records. The arrangement works satisfactorily in almost all cases.

The year saw further preparations for initiating weather data collection from the Heidrun field once the installation is put in place.

The Norwegian Meteorological Institute oversees the data collection on behalf of the Directorate and thus ensures the good quality of the enterprise.

Again in 1993, the Directorate collected natural environment data from the Barents Sea (Nordkapp bank), Tromsøflaket, and off Vesterålen. Oceanor was the contract partner who assisted the Directorate in this project, which had a budget framework of Nkr 5 million in 1993. Coast Guard vessels were used to deploy and recover measuring buoys, which offered considerable economic savings.

3.12 STRUCTURES AND PIPELINES

3.12.1 Oil leak on Draugen

On 14 November 1993, an oil film was observed on the water surface about 500 metres from the Draugen production installation. Production was stopped, and investigations were initiated using a remote control subsea rover. The leak turned out to come from a storage cell in the concrete gravity base. This cell and the others in the base were examined, and no further leaks were discovered. Production was restarted once the oil in the storage cell had been emptied into another cell.

Although the reason for the leak has not been fully determined, it is clear that it sprang from two tiny holes in the fillet between the cell wall and the cell dome. Shell and Norwegian Contractors, who built the platform, have initiated efforts to find a way to plug the holes. The cell will not be recommissioned until the fault has been repaired.

The operator believes that about nine cubic metres of oil escaped from the storage cell. Most of it dispersed quickly, and the amount that reached the surface during the leak is estimated at one cubic metre. The State Pollution Control Authority, which observed the spill from a reconnaissance aircraft while it took place, accepts the operator's figure for the scale of the leak as a realistic estimate.

3.12.2 Ringing and springing

In the model tank testing of the Heidrun concrete gravity base in 1992 it became apparent that large waves may induce a form of load on the structure that comes in addition to the loads for which the structure was engineered.

The effect, which takes the form of a resonant vibration in the structure, depends largely on wave heights, frequencies and shapes, and the vital dimensions of the concrete shaft. It is called ringing and allows waves to climb higher up the structure than allowed for in the conventional design assumptions. Though the phenomenon is not unknown, it was not considered significant for structures the size of the Heidrun and similar bases.

In a joint effort with the industry, the Directorate has initiated a major research project aimed at working out mathematical design models that will describe the effects observed in model trials. The project will last two to four years and is being executed by Veritec and Sintef. The industry is also applying a good deal of internal capacity to the problem.

In 1993 the Directorate in its supervisory duties made a special study of ringing in the Heidrun, Draugen and Troll projects. The Directorate is satisfied that the problem is being properly addressed by the operating companies.

3.12.3 Flare stack vibration

Cracks have been observed in flare stacks on a number of production installations in recent years. These observations come in addition to the discovery of a number of cracks above the water line in steel jackets. The findings have persuaded the Directorate to assess whether the industrial practices in this field are adequate.

Based on the distribution of the cracks in the flare stacks, it seems probable they were caused by wind eddies causing particular elements and large flames in the stacks to resonate together. All engineering standards only deal with single element vibrations, and there is therefore a need to develop methods for dealing with vibrations of lattices in a satisfactory manner. The work was started in 1993 by Veritec and Aker Engineering.

As a result the Directorate has amended the reference to industrial standards in the regulations. Work is going on in the European Union to write a new standard which will be issued in 1994. This new standard, which builds on the current German DIN 4133 standard, will we believe provide an even better reference for vibration design studies.

3.12.4 Collisions with ships

Three collisions were reported in 1993 between vessels and installations. In all three cases, the cause was the failure of the vessel's main engine, whereupon the vessel drifted into the installation. The damage to the installation was in each case relatively minor.

In the last 13 years, 16 collisions have been reported of vessels with installations. Also, a good number of dents in installations have been noted, indicating that minor collisions have occurred that were not reported. The material seems to indicate that there is no difference in collision frequency between large and small ships. The consequence of this finding is that, if vessels are allowed to enter the safety zone around an installation, the installation design must be adequate to tolerate a collision.

3.12.5 International standardisation

A committee was set up under the auspices of the Norwegian Building Standards Council in 1990 with the task of revising Norwegian Standard NS 3479 on Design of Structures and Design Loads. The Directorate was represented on the committee. After the committee started its work, work also started on a European Union standard concerning the same subject matter, from which time therefore the Norwegian committee has become a consultative body for the EU standard.

In 1991, the Norwegian Engineering Standards Association (NVS) set up national reference committees for a new ISO standard called Offshore Structures, Pipeline Transportation Systems for the Petroleum and Natural Gas Industries, and Line Pipe. The Directorate has been represented on these national reference committees.

3.13 GAS LEAKS, FIRES AND OUTBREAKS

3.13.1 Hydrocarbon leaks

During the year, 97 hydrocarbon leaks were reported to the Directorate, compared to 106 in 1992. None the less, an increase in the numbers of large and medium size leaks was noted. And even though there are more installations in operation and production levels are greater than ever before, the Directorate views the increase in leaks very seriously. During 1993, supervision of operators' measures to prevent leaks was therefore stepped up.

The provisional conclusions of the supervision show that it is important to combine technical measures with organisational and motivational measures. Hitherto the Directorate has concentrated mostly on the technical sides of gas leaks, while now more weight is given to the administrative and job organisational sides. The problem provides a good opportunity to strengthen the links between employees and company, the Directorate feels, which is particularly important in really getting to grips with the problem.

In this connection it is positive that some operators have already instituted systematic measures to reduce leak incidence. Their experience will be utilised in the Directorate's further supervisory work. In the Figure 3.13.1.a the distribution of hydrocarbon leaks by degree of severity is illustrated.

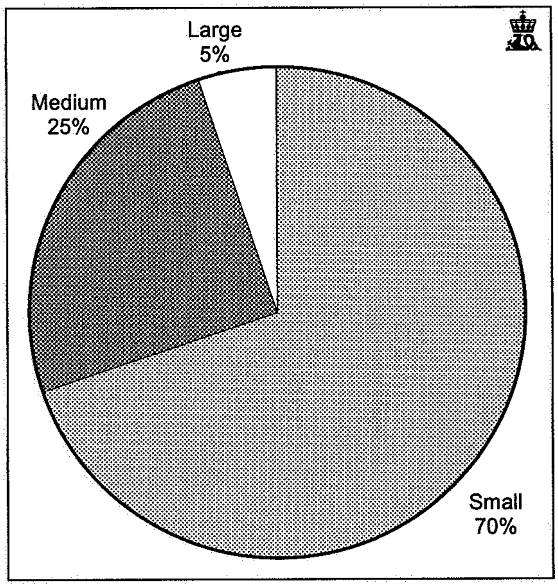
Table 3.13.1 shows how many of the leaks were de-

Table 3.13.1
Gas leaks detected by gas detection systems

Severity	Total number	Number detected automatically	Reading in % LEL	
			20 %	60 %
Minor	67	17	12	5
Medium	24	14	2	12
Major	5	2	0	2

(LEL = Lower explosion limit).

Fig. 3.13.1.a
Classification of reported hydrocarbon leaks by degree of seriousness



tected by gas detection systems. In fact only a small number of the total were in fact detected by detection systems, and most of those that were so detected, were large and medium size leaks.

Figures 3.13.1.b and c serve to illustrate the causes of the gas leaks, divided into operational faults and technical malfunctions. The divisions reflect the Directorate's assessment of the factors that were most paramount in each particular incident.

3.13.2 Fires and outbreaks

The Directorate registered 56 fires in 1993, compared with 52 in 1992. Fires in connection with welding operations accounted for most of the occurrences again in 1993.

Fig. 3.13.1.b
Causes of gas leaks – operational errors

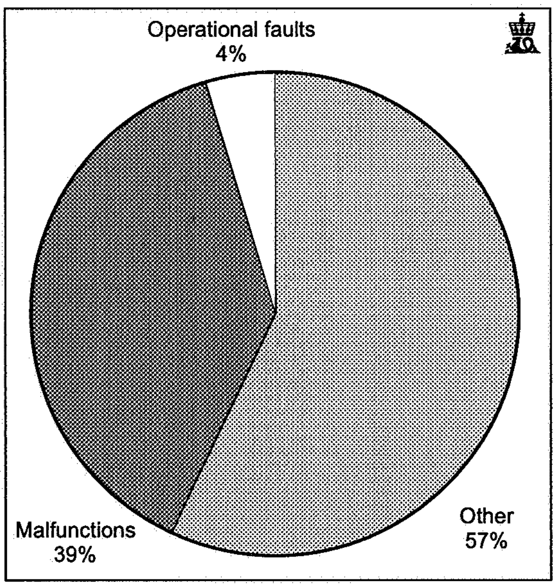


Fig. 3.13.1.c
Causes of gas leaks – faulty technical equipment

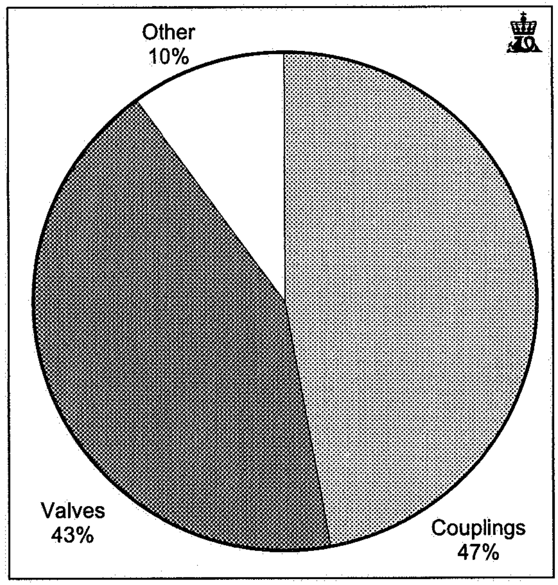


Table 3.13.2 summarises the scope and causes of fires and outbreaks reported to the Directorate in 1993. It will be seen that three of the reported fires are classified as major fires (class C). The Directorate notes that the fire statistics reveal a slight increase in small and medium size fires.

3.13.3 Fire on West Alpha

A fire broke out on 13 January 1993 on the mobile drilling unit *West Alpha* while drilling an exploration well in the Frigg area for operator Elf. The fire started in an engine room as a result of leaking diesel fuel. All personnel not required to deal with the situation were evacuated by helicopter to Frigg and nobody was seriously hurt. The engine room where the fire started, however, was severely gutted.

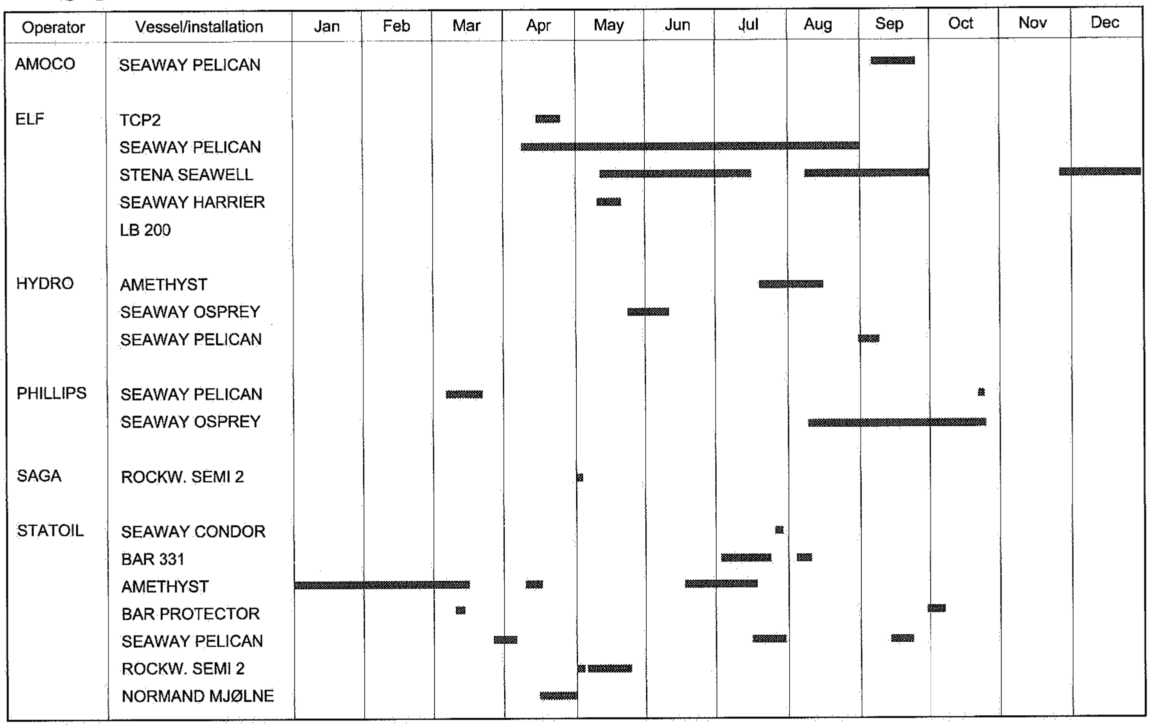
The inquest revealed poor layout and design, which among other things enabled the fire to put key security

Table 3.13.2
Summary of fires on fixed and mobile installations

	Fixed installations			Mobile installations		
	S	M	L	S	M	L
Welding	16	5		1		
Spontaneous ignition	7	5		1		
Electrical short circuiting	6	2		1		
Other causes	4	4		1	2	1
Total	33	16		4	2	1

S = Small, M = Medium, L = Large.

Fig. 3.14.1
Diving operations in 1993



functions out of action. Therefore it took more than five hours to extinguish the blaze, principally because the electric firewater pumps were locked out by the failure in the security system. The mooring winches also failed.

There are no other installations in the Norwegian sector that are identical to *West Alpha*, but a number of unfortunate circumstances in the accident may still be relevant on other types of drilling units, and on diving tenders and crane vessels which often feature similar engine room arrangements.

The factors of significance for the way the accident developed were largely linked to cable routing, the interdependency of the main and standby power systems, and the lack of training in using the engine room fire extinguishing system.

The lessons of the accident are being applied by the Directorate in the processing of consents to use mobile installations. The Directorate also questioned a number of operators to find out how they survey their drilling rigs before signing the lease contract. Some unclear points were found regarding how operators perceive that the offshore regulations should be applied to mobile installations. One positive thing, however, was noting that the rig industry, as a result of the fire, have implemented corrective action on their mobile units, particularly the route that cables take through the engine room.

3.13.4 Oil leak on Statfjord A

On 20 June 1993 a leak occurred in the utility shaft on Statfjord A. The leak, although ostensibly of oil, caused hydrocarbon gases to evolve, creating an explosive mix in parts of the shaft. The prerequisites for a major fire or explosion were therefore in place. There were no personnel in the shaft when the accident happened. The operator initiated evacuation of all non-essential personnel to the flotel, those permitted to remain all having special jobs to do in an emergency.

The total leakage was between 50 and 100 cubic metres of oil, which was collected in the drain systems. The leak did not cause any pollution, and nor was there any material damage except the general soiling of the utility shaft.

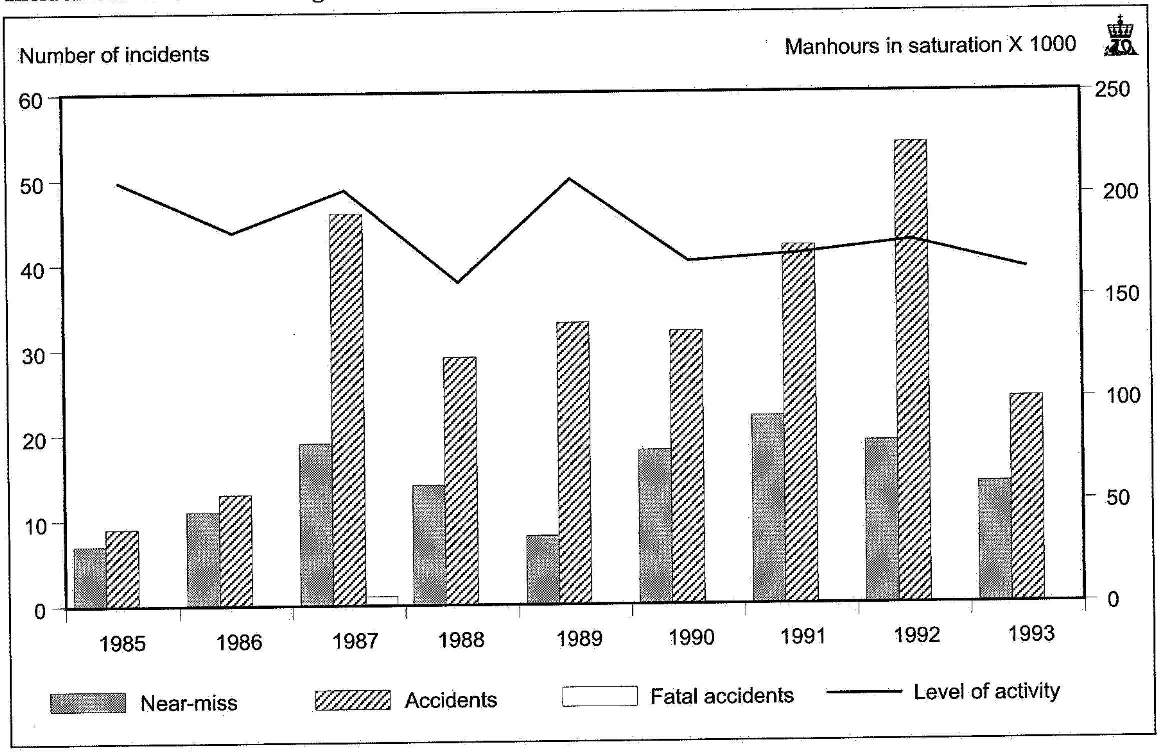
3.14 DIVING

3.14.1 Diving operations

In the current period, 877 surface oriented dives, 1241 bell runs (in saturation), 164,672 man hours in saturation, and two monobaric dives were registered on the Norwegian continental shelf. This was about the same level of activity in saturation as in previous years, though the number of surface oriented dives was far less. The mean bell run time for saturation diving was 5.4 hours and the mean saturation period 15.0 days. The figures represent a reduction in mean bell run time of 0.5 hours, but an increase in mean saturation period of 2.7 days, in both cases relative to 1992. The mean immersion time for surface oriented divers was 1.4 hours. The dives were carried out from ten different tenders and installations, as shown in Figure 3.14.1.

Diving operations were generally under inspection, maintenance and structural contracts for fields operated by Amoco, Elf, Norsk Hydro, Phillips, Saga and

Fig. 3.14.2.a
Incidents in saturation diving



Statoil. Diving in connection with construction work made up a large part of the operations, mostly for the hook-up of flowlines and risers and to give assistance with the emplacement of various structures.

Fig. 3.14.2.b
Incidents in surface oriented diving

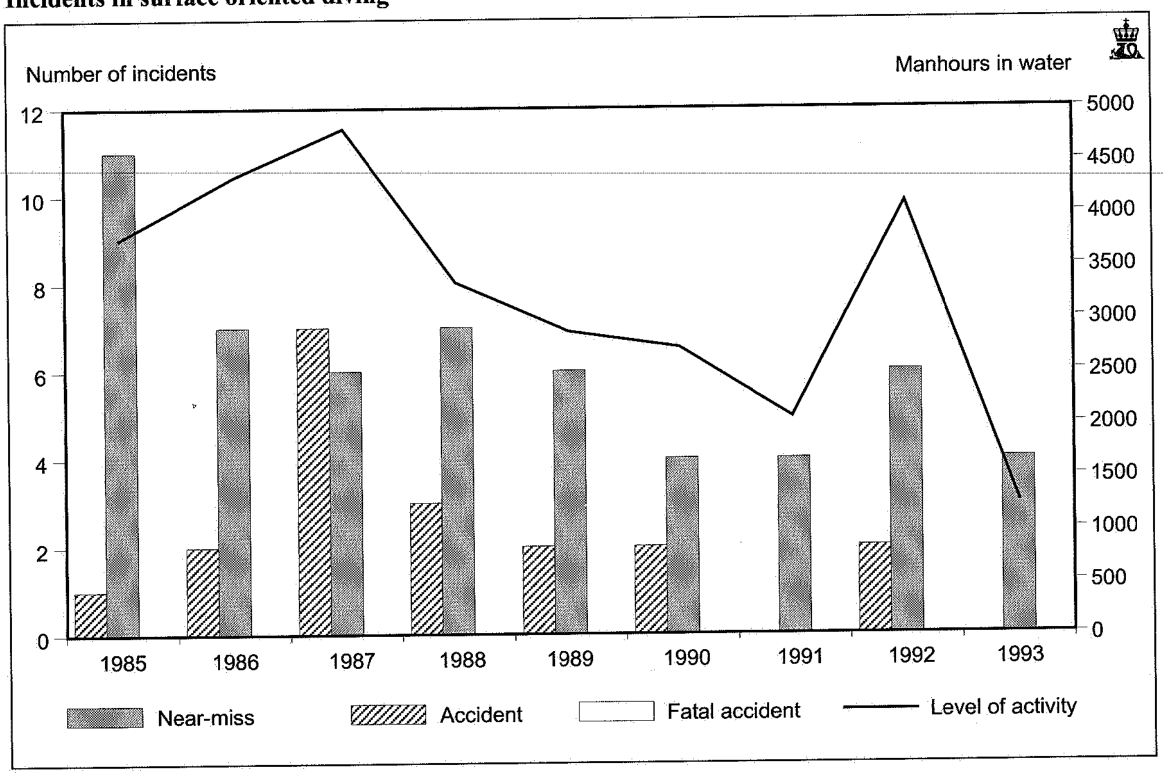


Table 3.14.2
Accidents related to type of injury

Type of injury	Saturation diving	Surface oriented diving
Outer ear infection	14	
Thermal injury		
Decomp. sickness	2	
Wounds	1	
Pain in muscle/joint		
Cold injury		
Fracture		
Infection	2	2
Hypoxia/Anexia		
Unconsciousness		
Barotraume - comp.		
Barotraume - decomp.	1	
Other illness/injury	4	
Total	24	2

3.14.2 Diving accident survey

Figures 3.14.2.a and b provide a summary of the events reported to the Directorate from 1985 to 1993 in connection with diving operations. The events are broken down into the following categories: incident, accident, and fatality. An accident is defined as any event that resulted in some form of personal injury. Thus, for example, infections of the outer ear are reported as accidents.

Figure 3.14.2.a shows that the number of accidents involving personal injury during saturation diving were almost halved since 1992, despite almost identical activity levels. The reduction is largely due to the big decrease in outer ear infections.

Table 3.14.2 gives a breakdown of how accidents involving personal injury were divided between the various injury categories. Two cases of decompression sickness were reported in 1993 in connection with offshore diving operations.

3.14.3 Diving research

In 1989, the Directorate joined with Statoil and Norsk Hydro in launching a joint *Programme for Research and Development in Diving Technology and Diving Medicine* (FUDT). In 1990, Saga Petroleum joined the programme; and other oil companies have from time to time made contributions in specific fields, either on an independent basis or through the Norwegian Oil Industry Association (OLF). The Directorate is very pleased that the oil companies can work together to reach common solutions to pressing offshore diving issues.

The Directorate is a member of the directors of the FUDT and sits in the various steering committees established for programme subprojects. These duties enable the Directorate to keep up to date on current research and development in the technical fields involved and maintain close ties with the industry. In recent years the Directorate has noted with satisfaction improvements in organisation and quality of R&D work looking into technical and health aspects of manned subsea operations.

In 1992 the Directorate provided an observer to the steering committee for the HADES project, a research programme to study decompression financed by Phillips. The project, started in 1990, was completed in 1993.

3.14.4 New contract structure

Recently a change in the operators' contracts for manned subsea operations has taken effect. The contracts are now very much shorter in time, often lasting only one or two weeks. Charter vessels and personnel work alternately in Norwegian and foreign sectors, and are often in action on a foreign shelf up to the moment a job commences on the Norwegian shelf. This alternation puts a great strain on company management systems and operations follow-up.

Short contracts also mean that the Directorate's supervisory activities must be carried out on a more spontaneous basis. The timing of diving operations is inherently often subject to change underway. As a result, some of the Directorate's supervision that was planned in consultation with the Health Directorate could not be carried out in 1993.

3.14.5 Expansion of WEA mandate

The Working Environment Act became effective for manned subsea operations on 1 January 1993. The record so far indicates that in 1993 most of the work done went to prepare inhouse requirements for manned subsea operations that are in conformity with the WEA.

4. Environmental Measures in the Petroleum Activity

4.1 INTRODUCTION

In recent years there has occurred a marked increase in the focus on environmental issues. These issues are therefore playing a more central role in energy policy design. In the petroleum activity, strong efforts must be made to prevent environmental impact due to the activity, and to contain the effects of the impact, should it occur. The costs involved can be expected to increase and may amount to substantial sums. It is therefore important that the industry in particular, and society as a whole, should address the issue carefully and resolutely.

Motivated by the growing focus on ecological soundness, the Directorate is implementing a series of actions which seek to reduce the regular emissions and discharges to the atmosphere and sea, as well as implementing actions of a precautionary nature. Security from environmental impact is defined in the general frameworks as a part of the safety concept, and safety aspects of the environmental requirements are generally addressed as an integral part of supervisory activity with safety. The Directorate's principal duties in environmental protection are thus in the field of precautionary measures, and specific environmental measures designed to prevent and contain pollution damage.

The main components of this work are the stipulation of regulations and other constraints for the activity, supervisory oversight, reports, specific projects, joint efforts with other authorities, and information services. These duties in sum make up a substantial part of the Directorate's total resource commitment.

4.2 FRAMEWORK AND CONDITIONS FOR ENVIRONMENTAL MEASURES

In 1993, the Directorate implemented activities in many areas that impose constraints in order to protect the external environment. Among other measures the Directorate:

- Participated in AKUP consequence analyses which are carried out before new areas of the continental shelf can be opened up for exploration drilling or production licence allocation
- Evaluated environmental expertise of applicants in fourteenth licensing round
- Participated with Ministry of Industry and Energy in discussions with operating companies regarding consequence analyses in connection with approval of plans for development and operation (PDO) and plans for construction and operation (PCO)
- Followed up environmental criteria and constraints established in Storting Propositions and other government papers in connection with consideration of development matters and consent applications
- Participated in work of Petroleum Law Committee on Norwegian and international rules for removal of disused installations from continental shelf
- Implemented evaluation of efficiency and design of ongoing and planned measures to reduce marine discharges and atmospheric emissions from the petroleum industry.

Regulatory work is also taking place in connection with the health and environmental risk of chemicals, this time in consultation with the State Pollution Control Authority (SFT) and Labour Inspection.

4.3 SUPERVISORY DUTIES

Very much of the Directorate's supervision of the operating companies was performed as an integral part of our supervision of health, safety and the working environment. This supervision targets the companies' internal control mechanisms, which are intended to provide a systematic means of ensuring that company operations during all phases are planned and executed in conformity with the government's requirements and the companies' self-imposed objectives and acceptance criteria.

Again in 1993, one of the areas spotlighted was operators' precautionary measures while drilling in ecologically sensitive areas. Special focus was given to the duty of implicated parties to report instances of seabed pollution.

4.4 CARBON DIOXIDE TAX

Since 1 January 1991, the Directorate has been assigned responsibility on behalf of the Ministry of Finance for enforcement of the *Carbon Dioxide Tax Act* on the Norwegian continental shelf. Apart from administrating the actual collection operation, the Directorate also supervises the metering systems for fuel and flare gas. To this end, the Regulations for *Measurement of Fuel and Flare Gas for Calculation of Carbon Dioxide Tax* in the Petroleum Activities were prepared, becoming effective on 1 October 1993.

The Directorate also considers complaints and other judicial problems in connection with the new tax. It must also consider the ongoing effects of the tax. This latter work is organised into annual meetings with the operating companies and analyses of the statistics reported by them.

In 1993, the tax was levied at a rate of 0.80 kroner per standard cubic metre of natural gas or litre of diesel oil consumed. The total 1993 emission of 6.8 million tonnes was in excess of the 1992 figure. Natural gas usage increased both for flaring and for fuel, and the consumption of diesel oil was also up. Since the increase in carbon dioxide emission was less than the increase in petroleum production, it is fair to say that the industry is moving towards a more energy-efficient production of oil and gas.

4.5 REPORTS AND EVALUATIONS

In 1993, the Directorate completed and contributed to many reports and evaluations, in part as documentation for the various ministries' ongoing efforts to establish environmental controls in connection with energy policy, and in part as documentation for its own duties.

On behalf of the Ministry of Industry and Energy the Directorate collaborated with the State Pollution Control Authority (SFT) to evaluate various measures connected with the national action plans to reduce acid rain and greenhouse gas emission. The Directorate and the SFT were responsible for preparing and reviewing various projected measures for the offshore industry. Among the proposals were ways to reduce atmospheric emissions from energy generation, flaring, cold venting, offshore buoy loading, terminal loading, and formation testing. The work described emission sources, physical measures, and the economics of each measure. The environmental benefits of each measure were also assessed where possible. The work to finalise the national action plans is not finished and will continue in 1994.

Emission prognoses for carbon dioxide (CO_2), volatile organic carbon (VOC) and nitrogen oxides (NO_x) from the petroleum activity were developed in collaboration with the SFT. Such prognoses are crucial yardsticks in monitoring national and international environmental obligations. Our environmental accounts and prognoses will also provide the basis for the Norwegian position in negotiations on reduction or stabilisation of climatic gas emissions.

The Directorate joined with the Pollution Control Authority as observers to the Norwegian Oil Industry Association (OLF)'s environment programme. We also supplied statistical data for many of the studies. The programme included various studies on emissions and marine discharges from the petroleum activity. The work lasted several years and was concluded in spring 1993. The OLF resolved to carry on with studies of this type in 1994 and the work will continue to take place in collaboration with the authorities.

The Directorate gave financial support to the Fishery Research Council programme: *Physical Injury to Fish by Seismic Surveys*, and also participated in the reference group for the project's quality control. The programme was concluded in 1993. The results indicate that catches may be reduced at a distance of up to 18 nautical miles from the air gun as the fish take fright. Mortality and injury to spawn and larvae were only demonstrated in the immediate vicinity of the air guns, defined as 1–2 metres from the source.

In 1993 the Directorate took part in the project called: *Experiences and Development of Consequence Analyses under the Petroleum Act*. The Ministry of Industry and Energy headed up the project in which representatives from a number of oil companies and competent public bodies participated.

4.6 TECHNOLOGY DEVELOPMENT

A broad range of research and technology development is carried out with the purpose of increasing the energy efficiency of existing and planned installations offshore. The energy-efficient equipment and methods available often stem from technologies which have other, added advantages, among them good reliability, ease of maintenance, and sound overall economy. The Directorate is therefore energetic in following up these developments, and pursuing the decision processes in the operating companies leading up to the selection of technical solutions and equipment.

In 1990, the Directorate issued Regulations for the *Implementation and Use of Risk Analysis*. A key principle embodied therein was the operating companies' obligation to set their own safety targets and risk acceptance criteria. In 1993, the Directorate has again continued to monitor industry activities in connection with the development of acceptance criteria for environmental risk.

The Petroleum Act and the regulations derived from it set requirements, not only for technical solutions and activities, but also for the constant development of safety and technology, in order to keep up with general advances and rising standards elsewhere in society. This is something the Directorate keeps watch on in many areas. In 1993 attention was focused on:

- Development of improved cleansing methods for produced water
- Development of burner to reduce nitrogen oxide emissions
- Development and use of new types of drilling mud, and work to obviate or at least minimise use of oil-based drilling mud
- Evaluation of various handling and disposal methods for oily cuttings
- Development of more efficient drainage systems
- Development of new fire-fighting agents as halons are phased out
- Work in connection with reduction of need for gas flaring during production operations and well testing
- Incineration of waste on installations
- Marking of containers and other storage options to ensure safe storage and transport of environmental hazard substances to shore
- Use and handling of biocides, heavy metals and low activity isotopes

- Development of methods for separation of heavy metals from produced water
- Composition of sacrificial anodes for corrosion protection.

The Directorate also carried out special studies aimed at examining the options for reducing emissions of nitrogen oxides (NO_x) from the petroleum industry. In 1993 developments occurred to advance the efforts already made by the Directorate which have the potential to reduce NO_x emissions. An extensive analysis of technology to reduce the emissions from various sources was undertaken, a task that also included evaluation of alternative means of reduction and the costs associated with each.

The water cut from production wells in Norway's offshore provinces is expected to increase until 2000. Produced water contains a mix of organic and inorganic impurities. The only current restriction on dumping the water in the sea is its oil content. As water production grows, the discharge of oil and other impurities will also grow, and the Directorate has commissioned a study to evaluate toxic activity and possible treatment of the produced water. All the parameters: water volume, oil content, and content of other components such as dissolved organics; vary greatly from one field to the next. It would also be extremely resource intensive to remove dissolved organics. Water production increased from 1992 to 1993 by 12 per cent, and the trend will continue. Therefore treatment systems and capacities will have to meet strict requirements if discharge limits are to be met.

4.7 OTHER ENVIRONMENT WORK

The Directorate takes part in a range of national and international forums of significance for the protection of the environment. Hopefully these activities allow us to influence their work and bring our opinions to bear. Another benefit is the competence they bring to the Directorate, enabling us to better attend to our duties in the field. In 1993, these organisations were among those singled out:

- Governmental Action Control Group (AKU)
- Paris Commission's Working Party for Protection from Oil Pollution
- International Maritime Organization (IMO)
- North Sea Offshore Authorities Forum (NSOAF)
- Environmental Northern Seas (ENS)
- Standardisation organisations CEN and ISO.

Since 1992, the Directorate has been a member of the technical committee of the NTNF research programme MUST, a programme for environment-friendly and profitable development of small petroleum fields. In addition to sitting on the technical committee, the Directorate is also active as an advisor in the evaluation of projects that may be interesting to the programme. The programme itself will last for a five-year period starting 1993 and has an overall cost budget of Nkr 111 million.

The Directorate also administers and operates the North Sea Seabed Clearance project, a scrap recovery programme which in 1993 had an operating budget of roughly Nkr 4.8 million.

4.8 COOPERATION WITH THE STATE POLLUTION CONTROL AUTHORITY

As provided in the tenets underlying the supervisory regime for the petroleum activities, the Directorate coordinates the practical implementation of supervision efforts by both the Directorate and by the State Pollution Control Authority (SFT) under their respective mandates, namely the Petroleum Act and the Pollution Control Act, including coordination of duties in connection with the issue of consents and discharge permits. The Directorate undertakes the supervision of the operators' systematic efforts to meet the requirements in the Regulations for *Licensee's Internal Control*, the Regulations for *Implementation and Use of Risk Analysis* and the Regulations for *Emergency Preparedness*, which were all laid down jointly by the two agencies.

In its coordination role the Directorate must evaluate the cost and safety aspects of actions contemplated by the pollution control authorities insofar as they may be of significance for the petroleum activity.

Also, the Directorate must, in consultation with the Pollution Control Authority, prevail on the industry to participate in environmental experience exchange programmes. The aim is to promote the incubation of solutions which are at the same time effective and hopefully also as economic as possible.

The Directorate also assists the State Pollution Control Authority with the staging of pollution control exercises.

5. Special Reports and Projects

In 1993, the Norwegian Petroleum Directorate appropriated a total of Nkr 19,384,817 for special projects. Of this amount, Nkr 6,169,570 was budgeted for projects in the Safety and Working Environment Division and Nkr 12,617,714 for projects in the Resource Management Division.

Another Nkr 4,653,490 was committed to the North Sea Seabed Clearance project.

Nkr 4,792,000 was made available for collection of meteorological and oceanographic data in the Barents Sea, under the guidance of the Directorate; while the PROFIT and RUTH programmes had budgets of Nkr 19,901,003 and 15,731,360, respectively, in the year.

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

5.1 RESOURCE MANAGEMENT

5.1.1 Exploration

Project title	Executive institution
Data Base for Sealing Faults	Geo-Recon
Reformatting to Work Station Format	Geco-Prakla
Interpretation on Work Stations	Geco-Prakla, Geomatic
Pore Pressure as Exploration Tool	Current Software
Salt Tectonic Studies in North Cape Basin	University of Texas
Geochemical and Biostratigraphic Analyses from Kong Karls Land, Svalbard	Institute of Energy Technology (IFE), University of Nottingham, England, University of Oslo
Third-party Biostratigraphic Dating	Continental Shelf and Petroleum Technology Institute (IKU Petroleumsforskning), Institute of Energy Technology (IFE), CB-Magneto
Svalbard Traverse and Ponam Project	Norwegian Polar Institute
Palaeopetroleum in Haltenbanken Reservoirs	University of Oslo
Mapping Analogue Exploration Plays in East Greenland	Saga Petroleum, Statoil, Norwegian Petroleum Directorate (NPD), University of Copenhagen
Exploration Play Data Base	GeoKnowledge
$^{40}Ar/^{39}Ar$ Dating of Uplift and Tectonics in Lofoten Area	University of Oslo
Geochemical Analysis and Statistical Evaluation of Potential Geochemical Standard Samples	Institute of Energy Technology (IFE), Rogaland Research, University of Oslo
Comparison of Tertiary Biostratigraphic Zoning by Third-party Consultants	NPD, Norsk Hydro, Saga Petroleum, Statoil and consultants.

Data Base for Sealing Faults

The properties of sealing faults are crucial in any evaluation of a prospect, discovery and field. In an attempt to encourage cooperation in exploration technology developments, the Directorate and the Norwegian operators Statoil, Norsk Hydro and Saga Petroleum have worked out a mutually acceptable structure for a data base for sealing faults.

Reformatting to Work Station Format

In order to exploit the Directorate's work stations for seismic data, it is essential that the data are stored in a suitable format. This project aimed to reformat the data in those cases where the necessary format was not obtainable by other means.

Interpretations on Work Stations

This project aimed to empower the Exploration Branch to utilise the latest technology in computer based interpretation of seismic data. The project also evaluated systems and general measures to build up competence in the field.

Pore Pressure as Exploration Tool

So as to make pressure data more conveniently used in the evaluation of projects, discoveries and fields, a data base structure for pressure data has been set up. Pressure data were received from Esso Norge, and stored in the data base with previously organised and quality verified pressure data.

Salt Tectonic Studies in North Cape Basin

Exploration plays resulting from salt movements will be important exploration targets in the North Cape Basin geological province in the Barents Sea. It is essential therefore to study them by modelling, various types of salt generation, salt tectonics, and diapir geometry. The results are useful in evaluating the trap potential of salt domes in the basin.

Geochemical and Biostratigraphic Analyses from Kong Karls Land, Svalbard

This project follows up the field work carried out in 1992 as a joint study between the Directorate, Norsk Hydro, Saga Petroleum and Statoil. The object of the expedition was to obtain a better understanding of the islands' geology in the hope of extrapolating the results to marine seismics acguired in the northern Barents Sea.

Some 380 specimens were collected. In 1993, about half of them were subject to biostratigraphic analysis, and a smaller number were analysed geochemically. The Directorate was responsible for the former analyses in the Jurassic to Lower Cretaceous interval, and for geochemical analyses of volcanic rocks. The basalt geochemistry provides valuable insights on the tectonic environment and thermal development in the lithosphere while volcanic activity was taking place. Other types of analyses were spread among the other partners.

Reference samples are stored in the Directorate and will be available when the final results are published.

Third-party Biostratigraphic Dating

This project dates specimens using dating methods which are outside the competence of the Directorate, such as strontium isotope analysis, silicate fossil analysis, and magneto-stratigraphy. The analyses are carried out in connection with internal studies by the Directorate of wells drilled on the Norwegian shelf.

Svalbard Traverse and Ponam Project

The Directorate takes part in this project which is a three year collaboration by several Norwegian and foreign research institutes. Its purpose is to study the Late Cenozoic development in the North Atlantic. The project was terminated in 1993 and the Norwegian contribution should aid our understanding of the mechanisms behind land rise and erosion in the Barents Sea.

Palaeopetroleum in Haltenbanken Reservoirs

The Directorate carried out a major internal study to examine the sources of oils encountered and the migration routes they may have followed in selected fields and wells on Haltenbanken. Using various geochemical methods, the hydrocarbon types in place in inclusions from wells on Haltenbanken, Nordland I and II were analysed to correlate them with the presumed source rock and to study migration and inflow history. Analyses were also made of nominally dry wells on the Halten Terrace to see if they were always dry, or whether there perhaps may have been hydrocarbons in the system at some stage. The results will be published in 1994.

Mapping Analogue Exploration Plays in East Greenland

This project is a three-year venture involving the Directorate, Saga Petroleum and Statoil. The aim is to improve the statistical expectation of securing resource supplies. By mapping and studying analogue basin configurations, sedimentation mechanisms, and trap plays onshore; we may learn something about similar features in the northern North Sea and Norwegian Sea. It is notable that East Greenland is a geological mirror of the mid-Norway continental shelf, and provides an convenient onshore analogue of the continental shelf. The main purpose of the project will be the field work at Wollaston Forland, where prerift, synrift and postrift sediments and tectonics will be analyzed in detail.

Exploration Play Data Base

One of the Exploration Department's main tasks is to keep the resource account. A key part of the account covers undiscovered resources. This project aims to construct a data base of exploration models, which can be linked to a resource estimation programme to rationalise the use of resources data and accounting programmes. It will simplify updating of the plays and prospects, and thus enable faster estimates to be run of undiscovered resources for the entire shelf or parts of it.

$^{40}Ar/^{39}Ar$ Dating of Uplift and Tectonics in Lofoten Area

Lofoten lies on the transition zone between the Norwegian Sea and the Barents Sea and has undergone a rather special geological evolution. Data on uplift and tectonics from Lofoten are important in modelling the geological evolution of those parts of the shelf off Lofoten that have not been explored, like the Vøring Basin. Argon isotopes, extracted from gneisses collected on land, were analysed to determine the age of crustal movements in the area.

Geochemical Analysis and Statistical Evaluation of Potential Geochemical Standard Samples

This project is one step in the establishment of Norwegian geochemical standards in the Directorate. The samples selected as Norwegian geochemical standards must satisfy a series of requirements to ensure that it is possible to analyse their various components. Potential oil and source rock standards were therefore subjected to a major analysis programme, embracing organic geochemical analyses, statistical evaluation of those analyses, homogeneity tests, strontium (Sr) and neodymium (Nd) isotope analyses, and the distribution of heavy metals between source rock and oil versus coal and oil.

Comparison of Tertiary Biostratigraphic Zoning by Third-party Consultants
This project which is a collaboration between the Directorate, Norsk Hydro, Saga Petroleum and Statoil, compared zoning methodologies used by competent geological consultants in order to improve dating coordination between them.

5.1.2 Development

Project title	Executive institution
Tariffs and Decision Behaviour	Foundation for Scientific and Industrial Research at University of Trondheim (SINTEF)
Exploiting Real Options in Development Projects	SNF
Small Field Development in Norway and the United Kingdom	Wood MacKenzie
Disparities between Socio-economic and Commercial Development Decisions	SNF
Simulation Study Troll Vest	Petec a.s
Simulation Study Gullfaks Sør	Scandpower
Mapping of Skirne and Byggve	Scott Pickford
Further Development of INVERS Analysis Tool	Andersen Consulting
Study of non-permanently Manned Installations	ABB Global Engineering

Tariffs and Decision Behaviour
This project aims to analyse how the various tariff systems and regulation systems may impact on the utilisation of the existing transportation system and on investment behaviour.

Exploiting Real Options in Development Projects
The SNF examined the feasibility of utilising real options in development projects. The key in this context is the valuation of the flexibility that is incorporated in development concepts and the handling of risk.

Small Field Development in Norway and the United Kingdom
Wood MacKenzie made a comparison of development of small fields on the Norwegian and UK sectors. One of the primary purposes was to discover if small field development is more economical in the UK than in Norway.

Disparities between Socio-economic and Commercial Development Decisions
The project is examining whether the tax system distorts field optimisation results, causing a disparity between optimisation based on socio-economics and optimisation based on commercial economics. The project particularly targets resource exploitation.

Simulation Study Troll Vest
Petec has devised a new reservoir simulation model based on the Directorate's new mapping of Troll Vest. The model will be utilised for evaluating the profitability of oil production from the gas province and its effects on the gas recovery factor from Troll Øst and Troll Vest.

Simulation Study Gullfaks Sør
Scandpower undertook a compositional simulation of gas injection in the Brent reservoir in Gullfaks Sør. The aim was to assess whether gas injection will enhance recovery of oil and condensate. Gullfaks Sør is a likely candidate for gas allocation, and the Directorate is weighing gas injection against gas sales, based on the outcome of this study and its own reservoir studies.

Mapping of Skirne and Byggve
Scott Pickford undertook to map the Skirne and Byggve fields. Integrated interpretations of the seismic data, cores, well logs and petrophysical data were performed. The maps will be used to evaluate a possible development of these fields.

Further Development of INVERS Analysis Tool
In 1993, the Directorate continued its work on an analysis tool for the Invers cost data base. One of the uses of this software is in connection with evaluation of cost estimates for new prospects.

Study of non-permanently Manned Installations
In 1993 the Directorate commissioned a study to evaluate the use of non-permanently manned installations on the Norwegian shelf. Technical and economic assessments were carried out based on resources and safety factors. A comparison and evaluation of Norwegian and other countries' regulations was a central part of the work.

5.1.3 Production

Project title	Executive institution
Improved Recovery from Gas Fields	Intera
Improved Oil Recovery Gullfaks	Rogaland Research Institute (RF)
Ekofisk Subsidence	Dr Mervyn Jones, SDR, University College London
Compressibility Evaluation on Ekofisk	IKU Petroleumsforskning
Valhall Core Analyses	Dr Mervyn Jones, SDR, University College London
Seismic Interpretation of Ekofisk Area	Petrolet A/S
Modelling Fractures and Fluid Transport	Professor R Bruhn, University of Utah
Well Problems in Overlying Strata	Paleoservices
Reservoir Studies of Chalk Fields	Institute of Energy Technology (IFE), Paleoservices, Reading University
Petrophysical Programme	Simon Petroleum Technology (SPT), Atlas Wireline Services (AWS)
Reservoir Simulation of Ekofisk	Petec a.s
Alternative Concept Costs in Southern North Sea	McDermott Engineering (Europe) Limited
Availability and Operating Costs	Det Norske Veritas Industri Norge AS
Water Treatment and Processing of Produced Water Offshore	Rogaland Research Institute (RF)
Water Flooding and Reservoir Souring	Capcis, University of Manchester
Computer Subsystems for Fiscal Metering	Simrad Albatross
Crude Oil Quality	West Lab A/S
Flowmeter for Oil, Gas and Water	Christian Michelsen Research (CMR)
Measures to Control Nitrogen Oxide Emissions	Det Norske Veritas Industri Norge AS, ECON
Use of Ultrasound Gas Meters on 16/11-S Platform	Institute of Energy Technology (IET)

Improved Recovery from Gas Fields
Intera has reviewed various methods of optimising the recovery from gas and condensate fields. The study examines phase behaviour, well conditions for sampling, fluid analyses, and selected reservoir processes.

Improved Oil Recovery Gullfaks
This project is a continuation of the 1992 project. It aims to evaluate what Improved Oil Recovery (IOR) methods and draining mechanisms are suited for use in the Cook formation on Gullfaks, phase 2. Also the utility of using a number of methods at the same or different times and places in the reservoir was evaluated.

Ekofisk Subsidence
This project aimed to examine the theoretical background for the seemingly linear relationship of net reservoir outtake and seabed subsidence on Ekofisk. The observed subsidence on the Ekofisk, Eldfisk, Vest Ekofisk and Valhall fields was used in the analysis.

Compressibility Evaluation on Ekofisk
In order to verify the results of the theoretical side of the *Ekofisk Subsidence* project, described above, the IKU was commissioned as a third party consultant. The results of both projects will be used as a basis for further efforts to predict the subsidence on Ekofisk, Eldfisk, Vest Ekofisk and Valhall.

Valhall Core Analyses
The purpose of this project is to evaluate the subsidence susceptibility on the Valhall field. The study will examine the results of reservoir fluid and gas compressibility on field compaction. Also, it will analyse whether water flooding has any effect on the shear strength of the rock and whether it will add to the problem of chalk production and well collapse on the field. The study will be completed in February 1994.

Seismic Interpretation of Ekofisk Area
This project involved interpretation of three dimensional seismics across the Ekofisk and Eldfisk fields. Petrolet A/S are performing the project which will be concluded in April 1994.

Modelling Fractures and Fluid Transport
Professor R Bruhn of the University of Utah was responsible for the development of a numerical model to simulate fluid flow through fractured reservoirs. The project has drawn widely on fracture data from the Lägerdorf project.

Well Problems in Overlying Strata
In many chalk fields problems are encountered due to breaking and deformation of the liner in production wells in the sediment layers (overburden) above the reservoir. In order to examine the sediments of Palaeogene (Eocene and Oligocene) age, outside consultants Paleoservices were contracted to conduct a detailed palynological zonation and dating study of well data from two chalk fields.

Reservoir Studies of Chalk Fields
During 1993 a number of minor studies and analyses of test samples from chalk fields were carried out. The methods used were biostratigraphy (nanoplankton and palynology), sedimentology, clay mineralogy, x-ray diffraction, and other specialised analyses on selected test samples in connection with various problems.

Petrophysical Programme
In 1993 the Directorate purchased two new software programmes for petrophysical interpretation running on the Unix platform. Tigress, a programme developed by Simon Petroleum Technology (SPT), will be used for log interpretation and log quality control. Horizon, developed by Atlas Wireline Services (AWS), will generally be used for permeability estimates.

Reservoir Simulation of Ekofisk
In connection with predictive simulations using the Directorate's simulation model for Ekofisk in preparation for the work on an expanded field study (UFS) and a new plan for development and operation (PDO) of Ekofisk, Petec a.s was drawn in as consultant.

Alternative Concept Costs in Southern North Sea
The results from this study are part of the Ekofisk area study. The project prepared parameters and investment cost estimates for specific development alternatives for the Ekofisk Centre.

Availability and Operating Costs
The results of this study were included in the Ekofisk area study. The project aimed to identify operating time and costs of predefined development alternatives for the Ekofisk Centre.

Water Treatment and Processing of Produced Water Offshore
Based on the expected increase in produced water before the year 2000, this project is examining problems linked to toxicity and possible treatment of the produced water. Various technologies to treat the produced water have been reviewed and the costs of implementing them have been sought clarified.

Water Flooding and Reservoir Souring
This is a joint project by Norwegian and British oil companies and authorities. Execution of the project is done by Capcis at the University of Manchester and aims to explore possible measures to reduce or prevent reservoir souring in seawater flooded reservoirs. The project is drawing to a close. A follow-up, the *Raw Water Programme*, has already begun. It looks at the consequences of omitting oxygen removal and chemical treatment of injected seawater, thereby hoping to reduce costs. The concept is interesting for many Norwegian fields.

Computer Subsystems for Fiscal Metering
The Directorate was assisted by Simrad Albatross in following up and testing the new metering computer system for the Ekofisk field. New digital technology has been utilised. The project reached its conclusion in 1993.

Crude Oil Quality
The aim of this project was to find an answer to how the selling value of crude oil can be worked out from a reference price and a value adjustment factor based on actual oil quality.

Flowmeter for Oil, Gas and Water
This project carried out tests for the development of a metering instrument that would monitor water, oil and gas flow rates simultaneously in an unprocessed well stream. Laboratory trials done by Christian Michelsen Research gave promising results and will be followed by realistic trials offshore. The project, which has been run on a multiclient basis for four years from 1990 to 1993, involved participation from Saga Petroleum, Elf, Amerada Hess, BP, Norsk Hydro, Fluenta and the Directorate.

Measures to Control Nitrogen Oxide Emissions
This project examines the options for reducing the NO_x emissions from the offshore petroleum sector, from both fixed and mobile installations using a range of methods. Technical solutions that may be able to reduce the volumes of NO_x emitted from gas turbines, diesel prime movers and flare stacks have been evaluated. The costs of each solution were estimated. Also different ways of measuring the emission levels have been discussed.

Use of Ultrasound Gas Meters on 16/11-S Platform
Until the present all fiscal metering of gas was done using orifice plates, which represent a well understood technology rooted in international standards. To achieve the desired accuracy, such systems must be large and heavy, and there are therefore compelling economic arguments to bring alternative technology into use.

Ultrasound flowmeters will steadily gain ground as fiscal metering units for gas, though there remain a few points needing to be clarified in the technology. The project aims to examine the documentation presented by operators in their applications to build, test and operate such flowmeters.

5.1.4 Data Management

Project title	Executive institution
Consulting Services for Well Data Release	Petec a.s, Allservice, TK-Service, Tape Technology Norge A/S
Petrophysical Quality Control	Petec a.s, Simon Petroleum Technology
Geodata Project	Various, see below
Wet Sample Handling	Geco-Prakla
Well Data Summary Sheets	NPD
Software Maintenance and Hire	Various, see below
Software Procurement and Development	Various, see below

Consulting Services for Well Data Release
This project covers a range of activities associated with the reprocessing and preparation of materials for release. A consultant was engaged to run a check on well trajectories and well identities and correct the data base. External contractors were also employed to help with copying of data compilations and printing of catalogues and publications.

Petrophysical Quality Control
In connection with implementation of the High Quality Log Data (HQLD) project to provide a total quality upgrade for all log data from Norwegian exploration wells, the services of external consultants were employed. Based on detailed specification requirements the Directorate recovered all paper logs and associated magnetic tapes for about 250 wells. They were controlled for quality of contents and well trajectory identification and sent to a consultant for compilation in a complete digital version. The project continues in 1994.

Geodata Project
The Directorate has instituted a joint initiative with Saga Petroleum, Norsk Hydro and Statoil for system development and operation of a common data base for geodata. The object is for the four partners to have direct access to for example seismic data from the common data base, where Directorate and company data will be stored. Modern high capacity storage media and transmission highways will be employed and the system will be updated with base data and company raw data. Access to data will be controlled by the rules and agreements for usage rights entered into, and costs will be split in proportion to how much the system is used.

The scheme is led by the Directorate which in December 1993 signed a contract for development of the system with a group of Norwegian firms. The system should be up and running by the beginning of 1995. From then on, also other oil companies and research institutes will be able to access the system to store their own data or retrieve data from other owners provided the usage rights are in order.

The development contract for the software went to IBM and Norwegian partners Nopec/ PGS, Current AS, Rogaland Research Institute (RF), AS Geodata, and Tape Technology Norge A/S, in keen competition with foreign bidders having long experience with state of the art storage systems.

Wet Sample Handling
In 1992 the Directorate received many extra wet samples from Statoil from wells for which the Directorate's backup stocks for scientific analysis were running low. External consultants were used to pack and mark the samples in the prescribed manner so that storage and retrieval can proceed efficiently. The project was started in 1992 and will be completed in 1994.

Well Data Summary Sheets
After the Directorate fell behind schedule a couple of years back with its Well Data Summary Sheets, an annual publication listing released well data from the continental shelf, things were back on track in 1992. Volume 18, describing wells released at year end 1992, was published in January 1993. At that time, all exploration wells more than five years old were reported in the Directorate's WDSS series.

Software Maintenance and Hire
To ensure that the Directorate's computer software is always up and running to assist with technical and administrative tasks within the Resource Management Division, maintenance contracts have been signed with these firms: OIS Contracting, Andersen Consulting, AS Geodata, Intera, Calcep, Sintef, Rogaland Research Institute, Geomatic, Geco-Prakla, Advanced Technology, Platt River Inc, Seres, Z&S Consultants Ltd, SSI, and Hyprotec.

Software Procurement and Development
So as to increase the availability of effective, modern applications, in 1993 programmes were purchased or developed from the following firms: Opheim Data, Geomatic, and Current Software.

During the year the Resource Management Division finished converting most of its older format systems from proprietary Norsk Data formats to Unix and Microsoft Windows based platforms.

5.1.5 RUTH

Project title	Executive institute
Use of Surfactants	RF – Rogaland Research
Use of Polymer-Gel	RF
Microbial Methods	RF
Combined Gas/Water Injection	IKU Petroleum Research
Use of Foam	RF, IKU
Gas Flooding	IKU

RUTH – Reservoir Utilization through advanced Technological Help, is a research programme conducted under the guidance of the Research Council of Norway, and administered by the Directorate. The programme aims in the first place to improve the recovery of oil, but also further development of the Norwegian research establishment. The overall budget will be roughly NOK 110 million, of which the State, through the Research Council, will provide NOK 60 million. The balance comes from 18 participating oil companies. The programme, started in 1992, will run for four years until 1995.

RUTH is organised into six sub-programmes as shown in the table above, representing six recovery methods which may contribute to improved oil recovery from Norway's offshore fields. RF – Rogaland Research and IKU Petroleum Research have been given main responsibility for the sub-programmes, though links are in place with many other research centres. Each sub-programme contains multiple subprojects. In 1993, roughly NOK 29 million was spent on 26 separate subprojects in the programme.

In connection with the programme, international links have been established with research institutes in France, England and Russia. Cooperation is also in place with operating companies for the planning of field-scale pilot projects to qualify new technology. In the first instance this will involve foam and polymergels. In addition, two projects will spotlight the environmental concerns of each method.

The annual RUTH-Seminar was held in the Directorate in October where roughly 130 delegates from eight countries were gathered. 1993 also saw the holding of two international workshops in specific technical themes. Fuller details of the RUTH programme are set out in a special brochure.

5.1.6 PROFIT

The research programme PROFIT (**P**rogram for **R**esearch **O**n **F**ield Oriented **I**mproved Recovery **T**echnology) was estalished in 1990. The Norwegian Petroleum Directorate takes part, on an equal footing, with 12 oil companies in funding and managing the activity. The research is carried out mainly by Norwegian research institutes.

PROFIT has a total budget of 68 mill. NOK over the 5 year period 1990–94, and includes two main projects:

Reservoir Characterization	45 mill. NOK
Near Well Flow	23 mill. NOK

Within Reservoir Characterization, important sub-topics have included the study of fractures and faults, improved mapping by means of seismics, homogenization of petrophysical data and description of reservoir uncertainties. Near Well Flow is devided into three sub-topics: Fracturing around injection wells, induced barriers (gel) and horizontal wells.

In 1993 research for approx. 18 mill. NOK was performed. Results from the previous year's research were presented at a seminar held at NPD in February 1993. NPD administers the programme. A special information brochure provides further details.

5.1.7 Joint Chalk Research Programme

This research programme was launched in 1982 on the initiative of Norwegian and Danish authorities and to date Nkr 43 million has been applied to the research.

In 1993 an agreement was signed by the Norwegian Petroleum Directorate, the Danish Energy Agency, and seven oil companies in order that phase IV of the programme should go ahead within a budget of Nkr 17.5 million. This phase, which will last three years, will particularly target the following themes:

- Characterisation of chalk rocks and cracks
- Mechanical properties of chalk rocks
- Effects of water injection.

The programme is administered by Amoco and the steering committee is headed alternately by the Danish Energy Agency and this Directorate. The Directorate will also head up implementation of one of the seven projects in the current phase.

5.1.8 SAFARI

Safari stands for *Cooperation on Field Analogues and Reservoir Information* and is a cooperative project between Norsk Hydro, Saga Petroleum, Statoil and the Directorate. The project collects quantitative, geological data from sediments onshore that are analogous to reservoir rocks in Norway's offshore provinces with the aim to build up a data base of quantified data on sedimentary and tectonic reservoir heterogeneities. The data collected will be used as the baseline data for geo-mathematical modelling tools and reference datum for conceptual geological modelling. They should be of great assistance in reducing uncertainties in well-to-well correlation. The objective is to achieve improved reservoir descriptions, which is a fundamental prerequisite for success in using enhanced recovery methods. The project is organised under a steering committee and two working groups with responsibility for sedimentary and tectonic heterogeneities, respectively.

Data acquisition for sedimentary heterogeneities is made on the basis of a survey of data requirements, and which aims to clarify the need for analogue studies of different types of deposit, and to specify the reservoir problems. In the choice of field analogues for reservoir formations of interest, the stress is on finding formations that are well exposed and which have the greatest possible similarity with respect to sedimentological processes and depositional environment. So far data have been collected from shallow marine, tidal deposits that are analogous to the Cook, Fensfjord and Sognefjord formations. Data have also been collected from shallow marine analogues of Brent, and from fluvial deposits that are analogous to the Lunde and Statfjord formations.

Other data have been acquired for modern deposit systems based on analysis of satellite scans. Horizontal heterogeneities seen on satellite pictures are a useful supplement to the vertical heterogeneities that we are familiar with from vertical exploration. The aim is to achieve better three dimensional modelling of breaks in sediments. Studies of modern systems to date have been carried out in fluvial and deltaic settings.

Data on tectonic heterogeneities have now been collected from areas having the same structural features as the Tampen area. The work concentrated on spatial distribution of the fault plane at seismic resolutions, and the relations between the former plane and larger, block-limited faults.

The financial administration of Safari is the responsibility of the Directorate, which is also responsible for coordinating the demand analyses.

5.2 SAFETY AND WORKING ENVIRONMENT

Project title	Executive institution
Standardisation in Petroleum Sector	Norwegian Engineering Standards Association (NVS)
Membership of Welding Institute	Welding Institute (WI)
Membership of Marine Technology Directorate	Marine Technology Directorate (MTD)
Membership of Norwegian Electrical Engineering Committee	Norwegian Electrical Engineering Committee (NEK)
Worldwide Offshore Accident Databank, WOAD	Det Norske Veritas Industri Norge AS
Petroleum Operations North of 74°30'N	NPD
Manned Underwater Operations, International Cooperation	NPD
Working Environment for Divers	Foundation for Scientific and Industrial Research at University of Trondheim (SINTEF)
Jack-up Assessment Procedures	Noble Denton Associates (NDA)
Accurate Pressure Readings in High-Temperature Deep Wells	Rogaland Research Institute (RF)
Gas Safety Programme	Christian Michelsen Institute (CMI)
Technical and Operational Aspects of Manned Underwater Operations	Oceaneering
Internal Control of Activities in Norway	Sintef
Kick Tests for Horizontal Wells	Rogaland Research Institute (RF)
Register of Work-related Diseases	NPD
Pressure and Temperature while Drilling under Extreme Conditions	Rogaland Research Institute (RF)
Safety and Working Environment in a Cold Climate	University of Tromsø
Mapping Cancer Risk among Norwegian Offshore Employees	National Cancer Register
Ageing and Loss of Health Certificate	NPD
Perceived Risk and Safety	University of Trondheim

Drilling in Deep Water	Rogaland Consultants
Hydraulic Well Intervention	Proffshore
Test Procedure for Jet Fire	Sintef and Norwegian Building Research Laboratory (NBL)
Grounding Maritime Installations	EFI
Designing for Flammable Materials	Norwegian Building Research Laboratory (NBL)
Leak Control in Flanged Connectors in Process Piping	Det Norske Veritas Industri Norge AS
High-Strength Concrete, Phase 3	Sintef
Ductility of High-Strength Concrete	Sintef
Reliability Based Design Methods for Pipelines	Sintef
High-Strength Steels in Offshore Engineering	Cranfield Institute of Technology
Corrosion Protective Coating	Sintef
Residual Strength in Damaged and Corroded Pipelines	Det Norske Veritas Industri Norge AS: Veritec
Ringing Vibrations in Offshore Installations	Sintef, Veritec
Extending Useful Life of Old Pipelines	NPD
Engineering Handbook for Mobile Installations	Marine Technology Directorate (MTD), and others
Guidelines for Risk Analysis of Installations	Det Norske Veritas Industri Norge AS: DNV-Technica
Client Controlled Research Programme on Steel Materials	Sintef
Flexible Flowlines in Deep Water	NPD
Hydrate Formation in Pipelines	Sintef
Reinforcement Bar Corrosion under Dynamic Load	Det Norske Veritas Industri Norge AS: Veritec
Geotechnical Site Surveys for Projected Installations and Pipelines	NGI
Guidelines for Load Effect Analysis	Aas-Jakobsen
Wind Conditions in Norway	Norwegian Building Standards Committee (NBR)
Guidelines for Corrosion Protection on Installations and Pipeline Systems	Jotun Cathodic Protection
Maintenance Management	Sintef
Requalification of Steel Structures	Sintef
Ekofisk in a Long Term Perspective	Sintef
Methods of Evaluating Supervisory Activities	Sintef
Registration of Deviations on Mobile Installations	Rogaland Consultants
Petroleum Industry Benchmarks	Norwegian Quality Competence Centre (NKK)

Standardisation in Petroleum Sector

Again in 1993, the Directorate helped sponsor the Norwegian Engineering Standards Association (NVS)'s efforts in petroleum sector standardisation. The work is generally aimed to look after Norwegian interests in ISO technical committee TC67 examining Materials, Equipment and Offshore Structures for Petroleum and Natural Gas Industries, its subcommittees and working groups. NVS performed the secretariat function for many of the committees and working groups.

Membership of Welding Institute

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

Membership of Marine Technology Directorate

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

Membership of Norwegian Electrical Engineering Committee

By joining the Norwegian Electrical Engineering Committee (NEK), the Directorate seeks to ensure that regulations in the electrical engineering field are continually under review and keep pace with advances in technology, international practices, and practical experience. The importance of doing so is all the more felt now that Norway is committed to comply with the Agreement on Technical Barriers to Trade in EFTA and the EU.

The Directorate also takes part in national and international joint work to formulate new regulations. This work is headed by NEK.

Worldwide Offshore Accident Databank, WOAD

This project is an annual subscription to the WOAD data base, which is a systematic directory of accidents in offshore petroleum operations worldwide. The root base is managed by Det Norske Veritas Industri Norge, which compiles and updates data on accident events on a current basis.

Petroleum Operations North of 74°30'N

This project started by looking at the risk of impact by bergs and drift ice at selected positions in the Barents Sea, and requirements that should be imposed for exploration activities in light of the eco-sensitivity of the region. The need for any extra measures in the supervision of activity in this area was evaluated. In 1993 the project continued in connection with the testing of exploration wells under cold climatic conditions, where the sensitivity of the environment is a vital concern.

Manned Underwater Operations, International Cooperation

This project aims to continue and expand established international cooperation in: safety and the working environment; standardisation of regulatory requirements and guidelines; and enhancements to technical systems for manned underwater operations. The project, which has been going on for several years and has produced invaluable results, is a major factor in supervision of underwater operations. In 1993 links with the EU Commission were established leading to plans for a working seminar in Luxembourg in 1994.

Working Environment for Divers

Projects over many years have produced results of considerable practical importance in relation to the working environment for divers. In 1993, the project mapped the working environment of saturation divers. The results will be used as background for supervision of diving activities now that the Working Environment Act since 1993 has been applicable to offshore diving operations.

Jack-up Assessment Procedures

There used to be major discrepancies in the calculation methods and philosophies of the various companies and institutions in assessing jack-up rigs. In the first phase of this project, international guidelines have been established for such evaluation. In 1993 the work continued with the aim of developing recommended practices that would make things more predictable for the industry relative to the government's requirements. The project work is intended to form a basis for an ISO standard for jack-up assessment.

Accurate Pressure Readings in High-Temperature Deep Wells

This project has already developed a model for forecasting the effects of high pressure and high temperature in different types of drilling mud, and the model was put to the test using data from a real well. The model is now available on disk, and dedicated user documentation has been written. The project which was originally planned to finish in 1992 was extended through 1993 on account of small empirical adjustments that needed to be made underway.

Gas Safety Programme

The Christian Michelsen Institute (CMI) in Bergen has spent several years consulting with the oil companies and government offices in a number of countries to research the explosion risk in modules in offshore installations. The project, started in 1990, was brought to a close in 1993 at a total cost of about Nkr 34 million.

Among other successes the project led to the development of a new and improved version of the FLACS computer model to simulate flame acceleration and blast pressure in modules. Also a PC programme to estimate blast pressure in modules (MicroFlacs) and a Gas Blast Handbook were developed.

Technical and Operational Aspects of Manned Underwater Operations

From experience we know that there are still technical and operational aspects of manned underwater operations which could be improved. The project has already highlighted problems such as diving bell battery emergency capacity, emergency training for diving personnel, and depth monitoring of divers. In 1993 the project focused on decompression tables for surface-oriented dives. The project also examined dehydration of divers, as loss of body fluids may represent a safety risk.

Internal Control in companies in Norway

So far the Internal Control project has achieved the following:

- Evaluated introduction of the *Internal Control Regulations* onshore
- Identified factors that promoted and those that did not promote introduction in a specific company
- Referred positive and less positive experiences back to the companies
- Developed evaluation tools to enable companies to evaluate their own internal control

- Provided material for supervisory agencies' follow-up of implementation and practice of internal quality control systems in companies.

The project was a collaborative effort between the Confederation of Industry (NHO) and the NTNF, with input from Norwegian authorities having supervisory responsibilities.

Kick Tests for Horizontal Wells

The drilling of highly deviated and horizontal wells demands special knowhow about how a gas kick can be detected, and how the kick can be circulated out from the well in a controlled manner. The project was initiated in 1991 and a full-scale test has already provided answers to a number of the issues. In 1993 the project continued. One task was the construction of a extensively instrumentated 200 metre test loop by Rogaland Research Institute, where it is possible to simulate the conditions in a horizontal well at a substantially more realistic level.

Register of Work-releated Diseases

The Directorate's data base of work-related diseases was established to provide a systematic framework for incoming reports. One of the uses of the register will be to help identify commitments and priorities for future supervision. Most importantly, it will feature a workable system to register and classify working environment factors, occupational categories, and diagnoses. A collaborative project was initiated by the Directorate and the Danish Labour Inspection aimed at refining our existing base. For their part the Danes could offer rich experience with a well run-in system and insights of the work done in this field in the European Union, where Denmark plays a leading role.

Pressure and Temperature while Drilling under Extreme Conditions

The drilling of high-pressure wells poses special operational and safety problems. This project aims to increase our understanding of the problems involved, so as to improve safety when drilling such wells. Field measurements of high-pressure wells were undertaken using both water-based and oil-based drilling mud, and a data base of laboratory measurements of various types of mud was initiated.

Safety and Working Environment in a Cold Climate

The Directorate provided funding via the Norwegian Research Council for a research programme at the University of Tromsø that deals with working in a cold climate. The programme got underway in 1989 on the initiative of Norske Shell, who needed data on work and safety in cold surroundings. The programme projects look at both the basic research side and the more clinical and applied issues, though with close links between basic research and practical problem solving in sub-zero temperatures. By supporting the project the Directorate hopes to enhance our national competence in cold climate research. The knowledge built up will be of help in planning and carrying out all petroleum activities, not just in the cold regions; and also for other types of onshore work in cold climates.

Mapping Cancer Risk among Norwegian Offshore Employees

Funds were made available to provide some of the support for a study of cancer risk in the offshore petroleum activity. The project was intended to be done by the Cancer Register, with the Oil Industry Association (OLF) as the main sponsor. The Directorate considered it important to initiate the monitoring of employees in case of long term effects caused by the working environment, and to build up a base containing exposure data for the various environmental factors. A pilot project was carried out, but the OLF was unable to find financing to complete the work.

Ageing and Loss of Health Certificate

This project included conducting a seminar called *Ageing of Offshore Personnel.* The project was carried out with the cooperation of the Health Directorate and examined issues related to the large numbers of employees who must leave their offshore work for health reasons before retirement age. A report was published containing the manuscripts of all the presentations at the seminar and a summary of the measures proposed.

Perceived Risk and Safety

This project aims to develop proposals for measures that may promote a better working environment by increasing personal safety and reducing the perceived risk to personnel working offshore. The project will examine what, if any, differences there are in perceptions by Norwegian workers and their British counterparts, whether the perceptions of Norwegian workers have changed in recent years, and the links between subjective (perceived) and objective (actual) risk. In 1993 a questionnaire and information to those who will take part in the study was formulated and contact was established with the relevant companies. The actual study will take place in 1994.

Drilling in Deep Water

This project seeks to facilitate future supervision of petroleum activities in deep ocean regions by setting up the frameworks for the activities and developing the Directorate's expertise in the field. The work started in 1992 with a survey of the issues. In 1993 thorough studies were made of matters having a special safety and working environment significance when drilling in deep water.

Hydraulic Well Intervention

Hydraulic well intervention, or *snubbing*, is becoming increasingly popular as a well workover tool in the North Sea. The task is generally done in connection with perforation and gravel packing, or acid flushing of the well. Also the equipment was used to shift and run completion strings. In 1993 the Directorate learned, through the project, how two operators in two different work operations observed the regulatory requirements for such work, and in particular how they maintained the required barriers.

Test Procedure for Jet Fire

Following an initiative by the Health and Safety Executive in the UK, the Directorate was invited in 1992 to take part in a working group charged with the task of writing a procedure for determining the resistance of passive fire barriers to jet fires. The work resulted in a common British-Norwegian procedure for testing such materials in a jet fire. Sintef, through the Norwegian Building Research Laboratory (NBL), advised the Directorate in the working group.

Grounding Maritime Installations

High shorting currents that occur in electrical systems offshore have caused there to be doubt whether bonding systems hitherto have been adequately robust. The Directorate has provided support for this industry financed project. Under the direction of the EFI, studies and measurements have been made of existing plant, and recommendations for improvements have been made, including suggestions to amend the regulatory requirements in the field.

Designing for Flammable Materials

The use of modern materials offers many advantages, not least weight savings and ease of maintenance. Gradually, former absolute demands for non-flammability have yielded to allow the newer materials to be used. However, it is of great significance for safety that the use of flammable materials is carefully controlled, and this project aimed to define criteria to decide where and in what quantities such materials can be used.

This work led to proposals for test and acceptance criteria for flammable materials used on offshore petroleum installations, and recommendations that design calculations and analyses of fire safety should be incorporated in the documentation used to evaluate fire risk caused by the increasing prevalence of flammables.

Leak Control in Flanged Connectors in Process Piping

This project is a continuation of one started in 1992 which aims to improve flanged connectors, mainly to help reduce the number of unintentional hydrocarbon leaks. The project aims to produce proposals for improvement of design calculations and practical work on flanged connectors. In 1993 the project compared the requirements in the various standards for mating flanged connectors.

High-Strength Concrete, Phase 3

This project is a continuation of the comprehensive work that started in 1986 which was funded by the industry and the authorities. One of the results of the preceding phases is Norwegian Standard NS 3473: *Concrete Structures, Design Rules*; which is currently considered the most advanced standard for high-strength concrete in the world. In Phase 3, additional experiments were performed to round off the projects in the first two phases and clear up a number of uncertainties. The project is now finished and its results can be written into NS 3473. The Standard is available in Norwegian and English versions.

Ductility of High-Strength Concrete

This project is a continuation of work to develop high-strength, high-ductility concrete for applications in structures which may experience particular stresses, such as impact, pressure shock, earthquake, heat and cold. The development of specifications for design and structural shaping of high-strength concrete exposed to particular stresses was also examined. The industry and the authorities were represented in the project.

Reliability Based Design Methods for Pipelines

The criteria in existing design codes may embody safety margins that are unnecessarily conservative, causing safety levels for pipelines to be inconsistent in relation to such risk factors as water depth, seabed uniformity and erosion resistance, fluid carried, and potential accident loads. In 1992 a pilot project was carried out, and the main project is scheduled to last until 1995. The Directorate is a member of the steering group for the project, which is sponsored by the industry with a total budget of Nkr 5.2 million in 1993.

High-Strength Steels in Offshore Engineering

This project is carried out at the Cranfield Institute of Technology in the UK and is a major collaborative venture with participation by many countries. On a broad basis the project initially studied the properties of modern high-strength steels in practical applications in the offshore environment. In 1993 the project continued its work to reduce the uncertainties of side-effects on the properties of such steels as strength is increased. The problems of hydrogen induced cracks were also examined, as this is a pressing issue on jack-up installations due to the growth of sulphate reducing bacteria (SRB).

Corrosion Protective Coating

The design lives of offshore installations are being steadily extended and the right combination of materials and coatings is decisive if the design life is to be realised. As yet cathodic debonding and the effects of various forms of surface treatment before the application of paint are poorly understood. Nor does there exist any effective accelerated ageing habitat to quickly and conveniently test the factors that influence the final result.

This project, which seeks to provide answers to these questions, is planned to run until 1998 with considerable support from the operators and coating manufacturers.

Residual Strength in Damaged and Corroded Pipelines
The Directorate has helped support this industry sponsored project aiming to develop methods for estimating the residual strength of pipelines, marine risers and tension legs once damage has been sustained or corrosion has set in. The project in its first phase focused in particular on ANSI and ASME-B31G, and studied possible optimisation of the estimation methods described in those standards. The work provided useful expertise in pipeline design. The experience will also be of value in developing suitable regulations and in the Directorate's supervision of damage once it occurs. The project will continue in 1994.

Ringing Vibrations in Offshore Installations
The Directorate initiated and has helped fund this industry sponsored project which has an overall budget of Nkr 5.3 million. The project aims to develop design models to describe the "ringing" vibrations observed in model trials with concrete gravity bases, so as to quantify the effects in a predictable and standardised manner. The project is expected to conclude in 1994.

Extending Useful Life of Old Pipelines
Through this project the Directorate has analysed the issues connected with extending the useful lives of pipeline systems. Certain principal issues have been examined, such as the studies and tests needed in the decision documents, factors that will help determine the new lifetime, and resumés of the technical development in pipeline design since the systems were originally engineered.

Engineering Handbook for Mobile Installations
This international, industry sponsored project will last two years and have a budget framework of roughly Nkr 2.1 million. It aims to develop guidelines for engineering design of floating production units, primarily by compiling, organising and refining existing expertise in the field. The handbook will help to increase the understanding of key principles and the theoretical background, provide a survey of the most appropriate analysis methods, and help spread the experience acquired in this important field.

Guidelines for Risk Analysis of Installations
This industry sponsored project is intended to develop guidelines for the seminal activities making up a risk analysis of a petroleum installation offshore. The guidelines will contain data and a reference manual plus computerised techniques for doing the analysis. The work is expected to close in 1994.

Client Controlled Research Programme on Steel Materials
In 1993 an initiative was taken to set up a broad-based research programme known as *Stålmat* jointly with the Norwegian Research Council and industrial interests. The aim is to gather manufacturers and users of steel in a common research programme thereby coordinating the various research that takes place on steel and stainless steel in Norway. Work to establish the Steel Materials programme will continue in 1994.

The Directorate supported a pilot project in 1993 designed to promote the transfer of experience from plant in operation to plant under planning. Ultimately it is hoped that safety on existing and new installations will be improved by such experience transfer.

Flexible Flowlines in Deep Water
In this project the Directorate shed light on the problems and constraints that affect installation and operation of flexible flowlines and marine riser pipes at depths greater than 350 metres. Much of the focus was on the challenges of laying techniques, pipeline burial and protection, status monitoring, repair methods, and fault conditions.

Hydrate Formation in Pipelines
It now appears that hydrate formation in pipelines may represent a bigger operational hurdle than hitherto assumed. The removal of hydrate plugs also has safety aspects. In this project the Directorate mapped the scope of the problem and incidents caused by hydrate formation in pipeline systems. Also, the various methods used by the operators to remove hydrates were examined. The project brought some expertise to the Directorate that will provide a nucleus for future supervision of operator tackling of the hydrate issue.

Reinforcement Bar Corrosion under Dynamic Load
The Directorate has supported this project which is sponsored by the industry and the government. The project plans to take two years and aims to clarify the properties of light-weight concrete with respect to corrosion protection and corrosion resistance in a marine environment. Improved knowledge in this field is necessary if we are to draw full benefit from the increasing popularity of lighter concrete in offshore structures, since till now there has been only limited understanding of its long term properties in seawater.

Geotechnical Site Surveys for Projected Installations and Pipelines
This project seeks to explore various geotechnical factors related to design, construction and operation of pipeline systems. The project's first phase looked in part at the strength of sand strata, thermal properties of soil, and stresses to pipelines in case of underwater avalanche. The project is funded by a number of oil companies and the Directorate. The work will be continued in 1994.

Guidelines for Load Effect Analysis
The untimely sinking of the Sleipner A installation showed that an error in a global analysis can have catastrophic results. This project has produced a supplementary chapter for the Directorate's *Guidelines for Loads and Load Effects* which deals with the way in which large-scale load effect analyses should be performed.

Wind Conditions in Norway

Under the guidance of the European standardisation organisation, CEN, European standards are being worked out for engineering design of wind load effects on structures. To aid the task a wind chart will be created for all of Europe, and this project will help production of the Norwegian part of the chart. The project has the support of many public institutions and independent firms and is planned to end in 1994.

Guidelines for Corrosion Protection on Installations and Pipeline Systems

The Directorate participated earlier with the industry in the revision of the Veritas Offshore Standard RPB 401 on Cathodic Protection Design. The work done then provided a good starting point for revision of the Directorate's own guidelines on corrosion protection, and demonstrated moreover that such a review was necessary. A draft has been assembled which will be circulated for comments in 1994 if plans hold.

Maintenance Management

The Directorate has continued this comprehensive project which targets maintenance management in light of the deficiencies that supervision unearthed in the maintenance systems of some companies. In 1993 the project devoted its time to informing the industry of the results of previous project phases.

Requalification of Steel Structures

This project is part of a research programme intended to develop a method for evaluating the strength of load-bearing members in steel jackets that have suffered a load exceeding their design load. Phase two will last two years and has a budget of Nkr 3.5 million.

Ekofisk in a Long Term Perspective

This project is an internal analysis that seeks to establish safety requirements and criteria on which to base the Directorate's supervision of pipeline node structures so as to meet the demands for reliable hydrocarbon delivery. The analysis is intended to provide a basis for determining the criteria the authorities should impose for safety and operating reliability, in order that the interests of the State, the operator, and other users of the transportation systems will all be adequately safeguarded.

Methods of Evaluating Supervisory Activities

This project sought to develop methods with which to evaluate the results of the Directorate's supervisory work and the companies' inhouse activities. The Directorate's resource situation means a sound basis for planning and implementing supervision is essential if the optimal benefit is to be obtained. The sharpening focus on governing systems entails some danger that the supervision will get bogged down in formalistic issues, where supervision loses any real content or effect. The project is planned to finish in 1994.

Registration of Exemptions on Mobile Installations

The object of this project was to set up a computerised register of all deviations that the Directorate has granted for mobile units in connection with processing of consent applications.

Petroleum Industry Benchmarks

This internal project worked on a description of general methods of defining benchmarks and using key figures. On the basis of interviews a status has been drawn up showing how benchmarks and key figures are used as management tools by three selected operating companies.

5.3 NORTH SEA SEABED CLEARANCE

Project title	Executive institution
North Sea Seabed Clearance	NPD

North Sea Seabed Clearance

The Directorate's seabed clearance project in 1993 concentrated on the Egersund Bank. This region, covering 1300 square kilometres, was chosen on the advice of fishery organisations and fishery authorities. It lies just east of an area swept by trawl in 1980–84. Fishermen reported many problems with obstacles and hindrances in the area.

Wires of various sizes, anchors, fishing gear, assorted chains and even containers were recovered from the seabed. The exact locations of 28 shipwrecks – including a submarine – were plotted, which is of great importance to fishermen who frequent the bank.

Again in 1993, the Norwegian Hydrographic Service's survey vessel, *M/S Lance*, was used to chart the bottom by sonar. The clearance contract was awarded to Stolt Comex Seaway A/S, of Haugesund.

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

6. International Cooperation

6.1 AID TO FOREIGN COUNTRIES

6.1.1 Aid through NORAD

In the year the Directorate engaged in development cooperation through the Norwegian Directorate for Development Cooperation (Norad) with Tanzania, Mozambique, Namibia, Bangladesh, and Nicaragua. Assistance was also given as before to the Committee for Coordination of Joint Prospecting for Mineral Resources in Asian Offshore Areas (CCOP).

The Directorate's work commitment in 1993 was the equivalent of four positions. In addition to reports and assistance, the duties also included overseeing consultants for such services as: seismic data acquisition, processing and reformatting of seismic tapes; maintenance of computer systems and software; and follow-up of consultants for technical services, contract evaluation, and support in negotations in connection with field developments. Most of the work in 1993 focused on the countries detailed below.

a) Bangladesh

The Directorate has for many years worked in conjunction with the Bangladesh Petroleum Institute (BPI) on the development of the Institute to become a professional advisory body to the Ministry of Energy and Mineral Resources. The work planned for 1993 was very much delayed due to difficulties in accessing the relevant data in Petrobangla, the national oil company. Efforts in the year therefore concentrated on tasks that as far as possible could be implemented using the data already available to BPI.

As in previous years, the tasks comprised assistance with the operation and maintenance of seismic processing hardware, evaluation of the software, and interpretation of seismics, well logs and geological data. The results of the pressure test funded by Norad in Bangladesh's sole oil well, *Haripur 1*, were interpreted jointly by BPI and the Directorate. The Directorate also assisted BPI in staking out its future role in the light of the proposed change in energy policy in the country, and in this connection a study trip was undertaken in order to discuss prospects there with the implicated parties.

The Norwegian scientific advisor, who was engaged through the Directorate to work in the BPI, concluded his service in July after three years of duty.

b) Namibia

The Directorate works in association with the National Petroleum Corporation of Namibia (Namcor), which comes under the Ministry of Mines and Energy. Much of the work was connected with the development of regulations and procedures for petroleum activities, including the approval of drilling programmes and follow-up of drilling activities, regulations for safety, regulations for a fishery expert onboard seismic vessels during shooting, regulations for electrical installations offshore, regulations for safety zones, and regulations for environmental data for offshore activities. The Directorate also assisted with evaluation of drilling programmes connected with activities in awarded licences.

A meeting was arranged between the Directorate and Namibia's Government Action Control Group (GACG) where Norwegian regulations, Norwegian supervision schemes and the Directorate's role in connection with accidents were all reviewed.

The task of operating the filing system installed at Namcor was duly followed up. The Directorate also supervised the seismic processing of Namibian data by Geco-Prakla.

c) Tanzania

The Directorate works together with the Tanzania Petroleum Development Corporation (TPDC) and the Ministry of Water, Energy and Minerals (MWEM). In 1993 efforts were concentrated on following up the reformatting of seismic tapes by Tape Technology Norge A/S, and their preparation for shipment to the TPDC with accompanying new systems. In connection with the shipment, a Directorate representative visited the TPDC to assist with filing and commissioning of the copying units. The Directorate also supervised the reprocessing of elderly seismic data from Songo Songo done by Geco-Prakla. The data are necessary in a remapping of the Songo Songo gas field to be carried out in connection with the planned field development. The data will be converted simultaneously to the same format as the reformatted data.

In connection with plans to develop the gas field for production of electric power in Dar es Salaam, the Directorate was asked by the MWEM to assist in the formulation of a project brief for Songo Songo. The job was done by Directorate personnel in collaboration with third party consultants (Petroteam a.s, Novatech a.s, Statoil and Vidkunn Hveding) in close association with MWEM, TPDC and Tanzania Electric Supply Co Ltd (Tanesco). The Directorate also assisted MWEM in selection, contract signature, and follow-up by seconding consultants to an advisory group for bid evaluation and post-bid negotiations between the Tanzanian negotiating group and bidders for the gas power project. Petroteam a.s heads the advisory group which also comprises personnel from Statoil and Novatech a.s. The project is largely financed by the World Bank.

d) Mozambique

The Directorate works jointly with *Empresa Nacional de Hidrocarbonetos de Mocambique* (ENH) on the evaluation of the Pande gas field in Mozambique. A group of three representatives from the Directorate visited ENH for a few days to collect and evaluate data from the field and engage in technical discussions with the local staff. Their evaluation was later duly presented to the hosts and the Directorate appraised the Pande core samples with a view to doing further detailed sedimentological studies. Samples from the latest Pande borehole are under appraisal at ResLab a.s.

The delimitation of the Pande field requires more seismics to be collected and interpreted by the ENH and the Directorate. The final appraisal wells will be decided on the results of this interpretation which will take place in spring 1994.

e) Nicaragua

The Directorate collaborates with the Nicaraguan national energy office, *Instituto Nicaraguense de Energia* (INE), to carry out a campaign for petroleum exploration on the Nicaraguan continental shelf. The work of preparing the necessary campaign materials and then conducting the campaign in association with INE was formerly assigned to Geco-Prakla. However, finalisation of the material has come almost to a halt as a proposed new Petroleum Act for the country is awaiting consideration by the National Assembly. In 1993 the Directorate assisted the INE to obtain, evaluate and organise the necessary data to include in information packages for the exploration campaign. Also started was the planning of a new filing system for INE which would improve data security before the exploration campaign and in connection with the privatisation process which Nicaragua is undertaking.

f) Asian offshore prospecting (CCOP)

The Directorate acts as the technical advisor to the Committee for Coordination of Joint Prospecting for Mineral Resources in Asian Offshore Areas (CCOP) in connection with Norad's support of a sub-project involving petroleum resources evaluation in the region. The project is carried out by NTH, Department of Geology and Mineral Resources engineering. It also provides partial funding, with Statoil, for the costs of a petroleum advisor from Statoil who works at the CCOP secretariat in Bangkok, Thailand. Also, Nopec a.s, in conjunction with Petrad (see below), planned the CCOP's participation in a major campaign to promote greater exploration activity in the region in connection with the World Petroleum Congress in Stavanger in May 1994. Again in 1993, the Directorate provided a technical expert for a workshop on resource estimation held in Kuala Lumpur in November.

In 1993 the project embraced a small subproject for the reinstallation and renewal of an Oil Drift Modelling programme that the Meteorological Institute developed earlier in a project with the Asian Council of Petroleum (ASCOPE). The subproject was carried out by Cooperating Marine a.s.

g) Miscellaneous advisory services

The Directorate offered advice for the collection of satellite data in the vicinity of the Cape Verde islands. The assignment was performed for the Swedish International Development Authority (SIDA) at the request of Norway's sister organisation, Norad, and under the auspices of a cooperation agreement between the two Scandinavian aid agencies. The Directorate also looked at continuing Norwegian support for the Southern African Development Community (SADC)'s Petroleum Exploration Programme and attended the SADC's Petroleum Conference in Windhoek on 19–22 October 1993. Elsewhere, the Directorate considered a World Bank/ Esmap request to Norad, asking for partial funding of a study into gas transportation from Iran to Pakistan and India. The Directorate was pleased to host a visit by the Director General of the newly constituted Directorate General of Hydrocarbons in India, who wished to become familiar with Norwegian petroleum administration in general and the Norwegian Petroleum Directorate's tasks, functions and organisation in particular.

6.1.2 Aid through PETRAD

From 1 January 1989 until 31 December 1993, the Directorate undertook a test project for Norad aimed at examining the feasibility of setting up a training scheme in Norway for petroleum administration and management executives. The target group is executives in public petroleum administration and the national oil companies in the developing countries.

The project, known as the *International Programme for Petroleum Management and Administration* (PETRAD), was the direct responsibility of the Director General of Petroleum.

Based on information regarding the need for executive training in the petroleum sector in Africa, Asia and Latin America, Petrad organised 42 courses and seminars, lasting from one day to eight weeks. Training was given in Africa, Asia and Norway. No less than 1850 executives from 47 countries attended the seminars. The budget for the project period was Nkr 27 million.

For the development and implementation of the project, Petrad sought to draw on all aspects of Norwegian competence in the petroleum sector. Some 250 representatives from 40 Norwegian institutions took turns as resource persons and lecturers. Petrad also engaged a score or so lecturers from developing countries as well as many experts from a wide range of international organisations.

The programme sought to cover a broad spectrum of issues concerning management and administration of petroleum activities, both upstream and downstream, and training was organised in four categories:

- The role of petroleum in sustainable development
- Petroleum resource management and administration

- Safety and environmental management and administration
- Management and administration of import, sale, distribution and use of petroleum products.

In the light of its experience with these courses and seminars, Petrad was able to develop two eight-week instruction programmes:
- Petroleum policy and management
- Management of petroleum operations.

These programmes were developed with the aid of 50 experts from Norwegian teaching establishments, consultants and operating companies.

The courses were first offered between 9 September and 1 November 1991, attracting 40 participants from 19 countries, among them Norway. The courses were then repeated from 4 May to 26 June 1992, attracting 40 participants from 20 countries; and from 30 August to 21 October 1993, attracting 43 participants from 19 countries. The courses were in great demand and participants came from high levels in their respective national oil companies and government departments.

Of the other activities in 1993, a series of five one-day *Top Management Briefings* was held in Safety Management for top executives of the national oil companies in Thailand, Malaysia, Indonesia, Singapore and the Philippines. A two-day seminar was held on *Crude Oil and Products Marketing and Supply in the Asia-Pacific Region* in connection with a convention of the Asian Council of Petroleum (ASCOPE, see above). A two-week course entitled *Managing the Development of a Petroleum Installation* was held for the same Council. Participants attended from the national oil companies and government agencies of the South East Asia region.

Petrad, ably assisted by an expert from BP Norway, also aided the Petroleum Authority of Thailand in introducing the Norwegian proprietary *International Safety Rating System*.

Much time was committed to the preparation of a several-year programme in petroleum administration and management in Russia, planned to start in 1994. The preparations were carried out in close association with the Ministry of Fuel and Energy of the Russian Federation.

Considerable efforts were made to help plan the Stavanger Petroleum Exploration Promotion Forum, a Petrad initiative that will be held on 2–4 June 1994, immediately after the Fourteenth World Petroleum Congress. At the Forum, countries from Asia and the former Soviet Union and Eastern Europe will present the areas they intend to open up for exploration activity. The plan is to make this an annual forum in Stavanger which will focus on different global provinces each year.

Petrad also assisted the Asian Council of Petroleum with planning and implementation of its vast ASCOPE-93 petroleum conference and exhibition staged in Bangkok in November.

Petrad was in the visiting party headed by Mr Gunnar Myrvang, a Norwegian minister, to Vietnam in March; and helped Norwegian firms in connection with establishing contact networks and project briefs in South East Asia and the Pacific Rim.

Feedback from Petrad programmes has always been gratifying and there is good reason to believe that these special seminars – and the work done by participants after difficulties have been cleared up – provide immediate and tangible economic benefits in the countries concerned.

The demand for Petrad courses and seminars has grown so large that the organisation has no chance of satisfying everyone.

The scope of the contacts that Petrad has built up during the trial years is unique. The Norwegian authorities and Norwegian industry have gradually grasped the significance of Petrad's effective means of spinning a high-level network of international contacts and the opportunities the network offers.

On account of the excellent results from the trial period, the Government resolved to establish Petrad on a permanent basis as a non-profit foundation from 1994. The co-founders are Norad and the Norwegian Petroleum Directorate.

The following individuals are the first directors of the foundation:
- Mr Vidkunn Hveding (chairman), former Minister for Petroleum and Energy
- Mr Fredrik Hagemann, Director General of Petroleum, Norwegian Petroleum Directorate
- Mr Sven A Holmsen, Assistant Director, Norad
- Mr Johan Nic Vold, Senior Executive Vice President, Statoil
- Ms Eva R Karal, Managing Director, Technological Institute.

Special advisor Reidar G Trædal of the Norwegian Petroleum Directorate was appointed secretary to the directors.

6.2 SAFETY AND THE WORKING ENVIRONMENT

The Directorate cooperates and enjoys extensive contacts with international professional organisations and political and technical bodies, both directly and indirectly through other Norwegian agencies. The purpose of this cooperation is as follows:
- To help ensure that safety and the working environment in the petroleum activity at least meet the accepted international standards
- To secure the supply of relevant information for competence building and regulatory development
- To furnish insights and experience in international forums to promote the positive development of safety and working environment issues.

Generally the cooperation has involved taking part in inter-governmental forums in Europe and the United Nations, supplemented by direct cooperation with various kinds of international and regional professional bodies. A list of the most important partners in 1993 is given below with an indication of the areas covered:

- North Sea Offshore Authorities Forum (NSOAF)
- EU Commission, in collaboration with Norway's Ministry of Local Government and Labour, on health, safety and the working environment (HSE)
- United Nations' International Maritime Organisation (IMO) and the International Labour Organisation (ILO), concerning safety at sea and the working environment, respectively
- Health and Safety Executive (HSE) in the United Kingdom
- Ministry of Energy, Denmark
- *Staatstoezicht op de Mijnen*, Netherlands
- European Diving Technology Committee (EDTC) and Association of Offshore Diving Contractors (AODC), on diving safety
- Marine Technology Directorate (MTD) in the United Kingdom, on inspection and maintenance of installations
- Welding Institute (WI) in the United Kingdom, on research and development of materials and welding
- American Petroleum Institute (API), to attend annual conferences on technical petroleum topics and standardisation
- National Association of Corrosion Engineers (NACE) in USA, to attend annual conferences on corrosion and surface treatment
- *Comité Européen de Normalisation Electrotechnique* (Cenelec), for electrical engineering standardisation in Europe, through the Norwegian Electrical Engineering Committee (NEK).

6.2.1 North Sea Offshore Authorities Forum (NSOAF)

In the field of safety management the Directorate participates in the North Sea Offshore Authorities Forum (NSOAF), which was established to provide a channel for talks and cooperation between supervisory authorities in countries having jurisdiction on the North Sea continental shelf. The Directorate considers the Forum a key development channel for promoting standardisation in offshore activities in the North Sea.

In 1992 the Forum established two working groups in which the Directorate is represented. The first seeks to facilitate a common understanding of the use of "Safety Cases" for mobile installations, and to refine the technique so that work done by one member state's authorities can be relied on by the other member states.

The other, under a Danish chairman, will seek to harmonise safety training requirements in the various North Sea countries. See section 3.9.3 for details.

6.2.2 The EU Commission

Since 1992 Norway, represented by the Norwegian Petroleum Directorate, has held observer status in the EU proceedings on health, safety and the working environment in the offshore petroleum activity.

This work comes under the EU's Safety and Health Commission for the Mining and Other Extractive Industries (SHCMOEI) and was until early 1993 implemented by the Working Party on Oil, Gas and Other Minerals Extracted by Borehole.

The Commission's activities were reorganised in 1993 and the working group is now known as the Committee on Borehole Operations. The Working Party (and now the Committee) were active in the work on the EU Minimum Directive for Health, Safety and the Working Environment in Offshore Petroleum Activities. The Directive was passed on 3 November 1992, and member states are now required to enact its provisions in legal instruments within two years. In Norway the provisions are already covered by current offshore legislation. The Committee on Borehole Operations is now planning its next activities.

6.2.3 Electro-engineering standards and regulations

The Norwegian Petroleum Directorate is a member of the following electro-technical committees:

- Cenelec, Working Group 12, Regulations for Installation of Explosion-proof Materials
- NEK, Standards Committee (NK) 18, Shipboard Installations
- NEK, Standards Committee (NK) 31, Electrical Equipment for Explosion-Hazard Areas
- International Electrotechnical Commission (IEC), Technical Committee 18, Electrical Installations of Ships and of Mobile and Fixed Offshore Units.

The Directorate's representative is now chairman of Working Group 18, which will prepare a new international standard for Electrical Installations of Mobile and Fixed Offshore Units.

6.3.4 International Labour Organisation (ILO)

In response to a request from the International Labour Organisation in Geneva, the Directorate in 1990 placed a highly qualified member of staff at the disposal of the ILO to conduct a study of the Labour Inspection's role in the petroleum industry. In this connection the Ministry for Foreign Affairs, through Norad, made funds available to implement a series of fact-finding and advisory missions to various petroleum producing countries. The study sought in particular to make a general survey of legislation and supervisory methods in the nations polled.

The study report gives an account of various types of supervision currently in force in the regulation of health, safety and the environment in the petroleum industry. It also examines the conditions that must be fulfilled if governmental control is to be effective in a sector of industry that combines extremely complex technologies with a high risk of accident or disaster, and massive consequences if something goes wrong.

It was decided in 1992 to extend the Directorate's involvement by one year to cover planning and preparation of an expert meeting on safety at work on offshore petroleum installations. In preparing a report containing background information for discussion at the meeting, much use was made of information and conclusions from the study on the Labour Inspection's role in the petroleum industry, mentioned above.

6.3 INTERNATIONAL STANDARDS (ISO)

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

The European Standardisation Organisation (CEN), is responsible for standardisation work in Europe. A document known as the Vienna Agreement, signed by CEN and ISO, the International Standardisation Organisation, binds Europe to utilise ISO standards where they exist. The Directorate is also directly involved in the standardisation work in CEN.

In Norway, the Norwegian Engineering Standards Association (NVS) has organised working groups that monitor the standardisation work at the international level. NVS also provides the secretariat function. The Directorate is actively involved in the working groups.

6.4 INFOIL/SESAME DATA BASE

The Directorate works jointly with the Norwegian Research Council in Norway and the Health and Safety Executive in the UK on the Infoil and Sesame research data bases, for which the Directorate has editorial responsibility. The data bases contain information on current and completed research projects in the petroleum industry. Since 1990, there has also been cooperation with the European Union through the Directorate General for Energy, DG XVII, which has permitted the base to include EU research projects in hydrocarbon technology. The base is available on diskette or CD-ROM; via the Scientific and Technical Network (STN) host system in Karlsruhe; and via Eurobases, the EU's central computing facility, in Brussels.

In 1993 work was done to simplify the routines for data input and a running demo of the base was developed on floppy disk.

6.5 RESEARCH COOPERATION ON ENHANCED OIL RECOVERY

Norway has participated in international research cooperation on Enhanced Oil Recovery (EOR) under the direction of the International Energy Agency (IEA) since 1979. Currently there are nine nations taking part, and cooperation is largely a matter of a commitment to undertake a certain volume of research in stipulated areas, and share results. On the Norwegian side the cooperation is now taken care of by RUTH, a research programme that the Directorate heads, described in more detail in section 5.1.5.

The Directorate is represented in the international steering committee.

6.6 LECTURES

In 1993, as previously, the Directorate was engaged to lecture and chair meetings at a number of courses and conferences concerning issues falling within the Directorate's field of interest in Norway and abroad. This activity is considered an essential channel in the mutual exchange of information and influence, not least in the light of the increasingly international flavour of regulations and other codes and provisions.

7. Statistics and Summaries

7.1 UNITS OF MEASUREMENT FOR OIL AND GAS

Oil and gas are often measured in volumetric units valid under certain defined ISO standard conditions (temperature 15 degrees Celsius, pressure 1.01325 bar). Oil volumes are stated in million standard cubic metres, for convenience abbreviated in this report to mcm (10^6 Sm^3); and gas volumes in billion standard cubic metres, for convenience abbreviated in this report to bcm (10^9 Sm^3). Standard cubic meter is abbreviated scm. NGL is reported in million tonnes (mton).

Oil and gas volumes are also often stated in tonnes oil equivalents (toe) if exact quantities are not required. This unit is useful when aggregating and comparing gas and oil volumes. The abbreviations mtoe and btoe are used here for convenience to denote million and billion toe, respectively.

The conversion of oil and gas quantities to toe is based on the energy released on combustion of the oil or gas. For a large variety of naturally occurring oil and gas compositions on the Norwegian continental shelf the energy in one tonne of oil is the same as that in 1000 scm gas. This gives rise to the following simple formulae:

- 1 tonne oil equals 1 toe oil
- 1000 scm gas equals 1 toe gas.

The specific gravity of oil varies between 0.8 and 0.9 grams per cubic centimetre (g/cc, g/cm^3), depending on its composition. For oils of unknown composition the density is usually assumed to be 0.85 g/cc. By this measure, 1 scm oil is equal to 0.85 toe.

7.2 SUMMARY OF SEISMIC SOLD AND RELEASED

The seismic data packages sold and released in 1993 and altogether are listed in Table 7.2.a and Table 7.2.b.

Table 7.2.a
Summary of number of sold seismic data packages (NPD-seismic)

NO	NAME	1993	Total
001	MØRE-TRØNDELAG-REGIONAL-PK-1		34
002	MØRE-TRØNDELAG-REGIONAL-PK-2		27
003	TAMPEN-SPUR		22
004	MØRE-SOUTH-84		22
005	TRØNDELAG-REGIONAL		25
006	HALTENBANKEN-VEST-84	1	24
007	FRØYABANKEN-84		27
008	MØRE-TRØNDELAG-PAKKE-2 *)		22
009	MØRE-TRØNDELAG-PAKKE-3 *)		28
010	TRÆNABANKEN		30
011	REG-DATA-NORDLAND-RYGGEN		22
012	NORDLAND-IV-85		11
013	REG-DATA-MIDT-N-SOKKEL		21
014	NORDLAND-II-83		23
015	NORDLAND-III-84	1	15
016	TROMS-II		12
017	REGIONAL-DATA-TROMS-ØST		18
018	FINNMARK-VEST-83		19
019	FINNMARK-VEST-84		20
020	NORDLAND-III-85	1	15
021	MØRE-SØR-TEST-84 *)		5
022	STOREGGA-85	1	7
023	VØRINGPLATÅET		12
024	VØRING-BASSENGET-85/86		12
025	LOFOTEN-VEST-86	1	13
026	JAN-MAYEN-85		1
028	VØRING-BASSENGET-87		12
029	NORDLAND-VI-87	3	15
030	NORDLAND-VII-87	1	13
031	NORDLAND-V-87	1	11
032	NORDLAND-VI-88	3	15
033	NORDLAND-VII-88		13
034	NORDLAND-V-73–79	1	11

NO	NAME	1993	Total
035	NORDLAND-VI-73–79	2	14
036	NORDLAND-VI-89	2	14
037	NORDLAND-VII-89	1	13
038	NORDLAND-VII-74/75	1	13
039	NORDSJØEN-SØR-TEST-89 *)		1
040	VØRING-BASSENGET-88	2	11
041	VØRING-BASSENGET-MERLIN-89	2	11
042	VØRING-BASSENGET-WESTERN-89	2	11
043	MØRE-BASSENGET-88	1	6
044	TYPEPROFILER-BARENTSHAVET *)		2
045	VØRINGBASSENGET-I-90	3	11
046	STOREGGA-90	2	4
047	VIKINGGRABEN-SØR-TEST-91 *)		1
048	VIKINGBANKEN-TEST-91 *)		3
049	NORSKEHAVET-74/79	1	1
050	VØRINGBASSENGET-II-ENSIGN-91	6	6
051	VØRINGBASSENGET-II-DIGICON-91	5	5
052	MØREBASSENGET-91	4	4
053	JAN-MAYEN-88	1	1
054	VØRINGBASSENGET-II-92	5	5
055	MØREBASSENGET-ENSIGN-92	3	3
056	MØREBASSENGET-DIGICON-92	3	3
100	TROMS-HOVEDPAKKE		35
101	REG-DATA-TROMS-BAR.HAVET-73		22
102	TROMS-III-83/84		17
103	TROMS-III-85		17
105	TROMS-I-ØST-77		20
106	TROMS-NORD-82-PAKKE-1		24
107	TROMS-NORD-83-PAKKE-3		23
108	TROMS-NORD-82-PAKKE-2		17
109	TROMS-NORD-83-PAKKE-4		17
200	BJØRNØYA-PAKKE-1		21
201	BJØRNØYA-SØR-84		21
202	BJØRNØYA-ØST-REGIONAL-84		18
203	BJØRNØYA-ØST-84		17
204	BJØRNØYA-TILLEGG-NORD		17
205	BJØRNØYA-VEST-REGIONAL-84		15
206	LOPPARYGGEN-ØST-REGIONAL-84		19
207	LOPPARYGGEN-ØST-85-SSL-DIAG		19
208	LOPPARYGGEN-ØST-85-NORD		19
209	LOPPARYGGEN-ØST-85-GECO-DIAG		19
210	LOPPARYGGEN-ØST-85-GRID		19
211	BJØRNØYA-ØST-TEST-85 *)		1
212	BJØRNØYA-VEST-86-DIAG		13
213	BJØRNØYA-VEST-86-HIGH		13
214	BJØRNØYA-VEST-86-MARGIN		12
215	BJØRNØYA-VEST-86-SWATH *)		1
216	BJØRNØYA-VEST-87		13
300	BARENTSHAVET-SØR-ØST-HOVEDPK		22
301	BARENTSHAVET-SØR-ØST-PAKKE-2		21
302	NORDKAPP-BASS-85-GECO-DIAG		20
303	NORDKAPP-BASSENGET-85-NORD		20
304	NORDKAPP-BASSENGET-85-GRID		21
305	NORDKAPP-BASSENGET-86-DIAG		20
306	NORDKAPP-BASSENGET-86-SØR		21
307	NORDKAPP-BASSENGET-86-NORD		14
308	FINNMARK-ØST-86-REGIONAL		19
309	FINNMARK-ØST-86-DIAG		18
310	FINNMARK-ØST-86-GSI		19
312	NORDKAPP-TEST-87 *)		1
400	BARENTSHAVET NORDVEST REGIONAL	1	2
500	BARENTSHAVET NORDØST REGIONAL	1	2

*) Not obligatory.

Table 7.2.b
Released seismic data (company seismic)

Package	Survey	Area	Kilometres
1 A	NH-8007	BL. 7/11	231.328
2 A	SG-8048	BL. 7/11	689.619
3 A	NH-8302	BL. 7/11	350.404
4 A	NHCN-82	BL. 7/8,11	1400.587
5 A	SH-82	BL. 2/5	872.699
6 A	SG-8052	BL. 2/2	541.722
7 A	BP80-019	BL. 2/1,7/12	985.315
8 A	EL-8180	BL. 2/6,2/9	1023.510
9 A	ST-501	BL. 33/2	696.000
10 A	ST-502	BL. 33/3	1182.771
11 A	ST-503	BL. 33/5,6	1307.000
12 A	NH-754	BL. 33/5	174.000
13 A	NAG-80	BL. 33/6	498.000
14 A	ANO-77	BL. 34/2	195.921
15 A	ANO-77-1	FELT 30,31	357.787
16 A	ANO-77-2	BL. 24/6	9.000
17 A	ANO-79	BL. 34/2	923.155
18 A	ANO-80	BL. 34/2	72.566
19 A	SA-530	BL. 35/3	1229.439
20 A	SAG-78	BL. 35/3	186.660
21 A	SG-8130	BL. 35/3	783.153
22 A	GULF-79-2	BL. 35/8,9	1000.323
23 A	GULF-80-1	BL. 35/8	1396.503
24 A	ANO-74	BL. 36/1	1515.589
25 A	SG-8252	BL. 2/2,3	1115.433
26 A	PSL-84-1	BL. 8/10	562.258
27 A	ST-8007	FELT 31	395.000
27 A	SH-8007	FELT 31/32	2495.000
28 A	TO-8513	BL. 29/3	25.287
29 A	TO-8510	BL. 29/3	261.665
30 A	SG-85	BL. 34/4	27.474
31 A	NH-8504	BL. 30/6	421.850
32 A	MN-85	BL. 35/11	587.980
33 A	NH-8502	BL. 30/9	1269.787
34 A	NH-8503	BL. 29/3,33/12	24.073
35 A	NH-8202	FELT 31,32	2072.594
36 A	SG-8127	FELT 35,36	813.636
37 A	SG-8133	BL. 34/11	350.377
38 A	SG-8425	BL. 31/2,3	275.184
39 A	NH-8104	FELT 32,36	1921.288
40 A	ST-8109	FELT 35,36	1318.896
41 A	81-007	FELT 31	339.599
42 A	EL-8307	BL. 34/8	2372.612
43 A	ST-8006	BL. 30/2,3,6	1948.741
44 A	BP-85	BL. 16/8	423.043
45 A	ST-8116	FELT 31,32	2194.671
46 A	G-81	BL. 35/8,9	519.484
47 A	GU-82	BL. 35/8	681.716
48 A	GU-81	BL. 35/8	376.311
49 A	ST-8313	BL. 34/10	276.587
50 A	ST-8112	BL. 30/2,3	368.311
51 A	ST-8111	BL. 30/6,9	347.830
52 A	G-8101	BL. 35/8,9	848.026
53 A	BP81-043	BL. 29/6,30/4	1375.896
54 A	NH-8502-3D	BL. 30/9	22431.769
55 A	NS-79	SYD 62	3710.355
56 A	NS-78	SYD 62	4638.521
57 A	PGE-82	BL. 2/7,10	700.213
58 A	NH-8201	BL. 2/8,11	1103.320
59 A	PGO-2/10-77	BL. 2/10	204.562
60 A	ANO-78-2	BL. 2/6,8 & 3/4	1540.000
61 A	ANO-78-3	VALHAL/HOD	363.927
62 A	ANO-79-1	BL. 2/5	90.834
63 A	PGE-80	BL. 2/4,7	716.189
64 A	PSL-84-2	BL. 2/7	235.360
65 A	ANO-83	VALHALL	393.692
66 A	ST-8421	BL. 2/9,12	592.346
67 A	NS-76	SYD 62	3569.609
68 A	ANO-80-1	BL. 2/5,8	199.091
69 A	CSSC-78-4	BL. 2/2	93.062
70 A	ST-404	BL. 1/9	454.590
71 A	EL-8201	BL. 3/7	592.000
72 A	SH-72	BL. 1/9	83.507
73 A	EL-8186	BL. 1/3	1743.788
74 A	PG-2/7-73	BL. 2/7	115.142
75 A	EL-8083	BL. 3/7	124.002
76 A	GULF-79	BL. 2/2,3	420.961
77 A	ST-809	BL.1/9,2/7	28.406
78 A	PGE-80-GE	BL. 2/4	25.995
79 A	ST-8013-81	BL. 1/9	121.976
80 A	CSSC-78-2	BL. 2/2,3	62.829
81 A	ANO-78-1	BL. 2/2,5	793.394
82 A	EL-980	BL. 2/6	356.736
83 A	PSL-84-3	BL. 2/4	440.268
84 A	EL-686	BL. 2/6	207.568
85 A	PG-2/4-73	BL. 2/4	101.000
86 A	ANO-76	BL. 2/4,5	251.148
87 A	ST-601	BL. 1/5	110.379
87 A	ST-602	BL. 1/2	406.030
87 A	ST-603	BL. 7/11	419.115
88 A	N2-70	BL. 2/1	226.399
89 A	SH-79-1	BL.1/3,2/1	598.979
90 A	PGE-79	BL. 2/4,5	120.029
91 A	A-79	BL. 1/6 & 2/4	344.734
92 A	ANO-80-2	BL. 3/4	117.580
93 A	SH-74-1	FELT 1	437.325
94 A	EL-8186-82	BL. 1/3	158.842
95 A	CSSC-78-3	BL. 3/4	52.681
96 A	CN2-73	BL. 2/1	639.479
97 A	CN2-76	BL. 2/1	430.723
98 A	SSL-7172	56-58 DEG	3274.995
99 A	CN2-77	BL. 2/2	357.822
100 A	SH-79-3	BL. 2/2	86.895
101 A	UN-80	BL. 2/2	153.508
102 A	C3-74	BL. 3/2	173.007
103 A	EL-8086	BL. 2/1,2,4,5	191.406
104 A	CN7-76	BL. 7/12	1124.482
105 A	C3-71	BL. 3/2	47.294
106 A	N7-71	BL. 7/9,12	202.283
107 A	MOB-79	FELT 10	177.163
108 A	CN7-73	BL. 7/12	478.447
109 A	PG-8/10-73	BL. 8/8,10,11	180.508
110 A	MOB-81-2	BL. 8/12	103.075
111 A	PW-8303	BL. 1/2	132.028
112 A	SH-72-5	BL. 3/5,8	54.340
113 A	A-80	ALBUSKJELL	76.730
114 A	ST-805	REG 57-62	2682.502
115 A	NERC-83	FELT 8,9	135.554
116 A	ANO-81	HOD	248.398
117 A	EL-8084	BL. 1/3, 7/12	140.533
118 A	TO-8401	BL. 25/4,24/6	168.103
119 A	TO-8605	BL. 30/10	563.399
120 A	ST-8410	BL. 8/3	592.514
121 A	ST-8629	FELT 12	1033.074
122 A	SH-84-1	FELT 25-31	957.388
123 A	SG-8603	BL. 25/6	1406.246
124 A	NH-8603	BL. 25/1	338.168
125 A	EL-8603	BL. 25/2	139.030
126 A	BN16-86	BL. 15/6	331.105
127 A	ST-8516	BL. 31/11	570.020
128 A	ST-8502	BL. 15/12	505.055
129 A	SBP-85	BL. 26/4	565.747
130 A	NA-85	BL. 16/10	460.576
131 A	M85-16	BL. 15/2,3	20.000
132 A	EL-8504	BL. 25/4	962.803
133 A	EL-8503	BL. 25/2,5	1654.389
134 A	BP-85-1	BL. 34/8	293.181
135 A	PSL-84	BL. 16/11	612.945
136 A	ST-8315	BL. 16/10	699.141
137 A	SH-83-2	BL. 30/11	252.862
138 A	EL-8302	BL. 16/6	529.731
139 A	E-83	BL. 16/7	454.945

Package	Survey	Area	Kilometres
140 A	ST-8215	BL. 15/9	99.800
141 A	NH-8204	BL. 15/5	154.004
142 A	ST-8004	BL. 15/6,9,12	293.107
143 A	ST-8107-GE	FELT 17	2109.984
144 A	ST-8104	BL. 15/8	50.779
145 A	SH-81	BL. 30/11	577.033
146 A	P-1712-81	BL. 17/12	519.839
150 A	EL-8602	BL. 30/10	110.000
151 A	TO-8506	BL. 24/6,25/4	265.000
152 A	BVI-85	BL. 15/2	302.479
153 A	NH-8408	BL. 16/10	477.000
154 A	EL-8303	BL. 25/4	559.219
155 A	ST-8202	FELT 26,27	259.170
156 A	ST-8201	FELT 26,27	5200.253
157 A	ST-8108	FELT 7	1566.000
158 A	SH-82-2	BL. 30/11	353.459
159 A	ST-8122	BL. 15/9,16/47	1020.340
160 A	E-82	BL. 16/7	308.573
161 A	EL-8206	BL. 15/3	1539.390
162 A	MOB-81-3	BL. 17/3,4,11	511.656
163 A	ST-8209	BL. 15/8	389.000
164 A	NH-8006	BL. 15/2	470.649
165 A	ST-8236	BL. 15/12	49.494
166 A	SH-82-1	BL. 31/2	69.438
167 A	CN-8525	BL. 25/7	1157.936
168 A	ST-508	BL. 15/5	289.799
169 A	NH-753	BL. 15/5	633.000
170 A	ST-8114	BL. 30/6,9	31.448
171 A	NH-8406	BL. 30/9	109.613
172 A	ST-507	BL. 15/2	245.119
173 A	EL-580	BL. 15/3	1120.380
174 A	ST-8107-WE	FELT 16,17	937.803
175 A	ST-8118	BL. 8/3	356.812
176 A	ST-8619	BL. 8/3	78.531
177 A	SH-74-2	BL. 17/11	450.270
178 A	PSE-78-1	BL. 17/12	381.374
179 A	SB-81	STORD BASIN	2314.596
182 A	A35-10-83	BL. 35/10	374.051
183 A	EL-8184	BL.25/7,10	471.882
184 A	EL-8202	BL. 25/1	431.191
185 A	EL-8304	BL. 34/7	522.899
186 A	EL-8284	BL. 25/7,10	375.177
187 A	G-8102-82	BL. 35/10	36.054
188 A	M-82	FELT 9,10,16	426.240
189 A	NH-8107	BL. 31/4	47.109
190 A	MOB-81-1	FELT 24,25	334.000
191 A	MOB-81-4	BL. 31/8	69.000
192 A	MOB-81-5	FELT 35,36	306.724
193 A	SH-8107	BL. 31/2	168.000
194 A	NSE-81	SYD 62	1253.738
195 A	SG-8232	BL. 34/8	1603.171
196 A	ST-8125	FELT 26,31,32	252.670
197 A	SG-8278	SYD 62	496.000
198 A	UH-81	UTSIRA HIGH	883.824
199 A	SH-76-1	BL. 25/12	257.552
200 A	SH-76	BL. 30/11	305.872
201 A	SH-84-2	FELT 34	970.211
202 A	AN30-77	BL. 30/2,3,6	835.608
203 A	CSSC-77	BL. 30/10	503.680
204 A	EL-780	BL. 25/4	366.661
205 A	EL-781	BL. 25/3,4,5	231.475
205 A	EL-782	BL. 25/3,4,5	231.475
206 A	EL-783	BL. 15/3	68.766
207 A	NH-752	BL. 30/7	656.000
208 A	ST-8121	BL. 30/6	20.031
209 A	ST-8123	FELT 30,31,32	47.116
210 A	ST-8105	BL. 15/12	49.057
211 A	NH-760	BL. 15/8	72.192
212 A	CSSC-78	BL. 34/5,7,8	436.887
213 A	SH-77	BL. 25/5	135.781
214 A	SH-77-2	BL. 34/2,5	119.943
215 A	SH-77-1	FELT 30,31	177.785
216 A	EL-580-78	BL. 30/7	22.136
217 A	NH-852	BL. 30/7	428.000
218 A	PSE-78	BL. 8/3	46.340
219 A	ST-810	BL. 24/12	29.328
220 A	MOB-79-1	FELT 16, 17	268.560
221 A	PG-1611-77	BL. 16/11	202.116
222 A	SH-79-2	BL. 30/11	235.517
223 A	SH-79-4	BL. 31/2	599.478
224 A	NH-954	FELT 30,31	1059.640
225 A	ST-906	BL. 9/2,3	490.372
226 A	ST-908	BL. 25/7	454.177
227 A	ST-909	FELT 31,32	1061.465
228 A	ST-910	FELT 34,35	586.466
229 A	ST-913	BL. 30/6,9	274.831
230 A	BP80-043	BL. 29/6,30/4	108.000
231 A	EL-8082	FELT 26	1231.765
232 A	NH-80-04	BL. 31/8,9	137.838
233 A	NH-80-05	BL. 35/10,12	967.005
234 A	NH-8002	BL. 33/5	28.000
235 A	NH-8004	BL. 31/8,9	128.322
236 A	NH-8005	BL. 35/10,12	92.234
237 A	NH-8008	BL. 16/7	654.888
238 A	NSE-80	SYD 62	1504.247
239 A	SH-8007-ORG	FELT 31/32	3952.116
240 A	CNST-82	SYD FOR 60	2589.000
241 A	TLGS-80	SYD 62	3938.069
242 A	CGT-81	SENT.GRABEN	2803.000
243 A	NH-8415	BL. 30/7	266.264
244 A	ST-8404	BL. 6/3,7/1	1005.516
245 A	SH-87-2	BL. 30/5,6	75.502
246 A	SG-8710	BL. 6507/6	827.280
247 A	SG-8820	BL. 34/4	296.559
1 B	SH-84	BL. 6407/9	1238.985
2 B	CN-8502	HALTENBANKEN	1002.000
3 B	NH-8102	TRÆNABANKEN	4699.883
4 B	BP-83	HALTENBANKEN	923.962
5 B	SG-8158	BL. 6507/11,12	236.813
6 B	SG-8258	BL. 6507/11,12	436.561
7 B	SG-8271	BL. 6407/2	638.185
8 B	ST-8110	TRØNDELAG VEST	280.384
9 B	ST-8306	HALTENBANKEN	325.840
10 B	EL-8204	TRÆNABANKEN	2934.451
11 B	ST-8217	TRÆNABANKEN	464.058
12 B	ST-8407	BL. 6609/5	422.139
13 B	EL-8502	NORDLAND 2	652.803
14 B	PW-83	BL. 6609/7	1056.637
15 B	SG-8445	BL. 6507/12	93.613
16 B	SG-8458	BL. 6507/11	162.952
17 B	SG-8558	BL. 6507/11	144.511
18 B	SG-8558-1	BL. 6507/11	92.074
19 B	SG-8658	BL. 6507/11	173.572
20 B	ST-8002	BL. 6507/7,8,9	214.532
21 B	ST-8102	BL. 6507/7,8,9	893.371
22 B	ST-8616	BL. 6407/4	202.161
23 B	ST-8634	BL. 6406/6	240.648
24 B	MN-84-3	BL. 6407/7	647.282
25 B	NH-8411	FRØYABANKEN	289.429
26 B	ST-8403	HALTENBANKEN	926.372
27 B	MN-85-1	NORDLAND 2	574.398
28 B	SH-85-1	HALTEN VEST	558.463
29 B	NH-8609	BL. 6407/7	171.704
30 B	SH-86-2	BL. 6407/9	154.269
31 B	NE-85A	BL. 6607/08	779.962
32 B	AE-86	BL. 6607/5	679.728
33 B	NH-8409	HALTENBANKEN	423.178

Fig. 7.3.a
Regional spread of exploration wells per operator

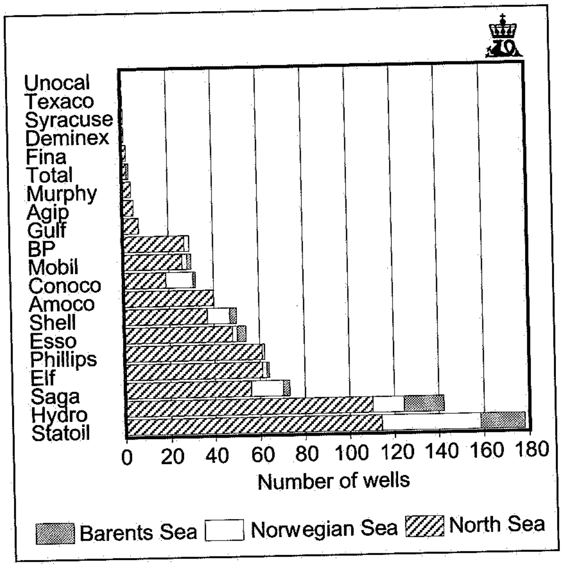
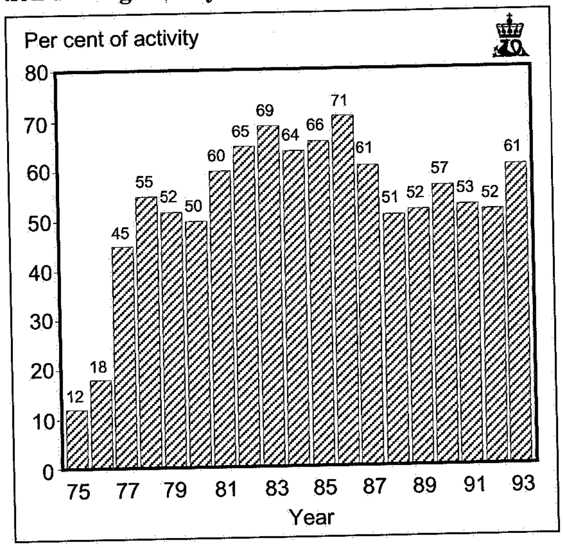


Fig. 7.3.c
Participation of Norwegian operators in exploration drilling activity



7.3 EXPLORATION DRILLING STATISTICS

By year end 1993, a total of 779 exploration wells had been started on the Norwegian continental shelf since the first was spudded in 1966. Of this number, 555 were wildcats and 224 appraisal wells.

By the same date, 726 exploration wells had been terminated, while 45 were suspended for various reasons. The reasons include deferred testing, possible completion as production wells, continued drilling, or subsequent plugging. At year end there were eight exploration wells being drilled.

The most northerly exploration well to date on the Norwegian continental shelf is 7316/5–1, which was drilled in 1992 under Hydro as operator. The furthest east is 7229/11–1, drilled by Shell in 1993; and the westernmost 6301/11–2, drilled by Statoil in 1991.

Exploration wells have been drilled by 20 different operating companies. The regional numbers drilled per operator are shown in Figure 7.3.a.

Estimates of the number of days of operation per company in 1993 are shown in Figure 7.3.b. Figure 7.3.c shows the Norwegian operating companies' share of drilling operations.

By year end 1993, the total length of exploration drilling had reached 2,505,613 metres; of which 77,400 metres were drilled in the year. The average total depth of the exploration wells reaching their prospective total depth in 1993 was 3474 metres.

Exploration well 1/6–6, drilled to prospective total

Fig. 7.3.b
Rigdays per operator 1993

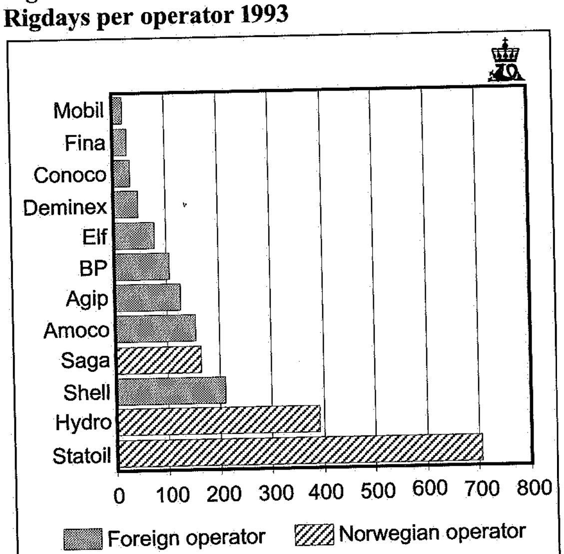


Fig. 7.3.d
Average waterdepth for exploration wells 1966–1993

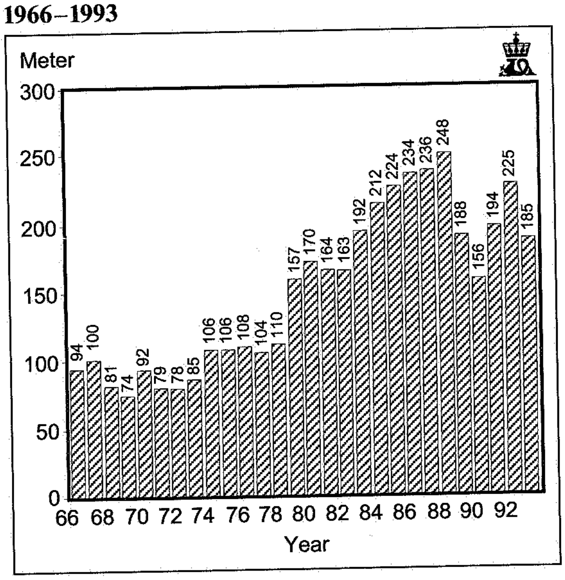


Table 7.3.a
Regional spread of spudded exploration and development wells

Year spudded	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90	91	92	93	Total
North Sea																													
Wildcat	2	6	10	12	11	11	11	17	12	18	20	12	14	18	23	19	27	20	22	13	14	9	9	15	18	23	21	14	421
Appraisal			2	1	6	5	3	5	6	8	3	8	5	10	10	15	13	7	11	14	5	8	10	6	9	13	14	5	202
Norwegian Sea																													
Wildcat															1	2	5	7	6	10	10	10	5	2	7	8	5	4	82
Appraisal																			1	6	5	4	1	1	1		2		21
Barents Sea																													
Wildcat															2	3	4	5	7	7	2	5	4	4	1	3	3	2	52
Appraisal																		1											1
Total exploration drilling																													
Wildcat	2	6	10	12	11	11	11	17	12	18	20	12	14	18	26	24	36	32	35	30	26	24	18	21	26	34	29	20	555
Appraisal			2	1	6	5	3	5	6	8	3	8	5	10	10	15	13	8	12	20	10	12	11	7	10	13	14	7	224
Exploration wells	2	6	12	13	17	16	14	22	18	26	23	20	19	28	36	39	49	40	47	50	36	36	29	28	36	47	43	27	779
Development wells								1	18	24	7	34	50	36	27	16	22	23	33	47	47	48	55	66	60	64	86	105	869
Total	**2**	**6**	**12**	**13**	**17**	**16**	**14**	**23**	**36**	**50**	**30**	**54**	**69**	**64**	**63**	**55**	**71**	**63**	**80**	**97**	**83**	**84**	**84**	**94**	**96**	**111**	**129**	**132**	**1648**

Table 7.3.b
Exploration wells by operating company and region

Operator	North Sea			Norwegian Sea			Barents Sea			Total		
	W	A	E	W	A	E	W	A	E	W	A	E
Statoil	64	50	114	38	6	44	19	1	20	121	57	178
Hydro	74	36	110	12	2	14	18		18	104	38	142
Phillips	41	20	61	1		1				42	20	62
Elf	44	17	61	2		2	1		1	47	17	64
Saga	46	10	56	14		14	3		3	63	10	73
Esso	28	20	48	2		2	4		4	34	20	54
Shell	26	11	37	5	5	10	3		3	34	16	50
Amoco	26	14	40							26	14	40
Conoco	19		19	4	8	12	1		1	24	8	32
Mobil	17	9	26	2		2	2		2	21	9	30
BP	13	14	27	2		2				15	14	29
Gulf	7		7							7		7
Murphy	3	1	4							3	1	4
Total	2		2				1		1	3		3
Agip	5		5							5		5
Deminex	1		1							1		1
Syracuse	1		1							1		1
Texaco	1		1							1		1
Unocal	1		1							1		1
Fina	2		2							2		2
Wildcat	421			82			52			555		
Appraisal		202			21			1			224	
Exploration			623			103			53			779

W = Wildcat
A = Appraisal
E = Exploration

Table 7.3.c
Exploration wells spudded in 1993 by operating company and region

Operator	North Sea			Norwegian Sea			Barents Sea			Total		
	W	A	E	W	A	E	W	A	E	W	A	E
Statoil	3	2	5	2	2	4	1		1	6	4	10
Hydro	2	3	5	1		1				3	3	6
Phillips												
Elf												
Saga	3		3							3		3
Esso												
Shell							1		1	1		1
Amoco	1		1							1		1
Conoco				1		1				1		1
Mobil												
BP	1		1							1		1
Gulf												
Murphy												
Total												
Agip	2		2							2		2
Deminex	1		1							1		1
Syracuse												
Texaco												
Unocal												
Fina	1		1							1		1
Wildcat	14			4			2			20		
Appraisal		5			2						7	
Exploration			19			6			2			27

W = Wildcat
A = Appraisal
E = Exploration

Table 7.3.d
Average water depth and drilling depth

Year	Average water depth (m)	Average total depth (m)
1966	94	3 015
1967	100	2 682
1968	81	3 303
1969	74	3 276
1970	92	2 860
1971	79	3 187
1972	78	3 742
1973	85	3 075
1974	106	3 163
1975	106	3 173
1976	108	3 314
1977	104	3 450
1978	110	3 432
1979	157	3 444
1980	179	3 209
1981	164	3 243
1982	163	3 457
1983	192	3 287
1984	212	3 247
1985	224	3 367
1986	234	3 248
1987	236	3 386
1988	248	3 598
1989	188	3 331
1990	156	3 619
1991	194	3 639
1992	225	3 560
1993	185	3 474

Table 7.3.e
Drilling rigs active on the Norwegian continental shelf as of 31 December 1993

Rig name	Number of wells	Number of reentries	Type of rig
Aladdin	1		Semi-submersible
Arcade Frontier (formerly Norjarl)	7		"
Borgny Dolphin (formerly Fernstar)	27		"
Borgsten Dolphin (formerly Haakon Magnus)	9		"
Bucentaur		1	Drill ship
Byford Dolphin (formerly Deepsea Driller)	27		Semi-submersible
Chris Chenery	2		"
Deepsea Bergen	38	3	"
Deepsea Saga	16	3	"
Drillmaster	5	1	"
Drillship	1		Drill ship
Dyvi Beta	6	1	Jack-up
Dyvi Gamma	1		"
Dyvi Stena	20	1	Semi-submersible
Endeavour	2		Jack-up
Glomar Biscay II (formerly Norskald)	39	1	Semi-submersible
Glomar Grand Isle	11	3	Drill ship
Glomar Moray Firth I	2		Jack-up
Gulftide	3		"
Henry Goodrich	2		Semi-submersible
Hunter (formerly Treasure Hunter)	6	3	"
Kolskaya		1	Jack-up
Le Pelerin	1		Drill ship
Mærsk Explorer	7		Jack-up
Mærsk Guardian	1		"
Mærsk Guardian	3		"
Mærsk Jutlander	4		Semi-submersible
Neddrill Trigon	3	1	Jack-up
Neptune 7 (formerly Pentagone 81)	13		Semi-submersible
Nordraug	12		"
Nortrym	32	3	"
Ocean Tide	5		Jack-up
Ocean Traveller	9		Semi-submersible
Ocean Victory	1		"
Ocean Viking	28	1	"
Ocean Voyager	2		"
Odin Drill	3		"
Orion	7		Jack-up
Pentagone 84	2	1	Semi-submersible
Polar Pioneer	31	6	"
Polyglomar Driller	11		"
Ross Isle	31	8	"
Ross Rig	31		"
Ross Rig (new)	21	3	"
Saipem II	1		Drill ship
Scarabeo	1		Semi-submersible
Sedco 135 G	3		"
Sedco 703	3	1	"
Sedco 704	3		"
Sedco 707	8		"
Sedco H	2		"
Sedneth I	3		"
Sovereign Explorer	3	1	"
Transocean 8	15	2	"
Transworld Rig 61	2		"
Treasure Prospect	1	1	"
Treasure Saga	45	4	"
Treasure Scout	23		"
Treasure Seeker	24	5	"
Vildkat Explorer	24	3	"

Rig name	Number of wells	Number of reentries	Type of rig
Vinni	5		”
Waage Drill I	2		”
West Alpha (formerly Dyvi Alpha)	22	2	”
West Delta (formerly Dyvi Delta)	37	5	”
West Vanguard	28	5	”
West Venture	12	2	”
West Vision	1		”
Yatzy	1		”
Zapata Explorer	13		Jack-up
Zapata Nordic	5		”
Zapata Ugland	5	1	Semi-submersible
	775	82	
In addition four wells have been drilled from fixed installations:			
Cod platform	1	1	
Ekofisk B	1		
Veslefrikk A	2		
	779	83	

Table 7.3.f
Spudded and/or concluded exploration wells in 1993

R = reentry, X = junked due to technical problems, S = side drilled, A, B, C = side drilled new well

Exploration well	Lic. no. Prod. lic. no.	Position north east	Drilling Spudded Concluded	Operator Drill rig	Well type Completion classification	Water depth (in metres) KBE in metres	Total depth (in metres) Geol period
1/06–06	718	56 36 41.13	92.02.10	Shell	Wildcat	70	5567
	011	02 57 18.19	93.03.08	Dyvi Stena	Dry well	25	Jura
6610/03–01	748	66 55 29.70	92.10.29	Statoil	Wildcat	309	3126
	177	10 54 06.28	93.02.17	Deepsea Bergen	Suspended	23	
25/02–15	722	59 48 53.54	92.11.14	Elf	Wildcat	120	3505
	026	02 30 06.20	93.01.13	West Alpha	Aband. after fire	23	
15/09–19 S	749	58 26 09.08	92.11.18	Statoil	Wildcat	84	4641
	046	01 55 47.26	93.01.31	Treasure Prospect	Susp. at 9 5/8"	22	
34/08–07 R	725	61 19 09.07	92.11.19	Hydro	Wildcat	334	5460
	120	02 33 32.15	93.02.10	Polar Pioneer	Oil/Gas	23	Trias
33/09–16	750	61 23 28.81	92.11.28	Mobil	Appraisal	227	2870
	172	01 57 01.93	93.01.19	Ross Isle	Hydrocarbons	22	L.Jura
34/07–21 A	752	61 17 36.84	92.12.11	Saga	Appraisal	192	3360
	089	02 04 21.14	93.02.12	Treasure Saga	Hydrocarbons	26	M.Jura
31/05–05	751	60 41 49.66	92.12.30	Hydro	Appraisal	319	1930
	085	03 29 08.74	93.02.11	West Delta	Susp. Oil/Gas	29	Jura
6608/10–03	753	66 02 06.66	93.01.07	Statoil	Appraisal	379	2920
	128	08 04 57.97	93.03.11	Ross Rig	Susp. Oil/Gas	23	E.Jura
25/02–15 R	722	59 48 53.54	93.02.08	Elf	Wildcat	120	3505
	026	02 30 06.20	93.03.01	West Vanguard	Susp. at 9 5/8"	25	
31/02–17 BR	719	60 52 57.08	93.02.14	Hydro	Appraisal	340	1838
	054	03 27 05.79	93.02.24	West Delta	Oil/Gas	29	
2/10–02	757	56 13 08.48	93.02.16	Saga	Wildcat	71	4164
	163	03 06 41.62	93.04.25	Treasure Saga	Suspended	26	Perm
34/08–08 R	730	61 22 46.19	93.02.16	Hydro	Appraisal	341	3625
	120	02 28 43.81	93.03.09	Polar Pioneer	Oil/Gas	23	Trias
15/09–19 SR	749	58 26 09.08	93.02.17	Statoil	Wildcat	84	3580
	046	01 55 47.26	93.04.29	Treasure Prospect	Susp. Oil	22	
25/11–17	755	59 03 26.51	93.03.01	Hydro	Wildcat	124	2257
	169	02 29 06.51	93.03.21	West Delta	Dry well	29	Basement
25/02–15 R2	722	59 48 53.54	93.03.05	Elf	Wildcat	120	3942
	026	02 30 06.20	93.04.11	West Vanguard	Dry well	25	
30/09–14	756	60 23 11.31	93.03.16	Hydro	Appraisal	107	3680
	079	02 42 18.58	93.05.14	Polar Pioneer	Oil/Gas	23	Jura
16/01–04	754	58 51 55.20	93.03.17	Statoil	Wildcat	112	2009
	167	02 17 56.12	93.04.13	Deepsea Bergen	Traces of gas	23	Perm/Devon
6506/12–09 S	760	65 06 52.02	93.04.04	Statoil	Appraisal	294	4910

Exploration well	Lic. no. Prod. lic. no.	Position north east	Drilling Spudded Concluded	Operator Drill rig	Well type Completion classification	Water depth (in metres) KBE in metres	Total depth (in metres) Geol period
	094	06 45 15.70	93.09.10	Ross Isle	Oil/Gas	23	Jura
7/07–03	759	57 27 41.61	93.04.20	Statoil	Appraisal	82	3584
	148	02 16 20.96	93.07.04	Deepsea Bergen	Dry well	23	Perm
15/06–07	758	58 35 21.41	93.04.24	Deminex	Wildcat	107	3540
	166	01 52 19.06	93.06.08	Vildkat Explorer	Dry well	25	Trias
2/04–18	762	56 41 56.95	93.04.26	Saga	Wildcat	69	622
	146	03 09 46.17	93.04.29	Treasure Saga	Suspended	26	
30/06–23 R	634	60 40 58.01	93.05.16	Hydro	Appraisal	151	3209
	053	02 55 58.97	93.05.21	Polar Pioneer	Oil/Gas	23	E.Jura
6407/09–06 R	499	64 19 58.07	93.05.19	Shell	Appraisal	297	1800
	093	07 44 23.70	93.05.30	West Delta	Oil	29	E.Jura
2/05–10	761	56 41 21.66	93.05.23	Agip	Wildcat	88	4701
	067	03 29 27.32	93.08.26	Polar Pioneer	Traces of oil	23	Trias
7/04–01	763	57 44 11.92	93.07.05	Statoil	Wildcat	83	3133
	148	02 11 38.95	93.08.21	Deepsea Bergen	Dry well	23	Perm
2/11–09	764	56 08 49.19	93.07.23	Amoco	Wildcat	72	
	033	03 27 15.34	93.12.23	Mærsk Gallant	Dry well	53	
7229/11–01	767	72 12 57.24	93.08.09	Shell	Wildcat	283	4630
	183	29 38 29.75	93.12.16	Ross Rig	Dry well	23	Carbon
34/07–22	766	61 16 42.37	93.08.15	Saga	Wildcat	226	2507
	089	02 10 18.72	93.10.01	West Delta	Oil	29	M.Jura
2/05–10 A	769	56 41 21.66	93.08.27	Agip	Wildcat	88	4715
	067	03 29 27.32	93.09.25	Polar Pioneer	Traces of oil	23	Trias
6507/08–06	770	65 24 35.96	93.08.29	Statoil	Wildcat	354	2846
	124	07 28 52.74	93.10.09	Deepsea Bergen	Dry well	23	Trias
6610/03–01 R	748	66 55 29.70	93.09.16	Statoil	Wildcat	309	4200
	177	10 54 06.28	00.00.00	Ross Isle	Hydrocarbons	23	Trias
2/07–29	765	56 18 43.62	93.09.18	BP	Wildcat	72	
	145	03 04 55.28	00.00.00	Mærsk Guardian		41	
34/08–10 S	768	61 21 16.3	93.09.28	Hydro	Appraisal	326	3470
	120	02 27 18.7	93.12.09	Polar Pioneer	Oil/Gas	23	Trias
6507/07–10	771	65 23 26.83	93.09.28	Conoco	Wildcat	394	3308
	095	07 19 56.32	93.10.29	Arcade Frontier	Dry well	24	Trias
6305/12–02	772	63 01 11.39	93.10.16	Hydro	Wildcat	146	Basement
	154	05 40 06.44	93.17.17	Deepsea Bergen	Hydrocarbons	23	
24/09–05	778	59 29 06.52	93.12.07	Fina	Wildcat	122	
	150	01 55 10.82	00.00.00	West Delta		29	
30/09–15	773	60 22 18.63	93.12.07	Hydro	Wildcat	104	
	104	02 55 24.80	00.00.00	Polar Pioneer		23	
34/08–11	780	61 21 46.94	93.12.10	Hydro	Appraisal		
	120	02 27 37.54	00.00.00	Polar Pioneer		23	
6608/10–04	776	66 02 25.5	93.12.15	Statoil	Wildcat		
	128	08 09 41.2	00.00.00	Ross Isle		23	
7128/04–01	779	71 32 27.1	93.12.19	Statoil	Wildcat		
	180	28 04 54.0	00.00.00	Ross Rig		24	
9/02–04	775	57 49 07.6	25.12.93	Statoil	Wildcat	92	
	114	04 31 10.7	00.00.00	Deepsea Bergen		23	
30/03–06 S	777	60 46 57.87	26.12.93	Statoil	Wildcat	175	
	052	02 53 51.95	00.00.00	Veslefrikk A		56	

Table 7.3.g
Drilling activity on Svalbard

Exploration well/ location	Position north east	Spudded	Con-cluded	Days drilling	Operator Licensee	Total depth metres	KB elev. over msl metres
7714/2–1 Grønnfjorden I (Nordenskiøld Land)	77 57 34 14 20 36	09.06.63 13.06.64 26.06.65 26.06.67	05.09.63 26.08.64 08.09.65 12.08.67	287	Norsk Polar Navig Norsk Polar Navig	971,6	7.5
7715/3–1 Ishøgda I (Spitsbergen)	77 50 22 15 58 00	01.08.65	15.03.66	277	Texaco Caltex-group	3304	18
7714/3/1 Bellsund I (Fridtjofsbreen)	77 47 14 46	23.08.67 29.06.68 07.07.69 10.07.74 16.07.75 22.08.80 01.07.81	02.09.67 21.08.68 16.08.69 18.09.74 20.09.75 05.09.80 10.08.81	299*)	Norsk Polar Navig Norsk Polar Navig	405	
7625/7–1 Hopen I (Hopen)	76 26 57 25 01 45	11.08.71	29.09.71	50	Forasol Fina-group	908	9.1
7722/3–1 Raddedalen (Edgeøya)	77 54 10 22 41 50	02.04.72	12.07.72	100	Total Caltex-group	2823	84
7721/6–1 Plurdalen (Edgeøya)	77 44 33 21 50 00	29.06.72	12.10.72	108	Fina Fina-group	2351	144.6
7811/2–1 Kvadehuken I (Brøggerhalvøya)	78 57 03 11 23 23	01.09.72 21.04.73	10.11.72 19.06.73	112	Terratest a/s Norsk Polar Navig	479	
7625/5–1 Hopen II (Hopen)	76 41 15 25 28 00	20.06.73	20.10.73	123	Westburne Int Ltd Fina-group	2840,3	314.7
7811/2–2 Kvadehuken II (Brøggerhalvøya)	78 55 32 11 33 11	18.08.73 22.03.74	19.11.73 16.06.74	186	Terratest a/s Norsk Polar Navig	394	
7811/5–1 Sarstangen (Forlandsrevet)	78 43 36 11 28 40	15.08.74	01.12.74	109	Terratest a/s Norsk Polar Navig	1113,5	5
7815/10–1 Colesbukta (Nordenskiøld Land)	78 07 00 15 02 00	13.11.74	01.12.75	373	Trust Arktikugol	3180	12
7617/1–1 Tromsøbreen I (Haketangen)	76 52 30 17 05 30	11.09.76 13.06.77	22.09.76 19.09.77	109	Terratest a/s Norsk Polar Navig	990	6.7
7617/1–2 Tromsøbreen II (Haketangen)	76 52 31 17 05 38	20.07.87 13.06.88	30.10.87 24.08.88	175	Deutag Tundra A/S	2337	6.7
7715/1–1 Vassdalen II (Van Mijenfjorden)	77 49 57 15 11 15	22.01.85	1)		Trust Arktikugol	2481	15.13
7715/1–2 Vassdalen II (Van Mijenfjorden)	77 49 57 15 11 15	30.03.88	01.11.89		Trust Arktikugol	2352	15.13
7816/12–1 Reindalspasset-I (Spitsbergen)	78 03 28 16 56 31	17.01.91	18.04.91		Norsk Hydro	2315	182.5

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

depth in 1992, is the deepest well to date on the Norwegian side. Here, Shell operated to a total vertical depth of 5542 metres below mean sea level.

The longest exploration borehole to date is 2/12–2S, sidetracked by Norsk Hydro in 1990. The length of the well is 5757 metres, but as it was drilled at an angle it did not reach as deep below the seabed as 1/6–6.

The average water depth for exploration wells drilled in 1993 was 185 metres. The greatest water depth in which a well has been drilled to date in the Norwegian sector is 523 metres: The well, 6607/5–2, was drilled in 1991 with Esso as operator.

Figure 7.3.d shows the average water depths in which exploration wells were drilled from 1966 to 1993.

Seventy-four different drilling rigs have been employed in drilling operations on the Norwegian continental shelf to date, nine of them under two different names. Fifty-two were semi-submersibles, 14 jack-ups, five drill ships, and three fixed installations. In 1993, there were 14 different drilling rigs exploring on Norway's offshore provinces.

Tables 7.3.a-f present the statistics for exploration drilling on the Norwegian continental shelf, while Table 7.3.g is a summary of wells on Svalbard.

7.4 DEVELOPMENT DRILLING STATISTICS

Since 1973, a total of 869 development wells have been commenced in the Norwegian sector; of which 434 are producers of oil, gas or condensate; and 136 are water or gas injectors. Of the total, 280 are out of service; being either suspended for later completion, or closed down for some other reason. The wells were drilled on 33 fields using 46 installations. Nineteen development wells were being drilled at year end 1993.

Full details of development wells started each year during the period 1973 to 1993 are given in Figure 7.4.a.

At year end, production or injection was underway from 27 fields and 38 installations. Five new fields came on stream in 1993: namely Brage, Draugen, Hod, Loke and Sleipner Øst.

The distribution of development wells by field is shown in Figure 7.4.b; while Figure 7.4.c shows the wells broken down by operating company.

The first development wells on Sleipner Øst, Embla, Frøy, Statfjord Øst, Tordis and Draugen were spudded in 1993. Except on Sleipner Øst, mobile rigs were used to drill the wells. They were, in order: *Mærsk Guardian*, *Treasure Saga*, *Treasure Prospect*, *Vildkat Explorer* and *Dyvi Stena*.

Of the 105 development wells spudded in 21 fields in 1993, 34 were drilled by ten different mobile units. The figures represent a major increase in development drilling activity by mobile rigs. In each of the three years before that, the figure was 14 wells from five mobile units.

Development wells broken down by installation are shown in Figure 7.4.d. Further details of development wells are compiled in Tables 7.4.a-c. Figure 7.4.e is a summary of the development wells drilled from mobile units.

Fig. 7.4.a
Development wells on the Norwegian continental shelf 1973–1993

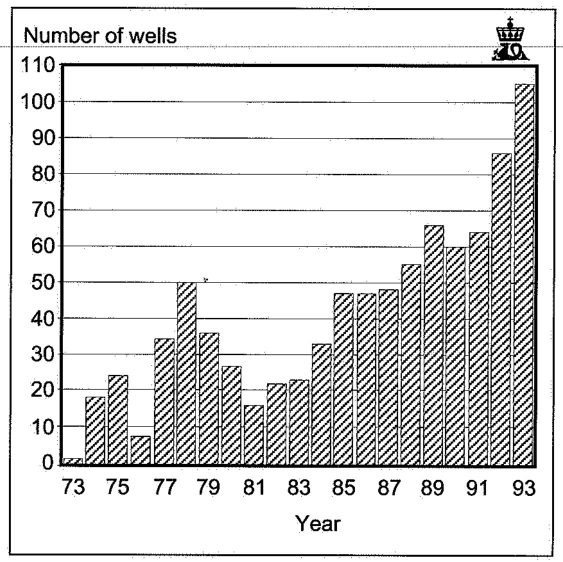


Fig. 7.4.b
Development wells per field

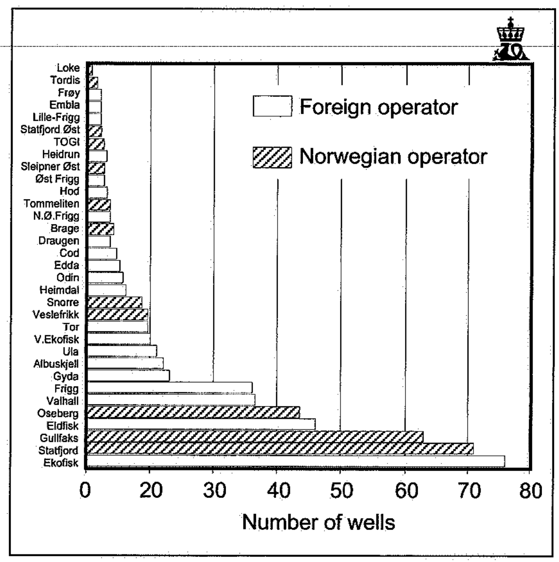


Fig. 7.4.c
Development wells per operator

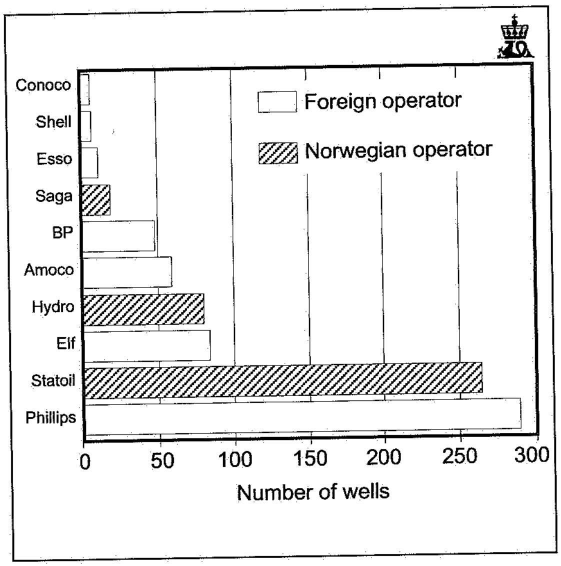


Fig. 7.4.e
Development drilling by mobile installations

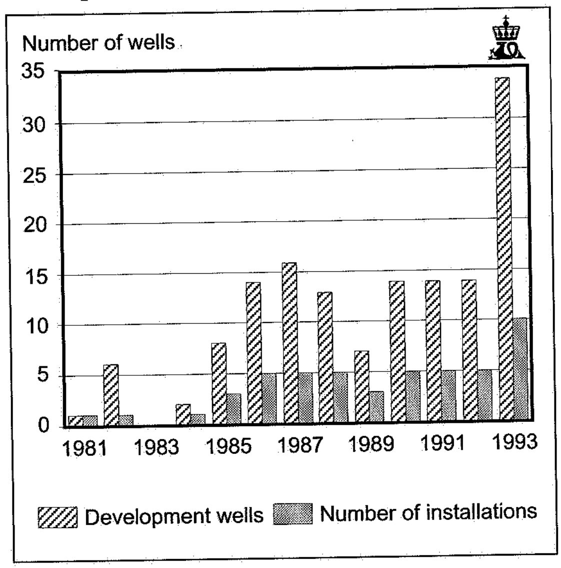


Fig. 7.4.d
Development wells drilled 1993 by installations

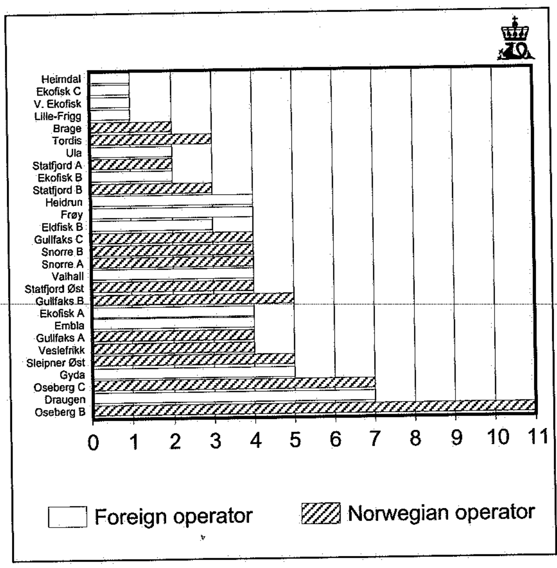


Table 7.4.a
Development drilling as of 31.12.1993

Field/installation	Total drilled	Spudded 1993	Oil	Producing Cond.	Gas	Injection/ observation	Drilling	Shut-down/ suspended
Albuskjell A	11			7				4
Albuskjell F	13							13
Brage	8	2	5			1	1	1
Cod	9			3				6
Draugen	7	7	2				1	4
Edda	10		5					5
Ekofisk A	31	4	23					8
Ekofisk B	37	2	21				1	15
Ekofisk C	28	1	17			4	1	6
Ekofisk K	28					27		1
Ekofisk W	8					8		
Eldfisk A	38		22					16
Eldfisk B	34	3	20					14
Embla	4	4	4					
Frigg (UK)	24							24
Frigg	28				14			14
Frøy	4	4					1	3
Gullfaks A	51	4	28			9		14
Gullfaks B	35	5	19			9	1	6
Gullfaks C	20	4	12			4	1	3
Gyda	26	5	14			7	1	4
Heidrun	6	4					1	5
Heimdal	12	1		8				4
Hod	6		5					1
Lille-Frigg	4	1					1	3
Loke	1				1			
Nordøst Frigg	7							7
Odin	11				7			4
Oseberg B	44	11	27			7	1	9
Oseberg C	23	7	10			6	1	6
Sleipner Øst	5	5			1		1	3
Snorre A	6	4	4			1	1	
Snorre P	11	4	6			4	1	
Statfjord A	47	2	25			15		7
Statfjord B	40	3	25			12	1	2
Statfjord C	35		23			10		2
Statfjord Øst	4	4						4
TOGI	5				5			
Tommeliten Gamma	7			6				1
Tor	19		12			1		6
Tordis	3	3					1	2
Ula	22	2	8			6		8
Valhall	53	4	23				1	29
V. Ekofisk	20	1		7				13
Veslefrikk	19	4	11			6	1	1
Øst Frigg	5				4			1
	869	105	371	31	32	136	19	280

Table 7.4.b
Development wells spudded or concluded in 1993

Lic.no.	Dev. well	Suspended	Concluded	Operator	Field/installation
631	34/07-P-25	91.03.09	93.02.15	SAGA	SCARABEO 5
737	34/07-A-04 H	92.09.01	93.01.07	SAGA	SCARABEO 5
743	15/09-C-02 H	92.10.12	93.06.29	STATOIL	TREASURE PROSPECT
744	34/07-A-05 H	92.10.15	93.03.28	SAGA	SCARABEO 5
748	25/02-C-02 H	92.10.19	00.00.00	ELF	MÆRSK JUTLANDER
742	2/08-A-29	92.10.24	93.01.05	AMOCO	VALHALL
750	33/09-C-02	92.10.29	93.03.22	STATOIL	STATFJORD C
728	2/07-B-02 A	92.11.01	93.01.05	PHILLIPS	ELDFISK B
754	30/06-C-04	92.11.20	93.01.17	HYDRO	OSEBERG C
755	31/04-A-04	92.11.20	93.03.05	HYDRO	VILDKAT EXPLORER
753	34/10-B-25	92.11.21	93.05.20	STATOIL	GULLFAKS B
757	33/12-B-29	92.11.29	93.03.04	STATOIL	STATFJORD B
759	30/03-A-15	92.12.02	93.01.30	STATOIL	VESLEFRIKK A
762	34/10-C-15 A	92.12.03	93.02.19	STATOIL	GULLFAKS C
765	7/12-A-14	92.12.08	93.02.28	BP	ULA
772	34/10-B-26	92.12.14	93.02.28	STATOIL	GULLFAKS B
769	34/10-A-39 A	92.12.15	93.02.23	HYDRO	GULLFAKS A
763	6507/07-A-52 H	92.12.18	93.02.09	CONOCO	TRANSOCEAN 8
758	33/09-A-23 A	92.12.23	93.03.06	STATOIL	STATFJORD A
768	2/01-A-24 A	92.12.25	93.02.06	BP	GYDA
761	2/04-A-13 A	92.12.27	93.02.08	PHILLIPS	EKOFISK A
766	30/09-B-32 A	92.12.29	93.01.22	HYDRO	OSEBERG B
773	30/06-C-20	93.01.20	93.03.30	HYDRO	OSEBERG C
776	30/09-B-09	93.01.23	93.02.11	HYDRO	OSEBERG B
764	2/08-A-30	93.01.28	93.05.03	AMOCO	VALHALL
760	2/07-B-10 C	93.01.29	93.04.07	PHILLIPS	ELDFISK B
777	30/03-A-16	93.01.31	93.04.26	STATOIL	VESLEFRIKK A
783	2/01-A-31	93.02.06	93.03.27	BP	GYDA
781	2/04-A-19	93.02.09	93.04.05	PHILLIPS	EKOFISK A
775	6507/07-A-33 H	93.02.10	93.03.19	CONOCO	TRANSOCEAN 8
785	30/09-B-09 A	93.02.12	93.03.12	HYDRO	OSEBERG B
778	34/07-P-40	93.02.15	93.04.22	SAGA	SNORRE P
771	34/10-C-16	93.02.20	93.09.30	STATOIL	GULLFAKS C
770	34/10-A-40	93.02.24	93.08.01	STATOIL	GULLFAKS A
780	7/12-A-16	93.03.01	93.05.20	BP	ULA
782	2/07-D-27	93.03.02	93.05.07	PHILLIPS	MÆRSK GUARDIAN
779	15/09-D-03 H	93.03.02	93.04.01	STATOIL	DEEPSEA BERGEN
767	31/04-A-04 A	93.03.05	93.04.21	HYDRO	VILDKAT EXPLORER
786	30/09-B-17	93.03.12	93.04.21	HYDRO	OSEBERG B
774	25/02-C-03 H	93.03.13	93.11.09	ELF	MÆRSK JUTLANDER
791	34/10-A-41	93.03.18	93.05.24	STATOIL	GULLFAKS A
792	34/10-C-17	93.03.22	93.06.22	STATOIL	GULLFAKS C
788	6507/07-A-53 H	93.03.22	93.05.16	CONOCO	TRANSOCEAN 8
787	33/09-A-32 A	93.03.29	93.07.14	STATOIL	STATFJORD A
784	30/06-C-20 A	93.03.30	93.05.07	HYDRO	OSEBERG C
796	15/09-D-01 H	93.04.01	93.06.07	STATOIL	DEEPSEA BERGEN
802	6407/09-A-53 H	93.04.05	93.11.08	SHELL	DYVI STENA
797	34/07-A-01 H	93.04.06	93.06.14	SAGA	SCARABEO 5
798	2/01-A-20	93.04.07	93.05.22	BP	GYDA
789	33/12-B-27	93.04.07	93.09.07	STATOIL	STATFJORD B
803	6407/09-A-55 H	93.04.08	93.04.26	SHELL	WEST DELTA
807	34/07-P-08	93.04.22	93.06.18	SAGA	SNORRE P
794	2/04-D-15 A	93.04.26	93.05.30	PHILLIPS	EKOFISK D
790	30/03-A-17	93.04.26	93.07.01	STATOIL	VESLEFRIKK A
806	30/09-B-05 A	93.04.26	93.07.03	HYDRO	OSEBERG B
804	6407/09-A-55 AH	93.04.27	93.06.07	SHELL	WEST DELTA
799	2/07-D-26	93.05.07	93.06.09	PHILLIPS	MÆRSK GUARDIAN
808	30/06-C-20 B	93.05.07	93.07.27	HYDRO	OSEBERG C
805	25/04-A-12	93.05.09	93.11.18	ELF	HEIMDAL
793	2/04-A-11 A	93.05.10	93.06.27	PHILLIPS	EKOFISK A
813	25/05-A-01	93.05.16	93.07.14	ELF	TREASURE SAGA
815	2/01-A-18	93.05.22	93.09.17	BP	GYDA
811	34/10-B-27	93.05.22	93.07.01	STATOIL	GULLFAKS B
810	7/12-A-11	93.06.02	93.11.13	BP	ULA
816	6407/09-A-58 H	93.06.09	93.06.23	SHELL	DYVI STENA
801	2/07-D-21	93.06.10	93.07.17	PHILLIPS	MÆRSK GUARDIAN
809	2/08-A-24 A	93.06.10	93.07.09	AMOCO	VALHALL
812	30/06-C-21	93.06.10	93.09.23	HYDRO	OSEBERG C
814	34/07-A-09 H	93.06.15	93.08.27	SAGA	SCARABEO 5
817	34/07-P-37	93.06.20	93.08.17	SAGA	SNORRE P
795	2/07-B-09 A	93.06.21	93.09.11	PHILLIPS	ELDFISK B

Lic.no.	Dev. well	Suspended	Concluded	Operator	Field/installation
819	2/04-A-21	93.06.27	93.09.30	PHILLIPS	EKOFISK A
820	34/10-B-28	93.07.01	93.10.19	STATOIL	GULLFAKS B
821	30/09-B-05 B	93.07.03	93.07.09	HYDRO	OSEBERG B
824	33/09-M-01 H	93.07.07	93.08.13	STATOIL	TREASURE PROSPECT
822	30/09-B-05 C	93.07.10	93.08.11	HYDRO	OSEBERG B
823	25/05-A-02	93.07.14	93.10.01	ELF	TREASURE SAGA
800	2/07-D-20	93.07.18	93.09.05	PHILLIPS	MÆRSK GUARDIAN
827	2/01-A-30	93.07.22	93.11.21	BP	GYDA
829	34/07-I-05 H	93.08.03	93.10.14	SAGA	VILDKAT EXPLORER
830	15/09-A-10	93.08.05	93.09.14	STATOIL	SLEIPNER A
832	6407/09-B-01 H	93.08.09	93.08.26	SHELL	DYVI STENA
826	30/09-B-11	93.08.11	93.09.19	HYDRO	OSEBERG B
831	33/09-M-02 H	93.08.13	93.09.23	STATOIL	TREASURE PROSPECT
835	34/07-A-06 H	93.08.28	93.11.08	SAGA	SCARABEO 5
818	2/04-B-01 A	93.08.30	93.11.04	PHILLIPS	EKOFISK B
834	2/04-A-21 A	93.08.31	93.11.24	PHILLIPS	EKOFISK A
825	34/10-A-32 A	93.09.09	93.10.04	STATOIL	GULLFAKS A
838	15/09-A-06	93.09.14	93.11.05	STATOIL	SLEIPNER A
840	30/09-B-11 A	93.09.20	93.10.10	HYDRO	OSEBERG B
828	2/08-A-10 B	93.09.22		AMOCO	VALHALL
841	30/06-C-18	93.09.22	93.10.28	HYDRO	OSEBERG C
836	2/07-B-12 A	93.09.28	93.11.19	PHILLIPS	ELDFISK B
843	34/07-P-17	93.09.29		SAGA	SNORRE P
833	34/10-C-19	93.09.30	93.12.09	STATOIL	GULLFAKS C
842	25/05-A-03	93.10.01	93.12.23	ELF	TREASURE SAGA
846	30/03-A-18	93.10.03	93.11.06	STATOIL	VESLEFRIKK A
849	34/10-A-32 B	93.10.04	93.10.28	STATOIL	GULLFAKS A
852	2/08-A-01 A	93.10.09	93.11.22	AMOCO	VALHALL
848	33/09-L-03 H	93.10.10	93.11.20	STATOIL	TREASURE PROSPECT
851	30/09-B-35	93.10.11	93.12.18	HYDRO	OSEBERG B
850	33/12-B-16	93.10.13	93.11.20	STATOIL	STATFJORD B
839	34/07-I-01 H	93.10.15	93.12.25	SAGA	VILDKAT EXPLORER
854	34/10-B-29	93.10.20	93.12.09	STATOIL	GULLFAKS B
845	33/09-A-27 A	93.10.21	93.11.09	STATOIL	STATFJORD A
855	6407/09-C-02 H	93.10.24	93.11.02	SHELL	DYVI STENA
858	30/06-C-18 A	93.10.28	93.12.03	STATOIL	OSEBERG C
847	2/04-C-13 A	93.11.03		PHILLIPS	EKOFISK C
856	15/09-A-28	93.11.05		STATOIL	SLEIPNER A
859	30/03-A-19	93.11.09		STATOIL	VESLEFRIKK A
857	34/07-A-10 H	93.11.09		SAGA	SCARABEO 5
861	6407/09-C-01 H	93.11.11	93.12.15	SHELL	DYVI STENA
844	6507/07-A-29	93.11.12	93.12.13	CONOCO	TRANSOCEAN 8
863	33/12-B-16 A	93.11.20		STATOIL	STATFJORD B
865	2/01-A-30 A	93.11.21		BP	GYDA
862	33/09-L-04 H	93.11.22	93.12.15	STATOIL	TREASURE PROSPECT
853	2/04-B-21 A	93.12.02		PPCO	EKOFISK B
868	30/09-B-30	93.12.03	93.12.06	HYDRO	OSEBERG B
867	30/06-C-22	93.12.04		HYDRO	OSEBERG C
860	34/10-B-29 A	93.12.10		STATOIL	GULLFAKS B
869	6507/07-A-35	93.12.13		CONOCO	TRANSOCEAN 8
837	34/10-C-18	93.12.15		STATOIL	GULLFAKS C
875	30/09-B-48	93.12.22		HYDRO	OSEBERG B
864	25/05-A-04	93.12.23		ELF	TREASURE SAGA
877	31/04-A-23	93.12.26		HYDRO	BRAGE
871	34/07-I-03 H	93.12.26		SAGA	VILDKAT EXPLORER

Table 7.4.c
Development wells drilled from mobile drilling units

Lic.no.	Dev. well	Spudded	Concluded	Operator	Drilling unit
800	2/07-D-20	93.07.18	93.09.05	PHILLIPS	MÆRSK GUARDIAN
801	2/07-D-21	93.06.10	93.07.17	PHILLIPS	MÆRSK GUARDIAN
799	2/07-D-26	93.05.07	93.06.09	PHILLIPS	MÆRSK GUARDIAN
782	2/07-D-27	93.03.02	93.05.07	PHILLIPS	MÆRSK GUARDIAN
796	15/09-D-01 H	93.04.01	93.06.07	STATOIL	DEEPSEA BERGEN
779	15/09-D-03 H	93.03.02	93.04.01	STATOIL	DEEPSEA BERGEN
774	25/02-C-03 H	93.03.13	93.11.09	ELF	MÆRSK JUTLANDER
813	25/05-A-01	93.05.16	93.07.14	ELF	TREASURE SAGA
823	25/05-A-02	93.07.14	93.10.01	ELF	TREASURE SAGA
842	25/05-A-03	93.10.01		ELF	TREASURE SAGA
755	31/04-A-04	92.11.20	93.03.05	HYDRO	VILDKAT EXPLORER
767	31/04-A-04 A	93.03.05	93.04.21	HYDRO	VILDKAT EXPLORER
848	33/09-L-03 H	93.10.10	93.11.20	STATOIL	TREASURE PROSPECT
862	33/09-L-04 H	93.11.22		STATOIL	TREASURE PROSPECT
824	33/09-M-01 H	93.07.07	93.08.13	STATOIL	TREASURE PROSPECT
831	33/09-M-02 H	93.08.13	93.09.23	STATOIL	TREASURE PROSPECT
797	34/07-A-01 H	93.04.06	93.06.14	SAGA	SCARABEO 5
835	34/07-A-06 H	93.08.28	93.11.08	SAGA	SCARABEO 5
814	34/07-A-09 H	93.06.15	93.08.27	SAGA	SCARABEO 5
857	34/07-A-10 H	93.11.09		SAGA	SCARABEO 5
839	34/07-I-01 H	93.10.15		SAGA	VILDKAT EXPLORER
871	34/07-I-03 H	93.12.26		SAGA	VILDKAT EXPLORER
829	34/07-I-05 H	93.08.03	93.10.14	SAGA	VILDKAT EXPLORER
802	6407/09-A-53 H	93.04.05	93.11.08	SHELL	DYVI STENA
803	6407/09-A-55 H	93.04.08	93.04.26	SHELL	WEST DELTA
804	6407/09-A-55 AH	93.04.27	93.06.07	SHELL	WEST DELTA
816	6407/09-A-58 H	93.06.09	93.06.23	SHELL	DYVI STENA
832	6407/09-B-01 H	93.08.09	93.08.26	SHELL	DYVI STENA
861	6407/09-C-01 H	93.11.11		SHELL	DYVI STENA
855	6407/09-C-02 H	93.10.24	93.11.02	SHELL	DYVI STENA
844	6507/07-A-29	93.11.12		CONOCO	TRANSOCEAN 8
775	6507/07-A-33 H	93.02.10	93.03.19	CONOCO	TRANSOCEAN 8
763	6507/07-A-52 H	92.12.18	93.02.09	CONOCO	TRANSOCEAN 8
788	6507/07-A-53 H	93.03.22	93.05.16	CONOCO	TRANSOCEAN 8

7.5 PRODUCTION OF OIL AND GAS

The total production of crude oil and natural gas on the Norwegian continental shelf was 138.9 mtoe in 1993. Production in 1992 was 132.7 mtoe. Tables 7.5.a-v, which look at each producing field in turn, and Figures 7.5.a-b, which give period summaries, set out production in more detail.

The data in Table 7.5.a summarise the Norwegian shares in Statfjord, Frigg, and Murchison. In the oil figures, NGL is included for Brage, the Ekofisk area, Embla, Gullfaks, Gyda, Hod, Mime, Murchison, Sleipner, Snorre, Statfjord, Tommeliten, Ula, Valhall and Veslefrikk.

The data for gas in Table 7.5.a indicate the volumes sold in all fields. Condensate is included in the field statistics for Brage, Frigg area, Gullfaks, Heimdal, Sleipner, Snorre, Statfjord and Veslefrikk.

Fig. 7.5.a
Oil and gas production on the Norwegian shelf 1971–1993

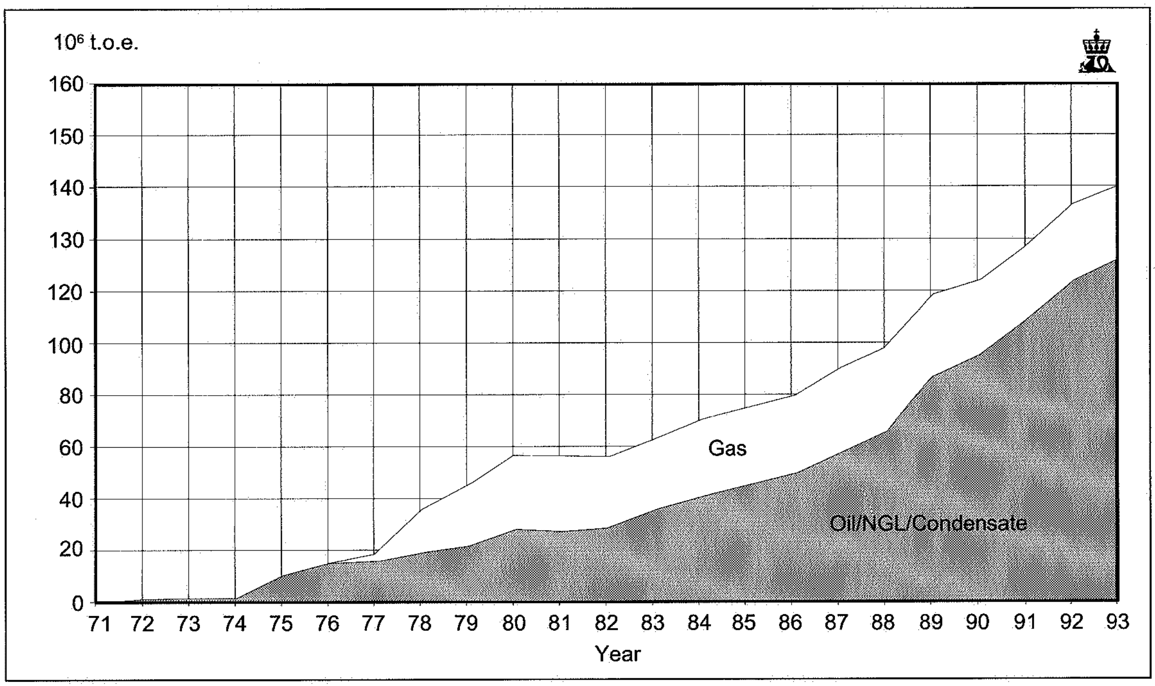


Fig. 7.5.b
Oil and gas production on the Norwegian shelf 1977–1993

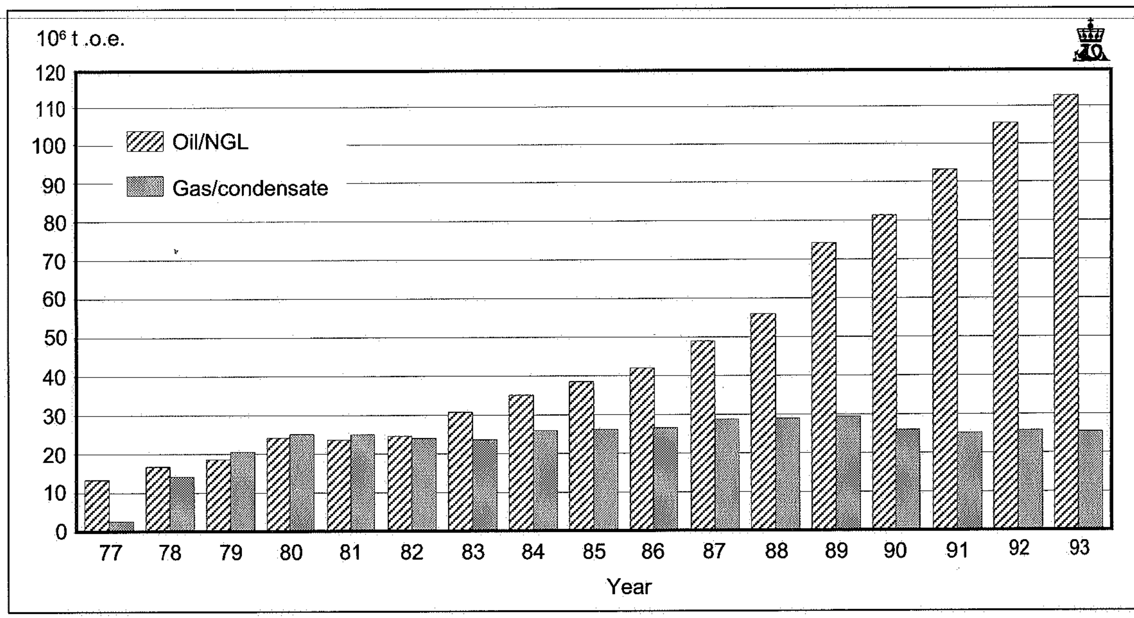


Table 7.5.a
Production in million tonnes oil equivalents (mtoe)

1993	Oil and NGL	Gas and condensate	Sum
Brage	0.899	0.025	0.924
Draugen	0.102	0.000	0.102
Ekofiskområdet	10.428	7.383	17.811
Embla	0.588	0.210	0.798
Friggområdet	0.000	4.225	4.225
30/6 Gamma Nord	0.165	0.000	0.165
Gullfaks	25.171	2.130	27.300
Gyda	3.245	0.483	3.728
Heimdal	0.000	3.905	3.905
Hod	0.740	0.204	0.944
Mime	0.055	0.014	0.069
Murchison	0.244	0.007	0.251
Oseberg	23.882	0.000	23.882
Sleipner Øst (incl. Loke)	0.159	1.160	1.319
Snorre	2.974	0.260	6.234
Statfjord	28.365	3.081	31.446
Togi	0.051	0.000	0.051
Tommeliten Gamma	0.392	1.298	1.690
Ula	6.297	0.472	6.769
Valhall	3.007	0.800	3.807
Veslefrikk	3.437	0.126	3.564
Sum 1993	113.151	25.785	138.936
Sum 1992	106.250	26.480	132.730
Sum 1991	93.124	25.639	118.763
Sum 1990	81.446	26.118	107.564
Sum 1989	74.280	29.364	103.644
Sum 1988	56.001	29.023	85.024
Sum 1987	49.016	28.797	77.813
Sum 1986	42.052	26.561	68.613
Sum 1985	38.479	26.276	64.755

Table 7.5.b
Monthly oil and gas production allocated to Ekofisk fields

1993	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Teesside	NGL Teeside	Gas Emden
	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3	10^3 Sm^3	10^6 Sm^3
JAN	1111	851	0.7	95	1003	107	744
FEB	989	750	0.3	85	899	97	661
MAR	1104	834	0.5	94	977	107	735
APR	1077	815	0.5	92	982	102	662
MAY	1115	835	2.5	94	1014	106	662
JUN	1055	789	0.6	83	962	100	581
JUL	1096	820	0.7	90	992	105	478
AUG	1070	803	0.6	81	965	103	515
SEP	1065	783	1.0	89	968	102	503
OCT	1139	842	2.3	99	1035	105	587
NOV	1107	805	1.1	98	1021	105	603
DEC	1217	858	1.3	101	1113	110	650
YEAR TOTAL	13145	9785	11.9	1101	11951	1249	7381

Table 7.5.c
Monthly gas and condensate production from the Frigg area

1993	Gas prod	Condensate prod	Gas flared	Gas fuel	Gas St.Fergus	Condensate St.Fergus
	10^6 Sm^3	10^3 Sm^3	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3
JAN	521	1	54	6	521	3
FEB	470	1	47	6	463	2
MAR	438	1	62	7	431	2
APR	405	1	56	6	398	4
MAY	459	2	82	6	454	2
JUN	108	0,3	156	2	102	1
JUL	289	1	104	6	286	3
AUG	233	1	62	5	229	2
SEP	266	1	80	8	257	2
OCT	345	1	45	8	342	2
NOV	355	1	57	7	359	1
DEC	364	1	48	8	363	2
ÅRSSUM	4253	12,3	853	75	4205	26

Figures are for the Norwegian share of Frigg 60.82 %, NØ-Frigg, Odin and Øst-Frigg 100 %. Sale from Lille-Frigg from Oct. 1993.

Table 7.5.d
Monthly oil and gas production from 30/6 Gamma Nord

1993	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Sture
	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3
JAN	19	44	0.0	0.1	18
FEB	19	47	0.0	0.1	18
MAR	21	53	0.0	0.1	20
APR	20	54	0.0	0.1	19
MAY	21	58	0.2	0.2	20
JUN	17	45	0.0	0.1	16
JUL	19	54	0.2	0.1	18
AUG	14	37	0.1	0.1	13
SEP	19	52	0.0	0.1	17
OCT	14	38	0.0	0.1	13
NOV	16	48	0.0	0.1	15
DEC	11	27	0.0	0.1	10
YEAR TOTAL	210	557	0.5	1.3	197

Table 7.5.e
Monthly oil and gas production from Gullfaks

1993	Stabilized oil prod	Gas prod	Gas flared	Gas fuel	NGL/cond Kårstø	Gas Emden
	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3	10^6 Sm^3
JAN	2179	232	5	27	19	135
FEB	1941	203	5	23	28	127
MAR	2520	261	3	27	37	166
APR	2464	260	6	27	35	172
MAY	2522	269	6	27	41	192
JUN	1617	175	17	19	16	68
JUL	2590	277	4	27	112	182
AUG	2583	285	4	26	42	199
SEP	2521	273	4	26	46	205
OCT	2610	278	4	26	44	218
NOV	2566	267	4	25	36	205
DEC	2563	266	6	25	39	200
YEAR TOTAL	28676	3046	68	305	495	2069

Table 7.5.f
Monthly oil and production from Gyda

1993	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Teesside	NGL Teesside	Gas Emden
	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3	10^3 Sm^3	10^6 Sm^3
JAN	326	48	1.0	4	304	33	40
FEB	293	43	0.2	3	273	30	36
MAR	328	48	0.1	4	305	34	40
APR	319	46	0.2	3	296	32	39
MAY	343	49	0.1	4	320	35	42
JUN	350	49	0.7	3	327	35	41
JUL	360	51	0.4	3	335	36	44
AUG	336	48	0.2	3	312	34	40
SEP	317	46	0.2	3	296	32	39
OCT	358	52	0.1	4	335	36	44
NOV	326	47	0.1	4	305	34	39
DEC	323	46	0.1	4	301	33	38
YEAR TOTAL	3979	573	3.4	42	3709	404	482

Table 7.5.g
Monthly gas and condensate production from Heimdal

1993	Gas prod	Condensate prod	Gas flared	Gas fuel	Gas sold	Condensate Kinneil
	10^6 Sm^3	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3
JAN	307	50	0.0	4	339	47
FEB	257	41	0.2	4	299	37
MAR	199	32	0.0	4	260	15
APR	252	41	0.0	4	249	32
MAY	308	50	0.0	5	270	46
JUN	310	50	0.0	5	297	48
JUL	229	37	0.1	4	222	38
AUG	173	28	0.2	2	164	18
SEP	352	56	0.0	5	336	51
OCT	350	56	0.0	5	355	50
NOV	368	59	0.0	5	369	54
DEC	348	56	0.0	4	345	50
YEAR TOTAL	3453	556	0.6	51	3505	486

Table 7.5.h
Monthly oil and gas production from Hod

1993	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Teesside	NGL Teesside	Gas Emden
	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3	10^3 Sm^3	10^6 Sm^3
JAN	93	25	0.1	2	88	5	23
FEB	79	19	0.2	1	75	5	19
MAR	85	19	0.2	1	81	5	19
APR	75	18	0.1	1	71	5	18
MAY	72	16	0.1	1	68	4	16
JUN	77	16	0.4	1	73	4	16
JUL	78	19	0.0	1	74	4	18
AUG	75	18	0.1	1	72	4	17
SEP	68	15	0.1	1	65	4	14
OCT	72	16	0.1	1	69	4	15
NOV	69	14	0.1	1	66	4	14
DEC	68	17	0.0	1	65	4	16
YEAR TOTAL	911	212	1.5	13	867	52	205

Table 7.5.i
Monthly oil and gas production from Mime

1993	Unstabilized oil prod	Gas prod	Stabilized oil Teesside	NGL Teesside	Gas Emden
	10^3 Sm^3	10^6 Sm^3	10^3 Sm^3	10^3 Sm^3	10^6 Sm^3
JAN	9	2	8	1	2
FEB	8	2	7	0	2
MAR	2	0	2	0	0
APR	6	1	5	0	1
MAY	9	2	8	1	2
JUN	7	1	6	0	1
JUL	8	2	8	0	2
AUG	8	2	7	0	2
SEP	6	1	6	0	1
OCT	5	1	5	0	1
NOV	1	0	1	0	0
DEC	0	0	0	0	0
YEAR TOTAL	69	14	63	2	14

Table 7.5.j
Monthly oil and gas production from Murchison

1993	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Sullom Voe	NGL S.Voe/St.Fer	Gas St.Fergus
	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3	10^3 Sm^3	10^6 Sm^3
JAN	31	4	0.2	1.4	28	1	0
FEB	26	4	0.3	1.2	24	1	0
MAR	24	4	0.3	1.3	22	1	0
APR	23	4	0.4	1.3	21	0	0
MAY	24	4	0.4	1.2	22	0	2
JUN	11	2	0.6	0.2	11	0	0
JUL	30	5	0.8	1.0	28	1	1
AUG	34	4	0.1	1.3	31	1	1
SEP	29	4	0.2	1.3	26	1	1
OCT	29	4	0.3	1.3	27	1	1
NOV	25	4	0.2	1.0	23	1	1
DEC	27	4	0.4	1.1	26	1	1
YEAR TOTAL	313	47	4.2	13.6	289	9	8

These figures are for the Norwegian share of Murchison.

Table 7.5.k
Monthly oil and gas production from Oseberg

1993	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Sture
	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3
JAN	2247	301	2	19	2238
FEB	2085	275	1	16	2073
MAR	2397	321	1	19	2387
APR	2359	313	1	19	2351
MAY	2433	324	3	20	2421
JUN	2108	286	4	16	2101
JUL	2474	333	2	20	2461
AUG	2481	334	1	20	2467
SEP	2409	324	1	21	2401
OCT	2489	351	2	22	2478
NOV	2407	325	1	21	2396
DEC	2502	354	2	19	2494
YEAR TOTAL	28391	3841	21	232	28268

Table 7.5.l
Monthly oil and gas production from Snorre

1993	Oil prod. unstab.	Gas prod	Gas flared	Gas fuel	Gas sale	Stabilized oil prod	NGL/cond Kårstø
	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3	10^3 Sm^3
JAN	370	33	4	2	0	366	15
FEB	440	41	1	3	0	433	28
MAR	611	56	1	4	0	600	44
APR	652	63	1	4	0	639	48
MAY	580	54	2	4	0	567	43
JUN	497	47	3	4	0	485	17
JUL	682	68	16	4	0	667	52
AUG	778	78	12	5	46	763	63
SEP	288	30	4	1	17	287	24
OCT	725	70	1	4	50	711	55
NOV	740	78	4	5	53	732	56
DEC	665	70	3	4	50	660	50
YEAR TOTAL	7028	688	52	44	216	6910	495

Table 7.5.m
Monthly oil and gas production from Statfjord

1993	Stabilized oil prod	Gas prod	Gas flared	Gas fuel	NGL/cond Kårstø	Gas Sale
	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3	10^6 Sm^3
JAN	2343	529	6	31	86	278
FEB	2549	541	6	32	131	250
MAR	3176	656	6	38	155	308
APR	3006	646	6	35	113	217
MAY	2811	595	7	32	106	189
JUN	2694	549	8	31	61	120
JUL	3119	668	9	36	84	207
AUG	2527	534	8	30	71	180
SEP	2400	529	5	30	144	276
OCT	3004	654	7	39	134	313
NOV	2870	640	6	38	135	314
DEC	2806	630	6	37	137	309
YEAR TOTAL	33305	7171	80	409	1357	2961

These figures are for the Norwegian share of Statfjord.

Table 7.5.n
Monthly oil and gas production from Tommeliten Gamma

1993	Unstabilized oil prod	Gas prod	Stabilized oil Teesside	NGL Teesside	Gas Emden
	10^3 Sm^3	10^6 Sm^3	10^3 Sm^3	10^3 Sm^3	10^6 Sm^3
JAN	48	114	34	11	105
FEB	47	111	33	11	103
MAR	50	117	34	12	108
APR	50	115	35	11	106
MAY	56	133	38	14	123
JUN	52	129	36	13	119
JUL	49	119	33	12	110
AUG	40	95	27	9	89
SEP	45	110	31	11	102
OCT	48	122	32	12	113
NOV	47	119	31	12	109
DEC	48	121	32	12	111
YEAR TOTAL	580	1405	396	140	1298

Table 7.5.o
Monthly oil and gas production from TOGI

1993	Gas prod	Condensate prod	Gas flared	Gas fuel	Stabilized oil Sture
	10^6 Sm^3	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3
JAN	293	6	0.1	4	5
FEB	277	6	0.0	4	5
MAR	240	5	0.3	4	4
APR	284	6	0.0	4	6
MAY	283	6	0.5	4	5
JUN	206	5	0.0	3	4
JUL	379	7	0.0	4	6
AUG	322	7	0.1	4	6
SEP	344	6	0.0	4	5
OCT	354	7	0.0	4	6
NOV	322	6	0.0	4	5
DEC	85	2	0.0	1	1
YEAR TOTAL	3389	69	1.0	44	58

Table 7.5.p
Monthly oil and gas production from Ula

1993	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Teesside	NGL Teesside	Gas Emden
	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3	10^3 Sm^3	10^6 Sm^3
JAN	623	49	0.3	6	595	43	38
FEB	548	44	0.3	5	527	37	34
MAR	657	51	0.3	7	629	46	39
APR	693	55	0.3	6	661	48	42
MAY	737	59	0.3	6	706	51	46
JUN	682	54	0.5	6	655	46	42
JUL	669	54	0.2	7	640	45	42
AUG	557	45	0.3	5	534	37	35
SEP	579	47	0.3	6	557	39	36
OCT	675	55	0.6	6	651	44	42
NOV	606	49	0.7	6	584	41	37
DEC	632	51	0.5	6	605	42	39
YEAR TOTAL	7658	613	4.6	72	7344	519	472

Table 7.5.q
Monthly oil and gas production from Valhall

1993	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Teesside	NGL Teesside	Gas Emden
	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3	10^3 Sm^3	10^6 Sm^3
JAN	359	82	0.3	5	341	19	79
FEB	317	72	0.6	5	302	17	69
MAR	369	84	0.7	5	352	19	80
APR	321	74	0.4	5	307	16	70
MAY	321	75	0.3	5	307	16	72
JUN	302	70	1.6	5	288	16	65
JUL	305	71	0.2	5	291	17	68
AUG	307	71	0.2	5	294	16	68
SEP	245	54	0.4	5	236	12	50
OCT	288	64	0.3	5	277	14	60
NOV	274	62	0.6	5	263	14	58
DEC	290	66	0.2	5	277	15	61
YEAR TOTAL	3698	845	5.7	60	3535	191	800

Table 7.5.r
Monthly oil and gas production from Veslefrikk

1993	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	NGL/cond Kårstø	Gas sale	Stabilized oil Sture
	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3	10^6 Sm^3	10^3 Sm^3
JAN	344	42	2	3	14	0	346
FEB	317	38	2	3	20	0	318
MAR	372	45	1	4	24	0	375
APR	336	41	0	4	22	0	336
MAY	334	40	1	4	21	0	335
JUN	182	22	2	2	12	0	184
JUL	310	38	0	4	18	0	310
AUG	360	44	1	4	22	33	363
SEP	326	40	1	4	21	26	327
OCT	355	43	1	4	19	16	358
NOV	314	38	2	4	17	15	316
DEC	361	43	1	4	20	27	363
YEAR TOTAL	3911	474	14	44	230	117	3931

Table 7.5.s
Monthly oil and gas production from Brage

1993	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	NGL/cond Kårstø	Gas sale	Stabilized oil Sture
	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3	10^6 Sm^3	10^3 Sm^3
JAN							
FEB							
MAR							
APR							
MAY							
JUN							
JUL							
AUG							
SEP	31	2	1	0	0	0	24
OCT	232	12	1	2	5	3	230
NOV	374	21	1	3	12	7	372
DEC	421	26	1	3	14	14	419
YEAR TOTAL	1058	61	4	8	30	24	1045

Table 7.5.t
Monthly oil and gas production from Embla

1993	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	NGL Teesside	Gas sale	Stabilized oil Teesside
	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3	10^6 Sm^3	10^3 Sm^3
JAN							
FEB							
MAR							
APR							
MAY	18	7	1	0	1	5	17
JUN	29	9	2	0	2	7	29
JUL	51	16	0	0	3	15	49
AUG	87	28	0	0	5	26	83
SEP	128	41	0	0	8	38	122
OCT	137	43	0	0	8	40	131
NOV	129	41	0	0	8	38	123
DEC	141	44	0	0	9	41	134
YEAR TOTAL	720	229	3	0	44	210	688

Table 7.5.u
Monthly oil and gas production from Draugen

1993	Stabilized oil prod	Gas prod	Gas flared	Gas fuel
	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3
JAN				
FEB				
MAR				
APR				
MAY				
JUN				
JUL				
AUG				
SEP				
OCT	19	1	1	0
NOV	77	4	4	0
DEC	27	1	1	0
YEAR TOTAL	123	6	6	0

Table 7.5.v
Monthly gas and condensate production from Sleipner Øst (incl. Loke)

1993	Condensate prod	Gas prod	Gas flared	Gas fuel	NGL/Cond. Kårstø	Gas Sale
	10^3 Sm^3	10^6 Sm^3	10^6 Sm^3	10^6 Sm^3	10^3 Sm^3	10^6 Sm^3
JAN						
FEB						
MAR						
APR						
MAY						
JUN						
JUL						
AUG	4	8	7	1		
SEP	83	108	27	6	34	77
OCT	192	212	9	7	207	202
NOV	250	274	7	8	264	249
DEC	298	320	5	10	313	306
YEAR TOTAL	827	922	55	32	819	834

7.6 NPD PUBLICATIONS IN 1993

Acts, regulations and guidelines

- *Acts, Regulations and Provisions* for the Petroleum Activity 1993. A compendium of the laws etc applying to the offshore industry issued each year and up to date on 1 January 1993. Published in two volumes. English and Norwegian text.
- Regulations for *Measurement of Fuel and Flare Gas for Calculation of Carbon Dioxide Tax* in the Petroleum Activities, with Guidelines. English and Norwegian text.
- Regulations for *Fiscal Measurement of Oil and Gas etc* in the Petroleum Activities, with Guidelines. English and Norwegian text.
- *Grenseflater til sokkellovgivningen.* Common Borders with the Continental Shelf Legislation. Norwegian text.

Studies and reports

- *Nød- og beredskapstrening for dykkepersonell.* Emergency and Rescue Training for Diving Personnel. Norwegian text.
- *Menneske-maskinforhold i kontrollrom for bemannede undervannsoperasjoner i petroleumsvirksomhet.* Man-Machine Factors in Control Room for Manned Subsea Operations in Petroleum Activity. An analysis of ergonomic factors. Norwegian text.
- *Menneske-maskinforhold i kontrollrom.* Man-Machine Factors in Control Room. An analysis of ergonomic factors. Norwegian text.

Other publications

- *Well Data Summary Sheets.* Volume 18, Wells completed 1987. English text.
- NPD Contribution no. 34. *En multidisiplinært, stratigrafisk studie av neogene sedimenter i sentrale deler av Nordsjøen (Ekofiskfeltet).* A multidisciplinary, stratigraphic study of Neogene sediments in central areas of the North Sea (Ekofisk field). Norwegian text.
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7.7 ORGANISATION CHART