Norwegian Petroleum Directorate

ANNUAL REPORT 1998

The Norwegian Petroleum Directorate shall provide for a highest possible creation of value and contribute to a safe conduct of the petroleum activities and a sound exploitation of the resources, while having due consideration for the environment.

The Norwegian Petroleum Directorate was established in 1972 and has approximately 350 positions. The Norwegian Petroleum Directorate answers to the Ministry of Petroleum and Energy with regard to resource management and administrative matters, and to the Ministry of Local Government and Regional Development for matters relating to safety and working environment. Within the area of CO_2 tax, the Norwegian Petroleum Directorate exercises authority on behalf of the Ministry of Finance.

The most important tasks of the Norwegian Petroleum Directorate are to have the best possible knowledge concerning discovered and undiscovered petroleum resources on the Norwegian continental shelf, to carry out supervision to ensure that the licensees manage the resources in an efficient and prudent manner and to supervise regulatory compliance so that a responsible safety level and working environment are established, maintained and further developed. The Norwegian Petroleum Directorate also has an important role with regard to influencing the industry to develop solutions which serve the best interests of society as a whole.

The Norwegian Petroleum Directorate provides advice to supervising ministries and has been delegated the authority to issue regulations and make decisions regarding consents, orders, deviations and approvals pursuant to the regulations.

Through its activities, the Norwegian Petroleum Directorate shall contribute towards making Norway a leader in environmental issues.

The Norwegian Petroleum Directorate shall also provide neutral information concerning the petroleum activities to the industry, the media and to society at large.

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Preface

Resource growth and production

The total resource growth in fields and discoveries on the Norwegian shelf in 1998 has been estimated to be approximately 287 million Sm^3 o.e., divided between 92 million Sm^3 liquid (oil, NGL and condensate), and approximately 196 billion Sm^3 gas. The resource growth as a consequence of new discoveries in 1998 is presumed to amount to 45-75 million Sm^3 oil (including NGL and condensate) and approximately 45-85 billion Sm^3 gas. Of these volumes, only the 6507/5-1 discovery of 34 million Sm^3 oil and 34 billion Sm^3 gas has been recorded under new discoveries, Resource Class 7. The other discoveries are still in an early evaluation phase, and have therefore not yet been recorded under new discoveries. In technical accounting terms, these volumes are still in the undiscovered resources group.

New estimates show a reduced potential for resources from potential future measures for increased recovery of about 100 million Sm^3 o.e. At the same time, the estimated average rate of recovery for the oil resources in oil fields in production and under development has increased from approximately 43 per cent in 1997 to approximately 44 per cent in 1998. A new review of the undiscovered resources has been made during 1998. The estimate has been changed, mainly on the basis of a review of the areas in the Barents Sea and confirmation of new exploration play models in the Vøring Basin. The estimate for undiscovered resources is now approximately 1.4 billion Sm^3 oil and 2.3 billion Sm^3 gas, or a total of 3.7 billion Sm^3 o.e. This is an increase of about 200 million Sm^3 o.e. since last year. This means that the total recoverable resources have been adjusted upwards by 400 million Sm^3 o.e. and are now 13.2 billion Sm^3 o.e., divided between approximately 6.5 billion Sm^3 o.e. oil/NGL and approximately 6.7 million Sm^3 o.e. gas.

In 1998, approximately 169 million Sm^3 oil (2.91 million barrels per day), approximately 8 million tonnes NGL/condensate and approximately 43 billion Sm^3 gas were produced for export. Gross gas production, including gas for injection, fuel, etc., amounted to approximately 73 billion Sm^3. The production of oil and NGL/condensate in 1998 was approximately 8 million Sm^3 o.e. lower than in the previous year. The most important causes of this were the production regulation resulting in a 3 per cent cut which was implemented from and including the month of May, delayed production start for new fields, technical problems on the installations and well problems.

Increased recovery

During 1998, the Norwegian Petroleum Directorate continued its focus on the challenges connected with measures to increase recovery. In particular, extended use of gas injection was evaluated and viewed in context with overall gas management on the shelf. A study of thin and marginal oil zones on the shelf showed that efforts in the years to come should primarily be aimed at Troll, Sleipner Vest, 7121/4-1 Snøhvit and 6407/1-3 Tyrihans Nord.

The industry cooperation forum FORCE had yet another active year, and agreement was reached in 1998 to continue FORCE until the end of 2001. A number of seminars were arranged under the direction of the forum regarding topics related to increased recovery. These seminars were of high technical quality, and were very well attended. Several new cooperation projects have been started during the year. The Norwegian Petroleum Directorate believes that these are important measures in order to realize even more of the identified recovery potential for oil. As of 31 December 1998, this has been estimated at 670 million Sm^3 oil.

In 1997, the Norwegian Petroleum Directorate awarded its IOR prize for the first time. The prize went to the Troll-Oil project with Norsk Hydro as operator, in recognition of courage and innovation in connection with increasing recovery from the thin oil zones on the Troll field. It is the intention of the Norwegian Petroleum Directorate that the prize will be awarded annually, if there are worthy candidates.

Development

The Norwegian Petroleum Directorate has considered the plans for development and operation of Snorre B Phase II, Gullfaks Satellites Phase II, Brage, Yme Beta Vest, as well as a supplement to the PDO for well group T in the Troll Vest gas province.

The plan for installation and operation of the Jotun gas pipeline has also been considered.

As a result of the somewhat extensive development plans that were submitted from the autumn of 1995 and up to the spring of 1997, activities in the industry reached a historic high in 1998. This led the Ministry of Petroleum and Energy to see a need for adjusting the timing of starting new projects. As regards the Norwegian Petroleum Directorate, the focus has been on consolidating and supplementing the decisions that have been made in order to meet the strong increase in gas deliveries to the Continent. Therefore, the spotlight has been aimed at taking care of the injection needs on the shelf so that the overall oil and gas resources can be exploited in the best possible manner. This challenge has been reinforced by falling oil prices throughout the year.

The work of paving the way for further development of time-critical discoveries and exploitation of existing infrastructure has been followed up through consideration of the plans submitted, and through announcement of blocks in the North Sea Round.

New discoveries

A total of eight discoveries were made on the Norwegian shelf during 1998, two in the Norwegian Sea and six in the North Sea. 32 exploration wells were completed during the course of the year: 21 wildcat wells (of which one well failed and was completed before it reached its target) and 11 appraisal wells.

Exploration for oil and gas in the deep-water areas in the Norwegian Sea continued in 1998. Four exploration wells were drilled in these areas. Three of the wells were dry. BP, as operator of well 6305/7-1, proved substantial gas resources in the southern part of the Ormen Lange dome. The Norwegian Petroleum Directorate regards this well as an appraisal of the deposit discovered by Norsk Hydro in 1997. The resource estimate for this structure is 315 billion Sm^3 gas. This is a clear increase compared with last year's estimate, which was 100 billion Sm^3.

Amoco, as operator of well 6507/5-1, made a significant oil and gas discovery on the Dønn terrace. The discovery has been named Skarv. Saga, as operator of well 6406/2-6, made a discovery of gas and condensate southwest of the Åsgard field. There is great uncertainty as to the size of this discovery, and further exploration drilling is necessary before the size can be established.

In the North Sea, Norsk Hydro proved oil southwest of the Heimdal field as operator of well 24/6-2. The company also made an interesting discovery in well 30/9-19 close by the Oseberg field. In other respects, the discoveries in the North Sea are small, however, there is still a possibility that some of these discoveries may provide good economy because they are located close to existing infrastructure.

Environment

The increasing attention surrounding environmental issues and the Directorate's responsibility and tasks in the area of the environment have become more visible through paramount goals and activity plans.

Prognoses for emissions of CO_2, NO_x, NMVOC, CH_4 and CFC have been prepared. The prognoses mainly show a certain decline in the expected emissions in the years to come. This is due both to delayed production and an expectation of somewhat less emissions for each unit produced.

In 1998, CO_2 emissions from activities subject to the CO_2 tax were about 8.3 million tonnes, which is equivalent to a reduction of about 1 per cent compared with 1997. The CO_2 emissions per produced unit increased by approximately 1.4 per cent.

A gratifying development trend is that the industry is now using a greater degree of new and environmentally friendly technology in connection with new development plans. At the same time, work is being done by several of the oil companies to map potential measures for reducing emissions on both new and older installations. A lot of work is also being done under the direction of MILJØSOK Phase II in order to develop and implement a cost-effective environmental strategy. The Norwegian Petroleum Directorate places emphasis on good cooperation and active participation in the MILJØSOK context. The Norwegian Petroleum Directorate has focused on the industry developing efficient and environmentally friendly solutions that simultaneously ensure good use of resources and creation of value.

The fields' final phase

Some of the larger fields on the Norwegian shelf are now approaching the time for cessation of production. Factors such as oil price, tariffs and remaining resources may have significance for the final shutdown date. The Norwegian Petroleum Directorate places special emphasis on ensuring that the remaining resources are produced to the greatest degree possible prior to shutdown.

The Norwegian Petroleum Directorate has undertaken an evaluation in connection with the recovery potential and timing of cessation for Gyda and Ula, and has made a recommendation for changes in the existing agreements. The cessation plan for Albuskjell has been processed. The Norwegian Petroleum Directorate is concerned with ensuring that the installations that are removed from production are disposed of in a way that is in accordance with national and international framework conditions.

Data management

In a situation where the amount of information is increasing and information technology is developing at a rapid pace, it is crucial for the effectiveness of the oil industry that new technology is put into use. The Norwegian Petroleum Directorate is still the project manager for the DISKOS project, which is a common data solution for 17 oil companies. Emphasis has been placed on reducing unnecessary reporting to the authorities. At the same time, the Norwegian Petroleum Directorate expends considerable resources on improving the quality of the data that has already been reported. This is in order to ensure that data which is incorporated in the Norwegian Petroleum Directorate's many reports, analyses and prognoses, is of the best quality possible. The Directorate also places great emphasis on ensuring that data which is no longer subject to confidentiality is made available to the industry in an efficient manner. The Norwegian Petroleum Directorate has participated in various industry initiatives for standardization of data models and use of terminology. The Petroleum Register, which is now the responsibility of the Norwegian Petroleum Directorate, is kept up-to-date with regard to both software tools and data content. The Norwegian Petroleum Directorate has also been among the initiators for establishing the industry network SOIL.

Accidents and events

Once again, there were no fatal accidents within the Norwegian Petroleum Directorate's sphere of responsibility in the petroleum activities in 1998, nor were there any accidents that led to serious damage to the environment or significant material loss or interruption of production. The absence of major accidents does not, however, mean that the activities are without risk. Because major accidents seldom occur, other indicators must be used in order to assess the overall risk level. On the basis of an overall evaluation, the Norwegian Petroleum Directorate believes that the risk level has been on the decline in recent years.

The frequency of accidents involving personal injury has stayed at about the same level in recent years. Even though the Directorate does not regard the injury rate in the petroleum activities as a whole to be particularly high, it still believes that the injury frequency must be reduced further.

For the first time in several years, the number of gas leaks has shown a decline, which may indicate that the efforts in this area are beginning to have an effect. The number of fires and near-fires is approximately constant, but relatively few of these are regarded as being serious.

The number of notifications of work-related diseases has continued to increase in 1998, but the Directorate has reason to believe that this is related to improved reporting of such diseases. It is still assumed that underreporting exists. In addition to the suffering experienced by the individual, work-related diseases cost the companies and society enormous amounts of money. Therefore, it is important that the companies contribute to a better foundation for prioritization of efforts in this area through good reporting.

The Directorate registers, investigates and follows up accidents, injuries and events, and uses the results as an important part of the basis for prioritizing measures. These priorities provide guidelines for the supervision, regulatory work, information activities and further development of the Directorate's own expertise.

Safety and working environment challenges

Experience gained from supervision shows that the petroleum activities on the whole take place within prudent frameworks and largely in accordance with regulatory requirements for safety and working environment.

The companies' efforts to reduce the cost level in the activities was further reinforced as a consequence of the decline in oil prices during 1998. The supervision has shown that, in the organizational change processes that are underway, the companies often place such strong focus on the financial goals that important preconditions for prudent operations are not adequately illuminated and safeguarded.

As a consequence of this and other factors, the Directorate fears that the positive development in safety and working environment during recent years may be in the process of turning. A consultant's report prepared on behalf of the Directorate and several operating companies concludes that a higher risk level may be expected in the years to come. The Directorate believes that a main challenge in the future will be to look after the management task in the area of safety and working environment in a manner than can restrain a development in an undesirable direction.

Regulatory development

In 1998, the Norwegian Petroleum Directorate continued work on a further simplification and clarification of the regulations. In the new regulations, which are scheduled to come into force in the year 2000, the number of topical regulations will be reduced from the current 14 to four, within the areas of management, operation, technology and documentation.

The regulatory reform does not have the objective of tightening the technical requirements placed on the activities, but will continue the current regulation within the frame of a new regulatory structure. The change will make the regulations more accessible and will provide the supervision authorities with more comprehensive and effective management instruments. In addition, the objective is to provide for greater use of recognized industry standards, as well as to improve the predictability in connection with application of the regulations vis-à-vis mobile installations.

As a step in the work to transfer as much as possible of the Norwegian Petroleum Directorate's guidelines to industry standards, the Directorate has also participated actively in 1998 in international and national standardization work with relevance for safety and the working environment in the petroleum activities. Once again, the Norwegian Petroleum Directorate has carried out annual updates of changes to the regulations in 1998 in order to ensure that the regulations are always as appropriate as possible, and that they are adapted to national and international developments.

In 1998, the Norwegian Petroleum Directorate commenced work on developing a system whereby owners of mobile installations can obtain a type of advance statement with regard to the installation's applicability in relation to the regulations on the Norwegian shelf. By adopting such a system, the Norwegian Petroleum Directorate inter alia hopes to contribute to cost-effective development and operation by preventing unnecessary costs as a result of incorrect interpretation and application of regulatory requirements.

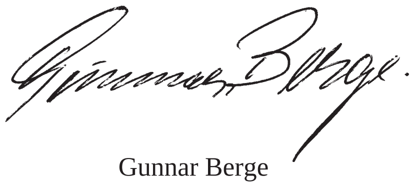
Led by the Ministry of Petroleum and Energy, work has continued in the area of resource management with regard to preparing topical guidelines for central areas under the petroleum regulations. In order to continue development of the regulations with a view towards supplementing, simplifying and making the regulations more functional, work is in progress on the preparation of a new main regulation for the resource management area. This regulation will cover all phases of the petroleum activities, and will continue the phase by phase division that applies in the Petroleum Act and the petroleum regulations.

International cooperation

As in previous years, the Norwegian Petroleum Directorate has had significant international involvement in 1998. There has been broad participation in international professional forums and the professional cooperation in the North Sea region has been safeguarded. In addition to the United Kingdom and Denmark, there is also now a close cooperation with the Netherlands and the Faroe Islands. The Norwegian Petroleum Directorate enjoys good cooperation with INTSOK, which has established an office in Stavanger. The cooperation with NORAD to assist developing countries within the field of petroleum management has also laid claim to a significant amount of work in 1998. Similarly, the Norwegian Petroleum Directorate has assisted PETRAD in the implementation of a number of seminars and conferences both in Norway and abroad.

There continues to be substantial interest in the Norwegian model for management of safety and working environment in offshore petroleum activities. A number of countries want to establish regulations which set clear goals for the activities through result-oriented requirements, as well as a supervision arrangement where comprehensive ideas, coordination on the part of the authorities and cooperation on the part of the parties involved are key elements. These countries have asked for the Norwegian Petroleum Directorate's assistance in the work on development of such a management model.

Stavanger, 22 March 1999



Gunnar Berge
Director General

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1. Resource management on the Norwegian continental shelf

An efficient management of the petroleum resources which provides the highest possible creation of value for society in general, demands that the Norwegian Petroleum Directorate continuously has the best possible overview of the total resources in producing fields and in discoveries, as well as estimates of the undiscovered resources on all parts of the Norwegian shelf.

Within the area of resource management, the Norwegian Petroleum Directorate shall assist the Ministry of Petroleum and Energy with expert advice and alternative strategies in connection with exploration, development, operations and decommissioning/disposal matters. The oil industry is capital-intensive and significant personnel resources are used in order to promote individual matters. Therefore, it is important that the authorities have continuous follow-up at a high level of technical expertise, in order to ensure that the overall socio-economic consequences are properly addressed.

Activity on the Norwegian shelf increased again in 1998. Investments in approved projects and projects that are underway increased so much that, in the first quarter, the authorities decided that several new projects would have to be postponed in order to curb the demand and pressure on the economy. Trends from 1997 involving delays, cost increases and profitable supplemental investments continued. We see that the NORSOK work involving efforts to reduce costs and implement projects faster has succeeded to a great extent. However, the ambitions were even greater, so that schedules and budgets are proving to be insufficient.

A high level of activity in all countries with oil and gas reserves has also contributed to the cost pressure, and has led to greater access to oil. When the demand fails dramatically as a consequence of financial problems inter alia in Asia, this leads to a substantial decline in the price of oil. Production regulation with an approximate three per cent cut from May to December 1998 was introduced in order to adjust to the market conditions. The cut, together with delays of new projects and production problems in excess of prognoses led to lower oil production than in the previous year.

Exploration activity declined in 1998, mainly because of the lack of qualified drilling installations. Towards the end of the year, the falling oil prices also had an impact. Once again, less oil was discovered during the year, but more gas was discovered than was produced.

The management of gas resources and the balance between liquid withdrawal and gas withdrawal from the large fields received even more attention in 1998. This was also the year when some options for taking more gas from the Norwegian shelf were waived. Thus, we are now faced with challenges in connection with balancing new developments against gas deliveries and the need for gas injection, or simply leaving the gas in place in a field for somewhat longer in order to increase liquid recovery.

The work on improving prognoses continued during the past year. The activity in the industry's cooperative forum, FUN, emphasizes the importance that both the authorities and the companies place on the work to further develop all types of prognoses in connection with the petroleum activities.

In 1998, the Norwegian Petroleum Directorate continued work on streamlining the reporting from the companies, standardization of terminology concepts and data formats, as well as quality control of old data for reuse in the oil companies. This includes the DISKOS data cooperation and the internal project, SAMBA. Efforts have been made to continue the FIND cooperation for the exploration phase and FORCE for increased recovery and improved exploitation of resources in 1998.

The work on modernizing the regulations and issuing topical guidelines is continuing under the leadership of the Ministry.

In terms of resource management, 1998 has also given rise to an increased focus on environmental commitment, and the Norwegian Petroleum Directorate has contributed actively in the MILJØSOK work.

1.1 REGULATORY DEVELOPMENT

In 1998, the regulatory work within the area of resource management has primarily concentrated on further development of the regulations with a view towards supplementing, simplifying and making the regulations more functional. A new main regulation for the resource management area is being prepared. This regulation will cover all phases of the petroleum activities, and will continue the phase-by-phase division which applies to the Petroleum Act and regulations.

The schedule for the work is coordinated with the Directorate's other regulatory work, and the plan is for the new regulations to enter into force on 1 January 2001.

The work on preparation of topical guidelines for central areas under the petroleum regulations has been continued under the leadership of the Ministry of Petroleum and Energy.

The objective of the regulatory work is to develop unified and efficient regulations for resource management that contribute to good, cost-effective and cooperative interaction between the petroleum industry and the authorities.

1.2 RESOURCE ACCOUNTING

The Norwegian Petroleum Directorate's resource accounting includes an overview of both the original marketable and remaining petroleum volumes on the Norwegian continental shelf. Changes in the resource accounting are inter alia due to new discoveries or that the resource estimates for existing fields and discoveries are adjusted based on new surveys or new production technology. The remaining resources are also reduced by production. The total resource accounting for the Norwegian continental shelf is shown in Table 1.2.a.

This year, the resource accounting is reported for the first time using four products: oil, gas, condensate and NGL. The recording of the petroleum products will thus be better and more accurate. However, this does have consequences for comparing the report with previous years. Some fields now report production of other products, and we cannot see changes in the estimates for recoverable reserves for the individual products. As a transitional arrangement, we have chosen to compare the resources in the form of liquid (oil, condensate and NLG) and gas. In connection with next year's reporting, it will once again be possible to differentiate by subproducts.

The resource classification system

The Norwegian Petroleum Directorate has followed previous practice in the way the discovered resources are classified and entered into the resource accounts. The resources are divided into 12 different classes: Classes 0 to 7 are for the discovered, recoverable resources, Class 8 is for the resources from possible future measures to increase the recovery factor and Classes 9 to 11 for undiscovered resources. The classes are:

Class 0:	Reserves where production has ceased
Class 1:	Reserves in production
Class 2:	Reserves with an approved development plan
Class 3:	Resources in the late planning stages (PDO approval within 2 years)
Class 4:	Resources in the early planning stages (PDO approval within 10 years)
Class 5:	Resources which may be developed in the long term
Class 6:	Resources where development is not very likely
Class 7:	Resources in new discoveries where evaluation is not complete
Class 8:	Resources from possible future measures to increase the recovery factor (measures which are not planned, possibly exceeding present-day technology)
Class 9:	Resources in prospects
Class 10:	Resources in leads
Class 11:	Unmapped resources

Class 8 expresses the Norwegian Petroleum Directorate's goal that the average future rate of recovery on the Norwegian shelf will be 50 per cent for oil, condensate and NGL and 75 per cent for gas. The class comprises the volume of oil and gas which may be recovered from current fields and discoveries, in addition to the resources from those measures which have already been identified and registered in the ordinary resource accounts.

The main principle in the classification system is that the original recoverable reserves in a field or a discovery shall be classified according to where they are located in the development chain from when a discovery is made, or a new measure to increase the recoverable resources in a field is identified, and up to when the production of the resources is complete. The system takes into account that a field or a discovery may have resources in several classes, i.e., resources of varying maturity in the development chain.

Resources is a generic term used for all types of petroleum volumes.

Reserves comprise recoverable resources in accordance with approved plans for fields in production and for fields under development. In other words, reserves are distributed among the first three classes. Distinction can be made between original recoverable and remaining reserves.

A *deposit* is an accumulation of petroleum in a geological unit, delimited by rocks with structural or stratigraphic boundaries, contact surfaces between petroleum and water in the formation, or a combination of these, so that the petroleum concerned is in continuous pressure communication through fluid or gas.

A *discovery* is a deposit or several deposits together, which through testing, sampling or logging, has shown probable mobile petroleum.

A *field* is one or more discoveries together which the licensees have decided to develop and for which the authorities have either approved a Plan for Development and Operation (PDO), or have granted an exemption from the PDO requirement.

There is only one discovery well for each discovery and each field. This means that wildcat wells which prove resources that are or will be included in the resource figures for an existing discovery or field are not considered to be new discovery wells. The discovery year is the year the discovery well was temporarily abandoned or completed.

Undiscovered resources comprise both mapped prospects (Classes 9 and 10) and unmapped resources in areas where play models have been defined (Class 11). There is always great uncertainty connected with analyses of undiscovered resources. The size stated for undiscovered resources is the statistical expected value.

Changes in 1998

Older fields and discoveries

For older fields and discoveries (i.e., discoveries made before 1998), the oil resources, including NGL resources, have increased by 79 million Sm^3 and the gas resources by 185 billion Sm^3.

The changes are based on revisions of the resource estimates for a number of the fields and discoveries. All of the adjustments are shown in Table 7.5.e, major changes are described below. Additional details concerning resource changes for the individual fields and discoveries are provided in Chapters 1.3-1.6.

New discoveries

During 1998, discoveries were made in eight exploration wells. Evaluation of the majority of the discoveries has not yet been completed, and the preliminary estimate is that the resource growth due to new discoveries in 1998 will be between 90 and 160 million Sm^3 o.e., divided equally between oil and gas. This is not enough to replace the year's production of oil, but it does cover the year's production of gas.

Production

Recovery of petroleum on the Norwegian continental shelf in 1998 was 169 million Sm^3 of oil, 44 billion Sm^3 of gas, 5 million Sm^3 of condensate and 5 million tonnes of NGL.

Resource status

The resource accounting for the Norwegian continental shelf is presented in Table 1.2.a, and the geographical distribution of resources is shown in Figures 1.2.a and 1.2.b. The resources on the Norwegian continental shelf are divided according to the Norwegian Petroleum Directorate's resource classification system.

Fields where production has ceased

Six fields ceased producing in 1998. The number of fields on the Norwegian continental shelf where production has ceased is now nine. The resources in these fields (Resource Class 0) are shown in Table 7.5.b.

Reserves in fields which are in production or have an approved development plan

As of 31 December 1998, 56 fields on the Norwegian continental shelf have been approved for development, including the nine fields where production has ceased. Troll is considered to be one field, in spite of the fact that it consists of separate developments with different operators. Five plans for development and operation have been approved (PDO/supplement to PDO): Snorre B Phase II, Gullfaks Satellites Phase II (Rimfaks and Gullfaks Sør), Brage, Yme Beta vest, supplement to Troll C (well group T in the Troll Vest gas province).

Three new fields started production in 1998; Gullveig, Tordis Øst and Varg. At the end of the year, a total of 39 fields were producing on the Norwegian continental shelf. Eight fields have been approved for development, but have not yet started production (Table 7.5.b).

This year's reporting of resources in fields that may be subject to subsequent development, and for resources from measures to increase recovery, follows the separate reporting practice introduced in 1997 (Table 7.5.b). Comparison

Figure 1.2.a
Geographical distibution of petroleum resources on the Norwegian continental shelf

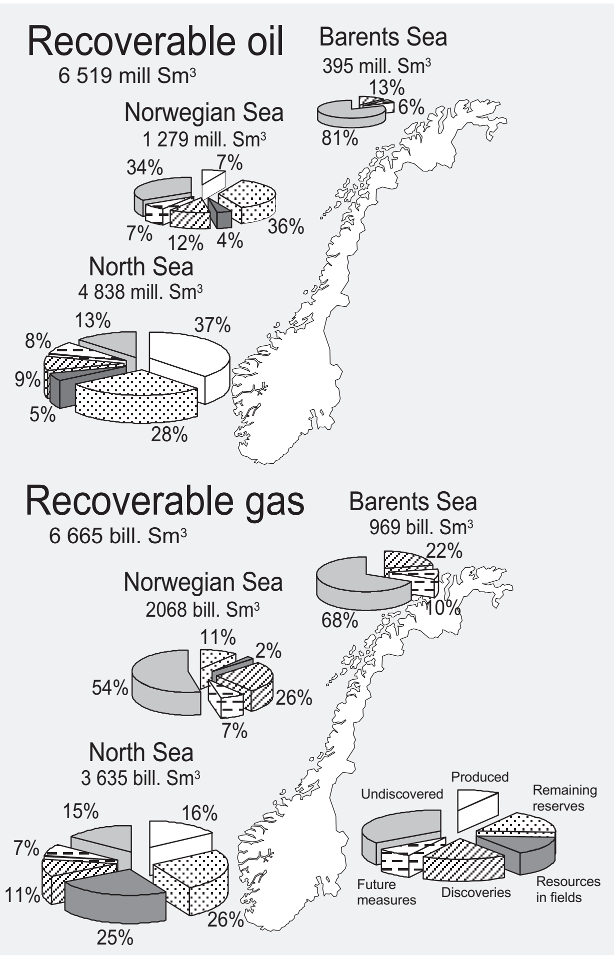
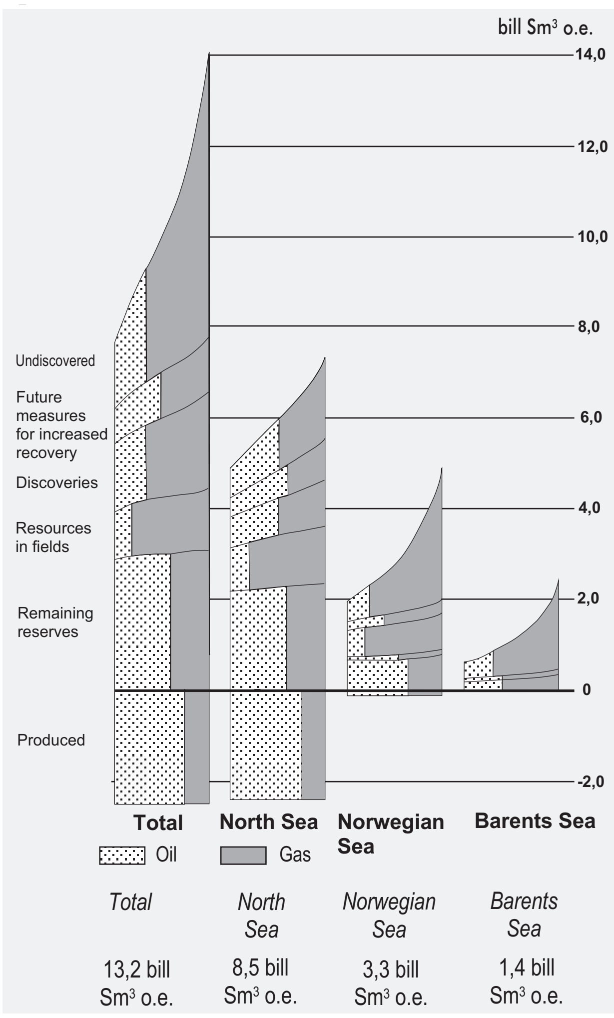


Figure 1.2.b
Geographical distribution of resources on the Norwegian continental shelf - with range of uncertainty



with the previous year is made under the categories liquid and gas (Table 7.5.e.).

The total recoverable reserves in fields approved for development are 5480 million Sm^3 o.e., divided between 3485 million Sm^3 oil, 1750 billion Sm^3 gas, 91 million Sm^3 condensate and 119 million tonnes NGL (Table 1.2.a). In addition, resources totaling 1226 million Sm^3 o.e. have been identified in the form of additional resources in fields. These are divided among 252 million Sm^3 oil, 956 billion Sm^3 gas, 2 million Sm^3 condensate and 13 million tonnes NGL.

A total of 2498 million Sm^3 o.e. has been produced, divided between 1920 million Sm^3 o.e. oil/NGL/condensate and 578 million Sm^3 o.e. gas.

Resources in discoveries in the late planning stages

As of the end of the year, there were 24 discoveries in the late planning stages (Table 7.5.c). These are discoveries which have submitted plans for development and operation for consideration by the authorities. This category also includes discoveries where the operator has indicated that a plan for development and operation will be submitted, and where it is assumed that a plan will be approved by the authorities within 2 years. The petroleum resources in these discoveries constitute a total of 753 million Sm^3 o.e.

Resources in discoveries in the early planning stages

As of the end of the year, there were seven discoveries in the early planning stages (Table 7.5.c). In other words, discoveries where it is assumed that a plan for development and operation will be approved during the course of 2-10 years. The resource volume constitutes 133.8 million Sm^3 o.e.

Resources in discoveries which may be developed in the long term

As of the end of the year, 50 discoveries (Table 7.5.c) have been identified which the Norwegian Petroleum Directorate believes may be developed over the long term, even though at the present time, many of the discoveries are not considered to be profitable by the licensees. This class also includes some discoveries in relinquished areas, which the Norwegian Petroleum Directorate nevertheless assumes will be re-awarded and developed over the long term. The registered resources amount to 381.2 million Sm^3 o.e.

Table 1.2.a
Total petroleum resources on the Norwegian continental shelf

		Oil million Sm^3	**Gas billion Sm^3**	**Cond. million Sm^3**	**NGL million tonnes**	**Total million Sm^3 o.e.**
RC	FIELD					
0	Reserves where production has ceased	32	112	0	4	149
1	Reserves in production	3015	1283	54	79	4454
2	Reserves approved for development	438	354	38	36	877
	Total Reserves	**3485**	**1750**	**91**	**119**	**5480**
	Sold up to and including 31 Dec. 1998	*1837*	*578*	*24*	*46*	*2498*
	Remaining reserves	**1648**	**1171**	**67**	**73**	**2981**
	Resources[1)]					
3	Resources in the late planning stages	177	486	2	8	675
4	Resources in the early planning stages	51	82	0.0	4	138
5	Resources that may be developed in the long term	19	388	0.0	1	408
6	Resources where development is not very likely	5	0	0,0	0	5
	Total resources in fields	**252**	**956**	**2**	**13**	**1226**
	Total recoverable resources	**3737**	**2706**	**93**	**131**	**6706**
3	Resources in the late planning stages	209	391	111	33	753
4	Resources in the early planning stages	67	53	3	8	134
5	Resources that may be developed in the long term	101	256	23	1	381
6	Resources where development is not very likely	29	55	0	1	85
7	Resources in new discoveries where evaluation is not complete	39	387	5	0,0	431
	Total discoveries	**444**	**1142**	**142.6**	**42**	**1784**
	Of which discoveries in 1998	34	34			68
	Total fields and discoveries	**4181**	**3848**	**236**	**173**	**8490**
	OTHER RESOURCES					
8	Resources from potential future measures to increase the recovery factor	500	500			1000
9-11	Undiscovered	1377	232			3695
	Total recoverable potential	**6058**	**6665**	**236**	**173**	**13184**
	Sold up to and including 31 Dec. 1998	*1837*	*578*	*24*	*46*	*2498*
	REMAINING	**4221**	**6087**	**212**	**128**	**10686**

1) Some discoveries have resources in several resource classes. The table summarizes the resources for the discoveries' lowest resource class, thereby enabling comparison of resources for discoveries provided in Table 7.5.c. The table contains the total resources and reserves in each resource class on the continental shelf divided between fields and discoveries. A number of fields and discoveries have resources in more than one resource class.

Table 1.2.b
Changes in the discovered resources

RC		Oil/NGL/Cond. million Sm^3	Gas billion Sm^3	Total million Sm^3 o.e
0	Technical change for fields where production has ceased	**36**	**73**	**109**
1-2	Reserves in fields approved before 1998	97	-31	65
3-6	Resources in connection with fields	-110	-60	-170
3-7	Resources in discoveries made before 1998	68	212	280
8	Resources from potential future measures to increase recovery rate	-130	20	-110
Total	**Total changes**	**-39**	**214**	**174**
	Produced in 1998	179	44	223
	CHANGE IN REMAINING	**-218**	**170**	**-49**

Resources in discoveries where development is not very likely

As of the end of the year, 36 discoveries have been registered for which profitable development is not expected without significant changes in technology or price (Table 7.5.c). Most of these discoveries are very small. Some have such poor reservoir properties that they cannot be produced profitably with today's technology and oil price. There is great uncertainty with regard to the resource estimate, however, the Norwegian Petroleum Directorate estimates that, technically, about 85 million Sm^3 o.e. may be produced from these discoveries.

Resources in discoveries where evaluation is not complete

As of the end of the year, 13 discoveries have been registered in this class. In addition to the eight new discoveries that were made in 1998, the class also includes five discoveries from previous years. The preliminary estimates for these discoveries total approximately 430 million Sm^3 o.e. (Table 7.5.c). This includes inter alia a preliminary increase in the resources in 6505/5-1 made by the Norwegian Petroleum Directorate. There are no official estimates for most of the discoveries made in 1998, however, the Norwegian Petroleum Directorate assumes that the total of these estimates will be about 100 million Sm^3 o.e., which will come in addition to the recorded resources. In accounting terms, this sum is still included in the undiscovered resources class.

Changes in resource estimates since the last annual report

A number of adjustments have been made to the resource and reserves estimates for fields and discoveries during 1998. The total changes are shown in Table 1.2.b. Table 7.5.e in Chapter 7.5 shows all changes from 1997 to 1998. The most important changes are discussed below:

Fields where production has ceased

Albuskjell, Cod and Øst Frigg

Minor technical changes.

Fields in production and fields approved for development

Frøy

The estimate of recoverable oil reserves has been reduced from 6.7 million Sm^3 to 5.9 million Sm^3. The reason is coordination with shutdown of the Frigg field and updated reservoir simulations.

Gyda Sør

The estimate of reserves in place and recoverable reserves for Gyda Sør has been increased as a result of new studies.

Oseberg

The reserves estimates have been increased due to new reservoir simulations.

Sleipner Vest

The reserves estimates in the oil zone have been decreased as a result of technical reservoir and geo-technical studies.

Åsgard

The reduction in oil is due to the reduction in recoverable oil from Smørbukk and the reduction in recoverable condensate from Midgard. However, Smørbukk Sør has increased its recoverable oil volume in relation to the previous report.

Heidrun

Estimates of recoverable reserves and reserves in place have been increased due to new studies.

Norne

The reserve estimate has been increased as a result of new studies.

Statfjord

The reserves estimate has been increased somewhat as a result of new studies.

Statfjord Øst

The reserves estimate has been increased somewhat as a result of a new reservoir model.

Tordis Øst
The reserves estimate has been reduced somewhat as a result of a new reservoir model.

Vigdis
The reserves estimate has increased somewhat due to a new reservoir model.

Varg
The reserves estimate has increased somewhat due to new studies.

Troll
The upward adjustment of the oil reserves is due to a new evaluation based on information and knowledge obtained through production.

Discoveries in the late planning stages

16/7-4 Sigyn
The resources have been adjusted upwards as a consequence of results from drilling in 1997.

25/11-15 Grane
The resources have been increased as a consequence of expected improved recovery.

34/11-1 Kvitebjørn
The resources have been adjusted upwards as a result of a new production strategy.

35/11-4 Fram
The resources have been adjusted upwards as a result of new studies.

6406/2-3 Kristin
The gas resources have been reduced as a consequence of a new geological model.

Discoveries in the early planning stages

35/9-1 R Gjøa
The gas resources have been reduced as a result of new studies.

Discoveries which may be developed over the long term

15/3-1 S
The change is due to new studies after the change in operator.

24/6-1 Peik
The resource estimate has been reduced as a result of new geological interpretation and a revised reservoir model.

24/9-5
The resource estimate has been reduced as a result of new studies after drilling of a well.

Name changes made in 1998

The Norwegian Petroleum Directorate has approved the following name changes in 1998:

- 16/7-4 changed its name to 16/7-4 Sigyn
- 2/12-1 Mjølner changed its name to 2/12-1 Freja

1.3 FIELDS WHERE PRODUCTION HAS CEASED

1.3.1 MIME

Production license:	070	**Block:**	7/11
Operator: Norsk Hydro Produksjon AS			
Discovery		Year:	1982
Development approved:	1992	Prod.start:	1992
		Prod.cease:	1994
Reserves, recovered:		0.4 million Sm^3 oil 0.1 billion Sm^3 gas	
Total investments (firm 1998-NOK):		NOK 0.4 billion	
Estimated disposal cost:		NOK 41 million	

Disposal
The cessation plan for Mime was approved in 1996. The installation will be brought to land for scrapping and condemnation in 1999. Disposal of the pipeline to Cod will be determined in light of the ongoing clarification program for pipelines.

1.3.2 NORDØST FRIGG

Production license:	024	**Block:**	25/1
Operator: Elf Petroleum Norge AS			
Discovery		Year:	1974
Development approved:	1980	Prod.start:	1983
		Prod.cease:	1993
Reserves, recovered:		11.6 billion Sm^3 gas 0.04 million tonnes NGL	
Total investments (firm 1998-NOK):		NOK 2.7 billion	
Disposal costs:		NOK 81 million	

Disposal
The control station and foundation on Nordøst Frigg were disconnected from the seabed and transported to land as one unit. The deck has been deposited on land and functions as a training center, the steel column is used as a breakwater in a marina for small boats, and the concrete foundation is used as an anchoring point for the breakwater.

The subsea installation has been brought ashore and scrapped.

1.3.3 ODIN

Production license:	030	**Block:**	30/7
Operator: Esso Expl & Prod Norway A/S			
Discovery		Year:	1974
Development approved:	1980	Prod.start:	1984
		Prod.cease:	1994
Reserves, recovered:		29.3 billion Sm^3 gas	
Total investments (firm 1998-NOK):		NOK 3.9 billion	
Accrued disposal costs:		NOK 101 million	

Disposal

The installations on the Odin field have been transported to land for scrapping and recycling. Disposal of the pipeline to Frigg will be determined in light of the ongoing clarification program for pipelines.

1.3.4 TOMMELITEN GAMMA

Production license: 044		**Block:** 1/9	
Operator: Den norske stats oljeselskap a.s			
Discovery:	1/9-4	Year:	1978
Development approved:	1986	Prod.start:	1988
		Prod. cease:	1998
Reserves, recovered:		3.9 million Sm^3 oil 9.2 billion Sm^3 gas 0.6 million tonnes NGL	
Total investments (firm 1998-NOK):		NOK 2.8 billion	
Operating costs 1998 incl. CO_2 tax, excl. tariffs and insurance:		NOK 11 million	

Disposal

The field produced better than expected in its last year, and the licensees are considering the possibility of resuming production at a later point in time. The installation is now shut down. The cessation plan for Tommeliten Gamma was submitted to the authorities in the summer of 1997, but no final decision has been made regarding permanent shutdown and disposal.

1.3.5 ØST FRIGG

Production licenses: 024, 026 and 112	**Blocks:** 25/1 and 25/2
Operator: Elf Petroleum Norge AS	
Discovery:	Year: 1973
Development approved: 1984	Prod.start: 1988 Prod. cease: 1997
Reserves, recovered:	9.4 billion Sm^3 gas 0.06 million Sm^3 condensate
Total investments (firm 1998-NOK):	NOK 2.6 billion
Accrued disposal costs:	NOK 113 million

Disposal

It is expected that the Storting will consider the cessation plan for Øst Frigg in the first quarter of 1999. The plan is to carry out preparations for disposal during the course of 1999.

Disposal of pipelines and cables will be determined in light of the ongoing clarification program for pipeline disposal.

1.3.6 FIELDS IN THE EKOFISK AREA WHERE PRODUCTION HAS CEASED

In connection with the start-up of operations on Ekofisk II in August 1998, the Cod, Vest Ekofisk, Albuskjell and Edda fields, as well as several installations in the Ekofisk Center itself, were shut down. The shutdown comprised a total of 14 steel installations secured to the seabed, as well as the subsea installations on Tommeliten Gamma. On Tommeliten Gamma, Albuskjell, Vest-Ekofisk and Edda, the licensees are considering the possibility of resuming production at a later point in time. See also Chapter 1.4.3 for a more detailed description of the individual fields.

1.4 FIELDS IN PRODUCTION AND FIELDS APPROVED FOR DEVELOPMENT

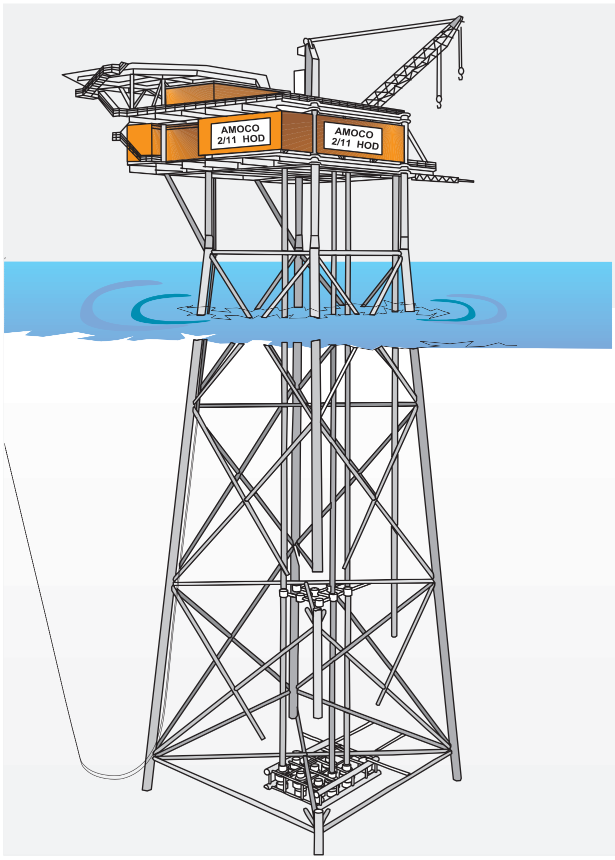
1.4.1 HOD

Production license:	033	**Block:**	2/11
Operator: Amoco Norway Oil Company			
Licensees:			
Amoco Norway Oil Company		25.00000 %	
Amerada Hess Norge AS		25.00000 %	
Enterprise Oil Norwegian AS		25.00000 %	
Elf Petroleum Norge AS		25.00000 %	
Discovery well:	2/11-2	Year:	1974
Development approved:	1988	Prod.start:	1990
Recoverable reserves:		9.3 million Sm^3 oil 1.8 billion Sm^3 gas 0.3 million tonnes NGL	
Total investments (firm 1998-NOK):		NOK 1.6 billion	
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:		NOK 56 million	

Production

The Hod field, see Figure 1.4.3.a, is the southernmost chalk field in the Norwegian part of the North Sea, and produces from reservoir zones in the Ekofisk, Tor and Hod formations. The field is divided into the three structures Hod Vest, Hod Øst and Hod Sadel. Both the western and the eastern structure were proven in 1974. Oil was proven in the Hod Sadel area in 1994.

Figure 1.4.1
Installation on Hod



The field is produced with the aid of depressurization. A total of eight wells have been drilled. Five of these wells were in production at the end of 1998.

Development

The development features an unmanned production installation, Figure 1.4.1. The installation is remote-controlled from the Valhall field, 13 kilometers to the north. Oil and gas are separated by means of a separation unit and then metered before being transported via pipeline to Valhall for further processing. Oil and gas are transported in a common pipeline to Valhall and then in the existing transportation systems to Teesside and Emden.

1.4.2 VALHALL

Production licenses: 006 and 033		**Blocks:** 2/8 and 2/11	
Operator: Amoco Norway Oil Company			
Licensees:			
Amoco Norway Oil Company		28.09377 %	
Amerada Hess Norge AS		28.09376 %	
Enterprise Oil Norwegian AS		28.09376 %	
Elf Petroleum Norge AS		15.71871 %	
Discovery well:	2/8-6	Year:	1975
Development approved:	1977	Prod.start:	1982
Recoverable reserves:		116.7 million Sm^3 oil 25.1 billion Sm^3 gas 3.9 million tonnes NGL	
Total investments (firm 1998-NOK):		NOK 21.1 billion	
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:		NOK 876 million	

Production

The Valhall field, see Figure 1.4.3.a, produces from limestone in the Ekofisk, Tor and Hod formations from the early Paleocene to the Upper Cretaceous Age. The production strategy on Valhall is based on depressurization with a high degree of compacting drive. Compacting of the reservoir rocks has led to subsidence of the seabed estimated at about 3.6 meters at the end of 1998. At the end of 1998, 40 production wells were producing on the field.

In order to increase the recovery rate of the oil, the operator is considering the possibility of starting water injection on the field. Water injection can be commenced from a new wellhead installation with 15 injectors.

Development

Valhall was originally developed with three installations, one for living quarters, one drilling and one production installation. In May 1996, a new riser platform was installed with room for 19 wells. The four installations are connected to each other by gangways. Figure 1.4.2 shows these installations.

Oil is separated from gas on Valhall by means of two separation units. The gas is compressed, dried and the dewpoint is checked. The heavier gas fractions, NGL, are separated on Valhall using a fractionating tower and are then mainly transported in the oil stream.

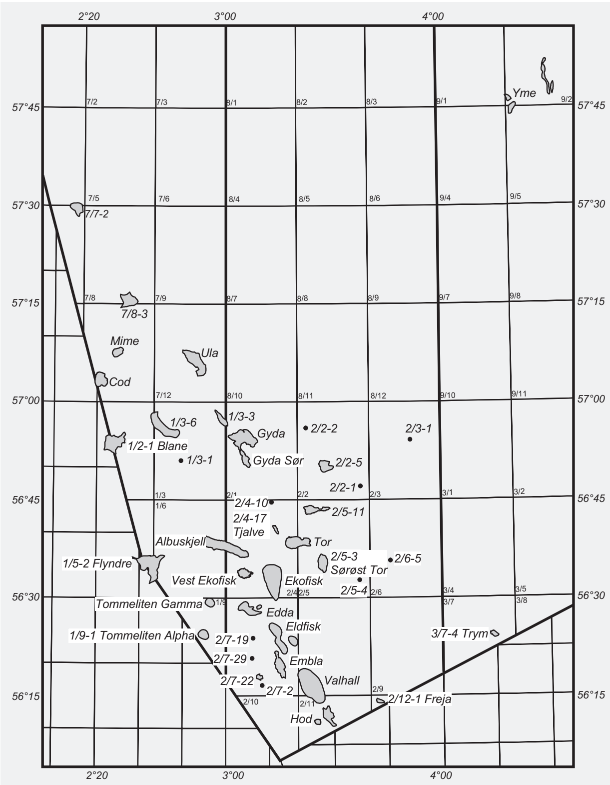
Oil and NGL are transported by pipeline to Ekofisk for further transportation to Teesside. Gas is transported in a new pipeline to Norpipe for further transportation to Emden. The oil production capacity is 27,000 Sm^3 oil/day and the gas treatment capacity is 10.7 million Sm^3 gas/day. Oil and gas are fiscally metered on Valhall. Oil is metered on the production installations and gas on the riser installation. The metering systems are part of the Ekofisk hydrocarbon distribution system.

Figure 1.4.2
Installations on Valhall

1.4.3 EKOFISK AREA

Production licenses:	018 and 018B		018 and 006	Tor Unitized
Fields:	Ekofisk, Eldfisk, Embla, Albuskjell, Cod, Edda, Vest Ekofisk		Tor	
Block:	2/4, 2/7, 1/6		2/4, 2/5	
Operator:	Phillips Petroleum Co. Norway		Phillips Petroleum Co. Norway	
Licensees:	Norsk Agip AS	13.04000 %	Norsk Agip AS	11.29740 %
	Elf Petroleum Norge AS	8.44900 %	Amerada Hess Norge AS	8.73766 %
	Fina Production Licenses AS	30.00000 %	Elf Petroleum Norge AS	11.94574 %
	Norsk Hydro Produksjon AS	6.70000 %	Fina Production Licenses AS	25.99096 %
	Phillips Petroleum Co. Norway	36.96000 %	Norsk Hydro Produksjon AS	5.80464 %
	Saga Petroleum ASA	0.30400 %	Phillips Petroleum Co. Norway	32.02086 %
	Den norske stats oljeselskap a.s	1.00000 %	Saga Petroleum ASA	0.26337 %
	Total Norge AS	3.54700 %	Den norske stats oljeselskap a.s	0.86637 %
			Total Norge AS	3.07300 %

Figure 1.4.3.a
Fields and discoveries in the Ekofisk area

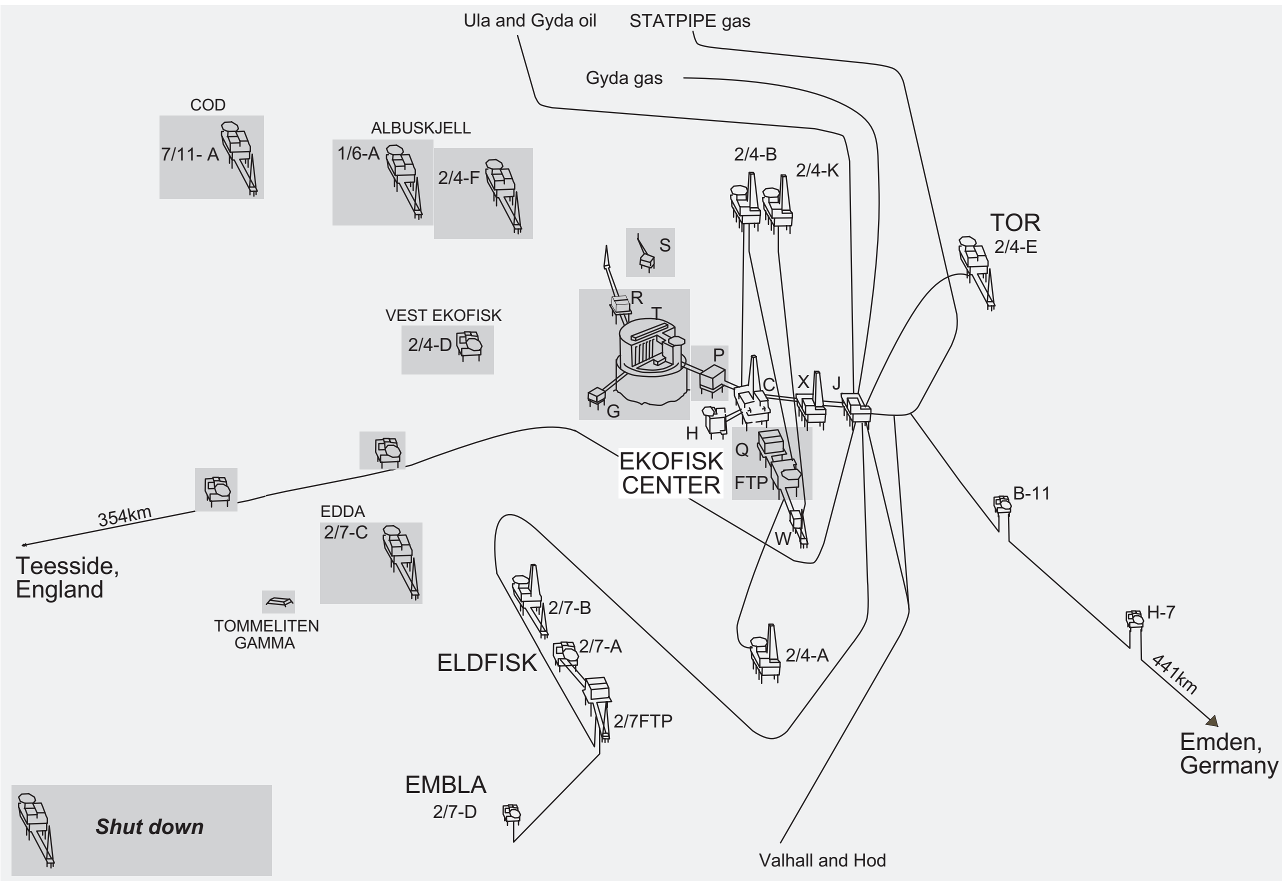


Production from the Albuskjell, Cod, Edda and Vest Ekofisk fields ceased in August 1998. Figure 1.4.3.a shows the fields in the Ekofisk area. As of 1 January 1999, the ownership distribution in Production License 018 was changed. SDFI will then receive a five per cent interest, and the licensees' interests will be reduced accordingly.

Production from Ekofisk started in 1971, and during the first years the field was produced to loading ships from four wells until the concrete tank with process facilities was in place from 1973. The Cod, Tor and Vest Ekofisk fields were developed and tied in to the Ekofisk Center from 1976-1978. At the same time, an oil pipeline was laid to Teesside and a gas pipeline to Emden. In 1979, the Albuskjell, Edda and Eldfisk fields were tied in to the Ekofisk Center. Production from Embla started in May 1993. The Ekofisk area comprises a total of 27 permanent installations.

Due to the subsidence of the seabed under Ekofisk, and an expectation of production from the field well into the next century, development of Ekofisk II was approved in 1994. The development has included a drilling and wellhead installation for Ekofisk, 2/4-X, and a joint process and export installation, 2/4-J. Both installations are tied to the old field center by gangways. There are also plans to build a new living quarters installation at the Ekofisk Center.

Figure 1.4.3.b
Installations in the Ekofisk area



Ekofisk II started producing in August 1998. Ekofisk, Eldfisk, Tor and Embla are connected to the new field center, while the installations on Albuskjell (1/6-A and 2/4-F), Cod (7/11-A), Edda (2/7-C) and Vest Ekofisk (2/4-D) are shut down. At the same time, seven of the old installations at the Ekofisk Center were shut down: 2/4-T, 2/4-R, 2/4-FTP, 2/4-Q and 2/4-P, 2/4-G (Amoco) and 2/4-S (Statoil). A cessation plan for the units that have been shut down in the area is now being prepared by the licensees and will be submitted to the authorities in the third quarter of 1999. Figure 1.4.3.b shows the installations in the Ekofisk area at the end of 1998.

Ekofisk

Production license: 018	**Block:** 2/4
Operator: Phillips Petroleum Co. Norway	
Discovery well: 2/4-2	Year: 1969
Development approved: 1970	Prod.start: 1971
Recoverable reserves:	410.7 million Sm^3 oil 146.6 billion Sm^3 gas 15.4 million tonnes NGL
Total investments (firm 1998-NOK):	Ekofisk I: NOK 42.9 billion Ekofisk II: NOK 23.1 billion
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:	Ekofisk I: NOK 1484 million Ekofisk II: NOK 1226 million

Production

The reservoir on Ekofisk lies at a depth of about 3000 meters and consists of jointed chalk rocks from the Tor and Ekofisk formations. Ekofisk is the largest field in the area, and the second largest oil field on the Norwegian continental shelf. About 80 production wells drain the field. After 27 years of production, approximately 55 per cent of the field reserves have been produced.

Ekofisk was originally developed with depressurization as the drive mechanism. Subsequently, limited gas injection and comprehensive water injection have contributed to a considerable increase in the rate of recovery of oil, from the original approximately 18 per cent to the current 40 per cent. Large-scale water injection began in 1987, and in the subsequent years the area for water injection has been expanded in several stages. Every day about 130,000 m^3 of water is injected into the reservoir from 36 wells. A total of 313 million m^3 of water was injected up to August 1998. Experience has shown that the water's displacement of the oil is more effective than expected, and the reserves estimate has been adjusted accordingly. In addition to water injection, the compacting of the soft chalk rocks also provides an extra drive for drainage of the field. This is reinforced by the fact that the injected water contributes to the weakening of the chalk. Ekofisk is expected to produce until 2029.

Measurements of the subsidence of the seabed at Ekofisk show that the rate of subsidence has decreased in the past year. The total subsidence as of November 1998 was 7.78 meters at Ekofisk H. The subsidence rate in 1998 was approximately 36 cm, compared with 40 cm in 1997. The new installations on Ekofisk are designed to withstand an additional 12-meter subsidence of the seabed.

Development

Figure 1.4.3.b shows the installations in the Ekofisk area. 17 of these are located on the Ekofisk field. The Ekofisk Center now consists of 14 installations connected by gangways, but only four of these are included in the new field center for Ekofisk II: the living quarters installation 2/4-H, the production installation 2/4-C, the new drilling and production installation 2/4-X and the new process installation 2/4-J. The other installations on the center have been shut down. 2/4-K and 2/4-W are water injection installations for Ekofisk. The production installations 2/4-A and 2/4-B will be shut down during the course of the next couple of years, and replaced by wells drilled from 2/4-X. A new living quarters installation connected by gangways to 2/4-X or 2/4-J is being planned.

Oil and gas are routed to the export pipelines via the process facility at 2/4-J on Ekofisk. After Ekofisk II was put into operation in August 1998, technical problems with the process facility have led to reduced capacity and reduced export from 2/4-J.

The gas from the Ekofisk area is transported via pipeline to Emden, while the oil, which contains the NGL fractions, is sent by pipeline to Teesside.

Eldfisk

Production license: 018	**Block:** 2/7
Operator: Phillips Petroleum Co. Norway	
Discovery well: 2/7-1	Year: 1970
Development approved: 1975	Prod.start: 1979
Recoverable reserves:	109.3 million Sm^3 oil 52.7 billion Sm^3 gas 4.6 million tonnes NGL
Total investments (firm 1998-NOK):	Eldfisk I: NOK 19.0 billion Eldfisk II: NOK 6.7 billion
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:	Eldfisk I: NOK 513 million Eldfisk II: NOK 191 million

Production

Eldfisk is the second largest field in the Ekofisk area. The Eldfisk reservoir lies at a depth of about 2800 meters and consists of jointed chalk rocks belonging to the Tor, Ekofisk and Hod formations. The field has a total of 47 wells producing from three separate structures; Alfa, Bravo and Øst Eldfisk. Since production started in 1979, Eldfisk has employed depressurization as the drive mechanism. A plan for development and operation of Eldfisk with full field water injection in Alfa and Bravo and limited gas injection in Alfa was approved by the authorities in December 1997. The water injection will start in October 1999, and the gas injection in February 2000. Several new injection and production wells will be drilled in 1999. This production strategy is expected to increase oil recovery significantly.

Development

Eldfisk was originally developed with three installations. Eldfisk B is a combined drilling, wellhead and process installation, while Eldfisk A and FTP are a wellhead installation and a process installation connected with a gangway. Eldfisk was tied in to the new Ekofisk Center in

August 1998 and is expected to produce until around 2017. Oil and gas are transported in two pipelines to the Ekofisk Center for further transportation to Teesside and Emden. Modifications have been made on Eldfisk and Ekofisk so that the oil from Eldfisk can go directly to the export pumps on 2/4-J. A new installation for water injection, 2/7-E, is under construction. This will be connected by gangway to FTP. The installation will also supply the Ekofisk field with some water through the laying of a water pipeline from Eldfisk to Ekofisk 2/4-K. Simultaneously with the development for water injection, modernization is now underway on the existing installations, inter alia through the replacement of old power generators.

Embla

Production license: 018	**Block:** 2/7
Operator: Phillips Petroleum Co. Norway	
Discovery well: 2/7-20	Year: 1988
Development approved: 1990	Prod.start: 1993
Recoverable reserves:	10.1 million Sm^3 oil 5.6 billion Sm^3 gas 1.1 million tonnes NGL
Total investments (firm 1998-NOK):	Embla I: NOK 2.2 billion Embla II: NOK 0.2 billion
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:	Embla I: NOK 39 million Embla II: NOK 3 million

Production

Embla is a fault-conditional sandstone reservoir of the Devonian and Jurassic Ages which lies at a depth of more than 4000 meters. The field produces from two separate sand layers through four wells, with depressurization as the drive mechanism. No pressure communication has been proven between the wells. Complex geology and poor seismic data have made surveys of the field difficult. The production course has shown a more positive trend than originally expected. New surveys conducted in 1997 have also indicated that Embla may have larger resources than previously estimated. Therefore, Embla's resource figures have been increased in 1998, and there are plans to drill two new wells on the field in 1999/2000.

Development

Embla started producing in 1993 with an unmanned wellhead installation which is remote-controlled from Eldfisk. Oil and gas are transported to Eldfisk and on to the Ekofisk Center for export. Embla is expected to produce until around 2017.

Tor

Production licenses: 018 and 006	**Blocks:** 2/4 and 2/5
Operator: Phillips Petroleum Co. Norway	
Discovery well: 2/5-1	Year: 1970
Development approved: 1973	Prod.start: 1978
Recoverable reserves:	28.3 million Sm^3 oil 11.7 billion Sm^3 gas 1.3 million tonnes NGL
Total investments (firm 1998-NOK):	Tor I: NOK 4.9 billion Tor II: NOK 0.3 billion
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:	Tor I: NOK 135 million Tor II: NOK 39 million

Production

The main reservoir on Tor lies at a depth of about 3200 meters and consists of jointed chalk rocks belonging to the Tor formation. The Ekofisk formation also contains oil, but has poorer production properties. In 1992, limited water injection was implemented on Tor. About 1200 m^3 water is injected daily on the field through one well. One water injection well is shut down because of technical problems. The water injection equipment is currently being upgraded to a capacity of 5700 m^3 water per day, and the water injection is expected to last throughout the lifetime of the field. Due to the capacity problems on 2/4-J, the Tor field has had reduced production since August 1998.

Development

The Tor field is developed with a combined wellhead and process installation with transportation through pipelines to the Ekofisk Center for export. Tor was tied in to the new Ekofisk Center in August 1998 and is expected to produce until around 2022.

Albuskjell

Production licenses: 018 and 018B	**Blocks:** 2/4 and 1/6
Operator: Phillips Petroleum Co. Norway	
Discovery well: 1/6-1	Year: 1972
Development approved: 1975	Prod.start: 1979 Prod. cease: 1998
Reserves, recovered:	7.4 million Sm^3 oil 16.0 billion Sm^3 gas 1.0 million tonnes NGL
Total investments (firm 1998-NOK):	NOK 6.5 billion
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:	NOK 61 million

Production

The main reservoir on Albuskjell contains gas/condensate in chalk rocks of the Tor formation, and lies at a depth of around 3200 meters. The overlying Ekofisk formation has poorer production properties and therefore drainage is minimal. The field has been produced with depressurization as the drive mechanism. Production from Albuskjell was halted in connection with start-up of Ekofisk II, but it is estimated that the remaining reserves may be produced commercially at a later point in time.

Development

Albuskjell was originally developed with two similar installations, 1/6-A and 2/4-F, with transportation of oil and gas by pipeline to the Ekofisk Center. 2/4-F has been shut down since 1990, and the wells will be permanently plugged in 1999. 2/4-A was temporarily shut down in August 1998. The licensees are considering the possibility of resuming production from the field at a later point in time, with the existing installation and horizontal wells.

Cod

Production license:	018	**Block:**	7/11
Operator:	Phillips Petroleum Co. Norway		
Discovery well:	7/11-1	Year:	1968
Development approved:	1973	Prod.start:	1977
		Prod. cease:	1998
Reserves, recovered:		2.9 million Sm^3 oil 7.5 billion Sm^3 gas 0.5 million tonnes NGL	
Total investments (firm 1998-NOK):		NOK 2.7 billion	
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:		NOK 35 million	

Production

The Cod reservoir contains gas/condensate in sandstone from the Paleocene Age, and is located at a depth of about 2900 meters. Production from the field was ceased in August 1998. At shutdown, it was estimated that about 70 per cent of the original reserves in place had been produced. Production of the remaining gas is not considered to be profitable.

Development

Cod was developed with a manned wellhead installation. Gas and oil were sent in a common pipeline to the Ekofisk Center. The Cod installation is shut down and the wells will be permanently plugged in 1999. Disposal of the installation is included in the overall cessation plan for the Ekofisk area, which will be submitted in the third quarter of 1999.

Edda

Production license:	018	**Block:**	2/7
Operator:	Phillips Petroleum Co. Norway		
Discovery well:	2/7-4	Year:	1972
Development approved:	1975	Prod.start:	1979
		Prod. cease:	1998
Reserves, recovered:		4.8 million Sm^3 oil 2.1 billion Sm^3 gas 0.2 million tonnes NGL	
Total investments (firm 1998-NOK):		NOK 4.6 billion	
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:		NOK 52 million	

Production

The main reservoir on Edda consists of chalk rocks of the Tor formation, and lies at a depth of around 3100 meters. The field is produced with depressurization as the drive mechanism. Since 1988, gas from Tommeliten Gamma has been transported to Edda and used for gas lift in the wells. Production from the field was halted in August 1998 when Ekofisk II was put into production. Evaluation of the field for potential subsequent production of the remaining reserves is underway.

Development

Edda was originally developed with a manned wellhead platform and production installation 2/7-C, and oil/gas was transported to the Ekofisk Center for export. The installation is now temporarily shut down until a final decision is made regarding shutdown or subsequent resumption of production.

Vest Ekofisk

Production license:	018	**Block:**	2/4
Operator:	Phillips Petroleum Co. Norway		
Discovery well:	2/4-6	Year:	1970
Development approved:	1973	Prod.start:	1977
		Prod. cease:	1998
Reserves, recovered:		12.2 million Sm^3 oil 26.9 billion Sm^3 gas 1.4 million tonnes NGL	
Total investments (firm 1998-NOK):		NOK 2.1 billion	
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:		NOK 14 million	

Production

The Vest Ekofisk reservoir lies at a depth of approximately 3100 meters and contains gas/condensate in jointed chalk rocks belonging to the Tor and Ekofisk formations. The field is produced with depressurization as drive mechanism. Production from Vest Ekofisk was halted in connection with start-up of operations on Ekofisk II, however, it is estimated that the remaining reserves may be produced commercially at a later point in time.

Development

Vest Ekofisk was originally developed with a wellhead installation which from January 1994 was remote-controlled from Ekofisk. Gas and oil were transported to the Ekofisk Center for export. The installation is now shut down and the wells will be permanently plugged. Disposal of the installation will be incorporated into the overall cessation plan for the Ekofisk area, which will be submitted in the third quarter of 1999. The licensees are considering resuming production from the field at a later point in time, with a new subsea installation and horizontal wells.

1.4.4 GYDA AND GYDA SØR

Production license:	019B	**Blocks:**	2/1 and 7/12
Operator:	BP Petroleum Dev. of Norway AS		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 30 %)		30.00000 %	
BP Petroleum Dev. of Norway AS		56.00000 %	
Norske AEDC A/S		5.00000 %	
Norske MOECO A/S		5.00000 %	
AS Pelican		4.00000 %	
Discovery well:		Year	
Gyda:	2/1-3	1980	
Gyda Sør:	2/1-9	1991	
Development approved:		Prod.start:	
Gyda:	1987	1990	
Gyda Sør:	1993	1995	
Recoverable reserves:			
Gyda		29.0 million Sm^3 oil 3.5 billion Sm^3 gas 1.5 million tonnes NGL	

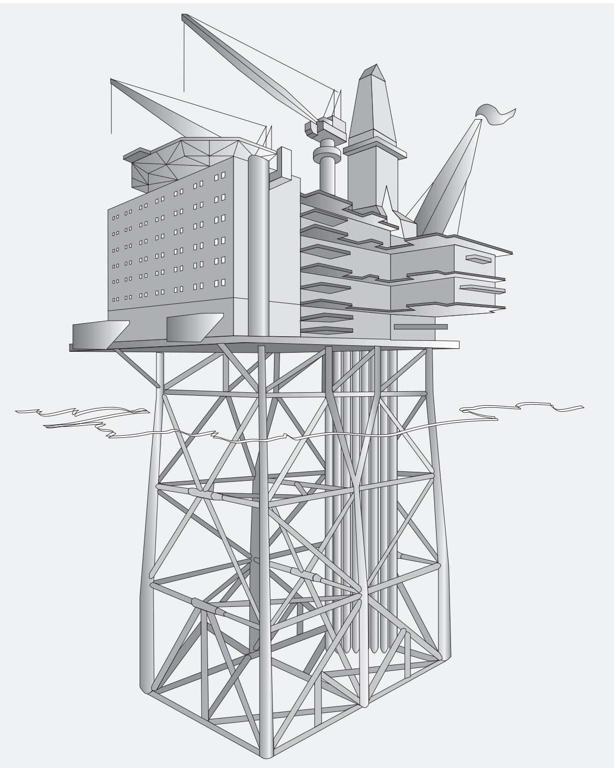
Gyda Sør	6.1 million Sm^3 oil 3.5 billion Sm^3 gas 0.7 million tonnes NGL
Total investments (firm 1998-NOK): Gyda and Gyda Sør	NOK 10.2 billion
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance: Gyda and Gyda Sør	NOK 322 million

Production - Gyda
The reservoir is made up of Upper Jurassic sandstone. Gyda is produced using water injection as the drive mechanism, see Figure 1.4.3.a. There are a total of 18 production wells and 11 injection wells on the field. Water production is increasing and measures to reduce water production are being evaluated continuously. Additional wells are being considered in order to increase the recovery.

Development - Gyda
The development solution for the field consists of a combined drilling, living quarters and processing installation with a steel jacket, see Figure 1.4.4. Production capacity is currently 14,300 Sm^3 oil per day and 1.8 million Sm^3 gas per day. Water injection capacity is 24,500 m^3 per day.

The oil is transported to Ekofisk via the oil pipeline from Ula, and then on to Teesside. The gas is transported in a separate pipeline to Ekofisk for further transportation to Emden. The oil and gas production is metered to fiscal standards prior to pipeline transportation to Ekofisk. The metering systems are included in the Ekofisk system for distribution of hydrocarbons.

Figure 1.4.4
Installation on Gyda



Production - Gyda Sør
Gyda Sør is produced using depressurization with the aid of two long-range wells from Gyda. No pressure communication has been observed between Gyda Sør and Gyda, although it is possible that there is pressure communication in the water zone. In order to increase recovery from Gyda Sør, the drilling of a third well has commenced. This well will be used for water injection.

Development - Gyda Sør
The wellstream is treated in existing facilities on Gyda.

1.4.5 ULA

Production license: 019		**Block:** 7/12	
Operator: BP Petroleum Dev. of Norway AS			
Licensees:			
BP Petroleum Dev. of Norway AS		80.00000 %	
Svenska Petroleum Exploration AS		15.00000 %	
AS Pelican		5.00000 %	
Discovery well:	7/12-2	Year	1976
Development approved:	1980	Prod.start:	1986
Recoverable reserves:		69.1 million Sm^3 oil 3.5 billion Sm^3 gas 2.5 million tonnes NGL	
Total investments (firm 1998-NOK):		NOK 12.4 billion	
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:		NOK 388 million	

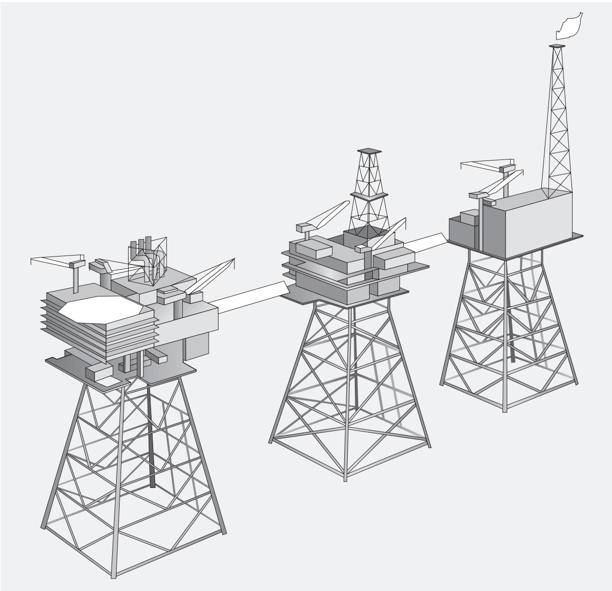
Production
The main reservoir consists of Jurassic sandstone and is produced using water injection as the drive mechanism, see Figure 1.4.3.a. Production now has a high and increasing amount of water. The operator is continuously evaluating various measures to shut out the water. At the end of 1998, there were 8 wells producing while 6 wells were used for water injection.

A new gas injection system was put into operation during the first quarter of 1998 for reinjection of produced gas. The WAG project (alternating water/gas injection) is initially planned for two wells.

The first well in the overlying reservoir zone began to produce in 1997. In order to improve the exploitation of the remaining reserves, the operator plans to drill new horizontal wells. The operator has conducted test production from the underlying Triassic reservoir. The test commenced in late 1995, but due to production problems, the test was extended to the end of 1996. The objective of the test was to evaluate the volume, productivity and possible communication with the reservoir in the Ula formation. A plan for development and operation (PDO) for the Ula Triassic deposits was submitted to the authorities in 1997, but was subsequently withdrawn.

Development
The development concept consists of three steel installations for production, drilling and living quarters respectively, see Figure 1.4.5. Production capacity is currently 24,000 Sm^3 oil per day and 1.6 million Sm^3 gas per day. Water injection capacity is 32,000 m^3 per day. The capacity for treatment

Figure 1.4.5
Installations on Ula



of produced water is approximately 19,000 m^3 per day. In 1998, about 85 per cent of the produced water on Ula was reinjected.

The oil is transported by pipeline via Ekofisk to Teesside. Statoil is the operator of the pipeline and the gas is injected in the Ula reservoir. The reinjection capacity for gas is 1.4 million Sm^3 per day. The oil production is metered to fiscal standards prior to pipeline transportation to Ekofisk. The metering system is included in the Ekofisk system for distribution of hydrocarbons.

1.4.6 YME

Production licenses: 114 , 114B and 114C	**Blocks:** 9/1, 9/2, 9/4 and 9/5
Operator: Den norske stats oljeselskap a.s	
Licensees:	
Den norske stats oljeselskap a.s (SDFI 30 %)	65.00000 %
Saga Petroleum ASA	25.00000 %
Deminex Norge AS	10.00000 %
Discovery well: 9/2-1	Year: 1987
Development approved: 1995	Prod.start: 1996
Recoverable reserves:	11.5 million Sm^3 oil
Total investments (firm 1998-NOK):	NOK 2.2 billion
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:	NOK 802 million

Production

Development of the Yme field, see Figure 1.4.3.a, will be carried out in several phases. Oil is produced from the Gamma Vest, Gamma Sørøst and Beta Øst structures. The oil is found in the Sandnes formation, which belongs to the Middle to Late Jurassic Age.

The main reservoir on Yme is in the Gamma Vest structure. The reservoir is for the most part produced by depressurization, but water is injected in one well, and downhole pumps are also used. Development of the deposits in Beta Øst was approved in November 1995. These deposits are produced with two subsea-completed wells. Depressurization with gas lift has been chosen as the drive mechanism. Development of the deposits in Gamma Sørøst was approved in February 1997. These deposits will be drained using depressurization.

In June 1997, well 9/2-7 S proved oil in the northern segment of the Beta Vest structure. The plan for development and operation of Beta Vest was approved in November 1998, and production will take place via the Beta Øst subsea installation.

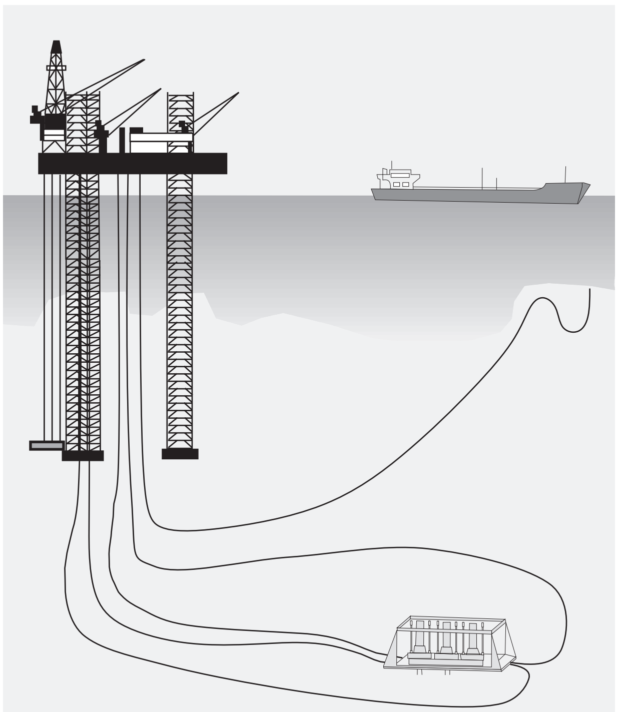
At the end of 1998, there were seven production wells. In the first half of the year, the surplus gas was injected into the main reservoir, but is now injected via well A-3 into the water-filled Epsilon structure.

Development

The field development concept consists of a jack-up installation and a storage tanker with buoy loading to shuttle tankers, Figure 1.4.6. The subsea installation on Yme Beta Øst is linked to Yme. There is no other infrastructure in the area. All oil from Yme is transported by ship to Mongstad for final separation of water and for fiscal metering.

The production installation has an oil production capacity of 8000 Sm^3 oil per day with the potential for upgrading. The gas treatment capacity is 800,000 Sm^3 gas per day, whereof 400,000 Sm^3 gas per day may be recirculated for gas lift.

Figure 1.4.6
Installations on Yme



1.4.7 VARG

Production license:	038	**Block:**	15/12
Operator: Saga Petroleum ASA			
Licensees:			
Saga Petroleum ASA		35.00000 %	
Den norske stats oljeselskap a.s (SDFI 30,000 %)		65.00000 %	
Discovery well:	15/12-4	Year:	1984
Development approved:	1996	Prod.start:	1998
Recoverable reserves:		5.5 million Sm^3 oil	
Total investments (firm 1998-NOK):		NOK 3.6 billion	
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance:		NOK 311 million	

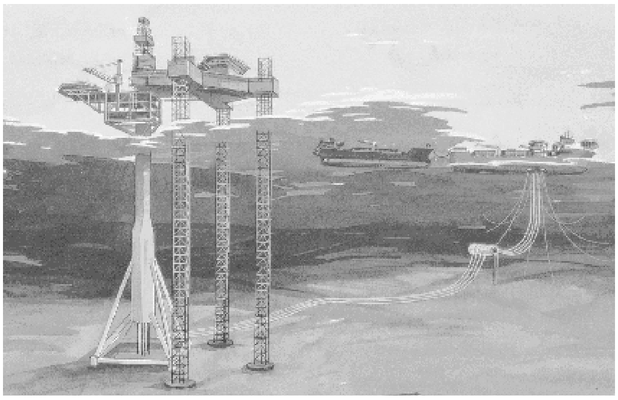
Production

The field contains oil in a greatly faulted sandstone reservoir from the Upper Jurassic Age. The production strategy is based on the use of WAG injection (alternating water/gas injection). The total number of wells is estimated to be 13. Production started on 22 December 1998 and injection of water and gas will start in early 1999.

Development

The plan for development and operation was approved in May 1996. Varg is developed with a production ship tied to a wellhead installation, see Figure 1.4.7. The wellhead installation was installed on the field in the summer of 1997, and pre-drilling of the production wells started at the end of 1997. The production ship anchored up on the field in the autumn of 1998. Planned production capacity is 9000 Sm^3 oil per day.

Figure 1.4.7
Installations on Varg



1.4.8 SLEIPNER AREA

Sleipner Øst

Production license: 046		**Block:**	15/9
Operator: Den norske stats oljeselskap a.s			
Licensees for the field:			
Den norske stats oljeselskap a.s (SDFI 29.6 %)		49.60000 %	
Esso Expl. & Prod. Norway AS		30.40000 %	
Norsk Hydro Produksjon AS		10.00000 %	
Elf Petroleum Norge AS		10.00000 %	
Discovery well:	15/9-9	Year:	1981
Development approved:	1986	Prod.start:	1993
Recoverable reserves:		38.4 billion Sm³ gas 9.5 million tonnes NGL 20.8 million Sm³ cond.	
Total investments (firm 1998-NOK):		NOK 23.5 billion	
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:		NOK 602 million	

Loke

Production license: 046		**Block:**	15/9
Operator: Den norske stats oljeselskap a.s			
Licensees:			
Den norske stats oljeselskap a.s (SDFI 29.6 %)		49.60000 %	
Esso Expl & Prod Norway AS		30.40000 %	
Norsk Hydro Produksjon AS		10.00000 %	
Elf Petroleum Norge AS		10.00000 %	
Discovery well:	15/9-17	Year:	1983
Development approved:	1991	Prod.start:	1993
Recoverable reserves:		3.5 billion Sm³ gas 0.5 million tonnes NGL 1.3 million Sm³ cond.	
Total investments (firm 1998-NOK):		NOK 0.8 billion	

Sleipner Vest

Production licenses: 046 and 029		**Blocks:**	15/9 and 15/6
Operator: Den norske stats oljeselskap a.s			
Licensees:			
Den norske stats oljeselskap a.s (SDFI 32.37453 %)		49.50291 %	
Esso Expl & Prod Norway AS		32.23936 %	
Norsk Hydro Produksjon AS		8.84653 %	
Elf Petroleum Norge AS		9.41120 %	
Discovery well:	15/6-3	Year:	1976
Development approved:	1992	Prod.start:	1996
Recoverable reserves:		128.1 billion Sm³ gas 8.7 million tonnes NGL 27.7 million Sm³ cond.	
Total investments (firm 1998-NOK):		NOK 19.9 billion	
Operating costs incl CO_2 tax, excl. tariffs, royalty and insurance:		NOK 395 million	

Gungne

Production license:	046	**Block:**	15/9
Operator: Den norske stats oljeselskap a.s			
Licensees:			
Den norske stats oljeselskap a.s (SDFI 34.4 %)		52.60000 %	
Esso Expl. & Prod. Norway AS		28.00000 %	
Norsk Hydro Produksjon AS		9.40000 %	
Elf Petroleum Norge AS		10.00000 %	
Discovery well:	15/9-15	Year:	1982
Development approved:	1995	Prod.start:	1996
Recoverable reserves:		4.5 billion Sm³ gas 0.5 million tonnes NGL 1.5 million Sm³ cond.	
Total investments (firm 1998-NOK):		NOK 0.4 billion	
Operating costs incl. CO_2 tax, lease of well slot, excl. tariffs, royalty and insurance:		NOK 23 million	

Production

Sleipner Øst, Loke and Gungne

The fields, see Figure 1.4.8.a, contain gas and condensate in reservoirs of the Tertiary and Jurassic/Triassic Age. The gas contains a relatively high amount of condensate. The Tertiary reservoir in Sleipner Øst is produced using injection of dry gas in order to extract more condensate than is achieved through depressurization. The injection gas may be taken from both Sleipner Øst and Sleipner Vest. Gas injection has gone on throughout 1998, and the reservoir pressure has increased somewhat. The plan is to start drilling new production/ injection wells again in 1999.

Production from the Tertiary reservoir in Loke was shut down in 1997. The well was extended for production from the Triassic reservoir, and production commenced in June 1998. Due to potential corrosion in the pipeline between the subsea well and Sleipner A, production was shut down after approximately two weeks. A decision was made to lay a new pipeline in 1999.

Production from Gungne takes place using one well on Sleipner A. The drilling of an extra production well is planned for 1999.

Sleipner Vest

The field contains gas/condensate. The reservoir lies in the Hugin formation from the Jurassic Age. The field consists of several fault blocks and the communication conditions in the reservoir are uncertain. The field is produced through depressurization. The gas in Sleipner Vest contains up to 9 volume per cent CO_2, which is separated from the gas and injected into a sand layer in the Utsira formation.

Some oil has been proven in the northern part of the field. The extent of this oil and the ability to produce it is uncertain and a production well was drilled into this area in the autumn of 1997. This well proved more oil than expected and additional studies were started. The well was tested in 1998, and an appraisal well was drilled to attempt to clarify the extent of the oil. Both the results from the test and from the new well were disappointing. The results indicate that there is a limited amount of oil in the relevant area, and that it would be difficult to produce. Additional studies are underway in order to evaluate the extent of the oil and whether or not it can be produced.

Development

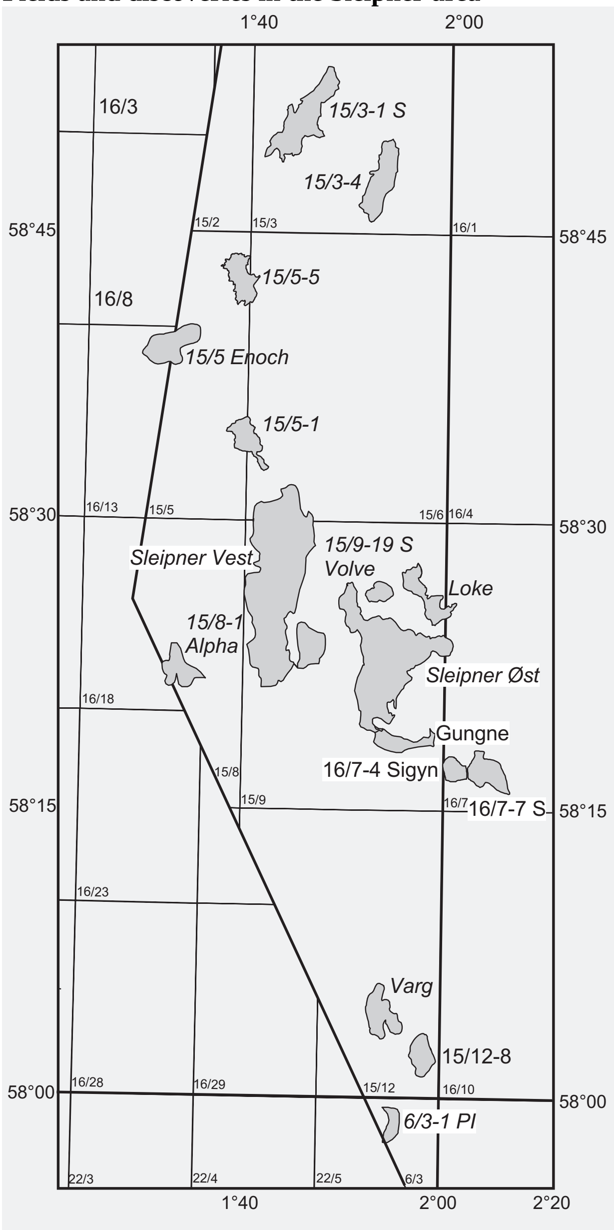
Sleipner Øst, Loke and Gungne are developed with an integrated process, drilling and living quarters installation with a concrete substructure (Sleipner A). In addition, a separate riser installation has been built (Sleipner R) with a gangway connection to Sleipner A. A subsea template has been installed for draining of the northern part of Sleipner Øst and one for draining Loke. Gungne is produced via a well from Sleipner A.

The first phase of the development of Sleipner Vest includes a wellhead installation, Sleipner B, and an installation for processing and removal of CO_2, Sleipner T. Sleipner B is located in the southern part of Sleipner Vest with wellstream transfer to Sleipner T, which has a gangway connection to Sleipner A. These installations use common utilities. The production facilities in the Sleipner area are shown in Figure 1.4.8.b

There are still some problems with the facilities for separation of CO_2 from the gas and the planned reduction in the CO_2 content is not being achieved. Work is underway to try to improve the facilities.

An agreement has been signed concerning sales and injection cooperation among the Sleipner fields. Sleipner Vest has been allocated gas sales under the contracts which were signed in 1991 in connection with the exercise of the 30 per cent options under the Troll gas sales agreement. The gas is transported via pipeline, both to Zeebrügge in Belgium, through Statpipe/Norpipe and through the Europipe system to Emden in Germany.

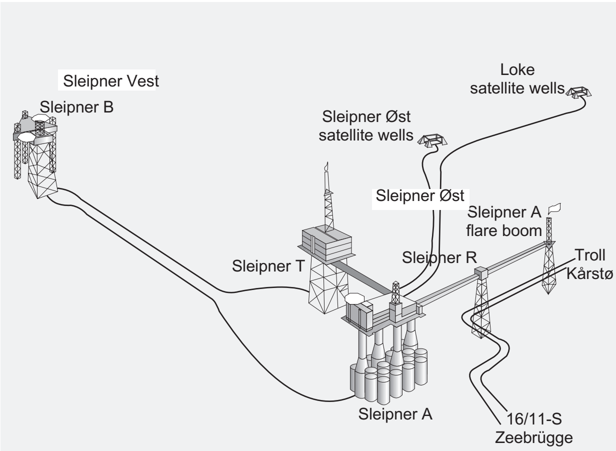
Figure 1.4.8.a
Fields and discoveries in the Sleipner area



The condensate from these fields is landed at Kårstø through a 250-kilometer pipeline from Sleipner R to Kårstø.

Total produced gas and condensate are metered to fiscal standard on the field.

Figure 1.4.8.b
Installations in the Sleipner area



1.4.9 BALDER

Production licenses: 001 and 028	**Blocks:** 25/11 and 25/10
Operator: Esso Expl. & Prod. Norway A/S	
Licensees:	
Esso Expl. & Prod. Norway A/S	100 %
Discovery well: 25/11-1	Year: 1967
Development approved: 1996	Prod.start: 1999
Recoverable reserves:	27.2 million Sm^3 oil
Total investments (firm 1998-NOK):	NOK 8.3 billion
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance:	NOK 545 million

Production

The Balder reservoir is sandstones from the Tertiary Age. They are poorly consolidated, but have good reservoir properties and contain relatively viscous oil. The Balder field, see Figure 1.4.12.a, consists of several separate structures. Six structures are included in the plan for development and operation. Five other structures have been mapped and as of the present time are considered to be prospects. It is expected that these will be included in the field in the future.

The field will be produced using natural water drive and water injection. Drilling of production wells has been underway throughout 1998.

Development

The development concept is based on seabed wells which are connected to a production and storage ship. The oil will be exported via tankers. In the PDO, the plan was for production to start between November 1996 and March 1997, however, completion of the ship has taken considerably longer than anticipated and has cost more than expected. Modification of the ship is currently underway in Scotland and production start-up is now expected in the summer of 1999.

Planned average plateau production of oil is 11,900 Sm^3 per day (75,000 barrels per day).

1.4.10 JOTUN

Production licenses: 027 P and 103B	**Blocks**: 25/8 and 25/7
Operator: Esso Expl. & Prod. Norway AS	
Licensees:	
Esso Expl. & Prod. Norway AS	45.00000 %
Enterprise Oil Norwegian AS	45.00000 %
Den norske stats oljeselskap a.s (SDFI 3.00000 %)	5.00000 %
Norske Conoco A/S	3.75000 %
Amerada Hess Norge AS	1.25000 %
Discovery well: 25/8-5S	Year: 1994
Development approved: 1997	Prod.start: 1999
Recoverable reserves:	30.7 million Sm^3 oil 1.8 billion Sm^3 gas
Total investments (firm 1998-NOK):	NOK 8.3 billion
Operating costs at plateau 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:	NOK 565 million

Production

Jotun, see Figure 1.4.12.a, comprises the discoveries 25/8-5 S, 25/7-3 and 25/8-8 S, all of which were made in 1994 and 1995. In all of the structures, oil was found in the Heimdal formation from the Paleocene Age. In the 25/8-8 S discovery, some free gas was also proven. The majority of the resources lie in production license 027P. An agreement concerning unitization between the two production licenses was signed in the autumn of 1997. Water injection, possibly in combination with natural water drive, is the planned drive mechanism.

Development

A wellhead installation and production ship have been outlined as the development concept, and construction of the installations was started in the autumn of 1997. The wellhead installation was placed on the field in August 1998, and drilling of production wells is planned to commence in early 1999. The estimated production start-up is the summer of 1999. The oil will be loaded on the field and connection to Statpipe is planned for export of gas which exceeds the need for fuel on the field.

1.4.11 HEIMDAL

Production license: 036	**Block:** 25/4
Operator: Norsk Hydro Produksjon AS	
Licensees for the field:	
Den norske stats oljeselskap a.s (SDFI 20 %)	40.00000 %
Marathon Petroleum Norge AS	23.79800 %
Elf Petroleum Norge AS	11.93900 %
Norsk Hydro Produksjon AS	15.80300 %
Total Norge AS	4.82000 %
Saga Petroleum ASA	3.47100 %
AS Uglands rederi	0.16900 %

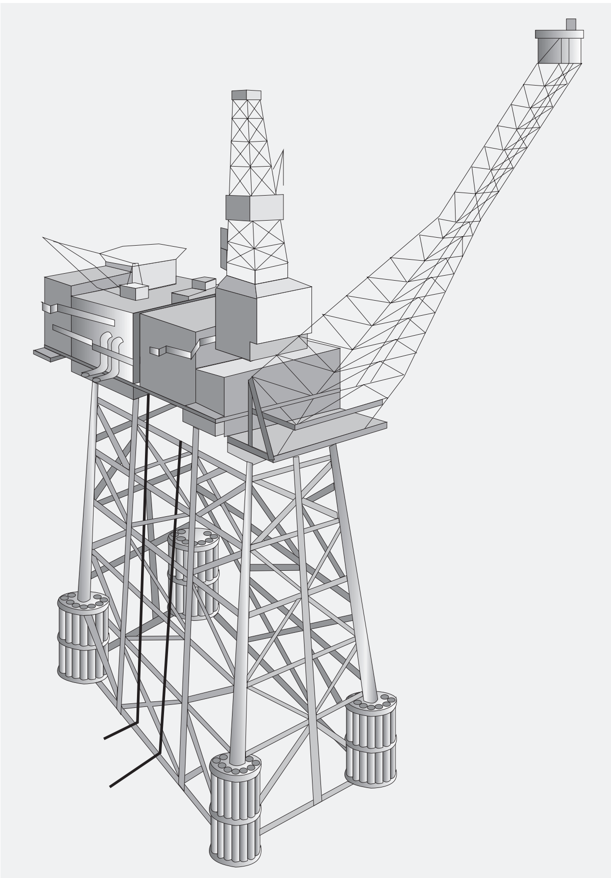
Discovery well:	25/4-1	Year:	1972
Development approved:	1981	Prod.start:	1985
Recoverable reserves:			6.9 million Sm^3 oil 42.6 billion Sm^3 gas
Total investments (firm 1998-NOK):			NOK 12.1 billion
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:			NOK 267 million

Production
The field, see Figure 1.4.12.a, produces from sandstones in the Heimdal formation. Ten wells have been drilled from the installation on the field, nine production wells and one observation well. Because of the powerful water drive in the field, both pressure development and water ascent are carefully monitored. According to the current plan, the field will produce until the summer of 1999.

Development
The Heimdal field has been developed with an integrated steel jacket structure with combined drilling, production and living quarters functions, see Figure 1.4.11. The deliveries of gas via Emden began in February 1986.

The gas from the Heimdal field is transported in Statpipe. The pipeline from Heimdal is tied into the Statpipe system at the Draupner riser platform. The condensate is transported from Heimdal to Brae in the British sector through a separate pipeline. From the Brae field the condensate goes to Cruden Bay in Scotland.

Figure 1.4.11
Installation on Heimdal



After a modification phase from 1999 to 2000, the installation will once again be put into operation for processing of the gas from 30/2-1 Huldra. A riser installation will also be built, which will be able to take in risers from other discoveries and transportation systems in the area.

1.4.12 FRIGG AREA

Frigg

Production license:	024	**Blocks:** 25/1 and 30/10 on the Norwegian shelf and 10/1, 9/5 and 9/10 on the British shelf	
Operator:	Elf Petroleum Norge AS		
Licensees:			
Norwegian part (60.8200%)			
Elf Petroleum Norge AS			16.06800 %
Norsk Hydro Produksjon AS			19.99200 %
Total Norge AS			12.59600 %
Den norske stats oljeselskap a.s			12.16400 %
British part (39.1800%)			
Elf Exploration UK Ltd			26.12000 %
Total Oil Marine Ltd			13.06000 %
Discovery well:	25/1-1	Year:	1971
Development approved:	1974	Prod.start:	1977
Recoverable reserves:	(Norw. share) (Norw. share)	119.2 billion Sm^3 gas 0.5 million Sm^3 cond.	
Total investments (firm 1998-NOK):		approx. NOK 21.0 billion	
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:		NOK 439 million	

Production
The field produces gas from the Frigg formation, which consists of sandstone from the Eocene Age. The production wells on CDP1 are permanently plugged. On DP2, the wells have reduced production potential due to water influx. Future development of produced water volume will be a crucial factor in determining when the field will be shut down. According to current plans, the last year of production will be 2001.

Development
The field was developed in three phases. Phase I consists of one production and one treatment installation on the British part of the field, as well as a living quarters installation (CDP1, TP1 and QP). Production from Phase I started in 1977.

Phase II consists of one production and one treatment installation located on the Norwegian part of the field (DP2 and TCP2). Production from Phase 2 started in 1978. Figure 1.4.12.b shows the installations in the Frigg area.

Phase III of the development comprises the installation of three turbine-driven compressors on TCP2. The compressor system is necessary in order to compensate for reduced reservoir pressure. These facilities were put into operation in the autumn of 1981.

Gas from Lille-Frigg is treated and metered on TCP2. In 1995, a new module was installed on this installation in order to treat oil and gas from Frøy. Prior to their shutdown, gas from Nordøst Frigg, Øst Frigg and Odin was also treated on Frigg. Transportation of gas from the Alwyn North field on the British side takes place via TP1.

TP1 has been converted from a processing installation into a riser platform. The gas is transported 355 km to St. Fergus in Scotland via two pipelines, each with a diameter of 813 millimeters. The liquid is transported in Frostpipe via Oseberg to Stura.

Frøy

Production licenses: 026 and 102	**Blocks:** 25/2 and 25/5
Operator: Elf Petroleum Norge AS	
Licensees:	
Den norske stats oljeselskap a.s (SDFI 41.616 %)	53.96000 %
Elf Petroleum Norge AS	24.75730 %
Total Norge AS	15.23460 %
Norsk Hydro Produksjon AS	6.04810 %
Discovery well: 25/5-1	Year: 1987
Development approved: 1992	Prod.start: 1995
Recoverable reserves:	5.9 million Sm^3 oil 1.5 billion Sm^3 gas 0.1 million Sm^3 cond.
Total investments (firm 1998-NOK):	NOK 5.9 billion
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:	NOK 196 million

Production

Frøy is an oil field. The reservoir lies in the Brent group of the Upper Jurassic Age. The production strategy is based on water injection. The field has 10 wells, of which six are production wells. The field is currently producing from three wells. The operator has reduced in-place and recoverable reserves based on experience with production wells and a new geological model. Today Frøy has low production and relatively high operating costs. Combined with low oil prices, this means that the field may experience unprofitable operations in the course of 1999

Development

The field is developed by means of a wellhead installation. Oil and gas are transferred in separate pipelines to Frigg for further processing and metering. The gas is transported on to St. Fergus. The oil is transported in Frostpipe to Oseberg, and from there on to the oil terminal at Stura. Figure 1.4.12.a shows an overview of the fields and discoveries in the Frigg area.

Lille-Frigg

Production license: 026	**Block:** 25/2
Operator: Elf Petroleum Norge A/S	
Licensees:	
Den norske stats oljeselskap a.s	5.00000 %
Elf Petroleum Norge AS	41.42000 %
Total Norge AS	20.71000 %
Norsk Hydro Produksjon AS	32.87000 %
Discovery well: 25/2-4	Year: 1975
Development approved: 1991	Prod.start: 1994
Recoverable reserves:	2.3 billion Sm^3 gas 1.2 million Sm^3 cond.
Total investments (firm 1998-NOK):	NOK 4.2 billion
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:	NOK 34 million

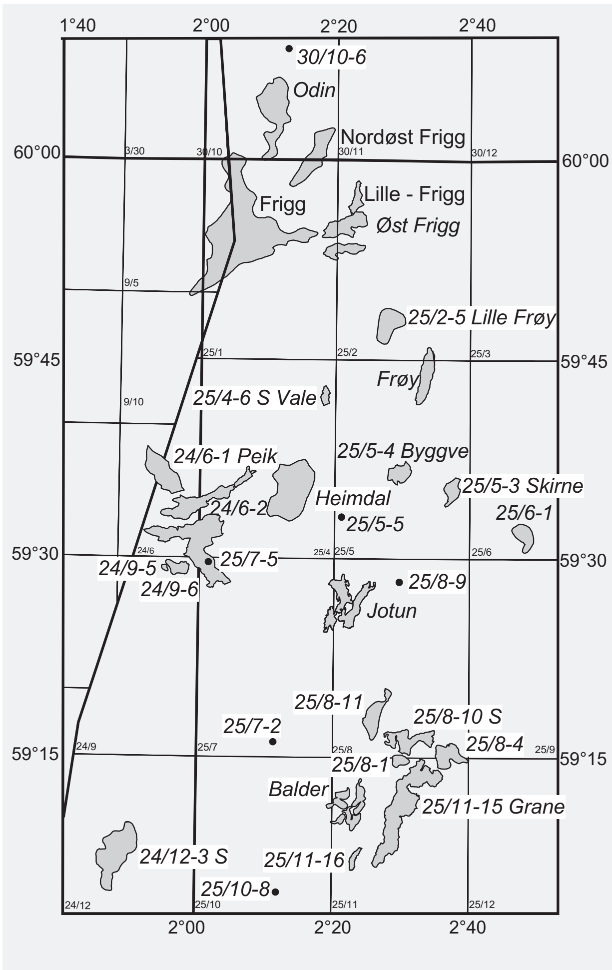
Production

Lille-Frigg is a gas/condensate field. The reservoir is located in the Brent group in a fault block which is an extension of the Heimdal ridge. Production is based on three production wells with depressurization as the production mechanism. The field is currently producing from only one well due to problems with water production. The recoverable reserves were 7 billion Sm^3 gas when the field was approved, and the estimate has now been reduced to 2.3 billion Sm^3 due to a more rapid pressure decline and water production. According to the plan, Lille-Frigg will cease production in early 1999.

Development

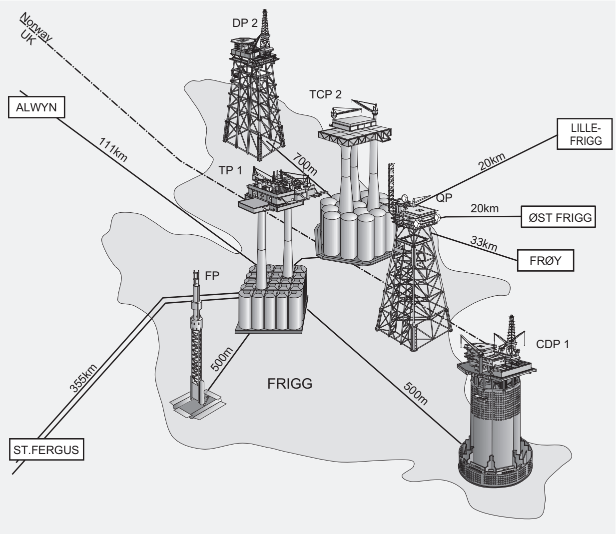
Lille-Frigg is developed with a subsea installation which is remote-controlled from Frigg. The untreated wellstream

Figure 1.4.12.a
Fields and discoveries in the Frigg, Jotun and Balder area



is transferred directly to Frigg for processing. The gas is transported via pipeline to St. Fergus. Stabilized condensate is transported via Frostpipe to Oseberg, and from there is sent to the oil terminal at Stura. Metering of condensate and gas takes place on Frigg.

Figure 1.4.12.b
Installations in the Frigg area



1.4.13 OSEBERG AREA

Oseberg

Production licenses: 053 and 079	**Blocks:** 30/6 and 30/9
Operator: Norsk Hydro Produksjon AS	
Licensees:	
Den norske stats oljeselskap a.s (SDFI 50.78379 %)	64.78379 %
Norsk Hydro Produksjon AS	13.68186 %
Saga Petroleum ASA	8.55276 %
Elf Petroleum Norge AS	5.76959 %
Mobil Development Norway AS	4.32720 %
Total Norge AS	2.88480 %
Discovery well: 30/6-1	Year: 1979
Development approved: Phase I 1984, Phase II 1988, Phase III 1996	Prod.start: 1988
Recoverable reserves:	336.0 million Sm^3 oil 16.4 billion Sm^3 gas 6.0 million tonnes NGL 0.5 million Sm^3 cond.
Total investments (firm 1998-NOK):	NOK 50.6 billion
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:	NOK 1216 million

Production
The first discovery proved gas in 1979, while subsequent drilling proved oil with a gas cap. The field consists of several reservoirs in the Brent group (Middle Jurassic), divided among three structures. The main reservoirs are in the Oseberg and Tarbert formations, but Etiv and Ness are also important contributors. The use of horizontal production wells was not included in the original plans, but most of the production wells are now drilled horizontally with good results. The reservoir pressure in Oseberg is maintained through gas injection, water injection and WAG. The injection gas is imported externally from Troll Øst (TOGI) and Oseberg Vest. There are 70 operative wells on the field including injection wells.

Development
Figure 1.4.13.b shows fields and discoveries in the Oseberg area. The oil part of the Oseberg field has been developed in two phases, see Figure 1.4.13.a. Phase I is developed with a field center in the south with two installations. Oseberg A comprises a processing and living quarters installation with concrete substructures, and Oseberg B comprises one drilling and water injection installation with a steel jacket. Average oil processing capacity is about 55,000 Sm^3 per day.

Phase II comprised development of the northern part of the field. The Oseberg C installation is an integrated production, drilling and living quarters installation (PDQ). Average oil processing capacity is about 23,000 Sm^3 per day.

The plan for development and operation for the gas phase (Phase III) of Oseberg was approved in 1996. Oseberg gas phase will start production in 1999/2000 with a gas allocation of 2 billion Sm^3 per year from the year 2000.

The gas phase will be developed with a new installation for processing of dry gas. The gas will be transported in a new gas pipeline to the Statpipe system via the Heimdal installation. The gas installation will have a capacity of 10 billion Sm^3 per year.

Oseberg A and Oseberg C are equipped with metering stations for fiscal metering of stabilized oil prior to pipeline transport to Stura. Purchase of injection gas from Troll (TOGI) is metered via the fiscal gas metering station installed on Oseberg A. Stabilized oil is exported from the terminal at Stura via two quay facilities which are linked to two identical fiscal oil metering stations.

Oseberg Vest

Production license: 053	**Block:** 30/6
Operator: Norsk Hydro Produksjon AS	
Licensees:	
Den norske stats oljeselskap a.s (SDFI 50.7838 %)	64.78379 %
Norsk Hydro Produksjon AS	13.68186 %
Saga Petroleum ASA	8.55276 %
Elf Petroleum Norge AS	5.76959 %
Mobil Development Norway AS	4.32720 %
Total Norge AS	2.88480 %
Discovery well: 30/6-15	Year: 1984
Development approved: 1988	Prod.start: 1991
Recoverable reserves:	1.6 million Sm^3 oil 6.0 billion Sm^3 gas
Total investments (firm 1998-NOK):	NOK 0.8 billion
Operating costs are incorporated in the unitized Oseberg	

Production

Oseberg Vest consists of a rotated fault block where the hydrocarbon-bearing zones are found in the Statfjord formation of the Lower Jurassic.

A coal-bearing shale zone divides the Statfjord formation into an upper and a lower reservoir zone. Gas was proven first with a thin oil zone in the upper reservoir zone. In order to produce as much of the oil as possible, a production solution with two horizontal production wells was chosen. One of these wells is temporarily shut down. In connection with the drilling of the first production well, oil was discovered in the lower reservoir zone. The field is produced with depressurization, but has natural pressure support from the gas cap.

Development

The field is developed with two horizontal production wells. The first production well, which started producing in 1991, is tied to Oseberg C, while the second well, completed in 1996, is tied to Oseberg B. All produced gas is injected into the Oseberg field.

Oseberg Øst

Production license: 053		**Block:** 30/6	
Operator: Norsk Hydro Produksjon AS			
Licensees:			
Den norske stats oljeselskap a.s (SDFI 45.40 %)	59.40000 %		
Norsk Hydro Produksjon AS	12.25000 %		
Saga Petroleum ASA	7.35000 %		
Elf Petroleum Norge AS	9.33300 %		
Mobil Development Norway AS	7.00000 %		
Total Norge AS	4.66700 %		
Discovery well: 30/6-5		Year: 1981	
Development approved: 1996		Prod.start: 1998	
Recoverable reserves:		23.5 million Sm^3 oil 0.8 billion Sm^3 gas	
Total investments (firm 1998-NOK):		NOK 4.4 billion	
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance:		NOK 430 million	

Production

The field consists of two structures which are separated by a sealed fault. Both structures contain several oil-bearing layers within the Brent group (Middle Jurassic) with varying porosity and permeability, as well as several different oil/water contacts. The intention is to maintain pressure with the aid of water and WAG injection. The field will be produced with six production, six injection and two water production wells.

Development

The field will be developed with an installation with living quarters, drilling equipment and first stage separation of oil, water and gas. Processing will be completed at the Oseberg field center. The installation will have the capacity to process 12,000 Sm^3 oil and 13,300 m^3 water per day. The maximum gas injection rate will be 1.4 million Sm^3 per day. The oil from the field will be transported in the Oseberg Transport System to Stura. All equipment is installed on the field, and production start-up is planned for February/March 1999.

Figure 1.4.13.a
Installations on Oseberg

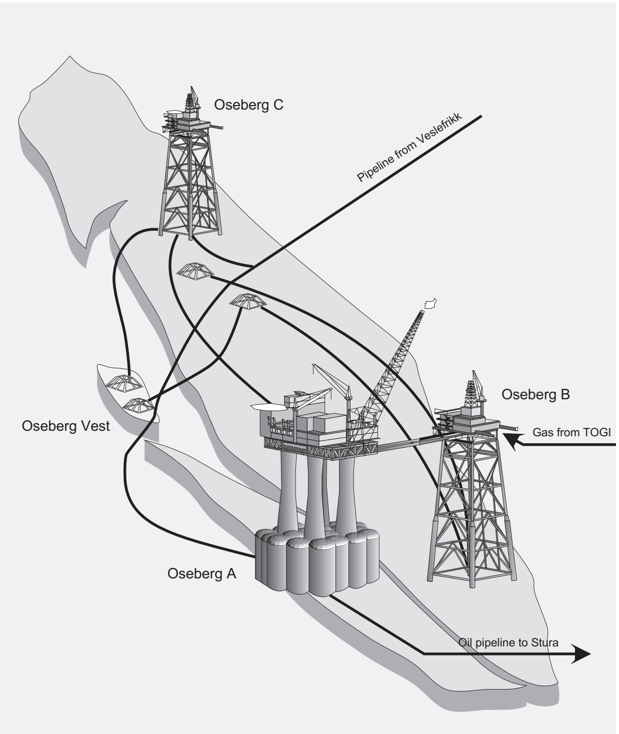
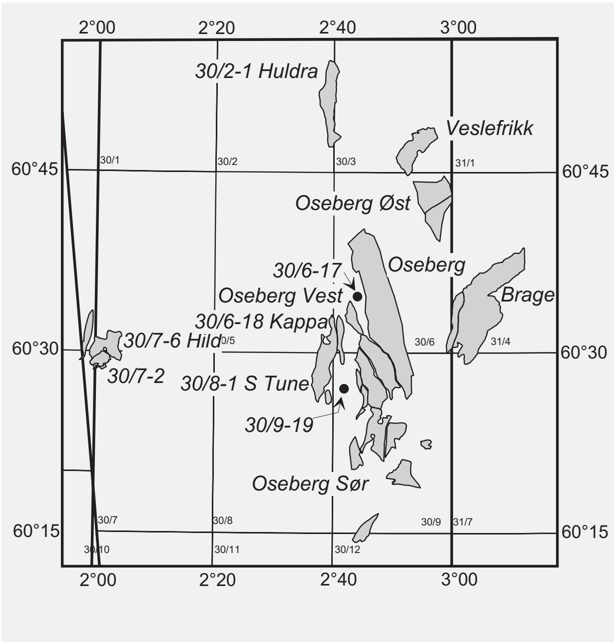


Figure 1.4.13.b
Fields and discoveries in the Oseberg area



Oseberg Sør

Production licenses: 079, 104 and 171	**Blocks:** 30/6, 30/9, 30/12
Operator: Norsk Hydro Produksjon AS	
Licensees:	
Den norske stats oljeselskap a.s. (SDFI 38.36 %)	56.58000 %
Norsk Hydro Produksjon AS	21.88000 %
Saga Petroleum ASA	10.14000 %
Norske Conoco A/S	7.700000 %
Mobil Development Norway AS	3.700000 %
Discovery well: 30/9-3	Year: 1984
Development approved: 1997	Prod.start: 2000
Recoverable resources:	53.5 million Sm^3 oil 11.4 billion Sm^3 gas
Total investments (firm 1998-NOK):	NOK 8.8 billion
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance:	approx. NOK 620 million

Production

Ten potential reservoir structures lie within the area defined by the operator as Oseberg Sør. Seven of these are incorporated in the basic estimates for Oseberg Sør. Hydro is the operator and the field is unitized. Most of the reserves lie in the Brent Group (Middle Jurassic), but discoveries have also been made in the Heather and Draupne formations (Upper Jurassic). The production mechanism is different for the various structures. The plan is to use water injection, gas injection and WAG injection for pressure maintenance.

Development

The field will be developed with one installation with living quarters, drilling module and first stage separation of oil and gas. Processing will be completed at the Oseberg field center. The oil will be transported in the Oseberg Transport System to Stura. A part of 30/9-3 Omega Nord can be reached by wells from the Oseberg field center, and will be produced from there.

1.4.14 BRAGE

Production licenses: 053, 055 and 185	**Blocks:** 30/6, 31/4 and 31/7
Operator: Norsk Hydro Produksjon AS	
Licensees:	
Den norske stats oljeselskap a.s (SDFI 34.2567 %)	46.95670 %
Norsk Hydro Produksjon AS	22.41820 %
Esso Expl and Prod Norway A/S	16.34340 %
Neste Petroleum AS	12.25750 %
Elf Petroleum Norge AS	0.66640 %
Saga Petroleum ASA	0.52480 %
Mobil Development Norway AS	0.49980 %
Total Norge AS	0.33320 %
Discovery well: 31/4-3	Year: 1980
Development approved: Phase I 1990 Phase II 1998	Prod.start: 1993
Recoverable reserves:	54 million Sm^3 oil 3.2 billion Sm^3 gas 0.9 million tonnes NGL
Total investments (firm 1998-NOK):	NOK 12.0 billion
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:	NOK 418 million

Production

Oil has been proven in two formations in the unitized part of Brage: Statfjord (Lower Jurassic) and Fensfjord (Upper Jurassic). Oil and gas have been proven in the Sognefjord formation (Upper Jurassic). Test production from the Sognefjord formation was started in the autumn of 1997. The plan for development and operation of the deposits in the Sognefjord formation was submitted in July 1998 and approved in October 1998.

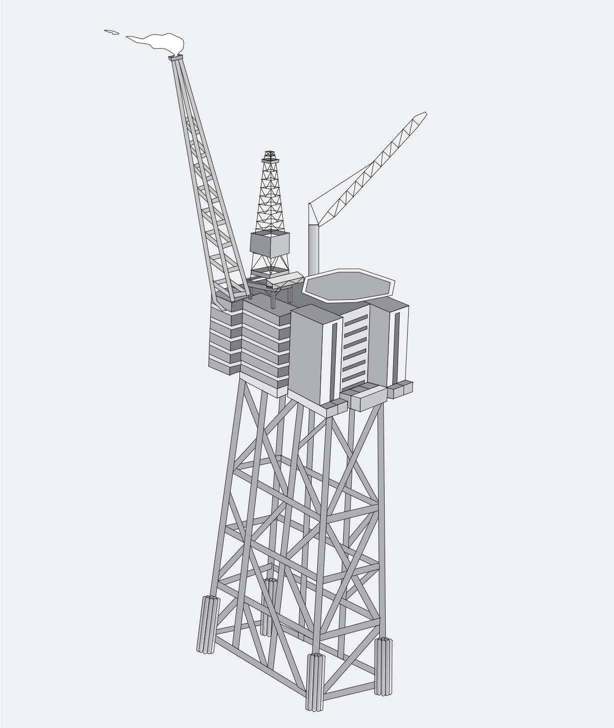
Development

The Brage field is developed with an integrated production, drilling and living quarters installation with a steel jacket, see Figure 1.4.14. The oil is transported via pipeline to Oseberg and further through the Oseberg line to Stura. A pipeline for gas is connected to Statpipe.

1.4.15 VESLEFRIKK

Production license: 052	**Block:** 30/3
Operator: Den norske stats oljeselskap a.s	
Licensees:	
Den norske stats oljeselskap a.s (SDFI 37 %)	55.00000 %
Total Norge AS	18.00000 %
Deminex Norge AS	11.25000 %
Petro-Canada Norge AS	9.00000 %
Svenska Petroleum Expl AS	4.50000 %
Norske Deminex AS	2.25000 %

Figure 1.4.14
Installation on Brage



Discovery well:	30/3-2	Year:	1980
Development approved:	1987	Prod.start:	1989
Recoverable reserves:		54.5 million Sm^3 oil 5.5 billion Sm^3 gas 1.6 million tonnes NGL	
Total investments (firm 1998-NOK):		NOK 11.2 billion	
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:		NOK 523 million	

Production
The field produces from reservoirs in the lower part of the Brent group and the Dunlin group (Intra Dunlin Sand) and the Statfjord formation.

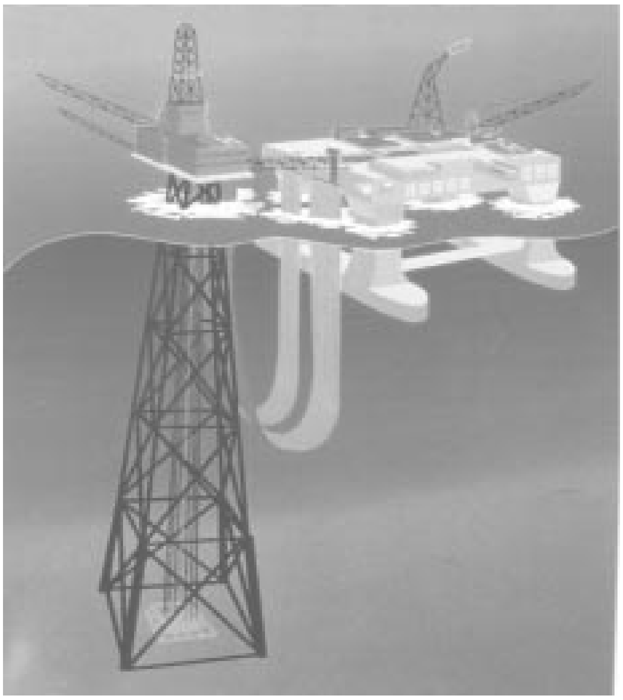
The production strategy for the reservoirs in the Brent group and the Dunlin group is to maintain pressure in the reservoir with the aid of water injection. Some of the wells will, however, be controlled with a lower well pressure than boiling point pressure. A decision has been made to implement WAG injection in the main field.

Production from the Statfjord formation started in 1997. The Statfjord formation has a gas cap and a higher content of associated gas than the other reservoirs.

A small discovery was made during the drilling of well 30/3-7 S in 1995. The well was tested in 1997. Well 30/3-7 B is the third track of well 30/3-7. Test production from the well started in 1998.

Development
The field has been developed with a permanent wellhead installation with a steel jacket and a semi-submersible installation with process facilities and living quarters, see Figure 1.4.15. There are 13 production wells and seven water injection wells. The semi-submersible installation is anchored and connected to the permanent wellhead installation.

Figure 1.4.15
Installations on Veslefrikk



An oil pipeline is connected to the Oseberg Transport System for transport to the Stura terminal. Gas is transported via the Statpipe system.

1.4.16 TROLL

Production licenses: 054 and 085	**Blocks:** 31/2, 31/3, 31/5 and 31/6
Operator: Den norske stats oljeselskap a.s Norsk Hydro Produksjon AS	
Licensees:	
Den norske stats oljeselskap a.s (SDFI 62.696 %)	74.57600 %
A/S Norske Shell	8.28800 %
Norsk Hydro Produksjon AS	7.68800 %
Saga Petroleum ASA	4.08000 %
Elf Petroleum Norge AS	2.35344 %
Norske Conoco A/S	1.66113 %
Total Norge AS	1.35343 %
Discovery well: 31/2-1	Year: 1979
Development approved: Phase I 1986 Phase II 1992	Prod.start: 1991
Recoverable reserves (Resource classes 1-2, incl. TOGI):	211.4 million Sm^3 oil 613.2 billion Sm^3 gas
Total investments (firm 1998-NOK) (incl. TOGI):	NOK 78.6 billion
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance: (incl. TOGI):	NOK 988 million

Structurally, the Troll field lies on the northwestern part of the Horda platform, see Figure 1.4.16.a. The field consists of three relatively large, rotated fault blocks with an easterly slope and extending over an area of 750 square kilometers. The water depth in the area is over 300 meters. The hydrocarbon-bearing layers are mainly sandstone of the Sognefjord formation, from the Middle to Late Jurassic Age. The field's gas column, which is more than 200 meters thick in the east, diminishes to the west, while the oil column drops from 22-26 meters in the west to 0-4 meters in the east. The development of the field has taken place in several phases. The Troll field was unitized in 1986.

In addition to the reported recoverable oil reserves, significant potential additional resources have been identified in Troll Vest. The total recoverable gas resources in the Troll field amount to 1328 billion Sm^3.

TOGI
The subsea system Troll Oseberg Gas Injection (TOGI) is controlled from the Oseberg Field Center and produces gas from Troll Øst for injection in the Oseberg field. Production and delivery of gas via TOGI started in February 1991. Up to the end of 1998, TOGI had delivered 19.4 billion Sm^3 gas to Oseberg. In all, the plan is to deliver 21.7 billion Sm^3 gas by the end of 2002. Norsk Hydro was responsible for the development of TOGI and is the operator in the operations phase.

Troll Phase I: Development of the gas reserves in Troll Øst

Production

A/S Norske Shell was the development operator for Troll Phase I. Statoil assumed the role of operator for the operation of the field in June 1996. During the course of 1998, the last of a total of 39 gas production wells was completed on Troll Øst.

Regular gas deliveries from Troll started on 1 October 1996. The gas is delivered to various customers on the Continent. Only a part of the gas in the field has been sold. Due to internal communication in the field, gas production from Troll Øst may have a great effect on future production of oil from Troll Vest. Therefore, great emphasis is placed on finding an optimal production strategy for oil and gas for the entire Troll field. In the autumn of 1998, a working group was established for the purpose of evaluating the production strategy for Troll. The working group consists of representatives from the operators, Statoil and Norsk Hydro, as well as the Norwegian Petroleum Directorate. The working group will complete its work in the spring of 1999.

Development

The gas reserves in Troll Øst are produced from Troll A, which is a permanent wellhead installation with a concrete gravity base structure. The gas from Troll Øst and Troll Vest is transported from Troll A via two multi-phase pipelines to the gas treatment facility at Kollsnes. At the land facilities, the condensate is separated from the gas and transported through a pipeline to the Stura terminal for further export to the market. The condensate will be flow-metered in a fiscal metering station before it leaves the Kollsnes terminal. The dry gas will be compressed and exported via pipeline to the Continent.

The Kollsnes facility has an export capacity of approx. 100 million Sm^3 gas per day. Metering of the gas to fiscal standard takes place through two identical metering stations for Zeepipe II A and II B respectively. Each metering station has a capacity of about 58.8 million Sm^3 per day. The gas treatment facilities at Kollsnes are arranged so as to accommodate additional expansion.

Troll Phase II: Development of the oil reserves in Troll Vest oil province and Troll Vest gas province

Production of oil from Troll Vest oil province

The oil province comprises the westernmost part of the field, which has a 22-26 meter oil column under a small gas cap. Production started in September 1995. Up to the end of 1998, 18 horizontal production wells and one gas injector had been drilled. During the past year, production has proceeded approximately as expected. Anticipated oil reserves have been increased slightly due to overall positive reservoir development and a longer production history.

The production strategy depends on conditions such as pressure development and communication with other areas of the field. In the southern part of the oil province, as much gas as possible is reinjected, while the strategy is a controlled production of free gas together with the oil in the northern part of the province. The wells in the oil province are divided among four subsea installations which are tied into Troll B.

Production of oil from Troll Vest gas province

The gas province comprises the middle portion of the field with an oil column of 11.5-14.5 meters and a gas column of up to 200 meters. Production of the oil reserves in the gas province may be time-critical in relation to the production of gas from both Troll Øst and Troll Vest. The stage-by-stage development has been important with regard to acquiring production experience from parts of the area before deciding on new development solutions.

The plans for development and operation of the first two subsea installations in the southern part of the Troll Vest gas province were approved by the authorities in May 1994 and July 1996 respectively. The first well group started producing in November 1995, and the second group in April 1998. Production development has been somewhat less favorable than expected after a gas breakthrough. Overall, the production rate is lower than predicted, which is mainly due to delayed progress in drilling.

A continued plan for development and operation of the oil in Troll Vest gas province was approved by the authorities in June 1997. The development plan includes nine subsea installations (well groups) with a total of 50 horizontal production wells, whereof several multibranched wells. Three well groups with 18 wells in the southern part of the gas province will be connected to Troll B, while six well groups with 32 wells in the northern part of the province will be connected to a new installation, Troll C. New field data and updated studies have shown that it would be profitable to increase the number of wells and subsea templates. In 1998, a supplement to the PDO was submitted, which covers the installation of an additional well group. This well group will be tied to Troll C. Plans for additional well groups may be submitted in 1999. During the course of 1997 and 1998, several observation wells have been drilled to inter alia obtain more information regarding communication between the provinces and to see how time-critical the resources are. Super critical production, where some production of free gas is allowed together with the oil, has been the presumed production strategy in this area.

Development

The oil reserves in the Troll Vest oil province and the southern part of the Troll Vest gas province are produced via Troll B, a floating concrete installation without storage capacity. A total of nine well clusters will be connected to Troll B. Troll B's production capacity is 42,500 Sm^3 oil per day. The oil is transported through Troll Oljerør (Troll oil pipeline) approx. 90 km to Mongstad. Gas which is

Figure 1.4.16.a
Fields and discoveries in the Troll, Fram and Gjøa area

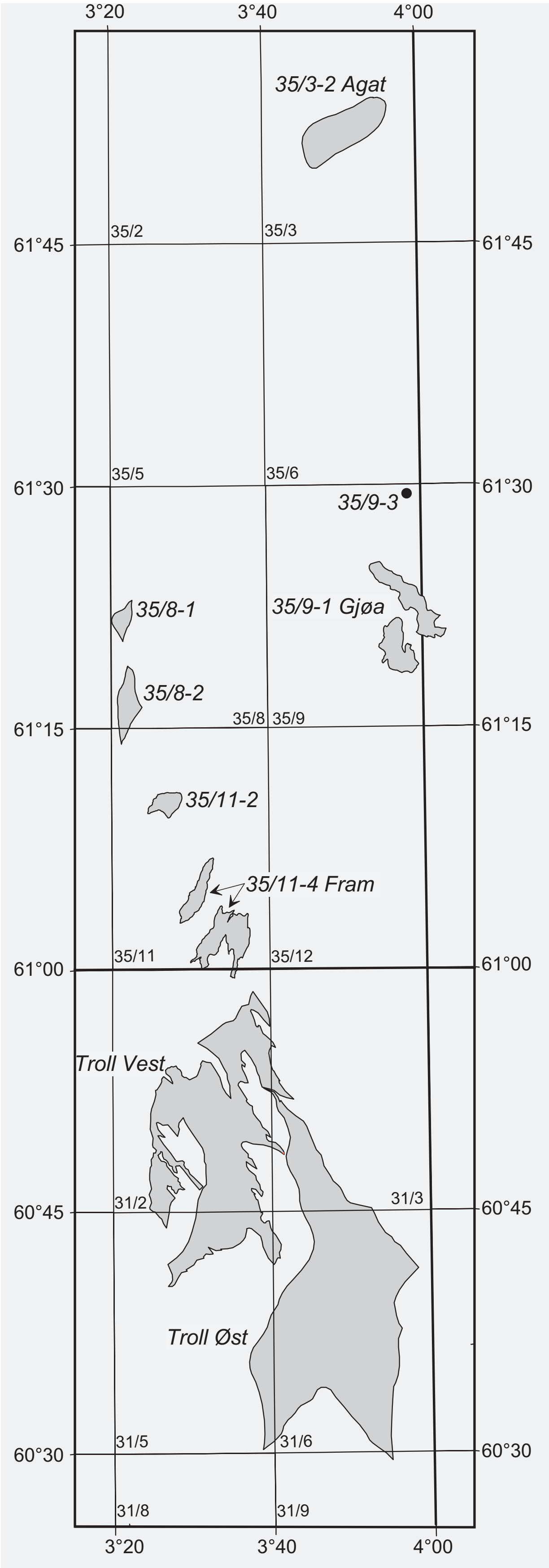
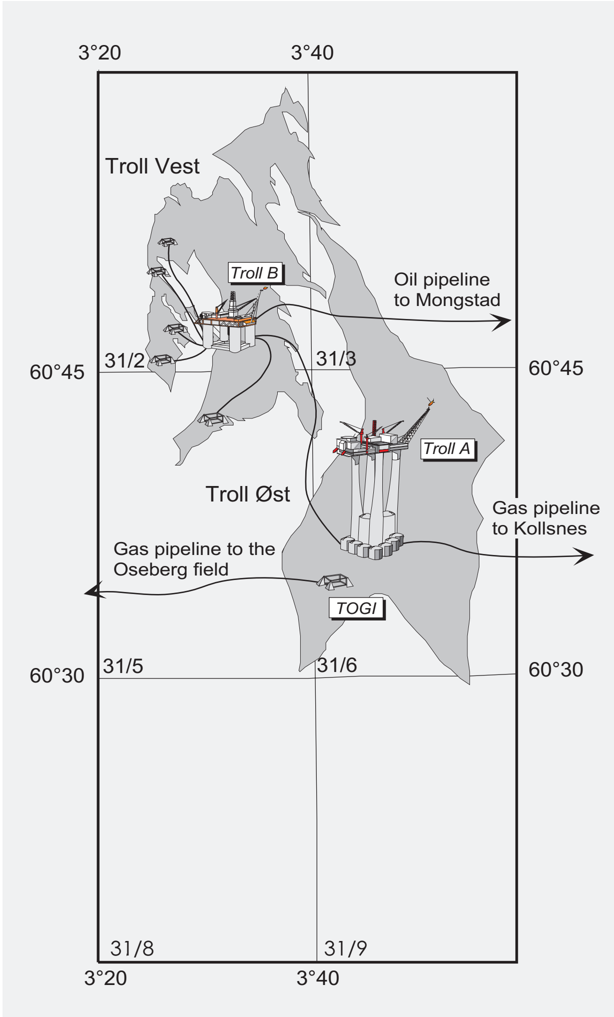


Figure 1.4.16.b
The Troll field



produced together with the oil is transported via Troll A to Kollsnes for treatment and further export to the market, see Figure 1.4.16.b.

At least seven well groups in the northern part of the gas province will be connected to a new installation, Troll C, which will be a semi-submersible steel installation. The installation will have an oil treatment capacity of 20,000 Sm^3 per day. A new oil pipeline will be laid from Troll C to Mongstad, and a gas pipeline will be laid to Troll A in order to utilize existing transportation opportunities to Kollsnes and on to the export market. Troll C is expected to be in production starting in the autumn of 1999.

Troll Phase III: Development of the gas resources in Troll Vest gas province

Development

Troll Vest gas province has a gas column of up to 200 meters over the oil zone. Approved and future recovery of the oil resources is regarded as being time-critical in relation to production of gas from Troll. Therefore, it is uncertain when major gas withdrawals from Troll Vest should start. The consideration for the optimal recovery of oil and gas, the Troll field's total commitments and physical delivery capability for gas, seen in context with gas supply solutions for the Norwegian shelf, will be included in the evaluation of the timing for development of Troll Phase III.

1.4.17 GULLFAKS AREA

Gullfaks and Gullfaks Vest

Production licenses: 050 and 050B	**Blocks:** 34/10
Operator: Den norske stats oljeselskap a.s	
Licensees:	
Den norske stats oljeselskap a.s (SDFI 73 %)	85.00000 %
Norsk Hydro Produksjon AS	9.00000 %
Saga Petroleum ASA	6.00000 %
Discovery well: 34/10-1 Gullfaks	Year: 1978
34/10-34 Gullfaks Vest	Year: 1991
Development approved:	Prod.start:
Phase I 1981	December 1986
Phase II 1985	
Gullfaks Vest 1993	
Lunde formation 1995	
Recoverable reserves: Gullfaks	315.4 million Sm^3 oil 21.2 billion Sm^3 gas 2.0 million tonnes NGL
Recoverable reserves: Gullfaks Vest:	3.6 million Sm^3 oil
Total investments (firm 1998-NOK):	
Gullfaks	NOK 72.0 billion
Gullfaks Vest	NOK 0.2 billion
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:	NOK 2499 million

Production

The Gullfaks field, see Figure 1.4.17.a, contains oil in sandstone from the Jurassic and Triassic Ages. The reservoir lies relatively shallow, and is made up of several angled fault blocks. The blocks have variable slope degrees and parts of the area are heavily eroded. The field is complicated to produce due to the many faults.

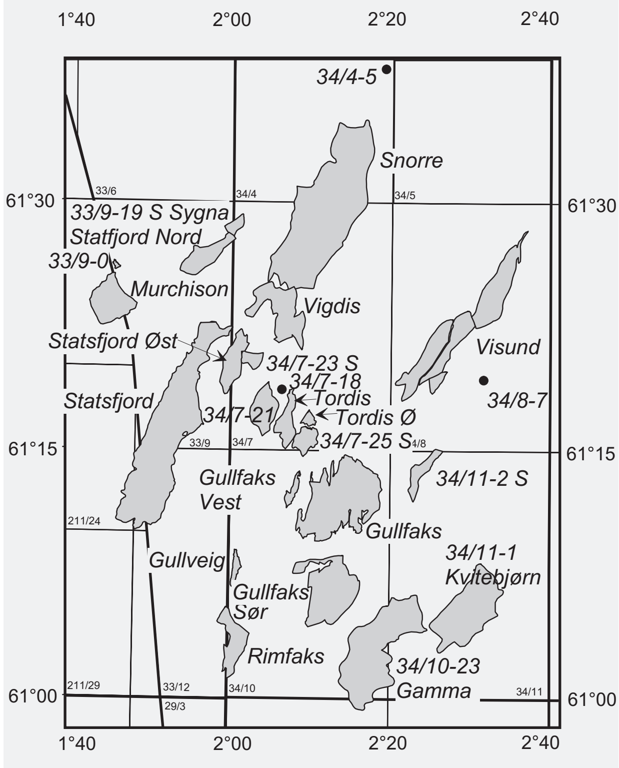
The reservoirs in Phases I and II are separated by a major north/south fault. Some communication across the fault has been proven in the northern area. Faults with more than 1000 meter skip distance delimit the field in the south, east and northeast.

The drive mechanism on the field is primarily pressure maintenance by means of water injection. Alternating injection of water and gas (WAG) is carried out where the method is appropriate. The use of gel to block water-producing layers has been attempted with successful results.

The number of operative wells, which varies over time, is approximately 90. Drilling of long range wells and sidetrack drilling from existing wells are important methods for increased oil recovery on Gullfaks.

Based on the basis reserves for the entire Gullfaks area, one or more of the Gullfaks installations may have a lifetime up to 2016. In the final stages, the utilization of the installations will depend on discoveries in prospects and third-party use of the facilities.

Figure 1.4.17.a
Fields and discoveries in the Gullfaks, Statfjord and Snorre area



Gullfaks Vest is an oil field which lies to the west of Gullfaks in block 34/10, see Figure 1.4.17.a. Production is based on natural water drive.

Development

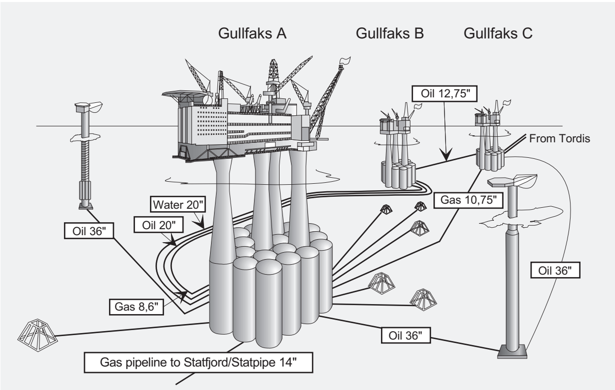
The Gullfaks installations are the Condeep-type concrete gravity base structures with steel frame topside, see Figure 1.4.17.b. The C installation is basically built as a copy of Gullfaks A. All three are fully-integrated process, drilling and living quarters installations, while Gullfaks B has a simplified process facility with only first stage separation.

Gullfaks A, which is situated on the southwestern part of the field, started production in December 1986. Treatment capacity for oil is 60,000 Sm^3 per day, while capacity for water is 35,000 m^3 per day. Water injection capacity on Gullfaks A is 75,000 m^3 per day. Gullfaks A is also equipped for gas injection with a capacity of 3.2 million Sm^3 per day.

Gullfaks B is situated on the northwestern part of the field and was put into production in February 1988. It has a first stage liquid capacity of 45,000 Sm^3 per day. The oil from Gullfaks B is transferred to Gullfaks A and Gullfaks C for further processing and storage. The water injection capacity is 30,000 m^3 per day. Injection water is transferred from Gullfaks A.

Gullfaks C is located on the eastern part of the field for production of the reserves in Phase II. Production started at the turn of the year 1989/1990. The process capacity of the installation is 60,000 Sm^3 oil and 30,000 m^3 produced water per day. Up to 60,000 m^3 water can be injected per day. At the end of 1995, a compressor was installed for injection of gas on Gullfaks C also, with a capacity of 2.2 million Sm^3 per day.

Figure 1.4.17.b
Installations on Gullfaks



Gullfaks A and C have storage cells for storage of stabilized oil. The oil is fiscally metered and exported via loading buoys to tankers. Processed rich gas is fiscally metered on Gullfaks A and C before it is sent into Statpipe via Statfjord C. Oil from Gullfaks Vest is metered with the aid of a test separator on Gullfaks C. The Tordis wellstream is metered after first stage separation on Gullfaks C. The metered and analyzed volumes are then further treated in the process facilities on Gullfaks C before the oil is loaded via the single-point buoy mooring system and the gas is delivered to Statpipe. Oil from Vigdis will be fiscally metered on Snorre prior to loading from Gullfaks A. The plan is also to load oil from the Visund field from Gullfaks A. Gas and liquid from Gullfaks Sør, Rimfaks and Gullveig will be metered using multi-phase meters in connection with a test separator.

Gullfaks as infrastructure
In addition to Gullfaks Vest, the installations on Gullfaks will also be used in connection with production from Tordis, Tordis Øst, Vigdis, Visund, Rimfaks, Gullfaks Sør and Gullveig.

May 1994 saw the beginning of deliveries from Tordis to Gullfaks C where the oil is processed. In 1995, approval was also granted to tie Tordis Øst into Gullfaks C. In 1994, it was decided that processed oil from Vigdis (via Snorre) would be delivered to Gullfaks A for storage and loading to tankers. A similar agreement for Visund was made in December 1995.

Development of the oil resources (Phase I) in Gullfaks Sør, Rimfaks and Gullveig, which was approved by the authorities in 1996, will be tied into Gullfaks A. According to the plan, Gullfaks Sør Brent Phase II, which comprises production of gas and associated liquid, will be tied into Gullfaks C. In 1995, the Gullfaks licensees, production license 050, were awarded previously relinquished areas of block 34/10. The Gullfaks installations can also be used for new discoveries in this area. There are also other discoveries which may be developed towards Gullfaks.

Gullfaks Sør

Production licenses: 50 and 50B	**Block:** 34/10
Operator: Den norske stats oljeselskap a.s	
Licensees:	
Den norske stats oljeselskap a.s (SDFI 73 %)	85.00000 %
Norsk Hydro Produksjon AS	9.00000 %
Saga Petroleum ASA	6.00000 %
Discovery well: 34/10-2	Year: 1979
Development approved: Phase I 1996	Prod.start: 1999
Recoverable reserves: Phase I:	25.4 million Sm^3 oil 1.2 billion Sm^3 gas
Recoverable resources: Phase II:	14.6 million Sm^3 oil 58.3 billion Sm^3gas
Total investments (firm 1998-NOK):	
Phase I:	NOK 4.5 billion
Phase II:	NOK 6.3 billion
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance:	
Phase I:	NOK 150 million
Phase II:	NOK 230 million

Gullfaks Sør lies about 9 km to the south of Gullfaks, see Figure 1.4.17.a, and contains oil and gas in sandstone from the Jurassic and Triassic Ages. The Brent reservoir contains oil and a gas cap with high condensate content. Several independent gas/oil and oil/water contacts have been observed. The Statfjord reservoir has a thicker oil zone and a smaller gas cap than the Brent reservoir. There is also oil and gas in the Lunde formation.

Phase I
Production
Gullfaks Sør Phase I comprises production of oil and condensate. The plan for development and operation of Phase I was approved in 1996 together with Rimfaks and Gullveig. The plan is to produce the liquid resources in Phase I through gas injection.

Development
The development solution comprises four subsea templates with 12 wells. The plan is to integrate development and operations with Rimfaks and Gullveig. Processing of the wellstream will take place on Gullfaks A.

Production start-up for Phase I is planned for April 1999. The field is expected to produce 13,000 Sm^3 oil per day which will be stored on and shipped from Gullfaks A. Produced gas will be reinjected in the reservoir. The initial gas injection capacity is planned to be 2.7 million Sm^3 per day. Gas will also be sent to Rimfaks for injection.

Phase II
Production
Gullfaks Sør Phase II comprises production of gas and associated liquid. In 1997, Gullfaks Sør Brent was allocated gas deliveries from 1999. The plan for development and operation was approved by the Storting on 8 June 1998.

Development
The plan comprises two new subsea templates and 13 wells, of which one is drilled from one of the existing templates from Phase I. In addition, provision will be made for installation of an extra subsea template with the possibility of drilling up to four extra wells. The plan is to process the wellstream on Gullfaks C. Planned production start-up is the year 2001. Early gas sales are secured by using gas from Phase I or by borrowing gas from the Gullfaks main field.

Rimfaks

Production licenses: 50 and 50B	**Blocks:** 34/10 and 33/12
Operator: Den norske stats oljeselskap a.s	
Licensees:	
Den norske stats oljeselskap a.s (SDFI 73 %)	85.00000 %
Norsk Hydro Produksjon AS	9.00000 %
Saga Petroleum ASA	6.00000 %
Discovery well: 34/10-17	Year: 1973
Development approved: Phase I: 1996	Prod.start: 1999
Recoverable reserves: Phase I	16.9 million Sm^3 oil -1.2 billion Sm^3 gas
Total investments (firm 1998-NOK): Phase I	NOK 3.9 billion
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance:	NOK 130 million

Production
Rimfaks, which lies approx. 15 kilometers southwest of Gullfaks, see Figure 1.4.17.a, contains oil and gas in sandstone in the Brent group and Statfjord formation from the Jurassic Age. The main part of the field lies in block 34/10, production license 050, while a small part extends into block 33/12. An agreement has been signed with production license 037 regarding production of the deposit which extends into block 33/12.

The reservoirs contain oil and gas with a high condensate content. The plan for development and operation of Phase I, which comprises the liquid phase, was approved in 1996 together with Gullfaks Sør and Gullveig. Phase II, which consists of the gas phase, is not included in this plan. The plan is to produce the field using gas injection.

Development
The development concept includes three subsea templates with 10 wells. Processing of the wellstream will take place on the Gullfaks A installation. Production start-up is planned for March 1999. The field is expected to produce 13,500 Sm^3 oil per day, which will be stored on Gullfaks A and shipped. The gas from the field will be reinjected in the reservoir. Rimfaks will also receive gas from Gullfaks Sør for injection. Initial gas injection capacity is planned to be 7.5 million Sm^3 per day.

Gullveig

Production licenses: 50 and 50B	**Block:** 34/10
Operator: Den norske stats oljeselskap a.s	
Licensees:	
Den norske stats oljeselskap a.s (SDFI 73 %)	85.00000 %
Norsk Hydro Produksjon AS	9.00000 %
Saga Petroleum ASA	6.00000 %
Discovery well: 34/10-37	Year: 1995
Development approved: 1996	Prod.start: 1998
Recoverable reserves:	4.2 million Sm^3 oil 2.9 billion Sm^3 gas
Total investments Phase I (firm 1998-NOK):	NOK 0.7 billion
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance:	NOK 25 million

Production
Gullveig contains oil in sandstones from the Brent group of the Jurassic Age, see Figure 1.4.17.a. Resources have also been proven in the Statfjord formation. The plan is to produce the field by means of depressurization.

Development
Gullveig started producing on 10 October 1998. The development concept comprises a subsea template with two wells that are connected to the Gullfaks A installation.

1.4.18 STATFJORD AREA

Statfjord

Production license: 037	**Blocks:** 33/9 and 33/12
Operator: Den norske stats oljeselskap a.s (1)	
Licensees:	
Norwegian part (85.46869 %)	
Den norske stats oljeselskap a.s	42.73434 %
Mobil Development Norway AS	12.82030 %
Norske Conoco A/S	9.43717 %
Esso Expl & Prod Norway A/S	8.54687 %
A/S Norske Shell	8.54687 %
Saga Petroleum ASA	1.60254 %
Enterprise Oil Norwegian AS	0.89030 %
Amerada Hess Norge AS	0.89030 %
British part (14.53131 %)	
Conoco North Sea Inc	4.843769 %
BP Petroleum Development Ltd.	4.843769 %
Chevron U.K. Ltd.	4.843769 %
Discovery well: 33/12-1	Year: 1974
Development approved: 1976	Prod.start: 1979
Recoverable reserves: 2)	555.7 million Sm^3 oil 56.4 billion Sm^3 gas 14.4 million tonnes NGL
Total investments (firm 1998-NOK):	NOK 72.5 billion
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:	NOK 2407 million

1) Mobil was operator of the field until 1 January 1987 when Statoil assumed responsibility as operator.
2) Norwegian share (85.46869 per cent)

Production

The Statfjord field, see Figure 1.4.17.a, consists of a large fault block sloping to the west, as well as a number of smaller fault blocks along the east flank. A smaller portion of the field extends onto the British continental shelf. The reservoirs on the Statfjord field consist of sandstone from the Brent group, the Cook formation and the Statfjord formation.

Up to the present time, the Brent reservoir has been produced with the aid of pressure support from water injection. A test project with WAG injection was implemented in 1997 in the lower Brent to examine the effect of supplementary gas injection. Based on the results of the project and reservoir studies conducted, it was decided in 1998 that WAG injection would be started in Brent. Calculations indicate that WAG injection provides increased oil recovery in the order of 12-13 million Sm^3.

The Statfjord formation has been produced with the aid of pressure support from gas injection. Implementation of a new production strategy for the Statfjord formation, with upflank water injection and supplementary gas injection in the upper Statfjord and downflank WAG injection in lower Statfjord, is still being evaluated. Tests with WAG injection in the lower Statfjord commenced in the autumn of 1994. Tests using water injection in the upper Statfjord started in February 1996. The future implementation of a new production strategy will take place in stages and will depend on additional production experience and reservoir studies.

The Cook reservoir came onstream in 1994. The production strategy for Cook is based on phasing in wells which have already penetrated the reservoir, and possibly deepening of existing wells. Production will receive pressure support from water injection.

In order to achieve better exploitation of the remaining reserves, the operator is continually updating the production strategy for the field. The strategy entails both more wells and extensive re-use of the wells in several reservoir zones. Use of horizontal wells and long-range, high-deviation wells is also included in the strategy.

Development

The field is developed in three phases with the fully integrated installations A, B and C, see Figure 1.4.18. The Statfjord A installation is located near the center of the Statfjord field. It is a fully integrated installation with a concrete gravity base composed of 14 storage cells and three shafts. Processing capacity for oil is roughly 67,000 Sm^3 per day, while the oil storage capacity is 175,000 Sm^3. The capacity for water injection on Statfjord A is about 69,000 m^3 per day. Statfjord A started producing in November 1979. Loading of oil takes place via one of the three oil loading systems on the field. From August 1992, production from Snorre has been received at Statfjord A after second stage separation. This has enabled better utilization of Statfjord A's available process capacity.

The Statfjord B installation is located in the southern part of the Statfjord field. It is a fully integrated installation with a concrete gravity base composed of 24 storage cells and four shafts. Production capacity is approximately 40,000 Sm^3 per day. The installation has its own storage capacity for oil, 302,000 Sm^3. Capacity for water injection on Statfjord B is approx. 64,000 m^3 per day. Statfjord B started production in November 1982.

The Statfjord C installation is located in the northern part of the Statfjord field. It is a fully integrated installation, structurally identical to Statfjord B. The production capacity is now approximately 52,000 Sm^3. The capacity for water injection on Statfjord C is about 62,000 m^3 per day. Statfjord C came onstream in June 1985. The Statfjord satellites have their own intake separator on Statfjord C with a capacity of roughly 25,000 Sm^3 oil.

Gas is transported via the Statpipe pipeline and sold in Emden, while NGL is removed at Kårstø and sold there. The United Kingdom takes its share of the gas through NLGP (Northern Leg Gas Pipeline) from Statfjord B to Shell's terminal in St. Fergus, Scotland where the gas is sold. Stabilized oil is stored in storage cells on each installation prior to being pumped onto tankers via one of the three loading systems on the field.

Oil and gas are metered to fiscal standard on each of the three installations. After Snorre started production, Statfjord A production is determined as the difference between the total volume metered on Statfjord A and the volume metered on Snorre.

A similar concept is used for determination of Statfjord C production after the Statfjord satellites began producing. The distribution between the satellites will be based on test separator metering, while the total volume from the satellites will be metered to fiscal standard.

The north flank of the Statfjord field will be developed with subsea installations tied to Statfjord C. Production start-up from the north flank is scheduled for the summer of 1999. In 1998, a decision was also made to tie the Sygna field to Statfjord C for processing, stabilization, storage and export.

Statfjord Øst

Production licenses: 037 (50 %) 089 (50 %)	**Blocks:** 33/9 and 34/7
Operator: Den norske stats oljeselskap a.s	
Licensees:	
Den norske stats oljeselskap a.s (SDFI 40.5 %)	52.70000 %
Esso Expl & Prod Norway A/S	10.25000 %
Mobil Development Norway AS	7.50000 %
Norske Conoco A/S	6.04140 %
A/S Norske Shell	5.00000 %
Idemitsu Petroleum Norge AS	4.80000 %
Saga Petroleum ASA	4.78800 %
Norsk Hydro Produksjon AS	4.20000 %
Elf Petroleum Norge AS	2.80000 %
Deminex Norge AS	1.40000 %
Enterprise Oil Norwegian AS	0.52060 %
Discovery well: 33/9-7	Year: 1976
Development approved: 1990	Prod.start: 1994
Recoverable reserves:	36.4 million Sm^3 oil 5.2 billion Sm^3 gas 1.8 million tonnes NGL

Total investments (firm 1998-NOK):	NOK 4.2 billion
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:	NOK 188 million

Production

The reservoir on the Statfjord Øst field consists of sandstones from the Middle Jurassic Age in the upper and lower part of the Brent group. The field is currently produced using pressure support assisted by water injection, with a total of six production wells and three injection wells. During the course of 1999, the seventh and final planned production well will be drilled and put into production. The need for a fourth injection well, as well as the need for well workovers and side drilling of the existing wells on the field, is constantly under evaluation.

On the basis of a new reservoir model, the oil reserves in Statfjord Øst were adjusted upwards in 1998 from 32.0 to 36.4 million Sm^3.

Development

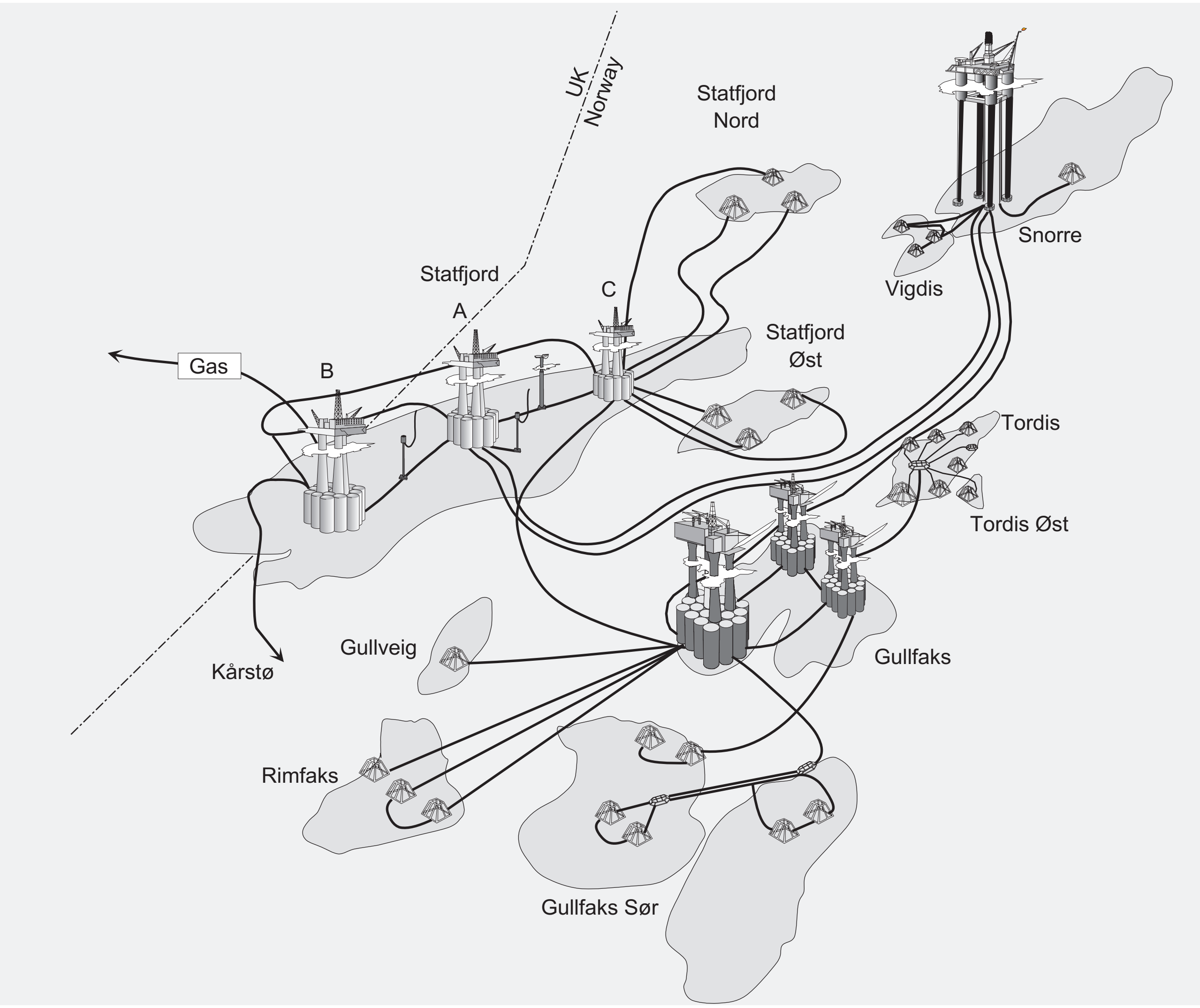
The field is developed with subsea installations which are coupled to the Statfjord C installation. The subsea installations consist of three templates, two for production and one for water injection, see Figure 1.4.18. Each template has four well slots. The wellstream is transferred via two pipelines to Statfjord C for processing, storage and further transportation. Statfjord Øst and Statfjord Nord utilize common processing facilities on Statfjord C. The inlet separator on Statfjord C has a production capacity of about 25,000 Sm^3 oil per day. The water injection capacity is approx. 18,500 m^3 per day.

The Statfjord satellites are metered to fiscal standard in a common metering system on Statfjord C. Return allocation to the individual satellite field is done on the basis of test separator metering.

Statfjord Nord

Production license:	037	**Block:**	33/9
Operator: Den norske stats oljeselskap a.s			
Licensees:			
Den norske stats oljeselskap a.s (SDFI 30 %)		50.000000 %	
Mobil Development Norway AS		15.000000 %	
Norske Conoco A/S		12.083334 %	

Figure 1.4.18
Infrastructure in the Statfjord, Gullfaks and Snorre area



A/S Norske Shell		10.000000 %
Esso Expl & Prod Norway A/S		10.000000 %
Saga Petroleum ASA		1.875000 %
Enterprise Oil Norwegian AS		1.041667 %
Discovery well:	33/9-8	Year: 1977
Development approved: 1990		Prod.start: 1995
Recoverable reserves:		40.6 million Sm^3 oil 3.0 billion Sm^3 gas 0.7 million tonnes NGL
Total investments (firm 1998-NOK):		NOK 5.1 billion
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:		NOK 582 million

Production

The reservoir on Statfjord Nord consists of sandstone belonging to the Brent group (Middle Jurassic) and sandstone of the Late Jurassic Age. The field is currently produced by means of pressure support aided by water injection with a total of seven production wells and three injection wells. During the course of 1999, the two final planned wells will be drilled, one production well and one injection well. There is continuous evaluation of the need for well workovers and side drilling of existing wells on the field.

Development

The field is developed with subsea installations connected to the Statfjord C installation. The subsea installations consist of three templates, of which two are for production and one for water injection, see Figure 1.4.18. Each template has four well slots. The wellstream is transferred via two pipelines to Statfjord C for processing, storage and further transportation. Statfjord Nord and Statfjord Øst use common facilities on Statfjord C. The inlet separator on Statfjord C has a production capacity of approximately 25,000 Sm^3 oil per day. The capacity for water injection is approximately 15,500 m^3 per day.

It has been decided that the last available well slot on the Statfjord Nord injection template will be used for an injection well on the Sygna field. Therefore, during the course of 1999, an upgrading of the water injection capacity to the Statfjord Nord area will be implemented in the amount of 12,500 m^3 per day, so that the injection capacity will be 28,000 m^3 per day.

The Statfjord satellites are metered to fiscal standard in a common metering system on Statfjord C. Return allocation to the individual satellite field is done on the basis of test separator metering.

Production from the Statfjord satellites has contributed to, and will over the next few years continue to contribute to, very good exploitation of the process facilities on Statfjord C.

1.4.19 TORDIS AREA

Tordis

Production license:	089	**Block:**	34/7
Operator:	Saga Petroleum ASA		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 51 %)		55.40000 %	
Esso Expl. & Prod. Norway A/S		10.50000 %	
Idemitsu Petroleum Norge AS		9.60000 %	
Norsk Hydro Produksjon AS		8.40000 %	
Saga Petroleum ASA		7.70000 %	
Elf Petroleum Norge AS		5.60000 %	
Deminex Norge AS		2.80000 %	
Discovery well:	34/7-12	Year: 1987	
Development approved:	1991	Prod.start: 1994	
Recoverable reserves:		29.1 million Sm^3 oil 2.1 billion Sm^3 gas 0.7 million tonnes NGL	
Total investments (firm 1998-NOK):		NOK 4.2 billion	
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:		NOK 87 million	

Production

The reservoir on the Tordis field consists of sandstone in the upper and lower part of the Brent group from the Middle Jurassic Age. Faults divide the field into three main segments, one southern, one western and one eastern segment. New interpretations suggest that good communication over the three different segments of the field is quite likely.

The plan is to produce the field, see Figure 1.4.17.a, with pressure maintenance with the aid of water injection using five production wells and two injection wells. Drilling of the injection wells has previously been postponed as the reservoir has more natural pressure support from the water zone than expected. Drilling of the first injection well on Tordis is now planned for the first quarter of 1999.

Development

The field is developed with a subsea installation which is connected to the Gullfaks C installation. The subsea installation consists of a central manifold with connection points for satellite wells and other well templates, see Figure 1.4.18.

The wellstream from Tordis is transferred to Gullfaks C and is separated in a dedicated one-stage process. Processing capacity for liquid from Tordis on Gullfaks C is 16,000 Sm^3 per day. Oil and gas are metered prior to further treatment in the existing process facilities on Gullfaks C. The oil is exported via loading buoys to tankers. The gas is transported in the Statpipe system.

In 1998, Tordis Øst was connected to the central manifold for the Tordis subsea installation, thereby contributing to good exploitation of the installations and the process capacity on Tordis.

Tordis Øst

Production license:	089	**Block:**	34/7
Operator:	Saga Petroleum ASA		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 51 %)		55.40000 %	
Esso Expl. & Prod. Norway A/S		10.50000 %	
Idemitsu Petroleum Norge AS		9.60000 %	
Norsk Hydro Produksjon AS		8.40000 %	

Saga Petroleum ASA	7.70000 %
Elf Petroleum Norge AS	5.60000 %
Deminex Norge AS	2.80000 %
Discovery well: 34/7-22	Year: 1993
Development approved: 1995	Prod.start: 1998
Recoverable reserves:	4.4 million Sm^3 oil 0.4 billion Sm^3 gas 0.1 million tonnes NGL
Total investments (firm 1998-NOK):	NOK 0.8 billion
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance:	NOK 19 million

Production

The field, see Figure 1.4.17.a, consists of two main segments, a northern and a southern segment, separated by an east-west oriented fault. For the most part, the reserves are found in the Tarbert formation belonging to the Brent group of the Middle Jurassic Age. Drilling of two observation wells in 1997 and a production well in 1998 have shown that the reservoir is more complex with a more complicated fault pattern than previously assumed.

The production plan for the field is to use one production well and one water injection well. The decision regarding the need for the injection well on Tordis Øst will be made after some production experience has been gained, and is dependent on the communication across the fault, as well as the amount of natural pressure support the field has from the underlying water zone. Tordis Øst commenced production on 15 December 1998.

Development

The field is developed by means of a four-well subsea template which is tied into the subsea manifold on the Tordis field, see Figure 1.4.18. The wellstream from Tordis and Tordis Øst is mixed and then transported through existing field pipelines to the Gullfaks C installation for processing, metering, storage and shipping.

The plan is that Tordis Øst will use one of the four well slots on the subsea template. A well slot has also been used for test production of the 34/7-21 discovery in 1998. The plan is to use remaining available slots for production of other discoveries in the area.

In the event of a need for water injection, Tordis Øst will receive injection water from Tordis. The injection well will be drilled from a new four-well subsea template that will be connected to the subsea manifold on the Tordis field. This template will be used for injection wells in the Tordis area, and will be installed during the course of 1999.

1.4.20 VISUND

Production license: 120	**Blocks:** 34/8 and parts of 34/7
Operator: Norsk Hydro Produksjon AS	
Licensees for the Visund field:	
Den norske stats oljeselskap a.s (SDFI 49.6 %)	62.90000 %
Norsk Hydro Produksjon AS	16.10000 %
Elf Petroleum Norge AS	7.70000 %
Norske Conoco AS	9.10000 %
Saga Petroleum ASA	4.20000 %
Discovery well: 34/8-1	Year: 1986
Development approved: 1996	Prod.start: 1999
Recoverable reserves:	48.5 million Sm^3 oil
Total investments (firm 1998-NOK):	NOK 11.3 billion
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance:	NOK 485 million

Production

The Visund field lies about 22 kilometers to the northeast of Gullfaks, see Figure 1.4.17.a, and contains oil and gas in sandstone from the Jurassic and Triassic Ages.

The reservoir is made up of tilted and rotated fault blocks. The field contains several separate liquid systems and is complicated to produce.

During production of the oil phase (Phase I), the drive mechanism will be pressure maintenance through water injection and gas injection. The drilling of 23 wells is planned in Phase I. All gas will be reinjected into the reservoir until a gas sales agreement has been realized.

Development

According to the plan for development and operation, the field will be developed with a semi-submersible steel installation equipped for complete stabilization of oil and injection of gas and water. The installation is designed to produce 16,000 Sm^3 oil per day, which will be transported via a pipeline to Gullfaks A for storage and shipping.

The initial planned gas injection capacity will be 10 million Sm^3 per day. Water from the Utsira formation and produced water will be injected with a capacity of 18,000 m^3 per day. Drilling and well maintenance will be carried out from the installation. Planned production start-up is May 1999.

1.4.21 VIGDIS

Production license: 089	**Block:** 34/7
Operator: Saga Petroleum ASA	
Licensees:	
Den norske stats oljeselskap a.s (SDFI 51 %)	55.40000 %
Esso Expl. & Prod. Norway A/S	10.50000 %
Idemitsu Petroleum Norge AS	9.60000 %
Norsk Hydro Produksjon AS	8.40000 %
Saga Petroleum ASA	7.70000 %
Elf Petroleum Norge AS	5.60000 %
Deminex Norge AS	2.80000 %
Discovery well: 34/7-8	Year: 1986
Development approved: 1994	Prod.start: 1997
Recoverable reserves:	30.7 million Sm^3 oil 2.2 billion Sm^3 gas
Total investments (firm 1998-NOK):	NOK 4.9 billion
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:	NOK 93 million

Production

The field consists of three separate main segments, one western, one middle and one eastern segment. The reservoir in the western and middle segment, which has been approved for development, consists of sandstones in the upper and lower part of the Brent group from the Middle

Jurassic Age. In the eastern segment (Vigdis Øst), oil has been proven in Upper Jurassic sand and in the Statfjord formation. Development of the resources in this segment will be viewed in context with further development of the entire Vigdis area.

The field is produced using pressure maintenance from water injection. Primarily, a total of eight production wells and four injection wells are planned. In order to increase the recovery from the main field, up to three additional production wells are being considered.

There is also a potential for additional resources in the surrounding structures, particularly in the eastern segment. Phase-in of potential additional resources can take place through drilling of wells from new subsea templates connected to the existing Vigdis installations, or through using slots which are freed when other wells are phased out due to high water production.

Development

The field, see Figure 1.14.17.a, is developed with subsea installations tied in to Snorre TLP. The subsea installations consist of three subsea templates, of which two are for production and one for water injection. Each subsea template contains four well slots. The wellstream is transferred to Snorre TLP for processing and metering. The process module for Vigdis on Snorre TLP is designed for an oil capacity of 18,000 Sm^3 per day. The stabilized oil is sent via a separate pipeline to Gullfaks A for storage and shipping. The gas that is produced from Vigdis is injected into the Snorre reservoir and contributes to increased oil recovery on Snorre.

Snorre TLP will also deliver injection water to Vigdis. The capacity for water injection is estimated to be approx. 22,000 m^3 per day.

There are several discoveries and prospects in the Vigdis area that are being considered for phase-in towards the Vigdis installations. Plans for future development of the Vigdis area will be considered during the course of 1999.

1.4.22 MURCHISON

Production license:	037	**Block:**	33/9
Operator: Oryx UK Energy Company [1]			
Licensees:			
Norwegian part (22.2 %)			
Den norske stats oljeselskap a.s		11.10000 %	
Mobil Development Norway AS		3.33000 %	
Norske Conoco A/S		2.45130 %	
Esso Expl & Prod Norway AS		2.22000 %	
A/S Norske Shell		2.22000 %	
Saga Petroleum ASA		0.41620 %	
Enterprise Oil Norwegian AS		0.23120 %	
Amerada Hess Norge AS		0.23130 %	
British part (77.8 %)			
Oryx UK Energy Company		68.72333 %	
Ranger Oil UK Ltd		9.076655 %	
Discovery well:	211/19-2	Year:	1975
Development approved:	1976	Prod.start:	1980
Recoverable reserves: [2]		13.3 million Sm^3 oil 0.4 billion Sm^3 gas 0.4 million tonnes NGL	

Total investments (firm 1998-NOK):	NOK 4.3 billion
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:	NOK 85 million

1) Oryx took over as operator of the field on 9 January 1995.
2) Norwegian share (22.2 per cent).

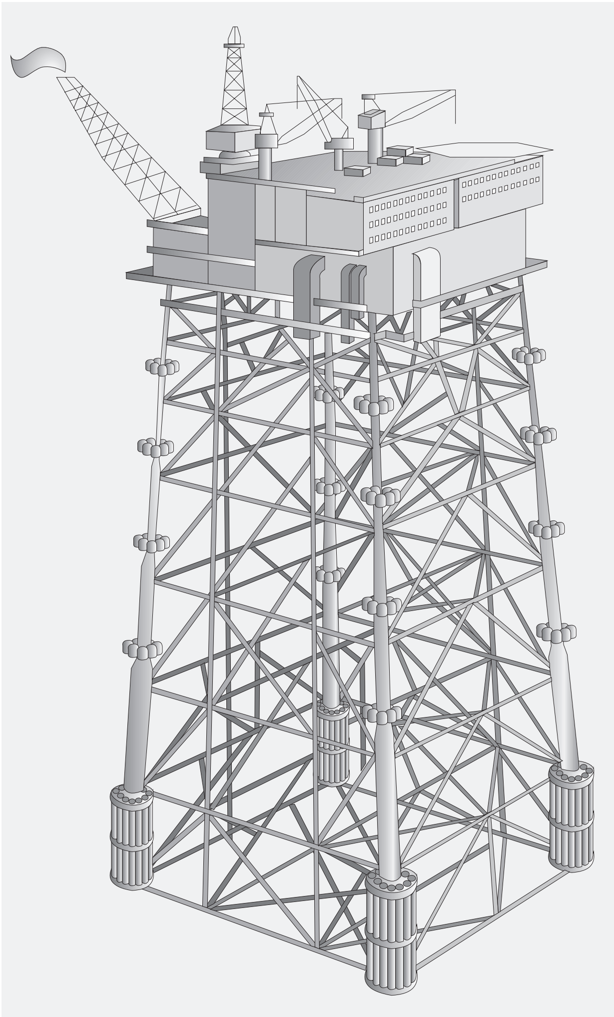
Production

The Murchison reservoir consists of sandstones belonging to the Brent group. The field has produced at nearly maximum liquid processing capacity since 1981, and water treatment capacity has been increased several times. Most of the production wells are now producing with a high water cut and some production wells have been shut down due to mechanical problems or very high production of water. Gas lift is used in some wells.

In the autumn of 1996, the Northeast horst, a small, separate structure within the unitized Murchison field, was drilled and put into production.

In order to increase oil production and extend field lifetime, damaged wells are repaired and new wells are drilled in undrained areas. Murchison is expected to produce until around the year 2004.

Figure 1.4.22
Installation on Murchison



Development

The field is developed with an integrated steel installation with a production capacity of 26,200 Sm^3 oil per day, see Figure 1.4.22.

Oil from Murchison is sent via pipeline to Sullom Voe on Shetland. The Norwegian share of the Murchison gas is landed via the NLGP pipeline (Northern Leg Gas Pipeline) to the Brent field on the British side, and on to St. Fergus, Scotland in the FLAGS pipeline (Far North Liquified and Associated Gas Gathering System). Gas deliveries through NLGP started in July 1983.

1.4.23 SNORRE

Production license: 089 and 057	Blocks: 34/7 and 34/4
Operator: Saga Petroleum ASA	
Licensees:	
Den norske stats oljeselskap a.s (SDFI 31.4 %)	41.40000 %
Saga Petroleum ASA	11.72450 %
Esso Expl. & Prod. Norway A/S	11.15810 %
Deminex Norge AS	8.87870 %
Idemitsu Petroleum Norge AS	9.60000 %
Norsk Hydro Produksjon AS	8.92650 %
Elf Petroleum Norge AS	5.95100 %
Amerada Hess Norge AS	1.18060 %
Enterprise Oil Norwegian AS	1.18060 %
Discovery well: 34/4-1	Year: 1979
Development approved:	Prod.start: 1992
Snorre Phase 1 1988	
Snorre - amended plan 1) 1994	
Snorre Phase 2 2) 1998	
Recoverable reserves: Phase 1	167.7 million Sm^3 oil 7.7 billion Sm^3 gas 5.7 million tonnes NGL
Recoverable reserves: Phase 2	57.6 million Sm^3 oil
Total investments (firm 1998-NOK)	
Phase: 1	NOK 34.0 billion
Phase: 2	NOK 11.7 billion
Operating costs Phase I, 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:	NOK 936 million

1) The amended plan for development and operation, which includes development of the upper portion of the Lunde formation in the reservoir zones L02-L05, upgrading of the process capacity on Snorre and increased use of gas injection in the reservoir, was approved in December 1994.

2) Plan for development of the northern areas of the field (Snorre Nord).

Production

The Snorre field, see Figure 1.4.17.a, consists of several larger fault blocks which are not generally regarded as having communication with each other. The reservoir rocks are fluvial sandstones in the Statfjord and Lunde formations of the Early Jurassic and Triassic Ages. The reservoir intervals vary from broad, continuous channel belts where reservoir communication is good, to narrower, isolated channel belts where the communication conditions are poorer.

Originally, the plan was to produce the field with water injection as the drive mechanism. Based on inter alia a pilot project in 1994 with WAG injection in the Statfjord formation, a decision was made to change the production strategy from water injection to downflank WAG injection in the entire Statfjord formation. Further optimization of the production strategy has also led to a change from water injection to upflank WAG injection in the Statfjord and Lunde formations in the eastern fault block on the field. Use of horizontal and high deviation wells drilled from the installation are also a part of the strategy.

In connection with preparation of a plan for development and operation (PDO) for the northern areas of the field (Snorre Phase 2) in 1998, a decision has been made to implement WAG injection as a production strategy for the entire field. The decision is based on comprehensive reservoir studies and results from WAG injection in the southern areas.

Development

The Snorre field will be developed in two phases. Phase I consists of a floating tension leg platform in the south (Snorre TLP), and a subsea template (Snorre SPS) connected to Snorre TLP in the central part of the field, see Figure 1.4.23. Oil and gas are separated in two stages on Snorre TLP, metered to fiscal standard, and transported further in separate oil and gas pipelines to Statfjord A for further processing. The oil from Snorre is exported via the loading system on Statfjord A. The gas is transported in the Statpipe system via Statfjord A. Snorre TLP started producing in August 1992.

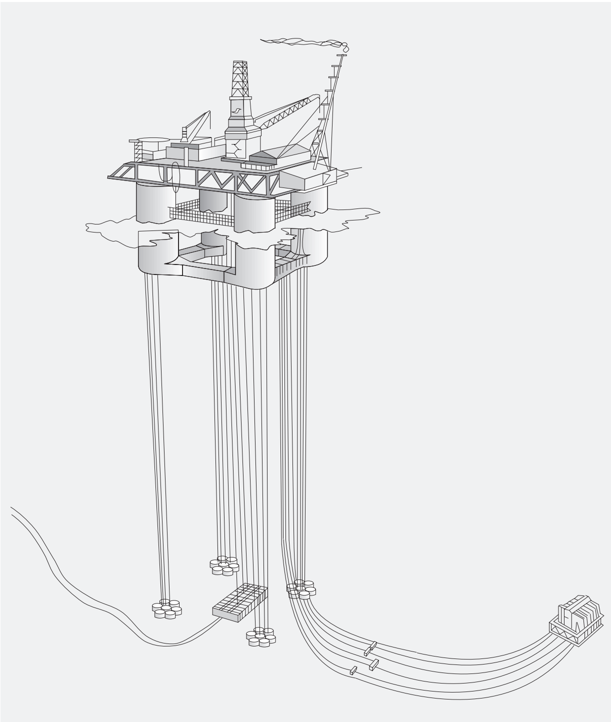
The increased reserves basis and increased need for gas injection have necessitated the upgrading of the process facilities on Snorre. Among other things, the capacity for oil processing and gas injection have been increased to 39,000 Sm^3 and 5 million Sm^3 per day, respectively. This upgrade was completed in 1997.

In connection with the development of Vigdis, a new process module for Vigdis was installed on Snorre TLP in 1996. The module contains a three stage separation train for full stabilization of oil from Vigdis, and is designed for an oil capacity of 18,000 Sm^3 per day. Oil from Vigdis is metered to fiscal standard and sent via a separate pipeline to Gullfaks A for storage and shipping.

A crossover pipeline has been laid between the Snorre and Vigdis process lines so that produced oil volumes from Vigdis can be transported both to Gullfaks and to Statfjord. Similarly, about half of the Snorre production may be transferred through this pipeline for processing on Gullfaks. This has been done to achieve a more flexible system.

Phase II of the Snorre development (Snorre B) comprises production from the northern part of the field. The plan for development and operation of Snorre Phase 2 was approved by the authorities in July 1998. The operator's plan is based on development with a semi-submersible steel production installation with drilling and injection facilities. The oil will be transferred to Statfjord B for storage and loading, while the gas will be reinjected into the Snorre reservoir in order to increase oil production.

Figure 1.4.23
Installations on Snorre



On Snorre B the oil processing capacity in first and second stage separation is designed for 18,000 Sm^3 per day. A capacity of 30,000 Sm^3 per day is planned for the third stage of separation, and this will provide for potential subsequent tie-in and final processing of partially stabilized oil from Snorre TLP. The capacity for processing and injection of gas is designed for 3 million Sm^3 per day. Provisions will be made for a potential subsequent upgrade of the gas capacity to 5 million Sm^3 per day. The decision regarding a potential upgrade will be based on production experience and further studies. Production start-up for Snorre B is planned for August 2001.

1.4.24 NJORD

Production licenses: 107 and 132	**Blocks:** 6407/7 and 6407/10
Operator: Norsk Hydro Produksjon AS	
Licensees:	
Den norske stats oljeselskap a.s (SDFI 30 %)	50.00000 %
Norsk Hydro Produksjon AS	22.50000 %
Mobil Development Norway AS	20.00000 %
Petro-Canada Norge AS	7.50000 %
Discovery well: 6407/7-1 S	Year: 1986
Development approved: Phase I 1995	Prod.start: 30.9.1997
Recoverable reserves:	31.6 million Sm^3 oil
Total investments (firm 1998-NOK):	NOK 7.8 billion
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:	NOK 428 million

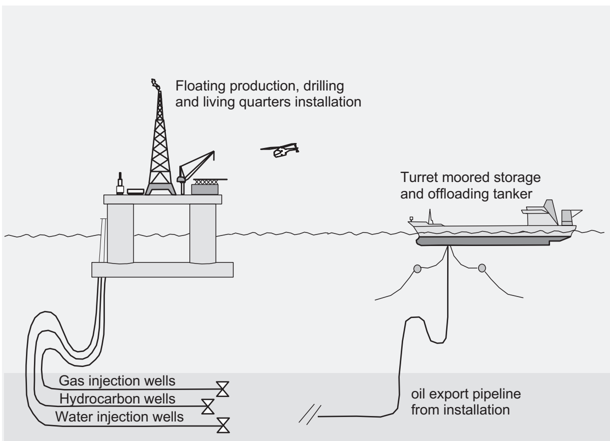
Production
The main reservoir is the Tilje formation of the Jurassic Age. The field, see Figure 1.4.25.a, is divided into a western and an eastern segment with a complicated fault pattern. The western segment, which contains oil and a minor gas deposit, will be produced by depressurization and limited water injection, while reinjection of produced gas is the drive mechanism for the oil-bearing eastern segment. Production experience may, however, lead to alternative drive mechanisms. At the end of 1998, three oil producers and three gas injectors were in operation.

The operator has mapped additional resources in the main structure and in adjoining areas. Reproduction and export of injected gas will be investigated by the operator when sufficient operating experience from the field is available.

Development
The Njord production installation consists of a spread catenary moored, semi-submersible production, drilling and living quarters installation, Figure 1.4.24. The installation is located directly over the field's subsea wells, which are connected to the installation via flexible risers. Of a total of 19 risers, the use of 15 is planned for production and injection purposes, one is used for oil export and three risers are available. The oil processing capacity is 11,000 Sm^3 per day. Water treatment and water injection capacity are each 2,500 m^3 per day, with flexibility for upgrading. The gas treatment and gas injection capacities amount to 10 million Sm^3 per day.

Stabilized oil is transferred to the tanker that lies 2.5 km from the installation for storage and loading onto shuttle tankers. The oil metering station is located on the deck of the storage ship, and stabilized oil is metered to fiscal standard in connection with transfer from storage ship to shuttle tanker.

Figure 1.4.24
Installations on Njord



1.4.25 DRAUGEN

Production license: 093	**Block:** 6407/9
Operator: A/S Norske Shell	
Licensees for the Draugen field:	
Den norske stats oljeselskap a.s (SDFI 57.88 %)	57.88000 %

A/S Norske Shell BP Petroleum Devel. of Norway AS Norsk Chevron AS	16.20000 % 18.36000 % 7.56000 %
Discovery well: 6407/9-1	Year: 1984
Development approved: Phase I 1988	Prod.start: 1993
Recoverable reserves:	111.3 million Sm^3 oil
Total investments (firm 1998-NOK):	NOK 16.2 billion
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:	NOK 519 million

Production
The Rogn formation of the Late Jurassic Age comprises the main reservoir. Additional resources have been proven in the Garn formation in the western part of the field, and phase-in is planned for when production from the Rogn formation begins to come off plateau in the year 2001/2002.

The field, see Figure 1.4.25.a, produces from five wells on the installation and two subsea-completed wells. Pressure support for oil production is ensured by five subsea-completed water injection wells. Associated gas is injected in a nearby water-bearing structure. Gas export via the Åsgard pipeline starting 1 October 2000 is being considered.

Figure 1.4.25.a
Fields and discoveries in the Norwegian Sea

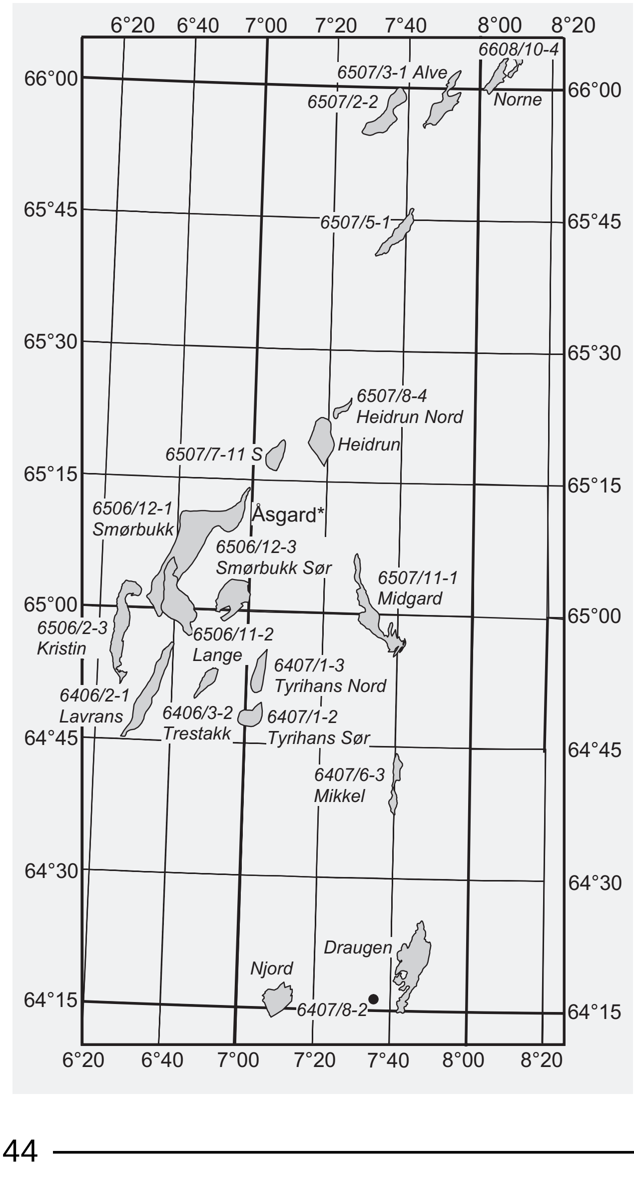
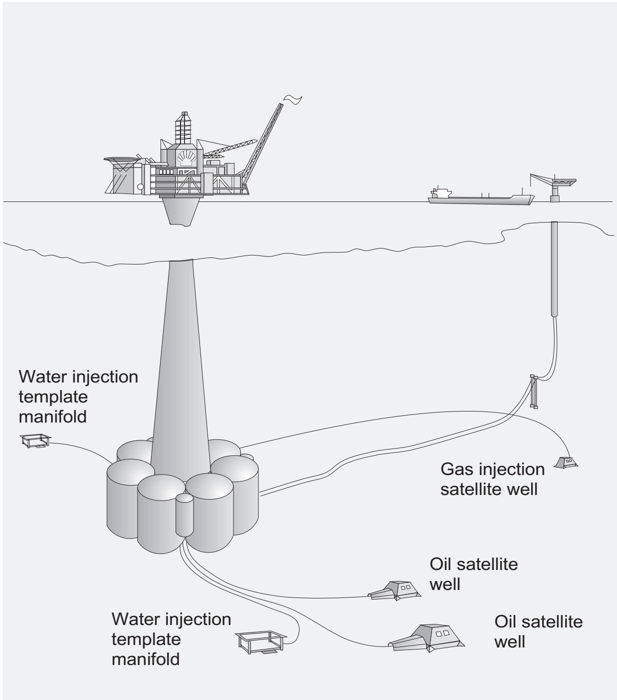


Figure 1.4.25.b
Installations on Draugen



Development
The field is developed with a concrete installation resting on the seabed with integrated topsides, see Figure 1.4.25.b. The installation has ten well slots and a total of 34 conductor casings. Production capacity has been upgraded to 33,400 Sm^3 per day. The water injection capacity is 42,000 m^3 per day. Treatment capacity for produced water amounts to 12,000 m^3 per day. The design capacities for gas treatment and gas injection are 1.2 and 1.04 million Sm^3 per day respectively. The daily production and injection of gas are well above the design capacities without resulting in limitations for the production of oil.

Stabilized oil is stored in tanks in the bottom of the installation. Oil is fiscally metered prior to export via floating loading buoys to tankers.

1.4.26 ÅSGARD

Production licenses: 094, 134, 062, 074 and 237	**Blocks:** 6506/11, 6506/12, 6507/11, 6407/02 and 6407/03
Operator: Den norske stats oljeselskap a.s	
Licensees:	
Den norske stats oljeselskap a.s (SDFI 46.95 %)	60.50000 %
Norsk Agip AS	7.90000 %
Total Norge AS	7.65000 %
Mobil Development Norway AS	7.35000 %
Neste Petroleum AS	7.00000 %
Saga Petroleum ASA	7.00000 %
Norsk Hydro Produksjon AS	2.60000 %

Discovery well:	6507/11-1	Year:	1981
Midgard			1984
	6506/12-1 Smørbukk		1985
	6506/12-3 Smørbukk Sør		
Development approved: 1996		Prod.start:	
Phase I		Phase I: March 1999	
Phase II		Phase II: 1 October 2000	
Recoverable reserves:		75.5 million Sm^3 oil 191.0 billion Sm^3 gas 28.3 million tonnes NGL 37.4 million Sm^3 cond.	
Total investments (firm 1998-NOK):		NOK 37.2 billion	
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance:		NOK 1700 million	

Åsgard comprises the development of the Smørbukk, Smørbukk Sør and Midgard discoveries, which are incorporated in a unitization agreement between the licensees in production licenses 062, 074, 094, 134 and 237. As a consequence of the agreement, Statoil and Saga are working in an integrated project with Statoil as operator. The agreement covers the development and construction periods.

Åsgard lies mainly within blocks 6506/11 and 6506/12 (Smørbukk), 6506/12 (Smørbukk Sør) and 6507/11 and 6407/2 (Midgard) on Haltenbanken, about 200 kilometers from land and 50 kilometers south of the Heidrun field. Åsgard, see Figure 1.4.25.a, is located in an area where the water depth varies from 240 to 300 meters. Recoverable reserves are estimated to be 191 billion Sm^3 gas, 75.5 million Sm^3 oil, 37.4 million Sm^3 condensate and 28.3 million tonnes NGL.

Production - Smørbukk

Blocks 6506/11 and 6506/12 were awarded under production licenses 094 and 134 in 1984 and 1987 respectively. Statoil was responsible for the Smørbukk discovery in 1984.

The Smørbukk discovery lies on a rotated fault block limited by faults to the west and north and structurally deeper areas towards the south and east. The reservoir formations Garn, Ile, Tofte, Tilje and Åre are from the Jurassic Age and contain gas, condensate and oil with a relatively high gas/oil ratio. The reservoir is located at depths of up to 4850 meters, which has led to a large portion of the reservoir having poor flow properties.

In the PDO, the operator planned to produce the Smørbukk discovery with a total of 38 wells, of which 22 are producers and 16 are gas injectors. Drilling of new wells resulted in some reduction in the estimates for in-place and recoverable resources. The new wells showed that the resource basis was smaller in the southern part of the Smørbukk discovery than previously assumed. This has led to adjustment of the production strategy and number of wells as compared with the PDO. The production strategy is initially based on reinjection of gas in order to optimize liquid recovery. At production start-up, four producers and three gas injectors will be drilled. The Smørbukk discovery will subsequently be produced using depressurization.

The recoverable reserves are estimated to be 70.7 billion Sm^3 gas, 32.5 million Sm^3 oil, 25.8 million Sm^3 condensate and 10.5 million tonnes NGL.

Production - Smørbukk Sør

Statoil discovered the Smørbukk Sør deposit in 1985. The petroleum trap in the Smørbukk Sør discovery is a salt dome to the northwest on the Halten Terrace. The reservoir rocks in the Garn, Ile and Tilje formations are from the Early to Middle Jurassic Age and contain oil, gas and condensate.

In the PDO, the operator planned to produce the Smørbukk Sør discovery with a total of ten wells, of which seven are producers and three are injectors. Subsequent optimization of the production strategy has resulted in changes to these figures. The production strategy is initially based on reinjection of gas in order to optimize oil recovery. At production start-up, five producing wells and two gas injectors will be drilled. Subsequently, the Smørbukk Sør discovery will be produced using depressurization.

Recoverable reserves are estimated to be 19.4 billion Sm^3 gas, 43 million Sm^3 oil and 2.9 million tonnes NGL.

Production Midgard

Blocks 6507/11 and 6407/2 were awarded under production licenses 062 and 074 in 1981 and 1982 respectively. Production license 237, awarded in 1998, comprises a minor part of block 6407/3. Saga discovered Midgard in 1981.

The petroleum trap which forms the Midgard discovery is a standing fault block (horst). The discovery is divided into four structural segments with main reservoirs in the Garn and Ile formations from the Middle Jurassic Age.

In the PDO, the operator planned to produce the Midgard discovery with a total of 12 production wells. The Midgard discovery will be produced using depressurization.

Recoverable reserves for the gas zone are estimated to be 100.9 billion Sm^3 gas, 11.6 million Sm^3 condensate and 14.9 million tonnes NGL.

Under the gas cap on the Midgard discovery there is a thin (11.5 meter) oil zone. An appraisal well (6507/11-5 S) was drilled in 1997 which confirmed the estimates of the oil resources on Midgard. Studies carried out during 1998 have shown that there is no commercial basis for producing the thin oil zone.

Development

The plan for development and operation (PDO) of Åsgard was approved by the Storting in June 1996.

Åsgard will be developed in two phases; an early liquid phase with planned production start in March 1999, and a gas export phase with delivery of gas from 1 October 2000. Åsgard is to deliver 6.3 billion Sm^3 gas in the year 2000, 8.9 billion Sm^3 per year in the years 2001-2006 and 10.8 billion Sm^3 per year as from 2007.

Åsgard will be developed with subsea-completed wells connected to a semi-submersible installation for gas and condensate treatment (Åsgard B), and a production and storage ship for oil (Åsgard A). A storage ship for condensate will also be connected to the gas center. In Smørbukk and Smørbukk Sør, parts of the gas will be reinjected so as to increase the liquid recovery.

The total treatment capacity is 48 million Sm³ per day for gas, 32,000 Sm³ per day for oil and 15,000 Sm³ per day for condensate.

Oil and condensate will be stored temporarily on the field and transported to land using shuttle tankers. The gas will be exported in a planned gas pipeline from Åsgard to Kårstø.

Oil, gas and condensate will be fiscally metered on the field. The gas volumes which go to export will be metered using ultrasound meters.

1.4.27 HEIDRUN

Production licenses: 095 and 124	**Blocks:** 6507/7 6507/8
Operator: Den norske stats oljeselskap a.s	
Licensees:	
Den norske stats oljeselskap a.s (SDFI 65 %)	76.87500 %
Norske Conoco A/S	18.12500 %
Neste Petroleum AS	5.00000 %
Discovery well: 6507/7-2	Year: 1985
Development approved:	Prod.start:
Phase I 1991	1995
Phase II Gas to Tjeldbergodden 1992	1996
Recoverable reserves:	180.4 million Sm³ oil 19.8 billion Sm³ gas
Total investments (firm 1998-NOK) :	NOK 40.1 billion
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:	NOK 726 million

Production

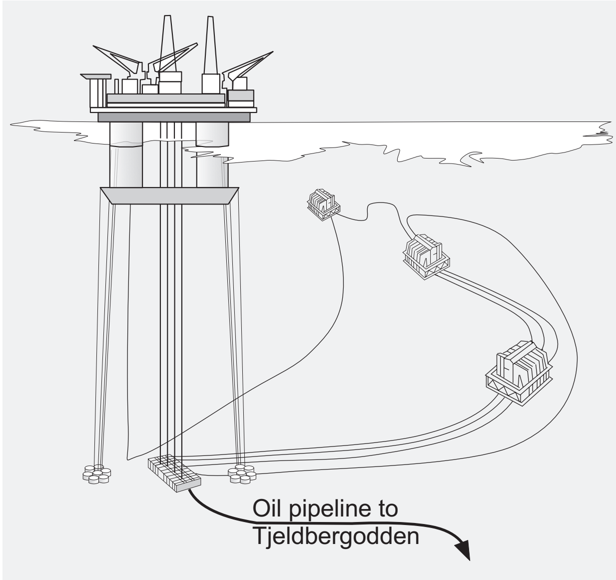
The oil and gas in the field have been proven in the Garn, Ile, Tilje and Åre formations from the Jurassic Age. The upper part of the reservoir is produced with the aid of water and gas injection. Production from the lower part of the reservoir is based on water injection. At the end of 1998, 17 oil producing wells, seven water injection wells and one gas injection well were in operation. Released gas is exported to the methanol plant at Tjeldbergodden.

Development

The field has been developed with a floating tension leg platform of concrete, installed over a subsea template with 56 well slots, see Figure 1.4.27. The northern part of the field will be produced via three subsea installations connected to the Heidrun installation. Production capacity is 41,000 Sm³ per day. Water treatment capacity is 24,600 m³ per day, and water injection capacity is 52,500 m³ per day. The design capacities for gas treatment and gas injection are 4.7 and 4.3 million Sm³ per day respectively. The daily rates for production and injection of gas are largely higher than the design capacities.

The oil on Heidrun is metered to fiscal standard prior to export to Mongstad and Tetney (UK) using direct tanker transportation without using oil storage on the field. Gas export via the Åsgard pipeline and further export of gas to Kårstø and the Continent is planned to commence as from 1 October 2000.

Figure 1.4.27
Installations on Heidrun



1.4.28 NORNE

Production license: 128	**Blocks:** 6608/10 6608/11
Operator: Den norske stats oljeselskap a.s	
Licensees for the Norne field:	
Den norske stats oljeselskap a.s (SDFI 55 %)	70.00000 %
Saga Petroleum ASA	9.00000 %
Norsk Hydro Produksjon AS	8.10000 %
Norsk Agip AS	6.90000 %
Enterprise Oil Norwegian AS	6.00000 %
Discovery well: 6608/10-2	Year: 1992
Development approved::	Prod.start:
Phase I 1995	6 November 1997
Recoverable reserves:	80.4 million Sm³ oil 15.0 billion Sm³ gas 1.4 million tonnes NGL
Total investments (firm 1998-NOK)::	NOK 12.4 billion
Operating costs 1998 incl. CO_2 tax, excl. tariffs, royalty and insurance:	NOK 634 million

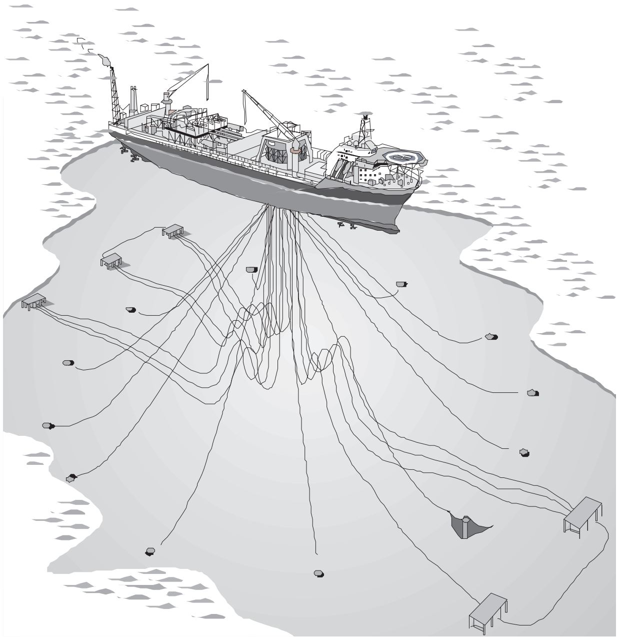
Production

The oil and gas in the field has been proven in sandstone from the Jurassic Age, the oil mainly in the Ile and Tofte formations and the gas in the Garn formation. The production strategy is water injection and reinjection of produced gas. At the end of 1998 there were six production wells, one gas injector and one water injector in operation.

Development

Field development is by means of subsea installations connected to a combined production and storage ship, see Figure 1.4.28. The subsea system consists of five well templates with four wells each and the possibility to tie in satellite wells. Production capacity for oil is 35,000 Sm³ per day. The water treatment capacity is 20,000 m³ per day

Figure 1.4.28
Installations on Norne



and the water injection capacity is 40,000 m^3 per day. The ship has a gas treatment capacity of 7 million Sm^3 per day, while the gas injection capacity is 6.7 million Sm^3 per day. The oil is stored in the ship before it is loaded onto shuttle tankers via a loading system aft on the production ship. Gas export via the Åsgard pipeline and further transportation to Kårstø and the Continent is planned starting from 1 October 2000.

1.5 DISCOVERIES IN THE LATE PLANNING STAGES

1.5.1 2/12-1 FREJA

Production license:	113	**Block:**	2/12
Operator: Amerada Hess Norge AS			
Discovery well:	2/12-1	Year:	1987
Earliest production start:		Year:	2001
Recoverable resources:		2.0 million Sm^3 oil 0.3 billion Sm^3 gas 0.1 million tonnes NGL	
Total investments (firm 1998-NOK):		NOK 0.6 billion	
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance:		NOK 20 million	

The discovery lies near the dividing line between the Norwegian and Danish shelves. 2/12-1 Freja, see Figure 1.4.3.a, lies in a complex faulted area between Fedagraben in the west and Gertrudgraben in the east. The reservoir is in Upper Jurassic sand at a depth of about 4900 meters. Faults segment the reservoir, and the field can be divided into separate fault blocks. The reservoir is deep and the reservoir pressure is one of the highest on the Norwegian shelf. The declaration of commerciality was submitted in June 1992.

A development using a wellhead installation with four well slots connected to transportation solutions on existing infrastructure is assumed.

1.5.2 1/3-3

Production license:	065	**Block:**	1/3
Operator: BP Petr. Dev. of Norway A/S			
Discovery well:	1/3-3	Year:	1983
Recoverable resources:		7.1 million Sm^3 oil 1.8 billion Sm^3 gas 0.8 million tonnes NGL	
Total investments (firm 1998-NOK):		NOK 1.1 billion	
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance:		NOK 35 million	

The deposit is an oil discovery made in the Ula formation from the Late Jurassic Age. BP took over Elf's interest as well as operatorship in the production license in 1997. An appraisal well, 1/3-9, was drilled in 1998 and proved greater resources than previously mapped.

Consideration is being given to developing the discovery using a wellhead platform with two horizontal production wells and possibly one water injection well. The field will be linked to Ula or Gyda, and consideration will be given to injecting produced gas into the Ula reservoir as a part of the Ula WAG injection project.

1.5.3 3/7-4 TRYM

Production license:	147	**Blocks:**	3/7 and 3/8
Operator: A/S Norske Shell			
Discovery well:	3/7-4	Year:	1990
Earliest production start:		2001	
Recoverable resources:		2.7 billion Sm^3 gas 0.7 million Sm^3 condensate	
Total investments (firm 1998-NOK):		NOK 0.5 billion	
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance		NOK 60 million	

The Trym and Lulita discoveries lie on the same salt-induced structure. The structures cross the boundary between the Norwegian and Danish shelves. Trym is considered to be 100 per cent Norwegian while it is assumed that Lulita extends onto the Norwegian shelf.

It is assumed that Trym is separated from Lulita, but with possible pressure communication in the water zone. The reservoirs lie in the Lindesnes and Bryne formations in the Upper and Middle Jurassic. The Lindesnes formation is relatively homogeneous with good reservoir properties, while the Bryne formation is extremely heterogeneous with varying reservoir quality.

The Danish part of Lulita has been developed by means of tying the development to the nearby Danish field, Harald. There is no unitization agreement for the Lulita field between the Danish and Norwegian owners. It is assumed that the Trym field will be developed with the aid of a subsea solution with a two-branch well, with gas export through an 8-km pipeline to the Harald installation on the Danish shelf.

1.5.4 15/9-19 S VOLVE

Production license:	046	**Block:**	15/9
Operator:	Den norske stats oljeselskap a.s		
Discovery well:	15/9-19 SR	Year:	1993
Earliest production start:		Year:	2002
Recoverable resources:		12.1 million Sm^3 oil 1.8 billion Sm^3 gas	
.		NOK 3.4 billion	
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance:		NOK 230 million	

This oil discovery, see Figure 1.4.8.a, was made in 1993 in rocks from the Jurassic/Triassic Age on the Theta Vest structure just north of Sleipner Øst. In 1997, a new well was drilled as a sidetrack to the original well (15/9-19 A). This well proved considerably more oil than expected. This gave a doubling in the estimate for recoverable oil, and also the basis for further appraisal in the area.

Work is proceeding on plans for a unitized development of this discovery with a potential produceable oil zone in Sleipner Vest and with 15/5-5.

1.5.5 15/5-5

Production license:	048	**Block:**	15/5
Operator:	Den norske stats oljeselskap a.s		
Discovery well:	15/5-5	Year:	1995
Earliest production start:		Year:	2002
Recoverable resources:		8.7 million Sm^3 oil 0.4 billion Sm^3 gas	
Total investments (firm 1998-NOK):		NOK 2.1 billion	
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance:		NOK 70 million	

This is an oil discovery in the Heimdal formation on the G structure in block 15/5, see Figure 1.4.8.a. In 1997, the 15/5-6 appraisal well was drilled on the discovery. It found oil, but in a thinner layer than the operator expected and the estimate for recoverable oil was therefore reduced. Various development concepts are being evaluated and unitization with other discoveries in the Sleipner area (15/9-19 S Volve and 16/7-4 Sigyn) is also a possibility.

1.5.6 16/7-4 SIGYN

Production license:	072	**Block:**	16/7
Operator:	Esso Expl & Prod Norway AS		
Discovery well:	16/7-4	Year:	1982
Earliest production start:		Year:	2002
Recoverable resources:		6.2 billion Sm^3 gas 2.2 million tonnes NGL 5.1 million Sm^3 cond.	
Total investments (firm 1998-NOK):		NOK 2.4 billion	
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance		NOK 80 million	

This discovery lies about 12 kilometers southeast of Sleipner A. The discovery, see Figure 1.4.8.a, was made in the Skagerrak formation and contains gas/condensate. A new well (16/7-7) was drilled in 1997 on what was believed to be an extension of the discovery towards the east, however, the results from this drilling indicate that this is a separate discovery with a different liquid composition. Development of the discovery as a satellite to Sleipner A is being considered. The gas may be used for injection in Sleipner Øst. Both subsea wells and a wellhead installation are being evaluated.

1.5.7 25/4-6 S VALE

Production license:	036	**Block:**	25/4
Operator:	Norsk Hydro Produksjon AS		
Discovery well:	25/4-6 S	Year:	1991
Earliest production start:		Year:	2001
Recoverable resources:		3.2 billion Sm^3 gas 3.9 billion Sm^3 cond.	
Total investments (firm 1998-NOK):		NOK 1.1 billion	
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance:		approx. NOK 100 million	

Gas/condensate has been proven in reservoirs from the Brent group of the Middle Jurassic Age. The drive mechanism is depressurization. The plan is to develop the discovery with a subsea installation linked to Heimdal, see Figure 1.4.12.a.

1.5.8 25/5-3 SKIRNE

Production license:	102	**Block:**	25/5
Operator:	Elf Petroleum Norge AS		
Discovery well:	25/5-3	Year:	1990
Earliest production start:		Year:	2002
Recoverable resources:		5.1 billion Sm^3 gas 1.0 Sm^3 condensate	
Total investments (firm 1998-NOK):		NOK 0.9 billion	
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance:		approx. NOK 80 million	

Gas has been proven in reservoirs of the Brent group from the Middle Jurassic Age. The drive mechanism is depressurization. The plan is to develop the discovery with a subsea installation tied in to Heimdal, see Figure 1.4.12.a.

1.5.9 25/11-15 GRANE

Production licenses:	169 and 001	**Block:**	25/11
Operator:	Norsk Hydro Produksjon AS		
Production license:	001	**Block:**	25/11
Operator:	Esso Expl & Prod Norway A/S		
Discovery well:	25/11-15	Year:	1991
Earliest production start:		Year:	2003
Recoverable resources:		112.0 million Sm^3 oil	
Total investments (firm 1998-NOK):		NOK 15.5 billion	
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance:		NOK 500 million	

The discovery, see Figure 1.4.12.a, is located about 7 kilometers east of Balder. The largest portion of the discovery lies in production license 169, however, parts extend into production license 001. The reservoir contains relatively heavy oil and lies in sand with good reservoir quality in the Heimdal formation of the Paleocene Age. In 1996, a 2-month test production was carried out from a horizontal well on the structure. A total of 77,000 Sm^3 oil was produced. The test production provided valuable information concerning production and processing of the oil in the discovery.

Injection of water, natural gas or CO_2 is being considered, and the final choice has not been made. Gas injection is used as a basis for the estimate of recoverable reserves and has led to an increase in this. If gas injection is chosen, there will be a need for import of gas and negotiations are underway to clarify whether gas can be obtained at acceptable terms. The plan is to use two installations sitting on the seabed for development, one for drilling and one for production and living quarters. The intention is to submit the plan for development and operation in the summer of 1999.

There are several discoveries/prospects surrounding the Grane discovery. The preliminary development plans also include the 25/11-16 discovery, and what is called the F prospect, which is probably an extension of the Grane discovery to the north.

1.5.10 25/11-16

Production license:	169	**Block:**	25/11
Operator:	Norsk Hydro Produksjon AS		
Discovery well:	25/11-16	Year:	1992
Earliest production start:		Year:	2003
Recoverable resources:			3.6 million Sm^3 oil
Total investments (firm 1998-NOK):			NOK 0.7 billion
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance:			NOK 10 million

This discovery was made in rocks of the Paleocene Age to the southwest of Grane. Development is planned using subsea wells tied in to Grane.

1.5.11 30/2-1 HULDRA

Production licenses:	051 and 052	**Blocks:**	30/2 and 30/3
Operator:	Den norske stats oljeselskap a.s		
Discovery well:	30/2-1	Year:	1982
Earliest production start:		Year:	2001
Recoverable resources:			18.7 billion Sm^3 gas 0.3 million tonnes NGL 7.4 million Sm^3 condensate
Total investments (firm 1998-NOK):			NOK 5.4 billion
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance:			approx. NOK 295 million

This is a gas discovery which lies to the northwest of Veslefrikk, Figure 1.4.13.b. Gas has been proven in the Brent group of the Middle Jurassic Age. Structurally, the Huldra discovery consists of a rotated fault block which slopes to the east. Under the main reservoir, there is a prospect in the Statfjord formation which will be drilled. Huldra has been granted gas allocation with planned production start-up in the year 2001.

The plan for development and operation of the Huldra discovery and the plan for installation and operation of the pipelines have been submitted to the authorities for approval. The plan is to develop the Huldra discovery with a permanent unmanned installation. Drilling is planned with a jack-up installation. Six production wells are planned. After first stage separation, gas and condensate will be transported to Heimdal and Veslefrikk respectively for final processing.

1.5.12 30/6-17

Production license:	053	**Block:**	30/6
Operator:	Norsk Hydro Produksjon AS		
Discovery well:	30/6-17 R	Year:	1986
Earliest production start:		Year:	2001
Recoverable resources:			0.5 million Sm^3 oil 1.3 billion Sm^3 gas
Total investments (firm 1998-NOK):			NOK 0.3 billion
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance:			NOK 4 million

This is a small oil and gas discovery in the Cook formation under the main reservoir on the Oseberg field. The deposit can be produced with one side-drilled well from the existing subsea well on Oseberg, see Figure 1.4.13.b.

1.5.13 30/6-18 KAPPA

Production licenses:	053 and 079	**Blocks:**	30/6 and 30/9
Operator:	Norsk Hydro Produksjon AS		
Discovery well:	30/6-18	Year:	1985
Earliest production start:		Year:	2001
Recoverable resources:			3.5 million Sm^3 oil 5.5 billion Sm^3 gas
Total investments (firm 1998-NOK):			NOK 1.3 billion
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance			NOK 18 million

30/6-18 Kappa is an oil field with a gas cap in the Statfjord formation in a structure west of Oseberg. The discovery, see Figure 1.4.13.b, will probably be developed with horizontal production wells from a subsea template and with transportation of the wellstream to Oseberg for processing.

1.5.14 30/8-1 S TUNE

Production licenses:	190 and 034	**Blocks:**	30/8 and 30/5
Operator:	Norsk Hydro Produksjon AS		
Discovery well:	30/8-1S	Year:	1995
Earliest production start:		Year:	2002
Recoverable resources:			20 billion Sm^3 gas 5.8 million Sm^3 cond.
Total investments (firm 1998-NOK):			NOK 2.4 billion
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance:			approx. NOK 210 million

30/8-1 S Tune is a gas/condensate discovery that lies 12 km to the west of the Oseberg field center. Tune, see Figure 1.4.13.b, consists of two main structures; the A and B structures. Gas/condensate has been proven in the A structure.

Two development solutions are being considered for Tune. Either a subsea development with transportation of the wellstream to Oseberg, or a permanent installation with transportation of the gas and liquid to Kollsnes. The plan is to develop Tune in two phases. In 1998, the operator applied for gas allocation based on development of the A structure.

1.5.15 33/9-19 S SYGNA

Production license: 037		**Block:**	33/9
Operator: Den norske stats oljeselskap a.s			
Production license: 089		**Block:**	34/7
Operator: Saga Petroleum ASA			
Discovery well:	33/9-19 S	Year:	1996
Earliest production start:		Year:	2000
Recoverable resources:		9.6 million Sm^3 oil 0.6 billion Sm^3 gas	
Total investments (firm 1998-NOK):		NOK 1.4 billion	
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance		NOK 110 million	

33/9-19 S Sygna is an oil discovery which lies partly in the northeastern part of block 33/9 and partly in the northwestern part of block 34/7, see Figure 1.4.17.a. Wells 33/9-19 S and the sidetrack 33/9-16 A, drilled in 1996, proved oil in sandstone in the Brent group from the Middle Jurassic Age. Two prospects near the Sygna discovery were drilled in 1998, but no hydrocarbons were proven in these prospects.

The plan for development and operation of the field was submitted to the authorities for approval in November 1998. The field will be developed and run with Statoil as the operator. The operator's plan is to develop Sygna with a four-well subsea template for production and with multiphase wellstream transportation to Statfjord C for processing, stabilization, storage and export of the oil. The plan is to extract the resources with two production wells and one water injection well. The injection well will be drilled from the existing injection template on Statfjord Nord. Production start-up is planned for August 2000, and the field is expected to produce until 2014.

The Sygna licensees have agreed on a firm distribution of ownership with 55 per cent to production license 037 and 45 per cent to production license 089.

1.5.16 34/7-21

Production license:	089	**Block:**	34/7
Operator: Saga Petroleum ASA			
Discovery well:	34/7-21	Year:	1992
Earliest production start:[1)]		Year:	1999
Recoverable resources:		9.4 million Sm^3 oil 1.2 billion Sm^3 gas 0.3 million tonnes NGL	
Total investments (firm 1998-NOK):		NOK 0.6 billion	
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance:		NOK 30 million	

The discovery is located in block 34/7 to the west of the Tordis field. Well 34/7-21 proved oil in rocks deposited during the late Jurassic Age. A sidetrack, 34/7-21 A, was drilled to delimit the oil discovery. The sidetrack confirmed the discovery, but showed that the lateral development and extent of the reservoir sand is difficult to map.

Due to the uncertainty connected with the extent of the sand and communication conditions in the reservoir, in 1998 the operator performed a test production from the discovery which lasted for six months. A well slot on the Tordis Øst subsea template was used for the test production. The purpose of the test production was to optimize the production strategy and the development concept. The results showed only limited pressure support, and injection will therefore be necessary in order to produce the resources. The uncertainty with regard to the reserves in place has been significantly reduced, and the test production has provided valuable production experience from the Topp Draupne sand.

Based on the proven resource basis, the operator is considering a development with subsea wells drilled from the existing and planned subsea templates in the Tordis area (see Chapter 1.4.19, Tordis Area). The plan is to submit the plan for development and operation to the authorities in the spring of 1999.

1.5.17 34/7-23 S AND 34/7-29 S

Production license: 089		**Block:**	34/7
Operator: Saga Petroleum ASA			
Discovery well:	34/7-23 S 34/7-29 S	Year: Year:	1994 1998
Earliest production start:		Year:	2001
Recoverable resources: 34/7-23 S H-vest:		2.1 million Sm^3 oil 0.2 billion Sm^3 gas	
Recoverable resources: 34/7-29 S H-nord		3.8 million Sm^3 oil 0.3 billion Sm^3 gas	
Total investments (firm 1998-NOK):		NOK 1.0 billion	
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance:		NOK 45 million	

The discoveries, see Figure 1.4.17.a, lie in block 34/7 southwest of the Vigdis field. Well 34/7-23 S proved oil in rocks deposited in the Late Jurassic Age. In order to improve the delimitation of the reservoir, a sidetrack was drilled from the well 34/7-23 A. The sidetrack confirmed the discovery.

Well 34/7-29 S was drilled to explore the potential in the northern H area. This well also proved oil in rocks deposited in the Late Jurassic Age. Ongoing work based on the well results and new geological interpretation of H-nord indicate that the resource estimate may be reduced somewhat.

It is assumed that pressure maintenance from water injection will be required to produce the discoveries. Based on the proven resource basis, the operator is considering a development with subsea wells phased into the Vigdis subsea installations.

1.5.18 34/7-25 S

Production license: 089		**Block:**	34/7
Operator: Saga Petroleum ASA			
Discovery well:	34/7-25 S	Year: 1996	
Earliest production start:		Year: 2000	
Recoverable resources:		2.3 million Sm^3 oil 0.2 billion Sm^3 gas	
Total investments (firm 1998-NOK):		NOK 0.2 billion	
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance:		NOK 16 million	

The discovery lies in block 34/7 to the east of the Tordis field, see Figure 1.4.17.a. Well 34/7-25 S proved oil in rocks deposited in the Late Jurassic Age. There is uncertainty connected with the extent of the reservoir sand and volume calculations for the discovery. New geological interpretation performed in 1998 shows that the discovery may contain greater resources than originally assumed. Pressure support from water injection is presumed necessary to produce the discovery.

Based on the proven resource basis, the operator is considering a development with subsea wells drilled from existing and planned subsea templates in the Tordis area (see Chapter 1.4.19, Tordis Area). The plan for development and operation may be submitted to the authorities during 1999.

1.5.19 34/11-1 KVITEBJØRN

Production license:	193	**Block:**	34/11
Operator:	Den norske stats oljeselskap a.s		
Discovery well:	34/11-1	Year:	1994
Earliest production start:		Year:	2003
Recoverable resources:		51.2 billion Sm^3 gas 4.4 million tonnes NGL 21.1 million Sm^3 cond.	
Total investments (firm 1998-NOK):		NOK 8.2 billion	
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance:		NOK 460 million	

34/11-1 Kvitebjørn lies about 17 kilometers southeast of the Gullfaks field, see Figure 1.4.17.a. Two exploration wells on the field have proven gas/condensate in sandstone in the Brent group of the Jurassic Age. The licensees have applied for gas allocation in 1998. An exploration well was being drilled at the end of the year in a saddle area towards 34/10-23 Gamma, inter alia in order to reduce the uncertainty with regard to potential communication between these discoveries. A likely development concept is a manned installation with simple processing equipment and a drilling module. The operator has applied for gas allocation in 1998. According to the most recent plans, the earliest production start-up is estimated at 2003.

1.5.20 6406/2-1 LAVRANS

Production license:	199	**Block:**	6406/2
Operator:	Saga Petroleum ASA		
Discovery well:	6406/02-1	Year:	1996
Earliest production start:		Year:	2004
Recoverable resources:		40.3 billion Sm^3 gas 5.3 million tonnes NGL 8.8 million Sm^3 cond.	
Total investments (firm 1998-NOK):		NOK 4.8 billion	
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance:		NOK 160 million	

Well 6406/2-1 in production license 199 was drilled in 1996 and proved condensate/gas in sandstones from the Jurassic Age. The Ile, Tofte and Tilje reservoir formations lie at depths of up to 4400 meters. In 1996, an appraisal well, 6406/2-2, was drilled which proved new resources. Well 6406/2-4 S was drilled in 1997, but was temporarily abandoned before it reached reservoir level. Drilling of this well was resumed at the end of 1998. The operator assumes production through depressurization.

The most interesting development solution appears to be a subsea installation tied to the planned tension leg installation on the Kristin discovery, see Figure 1.4.25.a.

Plans for unitized development

In 1998, work has proceeded towards establishing a coordinated development of the 6406/2-3 Kristin, 6406/2-1 Lavrans, 6406/3-2 Trestakk and 6407/1-2 Tyrihans discoveries. As of the end of 1998, no agreement had been reached regarding a unitization agreement.

1.5.21 6406/2-3 KRISTIN

Production license:	199	**Block:**	6406/2
Operator:	Saga Petroleum ASA		
Discovery well:	6406/2-3	Year:	1997
Earliest production start:		Year:	2004
Recoverable resources:		37.8 billion Sm^3 gas 7.0 million tonnes NGL 41.7 million Sm^3 cond.	
Total investments (firm 1998-NOK):		NOK 13.4 billion	
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance:		NOK 580 million	

Well 6406/2-3 in production license 199 was drilled at the turn of the year 1996/1997. The well proved gas/condensate in sandstones in the Garn and Ile formations of the Jurassic Age. Appraisal well 6406/2-5 was drilled in 1997 in order to clarify the gas/water contacts in the Garn and Ile formations. This well was dry. Later in 1997, a sidetrack was drilled (6406/2-5 A) which proved gas/condensate. In 1998, well 6506/11-6 was drilled in production license 134. The well proved resources in the northern part of the Kristin discovery, see Figure 1.4.25.a.

A potential production strategy is injection of gas in order to optimize liquid recovery. However, a high initial reservoir pressure, combined with a relatively low dewpoint pressure, means that gas injection is not relevant until after a few years of gas production.

The operator has applied for gas allocation in 1998. The most interesting development solution appears to be a tension leg installation.

Plans for unitized development

In 1998, work has proceeded towards establishing a coordinated development of the 6406/2-3 Kristin, 6406/2-1 Lavrans, 6406/3-2 Trestakk and 6407/1-2 Tyrihans discoveries. As of the end of 1998, no agreement had been reached regarding a unitization agreement.

1.5.22 6407/1-2 TYRIHANS

Production license:	073	**Block:**	6407/1
Operator: Den norske stats oljeselskap a.s			
Discovery well:	6407/1-2 Tyrihans Sør 6407/1-3 Tyrihans Nord	Year:	1983 1984
Earliest production start:		Year:	2004
Recoverable resources:			15.9 million Sm^3 oil 28.7 billion Sm^3 gas 5.6 million tonnes NGL
Total investments (firm 1998-NOK):			NOK 7.3 billion
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance:			NOK 300 million

6407/1-2 Tyrihans consists of two structures, Tyrihans Sør and Tyrihans Nord. The Tyrihans Sør discovery was made in 1983 and the Tyrihans Nord discovery was made in 1984 in production license 073, see Figure 1.4.25.a. The discoveries are probably in pressure communication through a common water zone. Tyrihans Sør is characterized as a gas/condensate discovery, while Tyrihans Nord contains an oil zone with overlying gas cap. The reservoirs are from the Middle Jurassic Age. An appraisal well was drilled on the Tyrihans Nord discovery in 1996. The well showed gas, oil and water. The transition zone makes it difficult to determine the oil/water contact exactly. The size of the oil zone in the Tyrihans Nord discovery is uncertain since the oil/water contact has not been proven.

The most likely production strategy is based on depressurization of the Tyrihans Nord discovery and gas injection in the Tyrihans Sør discovery in order to optimize liquid recovery. Several potential development concepts are being evaluated. The discoveries will most likely be produced with subsea-completed wells connected to either a separate production and storage ship or coordinated with other fields in the area.

Plans for unitized development

In 1998, work has proceeded towards establishing a coordinated development of the 6406/2-3 Kristin, 6406/2-1 Lavrans, 6406/3-2 Trestakk and 6407/1-2 Tyrihans discoveries. As of the end of 1998, no agreement had been reached regarding a unitization agreement.

1.5.23 6507/8-4 HEIDRUN NORD

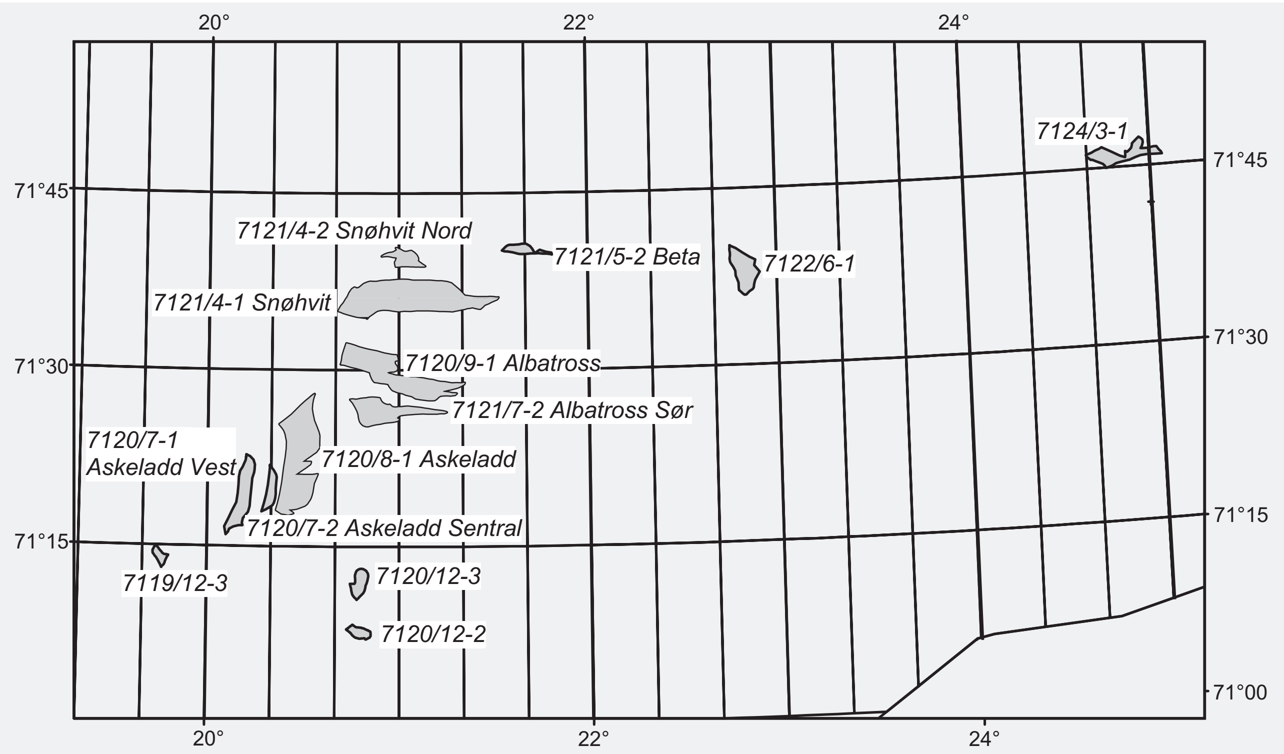
Production license:	124	**Block:**	6507/8
Operator: Den norske stats oljeselskap a.s			
Discovery well:	6507/8-4	Year:	1990
Earliest production start:		Year:	2001
Recoverable resources:			4.0 million Sm^3 oil
Total investments (firm 1998-NOK):			NOK 0.7 billion
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance:			NOK 3 million

The discovery lies in a fault block with sandstones in the Åre formation of the Jurassic Age, se Figure 1.4.25.a. The plan is to produce the discovery via Heidrun with one production well and one water injection well.

1.5.24 7121/4-1 SNØHVIT

Production licenses:	097, 099 and 110	**Blocks:**	7120/6,7121/4, 7121/5,7120/5
Operator: Norsk Hydro Produksjon AS for 097 Den norske stats oljeselskap a.s for 099 and 110			

Figure 1.5.24
Discoveries in the Barents Sea



Discovery well: 7121/4-1	Year: 1984
Earliest production start:	Year: 2003
Recoverable resources::	11.9 million Sm^3 oil 163.4 billion Sm^3 gas 6.9 million tonnes NGL 15.4 million Sm^3 cond.
Total investments (firm 1998-NOK):	NOK 14.3 billion
Operating costs at plateau incl. CO_2 tax, excl. tariffs, royalty and insurance:	NOK 424 million

The Snøhvit discovery is a gas/condensate discovery with a thin oil zone, see Figure 1.5.24. The reservoir consists of an east-west running, fault-controlled structure centrally located in the Hammerfest basin. The structure has wide lateral extension, about 130 km^2. The reservoir is from the Jurassic Age. Several alternative development concepts are being evaluated. The overall plan includes the Snøhvit, Albatross and Askeladden discoveries. The plan is to transport the gas to land via a pipeline for processing and conversion to liquid gas (LNG). About 80 million Sm^3 oil in place has been proven in Snøhvit, and the amount of recoverable resources will largely depend on the development solution. The operators are considering locating the LNG terminal on Melkøya just outside of Hammerfest.

1.6 DISCOVERIES IN THE EARLY PLANNING STAGES

1.6.1 2/4-17 TJALVE

Production license: 018	**Block:** 2/4
Operator: Phillips Petroleum Co Norway	
Discovery well: 2/4-17	Year: 1992
Earliest production start:	Year: 2007
Recoverable resources:	1.3 million Sm^3 oil 1.8 billion Sm^3 gas 0.1 million tonnes NGL
Total investments (firm 1998-NOK):	NOK 0.3 billion

2/4-17 Tjalve contains gas/condensate in a 50-meter thick sandstone reservoir in the lower Ula formation from the Upper Jurassic Age. The structure is a combined fault-conditional and stratigraphic trap which lies at a depth of about 4300 meters. The drive mechanism for production will be gas expansion through depressurization. The discovery well has been temporarily abandoned and may be used for subsequent production.

The discovery, see Figure 1.4.3.a, has been evaluated for a development with transportation via the Tor field to Ekofisk II, either through a seabed installation and pipeline or through a production well drilled from Tor, which lies at a distance of about seven kilometers from the Tjalve discovery. The timing of phase-in to Ekofisk II is being evaluated.

1.6.2 15/5-1 DAGNY

Production license: 048		**Block:** 15/5
Operator: Den norske stats oljeselskap a.s		
Production license:	029	**Block:** 15/6
Operator: Den norske stats oljeselskap a.s		
Discovery well:	15/5-1	Year: 1978
Earliest production start:		Year: 2006
Recoverable resources:		5.9 billion Sm^3 gas 2.0 million Sm^3 cond.
Total investments (firm 1998-NOK):		NOK 1.0 billion

This is a gas/condensate discovery in Jurassic rocks to the north of Sleipner Vest, see Figure 1.4.8.a. The most interesting development concept is subsea wells or an unmanned wellhead installation connected to Sleipner B or Sleipner T.

1.6.3 25/5-4 BYGGVE

Production license: 102	**Block:** 25/5
Operator: Elf Petroleum Norge AS	
Discovery well: 25/5-4	Year: 1991
Earliest production start:	Year: 2004
Recoverable resources:	3.1 billion Sm^3 gas 0.5 million tonnes NGL
Anticipated total investments (firm 1998-NOK):	NOK 0.3 million

25/5-4, the Byggve discovery, lies between Heimdal and Skirne, see Figure 1.4.12.a. The discovery can be developed with a horizontal gas/condensate well from a subsea installation, and can be tied in to Heimdal. Unitization with Skirne may be of interest.

1.6.4 25/5-5

Production license: 102		**Block:** 25/5
Operator: Elf Petroleum Norge AS		
Discovery well:	25/5-5	Year: 1995
Earliest production start:		Year: 2003
Recoverable resources:		4.3 million Sm^3 oil
Anticipated total investments (firm 1998-NOK):		NOK 0.7 million

25/5-5 lies about 6 km to the east of Heimdal, see Figure 1.4.12.a. One production well is planned.

Development with a subsea installation tied in to other installations is being considered. Production start-up depends on when capacity becomes available.

1.6.5 25/8-10 S

Production license: 027		**Block:** 25/8
Operator: Esso Expl. & Prod. Norway AS		
Discovery well:	25/8-10S	Year: 1997
Earliest production start:		Year: 2002
Recoverable resources:		16.4 million Sm^3 oil 0.7 billion Sm^3 gas
Total investments (firm 1998-NOK):		NOK 3.9 billion

1) Includes 25/8-11

The discovery consists of two structures proven through drilling of 25/8-10 S and 25/8-11 northeast of the Balder field. Oil has been proven in source rocks from the Paleocene and Early Jurassic Ages. The planned development concept is a wellhead installation tied in to Balder FPSO. The intention is for all separation to take place on Balder.

1.6.6 35/11-4 FRAM

Production license:	090	**Block:**	35/11
Operator:	Norsk Hydro Produksjon AS		
Discovery well:	35/11-2	Year:	1987
Earliest production start:		Year:	2004
Recoverable resources:			35.5 million Sm^3 oil 20.6 billion Sm^3 gas 3.4 million tonnes NGL
Total investments for unitized Fram-Gjøa-development (firm 1998-NOK):			NOK 19.6 billion

Production license 090 in block 35/11 was awarded in 1984. The Fram discovery lies 24 km to the north of the Troll field and consists of several structures that are gradually faulted downward from east to west, see Figure 1.4.16.a. So far, 11 wells and one sidetrack have been drilled in block 35/11. Of these, five wells have been drilled on what is defined as the Fram discovery, in other words, the F/C complex and the H structure. These wells have proven reservoirs with a gas cap and underlying oil in the Viking and Brent group of the Jurassic Age. The reservoir quality is quite variable. One appraisal well was drilled in 1998, which was permanently plugged and abandoned as dry with only weak traces of hydrocarbons. Nevertheless, the estimates of recoverable resources were increased in 1998 due to updated geology and reservoir studies.

Up to the autumn of 1998, the licensees worked on an independent development concept for the Fram discovery. This work is documented in a status report dated 18 December 1998. This concept did not provide sufficient profitability. Instead, the licensees have chosen to investigate a unitized development with Gjøa and other discoveries in the area. A unitized development will probably entail locating a floater between the Fram and Gjøa discoveries and a subsea production facility at each of the discoveries. The work plan for unitized development entails submission of a PDO in December 2000, and production start-up in November 2004.

1.6.7 35/9-1 GJØA

Production license:	153	**Block:**	35/9 and 36/7
Operator:	Norsk Hydro Produksjon AS		
Discovery well:	35/9-1	Year:	1989
Earliest production start:		Year:	2004
Recoverable resources:			9.8 million Sm^3 oil 21.3 billion Sm^3 gas 3.8 million tonnes NGL 1.0 million Sm^3 cond.

Production license 153 was awarded in 1988. With specific conditions regarding further exploration and evaluation of the area, an extension was granted in July 1998 for 79 per cent of the area in the production license. If the conditions are not fulfilled, at least 50 per cent of the original area must be relinquished after two years.

Within the area of the production license, which includes several structures in blocks 35/9 and 36/7, six wells have been drilled so far. The sixth was drilled in 1998, but technical problems prevented the collection of well data. Oil and/or gas have been proven in several reservoirs from the Jurassic Age. The main reservoirs are located in the Sognefjord and Fensfjord formations. The resources have been adjusted downward during 1998 on the basis of updated geology and reservoir studies.

Gjøa is an interesting candidate for gas deliveries. An allocation application was submitted to the Gas Supply Committee in the autumn of 1998.

A development together with 35/11-4 Fram is being considered as the most interesting option. A unitized development is discussed under Fram.

1.7 EXPLORATION ACTIVITY

1.7.1 GEOPHYSICAL SURVEYS

A total of 731,959 km of seismic data were collected on the Norwegian shelf in 1998. The number of kilometers refers to cmp-line kilometers.

In the North Sea, a total of 293,378 km of seismic data were collected, in addition to 236,349 km in the Norwegian Sea and 202,232 km in the Barents Sea.

The Norwegian Petroleum Directorate collected a total of 2,561 kilometers, UIB collected 270 km, while oil companies and seismic contractor companies collected a total of 729,128 km. Of this total, Norwegian oil companies collected 488,155 km and foreign oil companies collected 15,954 km. The contractor companies Geco, Geoteam, Nopec, PGS and Western collected 225,019 km for their own accounts.

Of the total seismic data collected, 3D seismic accounts for 687,856 km, 278,629 km in the North Sea, 212,010 km in the Norwegian Sea and 197,217 km in the Barents Sea. Figure 1.7.1 provides an overview of recent years' development with regard to the number of cmp-line kilometers collected.

1.7.2 EXPLORATION DRILLING

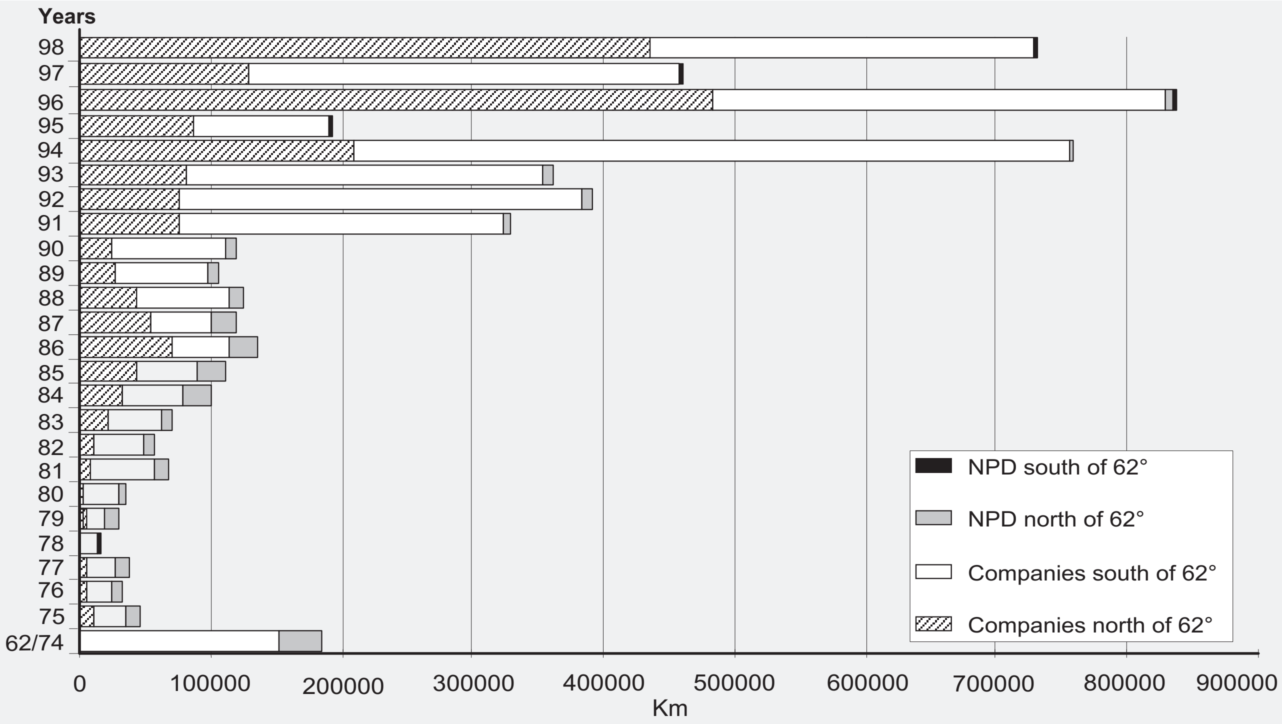
At the turn of the year 1997/1998, drilling of nine exploration wells was in progress.

26 exploration wells were spudded in 1998, of which 18 were wildcats and 8 were appraisal wells. Drilling activities in 1998 comprised 13 wildcat and seven appraisal wells in the North Sea and five wildcat wells and one appraisal well in the Norwegian Sea. In addition, two temporarily abandoned exploration wells were re-entered for further work; one in the North Sea and one in the Norwegian Sea.

At the turn of the year 1998/1999, four exploration wells were being drilled, one of these was re-entered. As of 31 December 1998, a total of 942 exploration wells had been spudded on the Norwegian continental shelf. These are divided between 673 wildcat wells and 269 appraisal wells, see Table 7.3.a.

In 1998, 32 exploration wells were completed or temporarily abandoned on the Norwegian shelf. In addition, one well, 1/5-3 SX, was given up for technical reasons

Figure 1.7.1
Seismic surveys on the Norwegian continental shelf 1962-1998



before it reached its target, while 34/7-26 SR was a re-entry for further operations. After well 6305/7-1 was reclassified from a wildcat well to an appraisal well, the wells are divided between 21 wildcat wells and 11 appraisal wells. The geographical distribution of the wells is as follows: 16 wildcat and eight appraisal wells in the North Sea, and five wildcat and three appraisal wells in the Norwegian Sea.

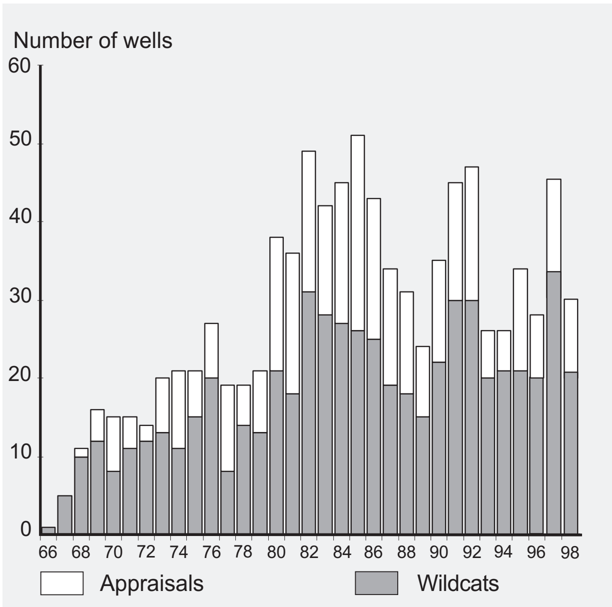
The operators for the wells completed or temporarily abandoned in 1998 were as follows: Statoil nine, Hydro eight, Saga six, Amoco four, BP two, and Mobil, Shell and Agip with one each.

A wildcat well is a well which is drilled in order to investigate whether petroleum may be found in a new, clearly defined geological unit, delimited by rock formations with structural or stratigraphic limits. An appraisal well is a well drilled in order to determine the extent and size of a petroleum deposit which has already been proven by a wildcat well. All exploration wells have one of these classifications when they are spudded. If it should later prove that a well does not meet the criteria for the classification it was originally given, it is reclassified.

As of 31 December 1998, 939 exploration wells were completed or temporarily abandoned on the Norwegian shelf. 76 exploration wells on the Norwegian shelf have been reclassified, 72 of these from wildcat to appraisal wells and four from appraisal to wildcat wells. After reclassification, these comprise 603 wildcat and 336 appraisal wells.

Table 7.3.f provides an overview of spudded and/or completed exploration wells in 1998.

Figure 1.7.2
Exploration wells completed per year after reclassification



In addition, as of year-end, a total of 52 exploration wells have been temporarily abandoned on the Norwegian shelf. The temporarily abandoned exploration wells with equipment remaining on the seabed are:

1/03-09 S	25/11-16	34/10-34
2/01-09 A	25/11-21 A	34/10-37 A
2/01-11	30/02-01	34/11-02 S
2/04-15 S	30/03-04	35/09-04 S

2/04-17	30/08-01 SR	6305/05-01
2/07-23 S	30/09-07	6406/02-02
2/07-25 S	30/09-08 R	6406/02-06
2/10-02	30/09-09	6407/07-02 R
2/12-02 S	30/09-10	6407/07-04
7/12-08	30/09-12 A	6506/11-04 S
7/12-09	30/09-13 S	6506/11-05 S
9/02-07 S	31/02-16 SR	6506/12-08
15/12-10 S	31/02-18 A	6506/12-11 SR
25/02-13	31/05-04 AR	6507/05-01
25/04-06 S	31/05-05	6507/08-04
25/05-04	31/04-07	6507/11-05 S
25/08-06	34/07-29 S	
25/08-11	34/08-04 A	

1.7.3 EXPLORATION TARGETS

Exploration activity in 1998 has largely continued to target Jurassic sandstone prospects. The number of wells drilled towards prospects in the Tertiary and Cretaceous showed a marked increase compared with the previous year. Of the 28 exploration wells spudded in 1998, 20 had Jurassic as the main prospect, five had the Tertiary, and three had the Cretaceous as the main prospect. In addition to the main prospect, secondary prospects were also the subject of investigation. These were divided among five in the Jurassic, six in the Cretaceous, three in the Tertiary and one in the Triassic.

1.7.4 NEW DISCOVERIES IN 1998

Eight discoveries have been made, of which two have been confirmed through formation testing. Six discoveries have been made in the North Sea and two in the Norwegian Sea, see Table 1.7.4. A more detailed description of the various discoveries may be found in Chapter 1.7.5.

1.7.5 DETAILED DESCRIPTION OF DRILLING IN 1998

Southern part of the North Sea

Five exploration wells, see Figure 1.7.5.a, were completed in the southern part of the North Sea in 1998 (Table 1.7.5.a). Four were wildcat wells and one was an appraisal well. One of the four wildcat wells (1/5-3 SX) was completed before it reached projected depth due to safety and technical drilling reasons. Appraisal well 1/3-9 S is temporarily plugged and abandoned. Well 9/2-8 S is reclassified to an injection well. There were no new discoveries of hydrocarbons in the area in 1998.

The Sleipner / Balder area

Eight exploration wells, see Figure 1.7.5.b, were completed in the Sleipner and Balder area in 1998 (Table 1.7.5.b). Six of the exploration wells were wildcat wells and two were appraisal wells. One discovery of hydrocarbons was made in the area in 1998.

Well 24/6-2, which was drilled to the west of the Heimdal field, struck oil with a gas cap in source rocks from the Tertiary Age. The well was production tested and the production rate was metered to 600 Sm^3 oil and 59,000 Sm^3 gas per day through a 19.2 mm choke opening.

Table 1.7.4
New discoveries in 1998

Exploration well	Operator	Hydrocarbon type	Reservoir level	Formation tested	Flow Rate (per day)	Choke opening	Size of discovery (recoverable) Oil/condensate (million Sm^3)	Size of discovery (recoverable) Gas (billion Sm^3)
24/6-2	Hydro	oil/gas	Paleocene	yes	600 Sm^3 oil 59 000 Sm^3 gas	19.2 mm	4-6	<1
30/3-7 A	Statoil	gas	Early and Middle Jurassic	no				<1
30/3-7 B	Statoil	oil/ gas	Early and Middle Jurassic	[1)]			1	2
30/8-3	Hydro	gas	Late Jurassic	no				<1
30/9-19	Hydro	oil/gas	Middle Jurassic	No [2)]	910 Sm^3 oil 370 000 Sm^3 gas	25.4 mm	2-4	5-7
34/7-29 S	Saga	oil	Late Jurassic	No [3)]			4	
6406/2-6	Saga	gas/cond.	Middle - Early Jurassic	No [4)]			0-25	0-40
6507/5-1	Amoco	oil/gas	Jurassic	Yes	862 Sm^3 oil 151 000 Sm^3 gas 178 Sm^3 oil 742 000 Sm^3 gas	38 mm 19 mm	34	34
			Cretaceous	Yes	923 Sm^3 oil 221 000 Sm^3 gas	17 mm		

[1]) test production underway, well 30/3-7 B reclassified to "test producer" in January 1999.
[2)] formation tested by appraisal well 30/9-19 A.
[3] formation test will be conducted later, is now temporarily plugged and abandoned.
[4)] liquid samples indicate presence of hydrocarbons

Table 1.7.5.a
Exploration wells drilled in the southern North Sea

Exploration well	Well classification	Production license	Operator	Total vertical depth (MSL)	Total depth (age)	Status (31 Dec. 98)
1/3-9 S	appraisal	065	BP	4337	Jurassic	oil[1)]
1/5-3 SX	wildcat	144	Conoco	1541	Tertiary	junked
2/8-17 S	wildcat	006	Amoco	2685	Permian	hydrocarbon trace
2/8-17 A	wildcat	006	Amoco	3145	Permian	hydrocarbon trace
9/2-8 S	wildcat [2)]	114	Statoil	3300	Jurassic	hydrocarbon trace

[1)] Temporarily plugged and abandoned
[2)] Reclassified to injection well

Table 1.7.5.b
Exploration wells drilled in the Sleipner and Balder area

Exploration well	Well classification	Production license	Operator	Total vertical depth (MSL)	Total depth (age)	Status (31 Dec. 98)
15/3-6	wildcat	187 [1)]	Amoco	2763	Cretaceous	dry
15/9-19 B	appraisal	046	Statoil	3360	Triassic	hydrocarbon trace
15/9-21 S	appraisal	046	Statoil	3907	Triassic	dry
16/1-5	wildcat	167	Statoil	2432	Permian	hydrocarbon trace
16/1-5 A	wildcat	167	Statoil	2005	Jurassic	hydrocarbon trace
16/10-4	wildcat	101	Agip	2540	Permian	dry
24/6-2	wildcat	203	Hydro	2722	Paleocene	oil/gas
25/11-22	wildcat	169	Hydro	1783	Cretaceous	dry

1) Drilled as a joint well between production licenses 187 and 025.

Table 1.7.5.c
Exploration wells drilled in the Oseberg and Troll area, Fram and Gjøa area

Exploration well	Well classification	Production license	Operator	Total vertical depth (MSL)	Total depth (age)	Status (31 Dec. 98)
30/3-7 A	wildcat	052	Statoil	4070	Early Jurassic	oil
30/3-7 B	wildcat [1)]	052	Statoil	4160	Early Jurassic	oil/gas/cond
30/6-25 S	wildcat	053[2)]	Hydro			in progress
30/8-3	wildcat	190	Hydro	3698	Early - Middle Jurassic	gas/cond
30/9-19	wildcat	079	Hydro	3560	Early Jurassic	oil/gas
30/9-19 A	appraisal	079	Hydro	3603	Early Jurassic	oil/gas
35/9-4 S	appraisal	153	Hydro	1261		[3)]
35/11-11	appraisal	090	Hydro	3201	Early Jurassic	dry

1) Will be reclassified to test production well
2) The well was drilled with Norsk Hydro as Operator for the unitized part of blocks 30/6 and 30/9.
3) Temporarily plugged and abandoned

The Oseberg and Troll area, Fram and Gjøa area
Seven exploration wells were completed in the Oseberg and Troll area, Fram and Gjøa area in 1998, see Table 1.7.5.c. Four of these were wildcat wells and three were appraisal wells. One of the appraisal wells (35/9-4 S) has been temporarily plugged and abandoned. Four discoveries of hydrocarbons were made in the area in 1998.

Well 30/3-7 A, which was drilled from the Veslefrikk installation, struck hydrocarbons in Middle Jurassic rocks. The main prospect proved to consist of dense sandstones from the Late Cretaceous Age. The discovery was not tested because a decision was made to drill well 30/3-7 B to inter alia delimit the discovery.

Well 30/3-7 B was drilled down in the discovery proven in the A well. Five hydrocarbon-bearing zones were struck in small, separate fault blocks in rocks from the Early to Middle Jurassic Age. The B well proved that the discovery in the A well has very poor reservoir properties, however, the B well also struck four other hydrocarbon-bearing zones. Test production indicates that the discoveries struck in the B well are small, however, the uppermost hydrocarbon-bearing zone may have an interesting supplementary potential. Well 30/3-7 B will be reclassified as a test production well.

Well 30/8-3 was drilled southwest of the Oseberg field, and proved gas/condensate in sandstone from the Middle Jurassic Age. The well was not tested due to poor reservoir properties. This is a very small discovery.

Well 30/9-19 was drilled west of the Oseberg field and proved oil and gas in Middle Jurassic sandstones. The discovery has been production tested in the oil zone by appraisal well 30/9-19 A. The production rate was measured at 910 Sm^3 oil and 370,000 Sm^3 gas per day through a 25.4 mm nozzle opening.

The Gullfaks, Statfjord and Snorre area

Five exploration wells, see Figure 1.7.5.d, were completed in this area in 1998 (Table 1.7.5.d). Three of the exploration wells were wildcat wells and two were appraisal wells. In addition, an appraisal well (34/11-4) has been spudded, but not completed as of year-end. One appraisal well (34/7-29 S) has been temporarily abandoned. Appraisal well 34/7-26 A has been reclassified to a production well. One new discovery of hydrocarbons was made in the area in 1998.

Well 34/7-29 S, which was drilled between the Statfjord Øst and Vigdis fields, struck oil in Late Jurassic rocks. A formation test is planned and the discovery is being evaluated.

Well results and interpretation of new seismic data indicate that the resource estimates may be reduced, and that the discovery may be in communication with the 34/7-23 S discovery.

The Norwegian Sea

Eight exploration wells, see Figure 1.7.5.e, were completed in this area in 1998 (Table 1.7.5.e), of which six were wildcat wells and two were appraisal wells. In addition, one wildcat well (6507/3-3) and one appraisal well (6406/2-4 SR) have been spudded but not completed as of year-end. Two of the wildcat wells, (6406/2-6 and 6507/5-1) have been temporarily abandoned. One of the six wildcat wells (6305/7-1) has been reclassified to an appraisal well. This well (6305/7-1), which was drilled with BP as operator in the southern part of the Ormen Lange dome, proved large gas resources. The Norwegian Petroleum Directorate now regards this well as a delimitation of the deposit that was proven by Norsk Hydro in 1997. The resource estimate for the structure has thus been increased substantially from 100 billion Sm^3 gas to about 315 billion Sm^3 gas.

In addition, there were two new discoveries of hydrocarbons in the area in 1998.

Table 1.7.5.d
Exploration wells drilled in the Gullfaks, Statfjord and Snorre area

Exploration well	Well classification	Production license	Operator	Total vertical depth (MSL)	Total depth (age)	Status (31 Dec. 98)
34/7-26 SR	appraisal	089	Saga	2660	Late Jurassic	oil
34/7-26 A	appraisal [1]	089	Saga	2583	Late Jurassic	oil
34/7-27	wildcat	089	Mobil[2]	2975	Early Jurassic	dry
34/7-28	wildcat	089	Saga	3005	Early Jurassic	dry
34/7-29 S	wildcat	089	Saga	2823	Middle Jurassic	oil[3]
34/11-4	appraisal	193	Statoil			in progress

1) Has been reclassified to production well.
2) Temporarily plugged and abandoned
3) The well was drilled as a joint well for production licenses 206, 037 and 089 in the Saga-operated production license 089.

Table 1.7.5.e
Exploration wells drilled in the Norwegian Sea

Exploration well	Well classification	Production license	Operator	Total vertical depth (MSL)	Total depth (age)	Status (31 Dec. 98)
6305/1-1	wildcat	209	Hydro	4523	Late Cretaceous	dry
6305/7-1	wildcat [1]	208	BP	3351	Late Cretaceous	gas
6406/2-4 SR	appraisal	199	Saga			in progress
6406/2-5 A	appraisal	199	Saga	4933	Early Jurassic	gas/cond
6406/2-6	wildcat	199	Saga	5239	Early Jurassic	gas/cond [2]
6505/10-1	wildcat	210	Shell	5028	Late Cretaceous	dry
6506/11-6	appraisal	134	Statoil	5310	Early Jurassic	gas/cond
6507/3-3	wildcat	159	Statoil			in progress
6507/5-1	wildcat	212	Amoco	4198	Early Jurassic	oil/gas [2]
6706/11-1	wildcat	217	Statoil	4291	Late Cretaceous	dry

1) 6305/7-1 reclassified to appraisal well.
2) Temporarily plugged and abandoned

Figure 1.7.5.a
Exploration wells drilled in the southern North Sea

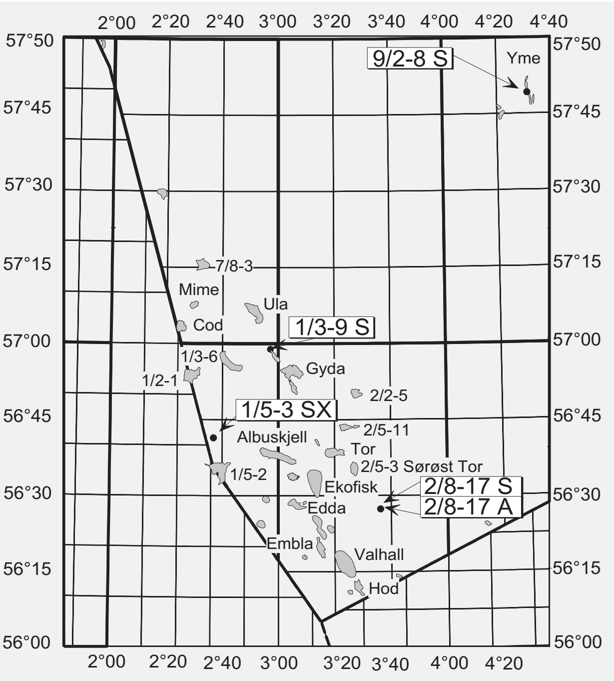


Figure 1.7.5.b
Exploration wells drilled in the Sleipner and Balder area

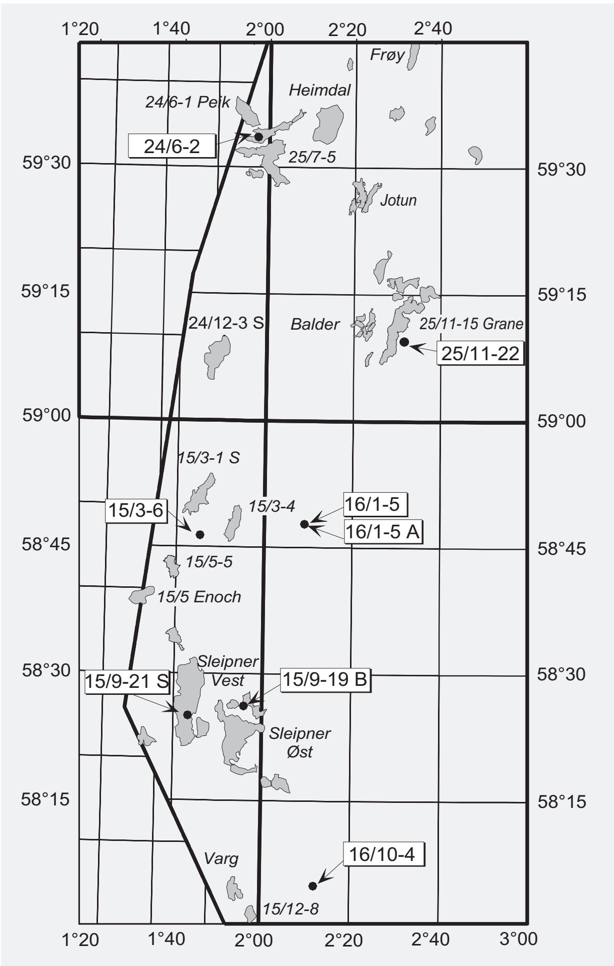


Figure 1.7.5.c
Exploration wells drilled in the Oseberg and Troll area, Fram and Gjøa area

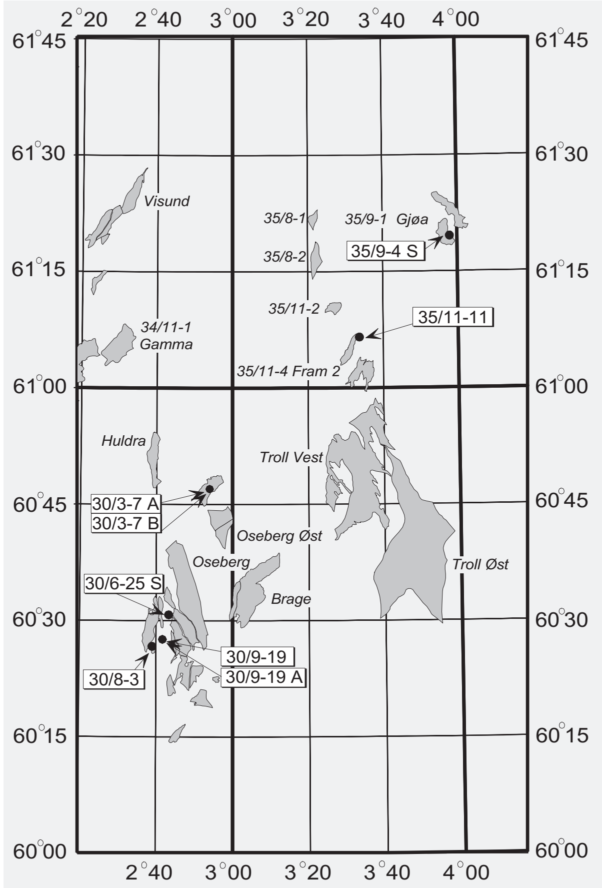


Figure 1.7.5.d
Exploration wells drilled in the Gullfaks, Statfjord and Snorre area

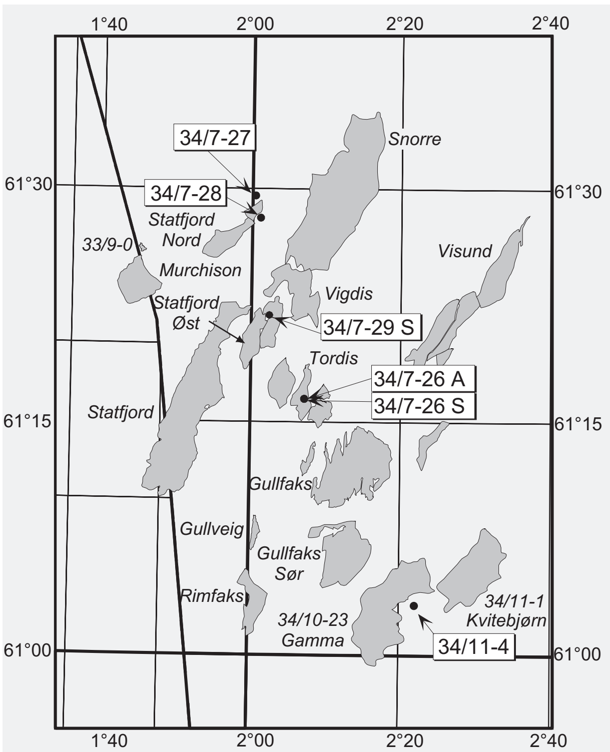
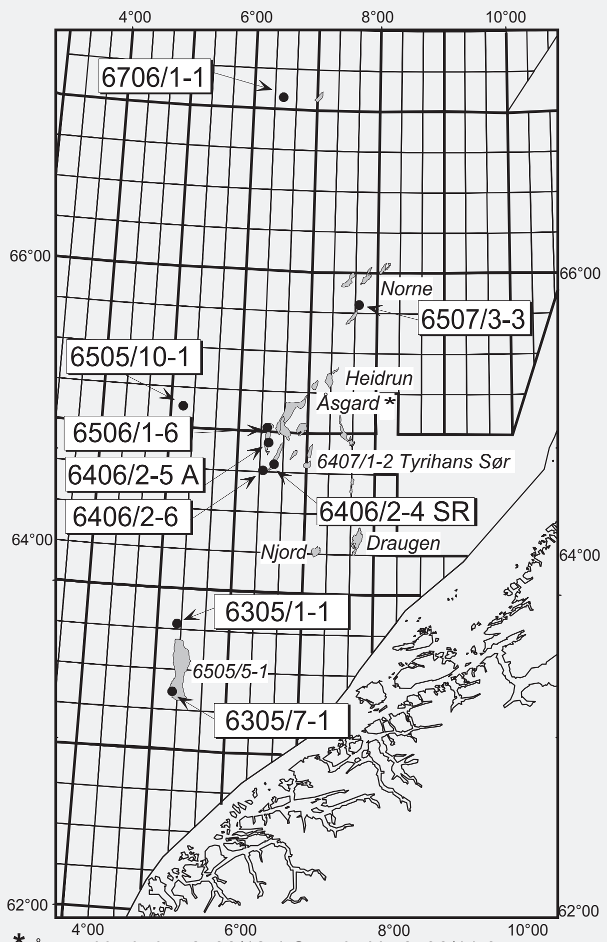


Figure 1.7.5.e
Exploration wells drilled in the Norwegian Sea



* Åsgard includes 6506/12-1 Smørbukk, 6506/11-3 Smørbukk Sør and 6507/11-1 Midgard

Well 6406/2-6, which was drilled to the south in the block between the previous discoveries Kristin and Lavrans, proved gas and condensate. The well has not been production tested, but liquid samples from the sandstone layer of the Lower and Middle Jurassic Age show that gas and condensate are present. The well has been temporarily abandoned, and evaluation of the results is in progress. The size of the discovery is uncertain.

Well 6507/5-1 was drilled on a structure located between Heidrun and the Norne field, and proved oil and gas in sandstone layers from both the Jurassic and Cretaceous Ages. Three separate production tests were conducted, two in the Jurassic and one in the Cretaceous. Additional appraisal wells are needed, both to determine the size of the discovery and to clarify the oil-gas ratio. The discovery has been named Skarv.

1.8 TRANSPORTATION SYSTEMS FOR OIL AND GAS

1.8.1 EXISTING TRANSPORTATION SYSTEMS

The various transportation systems for gas and oil/condensate from the Norwegian continental shelf are shown in Figure 1.8.1. Some of the transportation systems are British, where the Norwegian share of the transported volume comprises only a small part. This applies to:

- Northern Leg Gas Pipeline (NLGP), where Statfjord gas (British share) is transported to Shell's terminal at St. Fergus
- The Brent pipeline which transports Murchison oil to Sullom Voe on Shetland
- The Brae-Forties system which transports Heimdal condensate to BP's Kinneil terminal outside Edinburgh.

Gas transportation, Statpipe

Ownership structure

Den norske stats oljeselskap a.s.	58,25000 %
Elf Petroleum Norge AS	10,00000 %
Norsk Hydro Produksjon AS	8,00000 %
Mobil Development Norway AS	7,00000 %
Esso Expl. & Prod. Norway A/S	5,00000 %
A/S Norske Shell	5,00000 %
Norske Conoco A/S	2,75000 %
Saga Petroleum ASA	2,00000 %
Total Norge AS	2,00000 %

Statoil is the operator for operation of the system which includes:

- a rich gas pipeline from Statfjord to Kårstø. The transportation capacity for pipelines from Statfjord to Kårstø is 8 billion Sm^3 per day. The pipeline has an inner diameter of 710 mm (outer diameter 30").
- separation and fractionating plant at Kårstø, plus storage and loading facility
- dry gas pipeline from Heimdal to the Draupner S riser platform with a length of 155 kilometers and an inner diameter of 870 mm (outer diameter 36"), dry gas pipeline from Kårstø to Draupner S with a length of 228 kilometers and an inner diameter of 760 mm (outer diameter 28"), and a pipeline from Draupner S to the 2/4-S riser platform at the Ekofisk Center with a length of 190 kilometers and an inner diameter of 870 mm (outer diameter 36").

After production start, the Gullfaks, Veslefrikk, Snorre and Brage fields were connected to the Statpipe system upstream of the Kårstø facility. Sleipner has also been connected to Statpipe via a branch pipeline to Draupner.

Kårstø

The first North Sea gas was landed at Kårstø in March 1985. Delivery of dry gas from the terminal began in October 1985. The process facilities at Kårstø have a capacity of 25 million Sm^3 per day (rich gas).

At Kårstø, the heavy hydrocarbons are removed from the wet gas and sold as propane, butane, methyl propane and naphtha. Condensate from Sleipner is received at Kårstø via a separate pipeline from the Sleipner field. At Kårstø, the condensate is split into propane, butane, methyl propane and condensate and shipped on to the customers.

Both propane, butane, methyl propane, naphtha and condensate are stored in separate tanks, prior to being pumped via fiscal metering equipment to tankers.

Gas transportation, Norpipe

The pipeline system for transportation of natural gas from the Ekofisk Center to Emden in Germany is owned by Norpipe A/S. Gas from the Ekofisk area, Valhall and Statpipe is delivered to Norpipe. Norpipe A/S is a corporation which is 100 per cent-owned by Norsea Gas A/S.

Phillips Petroleum Company Norway is the technical operator of the pipeline, and is responsible for the economic and administrative functions.

A bypass line from Statpipe to Norpipe bypassing the Ekofisk Center has been laid in connection with Ekofisk II. In addition, Valhall is connected to Norpipe downstream of the Ekofisk Center.

The gas pipeline is 442 kilometers long and has an inner diameter of 869 mm (outer diameter 36"). The design capacity for the gas pipeline is about 19 billion Sm^3 per year.

There are two compressor stations on the gas pipeline, both on the German continental shelf. Norpipe is connected to Europipe so that gas from Norpipe can be delivered via the Europipe system and vice versa.

Ownership structure:

Phillips Petroleum Company Norway	15,89000 %
Fina Production Licences AS	12,90000 %
Norsk Agip AS	8,62000 %
Elf Petroleum Norge AS	5,04000 %
Norsk Hydro Produksjon AS	4,43000 %
Total Norge AS	2,36000 %
Den norske stats oljeselskap a.s.	50,00000 %
Elf Rex Norge AS	0,56000 %
Saga Petroleum ASA	0,30000 %

Norsea Gas A/S, Emden

Ownership structure:

Phillips Petroleum Company Norway	36,96000 %
Fina Production Licences AS	30,00000 %
Norsk Agip AS	13,04000 %
Elf Petroleum Norge AS	7,09600 %
Norsk Hydro Produksjon AS	6,70000 %
Total Norge AS	3,04700 %
Den norske stats oljeselskap a.s.	2,00000 %
Elf Rex Norge AS	0,85500 %
Norminol AS	0,30400 %

Phillips Petroleum Norsk AS is operator on behalf of the Phillips Group. The Norpipe system is connected to Europipe so that gas from Norpipe can be delivered via the Europipe system and vice versa.

Etzel gas storage

Ownership structure:

Ruhrgass	74,80000 %
Den norske stats oljeselskap a.s	20,10000 %
Norsk Hydro Produksjon AS	2,40000 %
Saga Petroleum ASA	1,20000 %
Elf Petroleum Norge AS	0,68955 %
Norske Conoco A/S	0,42090 %
Total Norge AS	0,38955 %

As of 31 December 1995, Ruhrgass took over Esso's and Shell's interests in the Etzel gas storage facility.

Gas transportation, Frigg

The Frigg Norwegian pipeline (FNA) is owned by the Norwegian Frigg licensees.

Ownership structure:

Norsk Hydro Produksjon AS	32,87000 %
Elf Petroleum Norge AS	21,42000 %
Den norske stats oljeselskap a.s	29,00000 %
Total Norge AS (operator)	16,71000 %

Some British fields are connected to the Frigg Norwegian line via MCP-01. While the installation was manned, the volumes from the British fields were metered on MCP-01. After demanning, the volumes from the British fields are metered on the individual installation.

St. Fergus

The terminal is owned by the Frigg Norwegian licensees and the Frigg British licensees (Elf UK 66-2/3 per cent, Total UK 33-1/3 per cent). Total Oil Marine UK is the operator.

Zeepipe

Ownership structure:

Den norske stats oljeselskap a.s (SDØE 55 %)	70,00000 %
Norsk Hydro Produksjon AS	8,00000 %
A/S Norske Shell	7,00000 %
Esso Expl. & Prod. Norway A/S	6,00000 %
Elf Petroleum Norge AS	3,29850 %
Saga Petroleum ASA	3,00000 %
Norske Conoco A/S	1,46299 %
Total Norge AS	1,29851 %

Zeepipe is a gas transportation system which is to transport gas from Kollsnes in Øygarden to the Continent. Phase I of the project comprises an 800 km long pipeline with an inner diameter of 966 mm (outer diameter 40") from Sleipner to Zeebrügge in Belgium. In addition, an approximately 40 km long line has been laid from Sleipner to the Draupner installation (16/11 S). Phase I, including the Zeebrügge terminal, was completed in 1993. The capacity without compression is about 12.6 billion Sm^3 per year.

Phase II comprises two pipelines from Kollsnes to Sleipner R and the Draupner installation respectively. The inner diameter is 966 mm (outer diameter 40"). The pipeline to Sleipner R, Phase II-A, was put into operation in 1996 and the pipeline to Draupner, Phase II-B, was put into operation in 1997.

Statoil is the operator.

Europipe

Ownership structure

Den norske stats oljeselskap a.s (SDØE 55 %)	70,00000 %
Norsk Hydro Produksjon AS	8,00000 %
A/S Norske Shell	7,00000 %
Esso Expl. & Prod. Norway A/S	6,00000 %
Elf Petroleum Norge AS	3,29850 %
Saga Petroleum ASA	3,00000 %
Norske Conoco A/S	1,46299 %
Total Norge AS	1,29851 %

This pipeline goes from Draupner (16/11 E) to Emden in Germany and is about 620 kilometers long. The pipeline has an inner diameter of 966 mm (outer diameter 40"). The capacity without compression is approximately 13 billion Sm^3 gas per year. Gas deliveries started as planned on 1 October 1995.

Statoil is the operator.

NorFra

NorFra is an 840 kilometer long pipeline with an inner diameter of 1016 mm (outer diameter 42") between Draupner (16/11 E) and Dunkerque in France. The pipeline has an initial capacity of 11.4 billion Sm^3 per year. The plan is for gas deliveries to start on 1 October 1998.

Ownership structure:

Den norske stats oljeselskap a.s (SDØE 60 %)	69,7088 %
Norsk Hydro Produksjon AS	6,4725 %
Saga Petroleum ASA	5,1780 %
Esso Expl. & Prod. Norway A/S	3,8835 %
Mobil Development Norway AS	3,8835 %
Total Norge AS	2,9126 %
Elf Petroleum Norge AS	2,1359 %
Norsk Agip AS	1,9417 %
A/S Norske Shell	1,2945 %
Neste Petroleum AS	1,2945 %
Norske Conoco A/S	1,2945 %

Statoil is the operator for the construction phase. The Ministry will designate the operator for the operations phase at a later date.

Haltenpipe

Haltenpipe is a 245 kilometer pipeline with an inner diameter of 381 mm (outer diameter 16") for transportation of gas from Heidrun to Tjeldbergodden. The pipeline has a capacity of 2-2.5 billion Sm^3 per year. The pipeline was put into operation in 1997. The owners are the same as for Heidrun and Statoil is the operator.

Oil transportation, Norpipe

The pipeline system for transportation of oil from the Ekofisk Center to Teesside in England is owned by Norpipe A/S. Norpipe receives oil from the fields in the Ekofisk area and the nearby Valhall, Hod, Ula, Gyda and Tommeliten Gamma fields. The British fields Judy and Joanne are connected to Norpipe and started production in October 1995. In addition, the Fulmar, Clyde, Auk and Gannet fields were tied into the Judy and Joanne pipeline in 1996.

Norpipe A/S is a corporation owned 50/50 by Statoil and the Phillips group. Phillips Petroleum Company Norway is technical operator of the pipeline, while Statoil is responsible for the economic and administrative functions.

Teesside

The ownership structure for the facilities at the Teesside terminal is split between Norpipe A/S and the Phillips group, through the Norpipe Petroleum UK Ltd. and Norsea Pipeline Ltd. companies. Phillips Petroleum Company UK Ltd. is the operator of the facilities.

Oil transportation, Oseberg Transport System (OTS)

A pipeline for transportation of stabilized oil from Oseberg to the Stura terminal was laid in the summer of 1987. The pipeline has an inner diameter of 670 mm (outer diameter 28") and has a design capacity of approximately 95,000 Sm^3 per day. By adding drag reducers, the capacity has been increased to about 117,000 Sm^3 per day.

The plant, including the Stura terminal, is owned and operated by a separate joint venture, I/S Oseberg Transport System. The participants in the company are the licensees in the Oseberg field. Norsk Hydro is the operator of the pipeline and the terminal. OTS was put into operation when production started from Oseberg. Veslefrikk, Brage, Frøy and Lille-Frigg have subsequently been connected to OTS.

Troll oil pipeline (Troll Oljerør)

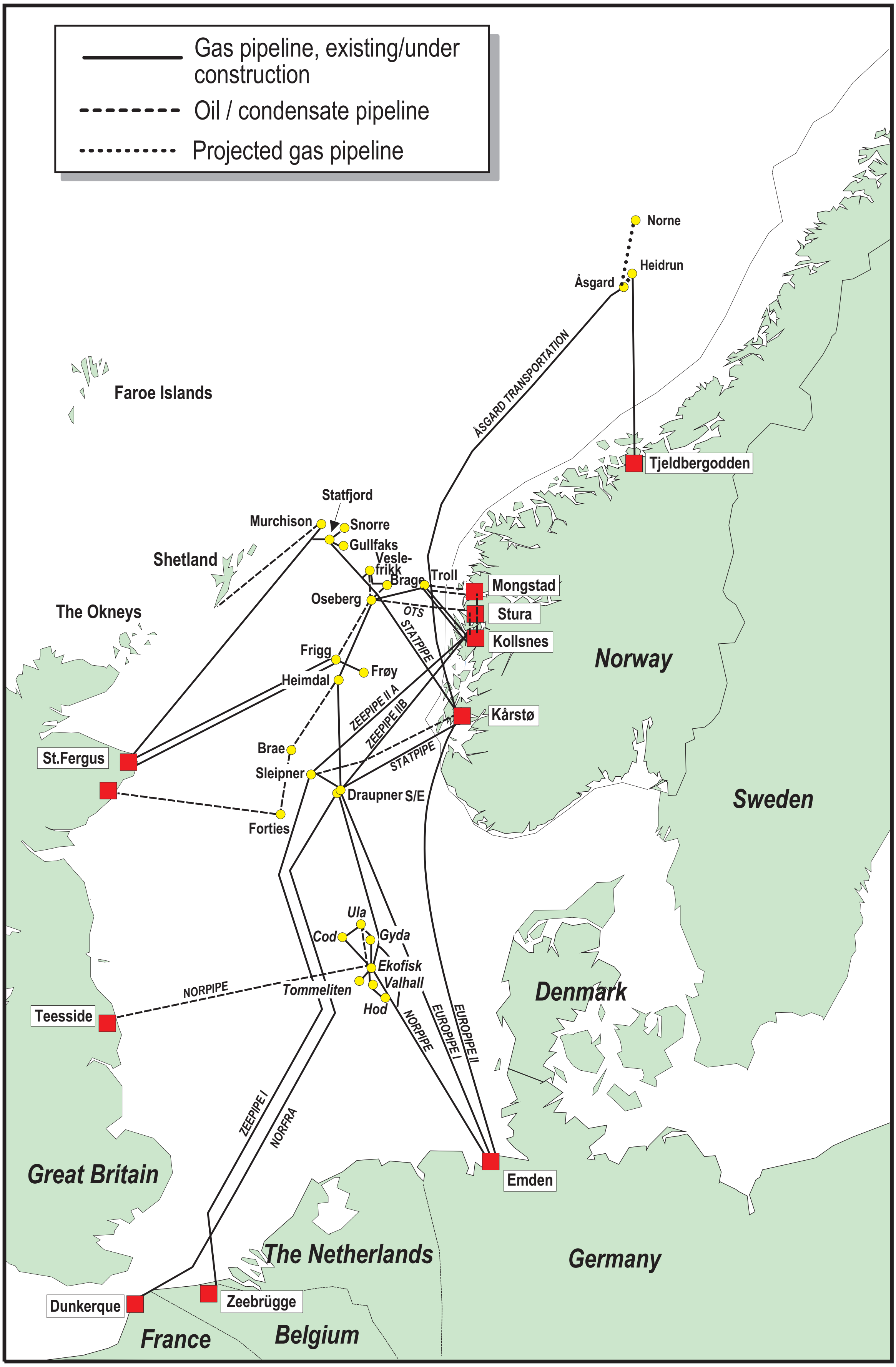
Ownership structure:

Den norske stats oljeselskap a.s (SDØE 62,696)	74,57600 %
A/S Norske Shell	8,28800 %
Norsk Hydro Produksjon AS	7,68800 %
Saga Petroleum ASA	4,08000 %
Elf Petroleum Norge AS	2,35344 %
Norske Conoco A/S	1,66113 %
Total Norge AS	1,35343 %

Troll oil pipeline transports oil from the Norsk Hydro-operated Troll oil installation to the terminal at Mongstad. The inner diameter is 381 mm (outer diameter 16").

Statoil is the operator of the pipeline which was put into operation in the summer of 1995.

Figure 1.8.1
Transportation systems for oil and gas from Norwegian fields



Frostpipe

Ownership structure:

Den norske stats oljeselskap a.s (SDØE 30 %)	50,00000 %
Elf Petroleum Norge AS (operator)	22,00000 %
Total Norge AS	14,25000 %
Norsk Hydro Produksjon AS	13,75000 %

Frostpipe is an approximately 80 kilometer long pipeline with an inner diameter of 374 mm (outer diameter 16") for transportation of stabilized oil and condensate from Frigg to Oseberg. The transportation system has a capacity of about 16,000 Sm^3 per day. Production start was in the spring of 1994.

Sleipner Øst condensate pipeline

Ownership structure:

Den norske stats oljeselskap a.s (SDØE 29,6 %)	49,60000 %
Norsk Hydro Produksjon AS	10,00000 %
Esso Expl. & Prod. Norway A/S	30,40000 %
Total Norge AS	1,00000 %
Elf Petroleum Norge AS	9,00000 %

Deliveries of condensate from Sleipner Øst started in 1993. The condensate is transported unprocessed through the 245 kilometer long pipeline to the terminal at Kårstø, where it is fractionated into commercial wet gas products and stabile condensate. The pipeline has an inner diameter of 474 mm (outer diameter 20"), and the transport capacity is 32,000 Sm^3 per day. The condensate from Sleipner Vest will also be transported through this pipeline from 1997. The Storting approved the construction of the pipeline in December 1989.

1.8.2 PROJECTED TRANSPORTATION SYSTEMS

Åsgard Transport

Åsgard Transport will be a 745 kilometer pipeline with an inner diameter of 1016 mm (outer diameter 42") for transportation of gas from Åsgard and other fields on Haltenbanken to Kårstø. The pipeline will have a capacity of about 19 billion Sm^3 per year. The plan is for the pipeline to commence operations on 1 October 2000.

Ownership structure:

Den norske stats oljeselskap a.s (SDØE 46,9 %)	60,45000 %
Saga Petroleum ASA	9,00000 %
Norsk Agip AS	7,90000 %
Total Norge AS	7,65000 %
Mobil Development Norway AS	7,35000 %
Neste Petroleum AS	5,00000 %
Norsk Hydro Produksjon AS	2,60000 %

Europipe II

Europipe II will be a 653 kilometer pipeline with an inner diameter of 1016 mm (outer diameter 42") for transportation of gas from Kårstø to Emden. The pipeline will have a capacity of 21.1 billion Sm^3 per year and the plan is for the pipeline to commence operations on 1 October 1999.

Ownership structure:

Den norske stats oljeselskap a.s (SDØE 60 %)	60,01000 %
Norsk Hydro Produksjon AS	4,7249 %
Saga Petroleum ASA	10,6309 %
Esso Expl. & Prod. Norway A/S	7,6780 %
Mobil Development Norway AS	1,1812 %
Total Norge AS	5,9061 %
Elf Petroleum Norge AS	0,0059 %
Norsk Agip AS	2,3600 %
A/S Norske Shell	1,1812 %
Neste Petroleum AS	3,6618 %
Norske Conoco A/S	2,6577 %

Statoil is the operator for the development phase. The Ministry will designate the operator for the operations phase at a later date.

Oseberg Gas Transport

Oseberg Gas Transport will be a 108 kilometer pipeline with an inner diameter of 869 mm (outer diameter 36") for transportation of gas from Oseberg to Statpipe via Heimdal. The pipeline will have a capacity of about 14.5 billion Sm^3 per year and planned operations start-up is 1 October 2000. Norsk Hydro is the operator of the pipeline.

Ownership structure

Den norske stats oljeselskap a.s. (SDØE 50,7838 %)	64,78380 %
Norsk Hydro Produksjon AS	13,68200 %
Saga Petroleum ASA	8,55300 %
Elf Petroleum Norge AS	5,77000 %
Mobil Development Norway AS	4,32700 %
Total Norge AS	2,88500 %

Heidrun Gas Transport

Heidrun Gas Transport will be a 37 kilometer pipeline with an inner diameter of 525 mm (outer diameter 22") for transportation of gas from Heidrun to Åsgard Transport at Åsgard. The pipeline will have a capacity of 4 billion Sm^3 per year and the plan is to put the pipeline into operation on 1 October 2000. Statoil is the operator of the pipeline.

Ownership structure

Den norske stats oljeselskap a.s. (SDØE 65,00000 %)	76,87500 %
Norske Conoco A/S	18,12500 %
Neste Petroleum AS	5,00000 %

Norne Gas Transport

Norne Gas Transport will be a 90 kilometer pipeline with an outer diameter of 16" for transportation of gas from

Norne to Heidrun Gas Transport. The pipeline will have a capacity of 3.6 billion Sm^3 per year and planned start-up of operations is 1 October 2000. Statoil is the operator of the pipeline.

Ownership structure

Den norske stats oljeselskap a.s (SDØE 55,00000 %)	70,00000 %
Saga Petroleum ASA	9,00000 %
Norsk Hydro Produksjon AS	7,50000 %
Norsk Agip AS	7,50000 %
Enterprise Oil Norwegian AS	6,00000 %

1.9 PETROLEUM ECONOMY

The petroleum sector makes a significant contribution to the overall creation of wealth in Norway. The sector's share of the gross national product has increased from 13 per cent at the beginning of the 1990s to 16 per cent in 1996 and 1997. In 1998, this share was reduced to 11 per cent.

The petroleum sector also accounts for a large share of total exports from Norway. In 1996 and 1997, this share was approximately 38 per cent. In 1998 the export share was reduced to 30 per cent.

The petroleum activities lead to employment both offshore and on land. Nearly 91,500 people were employed in petroleum-related activities in Norway in 1998, an increase of 15 per cent compared with the previous year.

1.9.1 EXPLORATION AND PLANNING ACTIVITIES

In 1998, 26 exploration wells were spudded, while the number of exploration wells in 1997 was 50. 17 wildcat wells and nine appraisal wells were spudded in 1998. Corresponding figures for 1997 were 38 and 12. On average over the period from 1966-1998, the number of spudded wildcat and appraisal wells has been 20 and 8, respectively.

Figure 1.9.1.a shows the costs of exploration and planning activities from and including 1980. The costs include exploration drilling, general surveys, discovery evaluations and administration. According to figures reported to the Norwegian Petroleum Directorate, the total exploration costs in the years 1980-1998 amount to approximately 7.5 billion 1998-NOK.

Exploration and planning costs for 1998 divided among the various types of costs are shown below. The figures are based on data reported by the operating companies. The same figures are used as a basis for Figure 1.9.1.b, which shows the percentage distribution of the costs.

Exploration and planning costs	Million NOK
Exploration drilling	4197
General surveys	1163
Field evaluations	932
Administration[1]	1282
Total	**7574**

[1] Administration costs include area fees.

In 1998, the share of exploration costs related to exploration drilling was 56 per cent, while the corresponding figure for 1997 is 65 per cent. The share of costs related to general surveys is 15 per cent in 1998 compared with 12 per cent in 1997. General surveys include inter alia collection of seismic data.

Figure 1.9.1.c shows the average drilling costs per exploration well, i.e. wildcat and appraisal wells. In 1998, drilling was carried out at a cost of around NOK 4.1 billion, and the cost per well is estimated to be about NOK 160 million. This is a relative increase compared with 1997 when drilling costs per well were about NOK 107 million.

Figure 1.9.1.a
Annual exploration and planning cost

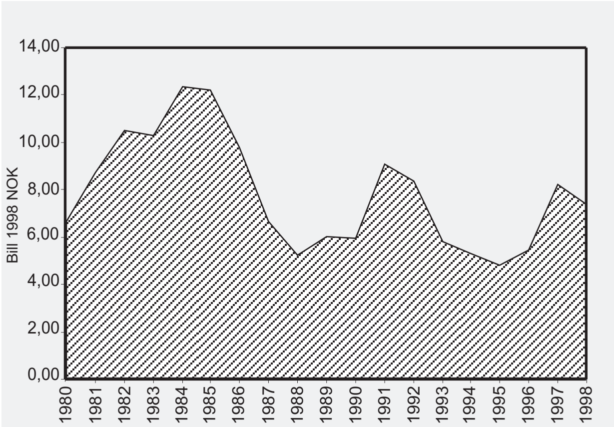


Figure 1.9.1.b
Percentage distribution of the cost

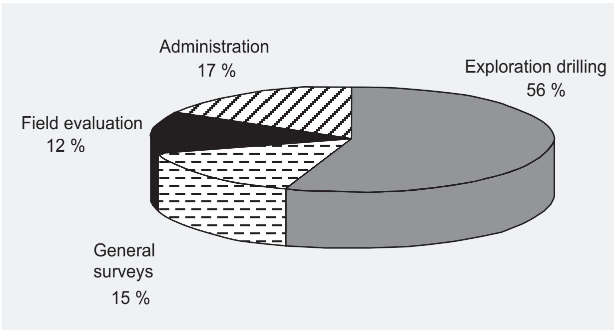


Figure 1.9.1.c
Average drilling cost per exploration well

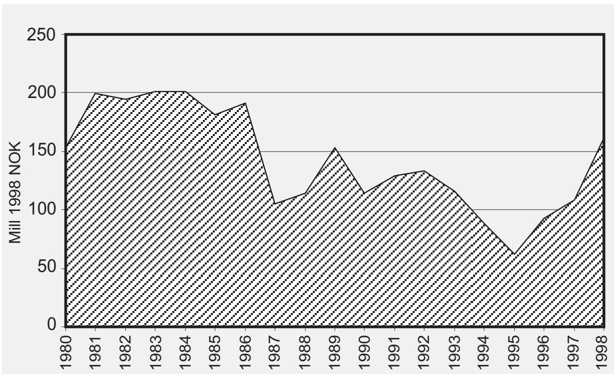
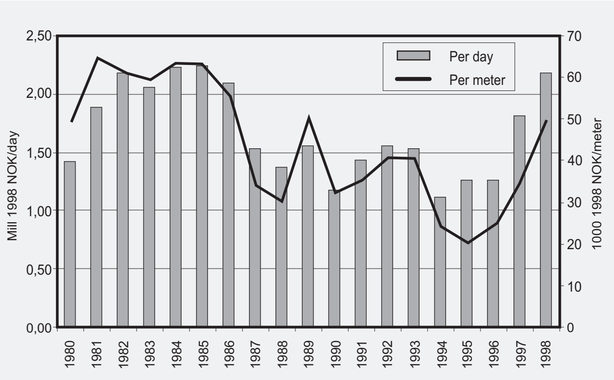


Figure 1.9.1.d
Average drilling cost per day and per meter drilled in the years 1980 - 1998



However, the total drilling costs have declined since 1997, when drilling was carried out for about NOK 5.3 billion.

Figure 1.9.1.d shows the average drilling costs per day and per meter drilled in the years 1980-1998.

1.9.2 THE STATE'S DIRECT FINANCIAL INTEREST

The State's Direct Financial Interest (SDFI) in the petroleum activities was established with effect from 1985. Statoil's ownership interests were then split into a financial interest to Statoil and a direct financial interest to the state. Up until the 14th licensing round, both Statoil and SDFI were normally awarded ownership interests in all production licenses which were awarded. From and including the 15th round, blocks were awarded without SDFI participation. In addition, interests were awarded to SDFI without Statoil receiving corresponding interests. Statoil is responsible for the operational and financial follow-up of the state's direct interest. An important consideration in the formulation of petroleum policy has been that the state shall collect a significant share of economic rent in the oil activities. SDFI, together with the petroleum taxation system and dividends from Statoil, comprise the state's revenues from the petroleum activities. The SDFI arrangement entails that the state pays a share of the investments and operating costs in a project corresponding to its interest. In the same way as all other licensees, the state will get its corresponding share of the production and revenues. As a consequence of significant ownership interests in the vast majority of licenses, SDFI is the largest investor on the Norwegian shelf, and is represented with a considerable volume in the exploration, development and operations phases.

1.9.3 THE CRUDE OIL MARKET

Global oil production in 1998 (excluding NGL) is estimated to be about 66.3 million barrels per day (Source: Oil and Gas Journal (OGJ) 28 December 1998). This corresponds to about 3.8 billion Sm^3 per year, and means an increase of 1.3 per cent from 1997. Production from the OPEC countries increased by two per cent. OPEC's production in 1997 was 27.2 million barrels per day in 1997, compared with 27.7 million barrels per day in 1998. The greatest increase was in Iraq. Production in Eastern Europe and the countries in the former Soviet Union was around 7.2 million barrels per day in both 1997 and 1998. Production in the USA declined somewhat, from 6.5 million barrels per day in 1997 to 6.4 million barrels per day in 1998.

Norwegian oil production also declined, from 3.1 million barrels per day in 1997 to 3.0 million barrels per day in 1998, accounting for 4.6 per cent of global production in 1998. OPEC's market share was just over 41.8 per cent, up 0.2 percentage points from 1997.

According to OGJ, the global proven oil reserves at the end of 1998 were 164 billion Sm^3, which means an increase of more than 2 billion Sm^3 during the year. The resources constitute 43 years of production at 1998 level. Most countries report unchanged resource estimates as compared with the end of 1997. Based on the resource estimates, the largest oil-producing area in the future will be the Middle East. This area contains 65 per cent of global oil resources.

At the beginning of 1998, the spot price of Brent Blend oil was about 17 dollars (USD) per barrel, compared with approximately USD 10 per barrel at the end of the year. Lower oil prices can, on the supply side, be explained by factors such as an increase of OPEC's production quotas in the autumn of 1997 and increased export from Iraq. Explanations on the demand side are an uncommonly mild winter in 1997-1998 and the financial crises in Asia and Russia. A weakened oil price measured in dollars was partially offset by an increased exchange rate for the dollar.

This meant that the Brent Blend price in Norwegian kroner (NOK) has declined by 30 per cent during the course of the year, while the price in USD has declined by more than 40 per cent. The spot price for a barrel of Brent Blend fell from NOK 115 to NOK 80 during the course of 1998.

1.9.4 NATURAL GAS MARKET

In 1998, Norway exported gas to the United Kingdom, Germany, the Netherlands, Belgium, France, Spain, Austria and Czechia. Figure 1.9.5.c shows the distribution of gas sales to the various buyer countries.

In 1998, export from Norway constituted 42.6 billion Sm^3 (40.48 MJ/Sm^3), an increase of about 0.3 billion Sm^3 (0.7 per cent) gas compared with the previous year.

The first gas sales were primarily based on depletion of accessible reserves in the individual fields. Norway entered a new era as a gas supplier on 1 October 1993 when deliveries under the Troll agreements (TGSA) got underway. These are sales contracts which offer the customers fixed annual volumes, where also other fields than Troll may provide deliveries. In connection with the Troll agreements, the authorities have established the Troll commercial model, which provides opportunities for the sale of associated gas and smaller gas fields.

Organization of Norwegian gas sales

Since 1986, the sale of Norwegian gas has been coordinated by a Gas Negotiation Committee (GFU) under the leadership of Statoil, and with participation by Norsk Hydro and Saga. Other companies are also involved in the negotiation of gas sales contracts. In 1993, the authorities set up the Gas Supply Committee (FU). This committee, which consists of the largest gas owners on the Norwegian continental shelf, shall have an advisory role vis-à-vis the Ministry of Petroleum and Energy in questions related to development and management of gas fields and transportation systems for gas.

Existing commitments
Field contracts
The fields which currently deliver under field contracts are Statfjord, Gullfaks, as well as fields in the Frigg and Ekofisk areas. Production from these fields is now in the decline phase, but they will still deliver gas for many years to come. Gas deliveries from the Ekofisk and Frigg areas started in 1977, from Statfjord in 1985, from Heimdal in 1986 and from Gullfaks in 1987. The gas from the Frigg area is delivered to the United Kingdom, while the other fields deliver to buyers on the Continent.

Troll gas sales agreements from 1986 (TGSA)
The TGSA agreements were signed in 1986 between the Troll licensees and buyers on the Continent. The buyer countries are Germany, the Netherlands, Austria, France, Belgium and Spain. At plateau (2005), the Troll agreements comprise 44.7 billion Sm^3 per year, including exercised purchase options.

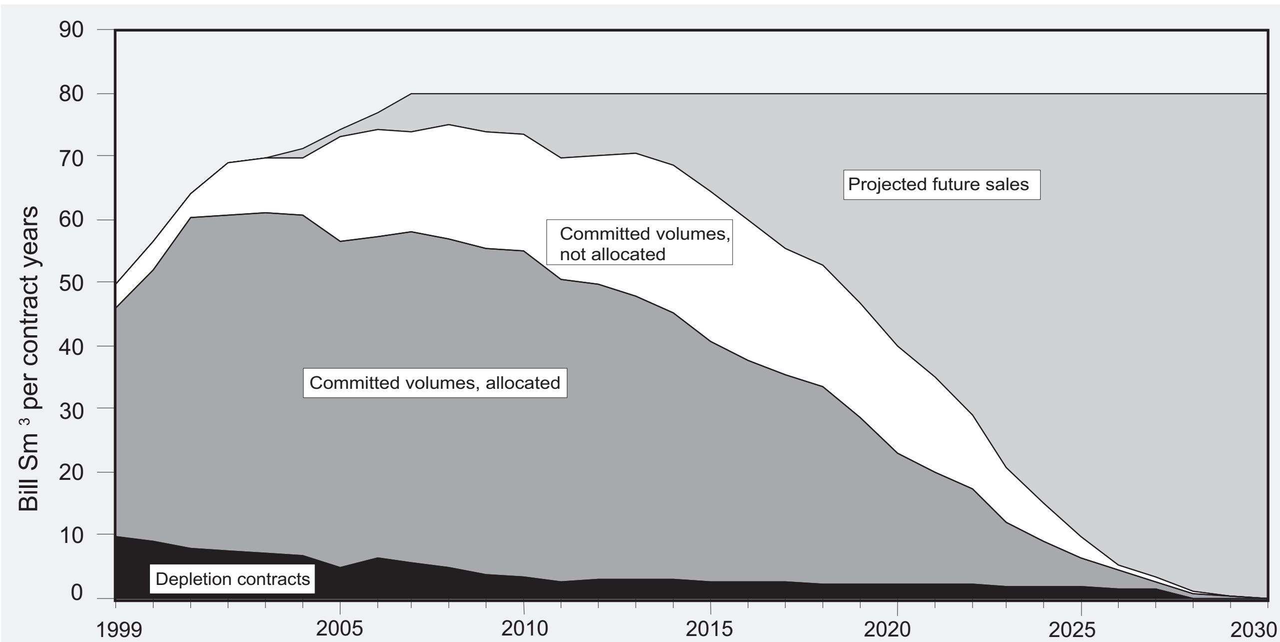
Newer commitments
In 1992, the Electrabel contract (Belgium) was signed. In 1993, two new contracts were signed for the sale of additional volumes to Ruhrgas and VNG (Germany). The following year, contracts were signed with MEEG (Germany) and GdF (France). In 1995, contracts were signed for additional sales to GdF (France). During the course of 1997, contracts were signed with the Italian company SNAM and the Czech company Transgas. In 1998, a contract has been signed with Alliance Gas (U.K.), while at the same time, purchase options on additional sales to SNAM and Transgas have been waived.

Potential new sales
In spite of a certain reduction in current sales commitments as a result of non-exercised purchase options, the Norwegian Petroleum Directorate still believes that it is likely that Norway's total gas sales over the long term may reach 80 billion Sm^3 per year. Figure 1.9.4 shows committed and potential new sales. Committed volumes are divided between field contracts, allocated supply contracts and non-allocated supply contracts. The Ministry of Petroleum and Energy allocates volumes after consultation with the Norwegian Petroleum Directorate and the Gas Supply Committee.

Use of gas in Norway
In 1995, the Ministry of Petroleum and Energy presented a separate report to the Storting regarding the use of gas in Norway. The Storting report presents the government's objectives and the possibilities for use of natural gas in Norway.

The most important Norwegian gas market is the market for injection gas on the continental shelf. The largest buyers are Oseberg and Ekofisk. The gas is injected in Oseberg in order to achieve increased oil recovery. Ekofisk buys gas from several fields for fuel. Gas is also the most important source of energy for operation of fields and transportation

Figure 1.9.4
Committed and projected future sales.



systems. It is primarily gas produced from the field itself which is used for these purposes. In 1998, a total of 24.7 billion Sm^3 gas was used for injection and 2.9 billion Sm^3 gas was used as fuel on the shelf.

Gas has been landed in Norway since Statpipe began operating in 1985. The gas is landed at Kårstø in northern Rogaland, at Kollsnes in Hordaland and Tjeldbergodden in Møre og Romsdal.

In northern Rogaland, an agreement has been signed regarding smaller deliveries to the distribution company Gasnor. All of Gasnor's customers have previously used fuel oil as a source of energy. Deliveries commenced in 1994. The company Naturgass Vest has started developing a distribution network for natural gas from Kollsnes in Øygarden. The first construction stage is a high pressure gas line from the Kollsnes gas plant to the Kollsnes industrial park where inter alia production of compressed natural gas for use in busses and other motor vehicles will be established.

In 1994, Statkraft, Statoil and Norsk Hydro set up a joint company, Naturkraft. Naturkraft received a license for development and operation of two gas power plants and still has an application pending for a discharge/emission permit from the State Pollution Control Authority. The plan is for the power plants to be established at Kårstø and Kollsnes. Total consumption of gas in the gas power plants will be 0.9 billion Sm^3 gas per year.

1.9.5 SALE OF PETROLEUM FROM THE NORWEGIAN CONTINENTAL SHELF

In 1998, 142.6 million tonnes of crude oil was sold from the Norwegian continental shelf. This represents a decrease of 4.2 per cent compared with 1997. The Netherlands was the largest recipient with 18.8 per cent of the shipments,

Figure 1.9.5.a
Sales of crude oil from the Norwegian shelf

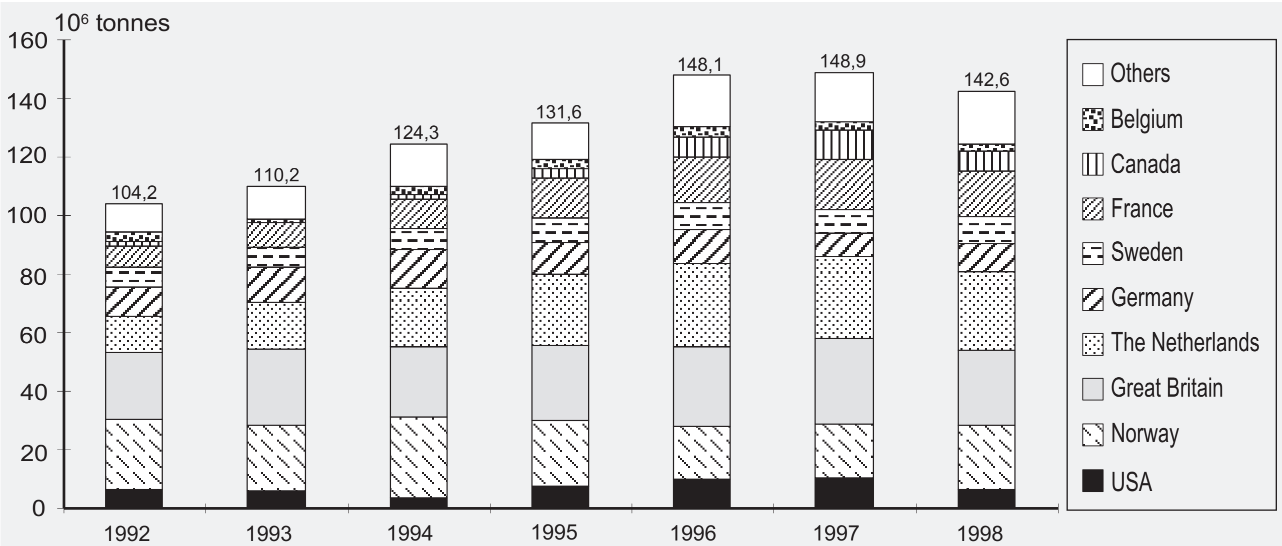
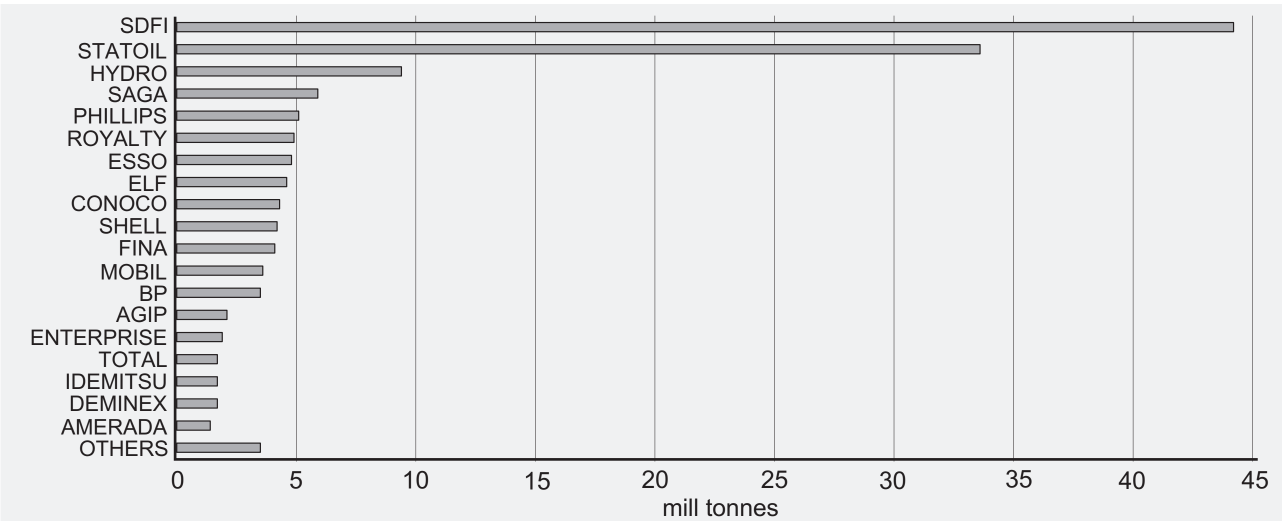


Figure 1.9.5.b
Sales quantities of oil/NGL (excl. condensate) per licensee in 1998



the United Kingdom received 17.9 per cent, Norway 15.5 per cent, France 10.9 per cent and Germany 6.7 per cent. In 1997, Norway received 12.4 per cent. Figure 1.9.5.a shows crude oil sales distributed by country in the period 1992-1998.

Up to 1988, Belgium and Canada are included in the group "others". Sale of NGL (including condensate) from the Norwegian continental shelf in 1998 reached 7.2 million tonnes. This is 1.1 million tonnes less than in 1997. Figure 1.9.5.b shows the sale of crude oil and NGL in 1998 distributed by licensees.

Norway exported 42.6 billion Sm³ gas in 1998. This is an increase of 0.3 per cent compared with 1997. 17.4 billion Sm³ was sold to Germany, 0.9 billion Sm³ to the United Kingdom, 10.4 billion Sm³ to France, 5.2 billion Sm³ to the Netherlands, 5.1 billion Sm³ to Belgium, 2.5 billion Sm³ to Spain, 0.7 billion Sm³ to Czechia and 0.4 billion Sm³ to Austria, see Figure 1.9.5.c. Figure 1.9.5.d shows

Figure 1.9.5.c
Sales quantities of gas per country

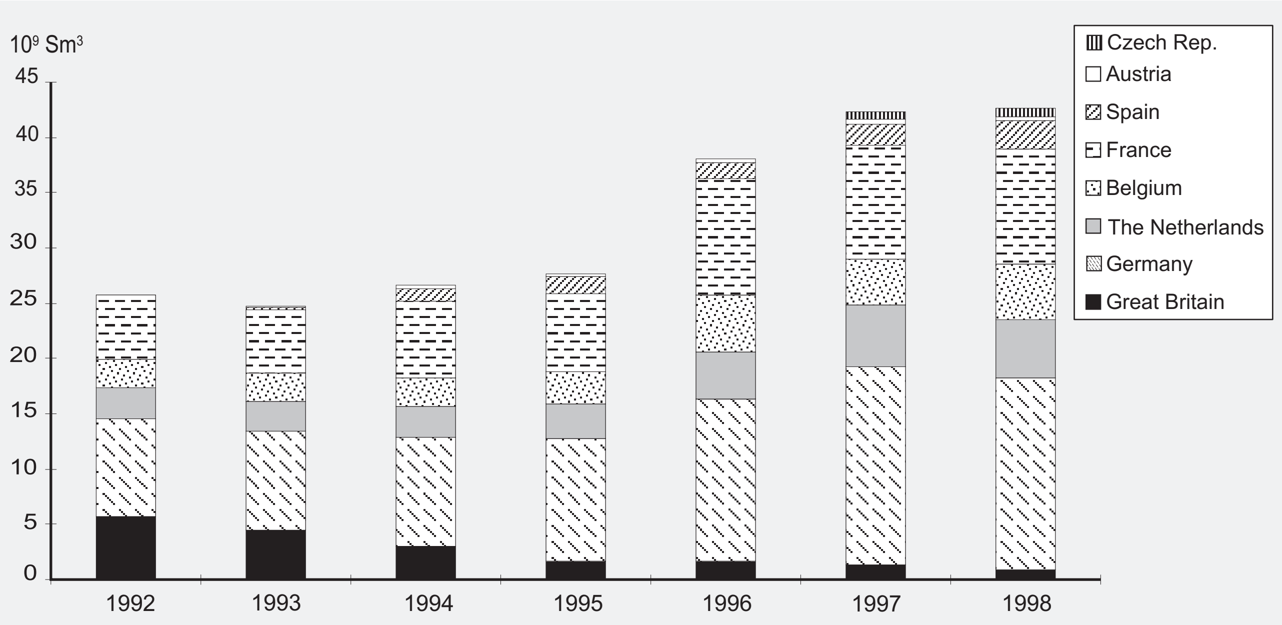
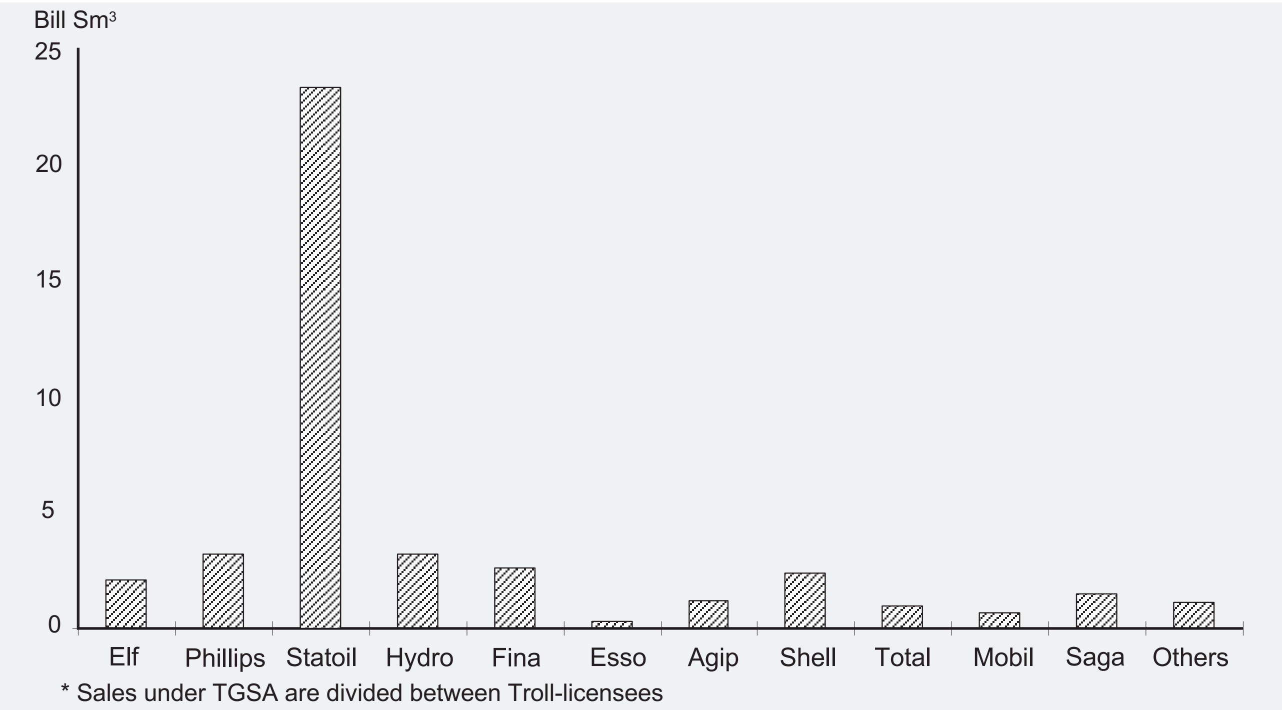


Figure 1.9.5.d
Sales quantities of gas per licensee in 1998



the gas sales distributed by licensees. Sales under the TGSA agreements are divided among the Troll licensees. In the column labeled "others", companies are not specified as this column contains figures from several small fields and it would be very inaccurate to specify them.

1.9.6 ROYALTY

The Norwegian Petroleum Directorate has been delegated the responsibility for collection of royalties from petroleum production. Production royalty is calculated according to the provisions of the Act relating to Petroleum Activities. The basis for calculation of the royalty is the value of the produced petroleum at each production area's loading point. As it is not customary to calculate the price of petroleum products at the loading point, in practice the calculation basis applied is the difference between the gross sales value and the costs incurred between the taxation point and the point of sale.

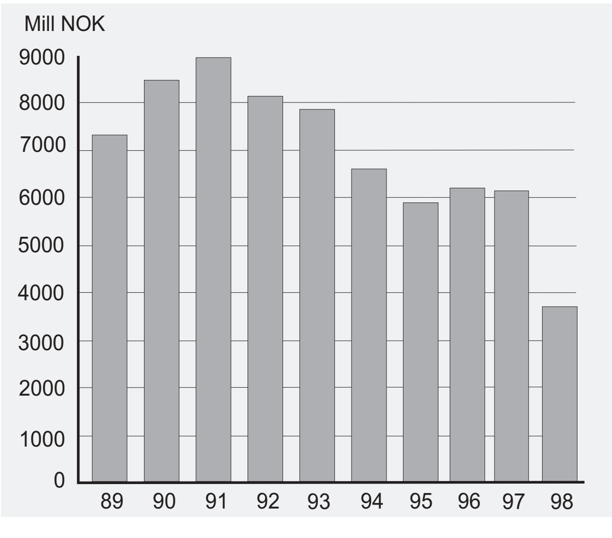
No production royalty shall be paid on production from deposits where the development plan is approved or requirements for a plan for development and operation terminate after 1 January 1986, cf. Section 4-9 of the Petroleum Act.

Interpretation and enforcement of the current laws and regulations in connection with calculation of royalties include problems of a legal, economic, processing and metering nature.

From 1 January 1992, the royalty rate for gas was set at nil, cf. Section 31 of the Petroleum Regulations. This means that, as of that date, royalty will only be levied on oil.

Since on some fields oil and NGL are a single product at the loading point, and the NGL is separated at a later stage, then for those fields royalty will be paid on the NGL. On the other hand, royalty will not be levied on NGL in those fields where NGL is part of the gas at the loading point.

Figure 1.9.6
Royalties paid 1989-1998



Total royalty

In 1998, licensees on the Norwegian shelf paid royalties totaling NOK 3,754,908,803 to the Norwegian Petroleum Directorate. Table 1.9.6.a shows the breakdown for the various petroleum products for 1997 and 1998. Figure 1.9.6 shows paid royalties from 1989-1998.

Table 1.9.6.a
Total royalty paid in 1997 and 1998 (million NOK)

Product	Field/area	1997	1998
Oil	Ekofisk area, Ula and Valhall	1 968,7	1 247,7
"	Statfjord	2 126,7	1 248,7
"	Murchison	13,6	19,5
"	Heimdal	21,1	10,8
"	Oseberg	1 170,2	662,5
"	Gullfaks	882,9	524,8
NGL	Ekofisk area	27,1	33,2
"	Valhall	5,3	5,7
"	Ula	2,0	1,2
"	Murchison	1,1	0,8
"	Frigg area	*1,6	0,0
Total		**6 220,3**	**3 754,9**

*Repaid royalty for gas for previous years

Royalty on oil

In 1998, NOK 3,714,081,511 was paid in royalties for oil from the Ekofisk area, Ula, Valhall, Statfjord, Murchison, Heimdal, Oseberg and Gullfaks, see Table 1.9.6.b. The royalty on oil is usually taken out in oil, but the Ministry of Petroleum and Energy has determined that the royalty on oil from Heimdal shall be taken out in cash as from 1 April 1993. Sale of the State's royalty oil is the responsibility of Statoil. Payment from Statoil to the Norwegian Petroleum Directorate is on a monthly basis. Settlement is at the norm price stipulated by the Petroleum Price Council. The received quantity of royalty oil has been reduced by more than 17 per cent in 1998, partly due to lower production from those fields where there is a royalty, but also because of the discontinuance of the royalty on Ekofisk (production license 018) from and including 7 August 1998 in connection with the new processing facility (Ekofisk II) being put into operation. In addition come significantly lower oil prices in 1998 as compared with the previous year, so that the royalty paid has been reduced by a total of 39.4 per cent.

Royalty on NGL

In 1998, NOK 40,827,292 has been paid in royalties on NGL. Table 1.9.6.c shows payments divided semi-annually per company/group.

Settlement of royalties paid in cash is on a six-month basis, with a three-month term for payment. The settlement for NGL has been made at contract prices which vary for the individual fields/groups.

There is an increase in the paid royalty on NGL from 1997 to 1998 of more than ten per cent.

Table 1.9.6.b
Royalty paid on oil (NOK)

Field/area	1st half	2nd half	Total 1998
Ekofisk area, Ula and Valhall	924 927 751	322 791 925	1 247 719 676
Statfjord	766 821 271	481 899 159	1 248 720 430
Murchison	9 225 124	10 298 080	19 523 204
Heimdal	8 634 713	2 200 307	10 835 020
Oseberg	336 505 204	325 943 085	662 448 289
Gullfaks	320 582 439	204 252 453	524 834 892
TOTAL	**2 366 696 503**	**1 347 385 008**	**3 714 081 511**

Table 1.9.6.c
Royalty paid on NGL (NOK)

Field/area	1st half	2nd half	Total 1998
Ekofisk area			
Phillips group	17 449 107	15 712 709	33 161 816
Amoco group (Tor)	4 156	-11 403	-7 247
Total Ekofisk area	17 453 263	15 701 306	33 154 569
Valhall	4 010 211	1 641 740	5 651 951
Ula	961 885	279 043	1 240 928
Murchison	398 007	381 837	779 844
Total all fields	**22 823 366**	**18 003 926**	**40 827 292**

1.9.7 AREA FEES ON PRODUCTION LICENSES

In 1998, the Norwegian Petroleum Directorate collected NOK 662,810,115 in area fees. The amount is broken down among production licenses as follows:

Table 1.9.7
Area fees by production licenses

Production licenses awarded per year	NOK
1965	68 721 181
1969	35 138 027
1971	3 184 977
1973	4 772 000
1975	9 718 500
1976	- 22 800 000
1977	3 518 399
1978	- 13 087 500
1979	- 20 805 000
1981	17 476 083
1982	13 814 763
1983	65 273 919
1984	115 303 083
1985	97 710 316
1986	44 443 411
1987	26 187 448
1988	75 479 575
1989	31 016 054
1991	100 412 357
1992	1 089 572
1993	2 106 274
1995	721 000
1998	3 415 676
Total	**662 810 115**

The Norwegian Petroleum Directorate has refunded NOK 136,262,241 in area fees in 1998. This represents the deductible portion of the area fee in the royalty settlement for production licenses 006, 018, 019A, 019B, 033, 037, 050, 053 and 079.

Figure 1.9.7.a shows the net area fee receipts for 1974-1998. New rates for the area fee came into force for the fee year 1998, cf. Section 39 of the Petroleum Regulations. This meant that the area fee for 1998 that was paid on 31 December 1997 according to the old rates had to be adjusted. In addition, a new rule was incorporated in Section 39, sixth subsection of the Petroleum Regulations to the effect that licensees could apply for a 40 per cent reduction of the prevailing rate for calculation of area fee if the right of first refusal in the production license was relinquished. Production royalties and area fees in 1998

Figure 1.9.7.a
Area fees 1974-1998

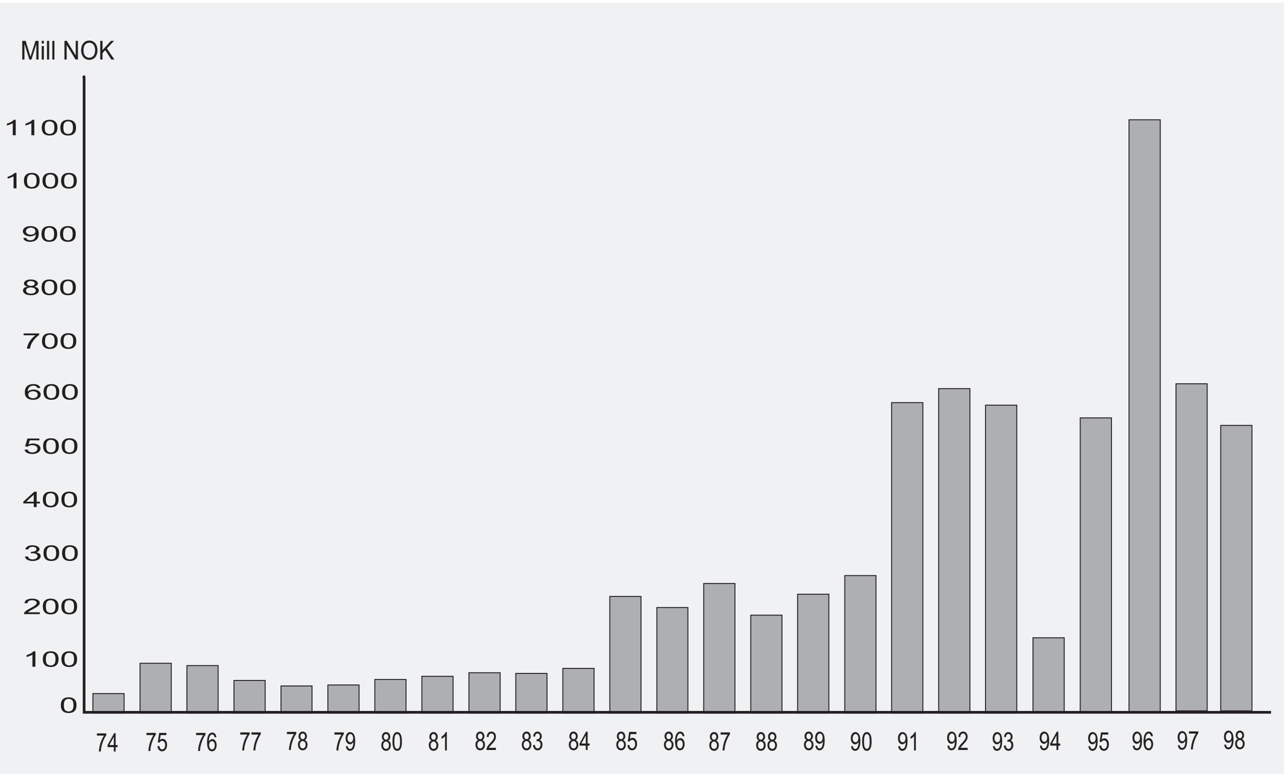
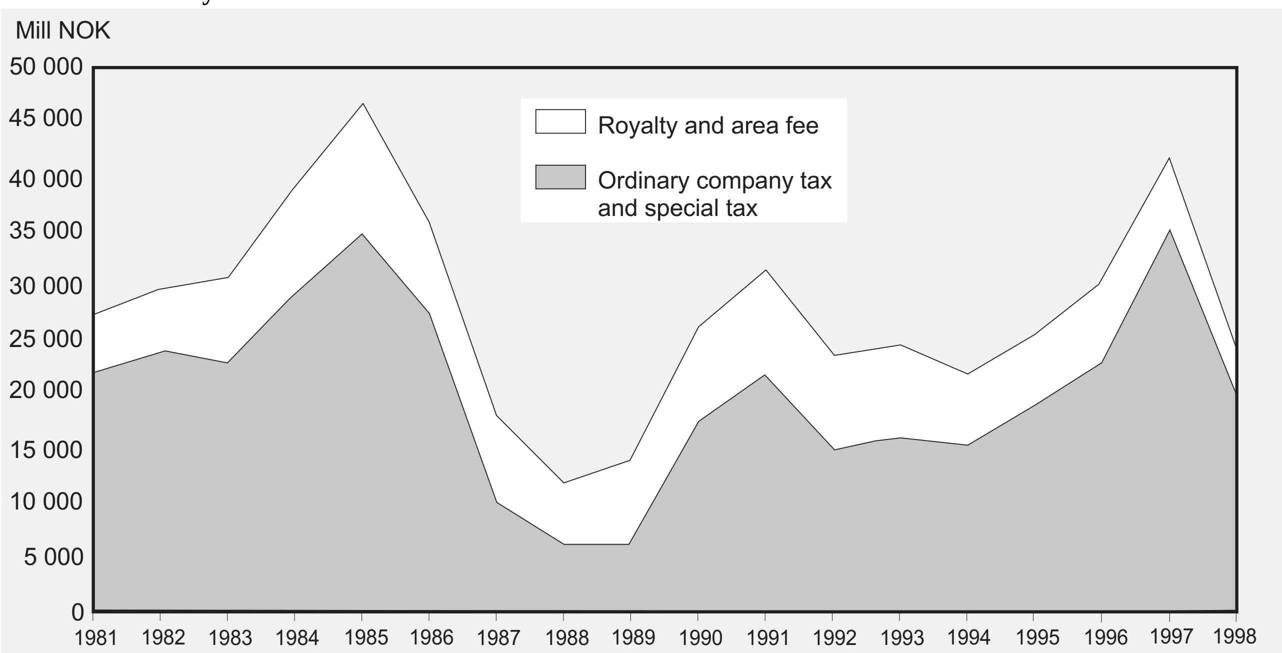
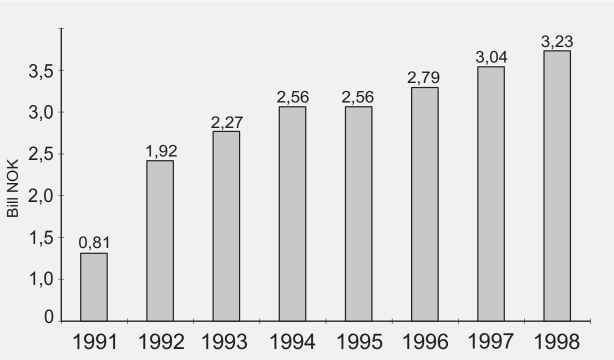


Figure 1.9.7.b
Total taxes and royalties 1981 - 1998



accounted for 18 per cent of the total taxes and fees paid from the petroleum activities. The proportion of the fees has varied over time. The highest proportion was in 1989 at 53%. Figure 1.9.7.b shows total taxes and royalties paid for 1981-1998.

Figure 1.9.8.a
CO_2 tax paid in 1991-1998 (bill NOK)



1.9.8 CO_2 TAX

The Act 21 December 1990 no 72 relating to tax on emission of CO_2 in the petroleum activities on the continental shelf entered into force on 1 January 1991. The Norwegian Petroleum Directorate has been given the

Figure 1.9.8.b
The tax rate for CO_2 tax (øre/Sm^3)

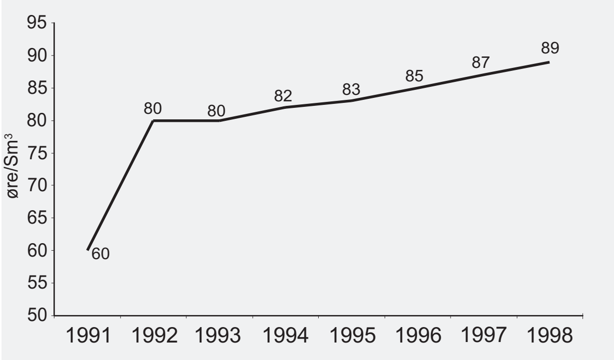


Table 1.9.8
CO_2 tax paid in the first and second half of 1998 (NOK)

Field:	1st half	2nd half	Total 1998
Ekofisk area	368 814 492	384 411 835	753 226 327
Frigg area	13 431 362	13 074 957	26 506 319
Gullfaks A+B+C	160 160 051	168 900 408	329 060 459
Yme	19 735 981	20 125 792	39 861 773
Gyda	19 277 770	18 749 025	38 026 795
Heimdal	18 065 644	17 060 980	35 226 624
Hod	101 094	80 456	181 550
Murchison	12 725 902	10 019 406	22 745 308
Oseberg A+B+C	153 663 750	151 368 530	305 032 280
Brage	33 935 220	36 066 360	70 001 580
Sleipner	123 098 168	130 529 892	253 628 060
Statfjord A+B+C	225 529 294	230 833 114	456 362 408
Ula	22 849 642	26 170 221	49 019 863
Valhall	44 773 908	46 486 179	91 260 087
Veslefrikk	28 652 501	33 019 849	61 672 350
Snorre	65 863 071	71 308 648	137 171 719
Draugen	29 782 614	35 821 414	65 604 028
Troll A	919 540	894 379	1 813 919
Troll B	40 681 200	47 422 760	88 103 960
Heidrun	65 544 086	62 351 389	127 895 475
Njord A	25 611 060	26 640 370	52 251 430
Norne	16 213 245	33 751 954	49 965 199
Odin*	0	-3 445 589	-3 445 589
Transportation systems:			
Norpipe	97 581 385	74 655 631	172 237 016
Statpipe	2 899 286	2 637 719	5 537 005
Total	**1 589 910 266**	**1 639 035 679**	**3 228 945 945**

*Repayment of tax overpayments 1994-1996.

authority to collect the CO_2 tax and to make administrative decisions necessary to enforce the Act, see Figure 1.9.8.a. The tax is calculated on petroleum flared and natural gas or pure CO_2 released to the atmosphere from installations used in connection with production or transportation of petroleum. The CO_2 Act also requires the companies to calculate tax for activities on Norwegian installations for transportation of petroleum which extend beyond the continental shelf. For fields which extend over the median line in relation to another state, the CO_2 tax is only calculated on the Norwegian share.

In 1997 and the first half of 1998, the CO_2 tax was fixed at NOK 0.87 and 0.89 per Sm^3 gas and NOK 0.87 and 0.89 per liter diesel. The tax for the second half of the year was NOK 1.07 per m^3 per liter diesel burned or released to the atmosphere. The tax is paid on a six-month basis with a three-month term of payment (as of 1 October and 1 April in the following year) by the operator of the individual fields and installations. Table 1.9.8 shows the total tax paid in 1998. The tax is broken down by the individual fields and transportation systems. Corrections relating to previous six-month periods are included. A total of NOK 3,228,945,945 was paid in 1998. Figure 1.9.8.b shows the tax rate for the CO_2 tax.

2. Safety and working environment administration

2.1 INTRODUCTION

The Norwegian Petroleum Directorate's performance of its administrative duties is based on a comprehensive administration of safety, working environment, health and the external environment. The Norwegian Petroleum Directorate has a coordinating role in relation to other public authorities that have independent supervisory responsibility. Furthermore, the Directorate draws upon expert assistance from other departments in areas where it has no expertise of its own.

Administration of safety and the working environment is based on the principle of supervision of the industry's control over its own activities. This assumes that regulations are designed and supervision is implemented in a way that supports the participants' responsibility to carry out prudent operations in accordance with the formal framework for the petroleum activities.

Therefore, supervision of regulatory compliance is primarily aimed at management systems and decision processes which have significance for safety and the working environment. Through its supervision activities, the Norwegian Petroleum Directorate seeks to stimulate improvement processes in the companies, as well as to evaluate the companies' ability to manage their own activities in accordance with the requirements of the authorities and of the companies themselves.

New cooperation forms in the industry have led to certain contractors receiving more comprehensive tasks and greater responsibility than previously. As a consequence of this, the Norwegian Petroleum Directorate has also carried out supervision activities directly vis-à-vis contractors in 1998.

The Norwegian Petroleum Directorate aims at providing continuity, systematism and a long-term perspective in the supervision of safety and working environment. In order to achieve this, the Directorate seeks to form an image of the development trends in this area over time, both in the industry as a whole and in the individual company. In areas where the development is not as expected, the Norwegian Petroleum Directorate can then prioritize measures vis-à-vis the industry as a whole, towards the licensees in a production license, towards an individual operating company, or towards other participants.

2.2 ACTIVITY LEVEL AND OIL PRICE - SAFETY AND WORKING ENVIRONMENT CONSEQUENCES

In 1998, the operating companies' activity plans were strongly influenced by the hefty decline in the price of oil which, at year-end, appeared as though it would last for some time. This development has intensified the oil companies' efforts to reduce the costs of both investments and operations.

This is reflected inter alia by:

- reduction in planned exploration activity
- postponement of development plans
- outsourcing
- company mergers
- reduction of operating costs
- reduction of manning

All of these measures can result in negative impacts on safety and the working environment, directly or indirectly, particularly if the processes that lead to the various decisions are not managed well.

Reduction in operating costs

The companies' efforts to reduce operating costs may give rise to challenges with regard to safety and the working environment. This applies firstly to existing installations, because they were designed and built with a given need for manning, maintenance, emergency preparedness, etc.

The Norwegian Petroleum Directorate's requirements do not stipulate specific demands regarding how the activities are to be organized, nor as regards manning. Reorganizations, including reductions in manning with the objective of optimizing manning levels, do not in themselves constitute any breach of the regulations for safety and working environment, as long as such processes are carried out in accordance with regulatory requirements, such as employee participation. It is only when the changes result in some form of activity that is not prudent that there is a formal basis on which to intervene.

Such effects may have a relatively long time perspective, and may take a long time to correct once they have occurred. Therefore, it would be too defensive for the Directorate to await a negative development before planning measures that can counteract an undesirable development. Therefore, the Norwegian Petroleum Directorate has prioritized supervision of the operating companies' management of organizational changes during the course of 1998, and will aim at a close follow-up of this area when planning activities in 1999.

Reduced activity level

The fact that the activity level is reduced as regards exploration activities and development of new fields does not have any immediate negative effect on safety and working environment. On the contrary, a reduced activity level over the shorter term can result in a gain in this area, as there has been such a large increase in the activity level for a period of some years that the question has been posed as to whether there was sufficient capacity to carry out the tasks in a satisfactory manner.

However, the Directorate fears that organizational changes and downsizing in the activities will lead to the loss of valuable expertise. If or when the oil price goes up again, there could be a relatively rapid upswing in the activity level. It may then take a long time to rebuild the lost expertise. If this factor is not reflected in the activity level, the development within safety and working environment in the petroleum activities on the Norwegian shelf may suffer a setback.

2.3 THE NORWEGIAN PETROLEUM DIRECTORATE'S SUPERVISION ACTIVITIES

2.3.1 SCOPE OF THE SUPERVISION

The Norwegian Petroleum Directorate expends a considerable amount of its personnel resources on supervision of how the responsible companies look after their duties regarding regulatory requirements. This use of resources is subject to reimbursement from the companies that are the objects of such supervision according to the *Regulations relating to refunding of expenses in connection with regulatory supervision of safety, working environment and resource management in the petroleum activities.* The reimbursable supervision includes the Directorate's activities relating to:

- planning of the supervision
- processing applications for production licenses
- processing plans for development and operation (PDO) and plans for installation and operation (PIO)
- processing applications for consent
- system audits and verifications, incl. preparation and completion work, travel time, etc.
- participation in status meetings with the projects
- participation in committee meetings with the licensees
- follow-up of hazardous and accident situations
- emergency preparedness exercises
- processing reports relating to incidents, etc.
- processing applications for exemptions from the regulations
- individual decisions and other use of measures
- meetings with relevant governmental departments
- management and administration

In 1998, the costs of 57,793 man-hours were refunded by the companies. In addition, the costs associated with assistance from other public agencies, use of consultants in the supervision, travel expenses, etc. are also covered.

Since the Norwegian Petroleum Directorate introduced the current system for registration of hours spent, the reimbursable hours have amounted to:

1991	-	40,446 hours
1992	-	47,614 hours
1993	-	54,611 hours
1994	-	60,715 hours
1995	-	60,661 hours
1996	-	59,989 hours
1997	-	56,817 hours
1998	-	57,793 hours

Staffing of the Norwegian Petroleum Directorate has remained more or less unchanged throughout these years. The increase in the reimbursable hours in the years 1991-1994 are mainly due to an improvement of the Directorate's routines for registering the various activities. The relatively minor variations in recent years are due to annual adjustments to other prioritized activities, such as regulatory development.

For purposes of comparison, the petroleum activities have exhibited the following developments in the period from 1990 - 1998:

- the number of installations has increased by 140 per cent
- the number of fields in production has increased by 80 per cent
- the number of exploration wells has increased by 45 per cent
- the number of development wells has increased by 145 per cent
- production of oil and gas has increased by 100 per cent
- total length of all transport pipelines has increased by 125 per cent
- the number of persons employed in the petroleum activities has increased by 35 per cent

During this period, the Norwegian Petroleum Directorate has implemented several measures in order to increase its internal efficiency. In addition to the fact that the very principles that form the basis for the Directorate's supervision are regarded as promoting efficiency, gains in efficiency have been achieved through a careful prioritization of work tasks and through use of modern information technology.

The Directorate's tasks and workload within administration of safety and working environment are not only determined by the volume of the petroleum activities as illustrated in the above summary, but also by factors such as aging of installations, development and use of new technology and, not least, by the industry's endeavors to reduce costs.

Over a longer time perspective, there will be a connection between the extent of the petroleum activities and the size of the administration apparatus. Over the shorter term, however, the Directorate believes that it would be unfortunate to reduce the scope of the supervision of the petroleum activities on the basis of relatively brief fluctuations in the activity level. Precisely because of the negative effects that can occur as direct and indirect consequences of low oil prices, it is more important than ever that a "counter-pressure" is maintained in the supervision the authorities exercise vis-à-vis the industry.

The level of safety and working environment that has been achieved in the petroleum activities, and which the Storting has desired, has been achieved through employing a long-term perspective in the efforts of both the industry and the authorities. If the development turns in a negative direction, it could take a long time to restore today's standard. A steady, continuous use of resources on the part of the authorities must therefore be expected to provide better results than adjusting the efforts upward and downward to conform with the short-term activity level in the petroleum activities.

2.3.2 THE COMPANIES' MANAGEMENT OF ORGANIZATIONAL CHANGES

In order to meet increased demands on profitability, the industry has increasingly implemented organizational changes and adjustments so as to achieve more efficient development and operations. New development projects have ambitious plans with regard to implementation time and economy. New project implementation models have been put into use which are characterized by new contract and collaboration forms between operator, contractor and subcontractor, as well as a great degree of parallel activities.

In 1998, the Norwegian Petroleum Directorate has continued its supervision aimed at organizational changes in the operations phase. In addition, the Directorate has focused on establishment of organizations for, and manning of, new installations.

Experiences and observations from supervision of fields in operation

The Norwegian Petroleum Directorate's experiences from supervision of the operators' management of organizational changes related to fields that are in the operations phase can be summarized in the following main points:

- The companies underestimate the complexity of the change processes. The focus is on the goal and, only to a small degree, on the process.
- The companies make little use of the available project management tools.
- Evaluations of the consequences of the change plans are often deficient.
- Little follow-up of suppositions and assumptions after the changes are implemented
- The best results are achieved where the project implementation has been formalized and the employees have participated.

Experiences and observations from supervision of new development projects

New development solutions entailing operations with a low manning level, new organization forms and a changed distribution of tasks between the installation and the organization on land place greater demands on systematic analysis of the work tasks in order to stipulate needs for expertise and manning, and as a basis for recruiting and training plans.

In 1998, the Norwegian Petroleum Directorate has carried out supervision of the establishment of new operations organizations. There has been a positive trend in the use and understanding of analyses, but there is still a need for improved clarification of the suppositions and assumptions that are used as a basis, to enable follow-up in the operations phase in respect of whether these issues have been addressed.

Experiences from the Norwegian Petroleum Directorate's supervision of the operators' planning and management of establishing organizations for new development projects can be summarized in the following main points:

- The companies consistently aim at tight manning plans with the use of flexible organization forms, multi-disciplinary work, "emergency teams", and where more functions are taken care of by the organization on land.
- The level of manning is fixed at an early stage, often before realistic activity analyses are conducted.
- Manning studies in the project phase are of variable quality, but with a positive trend towards increased use of a systematic approach.
- Suppositions and assumptions to be used as a basis are not clarified with a view towards follow-up in the operations phase.
- Ambitious new maintenance strategies have proven to be difficult to fulfill.
- IT provides new opportunities for efficient organization, but there is little illumination of the safety and working environment consequences, and the expectations in respect of efficiency gains may be exaggerated.

The Norwegian Petroleum Directorate has placed emphasis on carrying out supervision of how the companies plan and manage organizational changes and the establishment of new organizations, and how the assumptions that are made during the planning phase are followed up. The supervision has largely been based on dialogues with and advice to the various parties. The Directorate believes that contributing to transfer of experience between the companies in such issues is also an important tool.

The supervision has shown that there is greater understanding in the companies that organizational changes and establishment of new organizations require the use of planning, management and analysis tools, and that employee participation is a central precondition for a good result. The challenge will be to continue this positive development in light of increasing demands for reduced cost levels. The Norwegian Petroleum Directorate sees a trend towards some companies focusing unilaterally on goals in the form of savings without taking sufficient consideration of the process itself. Experience has shown that a good process is a pre-condition for achieving savings and efficiency, as well as for maintaining and further developing safety and the working environment.

2.3.3 SUPERVISION IN THE CONSTRUCTION PHASE OF MOBILE INSTALLATIONS

In the first half of 1998, the Norwegian Petroleum Directorate initiated supervision activities towards the operating companies' management of activities connected with construction of two mobile installations, "West Future II" and "West Navion". The installations are owned by Smedvig Offshore, and were to be hired by Norsk Hydro and Statoil respectively for use on the Troll and Åsgard fields. The Directorate planned this supervision on the basis of previous experiences with mobile installations, which indicates that it is important and desirable to get involved as early as possible in decision-making processes and activities.

However, the supervision activity triggered a legal review of the formal basis of authority for the Norwegian Petroleum Directorate's supervision of activities in this stage, which led to the Directorate stopping the supervision activities. According to the wishes of the parties involved in the two construction projects, the contact is therefore being continued within the framework of the Directorate's advisory functions.

2.3.4 SUPERVISION OF HOW THE INDUSTRY IS HANDLING IT PROBLEMS IN CONNECTION WITH THE NEW MILLENIUM

The Norwegian Petroleum Directorate has been working on the Year 2000 problem since the end of 1997. The Directorate has followed up the operators' work through surveys, meetings and audits. The Directorate has been particularly concerned with potential effects of problems in connection with the transition to the Year 2000 with regard to

- safety for people and the environment
- dependable deliveries of gas to receivers on the Continent
- regularity of oil production

In the summer of 1998, the Director General of the Norwegian Petroleum Directorate summoned the operating companies to a meeting where the Norwegian Petroleum Directorate presented its expectations for how the operating companies should handle the Year 2000 problem. In accordance with the Government's follow-up plan of April 1998, the Norwegian Petroleum Directorate took the initiative for conducting risk and vulnerability analyses for the gas deliveries from the Norwegian shelf.

The operators have set up a cooperation forum - Y2k Oil and Gas Forum - in order to exchange information and experience, and to create understanding for the importance of prioritizing the handling of this special problem. The Norwegian Petroleum Directorate participates as an observer at the monthly meetings of this forum.

2.4 REGULATORY DEVELOPMENT

2.4.1 DEVELOPMENT OF NEW REGULATORY STRUCTURE

Together with the State Pollution Control Authority and the Norwegian Board of Health, and in cooperation with the industry, the Norwegian Petroleum Directorate has continued work on revision of regulations in areas which deal with safety, working environment, health and the external environment. The work was commenced in 1997 with a point of departure inter alia in the new Petroleum Act with appurtenant regulations stipulated by Royal Decree, which entered into force on 1 July 1997, as well as underlying regulations.

It was decided in 1998 that the future underlying shelf regulations will consist of four regulations for the areas:

- management
- operations
- technology
- documentation

In addition, there is a goal that the four new regulations shall be issued and enforced by the three authorities jointly in accordance with the principles laid down in the system for coordinated supervision on the shelf.

The three-party regulatory forum, “External Reference Group for Regulatory Development” (ERR), has lent its principle support to the structure of the new regulations. Through ERR, the relevant parties are involved in the work on developing the contents of the four new regulations in a way that the Norwegian Petroleum Directorate has good experience from earlier regulatory development.

The revision work does not have the goal of making the requirements for the activities more stringent, but to continue the current regulation within the framework of a new regulatory structure. In the opinion of the Directorate, such a reorganization will make the regulations more accessible and provide the supervisory authorities with more comprehensive and effective management instruments. Furthermore, the objective is to provide for the use of recognized industry standards to a greater degree, improve predictability in connection with the application of the regulations vis-à-vis mobile installations, provide for more comprehensive and inter-disciplinary approaches to various areas and adaptation of the regulations to better fit the structure of the EEA regulations.

The work in 1998 has concentrated on developing the contents of the four regulations. According to the plan, the drafts are to be ready for consultation during the course of the fall of 1999, with a view towards completion on the part of the authorities in mid-2000.

2.4.2 ANNUAL UPDATES OF THE REGULATIONS

The Norwegian Petroleum Directorate conducts annual updates of the regulations in order to ensure that they are as appropriate as possible and are adapted to national and international development at all times. Thus, changes have also been made to the regulations in 1998. Proposals for changes in the regulations which will enter into force in June 1999 have been submitted for consultation in the industry.

2.4.3 REFERENCES TO NATIONAL AND INTERNATIONAL INDUSTRY STANDARDS IN THE SHELF REGULATIONS

The Norwegian Petroleum Directorate aims at shaping the overall regulations for safety and working environment in the petroleum activities in the most efficient way possible, inter alia through references being made insofar as possible to recognized national and international industry standards in the regulations. In connection with the annual revisions, the Directorate has had a dialogue with the Norwegian Technology Standards Institution (NTS) / NORSOK with a view towards incorporating references to NORSOK standards in the regulations. As of today, 38 NORSOK standards have been incorporated or proposed for incorporation.

Furthermore, in 1998 there has also been a continuous follow-up of international standardization work under the direction of ISO/IEC and CEN/CENELEC in those areas which touch on the regulations.

2.5 GUIDANCE AND INFORMATION

The Norwegian Petroleum Directorate aims at ensuring that all parties affected by the exercise of administration shall be able to obtain the best possible guidance with regard to interpretation and understanding of regulations and the supervision system. The Directorate views this part of the activities as a significant contribution to the endeavors to attain the best possible compliance with the intentions and requirements in the regulations. As for the industry, the guidance activities can contribute to avoiding unnecessary costs as a consequence of misunderstandings and "over-interpretation" of the regulations' requirements for safety and working environment.

A steadily increasing part of the guidance activities are oriented towards design and construction of mobile installations "on speculation"; in other words, installations where there is no application for consent from an operating company regarding a specific application on the Norwegian shelf.

Mobile installations are normally built at construction yards that have most of their experience and knowledge from shipbuilding, and therefore maritime regulations. The petroleum regulations have a different manner of approach to safety and working environment issues, which particularly foreign shipyards have difficulty relating to. Therefore, there is a great need for both a general dissemination of knowledge regarding the principles in the regulations and the supervision, and for clarifications of a more specific nature. This need appears to be pervasive for all of the participants in this industry.

2.5.1 THE ADVANCE STATEMENT SYSTEM FOR MOBILE INSTALLATIONS

The shipping industry has long argued for the development of a system with a form of "advance statement" for mobile installations. In 1998, the Ministry of Local Government and Regional Development asked the Norwegian Petroleum Directorate to commence work on developing such a system.

The intention of the system is that it shall contribute to providing the owners of mobile installations that have not entered into contracts for use on the Norwegian shelf, with improved predictability with regard to the installation's suitability in relation to the requirements of the petroleum regulations.

In order to develop such a system, a working group led by the Norwegian Petroleum Directorate was set up in the autumn of 1998. Other participants in the group are the Norwegian Shipowners' Association, the Norwegian Oil Industry Association, the Norwegian Federation of Trade Unions, the Federation of Oil Workers' Trade Union, the Norwegian Maritime Directorate, Det norske Veritas, the Federation of Norwegian Engineering Industries and the Norwegian Licensees' Association.

The plan is for the work to be implemented as soon as possible, during the course of 1999 if possible.

2.6 ACCIDENTS INVOLVING PERSONAL INJURIES

2.6.1 REPORTING OF PERSONAL INJURIES

The Norwegian Petroleum Directorate receives continuous reports regarding personal injuries in connection with petroleum activities on the Norwegian shelf. Fatalities, serious personal injuries and other serious incidents must be reported to the Directorate immediately. In addition to this immediate notification, all personal injuries which require medical treatment or which lead to absence during the following 12-hour shift, shall be reported to the Norwegian Petroleum Directorate on a special form. The form is also used to report occupational accidents to the National Insurance Administration. The registration of the information on the forms provides a basis for statistics, such as those presented in the Norwegian Petroleum Directorate's Annual Report. Detailed tables prepared on the basis of these registrations are found in Chapter 7.7.

Figure 2.6.1.a indicates that there is a higher risk associated with working on mobile installations as compared

Figure 2.6.1.a
Personal injury frequency on permanently located and mobile installations

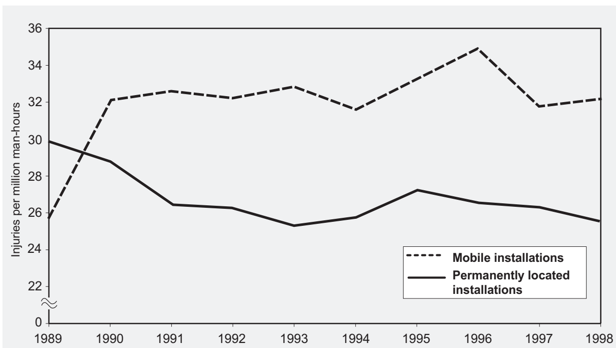
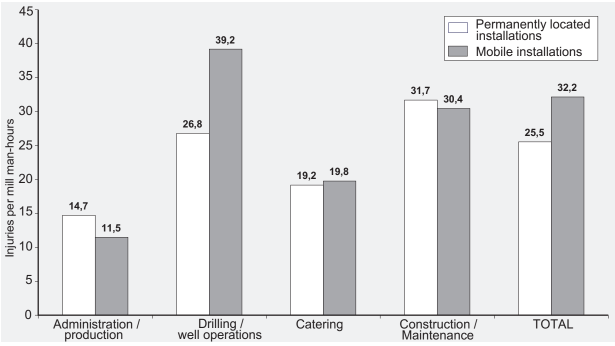


Figure 2.6.1.b
Personal injury frequency in 1998 for the main activities on permanently located and mobile installations



with permanently located installations. The overall personal injury frequency related to the number of man-hours on the installations is an average of 26 per cent higher on mobile installations as compared with permanently located installations. In addition to the injuries included in these presentations, 53 off-duty injuries were reported in 1998.

There were no fatal accidents within the Norwegian Petroleum Directorate's area of responsibility in the petroleum activities in 1998. The overall injury frequency for 1998 is shown in Figure 2.6.1.b. The figure also illustrates the injury frequencies for the main activities on the installations. On mobile installations, drilling and well operations emerge as the most hazardous, and it is the activities in the drilling area that contribute most to the relatively higher injury frequency. It is important to note that these activities include the largest personnel group and thus account for more than 50 per cent of the man-hours expended on mobile installations.

Two of the injuries were subject to police investigation in 1998.

2.6.2 PERSONAL INJURIES ON PERMANENT INSTALLATIONS AND MOBILE INSTALLATIONS

On permanent installations, we find the largest personnel group within maintenance and construction, representing about 46 per cent of the man-hours. This figure is somewhat lower than in previous years, but proportionately most injuries still occur within these activities on the permanently located installations.

As expected, the category administration and production had the lowest injury frequency both on permanent and mobile installations. A somewhat higher injury frequency in this category on permanent installations is assumed to be related to the fact that activities in the process areas on permanent installation are included, and that these activities entail a higher risk than purely administrative work.

Figure 2.6.2.a shows what types of accidents, in per cent of the total number of accidents, that occur most frequently on permanent and mobile installations respectively. Relatively, injuries in connection with handling tools and equipment occur with the same frequency, and mainly as a result of incorrect use, or that the person has taken up an unfortunate position in relation to the equipment being handled. This relates mainly to cuts and scrapes. On mobile installations, personnel in the drilling area are the most vulnerable, while most of the handling accidents on permanent installations occur in the process area. Handling accidents are also the most common cause of injuries among catering personnel.

Figure 2.6.2.a
Distribution of injuries on cause categories on permanently located and mobile installations

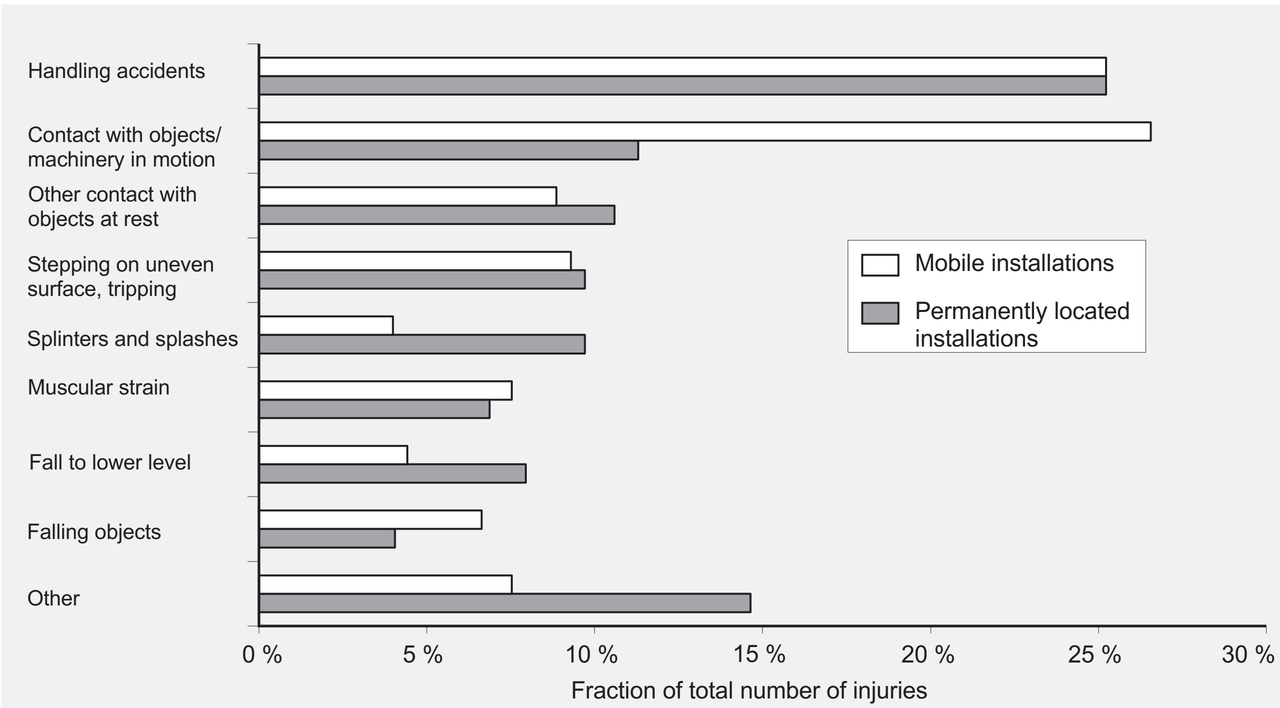
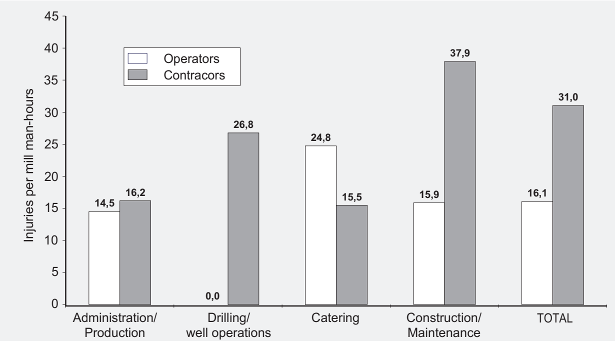


Figure 2.6.2.b
Personal injury frequency by operators and contractors - 1998 on fixed installations



Injuries that are caused by careless work on moving equipment or machine parts occur relatively more frequently on mobile installations than on permanent installations. Once again, the cause is often that the person has taken up an unfortunate position in relation to the safety zones around the equipment, but also that personnel are struck by parts that come loose.

Sprains or impact injuries from tripping or falling occur more often on permanent installations than mobile installations. Most of the injuries occur on slippery deck surfaces and in stairs. A proportionately higher share of eye injuries on permanent installations could indicate that the use of eye protection is not taken seriously enough. Otherwise, the distribution between the causes of injuries is approximately the same as for previous years.

Figure 2.6.2.b shows that contractor employees on permanent installations are more vulnerable to injury than operator employees. Most often, the operating companies will only have a few representatives on mobile installations, and only two operator employees were injured on mobile installations in 1998. The catering personnel group stands out in that the accident frequency is highest among the operator employees, and it has also increased in 1998 compared with 1997, while there has been a reduction of the injury frequency for contracted catering personnel.

Additional information regarding personnel injuries has been included in Chapter 7 - Statistics and Summaries.

Table 7.7.a provides an overview of personal injuries and man-hours on permanent installations over the past ten years, while Figure 7.7.a shows the development of the personal injury frequency during the same period.

Table 7.7.b shows the distribution of injuries and man-hours for operator and contractor employees on permanent installations over the past ten years.

Figure 7.7.b shows how the personal injury frequency for 1998 is divided between operator and contractor employees respectively.

Table 7.7.c is a cross-tabulation between occupation and type of injuries on permanent installations for 1998, and for the five-year period 1993-1997.

Table 7.7.d provides an overview of personal injuries and man-hours on mobile installations for the past ten years, while Figure 7.7.b shows the development of personal injury frequency during the same period.

Table 7.7.e is a cross-tabulation between occupation and type of injuries on mobile installations for 1998, and for the five-year period 1993-1997.

2.7 WORK-RELATED DISEASES

The incidence of work-related diseases can be an indicator of the quality of the working environment. During recent years, the Norwegian Petroleum Directorate has worked towards the goal of having the companies establish this as a working environment indicator and make active use of it in their preventive safety and environmental work. Therefore, it is a positive trend that more companies are beginning to compare the frequency of work-related diseases with personal injury frequency.

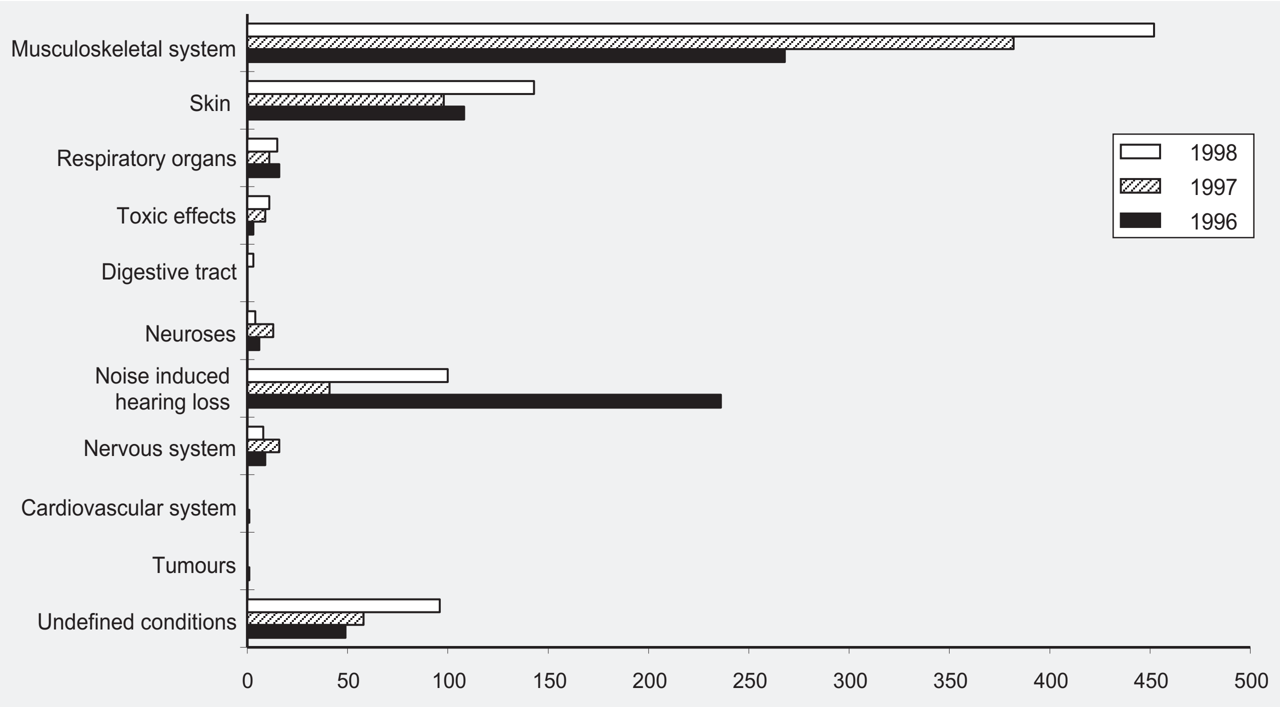
833 notifications regarding work-related disease were received by the Directorate in 1998, divided between 264 for operator employees and 567 for contractor employees. This is a 32 per cent increase in the total number of notifications as compared with 1997, giving a notification frequency of 27.1 incidents per million man-hours. This relatively significant increase is due to the fact that one of the major operating companies has started to report more incidents, while the notification frequency has remained more or less stabile for the other companies.

If we disregard hearing injuries due to noise (100 incidents), the frequency of other diseases is 23.8 cases per million man-hours. This is considerably higher than what has been reported for land-based industry. There may nevertheless still be a certain amount of under-reporting, as there are still few reports received from some companies that have many employees on the shelf. This also appears to be confirmed by the cause of the increase in 1998 as mentioned above.

Therefore, the Norwegian Petroleum Directorate will continue to work to achieve a more uniform reporting practice through contact with the companies, inter alia in the supervision context.

Figure 2.7.a shows the diagnosis group distribution of work-related diseases registered during the period 1996-1998, (in accordance with the ICD classification). As in the previous year, noise-induced hearing loss is included and split out as a separate group for 1998. This is because the reporting requirement for this type of disease was changed in 1997, in accordance with the regulations of the Directorate of Labour Inspection. While these incidents were previously to be reported in summary, they must now be reported individually. This will provide a better opportunity to follow up individual incidents. Even though there is a significant increase in reported incidents of noise-induced hearing loss, from 41 in 1997 to 100 in 1998, the number of recently discovered cases is low. There is reason to believe that more new cases have been registered than are reported to the Directorate.

Figure 2.7.a
Distribution of work-related diseases on diagnosis groups, 1996 - 1998



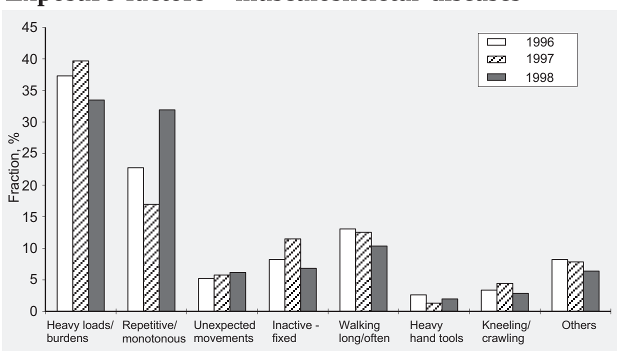
As previously, the picture is dominated by muscular and skeletal disorders (including disorders of the connective tissues). These types of disorders are normally referred to as repetitive strain injuries. They include back disorders, tendinitis and various forms of muscular pain. The number of such incidents has increased somewhat, while the proportion of repetitive strain injuries has gone down, to 54 per cent of the reported incidents in 1998 compared with 61 per cent in 1997. Even though the increase is probably due to changes in reporting practice as mentioned above, the high figure shows that it is important to direct efforts towards preventive work in relation to this type of ailment. Not surprisingly, the stated causes of the cases in this group are largely manual labor within the areas of drilling, maintenance and catering.

The exposures which are listed as the causes of these repetitive strain injuries are summarized in Figure 2.7.b. This figure includes data for the last three years.

The figure shows that handling of heavy loads and heavy lifts were listed as the most important causes of diseases in the muscular and skeletal systems in 1998, and that this proportion was nearly unchanged compared with the previous year. Another important cause of this type of injury was repetitive, monotonous work, which increased in significance as a causal factor from 17 per cent in 1997 to 32 per cent in 1998. Both heavy work and repetitive monotonous work are listed as causes of inter alia tendinitis and muscle pain. The proportion of cases of degenerative changes in knees and hips attributed to extensive walking on hard surfaces is relatively high, but is slightly reduced compared with the previous year. This may be related to a general aging of the workforce on the shelf. Heavy lifts, sudden movements and inactive/stationary work have often resulted in back problems (lumbago/sciatica). Difficult access, which means that work must be performed in a crawling position or while kneeling, is another frequent cause of various knee ailments.

Another large diagnosis group is skin conditions, and the number of incidents in this group increased, while the per centage was unchanged compared with the previous year. One-third of the cases relate to eczema on the hands after having been in contact with oil-based drilling mud. Some cases can also be attributed to other organic compounds, while epoxy is listed as the cause of six cases of contact eczema, compared with nine in the previous year. This group also includes 15 divers who have developed “diver’s hands” during pressurized periods. A new element in 1998 is that isocyanates were listed as the cause of four of the cases of eczema. Other cases in this

Figure 2.7.b
Exposure factors - musculoskeletal diseases



group are presumed to be caused by inorganic compounds, such as various metals and well chemicals.

Disorders of the respiratory system include asthma and bronchitis, as well as incidents of respiratory irritation due to airborne irritants such as oil vapor and welding smoke. In addition, seven cases of asbestos-related lung disease have been reported. These are employees who have been exposed in previous work, particularly on ships, and who have now developed asbestos-specific changes in the lung membrane. Isocyanate exposure is listed as the cause of two of the cases of bronchial asthma. The fact that a total of six cases of disease have been reported after exposure to isocyanates shows that it is still important to work on preventive measures in this area. The attention given to these types of substances in recent years may explain why relatively many cases of disease were reported in 1998 that may be due to isocyanate exposure.

The diagnoses grouped as toxic effects are a compilation of different symptoms occurring after exposure to various chemicals or gases.

Noise-induced injuries have been discussed above. With regard to the overall nervous system, this group contains diseases in the sense organs, such as irritation injuries to the eyes and ears.

Undiagnosed conditions include various symptoms that are due to exposure to undesirable working environment factors, but which are difficult to classify as disease. These also include sleep disturbances. It seems obvious that many people experience sleep disturbances after having worked a so-called swing shift. This shift system was listed as the cause of 71 cases in this group as compared with 43 in 1997, thus explaining the increase observed in 1998.

The various position categories which were exposed to work-related diseases are shown in Figure 2.7.c. Since there have been relatively many reports for employees in management positions in recent years, these have been put into a separate category. Workers within the drilling sector have normally been perceived as being particularly vulnerable. However, taking into account that this function performed 29.2 per cent of the total man-hours, the per centage of cases is considerably lower than would be expected. The proportion of reports for the catering staff group remained as high as in the previous year. The proportion in 1998 as compared with 1997 increased somewhat, and at 18.5 per cent, was significantly higher than the comparable number of man-hours for this group (9.6 per cent). In 1998, the number of reported incidents in the construction and maintenance group was basically unchanged as compared with the previous year. This group was responsible for 33.5 per cent of the total number of man-hours, and accounted for a similar share of the reported incidents of disease.

2.8 HYDROCARBON LEAKS, FIRES AND NEAR-FIRES

2.8.1 HYDROCARBON LEAKS

Table 2.8.1.a provides an overview of the reported hydrocarbon leaks over the past five years. Three of the leaks that occurred in 1998 are characterized as major, based on an overall evaluation of the events. The evaluation includes

Figure 2.7.c
Work-related diseases distributed on position categories

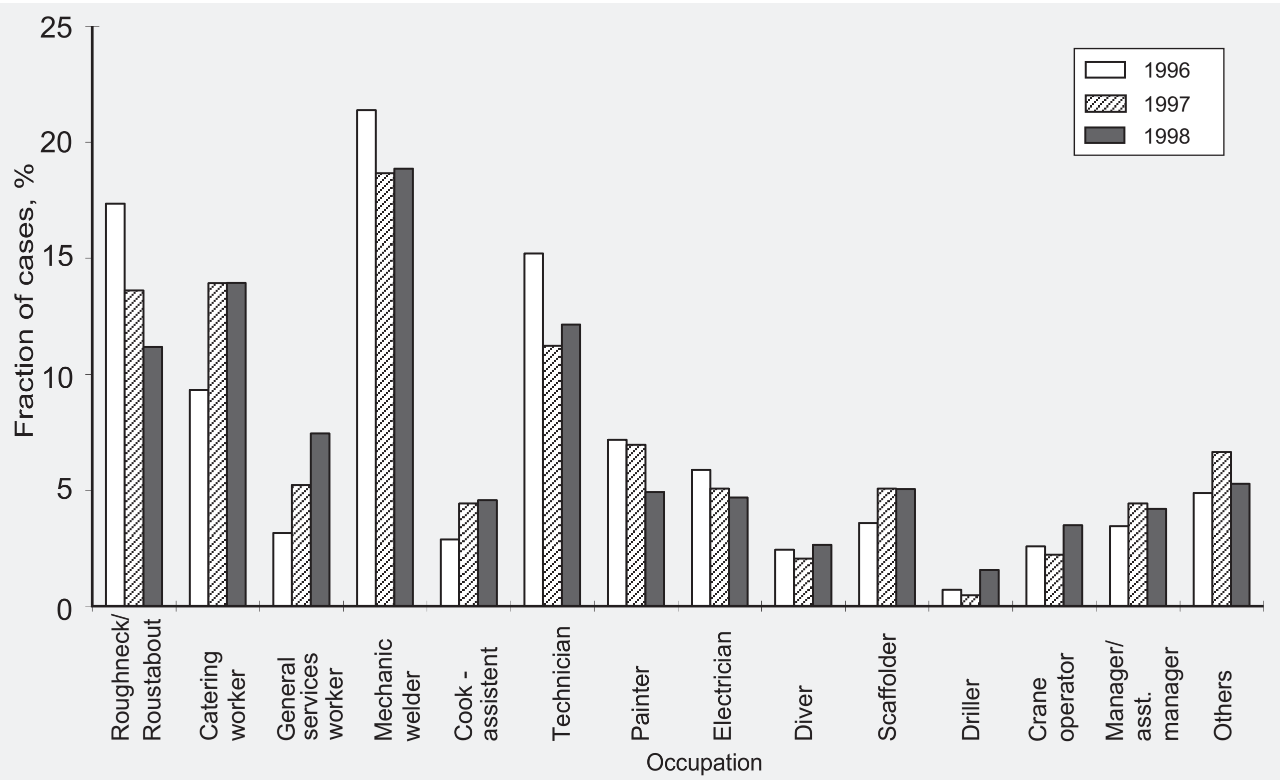


Table 2.8.1.a
Hydrocarbon leaks during the period 1994-1998, distributed according to severity

Year	Minor	Medium	Major	Total
1994	81	42	1	124
1995	98	33		131
1996	120	32	4	156
1997	156	27	3	186
1998	128	26	3	157

inter alia emission/discharge volumes, potential danger and causal relationships. The three leaks that were considered to be major were due to leakage through a closed valve, a fracture in a piece of piping and, finally, defective equipment.

In addition to the 157 leaks registered in the table, the Norwegian Petroleum Directorate also received reports of 123 incidents of hydrocarbon leaks in 1998 that are considered to be insignificant. The Directorate emphasizes that the reporting of such leaks is also of great value in the work to identify problem areas, types of causes, etc.

Seen in relation to the number of installations in operation and produced volumes, the Directorate believes that the situation and the danger scenario are stabile with regard to the trend in the number and severity of the reported leaks. The number of medium and major incidents has been stabile in recent years, while both the number of installations and the production volume have increased. The Norwegian Petroleum Directorate interprets the increase in the smallest leaks (minor and insignificant) to be a result of heightened focus on these incidents.

Several Norwegian operators have declared that their goal is to completely avoid emissions/discharges and gas leaks. The reduction in the number of leaks in 1998 could indicate that this strategy is giving results.

Table 2.8.1.b shows that the majority of the minor leaks, but also a significant share of the medium-sized leaks, are detected manually.

Figure 2.8.1.a shows where the hydrocarbon leaks occurred on the installations in 1998. We can see that the majority of the leaks occur in the process area and in the gas treatment area. The incidents are split more or less equally between these areas.

Figure 2.8.1.b indicates the main types of defects that lead to hydrocarbon leaks.

The Norwegian Petroleum Directorate receives few reports of incidents caused by corrosion and fractures, however, many of the incidents that occur have a high potential for danger. While two of the three major incidents in 1997 were caused by corrosion/erosion, only one of the incidents in 1998 had a similar cause. This incident was due to a fracture in the weld on a pipe branch, which led to large quantities of liquid and gas flowing out from an oil/gas separator. The leak could not be stopped with the aid of valves, because the piping was located between the separator and the nearest valve. The leak was reduced using depressurization, and was stopped by inserting a wooden plug in the opening.

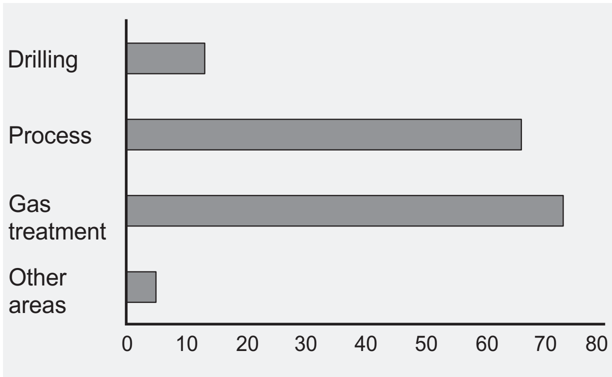
The second major leak was due to the leakage of large quantities of oil and gas through a valve that did not close as expected because of internal leakage.

The third major incident was due to failure of the heave compensator on a mobile drilling installation. The

Table 2.8.1.b
Distribution of hydrocarbon leaks according to severity and method of detection

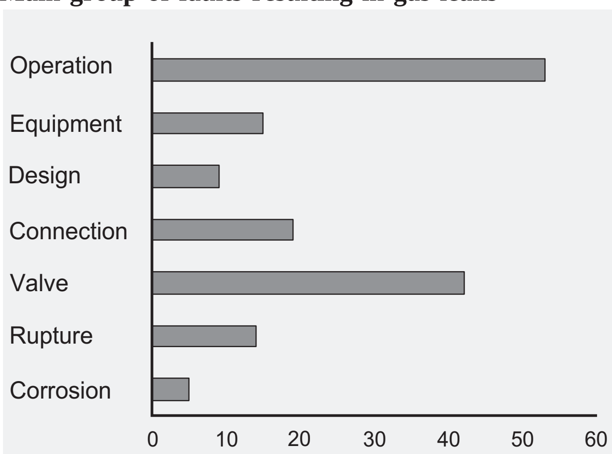
Severity	Number of leaks	Automatic detection	Manuel detection
Major	3	3	
Medium	26	13	13
Minor	128	43	82
Total	157	60	97

Figure 2.8.1.a
Area where gas leaks occurred



Drilling: Areas for drilling and well activities
Process: Areas for systems containing oil (wells, separators, etc.)
Gas treatment: Areas for systems normally containing gas only (compression, injection, flare)

Figure 2.8.1.b
Main group of faults resulting in gas leaks



Operation: Faulty operation, inadequate procedures or planning
Equipment: Deficiencies on equipment or instruments
Connection: Deficiencies in flanges or connections
Rupture: Cracks and fractures

installation had recently completed test production of a well when the incident occurred. The drill string was torn off when the heave compensator jammed, and well fluid and some hydrocarbons flowed out. No one was injured, but there was considerable damage to the drilling equipment.

As in 1997, defects in valves and operational errors caused most of the leaks.

In most cases, the leaks in valves were caused by leaks in seals/packing boxes and service plugs. Eight of the 42 leaks were so large that they were considered to be medium or major.

Operational errors accounted for one-third of the incidents in 1998, the same as for the previous year. The majority of these leaks occur in connection with maintenance work. Most often, the leak occurs in connection with the job itself, or immediately after the job is finished, because of inadequate closing of valves or tightening of bolts.

2.8.2 FIRES AND NEAR-FIRES

Over the last four years, the number of fires and near-fires has been relatively stabile. Most fires are caused by defects, see Table 2.8.2.a, in electrical equipment/cables or in equipment with hot surfaces, see Table 2.8.2.b.

All fires due to electrical equipment and cables are minor incidents, and most are due to short-circuiting in the cable.

The fires that are caused by high temperature account for the majority of, and the most serious, incidents. High temperatures may be due to factors such as:

- overheating of rotating equipment due to worn bearings or lack of lubrication/cooling,
- deficient insulation of exhaust ducts or combustion chambers,

Table 2.8.2.a
Fires and Near-Fires, 1994-1998

Year	Minor	Medium	Major	Total
1994	24	14		38
1995	11	7		18
1996	15	3	1	19
1997	22	2	1	25
1998	17	4	1	22

- failure in instrumentation (thermostat, fuel control, flame detector, etc.).

Fire on Sleipner A

The fire, which is characterized as major, occurred on the Sleipner A installation on 18 October 1998. The incident occurred in connection with the transfer of the contents of a diesel tank to a supply vessel. A valve which was incorrectly left open resulted in about 6000 liters of diesel running out. The diesel was probably ignited through contact with an uninsulated part on the exhaust duct of a generator.

The diesel spread over a large area between the living quarters and a generator module. The fire was extinguished with water canons and hoses during the course of about a half-hour. No one was injured during the incident, but the material damages from the fire are estimated at NOK 25-30 million. The fire caused an interruption in gas production which lasted for ten days.

Table 2.8.2.b
Causes of fires in 1998 distributed by size

Ignition source	Major	Medium	Minor	Total
Welding			1	1
Torch cutting			1	1
Electrical			6	6
High temperature	1	4	7	12
Other			2	2
Total	1	4	17	22

2.8.3 EXPERIENCE FROM SUPERVISION RELATED TO ELECTRICAL AND SAFETY SYSTEMS ON MOBILE DRILLING INSTALLATIONS

The Norwegian Petroleum Directorate has carried out several supervision activities in 1998 aimed at mobile drilling installations in operation and under modification. The purpose of this was to carry out supervision to ensure compliance with regulatory requirements with regard to electrical systems, equipment for detecting and fighting fires and explosions and emergency shutdown systems. In addition, the purpose has been to evaluate whether operating companies and owners of mobile drilling installations have allocated the necessary resources and established appropriate systems and routines for maintenance and control of the installation's technical equipment.

The Directorate notes that an improvement has taken place both on the part of the operating companies and the owners of the installations with regard to following up and correcting identified deviations from the regulations. However, there is still room for further improvement in this area.

The potential for improvement is linked to the scope and quality of the company's internal supervision and verification activities in connection with modifications, hiring and follow-up of installations in operation. Applications for consent which the Norwegian Petroleum Directorate receives in connection with use of mobile drilling installations also appear to indicate that the communication between the operating company and the owner of the installation does not function in a completely satisfactory manner. This is illustrated by the fact that the applications for consent do not provide a complete picture of the condition of the installation in relation to regulatory requirements for safety and working environment.

Supervision carried out by the Norwegian Petroleum Directorate shows that the need for further improvements is mainly related to

- testing of emergency shutdown systems, emergency power and fire water,

- routines for work permits and job preparation for work on safety systems,
- registration, installation and maintenance of electrical equipment for use in areas where there is danger of explosion,
- updating of drawings and documentation after modifications are made.

The pressure in the market with regard to availability of mobile drilling installations means that these units have been brought to land for regular maintenance and upgrading to a lesser extent than previously. Furthermore, the average age of these installations is steadily increasing, which creates challenges with regard to maintaining the desired safety level and functionality.

2.9 DAMAGE TO LOAD-BEARING STRUCTURES AND PIPELINES

The Norwegian Petroleum Directorate receives reports of damage to and incidents involving load-bearing structures and pipeline systems. The information is gathered in the CODAM database. In 1998, there were reports of 19 incidents related to load-bearing structures and 24 related to pipeline systems. The database now contains data concerning approximately 3260 incidents related to load-bearing structures and approximately 2130 related to pipeline systems.

2.9.1 SUBSEA PIPELINES AND RISERS

The majority of the damage to and incidents involving pipeline systems is in the categories of “insignificant” and “minor”. These are incidents which do not require much repair or follow-up. Incidents in the “major” category include, for example, leaks in pipelines and risers, incidents involving buckling of pipelines, as well as external and internal corrosion, etc., depending on the scope of the damage and the criticality.

In 1998, there were five major incidents and damage related to pipelines and risers:

- A discharge of 20-30 liters occurred from an 18” oil and gas pipeline in the Ekofisk area due to leakage in a coupling on the seabed. The leak occurred as a result of temperature changes in the coupling in connection with a brief shutdown in operations.
- In connection with an annual inspection, a minor gas leak was discovered in a flange, which proved to be caused by loose bolts on the flange. The bolts were tightened with the aid of divers, and the leak was stopped.
- Formation of a vertical bend was discovered in connection with inspection of a 20” oil pipeline in the Ekofisk area. This was due to the effects of the subsidence of the seabed. Damage to the weighting material on the pipeline was observed. Shortly thereafter, the pipeline was removed from service according to plan.
- During clean-up operations on the seabed, an anchor was discovered lying less than three meters from a 16” condensate pipeline. The anchor, together with 4000-5000 meters of anchor chain, was estimated to weigh approximately 21 tonnes. The anchor and the chain are probably from a tanker that has anchored in the area. The anchor and chain were removed by the operator and brought to land, and an attempt was made to identify the owner.
- In connection with an annual inspection, a horned mine from World War II was discovered close to a 20” condensate pipeline. The horned mine does not constitute any immediate danger to the pipeline, but an attempt will be made to remove the mine at an appropriate opportunity.

Load-bearing structures

Two incidents involving major damage to load-bearing structures were reported in 1998:

- A seawater riser loosened and fell down into the steel jacket on an installation, causing fracturing and formation of cracks on one of the jacket’s legs. It has been determined that the riser came loose as a result of fatigue.
- Upon inspection of a subsea installation, it was discovered that the top hatch was out of position and the valve actuators had suffered damage. It is assumed that the damage was caused by trawling equipment. A new hatch has been installed and the damaged parts have been replaced.

Collision between vessels and installations

Four collisions between vessels and installations were reported to the Norwegian Petroleum Directorate in 1998, compared with an average of two per year during the period 1987-1997

Two of the incidents were collisions between vessels and mobile installations, while one collision occurred between a vessel and a production ship, and one between a vessel and an installation permanently attached to the seabed.

The reported incidents led to limited damage to installations and vessels. The production ship suffered a minor hull indentation, while the other damage consisted of bent railings and supports, as well as a broken radar mast.

2.10 DIVING

During the years from 1993 to 1996, diving activities on the Norwegian continental shelf exhibited a strong decline, as the number of man-hours in saturation fell from 165,000 to 33,000 during this time period. This trend is partly due to the operating companies’ increased commitment to the use of remote-controlled intervention, repair and maintenance methods, but also to a generally lower level of activities in areas that involve diving. In 1997, however, the number of saturation hours tripled, while the figures for 1998 are approximately the same. This unexpected development must be assumed to be connected with the fact that the companies have changed their strategy in this area in recent years towards a more direct evaluation of the costs of the individual activity. In addition, today's diving technology and procedures are perceived as a safe intervention method. For certain types of work assignments and depth areas, this can mean that manned underwater operations are once again preferred over other methods.

With regard to safety and working environment in connection with manned underwater operations, the new trend can give rise to concern. The lack of qualified diving personnel has already led to the Norwegian Petroleum Directorate processing more applications for deviations from the regulations in 1998. Viewed in context with the development in the age distribution among diving personnel, and the lack of recruitment, it may prove to be increasingly difficult to grant consent to such deviations, as the conditions for this are that the Directorate, after an overall assessment, finds that the diving assignments can nevertheless be carried out in a prudent manner.

2.10.1 DIVING ACTIVITY IN 1998

During 1998, 193 surface-oriented dives and 710 bell runs totaling 80,000 man-hours in saturation were carried out on the Norwegian shelf and in connection with Norwegian pipelines in foreign sectors. This is approximately the same activity level as in 1997.

The diving operations have been carried out from five different vessels/installations. Diving activities have been divided among inspection, maintenance and construction activities on fields where Amoco, Elf, Hydro, Phillips and Statoil are the operators. Diving in connection with construction work has constituted a large portion of the activity.

2.10.2 PERSONAL INJURIES IN CONNECTION WITH DIVING

Figures 2.10.2.a and 2.10.2.b present a summary of the number of incidents reported to the Norwegian Petroleum Directorate for the years 1985-1998 in connection with diving activities. The incidents are subdivided into the categories near-accident and personal injuries. Here, personal injury is defined as incidents that require medical treatment, first aid, or that entail absence that extends into the next 12-hour shift. There have been no fatal accidents in connection with diving activities in the past ten years.

Figure 2.10.2.a
Incidents in saturation diving

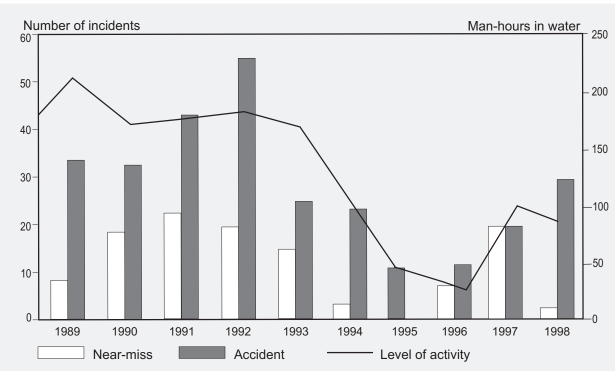
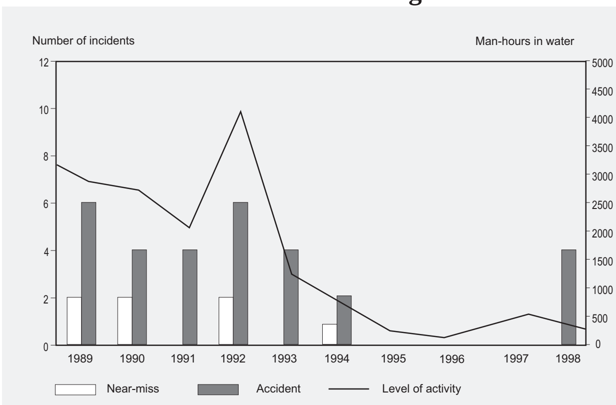


Figure 2.10.2.a shows that the number of reported accidents entailing personal injury related to saturation diving in 1998 has increased compared with 1997, even though the activity level has been about the same. Of the 29 reported personal injuries in connection with saturation diving, only one was of a serious nature. Of the remaining 28 incidents, 21 concern infections in the form of inflammation of the external auditory canal and skin infections.

Figure 2.10.2.b
Incidents in surface oriented diving



Two near-accidents were reported in connection with saturation diving, both characterized as serious. One of the incidents occurred during an underwater lifting operation when the diver was struck by a lifting basket that was being lowered. In the other incident, a partially open valve in the bottom door of the diving bell led to a significant pressure drop in the diving bell.

For the fifth straight year, there were no reported cases of bends in connection with diving in the petroleum activities in 1998.

2.10.3 EXPERIENCE GAINED FROM SUPERVISION OF THE DIVING ACTIVITIES

In 1998, the Norwegian Petroleum Directorate has inter alia directed attention towards the industry's measures to familiarize divers with work plans, equipment, procedures and experiences, as a part of the preparations for the annual season and for the respective assignments ("familiarization"). The Norwegian Petroleum Directorate believes that these activities can be improved with regard to making use of conclusions from experience reports, implementation of a familiarization program for individuals and for relief personnel, as well as in purely general terms in order to include safety-related information to a greater degree.

The Directorate also observed deficiencies in the established emergency preparedness and weak points as regards emergency equipment. In connection with execution of hyperbaric welding, the necessary emergency preparedness and procedures must be established to cover situations where the vessel is not able to maintain its position, and where it may be necessary to break the connection with the underwater chamber.

It was revealed that, in the opinion of the Norwegian Petroleum Directorate, some of the lifeboats for hyperbaric evacuation were not fully equipped to fulfill their intended functions under the companies' evacuation procedures. Improvements must inter alia be made in propulsion, towing and lifting out of the water. The Norwegian Petroleum Directorate believes that it is significant that the lifeboat be brought under control as soon as possible after being launched. On the basis of the results from a project Sintef has conducted for the Norwegian Petroleum Directorate, the Norwegian Oil Industry Association has taken up this challenge.

There have been more incidents reported recently that easily could have resulted in serious consequences. The majority of these incidents are connected with lifting activities. It is important that personnel who participate in lifting operations have the necessary qualifications and have gone through the necessary familiarization for the work that is to be performed.

The Directorate has observed use of emergency equipment that cannot be tested, or where the condition cannot be verified before the operation is commenced. In these cases, the Norwegian Petroleum Directorate has stressed the regulatory requirements stating that all components that are to be used during normal operations and in emergency situations must be tested in respect of function.

The Directorate has noted unsatisfactory handling of deviations when plans are made to deviate from procedures that have been prepared on the basis of recommendations from risk analyses. In several cases, procedures have been set aside or changed without controlled management of this process, and without the new procedure being subject to the necessary risk analysis. The Norwegian Petroleum Directorate has sent letters to the relevant operating companies and diving contractors asking that measures be implemented to improve this condition.

2.10.4 TRAINING

No saturation divers were trained in Norway in 1998. The Norwegian Professional Divers' School and the National Divers' School have trained a total of 91 divers in 1998 who have been issued Class 1 certificates.

2.10.5 RESEARCH AND DEVELOPMENT IN THE AREA OF DIVING

In 1998, the Norwegian Petroleum Directorate has continued its participation as a member of the board and the project management group in the diving-related research program, OMEGA. This involvement helps ensure that the Directorate's professional and technical staff is kept up to date with regard to ongoing research and development activities in this field.

In November 1998, the annual diving seminar was held as a joint seminar for both open sea diving and diving in sheltered waters.

2.11 TOPICAL SUBJECTS IN 1998

2.11.1 THE RISK LEVEL ON THE NORWEGIAN SHELF

Together with the operating companies Elf, Norsk Hydro, Saga and Statoil, the Norwegian Petroleum Directorate has had a project conducted to chart the risk level on the Norwegian shelf. The company Preventor carried out the work.

The report that was prepared addresses the risk level on the Norwegian shelf in two different time periods. First, there is an evaluation of the historical risk level during the period 1988-1997, followed by an estimate for the risk level in the next decade, i.e. 1999-2008. The risk level in these two periods was then compared with regard to development and possible trends.

The report addresses risk associated with the following types of installations, vessels and activities:

- permanently located and mobile production installations
- mobile drilling installations, including risk associated with movement
- standby, supply and anchor-handling vessels
- pipelaying and crane vessels
- diving activities
- helicopter transportation to/from and between installations
- pipeline transport of oil and gas
- oil transport from the installations by tanker

This means that the report also deals with certain types of risk and activities that fall outside of the Norwegian Petroleum Directorate's administrative responsibility.

The risk values that emerge from the report are related to

- risk of death for personnel
- risk of damage to the environment
- risk of material loss.

As it is defined in this context, the risk concept is somewhat limited in relation to the risk concept that is used as a basis for the administration of safety and the working environment in the petroleum activities. The report does not deal with risk associated with loss or deterioration of life and health as a result of work-related diseases, or the risk of lost time injuries. Nor has financial loss as a result of accidents and incidents that have consequences for operational availability and reliability of deliveries been included.

The main conclusions of the report can be briefly summarized as follows:

- Historical data show that there has been a marked improvement in personal safety since the 1980s, however, the positive trend may be in the process of reversing.
- During the ten-year period 1988-1997, there were no major accidents that were directly connected with the petroleum activities. However, it is important to recognize that a risk of such accidents has nevertheless existed during this period.
- The values for personnel risk are significantly higher for mobile drilling installations than for permanent and mobile production installations. This particularly applies to the risk of fatalities, which is estimated to be nearly five times higher, while the risk for personal injuries in general is approximately 30 per cent higher.
- The risk of accidents on standby vessels is nearly ten times higher than on production installations.
- Helicopter transportation accounts for a significant contribution to the total risk scenario for the petroleum activities.
- It is estimated that the risk of fatalities will increase by about 40 per cent in the next ten-year period.
- It is estimated that the risk to the environment will increase somewhat in the next ten-year period, and the report estimates a likelihood of 44 per cent for an oil blowout during the course of the next ten-year period.
- The risk of material loss in the next ten-year period is expected to remain more or less constant.

It is important to emphasize that the report presents the consultant's view of the risk scenario, with a point of departure in a pure risk analysis approach. However, the Norwegian Petroleum Directorate regards the report as being extremely interesting and useful in the strategic planning of measures that can contribute as much as possible to offset the negative trend outlined in the report.

2.11.2 USE OF STANDBY VESSELS

The demands on rationalization and streamlining in the petroleum activities have led to the companies increasing reevaluation of the need for the vessels that remain near the installations as an emergency preparedness measure against hazardous and accident situations.

Earlier, it was common practice to have a dedicated vessel at each individual installation. However, in recent years, the number of standby vessels has been reduced through one vessel taking care of emergency preparedness for two or more installations that are close together. The Norwegian Petroleum Directorate has followed this development, but does not believe that it has led to a weakening of the emergency preparedness, inter alia because the companies have prepared new operational preconditions and have chosen new solutions to handle the previous tasks of the standby vessels.

The regulations do not stipulate specific requirements regarding the use of standby vessels. The need for the emergency preparedness functions such vessels are to safeguard emerges through analyses of the hazardous and accident situations than can arise on the individual installations. If these emergency preparedness functions can be safeguarded with full efficiency in other ways, a solution without standby vessels may be acceptable.

The efforts of a standby vessel are the “last line of defense” in a chain of safety measures. Regulatory requirements for safety and working environment are built on the principle that accidents and injuries shall be prevented at the earliest possible stage in the chain of events. In other words, a company cannot choose solutions with an unacceptably high likelihood of accidents and injuries with reference to the fact that a standby vessel will be available.

Some companies have referred to the overall experience which shows that the number of cases where standby vessels have saved lives or other values are few. This factor should not be used as an argument to remove the standby vessel. As long as potential hazard and accident situations exist which, with a certain likelihood, can give rise to the need for the response of a standby vessel, such vessels must be available.

This means that financial considerations alone will not be an acceptable argument for removing a standby vessel. The vessel is intended to perform a function which, in such event, must be taken care of in some other equally satisfactory manner. In those cases where standby vessels have been removed, the Norwegian Petroleum Directorate has found that this requirement has been fulfilled.

2.11.3 RISKS ASSOCIATED WITH HELICOPTER TRANSPORTATION

Several incidents in recent years, particularly the helicopter accident near Norne in 1997 where 12 people lost their lives, have contributed to putting the spotlight on the risk associated with helicopter transportation of personnel in the petroleum activities.

Throughout the years, several proposals have been aired regarding alternative modes of transportation from land to the installations. So far, however, no solutions have been proposed that have represented any real alternative to helicopter transportation.

After an initiative from the Norwegian Petroleum Directorate in 1997, the Norwegian Oil Industry Association took responsibility for preparing draft guidelines for use of helicopters. The project has the following terms of reference:

“The project shall chart the significance helicopter transportation of personnel has on safety and working environment in the petroleum activities. Based on the results of this survey, recommendations and measures will be proposed that can make a positive contribution to improved safety and working environment in connection with helicopter transportation, including potential limitation of shuttling and commuting by helicopter."

The plan is for the guidelines that are prepared under this project to be completed during the course of the spring of 1999.

2.11.4 SAFETY MANNING DURING LABOR DISPUTE

There have been several labor disputes also in 1998, and many questions and inquiries to the Norwegian Petroleum Directorate regarding safety manning in connection with labor disputes. The Directorate has held a number of meetings with the parties regarding this topic. Therefore, the Directorate sent out a letter in May 1998 to clarify what the regulatory requirements in this area entail, and to provide advice regarding how the parties should conduct themselves in connection with labor disputes.

In this letter, the Norwegian Petroleum Directorate clarified, among other things, that the regulatory requirements entail that the operating company must submit a program for temporary shutdown and/or plugging of wells for the installations that are affected by a notification of a potential strike or lockout, no later than seven days prior to the date of the notified strike or lockout.

The operator shall not plan for an emergency shutdown, but for a controlled temporary abandonment of wells in accordance with the master plans outlined in the approved drilling program. Within this framework, the operator shall select the plugging/ shutdown program that will safeguard the requirement for establishing two barriers and securing the wells and the installation in the quickest possible manner.

The Norwegian Petroleum Directorate expects that the methodology that is used for stipulating the size of the safety manning is the same as for ordinary emergency preparedness planning. It must be possible to handle the defined hazard and accident situations that can arise using the available manning. Therefore, it is natural to use the existing emergency preparedness analysis as a basis and identify which defined hazard and accident situations are still relevant after the work operations are shut down. Which emergency team functions must be handled by the safety manning crew follow from the defined hazard and accident situations.

Insofar as possible, normal shift arrangements should determine who will participate in the safety manning. Trading offshore periods and permanent shifts should be avoided in this context.

2.11.5 NOISE AS A HEALTH RISK

In 1996, the Norwegian Petroleum Directorate sent out a joint letter to the industry with a more thorough explanation of central regulatory provisions regarding noise on installations in the petroleum activities. In this letter, the Directorate asked for information regarding the companies' work on setting up noise requirements by area, as well as charting of noise exposure that could cause hearing loss. In 1998, the Directorate sent a follow-up letter where the regulatory requirements were further illuminated, and which gave an account of the factors that require an application for non-compliance with the regulations in connection with noise.

A large quantity of information has been received from the companies in reply to these letters. This has provided the Norwegian Petroleum Directorate with a good picture of the noise conditions on the installations, and how work is proceeding on various measures to reduce noise. Particularly in the past two years, there has been a focus on noise conditions in the petroleum activities, and the Directorate is planning a seminar in the spring of 1999 which will include a summary of the feedback from the companies.

2.11.6 NEW CONCEPT FOR DERRICKS

In 1998, the Norwegian Petroleum Directorate has devoted considerable attention to the development of a new concept for derricks. The concept introduces an innovation in relation to traditional solutions for drilling and well workovers, which will inter alia entail that the drill string is handled using hydraulic stays. The new drilling concept has been selected for a number of recent projects, both for new mobile and permanent installations, as well as for modification of existing mobile installations.

The concept is a positive example of technological development, and includes elements that should contribute to reducing the risk of undesirable incidents and conditions. However, the Norwegian Petroleum Directorate's supervision has identified some safety and working environment problems associated with the technical solutions surrounding application of the concept on the individual installation.

Specifically, weaknesses have been uncovered with regard to location of equipment, protection of personnel from wind and the elements, as well as general working conditions in the drilling area. The Norwegian Petroleum Directorate believes that many of these difficulties could have been solved in a better way if the transfer of experience between projects and the cooperation between the parties involved had functioned better.

After several meetings with the supplier, drilling contractors and operators, most of the Norwegian Petroleum Directorate's comments have been addressed as regards ongoing and future deliveries of such derricks.

2.11.7 LIFTING GEAR AND FALLING OBJECTS

During the course of 1998, the Norwegian Petroleum Directorate has registered a marked increase in the number of incidents and near-misses related to falling objects. In the opinion of the Directorate, several of these incidents could have led to very serious accidents.

44 undesirable events in connection with lifting operations were reported in 1998, double the number from

the previous year. It is reasonable to assume that some of the increase can be attributed to improved reporting of near-misses, as a result of the fact that the problem area has received increased attention in recent years. However, the disturbing factor is that the number of incidents involving personal injuries has tripled, as 12 personal injuries in 1998 were connected with lifting operations.

Therefore, the figures may indicate a potential actual worsening of safety in connection with lifting operations, which, if true, is surprising and difficult to explain, because both the industry and the authorities have placed significant attention on this problem area. Normally, increased focus on a problem alone will lead to an improvement, at least over the short term. It is also the Norwegian Petroleum Directorate's opinion that, in this case, the industry has worked seriously and purposefully on this challenge, seemingly without achieving the desired effect.

Therefore, there is clearly a need for additional efforts in this area. The Norwegian Petroleum Directorate, together with the industry, will examine whether other approaches can provide a better result.

A preliminary review of the incident reports show that lifting operations in the drilling area alone account for 19 of the 44 incidents, compared with three in the previous year. Other lifting operations on the installation account for 20 incidents, while five of the incidents were related to lifting from and to supply vessels. The latter area is the only area that exhibited a decline in relation to 1997.

With regard to causal factors, these are divided into operational errors, defects on cranes and equipment defects. Operational errors account for about 40 per cent of the incidents. There is much to indicate that personnel who are involved in lifting operations do not always have the necessary understanding and respect for the forces that are associated with hanging and moving loads. The efforts to improve safety during lifting operations should therefore largely be aimed at methods for planning and organizing lifting operations, including ensuring that personnel have the necessary know-how.

The number of incidents that are due to defects on cranes or lifting gear also emphasize the importance of the "enterprise of competence" system functioning as intended in the regulations. In 1999, the Norwegian Petroleum Directorate will focus its efforts on this function, and will also follow up with a project regarding analysis of data from incidents.

2.11.8 NEW KNOWLEDGE REGARDING FIRE AND EXPLOSION

In connection with a major industry project in the U.K. where three Norwegian oil companies and two Norwegian scientific research institutions participated, a number of large-scale fire and explosion tests have been carried out. The project's first objective was to obtain information regarding characteristic qualities of fires and explosions, as well as methods to reduce the dangers. The second objective was to acquire exact information and data for use in connection with evaluation and improvement of fire and explosion models. The project was concluded in 1997 and the most significant conclusions were published. These were, in brief:

- Higher explosion pressure was measured than was indicated by the calculation models
- Some higher fire temperatures were measured than were calculated
- Use of water (sprinklers and deluge) had a favorable effect on all types of fires and explosion pressure

The conclusions from the project represent a challenge to the operating companies, perhaps particularly in relation to existing installations where the design may prove to have been based on explosion pressures which were too low.

The organization of operating companies on the British shelf (UKOOA) has commenced work on preparing new guidelines in this area. In addition to the British authorities, Statoil, Norsk Hydro and the Norwegian Petroleum Directorate are participating in the management group for this work. Several subgroups have also been set up including representation by Norwegian companies.

2.11.9 AUTHORITIES' COOPERATION ON INJURY STATISTICS

In 1998, the Norwegian Petroleum Directorate has continued its collaboration with the British Health & Safety Executive (HSE) regarding preparation of injury statistics for occupational injuries and work-related diseases.

The purpose of the collaboration is for the authorities in the two countries to achieve improved mutual insight into the data in these areas, chart common problem areas, contribute to transfer of experience and possibly implement measures if the conditions allow. The Norwegian Petroleum Directorate has also received insight into research that the HSE has had done within the area of accident analysis. This work may be useful in connection with follow-up of accidents on the Norwegian shelf.

3. Environmental measures in the petroleum activities

3.1 CONSIDERATION FOR THE ENVIRONMENT

The Norwegian Petroleum Directorate has noted that attention surrounding environmental aspects has increased significantly and that environmental considerations have attained a central position in the formulation of petroleum and energy policy. The Directorate's paramount objectives and goals more clearly reflect the Norwegian Petroleum Directorate's responsibility and tasks regarding the environment. The consideration for the environment is addressed as part of the work to ensure sound management of the Norwegian petroleum resources.

The main activities in this work are stipulation of regulations and other frameworks for the activities, preparation of reports and consulting activities for the responsible ministries, and supervision of the activities carried out by the operating companies. Other activities are participation in national and international forums which work on environmental issues, information work and cooperation with other authorities, particularly the State Pollution Control Authority (SFT).

3.2 MILJØSOK

MILJØSOK was established in 1995 in order to stimulate a more binding cooperation between the authorities and the oil and gas industry in order to solve the most important environmental challenges. The MILJØSOK report was submitted to the Ministry of Petroleum and Energy in December 1996. The report provides a comprehensive environmental status and description of the environmental challenges for Norwegian petroleum activities, a review of technical/economic alternatives and an evaluation of the means used in climate and environmental policy.

The next phase of MILJØSOK started in October 1997 when a Secretariat was established in connection with OLF (Norwegian Oil Industry Association), as well as a separate Council and Cooperation Forum. The Norwegian Petroleum Directorate participates in both the MILJØSOK Council and the Cooperation Forum. In 1998, the Directorate has participated in several working groups established by MILJØSOK, and places emphasis on good cooperation and active participation in the MILJØSOK context.

3.3 AUTHORITIES AND FRAMEWORKS

The Norwegian Petroleum Directorate and the State Pollution Control Authority have authority in the petroleum activities under the Petroleum Act and the Pollution Act. The Norwegian Petroleum Directorate also enforces the Act concerning CO_2 tax.

The petroleum legislation requires that all activities be carried out in a responsible manner that safeguards the safety of personnel, the environment and financial values.

The Pollution Act has the objective of ensuring proper environmental quality so that pollution and waste do not lead to health hazards, do not affect general well-being or harm nature's capabilities of production and self-renewal.

The regulations regarding management systems, risk analyses and emergency preparedness have authority in both of the central acts mentioned above, and are administered by the Norwegian Petroleum Directorate together with the rest of the technology regulations and the Working Environment Act. The supervisory responsibility among the authorities is distributed through the directive for organization of the supervision.

3.4 SUPERVISION OF THE ACTIVITIES

Security against pollution is covered under the safety concept as it is applied in the shelf activities, and supervision of environmental measures and environmental activities is an integral part of the supervision activities. The Norwegian Petroleum Directorate carries out supervision of internal control systems for operators and contractors in order to ensure that the activities are planned and implemented in accordance with the authorities' requirements and goals and acceptance criteria in the companies. The Norwegian Petroleum Directorate evaluates the overall safety, resource and economic aspects of environmental measures.

The comprehensive integrity of the authorities' supervision work is ensured through the Norwegian Petroleum Directorate's coordinating role in relation to the State Pollution Control Authority in the supervision activities. The common guidelines for the authority, which lie inter alia in the Norwegian Petroleum Directorate's administration of the supervision system and in the regulations regarding management systems, risk analysis and preparedness, also contribute to this. This area is also addressed in more detail in Chapter 2 on safety and working environment.

In its supervision of exploration drilling in environmentally sensitive areas, the Norwegian Petroleum Directorate has placed particular emphasis on preventive measures which the operators implement, and work is in progress to look at how the companies' risk and emergency preparedness analyses safeguard the consideration for environmental sensitivity in the actual planning of drilling operations. In addition, the Norwegian Petroleum Directorate has followed the operators' work on stipulating acceptance criteria for environmental risk, in other words, the risk the operator itself can accept for its activity.

The Norwegian Petroleum Directorate also carries out supervision of the use of equipment which measures fuel consumption and the quantity of gas used for flaring and cold venting. Collection of the CO_2 tax on the shelf is the responsibility of the Norwegian Petroleum Directorate, and the Directorate makes an annual evaluation of whether the tax contributes to reducing CO_2 emissions in an efficient manner. In 1998, the tax rate has been 89-107 øre per Sm^3 natural gas burned and cold vented and 89-107 øre per liter diesel consumed.

Figure 3.4.a
Emissions of CO_2 per Sm^3 oe. Emissions from use of diesel are not included.

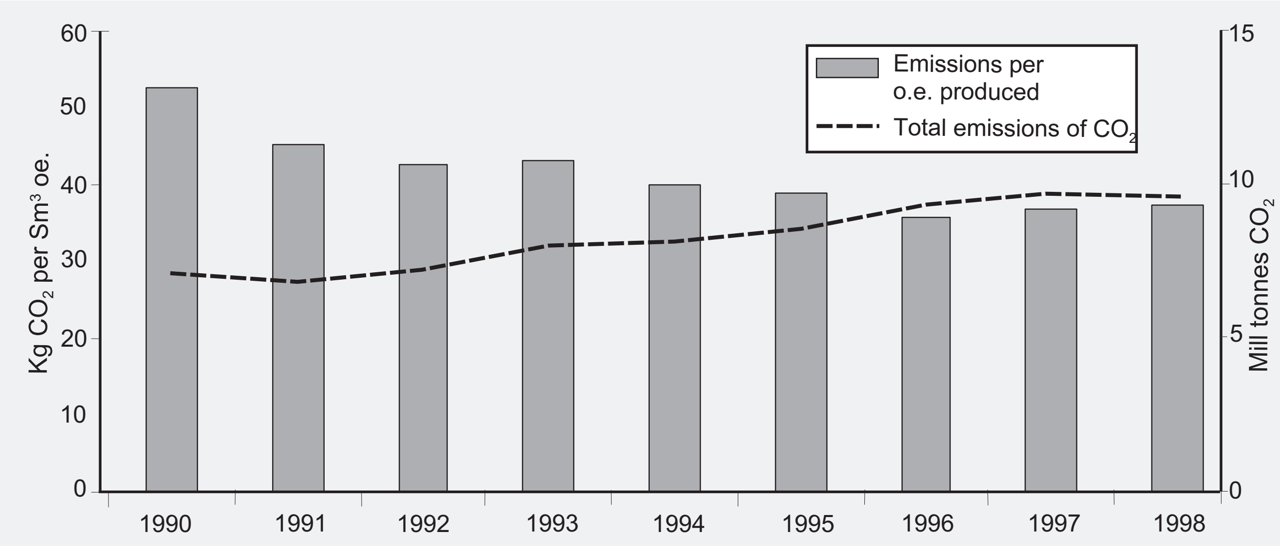
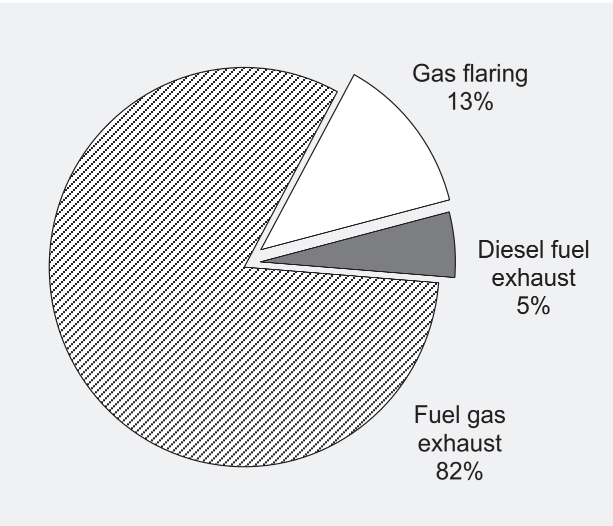


Figure 3.4.b
CO_2 - emission sources, 1998



Preliminary figures show that the CO_2 emissions from taxable activities were 8.3 million tonnes in 1998. This constitutes about 85 per cent of the total emissions of CO_2 from the petroleum activities as shown in Figure 3.4.a. This is a reduction of one per cent compared with 1997. Figure 3.4.b shows how the emissions are divided by source.

3.5 THE EXTERNAL ENVIRONMENT

When the Norwegian Petroleum Directorate evaluates impact analyses, plans for development and operation and applications for consent, the environmental aspects are a natural part of and fully integrated with the rest of the Norwegian Petroleum Directorate's evaluation. Great emphasis is placed on the ability to make use of technology which reduces the volume of emissions. Special emphasis is placed on measures that limit emissions at the source.

The Norwegian Petroleum Directorate also prepares prognoses for emissions of CO_2, nitrogen oxides, methane, CFC and NMVOC. Significant resources have been spent on implementing new routines for making prognoses for emissions to the air. The changeover has clearly improved the quality of the prognoses. The prognoses are an important basis from which to evaluate means so that national and international commitments may be followed up. In addition, there has been a collaboration with the State Pollution Control Authority (SFT) in connection with reporting of emissions and discharges. This work has resulted in SFT issuing common guidelines for reporting emissions/discharges from the petroleum activities which also cover the NPD's reporting needs.

An analysis of measures for No_x emissions in the sector has been conducted, and will be included as part of a cross-sector analysis where SFT has the primary responsibility. The Norwegian Petroleum Directorate believes it is important to work to influence the industry to develop efficient and environmentally friendly solutions that also provide the best possible economy.

3.6 DISPOSAL OF INSTALLATIONS

According to the Petroleum Act, the licensees shall submit a decommissioning plan 2-5 years before the expected termination of the use of an installation or the expiration of the license. The plan shall contain a proposal for continued production or shutdown of production and disposal of the installations.

Norwegian authorities have appointed an inter-ministry committee whose task is to develop a national policy for disposition of installations which have been used in the petroleum activities. This committee has also contributed to the international work under the Oslo and Paris Convention (OSPAR).

In the summer of 1998, OSPAR adopted a resolution regarding disposal of installations in the Convention area. The resolution means that the following installations must be brought to land:

1. Subsea installations
2. Floating steel installations
3. Small, permanent steel installations (substructure weight < 10000 tonnes)
4. Upper part of large, permanent steel installations (deck facilities and substructure down to the uppermost part of the piles on installations with a substructure weight > 10000 tonnes)
5. Deck facilities on concrete installations

Exceptions may be granted if the installations can serve other uses or if an overall evaluation in the individual case shows that there are preponderant reasons for disposal at sea.

An exception from the prohibition on sea disposal is made for the lowermost part of large, permanent steel installations (substructure weight > 10000 tonnes) placed on site prior to 9 February 1999, and the substructure on concrete installations. These parts of the installations may be evaluated on a case by case basis.

The Norwegian Petroleum Directorate is currently assisting the MPE in formulation of guidelines for cessation plans. Under the direction of the inter-ministry committee, a study program to evaluate disposal of pipelines is also underway. The plan is to complete the program in the year 2000. The Norwegian Petroleum Directorate is a key contributor of terms to the Ministry of Petroleum and Energy in this work.

The Norwegian Petroleum Directorate also contributes with assessments related to the decommissioning plans for the individual fields.

3.7 CLEAN-UP OF THE SEABED

In 1998, the Norwegian Petroleum Directorate's clean-up of the seabed took place in a 900- square km area on the Viking Bank. The area is fishery-intensive, and was chosen on the basis of recommendations from the fishermen's organizations and the fishery authorities. The compensation board for loss of fishery equipment has considered several cases concerning loss of and damage to equipment in this area.

Various chains, wires of various sizes, a ladder, a trawl door and various equipment with a total weight of approximately 7 tonnes were removed from the seabed. The exact position of an old shipwreck was determined, but the ship was not raised.

During this work, a large ship's anchor with chain was discovered very close to the Frostpipe pipeline south of the Oseberg field. After a meeting between the Norwegian Petroleum Directorate and Elf, Elf took care of immediate removal of the 21-tonne anchor and chain.

The project was carried out by AS Geoconsult, Øvre Ervik, using the vessel S/V Geograph.

The management committee for the clean-up campaign consisted of representatives from the Norwegian Petroleum Directorate, the Directorate of Fisheries, the Norwegian Mapping Authority – Hydrographic Survey, the Norwegian Fishermen's Association and the Norwegian Oil Industry Association.

3.8 GREENING OF GOVERNMENT - GREENING OF THE NPD

The Norwegian Petroleum Directorate is one of ten governmental bodies which, over the course of two years, shall test measures and systems in order to make operations as environmentally friendly as possible. In addition to reducing negative environmental impacts, the greening of government project provides the participating organizations with a good foundation for streamlining operations. Emphasis is placed on implementing the project so that the work can subsequently be continued in all governmental operations. The State Pollution Control Authority is assigned the responsibility for leading the project, while the Ministry of the Environment and the Ministry of Labor and Government Administration together are responsible for the project, which started in September.

The project has six commitment areas: energy consumption, purchasing, construction, transportation, waste management, use of information and communication technology (ICT).

In this project, the Norwegian Petroleum Directorate wants to focus on how we can reduce our own environmental burdens with the aid of ICT.

4. International cooperation

4.1 COOPERATION WITH NORAD

In 1998, the Norwegian Petroleum Directorate's assistance work financed by NORAD amounted to approximately five man-years. The majority of the assistance has been directed towards the following cooperating countries: Angola, Namibia, South Africa, Mozambique, Eritrea, India, Vietnam and Nicaragua. The Norwegian Petroleum Directorate has also continued its cooperation with the Coordinating Committee for Coastal and Offshore Geoscience Programmes in East and Southeast Asia (CCOP). One of the Norwegian Petroleum Directorate's employees was stationed as project coordinator at the technical secretariat in Bangkok in 1998.

The Norwegian Petroleum Directorate has come a long way towards meeting NORAD's objective of establishing long-term cooperation agreements with relevant institutions in the countries concerned. All main projects are governed by such agreements, and work or evaluations are proceeding for new agreements with Angola and Bangladesh. The form of institutional cooperation varies in the different countries. For some of the larger projects, attempts are made to contribute actively to the development of the cooperating institution by offering experience from the entire range of the Norwegian Petroleum Directorate's sphere of activities, both professionally and administratively.

In addition to personnel from the Norwegian Petroleum Directorate, extensive use is made of Norwegian suppliers of goods and consultant services in connection with implementation of the individual projects. Consultants are often selected in competition with international companies. Within these types of services, Norwegian expertise ranks high in an international perspective.

The following is a brief overview of the activities in the main development assistance countries and new projects which are planned:

Namibia

The Norwegian Petroleum Directorate has assisted in the formulation of regulations and follow-up of drilling operations. Namibia has built up a small, but highly qualified petroleum management system. Work is now in progress to establish a new cooperation project from 1999 in which the Ministry of Mines and Energy (MME) will be the cooperation partner. Namibia wishes to separate administration tasks from the state oil company, NAMCOR, so that the company can concentrate on commercial tasks. The new project will probably last for three to five years. The further development of framework conditions and the administration system, in addition to planning of gas development and further resource mapping, will be MME's main challenges in the years to come.

Mozambique

The Norwegian Petroleum Directorate has continued its support in the formulation of legislation, resource, pipeline and safety regulations and model contracts for the petroleum activities. Treaty negotiations with South Africa have also been concluded under Norwegian leadership. This work is carried out using Norwegian and international consultants in addition to the Norwegian Petroleum Directorate's own expertise. A special challenge has consisted of assisting Mozambique in separating the administration functions from the state oil company, ENH, and transferring these to DNCH (Directorate and main cooperation partner), while at the same time assisting ENH in continuing its commercial tasks. PETRAD has been used in connection with transfer of experience to both institutions.

Plans for development of the Pande gas field and build-up of gas-based iron and steel industry in Maputo (Mozambique) based on ore from South Africa were submitted in December 1997. In 1998, Norwegian experts have assisted Mozambique in the technical and commercial evaluation of these plans. If the project is realized, it will be one of the largest industrial projects in Africa. A similar but smaller facility is being planned in Beira. There are also plans for gas export to South Africa as a result of the positive results from exploration wells on the Temane field.

In addition, follow-up of drilling operations, data security, planning for storage of seismic data and general institutional support have been important activities. Further resource mapping is an important task for the cooperation institutions in Mozambique. A significant number of international companies have shown interest in exploration for oil, particularly in the deep sea areas, and for development of gas resources. Most of the prospective areas are now covered by licensing.

A new 4-year program for institutional support was approved by NORAD in 1997 and all agreements were in place by the end of 1998.

Eritrea

The Norwegian Petroleum Directorate has provided assistance concerning establishment of framework conditions, resource planning, assessment of environmental impact, studies of future gas strategy, promotion of exploration areas, data storage and seismic surveying. The Ministry of Energy and Mineral Resources is the main cooperation partner.

India

The Norwegian Petroleum Directorate has assisted our cooperation partner, DGH, with transfer of experience concerning a large part of the Directorate's sphere of responsibility. Storage of large quantities of data, general data management, resource evaluation, development planning and implementation of safety audits are areas of focus for the assistance. Several delegations from DGH have visited comparable technical milieus in the Norwegian Petroleum Directorate, and technical personnel from the Norwegian Petroleum Directorate have visited DGH. Most of the activities planned under the program have now been completed. A continuation of the program, with completion planned in the spring of 1999, is being evaluated in relation to Norway's general strategy for assistance to India.

Vietnam
The Norwegian Petroleum Directorate has continued its assistance concerning development of safety regulations and training in the area of safety management. The main cooperation partner is Petrovietnam (state oil company). SFT is cooperating in the same project.

CCOP
The Norwegian Petroleum Directorate has provided assistance to the cooperation organization in Eastern and Southeastern Asia which works on the mapping of petroleum resources in the area and lays plans for exploitation of these resources. A geo-professional expert from the Norwegian Petroleum Directorate has worked at CCOP's secretariat in Bangkok as a consultant. A number of professional seminars have been organized in the area for members of the organization, inter alia with the assistance of PETRAD. Assistance has also been provided in the form of software and training in the use of modern analysis methods.

Nicaragua
The Norwegian Petroleum Directorate has provided assistance concerning promotion, mapping of the resource potential and securing of data. Seminars have also been organized in the country in cooperation with PETRAD. INE is the main cooperation partner (office under the Ministry of Energy). The Petroleum Act has now been approved and licensing of exploration areas will be the main challenge for INE in the years to come.

South Africa
For quite some time, the Norwegian Petroleum Directorate has assisted NORAD and the Department of Mineral Resources and Energy (DME) in connection with identification of assistance needs in the petroleum sector and formulation of project applications. Organization of upstream oil and gas activities, establishment of framework conditions for marketing of natural gas in South Africa, organization of sales of petroleum, organization of state ownership interests in the petroleum sector and training are important areas for potential future Norwegian assistance. Final approval of the project was received in the autumn of 1998, and activities will be in full swing in the spring of 1999 with EDRC at the University of Cape Town as the executing institution on behalf of DME. The Norwegian Petroleum Directorate will assist EDRC in the work, which will also include the use of Norwegian researchers and consultants.

Angola
Angolans have received training in the Norwegian Petroleum Directorate, and Angola has also received support in connection with its work on statutes and regulations. Plans for further cooperation have been prepared and presented to NORAD. A decision concerning possible more extensive institutional cooperation will probably be made in 1999. Work is also underway on plans for potential support to the Southern African Development Community (SADC), which has its technical secretariat for the energy sector in Luanda.

4.2 COOPERATION WITH PETRAD

As a result of a pilot project carried out by the Norwegian Petroleum Directorate for NORAD during the period 1989-1993, PETRAD was established as an independent foundation by the Norwegian Petroleum Directorate and NORAD on 1 January 1994.

The objective of the foundation is to place Norwegian expertise and competence in the fields of management and administration of petroleum resources at the disposal of managers from the authorities and national oil companies in Africa, Asia, Latin America, Oceania and Russia/ CIS (Commonwealth of Independent States). This is accomplished by adapting seminars according to inquiry and need by the authorities in the above-mentioned regions, in addition to the organizing of two eight-week courses each year, "Petroleum Policy and Management" and "Management of Petroleum Operations". All PETRAD activities are aimed at senior and middle management personnel.

The activities are carried out through PETRAD engaging people who have a high level of competence in the petroleum activities. Up to now, PETRAD has made use of more than 300 experts from around fifty companies, institutions and authorities as lecturers and resource people in its courses and seminars. The eight-week courses in Stavanger integrate the overall Norwegian experience and expertise within petroleum administration and management. PETRAD also provides its course participants with comprehensive insight into the Norwegian petroleum industry and Norwegian culture through excursions and social events.

With the Norwegian Petroleum Directorate and NORAD as founders, PETRAD is viewed as a neutral representative and conveyer of knowledge from the Norwegian public authorities. The response shows that PETRAD has had a significant effect as a "door opener" and a creator of contacts in many countries.

The location of PETRAD in the Norwegian Petroleum Directorate means that the Directorate has a close and profitable cooperation with the foundation. The Norwegian Petroleum Directorate participates with lecturers and resource personnel both at courses and seminars in Norway and abroad.

In 1998, the Norwegian Petroleum Directorate contributed to the implementation of PETRAD's two annual 8-week courses, "Management of Petroleum Development and Operations" and "Petroleum Policy and Management", held in the Norwegian Petroleum Directorate's offices, this time with 44 participants from 31 nations.

The Norwegian Petroleum Directorate has also contributed to the accomplishment of the following seminars in 1998:

- Seminar on Petroleum Licensing, Nar'yan Mar, Russia
- Seminar on Petroleum Licensing, Arkhangelsk, Russia
- Seminar on Latvian Upstream Petroleum Resource Management, Riga, Latvia
- Seminar on Petroleum Policy and Management, Manilla, the Philippines
- Seminar on Petroleum Management and Promotion, Kathmandu, Nepal
- Seminar on Advanced Reservoir Management, Hanoi, Vietnam
- Training Programme for Socar and Azerigaz (Azerbaijan), Stavanger
- Unitization Workshop for PetroVietnam, Stavanger
- Seminar on Lithuanian Upstream Petroleum Resource Management, Vilnius, Lithuania

This activity contributes to professional exposure to and understanding of different cultures while, at the same time, it increases the total expertise for those employees of the Directorate who are involved.

The Norwegian Petroleum Directorate is also involved in connection with PETRAD's commitment in relation to Russia. This commitment is mainly coordinated under the Norwegian-Russian Forum for Energy and Environment, which is led by the Ministry of Petroleum and Energy. Under the forum, several working and expert groups have been established which are administrated by PETRAD with participation from Russia and Norway. The Directorate participates in all of these expert groups. The work is often carried out in the form of work seminars.

4.3 INTERNATIONAL COOPERATION WITHIN RESOURCE MANAGEMENT

Annual meetings with Danish and British authorities

As an oil and gas province, the North Sea is basically divided between the U.K., Norway and Denmark. Even though the individual fields are quite different, there are many similarities among the fields in the North Sea area. The petroleum resource management problems encountered by government agencies in the three countries are therefore similar in many ways.

Consequently, for many years the Norwegian Petroleum Directorate has carried out regular meetings with British and Danish resource management authorities who share basically the same responsibilities for their sectors as the Norwegian Petroleum Directorate does for the Norwegian shelf. For the U.K. shelf, it is the technical section of the Oil and Gas Division in DTI (Department of Trade and Industry) which is responsible for the resource aspect of exploration, development and operation activities. For the Danish shelf, the Danish Energy Agency (Energistyrelsen) has a similar responsibility.

The objective of the meetings is primarily to exchange opinions and experience from the respective activities. The U.K. activities are a few years ahead of us. It has therefore been very useful to draw on their experiences with regard to improved oil recovery, development of small fields and unitization. The Danes have particular problems related to chalk fields. It has therefore been valuable to acquire first hand information on their experiences. Data management and the environment are other areas where it has been very useful to exchange experience. Close cooperation is envisaged also in these areas.

During 1998, one meeting was held with the Danish authorities and one with the British authorities. Last year's meeting with the Danes took place in Copenhagen on 12-13 August. The main topic was mutual information and exchange of viewpoints related to exploration and development. Problems connected with border fields were discussed, and briefings were given regarding the respective research cooperation. Thoughts and ideas were also exchanged as regards international cooperation. More coordination is expected in this respect.

The 1998 meeting with the British authorities was held in Stavanger on 4-5 November. The general theme this time was exploration, development and production, as well as environmental factors. The British authorities talked about their experiences, while we contributed with an account of the conditions on the Norwegian shelf. The impact of low oil prices on future activities was also discussed.

Annual meetings with other countries' authorities - exploration phase

Since 1983, annual meetings on technical issues have taken place between the Norwegian Petroleum Directorate and state administration units in other Northern and Western European countries with responsibility for exploration for oil and gas.

In the beginning, England, Ireland, Denmark, Germany, the Netherlands and Norway took part in these meetings. Subsequently, France, the Isle of Man and the Faeroe Islands have joined.

The responsibility for hosting the meetings is on a rotation basis among the various countries. Norway has hosted these meetings twice previously. Ireland hosted the event in 1998.

The main issues of discussion at the meetings are geotechnical, exploration technology and data management issues, as well as challenges faced by the various countries in their efforts towards efficient discovery of new oil and gas resources.

The combined expertise and experience at these meetings is substantial, and the access to information is important for each individual participating country with a view towards developing optimal exploration strategies.

Annual meetings with other countries' authorities - fiscal metering
In those countries where Norwegian petroleum is landed, the authorities' responsibility and roles are stipulated in treaties and cooperation agreements. There is extensive cooperation on the part of the authorities in order to safeguard the individual country's requirements for fiscal metering. An important forum in this cooperation is annual meetings in which status and future activities in the area of metering technology are reviewed. The Norwegian Petroleum Directorate has previously established co-operation agreements with German and Belgian authorities. In 1998, agreements were also entered into with the British and French authorities.

In 1998, work was commenced on separate agreements for each individual transportation system into the U.K. The Norwegian Petroleum Directorate has taken the initiative in 1998 to make the necessary adjustments to existing agreements in light of the renegotiated Frigg Treaty.

International research cooperation regarding improved oil recovery
Since 1979, Norway has participated in international research cooperation under the direction of the International Energy Agency (IEA) regarding improved oil recovery using advanced methods. Nine countries currently participate, and the cooperation largely consists of a commitment for a certain scope of research in specific areas and the exchange of the results. For the period 1986-1995, the Norwegian aspect of this cooperation has been taken care of through the state research programs SPOR and RUTH, which have been led by the Norwegian Petroleum Directorate. From 1996, the cooperation projects have been financed through the RESERVE program of the Research Council of Norway.

Since 1986, the Norwegian Petroleum Directorate has represented Norway in the international management committee for this IEA cooperation.

Lecture activities
Also in 1998, the Norwegian Petroleum Directorate's staff members have been involved as lecturers in a number of international conferences, workshops and the like, in issues relating to resources. These activities are in demand and they are regarded as being very important in order to contribute to a mutual exchange of information and experience. The Norwegian shelf receives international focus with regard to exploration efficiency, development solutions, resource exploitation and use of new technology. Openness regarding both the overall resource scenario and solutions chosen on specific fields has provided a basis for stimulation of technology and promising cooperative relations between participants on the shelf. There is still considerable interest on the part of other countries as regards gaining insight into Norwegian resource management and the authorities' active instigator role in this context.

4.4 COOPERATION WITHIN MANAGEMENT OF SAFETY AND WORKING ENVIRONMENT

4.4.1 RUN ARC - COMPREHENSIVE SAFETY AND ENVIRONMENT REGIME FOR OIL AND GAS ACTIVITIES ON THE RUSSIAN CONTINENTAL SHELF

Since the autumn of 1997, the Norwegian Petroleum Directorate has participated in a tripartite cooperation between Russian, American and Norwegian (RUN) authorities to investigate the possibility of developing a comprehensive safety and environment regime for the oil and gas activities on the part of the Russian continental shelf which lies in the Arctic (ARC).

The Ministry of Natural Resources leads the project work on the Russian side. The Ministry cooperates closely with other authorities in Russia which are responsible for different aspects of regulation of the oil and gas activities in the country. The USA is represented by the Minerals Management Service (MMS), the technical authority on safety and the environment for inter alia offshore oil and gas activities. Based on the experiences from the previous "Boris" project, the Norwegian authorities have asked the Norwegian Petroleum Directorate to take responsibility for the Norwegian cooperation. The Ministry of Foreign Affairs finances the Norwegian part of the project.

The plan is to implement the project in three phases: preliminary study, development and implementation.

The first phase of the project, the preliminary study, was carried out from September 1997 to December 1998. This phase examined the current situation in Russia in the areas of safety and environmental legislation, responsibility of the authorities, safety management, emergency preparedness, environmental monitoring, etc. The results of this study are described in a report which also presents a number of proposals for what the Russian participants in the preliminary study believe must be done in order to develop a new safety and environment regime in Russia.

It emerges from the report that the situation is complex for those who have a need to proceed through the Russian system, both as regards regulations and the powers of the various authorities. On the one hand, the regulations and the government system are characterized by overlapping requirements and authorizations, while, on the other hand, there are areas without clear requirements or defined authority.

Among the measures suggested is a rewriting of a number of laws and regulations, as well as examining the possibility of establishing one body that shall be responsible for regulation of safety and environment in the petroleum activities on the Russian continental shelf.

The report has been sent out for consultation to various parties in Russia, such as local and regional authorities and both national and international oil and gas companies.

A conference is planned for the spring of 1999 to evaluate the results of the preliminary study and to look at the possibility of starting the next phase of the project, which is the development phase.

If the project is to succeed, it is crucial that it receives the necessary financial and technical resources available in Russia, and that the relevant political authorities support and place demands on the implementation of the project. These factors will be illuminated at the conference, which may also lay the foundation for a plan for the development and implementation phase.

4.4.2 INTERNATIONAL COOPERATION AGENCIES

The Norwegian Petroleum Directorate cooperates extensively with international technical institutions and government agencies, either directly or indirectly through Norwegian government agencies. The purpose of this cooperation is to:

- contribute to ensuring that safety and the working environment in the petroleum activities at least meet accepted international standards,
- ensure access to relevant information for competence building and regulatory development,
- contribute insight and experience in an international context in order to promote positive development in safety and working environment.

In general, the cooperation has consisted of participation in international governmental cooperation in Europe and in United Nations agencies, but also more direct cooperation with the various types of international and regional professional institutions. The most important partners in 1998 have been:

- NSOAF - North Sea Offshore Authorities Forum,
- IRF - International Regulators' Forum
- the EU Commission, in cooperation with the Ministry of Local Government and Regional Development, on safety and the working environment,
- the United Nations' organizations IMO and ILO regarding safety at sea and the working environment, respectively,
- the United Nations' organization UNEP IE regarding environmental measures in offshore petroleum activities
- European Diving Technology Committee (EDTC) and the Association of Offshore Diving (AODC) regarding diving safety,
- Centre for Marine & Petroleum Technology (CMPT), United Kingdom, regarding inspection and maintenance of installations,
- The Welding Institute (TWI), United Kingdom, regarding research and development of materials and welding,
- American Petroleum Institute (API), participation in annual conference on technical petroleum topics and standardization,
- National Association of Corrosion Engineers (NACE), USA, participation in the annual conference on corrosion and surface treatment,
- CENELEC, cooperation on electrical engineering standardization in Europe through the Norwegian Electrotechnical Committee (NEK).
- Bilateral cooperation between the Norwegian Petroleum Directorate and similar supervision authorities in Denmark, the Netherlands and the United Kingdom.

NSOAF - North Sea Offshore Authorities Forum

In the field of safety management, the Norwegian Petroleum Directorate participates in the North Sea Offshore Authorities Forum (NSOAF), where representatives from all the North Sea countries' governmental authorities in charge of supervision of offshore petroleum activities take part.

The goal of the forum is to ensure continuous improvement in safety and working environment for personnel who participate in petroleum activities in the North Sea and for society at large.

The members of NSOAF meet annually. Two independent working groups have been appointed, which meet biannually. The Norwegian Petroleum Directorate is represented in these groups.

One of the groups is to consider whether an NSOAF plan should be established with the aim of mutual acceptance of methods for documenting compliance with national regulatory requirements, such as the "Safety Case", which is specific to the individual mobile installation. This group is chaired by a Norwegian.

In 1997, this working group appointed an audit group that was to conduct a joint audit of a mobile drilling installation. The drilling contractor Noble Drilling was chosen as the subject of the audit, which was conducted in 1998 for one of the company's mobile drilling installations. The working group regards the audit as a useful contribution in the ongoing work, and the initiative also appears to have been well received by the contracting company. A similar audit directed at a different contractor is planned in 1999.

The other group, which has a Danish chairman, will seek to harmonize the requirements for safety training in the various North Sea countries.

IRF - International Regulators Forum

The International Regulators Forum (IRF) was established in 1994 by a group of authorities who wanted to promote a common understanding of issues related to safety, health and the environment.

The forum provides for exchange of ideas and opinions regarding methods and principles applied to efficient exercise of the supervision of safety and working environment, and exchanges facts regarding the supervision activities and informs one another regarding topical technical issues, regulatory developments, etc.

Within the possibilities and limitations stipulated through national frameworks for the activities, this will contribute to promoting a common understanding among the members with regard to issues such as: the role of the supervision authorities, use of means in the supervision, supervision methods, competence development, the relationship between the authorities and industry, etc.

The following participate in the cooperation in addition to Norway: Australia, the Netherlands, Newfoundland, Nova Scotia, the UK and the USA.

In 1998, IRF has worked particularly on developing a basic model for verification of floating production installations, and technical issues related to exploration for and production of petroleum at great sea depths.

The EU Commission

Since 1982, Norway, represented by the Norwegian Petroleum Directorate, has held observer status in the EU proceedings on safety and the working environment in offshore petroleum activities.

This work comes under the EU's "Safety and Health Commission for the Mining and Other Extractive Industries" (SHCMOEI), and the work is carried out by a working group called the Committee on Borehole Operations.

In connection with the work on harmonization of the requirements for safety training within the North Sea countries, a working conference was organized in 1997 under the direction of the EU in Luxembourg. The conference discussed common recognition of instruction/training certificates. SHCMOEI considered the final report from the conference in December 1998, and concluded that the Committee on Borehole Operations shall monitor the progress of this important harmonization work.

The Committee on Borehole Operations is also continuing its work regarding personal injury statistics for the offshore petroleum activities. Special attention is being given to lifting operations between vessels and permanent/mobile installations in this work.

UNEP - United Nations Environment Programme

In 1998, the Norwegian Petroleum Directorate became involved as a contributor in a forum for environmental issues in offshore petroleum activities under the direction of the United Nations' organization, UNEP. The forum is an interactive, Internet-based information system with free access. The system contains information regarding pollution sources, effects of pollution, as well as information regarding management, technology, legislation, training programs, etc.

Other contributors include the Dutch authorities, the oil industry through the E&P Forum, Brazil's Petrobras, the World Wildlife Fund and UNCTAD. The forum's web address is:
www.natural-resources.org/offshore.

5. Projects

5.1 PROJECTS WITHIN RESOURCE MANAGEMENT

5.1.1 INDUSTRY COOPERATION

FORCE

FORCE *("Forum for Reservoir Characterization and Reservoir Engineering")* is a cooperation forum on problems related to improved oil recovery. FORCE started in 1995 and, as of this year, was continued until the end of 2001. The forum includes 20 oil companies, the Research Council of Norway and the Norwegian Petroleum Directorate as members. All members are represented on the board, where Statoil holds the chairmanship. The secretariat is located in the Norwegian Petroleum Directorate.

The main goal of FORCE is to contribute to increasing oil recovery on the Norwegian continental shelf. The potential for improved oil recovery is large and, to some extent, time-critical. FORCE provides the companies with a forum in which to discuss important issues with each other, with the authorities and with representatives from the research and supplier industries. In their respective organizations, the FORCE members have broad expertise and experience which provide a unique opportunity for solving problems together, or initiating cooperation projects with external suppliers. The participants in FORCE discuss and initiate research, development and demonstration of methods and tools which can contribute to future improved oil recovery. For assistance in the work on putting key issues on the agenda and organizing seminars/meetings, the board of FORCE has established technical committees in central topics such as reservoir modeling, advanced wells and recovery processes.

In all, FORCE has contributed to the commencement of 25 projects at a cost of approximately NOK 50 million. Eighteen of these projects were in progress at the end of 1998.

FORCE organized the following seminars/workshops in 1998: "Modeling and evaluation of horizontal and multilateral wells", "Conditioning of reservoir models to dynamic data", "Intelligent wells" and "How to make reservoir models also consistent with seismic data?" The meetings in FORCE have been of high professional quality, and have contributed to improved understanding of topical issues for which the research community and the supplier industry are challenged to find solutions. All of the FORCE events have been very well attended.

FORCE organized a seminar with broad participation from the authorities and from the industry in order to summarize the first FORCE period (1995-1998) and to mark the fact that the cooperation will continue for another three years. At this seminar, the Norwegian Petroleum Directorate awarded an IOR prize for the first time. The prize was awarded to Troll Oil at Norsk Hydro for their courage and innovation in connection with oil production from the thin oil zones on the field. The intention is for the Norwegian Petroleum Directorate to award the IOR prize annually as long as there are worthy candidates.

FUN

FUN (*Forum for* ***F****orecasting and* ***Un****certainty Evaluation Related to Petroleum Production*) is a cooperative forum relating to problems within the areas of preparing prognoses and uncertainty evaluations for future oil and gas production. FUN was started in May 1997 and has 18 oil companies and the Norwegian Petroleum Directorate as members. The Ministry of Petroleum and Energy and OLF (Norwegian Oil Industry Association) are observers in the forum. The forum is organized with a board consisting of representatives from all of the members. The Norwegian Petroleum Directorate now holds the office of chairman, and the Norwegian Petroleum Directorate is also responsible for the secretariat.

The main objective of FUN is to develop better practice and methods with regard to estimating hydrocarbon resources, forecasting future production with associated emissions and discharges, uncertainty evaluations and decision processes. Two working groups have been set up. Working group 1 is to focus on improved information and reporting routines among the companies and between the companies and the authorities. Working group 1 shall also be the forum for changes in connection with reporting for the national budget. Working group 2 is responsible inter alia for initiating and being a program committee for workshops and seminars for managers and technical personnel. In addition, projects will be initiated through this working group.

In 1998, one management seminar and three workshops were organized. The title of the seminar held on 8 November was "Decision making under uncertainty - why does the unexpected always happen - can we handle it?". Nearly 100 participants attended from most of the oil companies on the Norwegian shelf, as well as participants from universities and research institutions. The program included presentations which covered a wide range within the field of decision-making under uncertainty. The presentations from the seminar may be found on the FUN web-site at *http://www.integra.no/FUN/*.

The following workshops were organized in 1998:

- Forecasting energy balances and energy related emissions - 30 January
- Integrated uncertainty analysis - 11-12 March
- National budget reporting - 29 April

In addition, FUN has worked on establishing a best practice project. A decision on the project will be made at the beginning of 1999. The goal of the project is to develop and describe best practice and methods for estimating hydrocarbon resources and associated emissions to air, forecasting, uncertainty analysis and best practice in order to make decisions.

FIND

FIND was established in 1996 as a cooperation forum for the exploration phase. Twenty-one oil companies as well as the Norwegian Petroleum Directorate are members. Norsk Chevron A/S, a new member, joined in 1998. All of the members are represented on the board, and Saga is the chairman. The secretariat is located in the Norwegian Petroleum Directorate.

The main objective of FIND is to focus on cooperation with regard to planning and implementation of projects with significance for future exploration on the Norwegian shelf. So far, four projects have been started. After an evaluation of a pilot project conducted in 1997, a decision was made to proceed with software development. The intention is to develop and integrate Petrobank software which can carry out rotation/matching of the seismic data, in addition to the developed modules with selection of cubes/random lines and downloading to the interpretation station. It is anticipated that the planned software will be completed during 1999. Fourteen companies and the Norwegian Petroleum Directorate, which is also the project manager, participate in the project.

The "Evaluation of Well Results" project has consisted of reporting prognoses for drilling and results from drilling all of the 195 exploration wells which were drilled during the period from 1990 to 1997. The result from the project confirms that the oil companies over-estimate the resources prior to drilling and underestimate the likelihood of making a discovery, particularly for high-risk prospects. For about 60 per cent of the discoveries, the proven resources in place are smaller than the minimum value prior to drilling. Statistical analyses show that the rock volume is the parameter that explains the majority (70 per cent) of the difference between prognoses of hydrocarbon volume prior to drilling and the result after drilling.

Statistical analyses of the likelihood of discoveries and the reasons for dry wells show that there is relatively good correspondence between the total, average likelihood of discovery, 23 per cent, and the actual rate of discovery, 27 per cent, when discoveries in Resource Class 6 ("development not very likely") are excluded. When the technical discoveries are also included, the discovery rate is 36 per cent. The board of FIND has decided that data from new exploration wells shall be reported to the Norwegian Petroleum Directorate on an annual basis.

The project "The Effects of Drilling Mud Components on the Quality of Geological Data" consists of five parts: (i) coring, geology and non-organic geochemistry, (ii) core analyses, (iii) organic geochemistry, (iv) PVT analyses, (v) well logging. The work on these topics is mainly carried out by consultants. Collection of data is largely complete, while interpretation and reporting are in full swing. So far, some interesting results have emerged, inter alia during coring and testing of washing methods for contaminated well material. The final report for the project as a whole is expected at the end of March 1999 and a workshop is planned for May in which the results will be presented to the project participants.

The project "Basin Analysis and Applied Thermochronology on the Mid-Norwegian Shelf" (BAT) consists of members from ten oil companies, the Norwegian Petroleum Directorate, the Geological Survey of Norway (NGU) and the universities in Oslo and Bergen.

The project will implement isotope-based dating of faults, sediments and rocks for analysis of origin, diagenesis and uplift history for the Mid-Norwegian shelf. Samples have been collected on Greenland based on land in Norway, as well as from exploration wells and shallow drilling. Construction of a database is in progress.

Equipment for the 40 Ar/39Ar laboratory at NGU has been ordered, and most of the build-up will take place in 1999.

DISKOS

The DISKOS project started as a collaboration between Saga Petroleum, Norsk Hydro, Statoil and the Norwegian Petroleum Directorate in 1993 for development and operation of a common database for technical petroleum data. The project now includes a total of 17 oil companies as well as the Norwegian Petroleum Directorate. The database includes most of the processed 2D and 3D seismic from the Norwegian shelf.

Access to the data is governed by the rules and agreements for usage rights which the parties have entered into, or which are stipulated in the Petroleum Act. A comprehensive access rights system in the database prevents unauthorized access to confidential data.

The database also contains quality-controlled data from exploration wells. The Norwegian Petroleum Directorate delivers weekly quality-controlled administrative data to the database. This data describes production licenses, blocks, fields, seismic navigation, well locations, pipelines, etc. The database now contains more than 18 terabytes of data. Use of the DISKOS system has exhibited a hefty increase during the past year, both as regards the number of users logged on and the amount of data downloaded from the database for further processing.

The data base and the network which the DISKOS members are connected to are operated by PetroData A/S. PGS Data Management has now assumed responsibility for the software development, taking over from IBM E&P Solutions. New versions of the software which handle new types of data were launched in 1998, and will be further developed in 1999.

A new business plan for the DISKOS project was introduced in 1998. The intention was to achieve a more market-oriented operation of DISKOS. In light of this, a completely new contract structure was established between the various partners.

The collaboration in the DISKOS group is headed by the Norwegian Petroleum Directorate. The costs of development and operation will be divided among the users of the system.

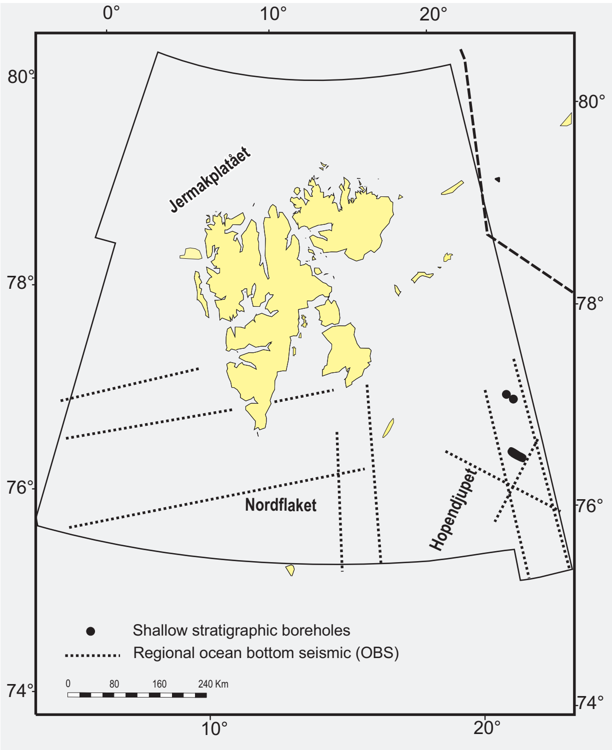
SAMBA
In recent years, the Norwegian Petroleum Directorate has been in the forefront with regard to the use of databases and analysis tools. This has provided great advantages in connection with production of reports and analyses, and in the delivery of final reports with a high level of quality to our customers. The SAMBA project has been established in order for the Norwegian Petroleum Directorate to maintain good, quality-controlled databases based on modern IT technology.

In this project, particular emphasis is placed on systematizing and integrating information which provides the Norwegian Petroleum Directorate with a better overview of the activities on the shelf. The SAMBA data base will contain information regarding production licenses, companies linked to the Norwegian Shelf, unitizations, resource estimates for discoveries and fields, historical and forecasted oil and gas production, costs, investments and income.

The project also emphasizes use of standards found in the market. POSC's (Petrotechnical Open Software Cooperation) Epicentre database is used in the data modeling.

SAMBA was started as a pilot project in 1996, and the first system modules were put into use by the Norwegian Petroleum Directorate in 1997. As of 1 January 1999, the system consists of the following modules: company, production license, agreement-based areas (units), fields, discoveries, deposits, resource estimates.

Figure 5.1.2
Shallow stratigraphic boreholes and regional ocean bottom seismic (OBS)



The plan is to expand this in 1999 with modules for prospects in connection with exploration activity and for profiles for oil/gas sales, costs, investments and income.

SAMBA was a central tool for the Norwegian Petroleum Directorate in connection with the autumn's national budget reporting to the Ministry of Petroleum and Energy. The entire resource accounting is now found in the database. Provisions have been made which mean that the data is easily accessible both for the ordinary end user in the Norwegian Petroleum Directorate and for an advanced user who wants to go into the database in more detail on his/her own in order to analyze the data.

5.1.2 OTHER PROJECTS

THE NORWEGIAN PETROLEUM DIRECTORATE'S GEOPHYSICAL AND GEOLOGICAL SURVEYS IN 1998

Geophysical surveys
Coastal areas - The Norwegian Petroleum Directorate has completed processing of 900 km 2D seismic that was collected during 1997 along the coast of the Møre and Trøndelag counties. Also, the detailed multi-beam echo soundings collected during this geophysical mission have been processed.

The northern Barents Sea - 2561 line kilometers of regional seabed seismic (OBS) were collected, divided among ten lines in the northern Barents Sea (Figure 5.1.2). The Institute of Solid Earth Physics (University of Bergen) was the operator for this collection of data.

The Norwegian Petroleum Directorate has completed processing of 283 km of seismic reflection data that was collected in 1997 on Nordflaket, to the northwest of Bjørnøya.

Geological surveys
Six shallow stratigraphic boreholes were drilled in the northern Barents Sea (Figure 5.1.2). In spite of very bad ice conditions, a total of 633 meters of core material were collected from the six drilling locations. The purpose of these shallow stratigraphic drillings is to supplement seismic mapping with geological information in the form of core samples of firm rocks under the uncompacted Quaternary material. The cores include rocks from the Triassic, Jurassic and Cretaceous Ages. IKU Petroleumsforskning was the operator for the collection.

5.2 PROJECTS IN THE AREAS OF SAFETY AND WORKING ENVIRONMENT

Basis study - maintenance management
In the autumn of 1996, the Norwegian Petroleum Directorate started a project to develop a method for systematic and comprehensive evaluation of the companies' own maintenance systems. Through this project, the Directorate wants to contribute to a general enhance-

ment of the quality of the operating companies' systems for managing safety-related maintenance, and to provide the companies with greater predictability with regard to the Norwegian Petroleum Directorate's expectations and requirements in this area.

The method has been developed in cooperation with the nuclear power and aviation industries, and has been tested over the course of four years in a series of pilot projects where several operating companies have participated. Experience gained from the pilot projects has provided valuable information for further development of a management model for safety-related maintenance, and for the Norwegian Petroleum Directorate's work on developing guidelines, which were published in 1998.

The basis study has also had a noticeable synergy effect in the industry in that several companies have used the method on their own initiative in their improvement measures.

Risk profile - consequences of organizational change processes

The Norwegian Petroleum Directorate employed the work of consultants with a view towards examining whether the organizational change processes that have been implemented in the petroleum activities in recent years can change the risk scenario, in other words, the relationship between the various contributions to the total risk. The study has included an evaluation of the significance of both organizational and technological changes, as well as changes related to the introduction of new information and communication technology.

Method for investigation of incidents

The Norwegian Petroleum Directorate employed the work of consultants with a view towards clarifying how human, technical and organization factors, as well as the interplay between these factors, contribute to the occurrence of undesirable incidents.

A method for investigation of incidents has been developed through this project. The method entails the systematic identification of human, technological or organizational causes at a level that makes it possible to prevent similar incidents from occurring again.

Survey of cancer risk

The Norwegian Petroleum Directorate participates with financial and professional support in a project started by the Cancer Registry of Norway in order to survey cancer risk among employees in offshore petroleum activities. The project also receives financial support from the Norwegian Oil Industry Association, the Norwegian Federation of Trade Unions, the Confederation of Norwegian Business and Industry and the Ministry of Local Government and Regional Development.

The background for the project is recognition of the fact that a number of physical, chemical and psycho-social working environment factors are unique to the petroleum activities. In addition, the organization of the work has consequences for nutrition, living conditions, social life and lifestyle. The project aims at surveying the frequency of cancer among former and current employees in the activities, and to examine whether a potential excess frequency may be related to the working environment and/or social conditions.

During the course of 1998, work has continued on identification of groups that will be followed over a lengthy period of time, in other words, those who have worked on the Norwegian shelf since the activities started and up to the present time. A questionnaire that will be used to chart the workers' exposure to potential carcinogens has been sent to everyone included in the survey, and processing of the responses has begun. The group that will be examined will be followed for many years in the future with regard to the development of cancer, and it will probably take many years before any conclusion can be drawn as to whether work on the shelf entails increased cancer risk.

The Norwegian Petroleum Directorate concluded its direct involvement in the project in 1998, however, the work will continue under the Cancer Registry.

Chemical exposure - "the Trondheim Project"

The Norwegian Petroleum Directorate has participated in the project group for the project entitled "Exposure to epoxy and polyurethane products and the scope of skin and respiratory diseases in connection with surface treatment" (often commonly referred to as "the Trondheim Project"), being carried out by the Department of Occupational Medicine at the Regional Hospital in Trondheim.

The background for the study is inter alia to obtain knowledge regarding exposure factors for personnel in connection with the application of various paint products. This is important in order to conduct risk analysis of dangers to health in connection with the various paint products, as well as to evaluate the effect of preventive measures. A questionnaire study has been conducted to chart the scope of work-related skin and respiratory ailments. The study showed that nearly half of those questioned stated that they experienced such ailments. The plan is to conduct an occupational hygiene study and conduct measurements on the basis of the information that emerges from the questionnaire.

Framework conditions, construction and operation of process facilities

In 1998, the Norwegian Petroleum Directorate has continued a project with SEVU which has had the goal of strengthening expertise regarding oil and gas processing as a foundation for the Directorate's framework-setting activities in the area of process technology. The project has included mapping of international frameworks (directives, etc.), relevant standards, operational factors and new technology in this area. The results of this work have been passed on to the Directorate's staff in this technical discipline in the form of courses.

5.3 THE NORWEGIAN PETROLEUM DIRECTORATE'S PARTICIPATION IN RESEARCH AND DEVELOPMENT PROGRAMS

In 1998, the Norwegian Petroleum Directorate has been involved in several public research programs and forums:

Offshore 2010

Offshore 2010 is a research program for user-controlled research and development in the petroleum sector. The program is administered by the Industry and Energy Section (IE) in the Research Council of Norway (NFR). The Norwegian Petroleum Directorate is a member of the board of Offshore 2010.

Petroforsk

Petroforsk is a research program for fundamental petroleum research. The program is organized by the Science and Technology Section (NT) in the Research Council of Norway. The Norwegian Petroleum Directorate is a member of the program board of Petroforsk.

Petropol

Petropol is a research program that addresses internationalization and adjustment - new challenges for the Norwegian petroleum industry. The program is administered by the Cultural and Social Section (KS) in the Research Council of Norway. The Norwegian Petroleum Directorate is a member of the program board of Petropol.

CORD

CORD is a forum where the oil industry and the research communities meet to discuss, define and initiate cost-effective production development through cooperation in R&D projects. The Research Council of Norway is responsible for administrative coordination of the program and SINTEF has the secretariat. The Norwegian Petroleum Directorate is on CORD's board of directors.

Center for Operations and Maintenance

The Center for Operations and Maintenance is a foundation that addresses development of expertise and R&D projects within operations and maintenance, both for the petroleum industry and for other industries. Stavanger College (HiS) is responsible for the technical aspects and the Norwegian Petroleum Directorate participates in the foundation's technical council.

6. Organization

6.1 DELEGATIONS

The duties of the Norwegian Petroleum Directorate are set out in the special instructions of 1 October 1992. Duties have also been assigned to the Norwegian Petroleum Directorate by delegation of authority. Such authority is delegated either directly pursuant to acts/regulations or by individual administrative decisions by a superior authority. Delegation applies to:

a) The Petroleum Act, Act 29 November 1996 no 72,
Including:
the Petroleum Regulations, Royal Decree 27 June 1997
the Safety Regulations, Royal Decree 27 June 1997
the Management Systems Regulations, Royal Decree 27 June 1997
the Safety Zone Regulations, Royal Decree 9 October 1987

b) The Working Environment Act, Act 4 February 1977, no 4,
Including:
the Working Environment Regulations, Royal Decree 27 November 1992
c) The CO_2 Act, Act 21 December 1990, no 72
d) The Tobacco Act, Act 9 March 1973, no 14
e) Act relating to scientific research and exploration for and exploitation of subsea natural resources other than petroleum resources, Act 21 June 1963 no 12,
Including:
Regulations relating to scientific research for natural resources on the Norwegian continental shelf, etc., Royal Decree 31 January 1969
Regulations concerning safe practices in scientific research and exploration for petroleum deposits on Svalbard, Royal Decree 25 March 1988

6.2 ORGANIZATIONAL CHANGES

During October 1998, it was decided that the Petroleum Resource Management Division would be reorganized into a team-based model as from 1 February 1999. The Division will be led by a team composed of the Division Director, four technical coordinators and eight process advisors. In addition, there are to be approximately 40 self-run teams that are to work on product-related tasks.

6.3 STAFF

At the end of 1998, the Norwegian Petroleum Directorate had 367 employees. Seventeen employees were on leave. Fifty-eight per cent of the employees are men and 42 per cent are women.

Twenty-one new employees were hired in permanent positions. Of these, two came from oil-related activities, 15 from other private industry or the public sector and two came directly from educational institutions.

Twenty-four staff members have left their positions, six of these as retirees. This represents 6.6 per cent of the positions.

The work on a common plan for comprehensive development of competence was nearly completed in 1998. New documents have been stipulated for personnel policy, salary policy and senior policy. As a part of the senior policy, all managers and employees between the ages of 50 and 55 have participated in mid-life seminars.

6.4 BUDGET/ECONOMY

Expenses

A total of NOK 269,093,064 was spent on the Norwegian Petroleum Directorate's operations in 1998.

The amount was appropriated as follows:

Operating costs	228 175 247
Supervision costs	11 356 877
Geological and geophysical surveys	29 558 338
Total	**269 090 064**

Of the operating budget, payroll costs account for NOK 145,560,092 (including employers' contribution), lease and operation of buildings account for NOK 36,662,913, and expenses in connection with consultancy assistance accounted for NOK 6,796,781.

The remainder, NOK 39,155,461, covers expenses related to travel, training, electronic data processing (EDP) operations, new investments in equipment, etc.

In addition to its regular operations, the Norwegian Petroleum Directorate is responsible for:

Cooperation projects	2 481 685
Administration of research program	1 208 073
Contribution to the PETRAD foundation	3 000 000
Project cooperation vis-à-vis Eastern Europe	1 289 862
Total	**7 979 620**

Revenues

In addition to paid production royalties, area fees and carbon dioxide taxes totaling NOK 7,510,402,618, the Norwegian Petroleum Directorate received NOK 109,725,008 in revenues:

Fee and tax income	1 454 449
Commission and cooperation income	5 382 309
Reimbursed supervision costs	49 322 486
Sale of survey material	37 364 476
Sale of publications	3 803 052
Miscellaneous income	2 185 624
Kindergarten fees	2 843 146
Reimbursed for job schemes	760 193
Reimbursed for maternity/adoption allowances	1 450 486
Reimbursed for apprentices	106 000
Reimbursed from other government bodies	5 052 787
Total	**109 725 008**

6.5 INFORMATION

In 1998, the Norwegian Petroleum Directorate launched its new periodical, the Norwegian Petroleum Diary (Sokkelspeilet). Two editions were published during the autumn. The publication will be issued quarterly, in both Norwegian and English versions.

The main objective of the Norwegian Petroleum Diary is to reflect the activity on the Norwegian continental shelf, and thereby to highlight the challenges which lie there. The periodical will provide background information and assess consequences, contexts and ripple effects, as well as focus on the main trends that affect activities in the Norwegian oil industry at any given time. The target group for the periodical consists of the authorities in Norway and cooperating countries, the oil, service and contracting industries, local, national and international business and industry, schools, media, labor unions, employees in the oil industry, research communities and society at large.

The primary focus of the Norwegian Petroleum Diary is not technology, but rather on lending a voice to the people and the milieus behind the technology. Boldness, honesty and diversity will be the trademark of the publication through its selection of material, approach and graphic design. The goal is that the Norwegian Petroleum Directorate, through the Norwegian Petroleum Diary, will create enthusiasm for and interest in our tasks, and in Norwegian oil activities.

The annual report occupies a central position in the Directorate's information activities, as does the continental shelf map, which was published with production licenses updated as of 1 June 1998. In addition, the Directorate issued a number of publications in 1998, which are listed in the next section. Forty-four press releases have been issued during the year, most of them in connection with the conclusion of exploration wells. Three issues of the Directorate's internal magazine *Oss Direkte* were published.

The Norwegian Petroleum Directorate's home page on Internet may be found at http://www.npd.no, and contains inter alia special reports and information concerning the Directorate's sphere of responsibility. Press releases, job vacancies and references to new publications are entered continuously. The information is available in both Norwegian and English, and is searchable. The public can subscribe to press releases by registering their e-mail address on the home page. There were an average of 22,400 visits to the home page per month, half from Norway and the remainder divided among 65 countries.

Use of the Nordic reference database OIL on the Internet (http://www.interpost.no/oil) increased from about 2,750 to about 3,500 hits per month divided among approximately 600-700 different institutions. The operating companies are the largest users of OIL. Links have been set up from/to some newspaper and periodical articles, which are thus accessible in full text format from the Internet. There was also an increase in the number of inquiries for articles and documents handled by the library.

More than 1000 inquiries for inspection of documents under the Freedom of Information Act were processed. This was an increase of 75 per cent from last year, and constitutes the highest number of inquiries to date in the 1990s. Together with several other government bodies, the Norwegian Petroleum Directorate now participates in the governmental project Electronic Mail Journal. The project, which is under the direction of the Norwegian Central Information Service, has the goal of promoting press publicity. Selected groups from the Norwegian press receive access to a database that contains the complete text of the governmental bodies' public journals.

In 1998, the Norwegian Petroleum Directorate terminated its receipt of information by telex. Messages from all license committees are now mainly received via electronic mail.

6.6 PUBLICATIONS RELEASED IN 1998

Acts, regulations and guidelines

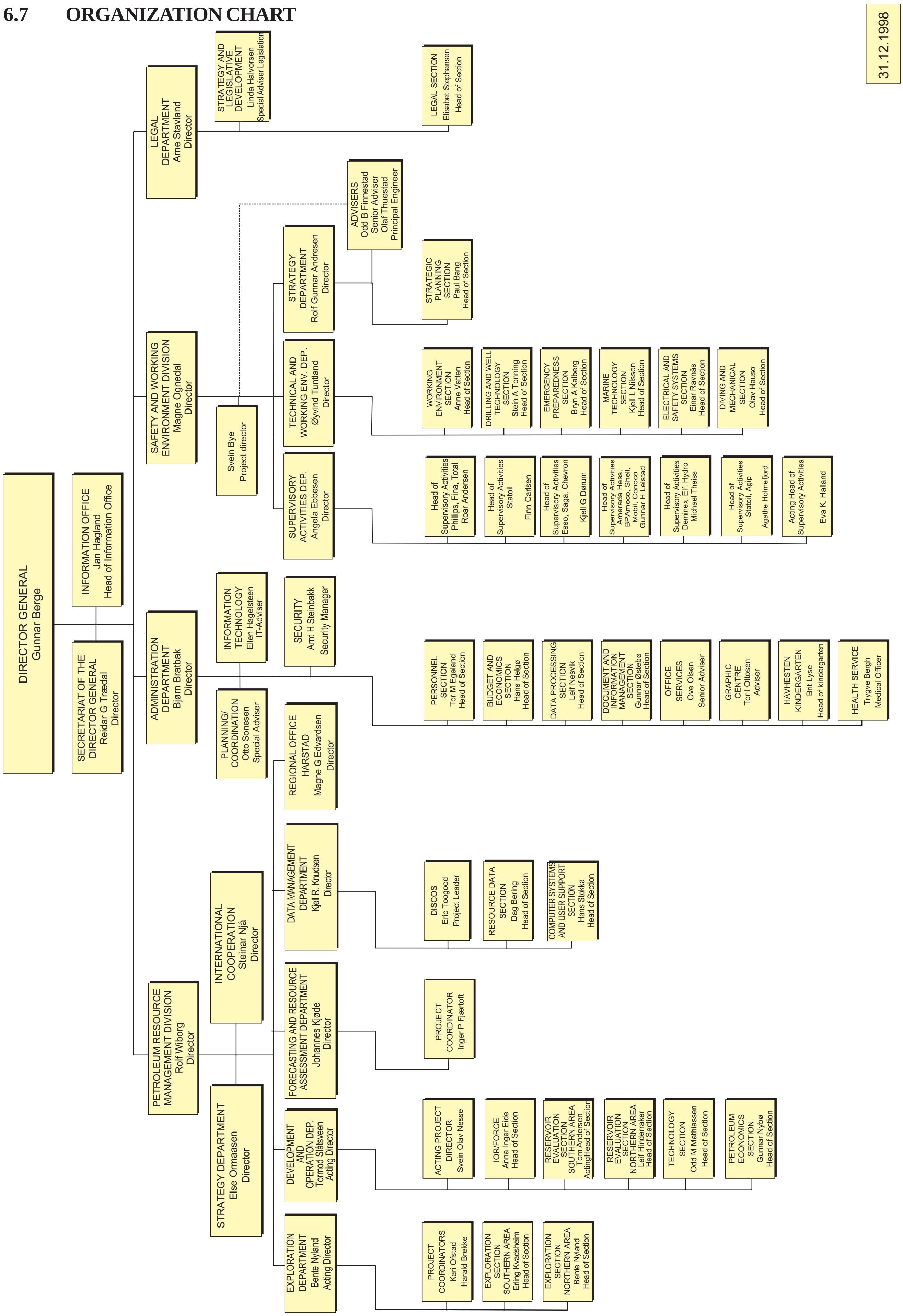
- Compilation of Acts, regulations and provisions for the petroleum activities in 1998.
  An updated compendium of the acts, regulations and guidelines applicable to the Norwegian continental shelf. Issued 1 June 1998.
- Act relating to worker protection and working environment
- Regulations to Act relating to petroleum activities
- Regulations relating to the Petroleum Register
- Regulations relating to safety in the petroleum activities
- Regulations relating to management systems to comply with authority requirements, etc.
- Regulations relating to reimbursement of expenses for supervision of safety, working environment and resource management, etc.
- Regulations relating to drilling and well activities and geological data collection, etc.
- Regulations relating to lifting appliances and lifting gear, etc.
- Regulations relating to load-bearing structures, etc.
- Regulations relating to marking of installations, etc.
- Regulations relating to electrical installations, etc.
- Regulations relating to environmental data, etc.
- Regulations relating to pipeline systems, etc.
- Regulations relating to process and auxiliary facilities, etc.
- Regulations relating to safety and communication systems, etc.
- Regulations relating to explosion and fire protection, etc.
- Regulations relating to systematic follow-up of the working environment, etc.
- Regulations relating to fishery expert on board seismic vessels, etc.

- Regulations relating to fiscal measurement of oil and gas, etc.
- Regulations relating to measurement of fuel and flare gas for calculation of CO_2 tax, etc.
- Regulations relating to manned underwater operations, etc.
- Regulations relating to implementation and use of risk analyses, etc.
- Regulations relating to emergency preparedness in the petroleum activities.
- Orientation concerning the arrangement of regulatory supervision relating to safety and the working environment, etc.

Other publications

- List of publications issued by the Norwegian Petroleum Directorate (Norwegian)
- Sokkelspeilet (English version: Norwegian Petroleum Diary)
- Norwegian Petroleum Diary
- Norwegian Petroleum Directorate Annual Report 1997 (Norwegian and English versions)
- Report from the DSYS diving data base in 1997 (Norwegian)
- A Comparative Study of Risk and Safety Perception of Norwegian and UK Offshore Personnel
- Report on hyperbaric evacuation (Norwegian)
- Project report - Evacuation and Rescue Means
- Loss of fluids in connection with diving (Norwegian)
- Norwegian Geochemical Standards Newsletter, Vols. 1-3
- NPD - Contribution No. 39
- Licenses, Areas, Area-coordinates, Exploration Wells
- Borehole list - Exploration Drilling
- Development Wells

6.7 ORGANIZATION CHART



7. Statistics and summaries

7.1 EXPLORATION LICENSES AND PRODUCTION LICENSES

7.1.1 NEW EXPLORATION LICENSES

As of 31 December 1998, a total of 252 exploration licenses have been granted. These licenses are valid for three years. The following licenses were granted in 1998:

Company	License No.
Elf Petroleum Norge AS	248
Total Norge A.S.	249
Den norske stats oljeselskap a.s	250
Enterprise Oil Norge Ltd.	251
BP Norge UA	252

7.1.2 SCIENTIFIC EXPLORATION

As of 31 December 1998, a total of 316 licenses for scientific exploration have been granted on the Norwegian continental shelf. As illustrated in Table 7.1.2, ten such licenses have been granted in 1998.

7.1.3 NEW PRODUCTION LICENSES

Eight production licenses were granted in 1998, of which five were split-offs, in other words, a part of the area in a production license is split off and a new production license is issued for the split-off area, cf. Chapter 3, Sections 3-10 of the Petroleum Act. This applies to production licenses 019 C, 037 B, 053 B, 102 B and 103 B in 1998. Four companies were granted operatorships. Statoil received four and BP, Hydro and Elf received one each, see Table 7.1.3.a. An overview of the licensing rounds with production licenses, granted area, relinquished and current area is shown in Table 7.1.3.b. Table 7.1.3.c shows Norwegian and foreign shares in the licensing rounds. Licensees, operators and other information on active production licenses is shown in Table 7.1.6.

Table 7.1.2
Licenses for scientific exploration for natural resources

License	Name	Subject			Area
		Geo-physics	Geology	Other	
307/98	Institüt für Meereskunde an der Universität Kiel			Marine geological	Skagerrak
308/98	Polar Marine Geosurvey Expedition			Seabed samples	Vøring Plateau and Bjørnøya
309/98	Alfred-Wegener-Institut für Polar- und Meeresforschung			Hydrographic	West of Svalbard
310/98	University of Tromsø			Marine geological	Northeastern Norwegian Sea and Western Barents Sea
311/98	P. P. Shirshov Institute of Oceanology	X	X	Biology	Norwegian Sea
312/98	Alfred-Wegener-Institut für Polar- und Meeresforschung	X	X	Biology	Northwestern Barents Sea, east and north of Greenland and Framstredet
313/98	University of Tromsø			Marine geological	Vågsfjorden, Malangen, Balsfjorden and Ramsfjorden, Troms
314/98	Stockholm University	X			Skagerrak
315/98	P. P. Shirshov Institute of Oceanology Russian Academy of Siences			Biology Hydrographic	Norwegian Sea
316/98	Institüt für Meereskunde an der Universität Kiel		X		Skagerrak

Table 7.1.3.a
Production licenses granted in 1998

Prod. lic.	Granted valid to:	Blocks		Licensees:	Share	SDFI
019 C	1998/09/14	2/1		AS Pelican	4.000000	
	2011/09/01	7/12	o	BP Petroleum Dev. Of Norway AS	56.000000	
				Den norske stats oljeselskap a.s	30.000000	(30.000)
				Norske Aedc AS	5.000000	
				Norske Moeco AS	5.000000	
037 B	1998/09/14	33/12		A/S Norske Shell	10.000000	
	2009/08/10		o	Den norske stats oljeselskap a.s	50.000000	(30.000)
				Enterprise Oil Norwegian AS	1.041667	
				Esso Expl. & Prod. Norway AS	10.000000	

Prod. Lic.	Granted valid to:	Blocks		Licensees:	Share	SDFI
				Mobil Development Norway AS	15.000000	
				Norske Conoco AS	12.083334	
				Saga Petroleum ASA	1.875000	
053 B	1998/09/14	30/6		Den norske stats oljeselskap a.s	59.400000	(45.400)
	2017/04/06			Elf Petroleum Norge AS	9.333000	
				Mobil Development Norway AS	7.000000	
			o	Norsk Hydro Produksjon AS	12.250000	
				Saga Petroleum ASA	7.350000	
				Total Norge AS	4.667000	
102 B	1998/01/22	25/5		Den norske stats oljeselskap a.s	50.000000	(30.000)
	2025/03/01		o	Elf Petroleum Norge AS	30.000000	
				Total Norge AS	20.000000	
103 B	1998/01/22	25/7		Amerada Hess Norge AS	12.500000	
	2021/03/01			Den norske stats oljeselskap a.s	50.000000	(30.000)
			o	Norske Conoco AS	37.500000	
114 C	1998/09/03	9/1		Deminex Norge AS	10.000000	
	1999/09/03	9/2	o	Den norske stats oljeselskap a.s	65.000000	(30.000)
		9/4		Saga Petroleum ASA	25.000000	
128 B	1998/01/30	6508/1	o	Den norske stats oljeselskap a.s	70.000000	(55.000)
	2004/01/30			Enterprise Oil Norwegian AS	6.000000	
				Norsk Agip AS	6.900000	
				Norsk Hydro Produksjon AS	8.100000	
				Saga Petroleum ASA	9.000000	
237	1998/01/30	6407/3	o	Den norske stats oljeselskap a.s	60.500000	(46.950)
	2027/04/10			Mobil Development Norway AS	7.350000	
				Neste Petroleum AS	7.000000	
				Norsk Agip AS	7.900000	
				Norsk Hydro Produksjon AS	2.600000	
				Saga Petroleum ASA	7.000000	
				Total Norge AS	7.650000	

Table 7.1.3.b
Production licenses and acreages as of 31 December 1998

License round	Granted day.mo.yr	Prod. license no.	Number of blocks* granted	relinq.	Area granted km^2	Area relinquished km^2	Area in prod. lic.s km^2
1.	1.9.1965	001-021	74	59	39842.476	37125.960	2716.516
	7.12.1965	022-022	4	4	2263.565	2263.565	
or.	25.8.1995	018B	1		102.503		102.503
	12.9.1977	019B	2		617.891	475.256	142.635
or.	14.9.1998	019C	2		323.219		323.219
2.	23.5.1969	023-031	9	2	4107.833	2682.948	1424.885
	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	036-036	1		523.937	326.571	197.366
or.	10.8.1973	037-037	2		586.834	304.356	282.478
or.	14.9.1998	037B	1		9.199		9.199

License round	Granted day.mo.yr	Prod. license No.	Number of blocks* granted	relinq.	Area granted km^2	Area relinquished km^2	Area in prod. lic.s km^2
3.	1.4.1975	038-040					
		and 042	7	5	1840.547	1665.310	175.237
	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
	7.11.1977	047	2	2	368.363	368.363	
	18.2.1977	048	2	1	321.500	203.498	118.002
	23.12.1977	049	1	1	485.802	485.802	
or.	16.6.1978	050	1		500.509	151.962	348.547
or.	11.8.1995	050B	1		98.403		98.403
4.	6.4.1979	051-058	8	2	4007.887	2671.790	1336.097
or.	14.9.1998	053B	1		8.494		8.494
5.	18.1.1980	059-061	3	3	1108.078	1108.078	
	27.3.1981	062-064	3	1	1099.522	876.292	223.230
	23.4.1982	073-078	6	2	2311.912	1890.425	421.487
6.	21.8.1981	065-072	9	3	3218.945	2263.008	955.937
or.	20.8.1982	079-079	1		102.167		102.167
7.	10.12.1982	080-084	5	5	2082.966	2082.966	
or.	8.7.1983	085-085	3		1621.160	725.816	795.344
or.	11.9.1992	085B	2		27.166		27.166
8.	9.3.1984	086-100	17	3	6338.273	4383.944	1954.329
9.	1.3.1985	101-111	13	3	5293.054	3814.125	1478.929
or.	22.1.1998	102B-103B	2		49.829		49.829
or.	26.7.1985	112-112	1		260.215	249.821	10.394
10a	23.8.1985	113-120	9	2	3075.433	2334.158	741.275
or.	11.8.1995	114B	1		11.059		11.059
10b	28.2.1986	121-128	9	3	3828.258	2922.587	905.671
or.	30.1.1998	128B	1		4.220		4.220
or.	11.7.1986	129-129	1	1	225.393	225.393	
11.	10.4.1987	130-137	11	7	4163.711	3873.036	290.675
	29.5.1987	138-142	11	8	2975.807	2629.076	346.731
12a	8.7.1988	143-153	16	2	4701.019	2580.212	2120.807
12b	9.3.1989	154-162	13	7	5031.262	3477.943	1553.319
13.	1.3.1991	163-184	36	12	12076.889	5227.659	6849.230
or.	13.9.1991	185-185	1		25.535		25.535
14.	10.9.1933	186-202	31		10509.915	535.510	9974.405
15.	2.2.1996	203-220	47		17405.807		17405.807
BHP	30.5.1997	221-236	19		5182.108		5182.108
or.	30.1.1998	237	1		17.567		17.567
			406	141	153018.985	92816.509	60202.476

* block or part of block   or = awarded outside of licensing rounds   BHP = Barents Sea Project

Table 7.1.3.c
Licensing rounds - Norwegian and foreign interests and operatorships at award

License round	Year	Number of blocks	Interest % Norwegian	Interest % foreign	Operator % Norwegian	Operator % foreign
1	1965	78	8	92	0	100
2	1969-1971	14	15	85	0	100
Statfjord (037)	1973	2	52	48	0	100
PL 037B	1998	1	52	48	100	0
3	1974-1978	22	58	42	63	37
PL 018B	1995	1	8	92	0	100
Ula (19B)	1977	2	50	50	0	100
PL 019C	1998	2	50	50	0	100
Gullfaks (050)	1978	1	100	0	100	0
PL 050B	1995	1	100	0	100	0
4	1979	8	58	42	68	32
PL 053	1998	1	100	0	100	0
5	1980	12	66	34	92	8
6	1981	9	64	36	50	50
Oseberg (079)	1982	1	100	0	100	0
7	1982	5	60	40	80	20
Troll (085)	1983	3	100	0	100	0
PL 085B	1992	2	69	31	100	0
8	1984	17	60	40	60	40
9	1985	13	60	40	55	45
PL 102B and 103B	1998	2	50	50	0	100
PL 112	1985	1	67	33	0	100
PL 114C	1998	3	90	10	100	0
10A	1985	9	64	36	67	33
PL 114B	1995	1	90	10	100	0
10B	1986	9	65	35	56	44
PL 128B	1998	1	87	13	100	0
PL 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
PL 185	1991	1	69	31	100	0
14	1993	31	68	32	100	0
15	1996	47	53	47	44	56
Barents Sea Project	1997	19	56	44	69	31
PL 237	1998	1	70	30	100	0

7.1.4 TRANSFER OF INTERESTS AND CHANGES IN OPERATOR

Transfer of interests

During 1998, 41 transfers of interest have been approved under Section 61 of the Act 22 March 1985 no 11 or the Act 29 November 1996 no 72 relating to petroleum activities. These are shown in Table 7.1.4.

Changes in operator

Three changes in operator were approved in 1998:

Production license 103

Operator: Amerada Hess Norge AS took over the operatorship from Norske Conoco A/S. Approved on 19 October 1998.

Production license 143

Operator: Norsk Hydro Produksjon AS took over the operatorship from BP Petroleum Development of Norway AS. Approved on 29 December 1998.

Production license 157

Operator: Norsk Chevron AS took over the operatorship from Den norske stats oljeselskap a.s. Approved on 6 January 1998.

Table 7.1.4
Transfer of interest 1998

Prod. Lic.	To	Share	SDFI	Date
019 C	BP Petroleum Dev. of Norway AS	4.778		16.09.1998
019 C	Norsk Hydro Produksjon AS	20		30.11.1998
019 C	AS Pelican	0.222		16.09.1998
025	Den norske stats oljeselskap a.s	11.8		03.06.1998
036	Norsk Hydro Produksjon AS	15		01.01.1998
037 B	Norsk Hydro Produksjon AS	9		16.09.1998
037 B	Saga Petroleum ASA	4.125		16.09.1998
037 B	Den norske stats oljeselskap a.s	35	43	16.09.1998
040	Total Norge AS	28.8		01.01.1998
046	Elf Petroleum Norge AS	1		01.01.1998
053 B	Norsk Hydro Produksjon AS	28.35		16.09.1998
064	Total Norge AS	5		01.01.1998
065	BP Petroleum Dev. of Norway AS	20		23.07.1998
078	Total Norge AS	15		01.01.1998
093	Norsk Chevron AS	7.56		09.02.1998
100	Total Norge AS	35		01.01.1998
103	Amerada Hess Norge AS	37.5		01.01.1998
110	Total Norge AS	20		01.01.1998
143	Norsk Hydro Produksjon AS	15		29.12.1998
143	Phillips Petroleum Norsk AS	10		22.12.1998
156	Norsk Chevron AS	20		09.02.1998
157	Norsk Chevron AS	30		09.02.1998
158	Norsk Chevron AS	20		09.02.1998
159	Enterprise Oil Norwegian AS	20		17.08.1998
172	Norske Conoco A/S	1.67		01.12.1998
172	Mobil Development Norway AS	2.78		01.12.1998
176	Norsk Chevron AS	15		09.02.1998
176	A/S Norske Shell	10		21.12.1998
182	Norsk Chevron AS	20		09.02.1998
190	Total Norge AS	10		01.01.1998
195	Norsk Hydro Produksjon AS	5		29.12.1998

Prod. Lic.	From	Share	Date
019 C	BP Petroleum Dev. of Norway AS	20	30.11.1998
019 C	Norske AEDC A/S	5	16.09.1998
025	Total Norge AS	11.8	03.06.1998
036	Elf Petroleum Norge AS	15	01.01.1998
037 B	Norske Conoco A/S	12.083334	16.09.1998
037 B	Enterprise Oil Norwegian AS	1.041667	16.09.1998
037 B	Mobil Development Norway AS	15	16.09.1998
037 B	A/S Norske Shell	10	16.09.1998
037 B	Esso Expl. & Prod. Norway A/S	10	16.09.1998
040	Elf Petroleum Norge AS	28.8	01.01.1998
046	Total Norge AS	1	01.01.1998
053 B	Elf Petroleum Norge AS	9.333	16.09.1998
053 B	Saga Petroleum ASA	7.35	16.09.1998
053 B	Total Norge AS	4.667	16.09.1998
053 B	Mobil Development Norway AS	7	16.09.1998
064	Elf Petroleum Norge AS	5	01.01.1998
065	Enterprise Oil Norwegian AS	20	23.07.1998
078	Elf Petroleum Norge AS	15	01.01.1998
093	Den norske stats oljeselskap a.s	7.56	09.02.1998
100	Elf Petroleum Norge AS	35	01.01.1998
103	Norske Conoco A/S	37.5	01.01.1998
110	Elf Petroleum Norge AS	20	01.01.1998
143	BP Petroleum Dev. of Norway AS	15	29.12.1998
143	Amoco Norway AS	10	22.12.1998
156	Den norske stats oljeselskap a.s	20	09.02.1998
157	Den norske stats oljeselskap a.s	30	09.02.1998
158	Den norske stats oljeselskap a.s	20	09.02.1998
159	Total Norge AS	20	17.08.1998
172	Amerada Hess Norge AS	4.45	01.12.1998
176	Fina Production Licenses AS	10	21.12.1998
176	Den norske stats oljeselskap a.s	15	09.02.1998
182	Den norske stats oljeselskap a.s	20	09.02.1998
190	Enterprise Oil Norwegian AS	10	01.01.1998
195	BP Petroleum Dev. of Norway AS	5	29.12.1998

7.1.5 RELINQUISHMENTS AND SURRENDERS

There have been 15 relinquishments/surrenders of production licenses in 1998. In two of the production licenses the total area was relinquished. This is shown in Table 7.1.5.

Table 7.1.5
Relinquishments

Production license (PL)	Operator	Block	Original area km^2	Relinquished area km^2 in 1998	Area in PL km^2
009	Elf	9/5	2233.446	107.236	0.0
019 B	BP	2/1. 7/12	617.890	323.219	142.635
037	Statoil	33/12	586.834	9.199	282.478
053	Hydro	30/6	508.360	8.494	325.458
102	Elf	25/5	523.937	26.123	236.149
103	Conoco	25/7	527.805	23.706	240.271
144	Conoco	1/5. 1/6	336.500	147.602	188.898
153	Hydro	35/9. 36/7	993.138	208.138	784.143
157	Chevron	6406/12	452.584	226.038	226.546
158	BP	6407/8	448.529	224.390	224.139
159	Statoil	6507/3	424.012	186.753	237.259
168	Statoil	25/10	267.501	123.863	143.638
175	Statoil	6402/10. 6402/11	969.378	540.024	429.354
176	Shell	6407/11. 6407/12	905.169	488.154	417.015
188	Elf	17/3	535.510	535.510	0.0

7.1.6 LICENSEES IN ACTIVE PRODUCTION LICENSES

Tabell 7.1.6
Licensees in active production licenses as of 31 December 1998

Prod. Lic.	Awarded	Blocks		Licensees	Share	SDFI
001	65/09/01	25/11	O	Esso Expl. & Prod. Norway A/S	100,000000	
	11/09/01					
001 P	65/09/01	16/ 1		Enterprise Oil Norwegian AS	50,000000	
	11/09/01		O	Esso Expl. & Prod. Norway A/S	50,000000	
006	65/09/01	2/ 5		Amerada Hess Norge AS	28,333333	
	11/09/01	2/ 8	O	Amoco Norway Oil Company	28,333333	
		3/ 4		Elf Petroleum Norge AS	15,000000	
				Enterprise Oil Norwegian AS	28,333333	
008	65/09/01	2/ 6		Amerada Hess Norge AS	50,000000	
	11/09/01		O	Saga Petroleum ASA	50,000000	
011	65/09/01	1/ 3	O	A/S Norske Shell	50,000000	
	11/09/01	1/ 6		Amoco Norway Oil Company	30,000000	
		1/ 6		Norske Conoco A/S	20,000000	
		1/ 6				
018	65/09/01	1/ 5		Den norske stats oljeselskap a.s	1,000000	
	28/12/31	2/ 4		Elf Petroleum Norge AS	8,449000	
		2/ 7		Fina Production Licenses AS	30,000000	
		7/11		Norsk Agip AS	13,040000	
				Norsk Hydro Produksjon AS	6,700000	
			O	Phillips Petroleum Company Norway	36,960000	
				Saga Petroleum ASA	0,304000	
				Total Norge AS	3,547000	
018 B	95/08/25	1/ 6		Den norske stats oljeselskap a.s	1,000000	
	00/12/31			Elf Petroleum Norge AS	8,449000	
				Fina Production Licenses AS	30,000000	
				Norsk Agip AS	13,040000	
				Norsk Hydro Produksjon AS	6,700000	
			O	Phillips Petroleum Company Norway	36,960000	
				Saga Petroleum ASA	0,304000	
				Total Norge AS	3,547000	
019	65/09/01	7/12		AS Pelican	5,000000	
	11/09/01		O	BP Petroleum Dev. of Norway AS	80,000000	
				Svenska Petroleum Exploration AS	15,000000	
019 B	77/09/12	2/ 1		AS Pelican	4,000000	
	11/09/01	7/12	O	BP Petroleum Dev. of Norway AS	56,000000	
		7/12		Den norske stats oljeselskap a.s	30,000000	(30,000)
				Norske AEDC A/S	5,000000	
				Norske MOECO A/S	5,000000	
019 C	98/09/14	2/ 1		AS Pelican	4,222000	
	11/09/01	7/12	O	BP Petroleum Dev. of Norway AS	40,778000	
		7/12		Den norske stats oljeselskap a.s	30,000000	(30,000)
				Norske MOECO A/S	5,000000	
				Norsk Hydro Produksjon AS	20,000000	
024	69/05/23	25/ 1		Den norske stats oljeselskap a.s	20,000000	
	15/05/23		O	Elf Petroleum Norge AS	26,420000	
				Norsk Hydro Produksjon AS	32,870000	
				Total Norge AS	20,710000	
025	69/05/23	15/ 3		Elf Petroleum Norge AS	33,200000	
	15/05/23			Norsk Hydro Produksjon AS	10,000000	
			O	Den norske stats oljeselskap a.s	46,800000	
				Total Norge AS	10,000000	
026	69/05/23	25/ 2		Den norske stats oljeselskap a.s	5,000000	
	15/05/23		O	Elf Petroleum Norge AS	41,420000	

Prod. Lic.	Awarded	Blocks		Licensees	Share	SDFI
				Norsk Hydro Produksjon AS	32,870000	
				Total Norge AS	20,710000	
027	69/05/23	25/ 8	O	Esso Expl. & Prod. Norway A/S	100,000000	
	15/05/23					
027 P	69/05/23	25/ 8		Enterprise Oil Norwegian AS	50,000000	
	15/05/23		O	Esso Expl. & Prod. Norway A/S	50,000000	
028	69/05/23	25/10	O	Esso Expl. & Prod. Norway A/S	100,000000	
	15/05/23					
028 P	69/05/23	25/10		Enterprise Oil Norwegian AS	50,000000	
	15/05/23		O	Esso Expl. & Prod. Norway A/S	50,000000	
029	69/05/23	15/ 6	O	Esso Expl. & Prod. Norway A/S	100,000000	
	15/05/23					
031	69/05/23	2/10		Fina Production Licenses AS	30,000000	
	15/05/23			Norsk Agip AS	18,260000	
			O	Phillips Petroleum Company Norway	51,740000	
032	69/05/30	2/ 9		Amerada Hess Norge AS	35,000000	
	15/05/30		O	Amoco Norway Oil Company	25,000000	
				Elf Petroleum Norge AS	15,000000	
				Enterprise Oil Norwegian AS	25,000000	
033	69/05/30	2/11		Amerada Hess Norge AS	25,000000	
	15/05/30		O	Amoco Norway Oil Company	25,000000	
				Elf Petroleum Norge AS	25,000000	
				Enterprise Oil Norwegian AS	25,000000	
034	69/11/14	30/ 5	O	A/S Norske Shell	100,000000	
	15/11/14					
035	69/11/14	30/11	O	A/S Norske Shell	100,000000	
	15/11/14	30/11				
036	71/06/11	25/ 4		Elf Petroleum Norge AS	18,702000	
	21/06/11			Marathon Petroleum Norge AS	46,904000	
			O	Norsk Hydro Produksjon AS	21,920000	
				Saga Petroleum ASA	6,611000	
				Total Norge AS	5,541000	
				AS Ugland Rederi	0,322000	
037	73/08/10	33/ 9		A/S Norske Shell	10,000000	
	09/08/10	33/ 9	O	Den norske stats oljeselskap a.s	50,000000	(30,000)
		33/12		Enterprise Oil Norwegian AS	1,041667	
				Esso Expl. & Prod. Norway A/S	10,000000	
				Mobil Development Norway AS	15,000000	
				Norske Conoco A/S	12,083334	
				Saga Petroleum ASA	1,875000	
037 B	98/09/14	33/12	O	Den norske stats oljeselskap a.s	85,000000	(73,000)
	09/08/10			Norsk Hydro Produksjon AS	9,000000	
				Saga Petroleum ASA	6,000000	
038	75/04/01	15/12		Den norske stats oljeselskap a.s	65,000000	(30,000)
	11/04/01	15/12	O	Saga Petroleum ASA	35,000000	
040	75/04/01	29/ 9		Den norske stats oljeselskap a.s	50,000000	(30,000)
	11/04/01	30/ 7		Total Norge AS	43,200000	
			O	Norsk Hydro Produksjon AS	6,800000	
043	76/08/06	29/ 6		Den norske stats oljeselskap a.s	50,000000	(30,000)
	12/08/06	30/ 4	O	Total Norge AS	50,000000	
044	76/08/27	1/ 9	O	Den norske stats oljeselskap a.s	71,880000	(30,000)
	12/08/27			Fina Production Licenses AS	15,000000	
				Norsk Agip AS	13,120000	
046	76/12/03	15/ 8	O	Den norske stats oljeselskap a.s	52,600000	(34,400)

Prod. Lic.	Awarded	Blocks		Licensees	Share	SDFI
	14/12/03	15/ 8		Elf Petroleum Norge AS	10,000000	
		15/ 9		Esso Expl. & Prod. Norway A/S	28,000000	
				Norsk Hydro Produksjon AS	9,400000	
048	77/02/18	15/ 5		Norsk Hydro Produksjon AS	9,300000	
	13/02/18		O	Den norske stats oljeselskap a.s	68,900000	(30,000)
				Elf Petroleum Norge AS	21,800000	
050	78/06/16	34/10	O	Den norske stats oljeselskap a.s	85,000000	(73,000)
	16/06/30			Norsk Hydro Produksjon AS	9,000000	
				Saga Petroleum ASA	6,000000	
050 B	95/08/11	34/10	O	Den norske stats oljeselskap a.s	85,000000	(73,000)
	01/08/11			Norsk Hydro Produksjon AS	9,000000	
				Saga Petroleum ASA	6,000000	
051	79/04/06	30/ 2	O	Den norske stats oljeselskap a.s	50,000000	(31,400)
	15/04/06			Norske Conoco A/S	25,000000	
				Total Norge AS	25,000000	
052	79/04/06	30/ 3		Deminex Norge AS	11,250000	
	15/04/06	30/ 3	O	Den norske stats oljeselskap a.s	55,000000	(37,000)
				Petro-Canada Norge AS	9,000000	
				Norske Deminex AS	2,250000	
				Svenska Petroleum Exploration AS	4,500000	
				Total Norge AS	18,000000	
053	79/04/06	30/ 6		Den norske stats oljeselskap a.s	59,400000	(45,400)
	17/04/06	30/ 6		Elf Petroleum Norge AS	7,000000	
			O	Norsk Hydro Produksjon AS	12,250000	
				Saga Petroleum ASA	7,350000	
				Total Norge AS	4,667000	
053 B	98/09/14	30/ 6		Den norske stats oljeselskap a.s	59,400000	(45,400)
	17/04/06		O	Norsk Hydro Produksjon AS	40,600000	
054	79/04/06	31/ 2		A/S Norske Shell	25,900000	
	30/09/30		O	Den norske stats oljeselskap a.s	58,800000	(40,800)
				Elf Petroleum Norge AS	3,104500	
				Norsk Hydro Produksjon AS	4,900000	
				Norske Conoco A/S	5,191020	
				Total Norge AS	2,104480	
055	79/04/06	31/ 4		Den norske stats oljeselskap a.s	46,000000	(33,400)
	17/04/06			Esso Expl. & Prod. Norway A/S	17,600000	
				Neste Petroleum AS	13,200000	
			O	Norsk Hydro Produksjon AS	23,200000	
057	79/04/06	34/ 4		Amerada Hess Norge AS	4,900000	
	15/04/06			Deminex Norge AS	24,500000	
				Den norske stats oljeselskap a.s	41,400000	(31,400)
				Enterprise Oil Norwegian AS	4,900000	
				Idemitsu Petroleum Norge a.s.	9,600000	
			O	Saga Petroleum ASA	14,700000	
062	81/03/27	6507/11	O	Den norske stats oljeselskap a.s	51,000000	(31,400)
	27/04/10			Neste Petroleum AS	9,800000	
				Norsk Hydro Produksjon AS	4,900000	
				Saga Petroleum ASA	9,800000	
				Total Norge AS	24,500000	
064	81/03/27	7120/ 8	O	Den norske stats oljeselskap a.s	74,250000	(30,000)
	17/03/27			Total Norge AS	5,000000	
				Norsk Hydro Produksjon AS	20,750000	
065	81/08/21	1/ 3		A/S Norske Shell	15,000000	
	22/01/01	1/ 3	O	BP Petroleum Dev. of Norway AS	55,000000	
				Den norske stats oljeselskap a.s	30,000000	(30,000)
066	81/08/21	2/ 2		Amerada Hess Norge AS	20,000000	
	20/01/01			Den norske stats oljeselskap a.s	50,000000	(30,000)
			O	Saga Petroleum ASA	25,000000	

Prod. Lic.	Awarded	Blocks		Licensees	Share	SDFI
				BP Petroleum Dev. of Norway AS	5,000000	
067	81/08/21	2/ 5		Den norske stats oljeselskap a.s	50,000000	(30,000)
	99/01/01		O	Norsk Agip AS	40,000000	
				Phillips Petroleum Norsk AS	10,000000	
069	81/08/21	7/ 8		Deminex Norge AS	5,000000	
	18/01/01			Den norske stats oljeselskap a.s	50,000000	(30,000)
				Norsk Hydro Produksjon AS	15,000000	
			O	Saga Petroleum ASA	30,000000	
070	81/08/21	7/11		Amoco Norway AS	14,700000	
	18/01/01	7/11		Den norske stats oljeselskap a.s	51,000000	(31,400)
			O	Norsk Hydro Produksjon AS	24,500000	
				Saga Petroleum ASA	9,800000	
072	81/08/21	16/ 7		Den norske stats oljeselskap a.s	50,000000	(30,000)
	18/01/01		O	Esso Expl. & Prod. Norway A/S	40,000000	
				Norsk Hydro Produksjon AS	10,000000	
073	82/04/23	6407/ 1	O	Den norske stats oljeselskap a.s	50,000000	(30,000)
	18/04/23			Norsk Hydro Produksjon AS	16,667000	
				Total Norge AS	33,333000	
074	82/04/23	6407/ 2	O	Den norske stats oljeselskap a.s	51,000000	(31,400)
	27/04/10			Mobil Development Norway AS	9,800000	
				Neste Petroleum AS	14,700000	
				Norsk Agip AS	14,700000	
				Saga Petroleum ASA	9,800000	
077	82/04/23	7120/ 7	O	Den norske stats oljeselskap a.s	75,000000	(30,000)
	18/04/23			Norsk Hydro Produksjon AS	15,000000	
				Total Norge AS	10,000000	
078	82/04/23	7120/ 9		Den norske stats oljeselskap a.s	50,000000	(30,000)
	18/04/23			Total Norge AS	25,000000	
			O	Norsk Hydro Produksjon AS	25,000000	
079	82/08/20	30/ 9		Den norske stats oljeselskap a.s	73,500000	(59,500)
	18/08/20		O	Norsk Hydro Produksjon AS	16,000000	
				Saga Petroleum ASA	10,500000	
085	83/07/08	31/ 3	O	Den norske stats oljeselskap a.s	82,000000	(73,000)
	30/09/30	31/ 5		Elf Petroleum Norge AS	2,000000	
		31/ 6	O	Norsk Hydro Produksjon AS	9,000000	
			O	Saga Petroleum ASA	6,000000	
				Total Norge AS	1,000000	
085 B	92/09/11	31/ 9	O	Den norske stats oljeselskap a.s	82,000000	(73,000)
	30/07/08	32/ 4		Elf Petroleum Norge AS	2,000000	
			O	Norsk Hydro Produksjon AS	9,000000	
			O	Saga Petroleum ASA	6,000000	
				Total Norge AS	1,000000	
086	84/03/09	6/ 3		Amerada Hess Norge AS	10,000000	
	20/03/09			Den norske stats oljeselskap a.s	70,000000	(30,000)
				Norsk Hydro Produksjon AS	10,000000	
			O	Saga Petroleum ASA	10,000000	
088	84/03/09	24/ 6		Den norske stats oljeselskap a.s	50,000000	(31,400)
	22/03/09		O	Total Norge AS	50,000000	
089	84/03/09	34/ 7		Deminex Norge AS	2,800000	
	24/03/09			Den norske stats oljeselskap a.s	55,400000	(51,000)
				Elf Petroleum Norge AS	5,600000	
				Esso Expl. & Prod. Norway A/S	10,500000	
				Idemitsu Petroleum Norge a.s.	9,600000	
				Norsk Hydro Produksjon AS	8,400000	
			O	Saga Petroleum ASA	7,700000	
090	84/03/09	35/11		Den norske stats oljeselskap a.s	50,000000	(30,000)
	24/02/09			Mobil Development Norway AS	25,000000	

Prod. Lic.	Awarded	Blocks		Licensees	Share	SDFI
			O	Norsk Hydro Produksjon AS	25,000000	
091	84/03/09	6406/ 3	O	Den norske stats oljeselskap a.s	50,000000	(30,000)
	20/03/09			Mobil Development Norway AS	33,000000	
				Saga Petroleum ASA	17,000000	
092	84/03/09	6407/ 6	O	Den norske stats oljeselskap a.s	50,000000	(30,000)
	20/03/09			Mobil Development Norway AS	40,000000	
				Saga Petroleum ASA	10,000000	
093	84/03/09	6407/ 9	O	A/S Norske Shell	16,200000	
	24/03/09			BP Petroleum Dev. of Norway AS	18,360000	
				Norsk Chevron AS	7,560000	
				Den norske stats oljeselskap a.s	57,880000	(57,880)
094	84/03/09	6506/12	O	Den norske stats oljeselskap a.s	44,000000	(26,400)
	27/04/10			Mobil Development Norway AS	14,700000	
				Neste Petroleum AS	9,800000	
				Norsk Agip AS	9,800000	
				Norsk Hydro Produksjon AS	4,900000	
				Saga Petroleum ASA	7,000000	
				Total Norge AS	9,800000	
095	84/03/09	6507/ 7		Den norske stats oljeselskap a.s	75,000000	(65,000)
	24/03/09			Neste Petroleum AS	5,000000	
			O	Norske Conoco A/S	20,000000	
097	84/03/09	7120/ 6		Amerada Hess Norge AS	11,250000	
	20/03/09	7120/ 6		Deminex Norge AS	10,000000	
				Den norske stats oljeselskap a.s	56,250000	(30,000)
			O	Norsk Hydro Produksjon AS	22,500000	
099	84/03/09	7121/ 4	O	Den norske stats oljeselskap a.s	50,000000	(30,000)
	20/03/09			Norsk Hydro Produksjon AS	12,500000	
				Total Norge AS	37,500000	
100	84/03/09	7121/ 7		Deminex Norge AS	4,000000	
	20/03/09		O	Den norske stats oljeselskap a.s	51,000000	(30,000)
				Total Norge AS	35,000000	
				Svenska Petroleum Exploration AS	10,000000	
101	85/03/01	16/10		Deminex Norge AS	5,000000	
	22/03/01			Den norske stats oljeselskap a.s	50,000000	(30,000)
			O	Norsk Agip AS	45,000000	
102	85/03/01	25/ 5		Den norske stats oljeselskap a.s	50,000000	(30,000)
	25/03/01		O	Total Norge AS	40,000000	
				Norsk Hydro Produksjon AS	10,000000	
102 B	98/01/22	25/ 5		Den norske stats oljeselskap a.s	50,000000	(30,000)
	25/03/01		O	Elf Petroleum Norge AS	30,000000	
				Total Norge AS	20,000000	
103	85/03/01	25/ 7	O	Amerada Hess Norge AS	50,000000	
	21/03/01			Den norske stats oljeselskap a.s	50,000000	(30,000)
103 B	98/01/22	25/ 7		Amerada Hess Norge AS	12,500000	
	21/03/01			Den norske stats oljeselskap a.s	50,000000	(30,000)
			O	Norske Conoco A/S	37,500000	
104	85/03/01	30/ 9		Den norske stats oljeselskap a.s	50,000000	(30,000)
	25/03/01			Mobil Development Norway AS	5,000000	
			O	Norsk Hydro Produksjon AS	24,000000	
				Norske Conoco A/S	11,000000	
				Saga Petroleum ASA	10,000000	
107	85/03/01	6407/ 7		Den norske stats oljeselskap a.s	50,000000	(30,000)
	21/03/01			Mobil Development Norway AS	20,000000	
				Petro-Canada Norge AS	7,500000	
			O	Norsk Hydro Produksjon AS	22,500000	
109	85/03/01	7120/ 2		Den norske stats oljeselskap a.s	61,945000	(30,000)

Prod. Lic.	Awarded	Blocks		Licensees	Share	SDFI
	22/03/01	7120/ 3		Mobil Development Norway AS	15,000000	
			O	Norsk Hydro Produksjon AS	23,055000	
110	85/03/01	7120/ 5		Amerada Hess Norge AS	8,330000	
	21/03/01	7121/ 5	O	Den norske stats oljeselskap a.s	50,000000	(30,000)
		7121/ 5		Total Norge AS	20,000000	
				Fina Production Licenses AS	5,000000	
				Norsk Hydro Produksjon AS	16,670000	
112	85/07/26	25/ 2		Den norske stats oljeselskap a.s	50,000000	(30,000)
	21/07/26		O	Elf Petroleum Norge AS	21,800000	
				Norsk Hydro Produksjon AS	17,300000	
				Total Norge AS	10,900000	
113	85/08/23	2/12	O	Amerada Hess Norge AS	50,000000	
	21/08/23			Den norske stats oljeselskap a.s	50,000000	(30,000)
114	85/08/23	9/ 2		Deminex Norge AS	10,000000	
	22/08/23		O	Den norske stats oljeselskap a.s	65,000000	(30,000)
				Saga Petroleum ASA	25,000000	
114 B	95/08/11	9/ 5		Deminex Norge AS	10,000000	
	01/08/11		O	Den norske stats oljeselskap a.s	65,000000	(30,000)
				Saga Petroleum ASA	25,000000	
114 C	98/09/03	9/ 1		Deminex Norge AS	10,000000	
	99/09/03	9/ 2	O	Den norske stats oljeselskap a.s	65,000000	(30,000)
		9/ 4		Saga Petroleum ASA	25,000000	
115	85/08/23	9/ 3	O	Den norske stats oljeselskap a.s	73,000000	(30,000)
	21/08/23			Deminex Norge AS	27,000000	
116	85/08/23	15/12		Amerada Hess Norge AS	10,000000	
	22/08/23	15/12		Den norske stats oljeselskap a.s	70,000000	(30,000)
				Norsk Hydro Produksjon AS	10,000000	
			O	Saga Petroleum ASA	10,000000	
117	85/08/23	25/ 6		Amerada Hess Norge AS	10,000000	
	22/08/23			Den norske stats oljeselskap a.s	50,000000	(30,000)
				Fina Production Licenses AS	15,000000	
			O	Saga Petroleum ASA	25,000000	
120	85/08/23	34/ 7		Den norske stats oljeselskap a.s	47,000000	(28,000)
	23/08/23	34/ 8		Elf Petroleum Norge AS	11,000000	
			O	Norsk Hydro Produksjon AS	23,000000	
				Norske Conoco A/S	13,000000	
				Saga Petroleum ASA	6,000000	
121	86/02/28	6407/ 5	O	Den norske stats oljeselskap a.s	50,000000	(40,000)
	22/02/28			Mobil Development Norway AS	20,000000	
				Norsk Hydro Produksjon AS	20,000000	
				Saga Petroleum ASA	10,000000	
122	86/02/28	6507/ 2		Amerada Hess Norge AS	20,000000	
	25/02/28			Den norske stats oljeselskap a.s	50,000000	(30,000)
				Mobil Development Norway AS	10,000000	
			O	Norsk Agip AS	20,000000	
124	86/02/28	6507/ 8	O	Den norske stats oljeselskap a.s	65,000000	(30,000)
	25/02/28			Neste Petroleum AS	10,000000	
				Norske Conoco A/S	25,000000	
127	86/02/28	6607/12		Den norske stats oljeselskap a.s	50,000000	(30,000)
	23/02/28		O	Elf Petroleum Norge AS	35,000000	
				Fina Production Licenses AS	15,000000	
128	86/02/28	6608/10	O	Den norske stats oljeselskap a.s	50,000000	(25,000)
	26/02/28	6608/11		Enterprise Oil Norwegian AS	10,000000	
				Norsk Agip AS	11,500000	
				Norsk Hydro Produksjon AS	13,500000	
				Saga Petroleum ASA	15,000000	

Prod. Lic.	Awarded	Blocks		Licensees	Share	SDFI
128 B	98/01/30	6508/ B	O	Den norske stats oljeselskap a.s	70,000000	(55,000)
	04/01/30			Enterprise Oil Norwegian AS	6,000000	
				Norsk Agip AS	6,900000	
				Norsk Hydro Produksjon AS	8,100000	
				Saga Petroleum ASA	9,000000	
132	87/04/10	6407/10		Den norske stats oljeselskap a.s	50,000000	(30,000)
	23/04/10			Mobil Development Norway AS	20,000000	
				Petro-Canada Norge AS	7,500000	
			O	Norsk Hydro Produksjon AS	22,500000	
134	87/04/10	6506/11	O	Den norske stats oljeselskap a.s	53,000000	(25,000)
	27/04/10			Norsk Agip AS	30,000000	
				Saga Petroleum ASA	7,000000	
				Total Norge AS	10,000000	
138	87/05/29	7122/ 6		Amerada Hess Norge AS	13,000000	
	23/05/29			Den norske stats oljeselskap a.s	50,000000	(30,000)
			O	Total Norge AS	37,000000	
142	87/05/29	29/ 9	O	Den norske stats oljeselskap a.s	70,000000	(30,000)
	27/05/29	30/ 7		Saga Petroleum ASA	30,000000	
		30/10				
143	88/07/08	1/ 2		Phillips Petroleum Norsk AS	20,000000	
	27/07/08			Den norske stats oljeselskap a.s	30,000000	(30,000)
				Enterprise Oil Norwegian AS	15,000000	
			O	Norsk Hydro Produksjon AS	35.000000	
144	88/07/08	1/ 5		Enterprise Oil Norwegian AS	25,000000	
	28/07/08	1/ 6		Den norske stats oljeselskap a.s	50,000000	(30,000)
		1/ 6	O	Norske Conoco A/S	15,000000	
				Amerada Hess Norge AS	10,000000	
145	88/07/08	1/ 9	O	Phillips Petroleum Norsk AS	40,000000	
	24/07/08	2/ 7		Den norske stats oljeselskap a.s	40,000000	(30,000)
				Norsk Agip AS	10,000000	
				Norsk Hydro Produksjon AS	10,000000	
146	88/07/08	2/ 4		Amerada Hess Norge AS	10,000000	
	27/07/08			Den norske stats oljeselskap a.s	30,000000	(30,000)
				Elf Petroleum Norge AS	20,000000	
				Phillips Petroleum Norsk AS	20,000000	
			O	Saga Petroleum ASA	20,000000	
147	88/07/08	3/ 7	O	A/S Norske Shell	50,000000	
	27/07/08	3/ 8		Den norske stats oljeselskap a.s	50,000000	(30,000)
148	88/07/08	7/ 4		Amerada Hess Norge AS	25,000000	
	24/07/08	7/ 7		Amoco Norway AS	10,000000	
			O	Den norske stats oljeselskap a.s	50,000000	(30,000)
				Total Norge AS	15,000000	
150	88/07/08	24/ 9		Den norske stats oljeselskap a.s	40,000000	(30,000)
	24/07/08			Enterprise Oil Norwegian AS	40,000000	
			O	Fina Production Licenses AS	10,000000	
				Saga Petroleum ASA	10,000000	
152	88/07/08	33/12		Idemitsu Oil Exploration (Norsk) a.s.	10,000000	
	25/07/08		O	Den norske stats oljeselskap a.s	80,000000	(30,000)
				Mobil Development Norway AS	10,000000	
153	88/07/08	35/ 9		A/S Norske Shell	12,000000	
	28/07/08	36/ 7		Deminex Norge AS	8,000000	
				Den norske stats oljeselskap a.s	50,000000	(30,000)
			O	Norsk Hydro Produksjon AS	20,000000	
				Saga Petroleum ASA	10,000000	
156	89/03/03	6406/11		Amerada Hess Norge AS	10,000000	
	99/03/03			Den norske stats oljeselskap a.s	30,000000	(30,000)

Prod. Lic.	Awarded	Blocks		Licensees	Share	SDFI
				Norsk Chevron AS	20,000000	
			O	Saga Petroleum ASA	40,000000	
157	89/03/03	6406/12		Den norske stats oljeselskap a.s	20,000000	(20,000)
	99/03/03			Norske Conoco A/S	10,000000	
			O	Norsk Chevron AS	30,000000	
				Phillips Petroleum Norsk AS	15,000000	
				Saga Petroleum ASA	25,000000	
158	89/03/03	6407/ 8	O	BP Petroleum Dev. of Norway AS	40,000000	
	28/03/03			Den norske stats oljeselskap a.s	30,000000	(30,000)
				Norsk Chevron AS	20,000000	
				A/S Norske Shell	10,000000	
159	89/03/03	6507/ 3	O	Den norske stats oljeselskap a.s	50,000000	(20,000)
	99/03/03			Enterprise Oil Norwegian AS	40,000000	
				Saga Petroleum ASA	10,000000	
163	91/03/01	2/10		Amerada Hess Norge AS	10,000000	
	00/03/01	2/10		Den norske stats oljeselskap a.s	50,000000	(35,000)
				Norsk Agip AS	10,000000	
			O	Saga Petroleum ASA	30,000000	
166	91/03/01	15/ 6		Den norske stats oljeselskap a.s	70,000000	(30,000)
	00/03/01		O	Deminex Norge AS	30,000000	
167	91/03/01	16/ 1		Amoco Norway AS	10,000000	
	00/03/01		O	Den norske stats oljeselskap a.s	50,000000	(20,000)
				Norsk Hydro Produksjon AS	30,000000	
				Phillips Petroleum Norsk AS	10,000000	
168	91/03/01	25/10		Amerada Hess Norge AS	25,000000	
	99/03/01		O	Den norske stats oljeselskap a.s	75,000000	(20,000)
169	91/03/01	25/ 8		Den norske stats oljeselskap a.s	50,000000	(35,000)
	00/03/01	25/11		Esso Expl. & Prod. Norway A/S	10,000000	
			O	Norsk Hydro Produksjon AS	40,000000	
171	91/03/01	30/12		Den norske stats oljeselskap a.s	50,000000	(35,000)
	00/03/01		O	Norsk Hydro Produksjon AS	30,000000	
				Mobil Development Norway AS	10,000000	
				Saga Petroleum ASA	10,000000	
172	91/03/01	33/ 9		Amerada Hess Norge AS	5,550000	
	25/03/01	33/ 9		Den norske stats oljeselskap a.s	50,000000	(35,000)
			O	Mobil Development Norway AS	27,780000	
				Norske Conoco A/S	16,670000	
173	91/03/01	35/10	O	Den norske stats oljeselskap a.s	50,000000	(20,000)
	00/03/01			Elf Petroleum Norge AS	15,000000	
				Mobil Development Norway AS	20,000000	
				Norsk Hydro Produksjon AS	15,000000	
174	91/03/01	35/12		Den norske stats oljeselskap a.s	50,000000	(35,000)
	01/03/01		O	Saga Petroleum ASA	30,000000	
				Norske Conoco A/S	20,000000	
175	91/03/01	6204/10	O	Den norske stats oljeselskap a.s	50,000000	(25,000)
	99/03/01	6204/11		Enterprise Oil Norwegian AS	10,000000	
				Neste Petroleum AS	10,000000	
				Phillips Petroleum Norsk AS	20,000000	
				Saga Petroleum ASA	10,000000	
176	91/03/01	6407/11	O	A/S Norske Shell	40,000000	
	28/03/01	6407/12		Den norske stats oljeselskap a.s	35,000000	(35,000)
				Norsk Chevron AS	15,000000	
				Norsk Hydro Produksjon AS	10,000000	
177	91/03/01	6610/ 2		BP Petroleum Dev. of Norway AS	20,000000	
	00/03/01	6610/ 3	O	Den norske stats oljeselskap a.s	50,000000	(20,000)

Prod. Lic.	Awarded	Blocks		Licensees	Share	SDFI
				Saga Petroleum ASA	30,000000	
181	91/03/01	7128/ 6		Amoco Norway AS	15,000000	
	99/03/01	7128/ 9	O	Den norske stats oljeselskap a.s	70,830000	(30,000)
		7129/ 4		Elf Petroleum Norge AS	14,170000	
182	91/03/01	7219/ 7		Den norske stats oljeselskap a.s	30,000000	(30,000)
	00/03/01	7219/ 8		Enterprise Oil Norwegian AS	20,000000	
				Norsk Chevron AS	20,000000	
			O	Saga Petroleum ASA	30,000000	
185	91/09/13	31/ 7		Den norske stats oljeselskap a.s	46,000000	(33,400)
	15/04/06			Esso Expl. & Prod. Norway A/S	17,600000	
				Neste Petroleum AS	13,200000	
			O	Norsk Hydro Produksjon AS	23,200000	
186	93/09/10	7/10		Amoco Norway AS	15,000000	
	99/09/10	7/11		Den norske stats oljeselskap a.s	50,000000	(40,000)
			O	Saga Petroleum ASA	20,000000	
				Total Norge AS	15,000000	
187	93/09/10	15/ 2	O	Amoco Norway AS	25,000000	
	99/09/10	15/ 3		Den norske stats oljeselskap a.s	65,000000	(40,000)
		15/ 3		Norsk Hydro Produksjon AS	10,000000	
189	93/09/10	25/ 8	O	Amerada Hess Norge AS	20,000000	
	99/09/10	25/ 9		Den norske stats oljeselskap a.s	70,000000	(45,000)
				Saga Petroleum ASA	10,000000	
190	93/09/10	30/ 8		Den norske stats oljeselskap a.s	50,000000	(50,000)
	99/09/10			Total Norge AS	10,000000	
				Elf Petroleum Norge AS	10,000000	
			O	Norsk Hydro Produksjon AS	30,000000	
191	93/09/10	31/ 1		Den norske stats oljeselskap a.s	60,000000	(45,000)
	99/09/10	31/ 2		Mobil Development Norway AS	10,000000	
		31/ 4		Neste Petroleum AS	10,000000	
		31/ 5	O	Norsk Hydro Produksjon AS	20,000000	
192	93/09/10	34/ 5		Den norske stats oljeselskap a.s	62,000000	(35,000)
	99/09/10		O	Mobil Development Norway AS	18,000000	
				Norske Conoco A/S	20,000000	
193	93/09/10	34/11		Norsk Hydro Produksjon AS	15,000000	
	01/09/10		O	Den norske stats oljeselskap a.s	80,000000	(40,000)
				Elf Petroleum Norge AS	5,000000	
194	93/09/10	35/ 4		Den norske stats oljeselskap a.s	55,000000	(45,000)
	99/09/10	35/ 5		Elf Petroleum Norge AS	10,000000	
			O	Norsk Hydro Produksjon AS	25,000000	
				Saga Petroleum ASA	10,000000	
195	93/09/10	35/ 8	O	BP Petroleum Dev. of Norway AS	25,000000	
	99/09/10			Den norske stats oljeselskap a.s	35,000000	(35,000)
				Norsk Hydro Produksjon AS	25,000000	
				Norske Conoco A/S	15,000000	
196	93/09/10	35/ 6		Norsk Hydro Produksjon AS	15,000000	
	99/09/10	36/ 4	O	Den norske stats oljeselskap a.s	75,000000	(25,000)
				Idemitsu Petroleum Norge a.s.	10,000000	
197	93/09/10	6306/ 2	O	Amerada Hess Norge AS	70,000000	
	99/09/10	6306/ 5		Den norske stats oljeselskap a.s	30,000000	(30,000)
198	93/09/10	6306/ 6	O	Den norske stats oljeselskap a.s	65,000000	(40,000)
	99/09/10			Elf Petroleum Norge AS	15,000000	
				Norsk Hydro Produksjon AS	20,000000	
199	93/09/10	6406/ 2		Den norske stats oljeselskap a.s	60,000000	(45,000)
	99/09/10			Mobil Development Norway AS	15,000000	
			O	Saga Petroleum ASA	25,000000	

Prod. Lic.	Awarded	Blocks		Licensees	Share	SDFI
200	93/09/10	6608/ 7	O	Den norske stats oljeselskap a.s	65,000000	(40,000)
	99/09/10	6608/ 8		Neste Petroleum AS	15,000000	
				Phillips Petroleum Norsk AS	20,000000	
201	93/09/10	7018/ 3		Den norske stats oljeselskap a.s	25,000000	(25,000)
	00/09/10	7019/ 1		Enterprise Oil Norwegian AS	25,000000	
				Neste Petroleum AS	15,000000	
			O	Norsk Agip AS	35,000000	
202	93/09/10	7227/11		Amerada Hess Norge AS	25,000000	
	99/09/10	7227/12	O	Den norske stats oljeselskap a.s	55,000000	(30,000)
		7228/ 7		Saga Petroleum ASA	20,000000	
		7228/10				
203	96/02/02	24/ 6	O	Norsk Hydro Produksjon AS	35,000000	
	02/02/02	25/ 4		Norske Conoco A/S	20,000000	
		25/ 7		Amoco Norway AS	15,000000	
				Den norske stats oljeselskap a.s	30,000000	(30,000)
204	96/02/02	24/ 9	O	Den norske stats oljeselskap a.s	65,000000	(30,000)
	02/02/02	24/11		Amerada Hess Norge AS	20,000000	
		24/12		Enterprise Oil Norwegian AS	15,000000	
205	96/02/02	32/ 1	O	Phillips Petroleum Norsk AS	30,000000	
	00/02/02	32/ 2		Norsk Hydro Produksjon AS	20,000000	
		32/ 4		Total Norge AS	20,000000	
		32/ 5		Den norske stats oljeselskap a.s	30,000000	(30,000)
206	96/02/02	33/ 5	O	Mobil Development Norway AS	75,000000	
	02/02/02	33/ 6		Saga Petroleum ASA	25,000000	
		34/ 4				
207	96/02/02	6302/ 4	O	Esso Expl. & Prod. Norway A/S	35,000000	
	04/02/02	6302/ 5		Den norske stats oljeselskap a.s	55,000000	(30,000)
		6302/ 7		Saga Petroleum ASA	10,000000	
		6302/ 8				
208	96/02/02	6304/ 9	O	BP Petroleum Dev. of Norway AS	45,000000	
	04/02/02	6305/ 7		A/S Norske Shell	25,000000	
				Den norske stats oljeselskap a.s	30,000000	(30,000)
209	96/02/02	6305/ 1	O	Norsk Hydro Produksjon AS	25,000000	
	06/02/02	6305/ 2		A/S Norske Shell	15,000000	
		6305/ 4		Esso Expl. & Prod. Norway A/S	10,000000	
		6305/ 5		Den norske stats oljeselskap a.s	50,000000	(35,000)
210	96/02/02	6404/ 3	O	A/S Norske Shell	30,000000	
	06/02/02	6405/ 1		Norsk Hydro Produksjon AS	20,000000	
		6504/ 9		Den norske stats oljeselskap a.s	50,000000	(30,000)
		6504/12				
		6505/ 7				
		6505/10				
211	96/02/02	6506/ 6	O	Mobil Development Norway AS	30,000000	
	02/02/02	6507/ 4		Norsk Agip AS	20,000000	
				Elf Petroleum Norge AS	20,000000	
				Den norske stats oljeselskap a.s	30,000000	(30,000)
212	96/02/02	6507/ 5	O	Amoco Norway AS	30,000000	
	02/02/02	6507/ 6		Enterprise Oil Norwegian AS	25,000000	
				Mobil Development Norway AS	15,000000	
				Den norske stats oljeselskap a.s	30,000000	(30,000)
213	96/02/02	6508/ 1	O	Saga Petroleum ASA	25,000000	
	02/02/02			Den norske stats oljeselskap a.s	55,000000	(30,000)
				Phillips Petroleum Norsk AS	20,000000	
214	96/02/02	6510/ 1	O	A/S Norske Shell	30,000000	
	02/02/02	6510/ 2		Mobil Development Norway AS	20,000000	
				Elf Petroleum Norge AS	20,000000	

Prod. Lic.	Awarded	Blocks		Licensees	Share	SDFI
				Den norske stats oljeselskap a.s	30,000000	(30,000)
215	96/02/02	6604/ 2	O	Saga Petroleum ASA	25,000000	
	04/02/02	6604/ 3		Norsk Hydro Produksjon AS	20,000000	
		6704/12		Norske Conoco A/S	15,000000	
		6705/10		Mobil Development Norway AS	10,000000	
				Den norske stats oljeselskap a.s	30,000000	(30,000)
216	96/02/02	6610/ 1	O	Amoco Norway AS	30,000000	
	02/02/02			Total Norge AS	25,000000	
				Enterprise Oil Norwegian AS	15,000000	
				Den norske stats oljeselskap a.s	30,000000	(30,000)
217	96/02/02	6706/11	O	Den norske stats oljeselskap a.s	65,000000	(30,000)
	06/02/02	6706/12		BP Petroleum Dev. of Norway AS	20,000000	
				Norske Conoco A/S	15,000000	
218	96/02/02	6706/12	O	BP Petroleum Dev. of Norway AS	25,000000	
	06/02/02	6707/10		Den norske stats oljeselskap a.s	50,000000	(35,000)
				Esso Expl. & Prod. Norway A/S	15,000000	
				Saga Petroleum ASA	10,000000	
219	96/02/02	6710/ 6	O	Norsk Hydro Produksjon AS	45,000000	
	06/02/02			Norsk Agip AS	40,000000	
				Fina Production Licenses AS	15,000000	
220	96/02/02	6710/10	O	Den norske stats oljeselskap a.s	70,000000	(30,000)
	06/02/02			Amerada Hess Norge AS	15,000000	
				Amoco Norway AS	15,000000	
221	97/05/30			Elf Petroleum Norge AS	10,000000	
	07/05/15		O	Norsk Hydro Produksjon AS	20,000000	
				Mobil Development Norway AS	15,000000	
				Saga Petroleum ASA	10,000000	
				Den norske stats oljeselskap a.s	45,000000	(30,000)
222	97/05/30			Elf Petroleum Norge AS	10,000000	
	07/05/15		O	Norsk Hydro Produksjon AS	20,000000	
				Mobil Development Norway AS	15,000000	
				Saga Petroleum ASA	10,000000	
				Den norske stats oljeselskap a.s	45,000000	(30,000)
223	97/05/30			Elf Petroleum Norge AS	10,000000	
	07/05/15		O	Norsk Hydro Produksjon AS	20,000000	
				Mobil Development Norway AS	15,000000	
				Saga Petroleum ASA	10,000000	
				Den norske stats oljeselskap a.s	45,000000	(30,000)
224	97/05/30	7217/ 9	O	Elf Petroleum Norge AS	30,000000	
	05/05/15	7217/12		Mobil Development Norway AS	25,000000	
		7218/ 7		Phillips Petroleum Company Norway	25,000000	
		7218/ 8		DEN NORSKE STATS OLJESESKAP A.S	20,000000	(20.000)
		7218/10				
		7218/11				
225	97/05/30			Norsk Agip AS	15,000000	
	07/05/15			Enterprise Oil Norwegian AS	15,000000	
				Neste Petroleum AS	10,000000	
			O	Saga Petroleum ASA	20,000000	
				Den norske stats oljeselskap a.s	40,000000	(20,000)
226	97/05/30			Norsk Agip AS	15,000000	
	07/05/15			Enterprise Oil Norwegian AS	15,000000	
				Neste Petroleum AS	10,000000	
			O	Saga Petroleum ASA	20,000000	
				Den norske stats oljeselskap a.s	40,000000	(20,000)
227	97/05/30			Norsk Agip AS	15,000000	
	07/05/15			Enterprise Oil Norwegian AS	15,000000	
				Neste Petroleum AS	10,000000	
			O	Saga Petroleum ASA	20,000000	

Prod. Lic.	Awarded	Blocks		Licensees	Share	SDFI
				Den norske stats oljeselskap a.s	40,000000	(20,000)
228	97/05/30	7222/ 6		Norsk Hydro Produksjon AS	20,000000	
	05/05/15	7222/ 8	O	Saga Petroleum ASA	30,000000	
		7222/ 9		Den norske stats oljeselskap a.s	50,000000	(30.000)
		7222/11				
		7222/12				
		7223/ 4				
		7223/ 5				
		7223/ 6				
229	97/05/30	7122/ 7	O	Norsk Agip AS	25,000000	
	05/05/15	7122/ 8		Enterprise Oil Norwegian AS	15,000000	
		7122/ 9		Neste Petroleum AS	15,000000	
		7122/10		Phillips Petroleum Company Norway	25,000000	
		7123/ 7		Den norske stats oljeselskap a.s	20,000000	(20.000)
230	97/05/30			Amerada Hess Norge AS	15,000000	
	07/05/15			Norsk Hydro Produksjon AS	15,000000	
			O	Mobil Development Norway AS	20,000000	
				Saga Petroleum ASA	15,000000	
				Den norske stats oljeselskap a.s	35,000000	(20,000)
231	97/05/30			Amerada Hess Norge AS	15,000000	
	07/05/15			Norsk Hydro Produksjon AS	15,000000	
			O	Mobil Development Norway AS	20,000000	
				Saga Petroleum ASA	15,000000	
				Den norske stats oljeselskap a.s	35,000000	(20,000)
232	97/05/30			Amerada Hess Norge AS	15,000000	
	07/05/15			Norsk Hydro Produksjon AS	15,000000	
			O	Mobil Development Norway AS	20,000000	
				Saga Petroleum ASA	15,000000	
				Den norske stats oljeselskap a.s	35,000000	(20,000)
233	97/05/30			Norsk Agip AS	15,000000	
	07/05/15			Norsk Hydro Produksjon AS	15,000000	
				Saga Petroleum ASA	20,000000	
			O	Den norske stats oljeselskap a.s	50,000000	(20,000)
234	97/05/30			Norsk Agip AS	15,000000	
	07/05/15			Norsk Hydro Produksjon AS	15,000000	
				Saga Petroleum ASA	20,000000	
			O	Den norske stats oljeselskap a.s	50,000000	(20,000)
235	97/05/30			Norsk Agip AS	15,000000	
	07/05/15			Norsk Hydro Produksjon AS	15,000000	
				Saga Petroleum ASA	20,000000	
			O	Den norske stats oljeselskap a.s	50,000000	(20,000)
236	97/05/30			Norsk Agip AS	15,000000	
	07/05/15			Norsk Hydro Produksjon AS	15,000000	
				Saga Petroleum ASA	20,000000	
			O	Den norske stats oljeselskap a.s	50,000000	(20,000)
237	98/01/30	6407/ 3		Norsk Agip AS	7,900000	
	27/04/27			Norsk Hydro Produksjon AS	2,600000	
				Mobil Development Norway AS	7,350000	
				Neste Petroleum AS	7,000000	
				Saga Petroleum ASA	7,000000	
			O	DEN NORSKE STATS OLJESELSKAP AS	60,500000	(46,950)
				Total Norge AS	7,650000	

7.2 SALE AND RELEASE OF DATA

7.2.1 REPORTING AND RELEASE OF DATA AND MATERIAL FROM THE SHELF

In connection with the Norwegian Petroleum Directorate's follow-up of the petroleum activities on the Norwegian continental shelf, the Norwegian Petroleum Directorate receives inter alia copies of reports, borehole logs and representative samples of drill cuttings and cores. The Norwegian Petroleum Directorate also receives oil samples from all tested wells.

As of 31 December 1998, the Norwegian Petroleum Directorate has stocked 108,716 meters of core material from 1,201 wells, 460,046 samples of washed cuttings from 1,265 wells and 526,034 wet samples from 1,506 wells. In addition, there are oil and condensate samples from 328 wells. This includes material from Svalbard, Hopen and Andøya as well as from some foreign wells, mostly from the British sector of the North Sea. In connection with NORAD assignments, the Norwegian Petroleum Directorate has also received material from Tanzania and Mozambique.

In 1998, the Norwegian Petroleum Directorate received 5,216 meters of cores, 35,249 samples of washed cuttings, 16,942 wet samples and 17 oil samples.

During the course of 1998, material has been extracted from 1,003 exploration wells, 94 foreign wells and 1,003 production wells for further examination.

The storage facility was closed for 67 working days due to work being conducted.

7.2.2 RELEASE OF DATA

The Norwegian Petroleum Directorate is responsible for publishing data and releasing material inter alia for the purposes of education and research. Geological and technical reservoir data are normally released two years after well completion. The licensees' interpretations are not released. "Well Data Summary Sheets" (WDSS) are issued annually. This publication shows which wells have been released and which core and log materials are available from the various wells. In addition, some technical data and test results are also given, as well as a composite log with lithology description of each well.

In addition to the WDSS, the Norwegian Petroleum Directorate issues the publication "Licenses, Areas, Area-coordinates, Exploration Wells", which contains an overview of each production license on the Norwegian continental shelf; license number, award date, operator, awarded area, current area, licensees and their interests, geographical coordinates for the areas, some data about each well drilled in the license and a map of the area with the wells plotted in. Some historical data and tables from the drilling activities are also included. This publication is issued annually with a half-yearly update. The Norwegian Petroleum Directorate has experienced a growing demand for released data as more data types with improved quality are made available. Some types of data can also be delivered in digital format on diskette or magnetic tape. Reference is otherwise made to the Norwegian Petroleum Directorate's list of publications.

The Norwegian Petroleum Directorate received 123 orders for data from a total of 1,313 wells. 78 orders were for film/hard copies from 502 wells, 33 were for digital data sets from 737 "High Quality Log Data project" (HQLD) wells, six were orders for digital core analyses from 19 wells and six were for digital direction data from 55 wells. This is an increase of 123 per cent compared with 1997.

The Norwegian Petroleum Directorate has delivered 64 other digital data collections. The most common are well lists (exploration and production wells), production licenses (current and historic), exploration areas and blocks, installations, pipelines and other collections listed in the Directorate's publications list. In addition, several special collections have been made to order.

In the Norwegian Petroleum Directorate's two core study rooms it is possible to examine core materials, drill cuttings and wet samples. In special cases, material may be made available for studies and analyses performed outside of the Directorate. Applications for release of data should be addressed to the Release Committee at the Norwegian Petroleum Directorate.

Thirteen applications have been considered in 1998. Of these, eight were for organic geochemistry studies, four for biostratigraphic and one for geophysical. A total of about 34 kg of sample material and 50 ml of oil was released.

In 1998, the Norwegian Petroleum Directorate's core study rooms were used by 29 different companies/institutions for examination of cores and/or geological sampling. The core study rooms have been used by external guests on 96 days, in addition to 116 days of use by employees of the Norwegian Petroleum Directorate.

As of 31 December 1998, the Norwegian Petroleum Directorate has released data from 1,128 seismic surveys, which cover 4,423,278 line kilometers of seismic.

A list of these surveys may be found in the publication "Released seismic surveys, Volume A and B". "Volume A" contains data packages for the North Sea, while "Volume B" contains packages for the Norwegian Sea.

7.2.3 SALE OF THE NORWEGIAN PETROLEUM DIRECTORATE'S SEISMIC DATA

The Norwegian Petroleum Directorate's regional and semi-regional seismic data (NPD seismic) is made available to the industry in the form of seismic data packages. In 1998, 57 packages were sold at a value of NOK 37 million. The table below shows the number of packages sold in 1998 and in total.

Package	Name	1998	Total
001	Møre-Trøndelag-Regional-Pk-1		35
002	Møre-Trøndelag-Regional-Pk-2	1	29
003	Tampen-Spur		22
004	Møre-South-84		22
005	Trøndelag-Regional	1	26

Package	Name	1998	Total
006	Haltenbanken-Vest-84	2	26
007	Frøyabanken-84	1	28
008	Møre-Trøndelag-Pakke-2 #)		22
009	Møre-Trøndelag-Pakke-3 #)		28
010	Trænabanken		30
011	Reg-Data-Nordland-Ryggen	2	24
012	Nordland-IV-85	2	15
013	Reg-Data-Midt-N-Sokkel	2	23
014	Nordland-II-83	3	27
015	Nordland-III-84	2	19
016	Troms-II		13
017	Regional-Data-Troms-Øst		18
018	Finnmark-Vest-83		19
019	Finnmark-Vest-84		20
020	Nordland-III-85	2	18
021	Møre-Sør-Test-84 #)		5
022	Storegga-85	2	15
023	Vøringplatået	2	17
024	Vøringbassenget-85/86	2	18
025	Lofoten-Vest-86	1	19
026	Jan-Mayen-85		1
028	Vøringbassenget-87	2	17
029	Nordland-VI-87	1	19
030	Nordland-VII-87		13
031	Nordland-V-87	1	13
032	Nordland-VI-88	1	19
033	Nordland-VII-88		13
034	Nordland-V-73-79	1	13
035	Nordland-VI-73-79	1	19
036	Nordland-VI-89	1	19
037	Nordland-VII-89		13
038	Nordland-VII-74/75		13
039	Nordsjøen-Sør-Test-89 #)		1
040	Vøringbassenget-88	2	17
041	Vøringbassenget-Merlin-89	2	17
042	Vøringbassenget-Western-89	2	17
043	Mørebassenget-88	2	14
044	Typeprofiler-Barentshavet #)		2
045	Vøringbassenget-I-90	2	17
046	Storegga-90	2	15
047	Vikinggraben-Sør-Test-91 #)		1
048	Vikingbanken-Test-91 #)		3
049	Norskehavet-74/79		1
050	Vøringbassenget-II-Ensign-91	2	15
051	Vøringbassenget-II-Digicon-91	2	15
052	Mørebassenget-91	2	15
053	Jan-Mayen-88		1
054	Vøringbassenget-II-92	2	15
055	Mørebassenget-Ensign-92	2	15
056	Mørebassenget-Digicon-92	2	15
057	Vestfjorden		5
058	Vestfjorden-77/78		5
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		3
500	Barentshavet Nordøst Regional		3

7.3 EXPLORATION DRILLING STATISTICS

As of 31 December 1998, a total of 942 exploration wells had been spudded on the Norwegian continental shelf since drilling commenced in 1966. Of these, 673 were wildcats and 269 were appraisal wells.

887 exploration wells have been completed and 52 wells were temporarily abandoned for various reasons. Some have been temporarily abandoned with a view to subsequent testing, possible completion as production wells, continued drilling or subsequent plugging.

The northernmost well on the Norwegian shelf is 7316/5-1, which was drilled in 1992 with Norsk Hydro as operator, the easternmost is 7229/11-1, drilled in 1993 by Shell, and the westernmost is 6301/11-2 drilled by Statoil in 1991.

The exploration wells have been drilled by 21 different operating companies. Regional distribution of total wells per operator is shown in Figure 7.3.a. The number of operating days per company in 1998 is shown in Figure 7.3.b. Figure 7.3.c shows the Norwegian operating companies' share of the drilling activities.

As of 31 December 1998, 3,046,295 meters have been drilled during exploration drilling, of which 84,214 meters were drilled in 1998. Average total depth for exploration wells that reached total depth in 1998 is 3.921 meters.

Figure 7.3.a
Regional spread of exploration wells per operator

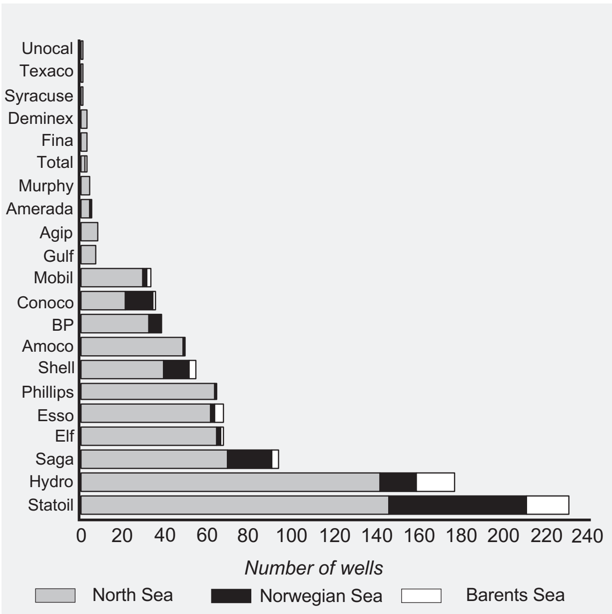


Figure 7.3.b
Rig days per operator

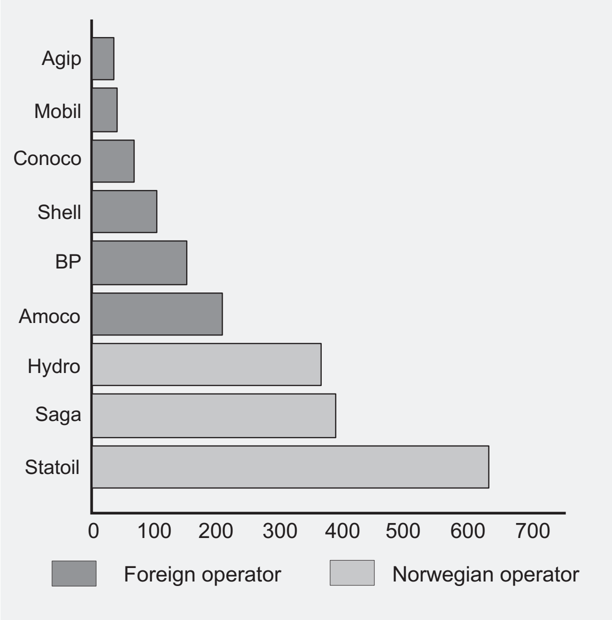
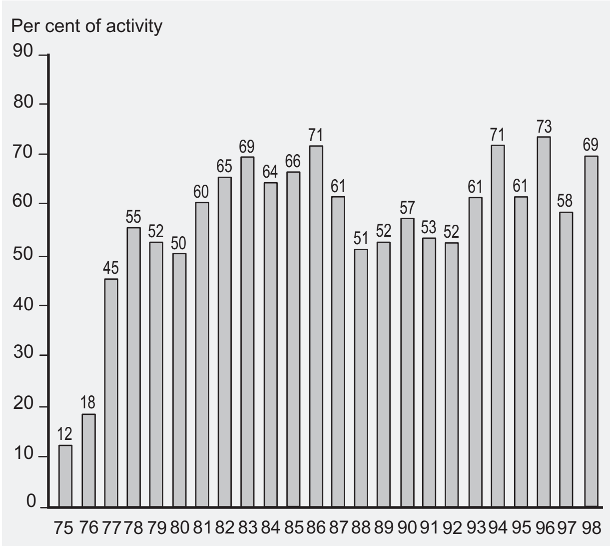


Figure 7.3.c
Participation of Norwegian operators in exploration drilling activity per year



Exploration well 6406/2-1, which was re-entered and drilled deeper by Saga Petroleum ASA in 1995, is the deepest well drilled so far on the Norwegian shelf with a depth of 5.870 meters MSL.

The longest well path for an exploration well so far is 9/2-8 S, which was drilled by Statoil in 1997/1998. The well path was 7,684 meters RKB (7,642 m MSL). The well was drilled at an angle and did not reach the same depth under the seabed as well 6406/2-1.

The deepest water ever drilled in on the Norwegian shelf is 1.274 meters. The well was 6707/10-1, which was drilled in 1997 with BP as operator. This is 751 meters deeper than the previous record. The average water depth for exploration wells drilled in 1998 was 275 meters. Table 7.3.d shows the average water depth for exploration wells drilled during the period 1966-1998.

Table 7.3.a
Regional spread of spudded 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	94	95	96	97	98	Sum
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	13	19	19	25	13	510
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	3	11	5	8	7	236
Norwegian Sea																																		
Wildcat															1	2	5	7	6	10	10	10	5	2	7	8	5	4	5	3	2	13	5	110
Appraisal																			1	6	5	4	1	1	1			2		3	4	4	1	33
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	18	22	21	38	18	672
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	3	14	9	12	8	270
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	21	36	30	50	26	942
Development wells								1	18	24	7	34	50	36	27	16	22	23	33	47	47	48	55	66	60	64	86	105	120	109	141	133	129	1501
Total drilled	**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**	**141**	**145**	**171**	**183**	**155**	**2443**

Table 7.3.b
Exploration wells spudded in 1998 (Regional spread)

Operator	North Sea			Norwegian Sea			Barents Sea			Total		
	W	A	E	W	A	E	W	A	E	W	A	E
Statoil	3	2	5	1	1	2				4	3	7
Hydro	4	3	7	1		1				5	3	8
Phillips												
Elf												

Operator	North Sea			Norwegian Sea			Barents Sea			Total		
	W	A	E	W	A	E	W	A	E	W	A	E
Saga	1	1	2	1		1				2	1	3
Esso												
Shell				1		1				1		1
Amoco	2		2							2		2
Conoco	1		1							1		1
Mobil	1		1							1		1
BP		1	1	1		1				1	1	2
Gulf												
Murphy												
Total												
Agip	1		1							1		1
Deminex												
Syracuse												
Texaco												
Unocal												
Fina												
Amerada												
Wildcat	13			5						18		
Appraisal		7			1						8	
Exploration wells			20			6						26

W = wildcat wells A = appraisal wells E = exploration wells

Table 7.3.c
Exploration wells by operating company (Regional spread)

Operator	North Sea			Norwegian Sea			Barents Sea			Total		
	W	A	E	W	A	E	W	A	E	W	A	E
Statoil	84	61	145	51	14	65	19	1	20	154	76	230
Hydro	94	47	141	15	2	17	18		18	127	49	176
Phillips	43	20	63	1		1				44	20	64
Elf	46	18	64	2		2	1		1	49	18	67
Saga	54	15	69	17	4	21	3		3	74	19	93
Esso	37	24	61	2		2	4		4	43	24	67
Shell	28	11	39	7	5	12	3		3	38	16	54
Amoco	35	13	48	1		1				36	13	49
Conoco	21		21	5	8	13	1		1	27	8	35
Mobil	20	9	29	2		2	2		2	24	9	33
BP	17	15	32	6		6				23	15	38
Gulf	7		7							7		7
Murphy	3	1	4							3	1	4
Total	2		2				1		1	3		3
Agip	8		8							8		8
Deminex	3		3							3		3

Operator	North Sea			Norwegian Sea			Barents Sea			Total		
	W	A	E	W	A	E	W	A	E	W	A	E
Syracuse	1		1							1		1
Texaco	1		1							1		1
Unocal	1		1							1		1
Fina	2	1	3							2	1	3
Amerada	4		4	1		1				5		5
Wildcat	511			110			52			673		
Appraisal		235			33			1			269	
Exploration wells			746			143			53			942

W = wildcat wells A = appraisal wells E = exploration wells

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

Year	Average water depth (m)	Average total depth (m)
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
1994	185	3 371
1995	152	3 084
1996	221	3 982
1997	234	3 242
1998	275	3 921

Table 7.3.e
Drilling installations active on the Norwegian continental shelf as of 31 December 1998

Installation	Number of wells	Number of re-entries	Type of installation
Aladdin	1		Semi-submersible
Arcade Frontier (was Norjarl)	7		"
Borgny Dolphin (was Fernstar)	27	8	"
Borgsten Dolphin (was Haakon Magnus)	9		"
Bucentaur		1	Drillship
Byford Dolphin (was Deepsea Driller)	43	2	Semi-submersible
Chris Chenery	2		"
Deepsea Bergen	59	4	"
Deepsea Saga	16	3	"
Deepsea Trym	11	1	"
Drillmaster	5	1	"
Drillship	1		Drillship

Installation	Number of wells	Number of re-entries	Type of installation
Dyvi Beta	6	1	Jack-up
Dyvi Gamma	1		"
Endeavour	2		Jack-up
Glomar Biscay II (was Norskald)	39	1	Semi-submersible
Glomar Grand Isle	11	3	Drillship
Glomar Moray Firth I	2		Jack-up
Gulftide	3		"
Henry Goodrich	2		Semi-submersible
Hunter (was Treasure Hunter)	6	3	"
Kolskaya		1	Jack-up
Le Pelerin	1		Drillship
Mærsk Explorer	7		Jack-up
Mærsk Gallant	2		"
Mærsk Giant	3		"
Mærsk Guardian	4	1	"
Mærsk Jutlander	15	2	Semi-submersible
Neddrill Trigon	3	1	Jack-up
Neptune 7 (was Pentagone 81)	13		Semi-submersible
Nordraug	12		"
Nortrym	32	3	"
Ocean Alliance	5		”
Ocean Tide	5		Jack-up
Ocean Traveler	9		Semi-submersible
Ocean Victory	1		"
Ocean Viking	28	1	"
Ocean Voyager	2		"
Odin Drill	3		"
Orion	7		Jack-up
Pentagone 84	2	1	Semi-submersible
Polar Pioneer	31	6	"
Polyglomar Driller	11		"
Ross Rig	29		"
Saipem II	1		Drillship
Scarabeo 5	4	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	"
Stene Dee (was Dyvi Stena)	25	2	"
Transocean Arctic (was Ross Rig (ny))	32	3	"
Transocean Leader (was Transocean 8)	25	2	"
Transocean Nordic	6		Jack-up
Transocean Prospect (was Treasure Prospect)	1	1	Semi-submersible
Transocean Searcher (was Ross Isle)	35	12	"
Transocean Wildcat (was Vildkat Explorer)	41	5	"
Transocean Winner (was Treasure Saga)	56	6	"
Transworld Rig 61	2		"
Treasure Scout	23		"
Treasure Seeker	24	5	"
Vinni	5		"
Waage Drill I	2		"

Installation	Number of wells	Number of re-entries	Type of installation
West Alpha (was Dyvi Alpha)	23	3	"
West Delta (was Dyvi Delta)	40	5	"
West Epsilon	2		Jack-up
West Vanguard	44	11	Semi-submersible
West Venture	12	2	"
West Vision	1		"
Yatzy	1		"
Zapata Explorer	13		Jack-up
Zapata Nordic	5		"
Zapata Ugland	5	1	Semi-submersible
	932	**105**	
In addition 10 wells have been drilled from fixed installations:			
Cod installation	1		
Ekofisk B	1		
Gullfaks B	1		
Sleipner A	1		
Ula A	1		
Veslefrikk A	5		
	942	**105**	

Table 7.3.f
Spudded and/or completed exploration wells in 1998

R=re-entry, X=junked well, S=side-drilled well, A/B/C=sidetracked new well. Positions with one decimal are preliminary.

Well			Reg. no PL no.	Position north east	Spudded Completed yr.mo.day	Operator Drilling installation	Well classification Status	Water depth KBE	TD (RKB) Age at TD
1/03-09	S		928	56 58 57.97	98.05.08	BP	Appraisal well	68	4516
			065	02 57 31.33	98.07.31	Mærsk Jutlander	Temp. abandoned	23	Jurassic
1/05-03	S	X	918	56 41 24.52	98.06.09	Conoco	Wildcat well	69	1566
			144	02 36 54.13	98.08.04	Byford Dolphin	Junked	25	Tertiary
2/08-17	S		912	56 27 21.19	97.12.04	Amoco	Wildcat well	69	2685
			006	03 36 05.18	98.01.28	Transocean Nordic	Hydrocarbons	40	Permian
2/08-17	A		924	56 27 21.19	98.01.28	Amoco	Wildcat well	69	3145
			006	03 36 05.18	98.02.21	Transocean Nordic	Hydrocarbons	40	Permian
9/02-08	S		895	57 49 07.58	97.06.24	Statoil	Wildcat well	93	7684
			114	04 31 11.00	98.02.02	Mærsk Giant	Reclass. to injector	42	
15/03-06			941	58 46 23.47	98.12.14	Amoco	Wildcat well	105	2793
			187	01 45 15.13	98.12.29	Mærsk Jutlander	Dry hole	25	
15/09-19	B		916	58 26 09.08	97.11.09	Statoil	Appraisal well	84	4250
			046	01 55 47.26	98.02.02	Byford Dolphin	Hydrocarbons	25	Triassic
15/09-21	S		926	58 25 04.58	98.03.23	Statoil	Appraisal well	108	5126
			046	01 43 04.61	98.05.23	West Epsilon	Dry hole	48	
16/01-05			939	58 47 53.52	98.10.12	Statoil	Wildcat well	105	2460
			167	02 09 12.14	98.11.21	Byford Dolphin	Dry hole	25	
16/01-05	A		945	58 47 53.52	98.11.21	Statoil	Wildcat well	105	2150
			167	02 09 12.14	98.12.06	Byford Dolphin	Hydrocarbons	25	
16/10-04			931	58 04 59.56	98.07.10	Agip	Wildcat well	76	2580
			101	02 11 57.20	98.08.10	Transocean Nordic	Dry hole	40	Permian
24/06-02			929	59 33 32.41	98.05.25	Hydro	Wildcat well	148	2722
			203	01 57 17.26	98.07.08	Transocean Leader	Oil/gas discovery		Paleocene
25/11-22			911	59 09 38.70	98.01.07	Hydro	Wildcat well	123	1805
			169	02 31 25.00	98.01.24	West Vanguard	Dry hole	22	Cretaceous
30/03-07	A		903	60 46 57.76	97.10.27	Statoil	Wildcat well	175	6678
			052	02 53 52.59	98.01.29	Veslefrikk A	Oil discovery	56	U. Jurassic
30/03-07	B		910	60 46 57.76	98.05.20	Statoil	Wildcat well	175	5979
			052	02 53 52.59	98.08.04	Veslerikk A		56	U. Jurassic
30/06-25	S		940	60 30 45.70	98.11.26	Hydro	Wildcat well	105	0
			053	02 43 16.00	00.00.00	West Delta		29	
30/08-03			914	60 26 40.54	97.11.13	Hydro	Wildcat well	93	3720
			190	02 38 58.02	98.01.05	West Vanguard	Gas/condensate discovery	22	Jurassic
30/09-19			937	60 27 35.38	98.09.08	Hydro	Wildcat well	105	3560
			079	02 41 38.94	98.10.30	West Delta	Oil/gas discovery	29	
30/09-19	A		942	60 27 35.38	98.10.30	Hydro	Appraisal well	105	3775
			079	02 41 38.94	98.12.21	West Delta		29	

Well		Reg. no PL no.	Position north east	Spudded Completed	Operator Drilling installation	Well classification Status	Water depth	TD (RKB) Age at TD
34/07-26	SR	902	61 16 29.38	98.01.06	Saga	Appraisal well	201	4690
		089	02 07 11.41	98.02.02	Scarabeo 5	Oil	25	Jurassic
34/07-26	A	925	61 16 29.38	98.02.02	Saga	Appraisal well	201	4290
		089	02 07 11.41	98.04.22	Scarabeo 5	Reclass. to production	25	U. Jurassic
34/07-27		933	61 29 32.30	98.09.01	Mobil	Wildcat well	311	3000
		089	02 00 21.90	98.10.07	Byford Dolphin	Dry hole	25	U. Jurassic
34/07-28		921	61 28 06.76	97.12.30	Saga	Wildcat well	305	2987
		089	02 01 05.12	98.03.02	Transocean Leader		24	U. Jurassic
34/07-29	S	923	61 21 51.69	98.03.04	Saga	Wildcat well	250	2733
		089	02 02 23.37	98.04.14	Transocean Leader	Temp. abandoned oil discovery	24	M. Jurassic
34/11-04		947	61 03 26.10	98.12.09	Statoil	Appraisal well	133	0
		193	02 22 46.50	00.00.00	Transocean Arctic		25	
35/09-04	S	930	61 19 32.50	98.07.13	Hydro	Appraisal well	390	1261
		153	03 57 55.23	98.08.12	Transocean Leader	Temp. abandoned	24	
35/11-11		927	61 06 31.42	98.04.16	Hydro	Appraisal well	359	3225
		090	03 33 39.03	98.05.22	Transocean Leader	Dry hole	24	U. Jurassic
6305/01-01		935	63 46 59.72	98.08.18	Hydro	Wildcat well	839	4560
		209	05 16 19.57	98.11.16	Transocean Leader	Dry hole	24	U. Cretaceous
6305/07-01		932	63 21 46.61	98.07.08	BP	Appraisal well	857	3377
		208	05 15 43.73	98.08.30	Ocean Alliance	Gas	26	U. Cretaceous
6406/02-04	SR	876	64 47 58.34	98.11.12	Saga	Appraisal well	274	0
		199	06 32 29.26	00.00.00	Deepsea Bergen		24	
6406/02-05	A	908	64 55 54.83	97.10.02	Saga	Appraisal well	341	5600
		199	06 26 58.65	98.02.23	Deepsea Bergen	Gas	23	U. Jurassic
6406/02-06		934	64 45 31.34	98.08.25	Saga	Wildcat well	302	5263
		199	06 22 54.69	98.11.07	Deepsea Bergen	Temp. abandoned	23	U. Jurassic
6505/10-01		917	65 07 59.69	98.03.28	Shell	Wildcat well	684	5028
		210	05 10 29.39	98.07.04	Ocean Alliance	Dry hole	26	U. Cretaceous
6506/11-06		922	65 01 25.24	98.02.24	Statoil	Appraisal well	378	5275
		134	06 25 10.71	98.08.22	Deepsea Bergen	Gas/condensate	23	U. Jurassic
6507/03-03		944	65 48 03.73	98.12.23	Statoil	Wildcat well	392	0
		159	07 43 28.69	00.00.00	Byford Dolphin		25	
6507/05-01		919	65 44 36.11	97.12.24	Amoco	Wildcat well	327	4224
		212	07 39 04.60	98.05.03	Mærsk Jutlander		25	U. Jurassic
6706/11-01		907	67 04 24.77	97.10.12	Statoil	Wildcat well	1238	4317
		217	06 27 47.70	98.03.22	Ocean Alliance	Dry hole	26	U. Cretaceous

83 different drilling rigs have been utilized for drilling on the Norwegian continental shelf, 15 of these under two different names. Of these, 54 have been semi-submersibles, 17 jack-ups, five drilling ships and seven permanent installations. During 1998, 11 different drilling rigs have been active in exploration drilling on the Norwegian shelf. Tables 7.3.a to 7.3.e contain statistics on exploration drilling on the Norwegian continental shelf.

7.4 DEVELOPMENT DRILLING STATISTICS

Since 1973, 1,501 development wells have been spudded on the Norwegian continental shelf; see Figure 7.4.b, 1,417 of these in the North Sea, and 84 in the Norwegian Sea where drilling started in 1992. 1,102 are production wells, 265 are water or gas injection wells and 103 are observation wells. 649 are currently out of service, temporarily abandoned for later completion, or shut down for other reasons. The wells have been drilled from 105 permanent installations (stationary, floating or subsea templates). Drilling was in progress on 17 development wells as of 31 December 1998. Figure 7.4.a shows development wells spudded per year during the period 1973-1998. As of 31 December 1998, production or injection is carried out from 74 installations divided among 41 fields. Three new fields have started producing in 1998: Varg, Gullveig and Tordis Øst. Four fields have terminated production: Nordøst Frigg, Odin, Mime and Loke. Tommeliten Gamma, Cod, Albuskjell, Vest Ekofisk and Edda were shut down in 1998. Development wells categorized by the various fields are shown in Table 7.4.a. Figure 7.4.c shows development wells categorized by operating companies. Drilling of the first development wells on the Gullveig, Varg and Oseberg Sør fields commenced in 1998.

In 1998, 129 development wells were spudded on 25 fields. 74 of the wells, i.e. 57 per cent, were drilled from 14 different mobile units, see Figure 7.4.d. The number of subsea-completed wells has shown a strong increase over the last seven years. This increase was particularly marked from 1995 to 1998 when the number of subsea-completed wells went up from 25 to 55, see Figure 7.4.e. This means that the percentage of subsea-completed wells drilled per year has increased from 7 per cent in 1992 to 43 per cent in 1998. Information on development wells is provided in Tables 7.4.a, 7.4.b and 7.4.c.

Table 7.4.a Development drilling

	Drilled	Drilled	Produces			Injects		Closed/Temp. abandoned
Field/installation	**total**	**1998**	**Oil**	**Cond.**	**Gas**	**gas/water**	**Drills**	
Albuskjell A	11			5				6
Albuskjell F	13							13
Balder A, B, C, D	25	9						25
Brage	40	4	22			12		6
Cod	9			4				5
Draugen A	10		7			1		2
Draugen B	3					3		
Draugen C	2					2		
Edda	10		5					5
Ekofisk A	35		18					17
Ekofisk B	40		22					18
Ekofisk C	33		18					15
Ekofisk K	33	2				30		3
Ekofisk W	8					8		
Ekofisk X	24	10	17					7
Eldfisk A	45		22					23
Eldfisk B	42		14					28
Embla	4		4					
Frigg (UK)	24							24
Frigg	28				7			21
Frøy	12		5			4		3
Gullfaks A	59		27			10	1	21
Gullfaks B	47	3	26			10		11
Gullfaks C	44	3	26			9		9
Gullfaks Sør	5	2					1	4
Gullfaks Vest	3		1					2
Gullveig	2	2	1					1
Gungne	1				1			
Gyda	35		11			10		14
Gyda Sør	1		1					
Heidrun A	22	4	17			2	1	2
Heidrun B	3					2		1
Heidrun C	3					3		
Heimdal	12			4				8
Hod	13		4					9
Lille-Frigg	4		1					3
Loke	2	1						2
Njord	9	4	3			2	1	3
Norne B, C, D	9	5	6			2		1
N-Ø Frigg	7							7
Odin	11							11
Oseberg B, C	116	7	42			19	1	54
Oseberg Sør	1	1					1	
Oseberg Vest	3		1					2
Rimfaks	3	2					1	2
Sleipner A	17				11	4		2
Sleipner D	2					2		
Sleipner Vest	12	2			9		1	2
Snorre A	11		7			3		1
Snorre P	32	4	14			10	1	7
Statfjord A	60	2	24			12	1	23
Statfjord B	60	5	30			12		18
Statfjord C	48	1	24			11		13
Statfjord G	1							1

	Drilled	Drilled	Produces			Injects		Closed/Temp. abandoned
Field/installation	total	1998	Oil	Cond.	Gas	gas/water	Drills	
Statfjord Nord	10	1	6			2	1	1
Statfjord Øst	11			6		3		2
TOGI	5				5			
Tommeliten Gamma	7			6				1
Tor	19		11			2		6
Tordis	10		5					5
Tordis Øst	3	1						3
Troll A	40	4			31			9
Troll B	1					1		
Troll D,E,F,G,H	63	17	27				1	35
Ula	28		7			7		14
Valhall A	72	3	26					46
Valhall F	15	5	12				1	2
Varg	6	6					1	5
V. Ekofisk	20							20
Veslefrikk	31	3	12			10		9
Vigdis	7	1	5			1		1
Visund	6	2					1	5
Yme A, B	10	1	4			2		4
Øst Frigg A	3							3
Øst Frigg B	2							2
Åsgard	23	12					2	21
	1501	**129**	**535**	**25**	**64**	**211**	**17**	**649**

Table 7.4.b
Development wells spudded and/or completed in 1998

H=subsea-completed, A/B/C=sidetracked new well, Y=branch well, X=junked well

Well	Reg.no	Position	Spudded	Operator	Classification	TD
	PL		Completed yr.mo.day	Installation	Status	(RKB)
2/01-A-21	1384	56 54 17.25	97.11.27	BP	Oil producer	8714 m
	019 B	03 05 06.49	98.07.23	Gyda	Temp.aband. at TD	
2/04-K-10 A	1456	56 33 55.73	98.05.19	Phillips	Water injector	4282 m
	018	03 12 22.00	98.07.03	Ekofisk K	Temp.aband. at TD	
2/04-K-11 A	1435	56 33 56.12	98.02.24	Phillips	Water injector	3416 m
	018	03 12 23.40	98.04.03	Ekofisk K	Water injector	
2/04-X-02	1447	56 32 50.91	98.04.19	Phillips	Observation well	4572 m
	018	03 13 08.08	98.05.23	Mærsk Gallant	Plugged	
2/04-X-02 A	1448	56 32 50.91	98.05.23	Phillips	Oil producer	4388 m
	018	03 13 08.08	98.06.01	Mærsk Gallant	Temp.aband. at TD	
2/04-X-05	1406	56 32 51.00	98.02.13	Phillips	Oil producer	4492 m
	018	03 13 08.00	98.03.16	Mærsk Gallant	Oil	
2/04-X-07	1464	56 32 50.98	98.06.01	Phillips	Oil producer	7775 m
	018	03 13 08.28	98.12.20	Mærsk Gallant	Temp.aband. at TD	
2/04-X-10	1399	56 32 51.08	97.12.14	Phillips	Oil producer	4512 m
	018	03 13 08.14	98.02.13	Mærsk Gallant	Oil	
2/04-X-12	1434	56 32 51.04	98.03.16	Phillips	Oil producer	3741 m
	018	03 13 08.44	98.04.17	Mærsk Gallant	Oil	
2/04-X-27	1503	56 32 51.72	98.10.17	Phillips	Oil producer	m
	018	03 13 08.23	98.10.24	Ekofisk X	Temp. abandoned at 13 3/8”	
2/04-X-31	1371	56 32 51.79	97.11.25	Phillips	Oil producer	4342 m
	018	03 13 08.26	98.01.12	Ekofisk X	Oil	
2/04-X-34	1465	56 32 51.75	98.08.16	Phillips	Oil producer	4363 m
	018	03 13 08.67	98.11.03	Ekofisk X	Temp.aband. at TD	
2/04-X-36	1409	56 32 51.86	98.01.06	Phillips	Oil producer	3399 m
	018	03 13 08.32	98.02.19	Ekofisk X	Oil	
2/04-X-39	1439	56 32 51.95	98.05.05	Phillips	Oil producer	5371 m
	018	03 13 08.31	98.08.13	Ekofisk X	Temp.aband. at TD	
2/04-X-40	1357	56 32 51.93	98.02.18	Phillips	Oil producer	4110 m
	018	03 13 08.45	98.05.01	Ekofisk X	Oil	

Well			Reg.no	Position	Spudded	Operator	Classification	TD
			PL		Completed yr.mo.day	Installation	Status	(RKB)
2/08-A-03	C		1459	56 16 41.08	98.09.07	Amoco	Oil producer	5602 m
			006	03 23 44.30	98.12.03	Valhall	Temp.aband. at TD	
2/08-A-05	B		1362	56 16 41.05	97.10.24	Amoco	Oil producer	3475 m
			006	03 23 43.68	98.01.07	Valhall	Oil	
2/08-A-06	A		1417	56 16 40.86	98.06.09	Amoco	Oil producer	2720 m
			006	03 23 43.65	98.07.29	Valhall	Oil	
2/08-A-19	A		1389	56 16 41.20	98.02.12	Amoco	Oil producer	4776 m
			006	03 23 44.11	98.03.10	Valhall	Temp.aband. at TD	
2/08-F-11			1391	56 16 35.61	98.01.07	Amoco	Oil producer	4388 m
			006	03 23 47.06	98.02.18	Mærsk Guardian	Oil	
2/08-F-12			1424	56 16 35.49	98.02.18	Amoco	Oil producer	5166 m
			006	03 23 47.10	98.04.23	Mærsk Guardian	Oil	
2/08-F-13			1457	56 16 35.58	98.06.01	Amoco	Oil producer	4567 m
			006	03 23 47.28	98.08.12	Mærsk Guardian	Temp.aband. at TD	
2/08-F-14			1446	56 16 35.66	98.04.24	Amoco	Oil producer	2635 m
			006	03 23 47.19	98.05.28	Mærsk Guardian	Oil	
2/08-F-17			1365	56 16 35.52	97.10.02	Amoco	Oil producer	4830 m
			006	03 23 47.25	98.01.28	Mærsk Guardian	Oil	
2/08-F-18			1489	56 16 35.51	98.08.18	Amoco	Oil producer	m
			006	03 23 46.90	00.00.00	Mærsk Guardian		
9/02-A-03			1427	57 49 07.58	98.02.02	Statoil	Gas injector	7684 m
			114	04 31 11.00	98.02.23	Mærsk Giant	Temp.aband. at TD	
15/09-B-11			1374	58 25 20.45	98.03.15	Statoil	Gas producer	4812 m
			046	01 43 04.37	98.07.25	West Epsilon	Gas	
15/09-B-22			1393	58 25 04.31	97.11.29	Statoil	Gas producer	8306 m
			046	01 43 04.48	98.10.31	West Epsilon	Temp.aband. at TD	
15/09-B-22	A		1394	58 25 04.31	98.11.16	Statoil	Gas producer	m
			046	01 43 04.48	00.00.00	West Epsilon		
15/09-C-02	A	H	1352	58 26 09.31	98.03.29	Statoil	Cond./gas	3500 m
			046	01 55 46.56	98.06.06	Byford Dolphin	Temp.aband. at TD	
15/12-A-02			1504	58 04 40.56	98.09.15	Saga	Oil producer	2978 m
			038	01 53 25.63	98.10.02	Noble Al White	Temp.aband. at TD	
15/12-A-05			1507	58 04 40.48	98.10.17	Saga	Oil producer	3852 m
			038	01 53 25.60	98.12.04	Noble Al White	Temp.aband. at TD	
15/12-A-08			1452	58 04 40.55	98.05.15	Saga	Oil producer	3347 m
			038	01 53 25.84	98.07.04	Noble Al White	Temp.aband. at TD	
15/12-A-11			1505	58 04 40.43	98.08.16	Saga	Oil producer	3566 m
			038	01 53 25.75	98.08.31	Noble Al White	Temp.aband. at TD	
15/12-A-14			1471	58 04 40.36	98.07.10	Saga	Water/Gas injector	4350 m
			038	01 53 25.71	98.08.15	Noble Al White	Temp.aband. at TD	
15/12-A-15			1529	58 04 40.38	98.12.25	Saga	Oil producer	m
			038	01 53 25.80	00.00.00	Noble Al White		
25/11-A-06		H	1210	59 11 28.42	96.10.07	Esso	Oil producer	1807 m
			001	02 21 37.38	98.10.12	West Alpha	Temp.aband. at TD	
25/11-B-07	A	H	1253	59 10 40.45	97.01.14	Esso	Oil producer	2891 m
			001	02 22 46.46	98.04.18	West Alpha	Temp.aband. at TD	
25/11-B-11		H	1410	59 10 42.54	98.01.23	Esso	Oil producer	2934 m
			001	02 22 44.00	98.04.13	West Alpha	Temp.aband. at TD	
25/11-B-14		H	1411	59 10 42.75	98.01.17	Esso	Oil producer	2167 m
			001	02 22 45.85	98.02.13	West Alpha	Temp.aband. at TD	
25/11-B-14	A	H	1412	59 10 42.75	98.03.20	Esso	Water injector	2695 m
			001	02 22 45.85	98.04.24	West Alpha	Temp.aband. at TD	
25/11-C-03	B	H	1402	59 11 00.62	97.12.21	Esso	Oil producer	2118 m
			001	02 24 32.52	98.01.07	West Alpha	Temp.aband. at TD	
25/11-C-12		H	1445	59 10 59.93	98.04.28	Esso	Water injector	2267 m
			001	02 24 36.26	98.05.27	West Alpha	Temp.aband. at TD	
25/11-C-13		H	1310	59 10 59.87	97.05.07	Esso	Oil producer	2725 m
			001	02 24 34.62	98.06.10	West Alpha	Temp.aband. at TD	
25/11-C-17		H	1493	59 10 59.03	98.10.14	Esso	Observation well	2450 m
			001	02 24 36.87	98.11.06	West Alpha	Plugged	
25/11-C-17	A	H	1494	59 10 59.03	98.11.06	Esso	Oil producer	3015 m
			001	02 24 36.87	98.12.10	West Alpha	Temp.aband. at TD	
25/11-D-10		H	1468	59 12 00.37	98.06.12	Esso	Observation well	2496 m
			001	02 24 35.21	98.07.15	West Alpha	Plugged	
25/11-D-10	A	H	1485	59 12 00.37	98.07.18	Esso	Observation well	3060 m
			001	02 24 35.21	98.07.23	West Alpha	Plugged	
25/11-D-10	B	H	1469	59 12 00.37	98.07.23	Esso	Oil producer	3060 m
			001	02 24 35.21	98.09.19	West Alpha	Temp.aband. at TD	
30/03-A-09	A		1480	60 46 57.66	98.08.12	Statoil	Oil producer	6680 m
			052	02 53 52.38	98.11.21	Veslefrikk A	Temp.aband. at TD	
30/03-A-10	A		1397	60 46 57.97	98.03.03	Statoil	Observation well	3260 m
			052	02 53 52.16	98.03.28	Veslefrikk A	Plugged	
30/03-A-10	B		1398	60 46 57.97	98.03.29	Statoil	Oil producer	3980 m
			052	02 53 52.16	98.05.11	Veslefrikk A	Oil	
30/09-B-13	A		1518	60 29 36.22	98.11.25	Hydro	Gas injector	m

Well			Reg.no PL	Position	Spudded Completed yr.mo.day	Operator Installation	Classification Status	TD (RKB)
			079	02 49 42.39	00.00.00	Oseberg B		
30/09-B-21	A		1450	60 29 36.17	98.05.14	Hydro	Observation well	3775 m
			079	02 49 42.76	98.06.07	Oseberg B	Plugged	
30/09-B-21	B		1451	60 29 36.17	98.06.08	Hydro	Oil producer	5219 m
			079	02 49 42.76	98.06.22	Oseberg B	Oil	
30/09-B-30	A		1407	60 29 36.13	98.01.21	Hydro	Oil producer	5724 m
			079	02 49 43.29	98.03.08	Oseberg B	Plugged	
30/09-B-30	B		1408	60 29 36.13	98.03.09	Hydro	Oil producer	5532 m
			079	02 49 43.29	98.04.28	Oseberg B	Oil	
30/09-B-41			1475	60 29 35.94	98.06.25	Hydro	Observation well	4089 m
			079	02 49 43.20	98.07.29	Oseberg B	Plugged	
30/09-B-41	A		1476	60 29 35.94	98.09.28	Hydro	Oil producer	6665 m
			079	02 49 43.20	98.11.13	Oseberg B		
30/09-F-20			1525	60 23 24.68	98.12.24	Hydro	Oil producer	m
			104	02 47 49.91	00.00.00	West Delta		
31/02-D-01		H	1472	60 52 03.17	98.08.01	Hydro	Observation well	2047 m
			054	03 26 12.14	98.08.13	Polar Pioneer	Plugged	
31/02-D-01	A	H	1473	60 52 03.17	98.08.14	Hydro	Oil producer	4220 m
			085	03 26 12.14	98.09.16	Polar Pioneer	Temp.aband. at TD	
31/02-L-41			1404	60 48 44.35	98.01.26	Hydro	Observation well	1708 m
			054	03 34 50.05	98.02.11	West Vanguard	Plugged	
31/02-M-42			1428	60 57 15.37	98.03.16	Hydro	Observation well	1855 m
			054	03 37 42.52	98.04.13	West Vanguard	Temp.aband. at TD	
31/02-P-13		H	1419	60 52 01.14	98.02.21	Hydro	Observation well	1967 m
			054	03 33 28.65	98.03.12	West Vanguard	Temp.aband. at TD	
31/02-P-14		H	1440	60 52 01.12	98.04.16	Hydro	Observation well	1815 m
			054	03 33 28.27	98.04.27	West Vanguard	Plugged	
31/02-P-14	A	H	1441	60 52 01.12	98.04.28	Hydro	Oil producer	5102 m
			054	03 33 28.27	98.06.14	West Vanguard	Temp.aband. at TD	
31/02-S-14		H	1477	60 53 42.09	98.07.12	Hydro	Observation well	1838 m
			054	03 39 16.44	98.07.26	West Vanguard	Plugged	
31/02-S-14	A	H	1478	60 53 42.09	98.07.29	Hydro	Oil producer	5010 m
			054	03 39 16.44	98.10.19	West Vanguard	Temp.aband. at TD	
31/03-S-41			1467	60 49 20.20	98.06.16	Hydro	Observation well	1755 m
			085	03 44 04.25	98.07.10	West Vanguard	Temp.aband. at TD	
31/04-A-20			1392	60 32 33.51	97.12.26	Hydro	Oil producer	7372 m
			055	03 02 50.35	98.05.23	Brage	Temp.aband. at TD	
31/04-A-33			1509	60 32 32.92	98.10.30	Hydro	Observation well	4227 m
			055	03 02 50.52	98.12.06	Brage	Temp.aband. at TD	
31/04-A-34			1491	60 32 33.09	98.09.01	Hydro	Oil producer	5783 m
			055	03 02 50.35	98.10.26	Brage	Temp.aband. at TD	
31/04-A-35			1481	60 32 33.17	98.07.25	Hydro	Oil producer	3862 m
			055	03 02 50.69	98.08.29	Brage	Temp.aband. at TD	
31/04-A-36			1453	60 32 33.17	98.06.06	Hydro	Water injector	4663 m
			055	03 02 51.03	98.07.14	Brage	Temp.aband. at TD	
31/05-I-11		H	1523	60 44 27.64	98.10.16	Hydro	Observation well	2332 m
			085	03 34 54.21	98.10.31	Polar Pioneer	Plugged	
31/05-I-11	A	H	1524	60 44 27.64	98.11.01	Hydro	Oil producer	m
			085	03 34 54.21	00.00.00	Polar Pioneer		
31/05-I-14			1405	60 44 27.64	98.01.11	Hydro	Observation well	1989 m
			085	03 34 54.21	98.01.23	Polar Pioneer	Plugged	
31/05-I-14	A	H	1430	60 44 27.64	98.01.23	Hydro	Oil producer	4633 m
			085	03 34 54.21	98.03.30	Polar Pioneer	Oil	
31/05-I-21	A	H	1386	60 43 42.50	98.05.25	Hydro	Oil producer	5060 m
			085	03 34 39.81	98.07.20	Polar Pioneer	Oil	
31/05-I-22	A	H	1396	60 43 42.75	97.12.19	Hydro	Oil producer	4500 m
			085	03 34 39.35	98.07.30	Polar Pioneer	Oil	
31/05-I-23		H	1413	60 43 42.86	98.04.02	Hydro	Oil producer	2040 m
			085	03 34 39.35	98.04.12	Polar Pioneer	Plugged	
31/05-I-23	A	H	1418	60 43 42.86	98.04.12	Hydro	Oil producer	4798 m
			085	03 34 39.35	98.05.23	Polar Pioneer	Oil	
31/06-A-09			1372	60 38 45.05	97.10.20	Statoil	Gas producer	1554 m
			085	03 43 35.39	98.04.09	Troll A	Gas	
31/06-A-21			1376	60 38 43.77	98.04.21	Statoil	Gas producer	1855 m
			085	03 43 35.08	98.05.16	Troll A	Temp.aband. at TD	
31/06-A-22			1377	60 38 43.69	98.01.01	Statoil	Gas producer	m
			085	03 43 35.08	98.01.05	Troll A	Temp. aband. at 14”	
31/06-A-23			1378	60 38 43.62	98.05.16	Statoil	Gas producer	m
			085	03 43 35.08	98.05.22	Troll A	Temp. aband. 14”	
31/06-A-37			1454	60 38 43.54	98.05.23	Statoil	Gas producer	2345 m
			085	03 43 35.53	98.06.13	Troll A	Temp.aband. at TD	
33/09-A-11	AY		1425	61 15 20.85	98.03.19	Statoil	Oil producer	4950 m
			037	01 51 15.02	98.10.25	Statfjord A	Oil	
33/09-A-25	A		1512	61 15 19.95	98.11.30	Statoil	Water injector	m

Well			Reg.no PL	Position	Spudded Completed yr.mo.day	Operator Installation	Classification Status	TD (RKB)
			037	01 51 13.90	00.00.00	Statfjord A		
33/09-A-41	A		1366	61 15 20.46	97.12.14	Statoil	Oil producer	4643 m
			037	01 51 13.95	98.02.17	Statfjord A	Oil	
33/09-C-19	A		1383	61 17 47.69	97.11.16	Statoil	Oil producer	5950 m
			037	01 54 09.15	98.01.07	Statfjord C	Temp.aband. at TD	
33/09-C-42	A		1343	61 17 47.71	98.01.10	Statoil	Oil producer	5300 m
			037	01 54 10.05	98.04.01	Statfjord C	Oil	
33/09-D-04		H	1532	61 26 49.96	98.12.30	Statoil	Water injector	m
			037	01 54 50.67	00.00.00	West Alpha		
33/09-E-04		H	1197	61 26 03.01	96.09.25	Statoil	Oil producer	2938 m
			037	01 55 30.23	98.02.13	Treasure Prospect	Temp.aband. at TD	
33/12-B-16	B		1511	61 12 24.75	98.10.22	Statoil	Oil producer	3997 m
			037	01 49 52.21	98.12.06	Statfjord B	Oil	
33/12-B-24	A		1460	61 12 24.07	98.08.13	Statoil	Oil producer	4361 m
			037	01 49 51.33	98.09.03	Statfjord B	Oil	
33/12-B-35	A		1500	61 12 23.97	98.09.16	Statoil	Oil producer	4605 m
			037	01 49 50.71	98.10.18	Statfjord B	Oil	
33/12-B-39	A		1426	61 12 23.84	98.04.11	Statoil	Oil producer	3909 m
			037	01 49 51.26	98.05.16	Statfjord B	Plugged	
33/12-B-39	B		1461	61 12 23.84	98.05.17	Statoil	Oil producer	4562 m
			037	01 49 51.26	98.07.05	Statfjord B	Oil	
34/07-E-02		H	1444	61 23 54.63	98.04.28	Saga	Water injector	4565 m
			089	02 04 04.70	98.06.22	Scarabeo 5	Temp.aband. at TD	
34/07-J-01		H	1495	61 16 29.70	98.09.11	Saga	Oil producer	4013 m
			089	02 07 11.87	98.12.21	Scarabeo 5	Temp.aband. at TD	
34/07-P-04			1363	61 26 56.83	97.09.07	Saga	Oil producer	4888 m
			089	02 08 37.37	98.03.22	Snorre P	Oil	
34/07-P-21			1429	61 26 57.46	98.05.16	Saga	Water injector	4915 m
			089	02 08 36.54	98.07.15	Snorre P	Temp.aband. at TD	
34/07-P-36			1506	61 26 58.11	98.10.09	Saga	Water injector	m
			089	02 08 37.60	00.00.00	Snorre P		
34/07-P-42			1479	61 26 58.37	98.07.31	Saga	Oil producer	3954 m
			089	02 08 36.52	98.08.28	Snorre P	Plugged	
34/07-P-42	A		1497	61 26 58.37	98.08.28	Saga	Oil producer	4109 m
			089	02 08 36.52	98.10.07	Snorre P	Oil	
34/08-A-01	B	H	1345	61 22 12.57	98.03.09	Hydro	Oil producer	4366 m
			120	02 27 35.13	98.04.02	West Delta	Temp.aband. at TD	
34/08-A-02		H	1381	61 22 12.80	97.11.16	Hydro	Gas injector	6500 m
			120	02 27 35.09	98.06.30	West Delta	Temp.aband. at TD	
34/08-A-03		H	1535	61 22 12.92	98.12.20	Hydro	Gas injector	m
			120	02 27 34.64	00.00.00	Visund A		
34/08-A-07		H	1360	61 22 13.26	97.10.06	Hydro	Oil producer	3642 m
			120	02 27 32.83	98.07.26	West Delta	Temp.aband. at TD	
34/10-A-19	A		1382	61 10 33.89	97.11.30	Statoil	Oil producer	2309 m
			050	02 11 22.99	98.01.27	Gullfaks A	Oil	
34/10-B-39			1458	61 12 09.90	98.04.03	Statoil	Oil producer	2474 m
			050	02 12 06.16	98.05.27	Gullfaks B	Plugged	
34/10-B-39	A		1527	61 12 09.90	98.12.06	Statoil	Oil producer	m
			050	02 12 06.16	00.00.00	Gullfaks B		
34/10-B-40			1482	61 12 09.94	98.09.01	Statoil	Oil producer	4069 m
			050	02 12 06.30	98.11.12	Gullfaks B	Temp.aband. at TD	
34/10-C-36	A		1280	61 12 54.77	97.05.30	Statoil	Oil prod./gas inj.	6164 m
			050	02 16 26.79	98.01.24	Gullfaks C	Oil	
34/10-C-37			1416	61 12 53.52	98.02.05	Statoil	Water injector	2672 m
			050	02 16 27.52	98.04.21	Gullfaks C	Temp.aband. at TD	
34/10-C-38			1437	61 12 54.68	98.04.27	Statoil	Oil producer	m
			050	02 16 26.13	98.05.27	Gullfaks C	Temp. abandoned at 10 3/4"	
34/10-C-40			1483	61 12 54.59	98.07.01	Statoil	Oil producer	m
			050	02 16 26.82	98.07.16	Gullfaks C	Temp. abandoned at 13 3/8"	
34/10-D-04		H	1543	61 07 26.68	98.06.27	Statoil	Oil producer	m
			050	02 14 39.66	98.08.14	Transocean Wildcat	Temp.aband. at TD	
34/10-E-04		H	1508	61 06 38.54	98.12.06	Statoil		m
			050	02 15 38.70	00.00.00	Transocean Wildcat		
34/10-F-04	A	H	1337	61 05 51.81	97.10.07	Statoil	Oil producer	5467 m
			050	02 16 35.81	98.02.11	Transocean Wildcat	Temp.aband. at TD	
34/10-G-02		H	1272	61 05 50.23	97.04.09	Statoil	Oil producer	5360 m
			050	02 16 36.25	98.10.30	Transocean Wildcat	Temp.aband. at TD	
34/10-H-02		H	1442	61 03 20.37	98.04.19	Statoil	Observation well	3972 m
			050	02 04 25.89	98.05.30	Transocean Wildcat	Plugged	
34/10-H-02	A	H	1443	61 03 20.37	98.05.30	Statoil	Oil producer	4493 m
			050	02 04 25.89	00.00.00	Transocean Wildcat		
34/10-J-01		H	1285	61 03 50.67	97.06.08	Statoil	Gas injector	4459 m

Well			Reg.no PL	Position	Spudded Completed yr.mo.day	Operator Installation	Classification Status	TD (RKB)
			050	02 00 56.65	98.06.04	Deepsea Trym	Temp.aband. at TD	
34/10-K-02	A	H	1498	61 08 10.45	98.08.22	Statoil	Oil producer	3463 m
			050	02 00 56.98	98.10.04	Deepsea Trym	Temp.aband. at TD	
6407/07-A-06		H	1513	64 16 14.93	98.10.25	Hydro	Gas injector	3600 m
			107	07 12 07.23	98.12.28	Njord	Temp.aband. at TD	
6407/07-A-07		H	1421	64 16 15.11	98.02.15	Hydro	Gas injector	3880 m
			107	07 12 07.93	98.05.28	Njord	Temp.aband. at TD	
6407/07-A-10	A	H	1277	64 16 15.78	97.12.09	Hydro	Oil producer	4772 m
			107	07 12 09.44	98.02.13	Njord	Oil	
6407/07-A-16		H	1499	64 16 16.69	98.09.08	Hydro	Oil producer	4418 m
			107	07 12 04.90	98.10.14	Njord	Oil	
6407/07-A-17		H	1533	64 16 16.85	98.12.30	Hydro	Oil producer	m
			107	07 12 04.11	00.00.00	Njord		
6506/11-G-04		H	1335	65 05 17.80	97.07.10	Statoil	Gas injector	6370 m
			134	06 39 43.59	98.11.28	Transocean Arctic	Temp.aband. at TD	
6506/12-I-01		H	1359	65 05 07.18	98.01.18	Statoil	Gas producer	4866 m
			094	06 40 54.43	98.10.25	Transocean Searcher	Temp.aband. at TD	
6506/12-I-03		H	1455	65 06 07.47	98.05.22	Statoil	Oil producer	m
			094	06 40 54.13	00.00.00	Transocean Arctic		
6506/12-I-04		H	1520	65 05 07.20	98.10.25	Statoil	Oil producer	5268 m
			094	06 40 54.75	98.12.02	Transocean Searcher	Temp.aband. at TD	
6506/12-K-01		H	1488	65 08 01.66	98.07.24	Statoil	Gas injector	5208 m
			094	06 42 25.27	98.09.05	Transocean Winner	Temp.aband. at TD	
6506/12-K-03		H	1358	65 08 01.97	97.06.24	Statoil	Gas injector	4664 m
			094	06 42 25.10	98.06.12	Transocean Winner	Temp.aband. at TD	
6506/12-L-02		H	1329	65 08 17.72	97.06.28	Statoil	Oil producer	5026 m
			094	06 46 57.36	98.01.12	Transocean Searcher	Temp.aband. at TD	
6506/12-L-03		H	1474	65 08 17.83	98.07.13	Statoil	Oil producer	5092 m
			094	06 46 57.49	98.08.14	Transocean Arctic	Temp.aband. at TD	
6506/12-P-01		H	1484	65 01 22.64	98.10.20	Statoil	Oil producer	4845 m
			094	06 52 45.83	98.11.22	Transocean Winner	Temp.aband. at TD	
6506/12-P-02		H	1423	65 01 22.83	98.02.17	Statoil	Oil producer	5163 m
			094	06 52 45.47	98.04.12	Transocean Arctic	Temp.aband. at TD	
6506/12-R-02		H	1470	65 02 00.35	98.06.16	Statoil	Gas injector	4080 m
			094	06 54 06.72	98.07.22	Transocean Winner	Temp.aband. at TD	
6506/12-R-04		H	1387	65 02 00.27	97.12.25	Statoil	Gas injector	4723 m
			094	06 54 07.05	98.02.16	Transocean Arctic	Temp.aband. at TD	
6506/12-S-01		H	1355	65 00 57.87	97.10.30	Statoil	Observation well	4990 m
			094	06 56 45.38	98.01.03	Transocean Winner	Temp.aband. at TD	
6506/12-S-01	A	H	1356	65 00 57.87	98.01.04	Statoil	Oil producer	5600 m
			094	06 56 45.38	98.04.06	Transocean Winner	Temp.aband. at TD	
6506/12-S-02		H	1432	65 00 58.08	98.04.08	Statoil	Oil producer	5850 m
			094	06 56 44.99	00.00.00	Transocean Winner		
6506/12-S-03		H	1490	65 00 57.96	98.08.17	Statoil	Oil producer	6929 m
			094	06 56 45.23	98.10.21	Transocean Arctic	Temp.aband. at TD	
6507/07-A-07			1367	65 19 33.14	97.07.12	Statoil	Oil producer	5253 m
			095	07 19 04.05	98.01.15	Heidrun	Oil	
6507/07-A-18			1433	65 19 32.76	98.03.29	Statoil	Oil producer	441 m
			095	07 19 02.61	98.05.08	Heidrun	Temp.aband. at TD	
6507/07-A-22			1390	65 19 32.89	98.01.03	Statoil	Oil producer	3300 m
			095	07 19 03.81	98.03.28	Heidrun	Temp.aband. at TD	
6507/07-A-37			1486	65 19 32.68	98.10.16	Statoil	Water injector	m
			095	07 19 03.70	00.00.00	Heidrun		
6507/07-A-40			1449	65 19 32.77	98.05.14	Statoil	Oil producer	3127 m
			095	07 19 04.52	98.08.01	Heidrun	Temp.aband. at TD	
6507/11-Y-01		H	1496	65 00 18.51	98.09.08	Statoil	Oil producer	m
			094	07 33 25.58	98.09.24	Transocean Winner	Temp. abandoned at 9 5/8"	
6608/10-B-04		H	1344	66 00 55.47	98.01.12	Statoil	Oil producer	2555 m
			128	08 03 16.37	98.02.06	Transocean Prospect	Oil	
6608/10-C-01		H	1422	66 00 51.89	98.02.12	Statoil	Water injector	m
			128	08 03 22.53	98.03.25	Transocean Prospect	Temp. abandoned at 13 3/8"	
6608/10-C-02		H	1501	66 00 51.97	98.10.01	Statoil	Water injector	4421 m
			128	08 03 21.93	98.11.27	Transocean Prospect	Temp.aband. at TD	
6608/10-D-02		H	1249	66 00 49.15	97.01.09	Statoil	Oil producer	4174 m
			128	08 03 28.53	98.01.05	Transocean Wildcat	Oil	
6608/10-D-04		H	1415	66 00 49.62	98.01.07	Statoil	Oil producer	3137 m
			128	08 03 28.09	98.06.18	Transocean Prospect	Oil	
6608/10-E-03		H	1487	66 02 43.50	98.07.29	Statoil	Oil producer	3110 m
			128	08 05 57.30	98.09.23	Transocean Prospect	Oil	

Table 7.4.c
Development wells drilled from mobile units 1998
H=subsea-completed, A/B/C=sidetracked new well, Y=branch well, X=junked well

Well			Reg.no	Position	Spudded	Operator	Classification	TD
			PL		Completed	Installation	Status	(RKB)
2/04-X-02			1447	56 32 50.91	98.04.19	Phillips	Observation well	4572 m
			018	03 13 08.08	98.05.23	Mærsk Gallant	Plugged	
2/04-X-02	A		1448	56 32 50.91	98.05.23	Phillips	Oil producer	4388 m
			018	03 13 08.08	98.06.01	Mærsk Gallant	Temp. aband. at TD	
2/04-X-05			1406	56 32 51.00	98.02.13	Phillips	Oil producer	4492 m
			018	03 13 08.00	98.03.16	Mærsk Gallant	Oil	
2/04-X-07			1464	56 32 50.98	98.06.01	Phillips	Oil producer	7775 m
			018	03 13 08.28	98.12.20	Mærsk Gallant	Temp. aband. at TD	
2/04-X-10			1399	56 32 51.08	97.12.14	Phillips	Oil producer	4512 m
			018	03 13 08.14	98.02.13	Mærsk Gallant	Oil	
2/04-X-12			1434	56 32 51.04	98.03.16	Phillips	Oil producer	3741 m
			018	03 13 08.44	98.04.17	Mærsk Gallant	Oil	
2/08-F-11			1391	56 16 35.61	98.01.07	Amoco	Oil producer	4388 m
			006	03 23 47.06	98.02.18	Mærsk Guardian	Oil	
2/08-F-12			1424	56 16 35.49	98.02.18	Amoco	Oil producer	5166 m
			006	03 23 47.10	98.04.23	Mærsk Guardian	Oil	
2/08-F-13			1457	56 16 35.58	98.06.01	Amoco	Oil producer	4567 m
			006	03 23 47.28	98.08.12	Mærsk Guardian	Temp. aband. at TD	
2/08-F-14			1446	56 16 35.66	98.04.24	Amoco	Oil producer	2635 m
			006	03 23 47.19	98.05.28	Mærsk Guardian	Oil	
2/08-F-17			1365	56 16 35.52	97.10.02	Amoco	Oil producer	4830 m
			006	03 23 47.25	98.01.28	Mærsk Guardian	Oil	
2/08-F-18			1489	56 16 35.51	98.08.18	Amoco	Oil producer	m
			006	03 23 46.90	00.00.00	Mærsk Guardian		
9/02-A-03			1427	57 49 07.58	98.02.02	Statoil	Gas injector	7684 m
			114	04 31 11.00	98.02.23	Mærsk Giant	Temp. aband. at TD	
15/09-B-11			1374	58 25 20.45	98.03.15	Statoil	Gas producer	4812 m
			046	01 43 04.37	98.07.25	West Epsilon	Gas	
15/09-B-22			1393	58 25 04.31	97.11.29	Statoil	Gas producer	8306 m
			046	01 43 04.48	98.10.31	West Epsilon	Temp. aband. at TD	
15/09-B-22	A		1394	58 25 04.31	98.11.16	Statoil	Gas producer	m
			046	01 43 04.48	00.00.00	West Epsilon		
15/09-C-02	A	H	1352	58 26 09.31	98.03.29	Statoil	Cond./gas	3500 m
			046	01 55 46.56	98.06.06	Byford Dolphin	Temp. aband. at TD	
15/12-A-02			1504	58 04 40.56	98.09.15	Saga	Oil producer	2978 m
			038	01 53 25.63	98.10.02	Noble Al White	Temp. aband. at TD	
15/12-A-05			1507	58 04 40.48	98.10.17	Saga	Oil producer	3852 m
			038	01 53 25.60	98.12.04	Noble Al White	Temp. aband. at TD	
15/12-A-08			1452	58 04 40.55	98.05.15	Saga	Oil producer	3347 m
			038	01 53 25.84	98.07.04	Noble Al White	Temp. aband. at TD	
15/12-A-11			1505	58 04 40.43	98.08.16	Saga	Oil producer	3566 m
			038	01 53 25.75	98.08.31	Noble Al White	Temp. aband. at TD	
15/12-A-14			1471	58 04 40.36	98.07.10	Saga	Water/Gas injector	4350 m
			038	01 53 25.71	98.08.15	Noble Al White	Temp. aband. at TD	
15/12-A-15			1529	58 04 40.38	98.12.25	Saga	Oil producer	m
			038	01 53 25.80	00.00.00	Noble Al White		
25/11-A-06		H	1210	59 11 28.42	96.10.07	Esso	Oil producer	1807 m
			001	02 21 37.38	98.10.12	West Alpha	Temp. aband. at TD	
25/11-B-07	A	H	1253	59 10 40.45	97.01.14	Esso	Oil producer	2891 m
			001	02 22 46.46	98.04.18	West Alpha	Temp. aband. at TD	
25/11-B-11		H	1410	59 10 42.54	98.01.23	Esso	Oil producer	2934 m
			001	02 22 44.00	98.04.13	West Alpha	Temp. aband. at TD	
25/11-B-14		H	1411	59 10 42.75	98.01.17	Esso	Oil producer	2167 m
			001	02 22 45.85	98.02.13	West Alpha	Temp. aband. at TD	
25/11-B-14	A	H	1412	59 10 42.75	98.03.20	Esso	Water injector	2695 m
			001	02 22 45.85	98.04.24	West Alpha	Temp. aband. at TD	
25/11-C-03	B	H	1402	59 11 00.62	97.12.21	Esso	Oil producer	2118 m
			001	02 24 32.52	98.01.07	West Alpha	Temp. aband. at TD	
25/11-C-12		H	1445	59 10 59.93	98.04.28	Esso	Water injector	2267 m
			001	02 24 36.26	98.05.27	West Alpha	Temp. aband. at TD	
25/11-C-13		H	1310	59 10 59.87	97.05.07	Esso	Oil producer	2725 m
			001	02 24 34.62	98.06.10	West Alpha	Temp. aband. at TD	
25/11-C-17		H	1493	59 10 59.03	98.10.14	Esso	Observation well	2450 m

Well			Reg.no	Position	Spudded	Operator	Classification	TD
			PL		Completed	Installation	Status	(RKB)
			001	02 24 36.87	98.11.06	West Alpha	Plugged	
25/11-C-17	A	H	1494	59 10 59.03	98.11.06	Esso	Oil producer	3015 m
			001	02 24 36.87	98.12.10	West Alpha	Temp. aband. at TD	
25/11-D-10		H	1468	59 12 00.37	98.06.12	Esso	Observation well	2496 m
			001	02 24 35.21	98.07.15	West Alpha	Plugged	
25/11-D-10	A	H	1485	59 12 00.37	98.07.18	Esso	Observation well	3060 m
			001	02 24 35.21	98.07.23	West Alpha	Plugged	
25/11-D-10	B	H	1469	59 12 00.37	98.07.23	Esso	Oil producer	3060 m
			001	02 24 35.21	98.09.19	West Alpha	Temp. aband. at TD	
30/09-F-20			1525	60 23 24.68	98.12.24	Hydro	Oil producer	m
			104	02 47 49.91	00.00.00	West Delta		
31/02-D-01		H	1472	60 52 03.17	98.08.01	Hydro	Observation well	2047 m
			054	03 26 12.14	98.08.13	Polar Pioneer	Plugged	
31/02-D-01	A	H	1473	60 52 03.17	98.08.14	Hydro	Oil producer	4220 m
			085	03 26 12.14	98.09.16	Polar Pioneer	Temp. aband. at TD	
31/02-L-41			1404	60 48 44.35	98.01.26	Hydro	Observation well	1708 m
			054	03 34 50.05	98.02.11	West Vanguard	Plugged	
31/02-M-42			1428	60 57 15.37	98.03.16	Hydro	Observation well	1855 m
			054	03 37 42.52	98.04.13	West Vanguard	Temp. aband. at TD	
31/02-P-13		H	1419	60 52 01.14	98.02.21	Hydro	Observation well	1967 m
			054	03 33 28.65	98.03.12	West Vanguard	Temp. aband. at TD	
31/02-P-14		H	1440	60 52 01.12	98.04.16	Hydro	Observation well	1815 m
			054	03 33 28.27	98.04.27	West Vanguard	Plugged	
31/02-P-14	A	H	1441	60 52 01.12	98.04.28	Hydro	Oil producer	5102 m
			054	03 33 28.27	98.06.14	West Vanguard	Temp. aband. at TD	
31/02-S-14		H	1477	60 53 42.09	98.07.12	Hydro	Observation well	1838 m
			054	03 39 16.44	98.07.26	West Vanguard	Plugged	
31/02-S-14	A	H	1478	60 53 42.09	98.07.29	Hydro	Oil producer	5010 m
			054	03 39 16.44	98.10.19	West Vanguard	Temp. aband. at TD	
31/03-S-41			1467	60 49 20.20	98.06.16	Hydro	Observation well	1755 m
			085	03 44 04.25	98.07.10	West Vanguard	Temp. aband. at TD	
31/05-I-11		H	1523	60 44 27.64	98.10.16	Hydro	Observation well	2332 m
			085	03 34 54.21	98.10.31	Polar Pioneer	Plugged	
31/05-I-11	A	H	1524	60 44 27.64	98.11.01	Hydro	Oil producer	m
			085	03 34 54.21	00.00.00	Polar Pioneer		
31/05-I-14			1405	60 44 27.64	98.01.11	Hydro	Observation well	1989 m
			085	03 34 54.21	98.01.23	Polar Pioneer	Plugged	
31/05-I-14	A	H	1430	60 44 27.64	98.01.23	Hydro	Oil producer	4633 m
			085	03 34 54.21	98.03.30	Polar Pioneer	Oil	
31/05-I-21	A	H	1386	60 43 42.50	98.05.25	Hydro	Oil producer	5060 m
			085	03 34 39.81	98.07.20	Polar Pioneer	Oil	
31/05-I-22	A	H	1396	60 43 42.75	97.12.19	Hydro	Oil producer	4500 m
			085	03 34 39.35	98.07.30	Polar Pioneer	Oil	
31/05-I-23		H	1413	60 43 42.86	98.04.02	Hydro	Oil producer	2040 m
			085	03 34 39.35	98.04.12	Polar Pioneer	Plugged	
31/05-I-23	A	H	1418	60 43 42.86	98.04.12	Hydro	Oil producer	4798 m
			085	03 34 39.35	98.05.23	Polar Pioneer	Oil	
33/09-D-04		H	1532	61 26 49.96	98.12.30	Statoil	Water injector	m
			037	01 54 50.67	00.00.00	West Alpha		
33/09-E-04		H	1197	61 26 03.01	96.09.25	Statoil	Oil producer	2938 m
			037	01 55 30.23	98.02.13	Treasure Prospect	Temp. aband. at TD	
34/07-E-02		H	1444	61 23 54.63	98.04.28	Saga	Water injector	4565 m
			089	02 04 04.70	98.06.22	Scarabeo 5	Temp. aband. at TD	
34/07-J-01		H	1495	61 16 29.70	98.09.11	Saga	Oil producer	4013 m
			089	02 07 11.87	98.12.21	Scarabeo 5	Temp. aband. at TD	
34/08-A-01	B	H	1345	61 22 12.57	98.03.09	Hydro	Oil producer	4366 m
			120	02 27 35.13	98.04.02	West Delta	Temp. aband. at TD	
34/08-A-02		H	1381	61 22 12.80	97.11.16	Hydro	Gas injector	6500 m
			120	02 27 35.09	98.06.30	West Delta	Temp. aband. at TD	
34/08-A-07		H	1360	61 22 13.26	97.10.06	Hydro	Oil producer	3642 m
			120	02 27 32.83	98.07.26	West Delta	Temp. aband. at TD	
34/10-D-04		H	1543	61 07 26.68	98.06.27	Statoil	Oil producer	m
			050	02 14 39.66	98.08.14	Transocean Wildcat	Temp. aband. at TD	
34/10-E-04		H	1508	61 06 38.54	98.12.06	Statoil		m
			050	02 15 38.70	00.00.00	Transocean Wildcat		
34/10-F-04	A	H	1337	61 05 51.81	97.10.07	Statoil	Oil producer	5467 m
			050	02 16 35.81	98.02.11	Transocean Wildcat	Temp. aband. at TD	

Well			Reg.no	Position	Spudded	Operator	Classification	TD
			PL		Completed	Installation	Status	(RKB)
34/10-G-02		H	1272	61 05 50.23	97.04.09	Statoil	Oil producer	5360 m
			050	02 16 36.25	98.10.30	Transocean Wildcat	Temp. aband. at TD	
34/10-H-02		H	1442	61 03 20.37	98.04.19	Statoil	Observation well	3972 m
			050	02 04 25.89	98.05.30	Transocean Wildcat	Plugged	
34/10-H-02	A	H	1443	61 03 20.37	98.05.30	Statoil	Oil producer	4493 m
			050	02 04 25.89	00.00.00	Transocean Wildcat		
34/10-J-01		H	1285	61 03 50.67	97.06.08	Statoil	Gas injector	4459 m
			050	02 00 10.58	98.08.11	Transocean Wildcat	Temp. aband. at TD	
34/10-K-02		H	1431	61 08 10.47	98.03.21	Statoil	Oil producer	4237 m
			050	02 00 56.65	98.06.04	Deepsea Trym	Temp. aband. at TD	
34/10-K-02	A	H	1498	61 08 10.45	98.08.22	Statoil	Oil producer	3463 m
			050	02 00 56.98	98.10.04	Deepsea Trym	Temp. aband. at TD	
6506/11-G-04		H	1335	65 05 17.80	97.07.10	Statoil	Gas injector	6370 m
			134	06 39 43.59	98.11.28	Transocean Arctic	Temp. aband. at TD	
6506/12-I-01		H	1359	65 05 07.18	98.01.18	Statoil	Gas producer	4866 m
			094	06 40 54.43	98.10.25	Transocean Searcher	Temp. aband. at TD	
6506/12-I-03		H	1455	65 06 07.47	98.05.22	Statoil	Oil producer	m
			094	06 40 54.13	00.00.00	Transocean Arctic		
6506/12-I-04		H	1520	65 05 07.20	98.10.25	Statoil	Oil producer	5268 m
			094	06 40 54.75	98.12.02	Transocean Searcher	Temp. aband. at TD	
6506/12-K-01		H	1488	65 08 01.66	98.07.24	Statoil	Gas injector	5208 m
			094	06 42 25.27	98.09.05	Transocean Winner	Temp. aband. at TD	
6506/12-K-03		H	1358	65 08 01.97	97.06.24	Statoil	Gas injector	4664 m
			094	06 42 25.10	98.06.12	Transocean Winner	Temp. aband. at TD	
6506/12-L-02		H	1329	65 08 17.72	97.06.28	Statoil	Oil producer	5026 m
			094	06 46 57.36	98.01.12	Transocean Searcher	Temp. aband. at TD	
6506/12-L-03		H	1474	65 08 17.83	98.07.13	Statoil	Oil producer	5092 m
			094	06 46 57.49	98.08.14	Transocean Arctic	Temp. aband. at TD	
6506/12-P-01		H	1484	65 01 22.64	98.10.20	Statoil	Oil producer	4845 m
			094	06 52 45.83	98.11.22	Transocean Winner	Temp. aband. at TD	
6506/12-P-02		H	1423	65 01 22.83	98.02.17	Statoil	Oil producer	5163 m
			094	06 52 45.47	98.04.12	Transocean Arctic	Temp. aband. at TD	
6506/12-R-02		H	1470	65 02 00.35	98.06.16	Statoil	Gas injector	4080 m
			094	06 54 06.72	98.07.22	Transocean Winner	Temp. aband. at TD	
6506/12-R-04		H	1387	65 02 00.27	97.12.25	Statoil	Gas injector	4723 m
			094	06 54 07.05	98.02.16	Transocean Arctic	Temp. aband. at TD	
6506/12-S-01		H	1355	65 00 57.87	97.10.30	Statoil	Observation well	4990 m
			094	06 56 45.38	98.01.03	Transocean Winner	Temp. aband. at TD	
6506/12-S-01	A	H	1356	65 00 57.87	98.01.04	Statoil	Oil producer	5600 m
			094	06 56 45.38	98.04.06	Transocean Winner	Temp. aband. at TD	
6506/12-S-02		H	1432	65 00 58.08	98.04.08	Statoil	Oil producer	5850 m
			094	06 56 44.99	00.00.00	Transocean Winner		
6506/12-S-03		H	1490	65 00 57.96	98.08.17	Statoil	Oil producer	6929 m
			094	06 56 45.23	98.10.21	Transocean Arctic	Temp. aband. at TD	
6507/11-Y-01		H	1496	65 00 18.51	98.09.08	Statoil	Oil producer	m
			094	07 33 25.58	98.09.24	Transocean Winner	Temp. abandoned at 9 5/8"	
6608/10-B-04		H	1344	66 00 55.47	98.01.12	Statoil	Oil producer	2555 m
			128	08 03 16.37	98.02.06	Transocean Prospect	Oil	
6608/10-C-01		H	1422	66 00 51.89	98.02.12	Statoil	Water injector	m
			128	08 03 22.53	98.03.25	Transocean Prospect	Temp. abandoned at 13 3/8"	
6608/10-C-02		H	1501	66 00 51.97	98.10.01	Statoil	Water injector	4421 m
			128	08 03 21.93	98.11.27	Transocean Prospect	Temp. aband. at TD	
6608/10-D-02		H	1249	66 00 49.15	97.01.09	Statoil	Oil producer	4174 m
			128	08 03 28.53	98.01.05	Transocean Wildcat	Oil	
6608/10-D-04		H	1415	66 00 49.62	98.01.07	Statoil	Oil producer	3137 m
			128	08 03 28.09	98.06.18	Transocean Prospect	Oil	
6608/10-E-03		H	1487	66 02 43.50	98.07.29	Statoil	Oil producer	3110 m
			128	08 05 57.30	98.09.23	Transocean Prospect	Oil	

Figure 7.4.a
Development wells per field

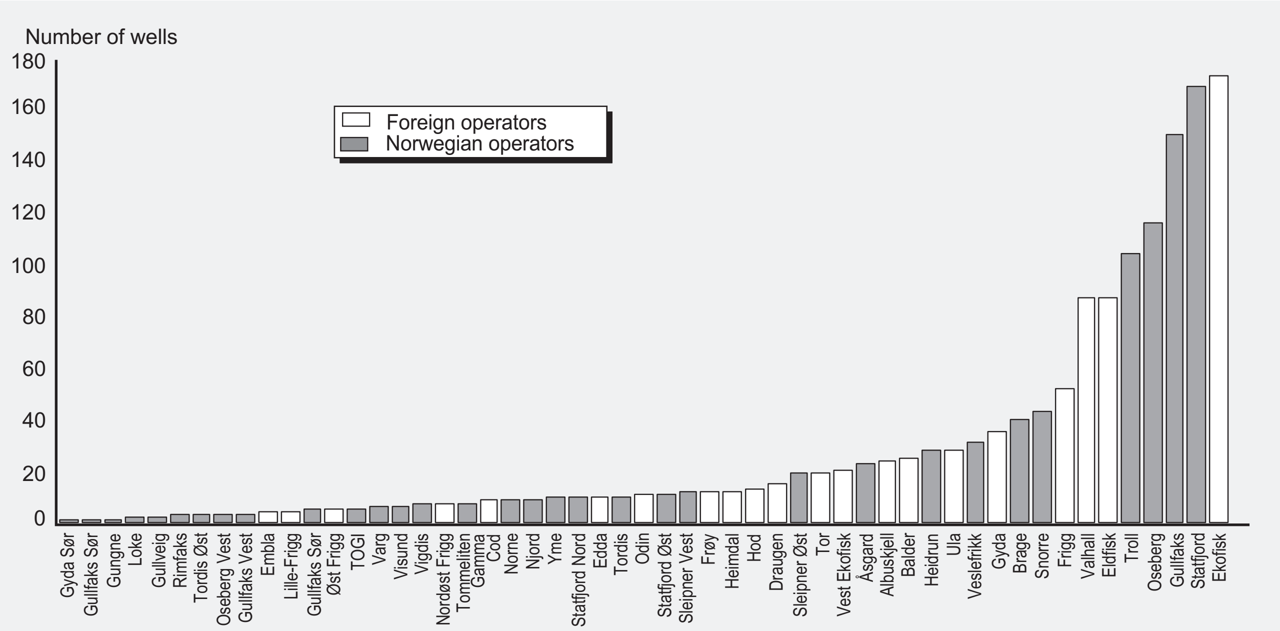


Figure 7.4.b
Development wells on the Norwegian continental shelf

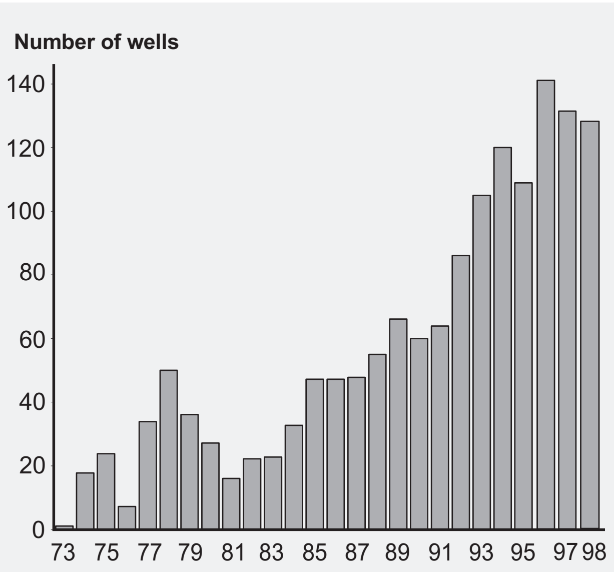


Figure 7.4.c
Development wells per operator

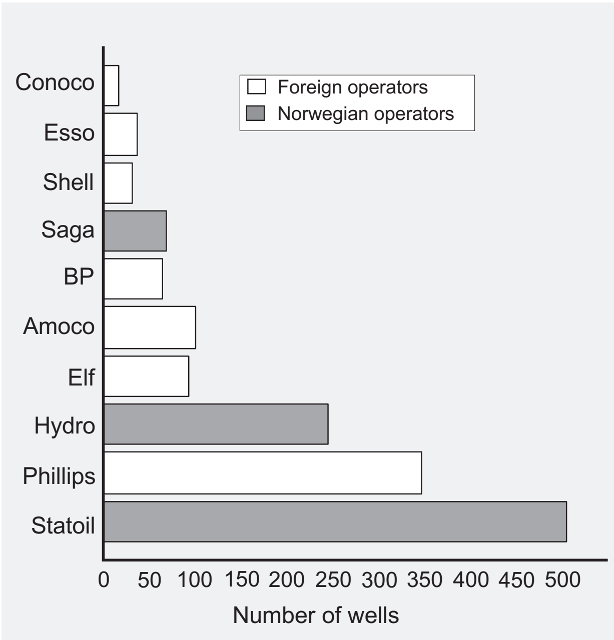


Figure 7.4.d
Development drilling by mobile installations

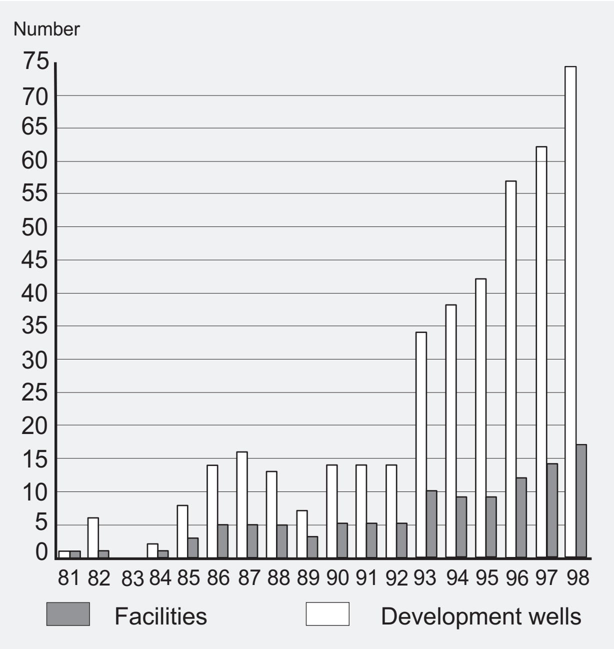
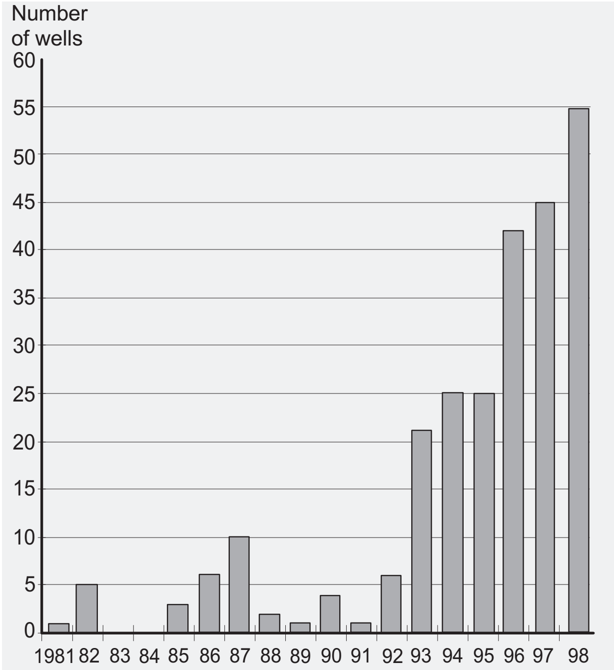


Figure 7.4.e
Subsea completed wells per year



7.5 RESOURCES IN DISCOVERIES AND FIELDS ON THE NORWEGIAN CONTINENTAL SHELF

Table 7.5.a
1998 discoveries reported as part of other fields or discoveries

Discovery:	Reported in field:
2/7-8	Eldfisk
2/11-10 S	Hod
9/2-3	Yme
9/2-6 S	Yme
9/2-7 S	Yme
15/9-20 S	Sleipner Øst
15/12-10 S	Varg
25/7-3 Jotun	Jotun
25/8-8 S Jotun	Jotun
30/3-6 S	Veslefrikk
30/6-19 Beta Sadel	Oseberg Øst
30/9-4 S Oseberg Sør	Oseberg Sør
30/9-5 S Oseberg Sør	Oseberg Sør
30/9-6 Oseberg Sør	Oseberg Sør
30/9-7 Oseberg Sør	Oseberg Sør
30/9-9 Oseberg Sør	Oseberg Sør
30/9-10 Oseberg Sør	Oseberg Sør
30/9-13 S Oseberg Sør	Oseberg Sør
30/9-14 G Oseberg Sør	Oseberg Sør
30/9-15 Oseberg Sør	Oseberg Sør
30/9-16 K Oseberg Sør	Oseberg Sør
33/9-0 Murchison NØ Horst	Murchison
34/7-13 Snorre Vest	Vigdis
34/10-21	Gullfaks Sør
34/8-4 S	Visund
6506/12-1 Smørbukk	Åsgard
6506/12-3 Smørbukk Sør	Åsgard
6507/11-1 Midgard	Åsgard
6608/10-4	Norne

Discovery:	Reported in discovery:
16/7-7 S	16/7-4 Sigyn
24/9-6	24/9-5
25/8-11	25/8-10 S
30/7-2	30/7-6 Hild
35/11-2	35/11-4 Fram
35/11-7	35/11-4 Fram
35/11-8 S	35/11-4 Fram
36/7-1	35/9-1 Gjøa
6407/1-3 Tyrihans Nord	6407/1-2 Tyrihans Sør
7120/7-1 Askeladd Vest	7121/4-1 Snøhvit
7120/7-2 Askeladd Sentral	7121/4-1 Snøhvit
7120/8-1 Askeladd	7121/4-1 Snøhvit
7120/9-1 Albatross	7121/4-1 Snøhvit
7121/7-2 Albatross Sør	7121/4-1 Snøhvit

Table 7.5.b
Reserves and resources in fields

Reserves where production has ceased (Class 0)[1)]

	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tonnes	Condensate 10^6 Sm^3	o.e 10^6 Sm^3	Discovery year
Albuskjell	7.4	16.0	1.0	0.0	24.7	1972
Cod	2.9	7.5	0.5	0.0	11.1	1968
Edda	4.8	2.1	0.2	0.0	7.2	1972
Mime	0.4	0.1	0.0	0.0	0.5	1982
Nordøst Frigg	0.0	11.6	0.0	0.0	11.7	1974
Odin	0.0	29.3	0.0	0.0	29.3	1974
Tommeliten Gamma	3.9	9.2	0.6	0.0	13.9	1978
Vest Ekofisk	12.2	26.9	1.4	0.0	40.9	1970
Øst Frigg	0.0	9.4	0.0	0.1	9.4	1973
Total	**31.6**	**112.1**	**3.8**	**0.1**	**148.6**	

1) Original recoverable reserves in fields where production has ceased is equivalent to the volume delivered. Any remaining recoverable resources are included in the appropriate resource classes.

Reserves in production or with approved development plan (Classes 1 and 2)

	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tonnes	Condensate 10^6 Sm^3	o.e 10^6 Sm^3	Discovery year[3)]
Balder[2)]	27.2	0.0	0.0	0.0	27.2	1967
Brage	54.0	3.2	0.9	0.0	58.4	1980
Draugen	111.3	0.0	0.0	0.0	111.3	1984
Ekofisk	410.7	146.6	15.4	0.0	577.3	1969
Eldfisk	109.3	52.7	4.6	0.0	168.0	1970
Embla	10.1	5.6	1.1	0.0	17.1	1988
Frigg	0.0	119.2	0.0	0.5	119.6	1971
Frøy	5.9	1.5	0.0	0.1	7.5	1987
Gullfaks	315.4	21.2	2.0	0.0	339.2	1978
Gullfaks Sør[2)]	40.0	59.5	0.0	0.0	99.5	1978
Gullfaks Vest	3.6	0.0	0.0	0.0	3.6	1991
Gullveig	4.2	2.9	0.0	0.0	7.1	1995
Gungne	0.0	4.5	0.5	1.5	6.7	1982
Gyda	29.0	3.5	1.5	0.0	34.4	1980
Gyda Sør	6.1	3.5	0.7	0.0	10.4	1991
Heidrun	180.4	19.8	0.0	0.0	200.2	1985
Heimdal	6.9	42.6	0.0	0.0	49.5	1972
Hod	9.3	1.8	0.3	0.0	11.4	1974
Jotun[2)]	30.7	1.8	0.0	0.0	32.5	1994
Lille-Frigg	0.0	2.3	0.0	1.2	3.5	1975
Loke	0.0	3.5	0.5	1.3	5.4	1983
Murchison	13.3	0.4	0.4	0.0	14.2	1975
Njord	31.6	0.0	0.0	0.0	31.6	1986
Norne	80.4	15.0	1.4	0.0	97.3	1992
Oseberg	336.0	16.4	6.0	0.5	360.7	1979
Oseberg Sør[2)]	53.5	11.4	0.0	0.0	64.9	1984
Oseberg Vest	1.6	6.0	0.0	0.0	7.6	1984
Oseberg Øst[2)]	23.5	0.8	0.0	0.0	24.3	1986
Rimfaks[2)]	16.9	-1.2	0.0	0.0	15.7	1983
Sleipner Vest	0.0	128.1	8.7	27.7	167.1	1974
Sleipner Øst	0.0	38.4	9.5	20.8	71.6	1981
Snorre	225.3	7.7	5.7	0.0	240.4	1979
Statfjord	555.7	56.4	14.4	0.0	630.8	1974
Statfjord Nord	40.6	3.0	0.7	0.0	44.5	1977

	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tonnes	Condensate 10^6 Sm^3	o.e 10^6 Sm^3	Discovery year[3)]
Statfjord Øst	36.4	5.2	1.8	0.0	43.9	1976
Tor	28.3	11.7	1.3	0.0	41.7	1970
Tordis	29.1	2.1	0.7	0.0	32.1	1987
Tordis Øst	4.4	0.4	0.1	0.0	4.9	1993
Troll [4)]	211.4	613.2	0.0	0.0	824.0	1979
Ula	69.1	3.5	2.5	0.0	75.9	1976
Valhall	116.7	25.1	3.9	0.0	146.9	1975
Varg	5.5	0.0	0.0	0.0	5.5	1984
Veslefrikk	54.5	5.5	1.6	0.0	62.1	1981
Vigdis	30.7	2.2	0.0	0.0	32.9	1986
Visund[2)]	48.5	0.0	0.0	0.0	48.5	1986
Yme	11.5	0.0	0.0	0.0	11.5	1987
Åsgard[2)]	75.5	191.0	28.3	37.4	340.7	1981
Total	**3 453.7**	**1 637.8**	**114.7**	**90.9**	**5 331.0**	

2) Fields with an approved development plan where production had not started as of 31 December 1998
3) Discovery year is defined as the year of the oldest discovery well included in the field.
4) Including TOGI

Resources in fields

	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tonnes	Condensate 10^6 Sm^3	o.e 10^6 Sm^3
Resources in the late planning stages (Class 3)	176.6	485.7	7.7	2.4	674.7
Resources in the early planning stages (Class 4)	50.9	81.9	4.4	0.0	138.5
Resources which may be developed over the long term (Class 5)	19.3	387.5	0.7	0.0	407.7
Resources where development is not very likely (Class 6)	4.9	0.4	0.0	0.0	5.3
Total	**357.7**	**1064.5**	**118.8**	**2.4**	**1332.2**

Table 7.5.c
Resources in discoveries

Resources in the late planning stages (Class 3)

Name of discovery	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tonnes	Cond 10^6 Sm^3	Total 10^6 Sm^3o.e	Discovery year
1/3-3	7.1	1.8	0.8	0.0	9.9	1983
15/5-5	8.7	0.4	0.0	0.0	9.1	1995
15/9-19 S Volve	12.1	1.8	0.0	0.0	14.0	1993
16/7-4 Sigyn	0.0	6.2	2.2	5.1	14.2	1982
2/12-1 Freja	2.0	0.3	0.1	0.0	2.5	1987
25/11-15 Grane	112.0	0.0	0.0	0.0	112.0	1991
25/11-16	3.6	0.0	0.0	0.0	3.6	1992
25/4-6 S Vale	0.0	3.2	0.0	3.9	7.2	1991
25/5-3 Skirne	0.0	5.1	0.0	1.0	6.0	1990
3/7-4 Trym	0.0	2.7	0.0	0.7	3.4	1990
30/2-1 Huldra	0.0	18.7	0.3	7.4	26.4	1982
30/6-17	0.5	1.3	0.0	0.0	1.8	1986
30/6-18 Kappa	3.5	5.5	0.0	0.0	9.0	1986
30/8-1 S Tune	0.0	20.0	0.0	5.8	25.8	1995
33/9-19 S Sygna	9.6	0.6	0.0	0.0	10.2	1996
34/11-1 Kvitebjørn	0.0	51.2	4.4	21.1	78.0	1994

Name of discovery	Oil $10^6 Sm^3$	Gas $10^9 Sm^3$	NGL 10^6 tonnes	Cond $10^6 Sm^3$	Total $10^6 Sm^3 o.e$	Discovery year
34/7-21	9.4	1.2	0.3	0.0	11.0	1992
34/7-23 S	5.9	0.4	0.0	0.0	6.3	1994
34/7-25 S	2.3	0.2	0.0	0.0	2.5	1996
6406/2-1 Lavrans	0.0	40.3	5.3	8.8	56.0	1995
6406/2-3 Kristin	0.0	37.8	7.0	41.7	88.6	1997
6407/1-2 Tyrihans Sør	15.9	28.7	5.6	0.0	51.9	1983
6507/8-4 Heidrun Nord	4.0	0.0	0.0	0.0	4.0	1990
7121/4-1 Snøhvit	11.9	163.4	6.9	15.4	199.6	1984
Total	**208.5**	**390.9**	**32.8**	**110.9**	**753.0**	

Resources in early planning stages (Class 4)

	Oil $10^6 Sm^3$	Gas $10^9 Sm^3$	NGL 10^6 tonnes	Cond $10^6 Sm^3$	Total $10^6 Sm^3 o.e$	Discovery year
15/5-1 Dagny	0.0	5.9	0.0	2.0	7.9	1978
2/4-17 Tjalve	1.3	1.8	0.1	0.0	3.3	1992
25/5-4 Byggve	0.0	3.1	0.5	0.0	3.8	1991
25/5-5	4.3	0.0	0.0	0.0	4.3	1995
25/8-10 S	16.4	0.7	0.0	0.0	17.1	1997
35/11-4 Fram	35.5	20.6	3.4	0.0	60.5	1991
35/9-1 Gjøa	9.8	21.3	3.8	1.0	37.0	1989
Total	**67.3**	**53.3**	**7.8**	**3.0**	**133.8**	

Resources which may be developed over in the long term (Class 5)

	Oil $10^6 Sm^3$	Gas $10^9 Sm^3$	NGL 10^6 tonnes	Cond $10^6 Sm^3$	Total $10^6 Sm^3 o.e$	Discovery year
1/2-1 Blane	0.1	0.0	0.0	0.0	0.1	1989
1/5-2 Flyndre	5.1	1.6	0.0	0.0	6.6	1974
15/3-1 S	4.0	1.8	0.0	14.6	20.4	1975
15/3-4	2.2	1.1	0.0	0.0	3.3	1982
15/5-2	0.0	3.6	0.0	0.3	3.8	1978
15/8-1 Alpha	0.0	4.1	0.5	1.1	5.8	1982
16/7-2	0.0	1.8	0.3	0.5	2.7	1982
18/10-1	1.2	0.0	0.0	0.0	1.2	1980
2/2-1	0.4	1.1	0.0	0.0	1.5	1982
2/2-5	2.4	0.0	0.0	0.0	2.4	1992
2/4-10	2.4	0.0	0.0	0.0	2.4	1973
2/5-3 Sørøst Tor	0.9	0.3	0.0	0.0	1.2	1972
2/6-5	0.9	0.0	0.0	0.0	0.9	1996
2/7-19	5.1	3.8	0.0	0.0	8.9	1990
2/7-22	0.0	0.6	0.0	0.0	0.6	1990
2/7-29	3.0	0.0	0.0	0.0	3.0	1994
24/12-3 S	1.8	0.1	0.0	0.0	1.9	1996
24/6-1 Peik	0.0	5.3	0.0	1.2	6.5	1985
24/6-2	0.0	0.0	0.0	0.0	0.0	1998
24/9-3	2.0	0.1	0.0	0.0	2.0	1981
24/9-5	2.7	0.0	0.0	0.0	2.7	1994
25/6-1	1.2	0.0	0.0	0.0	1.2	1986
25/7-5	8.0	0.0	0.0	0.0	8.0	1997
25/8-4	1.0	0.0	0.0	0.0	1.0	1992
25/8-9	0.9	0.0	0.0	0.0	0.9	1997
30/10-6	0.0	5.7	0.0	0.0	5.7	1992
30/7-6 Hild	13.1	33.4	0.0	0.0	46.5	1978

	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tonnes	Cond 10^6 Sm^3	Total 10^6 Sm^{3}o.e	Discovery year
34/10-23 Gamma	6.0	69.0	0.0	0.0	75.0	1985
34/4-5	2.2	0.3	0.0	0.0	2.5	1984
34/7-18	1.7	0.0	0.0	0.0	1.7	1991
35/10-2	0.0	1.6	0.0	0.0	1.6	1996
35/3-2 Agat	0.0	43.0	0.0	0.0	43.0	1980
35/8-1	1.9	13.5	0.0	0.0	15.4	1981
35/8-2	2.6	7.0	0.0	0.0	9.6	1982
35/9-3	0.4	0.2	0.0	0.0	0.5	1997
36/7-2	1.1	0.0	0.0	0.0	1.1	1997
6/3-1 Pi	0.3	0.0	0.0	0.0	0.3	1985
6406/3-2 Trestakk	6.2	0.0	0.0	0.0	6.2	1986
6407/6-3 Mikkel	4.0	17.0	0.0	0.0	21.0	1986
6407/8-2	0.4	1.4	0.0	0.0	1.8	1994
6506/11-2 Lange	3.5	1.8	0.0	0.0	5.3	1991
6507/2-2	0.0	7.7	0.0	0.0	7.7	1992
6507/3-1 Alve	1.6	8.5	0.0	0.0	10.1	1990
7/7-2	2.4	0.1	0.0	0.0	2.5	1992
7/8-3	1.5	0.0	0.0	0.0	1.5	1983
7120/12-2	0.0	10.7	0.0	0.0	10.7	1981
7120/12-3	0.0	4.1	0.0	0.0	4.1	1983
7121/4-2 Snøhvit Nord	0.2	3.5	0.0	0.0	3.7	1985
7121/5-2 Beta	3.2	0.5	0.0	0.0	3.6	1986
7122/6-1	3.2	0.0	0.0	5.7	8.9	1987
7124/3-1	0.0	2.1	0.0	0.0	2.1	1987
Total	**100.6**	**256.2**	**0.8**	**23.3**	**381.2**	

Resources where development is not very likely (Class 6)

	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tonnes	Cond 10^6 Sm^3	Total 10^6 Sm^{3}o.e	Discovery year
1/3-1	0.0	0.0	0.0	0.0	0.0	1968
1/3-6	1.5	0.9	0.1	0.0	2.5	1991
1/9-1 Tommeliten Alpha	3.2	3.5	0.3	0.0	7.1	1977
15/12-8	0.5	1.0	0.0	0.0	1.5	1991
17/12-1 Bream	1.0	0.0	0.0	0.0	1.0	1972
17/12-2 Brisling	0.2	0.0	0.0	0.0	0.2	1973
17/3-1	0.0	0.0	0.0	0.0	0.0	1995
2/2-2	0.0	0.9	0.0	0.0	0.9	1982
2/3-1	0.0	0.0	0.0	0.0	0.0	1969
2/4-11	0.0	0.0	0.0	0.0	0.0	1974
2/4-14	0.0	0.0	0.0	0.0	0.0	1989
2/5-4	7.8	0.4	0.0	0.0	8.2	1972
2/5-7	2.9	0.0	0.0	0.0	2.9	1984
2/7-2	0.0	0.0	0.0	0.0	0.0	1971
25/10-8	2.7	0.3	0.0	0.0	3.0	1997
25/2-5 Lille Frøy	1.5	1.6	0.2	0.0	3.4	1976
25/7-2	1.0	1.0	0.0	0.0	2.0	1990
25/8-1	0.0	0.0	0.0	0.0	0.0	1970
29/3-1	0.6	1.0	0.0	0.0	1.6	1986
30/6-14	0.0	0.0	0.0	0.0	0.0	1984
30/6-16	0.0	0.0	0.0	0.0	0.0	1985
33/9-6	0.0	0.0	0.0	0.0	0.0	1976

	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tonnes	Cond 10^6 Sm^3	Total 10^6 Sm^3o.e	Discovery year
34/10-40 S	0.0	0.6	0.0	0.0	0.6	1995
34/11-2 S	1.7	2.7	0.0	0.0	4.4	1996
34/8-7	0.0	0.0	0.0	0.0	0.0	1993
6201/11-1	1.0	0.3	0.0	0.0	1.3	1987
6204/10-2	0.0	0.0	0.0	0.0	0.0	1997
6204/11-1	0.0	10.3	0.0	0.0	10.3	1994
6306/5-1	0.0	1.0	0.0	0.0	1.0	1997
6406/11-1 S	1.0	0.0	0.0	0.0	1.0	1991
6507/7-11 S	0.0	0.0	0.0	0.0	0.0	1997
7/12-5	1.1	0.0	0.0	0.0	1.1	1981
7119/12-3	0.0	4.1	0.0	0.0	4.1	1983
7128/4-1	0.9	0.1	0.0	0.0	1.0	1994
7226/11-1	0.6	24.0	0.0	0.0	24.6	1987
7316/5-1	0.0	1.2	0.0	0.0	1.2	1992
Total	**29.2**	**54.9**	**0.6**	**0.0**	**84.9**	

Resources in new discoveries where evaluation is not complete (Class 7)

	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tonnes	Condensate 10^6 Sm^3	o.e 10^6 Sm^3	Discovery year
2/1-11	0.3	0.0	0.0	0.0	0.3	1997
2/5-11	1.0	0.1	0.0	0.0	1.1	1997
24/6-2	0.0	0.0	0.0	0.0	0.0	1998
30/3-7 A	0.0	0.0	0.0	0.0	0.0	1998
30/3-7 A	0.0	0.0	0.0	0.0	0.0	1998
30/3-7 B	0.0	0.0	0.0	0.0	0.0	1998
30/3-7 S	3.0	0.0	0.0	0.0	3.0	1995
30/8-3	0.0	0.0	0.0	0.0	0.0	1998
30/9-19	0.0	0.0	0.0	0.0	0.0	1998
6305/5-1	0.0	314.7	0.0	5.4	320.1	1997
6406/2-6	0.0	0.0	0.0	0.0	0.0	1998
6507/5-1	34.2	34.0	0.0	0.0	68.2	1998
6707/10-1	0.0	38.3	0.0	0.0	38.3	1997
Total	**38.5**	**387.1**	**0.0**	**5.4**	**430.9**	

Table 7.5 d
Original and remaining reserves in fields (Classes 1 and 2)

	Original recoverable					Remaining				
	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tonnes	Cond. 10^6 Sm^3	Total Sm^3 o.e	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tonnes	Cond. 10^6 Sm^3	Total Sm^3 o.e.
Balder	27.2	0	0	0	27.2	27.1	0.0	0.0	0.0	27.1
Brage	54	3.2	0.8	0	58.3	23.4	1.9	0.4	-0.1	25.8
Draugen	111.3	0	0	0	111.3	70.3	0.0	0.0	0.0	70.3
Ekofisk	410.7	146.6	15.5	0	577.3	163.3	37.1	6.0	0.0	208.0
Eldfisk	109.3	52.71	4.7	0	168.8	44.6	22.2	1.7	0.0	69.8
Embla	10.1	5.63	1.1	0	17.1	4.5	3.8	0.9	0.0	9.4
Frigg	0	119.2	0	0.5	119.6	0.0	7.0	0.0	0.1	6.9
Frøy	5.9	1.5	0	0.1	7.5	1.1	0.6	0.0	0.1	1.7
Gullfaks	315.4	21.2	2	0	339.2	72.6	4.5	0.8	-0.6	77.6
Gullfaks Sør[1)]	40	59.5	0	0	99.5	40.0	59.5	0.0	0.0	99.5
Gullfaks Vest	3.6	0	0	0	3.6	1.6	0.0	0.0	0.0	1.6
Gullveig	4.2	2.9	0	0	7.1	4.2	2.9	0.0	0.0	7.1
Gungne[2)]	0	4.5	0.5	1.5	6.7	Included in Sleipner 2)				
Gyda	29	3.5	1.5	0	34.4	2.4	-0.7	0.0	0.0	1.7
Gyda Sør[3)]	6.1	3.5	0.7	0	10.4	Included in Gyda 3)				
Heidrun	180.4	19.8	0	0	200.2	142.0	19.8	0.0	0.0	161.8
Heimdal	6.9	42.6	0	0	49.5	0.9	1.0	0.0	0.0	1.9

	Original recoverable					Remaining				
	Oil	Gas	NGL	Cond.	Total	Oil	Gas	NGL	Cond.	Total
	10^6 Sm^3	10^9 Sm^3	10^6 tonnes	$10^6 Sm^3$	Sm^3 o.e	10^6 Sm^3	10^9 Sm^3	10^6 tonnes	10^6 Sm^3	Sm^3 o.e.
Hod	9.3	1.8	0.3	0	11.5	3.0	0.6	0.1	0.0	3.7
Jotun[1)]	30.7	1.8	0	0	32.5	30.7	1.8	0.0	0.0	32.5
Lille-Frigg[4)]	0	2.3	0	1.2	3.5	0.0	0.2	0.0	0.0	0.0
Loke[2)]	0	3.5	0.6	1.3	5.5	Included in Sleipner 2)				
Murchison	13.3	0.4	0.4	0	14.2	0.8	0.1	0.1	0.0	0.9
Njord	31.6	0	0	0	31.6	29.6	0.0	0.0	0.0	29.6
Norne	80.4	15	1.4	0	97.3	73.9	15.0	1.4	0.0	90.8
Oseberg	336	16.4	6	0.5	360.7	90.0	16.4	6.0	0.5	114.7
Oseberg Sør[1)]	53.5	11.4	0	0	64.9	53.5	11.4	0.0	0.0	64.9
Oseberg Vest	1.6	6	0	0	7.6	0.5	6.0	0.0	0.0	6.5
Oseberg Øst[1)]	23.5	0.8	0	0	24.3	23.5	0.8	0.0	0.0	24.3
Rimfaks[1)]	16.9	-1.2	0	0	15.7	16.9	-1.2	0.0	0.0	15.7
Sleipner Vest[2)]	0	128.1	8.7	27.7	167.1	Included in Sleipner 2)				
Sleipner Øst[2)]	0	38.4	9.5	20.8	71.6	0.0	4.4	2.3	-2.9	8.8
Snorre	225.3	7.7	5.7	0	240.4	163.3	4.8	4.0	-0.4	172.8
Statfjord	555.7	56.4	14.4	0	630.8	71.1	16.8	5.3	-2.9	92.3
Statfjord Nord	40.6	3	0.7	0	44.5	27.8	2.2	0.5	-0.1	30.6
Statfjord Øst	36.4	5.2	1.8	0	43.9	20.8	4.3	1.6	-0.1	27.1
Tor	28.3	11.7	1.3	0	41.7	7.7	1.2	0.2	0.0	9.1
Tordis	29.1	2.1	0.7	0	32.1	10.9	0.7	0.3	-0.1	11.8
Tordis Øst	4.4	0.4	0.1	0	4.9	Included in Tordis				
Troll	211.4	613.2	0	0	824	165.7	574.4	0.0	0.0	739.5
Ula	69.1	3.5	2.5	0	75.9	10.7	-0.2	0.2	0.0	10.9
Valhall	116.7	25.1	3.9	0	146.9	60.2	13.7	1.8	0.0	76.3
Varg	5.5	0	0	0	5.5	5.5	0.0	0.0	0.0	5.5
Veslefrikk	54.5	5.5	1.6	0	62.1	20.5	3.9	0.7	-0.1	25.2
Vigdis	30.7	2.2	0	0	32.9	24.6	2.2	0.0	0.0	26.8
Visund[1)]	48.5	0	0	0	48.5	48.5	0.0	0.0	0.0	48.5
Yme	11.5	0	0	0	11.5	6.4	0.0	0.0	0.0	6.4
Åsgard[1)]	75.5	191	28.3	37.4	340.7	75.5	191.0	28.3	37.4	340.7

1) Fields with approved development plan where production has not yet started.
2) Gas production from the Sleipner area is metered in total. All production in this area is deducted from the reserves in Sleipner Øst.
3) Production from Gyda and Gyda Sør are metered in total. All production is deducted from the reserves in Gyda.
4) In previous years, Lille-Frigg liquid has been reported as oil. Due to changes in reporting routines, the liquid is now reported as condensate.
Small negative figures for remaining resources are due to technical accounting factors, and are due to a mismatch between the approximate original recoverable reserves and exact production figures.

Table 7.5.e
Changes in reserve/resource estimates between the 1997 and 1998 annual reports. Major deviations are discussed in Chapter 1.1 and Chapters 1.4 - 1.6

Reserves where production has ceased (Class 0)

	1998		1997		Difference 1998-1997	
	Oil, Cond., NGL	Gas	Oil, Cond., NGL	Gas	Oil, Cond., NGL	Gas
	10^6 Sm^3	10^9 Sm^3	10^6 Sm^3	10^9 Sm^3	10^6 Sm^3	10^9 Sm^3
Albuskjell	8.7	16.0				
Cod	3.6	7.5				
Edda	5.1	2.1				
Mime	0.4	0.1	0.4	0.1	0.0	0.0
Nordøst Frigg	0.1	11.6	0	11.6	0.1	0.0
Odin [1)]	0.0	29.3	0.1	27.3	-0.1	2.0
Tommeliten Gamma	4.7	9.2				
Vest Ekofisk	14.0	26.9				
Øst Frigg	0.1	9.4				

1) The change is not real as it is due to an error in the 1997 annual report. The figures in 1997 should have been identical to this year's figures.

Reserves in production or with an approved development plan (Classes 1 and 2)

	1998		1997		Difference 1998-1997	
	Oil, Cond., NGL	Gas	Oil, Cond., NGL	Gas	Oil, Cond., NGL	Gas
	10^6 Sm^3	10^9 Sm^3	10^6 Sm^3	10^9 Sm^3	10^6 Sm^3	10^9 Sm^3
Balder	27.2	0.0	27.2	0.8	0.0	-0.8
Brage	55.0	3.2	53.8	2.9	1.2	0.3
Ekofisk	430.9	146.6	424.2	153.2	6.7	-6.6
Eldfisk	115.4	52.7	118.8	56.1	-3.4	-3.4
Embla	11.5	5.6	9.7	6.3	1.8	-0.7
Frigg	0.5	119.2	0.5	119.2	0.0	0.0
Frøy	6.0	1.5	6.8	1.6	-0.8	-0.1
Gullfaks	318.0	21.2	316.6	23.8	1.4	-2.6
Gullfaks Sør	40.0	59.5	21.5	1.7	18.5	57.8
Gullfaks Vest	3.6	0.0	3.1	0.3	0.5	-0.3
Gullveig	4.2	2.9	2.7	1.2	1.5	1.7
Gungne	2.2	4.5	2.2	4.5	-0.1	0.0
Gyda	31.0	3.5	31.1	3.9	-0.1	-0.4
Gyda Sør	7.0	3.5	3.5	1.5	3.5	2.0
Heimdal	6.9	42.6	6.7	40.3	0.2	2.3
Hod	9.7	1.8	8.8	1.8	0.9	0.0
Jotun	30.7	1.8	30.7	0.7	0.0	1.1
Lille-Frigg	1.2	2.3	1.3	2.4	-0.1	-0.1
Loke	2.1	3.5	2.0	3.5	0.1	0.0
Murchison	13.8	0.4	13.8	0.4	0.0	0.0
Oseberg	344.3	16.4	333.8	16.4	10.5	0.0
Oseberg Sør	53.5	11.4	53.5	11.4	0.0	0.0
Oseberg Vest	1.6	6.0	1.6	6.0	0.0	0.0
Oseberg Øst	23.5	0.8	23.5	0.8	0.0	0.0
Rimfaks	16.9	-1.2	19.9	-1.7	-3.0	0.5
Sleipner Vest	39.0	128.1	38.5	128.1	0.5	0.0
Sleipner Øst	33.2	38.4	32.5	38.4	0.6	0.0
Snorre	232.7	7.7	172.4	5.7	60.3	2.0
Statfjord	574.4	56.4	576.0	54.9	-1.6	1.5
Statfjord Nord	41.5	3.0	41.9	3.1	-0.4	-0.1
Statfjord Øst	38.7	5.2	32.9	4.5	5.8	0.7
Tor	30.0	11.7	28.4	11.6	1.6	0.1
Tordis	30.0	2.1	30.0	2.1	0.0	0.0
Tordis Øst	4.5	0.4	5.8	0.5	-1.2	-0.1
Troll	211.4	613.2	208.5	647.2	2.9	-34.0
Ula	72.4	3.5	72.7	3.5	-0.3	0.0
Valhall	121.8	25.1	122.0	27.8	-0.2	-2.7
Varg	5.5	0.0	5.5	0.2	0.0	-0.2
Veslefrikk	56.6	5.5	56.8	5.2	-0.3	0.3
Vigdis	30.7	2.2	28.8	2.0	1.9	0.2
Visund	48.5	0.0	48.5	0.0	0.0	0.0
Yme	11.5	0.0	9.6	0.0	1.9	0.0
Norwegian Sea						
Draugen	111.3	0.0	111.3	0.0	0.0	0.0
Heidrun	180.4	19.8	155.0	12.8	25.4	7.0
Njord	31.6	0.0	31.6	0.0	0.0	0.0
Norne	82.2	15.0	72.4	0.0	9.8	15.0
Åsgard	149.7	191.0	163.5	191.0	-13.8	0.0

Resources in fields (Classes 3, 4, 5 and 6)

	1998		1997		Difference 1998-1997	
	Oil, Cond., NGL	Gas	Oil, Cond., NGL	Gas	Oil, Cond., NGL	Gas
	10^6 Sm^3	10^9 Sm^3	10^6 Sm^3	10^9 Sm^3	10^6 Sm^3	10^9 Sm^3
Resources in late planning stages (Class 3)	189.01	485.7	218.2	531.1	-29.19	-45.4
Resources in early planning stages (Class 4)	56.62	81.9	146.73	418	-90.11	-336.1
Resources which may be developed in the long term (Class 5)	20.21	387.5	11.5	65	8.71	322.5
Resources where development is not very likely (Class 6)	4.9	0.4	4.2	1.1	0.7	-0.7

Resources in the late planning stages (Class 3)

	1998	1998	1997	1997	Difference 1998-1997	
	Oil, Cond., NGL	Gas	Oil, Cond., NGL	Gas	Oil, Cond., NGL	Gas
	10^6 Sm^3	10^9 Sm^3	10^6 Sm^3	10^9 Sm^3	10^6 Sm^3	10^9 Sm^3
1/3-3	8.14	1.8		Reported in RC 4 in 1997		
15/5-5	8.7	0.4		Reported in RC 4 in 1997		
15/9-19 S Volve	12.1	1.8	12.5	2.0	-0.4	-0.2
16/7-4 Sigyn	7.96	6.2	3.1	5	4.86	1.2
2/12-1 Freja	2.13	0.3				
2/12-1 Mjølner			2.4	0.4		
25/11-15 Grane	112	0	95.8	0	16.2	0
25/11-16	3.6	0		Reported in RC 4 in 1997		
25/4-6 S Vale	3.9	3.2	5.9	3.9	-2	-0.7
25/5-3 Skirne	1	5.1	0.91	5.1	0.09	0
3/7-4 Trym	0.7	2.7	0.91	2.9	-0.21	-0.2
30/2-1 Huldra	7.79	18.7	7.59	18.9	0.2	-0.2
30/6-17	0.5	1.3		Reported in RC 4 in 1997		
30/6-18 Kappa	3.5	5.5	3.5	5.4	0	0.1
30/8-1 S Tune	5.8	20		Reported in RC 5 in 1997		
33/9-19 S Sygna	9.6	0.6	11	0.7	-1.4	-0.1
34/11-1 Kvitebjørn	26.82	51.2	18.52	44.9	8.3	6.3
34/7-21	9.7	1.2	9.4	1.1	0.3	0.1
34/7-23 S	2.1	0.2	2.0	0.3	0.1	-0.1
34/7-25 S	2.3	0.2	2.3	0.2	0.0	0.0
6406/2-1 Lavrans	15.92	40.4		Reported in RC 4 in 1997		
6406/2-3 Kristin	51.03	37.8	48.62	58.6	2.41	-20.8
6407/1-2 Tyrihans Sør	23.18	28.7		Reported in RC 4 in 1997		
6507/8-4 Heidrun Nord	4	0	4.9	0.4	-0.9	-0.4
7121/4-1 Snøhvit	36.17	163.5		Reported in RC 4 in 1997		

Resources in the early planning stages, discoveries (Class 4)

	1998	1998	1997	1997	Difference 1998-1997	
	Oil, Cond., NGL	Gas	Oil, Cond., NGL	Gas	Oil, Cond., NGL	Gas
	10^6 Sm^3	10^9 Sm^3	10^6 Sm^3	10^9 Sm^3	10^6 Sm^3	10^9 Sm^3
2/4-17 Tjalve	1.4	1.8	1.3	2.2	0.1	-0.4
15/5-1 Dagny	2.0	5.9		Reported in RC 5 in 1997		
25/5-4 Byggve	0.7	3.1		Reported in RC 5 in 1997		
25/5-5	4.3	0.0	4.3	0.0	0.0	0.0
25/8-10 S	16.4	0.7		Reported in RC 5 in 1997		
35/11-4 Fram	39.92	20.6	31.3	11.2	8.62	9.4
35/9-1 Gjøa	15.7	21.3	14.7	33.3	1.1	-12.0

Resources which may be developed in the long term (Class 5)

	1998	1998	1997	1997	Difference 1998-1997	
	Oil, Cond., NGL	Gas	Oil, Cond., NGL	Gas	Oil, Cond., NGL	Gas
	10^6 Sm^3	10^9 Sm^3	10^6 Sm^3	10^9 Sm^3	10^6 Sm^3	10^9 Sm^3
1/2-1 Blane	0.1	0	0.1	0	0.0	0.0
1/5-2 Flyndre	5.1	1.6	5.1	1.6	0.0	0.0
15/3-1 S	18.6	1.8	6.3	14.6	12.3	-12.8
15/3-4	2.2	1.1	2.2	1.1	0.0	0.0
15/5-2	0.3	3.6		Reported in RC 6 in 1997		
15/8-1 Alpha	1.75	4.1	1.7	4.1	0.1	0.0
16/7-2	0.89	1.8	0.9	1.8	0.0	0.0
18/10-1	1.2	0	1.2	0.0	0.0	0.0
2/2-1	0.4	1.1	0.4	0.0	0.0	1.1
2/2-5	2.4	0	2.4	0.0	0.0	0.0
2/4-10	2.4	0		Reported in RC 6 in 1997		
2/5-3 Sørøst Tor	0.9	0.3	0.9	0.3	0.0	0.0
2/6-5	0.9	0	0.9	0.0	0.0	0.0
2/7-19	5.1	3.8		Reported in RC 6 in 1997		
2/7-22	0	0.6	0.0	0.6	0.0	0.0
2/7-29	3	0	3.0	0.0	0.0	0.0
24/12-3 S	1.8	0.1	3.5	0.2	-1.7	-0.1
24/6-1 Peik	1.2	5.3	3.0	9.1	-1.8	-3.8
24/6-2	0	0				
24/9-3	2	0.1	2.0	0.1	0.0	0.0
24/9-5	2.7	0	5.0	0.0	-2.3	0.0
25/6-1	1.2	0	1.2	0.0	0.0	0.0
25/7-5	8	0		Reported in RC 7 in 1997		
25/8-4	1	0		Reported in RC 4 in 1997		
25/8-9	0.9	0	0.9	0.0	0.0	0.0
30/10-6	0	5.7	0.0	5.7	0.0	0.0
30/7-6 Hild	13.1	33.4	13.1	33.4	0.0	0.0
34/10-23 Gamma	6	69	6.0	69.0	0.0	0.0
34/4-5	2.2	0.3	9.4	28.6	-7.2	-28.3
34/7-18	1.7	0	1.7	0.0	0.0	0.0
35/10-2	0	1.6	0.0	2.6	0.0	-1.0
35/3-2 Agat	0	43	0.0	43.0	0.0	0.0
35/8-1	1.9	13.5	1.9	13.5	0.0	0.0

	1998	1998	1997	1997	Difference 1998-1997	
	Oil, Cond., NGL	Gas	Oil, Cond., NGL	Gas	Oil, Cond., NGL	Gas
	10^6 Sm^3	10^9 Sm^3	10^6 Sm^3	10^9 Sm^3	10^6 Sm^3	10^9 Sm^3
35/8-2	2.6	7	2.6	7.0	0.0	0.0
35/9-3	0.4	0.2	Reported in RC 7 in 1997			
36/7-2	1.1	0	2.0	0.0	-0.9	0.0
6/3-1 Pi	0.3	0	0.3	0.0	0.0	0.0
6406/3-2 Trestakk	6.2	0	Reported in RC 4 in 1997			
6407/6-3 Mikkel	4	17	4.0	17.0	0.0	0.0
6407/8-2	0.4	1.4	0.4	1.4	0.0	0.0
6506/11-2 Lange	3.5	1.8	3.5	1.8	0.0	0.0
6507/2-2	0	7.7	0.0	7.7	0.0	0.0
6507/3-1 Alve	1.6	8.5	1.6	8.5	0.0	0.0
7/7-2	2.4	0.1	2.4	0.1	0.0	0.0
7/8-3	1.5	0	1.5	0.0	0.0	0.0
7120/12-2	0	10.7	0.0	10.7	0.0	0.0
7120/12-3	0	4.1	0.0	4.1	0.0	0.0
7121/4-2 Snøhvit Nord	0.2	3.5	0.1	3.0	0.1	0.5
7121/5-2 Beta	3.2	0.5	3.2	0.5	0.0	0.0
7122/6-1	8.9	0	3.2	5.7	5.7	-5.7
7124/3-1	0	2.1	0.0	2.1	0.0	0.0

Resources where development is not very likely (Class 6)

	1998	1998	1997	1997	Difference 1998-1997	
	Oil, NGL, Cond.	Gas	Oil, NGL, Cond.	Gas	Oil, NGL, Cond.	Gas
1/3-1	0.0	0.0	0.0	0.0	0.0	0.0
1/3-6	1.6	0.9			1.6	0.9
1/9-1 Tommeliten Alpha	3.6	3.5			3.6	3.5
15/12-8	0.5	1.0	0.5	1.0	0.0	0.0
17/12-1 Bream	1.0	0.0	1.0	0.0	0.0	0.0
17/12-2 Brisling	0.2	0.0	0.2	0.0	0.0	0.0
17/3-1						
2/2-2	0.0	0.9	0.0	0.9	0.0	0.0
2/3-1						
2/4-11						
2/4-14						
2/5-4	7.8	0.4	0.0	0.0	7.8	0.4
2/5-7	2.9	0.0	2.9	0.0	0.0	0.0
2/7-2						
25/10-8	2.7	0.3	2.0	0.0	0.7	0.3
25/2-5 Lille Frøy	1.8	1.6	1.8	1.6	0.0	0.0
25/7-2	1.0	1.0	1.0	1.0	0.0	0.0
25/8-1						
29/3-1	0.6	1.0	0.6	1.0	0.0	0.0
30/6-14						
30/6-16						
33/9-6						
34/10-40 S	0.0	0.6	0.0	0.6	0.0	0.0

	1998	1998	1997	1997	Difference 1998-1997	
	Oil, NGL, Cond.	Gas	Oil, NGL, Cond.	Gas	Oil, NGL, Cond.	Gas
34/11-2 S	1.7	2.7	1.7	2.7	0.0	0.0
34/8-7						
6201/11-1	1.0	0.3	1.0	0.3	0.0	0.0
6204/10-2						
6204/11-1	0.0	10.3	0.5	10.3	-0.5	0.0
6306/5-1	0.0	1.0	Reported in RC 7 in 1997			
6406/11-1 S	1.0	0.0				
6507/7-11 S			Reported in RC 7 in 1997			
7/12-5	1.1	0.0	1.1	0.0	0.0	0.0
7119/12-3	0.0	4.1	0.0	4.1	0.0	0.0
7128/4-1	0.9	0.1	0.9	0.1	0.0	0.0
7226/11-1	0.6	24.0	0.6	24.0	0.0	0.0
7316/5-1	0.0	1.2	0.0	1.2	0.0	0.0

Resources in new discoveries where evaluation is not complete (Class 7)

	1998	1998	1997	1997	Difference 1998-1997	
	Oil, NGL, Cond.	Gas	Oil, NGL, Cond.	Gas		
2/1-11	0.3	0	0.3	0	0	0
2/5-11	1	0.1	1	0	0	0.1
24/6-2	0	0	New discovery in 1998			
30/3-7 A	0	0	New discovery in 1998			
30/3-7 A	0	0	New discovery in 1998			
30/3-7 B	0	0	New discovery in 1998			
30/3-7 S	3	0	3	0	0	0
30/8-3	0	0	New discovery in 1998			
30/9-19	0	0	New discovery in 1998			
6305/5-1	5.4	314.7	0	100	5.4	214.7
6406/2-6	0	0	New discovery in 1998			
6507/5-1	34.2	34	New discovery in 1998			
6707/10-1	0	38.3	0	38	0	0.3

UNITS OF MEASUREMENT FOR OIL AND GAS

Oil and gas are often measured in volumetric units under certain defined ISO standard conditions (temperature = 15°C and pressure = 1.01325 bar). Oil volumes are stated in million standard cubic meters (10^6 Sm^3) and gas volumes in billion standard cubic meters (10^9 Sm^3).

Conversion from volume units to oil equivalents for oil and gas volumes is used for the purpose of totaling or comparing oil and gas resources, and when exact quantities are not required.

Conversion to *oil equivalents* is based on the amount of energy released during combustion of oil and gas.

As from 1 January 1996, the Norwegian Petroleum Directorate states the total petroleum resources in Sm^3 oil equivalents (Sm^3 o.e.). Consequently, when adding up or comparing oil and gas volumes we will use the following conversion formula:

1 000	Sm^3 gas equals:	1 Sm^3 o.e.
1	Sm^3 oil equals:	1 Sm^3 o.e.
1	tonnes NGL equals:	1,3 Sm^3 o.e.

Conversion from the NGL unit of weight to Sm^3 *oil equivalents* is somewhat more uncertain, since the composition of the light hydrocarbon components can vary considerably from one field to another. The Norwegian Petroleum Directorate has chosen to use a constant conversion factor of 1.3 from tonnes NGL/condensate to Sm^3 o.e.

7.6 PRODUCTION OF OIL AND GAS

Production of oil and gas on the Norwegian continental shelf amounted to 223.1 x 10^6 Sm^3 o.e. in 1998. Production in 1997 was 229.2 x 10^6 Sm^3 o.e. Table 7.6.a and Figures 7.6.a and 7.6.b describe the production in greater detail.

For the Statfjord, Frigg and Murchison fields, Table 7.6.a shows the Norwegian share of the production.

Table 7.6
Production in million Sm^3 oil equivalents

PRODUCTION ————> CONSUMPTION ———> MARKETABLE PRODUCTS ————>

1998	Oil	Gas	Cond.	Gas Flare	Gas Fuel	Oil	Gas	NGL/ Cond.	Total
Brage	5.574	0.538		0.007	0.070	5.543	0.281	0.137	5.961
Draugen	11.194	0.551		0.014	0.057	11.194			11.194
Ekofisk area	17.158	5.271		0.081	0.732	16.411	5.011	0.530	21.953
Embla	0.525	0.198				0.489	0.186	0.024	0.699
Frigg area	0.740	0.961	0.079	0.003	0.038	0.786	0.918	0.016	1.720
Gullfaks	19.658	2.582		0.055	0.265	19.658	1.455	0.175	21.289
Gullfaks Vest	0.197	0.023				0.197			0.197
Gullveig	0.069	0.036				0.069			0.069
Gyda (incl. Gyda Sør)	2.467	0.881		0.002	0.035	1.740	0.484	0.138	2.361
Heidrun	11.690	1.976		0.017	0.122	11.897	0.566		12.463
Heimdal		1.428	0.228		0.038	0.204	1.326		1.530
Hod	0.312	0.060		0.001	0.004	0.294	0.054	0.010	0.358
Loke		0.030							
Murchison	0.290	0.057		0.007	0.014	0.269	0.006	0.005	0.279
Njord	1.695	0.458		0.012	0.050	1.696			1.696
Norne	6.316	1.094		0.031	0.067	6.316			6.316
Oseberg	24.071	7.466		0.016	0.295	24.103			24.103
Oseberg Vest	0.094	0.137			0.005				
Sleipner area		14.602	8.567	0.016	0.241		8.651	7.009	15.659
Snorre	10.048	1.367		0.038	0.118	10.091	0.457	0.431	10.979
Statfjord	16.595	6.851		0.095	0.420	16.596	2.512	0.851	19.959
Statfjord Nord	3.043	0.223				3.035	0.166	0.062	3.263
Statfjord Øst	4.227	0.596				4.236	0.246	0.092	4.574
Tommeliten Gamma	0.125	0.357				0.069	0.327	0.024	0.420
Tordis	3.550	0.371		0.003	0.035	3.970	0.320	0.137	4.427
Troll area	12.826	21.943	0.539	0.013	0.122	13.254	19.954		33.208
Ula	1.767	0.150		0.004	0.051	1.697	0.022	0.048	1.767
Valhall	5.440	1.018		0.016	0.079	5.168	0.965	0.161	6.294
Varg	0.010	0.001		0.001		0.010			0.010
Veslefrikk	3.254	0.914		0.010	0.056	3.266	0.277	0.114	3.657
Vigdis	4.725	0.332				4.724			4.724
Yme	1.953	0.087		0.020	0.012	1.970			1.970
34/7-21	0.420	0.045							
Total 1998	170.039	72.594	8.235	0.463	2.926	168.950	44.190	9.963	223.103
Total 1997	178.388	70.365	8.772	0.411	3.034	175.868	42.949	10.729	229.547
Total 1996	177.282	59.456	7.253	0.448	2.833	175.496	37.407	9.242	222.144
Total 1995	157.926	47.193	5.922	0.409	2.640	156.622	27.814	8.439	192.874
Total 1994	147.674	45.393	4.588	0.364	2.630	146.282	26.842	7.143	180.267
Total 1993	133.770	41.576	1.280	0.340	2.544	131.843	24.804	4.156	160.803
Total 1992	125.936	42.444	0.573	0.309	2.449	123.999	25.834	3.369	153.202
Total 1991	110.513	39.717	0.563	0.356	2.257	108.510	25.027	3.312	136.849
Total 1990	96.844	37.065	0.521	0.556	2.132	94.542	25.479	3.420	123.442
Total 1989	88.266	39.320	0.547	0.474	2.013	85.983	28.738	3.327	118.048
Total 1988	66.882	36.302	0.588	0.336	1.818	64.723	28.330	3.303	96.356
Total 1987	58.538	34.499	0.577	0.434	1.443	56.959	28.151	2.813	87.923
Total 1986	50.579	33.924	0.355	0.258	1.311	48.771	26.090	2.630	77.491
Total 1985	47.339	34.102	0.030	0.304	1.190	44.758	26.186	1.980	72.924

Figure 7.6.a
Oil and gas production on the Norwegian shelf 1971-1998

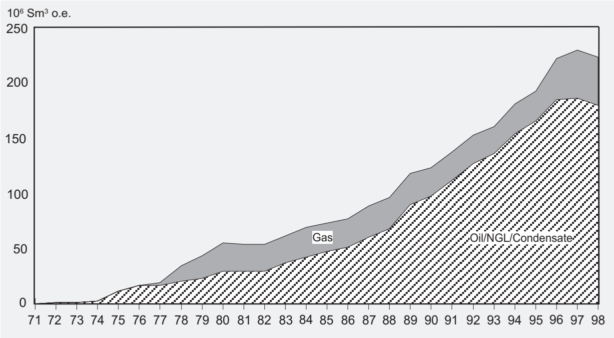
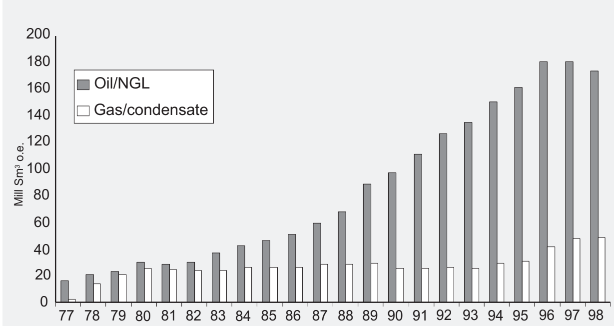


Figure 7.6.b
Oil and gas production on the Norwegian shelf 1977-1998



7.7 PERSONAL INJURIES

Figure 7.7.a
Personal injury frequency on permanently located installations (1989-1998)

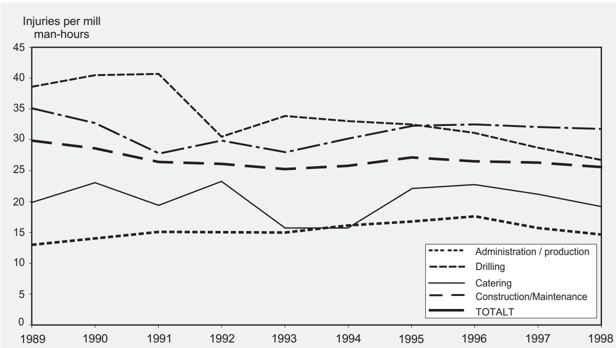


Table 7.7.a
Injuries/fatalities per million hours worked on permanently located installations (1989-98).

Year	Hours worked	Number of injuries (incl. fatalities)	Injuries and fatalities per mill hours worked	Fatalities
1989	19 935 604	597	29.9	1
1990	19 851 780	571	28.8	1
1991	22 263 332	589	26.5	0
1992	22 203 688	583	26.3	0
1993	25 411 568	643	25.3	2
1994	21 542 768	555	25.8	1
1995	21 828 159	594	27.2	1
1996	21 123 859	562	26.6	0
1997	21 337 937	562	26.3	0
1998	23 726 737	606	25.5	0
Total/aver.	**219 225 432**	**5862**	**26.7**	**6**

Table 7.7.b
Distribution of injuries and man-years on operator and contractor employees on permanently located installations (1989-1998)

FUNCTION		1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	
Administration/ production	Man-years	3 383 588	3 641 508	3 813 992	4 028 388	4 202 484	4 869 852	4 737 668	4 497 590	4 445 400	4 693 645	Operator
production		473 928	806 000	683 488	594 828	776 984	754 416	1 065 532	2 053 363	630 756	740 275	Contractor
	Injuries	44	50	53	54	60	76	77	73	66	68	o
		6	12	14	15	14	15	20	42	14	12	e
	Injury frequ.	13.0	13.7	13.9	13.4	14.3	15.6	16.3	16.2	14.8	14.5	o
		12.7	14.9	20.5	25.2	18.0	19.9	18.8	20.5	22.2	16.2	e
Drilling / well operations	Man-years	0	0	0	0	0	0	0	0	0	0	o
Well operations		3 430 336	3 267 524	3 609 268	3 772 080	4 175 080	4 268 576	4 676 412	4 670 118	4 913 477	4 967 799	e
	Injuries	0	0	0	0	0	0	0	0	0	0	o
		132	132	147	115	142	141	152	145	141	133	e
	Injury frequ.	0	0	0	0	0	0	0	0	0	0.0	o
		38.5	40.4	40.7	30.5	34.0	33.0	32.5	31.0	28.7	26.8	e
Catering	Man-years	548 080	638 352	720 564	747 968	802 776	731 848	707 668	779 369	842 930	928 852	o
		1 431 456	1 399 216	1 536 236	1 429 844	1 541 072	1 352 468	1 381 484	1 281 085	1 329 453	1 419 656	e
	Injuries	3	13	13	17	12	10	20	21	20	23	o
		36	34	31	34	25	23	26	26	26	22	e
	Injury frequ.	5.5	20.4	18.0	22.7	14.9	13.7	28.3	26.9	23.7	24.8	o
		25.1	24.3	20.2	23.8	16.2	17.0	18.8	20.3	19.6	15.5	e
Construction / maintenance	Man-years	3 838 172	3 810 768	3 999 372	4 088 032	4 342 728	3 199 820	3 149 848	3 137 696	3 171 689	3 087 333	o
Maintenance		6 830 044	6 288 412	7 898 800	7 542 548	9 570 444	6 365 788	6 183 632	4 704 639	6 004 233	7 889 178	e
	Injuries	70	63	65	80	39	48	48	47	44	49	o
		306	267	266	268	351	242	251	208	251	299	e
	Injury frequ.	18.2	16.5	16.3	19.6	9.0	15.0	15.2	15.0	13.9	15.9	o
		44.8	42.5	33.7	35.5	36.7	38.0	40.6	44.2	41.8	37.9	e
TOTAL	Man-years	7 769 840	8 090 628	8 533 928	8 864 388	9 347 988	8 801 520	8 595 184	8 414 655	8 460 019	8 709 830	o
		12 165 764	11 761 152	13 727 792	13 339 300	16 063 580	12 741 248	13 307 060	12 709 204	12 877 918	15 016 907	e
	Injuries	117	126	131	151	111	134	145	141	130	140	o
		480	445	458	432	532	421	449	421	432	466	e
	Injury frequ.	15.1	15.6	15.4	17.0	11.9	15.2	16.9	16.8	15.4	16.1	o
		39.5	37.8	33.4	32.4	33.1	33.0	33.7	33.1	33.5	31.0	e

Figure 7.7.b
Personal injury frequency on mobile installations 1989 -1998

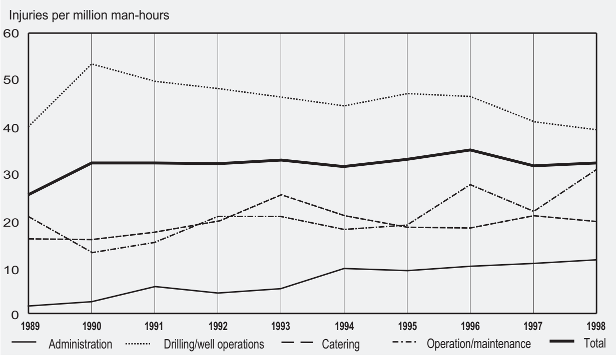


Table 7.7.d
Injuries/fatalities per million hours worked on mobile installations (1989-98).

Year	Hours worked	Number of injuries (incl. fatalities)	Injuries and fatalities per million hours worked	Fatalities
1989	3584740	92	25.7	2
1990	4328907	139	32.1	1
1991	4878152	159	32.6	0
1992	4380013	141	32.2	0
1993	4205431	138	32.8	2
1994	3513753	111	31.6	0
1995	2821541	94	33.3	0
1996	4989985	178	35.7	0
1997	6541619	208	31.8	0
1998	7028355	226	32.2	0
Total/aver.	**46272496**	**1486**	**32.1**	**5**

Table 7.7.c
Work accidents 1993-97 and 1998 on permanently located installations. Injury incident / occupation

	Occupation	Administration	Drill floor worker (roughneck)	Driller	Electrician	Caterer	Assistant	Instrument technician	Cook	Crane operator	Painter / Grit blaster	Mechanic / Motorman	Operator	Plateworker / Insulator	Pipeworker / Plumber	Service technician	Scaffolder	Welder	Derrickman	Other, unspecified	TOTAL	%
Injury incident	**Year**																					
Contact with objects or	1993-97	15	69	14	26	32	87	7	4	9	12	43	36	10	30	27	29	17	7	2	476	16.3%
machinery in motion	1998	3	12	3	3	4	8		1	2		8	7	1	4	2	6	2	4		70	11.6%
Fire	1993-97						1							2	1			1			5	0.2%
Explosion	1998																				0	0.0%
Fall to	1993-97	6	12		7	4	19	1		4	12	12	14	7	7	15	4	3	1		128	4.4%
lower level	1998	4	3	1	5	1	4	1		1	2	4	2	2	1	6	6	2			45	7.4%
Fall at	1993-97	2	13	2	5	17	11	3	3	6	8	15	12	4	9	7	7	8	3		135	4.6%
same level	1998		4			3	3				2	1	3			2	2			2	22	3.6%
Missteps	1993-97	13	19	5	16	10	32	6	1	4	13	21	16	9	13	20	15	11	2	2	228	7.8%
tripping	1998	4	3		3	3	7		2		13	3	3	3	2	4	2	5			57	9.4%
Falling	1993-97	4	12	4	8	10	16	3	3	2	4	17	4	8	3	12	18	11	2		141	4.8%
objects	1998		2				6	1	1		2	1	1		1	3	4		1		23	3.8%
Contact with	1993-97	19	14	3	36	10	27	20	4	9	14	42	31	19	17	17	37	10	6	2	337	11.6%
Objects at rest	1998	2	5	1	4	2	4	2	1		9	2	9	5	6	1	5	3			61	10.1%
Handling	1993-97	20	36	10	47	31	57	14	28	10	20	84	29	42	47	32	30	45	11	1	594	20.4%
accidents	1998	4	13	3	9	15	17	5	3	2	3	21	8	14	7	13	9	8	1		155	25.6%
Contact with chemical	1993-97	1	4		6	7	12		1	3	16	10	19	1	5	10	3	15	6	2	121	4.1%
or physical compound	1998	1	3		3		1				2	3	5	1	2	1	3	4			29	4.8%
Muscular	1993-97	18	17	4	18	13	21	5	5	3	9	33	24	7	11	14	21	7	6		236	8.1%
strain	1998	1	3	1	1	4	4	2	1		3	2	2	6	5		2	1	1		39	6.4%
Splinter and	1993-97	8	16	3	18	9	30	3	2	4	73	41	18	46	59	10	17	105	7	1	470	16.1%
splashes	1998		3		4		6				8	7	1	10	12	2	4	14	1	1	73	12.0%
Electrical	1993-97	1			1																2	0.1%
current	1998				3																3	0.5%
Extreme	1993-97	1			3	5	1	2	4	1		5	2	1	5			4			34	1.2%
temperature	1998								2			1	1					1			5	0.8%
	1993-97	2			2	2		1					1			1					9	0.3%
Other	1998	2	1		3	2	2	2			1	5	2		1	2		1			24	4.0%
	1993-97	110	212	45	193	150	314	65	55	55	181	323	206	156	207	165	181	237	51	10	2916	100.0%
TOTAL	1998	21	52	9	38	34	62	13	11	5	45	58	44	42	41	36	43	41	8	3	606	100.0%
	1993-97	3.8%	7.3%	1.5%	6.6%	5.1%	10.8%	2.2%	1.9%	1.9%	6.2%	11.1%	7.1%	5.3%	7.1%	5.7%	6.2%	8.1%	1.7%	0.3%	100.0%	
%	1998	3.5%	8.6%	1.5%	6.3%	5.6%	10.2%	2.1%	1.8%	0.8%	7.4%	9.6%	7.3%	6.9%	6.8%	5.9%	7.1%	6.8%	1.3%	0.5%	100.0%	

Table 7.7.e
Work accidents 1993-97 and 1998 on mobile installations. Injury incident / occupation

Injury incident	Occupation / Year	Administration	Drill floor worker (roughneck)	Driller	Electrician	Caterer	Assistant	Cook	Crane operator	Painter / Grit blaster	Mechanic / Motorman	Operator	Plateworker / Insulator	Pipeworker / Plumber	Service technician	Scaffolder	Welder	Derrickman	Other, unspecified	TOTAL	%
Contact with objects or	1993-97	5	69	12	2	3	47	1	1		11	5			8	1	4	12	1	182	25.0%
machinery in motion	1998	1	19	7	2		17	3		1	1			1	1	1	6			60	26.5%
Fire	1993-97																			0	0.0%
Explosion	1998													1						1	0.4%
Fall to	1993-97	4	6	2	1		8		1	2	2	2			3		5	3		39	5.3%
lower level	1998	1	1	2		1	4									1				10	4.4%
Fall at	1993-97	3	6	2		1	9	1	2		2	1			5		2	3	1	38	5.2%
same level	1998	1	1	1		1		2				1		1		1				9	4.0%
Missteps	1993-97	2	11	1	1	1	9		4			1			8	1		8		47	6.4%
Tripping	1998	2	3	1	1	2	4		1			1	1	2		1	1	1		21	9.3%
Falling	1993-97	2	15	2		1	6		5		2	1			5		4	3		46	6.3%
objects	1998	2	4		1	1	1							4		1	1			15	6.6%
Contact with	1993-97	5	14	2	5	3	8		3		3	1	1	1	12		4	9		71	9.7%
objects at rest	1998	1	3		1	1	4	1		1		1		2		1	4			20	8.8%
Handling	1993-97	4	47	5	1	6	22	11	2		13	4		3	8	2	5	7	3	143	19.6%
accidents	1998	1	16	5	4	1	7			6	1	1	1	5		3	3		3	57	25.2%
Contact with chemical	1993-97	1	4		1	1	4				6				5		2	2		26	3.6%
or physical compound	1998		1	1			1		1							1				5	2.2%
Muscular	1993-97	4	26	5	3	2	9	1	3		2	2			12			9		78	10.7%
strain	1998		9			2	2	1		1	1		1							17	7.5%
Splinter and	1993-97	3	7		3	1	6	2	1	1	3	1	2		3		11	2		46	6.3%
splashes	1998		1		2		1			2						3				9	4.0%
Electrical	1993-97																	1		1	0.1%
current	1998																			0	0.0%
Extreme	1993-97	1				1		2			2			1			1			8	1.1%
temperature	1998																			0	0.0%
	1993-97	1		1			2													4	0.5%
Other	1998									2										2	0.9%
	1993-97	35	205	32	17	20	130	18	22	3	46	18	3	5	69	4	38	59	5	729	100.0%
TOTAL	1998	9	58	17	11	9	41	7	2	13	3	4	3	16	1	13	15	1	3	226	100.0%
	1993-97	4.8%	28.1%	4.4%	2.3%	2.7%	17.8%	2.5%	3.0%	0.4%	6.3%	2.5%	0.4%	0.7%	9.5%	0.5%	5.2%	8.1%	0.7%	100.0%	
%	1998	4.0%	25.7%	7.5%	4.9%	4.0%	18.1%	3.1%	0.9%	5.8%	1.3%	1.8%	1.3%	7.1%	0.4%	5.8%	6.6%	0.4%	1.3%	100.0%	