United States
Environmental Protection
Agency

Industrial Environmental Research
Laboratory
Cincinnati OH 45268

EPA-600/7-80-023
February 1980

Research and Development

EPA

North Sea Pipelines

A Survey of Technology, Regulation and Use Conflicts in Oil and Gas Pipeline Operation

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EPA-600/7-80-023
February 1980

NORTH SEA PIPELINES
A Survey of Technology, Regulation and Use Conflicts in Oil and Gas Pipeline Operation

by

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Interagency Agreement No. 78-D-X0063

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FOREWORD

When energy and material resources are extracted, processed, converted, and used, the related pollutional impacts on our environment, and even on our health, often require that new and more efficient pollution control methods be used. The Industrial Environmental Research Laboratory - Cincinnati (IERL-Ci) assists in developing and demonstrating new and improved methodologies that will meet these needs both efficiently and economically.

This report describes the environmental effects of constructing and operating marine pipelines. Based on the information presented here, more environmentally suitable pipeline installations can be made. The information presented here is of interest to those engaged in planning, installing and operating marine pipelines. Further information may be obtained through the Resource Extraction and Handling Division, Oil and Hazardous Spills Branch, Edison, New Jersey.

David G. Stephan
Director
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PREFACE

In 1977, the U.S. Environmental Protection Agency (EPA), recognizing the New England River Basins Commission's (NERBC) continuing interest in offshore oil and gas activities, requested that NERBC undertake a study dealing with the environmental effects of submarine pipeline installation and operation. The project, entitled "OCS Pipeline Construction and Operation - Potential Environmental Problems and Recommendations for Mitigation of Impacts," was begun in January 1978.

This report, one in a series produced under this contract, focuses on pipeline-related experiences gained in the North Sea development area, a site of intensive offshore activity and a proving ground for many of the latest advances in marine pipeline technology.

Material for the report was collected from detailed interviews with industry, government, and private individuals associated with pipeline decisions in Norway, England, and Scotland. In addition, technical reports, engineering feasibility studies, progress reports, impact statements, and construction specifications were examined to document how decisions have been made, for what reasons, and with what effects. The report is a synthesis of these interviews, supported in part by details from some of the reports collected. It is not a detailed analysis of the technical reports, but does highlight the most significant pipeline-related issues currently being dealt with in the North Sea. The text is heavily footnoted for reference, and an appendix listing of reports collected is included. Much of the information has direct transferability to issues likely to arise during Outer Continental Shelf (OCS) development in frontier regions.

ABSTRACT

This project was undertaken to provide information on North Sea offshore pipelines and the processes used in route selection decisionmaking. It is designed to be used by persons involved in offshore oil and gas pipeline planning, including pipeline corridors and landfalls. The bulk of the information for the report comes from interviews with industry, government and private individuals associated with pipeline decisionmaking in Norway, England and Scotland. Supplemental information is derived from written sources.

A brief overview of offshore activity in both the United Kingdom and Norwegian sectors of the North Sea is presented, with special emphasis on the transportation systems established or proposed for the major commercial fields. The report then focuses on the specific issues arising from the installation and operation of each of these transportation systems. These issues include: regulations affecting pipeline placement, criteria for route selection, pipeline trenching and burial, and conflicts with the fishing industry in the North Sea.

This report is submitted in fulfillment of Interagency Agreement No. EPA-78-X0063 by the New England River Basins Commission under the sponsorship of the U.S. Environmental Protection Agency. This report covers the period August 1978 through December 1978, and work was completed as of August 30, 1979.

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ACKNOWLEDGMENTS

The task of adequately acknowledging all of those who assisted in a project this broad is a difficult one. We are indebted to William E. Nothdurft, who researched and wrote this report, and to a host of individuals scattered throughout England, Scotland and Norway who provided valuable insight and assistance. Special thanks go to Derek Lyddon, Chief Planner, Scottish Development Department, Niall Trimble, British National Oil Corporation, and Christian Hambro, Deputy General Director, Norwegian Ministry of the Environment for their assistance in making contacts and arranging appointments for Mr. Nothdurft with industry and governmental representatives in the United Kingdom and Norway.

Irvin M. Waitsman
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SECTION 1

NORTH SEA OIL AND GAS OVERVIEW

In the decade or so since the first discoveries of gas and oil were made in the North Sea, exploration, development, and production activities have grown steadily. While it is generally accepted that most of the major fields have been discovered, new discoveries continue to be made with surprising regularity. The most recent rumor is that British Petroleum (BP) may have made a big find west of the Shetland Islands. Driven by a complex array of economic factors, including the instability of foreign crude supplies, Britain's balance of payments problems, and the scale of Norwegian investments secured by the promise of petroleum revenues, offshore activity has expanded steadily into deeper water in an environment which, even in the best of times, is extremely hostile.

As of early 1977, proven recoverable oil reserves in the United Kingdom (U.K.) sector totaled 9.6 billion barrels (1.33 billion tons)[1] as compared to estimated recoverable reserves of between 18.7 and 21.6 billion barrels (2.6-3.0 billion tons).[2] Confirmed recoverable oil reserves in the Norwegian sector totaled 4.8 billion barrels (650 million tons).[3] Total proven recoverable gas reserves (both dry and associated) totaled 50-60 trillion cubic feet (1.42-1.70 trillion cubic meters) in the U.K. sector[4] and 22 trillion cubic feet (630 billion cubic meters) in the Norwegian sector.[5] Tables 1 and 2 provide a breakdown of oil and gas reserves in the U.K. sector. Table 3 provides a breakdown of reserves in the Norwegian sector.

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[1]Occidental North Sea Group, The Search for North Sea Oil, 1977, p.1.

[2]The Scottish Council, United Kingdom Oil and Gas: Situation Review, 1978, p.8.

[3]Norwegian Ministry of Petroleum and Energy, correspondence dated November 27, 1978.

[4]Scottish Council, Situation Review, p.9.

[5]Norwegian Ministry of Petroleum and Energy, correspondence dated November 27, 1978.

TABLE 1. ESTIMATED UNITED KINGDOM RECOVERABLE OIL RESERVES

	Barrels (billions)	Tons (billions)
Fields in production (7)	5.76-6.12	.8-.85
Fields committed to development (8)	3.6-4.32	.5-.6
Fields probably commercial and under appraisal	5.04-5.76	.7-.8
Named and unnamed fields under or awaiting appraisal	4.32-5.40	.6-.75
Total recoverable reserves	18.72-21.60	2.6-3.0

Source: The Scottish Council, (1978).

TABLE 2. ESTIMATED UNITED KINGDOM RECOVERABLE GAS RESERVES

	Trillion cubic feet
Remaining southern North Sea dry gas fields	25
Frigg dry gas (67% Norwegian, 35% UK)	9
Brent associated gas	4
Other associated gas	12-22
Total recoverable reserves	50-60

Source: The Scottish Council, (1978).

TABLE 3. ESTIMATED RECOVERABLE NORWEGIAN OIL AND GAS RESERVES

	Oil (billion barrels)	Gas (trillion cubic feet)
Ekofisk complex	1.43	8.83
Frigg (Norwegian sector)	(gas only)	3.88
Statfjord (Norwegian sector)	2.17	1.77
Valhall A	.23	.71
Other recoverable reserves	.98	7.06
Total recoverable reserves	4.81	22.25

Source: Norwegian Ministry of Petroleum and Energy, (1978).

The following is a brief overview of offshore activity in both the U.K. and Norwegian sectors of the North Sea, with special attention to the transportation systems established or proposed for the major commercial fields. Subsequent chapters deal with specific issues arising from the construction and operation of marine pipelines and shore terminals.

UNITED KINGDOM

Since the mid-1960's, roughly 500 exploration and 200 field appraisal wells have been completed in the U.K. sector of the North Sea, with a success ration of 1 in 6, as compared to the world offshore average of 1 in 20.[6] During the peak exploration period in 1974-75 up to 40 mobile drilling rigs were in operation, but by the first quarter of 1978 this total had dropped to 17.[7] Discoveries continue, however, and in 1977 five companies announced new finds (Conoco, BP, Total, Transocean, and Phillips).[8] During the early months of 1978 Elf Aquitaine announced an oil and gas find west of the Shetlands and exploration began on the first of the blocks granted in the fifth round of licensing with the British National Oil Corporation (BNOC)'s drilling of a well west of the Ekofisk complex.[9]

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[6]Scottish Council, Situation Review, p.7.

[7]Scottish Development Department, North Sea Oil Information Sheet, March 1978, p.3.

[8]Ibid, p.14.

[9]Ibid, p.3.

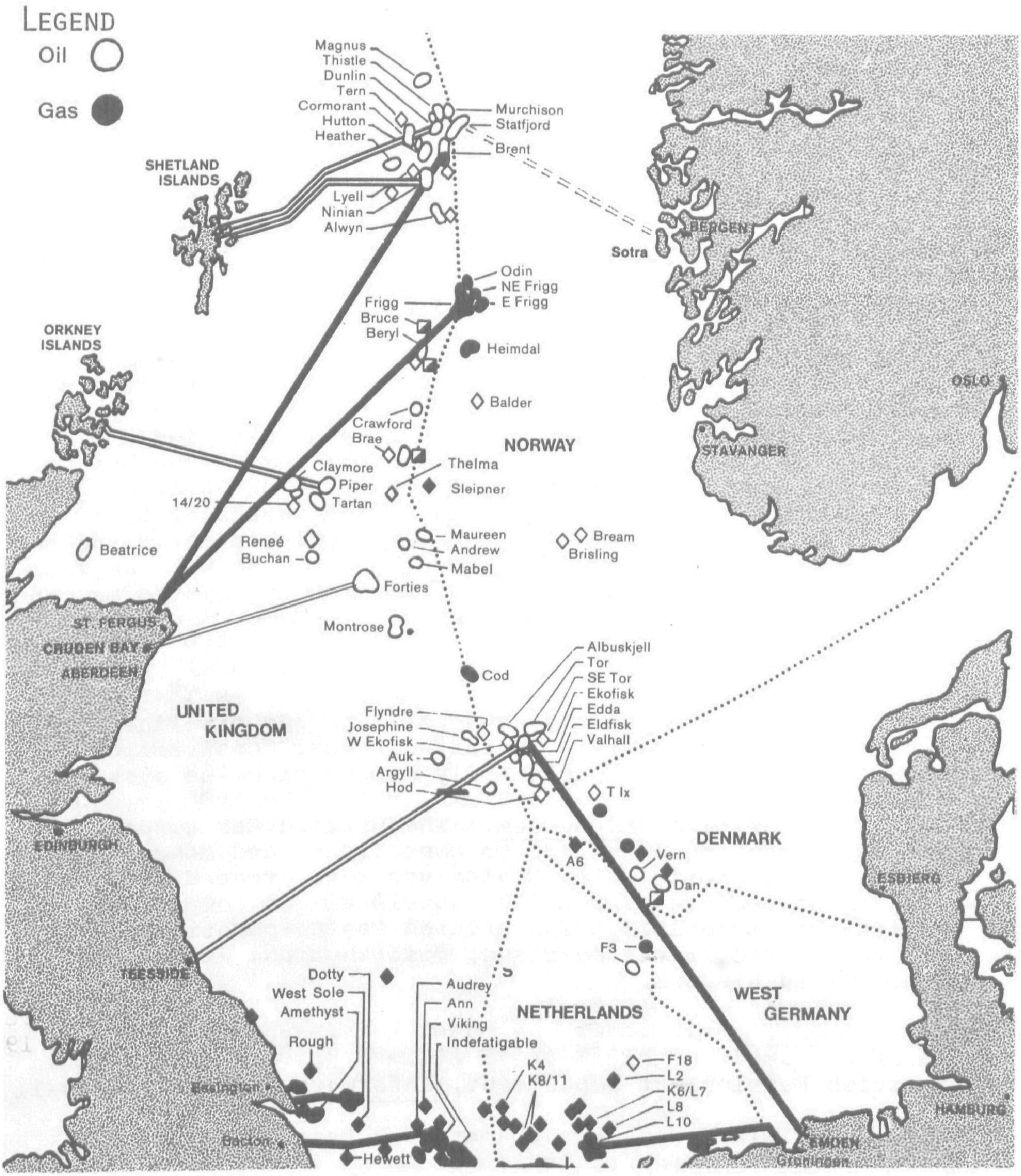
In the U.K. system, offshore blocks (tracts) are granted rather than leased to applicant companies or consortia, with a nominal payment and a royalty agreement. Leases are granted based on a variety of criteria, including:

- technical capability to successfully develop the block;
- financial ability to follow through with tract development;
- degree to which British-based oil companies are involved;
- negotiated terms of participation by government-owned companies (BNOC, British Gas);
- proportion of goods and services to be ordered from British firms (as monitored by the U.K. Offshore Supplies Office); and
- willingness to permit trade union involvement.

Although leases are generally granted following a set schedule of licensing rounds, the government will occasionally, upon application by a developer, grant blocks outside a licensing round. This will occur if it is felt to be in the national interest to develop the block. As an incentive to rapid development of granted blocks, half of the acreage of a block must be surrendered to the government after six years if the license holder has failed to move forward with development. Future leasing rounds are likely to involve additional conditions as government moves to exercise its control over development and production under recent legislation.

Since the installation of production platforms began in the mid-1970's, the drilling of production wells has grown steadily. By early 1978, about 280 production wells had been drilled and approximately 400 more are planned during the next five to seven years.[10] Figure 1 illustrates major fields discovered as of 1978 and their associated pipelines. Since June 1975, nine oil fields have begun production (see Figure 1 for locations). In order of the beginning of production, these "onstream" fields are: (1) Argyll (Hamilton Bros., June 1975); (2) Forties (BP, November 1975); (3) Auk (Shell, December 1975); (4) Montrose (Amoco, June 1976); (7) Piper (Occidental, December 1976); (8) Claymore (Occi-

[10] Scottish Council, Situation Review, pp.7-8.



Source: Bergen Bank, Petroleum Activities in Norway, 1978, p.7.

FIGURE 1. OIL AND GAS IN THE NORTH SEA AREA.

dental, November 1977); and (9) Thistle (Burmah-BNOC, March 1978).[11] The Frigg Gas field (Elf Norge/Total) began production in September, 1977.

Seven fields are currently in various stages of development, from platform fabrication and installation to development drilling: (1) Heather (Unocal); (2) Murchison (Conoco); (3) Ninian (Chevron); (4) Tartan (Texaco); (5) Buchan (BP); (6) Cormorant (Shell); and (7) Dunlin (Shell). Development plans are under Department of Energy review for Beatrice (Mesa), Fulmar (Shell), and Magnus (BP). Fields currently under development are those discovered between July 1973 and December 1975.[12] Thus, even under very heavy government pressure to develop and produce, it appears to be taking from three to five years to move from a field discovery to development drilling. The same can be said for those fields which have begun production. In all, 14 steel platforms have been installed and four more are committed, and eight concrete platforms have been installed with two more committed, for a total of 28 at a total cost of roughly $12 billion, not including installation.[13] It is estimated that as many as eight new steel platforms and seven new concrete platforms may be needed by 1985, as well as four semi-submersible conversions, three tension leg platforms, and three subsea completion units.[14]

Pipeline Systems[15]

There are currently seven oil and gas pipeline systems which are either completely installed, under construction, or planned. All but one are primarily marine pipeline systems.

The British Gas System. The British Gas Corporation (BGC) was established in 1972 to consolidate and manage the 12 regional gas councils which themselves were created after World War II to amalgamate over 1,000 individual gas companies, some in existence since 1812. The British Gas Corporation has a complete monopoly over the purchase, distribution, and sale of gas in the United Kingdom.

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[11] Scottish Development Department, Information Sheet, pp.10-11.

[12] Ibid, pp.11-12.

[13] Scottish Council, Situation Review, 1978, p.10.

[14] Ibid.

[15] The description of both pipeline and terminal systems is drawn primarily from the Scottish Councils' Situation Review, 1978, pp.11-16.

The BGC's Production Supply Division acts as a wholesaler, buying gas at its point of landfall and distributing it to its 12 regions and to a few very large industrial consumers (e.g., power plants, petrochemicals) through a nationwide complex of land pipelines, virtually all of which have been laid since the mid-1960's. Until recently, most of the gas supply for this distribution system came from the Bacton terminal (4 billion cubic feet (cu.ft.)/day) where processing of southern North Sea gas began in 1968, and from the Theddlethorpe and Easington terminals further north along the east coast of England, established to handle gas from the Viking and West Sole fields, respectively. Algerian liquified natural gas (LNG) is landed at the Canvey Island terminal near London.

British Gas is also empowered to explore for gas directly through two of its wholly-owned subsidiaries: the Gas Council Exploration Co. Ltd., which handles onshore exploration and recently located a commercial field in Dorset, in the south of England; and Hydrocarbons Great Britain Ltd., which is involved in offshore activity and will be developing several blocks in the Irish Sea.

The most recent and most important BGC pipeline system is the group of installed and proposed lines connecting the distribution system with the massive new terminal at St. Fergus, Scotland. (The St. Fergus terminal is designed to handle gas from the Frigg, Brent, and Piper fields in the northern North Sea and is discussed in greater detail below under "Oil and Gas Terminals.") As of June 1978, British Gas had completed two 36" pipelines along a 200 kilometer (km) route from St. Fergus to Bathgate, near Edinburgh. An additional 264 km 36" connecting line is now under construction. A fourth line, 42" in diameter, is also proposed along a more easterly route. The total capacity of the three 36" lines will be 3 billion cu.ft./day. The 42" proposed line would boost line capacity (throughput) by an additional 2 billion cu.ft./day. The estimated total cost of the three 36" lines, including booster stations, is approximately $320 billion.

<u>The Brent System</u>. There are three distinguishable pipeline systems serving Shell's Brent field complex. Each is outlined below.

Oil is gathered and transported from the <u>Brent Complex</u> to <u>Sullom Voe Terminal</u> in the Shetland Islands through a system of gathering lines linking Brent, Dunlin, Thistle, Hutton, and Cormorant to a 36" trunk line 150 km in length. The gathering lines comprise one 30 km 24" diameter pipeline and one 12 km 16" diameter pipeline. Maximum handling capacity is 1 million barrels per day (b/d), and the estimated installed cost is roughly $280 million. The system is expected to be operational by late 1978 and eventually additional adjacent fields will be linked to the system.

Associated gas with large amounts of gas liquids will be carried from Brent to St. Fergus Terminal through a 450 km 36" diameter line. Planned capacity will be 1 billion cu.ft./day, but it is expected that new associated gas from adjacent fields will be transported through the pipeline. Construction was completed in July 1978.

Natural gas liquids (NGL) (i.e., ethane, propane, butane, natural gasoline) will be separated from the methane in the Brent gas stream and are proposed to be piped from St. Fergus to the Mossmorran area, near Edinburgh, to a proposed gas liquids treatment plant and terminal. The estimated cost of the proposed 175 km, 16" - 18" diameter pipeline is roughly $90 million.

The Ekofisk System. Oil from the Ekofisk field complex in the Norwegian sector is transported to a terminal at Teesside on the east coast of England via a 354 km 34" diameter pipeline with a maximum handling capacity of 1.0 million b/d. The approximate installed cost is $550 million.

The Forties System. Oil from BP's Forties Field is transported from the field to Cruden Bay via a 180 km 32" marine pipeline with a maximum cost of $240 million. The crude oil is transported from Cruden Bay to Grangemouth via a 220 km 36" diameter pipeline with a 600,000 b/d throughput capacity. In the Grangemouth area, liquids are removed at the Kinneil Stabilization Plant and the crude is either piped to Grangemouth for refining or to the Hound Point Terminal on the Firth of Forth for export. Pipeline construction cost an estimated $76 million.

The Frigg System. Recoverable gas from the Frigg Field is transported by Total Oil Marine, Ltd. from Frigg to St. Fergus via two 365 km 32" pipelines (one for U.K. owned production, one for Norwegian owned production) roughly 70 meters apart. Approximately 100 km of smaller gathering lines may eventually link the East Frigg, Odin, and Heimdal fields to the main system. Both of the 32" lines pass through an intermediate compressor platform roughly halfway along the route. All the gas reserves from Frigg have been committed to BGC under twin 20-year contracts. Maximum handling capacity of the lines is projected to be approximately 2.4 billion cu.ft./day and the estimated total cost is $980 million.

The Ninian System. Oil from BP's Ninian field and Unocal's Heather field will be transported from Ninian to Sullom Voe via one 165 km 36" diameter pipeline with a maximum capacity of approximately 1 million b/d. Heather will be connected via a 35 km 16" diameter line. To date, the estimated total cost is $270 million. Adjacent fields are likely to join the pipeline at a later date.

The Piper System. Occidental's Piper crude oil is transported from the Piper field to Flotta Terminal, Orkney, via one 235 km 30" pipeline with a throughput capacity of about 650,000 b/d. Oxy's Claymore field is linked to the pipeline for crude transport via a 16" gathering line. Another 16" gathering line is under construction for moving associated gas from Claymore to Piper, where it will be linked to a completed 18" connecting pipeline for transporting associated gas (120 million cu.ft./day) from Piper Complex to Frigg Intermediate Platform and then transported via Total's 32" lines to St. Fergus. Texaco's Tartan field will probably be linked to Piper as well. The approximate installed cost of the oil lines to Flotta is $280 million; for the gas lines $90 million.

Oil and Gas Terminals

The major receiving terminals for oil pipelines are Sullom Voe (Shetlands), Flotta (Orkney), Cruden Bay (Scotland), and Teesside (England). Each is briefly described below, along with the St. Fergus gas terminal complex.

Sullom Voe Oil Terminal. The Sullom Voe terminal is designed to receive crude oil from the two pipelines from the Ninian and Brent systems. Constructed and, when completed in late 1978, operated by the Sullom Voe Association (composed of the oil companies in the Brent and Ninian Systems and the Shetland Island Council), the terminal will be capable of initially handling 1.2 million b/d with a design capacity of 3 million b/d when complete. Fifteen above-ground storage tanks provide storage capacity of 9.4 million barrels of crude. A crude oil stabilization plant will extract 45 million cu.ft./day of methane/ethane and 3,500 tons/day of propane/butane. Refrigerated propane/butane will be stored in four insulated tanks with a total capacity of 40,000 tons. Loading and berthing capacity are provided for tankers up to 300,000 deadweight tons (dwt). The total estimated cost of the project is over $1 billion.

Flotta Oil Terminal. The terminal at Flotta in the Orkney Islands handles the shipments of crude oil from Occidental's Piper and Claymore fields. Total storage capacity of the seven crude tanks is 4.5 million barrels. The stabilization plant handles up to 550,000 b/d of crude and extracts up to 25 million cu.ft./day of methane/ethane and 1,600 tons/day of propane/butane. Loading and berthing facilities can handle tankers up to 150,000 deadweight tons. The total cost of construction was approximately $25 million.

Cruden Bay Reception Terminal. Crude oil from BP's Forties field is landed at Cruden Bay, below Peterhead, Scotland and pumped south to Kinneil, then to the Grangemouth refinery or to the Hound Point Terminal for export. The pumping station has a handling capacity of 540,000 b/d and is capable of expansion. It was built at a cost of roughly $40 million. The Kinneil Stabilization Plant near the Grangemouth refinery is capable of extracting approximately 50 million cu.ft./day of methane/ethane, 1,650 tons/day of propane/butane, and 500 tons/day of natural gasoline. It was built at an estimated cost of $32 million. At the end of the Forties pipeline system is the Hound Point Terminal, which can export up to 500,000 b/d of crude not refined at Grangemouth. Seven above-ground tanks store up to 3.7 million barrels of crude. Loading and berthing facilities are capable of handling tankers up to 250,000 dwt. The small terminal was built at an estimated cost of $46 million. Quantities of gas liquids are pumped to the Granton gas works in Edinburgh for the manufacture of synthetic natural gas to meet the daily demand of Edinburgh.

Teesside Terminal. The stabilizing facilities at Teesside are owned by Norpipe Petroleum U.K. Ltd., which is owned jointly by the Phillips Group and Norway's Statoil. The NGL facilities and the utilities are owned by North Sea Pipelines Co. The terminal is expected to receive up to 30 million tons of crude oil per year at peak production from the Ekofisk complex. At peak it will produce almost 1.5 million tons per year of ethane, propane, and butane. Ten storage tanks have a capacity of 750,000 barrels each and six refrigerated tanks are planned for natural gas liquids. Loading and berthing facilities exist for tankers of up to 150,000 dwt. The total cost for the entire facility is expected to exceed $700 million.

The St. Fergus Gas Complex. The St. Fergus terminal complex, one of the largest in the world, was officially opened in May 1978, and is made up of three terminals. The Total Oil Marine Separation Terminal was constructed to separate small amounts of gas liquid from the predominantly "dry" gas stream from the Frigg field. Two essentially separate systems treat and meter the gas coming ashore through each of the two Frigg lines before it is passed to the British Gas terminal at the site. The handling capacity of the Total/Elf terminal is 2.4 billion cu.ft./day of raw gas, from which up to 250 tons/day of liquids can be extracted, stored, and shipped by truck. Total cost of the terminal is estimated at $185 million.

The Shell/Esso Separation Terminal will separate substantial quantities of gas liquids from the "wet" associated gas stream from the Brent field. Total handling capacity of this terminal will be 850 million cu.ft./day from which up to 6,000 tons/day of ethane, propane, butane, and natural gasoline will be extracted. The separated gas liquids are expected to be pumped through a 16"-18" land pipeline south to Mossmorran to a proposed gas liquids plant and export terminal. Temporarily, ethane will be piped directly to the new Boddam power plant.

The treated methane is then passed on to the pumping and distribution terminal.

The British Gas Pumping and Distribution Terminal was constructed to receive, further treat, odorize, and compress up to 3 billion cubic feet/day of methane from the Shell/Esso and Total/Elf separation plants. Eight compressors (two banks of four - three operating, one standby) with a total capacity of 139,000 horsepower raise the pressure of the treated methane from 600 psi to 1000 psi and pass it on to what will soon be three trunk lines linking the terminal with the British Gas distribution system roughly 200 km to the south. (In point of fact, only the Frigg gas needs to be compressed; Brent gas comes ashore at 1100-1400 psi and is passed to British Gas at 1000 psi.) The estimated cost of the British Gas facility is $80 million.

With the substantial increase of petroleum and petroleum feedstocks, the Scottish Development Department and Regional and District planners are working on contingency plans for a variety of downstream industries. An additional crude terminal and refinery is proposed for Nigg Point on the Cromarty Firth; an ammonia plant has been proposed by a Norwegian consortium for Peterhead; and a gas liquids treatment plant and ethylene cracker are proposed for Brent field gas liquids at Mossmorran. Other proposals are likely.

NORWAY

Development in the Norwegian sector of the North Sea dates from the Phillips discovery of the Ekofisk field in 1969.[16] The massive Ekofisk complex consists of seven fields situated in the southwest corner of the Norwegian sector: Ekofisk, West Ekofisk, Cod, Tor, Edda, Albuskjell, and Eldfisk. (See Figure 1.) Oil production from the Ekofisk complex averaged about 97.2 million barrels per annum in 1976 and 1977 and is expected to peak at about 215 million barrels in 1980-1981. Gas production is expected to peak in 1981 at about 740 billion cubic feet. Although Ekofisk was discovered and developed before Norway had established a governmental infrastructure to manage development, the transportation and production plans submitted in 1973 were made contingent upon participation by Norwegian companies. Statoil owns 50 percent of Norpipe A.S., which owns the pipelines, and Norpipe Petroleum U.K., Ltd., which owns the stabilizing facilities at the Teesside terminal. Statoil is 100 percent owned by the Norwegian government.

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[16] Much of the description of the Norwegian situation is drawn from the Bergen Bank's Petroleum Activities in Norway, 1978, pp.6-15.

The British gas field was declared commercial in 1972 and was developed with the limited participation of Statoil, the Norwegian equivalent of British National Oil Corporation (BNOC). The field straddles the boundary line between the United Kingdom and Norwegian sectors of the North Sea, and an agreement on the split of reserves (60.82 percent (%) Norwegian; 39.18% U.K.) was reached in December 1977. The field has estimated total reserves of gas of about 7 trillion cubic feet; production will likely peak in 1981 at about 520 billion cubic feet per annum. As indicated above, all the gas is sold under a 20-year contract to BGC at the St. Fergus landfall.

The combined gas and oil Statfjord field is the most important field discovered to date in the North Sea. Declared commercial in 1974, it, like the Frigg field, straddles the U.K./Norwegian mid-line and reserves are split at 11.11% U.K. and 88.89% Norwegian. Total estimated Norwegian reserves are roughly 2.2 billion barrels of oil and 1.8 trillion cubic feet of gas. Over a dozen oil companies comprise the Statfjord Group, but Statoil, the Norwegian oil company, dominates with 44.4% of the shares. Mobil (with a 13.3% share of the group) is the operator. Oil production and transportation, using single buoy mooring (SBM) and tanker from Statfjord A, the field's first producing platform, is projected for late 1979; gas will be re-injected in the first years. Statfjord's second platform - B - is planned for 1981 and Statfjord C is now being evaluated. A crude oil pipeline to Norway is under study and discussed elsewhere in this report. There are high hopes for the prospects of a new block adjacent to Statfjord, currently being referred to as the "Golden Block." A first well was successfully drilled in the summer of 1978.

The Valhall field was declared commercial in 1976, as was Hod just to the southwest. Both fields are close to the Ekofisk complex. Total reserves are estimated at 302 million barrels of oil and 706 billion cubic feet of gas. When production begins in 1981, oil and gas will be transported through a link with the Ekofisk pipeline system (oil to Teesside, gas to Emden). Peak production of roughly 95,000 barrels/day of oil and 150-200 million cu.ft./day of gas is expected to be attained by 1984.

The Murchison field northwest of Statfjord was declared commercial in 1977. Total reserves--estimated at 360 million barrels of oil--will be split between the U.K. (80%) and Norway (20%). The platform is under construction in the U.K. and will be towed out in 1979. Production may start in 1980.

Pipelines: The "Ekofisk Solution"

Norway's licensing laws specifically state that Norwegian oil and gas shall be brought ashore in Norway, unless the King decides otherwise.[17] To date, however, the technical difficulty of laying a pipeline through the Norwegian trench, which parallels the coast, and the absence of a market for gas in Norway have dictated that Norwegian hydrocarbons be sold elsewhere.

Currently, therefore, Ekofisk oil is transported 350 kilometers (km) to a terminal at Teesside, England through a 34" diameter pipeline which, with two booster stations, is capable of handling 1 million b/d. A 442 km 36" gas line was built from Ekofisk to the gas terminal at Emden, West Germany to handle Ekofisk gas and has a maximum capacity of approximately 2.12 billion cu.ft./day. While neither the oil or natural gas is landed in Norway, the entire system, built at an estimated cost of $1.45 billion, is owned by Norpipe A.S., a Norwegian pipeline company and operated by Phillips.[18] Transportation of oil started in 1975, dry gas in 1977, and transportation of natural gas liquids is planned for 1979.

But this so-called "Ekofisk solution" is only grudgingly accepted in a political sense. The Norwegian Parliament has requested that the Statoil/Mobil Group conduct a $60 million detailed feasibility study for an oil pipeline from Statfjord, across the Norwegian trench, to Sotra, an island near Bergen, Norway. The study, completed late in 1978, concluded that while pipeline installation across the trench was technically feasible with conventional pipelaying techniques, the cost of the pipeline will probably not be justified by the Statfjord find alone.[19]

The Current Political Environment

Norway is moving cautiously in its offshore development program. Reserves identified to date represent roughly ten times its petroleum needs. Norway's effort to control the pace of development by limiting the number of block offerings has been criticized by some in the media. There is a concern that when Ekofisk and Statfjord are developed there will be a great lag time before newer fields can pick up the slack in production.[20]

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[17] Ministry of Industry, Legislation Concerning the Norwegian Continental Shelf, October 1977.

[18] Norpipe, Brochure and Factsheet, 1978.

[19] Interview with Statoil officials.

[20] "Separation of Exploration and Production Phase", Scandinavian Oil-Gas Magazine, Vol. 6, No. 5/6, p.22.

Consequently, future licensing rounds are likely to stipulate the government's right to postpone field development and regulate the production profile, rather than simply delaying exploration altogether.

Pressure to accelerate licensing and development stems from three factors: (1) the prospect of peaking production from existing fields from 1985 to 1990; (2) the need for additional fields to be identified in the Statfjord area to justify the cost of any pipeline; and (3) Norway's short-term economic problems incurred on the promise of oil revenues.[21]

Norwegian officials and oil companies are faced with a difficult dilemma. The deep Norwegian trench and the limited domestic market for petroleum products have so far made pipelining to Norway a less than attractive prospect. Still, there is strong political sentiment in the country to "bring Norway's oil to Norway", and while the Ekofisk-Bravo blowout sensitized Norwegians to the inherent dangers of offshore development, this political sentiment remains strong and is likely to be an important component of any future development policy.

MARINE PIPELINES IN THE NORTH SEA: THE KEY ISSUES

This chapter has provided a brief overview of the current status of offshore activity in the North Sea, with special emphasis on the pipeline systems installed or under construction and their respective shore terminals. Of significantly greater interest, and the principal objective of this North Sea Pipeline Survey, is a better understanding about how the transportation decisions were made, who was involved, what kinds of impacts have been encountered, and how the process has been regulated by the governments involved. The following chapters address these issues.

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[21] Bergen Bank, Petroleum Activities, p.19.

SECTION 2

NORTH SEA PIPELINE PLANNING, PERMITTING, AND REGULATION

Until very recently, neither the British nor the Norwegian government has had much involvement in marine pipeline routing, construction, or operating activities. For the most part, both governments have viewed such decisions as basically technical and economic questions best dealt with by the companies involved. The most critical concern is the safety and stability of the pipeline and both governments have worked closely with industry representatives and safety specialists to achieve consensus on safety standards and to keep up with the rapidly developing technology of pipeline construction.

In contrast, there has been very little involvement by either government in the planning of offshore pipeline routes. The policy in the U.K. has been to wait and react to proposals from industry rather than conduct contingency planning in anticipation of industrial development proposals. Except for the unique case of the Shetlands, U.K. planners seldom choose sites for facilities ahead of time. The coastal planning guidelines developed in Scotland, classifying sections of the coast as conservation, development, or unclassified zones, came the closest to prior planning. This classification system appears to have had some effect. Most of the major new industrial facilities have been sited outside of conservation zones. However, when major industrial developments have been proposed for conservation areas, public policymakers have been successful in applying "national interest" override criteria to permit the facility to be developed.[22] The "wait and see" approach has also been applied to the question of regulations. The tendency in the U.K. is to refrain from promulgation of regulations for a particular activity until something happens that indicates such regulations are needed.[23]

[22] Interview with British National Oil Company officials.

[23] Interview with Scottish Development Department officials.

The approach in Norway is similar. Ministry of Petroleum and Energy officials wait for industry proposals, review and comment, and recommend alternatives to be studied.[24] Other agencies check proposals for safety, but apart from identifying potential landfalls, little pre-planning is evident until finds are confirmed. The legislation governing Norwegian continental shelf development tends to be very general.[25] Regulations to ensure compliance with legislative intent are drawn up by the Norwegian Petroleum Directorate (NPD), but again these regulations are generally concerned with issues of safety, inspection, and in some cases pollution control systems offshore, rather than methods of routing or siting decisions.

UNITED KINGDOM

The Petroleum and Submarine Pipelines Act of 1975, which regulates the construction and operation of offshore pipelines, is the principal vehicle for controlling the marine pipeline siting process in the United Kingdom. Prior to the Act, the offshore activities were loosely monitored through a number of other pieces of legislation. This section examines how onshore pipeline decisions are made, how marine pipelines were sited before the 1975 Act, and how the terms of the Act have been applied since it was passed.

Land pipelines fall under the control of the Pipeline Act of 1962, which divides pipelines into two classes. The routing of small pipelines under 10 miles in length requires planning permission from the district or regional planning authority. In the case of land pipelines greater than 10 miles in length, approval of the route and siting of associated structures is the responsibility of the Secretary of State for Energy. The design and external appearance of the pipeline's associated structures must be approved by the planning authorities. The company proposing lines greater than 10 miles must, upon application for planning permission, advertise for a 28-day public review.[26] Planning authorities' comments can cover such issues as (1) the effect of pipelines on future uses of the land (including mineral extraction); (2) the loss of prime agricultural land; (3) the

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[24] Interview with Ministry of Petroleum and Energy officials.

[25] Ministry of Industry, Legislation Concerning the Norwegian Continental Shelf, October 1977.

[26] Interview with official at H.M. Pipelines Inspectorate, Department of Energy.

loss of environmentally sensitive areas; (4) the effect on archeological sites; and (5) the hazards to public safety.[27] During the review period, the company, affected public, or the local planning authority may arrange public meetings. If the local authority raises an objection to the proposed pipeline, the Secretary of State for Energy is bound by the legislation to hold a public enquiry before making a decision. The effect of the local planning authority's comments is strictly advisory for lines over 10 miles, however; final authority rests with the Secretary of State for Energy.

Local or regional planning authorities, accustomed to controlling most land use decisions, express frustration at not being able to decide on pipeline permit applications, even though such applications may cover several local authorities. A principal frustration is that the required rights-of-way and density limitations for pipelines effectively eliminate substantial areas of potentially developable land, preempting local long-term development and infrastructure plans. For example, the required right-of-way for a 36" pipeline is 40 feet on either side. However, codes of practice call for a density limitation within 1250 feet on either side of the pipeline of one person per acre along each mile of pipe.[28] The councils want to establish corridors to minimize this "sterilization" of acreage by proliferating trunk lines. The British Gas Corporation (BGC) argues that pipelines should be independent and sited based on the product being carried. While the BGC consults extensively with local authorities in planning pipeline routes, the local authorities have only advisory powers, except with respect to surface installations.

Offshore pipelines constructed prior to the passage of the Petroleum and Submarine Pipelines Act (which is not retroactive) were controlled through a variety of means. Proposals were reviewed by both the Department of Agriculture and Fisheries, under the authority of the Dumping at Sea Act, and by the Department of Trade, under their navigation responsibilities. Upon review, these agencies gave authority to the Department of Energy to proceed. Most of the pipelines to the U.K. have been constructed under this loose arrangement, including Ekofisk to Teesside, Forties to Cruden Bay, Frigg to St. Fergus, Piper to Flotta, Brent and Ninian to Sullom Voe, and the several lines from the southern gas fields.

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[27] Interview with officials of the Grampian Regional Council.

[28] U.S. requirements (Title 49 CFR 192) specify that natural gas pipeline design and operating conditions meet criteria based on actual population density.

The passage of the Petroleum and Submarine Pipelines Act in 1975, however, consolidated and formalized the process of offshore pipeline application and approval. Under the terms of this Act, the Department of Energy (DEN) can issue regulations to govern the form and process of pipeline application. To date, however, those regulations which have been drafted have been vague. Because DEN's policy emphasizes performance over specific technologies used, and because the technology of offshore pipeline construction is changing rapidly, DEN issues what it calls "guidance notes" to assist companies applying for a pipeline construction authorization.

When DEN receives an application, it requires documentation that the applicant is technically and financially capable of constructing and operating the pipeline safely and of discharging any liability resulting from an accident. A detailed report on the route, design, construction, and operation of the proposed pipeline must accompany the application. The company must advertise a notice of application for 28 days and provide copies of the proposal to several cities along the coast. No public enquiries are specifically required under the Act, but the companies must gather and respond to all "observations" made about the proposal, not just the objections. The company must report the results of consultations with affected parties, including commercial fishermen, other offshore operators, and cable companies. In the meantime, DEN handles notification and coordination with other government agencies.

After all of these steps have been taken, notice of application expired, and differences resolved, DEN issues a letter of intent to formally authorize the pipeline. A further technical report on the specifications of the pipeline is requested, discussed, and approved, and the company can then begin construction. Actual formal authorization may take some time to process. Therefore, the letter of intent serves to speed construction while the paperwork is being completed and may specify any special requirements DEN wishes to issue as conditions for approval. DEN also monitors the construction process, inspects the equipment, monitors the testing results, and oversees inspection upon completion.[29] In general, the companies are required to comply with state-of-the-art standards on design and safety, such as those established by the Institute of Gas Engineers, the British Institute of Petroleum, the Department of Transportation's Office of Pipeline Safety, and the classification firm specializing in

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[29] Interview with official at H.M. Pipelines Inspectorate, Department of Energy.

offshore engineering, Det Norske Veritas. The same is true of land pipelines.

The Secretary of State for Energy cannot, on his own, recommend a change in the route after authorization; rather, the applicant must submit a request for a change of route. This means that conflicts with other uses or users, if not anticipated prior to authorization, may be unresolvable after authorization has been granted. (This may explain why final authorization may be delayed until the line is virtually completed.) Other problems may also arise now that the government is trying to encourage the design and routing of pipelines to permit offshore hookups with new fields to reduce the proliferation of pipelines to shore.

The Shell/Esso associated gas pipeline from the Brent field to St. Fergus was the first to be constructed under the terms of the new Act. Company officials reported that the principal objections raised during the review period were from other companies owning undeveloped offshore blocks along the proposed route. Among the conditions stipulated by DEN for the pipeline were (1) monthly progress reports; (2) immediate notice of incidents threatening the pipeline; (3) DEN-monitored quality control procedures; and (4) compliance with state-of-the-art industry standards unless specifically waived. Shell/Esso officials note that, although DEN has full authority to cancel an authorization if established procedures are not followed, the agency has been extremely receptive to advancing technology through research and detailed engineering studies, rather than simply establishing procedures which specify appropriate technologies.[30]

NORWAY

Although no marine pipelines have been constructed to Norway to date, a number of mechanisms are already in place to handle proposals in the future. Several agencies are involved. The Ministry of Petroleum and Energy is the principal offshore petroleum development policy analyst. It manages the leasing program and monitors development of the offshore fields. The Norwegian Petroleum Directorate (NPD) is the regulatory agent for day-to-day activities. The NPD is responsible for establishing regulations to implement the general policies approved by the Parliament and deals with technical questions about the interpretation of the law. Its regulations deal primarily with safety-related issues rather than routing decisions. Statoil

[30]Interview with Shell/Esso officials.

manages Norway's commercial interests. Although it is wholly-owned by the government, it functions as an ordinary oil company, and will have majority participation in all future licensing rounds in the Norwegian sector. Recently, Statoil was commissioned by the Norwegian Parliament to conduct a $60 million feasibility study of a pipeline from the Statfjord field to Sotra, near Bergen. Norpipe A.S. was established in 1973 by the Parliament to obtain control over the transportation system for oil and gas in the southern portion of the Norwegian continental shelf. The objective was for Norpipe to construct, own and operate the facilities.

Regulations developed by NPD to control offshore activity tend to be extensive and tough. But because so few pipelines are expected to be constructed to Norway, Norwegian officials seem to prefer less regulation and more attention to the application of specific stipulations to each case as it arises.

The Royal Decree of July 9, 1976 is the basis of the existing regulation of marine pipelines in Norway. Chapter 12, Sections 111-124 set out requirements for information disclosure and transportation plan documentation; route surveys; safety standards for load bearing capacity, weldability, corrosion, and concrete coating; installation plans; construction practices; trenching and burial; and emergency shutoff systems. For example Section 123, which deals with burial, stipulates: "To the extent reasonable, pipelines shall be protected by burial or other means to avoid mechanical damage caused by other activities along the route, including fishing and hunting, shipping, and exploration and exploitation of submarine natural resources."[31]

To translate the law into practice, NPD has specified the depth requirements of burial under conditions applicable to the Ekofisk situation (see Section 4 on trenching and burial) but generic regulations have not been promulgated. Similarly, NPD has specified inspection of the Ekofisk lines every six months for the first two years to carry out another legal requirement, but again, these rules may not apply or may be strengthened in other situations. The value of these inspections was dramatically displayed when a severe buckle was discovered in the Ekofisk-Teesside pipeline, caused by a dragging tanker anchor coming in contact with a section of the pipeline near shore.

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[31] Ministry of Petroleum and Energy, "Royal Decree of July 9, 1976, Relating to Safe Practice for the Production of Submarine Petroleum Resources, Chapter 12, Section 123", Legislation Concerning the Norwegian Continental Shelf, October 1977, p.255.

The pipeline was shut down for six weeks while the section of the pipe was replaced.

Perhaps the most unique aspect of the pipeline transportation and regulatory process in Norway is the degree of participation and influence of Det Norske Veritas, a private ship classification company that has become heavily involved in offshore activities. Under contract to the government and the participating oil companies, Veritas oversees pipeline design, (stress, materials, welding, corrosion protection, etc.), inspects pipe mills and coating yards, certifies every pipe joint, certifies the technical capability of the pipelaying barge and the details of the construction process, monitors and inspects the construction techniques (day and night), certifies underwater tie-ins, comments on jet barge suitability for conditions encountered, and conducts final tests (hydrostatic; video inspection).[32]

On the basis of their experience offshore, Veritas has published "Rules for the Design, Construction, and Inspection of Submarine Pipelines and Pipeline Risers", along with other codes -- including API codes -- which govern pipelaying safety procedures in the Norwegian sector and elsewhere in the world. They have been responsible for risk analyses and safety procedures and have issued "certificates of approval" for many steel structures in the Norwegian sector. In addition, the company maintains a "pipeline condition record" which documents all acceptable defects which occur during construction to simplify the inspection process later.

While in most respects Norway, like the U.K., prefers to react to industry's proposals rather than conduct extensive contingency planning programs, the pipeline/trench problem has resulted in a fairly extensive siting study. Statoil/Mobil Group's pipeline feasibility study, discussed in detail later in this report, included a survey of 400 km of coastline from which eight landfalls were singled out for more detailed investigation of such factors as route length, water depth, rock outcrops, and simplest route preparation.[33] Because of the nature of the western coast, the options were limited. Similar but significantly more detailed surveys have been made on the pipeline route itself. At the same time, the Statoil/Mobil Group, the operator of Statfjord, is conducting feasibility studies on the offshore loading alternative to pipeline transport.

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[32] Interview with officials of Det Norske Veritas.

[33] Interview with officials of Statoil.

In conclusion, it is accurate to say that both Norway and the U.K. tend to focus virtually all of their management attention on regulating pipeline construction and operation activities. The stimulus in both cases is an industrial proposal. Neither country is involved to any significant degree in prior planning of marine pipeline corridors or routes and, although some attention has been given to alternative landfall locations, these decisions are generally made by industry.

With this brief look at the planning and regulatory context, Section Three examines the way in which routing and landfall decisions have been made in the North Sea during the last decade.

SECTION 3

NORTH SEA PIPELINE ROUTING AND LANDFALL SITING

The North Sea has been, and continues to be, a major proving ground for new pipeline technology. The hostile deep water environment has spawned a whole new generation of pipelaying barges and tremendous advances in pipe fabrication, coating, welding, and trenching techniques. Given the scale of the engineering problems encountered and the cost of laying pipe under such conditions, it is reasonable to examine how North Sea operators have made pipeline construction and routing decisions.

The routing choices made for North Sea pipelines can provide illustrations of how decisions were made on the following types of issues: transportation by pipelines or tankers; location of landfall and terminal sites; the route selection methods themselves; causes of changes to planned routes; and the relative effects of technical, economic, environmental, and political factors in determining the final routes. In examining these issues, this section focuses on the systems planned or currently in place in both the U.K. and Norwegian sectors and emphasizes the decision process followed in each case rather than on the results of detailed technical surveys conducted by the companies involved. Information is derived largely from interviews with local and central government officials and technicians with the companies involved.

UNITED KINGDOM

Experience in the U.K. sector suggests that transportation decisions are determined almost exclusively by technical and economic criteria. Minor adjustments may be made for environmental or political reasons, but, for the most part, routing and landfall decisions for marine pipelines have been determined on a least-cost basis. As noted previously, there has been little effort by central government in either England or Scotland to influence offshore pipeline routing and landfall decisions, with the unique exception of gas terminal siting. British Gas, with a monopoly over gas distribution in the U.K., has largely determined where offshore gas will be landed, though they have had little influence on how the gas gets there. This discussion looks first at the gas pipeline and landfall experience and then examines the situation with oil.

The Conoco-Viking Field Case

Most of the gas from the southern North Sea gas fields, discovered in the mid-1960's, comes ashore at the big gas terminal at Bacton, England. Until the opening of St. Fergus, Bacton was the principal source of gas for the British Gas system.

When Conoco made its Viking gas field discovery slightly north of the center of the southern North Sea gas field complex, it proposed a 60 mile pipeline south to the Bacton terminal. For Conoco's purpose, it was both technically and economically the best pipeline/terminal alternative. Instead, British Gas Corporation (BGC) ordered Conoco to bring its gas ashore at Theddlethorpe north of Viking on the English coast. BGC felt that the Bacton site had grown so large and important that it was becoming a security problem and that it would be safer to, in a sense, diversify their sources of supply. Despite the fact that the new route was substantially longer (86 miles) and therefore more costly and would encounter sand waves, Conoco had no choice but to cooperate. As a result of having to go the longer, more costly route, Conoco was able to negotiate a better price for their gas. They also obtained planning permission without difficulty after only 12 months of consultation with local officials. Conoco attributes some of this success to having a company representative "on the ground" -- a Conoco employee who moved into the area, worked closely with the local authorities, and walked the application through the approval process with British Gas. Although the process went smoothly for Conoco, it is an excellent example of the effect central government can have in the U.K. on pipeline routing decisions through control of landfall options.[34]

The St. Fergus Terminal

In an effort to find a suitable landfall site for gas from the northern North Sea, BGC was again in charge. A preliminary survey of the northeast Scottish coast yielded two alternatives: (1) Wick, a small community near the farthest northeast tip of Scotland; and (2) the area south of Rattray Head, another headland roughly 50 miles north of Aberdeen. Both areas had reasonably gentle shore approaches and low population densities.

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[34] Interview with Conoco officials.

Both sites were roughly equidistant from the Frigg field, Total's major gas field, for which the terminal was initially being designed. However, British Gas Corporation, responsible for laying the land lines to link the terminal to the distribution system in the south, immediately ruled out Wick as prohibitively expensive, and the beaches south of Rattray Head were surveyed in more detail. Total, which wanted to bury the pipeline 10 - 15 feet below the seabed nearshore, conducted a survey of landfall approach alternatives and chose a spot near the village of Crimond, behind a shallow brackish pond called the Loch of Strathbeg. The site included an abandoned airfield still held by the government and a solid line of trees screening it from view from the road and village. The companies applied for planning permission to establish the terminal.

Unfortunately, the Crimond site is both a national nature reserve and an international reserve of the highest classification on four separate accounts: (1) it is an important migratory wildfowl habitat; (2) it is an important plant community; (3) the dune structure is a recent (1700's) and rare formation and unstable; and (4) the shallow brackish loch is highly productive and similarly rare.[35]

In response to the proposal, an environmental liaison group was formed by researchers at the University of Aberdeen. The University liaison group organized meetings with the industry representatives and the Aberdeen County Council. At the request of the Scottish Development Department, further offshore surveys were conducted and an alternative landfall was located at St. Fergus, just a few miles south of Crimond.[36]

British Gas Corporation claimed that they could have constructed the facility in such a way as to minimize the disturbance of plant life and bird habitat on the site and possibly cross the loch without significant disturbance. They admit, however, that they would have had to stabilize the shifting dune to bring in the pipe and that would have significantly altered the dune structure.[37]

In the end, however, the decisive blow was struck by the Department of Defense, which held the airfield. They wanted it

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[35] The preceding discussion is drawn from interviews with British Gas officials.

[36] Interview with Brian Clark, University of Aberdeen, and correspondence from the Scottish Development Department.

[37] Interview with British Gas official.

for a NATO radio center and ultimately refused to release it. Of interest, however, is the assertion by both industry and the county clerk's office that the environmental liaison group based at the University, and not the government planning application review process, had the greatest effect in the negotiations before the Defense Department stepped in.

Total went on to a section of beach near St. Fergus where a narrow break in the offshore rock outcrops below Rattray Head provided enough space for their two pipelines and where substantial open land was available behind the stable barrier dune system for British Gas Corporation to establish a 500 acre terminal. The soil, however, was boggy and unstable and a significant amount of surface soil had to be removed (to a depth of 15 feet in some places) and replaced with crushed rock and steel pilings.[38] In addition, since it lacked the natural tree screen from the highway that the Crimond site had, the St. Fergus site had to be planted with thousands of small fir trees.

Routing the Frigg Gas Lines

The anchor pattern deployed by a lay barge is such that if two lines are being laid parallel, they must be laid either at least two kilometers apart or very close together (70 meters), with the lay barges straddling the first line already on the seabed. Total had planned to lay their two 32" lines fairly far apart, but because of the problem of crossing other companies' blocks, the lines were laid close together. Between 1974 and 1977 approximately 60,000 12 meter joints were laid in depths of over 150 meters (490 feet). At Invergordon, Scotland, each joint was concrete-coated through a cage of reinforcing wire at thicknesses varying from 1 7/8 to 4 5/8 inches. Three lay barges, two bury barges, one diving support ship, two mini-submarines and their support ship, and 60 supply boats, tugs, and pipe transporters were employed in the job. Lengths of completed pipeline were joined in a chamber at the seafloor by a hyperbaric welding process developed by Total. An intermediate platform was installed 186 km from the field along the pipeline route.[39]

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[38] Interview with Total Oil Marine official.

[39] Total Oil Marine, Frigg: Gas from the North Sea, 1978.

The pipeline route was fully surveyed, and sediments consisted mostly of sands and soft clays. The route chosen was direct, with deviations near the field to avoid other licensed blocks. Near shore, Total identified, with the help of local fishermen, an offshore rock formation known as Rattray Rocks. They diverted the line around the rocks and a boulder clay structure for two reasons: (1) it was a valuable fishing area; and (2) crossing it presented a costly engineering problem. On the shore approach, considerable amounts of rock had to be blasted to clear a path for the pipe. Cross currents were strong and the pipe was heavily coated and fitted with flotation tanks to prevent its buckling during the laying and pulling process. The coastal dunes were excavated and a sheet pile trench was cut to the terminal.[40] The dunes were subsequently reinstated and vegetation was restored with the help of the Geography and Horticulture Department of the University of Aberdeen.

Routing the Brent Gas Line

Like Total, the Shell/Esso Group began by charting the shortest, so-called "great circle" route for their 450 km 36" pipeline to St. Fergus for Brent associated gas. The route of the line, known as the Far North Liquids and Associate Gas System (FLAGS) Gasline, has the following predominant characteristics:

- 80% of the route is in depths of over 100 meters, with a maximum depth of 165 meters;
- there are deep trenches and "pockmarks" along the route;
- in deep water the seabed is mainly soft silts and clays; and inshore is mainly sands and hard clays, rock, and rubble;
- tidal currents (though negligible in deep water) reach 1½ meters/second along the coast;
- the route crosses several fishing banks; and
- like Frigg lines, the line crosses Occidental's Piper line at a depth of over 100 meters.[41]

Because of the length, depth, and general expense of the project, Shell/Esso commissioned a number of independent surveys and consulted frequently with other users along the route, including fishermen's associations and other offshore operators.

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[40]Interview with Total official.

[41]Interview with Shell Expro and Esso Expro officials.

The results of the studies were summarized by NERBC and the trenching study results are reported elsewhere in this report.

The first deviations to the shortest route were made to avoid several trenches over 100 meters in depth and an area of "pockmarks", wide, relatively shallow holes or craters, which would cause pipeline spanning and decrease the safety and stability of the line. Consultations with the fishermen's association resulted in several additional routing changes. The original route crossed several prime trawling grounds and the fishermen initially proposed an alternate route to avoid the grounds. A third compromise route was finally agreed upon which skirted the edges of the grounds. Subsequently, however, the fishermen requested that the original route (or one very nearly like it) be followed because they preferred to trawl the edges of the banks, not the centers. A route running roughly down the center of each of the grounds -- and avoiding an area of 20 - 30 foot sand waves -- was agreed upon.[42] (Active sand wave areas were avoided along the entire length of the line, although Shell/Esso engineers are confident that it is technically feasible to safely place a pipeline through these regions.)

At the northern end of the line, the route was altered to avoid any conflict with the Ninian complex. After extensive surveys of the shore approach, the line's southern end was laid through roughly the same gap in the rock outcroppings as the Total lines has been. In all, surveys took roughly a year to complete. The pipelaying was completed in mid-June, 1978.[43]

However, because the Brent field gas is "wet," i.e., has a high liquids content, the Shell/Esso Group also needed a system for shipping gas liquids (ethane, propane, butane, etc.) from St. Fergus. Their original proposal was to link St. Fergus to a natural gas liquids (NGL) plant and to ship propane and butane from a terminal at Peterhead, which met the 10 - 12 meter depth requirement of NGL tankers. However, several major objections were raised. First, many felt the harbor was too busy and too small for safe maneuvering of NGL tankers. Secondly, the density of residential development around the harbor was felt to be at risk. Thirdly, and most significant in the long run, was a finding by the company that the seawall forming the protected harbor would need to be substantially improved in order to provide protection from high storm waves. Moreover, the local fishing association argued persuasively that the fishing boats be given priority entry in port during storms, thus making the berthing problem for tankers that much more complex.

[42]Interview with Shell/Esso officials.

[43]See footnote 42.

Shell/Esso eventually dropped the Peterhead NGL terminal proposal in favor of a 175 km land pipeline south to Mossmorran on the Firth of Forth linking up to an ethylene cracker and NGL shipping terminal. The proposed terminal met with stiff opposition from residents in the area who were skeptical of the safety of the proposed facilities; tentative approval was granted however and, subject to the Sectetary of State being satisfied with the safety of the project, it is likely to proceed.[44]

Forties Field to Cruden Bay

BP is, by experience, a pipeline company. Although it is their practice to develop a series of transportation scenarios even before the field is fully developed, the company has generally discovered large, high-pressure fields for which pipelines were the only economic transportation option.

This was the case with the Forties Field where BP chose pipelines to deliver the crude oil to shore. The closest landfall to the Forties Field is Cruden Bay, which lies almost due west of the field and is one of the few "soft landing" sites on the Northeast Scottish coast. In planning the route, BP worked closely with fishermen. Through these consultations, BP was able to locate rock outcrops, boulder zones, and fishing grounds which were subsequently avoided in the 110 mile long final route. Diversions cost the company $1 - 2 million, one to two percent of the total cost of the line.[45]

The pipeline was designed and built in four years. Construction covered three seasons from 1973 to 1975. The majority of the route was in depths of 350 - 450 feet with seabed conditions ranging from sand waves to stiff clays. Approximately ninety percent of the route consisted of loose materials such as sand and silt.

Survey work covered roughly three years from 1971 - 1973. A preliminary survey was conducted in 1971, followed by consultations with a variety of interested parties, and culminated in a detailed survey in 1972. Survey techniques included sidescan sonar, echo soundings, and use of a sub-bottom profiler. Core samples and photographs were collected and current meters deployed along the route. In 1973, further surveys were undertaken in an area of sand waves to establish whether they had moved dur-

[44] See footnote 42.

[45] Interview with BP officials.

ing the preceding winter. In all, surveys cost roughly $500,000.[46]

BP had considered Peterhead as the pipeline landfall at first but soon ruled it out because of harbor traffic, the presence of substantial rock outcrops, and the cost of rights-of-way. (In this regard, BP officials note that the landfall decision can be determined as much by ability to purchase rights-of-way at reasonable cost as by such recognized factors as distance.)[47]

BP feels that the Cruden Bay landfall was made with limited public disruption. Environmental effects (which appear to be minimal) have been monitored by researchers at the University of Aberdeen. BP officials jokingly commented that their biggest landfall problem was disrupting the local golf course. Regional Council officials were pleased with the quality of the restoration of the beachfront and right-of-way.

The Brent Field to Sullom Voe

The 36" trunkline linking the Brent System (including Brent, Cormorant, Dunlin, Hutton, and Thistle) to the oil terminal at Sullom Voe, Shetland is a joint venture of some 17 companies, with Shell Expro as the operator. Design began in 1973 and construction took place from 1975 - 1977.[48]

While Shetland was clearly the closest feasible pipeline landfall to the northern North Sea area, Shell encountered numerous engineering difficulties in the shore approach through Firths Voe to the landfall chosen for the terminal.

The unusually rugged seabed through Yell Sound approaching Firths Voe made pipelaying difficult. For approximately six miles offshore, the seabottom consists mainly of rock outcrops, pinnacles, and cliffs, in addition to smoothly undulating bedrock and occasional boulder cover. Following initial surveys to find a suitable route, Shell contracted for engineering studies to determine methods to deal with sea bottom conditions. After examining a number of plans, the method chosen included three activities:

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[46] D.B.L. Walker, A Technical Review of the Forties Field Submarine Pipeline. Paper prepared for 1976 Offshore Technology Conference, 1976, pp.819-821.

[47] Interviews with BP officials.

[48] M. Daniels and J.C. Swank, Northern North Sea Pipelines -- the Brent System. Paper prepared for the 1976 Offshore Technology Conference, 1976, p.803.

- blasting bedrock and boulders to eliminate rock pinnacles and level off the sea bottom;
- depositing stone fill on the seabed to cover unacceptable bedrock and boulders, maintaining a minimum depth of two feet; and
- grading the fill to provide a bed for pipe-laying.

In addition, sidescan sonar and echo sounding revealed three distinct zones, totaling approximately 3000 feet, which were unacceptable for pipeline laying. This bottom profiling was also used to determine the minimum acceptable bed width - 60 feet.[49]

The preparation effort required a survey vessel, six stone transport ships, and a variety of auxiliary tugs. A total of 45,000 tons of crushed stone was mined from two quarries near Peterhead, transported to quayside at Peterhead Harbor (3,900 truck loads), and shipped 200 miles north to Yell Sound in the Shetlands. It was determined that the vessels, moored alongside a work barge, could dump a gravel bed roughly 120 feet x 80 feet to a depth of four feet with each 1,000 tons released in roughly 150 feet of water. Careful diver inspection for alternative routes reduced what was anticipated to be a substantial blasting effort to almost nothing.

The laying operation itself, through the six miles of Yell Sound, involved depths of over 300 feet and currents of up to six knots. Under these conditions, an extremely complex positioning system, involving twenty surveying and electronic techniques, was required to lay the 36" pipe on a 60 foot prepared bed. Vickers Oceanic's Pisces II submarine was used to monitor pipe touchdown on the narrow bed whenever conditions permitted.

Submarine surveys after installation showed considerable spanning over the entire six mile stretch of the route through the sound, and steps to stabilize the line, including placing grout-filled mattresses and crushed gravel under the pipe, were planned for October 1975. In September 1975, the pipe floated to the surface over a distance of some 400 feet. After the pipe had been re-stabilized (using concrete saddles), inspection showed a loss of concrete coating over 60 percent of the pipe. It was concluded that vertical vibrations of the pipe caused by the vortex of bottom currents around the spanned pipe had caused the pipe to hammer repeatedly against the sea floor, breaking off the concrete coating. Despite the floating incident and the

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[49] Ibid, p.805.

loss of weight coating, the pipe itself was apparently undamaged.[50]

BP, faced with the same problem in routing their pipeline to Sullom Voe from the Ninian complex, chose to avoid the high currents and difficult bottom conditions in Yell Sound in favor of a longer and, initially at least, somewhat more expensive route through an ancient sandy-bottom fault leading to Lunna Ness.[51]

The Piper Field to Flotta

Though, like BP, they tend to favor pipelines, Occidental officials outlined a number of reasons for choosing the 30" pipeline to the Orkney Island of Flotta to transport Piper, and later Claymore, oil and associated gas liquids. From the beginning, Occidental was confident of at least 250,000 barrels/day (b/d) production from Piper and optimistic about the chances of discovering other fields in the area. The expected production levels suggested that tankering would be clearly uneconomic. In addition, the company had had a series of bad experiences with single buoy systems elsewhere in the world (especially the Mediterranean) and found maintenance to be a problem. Finally, the tanker loading downtime likely from bad weather in the northern North Sea made stable production extremely unlikely.[52]

The choice of a landfall at Flotta in Scapa Flow in the Orkneys was less than a straightforward decision and illustrates the occasional importance of considerations other than economic feasibility in site selection. As soon as Piper was discovered (January 1973), Occidental "walked" the northeast coast of Scotland in search of a suitable landfall and terminal site. The coastline directly opposite Piper, near Wick, is generally characterized by steep cliffs rising directly out of the sea. Nevertheless, nine potential sites were identified. The Orkneys were included primarily because of a chance airplane conversation between an Occidental official and a retired Royal Navy captain living in the Islands who suggested that, because of the deep waters of Scapa Flow and availability of land, the Orkneys should be considered.[53] Flotta, though more isolated than other Scapa Flow landfalls, was chosen as the site likely

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50 *Ibid*, p.807.

51 Interviews with BP officials.

52 Interview with Occidental North Sea Group officials.

53 See footnote 52.

to cause the least effect on traditional patterns of life and the natural environment.[54]

Occidental's final decision to go to Flotta was based primarily on the warm welcome they received from the Orcadians. They attribute this to several factors. First, the consortium was one company, not several (as in the case of the Shetlands), and they were easier to cope with. Second, the consortium included the Thomson North Sea Group: a Scottish family involved in several newspapers and other operations, who had intimate knowledge of the way things are done in the Islands and were trusted by the Orcadians. Third, there was land available and, though it had to be designated for industrial use, the Islands had already been singled out as a development area by Scottish authorities. Fourth, the Orkneys had been the site of a large naval base for many years during and following World War II. The 18,000 Orcadians were used to supporting a 30,000-man naval force and wanted to regain the economic benefits they had lost when the base was decommissioned. Fifth, the Orkney Islands' authorities were pleased with Occidental's willingness to meet their development conditions, negotiate terms, and proceed cautiously. Outline planning approval was granted to Occidental within a year of the Piper find, something of a record.[55]

Route selection from Piper posed no significant problems offshore. The pipeline runs in a straight line from Piper to Scapa Flow. Inside Scapa Flow, Occidental's engineering consultants (Bechtel) identified a number of wrecks and navigation barriers from the war and the pipeline was routed around them. Sediments along the route were suitable for trenching in most areas and gravel beds were laid in areas of rock outcrop. Concrete saddles (covering roughly 500 meters) were laid for extra stability in some areas and to provide access for subsea pipeline hookups at a later date.[56]

With the completion of these main oil and gas trunk lines it is unlikely that many more will be proposed to the U.K. There are a number of reasons for this conclusion. For one thing, as production from the early finds levels off and begins its decline, it makes sense economically to use the excess capacity in existing trunk lines to accommodate the production requirements of new fields. In addition, the government is under some pressure to limit the proliferation of offshore pipelines, shore terminals, and land trunk lines, except insofar as British Gas must

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[54] Occidental North Sea Consortium, The Flotta Story: Development of an Oil Handling Terminal (Second Ed.), July 1978, p.11.

[55] Interview with Occidental officials.

[56] See footnote 55.

plan for ensuring the security of gas supplies. Moreover, energy conservationists (and some Scottish nationalists) are arguing persuasively for stretching out the duration of productivity by flattening the peak in the production profile of fields currently being developed.[57]

Consequently, most of the recent pipeline proposals have been for relatively short offshore lines to link new fields to existing major trunk lines. In this regard, for example, Conoco negotiated an agreement in 1976 with the operators of the Brent oil pipeline system to link their Murchison field to Dunlin by means of a ten-mile, 16" diameter pipeline. Conoco evaluated tankering, but the uncertainty of offshore loading, the cost of a concrete storage platform, and the relatively high proportion of volatile gas liquids in the Murchison oil stream, persuaded them that the pipeline was the best and most economical alternative. Similarly, Texaco is negotiating with Occidental to link its Tartan field to the Piper line to Flotta,[58] with associated gas transferred, also via Piper, to the Frigg gasline to St. Fergus.

There are some potential exceptions, however. The nearshore Beatrice field being developed by Mesa will, under government order, require a pipeline to shore. However, the technical problems of pipelining oil with as high a wax content as Beatrice oil have been difficult to resolve. There is speculation that Pan Ocean's Brae field may have sufficient capacity to justify yet another gas line to St. Fergus. British Gas is rumored to be looking for another Scottish terminal site beyond St. Fergus, again to increase the security of the supply system. And the possibility of substantial reserves west of the Shetlands may mean a new pipeline to the northern coast of Scotland.[59]

Finally, pursuing its interest in a gas gathering trunk line running roughly down the median line in the North Sea to link up marginal and, as of yet, undeveloped gas fields, Gas Gathering Pipeline Company, on behalf of the British government, has completed a survey of potential new pipeline landfalls. The report was still under review by the Department of Energy in July 1978, but onshore, coastal, and offshore siting criteria have been developed for screening pipeline routes and landfalls.

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[57]Interview with Gordon A. MacKay, University of Aberdeen.

[58]Interview with Conoco officials.

[59]Interview with British National Oil Corporation official.

The criteria, listed in Table 4, are largely technical and economic considerations for judging prelimiary suitability. Obviously, these are "best case" conditions. Pipelines and landfall sites with many of the negative criteria on the list have already been built because other factors, generally economic, have outweighed the technical problems.

NORWAY

Norway's experience in marine pipeline construction is limited to the Ekofisk lines to Teesside, England (34" oil) and Emden, West Germany (36" gas) and ownership of one of the Frigg gaslines to St. Fergus. Considerable study has been done on the feasibility of pipelines from Frigg to Kaymøy (gas), from Statfjord to Sotra (oil) and gas gathering lines along the boundary between Norway and the U.K. Norwegian law calls for all oil and gas found in the Norwegian continental shelf to be brought ashore in Norway, unless specifically excepted by the King.

In the case of Ekofisk, Phillips requested exceptions for both gas and oil. Phillips' request was based on their conclusion that it was not economically or technically feasible to construct a gas pipeline through the Norwegian trench and that even if it were possible, there was simply no significant market for gas in the country. Phillips cited similar reasons for requesting exception for Ekofisk oil and further claimed that the technology for offshore loading was not good enough to handle production conditions in the North Sea. Subsequently, both requests were approved.

The Ekofisk Pipelines

The heart of the Ekofisk operation is Ekofisk Center, a huge concrete gravity platform, with a one million barrel storage capacity, that separates the well stream, processes the oil and gas, and controls the production rate. The oil pipeline is 220 miles long and includes two intermediate pumping platforms at roughly the one-third points along the line. Water depths along most of the route exceed 200 feet, with maximum depth of 314 feet. The sea bottom is mostly sand and silty sand. One area of rock outcrops was encountered roughly five miles from shore in about 100 feet of water. Tidal and storm currents are low.[60]

The route of the oil line is essentially a straight line from Ekofisk to Teesside with two variations. The first was to avoid a ship anchorage area near the Tees Harbor entrance.

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[60] Phillip S. Massey, "Ekofisk-Teesside Line to Operate Continuously," Oil and Gas Journal, February 24, 1975, p.86.

TABLE 4

PHYSICAL CONSTRAINTS ON PIPELINE LANDFALLS

CRITERIA FOR EVALUATION

Onshore (above limit of marine activity)

1. 500 acres land with slope under five percent; well drained; average bearing capacity.
2. within one mile of coast; or
3. two sites with similar physical characteristics: one 50 acres within one mile of coast, one 500 acres within five-ten miles of the coast.

Coastal (from low water mark to upper limit of marine activity)

1. less than ten percent slope.
2. sediment at least three meters.
3. absence of unstable/very mobile sediments.
4. absence of hard untrenchable rock outcrops.
5. absence of high velocity currents.
6. absence of rock cliffs (ten meter high soft sediment cliffs permissible).
7. absence of unstable sand dunes.
8. space for landing two pipelines (100-200 meters).

Offshore (low water mark to depth of 100 feet)

1. less than ten percent slope, low to moderate undulation.
2. sediments at least two meters deep.
3. absence of mobile seabed sediments, especially sand waves.
4. absence of high velocity currents.
5. absence of untrenchable rock.
6. absence of deep trenches; other major seabed irregularities.
7. absence of minor seabed irregularities.

Source: Gas Gathering Pipeline Company, (1978).

Another was required to avoid a sharp change in bottom profile which would have resulted in an unacceptable span. In general, however, the route surveyed turned out to be relatively smooth and presented Norpipe, the owner, and Phillips, the operator, with little difficulty. Three laybarge spreads completed the pipeline in one year (1973-1974).[61] The processing and terminaling operation at Sea Sands, Teesside is located on approximately 1.8 square kilometers (km) of reclaimed land. At the facility, natural gas liquids will be separated from the crude stream and shipped by tanker to Norway's Rafnes petrochemical plant at Bamble at a lower than present market price.[62] Crude oil is stored at Norpipe's Greatham tank farm, roughly 4 km north of the terminal, in ten tanks with a total capacity of one million tons (7.2 million barrels). In 1977, roughly half of the crude shipped from the terminal was divided equally between the U.S. and U.K. The balance went to France (ten percent), Norway (thirteen percent), West Germany (nine percent), Sweden (five percent) and others.[63]

The routing and construction of the gas line to Emden was considerably more complex. The pipeline crosses the continental shelves of Norway (48 km), Denmark (50 km), and West Germany (342 km);[64] nine active communication cables; and the busiest shipping channel in the world. Norpipe augmented initial surveys done by Phillips with additional sidescan sonar, magnetometer, and echo sounder surveys to lay out a formal route.[65]

Four laybarges were used to lay the marine section of the pipeline (250 miles) and two intermediate booster platforms were installed at the approximate one-third points in the line. All but three kilometers were laid in one season (1974). Construction permits were required from all three governments (as were operating permits later). Several adjustments were made to the line to avoid various geologic problems.

Communication cables posed special problems. The pipeline had to be buried two meters below each of the cables along the route and be no closer than 1.5 miles from a cable repeater sta-

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[61] Ibid.

[62] Interview with Norpipe officials.

[63] Norpipe, Annual Reports and Accounts, 1977, p.15.

[64] Norpipe, Brochure, p.3.

[65] Interview with Norpipe officials.

tion. Cable companies, given estimated notices of laybarge approach to the cables, would cut the cable and lay it back a half mile in each direction. The pipe was laid, one to one and one-half miles of it was trenched (usually three to four passes were required to reached desired depths), and the cable spliced by the cable company.

The shore approach to Emden was through a broad mudflat area in which a 2,000 foot dike was dredged. At the shore two rows of sheet piling were driven and a 15 foot ditch was dug from the land side. The pipe was pulled from the laybarge, which was anchored 1,500 feet offshore. Further offshore a 15 mile ditch was constructed to provide two meter cover in mud and tidal flats and three meter cover at all channels. German authorities halted construction work along a two mile section near Juist Island during the winter because of fear that the ditch would cause erosion damage to the south end of the island.[66] Other route problems encountered by Phillips, particularly with respect to trenching requirements, are dealt with elsewhere in this report.

The "Ekofisk Solution" was an innovative answer to the problem posed by the Norwegian trench. But because of the legal requirement to land Norwegian petroleum in Norway and the public pressure to bring it to shore, extensive route planning programs have been initiated, primarily for the Statfjord field in the northern sector of the North Sea.

<u>The Statfjord-Sotra Pipeline Routing Study</u>

The Statfjord field was discovered in 1974 and the operators, the Statoil/Mobil Group, immediately undertook an examination of the feasibility of an oil pipeline to the Norwegian coast. A report covering deepwater technology and landfall problems (primarily rock outcrops) was prepared in 1975 and forwarded to the Ministry of Industry (responsible at that time for continental shelf development), and then to Parliament. From the beginning, the private companies (Mobil and others) favored offshore loading, but Statoil claimed the pipeline could be built with existing technology and that view prevailed in the preliminary report.[67]

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[66] Don P. Shaub, "Line from Ekofisk to Emden Nearly Completed," <u>Oil and Gas Journal</u>, January 12, 1976, p.82.

[67] Interview with Ministry of Petroleum and Energy officials.

Parliament, in an attempt to find ways of bringing Norwegian petroleum to Norway, requested that Statoil undertake a $60 million detailed route planning and feasibility study. It also asked the licensees to examine the offshore loading question in more detail. In the interim, a temporary permit is expected to be granted for tankering oil from the Stratfjord A platform. The terms of the permit require segregated ballast water for all tankers used.[68]

The feasibility study, completed in late 1978, covered deepwater technology, route planning, construction schedules and costs, and proposed terminal sites. The following discussion, drawn from interviews with Statoil officials, discusses the survey, and the solutions proposed in the study for pipeline routing and landfall selection.

The slope from the Statfjord plateau to the Norwegian trench is relatively gentle and bottom sediments consist generally of a thin layer of soft sediment (20 cm) overlaying hard clays. On the shoulder of the slope (along which the proposed route runs diagonally) the sediments consist of dense sands giving way to soft clays near the bottom. The trench bottom itself consists of soft oozy clays, as deep as 40 meters in places, all the way to the nearshore area. The depth of the trench in the area of the proposed pipeline is 300-350 meters (985 to 1,050 feet).

The proposed route deviates in a number of places along the trench to avoid pockmarks characteristic of the northern North Sea. The pockmarks, running anywhere from ten to one hundred meters in diameter, are thought to be formed by the slow seepage of migrating natural gas.

Offshore surveys were done with high-precision echo sounders, shallow (50 meters) seismic profilers, and high resolution sidescan sonar equipment. The sidescan sonar, towed 20 meters above the bottom, allowed Statoil to clearly delineate pockmarks along the route and also identified trawl door marks which helped them determine the intensity and direction of trawling along the route. Bottom profile passes were made at every 600 meters offshore, 50 meters nearshore, and 15 meters near the shore approach.

Current readings were hampered by loss of current meters to trawl fishing, but evidence suggested minimal bottom currents, and sidescan sonar showed very limited backfilling in areas marked by trawl doors.

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[68]Interview with Ministry of the Environment official.

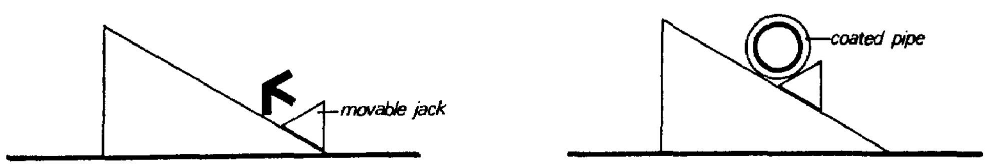
Severe problems were encountered in the effort to find a suitable shore approach and landfall. The entire coastline out to depths of 100 to 200 meters consists of crystalline gneiss outcrops, shelves, cliffs, and pinnacles. The coastline was examined for a distance of some 400 kilometers and eight potential (but still very difficult) landfall and terminal areas were identified.

Based on its proximity to Bergen, the most likely candidate area for a terminal was the Island of Sotra. Subsequently, two areas on the south side of Sotra were eliminated due to difficulties in the approach -- a rock cliff rising straight up from a depth of 200 meters. Three other potential landfalls were eliminated based on videotapes taken by submersible. Finally, Vindeness, on the eastern side of the island, was tentatively selected as a terminal site by officials, based in large part on the harbor's existing infrastructure.

The actual landfall site chosen was strictly a case of "the lesser evil." The site is some 20 kilometers north of the terminal site on a small island northwest of Sotra. The route to the terminal site involves eleven inter-island crossings, onshore trenching, and three tunnels (the longest of which is 700 meters). The subsea profile of this landfall indicated that it was the most acceptable, though still difficult, option. A 1.3 kilometer boulder zone in 60 meters of water needs to be blasted and the gullies filled with crushed rock. In areas where gravel dumping is impractical to fill span zones, the mechanical devices illustrated in Figure 2 will be employed to support the pipe.

One additional site, an area designated by the local government as a recreation area, has been chosen as an alternative landfall site.

The study concluded that a pipeline across the Norwegian trench is feasible. However, results suggested that landfall problems were as significant as crossing the trench in determining the feasibility of constructing the line. Tests have also proved that deepwater repairs are feasible, a vital consideration in establishing the security and feasibility of the project. However, many Norwegian officials speculate that finds to date from Statfjord alone will not justify the cost of constructing the Statfjord to Sotra pipeline and place their hopes on a major find in the "Golden Block." Other officials note, however, that even if it proves economically inadvisable, the pipeline proposal may go through for political reasons.



Source: NERBC, 1978.

FIGURE 2. MECHANICAL PIPE SUPPORTS FOR SPAN AREAS.

SECTION 4

PIPELINE TRENCHING AND BURIAL

Like so much of offshore technology, the notion of submarine pipeline trenching and burial comes from onshore experience, where pipelines were buried to protect them from a variety of obvious land-based risks. Offshore, however, the risk is vastly less. Pipelines are trenched, and subsequently buried by either natural or artificial processes, to ensure the stability of the line against bottom currents and the safety of the line against bottom fishing equipment and dragging ship anchors.

Until recently, both governments and oil companies have accepted this operational theory. But as pipeline construction moved out of the relatively calm, shallow waters and sandy bottom of the Gulf of Mexico to the harsh climate, deep water, and alternating soft sediments and hard clays of the North Sea, developers have begun to question the accepted wisdom of trenching. It is a complex issue, involving the limits of deepwater technology, the nature of the deepwater environment, and the conflicting needs of users of the seabottom.

RECENT PRACTICES AND EXISTING REGULATIONS

All but one of the major pipelines in the North Sea have been trenched and buried or are in the process of being buried. Despite the fact that no rigid requirements have been set by either the United Kingdom or Norway, the developers have felt heavily pressured to bury pipelines. Occidental's pipeline to Flotta is trenched along its entire length to a depth of two meters. Gravel beds fill areas where unacceptable spans were detected, and concrete saddles have been installed to cover hydrocouples and existing or potential tie-in areas.[69] Total Oil Marine followed similar procedures for its two gas lines from the Frigg Field, as have BP and others.[70]

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[69] Interview with Occidental officials.

[70] Interview with Total Oil Marine officials.

The requirement for trenching is an operating regulation, rather than law, in both the U.K. and Norway. For example, Norwegian law calls for protection of submarine pipelines "through trenching or other means."[71] The Norwegian Petroleum Directorate has issued interim regulations which call for three meter burial of pipelines within two miles of a platform, five miles of a multi-platform complex, or at the shore approach out to a water depth of 50 meters. Elsewhere along the pipeline, trenching must be to a depth of one meter. In point of fact, however, these regulations were developed for the Ekofisk pipeline, and Norwegian officials suggest that, since they expect few pipelines, they will review each case individually and issue regulations appropriate to each case.[72]

BURYING THE EKOFISK-EMDEN GAS LINE

Norpipe has experienced a number of burial problems with their pipelines from the Ekofisk complex. For gas lines to Emden, a total of twelve trenching barges were contracted to trench the line. An average of 3.2 passes were required, with a maximum of 9 passes in one area of hard clay, to trench the line to required depths. Underwater videotape inspection revealed that natural backfilling had not occurred at the time of start-up along sections of the pipeline in the Danish sector of the continental shelf. As a condition of start-up, Danish authorities requested that Norpipe backfill the entire Danish section of the line to a depth of 50 centimeters (cm) by July 1, 1980. Because of the absence of available systems for deepwater artificial burial, Norpipe selected two companies, the Aker-Volker Group and Stolt-Nielson Rederi, to develop proposals for burying the pipeline. Though neither company had operational systems available, the proposals are likely to involve massive modifications to dredging and stone hopper vessels which will be designed to drop crushed stone over the exposed pipe. Figure 3 illustrates this general concept.

Norpipe currently estimates that something on the order of 200-400,000 tons of crushed stone will be required to provide 50 cm of cover for the 50 kilometers (km) that the pipeline crosses the Danish shelf, at an estimated cost of $90 million.[73]

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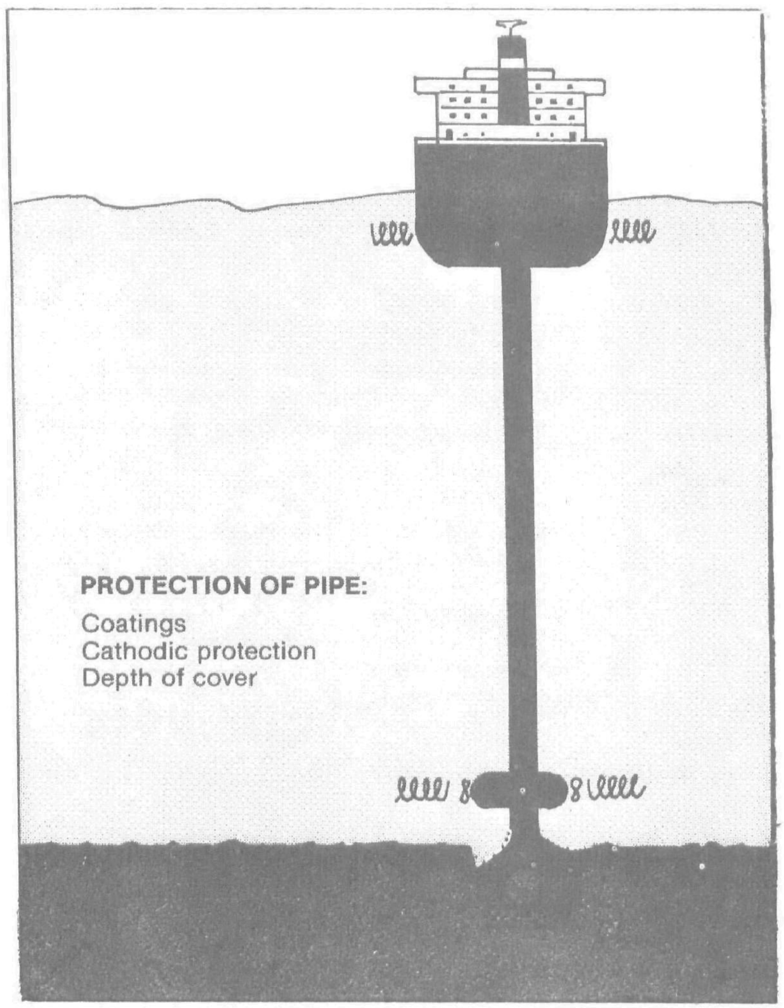
[71] Ministry of Petroleum and Energy, Legislation Concerning the Norwegian Continental Shelf, October 1977, p.255.

[72] Interview with Norwegian Petroleum Directorate officials.

[73] Interview with Norpipe officials.



Source: Det Norske Veritas, Safety, Life, Property, (1978). p.11.

FIGURE 3. ARTIFICIAL BURIAL USING CRUSHED STONE.

THE VALIDITY OF THE SAFETY/STABILITY RATIONALE

When the Shell-Esso Group began plans for their massive gas line (FLAGS) from the Brent field to St. Fergus, they initiated a number of studies to test the validity in deep water of the notion that trenching and burial effectively protects a pipeline from damage from trawl doors and anchors and ensures stability. The results of these studies are discussed in NERBC's Tech Update series. To summarize, however, Shell-Esso found that:

- there is insufficient bottom current in deep water areas to provide sediment transport and resulting natural burial;
- trenches cut in the soft sediments which characterize deep water areas tend to have a wide profile rather than a narrow, well-defined profile;
- current technology in concrete coating and steel reinforcing on pipelines is such that impacts from trawl doors will cause no more than a scratch (16 mm deep) on the pipeline coating and damage to the pipe will not occur;
- concrete coating does a more reliable job of weighting the pipe for stability than trenching;
- trawl doors sliding into a shallow or wide profile trench have more chance of being damaged than if the pipe had been laid directly on the sea bottom; and
- burial will not protect a pipeline from dragging rig or tanker anchors.[74]

In addition, consultations with fishermen revealed that artificial burial through the use of crushed stone caused more problems than it solved. According to the fishermen, the stone gets gathered into the cod end of their nets, wears a hole, releases both the fish and the stone, leaving the fishermen with no catch, damaged gear, and nowhere to go for compensation.[75]

Others involved in pipeline construction in the North Sea have watched the Shell-Esso studies with interest. The United Kingdom Department of Energy was sufficiently impressed by the results to let the FLAGS line be built substantially untrenched,

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[74]Interview with Shell Expro and Esso Expro officials.

[75]Interview with official of the Scottish Fishing Vessel Owners Association.

except for sections near shore. There is also some indication that the Statoil/Mobil Group, Norway's state-controlled oil company, will endorse the Shell-Esso findings and will apply them to the proposed Statfjord-Sotra pipeline.[76] On the other hand, BP contests the fundamental contention that there is little deepwater current and sediment transport, citing their own studies that water near the bottom in deep areas had too much sediment to be used for well injection.[77]

Det Norske Veritas (DNV), the classification company most involved in safety studies and risk analyses, has also closely examined the Shell-Esso studies and has decided that existing pipeline coating and reinforcing technology is sufficient to protect pipe from any trawl damage and that trenching has an only marginal effect on pipeline stability. DNV reasons that: (1) vessels will never, even in cases of equipment failure, anchor in mid-sea; and (2) most vessel anchors used in the North Sea do not penetrate very deeply. Tanker or rig anchors, on the other hand, penetrate very deeply and existing trenching methods cannot trench pipelines deep enough to provide protection from dragging rig or tanker anchors. Figure 4 illustrates this point. DNV's conclusion is that there is no effective way to protect against dragging rig and tanker anchors, except to route pipelines around areas with a high likelihood of tankers or rig traffic.[78]

As a consequence of both the Shell-Esso studies and their own independent risk analyses, DNV now recommends against trenching in deepwater areas to achieve safety and stability. Apparently, the United Kingdom and Norway agree. The FLAGS line was installed largely untrenched and Norwegian officials now suggest they may drop the trenching requirement altogether for coated and reinforced pipe with a diameter of greater than 16 inches if the pipeline is otherwise sufficiently protected. To protect pipe in work areas (e.g., 30-50 meters from a platform) concrete saddles may be required.[79]

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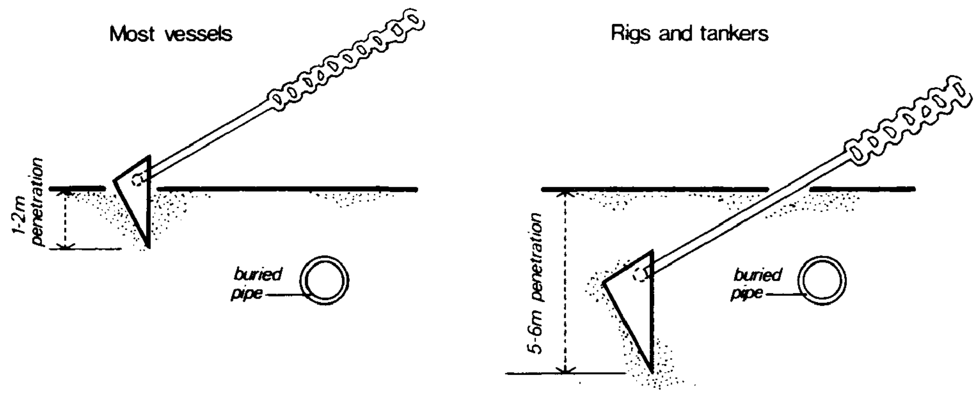
[76] Interview with Statoil officials.

[77] Interview with BP officials.

[78] Interview with Det Norske officials.

[79] Interview with Norwegian Petroleum Directorate officials.



Source: NERBC, (1978).

FIGURE 4. ANCHOR PENETRATION.

Phillips has abundant evidence that, at least insofar as dragging anchors are concerned, DNV's conclusions are largely valid. Last year a 50,000 dwt tanker dragged its anchor across the Ekofisk-Teesside oil line 4 miles off the harbor mouth. A subsequent inspection revealed a five-inch dent and the pipeline was shut down for six weeks while the section was removed and repaired.[80]

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[80] Interview with Norpipe officials.

These observations raise a final finding on the trenching controversy. DNV and others are now persuaded that the major cause of pipeline problems (such as the floating incident near Sullom Voe and the anchor incident at Teesside) is loss of concrete coating from passes by jet sleds during the trenching process. And, the deeper a pipe is trenched, the more passes are required by the jet sleds and the more likely that damage to or loss of concrete coating will occur.[81, 82]

It seems clear, from interviews with both Norwegian and United Kingdom officials, oil company representatives, and the fishermen, that there is no longer a reasonable rationale for trenching and burial and that the theory that worked onshore simply does not hold up in deep water. In view of this conclusion, it may well be that subsequent North Sea pipelines will not be trenched, except in high current areas where weight coating alone is insufficient to guarantee stability. In such areas natural backfilling will, in most cases, ensure sufficient cover.

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[81] Interview with Det Norske Veritas officials.

[82] Work is now underway by Kvaerhar Myhren, a Norwegian firm, to modify trenching machines which will enable them to dig deeper with each pass. By reducing the number of passes required to reach desired trench depths, risk of damage to pipelines and coating may also be reduced.

SECTION 5

CONSULTATION, ACCESS, AND DEBRIS: THE FISHING ISSUES

As a general rule, commercial fishermen and their representative organizations, have exerted less political influence in Norway and the United Kingdom than have their American counterparts. Moreover, there is little evidence in either North Sea country of the kind of legislative support that fishermen in the United States have enjoyed. As a result, there is a high degree of frustration among fishermen in their ability to influence the government-industry offshore development decision process, simply and succinctly explained by the head of one Scottish fishermen's organization: "The decisions are made above our level."[83]

CONSULTATION

In the United Kingdom, the official vehicle for consultation is the Fisheries and Offshore Oil Consultative Group, an organization created in 1974 (largely as a result of pressure from fishing industry organizations) to serve as a forum for broad term planning and coordination among oil companies, fishermen, and government officials. Though the organization has been in existence for several years, and provided the impetus for establishment of a compensation fund for damaged gear, most of the participants seem to agree that the group does not work well. Participants describe the Consultative Group as defensive and combative, a forum for trading charges of abuse.[84]

Still, the fishermen recognize that the Group is, at present the only method they have for holding the oil industry and government accountable in a public forum, in which the fishermen are equal participants.[85]

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[83] Interview with official of the Scottish Fishing Vessel Owners' Association.

[84] Interviews with oil company executives, Department of Energy official, and representative of the fishing industry.

[85] Interview with official of the Scottish Fishing Vessel Owners' Association.

Presently, no such official forum exists in Norway. The principal way in which fishermen are kept abreast of oil-related developments is through meetings called by the Ministry of Petroleum and Energy about every six months.[86]

In point of fact, however, informal bilateral coordination between the fishermen and the individual oil companies is the most effective means of consultation on both sides of the North Sea. Predictably, the results vary with the degree to which individual companies wish to cooperate. Fishermen give high marks to BP, Shell, and Total for their efforts to consult frequently on pipeline proposals, the route deviations they made based on fishermen's requests, and their efforts to give prior notice for any construction activity planned in an offshore area.[87] Other companies have been less accommodating and, if they entertain fishermen's advice and requests, showed little evidence of taking their requests seriously. The United Kingdom Offshore Operators' Association (UKOOA) operates primarily at the policy level in London and maintains no personnel in Aberdeen, the center of U.K. offshore operations.

The United Kingdom's Submarine Pipelines Act, discussed in Section 2, requires oil companies to apply for permission for pipeline construction. The legislation provides specifically for the Department of Energy to consult with fishermen's organizations before granting permission. This has generally meant meeting with the Scottish Fishermen's Federation which represents the smaller commercial operators, or the Aberdeen Fishing Federation Ltd., which represents the larger operators.

In practice, however, the oil companies seek the advice of these organizations privately in the pipeline pre-planning stage before submitting a request to the Department of Energy. In addition, the U.K. Department of Agriculture and Fisheries serves as a "go-between" in government circles to ensure that the needs of the fishermen are considered. While this agency played a very active role prior to passage of the Act, it is not clear to the participants how the agency will operate now that the Act in in force.[88]

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[86] Interview with representative of the Ministry of Petroleum and Energy.

[87] Interview with representative of the Scottish Fishing Vessel Owners' Association.

[88] Interviews with representatives of several oil companies.

In Norway, the fishermen have gained some important concessions from government. Two of four areas planned for development north of the 62nd parallel have been dropped due to fishermen's opposition and many of the blocks in the areas still scheduled for development have been withdrawn.

Two issues predominate in discussions with those close to the fishing interests: the de facto loss of access to fishing areas caused by platform, wellhead, and pipeline installations, and the damage caused by debris left on the bottom during the construction of pipelines and the operation of rigs, platforms, and supply vessels. Each is examined in some detail below.

LOSS OF ACCESS

Although both Norway and the U.K. have specified safety zones around drilling and production installations (500 meters), neither government has designated limitations on fishing activities along pipelines. Nevertheless, commercial trawl fishermen feel pressured, both by circumstance and by oil companies, not to trawl in the vicinity of pipeline installations. This in itself is curious, given the contention by several companies, notably Shell and Statoil, that trawl gear cannot damage exposed coated pipe.

In the U.K., willful and negligent damage to pipelines is a statutory offense for which the skipper/owner of the vessel in question is fully liable.[89] And despite the fact that pipelines in the North Sea are largely buried, they do become exposed, they do span, they do lose their concrete coating, and they are vulnerable. The fishermen, though they tend to be risk-takers, are fully aware of this. The possibility that a pipe may be vulnerable, combined with the debris normally accompanying trenching operations, is sufficient to make any operator cautious. The cost of being wrong is enormous, and even if it is ruled as accidental, the results of hooking a pipe, in terms of lost gear and time, can be significant.

What it all boils down to is compensation. Damage to gear from debris is covered by a standard procedure for compensation in both Norway and the U.K. No such procedure exists for compensating the fishermen for loss of access to fishing grounds, whether de jure (i.e., with respect to safety zones required by law around installations) or de facto (i.e., areas effectively sterilized by existence of a pipeline).

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[89] Interview with representatives of the Scottish Fishing Vessel Owners' Association.

Thus, if pipeline debris causes damage to, or loss of, gear, compensation can be sought. But if a fisherman chooses not to trawl near pipelines for fear of such damage, or of hooking a pipeline span, no compensation is forthcoming, despite the fact that a loss of catch occurs in both cases. In the case of debris, the loss is obvious; in the "avoidance" case, however, some other demonstration is necessary, and this is extremely difficult.[90]

In the U.K., the Offshore Operators Association has declared that it prefers to compensate fishermen for cutting their gear loose if they hook a pipeline, rather than risk damage to a pipeline. Compensation of gear is obviously cheaper. But it also takes time and there has been no parallel offer to compensate the fishermen for lost catch and lost time. Consequently, it is understandable that the fishermen will treat large areas around a pipeline as de facto "sterilized."[91]

A University of Aberdeen study, commissioned by the British Fishing Federation and the Scottish Fishermen's Federation, though hampered by inconsistencies in available catch data and the difficulty of arriving at acceptable methodologies for calculating loss, estimates that existing pipelines cause a loss of access for fishing of between 30.9 and 771.8 square miles and a corresponding estimated loss of catch of between 66 and 1650 tons annually. The variation in estimates reflects whether one assumes a 100 meter or 500 meter sterilization zone around pipelines.[92]

Of special concern to the fishermen is the proliferation of trunk lines to shore and gathering lines among fields. The latter is the source of significant current discussions among fishing and oil interests and government policy makers. Already, there are powerful economic arguments for linking new fields to existing trunk lines where excess capacity exists, or where throughput is declining as a field ages. However, the tendency for triangular pattern of gathering lines to be constructed among producing areas sterilizes not only the area along the

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[90] Department of Political Economy and the Institute for the Study of Sparsely Populated Areas, Research Report 1: Loss of Access to Fishing Grounds Due to Oil and Gas Installations in the North Sea, University of Aberdeen, March, 1978, p.2.

[91] Ibid, p.11.

[92] Ibid, p.54.

pipe, but, according to the fishermen, the area of water inside the triangular boundaries as well.[93]

U.K. policy on the matter of new pipelines is unclear. And the picture is somewhat muddied by independent pressure groups in Scotland who want production slowed. At issue, however, is whether the U.K. will even out its production profile to extend the life of the fields, or accentuate it with new pipelines to offset its balance of payments problems, not whether pipelines significantly reduce fishing access.

Another access problem of potentially greater impact in the U.K. is development of blocks in the Moray Firth, a rich fishing area already being developed by MESA at the Beatrice field, and east of the Shetland Islands, where new finds have been announced by BP and others. The fishermen point to U.S. policy on "negative nominations" and claim there are national interest values in protecting these especially valuable areas for fishing.[94]

Their point is made clearly by a fishing organization representative, who explains: "It's a fair deal we're asking for; we don't even want monetary compensation, if they'd just not lease prime fishing areas. But if they do sterilize important fishing areas, we'll expect compensation."[95]

Of course, the loss of access -- or "sterilization" -- applies just as powerfully for the fishermen to rig operations, platform siting, pipeline junctions and sub-stations, and well-head locations at survey work. It is this type of prevention of access that most affects Norwegian fishermen, who do not yet have to contend with pipelines in their waters.

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[93] Interviews with both oil industry and fishing industry representatives.

[94] Interview with Gordon A. MacKay, Institute for Sparsely Populated Areas, University of Aberdeen.

[95] Interview with representative of the Scottish Fishing Vessel Owners' Association.

DEBRIS

Certainly the most emotional fishing/offshore oil issue in the North Sea is the debris problem. The commercial fishermen have encountered debris in areas of abandoned drill sites, along pipelines, and in those areas of the North Sea that see heavy service boat operation between shore-based service bases and offshore operations. The debris they have encountered during trawling ranges from refuse, such as oil drums and scrap metal, to lengths of steel cable, steel superstructure, pipe turnings, and heavy equipment which is cheaper to dump overboard than repair.

The debris issue is closely tied to the access question. One Norwegian study cites a one-third decrease in available fishing areas in the North Sea due to debris during the period from 1966 to 1971.[96] Heavy pressure from the fishing industry and recent ocean dumping legislation have reduced, but by no means eliminated, the problem.

With respect to pipelines, there are three types of debris that cause problems for the fishermen: (1) the exposed boulders and heaps of heavy clay caused by trenching activities; (2) the piles of crushed stone sometimes used by the oil companies to cover pipelines that become exposed or are never covered naturally; and (3) the debris and refuse tossed overboard by pipeline contractors during construction.

Both Norway and the U.K. have established compensation funds through which fishermen can recoup some or all of the cost of replacing gear damaged by debris that cannot be identified as belonging to a specific company. In the U.K., the UKOOA established a compensation fund administered by the fishing associations with an initial balance of roughly $60,000. To date, approximately $120,000 has been paid out. The majority of the claims have been by small operators, and have averaged $800 per claim. For the most part, neither damage to vessels themselves, nor lost catches of fishing time are covered by compensation, although a $1500 per incident maximum "hardship" payment can be added. The oil industry sees damage to vessels as an issue for the insurance companies, and has so far refused to consider lost time as an item suitable for compensation.[97]

In Norway, debris damage claims are made to the government. The state pays in any case where it is probable that gear damage or loss is oil-related. Having paid the claim, government offi-

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[96] Interview with representatives of the Ministry of Petroleum and Energy.

[97] Interview with representative of the Scottish Fishing Vessel Owners' Association.

cials then track the cause of damage to the company involved, where possible, and require repayment. The total paid to date is nearly $2 million. Again, though, compensation covers only damaged or lost gear.[98]

Fortunately, officials in the newly-established Ministry of Petroleum and Energy are particularly concerned about the extent of the debris problem and debris-related claims, and will soon propose to the Norwegian Parliament that fishermen not only be compensated for lost gear, but also for lost fishing time and loss of access to fishing ground, whether _de jure_ or _de facto_.[99]

The Norwegian government, through the Oil Directorate, has also been responsible for the most comprehensive debris survey and cleanup program to date. Although diving certificates required at the completion of pipeline construction or drilling activities indicated no significant debris in Norwegian waters, the government recorded some 2,000 complaints from fishermen and finally conducted an underwater study of its own and detected substantial debris, particularly along pipeline routes and major supply routes.[100] Consequently, the Petroleum Directorate ordered Norpipe and Phillips to resurvey the marine portions of the Ekofisk to Emden gas pipeline and the Ekofisk to Teesside oil pipeline and to identify and retrieve all debris located along the route. Phillips and Norpipe contracted with Fred Olsen Oceanics A/S for both visual inspection and retrieval, employing the support vessel _M/S Bergholm_ and the submersible vessel _Pisces 10_. Work on the Emden gas line lasted from July 26 to October 7, 1977, and work on the Teesside oil line lasted from October 7 to December 11, when it was postponed due to bad weather. Work was completed during the 1978 work season.[101]

A list of potential debris items, or targets, was prepared from sidescan sonar recordings taken along a 100 meter wide strip centered on the pipeline, and compared with submersible sightings and earlier sonar readings. The targets were then classified as

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[98] Interview with official of the Norwegian Ministry of the Environment.

[99] Interview with officials of the Ministry of Petroleum and Energy.

[100] Interview with officials of the Norwegian Petroleum Directorate.

[101] Interview with Norpipe officials.

either rubbish, which was judged to be of no danger to trawl nets, divers, or the pipe itself, or debris of obvious potential harm. Debris targets were generally large wires or hawsers, steel pulley blocks, large plates or pipes, anchors, heavy equipment, rails, concrete-filled drums, wire loops, or pipe bevel turnings. The submersible vessel photographed both types of objects and if the target was identified as debris, it was either lifted to the surface or marked for future recovery.[102]

NERBC has a detailed report, in rough draft form, of the types of targets identified. The information is generic in nature and is likely to have comparability in any OCS operation area. During the 1977 season, the cost to Phillips and Norpipe of resurvey and retrieval activities approached $4 million.[103]

Since the project was completed, Norpipe has recommended that a standard debris clause be included in offshore contract specifications to prevent debris dumping during construction work. These specifications are quoted below:

> "During the work, Contractor shall not dispose of any material into the sea or air, which can be of danger to or interfere with other marine activity or life. The sea floor, sea, or air shall not be contaminated.
>
> As soon as the work is completed, the seabed shall, if practical, be brought back to original condition and Contractor shall clear the premises of debris, waste material, and equipment remaining from the work. Nothing shall be left which can interfere with fishing, marine, or other activity. All material belonging to Company shall be loaded for storage or to a location as directed by the Company Representative.
>
> Contractor shall be responsible for the recovery of any debris it dumps and shall bear the cost of such recovery operations.[104]

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[102]Norpipe, Debris Survey Scope of Work, 1978, pp.2-11.

[103]Interview with Norpipe officials.

[104]Norpipe, Debris Clause.

APPENDIX

The following is an annotated bibliography of reports gathered from the sources interviewed while preparing this document. Each entry contains a bibliographic citation and a brief description of the information contained in each document. Entries are organized by country, and then by organization providing the information.

ENGLAND

BRITISH GAS CORPORATION

The following are documents prepared by British Gas Corporation:

A Guide to Noise and Its Assessment, 1974. 10pp.

Methods of measuring noise with footnote on compressor stations.

A Guide to Noise Legislation, 1974. 9pp.

Historical background and implications of noise legislation on gas industry.

Environmental Impact Analysis in the British Gas Industry; Parts I and II. Prepared for the Symposium on the Gas Industry and Environment, Minsk, USSR, June 1977.

General considerations and practical application of environmental impact analysis to gas industry facilities.

Gas Plants and People. Prepared for Symposium of the Institute of Gas Engineers, November 1976. 25pp.

Environmental implications of gas pipeline and facility construction and operation.

Onshore Development of the Frigg Gasfield, July 1974. 24pp.

Description of St. Fergus terminal, including plans, requirements, pipeline route map and pictures.

Onshore Requirements for Oil and Gas Reception. Prepared for Offshore Oil - Onshore Industry Conference, Liverpool, November 1974. 31pp.

Comprehensive look at onshore requirements for offshore oil and gas receiving terminals.

Pollution Control: A Summary of the Control of Pollution Act of 1974, December 1977. 12pp.

Interpretation of the 1974 Act for use by the gas industry.

To See or Not To See, undated. 15pp.

Description of facility design considerations to minimize visual impacts.

Additional information provided by British Gas:

Institution of Gas Engineers. Recommendations on Transmission and Distribution Practice: Steel pipelines for high pressure gas transmission, Editions 1 and 2, 1977. 141 pp.

Description of design, planning, construction and materials standards for high pressure gas pipelines.

Ministry of the Environment. Planning Permission: A Guide for Industry, 1978. 30pp.

Guide to the British development permits process.

Photos - variety of black and white and color photos of terminals, compression stations, landfall construction and restoration.

OCCIDENTAL INTERNATIONAL OIL COMPANY

The following documents were prepared and provided by Occidental:

Occidental North Sea Consortium Information Sheet, June 1978. 16pp.

Update on Occidental-related offshore and onshore activities.

The Flotta Story: Development of an Oil Handling Terminal, July 1978. 24pp.

Description of how Flotta was chosen and built. Includes maps.

The Search for North Sea Oil, 1977. 25pp.

Outline of history, process, facilities and people involved in offshore exploration and development. Includes photos.

SHELL/ESSO GROUP

The following were provided by the Shell/Esso Group:

Broussard, D. L., et al. "FLAGS Gasline - Design for Seabed Safety and Stability". In European Offshore Petroleum Conference and Exhibition, London, October 1978.

Technical Report on FLAGS gasline routing and results of trenching experiments.

Dept. of Energy (U.K.). Landfall Construction Permit Conditions. issued to Shell/Esso, April 1976. 2pp.

Conditions guiding Brent gasline landfall construction at St. Fergus, Scotland.

Shell/Esso Group. FLAGS Gasline: Seabed Safety and Stability. presentation to Dept. of Energy, October 1977. unnumbered.

Summary of results of trenching experiments and routing decisions. Includes map of route alternatives resulting from discussions with fishing industry representatives.

Sample report - prepared by Dr. William Ritchie (under contract to Shell/Esso Group).

Results of periodic survey of restoration success at St. Fergus landfall.

BRITISH PETROLEUM COMPANY, LIMITED

BP provided the following report:

Larminie, F. G. "The Onshore Handling of Oil". In Petroleum and the Continental Shelf of Northwest Europe. edited by H. A. Cole; John Wiley & Sons, New York, 1975. 2:39-47.

Description of main components of land pipeline systems, including pipelines, gas separation units, storage and loading terminals.

DEPARTMENT OF ENERGY (U. K.) - H. M. PIPELINES INSPECTOR

The Inspector's office prepared and provided the following document:

Application for a Submarine Pipeline Works Authorization (Draft), August 1977. 8pp.

Sample of "guidance notes" produced by DOE (U.K.) to aid industry in complying with the Petroleum and Submarine Pipelines Act of 1975.

SCOTLAND

TOTAL OIL MARINE

The following documents were prepared and provided by Total:

Frigg: Gas from the North Sea, 1978. unnumbered.

Review of Frigg Gasfield development. Printed for formal opening of St. Fergus terminal.

Total Information - Number 71, 1977. unnumbered.

Review of entire Frigg operation.

Photo - aerial of St. Fergus terminal.

SCOTTISH DEVELOPMENT DEPARTMENT

All the following documents were prepared and provided by the Department:

"Land and Industry - Offshore and Onshore Physical Constraints for Pipeline Landfalls." Oil and Gas Forward Planning Discussion Paper No. 302, October 1975. 17pp.

Examination of physical constraints at various potential pipeline landfall sites.

National Planning Guideline Series, 1977. unnumbered.

Guidelines for planners considering large industrial sites and rural land use issues.

North Sea Information Sheet, Nov. 1977. 13pp. and
North Sea Information Sheet, March 1978. 16pp.

Quarterly summaries of OCS-related developments. Includes maps.

Physical Criteria for Evaluating Pipeline Landfalls, 1978. 1p.

List of criteria for determining physical suitability of alternative landfall sites.

Planning Advice Note No. 13 - Planning and Geology, Dec. 1975. 14pp.

Discussion of geologic considerations in planning.

Planning Advice Note No. 17 - High Pressure Methane Gas Pipelines, June 1977. 7pp.

Legal and technical requirements and planning considerations for local authorities on land pipelines.

GRAMPIAN REGIONAL COUNCIL

The Council's Department of Physical Planning prepared and provided the following documents:

Contingency Plan for Petrochemical Industries, July 1978. 105 pp.

Siting strategies for petrochemical plants.

Pipelines, May 1978. 3pp.

Legal and engineering requirements for pipeline rights-of-way.

Onshore Pipeline Corridor Feasibility Report, July 1976. 8 pp.

Discussion of the implications of the corridor concept.

THE SCOTTISH COUNCIL

The Scottish Council - Development and Industry prepared the following report:

United Kingdom Oil & Gas - Situation Review, February, 1978, 28pp.

Overview of the state of North Sea oil and gas development as of December, 1977.

UNIVERSITY OF ABERDEEN

Three departments within the University were contacted and provided the following information:

Department of Geography - Project Appraisal for Development Control Research Unit (PADC).

Environmental Impacts of Selected Linear Developments (DRAFT). PADC 17F, undated. 43pp.

Preliminary look at environmental impacts of developments like pipelines.

Past and Current Work (of PADC), undated. 9pp.

Prospectus on work in environmental impact assessment. Includes publications list.

Planning Information Sheet: Gas Terminals. PADC 12D (iv), undated. 18pp.

Review of gas terminal characteristics, requirements and impacts.

Planning Information Sheet: Oil Refineries. PADC 12D (ii), undated. 10pp.

Characteristics, requirements, and impacts of oil refineries.

Research on Impact Analysis and Environmental Planning, undated. 9pp.

Outline of future research programs in environmental assessment.

Department of Political Economy - Institute for the Study of Sparsely Populated Areas.

Department of Political Economy. Loss of Access to Fishing Grounds Due to Oil and Gas Installations in the North Sea. Commissioned by the British Fishing Federation and Scottish Fisherman's Federation, 1978. 152pp.

Detailed study on effects of platforms and pipelines on access to commercial fishing grounds.

Department of Zoology.

Sullom Voe Environmental Advisory Group. Oil Terminal at Sullom Voe Environmental Impact Assessment, May 1976. 133pp.

Report of interdisciplinary group assessing construction impacts from Sullom Voe oil terminal.

Text of Presentation to Nature Conservancy Council, July 1978.

Outlines how the Shetland Oil Terminal Environmental Advisory Group (SOTEAG) - designed to monitor the terminal's operation - works. Includes list of members and monitoring projects.

NORWAY

U. S. EMBASSY

The Embassy provided the following documents:

Bergen Bank. Petroleum Activities in Norway, June 1978. 38 pp.

Introduction to petroleum related activity in Norway including structure of state controlled development companies.

Economic Trends Report - Norway, June 1978. 9pp.

Brief examination of current Norwegian economic problems, some related to oil-related development/investment issues.

MINISTRY OF PETROLEUM AND ENERGY (formerly Industry and Crafts)

The Ministry prepared the following basic documents regarding Norwegian offshore oil development:

Factsheet: The Norwegian Continental Shelf, April 1978. 22 pp.

Status report on Norwegian OCS activities.

Legislation Concerning the Norwegian Continental Shelf, October 1977. 273 pp.

Compilation of all Norwegian laws governing OCS activities.

The following are Parliamentary Reports which the Ministry prepared for the government on various aspects of Norwegian OCS development:

No. 33 - Annual Report of Statoil for 1976-1977 and Statoil Development Plan for 1978, 1977-78 . 42pp.

No. 92 - Landing of Petroleum from Valhall and Hod Fields, 1976-77. 22pp.

No. 91 - Petroleum Exploration North of 62°N, 1975-76. 128 pp.

No. 90 - The Development and Landing of Petroleum from Statfjord Field and a Gas Trunk Line, 1975-76. 46 pp.

No. 77 - Landing of Gas from the Frigg Area, 1973-74. 37 pp.

No. 51 - Landing of Petroleum from the Ekofisk Area, 1972-73. 68 pp.

The following Parliamentary Propositions were also provided:

No. 72 - Announcement and allocation of blocks on the continental shelf, and drilling for petroleum under the direction of the state, 1977-78. 15 pp.

No. 114 - Exercise of Statoil's option to participate in the development of a deposit in the Statfjord Field, 1974-75. 16 pp.

NORWEGIAN PETROLEUM DIRECTORATE (NPD)

The Directorate provided a complete Publications List of all NPD publications and maps - in English.

The Directorate also prepared and provided the following English translations of Norwegian offshore guidelines and regulations:

Guidelines for the inspection of primary and secondary structures of production and shipment installations and underwater pipeline systems, 1978. 17 pp.

Provisional Regulations relating to worker protection and working environment, etc., in connection with exploration of submarine petroleum resources, 1978. 15 pp.

Regulations for cranes on production installations, 1977. 20 pp.

Regulations for drilling for petroleum in Norwegian internal waters, territorial waters, and on the Continental Shelf. 2nd Edition, 1977. 37 pp.

Regulation for Production and Auxiliary Systems on Production Installations, etc., 1978. 37 pp.

Regulations for production, etc., of submarine petroleum resources, 1977. 34 pp.

Regulations for the structural design of fixed structures on the Norwegian Continental Shelf, 1977. 78 pp.

The following documents were provided - in Norwegian only:

General Guidelines for Inspection and Clearing of Abandoned Drillsites, December 1977. 2 pp.

Oljedirectoratet, arsberetning 1977, 1977. 81 pp.

Annual report for 1977, includes map.

Trenching and Burial of Pipelines on the Norwegian OCS, March 1978. 15 pp.

Regulations, trenching techniques, burial methods and seafloor conditions on the Norwegian Shelf.

DET NORSKE VERITAS (DNV)

The following technical documents were prepared by Det Norske Veritas:

Analysis and Management of a Pipeline Safety Information System, December 1977. 8 pp.

Summary of University of Oklahoma analysis of gas pipeline system safety.

Det Norske Veritas, February 1978. 20 pp.

Prospectus on company activities including involvement in Norwegian OCS oil and gas activities.

Det Norske Veritas Annual Report 1977, February 1978. 40pp.

Detailed information on scope of company activities.

Method for Performing Risk Assessment of Submarine Pipelines, March 1978. 7 pp.

Brief description of DNV's methods for assessing risks to pipelines.

Research and Development in Det Norske Veritas, May 1978. 12 pp.

Outline of DNV research in progress.

Rules for the Design, Construction and Inspection of Submarine Pipelines and Pipeline Risers, 1976. 73 pp.

Detailed rules for safety regulation of marine pipelines.

Safety: Life, Environment, Property, April 1978. 16 pp.

Prospectus on Risk and Reliability Analyses.

Statistical Evaluation of Failures to Cross Country Oil Pipelines in Western Europe, March 1978. 6 pp.

Information on incidence and causes of pipeline failures from 1966 - 1976.

Veritas, February 1978. 91: 12 and 28.
Veritas, November 1977. 90: 27-30.

Quarterly journal describing various Det Norske Veritas activities.

DNV also provided 3 DNV single sheets and a Norwegian journal containing additional offshore pipeline related information:

Loose sheets:

DNV-1: Factors affecting pipeline dimensions
DNV-2: Flow chart in offshore pipelaying
DNV-3: Description of pipeline failure events in Gulf of Mexico.

Norwegian Maritime Research, 1978. 6(1).

NORPIPE

Norpipe provided the following information:

Loken, P. A., "Ekofisk-Emden". Norsk Oljerevy, March 1977. 4 pp.

Reprint of magazine article describing the Ekofisk to Emden pipeline. (In Norwegian)

Massey, P. S., "Ekofisk-Teesside line to operate continuously." Oil and Gas Journal, February 1975. p. 85-89.

Description of Ekofisk to Teesside natural gas pipeline.

Norpipe: Annual Report and Accounts 1977. 28 pp.

Detailed information on scope of company activities.

Norpipe Brochure and Factsheet, undated.

Brief description of Norpipe offshore activities.

Shaub, D. P., "Line from Ekofisk to Emden nearly completed." Oil and Gas Journal, January 1976. p.78-86.

Description of final stages of construction of Ekofisk to Emden pipeline.

MISCELLANEOUS PERIODICALS AND ARTICLES

Daniels, M. and J.C. Swank, "Northern North Sea Pipelines - The Brent System." Offshore Technology Conference, 1976. Preprint #2601: 803-817.

Noroil, July 1978. 6(7).

Northern Offshore, June 1978. 7(6).

Scandanavian Oil-Gas Magazine, 1978. 6(5/6).

Walker, D.B.L., "A Technical Review of the Forties Field Submarine Pipeline." *Offshore Technology Conference*, 1976. Preprint #2603: 816-826.

TECHNICAL REPORT DATA

(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA-600/7-80-023	2.	3. RECIPIENT'S ACCESSION NO.
4. TITLE AND SUBTITLE NORTH SEA PIPELINES: A SURVEY OF TECHNOLOGY, REGULATION AND USE CONFLICTS IN OIL AND GAS PIPELINE OPERATION		5. REPORT DATE February 1980 issuing date
		6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) William E. Nothdurft		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS New England River Basins Commission, 53 State Street, Boston, Massachusetts 02109		10. PROGRAM ELEMENT NO. INE 826
		11. CONTRACT/GRANT NO. IAG No. 78-D-X0063
12. SPONSORING AGENCY NAME AND ADDRESS Industrial Environmental Research Laboratory, Office of Research and Development, U.S. Environmental Protection Agency, Cincinnati, Ohio 45268		13. TYPE OF REPORT AND PERIOD COVERED Final 8/78 - 12/78
		14. SPONSORING AGENCY CODE EPA/600/12

15. SUPPLEMENTARY NOTES

16. ABSTRACT

This project was undertaken to provide information on North Sea offshore pipelines and the processes used in route selection decision-making. It is designed to be used by persons involved in offshore oil and gas pipeline planning, including pipeline corridors and landfalls. The bulk of the information for the report comes from interviews with industry, government and private individuals associated with pipeline decision-making in Norway, England and Scotland. Supplemental information is derived from written sources.

A brief overview of offshore activity in both the United Kingdom and Norwegian sectors of the North Sea is presented, with special emphasis on the transportation systems established or proposed for the major commercial fields. The report then focuses on the specific issues arising from the installation and operation of each of these transportation systems. These issues include: regulations affecting pipeline placement, criteria for route selection, pipeline trenching and burial, and conflicts with the fishing industry in the North Sea.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Pipelines Oils Natural Gas Continental Shelves	North Sea Pipelines Route Selection Criteria Trenching & Burial Fishing Industry Conflicts	

18. DISTRIBUTION STATEMENT RELEASE TO PUBLIC	19. SECURITY CLASS *(This Report)* UNCLASSIFIED	21. NO. OF PAGES 78
	20. SECURITY CLASS *(This page)* UNCLASSIFIED	22. PRICE

EPA Form 2220-1 (9-73)

☆ U.S. GOVERNMENT PRINTING OFFICE: 1980-657-146/5575