North West Hutton
Decommissioning Programme

February 2005

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Glossary of Terms and Abbreviations

Term/Abbreviation	Definition
A	
ABS	Acrylonitrile-Butadiene-Syrene.
Aerobic	A chemical or biological process that requires the presence of oxygen.
ALARP	As Low As Reasonably Practicable, a fundamental principle in UK safety legislation.
Anthropogenic	The term for a substance or impact that arises from human activity.
Anodes	Blocks of alloy (aluminium & zinc) that protect steel against corrosion.
Anoxic	Lacking oxygen.
APE	Alkylphenol Ethoxylates, surfactants that help dissolve oils and greases.
AWJ	Abrasive water jet. Uses high-pressure water with entrained abrasive material to cut through steel and other materials.
B	
Barite	The weighting agent used in drilling muds.
Benthic communities	The assemblages of plants and animals that live on and in the seabed.
Benthos	The bed of the sea and the water column immediately above it.
Bio-degradation	The break-down of a substance or material by bacteria.
Biodiversity	A measure of the variety of living organisms found at a site.
Biogenic reefs	Reefs comprising the living or dead parts of marine organisms.
Bottles/Bottle legs	The four large-diameter corner legs that are part of the footings.
Bracing	Steel members linking parts of the jacket.
BRT	Beneath Rotary Table.
Bq/g	Bequerels per gram (1Bq is one disintegration per second).
C	
Caissons	Caissons are vertical steel pipes attached to the legs of the jacket, running from the topsides down into the water column. They are used to import seawater and discharge permitted aqueous waste to the sea.
Cetaceans	Collective name for the group of marine mammals comprising whales, dolphins, and porpoises.
Chatham House rule	An agreement in a meeting whereby opinions are expressed on a non-attributable basis.
Christmas Tree	The set of valves, spools and fittings connected to the top of a well to direct and control the flow of formation fluids from the well.
Chromel-Alumel	An alloy of chromium and aluminium.
CO_2-E	Carbon dioxide equivalent, a measure of total greenhouse gas emissions.
Cold Cutting	A cold method of cutting that does not require hot gas, i.e. hacksaw, diamond wire, abrasive water jet etc.
Conductors	Steel tubes running from the wells on the seabed to the topsides.
CVP	BP's Capital Value Process, part of the sequence of checks and balances in BP's decision-making process.
Cuttings	The fragments of rock generated during the process of drilling a well.

D

DEFRA	Department of Environment, Food and Rural Affairs
Demersal	The term for organisms that live on or close to the seabed.
Densitometer	An instrument used for the measurement of density.
Derogation	An exemption from the requirement to remove the footings of a steel structure from the seabed.
DfT	Department for Transport
Directional drilling	Drilling a well at an angle, to gain access to a reservoir that does not lie directly beneath a drilling rig or platform.
Diversity	A measure of the number of species in an area, and the numbers of individuals in each of those species.
Drilling Derrick	The structure used to support the crown blocks and the drillstring of a drilling rig.
Drilling Template	A steel structured guide frame located on the seabed that acts as a guide during the drilling operations.
DTI	Department of Trade and Industry
DW	Diamond Wire. This cutting method uses a strong wire with diamond beads embedded along its length.
Duty of Care	A legal obligation requiring that waste is handled properly and is only transferred to those authorised to handle best or dispose of it.

E

EA	Environmental Act
EC	European Commission
EEC	European Economic Community
EIA	Environmental Impact Assessment. A formal process, which assesses the potential environmental impacts from a proposed activity.
Environmental Statement	The document describing the results of an Environmental Impact Assessment
EPA	Environmental Protection Act
ERA	Environmental Risk Analysis.
EU	European Union
Excavate	Excavate in this document means to remove the drill cuttings from around the base of the structure to expose the lower members of the structure and to disperse the drill cuttings away from the immediate vicinity of the jacket.

F

Fauna	The collective term for all animals.
FEPA	Food and Environment Protection Act
FishSafe	FishSafe is a computer-based early warning system developed by UKOOA for the fishing industry to warn of the presence of underwater equipment and pipelines.
FLAGS	Far North Liquids and Associated Gases System.
Flora	The collective term for all plants.
Footings	The lower part of the jacket, from about 100m depth to the seabed.
ft	Feet.

G

GHG	Green House Gas.
GJ	Gigajoule, a unit of energy equal to 1,000,000,000 joules.
Grillage	A welded framework of beams and plates several metres high built on a vessel or barge to support the weight of a load.
Grout	Cement used to secure tubing and piles in the seabed.

H

HAZID	Hazard Identification. A qualitative technique used to identify the likely failure modes that would be encountered during an operation.
HLV	Heavy Lift Vessels, used to install or remove offshore facilities.
Hook-up	The process of connecting all the pipework and other utilities in the topsides so that offshore production can begin.
Hot Cutting	Method of cutting using hot gas i.e. oxy-acetylene.
HSE	(The UK) Health and Safety Executive.
Hydrocarbons	Any compound containing only hydrogen and carbon.

I

ICES	International Council for the Exploration of the Sea, an organisation that coordinates and promotes marine research in the North Atlantic.
Impalloy	Alloy containing aluminium, indium and zinc.
IRG	Independent Review Group.
IPPC	Integrated Pollution Prevention Control
IRPA	Individual Risk Per Annum.

J

Jacket	The steel structure that supports the topsides. The lower section, or "legs" of an offshore platform.
JNCC	Joint Nature Conservation Committee is the UK Government's wildlife advisor.

K

Km	Kilometre.
KP	Key Point.

L

LAT	Lowest Astronomical Tide.
LSA scale	Low Specific Activity scale, derived from naturally occurring radioactive minerals in the rock strata.

M

M	Metre.
Marine	To do with the sea.
m/s	Metre per second.
Mattresses	Heavy concrete mats used to protect and stabilise facilities on the seabed.
MCA	Marine Coastguard Agency
MOD	(The UK) Ministry of Defence
Modules	Structural units, which are which are assembled to form the platform topsides.
MSF	Module Support Frame, supporting the topsides on top of the jacket.
Mud	A mixture of fluids and solids used in the drilling operations to drill wells. Muds can be water based or non-water based.

N

NGL	Natural gas liquid.
NHDA	National Hydrocarbons Data Archive.
Nonyl Phenol	A chemical used in a variety of processes and products including lubricating oil and grease additives, and surfactants.
NUI	Normally Unattended Installation.

O

OLF	Oljeindustriens Landsforening, The Norwegian Operators Association.
OSPAR	Oslo and Paris Convention

P

Pad-eye	A specially-designed lifting point on a module.
PAH	Polycyclic Aromatic Hydrocarbons, a group of over 100 different chemicals formed during the incomplete burning of fossil fuels.
PCB	Polychlorinated Bi-phenyls, used in capacitors and transformers.
Pelagic	Organisms living in the water column.
PEP	Project Execution Plan.
Phytoplankton	The collective term for the microscopic plants that drift or float in the water column. Phytoplankton consists mainly of microscopic algae. They are the primary producers in the sea and form the basis of food for all other forms of aquatic life.
Pig	A device with blades or brushes inserted in a pipeline for cleaning purposes. The pressure of the stream of fluid behind the pig pushes the pig along the pipeline to clean out rust, wax, scale and debris. These devices are also called scrapers. An instrumented pig is a device made of rubber or polyurethane that has electronic devices. An instrumented pig is run through a pipeline to record irregularities that could represent corrosion. An instrumented pig is also called a smart pig.
Pigging	The act of forcing a device called a pig through a pipeline for the purposes of displacing or separating fluids and cleaning or inspecting pipelines.
Piles	Heavy beam of concrete or steel driven into the seabed as a foundation or support for the jacket structure.
Pile Guides	Guides for the piles during piling.
Pinnipeds	Collective name for the group of marine mammals comprising seals, sea lions and walruses.
PLL	Potential Loss of Life.
Plug	Rubber or cement fitting, filling the well to seal it.
POB	Persons on board, the number of people living on a platform or rig.
Polychaete	The class of annelid worms which possess distinct segments.
PPC	Pollution Prevention Control.
Production Tubing	A wellbore tubular used to produce reservoir fluids. Production tubing is assembled with components to make up the production string.
PVC	Polyvinyl chloride, a thermoplastic resin produced by the polymerisation of vinyl chloride.

Q

QRA	Quantitative Risk Assessment.

R

Riser	A steel conduit connecting a pipeline to the production installation.
ROV	Remotely Operated Vehicle.

S

SAC	Special Area of Conservation. Areas considered to be important for certain habitats and non-bird species of interest in a European context.
Sacrificial Anode	A block of alloy, commonly of zinc or aluminium alloy, which is sacrificed to provide corrosion (cathodic) protection for the steel structure to that it is attached.
SAL	Surface Active Layer, a thin layer on the surface of a cuttings pile.
SEPA	Scottish Environmental Protection Agency
Shannon-Wiener diversity index	A way of expressing complex data on the numbers of species present and their density per unit area in a single figure.
Sidescan Sonar	Side looking sonar system used to map seabed features.

Sidetrack	To drill a secondary wellbore away from an original wellbore. Creation of a new section of the wellbore for the purpose of detouring around an obstruction in the main borehole, or of reaching a different target.
Slot	A designated hole in the offshore structures through which a well is drilled.
SOR	Statement of Requirements.
Span	A stretch of pipeline, which has become unsupported.
SSCV	Semi-Submersible Crane Vessels, also known as heavy lift crane vessels.
SSIV	Sub Sea Isolation Valve.
Subsea Well	A well in which the wellhead, Christmas tree and production control equipment is located on the seabed.
Substratum	A general term for the surface or layer on which organisms live.

T

TBT	Tributyltin
Te	Tonne, a metric unit of mass equal to 1,000 kilogrammes.
Tee	A connection shaped like a ‘T’.
Topsides	The term used to describe all the decks, accommodation and process modules that are located on top of the jacket.
Trench	A long deep furrow or ditch in the seabed.
Trenched	Placed in a trench.

U

UKCS	United Kingdom Continental Shelf.
UKOOA	United Kingdom Offshore Operators Association
Umbilical	Cable and tubing-like structure that provides utilities and communication to sub-sea equipment to allow it to be operated.
Units	The units throughout the document are imperial and metric, used appropriately as within the oil and gas industry.

V

Vessel spread	The fleet of vessels used for any particular activity or operation.
VIPs	BP value improving practices.
VOC	Volatile Organic Compound.

W

Wellbore	The wellbore is the openhole or uncased portion of the well.
Wellhead	The system of spools, valves and assorted adapters that provide pressure control of a production well.

X

X-mas Tree	See Christmas Tree.

Z

Zooplankton	The collective term for the animals that float/drift in the water column.

1 INTRODUCTION

This document sets out the Decommissioning Programme for the facilities at the North West Hutton field, in Block 211/27a of the United Kingdom Continental Shelf (UKCS). The facilities at North West Hutton comprise a steel platform, wells and pipelines that were installed to produce hydrocarbons and associated products from the North West Hutton reservoir, discovered in 1975. The main facility is the steel platform (Figure 1.3) which was designed by McDermott Engineering, London and was built at various locations around the United Kingdom and northern Europe. The facility was installed and commissioned offshore between 1981 and 1983. The platform is operated by Amoco (UK) Exploration Company, on behalf of Amoco (UK) Petroleum Limited, a subsidiary of BP plc, and here-after referred to as BP throughout this Decommissioning Programme. BP own 25.8% of the field, and the other owners are Cieco with 25.8%, Enterprise Oil plc with 28.4% and Mobil North Sea Limited with 20.0%.

The North West Hutton field was discovered by Amoco (U.K.) Exploration Company in 1975, and is estimated to have originally contained about 487 million barrels of oil. It has only been possible to recover 126 million barrels of oil (26% of the total oil in place) since production started in 1983. This is somewhat lower than several North Sea fields of a similar size and is mainly due to the very complex geology of the rock formations that contain the oil.

Figure 1.1: Location map of North West Hutton field

The field owners have undertaken several years of study work and investment in an effort to maintain viable production from the reservoir. In 1996 a thorough evaluation was completed to ensure that there were no undeveloped oil reserves or prospects in the vicinity of the platform. This study concluded that no additional reserves could be recovered from the field, and consequently the owners applied to the United Kingdom Department of Trade and Industry (DTI) in May 2002 for consent to cease production. This application was approved and the North West Hutton field officially ceased production on 1st January 2003 although relatively small volumes had been produced during 2002.

Since the facilities at North West Hutton no longer serve the purpose for which they were designed and installed, and are not necessary for production or export from any other field, the owners have prepared this Decommissioning Programme for the field as required by the Petroleum Act 1998.

Although well abandonment is covered by a separate approval process, it is also and integral part of this Decommissioning Programme. Details of the well abandonment, including an inventory of the individual wells are therefore included in this Decommissioning Programme in Section 11.

1.1 North West Hutton Decommissioning Programmes

This document contains separate Decommissioning Programmes for each set of notices served under Section 29 of the Petroleum Act 1998 for the North West Hutton facilities. The Decommissioning Programmes are as follows:

Programme 1: Platform and Associated Equipment

- The North West Hutton topsides.
- North West Hutton jacket, and all the associated subsea equipment including the drilling template.
- Drill cuttings pile present on the seabed at the base of the jacket.

Programme 2: Pipeline PL 147

- The 10" gas import pipeline (PL 147) from the Ninian Tee to North West Hutton.
- The North West Hutton platform equipment and riser associated with the 10" gas import pipeline (PL 147).

Programme 3: Pipeline PL 148

- The 20" oil export pipeline (PL 148) from North West Hutton up to the Cormorant Alpha tie-in.

The North West Hutton Decommissioning Programme is set out in accordance with the DTI Guidance Notes for Industry, 'Decommissioning of Offshore Installations and Pipelines under the Petroleum Act 1998' in order to clearly present the reasoning and activities involved in these programmes. This document incorporates and presents the three decommissioning programmes as one, which is permitted by the guidelines. These Decommissioning Programmes are being submitted by BP on behalf of the relevant Section 29 holders, see Table 1.1.

No.	Decommissioning Programme Description	Section 29 Notice Holders	Applicable Sections
1	The North West Hutton platform and appurtenances including the drilling template and drill cuttings pile	Amoco (UK) Exploration Company Amoco (UK) Petroleum Limited CIECO Exploration and Production (UK) Limited Enterprise Oil (UK) Limited Mobil North Sea Limited	1.0 to 9.0 inclusive 11.0 to 20 inclusive
2	The 10" Gas Import Pipeline (PL 147) from the Ninian Tee to the North West Hutton platform and the North West Hutton platform associated equipment and riser	Amoco (UK) Exploration Company CIECO Exploration and Production (UK) Limited Enterprise Oil (UK) Limited Mobil North Sea Limited	1.0 to 3.0, 4.4, 5.5, 6.1 to 6.5, 6.6.5, 10.1, 10.2, 10.3 and 10.5
3	The 20" Oil Export Pipeline (PL 148) from the North West Hutton platform up to the Cormorant 'A' platform tie-in.	Amoco (UK) Exploration Company CIECO Exploration and Production (UK) Limited CNR International (UK) Limited ENI (ULX) Limited Enterprise Oil (UK) Limited Kerr-McGee North Sea (UK) Limited Mobil North Sea Limited Westoil Operations Limited	1.0 to 3.0, 4.4, 5.5, 6.1 to 6.5, 6.6.5, 10.1, 10.2, 10.4 and 10.5

Table 1.1: List of Programmes, Section 29 Holders, and applicable Sections of this document

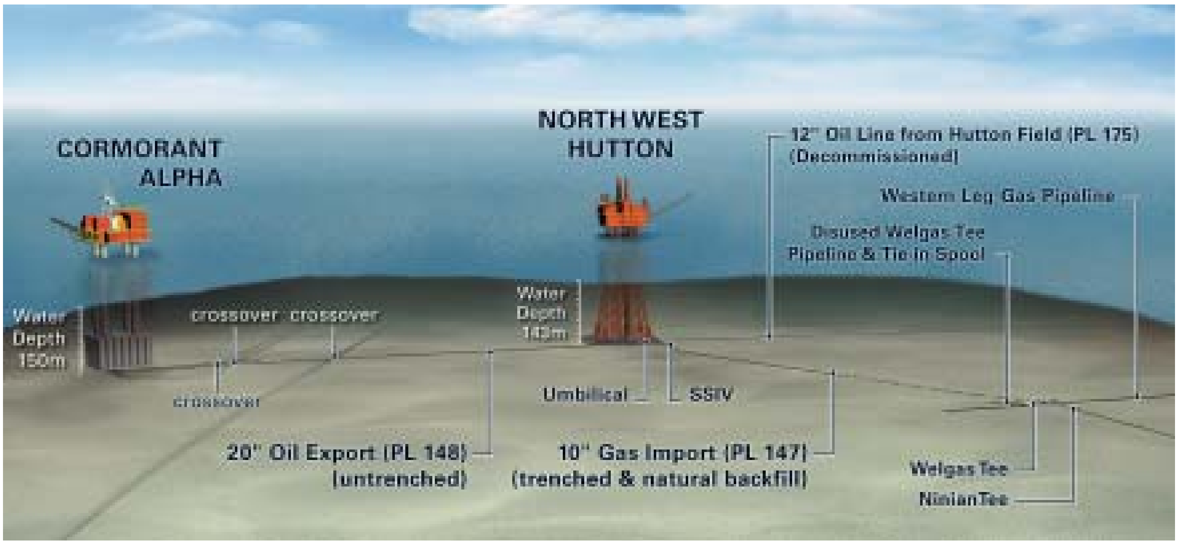


Figure 1.2: North West Hutton field layout

This Decommissioning Programme presents a thorough and detailed review of the study work, evaluations and recommendations proposed by the owners for decommissioning the North West Hutton facilities. This document is structured as follows:

- Introduction **Section 1**
- Executive Summary **Section 2**
- Background Information **Section 3**
- Evaluation of Options and description of the recommended Decommissioning Programme **Sections 4 to 12**
- Management, Costs and timing of the recommended Decommissioning Programme **Sections 13 to 18**
- Environmental Impact Assessment Summary **Section 19**

BP has established a public website to post news and information on the progress of the North West Hutton facilities Decommissioning Programme and associated activities. www.bp.com/northwesthutton. See Section 12 of this document for further details of this website.

Oil Pipeline PL 175 North West Hutton platform associated equipment and riser

In addition to the work being carried out in the three North West Hutton Decommissioning Programmes the following additional work will also be carried out:

- The decommissioning of the North West Hutton platform equipment and riser associated with the 12" oil export pipeline (PL 175) from the Hutton Tension Leg platform to the North West Hutton platform.

The decommissioning of this piece of PL 175 does not constitute part of any of the North West Hutton Decommissioning Programmes but is being carried out on behalf of the Hutton owners under the terms of the "Agreement Relating to the Offtake of Crude Oil from the Hutton and North West Hutton fields" (Ref. 4.11), along with the North West Hutton facilities.

Decommissioning Work	Section 29 Notice Holders	Applicable Sections
The North West Hutton platform equipment, riser and the remaining section of the tie-in spool associated with the 12" Oil Export Pipeline (PL 175) from the Hutton Tension Leg platform to the North West platform.	CIECO Exploration and Production (UK) Limited CNR International (UK) Limited ENI (ULX) Limited Enterprise Oil (UK) Limited Kerr-McGee North Sea (UK) Limited Westoil Operations Limited	1.0 to 3.0 and 4.4

Table 1.2: List of Section 29 Notice Holders and applicable sections of this document which contain information relating to the decommissioning work associated with PL 175

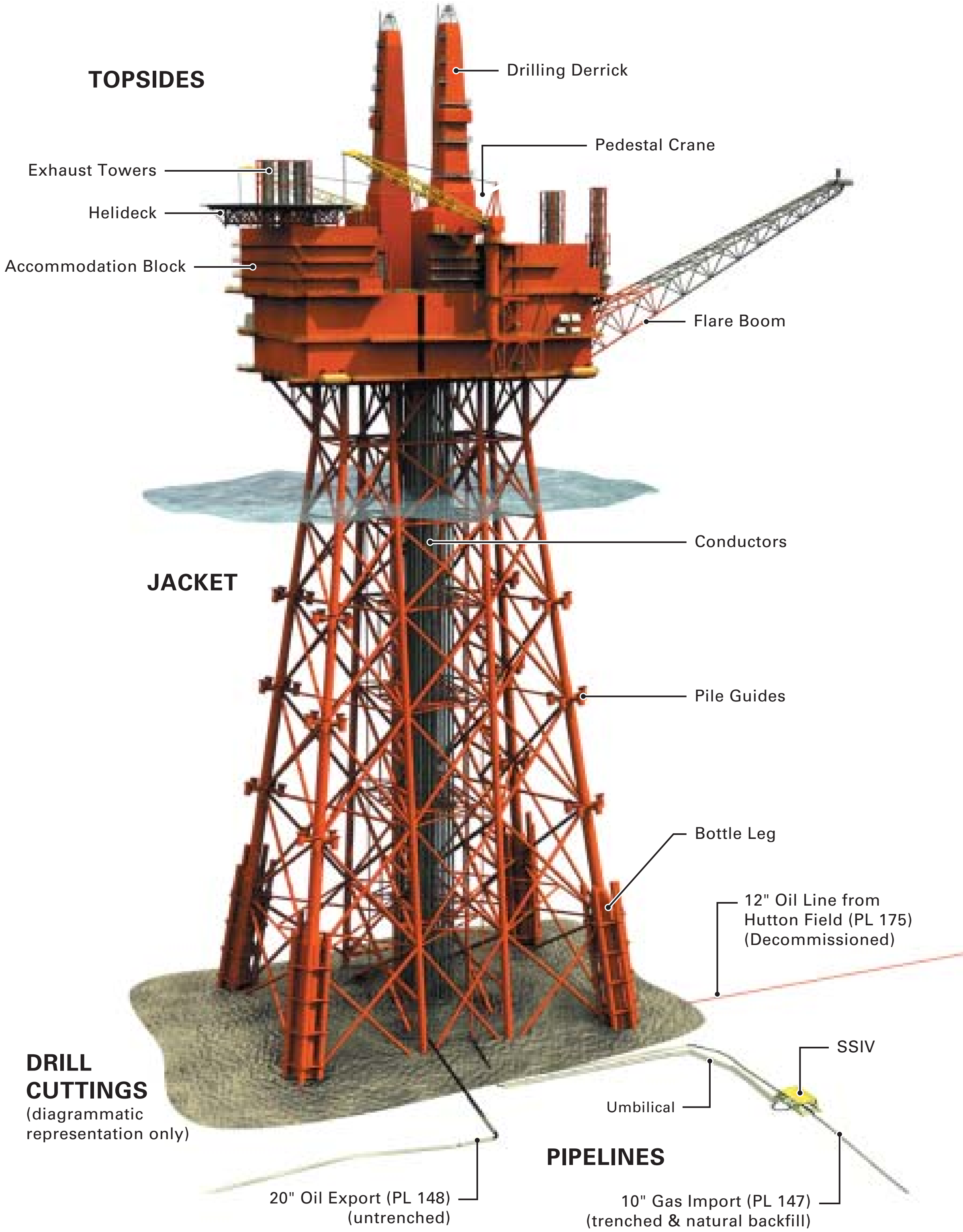


Figure 1.3: North West Hutton platform.

2 EXECUTIVE SUMMARY

2.1 Introduction and Recommendations

The North West Hutton field, in Block 211/27a of the United Kingdom area of the North Sea, officially ceased production on 1st January 2003 and is being prepared for decommissioning. The North West Hutton installation is a large, steel jacket platform, located 130km north east of the Shetland Islands in a water depth of some 140m and is a typical example of the platforms designed in the late 70's and installed in the early 80's. The installation comprises a steel jacket support structure, and drilling template fixed to the seabed, on which sit the various topsides modules which were required to operate the platform safely.

Prior to cessation of production (COP) a range of studies confirmed that there are no further commercial oil and gas opportunities or alternative uses for the platform at its present location.

Photograph courtesy of Charles Hodge, Lowestoft, Norfolk

Figure 2.1: Photograph of the North West Hutton platform.

A Decommissioning Programme has therefore been prepared by the North West Hutton owners (Table 2.1) and the following summarises the recommendations for decommissioning the field:

- The topsides should be totally removed and returned to shore for reuse, recycling or disposal. (Figure 2.4)
- The steel jacket should be removed down to the top of the footings and returned to shore for re-use or recycling.
- The jacket footings should remain in place. This is the lower part of the jacket including the piles which fix the structure to the seabed. (Figure 2.5) This would therefore be the basis for a derogation application under the terms of the OSPAR 98/3 Decision, if accepted by the UK Government.
- The drill cuttings pile should be left in place on the seabed. These are the rock cuttings brought to the surface during drilling operations.
- The 10" gas import pipeline should be left in place as it is already trenched and buried and the 20" oil export pipeline should be trenched and buried. Pipeline ancillary and protective equipment should be removed.

These recommendations are based on a comparative assessment of all options, involving some 50 external studies.

An Independent Review Group of six environmental experts and engineers from the UK, Norway and Germany has verified that the assessment process and studies were comprehensive and objective.

A stakeholder consultation process has gathered views from a wide range of organisations and individuals during 2003 and 2004 and these have also been taken into consideration in arriving at the recommendations.

The North West Hutton owners believe that these recommendations provide the most balanced solution for North West Hutton, taking account of the safety, environmental, social, technical and economic aspects of various options studied.

During the comparative assessment study and stakeholder consultation processes, certain critical factors emerged for each of the main elements to be decommissioned which had a major influence on the final recommendations:

Topsides – Technical Feasibility and Safety Risk

- Various removal methods are possible but reverse installation is considered to be the preferred option as offshore deconstruction would involve higher safety risk and single lift technology is not yet available.
- The removal operations will be technically challenging and will require detailed planning and rigorous management to ensure that these activities can be completed safely.

Jacket – Safety Risk, Technical Feasibility and Social Impact

- The three options studied are all technically challenging – full removal, removal to top of footings and partial removal of footings to the top of the drill cuttings pile.
- A significant differentiator between these options has been the analysis of safety risk. Full or partial removal of the jacket footings would involve an unacceptable level of safety risk, particularly for the divers who would be required for key parts of the operation, notably a greatly increased risk of a fatality – a 1 in 7 chance (14%), of someone being killed during full removal operations (13% for partial removal of the footings) compared to a 1 in 20 chance (5%) for removal to the top of the footings. The levels of risk for full removal are compared with oil and gas operations and other industries in Figure 2.6.
- Studies undertaken by a Danish engineering consultant have shown that the risk of project failure for partial and full footings removal was 70% and 45% respectively, due to high levels of technical risk. These are considered to be unacceptably high compared with removal to the top of the footings which is 23%. (See Figure 2.2)
- Leaving the footings in place and partial removal would present a potential snagging risk for trawling and would result in the continued exclusion of a small area of the seabed for fishing activities. Measures will be required to minimise this risk.

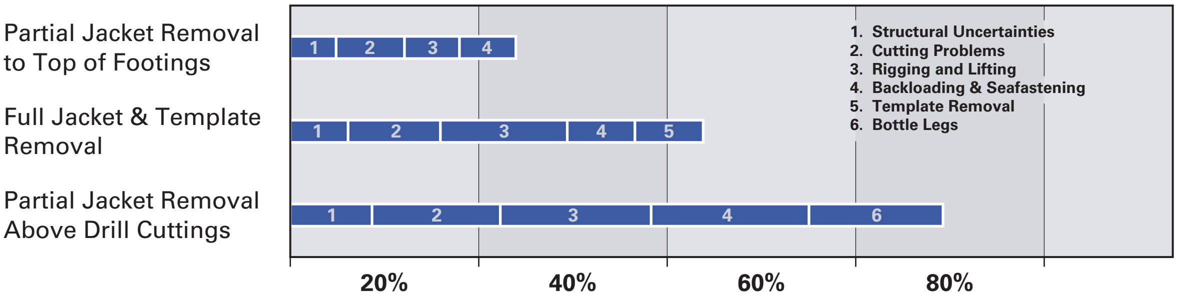


Figure 2.2: Probability of Project Failure. *COWI: Removal of the North West Hutton Jacket Quantitative Comparative Assessment 2004.*

Drill Cuttings Pile – Environmental and Social Impacts

- The option which provides the least environmental impact is to leave the pile in place to allow the seabed to recover naturally.
- There would be disproportionate resource usage and environmental impact associated with operations to move or remove the pile.
- Any such operation is likely to result in contamination of areas of the seabed which have already recovered.
- The seabed in the area is very stable and the pile will remain for a long period but with minimal environmental impact.
- Recovery to shore would ultimately involve the use of valuable landfill capacity.

Pipelines - Technical Feasibility and Social Impact

- Trenching and burying is the best solution as it achieves a similar outcome to total removal but with lower operational safety risk, and energy use and minimises risk to other sea users.

The critical factors identified above for the topsides, jacket, drill cuttings pile and pipelines recommendations are discussed in more detail later in this Executive Summary and in the full decommissioning programme.

Decommissioning Programmes

The decommissioning programme contains separate programmes for each set of notices served under Section 29 of the Petroleum Act 1998 (Table 1.1, Section 1) for the North West Hutton facilities. The Decommissioning Programmes are as follows:

Programme 1: Platform and Associated Equipment

- North West Hutton topsides.
- North West Hutton jacket and drilling template.
- Drill cuttings pile present on the seabed at the base of the jacket.

Programme 2: Pipeline PL 147

- 10” gas import pipeline (PL 147) from the Ninian Tee to North West Hutton and associated pipeline support equipment on North West Hutton.

Programme 3: Pipeline PL 148

- 20” oil export pipeline (PL 148) from North West Hutton up to the Cormorant ‘A’ tie-in and associated pipeline support equipment on North West Hutton.

The North West Hutton Decommissioning Programme is set out in accordance with the DTI Guidance Notes for Industry, *‘Decommissioning of Offshore Installations and Pipelines under the Petroleum Act 1998’* in order to clearly present the reasoning and activities involved in these programmes. This document incorporates and presents the three decommissioning programmes as one, which is permitted by the guidelines. Section 29 of the Act identifies those parties liable for decommissioning, and the companies liable for the three separate programmes are listed in Section 1 of the programme.

The platform is operated by Amoco (UK) Exploration Company, on behalf of Amoco (UK) Petroleum Limited, a subsidiary of BP plc, and here-after will be referred to as BP throughout this Decommissioning Programme. BP operates the field on behalf of the owners with whom the decommissioning responsibility lies. The owners are shown in Table 2.1.

Field Owners	Percentage
Amoco (UK) Exploration Company	25.8
CIECO Exploration and Production (UK) Limited	25.8
Enterprise Oil (UK) Limited	28.4
Mobil North Sea Limited	20.0

Table 2.1: North West Hutton field owners.

2.2 Background Information

2.2.1 Environmental Setting

Figure 2.3: Location of North West Hutton.

The field is located in the northern North Sea 130km north east of the Shetland Islands. The water depth is 144m and the weather conditions can be extreme especially in winter.

The marine environment of the North West Hutton field is typical of large areas of the northern North Sea. Marine mammals have been sighted in the area and a variety of seabirds use the area for feeding and breeding particularly in May and June. There are no designated conservation areas or vulnerable species in the area. The coral "Lophelia pertusa" grows opportunistically on the subsea jacket structure, which is protected under the EC Habitat Directive. But the presence of Lophelia does not affect the decommissioning outcome for the jacket because it is opportunistic.

Fishing is the only other significant commercial activity undertaken in the area. The area is classified as of "moderate" economic value for fishing activity, and the level of fishing effort is generally low compared with other areas of the North Sea. Commercial shipping traffic also uses the area although the majority is directly associated with oil and gas activity.

2.2.2 Facilities to be Decommissioned

The North West Hutton platform is an integrated oil and gas drilling, production processing and accommodation facility. It is fairly typical of the larger, steel platforms designed in the late 1970's and installed in the early 1980's.

Topsides

The North West Hutton topsides are constructed from individual modules and components, see Figure 2.4. A total of 22 "heavy" lifts were required to install the modules on the support structure and the total weight of the topsides is about 20,000 tonnes. Over 97% of the weight of the topsides comprises carbon steel used for the structure and the processing equipment.

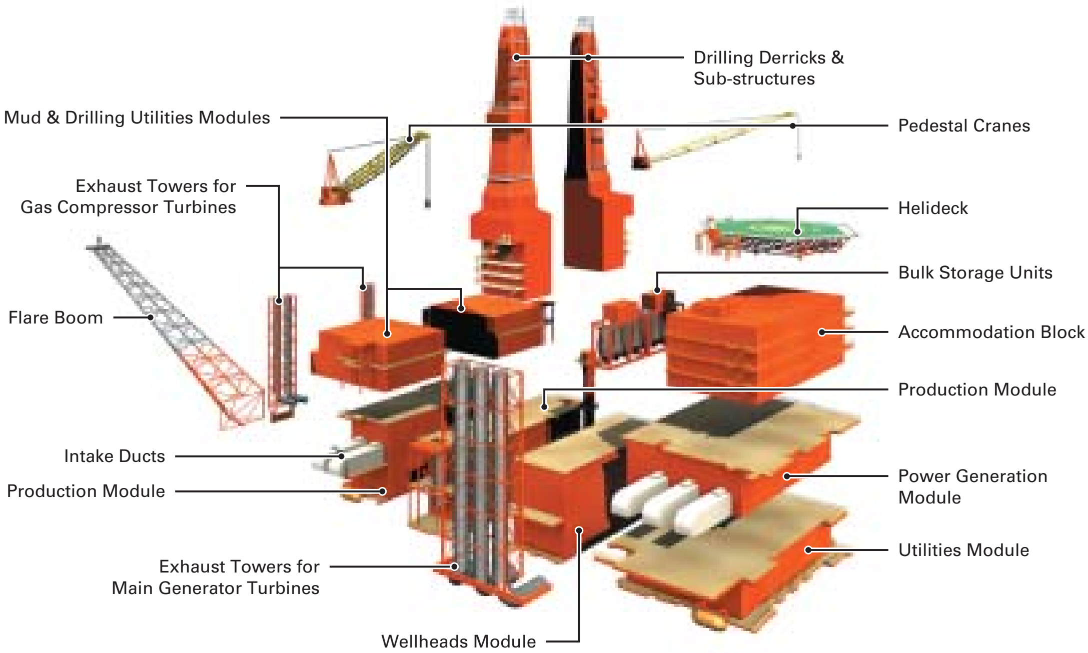


Figure 2.4: Computer generated diagram of the main components of the topsides on North West Hutton, showing the modular construction.

Jacket

The main support structure, or jacket, is an eight-legged structure weighing about 17,500 tonnes, including the weight of the piles, see Figure 2.5. The jacket was launched from a barge and fixed to the seabed using steel piles. Before the jacket was positioned in the field, a steel template weighing about 290 tonnes was fixed on the seabed and this enabled seven wells to be drilled prior to installation of the platform. The template is now considered to be an integral part of the jacket.

The lower part of the jacket - the "footings" - extends to about 40m above the seabed; it comprises very large diameter (5.5m) legs, bracings and piles which together account for about 50% of the total weight of the jacket.

During installation in 1981 some of the members on the lowest level of the jacket were damaged in a storm. Repairs were subsequently made to make the jacket safe for operations, and this resulted in the accumulation of about 100 tonnes of cement grout around the base of the legs.

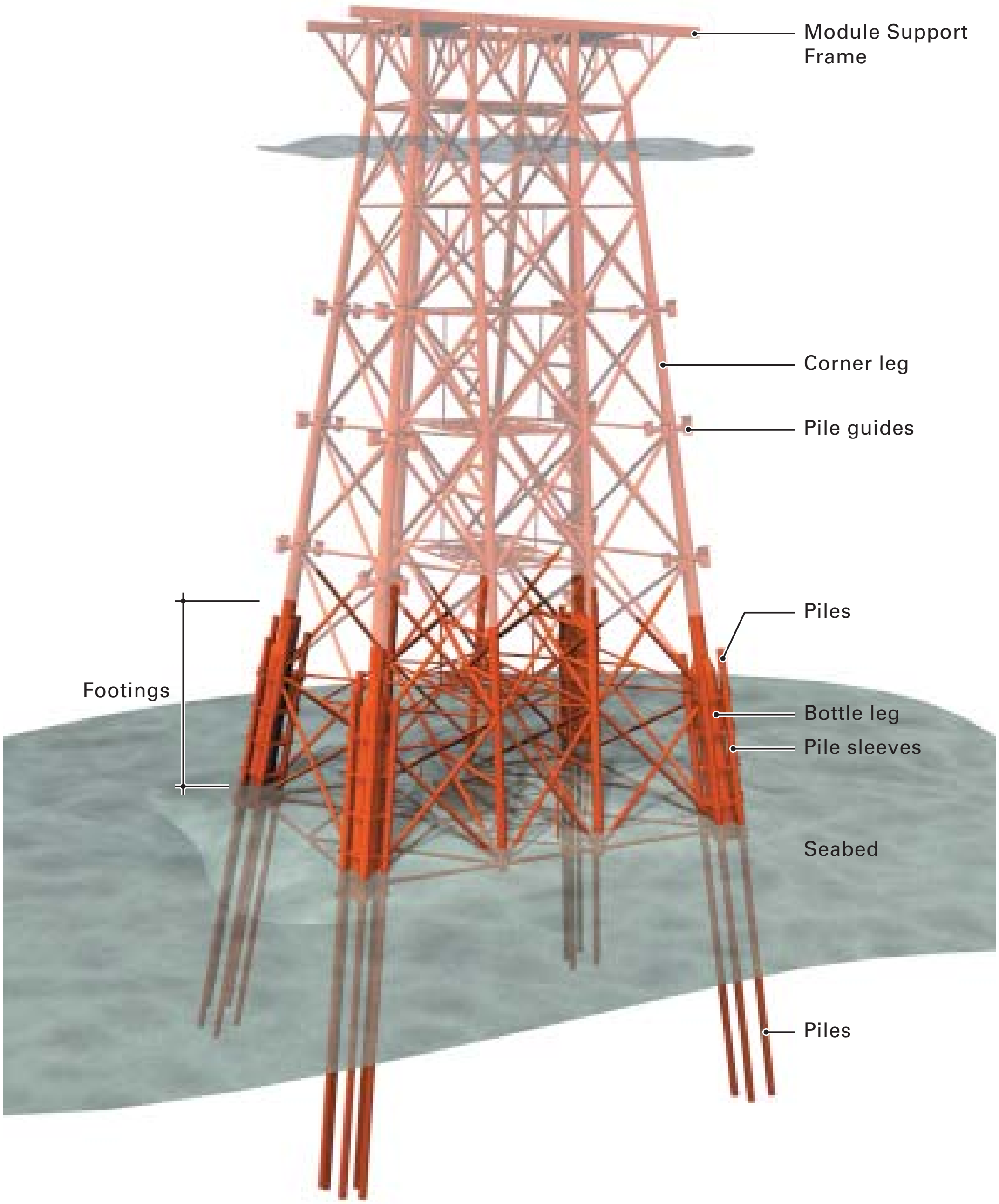


Figure 2.5: Computer graphic of the main components of the North West Hutton jacket.

Pipelines

The Decommissioning Programme covers two pipelines, one used for oil export and the other used for gas import. Both pipelines are constructed of steel and covered with a protective coating of coal tar epoxy. The outer layer comprises a concrete coating used to protect and also weight the pipeline. Both pipelines are protected from corrosion by sacrificial anodes. At various locations along each pipeline, concrete mattresses are used to support and protect certain areas such as the crossing of another pipeline.

The 10" gas pipeline (PL 147) is approximately 13km in length and was originally used to export gas to the gas transportation system which lies to the south of North West Hutton. In 1994, it was disconnected and connected to the Ninian field gas export line, so that North West Hutton could import gas for use as fuel. The pipeline was trenched to a depth of 0.45m below the seabed at the time of installation. The line is currently fully trenched along 100% of its length and buried along approximately 73% of its length.

The 20" oil pipeline (PL 148), jointly owned with the Hutton field, was used to export oil and natural gas liquid (NGL) from the North West Hutton field to Cormorant Alpha which lies approximately 13km to the west. The oil pipeline has not been trenched and lies on the seabed.

Drill Cuttings Pile

The rock "cuttings" resulting from the drilling operations have accumulated on the seabed around the base of the jacket to form a drill cuttings "pile". During the period of development drilling on North West Hutton between 1982 and 1992, the approved and licensed disposal method for these cuttings was to discharge them onto the seabed after cleaning. The pile currently has a maximum depth of 5.5m in the centre and rapidly thins to approximately 1.5m around the jacket legs. The pile actually extends to between 20m and 70m beyond the jacket legs. The pile has a surface area of approximately 0.02km^2 and consists predominantly of rock (48%) and seawater (45%): the remaining material comprises the oil used in the drilling fluid together with small amounts of other chemicals used in the drilling operations. The total volume of the pile including the seawater is approximately 30,000m^3.

2.3 Principles Used to Assess Decommissioning Options

2.3.1 Introduction

The North West Hutton owners used a thorough screening and evaluation process to arrive at the recommended option for decommissioning the North West Hutton facilities. This was designed to assess the technical, safety, environmental, financial and societal impacts for all the decommissioning options.

2.3.2 Legal Requirements

The decommissioning of disused offshore installations is governed under UK law by the Petroleum Act 1998. The DTI's Guidance Notes for Industry on the Decommissioning of Offshore Installations and Pipelines under the Petroleum Act 1998 also incorporates the UK's international obligations relating to the disposal of offshore installations which fall under the OSPAR conventions.

OSPAR Decision 98/3 requires that all installations be completely removed to be re-used, recycled or disposed of on land. A base case of total removal is therefore the starting point of all evaluations and assessments for the decommissioning of the North West Hutton facilities. However, OSPAR Decision 98/3 allows a potential "derogation", which is an exemption from the general presumption of total removal for all or part of the "footings" of steel installations weighing more than 10,000 tonnes, and placed in the maritime area before 9th February 1999.

The DTI's Decommissioning Guidance Notes state that the decommissioning programme should be consistent with international obligations and take into consideration:

- the precautionary principle
- best available techniques and best environmental practice
- waste hierarchy principles
- other users of the sea
- health and safety law
- proportionality
- cost effectiveness

2.3.3 Method and Evaluation Process

Studies Undertaken

The North West Hutton owners commissioned a wide range of detailed studies to fully understand all aspects of the project. A list of all study references is published in Section 20 of the full Decommissioning Programme. The studies were designed around five key assessment criteria namely:

- **Technical** feasibility of implementing the operations;
- **Safety** of all personnel involved in the decommissioning activities both offshore and onshore;
- **Environmental** impact of all activities at the offshore location and also the onshore dismantling and disposal site;
- **Societal** impact on users of the sea, businesses and communities with the potential to be impacted by the decommissioning activity; and
- **Financial** requirements of the work programme.

Each of the studies was scoped to provide key information related to one or more of the above evaluation criteria. Complicated modeling and analytical techniques or weightings to combine the five assessment criteria were not deemed to be applicable.

Each of the studies was implemented by a variety of external contractors, consultants and other specialists and resulted in the decommissioning recommendations presented for North West Hutton. The range of studies completed can be categorised as follows:

- Studies to identify alternatives to decommissioning, or uses for the platform either in the current location or other locations that align with the intent of the waste hierarchy.
- Removal studies to evaluate the full removal of the North West Hutton platform and all associated material to achieve a clear seabed.
- Research projects and joint industry projects to better define and understand areas of decommissioning generally acknowledged as problematic.
- Comparative assessment studies to describe and compare the alternative options in line with the requirements of the Petroleum Act (1998) and where applicable, OSPAR decision 98/3.

Assurance

To ensure that the study findings are independent and objective, the North West Hutton owners invited an international group of engineers and scientists to review all the studies. The Independent Review Group (IRG) has assessed each of the comparative assessment studies for adequacy of scope, clarity, completeness, methodology, relevance and objectivity of conclusions.

The IRG review was completed in April 2004 and a report has been published by the group which is included in Section 20 and is available on the North West Hutton public website. Amongst other main conclusions, the report states that:

"The scope of studies undertaken was sufficiently comprehensive, their quality was satisfactory and they provide an adequate basis for the comparative assessment process".

Further details of the IRG terms of reference and conclusions are given in Sections 12 and 20.

Risk Tolerability

The safety risk for decommissioning options was evaluated through the use of quantitative risk assessment (QRA) techniques which provided a numerical evaluation of the risks. The numerical estimates utilise risks expressed in terms of each worker's or individual's risk on an annual basis. An individual's risk is defined as the likelihood that a specific individual will be harmed due to exposure to specific hazards. The summation of each individual's risk gives the overall Potential for Loss of Life (PLL) which estimates the collective risk to all workers involved in removal operations.

For example if a single individual has a risk of 1×10^{-3} per year (or 1 in 1000 per year) then out of 1000 employees with a similar risk there will be one fatality in any single year. The PLL in this example would be 1 (or 100%) assuming continuous working.

PLL and Individual Risk Per Annum (IRPA) are directly linked in terms of the number of people involved and also the time spent undertaking the project activities.

The risk is a combination of the likelihood of a hazardous event occurring, the likelihood that someone will be present when the event occurs and the likelihood that the specific person will be fatally injured by the effect of the event.

The legislative criteria for acceptability of risk to personnel is that the risk of fatality for an individual shall not be greater than 1×10^{-3} per year (1 in 1000) and shall be as low as is reasonably practicable (ALARP). ALARP is simply a demonstration that all reasonably practicable measures have been taken to reduce risks from each of the identified hazards and that nothing more can be done to reduce risks further.

The BP criterion for acceptability of risk is that the risk of fatality for an individual shall not be greater than 5×10^{-4} per year (1 in 2000).

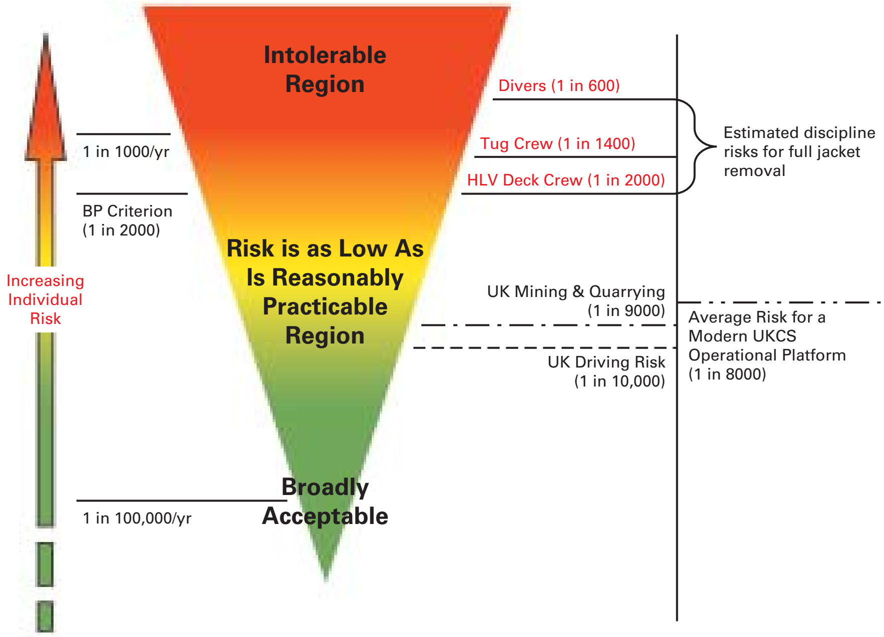


Figure 2.6: ALARP Triangle, which compares levels of risk for a sample of individuals involved in the full jacket removal against other industry and social risks.

The additional hazards and uncertainties involved in removal of the footings contribute to the high individual risk values for full jacket removal. A number of these hazards i.e. grout removal and damage to the structure are not prevalent with removal of the upper jacket section and hence individual risks associated with partial removal are reduced. It is also likely that divers will only be required for footings removal and hence this high risk is not a factor in partial removal.

Whereas the individual risks are lower for partial removal, certain workers will still carry relatively high levels of risk as significant hazards remain with the removal of the upper jacket sections. The Deck Crew for example has a predicted individual risk of fatality of 1 in 2600 for partial removal against 1 in 2000 for full removal. It should be born in mind however that individual risks are presented on an annual basis which partially explains the similarity in the figures.

This difference in individual risk between the two options when combined with the differing durations of the two options combines to give the overall significant difference in the probability of fatalities between the full and partial jacket removal options. See Section 2.4.3 for further details.

Evaluation of Impacts

A summary of the criteria and their acceptability levels is shown in Table 2.2; the evaluations are a combination of qualitative and quantitative impacts. These criteria were used for the evaluation of options for the jacket, drill cuttings and pipelines.

Risk Factors	Nature	Acceptable	Marginal	Unacceptable
Safety of personnel	Mainly Quantative	A region of low risk – broadly acceptable region. Risks in this area are generally regarded as insignificant and adequately controlled. IRPA is well within the recognised threshold of 1 in 1000.	A region of intermediate risk, a tolerable region where people are prepared to tolerate the risk to secure the benefits. IRPA is around the recognised threshold of 1 in 1000.	A region of high risk - region considered unacceptable whatever the level of benefit associated with the activity. IRPA is above the recognised threshold of 1 in 1000.
Impacts on the environment	Quantitative/ Qualitative	The proposed operations may provide a benefit, no change or at worst negligible environmental impacts.	The proposed operations cause some, possibly significant, environmental disturbance that is localised and of short duration.	The proposed operations cause significant environmental disturbance that is widespread and/or long-lasting.
Impacts on society	Mainly Qualitative	There are tangible positive benefits, or possibly no discernible negative impacts.	The proposed operations may result in small impacts.	There is potential for significant negative impact.
Technical	Mainly Qualitative	Equipment and techniques are known and have a track record of success.	Equipment and techniques have a limited track record or require development.	Equipment and techniques have no track record.
Economic	Quantitative	Cost is important but is not used as a prime differentiator. It is included for completeness and as a measure of proportionality when considering the other four criteria.		

Table 2.2: Summary of criteria and acceptability levels for options for decommissioning the jacket.

2.4 Assessment of Decommissioning Options

2.4.1 Alternative Use and Re-use of the Facilities

Studies evaluating the potential re-use of all or part of the North West Hutton facilities in the present location show that there are no feasible alternatives to decommissioning. This is primarily due to the remote northern location and extreme weather conditions. Possible re-use of the platform at another location is not feasible due to the age and condition of the equipment and if the equipment was disconnected and moved there is no guarantee it would function satisfactorily. Studies also show that there are no viable commercial opportunities in support of other oil and gas activities in the area. In the absence of such opportunities the only alternative is to consider decommissioning the facility. Re-use of parts of the facility will be pursued as an alternative to re-cycling.

2.4.2 Topsides Decommissioning

OSPAR Decision 98/3 requires that the topsides of all installations will be returned to shore for re-use or recycling. The North West Hutton topsides studies therefore examined methods of removal using the five evaluation criteria as the means of comparison. The removal methods studied were:

- Offshore deconstruction (piece-small removal).
- Reverse installation.
- Single lift.

The preferred method, based primarily on the safety, and technical criteria, is reverse installation (Section 7.3).

The studies indicate that removal of the topsides by reverse installation is feasible. All components of the topsides will be returned to shore for re-use, recycling or disposal. This will involve 22 lifts up to a maximum lift of 2,800 tonnes. The studies indicate that the operation will be technically challenging but achievable, and the environmental assessment does not identify any major risks. The safety assessment indicates that this aspect of the project carries significant risks to personnel both offshore and at the onshore decommissioning site.

A number of hazards are predicted which may expose key disciplines to potentially high levels of individual risk. However, unlike jacket removal which involves a high degree of uncertainty and technical challenge, the ability to thoroughly assess the topsides modules prior to lifting may provide opportunities to eliminate or reduce the impact of these hazards further, thereby reducing overall risk.

The analysis undertaken includes an estimated 6 months preparatory work phase involving high manning levels to prepare for module removal. This preparatory phase, though not high risk, significantly contributes to the overall risk through exposure to normal offshore risks e.g. helicopter travel.

The significant number of personnel involved combined with an extended timescale for removal results in a relatively high level of risk for topsides removal. Opportunities to reduce the overall exposure time to individuals will also reduce the removal risk.

The overall risk of a fatality occurring during operations to remove and re-use or recycle the topsides is estimated to be around 9.6% or a 1 in 10 chance of a fatality during the project.

This assessment of safety risk indicates that whilst feasible, all activities associated with topsides removal will require rigorous design, assessment and management to ensure that risk to personnel is minimised.

Recommendation: The North West Hutton topsides should be totally removed and returned to shore for re-use, recycling or disposal.

2.4.3 Jacket Decommissioning

The drill cuttings and jacket have been evaluated separately in the comparative assessments to ensure each was considered on its own merits. This is a major factor in the jacket study work, because most of the drill cuttings would have to be removed to gain access to the base of the footings, seabed brace members and the template for complete jacket removal.

The North West Hutton jacket is the largest fixed steel, offshore oil and gas structure that has been considered for decommissioning anywhere in the world to date. A wide range of study work was implemented and the overall purpose was to:

- identify all of the currently available techniques, and the potential new techniques, for jacket removal; and
- assess the technical, safety, environmental, societal and cost implications of removing the North West Hutton jacket with the preferred technique.

Photographs courtesy of Charles Hodge, Lowestoft, Norfolk

Figure 2.7: Photographs of the North West Hutton Jacket.

Techniques for Removal of the Jacket

Three main techniques for removal of the jacket were identified and evaluated, as follows:

Reverse Installation and Single Lift
These two methods would involve removal of the entire jacket by buoyancy methods or a purpose-built vessel. No equipment to implement such operations currently exists. Studies have shown that the damage sustained during the installation of the platform has left the jacket unable to withstand the forces that would be imparted by such a removal technique. The size of the jacket, the presence of the excess grout from the installation difficulties and the severe and unpredictable weather of the remote location of North West Hutton are also problematic and are not best suited to the first use of a major new technique.

Offshore Deconstruction
This method would involve the major use of underwater cutting techniques and large offshore cranes, similar to those used for the topsides removal, to remove the jacket in sections. Offshore deconstruction has been used before but proved highly complex. It is not directly comparable with the technique of reverse installation to be used for the topsides, and is a considerable extrapolation from any work previously undertaken.

Overall, the studies indicate that offshore deconstruction is the most feasible and viable method for jacket removal. This method therefore formed the basis for comparison of the jacket removal options. This does not preclude other methods coming forward in the future.

Jacket Removal Operations

The study work evaluated in detail all aspects of the offshore deconstruction operations required for full removal of the jacket. The operations are theoretically achievable and utilise existing technologies, but no equipment to handle, cut and lift the components the size of the North West Hutton jacket is currently available. The deconstruction activity would involve the progressive cutting and removal of the jacket, starting at the surface and gradually working downwards. At least 20 lifts weighing up to 3,000 tonnes would be required. The largest jacket removal to date, involved three major lifts.

The base of the jacket was severely damaged by a storm during its installation and as a result of this damage there is also a large quantity of excess grout around the base of the four legs, and in particular Leg B1.

These technical considerations and the fact that the North West Hutton jacket may be a candidate for derogation, led to the comparative assessment of three options for the decommissioning of the North West Hutton jacket. These options were developed during the course of the work and were suggested by the Independent Review Group (IRG) and supported by the DTI. The presumption remains that of clear seabed, but the three options selected were:

- Total jacket and template removal to provide a clear seabed.
- Removal of all jacket components down to the top of the drill cuttings pile.
- Removal of all jacket components down to the top of the footings.

Comparative Assessment

The study focus was on the full removal of the jacket. A significant number of potential major hazards were identified by the studies and the main areas of concern were:

- Reliability of subsea cutting and rigging technology particularly for critical cuts immediately prior to the lift and the large leg cuts.
- Dropped loads.
- Falling objects during all aspects of operations.
- Transfer of the irregular loads to moving barges offshore, and securing activities of this scale.
- The likely requirement for the use of divers in major deconstruction activities.
- Onshore demolition and dismantling.

These activities are similar for the full and partial removal options although there are major variations, such as cutting through the large diameter legs ("bottle legs"), and these were included in the studies. Each bottle leg is approximately 5.5m in diameter and has five piles, each with a diameter of 1.5m This allowed the three options to be compared in detail to fully understand the implications of each. The results of the studies are presented in the Table 2.3 using the safety, environmental, societal, technical and economic evaluation criteria as the basis for the comparison.

Summary of Jacket and Footings Options			**Jacket and Footings Removal**	**Jacket and Footings Partial Removal**	**Jacket Removal to - 100m**
Safety	Probability of Loss of Life Number of Lost Time Injuries (LTI)		14% 16	13% 15	5% 6
Environment	GHG CO_2E Total Energy requirement Footprint Persistence	Tonnes GJ km^2 years	42,000 520,000 None None	44,000 568,000 <0.01 >500 years	38,000 559,000 <0.01 >500 years
Societal	Impact on Fisheries UK Employment Impact	 Man/years	None 196	No go fishing area not studied	No go fishing area 66
Technical	Technical risk of failure		45% Damage to footings Cutting/rigging difficulty and complexity	70% Cutting bottles is high technical risk	23% Cutting/rigging difficulty and complexity
Economics	Cost		See Section 13 for Cost Information		

Table 2.3: Summary of jacket and footings decommissioning options.

Option - Jacket and Footings Partial Removal down to top of Drill Cuttings

This option is similar in safety and environmental exposure to that of the full removal option; see the similarity of data for these criteria in table 2.3. However the partial removal option does not leave a clear seabed and the site would remain an obstruction for fishing, which is the main societal impact. Parts of the structure that remain would still protrude out of the drill cuttings up to a height of 10 metres above the seabed, as this is the lowest level at which it is feasible to cut the large bottle legs, due to the stiffening and braces at the lower levels. The technical challenge is significant for this option, and as can be seen from the table the risk of project failure is predicted by an independent report as 70%. This is higher than the complete removal option at 45%. This is also reflected in the costs which are higher for partial removal than the complete removal option.

Comparing this partial removal option with that of the removal of the jacket down to the top of the footings shows that for removal to the top of the footings there is less safety and environmental risk. The fishing obstruction remains, but that is the same for both the options. Technically and financially removal to the top of the footings is better, as it has a much lower risk of project failure at 23%.

To summarise, the partial removal option is less favourable than the complete removal option as there is a higher technical risk and it does not remove the obstruction to fishing. It is less favourable than removal to the top of the footings option because there is a much higher safety and technical risk, and the two options are similar with regard to fishing.

This option is therefore eliminated from further consideration. The two options of full jacket and footings removal and removal of the jacket to the top of the footings, i.e. derogation, are now considered further.

Comparison of Total Jacket Removal and Removal to the top of the Footings

The risk of project failure was determined by an independent consultant from Denmark. The conclusion was that there was a much greater risk of project failure that is, severe difficulties in completing the work, cost and schedule over-runs, for the complete removal (45%) than the removal to the top of the footings (23%). The figure used in BP to define a serious over-run, or 'project failure' is 15%. These figures clearly show that all activity associated with the removal of the jacket entails high levels of technical risk, but that work on the footings is significantly more difficult.

Such risks are considered unacceptable in terms of industry and BP standards. Even allowing for reasonable improvements from mitigation measures, the risks remain high. A significant proportion of the risk is attributable to removal of the lower-most components due to existing damage and the large accumulations of grout around the legs. This combination of damage and excess grout around the legs is not normal and is a significant factor in the removal operation.

It is also likely that divers would be needed to assess the damage for feasibility of lifting some components and to remove some grout for safety reasons, i.e. the grout is liable to fall during lifting with the risk of injury to personnel.

The other technical risks that have been discussed qualitatively above, are quantified in the 45% and 23% figures. These are the increased difficulty of cutting and rigging at the greater depths of the footings and transferring these loads to the transportation barges. All the above technical difficulties are reflected in the costs, where full removal is about twice the cost of removal to the top of the footings.

More importantly these technical risks are reflected in the safety exposure for the two options. The calculated Potential Loss of Life (PLL) is estimated as 14% (1 in 7 chance of a fatality during a project) and 5% (1 in 20 chance), for total removal and removal to the top of the footings respectively. The number of accidents, referred to as a Lost Time Incident (LTI), for the two options is calculated as 16 and 6 respectively. This is the number of potential serious accidents that would mean personnel were not able to return to work for at least three days. This is almost a three-fold increase in the safety risk associated with footings removal, which is a very significant increase in the risk of someone being killed. See Figure 2.6 for further risk of fatality analysis for this option.

On a like for like basis, North West Hutton as an operational production platform with major hydrocarbon hazards, operated with approximately one quarter of the fatality risk associated with jacket removal.

It should be noted that the use of analytical methods in determining the risk of fatalities tends to underestimate, rather than overestimate, the risk to personnel. This is evident in the fact that fatalities have occurred in several decommissioning projects to date.

The studies do not identify any significant environmental hazards and the CO_2 emissions and energy use balance are broadly similar for the two options. This is because the extra energy used for removing and recycling a greater proportion of the steel (i.e. jacket and footings removal) is offset by the indirect energy cost of leaving steel on the seabed (jacket removal to -100m), and the theoretical need therefore to manufacture new steel to replace recyclable steel left on the seabed.

Neither option would hinder free passage of ships so all collision risk is eliminated. Leaving the footings on the seabed would present an obstruction to commercial fishing operations in the area, but would not affect the overall available catch. The possibility of fishing equipment becoming snagged on the structure which remains on the seabed is recognised, but the probability that such an event would occur, given the mitigation measures that would be in place, is considered to be low. These mitigation measures will be the subject of consultation with relevant fishing organisations and are expected to include the use of guard vessels during decommissioning operations and the updating of Kingfisher Information Service bulletins and the FishSafe database to ensure that a change of designation from ‘installation’ to ‘obstruction’ is effectively communicated.

On the basis of the above factors, the assessment indicates that the level of risk associated with the removal of the footings is not proportional to the benefits. An almost three-fold increase in the risk of a fatality during the operations to remove and dispose of the footings is deemed unacceptable. The complexity and risk of removing the footings of a large structure is acknowledged by OSPAR Decision 98/3 for jackets weighing over 10,000 tonnes. The recommendation is therefore to leave the footings of the North West Hutton jacket in place.

Recommendation: The North West Hutton jacket should be removed down to the top of the footings (Figure 2.8) and returned to shore for reuse or recycling. The footings structure should remain *in-situ*.

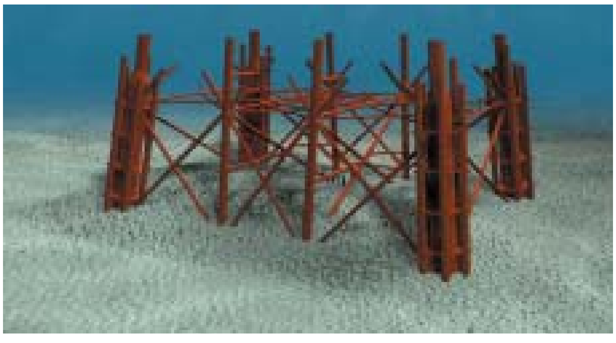


Figure 2.8: Computer graphic of the North West Hutton support structure after removal to the top of the footings.

2.4.4 Drill Cuttings Pile

The North West Hutton cuttings pile consists of about 30,000m^3 of oil-based and water based drill cuttings together with seawater, covering a relatively small area of around 0.02km^2. The drill cuttings pile consists mainly of rock and seawater, but most of the study work focused on the environmental effects of the oil and other contaminants present in the pile. A thorough evaluation of the potential short- and long-term environmental impacts of the cuttings pile was carried out.

The cuttings pile has been the subject of detailed analysis to ensure that the impacts and behaviour of the pile are understood as well as possible. The field owners have also participated in a number of industry-wide studies designed to further develop overall understanding.

Comparative Assessment of Options for the Drill Cuttings Pile

A range of possible options for dealing with the drill cuttings pile has been evaluated in detail using information from specially commissioned studies and the findings of wider research. The options evaluated are listed in Table 2.4.

Category	Description of option	Outcome
***In-situ* Options**	Leave *in-situ* to recover naturally.	Maintain the current status of the pile.
	Excavate cuttings.	Displace cuttings to surrounding seabed to access base of jacket.
	Leave *in-situ* and cover.	Method to effectively "Seal" the cuttings pile in the current condition.
Removal Options	Retrieve and re-inject offshore.	Cuttings pile lifted to surface and re-injected down newly drilled wells.
	Retrieve and return to shore for disposal.	Cuttings pile lifted to surface and taken onshore for treatment and disposal.

Table 2.4: Summary of options evaluated for decommissioning the drill cuttings pile.

The results of the comparative assessment are shown in Table 2.5.

The studies indicate that all the options are technically feasible and that the safety risks are within acceptable limits. However the re-injection options are not legal and there is no onshore treatment facility that is commercially available to treat the drill cuttings. Recovery trials have been performed but considerable work would be necessary to develop an industrial scale operation to remove drill cuttings on this scale. This increases the technical uncertainty and risk of these options which is reflected in the much higher costs that the *in-situ* options. More significantly the increased uncertainty and scope of the removal options is reflected in the safety exposure, where the risks are nearly 10 times greater for the removal options than the *in-situ* options. The risks are primarily associated with drilling activities and material handling.

Surveys of the effects of the pile over a number of years indicate that the seabed surrounding the cuttings pile that was impacted during the operational phase has undergone a significant degree of natural recovery. The materials within the pile itself and the immediate surrounding area will, however, remain for a significant period. The pile could persist for one thousand to five thousand years.

Environmental assessment of the removal techniques indicate that most of the material would be successfully removed, which is a positive outcome. However retrieval would result in the "bulking-up" of material, with the amount of the retrieved seawater likely to be between 10 and 20 times the present volume of the pile, and the operations could lead to some recontamination of the seabed that has already recovered. All of this material would then have to be transported and treated. Excavation would not remove the material and presents the worst case for recontamination. There are therefore significant environmental issues associated with all intervention options both offshore and onshore, which make these less desirable than the *in-situ* options.

Societal studies indicate that leave *in-situ* could have a potential impact on fishing activity, but there is no record of drill cuttings piles causing interference or contamination of trawling activity and equipment. Removal and transport to shore followed by treatment and disposal would have a negative impact on communities due to the large movement of materials and, more significantly, would impact on landfill capacity.

Summary of Drill Cuttings Options		Leave in situ & Monitor	Cover	Excavate	Re-inject on site	Re-inject offsite	Onshore treatment
Safety	Probability of Loss of Life	0.20%	0.6%	0.50%	6.4%	6.4%	2.2%
	Number of Lost Time Injuries (LTI)	<1	<1	<1	7	7	3
Environment	Total Energy requirement (GJ)	6,500	73,000	33,000	275,000	298,000	419,000
	GHG CO_2 E (tonnes)	500	6000	3000	20,000	22,000	186,000
	Footprint (km^2)	0.02	0.02	>0.02	Negligible	Negligible	Negligible
	Persistence (years)	1000-5000	Irreversible	<1000-5000	Negligible	Negligible	Negligible
		Recovery in surr seabed	Resources needed 90,000 tonnes/rock				Landfill capacity >300,000 m^3
Societal		Potential fisheries interaction					
	UK Employment Impact (Man yrs)	1.6	not studied	not studied	301	not studied	242
	Tax Impact to Society (£mm)	0.2	3.0	4.0	17-44	17-44	18-46
Technical		Yes	Feasible	Feasible	**Recovery needs development from trial to industrial scale**		
					Tech feasible but not legal	Tech feasible but not legal	Onshore treatment not commercially available
Economics	Cost (£mm)	0.5	8	9	43-110	43-110	46-114

Table 2.5: Summary of the decommissioning options for the drill cuttings pile.

The environmental assessment showed that in spite of the predicted longevity of the pile if left *in-situ* and even allowing for occasional minor disturbance, the impact of the pile would be minimal, and recovery of the seabed would proceed albeit very slowly. There would be disproportionate risk, resource usage and environmental impacts associated with operations to move or remove the pile. The recommended option is therefore to leave the pile *in-situ* to recover naturally, and this is also the best environmental option. This course of action does not change the current status of the pile. The pile would be monitored and subject to on going surveys to check that the seabed recovery process is as expected. We will also continue to monitor future discussions and decisions under the OSPAR framework for their relevance to the North West Hutton pile.

Recommendation: The North West Hutton drill cuttings pile should be left *in-situ* to recover naturally.

2.4.5 Pipeline Decommissioning – PL 147 and PL 148

As with the other components of the North West Hutton infrastructure, the history, current status and options for the pipelines were studied in detail. The gas pipeline PL 147 is currently trenched to 0.45m below the seabed and rock-dumped and self-buried. The oil pipeline PL 148 lies on the seabed. Throughout their lives the pipelines have been surveyed and maintained, and the survey record shows that the seabed is stable and that no major spans have developed.

The options studied for the pipelines were as follows:

- Leave *in-situ* on the seabed
- Trench and bury to below the seabed
- Recover the pipelines.

The results of the comparative assessment of these three options are shown in Table 2.6

Summary of Oil and Gas Pipeline Options				Leave in situ	Trench and Bury	Recover
Safety	Probability of Loss of Life	PLL	Gas PL-147	0.20%	0.20%	1.90%
			Oil PL 148	0.21%	0.28%	2.10%
Environment (figures are for both oil & gas line)	Waste Generated	Tonnes		Negligible	Negligible	7,600
	GHG CO_2 E	Tonnes		8,000	11,000	14,000
	Total Energy requirement	GJ		111,000	150,000	193,000
	Footprint	km^2		Negligible	0	0
	Impact on landfill site	Tonnes		Negligible	Negligible	4,000
	Persistence	years		300	300	0
Societal	Impact on Fisheries		Gas PL-147	No impact	No impact	No impact
			Oil PL-148	Snagging risk	No impact	No impact
	UK Employment Impact	Man/years		61	69	180
	Tax Impact to Society	£mm	Gas PL-147	1.2	2	5.2
			Oil PL-148	0.8	1.2	3.6
Technical			Gas PL-147	Feasible	Feasible	Feasible
			Oil PL-148	Feasible	Feasible	Feasible
Economics	Cost	£mm	Gas PL-147	3	5	13
			Oil PL-148	2	3	9

Table 2.6: Summary of the decommissioning options for the pipelines PL 147 and PL 148.

There are no significant environmental concerns associated with any of the pipeline decommissioning options as these involve relatively minor localised disturbance for trenching or removal. From a technical and safety consideration all of the options are feasible utilising tried and tested technology with acceptable safety parameters, although there is almost a ten-fold increase in the safety risk associated with the recovery options.

For the pipeline removal option, however, there are potential hazards and environmental impacts for recycling and disposal; e.g. the potential loss of the concrete coating to the sea as the pipeline is lifted, the removal of the concrete to access the steel for recycling, hazards from the pipeline corrosion coating system during cut-up and disposal. It is these activities that increase the safety exposure.

The predicted deterioration of the pipelines over time indicates that they could remain for at least 300 years. If the line is left on the seabed the nature of the deterioration raises the possibility of the oil pipeline being impacted by trawling activities and possibly damaging nets, or that sections of line could be moved from their present location on the seabed. These possibilities can be eliminated by trenching and burying, or removing, the pipelines.

Although both methods are achievable, trenching and burying achieves a similar outcome to total removal but with significantly lower risk to personnel and lower environmental impact, e.g. removal involves 4000 tonnes impact to land fill sites. The stability of the seabed around North West Hutton is conducive to this approach. The recommendation is therefore to trench and bury the oil line and leave the gas line which is already trenched and buried.

The North West Hutton owners will ensure that the site of the pipelines remains free from obstructions. This will involve a monitoring programme and the first survey will be carried out within one year of completion of the decommissioning work to provide baseline data. A second survey will be carried out within 3 to 5 years and the results will be used to determine the future survey regime in consultation with the UK Government.

Recommendation: North West Hutton 10" gas pipeline PL147 will be left *in-situ* as it is already trenched and buried and the 20" oil pipeline PL148 would be trenched and buried beneath the seabed. Ancillary and protective equipment would be removed.

2.5 Interested Party Consultation

The North West Hutton owner's conducted an open and comprehensive dialogue process with all interested parties. Several meetings have been held with groups and individuals, and all parties have been regularly updated by telephone, e-mail and letter. Representatives of the Independent Review Group (IRG) attended two of the general stakeholder meetings to hear views and present the IRG findings. Details of issues raised through this consultation process are documented in Section 20. The public consultation process will continue and the final draft of this decommissioning programme will reflect any issues raised. The public website for information on North West Hutton Decommissioning is: www.bp.com/northwesthutton.

2.6 Debris Clearance and Site Monitoring.

Debris will be removed during the decommissioning activities and final site clearance programme. Trawling sweeps will be made around the platform and along the former pipeline routes to ensure that the seabed has been cleared of obstructions. The sweeps will also collect any smaller items of debris that may not have been detected during the earlier operations. The results of the trawling sweeps will be submitted to the DTI and will be available for inspection by any interested parties.

Within a year of the completion of the decommissioning activity and debris clearance recommended by this programme, the site will be subjected to a physical and environmental survey to establish a post-decommissioning baseline for the site. The scope of the post-decommissioning survey will be agreed in consultation with the DTI before any survey work is carried out and the results submitted to the DTI. The information obtained from this survey and all previously available survey information will then be used by the field owners in conjunction with the DTI to establish an appropriate scope and schedule for future surveys to monitor the condition of the site, the structure and all other material left *in-situ*., to ensure they remain as expected as a result of this decommissioning programme. The results of all future surveys will also be submitted to the DTI.

The field owners are aware that all items left *in-situ* as part of this decommissioning programme remain their property and that they have a continuing liability for these items. The field owners are committed to ensuring that future obligations arising from the implementation of this decommissioning programme are met.

2.7 Onshore Treatment and Disposal of Materials

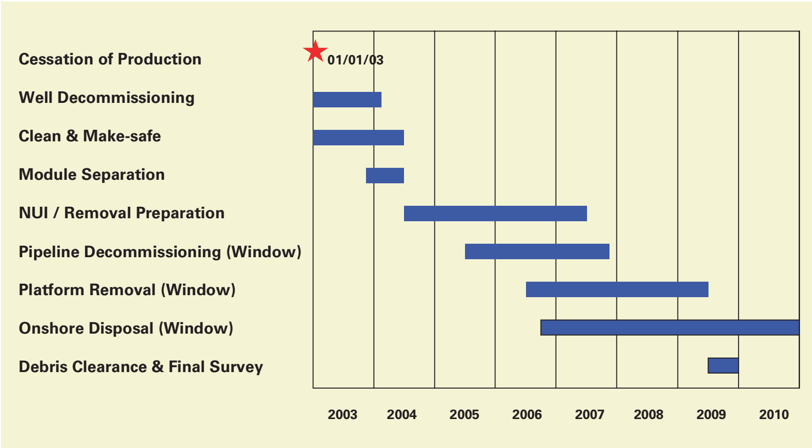
All waste materials generated in the process of decommissioning North West Hutton and its facilities will be treated or disposed of by licensed contractors at licensed sites with all the necessary permits and consents. The contractors will be chosen through an extensive BP selection process, where environmental and safety considerations will be paramount, and the social impacts assessed.

BP's duty of care extends beyond the quayside and BP will work with the onshore licensed disposal sites to ensure that all dismantling and waste treatment and disposal is carried out in a responsible manner. BP will also ensure that the waste hierarchy is applied, in that material is reused and recycled wherever possible in preference to being disposed of.

Upon completion of the onshore treatment and disposal of North West Hutton and its facilities BP will make available data on the quantities of waste recycled and disposed, and the sites and methods used to dispose of hazardous waste. Procurement decisions may result in some of the platform and its facilities being delivered overseas for onshore disposal. The regulations on the Trans-frontier Shipment of Waste would apply for all waste disposed overseas.

2.8 Schedule and Cost Summary

The proposed schedule of activity is shown below. At this stage these are indicative timings and durations. The indicative programme provides relatively wide windows for offshore activities, which are not necessarily continuous, but indicate timely removal. Discussions with the contractors likely to perform the work reveal that they value flexibility wherever possible as this enables them to schedule work more efficiently.



Detailed cost estimates have been developed for all aspects of the recommended decommissioning activity. The estimates are based on the best available data from contractors, detailed studies and standard industry data. There is, however, a general lack of track record in these activities and the cost summaries reflect this in the range of uncertainty.

The mean or expected cost for the overall decommissioning programme for North West Hutton as recommended is £160 million.

2.9 Legacy

We intend to use the lessons learned from planning and implementing the North West Hutton decommissioning project to enhance the industry's technical capability for future decommissioning challenges. In the meantime, we will continue to support research into large steel jacket removal technology in collaboration with other operators and major contractors.

We will also continue to support the UKOOA drill cuttings joint industry project which is investigating options for managing drill cuttings piles and will monitor future discussions and decisions under the OSPAR framework for their relevance to the North West Hutton pile.

The owners of the North West Hutton installation and pipelines will be responsible for monitoring material left on the seabed as a result of carrying out this decommissioning programme and for ensuring that the site and material left *in-situ* remain as expected.

Should remedial action be proposed, to deal with any issues identified by this monitoring programme, a comparative assessment of the safety, environmental, social, technical and cost impacts of such action would initially be carried out. The comparative assessment would be used to determine the benefits of possible remedial action. Any remedial action would be subject to the submission of a revised decommissioning programme for approval by the relevant authorities.

3 BACKGROUND INFORMATION

3.1 Introduction

This section presents a review of the physical, biological, and socio-economic characteristics of the offshore area in which North West Hutton is located and much of the information given in this section is taken from the Environmental Impact Assessment (EIA) (Ref 3.1). A thorough appreciation of this is essential to assess the potential effects of the planned decommissioning programme on the environment and other users of the sea. The North West Hutton field, located in Block 211/27a of the UKCS, is one of several fields in an area known as the East Shetland Basin. The field is located 130km (80 miles) north east of the coast of Shetland and 450km (285 miles) north east of Aberdeen. The water depth is approximately 144m (470 ft.).

3.2 Layout of the Facilities Covered in this Programme

The position and layout of the North West Hutton facilities covered in this programme are shown in Figure 3.1. The location of other structures and facilities in the surrounding area is shown in Figure 3.2.

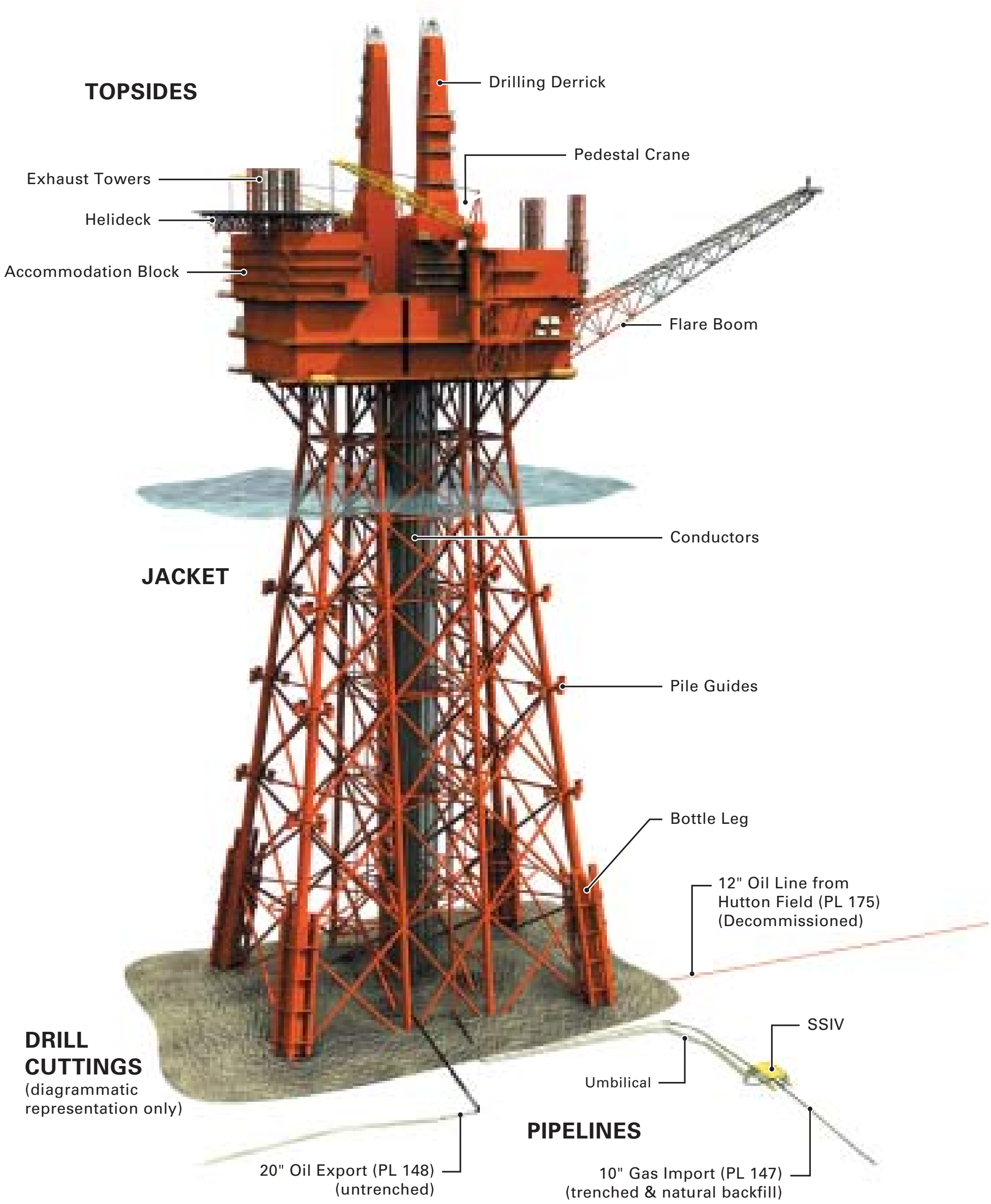


Figure 3.1: Layout of the North West Hutton facilities.

3.3 Adjacent Facilities

The North West Hutton platform has three pipeline connections which were used to import and export oil and gas. The pipelines are shown in Figure 3.2.

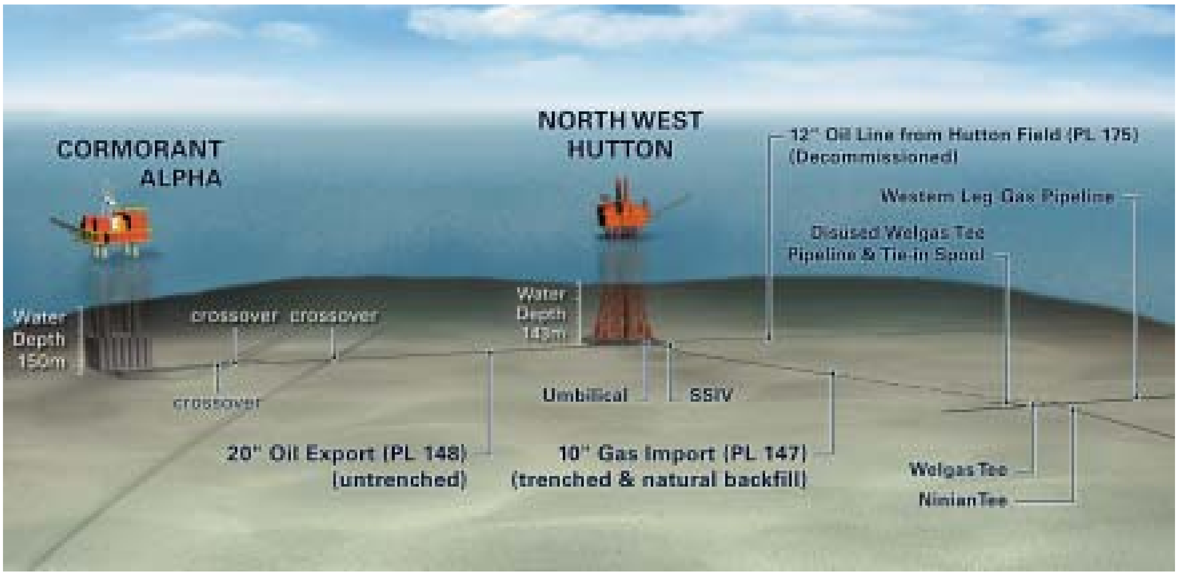


Figure 3.2: North West Hutton and adjacent facilities.

Oil production from the North West Hutton Field was exported via the 20" oil pipeline PL 148 to the Cormorant 'A' platform, located approximately 13km to the west. Oil from the North West Hutton pipeline was then pumped from Cormorant 'A' to the Sullom Voe oil terminal via the "Brent System" pipeline together with oil from a number of other fields. In the years leading up to cessation of production, the volume of oil exported decreased and in its last year of production North West Hutton accounted for only 0.1% of the throughput at Sullom Voe. The economic impact of the cessation of production at North West Hutton on Cormorant 'A', the Brent Pipeline System and the Sullom Voe terminal is therefore insignificant.

In the early years of production, excess gas (referred to as "associated gas") produced together with the oil at North West Hutton was exported to St Fergus in North Eastern Scotland for use as fuel onshore. The North West Hutton 10" gas pipeline PL 147 was installed to export this gas from North West Hutton to a subsea connection in the "FLAGS - Far North Liquids and Associated Gas System" system located approximately 13km south of North West Hutton. In 1989, as oil production from North West Hutton declined, the volume of gas also declined to a point where there was insufficient to supply the fuel requirements for the platform. As a result, PL 147 was disconnected from the FLAGS system and a new subsea connection was made to the nearby gas export pipeline from the Ninian field. PL 147 was then used to import gas to supplement the fuel gas supply for North West Hutton. This gas import ceased in late 2003 as North West Hutton was prepared for decommissioning. There will be no material impact on the Ninian field and surrounding fields as the relatively small volumes of gas previously purchased by North West Hutton will be either exported for sale or used as fuel for the Ninian field.

A third pipeline PL 175 was connected to North West Hutton to enable oil from the Hutton field in Block 211/28 (operated by Kerr McGee) to be transported onwards to Sullom Voe via the North West Hutton oil export pipeline, PL1 48 and the Brent system. The Hutton field Tension Leg Platform was located approximately 8km east of North West Hutton. Pipeline PL 175 has been disconnected from North West Hutton and was decommissioned in 2001 by the Hutton owners as part of the separate Hutton field decommissioning programme (Ref. 3.3).

All operational activities associated with the three pipelines have now ceased, and the decision to decommission North West Hutton will have no material economic or other impact on adjacent fields or facilities.

3.4 Physical, Meteorological and Oceanographic Conditions

Table 3.1 summarises information about the physical, meteorological and oceanographic conditions at North West Hutton and the area immediately around the platform. More detailed information, which may have been used in some of the technical and environmental impact assessments which were conducted to support this decommissioning programme, may be found in the Appendices or the reports listed in the references.

Aspect	Information	
Platform location	61 06'23.950"N, 01 18'32.974"E	
Seabed surface soil type	Sand, silt, and very stiff to very hard clay	
Water depth	144.3m LAT	
Maximum tidal range	2.3m	
Nearest land	The Shetland Islands, 130km (80 miles) south-southwest	
Nearest platform	Cormorant 'A', 13km west	
Distance to median line	Median line with Norway is 25 km east	
Waves	**1 year**	**50 years**
Significant wave height	11.6m	16.1m
Maximum wave height	21.6m	29.9m
Winds (maximum)	**1 year**	**50 years**
1 hour mean	25.9m/sec	36.5m/sec
1 minute mean wind speed	NA	42.5m/sec
3 second gust of wind	NA	50.0m/sec
Currents	**1 year**	**50 years**
Maximum surface speed	0.73m/sec	0.82m/sec
Maximum seabed speed	0.47m/sec	0.53m/sec
Temperatures	**1 year**	**50 years**
Air	-6 C	+27 C
Sea surface	0 C	+18 C

Table 3.1: Summary of the physical, metrological and oceanographic conditions at North West Hutton.

Over the past 20 years many aspects of the offshore environment of the East Shetland basin have been studied in detail, during field-specific surveys and monitoring programmes, and as part of wider-area surveys. BP has carried out numerous surveys around and centred on the North West Hutton location, and these are listed below in Table 3.2. These surveys, in conjunction with the United Kingdom Offshore Operators Association (UKOOA) Drill Cuttings JIP study (Ref: 3.16) make the North West Hutton pile and surrounding seabed one of the most comprehensively investigated in the UKCS.

Year	Transect Direction	No. Stations	Hydrocarbons	Metals	Biology	Notes
1985	NE/SE	9	Yes	No	No	
1989	NE/SE	12	Yes	No	No	
1992	N	12	Yes	Yes	Yes	3-D mapping of pile; vibro-coring, grain size and radioisotope study.
1997	N	11	Yes	No	Yes	Sampling along the 1992 transect from 50m-400m and 7,500m
1999	N	26	Yes	No	Yes	Survey from 1992 transect 100m-10,000m
2002	N & ESE	17	Yes	Yes	Yes	Survey of combined 1992 and 1985 stations. Measured granulometry and a subset of samples for PAH, LSA, PCB, TBT and APE compounds.
2003	N/A (Survey of cuttings pile below jacket)	11	Yes	NE/SE	Yes	Samples at depth during conductor removal operations, plus surface of cuttings pile below jacket. Samples of cuttings pile also analysed for PAH, PCB.

Table 3.2: Summary of sampling from North West Hutton seabed and cuttings pile. (Ref. 3.6)

Results from the surveys, including physical, chemical and biological parameters have been analysed, to establish trends in concentration and the extent of biological disturbance over time (section 9.2.5 explains these results in further detail for both the drill cuttings pile and the surrounding seabed).

Since the discharge of oil contaminated drill cuttings from North West Hutton ceased in 1992, natural processes have markedly reduced the area of hydrocarbon contamination around the platform. In 2002, total hydrocarbon concentrations (THC) ranged from 48,800ppm on the cuttings pile to 12,100ppm at a distance of 100m from the platform. Compared with concentrations in 1992, hydrocarbons in 2002 had decreased by 75%, 86% and 93% at 100, 200 and 300m north of the platform, respectively. The concentrations of contaminants in surrounding sediments are in the range of those that have been recorded around other platforms.

A THC of 50ppm is a documented threshold above which effects are seen in the biological community. In 1992, the 50ppm contour was 1,200m-2,500m from the platform, but by 2002 it had reduced to 600-800m from the platform.

The diversity and structure of the benthic community has largely recovered to background conditions. In 1992, species indicated undisturbed sediments by 1200m from the platform, but by 2002 the zone of disturbance had decreased to 400m.

3.5 Fishing and Commercial Activities

3.5.1 Fishing

The commercial value of the fisheries in the North East Shetland Basin, in which North West Hutton lies, is moderate in comparison with other areas of the North Sea (Ref. 3.2). Several pelagic and demersal species are regularly caught, including mackerel, herring, haddock, cod, whiting, saithe and ling.

For the purposes of measuring and interpreting statistical information about commercial fishing activity, the International Council for the Exploration of the Seas (ICES) has divided the North Sea into a large number of areas designated by rectangles; North West Hutton is located in ICES rectangle 51F1. The monthly totals for this rectangle of ***hours fished***, and ***fish landed***, are shown for the years 1999-2003 in Figures 3.3a and 3.3.b (Ref. 3.1) where the total hours fished were 2,806, 4,203, 3,458, 15,240, and 12,200 respectively. The overall level of UK fishing effort in this area is moderate in comparison to other ICES rectangles in the North Sea, where average annual fishing effort exceeds about 20,000 hours. Only a small amount of shellfish is caught in the area around North West Hutton.

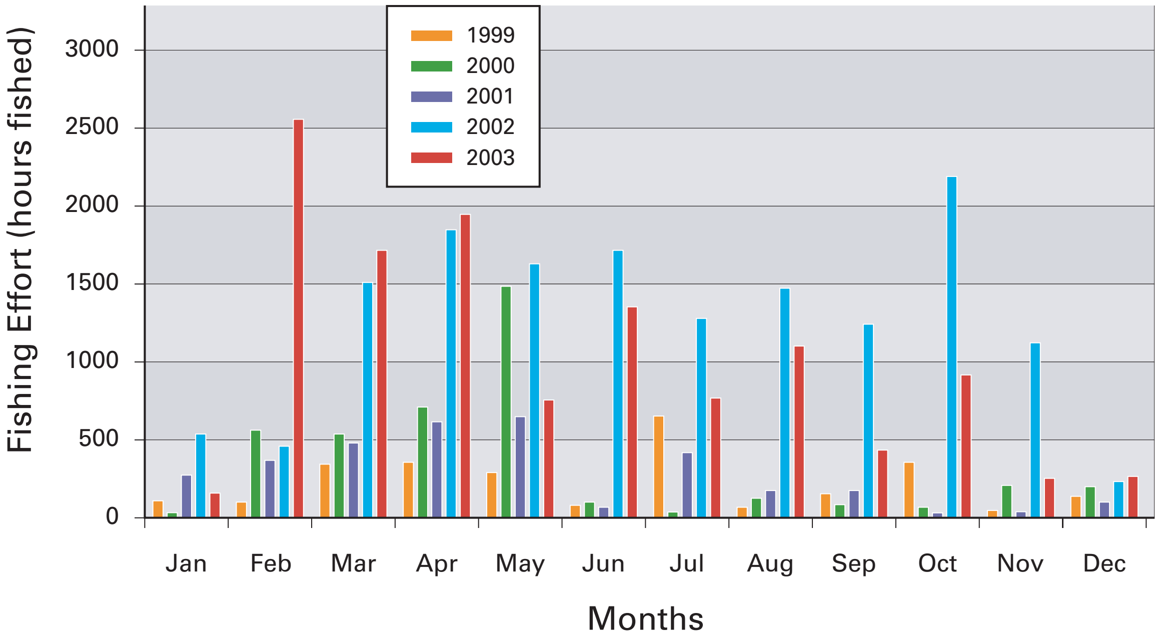


Figure 3.3a: Monthly fishing effort for ICES rectangle 51F1 for 1999-2003 (Ref. 3.1).

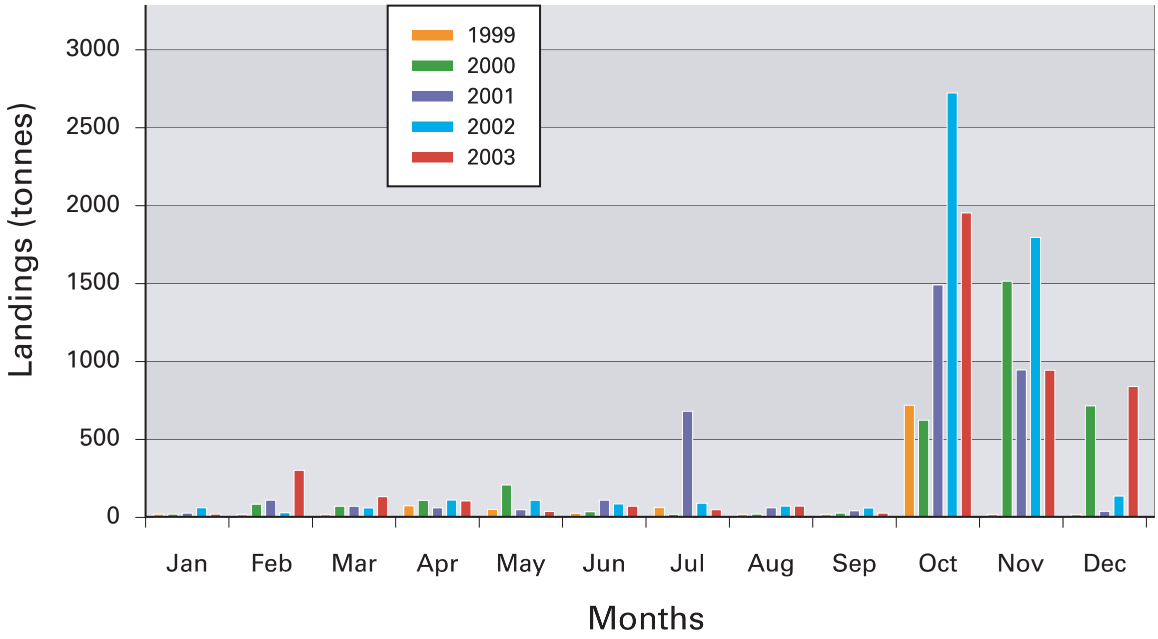


Figure 3.3b: Monthly fish landing for ICES rectangle 51F1 for 1999-2003 (Ref. 3.1).

3.5.2 Commercial Activities

The locations of adjacent oil and gas facilities are shown in Figure 3.2. With the exception of fishing and shipping, there are no other known commercial activities in this area of the North Sea. There are five shipping lanes within 20km of the North West Hutton platform (Ref. 3.3), used by a total of some 1,800 vessels each year. Most of this traffic is associated with the offshore oil and gas industry, and includes shuttle tankers and supply boats. The Ministry of Defence (MOD) does not use the area around the platform for routine military training or testing. There are no subsea telecommunications or power cables within the area of the platform. One non-dangerous shipwreck has been charted by the UK Hydrographic Office, 19km to the southwest of the platform.

3.6 Ecology

3.6.1 Plankton and Primary Production

Plankton, the microscopic plants (phytoplankton) and animals (zooplankton) that drift with the currents of the sea are the essential foundations of the marine food web. Phytoplankton are found in the depth range 0-30m and produce energy by photosynthesis, whereas the zooplankton that graze upon them may be found throughout the water column.

The North Sea has a rich and diverse planktonic community. The abundance of planktonic organisms varies throughout the year, with a major peak in the spring and a secondary peak in autumn, both of which are associated with changes in the concentrations of nutrients in the water column.

The planktonic populations found in the area around North West Hutton are typical of those found in temperate areas of the continental shelf. In addition, however, they exhibit an input from oceanic populations that have been carried around the north of Scotland in the North Atlantic Drift (Ref. 3.4).

3.6.2 Seabed Communities

Seabed communities in the North West Hutton field have been surveyed several times during the operational life of the platform, principally to assess the impact of the permitted discharge of drill cuttings. As a result, the original condition of the seabed at the site, the localised effect that the discharge of cuttings has had, and the extent to which the seabed may be recovering now that the discharge of cuttings has ceased, are all well understood (Refs. 3.5 and 3.6).

The seabed sediments range in size from silts to fine sand. These fine-grained deposits are typical of large areas of the deep water of the east Shetland Basin where the bottom currents are weak and the effect of surface wave action reduced.

The extent of the drill cuttings pile can be determined by examining changes in the grain size of the sediments, and increases in the concentrations of certain contaminants associated with drilling fluids and cuttings. Beyond the edge of the drill cuttings pile, the natural seabed communities are dominated by species such as polychaete worms and snails, which burrow into soft sediments. These communities are described as very diverse, because they are composed of a large number of different species, and in any given area of seabed there may be about the same numbers of individuals in each of the species groups present. Within the zone of influence of the cuttings pile the diversity of seabed community decreases, because some of the species are less able to tolerate the elevated concentrations of hydrocarbons than others. Conversely, some species thrive because they are more tolerant, and the number of individuals increases because there is less competition.

3.6.3 Fish and Shellfish

The North Sea has a wide variety of fish that live on or close to the seabed (demersal species) or in the water column (pelagic species). Many of these are the target of commercial fishing operations and the subject of international control and quotas. Adult fish of both pelagic and demersal species are widely distributed over large areas of the North Sea, and may move considerable distances in search of food or during migrations.

The main areas in which certain species tend to spawn, or which are used as nursery areas by juveniles, are often more clearly definable than the ranges of the adults, and may be more vulnerable to localised impacts. Table 3.3 indicates the main spawning and nursery seasons for some important species in the vicinity of North West Hutton. As a result of this, wherever possible, decommissioning work will be undertaken outside the peak spawning months of February and March.

Shellfish, including crabs, lobsters and prawns, may be found on a range of both hard and soft sediments on the seabed. The shellfish communities around North West Hutton are neither abundant nor of high commercial value.

SPECIES	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Cod	S	S	S	S								
	Have localised spawning areas across the North Sea, one of which coincides with the North West Hutton area.											
Haddock	N	S/N	S/N	S/N	S/N	N	N	N	N	N	N	N
	Both nursery and spawning areas are widespread across the northern North Sea and overlap the North West Hutton area.											
Saithe	S	S	S	S								
	Spawning areas are widespread across the northern North Sea and cover the North West Hutton area.											
Norway Pout	S/N	S/N	S/N	S/N	N	N	N	N	N	N	N	N
	Both nursery and spawning areas are widely distributed over the northern North Sea and Atlantic Shelf off Shetland, with high concentrations occurring in the north West Hutton area.											
Mackerel	N	N	N	N	N	N	N	N	N	N	N	N
	Have widespread nursery grounds over the North Sea and the Atlantic Shelf, which coincide with the North West Hutton area.											
Blue whiting	N	N	N	N	N	N	N	N	N	N	N	N
	Have nursery grounds that cover large areas of the northern North Sea and deeper water west of Shetland. These nursery areas overlap the North West Hutton area.											

Key: **S = Spawning** **N = Nursery**

Table 3.3: Common species of fish and their spawning areas in the North West Hutton area (Ref.3.1).

3.6.4 Marine Mammals

The term "marine mammal" refers to two main groups of mammal found at sea, the cetaceans (whales, dolphins, porpoises) and the pinnipeds (seals). Many of the species in these groups travel widely in the world's oceans in search of prey, or when moving between feeding and breeding grounds. It has been estimated that 22 species of cetaceans are either resident in, or pass through, UK offshore waters (Ref. 3.7). Large numbers of cetaceans are found in the North Sea and on the Atlantic Shelf, and the geographical distribution of any single species is rarely restricted to just one area.

Cetacean sightings are relatively common in the coastal and offshore waters north-east of the Shetland Islands (Table 3.4). Species regularly seen in this area include the fin whale, minke whale, killer whale, harbour porpoise, white-beaked dolphin and white-sided dolphin (Ref. 3.7). All of these species are common and widely distributed in the northern North Sea, particularly during late summer and early autumn (Table 3.4).

SPECIES	Seasonal Occurrence of Cetaceans											
Minke Whale	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	Regularly sighted around the Hebrides and northern north Sea, with a preference for coastal waters of less than 200m depth.											
Killer Whale	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	Widely distributed with sightings in both inshore waters and the deeper continental shelf.											
Harbour Porpoise	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	Distributed throughout the northern and central North Sea, and occur in the local North West Hutton area in July.											
White-sided Dolphin	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	Commonly sighted over the continental Shelf, slope and deeper waters of the northern north Sea.											
White-beaked Dolphin	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	Widespread throughout the North Sea with sightings within inshore waters around Shetland, and the continental shelf to the north of Shetland.											

Key: Occurrence	Not recorded	Peak months

Table 3.4: Distribution and occurrences of cetaceans in the northern North Sea (Ref. 3.1).

In the North Sea the pinnipeds are represented by the grey and the common seals, both of which are resident in UK waters; approximately 22% of the total UK population of common seal is found along the coastline of the Shetland Islands. Both species undertake regular feeding excursions, perhaps travelling as much as 40km over a period of 2-3 days; they usually return to their original haul-out sites onshore (Ref. 3.8). Little is known about any possible long-distance movements of either species, but it is unlikely that significant numbers of seals would be found in the vicinity of North West Hutton, 126km from the nearest coast.

3.6.5 Seabirds

Many areas and sites in the North Sea and on the adjacent coastlines are of international importance for a variety of seabirds. The different types of coastal habitat provide nesting sites for many species, and the rich inshore and offshore waters are used as feeding grounds. Of particular value and conservation importance are the coastline of the Shetland Islands, which offers an abundance of safe nesting sites, and the offshore waters of the East Shetland Basin, which yield a rich supply of food for birds foraging from those sites.

Fulmar, kittiwake, guillemot, puffin, gannet and razorbill are all found at North West Hutton throughout the year, and the most abundant species is the fulmar. The number of seabirds found in the vicinity of the platform decreases during the breeding season (May to June) when large numbers of birds return to their coastal breeding colonies.

Because possible oil pollution poses a particular risk to seabirds, an 'offshore vulnerability index' has been compiled to highlight the locations and seasons in which different species may be more or less vulnerable to pollution (Ref. 3.9). The index takes into account a number of factors such as the overall size of the population, its geographic distribution, and its ability to recover from local mortality. Figures 3.4a and 3.4b show the monthly seabird vulnerability index for North West Hutton and the surrounding area. Seabird vulnerability at North West Hutton is "very high" in July, when large numbers of guillemots, razorbills and puffins become temporarily flightless during their annual moult, and are therefore confined to the water surface. Vulnerability remains high in the autumn, as birds move back offshore from their coastal nesting sites (Ref. 3.1).

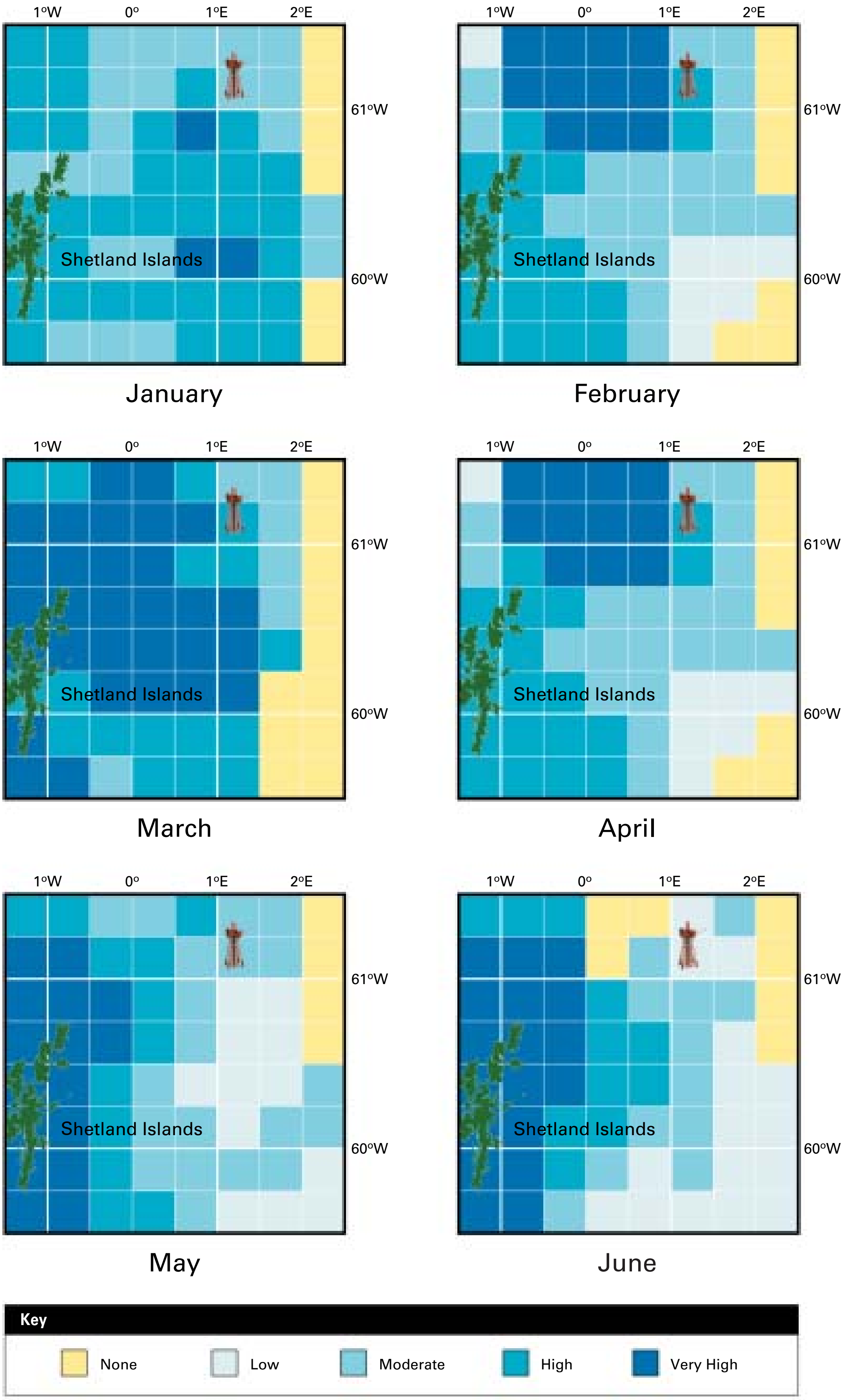


Figure 3.4a: Offshore vulnerability index for seabirds for January to June (Ref 3.1).

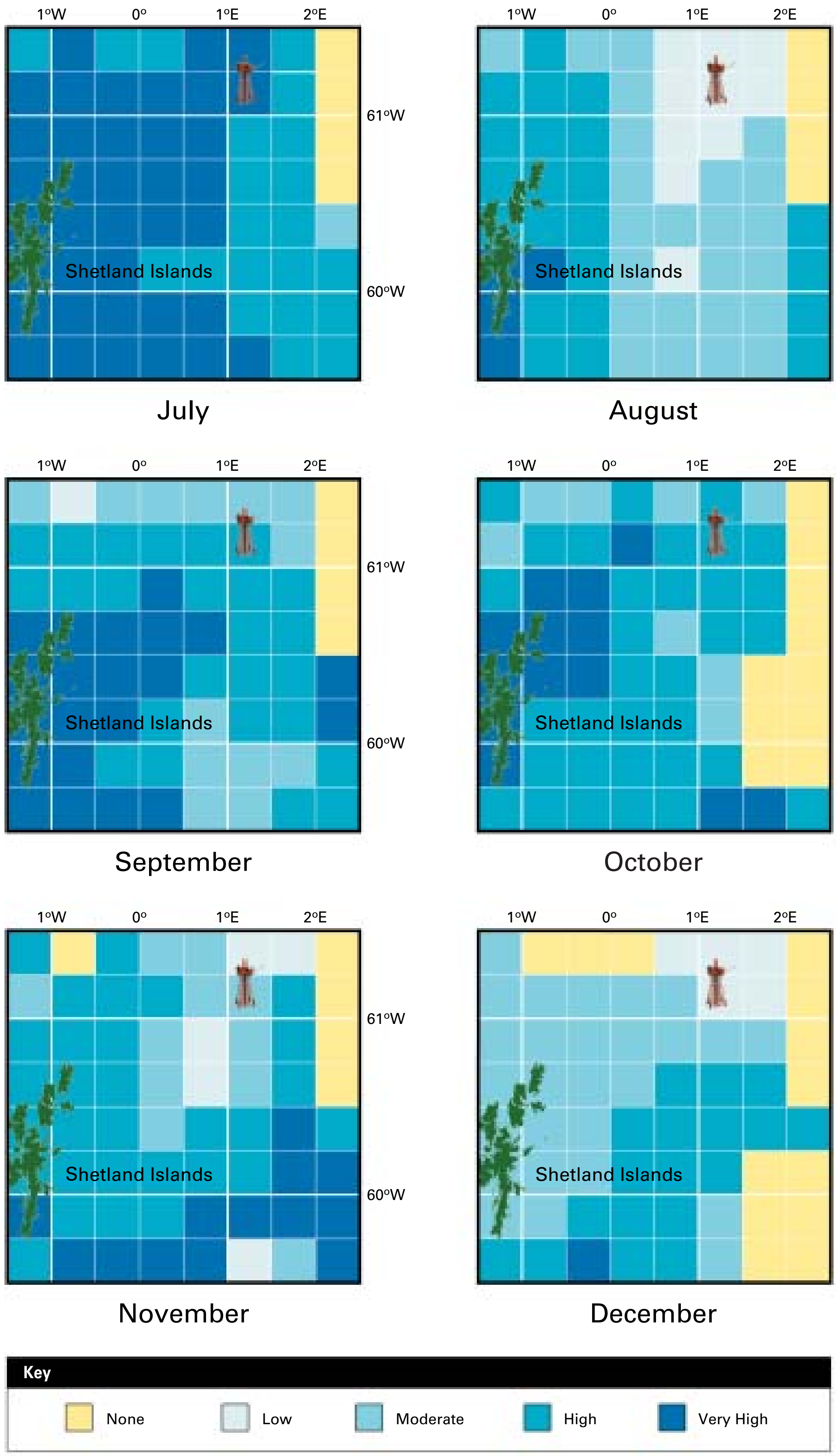


Figure 3.4b: Offshore vulnerability index for seabirds for July to December (Ref 3.1).

3.7 Conservation Status

3.7.1 Introduction

EC Directive 92/43/EEC (Ref. 3.10) on the Conservation of Natural Habitats and of Wild Flora and Fauna (the "Habitats Directive") and EC Directive 79/409/EEC (Ref. 3.11) on the Conservation of Wild Birds (the "Birds Directive"), are the main instruments of the European Union for safeguarding biodiversity. Annexes I and II respectively of the Habitats Directive list certain habitat types and species that are in greatest need of conservation at a European level. The Directive requires the establishment of a European network of important high quality sites (Special Areas of Conservation [SAC]) that will make a significant contribution to conserving these habitats and species.

In the UK, the Habitats Directive was enacted by the Conservation (Natural Habitats etc.) Regulations 1994 (Ref.3.12) and applied to the land, and inshore waters including territorial waters out to 12 nautical miles. With the implementation of the Offshore Petroleum Activities (Conservation of Habitats) Regulations in 2001 (Ref.3.13), the Habitats Directive was extended to include all waters out to a limit of 200 miles. The UK government is presently identifying candidate SACs in UK offshore waters, and the four Annex I habitats currently under consideration are listed in Table 3.5, along with four Annex II species known to occur in the UKCS.

Annex I habitats	Annex II species
Sandbanks that are slightly covered by seawater all the time	Grey seal
Reefs	Common seal
Submarine structures made by naturally leaking gas	Bottlenose dolphin
Submerged or partially submerged caves	Harbour porpoise

Table 3.5: Four Annex I habitats being considered for SAC status, and the four Annex II species found in the UKCS (Ref. 3.5).

3.7.2 Annex I Habitats

There are no known naturally occurring Annex I habitats in the immediate vicinity of North West Hutton. The habitat "reefs" includes a group called 'biogenic reefs' which are extensive hard structures formed by the growth of either cold water corals such as Lophelia pertusa, or the colonial polychaete Sabellaria spinulosa. There are no such reefs on the seabed around North West Hutton, but there are numerous colonies of Lophelia growing on the platform legs. The distribution of this species on the platform was surveyed in 2002, and a total of 332 separate colonies were identified, ranging in diameter from 40-110cm (Ref 3.14). Most colonies were found on the deeper parts of the jacket, below 220ft.

The presence of Lophelia on North West Hutton is an interesting example of the general phenomenon of "opportunistic colonisation" or "marine fouling", where seaweeds, and animals such as mussels, anemones and soft corals, settle and grow on man-made structures at sea. In the 30 years since fixed platforms were first placed on the UKCS, much has been learned about the distribution, growth rates and succession of the fouling communities that become established offshore. For the drifting spores and larvae of marine plants and animals, platforms offer hard surfaces suitable for colonisation at distant offshore locations where the predominant seabed substratum may be soft sediment such as mud or silty sand. The colonies of Lophelia on North West Hutton are therefore of general scientific interest, but stakeholder consultation has indicated that these communities are not of conservation value because they are opportunistic settlements growing on an introduced surface that is not representative of the natural seabed in the area.

3.7.3 Annex II Species

At North West Hutton Annex II species which have been sighted include harbour porpoise, small numbers of which have been observed in July (Ref. 3.15) and the common seal. Although there are currently no proposed SACs for harbour porpoise in the UK, the Government is re-examining distribution data for this species in an attempt to find likely areas for SACs. Since harbour porpoise are generally more common in near-shore waters, SACs for this species are likely to be located close to the coast.

3.8 Onshore Sites for Dismantling and Treatment

It is a general requirement that all equipment decommissioned and removed from offshore installations is returned to shore for processing and reuse or disposal. No decision has yet been made about which sites or onshore facilities would be used to receive, treat and dispose of material brought back to shore from North West Hutton. For the purposes of preparing the Environmental Assessment, two existing industrial locations were selected as being representative of possible sites. Teesside, on the east coast of England, is an existing industrial location which has handled decommissioned structures. Stord, on the west coast of Norway, is located in a relatively un-developed, non-industrial setting, but nevertheless has been used for receiving and dismantling large platforms. Figure 3.5 shows the location of these two sites in relation to the North West Hutton platform.

There are no particular sensitivities within either site, but both are located close to areas recognised for their natural beauty and conservation value with respect to flora, fauna and amenity (Figures 3.6 and 3.7).

Figure 3.5: Location map of potential onshore disposal sites for North West Hutton (Ref 3.1).

Figure 3.6: Location map for Tees Estuary and conservation sites in the area (Ref 3.1).

Figure 3.7: Location map for Stord in Norway and conservation sites in the area and on route (Ref 3.1).

These summary descriptions have been included because it is important to gain a full understanding of the potential effects of the whole decommissioning programme, including the impacts of both offshore and onshore operations. The potential effects of transporting, handling, recycling and disposing of all material from the facilities will be assessed with the same care and attention as the offshore operations and onshore dismantling activity. The sites that might receive and treat these different types of material have not yet been selected, however, and it is not possible to give site-specific details of potential impacts in this programme.

The sites will be selected as part of the ongoing engineering and contractual activity and environmental considerations will be central in that selection process.

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4 DESCRIPTION OF ITEMS TO BE DECOMMISSIONED

4.1 Introduction

The structures and materials included in this decommissioning programme are:

- the North West Hutton platform, which comprises a steel support structure (the jacket), drilling template, and topsides;
- the 10” gas import pipeline from the Ninian tee (PL 147);
- the 20” oil export pipeline to Cormorant Alpha (PL 148);
- the drill cuttings pile on the seabed around the base of the jacket; and
- seabed debris and other items within the vicinity of the platform and pipelines.

This section presents a detailed description of the items to be decommissioned; their location in the North West Hutton field is shown in Figures 3.1 and 3.2 Section 3. Quantitative information about the different types of material contained in the items is presented in Section 5.

4.2 Description of the North West Hutton Platform

The North West Hutton platform is an integrated oil and gas drilling, production processing and accommodation facility. It was designed to access reserves of oil and gas, and process these fluids offshore so that they could be exported safely to land. The main components of the platform are shown in Figures 4.1 and 4.4. Information on the size and weight of components is summarised in Tables 4.1, 4.2 and 4.3.

4.2.1 Support Structures

The main support structure, or jacket, is an eight-legged structure, with vertical and horizontal bracing that provides its overall structural strength. The jacket was built onshore and the complete unit then transported to its present location by barge, launched, positioned over the drilling template, and fixed to the seabed using steel piles.

Each of the four main corner legs has five 60” diameter piles securing it to the seabed. The piles were installed by lowering them through a series of guides which are fixed to the jacket. At the base of the jacket the piles enter 35m long sleeves called pile-sleeves and are driven into the seabed. The pile sleeves are fixed to the lower part of each corner leg, and the connection between the piles and the sleeves is made by cementing (“grouting”) them in place. These legs and the associated piles and pile sleeves are referred to as “bottles”, and the section of the jacket from the seabed to the top of the bottles and piles, including all the bracing and other equipment, is referred to collectively as the “footings” (Figure 4.2). The footings is that section of the jacket below the highest point of the piles, which are approximately 40 metres above the seabed and the total weight, including piles and grout, is approximately 9,000 tonnes (Ref. 4.3).

Sacrificial anodes made from an alloy comprising mainly aluminium and zinc (Section 5), protect the jacket and other underwater steel components against corrosion.

A steel module support frame (MSF) is located on top of the jacket to support the footprint area of the topsides modules and transfer the topsides weight evenly into the jacket structure. This structure was installed separately and weighs approximately 1,430 tonnes (Ref. 4.2). Although effectively a part of the jacket structure, this weight is in addition to the quoted weight of the jacket.

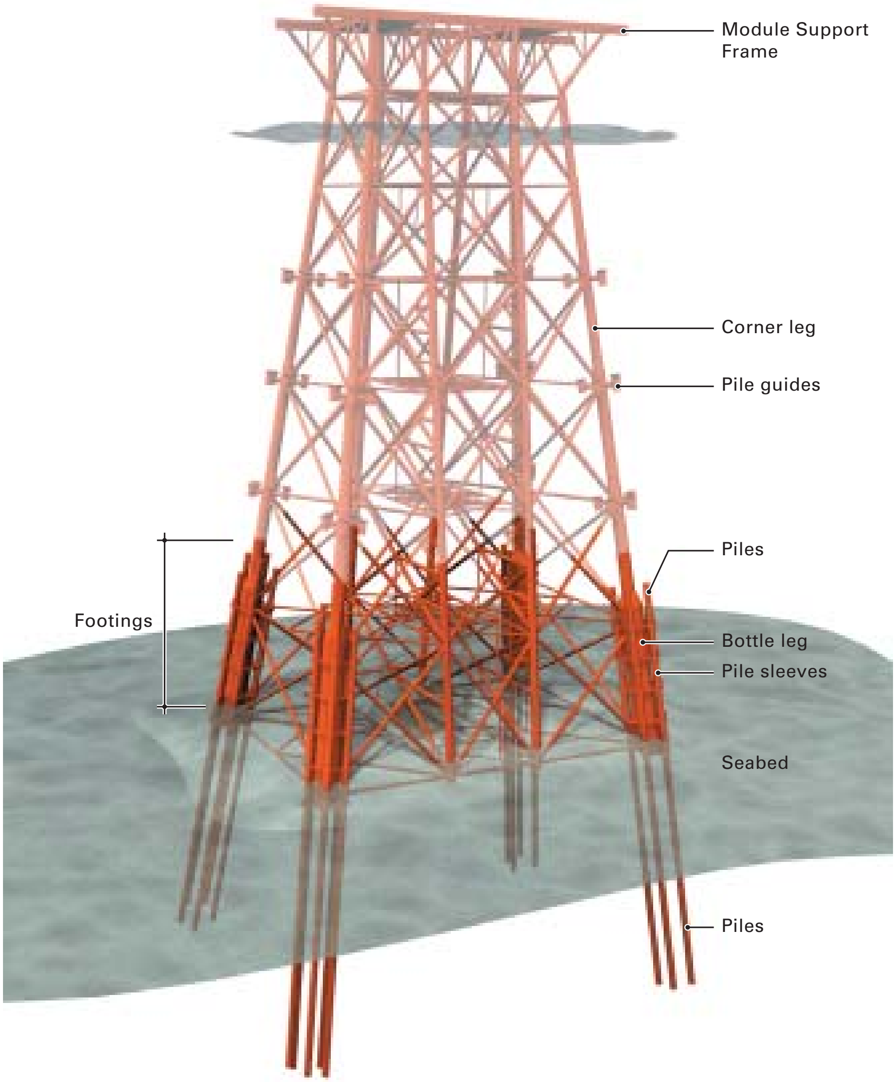

Figure 4.1: Computer graphic of the main components of the North West Hutton jacket.

Component	Number	Dimensions	Total Weight (tonnes)
Jacket	1	154m high **(1)**	14,070
Anodes	1,840	3.0m x 0.25m x 0.25m	800 **(6)**
Piles **(2)**	20	105.5m x 1.54m (60″dia)	2,600 **(3)**
J tubes	6	0.3m (12″) diameter	**(4)**
Risers	3	0.26m – 0.51m (10″ to 20″) diameter	**(4)**
Caissons **(5)**	12	0.26m – 0.9m (10″ to 36″) diameter	**(4)**
Total			**17,470**

Table 4.1: The size and weight of component parts of the North West Hutton jacket. All weights are tonnes dry weight in air (Ref.4.1).

Notes

1. The jacket comprises 2 rows of 4 legs. The base is 85.6 x 59.7m, tapering to 47.7 x 21.8m at the top.
2. There are five 60″ diameter piles at each corner, and they penetrate 55-62m into the seabed .
3. The total weight of piles is 5,200 tonnes. The weight secured to the jacket above the seabed is 2,600 tonnes, including 400 tonnes for grout.
4. These items are included in the jacket weight.
5. Details of the caissons are shown in Table 4.2.
6. Installed mass is 800 tonnes, estimated existing mass 400 tonnes (Ref. 4.5).

Description of Items to be Decommissioned

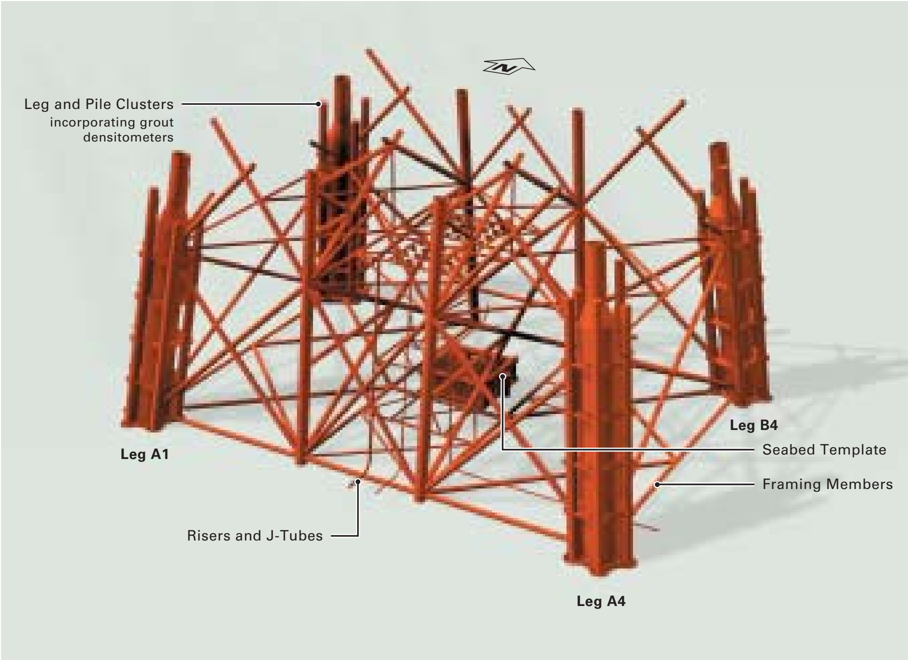

Figure 4.2: Computer graphic showing the make up of the North West Hutton jacket footings.

Number	Size	Function	Termination depth (1)
2	32″	Firewater lift	-17.6 and -16.2
3	36″	Seawater lift	-41m
1	75″	Potable water source	-37m
1	36″	Oil-based drill cuttings	-60m
1	18″	Cooling water disposal	+8m
1	36″	Production	-67m
2	14″	Water-based drill cuttings	+6m and +5m
1	75″	Produced water disposal	-15m

Table 4.2: Details of the caissons on North West Hutton (Ref. 4.6)

Notes

1. This is the depth relative to LAT.

Photographs courtesy of Charles Hodge, Lowestoft, Norfolk

Figure 4.3: Photographs showing the size and scale of the North West Hutton jacket.

4.2.2 Topsides

The platform topsides were assembled from a number of individual modules which were lifted into position by a large floating crane vessel once the jacket had been installed. These cranes are sometimes referred to as "heavy lift vessels" (HLV) or "semi-submersible crane vessels" (SSCV). Each module contains equipment to provide a specialised function such as oil separation, gas compression, drilling, or accommodation. The majority of each module was constructed onshore, and then all the necessary process, utility and electrical connections were completed in an intensive phase offshore known as "hook-up".

A total of 22 heavy lifts was required to construct the topsides (Ref. 4.4). The relative position of the modules is shown in Figure 4.4 and details of their function and dimensions are given in Table 4.3. In addition to the main modules, a significant number of other items necessary for safe and effective production operations are installed on the topsides, including a flare boom, cranes, two drilling derricks and exhaust towers.

The wells necessary for the production of oil were contained in a series of 40 pipes (referred to as conductors) that protected the wells from the seabed up to the platform at surface. These conductors, which have now been removed, were supported by six guide frames which are an integral part of the jacket.

The pipelines on the seabed are connected to the topsides by steel tubes called risers. Other steel pipes called caissons run from the topsides into the sea, and performed a number of functions including the lifting of seawater for process cooling, fire water, discharge of drill cuttings and other utility functions.

Photographs courtesy of Charles Hodge, Lowestoft, Norfolk

Photograph of North West Hutton topsides.

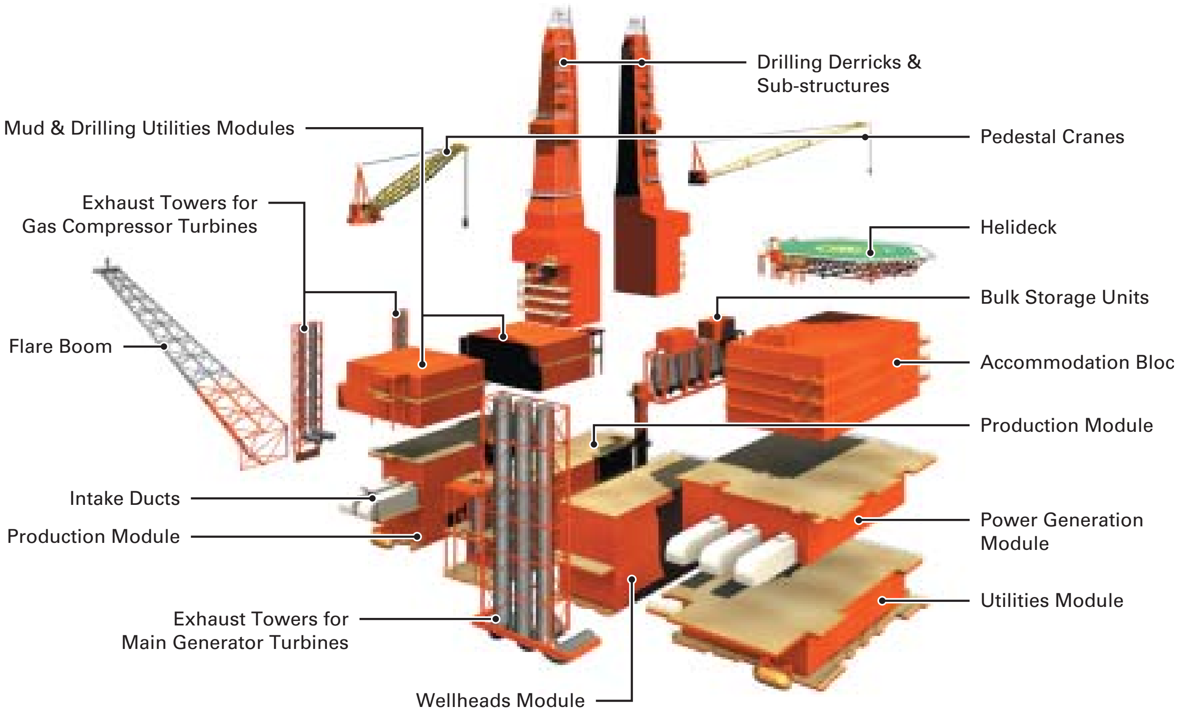

Figure 4.4: Computer generated diagram of the main components of the topsides on North West Hutton, showing the modular construction.

Module Reference	Description	Dimensions (metres-lxbxh)	Weight
M1	Power generation module	60 x 26 x 9	2,660
M2	Utilities module	45 x 26 x 9	2,000
M3	Wellheads module	45 x 15 x 20	1,830
M4	Production modules (two)	61 x 14 x 20	2,540
M5			2,780
MM1	Mud and drilling utilities modules (two)	25 x 21 x 10	1,420
MM2			1,350
LQ	Accommodation and recreation module	45 x 20 x16	1,860
H	Helideck	35 x 30 x 4	300
SS1	Derrick sub-structures (two)	19 x 22 x 26	990
SS2			1,000
Flare	Flare boom	85 x 6 x 5	**(1)**
DD1	Drilling derricks (two)	9 x 8 x 39	**(1)**
DD1			
ET S/E	Exhaust tower for main compressor turbines	8 x 4 x 35	**(1)**
ET S/W	Exhaust tower for sales gas compressor turbines	4 x 2 x 24	**(1)**
ET M1	Exhaust tower for main generator turbines	14 x 5 x 33	17
BS1	Bulk storage units (two)	16 x 5 x 15	**(1)**
BS2			
CPE	Pedestal cranes (two)	8 x 4 x 50	**(1)**
CPW			
T101/202	Intake ducts for main compressor turbines	16 x 4 x 5	**(1)**
MSF	Module support frame	78 x 22 x 15	1,430
Total estimated dry weight of topsides			**20,160**

Table 4.3: The size and weight of component parts of the North West Hutton topsides. All weights are tonnes dry weight in air (Ref. 4.2).

Notes

1. The weight of this component is included in the weight given for the associated main module (Figure 4.4).

4.3 Description of the North West Hutton Drilling Template and Wells

A 20 slot drilling template (Ref. 4.1) was installed on the seabed and 7 wells were drilled prior to the installation of the platform. This technique, known as pre-drilling, allows early start-up of production once the platform is commissioned. The template is of tubular steel construction 12.8m long, 12.2m wide and 3.7m high, and weighs 290 tonnes; it is fixed to the seabed by three 20" diameter piles each approximately 15m long (Figure 4.5). For all evaluation purposes in this decommissioning programme, the steel drilling template is considered to be an integral part of the jacket at the seabed level.

The North West Hutton platform was designed to accommodate a maximum of 40 wells at any one time (referred to as 40 "Slots"). A total of 53 operational wells (including new wells and sidetracks) were drilled into the reservoir over the life of the field; the last well was drilled in 1992 (Ref. 4.7). The wells were drilled using a technique known as "directional drilling", which enabled the entire reservoir to be accessed from the platform. There are therefore no subsea wells or subsea production facilities associated with the North West Hutton development.

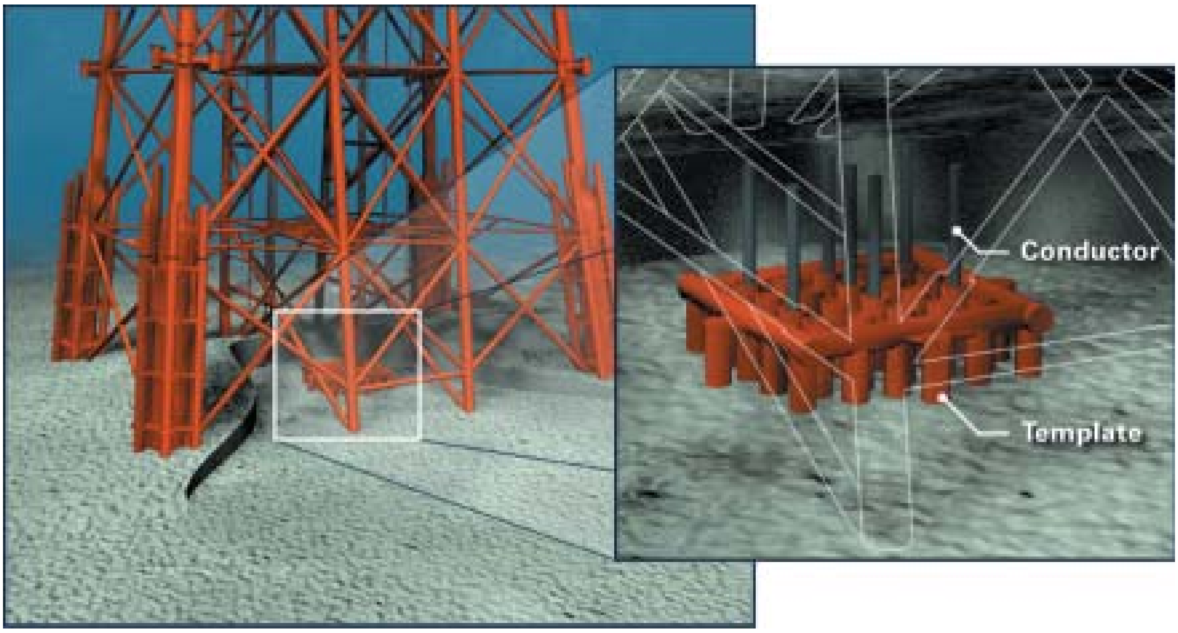

Figure 4.5: Computer generated diagrams illustrating the design of the North West Hutton drilling template.

The wells at North West Hutton are constructed from concentric steel pipes cemented into the wellbore. The oil and gas from the reservoir were transported safely to the platform for processing by means of steel pipes known as "production tubing". In the zone from the seabed to platform the production tubing is housed inside the conductor pipes, to give it additional protection.

4.4 Description of the North West Hutton Pipelines

There are three separate pipelines (Figure 4.6.) associated with North West Hutton, as follows:

PL 147 A 10" gas pipeline originally used for natural gas export to the FLAGS pipeline system, and latterly used to import gas for fuel purposes from the Ninian Field. A small section (120m long) of disused 10" pipeline at Welgas Tee is also included in this programme.

PL 148 A 20" pipeline used to export crude oil from the North West Hutton platform to the Cormorant Alpha platform.

PL 175 A 12" crude oil pipeline used to import oil from the nearby Hutton TLP for onward transportation via PL 148. The Hutton field has been decommissioned, and this pipeline has been disconnected from North West Hutton at the subsea spool piece.

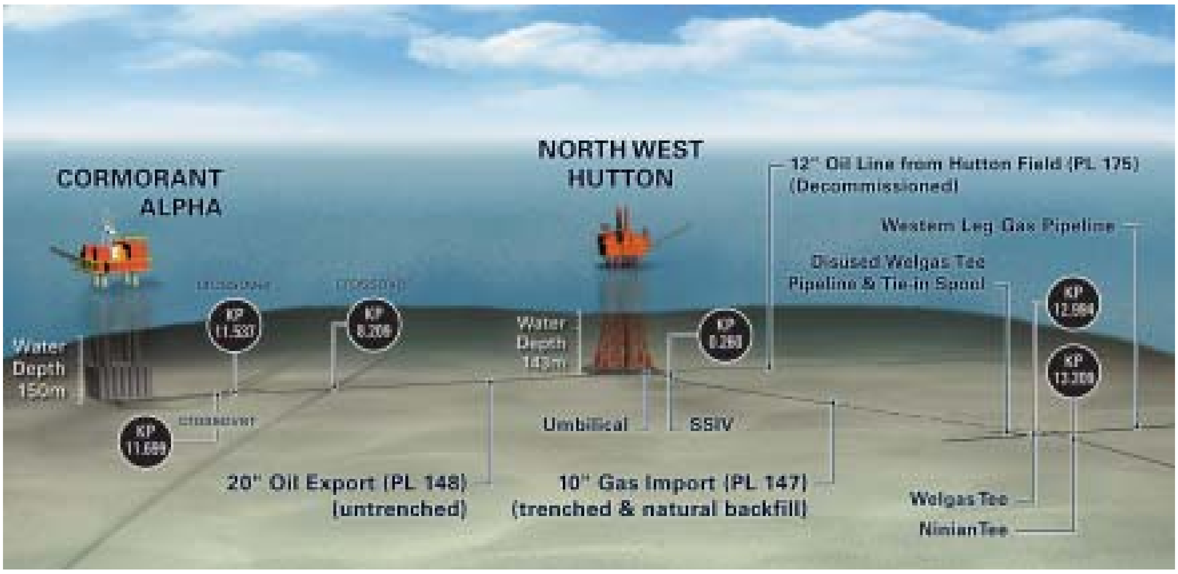

Figure 4.6: Layout of pipelines in the North West Hutton field.

The pipeline PL 175, riser and spool piece are owned by the Hutton field partners and its decommissioning was approved under the Hutton Decommissioning Programme (Ref. 4.13).

It has been agreed that the decommissioning of the PL 175 riser and subsea spool piece at North West Hutton will be carried out by the North West Hutton owners on behalf of the Hutton owners under the terms of the *'Agreement Relating to the Offtake of Crude Oil from the Hutton and North West Hutton'* (Ref. 4.11), along with the North West Hutton facilities. The risers on North West Hutton associated with PL 147, PL 148 and PL 175 will be decommissioned along with the topsides and support structures. The spool pieces will be left in place because they are buried and any exposed ends will be protected. If any section of the jacket is left on the seabed then any corresponding section of the risers will remain attached to the jacket.

The riser associated with PL 148 on Cormorant Alpha will be disconnected and isolated with blind flanges at the topsides and the bottom of the riser. The riser will be filled with inhibited seawater and monitored to ensure its integrity, and will be decommissioned along with Cormorant Alpha topsides and structures, as it is part of the Brent System and is owned by the Brent owners (Figure 10.8 Section 10).

4.4.1 10" Natural Gas Export / Import Pipeline (PL 147)

The gas pipeline (Figure 4.7) was originally used to export gas to the FLAGS natural gas transportation system. In 1994, it was disconnected from the FLAGS system and connected to the Ninian field gas export line, so that North West Hutton could import gas for use as fuel. As part of this switch in duty of the pipeline, a 260m section of pipeline was disconnected, made safe and left on the seabed near the original tie-in point of the Western Leg Gas Pipeline (Cormorant A to Brent). This disused section of line and the associated protective equipment is included in the evaluation of the overall decommissioning programme for North West Hutton.

The existing pipeline is constructed from steel with an external protective coating of coal tar epoxy and concrete, and is protected against corrosion by the use of sacrificial anodes (Ref. 4.8). A 250m long section of 6" diameter flexible, composite pipeline was used to make the connection to the Ninian gas system. At a distance of about 260m from the North West Hutton platform a sub-sea isolation valve (SSIV) is incorporated in the line together with an umbilical that allows the valve to be controlled from the platform. The SSIV was installed as a safety feature to enable the gas from the pipeline to be shut off in an emergency.

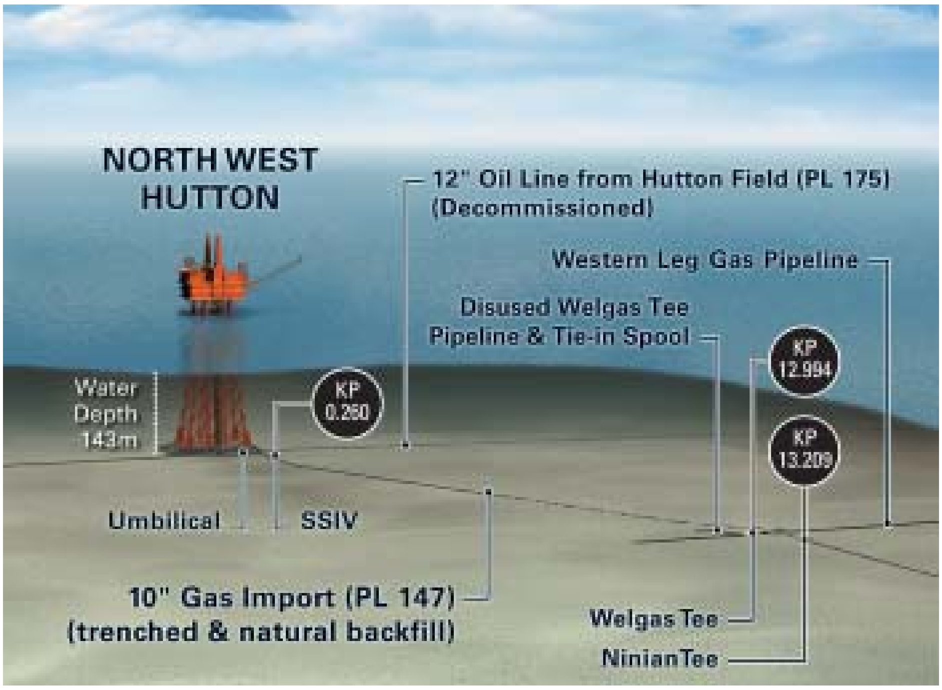

Figure 4.7: North West Hutton 10” gas pipeline PL 147.

The pipeline was trenched to a depth of 0.45m below the seabed at the time of installation. The line is currently buried along approximately 73% of its length (Ref. 4.8) by rock positioned to protect it and also by natural backfilling of the trench with seabed sediments. The only areas currently lying proud of the seabed are the connections to the SSIV, the SSIV itself and the flexible section used for the tie-in to the Ninian pipeline.

The pipeline crosses one other pipeline, the Western Leg Gas Pipeline (Cormorant A to Brent) and this crossing is supported and protected by concrete structures known as mattresses.

The pipeline and associated equipment on the seabed have been regularly inspected and fully maintained since installation.

A schematic of the gas pipeline PL 147 is shown in Figure 4.7, and the main components of the pipeline are listed in Table 4.4.

4.4.2 20” Oil Pipeline (PL 148)

The 20”oil pipeline (Figure 4.8) was used to export oil and natural gas liquid (NGL) from the North West Hutton field and the nearby Hutton field to Cormorant Alpha. From Cormorant Alpha the oil was exported via the Brent system to Sullom Voe in the Shetland Islands.

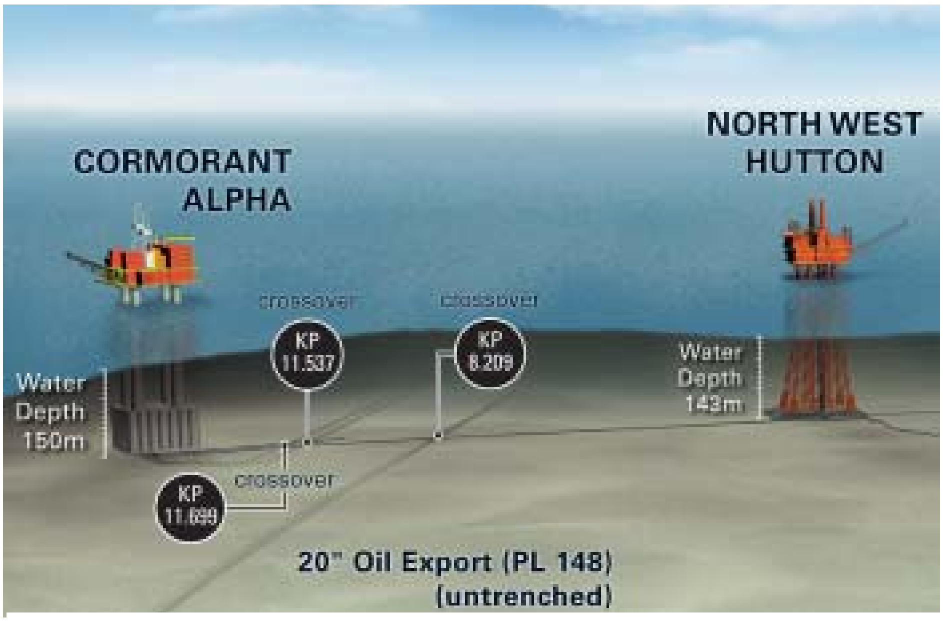

Figure 4.8: North West Hutton 20" oil pipeline PL148.

The pipeline is constructed of steel with a coal tar and concrete coating, in a similar manner to the gas pipeline (Ref. 4.8). Sacrificial anodes are located along the length of the pipeline to provide protection against corrosion.

The oil pipeline has not been trenched and lies on the seabed. It crosses three other lines listed below and these crossings are protected with concrete mattresses.

- KP 11.699 – Flow line P1
- KP 11.537 – P1 Control Line
- KP 8.209 – 10" Western Leg Gas Pipeline

A schematic of the oil pipeline PL148 is shown in Figure 4.8, and the main components of the pipeline are listed in Table 4.4.

The pipeline and associated equipment have been regularly inspected and fully maintained since installation (Ref. 4.8).

Table 4.4 gives further information on the pipelines, SSIV and control umbilical and the concrete mattresses that are used to protect some parts of these lines.

	Pipelines					
		Gas Import (PL147)				
Aspect	**Oil Export (PL148)**	**Steel**	**Flexible**	**Disused Wellgas Tee Section**	**SSIV Skid**	**Control Umbilical**
Status	Not trenched	Trenched to 0.45m **(1)**	Not trenched	Trenched to 0.45m	In shallow trench **(3)**	Resting on seabed **(2)**
Diameter	20"	10"	6"	10"		
Length	12.85 km	12.9 km	250.4 m	120m	16.0m x 3.8m x 2.5m	400m
Material	Carbon Steel **(4)**	Carbon Steel **(4)**	Composite steel / synthetic	Carbon Steel **(4)**	Steel / Grout filled tubulars	Plastic and Steel
Weighting/ Protection	45mm reinforced Concrete	45mm Reinforced Concrete		45mm Concrete Weight Coat	**N/A**	**N/A**
Weight	5,300 tonnes	2,400 tonnes	12 tonnes	20 tonnes	90 tonnes	10 tonnes
Anodes	Yes	Yes		Yes		
Mattresses	300 tonnes	None	430 **(5)**	100 tonnes **(7)**	None **(6)**	230
Bridge/ Crossing	Minor (5m) Rock Dump at Crossing to Wellgas Leg	None	419 **(5)**	None	None	None

Table 4.4: Summary of pipeline equipment.

Notes

1. Nominally, there is 0.2 to 0.45m of coverage (soil, rock) above the gas pipe line, which is covered for 73% of its length.
2. The whole length of the umbilical is protected by 63 concrete mattresses weighing a total of approximately 230 tonnes.
3. The SSIV skid rests in the gas import trench, which is nominally 0.45m deep.
4. The steel pipe is protected against corrosion by a 5mm thick coal tar epoxy coating and aluminum bracelet anodes – 211 on the oil pipeline – 212 on the gas pipeline.
5. The whole length of the flexible is protected by 30 mattresses weighing approximately 430 tonnes in total and some areas are supported by bridges and crossings which have a total weight of approximately 419 tonnes.
6. There are no mattresses but a few sand bags.
7. The length of the pipeline section is protected by 14 flexible mattresses, weighing approximately 100 tonnes in total.

N/A = Not applicable.

4.5 Description of the North West Hutton Drill Cuttings Pile

The drill cuttings pile is an accumulation on the seabed around the base of the jacket that consists predominantly of rock "cuttings" from the drilling operations. When wells are drilled a fluid, referred to as "mud", is circulated into the well to control pressure and remove the small pieces of rock generated by the drilling operation. During the period of development drilling on North West Hutton between 1982 and 1992, the approved disposal method for these cuttings was to discharge them onto the seabed after cleaning.

It is estimated from drilling records that approximately 28,000m^3 (Ref 4.12) of cuttings were discharged at North West Hutton prior to the cessation of drilling in 1992. The cuttings were discharged through a caisson at a depth of -60m below sea level for oil-based mud cuttings and +6.0m for water-based mud cuttings. The relatively low current speeds in the area resulted in the cuttings forming a pile on the seabed around the base of the platform. The pile presently has a maximum depth of 5.5m in the centre and quickly thins to around 3m and then thins gradually to approximately 1.5m (Ref. 4.10) just beyond the perimeter of the jacket legs. The pile is elliptical in shape and orientated along a NE/SW axis as a result of the influence of the prevailing currents in the area. Figure 4.9 shows the latest side-scan sonar image of the cuttings pile at North West Hutton.

Prior to discharge, the cuttings were cleaned to remove excess drilling mud. Because of the nature of the rock and the drilling mud, a small amount of residual mud remained coating the rock and as a result was incorporated in the cuttings pile.

The muds used at North West Hutton contained a number of constituents to provide the necessary properties for use in drilling, such as density and viscosity. Approximately 32% of the mud used on North West Hutton was water-based, and 68% oil-based. The oil-based mud comprised predominantly an oil/water emulsion, with barite as a weighting agent. The type of oil used in the mud changed as suppliers developed their products. Barite, the weighting agent, is an inert, naturally-occurring mineral. Other chemicals were used in relatively small quantities during the drilling operations. During drilling operations, a close control is kept on the volumes and constituents of the drilling mud system. Additional information on the contents of the drill cuttings pile is provided in Section 5.

Parameter	Value
Physical data	
Area of seabed covered	23, 750 m^2 (Ref. 4.9)
Density of material in pile	1.67 kg/m^3 (average bulk density)
Volume of pile	30, 000m^3 (Includes cuttings material and seawater)
% of pile – rock	48
% of pile- water	45
% of pile - oil and trace contaminants	7

Table 4.5: Description of the drilling cuttings pile at North West Hutton (Ref. 4.10).

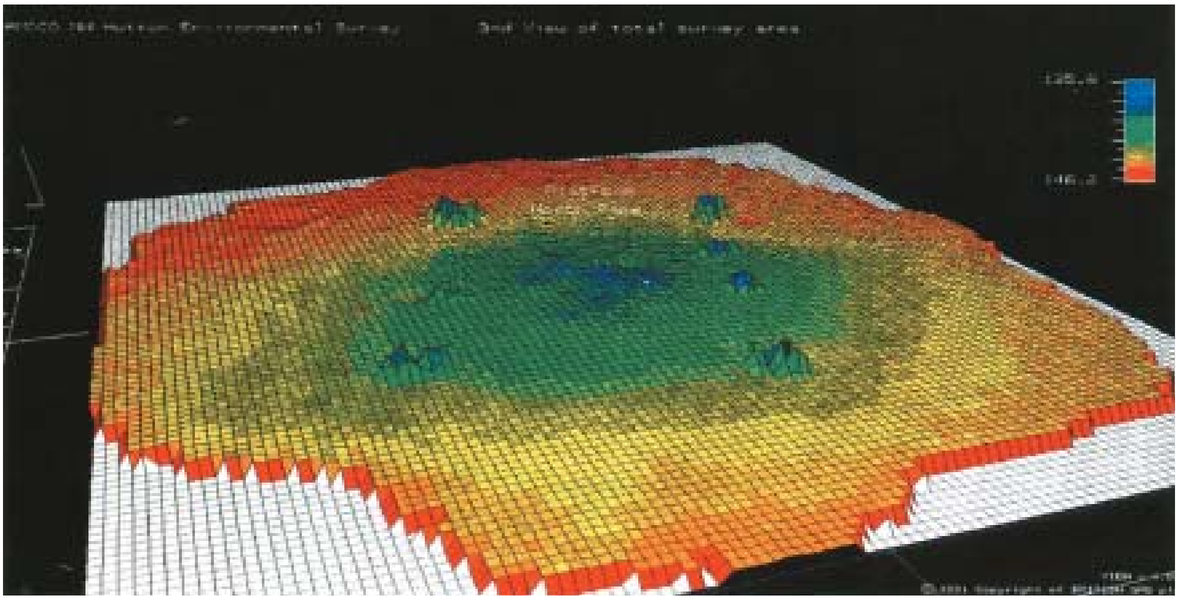

Figure 4.9: Side-scan sonar image - Brown and Root Survey (1992) of the North West Hutton drill cuttings pile (Ref. 4.10).

4.6 Debris and Other Material

The cuttings pile directly beneath the platform contains items and material inadvertently lost from the platform, or from ROVs and divers working subsea. This includes cement, scaffold poles, gratings, tools and welding rods.

The most recent survey of the natural seabed in the immediate vicinity of the platform shows the presence of a small number of items which have accumulated over the life of the platform.

The jacket was damaged during installation as the result of a severe storm. This damage included areas around the pile sleeves and pile grouting system. As a result, a total of about 100 tonnes of grout was spilled onto the seabed around the four main legs, particularly at leg B1.

An inspection survey of the routes of PL 147 and PL 148, carried out in 2001, showed that there were relatively minor amounts of debris along these pipelines.

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4.4 HEEREMA Marine Contractors, North West Hutton, Platform Removal Feasibility Study, Document No. E/1018 (2205), Rev 2, 29th October 1999.

4.5 "Report TEC 01", CORRPRO Companies Europe Ltd, North West Hutton, Life Assessment of Jacket Footings, 19th September 2003.

4.6 WS Atkins Oil and Gas, North West Hutton, Appurtenance Arrangement (Sheet 4 of 5), Drawing No. NWH-APD4, dated January 1999.

4.7 North West Hutton Cessation of Production Application, Rev. 4, July 1999.

4.8 "Report TEC 14–18", JP Kenny, North West Hutton, Pipeline Decommissioning – Technical Summary Report, Rev 03, 21st November 2003.

4.9 "Report TEC 11/12", Technical Review of the Options of Covering, Relocation, CAD, and Recovery for Onshore Treatment of the North West Hutton Drill Cuttings Pile, Report 296.UK.0303.1 (Rev.0), June 2003.

4.10 Brown and Root Survey (1992), North West Hutton Drill Cuttings Report, Document No. M70381(0753R) 160293, Rev 1,16th February 1993.

4.11 Agreement Relating the Offtake of the Crude Oil from the Hutton and North West Hutton Fields. Conformed copy including Amendments Effected by Amendments No. 1, 11th October 1984.

4.12 "Report ENV 08", BMT Cordah Ltd, Long-term Trends in Seabed Disturbance Around the North West Hutton Platform, Document No. BPX54/NWH/04, 2004.

4.13 Kerr McGee, 2002, Hutton Field De-commissioning Programme.

5 INVENTORY OF MATERIALS

5.1 Introduction

This section gives information on the materials that will be present on or in the facilities at the time of decommissioning.

A comprehensive materials inventory for the platform is available from detailed and up-to-date records maintained for operational, safety and environmental reasons. The weights of structural material have been derived or estimated from the "as built" drawings or original materials specifications, taking account of subsequent major modifications. Weights and volumes of movable items (including fluids) are obtained from the shipment records of material received by, and shipped from, the platform. In addition, the records have been cross-checked and supplemented by specific surveys implemented in preparation for the forthcoming decommissioning activity.

Following cessation of production the wells were isolated, the conductors removed and the platform was cleaned in preparation for decommissioning.

The inventories for the facilities are presented in a sequence, from topsides to drill cuttings pile in the following sections.

5.2 Topsides

Table 5.1 presents an inventory of the material in the topsides modules and all associated equipment described in Section 4.2.2. Table 5.2 show an estimate of all residual material that will be present in the topsides at the time of removal and will therefore need to be dealt with at the onshore location. The inventories are based on databases of the platform plus specific inventories prepared by specialist companies. The residual wastes in Table 5.2 were compiled from an offshore independent residual waste survey (Ref 5.2). The estimate for Low Specific Activity (LSA) material was calculated following a programme of monitoring, sampling and analysis, the results from which were extrapolated throughout the plant in areas where LSA could potentially occur.

Material	Weight (tonnes)
Alloy Steel	131
Aluminium	21
Carbon Steel in Equipment	7,284
Cement	60
Copper	138
Glass Reinforced Plastic (GRP)	25
Iron	15
Poly Vinyl Chloride (PVC)	214
Stainless Steel	7
Structural and other steel	12,382
Others materials **(1)**	14
Total (2)	**20,291**

Table 5.1: Estimated weights of material comprising the North West Hutton topsides (Ref. 5.1).

Notes:

1. Other materials, includes non-ferrous metals, plastics, and rubber.
2. This value is within 1% of the weight of 20,160 tonnes quoted in Table 4.3, which is accurate for engineering estimates.

Waste	Location	Estimated Weight (tonnes)
Residual hydrocarbon Sludge **(1)**	Oil production and separation system	21
Production chemicals	Tanks/pumps	0.6
Drilling chemicals	Tanks/pumps	9.3
LSA scale **(2)**	Pipework	4.9
Diesel oil	Tanks/pumps	0.1
Heating medium	Tanks/pumps	0.5
Hydraulic oil	Tanks/pumps	0.04
Lube oil	Tanks/pumps	1.3
Seal oil	Tanks/pumps	0.7
PCBs	Transformer and fluorescent lamp fittings	0.034
Mercury	Fluorescent tubes	0.00034
Asbestos	Modules	5.0

Table 5.2: Estimated quantities of residual materials on North West Hutton topsides after cleaning (Ref. 5.2).

Notes

1. This is the worst-case estimate of the quantity of hydrocarbon that will be present in the topsides. A range of estimates was calculated assuming a, 2mm and 5mm thickness of hydrocarbon / sludge residue in vessels and pipe work. Estimates ranged from 9.8 tonnes (for a 2mm thick layer) to 21 tonnes (for a 5mm thick layer) (Ref. 5.2).
2 This is the worst-case estimate for the quantity of LSA scale remaining in the topsides and is included in the residual hydrocarbons/ sludge total and has been calculated using the results of an offshore sampling and analysis programme. The results from this programme have been extrapolated to vessels and pipework where LSA scale could potentially be found. Estimates of the mass and total activity of the scale were made assuming that the layer of residual material was 1mm or 5mm thick. The estimated totals were 960kg and 2.2MBq (for a 1mm thick layer), and 4,900kg and13.9MBq (for a 5mm thick layer) (Ref. 5.2).

All of the waste is expected to fall within the limits of the Radioactive Substances (Phosphatic Substances Rare Earths etc.) Exemption (Scotland) Order of 1962, because all of the samples analysed from offshore were less than 14.8Bq per gram. However, the waste is still radioactive waste and BP will dispose of it according to our Duty of Care. BP will consult with the appropriate regulatory bodies on the transportation and disposal of items containing radioactive materials and wastes.

5.3 Support Structures

Table 5.3 presents an inventory of the materials in the support structures, including the jacket and the drilling template.

Item	Material	Weight (tonnes)
Jacket, caissons, risers and J-tubes	50D steel	14,070
Drilling template **(1)**	Steel	290
Piles **(2)**	50D steel	2,200
Anodes **(4)**	Impalloy Galvulum I **(3)**	400
Grout	Cement	400
Marine growth **(5)**	Organic plants and animals	600
Total estimated weight of support structure material		**17,960**

Table 5.3: Estimated weight of materials comprising the North West Hutton support structures (Ref. 5.3).

Notes

1 Weight of drilling template includes anodes, piles, grout and marine growth.
2. This represents the proportion of the total weight of the piles that will be removed once they have been severed at a depth of about 3m below the level of the seabed.
3. Impalloy Galvulum comprises 80% aluminium and 20% zinc.
4. It is estimated that the total weight of the anodes on North West Hutton is now 400 tonnes, as a result of the planned anode usage that has occurred since the platform was installed (Ref. 5.4). The installed weight was 800 tonnes.
5. Estimated fresh wet weight in air (Ref. 5.5).

5.3.1 Grout Densitometers

Grout densitometers are attached to the five pile sleeves on the bottle legs near the underside of the pile guide frame at a depth of approximately 115m. There are 20 densitometers each with two Caesium 137 sources i.e. 40 sources in total. The Scottish Environment Protection Agency (SEPA) has indicated that they would expect the grout densitometer sources to be removed.

Due to the nature of the radioactive sources, it will be safer to remove the sources as a subsea activity rather than on the surface. The sources can be removed using a Remotely Operated Vehicle (ROV) then placed into containers, prior to being lifted to the surface. This subsea operation will be undertaken by ROVs and not divers, and therefore there is no risk that people will be exposed to radioactivity. The removal of the densitometer sources will not cause any drill cuttings pile disturbance. Once on the surface the containers holding the sources will be returned to the appropriate authority for disposal.

The Grout Densitometer sources will be disposed of within the UK, through licensed disposal companies, in accordance with local environmental requirements and legislation, to the approval of the appropriate authority.

5.4 Well-Related Material

Table 5.4 lists the material from the North West Hutton wells that has already been removed in preparation for decommissioning. All material has been taken to shore for recycling or re-use.

Item	Material	Weight (tonnes)
Conductors and casing	Steel **(1)**	5,200
	Cement	1,720
Tubing and other equipment	Steel	350
Wellheads/Xmas trees	Steel	200
Total estimated weight removed from wells		**7,470**

Table 5.4: Weight of materials removed from the North West Hutton wells in preparation for decommissioning.

Note

1. Estimated weight from well programmes.

5.5 Pipelines

Table 5.5 presents an inventory of the materials in the pipelines PL 147 and PL 148. Both the pipelines have been cleaned and filled with seawater in preparation for decommissioning.

Item	Material	Weight (tonnes)
Pipelines	Steel	3,679
	Concrete coating and steel reinforcing bars	3,638
	Coal tar enamel coating	215
	Galvalum III anodes	50
	LSA scale and hydrocarbons	N/A
Mattresses and bridges	Concrete	1,368
Flexible line	Steel	12
	Composite materials	N/A
SSIV skid	Steel	31
SSIV umbilical	Composite materials	10
Redundant FLAGS tie-in spool	Concrete and reinforcing bar	12
	Steel	10
	Coal tar enamel coating	0.6
	Galvalum III anodes	0.2
Total estimated weight of pipeline associated material		**9,025.8**

Table 5.5: Estimated weight of materials in the North West Hutton pipelines (Ref. 5.6).

5.6 Drill Cuttings Pile

Table 5.6 presents an inventory of the material in the drill cuttings pile. The volumes are close approximations based on a detailed review of the drilling records and analysis of numerous samples that have been collected from the pile itself. It should be noted that sampling the pile from within the confines of the jacket has been limited due to the difficulty of accessing this complex area.

Containment	Average		Worst Case	
Total Oil	(tonnes)	(%)	(tonnes)	(%)
Total Oil	2,605	5.1	3,651	7.2
Diesel	521	1	731	1.4
Low Toxicity Oil	2,085	4.1	2,922	5.7
PAH	39.4	0.08	41.1	0.08
Nonyl Phenol	2	0.004	3.6	0.08
Ba	5,143	10.1		
Zn	29.8	0.06		
Ph	8.7	0.02		
PCB	0.004	<0.00001	0.009	<0.00002

Table 5.6: Estimate of total hydrocarbon and contaminant loading in the North West Hutton drill cuttings pile (Ref. 5.5).

5.7 Debris and Other Seabed Items

Despite careful planning and management of offshore operations small items of equipment can be accidentally dropped into the sea and fall to the seabed. Additional items such as cables and chains can be lost during marine activities. Such items identified during the decommissioning activities and post decommissioning survey will be removed.

5.8 Onshore Treatment and Disposal of Materials

All waste materials generated in the process of decommissioning North West Hutton and its facilities will be treated or disposed of by licensed contractors at licensed sites with all the necessary permits and consents. The contractors will be chosen through an extensive selection process, where environmental and safety considerations will be paramount, and the social impacts of onshore activities will be assessed.

BP's duty of care extends beyond the quayside and we will work with the onshore licensed disposal sites and will ensure that all dismantling and waste treatment and disposal is carried out in a responsible manner. The principles of the waste hierarchy will be applied, in that material will be re-used and recycled wherever possible in preference to being disposed of.

Upon completion of the onshore treatment and disposal of North West Hutton and its facilities data will be available on the quantities of waste recycled and disposed of, and the methods and sites used to dispose of hazardous wastes.

Procurement decisions may result in some or all of the platform and its facilities being delivered overseas for onshore disposal. Trans-frontier Shipment of Waste Regulations 1994 would apply to all materials or waste delivered overseas for the purposes of recovery or disposal. In this event, prior notification will be given to the Competent Authorities, before commencement of decommissioning activities.

References

5.1 North West Hutton Technical Datapack, Document No. EOS-NWHD-BPA-FAC-DSB-001 Rev A, 22nd November 1999.

5.2 Lloyd's Register, North West Hutton Decommissioning Residual Waste Survey, Reference 0391215/R/004, May 2004.

5.3 "Report TEC 05", AKER KVAERNER, North West Hutton, Jacket Information Package, Document No. 8226-NWH-ST-004, 13th May 2003.

5.4 "Report TEC 01" Corrpro Companies Europe Ltd, North West Hutton, Life Assessment of Jacket Footings, Rev 0, 19th September 2003.

5.5 "Report ENV 01", BMT Cordah Ltd, Environmental Statement in support of the De-commissioning of the North West Hutton Facilities, Report No. BPX067/ES/2003, June 2004.

5.6 "Report TEC 14 - 18" J P Kenny, Pipeline Decommissioning Technical Summary Report, Document No. 05 2416 01 G 3 011, Rev 03, 21st November 2003.

6 GUIDING PRINCIPLES AND SCREENING PROCESS

6.1 Introduction

The responsible decommissioning of disused oil and gas facilities is integral to the exploration and production business lifecycle ensuring that the process of decommissioning the North West Hutton facilities achieves a balance of the highest, safety, environmental, societal, technical and financial standards, is the basis of all removal and disposal activities.

This section sets out the guiding principles upon which all the evaluations and recommendations for the effective decommissioning of the North West Hutton facilities are based. It provides a description of how the screening of the decommissioning options for each of the facilities was carried out and how the short-list for detailed evaluation was compiled.

6.2 Guiding Principles

The decommissioning of disused offshore installations is governed under UK law by the Petroleum Act 1998 (Ref.6.1) The UK also adheres to the 1992 Oslo and Paris (OSPAR) Convention (Ref.6.2) for the protection of the Marine Environment of the North East Atlantic. Specific agreement on the decommissioning of offshore installations is set out in OSPAR Decision 98/3 (Ref.6.3) as agreed at a ministerial meeting of the OSPAR Commission in July 1998 in Sintra, Portugal.

Under the OSPAR Convention, there is a presumption that all installations will be completely removed to be re-used, recycled or disposed of on land. Decision 98/3 states that *'the dumping, and leaving wholly or partly in place, of disused offshore installations within the maritime area is prohibited'*. A base case of total removal must therefore form the starting point of all evaluations and assessments for the decommissioning of the North West Hutton facilities. However, OSPAR Decision 98/3 allows a potential "derogation" (an exemption from the general presumption of total removal) for all or part of the "footings" of steel installations weighing more than ten thousand tonnes, placed in the maritime area before 9th February 1999.

The DTI's Decommissioning Guidance Notes (Ref.6.4) state that the decommissioning programme should be consistent with international obligations and take into consideration:

- the precautionary principle
- best available techniques and best environmental practice
- waste hierarchy principles
- other users of the sea
- health and safety law
- proportionality
- cost effectiveness

Of particular importance is the waste hierarchy principle which is a key element in Decision 98/3. The conceptual framework, which translates sustainability into practice, advocates that the management of waste should follow the "reduce, reuse, recycle and dispose" principle. This framework forms the core of the North West Hutton decommissioning waste management strategy.

In addition to the legislation and general principles outlined above, the business values and policies of the North West Hutton owners will underpin the process of preparing for decommissioning, particularly with regard to five key assessment factors or criteria: safety; environmental issues, societal impact, technical feasibility, and financial management.

These guiding principles informed the process by which the North West Hutton owners identified and assessed all decommissioning options, in order to balance all the factors and seek to meet the needs of all stakeholders wherever possible.

6.3 Assessment Methodology

The North West Hutton owners have developed and implemented a robust assessment methodology, in order to determine the best decommissioning option for each of the North West Hutton facilities.

The methodology includes the assessment of the advantages and disadvantages of each option in relation to the five key criteria. A thorough understanding of the "performance" of the options in each of the criteria, and the risks or benefits they impart, is therefore necessary to provide the information upon which an objective comparative assessment of the decommissioning options can be made.

The owners of North West Hutton have adopted a long-term and comprehensive approach to studying the decommissioning requirements of the field. This is demonstrated by the range of studies implemented over a number of years including work specific to the North West Hutton installation and also participation in joint projects within industry and academic institutions. All these studies and projects are listed in Section 20 Appendix.

The major effort to study removal of the platform in detail commenced in 1999 although various studies relating to decommissioning have been ongoing since the early 1990s. A wide range of studies implemented by a variety of contractors, consultants and other specialists has resulted in the recommendations contained in this document. The range of studies completed can be categorised as follows:

Studies to Identify Alternatives to Decommissioning

The purpose of these studies was to determine if there were further uses for the platform, either at its present location or at other locations. This would eliminate the need to dismantle and recycle or dispose of the material, and would align with the intent of the waste hierarchy.

Removal Studies

This series of studies set out to examine all the issues associated with the full removal of the North West Hutton platform and all associated material to achieve a clear seabed.

Research Projects

A series of joint industry projects to better define and understand some areas of decommissioning universally acknowledged as problematic and of particular direct relevance to North West Hutton.

Comparative Assessment Studies

A series of specific studies aimed at clearly describing and comparing the alternative options for the North West Hutton platform facilities in line with the requirements of the Petroleum Act (1998) and where applicable, OSPAR decision 98/3.

In order to ensure that the findings of these studies were independent and objective, the North West Hutton owners invited an international group of scientists and engineers to review all the studies. The Independent Review Group (IRG) was asked to assess each of the studies for adequacy of scope, clarity, completeness, methodology, relevance and objectivity of conclusions. The final report on the IRG's findings (Ref.6.5) is available as a reference document for this decommissioning programme (Section 20 Appendix).

The North West Hutton owners recognise that a purely scientific assessment of the impacts and risks will not reflect the views of all stakeholders, particularly when the different risks and benefits are valued differently by different stakeholder groups. Although a numerical evaluation model was suggested at the outset as a possible process for balancing the different factors, it was decided after consultation with stakeholders that the issues were too complex to be reduced to numerical weightings. An ongoing consultation process with stakeholders was agreed as a more valuable and effective way of reaching a balanced solution for the decommissioning of North West Hutton.

Taking account of societal aspects is therefore an essential part of the process of evaluating how to balance different factors in building the best decommissioning solution. An integrated stakeholder consultation process has been an invaluable part of the comparative assessment of the decommissioning options for each of the North West Hutton facilities.

6.4 Comparative Assessment Criteria

A common understanding of each of the comparative assessment criteria is essential, and this section describes how they were defined and assessed. Each of the criteria requires a specific approach to ensure the appropriate consideration of relevant factors is achieved for each aspect of the programme. The five assessment criteria are:

- safety
- environmental impact
- social impact
- technical feasibility
- financial management

6.4.1 Safety

Identifying and quantifying the major safety risks to all personnel involved in the decommissioning operations is a major part of the comparative assessment.

The safety of all workers involved in the decommissioning activities, both onshore and offshore, is a priority when assessing whether to carry out a particular operation. To this end, the safety case regulations require that an 'Abandonment Safety Case' (Ref. 6.20) be prepared prior to any decommissioning activities associated with platform removal taking place. The Duty Holder, by means of the Safety Case, must demonstrate that the proposed arrangements for decommissioning of the installation reduce the risks to people to the lowest level that is reasonably practicable (Ref. 6.7).

Furthermore, legislation requires the Duty Holder to reduce the risks to personnel to *as low as reasonably practicable* (ALARP) The Guidance on ALARP (Ref. 6.8) sets out a 'tolerability of risk' framework which consists of three regions of risk:

- A region of high risk – unacceptable region (considered unacceptable whatever the level of benefit associated with the activity).
- A region of intermediate risk – tolerable region (region where people are prepared to tolerate the risk to secure the benefits).
- A region of low risk – broadly acceptable region (risks in this area are generally regarded as insignificant and adequately controlled).

A core part of the assessment process is the identification of all hazards associated with the decommissioning work, an assessment of the associated risk and whether the level of risk is acceptable. One method of evaluating risk is through the use of quantitative risk assessment (QRA) techniques which provide a numerical evaluation of the risks. The numerical estimations are expressed in terms of Potential Loss of Life (PLL) which estimates the collective risk to all workers exposed by the Project Activities, and individual risk per annum (IRPA) which estimates the likelihood of an individual becoming a fatality in any one year while exposed to project activities.

PLL and IRPA are directly related in terms of the number of people and the time spent on the project activities.

$$PLL = IRPA \times \frac{\text{Number of people working on the project}}{\text{Fraction of time working per year}}$$

In terms of risk acceptability, the requirement is on duty holders to set their own criteria for the acceptability and tolerability of risk. However, the HSE commonly define the maximum tolerable level of individual risk of fatality as 1 in 1,000 per year, and for the broadly acceptable level of individual risk to be set in the range 1 in 100,000 to 1 in 1 million per year. For comparison, the risks of fatality in the manufacturing and agriculture industries are 1:77,000 and 1:17,000 respectively.

The 1 in 1,000 fatality per year means that there would be 1 fatality in every 1,000 man-years of work, e.g. 100 men working for 10 years or 1,000 men working for 1 year.

The QRA has been undertaken using established techniques to provide an estimate of removal and disposal risks. The technique utilises relevant historical accident data, and is based on the assumption that these statistical trends will be repeated for similar work or activities in the future. The data used has been examined to determine whether more recent safety management practices may have reduced the potential accident rates. For example, the most recent statistics on diving accidents have not yet been published; the available data may reflect unsafe practices no longer utilised in the diving industry. The use of this, and other data was subsequently factored to recognise the development of safety management systems in recent years and hence are believed to include appropriate levels of risk mitigation.

Where accident data is not available, or is deemed to be irrelevant to decommissioning activities, the accident-initiating events are estimated by the use of event tree analysis which accounts for available preventative and mitigation measures. For example, the potential for dropped objects falling from the jacket has to be estimated as there is little historical data. On its own, however, a dropped object may not necessarily result in an injury to personnel; the potential for injury is dependent on the presence of individuals below the dropped object. This risk estimation approach assumes the implementation of Safety Management Systems and risk mitigation measures but also recognises that failures do occur in such systems and this has been estimated in the analysis.

At this stage in the evaluation, BP believe that the approach taken along with the careful analysis of available data has resulted in a risk picture which, including for the provision of mitigation measures and Safety Management Systems provides a credible risk model for decommissioning of the North West Hutton platform. However, as engineering and safety management systems are developed for the chosen option the ALARP principle will be applied to mitigate the risk to personnel.

The amount of reliance placed on QRA in a decision-making process will depend upon any assumptions which have been made, the complexity of the events being modelled and the associated degree of uncertainty. Although numerical values can help with the calculations of safety risk, decisions about human lives at risk cannot be reduced to numbers alone. When there is a great deal of uncertainty associated with a proposed activity other factors, such as engineering, operational and qualitative analysis, must also be taken into account. This is the situation with the decommissioning of large fixed steel structures due to the lack of industry experience.

6.4.2 Environmental Impact

Evaluating the impact of all decommissioning activities on the offshore and onshore environment is a key part of the comparative assessment. A systematic Environmental Impact Assessment (EIA) (Ref. 6.19) (Summary of EIA Section 19) was undertaken and this provided a clear understanding of the effects of decommissioning the facilities on the environment. Measures have been developed in line with best industry practice in order to mitigate where possible, or reduce and remedy any impacts that are unavoidable.

The Environmental Impact Assessment evaluates the overall impact of the decommissioning activities on:

- marine flora and fauna
- energy consumption
- all emissions to the atmosphere both onshore and offshore
- the impact on other users of the sea as well as the impact on onshore amenities

The assessment process is based on recognised techniques and standard methodologies for evaluating the environmental impacts from the various operations and tasks under evaluation. The assessment also considers the availability of, and benefit derived from, potential mitigating measures. The assessment takes into account the volume, nature, location and impacts caused by all the material and waste associated with the operations being assessed.

6.4.3 Social Impact

The comparative assessment has attempted to measure the impact on society of all decommissioning activities and potential options. The most significant areas assessed have been the economic impact (as measured by the employment created and income generated from different activities), and the impact on other sea users, primarily the commercial fishing industry. Included under economic impact is the issue of how the North West Hutton owners will be able to offset decommissioning costs against tax. Although this can be seen as a negative impact on society, a loss of tax revenue for the Government with the potential for impacting public spending, it is also a fact that the decommissioning expenditure will generate tax benefits in other areas such as income tax, so that the actual net impact is difficult to quantify. There has also been an effort to take into account society's views and concerns through a stakeholder engagement process.

The participation of representative groups from society in the consultation process is very important and as many different organisations and individuals as possible have been invited to take part. The process was designed to highlight conflicting concerns, and priorities that must be taken into account. Various stakeholder engagement processes are being utilised including: workshops, face-to-face meetings, written correspondence and an interactive web-site.

6.4.4 Technical Feasibility

Collecting baseline technical data is the starting point for assessing the feasibility of all engineering activities. Technical studies have been commissioned from a number of reputable experts and companies in order to assess every aspect of decommissioning the North West Hutton facilities.

Since there is little experience of decommissioning large fixed steel structures, and none for structures of this size and complexity, the assessment of the technical feasibility of different decommissioning activities is based on existing industry experience and available equipment.

Consideration has been given to new decommissioning technologies, and the North West Hutton owners have participated in joint industry projects (Ref.6.6) assessing the development of new decommissioning technologies. None of these systems is, however, currently available, but this does not preclude new technologies being developed in the future.

There are many uncertainties associated with the operations due mainly to the nature of offshore work, the structural condition of the facility, and the lack of industry experience of carrying out these operations on such a large scale. QRA techniques, engineering and operational analysis have been used in combination to provide comprehensive robust quantitative and qualitative assessments of each option. These were then used in the decision-making process for the selection of optimal technical solutions. Technical feasibility and risk cannot be assessed in isolation but must always consider the implications for the safety risk to workers, potential impact on the environment, risk to other users of the sea, and the overall costs.

Technical feasibility and risk were evaluated by examining individual tasks and overall procedures in detail. The feasibility of activities, operations or options, and their associated technical risks were assessed by evaluating a number of key issues including: the availability of equipment; the complexity of operations; the level of industry experience relating to the operation; the likelihood that a major failure would occur; and the implications for the option if a failure were to occur.

Two of these issues are of particular importance when evaluating the feasibility and risk of decommissioning operations. If an operation can be carried out using existing equipment for which there is a record of application, this will generally result in a significantly lower technical risk for the decommissioning programme than that associated with the requirement to develop new equipment or procedures. The ability to evaluate similar operations enables a significantly greater level of certainty to be applied to an outcome than is the case for an operation that has never been attempted before.

The risks and implications of operational failure are key factors in evaluating technical risk. This is particularly relevant where failure during an operation brings a significant increase in risk as a result of the need to undertake additional activities in an attempt to rectify the situation.

6.4.5 Costs and Financial Management

The costs for decommissioning North West Hutton have been determined from a range of studies looking in detail at all aspects of the work programme. Cost estimates have been subjected to detailed scrutiny based on input from specialist contractors, comparison with industry norms and incorporation of data from previous decommissioning activity.

The estimated costs for undertaking particular decommissioning options on the North West Hutton facilities are presented as a range of possible costs; this range provides an indication of the level of uncertainty associated with the particular option. These estimates are the best that can be obtained and were compiled on the basis of industry knowledge of the planning, operations, procedures and contingencies required for activities such as decommissioning, and on the unit costs of equipment, plant and personnel. All the estimates are subject to significant uncertainty due to the lack of direct experience of similar decommissioning projects.

6.5 Method for High Level Option Selection

Complicated modelling and analytical techniques to combine the five criteria were not deemed to be applicable for determining the recommended decommissioning option (see Section 6.3). Modelling and other techniques were, however, applied in some of the individual studies.

A wide range of potential decommissioning options was evaluated and a short list of options selected for more detailed study. The performance of each option in each of the five assessment criteria was assigned to one of three qualitative levels of acceptability as defined in Table 6.1.

Risk Factors	Nature of Assessment	Level of Acceptability		
		Acceptable	Marginal	Unacceptable
Safety of personnel	Mainly Quantitative	A region of low risk – broadly acceptable region risks in this area are generally regarded as insignificant and adequately controlled. IRPA is well within the recognised threshold of 1 in 1000	A region of intermediate risk – tolerable region where people are prepared to tolerate the risk to secure the benefits. IRPA is around the recognised threshold of 1 in 1000	A region of high risk - region considered unacceptable whatever the level of benefit associated with the activity IRPA is above the recognised threshold of 1 in 1000
Impacts on the environment	Quantitative/ Qualitative	The proposed operations may provide a benefit, no change or at worst negligible environmental impacts	The proposed operations cause some, possibly significant, environmental disturbance that is localised and of short duration.	The proposed operations cause significant environmental disturbance that is widespread and/or long lasting.
Impacts on society	Mainly Qualitative	There are tangible positive benefits or possibly no discernible negative impacts	The proposed operations may result in small impacts.	There is significant disamenity
Technical	Mainly Qualitative	Equipment and techniques are known and have a track record of success	Equipment and techniques have a limited track record or require development	Equipment and techniques have no track record.
Economic	Quantitative	Cost is important but is not used as a prime differentiator. It is included for completeness and as a measure of proportionality when considering the other four criteria.		

Table 6.1: Risk Factors and acceptability levels.

6.6 Results of High Level Option Selection

This section sets out the decommissioning options for each of the North West Hutton facilities and identifies the options short-listed for the comparative assessment. The areas highlighted in blue for each of the facilities indicate the options that have been short-listed for further detailed examination. Each of these options is then evaluated in detail by the agreed criteria in Sections 8, 9 and 10 of this document.

6.6.1 Reuse of the Installation.

In accordance with the waste hierarchy principles, one of the first decommissioning options the North West Hutton owners considered was the reuse of the platform as a whole along with its associated facilities, either in the oil and gas industry, or as a 'new use' *in-situ* or at a new location.

Disused offshore facilities are successfully reused in other parts of the world but typically this option is only applicable for a relatively small number of smaller standard structures. The concept is relatively new in the North Sea where structures similar to North West Hutton are generally built for the specific requirements of the field they service. Several studies have been carried out by companies operating in the North Sea assessing the opportunities for reuse within the industry and for 'new use' potential. The following discussion briefly reviews the possibilities for North West Hutton.

6.6.1.1 Oil and Gas Reuse in the Present Location.

Several studies of potential oil and gas reserves in the area surrounding North West Hutton were carried out during the life of the field and in particular from 1995 to 1998. These studies clearly indicated that there are no commercial oil and gas reserves that could be accessed to extend the life of the North West Hutton platform. The results of these studies formed the basis of the Cessation of Production Application (Ref. 6.9) prepared for the field and accepted by the DTI. This option is therefore eliminated and not considered further. It should be noted that any such opportunity would only delay and not ultimately remove the need for decommissioning.

6.6.1.2 Oil and Gas Reuse in an Alternative Location.

The production facilities at North West Hutton are based on 1970s technology much of which is now obsolete. Wholesale redeployment of the facility is not appropriate, and would require the topsides to be removed in a manner similar to that described for decommissioning later in this document. Attempts to re-use parts of the installation for a wide range of uses will be a key part of the disposal process described later in this document.

6.6.1.3 New Use or Alternative Uses

Studies into 'new use' opportunities outside the oil and gas industry have been carried out by the North West Hutton owners (Refs.6.10 and 6.11). These studies assessed opportunities for using the platform for a wide range of uses, from realistic to highly speculative. The alternative uses that were evaluated included wind farms, marine research stations, wave power plants, fish farming sites and training centres. None of the reuse opportunities evaluated were found to be economically viable. These findings are consistent with the results of similar studies carried out generically and for specific northern North Sea installations.

A number of factors including the remote location, difficulty of access, extreme weather, high maintenance costs and the design life influence the overall economics for the North West Hutton site. As with re-use, possible alternative use of North West Hutton facilities in one of these applications only postpones the requirement for decommissioning.

Since no viable new use opportunities were identified, this option was not considered to be feasible and not taken forward for further assessment.

6.6.2 Decommissioning the Platform

The above discussion eliminates the possibility of alternatives to decommissioning. This section describes the decommissioning methods available for each of the North West Hutton facilities.

6.6.2.1 Topsides

Under current regulations, the topsides of all structures must be removed to shore and reused, recycled or disposed of. Studies carried out by the owners, and data from other projects, indicate that removal of the North West Hutton topsides is feasible (Refs. 6.12, 6.13, 6.14 and 6.15). Certain aspects of the way in which the North West Hutton topsides were installed will present some technical and engineering problems during removal operations. Although these result in safety risks, they can be managed to an acceptable level using existing technology and experience. Accordingly only the option of complete removal to shore has been considered for the North West Hutton topsides (Table 6.2).

Facility	Selected Option
Topsides	Complete removal to shore

Table 6.2: Removal option for topsides.

6.6.2.2 Jacket

The base case for the decommissioning of the North West Hutton jacket is total removal. Studies on complete jacket removal indicated that total removal of the jacket would present major technical and safety risks and uncertainties that required additional investigation (Refs. 6.13, 6.14, 6.15, 6.16 and 6.17). These issues arise when considering the removal of the whole jacket because of its size and complexity.

The greatest level of uncertainty is associated with the removal of the lower part of the jacket, from a depth of approximately 100m to the seabed at 140m. In this part of the jacket sometimes called the "footings", the very large legs and members in the final 25% of the height of the jacket account for about 50% of the total weight. The potential engineering difficulties and safety risks attendant on removing such large and complex structures is acknowledged in OSPAR Decision 98/3 (Ref. 6.3). This contains a provision to allow the consideration by regulators of an application for "derogation" (exemption) from the requirement to completely remove the footings of jackets weighing more than 10,000 tonnes.

In line with OSPAR Decision 98/3 alternative options for the jacket were therefore considered in detail using the comparative assessment methodology. The short-list of possible options for the jacket is presented in Table 6.3.

Facility	Options Selected for Assessment		
Jacket	Complete removal of the jacket. Jacket, footings and template taken to shore for re-use or recycling.	Removal of the jacket and partial removal of the footings as close as possible to the present seabed level, i.e. the top of the drill cuttings.	Removal of the jacket down to the top of the footings at a depth of approximately 100m.

Table 6.3: Selected options assessed for jacket removal.

Figure 6.1: Jacket removal options.

6.6.4 Drill Cuttings

A comprehensive JIP recently completed by the United Kingdom Offshore Operators Association (UKOOA) (Ref.6.18), assessed the existing and potential long-term impacts of drill cuttings accumulations on the seabed. As a result of this study, the following management options were proposed for dealing with historic drill cuttings piles: covering, removal and natural degradation *in-situ*. The studies concluded that there was no single, obvious course of action that would clearly provide the most appropriate solution in terms of environmental benefit. The short-list of possible options for the North West Hutton drill cuttings pile is presented in Table 6.4. This includes the additional option of "excavation" because this activity could be used to expose the base of the jacket for total removal (see Section 9.6).

Facility	Options Selected for Assessment				
	***In-situ* options**			**Drill cuttings**	
Drill cuttings	Natural degradation *in-situ*	Excavate pile and leave at present location.	Cover pile with inert material.	Complete removal to surface and re-injection offshore.	Complete removal to shore for disposal.

Table 6.4: Selected options assessed for dealing with the drill cuttings pile.

6.6.5 Pipelines

Options for decommissioning the North West Hutton pipelines have been assessed in line with the DTI guidelines (Ref. 6.4) and the requirements of the Petroleum Act (1998) (Ref. 6.1).

All flexible lines and other ancillary pipeline equipment which are not trenched or buried will be completely removed to shore for recycling and disposal. The options for the two main pipelines are presented in Table 6.5.

Facility	**Options Selected for Assessment**		
10" gas import pipeline – PL 147	Complete removal to shore.	Leave *in-situ* trenched and buried.	
20" oil export pipeline – PL 148	Complete removal to shore.	Trench and bury.	Leave *in-situ* on seabed.

Table 6.5: Selected options assessed for decommissioning pipelines PL 147 and PL 148

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7 TOPSIDES DECOMMISSIONING

7.1 Introduction

There is a legal requirement that the topsides of all installations will be returned to shore for re-use or recycling. Detailed studies of structural integrity confirm that the topside components are capable of withstanding the operations required to remove them to shore for recycling. It is therefore not necessary to consider alternative decommissioning options. The potential for re-use and alternative use in the current location have been thoroughly investigated and eliminated from further consideration as described in Section 6.

This section describes the potential methods for decommissioning the platform topsides by removing them and taking them to shore for recycling. It summarises the activities required to dispose of the modules themselves and the residual materials in the topsides systems.

The North West Hutton topsides comprise individual modules and components detailed in Sections 4 and 5 which were installed on the module support frame by a SSCV in 1982. A total of 22 "heavy" lifts was required and the total weight of the topsides, with all of its tanks and pipes empty (the "dry weight"), is approximately 20,160 tonnes.

This section:

- lists the potential removal methods;
- presents a summary description of each method; and
- describes the selection process and the proposed method for removal.

Photograph courtesy of Charles Hodge, Lowestoft, Norfolk

Photographs showing North West Hutton Topsides.

7.2 Description of Possible Removal Methods

There are several possible methods for removing the topsides. These are listed in Table 7.1 and described in more detail in the Sections that follow.

Method	Description
Offshore deconstruction	Each of the modules and components would be cut into small manageable pieces offshore, using hydraulic shears and other cutting techniques. These pieces would be removed using the platform cranes and then transported to shore on supply boats or transport barges.
Reverse installation with HLV	The modules and other components that comprise the topsides would be separated from each other and lifted from the platform using a HLV. This programme would effectively be a reverse of the original installation procedure.
Removal by "Single lift vessel"	The complete topsides would be removed in one piece by transferring it onto a single lift decommissioning vessel.

Table 7.1: Possible methods for removing the topsides.

7.2.1 Offshore Deconstruction

For removal by offshore deconstruction (sometimes referred to as "Piece-small" or "Piecemeal" removal) the topsides would be broken up offshore using traditional cutting and lifting methods, and then transported to land in ordinary supply or cargo vessels. Personnel would methodically work their way through the topsides, using hydraulically-operated shears and other cutting equipment to dismantle the structure into pieces weighing no more than the rated lifting capacity of the platform cranes which is 55 tonnes. In general the pieces would weigh much less than this, e.g. pipe-work cut into lengths and put in skips. The major activities in this option would be:

- Empty and clean all pipes and vessels; this activity has been completed.
- Select and mark each piece of equipment and each section of module to be cut.
- Rig temporary scaffolding and lifting points as required.
- Take the weight of each piece on a crane, and use the shears to cut it free.
- Lift each piece out of the module, and deposit it on the platform or in a skip.
- Lift full skips / large items from the platform to a supply boat.
- Take full skips to shore for onward transportation and recycling.

The Piece-small option (Refs. 7.1 and 7.2) would use what is essentially onshore technology to perform a long programme of progressive dismantling that would have to be planned carefully to ensure the safety of personnel. It is likely that several teams would work on the platform at once, and their work would have to be organised to make best use of the limited space in the crowded topsides of North West Hutton.

7.2.2 Reverse Installation

It would be feasible to remove the modules using an SSCV, in a programme that was essentially the reverse of the installation process (Figure 7.1). Studies show that a series of 22 heavy lifts (Refs. 7.2, 7.3, 7.4, 7.5 and 7.6) would be required to clear the topsides down to the module support frame. The major activities for this technique would be:

- Empty and clean all pipes and vessels; this activity has been completed.
- Disconnect the piping, electrical wiring and other services that link the modules; this activity has been completed.
- Remove or secure items of loose equipment.
- Install or reinstate lifting points on the modules.
- Separate the structural connections between the modules.
- Lift the modules onto the SSCV or transport barge and, if necessary, fasten in place.
- Transport all modules to shore for dismantling.

The individual structural integrity of the modules has not changed since installation, but offshore survey work would be required to ensure that each section is sufficiently strong and stable enough to be lifted. In some cases it might be necessary to add additional strengthening or reinforcement prior to removal, but this should not be significant. The majority of the lifting points were removed after installation to allow the modules to be stacked on each other. New lifting points would have to be installed and thoroughly tested prior to any lifting operations.

1 Heavy lift vessel lifting the flare boom

2 Flare boom being placed on the deck of the heavy lift vessel

3 Large module being lifted by heavy lift vessel

4 Large module being placed on a transportation barge

5 Large module being lifted by heavy lift vessel

6 Module support frame being lifted by heavy lift vessel

Figure 7.1: Computer generated diagrams illustrating 'reverse installation' technique.

7.2.3 Single Lift

The term "single lift" applies to those options in which a vessel is used to lift off the topsides with only a minimum requirement for offshore deconstruction. Several designs have been proposed for purpose-built single lift decommissioning vessels that would be capable of removing topsides or steel jackets in one piece and transporting them to shore (Figures 7.2a, 7.2b and 7.2c). The designs include modified oil tankers or semi-submersibles, innovative new semi-submersibles, and arrangements of barges. These methods remain unproven, however, and no such vessel is currently available for a platform the size of North West Hutton (Refs. 7.8 and 7.9).

The major activities in this option would be:

- Strengthen the MSF for single lift activity by installing additional structural steel.
- Pre-cut the MSF to separate it from the jacket legs.
- Manoeuvre the single lift vessel alongside and around the jacket.
- Make load bearing connections between the topsides and the single lift vessel.
- Transfer the load from the jacket legs to the vessel and lift the topsides from the jacket.
- Transport to shore and transfer the whole topsides to land / near-shore location.

Figure 7.2a: MPU Heavy Lifter 'single lift' method (Ref.7.17).

Figure 7.2b: Monitor 'single lift' method (Ref. 7.16).

Figure 7.2c: Excalibur 'single lift' method (Ref. 7.15).

Note The three 'single lift' methods illustrated above are not currently available.

7.3 Selection of Removal Method

7.3.1 Introduction

The potential removal methods for decommissioning the topsides were assessed using the methodology described in Section 6. This included consideration of the following issues:

- the technical difficulty, including the timely availability of fit-for-purpose equipment, procedures and people, such that the option can be completed successfully;
- the potential safety risk to our personnel, contractors and other third parties;
- the potential to cause environmental impact at sea, on land, or in the atmosphere;
- the impact on society in general; and
- the cost, including the need for pre-investment, the reliability of cost estimates and the potential for cost over-run.

The issues that differentiate the removal methods most clearly are technical complexity and safety, and the assessment focussed on these issues. The technical complexity, particularly for single-lift methods, also resulted in cost uncertainty.

Several reports and studies were commissioned (Refs. 7.8 and 7.9) to examine the relative merits of each method in the various criteria. Some of the reports presented qualitative information based on industry experience, interviews with engineering companies and contractors, or an analysis of historical performance.

Other studies used numerical data to estimate or predict the likely values for some criteria, for example safety risk and cost. Section 7.3.2 briefly describes the results of these studies.

7.3.2 Assessment of Three Removal Methods

7.3.2.1 Offshore Deconstruction

This method would present significant challenges in planning and execution (Ref. 7.1). Personnel would be working offshore carrying out a very extensive programme of cutting, rigging, working at height, and lifting. These are recognised as some of the highest risk activities carried out offshore.

There are major issues of providing living accommodation for personnel, ensuring continuing structural stability, working in confined spaces, and removing the flare and derricks. High level screening of the safety and logistic issues led to the elimination of this as a practical method for North West Hutton (Ref 7.2). Offshore deconstruction is not the correct method for the North West Hutton topsides, although it could be for other installations.

7.3.2.2 Reverse Installation

There is a long history of heavy lifting in the North Sea, and the equipment, techniques, risks and management of the process are all well understood. Even 20 years after the installation of North West Hutton, however, the crane lifting capacity and reach of the cranes required to remove the North West Hutton modules remain a limiting factor and the unpredictable weather at the location of the platform adds to the challenge.

Studies by specialist heavy lift contractors (Refs. 7.3, 7.4, 7.5 and 7.6) have concluded that there are no insurmountable technical difficulties to removing the modules by heavy lift vessel. Removal of the modules would, nevertheless, be a complex operation with a number of significant risks that would require careful assessment, planning and management. Heavy lifting during decommissioning programmes requires loads to be lifted from a fixed structure onto a moving barge, and this is more weather-sensitive than lifting a similar load from a cargo barge onto a fixed structure.

The extent of the lifting operations, the difficulties back-loading onto barges and the dependency on the correct planning, preparation and implementation, combined with transfer to shore for disposal result in this phase of the decommissioning programme being classified as a high risk operation. The safety impact associated with the removal of the topsides by reverse installation was fully assessed using hazard identification and quantitative risk assessment techniques and included the risk evaluation of not only the offshore removal but also the preparatory activities prior to lifting, the transportation to shore and onshore demolition phases (Ref. 7.7).

A wide range of potential hazards exists with the removal of the topsides. Each individual hazard event was assessed using recognised techniques such as QRA (Section 6.4.1) to evaluate the associated risk. The analysis showed that dropped loads, falling objects, occupational accidents during the preparation and removal activities, and onshore dismantling contributed 94% of the total risk.

The estimated risk for removal of the topsides in terms of Potential Loss of Life (PLL) is 9.6% or one fatality in every 10.5 topsides removal projects. This is a measure of the exposure of the whole work force for the duration of the Project.

The risk to individuals is another measure of exposure and this varies with the nature of the work they perform, e.g. a rigger has greater exposure to hazards than a cook. The individual risk per annum (IRPA) to a fatality for the higher risk categories, which include rigging crew and tugboat crew, are 1:1,500 to greater than 1:1,000. These predicted risks are on the boundary of intolerable risk (see Section 6.4.1 for a discussion of these terms and acceptability levels).

7.3.2.3 Single-lift

For topsides removal, the single lift method offers potential advantages including a significant reduction in the amount of preparatory work required offshore compared to other options. The advantages are, however, offset by the significantly increased technical risk of the lift itself, particularly as North West Hutton was not designed for single lift. There is no track record for this method and there are a very limited number of onshore facilities that could accept such a large structure for subsequent dismantling.

One potential advantage of single lift would be the ability to re-use the entire topsides for a subsequent development. As stated earlier, however, the North West Hutton owners have not identified any re-use opportunities for the topsides as a single unit.

7.3.3 Comparison of Removal Methods

The results of the assessment of the possible removal methods are compared and discussed below.

Offshore Deconstruction (Piece small) Method

The equipment and techniques for this method are well established and have been widely used but only onshore where large equipment can be readily used, unlike offshore. There is currently no experience or proven procedures for using this method on a platform the size and complexity of North West Hutton, planning and executing the work would be a major challenge. The exposed location, restricted working space and congested nature of the platform means there are significant and unacceptable safety risks to personnel due to the numerous cuts, material handling, working at heights and crane lifts that are associated with this method. There would also be significant helicopter and marine vessel movements, which are also high-risk activities. There is also the health and environmental difficulties of dealing with waste, e.g. asbestos and LSA, offshore without the facilities and procedures that are available at established onshore disposal sites. There is the potential for significant cost over-run due to the difficulty in estimating the scope of work and because there is no historical cost data against which to benchmark.

Reverse Installation

The method of reverse installation is proven, with the equipment, techniques and technology used being mature. The hazards to personnel are well understood from installation activities and this provides a sound basis for approaching the removal activities. The reverse installation lifts are heavier and therefore considerably fewer compared to the offshore deconstruction method resulting in less risk to personnel. The modules are lifted and brought ashore, similar to as they were constructed, and the waste is contained within the modules and dealt with by the established disposal sites. There is less risk to cost over run as the scope of work can be clearly defined and with historical cost data available from installation projects this will allow more credible benchmarking.

Single Lift

With this method the risk to personnel offshore could be significantly reduced, as only one single lift is required. However the platform still has to be dismantled and some of this risk is shifted to the inshore and onshore locations. Single lift technology is still being developed and at present equipment is not available on the market. The exposed northern location, size and weight of North West Hutton platform are a further challenge which would stretch this technology to the limit. The technology can therefore be classified as being immature and unproven giving rise to a number of significant engineering challenges, and with the lack of experience, experienced personnel and proven procedures, this method is considered a high technical risk with the high potential of a cost over-run.

On the basis of the above assessment and comparison, it is clear that at this time the only feasible and safe method of removing the North West Hutton topsides is by reverse installation. This would require the use of existing equipment and procedures, in a programme that could be carefully controlled and managed. The method would result in the return of whole modules to a suitably equipped and licensed receiving site onshore.

7.4 Reverse Installation Programme for Decommissioning the Topsides

7.4.1 Decommissioning of Wells and Removal of Conductors

Well decommissioning and conductor removal operations have already been completed for North West Hutton. Although well abandonment is covered by a separate approval process (Ref. 7.10), it is also an integral part of this programme. Details of well abandonment, including an inventory of the individual wells are therefore included as Section 11 of this Decommissioning Programme. This activity did not commence until all opportunities for continued oil production and alternative uses *in-situ* had been exhausted. A brief description of the well decommissioning activity for North West Hutton is given below.

The aims of the well decommissioning programme were:

- To permanently and securely isolate and seal all hydrocarbon and other pressured formations.
- To remove all equipment down to 3m below the seabed.

The wells have been isolated from the hydrocarbon reservoir using three separate cement plugs (Figure 7.3). Two plugs were set deep in the well to ensure that the reservoir is completely sealed off. A third cement plug was then installed at a depth of around 500m below sea level. This activity was carried out on 24 wells. The other 16 wells had been decommissioned previously on an "as required" basis since 1993. All fluids in the well bores were pumped back into the reservoir before isolation and all other fluid was transported to shore for appropriate treatment.

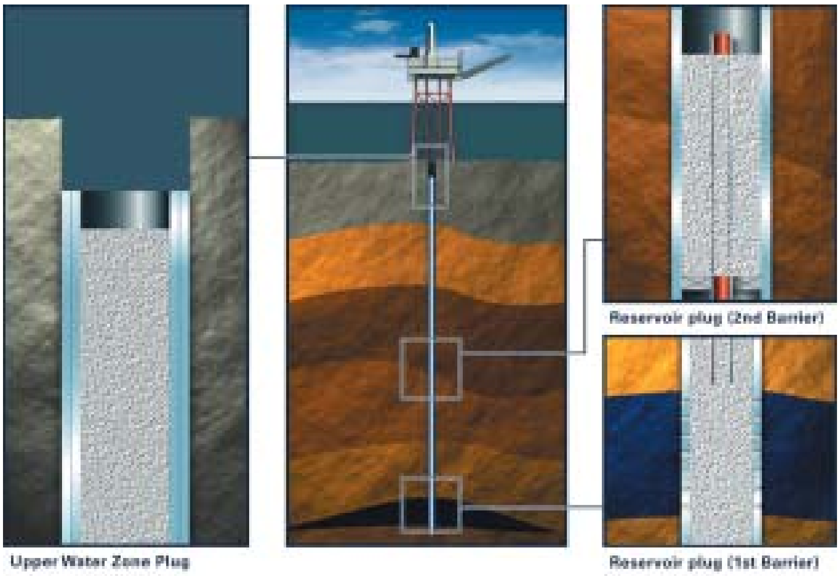

Figure 7.3: Well abandonment showing location of the cement plugs.

The final activity of well decommissioning was to remove the tubing, casing and conductor pipes that connect the wells to the process plant. Thirty-two of the forty conductors were removed to 3m below the seabed. Seven of the North West Hutton wells were pre-drilled through the template prior to installation of the platform, and because of their design it was not possible to retrieve them from the template; these wells were therefore cut as close as possible to the seabed level, (i.e. the top of the drill cuttings pile). Problems were encountered during the retrieval of one conductor and, again, this was severed as close as possible to the seabed level. All equipment recovered during the well abandonment programme has been returned to shore for recycling and disposal as appropriate.

The programme for the wells has removed as much equipment as is physically possible with the platform *in-situ*. The removal of any remaining equipment is considered an integral part of the jacket programme, described in Section 8.

7.4.2 Preparatory Work for Topsides Removal

Before the dismantling or removal operations begin, it will be necessary to prepare the topsides to ensure that all safety and environmental risks are minimised. These operations can be divided into two distinct activities referred to as "cleaning and engineering-down" and "module separation".

7.4.2.1 Cleaning and Engineering-Down

This activity is required to ensure that the plant is free from all chemicals and hydrocarbons associated with the production phase (Ref. 7.11). It is also necessary to ensure that all equipment is shut down and isolated in the correct manner to prevent possible injury to personnel involved in the subsequent dismantling phases.

Cleaning of equipment and safe handling of waste is a relatively routine but closely controlled operation offshore. The major steps involved in the operation are as follows:

- Remove all hydrocarbons from the production systems by purging and flushing to the normal handling and export systems.
- Systematically isolate equipment from all power and production inputs and outputs and ensure that it is safe for human intervention or access.
- Open systems and remove any remaining production residues, chemicals and other materials. Ensure these are stored correctly and disposed of via the appropriate disposal route.
- Once these activities have been completed, each system is "signed off" by the technical authority as cleaned and non-hazardous.

This work has been completed for the North West Hutton Platform. An independent residual waste survey (Ref. 7.12) has been conducted to estimate the waste remaining post-cleaning, and to enable an inventory of the topsides to be provided to the onshore dismantling yard. The results of this survey were summarised in Section 5.

7.4.2.2 Module Separation

The second stage of preparation for removal (Ref. 7.13) involves:

- Cutting and separating the process piping, electrical connections and other services that connect the platform systems between each module. This work was completed in July 2004.
- Structural separation of the modules so that they can be lifted individually from the topsides. This involves removing the welds and structural connections that hold each of the components together. There is also a substantial amount of work involved in removing walkway sections and other items that interlink the various modules. The major part of this work will take place immediately before the removal of the topsides.

7.4.3 Lifting and Transportation to Shore

After completion of the preparation activities, the crane vessel will remove the modules sequentially and position them either on the crane vessel itself or on to a prepared barge. The modules will be sea-fastened into position and transported to the designated onshore dismantling yard (Refs. 7.3, 7.4, 7.5 and 7.6). The lifting, sea-fastening and onwards transportation of the topsides will consist of complex operations requiring careful planning and engineering assessment to minimise the high potential risk.

7.4.4 Receiving and Dismantling Onshore

The onshore receiving location for dismantling North West Hutton has not yet been selected and it is possible that more than one site will be used. The Environmental Impact Assessment (Ref.7.14) has therefore not evaluated the onshore environmental impacts of using a specific disposal site for the North West Hutton topsides. It has, however, assessed generic onshore environmental impacts, for example those arising from the transportation of material by road, onshore dismantling, and recycling and reprocessing, at two established locations. The assessment of potential impacts at these sites does not preclude the use of alternative sites, and it should be noted that the final site(s) will only be selected after rigorous assessment and confirmation that all the necessary permits, procedures, competences and other requirements are in place.

Because of the size of the modules, it is likely that they will be stored at or close to the receiving quay prior to dismantling. The modules will be transferred onshore and then held in a secure area equipped to contain, handle and treat any potential liquid contaminants and rainwater run-off.

It is unlikely that any of the North West Hutton modules will be suitable for re-use (Section 6.6.1). New uses may be found for certain individual items, particularly turbines, pumps and motors. For all other components the North West Hutton owners plan to maximise the amount of material that is recycled, and aim to re-cycle 97% of the topsides material by weight (Ref. 7.14).

Recommendation: The topsides should be totally removed by the reverse installation method and returned to shore for reuse, recycling or disposal.

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7.12 Lloyd's Register, North West Hutton Decommissioning Residual Waste Survey, Reference 0391215/R/003, February 2004.

7.13 Wood Group / Rigblast, North West Hutton Decommissioning Project, Module Process & Utility Separation FEED, Document No. 37NWH-E034F0047-Z-RE-0006, October 2003.

7.14 "Report ENV01", Environmental Statement in support of the De-commissioning of the North West Hutton Facilities, Report No. BPX067/ES/2003, June 2004.

7.15 Excalibur Engineering BV website: www.excalibur-engineering.com.

7.16 Monitor, website: www.monitoroil.com.

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8 JACKET DECOMMISSIONING

8.1 Introduction and Background

The screening studies on removal technologies and options (Section 6) have shown that it is not feasible to use the jacket for any other purpose at its present location. As a result of this finding, a series of studies was commissioned to evaluate removal of the jacket structure.

This section presents a comprehensive summary of the study work undertaken and the subsequent findings. The following topics are covered:

- a description of the condition of the jacket;
- an assessment of possible methods for removing the whole jacket down to the seabed;
- an evaluation of the technical, safety, environmental, societal and cost implications of undertaking jacket removal;
- a comparative evaluation of alternative removal options involving the partial removal of the jacket; and
- a recommended option for decommissioning the jacket.

It should be noted that this evaluation assesses the removal of the jacket as a stand-alone operation. The presence of the drill cuttings around and covering the base of the jacket structure is not included as part of the evaluation at this stage. The rationale for this is to ensure that the full implications of jacket removal are understood without other factors complicating or masking issues.

8.2 Present Condition of the Jacket

The North West Hutton jacket is the largest fixed steel, offshore oil and gas structure that has been considered for decommissioning anywhere in the world to date. Information about its structure, composition and dimensions is presented in Sections 4 and 5 of this programme. A detailed understanding of the condition of the structure is an essential starting point for effective evaluation of removal options.

During its working life, the platform was regularly inspected and independently certified for continued operation. This inspection regime will continue until the platform is removed.

During installation of the jacket in 1981, the piling operation to secure it to the seabed was interrupted by a severe storm. Movement of the partially secured structure during this storm resulted in significant damage to the lower parts of the jacket. Following the storm, the piling process to secure the jacket was completed successfully, but a major programme of inspection and repair was necessary to ensure the long-term integrity of the structure. The damage that was sustained, and the subsequent remedial work, is fully documented (Refs. 8.1, 8.2 and 8.3), and the issues which have a particular bearing on decommissioning are as follows:

- Large sections of plan bracing elements at the seabed level, necessary for the integrity of the jacket during transport and launching, became detached or were intentionally severed. Numerous cracked welds were detected and repairs implemented where necessary to restore structural integrity.
- A large accumulation of grout (cement) was detected around Leg B1 and there is grout around the other three main legs (Figures 8.2a and 8.2b). The jacket was designed to allow the piles to be driven into the seabed to form the piled foundation and then the piles connected to the jacket by means of grout, thereby supporting the platform weight on the piles. This grouted connection was made by filling the annuli between the pile and pile sleeve with grout (see figure 8.1), where the bottom of the annuli was sealed by pre-installed rubber packers. A large number of these packers failed due to storm damage and the grout leaked out. In some cases, i.e. leg B1, several attempts were necessary before the bottom of the annuli were sealed and a large quantity of grout leaked out onto the lower sections of steelwork, i.e. the mud mats, and the seabed.
- Four major structural clamps were mechanically attached to the jacket at a depth of 130m and grouted in place to restore structural integrity and original design life.

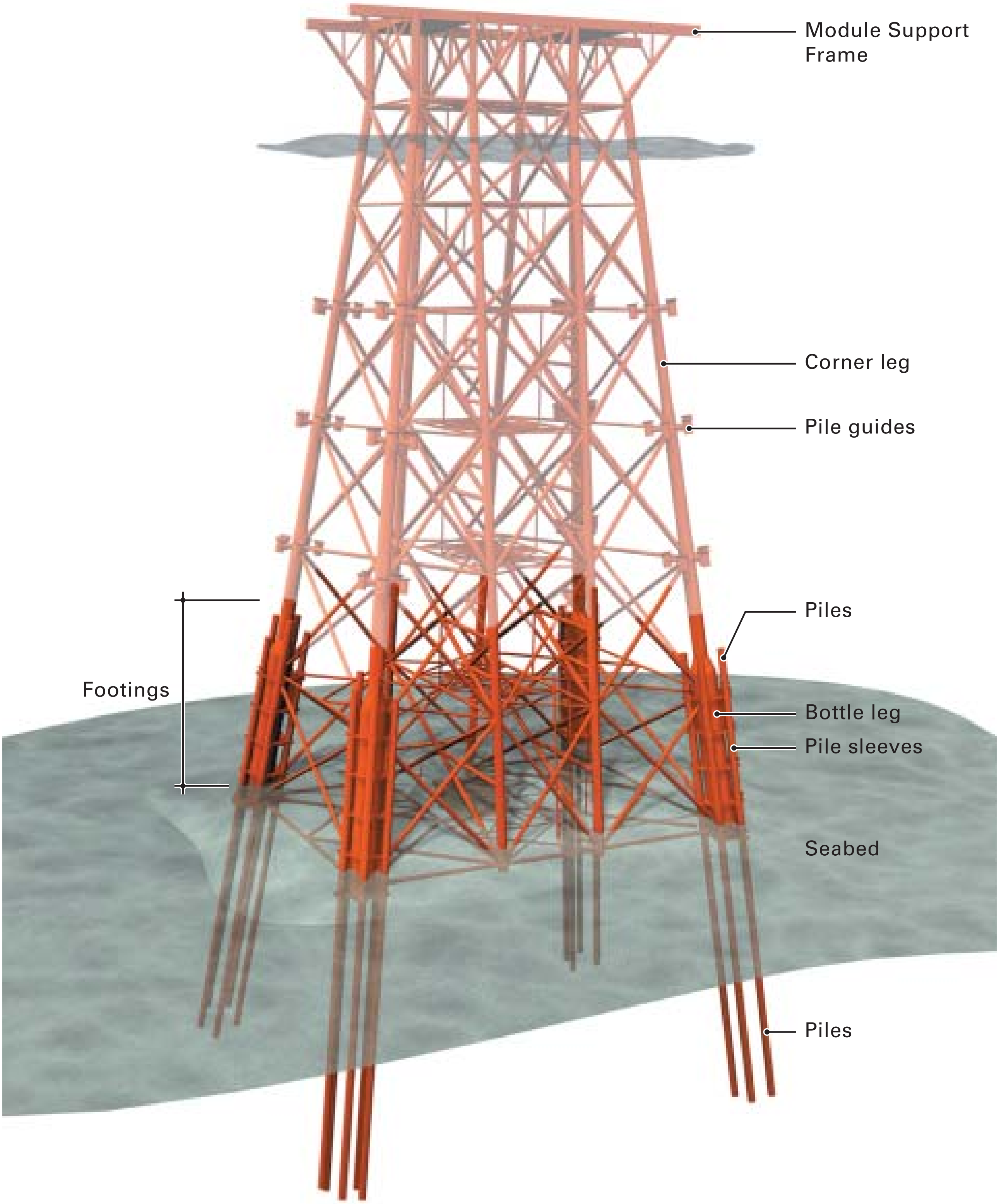


Figure 8.1: Computer generated diagram of the North West Hutton jacket.

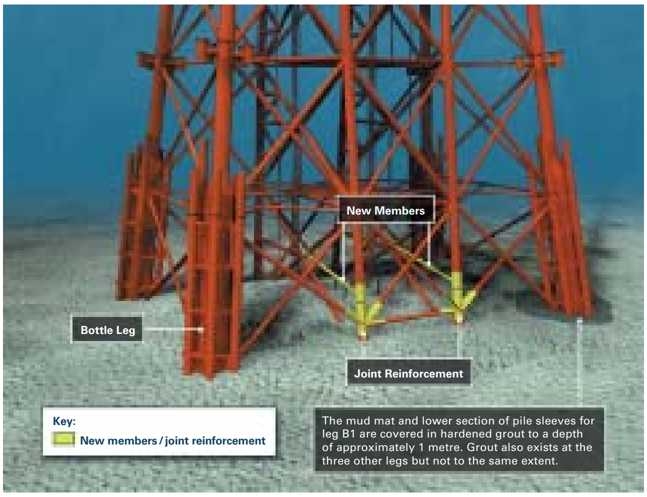


Figure 8.2a: Computer generated diagram indicating the repaired sections of the lower part of the jacket and the grout around Leg B1.

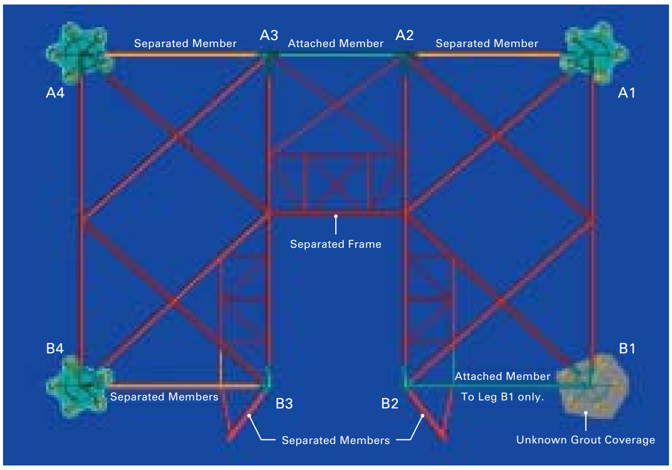


Figure 8.2b: Engineering diagram showing the repaired sections to the lower part of the jacket (Ref. 8.3).

8.3 Assessment of Jacket Removal Options

8.3.1 Introduction

OSPAR Decision 98/3 (Ref. 8.5) includes a presumption of complete removal for all offshore structures. The range of studies undertaken for the North West Hutton jacket complies with this requirement and includes screening studies to evaluate techniques, and a range of detailed studies to fully understand the implications of undertaking those techniques.

The overall purpose of the study work was to:

- identify all of the currently available techniques, and the potential new techniques, for jacket removal;
- assess the technical, safety, environmental, societal and cost implications of removing the North West Hutton jacket; and
- provide information to identify one or more techniques that could be safely and effectively used to remove the North West Hutton jacket.

The studies were carried out by a range of companies, including structural experts, safety specialists, removal contractors, diving contractors and specialist demolition companies.

8.3.2 Summary and Screening of Removal Techniques

All the potential methods for removing the jacket can be grouped into the following three categories (Ref. 8.6):

- Reverse installation.
- Single lift.
- Offshore deconstruction.

The screening process reviewed the application of these techniques for North West Hutton, and is summarised below.

8.3.2.1 Reverse Installation

Reverse installation is not a practical option. The North West Hutton jacket was constructed onshore, launched from a transport barge at the field location and then floated into its final position. The closest approximation for the reverse installation would be to attach a buoyancy system to the structure and then use it to "re-float" the entire jacket so that it could be towed to an inshore deconstruction site (Ref. 8.7). No such systems are currently available for applications of this magnitude and it is doubtful if the method is feasible for North West Hutton because of the damage to the jacket.

8.3.2.2 Single Lift

Single lift would entail using a purpose-built vessel, preferably capable of lifting the entire structure, to lift it from the seabed and either carry it to shore or positioning it on a barge for transport to the dismantling site. BP and a number of other companies (Ref. 8.8) recognised the potential importance of these techniques and a number of joint projects have been funded and carried out to develop the technology. At present, no single lift systems of sufficient capacity for the North West Hutton jacket are available.

In order to fully assess reverse installation and single lift, it is necessary to consider the ability of the jacket to be lifted by such a method. During the initial launch and also during any potential recovery by methods such as those described above, the jacket would have to withstand considerable dynamic forces due to the loading from raising of the entire structure, wave and current action, and the resultant motion of the vessels and subsequent transportation.

A detailed study was carried out to determine if the North West Hutton jacket could withstand these forces (Ref. 8.9). The study used "finite element modelling", a detailed computer-aided engineering tool, to assess the condition of the structure at every stage of the operation. The study clearly showed a high probability that the jacket would collapse during such an operation. The main reason for the predicted collapse is the loss of jacket strength resulting from the damage and subsequent removal of the plan bracing at the seabed level. The main function of this bracing was to provide support to the bottle legs during the original transportation and launch of the jacket. Re-instatement of this bracing is not feasible.

There are several different concepts for implementing such operations, but at present many do not have the size or capacity to lift a jacket as large as North West Hutton, and transport it to the UK. They would also have to deal with the damage and stability problems described above. Reverse installation and single lift were therefore eliminated as options that were presently not viable for removing the complete jacket as a single unit, and they were not subjected to additional analysis.

8.3.2.3 Offshore Deconstruction

Offshore deconstruction, using a crane vessel, has been used to remove jackets but it has never been implemented on a jacket of this size. Several small jackets have been successfully removed using crane vessels, for example in the Southern North Sea, but these effectively constitute reverse installation operations as the jacket is lifted from the seabed as a complete unit.

Offshore deconstruction involves severing the steel members of the jacket in a sequential operation to detach sections of various sizes that are then removed by a large floating crane. The operation starts at the top of the jacket and systematically progresses down towards the seabed. The severed sections are then safely positioned and secured on the crane vessel or barges for transport to shore. The maximum size of the individual sections that can be removed is governed by the lift capacity of the crane vessel and the practical constraints of positioning and securing the sections for transportation.

At present, therefore, offshore deconstruction using a heavy lift crane vessel is the only viable method for removal and transportation of the complete North West Hutton jacket. The following sections describe how this technique could be used to remove the North West Hutton jacket.

8.4 Assessment of Jacket Removal by Offshore Deconstruction

8.4.1 Introduction

The removal of the North West Hutton jacket by offshore deconstruction has been studied in detail over a number of years. A wide range of technologies is required and a clear understanding of the complex equipment requirements and removal operations is necessary. The expertise to implement such operations resides with a small number of highly specialised and competent contractors and sub-contractors. These contractors and other specialists were utilised to develop a thorough technical understanding of the removal operations.

8.4.2 Jacket Removal Overview

The main studies (Refs. 8.10, 8.11, 8.12, 8.13, 8.14 and 8.15) to determine the technical aspects of jacket removal were carried out by marine and sub-sea contractors with expertise in the field. These contractors operate the crane vessels and sub-sea equipment that would be required to remove the jacket. There is no track-record of removing a structure the size of the North West Hutton jacket by any technique, including offshore deconstruction. The studies examined in detail the deconstruction sequence necessary for complete removal of the jacket and template down to the original seabed.

The reports made different recommendations on certain key aspects, including where to section the jacket, the cutting methodology and the total number of lifts required. The studies highlighted a number of common risks which represented the key offshore considerations for removal, and required additional assessment before any detailed methodology could be developed for the implementation of a removal programme. These are as follows:

- The amount of preparatory work required before each lift, e.g. cleaning and removal of anodes.
- The reliability of cutting techniques and the need to confirm that each member has been successfully cut (Refs. 8.16, 8.17 and 8.18).
- The need to develop and apply large-scale rigging techniques so that large sections of the jacket could be securely attached to a crane and lifted safely, with minimal risk of a dropped load (Refs. 8.16, 8.17 and 8.18).
- The safety risks associated with the likely requirement to deploy divers during a complex deconstruction activity (Refs. 8.19, 8.20 and 8.21).
- The risks associated with placing and securing (“back-loading”) large sections on a barge safely, while it is moving in the seaway.
- Specific difficulties related to the lower-most sections of the jacket and the template (Refs. 8.21, 8.22 and 8.23), including the damage to the jacket, the presence of excessive grout, and inter-action with the drill cuttings.

Some of the risks, such as cutting effectiveness, remain unchanged regardless of the stage of operations or the depth at which an activity is taking place. Others vary with the depth of the operation; for example, wave loading is a concern near the surface and structural uncertainty is a major concern at the base of the jacket.

The risks and uncertainties, such as the safety of personnel, use of divers, dropped loads and falling objects (Refs. 8.21 and 8.22) were of sufficient concern that a comparative assessment of the jacket removal options was undertaken, this includes an additional study (Ref. 8.25) to compare the technical challenges of the removal options. The overall assessment methodology was discussed in Section 6 and the results are described below.

8.5 Comparative Assessment of Jacket Removal Options

8.5.1 Introduction

Using the methodology described in Section 6, the comparative assessment for the jacket examined three different scenarios for full and partial removal of the jacket, as outlined below (Figure 8.3).

- Full removal of the jacket and associated equipment to achieve a clear seabed (Figure 8.3a). This option would remove all installed equipment to below the original, natural seabed level.
- Removal of the jacket above the present "seabed" formed by the drill cuttings pile (Figure 8.3b). This option was introduced as the study work progressed based on project scrutiny, independent review and stakeholder feedback.
- Removal of the upper jacket down to the top of the footings (Figure 8.3c). This option utilises the transition to the relatively large, heavy steelwork of the footings as a natural breakpoint.

  It recognises the difficulty of recovering the lower section of a large jacket. As defined in the DTI Guidelines, the 'footings' means those parts of a steel installation which are below the highest point of the piles which connect the installation to the seabed. i.e. the foundations of the jacket. A large jacket is defined in the DTI Guidelines as greater than 10,000 tonnes. (Ref. 8.24).

Figure 8.3a: Computer graphic of the North West Hutton site after complete removal of the jacket and associated equipment.

Figure 8.3b: Computer graphic of the North West Hutton support structure after removal of the jacket above the drill cuttings pile.

Figure 8.3c: Computer graphic of the North West Hutton support structure after removal of the upper jacket to the top of the footings.

These three decommissioning options for the jacket were subject to a detailed study and review process, which provided specific information relating to each of the assessment criteria; Technical, Safety, Environmental, Societal and Economic. The remainder of this section describes the assessments and the findings of the studies.

8.6 Assessment of the Option of Full Jacket Removal

The proven method for removing the jacket is to cut it into sections underwater, and lift the sections onto the crane vessel or barges for transportation to land. This section presents a description of the technical and engineering programme of work that would be undertaken to implement this option.

8.6.1 Technical Description of Removal Operations

8.6.1.1 Description of Preparatory Work Offshore

Removal of the jacket would require the use of heavy plant, barges and support systems similar to those that would be used for the removal of the topsides. The operations would be a greater challenge, because removal of the jacket would require co-ordination of sub-sea and surface activities. The following description assumes that the topsides and module support frame have been successfully removed prior to commencing the jacket removal operations offshore.

The entire programme would need to be planned in great detail. The position of each cut, and the size and weight of each individual section would be determined together with an assessment of how the component would behave when submerged and how the behaviour changes as large volumes of water drain out as it is brought to the surface. Contingency measures would also have to be planned; for example, divers may be required to set up the cutting equipment in difficult situations, for rigging deployment, or in the event of a tool failure.

Large steel supports and structures for securing each section for transport would be designed and fabricated prior to the operation. The barges would be prepared for receiving and carrying each specific load.

Inspection of the jacket would be required prior to any operations and before each section was removed.

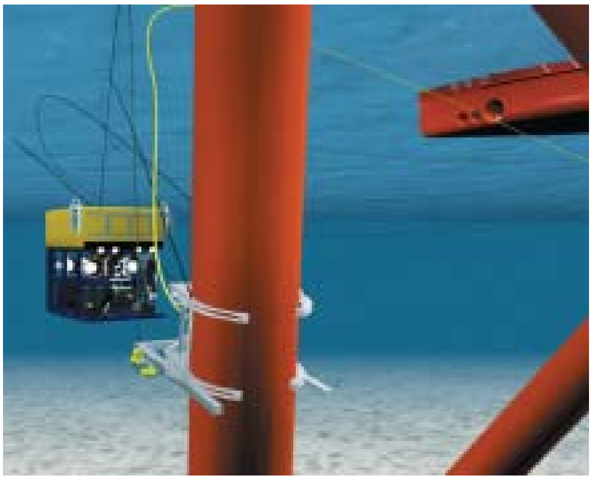
8.6.1.2 Description of Cutting and Lifting Operations

Some preparation of the structure would be carried out by support vessels in advance of the main lifting operation. The main operation would, however, require co-ordination of the crane vessel, transport barges and support vessels (Figure 8.4).

Each component would have to be properly secured while it was being cut, because of the large residual stresses that exist in a structure of this size. No such method is available for a structure as large as North West Hutton and a new system would have to be designed and tested. The final cuts to free each section would be crucial as the crane would be attached at this time. Any delay caused by malfunction or failure of the cutting operation at this stage could result in structural failure, damage to equipment or other major operational problems.

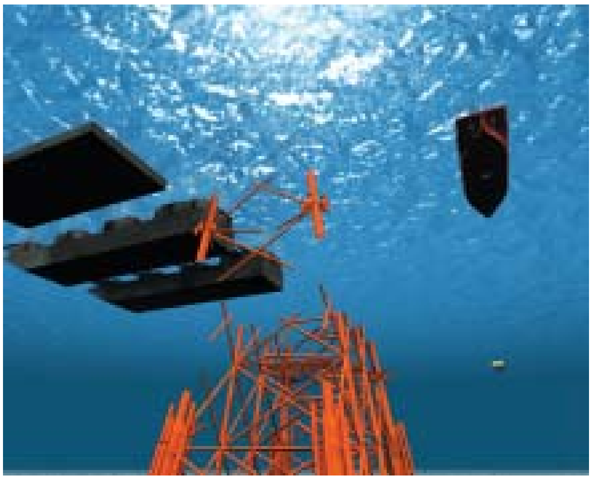
Existing cutting techniques have not been used on a jacket the size of North West Hutton, which has large diameter legs containing internal components (Refs. 8.16, 8.17 and 8.18). One of the major tasks in this programme would therefore be to extend the range and capability of the equipment so that it could safely and efficiently cut and lift the large sections of the North West Hutton jacket.

It would be preferable, from a safety point of view, to deploy remotely operated subsea work vehicles (ROVs) to carry out all the work, without the requirement for divers. The offshore industry has made significant advances in the design and application of remote operations, but the studies indicate it is probable that divers would be required for some of the removal operations (Refs. 8.21 and 8.23). The most likely requirement for divers would be during the removal of the lower-most parts of the jacket. Cleaning and cutting operations here would be complex, where the jacket and the template are surrounded by grout and other material that prevents them from being freed from the seabed using remotely operated cutting techniques. These operations would pose a high safety risk to divers.



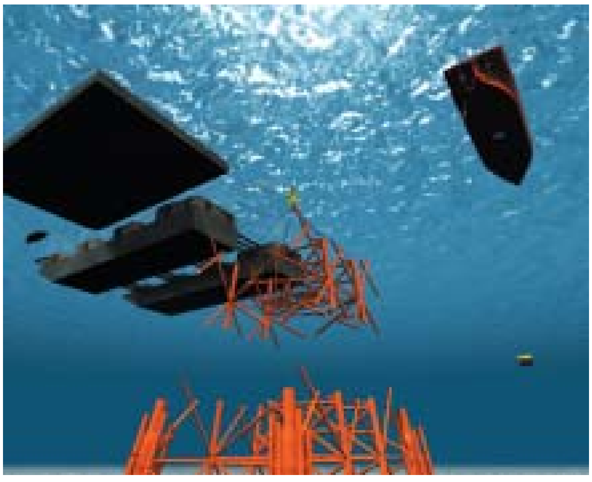
1 Due to the sheer size of the jacket, it requires to be cut into 15 to 20 sections. Over 100 jacket members will have to be cut, some with a diameter as large as 3 metres. This shows cutting using diamond wire techniques

2 Top section of the jacket being lifted by a heavy lift vessel to be placed onto a transportation barge

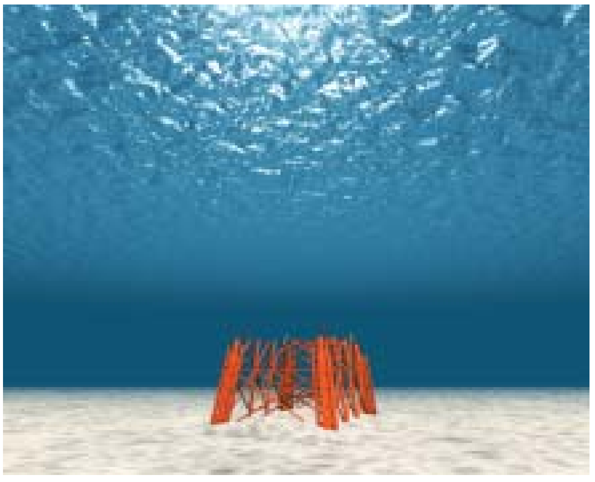


3 Small subsea section of the jacket being lifted to the surface by heavy lift vessel

4 Jacket section being lowered onto a barge for transportation to the shore for disposal



5 Large subsea section of the jacket being lifted to the surface by heavy lift vessel



6 Jacket footings on the seabed

Figure 8.4: Computer generated diagrams showing examples of the type of lifts required to get to top of footings.

8.6.1.3 Description of Operations to Transfer Loads and Transport them to Land for Dismantling

Whilst not routine, the use of cranes, vessels and barges to transfer loads, is a relatively well-known, and closely controlled and monitored, activity for offshore operations. Knowledge of such operations is derived mainly from construction activities, including the lifting and placement of jackets, topsides and modules. Unlike installation operations, however, the exact weight, condition and geometry of the lifts required for dismantling will not be known in advance. In addition, transferring a large load onto a barge in open seas is a difficult and high-risk marine operation (Figure 8.4).

These uncertainties would require additional focus on planning and preparation, in addition to more closely controlled procedures for implementing the operations. Once the removed section arrived at the surface it would be inspected, before being set down on a specially-constructed support frame known as "grillage". This is a welded framework of beams and plates several metres high, located on the deck of the transportation barge, that supports the weight of the jacket section and resists the dynamic loads encountered in transportation.

Sea fastening, consisting of plates and tubes welded in place, would be used to hold each section of jacket on the grillage. The sea fastening operation is a particularly hazardous part of the overall procedure because the deck personnel would potentially be exposed to falling objects, and the movement of an unstable load. Sections would be transported either on the deck of the crane vessel or on a separate transport barge.

During all of these procedures, including onshore demolition there would be a significant safety risk to people and plant due to falling objects including loose structural components, marine growth and, particularly, grout and drill cuttings from the lower sections (Refs. 8.22, 8.26, 8.27, 8.28. 8.29 and 8.30).

8.6.1.4 Description of Onshore Dismantling Operations

At the onshore receiving sites, components would be further dismantled using remote and manual cutting techniques. Hydraulic shears would be used to cut through steel bracings and smaller components. Larger components, including the relatively thick steel in the footings, would be dismantled using hot or cold cutting techniques.

Standard rigging and lifting equipment, and ancillary equipment, would be used to lift, move and hold many of the items during these processes.

The aim of onshore dismantling would be to break down material into pieces approximately 1.5m x 0.5m. This is the recommended size for delivery to steel recycling plants.

All the anodes on the structure would be removed at the onshore receiving site and would be transported to a suitable facility for recycling. The steel would be sent for recycling although, wherever possible, every effort would be made to re-use components in other applications. Marine growth would be removed offshore where this is practicable and safe to minimise the quantity of marine growth brought onshore; this would avoid the introduction of foreign species into areas that would not normally be found and reduce the quantity of material to be disposed of. Any marine growth remaining on the structure would be sent to onshore landfill.

It is anticipated that over 97% of the recovered jacket would be reused or recycled, and contractual arrangements and other incentives would be put in place to ensure that this figure is maximised.

8.6.2 Technical Assessment of Full Jacket Removal

8.6.2.1 Introduction

The comprehensive range of technical and safety studies on jacket decommissioning (Section 20 Appendix) has highlighted a number of important constraints or issues relating to the complete removal of the North West Hutton jacket. These are discussed in the following sections.

8.6.2.2 Cutting and Lifting Techniques

It is conservatively estimated that removal of the jacket down to the seabed will require approximately 20 scheduled major lifts involving a total of 250 cuts (Refs. 8.10, 8.11, 8.12, 8.13, 8.14, 8.15, 8.16 and 8.17). It is probable that the total number will be substantially higher due to the need to remove obstructions and potential dropped objects. This does not include removal of the lowest level of bracing or the template which is discussed later.

It is probable that the required equipment can be successfully developed from existing technology. The cutting methods that are most likely to be deployed are diamond wire (DW) and abrasive water jet (AWJ). Hydraulic shears could be used for members up to 1m in diameter.

The diamond wire cutting method uses a strong wire with diamond beads along its length (Figure 8.5). The wire runs round a series of pulleys and is rotated very quickly, like a chain saw, to cut through steel members containing stiffening or pipe-work. Abrasive water jet cutting uses high-pressure water with entrained abrasive material to cut through members and is best suited to simple tubular components.

These two methods would be suitable for severing all members down to the top of the footings at 100m below sea level. The main risks are associated with the reliability of the cut, and the safe handling of the securing, cutting and rigging equipment; the rigging equipment alone can weigh up to 40 tonnes. The size and weight of the equipment that would have to be used presents two main problems; achieving safe access in and around the jacket structure, and positioning the unit to accurately cut the structural members.

Both the diamond wire and abrasive water jet cutting techniques are prone to operational difficulties that can lead to incomplete cuts. For intermediate or preparatory cuts on the North West Hutton jacket such events would probably result in the requirement to repeat the cut, and there would be no major impacts apart from time delay and additional cost. For the final 3 or 4 structural cuts required to free each section for lifting, however, failure to complete a cut would represent a major source of risk because the crane would be attached to the section in readiness to lift. A cutting failure at this stage of the operation could result in the equipment and vessels being exposed to a severe risk of damage due to loss of stability and integrity of the section being removed, which would in turn result in additional safety risks to personnel, and potential failure of the whole project.

Figure 8.5: Photograph of a diamond wire cutter.

Development work will be required to design and manufacture clamps and rigging equipment with the size and capacity required for use on North West Hutton. Lifting clamps are used widely in construction and installation activities, and although they are generally reliable failures have occurred, e.g. piles have been dropped. During installation work, the sections being lifted are new, of known weight and geometry, and are attached to the crane by a very secure shackle and pad-eye system. For the North West Hutton decommissioning operations, however, lifting clamps would have to be attached sub-sea without a complete understanding of the section geometry or weight. The clamps would rely on friction as the prime method of attaching the rigging to the section being lifted. During lifting operations, any failure of the clamps or rigging equipment would result in the load being dropped onto the remainder of the jacket structure or, more significantly, onto the crane vessel or transport barge where personnel will be present. This is a risk in all construction lifts, but in a deconstruction operation such as that required for North West Hutton, there would be more uncertainty, and this would increase the overall risk of a catastrophic failure.

8.6.2.3 Removal of the Footings

The removal of the footings would require the use of different equipment due to the size and nature of the structure. Although the footings only account for 25% of the height of the jacket, they represent approximately 50% of the total weight because they are required to support the whole of the platform structure and secure it to the seabed. The risks associated with removal operations for the footings are similar to those associated with the removal of the upper jacket, but more severe due to the damage to the lower part of the jacket and the presence of the drill cuttings and grout.

The major components of the footings are the four main legs (or "bottle legs") including the piles (Figure 8.6). These legs are 5.5m in diameter and the five pile sleeves around each leg result in an overall diameter of more than 10m. Each bottleleg weighs about 1,600 tonnes and would be lifted as a single unit.

The support bracing would be removed in a similar way to that described for the upper jacket, although the damage described earlier would require careful consideration and analysis. The members lying on the seabed would have to be removed in smaller sections which would require additional lifts.

Removal of the bottle legs themselves would require the drill cuttings and other grout to be removed from around the base of the legs so that the units could be inspected and full disconnection of all members confirmed (Ref. 8.3). These operations would include the removal of about 100 tonnes of grout, including a deposit up to 1m thick around leg B1 (Figures 8.2a and 8.2b). This is a major undertaking that is likely to require a significant amount of diving activity, with its associated elevated safety risk.

To remove a bottle leg, each of the five piles would have to be severed, using an internal cutting tool, to release the leg from the seabed so that it could be lifted to the surface by crane. Several major risks have been identified for this operation.

- Although each of the North West Hutton piles has been inspected and access to the necessary cutting depth has been confirmed, it may not be possible to cut all of the piles internally. Access problems for the cutting tool have been encountered during pile-severing operations on other projects.
- Another risk arises as a result of a combination of the leg design, the storm damage described above, and the cutting technique. The legs are not vertical but slope inwards at an angle of 7 degrees; this is known as the "batter" of the jacket and is part of the original design. This will result in a tendency for the leg to fall inwards once freed from the seabed and it would be necessary to restrain the leg to prevent this. The leg would therefore have to be attached to the crane, or otherwise restrained, while the piles were being cut. This would be a complex task and would introduce significant risks, including the risk of overloading the rigging or crane due to the high dynamic loads that might be experienced as a result of releasing and lifting such a load from the seabed. The final pile cutting would also be critical because it would be subject to the severe difficulties that would arise in the event of equipment failure or an incomplete cut.
- The lifting of an unstable load of 1,600 tonnes in such a manner is a major risk. The failure mode could involve unplanned movement of the leg, ultimately leading to a dropped load and damage to the crane or equipment. The risk associated with lifting such a load from 140m below sea-level, rotating it to a horizontal position and loading it safely on to a transport barge is significant, and exposes personnel to a severe risk of injury or fatality (Refs. 8.22, 8.25, 8.26, 8.27, 8.28, 8.29 and 8.30).
- Falling objects pose a particular risk in this operation. It is highly likely that grout and drill cuttings would be attached to the leg, but in a very uncertain and unstable manner. Quantities of these materials could therefore become detached from the legs in a completely unpredictable way at any time while the legs were being manoeuvred onto the crane vessel or barge.

8.6.2.4 Removal of Damaged Bracings and Drilling Template

The final stage of complete jacket removal would involve removing the damaged bracing and the drilling template from the seabed. This would require an intensive campaign of diver-based activity to inspect, cut and lift the structural sections. These parts of the installation cannot be inspected prior to removal of the drill cuttings. Experience from similar projects suggests that significant quantities of grout will be present and that the extensive use of explosive cutting techniques would be required to free the template in small sections from the redundant well equipment.

The final activity of full removal would be the survey and removal of any remaining debris.

8.6.2.5 Use of Explosives

Whilst it is not anticipated or planned for explosives to be used in any way to cut the jacket or any of the associated subsea equipment, operational necessity may dictate that an explosives engineering solution be considered as a contingency to a subsequent unknown situation, or contractors may propose the use as a contingency to cut holes for drainage. In this eventuality, BP will refer this matter to both the DTI and the Joint

Nature Conservation Committee (JNCC) prior to the deployment of any explosives offshore. At this point, it will be deemed appropriate to use whatever systems are regarded as "best in class" for the identified task. Any chosen provider will have been evaluated on their ability to provide the most innovative solution, while at the same time following and implementing optimal mitigation procedures in accordance with JNCC guidelines. It should be noted that this would apply to either of the three jacket removal options not just the full removal option.

8.6.2.6 Summary of Technical Assessment of Full Jacket Removal

All offshore activities carry risks which are accepted and normally successfully managed. The above description identifies all of the significant risks associated with complete removal of the jacket. Typically, when risks are considered excessive, the activity is eliminated or mitigating actions are put in place. For the risks identified above, the ability to successfully mitigate the risks is limited and the magnitude of the risks far outweighs any positive benefits.

The complete removal of the jacket would require a period of intensive operational activity with large numbers of vessels, equipment and personnel exposed. Studies indicate that there would be significant technical risks and concerns associated with all the major lifts. Removal of the footings, in particular the main "bottle" legs, would result in major technical concerns that stem directly from the design of the jacket and the presence of significant damage, drill cuttings and grout. Information from other projects suggests that template removal carries a high risk of failure, or would require extensive use of divers and explosives, with all the attendant risks associated with these activities.

The "Quantitative Assessment of Technical Risk" study (Ref 8.25) estimated the likelihood of technical failure as being 45%, primarily because of the technical challenges of structural stability; cutting, rigging and lifting; back-loading and sea-fastening; and working in the drill cuttings zone.

All technical risks tend to have direct implications for safety risks, and these are discussed in the following section.

8.6.3 Safety Evaluation of Full Jacket Removal

8.6.3.1 Introduction and Method

The safety impact of the above operations was evaluated using the standard and accepted techniques of hazard identification (HAZID) and Quantitative Risk Assessment (QRA).

HAZID is a qualitative technique that uses specialists in the methodology being reviewed and safety specialists to identify the likely hazards and failure modes that would be encountered during an operation. Quantitative Risk Assessment (QRA) is used to analyse and rank scenarios identified in the hazard analysis to provide quantitative data for use in decision-making on risk and for the comparison of alternative options.

QRA uses a variety of methods including the use of historic data and event trees to calculate accident probabilities and consequences in order to determine Risk Assessment results present the risk associated with accidents in terms of frequency and number of fatalities.

The jacket removal operation was thoroughly assessed and included the risk evaluation of offshore removal, transport and onshore dismantling.

A variety of potential hazards were identified ranging from relatively low consequence hazards such as occupational slips, trips and falls, to high consequence hazards such as a dropped load. Each individual hazard event was assessed to evaluate the associated risk. The main contributors to the overall fatality risks are presented in Table 8.1.

Dropped Loads	Any unstable sections could compromise the safe lift of the sections onto the crane vessel. Failure of rigging could result in dropped loads onto the decks of the crane vessel or barge.
Falling loose items	Preparation of the jacket sections will be required on the crane vessel prior to transfer to barges. In addition personnel will be required on the barges for sea fastening activities. Personnel may be exposed to falling loose items particularly grout and drill cuttings during these activities.
Diver activities	Failure of technology may require diver intervention to complete section cuts or install clamps for structural integrity. Diving activities will be required for the removal of the template, grout and damaged members.
Cutting	Incomplete cuts could compromise the integrity of the crane and the crane vessel itself. The stability of the cut sections could affect the safe lift of the sections and their transfer to the barges.
Sea-fastening	The sea-fastening of cut sections requires personnel to be present on the barges as the sections are lowered. Personnel will be exposed to the potential for dropped loads/loose items as identified above.
Towing	The stability of the loaded barges and the potential effect of weather on these activities are crucial considerations for safe transfer of the sections to shore. Loss of a section or barge could jeopardise the towing vessel with the subsequent risk to personnel.
Occupational Risk	A large number of personnel will be involved in the removal of the jacket. General occupational risks will be present for these individuals including slips, trips and falls as well as more high risk activities including working at heights, basket transfers and over-the-side working.
Onshore disposal	Jacket sections will require significant onshore cutting with many of the already identified hazards present during this phase of work. A robust safety management system will be required at the disposal yard to manage the risks during disposal activities.

Table 8.1: Predominant safety risks of operations to remove the whole jacket.

8.6.3.2 Results of the Safety Evaluation of Full Jacket Removal

On the basis of the output from the technical studies, the results of the safety studies assumed that divers would be used on the operation. The analysis yielded the following results for total removal of the jacket and template (Refs. 8.22 and 8.25).

- Potential Loss of Life (PLL) — 14%
- Loss of Life on a Project basis — 1 in 7 chance of a fatality during a project
- Individual Risk per Annum (IRPA) — 1 in 2,000 for deck crew
  1 in 600 for divers

To put these figures into context, the predicted potential loss of life (PLL) for North West Hutton during production operations was 7.7% on an annualised basis. The risk of fatality with jacket removal was calculated on an assumption that operations will take between 3 and 4 months to complete. Annualising the predicted risk for comparative purposes gives a PLL for jacket removal of 30% or 4 times the risk of production operations.

Neither the industry nor the regulatory authority, has established a recognised maximum or intolerable PLL limit. However, the Health and Safety Executive, and industry in general, use a related measure known as the "Individual Risk Per Annum" (IRPA) which calculates the specific fatality based on the probability that the individual will be exposed to the hazard event. PLL and IRPA are directly related in terms of the number of people and time spent in the activities.

$$PLL = IRPA \times \frac{\text{Number of people working on the project}}{\text{Fraction of time working per year.}}$$

In terms of risk acceptability, the requirement is on the duty holders to set their own criteria for the acceptability and tolerability of risk. However, the HSE commonly define the maximum tolerable level of individual risk of fatality as 1 in 1000 per year, and for the broadly acceptable level of individual risk to be in the range 1 in 100,000 to 1 in 1 million per year, (see also 6.4.1).

BP's own criteria for acceptability of risk is that the risk of fatality for an individual shall not be greater than 5 x 10^{-4} (1 in 2,000).

During operations to decommission the whole jacket by total removal, the IRPA for the deck crew involved in the lifting activities is predicted to be approximately 1 in 2,000 per year. This is close to the "intolerable" level (1 in 1,000 per year) defined by the HSE. The corresponding diving risk has been estimated to be 1 in 600 which is above the intolerable level for individual risk.

It is important to note that the evaluation of safety risk is normally based upon historical statistical data gained from performing similar activities. As subsea deconstruction is a relatively untested activity, in many cases there is little or no directly relevant statistical data available for modelling purposes. Existing construction and installation data have to be used, or probabilities estimated by means of alternative approaches (e.g. through the use of event tree analysis). It is therefore probable that the modelling undertaken does not take account of all the risks and consequently has underestimated the risk in certain activities.

Unfortunately this is borne out by the experience to date from relatively few North Sea decommissioning projects, where there have been a number of fatalities. Sadly this illustrates the high risk nature of decommissioning both onshore and offshore.

8.6.4 Environmental Impacts of Full Jacket Removal

The EIA (Ref. 8.31) assessed all the potential environmental impacts associated with operations to fully remove the jacket and template.

The use of vessels, the programme of underwater cutting, and the use of onshore receiving and recycling sites, would all give rise to a range of negative environmental impacts. The impacts and their significance are summarised in Table 8.2. While some of the impacts are negative, none of the impacts are significant as discussed in the EIA.

Operation or Activity	Main Impacts	Significance
Physical presence of vessels associated with cutting and lifting	All impacts short-lived and localised	
	Anchor disturbance of the seabed Physical presence of vessels Vessel marine discharges	• Impacts restricted to work site
	Creation of underwater noise	• Low densities of marine mammals in area
	Burning of fuel	• Vessel energy usage estimated to be 300,000 GJ • Gaseous emissions of minor significance
Possible use of explosives for cutting template	Disturbance and possible injury to fish and marine mammals	• Follow guidance and advice of Joint Nature Conservation Committee (JNCC) • Limited to essential use
Reception and dismantling at coastal site; onshore transportation, and recycling	Odour, noise and nuisance of operations	• All operations conducted at licensed and audited sites • Impacts likely to be at a low level and similar to those previously experienced at these locations
Removal of structure from the marine environment	Restore seabed to original condition	• Positive impact through removal of structure from seabed • Total energy usage of approximately 6,600 households
Emergency events (includes sinking of vessel, loss of component when lifted)	Discharges to marine environment and disturbance of seabed	• Probability of event is very low, although consequences are high

Table 8.2: Environmental impacts of total removal of the jacket (Refs. 8.31 and 8.32).

8.6.5 Societal Impacts of Full Jacket Removal

The studies on the societal impacts of the decommissioning programme made a detailed investigation of the potential impact on the fishing industry and also the wider economic impacts resulting from the overall decommissioning activity (Refs. 8.34 and 8.35).

Fishing is the only commercial activity directly affected by the presence of the North West Hutton platform. In 1981 a 500m radius exclusion zone was established around the platform for safety reasons. Removal of the whole jacket would restore this area (0.75km^2) to fishing activity. The commercial value of this area is "moderate" (Ref. 8.36), and it is unlikely that the restoration of this small area would have a noticeable effect on fish catches. The main benefit of removing the whole jacket would be the elimination of the requirement to plan trawling patterns around the location.

In terms of the overall economic benefit of the jacket removal, the study showed the impacts to be relatively minor in magnitude. There is no indication that there would be any sustainable positive impact on employment as a result of activities to remove, dismantle and recycle the jacket, and this is in line with the findings of wider studies on the overall impacts of decommissioning activity. The study (Ref. 8.35) indicates that the activity will benefit existing offshore suppliers and bases in the EU mainly in the UK, Netherlands and Norway. The study also shows that although some additional onshore jobs may be created in the recycling, construction and business service sectors, these would be relatively short-term and lower-skilled.

Removal of the jacket and template would result in the seabed being left free of obstructions with the piles severed at a depth of about 3m below the mudline. The majority (at least 97%) of material in the jacket would be recycled and used in the manufacture of further items and products.

The studies, including the EIA, undertaken by the North West Hutton owners,and discussions with interested parties, have shown that the programme for decommissioning could have some potentially positive societal impacts. There is also the potential for negative impacts, mainly associated with the onshore aspects of transportation and recycling activity – for example community disturbance issues - but it will not be possible to measure these accurately until the actual onshore recycling locations are known.

The potential for positive societal impacts includes:

- Removal of a physical obstruction on the seabed which would represent a potential snagging hazard for the fishing industry and would otherwise require a range of mitigation measures to ensure this area is clearly marked as not over-trawlable.
- Re-opening of access to this part of the seabed for the fishing industry, although this will not be a significant commercial benefit.
- Creation of modest levels of short-term employment at one or more onshore recycling locations.
- Achieving a high figure for the overall percentage of the North West Hutton platform to be reused or recycled.

8.6.6 Summary of Full Jacket Removal

The assessment of the complete removal option for the North West Hutton jacket indicates that the key factors that need to be considered in the evaluation of this option are:

- The sheer scale of the activity and the high level of technical uncertainty associated with achieving the objectives;
- the unacceptable level of safety risk that directly results from this uncertainty; and
- the likely requirement for the intensive use of divers particularly for recovery of the lower-most sections of the structure.

The main positive benefit from full removal is full restoration of access for fishing activity.

The North West Hutton owners have considered the individual and collective implications of these findings. They believe that the levels of technical and safety uncertainty identified in the study work are intolerable, and cannot obviously be reduced, this is supported by independent studies (Refs. 8.16. 8.17, 8.25 and 8.30). Accordingly, additional options were studied and compared with the option of total removal, before reaching a final recommendation.

The assessment of full removal indicated that the most significant risks were associated with the removal of the footings and the lower-most section of the jacket. Accordingly, the additional options that were studied for the North West Hutton jacket were ‘partial removal’ of the footings and ‘removal of the jacket to the top of the footings’.

8.7 Assessment of the Option of Partial Removal of the Footings

8.7.1 Technical Evaluation of Partial Removal of the Footings

In this option, the jacket and all equipment down to the level of the drill cuttings (i.e. the present effective seabed level) would be removed and taken to shore. Two studies addressed this specific option in detail (Refs. 8.19 and 8.20). The studies were carried out by specialist diving contractors, who represent the best source of expertise on the specific underwater operations required.

The upper part of the jacket, down to the top of the footings at -100m, would be removed using techniques and programmes of work identical to those described in Section 8.6.1. Consequently all the risks and concerns for this option are the same up to this stage.

After removal of the upper jacket, the exposed footings above the level of the drill cuttings pile would be removed in sections. This would be achieved by cutting through members, and the legs themselves, as close as practicably possible to the level of the drill cuttings pile (Figure 8.3.b). The advantages of this approach are that there is no requirement to access the areas of the footings severely affected by grout, drill cuttings and the major area of damage at the lowest level of bracing. In addition, the drilling template, which represents a major source of technical challenge, would remain in place.

The major difference between this option and the total removal option would be the requirement to sever the bottle legs themselves. This would involve cutting operations that would be significantly more complex than those required to free the bottle legs by cutting the piles internally.

The design of the bottle legs includes shear plates at the lowest level and there is substantial internal stiffening to reinforce the leg behind the incoming braces (Figure 8.6). The most practical level to cut the leg is therefore above these shear plates and stiffening. This makes access for ROVs and the cutting equipment far more practicable, and also makes it possible to adjust or move the location of the cut if there is any operational problem or cut failure. This would leave about 3 to 6 metres of the bottle leg visible above the cuttings, i.e. a height of about 10m above the seabed level.

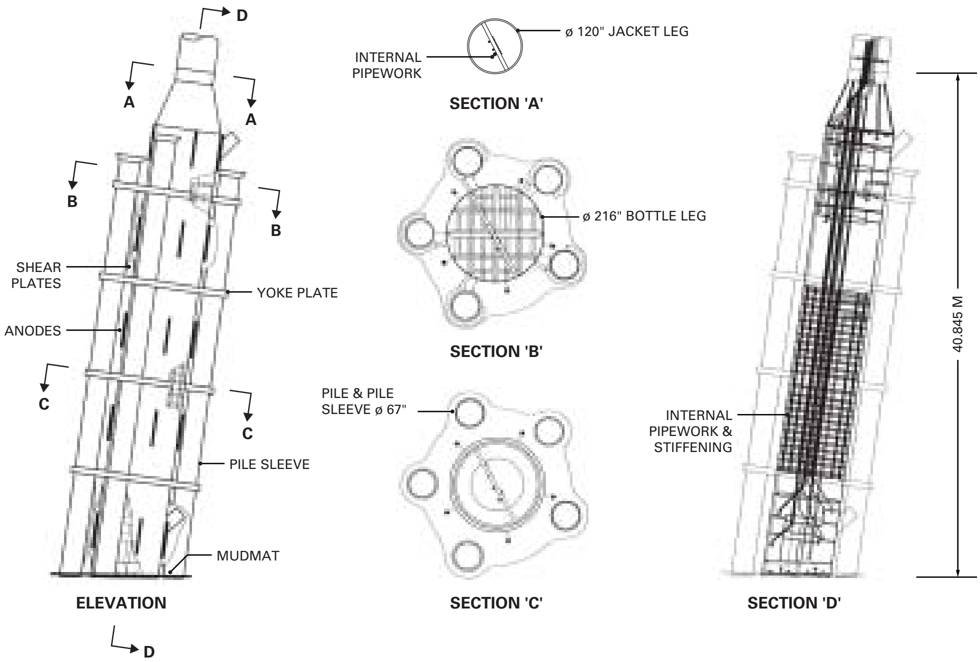


Figure 8.6: Drawings detailing complexity and size of the bottle legs.

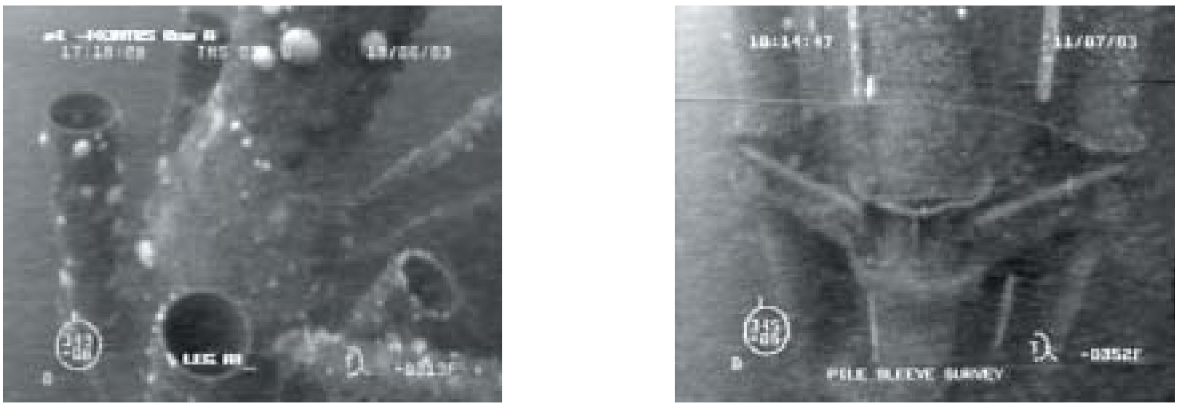


Figure 8.7: ROV pictures of the bottle legs showing the poor visibility.

To sever the bottle legs a section of each of the piles and pile sleeves would have to be removed to gain access to the main leg. These cuts could be either external or internal and two cuts would be required on each pile. Each cut would be required to sever the combined thickness of the pile sleeve, the grout and the pile itself, as opposed to just the pile as in the complete removal option. One of the major technical problems identified in the studies is how the pile sections, weighing up to 10 tonnes, could be successfully extracted and rigged for removal to the surface (Refs. 8.19 and 8.20). This operation is made significantly more complicated by the 7 degrees' batter' of the leg, which makes each of the five piles unique with regard to the details of the cutting and rigging.

Once the pile sections had been removed, it would be necessary to rig the section of the bottle leg for removal to the surface, as described in Section 8.6.1. The leg itself would then be severed using diamond wire (Figure 8.5) because it would be necessary to cut through the internal pipework within the leg (Figure 8.6). Each bottle leg is more than 5.5m in diameter, excluding the piles. The largest leg cut required otherwise is 3.0m and the need to develop and implement the technology capable of achieving a larger cut, with the required level of confidence, presents a significant challenge. Divers would be required for these operations (Ref. 8.21), and the safety implications of extensive diver operation have already been discussed.

The operations required to cut and lift the severed leg to the surface, and transport it to shore, would be similar to those described in Section 8.6.1. All the technical difficulties identified there would also apply to these lifts, but would have a much increased risk of failure (Refs. 8.19 and 8.20). The estimated increase in the likelihood that the cut would be unsuccessful is so great that the practical feasibility of making this cut is in severe doubt. At the very least large inspection holes would have to be cut in the leg to gain internal access for inspection and may even require some cutting of internal pipe-work. This would represent a further application of technology that is as yet untried at this scale, and would therefore require the successful implementation of a major technical development (Refs. 8.19 and 8.20).

To summarise, the option of partially removing the jacket close to the existing seabed (above the drill cuttings pile) carries many of the same technical risks as full removal. There would be a reduction in technical risk because the template and lower bracing would be left *in-situ*, but this would be more than offset by the increased risk associated with severing the bottle legs in particular. This increased technical risk is also associated with cutting and handling the piles by doubling the number of cuts and lifts as well as increasing the complexity of cutting operations.

The quantitative risk assessment study indicated that the additional work scope for cutting through the legs is a greater technical challenge than that of recovering the template and the jacket members on the seabed that are buried in the drill cuttings pile. The overall risk of technical failure was calculated to be 70% (Ref. 8.25), which in terms of a "construction project" is unacceptable.

8.7.2 Safety Evaluation of Partial Removal of the Footings

As discussed in Section 8.6, the technical risk and safety risk are inextricably linked. The safety risk for the upper part of the jacket is identical to that described for full removal. The risks associated with the partial removal of the footings are similar to those presented by full removal but with a different emphasis. In the partial removal option the main risks are associated with diving and cutting, whereas in the full removal option falling objects, for example grout and drill cuttings, would pose significant risks. The risks in Table 8.1 therefore still apply and the change in emphasis described above was covered in the QRA. Towing of the cut sections to shore and onshore disposal are considered unaffected by this option.

The QRA of the partial removal option has estimated the PLL at 13%, i.e. it is predicted that there would be 1 in 8 chance of a fatality during a project(Refs. 8.22, 8.25, 8.28, 8.29 and 8.30). This represents a slight decrease in risk when compared with total jacket removal risks which estimated the PLL as 14% (1 in 7 chance). However there is considerable uncertainty on the cutting and rigging and associated diving work for the partial removal of the bottle legs. If this were to increase, which is quite possible, then the risk profile for this option would increase.

8.7.3 Environmental Impacts of Partial Removal of the Footings

The environmental impacts for partial removal of the footings are almost identical to those described in Section 8.6.4 for full removal. The main difference is that approximately 3,000 tonnes of steel will be left in place and therefore unavailable for recycling. The environmental impact study demonstrates that the emissions profile resulting from this is effectively neutral as the loss of recycling opportunity is offset by the energy saved due to the shorter duration of operations, and the energy required to re-cycle steel onshore (Refs. 8.31 and 8.32).

The anodes and the steel will gradually corrode and be released into the sea as corrosion products. The rate of release and nature of the materials involved will not cause any significant environmental impacts (Ref. 8.31).

The short-term environmental impacts would be reduced due to lower overall activity at the site, and in particular the elimination of the requirement to use cutting techniques, including the use of explosives, to remove excess grout, the lower leg sections and the template. This would, however, be significantly offset by increased cutting operations to sever the main legs and pile structures. The main negative aspect is the continued presence of material on the seabed at this location.

Studies were implemented to determine the likely longevity of the footings material if left *in-situ*. It is likely that remaining material would deteriorate slowly because of the low energy environment in the deep water at North West Hutton, the low current speeds at the site, and the low water temperature in this part of the North Sea. The anodes would last for about 30 years, and the steel structures for between 500 and 1,000 years (Ref. 8.33).

8.7.4 Societal Impacts of Partial Removal of the Footings

The potential impact on the fishing industry and wider economic and employment impacts are considered to be the main societal issues that must be addressed when evaluating the option of the partial removal of the footings.

For the fishing industry, partial removal of the jacket would mean a continuing requirement for demersal trawling patterns to be planned around the location, as the remaining footings would represent a potential snagging risk.

If part of the footings were to remain on the seabed it would be necessary to ensure that information on their size and location is communicated through the Kingfisher Information Service bulletins and charts, and that the 'FishSafe' database was updated to include a change of designation from 'installation' to 'obstruction'.

The area within which North West Hutton is located is deemed to be of "moderate" overall economic value for fishing. The overall size of catches would not be affected by the implementation of the partial removal option.

The results of an economic impact study which examined the possible options for the jacket, found that the partial removal option would have no significant effect on the overall scale of work available to contractors. There are therefore no significant offshore or onshore economic impact or employment factors which would have an important bearing on the selection of this option (Ref. 8.35).

8.7.5 Summary of Partial Removal of the Footings

The assessment shows that, overall, partial removal of the footings (which would require the bottle legs to be severed) has risks and uncertainties of a similar or greater magnitude to those of complete removal of the jacket. Partial removal of the footings would present a high level of technical uncertainty and an intolerable level of safety risk that is a direct consequence of this technical uncertainty. The extent and complexity of diving operations in both options is approximately the same (Refs. 8.19, 8.20, 8.21, 8.25, 8.26, 8.27, 8.28, 8.29 and 8.30).

Following the successful implementation of the partial removal option, trawler operations would not be feasible over the site. This would present an obstruction to commercial fishing operations in the area, but would not affect the overall available catch. The possibility of fishing equipment becoming snagged on the structure which remains on the seabed is recognised, but the probability that such an event would occur, given the mitigation measures that would be in place, is considered to be low.

8.8 Assessment of the Option of Jacket Removal to the Top of the Footings

The assessments described above in Sections 8.6 and 8.7 would involve the removal of all or most of the footings. In large steel jackets such as North West Hutton, the top of the footings represents a transition from the support steelwork which comprises the major part of the jacket height, to the much more robust and reinforced foundations required to safely anchor the whole platform to the seabed. This represents a natural engineering transition point for consideration as a cut-off level for removal, and is recognised as such in the DTI Guidelines (Ref.8.24).

This section describes the alternative option of removing the jacket structure down to the top of the footings.

8.8.1 Technical Evaluation of Removal of the Jacket to the Top of the Footings

This option would involve retrieval of the jacket and all equipment down to the transition point from the jacket structure to the footings, at approximately 100m below sea level.

All of the removal requirements for the upper part of the jacket down to the top of the footings are identical to those described in Section 8.6.1; consequently all the operational activities, risks and concerns are the same as in this option.

The quantitative risk assessment study (Ref. 8.25) indicated that there would be a highly significant reduction in the overall technical risk by restricting removal operations to the upper jacket only. This reduction is the result of two factors; firstly the risk of failure would be reduced because the total amount of work undertaken would be smaller, and, secondly, the technical risks associated with removal of the footings, damaged bracing, excess grout, and drilling template would no longer apply. The overall risk of technical failure of an operation to remove the jacket down to the top of the footings was estimated to be 23% (Ref. 8.25). Although significantly lower than the options of total or partial removal this still represents a significant risk, reflecting the immaturity of decommissioning experience, equipment and techniques.

8.8.2 Safety Evaluation of Removal of the Jacket to the Top of the Footings

As discussed above in Section 8.6, the technical risk and safety risk are inextricably linked. The safety risk for the removal of the upper part of the jacket is similar in nature to that described for full removal, but is much smaller. In particular the safety risks associated with the removal of the footings and the template are eliminated completely. The QRA of this option (Ref. 8.22, 8.25, 8.29 and 8.30) predicts a PLL of approximately 5%, representing a 1 in 20 chance of a fatality during a project. When compared with the estimated safety risk of total removal, this represents a reduction in risk of approximately 65%.

8.8.3 Environmental Impacts of Removal of the Jacket to the Top of the Footings

The environmental impacts for jacket removal to the top of the footings are similar to those described in Section 8.7.3. For this option approximately 9,000 tonnes of steel will be left in place and therefore unavailable for recycling (Ref. 8.37). The Environmental impact study demonstrates that the energy budget of this option is effectively neutral because the loss of recycling opportunity is completely offset by the energy saved due to the reduction in the extent of offshore operations.

In this option there would be fewer short-term environmental impacts from the decommissioning activities themselves than in the other two options. This would result from the lower overall level of activity, and in particular the elimination of the requirement to use cutting techniques including significant use of explosives to remove excess grout, the bottle sections and the template.

As with the option of partial removal of the footings, the option of removing the jacket to the top of the footings would result in steel and anodes being left in the marine environment. These materials would gradually corrode and be released into the sea as corrosion products. As a consequence of the predicated rates of release and the nature of the materials involved, this process would not cause any significant environmental impacts.

Studies were implemented to determine the likely longevity of the footings if they were left *in-situ* at the North West Hutton site. The depth of the water combined with low currents speeds and low temperature would result in relatively slow deterioration. The anodes would be likely to last for about 30 years and the steel structures for between 500 and 1,000 years (Ref. 8.33).

8.8.4 Societal Impacts of Removal of the Jacket to the Top of the Footings

The potential impact on the fishing industry and wider economic and employment impacts are considered to be the main societal issues that must be addressed when evaluating the option of removing the jacket to the top of the footings.

For the fishing industry, jacket removal to the top of the footings would mean a continuing requirement for demersal trawling patterns to be planned around the location, as the footings would represent a potential snagging risk.

In this case it would be necessary to ensure that information on the size and location of the North West Hutton footings is communicated through the Kingfisher Information Service bulletins and charts, and that the 'FishSafe' database was updated to include a change of designation from 'installation' to 'obstruction'.

The area within which North West Hutton is located is deemed to be of "moderate" overall economic value for fishing. The overall size of catches would not be affected by the implementation of the option to remove the upper part of the jacket.

The amount of work required to remove the jacket down to the top of the footings would be about half that required to remove the whole of the jacket. In terms of this project, this reduction in effort is very significant but in terms of the overall level of economic activity in both the offshore and onshore sectors this reduction would be negligible. There would be no significant impact on overall employment (Ref. 8.35).

8.8.5 Summary of Removal of the Jacket to the Top of the Footings

The foregoing assessments show that there would be a very large reduction in technical and safety risk if the jacket were removed to the top of the footings at a depth of 100m. It is also apparent that, despite this reduction, the operation that would be required to remove the upper part of the jacket would still result in high levels of technical and safety risk.

The impact of this option on fishing patterns around the site is recognised. The presence of the footings at the North West Hutton location would represent a potential obstruction for demersal and deep pelagic fishing operations and therefore trawling operations would not be feasible over the site. This would present an obstruction to commercial fishing operations in the area, but would not affect the overall available catch. The possibility of fishing equipment becoming snagged on the structure which remains on the seabed is recognised, but the probability that such an event would occur, given the mitigation measures that would be in place, is considered to be low.

8.9 Cost Assessment

The costs for the three jacket removal options are discussed in Section 13. The costs are order of magnitude and reflect the uncertainties and risks for executing removal work on the scale of North West Hutton. BP has submitted cost details for these removal options to the DTI but for reasons of commercial sensitivity these have not been included in this programme.

8.10 Comparative Assessment and Conclusions of Jacket Removal Evaluations

The following discussion does not take account of the requirement, as a minimum, to excavate and relocate the drill cuttings in order to complete full removal of the jacket and template. This is addressed in Section 9.

In reaching the final conclusion one aspect that should be emphasized is the scale of the jacket, which is relevant for all operations but particularly the technical and safety challenges. Figure 8.8 shows photographs of work during construction, and the scale is further demonstrated by the computer graphic of a diver shown next to a bottle leg. This is particularly relevant for cutting the bottle legs, which would involve the use of divers, with the attendant safety exposure. The computer graphic shows scale but simplifies the operations, because in reality visibility would be very poor (Figure 8.7), the structure would be covered in marine growth and there are appurtenances and the potential for debris, which complicates all work activities.

Figure 8.8: Computer generated diagram and photographs showing size and complexity of the bottle legs.

The various technical and safety studies undertaken by specialist contractors on behalf of the North West Hutton owners clearly demonstrate that the removal operations associated with all the major components of the North West Hutton jacket carry substantial safety risk to the personnel carrying out the work both offshore and onshore. The technical risk that could result in failure to achieve the objectives of each of the options is also significant, and is a consequence of the size and nature of the equipment involved, the requirement to develop new tools, and the overall lack of experience with operations on such a scale (Refs. 8.10, 8.11, 8.12, 8.13, 8.14, 8.15, 8.16, 8.17, 8.18, 8.19, 8.20.and 8.21).

The overall risk of fatalities and technical failure increases substantially if removal of the footings and template are included. Several detailed evaluations, using standard and recognised methods, clearly show that the safety risks to personnel during removal operations for the footings and template would be intolerably high, as judged by both BP and industry criteria (Ref. 8.22, 8.25, 8.26, 8.27, 8.29, 8.29 and 8.30). Furthermore, there is little scope for mitigation of the identified risks, because of the nature of the operation, the number of personnel required and the amount of equipment involved.

In terms of overall environmental risks, removal to the top of the footings presents the most favourable outcome, although, none of the options result in any significant environmental concerns. None of the materials in the jacket components, or their corrosion by-products, would have any adverse toxic effects in the marine environment.

Recovery to the top of the footings would result in the smallest amount of direct gaseous emissions because of the shorter duration and smaller amount of work. When the energy associated with manufacturing the steel not available for recycling is taken into account, the energy figures for each option are broadly equal. The overall use of energy and the consequent atmospheric emissions are significant in local terms but are not significant in a regional context.

The only real practical benefits that would be gained as a result of complete removal of the jacket and template would be the reopening of the site for fishing, and the elimination of any snagging risk. Conversely, the options in which components were left on the seabed would result in the site remaining an obstruction to fishing. The longevity of any steel work remaining in place is significant and it will persist for a minimum of several hundred years. The obstruction resulting from steel work left *in-situ* will be no different from other seabed obstructions as appropriate marking and mitigation will be put in place.

The following table summarises the key qualitative and quantitative factors.

Criteria	Full Removal	Partial Footings Removal	Removal to Top of footings
Safety Probability of a fatality No. of lost time injuries	**14%** **16**	**13%** **15**	**5%** **6**
Environmental Impact Energy (Household equivalents) CO_2-E (Household equivalents) Footprint - km^2 Persistence -Years	6,600 6,400 None None	7,300 6,800 <0.01 >500	7,100 5,900 <0.01 >500
Societal Impacts on fisheries UK Employment - man years	None 196	No-go fishing area Not studied	No-go fishing area 66
Technical Probability of a major technical failure	45%	70%	23%
Economic	See Section 13		

Table 8.3: Summary of key qualitative and quantitative factors for three jacket removal options.

8.11 Recommended Decommissioning Option for the Jacket

On the basis of the above evaluation of the options using the technical, safety, environmental, societal and economic factors, it is recommended that the jacket should be removed down to the top of the footings at approximately 100m below sea-level. The footings, integral template and damaged bracing will be left *in-situ*.

Recommendation: The North West Hutton jacket should be removed down to the top of the footings and returned to shore for reuse or recycling. The footings structure should remain *in-situ*.

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9 DRILL CUTTINGS

9.1 Introduction

This section describes the options for decommissioning the North West Hutton cuttings pile as a discrete entity, and evaluates them within the framework of the guiding principles discussed in Section 6. In order to provide a clear appreciation of the advantages and disadvantages of different options, any potential effects of the presence of the North West Hutton jacket are disregarded for the purposes of this evaluation. This section presents:

- an outline history of the pile and a description of its present composition and effect on the surrounding seabed;
- descriptions of possible options for decommissioning the pile;
- an evaluation of the technical, safety, environmental, societal and cost implications of these options; and
- a recommended option for decommissioning the drill cuttings pile.

9.2 Present Composition, Condition and Effects of the North West Hutton Drill Cuttings Pile

9.2.1 Introduction

This section gives further information about the history and physical nature of the drill cuttings pile and of the surrounding seabed that have an important bearing on the various options that could be used to decommission the pile.

9.2.2 History

The wells at North West Hutton were drilled to a depth of about 3,300m below the level of the seabed, and the resulting rock cuttings were treated on the topsides before being discharged to sea under licence, as was common industry practice at that time (Sections 4 and 5). A total of 53 wells and partial wells (commonly referred to as "sidetracks") were drilled at North West Hutton, with the last well being drilled in 1992.

Drill cuttings are formed as the drill bit creates the hole. The cuttings are generally small in size, typically less than 0.5cm in diameter and irregular in shape. The cuttings are removed from the well by a fluid referred to as "drilling mud" or "drilling fluid", and carried back to the topsides where they are cleaned to remove excess drilling fluid. On North West Hutton, and other installations, the cleaned cuttings were then discharged into the sea from caissons. The cuttings fell to the seabed where a large proportion of the cuttings, including any remaining coating of drilling fluid, accumulated as a pile on the seabed directly beneath the platform.

The North West Hutton wells were drilled with two types of drilling fluid (Refs. 9.1 and 9.2). The upper sections (down to around 1,000m) were drilled with a water-based fluid, but for the lower sections, an oil-based fluid was used. At the time, oil-based fluids were widely used to control difficult drilling conditions such as those encountered at North West Hutton. The North West Hutton pile will therefore have formed with discrete layers of water-based and oil-based cuttings. Although samples of the pile show different compositions, there is, however, no detectable evidence of such layering within the pile.

The size, extent and composition of the pile were summarised in Sections 4 and 5. Because of the water depth at the North West Hutton location, which results in very low wave action at the seabed and generally weak seabed currents, the pile lies largely within the confines of the jacket legs. It is elliptical in shape, with its long axis running NE-SW, and has a maximum diameter of approximately 200m (Figure 9.1) (Ref. 9.1).

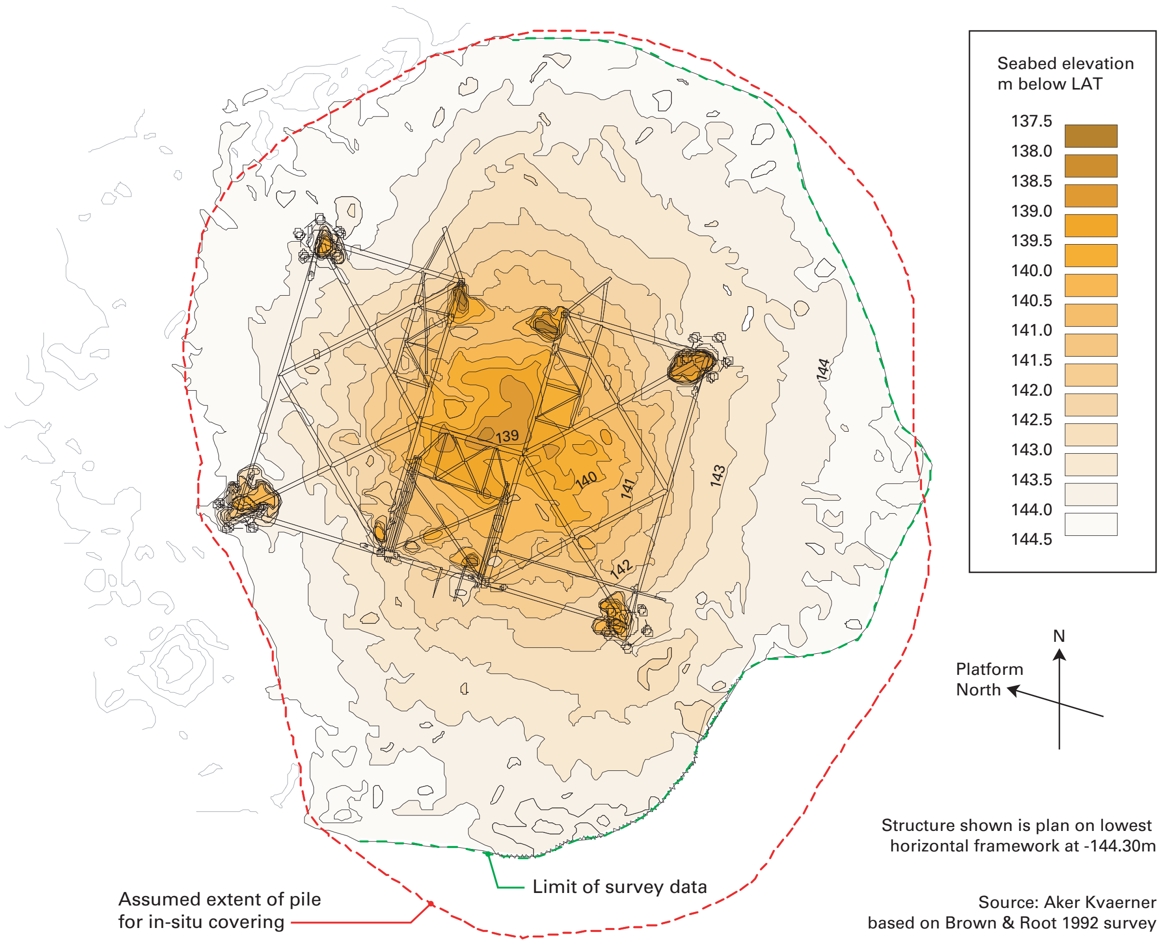

Figure 9.1: Contour map of the North West Hutton drill cuttings pile (Ref. 9.3).

As the cuttings were discharged and settled on the seabed, the irregular size and shape created voids between the cuttings particles (like pebbles on a beach) which filled with seawater. As the cuttings particles were compressed in the presence of the seawater and further deposition of cuttings added weight, some of this water was squeezed out, but a significant amount remains entrained or trapped within the pile. It is estimated that approximately 45% of the pile (by volume) consists of seawater trapped between the solid particles (Refs. 9.4 and 9.5). As a result of this high proportion of water, the pile is relatively weak; it has a low "shear strength". Consequently, the pile tends to slump and has a relatively flat profile, attaining a maximum height of 5.5m above the seabed (Figure 9.2). Using side-scan sonar images, the volume of the drill cuttings pile, including the volume of seawater, has been calculated to be 30,000m^3.

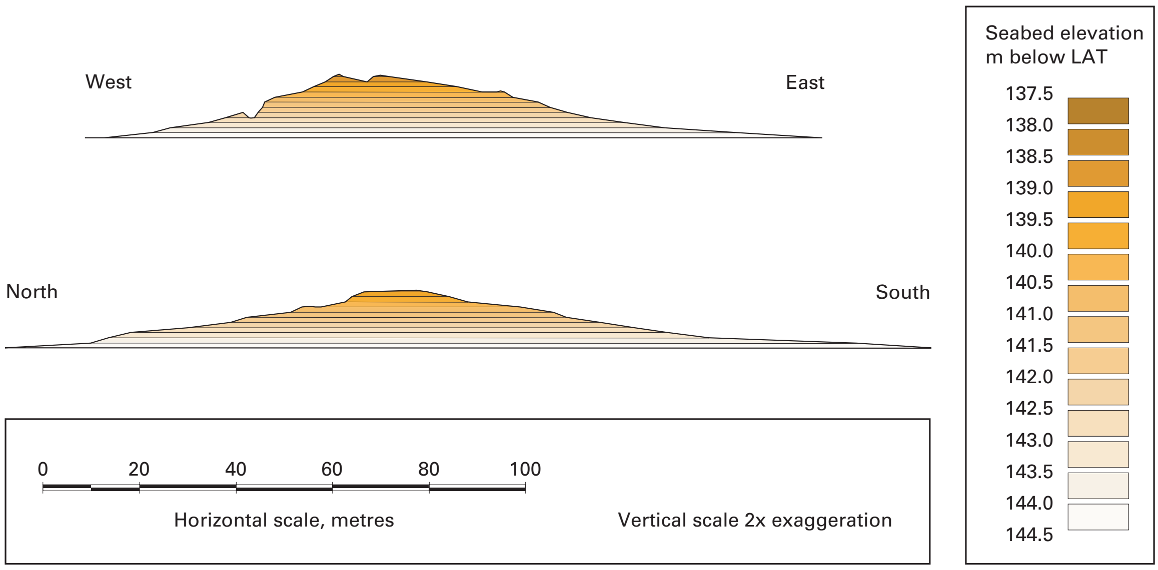

Figure 9.2: Cross section through the North West Hutton drill cuttings pile (Ref. 9.5).

9.2.3 Composition

The present composition of the pile was shown in Section 5, Table 5.6. This data has been derived from the analysis of samples taken from the pile and surrounding area during numerous seabed surveys.

9.2.4 Physical Nature of the Drill Cuttings Pile

The upper surface of the pile is in contact with seawater, and a thin layer here (about 0.5cm thick) is exposed to an aerobic environment. The concentrations of hydrocarbons and some other contaminants in this layer have been decreasing (Refs. 9.1 and 9.4) since discharges ceased, as a result of natural weathering caused by physical processes such as current and wave action, bio-degradation by bacteria, and by bioturbation by seabed organisms.

The water depth, low temperature (approximately 4 C) and very low energy levels from wave and current action in the vicinity of North West Hutton result in this upper, "recovering", layer remaining in a stable condition. This in turn indicates that there is very little leaching or transfer of hydrocarbons and other material from deeper layers of the pile into the surrounding environment.

The leaching rate will depend on a number of factors including conditions for weathering and disturbance of the pile, but industry studies applied to North West Hutton pile suggest that the total leach rate of oil from the pile is 2-3 tonnes per annum (Ref. 9.1). The relatively low leach rate is consistent with observations of the pile and also modelling results that provide estimates of the likely persistence of an undisturbed pile.

There is some anecdotal evidence that the recovered layer can, in places, form a fragile 'crust' that may reduce the movement of material out of the pile, although it is not strong enough to protect the pile against physical impact. Contaminants are therefore predominantly contained within the pile, but if the surface layer were disturbed, material would be released; the amount of material released would depend on the size and nature of the disturbance. Once the source of the disturbance is removed, the aerobic conditions at the new surface or interface rapidly weather the material and form a new aerobic surface layer (Figure 9.3).

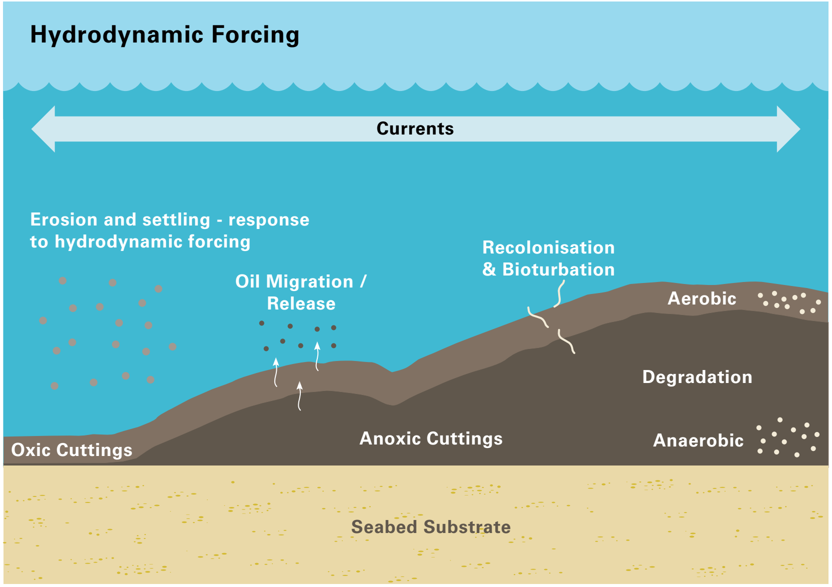

Figure 9.3: Schematic of cross-section of generic cuttings pile showing the main features and processes on and in a large drill cuttings pile.

9.2.5 Understanding of the North West Hutton Drill Cuttings Pile and the Surrounding Area

A total of seven major sampling and survey programmes (Table 3.2, Section 3.4) plus additional opportunities for analysis have been conducted on and around the North West Hutton cuttings pile since 1983 to assess and monitor the nature of the pile and its effects on the marine environment (Refs. 9.1 and 9.4). These surveys, which have extended up to 10km from the platform, provide a comprehensive picture of the extent of the pile's impact on the seabed and the ongoing natural recovery processes.

The presence of cuttings material, and its effects on the environment, can be measured in a number of ways.

9.2.5.1 Hydrocarbons and Benthic Communities

Typically, the presence of hydrocarbons (for oil-based drill cuttings piles such as that at North West Hutton) and the presence of barium in the form of "barite", can be used as "markers" for the presence of drill cuttings material. The presence of hydrocarbon concentrations in excess of 50ppm has been demonstrated to be an accepted threshold above which benthic communities are affected (Ref. 9.1). Figure 9.4 shows the reduction in hydrocarbon concentration with time and distance from the platform. This shows that small amounts of drilling material, evidenced by raised hydrocarbon levels, were detectable between 2,500m and 5,000m from the platform in 1985. (It is important to note that at these distances the impact of other installations and activity may also be affecting the results). The detection of hydrocarbons at these sampling points is most likely to be due to very fine material being carried by the current as the cuttings were originally discharged (Ref. 9.6).

9.2.5.2 Diversity Indices

In general, increasing hydrocarbon concentration is likely to lead to a reduction in the number of species present in seabed (benthic) communities. The effects of the presence of drill cuttings are detected by sampling the seabed communities at different distances from the cuttings pile and comparing these with communities from similar but uncontaminated areas of seabed.

The Shannon-Wiener diversity index is a way of expressing complex data on the numbers of species present and their density per unit area in a single figure. It is used to describe the composition of the seabed communities and to illustrate how these have been affected by the platform's operations.

Normal undisturbed sites in the central and northern North Sea often have diversity index values of over 5, but in severely disturbed areas, such as those adjacent to accumulations of oily cuttings, the index can be less than one.

Figure 9.5 shows the recovery in the diversity of the benthic species to typical background levels in relation to time and distance from the platform, to typical background levels.

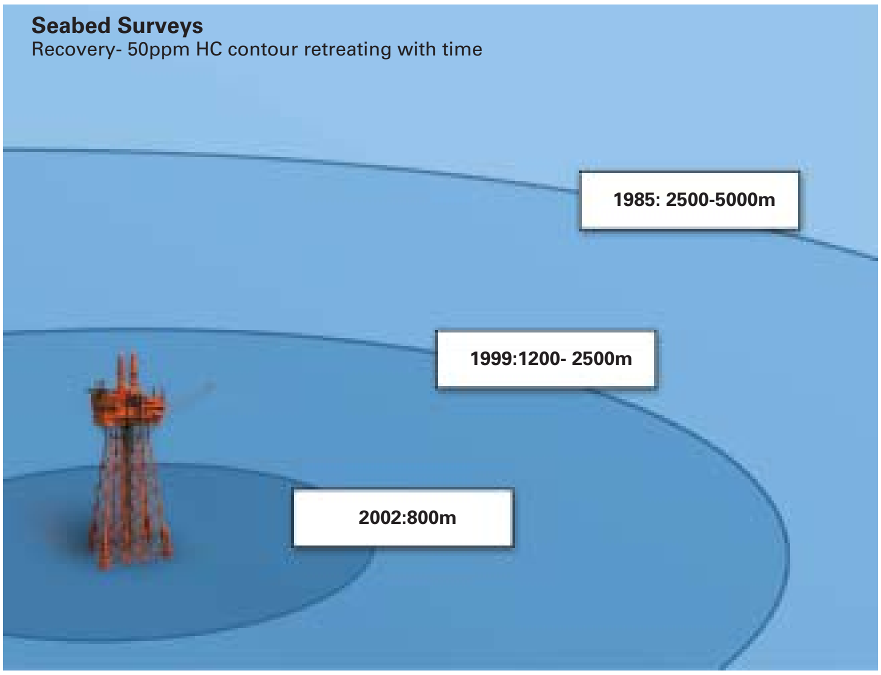

Figure 9.4: Diagram indicating reduction in hydrocarbon concentration with time around North West Hutton.

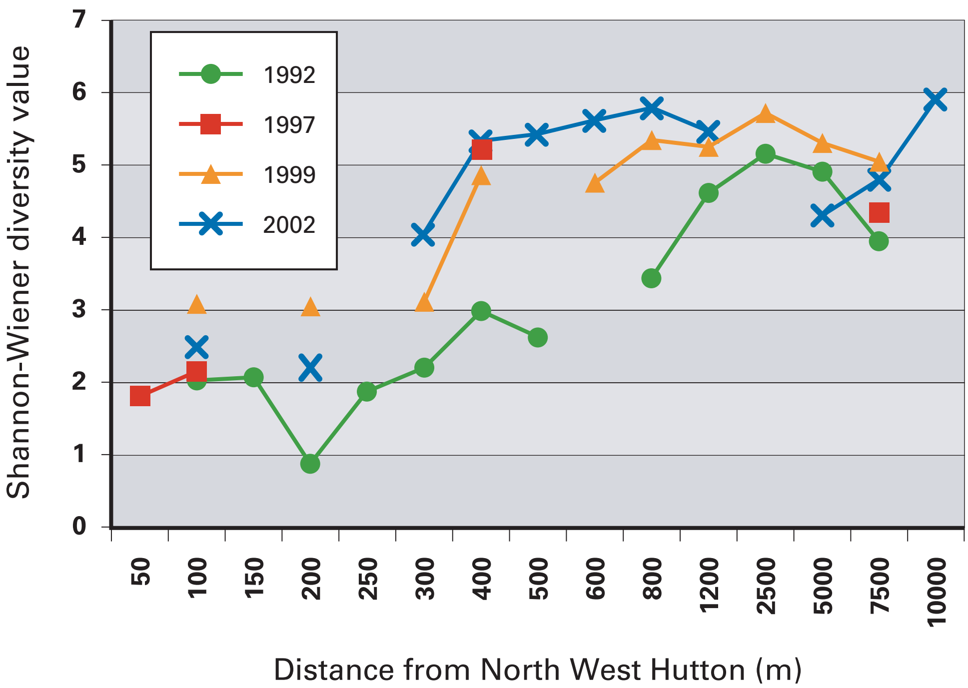

Figure 9.5: Chart indicating improvements in species diversity with time around North West Hutton.

Figures 9.4 and 9.5 provide a clear indication of how the area around the North West Hutton cuttings pile has recovered and how the recovery has progressed with time since drilling operations ceased in 1992. At sites more than 400m from the platform the diversity of benthic faunal communities has returned to typical levels. It is anticipated that the recovery will continue, but it is likely to slow significantly as the recovered zone approaches the main drill cuttings pile around the platform. This is because the recovery processes take significantly longer in the main pile itself due to replenishment of hydrocarbons from within the pile, and the absence of biodegradation in material below the aerobic surface layer (Refs. 9.1 and 9.7).

An important finding from these surveys of the pile and surrounding area is that material from the undisturbed pile is not spreading and affecting the surrounding seabed in the recovered zone.

9.2.5.3 Barium

Barite is a widespread and naturally occurring mineral used to add weight to drilling fluids. Barium concentrations decrease with distance from the platform and by 5km from the pile they are at levels typical of background for this area of the North Sea (Ref. 9.6).

9.2.5.4 Trace Contaminants

Trace contaminants including polychlorinated biphenyls (PCBs) and alkylphenol ethoxylates (APEs), commonly known as endocrine disruptors, have also been detected in and around the pile. PCBs decrease with distance from the platform, from 7ppb at 200m to <0.1ppb at 5000m. PCB values in the North West Hutton cuttings pile are similar to those reported as part of the UKOOA JIP (Joint Industry Project) Phase II programme (Ref. 9.13).

Nonylphenol (a breakdown product of APE) is present in variable concentrations (880-120,000ppb) on the cuttings pile but at lower concentrations by 500m (12ppb) (Ref. 9.6).

The possible presence of LSA (low specific activity) scale in cuttings discharged from North West Hutton was evaluated in radiochemical surveys in 1992, and these indicated that none is present (Ref. 9.6).

9.2.5.5 Food Chain Effects

Additional work conducted under the JIP on drill cuttings concluded that undisturbed drill cuttings piles are predicted to have negligible effects on the food chain. The UKOOA report (Refs. 9.8 and 9.9) also concluded that disturbing the pile could cause a local fish-kill but such effects would not be carried up the food chain to higher organisms.

9.3 Assessment of Decommissioning Options for the Drill Cuttings Pile

As stated in Section 6 "Principles", the intent of the evaluations of the decommissioning options for the North West Hutton jacket and drill cuttings has been to ensure that the identification of appropriate options for these two components is not biased or adversely affected by the obvious inter-relationship between them.

Options for dealing with drill cuttings piles, such as that present at North West Hutton, have been examined in considerable detail by the UK and Norwegian oil and gas industry. The results and guidance prepared by UKOOA represents the fullest appreciation of this complex subject, gathered from an exhaustive series of technical and environmental studies (Ref. 9.8).

The UKOOA studies concluded that there are several decommissioning options, grouped in three broad categories - Natural Degradation; Covering; and Retrieval - which are realistic and feasible for large cuttings piles in deep water. Each possible option presents a different set of technical, safety, environmental, societal and cost issues.

The assessment studies for the North West Hutton drill cuttings pile reviewed a wide range of options identified for dealing with the issue (Ref. 9.5). A total of six methods, each of which can be broadly included in the three main categories listed above, were screened by the project for the North West Hutton cuttings pile. Of these, two were excluded in the screening and four were taken forward for detailed evaluation; an additional option, "Excavation", was added because of the particular location and circumstances of the North West Hutton pile. The results of the screening exercise are summarised in Table 9.1. Each of the short-listed options is described and evaluated in detail in Sections 9.4 to 9.7.

Category	Description of option	Discussion
Natural Degradation	Leave *in-situ* to recover naturally.	Maintains the current status of the pile with no additional disturbance. Section 9.4
	Enhanced Bio-degradation.	Enhance the rate of bio-degradation by adding nutrients and oxygen and possibly heat. Option not pursued due to unproven technology and poor evaluation in the UKOOA drill cuttings JIP.
	Excavate cuttings to access footings.	Added for consideration as the least technically onerous method of accessing the footings and other seabed equipment. **Section 9.6**
Cover	Leave *in-situ* and cover with inert material (Sand, gravel, rock).	Method to "seal" the cuttings pile in its present condition using conventional offshore technology. **Section 9.5**
	Contained Aquatic Disposal.	Transferring the cuttings to a "dredged pit" close to the existing location and covering them. Option not pursued as it is impractical on this scale.
Retrieval	Retrieve and re-inject offshore.	Requires the cuttings to be lifted to surface, treated and then re-injected together with associated volumes of seawater into new wells at the present location or existing wells elsewhere. **Section 9.7**
	Retrieve and return to shore for treatment and disposal.	Requires the cuttings to be lifted to the surface and transported onshore. The cuttings and seawater would then be treated and disposed of. **Section 9.7**

Key: ☐ ***An option short-listed for further evaluation***

Table 9.1: Possible decommissioning options for the North West Hutton drill cuttings pile.

9.4 Option "Leave *in-situ* to degrade naturally"

9.4.1 Description

As stated earlier, this section evaluates options for the cuttings pile as a stand-alone entity, in order to provide a balanced assessment based on issues related only to the drill cuttings pile. The "leave *in-situ*" option could only be achieved, however, if the bottle-legs and the lower bracings of the jacket were left in place on the seabed.

Natural degradation, as the name suggests, would involve leaving the pile in its present location to continue recovery by natural processes. The processes of weathering and bio-degradation by marine organisms would continue to slowly reduce the concentration of hydrocarbons in the cuttings.

9.4.2 Technical Feasibility

This option would not require any operations to be conducted on the pile and there are therefore no technical challenges. A programme of monitoring would be developed to assess the condition of the pile from time to time, to ensure that it remains stable, that recovery continues and there is no impact on the surrounding seabed. The scope, frequency and duration of such a programme would be commensurate with the known and predicted significance of the impacts of the pile.

9.4.3 Environmental Impact

9.4.3.1 Zone of Effect on Seabed

Since drilling ceased in 1992, the area of adjacent seabed affected by elevated concentrations of hydrocarbon has decreased in size as described above. It is predicted that this recovery will continue as the outer margin of the cuttings pile, less than 20cm thick, bio-degrades and slowly mixes with natural seabed sediment (Ref. 9.7). The area of seabed exhibiting physical, chemical and biological perturbation as a result of the presence of the pile will also decrease with time. It is estimated that the rate of recovery will slow as the recovered zone encroaches on the main body of the pile. At this stage, the recovery will reach equilibrium and although recovery will be continuing, the pile will appear to be stable for a significant period time (Ref. 9.7).

9.4.3.2 Release of Hydrocarbons

The pile itself is stable; the upper surface has formed an aerobic layer of recovered material, which crusts in places and may provide some degree of protection against physical disturbance. Hydrocarbons are presently leaching from the surface of the pile at a low rate, estimated to be around 2 -3 tonnes per year (Ref. 9.1). The annual input of hydrocarbons to the sea from this slow release is very small and generally insignificant in overall terms, although the additive and undesirable nature of all inputs is recognised. Many such releases occur as a result of natural discharges from the seabed, and the marine ecosystem has the capacity to bio-degrade small localised inputs, with no observable effects on the wider environment.

9.4.3.3 Movement of Material from the Pile to Adjacent Seabed

If the pile were left unprotected at its present location, it is likely that it would experience very minor physical disruption from currents, extreme wave action, and external sources such as fishing gear and anchor chains. This would result in the short-term re-suspension of cuttings and hydrocarbons into the water column (Ref.9.7).

Trials and studies of this minor re-suspension behaviour have shown that the disturbed material rapidly returns to the seabed at or close to the original location (Ref. 9.8). All such disturbances have been shown to affect the pile superficially at the areas of contact. The material from such disturbance will therefore cause no significant or detectable spreading of the affected zone. Any cuttings exposed to seawater by the removal of the surface of the pile would biodegrade and a new aerobic layer would form rapidly.

9.4.3.4 Predicted Long-term Persistence

One of the important parameters when considering the leave *in-situ* option is the time required for the pile to bio-degrade completely. Using a computer model developed as part of the UKOOA investigation, detailed modelling studies were undertaken to estimate how long the pile would exist if left to recover naturally at the North West Hutton site (Ref. 9.7). Over the long-term, the extent and volume of the pile would be influenced by several factors, particularly gradual biodegradation, occasional extreme wave and current action, and occasional physical disruption by fishing gear. Modelling studies show that the combination of these factors would result in a gradual decrease in the volume of the pile with time. The modelling results indicate that the pile would be likely to persist for between 1,000 and 5,000 years, and it is recognised that uncertainties in the model could result in a longer duration (Refs. 9.1 and 9.7). Although the model results have a wide range of uncertainty, the longevity predicted by the model is consistent with the slow release of hydrocarbon from the pile, and the results of the surveys that indicate that the pile is very stable and that all the constituents are effectively “locked in” to the pile unless they are disturbed by natural forces or intervention.

9.4.4 Societal Impact

9.4.4.1 Potential Impacts on Commercial Fisheries

During consultation, some stakeholders expressed the concern that the long-term presence of hydrocarbons and other contaminants in the pile could lead to contamination of fishing gear and tainting of fishing catches, which in turn could adversely impact commercial fishing activities in the area. Commercial fishing has been carried out around the North West Hutton platform throughout its operational life, including the period when the “footprint” of the cuttings pile attained its maximum extent, and there have been no recorded instances of fishing gear contamination or tainting of catches during this period. Fish have been caught from these areas and no problems or issues have been reported in relation to these catches or indeed from other similar areas of the North Sea. In addition, studies by UKOOA have shown that species of fish caught close to cuttings piles have about the same level of hydrocarbon and other contaminants in their tissues as fish caught in the open sea away from platforms (Ref. 9.9). No evidence of tainting has been found in fish caught in close proximity to platforms. It is therefore unlikely that fish caught around a cuttings pile would exhibit any characteristics affecting the subsequent commercial sale.

9.4.4.2 Potential Impacts on Fishing Activity

Fishing over the pile itself would only be possible if the jacket footings were removed. Evidence from field trials suggests that trawling over cuttings piles creates minimal disturbance, and there is no evidence that fishing gear is damaged or contaminated as a result (Ref. 9.8).

9.4.4.3 Presence of Hydrocarbons

Monitoring, modelling and industry studies indicate that under normal circumstances hydrocarbons would leach or escape from the pile into the water column at a very low rate (2-3 tonnes per year) (Ref. 9.1). Studies show that the input of this quantity of oil to the water column over the course of a year, and its subsequent dispersal and bio-degradation, would be unlikely to cause any visual or ecological impacts.

9.4.5 Safety of Personnel

There would be no activities associated with decommissioning the pile and therefore no direct safety risk to personnel. Periodic surveys undertaken as part of the long-term monitoring programme would represent a low level of risk for personnel on survey vessels.

9.5 Option "Leave *in-situ* and Cover with Inert Material"

9.5.1 Description

To achieve this decommissioning option, the pile would be covered by layers of inert material designed to further stabilise the pile and prevent the low levels of hydrocarbon release described above. The covering material would be placed by a surface vessel designed specifically for "rock dumping" activities to protect and stabilise sub-sea structures. The initial cover would be a layer of coarse sand and fine gravel, overlain with layers of gravel and armour stone. The layer of armour stone would minimise the risk of nets snagging on the covered pile, and the risk that bottom-towed fishing gear would remove material from the pile cover. The covering technique would require transportation of sand, gravel and rocks from an onshore quarry and depositing these in a series of layers on top of the cuttings pile. Material would be accurately placed over the pile using a "fall-pipe vessel" specially designed for similar activities, for example placing gravel and small rocks to protect pipelines and other equipment on the seabed (Figure 9.6). Studies have indicated that about 90,000m^3 of material would be required to cover the North West Hutton pile, creating a structure with a maximum height of approximately 9m above the seabed and covering an area of seabed slightly larger than the existing pile which is about 0.02km^2. It is estimated that the programme to install the cover would take 10-14 weeks (Ref. 9.5).

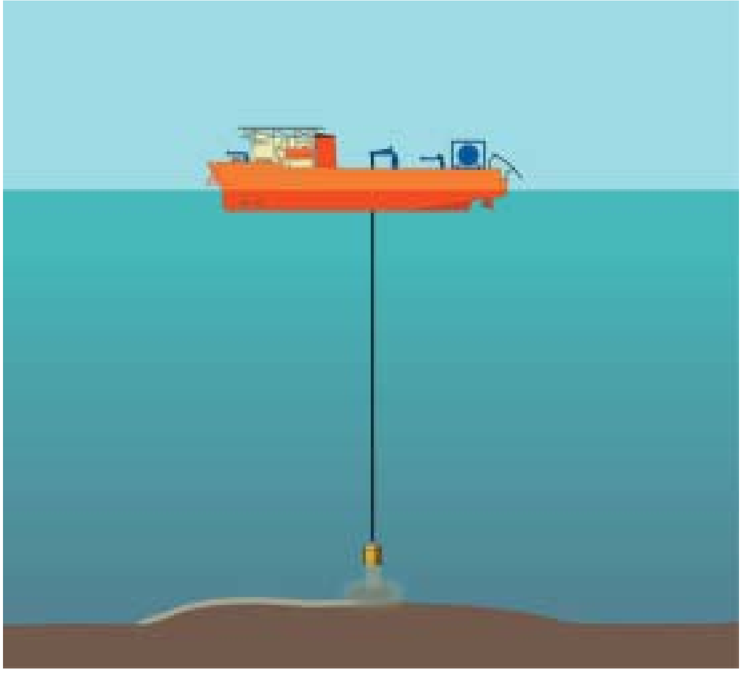

Figure 9.6a: Computer graphic of operations to cover the drill cuttings pile with footings removed.

Figure 9.6b: Computer graphic of operations to cover the drill cuttings pile with footings in place.

9.5.2 Technical Feasibility

Several detailed studies have shown that it would be possible to cover the pile with a protective layer designed to seal and protect the pile from disturbance. The cover would be stable under wave, current and trawling loads although some disturbance and break-up of the cover is inevitable with time (Ref. 9.5). Although any proposed cover design would be thoroughly reviewed and risk-assessed prior to installation, there is a risk that the deposited material would sink into the pile itself and cause some disturbance and redistribution of pile material. Such an occurrence would not cause major problems although it may result in a technical failure of the cover to provide the intended "seal" properties of the covered pile.

The installation of the cover is effectively an irreversible operation and therefore it is difficult to envisage how the previous status could be restored in the event that a problem develops.

9.5.3 Environmental Impact

9.5.3.1 Disturbance of the Cuttings Pile during Placement: The fall pipe vessel can place material accurately although the activity of depositing dense gravel and rock from the surface to the seabed in 140m of water would result in energy being transferred to the cuttings pile. This activity would inevitably lead to the disturbance and re-suspension of material into the water column, particularly in the early stages of the operation. In reality, the effects of such disturbance, whilst undesirable, are likely to be relatively small and lead to minor impacts that would be localised and short-lived (Ref. 9.1).

9.5.3.2 Leaching of Contaminants: Oil is estimated to be leaching from the uncovered pile at the rate of about 2-3 tonnes a year (Ref. 9.1). The cover would be designed to effectively seal in all the contaminants. It is therefore assumed that the rate of leaching from the covered pile would be close to zero.

9.5.3.3 Long Term Fate of the Pile: The contents of the pile would effectively be sealed, and there would essentially be no exchange between the pile and the surrounding environment. Consequently, biodegradation would proceed at an even slower rate than that predicted for the uncovered pile left *in-situ*. Bearing in mind the intended design of the cover, and the longevity of the pile if left uncovered (Section 9.4.3.4), a covered pile would, in effect, be a permanent feature on the seabed that exhibited little or no change with time.

9.5.4 Societal Impact

9.5.4.1 Impacts on Other Users of the Sea:If the pile were protected by a contoured over-trawlable cover, it would not present an impediment to normal fishing operations (Ref 9.5). In the absence of any residual structural items from the platform, the area of seabed covered by the pile could then be accessed safely by commercial fishing vessels.

9.5.4.2 Short- and Long-Term Environmental Impacts: Some stakeholders expressed concerns regarding the potential for environmental impacts caused by the construction of the cover, long-term leaching, and slow breakdown of the cover. These have been discussed under "environmental impact", Section 9.5.3.

9.5.4.3 Employment: Quarrying material and building the cover would use existing facilities and technologies. Although involving a reasonably large amount of sand, gravel and rock, this activity would have a relatively minor and short-term impact by supporting existing employment and is unlikely to be a stimulus for any significant new employment or commercial opportunities (Ref 9.10).

9.5.5 Safety of Personnel

Rock dumping is a relatively well-understood procedure utilising established techniques and equipment. Consequently, the associated risks are known and can be managed and mitigated to the extent that the overall risk is considered low.

The offshore risks associated with covering the drill cuttings pile fall predominantly into general occupational and vessel risks. The technology, although large in scale, is relatively straightforward and is such that failures will generally result in delay and hence increased risk due to an increase in the duration of the project.

The increased activity associated with installing the rock cover on the cuttings pile would result in an overall increase in safety risk for those involved in the operation. It is estimated that the risk of fatality (PLL) for covering operations conducted after the footings had been removed would be less than 0.6% (Refs. 9.11 and 9.12).

9.6 Option "Excavate and Disperse" the Drill Cuttings

9.6.1 Description

The term "excavate" in this document refers to the operations required to remove the drill cuttings from around the base of the structure, to expose the lower members of the structure and disperse the drill cuttings away from the immediate vicinity of the jacket. It is an option that could be used to access the footings should this be required as part of the jacket removal programme.

Excavation could be carried out using hydraulic removal or dredging systems deployed remotely (Ref. 9.5). Material would be moved from the pile and deposited in the local area where it would disperse and then settle onto the adjacent seabed. Various types of equipment are available to implement such operations.

9.6.2 Technical Feasibility

Seabed sediments are routinely excavated by a variety of methods, including water-jetting, suction hoses and hydraulic dredgers. Operations significantly larger in scale than those that would be required for the North West Hutton drill cuttings pile are routinely implemented for construction activities by other industries, and also in seabed mineral recovery operations. Apart from the location, weather issues and the presence of obstructions there appear to be no major technical obstacles to such an operation.

9.6.3 Environmental Impact

9.6.3.1 Impacts of Excavation

Moving the cuttings in this manner would result in the dispersal of the present pile, which has a relatively compact shallow-peaking geometry, and the creation of a relatively flat feature on the surrounding seabed. Modelling shows that the mixture of seawater and cuttings particles would disperse in the near-bottom currents and settle over an area considerably larger than that covered by the present pile.

Consequently, areas of seabed that have now recovered, or are in the process of recovering, from the impact of the original discharge of cuttings, would become re-contaminated. This re-contamination would be more severe, and would occur over a shorter period of time, than that which resulted from the original discharge. The excavation and dispersal of pile material would be completed over a period of about 10 weeks, whereas the periodic discharge of cuttings during drilling took place over several years. Excavation of a pile of this size may require regulatory approval.

9.6.3.2 Impacts of Re-distributed Cuttings

Studies conducted during the UKOOA drill cuttings initiative have indicated that the hydrocarbons and other material within cuttings piles are effectively bound to the solids. It is therefore unclear if the excavation and re-deposition of the North West Hutton cuttings pile would result in the release of significant quantities of oil into the water column. It is not possible to predict how much oil might be released or if the quantities would be sufficient to cause even a minor sheen or slick on the sea surface.

Excavating and re-depositing the cuttings as a more widely spread layer would result in the exposure of a larger proportion of the pile to aerobic conditions. This would result in a greater environmental loading of hydrocarbons and other material. Modelling studies indicate that the redistributed pile would bio-degrade more quickly than the pile left *in-situ*. This more rapid recovery would be offset by a corresponding increase in the rate of release of material into the surrounding environment.

9.6.4 Societal Impact

Some stakeholders expressed concerns that if excavation were to result in significant re-contamination of areas of the seabed that had recovered, and an increase in the rate of release of hydrocarbons, then this solution would be less acceptable to society than other solutions.

9.6.4.1 Impacts on Other Users of the Sea

During excavation operations, it is likely that the existing 500 metre exclusion zone would remain in place and that, in addition, a guard vessel would be deployed to ensure the safety of other sea users in the vicinity.

As for the longer term, the potential impact on commercial fishing is considered to be the main issue. There are no studies which specifically investigate the results of fishing over an excavated pile. However, evidence from field trials suggests that trawling over cuttings piles generally creates minimal disturbance, and there is no evidence that fishing gear is damaged or contaminated as a result. It is therefore likely that the more widely spread layer of drill cuttings created by the excavation operations would not have a long-term impact on commercial fishing activity (Ref. 9.5 & 9.8).

9.6.4.2 Economic Benefit

The expenditure involved in excavation operations would provide a short-term benefit to companies involved in such subsea activity, but there are no long-term sustainable economic or employment benefits apparent from this work (Ref. 9.10).

9.6.5 Safety of Personnel

Excavation of the pile would be carried out by a support vessel equipped with the appropriate remotely operated sub-sea excavation systems. Such an activity would employ equipment with a relatively well-understood method of operation and there are no adverse safety implications associated with the use of such equipment. The risks associated with excavation are similar to those of rock dumping, in that the majority of risks are occupational and vessel-related. The risk of a fatality is estimated to be less than 0.5% (Refs. 9.11 and 9.12).

9.7 Option “Retrieve and Dispose of Cuttings Onshore or by Re-injection Offshore”

9.7.1 Description

These options require the retrieval of the cuttings from the seabed, followed by either re-injection offshore or return to shore for treatment and disposal. Several different systems could be used for retrieval, including an ROV-deployed hydraulic dredging system or a retrieval system deployed from a more traditional dredging vessel. Material could be stored on the retrieval vessel or transferred to another vessel for transportation to the shore or reinjection site. For onshore disposal, the cuttings would be treated to remove excess water, to recover oil for possible re-use, to treat other contaminants, and prepare the residual solid material for onshore disposal. The offshore retrieval operation would take several months and could extend over two summer seasons (Ref. 9.5).

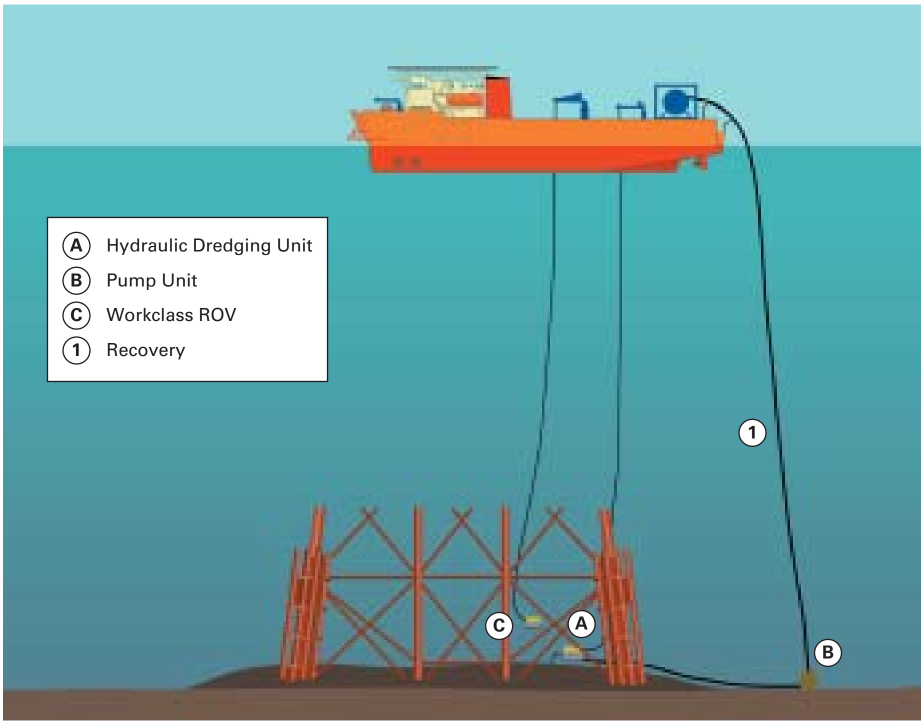

Figure 9.7: Computer graphic of example of a system to retrieve drill cuttings for disposal onshore or re-injection.

9.7.2 Technical Feasibility

9.7.2.1 Offshore Retrieval and Shipment

A small-scale drill cuttings retrieval trial was completed on North West Hutton during 2001 as part of the UKOOA drill cuttings programme – phase 2 (Ref. 9.8). The trial indicated that it is technically feasible to recover cuttings to the surface albeit with a substantial volume of entrained seawater that is required to physically lift the cuttings. A full-scale retrieval of a cuttings pile has never been attempted and would present a substantial technical risk due to the scaling-up of the operations, and the associated difficulties identified during the pilot trial.

Any retrieval operation on North West Hutton would be undertaken in the presence of the jacket footings. The retrieval rates of any equipment deployed would therefore be restricted to 10-50 m^3/hr of material, because of technical and operational restraints. The studies and the trials have indicated that the minimum volumes of seawater that would be retrieved with entrained cuttings would be six times the volume of cuttings, and the optimum average achievable would be between 10 and 20 times (Ref. 9.8). Any retrieval operation would therefore have to handle and dispose of between 300,000m^3 and 600,000m^3 of contaminated seawater, in addition to approximately 30,000m^3 of cuttings pile material. Dealing with such quantities would present significant challenges, and there would be risks associated with the intensive operations required to handle, transport, store and treat these materials.

A retrieval operation could not practically guarantee removal of all the cuttings material. This is because of the technical difficulties of retrieval, and the lack of ability clearly to distinguish between the cuttings material and the seabed.

9.7.2.2 Re-injection

UK and international law does not presently allow lifting and re-injection of material such as historic drill cuttings piles. It would be technically feasible to re-inject the cuttings either from a drilling rig located close to the North West Hutton site or from a suitably equipped fixed installation at another site. It has been assumed that the full waste stream recovered (i.e. all the cuttings and seawater) would have to be re-injected. Re-injection at the North West Hutton site would involve drilling at least two new wells with a mobile drilling rig, and re-injecting the cuttings at a depth of at least 5-6,000ft below the seabed. Re-injection at another operating platform would be technically feasible, but is unlikely to be practical and is currently not available (Ref. 9.5).

The possible future disposal of the drill cuttings pile by re-injection was reviewed as part of the overall decision to cease production at North West Hutton. Given the ongoing legal uncertainty surrounding the lifting and re-injection of historic drill cuttings piles, the evaluation showed clearly that drilling new wells would be more cost-effective than retaining platform wells together with all the associated safety systems.

9.7.2.3 Onshore Treatment and Disposal

There is no existing plan or experience for disposing of recovered cuttings onshore. "Fresh" cuttings from ongoing operations are treated effectively in a process known as thermal desorption which uses heat to extract and recover the oil leaving the solids to be sent to landfill. In the case of the recovered cuttings from North West Hutton the slurry (cuttings and water) would be put through a separation process (hydrocyclone or shaker) and the solids and liquids would be separated. The solids (plus small amounts of residual water) would then be treated by thermal desorption and the hydrocarbon would be recovered. Liquids would be treated and discharged under consent. Solids would be likely to be classified as hazardous waste and so would be disposed of to a hazardous waste landfill. The hydrocarbons may be suitable for reuse or may have to undergo further specialist treatment.

No existing plant or treatment site has the capacity to deal with the large volumes of watery waste, with its inherently variable contaminant loading, that would be generated during such a programme. A new treatment plant would have to be designed and constructed.

9.7.3 Environmental Impact

9.7.3.1 Offshore Retrieval and Shipment

During the retrieval operations, a proportion of the pile material would escape into the water column. Some material would not be fully recovered by the system, and progressively deeper layers of the pile, containing un-degraded cuttings material, would be exposed as retrieval continued. Both types of event would result in oil and contaminated solids being released into the water column in the form of a plume. Oil from this plume might cause small surface slicks from time to time, depending on the rate of retrieval and the type of material being recovered. Parts of the adjacent seabed would be affected by the settlement of disturbed cuttings.

9.7.3.2 Re-injection

A minimum of two new disposal wells would have to be drilled if the cuttings were to be re-injected at the North West Hutton site. This would create a range of relatively small impacts offshore that are well understood and managed. Injection at an existing facility may be able to use existing, redundant wells, in which case few additional impacts would arise.

9.7.3.3 Onshore Treatment and Disposal

A total of 300,000m^3 to 600,000m^3 of seawater contaminated with hydrocarbons and other material would have to be separated from the recovered slurry, treated and then discharged under licence from the onshore reception or treatment facility. Thermal desorption treatment would cause few impacts, although care would have to be taken during the transportation and storage of untreated material. Treated material is likely to be classified as hazardous, and would have to be disposed of to landfill site designated for such material. Existing hazardous waste sites in the UK are in high demand and using them for the disposal of bulk residual drill cuttings would impact on this resource (Refs. 9.1 and 9.5).

9.7.3.4 Energy Use

All the retrieval and disposal options are highly energy-intensive because of the extensive use of marine vessels, and the treatment of cuttings onshore. Data on the energy-use of each option is presented in Table 9.2 in Section 9.9.

9.7.4 Societal Impact

9.7.4.1 Other Users of the Sea

During retrieval and disposal operations, it is likely that the existing 500 metre exclusion zone will still be in place. In addition, a guard vessel would be deployed to ensure the safety of other sea users in the vicinity of the operations.

As for the longer term, the potential impact on commercial fishing is the main issue. Since field trials suggest there is no evidence that fishing gear is damaged or contaminated as a result of trawling over cuttings piles, retrieval and disposal of the North West Hutton cuttings pile would not have a significant positive impact on commercial fishing activity (Ref. 9.5).

9.7.4.2 Economic Benefit

All the "retrieval and disposal" options are relatively expensive, and they would provide a short-term commercial benefit to specialist companies involved in both the offshore and the onshore activities, resulting in the support of existing employment for the duration of the retrieval and disposal operations. However, there appear to be no significant long-term sustainable benefits from these options and studies indicate they would not result in the creation of permanent jobs (Ref. 9.10).

9.7.4.3 Use of Onshore Resources

Any disposal of the cuttings onshore would make a noticeable demand on the available UK sites for the disposal of hazardous waste. There are indications that the landfill directive will greatly reduce the availability of hazardous waste storage space and the disposal of cuttings residue would represent a major burden on the system. Further environmental and social impact studies would be required at the stage when potential onshore landfill locations were identified to assess impacts on communities and amenity value.

9.7.4.4. Stakeholders

Some stakeholders have expressed the view that the 'precautionary principle' should be used to address this issue – in other words that the best approach would be the removal and disposal of the cuttings pile. However some other stakeholders have cautioned against distributing the pile because of concerns over redistribution of pile material and the impact this would have on the environment. The generic 'legacy' issue of how North Sea drill cuttings piles should be regulated and managed in the future is the subject of ongoing OSPAR discussion, and BP will monitor developments in this area for relevance to the North West Hutton drill cuttings pile.

9.7.5 Safety of Personnel

Cuttings retrieval and disposal offshore or onshore would use existing techniques and equipment, in a large-scale programme never before attempted in the North Sea. It is likely that the cuttings could be recovered remotely without the requirement for divers.

Drilling and re-injection into new disposal wells, re-injection at an offsite location, and disposal onshore are all relatively standard offshore operations with known hazards and associated risk (Refs. 9.11 and 9.12).

The overall risk of this option is, however, relatively high when compared with the other options for the cuttings pile, because of its duration and the large number of personnel that would be required. During retrieval of the cuttings significant operational risk will exist as a consequence of the need for simultaneous multiple vessel activity within the North West Hutton field.

The risk of a fatality in the sub-options described above therefore ranges from 2.2% (for onshore disposal) to 6.4% (for re-injection). These values are significantly higher than those for the leave *in-situ* options, which range from 0.17% to 0.55% (Refs. 9.11 and 9.12).

9.8 Cost Assessment

The following section discusses the estimated costs for implementing the options for the drill cuttings pile. The implications of long-term monitoring of the site are discussed in Section 18.

The estimated cost for leaving the drill cuttings *in-situ* is £0.5m for the long term monitoring of the site.

The cost of covering the cuttings was estimated to be in the region of £8 million.

Excavation of the cuttings would cost between £8 million and £9 million.

The costs for lifting the cuttings and disposing of them by re-injection or on land are similar. Both are subject to significant uncertainty because of the technical and environmental risks discussed above. The costs for these options are estimated to range from £43 million to £114 million.

9.9 Comparative Assessment of Options for the Drill cuttings Pile

This section draws together the findings from Sections 9.4 –to 9.7, and presents a comparative assessment of the options for decommissioning the cuttings pile. The options reviewed are:

1. **Leave *in-situ* without treatment**, which is only achievable if part of the footings is left in place.
2. **Cover with an inert layer**, which is only achievable if part of the footings is left in place.
3. **Excavate and disperse.**
4. **Retrieve and re-inject.**
5. **Retrieve, and treat and dispose onshore.**

The study work carried out specifically for North West Hutton, and supported by a large body of general work carried out on drill cuttings, suggests the following:

- Cuttings piles *in-situ* on the seabed introduce material into the marine environment but they remain stable in the absence of significant disturbance from natural or man-made sources.
- Large scale disturbance of a pile would lead to a significant increase in the short-term environmental loading of cuttings material in the vicinity of the pile.
- Retrieval operations could remove some or all of the material, but although feasible are a significant technical challenge that would be highly energy-intensive and create significant environmental and safety risks associated with transport, handling and long-term storage.

The extensive sampling and study work conducted on the North West Hutton cuttings pile indicates clearly that a significant degree of natural recovery has occurred on the seabed around the pile since drilling ceased in 1992. The pile is very stable because of the low current speeds and wave action in the area, and will remain so in the absence of significant man-made disturbance.

It is clear from the study work that there are two main outcomes for dealing with the drill cuttings that involve either leaving the cuttings on the seabed at or near the present location to recover by natural processes, or removing some or most of the cuttings from the present location for disposal elsewhere. In general, the technical and safety issues associated with the removal processes are significantly greater than those for the leave *in-situ* cases because of the complexities of accessing, lifting, handling, treating and disposing of large volumes of cuttings and associated seawater.

The environmental aspects of the evaluation are somewhat more complicated to assess. The leave *in-situ* options would result in the contents of the pile remaining in the marine environment. The rate of recovery and hence the rate of release of the contents from the pile is dictated by the action taken on the pile. Moving the pile on the seabed by mechanical means would result in a faster natural recovery of the pile material, but areas of the seabed presently exhibiting low levels of contamination would become re-contaminated by such activity. Alternatively, covering the pile should contain the material and essentially prevent the release of contaminants, and hence increase the overall recovery time.

Operations to retrieve the pile would have offshore and possibly onshore impacts. During retrieval, a volume of seawater 10-20 times the volume of the pile volume recovered would become contaminated, and would have to be treated prior to disposal. The retrieval operation would also result in the redistribution of pile material into the surrounding water and seabed as a consequence of both physical disruption and the removal of the recovering aerobic surface layer which would expose the un-recovered material beneath.

Retrieving some or all of the pile material would have the benefit of directly removing a significant proportion of the material from the present offshore location, and this would allow the site to recover more quickly. The main disadvantage of retrieval, from an environmental viewpoint, would be the creation of a sizeable new waste stream that would have to be transported, treated, stored and disposed of. The relocation of this volume of material for handling onshore would impact significantly on the treatment site and also on the utilisation of hazardous waste landfill, in addition to the requirement to deal with the large volume of seawater either by treatment or discharge. It is also clear from the studies that the amount of energy and other resources that would be required to complete the removal would be far in excess of the energy value of the hydrocarbon and other material contained within the pile itself. Although these aspects are not directly comparable, they do provide an indication of the proportionality of the activity and also the complexity of implementing the overall evaluation.

Disposal by re-injection would alleviate the environmental concerns associated with onshore treatment but is not permitted under UK or International Law. A re-injection operation on this scale has not been attempted before, however, and therefore carries a risk of failure that could lead to unanticipated environmental consequences. As with onshore disposal, the energy and resources required to implement this option do not appear to be proportional to the benefits achieved by removing some or all of the pile.

From a societal perspective, the main issue regarding the options of natural recovery is the impact on fishing activity. Numerous studies of the effects of cuttings piles on fish and fishing activity have demonstrated that there are no significant effects, although the concerns of the fishing industry over the potential for tainting of fishing gear and fishing catches are acknowledged. It is therefore considered that there would be some impact on fishing activity by leaving the pile *in-situ* but that this would be minor.

A decision to retrieve the pile would result in short-term economic benefits due to the expenditure associated with the operations. Studies indicate that there is little opportunity for sustainable new industries or sectors as a result of a retrieval operation.

Disposal of the material by re-injection would have little adverse societal impact with the exception of short-term disruption to other users of the sea caused by the presence of a drilling rig at the re-injection location. Onshore disposal would, however, result in some onshore disruption and possibly significant nuisance as a result of increased vehicle activity and, in particular, the utilisation of scarce hazardous waste landfill resources.

From a cost or economic perspective the leave *in-situ* options have significantly lower overall costs and less economic risk than the removal options. The leave *in-situ* costs range from £0.5m to £8m compared to a range of £43m to £114m for the retrieval options. It should also be noted that the retrieval costs are subject to significant uncertainty, because of the nature of the operations involved.

The following table attempts to summarise the key qualitative and quantitative factors.

Criteria	Leave *in-situ*	Cover & Leave	Excavate & Leave	Recover & Re-inject	Recover & Dispose Onshore
Technical Risks	No material risks	Low overall risk of implementation. Some risk of failing to meet long term design intent	Low overall risk of implementation	Moderate technical risks associated with retrieval and disposal	Moderate technical risks associated with retrieval, onshore treatment and disposal
Safety (Probability of Fatality)	**0.17%**	**0.55%**	**0.48%**	**6.4%**	**2.2%**
Environmental Impact					
Energy (households)	80	900	400	3.500 (onsite) 3,800 (offsite)	5,300
CO_2–E (households)	80	900	400	3,200 (onsite) 3,500 (offsite)	29,000
General	Minor impact of natural recovery mechanisms. Affected area decreasing	Minor impact of natural recovery Mechanisms. Cover will reduce or eliminate recovery process.	Significant spreading of material onto adjacent seabed. Covering area greater than original pile	Potential for minor / moderate spreading of material onto adjacent seabed. More rapid recovery of affected area	Potential for minor / moderate spreading of material onto adjacent seabed. More rapid recovery of affected area. Potential environmental impacts at treatment and disposal sites.
Persistence	1,000- 5,000 years	Indefinitely	<1,000 – 5,000 years	N/A	N/A
Societal Issues	Minor Impact on fishing activity	Minor impact on fishing activity	Minor impact on fishing activity	Minor economic benefit due to increased activity	Minor economic benefit due to increased activity. Dis-amenity due to onshore treatment and landfill usage.
Economic	0.5	8	9	43-110	46-114

Table 9.2: Summary of options for decommissioning the drill cuttings pile.

Notes

1. Energy is expressed in terms of the average energy use of UK households. In 2001 the average energy use was 80GJ, and the average CO_2–E emissions in 2000 was 6 tonnes.
2. For Energy and CO_2 figures in tonnes and GJ see Environmental Impact Statement.

9.10 Recommended Decommissioning Option for the Drill Cuttings Pile.

There are clearly positive and negative aspects to each of the options evaluated for decommissioning the cuttings pile. On the basis of a thorough assessment and evaluation of all the data, it is recommended that the North West Hutton cuttings pile should be left in place to recover naturally. This is also the best environmental option.

The main drivers for this course of action are the clear evidence that the pile remains very stable and that the natural recovery processes result in only minor inputs of hydrocarbons and contaminants to the marine environment. The pile would exist at its present location for a very long time and would represent a minor disturbance to commercial fishing activity.

Removal of the pile would speed the recovery of the seabed at the site, but the environmental impacts, the safety and technical risks, and the costs of the required operations are not proportional to the benefits that would be gained by removal.

Debris clearance and ongoing monitoring will be an integral part of the long-term option to leave the drill cuttings in place. BP will also continue to be involved in industry research investigating the best techniques for managing drill cuttings piles, including the UKOOA Joint Industry Project, and will monitor future discussions and decisions under the OSPAR framework for their relevance to the North West Hutton pile. These studies and decisions will be taken into account in any decisions concerning the ongoing management of the drill cuttings pile at the North West Hutton field location.

Recommendation: The North West Hutton drill cuttings pile should be left in place to recover naturally.

References

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10 PIPELINES

10.1 Introduction

This section presents the results of the assessments that were carried out to determine the appropriate decommissioning programmes for the North West Hutton gas and oil pipelines. These pipelines are no longer required (Section 4) and no potential commercial use can be foreseen for them in their present locations. Both of these pipelines are about 13km long, the 10” gas line, PL 147 is trenched and the 20” oil line PL 148 is un-trenched. The two pipelines are discussed separately in this section, which:

- Describes the techniques that could be used to decommission the pipelines.
- Describes the pipelines and summarises their histories.
- Describes their present condition, and the cleaning that has been carried out before any decommissioning programme is implemented.
- Discusses the approach and method that was used to select the decommissioning option for each pipeline.
- Identifies the potential decommissioning options for each pipeline.
- Assesses technical feasibility, safety risks, environmental impacts, societal impacts and costs of each option. The methods used to assess these different criteria are the same as those used for the other North West Hutton facilities (Section 6).
- Recommends a decommissioning option for each pipeline.

To assess the advantages and disadvantages of the options for each pipeline, a comparative assessment was carried out which addressed all of the issues identified in the DTI Decommissioning Guidelines, namely:

- the present condition and degree of burial of the pipelines;
- the potential impact in the marine environment of carrying out any of the decommissioning options;
- the energy use of each option;
- the potential impact on users of the sea if the pipelines were left in place; and
- the rate of deterioration of the pipelines if left in place, and their possible future effects on the environment as they deteriorate.

10.2 Applicable Techniques for Decommissioning the Pipelines

The main decommissioning options for the pipelines can be separated into two broad categories, namely; leave *in-situ* or remove and return to shore. Several alternative options and methods of implementation are possible within these broad categories. The following section gives a brief description of different techniques that could be used to decommission North West Hutton pipelines PL 147 and PL 148.

10.2.1 Pipelines Left *in-situ*

10.2.1.1 Selective Removal

This technique is used when some parts of a pipeline are buried and some exposed. To render the pipeline completely buried, the exposed parts are removed by cutting out sections and taking them to shore for recycling. The cut ends of pipe are then buried in the natural sediment, so that the entire length of the remaining pipe is left buried.

10.2.1.2 Rockdumping

Aggregate, usually from an onshore quarry, is transported offshore in a rock-dumping vessel and then carefully placed over selected areas of the line, using a “fall pipe”. In this way a low mound of aggregate is built up, covering the pipe and creating a profile over which trawling gear may be towed unhindered. The exposed sections of a partially buried pipeline could also be covered by “selective rock-dumping” using the same system.

10.2.1.3 Trench and Bury

In this technique, a trench is dug either alongside or beneath the pipeline, and the line is laid into it (Figure 10.1). The trench can then be backfilled with the sediment that was removed from it, or it may be left to backfill naturally as a result of currents and wave action.

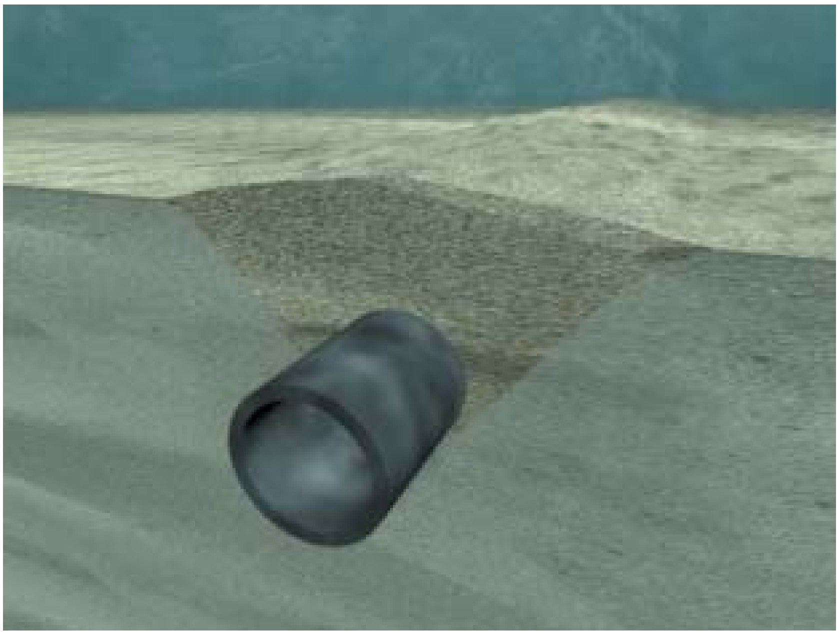


Figure 10.1: Trench and bury technique.

10.2.2 Techniques for Removing Pipelines

10.2.2.1 "Reverse S lay" and "Reverse J lay"

These are two techniques for pulling the pipe to the surface after it has been separated from the platform or pipeline to which it was connected. Both methods require the use of a specialist pipe-laying vessel or barge which is anchored over the pipeline, and then moves along the route of the pipeline recovering the line as it progresses. One end of the pipe is pulled up to the vessel by a wire. In S-lay, the pipe is cut and recovered from a horizontal position on the deck, whereas in J-lay, the pipe is held vertically at surface, and the cut sections are lifted off by crane (Figures 10.2 and 10.3). In both methods, sections of pipe between 12m and 24m long are cut off, transferred to an adjacent cargo barge and taken to shore for recycling.

10.2.2.2 "Cut and Lift"

In this technique, remote or diver-assisted mechanical methods or "hot cutting" techniques are used to cut the pipe into sections on the seabed. These 12m or 24m long sections would then be lifted to the surface by the crane on the support vessel, and stored on cargo barges for transportation to the shore (Figure 10.4).

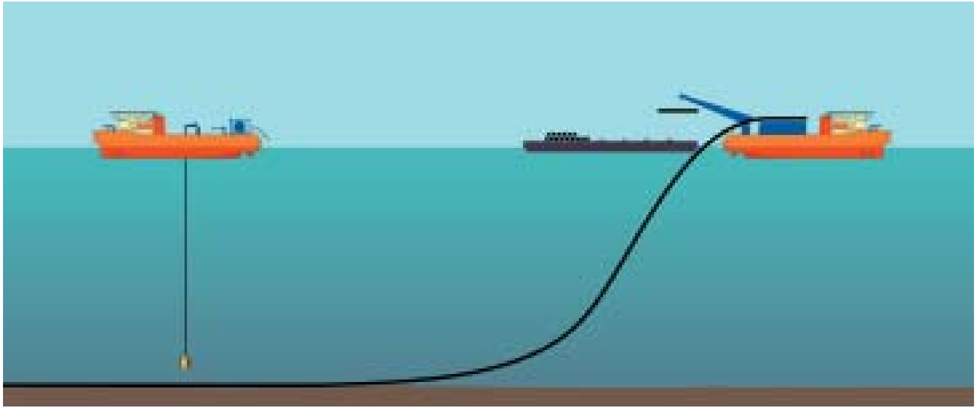


Figure 10.2: "Reverse S lay" recovery technique.

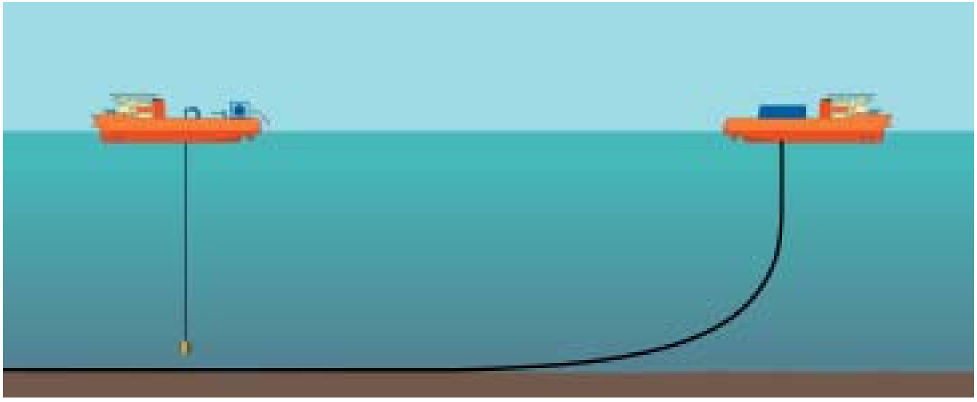


Figure 10.3: "Reverse J lay" recovery technique.

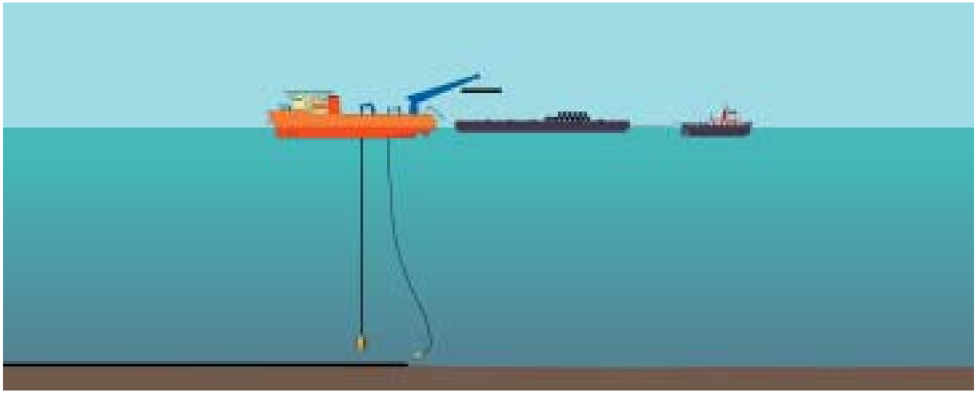


Figure 10.4: "Cut and lift" recovery method.

10.3 Decommissioning the 10" Gas Line PL147

10.3.1 Items to be Decommissioned

10.3.1.1 Materials and Inventory

The gas line is a trenched, 10" diameter pipe which runs from North West Hutton to a junction with the Ninian pipeline called the Ninian Tee (Figure 10.5). It comprises approximately 2,400 tonnes of steel pipe and concrete coating (Section 5). Constructed in 1982, it was originally used to export gas from North West Hutton to the St Fergus gas terminal via the FLAGS pipeline. As production at North West Hutton declined, however, there was insufficient gas from the field to meet the platform's requirement for fuel gas, and so the pipeline was re-commissioned in 1994 to import gas from the Ninian Central platform through the Ninian Fuel Gas Pipeline System.

The pipeline extends from the North West Hutton platform to the flexible line ("spool piece") at the Ninian Tee tie-in. The North West Hutton owners own the pipeline from the North West Hutton platform to its connection with the Ninian Tee, including the 6" diameter 250m long flexible tie-in spool (Figure 10.5). The following equipment will be removed and returned to shore for recycling:

- The 6" flexible spool piece at the Ninian Tee.
- The SSIV, control umbilical and other associated equipment.
- The redundant Welgas Tee pipeline and tie-in spool from the export tie-in (PL 147) to the Western Leg gas pipeline (PL 17) see note below.
- All loose items including bridges, mattresses and supports.

The Western Leg Gas Pipeline PL 17 is operated by Shell and still in operation. Only the disused Welgas Tee pipeline and tie-in spool associated with the North West Hutton will be removed and returned to shore for recycling (as part of PL 147).

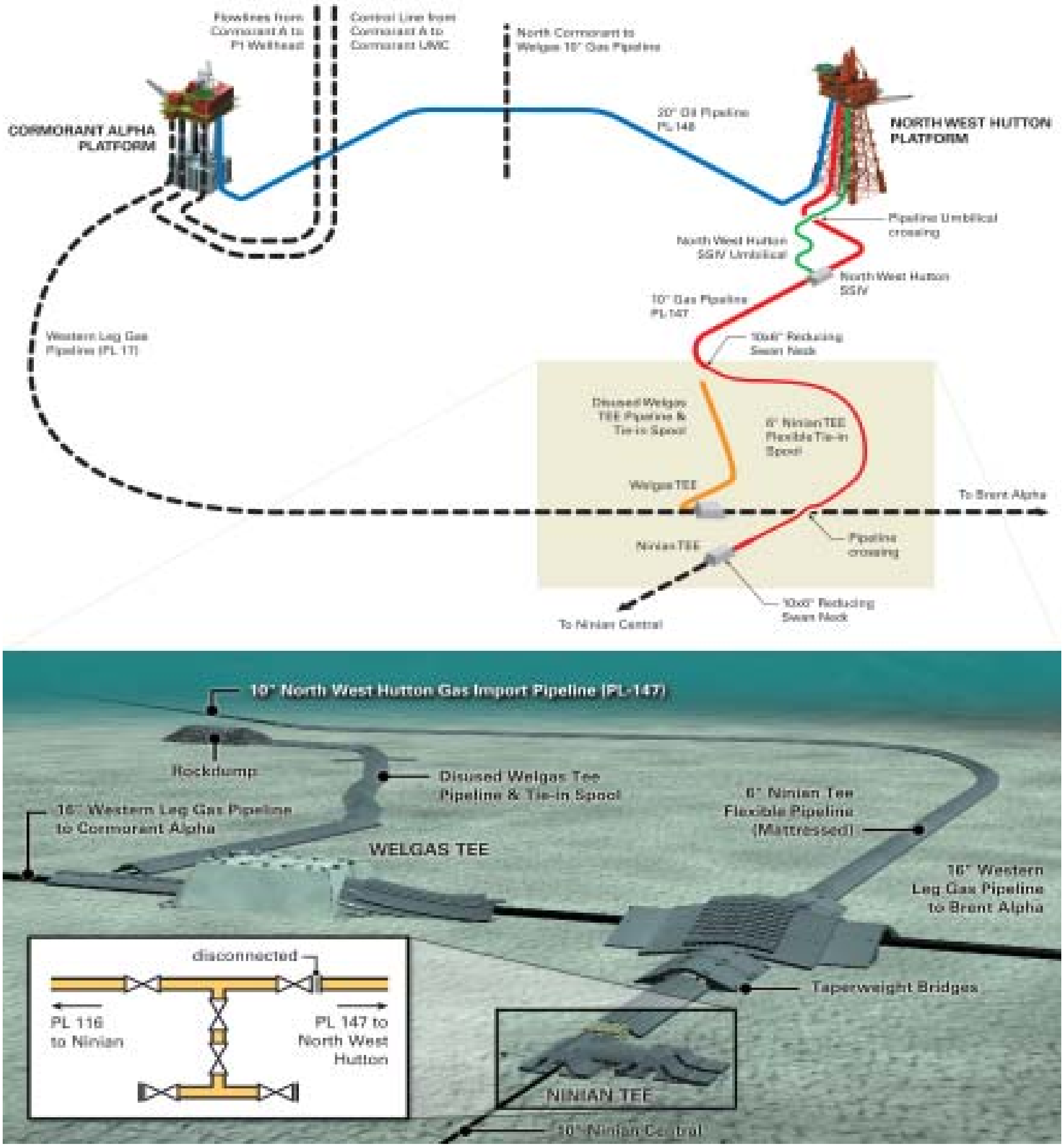


Figure 10.5: North West Hutton pipelines including detail of Ninian Tee.

10.3.1.2 Burial Status

The 10" gas pipeline lies in a trench approximately 0.8m deep with the top of the pipe nominally 0.45m below the level of the surrounding seabed. The trench was designed to fill naturally with seabed material and additional rock dumping was undertaken to protect certain sections of the pipe. The trench over time has naturally back filled although some minimal exposure still remains.

The depth of soil covering the pipe within the trench ranges from 0 to 1.0m and is typically 0.2m. A typical cross section of this soil covering is illustrated in figure 10.6a, which shows the original design intent of being trenched to 800mm.

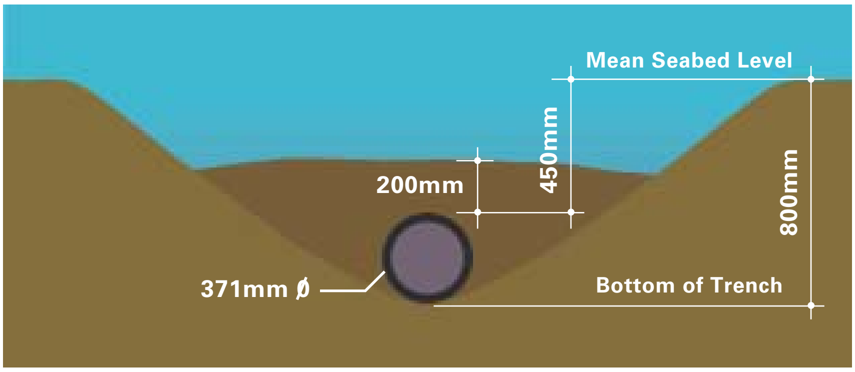


Figure 10.6a: Typical Cross Section showing natural backfill.

Regular inspections have been performed using a Remotely Operated Vehicle (ROV) deployed from a survey vessel. The pipeline is classed as exposed whenever it is visible within the trench. Since the pipeline is trenched any exposed pipe remains below mean seabed level. Recent surveys show that any exposures have been largely 'crown' exposures i.e. the very top of the pipe being exposed, see figure 10.6b, or the top half of the pipe.

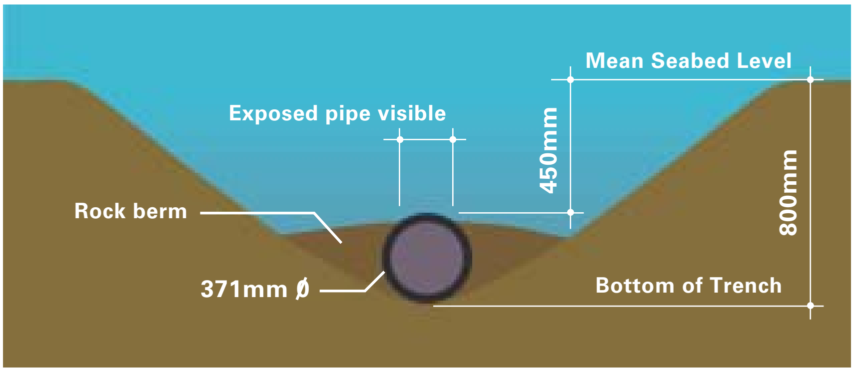


Figure 10.6b: Crown of pipe exposure.

In addition to the natural backfill, rock was placed at some locations to correct free-spans within the trench. This is where the pipe was not resting on the bottom of the trench when it was installed and this gap, or span, was filled to support the pipe. This was done for operational reasons and to prevent overstressing of the pipe.

The overall burial trend from 1993 to 2001 is shown in table 10.1. The results of these surveys clearly indicate that the total length of exposed pipeline is gradually decreasing, indicating continued self burial of the line. The exposed length of the line has reduced from 100% when installed in 1982 to 26.6% (3475m) when last inspected in 2001.

Year of survey	Total amount of pipeline exposed	
	Length (m)	Proportion of line (%)
1993	10,631	85.3
1996	8,368	64.6
1997	4,599	35.1
1999	3,973	30.5
2001	3,475	26.6

Table 10.1: Survey data for the 10" gas pipeline (Ref. 10.1).

This process is expected to continue over time, see figure 10.6c.

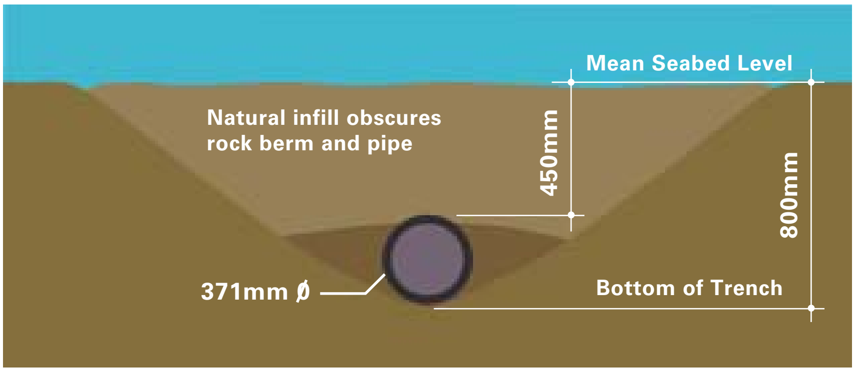


Figure 10.6c: Long term burial.

There are 432 individual exposures ranging in length from less then 10m up to a maximum of 90m, the distribution is as follows:

- 334 are less than 10m
- 72 are 10 to 20m
- 20 are 20 to 30m
- 2 are 30 to 40m
- 2 are 60 t0 70m
- 2 are 80 to 90m

These individual exposures are distributed evenly along the pipeline route. Of the 26 exposures greater than 20m in length, 23 are located within 7.7km of North West Hutton and three at the Welgas tee approach. The greatest individual exposed length is about 90m and is an as-built feature, associated with the sub-sea isolation valve (SSIV).

The pipeline crossings and the sub-sea isolation valve (SSIV) are untrenched and exposed by design; see August 2001 Longitudinal Profiles survey data in Section 20.7. At these locations 50m long transition sections of pipeline take the pipe from full trench depth to seabed level for the 'tie-in' to these seabed facilities. However once the pipeline crossings, the SSIV and its tie-in spool pieces are removed, which is the case for all the decommissioning options being considered, then all the 6 exposures greater than 30m in length will have been removed, leaving all the remaining pipe below mean sea bed level.

10.3.1.3 Present Condition

During service the pipeline was used only for the export, and latterly the import, of "dry" gas, (i.e. gas with no free water or liquid hydrocarbon). Following cessation of production, the line was cleaned by pigging and then flooded with seawater. The line has been disconnected from the Ninian Tee but remains connected to North West Hutton (Figure 10.7).

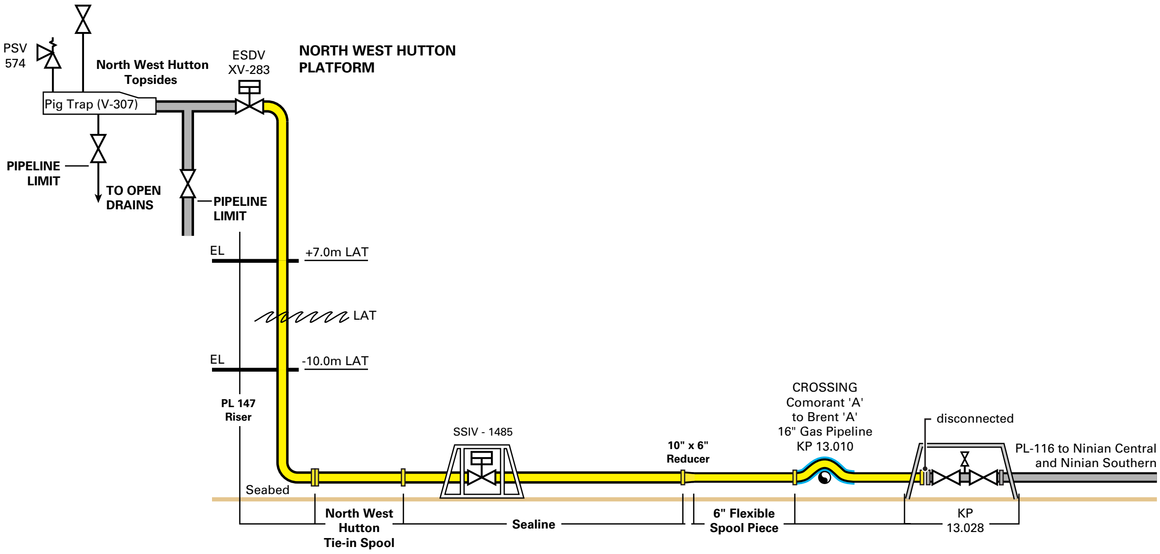


Figure 10.7: Schematic showing details of the 10" gas pipeline PL 147 (not to scale).

Individual exposures are distributed evenly along the pipeline route. Of the 26 exposures greater than 20m in length, 23 are located within 7.7km of North West Hutton and three at the Welgas tee approach. The greatest individual exposed length is 89.3m and is an as-built feature, associated with the SSIV. (See August 2001 Longitudinal Profiles survey data Section 20.7)

Depth of Exposure:

Where exposures occur, the extent varies from crown of pipe to full circumferential exposure. A typical crown exposure is illustrated in Figure 10.6. Almost all exposures are contained within the trench and are below mean seabed level (see Section 20.7).

10.3.2 Description of Options for the 10" Gas Line PL147

The following section discusses the available options for decommissioning the gas pipeline PL 147.

10.3.2.1 Option 1: Leave *in-situ* – Trenched and Buried below the Seabed.

The pipeline would be disconnected from the North West Hutton jacket at the subsea spool-piece and this section plus the SSIV and the flexible connection close to the Ninian Tee would be recovered. Divers or remote techniques would then be used to ensure that the exposed ends of the pipeline were completely buried.

The line would then be left filled with seawater and allowed to further self bury. The whole pipeline route would then be surveyed by ROV, and any items of debris would be removed. A trawler would then undertake a sweep of the route using bottom-towed gear, to confirm that no items of debris that might pose a risk to other users of the sea remained on the site.

The condition and burial status of the pipeline would then be monitored periodically by an inspection programme.

10.3.2.2 Option 2: Pipeline Removal and Onshore Disposal.

Studies have indicated that although a number of removal techniques are feasible, the "cut and lift" method is recommended for this situation (Ref. 10.1). This method would reduce the likelihood that significant amounts of concrete coating would become detached from the pipeline and fall to the seabed during the recovery operations.

The line would be disconnected as described above. Divers or remotely operated equipment from a support vessel would then progressively cut the pipeline on the seabed. As most of the length of the pipeline is currently buried, it would be necessary to uncover the pipeline using subsea excavation or dredging techniques. Sections up to 24m long would be lifted by the support vessel crane onto cargo barges for subsequent transportation back to the shore. After the whole line had been removed, the route would be surveyed and any significant items of debris removed. A trawler would then undertake a sweep of the route using bottom-towed gear, to confirm that no items of debris that might pose a risk to other users of the sea remained on the site.

All recovered material would be returned to an onshore location for reuse, recycling or as a last resort disposal.

10.3.3 Assessment of Options for the 10" Gas Line

10.3.3.1 Technical Feasibility

No major technical issues were identified with any of the decommissioning options for the 10" gas pipeline. Leaving the line trenched *in-situ* involves significantly less work than removing the line and therefore carries less technical risk. The highest technical risks are associated with uncovering the line and lifting the pipeline to surface whilst minimising loss of material, particularly pipeline coating, to the seabed (Ref. 10.1).

10.3.3.2 Safety of Personnel

Remote techniques will be used wherever possible to implement the work scope for pipeline decommissioning (Refs. 10.1, 10.2 and 10.3). It is probable that divers will be required for certain aspects of the programme. The overall safety evaluation indicates that the safety risks associated with the leave *in-situ*, and the removal options are within acceptable limits; all the operations, whilst not routine, do have a track record. Table 10.2 presents the risks to personnel during execution of the work for the various options for pipeline PL 147.

Decommissioning Option	PLL Risk of fatality
Decommission *in-situ* with no remedial work	0.2%
Decommission *in-situ* with remedial trenching & burial	0.2%
Complete removal by "cut and lift"	1.9%

Table 10.2: Risks associated with the various decommissioning options for the 10"gas pipeline PL 147.

The overall safety risk for personnel involved in the operations to remove the 10" gas pipeline is far higher than in any of the leave *in-situ* options. This is due to the significant amount of activity involved in removal and in particular the hazards associated with cutting, rigging, and lifting operations.

10.3.3.3 Environmental Impacts

The overall potential environmental impacts associated with pipeline decommissioning activities are considered to be generally low (Ref. 10.4).

Short-term Impacts

For the option "leave buried" there may be some minor disturbance of seabed sediments when the ends of the pipe are disconnected.

In the "cut and lift" option, seabed sediments along the entire route would be disturbed because the pipe would have to be uncovered before it could be retrieved. Sediments would be removed by water-jetting, jet-prop or mechanical digger. For sections close to the jacket, it is possible that some drill cuttings could be disturbed, with some minor release of oil and contaminated cuttings into the water column. The vessels would use fuels and produce combustion gases, and transportation on land to recycling sites would use fuel and produce combustion gases. Recycling would require the removal of the concrete coating to allow access to the steel. This could result in potential hazards and environmental impacts during lifting, cutting and disposal works, although recycling the steel in the pipes would help conserve resources, but it is likely that the pipe coatings would go to landfill.

Long-term Impacts

All the decommissioning options for the 10" gas pipeline would result in the surface of the seabed being left free from obstructions.

In the option "leave buried", the steel pipe would slowly corrode and then collapse, eventually leaving a thin trace of corroded metal and broken concrete completely buried in the sediment. Since the inside of the pipe has been cleaned there would be no release of hydrocarbons to sea. Studies indicate that the anodes would cease to provide cathodic protection after 35–40 years, and that the pipeline would persist for a period of about 300 years as it slowly degrades and collapses (Ref. 10.1). Although these timescales cannot be accurately predicted and the pipeline may last longer, this has no material impact on the overall assessment.

Fuel would be used, and combustion gases released, during periodic inspections and potential remedial activities but the amounts are insignificant in overall terms.

If the removal option were implemented, some sections of concrete coating may be lost during the recovery process. These may be left on or in the seabed, although it is anticipated that cleaning sweeps would remove any significant items. No other long-term environmental impacts have been identified.

Onshore impacts will be limited to recycling issues (removal of concrete and recycling of steel) and short-term nuisance caused by transportation and the use of landfill sites for any material that cannot be recycled.

10.3.3.4 Societal Impacts on Other Users of the Sea

The pipeline is presently trenched and mostly buried. The 'FishSafe' system is designed to alert fishing vessels to potential snagging hazards, and it requires spans of over 10m long and 0.8m above the seabed to be displayed on the system. There are currently no spans on this pipeline which require to be identified as potential obstructions, and no such spans are anticipated in the future. The seabed along the route of PL 147 is flat and very stable (Ref. 10.1) and it is very unlikely that a trawl board would interact with the line in its present state of burial. The use of a trawler to sweep the line will confirm this. There is no history of any major incident or interaction between fishing gear and the pipeline resulting in damage or compensation claims.

If the whole pipeline were removed by "cut and lift", the potential small safety risk to fishermen would be eliminated.

10.3.3.5 Cost Assessment

The estimated costs for each of the options for decommissioning the 10" gas pipeline PL 147 are discussed below.

To leave the 10" gas line PL 147 *in-situ*, trenched and buried the estimated cost is £3m (+ or – £0.3m) for the flushing, cleaning and disconnection work and the removal of identified equipment.

The incremental cost for any residual trenching or covering work is estimated at £2m (+ or – £0.2m).

The incremental cost for removing and disposing of PL 147 onshore is estimated to be £10m (+ or - £5m). This cost is based on un-burying the pipeline and removing it to the shore for recycling and disposal.

The estimated costs, approximately £0.25m, associated with the long-term monitoring of the site are included in the costs for leave *in-situ* and the remedial trenching options.

10.3.4 Recommended Decommissioning Option for the 10" Gas Line PL147

The options for decommissioning the 10" gas pipeline have been assessed in terms of their technical feasibility, safety risk, societal impact, environmental impact and cost. There are no significant technical or safety issues that constrain the selection of any option, but the increased risks associated with the removal of the line are significant. There are no significant environmental concerns associated with any option.

The main area of concern for the evaluation centres on the possible effects of the presence of the line, and in particular future deterioration of the line and the potential risk this poses for fishing activity. Because the line is buried, however, any such risks are negligible or non-existent.

The DTI Decommissioning Guidelines state that a decision on the appropriate depth of burial of pipelines will take account of seabed conditions and other relevant factors and that the expected burial would be to a minimum depth of 0.6m above the top of the pipeline (Ref. 10.5). As stated earlier, PL 147 has been trenched to a depth 0.45m below the seabed level and has self buried to give an average cover of 0.2m (Figure 10.6). The implications of this were reviewed and the recommended outcome is considered acceptable for the following reasons:

1) The 0.6m guideline is a general guide for the UKCS based on variable seabed stability conditions. As a general rule, seabed stability in the deep water of the northern North Sea, where near-bottom current speeds are generally low, is significantly greater than other areas.

2) Numerous general and specific surveys of the North West Hutton pipelines confirm that the seabed is stable.
3) Operations to re-trench the line and backfill with sand or rock to achieve the 0.15m additional burial required to meet the 0.6m guide value would cause disproportional disturbance to the seabed and would require the removal of existing material to gain access.

The overall conclusion and recommendation is that the trench and burial depth is adequate to ensure the future stability of PL 147

At the pipeline crossing additional precautions would be necessary. The pipeline will be cut and removed at the crossing but this might be deferred until the other pipeline is decommissioned. However the most appropriate course of action will be determined nearer the time and will be subject to agreement with the pipeline owners and the regulatory authorities.

The recommended option for the 10″ pipeline PL 147 is to leave the line trenched and buried *in-situ* with no additional remedial work required.

Recommendation: The gas pipeline PL 147 should be left *in-situ* as it is already trenched and self burried over majority of its length. Ancillary and loose protective equipment should be removed.

10.4 Decommissioning the 20″ Oil Line PL148

10.4.1 Items to be Decommissioned

10.4.1.1 Materials and Inventory

The 20″ diameter concrete-coated, steel oil export pipeline runs for approximately 13km from North West Hutton to the Cormorant Alpha platform. BP is responsible for the whole pipeline from the North West Hutton platform to its connection with the Cormorant Alpha riser, including the tie-in spool (Figure 10.8). It comprises approximately 5,200 tonnes of steel pipe and concrete coating (Section 5).

10.4.1.2 Burial Status

The 20″ oil pipeline lies on the surface of the seabed, and is not trenched. The most recent survey, conducted in 2001, found that the pipeline was exposed for 99.8% of its length and had 4 spans more than 10m long. All of the spans identified were less than 0.4m high which is well within the *'Fishsafe'* height of 0.8m. Spans of 0.8m above the seabed or higher are displayed as potential obstruction and snagging hazards for commercial fishing on the *'Fishsafe'* system. The pipeline crosses over 3 other pipelines and control lines along its route and these are protected by rock dump and concrete mattresses; their locations are shown in Figure 10.5.

10.4.1.3 Present Condition

The pipeline was used to export oil from North West Hutton and also the Hutton oil fields. On cessation of production, the line was pigged and flushed from North West Hutton to Cormorant Alpha using deoxygenated seawater dosed with cleaned biocide. A detailed programme of pigging and flushing continued until the concentration of oil in the water received at Cormorant Alpha indicated that hydrocarbons had been removed. A maximum threshold of 40ppm of oil in water was set to determine that the line was sufficiently clean; in the event a lower level of approximately 30ppm was actually achieved. Results from the pigging operation and inspection of the surface equipment provide assurance that all significant hydrocarbon material has been removed from the pipeline.

The pipeline was filled with inhibited water to protect downstream equipment at Cormorant Alpha prior to final disconnection (Figure 10.8).

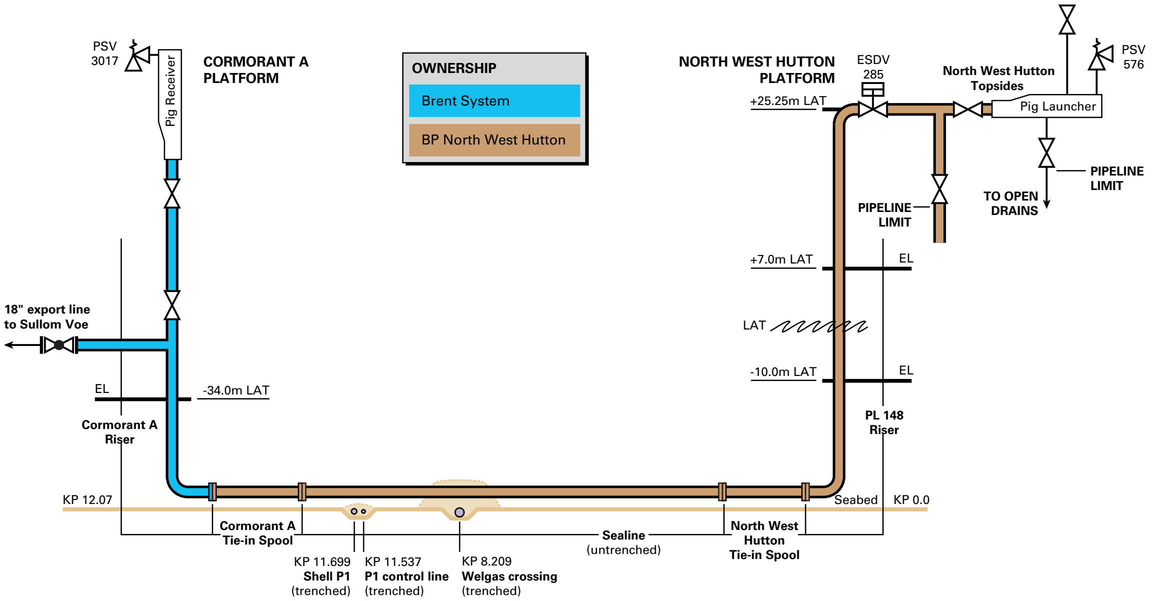


Figure 10.8: Schematic showing details of the 20” oil pipeline PL 148 (not to scale).

10.4.2 Descriptions of Options for the 20” Oil Line PL148

The following section discusses the available options for decommissioning the 20” oil pipeline PL 148.

10.4.2.1 Option 1 – Leave the Pipeline *in-situ* on the Seabed

The most straightforward decommissioning solution would be to leave the pipeline *in-situ* on the seabed. This would involve disconnecting the pipeline from the installations and ensuring that both ends of the pipeline were buried to reduce any snagging hazard. Following removal of all loose items and debris, the line would be left. A trawling sweep would be performed to ensure that the line did not pose a snagging hazard. Periodic surveys would be implemented to ensure that no spans or other problems develop over time.

10.4.2.2 Option 2: Trench and Bury the Line

In this option, the line would be disconnected as described above. Trenching and burying would be achieved using a support vessel and a purpose-built tool to trench and bury the line. The tool would be positioned over and around the pipeline and the equipment would then be towed along the length of the line creating a trench into which the pipeline would settle. The tool would then be towed along the line again to replace the material extracted from the trench over the pipeline. Burial would be to a depth of 0.6m below the seabed in line with the DTI guidelines.

Additional precautions would be necessary at pipeline crossings. These would either require leaving the crossing until the other pipeline is decommissioned and dealing with both at the same time, or using the “cut and lift” technique to remove the section of pipeline not able to be trenched due to the crossing. Pipeline PL 148 has 3 crossings at which the pipe would need to be cut and removed (Figure 10.5).

Following completion of the trench and bury operation, the whole pipeline route would then be surveyed by ROV, and any significant items of debris would be removed. A trawler would then undertake a sweep of the route using bottom-towed gear, to confirm that all significant items of debris had been recovered.

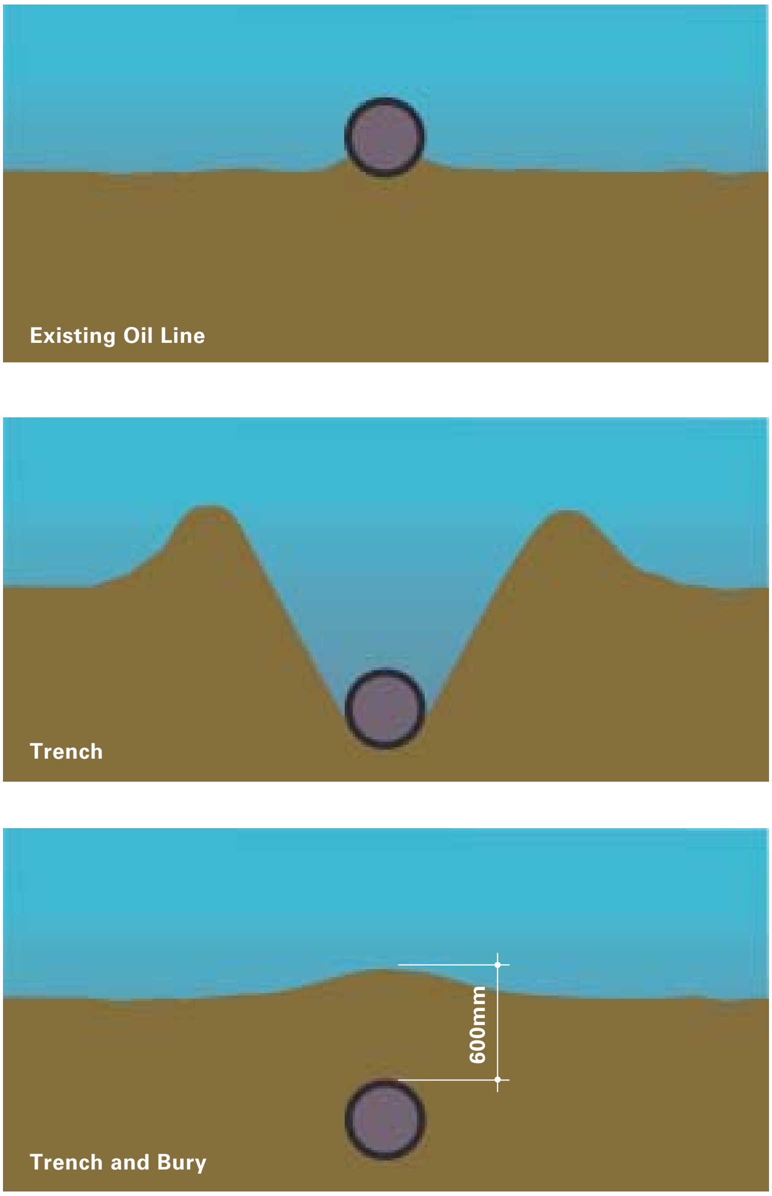


Figure 10.9: Diagrams illustrating the process of trench and bury (Ref. 10.1).

10.4.2.3 Option 3: Pipeline Removal and Onshore Disposal

Studies have indicated that although a number of removal techniques are feasible, the "cut and lift" method is recommended for this situation (Ref. 10.1). This method would reduce the likelihood that significant amounts of concrete coating would become detached from the pipeline and fall to the seabed during the recovery operations.

The 20"pipeline would be disconnected as described above. Divers or remotely operated equipment from a support vessel would then progressively cut the pipeline on the seabed. Sections up to 24m long would be lifted by the support vessel crane onto cargo barges for subsequent transportation back to the shore. After the whole line had been removed, the route would be surveyed and any significant items of debris removed. A trawler would then undertake a sweep of the route using bottom-towed gear, to confirm that no significant items of debris remained on the site. As with the trenching option, the pipeline crossings would have to be managed carefully as part of this process.

All recovered material would be returned to an onshore location for reuse, recycling or disposal.

10.4.3 Assessment of Options for the 20” Oil Line

10.4.3.1 Technical Feasibility

There are no major technical issues identified with any of the decommissioning options for the 20” oil pipeline.

Leaving the line *in-situ* involves significantly less work than removing the line and therefore carries less technical risk. The highest technical risks would be associated with lifting the pipeline to surface whilst minimising loss of material, particularly pipeline coating, to the seabed. Some degree of risk would be associated with the trench and bury option because unanticipated seabed conditions (e.g. the presence of boulders) or other relevant factors may be encountered which would cause operational problems. Such eventualities are, however, considered to be unlikely; as other pipelines in the area have been trenched successfully (Ref. 10.1).

10.4.3.2 Safety of Personnel

Remote techniques will be used wherever possible to carry out the work. It is probable that divers will be required for certain aspects of the programme. The overall safety evaluation indicates that the safety risks associated with leave *in-situ* and pipeline removal are within acceptable limits since all the operations, whilst not routine, do have a track record. Table 10.3 presents the risks associated with the various decommissioning options for PL 148 (Ref. 10.2 and 10.3).

The overall safety risk for personnel involved in the operations to remove the 20” oil pipeline is far higher than in any of the leave *in-situ* options. This is due to the significant amount of activity involved in removal and in particular the hazards associated with cutting, rigging, and lifting operations, and the onshore dismantling work.

Decommissioning Option	PLL Risk
Decommission *in-situ* with no remedial work	0.21%
Decommission *in-situ* with remedial trenching & burial	0.28%
Complete removal by “cut and lift”	2.1%

Table 10.3: Risks associated with the various options for decommissioning the 20” oil pipeline PL 148.

10.4.3.3 Environmental Impacts

The overall potential environmental impacts associated with pipeline decommissioning activities are generally low (Ref. 10.4).

Short-Term Impacts

In the option to leave the pipeline *in-situ* on the seabed, there are no identified environmental impacts apart from the physical presence of the line on the seabed. The line has been in position for over 20 years.

The trench and burial operations would disturb clean sediment and thus impact benthic communities in the immediate vicinity of the present pipeline route. Small amounts of cuttings may be disturbed towards each end of the pipeline, and this may cause a local impact on the adjacent seabed. Any impact from such activity would be relatively minor and last only a few months. The vessels involved in the work would cause a very localised and transient impact on other users of the sea and give rise to localised atmospheric emissions due to fuel usage.

In the “cut and lift” option, seabed sediments along the entire route of the pipeline would be disturbed but the short-term disturbance would be less than for the trench and bury option. For sections close to the jacket, it is possible that some oily cuttings could be disturbed, with some minor release of oil and contaminated cuttings into the water column. The vessels would use fuels and produce combustion gases, and transportation on land to recycling sites would use fuel and produce combustion gases. Recycling would require the removal of the concrete coating to allow access to the steel. This could result in potential hazards and environmental impacts during lifting, cutting and disposal work, although recycling the steel in the pipeline would have a positive environmental impact by conserving resources, but the energy saved by recycling would be at least partially offset by the fuel used during the recovery of the line.

Long-Term Impacts

In the leave *in-situ* option, the pipeline would gradually deteriorate and eventually break-up. The corrosion products from the steel are benign and would not cause any significant environmental impacts. The concrete coating would most likely break-up and could potentially be spread from the pipeline location by trawling activity. Studies show that the anodes would cease to provide cathodic protection after about 35 - 40 years, and the pipeline could be present in the seabed for 300 years or longer, as the slow process of corrosion and degradation continues (Ref. 10.1).

In the option "trench and bury", the steel pipe will slowly corrode and then collapse in the manner described above. The trenching of the pipeline will, however, ensure that steel and concrete remained completely buried in the sediment as the slow breakdown takes place.

Fuel would be used, and combustion gases released, during periodic inspections and potential remedial activities.

In the pipeline removal option, the seabed would be left clear of potential obstructions. It should be noted that sections of concrete coating may be lost during the recovery process and these may be left on or in the seabed, although it is anticipated that cleaning sweeps would remove any significant items. No other long-term environmental impacts have been identified.

Apart from the possible nuisance associated with transportation and recycling activities, there would be very little onshore environmental impact. It is anticipated that the majority of material could be recycled, although it is possible that the concrete coating could be sent to landfill.

10.4.3.4 Societal Impacts on Others Users of the Sea.

If the pipeline were completely buried to a depth of 0.6m, the safety risk to fishermen would be eliminated. The seabed along the route of PL 148 is flat and very stable (Ref. 10.1) and it is very unlikely that a trawl board would interact with the line if it were buried as described. The use of a trawler to sweep the line will confirm this. There is no history of any major incident or interaction between fishing gear and the pipeline resulting in damage or compensation claims.

If the whole pipeline were removed by "cut and lift", there would be no safety risk to other users of the sea, and a very small area of seabed would once again be available for fishing operations.

If the pipeline were left *in-situ*, the steel would gradually corrode and the concrete coating would eventually break up. Periodic surveys would be implemented to monitor the condition of the line, and remedial works would be undertaken at this time to ensure the pipeline remained in a safe condition. Snagging hazards represent a safety risk for the commercial fishing industry. It is also likely that debris from a deteriorating pipeline would be spread from the present route of the pipeline.

10.4.3.5 Cost Assessment

The estimated costs for each of the oil pipeline PL 148 options are discussed below.

To leave PL 148 *in-situ* on the seabed the estimated cost is £2m (+ or - £0.2m) for flushing, cleaning and disconnection work.

The incremental costs for trenching and covering the pipeline is £1m (+ or - £0.1m).

The incremental cost for recovering and disposing of PL 148 onshore is £7m (+ or -£3.5m). This wide range is attributed to the possible use of new technology, weather conditions and technical challenges associated with seabed and soil conditions.

The estimated costs, approximately £0.25m, associated with long-term monitoring of the site are included in the costs for the leave *in-situ* and remedial trenching options.

10.4.4 Recommended Decommissioning Option for the 20″ Oil Line PL148

The options for decommissioning the 20″ pipeline have been assessed in terms of technical feasibility, safety risk, environmental impact, societal impact and cost. Technical issues do not constrain the selection of any option, but the increased safety risk associated with removal of the line is a factor. There are no significant environmental concerns associated with any of the options.

The main area of concern for the evaluation centres on the possible effects of the presence of the line, and in particular future deterioration of the line and the potential risk this poses for fishing activity. The pipeline has been present and clearly marked on navigation charts for over 20 years. Although fishing around the routes of pipelines is not recommended, there are no exclusion zones and well maintained operational pipelines such as those at North West Hutton do not create an obstruction for fishing activity.

Ensuring that the pipeline does not create a hazard for fishermen in the future is readily mitigated by trenching and burying, or by removal of the pipeline. Trenching and burying presents a lower overall risk and would provide a permanent solution.

At the pipeline crossings additional precautions would be necessary. The pipeline will be cut and removed at the crossings but this might be deferred until the other pipeline is decommissioned. However the most appropriate course of action will be determined nearer the time and will be subject to agreement with the pipeline owners and the regulatory authorities.

Decisions on the appropriate depth of burial of the pipeline will take account of seabed conditions and other relevant factors however the recommended option for the 20″ oil pipeline PL 148 is to trench and bury the pipeline to a depth of 0.6m below the seabed.

Recommendation: The oil pipeline PL148 should be trenched and buried beneath the seabed. Ancillary and loose protective equipment should be removed.

10.5 Combined Programme for the Two Pipelines

10.5.1 Rationale

The North West Hutton owners would carry out the approved decommissioning options for pipelines PL 147 and PL 148 with an optimised vessel mobilisation, so that all operations can be effectively and safely completed with minimal disturbance to other users of the sea.

10.5.2 Summary of the Decommissioning Programme for PL 147 and PL 148

The relative impacts of the alternative decommissioning options for the 10″ gas pipeline PL 147 and the 20″ oil pipeline PL 148, are summarised in Table 10.4.

Criteria		Units	Pipeline	Leave *in-situ*	Trench and Bury	Remove
Safety	Probability of Loss of Life	PLL	Gas (PL-147) Oil (PL-148)	0.20% 0.21%	0.20% 0.28%	1.90% 2.10%
Environmental (Figures are for both oil & gas line)	GHG CO_2 E **(1)**	Households		1,300	1,700	2,200
	Total Energy Requirement **(2)**	Households		1,400	1,900	2,400
	Footprint	km^2		Negligible	0	0
	Impact on landfill site	Tonnes		Negligible	Negligible	4,000
	Persistence	Years		300	300	0
Societal	Impact on Fisheries		Gas (PL-147) Oil (PL-148)	No Impact Snagging Risk	No Impact No Impact	No Impact No Impact
	UK Employment Impact	Man Years		61	69	180
	Tax Impact to Society	£m	Gas (PL-147) Oil (PL-148)	1.2 0.8	2 1.2	5.2 3.6
Technical				Feasible	Feasible	Feasible
Economics	Cost	£m	Gas (PL-147)	3	5	13
			Oil (PL-148)	2	3	9

Table 10.4: Summary of relative impacts of the alternative decommission options for the 10" gas line PL 147 and the 20" oil line PL 148 (Refs. 10.2 and 10.3).

Notes:

1. Gaseous emissions are expressed in terms of CO_2 equivalents (CO_2-E). In 2000 the average annual CO_2-E emission for each UK household was 6 tonnes.
2. Energy is expressed in terms of the average energy use of UK households. In 2001 this was 80 GJ.

The 20" oil pipeline was installed un-trenched on the seabed and periodic surveys have identified no significant stability problems. The condition and degree of exposure of the pipeline have remained constant over time. It can therefore be assumed that without intervention the pipeline will remain exposed on the seabed for a long period until full pipeline degradation occurs.

The 10" gas pipeline was installed trenched to a depth of approximately 0.8m, with natural backfill. This protected the pipeline from hydrodynamic loads and trawl gear interaction. In 1989 over 8.5km of the line was rock dumped due to spanning and exposure in the trench. A further 1.7km has been covered by natural backfill and now only about 3.4km is exposed, i.e. is visible.

The Sub Sea Isolation Valve (SSIV), umbilical and a section of flexible pipeline associated with the pipeline will be removed separately; these works have been covered in the costs for the pipeline.

All the options are technically feasible and cost is not a big differentiator. However there is more work and risk associated with the recovery option and this is reflected in the costs. It is also reflected in the safety risks where the recovery option results in a safety exposure to personnel which is 8 to 10 times greater than that for the other two options.

There are no significant environmental issues, although it is evident that the greater the work scope, the greater will be the use of energy and the amount of CO_2 emissions. The continued presence of material on the seabed is recognised for the leave *in-situ* option for the oil pipeline, but this impact would be mitigated if the line were buried. In both cases it is estimated the lines would persist for about 300 years. The total mass of material in the lines is about 7,600 tonnes; 3,600 tonnes is steel which would be re-cycled and the other 4,000 tonnes could impact landfill sites.

There is no anticipated risk to fishing activities for the gas line, which is trenched and effectively buried over approximately 73% of its length. There is a snagging risk for the oil line if it was left *in-situ* on the seabed, and this is likely to increase with time as the pipeline degrades. If the line were buried then this risk would be virtually eliminated.

The aim of the decommissioning programme for the pipelines is to achieve an appropriate balance between short-term risks from the implementation of the programme, any residual risk to other users of the sea, and potential environmental impacts. Burying the 20" oil line, and confirming the burial status of the 10" gas line, provides this balance by using proven technology to effectively eliminate the potential risk to other users of the sea. The implementation of a monitoring programme will ensure that this long-term condition is maintained.

10.5.3 Programme Timing and Schedule

The timely and effective implementation of pipeline decommissioning is the aim of the pipeline owners. Pipeline decommissioning activity can be implemented separately from activity associated with decommissioning the main installation with no detrimental impact on either programme. The volume of activity and the number of vessel movements associated with the work, however, make effective co-ordination between all the activities prudent.

The decommissioning programme for the pipelines will require the utilisation of scarce resources for which there is a great demand from other offshore activities, including crucial maintenance programmes for existing producing installation. The contracting strategy for the work will therefore allow contractors a degree of flexibility in the timing of the programmes, which will assist their operations and help to contain overall costs. The pipelines will not deteriorate in the short-term, and so the issues of pipeline condition and integrity do not create any problems in terms of the timing envisaged.

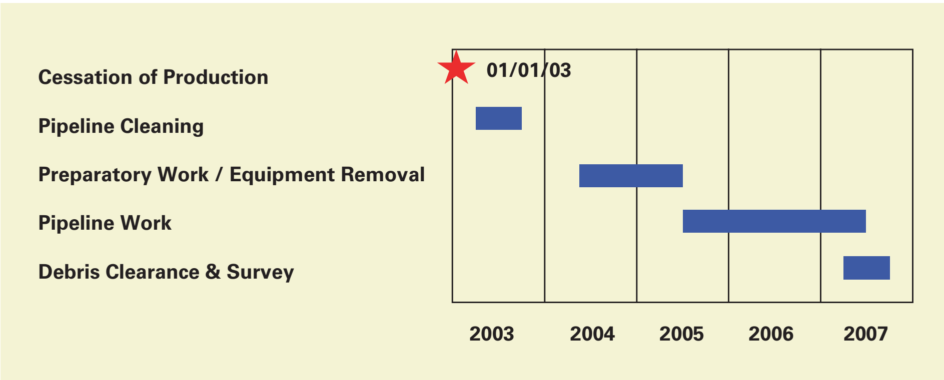


Figure 10.10: Possible schedule of decommissioning programme for the pipelines.

10.5.3.1 Outline Programme of Works for Pipeline Decommissioning

- Pre-decommissioning underwater survey of the PL 147, PL 148 and all associated equipment on the seabed.
- Disconnect and remove sections of North West Hutton (PL1 47 and PL 148) and Cormorant Alpha (PL 148 only) including fitting at blind at Cormorant Alpha end.
- Remove all concrete mattresses and other loose items from the pipeline corridors.
- Remove the SSIV umbilical and protection frame from PL 147.
- Remove the redundant tie-in spool for PL 147.
- Trench and bury the entire length of the 20" oil line to a depth that takes into account the seabed conditions and other relevant factors and the expected burial would be to a depth of 0.6m above the top of the pipeline.
- Perform a post-decommissioning sweep of the seabed along both lines and confirm that they do not constitute a seabed obstruction.
- Return all retrieved items to the shore for re-use, recycling or safe disposal as appropriate.
- Remove the redundant Welgas tie-in spool and pipework

At the pipeline crossings additional precautions would be necessary; the pipeline will be cut and removed at the crossing but this might be deferred until the other pipeline is decommissioned. However the most appropriate course of action will be determined nearer the time and will be subject to agreement with the pipeline owners and the regulatory authorities.

10.5.4 Monitoring Programme for Material Left on the Seabed.

The North West Hutton owners will ensure that the site of the pipelines remains free from obstructions. This will involve a monitoring programme to confirm that the pipeline remains safely buried. The method of inspection will be the most appropriate available at the time of survey. At present this is most likely to be a visual inspection by ROV or by a ROV carried sub-bottom profiler utilising acoustic pulse induction methods.

The first survey will be carried out within one year of completion of the decommissioning work to provide baseline survey data and confirmation that the pipeline is not a hazard to other users of the sea. A second survey will be carried out within 3 to 5 years of the initial post decommissioning survey, with a future survey regime being determined in conjunction with the DTI, based on the analysis of the first two surveys.

References

10.1 "Report TEC 14 - 018" J P Kenny, North West Hutton, Pipeline Decommissioning – Technical Summary Report, Document No. 05-2416-01-G-3-011, Rev 03, dated 21st November 2003.

10.2 "Report SAF 05", Andrew Palmer & Associates, North West Hutton, Pipelines Decommissioning Study – HAZID, Document No. 4760A-RPT-002, Rev. 2, dated 14th August 2003.

10.3 "Report SAF 06", Andrew Palmer & Associates, North West Hutton Pipelines Decommissioning – Quantitative Risk Assessment, Document No. 4760A-RPT-001, Rev 2, dated 14th August 2003.

10.4 "Report ENV 01", Environmental Statement in support of the De-commissioning of the North West Hutton Facilities, Report No. BPX067/ES/2003, June 2004.

10.5 DTI Oil and Gas Guidance Notes for Industry Decommissioning of Offshore Installations and Pipelines under the Petroleum Act 1998, Published by Offshore Decommissioning Unit, Department of Trade and Industry, 21 August 2000.

11.1 Well Abandonment and Conductor Removal

This section summarises the final condition of the wells on the North West Hutton platform at the end of the well abandonment and conductor removal phases. Reference should also be made to Section 7.4.1 of the programme. Table 11.1 lists the forty North West Hutton Wells. Of the original 40 wells, seven were drilled from the subsea template, known as 'tieback wells'; the remaining 33 were drilled from the platform, known as 'platform wells'.

Of the forty wells on the North West Hutton, thirteen were partially abandoned by Amoco in 1993, and a further three were abandoned later. In these wells the reservoir section has been fully abandoned, most of the tubing and some of the casing strings have been removed.

Between 2002 and 2004 all the wells were fully abandoned, and the majority were abandoned in two phases. The first phase was to plug the wells. This was accomplished with normal well intervention techniques, including coiled tubing. The second phase was to remove tubing, casing and conductors from the forty wells. Table 11.2 shows, for each well, the dates when the two phases of abandonment were started and completed. All forty wells have now been fully abandoned.

Operations commenced in May 2002 and were completed in January 2004. Details of the final status of all wells are included in the well abandonment reports (Reference 11.1), which are available for review at BP and in the future at the National Hydrocarbons Data Archive (NHDA). The final status was notified to the Health & Safety Executive at the end of the wells operations.

Well No.	Slot No.	Type of Well	Platform Well / Tie- Back Well	Well Abandonment Report	Comments
A4	5	Producer	Tie-Back Well	211/27-A04	
A5	13	Producer / Water Injector	Tie-Back Well	211/27-A05	Producer, then changed into a water injector in 1994
A6	11	Water Injector	Tie-Back Well	211/27-A06	
A7	8	Producer / Water Injector	Tie-Back Well	211/27-A7	Producer, then changed into a water injector in 1984
A8Z	35	Water Injector	Platform Well	211/27-A8Z	
A10	22	Producer	Platform Well	211/27-A10	
A11	7	Producer	Platform Well	211/27-A11	
A12	28	Producer / Gas Injector / Water Injector	Platform Well	211/27-A12	Producer then changed into a gas injector in 1985 and then a Water Injector in 1992
A14	39	Producer	Platform Well	211/27-A14	
A17	27	Producer	Platform Well	211/27-A17	
A18	6	Water Injector	Platform Well	211/27-A18	
A21	25	Producer / Water Injector	Platform Well	211/27-A21	Producer, then changed to water injector in 1985
A22	23	Water Injector	Platform Well	211/27-A22	
A23	4	Producer	Platform Well	211/27-A23	
A25	19	Producer	Platform Well	211/27-A25	
A27Z	24	Producer	Platform Well	211/27-A27Z	Was Well A27 sidetracked in 1985 and became Well
A28Z	21	Producer	Platform Well	211/27-A28Z	A27Z Was Well A28 sidetracked in 1987 to become Well A28Z
A29	10	Producer	Platform Well	211/27-A29	
A31	3	Producer	Tie-Back Well	211/27-A31	Was well A1
A32	30	Water Injector	Platform Well	211/27-A32	
A33	2	Producer	Platform Well	211/27-A33	Was wells A9 and A13
A34	38	Producer	Platform Well	211/27-A34	Was well A24
A35Z	17	Water Injector	Platform Well	211/27-A35Z	Well A35 was sidetracked in 1988 to become Well A35Z
A36	32	Producer	Platform Well	211/27-A36	
A37	34	Producer	Platform Well	211/27-A37	
A38	16	Producer	Platform Well	211/27-A38	
A39	37	Producer	Platform Well	211/27-A39	
A40	40	Gas Injector	Platform Well	211/27-A40	
A41Z	29	Producer	Platform Well	211/27-A41Z	Well A41 was sidetracked in 1991 to become Well A41Z
A42Z	12	Producer / Water Injector	Platform Well	211/27-A42Z	Was well A26, changed to Well A42 in 1989 and then sidetracked in 1989 to become Well A42Z. Converted to a water injector in 1991.
A43Z	9	Producer	Platform Well	211/27-A43Z	Was well A20, this well was sidetracked in 1984 to become Well A20Z and was then side tracked again in 1990 to become A43Z.
A44	36	Producer	Platform Well	211/27-A44	
A45	14	Producer	Platform Well	211/27-A45	Was well A19
A46	15	Producer	Tie-Back Well	211/27-A46	Was well A3Z and sidetracked in 1990 to become Well A46
A47	31	Producer	Platform Well	211/27-A47	
A48	18	Producer	Platform Well	211/27-A48	Was well A16
A49	26	Producer	Platform Well	211/27-A49	
A50Z	33	Producer	Platform Well	211/27-A50	Was wellA30 and sidetracked in 1991 to become Well A50Z
A51	1	Producer	Tie-Back Well	211/27-A51	Was well A2
A52	20	Producer	Platform Well	211/27-A52	Was well A15, sidetracked in 1992 to become Well A52

Table 11.1: List of the Abandoned North West Hutton Wells.

	PHASE 1 - Well Plugging		PHASE 2 – Tubing, Casing and Conductor Removal	
Well	**Commencement**	**Conclusion**	**Commencement**	**Conclusion**
A04	24/12/2002	08/03/2003	06/10/2003	15/10/2003
A05		21/03/1999	09/11/2003	03/12/2003
A06	21/01/2003	18/03/2003	08/12/2003	16/12/2003
A07		October 1993	22/10/2003	24/10/2003
A08z	31/08/2002	19/02/2003	11/07/2003	15/07/2003
A10		August 1993	29/08/2003	01/09/2003
A11	14/01/2003	19/03/2003	24/10/2003	28/10/2003
A12	13/10/2002	23/04/2003	06/08/2003	09/08/2003
A14	03/11/2002	30/04/2003	29/06/2003	07/07/2003
A17	15/10/2002	24/10/2002	15/07/2003	20/07/2003
A18	05/01/2003	20/04/2003	30/10/2003	09/11/2003
A21	25/08/2002	17/04/2003	18/08/2003	22/08/2003
A22	28/10/2002	24/04/2003	24/08/2003	29/08/2003
A23		August 1993	15/10/2003	17/10/2003
A25	15/02/2003	24/03/2003	23/12/2003	29/12/2003
A27z		21/07/1993	22/08/2003	24/08/2003
A28z		25/10/1993	02/09/2003	13/09/2003
A29		July 1993	17/10/2003	08/12/2003
A31	16/12/2002	24/12/2002	29/09/2003	06/10/2003
A32	13/09/2002	15/03/2003	14/08/2003	18/08/2003
A33	26/12/2002	07/01/2003	23/09/2003	28/09/2003
A34	05/08/2002	10/02/2003	22/06/2003	29/06/2003
A35z	10/03/2003	23/03/2003	31/12/2003	13/01/2004
A36	03/07/2002	16/03/2003	20/07/2003	25/07/2003
A37		June 1993	09/07/2003	10/07/2003
A38	06/02/2003	17/03/2003	03/01/2004	07/01/2004
A39	12/07/2002	02/05/2003	15/06/2003	22/06/2003
A40		September 1993	06/07/2003	08/07/2003
A41z	27/09/2002	15/10/2002	10/08/2003	14/08/2003
A42z		July 1993	16/11/2003	22/11/2003
A43		August 1993	19/10/2003	22/10/2003
A44		1992	09/06/2003	15/06/2003
A45	28/01/2003	08/02/2003	17/12/2003	21/12/2003
A46		28/03/1993	13/01/2004	16/01/2004
A47		24/07/1993	30/07/2003	01/08/2003
A48		27/07/1993	20/01/2004	22/01/2004
A49	23/10/2002	30/10/2002	02/08/2003	06/08/2003
A50z	20/08/2002	03/10/2002	20/07/2003	30/07/2003
A51	26/11/2002	27/02/2003	13/09/2003	22/09/2003
A52		16/08/1993	16/01/2004	20/01/2004

Table 11.2: Dates of the start and finish of the two Well Abandonment Phases for each of the wells.

References

11.1 North West Hutton Well Abandonment Reports, Phase 1 and Phase 2 - July 2002 - January 2004

12 INTERESTED PARTY CONSULTATION

Note: This Section will be completed after statutory consultation, post first draft of this Decommissioning Programme.

12.1 Introduction

The UK oil and gas industry is committed to engaging with stakeholders by providing information on and discussing the economic, environmental and social impact of its activities.

This section describes how the North West Hutton owners have been carrying out consultations with interested parties on issues arising from the decision to decommission the field. It summarises the main issues raised by stakeholders so far and how the feedback has been used in developing the decommissioning proposals for the platform, pipelines and drill cuttings.

In the UK, the decommissioning process requires a statutory 30 day public consultation plus consultation with four specifically nominated organisations (Ref. 12.1). Prior to this stage, the North West Hutton owners have implemented a wider process of consultation intended to ensure that other interested parties have an opportunity to be involved throughout the process.

This section also describes the membership and findings of the Independent Review Group, established to review the comparative assessment studies.

12.2 Consultation Plan and Schedule

Consultation was planned in three phases:

Phase One – identification of interested parties, establishment of a stakeholder register and initial dialogue to determine main issues.

Phase Two – continuing dialogue on major issues, including one-on-one meetings as required.

Phase Three – discussions of comparative assessment findings and the impact on recommendations for pipelines, jacket footings and drill cuttings pile.

The major milestones in this consultation process to date have been:

3Q 2002	Research and identification of potential interested parties in addition to those listed in the DTI guidelines as statutory consultees.
4Q 2002	Letter sent to first group of interested parties (copy in Appendix 1)
	Follow up telephone calls and compilation of initial stakeholder register based on responses to the letters.
1Q 2003	Beginning of Phase Two consultations with first general stakeholder meeting in Aberdeen and private meeting with individual organisations. (Appendix 2)
	Dedicated public website established for North West Hutton decommissioning.
	Independent Study Review Group established to audit comparative assessment process.
2Q 2003	General stakeholder meeting in Aberdeen and private meetings with individual organisations. (Appendix 3)
3Q/4Q 2003	Continuation of Phase Two consultation including private meetings with individuals
1Q 2004	Independent Review Group audit of comparative assessment studies completed
	Private meetings with individual organisations
2Q 2004	General stakeholder meeting in Aberdeen and private meetings with individual organisations (Appendix 4)
	Independent Review Group report published

12.3 Consultation Process

Initial letters were sent in November 2002 to some 60 organisations and individuals on our original invitation list, which had been sourced from existing stakeholder contacts, with additional input from other operators based on recent decommissioning consultation experience.

A stakeholder register, based on responses to the letter, was established and has subsequently been expanded to include around 60 registered interests.

Three general stakeholder meetings have been held in Aberdeen, on 6th February 2003, 12th June 2003 and 6th May 2004. These were run under the Chatham House rule by an independent facilitator provided by Forthroad Ltd, who also produced reports on the meetings which are published on our website at: www.bp.com/northwesthutton.

This website has been used to post information on North West Hutton decommissioning activity as well as containing reports of the stakeholder meetings and copies of presentation material. The option of communicating by e-mail directly with company representatives through the website has also been available since the web site was established.

In addition to the general meetings, each registered stakeholder has received e-mail communications from BP providing updates on the status of the project and a reminder of the website address where more detailed information is made available.

Some stakeholders have requested private meetings with BP to share their views on the key issues and these have taken place as part of the Phase Two consultation process, but at the request of these stakeholders details of these meetings have not been published.

Every effort has been made to ensure that all stakeholders are accommodated and that the whole process is as widely accessible as possible. To help enable this, dates for meetings in London have been offered, to accommodate those who were unable to attend the Aberdeen meetings. However, there has been minimal interest in this option and no additional general meetings have so far been required.

12.4 Consultation – Issues Raised

During the consultation process so far several key issues have been raised by interested parties. These are as follows:

- Consultation has confirmed that the main areas of interest are in the proposals for the drill cuttings pile, pipelines and jacket footings.
- There has been a high level of interest in understanding how the North West Hutton owners will arrive at solutions for these issues which balance all of the factors being studied– safety, economic, social, technical and environmental impacts.
- It was the view of the majority of stakeholders that recommendations should be tested against Sustainable Development (SD) principles but that there was probably no single SD assessment model which would provide a definite answer.
- Some stakeholders have expressed the view that an option of leaving the 20 inch oil pipeline in place rather than trenching and burying or completely removing would not be appropriate.
- Concerns have been expressed that a leave in place option for the jacket footings would mean a significant snagging hazard for fishing activity and would set an unwelcome precedent for future decommissioning of similar installations.
- Concerns were expressed that an option of leaving the drill cuttings pile in place would present a 'tainting' risk for commercial fishing nets and catches.
- The North West Hutton owners were challenged to investigate more thoroughly 'partial removal of the footings' closer to the top of the drill cuttings pile.
- Stakeholders requested that our proposals should take into account what happens to waste material after it has been passed to onshore contractors and that North West Hutton owner's duty of care should not stop 'at the quayside'.
- Some stakeholders have expressed concern that the options for the drill cuttings pile and jacket footings should be based primarily on stand-alone evidence and not solely on the interaction between the two.

- Stakeholders requested assurance on the independence of the Independent Review Group.
- Stakeholders requested that should North West Hutton owners submit a programme to the DTI which includes a recommendation to leave the jacket footings in place based on safety or technical uncertainty, there should also be a statement of intent to continue investigating these issues, so that there is a possibility of future action to remove any material left on the seabed.

More details of all the issues and questions raised by the stakeholders together with BP responses are included on the North West Hutton Decommissioning website as part of the reports of general stakeholder meetings.

In the draft decommissioning programme, the North West Hutton owners have taken into account views expressed by stakeholders through the following actions:

- Ensuring that the comparative assessment studies focus on the key issues of pipelines, footings and drill cuttings, and that they are independently verified.
- Applying sustainable development principles where appropriate to inform the recommendations for pipelines, jacket footings and drill cuttings pile.
- Including proposals for mitigation measures to be taken by the North West Hutton owners to minimise the safety risk for other users of the sea, particularly snagging hazards for fishermen from material left on the seabed.
- Undertaking additional comparative assessment studies looking at 'partial derogation' scenarios.
- Completing a comprehensive Environmental Impact Assessment which includes the handling of all wastes arising from decommissioning.
- Consideration of the footings and drill cuttings pile challenges on a stand-alone basis (although bringing these together ultimately).
- Representation from the Independent Review Group at general stakeholders meeting and requesting a final statement from the IRG which confirms their independence.
- As a result of stakeholder comment on the issue of ongoing liability and possible future action to remove any material left on the seabed, a statement of intent on these issues has been included in the decommissioning programme (Section 2.9).

12.5 Independent Review Group

In January 2003, Professor John Shepherd of the University of Southampton was invited by the North West Hutton owners to establish an Independent Review Group (IRG) of scientists and engineers to examine and comment in an independent and objective way on the comparative assessment studies being undertaken for North West Hutton Decommissioning.

The IRG was established in February 2003 with the following membership.

Professor John Shepherd (Chairman)

Torgeir Bakke (Norwegian Institute for Water Research)

Professor Michael Cowling (University of Glasgow)

Professor William Dover (University College London)

Professor Juergen Rulkoetter (University of Oldenburg)

Professor Brian Wilkinson (Visiting Professor at Universities of Reading and Newcastle)

Richard Clements (Secretary)

The IRG met on eight occasions during 2003 and early 2004 and the main work undertaken was to:

- Read and review the reports of all relevant comparative assessment study work (including contractor scopes of work) commissioned for or produced for BP.
- Provide views and guidance on the above in respect of the scope, clarity, completeness, methodology, relevance and objectivity of conclusions.
- Advise on any further research or actions to address identified gaps that would otherwise prevent an informed decision.
- Make recommendations for additional work as necessary which should be practicable and achievable within the timeframe for the submission of the decommissioning programme.
- Be satisfied that all relevant stakeholder comments have been addressed within the scope of each study where practicable to do so.

The IRG review was completed in April 2004 and a report has been published by the group which is available on the North West Hutton public website. Amongst other main conclusions the report states that:

- *"The scope of the studies undertaken was sufficiently comprehensive, their quality was satisfactory, and they provide an adequate basis for the comparative assessment process"*.

References

12.1 Department of Trade and Industry (DTI), Decommissioning of Offshore Installations and Pipelines under the Petroleum Act 1998, www.og.dti.gov.uk.

12.2 North West Hutton Decommissioning Project, Report of the Independent Review Group, 26th April 2004.

13 COST SUMMARY FOR DECOMMISSIONING NORTH WEST HUTTON

The overall cost for the proposed decommissioning programme is expected to be of the order of £160 million. This involves removal of the topsides, removal of the upper jacket down to the top of the footings, leaving the drill cuttings in place and monitoring, and the trench and bury option for the pipelines.

The work scope covered by this overall cost includes:

- The reservoir isolation work which involved the abandonment of 40 wells and the removal of 40 conductors.
- Topsides cleaning, engineering down, module separation work, preparation for Normally Unattended Installation (NUI) and follow on NUI operating activities.
- Platform logistics, operational and maintenance support throughout the decommissioning activities.
- Topsides preparation and final module separation work, removal of the modules and transportation to shore.
- Jacket preparation and removal, lifting and transporting to shore.
- Pipeline trenching and burial, and removal of all ancillary equipment.
- Onshore receipt, reuse, recycle and disposal of all material.
- Project Management, engineering and future monitoring of the site.

Cost estimates have been developed for all aspects of the decommissioning activity. The estimates are based on data from contractors, detailed studies and standard industry data. The estimates indicate a range of uncertainty caused by a number of factors including the technical, safety and environmental risks detailed in this programme and also contracting risks associated with the work yet to be completed. The majority of the work associated with the removal of North West Hutton platform will be competitively tendered. The tendering activity will mitigate the commercial uncertainty currently in the estimates.

BP has submitted cost details for all removal options to the DTI, but for reasons of commercial sensitivity these costs have not been included in this programme. However the options for the jacket, drill cuttings and pipelines are discussed below.

The cost ranges for the jacket removal options are shown in figure 13.1. The three options presented are:

- Total jacket and template removal to provide a clear seabed
- Partial Jacket removal down to the top of the drill cuttings pile
- Partial Jacket removal down to the top of the footings

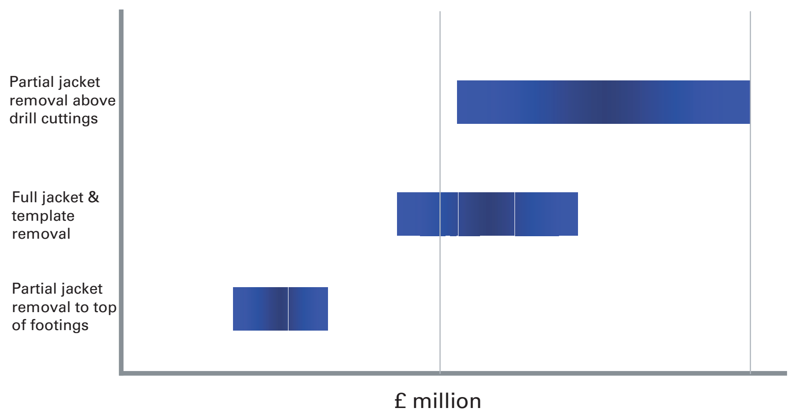


Figure 13.1: Comparison of jacket costs.

These costs are order of magnitude and reflect the uncertainties and risks of executing removal work on this scale, with no track record, and hence no benchmark for costs. This shows that the costs are approximately in the ratio of 1 : 3 : 2 for the options - partial jacket removal to top of footings, partial jacket removal above drill cuttings and full jacket and template removal. The removal option down to the top of the drill cuttings is the most expensive but also the least favoured from a technical and safety perspective, see sections 2 and 8.

The cost ranges for the drill cuttings options are given in table 2.5 and section 9.8. The ranges for the options are for the removal and onshore treatment £46 million to £114 million, this range narrows slightly for removal and re-injection to £43 million to £110 million; for the excavate and relocate on the seabed, or leave *in-situ* and cover options the costs are about £8 million to £9 million; and for the leave *in-situ* and monitor option the cost is about £0.5 million. The wide ranges for the drill cutting removal options are a reflection of the uncertainties, risks and lack of facilities and experience for the activities required to carry out the work on the scale required. The costs are order of magnitude. For the other three options the work scope and methods are better defined, and therefore so too are the costs.

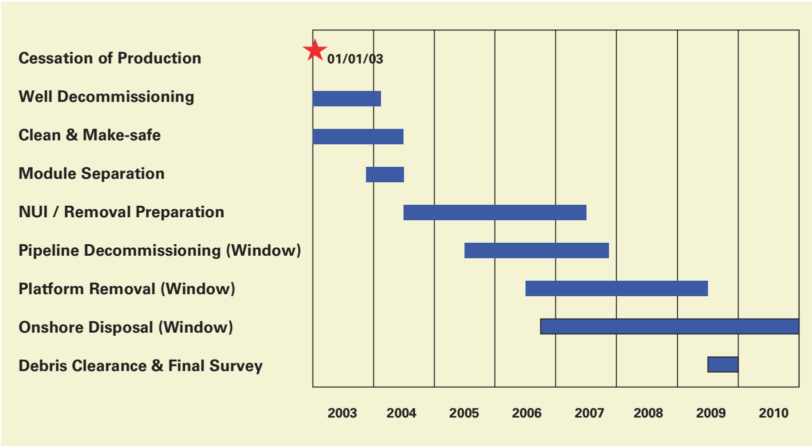
The costs for the pipeline options studied are given in table 2.6 and section 10. The costs are for recover and bring to shore about £22 million; for trench and bury about £8 million; and for leave *in-situ* about £5 million. These costs are reasonably well defined as the work scope and activities are known with reasonable certainty, and similar work has been undertaken in the past. These costs include for cleaning the pipelines and future monitoring.

The costs are expressed in 2004 values, and all include allowances for engineering, project management and support costs. The wide ranges for some options reflects the uncertainties and risks of executing large, novel work scopes, whereas for the smaller and better defined work scopes the costs are based on the assumption that the work is carried out as planned.

14 SCHEDULE

The UK decommissioning guidelines require timely removal of redundant offshore installations unless there are over-riding justifications for leaving them in place for a period of time. There are no identified drivers to postpone decommissioning of the North West Hutton facilities and the activity will therefore be carried out in a timely and efficient manner.

The schedule presented below provides indicative timing for the activities required to fully decommission North West Hutton.



This indicative programme provides relatively wide windows for offshore activities and does not represent continuous activity. Discussions with the contractors likely to tender for the work reveals that they value flexibility wherever possible as this enables them to schedule work more efficiently.

This provides the opportunity for cost savings to the contractors, and for the overall project, without imparting any significant delay to achieving the overall objectives. Such flexibility also enables more efficient use of physical and natural resources both onshore and offshore. It is also important in helping to ensure safety in the application of relatively untested equipment and procedures.

There is also a requirement for ongoing survey and inspection of the site. This is not shown on the schedule, but is discussed more fully in Section 18.

15 LICENCES ASSOCIATED WITH DECOMMISSIONING NORTH WEST HUTTON

As the decommissioning project progresses, the appropriate permits, consents and licences for all activities will be put in place with the relevant authorities. The responsibility for ensuring that the appropriate documentation is in place will rest either with the operator of the field or with the various contractors who will be responsible for different aspects of the removal and disposal activities.

All permits, consents and licences will be managed within the overall project management structure, discussed in Section 16.

A Summary of the applicable legislation for the Decommissioning of the North West Hutton facilities can be found in Section 20.

16 PROJECT MANAGEMENT

16.1 Introduction

The North West Hutton Decommissioning Project represents an important and highly significant activity for the joint owners of the field. The project management process will require the rigorous levels of quality control, inspection and assurance that would be expected for a capital investment project of this size. BP as the operator of the field will be responsible for the implementation of the overall project management.

BP has a well developed, company-wide approach to project management and this is being applied rigorously to all aspects of the North West Hutton Decommissioning project. A dedicated team "The North West Hutton Decommissioning Team" has been established to develop and implement the project from inception through to the completion of all operations and final inspections of the site.

BP has three "business units" to manage operations in the UK sector of the North Sea. Each business unit comprises specialist "performance units" which control a specific aspect of the overall operation. The North West Hutton Decommissioning Project organisation is part of the "Developing Asset Business Unit".

The Performance Unit and Business unit and also group-wide functions provide the control for ensuring successful implementation of the project.

16.2 Health, Safety and Environment

BP recognises that HSE performance is critical to the success of the business, and is distinctive world-wide in its pursuit of health, safety and environmental performance. BP's commitment to HSE Performance is one of the five Group Business Policies (Ethical Conduct, Employees, Relationships, HSE Performance, Control and Finance) (Ref. 16.1).

BP's goals for HSE are simply stated as a key policy:

- no accidents
- no harm to people
- no damage to the environment

The BP HSE Management System Framework and key processes exist to support the HSE Expectations and encompass the complete spectrum of health, safety and environmental risk management including security, and the technical and operational integrity of facilities and equipment. These are the boundaries within which the North West Hutton Decommissioning Project will have to operate to achieve the highest possible level of safety and performance.

BP's HSE Management System Framework provides a broad-based set of Expectations integrated into thirteen elements of accountability. These expectations outline BP's requirements for the management of:

- safety and accident prevention
- plant and equipment integrity
- pollution prevention
- energy conservation
- personal, occupational and environmental health
- personal/physical security
- product stewardship
- sustainable development

This framework focuses on critical HSE needs and activities, and consistently delivers improved HSE performance. The thirteen elements of BP's HSE Management System Framework are detailed below:

1. Leadership & Accountability
2. Risk Assessment
3. People, Training and Behaviours
4. Working with Contractors and Others
5. Facilities Design and Construction
6. Operations and Maintenance
7. Management of Change
8. Information and Documentation
9. Customers and Products
10. Community and Stakeholder Awareness
11. Crisis & Emergency Management
12. Incidents Analysis and Prevention
13. Assessment, Assurance and Improvement

Addressing the full set of HSE Expectations is mandatory for every activity across the entire BP organisation

The studies undertaken in support of this decommissioning programme address the applicable elements of the HSE Management Framework at this stage in the decommissioning of North West Hutton.

As the project is defined further and moves towards the execution phase all elements will be required to be assessed to ensure the undertaking of the project with minimal risk.

16.3 Technical

The North West Hutton Decommissioning Project will be executed within the framework of the BP Capital Value Process (CVP) and the BP HSE Management System discussed above. This sets the standards and controls for commercial execution and delivery of HSE excellence.

Technical delivery is core to the delivery of any project. This is managed within the CVP framework with engineering definition and construction developing in ever-greater detail through the Appraise – Select – Define - Execute – Operate phases. The major difference for North West Hutton is that this is a decommissioning, i.e. de-construction project, not a construction project for which the CVP was originally conceived. There will be no "Operation" phase, however, and the technology as such is a means to an end rather than a key deliverable; nevertheless, the same standards of technical rigour and processes will be applied.

Key control for the technical execution of the project will be established through the Project Execution Plan (PEP), Statement of Requirement (SoR) and the Assurance Plans. The PEP sets out how the project will be executed and establishes key controls and communications. Contracting Strategy and clarity on interfaces and responsibilities is central to this execution.

The SoR is the prime technical document that sets out the technical requirements of the project and these include:

- Technical objectives and philosophy
- Site factors and data
- Regulatory requirements
- Design standards, with clarity on order of precedence
- Engineering deliverables to execute and control the project
- Third Party Compliance, permits and consents

The SoR develops into the basis of design and ultimately into the contractors' detailed design briefs, documentation and procedures. A change-control process will be established by the project to ensure that the contractors deliver the technical objectives set out in the SoR.

Decommissioning on the scale of North West Hutton is a new endeavour and brings new project challenges. It is also a brown-field project (i.e. it involves work with existing equipment) with all the attendant difficulties and uncertainties. Assurance Plans will be essential to review and challenge the engineering and execution of the project at all phases of the CVP. This will be done through audits and processes such as the BP value improving practices (VIPs), which will review critical areas of the project to ensure best practice is being achieved.

BP will provide a quarterly written report on the progress of the decommissioning works to the DTI. This report will include information on the following topics:

- Health Safety and Environment.
- Highlights.
- Overall Project Status.
- Stakeholder Engagement.
- Approvals.
- Permits & Consents.
- Structures Removal.
- Waste Management.
- Concerns.
- Forthcoming Key Events.
- Costs.

16.4 Reporting

In the Define and Execute phases the DTI will be kept regularly informed of the progress of the decommissioning work, and of any major variations, developments or HSE issues.

Within four months of completion of the works or a major component of the works, e.g. pipelines or topsides work; a close-out report will be submitted to the DTI addressing the following topics:

- An overview of the works and the decommissioning programme as a whole.
- Confirmation that the work has been carried out in accordance with the programme.
- A description of any major variations, and any permits required for these variations.
- A description of the major milestones in the schedule and were they achieved.
- Results of debris clearance and any surveys undertaken, including any independent verification reports.
- Updated schedule, if necessary, for any future monitoring required.
- A summary of actual costs and an analysis of actual versus estimated costs and an explanation of any variations.

References

16.1 BP HSE Policy and BP HSE Management System

17 DEBRIS CLEARANCE

In this context, debris refers to material that is not covered in the inventories of material contained in or associated with the platform and the pipelines.

The presence of seabed debris around the facilities in the North West Hutton field has been discussed several times in the preceding sections. This debris has accumulated as a result of activities associated directly with the operation of the field. It also includes material from other activities which may have been inadvertently dragged or introduced into the area. Debris clearance will take place during the removal activities themselves and also as part of the final assurance activities on completion of operations.

Sections 7-10 describe the decommissioning outcomes proposed for the topsides, jacket, drill cuttings and pipelines. All material associated with these items will be handled in the manner described. During the operations to carry out the recommended programme, it is likely that sub-sea activities, particularly those close to the seabed (e.g. pipeline activities), will encounter items of debris. All items of debris identified will be assessed and recovered or managed in the most appropriate manner to ensure that the seabed is left in the condition proposed by this decommissioning programme. These over trawl sweeps will be carried out by the fisherman.

The area covered by the debris survey will be the area within the 500 metre zone around the platform and the corridor of the pipelines out to 100 metres either side of each pipeline. The initial debris survey will be by means of a ROV, with items being removed by means of an ROV or by other methods as required.

Following completion of decommissioning activities on North West Hutton, a final programme of clearance will be implemented to ensure that the recommended outcome has been achieved. The methodology for achieving this assurance will involve several sweeps of the site by trawlers using specially adapted equipment. The sweeps will be implemented in several directions around the site of the platform and also along the route of the two pipelines included in this programme.

The sweeps will ensure that there are no seabed obstructions in the vicinity of the various work sites. If obstructions are encountered, the nature of the obstruction will be identified and, if necessary, a separate intervention will be made to remove the obstruction. Information from surveys around North West Hutton and similar activities elsewhere indicates that these assurance sweeps will collect, and enable the removal of, smaller items of debris not identified by other activities.

The results of seabed surveys, trawler sweeps and debris removal will be collated into a report and submitted to the DTI's Offshore Decommissioning Unit. This report will form the basis of any on-going surveys and monitoring for the platform site and the pipeline routes.

18 PRE- AND POST- DECOMMISSIONING MONITORING AND MAINTENANCE

18.1 Pre-Decommissioning Monitoring

The North West Hutton owners have ensured that the site of the platform, pipelines and the surrounding area have been subject to comprehensive monitoring and survey work to understand the impact of ongoing operations. This information will provide the baseline for all future monitoring activity and evaluation.

18.2 Post Decommissioning Monitoring

Within a year of the completion of the decommissioning activity and debris clearance recommended by this programme, the site will be subjected to a physical and environmental survey to establish a post-decommissioning baseline for the site.

The scope of the post-decommissioning survey will be agreed with the DTI before the work is carried out and the survey results submitted to the DTI. The environmental survey is likely to be based upon the transects and stations sampled in the 20002 survey (see table 3.2 in Section 3) to allow temporal recovery trends to be evaluated. Samples will be analysed for hydrocarbons, metals and other trace contaminants. The morphology of the drill cuttings pile my also be evaluated if it is believed to have been disturbed during decommissioning activities.

In light of the results of the post decommissioning survey findings and all previously available survey information the field owners in conjunction with the DTI, will determine the scope and frequency for future surveys to monitor the condition of the site, the structure and all other material left *in-situ*, to ensure they remain as expected as a result of this decommissioning programme. The results of all surveys will be submitted to the DTI.

The field owners are aware that all items left *in-situ* as part of this decommissioning programme remain their property and that they have a continuing liability for these items. The field owners are committed to ensuring that future obligations arising from the implementation of this decommissioning programme are met.

19 ENVIRONMENTAL STATEMENT SUMMARY

19.1 Introduction

As described in Section 6.4.2, as part of the comparative assessment study work undertaken to support the decommissioning programme for North West Hutton, an Environmental Impact Assessment (EIA) has been undertaken. The results of the EIA are presented in the North West Hutton Environmental Statement (Ref. 19.1).

This section of the decommissioning programme presents a brief summary of the Environmental Statement, but focuses on a description of the methodology used in the Environmental Risk Analysis (ERA) process, the results obtained for each of the potential outcomes and a discussion of which outcome offers the lowest environmental risk. A summary of the environmental description of the North West Hutton location is given in Section 3.

The complete Environmental Statement includes:

- a description of the environmental setting at North West Hutton.
- a description of the method used to assess the environmental effects of operations and outcomes (the ERA).
- the results of the ERA that could arise as a result of planned and accidental events arising during the operations.
- an indication of the mitigating measures that would be adopted to reduce or eliminate potential effects, including monitoring.
- calculations of the energy that would be used, and the total emissions of gases that would arise, as a result of completing any of the outcomes.
- an analysis of the relative environmental advantages and disadvantages of the outcomes for each facility, with a recommendation of the outcome that, overall, may provide the least environmental effect.

19.2 Method Used to Assess and Compare Environmental Risks

A four stage process (an Environmental Risk Assessment [ERA]) was used to assess environmental risks and compare the different outcomes for facilities.

The method used to undertake the ERA is one that has been widely applied internationally in the exploration and production industry, and in other industrial sectors. The methodology has been adapted from the approach to risk assessment and rating given in the British Standard BS 8800:1996 (Ref. 19.2), the DTI Guidelines for Environmental Statements (Ref. 19.3), the methods used in numerous statutory ESs for UK offshore oil and gas projects (which are legally required to demonstrate a risk-based approach), and the methods used specifically by BP during the preparation of ESs for the Magnus Enhanced Oil Recovery Project (Ref. 19.4) and the Clair Phase 1 Development (Ref. 19.5). These ESs have been subject to rigorous review during the statutory consultation and approval process.

(1) Each potential programme and outcome for each facility was reviewed, and the events and operations that would or could give rise to environmental effects in any environmental compartment were identified.

(2) Each effect was assigned to an environmental risk category (Table 3) on the basis of the probability of the impact occurring and the severity of the consequences if it occurred. Pre-defined probability (Table 1) and consequence criteria were used to evaluate the environmental risk (Table 2). The environmental effects were assessed on the assumption that the mitigation measures (measures to reduce the likelihood or consequence of a risk, or eliminate it) proposed by or stated in the project programme, would be in place.

Category	Description	Probability (unplanned events) or frequency (planned events)
Definite	Will definitely occur (e.g. during every planned emission or discharge). Applies to all planned events.	Probability: one occurrence per causal event. Frequency: continuous or intermittent occurrence whenever the causal event takes place.
Likely	Likely to occur during normal operation, given the controls/mitigation proposed.	Probability: one occurrence per 2 to 50 events. Frequency: daily to three-monthly.
Possible	Could occur infrequently during normal situations given the controls/mitigation proposed, or more readily during abnormal or emergency situations, e.g. minor spillages during fuel loading operations at sea.	Probability: one occurrence per >50 to 1,000 events. Frequency: >three-monthly to yearly.
Unlikely	Unlikely during normal operation given the controls/mitigation proposed, but may occasionally occur during abnormal or emergency situations, e.g. 'significant' (>1 tonne) overboard spill.	Probability: one occurrence per >1,000 to 10,000 events. Frequency: >yearly to 10-yearly.
Remote	Extremely unlikely given the controls/mitigation to be put in place, e.g. serious tier 3 spill event.	Probability: one occurrence per >10,000 events. Frequency: >10-yearly.

Table 19.1: Probability criteria for defining the likelihood of routine and non-routine activities or events.

Environmental Consequences	Social Consequences
SEVERE	

• Degradation or loss of habitats or ecologically, commercially or culturally important species.
  • Extent: At a regional, national or international scale.
  • Duration: Low prospects of recovery to a representative state, within several decades in highly affected areas.
• Atmospheric emissions at levels equivalent to or above the annual GHG or VOC tonnages for the UKCS oil and gas industry. This approximates to 5-100% of the total annual CO_2-E emissions from all UK households.
• Permanent, widespread impacts on resource quality and availability (i.e. of water, energy or raw material) to the long-term detriment of dependent businesses, communities, individuals, environment and socio-economic conditions.
• Permanent impact on status of internationally important or nationally protected sites or species, e.g. coastal regions of Shetland.
• Tier 3 spill or catastrophic emergency event, with consequences on a national or international scale.
	• Well-established and widely held areas of concern in society on a national or international scale, including possible perception of threats to the global environment, e.g. global warming, and wider issues of sustainability.
	• Permanent, detrimental health impacts (any number of people)
	• Permanent and widespread negative effects on human well- being (typically, but not necessarily, arising from nuisance).
	• Permanent disruption to business, communities or individuals, with permanent consequential loss of revenue, assets or amenities.
	• Requirement to dispose of controlled waste beyond national disposal capacity.

MAJOR	

• Degradation or loss of habitats or ecologically, commercially or culturally important species over a wide area of seabed.
  • Extent: Generally more than 1,000m from the source of the impact, or beyond the perimeter boundaries of onshore sites.
  • Duration: Limited prospect of recovery to normal healthy conditions. Recovery to a representative state would generally be in the order of decades in highly affected areas.
• Atmospheric emissions at levels equivalent to or above the annual GHG or VOC tonnages for BP in the UKCS. This approximates to 1-5% of the total annual CO_2-E emissions from all UK households.
• Substantial but ultimately reversible impacts on resource quality and availability (i.e. of water, energy, or raw material) to the detriment of dependent businesses, communities, individuals, environment and socio-economic conditions.
• Serious, long-term, but ultimately reversible, impact which would affect the status and/or management of internationally important or nationally protected sites or species e.g. coastal regions of Shetland.
• Tier 2 or 3 oil spill or major emergency event, with consequences on a local or regional scale.
	• Concern on a regional rather than local or global level involving multiple interest groups. Perception of threat to the regional environment and issues of regional sustainability.
	• Reversible, detrimental health impacts (any number of people).
	• Widespread and sustained negative effects on human well- being (typically on a scale of months to years; also typically, but not necessarily, arising from nuisance).
	• Long term (typically on a scale of months to years) disruption to businesses, communities or individuals, with sustained consequential loss of revenue, assets or amenities.
	• Requirements to dispose of controlled waste beyond 50% of the annual disposal capacity of the waste management region (e.g. county or regional level).

Environmental Consequences	Social Consequences
MODERATE	

• Degradation or loss of habitats, or ecologically, commercially or culturally important species over a wide area of seabed.
  • Extent: Generally within, but may extend beyond, 1,000m from the source of impact, or beyond the perimeter boundaries of onshore sites.
  • Duration: This generally leads to short-term disruption with the potential for recovery to normal conditions within several years -typically less than a decade - but may extend beyond this period close to the impact source.
• Atmospheric emissions at levels equivalent to or above the consented annual tonnage for the NWH field when it was operating. This approximates to 0.1-1.0% of the total annual CO_2-E emissions from all UK households.
• Temporary (scale of weeks to months) impacts on resource quality or availability (i.e. of water, energy or raw material) causing nuisance to dependent communities, groups of people or affected individuals, but not to the detriment of the local environment or socio-economic conditions.
• Short-term, reversible impact on internationally important or nationally protected sites or species e.g. coastal regions of Shetland, which could not compromise the status or management of these sites or species.
• Uncontrolled tier 1 oil spill or small-scale emergency event.
	• Concern at the community, rather than individual or single interest group, level. Perception of a threat to the community environment and issues of local sustainability.
	• Local negative effects on human well-being (but not health), typically on a scale of weeks to several months (also typically, but not necessarily, arising from nuisance).
	• Short term (typically on a scale of days to weeks) disruption to businesses, communities or individuals, with short term consequential loss of revenue, assets or amenities.
	• Requirement to dispose of controlled wastes at 10% to 50% of the disposal capacity of the waste management region (e.g. county or regional level).

MINOR	

• Disruption to habitats, or ecologically, commercially or culturally important species over a localised area of seabed.
  • Extent: Generally within, but may extend beyond, 500m from the impact source, or within the perimeter of an onshore site.
  • Duration: Short-term disruption, with the potential for rapid recovery to a normal, representative state typically within months depending on the timing of the event in relation to the annual recruitment pattern.
• Atmospheric emissions at levels within the consented daily tonnage for the NWH field when it was operating. This approximates to 0-0.1% of the total annual CO_2-E emissions from all UK households.
• Localised and transient impact on resource quality or availability (i.e. of water, energy, raw material or labour) affecting the well- being of individuals.
• Highly transient, reversible impact on locally protected sites which could not affect or compromise the status or management of these sites.
• Contained and non-notifiable oil spill.
	• Concern at the level of individual people, individual businesses or single interest groups. Perception of a threat to the environment used by, and issues of sustainability relating to, individuals and single interest groups.
	• Short-term (typically on a scale of hours to days) nuisance which causes inconvenience to individuals.
	• Short-term disruption (typically on a scale of hours to days) to individual businesses rather than to communities, with transient consequential loss of revenue, assets and amenities.
	• Requirement to dispose of controlled wastes at 1% to 10% of the disposal capacity of the waste management region (e.g. county or regional level).

Environmental Consequences	Social Consequences
NEGLIGIBLE	

• Transient disruption to habitats, or ecologically, commercially or culturally important species.
  • Extent: Within 500m of the source of the impact
  • Duration: Potential for recovery to a normal, representative state, generally within hours to days.
• Atmospheric emissions from transient and/or small scale sources (e.g. exhausts from small items of plant or equipment).
• Negligibly small impacts on resource availability or quality which is not to the detriment of people, the environment, or socio-economic conditions.
• No impact on status of protected sites or species.
• No spills or emergency events.
	• No concern or perception of threats by people, communities or interest groups.
	• Transient nuisance (scale of hours) which does not cause negative effects on human health, well-being, revenue sources, assets or amenities or social disruption.
	• Requirement to dispose of controlled wastes at less than 1% of the disposal capacity of the waste management region (e.g. county or regional level).

POSITIVE	
• Enhancement of habitats, or ecologically, commercially or culturally important species.	• Enhancement of human prosperity, health, well-being or amenities. • No requirement to dispose of controlled waste to land-fill.

Table 19.2: Consequence criteria for defining the characteristics of environmental effects.

Consequence	Probability				
	Remote	Unlikely	Possible	Likely	Definite
Severe	R.6	U.6	P.6	L.6	L.6
Major	R.5	U.5	P.5	L.5	L.5
Moderate	R.4	U.4	P.4	L.4	L.4
Minor	R.3	U.3	P.3	L.3	L.3
Negligible	R.2	U.2	P.2	L.2	L.2
Positive	R.1	U.1	P.1	L.1	L.1

Highly Significant Zone	Significant Zone	Not Significant Zone	Positive Zone

Key:

(3) The four risk categories were:

Highly significant	An unacceptable level of risk that should be eliminated or reduced to an acceptable level by developing specific control or mitigation measures.
Significant	A tolerable risk that is considered "As Low As Reasonably Practical" (ALARP). There is scope for further reducing the effect by control or mitigation measures.
Not significant	A risk with a trivial effect that could be managed by standard control and mitigation measures.
Positive	Any type of risk that would result in a positive or beneficial effect in the environment.

Table 19.3: Matrix showing how the criteria of probability and consequence are combined to generate an overall risk rating.

(4) Assigning the negative risks to one of three categories allowed a wide range of potential risks to be screened, so that attention could be focussed on important risks – in the categories "highly significant" and "significant" - that could be influential in the selection of an outcome for those facilities where more than one outcome was available. Risks in these categories were then subjected to more detailed assessment in order to provide information about the absolute level of impact that might be experienced should the risk be realised.

Different outcomes for any facility were compared by a combination of quantitative and qualitative examinations of their performance. The numbers of positive, "highly significant" and "significant" risks in each outcome were compared, but this analysis was tempered by a consideration of the qualitative nature of the risks being examined. The amount of the facility removed to shore was expressed as a percentage removed (%) in relation to the total mass of material presently at the site.

The relative use of energy and the gaseous emissions in each outcome were also compared, bearing in mind that prediction of energy use and gaseous emissions in decommissioning activities may be subject to confidence limits of +/- 20-30%. Energy was expressed in gigajoules (GJ) and in terms of the average energy use of UK households; in 2001 the average annual consumption of energy by each UK household was about 80GJ, and energy requirements were expressed in UK household equivalents as well as absolute amounts. Gaseous emissions were expressed in terms of tonnes of carbon dioxide equivalents (CO_2-E) which indicates the greenhouse gas potential of all the gases emitted. In 2000, the average annual CO_2-E emissions for each UK household was about 6 tonnes CO_2-E.

19.3 Decommissioning the Topsides

19.3.1 Outcome: Decommissioning the Topsides by Total Removal

In accordance with legislation, the topsides will be completely removed and returned to shore for recycling and disposal. All the modules and associated equipment will be removed by a heavy lift vessel (a large floating crane capable of lifting about 7,000 tonnes), in a programme that is the reverse of the original installation process.

Onshore, the modules will be progressively dismantled in a managed programme that will identify the different materials on and in the structures, and ensure that they are handled, stored, treated and disposed of safely. Careful attention will be paid onshore to separating the different types of material from the topsides. Specialist contractors and disposal firms will deal with any residues of hazardous waste that remain in pipe work or equipment. The structural components will be dismantled by mechanical cutting techniques so that the pieces can be transported to recycling or disposal sites. The project would aim to recycle at least 97% of the topsides structure by weight.

19.3.2 Environmental Risks: Decommissioning the Topsides by Total Removal

The ERA identified 13 "significant" risks associated with this outcome. The majority of these risks would have "minor" consequences for the environment, as a result of cutting and lifting operations, and the activities of vessels. Most impacts would be very localised and short-lived, and similar to those that may be caused by a variety of normal offshore activities. There would be no planned discharges of oil or chemicals to sea other than those from the normal operations of vessels.

Only the remote possibility of an accidental spill of oil following a vessel collision would result in a "significant" risk with a "major" consequence. This remote event is common to all activities requiring the use of vessels offshore, and while the risk is not ignored, it is omitted from the following analyses and comparison of outcomes for the North West Hutton facilities.

All material would be treated or disposed of by licensed contractors at licensed sites. BP's Duty of Care extends beyond the quayside and we would work with onshore licensed disposal sites to undertake all dismantling activities in a responsible manner. The environmental impacts that would be experienced at any onshore site selected for receiving and dealing with material from North West Hutton would be short-lived, localised and managed, and similar to those that have previously arisen during past commercial activities at the site.

OUTCOME	Number of risks in each category			% remove	Energy		Emissions	
	Positive	Significant	Highly significant		GJ	Household equivalents	CO_2-E	Household equivalents
Remove completely and recycle	4	13	0	100	600,000	7,500	44,000	6,900

Table 19.4: Summary of environmental assessment for decommissioning the topsides.

19.4 Decommissioning the Jacket

19.4.1 Outcome: Decommissioning the Jacket by Total Removal

The impacts offshore and onshore arising from the decommissioning of the jacket would be very similar to those that would arise from decommissioning the topsides, and would be localised and temporary. The jacket would be cut underwater into 8-10 main sections, lifted by a heavy lift crane and taken to shore for recycling. Cutting would be achieved by a combination of abrasive water jet cutting and diamond wire cutting. The jacket legs and bracings do not contain any oil or chemicals, and the bulk of material that would be handled is steel and sacrificial anodes made of aluminium alloy. It is possible that the jacket would be taken to the same onshore site as the topsides for dismantling and recycling.

19.4.2 Environmental Risks: Decommissioning the Jacket by Total Removal

The impacts offshore and onshore arising from the decommissioning of the jacket would be very similar to those that would arise from decommissioning the topsides. The ERA identified 14 "significant" risks associated with this outcome. The majority would have "minor" consequences for the marine environment and are associated with the cutting and lifting operations, and the activities of vessels. Most impacts would be very localised and short-lived, and similar to those that may be caused by a variety of normal offshore activities. Planned activities associated with the removal of the jacket would not result in significant environmental impacts, but it is possible that if part of the jacket were to fall onto the drill cuttings pile, this disturbance of cuttings could result in a local, short-lived impact to the benthos and water column. It is likely that impacts to the benthos would be confined to the area of seabed presently affected by the presence and effects of the cuttings pile. There would be no planned discharges of oil or chemicals to sea other than those from the normal operations of vessels.

OUTCOME	Number of risks in each category			% remove	Energy		Emissions	
	Positive	Significant	Highly significant		GJ	Household equivalents	CO_2-E	Household equivalents
Remove completely and recycle	5	14	0	100	261,000	3,300	21,000	3,200

Table 19.5: Summary of environmental assessment for decommissioning the jacket.

19.5 Decommissioning the Footings

Three decommissioning outcomes were considered for the footings; total removal, partial removal, and leave *in-situ* and monitor.

19.5.1 Total Removal of the Footings

19.5.1.1 Outcome: Decommissioning the Footings by Total Removal

Cutting techniques such as abrasive cutting and diamond wire cutting would be used to cut the bracings, bottlelegs and piles. The footings would be dismantled into 30-40 which included the damaged seabed members sections and lifted to the surface by heavy lift vessel, for return to shore and recycling. The removal of the template lying on the seabed would require the use of explosives underwater and individual charges would probably be of about 5-7kg.

The majority of the existing volume of cuttings would have to be removed to permit access to the footings so that they could be totally removed and returned to shore for recycling.

19.5.1.2 Environmental Risks: Decommissioning the Footings by Total Removal

The potential environmental risks of the necessary activity to remove the cuttings pile to allow removal of the footings would be similar to those described for the total removal of the cuttings pile (Section 19.6). The suction dredger option is the scenario adopted for the purposes of comparing outcomes. Furthermore, for the purposes of the EIA the assumed method of disposal is by re-injection to new wells on-site, since this route offers a smaller number of impacts than others (Section 19.6) and thus does not prejudice the evaluation of the outcome to remove the footings totally by assigning it the worst-case cuttings disposal risk.

On the basis of these assumptions, the ERA identified 33 “significant” risks associated with this outcome, of which 14 relate to the recovery and disposal of cuttings and 19 to the removal and disposal of the footings. This outcome does not exhibit any “significant” risks which would have a “major” consequence for the environment. Some events would have a “moderate” consequence and these include; the re-suspension of cuttings during recovery; the accidental spillage of cuttings during recovery or transportation and off-loading, and the effects of using underwater explosives to remove the template (the only technique available to remove the template). These events would cause impacts in the water column, and to the seabed and its associated benthic communities.

Underwater explosions cause pressure waves and loud noises that can be damaging or fatal to marine mammals, fish and plankton. The severity of any such impact depends on the size and type of charge used and the proximity of individuals when it is detonated. There are no particularly significant areas for juvenile fish or shellfish in the area, although the platform is located within the large areas used for the spawning of several species. Marine mammals exhibit a variety of responses to underwater noise, and there is some information with which to judge the potential effects of noises of different frequencies and intensities. Harbour porpoises, minke whales and Atlantic white-sided dolphins are all known to be present on occasion, in the North West Hutton area.

This outcome would result in 2 positive impacts, namely the removal of an obstruction from the seabed, and the exposure of a small area of seabed and benthos.

19.5.2 Partial Removal of the Footings

19.5.2.1 Outcome: Decommissioning the Footings by Partial Removal

The large-diameter bottlelegs and the bracings would be severed by diamond wire cutting and abrasive water jet cutting, so that the footings were cut down to about 3-6m above the present profile of the cuttings pile. The remainder of the footings would be left buried in the cuttings pile. Cuttings would not have to be removed to complete these cuts but there may be some minor disturbance of the cuttings. All material recovered from the seabed would be returned to shore for recycling or disposal.

19.5.2.2 Environmental Risks: Decommissioning the Footings by Partial Removal

The ERA identified 15 “significant” risks in this outcome, the most serious of which had a consequence rated as “minor”.

There is a risk that sections of footings could be accidentally dropped during lifting, and this could result in the disturbance of the cuttings pile. It is likely that impacts to the benthos would be confined to the area of seabed presently affected by the presence and effects of the cuttings pile.

Those parts of the footings left on the seabed (and partially buried in the cuttings pile) would corrode over a long period of time. This would have essentially no impact on the water column or benthos, because corrosion products are inert and not toxic. The most significant effect of leaving parts of the footings on the seabed would be small but long-term effect on commercial fishing operations. Fishing would be limited over the area occupied by the remains of the footings because of the seabed snagging risk they would represent, although mid-water trawling could be carried out in the water column above the footings. Any obstruction will be clearly marked on navigation charts and additional mitigation measures would be reviewed.

19.5.3 Leave the Footings *in-situ* and Monitor

19.5.3.1 Outcome: Decommissioning the Footings by Leaving *in-situ* and Monitoring

The whole of the footings (about 40m high and weighing about 9,500 tonnes) would be left on the seabed. Over time the steel structure would corrode, and eventually collapse onto the seabed. The corrosion products would be largely inert and not bio-available, and would not impact the local benthic or “pelagic” (water column) communities. Monitoring of the footings would be required for an unspecified period of time.

19.5.3.2 Environmental Risks: Decommissioning the Footings by Leaving *in-situ* and Monitoring

If the footings were left *in-situ*, impacts could arise as a result of their long-term presence, and ultimate deterioration and collapse. In addition, monitoring activities would use fuel, and give rise to gaseous emissions, but both sources of impact would be trivial in the context of general commercial activity in the North Sea and compared to the fuel requirements for complete removal of the footings.

The ERA identified 1 "significant" risk associated with this outcome. The footings would represent a potential snagging point for bottom-towed fishing gear, and it was concluded that the long-term presence of the footings would have a socio-economic effect on the fishing industry. However, given the relative economic value of the North West Hutton area for fishing, and the small area of seabed that would not be available for fishing, the overall socio-economic impact of leaving the footings *in-situ* is expected to be "minor".

19.5.4 Comparison of Outcomes for the Footings

The performance of the three potential outcomes for the footings is shown in Table 19.6. To enable the fullest possible comparison, a variation of the outcome "complete removal" is also given (1b) which excludes all of the risks that would be incurred in partially removing the cuttings pile to allow this outcome to be undertaken.

OUTCOME	Number of risks in each category			% remove	Energy		Emissions	
	Positive	Significant	Highly significant		GJ	Household equivalents	CO_2-E	Household equivalents
1a. Complete removal and recycle	12	33	0	100	535,000	6,700	41,000	6,500
1b. Complete removal and recycle	6	19	0	100	260,000	3,300	21,000	3,200
2. Partial removal	5	15	0	75	307,000	4,000	23,000	3,600
3. Leave *in situ*	1	1	0	0	298,000	3,800	17,000	2,700

Table 19.6: Summary of environmental assessment for decommissioning the footings.

Notes:

1a. This outcome includes all the risks that would necessarily be incurred in removing of the cuttings, and has been debited with the energy and emissions estimated necessary for removing this volume of the cuttings pile and reinjecting on-site.

1b. This outcome excludes any risks associated with removing the cuttings.

The positive risks in the outcomes "2. Partial removal" and "3. Leave *in-situ*" are associated with minor inputs of organic material (nutrients) from vessels, and the small "reef effect" that might be created by the continued presence of part of the footings, and may all be regarded as trivial. Complete removal would eliminate an obstruction from the seabed, and also re-expose a small part of the seabed which would subsequently be recolonised by benthic species.

None of the outcomes exhibits any negative risks that would be "highly significant"; all of the risks were either "significant" or "not significant".

The outcome "3. Leave *in-situ*" has 1 positive and 1 "significant risk". This risk relates to the socio-economic effect to fishermen of the long-term presence of a feature on the seabed. Given that there would be a long-term monitoring programme should the footings be left in place, and that measures would be available both for fishermen to avoid the footings obstruction and continue fishing activities at other sites, it is believed that this risk can be managed effectively. The outcome "3. Leave *in-situ*" has the lowest energy use of the technically feasible outcomes considered. The outcome "1b. Complete removal without any requirement to move the cuttings pile", included for comparative purposes, might use less energy, but the difference (38,000GJ, 15%) is probably not significant given the assumptions that have to be made regarding the estimation of energy use in decommissioning outcomes.

The outcome "2. Partial removal of the footings" incurs many more "positive" and "significant" impacts than outcome "3. Leave *in-situ*", but does not eliminate the single socio-economic risk that the footings would represent to the fishing industry. It would use about 3% more energy than outcome "3. Leave *in-situ*", but this difference is probably not significant given the method used. This outcome would, however, give rise to about 35% more CO_2-E emissions than the outcome "3. Leave *in-situ*", principally because of combustion of fuel by vessels. The outcome "2. Partial removal" would also use more energy (47,000GJ, about 18%) than the comparative outcome "1b. Complete removal without any requirement to move the cuttings pile", because it would use energy for both offshore removal operations and for replacing material not returned for recycling onshore. If the drill cuttings were to be covered, depending on the height of the stumps of the bottle legs above the pile, these would be partially covered by the thickness of the cover material itself. To completely cover the stumps and to offer some protection against erosion of the pile, it is likely that the thickness of the cover would have to be significantly increased from that proposed to cover the pile alone. This would in turn increase the area of seabed covered, the quantity of material required to construct the cover and the volume of the covered pile.

The outcome "1a. Complete removal after removal of the cuttings pile" has twice the number of "positive" impacts exhibited by "2. Partial removal". Only 4 of these are significant, however, relating to the removal of obstructions from the seabed and the exposure of a small area of the benthos. The other positive impacts are trivial and result from the input of organic material from vessels offshore. The outcome "1a. Complete removal after removal of the cuttings" also has twice the number of "significant" impacts in comparison with the outcome "2. Partial removal", as a result of the multiple effects of both removing the cuttings pile and then removing the footings. In addition, this outcome would use about 74% more energy than the nearest outcome "2. Partial removal". This difference is significant given the assumptions that have to be made regarding the estimation of energy use in decommissioning outcomes.

From our assessment of the environmental risks, the outcome for the footings that offers the least environmental impact would be "3. Leave *in-situ*". There is no over-riding environmental imperative for their removal, and operations to remove them completely would incur associated environmental risks as a result of the need to remove at least 90% of the cuttings pile.

If the footings were required to be removed, the most environmentally preferable method to remove the cuttings would be by using the suction dredger tool.

19.6 Decommissioning the Drill Cuttings Pile

There are six outcomes for decommissioning the cuttings pile. The range of offshore activities, and the extent to which the pile may be disturbed or removed, varies considerably from outcome to outcome. Consequently, there are significant differences in the type, number and severity of the environmental risks that would arise either as a result of carrying out the operations to deal with the pile, or from the resultant long-term condition of the pile.

19.6.1 Leave *in-situ* and Monitor

19.6.1.1 Outcome: Decommissioning the Cuttings Pile by Leaving *in-situ* and Monitoring

No remedial work would be carried out on the pile which would be left uncovered at its present location. Its condition and effects on the immediate environment would be monitored by means of an approved long-term programme. This outcome could only apply if the footings were also left *in-situ*.

19.6.1.2 Environmental Risks of Decommissioning the Cuttings Pile by Leaving *in-situ* and Monitoring

The ERA identified 16 "significant" risks associated with this outcome, the most serious of which would have a "moderate" consequence.

If the cuttings pile were left *in-situ* it is estimated that it will persist for one to five thousand years (although it is recognised that uncertainties in the model used to predict its persistence may result in a larger duration). During this time the hydrocarbons in the pile would degrade (break down) only slowly. Currents, wave action and bioturbation (the physical mixing of the material by animals living on the seabed) may disturb the SAL from time to time, and this may result in the release of small amounts of oil into the water column. This would be dispersed and diluted by currents, and would not cause surface slicks at the site.

Cuttings, oil-based muds and other contaminants in the pile have caused measurable impacts on the surface of the seabed around North West Hutton and this has been carefully monitored. Since the discharge of cuttings ceased in 1992, the zone of seabed surface impact around the periphery of the cuttings pile has decreased. At present the pile is causing only a minimal impact in the adjacent water column and surrounding benthos. The seabed around the pile would slowly recover from the impacts of oily cuttings, and the area of seabed exhibiting elevated concentrations of hydrocarbons and metals, and perturbed benthic communities (affected by physical or chemical factors and therefore not completely similar to areas of "natural" seabed), would continue to decrease. Fish may be exposed to increased concentrations of hydrocarbons, but there is no evidence to suggest that fish caught in the vicinity of piles such as that at North West Hutton exhibit concentrations that are significantly higher than those of fish taken from areas away from platforms. No examples of tainted fish (fish having a smell or taste that is noticeably different to the "normal" smell or taste of that species) have been found around cuttings piles.

It is possible that the periphery of the pile could be disturbed by bottom-towed fishing gear. This would lead to the re-suspension of cuttings into the water column and their subsequent resettlement on the seabed. Such incidents would cause local and short-lived impacts on the water column. They could also lead to a spreading and thinning of the pile, with a consequent increase in biodegradation rates, as well as possible contamination of clean seabed. However, if the pile is left *in-situ*, disturbance by bottom-towed fishing gear is not likely to be frequent.

19.6.2 Leave *in-situ*, Covered

19.6.2.1 Outcome: Decommissioning the Cuttings Pile by leaving *in-situ* Covered

After removal of the jacket, the cuttings pile would be covered by 90,000 m^3 of sand, gravel and rock which would be placed in layers. This would help to reduce the rate at which contaminants leach from the pile and also help to protect the extremities of the pile from physical disruption by bottom-towed fishing gear. The condition of the pile and its effects on the immediate environment would be monitored by means of a long-term programme agreed with the authorities.

19.6.2.2 Environmental Risks of Decommissioning the Cuttings Pile by Leaving *in-situ* Covered

The ERA identified 18 "significant" risks associated with this outcome, the most serious of which have "moderate" consequences.

The covering operation might result in the re-suspension of small amounts of cuttings and oil into the water column, and the subsequent resettlement of cuttings onto the seabed, although covering operations would be carried out in such a way as to minimise this effect. It is possible that some clean areas of seabed could be impacted by the resettlement of oily cuttings, and that chemical and biological perturbation resulting from the presence of the cuttings pile could be increased. Such an increase might be detectable for a small number of years after completion of the covering operations, but the area affected would decrease slowly as biodegradation processes took effect.

Little information is available about the degree to which contaminants would remain sealed under such a cover, or the degree to which biodegradation might continue beneath the cover. However, given the low energy environment of the seabed at North West Hutton, and the fact that the cover would be designed to prevent the migration of contaminants, it is likely that the chronic inputs of contaminants that might arise from a covered pile would be small, and would result in minor, localised effects in the adjacent seabed and water column.

19.6.3 Excavate, Leave and Monitor

19.6.3.1 Outcome: Decommissioning the Cuttings Pile by Excavating, Leaving and Monitoring

The pile would be excavated from its present location using a subsea excavation tool and deposited on the nearby seabed in an operation lasting several weeks. This operation would essentially create a larger and flatter cuttings pile than that which currently exists. This would be much larger than the existing chemical or physical footprint of the pile, but would still partly be within an area of seabed that was experiencing some level of degradation from the historic discharge of cuttings at the North West Hutton site. More of the pile would no longer be anoxic, and biodegradation of the pile would be faster compared with leave *in-situ*.

The excavation would disturb the cuttings, potentially releasing oil and contaminated cuttings into the water column. Settlement of the re-suspended cuttings would contaminate the adjacent seabed, including areas beyond the present limit of the cuttings pile. The condition of the relocated pile and its effects on the immediate environment would be monitored by means of a long-term programme agreed with the authorities.

19.6.3.2 Environmental Risks: Decommissioning the Cuttings Pile by excavating, Leaving and Monitoring

The ERA identified 5 "highly significant" and 26 "significant" risks associated with this outcome. The "highly significant" risks would be caused by the gross disturbance of the whole pile, and by the subsequent formation and long-term presence of a new layer of re-settled cuttings over the adjacent seabed. The resettlement of the disturbed cuttings onto clean seabed would have measurable effects on the benthos by killing organisms and reducing the diversity (a measure of the number of individuals and the number of different species) of benthic communities over the whole area of the physical footprint of the new layer.

The introduction of a proportion of the oil in the cuttings pile into the water column would impact the pelagic community at least for the duration of the operation. Disturbance of the pile may create a surface slick of oil that would be evident for the duration of operations, and could impact seabirds and sea mammals in the area.

The redistribution of the cuttings in a thinning more dispersed pile would accelerate the rate at which the total burden of hydrocarbons was biodegraded, and so the pile would persist for less time than the pile *in-situ*.

19.6.4 Retrieve and Re-inject on-site

19.6.4.1 Outcome: Decommissioning the Cuttings Pile by Retrieving and Re-injecting Onsite

The cuttings would be recovered to the surface using an ROV (Remotely Operated Vehicle) underwater suction tool. This would progressively re-cover the pile and deliver a slurry of approximately 10 parts water: 1 part cuttings. They would be transferred to an adjacent drilling rig, and then slurrified (ground into a fine suspension mixed with water) and pumped into purpose-drilled re-injection wells at the North West Hutton site. The slurrified cuttings would thus be permanently sealed into a layer of rock deep beneath the seabed.

19.6.4.2 Environmental Risks: Decommissioning the Cuttings Pile by Retrieving and Re-injecting On-site

The ERA identified 14 "significant" risks associated with this outcome. The main risk would arise as the result of an accidental spillage of cuttings during transfer to the re-injection site or while being stored on-site before re-injection. A small proportion of the pile might also be re-suspended during retrieval and then resettle onto the adjacent seabed.

19.6.5 Retrieving and Re-injecting Off-site

19.6.5.1 Outcome: Decommissioning the Cuttings pile by Retrieving and Re-injecting Off-site

The cuttings would be recovered to the surface using an ROV underwater suction tool. This would progressively re-cover the pile and deliver a slurry of approximately 10 parts water: 1 part cuttings. They would then be transported to a suitable existing platform in the North Sea, where they would be slurrified and pumped into existing wells which were deemed suitable for the disposal of cuttings.

19.6.5.2 Environmental risks: Decommissioning the Cuttings Pile by Retrieving and Re-injecting Off-site

The ERA identified 20 "significant" risks associated with this outcome, many of which were identical to those described for the "on site" re-injection outcome (Section 19.6.4). It was concluded, however, that the potential for accidental spillage is greater for the outcome of off-site re-injection compared with on-site re-injection, because the logistics of handling the cuttings are more complex.

19.6.6 Retrieve, Take to Shore and Treat

19.6.6.1 Outcome: Decommissioning the Cuttings Pile by retrieving, Taking to Shore and Treating

The cuttings would be recovered using an ROV underwater suction tool. This would progressively recover the pile and deliver to the surface a slurry of approximately 10 parts water: 1 part cuttings, which would be stored in suitable vessels or tanks, transported to shore, and transferred to holding tanks. At a licensed site onshore, the cuttings would be de-watered and then treated to remove the hydrocarbons, which would be recycled. The residual solid material would then be transported to landfill sites for final disposal.

19.6.6.2 Environmental Risks: Decommissioning the Cuttings Pile by Retrieving, Taking to Shore and Treating

The ERA identified 34 "significant" risks associated with this outcome. The worst "significant" risks, with "moderate" consequences, arise as the result of the transportation onshore by road, and subsequent treatment, of large volumes of cuttings material.

Experience from limited, small scale trials has shown that under normal operating conditions there is limited re-suspension of material during the recovery operation, although a small plume may be generated. Some operational upsets may result in the discharge of cuttings into the water column and this could cause impacts to benthic and pelagic organisms.

Recovered material would have to be temporarily stored onshore because the treatment capacity presently available is not able to process material as quickly as it can be retrieved. Processing would be undertaken at licensed sites, and there would be few impacts from the controlled operations.

The major effect of the onshore treatment of such a large quantity of cuttings would be the amount of energy required for treatment, although the ultimate disposal of the material to landfill would also create an impact. There may also be impacts resulting from the transportation of large quantities of material by road from the quay-side to the treatment plant, and from the treatment plant to a suitable landfill site.

Some of the technical aspects of this option remain to be resolved, particularly the bulk transfer of watery cuttings from the vessel to the shore. Overall, this outcome uses proven techniques albeit in a lengthy, relatively energy-intensive operation that would take more than one year to complete. The available treatment methods would produce a dried product which would still contain contaminants, and so would be likely to be classed as hazardous and would only be suitable for disposal at a hazardous landfill site.

19.6.7 Comparison of Outcomes for the Cuttings Pile

The relative performance of the six potential outcomes for the cuttings pile are shown in Table 19.7.

OUTCOME	Number of risks in each category			% remove	Energy		Emissions	
	Positive	Significant	Highly significant		GJ	Household equivalent	CO_2-E	Household equivalent
Leave untreated *in-situ*	0	16	0	0	6,500	80	500	80
Cover and leave *in-situ*	4	18	0	0	73,000	900	6,000	900
Excavate and leave	4	26	5	0	33,000	400	3,000	400
Retrieve and reinject on-site	6	14	0	100	275,000	3,500	20,000	3,200
Retrieve and reinject off-site	6	20	0	100	298,000	3,800	22,000	3,500
Retrieve, treat & dispose onshore	6	34	0	100	419,000	5,300	186,000	29,000

Table 19.7: Summary of environmental assessment for decommissioning the cuttings pile.

The outcome "excavate and leave" exhibits 4 positive risks but these are associated with the input of organic material from vessels into the marine environment and are trivial. The outcome exhibits 5 "highly significant" negative risks as a result of the uncontrolled re-suspension of the entire cuttings pile into the water column and the subsequent covering of a large area of natural seabed by a layer of resettled cuttings. Excavation might reduce the physical and chemical persistence of the pile material compared to the undisturbed pile, but the impacts to the seabed, water column, and benthos would be immediate and "major", and the impacts of the resettled layer of cuttings to the seabed and benthos would be long-term and "major".

The outcome "cover and leave" exhibits 4 positive risks, again all associated with the input of organic material from vessels into the marine environment, and they are all trivial. The outcome exhibits 18 "significant" negative risks, and with the exception of risks from major accidental oil spills following a collision, the consequences of all are rated as "minor". Covering would be expected to reduce, but not completely halt, the slow leaching of contaminants from the pile, and it would provide long-term protection to the surface of the pile from physical disturbance. Degradation of hydrocarbons within the pile would essentially cease, and the existing burden of contaminants would remain locked within the pile material for a long period of time. The cover would be over-trawlable, but it is acknowledged that in time the cover would begin to break down under the influence of natural and anthropogenic forces, and would have to be repaired or replaced. Covering the pile therefore encapsulates the pile and its contaminants (albeit for many centuries) but does not remove or reduce the burden of contaminants.

The outcome "retrieve and re-inject on-site" would result in the removal of the whole pile from the seabed, and if executed properly would provide a single, complete solution for the management of the pile. However, this outcome would not currently be allowed in the UKCS under international conventions. Two of its positive risks are important, the exposure of "natural" seabed for further recovery and colonisation, and the removal of a feature on the seabed that may have an effect on commercial fishing operations. These positive risks are common to the other outcomes "retrieve and re-inject off-site" and "retrieve and dispose onshore", but could only be realised if the whole of the footings were also removed.

The outcome "retrieve and re-inject on-site" exhibits 14 "significant" negative risks, including a "moderate" impact to the water column caused by the re-suspension of cuttings during retrieval, and "moderate" impacts to the water column and seabed if retrieved cuttings were accidentally spilt into the sea. These potential impacts could arise during ongoing operations spread over many weeks, and as such would be amenable to tight control, management intervention, and development and improvement in the procedures and techniques used. It could therefore be expected that both the "planned" risk (re-suspension of cuttings during retrieval) and the "unplanned" risk (spillage of cuttings back into the sea) could be reduced further to very low levels. The outcome would use about 30 times more energy than the least energy-intensive outcome ("leave *in-situ*"), but this is a "one-off" cost for the final elimination of the pile as source of environmental risk.

The outcome "retrieve and re-inject off-site" has the two important positive risks as discussed above. This outcome has 20 "significant" negative risks, somewhat more than the "on-site" outcome. This is because off-site re-injection would involve more handling, storage and transportation of the cuttings, with a consequently higher risk of accidental spillage into the sea. This difference aside, the outcome offers all the positive aspects of on-site re-injection and also has the benefit of not requiring new wells to be drilled. Using the assumptions stated in this EA off-site re-injection would, however, use about 8% more energy than as on-site re-injection. This outcome would also not be currently allowed in the UKCS under international conventions or UK law.

The outcome "retrieve and dispose on shore" again has two positive risks that are important, as discussed above. This outcome exhibits a total of 34 "significant" negative risks, nearly twice as many as the outcome "retrieve and re-inject off-site". In addition to the risks associated with the re-suspension of cuttings and their transportation at sea, this outcome incurs risks relating to the storage, treatment, transportation and final disposal of cuttings onshore. As such it exhibits potential risks to individuals, communities and infrastructure onshore; there is greater scope in this outcome for accidental spillages, including into near-shore or coastal waters, and on land. It is possible that large amounts of material may have to be transported by road to treatment or disposal sites, and while the environmental impacts of road transport may be commonplace, this outcome may result in a specific period of heightened activity at a particular site. The status of cuttings material after treatment to remove hydrocarbons remains problematical, but it is likely that all the residual material would be classed as hazardous waste. If this were the case, a new landfill site would have to be constructed in Scotland or the waste would have to be transported to a site in England. This is the most energy-intensive outcome for the cuttings and would use about 40% more energy than "retrieve and re-inject off-site"; this may be a significant difference given the method used to calculate energy use. In addition, because the cuttings would be treated onshore, this outcome may result in 8 times the level of O_2-E emissions of the next outcome, retrieve and re-inject off-site.

The outcome "leave *in-situ*" exhibits 16 "significant" risks, approximately the same number as the outcomes "cover and leave" and "retrieve and re-inject on-site". The physical presence of the pile, the potential effects of disturbance and spreading by over-trawling, would all result in risks that had a "moderate" consequence. The seabed, benthic community, water column, pelagic community, and commercial fishing could all be affected to varying degrees by the long-term presence of the pile and its contaminants. This is the least energy-intensive of the outcomes.

It is therefore concluded that, from an objective consideration of potential environmental impacts, and bearing in mind the site-specific characteristics of the North West Hutton pile and environment, the outcome for the cuttings pile that offers the least environmental impact would be "leave *in-situ*". The pile is presently stable, and the rate of leaching of oil is very low. The seabed around the edge of the pile is recovering from the impacts associated with the historic discharge of cuttings, and this recovery will continue. The pile itself would continue to degrade very slowly over a long period of time. Its continued presence at the North West Hutton site would not affect any sensitive marine environments, or any rare or sensitive species, and would be unlikely to result in any effects on the marine food chain. The agreed monitoring programme would be able to detect changes in the characteristics, nature and effects of the pile as it ages. If the outcome for the footings is "leave *in-situ*" then the presence of the footings with clear marine chart marking and other measures would help to minimise the possibility of accidental physical disturbance of pile material by bottom-towed fishing gear. Furthermore, if the footings were to be left then the two important positive risks associated with all three of the "removal" outcomes for the pile – exposure of the natural seabed and removal of a feature that might interfere with commercial fishing - would not be realised.

19.7 Decommissioning the Pipelines

There are three main outcomes for the two pipelines. All the outcomes, and the methods of achieving those outcomes, are feasible for both the 10" trenched gas import pipeline and the 20" untrenched oil export pipeline. Both pipelines will have been thoroughly cleaned before decommissioning, and so no decommissioning outcomes will release any significant amounts of hydrocarbons into the sea.

19.7.1 Leave *in-situ*

19.7.1.1 Outcome: Decommissioning the Pipelines by Leaving *in-situ*

The lines would be left *in-situ*, without treatment and filled with seawater, and their condition would be monitored periodically in an agreed programme. The 10" line would be more or less completely buried with sediment, whereas the 20" line would sit on the seabed. The lines would slowly deteriorate over a long period of time.

19.7.1.2 Environmental Risks: Decommissioning the Pipelines by Leaving *in-situ*

The 10" trenched line would eventually collapse into its existing trench. The presence of the line and its slow degradation would not result in any significant impacts to the seabed or the pelagic or benthic communities. The line would pose some risk to bottom-towed fishing gear, but this would be small because over 70% of the line is already covered by sediment that has naturally back-filled into the trench.

The 20" line would also collapse, but this would not cause significant impacts in the pelagic or benthic communities. Because this line is located on the surface of the seabed, its collapse would create a line of debris (concrete and steel) that would be more prone to interaction with towed fishing gear.

The ERA identified 3 "significant" risks associated with this outcome. The worst "significant" risk, with a "moderate" consequence, would be the socio-economic consequences for fishermen of the presence of material on the seabed.

19.7.2 Trench and Bury

19.7.2.1 Outcome: Decommissioning the Pipelines by Trenching and Burying

The oil pipeline would be buried using a towed plough to ensure that it was covered by at least 0.6m of seabed sediment. The gas line would be remedially trenched by plough or other appropriate equipment. Remedial trenching would be undertaken on those sections that presently exhibit spanning, to ensure that they were completely buried in the sediment.

19.7.2.2 Environmental Risks: Decommissioning the Pipelines by Trenching and Burying

Clean sediment would be thrown up into the water column during the burial operations, but this would cause negligible impact. The vessels used in the operation would create gaseous emissions. Burial would result in potentially recyclable material not being retrieved from the sea. Resources would be needed for periodic inspections and for potential remedial activities in the future.

A small area of the seabed along the length of each line would be disturbed, and the benthic communities there would be destroyed. Where pipelines are buried by part of the cuttings pile, some contaminated sediments would be dispersed into the water column, but these impacts would be localised and transient. Once the lines were buried with natural sediment, benthic communities typical of the area would quickly become re-established.

The ERA identified 9 "significant" risks associated with this outcome, none of which had a consequence rated worse than "minor".

19.7.3 Remove and Dispose Onshore

19.7.3.1 Outcome: Decommissioning the Pipelines by Removing and Disposing Onshore

Several methods are available for the total removal of both lines, and for the 10" line the existing over-burden of sediment would have to be removed by dredging or water-jetting before the pipeline could be lifted. However, all of the possible methods result in the complete pipeline being retrieved to the surface, taken to shore, and disposed of by recycling and other appropriate routes. The seabed on both routes would be left clear for fishing.

19.7.3.2 Environmental Risks of Decommissioning the Pipelines by Removing and Disposing Onshore

All the removal methods would result in a small number of minor impacts to the seabed and benthic communities immediately adjacent to the pipeline. Where pipelines are buried by part of the cuttings pile, some contaminated sediments would be dispersed into the water column, but these impacts would be localised and transient.

19.7.4 Comparison of Outcomes for the Pipelines

There are three possible outcomes and their performance is shown in Table 19.8.

OUTCOME	Number of risks in each category			% remove	Energy		Emissions	
	Positive	Significant	Highly significant		GJ	Household equivalent	CO_2-E	Household equivalent
Leave untreated *in-situ*	5	3	0	0	113,000	1,400	8,000	1,300
Trench and bury	6	9	0	0	150,000	1,900	11,000	1,700
Retrieve and dispose onshore	6	12	0	100	193,000	2,400	14,000	2,200

Table 19.8: Summary of environmental assessment for decommissioning the pipelines.

None of the outcomes for the pipelines would exhibit a negative risk that would be rated as "highly significant". All three outcomes exhibit about the same number of positive risks, but in the outcomes "trench and bury" and "retrieve and dispose onshore" two of the positive risks are important, namely the reestablishment of natural sediment for the colonisation of benthic communities, and the removal of a potential obstruction to fishing from the seabed.

The outcome "leave *in-situ*" has 5 positive risks but they are all trivial. It exhibits the smallest number of "significant" negative risks, but the risk of entanglement with fishing gear the risk is rated as "moderate", and this is an important factor in assessing this outcome. The outcome has the lowest energy use and given the method used to estimate energy use the difference between this outcome and the next ("trench and bury") may be significant.

The outcomes "trench and bury" and "retrieve and dispose onshore" accomplish one similar outcome, namely the removal of the pipelines from the seabed and their consequent elimination as a potential snagging feature for commercial fishing operations. They exhibit 9 and 12 “significant risks” respectively; the difference should be treated with caution because the additional risks for “retrieve and dispose onshore” arise from a presumed worst-case accidental oil spill from the recovery vessel at a location close to the coast. With the exception of these spill risks, all the “significant” risks in both these outcomes were rated as having “minor” consequences at worst. The outcome “retrieve and dispose onshore” has a higher use of energy, and a greater amount of CO_2-E emissions than “trench and bury”, and the differences in both these measures (about 30%) may be significant within the context of the method used and assumptions made to compute energy and emission values. The outcome “retrieve and dispose” is therefore unlikely to result in any real energy or emissions savings.

From our assessment of the environmental risks, the outcome for the pipelines that offers the least environmental impact would be “trench and bury”. Although it has more “significant” negative risks than leave *in-situ*, it is suggested that these additional risks, which would be short-term and localised, are outweighed by the important positive effect of removing the pipelines permanently from the surface of the seabed and thus eliminating any possible interaction over the long-term with bottom-towed fishing gear.

References

19.1 “Report ENV01”, BMT Cordah Ltd, Environmental Statement in support of the De-commissioning of the North West Hutton Facilities, Report No. BPX067/ES/2003, June 2004.

19.2 BSI, 1996. BS 8800:1996 A Guide to Occupational Health and Safety Management Systems, British Standards Institution, London.

19.3 DTI, 2003. Oil & Gas. http://www.og.dti.gov.uk/.

19.4 BP, 2000. Magnus Enhanced Oil Recovery (EOR) Project Environmental Statement. D/1039/2000.

19.5 BP, 2001. Clair Phase I Development – Environmental Statement for Offshore Activity. D/1228/2001.

20 APPENDIX

20.1 Letter to Interested Parties

20.2 Report of 6th February 2003 Stakeholder Meeting

20.3 Report of 12th June 2003 Stakeholder Meeting

20.4 Report of 6th May 2004 Stakeholder Meeting

20.5 List of Comparative Assessment Studies

20.6 Report by the Independent Review Group (IRG)

20.7 Longitudinal Profiles

20.8 Summary of Applicable Legislation

20.1 Initial Letter to Interested Parties

Norrie Ramsay
Projects & Decommissioning Manager
Northern Business Unit

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Burnside Road
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29 November 2002

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Dear «Mr» «Surname»

NORTH WEST HUTTON DECOMMISSIONING

I am writing to inform you that BP has started preparations for decommissioning the North West Hutton oil field, located some 130 km North East of the Shetlands Islands.

Continuing investment in North West Hutton in recent years by BP and co-venturers CIECO Exploration and Production (UK) Ltd, Mobil North Sea Ltd and Enterprise Oil UK Ltd, has been successful in extending field life beyond previous expectations. However, low levels of production mean the field is now uneconomic and the technical and commercial case for ending production has been accepted by the Department of Trade and Industry.

The field is currently shutdown and well abandonment work is underway. This work will continue into next year and preparations are also being made for a topsides clean up programme scheduled to begin early next year.

Platform removal will not begin until we have completed comparative assessments for the key removal and disposal options, investigated alternative uses and submitted a full decommissioning programme acceptable to the DTI. In carrying out these assessments, we will take into consideration safety and the availability of suitable technology as well as the environmental, economic and social impacts of the different removal and disposal options.

We also intend to consult widely with all who have an interest in the decommissioning of North West Hutton and invite you to take part in this consultation process.

If you are interested in taking part, I would be grateful if you could complete the attached form and return it to Richard Grant at the above address, by fax to 01224 832841 or by e-mail to grantrc2@bp.com, so that we can establish a stakeholder consultation register. Please pass the form to anyone else in your organisation who might be a more appropriate contact for consultation.

BP Exploration Operating Company Ltd
Registered in England & Wales No. 305943
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Inc. with limited liability in Wilmington
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In the meantime, a fact-sheet on North West Hutton is enclosed with some background on the history and size of the field and we also intend to set up a website where new information and progress updates on decommissioning will be posted. Information on all aspects of BP, including our North Sea operations, can be found at www.bp.com.

Yours sincerely

Dr Norrie Ramsay
Decommissioning Manager

To:

Norrie Ramsay/Richard Grant
East Production Unit – NW Hutton Decommissioning Team
BP
Burnside Road
Farburn Industrial Estate
Dyce
Aberdeen AB21 7PB

Fax No 01224 832841

I am interested / not interested in taking part in consultation with BP on the decommissioning of the North West Hutton installation.

NAME ....

ORGANISATION..

ADDRESS ....

TEL .... FAX ....

E-MAIL ....

My main areas of interest are:

Environmental Impact	Social Impact
Safety	Economic Impact
Sustainable Development	Technology

Other (please specify) ....

Signed .... Date ....

Data Protection Statement

Your contact details are securely held by BP and will be treated confidentially as part of our consultation process on North West Hutton decommissioning.

20.2 Report of 6th February 2003 Stakeholder Meeting

BP STAKEHOLDER MEETING

N.W. HUTTON DECOMMISSIONING CONSULTATION

6th February, 2003

Aberdeen

Produced by

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INTRODUCING FORTHROAD

ForthRoad Limited has prepared this report under contract to BP. ForthRoad is a specialist organisational development consultancy experienced in organising and facilitating workshops bringing together people with similar interests to consider key issues and progress within that. Further information about ForthRoad is available through its web site: www.forthroad.com.

WELCOME AND CONTEXT SETTING – NORRIE RAMSAY, DECOMMISSIONING MANAGER

Norrie addressed the purpose of the stakeholder consultations. He talked about the dilemmas facing BP in this respect with competing priorities from different issues such as safety, technical ability, environmental and societal impact, and economics. He hoped that these sessions would help BP understand the issue better and produce a better solution at the end of the day.

DECOMMISSIONING CONTEXT PRESENTATION – STEVE JOHNSTON, DECOMMISSIONING TEAM LEADER

Steve Johnston gave an overview presentation outlining the background to decommissioning, North West Hutton status, current legislation, the decommissioning schedule and key challenges.

A copy of this presentation can be accessed using this web link:
http://www.bp.com/location_rep/uk/bus_operating/nw_hutton_decom/index.asp

The presentation was followed by table discussions. A number of the key questions from each table are aptured here together with the BP answers given on the day:

- **Does BP have a corporate position on decommissioning in general?**
  Yes – there is a section on our public website. This is underpinned by BP's Group Policies, commonly known as 'What We Stand For' covering a number of areas including HSE performance.
- **Did the original design and development of North West Hutton in the early 80s take account of decommissioning requirements?**
  It was designed in line with regulations in force at the time. It was not possible to anticipate how expectations and regulations would change through field life
- **Are all of the co-venturers in agreement with BP's approach to NWH decommissioning and stakeholder consultation?**
  Yes – and there are regular meetings to discuss all aspects of our plans.
- **Does derogation apply to drill cuttings and pipelines?**
  No – only to the jacket footings.
- **Why is recycle rather than re-use the plan for North West Hutton?**
  The age, design and size of the installation mean it is not possible to take it to a new location for re-use as an operational platform. Certain components may be suitable for reuse and these opportunities will be pursued.
- **Is single lift a possibility for the installation rather than removing smaller pieces?**
  Single lift technologies are being researched but none is yet developed.
- **What is the timeline for submission of the decommissioning programme to the DTI?**
  We expect that the first draft will be submitted by the end of 2003.
- **Is there a drilling template under the cuttings pile and can it be removed without disturbing the pile?**
  There is a template – approximately 12 metres square and 3 metres high. The cuttings pile would need to be moved to gain access to the template.
- **What are the dimensions of the cuttings pile?**
  Approximately 160m by 120m and 5m high at the peak.
- **What is the height of the jacket footings?**
  Approximately 40 metres.

COMPARATIVE ASSESSMENT STUDIES - ANDY FOSTER, SENIOR ENVIRONMENTAL ADVISOR & GLYN HARRIS, DECOMMISSIONING PROJECT MANAGER

This presentation focused on comparative assessment studies on the options for pipelines, drill cuttings pile and jacket footings and the independent review process.

This presentation can be accessed at:
http://www.bp.com/location_rep/uk/bus_operating/nw_hutton_decom/index.asp

The following points were made and questions posed during the plenary discussion:

QUESTION: Will BP be specific in the DTI submission about where components of the topside and jacket will be taken following their removal?
ANSWER: BP stated that whilst this could be stated "in principle" this would not be possible in detail until after DTI approval was obtained and contracts outlining the detail of these activities could be entered into.

- There was discussion around the environmental studies that had been carried out on the repopulation of marine species, following the end of drilling operations and the discharge of drill cuttings on N.W Hutton some 10 years previously. There were questions as to whether these studies had been published. It was felt that the amount of data available and the finding about repopulation meant that N.W. Hutton was well placed in this respect.

- There was conversation about the recent OSPAR meeting on Drill Cuttings Removal. Although there were differing opinions at that meeting it was not felt that OSPAR, would move to creating a measure immediately and it is more likely that more research will be required.
- It was also stated that it seemed to make environmental sense to leave the Drill Cuttings rather than to disrupt the seabed. This also left open the future options where legislation or technology may change the position.

In the second part of this presentation Glyn Harris discussed Jacket Footings and Pipeline issues.

- A view was expressed that the position on pipelines should be complete removal or burying. Current discussions indicated that where it could be demonstrated that it had been trenched, buried and cabled, this would be acceptable. BP gave some reassurance on the issue of concrete degradation where there had been a worry that debris from degradation or following removal could create an additional hazard.
- There was discussion around the exact scope covered by North West Hutton Pipeline decommissioning. BP explained that the SSIV (Sub Sea Isolation Valve) would be removed from the gas import line. This piece of equipment is within the 500m zone but does not impact the drill cuttings pile. The area to be addressed went up to but did not include the Ninian Tee. It was noted that a more comprehensive schematic would be helpful and BP undertook to provide this on the web site. The Maureen example was cited as good practice in this area.
- In response to other questions concerning the status of the pipelines BP confirmed that surveys had revealed that there were no spans on the NWH oil export line, that there had been some rock dumping on the gas line and that the gas line was trenched.

It should be stated that the opinions mentioned here were individuals opinions rather than a consensus but no opposing views were stated in the meeting not mentioned here.

SYNDICATE SESSION

Participants were asked to discuss any issues arising and address the following questions at their respective tables:

- Is the comparative assessment process comprehensive and coherent?
- Which of the issues identified by BP are the most critical?
- Are there other issues you wish to raise?

Table One

Table one made the following points following its discussion, talking first about the Comparative Assessment Studies:

- Generally comprehensive but some areas of uncertainty need to be discussed. This is the stimulus for additional study. How would BP manage uncertainty? e.g. what if BP were unable to cut something as they thought. What contingency plans could there be. It was suggested that BP could look at further industry studies to establish these alternatives.
- Comprehensive as any other: nothing new, standard 5 areas, meets the standard.
- There was some discussion around the term coherent. How to get balance between these areas (Social, Economic, Technical, Safety and Environmental).
- No common weighting/metric – safety versus environment. Real challenge to get balance. Cost could be a common metric but this was not ideal. How do you put a cost on a Blue Whale or the environmental loss of a Salt Marsh compared to the creation of new jobs? There are ways of doing this.
- Could we change the word coherent to rational?
- Is it objective and thorough if subjected to specialist audit – financial, technical, environmental etc? It also needs to be transparent and holistic.
- Any specialist audit should be conducted by a different set of experts from the BP independent review group.
- The process should be transparent, should learn from previous decommissioning activities and take a holistic approach.

- Issues can be separated BUT need holistic assessment. You can separate cuttings, footings and pipelines but in the end you need to bring them back together.
- The assessment will be criticised for bias.
- Derogation imperative will be dominant. North West Hutton will be the first UK only platform where derogation may be applied. There will have to be a water tight case.
- There are fishing concerns.
- Concerns around re-use, LSA.

Table Two

Table two made the following points following its discussion:

- Economics.
  - o Explanation of use of public money - decommissioning costs can be offset against tax paid during operational life of the field. Will people feel they have some sort of stake?
  - o Monitoring Costs - BP needs to commit to this on an ongoing basis (Cuttings Pile etc) There would have to be contingency planning. What would happen if BP were sold or broken up?
  - o Liability issues.
- Social aspects.
  - o Look at job benefits.
  - o Knock on revenue.
  - o Waste management sub contactors.
- Public Perception - biggest issue. Whole process and documentation needs to be transparent.
- Perception of the Independent Body: - Could BP provide information on who is on it?
- There needed to be Accreditation of the whole approach. Endorsement of right approach.

Comparative Assessment Studies

- Timing of operation should be assessed - when do you do things to get the best effect. What were the requirements for technical detail? Certain level needed in DTI submission. E.G. Would cutting be by water-jet or explosives etc (these have different impacts). Generally more detail was welcome.
- Contingency - How do you account for not physically being able to do it?
- Issues weighting.
  - o Transparent objectives.
  - o Understandable.
  - o Feedback with iterative process.

Important Issues

- H&S priority is recognised.
  - o Others are stakeholder dependent.
- Cost – not exclusion factor but value for money?/Linked to weighting.

Table Three

Table three made the following points following its discussion:

- Political aspects, precedent, reputation do they form another area to be considered and how? No answer from the table – this is a huge area. Is it in the CAS or not?
- Issues were discussed on the comparative importance of 5 areas. BP might start at Safety BUT shouldn't you start at Technology and then do it safely.
- None is more important than the other - different times different lenses.
- The issue of re-use was raised. How would this effect decisions. In the case of steel from the jacket. If we knew a use for it would that change where we took it to after removal.
- "Don't stop at the quayside" BP should track and measure the impact of ongoing activity and particularly waste disposal.

Comparative Assessment Studies

- Reasonably comprehensive. How do you draw it all together at the end into one coherent piece?
- Challenge for BP to go beyond the boundary.
- Impact of Policy Framework? – Precedent.
- Political and public perceptions.
- Break open the social bubble.
- How could BP generate a common currency for the 5 elements. Cost not the best way.
- Timing - are we going to be able to complete all the CAS work by the end of the year. Will it be thorough?
- It would be good if the feedback process was iterative rather than everything coming out at the at last minute.
- Health & Safety is very important. BP is a business but cost is not priority issue. Value for money is important.

ADDITIONAL ISSUES

Participants identified the following additional issues:

- Issue of precedent setting.
- Partial removal as an interim state/continuous monitoring.
- Difficult to justify financially as an ongoing commitment.
- Ensure licences are available for onshore contractors as part of the process – no one is bounced.
- Issues of breaking the "Social Bubble" – the 6th Bubble - political, societal, green.
- Timing a big issue.

FUTURE CONSULTATION

- Use topic specific groups, then bring these together to integrate (careful not to isolate).
- Meet when there is something to tell us.
- How to take on the challenge of balancing the 5 issue areas.

APPENDIX ONE: PARTICIPANTS' FEEDBACK

The following feedback was given by participants:

WHAT WORKED WELL	WHAT WOULD HAVE BEEN BETTER
Good spread of people and good calm thinking	Balance more Detail with Integration of Issues
Constructive Process	Demands on Time
Background level of detail progression	More on Status of Project in Presentation
Mix of people	Themed Sessions
Lunch	Vary Location?
Networking	Acoustics
1st Table Session after Presentations	Clarity on Stakeholder Process Timetable
Brief pre-read Right Approach Right Agenda Right Duration	Try and get some of the Wider Green 5 here eg Green peace, WWF →to know what they are thinking on this -->Perhaps more Critical
	Some assumptions were made eg a lot of talk was kind of assuming Eg Drill Cuttings would be left in place

APPENDIX TWO: LIST OF PARTICIPANTS

Geoff Anderson	ForthRoad
Marcus Armes	University of East Anglia
Ron Beard	Halcrow
Jan Bebbington	University of Aberdeen
Eric Breuer	Scottish Association for Marine Science
Zoe Crutchfield	JNCC
Mike Curtis	SEPA
Tracy Edwards	JNCC
Gina Ford	RSPB
Susan Gass	Scottish Association for Marine Science
Ray Johnstone	FRS Marine Lab
Murdo Maciver	Shetland Decommissioning Co
Kostas Rados	Robert Gordon University
Michael Sutherland	Scottish Fishermens Federation
John Watt	Scottish Fishermens Federation
Alan Wishart	Lerwick Port Authority
Phil Dyer	Shell
Andy Foster	BP
Richard Grant	BP
Glyn Harris	BP
Gordon Harvey	BP
Steve Johnston	BP
Simon Merrett	BP
Norrie Ramsay	BP

APPENDIX THREE: SYNDICATE GROUP FLIPCHARTS

Group One

1. IS COMPARATIVE ASSESSMENT:-

a) COMPREHENSIVE — Generallyyes but areas of uncertainty need to be discussed
Stimulus for additional study

b) COHERENT — Depends on approach to achieving balance
Weighting – Metrics

PREFER RATIONAL
OBJECTIVE (REF TO AUDIT)
TRANSPARENT
HOLISTIC
⇓
ASSESSMENT (subject to review group scrutiny)

DEROGATION IMPERATIVE

2. FISHING CONCERNS

3. RE-USE, LSA

Group two

ISSUES?

ECONOMICS
-- PUBLIC MONEY
-- MONITORING COST
-- LIABILITY ISSUES
⇒ COMPANY BREAK-UP?

SOCIAL ASPECT
-- ASSOCIATED JOBS
-- KNOCK-ON REVENUE
⇒ SUB-CONTRACTORS

PUBLIC PERCEPTION
-- ENSURE TRANSPARENT
-- INDEPENDENT BODY
⇒ 'ACCREDITATION' ?
⇒ 'ENDORSE

COMPARATIVE ASSESSMENT

TECH DETAIL
-- TIMING OPTIONS ?
-- LEVEL REQUIRED FOR REAL ASSESSMENT (eg explosives)
-- CONTINGENCY PLANS

ISSUE WEIGHTING
-- TRANSPARENT OBJECTIVES
-- UNDERSTANDABLE
-- FEEDBACK WITH ITERATIVE PROCESS

IMPORTANT ISSUES

H&S PRIORITY RECOGNISED
-- OTHERS STAKEHOLDER DEPENDENT

COST
-- NOT EXCLUSION FACTOR
BUT VALUE FOR MONEY?
-- LINKED TO WEIGHTING

Group three

OTHER ISSUES

→ Re-use?
→ considered
(on and offshore-use)

Decommission

Assessment process

* interaction of aspects of CA (weightings) - all important and depends where you come from
* robust & defendable
* boundaries & responsibilities
  (e.g. licenses for disposal
  -contractors)
* break open the social bubble

Other issues in Models

- impact on policy framework
- "political perceptions"
  "public perceptions"
- risk issues
- common currency of elements

20.3 Report of 12th June 2003 Stakeholder Meeting

NORTH WEST HUTTON DECOMMISSIONING

STAKEHOLDER MEETING

BP

Marcliffe Hotel, Aberdeen

12th June, 2003

Produced by

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INTRODUCING FORTHROAD

ForthRoad Limited has prepared this report under contract to BP. ForthRoad is a specialist organisational development consultancy experienced in organising and facilitating workshops bringing together people with similar interests to consider key issues and progress within that. Further information about ForthRoad is available through its web site: www.forthroad.com.

INTRODUCTION/PURPOSE

The purpose of the meeting was to hear stakeholder views on BP's developing plans for North West Hutton decommissioning. This meeting was the second stakeholder meeting, the first having taken place on 6th February 2003. The key issue areas around which consultation is taking place are drill cuttings, jacket footings and pipelines. The first stakeholder meeting set context around these themes, the second was designed to update progress on the Comparative Assessment studies and to consider the decision making process further including the potential for applying sustainable Development Techniques.

Organisations represented at the meeting were:

Aberdeenshire Council
Atlantic Frontier Environmental Forum
DTI – Oil and Gas Industry Development Directorate
FRS Marine Lab
JNCC
Lerwick Port Authority
North West Hutton Independent Study Review Group
Offshore Contractors Association
Peterhead Bay Authority
RF Rogaland Research
Ross Deeptech
Scottish Fishermens Federation
Shell
Shetland Decommissioning Company
University of East Anglia
University of Aberdeen

BP attendees:

Andy Foster
Richard Grant
Glyn Harris
Steve Johnston
Blair McKay

Simon Merrett

Note: Comments detailed in this report are those of meeting participants and do not necessarily express the views of BP.

NORTH WEST HUTTON STATUS UPDATE – STEVE JOHNSTON

Steve Johnston opened the meeting by presenting a status update on North West Hutton and setting the context for the day's agenda, including an overview of progress with the comparative assessment studies.

Brian Wilkinson, on behalf of the Independent Study Review Group, made a brief presentation on the Group's terms of reference, membership and output.

This presentation material will be posted on BPs public website at - http://www.bp.com/location_rep/uk/bus_operating/nw_hutton_decom/index.asp

The following questions were posed and answers given in relation to Steve Johnston's presentation:

Question 1: For clarity, have ENGOs been invited to meetings but not turned up? Answer: Yes, we have a wide-ranging list of around 60 stakeholders and the meetings are open to anyone with a genuine interest. We have tried to encourage wide participation including the option of meetings in other locations and one-on-one meetings.

Question 2: Can you clarify the removal window, as this seems to have slipped by one year? Answer: It slipped by a year due to the planning time required as well as the likely availability of equipment to implement the workscope.

Question 3: Regarding statistics on jobs, are you talking about jobs that would be created? Answer: These are jobs that would be attributable to the specific operation, it is effectively "work-expended" and does not necessarily imply jobs created. They are not jobs that will be "lost". It is important to note that the main purpose of generating these figures is to allow a comparison of the various decommissioning activities. **Comment:** When announcing information regarding jobs to the media it is important to be absolutely clear about whether you are meaning the creation of jobs, the sustaining of jobs or getting rid of jobs.

Question 4: Is it your intention to let anyone have access to reports in any form? Answer: All reports will be available as part of the decommissioning programme process. If people have an interest in specific studies then they can contact us and we will share that data.

Question 5: Is there guidance from DTI as to how many studies are required? Answer: DTI provides comprehensive guidelines on the decommissioning process including a comparative assessment. Our approach has been to review the guidelines, the work done by others and include this in a process applicable to the specific issues related to North West Hutton.

Question 6: Have you considered the impact of changes in legislation, for example those regarding landfill? Answer: That will be covered in the recovery study being carried out. Where it is foreseeable we are trying to allow for changes in legislation. Our decisions do take into account foreseeable changes over the longer term.

Question 7: How do you cope with ongoing liability if you leave material on the seabed? Answer: Our desire is for an outcome that will result in a very low residual liability. We are still developing these aspects for inclusion in the decommissioning programme.

Participant Comment: The content of the presentation regarding drill cuttings seems to imply excavation and earth moving. There are better options for doing this.
Response: It should be noted that the information presented is a a high level summary. BP participated in the cross industry study about Drill Cuttings. We have looked at a whole range of options and drawn up a short list based on those that are applicable to our platform. The range of options has also been independently reviewed. However, we would be interested to hear about other options.

Question 8: Have you considered the safety implications and impact in other situations, besides those outlined in the slides? (Risk from Pipelines)
Answer: Yes, but the safety impact detailed (in the matrix on the slide) is focused on physical operations work. Risks to other sea users is a very important aspect and is included in our "societal" group of studies.

Question 9: Do you consider the big picture in terms of what new options might be possible in the future due to emerging technologies?
Answer: The longer term is considered by BP and the rest of the industry through a number of joint industry projects. However, there comes a time when we need a cut off point and action is required on North West Hutton based on what we know now.

Question 10: Please explain more about the plugging that has been done on the wells.
Answer: The wells have all been plugged using two cement plugs deep in each well with a third plug near to the surface. We have used criteria in excess of standard minimum requirements.

SUSTAINABLE DEVELOPMENT – JAN BEBBINGTON

Jan Bebbington presented on the principles of sustainable development and discussed some models for SD assessment. Jan's presentation will be posted on the BP public website at -
http://www.bp.com/location_rep/uk/bus_operating/nw_hutton_decom/index.asp

The following questions were posed and answers given in relation to Jan Bebbington's presentation:

Question 1: Regarding the Risk and Policy Analysis model, isn't it possible that different stakeholder groups could come up with different weightings for each of the measures?
Answer: The final weighting applied is an average of all those provided by the stakeholders. If it is a small enough group of stakeholders it does not have a major effect but if you were dealing with a large number of stakeholders some might end up seeing their original weighting disappear when the average is calculated.

Question 2: Do you introduce a discounted cost analysis into the SAM Model?
Answer: None of the numbers are weighted, it is not discounted. There are all sorts of enhancements you can add to the analysis including carrying out geographic analysis of negative and positive impact but it becomes a more complex process.

Question 3: Could the methodology be applied to different energy use options, for example oil field versus wind turbines?
Answer: It could be applied but it becomes a lot more complex

Question 4: Where do presentation costs figure in the SAM model?
Answer: Presentation or reputation isn't in the model as it stands but that could be made a capital category if it was seen as crucial.

Question 5: I find the phrase 'Sustainable Development' unhelpful. Couldn't we just call it good practice rather than sustainable development?
Answer: The models presented have been developed in the context of looking ahead to where things are heading in the future, therefore sustainable development is applicable. However, it could also be seen as good practice.

SYNDICATE SESSION

Participants were organised into three syndicate groups and asked to consider and provide feedback on the following questions:

1. What do you think of the use of sustainable development techniques to aid the decision making process?
2. What other elements might be taken into account?
3. What thoughts do you have around the dilemmas this process reveals?

Each group was asked to consider the questions in relation to one of the following topics:

- Jacket & Footings
- Drill cuttings
- Pipeline

Group One: Jacket & Footings

Group one made the following points in response to the questions:

- Sustainable development is a useful tool but it should not constitute the whole decision making process.
- It could be used with other processes and assessment techniques and conclusions from the sum of these tools could be developed.
- The key thing missing is the issue of reputation and how that is managed – sustainable development provides more of a presentation tool, rather than managing reputation.
- An ideal spider-gram (ref Sustainable Development Presentation) with all the appropriate measures would be useful.
- Avoid complex weighting systems as this only brings about debate. These need to be transparent.
- Using money as the key value judgement could be dangerous – BP might be seen as simply going for the cheapest option.
- A regulatory element needs to be added.
- Jackets, cuttings and pipelines are all interlinked by critical paths so it is difficult to separate them.
- There are also links between other aspects, such as HSE and the environment.
- A “sustainable solution” is the overall objective.

Group Two: Drill Cuttings

Group two made the following points in response to the questions:

- The group did not think highly of sustainable development techniques. As long as the mechanism is holistic and transparent it doesn’t need to be labelled “sustainable”.
- It might not be possible to bottom out all issues in one document, rather it might make more sense to offer an interim solution.
- There is clear linkage between all the elements.
- Testing the water of opinion about the preferred approach is key.

Group Three: Pipelines

Group three made the following points in response to the questions:

- Reputation is a big issue.
- Objectivity is key – how do you ensure transparency in the final decision making process?
- It is important to have discussion about the weightings applied and why they have been given a certain weighting i.e. if you ran the same series of discussions on scoring weightings with a range of stakeholders one or two minor changes can make a massive difference to the bottom lines.
- The system is not closed i.e. a lot of the issues are dependent on others in the box.

- Few areas are independent.
- Why is BP engaging in this exercise? Who is it trying to influence - the stakeholders, DTI or is it just trying to be seen to be doing the right thing? There was a slight cynicism that sustainable development concept was being seen as a presentational tool.
- The sustainable development framework concept provides at best a contextual “testing mechanism” and should only be seen as one component in decision-making.
- The group approached things from a very simplistic point of view i.e. 3, 2, 1, where 3 was the best score for each of the subheadings. The group also applied a weighting to the different issues – again though very simple this is incredibly subjective. To get an overall score the group merely multiplied the weighting by the score. That meant for this group that the best option was leaving the pipeline in place, followed by trench and bury and lastly recovery and removal. The group however was honest enough to admit that by changing the weighting by only a few points in some cases you could actually make these three come much closer together.
- There is a need for a lot more data before we can say whether this technique is robust and reliable e.g. going through the subheadings, an area like energy is not straight-forward. You use energy to recover the pipeline with the hope of recycling the steel but is that in itself viable? i.e. you need a lot more information on the market for such recycled steel before making any kind of judgement on the issue.

PLENARY DISCUSSION

A plenary discussion followed the syndicate groups’ feedback and following points were made, questions posed and responses given.

Question: is there an obligation to remove the pipeline?
Answer: No, not in the same way as there is an OSPAR decision on what must be done with redundant installations. However, we are investigating the range of possible solutions to ensure that the most satisfactory outcome is achieved.

Question: Have options to reuse the jacket been considered
Answer: Yes, a number of comprehensive and wide-ranging studies have been implemented. However, the relatively remote and hostile location make any opportunities uneconomic. (It should also be noted that the requirement to decommission would still exist).

Question: Are you conducting a reputation risk analysis?
Answer: We do a risk review like we do in all other areas of our business; we are constantly assessing the key risks.

Question: Have you tried to integrate these risks?
Answer: We are trying to fully understand the risks to all stakeholders. This is to ensure that the solution presented balances the main issues and concerns and is therefore the most widely acceptable and lowest risk outcome. This meeting is a significant part developing that understanding.

The conversations subsequently widened to include more general comments and feedback, The comments are those of participants to the meetings and do not necessarily reflect the views of BP.

Participant Comments:

- The group recognised that weightings could be different based on who was conducting the exercise – it might be valuable to have a spread of scores from different perspectives as an aid to making a final judgement. Average the weightings and look at incremental difference across the spectrum of Stakeholder weightings?
- Decommissioning should be done as one shot, not in interim stages.
- An interim model would not be acceptable to the DTI at present.
- If cuttings and footings were left in place you (BP) would have to keep monitoring so that this would be an on-going issue.
- Cutting and removal technologies might improve and there needs to be room left to factor that in if the cuttings and footings are left in place.
- We think that either everything must stay, or everything must go – you couldn’t get rid of the installation but leave the cuttings.

- You have flexibility as to what the right approach is but it will be important to put pressure on the DTI to work through issues with you at each juncture. Part of that exploration will have to include NGOs.
- There is a risk to reputation from perceived failure to honour undertakings made to stakeholders and in public statements at the time when the original licence to operate was granted. This needs to be factored into the comparative assessment model.

FEEDBACK ABOUT THE MEETING

Participants were asked what went well during the meeting and what could have been done better.

Participants made the following points in relation to the question: what went well?

- Excellent facilitation.
- Workshop table set up is good.
- Good sized groups.
- Presentations round the walls.
- Data/statistics in presentation.
- Good lunch.
- Introducing a wider view is very valuable.

Participants made the following points in relation to the question: what could have been better?

- Work us a bit harder – better use of time.
- Ensure NGO participation – possibly by visiting them.
- Could do with a meetings on the procurement process and timetable.

Question- Assumption is that NGOs come here but to what extent does BP go out to the NGOs? Answer: BP has and will continue to make every effort to meet with all interested parties either at meetings like this or one-on-one should this be required. We cannot force people to attend.

BP REMARKS & NEXT STEPS – STEVE JOHNSTON

Steve Johnston gave feedback about the output from the meeting and summarised some next steps for BP. This included the following points:

- This meeting has stimulated a great deal of extremely valuable input from participants and it has generated a lot more issues that will be considered.
- The purpose was to give you an update on our progress and gain your feedback and views as to the key issues and your opinions regarding the decommissioning in light of the progress made.
- It was valuable to have clarity around the Independent Review Group and a great presentation from Jan Bebbington on sustainable development. We hope that the presentation from the independent review group and the session on sustainable development added significantly to the meeting and understanding of the overall process.
- It seems that sustainable development, put in the correct context, can be a valuable addition to the decision making process.
- We will formulate thoughts and plans over the next few months and will have some preliminary proposals by the end of the summer which we would hope the get your views on.

20.4 Report of 6th May 2004 Stakeholder Meeting

BP STAKEHOLDER MEETING

N.W. HUTTON DECOMMISSIONING CONSULTATION

Ardoe House, Maryculter, Aberdeen

Thursday 6th May 2004

Produced by

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Context

The meeting was organised in order to:

- Present stakeholders with the main findings from the completed comparative assessment studies designed to identify the best solutions for the pipelines, drill cuttings pile and jacket footings.
- Present the Independent Review Group findings and answer questions about their work.
- Invite stakeholders to discuss the comparative assessment findings and give their interpretation of what they are indicating.
- Outline the timeline and process that will be used to reach a decision on best solutions.

Introducing ForthRoad

ForthRoad Limited has prepared this report under contract to BP. ForthRoad is a specialist organisational development consultancy experienced in organising and facilitating workshops bringing together people with similar interests to consider key issues and progress within that. Further information about ForthRoad is available through its web site: www.forthroad.com.

Summary

The meeting was attended by 19 stakeholders together with 5 members of the BP project team involved in the North West Hutton decommissioning project.

The initial part of the day comprised presentations from the North West Hutton Project team on the current situation together with a presentation from Professor John Shepherd on the findings of the Independent Review Group (IRG).

The afternoon was spent in syndicate sessions in order to obtain the views and opinions of the stakeholders. These were shared and debated. In conclusion, the attendees were thanked for their contribution. The outcomes and presentations from this meeting will be reported on the North West Hutton public website www.bp.com/genericarticle.do?categoryId=97&contentId=2015801

BP also made a commitment that stakeholders would be informed of future actions and key decisions.

Meeting detail

North West Hutton Status Update

Norrie Ramsay, Decommissioning Manager, outlined the progress on decommissioning North West Hutton in the last three years. The installation sits in 143 metres of water and equals the height of Canary Wharf. It was originally designed to handle 130,000 barrels a day; although peak production was only 80,000 barrels a day and the field was shut down in 2003, some 20 years after coming on stream.

In terms of the current decommissioning work, well abandonment is complete, with all conductors recovered and all wells plugged and the reservoir isolated. The topside pipe work and cabling between the modules is all separated. He reiterated that whatever is decided, North West Hutton will set a standard for anything else that will follow.

It is anticipated that by mid July 2004 the platform will be a normally unattended lighthouse mode installation (NUI) until its future is decided. He concluded by saying that decommissioning has taken 3 years and £50m to get this far.

This presentation can be viewed on the North West Hutton public website
www.bp.com/genericarticle.do?categoryId=97&contentId=2015801

There were no questions.

Comparative Assessment Process Update

Glyn Harris from the Decommissioning Project Team said that the Comparative Assessment had been carried out within the legislative framework. Five criteria have been used to assess impact – Safety, Societal, Environmental, Economic and Technical.

Three issues have been studied — the oil and gas pipelines, jacket and drill cuttings pile.

1. **Pipelines:** three options were considered - leave, trench and bury or remove. Remove was discussed in the context of cut and lift, and reverse installation methods.
2. **Removal of the jacket:** The jacket weighs 18,000 tonnes. The three options considered were full removal, cut at sea bed level (top of cuttings pile) , cut at top of footings.
3. **Drill Cuttings:** The broad options under consideration were – leave *in-situ*, excavate, cover and remove.

There was only one question:

"When cutting at the top of the footings, how many metres are you looking above sea bed?" The answer was 30/40 metres.

This presentation can be viewed on the website at
www.bp.com/genericarticle.do?categoryId=97&contentId=2015801

Independent Review Group Findings

Professor John Shepherd led this presentation. Copies of the Independent Review Group Report (IRG) were available at the meeting. This can also be viewed on the North West Hutton public website.

He made specific allusion to Annex 4 – a summary of IRG comments on the Comparative Assessment Studies. He said that considerable detail was available behind the specific comments and could be viewed by contacting BP.

Professor Shepherd then continued to outline the composition of the IRG. He said that they were:

- All professionals whose expertise covered the fields of oceanography, geo technical, hydrology, engineering and marine geo chemistry.
- All academics. No one was employed in Industry although some occasionally carried out consultancy services.
- All paid by BP in the IRG as consultants.
- All retained their independence from BP. This was achieved by the fact that they were academics and also that they had explicitly retained the right to publish their own comments on the IRG findings, should they disagree with BP.

The purpose of the IRG was seen as a quality control mechanism. The Group has examined and commented on all reports and assessments without fear or favour. This process has been derived from the Brent Spar learning highlighting the importance of an independent peer review to ensure public confidence on the conclusions reached.

The process has been to take reports as submitted, to comment on them and then return to the authors for a response on their findings. During the course of the process the IRG has met seven times and been involved in a number of teleconferences and has reviewed around fifty (50) reports. This has involved one hundred and twenty (120) man days of work including some revisions and reviews with BP. Not all the IRG members read all the reports. However at least two members reviewed each one. They would then synthesise the reports and distribute to the rest of the Group. They were all discussed in plenary sessions and consensus was reached on each.

The IRG has had demonstrable influence on the review process. A number of pieces of work have been undertaken that would not otherwise have been carried out. For instance, there was concern that BP had not considered studying the possibility of cutting the footings immediately above the cuttings pile. It was felt that it might be technically possible and have some benefits. A number of additional studies were therefore commissioned by BP to look at the practicality of this extra option.

Another example of the IRG influence was in the cuttings pile modelling. Originally the studies ran the Joint Industry Project (JIP) model. This presented a central case with no indication on the range of uncertainty of the results. The IRG wanted to quantify the range of uncertainties in these assessments – particularly relating to the length of time the pile would persist if left undisturbed. A revised study was subsequently commissioned with key parameters agreed.

Overall, the IRG has been satisfied with BP and the responses of the contractors who carried out the studies There have been no stand offs. In conclusion, the IRG believes the final study is free of significant errors or misrepresentations. It believes the range of areas covered is fine, the scope of the studies is adequate, that the job has been done sufficiently well to be fit for purpose.

The IRG has some advice for BP and others:

- Potential rate of recovery and recolonisation of the cuttings pile should not be overstated.
- Levels of confidence in qualitative predictions of the outcomes should not be over stated.
- The IRG see no reason why the cuttings pile should be a major long term threat to the marine environment. Small quantities of Anoxic sediments are not uncommon in marine environments.

Professor Shepherd concluded by saying that it must be recognised that selecting the final option has to be the combined responsibility of BP and the Regulator.

There were a number of questions:

– Q: "Has this group done a review of similar activities that have taken place before or currently?"
– A: "All but one of the Group were involved in reviewing the studies carried out for the UKOOA drill cuttings JIP Programme. Several of us have provided decommissioning advice on projects such as the Maureen report submitted to DTI".

– Q: "Have you considered the environmental impact of removing drill cuttings?"
– A: "The result of removal operations would be to create a semi natural scar on the seabed."

– Q: "It was commented that the European involvement in the IRG was a good thing".

– Q "Have you reviewed the possibility of changing hydrodynamics affecting cutting pile over a period of time?"
– A: "Main hydrodynamics are tidal and this is the biggest factor. The Env 04 study covers hydrodynamics although it is not a detailed study as it was not thought it would be a major factor. The biggest environmental change would be a new Ice Age!"

– Q "Can the Review Group be sure that all other engineering issues have been considered?"
– A: "Our function is to review not do studies. We have two (2) engineers and a further member with an Engineering background on the IRG who are satisfied that all aspects have been covered. We did far more work on engineering than anticipated up to TEC 29 – more than any other area. In fact, we had several closed sessions together with some quite active, lively, face to face sessions with BP and the Contractors."

The presentation of the IRG concluded here. The slides for this presentation can be viewed on the North West Hutton public website on bp.com

Syndicate Context

Norrie Ramsay kicked off this session and was followed by Glyn Harris and Katie Denny who summarised the data which the studies had developed.

Norrie Ramsey repeated that the object of the meeting was to get everyone's input – in effect "to help BP choose between oranges and apples. The delegates now know exactly where BP has got to on the North West Hutton project. Around £50 million has been spent by BP so far. Everyone has a view on this project; inevitably there will be diversity of opinion.

North West Hutton is the first decommissioning project of this magnitude and complexity so far in the North Sea. So, BP cannot look to lessons learned. He said the meeting and BP need to look at offshore and onshore aspects of the impact of their decisions fully. This is an International issue. Some of the contractors with critical skills and experience in this area are based in Norway; some are Dutch, Italian, and American and so on.

He stated that in being first, the Project is creating a legacy for the industry. He extolled the group to look at the big picture and the sustainability issues and not to just look at this project in isolation. He emphasized its complexity and acknowledged that these issues were emotive but insisted that this was the delegates' opportunity to influence the outcome.

Norrie went on to emphasize that this was not academic exercise. The decision affects real lives. It covers big issues such as the potential loss of life. There are a number of safety issues which BP owns and that means that Norrie Ramsay as Project Manager is personally accountable. He emphasized just how seriously BP takes the Safety issue. He then explained that Glyn and Katie would run through the data in each of the areas. He emphasized that there is a lot of data in the slides but the importance of the process was that if there was any lack of clarity it should be tested. Finally, he stated that the recommendations from the meeting would be fed back into the process.

Glyn Harris then presented three (3) slides of data– 2 on pipelines, 1 on the jacket footings. Katie Denny then presented the slide on the drill cuttings.

The five impact criteria remained common throughout - Safety, Environmental, Societal, Economical, and Technical.

Some questions and comments on the data ensued:

– Q: How did the safety risk of pipeline removal equate to other similar risks?
– A: A 2.1% risk for recovery is similar to the risks involved in laying a new pipeline.

– Q: "Why have you not accounted for risk to fishermen?
– A: All safety numbers are around doing the work, so no assessment has been made in this part of the comparative assessment studies of the impact on other sea users. This is included under societal impact Because man hours expended fishing over the whole North Sea are significant, the impact would not be high in this context. These figures are for project work.

– Q: "What I find difficult is to weight the importance of these drivers? Is 2% acceptable or not acceptable"
– A: Comparing safety figures must be done with care to ensure a like with like comparison. One useful comparison is that if we annualised the decommissioning activities, because the Project is shorter than one year continuous working, and compared with North West Hutton Operational risk for a year then the project is 5 times more risky.
– Comment I would be cautious about referring to minor snagging risk (from pipelines). The risk becomes higher as the pipelines disintegrate.
– A: We agree – 'minor' should be removed from this description.

– Q: " What is the snagging risk if no action is taken to trench the pipelines?
– A: The gas line is trenched but not fully covered The oil line sits on the seabed and could present a snagging risk if left *in-situ* as the condition of the line and concrete coating deteriorate over time.

– Q: "How actively has BP reviewed innovative solutions around the recovery of drill cuttings?
– A: BP has taken an active part in the UKOOA joint industry project investigating solutions for drill cuttings. The meeting was also provided with an explanation of waste hierarchy policy within BP.

– Q: "Is landfill cost more expensive than re-use?
– A: BP has a duty of care for the whole process to the very last tonne. If additional landfill capacity had to be created this would have a variety of impacts.

– Q: "When you have looked at societal and economical impacts have you looked at time?
– A: Yes, where appropriate. But some impacts are only measured over the timespan of the project.

– Q "Perpetual liability – do the economics take this into account?
– A: No, the financial impact is small for the most part – eg monitoring costs.
– Comment: You should do more investigation into societal impacts such as the impact on fishing over time.

– Q: What about the impact on Employment – what timescale is that over?
– A: Duration of the project

– Q: Do the economics take into account monitoring? As comparative timescales they seem to be different.
– A: That is true. Clearly with removal, the time scales are short. With the pipelines, for example, leaving them in place has an ongoing monitoring cost but this would be relatively small and could be done by ROV. Providing everything is fine the inspection intervals can be reduced. For the most part longer term costs are less significant due to the effects of Discounted Cash Flow.

– Q: Issues like economic, societal, how are you taking the conclusions from these factors? Are you not weighting them?
– A: Environmental and societal issues can be like apples and oranges. This is one of the reasons why we are consulting with you. We are not using a black box approach.

– Q: Are costs not a differentiator?
– A: In the case of the pipelines no, because the costs are relatively small. As we move onto Topsides and the Cuttings Pile these become more of a consideration.

– Q: If you take this project and multiply over all the other platforms decommissioning how much will this impact society as the high cost of decommissioning diverts funds from future investment?
– A: For BP, with a large portfolio and major investment track record this is not a major issue but it may be a factor for smaller companies.

– Q: Tax impact under "society" what does that mean?
– A: Some of the tax paid on this field can be recovered by offsetting the costs at the time of decommissioning.

– Q: What do you mean by a 50% risk of not being able to successfully remove the jacket footings?
– A: This is an independent assessment of the risk of successfully completing the task of removing the footings, based on an analysis of the technical challenge and the uncertainties concerning issues such as the damaged members in the lower part of the jacket, excessive grout around one of the legs etc.

Drill cuttings pile comparative assessment.

Katie Denny then outlined the data for Drill Cutting comparative assessment.

Someone from the floor queried her use of the expression that this has "Never been done before". It was their view this should not be a get out clause. It was clarified that this was in the context of an inability to benchmark which makes figures less certain.

Other points raised included:

– Disposal of drill cuttings in existing wells may be illegal but should not be a show stopper – ie BP should still study it as an option.

– Dispersal of drill cutting was surely one area where a precedent has been set? It was agreed that this had been done before using the 'excavation' method.

Finally, in this session the point was made that the safety of other sea users should be taken into greater account. That it would in BP's interests to capture these risks.

Syndicate Session

Participants were asked to discuss any issues arising and address the following questions at their respective tables:

- What is your reaction to the Data?
- What possibilities do you see for resolving some of these dilemmas.
- What would your advice to BP be?
- Are there other issues you wish to raise?

Table 1

Overall the reaction to the data was that it was good news. The Issues that the Table 1 saw were

– Risk & risk transfer. Particularly in the context of other sea users.
– Boundary of analysis – what comes in /what comes out?
– Show stoppers - nothing to stop BP setting up cross industry groups to share knowledge.

Dilemmas? – As a 'trench & bury' team, they felt the pipelines solution was clear. However for the drill cuttings pile and particularly the jacket footings, they saw a big dilemma was in the precedent being set for the industry, the impact on other sea users, the changing legal and political environment. In terms of how the 5 criteria would be used as filters, it was clear how the safety criterion would be used but less clear for the others.

Advice for BP? To do what they can now but not closing the door to future technical developments. To endeavour to use the project to advance industry knowledge. Finally, to make the solution open ended. Then, technology can, at some future date, enable a better solution than currently possible.

Table 2

The group agreed that the data was sufficient for BP to make a decision. They felt that the devil would be in the detail and would like greater access to it. The use of IRG was to be commended. They believed that the approach overall was "as good as it can get".

The group suggested that there was not enough data on onshore treatment. They also believed that the actual technological or scientific information for removal could not be properly analysed with the data available at the meeting.

It was their recommendation to BP that it was important to get closer to the fishermen quickly. It was also felt that there could be lessons learned from the Maureen experience.

This group also supported the 'trench and bury' option and felt that the drill cuttings should be left in place. However they intimated that the eventual outcome would be a political decision.

The Table had no discussion on proposals for the jacket.

Someone from the Floor asked what sort of lessons could be learned from Maureen as the facilities are so different?

The answer was that the Maureen decommissioning ran over a few years and generated very little public interest. It was felt that media management and communications was paramount. If the case for North West Hutton was not seen to be robust politically and environmentally, it could founder. BP has got to be mindful of the wider context.

Table 3

The Group believed the general approach is valid and that the Studies were comprehensive and competent. They saw the setting up and involvement of IRG was a positive development that helped to make the position understandable.

They acknowledged that uncertainties remain. There was a debate about what value there was to be had in refining them further.

As regards the Comparative Assessment Process, they believed the drivers (safety, societal, environmental, cost, and technical) were not all of the same nature. Safety for example if rigidly applied would rule out the total removal and partial footings removal options.

They continued that technical and safety issues combine to present some stretch issues. They are not drivers for choice. "You can do anything you can make anything, as long as you spend enough money". Ultimately, the major drivers in decision making will be cost and societal perception. The group counselled that Brent Spar must be remembered - if something goes wrong it will be difficult to get back on track.

The Group considered that both the oil and gas lines should be buried. They believed that both of these pipelines could be left in place as long as sea bed is proven to be stable and fishing risks are minimised.

The Group also suggested that there was a certain artificiality in the situation. This was because regulation is forcing BP to look at this project in this time frame but not adequately allowing for solutions at a later date.

The Group said that partial removal was a high risk, time-limited derogation was a possible approach. They recommended that BP remove what can be removed currently – ie down to the footings under OSPAR derogation but also make a commitment to take account of future developments in technology.

This view made the choice about Drill Cuttings a "no-brainer" as a decision first needs to be made about footings.

Finally, they recommended that creating a good societal case was paramount. The key thrust should be that as much as possible is being done at the moment and this will get through OSPAR. BP should also be committed to doing something in future.

Closing Remarks

Delegates were asked whether any of them felt that they would like to ask any additional questions, whether anything had been left unsaid.

Someone asked if anything was said about decommissioning when the platforms were originally put in? There has been discussion between the government of the day and some industry areas where assurances had been given around total removal. There was a general floor discussion around the situation that there are no specific licence issues as long as you complied with the law of the day. When North West Hutton was agreed it was as per the 1958 Geneva Convention - oil companies have to comply with the law of the day.

Norrie Ramsay said that the input from their stakeholders was vital for BP. In his view, the meeting objectives had been achieved. With regard to the issues raised around assessing the impact on other sea users and their concerns, Norrie stated that this had indeed been addressed and that perhaps in this session this had been understated however he agreed to take this away as an action for BP. In addition, he said he was cognisant that all societal views were still not represented and they all must be mindful of that.

He concluded that he had taken away three main things from the day:

- The importance of gaining a consensus of views on right decision but building this into context and long term legacy.
- The Safety of other sea users and the need to test with fishing organisations that BP are getting it right.
- That he had heard the message from the attendees that cost was still a consideration but that societal impact must be properly assessed.

Finally, he said that the Team will commit to getting back to the delegates on BP's recommendations when these are finalised and that a draft report of today's meetings would be sent to all delegates for their approval before being published on BP's website. He also invited any of the delegates to contact the team if they wanted clarification on any of the material raised and thanked them all for their contribution and their time.

Appendix

Attendees

Paul Abernethy – Scottish Enterprise
Marcus Armes – University of East Anglia
Richard Austin - IMCA
Jan Bebbington – University of Aberdeen
Dave Bevan – National Federation of Fishermen's Organisations
Eric Breuer – Scottish Association for Marine Science
Zoe Crutchfield – JNCC
Michael Curtis – SEPA
Phil Dyer – Shell
Paul Dymond – UKOOA
Michael Forman – Fishermen's Association Limited
Mark Gordon – Aberdeen City Council
Ray Johnstone – FRS Marine Lab
Alasdair McIntyre – Atlantic Frontier Environmental Forum
Donald Mc Kernie – Highlands & Islands Enterprise
John Shepherd – Independent Review Group
Michael Sutherland – Scottish Fishermen's federation
John Watt – Scottish Fishermen's Federation
Graham White - DTI

BP North West Hutton Decommissioning Team Attendees

Katie Denny
Richard Grant
Glyn Harris
Howard Keith
Norrie Ramsay

Forth Road Facilitators

Geoff Anderson
Kanthi Ford

20.5 List of Comparative Assessment Studies

Study Title	*Contractor*	*Date*	*Document No.*
SAFETY			
SAF01A - North West Hutton Decommissioning Hazard Identification Review Assessment	Hereema Marine Contractors Nederland B.V.	2nd April 2003	
SAF01B - Quantitative Risk Assessment of Removal of the North West Hutton Jacket - HMC's Procedure	Risk Support Risk Management Strategies	15th July 2003	R205
SAF02A -Quantitative Risk Assessment of the Removal of the North West Hutton Jacket - Saipem's Procedures	Risk Support Risk Management Strategies	17th July 2003	R211
SAF02C - Quantitative Risk Assessment of the Removal of the North West Hutton Jacket - BP Model	Risk Support Risk Management Strategies	23rd July 2003	R-BP Case
SAF03 & 04 - Quantitative Risk Assessment of Options for Recovering Drill Cuttings	Risk Support Risk Management Strategies	18th July 2003	R213
SAF05 - North West Hutton Pipelines Decommissioning Study HAZID	Andrew Palmer & Associates	14th August 2003	4760A-RPT-002
SAF06 - North West Hutton Pipelines Decommissioning Study HAZID	Andrew Palmer & Associates	14th August 2003	4760A-RPT-001
SAF07A - Independent Review of Jacket Removal HAZIDs and QRAs	Det Norske Veritas (DNV)	24th September 2003	
SAF07B - Independent Review of cuttings HAZIDa and QRAs	Det Norske Veritas (DNV)	25th September 2003	
SOCIETAL			
SOC01 - BP North West Hutton Decommissioning Fisheries Overview	SFF Services Ltd.	2003	
SOC02 - North West Hutton Decommissioning Economic Impact Report	DTZ Pieda Consulting	2003	

Study Title	Contractor	Date	Document No.
ENVIRONMENTAL			
ENV01 - Environmental Impact Statement in support of the Decommissioning of the North West Hutton facilities	BMT Cordah Limited	June 2004	BPX067/ES/2003
ENV02 - Energy and Emissions Report for the Decommissioning of North West Hutton	BMT Cordah Limited	2003	
ENV03 - Evaluation of the distribution of the cold-water coral *Lophelia pertusa* on the North West Hutton Platform	BMT Cordah Limited	11th March 2003	BPX54/NWH/05
ENV04 - North West Hutton Cuttings Pile Modeling	BMT Cordah Limited	31st March 2003	280000/03
ENV05 - Analysis of samples collected from cuttings pile at North West Hutton	BMT Cordah Limited	30th June 2004	BPX45/NWH/04
ENV06 - Pipeline Cleanliness Assessment / Assurance	J.P. Kenny	11th November 2003	02-2416-01-0-3-002
ENV08 – Long-term Trends in Seabed Disturbance around the North West Hutton platform	BMT Cordah Limited	2004	BPX54/NWH/04
TECHNICAL			
TEC01 - Life Assessment of Jacket Footings	Corrpro Europe Limited	19th September 2003	
TEC02A - North West Hutton Substructure Decommissioning Comparative Assessment Detailed Removal Method	Hereema Marine contractors Nederland B.V.	24th June 2003	G1100-RP01
TEC02B & SAF01A - North West Hutton Decommissioning Study Year 2003 Refreshment Study Report	Saipem UK	2003	973000-NWH 2003-001
TEC03A - Inspection Report containing Information from Video Logs and Workscope	Subsea 7	14th January 2004	AB-R-RP-01208
TEC03B - Grout Densitometer Removal Proposal	Subsea 7	8th January 2004	AB-T-pp-00109

Study Title	*Contractor*	*Date*	*Document No.*
TEC04A - Independent Comparative Assessment of Partial Jacket Removal	Noble Denton Europe Ltd.	4th July 2003	A4113/NDE/MG B/1
TEC04B- Jacket Removal Study for Complete or Partial Removal	Global Maritime	2nd July 2003	GM-22875-0703-1408
TEC05 - Jacket Information Package	Aker Kvaerner	13th May 2003	8226-NWH-ST-004
TEC06 - Alternative Removal Methods	BP	June 2003	
TEC 07 - A Review of Jacket Footings Removal using Explosives	Explosive Engineering Associates	234r June 2003	
TEC09 - Study Sponsored by the Decommissioning Technology Forum Jacket Removal	Task Force Industry	July 2003	
TEC10 - North West Hutton Decommissioning Drill Cuttings Transfer Method Study	Scan Tech UK	21st May 2003	J-1090
TEC11 & 12 - Technical Review of the Options of Covering, Relocating, CAD, and Recovery of Onshore Treatment of the North West Hutton Drill Cuttings Pile.	Dredging Research Ltd.		
TEC13 - North West Hutton A Synopsis of Environmental Studies of the Cuttings Pile and surrounding Seabed	BMT Cordah Limited	24th May 2004	L3/AB/26(a)/T/O AM/30.4.02/A
TEC14 - 18 & ENV06 - Pipeline Decommissioning - Te chnical Summary Report	JP Kenny	21st November 2003	05-2416-01-G-3-011
TEC25 - Investigation of Jacket Lifting and Footings Options for North West Hutton Decommissioning	Altair Engineering	25th June 2003	BPABD-29-03-R-01
TEC26 - North West Hutton Drilling Template & Mud Line Brace Decommissioning - Drilling Template Removal & Brace Cutting Study Report	Technip-Coflexip	4th July 2003	
TEC27 - Jacket Damage Identification & Drill Cuttings Partial Removal Study	Aker Kvaerner	22nd December 2003	8226-NWH-ST-16

Study Title	*Contractor*	*Date*	*Document No.*
TEC28A - Removal of the North West Hutton Platform - Overview of the Subsea Operations Rev 1.0	Stolt Offshore	14th November 2003	MEC-066-040
TEC28B - North West Hutton Decommissioning Leg Cutting Review - Ja cket Leg Cutting Study	Technip-Coflexip	5th December 2003	
TEC 29 Removal of the North West Hutton Jacket - Quantitative Comparative Assessment	COWI	26th March 2004	P-058983-A-100
ECONOMIC			
ECO01, 04, 05 and 06 - North West Hutton Decommissioning Project Cost Estimate Summary	BP	14th January 2004	
ECO03 - Impact on Scrap Steel Market	BP	2003	
ECO05 - North West Hutton Pipelines Decommissioning Economics of Options	JP Kenny	2003	05-2416-01-P-3-009
ECO07 - North West Hutton Decommissioning Project Long Term Monitoring Requirements	BP	27th August 2003	

20.6 Report of the Independent Review Group (IRG)

NORTH WEST HUTTON DECOMMISSIONING PROJECT

REPORT OF THE

INDEPENDENT REVIEW GROUP (IRG)

26 April 2004

NORTH WEST HUTTON DECOMMISSIONING PROJECT

INDEPENDENT REVIEW GROUP (IRG)

FINAL REPORT

CONTENTS

Introduction

In January 2003 Professor John Shepherd FRS was invited by BP to establish an Independent Review Group (IRG) of scientists and engineers to examine and comment, in an independent and objective way, on an extensive series of comparative assessment studies relating to the development of proposals for the decommissioning of the North West Hutton platform in the North Sea. The studies were grouped into four themes: technical, environmental, socio-economic and safety. There were six IRG Members, including the Chairman Professor Shepherd, together with a Technical Secretary. The IRG first met in March 2003 and completed its work in March 2004. The IRG task involved the study and critique of some 40 major reports requiring in total an input of about 120 days effort. This report presents the IRG final summary comments on all the Comparative Assessment studies, and an overview and conclusions of the procedure.

Membership

Chairman	Prof. John Shepherd, MA, PhD, CMath, FIMA, FRS
Project Co-ordinator	Prof. W.B Wilkinson, BScEng, BScGeol, PhD, FICE, FCIWEM, FGS, CEng, CGeol, F Russ Acad Nat Sci
Members	Research Scientist Torgeir Bakke, Cand.real. (MSc equiv.) Marine Biology
	Prof. Michael Cowling, BEng, PhD, CEng, CMarSci, FIMarEST, FSUT, MIM
	Prof. William Dover, FIMechE, CEng, FINDT
	Prof. Dr. Jürgen Rullkötter, Dipl.-Chem., Dr. rer. nat. habil., AAPG, DGMK, DGMS, EAOG, GDCh, GS
Secretary	Mr Richard Clements CEng, MIMechE, MIMarEST

Short biographies of the members of the Independent Review Group are given in Annex 1.

Terms of Reference

The terms of reference of the IRG are given in full in Annex 2.

Activities of the Independent Review Group

The IRG met on 8 occasions, on the following dates: 13 March 2003, 6th June 2003, 3rd - 4th July 2003, 29th August 2003, 1st October 2003, 28th October 2003, 10th December 2003, and 29th January 2004. Two teleconferences were held on 25th March 2003 and 6th June 2003. A brief report of the significant points that arose at each meeting is given in Annex 3.

In addition, a member of the IRG attended a stakeholder consultation meeting on 12th June 2003.

In accordance with its terms of reference, the work undertaken by the IRG was (inter alia) to

- read and review the reports of all relevant comparative assessment study work (including contractor scopes of work) commissioned for or produced by BP.
- provide views/guidance on the above in respect of the scope, clarity, completeness, methodology, relevance and objectivity of conclusions.
- advise on any further research or actions to address identified gaps that would otherwise prevent an informed decision.
- make recommendations for additional work as necessary which should be practicable and achievable within the timeframe for the decommissioning programme submission.
- be satisfied that all relevant stakeholder comments have been addressed within the scope of each study where practicable to do so.

In particular

- Where the IRG identified short-comings in the presentation and/or the content of the reports of the studies, in its preliminary comments, BP responded by calling on the contractor to redraft the report or undertake additional work as necessary. In most cases the contractors' revisions of the reports constituted an adequate response to the comments made and a single revision cycle was sufficient.
- The IRG identified one potential decommissioning option which it considered had not been examined in sufficient depth i.e. removing the structure down to the cuttings pile level. BP responded by carrying out 4 additional studies related to this option (TEC27, TEC28A&B and TEC29) to look at cutting the jacket structure, particularly the bottle legs at or just above the surface of the drill cuttings pile.
- The IRG also identified several other areas where additional work was needed (eg the cuttings pile modelling study). BP responded positively to these recommendations and subsequently commissioned the additional work required.
- In some cases the impact of BP generic policies required clarification (eg use of explosives, divers, cutting tools, simulation training etc). BP has accepted the need to explore these further once the decommissioning option has been recommended and approved by DTI. For each of the Comparative Assessment studies a brief summary of the IRG comments, the BP responses to these, and the IRG's view on those responses is given in Annex 4.

The IRG functioned as an independent entity, working primarily with data and information supplied by BP project staff. Most but not all of its meetings had BP staff in attendance, which greatly facilitated the execution of the work and prevented unproductive misunderstandings. The IRG discussions were not inhibited in any way, nor were the decisions reached influenced by the presence of BP staff. In addition, many issues were debated and resolved wholly independently by IRG members communicating by telephone and by email.

Overall Evaluation and Conclusions/Recommendations

The Independent Review Group confirms that:

- it has read and reviewed all the reports of the comparative assessment studies.
- the contractors and authors have responded positively to the comments and criticisms made of the work undertaken and the reports thereof.

- additional information requested by the Independent Review Group was made readily available
- the final reports of the comparative assessment studies are, so far as we are aware, free of serious errors, significant omissions or mis-representations.

It should be noted that:

- The Independent Review Group provided peer review of the quality of the studies carried out. The final responsibility for the contents of the reports however rests with their authors and BP, and the IRG does not necessarily support or endorse every statement in the individual study reports.
- While the IRG reviewed the specification of the work for the various studies, the selection of contractors to undertake the work lay with BP. The IRG had no remit for this.

The IRG *will not comment* on the final decommissioning option selected. Its role is to ensure that an appropriate range of options has been examined in sufficient depth, so that the information available is adequate for a rational decision to be reached by BP.

The Independent Review Group considers that

- The range of decommissioning options examined was satisfactory, covering all the relevant options identified by the UKOOA Drill Cuttings Initiative JIP (Note that this JIP only covered the technical & environmental issues relating to drill cuttings, and not other aspects of the decommissioning).
- The scope of the studies undertaken was sufficiently comprehensive, their quality was satisfactory, and they provide an adequate basis for the comparative assessment process.
- The grouping of the studies into technical, environmental, socio-economic and safety themes was generally useful. However, this did in some cases lead to a degree of overlap, and in others to a lack of continuity (e.g. consistency of the options for removing the structures and for dealing with the cuttings piles). So far as we are aware, these difficulties have been overcome.
- BP has consistently responded in a timely and positive way to the IRG comments & suggestions made by the IRG, including on occasion participation in extended full and frank discussions of the issues raised.
- In some cases, minor misunderstandings arose about the scope of the studies and/or the technical issues involved, and the IRG made suggestions which were unrealistic or infeasible within the CA boundaries [eg collecting more geotechnical information in the short term]. So far as we are aware, these difficulties have been resolved.
- The IRG was particularly concerned that clear policies for longer-term monitoring of the impacts of the option selected, provision for the analysis of the results of such monitoring, and an operational plan for responding appropriately to such results, should all be in place, and that liabilities for the costs of such longer-term commitments should be clear. The principles have subsequently been established and BP has confirmed that these will be implemented as the work progresses.
- The IRG considers that interactions with stakeholders and representation of their views are very important, and notes that because of the postponement of one stakeholder consultation meeting, it was not possible for the IRG to achieve the level of interaction that would have been desirable. However, IRG members were able to view recorded stakeholder comments and independent reports of stakeholder meetings published on the BP website.

Finally, the IRG advises that

- The potential rates of recovery and recolonisation of any cuttings piles which may be left in place should not be overstated. The recovery processes will be confined to a thin surface layer and to the periphery of the pile for a very long time, and the areas affected, which are quite small, should realistically be accepted as being environmentally damaged for the foreseeable future.
- Neither the levels of confidence achievable in quantitative predictions of the fate of the seabed environment after decommissioning, nor the extent of difficulties in dealing with cuttings which may be removed to shore, should be overstated.
- There is no reason to regard cuttings piles as a major long-term threat to the environment. They have caused significant damage to small areas of the seabed, which will persist with only slow amelioration if they are not covered or removed.
- Technically or environmentally attractive decommissioning options may involve activities (e.g. the use of divers) which are discouraged by company or industry policies. Such options should not automatically be disallowed, but retained for consideration with the appropriate risks identified.
- The investigations carried out as part of the Comparative Assessment have clarified many technical issues, and allowed useful quantitative assessments of the most important risk factors to be made. However the results are in many cases not very precise, and the credibility of the results will be enhanced if the remaining uncertainties are acknowledged and quantified so far as possible.

IRG summary comments on the final reports of the individual studies are given in Annex 4. The IRG's detailed comments and the BP responses to these comments are held by BP with the individual reports.

Professor J.G. Shepherd FRS

Chair of Independent Review Group

26 April 2004

Annex 1 – Members' Biographies

Professor John Shepherd, MA, PhD, CMath, FIMA, FRS

Professor John Shepherd MA PhD CMath FIMA FRS is Director of the Earth System Modelling Initiative and Professor of Marine Sciences in the School of Ocean and Earth Science, Southampton Oceanography Centre, University of Southampton, UK. He is a physicist by training, and has worked on the transport of pollutants in the atmospheric boundary layer, the dispersion of tracers in the deep ocean, the assessment & control of radioactive waste disposal in the sea, on the assessment and management of marine fish stocks, and most recently on Earth System Modelling. His current research interests include the natural variability of the climate system on long time-scales, and the development of intermediate complexity models of the Earth climate system for the interpretation of the palaeo-climate record. He graduated (first degree in 1967 and PhD in 1971) from the University of Cambridge. From 1989-1994 he was Deputy Director of the MAFF Fisheries Laboratory at Lowestoft, and the principal scientific adviser to the UK government on fisheries management. From 1994-1999 he was the first Director of the new Southampton Oceanography Centre. He has extensive experience of international scientific assessments and advice in the controversial areas of fisheries management and radioactive waste disposal as well as climate change, and has taken a particular interest in the interaction between science, economics, and public policy. He is a Regional Director of the new Tyndall Centre for Climate Change Research, and a Fellow of the Institute of Mathematics and its Applications. He was elected a Fellow of the Royal Society in 1999.

Research Scientist Torgeir Bakke, Cand.real. (MSc equiv.) Marine Biology

Mr Bakke has been a research scientist at the Department of Marine Ecology at the Norwegian Institute for Water Research, NIVA since 1980. During this period he has also held positions as Head of the Marine Department (1991 - 1995), and Research Manager for Industry and for Oil and Gas at NIVA (1985 - 1998). His main field of research since 1978 has been fate and effects of oil hydrocarbons on marine organisms and systems. Since 1982 he has conducted research on the environmental impact of various types of drill cuttings, including the development of simulated seabed tests on the degradation and effects of oil based and synthetic drill cuttings by use of experimental ecosystems. Since 1987 he has also coordinated a national expert group established to evaluate the annual environmental monitoring surveys conducted around Norwegian oil and gas fields, and to produce annual status reports of the Norwegian shelf for the authorities.

Professor Michael Cowling, B Eng, PhD, CEng, CMarSci, FIMarEST, FSUT, MIM

Professor Cowling has been a Professor at the University of Glasgow since 1990, and has been Director (formerly Centre Coordinator) of the Glasgow Centre for Marine Technology since 1984. In 2002 Professor Cowling was appointed as a Vice-president of the Institute of Marine Engineering Science and Technology (IMarEST).

Professor Cowling is currently an Independent member of the OST Inter-Agency Committee for Marine Science and Technology (IACMST) and chairs its Marine Environmental Data Action Group (MEDAG). Professor Cowling is also a member of the UK Marine Foresight Panel and was a member of the NERC/ DTI Scientific Group on Decommissioning (Brent Spar, phase 2).

Professor Cowling has conducted public and industry-funded research on stress analysis, fatigue and fracture mechanics applied to welded joints, cast steel nodes, polymer composite secondary structure and adhesively-bonded pipework for the Offshore Industry. He was instrumental in developing a reliability-based approach to failure assessment and was Programme Champion for a multi-phase EPSRC National Programme on Defect Assessment in Offshore structures. More recently his research has been at the interface between engineering and biology and he has led three large EU projects on biofouling reduction on underwater instrumentation, which have included detailed studies of environmental impact and risk of various approaches. Other interests increasingly involve marine data and information, and the mapping of it.

Professor Cowling has been author, co-author, and editor of some 100+ papers, books, etc.

Professor William Dover, FIMechE, CEng, FINDT

Professor Dover has been a Professor at University College London since 1983, Shell Professor of Mechanical Engineering since 1987, Centre Coordinator of the London Centre for Marine Technology, and Head of the UCL NDE Centre.

Professor Dover has conducted extensive research on stress analysis, fatigue, fracture mechanics and NDT applied to welded joints, tubular welded connections, and drillstrings for the Offshore Industry, MOD (N), Aerospace and Nuclear Industry. He has been a member of various Government committees, acted as a Consultant for The World Bank and been Programme Champion for a series of EPSRC National Programmes on Fatigue of Offshore structures.

Professor Dover has been Author, co-author, and editor of some 200 papers, books etc.

Professor Jürgen Rullkötter, Dipl.-Chem., Dr. rer. nat. habil., AAPG, DGMK, DGMS, EAOG, GDCh, GS

Professor Rullkötter is a professor of organic geochemistry at the University of Oldenburg, Germany. He received his PhD degree at the University of Cologne in 1974. With his experience in analytical and natural product chemistry he joined the Institute of Petroleum and Organic Geochemistry at the Research Centre Jülich (Germany) where he stayed for 17 years to investigate the bulk and molecular composition of fossil organic matter and petroleum. This research largely contributed to the understanding of the chemical processes and quantitative aspects of petroleum formation. Biological marker parameters developed during that time are now widely used in the petroleum industry for oil/oil and oil/source rock correlation, for maturity assessment of organic matter and crude oils, and for studying bacterial degradation of oils in reservoirs.

With the development of environmental concerns, Professor Rullkötter extended his research to the microbial transformation of petroleum compounds in natural oil seeps and anthropogenic oil spills and, as a side aspect, to the investigation of asphalts used by the ancient Egyptians for mummification. After he joined the University of Oldenburg in 1992, much of his research was devoted to paleoenvironmental and paleoclimatic reconstructions based on the organic matter in marine sediments from the continental margins of the world's oceans and to early diagenetic processes in coastal sediments of Holocene and Recent age. He continued to work, however, on several aspects of petroleum in the environment and, among others, served on the NERC Committee on Decommissioning dealing with the scientific aspects of deep sea disposal of offshore structures, with the Brent Spar as an example of the environmental aspects of dismantling and using its parts for a harbour extension.

Professor Brian Wilkinson BScEng, BScGeol, PhD, FICE, FCIWEM, FGS, C Eng, C Geol, F Russ Acad.Nat.Sci.

Professor Wilkinson is an environmental engineer, geologist and surface and ground water hydrologist with 40 years experience. He is currently Visiting Professor at the Universities of Reading and Newcastle upon Tyne and an independent consultant. His PhD from University of Manchester[1968] was in Soil Mechanics. He has worked with consulting engineers on the design and construction of large dams and water supply projects and was a Senior Engineer at the Water Resources Board [1969 to 1974]. As Head of the Water Resources Division of the UK Water Research Centre he led a wide range of research projects. From 1984 to 1989 he was Professor of Civil Engineering at Cranfield University. In 1989 he was appointed Director of the Institute of Hydrology and in 1995, became the first Director of the Centre for Ecology and Hydrology with responsibility for a £30m pa research budget. During this time he was UK Government Hydrological Adviser to the World Meteorological Organisation Commission for Hydrology and the UK Science Representative and Leader of the UK Science Delegation to the 1997 UNESCO General Conference. He was a founder member of the European Water Research Directors' group EURAQUA. Recently he has been involved in assessment and monitoring of the £1bn EC environmental research programme and has led a UNESCO International Review Panel examining the environmental impacts of proposed uranium mining in a major World Heritage site in Australia. He has published some 80 papers and edited several books.

Mr Richard Clements,
BSc, CEng, MIMechE, MIMarEST

Mr Clements is a consultant engineer, currently involved in the administration of UK and European research projects and the dissemination of their results. His early career was concerned with the marine application of gas turbines, mainly in warships for the Royal Navy, the Royal Netherlands Navy and the Imperial Iranian Navy. He moved to the Research and Development department of Shell International Marine and was involved in exploring the possibilities of applying nuclear power and modifying the steam cycle for tankers' propulsion plant following the rise in fuel prices in 1973. He was also involved in a variety of investigations, notably with ships' steering gear and anchoring equipment, to improve operations and avoid failures. During this time, he was seconded to Shell Research to undertake a project to develop sub-sea valves and avoid problems arising from corrosion. Later, he was seconded to the Marine Technology Directorate where he was responsible for the administration of UK research funds for both the marine and the offshore oil industry.

Mr Clements has acted as Secretary for the Scientific Group on Decommissioning, appointed by NERC to advise the Minister for Science on proposals for the disposal of the Brent Spar made by Shell Expro. Subsequently, he was the Secretary for a Scientific Review Group established to act as an independent scientific and technical accreditation and advisory group for the UKOOA Drill Cuttings Initiative

NORTH WEST HUTTON DECOMMISSIONING PROJECT INDEPENDENT STUDY REVIEW GROUP

Annex 2 - Terms of Reference

The Independent Study Review Group will:

- remain in operation until 17th October 2003. If any further service is required this will form a separate service order [Note: at the request of BP the closing date was extended to 31st March 2004].
- address comparative study issues relating to decommissioning options for the pipelines, jacket footings and drill cuttings.
- read and review existing project documentation to ensure an understanding of the relevant issues for the comparative assessment process.
- read and review all relevant comparative assessment study work (including contractor scopes of work) commissioned for or produced by BP.
- provide views/guidance on the above in respect of the scope, clarity, completeness, methodology, relevance and objectivity of conclusions.
- advise on any further research or actions to address identified gaps that would otherwise prevent an informed decision.
- make recommendations for additional work as necessary which should be practicable and achievable within the timeframe for the decommissioning programme submission.
- be satisfied that all relevant stakeholder comments have been addressed within the scope of each study where practicable to do so.
- provide written reports with commentary on each study for use on BP's public website,
- provide a statement for public use by BP at the conclusion of the comparative assessment process on the group's findings for individual studies and on the process which BP will employ to draw together a holistic view of the CA work.
- normally provide any input within 10 working days of a request being made by BP.

The Independent Study Review Group, or any member thereof, will have the right to publish the findings of their scientific review including any objection after notifying BP with sufficient notice to enable BP to comment and correct any misunderstandings.

Membership and meetings

- The Group will operate under the chairmanship of Professor John Shepherd and will comprise 4/5 members plus a secretary, calling in any additional expertise if necessary for specific issues.
- Frequency of group meetings will depend on the CA study schedule but allowance for 4 meetings of two days each has been made.
- At least one group member will attend each stakeholder consultation general meeting as an independent observer / expert.
- BP will provide a project manager as main point of contact.

Annex 3 - Activities of The Independent Review Group

1st Meeting - 13 March 2003

The purpose of this meeting was to:

- start the process of independent assessment of the BP Comparative Assessment (CA) studies:
- give the Group an overview of the present position and the forward plan:
- review the composition of the Group to ensure that all the necessary expertise is available.
- to plan the way forward.

Draft Terms of Reference for the IRG were discussed and the review process agreed.

The breadth of expertise within the IRG was reviewed and the possibility of inviting an additional member to provide expertise in the field of social engineering was discussed. It was agreed that this would not be necessary until the full scope of work became clear.

Teleconference – 25 March 2003

This was held to review progress with the actions arising from the first meeting, to consider the studies that the IRG would review and the members of the IRG that would be responsible for each. This enabled the IRG to start its work most expediently in order to meet the timescale envisaged.

Teleconference – 6th June 2003

The main purpose was to review progress with the issue of reports to the IRG and the scope of work anticipated. It was agreed that additional expertise in the field of materials and corrosion would be beneficial and that Professor Cowling should be invited to join the IRG. This completed the membership of the IRG. Progress was such that the meeting planned for early July was expected to provide sufficient material to justify a full meeting.

It was agreed that the IRG would be represented at the planned Stakeholders meeting by Professor Wilkinson.

2nd Meeting – 3rd - 4th July 2003

Professor Wilkinson reported on the Stakeholder meeting and the main points that had arisen.

Within the review of individual studies, a lead member of the IRG was identified to compile the formal response to BP on behalf of the IRG. The need for expertise on QRA matters within the IRG was discussed and it was agreed that studies on this subject would be reviewed on a "common-sense approach" and that it would not be necessary to find an additional member.

For the majority of the individual studies, the review comments were generally of a detailed nature that could be dealt with by discussion between the lead personnel for the IRG and BP. However, there was one item of substance that prompted further action. The IRG questioned the BP assumption that there were only two technically feasible outcomes i.e. full removal or jacket removal down to -100m rather than any intermediate solution. BP responded to this by commissioning an additional study to consider alternatives and to provide evidence for evaluating them. The IRG considered that such evidence would be necessary to support the final choice for decommissioning.

The IRG was not convinced that the conclusions of the study of Drill Cuttings Pile Modelling (ENV04) could be substantiated by the current application of the model developed during the JIP on Drill Cuttings. The IRG requested that the report should be expanded to include additional work to validate the sensitivity of the model to uncertainty in key parameters, which BP subsequently commissioned. The IRG considered that the final outcome of this study would be important for the presentations to Stakeholders and was concerned that it should be credible, even though the overall conclusion was likely to be that the pile would persist for a long time if left *in-situ*.

The IRG identified the report on the Environmental Impact Assessment (EIA) (ENV01) as being critical to the selection of the decommissioning option and its subsequent presentation to the Stakeholders. For this reason, all members of the IRG would review this report, concentrating on the way in which the results of the individual studies had been fed into the EIA.

A standard format was agreed for recording the IRG review comments, the BP response to them and the action to be taken.

3rd Meeting - 29th August 2003

BP reported that additional studies had been commissioned to review reports on QRA subjects (SAF01-06) and it was agreed that the IRG would review these additional reports in conjunction with the originals.

A substantial number of studies had been completed and reported so that the IRG's review comments and BP's response could be discussed in detail. The resulting actions required were agreed between the lead personnel for each study.

The IRG was concerned that the BP company policy to limit diving operations to only those that were unavoidable could be interpreted as preventing serious consideration being given to a potential solution that involved the use of diving operations.

It was agreed that the standard format for recording the review comments and response to them would be made available on request with the relevant study. The IRG would produce a Final Report that would be put on the North West Hutton Decommissioning web site. This report would contain an Annex in which the review and its outcome would be summarised for each study.

4th Meeting – 1st October 2003

The main purpose of this meeting was to discuss reviews of reports that had been completed since the previous meeting.

A draft version of the IRG Final Report was discussed and the proposed content agreed.

As a result of review comments, BP had commissioned further studies and the IRG was given the details. It became clear that the CA studies would not be completed in the timescale originally envisaged and it was agreed to extend the IRG contract for a further 5 months. This would also cover the rescheduled Stakeholder meeting at which the IRG would be represented.

The IRG observed that, as a general rule, the studies have been undertaken without extensive reference to each other, which is inevitable for this number of studies and the short timescale. The success of the project overall would depend on the way in which the results were finally brought together and the interpretation that derived from them. The IRG recognised that this would be BP's responsibility but suggested that the IRG may wish to comment on the overall interpretation of the results.

BP explained its approach to safety studies in general and to those involved in the decommissioning project in particular.

The IRG expressed a particular concern about the way the results were reported in the Environmental Impact Assessment, even though this was a standard approach for this type of work. The concern was that the interpretation of options coloured red (i.e. highly significant risks) would be that these are automatically unacceptable rather than only potentially unacceptable. BP assured the IRG that highly significant risks identified in the EIA would not automatically rule out certain outcomes, but rather 'flag up' risks for subsequent discussion in the text.

5th Meeting – 28th October 2003

The format for this meeting was similar to the previous ones and a number of reviews that had been completed since the previous meeting were discussed.

The IRG identified a particular concern about the uncertainty of the geotechnical data with respect to the covering of the drill cuttings pile and the subsequent monitoring of "hot spot's, if this was to be the selected option. BP agreed that it would revise its response to change the emphasis to state that the covering option would not be rejected due to technical uncertainty. BP would also state in its response that if the covering option was selected it would be highly likely to collect further geotechnical data.

The present position of the Environmental Impact Assessment (ENV01) was discussed, particularly concerning how comments on several different drafts would be considered. Although there will be a later version of this report, it was agreed that BP would respond to all the review comments made to date and identify where these are referred to in the text of the current version. The IRG was concerned that the use of coloured bands in the ranking tables may not lead to good decision making and BP agreed that the study would include a qualitative discussion of the impacts for each of the options (see above).

The Chairman had been involved in discussions on an extended scope of work for the Drill Cuttings Pile Modelling (ENV04) and the IRG were satisfied that the additional work to validate the sensitivity of the model would provide a more thorough scientific analysis of the problem. Work on this study needs to be completed within the new timescale envisaged for the result to be used in the final version of the EIA.

The meeting reviewed the Terms of Reference for the IRG and it was agreed that they had all been satisfied. Although most of the meetings had taken place with BP present, the members of the IRG were satisfied that this had not jeopardised the independence of the IRG. However, it was agreed that some separate meetings would be held in future to ensure that there were no outstanding issues that could bring the IRG's independence into question.

6th Meeting – 10th December 2003

This meeting took place in two parts, the first being a meeting of the members of the IRG only, followed by a full discussion of all the outstanding work with BP. The two parts are reported separately below:

IRG Meeting

The IRG met separately at the beginning of the day to consider whether the review process had been genuinely independent or whether the presence of BP at all the previous meetings had inhibited discussion of any particular items. All the members of the IRG were present and in agreement that they had discussed each of the studies openly and without feeling constrained. When necessary, they had been able to make criticisms of the studies and BP had responded acceptably.

It was felt that there had been insufficient IRG interaction with Stakeholders even though one member had attended one of the two meetings that had been held during the contract period for the IRG. It was agreed that the Chairman would comment to this effect in the IRG Final Report.

The status of the Close Out documents was conditional in some cases on further action being taken by BP but the IRG accepted that it would not be practical or necessary to monitor the process any further.

The IRG was concerned that one of its Terms of Reference states "provide a statement for public use by BP at the conclusion of the comparative assessment process on the group's findings for individual studies and on the process which BP will employ to draw together a holistic view of the CA work". This would be discussed with BP to determine how it can be achieved satisfactorily.

The IRG was also concerned that the study ENV01 should be looked at in detail as it is the collation of the results of all the studies. There was a particular concern that the results of study ENV04 were being given more credibility than the IRG considered reasonable in view of the questions still remaining over certain parts of the results of ENV04; it was agreed that this should be discussed in detail at the later meeting with BP.

IRG meeting with BP.

The views of the IRG concerning its independence and interaction with Stakeholders were reported to BP. The primary response from BP concerned the Stakeholders' meetings, which had not been strongly supported. BP had therefore held a series of meetings with individual Stakeholders to discuss specific issues but considered that these must remain confidential. BP undertook to provide a list of all its contacts with Stakeholders for the IRG's information. However, BP reported that no significant matters of concern to the IRG had been raised and that it was content with the level of interaction between the IRG and Stakeholders. One more Stakeholder meeting was planned for January/February and after that, further Stakeholder consultation will be triggered when BP submits the proposed decommissioning schedule to the DTI. BP also reported that all Stakeholders were informed each time the North West Hutton web site was updated and comments were invited but this provokes very little response.

It was agreed that BP would present more information on the process for achieving the final submission to the DTI at the final meeting of the IRG.

COWI made a presentation to the meeting to explain how they intended to approach the new study "TEC29 - Quantitative Comparative Risk Assessment" commissioned by BP as a result of previous IRG comments and intended to give an holistic view of the Comparative Assessment work.

The meeting reviewed progress with the Comparative Assessment studies and the IRG review process and agreed on a timetable to complete the work. It was agreed that one more meeting in late January 2004 would be necessary to discuss the remaining work that would be completed and reported by that time.

The format of the IRG's Final Report was discussed and it was agreed that it should contain sufficient information to enable it to be read independently of the Comparative Assessment studies and the final BP submission to DTI. It was intended that it would be available on the North West Hutton web site but would not be published. The IRG review comments for the individual Comparative Assessment studies would not be available on the web site but would be supplied with the relevant study report if requested.

7th Meeting – 29th January 2004

A number of studies were ready to be closed out and BP's responses to the IRG comments were discussed so that the formal documents could be prepared after the meeting.

There was a long discussion of TEC29, which included a representative from COWI, the company responsible for the study. The IRG considered this to be a good report that drew many of the results from previous studies together. BP observed that the substantial discussion of important, fundamental points would be helpful with its review of the work completed to that time, noting that some sections of the report (particularly those relating to safety) are still under development.

BP withdrew from the meeting while the IRG discussed ENV04. The IRG was concerned that there is still an undesirable level of uncertainty associated with the results and a limitation should be placed on the use of these results in ENV01. It was particularly concerned with the prediction that there would be no noticeable trace of drill cuttings after 10 years if they were to be stirred up and spread over the sea bed. The predicted distance that the cuttings would be spread was considered to be too high and the degradation rate was unlikely to be as high as predicted. The IRG accepted that the results from the model are otherwise generally reasonable but was concerned that too much emphasis might be placed on them. These conclusions were reported to BP. The IRG agreed to suggest that appropriate caveats be included in ENV01 where the model results were used.

BP informed the IRG about the process that will be followed to finalise the submission to the DTI. It was agreed that, if further involvement by one or more members of the IRG is required, it will be requested on an ad-hoc basis.

Finally, the IRG met on its own to consider whether any specific concerns need to be high-lighted in its report and to produce an overall conclusion from its review activities. The IRG reported the results of its discussion to BP, recommending that the case for drawing conclusions should be presented as a progressive story from which the recommendations emerge, in order to avoid the possible inference that the final recommendation for the decommissioning programme had been pre-selected and the results had "proved" it to be the right one. The IRG also recommended that the analysis should be neutral and objective without over-emphasising any specific factors e.g. diving risks or the cost of processing cuttings on shore.

Annex 4 –Summary IRG Comments on the Comparative Assessment Studies

SAF01A&B Jacket and Footings HAZID

SAF02A, B&C Jacket and Footings QRA

SAF07A DNV review of SAF01 & 02

SAF01A & B are Hazard Identification (HAZID) studies undertaken by two different contractors, Heerema and Saipem. The HAZIDs followed an accepted formal process involving a group of individuals with expertise in the field of heavy lifts, a QRA consultant and members of the BP Decommissioning Team. The range of expertise of the individuals present at the session ensured objectivity and also minimised the risk of hazards being excluded.

The HAZID lessons that came out of the study fell into four categories - operational and marine activities, ROV, cutting, lifting and backloading and foundations.

The proposed method for removal of North West Hutton is a major ROV activity. It is not clear whether the intention and the reality will be solely ROV or whether divers may be needed. It is likely that some things could go wrong in the large number of activities to be undertaken and this may require diver intervention. Hence the reason for undertaking SAF02C which examines the risk of using divers in this project.

It would seem that cutting methods might need further exploratory work. It was noted that on occasion the process could be interrupted. The subsequent solution to this problem did not appear to have been examined in detail and hence has not been assessed.

The report does not go into great detail on the strength and stability aspects for each phase of the operation. Detailed analysis is necessary for every stage, prior to starting, to avoid unforeseen problems and incorrect assumptions. In addition for a large operation such as North West Hutton calculations for details such as 'tags' might be important.

Several mentions are made of the soil plug inside the foundation piles and the possible variety of conditions that could be met in this region. Moving from a clearly defined steel structure to the unknowns of the plug is a problem. Preliminary survey work has been performed (TEC03) but more detailed work would be required depending on how the work progressed.

BP has confirmed that all of these aspects have or will receive attention in follow up studies.

SAF02A, B&C were QRA studies based on the HAZIDs performed by Saipem and Heerema. Four risks were considered including Potential Loss of Life (PLL), individual risks per year, delay days, and frequency of spillage.

A significant factor in the risk calculations was that from onshore dismantling operations. It might be better to consider onshore and offshore separately, although the results are clearly discernible. In this way the key contributors to risk in both aspects of the work can be more easily identified. SAF02C for example incorporated the use of divers. The additional consideration of the use of divers did not change the total risk significantly but was appreciable when only the offshore operation was considered. This analysis is included in the reports.

Individual risk per annum may be a better alternative indicator as the Fatality data is dependent on job size giving answers almost directly related to the weight of the platform being considered. [Note: For the platform removal this requires one to consider removing the platform 5.37 times in order to give work for a year]. For North West Hutton the IRPA was calculated as approximately 7E-4 which can then be compared to that for BP's operational assets. (Both measures are presented in the reports and IRPA and PLL are directly related. IRPA is useful for comparison with BP assets and this has been done)

BP has decided to have a final review of the reports and ensure that there is a clear distinction between the risks for onshore and offshore work.

SAF07A is a review by DNV of SAF01A&B and SAF02A, B&C documents given that the studies were at a conceptual level. DNV conclude that the HAZIDS appear to have been performed in a systematic manner. DNV note that QRAs for decommissioning are at an early stage and that there are no industry adopted approaches.

SAF07A is a good technical review that supports the earlier studies. It would seem that there is now sufficient information, and confirmation of the quality of that information, to allow the decision making process to be possible. There is still a need, eventually, to include the method involving partial removal of the footings and this will be addressed in a new BP study.

SAF03 **Drill Cuttings HAZID**

SAF04 **Drill Cuttings QRA**

SAF07B **DNV review of SAF03 & 04**

The SAFO3 and SAFO4 studies use a quantitative risk assessment on eight drill cutting management options. They recognised at the outset that, because of the many uncertainties in almost all of the operational activities associated with the options, there was the need to adopt pessimistic assumptions in quantifying the risks. They also identified escalation conditions that, while not particularly hazardous in themselves, are component failures that have an effect on the 'system' and change operational approaches or cause delays which in turn lead to increased risks. Four risk measures have been evaluated: potential loss of life (PLL); individual risks per year; delay days; and frequency of spillage for each of the eight options. Injury risks are included alongside PLL risks.

The IRG drew attention to the need to make closer connections with assumptions and outcomes from some other studies and reports, as well as the need to be more precise about the scope of the SAF03/04 study. The IRG also pointed out that the assumed risks were for very specific activities and that in reality small differences in procedures may be adopted during implementation of an option. The IRG also concurred with the DNV (SAF07B) review of SAF03 and SAF04, that certain risks had been underplayed. BP has produced satisfactory responses to the matters raised and there are no outstanding issues to be resolved before the decision making process can proceed.

SAF05 **Pipelines HAZID**

SAF06 **Pipelines QRA**

SAFO5 and SAFO6 comprise a pair of related reports which aimed to identify the hazards associated with three decommissioning options for the two pipelines (a 10″ gas line and a 20″ oil line) and to perform a quantitative risk assessment of these options. SAF06 also included a risk assessment of the long-term survey requirements for two of the decommissioning options. The procedures and calculations used to establish the potential loss of life [PLL] for all three options are clearly described and presented.

The IRG drew attention to the interaction between the pipeline decommissioning procedures and the decision on the removal or otherwise of drill cuttings. Similar connections were made between the pipeline decommissioning options and the removal of debris along the line of the pipelines. The IRG highlighted the usefulness of non-fatal accident statistics in addition to PLL and the importance of understanding the differences in risk arising from differences in pipeline cleaning processes.

BP has produced satisfactory responses to the matters raised and there are no outstanding issues.

SOC01 Jacket Footings, Drill Cuttings and Pipeline Impact on Fishermen.

The IRG recognised that this study involved a qualitative approach and so is less of an academic study than usual. As a result some of the statements in the report are not backed up by verifiable data. The report presented a strong argument for not leaving obstacles at the bottom. It rates the North West Hutton area as high as 8 on a scale 1-10 of importance among North Sea fishing areas. The report confirms the Scottish Fishing Federation public position on the key issues, relating to their stated 'clean sea bed' policy, safety and precedent setting.

The IRG identified a number of fairly minor changes to the report which were necessary or desirable and is satisfied that the actions to be taken constitute a satisfactory response to the comments & suggestions made.

SOC02 **Jacket Footings, Drill Cuttings and Pipeline Economic Impact Assessment**

This study deals with the costs and employment opportunities associated with the decommissioning options for North West Hutton (topside, jacket, jacket & footings, cuttings pile and pipelines). Monitoring is also taken into account where appropriate. Using cost estimates [provided by BP] as inputs the outputs are calculated for different employment sectors using standard tables available for Scotland and the UK. The outputs so generated are considered in terms of direct, indirect and induced impacts, converted to income and further expressed in man-years employment for the different sectors of activity. The lost opportunity costs incurred by both UK government and BP for the decommissioning options are also identified in broad terms.

The study gives a useful insight as to the number of jobs likely to be created in Scotland and in the UK overall for each of the main elements of the decommissioning and the options within elements.

However, the report takes a rather limited view of socio-economic impacts, since essentially only the direct costs to BP and UK Government, and the employment created, are considered, using a fairly mechanistic modelling procedure. There are also much wider socio-economic aspects of decommissioning activities (noise, traffic, value-for-money…). It is not clear how these are going to be addressed (except perhaps via the stakeholder dialogue process).

It is also difficult to discern any overall conclusion, except that the magnitude of the costs and benefits is moderate, and it would be useful if the outcome of the study could be communicated more cogently.

The IRG identified a number of shortcomings in the report, and is satisfied that the actions proposed will correct these, but remains concerned that there are wider socio-economic issues which were out-with its scope, and which will need to be addressed. BP has given assurance that these will be addressed as part of the environmental and social impact assessment work which will be required when the onshore locations for recycling and disposal of material are known.

ENV01 Environmental Impact Assessment

The Environmental Impact Assessment has been carried out based on the information from the other Comparative Assessment studies, using both fairly standard semi-quantitative risk assessment and comparison methods, and useful extensions thereof where required (e.g. in the categorisation of environmental and socio-economic impacts).

The Environmental Statement is well organized and easy to read. As far as the IRG is aware, no risk factors of importance have been left out for any of the decommissioning activities planned, and the assessment of the risks is sound. The Executive Summary is an accurate summary of the main report.

There were a number of unresolved concerns with the final draft (Jan 2004) seen by the IRG (see below), including especially:-

- The predictions based on the ENV04 model were presented with insufficient caveats.
- There is a substantial section in the report that addresses the 'Excavate and leave *in-situ*' option. It was not made sufficiently clear in the body of the report that the environmental consequences of this option were extremely uncertain, and that it was not the option that would be selected to access the footings, if this were necessary, (as it would be discarded in favour of using a suction dredge)
- The treatment of the option of partial removal & covering was not dealt with accurately (it is feasible but expensive, with small benefits)

Appropriate actions have been agreed between the IRG and BP to resolve these concerns, and provided that these final close-out actions & amendments are implemented as agreed, the IRG is satisfied that the report and its conclusions are soundly based.

ENV02 Jacket Footings, Drill Cuttings and Pipelines Energy and Emissions study

This report was prepared in parallel with several other reports in the ENV and TEC series. The study does not consider the full range of technical options e.g. for recovery of the drill cuttings identified in TEC11/12, but rather focuses on a typical scenario. The study uses the standard IoP methodology and has been carried out thoroughly and competently. However, this methodology considers only energy usage and gaseous emissions: other environmental impacts are dealt with elsewhere.

The results are not surprising, insofar as the major contributions are from vessel movements and replacement of materials (mainly steel) which are left *in-situ* or recycled. The absolute levels of energy usage are non-trivial, and are likely to be a significant contribution to costs. The differences between the options are relatively small, and are unlikely to be a decisive factor in the comparative assessment. The absolute levels of gaseous emissions (which are dominated by CO_2) are also quite small.

The IRG is satisfied that the major conclusions of the report are sound. The actions to be taken by BP to deal with minor inconsistencies & omissions will deal with these satisfactorily.

ENV03 Jacket Footings Lophelia Study

The report has evaluated ROV video coverage of the North West Hutton jacket below 45 m water depth. From the video material the number of Lophelia pertusa colonies is assessed, together with their physical appearance (form, diameter, colour) and their spatial distribution (depth, orientation) on the installation. The report also covers sensitivity of the corals to sedimentation/smothering, attack by seeping hydrocarbons and legal aspects.

The overall quality of the report is high, and gives a credible impression of the occurrence and state of the colonies. The IRG has commented on a number of smaller items to be addressed in a report revision. BP has accepted these comments and responded to them in a way that appears satisfactory to the IRG.

ENV04 Drill Cuttings Pile Modelling

This study involved the application of both the short-term and the long-term models of drill cuttings deposition, resuspension, erosion and bioremediation developed by the contractors before and during the UKOOA JIP study on Drill Cuttings. Estimates of the parameters involved were available from the JIP work, but in many cases these estimates are still very uncertain.

The IRG considers that the principal conclusion of the modelling studies, i.e. that the pile left *in situ* is likely to persist for several thousand years, is sound. However, this estimate remains very uncertain, as it is sensitive to a number of parameters whose magnitudes are also uncertain. The IRG requested additional work to examine the model's sensitivity to a number of parameters. This work on the sensitivity studies (Part 2) has highlighted a number of issues concerning the behaviour of the model and the parameterisation of potentially influential processes which have not been completely resolved. These are of particular concern in relation to the resettlement of cuttings if the pile is disturbed. BP recognises the concerns raised by the IRG and will ensure that the modelling results are used in the Environment Assessment Studies and in the decommissioning programme with appropriate caveats which fully acknowledge the uncertainties in the model predictions. The actions proposed in response to IRG comments for the use of the results should however allow for these remaining uncertainties adequately. Provided that the final close-out actions & amendments are implemented as agreed, the IRG is satisfied that the results of the study will have been used in an acceptable manner.

ENV05 Cuttings Pile Benthic Community Sampling (ROV)

Core samples from below the surface of the North West Hutton cuttings pile were collected after a crater had formed following the removal of conductors. Sampling was done by ROV in 2003 concurrently with selected samples taken from the surface of the cuttings pile adjacent to the installation. The samples were analysed for different toxic compound classes (THC, PAHs, PCBs, and APEs) in order to compare with data on surface samples collected during previous surveys. The report is well written and gives a valuable snapshot view of the internal composition of the pile. Significant conclusions are that similar THC levels were found in all positions of the pile, there was no significant difference between surface and internal levels of THC, internal levels of PAHs were clearly higher than levels close to the pile surface and no change in hydrocarbon levels of the pile material has occurred since a previous survey in 1992.

All comments made to the report by the IRG have been dealt with by BP and in a manner satisfactory to the IRG.

ENV06 Pipelines Cleanliness Assessment/Assurance

The report assesses the processes of cleaning and of determining the cleanliness of an oil and a gas pipeline currently connected to the North West Hutton platform. Cleaning will be performed to achieve a final hydrocarbon concentration in the cleaning fluid as low as possible, but definitely below 40 ppm. Fluids and debris from cleaning will be processed according to the applicable regulations dependent on hydrocarbon concentration levels.

The revised version of the report will contain information on the status of the pipeline before cleaning, detailed information on the cleaning procedures and materials used and on the state of the pipeline after cleaning.

ENV08 Long Term Trends in Seabed Disturbance

The report is a compilation and comparison of the available results from environmental surveys performed in the vicinity of the North West Hutton platform during the period 1985 to 2002. The six surveys performed during this period cover seabed distribution patterns of total hydrocarbons, PAHs, PCBs, TBTs, alkyl phenoxylated ethoxylates (APEs), metals, LSA radiochemical patterns, and structure and effect patterns of benthic infauna from point sampling campaigns. Additional information used are results from 3-D mapping of the pile surface (1992), time-lapse camera and current recordings (1997), and additional reports and data from BP and certain unpublished reports. The last drilling discharges at North West Hutton occurred in 1992, and the surveys after that must be expected to reflect a recovery period.

The report is comprehensive and well written. It makes a reliable attempt to compare the environmental changes over time, in spite of the fact that survey design and analytical procedures have differed between the surveys, partly due to different contractors involved. Because of this, the data are treated with due caution, and due to incompatibilities of methods the evaluation of quantitative data is essentially restricted to the four last campaigns since 1992. The IRG requested that BP remove the conclusion that the 50ppm hydrocarbon contour would be close to the platform by 2012, since the data had been misinterpreted. It was further noted that the data were only relevant to the surface layer of the cuttings pile. BP agreed to amend the report and to note that the recovery seen is surface recovery only.

Overall, the report appears to give a reliable impression on the status and trends in seabed contamination and faunal effects at the sediment surface around the North West Hutton platform up to the present.

The IRG reached agreement with BP that the recovery of the surface layer will no longer be considered an indication of remediation of the entire pile. The report will be modified accordingly. All other technical criticism was dealt with to the satisfaction of the IRG.

TEC01 Life Assessment and Corrosion Mechanisms (ROV)

Based on historical data provided by BP, the report assesses the life expectancy and breakdown mechanism of the footings of the North West Hutton platform and suggests their future monitoring, taking into consideration the influence of the sacrificial anodes at the present time and after their total consumption. The theoretical calculations take into account the summed surface areas of the construction parts and data on the environmental conditions, and result in a life expectancy before the anodes are consumed of between 22 and 38 years. The life expectancy of the footings under free corrosion will vary depending on the size of the members from 100 years to a minimum of 560 years for the large bottle leg sections. The theoretical considerations and NW-Hutton-specific parameterisations are straightforward and have led to reliable results.

The report discusses the possible effect of hydrogen sulphide formed by the anaerobic activity of sulphate-reducing bacteria in the deeper parts of the cuttings pile on the corrosion of the platform footings, but does not include this effect into the calculations due to the lack of direct evidence and pertinent analytical data. BP does not believe that the presence of sulphate-reducing bacteria will be material to the life assessment of the footings. The IRG concurs with this view.

Minor corrections were handled satisfactorily by BP.

TEC02A }
TEC02B } Jacket and Footings Removal Study (Heerema and Saipem reports)

TEC04A }
TEC04B } Independent review of Heerema and Saipem reports

TEC02A & B describe proposals for two decommissioning options for North West Hutton:

- removal of the jacket;
- removal of the jacket and footings.

The reports by two major contractors (Heerema and Saipem) are well written and address most of the important issues.

The proposed methods for removal of North West Hutton are both major ROV activities. It is not clear from the reports whether the intention and the reality will be solely ROV or whether divers may be needed. ROV working is extremely complex and needs careful consideration. There would appear to be several aspects here that have not been considered. Firstly, given the complexity of the structure, it is not possible to determine, without detailed consideration, whether the tasks required can be accomplished by ROV. The only way to do this is by computer simulation. Demonstration of the technical feasibility of using ROVs for this whole operation is a necessary first step.

Cutting tools are a major element of the platform removal process. A review of cutting techniques for this particular application (working down to -144m) has been noted as an area requiring further investigation.

Large steel platforms like North West Hutton have built-in stresses due to the method of manufacture and the problems that may occur during launch. Internal stresses will be released during cutting and, if not carefully considered, can lead to instability. Ideally the presence or magnitude of these stresses should be determined.

Rigging, lifting and back loading onto barges of large sections is a major activity of decommissioning. The stability of each section identified for removal will need careful consideration. It is anticipated that structural analysis of the sections will be necessary and that this will need a complete inventory of the state of the sections from NDT records or new examinations if these are not available. Precise prediction of the centre of gravity for each section is also required in order to avoid uncontrolled movement of sections and possible entanglement with other parts of the structure. The associated problems of the releasing of stabilisers or tags on the cut sections needs to be addressed in analysis and feasibility studies. Large clamps or 'choked' large slings are proposed and these will represent a considerable problem for ROV deployment. Feasibility studies using computer simulation and extensive training will be necessary.

TEC04A&B are reports from Noble Denton and Global Maritime and review the TEC02A&B studies. Both are clearly written, good reports, and have observations in line with the IRG views.

One area receiving further coverage concerned the difficulties associated with removing the footings. This arises partly due to the assumptions by Heerema and Saipem that drill cuttings would have been removed prior to work commencing in this area. It has been noted that the steel/soil interface needs a thorough survey before commencing work and that lifting damaged footings would require careful assessment/investigation before commencing work.

The HAZID and risk assessment sections were also quite valuable as they built on the previous studies by Heerema and Saipem. One particular feature that came out was that the partial removal of the platform is feasible and could be achieved at low risk but that full removal is considerably more difficult and with a much higher risk. It is concluded that there is a very big difference between the two undertakings and this appears to be a reasonable conclusion.

The option of removing the structure just above the drill cuttings pile surface was not considered and subsequently BP has initiated a further study to look at this (TEC 29). BP has also properly addressed the other uncertainties mentioned above and confirmed that further work will be included at the appropriate stage during decommissioning.

TEC03 Internal Pile Survey (ROV)

The IRG requested a brief note from BP, which has been satisfactorily provided, on the results of an ROV survey which in particular had provided data on the position of soil plugs in the piles and the 20 grout densitometers. The latter each contain a caesium137 radioactive source. The IRG noted that:

- the soil plugs were at some depth below the sea bed so should not cause problems in any pile cuttings operation and
- following some development work, BP will remove the grout densitometers and dispose of these to shore following accepted procedures.

TEC05 Jacket Footings Material Inventory

The objective of this report was to identify the available information regarding the current state of the jacket, and relevant other information, such as Metocean and soil data. Overall this report is useful baseline information to set in context the removal options considered elsewhere. Most of the report comprises a review of inspection and survey information gathered through the life of the platform. There are a large number of associated drawings, some difficult to read. The information shows that there are significant areas of damage to the structure, some dating from the installation phase. Some areas of damage have been repaired/strengthened. BP agrees that there are areas of technical risk which will have to be treated very conservatively, i.e. by the removal of small pieces.

Pile soil plug data not sufficiently covered in this report will be presented in the TEC03 report following an appropriate survey. The information in the TEC05 report was made available to the authors of the TEC02A&B reports.

The reference materials cited in the report will be fully available. Aker Kvaerner will be the custodians of the documents and this company will be involved throughout the decommissioning process.

Other small items to be revised were dealt with satisfactorily by BP.

TEC06 Alternative Removal Methods

The aim of TEC06 was to examine a wide range of options for a total removal of the North West Hutton jacket and footings. It appears to be based on both a May 2003 workshop and on the findings of other CA reports. The damage sustained during load out, and the desirable objective of avoiding the use of divers, eliminated many of the possibilities considered.

TECO6 considered a total single lift. It concluded that even if a Single Lift Concept were available the damage to the lower members of the structure would negate a single lift. The report also considered buoyancy methods, piece - small removal, and explosive cutting. All were deemed to be unsuitable.

TEC07 Jacket Derogation Options Review

The BP specification for the TECO7 study required a wide range of derogation options to be examined. However the TECO7 report that emerged focussed on the use of explosives in the decommissioning process. BP recognised the limited extent of the work to date and will be establishing additional studies to examine the wider range of options. Nevertheless the TECO7 report, although restricted in scope with respect to the specification, presents a good overview of the potential use of explosive cutting for marine work in general and North West Hutton in particular.

The report indicated BP's unwillingness to use divers if avoidable and this is considered by the report's author as a 'show stopper' to the widespread deployment of this technology for jacket and footing removal at North West Hutton. While BP notes it is unlikely that explosives will be used for cutting the jacket there is recognition that there may be some non- routine situations where they may need to be deployed.

The report addressed briefly the environmental impact resulting from the use of explosives in the sea and describes some of the mitigation measures available/under development to attenuate explosive shock waves. BP considers that, while the use of explosives for cutting the upper part of the jacket is unlikely, they may be needed for template and footing removal or as a contingency measure. The IRG endorses BP's proposed monitoring of developments in methods to reduce the effects of explosive shock on marine structures and the environment.

TEC09 Subsea Cutting and Lifting

TECO9 is a collaborative examination by the industry of the methods that could be used to decommission a large jacket structure. It considers cutting, rigging, lifting, back loading, sea faring and transportation procedures. The Forties Charlie four leg jacket was used as an example for the studies and workshops leading to the report. The report and its comprehensive appendices are clearly written. Much of the work is directly relevant to the North West Hutton decommissioning but it excludes any detailed examination of the removal of the lower frame and the drill cuttings. It brings out the previous experience from the main contractors and gives valuable considered advice to the industry.

Recommendations were made for necessary improvements to cutting tools, and the need for improved metrology (the shape and size of each component as they are lifted and back loaded) is extremely important. Movements due to relaxation or springing were noted as important factors needing careful analysis prior to section removal.

The possibility of damage due to fatigue or overload was also noted. The consequence of these changes together with the additional fatigue loading that could arise during decommissioning need careful analysis as fracture of members during lifting, loading, or whilst on the barges is unacceptable from the safety point of view.

The workshops conducted as part of this study were valuable and distilled across some very useful requirements. Perhaps the need for extensive analysis, technology development, procedure development, and training prior to commencement of a major decommissioning project needs to be emphasized slightly more than found in the report. Appropriate analysis and training work conducted prior to the start of decommissioning is valuable and can make a major contribution to safety.

It was a valuable exercise that brought out the main points that need to be considered for decommissioning and indicated the areas that need to be investigated for the anticipated technology requirements.

TEC10 Drill Cuttings Pile Excavation Study

The original BP specification for the TEC10 study was to identify types of equipment and technical issues to be considered in excavating the cuttings to give access to the jacket, lower braces, drilling template and pipeline spool pieces.

The contractor focussed the study on a single tool, the hydrodigger. This tool uses a large downward flow of water to displace sediment laterally. The report indicates that the tool has been used successfully for sea bed sediment displacement at a number of sites. The system has no means of containing the displaced sediment. Its application at North West Hutton would lead to the re-suspension of a large volume of contaminated drill cuttings in the immediate environment. It is highly unlikely that this would be acceptable in environmental terms.

The study also estimated the volume of cuttings that would be displaced from an area adjacent to the platform legs. A 1 on 2 slope was assumed but in view of the very low shear strength of the cuttings pile material it is highly unlikely that this could be safely achieved. A much flatter slope would be needed and consequently a much greater volume of cuttings would be disturbed. For these reasons the IRG considered that the hydrodigger was an inappropriate tool for removing cuttings to expose the footings. The IRG noted that suction dredge methods which should reduce the spread of cuttings material in the adjacent marine environment, in comparison with the hydrodigger, are considered in TEC11-12.

The IRG is satisfied with the BP response to its technical comments. The drill cuttings slope and excavation volume is being addressed further in TEC27.

TEC11 Drill Cuttings Covering Study
TEC12 Drill Cuttings Removal JIP

The report is a largely theoretical treatment of the various options for handling the drill cuttings pile at the bottom of the North West Hutton platform (except for the leave-in-place option). The report excludes consideration of the environmental impacts of the technical options. BP confirms that these will be addressed in ENV01. The review builds upon previous studies, particularly the UKOOA JIP I and JIP II studies, including the lifting trial field experiment, but it goes beyond these studies considering the operational steps in greater detail and by bringing in additional information, e.g. from a possible contractor who could perform part of the tasks involved.

This is a well-constructed report, which seems to have dealt with the main issues satisfactorily. The review is nice to read and easy to follow, although it is somewhat narrative and not free of repetitions. The conclusions appear to be well founded where sufficient background information is available, but lack of such information creates serious uncertainties with respect to the lifting, cuttings treatment, and geotechnical properties of the cuttings material.

In the response to the IRG comments, BP recognises these issues. They will be borne in mind during the Comparative Assessment, but are considered not to be material to the completion of the CA process. BP also fully recognises that additional work is likely to be needed should either lifting or covering be chosen. The IRG considers that BP has dealt with its comments in a satisfactory manner.

TEC13 Drill cuttings Material Inventory

The report essentially consists of two parts. The second part is an extended table listing 55 publications, technical reports etc. from 1986 to 2003 dealing with the investigation of the physical, biological and chemical properties of the North West Hutton cuttings pile and the surrounding seabed. This is an extremely valuable compilation and appears to properly reflect the contents of the written material in the form of a series of bullet essentials.

The first part of the report is a text summary of the results of the investigations listed in the table, being an extension of a previous compilation by Hartley-Anderson (2000). The short summary on physical (pile size and shape, physical properties, and other physical considerations), chemical (hydrocarbons, metals, endocrine disruptors, sulphide and sulphate, tributyl tin, and PCBs) and biological data gives the reader a rapid and valuable total impression of the information available for the North West Hutton cuttings deposit.

Information not specifically or extensively covered in the previous work include the level of contamination in the cuttings pile at depth, the total contaminant inventory of the pile, and some geotechnical properties. These items will be picked up in other reports and BP will take care that this is done appropriately.

BP dealt with all critique to the satisfaction of the IRG.

TEC14 Pipelines Life Assessment and Corrosion Mechanisms
TEC15 Pipelines Options Technical Assessment
TEC16 Pipelines 20 year Life Review
TEC17 Pipelines Trench Study
TEC18 Pipelines Material Inventory

TEC14 – 18 comprise a set of related reports which address the options for various stages in the decommissioning of two pipelines, a 10″ gas line and a 20″ oil line. The original reports were separate documents from the same contractor. This resulted in much unnecessary duplication of background information. There were also inconsistencies between similar assessment procedures in different reports. As a result of these issues being highlighted by the IRG, BP arranged for the individual reports to be consolidated into a single report. This process produced a marked improvement in the quality of the report and consistency of approach.

The BP responses to a number of the technical issues raised by the IRG are to ensure that specific issues are included in the future comparative assessment of options for decommissioning. In the view of the IRG this is a suitable method of dealing with these topics.

Overall, for these pipeline studies, BP has produced satisfactory responses to the matters raised by the IRG and there are no outstanding issues.

TEC25 Jacket Lift Analysis

The report presents the results of a study of the specific options for dealing with the jacket structure in the decommissioning process. The two options considered are (i) complete removal in one lift and (ii) partial removal (cutting at -100m) followed by collapsing of the footings section. The IRG highlighted the fact that the study is somewhat limited by the basic assumptions used in the analysis, but nevertheless recognised that the results are useful and in particular show that a single lift solution is not viable.

BP has acknowledged the limitations of what has been done and there are no outstanding issues.

TEC26 Template and Seabed Member Removal Study

TEC26 proposes a means of removing the drilling template and mudline braces, pile heads, residual debris, etc, located at the foot of North West Hutton. The report assumed that prior to the start of the work the jacket structure and the drill cuttings pile would have been removed.

The report noted the uncertainties over the condition of some of the mudline members and the template. The uncertainty over the strength of these members would make ROV working more difficult. They need to be examined for condition during the removal work. For this and other reasons, such as explosive cutting, strong justification is given for saturation diving.

The report is clear and well presented. It shows the difficulties associated with the removal of all the mudline parts of North West Hutton and especially draws attention to the need for saturation diving to complete the tasks. The work would be difficult and dangerous.

TEC27 Jacket Damage – Identification and Drill Cuttings Removal

This report provides a statement of (a) damage to the lower frame, (b) the degree of attachment of the mudline bracing to the legs and (c) an estimate of the volume of cuttings to be removed to gain access to the lower footings. The report is in two parts - one containing text and the other figures. Unfortunately the two parts are not cross- referenced. This has led to inconsistency in relation to some of the attachment details. Apparently the part with the figures contains the correct information.

There are two conclusions relating to structural integrity but only one of these is discussed in any detail in the preceding text section. The second conclusion also needs to be supported by discussion in the text.

The type of calculations [Taylor type, total stress] used to assess the volume of cuttings to be removed to access the legs and braces are acceptable as a first estimate. Following an IRG/BP discussion it appears that the contractor has misinterpreted the relationship between the height of the cuttings pile and the slope and consequently has allowed flatter slopes than would be necessary below the platform on the basis of the slope instability method used. The volume of cuttings to be removed has therefore been overestimated. If there is a need to access the footings during the decommissioning process, the volume of cuttings to be removed will have to be recalculated. The IRG wishes the contractor in due course to recalculate the cuttings to be removed and to make some small modifications to the report but overall finds it to be satisfactory.

TEC28A Partial Derogation & Feasibility of Cutting Bottle Legs

TEC28A is in two parts. The first addresses the question of whether North West Hutton can be cut through the bottle leg or just below the seabed. The second section is a review of subsea operations. This is a well written and thoughtful report.

The report clearly identifies the uncertainties and possible difficulties of (a) cutting the bottle legs above the drill cuttings pile and (b) cutting the pile clusters just below the sea bed so that the total bottle legs may be removed. It is a substantial addition to the technical studies undertaken by BP and the IRG consider it to be a valuable exercise.

It concludes that it may be feasible to cut the bottle legs above the yoke plate at -137.5 m and -129.8 m but there is no guaranteed method of cutting the large legs and further inspection and development work is needed

A major cause of concern expressed in the report is the presence of internal stiffeners and pipework.

The case for limited diver intervention is well made. It would seem appropriate to assume that divers would be required from the outset, albeit in a limited capacity, but to review the necessity for diving intervention during the detailed studies that will follow.

The report gives a comprehensive review of the cutting activity, superior to those in previous studies. It clearly sets out how the cutting may be undertaken, and, in principle suggests that it is possible. However there is uncertainty for both diamond wire or abrasive water jet and it is concluded that trials would be necessary.

The IRG note that partial leg removal, although technically feasible given a wide range of preparatory work and trials, is an activity that could prove to be hazardous. In particular the problems associated with overall stability, final cutting with simultaneous use of an HLV and difficulties associated with pile sections becoming wedged may prove difficult to overcome. These problems mean that guaranteed successful removal could not be predicted at this stage.

The uncertainties associated with cutting the piles, the possibility of attached grout and the major problem of stability during this operation are clearly presented and are a cause for concern in this possible alternative removal option. The IRG does not consider that the contractor has overestimated the problem. It could be extremely difficult and potentially hazardous to attempt full bottle removal.

The second section describes in detail subsea operations that may be necessary in the removal of North West Hutton. In particular it highlights the advantages of a mixed diver/ROV operation in a balanced manner. The suggestion that diving should be considered from the outset but may prove to have a minor role in the eventual method adopted is sensible.

This section covers all the important subsea activities and identifies a wide range of possible problems that may arise. The IRG consider this section to be an excellent extension to previous studies in that it goes further and considers many aspects in more detail than found in earlier reports.

TEC28B Feasibility of Cutting Bottle Legs

The report describes a diver based approach to cutting the bottle leg very close to the top of the drill cuttings pile. It appears to understate some of the difficulties that may be experienced in cutting and removing the bottle legs at this level.

While the report recognises that a preferred cutting position would be above the pile sleeve yoke at -137.5m, this would leave 2 to 8 m structure above the mudline. The cutting position examined is therefore below this in a section carrying shear plates. This, if successful, would give much less of a residual structural upstand.

Following a review of diamond wire, explosive and abrasive jet cutting the use of jets as the principal method is offered and costed. However the point is made strongly that there are major uncertainties concerning the internal construction of the bottle legs [e.g. the extent and position of stiffening structures] and that an internal inspection of the legs would be needed. However no indication is given as to the methods that would be used if internal stiffening structures or any pipework were present or whether these would be 'showstoppers' or not.

The report shows that bottle leg cutting near to the top of the drill cuttings pile would involve extensive diving and ROV operations.

TEC29 Removal of Jacket - Quantitative Comparative Risk Assessment

The report describes an extensive study of comparative risks associated with specific decommissioning options, and is based on the use of Bayesian Probability Networks (BPN). The report demonstrates, in a powerful manner, the potential usefulness of the BPN approach to comparative risk assessment where there are viable realistic but complex options to be considered, and a preferred solution to be selected. In many ways the report is an exemplar of what can be done.

The study is focused primarily on technical issues associated with the decommissioning options and does not deal with the related environmental issues in any great detail.

The IRG drew attention to the need to be very careful with definitions of failure and calibration of risks. With sufficient attention to detail such analyses should be very useful to the wide range of stakeholders associated with the decommissioning of North West Hutton and other sensitive installations. The IRG also highlighted certain inconsistencies within the draft report with respect to the qualitative description of risks, the base statistics used, the assumptions of what constitutes ‘failure’.

The BP responses to the matters raised were positive and helpful, and they have agreed to address all of the IRG concerns in the final project report. However, the timing of the completion of the TEC29 study precluded the IRG from reviewing the final version of the report.

ECO01
ECO04 Cost Estimate Summary and Risk Analysis Review
ECO05
ECO06 Economics and BRISK of Cost Estimates

These studies of estimated costs and their uncertainties are commercially confidential but were presented to the IRG for information, and were not formally reviewed as they were outwith the scope of the IRG remit. The IRG did however examine the reports, and did not consider that there were any issues within its competence to be addressed.

ECO03 Impact on Scrap Steel Market

This is a very brief report drawing on information presented in a 2002 DTI Steel Recycling Fact Sheet.

The BP report concludes that the recyclable steel from North West Hutton will make up less than 0.07% of the annual UK scrap metal use and consequently will have minimal effect on the UK scrap market.

The IRG finds the report and its conclusions to be satisfactory.

ECO07 Long Term Liability

The purpose of the study was to estimate the costs of monitoring which will be needed following the decommissioning of North West Hutton. At present the decommissioning outcome is unknown, and consequently a range of monitoring options for platform site and pipelines are considered. The report notes that monitoring proposals are a requirement of the DTI guidelines. This report appears as the only one in the Comparative Assessment addressing the post-decommissioning monitoring issue, which is potentially of great interest to the stakeholders.

Although the IRG considers that the actions identified by BP will deal satisfactorily with the editorial issues of the report, it still considers that further clear and firm statements about responsibility for the costs of any unexpected remedial activities would be reassuring to stakeholders. The principles have subsequently been established and BP has confirmed that these will be implemented as the work progresses.

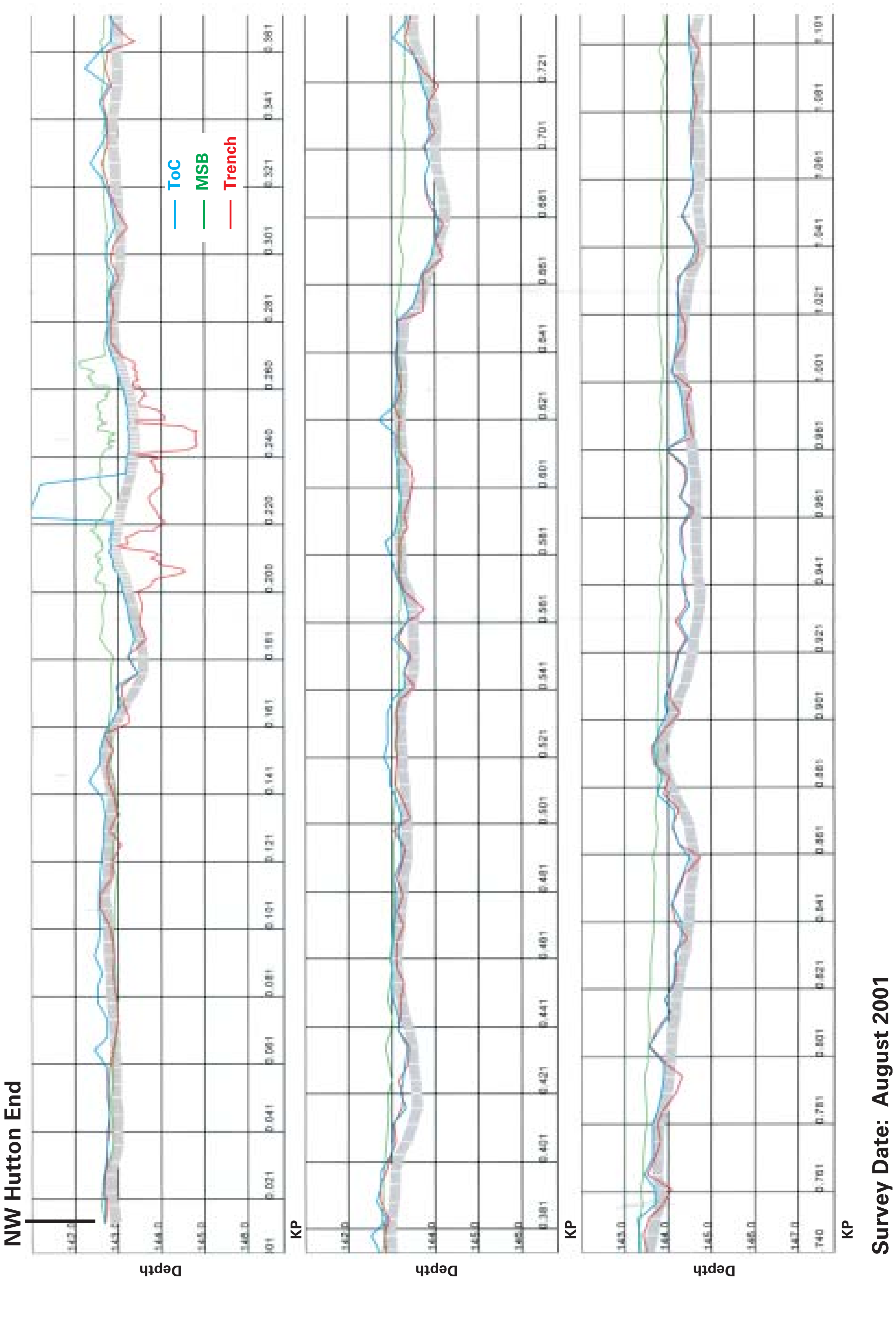
20.7 Longitudinal Profiles

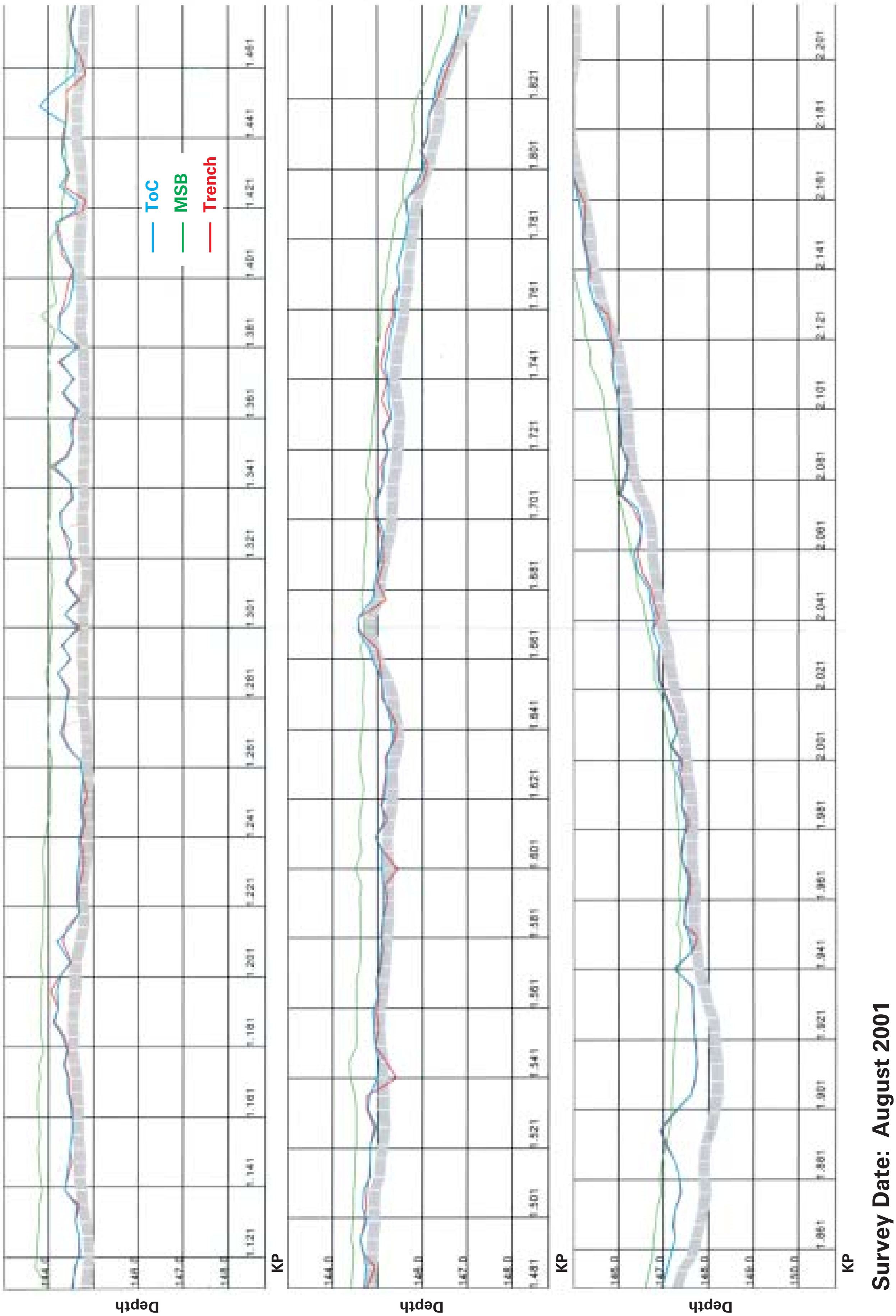
Key

- Red line represents trench
- Grey line represents pipe
- Green line represents mean seabed (MSB) level.
- Blue line shows loose top cover (ToC) or mattresses or structure
- Spans occur where red line is completely below grey line.

Note,

The longitudinal profile shows that the 10" gas pipeline (PL 147) is completely trenched and below the mean seabed level. The areas where the pipeline is shown to be above the trench are at the SSIV and pipeline crossings. These sections of the pipeline will be removed as part of the decommissioning works.


NW Hutton End
ToC
MSB
Trench
Depth
KP
Survey Date: August 2001


ToC
MSB
Trench
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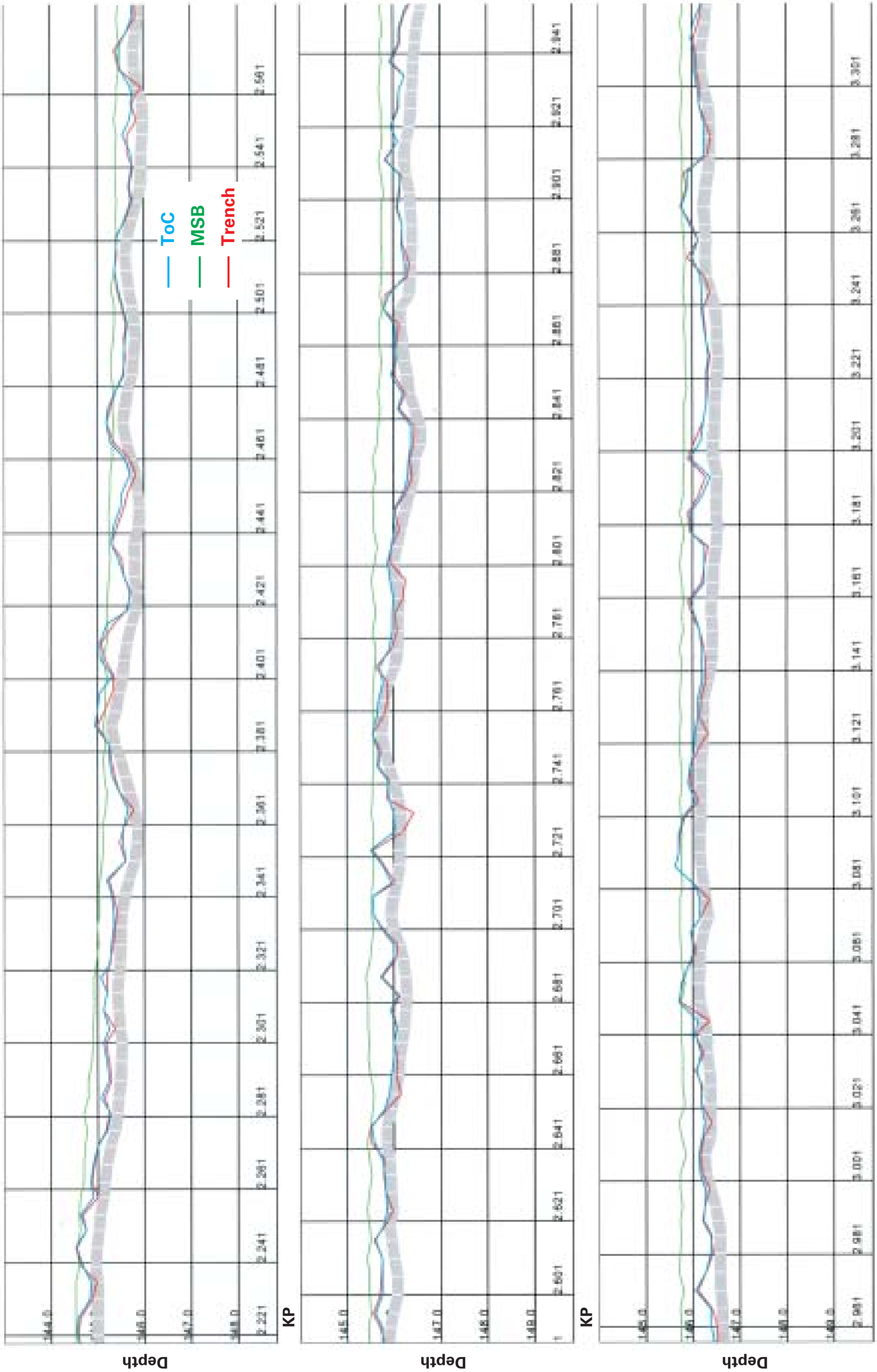

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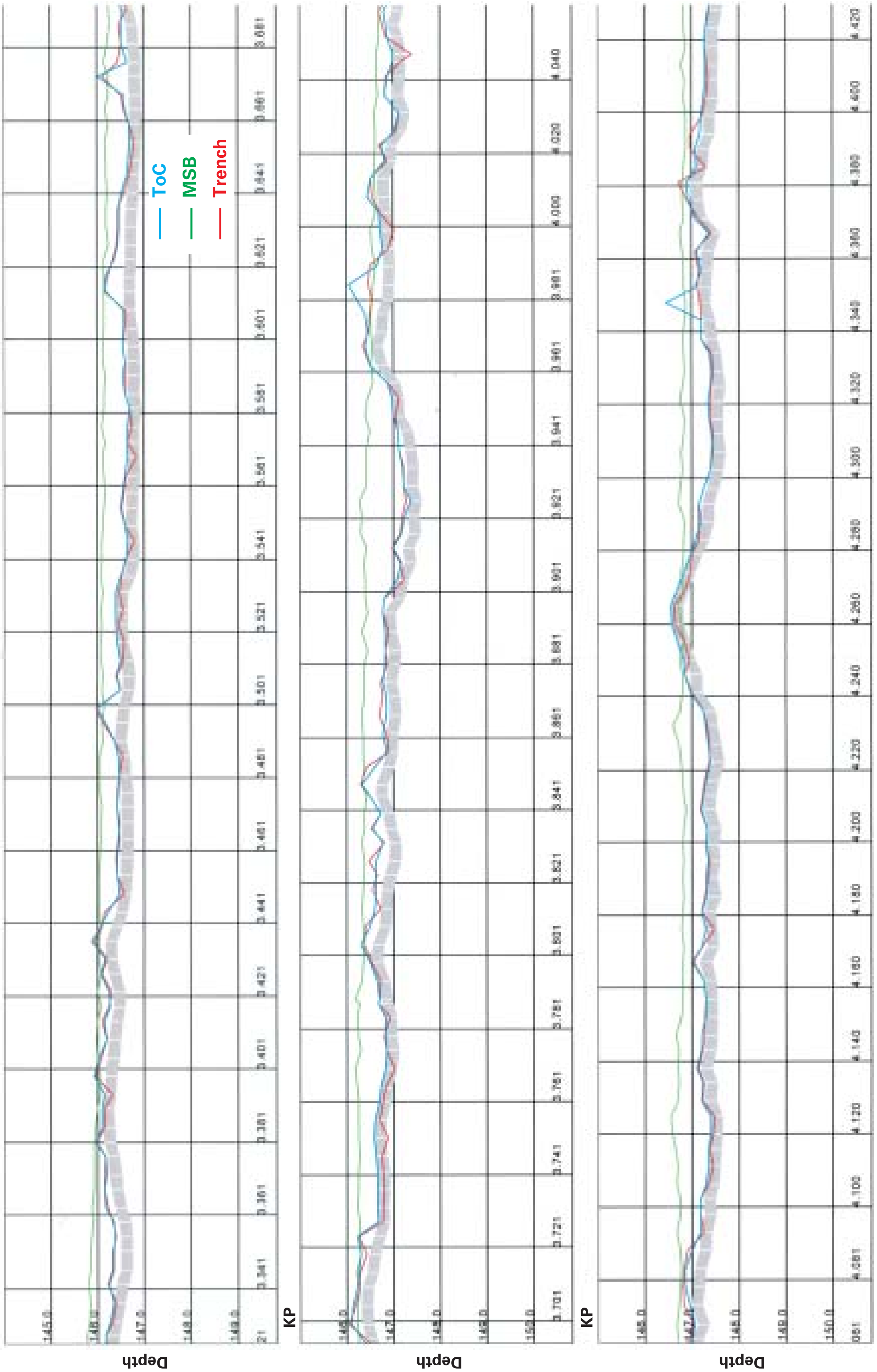

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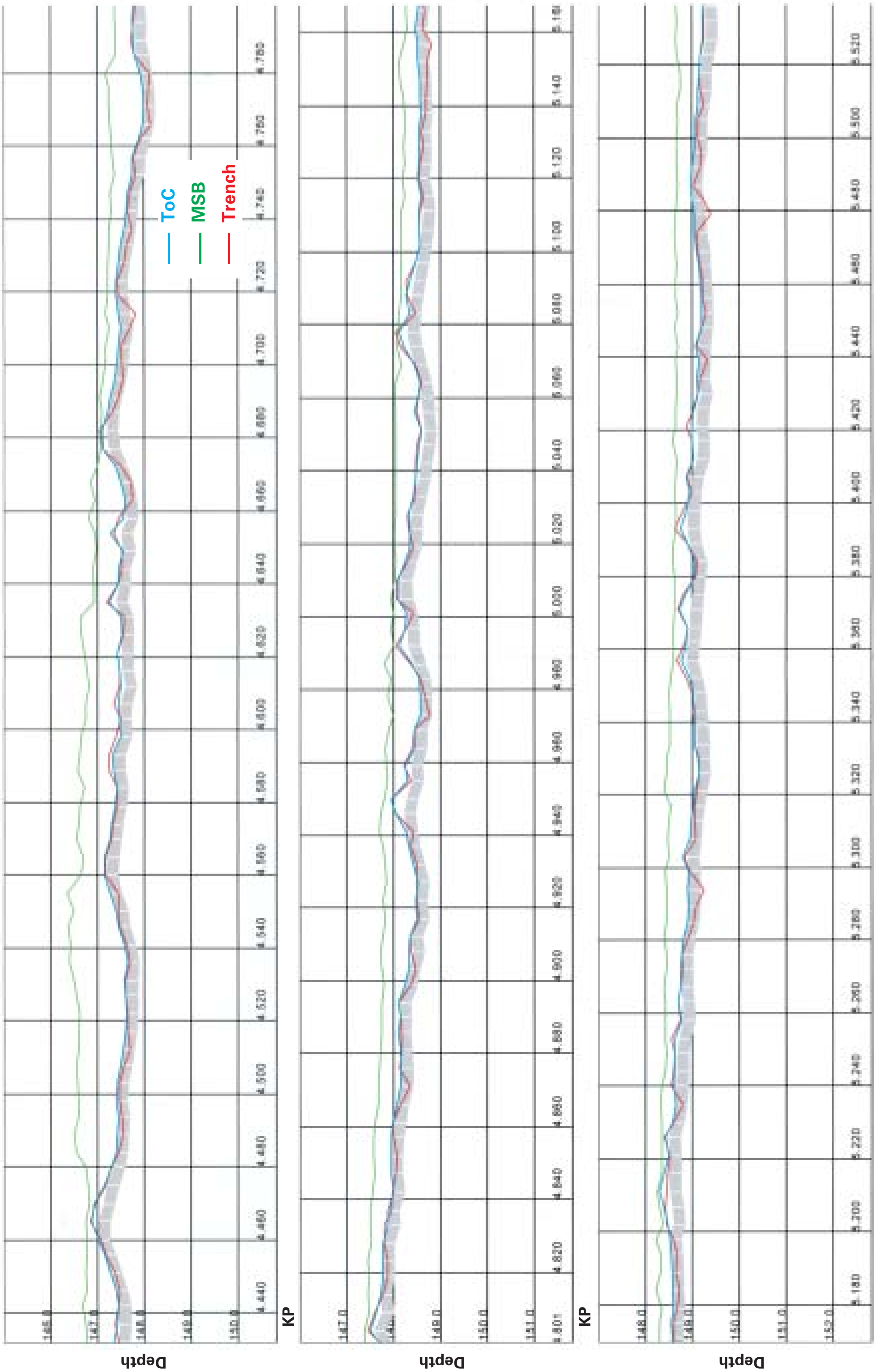

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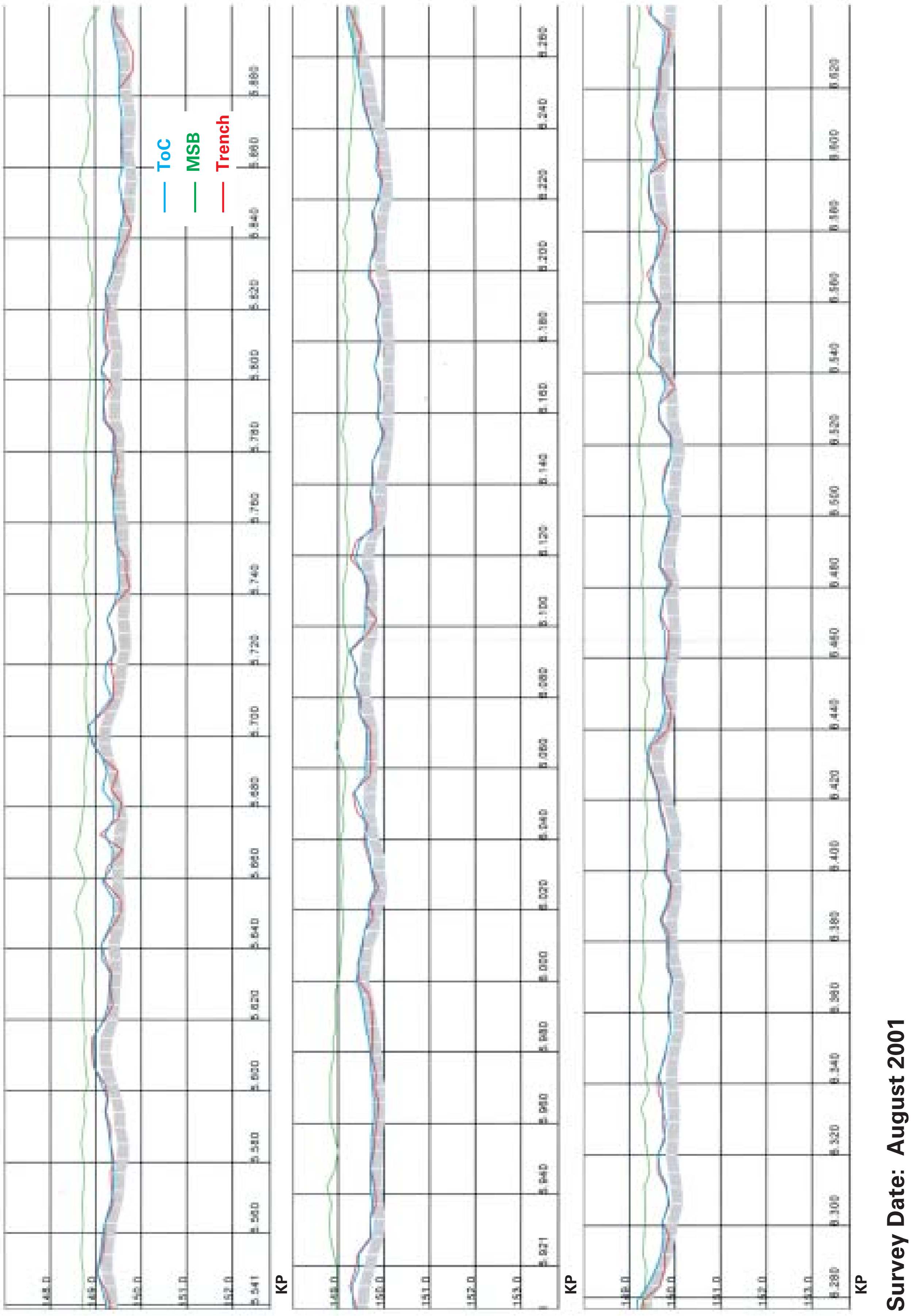
ToC
MSB
Trench
Depth
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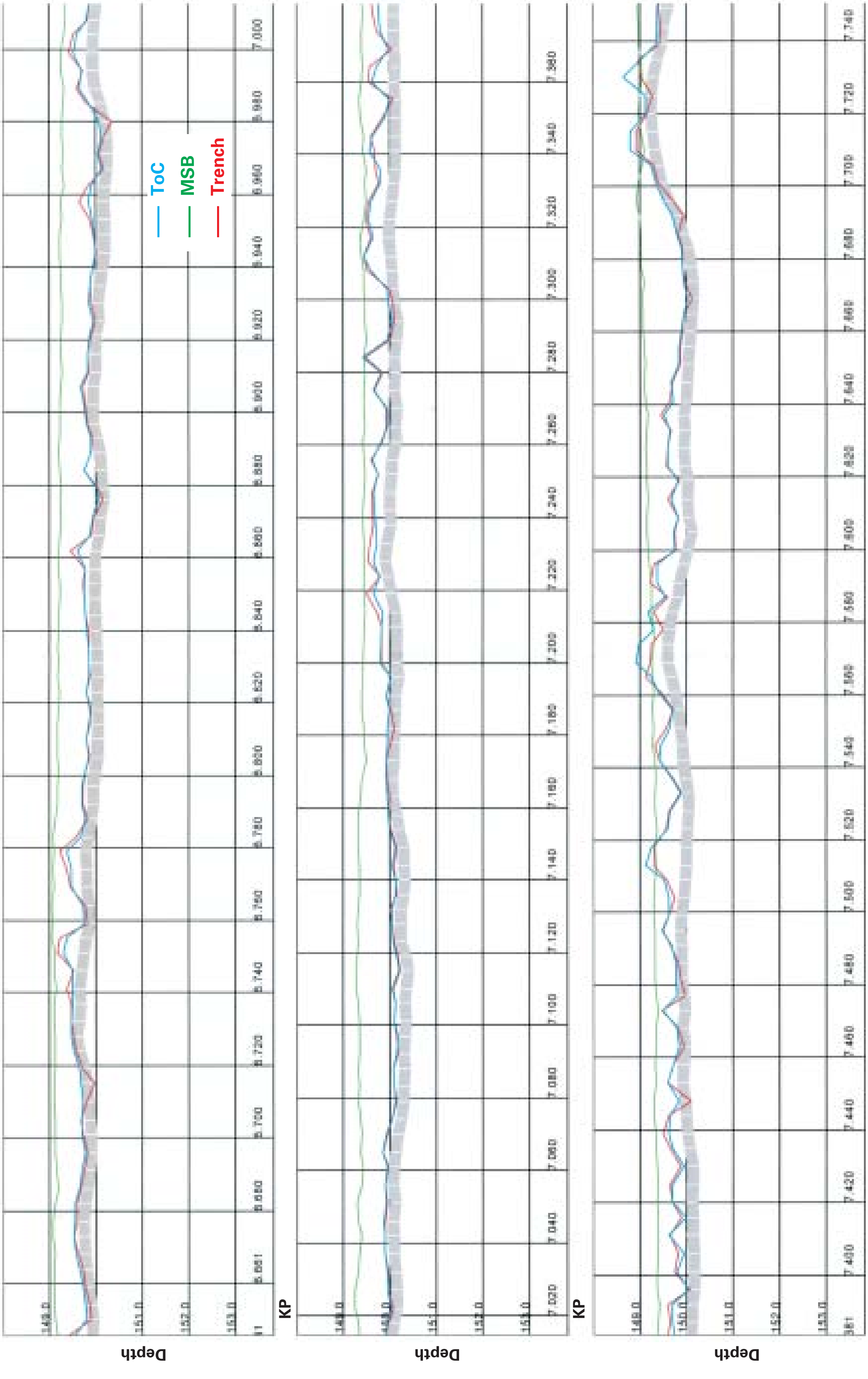
Survey Date: August 2001



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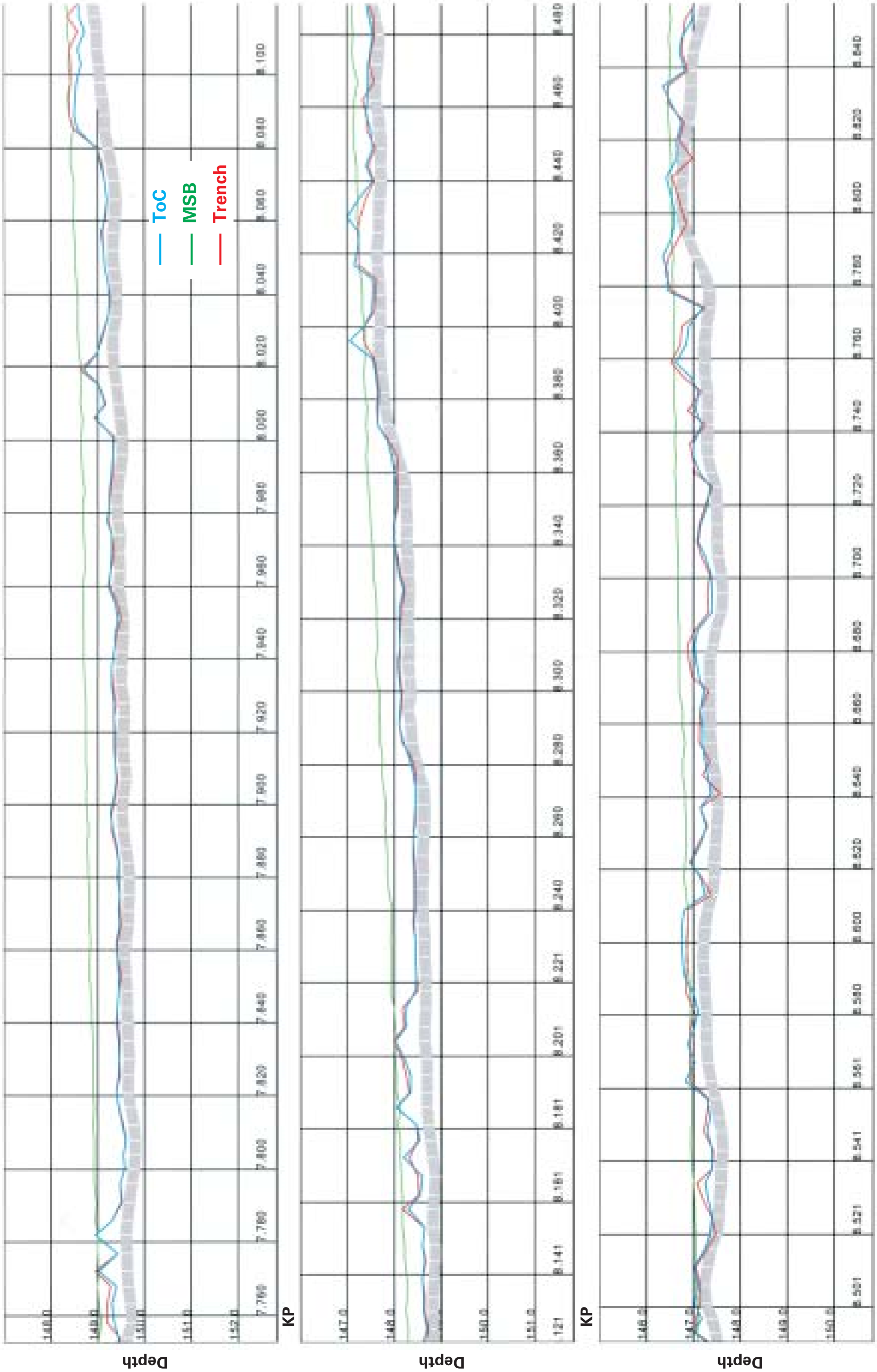

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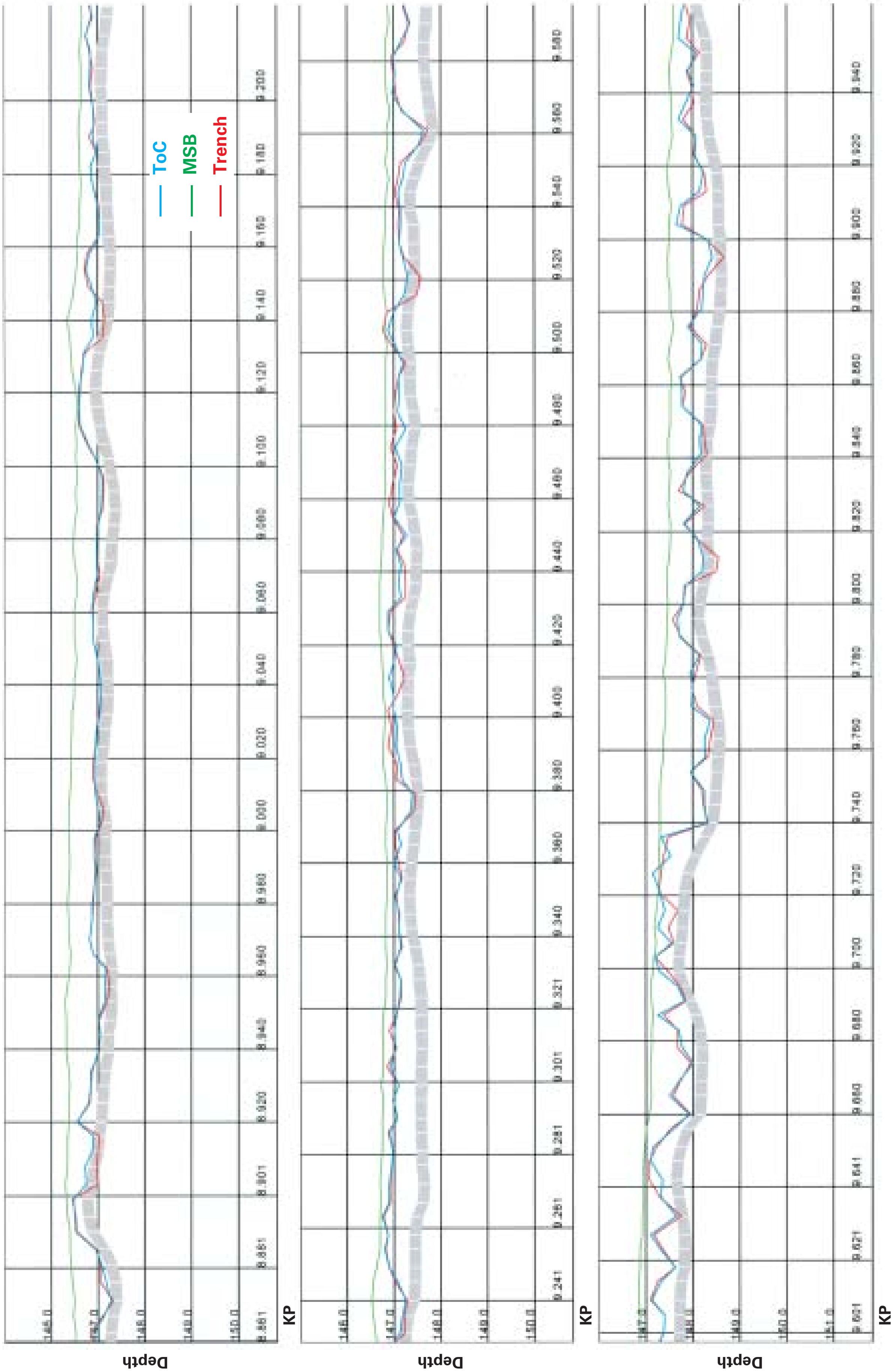
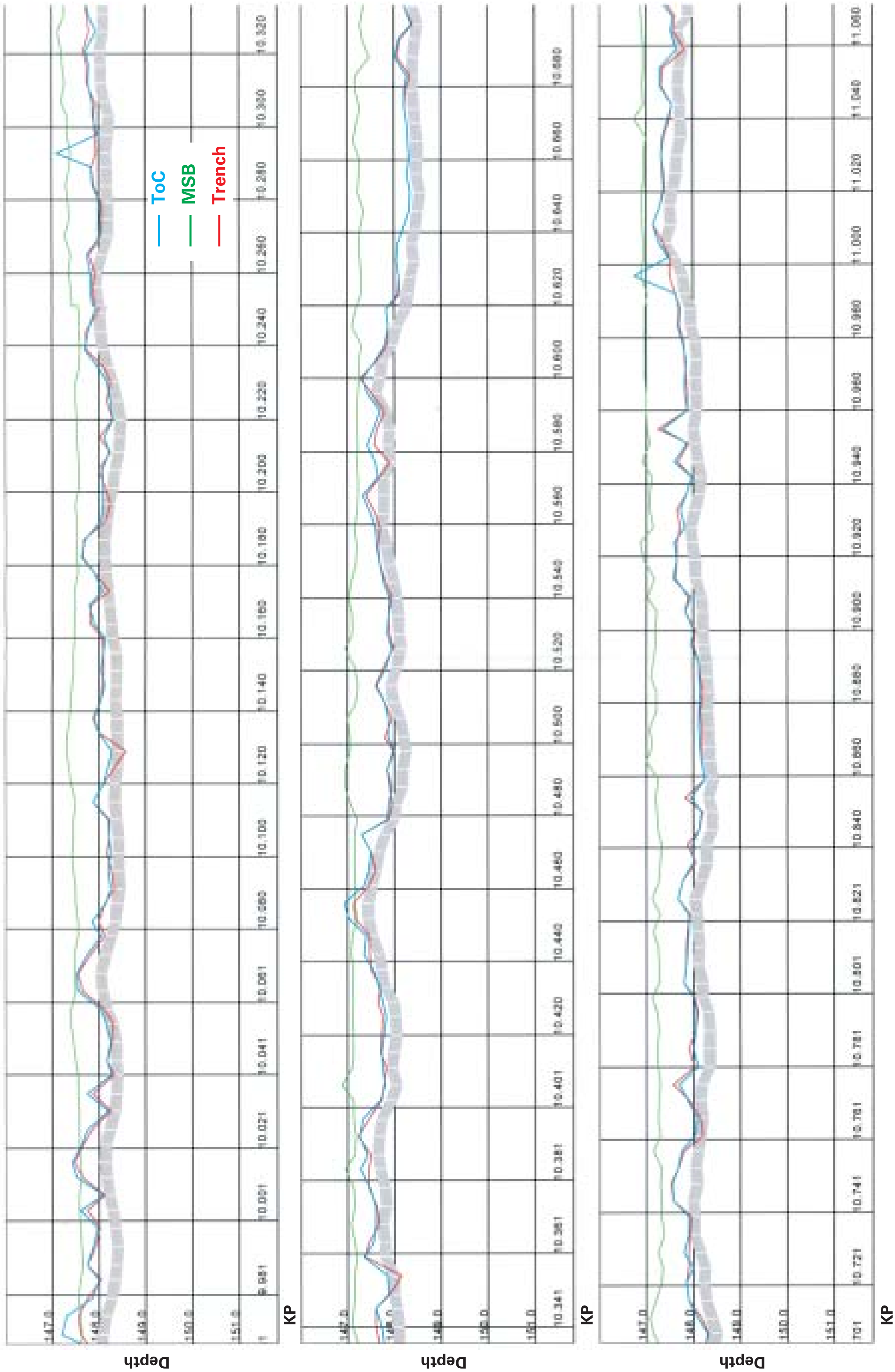


Survey Date: August 2001



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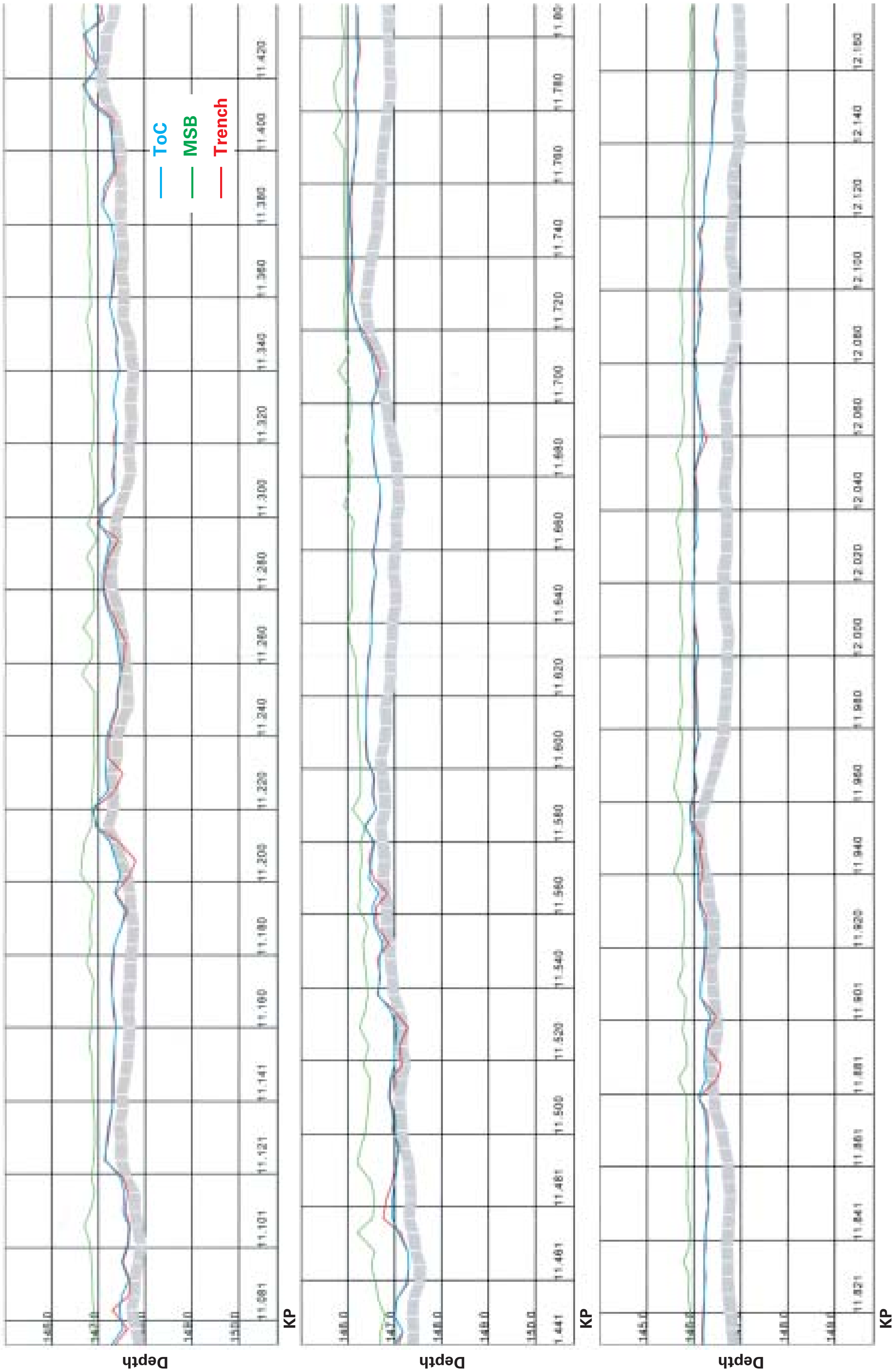

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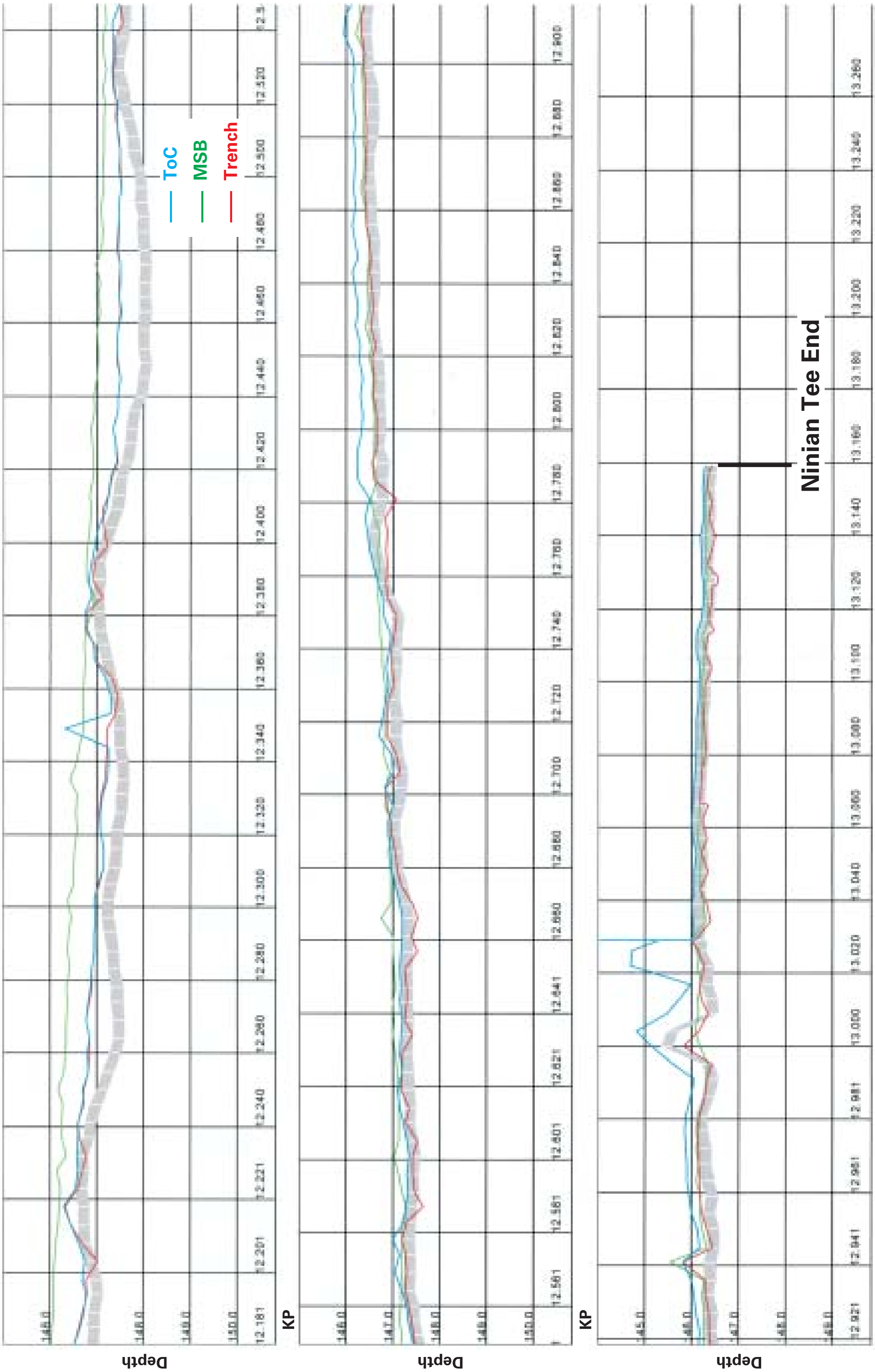

Survey Date: August 2001

20.8 Summary of Applicable Legislation

Aspect	Applicable Legislation: English	Applicable Legislation: Scottish	Regulator: English	Regulator: Scottish	Requirement
Costal Concerns	*Coastal Protection Act 1949 Section 34, (as extended by the Continental Shelf Act 1964*		DfT		Provides that where obstruction or danger to navigation is caused or is likely to result, the prior written consent of the Secretary of State for the Department for Transport (DfT) is required for the siting of the offshore installation.
Costal Concerns	*Dangerous Substances in Harbour Areas Regulations*		HSE		Controls the carriage, loading, unloading and storage of all classes of dangerous substances in harbours and harbour areas.
Decommissioning	*Petroleum Act 1998*		DTI		This Act consolidates Parts I and II of the Petroleum Act 1987 with other petroleum enactments including the Petroleum (Production) Act 1934, the Petroleum and Submarine Pipe-lines Act 1975 and the Oil and Gas Enterprise Act 1982. It provides a framework for the decommissioning process.
Health & Safety	*Health and Safety at Work Act 1974 and all the applicable legislation that lies beneath this over-riding Act.*		HSE and Environmental Health Department of Local Authority		The law imposes a responsibility on the employer to ensure safety at work for all their employees. As well as this legal responsibility, the employer also has an implied responsibility to take reasonable steps as far as they are able to ensure that the health and safety of their employees is not put at risk.
Health & Safety	*Control of Substances Hazardous to Health (COSHH)*		HSE		Using chemicals or other hazardous substances at work can put peopleís health at risk. The law requires employers to control exposure to hazardous substances to prevent ill health
Health & Safety	*The Offshore Installations (Safety Case) Regulations 1992*		HSE		The Safety Case demonstrates that risks of major accidents are identified and that measures are, or will be, taken to reduce risks to persons affected to as low as reasonably practicable. The existing North West Hutton Field Safety Case will be updated. If a heavy lift vessel is to be used in the removal, then notification of construction activity to HSE will be required.
Pollution Prevention	*Environmental Act 1995*		EA	SEPA	The provision of this Act is to encourage producers to promote the waste hierarchy.
Pollution Prevention	*Environmental Protection Act 1990*		EA	SEPA	Part I of the EPA identifies PPC as an integrated approach to pollution control. Part II sets out waste management and disposal requirements that affect all companies producing controlled waste, particularly section 34 that introduces the Duty of Care.
Pollution Prevention	*Food and Environment Protection Act 1985*		DEFRA	DTI	The dumping of wastes at sea is prohibited, except under licences issued under Part II of the Food and Environment Protection Act 1985 (FEPA II). The categories of licensed waste have included sewage sludge, solid industrial waste and dredged materials. Under the OSPAR Convention, only dredged material, fish processing waste, inert materials of natural origin and vessels or aircraft may now be disposed of at sea in the UK under FEPA II.
Pollution Prevention	*Offshore Chemical Regulations*		DTI		These regulations apply the provisions of the OSPAR decision to formulate a Harmonised Mandatory Control System for the use and discharge of chemicals used in the offshore oil and gas industry. Permits are required for both the use and discharge of chemicals
Pollution Prevention	*Offshore Petroleum Activities (Oil Pollution Prevention and Control) Regulations 2004*		DTI		Cover oil discharges and spills. Permits will be required to undertake any activity which could result in a spill or discharge of oil into the sea. They are expected to be in force early in 2005, and to replace the Prevention of Oil Pollution Act 1971 (below).
Pollution Prevention	*Prevention of Oil Pollution Act 1971*		DTI		Covers oil discharges. Prohibits any discharge of oil into the sea from oil and gas operations unless an exemption has been specifically issued. An exemption is therefore required for all exploration and production discharges that contain residues or traces of mineral oil. Controlled discharges include produced water, oil-based mud drill cuttings, sands and sludges. Specific requirements regarding oil content, sampling, analysis and reporting requirements are included with each exemption
Pollution Prevention	*Pollution Prevention and Control Act 1999, under which come PPC (England and Wales) Regulations 2000, and the PPC (Scotland) Regulations 2000, as amended*		EA	SEPA	Require operators of installations carrying out specified activities to submit an application for a permit. The Regulations implement the European Community (EC) Directive 96/61/EC on Integrated Pollution Prevention and Control (ìth e IPPC Directiveî), while also building on pre-existing national arrangements for pollution control introduced under the Environmental Protection Act 1990 (EPA 90). The Act employs an integrated approach to regulating certain industrial activities and installations that may cause pollution or have other environmental effects.

Aspect	Applicable Legislation		Regulator		Requirement
	English	Scottish	English	Scottish	
Waste Management	*Environment Protection (Duty of Care) Regulations 1991*		EA	SEPA	Covers consignment of waste. The Duty of Care is a legal obligation which applies to anyone who imports, produces, carries, keeps, treats or disposes of waste. The subcontractors responsible for the onshore disposal of North West Hutton will be responsible for ensuring that the chain of Duty of Care documentation is initiated. Either BP or the contractor will be designated as the producer of the waste (depending on the details of the disposal contract) and all parties in the chain of waste will be required to ensure that all other parties act within the law.
Waste Management	*Hazardous Waste Directive (91/689/EEC)*		EA	SEPA	Covers all Hazardous Waste. Catalogues waste from all sources of waste generation, identifying their hazardous status. The most significant aspects of the North West Hutton topsides and jacket will be LSA, asbestos and hydrocarbon residues.
Waste Management	*Landfill Directive (199/31/EEC)*		EA	SEPA	Introduced to reduce the amount of biodegradable material being sent to landfill. It imposes a ban on co-disposal of hazardous, non-hazardous and inert waste in the same landfill; in addition certain types of wastes are banned including liquid wastes. All waste must undergo pre-treatment prior to disposal in order to reduce potential harm to the environment.
Waste Management	*Landfill Tax Regulations 1996*				A tax on the disposal of waste to licensed landfill (unless exempt). Landfill tax is applied to the license holder for the landfill site, who then applies the rate of tax to those depositing waste as part of landfill charges.
Waste Management	*Merchant Shipping and Maritime Security Act 1997*		DfTand MCA		Covers waste storage and handling on the dock / quayside. This act requires waste to be landed at dedicated reception terminals
Waste Management	*Prevention of Oil Pollution (Reception Facilities) Order 1984, replaced by the Merchant Shipping (Port Waste Reception Facilities) Regulation 1997*		EA MCA	SEPA	Covers waste storage and handling on the dock / quayside. Oil loading terminals, repair and other ports must have shore facilities for reception of landed oily wastes
Waste Management	*Radioactive Substances Act 1993, as amended*		EA	SEPA	Covers all radioactive waste. Requires authorisation for the use of radioactive substances, but the act additionally deals with the accumulation and disposal of radioactive waste. Authorisation is required before such waste can be caused or permitted to be disposed of.
Waste Management	*Special Waste Regulations 1996, as amended*		EA	SEPA	Covers all hazardous waste. Define special waste in accordance with the EU Hazardous Waste List. The regulations provide for a consignment note system which allows the Environment Agency / Scottish Environment Protection Agency to monitor the movement and location of such wastes.
Waste Management	*Transfrontier Shipment of Waste Regulations 1994, as amended by the Environment Act 1995 (Consequential Amendment) Regulations 199, and the Special Waste Regulations Council Regulation 259/93/EEC of 1 February 1993 on the supervision and control of shipments of waste within, into and out of the European Community, as amended.*		EA	SEPA	Once the North West Hutton facilities have been moved from their current location and prepared for landing onshore in the UK for recycling and disposal, they will fall under UK waste management law and policy. If it is decided that the structures are to be disposed of to Norway, they will fall first under the transfrontier shipment of waste regulation and then, when transferred to Norway, under Norwegian policy. The international shipment of waste is governed by multilateral environmental agreements that take effect through EU and national legislation. This legislative framework provides a system of control that requires those wishing to ship hazardous wastes to use a consignment note so the countries concerned can provide prior informed consent to the movement. These systems are implemented in national states by bodies nominated as competent authorities. According to the EU Regulations, the notified (the original producer, the holder or the person designated by the laws of the State of dispatch in the case of waste imported into or in transit within or through the Community) must apply for authorisation to the competent authorities of destination and send a copy of the application to the authorities of despatch, transit or destination. The notifier must make a contract with the consignee for the disposal of the waste. The contract must oblige: the notifier to take the waste back if the shipment has not been completed or if it has been affected in violation of this Regulation; the consignee to provide a certificate to the notifier that the waste has been disposed of in an environmentally sound manner.

Aspect	Applicable Legislation		Regulator		Requirement
	English	Scottish	English	Scottish	
Waste Management	*Waste Management Licensing Regulations 1994*		EA	SEPA	These regulations underpin the entire waste management licensing system, implementing the requirements of the EU Waste Framework Directive (75/442/EEC as amended). The regulations detail the definition of waste, disposal and recovery operations, and who requires a license
Waste Management	*EC Regulations 2037/2000 on Substances that Deplete the Ozone Layer*				Halon removal is a legal requirement under the EC Regulation 2037/2000 on Substances that Deplete the Ozone Layer. The decommissioning of halon was required by the end 2003 and all halon was removed from North West Hutton prior to this date and destroyed or recycled for critical users.
Water Management	*Water Resources Act 1991*	*Control of Pollution Act 1974, as amended by the Water Act 1989*	Relevant individual Water Authority	Scottish Water	Principle regulations within the UK that control water quality, quantity, prohibiting the discharge of any poisonous, noxious, or polluting substances. A discharge consent is required, with authorisation from the relevant regulatory body.
Safety Management	*Offshore Installations (Safety Case) Regulations 1992*		HSE		Submission of Safety Case for abandonment of a fixed installation.
Notification of Offshore Activities			Hydrographic Office		At least six weeks advance notification of offshore activities is required by the Hydrographic Office so that they can prepare Notices to Mariners to update Admiralty charts. The Radio Navigation Warnings section of the Hydrographic Office should be contacted 24 hours before any decommissioning activities are due to commence (e.g. towing of topsides). The Contact Details are: Duty Officer Tel No. 01823 723315 (direct) or 01823 337900 ext 3289 Fax No. 01823 322352 Email: rnwuser@ukhornw.u-net.com

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Confidentiality Statement

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