Services to
Industry Groups: Energy

Oil and Gas Decommissioning Opportunity Review

Scottish Enterprise

Oil and Gas Decommissioning Opportunity Review

July 2005

Oil & Gas Decommissioning Opportunity Review

A report to Scottish Enterprise Grampian by

Douglas-Westwood Limited and the TCS Partnership

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1. SUMMARY AND CONCLUSIONS

1.1 Summary

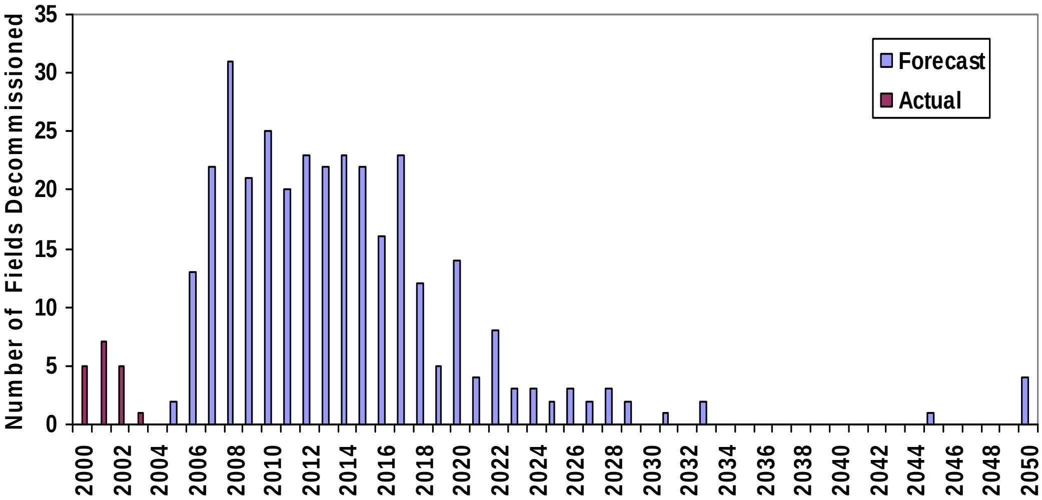


Figure 1.1: Decommissioning Dates – All North Sea Sectors

On present estimates we expect the value of the North Sea decommissioning market to begin strong growth in 2009 and a high level of activity to continue until around 2020. Factors that could delay this include significant increases in oil & gas prices and a lack of availability of heavy lift vessels.

Many past forecasts have seriously underestimated how long the decommissioning market would take to develop, for a number of reasons:

- New technology and management practices have extend the life of fields.
- Increased inward investment arising from a new generation of small and 'tail-end' operators committed to field life extension.
- The success of the UK 23rd Round where the highest number of applications since 1972 have been received and which will materially forestall the timing of decommissioning.
- Since 2003, oil (and gas) prices have been rising strongly, extending the economic lifetime of existing fields and increasing the price used by operators to sanction developments.

However, activity is now beginning across the sectors of the North Sea and the next decade should see the growth of a sector that offers many business opportunities for the Scottish supply chain.

It is important to recognise that the opportunities for Scottish industry are not confined to the UK sector and that Norway in particular offers good prospects. Norwegian company Aker Kvaerner's announcement that they will use the Greenhead Base, in Lerwick, as a site for onshore disposal of parts of the Total-owned Frigg platform is an example of this.

The market for offshore field decommissioning is a subject of considerable complexity. It demands oil companies and contractors develop an understanding of many factors including the regulatory framework within which the decommissioning process has to operate (if only as each regulatory requirement contains business opportunities). The decommissioning process has five key stages:

1. Consideration of decommissioning implications during the initial project definition and field development.
2. Decommissioning consideration during annual review of asset performance through to the 'cessation of production' (COP) decision.
3. Preparing all necessary compliance documentation for decommissioning.
4. Execution of the decommissioning programme.
5. On-going monitoring and management of residual liabilities.

Although it is logical that the industry should focus on stage 4 – the actual decommissioning process, all phases generate business opportunities for the supply chain.

1.2 The Market

Table 1.1: Summary of Market Values based on COP

2005-2050	*£ billion*
All North Sea – Full Removal	15.5
All North Sea – Minimum Removal	12.5
UKCS – DTI Estimates	15.0
UKCS – UKOOA Estimates	9.1
UKCS – this study	**8.3**
2005-2015	
UKCS – this Study	**6.3**

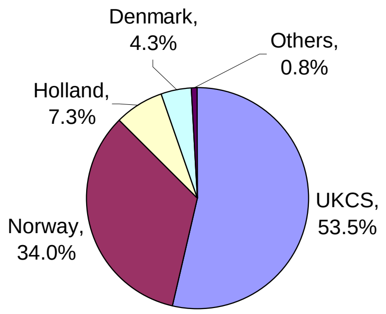


Figure 1.2: Total North Sea Decommissioning Market

There are two possible bases of estimates of total removal costs based on present views of fields' year of cessation of production.[1] The first, £15.5 billion, is for full removal of all offshore facilities including concrete gravity structures, whilst the second £12.5 billion, is for the minimum compliant cost which assumes that applications will be made under the OSPAR derogation procedures to leave in-situ concrete gravity bases and the footings of steel jackets weighing more than 10,000 tonnes.

Based on the lower figure, the UK will form the largest market at some £8.3 billion of which we expect £6.3 billion be spent over the next decade. Norwegian market development will lag the UK and continue long after most of the UK sector has been decommissioned.

Estimating annual expenditure is a much more complex problem to which there is no precise solution.

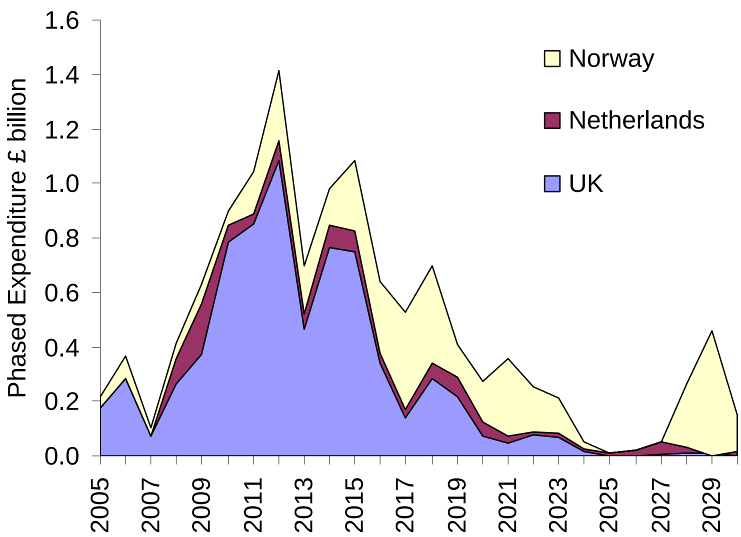


Figure 1.3: Annual North Sea Decommissioning Expenditure Forecast – Main Countries

Despite the beginnings of some Norwegian projects, overall decommissioning activity in the North Sea will be dominated by the UK sector.

When the phasing of expenditure throughout field decommissioning programmes is taken into account, the supply chain is likely to see annual business values as shown alongside.

In addition, smaller amounts of work will also occur in the Danish and German sectors.

[1] In the UK DTI grants COP and the operator is unable to proceed towards decommissioning with this.

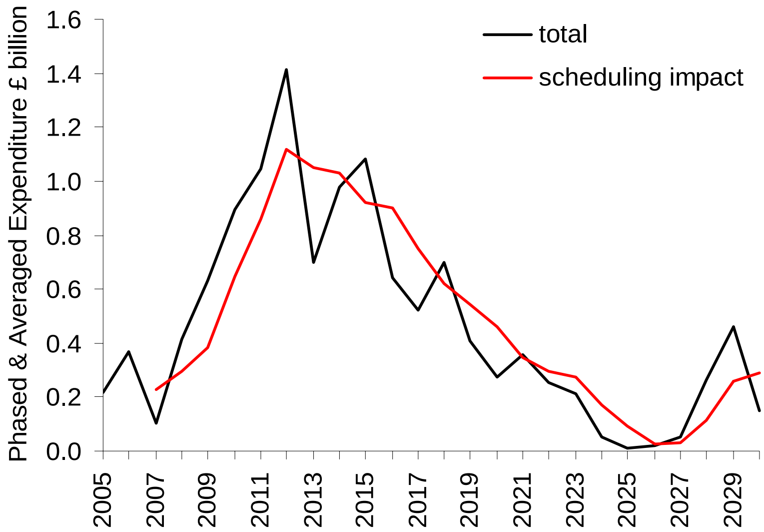


Figure 1.4: Annual North Sea Decommissioning Expenditure – Scheduling Impact

In addition to the phasing of expenditure, there will also be some additional smoothing as a function of the availability of heavy lift vessels and other services. We also expect operators to group together decommissioning to reduce overall costs. Both factors which will serve to further spread the expenditure peaks over time.

In the chart we endeavour to take into account these factors.

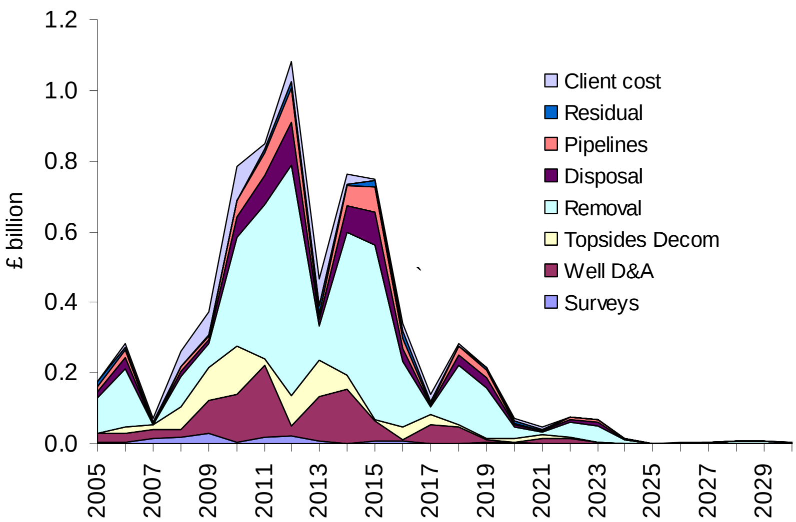


Figure 1.5: Annual UK Decommissioning Expenditure – by Main Supply Sector

If operators' present plans hold true, then after 2007 we expect the UK market to grow dramatically with £6.3 billon worth of business to be available to the supply chain over the next decade.

Table 1.2: UK Decommissioning – Annual Spend Forecast to 2015 (£ million)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total
Surveys	4	3	13	20	30	5	19	24	10	1	9	138
Well P&A	26	26	28	23	106	154	237	36	154	193	75	1058
Topsides Decommissioning	0	18	15	69	100	154	23	100	125	49	5	658
Facility/Subsea Removal	99	165	0	86	67	307	437	653	96	403	494	2807
Reception & Disposal	19	32	0	17	14	65	95	145	22	94	119	622
Pipelines	14	25	0	14	11	51	74	113	17	73	92	484
Residual Liability	9	4	7	1	4	3	15	22	33	5	22	125
Operator Costs	1	13	10	48	70	108	16	70	88	34	4	462
Total	172	286	73	278	402	847	916	1163	545	852	820	6354

Our overall view is that based on current decommissiong dates the North Sea decommissioning market is likely to peak at about £1.1 billion and possibly in 2012. However, operators could still delay physical decommissioning of individual fields significantly beyond their COP date.

As in every other sector, the revenues available to the contractors will be a function of their position in contract sequence from planning, through removal, to residual activities.

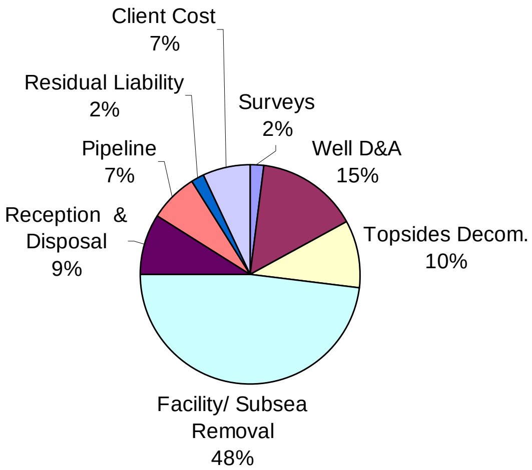


Figure 1.6: Business Segmentation

The physical removal of offshore structures will account for almost half the industry's spend. The largest part of this is the costs of heavy lift vessels. The decommissioning and abandonment of wells is also a major activity and there is a major potential for those able to offer low cost approaches.

Residual Liabilities refer to the post-decommissioning monitoring and long-term surveillance of the cleared site.

1.3 Opportunities for Scottish Industry

In this report we identify some 40 different activities involved in decommissioning and the Scottish supply chain has the capability to address much of the associated market, from insurance to inspection, from project management to public relations, from safety assessments to subsea contracting.

There are, however, two major gaps:

- Heavy lift vessels – where there is no Scottish ownership;
- Personnel – there is little decommissioning sector experience and this must be built.

In all other sectors there would appear to be considerable capability, as Scotland probably possesses one of the world's largest and widest capability offshore industry clusters.

The major challenge is to reduce costs of the large engineering tasks. The original massive North Sea platforms were not installed with a view to ease of decommissioning, so when the main activity begins there will be considerable potential for companies able to offer new cost effective solutions.

To win business, suppliers must be registered with FPAL and also become pre-qualified with the top-level decommissioning 'Tier 1' contractors, such as the heavy lift and project management companies, not only in the UK but also in Norway and the Netherlands.

As the North Sea has matured and field development activity has fallen heavy lift vessel capacity has transferred to other parts of the world. Proposed decommissioning activity will have to compete for lift vessel time with new field developments in other regions, a factor that may serve to further slow the development of the market. For this reason, field operators should consider taking long-term options on heavy lift vessels in order to assure themselves of capacity to meet future decommissioning requirements.

2 INTRODUCTION

This report was commissioned by Scottish Enterprise Energy Team and produced by Douglas-Westwood Limited and the TCS Partnership in June 2005. Its objectives are to review the opportunities associated with the market for the decommissioning of North Sea offshore fields.

To many suppliers decommissioning will be a business sector with which they are unfamiliar. Secondly, we recognise that the reader may not be in the supply sector, but perhaps in finance, the public sector or indeed may be an operator. This report assumes no reader knowledge of the subject, endeavours to provide a detailed briefing for these different user groups and is, therefore, structured as follows:

1. SUMMARY
2. INTRODUCTION
3. NORTH SEA FACILITIES – We begin by discussing and tabulating numbers and types of North Sea installations as these ultimately define the market prospects.
4. THE REGULATORY REGIME – Decommissioning is a complex business area and much of this originates from the raft of international and national laws and regulations within which the activity will be carried out. To a great extent these are more onerous in Europe than those that would be applied in other regions of the world. Therefore our review is possibly more comprehensive than might normally be found in a conventional market report.

   It should also be recognised that many of these regulations generate specific business opportunities.
5. HOW FIELDS ARE DECOMMISSIONED – In this section we consider the complete process of decommissioning from the point of view of the decommissioning project manager. This ranges from the initial review of the available options and the physical act of decommissioning itself, through to the often-forgotten subject of residual liabilities.
6. THE SCOTTISH SUPPLY CHAIN – We examine the structure of the supply chain involved in the various stages of decommissioning, from the main 'Tier 1' contractors, to their 'Tier 2' suppliers and 'Tier 2' sub-suppliers. We also discuss the financial factors in these areas and comment upon the ability to benefit through experience
7. NORTH SEA ABANDONMENT PROGRAMMES – North Sea programmes are listed together with a selection of specific case studies.
8. DECOMMISSIONING ACTIVITY FORECASTS – This analysis is driven by data contained in the TCS North Sea Decommissioning Database. From this we develop expenditure forecasts, ultimately focusing on the UK sector segmented by main business sectors.

Table 2.1: Regional Definitions

Name	*Geographic Area*
UKCS	United Kingdom Continental Shelf
North Sea	All countries that border the North Sea (complete UKCS), Norway, Denmark, Netherlands, Germany
OSPAR	North East Atlantic – see map

This report uses information is taken from the TCS Abandonment Handbook and database in May 2005 which includes all facilities in operation or under construction.[2] The database does not include facilities under design but not committed to construction, or potential field developments.[3]

[2] The TCS source material is derived from published sources including the dti website www.og.dti.gov. Information on Norwegian facilities are taken from current data published by the Norwegian Petroleum Directorate. Information on the Dutch sector is taken from the Ministerie van Economische Zaaken – Oil & Gas in the Netherlands, website http://info.minez.nl/. Information on the Danish facilities taken from the Danish Energy Agency publication – Oil & Gas Production in Denmark. The published material is supplemented by information supplied by Operating companies.
[3] Noroil Publications issues tri-annual surveys of oil & gas field developments, in development, under consideration or shelved. Further information can be obtained by emailing noroilcontacts@enterprise.net

3 NORTH SEA FACILITIES

Figure 3.1: UK Sector – Main Infrastructure

Map courtesy of Petroleum Economist

		
Small Steel Platform (Brig – BG)	Large Concrete Platform (Gullfaks – Statoil) with modules being installed	Large Steel Platforms (Ekofisk – Phillips) with abandonment operations underway

Figure 3.2: North Sea Platforms

3.1 Development of Oil & Gas Industry in the UK North Sea

In 1965 BP discovered the West Sole Gas Fields in the UK sector, then between 1966 and 1969 Shell discovered the Leman, Indefatigable and Hewett Fields. In 1969 Amoco found the Montrose field and in Norway the giant Ekofisk fields were discovered. Production from many of these large fields continues today although production rates are declining and the issue of decommissioning arises.

The Ministry of Power issued the first offshore licence in 1964, and its successor, the Department of Trade & Industry, issued the one-thousandth licence in 1999.

The Petroleum Act 1998 vests all rights to the nation's petroleum resources in the Crown. But the Secretary of State (for Trade and Industry – i.e. the Government) can grant licences[4] that confer exclusive rights to "search and bore for and get" petroleum. Each of these licences confers such rights over a limited area and for a limited period. Part III of the Act deals with Submarine pipelines[5] and Part IV deals with Abandonment of Offshore Installations.[6]

Licences can be held by a single company or by several working together, but in legal terms there is only ever a single Licensee, however many companies it may include. All the companies on a Licence share joint and several liabilities for operations conducted under it. Each Licence actually takes the form of a Deed, which binds the Licensee to obey the licence conditions regardless of whether or not s/he is using the Licence at any given moment.

In 1994, the EU laid down strict rules that Member States have to follow when issuing petroleum licences, covering such things as the factors that may (and may not) be taken into account when deciding whether or not to issue a licence, and the minimum amount of public consultation. These rules were contained in the Hydrocarbons Licensing Directive,[7] which was implemented in the UK in 1995 by means of Hydrocarbons Licensing Directive Regulations.[8]

3.2 North Sea Oil & Gas Infrastructure

3.2.1 Number of Fields – Start of Production by Year

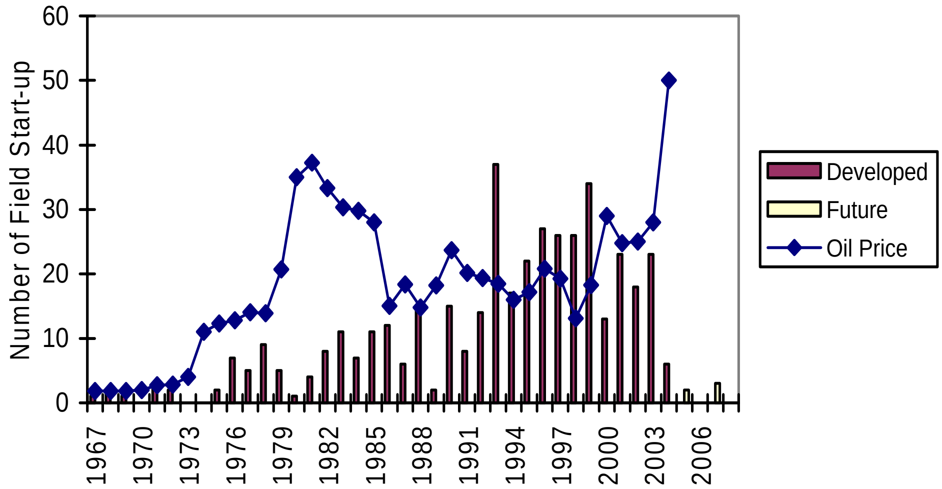


Figure 3.2: Number of Fields – Start of Production by Year

[4] The Government grants licenses under terms that reflect its obligations in International Law. This is discussed in more detail in Chapter 3 of this report.
[5] For more information see the website www.og.dti.gov.uk/upstream/infrastructure
[6] For more information see the website www.og.dti.gov.uk/upstream/decommissioning
[7] For further information see website http://europa.eu.int
[8] For further information see website www.legislation.hmso.gov.uk

The North Sea Oil & Gas infrastructure has developed since 1962, with peaks of activity occurring in 1977, 1985 and 1993. The frequency of field start-ups by year is shown above. As the North Sea basin matures, and the size of oil & gas finds decrease in size, future developments are likely to focus on subsea completions or extended reach drilling from existing facilities.

3.2.2 Distribution of Facilities by Country

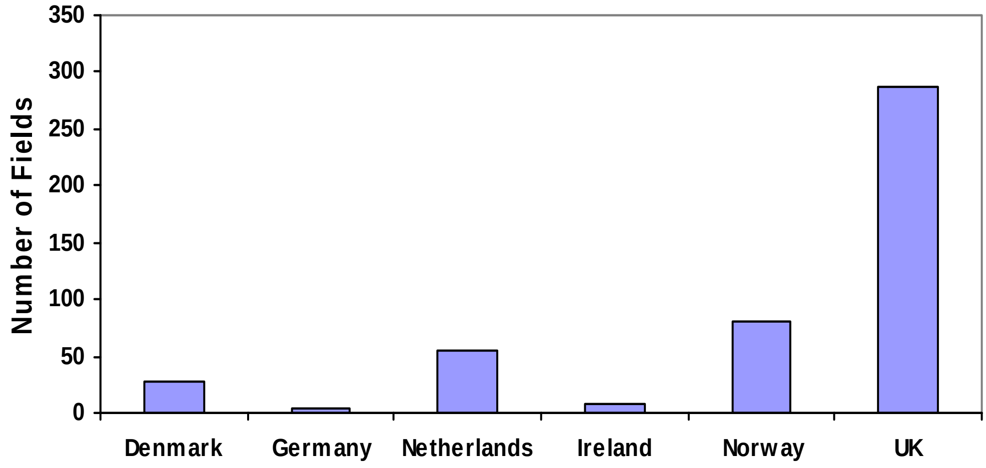


Figure 3.3: Distribution of Fields by Country

A total of 444 fields have been developed, or are in the process of being developed, in the North Sea. The distribution of fields by country is shown above.

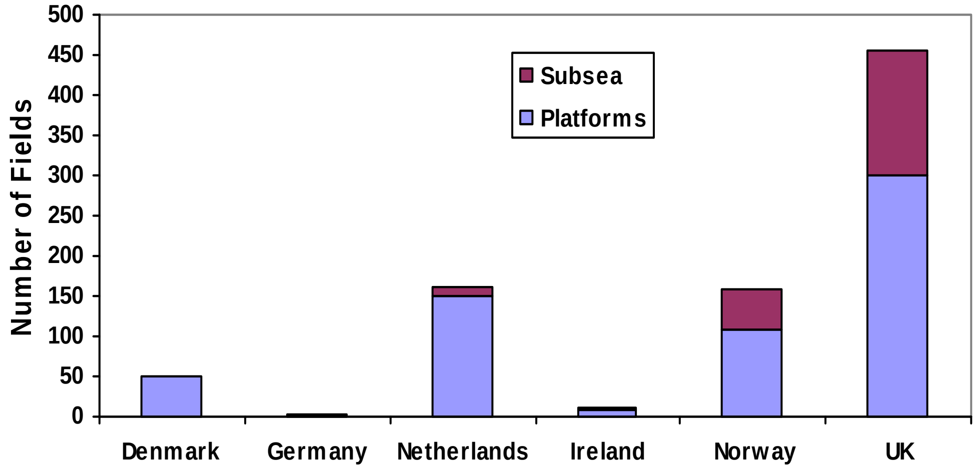


Figure 3.4: Development Type by Country

Within these 444 fields a total of 832[9] production facilities – either fixed and floating platforms or subsea completions – are either in production or in the process of development. Whilst the UK presents the greater decommissioning opportunity by virtue of its number of facilities, companies positioned to take advantage of this market would also be in a position to enter other sector markets.

[9] OSPAR maintains a database of offshore facilities, compiled from data supplied by the Operators. This database lists 921 identified facilities including those in Spanish waters falling into the OSPAR region. The difference in number between the OSPAR and TCS facility number is accounted for by the treatment of subsea facilities. TCS counts the subsea facilities around a fixed platform as part of the fixed facility, while OSPAR counts them separately.

3.2.3 Age of Infrastructure

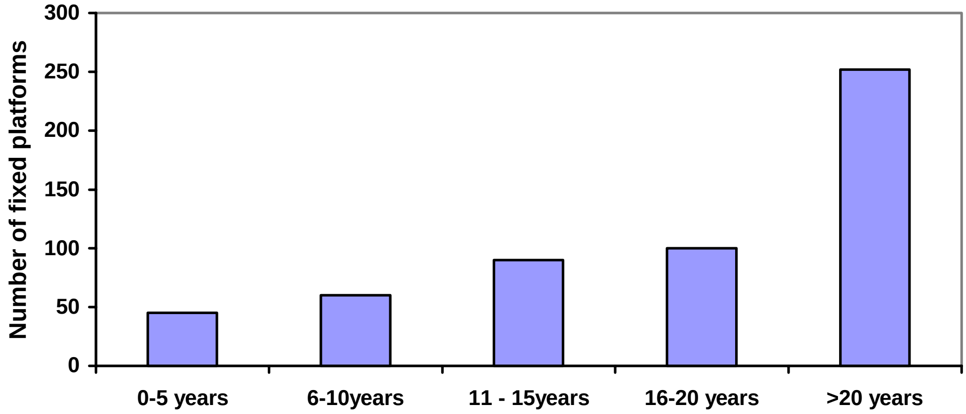


Figure 3.6: Age of Existing Platforms

The offshore platforms were all designed and constructed in compliance with all applicable national regulations, and appropriate codes and standards. The design specifications for structures, piping, electrical and control systems are normally listed in each platform's safety case document.

Since the first platforms were installed, in the North Sea in 1968, all platform substructures and topsides structures have demonstrated adequate overall reliability and robustness.

Variations in water depth and soil conditions ensure all the facility substructures are unique, but it is useful to subdivide into jackets, floating production systems and jack-up platforms. The jacket category also readily subdivides into:

- First generation 1960s and 1970s; these structures were designed primarily in accordance with the American Institute of Steel Construction (AISC) and the American Welding Society (AWS) procedures.
- In the UK, second generation 1980s and early 1990s; modifications, additions and new structures were designed in accordance with the Offshore Installations (Construction & Survey) Regulations.
- In the UK, third generation mid 1990s onwards were designed in accordance with the new Offshore Installations & Wells (Design & Construction) Regulations.

The majority of first generation structures are now beyond their original service life of typically 25 years,[10] and are strongly reliant on robust processes to manage risks and assure structural integrity.

Second generation structures are at the point in the design evolution where robustness and fatigue design considerations reached their most conservative, and so these are among the lowest risk structures in the North Sea with high reliability and high post damage survivability.

Third generation structures represent a consolidation in the design evolution where the high confidence in the design and fabrication process, advances in computational power, and project cost pressures resulted in more minimalist design configurations. These structures generally have lower post damage survivability, but high operational reliability.

[10] Platforms were originally designed for a mixture of service conditions. Process systems/equipment was typically designed for a service life set to the expected production life of the reservoir or 25 years if greater, whilst the topside structure was designed for a life of 3 times service conditions or 75 years. Jacket minimum fatigue lives were often set at a minimum 100 years.

3.2.4 Number & Type of Facility by Country

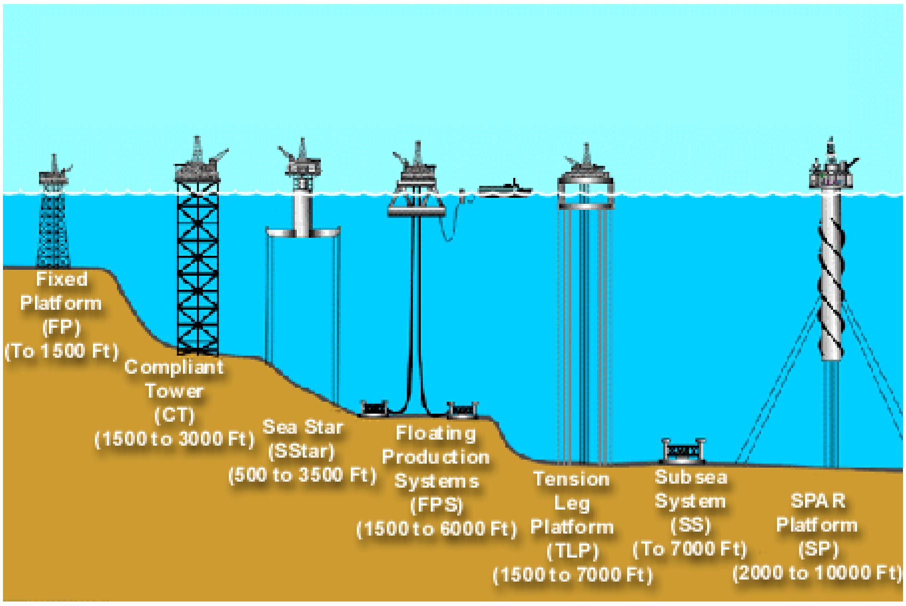
Table 3.2: Number of Facilities in the North Sea by Country

	Steel structures	*Steel gravity structures*	*Concrete gravity structures*	*Floating production*	*Jack up*	*TLP*	*Subsea*	*Total*
Denmark	46	0	1	0	1	0	1	49
Netherlands	140	1	1	0	6	0	12	160
Germany	2	0	1	0	0	0	0	3
Ireland	2	0	0	0	0	0	3	5
Norway	71	0	9	17	1	2	51	151
UKCS	245	1	8	30	7	1	155	447
Total	**506**	**2**	**20**	**47**	**15**	**3**	**222**	**815**

The total number of individual operating facilities, by type and by country is given in the table. As can be seen, the UK has more steel structures on its continental shelf than other countries in the North Sea, whilst Norway has the greater number of concrete gravity structures. The category of 'subsea', refers to collective subsea systems and hence does not identify individual subsea wells, subsea production manifolds, wellhead protection frames, pipeline end manifolds, and pipeline protection structures.

A diagrammatic representation of some of the facility types is shown below.

Figure 3.5: Types of Facilities



3.2.5 Number of Steel Jackets

Some 92% of the region's steel jackets weigh less than the OSPAR derogation weight of 10,000 tonnes, with the larger jackets being confined to the UK and Norwegian continental shelves.

Table 3.2: Number of Steel Jackets by Installed Weight (tonnes) & Country

Country	<2000	2001-4000	4001-10,000	10,001 -20,000	>20,000	Total
Denmark	40	5	1	0	0	46
Netherlands	140	0	0	0	0	140
Germany	2	0	0	0	0	2
Ireland	0	2	0	0	0	2
Norway	12	16	35	8	0	71
UKCS	167	22	24	26	6	245
Total	361	45	60	34	6	506

Table 3.3: Number of Steel Jackets by Water Depth and Country

Country	<30m	31-55m	56 -100m	101-150m	>150m	Total
Denmark	0	41	5	0	0	46
Netherlands	115	25	0	0	0	140
Germany	1	1	0	0	0	2
Ireland	0	0	2	0	0	2
Norway	4	0	49	15	3	71
UKCS	77	99	27	36	6	245
Total	197	166	83	51	9	506

Table 3.4: Number of Facilities by Water Depth

Facility	<30m	31-55m	56 -100m	101-150m	>150m	Total
Fixed platforms	196	168	82	51	9	506
Floating Production	1	0	14	18	14	47
Subsea systems	24	24	55	82	37	222
Concrete Gravity	1	2	6	2	2	20
Steel Gravity	0	1	1	0	0	2
Jack-up	7	3	4	0	0	15
TLP	0	0	0	2	2	3
Total	229	198	162	162	64	815

3.2.6 Pipeline Infrastructure

Table 3.5: Pipeline Lengths in Kilometres by Diameter (inches)

Country	<6	8-10	12-14	20-24	36	40>	Total
Denmark	103	108	137	319	215	0	882
Netherlands	391	393	343	617	599	0	2343
Germany	127	0	0	118	0	0	245
Ireland	0	12	7	61	0	0	80
Norway	267	409	852	849	2105	2397	6879
UKCS	1507	1226	1595	2801	4637	7	11773
Total	2395	2148	2934	4765	7556	2404	22202

The subsea pipeline network, developed over the same period, is summarised above. A wide variety of pipeline diameters have been utilised, but for the table, diameters have been grouped about the nominal diameters shown. For each pipeline size the total length of pipeline is given in kilometres. The total weight of the pipeline infrastructure is approximately 14 million tonnes.

3.2.7 Wells

Table 3.6: UKCS Well Numbers by Location

Location	Wells
Northern North Sea	5415
Central North Sea	911
Southern North Sea	1355
West of Britain	287
West of Shetlands	258
Total	8226

The total number of wells in the UKCS is estimated at 8,226.[11] This can be broken down by UKCS region as shown alongside.

For licensing purposes, the UKCS is divided into quadrants, each measuring 1º longitude by 1º latitude. Each of these quadrants is given a unique number and is subdivided into 30 blocks. In some instances a block may be further divided into sub-blocks; a, b, c, etc. as shown. The average size of a complete block is approximately 250 square kilometres.

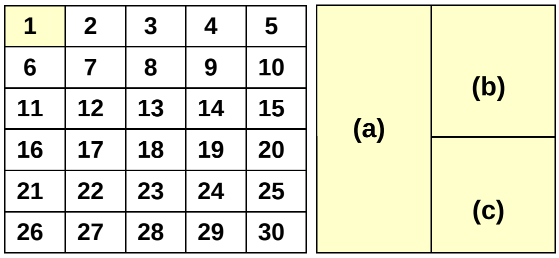


Figure 3.6: UKCS Block Structure

All wells drilled in the UKCS are allocated a unique identifier and require the consent of the appropriate Government department. A typical well designation number will comprise:

15/16a-T10A

Quadrant identifier	**15**
Block Number within quadrant 15	**16**
Part of block number 16	**a**
Platform identifier, in this case the Tartan Platform. If no identifier is given, the well is a sub sea well	**T**
Sequential well identification number	**10**
Well history identifier, this well has been spudded once and re-drilled. Letters Y, Z identify sidetracked wells	**A**

Figure 3.7: UKCS Well Identifiers

3.2.8 Third Party Access to Offshore Infrastructure

The investment required to build the infrastructure needed to transport oil & gas from offshore fields is characterised by significant costs and irreversibility. This can lead to conflict between the efficient use of resources and the wish for greater competition.

The evolution of offshore infrastructure on the UKCS has been characterised by companies developing pipelines for sole usage, followed by ullage (i.e. spare capacity) progressively being made more available for use by third parties on payment of a tariff for transportation and processing services. Field-dedicated lines are economically viable when fields are relatively large but become less viable as fields get smaller. As a consequence, there is scope for gains by all parties if the owners allowing access to their existing infrastructure, with the infrastructure owners gaining additional revenue from the new users, make the development of small fields viable.

[11] Well data/information is available on the DTI website www.og.dti.gov.uk/upstream/well_consents

3.3 Scottish Support Infrastructure

Whilst this report focuses on decommissioning of the offshore infrastructure, the associated onshore support infrastructure through to the downstream receiving and processing plants form an integral part of the oil industry 'system' dynamics. Decommissioning of offshore facilities will progressively impact the onshore infrastructure. This section of the report describes the onshore support infrastructure from supply base facilities through support services, construction sites, pipeline landfalls and oil terminal facilities.[12]

Supply Bases – Aberdeen and Peterhead harbours provide the important supply base and warehousing facilities in support of offshore activities. Dundee and Montrose harbours also play a role in the handling of oil-industry vessels. Significant infrastructure has also been developed at Lerwick in the Shetlands, which includes service bases and rig maintenance facilities.

Supply Services – Aberdeen and Peterhead are the centres for equipment and tool suppliers and the service companies like Wood Group and Amec supplying offshore operations and maintenance operatives. It has been estimated that some 18,000 people are employed in offshore work and a further 23,000 in onshore administrative and service functions and a further 18,000 people indirectly employed through the complete supply chain.[13]

Fabrication Sites – The gradual reduction of oil & gas construction activities in the North Sea is a consequence of the maturity of the existing offshore infrastructure. This has resulted in the closure of many construction yards like Ardersier, Nigg, Hunterston and Loch Kishorn. Some pipeline construction and brown field related fabrication still takes place at facilities in Wick and Evanton on the Cromarty Firth. Also particually active is Burntisland Fabrications Limited who won the contract for the management, fabrication and provision of assistance with commissioning of the 3,650t wellhead deck, for the Buzzard field to be constructed at the company's facilities at Burntisland and Methil. The company is also working on the BP Rhum Project.

Pipeline Landfall – The offshore pipeline network links up to landfall sites in Scotland including:

- The Forties oil pipeline lands at Cruden Bay, north of Aberdeen, from which it tracks to the Kinneil plant at Grangemeouth.
- A number of gas pipelines from the central and northern North Sea land at St Fergus.
- Oil trunk lines land at the Flotta terminal in Orkney.

Oil Terminals

- The Sullom Voe Terminal in Shetland handles production from more than 24 oil fields. Some 275 tankers are currently handled at the terminal each year for the export of oil.
- The Flotta terminal in Scapa Flow receives oil from the Piper-Claymore-Tartan pipeline system.
- The Nigg oil terminal in the Cromarty Firth was built to handle oil via a pipeline from Beatrice and tanker shipments of oil from Gryphon and the Captain fields. As these fields cease production Nigg is looking to extend its operations.
- The St Fergus terminal was established to receive and process gas from the central and northern North Sea for onward transmission into the British Gas pipeline network.
- Mossmorran is the site for two petrochemical plants in Fife; the first handles natural gas liquids and the second, ethane. NGL is received via a pipeline from St Fergus.
- Grangemouth is a major refining facility with utility and distribution infrastructure. Some 1,500 tankers carrying oil and oil products move through Grangemouth each year.

[12] The source material for this section is taken from the position paper: *'A Strategy for Scotland's Coast and Inshore Waters'* prepared for the Scottish Coastal Forum in 2003.
[13] Aberdeen City & Aberdeenshire Council: *'Oil and Gas Prospects –Update'*

4 THE REGULATORY REGIME

4.1 Introduction

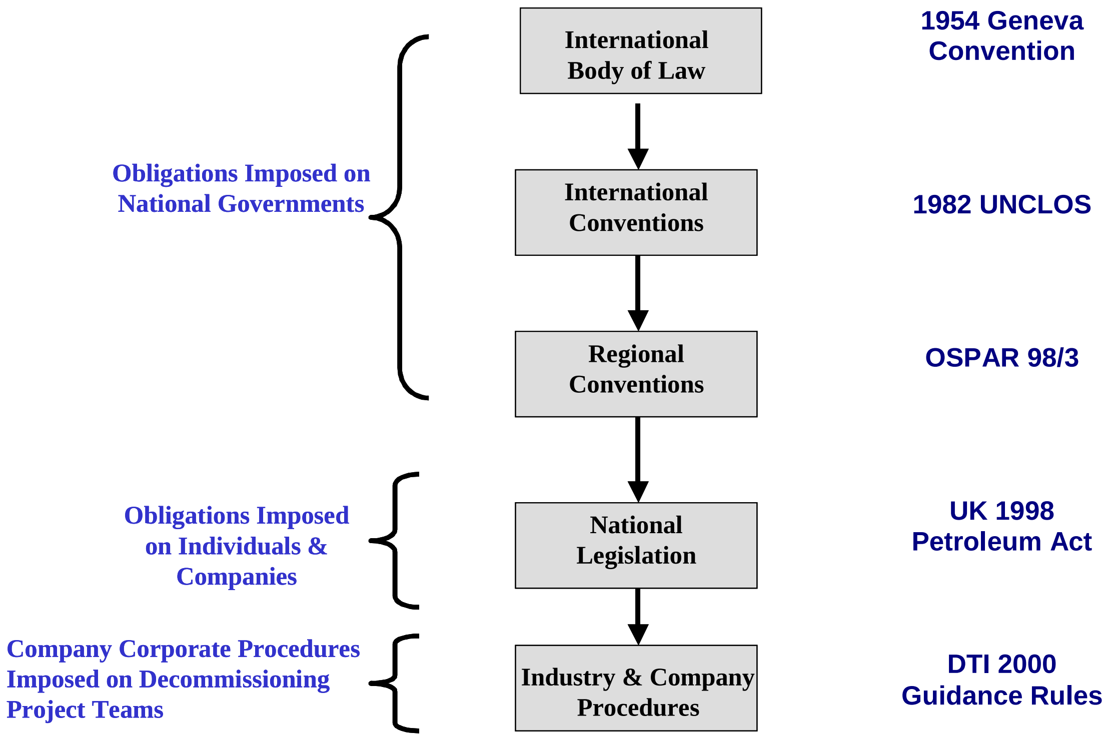


Figure 4. 1: Hierarchy within the Regulatory Regime

The laws and regulations surrounding decommissioning are many and complex. However, it is very important for would-be players to have a level of understanding, not only for reasons of compliance, but also because the regulatory regime generates considerable numbers of market opportunities for suppliers.

In summarising the regulatory regime governing decommissioning activities, this report follows the hierarchy described above. In this Chapter we outline National Legislation of the UK and other North Sea countries.[14]

[14] International Law and Conventions and Regional Conventions are discussed in considerable detail in the *'TCS Abandonment Handbook, 2005*', TCS Partners

4.2 UK Legislation

4.2.1 The Petroleum Act 1998

The 1998 Petroleum Act is the main statutory framework for the abandonment of offshore oil and gas facilities. The principal provisions of the Act defined in **Part IV – Abandonment of Offshore Installations**, are:

- To require the submission of costed abandonment plans for all offshore installations
- Once the abandonment plan has been approved, to make the parties who submitted the plan jointly and severally liable to ensure that it is carried out.
- To enable the Secretary of State to make regulations relating to abandonment and to make provision for the prevention of pollution.

The Act, however, does not define these standards; rather, the government chooses to use guidelines to allow flexibility as it is not possible to predict what the circumstances will be in terms of the balance of practicability and cost at the time of abandonment. Instead, a case-by-case evaluation of each abandonment programme will be undertaken in consultation with relevant interested parties to ensure that the optimum compliant solution is selected for each installation.

The Health and Safety Executive will set and enforce standards for the safety of the workforce engaged in abandonment. The vehicle for this is the "**Abandonment Safety Case**".

Section 29 of the Act defines the responsibilities of the parties required to prepare abandonment programmes and section 29-(1) defines the process by which the responsible parties are identified. Parties named are jointly and severally responsible for submitting an abandonment programme for approval and completing such works as defined in the programme.

The Government are keen to maximise the economic recovery of oil and gas from the UKCS, and recognise the benefits that small specialist companies contribute towards this. The Government also recognises that decommissioning costs can be substantial and aims to ensure the taxpayer is not left to assume these costs on default by an incoming company.

In all instances of licence transfer, the new co-venturer will be served with an **s.29 notice**. This will usually prompt the departing co-venturer to seek release from his s.29 notice and liability for undertaking decommissioning of the facility. When deciding whether or not to withdraw an s.29 notice, the DTI will assess the impact it would have on the funding of the decommissioning activity. The assessment is based on determining the impact on the financial strength of the remaining s.29 holders. Two primary outcomes are possible:[15]

- The DTI will withdraw the s.29 notice from the departing co-venturer where a large company remains on notice and/or the financial strength of the remaining s.29 holders is not substantially weakened.
- The DTI may withdraw the s.29 notice from the departing co-venturer where a financial security arrangement (FSA) is established to cover default by one, or more, of the remaining s.29 holders.

The 1998 Petroleum Act does not define what constitutes an effective FSA. Section 104 of the Finance Act 1991 defines an effective FSA for tax purposes as being;

"..a contract under which a person undertakes to make good any default by a participator in an oilfield in meeting the whole or any part of those liabilities of his which (a) arise under a relevant agreement relating to that field and (b) are liabilities to contribute to field abandonment costs, and such a contract is an abandonment guarantee regardless of the form of the undertaking of the guarantor and, in particular, whether or not it is expressed as a guarantee or arises under a letter of credit, a performance bond or other instrument".

An interpretation of the above definition of an effective FSA is given in the DTI guidelines discussed in detail below.

[15] Details are given in the fsapaper1 and fsapaper2 issued by the DTI Offshore Decommissioning Unit (ODU)

4.2.2 Health and Safety at Work Act 1974

The Offshore Installations (Safety Case) Regulations 1992 are made under the 1974 Act. Operators of offshore installations are required to submit an **abandonment safety case** to the Health and Safety Executive (HSE) at least six months before commencing decommissioning operations. The safety case must detail the methods and procedures to be used to ensure that risks to personnel are adequately controlled and are as low as is reasonably practicable (ALARP).

Regulation 9 requires that the Safety Case include:

- Details of the Owners' Safety Management System (SMS);
- Evidence that the SMS has been audited;
- Evidence that all hazards with the potential to cause a major accident have been identified;
- Evidence that all risks have been evaluated, and measures have been taken, or will be taken, to reduce the risks to persons affected by those hazards to the lowest level that is reasonably practicable.

Schedule 7 defines particulars to be included in the Safety Case for the abandonment of fixed structures to be:

- Full details of the works programme, taking full account of the design and method of construction of the installation and its plant.
- Site plans and details including meteorological, oceanographic and seabed details.
- The number of persons involved in the operation, evaluation of fire and explosion risks and means of escape from the facility, taking into account each phase of the proposed removal sequence.
- Impact of combined operations, that is, the associated deployment of attendant support vessels.
- Details of temporary structural condition, loads and stability of the structure.

The HSE regulations will continue to apply to installations left in-situ after cessation of production and decommissioning if worker intervention is required for whatever reason.

A Report on Research Needs for Health and Safety of Workers during Decommissioning and Removal of Fixed Offshore Installations was commissioned by the HSE to identify any outstanding research needs to ensure that abandonment work can be undertaken safely.[16] A formalised study of decommissioning hazards (DEHAZ) was developed[17] which comprises five stages of sequence, methods, waste control, safeguards, and temporary service and life support.

The report argues that such a DEHAZ procedure would provide HSE with a common model when considering the abandonment safety case.

Few major research needs on safety aspects of abandonment were identified that were not being addressed already, this being consistent with the oral evidence given to the House of Commons select committee on decommissioning.

4.2.3 Other Relevant UK Acts & Regulations

As with any other complex and potentially hazardous industrial process, a considerable number of other Acts and Regulations apply to the permissions required for and processes involved in decommissioning. The most significant of these are summarised in the appendices.

[16] Report OTH 95 488, prepared by R Street and J Mirzoeff for the Health and Safety Executive, published 1995

[17] *'Decommissioning – The Safe Approach'*, paper by M. Corcoran et al, Third International Conference on Decommissioning Offshore, Onshore Demolition and Nuclear works, 1992 UMIST

4.3 UK Guidelines

4.3.1 DTI Guidance Notes for Industry on the Abandonment of Offshore Installations and Pipelines under the Petroleum Act 1998

In May 1995 the DTI issued for comment its Guidance Notes on the Abandonment of Offshore Installations and Pipelines under the terms of the Petroleum Act of 1987.

During the summer of 1995 and following pressure from environmentalists, Shell reversed its plans to dump the Brent Spar. The dumping option was discussed at the North Sea Ministers' conference held in Copenhagen during June, then the OSPAR commission meeting at the end of June resulted in a moratorium on dumping of removed offshore installations. This was followed by the OSPAR 98/3 Decision, which defined the regime to be applied to decommissioning of offshore installations in the North Sea area.

These developments were incorporated into a revised issue of the UK Guidance Notes whose aim is to provide guidance in the preparation of the Abandonment Programme, as required under the 1998 Petroleum act. Although not intended to be prescriptive, guiding principles and specific guidance on abandonment standards are given.[18]

4.3.2 Guiding Principles

The notes define a set of guiding principles for developing a specific facility abandonment programme.

There is a presumption in the Guidelines that all offshore installations will be re-used, recycled or disposed of on land. Any exceptions to this will be assessed individually under the derogation process of OSPAR Decision 98/3.

The Department of Trade and Industry's Offshore Decommissioning Unit (ODU) will take the lead in co-ordinating consideration of decommissioning programmes submitted for approval. [19]

All decommissioning programmes will be consistent with international obligations with regard to:

- The precautionary principle
- Best available techniques and best environmental practice
- Waste hierarchy principles
- Other uses of the sea
- Health and safety law
- Proportionality
- Cost effectiveness.

The notes reconfirm that after 9th February 1999 no installation or structure shall be placed on the UKCS unless its design and construction is such that entire removal is feasible.

4.3.3 Specific Guidance

Under the OSPAR Decision 98/3, which has been accepted by the UK Government, the disposal at sea and the leaving wholly or partly in place of disused offshore installations is prohibited. There is a presumption in favour of re-use, recycling or final disposal on land.

Topsides – The topsides of all installations must be returned to shore for re-use, recycling or final disposal on land. It should be noted that re-use is preferred over recycling and recycling over disposal.

Steel Jackets weighing less than 10,000 tonnes – these must be completely removed for re-use, recycling or final disposal on land. The jacket piles should be severed below the seabed at such a depth to ensure that any remains are unlikely to be exposed.

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[18] A full copy of the DTI guidelines can be downloaded from the website www.og.dti.gov.uk

[19] See Annex A, Guidance Notes for Industry, Decommissioning of Offshore Installations and Pipelines under the Petroleum Act 1998

Figure 4.2: North West Hutton 'Before and After' Proposed Decommissioning

Picture: BP

Steel Jackets weighing more than 10,000 tonnes – For steel jackets weighing more than 10,000 tonnes it is possible to seek a permit allowing the footings to be left in place. (BP are currently seeking approval for this approach in the case of North West Hutton – see figure above.) The upper sections of the jacket are required to be removed and returned to land for re-use, recycling or disposal. The 'footings' are defined as those parts of the steel jacket that are below the highest point of the piles.

If the owners of the installation wish the Government to consider seeking derogation under the OSPAR rules, it is necessary to prepare detailed assessment documents. If the Government is satisfied that a case has been made, it will undertake consultations with the other OSPAR Contracting Parties as described in the Appendix.

Gravity Based Concrete Installations – The topsides must be returned to shore for re-use, recycling or disposal. It is possible to seek a permit to allow the concrete base to be left in-situ or disposed of at a deep-water licensed site. This requires preparation of detailed assessment documents. If the Government is satisfied that a case has been made, it will undertake consultations with the other OSPAR Contracting Parties.

Floating Installations – Floating installations including Floating Production Facilities; Floating Production, Storage and Offloading vessels; Single Buoy Moorings, etc, will be floated off location for re-use elsewhere. Where no re-use opportunity exists, the units will be towed to shore for storage or dismantling in line with the hierarchy of waste disposal options.

Sub-sea Installations – Sub-sea installations include drilling templates, production manifolds, wellheads, protective structures, anchor blocks, anchor chains, risers and riser bases. Such installations must be removed for re-use, recycling or disposal on land. Any piles should be cut below the seabed at such a depth to ensure that any remains are unlikely to be exposed.

If the owners of the subsea installation wish the Government to consider seeking derogation under the OSPAR rules, it is necessary for the owners to prepare the detailed assessment documents described in section 3.3 above. If the Government is satisfied that a case has been made, it will undertake consultations with the other OSPAR Contracting Parties as described in section 3.3.1 above.

Pipelines – OSPAR Decision 98/3 does not apply to pipelines, nor are there any international guidelines referring to decommissioning of pipelines. For the first time, we have in the guidance notes an indication of the standards for abandonment of the UKCS's 8,000 km of subsea pipelines.

Small diameter pipelines and flexible flowlines should normally be entirely removed. This would account for approximately 20% of the UKCS pipeline infrastructure.

Larger pipelines may be abandoned in-situ after cleaning, filling with corrosion inhibitor and sealing of exposed ends, providing:

- The lines are adequately buried or trenched over a sufficient length and are likely to remain so, without development of free spans.
- Surface laid lines are likely to self bury over time. (Other surface laid lines are buried or trenched as part of the abandonment process.)
- Lines which, due to structural damage or deterioration or other causes, cannot be recovered safely and efficiently.

The assessment of extent of burial or trenching and the impact of seabed sediment stability will have to be taken on the basis of individual circumstances.

If the owners of the pipeline wish the Government to consider permitting the leaving of a pipeline in-situ it is necessary to prepare detailed assessment documents similar to those described above. Pipelines left in-situ will be subject to a suitable monitoring programme agreed with the DTI.

Drill Cuttings – No precise guidance is given in the notes to the treatment or otherwise of drill cutting mounds. While no accurate figures exist for such materials, it has been estimated that in excess of 1.5 million tonnes of drill cuttings exist in the central and northern North Sea areas. Drill cutting disposal options will be evaluated in accordance with the Framework developed as part of the UKOOA drill cuttings research project.

4.3.4 Planning For Abandonment

The consideration and approval of abandonment plans will be co-ordinated by the Aberdeen-based Offshore Decommissioning Abandonment Unit (ODU) of the DTI. The ODU will act as the single point for contact and/or consultations with other government departments.

Whilst current international obligations will require the majority of offshore installations to be removed and returned to shore, the technical, environmental, safety and economic issues appropriate to a particular facility will vary. In order to ensure that the process leading to approval of a decommissioning programme is transparent, open to public debate and receptive to informed comment, the ODU proposes a six stage decommissioning approval process.

Planning for Abandonment

Stage 1: This commences a minimum of three years before planned cessation of production, and is instigated by the Operator of the facility. It is interesting to note the department's wish to encourage co-operation between operators of adjacent facilities in the planning of abandonment operations, and to promote the sharing of technical information and experience amongst operators. (Encouraging co-operation is one thing, to realise an environment in which co-operation flourishes is quite another. It does not happen automatically, but requires a commitment by all concerned and most probably a third-party facilitator. Ed)

Stage 2: This stage covers the preparation and submission of a draft abandonment programme to ODU, before it is issued for consultation under stage 3. If the Operator is seeking a derogation ruling under the OSPAR procedures, the assessment process described in the Appendix, will commence at this stage.

Stage 3: This stage covers the consultation process with all interested parties, the extent of which will depend on the circumstances of the specific case. Consultations with OSPAR and the OSPAR contracting parties are undertaken under the leadership of the DTI.

Stage 4: On completion of the consultation process, a final draft of the decommissioning programme will be prepared for submission under the terms of the 1998 Petroleum Act.

Stage 5: This stage covers the implementation of the approved decommissioning programme up to the completion of final close out site surveys, and submission of close out documentation.

Stage 6: The final stage covers the arrangements for ongoing monitoring, maintenance and management of the decommissioned site, the scope and duration of which is agreed with the DTI in consultation with other Government Departments.

Two special cases are recognised in the notes. Firstly, delaying an abandonment operation following cessation of production. This may arise when facilities are to be mothballed with the possibility of future satellite tie-ins, or where the physical removal is delayed to facilitate combined field abandonment. In both cases the extent of decommissioning undertaken should not prejudice the future abandonment options.

The second special case relates to median line fields, in which case the department will take the lead in consultations between governments on abandonment proposals.

4.3.5 The Decommissioning Programme

In most cases the rules of OSPAR Decision 98/3 will apply and the decommissioning programme will address the process of decommissioning, removal, re-use and recycling or final disposal on land. The programme will vary according to the specific attributes of the facility, but in summary is expected to address the following:

1. **Introduction**
2. **Executive Summary**: The essential features of the proposed method of decommissioning.
3. **Background Information:** Layout of the field and the facility, location of adjacent facilities, environmental conditions, seabed conditions, fishing and other commercial activity in the area.
4. **Description of Items to be Decommissioned:** A full description with drawings of the facility, with components, weights, status, and inspection results and seabed surveys results.
5. **Inventory of Materials:** A full inventory of onboard consumables, sampling results of hazardous materials and process system residues.
6. **Removal & Disposal Options:** Including options considered and reasons for rejection, re-use opportunities and benefits. If derogation is being sought under OSPAR Decision 98/3, then a detailed comparative evaluation of disposal options would be included.
7. **Selected Removal & Disposal Options:** The sequential operational process of decommissioning including shut in of operations, cleaning and removal of wastes, well abandonment summaries,[20] removal and disposal route of facility components, details of any material to be left on the seabed with predicted degradation rates.
8. **Drill Cuttings:** Details of any drill cuttings located on the seabed, of wells drilled with drilling fluids used and survey data with sampling results. Comparative assessments of options for dealing with drill cuttings and if drill cuttings are to be left in-situ, a monitoring programme.
9. **Environmental Impact Assessment: I**ncluding impact on the marine environment, emissions, consumption of natural resources and energy used, etc.
10. **Pipelines:** Pipelines should be contained in a separate programme although may be presented in this document. A pipeline programme will generally address: list of items to be decommissioned, status of lines with survey data, identification of options, selected option, cost, timing and monitoring required.
11. **Interested Party Consultations:** Full record of consultation process, with responses and description of how these have been addressed and taken into account in finalising the decommissioning programme.
12. **Costs:** Including cost of preferred option, ongoing monitoring costs and recovered equipment resale values.
13. **Schedule:** A project plan is included within this section.
14. **Licences Associated with the Disposal option:** A list of licences and or permits required to complete the decommissioning programme.
15. **Project Management & Verification:** Details of how the decommissioning programme will be managed and what verification will be provided to the DTI.
16. **Debris Clearance:** Including proposals for identification and removal of seabed debris with extent of the seabed to be covered. Verification of seabed clearance will be required from an independent organisation.
17. **Pre and Post-Decommissioning Monitoring and Maintenance:** The programme of ongoing seabed sampling against baseline survey results, inspection and maintenance requirements.
18. **Supporting Studies:** Referenced where undertaken.

The Decommissioning programme submission process will run in parallel with the following:

- The preparation of the Cessation of Production (COP) document for consideration by the DTI Oil and Gas Directorate.
- Consideration by the HSE of the Abandonment Safety Case.
- Any onshore disposal consents or licences required.

[20] Well abandonment is regulated under the model clauses incorporated into each licence and is not subject to the provisions of the Petroleum Act of 1998. The decommissioning programme should, however, include an outline of well abandonment plans.

4.3.6 Cessation of Production Plan

During the life of a field the DTI Oil and Gas Directorate will monitor operations using Field Reports prepared by the Operator. These regular Field Reports provide for reviews of the longer-term development of the field and for reviews of the potential for further incremental activity. As the forecast end of field life approaches the Field Reports are used to demonstrate that all economic developments have been pursued and this will enable the DTI to agree with the Licensees that Cessation of Production (COP) from the field is appropriate.[21]

The normal economic criteria for deciding when a field's production is no longer economic and that production should cease is defined as, taken over a reasonable period, the value of the hydrocarbons produced no longer covers the true cost of production.

The Guidance Notes require that Operators retain sufficient information after COP to enable other interested potential operators to take a reasonably informed view about the potential for field redevelopment.

The amount of detail required in the COP documentation, which should be submitted up to five years before the proposed COP date, should provide at least the following:

Cessation of Production Plan

1. **Executive Summary:** A management summary of the document contents.

2. **Field Economic Limit Criteria:** A detailed economic analysis of:
   - Definition of economic limit with determination of cut off rates and timing
   - Cash flows over the period up to the economic limit and two years beyond
   - Information on risks & sensitivities which would advance or postpone the economic limit
   - The costs and any revenues from COP
   - Estimate of decommissioning costs.

3. **Field Life Extension – Options Investigated**: An outline of concepts of possible incremental activity together with economics. Annual data for production, capital and operating costs should be provided with pre-tax Net Present Values and Internal Rates of Return. It is considered important to record why such opportunities were not viewed as economic to pursue. Such opportunities may include some or all of the following:
   - 3D seismic data
   - Infill or additional wells or re-completions
   - Development of un-drained horizontal/fault blocks
   - Increased gas/water/oil handling /processing
   - Increased injection or artificial lift
   - Maintenance regime
   - Reduced manning.

4. **Final Field Status**: A summary of the field layout and the impact of removing the facilities on future handling of satellite and or third party production. Reservoir maps indicating the estimated location and distribution of remaining technically recoverable hydrocarbons.

5. **Additional Development Status**: A summary of all nearby fields that could potentially be developed from the existing facility and infrastructure.

6. **Conceptual Decommissioning Plans**: An indication of the proposed decommissioning programme with sequence of events leading up to decommissioning.

[21] For further details see "Guidance Notes on procedures for regulating offshore oil and gas field developments" issued by the DTI Oil & Gas Directorate.

4.4 Cross Boundary Decommissioning Obligations

In April 2005, the Governments of the UK and Norway signed a Framework Agreement to co-operate in the development of fields that spanned the UK/Norway divide in the North Sea.

Article 1.14 of that Agreement addressed decommissioning liabilities. In respect of Installations, decommissioning plans are subject to the approval of the Government on whose continental shelf the installation is situated after full consultations with the other Government. The aim of both Governments shall be to seek to reach agreement on decommissioning methods and standards and both Governments shall approve the timing of any such decommissioning. In making decisions on decommissioning plans, the Governments shall address fully and take proper account of the following:

a) Applicable international requirements, standards or guidelines
b) Safety hazards associated with decommissioning
c) Safety of navigation
d) Environmental impact of the proposed plan
e) Impact on other uses of the sea
f) Best available cost effective techniques
g) Economic factors
h) Timetable
i) Impact on continued effectiveness of remaining infrastructure
j) Views raised by other persons
k) Other relevant matters raised by either Government.

Article 3.12 of the Agreement states that the two Governments will agree on the timing of the cessation of production from a Trans-Boundary Reservoir.

It is expected that this Cross-Boundary Agreement will mark a trend towards a unified regulatory approach across all those states being contacting parties to OSPAR and the European Union.

4.5 Related National Legislation

4.5.1 Netherlands

Most of the Dutch platforms are in water depths of 30 - 50 metres, in areas with heavy shipping traffic. Section 26 of the Netherlands Continental Shelf Act empowers the ministry to issue regulations for abandonment. In 1967 such regulations were issued, in which section 68 reads: “a production facility that is no longer in use must be removed completely”.

The Netherlands supported the June 1995 OSPAR ban on the dumping of platforms, which is consistent with existing Government regulations.

4.5.2 Denmark

Danish platforms tend to be in water depths of about 40 metres. The Subsoil Act of 1981 and the Model Licence for Exploration and Production of Hydrocarbons prescribe the conditions to be executed on expiry of a licence. If the Government does not wish to acquire the facility, it may demand that all or part of it be removed.

Denmark supported the June 1995 OSPAR ban on the dumping of platforms, and it is likely all Danish platforms will be removed entirely to shore.

4.6 Norway

Norwegian platforms tend to be in water depths greater than 100 metres and include some of the largest offshore platforms ever built. The Norwegian policy, [22] like that of the UK, is based on a case-by-case review of all options, in the light of the IMO guidelines and the London and Oslo conventions. Evaluation of options will be based on a socio-economic context, where abandonment costs are weighed against the technical, environmental and safety aspects involved. Norway did not support the June 1995 OSPAR ban on the dumping of platforms, but is bound by the later OSPAR Decision 98/3.

Associated Norwegian legislation includes:

Associated Norwegian legislation includes:

- **The Petroleum Act 1985** relates to petroleum operations and guidance in preparing abandonment plans for Parliament's approval. The **Petroleum Directorate's guidelines** issued in September 1990 required that all installations must be designed so that it is technically possible to remove them. The 1985 Act was replaced by the **Petroleum Act 1996,** which requires the Licensee to submit a decommissioning plan prior to the shut down of an offshore facility.

- **Act No 11 Removal Cost Division Act 1986** establishes the basis on which abandonment costs are shared between the Government and operating companies. The Licensees are entitled to an allocation from the state when the final disposal is taking place. The allocation is based on the Licensee's tax liability in the years the installation was in use.

- **Act No 6 Pollution Control 1981** regulates the disposal of special wastes and outlines the basis for granting permits. Section 20 of the act contains rules for closing down and terminating operations whereby the pollution control authorities review such operations and are then able to order measures considered necessary to avoid pollution. Whilst the Act covers preparation for dumping, the actual dumping is covered by **Act No7 Seaworthiness Act 1903,** which contains rules concerning dumping. The Act does not cover toppling and abandonment of fixed facilities. If facilities are to be dumped in internal Norwegian waters or territorial waters, a permit will be required from the Coastal Administration under the **Harbours Act of 1984**.

- **The Safety Regulations 1985.** A permit must be obtained from the Ministry of Labour and local Government before commencing a removal operation.

4.7 Industry & Corporate Procedures

Industry organisations, such as UKOOA, have not issued industry guidance on decommissioning but have acted as a focus for technology development including that for drill cutting treatment.[23]

Individual companies responsible for implementing decommissioning programmes will have corporate procedures covering the planning and execution of decommissioning to which individual project teams will be required to comply. Some of the issues underlying such procedures are discussed in more detail in Chapter 4 of this report.

4.8 Regulatory Trends

Decommissioning activities within the North Sea occurs within a highly regulated environment. The minimum requirements for decommissioning are well defined within National Legislation that reflects the international obligations imposed on National States by International Treaties and Conventions. The process of decommissioning is further regulated under a series of Health, Safety and Environmental Legislation. It is expected that with time the decommissioning regulations covering the Mediterranean and the Baltic regions will closely align with that introduced under the OSPAR jurisdiction. Monitoring the development of European-wide decommissioning legislation and practice is the European Commission Director General DG 17.[24]

[22] Dag Erlend Henriksen, *'An explanation of Norwegian Abandonment Policy'*, paper to the Institute of Petroleun conference, North Sea Facilities Abandonment, February 1995
[23] For details see the UKOOA website www.oilandgas.org.uk
[24] The EC- DG17 directorate website is on http://euopa.eu.int?comm/dgs/energy_transport/index.html

5 HOW FIELDS ARE DECOMMISSIONED

5.1 Introduction

The decommissioning of an offshore facility is considered in three distinct phases:

1. Pre-planning for decommissioning including **the review of options** available through the operating life of the facility, and the actions necessary to demonstrate compliance with regulatory obligations. The facility operator will largely undertake this phase with input from specialist consultants and advisors.

2. The second phase of decommissioning encompasses the physical act of **decommissioning** with the facility operator utilising prime contractor(s) and sub-contract arrangements.

3. The third phase, and the element not always recognised, is the management of **long-term residual liabilities**. This will include long-term surveillance and testing of any seabed remains of the facility or pipelines.

The following description of how to decommission a field follows the three-phase process described above.

It is important to note that every Step and Sub-process in the decommissioning procedure generates business opportunities and many offer considerable long-term potential for Scottish companies.

5.2 Decommissioning Planning within the Regulatory Process

This section considers decommissioning planning as a process, in the broadest sense, in order to examine the concept of total asset management; where the facilities are designed not only to minimize CAPEX and OPEX but also to maximize economic value from the asset and residual value on final cessation of production, and minimize decommissioning costs.

For the purpose of this Chapter, a five step process of discrete but interrelated activities are related by time, where the time of abandonment is represented by t= 0.

The five steps are summarised as:

Step 1: Consideration of decommissioning implications during initial project definition and development.

Step 2: Decommissioning consideration during annual review of asset performance through to the cessation of production decision.

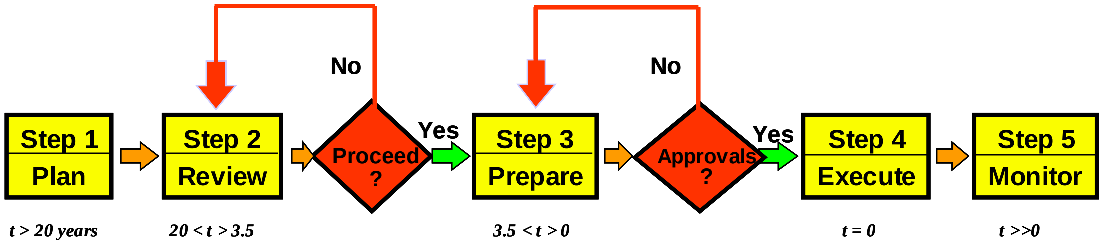
Step 3: Preparing all necessary compliance documentation for decommissioning.

Step 4: Execute the decommissioning programme.

Step 5: On-going monitoring and management of residual liabilities.

There is a danger that companies focus on the technical and regulatory impact of decommissioning and ignore the wider consequences of what they are doing. The result can be an increase in unwanted and negative scrutiny and opportunities for the growing influence of anti-oil company activists. Therefore the last section of this Chapter addresses the wider implication of the management of reputation risk and how this should be addressed within the decommissioning management process.

5.2.1 STEP 1: Project Inception – Plan for Abandonment



The Abandonment Planning Process

Sub-processes:
- Production forecasts and field economics
- Design for decommissioning
- Estimate decommissioning costs and liabilities
- Estimate abandonment programme
- JOA security provisions/requirements
- Design for re-use

These sub-processes provide input into the initial overall field investment appraisal, and potentially the development concept selected.

A question that naturally arises is whether some additional provision can be made during the initial field design stages to simplify future decommissioning operations. The scope to achieve significant benefit is often constrained by the discounting techniques used to evaluate investment proposals; that is, the present value of future savings is limited if decommissioning is far into the future. However, even if such pre-investment is not viable, designers of new facilities need to consider the impact of decommissioning so as not to make such operations more complex, or difficult, than they otherwise need to be.

Most countries now have requirements relating to the disclosure of decommissioning liabilities in the Company's annual reports. In the UK, the accounting standard FRS 12[25] requires provision to be made, now, for a future obligation.

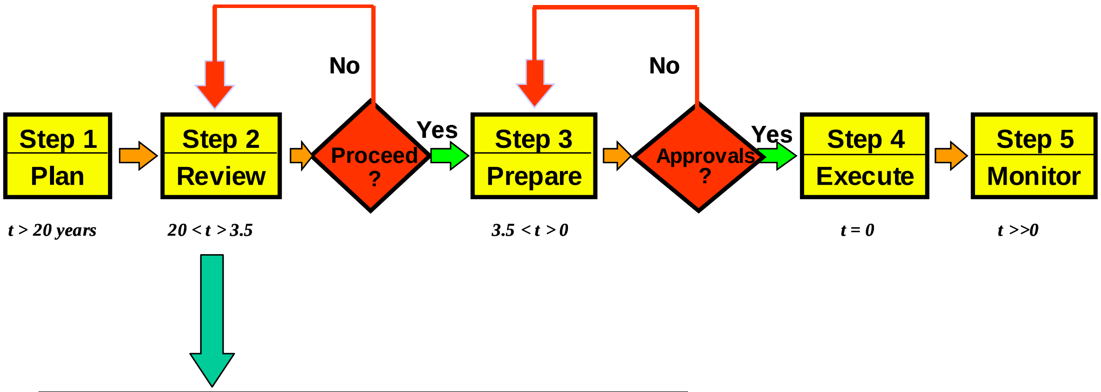
The Oil Industry Accounting Committee issued decommissioning guidance notes in January 2000 on preparing decommissioning estimates. Most Joint Operating Agreements (JOAs) include provisions that oblige the contracting parties to negotiate, in good faith, an abandonment agreement at the appropriate time in the future. In its most general terms the abandonment agreement provides for the equitable sharing of liabilities between the participants, and an obligation on each to provide security, to the others, for their share.

In the UK, section 29 of the UK Petroleum Act 1998, the Secretary of State will require by written notice to the JOA partners, jointly, to submit a programme setting out the measures, and dates, to prepare an abandonment programme. All persons/companies named on the section 29 notice are jointly and severally responsible for submitting and implementing an approved abandonment programme. Most countries have similar regulations defining the joint and several liability for decommissioning.

Design of a facility for future re-use on another field is not normally addressed during initial project appraisal stages. Indeed, the opposite may be true in that a facilities process system is designed specifically to suit a specific flow-rate and well fluid composition, making it difficult to economically adapt for re-use. A decision is therefore required, at this stage, on the level of investment appropriate to maximise re-use opportunities or residual value.

[25] *FRS 12 Provisions, contingent liabilities and contingent assets'*

5.2.2 STEP 2: Continuous Review of Asset Performance



Sub-processes

- Review reservoir performance
- Evaluate subsurface opportunities
- Identify opportunities for third party / satellite tie-ins
- Review abandonment costs and options
- Review abandonment timing, economic forecasting
- Review opportunities for asset re-use
- Preparation and submission of regular Field Reports
- Track market for asset trades

There are a number of options for maximizing remaining value from maturing assets including:

- Field re-development by the installation of enhanced recovery techniques. A notable example of such a strategy was the £1.3 billion redevelopment of the Brent field.

- Refurbishment and replacement of existing facilities to improve production and lifting efficiencies by replacing processing equipment, removing redundant equipment or by undertaking opportunities to re-structure existing operations to improve the remaining life cycle economics and, in particular, OPEX costs.

Such options evaluated for mature fields will affect returns in the short term only; inevitably the hard decisions of abandonment will have to be addressed.

The estimate of decommissioning liabilities are required to be verified each year and reported in the company accounts as future liabilities. Changes in discounted amounts are reported direct to the profit and loss account. It is, therefore, important to ensure that estimates are prepared in a prudent manner in compliance with the requirements of, for example, FRS 12, as described under step 1.

Much of the information described above is required to be incorporated into an annual Field Report submitted to the regulatory authorities.

5.2.3 Trading on of Assets

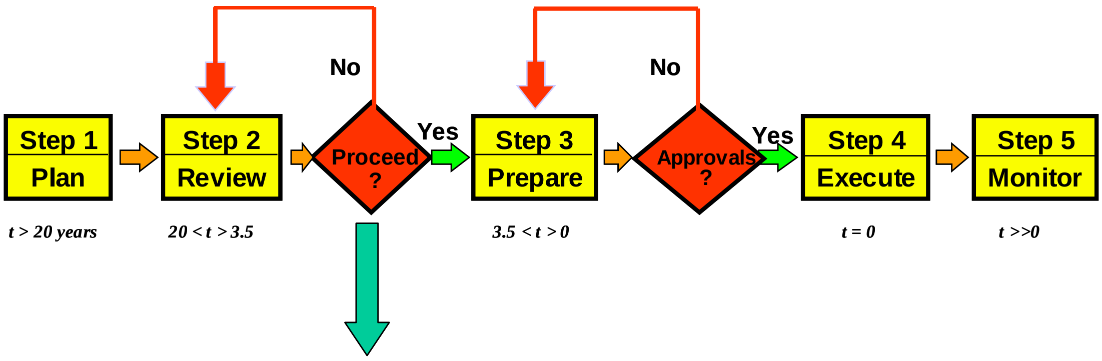
The trading of maturing assets has developed in the North Sea during the past five years. In all instances, under UK rules, where an asset is sold, the new buyer will be served with a section 29 notice under the 1998 Petroleum Act. At the same time, the seller of the asset will seek withdrawal from their section 29 notice liabilities.

Whether a section 29 release is given will depend the financial strength of the remaining section 29 holders. If the decommissioning is some time in the future, forecasting the abilities of companies to meet large expenditures in the future is difficult. Unless there is at least one company remaining on notice with satisfactory financial strength, a formal Financial Security Arrangement (FSA) will need to be put in place, and approved by the regulatory authorities.

5.2.4 Potential Market for Re-use

To date, the oil & gas industry has mainly considered recycling of equipment or equipment packages rather than re-use of complete facilities. To change this attitude may be a long process but needs to be tackled ahead of the actual decommissioning programme. Whether a company uses an external broker or manages the marketing of the facilities in-house, the basis is the same. Potential buyers will need to be screened to ensure that equipment will be used in a manner compatible with the seller's position. The experience gained in the marketing of the Hutton TLP, the Maureen facilities and Froey platform all indicate this to be a lengthy process.

5.2.5 Review Optimum Point to Cease Production



The decision on whether to proceed with Cessation of Production programmes will occur as recoverable reserves are exhausted and the incremental recovery costs prove financially less attractive.

Three financial models have traditionally been used to identify the optimum point in time to cease production.

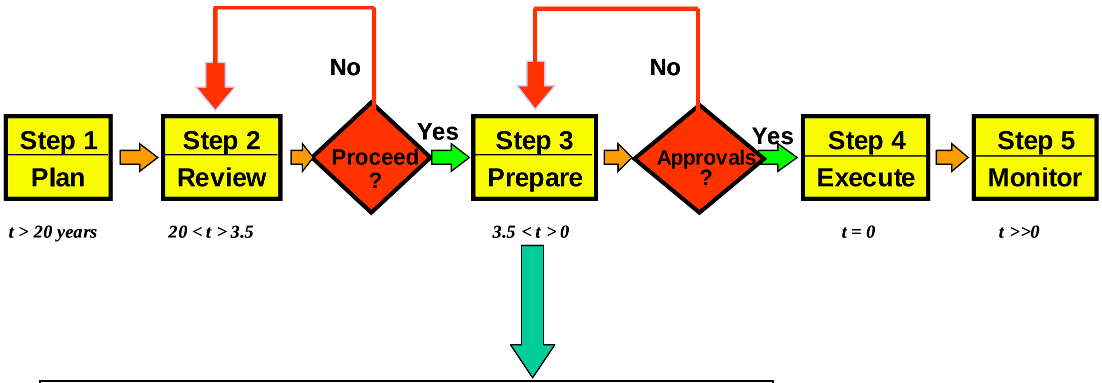
1. Negative net profit being the point where operating costs, including tax liabilities, exceed revenue from production.
2. A minimum margin on ongoing expenditure requires an additional margin on expenditure to cover allocation of operating overheads, but like Negative Net profit it fails to take account of future field cash flows.
3. Maximising Remaining Net Present Value incorporates into the calculation all future cash flows, including decommissioning liabilities and available tax relief over time.

The strategy of maximising remaining NPV has one serious drawback: its failure to take into account potential future revenues from third party tariff or satellite field development which may not be defined at the point the decision is being taken on whether to cease production. In some cases an asset appearing uneconomic in isolation may create opportunities enabling the partners to undertake other investments in the future should market conditions improve. Ignoring this option and valuing the remaining reserves at today's price can lead to a significant underestimation of the value of the asset.

Professor Alex Kemp of Aberdeen University has concluded that utilising the remaining NPV criteria leads to a later date for decommissioning than when using the net profit criteria.

A key output from the financial analysis is to identify the key point that will trigger the commencement of preparing for decommissioning. This will likely be the point where the remaining NPV equates to approximately 150% of the estimated decommissioning cost. At this point security provisions will be triggered and the decommissioning project team mobilised.

5.2.6 Step 3: Preparation for Abandonment



Sub-processes

- Instigate abandonment programme
- Undertake option screening and preliminary engineering
- Undertake detail engineering and specialist studies
- Finalize contracting strategies based on condition surveys
- Prepare Cessation Of Production Plan
- Prepare Well Abandonment Programme
- Prepare Abandonment Safety Case
- Prepare Environmental Impact Assessment
- Initiate consultation process and public relations programme
- Prepare budget proposals
- Prepare Decommissioning Programme
- Initiate Asset and/or component marketing.

When financial models indicate an optimum time to cease production, the project teams will be mobilised.

Initial engineering studies will be undertaken to define the critical elements/stages in the decommissioning sequence.

To control out-turn costs, it is vital that the condition of the facility is known precisely and reflected in the contracting strategy. This will entail detailed survey work of the facility covering:

- Weight survey of the platform, identifying changes from the as-built/installed condition
- Inventory surveys, list and quantities of consumables, hazard material inventories
- Sample and analysis of process equipment residues
- Survey of process systems, identifying changes to system from operating manuals, P&IDs and as-built documents
- Structural surveys to confirm fabric condition
- LSA survey and sampling
- Location of support documentation, construction data, installation and operating manuals
- Seabed surveys and sampling seabed sediment and pile cuttings if present.

It is preferable that seabed sediment sampling and analysis is carried out periodically over a number of years so that contaminate degradation can be estimated.

The first key document in the compliance process is the **Cessation of Production** (COP) submission for which some initial engineering studies and surveys will require to be completed. The format of the COP document will vary between countries but will generally contain the information shown below.

5.2.7 The Cessation of Production Document

Cessation of Production Document
1. **Executive Summary** A management summary describing the field status with substantiating data and arguments supporting the proposal to cease production. 2. **Field Economics** This section will give detailed economic analysis of the following: • Definition of economic limit, i.e. criteria for cessation of production • Cash flow over the period up to the economic limit and two years beyond • Detailed information on any factors that would advance or postpone the economic limit • The cost and revenues associated with COP, i.e. capital and operating expenses and any residual value of the field assets • The form and costs of abandonment if these affect the timing of the economic limit. 3. **Field Life Extensions** – Options Details have to be given of all concepts and options for field life extension that have been investigated together with economics. Annual production volumes, capital and operating costs should be provided for each option with NPV and IRR on a pre-tax basis. It is important to record for potential future operators why opportunities were not viewed as economic. 4. **Final Field Status** The field status report gives: • The surface layout of the facility including platforms, wells, infield flowlines, export pipelines, topside processing facilities and any subsea completions or manifolds. • Details of any third party production that is process or transported via the current facility. • The impact of decommissioning the facility on potential future opportunities for handling satellite or third party production. The document should also contain reservoir maps with an indication of remaining technically recoverable reserves that will be un-drained at the time of cessation of production. 5. **Additional Development Status** A summary should be included giving details of nearby fields which could be developed from the existing facilities and infrastructure, together with reasons why such developments cannot proceed. 6. **Conceptual Decommissioning Plans** An indication of the proposed decommissioning plan should be included, giving the sequence of events with schedule and cost of operations.

A number of other documents will be compiled for formal review by the regulatory authorities, and will include the following:

5.2.8 The Well Abandonment Programme

Operators are required to obtain government consent to abandon any well. This entails the submission of a well abandonment programme for approval, which demonstrates that all practicable steps have been taken to:

- Control the flow and escape of hydrocarbons
- Prevent damage to adjoining strata
- Isolate all permeable formations from one another
- Prevent possible crossflow
- Prevent contamination of aquifers
- Abandon wells in an efficient and workmanlike manner.

The programme will detail the procedures and equipment to be used in the shut-in, isolation and abandonment of wells and will cross-refer to elements of the decommissioning safety case.

5.2.9 Decommissioning Safety Case

The Safety Case for the abandonment of fixed structures will include:

1. Sufficient particulars are to be provided, including programmes of works, to demonstrate that the proposed arrangements, methods and procedures for dealing with well abandonment, decommissioning the installation and demolishing, and dismantling the installation. These should take adequate account of the design and method of construction of the installation and its plant, and reduce risks from major accidents to the lowest level that is reasonably practicable.
2. A scale plan of the location of the installation and of anything connected to it, and particulars of:
   - The meteorological and oceanographic conditions to which the installations may foreseeable be subjected
   - The properties of the seabed and subsoil at its location.
3. A description, with scale diagrams, of the main and secondary structures of the installation and its materials, its plant and the connections made to any pipeline or installation.
4. Particulars of the operations that were being carried out, including:
   - Activities on and in connection with the installation relating to each operation
   - A description of any wells connected to the installation.
5. The maximum number of persons at work on the installation during decommissioning, demolition or dismantlement.
6. Particulars of plant and arrangements for the detection of gas, fire and smoke, the prevention and mitigation of fires, and the protection of persons from their consequences.
7. Particulars of escape routes, embarkation points and plant (including lifeboats) to enable the full and safe evacuation, escape and rescue of persons to take place in an emergency.

In preparing the above documentation, decommissioning can be considered to start when production operations cease, and culminates in the removal of either the whole of the installation or parts of it, as agreed between the operator and the Secretary of State under the terms of the Petroleum Act 1998. The offshore abandonment safety case should be extended to include those operations that may be completed on the beach.

The process of abandonment may include a time lag between cessation of production and completion of removal operations. In such cases the process plant may be decommissioned but the installation maintained intact for a period pending its subsequent removal.

The abandonment safety case needs to demonstrate that those persons who are required to work on the installation after cessation of production are properly safeguarded. As plant is progressively decommissioned, the operational status of the installation will change. The hazards will change accordingly, primarily due to the abandonment of wells and cessation of hydrocarbon processing and storage. The safety management system may also change to reflect the changed hazards and the practicability of maintaining utility and safety systems in place. It may be necessary to provide other systems to take the place of safety systems which need to be decommissioned.

Where an installation is to be decommissioned but removal is to be deferred for an extended period, the operator will need to demonstrate in the safety case that a regime of maintenance will be implemented to prevent undue deterioration of the installation which might otherwise put at risk those on board, or visitors, or those engaged in the final removal operation.

5.2.10 The Decommissioning Programme

This is the key document in the planning and approval process, and will address the following points:

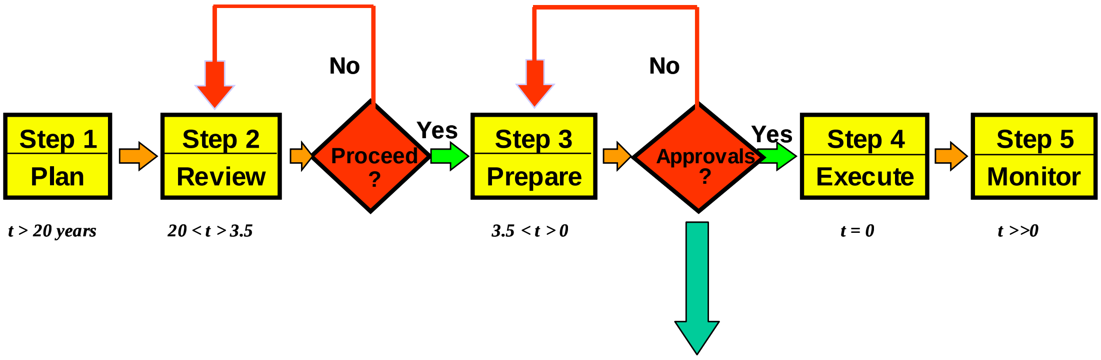
The Decommissioning Programme

1. **Introduction**
2. **Executive Summary:** Outlining the background to the programme and the essential features of the proposed method of decommissioning.
3. **Background Information:** Layout of the field and the facility to be decommissioned, location of adjacent facilities, information on local environmental conditions, seabed conditions, fishing and other commercial activity in the area.
4. **Description of Items to be Decommissioned:** Including drawings of the facility, with components, weights, status, inspection results and seabed surveys results.
5. **Inventory of Materials:** A full inventory of onboard consumables, sampling results of hazardous materials such as LSA scale, hydrocarbons, sludges and process system residues.
6. **Removal & Disposal Options:** Including a list of options considered and reasons for rejection. Options may include re-use opportunities and benefits from campaign strategies.

If derogation is being sought under OSPAR Decision 98/3, then a detailed comparative evaluation of disposal options would be included within this section.

7. **Selected Removal & Disposal Options:** The sequential operational process of decommissioning including shut in of operations, cleaning and removal of wastes, well abandonment summaries, removal and disposal route of facility components, details of any material to be left on the seabed with predicted degradation rates.
8. **Drill Cuttings:** Details of any drill cuttings located on the seabed, details of wells drilled with drilling fluids used, survey data with sampling results. A comparative assessment of options for dealing with drill cuttings should be given. If it is proposed to leave the drill cuttings in-situ, a monitoring programme should be proposed.
9. **Environmental Impact Assessment:** Including impact on the marine environment, emissions to air and water, consumption of natural resources and energy used, other consequential impact on the physical environment or amenities.
10. **Pipelines:** Pipelines should be contained in a separate programme although may be presented in this document. A pipeline programme will generally address; list of items to be decommissioned, status of lines with survey data, identification of options, selected option, cost, timing and monitoring required.
11. **Interested Party Consultations:** Full record of consultation process, with responses and description of how these have been addressed and taken into account in finalising the decommissioning programme.
12. **Costs:** Including cost of preferred option, ongoing monitoring costs and recovered equipment resale values.
13. **Schedule:** A project plan is included within this section.
14. **Licences Associated with the Disposal Option:** A list of licences and/or permits required to complete the decommissioning programme.
15. **Project Management & Verification:** Details of how the decommissioning programme will be managed and what verification will be provided to the DTI.
16. **Debris Clearance:** Proposals for identification and removal of seabed debris following decommissioning, with extent of the seabed to be covered. Verification of seabed clearance will be required from an independent organisation.
17. **Pre and Post-Decommissioning Monitoring and Maintenance:** A programme of ongoing seabed sampling against baseline survey results, with inspection and maintenance requirements appropriate to the proposed decommissioning option.
18. **Supporting Studies:** Where supporting studies have been undertaken, they should be referenced with the programme.

The approval cycle of the prepared documentation is as previously discussed. In addition the approval of co-ventures and shareholders will be necessary.



The approval cycle is in three main parts.

1. Consultations – The consultation process is defined under section 29(3) of the Petroleum Act 1998. These consultations will be with representatives of those parties affected by the decommissioning proposals. Statutory consultees will be advised by the DTI in the UK.

The Operator acting on behalf of the JOA partners will also be asked to announce its proposals by placing a public notice in appropriate national and local newspapers. The trend has been to set up an Internet website devoted to the decommissioning programme. The website contents include the documentation included in the formal decommissioning programme submissions, a news section with updated information, and sections explaining the facility and decommissioning issues in layman's terms. In some instances the website set up has been used to carry marketing information used in effort to sell on the complete asset or components thereof.

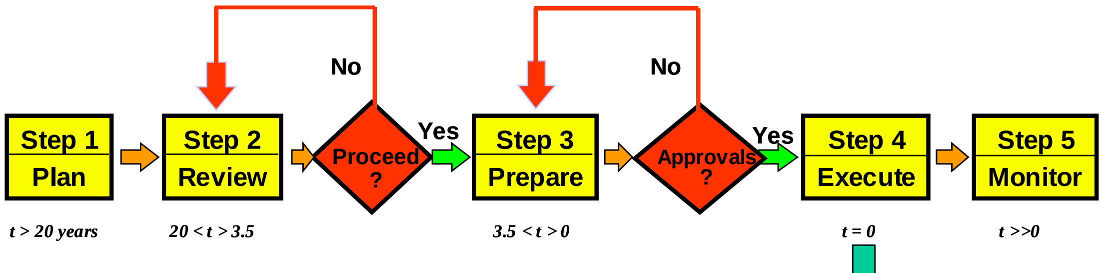
The results of the consultation process have to be reported in the final issue of the decommissioning programme. In more complex cases involving application for a permit under the derogation procedures, a much longer consultation process is required which will be co-ordinated with the DTI.

2. Regulatory Approvals – The principal regulatory approval will relate to the formal decommissioning programme by the DTI. Other Government departments will be involved in the review and approval of the well abandonment programme, decommissioning safety case and the pipeline-decommissioning programme.

Each of the section 29 notice holders will be informed by written notice when the Secretary of State has approved the programme.

3. Corporate and Partner Approvals – The decommissioning programme has to include a letter from each co-venturer signifying that the Operator on their behalf is submitting it.

5.2.11 Step 4 – Execution of the Abandonment Plan



Sub-processes

- Let contracts and subcontracts
- Mobilize offshore resources
- Manage handover from platform operational teams to demolition and removal teams
- Remove and dispose all platform consumables
- Well abandonment and process shutdown
- Isolate platform facilities from wells and export/import pipelines
- Decommission process and utility systems
- Dismantle offshore facilities
- Land removed offshore facilities at reception site
- Sale of recovered equipment
- Site clean up and verification surveys
- Demobilize offshore spreads
- Onshore demolition of returned goods, disposal of hazardous materials and industrial wastes.

Flexible Implementation Strategies – Potential cost savings can be realized through innovative approaches to the implementation of an abandonment plan. In this Chapter just two opportunities are discussed.

- **Multiple Managed Abandonments** whereby owners may defer abandonment start to coincide with other facilities' abandonments in order to obtain economies of scale. Alternately, owners may schedule abandonment to allow collective abandonment strategies to be developed and executed.
- **Flexible Time Based-contracts** will allow the owner either to abandon the facility as soon as production ceases, or to defer abandonment to suit re-use schedule.

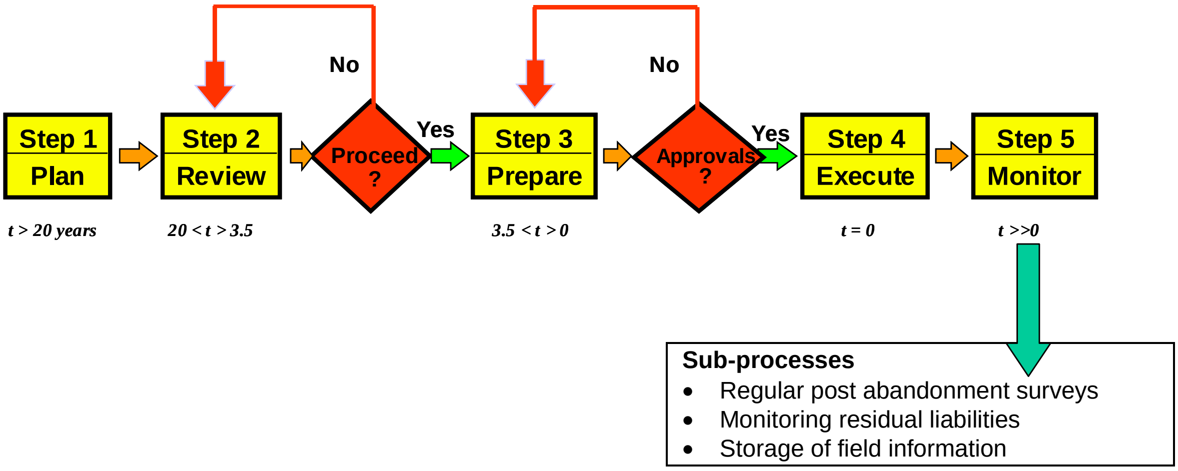
Both of these strategies require that flexibility is written into the contracts themselves with flexible operating windows, elimination of cost penalty clauses related to schedule variation or liquidated damage penalties.

Residual Value of Abandoned Facilities – Residual value for recovered facilities can be realized through implementation of an asset recovery programme. To be managed successfully, any asset recovery programme needs to commence significantly ahead of actual abandonment operations, as the salvage value is highly opportunistic depending on market conditions at any given time.
A number of potential opportunities exist:

- Owner re-use of the facility by relocating onto marginal field
- On-sale of complete facilities for refurbishment and subsequent re-use
- Sale of complete equipment packages removed from the facility
- Sale of scrap material for recycling.

Business Continuity Team – In support of the decommissioning project team it is prudent to activate a business continuity and emergency response team to handle the wider collateral issues as and if they should arise. This is discussed in more detail at the end of this Chapter.

5.2.12 Step 5 – Post Abandonment Monitoring



Residual liabilities will arise where an offshore facility is not truly removed. Under the 1998 Petroleum Act, title and the associated responsibilities rest with the licensees in perpetuity. If a permit is issued under the OSPAR derogation procedure the minimum requirements for surveys and testing will be conditions attached to the permit. Otherwise the requirements for routine inspection and testing will be defined in the approved abandonment programme.

Two options are therefore available in developing abandonment strategies for the management of residual liabilities.

- Avoid residual liabilities by removing the offshore facilities completely and cleaning the site area of any loose debris, with final verification by third party, e.g. by trawling clear.
- Or, accept residual liabilities by including within the JOA security agreement for partners to contribute funds to cover the cost of regular inspection and maintenance of the debris pile, and to provide income for payments of insurance premiums to cover large claims or for any uninsured claims, and for the fund administration.

The option chosen will be dependent on the levels of perceived risk.

It will be required of Operators that they retain information that might include the final full field reservoir simulation model, the final geological model, copies of the field development programme, field reports, and production and injection profiles on a well-by-well basis.

The purpose of retaining such information is to facilitate other interested parties' review of potential for field redevelopment. Such redevelopment may become feasible if new technology allows significantly improved recovery or product prices increase.

5.2.13 Reputation Management

This offers specialist PR companies an interesting business opportunity. Decommissioning activities pose a particular threat to a company's reputation, and therefore needs to be managed over and above any minimum regulatory requirements. Reputation management involves anticipating, acknowledging and responding to changing values and behaviours on the part of all stakeholders.

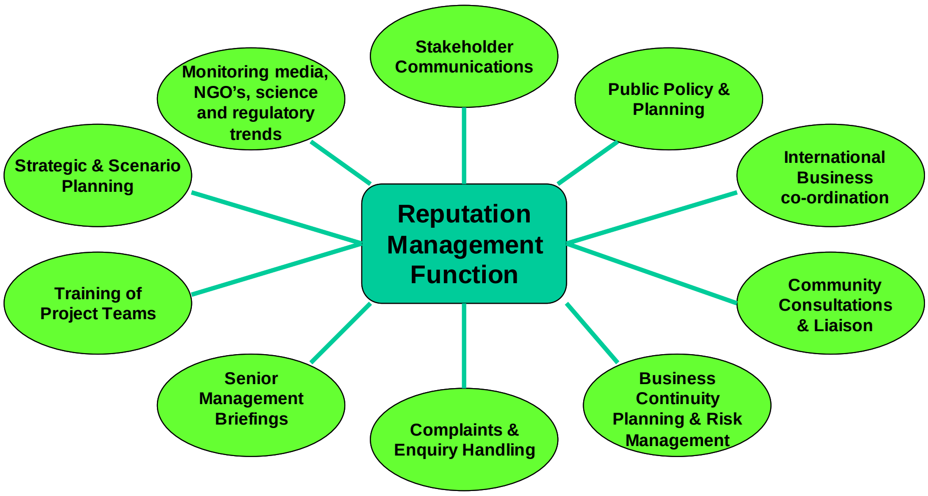


Figure 5.1: Reputation Management Functions

Reputation Management Functions

Stakeholder Communications includes all reporting and compliance, particularly the social and environmental impacts of operations.

Public Policy & Planning. Individual decommissioning programmes must be seen to comply with and be compatible with corporate policy and objectives.

International Business Co-operation includes co-operation between divisions of a multi-national company, co-operation between different operating divisions and different national industry bodies.

Community Consultations & Liaison covers the location from which existing facility support workers originate through to the community where the recovered facilities will be landed and maybe re-used.

Business Continuity Planning and Risk Management. Emergency response procedures and handling of the media may also be included.

Complaints and Enquiry Handling procedures must ensure that questions or enquiries from whatever source are handled, and seen to be handled, promptly and efficiently.

Senior Management Briefings refer to internal communications between the decommissioning project teams and senior management responsible for corporate reputation management.

Training of Project Teams. It should not automatically be assumed that project personnel are familiar with the wider business implications of their project or the emergency response measures in place.

Strategic & Scenario Planning is important in managing uncertainty and incorporating trends and influences identified from other sources.

Monitoring Media, NGOs, Science and Regulatory Trends is the prime input into scenario planning. It provides the basic information from which future trends in stakeholder values and behaviour can be assessed.

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5.3 Decommissioning

An efficient decommissioning programme is dependent on the specific characteristics of a particular facility, but some generalisations can be made. Although the decommissioning options for steel platforms presume total removal although for jackets weighing in excess of 10,000 tonnes, however, the OSPAR[26] derogation process may permit the foundation of the jacket to be left in-situ. A number of options exist for the end destination of recovered material based on the waste hierarchy of re-use, recycle and final disposal as waste.

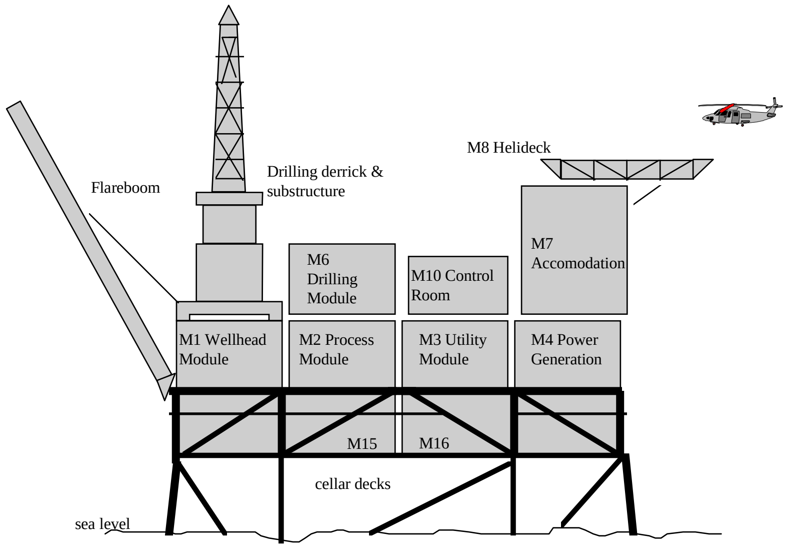


Figure 5.2: Platform Schematic

There is no such thing as a typical offshore platform, but the figure above is a simplified schematic of an actual platform. The topside facilities consist of 10 modules with a total dry weight of 17,400 tonnes, stacked in two layers. The very early platforms would have a larger number of modules of smaller weight, whilst later platforms have fewer modules of larger weight. This difference is due to the heavy lift capability at the time of installation. (The current lift capacity has not increased since 1993).

The more recent large offshore platforms have utilised an integrated deck structure, weighing in excess of 10,000 tonnes, which in effect combines the modules 1 to 4 of our typical platform into a single deck. The accommodation and drilling facilities are separate modules, stacked atop the integrated deck, much as our example platform.

The jacket, in our example platform, is an eight-leg, barge launched structure, weighing 12,300 tonnes in air, and installed in 80 metres of water. Later jacket designs, for this size of topside and water depth, would most probably have been designed to be lift installed, rather than launched.

5.3.1 Engineering Activities

Information is the key to the successful development of an abandonment strategy that meets the facility owner's obligations in law and the consideration of:

a) Developing methodologies that are safe, with all risks identified and mitigation measures defined to ensure that risks are kept as low as reasonably practicable.

b) The least detrimental impact on the environment, minimum interference with other users of the sea and the minimum risk of environmental pollution.

c) The techniques and equipment resources necessary to undertake the abandonment operations are cost effective. Information is available in sufficient detail to enable a scientific

[26] See Chapter 3 of this report for details of the OSPAR derogation process

and systematic evaluation of the proposed abandonment option(s) by independent assessors and other interested parties involved in the consultation process.

The process leading up to the commencement of cessation of production is illustrated below.

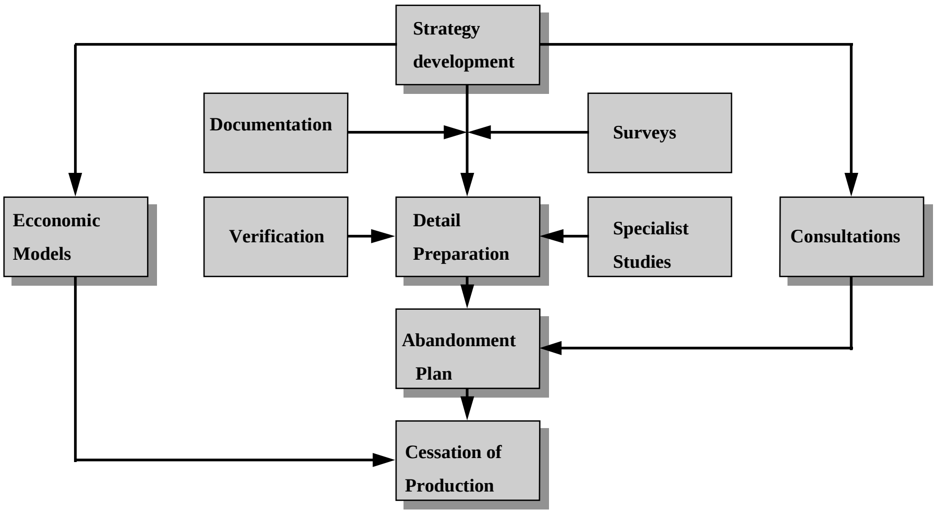


Figure 5.3: Cessation of Production Process

THE DOCUMENTATION SURVEY

A survey of all available documentation relating to the offshore facility design, procurement records, fabrication, installation, commissioning, start-up, operational records and of subsequent inspection, maintenance and repair records is the starting point. It must be appreciated that for many offshore facilities, this documentation is liable to be incomplete, unreadable or unreliable, (hard copies of the documents may be 15 to 25 years old).

The later generation of platform designs based on electronic data systems may also be of little use due to obsolete hardware or limited life expectancy of the stored material (e.g. magnetic tape). In many situations, the information retrieved would be subject to verification through audits.

The results of the initial documentary surveys are used to define areas of information deficiency to be remedied through field surveys.
If not addressed at the facility design stage, the initial definition of all available options for the facility's decommissioning and removal will identify additional information required to complete the option evaluation and bidding process.

PRE-ABANDONMENT SURVEYS

The objective of the pre-abandonment surveys is to assess the condition of the offshore facilities, structure and environment prior to commencement of detail engineering and planning activities. A number of different surveys are required, as discussed below.

A geophysical survey is carried out using a Survey or Diving Support Vessel (DSV) fitted with a remotely operated vehicle (ROV). The survey will need to include:

- A sonar survey of the seabed to determine and record the location of all obstruction for a distance of up to 1,500 metres around the platform.
- A survey around the jacket base to determine the depth of jacket self-penetration, piles internal soil plug depth, extent of seabed scour and depth and take samples of the drill cuttings mound.
- Gathering of additional environmental and geophysical data to supplement existing data.
- Survey in-field and export pipeline along their length to identify free spans or exposed lengths of pipeline.
- The prospective reception sites for recovered material will be identified and surveyed.

An environmental survey is necessary to identify:

- The local shipping traffic type, density and routes so that the impact of abandonment options on the safety of surface and subsurface navigation can be evaluated.
- The local marine eco-system, seawater chemistry and marine life in order to permit evaluation of immediate and long-term impact of the various abandonment option.
- The risk that any seabed debris will deteriorate or shift from its intended long-term position.
- The onshore reception facilities and sites for disposal of toxic, hazardous or industrial waste materials.

The environmental survey should also include initial discussions and consultations with the regulatory authorities and other interested parties, such as the fishing industry, who are able to offer local or specialist knowledge or assistance in completing the abandonment option evaluation process.

A structural survey of the facility structure is required, above and below the waterline to:

- Assess general structural soundness, i.e. evidence of corrosion or mechanical damage such as pitting, dents, straightness, etc., which may impair intended subsequent operations.
- Access for, and ease of, structural strengthening.
- Determine the existence, and status, of existing lift attachment points, which will require NDT.
- Determine interfaces between deck modules and jacket structure to confirm cutting scope and any restrictions to cutting techniques.
- Take samples from internal partition walls and thermal insulation materials to identify the presence of materials such as asbestos.
- Identify any discrepancies between the as-found condition of the structure, the as-built information and the original design assumption.
- Verify, below the water-line, existing pipeline tie-ins, extent and thickness of marine growth, status of corrosion protection systems to estimate the degree of corrosion loss in the material thickness of critical element.

In conjunction with the structural survey, a weight audit will be conducted to identify items added and their distribution within the facilities, during the facility's operating life. This survey would be correlated with the weight control records generated during the original design and with the construction yard weight verification records and offshore lift installation records. An abandonment weight control system can then be initiated, to record all further temporary items added and items removed or relocated during abandonment operations.

A process survey is required to identify any additions or major modifications made to the onboard process systems during the plant's operational life. Past experience has shown that many offshore facilities undergo significant modifications and updates during this life cycle.

The quantities of oil, gas and other hazardous material inventories remaining onboard at shutdown need to be estimated and their location identified. Materials other than hydrocarbon inventories, with their locations, are to be found in the COSHH register, or equivalent hazardous substances list, sourced from the Statutory Operations Manual. Where possible, samples of tank residues should be taken for examination and the existence of any radioactive scale formations checked. Any offshore facility that has handled wet sour gas should be checked for the occurrence of iron sulphide (pyrophoric) scales on unprotected carbon steel. These scales are safe whilst wet, but warm and dry conditions create potential fire and explosion hazards.

PRELIMINARY ENGINEERING

On completion of the offshore surveys, the original options for abandonment will be revisited. Some preliminary engineering is undertaken to rank the options in terms of practicability. At this stage a concept safety evaluation (CSE) and concept environmental impact assessment will be undertaken to further rank the options. Initial costing of the various options is completed and fed into the financial models confirming the economic case for ceasing production. The outcome of the preliminary engineering phase will be a preferred and costed option for abandonment and a strategy for its execution.

DETAIL ENGINEERING

This detail-engineering phase is critical to maximise the efficient use of offshore marine equipment, and to define the safe and most cost effective disposal technique. The scope will be sufficient to produce, in conjunction with the prime contractors, a detail decommissioning removal and disposal operations manual with identified work elements, job packs and a permit to work system.

If the facilities are to be re-used, additional considerations with respect to fatigue, material traceability and re-installation are required. Fatigue considerations must include determination of residual life remaining after the initial in-service period and planned service life at the new location.

Full structural analysis of the structures, will be required to prove the structural integrity during the removal, transportation and offloading at the reception facilities. All temporary works will be designed and fabricated, rigging sets specified and sourced and marine equipment selected suitable for the intended operations.

Regardless of the original intended service life of process and utility systems and components, the residual life span will be dependent on the extent of the end of life maintenance programme. In many cases, such maintenance programmes will be progressively reduced towards field shutdown to manage costs. The residual value of such components will, therefore, depend on an early recognition of the re-use potential. Re-certification and pressure testing of process equipment will almost certainly be required, with some upgrading of safety and monitoring systems to meet current safety legislation. Instrument systems (including telecommunications) rarely match the new field requirements, so will form part of the refurbishment programme considerations.

Plans should be initiated for the original vendor of primary equipment (e.g. power generators, firewater pump packages, etc.) to be contacted to strip down and refurbish such systems, so as to provide on going performance guarantees.

Traditionally, process systems are designed around specific field reservoir characteristics of composition, temperature, pressure and flow characteristics, often with the intention of optimising the design to the assumed characteristics. If re-use is considered, the engineering intent is to verify the characteristics of the 'as-is' process system and evaluate the resultant impact on reservoir performance and, hence, field economics, where re-use is an option.

An integral element of the engineering phase is the completion of the necessary safety studies, hazard analysis and reliability analysis to support the abandonment safety case and the preparation of the documentation in support of the abandonment plan.

5.3.2 Well Abandonment & Cessation of Production

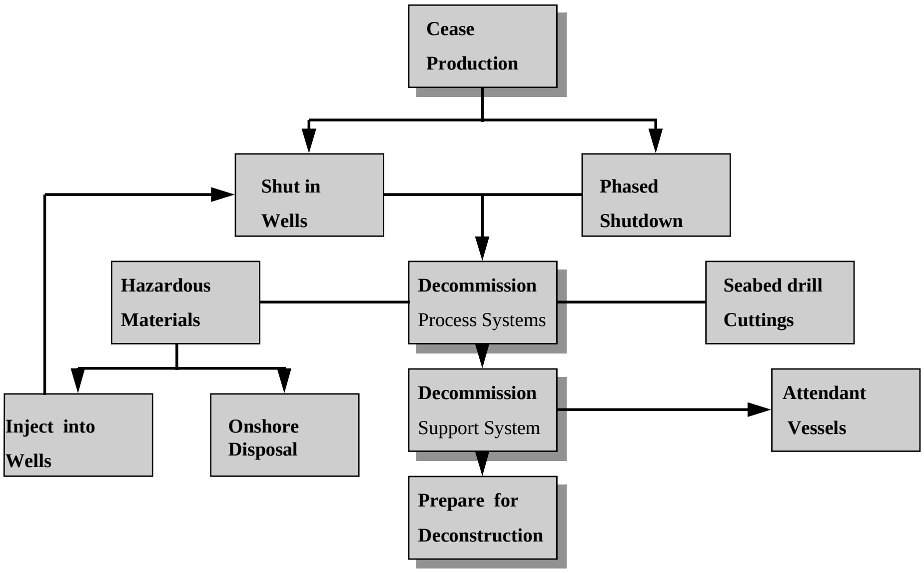


Figure 5.4: Decommissioning Process

The production process will undergo phased shutdown in conjunction with shut-in of the wells, and isolation of the export risers and pipelines. Essential services have to be maintained to support such activities. As offshore decommissioning operations proceed, a point will be reached at which it will be necessary to shut down systems and transfer essential services over to attendant support vessels.

Well Abandonment

Well abandonment operations are typically carried out using the platform drilling rig or where the platform's drilling facilities have been removed, workover rigs or coiled tubing equipment is used to set the cement plugs that isolate the reservoir producing zones from the surface.

When developing the well abandonment procedures, the possibility of disposing of platform hazardous material inventories downhole and the opportunities of recovering drill cuttings from the seabed and re-injecting them into the reservoir should be evaluated. (Much research and evaluation of re-injection technologies have been undertaken in recent years, e.g. the work by Moschovidis.[27]) The slurrification unit, storage tanks and injection pumps would need to be shipped offshore and commissioned before re-injection operations could commence. The suction pumps necessary for recovery of the drill cuttings from the seabed are still under development.

The abandonment of production wells encompasses three principal activities:

- Isolation of the reservoir from the surface, and of different producing zones
- Treatment of the annuli between casing string
- Cutting and retrieval of the upper casing strings.

Under the terms of the Petroleum Production Regulations, the well abandonment programme has to demonstrate that the proposed operation will:

- Control the flow and escape of hydrocarbons
- Prevent damage to adjoining strata
- Isolate all permeable formation from one another
- Prevent possible crossflow
- Prevent contamination of aquifers.

[27] Z A Moschovidis et al *'Disposal of Oily Cuttings by Downhole Periodic Fracturing Injections, Valhall, North Sea: Case Study and Modelling Concepts'* SPE paper 25757, 1994

5.3.3 Decommissioning of the Platform

Platform decommissioning includes all work elements that contribute towards the preparation of the topside facilities for cutting and removal. The facility's existing operating personnel, supported by specialist sub-contractors, will usually be responsible for ceasing production, shutting down and depressurising the process systems and equipment. During decommissioning operations, the platform facilities must remain fully operational with respect to essential services, which will generally include:

- Electrical power
- Fire and safety systems, deluge systems and fire monitors
- Accommodation and life support systems
- Evacuation systems, both helicopter and lifeboats
- Plant air and inert gas systems
- Seawater system (including water injection facilities)
- Fuel gas systems
- Diesel fuel
- Oil water clean-up facilities
- Communications, both onboard PA systems and platform/shore communications.

Electrical Power

The single most important service during decommissioning will always be power supply to the living quarters, fire and gas systems, fire water systems, HVAC systems and lighting, welding equipment, etc. Power will be maintained from the platform facilities for as long as possible after which power will be imported from the attendant vessels on location. Temporary generators may need to be taken out to the platform to supplement the main and emergency generators as they are taken out of service.

Fire and Safety Equipment

The priority of fire and safety equipment will change during the course of decommissioning. Immediately after platform shutdown the fire and safety requirements will be essentially the same as for normal operations. As the process system is decommissioned, the hazards on the platform are reduced.

Lifeboats will be required to be fully operational during the initial decommissioning phase. Special attention needs to be paid to retaining unobstructed escape routes and housekeeping is a critical aspect – there is a history of fatalities during construction phases due to garbage / diesel fires.

The vent and flare systems need to be maintained fully operational as gas pipelines and vessels will need venting safely. If it is necessary to maintain a flaring capability, the flare ignition facility will require back-up propane bottles as the fuel source, however, it is more likely that venting rates will be low enough to allow cold venting.

Accommodation and Life Support Systems

Offshore crews for decommissioning and support services could number between 50-100 men. The accommodation provided on offshore platforms varies from less than a dozen on a not-normally-manned platform to 200+ on a facility with full accommodation provision. In both cases, at some point temporary accommodation will be required to support the decommissioning operations, either from an attendant accommodation vessel or alternately from the attendant heavy lift crane vessel (HLV).

Decommissioning Services

A variety of equipment will be required to be shipped out to the platform for decommissioning purposes. Such equipment will include special items for cleaning, purging and liquids removal, small tools, scaffolding and mechanical handling equipment. Liquid removal and storage tanks will require space and access, being handled by the platform's existing cranes. Consumables, such as diesel and potable water will require to be supplied to the facility.

Oil and Gas Systems

The oil and gas systems represent the major portion of the decommissioning operation, it being the flammable aspects of the fluid inventories that dictate the appropriate procedures. While there are no typical system descriptions, the diagrams below show the principal elements of a process system, and of a gas system.

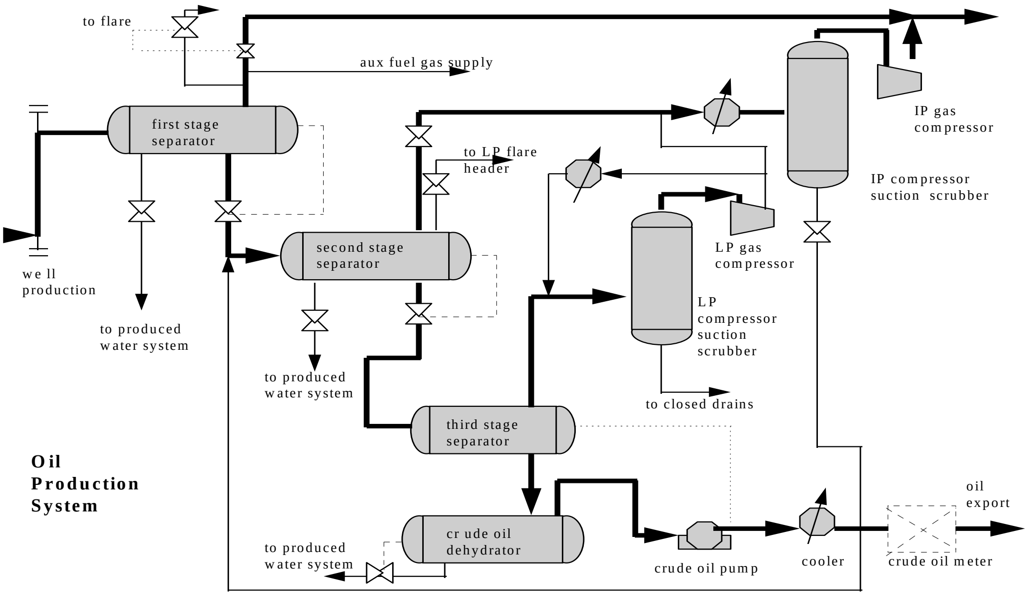


Figure 5.5: Oil Production System

It is usual for the facility's oil water treatment system to remain operational during decommissioning to remove the oil contamination thereby allowing the bulk of liquid to be dumped overboard in compliance with regulatory requirements for oily water discharge. The skimmed oil is routed to storage drums or barge tanks. Where separation of liquids with high oil content cannot be accommodated on the platform, such liquids will be drained off to barge-mounted tanks.

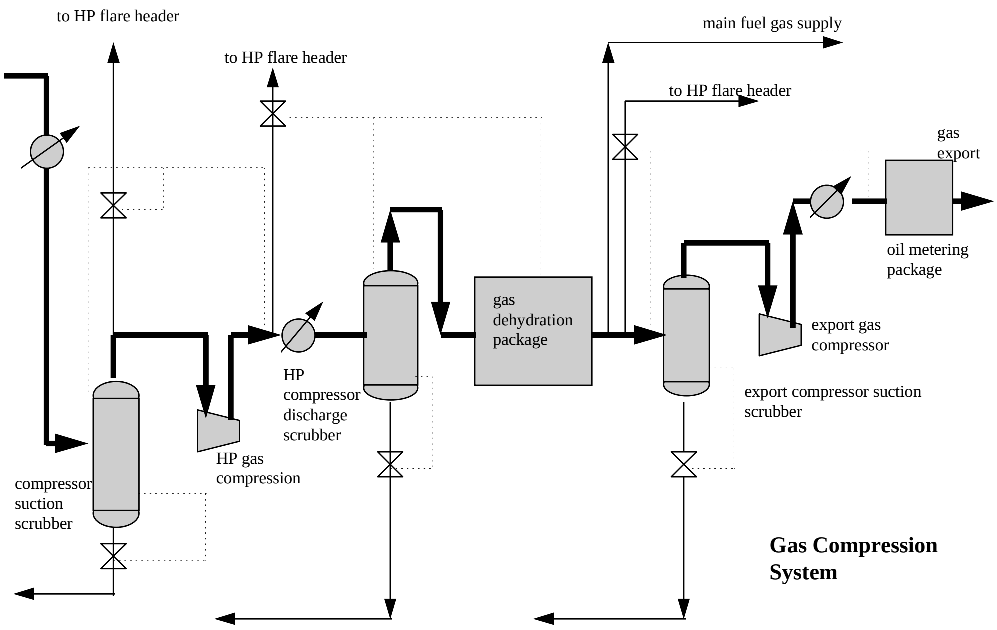


Figure 5.6: Gas Production System

On cessation of production, vessels and associated pipework are depressurised and drained of liquid. Internal vessel deposits may contain gas at atmospheric pressure (possibly flammable), oil residues, heavy sludges, waxy coatings and, in some vessels, LSA scale. All such vessels and pipework must be cleaned to remove such hazardous residues.

System Inerting

The prime purpose of the decommissioning operation is to render the process system free from hazards during the deconstruction phase. An essential aspect of this concept is the guarantee of an atmosphere free from inflammable gas mixtures when any pipe cutting takes place. The standard procedure to achieve this is a nitrogen blanket. Although there are several methods for achieving this, the more common is the use of a nitrogen foam inerting system.

All disconnection and cutting operations will have to be undertaken under a strict permit to work system.

5.3.4 Topside Removal

The procedure for removing the topside structures will be dictated by the marine spread provided by the decommissioning contractor. The most straightforward option is that of reverse installation, that being to lift off the topside module components in the same sequence as they were originally installed.

1. Cut free the module or item to be lifted. This will include secondary structural items such as cladding, deck infill panels, walkways and handrails, and primary bearing fixings.
2. Reinstatement of padeyes or installation of padeyes, prefabricated onshore, where the original padeyes have been removed. Structural reinforcing members are installed, where necessary, to strengthen the module/deck for lifting.
3. A flat top cargo barge pre-fitted with foundation grillages and sea fastening is towed to the facility.
4. The lift rigging sets are installed on the module/deck, consisting of cable-laid wire rope slings and shackles for lifting of the modules/deck, and crossed tugger wire line attached to provide rotational control of the module/deck during lift off operations.
5. The Heavy Lift Vessel (HLV) lifts the module/deck off the platform and sets the load down onto the cargo barge, the sea fastenings are completed, the lift rigging disconnected from the crane hook, and the cargo barge towed back to shore.

Figure 5.7: Typical Topside Removal

The crane capacity available has increased significantly in the last ten years, with capacities now available in excess of 12,000 tonnes. This presents an opportunity to combine smaller modules into packages to realise advantages of the larger crane capacity. The combined modules are laced together with pre-stressed tendons, and it is likely that significant strengthening will be required to ensure structural integrity of the combined lift.

While the objective of such an approach is to reduce costs by reducing the number of HLV barge days, the cost of additional offshore work to prepare the packages for lifting and the associated cost of attendant accommodation and support vessels, may outweigh the potential savings.

The part-demolition option is the counter option to the combined lift option. In this case the objective is to reduce the weight of the module such that it falls within a pre-defined lift vessel class. This may mean removing large items of equipment and elements of secondary steel. The exact requirements, and their practicability, will depend on the specific module attributes and available crane specifications.

The marine spread required for topside removal operations will include:

- Flat top cargo barges, pre-fitted with module support grillages and sea fastenings
- Ocean going tugs for cargo barge tows
- Dump barges for back loading miscellaneous scrap items
- Safety/standby vessel during preparation for module removal
- Supply vessels may be necessary to ship consumables needed in support of deconstruction preparations to the platform
- HLV for removal operations, together with attendant anchor handling tugs
- Helicopter services to transfer personnel to and from the platform facility and/or the HLV.

5.3.5 Jacket Removal

Since the OSPAR decision of 1998, the number of options available for removing jacket structures has been reduced to total removal, or for jackets weighing in excess of 10,000 tonnes, removal to the top of the foundation level. In the North Sea jackets have been successfully removed either in one piece or by cutting in sections (see case studies in Chapter 7).

The North West Hutton jacket will be the first jacket seeking derogation to permit the jacket foundations, drill cuttings and drilling template to be left in-situ.

Figure 5.8: Typical Jacket Removal

A typical jacket removal process would proceed as follows:

- After removing the topside structures an ROV would be run to survey the jacket down to the mud line, to locate and subsequently to remove any debris or loose items.
- Divers would disconnect, rig up and remove pipeline spools and control umbilicals to provide 30–50m clearances around the jacket.
- All proposed cut lines on the jacket would be surveyed and marked.
- All jacket secondary members would be cut using diamond wire or abrasive cutting equipment.
- If the jacket is to be removed in sections, it would be necessary to cut access holes into the jacket legs to cut internal grout, injection, ballast and control lines.
- Soil plugs would be removed from inside the foundation piles, and piles pre-cut, after verification of on-bottom stability in the cut condition.
- Lifting points would be welded onto the jacket, or holes cut and lifting trunnions inserted.
- The jacket legs would be pre-cut, rigging and tugger sets installed, final cuts made, the jacket (or sections) lifted clear and set down onto the deck of the crane barge before back loading onto cargo barges and shipped back to shore for final dismantling.

5.3.6 Onshore Disposal

The ideal onshore reception facility for salvaged topside modules/decks and jackets will have a deep water offloading quay, with access to an infrastructure having direct access to rail, main road and sea routes. The site will require planning permission for demolition of offshore facilities and licensed to store, temporarily, hazardous materials.

Offloading at the Reception Facility

Figure 5.9: Typical Facility Arrangement

The picture shows a typical arrangement using multi-wheeled trailers that can be seen underneath the deck structure.

The cargo barges loaded with recovered deck modules will be brought alongside the quayside, under the direction of the Harbour Master, and moored. Two methods are available for offloading barges, depending on the weight of the deck module:

- Multi-wheeled trailered operation
- Module offloaded by direct lift.

The demolition site is a fenced compound area, with ticketing for incoming and outgoing traffic. Exit from the site is via a weighbridge and gatehouse which tracks the movement of materials transported by road. Materials directly loaded out from the site onto vessels are covered by yard security and the appropriate shipping documents.

Strip-out and Disposal of Hazardous Materials

All demolition operations are required to comply with the Health and Safety at Work Act 1992 (HSAWA-92). The main areas for special attention are the removal of hazardous materials from the modules, purging and cleaning of pipework and vessels not completed offshore, the identification and removal of asbestos and radioactive scales (LSA).

All residual liquids will be removed from the process modules, and the purged status of process systems maintained. All liquid inventories removed will be collected into 45 gallon drums and checked by an on-site chemist before being sealed.

All lube oil and oil reservoirs of compressors and other machines will be drained and flushed to ensure such equipment is free of oil residues. Special precautions will be taken as lube oil and its residues are classified as carcinogenic. The lube oil and flushing agents will be collected in drums and labelled.

Examples of other hazardous material handling requirements include: batteries, fridges, freezers and cool drinks cabinets which may contain CFCs, halon containers, etc.

To comply with the Health and Safety at Work Act a RPS will survey the modules for LSA scale, and monitor the removal of contaminated items for shipment to a specialist decontamination centre, under the Ionising Radiation Regulations 1985, with disposal of LSA scale being undertaken in accordance with the requirements of HMIPI.

Asbestos can be a significant material in construction of accommodation modules and control rooms. Where such materials are present, tents are required around the module, or section of the module, to form the negative pressure atmosphere required for the asbestos removal operation. The tented area must be complete with airlocks and filter systems, with controlled entry using respirator sets. An independent Asbestos Inspector will monitor operations for the removal, bagging and transport of the asbestos to registered landfill sites.

Non-hazardous industrial waste material consisting of non-asbestos lagging, gasket material, plastic panels and trims, non-asbestos ceiling tiles, carpeting, fixtures and fittings and bagged fibreglass mat insulation will all be removed and transported to regulated land fill sites.

Demolition of Modules

Once all hazardous materials are removed from the module, the necessary permits will be issued to allow demolition to begin. The modules will be soft stripped, i.e. cleared of all cabling, control panels, furniture fixtures and fittings prior to demolition.

Equipment items identified for possible resale are removed to covered warehousing, while the remaining module carcass is demolished, using conventional oxy-acetylene cutting and caterpillar tractor mounted hydraulic shearing cleavers. The resulting scrap metals are sorted by type and grade before being shipped out.

5.3.7 Pipeline Abandonment

Pipelines are taken to include all pipelines, (both buried and surface laid), pipeline bundles, flexible flowlines, umbilicals, export and infield pipelines. Also included are the pipeline associated structures including pipeline crossings, pipeline manifolds, tie-in points and their protective structures.

Pipelines differ from other offshore structures considered in the decommissioning debate in as much as they may well cross other owners' property, or even extend beyond national boundaries with differing regulatory requirements.

A considerable number of different parties, with differing standpoints, will therefore have an interest in the decommissioning of pipelines. These parties have very different views on financial profit, environmental, ecological and safety aspects and which is the more significant. All views will need to be addressed to arrive at a consensus on the optimum removal strategy for pipelines.

Legal Requirements for Removal of Pipelines

International legislation for pipeline removal has yet to be fully defined. The '1982 Law of the Sea Conference' did not specifically address the question of removal of pipelines, nor did the subsequent International Maritime Organisation guidelines on removal of offshore structures. The most comprehensive guidance to date on the abandonment of pipelines is that produced by the UK's Department of Trade and Industry (DTI).[28] The guidance notes recognise three principal abandonment options:

- Total removal
- Burial or trenching of the pipeline to adequate depths
- Leave pipeline in-situ.

The guidance notes define three post-abandonment requirements, these being:

- The persons who own a pipeline at its abandonment will normally remain the owners of any residues. Any residual liability remains with the owners in perpetuity. Owners will also be responsible for complying with any conditions attached to the approval of the abandonment programme.
- Any remains of pipelines will be subject to monitoring at suitable intervals specified in each abandonment programme and may require maintenance or remedial action in the longer term.
- Any compensation arising from any effects at sea of the abandonment of a pipeline will be a matter for the owners and affected parties.

The approach taken in reviewing options proposed for abandonment of pipelines will be based upon:

- Decisions taken on a case by case basis.
- Any removal or partial removal of a pipeline should be performed in such a way as to cause no significant adverse effects upon the marine environment.

[28] DTI Consultative Document *'Guidance Notes for Industry, Abandonment of Offshore Installations and Pipelines under the Petroleum Act 1987',* issued May 1995

- Any decision that a pipeline may be left in place should have regard to the rate of deterioration of the material involved and its present and possible future effect on the marine environment.

This last criteria raises the question of what will change when a pipeline is shutdown and how quickly will it decay? When it does, will this action cause more or less problems? Since this has not happened yet, it is difficult to quantify. Studies have indicated that corrosion is not likely to be a significant degradation mechanism for perhaps 100 -150 years after abandonment.

Determination of any potential effect on the marine environment should be based upon scientific evidence, taking into account the effect on water quality; geological and hydrographical characteristics; the presence of endangered or threatened species; existing habitat types; local fishery resources; and the potential for pollution or contamination of the site by residual products from, or deterioration of, the pipeline.

Based on the above criteria, the guidance notes provide an indication of which pipelines may remain in-situ, these include:

- Those which are adequately buried or trenched over a sufficient length and which are likely to remain so.
- Those which were not buried or trenched at installation but which are likely to self bury over a sufficient length within a reasonable time and remain so buried.
- Those where burial or trenching of the exposed sections is undertaken to a sufficient depth and is likely to be permanent.

Small diameter infield pipelines and flexible flowlines should normally be entirely removed.

Such regulatory requirements will be used as the basis for defining the options for decommissioning and abandonment or recovery of pipelines.

Decommissioning of Pipelines

Standard procedures for decommissioning of any pipeline include cleaning and purging of all internal hydrocarbons. This removes all the volatile liquids hazardous to the marine environment leaving only the coated steel pipe on the seabed.

A typical example of such a pipeline decommissioning process, which is taken from the Dutch Sector of the North Sea includes:[29]

- Residual condensate was removed from the pipeline using foam pigs propelled by nitrogen. Pig running was carried out using the permanently installed pig traps on the platforms.
- The pipeline was thoroughly cleaned (after condensate removal) using foam pigs with plugs of seawater and detergents, again using nitrogen as a propellant.
- Seawater was used to flood the pipeline (after cleaning operations) when the lower explosive limit (LEL) in the pipeline (measured at the pipeline ends) was less than 5%.
- Divers then exposed a section of pipeline on the seabed at the bottom of the platform.
- The vertical riser was cut from the pipeline at the bottom elbow, then further cut into manageable sections and removed to the deck of the platform.
- A pipe plug with bleed hole was installed in the open end of the pipeline on the seabed, and a foam pig, propelled by treated seawater, was run to the plug.
- Once the foam pig had reached the pipe plug, the bleed hole in the plug was stopped off.
- The recovered sections of the riser were transported to the contractor's yard, and the remaining pipeline left clean and safely flooded with inhibited seawater.

[29] RP Starsmore "History of a wet gas transportation pipeline from design through to decommissioning", presented at the Pipeline Industries Guild, London, January 1990

Techniques and Options for Removal of Pipelines

Table 5-1: Reported Incidents of Abandonment or Recovery of Pipelines

Location	Pipeline Size	Length	Method of Recovery
W. Africa	8 inch dia	600 m	Reeled
India	12 inch dia 14 inch dia 12 inch dia	72m 78m 75m	Reverse lay Reverse lay Reverse lay
N. Sea	18 inch dia	9 km	Reverse lay
N. Sea	26 inch bundle	6.1 km	Cut up on seabed
Brazil	4 & 6 inch flexible	Various	Reverse lay
Mediterranean	6 inch flexible		Reverse lay
N. Sea	6 inch flexible	7.5 km	Reeled
N. Sea	6 inch	610m	Reeled
N. Sea	12 inch	260m	Cut on seabed recovered in sections
N. Sea	3.5 inch	550m	Reeled
Egypt	14 inch	360m	Reverse lay
N. Sea	20 inch	42 km	Abandoned in trench
N. Sea	6, 8 & 10 inch	32 km	Reeled with onboard flowline cutter

As the table[30] shows, only a small number of pipeline abandonment's and/or recoveries have been recorded worldwide.

The burial method of abandoning pipelines consists of trenching the line to below the seabed, and covering with backfill. It may be that natural backfill is sufficient, in which case trenching is the only task necessary.

The methods used to trench and cover an abandoned pipeline are likely to be very similar to those developed for new pipelines. Plain ploughs and trenchers may be used to dig a trench, and the pipeline pulled sideways into it. On-line trenchers might be employed to travel along the pipeline, trenching and even backfilling to leave the pipeline covered. Alternatives to mechanical ploughs are jet sleds – water jets used to blast the soil away. Both types of machine suffer one major drawback. They cannot cope with hard material or rock filled sediments, which would prevent a trench being cut.

Assuming seabed conditions are favourable. The procedures used are as follows:

- A seabed survey along the pipeline route is carried out to determine pipeline location and up to date seabed topography.
- The towing vessel positions at the end of the pipeline and the plough is lowered to the seabed.
- Accurate positioning of the plough beside or underneath the pipe is carried out using divers and/or ROVs.
- Tow cables are slung on the device and the tow vessel takes up slack.
- Trenching proceeds.
- Control and monitoring of the ploughs progress is provided by the ROV camera.

[30] MW Cooper "The abandonment of offshore pipelines", presented at the Pipeline Industries Guild, London, January 1990

If the device encounters unexpected tough seabed material at the pipeline section destined to be buried, the pipeline would need to be cut and recovered. This would represent an unacceptable delay and additional cost, so it is likely to be dealt with later after the rest of the pipeline has been buried. Time will be spent disconnecting the tow cables, re-positioning the device and re-starting in the nearest region of good soil. This also applies when the pipeline has crossings and fittings along its route. In addition, the deteriorated condition of the coatings might hamper operations if they have degraded. The cost of trenching is, therefore, also dependent on other factors in addition to the type of soil in which the line is laid.

Recovery Techniques

Only a limited number of pipelines have ever been recovered, and of these the majority were recovered by reverse lay techniques. Recovering a pipeline by reverse lay at the end of its life may prove more difficult than originally laying it. The primary problem (as with laying) is preventing a buckle in the line.

The type of vessel selected to recover a pipeline will be chosen by the calculated tension required. As the overall weight including marine growth may be greater than when new, it is likely that the tension required to recover the line will be higher than under original laying. In some cases, it may be impossible to recover by reverse lay, due to fragility of the line.

There are several methods of laying a pipeline, the most common being to lower it over the stern of a lay vessel in a `S' shape configuration along a stinger with a brake device (tensioner) holding the free end. More pipe is welded on to the pipeline and the vessel moves forward lowering the pipe over the stern.

Alternative methods have also been developed which can also be used for recovery. In particular the *Stena Apache* utilises a large 82-foot diameter reel capable of carrying up to 50 miles of continuous steel pipe of approximately 2,000 tonnes in weight. This system is only suitable for lines that do not require concrete weight coating.

In this case, the pipeline is welded together onshore, wound round the drum, transported offshore and reeled out under control using a breaking mechanism (tensioner) similar to the more conventional lay vessel.

For many of the traditional smaller infield collection systems, this type of vessel offers an easy means of collecting quantities of pipeline without cutting it into shorter lengths offshore. With careful planning several lines can be removed from the seabed by reversing the reel and pulling the line back onto the drum. The end of each line can be welded to the next to form one long length and returned to shore to be unreeled directly onto trucks or lorries for recycling.

An alternate recovery method was utilised to recover the North Sea Argyll flowlines. The method is based on using a large platform supply vessel or anchor-handling vessel. Recovery of the flowline starts with the vessel holding station over the flowline end. An ROV runs a recovery wire and attaches it to the flowline recovery head. A deck-mounted winch picks up the flowline end and the powered reel starts spooling on the flowline.

A rubber tyred linear winch pulls the flowline from the top of the reel and pushes it through a hydraulic shear cutter. The flowline is cut into 11 metre lengths, after which it passes through a series of three treatment centres. At the first station the flowline is checked for low specific activity (LSA) radioactive scale, at the second station the pipe ends are sealed with polyurethane foam applied within a heavy duty clear plastic bag. At the final station, flowline lengths are bundled into packages for offloading.

Such a procedure produced considerable cost savings over conventional reeling operations.

Some laying vessels have self-contained pipe storage, others rely on container barges to supply them with pipe. So when recovering a pipeline, the cost will vary depending on the capability of each individual barge.

The cutting method for pipe, as with structural members, is a developing technology. Various techniques have been investigated, some tried and tested, some innovative. The problems of recovering pipelines are the requirement of speed and the avoidance of buckles.

It is necessary to cut a pipe string in about 10 minutes to allow the vessels average speed to match that for laying. But also, in the confines of a ship, the technique must not be dangerous to personnel. Explosive methods must, therefore, be ruled out. Water jet cutting is at present quite slow, and thermic lance cutting, whilst fast, at present only has manual applications. The most promising method will probably be with the hydraulic shearing cutters, initially developed for the onshore demolition industry.

If cutting methods for vessel use have development problems, the same is true with subsea cutting. In the situation where the only method available is cut and lift, what speed and cost can be expected?

The added cost of diving can be offset by the ability to perform multiple cuts simultaneously. It is traditional for the recovery vessel to lift pipe sections by crane. To speed up the process, perhaps buoyancy bags and tethers could be used to raise the pipe strings, while a container barge picks them off the surface one by one.

An alternative to cut and lift is Controlled Depth Tow (CDT), a variation of another laying technique. The procedure after cleaning would be to:

1. Cut pipeline at two points (perhaps 5 km apart).
2. Fit towing heads and remove water from the line.
3. Clamp buoyancy bags at selected intervals.
4. Attach cables to towing heads and pick up the pipeline using tugs at each end.
5. The first tug moves off, second tug reverses, the pipeline lifts off.
6. The tugs tow pipeline to shore location, where a beach-pull winch draws pipeline onshore where sections are cut until the whole length has been recovered.

CDT could be used to recover infield lines (which tend to be of small diameter and shorter length) in one piece. The transportation by CDT requires good weather and as short a distance to shore as possible.

It is concluded that techniques are currently available for the decommissioning and either abandonment or removal of submarine pipelines. These operations can be executed taking full account of cost, pollution risk and waste management procedures onshore. The selection of the appropriate removal option will need to address:

1. The status of the pipeline and its constituent materials
2. The extent of exotic material used (residual value of recovered material)
3. The condition of the pipeline relative to its original specifications
4. Handling and disposal of contents and residues
5. Crossings
6. Other pipeline components (e.g. valves, ‘T’s, protective structures)
7. Potential plans for the regions future development.

The main political issues relating to option selection include:

- The status and requirements of international and national legislation
- The concern for safety
- Environmental concerns
- Final disposal of recovered material
- Perception of the international community to abandonment issues
- The views of other parties involved in the sea (e.g. fishermen).

5.3.8 Site Clearance and Verification

A four-stage site clearance and verification programme will normally satisfy the various regulatory authorities that the abandonment operations have been completed in accordance with the approved abandonment plan.

Location Survey – this is undertaken after abandonment operations have been completed, but before debris removal commences. The survey may be conducted by a towed sidescan or multibeam sonar operated from a DSV or Survey Vessel. The survey site will extend for at least a 500-metre radius from the original facility seabed base area, unless the earlier pre-abandonment surveys have identified debris outside this zone that could be attributable to the original facility. The results from this location survey would be reviewed with DTI, the facility owner and contractor's representatives to define the scope and extent of debris removal operations.

Debris Removal – From an operational perspective, the efficient selection of a vessel from which to conduct debris recovery will depend on a number of factors including: weather conditions at the site location, amount and size of debris to be recovered and the water depth at the site. A number of specialist vessels exist, equipped with a selection of hydraulic operated grabs, which are capable of operating down to depths of 600 + metres, being suitable for such operations.

Site Verification – The regulatory authorities require that verification of seabed clearance is sought from an independent organisation. For the North Sea area, a fisherman from the Hull Trawlermen's Federation or the Scottish Fishermen's Federation would meet the "independent" criteria.

A trawl survey of the area is performed in a systematic manner with continuous relay of trawl net position back to the vessel for accurate plotting of coverage. The net is deployed and the vessel navigated along a predetermined track. The nominal distance between adjacent tracks is 100 feet. Where total removal of the offshore facility has been undertaken, the trawl area will cover a 1,500 metre radius from the original facility location. Where partial removal has been undertaken, the trawl area would cover an annulus of outer radius 1,500 metres and inner radius of 500 metres.

Within 14 days of completing the verification trawl, the independent verification body will issue a seabed clearance certificate.

Post Abandonment Survey – The regulatory authorities will normally require that a post abandonment sampling survey be undertaken to monitor levels of hydrocarbons, heavy metals and the macrobenthic populations at agreed locations.

Typically a grab survey would be composed of two transects, oriented along any perpendicular to the prominent on-bottom currents, with samples taken at up to 20 stations. Samples taken will be tested for:

- Particle size analysis;
- Metal analysis to identify any heavy metals present, their distribution and concentrations;
- Hydrocarbon analysis to identify contamination levels within sediments;
- Biological analysis to identify faunal communities and diversity.

The baseline information gathered during this and previous surveys will be used to confirm the ongoing site monitoring programme, and its interpretation against the base line measurements.

5.4 Key Technologies – Impact on Decommissioning Methodology

Well Decommissioning – is a major cost item which, in some cases, may require the use of a mobile drilling rig which currently could cost in excess of $200,000 per day. There is a very strong commercial case for developing alternatives for well abandonments and decommissioning.

Heavy Lift Vessels – a key requirement is for new technology to find an alternative to the use of heavy lift vessels. This is driven by two factors, the first being to reduce the cost of decommissioning and the second to secure an alternative to an aging heavy lift fleet. All of the new technology proposals have centred on a newbuild vessel that can remove platform topsides in a single lift. The vessels have included jack-up units, semisubmersibles, twin tankers linked together and special design buoyancy frames.

Should any one of these new removal concept vessels be built, there are implications for the decommissioning process. Firstly, the platform decks were designed to be installed as separate modules/units. If the decks are to be lifted as single units they will require substantial amounts of reinforcement/strengthening, all of which will have to be fitted offshore in less than perfect conditions.

Offloading – secondly, once removed, there is a problem in how to offload at the designated reception facility. There are two options available. Firstly the removal vessel, together with its deck load, sails into the reception yard and parks beside a finger jetty. The vessel is then ballasted down and the deck set down on the jetty from where it is transported/skidded to the demolition area of the site. This option would require the construction of a purpose built jetty to suit the specific vessel dimensions and draught.

The second alternative is a double marine handling procedure. In this case the removal vessel with its deck load sails into a sheltered inshore location. The vessel is ballasted down and the deck set onto a cargo barge floated into the vessel area. This would be a controlled operation and would require significant load distribution frames on the cargo barge designed to permit trailer or skid offloading. After the load transfer, the cargo barge, with the removed deck, is sailed into the reception yard and the deck trailered/skidded over the quay edge and on to the demolition pad.

The development of all new vessel concepts needs to be tracked to identify related opportunities for proposed onshore reception facilities and suppliers of loadout / backloading systems.

Realising Residual Values – As the offshore installation components are landed at the onshore reception facility there is an increasing requirement to dispose of the used equipment, in a manner to maximise re-use/recycling targets and to maximise residual value of recovered equipment, whilst minimising sellers' ongoing liabilities. Much of this equipment will have a significant residual value, which can potentially offset some of the major decommissioning costs.

As with most aspects of the offshore industry, the market is global. There is a strong potential for the use of used equipment in the emerging markets of West Africa and the Caspian. In these locations, equipment does not necessarily need to meet the same criteria for use in the North Sea – particularly in more benign environments and for a relatively short field life.

It is necessary, however, to ensure that potential buyers in such areas are reputable and have both the technical and financial resources to make proper use of such equipment and to execute their liabilities at the end of the equipment's useful life.

This could be accomplished using an integrated database of used equipment. A further significant benefit is the relative ease with which prospective purchasers can source their equipment and its final destination can be traced. Actual sales would be accomplished using direct advertising and sale through to Internet-based auctions. Implementing such a strategy utilises refurbishment, refitting and re-certification capabilities that are a natural development of existing skill sets, combined with new skills of marketing and advertising.

6 THE SCOTTISH SUPPLY CHAIN

6.1 Introduction

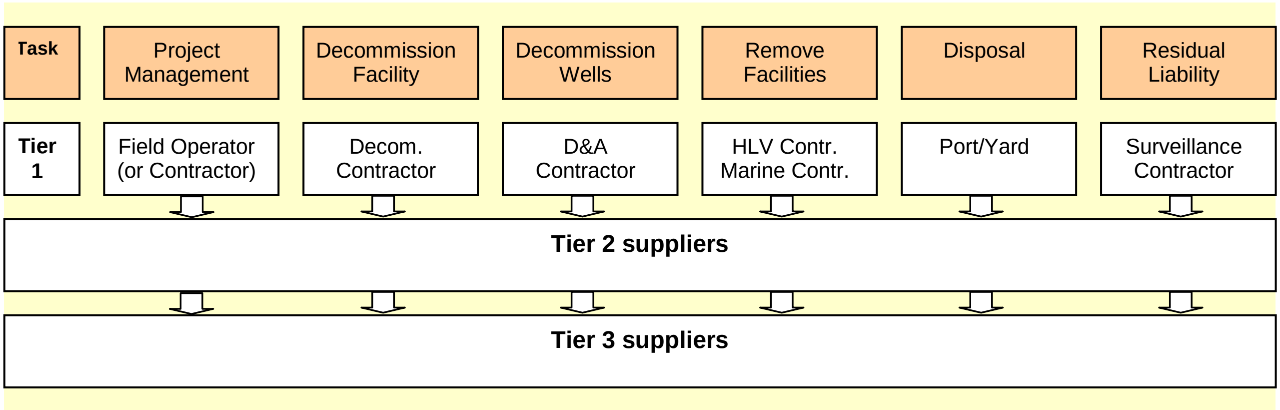


Figure 6.1: Supply Chain Structure by Key Activity (simplified)

As shown in the chart above, the decommissioning supply chain can be structured around six key 'headline' activities of:

- Project Management
- Facility Decommissioning
- Well Decommissioning & Abandonment
- Facility Removal
- Disposal
- Residual Liability.

Each one of these activities has its own subsidiary supply chain and we consider three levels or 'tiers'. Within the Tier 2 and Tier 3 Groups we can identify requirements for at least some 40 specific types of supply activity.

Table 6.1: Tier 2 & 3 Suppliers

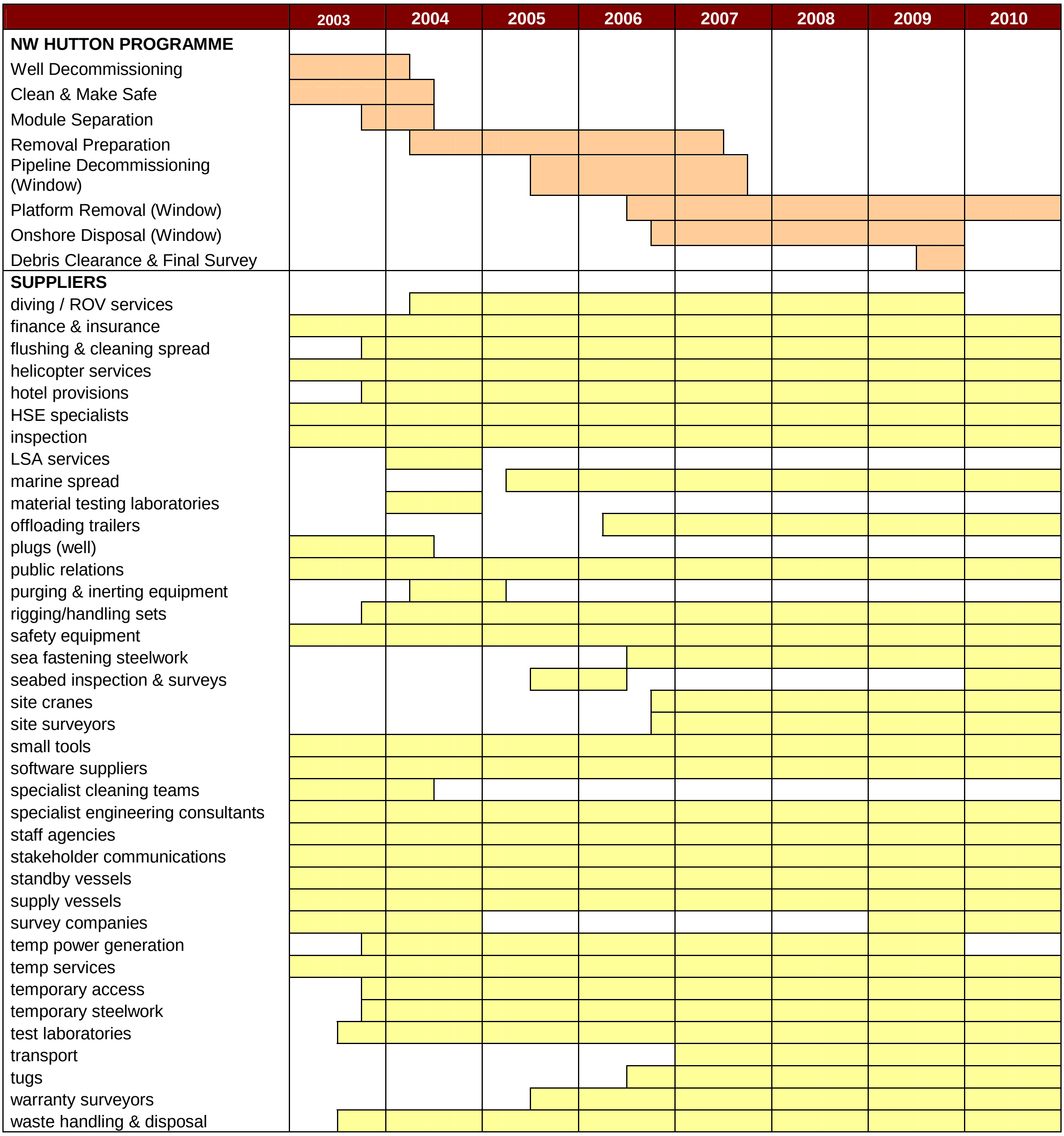
• cuttings recovery & injection	• diving / ROV services
• drill vessel & marine spread or JU unit	• finance & insurance
• flushing & cleaning spread	• helicopter services
• hotel provisions	• HSE specialists
• inspection	• LSA services
• marine spread /tugs/cargo barges/standby/ DSV	• material testing laboratories
• mechanical shears	• offloading trailers
• plugs (well)	• public relations / stakeholder communications
• purging & inerting equipment	• rigging/handling sets
• safety equipment	• sea fastening steelwork
• seabed inspection & surveys	• site cranes
• site surveyors	• small tools
• software suppliers	• specialist cleaning teams
• specialist engineering consultants	• staff agencies
• stakeholder communications	• standby vessels
• supply vessels	• survey companies
• surveyors	• temp power generation
• temp services / lighting / power gen / safety equ.	• temporary access (scaffolding & rope access)
• temporary steelwork fabrication	• test laboratories
• transport	• tugs
• warranty surveyors	• waste handling & disposal

Table 6.2: Decommissioning Supply Chain

	Project Management	Decommissioning	Well D&A		Facility Removal			Disposal		Residual Liability
	JOA Partners	Shut Down, Isolate & Decommission	Platform Wells	Subsea Wells	Platforms	Subsea Equipment	Pipelines	Reception Facility	Asset Sale	Monitoring
Tier 1	Field Operator	Decommissioning Contractor (*may be incumbent op/maint. contractor)*	D&A Contractor	D&A Contractor	HLV Contractor	Marine Contractor (*could be HLV contractor)*	Marine Contractor (*could be HLV contractor)*	Reception Yard	Auctioneers & Valuers	Long-term Surveillance Contract
Tier 2	• Specialist Engineering Consultants • Survey Companies • HSE specialists • Public Relations • Stakeholder comms. • Compliance/Certification • Finance & Insurance	• Purging & Inerting equ. • LSA Supervisors • Specialist cleaning teams • Hotel provisions • Temp power generation • 3rd party inspection • Waste handling & disposal • Diving/ROV services	• Coiled tubing • Services • Hotel • 3rd party inspection • Cuttings recovery (& injection?)	• Drilling rig & Marine spread • Diving/ROV spread • Surveyors • 3rd party inspection	• Cutting equ • Temporary access • Marine spread • Diving/ROV spread • 3rd party inspection & site clear surveyors	• Cutting equ • Marine spread • DSV • Diving/ROV spread • 3rd party inspection & site surveyors	• Cutting equ • Marine spread • DSV • Diving/ROV spread • 3rd party inspection & site surveyors	• Offload'g trailers • Site cranes • Mech shears • Waste handling & disposal • LSA Services	• Inspect'n • If re-use then….. engineer /fab or refurbish /renew. equip/ project mgt/ certificati on	• Seabed inspection & surveys
Tier 3	• Software suppliers • Web designers • Staff agencies • Material testing laboratories	• Temporary access, (scaffolding & rope) • Safety equipment • Rigging/handling sets • Small tools • Standby vessels • Supply vessels • Helicopter services	• Cement supplies • Plugs • Component supplies • Standby & supply vessels/tugs • Helicopter	• Cement supplies • Plugs • Component supplies • Standby & supply vessels/tugs • Helicopter	• Rigging sets • Temporary steelwork fab • Sea fastening steelwork • Consumables • Helicopter • Temp services – lighting/ safety equ. • Warranty surveyors	• Rigging sets • Consumables • Helicopter	• Flushing & cleaning spread • Rigging sets • Consumables • Helicopter • Bulk waste disposal	• Temp access • Consuma bles • Transport	• Web design • Brochure design • Promotio nal video	• Test labs

• Marine spread = tugs /cargo barges/standby vessels

Table 6.3: An Actual Programme Timeline with Tier 2 & 3 Suppliers



The top part of the above table is the published programme for the £160 million decommissioning of BP's N W Hutton field. However, this is complicated by the availability of the critical items such as heavy lift vessels, also receipt of OSPAR approval for leaving in place the platform footings. This results in specific tasks being allocated wide 'windows' of time in the programme.

To this we have added our own view of the timelines for the provision of services by Tier 2 and 3 suppliers. The very long 'tails' results from tasks being likely to be triggered anytime within a two or three year period.

6.2 Supply Chain Gaps

In general, Scotland in particular (and to a lesser extent the wider UK) is well supplied with companies that can undertake all the appropriate work involved in the decommissioning process, with three specific exceptions:

- Personnel – there is little experience of managing decommissioning contracts (compared to new field installations).
- Heavy Lift – there are no Scottish (or UK) vessels.
- Ports/Yards – are not presently set up to receive, dismantle and/or store large jacket and topsides units. However, as proven in Shetland, these can be established at a number of existing facilities.

It should be noted that the market is not just the UK sector and that Norway offers considerable potential for partnerships with Norwegian companies. The value of this has already been demonstrated with the success of the Shetland Decommissioning Company regarding Aker Kvaerner's use of the Greenhead Base, Lerwick, for parts of the Frigg Decommissioning project. (See case study below).

6.3 Contracts

A second factor that can have major influence on the supply chain is the structure of a field decommissioning contract. In the small number of instances of UK sector decommissioning that have happened to date it has been usual for the field operator to manage the contract. However, increasingly most oil & gas company operators are not structured to handle this type of project and may wish to contract the project out to another organisation which could be a heavy lift contractor or perhaps a major project management company.

A study for Scottish Enterprise stated that there is "some consensus that the operators do expect that, from a contractual standpoint, most decommissioning work will be undertaken using a form of EPIC style contract based around one major contractor".[31]

As projects of this size would, by EC rules, have to be widely advertised, there is a real possibility that a large proportion of the work could end up benefiting foreign suppliers, particularly the heavy lift contractors who could also choose to act as EPC.

Given that the heavy lift contractor is likely to be a non-UK company, in order to assure maximum Scottish content, it is highly desirable that the contract includes instruction to deliver the removed facilities to a Scottish port/yard.

6.4 Costs, Pricing & Liability

6.4.1 Cost Definition

Operational costs – are those normally associated with a decommissioning programme, and can be readily estimated using conventional methods.

Compliance costs – are those associated with fulfilling all compliance requirements and may well be significant where an application for derogation is sought under the Ospar 98/3 procedures.

Risk management costs – the prime costs are those of decommissioning all risk insurance cover; together with third party risk assessment reports are.

[31] *The Decommissioning Market & Capability Of Scottish East Coast Ports* – Scottish Enterprise, 2003

Residual liabilities – are both the costs of providing ongoing monitoring, and surveillance of the site after decommissioning, and those consequential of disposing of recovered and landed goods. It should be remembered that residual liabilities are liabilities in perpetuity.

Reputation management – decommissioning operations are the subject of, at times, intense scrutiny by a wide class of stakeholders. Accordingly, all companies in the decommissioning supply chain should address reputation management.

Opportunity costs – delaying decommissioning buys time in which oil prices may rise, third party income may be generated or satellite fields be developed.

Residual value opportunities – at worst the recovered unit will realise scrap value, which will partly offset onshore reception and breakage charges - at best the facility may find a market value.

Tax position – this may well impact on the timing and structure of contracts and is driven by the complex conditions attached to the allowance of decommissioning costs against taxable income.

6.4.2 Who is Interested In Decommissioning Cost and Why?

Operating company – is required under FRS12,[32] to record provisions for decommissioning costs as soon as the platform is installed.

Partners – joint operating agreement partners, in relation to the amount they will ultimately be obliged to pay and because of the joint and several liabilities, each will be looking for security from venture partners.

Investment analysts & shareholders –these will naturally be looking for moves to protect future earnings of the company upon which share prices are based.

Governments – are concerned that the final cost relievable against tax is justified, but at the same time wish to encourage smaller reserves to be tied back into the existing infrastructure and consequently prolong the taxable oil & gas revenue stream.

6.4.3 Risks

Estimating risks – are those associated with normal industry estimating methodology, and will include variations in estimated quantities, unit rates (e.g. of equipment hire rates or labour rates) and errors and omissions in scope definition.

Technical risks – include the condition of the facility compared with when the estimates of cost were and in addition the specification of non-feasible operations.

Management risks – largely from undefined or ill-defined corporate and project-specific procedures, responsibilities and accountabilities, together with inadequate support or control of the management team.

Personnel risks – are normally associated with availability of the necessary experienced resources to undertake an operation.

Contractual risks – including contractor/sub-contractor default or non-performance, scope variations and liabilities and the impact of inappropriate terms and conditions.

Risk management – when the programme and cost estimates are prepared, they will be subject to a detailed risk analysis. Risk identification is by use of event trees, fault trees, HAZOPs, safety audits and checklists, to identify all cost risks.

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[32] FRS12 is a Financial Reporting Standard that specifies what should be included in a decommissioning cost and reported in a company's annual report.

6.4.4 Management of Cost by Contract

Contracting strategies – will include fixed price, cost-plus and risk sharing where appropriate.

Campaign strategies – whereby owners may defer a decommissioning start to coincide with other facilities' decommissioning schedules in order to gain economies of scale.

Flexible time-based contracts – will allow the owner either to abandon the facility as soon as production ceases, or to defer abandonment to suit potential re-use schedules.

Sail-by contracts – constructed with wide contract windows, allowing the contractor to execute the removal work in order to maximise utilisation of equipment and personnel.

Contract terms & conditions – the inclusion of inappropriate terms and conditions can have a detrimental result. These generally creep into a contract when a template document is used.

6.4.5 Timing of Contracts and Supplier Capacity

As the North Sea matured, the main contractors transferred their major capital assets such as heavy lift vessels to other regions with the downturn in new build work. Therefore, there will inevitably be a premium charge at the time of decommissioning to bring in resources from other regions. As a result, contractor investment is unlikely to be forthcoming until the market firms, which leaves a potential gap in capacity between now and the emergence of the main decommissioning market.

One means of overcoming this is that of Forward Contracting Strategies, whereby a contract is signed today for a decommissioning project in the future, normally 5-8 years ahead. In consideration of booking advance capacity, the contractor is paid a commitment fee, much like the price of a financial option.

6.4.6 Will Decommissioning Costs Reduce with Experience?

Experience of decommissioning in the North Sea is still limited. It has been claimed that as decommissioning operations increase there will be a corresponding reduction in costs. The other side of the learning curve is the 'forgetting curve' as those associated with specific installations retire from the industry.

6.5 Personnel

The increasing problem of offshore industry personnel shortages is well-reported and in particular of senior individuals at project manager level. The decommissiong of offshore installations presents a particular difficulty in this respect as so few instances have occurred offshore UK.

A further practical consideration is that many of the older platforms were not documented to today's standards and this also applies to the considerable modifications that are carried out over the lifetime of a structure. The individuals that have the detailed knowledge are mainly within five years of retirement. There is, therefore, a need to capture this knowledge and experience if only to aid the eventual decommissioning process.

6.6 Heavy Lift

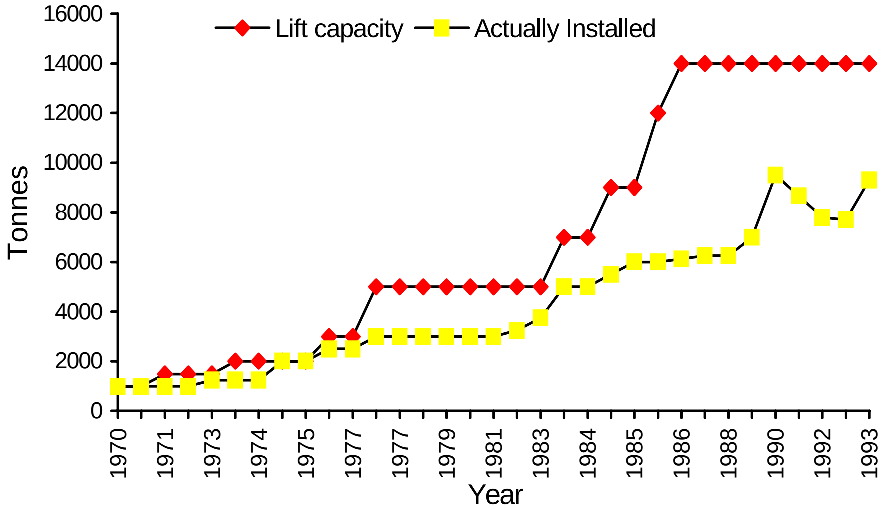


Figure 6.2: Vessel Lift Capacity and Maximum Weight Installed

The maximum capacity of heavy lift vessels grew steadily until 1986 when 15,000 tonnes became available. The maximum weight installed so far in the North Sea was, however, 10,000 tonnes.

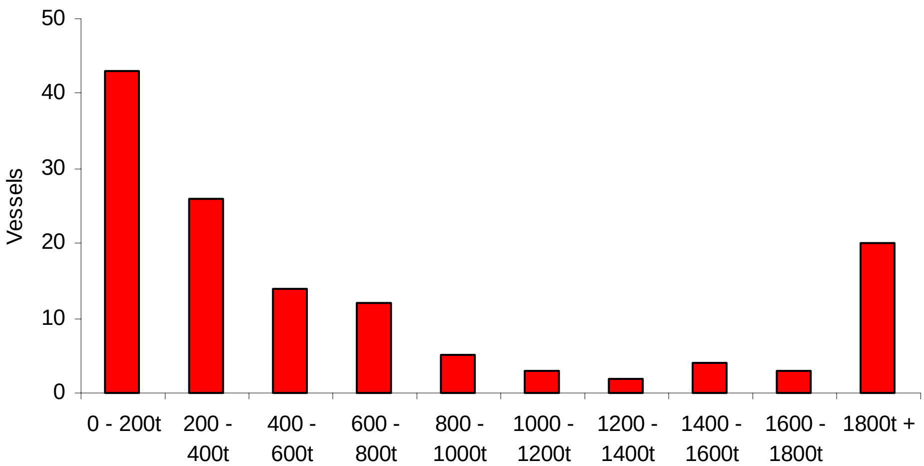


Figure 6.3: Crane / Derrick Barges by Lifting Capacity (Worldwide)

There are 135 vessels currently in this fleet with widely varying lifting capacities. Of these, 21 have a lifting capacity of over 1,800 tonnes including two new vessels primarily targeted at the decommissioning market. Other vessels may be at concept stage but we are not yet aware of them.

As the level of installation activity has reduced in the North Sea, there has been a reduction in the number of heavy lift vessels that are available in the region. We are not aware of these vessels being owned by Scottish companies or normally being Scottish (or UK) based.

Table 6.4: **Crane / Derrick Vessels with Lifting Capacity > 1800 tonnes**

Name	Type	Manager	Build Year	Lift Capacity (t)
Asian Hercules II	Sheerleg Crane	Smit	1997	3,200
Balder	Semi-submersible Pipelay	Heerema	2002	2,500
Castoro Otto	Monohull Derrick/Pipelay	Saipem		2,200
DB 27	Pipelay/Derrick	McDermott	1974	2,400
DB 30	Pipelay/Derrick	McDermott	1999	3,080
DB 50	J-Lay/Derrick	McDermott	1988	4,400
DB 60	Pipelay/Derrick	McDermott	1974	1,800
DB 101	Derrick	McDermott	1978	3,500
Fuji	Floating Crane	Fukada	2003	3,000
HD-2500	Derrick/Lay Barge	Hyundai	1979	2,500
Hermod	Semi-submersible Crane Vessel	Heerema	1978	4,000
Kongo	Floating Sheerleg Crane	Fukada	1989	2,050
Musashi	Floating Sheerleg Crane	Fukada	1974	3,600
Rambiz	Twin Hull Lift (transportation) Vessel	Scaldis	1996	4,000
Saipem 3000	Heavy Lift Dynamic Positioning Vessel	Saipem	2002	2,400
Saipem 7000	Semisubmersible Crane & Pipelay	Saipem	1984	7,000
SLC 5000	Sheerleg Crane	McDermott	1976	5,000
Suruga	Crane	Fukada	1991	2,200
Taklift 4	Sheerleg Crane	Smit	1981	2,400
Thialf	Multifunction Construction Vessel	Heerema	2001	7,100

Source: Oilfield Publications Limited – *Construction Vessels of the World*

In considering the list above, it should be noted that some as simple flat bottomed barges are not suited to northern North Sea waters.

Furthermore, as North Sea activity has fallen dramatically, proposed decommissioning activity will have to compete for lift vessel time with new field developments in other parts of the world, a factor that may serve to slow the development of the market.

6.7 Ports/Yards

Greenhead Base, Lerwick – Frigg Decommissioning Contract Success

In 2000, Shetland Islands Council and the Lerwick Port Authority formed the Shetland Decommissioning Company with the SIC investing £300,000 over two years to evaluate business opportunities.

In June 2004, the Norwegian company, Aker Kvaerner, announced that they will use the Greenhead Base, in Lerwick, as an exclusive site for onshore disposal of the Total-owned Frigg platform. Aker Kvaerner has entered into a pre-bid agreement (PBA) with the Shetland Decommissioning Company (SDC), SBS Logistics and Onyx UK (one of the UK's leading waste management companies), which also includes a commitment by the parties for the development of a long-term agreement. The development could create between 30 and 40 local jobs by the end of 2005.

In October 2004, Aker Kvaerner were awarded the £250 million contract which involves around 20,000 tonnes of steel and other materials to be shipped into Lerwick over the next three years in what is being described as a major new industry for the islands.

Aker Kvaerner Offshore Partner and their sister company Aker Stord have earlier removed and demolished the Odin platform on behalf of the Esso oil company from the Norwegian sector and the 110,000 tons Maureen A-platform (Phillips UK) from the UK sector.

ABLE – TERRC – Long-established in Decommissionig

Able UK Limited in Hartlepool own and operate what is probably the largest purpose designed facility for recycling redundant marine structures including ships. The facility complies with health, safety and environmental standards of the UK, Europe and the USA, clients include some of the major international oil companies including BHP Hamilton, ExxonMobil, NAM bv, Phillips Petroleum, Shell UK, Total, etc. Able's track record includes 16 platform and topsides dismantling contracts.

With the benefit of what is probably the largest dry dock in the world (some 25 acres), the facility can accommodate ships up to 366m long in the dry dock. In keeping with the intended use of the site, ABLE renamed the yard TERRC (Teesside Environmental Reclamation and Recycling Centre). The company has recently announced the Phase 2 development for the facility which will see the commencement of refurbishing the dry dock.

ABLE was contracted by ExxonMobil for dismantling the **Camelot CB platform**, situated in block 53/2 in the southern North Sea. Platform removal operations began on November 3, 2002 using the heavy lift vessel, *Thialf*. On November 4, the platform topsides were removed from the field and on the November 6th the steel jacket was removed from the seabed. Both the jacket and topsides were loaded onto a barge and transported to the Able UK Limited yard in Teeside where the structures will be dismantled. The facility is targeted for re-use, however, if no re-used alternatives can be found for the components, they will be recycled.

The role of the port/yard site is to receive, dismantle, sell and/or store for re-use. It has been noted that due to the complexity of dismantling and refurbishing production platforms, not forgetting the subsea installations, pipelines, drill cuttings, etc (if so required by the respective licensing authorities) and the likely impact on the environment, there are unlikely to be many sites established for onshore disposal and/or recycling of facilities.

The nature of the materials ranges from 'clean items' to 'dirty' items that require a combination of hard standing with gullies and trap for run-off liquids. At the extreme there are the issues of handling the LSA – low specific activity (low-level radioactive) – materials that result from the long-term flow of well fluids through well tubulars and topsides process plant. In short, the size and nature of the materials to be handled together with the 'scrap yard' nature of the dismantling process may not be thought to be particularly appropriate by some ports in light of their other activities.

The requirements for a yard/port to properly operate in decommissioning include:

- Available quay space and load capacity including roll-on/roll-off capacity
- Water depth, currents and tide
- Cranage/transport
- Accommodation available, in the form of covered warehousing, open storage, bonded warehouse industrial units and offices
- Services available on or near the port (e.g. ability to handle LSA materials)
- Availability of skilled and unskilled labour and industrial relations record
- Road, rail and other communications
- Proximity to offshore locations
- Links to a steel mill.

Barges may requires a quay over 220m long. Allowance should also be made for other support vessels to be accommodated at the same time although these could lay alongside other quays.

In the event that cargo barges were to be used instead, facilities would need to be built for skidding off the jackets and topsides and manoeuvring them on the quayside, necessitating foundations for minimum 250 tonne winches, ramps and hard pads for supporting the loads.

It has been noted that "at their peak, the six main Scottish fabrication yards employed some 10,500 tradesmen. By mid 2003 over the entire UK, employment in the industry had shrunk to 3,500 tradesmen. Of the six original yards in Scotland, only one remained active by mid 2003 – Burntisland

Fabrications Ltd. In early 2004 the Methil facility was re-opened as a result of a significant oil & gas contract but its future beyond 2005-2006 is still in doubt."[33]

Table 6.5: Scottish Offshore Construction Yards

Yard	*Operator*	*Loadout (in?)*	*Status*	*Comment*
Burtisland	Burntisland Fabrications Ltd	5,000t (5.9m WD)	Open (Buzzard fabrication)	
Methil	Burntisland Fabrications Ltd	10,000t	Open (Buzzard fabrication)	Future beyond 2005-2006 is still in doubt
Nigg	ex KBR		Mothballed	
Lewis (Arnish)	Cambrian Engineering		Open	Presently engaged in wind turbine tower fabrication
Ardersier	ex KBR		Closed	Marina / housing development
Hunteston	Clyde Ports		Mothballed	On wrong side of the country?

In 2002, the Highlands and Islands Enterprise commissioned the Halcrow group to examine future options and to investigate market opportunities for a range of inter-linked industrial sites, including ports around the inner Moray Firth and the KBR Caledonia offshore fabrication yard at Nigg. The overall view was that the "*Nigg Yard and Terminal is one of the few UK sites that could be operated as an integrated decommissioning location, although the full market potential is still to be proven*".

The OPL Offshore Shipbuilders and Fabrication Yards of the World (3rd edition) lists a further 28 'yards' in the rest of the UK. There is a high potential for competition to Scottish locations from Teeside, the Tyne and Great Yarmouth/Lowestoft. Of particular note is the Able UK Limited yard in Teeside (discussed above) which has won 16 contracts from the UK, Norway and The Netherlands since 1985.

6.8 Re-use

Refurbishment and re-use of decommissioned platforms is a thriving activity in the US Gulf of Mexico and instances of re-use of small platforms have occurred in the North Sea. This is possible due to the fact that, in general, design life is usually 1.5 to 4 times the producing life and some critical areas of a structure may have been designed with a 100 year fatigue life.

There is considerable enthusiasm on the part of many contractors who understand the commercial logic of being able to re-certify components and refurbish entire structures.

Studies[34] based on Gulf of Mexico experience, have indicated that markets for re-use are likely to show little interest until a suitable and sizeable stock of equipment is readily available. A business, therefore, has to be structured in such a manner as to provide sufficient storage capacity and have capital available to provide a facility for storing platforms and modules pending sale.

[33] Enterprise and Culture Committee, *Evidence Received for the Renewable Energy in Scotland Inquiry. Submission from Burntisland Fabrications Ltd*. Feb 2004

[34] See also the paper by P. Stephenson of Able UK to the conference on `The Reuse of Offshore Production Facilities', Den Helder, Netherlands, October 1999.

7 NORTH SEA DECOMMISSIONING PROGRAMMES

7.1 Introduction

This section presents a listing of decommissioning programmes by country and a list of decommissioning programmes under review that lists immediate opportunities for Tier 1, 2 and 3 companies.[35] Finally a list of case studies is presented that describes the decommissioning methodology, contracting strategy and Tier 1 companies for a sample of the completed programmes.

Abbreviations used in the tables are:

- FPF – floating production facility
- FPSO – floating production, storage and offloading facility
- CALM buoy – catenary anchor leg mooring buoy
- SALM – single anchor leg mooring buoy.

7.2 Completed Decommissioning Programmes

Table 7.1: Decommissioning Programmes to 2004

Steel Platforms	*Floating Production Units*	*Subsea Completions*	*Gravity Structures*	*TLPs*	*Jack-up Units*
25	7	5	3	1	3

The above table shows decommissioning programmes completed, those in the process of consultation, or awaiting execution. Within the North Sea, industry experience of decommissioning is limited but growing, based upon 44 contracts completed to date, in water depths up to 120 metres. Further details are given in the appendix.

7.3 Decommissioning Programmes in Progress

Table 7.2: Decommissioning Programmes in Progress

Field /Installation	*Operator*	*Installation*	*Cessation Plan Website*
N.W. Hutton	BP	Large fixed steel platform. The first draft of the cessation plan was published in 2Q 2004.	www.bp.com
Brent	Shell	Second draft cessation programme for the Brent flare and the Spar anchor blocks is available for review on the website.	www.shell.co.uk
Frigg	TotalFinaElf	The Frigg cessation programme covers a number of facilities: • CDP1 – concrete gravity platform • DP2 – fixed steel platform • FP – fixed steel platform • QP – fixed steel platform • TCP2 – concrete gravity platform • TP1 – concrete gravity platform • MCP-01 – concrete gravity platform The cessation programme and OSPAR consultation documents are available for review on the website.	www.elfep.no

[35] A description of Tier 1,2 & 3 companies in the decommissioning supply chain is given in Chapter 5 of this report.

Field /Installation	Operator	Installation	Cessation Plan Website
Ekofisk	ConocoPhillips	The Ekofisk cessation programme covers 15 installations: • Ekofisk 2/4A - fixed steel platform • Ekofisk 2/4 B – fixed steel platform • Ekofisk 2/4 FTP – fixed steel platform • Ekofisk 2/4 H – fixed steel platform • Ekofisk 2/4 Q – fixed steel platform • Ekofisk 2/4 P – fixed steel platform • Ekofisk 2/4 R – fixed steel platform • Ekofisk 2/4 T – the Ekofisk Tank • Albukjell 2/4 F – fixed steel platform • Albuskjell 1/6A – fixed steel platform • Cod 7/11 A – fixed steel platform • Edda 2/7 C – fixed steel platform • West Ekofisk 2/4 D – fixed steel platform • 36/22 A UK – fixed steel platform • 37/4 A UK – fixed steel platform	www.phillips66.no/cessation
Beatrice	Talisman Energy (UK) Ltd	Four-platform complex, two of which are bridge linked.	www.talismanenergy.co.uk /beatricedecommissioning

7.4 Decommissioning Programmes under Consideration

The following tables give details of decommissioning programmes under consideration, and for which details can be seen on the companies' websites. (Fields developed via a deviated well from a host platform are not counted in this table. Some subsea wells will be shut in and left in-situ until removal of the host tieback platform.)

Table 7.2: Decommissioning Contracts Under Consideration

COP Year	Field	Operator	Facility	Forecast Cost[36]
2000	Bladon	Talisman	S/S wells	
	Blenhiem	Talisman	FPSO + s/s wells	
	Dawn	ExxonMobil	S/s wells	
2001[37]				
2002	Hutton	Kerr McGee	TLP + s/s	
	NW Hutton[38]	BP	1 Platform	
2003[39]				
2004	Beauly	Talisman	S/s wells	
	Camelot	ExxonMobil	2 P'forms	
2005 [40]				
2006	Auk[41]	Shell	1 P'form	£50m
	Balmoral	CNR	! FPU + 14 s/s wells	£41m
	Corvette	Shell	1 P'form	£15m
	Hewett	Tullow	6 P'forms	£53m
	Kestral	Shell	S/s wells	£3m
	Mallard	Shell	S/s wells	£8m
	Merlin	Shell	S/s wells	£5m
	Monan	BP	S/s wells	£4m
	Vixen	ConocoPhillips	S/s wells	£3m

[36] Costs quoted in 2005 money & rounded up to nearest £1m, costs are for individual platforms, the cost for a portfolio of assets may be discounted.
[37] No contracts completed in 2001.
[38] COP in 2002, BP is currently seeking expressions of interests from contractors for removal of platform.
[39] A number of s/s wells were closed in but left in wet storage for subsequent removal with host platforms.
[40] No field COPs in 2005.
[41] Subject to asset trade, COP may be extended out to 2012.

COP Year	Field	Operator	Facility	Forecast Cost[42]
2007	Alison	Venture Production	S/s wells	£4m
	Angus 2	Amerada Hess	S/s wells	£2m
	Ann	Venture Production	S/s wells	£3m
	Brae South[43]	Marathon	1 P'form	£100m
	Excalibur	ExxonMobil	1 P'form	£7m
	Jupiter II	ConocoPhillips	1 P'form	£10m
	Lancelot	ExxonMobil	1 P'form	£8m
	Thelma	CNR	S/s wells	£6m
2008[44]	Appolo	BG	S/s wells	£3m
	Audrey	Venture Production	2 P'forms + s/s wells	£16m
	Bell	Perenco	S/s wells	£2m
	Bessemer	Perenco	1 P'form	£11m
	Birch	Venture Production	S/s wells	£8m
	Caister	ConocoPhillips	1 P'forms	£12m
	Caledonia	ConocPhillips	S/s wells	£2m
	Clyde	Talisman	1 P'form	£67m
	Curlew	Shell	FPSO + s/s wells	£13m
	Cyrus	BP	FPS + s/s wells	£10m
	Dalton	Burlington	S/s wells	£8m
	Davy	Perenco	1 P'form + s/s wells	£11m
	Deben	ExxonMobil	S/s wells	£3m
	Della	ConocoPhillips	S/s wells	£3m
	Don	BP	S/s wells	£9m
	Egret	Shell	S/s wells	£3m
	Fergus	Amerada Hess	S/s wells	£3m
	Fife	Amerada Hess	FPSO + s/s wells	£7m
	Flora	Amerada Hess	S/s wells	£2m
	Foinaven	BP	FPSO + s/s wells	£45m
	Galahad	ExxonMobil	1 P'form	£10m
	Galley	Talisman	FPU + s/s wells	£10m
	Gawain	ExxonMobil	S/s wells	£3m
	Glamis	ENI	S/s wells	£3m
	Guinevere	ExxonMobil	1 P'form	£8m
	Heron	Shell	S/s wells	£3m
	Hudson	Amerada Hess	S/s wells	£10m
	Ivanhoe	Amerada Hess	S/s wells	£5m
	Kingfisher	Shell	S/s wells	£10m
	Kyle	CNR	S/s wells	£7m
	Larch	Venture Production	S/s wells	£5m
	Leadon	Kerr McGee	FPSO + s/s wells	£18m
	Loyal	BP	S/s wells	£10m
	Lyell	CNR	S/s wells	£10m
	MacCulloch	ConocoPhillips	FPSO + s/s wells	£19m
	Newsham	BP	S/s wells	£2m
	Orion	Talisman	S/s wells	£6m
	Orwell	Tullow	S/s wells	£6m
	Osprey	Shell	S/s wells	£8m
	Pickeral	Perenco	2 P'forms	£15m
	Rene	ConocoPhillips	S/s wells	£5m
	Rob Roy	Amerada Hess	FPU + s/s wells	£14m
	Rough	Dynergy	5 Platforms	£112m
	Rubie	ConocoPhillips	S/s wells	£2m
	Skua	Shell	S/s wells	£5m
	Sterling	ENI	S/s wells	£2m
	Thistle	Lundin	1 P'form	£78m
	Waverney	Perenco	1 P'form	£7m
	Windermere	RWE	1 P'form	£8.5m
	Yare	Tullow	S/s wells	£2m

[42] Costs quoted in 2005 money & rounded up to nearest £1m, costs are for individual platforms, the cost for a portfolio of assets may be discounted.
[43] Decommissioning Programme has not been submitted hence COP date is expected to slip.
[44] There are a large number of subsea wells scheduled for plugging & abandonment in 2008. It is likely that the majority will be rolled into single decommissioning contracts, which is the number reported in chapters 8 & 9 of the report.

COP Year	Field	Operator	Facility	Forecast Cost[45]
2009	Anglia	Gaz de France	1 P'form + s/s wells	£8m
	Bains	Centrica	S/s wells	£2m
	Bittern	Shell	FPSO + s/s wells	£39m
	Brigatine	Shell	2 P'forms	£13m
	Cormorant	Shell	S/s wells	£16m
	Dunlin[46]	Shell	Concrete GBS	£70m
	Eider	Shell	1 P'form	£59m
	Grant	Total	S/s well	£3m
	Inde	Perenco	10 P'forms	£98m
	Inde	Shell	6 P'forms	£52m
	Ketch	Shell	1 P'form	£14m
2009 cont	Miller	BP	1 P'form	£78m
	Ninian	CNR	Concrete GBS + 2 P'forms	£214m
	Otter	Total	S/s	£4m
	Pelican	Shell	S/s wells	£12m
	Strathspey	ChevronTexaco	S/s wells	£13m
	Teal	Shell	FPSO + s/s wells	£22m
	Teldord	Encana	S/s wells	£6m
	Tern	Shell	1 P'form	£68m
	Thames	Tullow	3 P'forms	£40m
	Tiffany	ENI[47]	1 P'form	£63m
	Toni	ENI	S/s wells	£10m
	Vampire	ConocoPhillips	1 P'form	£5m
	Victor	ConocoPhillips	1 P'form + s/s wells	£8m

[45] Costs quoted in 2005 money & rounded up to nearest £1m, costs are for individual platforms, the cost for a portfolio of assets may be discounted.
[46] Asset is up for sale and COP may as a consequence be delayed.
[47] ENI has sold on the Tiffany and Toni assets.

7.5 Case Studies

The following case studies are representative examples of the decommissioning contracts completed to date in the North Sea.

7.5.1 The Odin Field

Field:	**Odin**
Operator:	Esso Norge A/S
Facility:	Odin was a medium sized gas field that ceased production in 1994. The facility consisted of a single steel jacket weighing 6,150 tonnes and a topside weighing 7,300 tonnes.
Decommissioning:	The platform was removed completely and recovered to shore for recycling. The topside was removed as a series of modules. The jacket was removed by cutting into sections and removing each in turn. The recovered sections were landed at the Eldoey quay before being moved onto a specialist demolition pad.
Contracting Companies:	Tier 1 Project Management: Aker/Saipem JV Removal: Saipem Onshore Reception: Aker Stord – Eldoeyane yard Tier 2 Engineering: Aker Offshore Partners Onshore Demolition: Aker Stord Hazardous Waste Disposal: Sunnhordland Interkommunale Miljoeverk
Notes	 Saipem removing and back loading Odin topsides.  Removing the Odin jacket in sections. The jacket was cut using a combination of abrasive and diamond wire cutting.

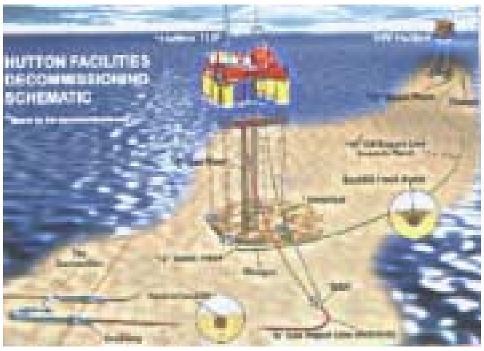
7.5.2 The 2/4 Platform

Field:	**2/4 S Platform**
Operator:	Statoil
Facility:	The 2/4 S Platform was a riser platform within Norway's Ekofisk complex.
Decommissioning:	The platform was removed completely and recovered to shore for recycling. The 5,000 tonne platform topside structures were removed in 2001 and delivered to the Lyngdal Hausvik recycling yard in southern Norway where they are being offered in a sales campaign. Buyers were found for a number of items including fire-pumps, generators, flare stacks, etc.
Contracting Companies:	Tier 1 Project Management: Statoil Decommissioning: ABB Offshore Systems Removal: Heerema Onshore Reception: Lyngdal Recycling Equipment Resale: Web Platform Brokers
Notes	 The 2/4 S platform before decommissioning. Offloading the recovered decks at the recycling yard. 

7.5.3 The Maureen Platform

Field:	Maureen Platform
Operator:	Phillips
Facility:	Maureen was an oil field that ceased production in 1999 and removed in 2001.
Decommissioning:	Maureen was a steel gravity-based structure that weighed 112,000 tonnes with an integrated deck weighing 19,000 tonnes. In 2001 the platform was refloated and towed to Aker Offshore Partnerships decommissioning site at Stord in western Norway. Combined deballasting of storage tanks and water injection under the skirts refloated the platform. Once floating the complete platform was towed to an inshore reception facility. The whole platform was dismantled, the steel storage tanks were re-used to form a deep-water quay, and the topside equipment sold off or recycled.
Contracting Companies:	Tier 1 Project Management: Phillips Decommissioning: Amec Well P&A: TEAM Removal/refloating & tow: Aker Marine Contractors Subsea Decommissioning: Coflexip Stena Offshore Onshore Reception: Aker Offshore Partnership Tier 2 Engineering: ODE; Reverse Engineering EIA: AURIS
Notes	 Maureen platform during refloating and prior to tow from site.

7.5.4 The Hutton TLP

Field:	**Hutton TLP Platform**
Operator:	Kerr McGee
Facility:	The Hutton TLP was the first tension leg platform to be built and installed in the North Sea.
Decommissioning:	After decommissioning the process systems and well P&A, the platform was disconnected from the seabed and towed to Vats Fjord in western Norway. The TLP was later towed to Murmansk where the topside was removed from the Hull structure. It was intended to re-use the topside facility and to use the hull structure as the base for a new decommissioning vessel.
Contracting Companies:	Tier 1 Project Management: Kerr McGee Removal/refloating & tow: Saipem UK Subsea Decommissioning: Coflexip Stena Offshore Onshore Reception: Maritime GMC – Vats Fjord.
Notes	 Schematic of the Hutton TLP facility.

8 DECOMMISSIONING ACTIVITY FORECASTS

This Chapter describes the decommissioning market in four parts:

1. The forecast timing of decommissioning contracts
2. The risks associated with forecast timing
3. The overall value of the decommissioning market
4. The component value of the decommissioning market.

The time element in awarding decommissioning contracts is a significant uncertainty in the planning of any company providing services or equipment to this market.

8.1 Timing of Decommissioning Contracts

The criteria used to determine the appropriate time to initiate a particular field abandonment programme are complex, for they have to evaluate the interactive effects of current and future oil price; fiscal policy; operating costs; interest rates, exchange rates; recovery rates; third party tariff/rental income; potential to realise residual value in recovered equipment; the regulatory regime in place at the time and the economic competitiveness of the particular field compared to other worldwide investment opportunities.[48]

An additional factor has occurred in the North Sea since 1996, when the first predictions of decommissioning contracts were presented. This has arisen from the trading of assets by established Exploration and Production (E&P) companies to "harvester"[49] companies specialising in releasing locked-in value from mature[50] producing assets. The consequence has been a significant postponement of decommissioning commitments for those assets so traded.[51]

The forecast North Sea decommissioning dates, based on 2005 estimates[52] are given in figure 8-1. The decommissioning dates given are indicative of cessation of production (COP). Decommissioning planning and contract award procedures will usually occur during a 2-3 year period before the quoted date, and be executed during a 2-3 year period after the quoted dates. Some fields, such as Beatrice and Ekofisk[53] have significant decommissioning schedules from cessation of production until final removal of facilities.

The decommissioning dates are estimated on a field stand-alone basis; that is, that all platforms in a field will be decommissioned and removed at the same time, but field-decommissioning dates are independent. It is expected that oil companies may utilise the concept of campaign strategies to manage decommissioning costs; that is, that different field decommissioning programmes will be combined into single contacts to save on field mobilisation costs and ensure efficient utilisation of equipment.

Depending on market capacity, it may be that some decommissioning contracts planned for 2009, as an example, may be delayed to avoid demand exceeding capacity and the consequential impact on day rate costs.

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48 Some of the factors to be considered in the economic determination of the optimum time to cease production are discussed further in Chapter 4 of this report.

49 Harvester companies include companies such as Talisman, a Canadian company specialising in mature asset operations.

50 A mature field is defined as a field where the remaining net present value of production is equal to or less than 150% of the decommissioning liability.

51 An example of which is the Beatrice field which BP were planning to decommission in 1996, before selling on to Talisman who continued production until 2005 at which point the platforms will be decommissioned and converted to wind farms with final removal planned for 2013.

52 Decommissioning dates are taken from the TCS database, the source material for which is published information supported by data from operating companies and proposed decommissioning programmes.

53 See Chapter 7 for details of the Ekofisk decommissioning programme.

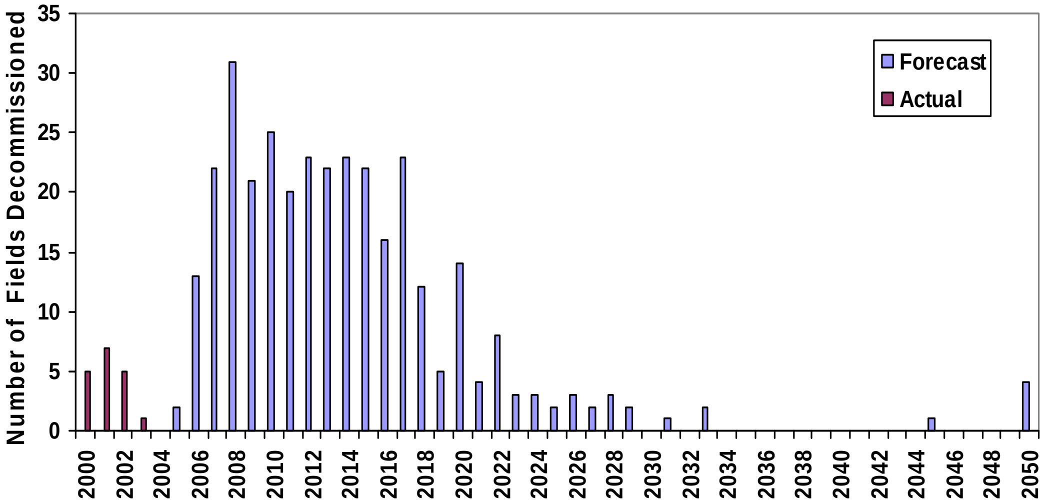

Figure 8.1: North Sea Decommissioning Dates – 2005 Estimates

There has been some slippage in issued decommissioning programme COP dates due in part to the volatility of the oil price which increased from $29/bl in February 2004 to a high of $55/bl and a current swing of $45 – $50/bl. [54]

However, Professor Kemp,[55] in a series of studies has concluded that sensitivity of abandonment dates to oil price is not as strong as first thought, even though there is a tendency for the dates to be shifted into the future the higher the oil price realised.

There may be two reasons for this. The first is the propensity to enter into forward contracts for a percentage of oil produced thereby mitigating impact of short-term price volatility. The second reason is that at some stage in the field life, production decline curves dictate financial consideration of costs and revenues in deciding COP dates.

A second factor delaying decommissioning dates has been the result of intensive effort, on the part of the DTI and UKOOA,[56] to encourage field life extension initiatives and the entry into the market of new companies specialising in squeezing value from mature producing assets.

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[54] The 1999 Brown book estimated field life costs per barrel as follows:

Fields starting production before 1980	*cost$/bbl $15.75*
Fields starting production between 1980-85	*$22.50*
Fields starting production 1986-90	*$20.50*
Fields starting production 1991-98	*$13.50*
Recent fields	*$10.50*

These costs per barrel may be interpreted as the constant real oil price that would yield a pre tax real return of 10% pa. Oil prices would need to fall 10% below these levels to affect field economics independent of field production rates.

[55] For example, see Professor A Kemp, Aberdeen University *'Economic & Fiscal Aspects of Abandonment'* Euro Forum conference on Cost Effective Solutions for the Abandonment of North Sea Platforms – London 1995

[56] See both the PILOT and UKOOA websites for details of such initiatives.

8.1.1 Decommissioning Programmes by Country

The North Sea decommissioning dates may be further broken down by country.

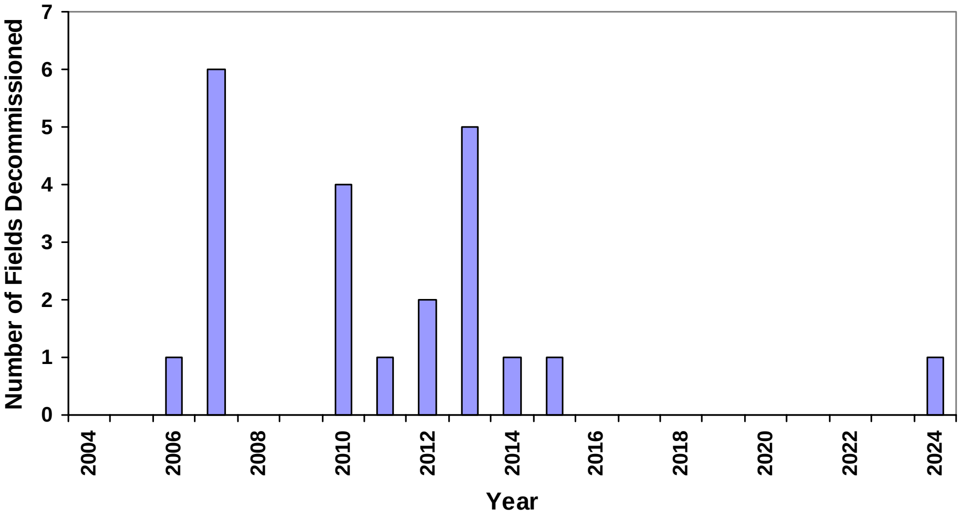

Figure 8.2: North Sea Decommissioning Dates – Denmark – 2005 Estimates

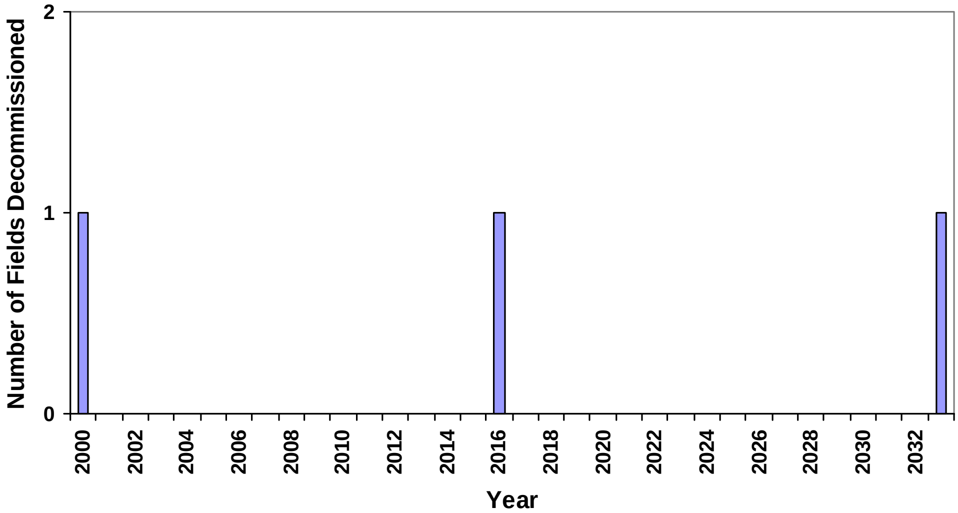

Figure 8.1: North Sea Decommissioning Dates – Germany – 2005 Estimates

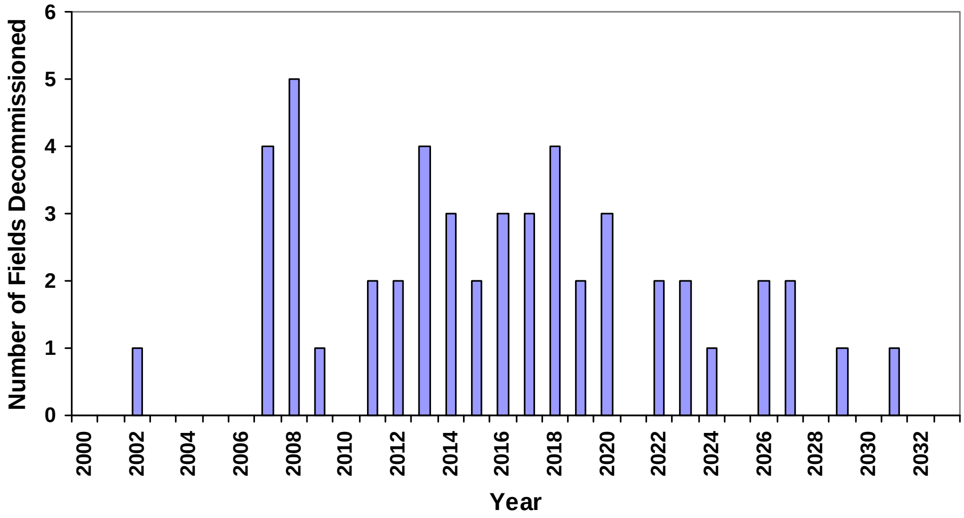

Figure 8.2: North Sea Decommissioning Dates – The Netherlands – 2005 Estimates

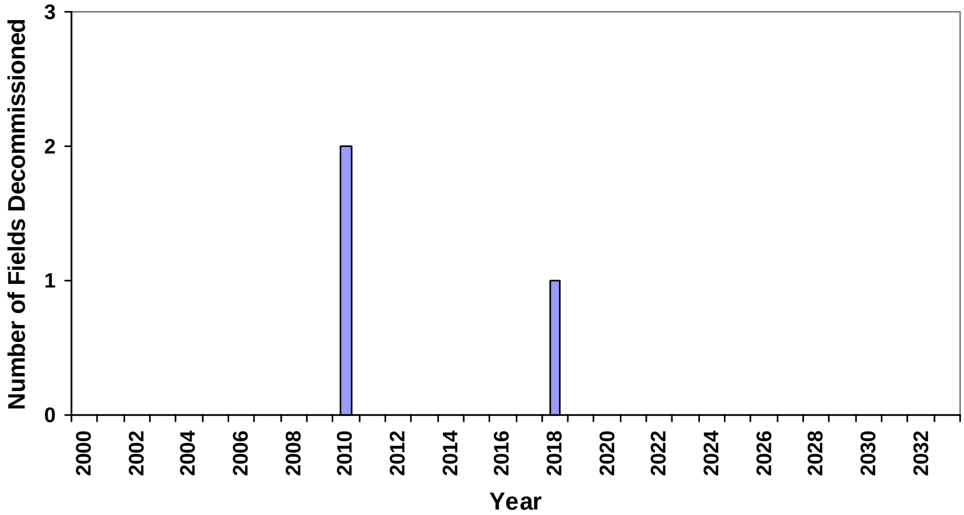

Figure 8.3: North Sea Decommissioning Dates – Ireland – 2005 Estimates

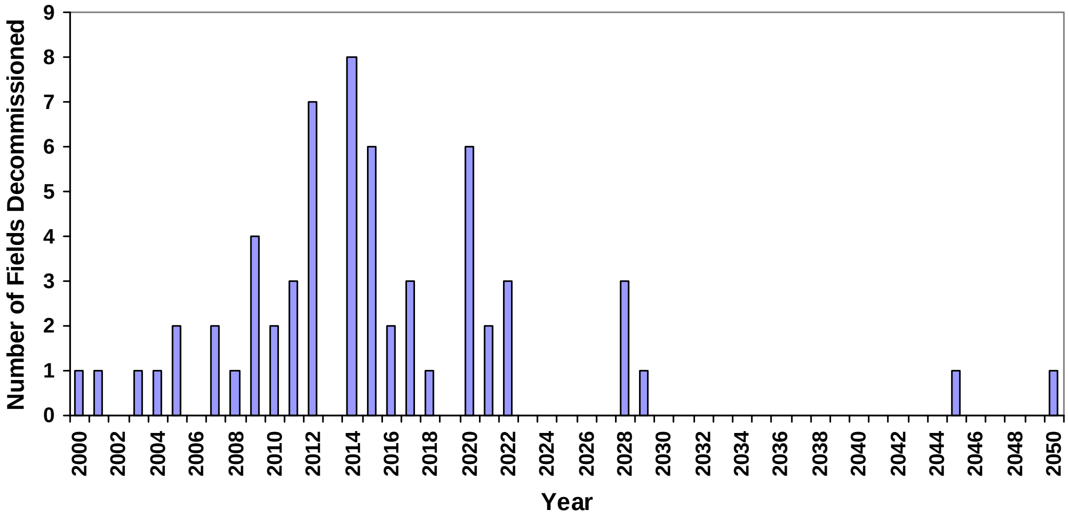

Figure 8.4: North Sea Decommissioning Dates – Norway – 2005 Estimates

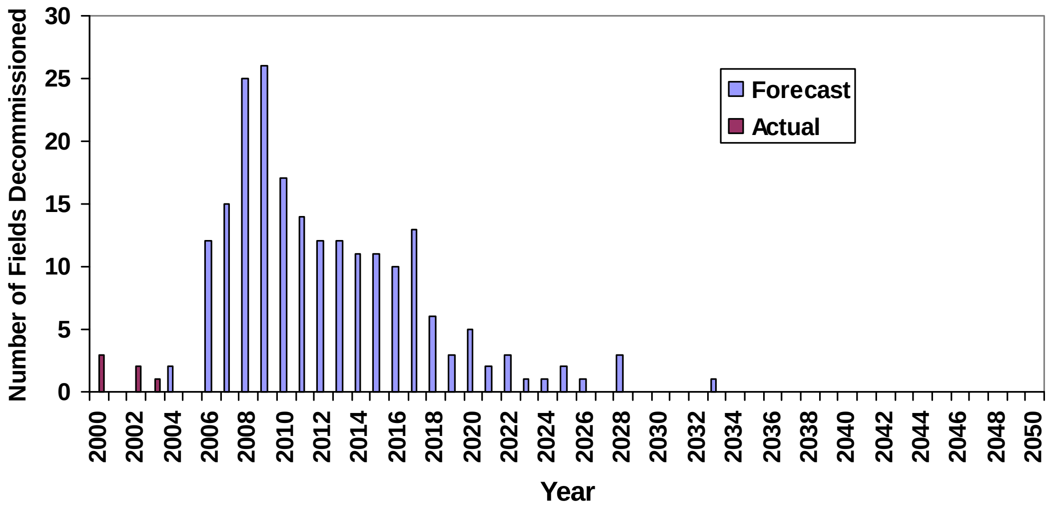

Figure 8.5: North Sea Decommissioning Dates – UKCS – 2005 Estimates

8.1.2 Comparison of Forecast Decommissioning Dates with DTI Estimates

As a comparison with our generated decommissioning forecasts, we give below a summary of the DTI forecasts.

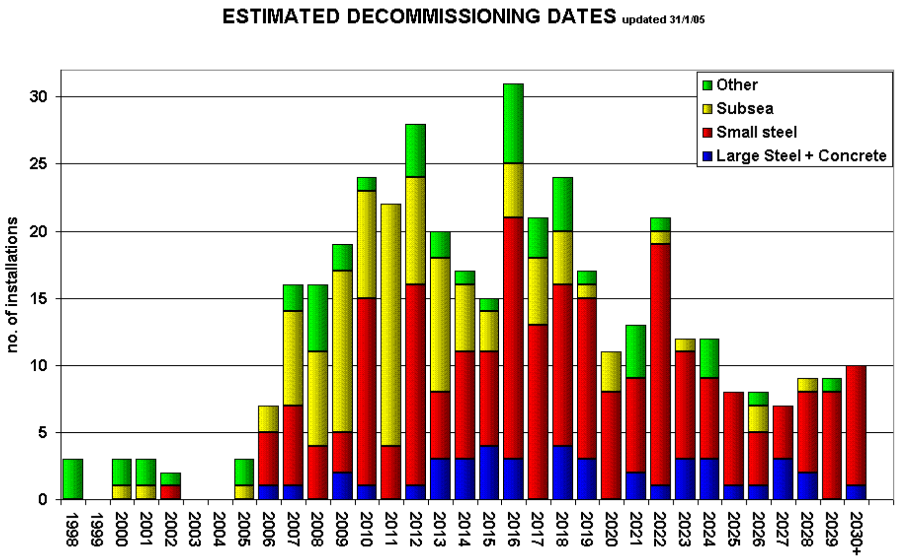

Figure 8.6: UKCS Decommissioning Dates – DTI 2003 Estimates

There is some difference in figures between our estimate and that of the DTI, but the peak number of contracts per year are compatible in the two sets of data.

8.1.3 Variation of Decommissioning Dates with Time

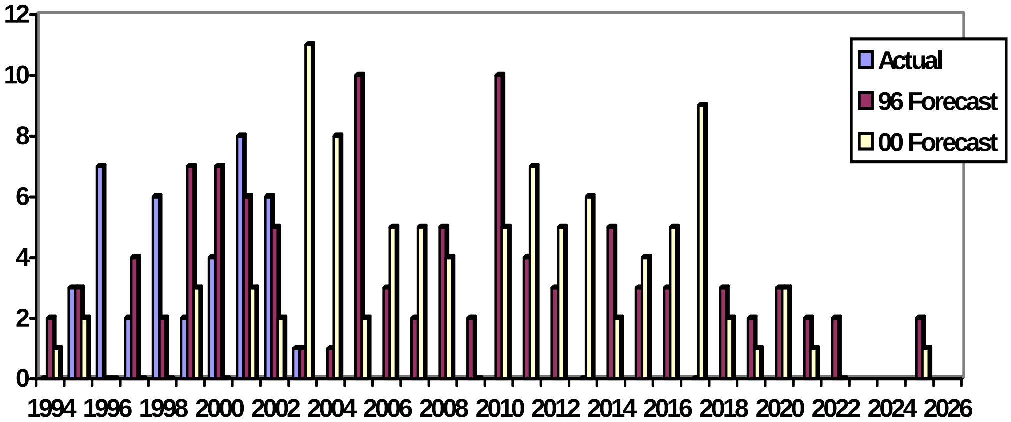

Figure 8.7: North Sea Field Decommissioning Dates – Estimated 1996-2000

Figure 8.9 shows the change in decommissioning dates for the 1996 and 2000 estimating periods. [57] A consequence of the uncertainty of forecasting decommissioning dates is impacting on service contractors planning for future work. In particular for those companies seeking to raise capital for investment in new facilities and equipment, the level of uncertainty in timing is a barrier to delivery.[58]

[57] Note that later forecasts include subsea completions and tiebacks omitted from earlier numbers.

[58] As an example, in 1996, investment funds were withheld from a proposed onshore reception facility due to the perceived risk arising from the uncertainty in timing of decommissioning contracts.

8.2 Decommissioning Costs

8.2.1 Methodology

The decommissioning costs quoted below are derived from the TCS database routines that consist of a number of interrelated databases.

The first database contains a listing of physical platforms and their attributes, including for instance, location, water depth, type of platform, component weights, and original installation vessel.

In order to generate a class two estimate, estimated quantities of materials are required in addition to the basis platform attributes. This data is contained in a second database giving weight densities, breakdown of topsides by function into component weights, for example: including steel, equipment, piping materials, cladding and electrical components.

The estimating database contains the standard base unit measurements, for example, time to cut through steel of varying thickness with various cutting equipment, time to cut through and coil cables, time to remove equipment of various weights, time to fit lifting rigging and sail speed of various marine vessels under different conditions. The database also contains data on unit rates for personnel, productivity factors for different regions of the world, unit rates for vessels and equipment including estimating quantities for consumables.

The routines then construct a decommissioning estimate data-table for the specific asset, based on total removal of the facility and for the minimum compliant condition. The removal concept closely follows the original installation sequence and addresses all aspects of the process.

The Level 2 budget estimates generated are sufficient for forward planning across a portfolio of assets and compliance with FRS12 annual reporting requirements.[59]

8.2.2 Total North Sea Decommissioning Costs

Costs have been calculated for well abandonment, decommissioning, deconstruction, transport to shore and final disposal.

Two estimates have been prepared. The first is for full removal of all offshore facilities including concrete gravity structures, whilst the second is for the minimum compliant cost which assumes that applications will be made under the OSPAR derogation procedures to leave in-situ concrete gravity bases and the footings of steel jackets weighing more than 10,000 tonnes. On this basis, the estimated removal costs of all North Sea facilities, of in-place and facilities under development are as follows.

Table 8.1: Total Decommissioning Cost Comparisons

Option	*1996 Estimate*	*2005 Estimate*
Full Removal	£9.20 billion	£15.47 billion
Minimum Compliant Removal	£8.28 billion	£12.54 billion

The difference in cost between the 1996 and 2005 estimates is partly an inflationary driver but also reflects the increased number of facilities brought on stream.

8.2.3 Decommissioning Costs by Country

The following table compares the full removal costs for the principal states with an interest in the North Sea.

[59] For details of FRS 12 reporting requirements see Chapter 4 of this report.

Table 8.2: Full Removal Costs by Country

Country	*1996 Estimate*	*2005 Estimate*
UKCS	£5.30 billion	£8.32 billion
Norway	£2.22 billion	£5.29 billion
The Netherlands	£0.80 billion	£1.13 billion
Denmark	£0.33 billion	£0.67 billion
Others	£0.58 billion	£0.13 billion
Total	£9.23 billion	£15.54 billion

In a presentation entitled "Decommissioning Issues in the UK Sector" given in Bergen, the DTI reported the results of a study they had commissioned, which estimated the total decommissioning costs for the UKCS at £15 billion.[60] This is considerably higher than our estimate of £8.32 billion. A further comparison with the UKOOA estimate, taken from their economic report 2004, gives a UKCS cumulative cost of £9.1 billion This UKOOA estimate is within 10% of that presented in the TCS database, and within the estimating tolerances.

Because of uncertainties in timing of decommissioning dates, we quote base costs in terms of today's money, i.e. what the decommissioning cost would be if undertaken today. The actual future cost will be higher, depending part on inflationary effects but more significantly on market conditions at the time.[61]

8.2.4 Cumulative Decommissioning Costs

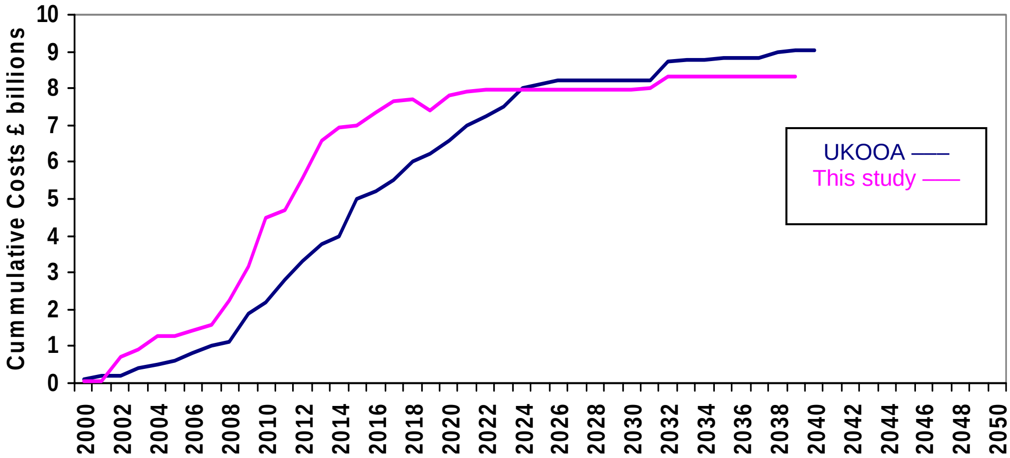

Figure 8.8: UKCS Cumulative Costs by Year

The full decommissioning cost will accrue with time as shown above. The reason for the shift in our curve to the left may be due to the fact that costs are assigned to **the year of cessation of production** and not to the expected decommissioning cash flows

[60] The basis of the DTI estimate has not been published so direct comparison with our estimate is not possible. One explanation may be the difference between money of the day estimates and our estimates in today's money.
[61] The day rates for marine equipment do not increase year on year in line with inflation but fluctuates in line with demand.

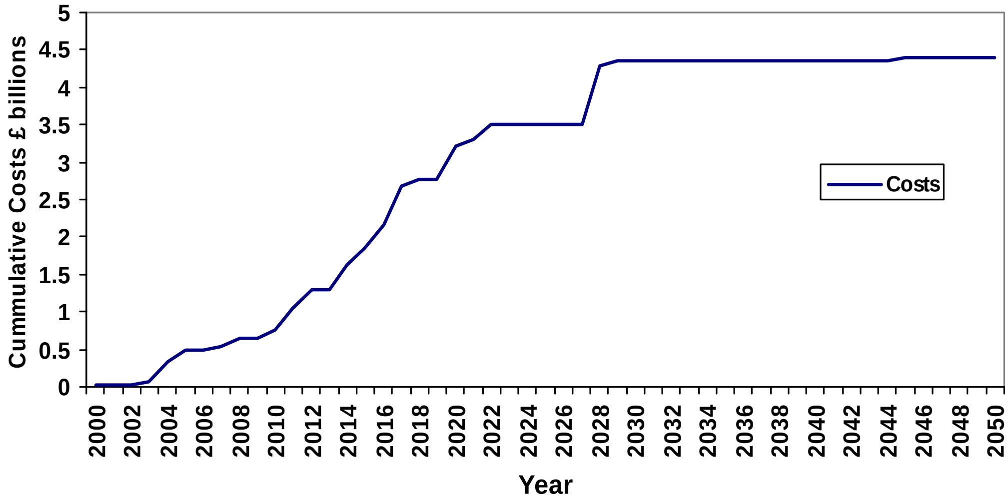

Figure 8.9: The Netherlands Cumulative Costs by Year

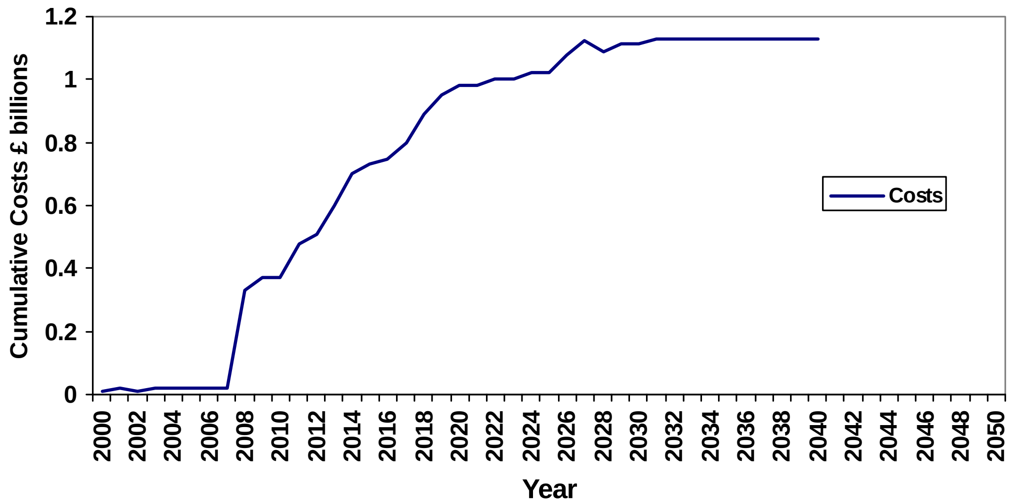

Figure 8.10: Norway Cumulative Costs by Year

The Norway cumulative costs are added in the year of cessation of production, as with the UK and The Netherlands. However, published decommissioning programmes for Ekofisk and associated facilities indicate a significant spread on programme durations for removal of facilities. Because of the size and cost of Ekofisk decommissioning, this delay will skew the cumulative curve to the right.

In all cases the cumulative costs are for full removal options. However, for Norway, derogation has been given for the Frigg and Ekofisk concrete gravity structures and it is assumed this will set a precedent for future decommissioning of concrete gravity structures. The cumulative costs for Norway, therefore, include for full removal of steel structures and partial removal of concrete gravity structures.

8.3 Decommissioning Cost across the Supply Chain

The decommissioning supply chain is discussed in detail in Chapter 5 of this report. To apportion the total North Sea decommissioning market of £12.5 billion across the supply chain approximate distribution percentages have been used. The exact distribution across individual North Sea platforms will vary depending on the attributes of the specific facility. The following table should therefore be taken as indicative only.

Table 8.3: Decommissioning Costs across the Supply Chain

Supply Chain Component	*% of Total*	*Value £m*
Surveys	2%	£250
Well D&A	15%	£1,881
Decommissioning	10%	£1,254
Facility/ Subsea Removal	48%	£6,020
Reception Facility & Disposal	9%	£1,129
Pipeline	7%	£877
Residual Liability	2%	£250
Client Cost	7%	£877
Total	100%	£12,538.00

The largest cost element is the cost of removing the structures from their offshore locations and delivery to an onshore reception facility. Of this amount of £6 billion, some 35% is the direct cost of hiring the heavy lift equipment, the remainder being supporting and specialist services that may be contracted out by the tier 1 contractor to level 2 & 3 suppliers.

Table 8.4: UKCS Decommissioning Costs across the Supply Chain

Supply Chain Component	% of Total	Value £m
Surveys	2%	£166m
Well P&A	15%	£1,248m
Decommissioning	10%	£832m
Facility/ Subsea Removal	48%	£3,994m
Reception Facility & Disposal	9%	£749m
Pipelines	7%	£582m
Residual Liability	2%	£166m
Client Cost	7%	£582m
Total	100%	£8,319 billions

The table breaks the decommissioning costs across the supply chain as an annual spend for the next ten years. Costs are recalculated in money of the day with an assumed inflation rate of 2.5% pa, with the exception of removal costs, which are dominated by marine equipment hire rates that are not inflation, but market, driven. Decommissioning costs are spread over a period of time. In reporting overall decommissioning costs above, they are assigned to the year of cessation of production. In the cost assigned across the supply chain a distribution of costs is assumed as follows.

Table 8.5: Time Spread of Decommissioning Costs

Element	Surveys	Well P&A	Decom	Removal	Reception	Pipelines	Residual	Client
Time in years relative to COP - year 0	-1	1	0	2	2	2	3	0

9 APPENDICES

9.1 Appendix A – Other Relevant UK Acts and Regulations

Food and Environmental Protection Act 1985
The requirements of the international conventions on **dumping at sea** are incorporated into UK domestic law through this act. Offshore disposal requires a licence under the FEPA. The FEPA stipulates that deep sea disposal will be allowed only if demonstrated to be the 'Best Practicable Environmental Option (BPEO)' and is consistent with international obligations. The BPEO must consider all options for disposal.

Coast Protection Act 1949 extended by the Continental Shelf Act 1964
The prior consent of the Secretary of State is required for the siting of a drilling or production platform, or a pipeline. Such consents may be subject to a requirement that when the structure is abandoned the Secretary of State must be notified and the **site cleared** to his satisfaction. The satisfactory completion of a decommissioning programme approved under the 1998 Petroleum Act should satisfy any removal conditions attached to Coast Protection Act consent.

Petroleum (Production – Seaward Areas) Regulations 1988
These regulations provide for consents for the **plugging and abandonment of exploration and production wells**.

Prevention of Oil Pollution Act 1972
These regulations control discharges of oil and operators will be required to make provision to **remove and recycle all oil recovered** from an offshore installation or pipeline.

Special Waste Regulations 1996
Depending on its nature and composition, waste material may be defined as special waste. The regulations require **all movement of special waste to be tracked** from its source through to the final waste management facility using a consignment note system.

Transfontier Shipment of Waste Regulations 1994
The **international movement of waste** is controlled by means of Council Regulations (EEC) No 259/93. The Regulations are enforced by the Environmental Agency in England & Wales and SEPA in Scotland.

Petroleum and Submarine Pipelines Act 1975
The construction of any pipeline within the UKCS requires authorisation from the Secretary of State. Conditions attached may typically include requirements to take measures, on **abandonment of the pipeline**, to ensure that it does not become a hazard to navigation or fishing or a source of pollution. Measures may include removal of the pipeline, sealing the end of a pipeline left in-situ and cleaning of the interior of the pipeline.

Control of Pollution Act 1974
The Act controls the **disposal of controlled wastes**. The Environmental Protection Act of 1990 has largely superseded it.

Water Resources Act 1991
Under this Act it is an offence to cause or knowingly permit any poisonous, noxious or **polluting matter to enter any controlled waters** defined as six nautical miles from the defined coastline in England and Wales and in Scotland to be three nautical miles measured from the baseline of the territorial waters.

Environmental Protection Act 1990 & Waste Management Licensing Regulations 1994
This makes provision for the improved **control of pollution** arising from certain industrial and other processes. The objectives are to ensure that in carrying out a prescribed process the best available techniques not entailing excessive cost will be used. Part 2 of the Act addresses the Duty of Care requirements for the handling, transport and disposal of waste material in accordance with a **waste management licence**.

Radioactive Substances Act 1993
This Act replaces the previous Radioactive Substances Act of 1960. An Authorisation Certificate is required for the storage and **disposal of naturally occurring radioactive materials** (NORM).

Ionising Radiation Regulations 1985
These Regulations deal with the **protection of personnel** from the detrimental effects of exposure to ionising radiation.

Transfrontier Shipment of Radioactive Waste Regulations 1993
Where an installation contains radioactive waste and it is proposed that the removed installation be taken to another country for re-use, recycling or disposal, the provision of this Act will apply. The Act provides a system of authorising **shipments of radioactive wastes** between Member States of the EC.

Production Licence – Model Clauses
The Model Clause 19(2) provides that the licensee shall not **abandon a well** without the Secretary of State's written consent. Warne and Walde[62] have suggested that in theory, the Secretary of State's consent might be expressed in terms wide enough to include removal of the facility.

Health and Safety Act 1974; Asbestos (Licensing) Regulations 1983
Licences are issued under these Regulations by the Health and Safety Executive (HSE) to contractors legally entitled to carry out work relating to the **removal of asbestos**. Such operations require constant monitoring and decontamination of premises after completion of strip-out.

Control of Asbestos at Work Regulations 1987 and 1990 Amendments.
These regulations control the exposure of personnel employed in areas where **asbestos** is used or may be encounted. Employers' duties include conducting hazard assessment of each stage of the strip-out, demolition, handling, storage, movement and disposal work. The hazard assessment is used to develop method statements, equipment to be used and mitigation methods to prevent spread of asbestos material or dust. Prevention of significant air pollution from asbestos fibres and dust is also controlled by the 'Control of Asbestos in the Air Regulations 1990'. The Regulations require that asbestos is stored in sealed containers, labelled in accordance with the 'Chemicals (Hazardous Information and Packaging) Regulations 1993', and transported in accordance with the 'Road Traffic (Carriage of Dangerous Substances in Road Tank Containers) Regulations 1992'.

The Dangerous Substances in Harbour Areas Regulations 1987
These Regulations apply to any **hazardous material that is offloaded, stored or transferred in a harbour**. Also included is the purging, gas freeing and cleaning of any tank that contained a hazardous or dangerous substance. A dangerous or hazardous material shall not be brought into a harbour unless not less than twenty four hours and not more than fourteen days' notice is given to the harbour master or berth operator.

Waste Regulation Authority (WRA)
Landfill sites are authorised by the appropriate Waste Regulation Authority. The authorisation specifies which wastes the site is approved to receive and which are prohibited. By so doing, landfill sites can be ranked in terms of the waste type they are licensed to accept, which may range from inert material up to special waste.

Waste Management Licensing Regulations 1994
The Waste Management Regulations provide a **definition of waste material**. Depending on the nature and composition of the waste, it may be defined as special waste as regulated by the 'Control of Pollution (Special Waste) Regulations 1980' and the 'Control of Pollution (Landed Ship's Waste) Regulations 1987', or as radioactive waste, which is covered by the 'Radioactive Substances Act 1993'.

Export Controls
The **export of oil & gas installations** for re-use outside the UKCS may be subject to United Kingdom export controls. The Export Control Organisation of the DTI addresses queries relating to export licenses. An export license will always be required if the destination is subject to UN Security Council Resolutions.

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[62] P.Warne & T.Walde paper "Minimising the impact of Decommissioning: Legal and Insurance Issues - a Practical Guide." Institute of Petroleum Conference on Minimising the Impact of Decommissioning, Feb 1996

9.2 Appendix B – Legislative Contacts

Contact Addresses
International

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Secretariate
Helsinki Commission (HELCOM)
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Fax: 0035 89 622 2239

Co-ordinator of MAP (Mediterranean Action Plan)

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Fax: 00 32 2 296 8825

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OSPAR CONTRACTING PARTIES

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1200 Bruxelles
Belgium
Tel: 00 32 2 773 2120
Fax: 00 32 2 770 6972

Denmark

International Division
National Agency of Environmental Protection
Ministry of the Environment
Strandgade 29
DK-1401 Copenhagen K
Denmark
Tel: 00 45 32 66 05 62
Fax: 00 45 32 66 05 00

France	Ministere de l'Environnement et des Finances Direction de la Prevention des Pollutions 41 Boulevard Vincent Auriol F-75703 Paris Cedex 13 France *Tel: 00 33 1 44 97 09 21* *Fax: 00 33 1 44 97 09 08*
Germany	Bundesamt fur Seeschifffahrt und Hydrographies Bernhard-Nocht- Str. 78 D-20359 Hamburg Germany *Tel: 00 49 40 3190 3520* *Fax: 00 49 40 3190 5035*
Ireland	Department of Communications, Marine and Natural Resources Petroleum Affairs Division Beggars Bush Haddington Road – Dublin 4 Ireland *Tel: 00 353 1 678 2690* *Fax: 00 353 1 660 4462*
Netherlands	Ministry of Transport, Public Works & Water Management Rykswaterstaat Directorate General for Water Management PO Box 20906 NL-2500 E, The Hague Netherlands *Tel: 00 31 70 35 19 041* *Fax: 00 31 70 35 19 078*
Norway	Norwegian Petroleum Directorate PO Box 600 N-4001 Stavanger Norway *Tel: 00 47 51 87 60 00*
	Ministry of the Environment PO Box 8013 N-0030 Oslo Norway *Tel: 0047 22 24 58 14* *Fax: 0047 22 24 95 63*
Spain	Ministerio de Medio Ambiente Direction General Calidad y Evaluacion Ambiental Plaza San Juan de la Cruz S/N E-28071 Madrid Spain *Tel: 00 34 91 597 63 56* *Fax: 00 34 91 597 59 80*
United Kingdom	Department of Trade and Industry Oil and Gas Decommissioning Unit Atholl House 86/88 Guild Street Aberdeen AB11 6 AR United Kingdom *Tel: 00 44 1224 254 020* *Fax: 00 44 1224 254 019*

9.3 Appendix C – List of Abbreviations

International Organisations and Terms

ACOPS	Advisory Committee on Pollution of the Sea
COFI	FAO Committee on Fisheries
DNV	Det Norske Veritas
EC	European Community
EEZ	Exclusive Economic Zone
ESCAP	Economic and Social Commission for Asia and the Pacific
FAO	Food and Agriculture Organisation of the UN
FOEI	Friends of the Earth International
GESAMP	Group of Experts on the Scientific Aspects of Marine Pollution
GIPME	Global Investigation of Pollution in the Marine Environment
IHO	International Hydrographic Organisation
IAEA	International Atomic Energy Agency
ILO	International Labour Office
IMCO	Intergovernmental Maritime Consultative Organisation
IMO	International Maritime Organisation
IOC	Intergovernmental Oceanographic Commission
ITU	International Telecommunication Union
LDC	London Dumping Convention 1972
MARPOL	Marine Pollution (result of International Convention for the Protection of Pollution from Ships 1973 and 1978)
MEPC	IMO – Marine Environmental Protection Committee
MMS	United States – Mineral Management Services
NPD	Norwegian Petroleum Directorate
OECD	Organisation for Economic Co-operation and Development
OPEC	Organisation of Oil Exporting Countries
SPREP	South Pacific Regional Environmental Protection
UNCTAD	UN Conference on Trade and Development
UNEP	United Nations Environmental Programme
UNESCO	United Nations Educational Scientific and Cultural Organisation
UNCLOS	United Nations Convention on the Law of the Sea
WHO	World Health Organisation
WMO	World Meteorological Organisation

UK Government Organisations

DOE	Department of the Environment
DTI	Department of Trade and Industry
FCO	Foreign and Commonwealth Office
HMIPI	Her Majesty's Industrial Pollution Inspectorate
HMIP	Her Majesty's Inspector of Pollution
HSE	Health and Safety Executive
MOD	Ministry of Defence
MSA	Department of Transport's Marine Safety Agency
MAFF	Ministry of Agriculture Fisheries and Food (now DEFRA)
NERC	National Environmental Research Council
NRA	National Rivers Authority
SOAFD	Scottish Office Agriculture and Fishers Department
UKCS	United Kingdom Continental Shelf

UK Non-Government Organisations

BISPA	British Iron and Steel Producers Association
BRINDEX	British Independent Oil Exploration Companies
ICE	Institute of Civil Engineers
IOS	Institute of Oceanographic Science
IPLOCA	International Pipeline and Offshore Contractors Association
JNCC	Joint Nature Conservation Committee
MCS	Marine Conservation Society
NERC	National Environmental Research Council
NGO	Non-Government Organisations
SFF	Scottish Fishermen's Association
UKOOA	United Kingdom Offshore Operators Association

Environmental and Safety

BPEO	Best Practicable Environmental Option
COSHH	Control of Substances Hazardous to Health
CSE	Concept Safety Evaluation
DEHAZ	Decommissioning Hazard Analysis
DSP	Decommissioning Safety Plan
EIA	Environmental Impact Assessment
F & G	Fire and Gas
HAZAN	Hazard Analysis
HAZOP	Hazard and Operability Analysis
HVAC	Heating. Venting & Air Conditioning
IPC	Integrated Pollution Control
LSA	Low Specific Activity Radioactive Scale
MEG	Mono ethylene glycol
NORM	Naturally Occurring Radioactive Materials
OSC	Offshore Safety Case
PCB	Polychlorinated biphenyl
RPS	Radiation Protection Supervisor
SMS	Safety Management Systems
TEG	Triethylene glycol

Legal & Insurance Terms

Abrogation	Do away with
CA	Certifying Authority
Contingent	Dependent on a probability, conditional, not absolute
Customary International Law	International law developed through state practice
de facto	As a fact
de jure	As a right
ex aequo et bono	A decision of the IJC based not on strict rules of international law but on such general principles as seem appropriate to the Court
Indemnify	Secure against any loss
IJC	International Court of Justice
jus cogens	Certain fundamental rules of customary international law incapable of being modified by treaty
jure gestionis	State acts of a commercial nature
jure imperii	State acts of a sovereign nature
Municipal Law	Internal law of a State
MWS	Marine Warranty Surveyor
OIL	Oil Industry Company
opinio juris	The belief that a practice is obligatory
OIAC	Oil Industry Accounting Committee
pacta sunt servanda	The rule that treaties are binding on the parties
P&I Club	Protection and Indemnity Associations
res communis	Areas of territory not open to acquisition by a state but held to be open to the international community
SORP	Statement of Recommended Practice
terra nullis	territory not belonging to a State which may be acquired by occupation
travaux préparatoires	Preparatory material of a treaty
ultra vires	Beyond the powers of legal authority

9.4 Appendix D – Completed Decommissioning Programmes

Table 9.1: UKCS Completed Decommissioning Programmes

Field / Installation	Operator	Water Depth	Main Installations Decommissioned	Approved Decomm-issioning Option	Year of Approval
West Sole	BP	25m	Fixed Steel Platform	Removal to shore	1982
Piper Alpha	Occidental	148m	Fixed Steel Platform	Toppling following catastrophic collapse	1988
Crawford	BHP	117m	FPF CALM Buoy Subsea Facilities	Removal to shore Removal to shore Removal to shore	1991
Argyll, Duncan and Innes	BHP	79m	FPF CALM Buoy Pipelines	Removal to shore Removal to shore Removal to shore	1992
Blair	AGIP		Pipelines	1 x Re-use 1 x Decommissioned and left in-situ	1992
Angus	Amerada Hess	80m	FPSO	Re-use	1993
Forbes AW	BHP	23m	Fixed Steel Platform	Removal to shore	1993
Esmond CP & CW	BHP	30m	2 x Fixed Steel Platform	Removal to shore	1995
Gordon BW	BHP	17m	Fixed Steel Platform	Removal to shore	1995
Emerald	MSR	150m	FPSO Pipelines	Re-use Decommissioned and left in-situ	1996
Frigg FP	TotalFinaElf Norge	100m	Flare Column	Removal to shore	1996
Leman BK	Shell	37m	Fixed Steel Platform	Removal to shore	1996
Staffa	Lasmo		Pipelines	Removal to shore	1996
Viking AC, AD, AP & FD	Conoco	24m	4 x Fixed Steel Platforms	Removal to shore	1996
Brent Spar	Shell	140m	Oil Storage and Loading Facility	Re-use as part of quay extension	1998
Donan	BP	140m	FPSO	Re-use	1998
Fulmar SALM	Shell	82m	SALM Buoy 16" Pipeline	Removal to shore Decommissioned and left in-situ	1998
Blenheim and Bladon	Talisman	140m	FPSO Pipelines	Re-use Removal to shore	2000
Durward and Dauntless	Amerada Hess	90m	FPSO Subsea Facilities	Re-use Removal to shore	2000
Maureen and Moira	Phillips	95m	Large Steel Gravity Platform Concrete Loading Column Pipelines	Removal to shore for re-use or recycling Removal to shore for re-use or recycling 2 x removal to shore 1 x decommissioned and leave in-situ	2000
Camelot CB	ExxonMobil	15m	Fixed Steel Platform	Re-use or removal to shore for recycling	2002
Durward and Dauntless	Amerada Hess	90m	Pipelines	Decommissioned and left in-situ	2002
Hutton	Kerr-McGee	148m	Tension Leg Platform Pipelines	Re-use 1 x removal to shore 1 x decommissioned and left in-situ (with future monitoring programme)	2002

Field / Installation	Operator	Water Depth	Main Installations Decommissioned	Approved Decommissioning Option	Year of Approval
Forbes and Gordon Infield Pipelines	BHP	20m	Infield Pipelines	Decommission and left in-situ - retrench any area of pipeline with less than 0.4m depth of cover	2003
Frigg TP1, QP & CDP1	Total E&P Norge AS	100m	Treatment Platform 1 (TP1), Quarters Platform (QP) and Concrete Drilling Platform 1 (CDP1)	Concrete substructures to remain in place. Concrete topsides to be removed to shore. Steel installations to be removed to shore. Infield Pipelines to be removed to shore	2003

Table 9.2: Norwegian Completed Decommissioning Programmes

Field / Installation	Operator	Water Depth	Main Installations Decommissioned	Approved Decommissioning Option	Year of Approval
Odin	ExxonMobil	103m	Fixed Steel Platform	Removal to shore Pipelines decommissioned and left in-situ	1998
North East Frigg	TotalFinaElf	100m	Subsea equipment Articulated offloading column	Removal to shore Removal to shore and re-used as a marine jetty	1996
Mime	Norske Hydro	80m	Subsea equipment	Removal to shore	1999
			Pipelines	Removal to shore	
2/4 S	Statoil	72m	Fixed steel riser platform	Removal to shore	2001
Lille Frigg	TotalFinaElf	100m	Subsea equipment	Removal to shore	2001
			Pipelines	Decommissioned and left in-situ	
East Frigg	TotalFinaElf	100m	Subsea equipment Pipelines	Removal to shore Decommissioned and left in-situ	2001
Tommeliten Gamma	Statoil	70m	Subsea equipment Pipelines	Removal to shore Decommissioned and left in-situ	2001
Yme	Statoil	93m	Jack-up production unit Pipelines	Removal to shore Decommissioned and left in-situ	2001
Froey	TotalFinaElf	120m	Fixed Steel Platform	Removal to shore	2002

Table 9.3: Dutch Completed Decommissioning Programmes

Field / Installation	Operator	Water Depth	Main Installations Decommissioned	Approved Decomm-issioning Option	Year of Approval
K13-C and K13-D	Wintershall	28m	2 x Fixed Steel Platform	Removal to shore	1989
K10 C	Wintershall	25m	Fixed platform	Removal to shore and re-used	1997
K13-B	Wintershall	28mm	Fixed platform	Removal to shore	1997
K13-D	Wintershall	28m	Fixed platform	Removal to shore and re-used	1998
L14-S1	Gaz de France	25m	Fixed platform	Removal to shore	1998
L11a-A	Gaz de France	29m	Fixed platform	Removal to shore and topsides re-used	1999
L10K	Gaz de France	28m	Fixed platform	Removal to shore	2000
P2-SE	Clyde	26m	Jack-up platform	Removal to shore and re-used	2001
P12-C	Clyde	28m	Fixed platform	Removal to shore	2001
P2-NE	Clyde	26m	Jack-up platform	Removal to shore and re-used	2002

Table 9.4: German Completed Decommissioning Programmes

Field / Installation	Operator	Water Depth	Main Installations Decommissioned	Approved Decomm-issioning Option	Year of Approval
Schwedeneck See A & B	RWE-DEA	20m	2 x Concrete gravity platforms	Removal to shore for disposal	2002

Table 9.5: Spanish Completed Decommissioning Programmes

Field / Installation	Operator	Water Depth	Main Installations Decommissioned	Approved Decomm-issioning Option	Year of Approval
Amposta	Shell Espana	61m	2 x fixed platforms	Removal to shore for disposal	1989