

The Decommissioning of Offshore Oil
and Gas Installations: A Review of
Current Legislation, Financial Regimes
and the Opportunities for Shetland

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2002 STEP Placement

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Remit

This project had four main objectives:

- To research and summarise the current legislation/regulation (national and international) surrounding the process of oil rig decommissioning in the UK.
- To research the issue of long term liabilities arising from decommissioned installations which have not been **completely** removed (for instance, maintenance, accidents, maritime traffic management and so on). In particular, what were the existing provisions for residual liability, proposals for changes and implications of existing and future arrangements?
- To investigate and isolate the specific taxation implications of the decommissioning of oil installations in the North Sea. What, in fact, these are? And what are their implications?
- To research and assess the current position of Shetland with regard to the opportunities for attracting decommissioning work.

Chapter 1

Background Information to Oil and Gas Installation Decommissioning

1. Context

Presently there are 6,500 offshore oil and gas production installations world wide, located on the continental shelves of some 53 countries. Over 4,000 are situated in the Gulf of Mexico, some 950 in Asia, some 700 in the Middle East and some 600 in the North Sea and North East Atlantic.

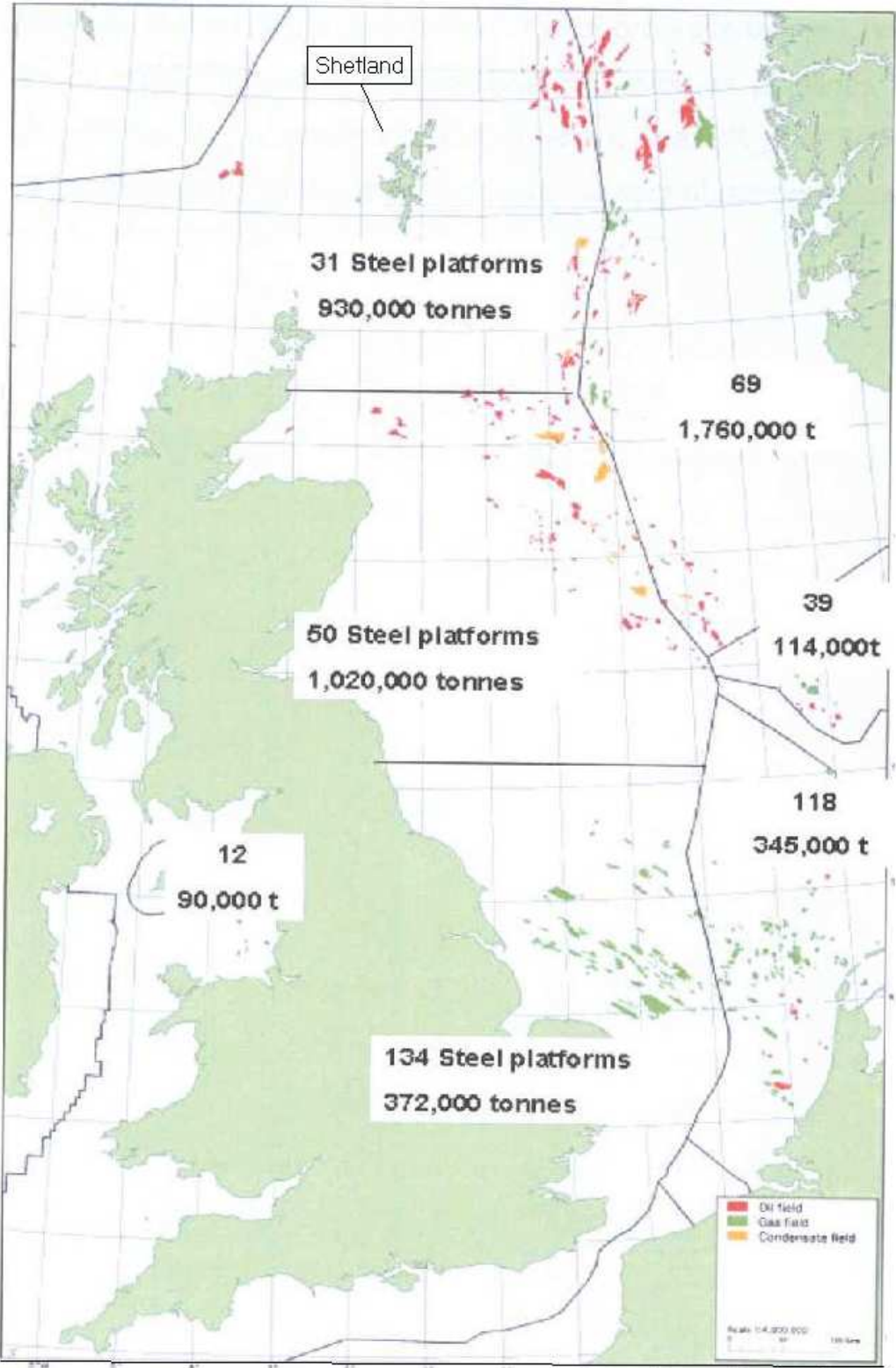
The United Kingdom Continental Shelf (UKCS) is home to some 312 structures extracting oil and gas. These include subsea equipment fixed to the ocean floor as well as platforms ranging from the smaller structures in the Southern and Central North Sea to the substantial installations in the Northern North Sea built to withstand very harsh weather conditions in deep waters. Many of the structures were constructed in the 1970s and were hailed as technological feats when they were installed.

The table below shows the location of North Sea installations by type and country¹:

| Country | Steel Jacket | Concrete Substructure | Subsea | Floating | Total |
|-------------|--------------|-----------------------|--------|----------|-------|
| UK | 227 | 12 | 56 | 17 | 312 |
| Norway | 69 | 13 | 54 | 9 | 145 |
| Netherlands | 118 | 2 | 7 | | 127 |
| Denmark | 39 | | | | 39 |
| Germany | 1 | 1 | | | 2 |
| Total | 454 | 28 | 117 | 26 | 625 |

¹ Scottish Enterprise Energy Team, "Offshore Decommissioning: Opportunities for Scottish Based Businesses", 2002, Pg12

Sector map showing the number of steel platforms and total tonnage of steel²:
→



² Scottish Enterprise Energy Team, "Offshore Decommissioning: Opportunities for Scottish Based Businesses", 2002, Pg14

2. The task ahead

Many oil and gas fields are now entering (or already have) into the twilight of their productive lives and, thus, the energy sector now faces the equally challenging task of decommissioning redundant oil and gas installations. There is a clearly identified legal and regulatory framework, incorporating international, regional and national concerns which governs the decommissioning process. Under current regulatory requirements for the North East Atlantic (which includes the North Sea), some 80% of structures will be completely removed from their current sites and brought to shore. The rest, which comprise the very large and heavy steel or concrete installations, will be looked at on an individual basis to assess whether it is technically feasible and safe to remove the structures, bearing in mind that there is a general presumption for total removal.

3. What is decommissioning?

The UK Offshore Operators Association (UKOOA) defines decommissioning as³:

“The process which the operator of an offshore oil and gas installation goes through to plan, gain government approval and implement the removal, disposal or re-use of a structure when it is no longer needed for its current purpose.”

Decommissioning can be, and usually will be, a long-term process. Phillips Petroleum UK began to think about the decommissioning of their Maureen platform in 1993 – the platform was finally removed in 2001.

4. When will structures in the North Sea be decommissioned?

It is difficult to predict accurately the exact date of decommissioning for each structure. There are three main reasons for this:

- Technological advance allows more efficient and extensive oil recovery and so prolongs the life of the field;
- The growing practice of developing smaller satellite fields using new subsea systems that ‘tie back’ to existing platforms is also expanding the life expectancy of current infrastructure;
- The price of oil (characterised by a degree of volatility) helps determine whether it is economic to extract oil from a particular field.

³ <http://www.ukooa.co.uk/issues/decommissioning/background.htm#whatis>

Based on current knowledge, however, it is thought that the bulk of North Sea decommissioning will take place between 2005 and 2020.

5. How many installations have been decommissioned so far?

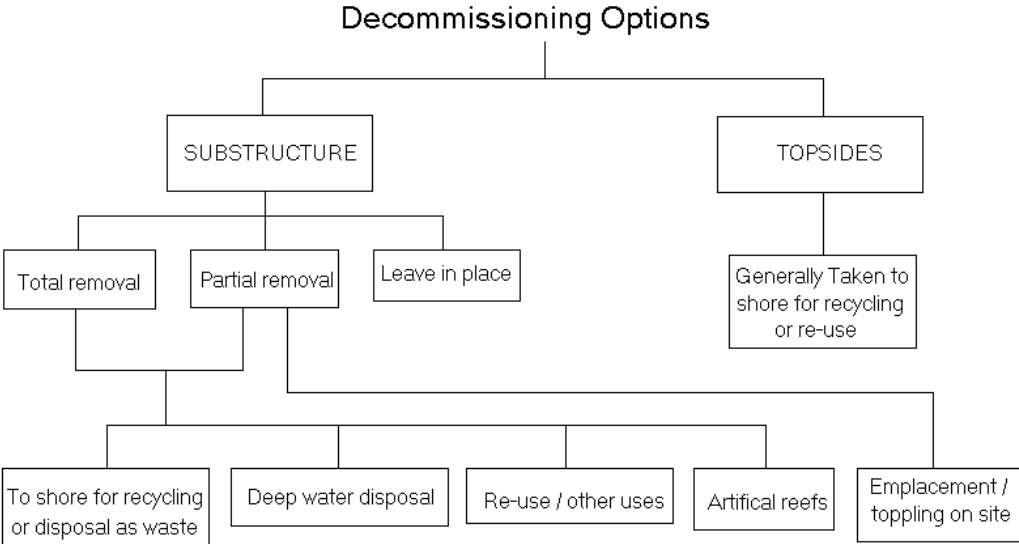
To date there is relatively little experience of removing structures from the North Sea. So far, some 30 small steel structures and sub-sea installations have been successfully decommissioned in the shallow waters (30-50 metres) of the Southern North Sea sector, including 20 from UK waters.

The largest structure decommissioned so far is the Odin platform in 1997. The steel substructure, weighing 6,200 tonnes, was removed from the North Sea in waters 100 metres deep. None of the largest structures, those weighing over 10,000 tonnes, has ever been removed anywhere in the world.

6. The decommissioning options & striking the right balance

There are a number of different ways to remove and dispose of an offshore installation. Exactly which are applicable to any individual installation will depend on a number of factors such as type of construction, size, distance from shore, weather conditions, and the complexity of the removal operation including the safety considerations for the workers.

The diagram below depicts the main options open to offshore operators⁴:



⁴ "Decommissioning Offshore Oil and Gas Installations: Finding the Right Balance", OGP Discussion Paper, 1996, Pg7-9

After consideration of the relevant legislation and regulation, recommending which decommissioning option is the most appropriate in any particular case has to take into account at least five key factors:

- Potential impact on the environment;
- Potential impact on human health and safety;
- Technical feasibility of the plan;
- Economic impact;
- Public concern.

These criteria must be carefully balanced to ascertain the most beneficial (or the least harmful) course of action.

Chapter 2

Existing Legal and Regulatory Provisions for Oil and Gas Installation Decommissioning

1. General Framework

The British Government's policy with regard to the decommissioning of offshore oil and gas installations on the United Kingdom Continental Shelf (UKCS) is stated quite clearly in the Guidance Notes for Industry (Decommissioning of Offshore Installations and Pipelines under the Petroleum Act 1998) produced by the Aberdeen-based Oil and Gas Office of the Department of Trade and Industry (DTI):

“Government will seek to achieve effective and balanced decommissioning solutions which are consistent with international obligations and have a proper regard for safety, the environment, other legitimate users of the sea and economic considerations. The Government will act in line with the principles of sustainable development.” (Pg3)

2. International Conventions

2.a. United Nations Convention on the Law of the Sea

Internationally, the UK has a number of obligations concerning the decommissioning of offshore installations which have their origins in the United Nations Convention on the Law of the Sea (UNCLOS) of 1982⁵ which entered into force in 1994 and was finally ratified by the UK in 1997. Article 60(3) notes that:

“Any installations or structures which are abandoned or disused shall be removed to ensure safety of navigation, taking into account any generally accepted standards established in this regard by the competent international organisation. Such removal shall also have due regard to fishing, the protection of the marine environment and the rights and duties of other States. Appropriate publicity shall be given to the depth, position and dimensions of any installations or structures not entirely removed.”

⁵ UNCLOS(1982) superseded the 1958 Geneva Convention on the Continental Shelf. Article 5(5) of the Geneva Convention determined in no uncertain terms that “any installations which are abandoned or disused must be entirely removed”. The UK ratified the Geneva Convention and it entered into force in 1964 - long before deep-sea structures were ever emplaced.

The International Maritime Organisation (formed in 1989 and based in London), which adopted the IMO Guidelines and Standards setting out the global criteria for removal of offshore installations, is the competent international organisation for UNCLOS (1982)⁶.

2.b. OSPAR

In addition, 1992 witnessed a new regional convention, the Convention of the Protection of the Marine Environment of the North East Atlantic (*the OSPAR Convention*). This convention, a replacement and modernisation of the 1972 Oslo Convention on the Protection of the Marine Environment by Dumping from Ships and Aircraft and the 1974 Paris Convention on the Prevention on Marine Pollution from Land-Based Sources, came into operation in 1998. The Convention's main roles are to control disposal of all waste at sea and discharges from land. Including the EU, there are 16 contracting parties of which the UK is one.⁷

In July 1998 a new binding framework (OSPAR Decision 98/3) for the decommissioning of offshore installations was established by the First Ministerial meeting of the OSPAR Commission. Generally, the primary decision made quite clear that: *"The dumping, and the leaving wholly or partly in place, of disused offshore installations within the maritime area is prohibited."*⁸

More specifically, recognition by OSPAR 98/3 of the difficulties involved in removing in their entirety the 'footings' of large steel jackets weighing more than 10,000 tonnes and in removing concrete installations ensured that provisions were made for a derogation from the main 'general' rule highlighted above (assessed on a case-by-case basis).

In particular:

- The topsides of all installations must be returned to shore;

⁶ The 1989 IMO Guidelines require the complete removal of all structures in waters less than 100 metres (since January 1998 – previously it was 75 metres) and substructures weighing less than 4,000 tonnes. Those in deeper waters can be partially removed leaving 55 metres of clear water column for safety of navigation. All new structures installed after 1 January 1998 must be designed so as to be feasible for complete removal.

⁷ Until 1995, the OSPAR Convention did permit, under certain circumstances, the disposal at sea of parts or all of the disused offshore installations. After the Brent Spar incident in 1995, a moratorium on all disposals at sea of offshore structures was introduced (although not signed up to by the UK and Norway).

⁸ The IMO Guidelines and Standards do not preclude a coastal state from enacting more stringent regulations for existing or future installations or structures within its national jurisdiction. The UK Government's acceptance of OSPAR Decision 98/3 means that IMO Guidelines and Standards will be subordinated, for the most part, to that of OSPAR when contemplating the decommissioning of offshore installations.

- All steel installations with a jacket weight of less than 10,000 tonnes must be completely removed for re-use, recycling or final disposal on land;
- For steel structures with a jacket weight greater than 10,000 tonnes it is possible to consider whether the footings of the installation may remain in place;
- For concrete installations it is possible to consider whether they should be left wholly or partially in place;
- All installations emplaced after 9 February 1999 (when OSPAR 98/3 came into force) must be completely removed;
- Exceptions can be considered for other structures when exceptional and unforeseen circumstances resulting from structural damage or deterioration or other reasons which would prevent the removal of a structure.

Pipelines are not covered by OSPAR Decision 98/3. There are no international guidelines on the decommissioning of disused pipelines.

OSPAR Decision 98/3 will next be reviewed by the OSPAR Commission in 2003 (and at regular intervals thereafter to consider the appropriateness of the derogation criteria in view of experience and technical advance)

3. United Kingdom Legislation and Regulation

The decommissioning of offshore oil installations on the UKCS was controlled until recently through the 1987 Petroleum Act. 1998 saw the passage of a new Petroleum Act which consolidated the decommissioning provisions of the 1987 Act and various other petroleum legislation.

The Petroleum Act 1998 is administered by the DTI and provides a clear framework for the orderly decommissioning of offshore installations and pipelines on the UKCS.

The general presumption is that all offshore installations will be re-used, recycled or disposed of on land. Any exceptions will be assessed individually on a case-by-case basis in accordance with the provisions of OSPAR 98/3.

Before the owners of an offshore installation can proceed with decommissioning they must obtain approval under the Petroleum Act 1998 of a decommissioning programme which outlines the proposed plans.

DTI's Guidance Notes for Industry stress that:

“A decommissioning programme will be consistent with international obligations and have 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. Each decommissioning programme will be subject to full and open consultations.” (Pg39)

Moreover, the following will need to be obtained in addition to approval of the decommissioning programme:

- Confirmation that the requirements of the Coast Protection Act 1949 have been fulfilled;
- Acceptance of an Abandonment Safety Case under the Offshore Installations (Safety Case) Regulations 1992 (installations only);
- Completion of notification requirements to Health and Safety Executive (HSE) under regulation 22 of the Pipeline Safety Regulations 1996;
- Approval of a well abandonment programme in accordance with the obligation contained in the petroleum production license.

The disposal of materials on land must comply with the relevant health, safety, pollution prevention and waste requirements, including in particular Part II of the Environmental Protection Act (1990). In certain circumstances authorisation under the Radioactive Substances Act (1993) may also be necessary.

Other important acts that have to be considered include, but are not limited to⁹:

- Health and Safety at Work etc Act (1974);
- The Waste Management Licensing Regulations (1994);
- Special Waste Regulations (1996);
- Transfrontier Shipment of Waste Regulations (1994).

⁹ See annex D of the DTI Guidance Notes for Industry for the full range of regulations that may or may not be appropriate.

Decommissioning is not an event but a process with an indefinite horizon. There are three key post-decommissioning requirements as stipulated by the Petroleum Act 1998.

- Any residual liability remains with the owner in perpetuity;
- Any remains of installations or pipelines will be subject to periodic monitoring specified in the decommissioning programme and may necessitate maintenance or some form of remedial action in the longer term;
- The information confirming the existence of said remains will be passed onto mariners and appropriate hydrographical services and will be marked on nautical charts

4. Norwegian Legislation and Regulation

The decommissioning process of North Sea oil and gas installations in Norway is broadly similar to that in operation within UK territorial waters. Like Britain, Norway is a contracting party to the OSPAR Convention and, thus, subject to the constraints imposed by OSPAR Decision 98/3 (described in section 2.b).

The Petroleum Activities Act (1996) requires that disposal decisions are to be made on a broad-based evaluation in each individual case¹⁰, with emphasis placed on technical, safety, environmental and economic aspects, and well as the consideration for other users of the sea. Envisaged, is a cost-benefit analysis where the costs and safety risks associated with various disposal alternatives are carefully balanced against the environmental, fisheries and other users' interests, and that alternative uses should be considered and may be acceptable.

In addition to the Petroleum Activities Act, other Norwegian legislation - such as the Pollution Control Act, the Harbours and Navigation Act and the Working Environment Act, with associated regulations – must be consulted and addressed for an oil or gas installation decommissioning to come to final fruition.

The Norwegian Parliament will make the final decision in accordance with the Petroleum Activities Act (1996) concerning the decommissioning of an offshore installation.

¹⁰ The Regulations to the Petroleum Act specify that a Cessation Plan shall contain a Disposal Plan and an Environmental Impact Assessment report (an EIA is also required in the UK Decommissioning Programme)

Chapter 3

Provisions for Meeting Residual Liability Obligations from Decommissioned North Sea Oil and Gas Installations

1. Introduction

What is residual liability? Once the ‘process’ of decommissioning of redundant oil and gas installations has been completed it is inevitable that some residue (in the broadest sense of any physical presence) shall remain, even after ‘complete’ removal to shore. Someone, or something, must bear responsibility for this residue – and, thus, the concept of residual liability is introduced. Who, in legal terms, enjoys the rights and shoulders the responsibilities of ownership?

2. International Regulation of Residual Liability?

The IMO Guidelines and Standards (1989) note that Coastal States should ensure:

“Legal title to installations or debris remaining on the sea bed is unambiguous and responsibility for periodic monitoring, maintenance and the financial ability to assume liability for future damages are clearly established.”

Thus, the IMO does not go as far as to provide a framework (in terms of ‘who’) for the meeting of residual liability obligations but, instead, simply states that one should be in place. Other than the vague IMO guideline highlighted above there are no other international conventions, of which Britain is a party to, which addresses the issue of residual liability for redundant sea-based oil and gas installations¹¹.

3. Residual Liability in the UK

3.a. Short Run

¹¹ House of Commons written answer for 25th June 1996 & the reply from Energy Minister Brian Wilson to a Parliamentary Question from Kevin McNamara (12th June 2002)

On the other hand, the UK Government's Guidance Notes for Industry on Decommissioning (prepared by the Oil and Gas Office of the DTI) state quite forcefully with respect to residual liability that:

"The persons who own an installation or pipeline at the time of its decommissioning will normally remain the owners of any residues. Any residual liability remains with the owners in perpetuity." (Pg36)

Furthermore:

"Any claims for compensation by third parties arising from damage caused by any remains will be a matter for the owners and the affected parties and will be governed by the general law." (Pg36)

3.b. Long Run

Nonetheless, such an unequivocal statement may not be applicable in the longer term. As commercial enterprises, and thus a potential victim to the vagaries of the free market, individual companies may not exist in perpetuity, whereas the government, or a government agency, should. The government has recognised this fact and concedes in the Guidance Notes on Industry that it is *"willing to consider any scheme which is proposed."*

3.b.i A Special Case – Financial Security Agreements?

Despite this there does exist a 'special case' where the Government has a clearly defined policy to ensure acceptable financial provision for decommissioning (and presumably for any post-decommissioning residual liability).

The DTI Guidance Notes for Industry notes:

"In the last few years there has been significant interest in the assignment of mature UKCS oil and gas assets from large companies to smaller ones. Ministers have agreed that such activity on the UKCS should be encouraged and that there should be a free trade in mature offshore oil and gas assets as a means of extending field life and maximising economic recovery." (Pg10)

At the same time the Government has acknowledged that it has a duty to ensure that the taxpayer is not exposed to an unacceptable risk of default in meeting the costs associated with decommissioning (the OSPAR 98/3 Decision ensures **someone** must bear the decommissioning cost).

Accordingly the Government has developed a policy to ensure that adequate security for decommissioning costs is available in certain circumstances.

Under the provisions of the Petroleum Act (1998), the DTI can require participants in a licence to provide Financial Security Agreements (FSAs). These are normally required by the DTI in situations where the DTI considers that the remaining participants in a licence may not include parties with the financial strength to carry out the decommissioning obligations.

The nature and format of FSAs can include Parent Company Guarantees (PCGs), Letters of Credit, Performance Bonds, etc.

Until the publication of revised DTI guidelines under the Petroleum Act (1998), it had been anticipated that PCGs would constitute adequate FSAs for DTI purposes. However, those revised guidelines indicated that:

- a) The DTI sought Cash, Irrevocable Standby Letters of Credit or on-demand Performance Bonds issued by Prime Banks; i.e. banks with AA rating or better as defined by Standard & Poors or Aa2 or better as defined by Moodys;
- b) The DTI may consider alternative insurance based schemes; and
- c) PCGs were very unlikely to be acceptable to the DTI as the need for the security to be called upon is most likely to arise in cases where the group as a whole is in financial difficulties.

The requirement to provide a FSA per a) above would potentially result in significant additional costs for many companies, particularly the larger and more financially robust companies.

Since 1999 the Industry Insurance Steering Group (comprising representatives from Shell, BP, Amoco, Enterprise, Conoco and Talisman), have therefore looked at how best to meet likely DTI requirements in a sound, even-handed and practical manner.

The aim being to enable a more flexible and practical choice of security types and providers than the limited choice described in the 'guidelines'. This would benefit the Industry as a whole, particularly the smaller and medium players, and at the same time provide the DTI with the same or a better level of comfort than under the guidelines.

One avenue explored was the development of an 'Industry Mutual Guarantee Fund' (IMGF) type product which would apply to the whole industry and would address the following key areas of concern:

- The provision of security guarantees per se;
- Protection against decommissioning cost overruns;
- Residual liability

The IMGF approach proved not to be a sound way forward – principally because of the disproportionate cost and liability burden it would place on the ‘major’ companies.

Various FSA options are presently under consideration and discussions between the Industry and the DTI have taken place but no formal acceptance or agreement has been reached yet.

On the other hand, the DTI appear not to require an FSA for a particular licence where one of the ‘major’ oil companies remains a licensee. This informal practice is not, however, reflected in the guidelines.

3.b.ii In the Dark?

Excluding the ‘special case’ involving the transfer of assets mentioned above there is no general mechanism in the UK to ensure that long term residual liabilities are met. This, undoubtedly, is a serious oversight as it is perfectly possible that in the long run some firms will cease to operate and, yet, there will remain residual liabilities to shoulder.

This current impasse is for two key reasons:

- No such significant situation has arisen and, as a result, the Government’s hand has not been forced by circumstance; and more importantly
- A suitable compromise between the Government and Industry concerning specific residual liability proposals has not been reached.

3.b.iii Proposals

Various proposals have been discussed within the offshore industry:

- The transfer of liability from owners to a body such as Trinity House (who already have responsibility for wrecks in UK waters);
- The formation of a so-called “Protection and Indemnity Club” funded by the companies, to provide cover for the residual liability;
- Industry Mutual Guarantee Fund – discussed elsewhere;
- The most influential proposal which has garnered the most industry support recommends that the Government assume ownership of any residues upon satisfactory completion of an approved decommissioning plan, and the industry would fund insurance to give Government financial protection against any claims from civilian

interests. The Government gave only a luke-warm (at best) response to such a suggestion as a consequence of their belief that the owners and operators of offshore installations should, ultimately, bear any residual liability.¹²

4. Residual Liability in Norway

4.a. Basic Presumption

The rigidity of the British approach is in marked contrast with the Norwegian provisions for residual liability¹³. Initially, the first two paragraphs of Section 5-4 ('Liability') of the Petroleum Activities Act (1996) echoes the British stance:

"If the decision is abandonment, the licensee or owner shall be liable for damage or inconvenience caused willfully or inadvertently in connection with the abandoned facility, unless otherwise decided by the Ministry. If there are more than one party liable...they shall be jointly and severally liable for financial obligations, unless otherwise decided by the Ministry."

4.b. An Interesting Legislative Addition

Following recent changes to the Petroleum Activities Act (1996), however, if an abandonment decision is made, the Norwegian Government may make an agreement with licensees and owners for the State to take over ownership of redundant installations, provided an agreed decommissioning plan has been properly executed, in return for a contractually agreed financial consideration from the operator(s) to cover the anticipated future liabilities. The Act also provides for the setting up of an agency to which responsibility for structures left in place can be transferred.¹⁴

This added degree of flexibility, enshrined in legislation, is more likely than not a reflection of the role played by the Norwegian State in the energy sector. Through Statoil (50% State owned) the Norwegian government has an active role in the ownership of oil installations and, thus, bears some liability regardless of any transfers.

¹² Which is in line with the rest of the economy as there is no suggestion that other sectors of the economy should not have to face residual liability – what makes the oil and gas industry any different?

¹³ As was mentioned earlier the DTI Guidance Notes for Industry were quite forceful in their assertion that 'any residual liability remains with the owner in perpetuity'.

¹⁴ Section 5-4 of the Petroleum Activities Act (1996) - *"In the event of decisions for abandonment, it may be agreed between the licensees and the owners on one side and the State on the other side that future maintenance, responsibility, and liability shall be taken over by the State based on an agreed financial compensation."*

5. The Costs of Residual Liability

5.a. Cost 'Types'

It is possible to identify three broad categories of long-term costs which may accrue after the decommissioning programme has reached completion:

- 'Legitimate' costs, identified and foreseen in the decommissioning process – i.e. maintenance, monitoring and so on;
- 'Unfortunate' costs – i.e. 'Acts of God' which the owner must respond to such as severe weather damage;
- 'Illegitimate' – i.e. Negligence in the completion of a decommissioning project which may lead to claims against the owner.

5.b. Predicting Costs?

- 'Legitimate' costs – On the one hand we can very accurately estimate the costs involved in certain aspects of the post decommissioning programme such as installing navigational aids on the footings of oil or gas installations remaining in place. Unfortunately, in the longer run it is more problematic to predict costs since it is uncertain what will transpire – we cannot estimate the maintenance costs of an installation remaining in place until we realise the extent of decomposition.
- 'Unfortunate' costs – An intrinsically difficult task: 'Acts of God' necessarily involve a degree of uncertainty.
- 'illegitimate' costs – As with 'unfortunate' costs there is a degree of chance associated with 'illegitimate' costs. Whether there is a leakage of hydrocarbons into the sea depends on the extent of negligence in the decommissioning process, and crucially, on luck. Prediction, thus, is difficult.

5.c. Interaction

The 'types' of costs identified above are not independent, but interact and reinforce. A comprehensive set of post-decommissioning measures should keep legal claims (against the oil or gas company for 'negligence') to a minimum but, nonetheless, could be an expensive process.

TotalFinaElf plan to install navigational beacons on three concrete structures which the company plans to leave in situ in the North Sea (from their Frigg

Field). It is fair to say that a 'good', 'thorough' decommissioning programme will be more cost-effective in the long run than a 'shoddy' programme. The TotalFinaElf plan to install navigational aids on decommissioned Frigg Field structures is an expensive measure but, in the longer-term, will mitigate the risk of damage to others (especially boats) and thus, to a degree, insulate the firm from damaging claims.

5.d. Recent Attempts?

At present the DTI has no figures on the potential residual liability costs should liability be transferred to the UK Government or the potential costs incurred by the oil and gas industry should the current firm-centered situation continue to prevail.

The decommissioning programmes submitted to the DTI contain a full cost breakdown, including the costs of the post-decommissioning programmes, but such information is not revealed publicly. Issues of commercial confidentiality and the threat of commercial damage led to the DTI agreeing to the request from the industry that a full cost breakdown did not have to be included in the decommissioning programme made available to non-DTI bodies, groups and individuals. Numerous emails, phone calls to individual companies failed to elicit any information.

5.e. General Observations

The costs associated with such liabilities are directly affected by the scale of the items left in place and the risks associated with them. If there is full removal of an oil or gas installation the costs associated, post-decommissioning, should be minimal. For instance, the Phillips' Maureen platform, which has now been removed has left, as its only trace, a small pile of drill cuttings on the seabed and a buried oil-loading pipeline.

The vast majority of items will be removed in their entirety. Items can only be left in situ after a rigorous assessment of environment implications, safety impacts and scrutiny by Government (and a wider public) of the particular circumstances. This suggests that, *ceterus paribus*, if the items did pose a significant risk they would not be allowed to remain

Over the short to medium term some degree of monitoring is likely to be involved and it is this which is likely to be the main cost with costs reducing as behaviour is confirmed.

Potential items for which a case to leave could include the stumps of large steel jackets, large concrete substructures, historic drill cutting accumulations and pipelines and cables but each would be subject to a detailed assessment before a recommendation could be made for approval by Government.

In the marine environment, and particularly the North Sea, one cannot always predict with precision, very far in advance, the associated costs. It would, therefore, be misleading to speculate about future costs in this area, or to use estimates for one decommissioning programme to extrapolate to other installations, all of which have their own particular set of issues for attention.

It is arguable that long-term residual liability will not contribute, significantly, to the overall decommissioning cost for two reasons:

- A legislative presumption that offshore installations are fully removed;
- A vigorous regulatory process that ensures derogation from the presumption for removal is closely tied to the risks posed to other users of the sea.

5.f. Conclusion

In conclusion, it is impossible from this position to calculate how much long term residual liabilities will 'cost'. This is for two reasons:

- Informational issues – the industry does not wish to divulge their estimations;
- Time issues – decommissioning is a process which extends far into the future and it is impossible to 'predict' the future.

Perhaps the only way to get an estimate of costs would be to pose the industry the following question:

“How much would the oil and gas industry be willing to pay the government to have on-going liability transferred to the State?”

This question has yet to be asked.

Chapter 4

UK Continental Shelf Upstream Oil and Gas Fiscal Regime

1. Tax and Decommissioning

In the UK, most decommissioning expenditure can be set against the licensee's tax bills. The numbers vary from field to field but for the UK Continental Shelf as a whole the taxpayer will meet around 50% of the costs.¹⁵ Keith Mayo of the DTI noted in a recent paper that:

*As the total decommissioning bill is estimated to be around £10 billion or more [decommissioning tax breaks involve] significant money. It's unreasonable to expect the taxpayer to fund decommissioning expenditure that is unjustified. Cost is certainly not the dominant factor in considering decommissioning proposals, but it must be taken into consideration."*¹⁶

It is fair to say that estimating the cost of decommissioning for the UK sector at £10 billion is very conservative. The most recent figures suggest that the decommissioning market could rise to over £30 billion, but more than likely will be in the area of £20 billion. This will pose a significant burden on a Treasury famed for its 'prudence' and it is possible that recognition of this fact will lead the UK delegation at the next OSPAR Convention in 2003 to push for a relaxation of the OSPAR regulations regarding decommissioning.

Why doesn't the Government simply abolish the rebates offered to the industry in relation to decommissioning offshore oil and gas installations? Abolition would, in an instant, remove the financial headache posed to the Treasury of part-financing the decommissioning process in the North Sea. Two reasons are readily apparent:

- The industry has factored rebates into their financial planning and investment decisions. Fiscal stability is critical in any industry which plans in the long term and abolition could threaten the solvency of previously 'secure' companies;
- Whilst the taxpayer will bear a sizeable share of the decommissioning burden the figures involved, though appearing large at first, are small in comparison to the Treasury receipts generated by the offshore oil industry.

The UK North Sea fiscal regime is described below.

¹⁵ "Decommissioning Achievements in the UK: Experiences and Challenges Ahead", Keith Mayo, NPF North Sea Decommissioning Conference, 26-27 February 2002

¹⁶ Ibid.

2. Overview

The Department of Trade and Industry (DTI) Oil and Gas Unit states that¹⁷:

“The North Sea fiscal regime is one of the main mechanisms for capturing for the nation the economic benefits from the UK’s oil and gas resources. The special UKCS tax regime is designed to secure an appropriate share of profits for the nation while offering stable, attractive and economically sound investment conditions to the oil industry.”

3. The main features

There are three distinct layers:

3.a. Royalty

In order to produce oil and gas offshore, a licence is required from the UK government. Fees are payable to acquire licences and, amongst other conditions, on certain fields there is an obligation to pay a royalty.

Royalty is payable at 12½ per cent of the landed value of the petroleum won and sold, less an allowance for the cost of bringing the petroleum ashore and treating it. Royalty is not payable for any field approved after 31 March 1982.

3.b. Petroleum Revenue Tax

Petroleum Revenue Tax (PRT), which was introduced by the Oil Taxation Act 1975, applies only to fields where development consent (or approval of a development programme) was first given before 16 March 1993 (taxable fields). It is therefore only of historic interest except for the 75 PRT paying fields within the regime, which are still material to the UKCS. PRT is essentially a windfall tax on the profits from winning oil and gas under a UK licence. It is a tax on profits related to separate geological and technically determined fields, charged on the difference between income and expenditure with allowances designed to ensure it targets only the large, most profitable fields. Since 1993 the rate of PRT has been 50%. Any royalty paid in respect of a field is deducted in computing PRT profits for that field.

PRT differs from corporation tax in that there is no capital/revenue distinction. As such, fields generally do not become PRT paying until ‘payback’ is reached since losses can be carried forwards or backwards indefinitely.

¹⁷ <http://www.og.dti.gov.uk/upstream/taxation/index.htm>

Incomings (positive amounts) for PRT purposes include three main items: the gross profit arising from disposals of oil and gas produced by each participator in each chargeable period (known as equity), tariff receipts (consideration received in return for use of assets by, or provision of services to, participators in other fields) and disposal receipts (consideration received from disposal of certain assets).

As noted above, PRT is a field-based tax and, in general, it is only expenditure incurred on an oil field that can be set against the income from that field. Most expenditure incurred by oil companies working on the UKCS is related to particular oil fields. Other reliefs (oil allowance and safeguard) are also available on an in-field basis, as is tariff receipts allowance. There are also provisions for cross-field reliefs (such as abortive exploration relief and research relief).

The rules allowing field-related expenditure for PRT purposes do not distinguish capital from revenue and almost all expenditure qualifies for 100% relief as it is incurred.

Relief is available for expenditure incurred for one or more of the following field purposes:

- Searching for oil and gas within the field or within 5km of the field boundary as determined by the DTI. This includes all the exploration expenditure that is incurred in finding the field, but not any abortive exploration expenditure incurred more than 5km from what becomes the field boundary;
- Ascertaining the extent or characteristics of the field. Typically this would include pinpointing the location of all the oil and gas within the field and may take place until close to the end of field life;
- Winning oil and gas from the field. This includes the construction of any platform or undersea facilities and most of their day to day running costs;
- Transporting oil and gas to the UK or certain places outside the UK.
- The initial treatment of oil and gas. This includes such things as separating crude oil from gas and liquifying gas for transportation;
- The initial storage of oil and gas up to a maximum of 10 times the daily production from the field;
- Disposing of crude oil and gas sold at arm's length. This covers the cost of selling to third parties;
- Various costs associated with decommissioning the field or with decommissioning assets used for a field purpose.

3.c. Corporation Tax

Corporation Tax (CT), which is charged on the profits of oil and gas companies in much the same way as any other industry. In the case of new fields, this is now the only tax on profits. The main rate of CT is currently, at 30 per cent, one of the lowest company tax rates in the world. Both Royalty and PRT are deductible in computing profits for CT purposes, and profits from upstream oil and gas activities are ring-fenced so that they cannot be reduced for CT purposes by any losses or reliefs arising from any other activity, including downstream oil and gas operations. The basic premise of the ring fence is that corporation tax on profits from oil extraction activities should be paid in full as the profits accrue, undiluted by any losses or any other form of relief arising from any other business activity whether in the UK or elsewhere. The ring fence imposes restrictions to achieve this.

Capital expenditure on oil exploration and extraction activities in the North Sea is relieved under the relevant capital allowances provisions that apply to plant and machinery, long life assets, mineral extraction, industrial buildings and scientific research. Expenditure on the decommissioning of fields which is capital in nature will also normally qualify for relief within the capital allowances code at a rate of 100%. The special 100% capital allowance available for these costs may be carried back against profits for up to three years, in contrast to the usual one year carry back.

4. Interaction

The tax regime which applies to any particular oil field therefore depends on the date on which it received development consent. Current marginal rates of tax vary between 69.4 per cent and 30 per cent depending on the age of the field in question and its taxable position (though it should be noted that many smaller, less profitable fields pay no PRT, even though they are in principle within the PRT net):

- 69.4% if liable to Royalty, PRT and CT (approved before 1 April 1982 and in a PRT-paying position)
- 38.8% if liable to Royalty and CT (approved before 1 April 1982 and shielded from paying PRT by allowances or other reliefs)
- 65.0% if liable to PRT and CT (approved between 1 April 1982 and 15 March 1993 and in a PRT-paying position)
- 30.0% if liable only to CT (approved between 1 April 1982 and 15 March 1993 and shielded from paying PRT by allowances or other reliefs or approved after 15 March 1993)

5. Recent developments

5.a. Royalty

As announced by the Chancellor of the Exchequer in his Budget speech on 17 April 2002, the Government intends, subject to consultation on the appropriate timing, to abolish North Sea Royalty. The DTI has recently published a consultation paper (11 July 2002) which seeks comments from holders of petroleum production licences and others on the appropriate timing of abolition of North Sea Royalty.

The effect of abolition of Royalty on licencees with an interest in a particular field will depend on whether profits from that field are subject to PRT as well as Corporation Tax. It will also depend on the timing of abolition and on the level of oil and gas prices.

In aggregate, the net benefit to licencees from abolition of Royalty in the next year or so would be of the order of £200 million in a full year, though with the benefit rapidly falling to around £100 million a year in line with the expected fall in production from Royalty-paying fields.

The consultation period closes on 4 October 2002.

The UK Offshore Operator's Association (UKOOA), representative body for 30 exploration and production companies in the UK, wants the Government to 'get a move on' and withdraw Royalty immediately as they claim up to £2 billion of new investment in mature oil and gas fields could be delayed. The operator's organisation argue that further investment was seen as crucial to prolonging activity in Britain's oldest offshore fields, now nearing the end of their commercial lives, but which experts believe could hold a further 4 billion barrels of oil equivalent.

5.b. Supplementary levy

Under the changes announced on 17 April 2002 by the Chancellor in his Budget speech, companies producing oil or gas in the UK or on the UKCS will pay a supplementary charge of 10% on profits, in addition to the current 30% Corporation Tax on these ring fence profits. The charge will be calculated on virtually the same basis as ring fence corporation tax, and administered in the same way as corporation tax. Although the profits base for the supplementary charge will in most respects be identical to that for general Corporation Tax, the charge will not allow any deduction for companies' financing costs. This is to prevent companies manipulating their levels of borrowing between ring fence and non-ring fence activities to minimise the impact of the supplementary charge.

The Government is also introducing enhanced first year allowances for capital investment in ring fence trades as an investment incentive. These first year allowances will mean that 100% of most North Sea capital expenditure will be allowable for corporation tax (including the 10% supplementary charge) in the year that the expenditure is incurred.

Both these measures were applied with immediate effect to profits/expenditure arising on or after 17 April 2002.

UKOOA has raised concerns that investment in the UKCS will be hit as a result of the proposed changes to the North Sea fiscal regime. Beverly Mentzer, chair of UKOOA's Fiscal Policy Group argues that¹⁸:

"Taxes are being increased at precisely the wrong time in the North Sea's life. Because of its maturity, high costs and small fields, the UKCS fiscal regime needs to be attractive if companies are to continue to view the North Sea as a good province to invest in."

Figures released by the petroleum economist Professor Alex Kemp of Aberdeen University indicate that the additional tax the industry will have to pay as a result of the supplementary tax will amount to as much as £8 billion by 2010. UKOOA estimate that exploration and production expenditure in the UK could fall by up to 20% over the next eight years as a direct result of the tax changes, putting up to 50,000 jobs at risk¹⁹.

Paymaster General Dawn Primarolo, the most senior minister outside the cabinet, believes that UKOOA has exaggerated the detrimental effects of the supplementary levy. The Government line is that the abolition of Royalty combined with the change to capital allowance relief helps counteract the effect of the supplementary levy and, as such, there should be no effect on investment or on jobs. Perhaps even a positive effect.

The Government line believes that the North Sea tax regime needs to strike the right balance between a fair share of profits for the nation from the exploitation of what is a scarce resource and encouraging investment. Since the abolition of the PRT on future fields in 1993 it was felt there was not the right balance. The measure of 100% first year allowances on capital expenditure plus the commitment to abolish North Sea Royalty, balanced with the supplementary 10% charge, is that right balance²⁰.

¹⁸ <http://www.ukooa.co.uk/media/view-press.cfm/246>

¹⁹ <http://www.ukooa.co.uk/media/view-press.cfm/246>

²⁰ Press and Journal, "Senior Minister Argues the Case for Controversial Oil Tax", David Perry, 26th June 2002

Chapter 5

The Shetland Decommissioning Company: A Golden Opportunity?

1. Introduction

A recent report by the Scottish Enterprise Energy Team confidently announced that *“during the next couple of decades decommissioning of offshore structures is destined to become another major opportunity for Scotland.”*²¹

It is imperative that the United Kingdom does not miss this opportunity given the potential size of the market. It is estimated by Scottish Enterprise that the market size for the entire North Sea is unlikely to be less than £20 billion and could be upwards of £30 billion. This expenditure will be spread over a period of 20 to 30 years and, crucially, will occur on the doorstep of the United Kingdom.

It is within this context that the Shetland Decommissioning Company was formed with the explicit aim of bringing decommissioning business, most notably the onshore dismantling of steel platforms, to Shetland.

2. An Important Distinction

A distinction is to be made between UK-wide and local (or Shetland) issues. The Energy Team of Scottish Enterprise note in their recent decommissioning report (Pg6) that the key driver behind total decommissioning costs (between 60% and 70%) is associated with the offshore heavy lift contractor and currently the heavy lift equipment is owned and operated by Dutch and Italian companies. If the *“status quo remains then Scotland’s slice of the cake for platform removal will be limited to the supply of offshore labour, diving vessels, and onshore disposal”*. It is almost certain that, due to competitive market pressure, a least one ‘new generation’ heavy lift vessel will be commissioned and Scottish Enterprise believe it is critical that such a vessel should be Scottish based:

“We estimate that if one of the new generation vessels could be based in Scotland then the value of steel platform removal work coming to Scotland could amount to £4.5 billion...Without a vessel based in Scotland the value of removal work coming to Scotland may be as low as £1.5 billion”. (Pg6)

²¹ Scottish Enterprise Energy Team, “Offshore Decommissioning: Opportunities for Scottish Based Businesses”, 2002, Pg2

This is a UK-wide issue – the location of a heavy lift vessel (assuming it will not be based in Shetland) will not considerably affect the Shetland decommissioning market. Shetland has to market its own capabilities and qualities which will help it stand out from other competitors. The share of the market (if any) which goes to Shetland will be determined, ultimately, by local factors.

3. Prospects for Shetland

The prospects for the Shetland Decommissioning Company are very positive in a market that can only sustain a handful of decommissioning yards on both sides of the North Sea (most decommissioning work will go to either the UK or Norway). The Energy Team of Scottish Enterprise anticipate:

“That there will be a requirement for about three decommissioning yards in the UK. Able UK, based in Teeside is well established to dominate the Southern North Sea market and the deep water in Shetland along with its proximity to the Northern North Sea fields will give the Shetland Decommissioning Company a distinct advantage over its UK competitors. We believe however that the market could support an additional yard located in Scotland.” (Pg7)

The vast sums of money being discussed in reference to decommissioning and the small number of decommissioning yards envisaged will ensure that each yard will attract a significant amount of business²² which for a small community such as Shetland could prove to be of enormous benefit.

4. Company Information

Shetland Decommissioning Company is currently:

*“A Company, limited by guarantee, established to market and develop the decommissioning and oil related capabilities within Shetland...it is intended that when the decommissioning market develops within the North Sea that the company will be established as a trading organisation to carry out decommissioning projects”.*²³

The organisations participating in the company are:

- The Lerwick Port Authority

²² Assuming business is split approximately equally between all the yards, both in the UK and in Norway.

²³ Shetland Decommissioning Company Limited Company Profile, Murdo MacIver, 2001

- SBS Logistics Ltd
- 60 North Recycling
- Shetland Islands Council
- Shetland Enterprise Ltd

Board of Directors:

Chairman

- Mr Allan Wishart

Directors

- Mr Brian Anderson
- Mr Alistair Cooper
- Mr Keith Fletcher
- Mr David Finch

Staff

- Business Development Manager – Murdo MacIver
- Business Development Assistant – James Johnson

5. What has Shetland to offer?

- Shetland is located close to the East Shetland basin. Shetland is the closest landfall for installations in the Northern North Sea, and tow distances from the Central North Sea are comparable to those to the UK mainland (tow distances are crucial given that a heavy lift vessel can cost up to £500,000 per day).
- Shetland has a skilled workforce with over 30 years experience in the oil and gas industry as a consequence of the presence of the Sullom Voe Oil Terminal, the offshore supply sector and the aviation infrastructure for offshore transfers.
- Sheltered deep water of between 35m and 75m lies off the east coast of the islands within a short distance of the Lerwick Greenhead Base (where SDC is based). This sort of depth is critical for the de-ballasting operations required for the transfer of the deck loads to cargo barges. Such a depth is suitable for using traditional heavy lift crane ships as

well as the new generation single lift vessels under development (which need at least 20m).

- Shetland has a sizeable, international airport located at Sumburgh, approximately 26 miles south of Lerwick. There is a daily roll-on, roll-off ferry service to Aberdeen. Transport links are frequent and usually reliable.
- There are several tugs (with fire-fighting and oil containment capabilities) based permanently in Shetland, designed for berthing tankers at the Sullom Voe jetties. These tugs should suffice for the handling of any decommissioning traffic that may come to Shetland.
- The Greenhead Base has large new concrete quaysides (constructed in 1997/98) that, along with ample laydown and storage areas, make it particularly suitable for the offloading and dismantling of offshore structures.
- Local companies, including those participating in SDC, have established successful track records in providing logistics, scrapping, waste management and drill cuttings disposal services to the North Sea industry²⁴. This expertise can be transferred to the decommissioning of redundant oil and gas installations.

6. Factors Working Against Shetland?

- Competition for other sites such as Nigg Bay and the other big fabrication yards could offer challenges to Shetland's position if they involve themselves in the decommissioning industry and begin to take it seriously. At present these yards would find it hard to compete with their present wage structure and the recent downturn in the oil fabrication industry means that such yards are largely lying dormant. But if these operations re-emerge and re-establish themselves as decommissioning facilities then they will have a clear-cut advantage over Shetland in terms of infrastructure.

The main UK competition is likely to be from Able in Teeside but the question of geographical distance and the sheer size of the potential market will allow room in the market for both Shetland and Able.

- Heavy lift vessels require a draught of at least 20 metres. The depth of Lerwick Harbour, in places, falls to as little as 9 metres.

The Shetland Decommissioning Company does not see this as a problem. Within half a kilometre of the Greenhead base there is deep

²⁴ Local companies have also, over the years, acquired Quality Management Accreditation such as ISO 14000 etc which the industry requires.

water of 50 metres and apart from Aker in Norway no other competitor in the decommissioning market can provide for direct transfers and must instead rely on transfers to a barge.²⁵

- A further issue concerning heavy lift vessels concerns their relative scarcity and the fact that they are not based in Scotland. This is a serious issue for the UK as a whole but does not pose significant problems for Shetland.

The same vessels are used to transfer newly constructed installations from the fabrication yard (often in Scotland) to their zone of production. If the home base of the heavy lift vessels has no impact on the commissioning business then it is apparent there will equally be no problems in the decommissioning side of the industry.

7. Contribution to Local Economy

There is now a general realisation that the onshore dismantling of offshore installations will not create many jobs. Industry estimates suggest approximately 150 to 200 jobs per annum will be required in the UK.

In a recent study as part of the Pilot Task Force²⁶ it was estimated that onshore disposal would provide only 8% of the total decommissioning jobs associated with platform decommissioning.²⁷

These estimates have recently been supported by Aker in Norway who are predicting a requirement for 100 jobs on average and a requirement for two decommissioning yards to serve the Norwegian sector (the Norwegian market is approximately two-thirds the size of the UK market).

The precise number of jobs created in Shetland will depend on the scale and number of projects though the Shetland Decommissioning Company do not envisage the figure exceeding 100 or falling below 50 new jobs per annum. This may appear at first glance to be a rather meagre return but I believe there are three mitigating factors:

- 50 jobs is a welcome boost for a small, rural, isolated economy experiencing a degree of depopulation;
- The created jobs will be well paid, skilled and sustainable;

²⁵ These vessels are not designed and built to pull up alongside the quay given their vast size.

²⁶ <http://www.pilottaskforce.co.uk>

²⁷ Offshore deconstruction will create and sustain the most number of jobs during the decommissioning process – this is an area in which Shetland will not feature strongly and thus will not attract significant employment or financial benefit.

- The benefit to Shetland will accrue not only in terms of direct decommissioning jobs but through the vast sums of money which will be injected into the local economy and through servicing the decommissioning industry.

It is important to bear in mind that the decommissioning industry experiences a 'high cost - no income' constraint in that decommissioning is a costly process that delivers no stream of income. The incentive to complete the project quickly is simply not there. Cost-minimisation rather than project-completion is the main aim. This is in contrast to the construction of oil and gas installations where there is pressure to bring the installation online and into production.

The massive escalation of costs in the decommissioning of Phillips' Maureen platform brings sharply into focus the need to keep costs to a minimum which will preclude simply 'throwing' labour at decommissioning projects.

Crucially, the size of the market (and contribution to the Shetland economy) depends explicitly on the national, regional and international regulations surrounding decommissioning. The escalation of costs associated with recent decommissioning projects may encourage the industry to press for a relaxation of OSPAR regulations (which are the basis for the UK decommissioning process).

The OSPAR Decision 98/3 established by a Ministerial meeting in 1998 produced a new binding framework for the contracting parties, including the UK, of which the primary decision made quite clear that: *"The dumping, and the leaving wholly or partly in place, of disused offshore installations within the maritime area is prohibited."*

Recognition of the difficulties in removing in their entirety the 'footings' of large steel jackets weighing more than 10,000 tonnes and in removing concrete installations ensured that precise provisions were made for a derogation from the main 'general' rule highlighted above.

It is a distinct possibility that OSPAR provisions for derogation will be weakened and this will ensure a greater proportion of offshore installations shall remain in situ rather than be taken ashore for onshore dismantling. Such an eventuality is certain to affect the potential size of the decommissioning market.

8. Timing

An operator who is considering the decommissioning of a redundant oil or gas installation confronts the 'high cost - no income' constraint. As the recent decommissioning report of Scottish Enterprise notes:

“A prime objective of both operator and government is to maximise the production from any field and combined with the financial ‘penalty’ of decommissioning at the end of field life there is every incentive to delay cessation of production for as long as possible. This may be done by introducing cost saving measures in the production and operating processes and could include selling the asset to a lower cost Operator or by utilising new drilling and production technology or by a combination of all of these measures.” (Pg16)

Factors such as the oil price and the tax regime may also influence when production ceases.

A good example of this field life extension is Shell's Auk field which was installed in 1974 with a life expectancy of no more than 7 years – the latest prediction is that it could produce until 2010.

The Shetland Decommissioning Company is well aware of the frustrations associated with continual ‘slippage’ and it believes the earliest opportunity for decommissioning work to come to Shetland is 2006. On the other hand the SDC hope to be involved with engineering, preparation, bidding, pre qualification work, etc in the intervening period.

9. Environmental Impact

As an island community, Shetland is reliant on natural resources and must place a heavy emphasis on environmental protection. Proper safeguards must be in place to ensure the continued viability of agriculture, aquaculture, fishing, tourism, etc.

Fortunately, environmental impact studies suggest that Shetland will suffer minimal environmental degradation from decommissioning. Apart from the visual impact for a month or two of having a large structure in the harbour Shetland will not be burdened by environmental concerns.

With a large-scale decommissioning project it is inevitable that waste will accumulate. The Shetland Decommissioning Company has identified disposal routes for all types of waste that might come out of a structure. Most will be removed from Shetland but it is expected that there will be a requirement for a landfill site to dump remaining waste. Just 3% of a redundant oil or gas structure will be placed in Shetland landfill sites²⁸. As yet no landfill sites in Shetland have been identified.

²⁸ In absolute terms 3% constitutes a significant tonnage for a local community to deal with.

10. Does the Shetland Economy Have the Skills and the Resources?

Shetland is seen as providing a facility and a location but beyond that it is likely, in the early days of the industry at least, that the main contractors will be the large UK and Norwegian engineering firms such as AMEC, Wood Group, and AKER. These firms will subcontract out and involve the wider local community.

The Shetland Decommissioning Company believe there are sufficient skills within the local labour market to service the day to day running of any operation (if this was not the case then the main contractor could bring labour from the UK mainland as has happened frequently in the past with respect to other oil/gas projects – notably, the refitting of the Sullom Voe oil terminal in the summer of 2001 required a sizeable contingent of temporary workers from outside Shetland).

The key role for the main contractor is to bring management skills and financial security to the decommissioning industry whilst Shetland provides the resources for day-to-day operations. Ultimately, it is hoped Shetland can adapt and learn from outside contractors and further down the road Shetland might at some point win contracts on their own ability having acquired the skills and learnt from external parties. In this respect, Shetland will be following a pattern set in the early days of the oil industry in the North Sea – evolving an indigenous, autonomous operation through contact with ‘outsiders’.

11. Between Now and Then?

Projections indicate that the earliest Shetland can expect to witness an offshore installation in Lerwick harbour is 2006, 4 years away. What is the Shetland Decommissioning Company ‘doing’ between now and then?

At present the company has just two employees who aim, over the next few years, to carry out business development and marketing, keep abreast of industry development, keep Shetland in focus in the oil industry and carrying out pre-qualification and bidding.

What kind of support has the SDC received from other groups and bodies? There is little or no local opposition to the plans to bring decommissioning work to Shetland. The Shetland Islands Council has been of great assistance in providing funding and resources for the company to operate in the lean early years of the industry and local companies have been keen to involve themselves in what, potentially, is a lucrative business.

Central Government and, in particular, the Department of Trade and Industry (DTI) have not been as encouraging as hoped. The DTI has formed a dedicated decommissioning unit within its Aberdeen based oil and gas

section but so far has concentrated on approval of decommissioning programmes rather than supporting the infant decommissioning industry in the UK.

The DTI has provided no funding to firms hoping to capitalise on the decommissioning work and, some suggest, have no intention of doing so. So far, all decommissioning work has gone to Norway. Perhaps the lack of political support for the industry is a consequence of a government scarred by its experiences with the Brent Spar.

12. Key Findings and Recommendations

Key Findings:

- The market is potentially very lucrative;
- The share of the market which goes to Shetland will be determined by local factors;
- Shetland is likely to be one of at least two sites in the UK dealing with decommissioning work;
- Shetland has many factors working in its favour, particularly its proximity to the Northern North Sea and deep water capability;
- Decommissioning work will contribute to the local Shetland economy, but in terms of revenue rather than jobs;
- It will be 2006, at the earliest, that decommissioning work can begin in Shetland;
- The environmental impact will be small;
- Shetland will provide the resources for the day-to-day operations whilst the external main contractor will bring management skills and financial security.

Recommendations:

- The Shetland Decommissioning Company should continue to market Shetland as a potential base for decommissioning to the oil industry – Shetland has the resources but it must be considered as a realistic option by the industry;

- Central Government should acknowledge the potential benefits from a decommissioning industry and support that industry;
- All those interested in securing decommissioning work for Shetland should urge the OSPAR contracting parties not to weaken the OSPAR framework.