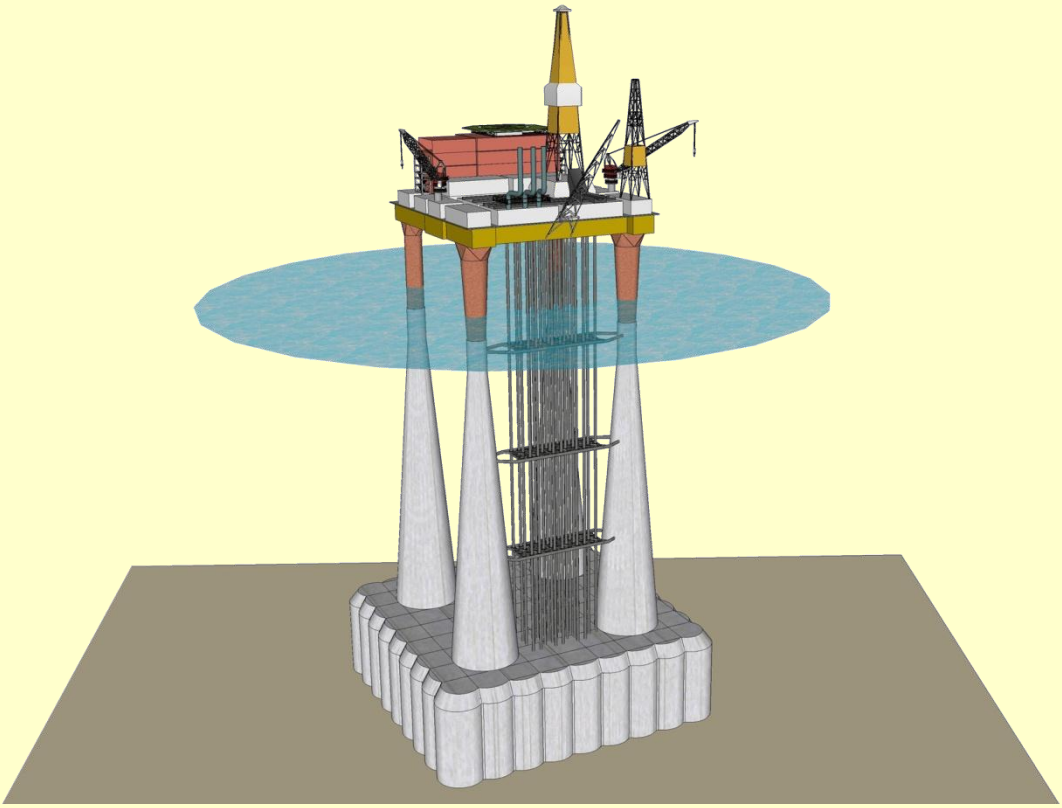
FairfieldEnergy

Dunlin Alpha Decommissioning



Concrete Gravity Base Re-use

Options and Conclusions

First issued May 2010

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Dunlin Alpha Decommissioning

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T.F. Kimber	Dunlin Decommissioning Manager		27 July 2011

Dunlin Alpha Decommissioning

Concrete Gravity Base Re-use

Options and Conclusions

Contents

Appendices

1. Executive summary

This report has been prepared by Fairfield Energy, as operator of the Dunlin Cluster of fields in the UK North Sea, to consider potential re-use options for the Dunlin Alpha concrete gravity base (CGB) structure, should the CGB remain at the current location following cessation of hydrocarbon production from the fields.

The end of the economic life of the Dunlin facilities will be defined by the exhaustion of recoverable hydrocarbon reserves in the Dunlin catchment area, as demonstrated by the operator's application for Cessation of Production and requiring the approval of the UK Secretary of State for Energy and Climate Change. Therefore, any future re-use of the Dunlin CGB would be for a non-hydrocarbon venture.

Re-use assumes the design life of the CGB could be extended, and would require replacement of the current platform topsides to suit any new use. Regardless of the type of new use, at the end of this new use phase the CGB would still remain in place and would require decommissioning at some future date. Re-use at the current location is therefore regarded as a deferment of CGB decommissioning rather than being a final solution.

In this report, Fairfield Energy assesses the potential re-use options, and concludes that at this time no suitable re-use option has been identified for the Dunlin Alpha CGB. It should be noted that, to date, no re-use opportunities have been identified for any previously decommissioned CGB, despite some of these being considered potentially more attractive for re-use than the Dunlin Alpha CGB, given its remote location and termination below sea level.

The possibility of storing carbon dioxide (CO_2) in the Dunlin reservoir as a potential re-use option has been reviewed in detail by an independent consultant. The conclusion is that this is not economically viable due to the limited capacity of the Dunlin reservoir for CO_2 sequestration; the cost of providing a CO_2 pipeline and associated infrastructure; and the inefficiency of using a large, aging, high maintenance platform for the facilities required for sequestration.

Should derogation be granted by the Department of Energy and Climate Change for the CGB to remain at its current location once hydrocarbon production has ceased, the CGB will be made available to qualified prospective sponsors for the pursuit of re-use opportunities.

2. Introduction

The Dunlin Cluster of fields is located in the UK North Sea, some 500km north-northeast of Aberdeen, and is operated by Fairfield Energy Limited on behalf of itself and MCX, a subsidiary of Mitsubishi Corporation. Details of the fields and the facilities are given in Appendix A.

The Dunlin Alpha platform, known as Dunlin A, came into operation in 1978 and acts as the production hub for the fields. Dunlin A (shown below) is a concrete gravity base (CGB) structure, supporting a steel topsides deck and production facilities.

Once an offshore installation has reached the economic end of its life as a production facility, it is required to be decommissioned. The UK has a comprehensive regime controlling the decommissioning of offshore oil and gas installations, which favours re-use, recycling or final disposal on land of offshore facilities.

As a reasonable and prudent operator, Fairfield Energy is engaged in determining and evaluating its decommissioning commitments. For the Dunlin field, the decommissioning of the Dunlin A CGB is the most significant area of decommissioning activity. For reference, Appendix B describes the seven options being considered for decommissioning the CGB. Six of these options were presented to stakeholders on 21 January 2010 in Aberdeen, as part of a public consultation process; a seventh option was added in July 2011.

This report focuses on one of those seven options, namely the potential re-use of the Dunlin A CGB, should it remain at the current location following cessation of production.

Separate reports address the other decommissioning options. One of these is a technical report on the possibility of refloating the CGB prior to taking it to another location. That report (Ref.1) concludes that the CGB cannot be

refloated due to technical challenges and associated risks, hence re-use of the Dunlin CGB at another location is not considered in this re-use report.

Appendix C of this report presents the findings of an independent study, conducted by Genesis Oil & Gas, into the possibility of storing carbon dioxide (CO_2) in the Dunlin reservoir as a potential re-use option.

Appendix D presents a sample announcement for the Official Journal of the European Union, for announcing the sale of the CGB for potential re-use as a non-hydrocarbon production facility.

Appendix E presents a summary of Liabilities under the Petroleum Act 1998. Fairfield Energy believes that re-use opportunities for the CGB at the current location are more likely to be identified if the future of the CGB is agreed as soon as possible, under the provisions of the OSPAR Convention (Ref 2). This will reduce the uncertainties concerning the level of ongoing liabilities associated with the CGB for current and former owners, as defined by the Petroleum Act 1998 and the amendments in the Energy Act 2008. An early agreement will help to define an appropriate level of security to cover any ongoing residual liabilities, and will assist a sponsor of any proposed CGB re-use activity to lodge the required security from the date of the CGB title transfer.

3. Re-use options

3.1 Introduction

Many possibilities have been suggested for the re-use of decommissioned offshore oil and gas platforms. Included among the possibilities are:

- Centres for wind or wave power generation
- Scientific research centres, notably for marine research
- International electrical power distribution hubs
- Communication and navigation centres
- Meteorology stations
- Diver training centres
- Artificial reefs
- Fish farms
- Prisons
- Casinos

This is not an exhaustive list and other possibilities are thought to have been proposed. However, it should be noted that the remote location of Dunlin A and the unique truncation of the CGB concrete legs below sea level, would present significant challenges to establishing a commercially viable re-use enterprise based on the CGB

Given this wide diversity of possible opportunities, Fairfield Energy, a small independent oil and gas company established in 2005, does not have the resources or core skills to seek out viable re-use options for the Dunlin A CGB. It is the company's intention, therefore, to announce online the availability of the CGB for re-use in the Official Journal of the European Union (see http://www.ojec.com/WhatIsTheOJEC.aspx).

It would be a requirement that any interested re-use sponsor must demonstrate financial strength and technical competence. Following this, technical and commercial information would be provided by Fairfield Energy to allow the sponsor to develop a business case and environmental statement for re-use of the CGB, having regard for the residual liability security discussed above.

A sample announcement for this purpose, which would appear in the Official Journal of the European Union, is shown in Appendix D.

3.2 Carbon dioxide sequestration

A more recent suggestion for re-use of redundant offshore installations relates to the possibility of storing CO_2 in hydrocarbon reservoirs which are no longer in production, referred to as CO_2 sequestration. Sometimes associated with CO_2 sequestration is the possibility of simultaneously enhancing oil recovery, although this would not be classed as a re-use option for Dunlin. A technical study of these possibilities for the Dunlin A CGB was commissioned by Fairfield Energy (Ref.3). The findings of this study are described in Appendix C.

3.3 Precedents

To date, there is no known example of an offshore installation, following its decommissioning, being re-used at its location for another purpose. While equipment and components of some installations have found re-use opportunities elsewhere, re-use of a complete topsides or substructure has not occurred, principally due to the technical complexity of moving a platform or converting it to another use, and the associated costs.

Of relevance to the possible re-use of the Dunlin A CGB are three CGB platforms (TCP2, CDP1 and TP1), formerly operated by Total in the Frigg field, which straddled the UK-Norway median line in the North Sea. These structures were decommissioned under the Frigg Field Cessation Plan during the period 2005 to 2009. While the topsides of each of the platforms was removed and brought ashore for recycling and disposal, the CGBs remain in place, having been granted derogation under OSPAR Decision 98/3. Operator Total investigated possible re-use options for the CGBs but concluded that there were no technically feasible and economically viable arrangements for doing so. Re-use relating to the Frigg structures can be read in Section 7 of the Frigg Field Cessation plan (Ref. 4) which can be viewed at:

http://www.total.no/en/Resources/Scripts/GetResource.ashx?resource=10179f0a-a0ca-433e-873e-0965065940a3

A fourth CGB platform, MCP-01, also operated by Total in the UK sector and which acted as a compression platform for gas from the Frigg field, was also decommissioned in this way. It should be noted that the MCP-01 CGB is located closer to shore than Dunlin A (173km) and in shallower water (94m), and its CGB extends above sea level. In theory these characteristics should make it a more attractive proposition for possible re-use that those pertaining at the Dunlin A CGB, but despite this no re-use opportunity has been identified for the MCP-01 CGB.

Decommissioning of platforms in the Ekofisk field offshore Norway, operated by ConocoPhillips, sets another precedent. Under the Ekofisk 1 Cessation plan, initiated in 1994, fourteen steel platforms will be removed from the field over the period 2005 to 2013. However, the Ekofisk concrete storage tank, which weighs 1.2 million tonnes, will remain in place having been granted derogation under the OSPAR rules governing decommissioning.

4. Conclusions

At the time of writing this report, no technically feasible or economically viable re-use has been identified for the Dunlin A CGB. To date, no decommissioned CGB structure has been re-used for business or research activity. Fairfield Energy believes that among the CGBs decommissioned thus far, there are potentially more attractive re-use opportunities than those presented by Dunlin A, but no re-use plans have been identified for these structures

With reference to the findings of the technical study described in Appendix C, the concept of attempting to implement a CO_2 sequestration project or CO_2 enhanced oil recovery project at Dunlin A would be commercially unrealistic and technically challenging. It is also clear that a source of CO_2 is not available at the Dunlin location and Fairfield Energy is unaware of any schemes designed to transport significant volumes of CO_2 into the Dunlin area. Therefore, no further consideration will be given to CO_2 sequestration or enhanced oil recovery re-use options for Dunlin A.

Assuming that derogation will be granted for the Dunlin A CGB to be left in place in accordance with OPSAR Decision 98/3, the level of uncertainty relating to residual financial liability will be more readily defined. In turn, this will enhance the potential for identifying viable re-use options for the CGB. Fairfield Energy will ensure that any re-use opportunities proposed by qualified sponsors can be assessed by those sponsors against relevant technical and commercial data provided by Fairfield, as described in Appendix D. This would allow Fairfield and a potential re-use sponsor to enter into early negotiations about commercial terms, a potential CGB title transfer date and practical transition arrangements.

In order to facilitate this possible course of action, Fairfield will continue to investigate the wider decommissioning options for the Dunlin A CGB as summarised in Appendix B, and if found to be appropriate, the company will submit a Derogation Application to the UK Department of Energy and Climate Change during the fourth quarter of 2010 for consideration by OSPAR. Should derogation be granted, Fairfield will issue announcements for the Dunlin A CGB re-use opportunity during 2011/12.

5. References

1. Fairfield Energy. Dunlin CGB Refloat Report, July 2010.
2. OSPAR Decision 98/3. OSPAR Convention for the Protection of the Marine Environment of the North-East Atlantic. OSPAR Decision 98/3 on the Disposal of Disused Offshore Installations.
3. Genesis Oil and Gas Consultants Ltd. CO_2 Opportunities for Dunlin Alpha, April 2010.
4. Frigg Field Cessation Plan. Total E&P Norge AS, 9 May 2003 (http://www.total.no/en/Resources/Scripts/GetResource.ashx?resource=10179f0a-a0ca-433e-873e-0965065940a3
5. Ekofisk 1 Cessation. ConocoPhillips Norge, 1994

Appendix A

Dunlin field and surrounding area

Appendix A

Dunlin field and surrounding area

Contents

A.1 Dunlin Cluster

The Dunlin Cluster of fields is located in the UK sector of the North Sea, and is operated by Fairfield Betula Limited (FBL) and Fairfield Fagus Ltd (FFL), both of which are wholly owned subsidiaries of Fairfield Energy Ltd. The licence interests in the Dunlin Cluster are collectively owned by FBL and FFL (70%) and MCX Limited (30%), a wholly owned subsidiary of Mitsubishi Corporation.

The Dunlin Cluster of fields is located in Blocks 211/23 and 211/24 of the UK Continental Shelf, some 500km north-northeast of Aberdeen within the East Shetland Basin, and 11.2km from the boundary line with Norway. (Figure A.1a).

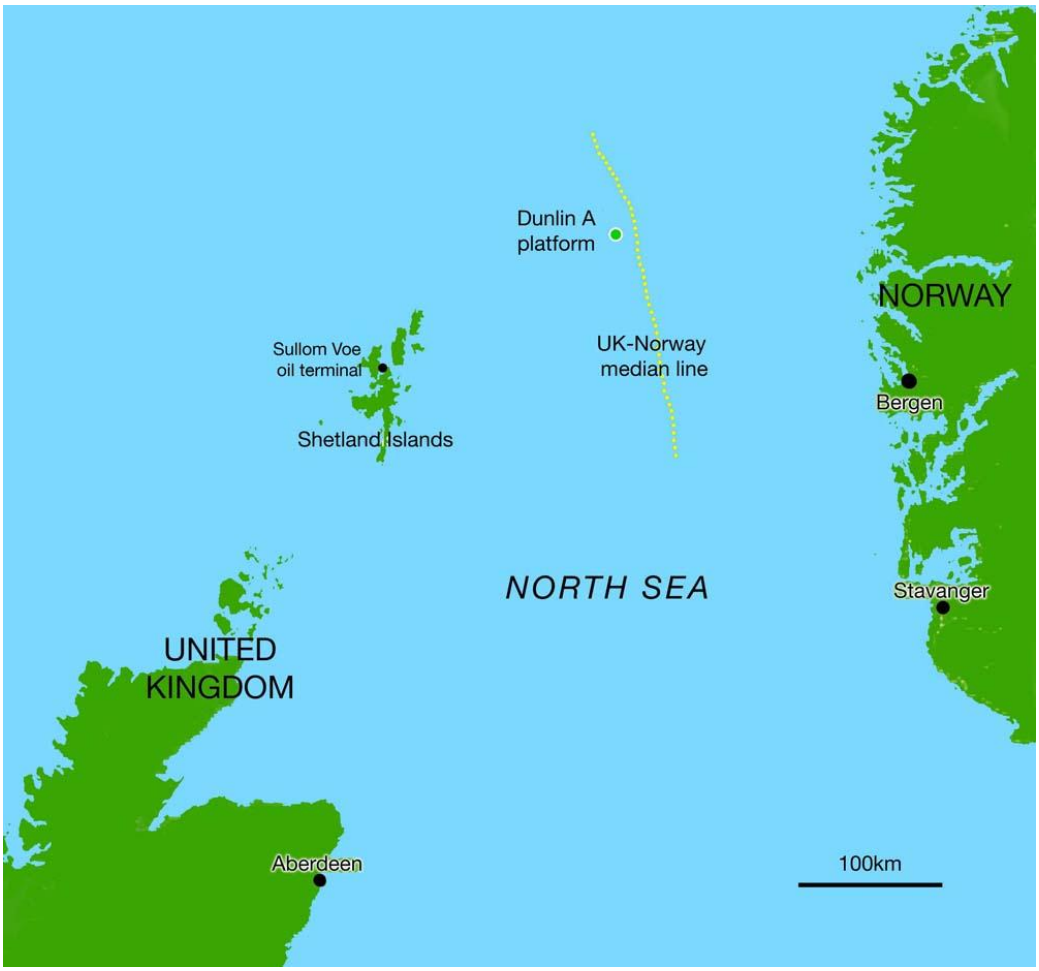

Figure A.1a Dunlin field location map

The Dunlin Cluster comprises the Dunlin, Dunlin South West (operated by FBL), Osprey and Merlin fields (operated by FFL). The Dunlin Alpha platform, normally referred to as Dunlin A, stands on the seabed above the Dunlin field. The Dunlin A platform is a fixed installation, serving as a production facility for the Dunlin, Dunlin South West, Osprey and Merlin fields. Oil production from the fields is exported from Dunlin A via pipeline to the Cormorant A platform, and from there by pipeline to the Sullom Voe oil terminal in the Shetland Islands.

The main Dunlin hydrocarbon reservoir is reached from wells located on the Dunlin A platform. Dunlin South West is a separate hydrocarbons accumulation, also reached by wells from the Dunlin A platform.

The Merlin and Osprey fields are separate reservoirs, accessed by subsea wells located on the seabed. These fields are 'tied back' to the Dunlin A platform by a set of seabed pipelines and control lines.

Dunlin A also acts as a pumping station for crude oil imports from the Thistle and Murchison fields, which, after being combined with production from the Dunlin Cluster, are also exported via the Dunlin/Cormorant export pipeline.

The nearest manned installation to the Dunlin facility is the Thistle A platform, approximately 12km to the north.

The general arrangement of the Dunlin Cluster facilities and pipelines is shown in Figure A.1b.

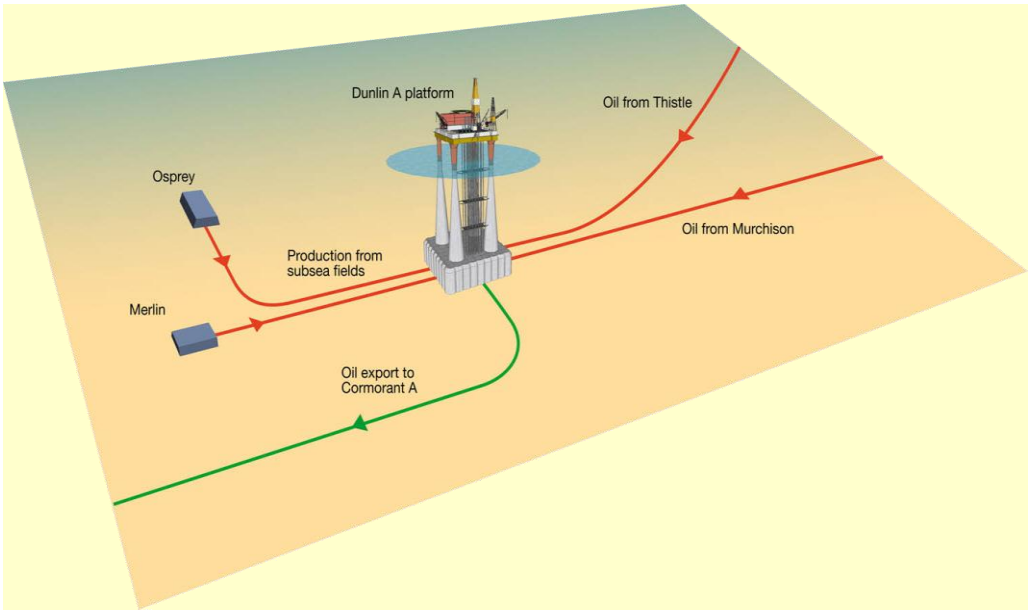

Figure A.1b Dunlin, Osprey and Merlin facilities

The Dunlin A platform was installed in 1977 and production started in 1978. Production began from Osprey in 1991 and from Merlin in 1997.

The Dunlin A platform, located in 151m of water, consists of a four-legged concrete gravity base (CGB) substructure with topsides supported by a steel box girder frame, as shown in Figure A.1c.

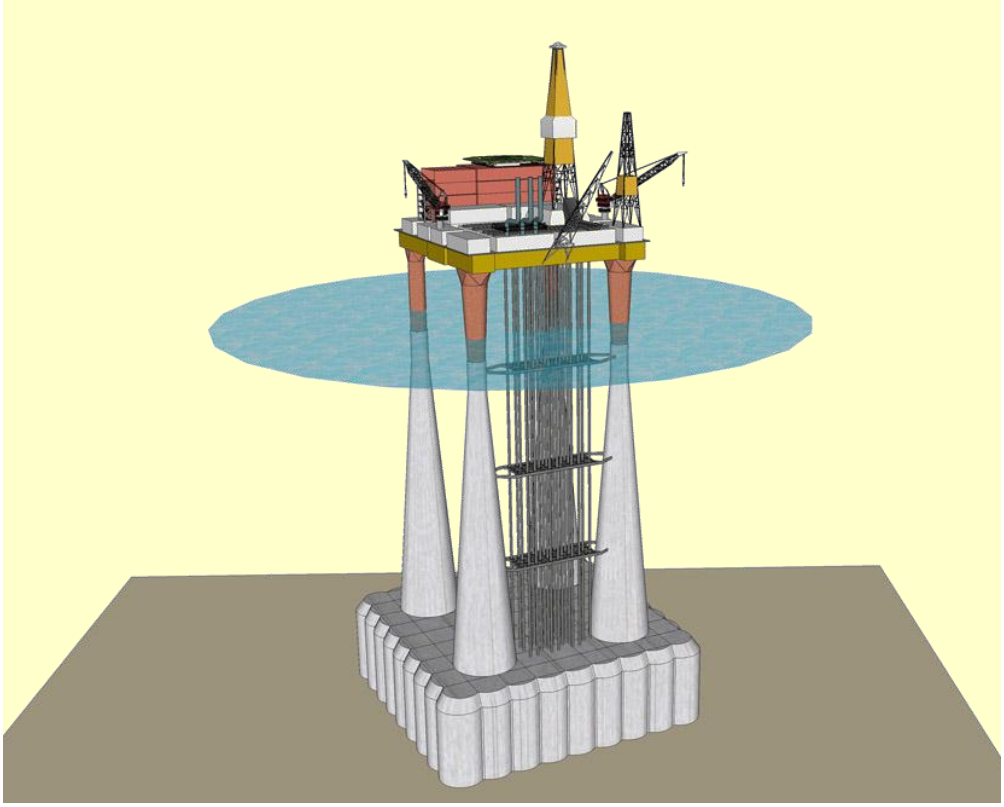

Figure A.1c Dunlin A platform

The installation was designed to:

- Serve as a production facility for the Dunlin, Osprey and Merlin fields.
- Serve as a drilling facility for the Dunlin fields.
- Provide separation of oil and water within the CGB.
- Accept oil imported from Thistle A and Murchison A, prior to onward transmission to Cormorant A via pipeline.

The Dunlin A CGB design basis was developed to satisfy several competing criteria, namely:

- Location of the construction yard in shallow water in The Netherlands.
- Provision of sufficient self-buoyancy for the towed voyage to the field.
- Seabed and environmental conditions at the field.
- Topsides load to be supported.

Two separate 16 inch diameter pipelines import oil from Murchison A and Thistle A to Dunlin A, while a 24 inch diameter oil export line runs from Dunlin A to Cormorant A. Additionally, two 8 inch diameter subsea pipelines associated with the Merlin and Osprey developments are routed to Dunlin A.

The Osprey field facilities consist of two subsea drilling templates and a subsea manifold located some 7km north of Dunlin A in water depths ranging from 155m to 165m.

The Merlin field facilities consist of three subsea production wells and a water injection well, located 7km west of Dunlin A in water depths ranging from 155m to 165m.

A 23km long, 119mm diameter electric power cable runs in a trench from the Brent C platform to Dunlin A to supply the latter with part of its power requirements.

A detailed description of the Dunlin A platform is given in Section A.4.

A.2 Environmental aspects

This section presents a summary of the general environmental conditions around the Dunlin A platform.

To evaluate any likely impact of the options considered for the decommissioning process, the present day environmental conditions need to be understood. The current environmental status reflects historical operational and disposal practices of the offshore and marine industries. Over time, the results of these activities have been modified by the effects of wind, wave and tidal currents, both on the seabed and in the water column.

The meteorological conditions of the region are characterised by rapidly changing weather conditions. Wind direction is commonly from the south and southwest throughout the year, but north and northeast winds can dominate between May and August.

The significant wave height ranges from 8.7m (monthly) to 11.4m (annually) with the maximum 100-year significant wave height estimated to be 15.6m.

The water current patterns in the area are complex, with strong non-tidal currents interacting with relatively weak tidal flows. Water currents in the area predominantly flow from the northeast to southwest although this is less apparent at greater water depths where current velocities decrease.

The seabed surface around Dunlin A consists of fine to gravelly sands with some shell debris. The surface is characterised by a number of natural and man-made features including minor depressions, cobbles and small boulders, extensive anchor scarring, rock dumps, and items of debris.

A drill cuttings accumulation covers part of the Dunlin A CGB structure and adjacent seabed. The cuttings were generated from the start of drilling activities in 1978.

Any potential effects of the Dunlin Cluster development on the biological environment are expected to be localised and confined to organisms that live in or on the seabed and, to a lesser extent, in the water column. The marine life includes:

- Plankton - The plankton community around the Dunlin area is typical of that found in the northern North Sea
- Seabed communities - The seabed surface around Dunlin A platform supports a diverse range of animal communities, with no clear dominant species. Bristle worms (polychaetes) make up the majority of recorded species.
- Coral - *Lophelia pertusa* is a coral which develops on hard surfaces in cold, dark, nutrient-rich waters between 100m to 400m deep. It has been observed on parts of the CGB. This species is important as it is protected under the European Habitats Directive 1992, Annex II.

- Fish - Fish catch statistics, compiled by the Marine and Fisheries Agency, show that the area around the Dunlin A platform is dominated by the open water (pelagic) species Atlantic mackerel and the near seabed (demersal) species Atlantic haddock and Atlantic cod. Catches also include whiting, saithe, pollack, plaice, turbot, halibut, lemon sole, megrim and the Norway lobster.
- Sea birds - A number of the bird species likely to be present in the Dunlin area are protected. Species observed include fulmars, guillemots, gannets, kittiwakes, puffins and razorbills.
- Marine mammals - Marine mammals observed in the waters surrounding the Dunlin A platform include whales, dolphins and seals. A number of these mammals are protected under the Habitats Directive, Annex II. The minke whale, killer whale and pilot whale have been sighted in the vicinity of the Dunlin platform on a more regular basis than other cetacean species.

A.3 Socio-economic aspects

The Dunlin A platform stands in open seas with the nearest surface structures being the Thistle, Murchison, Cormorant and Brent platforms. Shipping activity in the area is of low density, primarily related to vessels passing between Aberdeen and offshore facilities in the northern North Sea. Fishing vessels are also likely to be present in this area.

A.4 Dunlin Alpha platform

A.4.1 Introduction

Design and construction of the Dunlin A CGB structure was carried out by the Anglo Dutch Offshore Concrete (ANDOC) contractors' consortium in The Netherlands during the 1970s. The Dunlin A platform was installed in 1977 and, after the drilling of initial wells, oil production began in 1978.

The platform base is 104m square and the platform is over 200m high from the seabed to the top of the drilling derrick. The CGB weighs approximately 320,000 tonnes, including internal equipment and solid ballast in the CGB base, while the topsides weighs a further 20,000 tonnes.

To give an appreciation of scale, Figure A.4.1a shows a graphic representation of the platform in comparison with the Big Ben clock tower in London, which is 96m high.

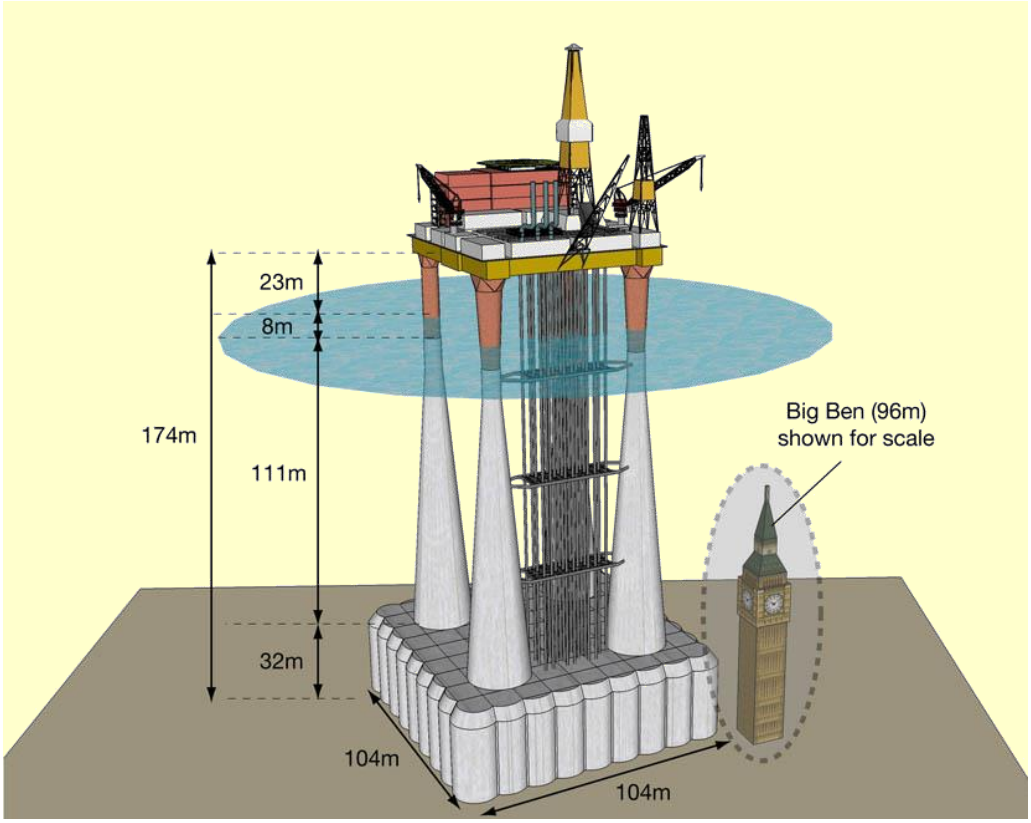

Figure A.4.1a Dunlin A compared with Big Ben for scale

Figure A.4.1b below shows the main components of the platform.

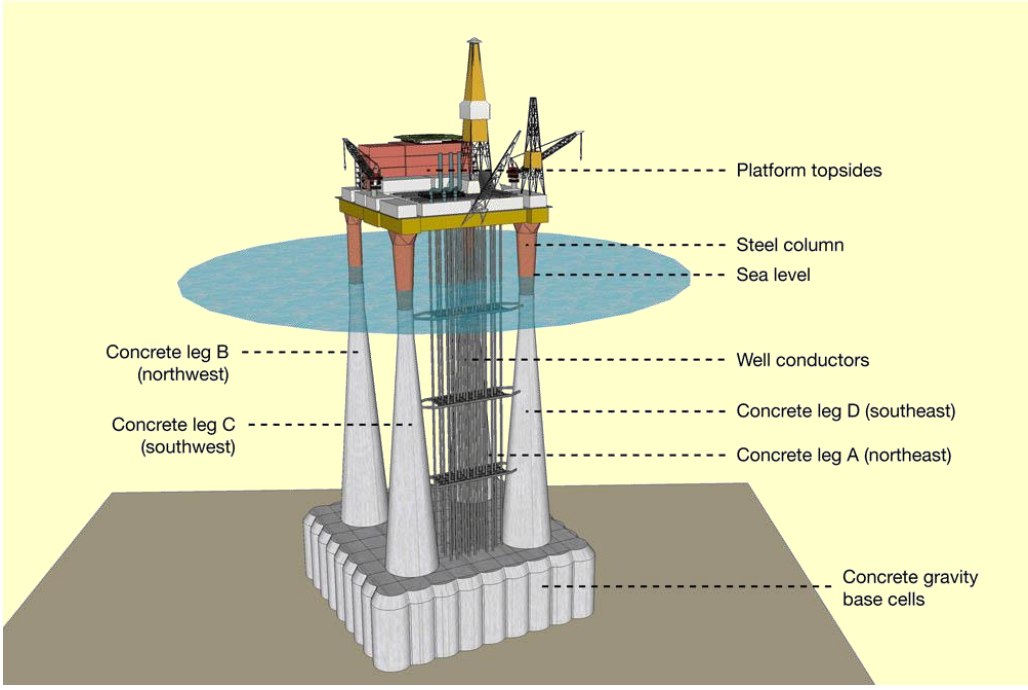

Figure A.4.1b Dunlin A platform main components

The platform was designed as a drilling and production installation. The 20,000 tonnes topsides includes the following facilities:

- Drilling
- Oil and gas processing and metering
- Produced water treatment and water reinjection
- Power generation, utility and safety systems
- Oil export pumping
- Personnel accommodation for 129 people
- Helideck

The platform was designed to accommodate 48 wells. Well fluids pass from the subsurface reservoir to the topsides within steel pipes, one per well, referred to as well conductors. The conductors are held in three steel guide frames located between platform Legs C and D.

A.4.2 Concrete gravity base structure

The CGB extends from the seabed to 8m below sea level where the tops of the concrete legs are joined to the steel superstructure. The CGB, including internal equipment and solid ballast in the base, weighs approximately 320,000 tonnes.

The base of the CGB, which is 32m high, is divided into 81 compartments, referred to as cells, arranged in a 9 x 9 matrix as shown in Figure 4.2a.

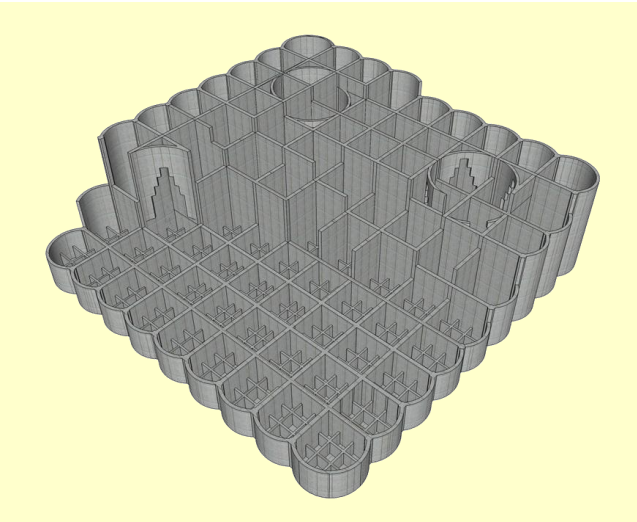

Figure 4.2a Cells in the CGB (cutaway view)

Of the 81 cells, the original purpose of 75 of these was to provide additional separation of oil and water prior to oil export. The remaining six cells, located between Legs C and D, were not used for oil and water separation and are filled with seawater. The 48 well conductors pass through the six cells, each conductor being protected by an outer carbon steel sleeve throughout the height of the cells. The six cells were designed to allow seawater to be pumped around them to cool the conductors.

Each cell is 11m square. Inside the bottom of each cell, secondary 4m-high concrete walls reinforce the base and sub-divide the bottom of each cell into nine open-topped compartments. All open-topped compartments in all of the cells were filled with ballast prior to the closure of the cells with convex concrete roofs.

A stiffened steel plate wall runs around the perimeter of the base to form a skirt, and penetrates the seabed to a depth of 4m. Two further steel walls run underneath the base slab of the CGB in each direction, creating nine sub-base compartments. See Figure 4.2b below.

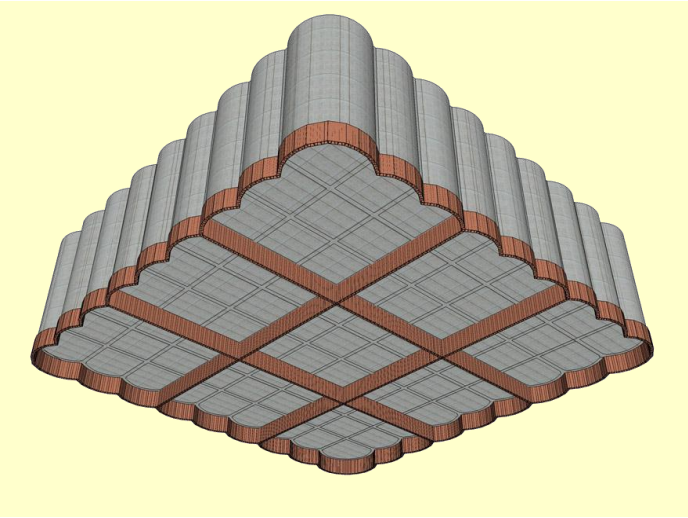

Figure 4.2b Steel skirt and walls

Rising up from the roof of the base cells are four concrete legs, each 111m high. These reduce in outside diameter from 22.6m at the bottom to 6.6m at the top, where they join the steel superstructure at 8m below sea level. The legs are designed as hollow shafts, with concrete walls generally being 700mm thick but increasing to 1200mm at the top and the bottom. Each of the concrete legs weighs approximately 7600 tonnes.

Four steel columns constructed from stiffened steel plate extend 31m from the top of the concrete legs, rising beyond the sea surface to the underside of the topsides deck. These columns are bolted and grouted into the top of the concrete legs. The steel columns C and D weigh some 500 tonnes each and taper from approximately 6m diameter at the top of the concrete legs to approximately 8.7m square at the underside of the deck. The other two columns (Legs A and B) weigh approximately 300 tonnes each and are 5.4m diameter changing to a square section at the deck underside. See Figure 4.2c below.

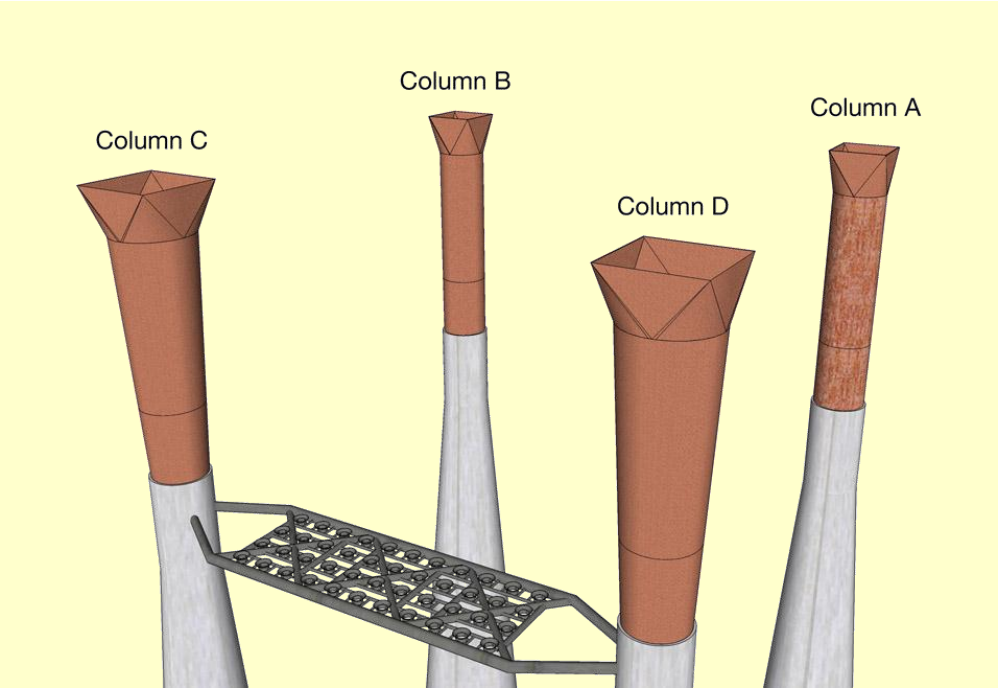

Figure 4.2c Steel columns at the tops of the concrete legs

Equipment and pipework are distributed within the legs, in different combinations. Access stairways, lift shafts, platforms and service openings extend from the top of the legs down to the base of the structure.

Spanning between Legs C and D are three horizontal guide frames which hold the well conductors in a 12 x 4 matrix. The function of these frames is to provide horizontal support to the well conductors against wave action forces. Each of the three frames weighs approximately 200 tonnes.

The deck structure above the steel columns consists of a lattice of steel box girders approximately 85m by 67m in plan. The lattice is 6m deep and is equipped with a deck at top and bottom to support equipment. The deck structure also supports a number of modules which contain drilling facilities, production and utilities equipment and accommodation units.

A.4.3 Platform lifecycle

A.4.3.1 Platform construction and installation

The Dunlin A CGB base slab and cell walls were constructed in a purpose-excavated dock in The Netherlands using conventional civil engineering construction methods for casting concrete walls. After the cell walls were completed, the dock was flooded and the structure was floated into deeper water. The cell roofs were then completed using pre-cast concrete shaped sections to support the cell roof concrete while it dried.

The concrete legs were then constructed using a slip-form method. In this type of construction wet concrete is poured continuously into moulds. The moulds are continuously moved slowly upwards, using jacks, while the concrete at the bottom of the mould sets.

Pipework, pumps, manifolds and access steelwork, required for the installation and operation of the platform, were installed at their design locations during the construction programme.

With the base cells and legs completed the platform was towed approximately 850km to a Norwegian deepwater fjord. Solid granular ballast was added in the base of the cells up to the level of the 4m-high secondary walls within the cells.

By controlled introduction of seawater into the base cells, the structure was submerged to a draught where the water level was near the top of the legs. The steel columns were lifted on to the top of the legs using floating crane vessels and bolted into position.

The deck structure was fabricated in sections in The Netherlands. These were assembled into a single structure on supports over water. Following this, production equipment and other facilities were installed on the deck. A transportation barge was floated between the supports. By deballasting the barge it rose in the water to pick up the deck structure.

The barge was then towed to the Norwegian fjord, with the deck structure onboard. Here, with the CGB submerged to allow the deck to be floated over the legs, the deck was installed on top of the CGB steel columns by a process which reversed that for loading it onto the transportation barge. By carefully deballasting the submerged structure and ballasting the transportation barge simultaneously the deck load was transferred to the CGB.

At this stage, additional topsides modules were installed on the deck using floating cranes before the platform was further deballasted to its towing draught. The platform was subsequently towed a distance of 400km by seven ocean-going tugs to the Dunlin field location in the North Sea.

Once on location the platform was positioned accurately and more seawater was added to the cell bases under careful control, until the platform touched the seabed. The final flooding of the cells caused the steel skirts around the base to penetrate fully into the seabed. Any water trapped within the underbase compartments formed by the steel skirts escaped through preinstalled vent lines in the base.

Platform installation was completed by pumping cement grout, through preinstalled grout lines, under the base to fill any spaces present between the base slab and the seabed. The grout displaced any trapped seawater via the vent lines. Following the completion of the grouting operations the grout lines and vent lines were left grout-filled.

Once installation of the platform was complete, the drilling module was installed on the topsides and drilling of the wells began.

A.4.3.2 Concrete gravity base operational history

The Dunlin A CGB was installed during late summer of 1977. Following completion of the initial drilling phase, crude oil production started in 1978.

For the early period of Dunlin operation (1978-1995), fluids from Dunlin's production wells were first passed through separation vessels on the topsides to separate gas from liquids. The liquids (oil and produced water) were then piped through Leg B of the CGB to those cells in the base of the CGB designated for oil and water separation

In the base of the CGB, the 75 oil and water separation cells are configured as four separate groups, A-D, as shown in Figure A.4.3a below. The cell groups provided gravity separation of oil and water, and were operated in a sequence, as follows:

- One cell group was used as a receiving volume taking fluids from the final stage of topsides separation.
- Two cells groups were used for further oil and water separation.
- The fourth cell group, where separation had progressed furthest, acted as the source of dry export quality oil, which was pumped to the topsides for fiscal metering and export.

By means of pipework and valves, these operations could be cycled around the cell groups in turn.

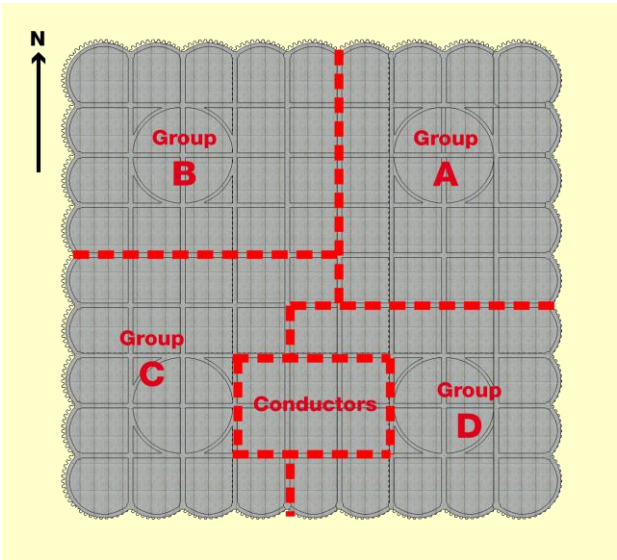

Figure A.4.3a Cells arranged in five groups

As the oil and produced water entered the CGB cells, displaced export oil was returned to the topsides and pumped into the oil export pipeline.

While the oil was contained in the upper part of the four cell groups as four separate oil volumes, the produced water below the oil was in effect one large single volume. This was achieved by interconnecting ports in the walls of the cells at low levels to allow water to move between the four groups. The water

could be pumped from the base of the cells and was returned to the topsides for treatment to meet licensed quality standards prior to discharge to the sea.

The cells have a large volume, designed to give the CGB the necessary self-buoyancy during the towing phases. As a result, the cells provided long liquid retention times for the production fluids when the cells were used for oil and water separation. The long retention times produced a very quiescent flow environment, allowing very effective oil and water separation to occur. Combined with the fact that oil volume in the cells was minimised for commercial reasons, the resultant oil volume in the tanks was relatively low compared to water volume.

A fifth group of six cells between Legs C & D surrounds the platform's 48 production well conductors. This group was not used for oil and water separation. Pumped seawater continuously circulates through this conductor cell group to remove heat arising from the well conductors. Control of the temperature gradient between the conductor cell group, the surrounding cells and the sea is necessary to maintain the structural integrity of the CGB.

This method of operation continued until the Dunlin A topsides separation facilities were modified after 1995 to allow three-phase separation of oil, gas and water on the topsides, thereby eliminating the need to use the CGB cells on a routine basis for oil and water separation. From then on, the cells generally remained water-filled. There were occasional exceptions to this when the cells were used occasionally to hold produced fluids during platform startup to allow the topsides production system to warm up sufficiently to meet oil export specification. This would occur some four to six times a year for a duration of about eight hours. On other occasion, the cells were used to receive and separate oil from process vessel flush water prior to periodic platform maintenance shutdowns; or as security should the Cormorant A receiving systems shut down temporarily and close the export pipeline path from Dunlin.

The commissioning of the Osprey and Merlin fields occurred in 1991 and 1997 respectively. During this period the CGB cells were occasionally used if the circumstances outlined above required this. Fluids produced during startup of Osprey and Merlin were routed to the CGB cells until such time that their arrival temperature had risen sufficiently to allow effective oil and water separation, and to achieve statutory discharge standards.

Following such events, fluids diverted to the cells were subsequently returned to the topsides and passed through the process system during stable operating conditions. Although the CGB cells were not in routine use, the cells contained some residual oil trapped at the tops of the cells (known as 'attic oil').

From the late 1990s, failures in pipework installed in Legs A and B of Dunlin A, together with minor leaks through the concrete floors of the legs, began to occur. Where pipework was not encapsulated in concrete and where appropriate isolation could be achieved, pipework repairs were undertaken.

In 1999 attic oil leaked from the cells below Leg A through the concrete into the leg. The leak probably followed the path of a redundant vent line, and a significant volume of oil and liberated gas was released into Leg A. The leak into Leg A required the leg to be flooded with seawater, in accordance with the Dunlin A Concrete Structure Emergency Procedures Manual, to reduce the differential pressure and oil ingress rate across the leak path. The leak stopped and oil contained within Leg A was subsequently recovered through the process system. Attempts were made in 2003 to seal the leak path to enable Leg A to be pumped dry prior to effecting permanent repairs. However, the leak could

only be controlled by maintaining seawater in Leg A at a level about 70m above seabed. This continues to prevent access for permanent repairs.

In 2004 attic oil leaked into Leg B as a result of pipework failure due to corrosion in a section of an oil pipeline running between the topsides and the cells (known as a 'rundown line'). As with Leg A, the contained volume of oil was subsequently recovered, but in this case it was possible to repair the pipework.

In order to remove the potential for further oil and gas ingress, a project for the removal of attic oil, and the permanent decommissioning of the CGB cells and associated rundown and oil export lines, was successfully undertaken in 2006/7 by the platform's then operator, Shell. This effectively isolated the CGB cells from the process system, making any occasional use of the cells, as described above, impossible.

However, the partial flooding of Leg A to 70m above the seabed level continues to be maintained to prevent ingress of liquids from the CGB cells into Leg A.

In accordance with the Dunlin A Concrete Structure Emergency Procedures Manual, if further flooding of Leg A occurs, Legs B, C and D must also be flooded to avoid the generation of tensile loads which could have the potential to cause cracking in the roofs of the cells beneath the other legs.

It is possible Legs B, C and D may also experience water ingress over time.

A.4.3.3 Drilling history

Following the drilling of nine exploration and appraisal wells in the Dunlin field prior to platform installation, the first platform development wells were drilled soon after the Dunlin A platform was installed in 1977. In all, the Dunlin A platform has 48 well slots. A number of wells have been re-drilled to access other parts of the reservoir.

The drilling programme has resulted in a total well stock of 34 production and 10 water injection wells, plus one drill cuttings reinjection well (now out of use).

The Dunlin South West hydrocarbon accumulation was developed with an extended reach well drilled from the Dunlin A platform in 1996. In 1998 a second producing well was drilled into Dunlin South West.

In 1997 an unsuccessful (dry) well was drilled in an attempt to appraise and possibly develop the untested Dunlin North West prospect. The well was subsequently plugged.

A.4.3.4 Drill cuttings

As a well is drilled, the rotating cutting tool (the drill bit) must be cooled because this generates significant heat when grinding into the rock. In addition, the resulting rock chips, or 'cuttings', must be removed from the well. Furthermore, as the well gets deeper it is necessary to have sufficient hydraulic pressure at the drill bit in order to overcome any gas pockets or oil pressure encountered as the drilling proceeds to its target depth.

All of these requirements are met by using a drilling fluid, circulating from the topsides drilling rig into the well and returning to the surface, carrying the drill cuttings with it. The fluid is known as drilling mud, a heavier-than-water mixture of oils, synthetic polymers, water and natural clays which are mixed in various proportions to suit the well conditions during the drilling phase.

At the drilling rig on the topsides, the drilling mud is separated from the rock cuttings and the mud is recycled. The cuttings are discharged down a chute

beneath the platform towards the seabed. Inevitably, rock cuttings have a thin film of drilling mud adhering to them.

For Dunlin A platform drilling, a bentonite water-based drilling mud was used to drill all the top sections of the wells, with a mix of water-based drilling muds and oil-based drilling muds used in the deeper well sections.

A drill cuttings accumulation covers part of the Dunlin A CGB structure, sitting on the cell roofs beneath the well conductors, and spills on to the adjacent seabed on that side of the platform's base, as shown in the impression in Figure A.4.3b below.

The Dunlin platform has several years of its production life still to run and further drilling from the platform is likely. However, any future Dunlin drilling programme will require cuttings to be shipped to shore for disposal, therefore the current drill cuttings accumulation will not change.

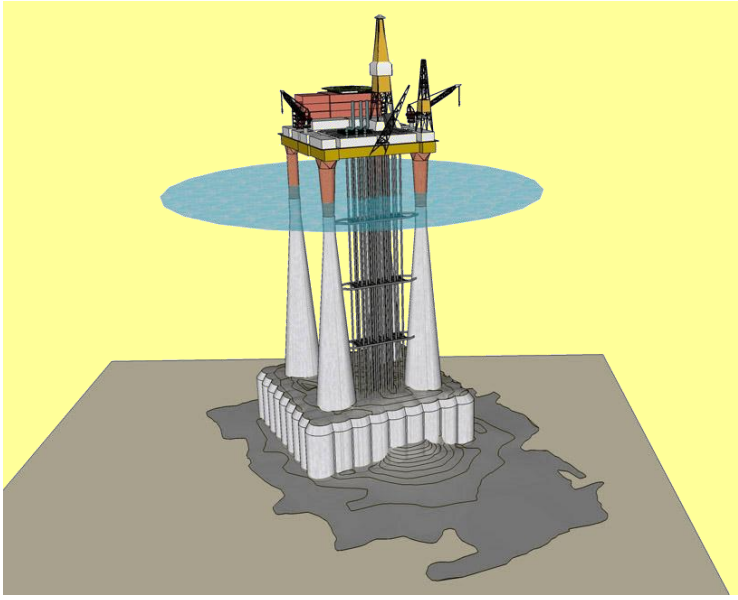

Figure A.4.3b Dunlin A showing a representation of the drill cuttings accumulation at the CGB base

In general, current drilling practice precludes the use of oil-based muds (muds with mineral oils as the base fluid) and the offshore discharge of drill cuttings. However, prior to 1991, this was not the case and therefore oil-based muds were used for some wells on Dunlin A, hence the cuttings accumulation is likely to contain hydrocarbons which might have the potential to affect marine ecosystems.

Chemical analyses of samples from the Dunlin A drill cuttings accumulation are not available but early drilling operations in the field would have used similar fluids to those used for the nearby Brent field. Data for the Brent cuttings accumulation are available. In summary, for Dunlin A the hydrocarbon content is likely to be in the range 30-150g/kg near to the platform, reducing to below 15g/kg at a distance of approximately 100m from the platform.

There have been a number of physical surveys of the cuttings accumulation at Dunlin A to measure its extent and to estimate the probable volume of the deposited material. The latest was undertaken in 1996 by Shell, the former Operator of the Dunlin field. The survey data are shown in Table 4.3 below.

Survey	Cuttings accumulation CGB	Cuttings accumulation on seabed
Volume	4000m^3	10,300m^3
Maximum thickness	Approx 4m	Approx 11m
Surface area	3300m^2	22,000m^2 (worst case estimate)

Table 4.3 Estimated size of the Dunlin A drill cuttings accumulation

The European protocol OSPAR Recommendation 2006/5 on a Management Regime for Offshore Cuttings Piles sets the Best Environmental Practice (BEP) criteria for managing drill cuttings accumulations.

There are two key criteria in the recommendation, which if exceeded, indicate action should be taken to mitigate the environmental effects of drill cuttings accumulations.

The first of these criteria relates to the rate of oil loss from the cuttings to the water column over time. Applying the OSPAR criterion, Dunlin A showed a predicted rate of oil loss to the water column of approximately five tonnes per year, which was below the 10 tonnes per year OSPAR threshold value.

The second criterion relates to the environmental persistence of hydrocarbons over the area of seabed. For Dunlin A this is approximately 125km^2-year, well below the OSPAR threshold value of 500km^2-year.

A.4.3.5 Cells contents

The operational life of the CGB cells has been described earlier (Section A.4.3.2).

The cells system was decommissioned in 2006/2007 after an attic oil programme successfully removed mobile oil trapped at the top of the cells. The attic oil programme recovered oil trapped in the spaces in each cell above the oil outlet ports by displacement with carbon dioxide (CO_2) gas. In three of the four cell groups (B, C & D), the CO_2 was removed chemically from the spaces by dosing the seawater in the cells with potassium hydroxide. The cells have been left filled with the treated seawater and the pipework was filled with a gel to inhibit corrosion.

In cell group A, a leak in the cell wall prevented the chemical removal of the CO_2, hence natural scavenging of CO_2 from the seawater has been relied on. The pipework was sealed through injection of buoyant wax particles.

The classes of materials inside the cells include:

- Treated seawater (accounting for 95-97 per cent of the contents volume)
- Inert granular ballast
- Inorganic minerals (clays and sands) originating from the well fluids.
- Hydrocarbons which may have settled at the base of the cells and adhered to the cell internal surfaces.

- Inorganic precipitates (e.g. scales and sediment) formed by reactions in the cells.
- Inorganic material such as trace metals and normally-occurring radioactive material.
- Oil-soluble materials introduced through platform operations.

The contents of the CGB cells and their potential environmental impact if released have been evaluated independently by Intertek METOC. This report concludes that the residual contents of the CGB will not pose an unacceptable risk to the environment. The report can be viewed at http://www.fairfield-energy.com/pages/view/dunlin-cells-contents-impact-assessment.

Appendix B

Concrete gravity base decommissioning options

Appendix B

Concrete gravity base decommissioning options

Contents

B.1 Introduction

A brief description of the theoretical options for decommissioning the Dunlin A CGB is presented in this appendix, without comment on their feasibility or relative merits. Six of these options were presented to stakeholders on 21 January 2010 in Aberdeen, as part of a public consultation process; a seventh option was added in July 2011.

The seven theoretical decommissioning options for the Dunlin A CGB are as follows:

- Re-use of the platform at its current location
- Refloat and tow the platform for re-use at another location
- Refloat and tow the platform inshore for deconstruction and onshore recycling and disposal of materials
- Complete in situ (at current location) deconstruction of the platform for removal to shore and onshore recycling and disposal of materials
- In situ decommissioning, leaving the CGB wholly or partially in place, having three sub-options:
    1. Topsides and steel columns removed to 8m below sea level, with navigation aids to mark the structure mounted on an extension to one leg.
    2. Topsides, steel columns and concrete legs removed to 55m below sea level to provide clear water for navigation, as required by the International Maritime Organization (IMO).
    3. Topsides removed. Controlled collapse of the four CGB legs to the seabed. (This sub-option was added to the theoretical options in July 2011, and was not presented to stakeholders on 21 January 2010 in Aberdeen)

For all the above options it is assumed that all the facilities would be flushed and the wells plugged and abandoned, prior to cutting and removing the well conductors either below seabed level or above the cell roofs. All activities would be carried out in compliance with Best Environmental Practice and relevant regulations, and pipelines would be addressed in accordance with the UK Department of Energy and Climate Change (DECC) Guidelines.

Each of the above options is addressed in detail in separate Fairfield Energy study reports. These may be accessed through the Dunlin Decommissioning website at http://www.fairfield-energy.com/pages/view/dunlin-study-reports

B.2 Re-use at current location

The end of the economic life of the Dunlin A facilities will be defined by the exhaustion of recoverable hydrocarbon reserves in the catchment area. Therefore any future re-use of the platform would be for a non-hydrocarbon venture. This assumes the design life of the CGB could be extended, and would require replacement of the current topsides.

Regardless of the type of new use (for example, carbon dioxide sequestration or wind power generation), at the end of the new use the CGB would still remain in place and would require decommissioning at some future date.

B.3 Refloat and tow for re-use at a new location

This option is only likely to occur should another use arise at the end of Dunlin's field life. Furthermore, re-use represents a postponement of the final decommissioning operation rather than a genuine decommissioning option.

B.4 Refloat and tow inshore for deconstruction and disposal

The offshore industry's current maximum heavy lift vessel capability is approximately 14,000 tonnes. While there are current plans to develop lift concepts with up to 40,000 tonnes capacity, there are no anticipated plans to develop a vessel with sufficient capacity to lift the 320,000 tonnes CGB. Consequently, buoyancy must be used to refloat Dunlin A from its current location.

The platform could be relocated with topsides in place, although the additional weight of the topsides at the highest point of the installation would make the refloat of the structure significantly more challenging. Whether the topsides was removed offshore, or left in place and subsequently removed inshore, the topsides would be dismantled and the materials recycled.

The CGB would be deconstructed in stages, the final stages requiring a dry dock. The concrete generated by this process could be recycled.

The sequence of activities required to refloat and deconstruct the CGB inshore would be as follows:

- Remove topsides and take to shore, or leave in place
- Remove drill cuttings accumulation
- Refloat platform
- Remove and treat ballast water
- Transport to inshore deep water location
- Remove topsides if still in place
- Partially deconstruct the CGB inshore and remove solid ballast
- Move partially deconstructed platform into dry dock
- Complete deconstruction and disposal onshore

B.5 In situ deconstruction

In order to deconstruct the Dunlin A platform in its present location (in situ), the following activities would be necessary:

- Remove topsides
- Remove conductor support frames
- Remove drill cuttings accumulation
- Remove ballast water in cells
- Remove concrete legs by cutting and lifting by floating crane
- Cut and remove cell roof sections in pieces capable of lifting by floating crane
- Cut and remove cell wall sections in pieces capable of lifting by floating crane
- Cut and remove cell floor sections in pieces capable of lifting by floating crane
- Cut and remove skirt sections in pieces capable of lifting by floating crane
- Clear seabed of all debris

Because of the complex geometry of the wall intersections and the thickness of the concrete sections in the CGB, this option would require development of technologically advanced remotely operated subsea cutting tools and methods, and new bracing methods for the concrete legs during the cutting operations.

B.6 In situ decommissioning to 8m below sea level

In some cases, under both the DECC Guidelines and OSPAR Decision 98/3, concrete gravity base platforms installed before 1999 can be decommissioned by removing the topsides and leaving some or all of the main concrete gravity base in situ.

One approach for in situ decommissioning of Dunlin A would be to remove the topsides and all external platform steelwork, and the steel columns at the top of the legs, and leave the entire concrete structure in place. The tops of the concrete legs would be at 8m below sea level. As this would provide no navigable water over the CGB, the structure would require marking with navigation warning devices, as required by the IMO.

The activities required for this option would include:

- Remove topsides
- Remove conductor guide frames
- Remove steel columns to 8m below sea level
- Install a vertical extension to one leg to support navigation warning devices above sea level

The resulting structure is shown in Figure B.6.

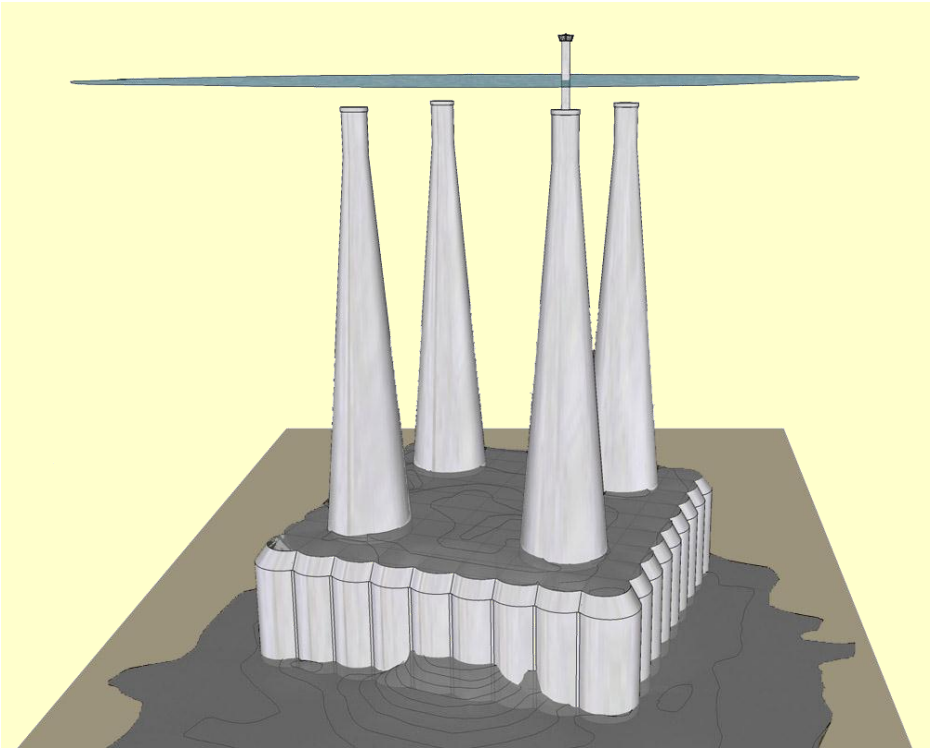

Figure B.6 In situ decommissioning to 8m below sea level

B.7 In situ decommissioning to 55m below sea level

For in situ decommissioning of Dunlin A, a second approach would be to remove the topsides and the upper part of the legs to give 55m clear water below sea level, to provide freely navigable water over the remaining parts of the structure, as required by the IMO.

The activities required for this option would include:

- Remove topsides
- Remove conductor guide frames
- Cut and remove legs to 55m below sea level, requiring restraint of partially cut legs while completing the cutting and lifting of the freed section.

The resulting structure is shown in Figure B.7.

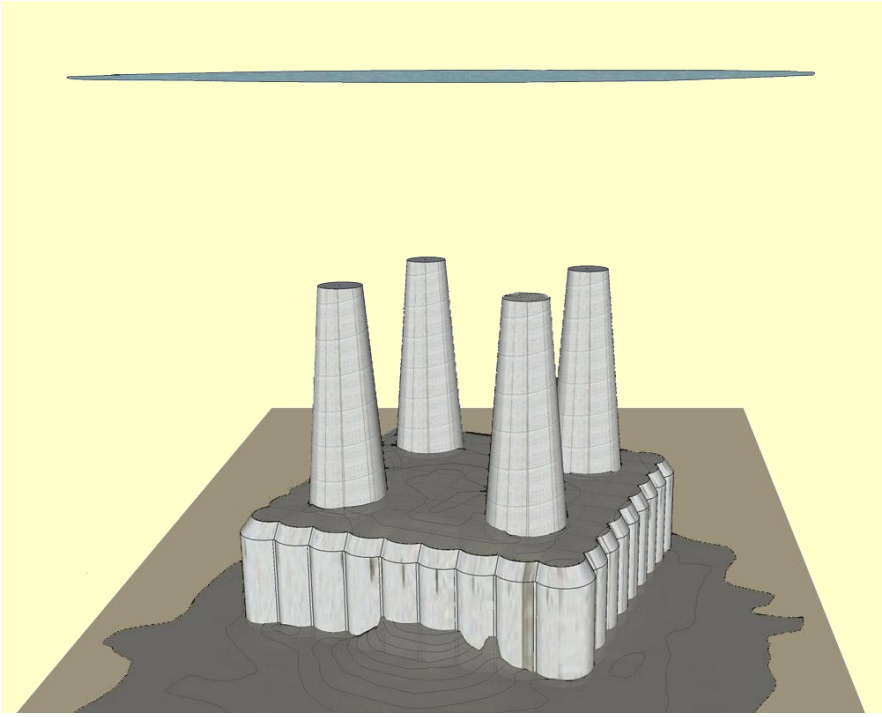

Figure B.7 In situ decommissioning to 55m below sea level

B.8. In situ decommissioning to 110m below sea level

A third approach for the in situ decommissioning of the Dunlin A CGB would be to remove the topsides, followed by conducting a controlled collapse of the legs as illustrated in Figure B.8. The activities required for this option would include:

- Remove topsides
- Remove conductor guide frames
- Deploy explosive charges to create collapse of the legs in a controlled and predictable manner at a level around 10m above the CGB base. An alternative method of collapsing the legs would be to use diamond wire cutting technology to progressively cut the leg wall sections segmentally (i.e. not through the leg cross section) In both cases the internal pipework would be bent or sheared as each 7600 tonne leg fell to the seabed.

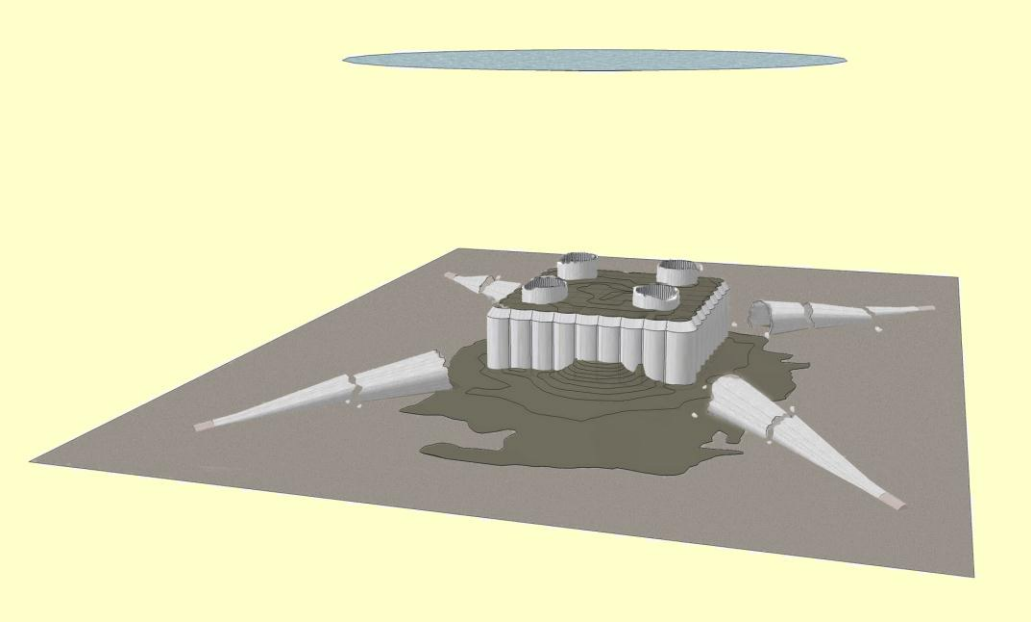

Figure B.8. In situ decommissioning to 110m below sea level

Appendix C

Carbon dioxide sequestration and enhanced oil recovery

GENESIS

Technical Note

CO_2 Opportunities for Dunlin Alpha

Genesis Job Number J-71612/B

Client: Fairfield Energy Ltd

5th May 2010

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GENESIS

CLIENT:	**Fairfield Energy Ltd**
PROJECT/JOB TITLE:	**CO_2 Opportunities for Dunlin Alpha**
DOCUMENT TYPE:	**Technical Note**
DOCUMENT TITLE:	**CO_2 Opportunities for Dunlin Alpha**
GENESIS JOB NUMBER:	**J-71612B**
DOCUMENT NO./ FILE NAME:	**J71612-B-A-TN-001-B2.docm**

B2	5/5/10	Final issue	RN	R MacP	R MacP	
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CONTENTS

List of Figures

List of Tables

1 BACKGROUND

Fairfield Energy operates the Dunlin Cluster of fields in the UK North Sea, located some 500km north-northeast of Aberdeen in around 150m of water.

The Dunlin Alpha platform, known as Dunlin A, acts as the production hub for the fields. Dunlin A is a concrete gravity base (CGB) structure, supporting a steel topsides deck and production facilities.

Fairfield Energy is presently engaged in determining and evaluating its decommissioning commitments for the Dunlin Cluster. As part of these activities Fairfield Energy is evaluating a number of potential decommissioning options, including the possible re-use of the platform. One of these re-use options focuses on the potential use of the Dunlin reservoir for carbon dioxide (CO_2) sequestration. It should be noted that CO_2 could also be used to promote enhanced oil recovery (EOR) from the reservoir. EOR is not classed as a re-use option for Dunlin as it could be a method for extending the life of the reservoir. However, as EOR shares several aspects of CO_2 usage in common with CO_2 sequestration, it is also addressed in this report.

2 PRINCIPLES OF CO_2 EOR AND SEQUESTRATION

Both CO_2 EOR and CO_2 sequestration require a source of CO_2. Typically the CO_2 is captured from industrial point sources, processed, and transported via pipelines (or ships in certain cases) and injected into the reservoir or aquifer formations. The difference between CO_2 EOR and CO_2 sequestration is illustrated in Figure 2-1 and described briefly below.

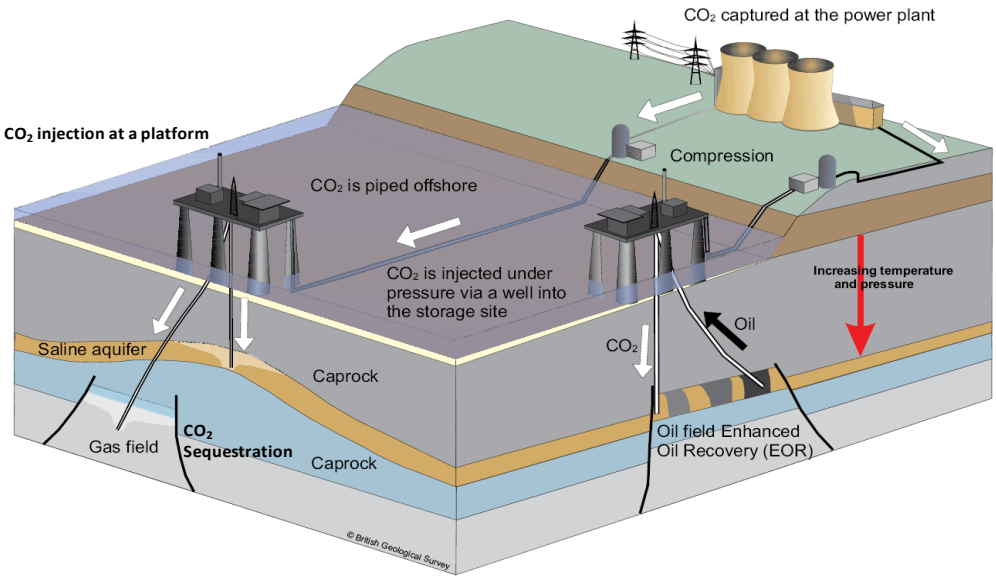

Figure 2-1 Schematic showing the major elements of CO_2 EOR and CO_2 sequestration processes

2.1 CO_2 EOR

CO_2 EOR is a tertiary recovery method that can increase oil recovery beyond the levels achievable by conventional recovery methods. Conventional recovery includes:

- Primary recovery**,** applied during the initial production phase. Oil is produced using the natural pressure within the reservoir to drive the fluids to the surface through the producing wells.
- Secondary recovery (or water flooding), applied when the pressure of the reservoir falls too low for the oil to produce naturally. At this stage water is usually injected to maintain a high pressure within the reservoir and drive the oil towards the producing wells.

Following conventional recovery there are a number of tertiary recovery methods which are typically more complex, costly and difficult to justify economically. One of these is CO_2 EOR, which can result in an additional 5-15% of the original oil in place being recovered if deployed in a suitable reservoir. The CO_2 injected into the oil reservoir becomes miscible, reducing the viscosity of the oil and increasing its mobility.
Figure 2-2 illustrates the recovery process.

CO_2 is injected through a number of injection wells to provide a miscible CO_2 drive front. Often the CO_2 injection is alternated with water injection to contain the CO_2 in a tight sweep. The objective is to drive a front of CO_2 through the oil towards the producing wells.

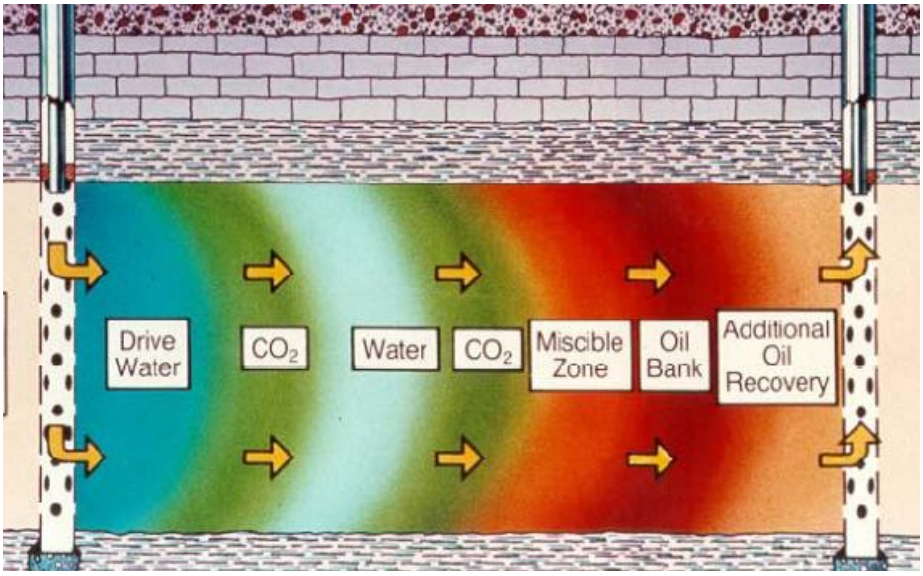

Figure 2-2 EOR recovery mechanism for oil reservoirs

The recovery mechanism results in a tertiary peak of oil production which occurs several months or even years after the injection of CO_2 begins (see Figure 2-3).

However, large quantities of recycled CO_2 and produced water are associated with EOR, presenting technical and commercial challenges to EOR applications for offshore installations in the North Sea.

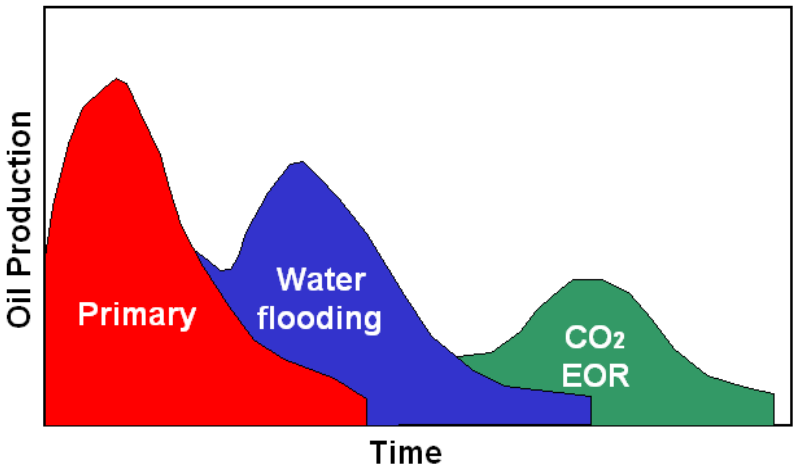

Figure 2-3 Typical CO_2 EOR recovery profile

At present there are no onshore or offshore applications of CO_2 EOR in Europe, although the technique has been commercialised elsewhere, notably onshore in the USA.

2.2 CO_2 SEQUESTRATION

CO_2 sequestration involves the permanent disposal of CO_2, usually into a depleted gas/condensate reservoir or saline aquifer, without increasing hydrocarbon gas or oil recovery.

For normal operation of the Dunlin reservoir, water injection is required to maintain pressure in the reservoir to produce the oil. Once production has ceased, the oil will have been replaced by water but the reservoir will remain at a relatively high pressure.

As the Dunlin reservoir is a 'closed' geological structure (i.e. the reservoir is not in pressure communication with surrounding aquifers) it is not suitable for large scale CO_2 sequestration unless fluid is also withdrawn from the reservoir. CO_2 injection will cause further pressurisation which limits the amount of CO_2 that can be stored in this type of reservoir. The capacity available for CO_2 can be increased by extracting oil and/or water, but effectively this is CO_2 EOR rather than sequestration alone.

For gas and gas/condensate fields the situation is different as production from the reservoir is usually driven by expansion of the gas without the need for water injection to maintain pressure. Thus pressure is likely to be very low by the time these fields reach the stage where CO_2 storage can be considered. The gas/condensate reservoir is basically re-filled with CO_2.

‘Open’ geological structures such as saline aquifers offer the greatest potential for large scale CO_2 sequestration storage. CO_2 injected into open aquifers displaces the saline water laterally with minimal, local changes in pressure. The storage capacity of an open saline aquifer is determined by the effectiveness of this displacement (referred to as ‘sweep efficiency’), plus the proportion of the saline aquifer that is capable of trapping the CO_2, as the CO_2 front moves through the aquifer.

3 MAIN DESIGN ISSUES WITH CO_2

The section describes some of the key design issues associated with CO_2. They apply to both CO_2 sequestration and CO_2 EOR.

3.1 Corrosion

CO_2 is a benign fluid when dry but becomes an aggressive and difficult fluid to handle when wet.

Facilities for offshore platforms located in fields with low sour gas concentrations (i.e. CO_2 and H_2S) are designed mainly with carbon steel components. High concentrations of CO_2 are extremely corrosive to carbon steel in the presence of water. Any carbon steel components in contact with wet CO_2 will corrode rapidly, up to 25 mm/year in certain conditions. Corrosion inhibitors cannot mitigate the high corrosion rates. For any process equipment or wells where high concentrations of wet CO_2 are present, carbon steel is not an acceptable material.

13 Chrome (13 Cr) stainless steel tubing is often the standard material used in well tubing for conventional oil and gas fields with low CO_2 concentrations. Although 13 Cr is more resistant to CO_2 corrosion it is still susceptible to corrosion when combined with chlorides, which are present in the reservoir from the seawater injection. Figure 3-1 below shows the resistance of 13 Cr to CO_2 and chlorides. It can be seen that with high CO_2 and chlorides, 13 Cr has a poor corrosion resistance even at low temperatures.

Very low concentrations of residual oxygen can be present in the CO_2, as a result of the onshore CO_2 capture process. This oxygen can cause stress corrosion cracking of 13 Cr. Stress corrosion cracking can be caused by concentrations of oxygen typically no greater than 10 ppb (parts per billion) in the water phase.

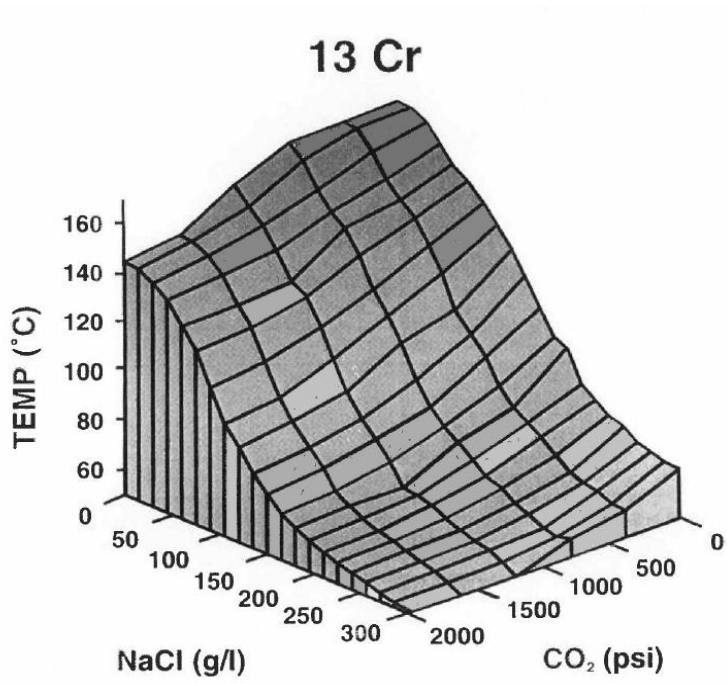

Figure 3-1 Resistance of 13 Chrome stainless steel to CO_2 and chlorides to maintain CO_2 corrosion rate below 0.05 mm/yr

3.2 Elastomers

CO_2 attacks elastomers which are often found downhole in well packers or in topsides valve seals or seats. CO_2 acts as a solvent at high pressure and makes many elastomers unsuitable for use with CO_2. Also, on depressurisation, explosive decomposition of elastomers can occur as the CO_2 expands within the material. CO_2 resistant elastomers are available but would not routinely be used unless CO_2 was specified in the original design.

3.3 Cement corrosion

CO_2 attacks Portland Cements used to provide the seal between the well casing and reservoir. If cement breakdown occurs leak paths can be created, either through the well annulus, or in the worst case through the cap rock. CO_2 resistant cements are available but would not routinely be used in wells normally handling low CO_2 well fluids.

3.4 CO_2 physical properties

CO_2 has unusual physical properties which would not normally be accommodated in terms of the design of equipment on conventional oil and gas platforms. Such design considerations include:

- If dense phase or liquid CO_2 is depressurised to atmospheric pressure it will form a solid below the triple point pressure of around 5.5 barg.

This provides design challenges for vent piping and equipment depressurisation.

- CO_2 becomes extremely cold on depressurisation, reaching temperatures as low as -78ºC at atmospheric pressure. Again this provides challenges for vent design and materials.
- CO_2 is denser than air and is toxic to humans in high concentrations. This presents many safety challenges on offshore installations. It is important to maintain an open structure with good ventilation, and avoid low pockets where CO_2 could collect. Gas detection, escape routes and safety equipment on conventional installations would all need to be modified for CO_2 operation.
- High pressure dense phase CO_2 can explode under certain conditions called a BLEVE (boiling liquid expanding vapour explosion), similar to the behaviour of liquid petroleum gas (LPG).

The CO_2 phase envelope is shown in Figure 3-2.

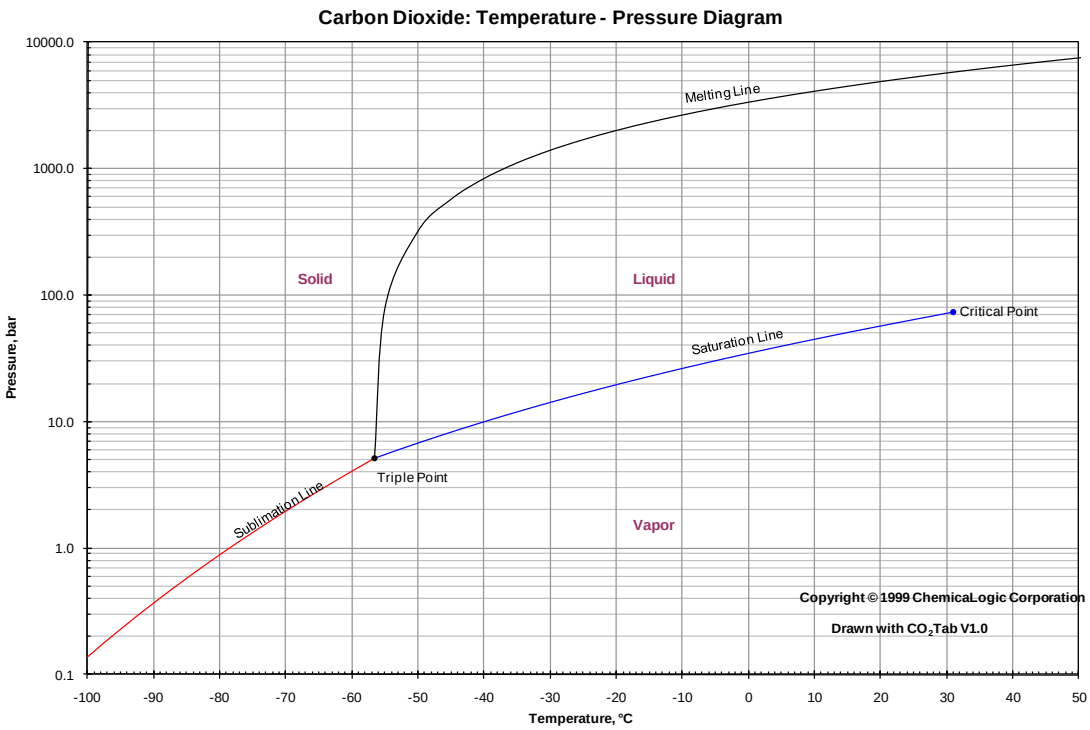

Figure 3-2 CO_2 phase envelope

3.5 Solubility

CO_2 is 20 times more soluble in water than methane and is also soluble in crude oil, usually as a component within the associated dissolved hydrocarbon gas. This has design implications for a conventional oil and gas platform as CO_2 is carried through the entire separation train, crude export, and produced water handling processes.

4 TYPICAL CO_2 EOR TOPSIDES PROCESS

This section describes typical well and topsides facilities process requirements for CO_2 EOR. A high level process flow diagram is shown in Figure 4.1. It should be noted that EOR facilities are specific to each reservoir, hence the process diagram should only be considered indicative.

Descriptions are given below for eight main aspects of the process and a comparison made with the Dunlin facilities. A view is then taken on whether any of the existing Dunlin facilities could be re-used.

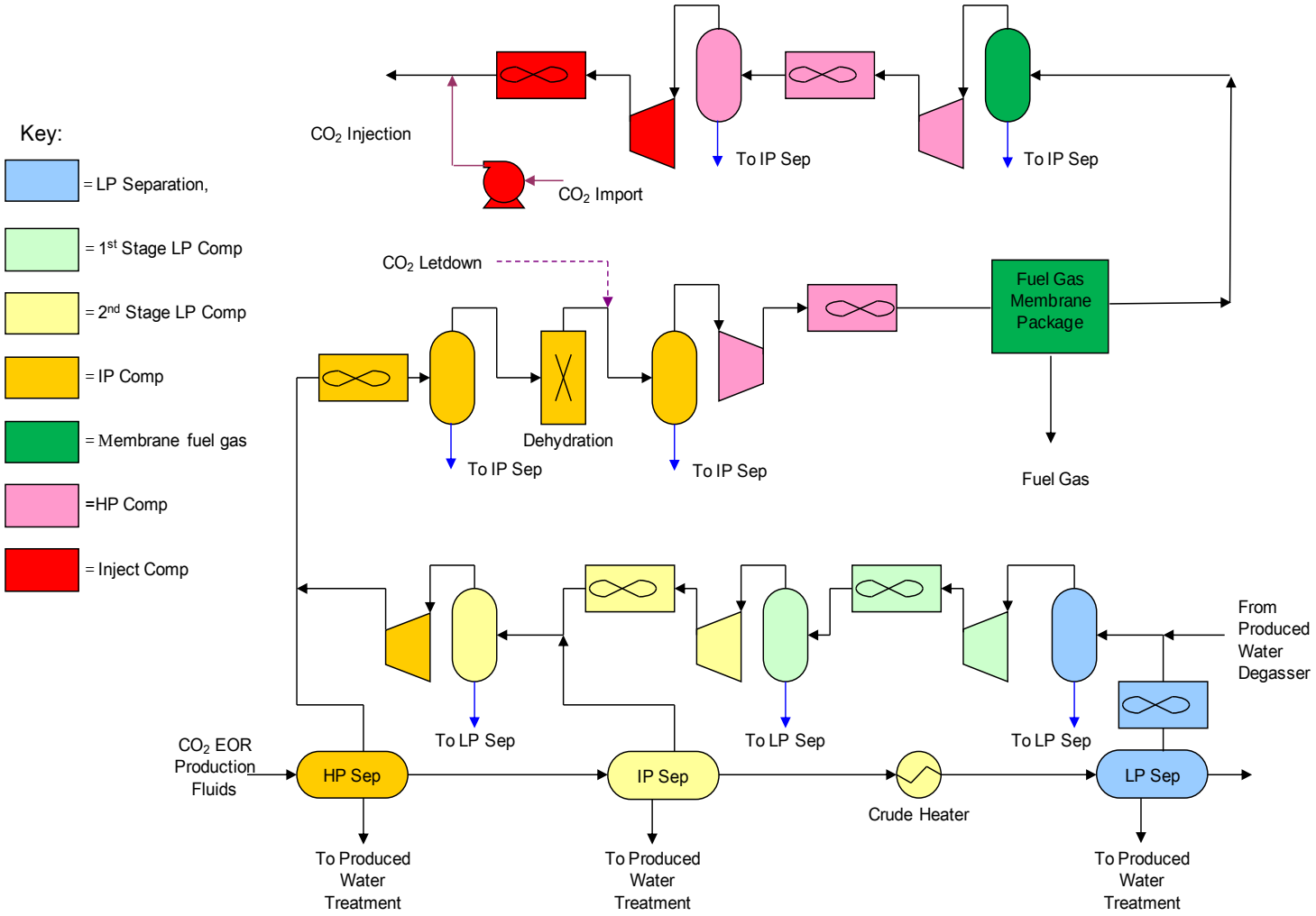

Figure 4-1 Typical CO_2 EOR process

4.1 Wells and CO_2 injection

Description

Initially, pure dry CO_2 from the supply pipeline is injected into the reservoir through the CO_2 injection wells. Dry CO_2 is non-corrosive, but although the CO_2 is dry at the top of the injection well it contacts seawater at the base of the well as it passes into the reservoir. As the CO_2 front passes through to the producing wells, the fluids recovered at the producing well will contain an increasing concentration of CO_2, and large quantities of produced water associated with the oil production.

The conditions in the wells are corrosive due to a combination of wet CO_2, high temperature and the presence of chlorides.

All the wells need to be designed specifically for CO_2 including:

- CO_2 resistant cement in new wells and plugged and abandoned wells.
- Suitable tubing materials for high temperature wet CO_2.
- High tubing stresses caused by low temperatures during CO_2 injection and depressurisation.
- Suitable CO_2 resistant elastomers

Dunlin wells

Dunlin has conventional 13 Cr production wells and injection wells lined with glass reinforced epoxy or plastic. None of the wells is designed for CO_2 concentrations, which can reach 80 to 90 mol% wet CO_2 in the gas phase of the production wells, and almost pure CO_2 in the injection wells.

Re-use potential

Previous CO_2 EOR and sequestration project studies, completed by Genesis, have demonstrated that new wells or well workovers are required where the wells are not already subject to high sour gas (CO_2 or H_2S) service.

The Dunlin wells are over 30 years old and the field has relatively low CO_2 concentration of 3.5 to 4.5mol%. It is extremely unlikely the Dunlin wells would be suitable for CO_2 service, nor be in the correct well locations for CO_2 sweeps. Workovers would be required for both injection and production wells. In addition, existing wells not required for EOR would need to be plugged and abandoned using CO_2 resistant cement.

Dunlin has 40 development wells entering into the reservoir. Such a large number of penetrations into the reservoir increases the potential leak paths for CO_2 to the surface, and presents challenges for long term monitoring of the reservoir.

4.2 Separation and oil export

Description

The production fluids from the wells arrive into the production separator train. Initially these fluids have low concentrations of CO_2 and consist of oil, hydrocarbon gas and produced water. As the CO_2 EOR begins to take effect, oil production starts to increase along with an increase in the amounts of CO_2 and produced water coming from the wells. The impact on the process equipment is as follows:

- The produced fluids would be extremely corrosive, hence carbon steel separators or pipework would not be suitable. Even if vessels are lined, (unless the linings are designed specifically for CO_2) breakdown can occur during depressurisation, so linings are unlikely to be suitable. Duplex stainless steel is often used for CO_2 separation trains.
- As CO_2 breakthrough occurs and CO_2 recycle builds up, large volumes of CO_2 would be released from the first stage separator. Typical CO_2 recycle rates for EOR are in the order of 5 to 15 million standard cubic metres per day and the concentration of the gas from the separator typically reaches around 90 mol% of wet CO_2.
- The CO_2 is carried through the separation trains, contained in both the oil and produced water. High concentrations of CO_2 are found in second and third stage separators and also in the produced water system. Conventional water treatment processes can be detrimentally affected by the large amounts of CO_2 released in the produced water system.
- Crude heating and very low final stage separation pressure is often required to reduce the CO_2 concentration sufficiently to meet the crude export pipeline specification.
- CO_2 tends to strip LPGs from crude oil, leading to richer associated hydrocarbon gas. This can adversely affect the value of the crude unless the LPGs are recovered as part of the processing.
- The volume of gas and water handled is often much higher than that originally designed for on the platform.

Dunlin facilities

- Dunlin separators are lined carbon steel vessels and all associated pipework is carbon steel
- The separators are designed for relatively low volumes of associated hydrocarbon gas with a low CO_2 concentration (3.5 to 4.5 mol%). No heating of the crude is presently carried out on Dunlin. The crude is exported at pressure as live crude into the Brent pipeline system.
- The CO_2 specification for the Brent pipeline is 0.25% wt.

Re-use potential

The existing Dunlin separation train would not be suitable for re-use because:

- A new corrosion-resistant separation train and associated pipework would be required to process the combined EOR CO_2, water and hydrocarbon fluids.
- To meet the CO_2 pipeline export specification, a low pressure final stage separator could be required along with heating upstream of the separator to drive off the CO_2. Providing heating would require either a new waste heat hot oil system or electric heating.
- Alternatively, oil export could be achieved by offloading to tanker but the ship vapour pressure specification would still need to be met for loading, and hence oil heating would still be required.

It may be possible to re-use or adapt the existing oil export pumps.

4.3 Compression

Description

Compression of the CO_2 as it exits the wells is required to recompress it and return it for re-injection. The CO_2 is compressed and usually dehydrated. By removing water from the CO_2 it is possible to use carbon steel for equipment downstream of dehydration. Typically several stages of compression are required, depending on the final injection pressure. The recycled CO_2 is mixed with fresh CO_2 from the import pipeline prior to re-injection. Over time the recycled CO_2 flow and concentration increases and the amount of fresh imported CO_2 declines.

Dunlin facilities

Dunlin has no compression facilities except for low pressure fuel gas compression, therefore a new CO_2 dehydration and compression module would be required.

Re-use potential

There is no re-use potential.

4.4 Produced water

Description

Produced water from each of the process separators is usually routed to a produced water handling system. The high volumes of CO_2 dissolved in the produced water mean large volumes of CO_2 are released from the produced water degasser. Capacity constraints in produced water handling systems can occur when CO_2 EOR is applied. The water cut of the produced oil is already high from the earlier water injection used in secondary recovery operations. The additional oil produced by EOR brings additional water

onboard which may exceed the capacity of the existing handling systems. Effects of CO_2 on produced water treatment equipment include:

- Hydrocyclones - modification to the cyclone's reject stream orifice is usually required as much more CO_2 is released within the cyclone compared to hydrocarbon gas breakout. CO_2 breakout can have a detrimental effect on hydrocyclone performance although trials have shown they can still be effective.
- Degasser – up to 20 times more CO_2 is released from the produced water degasser compared to the gas released from conventional hydrocarbon production processes. Degasser vents are often not large enough to handle the additional gas. The CO_2 is also valuable - the cost of capturing and transporting CO_2 can be up to £50/tonne. Often the value of CO_2 justifies the cost of fitting a low pressure compressor on the degasser to recover the CO_2.

Dunlin facilities

Dunlin has a conventional hydrocyclone system constructed partly in duplex stainless steel. The degasser and associated pipework is carbon steel. Off-gas from the degasser is presently vented to atmosphere.

Re-use potential

It is possible some or all of the produced water system could be re-used but this would require detailed studies to determine how much of the system is suitable. A new degasser vent recovery compressor would be required. Additional water handling capacity may also be required.

4.5 Fuel gas

Description

Fuel gas supply presents a significant issue for CO_2 EOR projects because:

- Associated hydrocarbon gas will rapidly become contaminated with CO_2.
- Beyond 40 mol% CO_2, fuel gas cannot be burned in conventional gas turbines.
- A membrane separation package could be required to purify the separator off-gas. Membranes are power intensive and additional compression would be required to recompress the separated gases.
- Alternatives to fuel gas supply would be diesel-driven generators, or a new pipeline to import gas from a third party, but both of these have high operating costs.

Dunlin facilities

Dunlin has no compression. Fuel gas is gathered from the production separators, superheated and burned directly for power generation. There is presently no third party supply of gas available.

Re-use potential

There is no re-use potential.

4.6 Power generation

Description

Conventional gas turbine power generators can be used but need to be adapted for high CO_2 concentration in the fuel gas. CO_2 EOR requires significant power input, hence it is unlikely that a conventional platform would have enough power generation onboard to support EOR facilities.

Dunlin facilities

The Dunlin platform has 32MW of power (2 x 13.8MW Avon and 2 x 2.2MW Solar turbines).

Re-use potential

Existing power generators could be used but additional units would be required to drive the EOR compression module.

4.7 Structural loading

Description

CO_2 EOR modules are large and complex, and can weigh between 5000 and 15000 tonnes depending on capacity (including structural steel work and equipment bulks).

Dunlin facilities

The Dunlin platform has a simple separation processing train, water injection, drilling rig, power generation and accommodation. Spare weight capacity on the existing deck and legs is limited. A recent study, completed by Fairfield Energy, showed that structural strengthening of the steel columns at the top of the legs was required for the installation of a 2000 tonnes module.

Re-use potential

The concrete legs maybe suitable for reuse but it is likely existing steel legs would either need to strengthened or replaced. Given the age of the structure and potentially high future maintenance costs, an alternative consideration would be to install a new jacket and topsides.

4.8 CO_2 venting

Description

CO_2 cannot normally be handled in a conventional flare system for the following reasons:

- CO_2 is non-flammable and an asphyxiate. A purpose-designed vent tower and discharge nozzle is required. Detailed dispersion analysis is required to ensure dangerous concentrations of CO_2 do not reach deck level.
- CO_2 forms solids on depressurisation, therefore vent headers have to be designed to handle potential solids build up.
- CO_2 temperature can be as low as -78ºC. The vent construction material is usually 316 stainless steel.

Dunlin facilities

Dunlin A has a conventional hydrocarbon flare system and flare tower. The flare system is constructed from carbon steel.

Re-use potential

A new dedicated CO_2 vent header would be required. The existing flare tower could potentially be re-used subject to detailed CO_2 dispersion analysis.

5 TYPICAL CO_2 SEQUESTRATION TOPSIDES PROCESS

Description

The facilities required for CO_2 sequestration are relatively simple compared to those for EOR. Subject to detailed studies it could be feasible to accommodate the new equipment on the existing Dunlin A structure. Considerations include:

- A new CO_2 riser and pig receiver would be required.
- CO_2 pipelines have to operate above 90 barg and are typically designed for less than 150 barg to avoid a high design pressure pipeline and associated capital cost. Depending on the CO_2 injection pressure required on Dunlin, a new CO_2 booster pump could be required.

- A new dedicated CO_2 manifold would route the CO_2 to the injection wells.
- Complete workover or new injection wells would be required to install CO_2 resistant materials.
- While additional power demand is likely to be small and in theory could be met by the existing power generation system, there would be no source of fuel gas. Hence power would either have to be supplied from bunkered diesel or from a third party source of electric power or fuel gas. In all cases operating costs would be high.
- A new CO_2 vent system would be required to vent the CO_2 manifold.

Re-use potential

None of the existing process facilities would be suitable for re-use with the exception of:

- The existing GBS and deck. The new equipment required for CO_2 sequestration is minimal so any weight constraints on the existing platform structure could be overcome by removing redundant process equipment.
- Power generation, but requiring an alternative fuel source of either gas or power.
- Possibly the flare tower

Re-using a structure as large as Dunlin for the limited facilities required for CO_2 sequestration does not appear to the optimum technical or financial development solution. Dunlin is already 30 years old and maintenance costs will continue to increase.

There have been a number of studies which have proposed a UK or European CO_2 infrastructure hub. Most studies propose a large CO_2 pipeline trunk line running from south to north midway between the UK and Europe, passing close to the major sequestration and EOR potential reservoirs. Feeder pipelines would then tie into this header from the major power producing areas in Europe and the UK. Specific existing platforms, probably the larger and newer facilities, would become CO_2 distribution hubs for a particular region. If such a hub develops it could potentially encourage potential low cost subsea developments for CO_2 sequestration. Rather than maintaining large and aging platforms such as Dunlin, subsea pipelines and injection wells could be provided. If a particular reservoir required higher injection pressure than that provided by the main trunk line, a pressure boosting pump could be installed on the CO_2 distribution hub platform.

6 CO_2 EOR AND STORAGE POTENTIAL AT DUNLIN

The original oil in place (OOIP) for the Dunlin field was stated as 825 million barrels, or 110 million tonnes (mt).

Dunlin is referenced as a reservoir with EOR potential in two major studies: one issued by the Scottish Centre for Carbon Studies on behalf of the Scottish Government [(1)], the other by The Institute of Energy on behalf of the European Commission [(2)]. Both studies used an average CO_2 EOR recovery of 10% of OOIP, leading to theoretical additional recoverable reserves of around 82 million barrels. It should be noted that the current oil recovery achieved from Dunlin, using water flood, is already high at around 60%. It is therefore possible that further recovery using EOR would tend towards the lower end of the typical EOR recovery range of 5% to 15%.

The amount of CO_2 which typically remains in a reservoir following CO_2 EOR is 23% of the OOIP [(2)]. For Dunlin, this would equate to a total CO_2 storage capacity of 0.23 x 110mt or 26mt of CO_2. Again this correlates well with 27mt storage capacity referenced in the Scottish Government study [(1)]. Neither study identifies Dunlin as a candidate for pure CO_2 sequestration without EOR.

Calculation of CO_2 injection rate requires a detailed reservoir and facilities optimisation process. Higher CO_2 injection rates result in a faster EOR response from a reservoir leading to higher peak oil production and improved recovery. The disadvantages of high CO_2 injection rates include larger facilities and higher capital cost, greater energy consumption and operating costs. Reference 2 provides a range of annual CO_2 injection rates for Dunlin from 1.3mt to 2.6mt of CO_2 per year, assuming a 10 to 20 year project life.

It is useful to compare Dunlin CO_2 capacity in the context of Scottish and UK CO_2 emissions. Scotland's total CO_2 emissions in 2006 were estimated to be 44mt, equating to around 8% of the total UK emissions of approximately 557mt. Figure 6-1 shows the breakdown of CO_2 emissions from power generation plants in Scotland and Northern England, totalling some 71mt of CO_2. Power plants give rise to 33% (~184mt) of the UK's total CO_2 emissions.

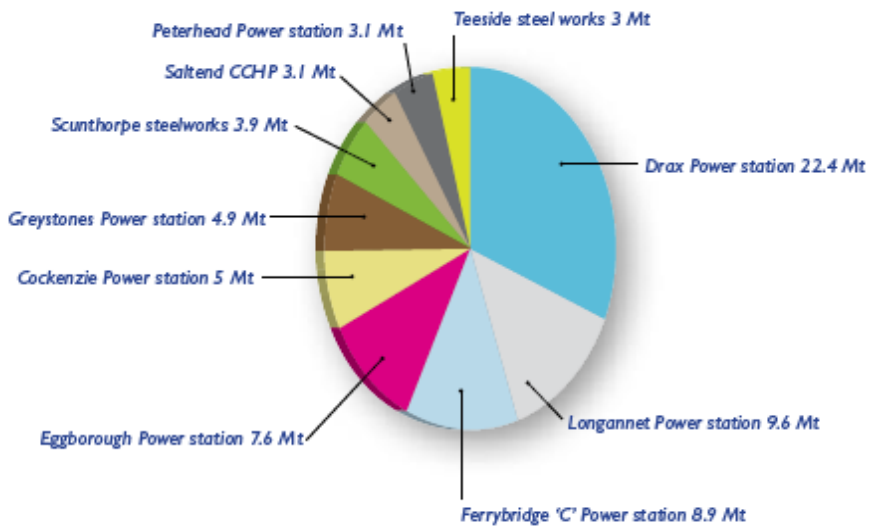

Figure 6-1 Power station CO_2 emissions in Scotland and Northern England [(1)]

The potential for CO_2 disposal in the Dunlin reservoir represents between 0.25% and 0.5% of UK CO_2 emissions for a period of up to 20 years.

7 DUNLIN EOR AND SEQUESTRATION INDICATIVE COST ESTIMATES

7.1 CO_2 EOR indicative cost estimates

CO_2 capture and transportation would usually be provided by a third party, which would deliver the CO_2 to a local CO_2 hub and distributes it to various users. CO_2 capture and transportation costs are typically around £20 to £40/tonne[(1)]. Given the remoteness of Dunlin, CO_2 supply costs would be at the higher end of this range.

Dunlin's remoteness from major sources of CO_2 creates a significant disadvantage for CO_2 disposal. The field lies around 500km from the Peterhead gas fired power station, which is the nearest UK major power producer, and around 700km from Fife in Central Scotland where other major power stations are located. If Dunlin were to be utilised for EOR or sequestration alone, CO_2 would need to be supplied as part of a much larger CO_2 pipeline network, serving other fields. An EOR development on Dunlin could not justify the installation of CO_2 pipelines for its sole use.

Reference 1 provides costs for a number of transportation hubs, including one to a hub in the Dunbar field which is the closest platform to Dunlin. Both shipping and pipeline options were considered. The overall cost range for a Dunbar hub was between £1.3 and £1.7 billion for capital cost, with annual operating costs between £50 and £170 million.

The European Union carbon emissions price value (EU ETS) is presently around 15 euros/tonne CO_2 (£14/tonne), which is well below the present cost to capture CO_2 and transport it to North Sea disposal sites. Government subsidies are required to justify investment in CO_2 transportation infrastructure.

This technical review has shown there is limited re-use potential for the existing Dunlin facilities for CO_2 EOR. Dunlin would require new or re-completed CO_2 EOR injection and production wells, a new dedicated CO_2 processing module and possibly a new jacket to handle the new module weight. Clearly this would be a major capital and operating investment.

Reference 1 provides a recent technical and economic evaluation into a CO_2 EOR hub at the Claymore area situated much closer to CO_2 sources in the Central North Sea. Claymore is a similar type and size of oil field to Dunlin. The study estimated capital expenditure at around £1.1 to £1.2 billion and annual operating costs of £90 million.

The cost of supplying CO_2 is uncertain and depends on the cost to power companies of emitting CO_2. At present, the value for sequestrated CO_2 is 15 euros/tonne CO_2 (£14/tonne), set by the European Union carbon emissions price value (EU ETS). This is well below the present cost to capture CO_2 and transport it to North Sea disposal sites. If in the future the cost of emitted CO_2 increases so it costs less to capture and transport than to emit it to atmosphere, then owners of disposal sites could either be provided with CO_2 at no cost or even potentially charge power companies a tariff for disposal. Assuming CO_2 is supplied at no cost to the platform, the Claymore project realised an internal rate of return of 12% to 16% with an oil price of $70/barrel. Allowing for a third party capture and transportation tariff for supplying the CO_2, the breakeven oil price was estimated at over $100/barrel to make EOR economic for the Claymore field. Given the remoteness of the Dunlin field the breakeven oil price for CO_2 EOR would be likely to be well in excess of $100/barrel, and possibly as high as $150/barrel.

7.2 CO_2 sequestration indicative cost estimates

At present, the value for sequestrated CO_2 is 15 euros/tonne CO_2 (£14/tonne), set by the European Union carbon emissions price value (EU ETS). This is well below the present cost to capture CO_2 and transport it to North Sea disposal sites.

CO_2 sequestration for Dunlin could be achieved using the existing Dunlin GBS as the topsides equipment required would not create high loading. New topsides equipment required would include a CO_2 booster pump, topside manifold and CO_2 vent. The indicative cost of these topsides facilities would be of the order of £20 to £40 million based on previous sequestration study estimates.

New or re-completed wells for CO_2 injection would also be required. Typically, a single injection well can handle around 1 million tonnes/year of CO_2, hence around three injection wells would be required on Dunlin to dispose of up to 2.6mt/annum. This assumes no pressure would build up in the reservoir and removal of fluids from the reservoir would not be required. Assuming well costs of around £5 to £7 million per well, total well costs would be £15 to £20 million, resulting in a total capital cost including topsides facilities in the order of £35 to £60 million.

Sequestration operating costs would be high as the maintenance cost for a large platform would be incurred, while only a small area of the platform would be used for sequestration facilities. Furthermore, there would be no power supply for the CO_2 booster pump, requiring either diesel power generation or third party gas import.

For sequestration at Dunlin, it could be more cost effective to provide either dedicated subsea facilities, or a new, smaller, purpose-built platform. If a CO_2 supply hub develops in the future, the CO_2 hub platform could host the booster pumps for subsea injection.

7.3 CO_2 EOR and sequestration cost estimate summary

Table 7-1 shows a summary of the indicative costs.

Table 7-1 Indicative CO_2 EOR and CO_2 sequestration cost estimates

	CO_2 EOR		CO_2 Sequestration	
	Capex	Opex	Capex	Opex
Capture and transportation hub (shared cost included in third party tariff)	**£1.2 to £1.7 billion**	**£50 to £170 million /year**	**£1.2 to £1.7 billion**	**£50 to £170 million /year**
Dunlin Facilities	**£1.1 to £1.2 billion**	**£90 million/year**	**£50 to 100 million**	**Unknown**

Table 7-1 demonstrates the large differential between the cost and complexity of EOR compared to sequestration. The facilities costs are typically an order of magnitude higher for EOR. The cost of providing a CO_2 capture and transportation pipeline system and strategic hub platforms for distribution of the CO_2 would be in excess of £1 billion. Single, remote reservoirs such as Dunlin could never justify the cost of the transportation infrastructure required, and the supply of CO_2 have to be part of a large scale, co-ordinated CO_2 capture and transportation project for the UK and/or Europe.

8 CONCLUSIONS

For reasons of excessive cost and poor economics, this report has demonstrated CO_2 EOR is not a viable proposition for extending the hydrocarbon producing life of Dunlin A. Furthermore, CO_2 EOR is potentially a reserves enhancement technology and is not regarded as a re-use option following decommissioning of the platform.

While CO_2 sequestration is a potential re-use option for the Dunlin platform, it is not economically viable. The main reasons are: the cost of providing the CO_2 pipeline and associated infrastructure; limited Dunlin reservoir capacity for sequestration; and the inefficiency of using a large, aging, high maintenance platform for the minimal facilities required for sequestration.

More detailed conclusions are presented below.

8.1 CO_2 EOR

- The Dunlin reservoir is suitable for CO_2 EOR. However, it is remote, almost 500km distant from the nearest significant CO_2 source and around 700km away from the major point sources of CO_2 in the central region of Scotland.
- Very few of the existing Dunlin A process facilities would be suitable for re-use in CO_2 EOR service because of capacity constraints and incompatible materials of construction. Dunlin has no compression and limited power generation.
- Re-completed or new injection and producing wells would be required, designed for CO_2 service.
- CO_2 EOR is technically feasible but would require a new, large and complex CO_2 processing module in the order of 5000 to 15000 tonnes. The facilities would include a CO_2 separation module, produced water handling, CO_2 compression and dehydration, membrane fuel gas recovery and additional power generation.
- It is unlikely the existing steel columns on the GBS legs or the deck could carry the weight of the new module. A recent Dunlin project to install a 2000 tonnes module required deck and top column strengthening. A new purpose-built platform could be more cost effective.
- The existing structure is over 30 years old and likely to incur high future maintenance costs.
- CO_2 capture and transportation pipeline and hub would cost in the order of £1.2 to £1.7 billion. Dunlin alone could not justify the installation of such a system and it would need to be part of a wider co-ordinated CO_2 infrastructure hub system. The tariffs for CO_2 supplied to Dunlin would be high unless significant government subsidy is provided or, CO_2 value through the European carbon credit system increases substantially from the present value of around 15 euros/tonne.
- The Dunlin facilities and well costs for EOR facilities would be in the order of £1 billion. A breakeven oil price for a Dunlin CO_2 EOR project would be in excess of $100/barrel, and possibly closer to $150/barrel given the remoteness of the platform.

8.2 CO_2 sequestration

- The Dunlin reservoir may have limited capacity for large scale CO_2 sequestration given that the reservoir is already pressurised by water injection and is a closed reservoir structure. The capacity will depend on the maximum allowable pressure in the reservoir.
- CO_2 pipeline supply infrastructure costs would need to be shared as part of a much wider CO_2 network and hub as described in Section 5.
- Very few of the existing Dunlin facilities are required or are suitable for CO_2 sequestration. New topsides equipment would be required, including a new CO_2 manifold, CO_2 booster pump and vent system.

- Existing power generation equipment on the platform could be re-used but an alternative power source will be required as hydrocarbon gas would no longer be available on the platform.
- New CO_2 injection wells would be required.
- As minimal facilities are required for sequestration, much of the space on Dunlin A would be unused, but the entire platform would require maintenance. As described in Section 6, a subsea development would possibly be more attractive if in the future a CO_2 distribution hub developed in the area. Pressure boosting could then be located on the hub platform.

9 REFERENCES

1. Opportunities for CO_2 Storage around Scotland - an integrated strategic research study. Scottish Centre for Carbon Storage for the Scottish Government, University of Edinburgh, April 2009
2. Enhanced Oil Recovery using Carbon Dioxide in the European Energy System. The Institute of Energy, Netherlands. Report EUR 21895 EN, December 2005

Appendix D

CGB Re-use: Sample announcement for Official Journal of the European Union

Appendix D

CGB Re-use: Sample announcement for Official Journal of the European Union

Fairfield Energy Limited is an independent British oil and gas company which operates the Dunlin field in the UK North Sea on behalf of itself and MCX (a wholly owned subsidiary of Mitsubishi Corporation). When the field reaches the end of its economic life the infrastructure will be decommissioned.

Dunlin is located some 500km north-northeast of Aberdeen in 150m of water. The main structure to be decommissioned is the Dunlin A platform, consisting of a 240,000 tonnes concrete gravity base (CGB) substructure with four legs, supporting a 20,000 tonnes topsides, comprising a steel deck with oil and gas drilling and production facilities.

Fairfield Energy, in developing its decommissioning plans on behalf of the owners, anticipates that the most acceptable decommissioning mode for the CGB will be to leave the CGB in place, with topsides removed. This is contingent upon confirmation from the UK oil & gas regulator, the Department of Energy and Climate Change.

This situation will create a possible opportunity for others to use the CGB for purposes other than hydrocarbon production. To maximise the notice period available for such action, Fairfield Energy will be offering the CGB for sale. Individuals or organisations interested in buying the CGB will be subject to an assessment of financial strength and technical competence before being accepted as credible potential buyers.

Acceptable individuals or organisations will be provided with technical and commercial information, including:

- CGB drawings and design specifications
- Detailed description of the proposed 'as left' condition of CGB legs
- Oceanic and climate data relevant to the Dunlin location
- Dunlin Decommissioning Environmental Statement
- Draft CGB sale and purchase agreement
- Details of the required value and form of residual liability security
- Timetable for the availability of the CGB for transfer

Interested parties should address their initial enquiries to:

Fairfield Energy
Ash House
Fairfield Avenue
Staines
Middlesex
TW18 4AB
United Kingdom

T: +44 (0) 1224 37 27 77
Email: info@fairfield-energy.com

Appendix E

Liabilities under the Petroleum Act 1998

Appendix E

Liabilities under the Petroleum Act 1998

Under the provisions of Sections 29 - 45 of Part IV of the Petroleum Act 1998 (as amended by the Energy Act 2008) the Government has the powers to impose on certain parties an obligation to decommission offshore installations and pipelines.

This regime is administered by the Department of Energy and Climate Change (DECC) and formal notification of decommissioning obligations is made by the Secretary of State to all relevant parties by the issuance of what has colloquially become known as a 'Section 29 Notice' (i.e. a Notice issued under the provisions of the Petroleum Act 1998 Section 29).

Section 29 Notices are routinely issued to the operator and owners of an installation or pipeline who, in general terms have 'benefited' from specific UK offshore oil and gas developments but in fact, a very wide group of persons may be served with a Section 29 Notice.

Parties in receipt of a Section 29 Notice are required to prepare and submit a decommissioning programme to DECC at an appropriate time for approval by the Secretary of State. In practice, decommissioning programmes are likely to be requested a few years prior to cessation of production. The decommissioning programme must contain cost estimates, time schedules and any ongoing maintenance provisions as necessary. Parties have a 'joint and several' obligation to fund and undertake decommissioning works associated with the offshore development specified by the Notice. This means that any one person served with a Section 29 Notice could potentially be liable for the entire decommissioning cost.

Entities in receipt of Section 29 Notice may also be required to provide an appropriate security to satisfy the Government that funds will be available for decommissioning and any necessary maintenance required once oil and gas reserves have been commercially exhausted and production has ceased. Following the Energy Act 2008 such security may be requested at any stage in the installation or pipeline's lifetime.

Parties in receipt of Section 29 Notices relevant to Dunlin A are:

Fairfield Betula Limited

MCX Dunlin (UK) Limited

Shell U.K. Limited

Esso Exploration and Production UK Limited

Statoil (U.K.) Limited

OMV (U.K.) Limited

DECC has published guidance on decommissioning. These guidelines are available at:

https://www.og.decc.gov.uk/regulation/guidance/decommission.htm