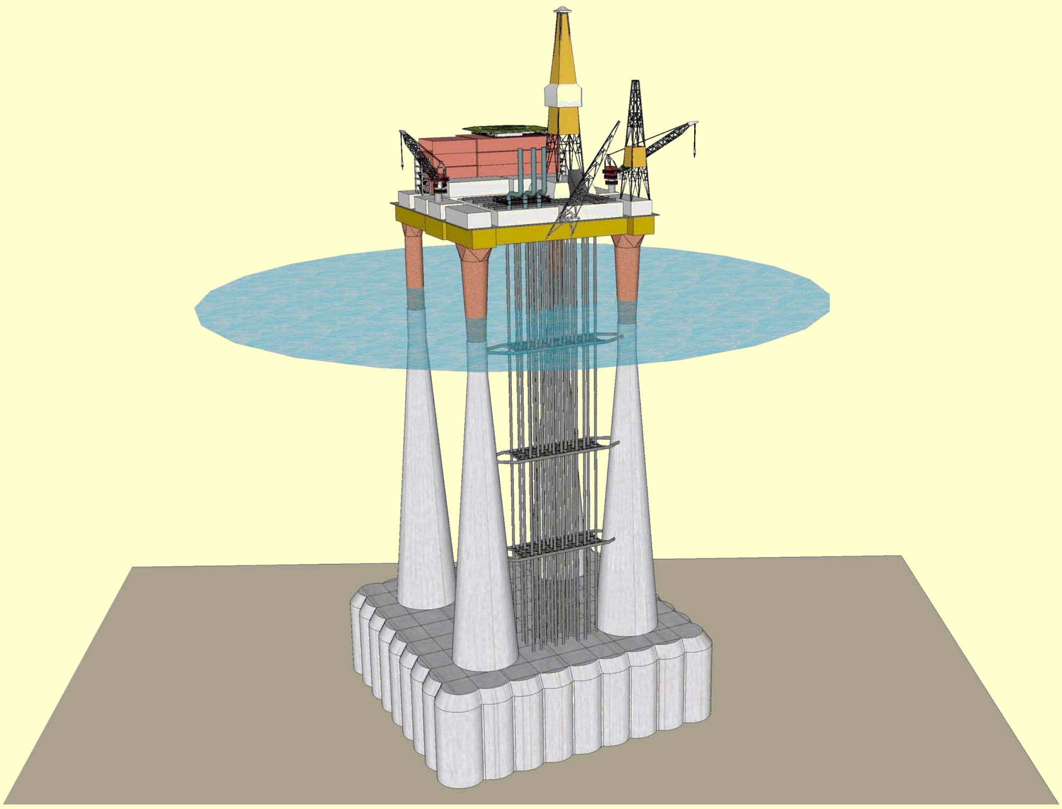
Dunlin Alpha Decommissioning



Concrete Gravity Base

In Situ Deconstruction

Options and Conclusions

October 2011

Dunlin Alpha Decommissioning

Fairfield Document Approval Record

Document Title and Issue Date
Dunlin Alpha Decommissioning Concrete Gravity Base In Situ Deconstruction Options and Conclusions First issue date: 10 October 2011

Approver	Company Position	Signature	Date
T.F. Kimber	Decommissioning Manager	TKimber	10 October 2011

Dunlin Alpha Decommissioning

Concrete Gravity Base

In Situ Deconstruction

Options and Conclusions

Contents

1. Executive summary

2. Introduction

3. Offshore deconstruction options
   - 3.1 Dunlin A platform
   - 3.2 Deconstruction procedure
   - 3.3 CGB legs and columns
   - 3.4 Removal of legs and columns
   - 3.5 Personnel access inside CGB legs

4. Discussion
   - 4.1 Cutting technology
   - 4.2 Heavy lift vessel support
   - 4.3 Restraining the leg during cutting
   - 4.4 Floating off the cut leg section
   - 4.5 Pressure retaining capacity of the leg

5. Conclusions

6. References

Appendices

A. Dunlin field and surrounding area

B. Concrete gravity base decommissioning options

C. Review of cutting methods by CUT

D. Review of marine operations by GL Noble Denton

E. Review of leg section external support by Atkins

F. Review of leg section float off by Offshore Design Engineering

G. Review of leg section pressure containment by Atkins

H. Atkins decommissioning capability profile

J. CUT decommissioning capability profile

K. GL Noble Denton decommissioning capability profile

L. ODE decommissioning capability profile

1. Executive summary

This report has been prepared by Fairfield Energy to consider the possibility of entirely removing the Dunlin Alpha concrete gravity base (CGB) structure from its current location by deconstructing the CGB offshore, followed by transporting the recovered materials to shore for subsequent disposal. This operation, referred to as in situ deconstruction, has been considered as part of a possible platform decommissioning programme once hydrocarbon production from the Dunlin field has ceased, which is not anticipated until 2018 or later.

As it is not possible to refloat the Dunlin Alpha platform and tow it to another location, any attempt to deconstruct the CGB would have to be carried out offshore at the current location in the field. A separate report presents the technical analysis related to refloating the platform.

To date, other large concrete platforms which have been decommissioned have been left in place with topsides removed, for example in the Frigg and Ekofisk fields, as no viable methods have been found to deconstruct them on location in a controlled way. To remove a concrete structure such as the Dunlin Alpha CGB, which weighs around 320,000 tonnes, would require large scale underwater cutting operations to be carried out that are capable of cutting through very thick reinforced concrete in the platform's legs and base, and through any steel equipment inside the structure. In addition, the cutting technique and procedures would have to ensure that the concrete sections being cut, and the overall structure, remain stable throughout the process, despite being subjected to fluctuating environmental conditions in the northern North Sea, and that the cut sections could be safely lifted onto a transportation barge. Such an operation has not yet been attempted.

To assist with assessing the feasibility of the in situ deconstruction option, Fairfield Energy commissioned four leading independent companies with relevant expertise to conduct reviews into the activities involved. The companies are Atkins, Cutting Underwater Technologies, GL Noble Denton and Offshore Design Engineering. The technical reviews conducted by these companies are presented in Appendices C to G.

In addition to the operational requirements of maintaining structural stability during the cutting process and the ability to lift large concrete sections, restrictions exist at Dunlin Alpha regarding personnel health and safety. These are explained in Section 3.5 of this report. These constraints would not allow personnel to work inside the legs of the CGB to remove internal equipment prior to cutting operations, nor would divers be allowed inside the legs once these had been flooded.

An assessment of the combination of the operational requirements and constraints - cutting technology effectiveness, structural stability, lifting capability, and personnel health and safety – has led Fairfield Energy to conclude that it would be possible to sever the legs of the CGB at a depth of eight metres below sea level, in the vicinity of the connection between the concrete legs and the steel columns above. Cutting the legs at depths below this level would not be attempted as the risks involved would not be manageable.

Therefore, as the legs of the CGB would remain largely intact, the base of the CGB could not be cut and removed. Consequently no study work has been undertaken on the cutting of the CGB base for this report, nor on the onshore recycling of the CGB.

In summary, while the Dunlin Alpha topsides and supporting steel columns would be removed and taken to shore for subsequent recycling and disposal, the CGB would be subject to a derogation application to gain approval for the CGB to be left wholly or partly in place.

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 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 end of its economic 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 320,000 tonnes Dunlin A CGB is the most significant area of decommissioning activity. Fairfield Energy is considering seven options for decommissioning the CGB, six of which were presented to stakeholders on 21 January 2010 in Aberdeen as part of the public consultation process; a seventh option was been added in July 2011. These options are described in Appendix B.

This report focuses on one of those six options, namely the in situ deconstruction and onshore disposal of the Dunlin A CGB.

Separate reports address the other six options and can be viewed at http://www.fairfield-energy.com/pages/view/decommissioning. 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. Therefore any CGB deconstruction work that might be possible would have to be performed offshore in the Dunlin field, the subject of this report.

The platform sits in 151m of water. To give an appreciation of scale, Figure 1.1 shows a graphic representation of the platform in comparison with the Big Ben clock tower in London, which is 96m high.

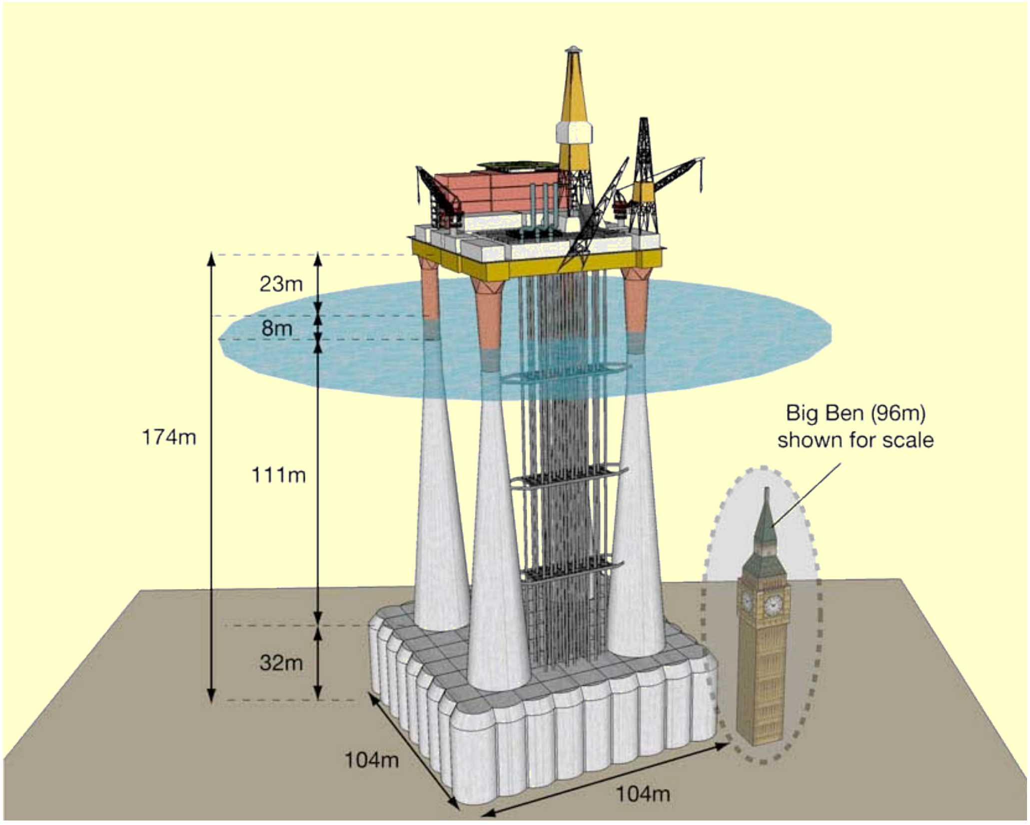


Figure 1.1. Dunlin A compared with Big Ben for scale

Removal of the platform from its current location, once the topsides had been removed, would focus on cutting the legs and base of the CGB into sections to enable these to be lifted from the sea and transferred to a barge for transportation to shore. Figure 1.2 shows the CGB (with topsides removed) as it would be prior to removal operations beginning. This view shows the steel columns that support the topsides deck remaining in place on top of the concrete legs as these could potentially be used for creating attachment points for lifting slings.

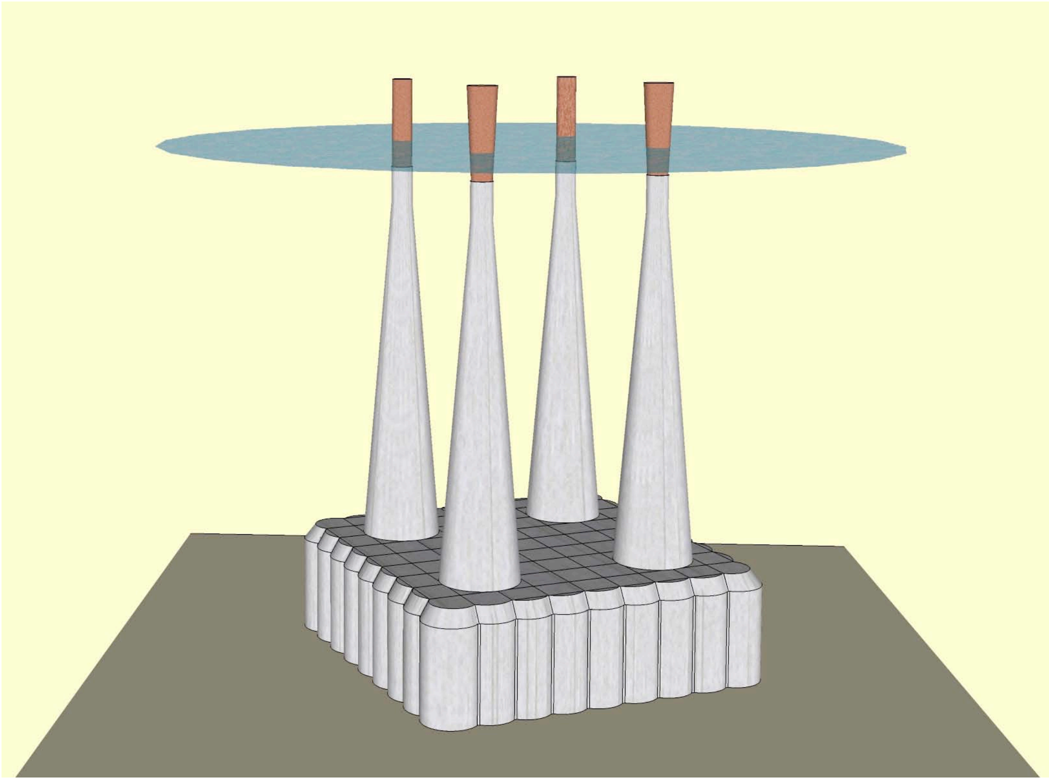


Figure 1.2. CGB prior to removal operations beginning

Removal would begin with the cutting of the CGB's four legs. Cutting and lifting operations for a structure as large as the Dunlin CGB, standing in 151m of water, would involve major activities in the harsh environment of the northern North Sea - an offshore operation of this type and at this scale has not been attempted before. Therefore, to help assess whether such operations would be viable in practice, Fairfield Energy commissioned four independent expert companies to evaluate the principal activities that would be involved in the removal of a CGB leg, taking account of available technology, the prevailing environment and the risks involved.

The findings of the four companies in relation to these operations are presented in Appendices C to G of this report. The subjects of the studies can be summarised as follows:

- A review of different methods for cutting through large diameter reinforced concrete sections underwater, and their possible application to the CGB. Evaluated by Cutting Underwater Technologies and presented in Appendix C.
- Removing the cut section of leg by a heavy lift crane vessel, with or without external buoyancy being added to the leg section. This study was conducted by GL Noble Denton and is presented in Appendix D.
- An assessment of a method for temporarily supporting the cut leg section with a purpose-designed external bracing frame during the cutting operation. This support would be necessary to resist the wave forces acting on the leg section as this could overturn it as it was severed from the lower part of the leg. The assessment was carried out by Atkins and is reported in Appendix E.

- Removing the cut leg section by floating it off the leg, with or without additional buoyancy being added. This study was conducted by Offshore Design Engineering (ode) and is presented in Appendix F.
- An assessment of the pressure retaining capacity of the cut section of leg, relating to its ability to hold compressed air as a possible method of floating the leg section by buoyancy. The assessment was carried out by Atkins and is reported in Appendix G.

Profiles of the four companies describing their offshore decommissioning expertise are included in Appendices H to L of this report.

Section 3 of this report describes the Dunlin platform and the procedure for how the removal of a leg section might be attempted. Section 4 discusses the methods for doing this and highlights the challenges involved, calling on the findings of the reports listed above. In Section 5, Fairfield Energy draws its conclusions about the viability of removing the Dunlin CGB by deconstructing the structure at its current location.

3. Offshore deconstruction

3.1 Dunlin A platform structure

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 method of platform construction is described in Appendix A. The Dunlin A platform was installed in 1977 and, after the drilling of initial wells, oil production began in 1978. Figure 3.1b below shows the main components of the platform.

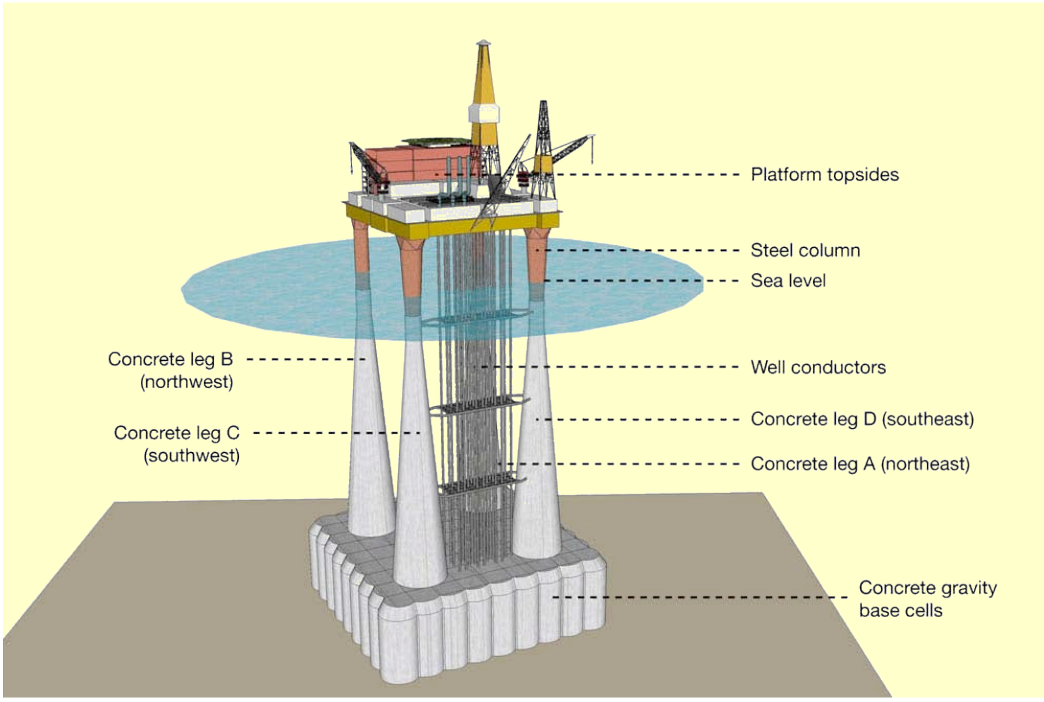


Figure 3.1b Dunlin A platform main components

The main components of the Dunlin A platform are:

- The CGB base, measuring 104m by 104m and 32m high, sitting on the seabed. The base is subdivided internally with concrete walls into 81 cells, 75 of which were used to assist oil-water separation until 1995, after which the platform's operating practice changed and these cells were no longer used. The other six cells in the base are used for the cooling of the well conductors using circulated seawater.

- Four 111m high concrete legs rise up from the base to 8m below sea level.

- Four 31m tall steel columns, attached to the tops of the concrete legs at 8m below sea level, rising above sea level.

- A 20,000 tonnes steel deck and modular topsides, supported on the steel columns.

- Well conductors to convey hydrocarbons from the Dunlin reservoir to the topsides. The conductors are supported by three steel guide frames fixed between legs C and D.

As the CGB cannot be refloated for towing to shore (Ref.1), its deconstruction would have to be carried out at the platform's current location, with the materials produced being transported to shore for subsequent disposal.

It is anticipated that the platform's 20,000 tonnes topsides will be removed by lifting it from the CGB as one structure or in parts. While the offshore industry's current maximum heavy lift vessel capability is approximately 14,000 tonnes, there are plans to develop lift concepts with up to 40,000 tonnes capacity in the time scale envisaged for the decommissioning of Dunlin, which would be capable of removing the topsides in a single lift. It is expected that as part of the topsides removal, the steel columns supporting the topsides would be severed at around 16m above sea level, leaving a section of column some 24m in height attached to each concrete leg.

The CGB weighs approximately 320,000 tonnes, including internal equipment in the legs and solid ballast in the CGB base. There are no anticipated plans to develop an offshore vessel with sufficient capacity to lift the CGB, and hence removal of the CGB would require deconstructing it at its current location.

3.2 Deconstruction procedure

Prior to any deconstruction work involving the CGB, the topsides would have been removed and taken to shore for dismantling and recycling. Topsides removal is not covered in this report but will be addressed in the detailed Decommissioning Programme for the Dunlin Cluster.

In addition to topsides removal, the following activities would also be completed prior to CGB deconstruction:

- Wells plugged and abandoned
- Well tubing terminated below seabed level; well conductors removed
- Subsea pipelines, flowlines and cables disconnected from the platform

Consideration will be given to the environmental impacts of drill cuttings removal from on and around the CGB base, and the removal of the contents of the CGB cells, should the option of complete platform deconstruction and removal prove to be technically viable. A separate report assesses the contents of the CGB cells (Ref. 2).

Following the completion of the preparatory tasks outlined above, the CGB could, in theory, be deconstructed offshore in the following sequence:

- Remove the three conductor guide frames, transport to shore.
- Separate the steel columns from the tops of the concrete legs at their interface (8m below sea level) and remove the steel columns to shore. However, for cases involving the removal of the concrete legs by cutting and lifting, most of the height of the steel columns may be left in place (as shown in Figure 1.2) to provide attachment points for heavy lift cranes and/or external buoyancy tanks.
- Sever the concrete legs from the CGB base, either as four entire leg structures or by cutting each leg into large sections. Lift or float off the legs/sections and transport the recovered material to shore, including internal equipment inside the legs.

- Progressively break up the CGB base (roof, walls, internal cell walls and base slab). Lift and transport the recovered material to shore, including solid granular ballast at the bottom of the cells.
- Remove the grout from the seabed under the CGB and the 4m deep steel skirts penetrating into the seabed, and transport the recovered materials to shore.

All of these operations would require specialised cutting equipment and the support of a heavy lift crane vessel and transportation barges. Methods of attaching purpose-designed lifting points to the cut sections would have to be developed.

For the complete CGB removal sequence to be achieved, the legs of the CGB would have to be removed first. The remainder of this report focuses on the CGB legs and the possibility of removing them.

3.3 CGB legs and columns

Rising up from the roof of the CGB base are four reinforced 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 columns 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. See Figure 3.3a.

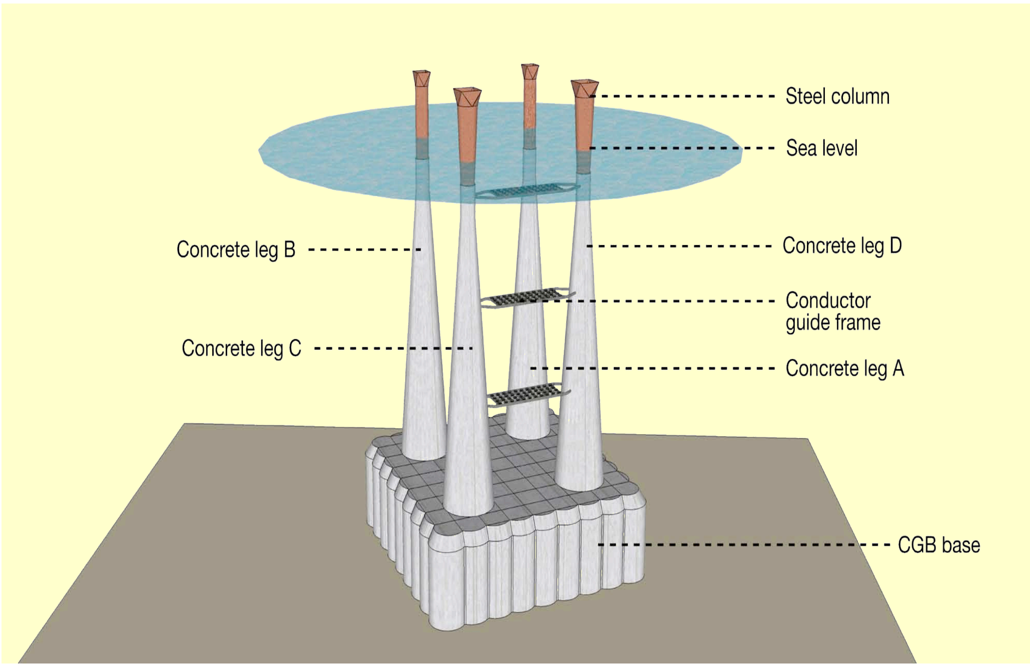


Figure 3.3a CGB with topsides and conductors removed

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 on Legs A and B weigh approximately 300 tonnes each and are 5.4m in diameter, changing to a square section at the deck underside. See Figure 3.3b below.

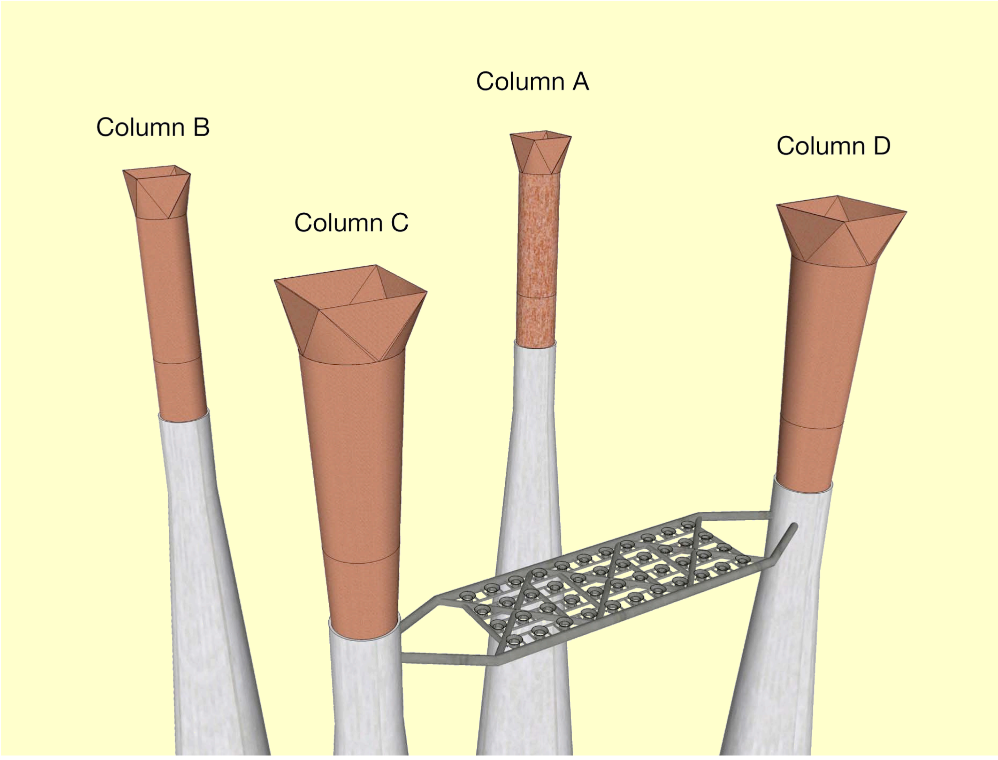


Figure 3.3b Steel columns at the tops of the concrete legs

The Leg A and Leg B steel columns are connected to the concrete legs with one external row of 40 bolts, 50mm in diameter, plus two internal rows of 40 bolts of the same size (120 bolts in total per leg). The Leg C and Leg D steel columns are connected to the concrete towers with two external and two internal rows of bolts (160 bolts in total per leg). The bolted connection is shown in section in Figure 3.3c below.

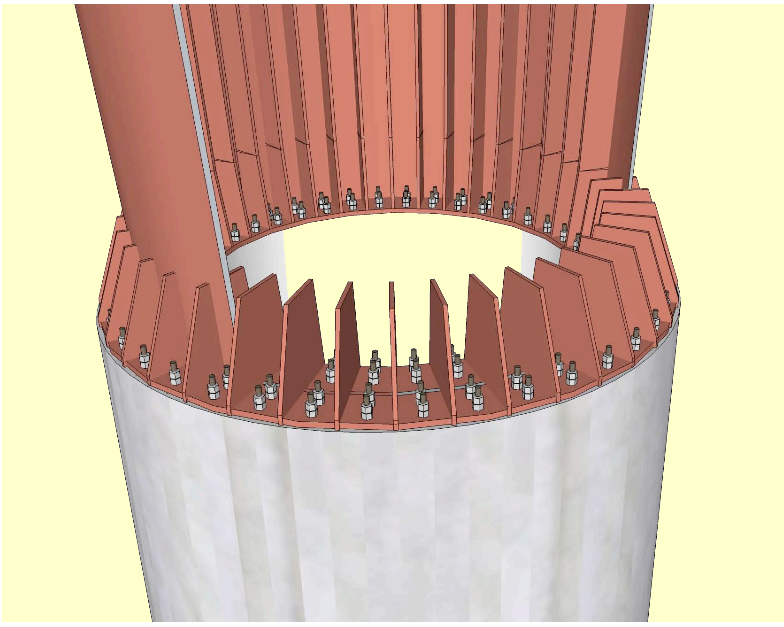


Figure 3.3c. Bolted connection between concrete leg and steel column

Spanning between Legs C and D are three horizontal guide frames. 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.

Equipment and pipework (up to 36 inch in diameter) are distributed within the four legs, in different combinations. In addition, access stairways, lift shafts, platforms and service openings extend from the top of the legs down to the roof of the CGB base. The quantity and complexity of the equipment arrangements inside the legs is too great to include within this document. However, a series of engineering drawings that convey the nature of the internal equipment in the legs can be viewed at:

http://www.fairfield-energy.com/pages/view/Dunlin CGB legs internals

For reference, the principal pipework lines and diameters which pass through the legs include:

Leg A
Seawater standpipe 36 inch
Conductor cooling water supply 6 inch
Conductor cooling water return 6 inch

Leg B
Four 16 inch/28 inch oil lines

Leg C
2 x 24 inch risers
1 x 20 inch risers
2 x 16 inch risers
4 x 14 inch J-tubes
2 x 10 inch J-tubes

Leg D
2 x 20 inch risers
4 x 14 inch J-tubes
2 x 10 inch J-tubes

Risers are pipelines which enter the base of the CGB and connect to the platform topsides, conveying oil, gas and water, for example the main 24 inch diameter oil export line from Dunlin A. J-tubes also enter the CGB base and connect to the topsides, and act as conduits for other lines, for example flowlines carrying fluids to and from subsea fields, control umbilicals and power cables.

3.4 Removal of legs and columns

For the purposes of assessing the feasibility of removing the CGB legs, Fairfield Energy has considered three elevations for leg cutting, namely:

- At 8m below sea level. This is the level at which the steel columns are connected to the tops of the concrete legs. Compared with cutting large diameter reinforced concrete at deeper underwater levels, this cut would be relatively straightforward to make.

- At 55m below sea level. This level corresponds to the level which would give a depth of clear navigable water above the structure, as recommended by the International Maritime Organisation, should the CGB be left in its current location at this reduced size.
- At 110m below sea level, some 9m above the CGB base and above the drill cuttings accumulation. This option holds the potential to remove an entire leg in a single operation.

The cutting levels are shown in Figure 3.4a below

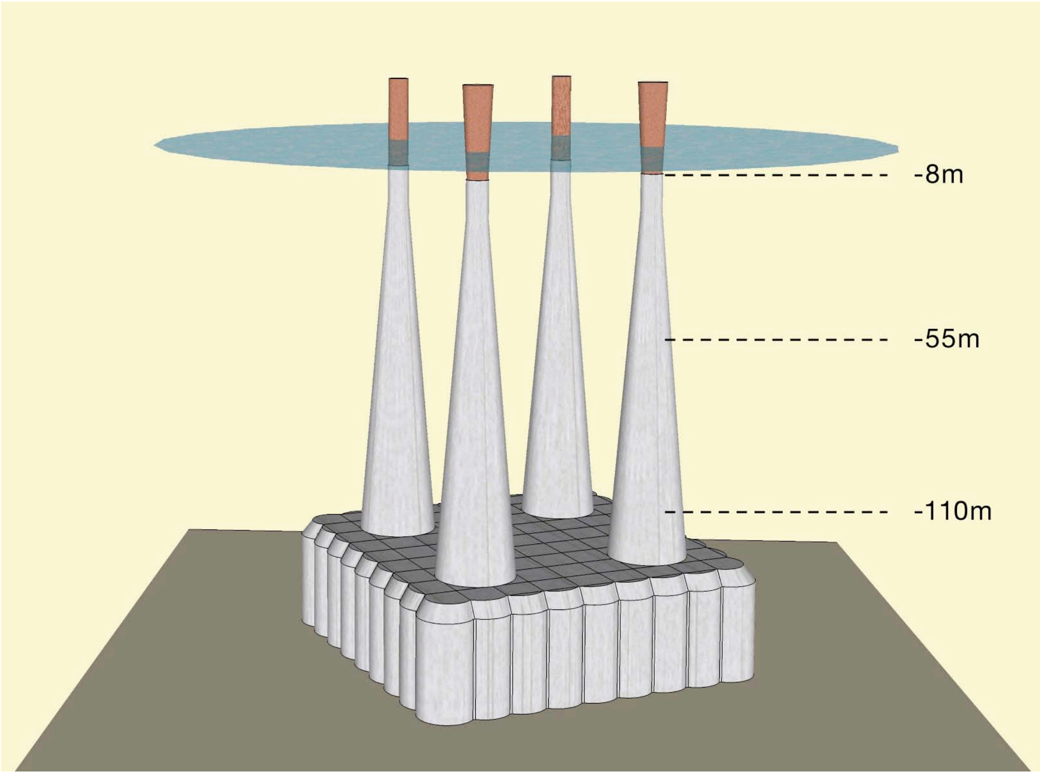


Figure 3.4a. Three underwater cutting levels for the CGB legs

The two deeper levels, which present the greater challenges, have been the main focus of an assessment of different cutting methods performed by specialist contractor Cutting Underwater Technologies. The methods assessed are:

- Shaped explosive charges
- Abrasive water jets
- Track saw/chain saw/diamond stitch drilling
- Reciprocal wire/chain sawing
- Diamond wire cutting

The results of the assessment are presented in Appendix C. It should be noted that the internal equipment in the legs could not be removed prior to any leg cutting operations for health and safety reasons (see Section 3.5), therefore any underwater cutting technology employed would have to be capable of cutting through reinforced concrete and a wide variety of steel pipework and internals in the same operation.

In addition to an assessment of the capability of underwater cutting technology, consideration must also be given to methods for holding the leg section steady during cutting. Environmental loads constantly act on the concrete structure, resulting from wind, tidal and current flows, together with changes in static loading due to tidal depth variations. During cutting, such environmental loads would produce shear forces on the leg section which could displace or ‘slide’ the section off the lower leg, and bending moments, which could ‘push over’ the cut leg section. These effects would be greater in magnitude as the depth of the cut increased, as shown in Figure 3.4b.

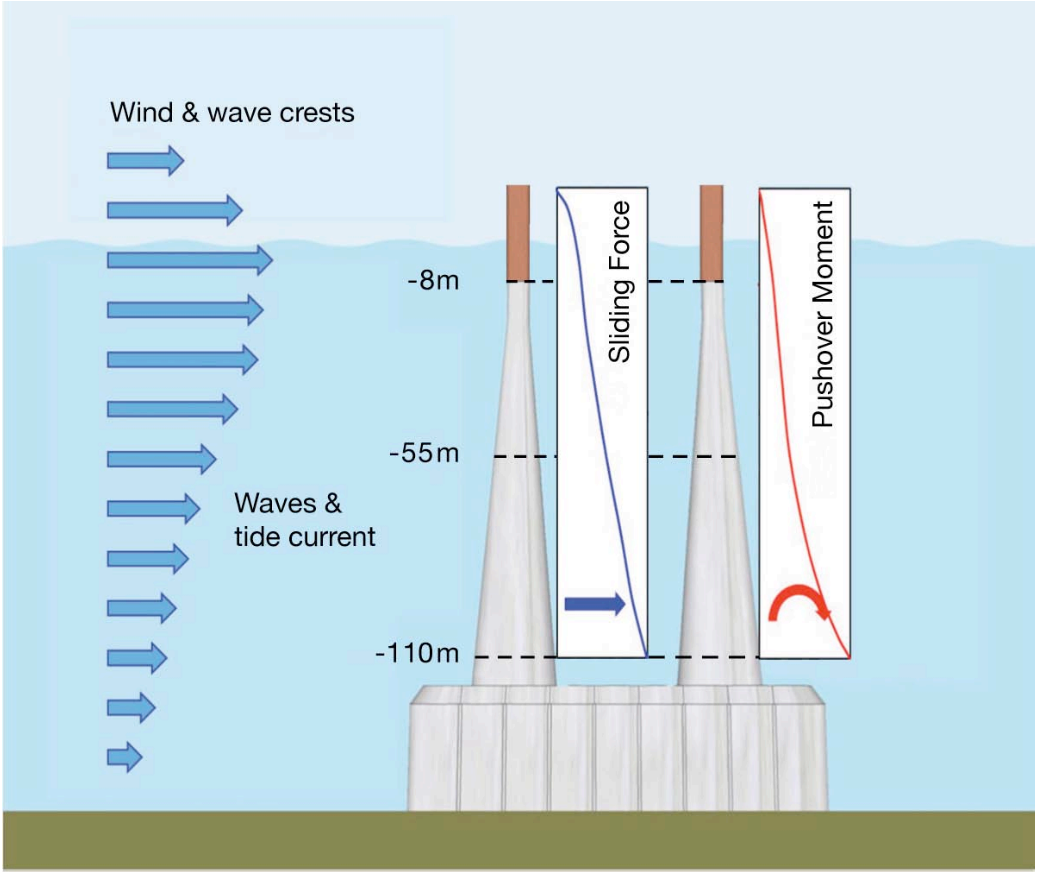


Figure 3.4b Environmental forces acting on the legs of the CGB

Theoretically, the effects of these forces could be mitigated by maintaining a tensile load in the legs throughout the cutting operation, for example, by applying an upwards lifting force to the leg section by a heavy lift crane vessel. This concept is shown in Figure 3.4c. The leg section if cut at 55m below sea level would weigh around 2600 tonnes.

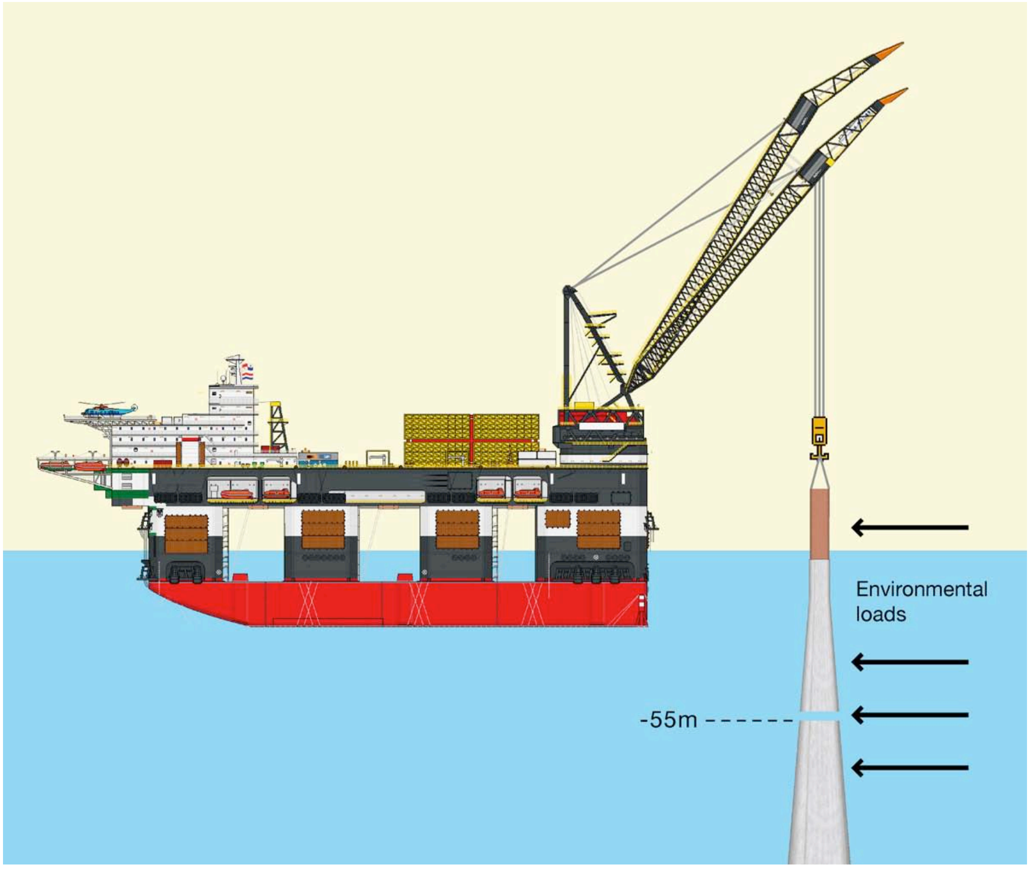


Figure 3.4c. Heavy lift vessel supporting section of leg cut at -55m

However, the stability of the crane vessel would also be affected by the prevailing environmental conditions, its response being determined by the vessel's motion characteristics. To assess the ability of a heavy lift vessel to stabilise the cut leg section against environmental loads, Fairfield Energy commissioned Noble Denton to evaluate the characteristics of a typical heavy lift crane vessel in these circumstances. The vessel selected for the evaluation is the semisubmersible crane vessel *Thialf* belonging to Heerema Marine Contractors, one of the largest heavy lift vessels in the offshore industry. The work focused on the practicality of maintaining a constant tensile load in varying environmental conditions for a period of 72 hours (the anticipated leg cutting time estimated by CUT), having regard for the overall safety of the crane vessel. The motion of the vessel would create additional bending moments on the leg due to the difference in motion characteristics of the leg and the vessel. This work is presented in Appendix D.

As a further safeguard to prevent the cut leg section from being displaced or overturned by environmental loads, Fairfield Energy commissioned Atkins to propose a conceptual design for an external support frame that could hold the cut section steady during the cutting operation. This work is presented in Appendix E.

As an alternative to lifting the leg section off, consideration has also been given to introducing buoyancy to the cut leg section to allow this to be floated off rather than lifted off. Accordingly, Fairfield Energy commissioned ode to assist with the 'float off' evaluation. Ode assessed the potential for using the leg's internal volume as a buoyancy chamber by filling this with compressed air as well as adding external buoyancy tanks to the legs. This work is presented in Appendix F. The basic concept is shown in Figure 3.4d.

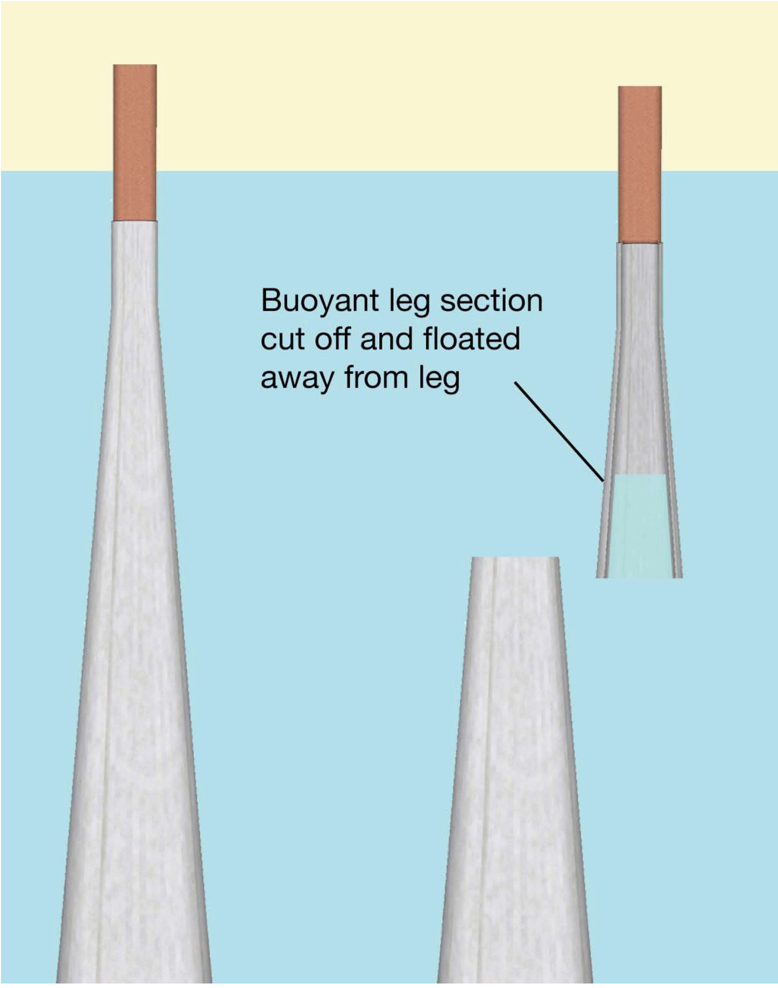


Figure 3.4d. Concept of floating off the cut section of leg

In a further study related to floating off a leg section, Atkins was requested to determine the maximum safe air pressure that could be applied to the leg internal volume from the perspective of maintaining the structural integrity of the leg section. This work is presented in Appendix G.

3.5 Personnel access inside CGB legs

In relation to offshore deconstruction work, this section addresses the restrictions imposed by Fairfield Energy on personnel being allowed to access the inside of the legs of the CGB, for health and safety reasons.

All four CGB legs were designed to allow entry by operations personnel to gain access to equipment and pipework distributed within the legs. For this purpose, lift shafts, access stairways, vertical ladders, platforms and service openings extend from the top of the legs down to the roof of the CGB base. The legs were designed to be maintained dry and ventilation systems are provided to circulate air inside them.

In the context of decommissioning operations, personnel entry into the legs might be proposed for the possible removal of internal equipment from a particular zone prior to a leg cutting operation, to give the cutting operations a greater chance of success. In addition, the use of divers may be proposed as the legs would be flooded prior to cutting operations beginning.

The primary consideration of Fairfield Energy in the contemplation of any access to the CGB legs is that of ensuring that the health and safety of personnel undertaking the work is held paramount. Access to the CGB legs is and has always been subject to strict entry procedures, which recognise that personnel required to work within the legs could be exposed to health and safety risks due to the restricted leg space. The entry procedures specify the requirements for adequate ventilation within the legs, and actions for emergency evacuation and recovery. Since Dunlin platform operations began in 1978, the entry procedures have become increasingly rigorous. This reflects greater health and safety awareness across the industry; changing conditions inside the legs, for example flooding in Leg A which presents a risk of hydrogen sulphide being present in the atmosphere (see Appendix A); and events in the wider industry relating to accidents inside the legs of offshore concrete structures, notably two fatalities on the Brent Bravo platform in 2003.

The Health & Safety at Work etc Act 1974, the Offshore Safety Case Regulations 2005 and related statutory provisions, approved codes of practice and industry best practice, impose obligations and expectations on Fairfield Energy and its contractors regarding the management of health and safety risks. Accordingly, Fairfield Energy's health and safety policy establishes unequivocal aims and expectations for ensuring that its business activities minimise, so far as is reasonably practicable, risks to health and safety. Fairfield and its contractors will apply the company's health and safety policy to any contemplated operations involving CGB access.

Risk assessment is the principle method for ensuring fulfilment of acceptable standards of health and safety. Risk assessment, which is required by UK health and safety legislation, is a technique commonly applied to an activity in order to identify the hazards to health and safety, and to determine the actions necessary to avoid or control risk. Fairfield Energy has a risk assessment methodology that is applied as part of the project planning process. The methodology considers the hazards to health and safety – that is to say, the possibility of harm occurring to personnel – arising from any contemplated activity.

Once all the hazards have been identified, the severity of the possible consequences and the likelihood of the consequences actually occurring, are combined to determine the level of health and safety risk associated with the contemplated activity. At this stage it may be determined that the level of risk associated with a particular activity is unacceptable, or that the activity is acceptable but only after specific risk elimination, risk reduction or risk mitigations have been applied.

Fairfield Energy provides a 'Risk Assessment Matrix' for employees and contractors which facilitates discussion and communication on health and safety risk during activity planning. The Risk Assessment Matrix is designed to provide a structured and systematic approach to risk assessment that particularly enables options to be compared in terms of the level of associated health and safety risk. The Risk Assessment Matrix also provides indication of categories of risk that may not be acceptable, or which may require consideration and authority for action from a senior level within the company.

Activities that could carry a foreseeable consequence of death or serious injury to personnel will not be sanctioned by Fairfield Energy, unless the risks can first be reduced to a level that is acceptable. Acceptability of risk is a broad concept that takes into account stakeholder expectations, including societal perceptions of risk, in addition to the statutory responsibility of the Fairfield Energy board, management and employees.

For operations which could require personnel to work within the CGB legs, the risk assessment would evaluate whether suitable and sufficient air supplies could be secured; that acceptable means of emergency escape and rescue could be provided; and that personnel are not put at risk from materials or equipment falling from above.

The leg access procedures currently used during the operational phase of Dunlin would form a basis for these considerations. However, the risk assessment would need to take account of any variations that apply with the platform being in non-operational mode, and with decommissioning and possible deconstruction activities taking place.

As described in Appendix A, leg flooding incidents have occurred in Leg A and Leg B. In 1999 oil leaked from the cells in the base 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 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 in the base. As with Leg A, the contained volume of oil was subsequently recovered, but in this case it was possible to repair the pipework.

Following these incidents, air quality in the legs has deteriorated, giving rise to the risk of hydrogen sulphide and hydrocarbon vapours being present, making working, emergency response and evacuation procedures more challenging. As a result, leg access is only sanctioned for essential activities. Therefore, in balancing the risk to personnel with the value of any work inside the legs relating to decommissioning, for example the removal of internal equipment in the concrete cutting zones, Fairfield Energy considers such operations to present an unacceptable risk to personnel safety, and would therefore exclude such operations.

Where access is contemplated below the water level in a flooded leg, or where external access to the legs is required, the risk assessment would evaluate the risks to divers in particular. Diving operations are an inherently hazardous activity, requiring a high standard of risk control and mitigation to be in place before the diving activity can be considered to be acceptable. Given the restricted workspace within the flooded legs, the associated risks of entrapment of divers from service conduits, stairways, ladders, platforms and other equipment within the legs, and the risks to divers from collapse or instability of overhead structures, Fairfield Energy considers that the use of divers in these circumstances would present an unacceptable risk to personnel safety, and would therefore exclude such operations.

As stated above, in the context of decommissioning operations, personnel entry into the legs might be proposed for the possible removal of internal equipment from a particular zone prior to any leg cutting operations, to give the cutting operations a greater chance of success. Such operations are considered to impose an unacceptably high risk to the health and safety of personnel for the following reasons:

- Due to the design of Dunlin A, much of the pipework within the legs is pressured by the surrounding sea, for example the J-tubes, which are not provided with installed isolation. Consequently the industry standard of 'double block and bleed' isolations for safety cannot be established and therefore Fairfield Energy would not sanction any work involving cutting pipework that conveys high water pressure, as this could flood an entire leg very quickly.
- The internal pipework and equipment were installed as the concrete legs were built in 1976/77. Much of the internal pipework weight is 'self-carried' vertically (pipework effectively in compression under its own weight) with relatively lightweight beams installed at various elevations to restrain horizontal movement. This method of installation means that if pipework was removed from a particular zone prior to leg cutting there would be the potential for the pipework suspended above the cut zone to collapse, unless significant additional support was provided.

4. Discussion

This report investigates the potential for complete removal of the Dunlin CGB by a process of offshore deconstruction, to be followed by onshore recycling and disposal. In particular, the report has focused on the technical challenges associated with the removal of the CGB's four concrete legs, as their removal would be a necessary first step to achieve the complete removal of the CGB.

Removal of the legs has focused on cutting these structures into large sections for lifting onto a barge for transportation to shore. The cutting elevations evaluated were selected to be at -8m, -55m and -110m below sea level, as explained in Section 3.4. Fairfield Energy has taken the view that if it can be demonstrated that cutting and removal operations could be achieved at these underwater levels from the perspectives of both technical capability and safety, then further analysis could be undertaken to establish the cutting elevations for the optimum leg removal sequence. It should be noted that the concept of demolishing the legs, each of which weighs around 7600 tonnes, by progressive 'piecemeal' breaking of the concrete from the leg tops downward has been ruled out by Fairfield Energy as this approach would be too diver-intensive and would entail the exposure of personnel to significant risk, which must be minimised.

The size and weight of the CGB legs would have a major influence on the practicality of removing them. The -8m cut level coincides with the interface between the tops of the concrete legs and the steel columns on top of these. The 31m high columns weigh between 300 and 500 tonnes each, and if their tops were cut off at around 16m above sea level as part of the topsides removal process, these weights would be reduced. Cutting and lifting the remaining sections of the steel columns from the legs would be achievable using methods well known in the offshore industry.

However, assuming that severing the legs at the deeper elevations could be achieved in practice, cutting at -55m below sea level would produce a 71m high leg section (with steel column attached) weighing around 2600 tonnes, and cutting an entire leg free at -110m would produce a 126m high leg section of around 7600 tonnes. These would be significant loads to manage in a benign inshore environment; the complexity of the task would be substantially increased if the operation were to be undertaken in the open waters of the northern North Sea.

Whether the cut were to be made at -55m or -110m, the leg removal concepts face two fundamental common issues, namely:

- The ability to successfully cut through the reinforced concrete leg cross-section together with the pipework and equipment inside the leg.
- The ability conduct the associated marine operations to manage the stability of the leg section above the cut elevation during the cutting and subsequent removal of the leg section to the surface, having regard for prevailing weather conditions. The marine operations evaluated include the use of a heavy lift vessel, underwater bracing of the leg, and 'float off' of the leg section under buoyancy.

Given the scale and complexity of the challenges, and the fact that such an offshore deconstruction operation has not been attempted before for a CGB, Fairfield Energy commissioned the services of four independent expert companies to evaluate the key stages of the leg removal process. For leg removal to be successful, and thereby allow the subsequent deconstruction of the base of the CGB to be considered, it is vital that these key stages be achievable, separately and in successive combination. Each of the evaluations is presented in full in Appendices C to G. Their principal findings are summarised in the following discussion sections, highlighting the technical and safety challenges that would be involved in the leg removal process.

4.1 Cutting technology

Cutting Underwater Technologies (CUT) conducted an assessment of different methods for cutting reinforced concrete underwater, and the possible application of those methods to the cutting of the legs of the CGB at its current offshore location (Ref 3). The full report is included in Appendix C.

Five broad categories of cutting techniques were considered, namely:

- Shaped explosive charges
- Abrasive water jets
- Track saw/chain saw/diamond stitch drilling
- Reciprocal wire/chain sawing
- Diamond wire cutting

Cutting operations for the legs of the CGB were evaluated for depths of 8m, 55m and 110m below sea level. Details of the legs at these depths are summarised in Table 4.1.

	EL -110m		EL -55m		EL -8m	
Leg	**A&B**	**C&D**	**A&B**	**C&D**	**A&B**	**C&D**
Leg						
Outer diameter (m)	21.32	21.32	13.80	13.80	6.60	6.60
Inner diameter (m)	19.77	19.77	12.45	12.45	4.80	4.80
Thickness (m)	0.77	0.77	0.68	0.68	0.90	0.90
Vertical reinforcement Number of bars Diameter (mm)	 1536 20	 1088 25	 896 20	 1152 20	 576 20	 640 20
No. of steel tendons	96	96	96	96	68	68

Table 4.1. CGB leg details at target cutting depths.

The feasibility of the cutting operations was evaluated taking into account:

- The legs of the CGB would be deliberately and irreversibly flooded before commencement of the cutting operations to avoid the uncontrolled surge of water from the sea into a leg as the cut was started
- No diver access inside the legs would be allowed
- No preparatory work would be possible to remove or secure the equipment inside the legs

- There could be no guarantee of equipment stability inside the legs at the -55m and -110m levels

The work undertaken by CUT concluded that the two cutting techniques with the greatest chances of successfully severing the CGB legs would be the diamond wire and the reciprocal wire methods. On balance, an orbital diamond wire cutting machine (DWCM) presents some key advantages over the reciprocating wire method, including:

- Lower weight and more compact.
- The possibility of building a purpose-designed scaled-up DWCM, although it should be noted that this would need to be significantly larger in scale than any existing machine (for example, about six times larger for the -110m level cut). While reciprocal wire cutting has been proven on a large scale in ship salvage operations, it has never been deployed for cutting reinforced concrete in the horizontal plane, as would be required to cut the CGB legs.
- Controlled deployment of an orbital DWCM in a stage-wise procedure around the circumference of a CGB leg, enabling the cut to be made from each side of the leg.
- A DWCM creates a thin clean cut line with relatively constant width, compared with a wider and more irregular cut line created by reciprocating wire. With the regular diamond wire cut, shims could, in theory, be inserted between the cut edges of the concrete. Shim insertion would be necessary to ensure the 10mm diameter diamond wire would not become trapped, and to recreate continuity in the concrete to transfer vertical loads.
- An orbital DWCM requires less operational time, and less wire to be held on the machine as it would not have to encircle the circumference of the leg as would the reciprocating wire. Although the diamond wire would wear in operation, it may be possible to design a DWCM that stored enough wire length to complete the cutting operation without wire replacement by divers. However, this would increase the overall tool weight and its complexity. If such a DWCM could not be built, diving work would be required to service the machine and replace the cutting wire subsea (assuming that the wire could be replaced with the shims in place).

CUT's concept for an orbital DWCM mounted on a CGB leg is shown in Figures 4.1a and 4.1b below, depicting the diamond wire (in red) prior to and during cutting.

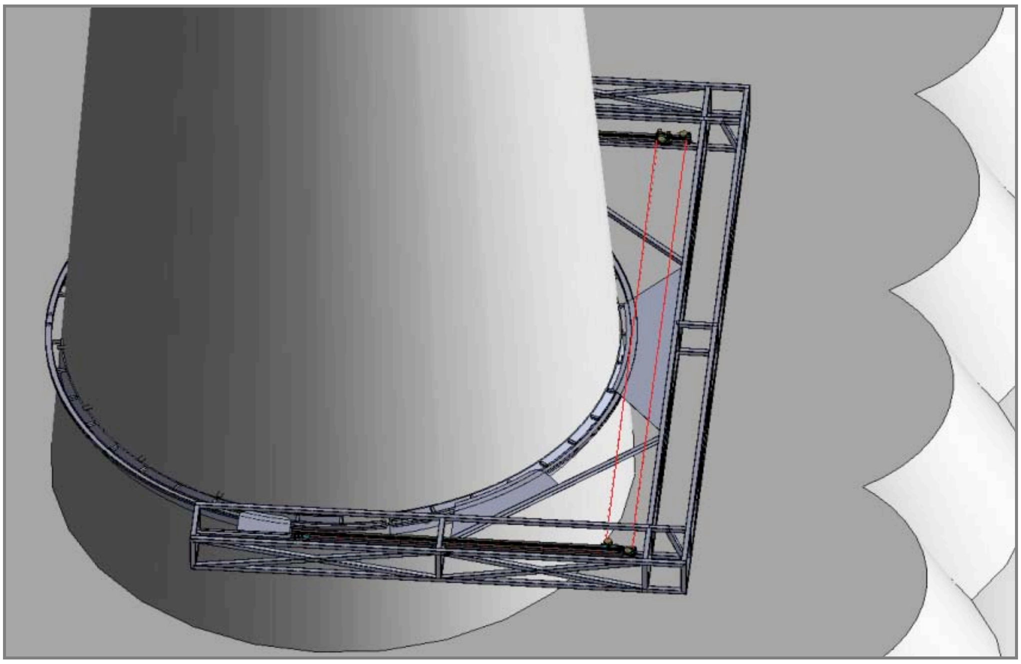


Figure 4.1a. CUT concept for an orbital diamond wire cutting machine, prior to cutting

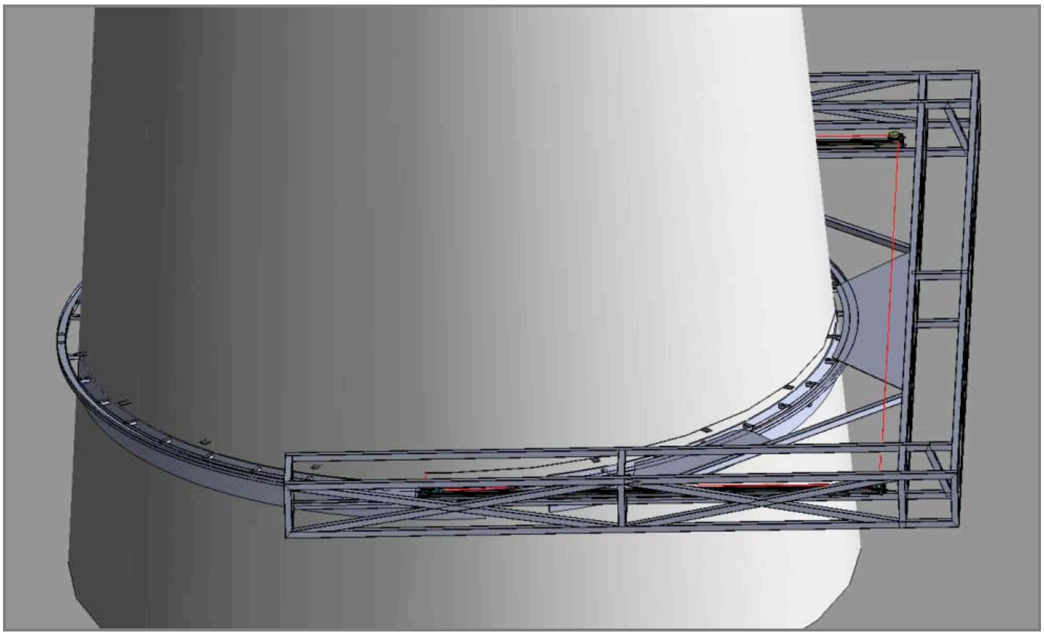


Figure 4.1b. Diamond wire progressing through the leg. At this stage the machine would be moved to the other side of the leg to repeat the process.

If the diamond wire cutting operation proceeded as planned, CUT estimates this would require an approximate cutting time of between three and eight days for the leg at the -110m level, two to three days at the -55m level, and one to two days at the -8m level.

However, despite these apparent advantages for diamond wire, CUT concludes that severing the legs at -55m or -110m would only be possible with any certainty of success if the internal equipment and pipework in the legs were first removed or stabilised. The unpredictable free movement of the internals could cause the thin wire to become pinched or jammed as a result of items moving or collapsing within the leg, and this could terminally damage the diamond wire during the cutting operation. It must be re-emphasised that Fairfield Energy would not permit personnel to remove or stabilise the internals inside the legs for health and safety reasons (see Section 3), and the use of remotely operated vehicles inside the legs once flooded would not be possible due to the complexity of gaining access through the walls of the legs and the nature of the items within the legs.

Furthermore, to prevent the sawn gap in the concrete from closing in an uncontrolled fashion onto the 10mm diameter diamond wire due to dynamic forces acting on the concrete leg section above the cut, shims would have to be inserted into the cut. Although this procedure has been used successfully underwater on smaller steel structures, it has not been employed before for underwater cutting of a large concrete structure such as the CGB. In addition, should the wire become trapped, Fairfield Energy believes that it would not be possible to fit a replacement diamond wire as the shims would prevent the new wire traversing over the completed cut section to reach the uncut concrete face.

Given the anticipated time of up to eight days to complete the severance of a leg section, the potential for the wire to be trapped or broken is significant. The leg cutting operation would be exposed to several tidal cycles and the uncertainty of wind, wave or current changes within the time period. The resultant environmental forces on the leg would cause the saw cut, which would be only slightly wider than the 10mm wire, to open and close, particularly as the diamond wire traversed further across the leg section. The opening and closing motion could trap and/or break the diamond wire.

Having given consideration to the factors above, Fairfield Energy is of the view that DWCM may provide a chance of cutting through the legs, but the cutting technology has several significant uncertainties:

- The potential for diamond wire breakage due to the wire becoming trapped as the cut gap following the wire closes due to environmental loads acting on the leg above the cut line.
- The potential for diamond wire breakage due to the insecurity of the large amount of pipework and other equipment inside the leg.
- The need for a single length of wire to survive the breakage risks discussed above and be sufficiently durable to cut through the entire leg cross section without loss of cutting performance due to wear.
- The difficulty of inserting shims into the narrow sawn gap in the concrete, and the obstruction the shims would present to bringing a replacement wire to the uncut face of the leg.

To address the possibility of overcoming some of the uncertainties associated with diamond wire cutting, Fairfield Energy commissioned GL Noble Denton to investigate the potential for using a heavy lift vessel to maintain the stability of the cut leg section, as discussed below in Section 4.2. For this analysis, and the subsequent evaluations carried out by Atkins and ode, attention has been focused on a leg section cut at the -55m level to determine if this would be possible, before considering the entire leg being cut at the -110m level, which would be significantly more challenging due to both scale and water depth.

4.2 Heavy lift vessel support

Fairfield Energy commissioned GL Noble Denton to analyse the stability of the CGB cut leg section in various weather conditions to determine if the leg section would 'slide' or 'overturn' due to the environmental loads acting upon it (Ref. 4). The analysis also evaluated the effect of providing crane hook support to the leg section from a heavy lift vessel throughout the underwater cutting operation. The full report is included in Appendix D.

The analysis:

- Considered a situation where the CGB leg had been cut at an elevation 55m below sea level, creating a weight on the crane hook of the order of 2800 tonnes.
- Considered the use of a large semisubmersible crane vessel (SSCV) applying up to 1000 tonnes 'stabilising' uplift on the leg during the latter phases of the cut.
- Identified whether the heavy lift vessel would improve or worsen the leg stability during the cutting process.

Offshore lifting operations may be subjected to a wide range of environmental conditions depending upon the season, duration of the operation, and sensitivity of the activity. Where an operation is of short duration (less than 72 hours) weather conditions can be forecast with sufficient accuracy to allow relatively low design wave heights to be adopted for the analysis. For a longer operation, which could be likely for the cutting of a CGB leg, the risk of deteriorating weather increases rapidly, hence offshore practice requires that a safe condition is attainable, where the structure being lifted can resist environmental conditions having a low (10%) probability of being exceeded. Drawing on its extensive database for conditions in the North Sea, GL Noble Denton selected the following design conditions (referred to as the 10 year seasonal storm) for analysing the stability of the CGB leg section cutting and lifting operation:

• Significant wave height	10.9m
• Range of associated wave period (peak)	13 to 17.5 seconds
• Wind speed	72.3 knots
• Surface current	1.0 knots

A detailed weight estimate was made for the leg section cut at 55m below sea level, resulting in a weight of 2666 tonnes. For lifting operations a weight of 2800 tonnes was used, as this provides some contingency. For calculating the overturning moments created by environmental forces acting on the leg section, a value of 2666 tonnes (without contingency) was used as this lower weight would give a more conservative result.

For modelling purposes for the analysis, GL Noble Denton selected semisubmersible heavy lift vessel *Thialf*, owned by Heerema Marine Contractors, one of the largest heavy lift vessels in the industry, for which the motion characteristics in different environmental conditions are well understood. The vessel has two main cranes, each rated to a maximum of 7100 tonnes at the main hoist. The cut leg section being supported by one of *Thialf's* two cranes is shown diagrammatically in Figure 4.2.

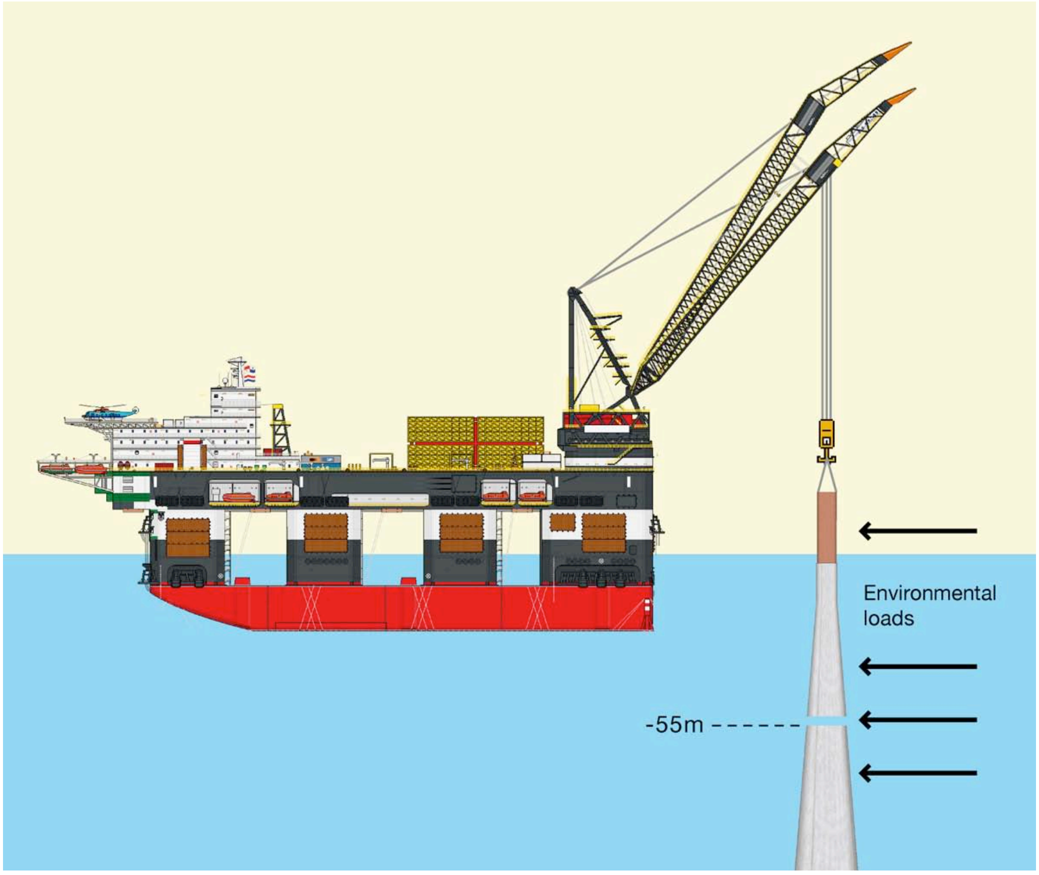


Figure 4.2. Heavy lift vessel *Thialf* supporting the leg section cut at -55m

The study concluded that:

- Application of a crane hook load by the heavy lift vessel during underwater cutting of the leg could be detrimental to the operation. Calculations show that snatch loads could occur in relatively mild sea conditions, which could displace the leg section during the process of cutting, or damage the leg cutting mechanism, rigging, or lift points/attachments on the leg sections. The introduction of large and unpredictable snatch loads would not be acceptable to the Marine Warranty Surveyor.
- It would not be advisable to impose a hook uplift load while cutting, except immediately prior to making the final lift.
- The factor of safety related to the risk of the cut leg section overturning is calculated to be 0.52 in the sea conditions of a 10 year return seasonal storm wave. This factor is considered to be unacceptable. GL Noble Denton guidelines require a factor of safety of at least 1.2 against the 10 year return storm.
- Leg section stability would be problematic even for a weather restricted operation. Since the reliability of weather forecasting beyond 72 hours is limited, a weather restricted operation should not exceed this. However, underwater cutting technology is unproven for diameters as large as the CGB legs and this would increase the uncertainty in the duration of the cutting process and hence the risk of exposure to severe weather.
- The potential for leg overturning and sliding in moderate sea states would require either the provision of additional restraint or the adoption of highly

restrictive operational sea conditions. Attaching buoyancy tanks to the leg section (see Section 4.4) would increase the risk of the leg section overturning as the leg and tanks together would attract greater environmental loads.

- Installation of lift points would be required to lift the leg section, weighing approximately 2800 tonnes. This would require substantial structural reinforcement of the steel column at the lift point attachment.
- It would be difficult to confirm the integrity of the steel column, concrete section and the bolted attachment. This fact would pose a serious threat to safety during any lifting or set-down operation.

Based upon these findings, GL Noble Denton recommends that:

- A heavy lift vessel should not be used to support the leg section during cutting.
- Underwater cutting technology needs to be further developed to ensure the leg section could be cut and removed in a suitably short weather window.
- Consideration should be given to restraining the leg underwater by external means during cutting.
- Further assessment would be required for determining a method for creating secure lifting attachment points for the leg section.

4.3 Restraining the leg during cutting

Atkins was commissioned by Fairfield Energy to study the possibility of restraining the leg underwater during the diamond wire cutting operation at 55m below sea level (Ref. 5). This analysis was carried out to determine whether the cut leg section could be held steady against the environmental loads in summer storm conditions to prevent the section being displaced by shear forces or overturned by bending moments. The environmental conditions assessed were the same as those used in the Noble Denton study described in Section 4.2. Atkins technical note is included in Appendix E.

Atkins calculated that the overturning moment that would be exerted on the leg section in the summer storm conditions would be approximately 22,500 tonne-metres, a very significant force. The company proposed a device to provide the temporary support for resisting the overturning moment, as illustrated in Figure 4.3. The device would be intended to be reused on all four CGB legs, and would be attached to the leg by drilling and inserting pins into the concrete. It is estimated that each fully designed and fabricated structural steelwork support unit, fully equipped with a range of cutting tools and remote control instrumentation, would weigh about 100 tonnes and be approximately 5m in length. Around twelve units would be required.

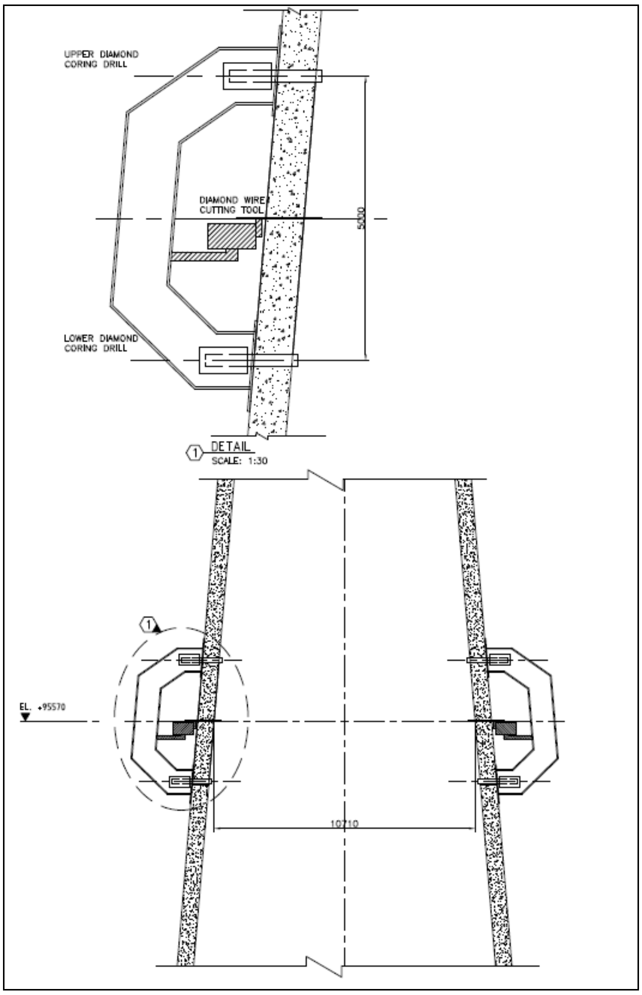


Figure 4.3. Bracing support device attached around the leg at 55m below sea level

Atkins envisaged that the leg section would be hooked up to the crane of a heavy lift vessel with slack slings before the final cutting of the leg was performed. During cutting the leg sections would be held in place against wave action by the temporary clamps in the bracing support device. The leg would be vulnerable to environmental forces from the start of final cutting until the bracing device was removed and the cut leg section was lifted from the sea. If most of the final cuts were completed and a summer storm arose unexpectedly, or if the diamond wire cutting tool failed and caused delay, it would be necessary to disconnect and de-rig the crane slings to move the heavy lift vessel away from the CGB. In such a condition the temporary supports for the cut leg must be designed and installed with the capacity to resist the hydrodynamic loading. Due to the thickness of the leg at the -55m elevation, Atkins concluded that it is unlikely any restraint frame would be able to provide the same strength as the uncut leg. In order to do so, the frame components would have to be impractically large, causing difficulties in handling and installation.

Should the cutting operation fail and have to be suspended for a lengthy period, then the CGB leg could be exposed to more onerous winter environmental conditions. These conditions would include the largest wave expected in 100 years, being 28.7m high, which would subject the leg section at the cut elevation of -55m to an overturning moment of around 36,800 tonne-metres.

Designing the bracing support to be able to withstand forces of this magnitude would make handling and installation even more difficult and dangerous in the offshore environment.

Atkins concluded that the required sizes and weights of the bracing support system would present significant technical and marine operational challenges to the point of becoming impractical.

4.4 Floating off the cut leg section

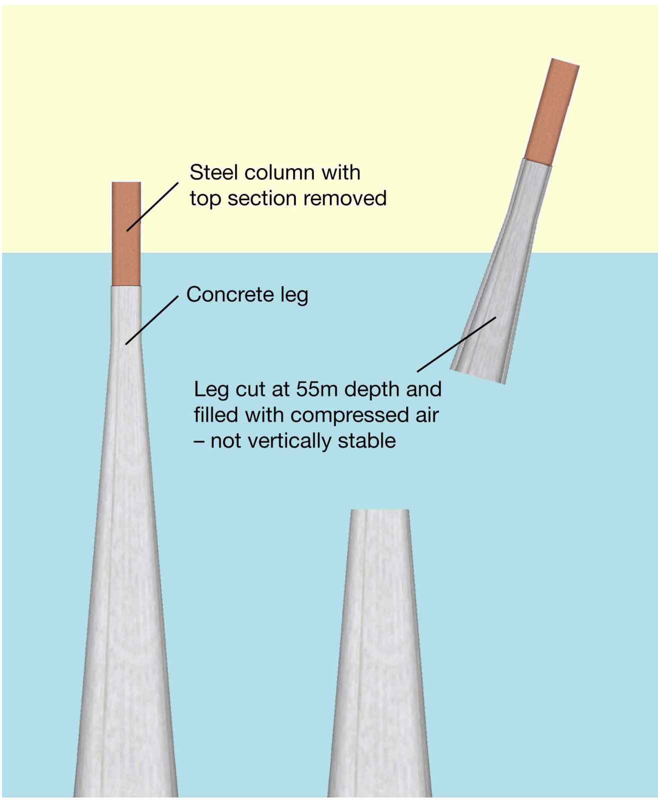
Fairfield Energy commissioned ode to assess the practicality of floating the upper section of a leg of the CGB away from the platform, after it had been severed at 55m below sea level. Ode's work focused on the buoyancy and hydrostatic stability of the leg section, and the practical issues of preparing the leg section for floatation (Ref.6). The detailed ode report is presented in Appendix E.

The leg section would weigh over 2600 tonnes. Buoyancy would have to be provided to the leg section for this float. The installation of a gas tight bulkhead at the top of the leg section would be feasible in concept, thereby allowing compressed air to be injected into the section to displace water from its lower open end to create buoyancy. In parallel with the ode study, Fairfield Energy commissioned Atkins to asses whether the leg section could withstand the internal pressure created by the introduction of compressed air (Ref. 7). The Atkins technical note on this subject is summarised in Section 4.5 and presented in Appendix F.

Other conceptual methods for creating buoyancy would be to attach external buoyancy tanks to the leg section, or by filling the leg section with buoyant materials such as foam.

Ode reviewed five possible methods for floating the leg section, which are summarised below with supporting diagrams, noting their viability.

1. **Leg section filled entirely with air**

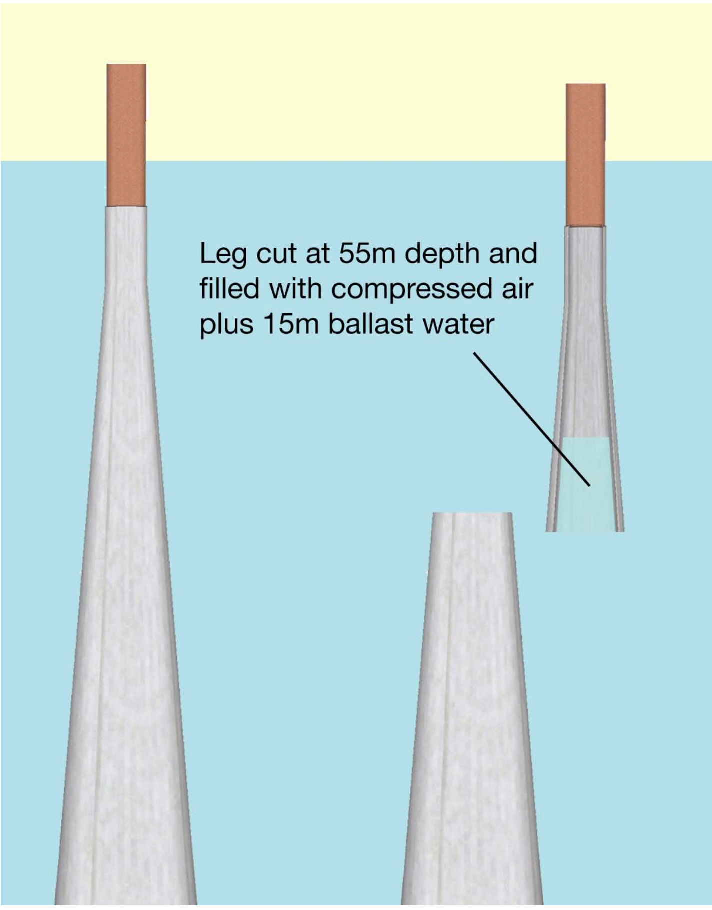


Ode concluded that completely emptying the leg section by displacing the water with compressed air would make the section buoyant, but it would be unstable and the section would capsize.

Furthermore, the Atkins study showed that the air pressure within the leg required to keep the leg section afloat would crack the concrete, creating leakage paths. This would allow the compressed air to escape and cause the section to sink.

For these principal reasons, this method of floating the leg section is considered by Fairfield Energy to be unviable.

2. **Leg section air-filled and with ballast water added at the bottom of the section to make it float stably in a vertical position.**



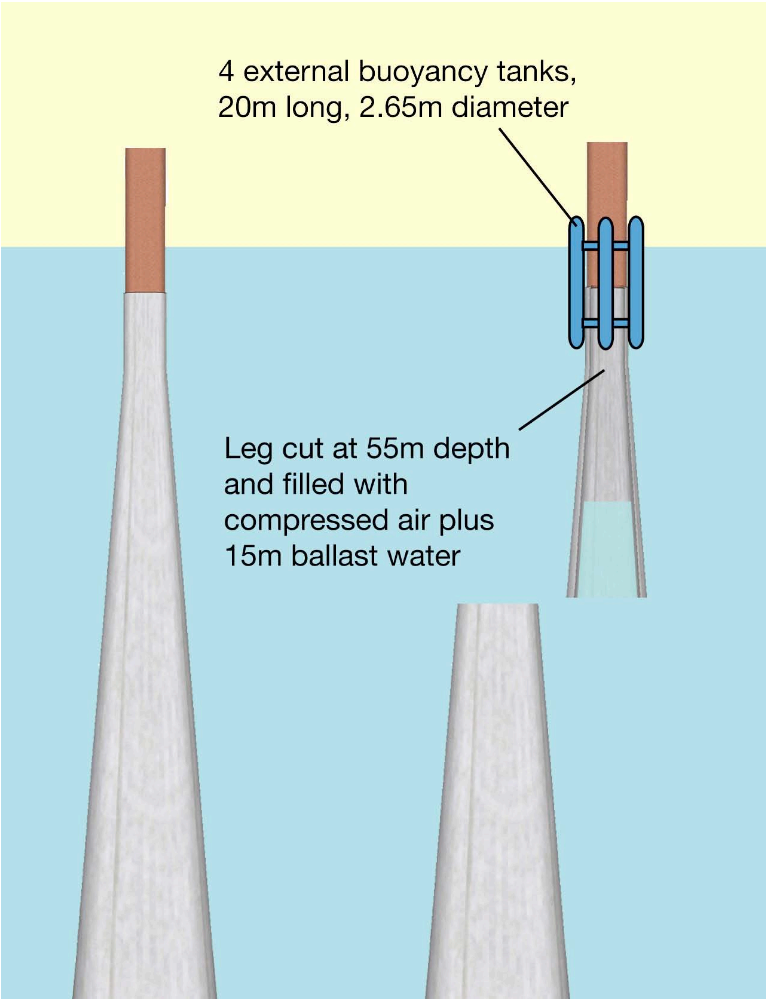
The leg section could, in theory, be partially air-filled with ballast water filling its lower portion to make the section float in a stable manner in the vertical position.

However, ode concluded that the floating draft required for the section to be hydrostatically stable would be greater than the depth of the cut, hence the section cut off the CGB would not float free. If the floating section were to be separated from the CGB, the section would not maintain floating equilibrium or have the dynamic stability required because the volume of the compressed air would change with draft, thereby allowing the amount of ballast water to vary and negate the change to the displacement caused by the change in draft.

In addition, the Atkins study showed that the air pressure within the leg would crack the concrete, and the air would leak out, casing the leg section to sink.

For these principal reasons, this method of floating the leg section is considered by Fairfield Energy to be unviable.

3. **Leg air-filled and with ballast water added at the bottom of the section, plus external buoyancy tanks attached.**



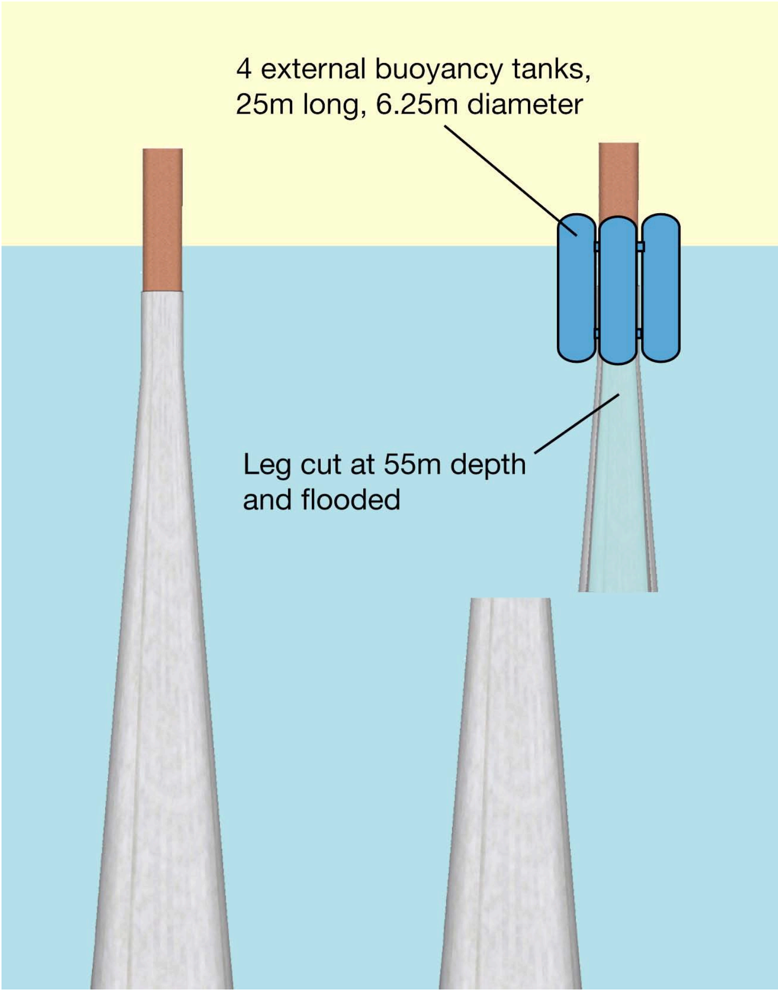
The ode work showed that floating the leg section off the CGB using only its own buoyancy would not be not feasible. Therefore, this case was considered where the leg section was air and water filled as described above, with external buoyancy tanks being attached to the leg section. The buoyancy tanks would allow the cut section of leg to float clear of the remaining CGB without assistance and would provide additional water plane area that would compensate for the change of buoyancy due to change in compressed air volume, caused by variation in draft due to wave action or any other external action.

A 54m floating draft was selected to allow 1m clearance between the cut section and the remaining leg structure. To maintain the 54m draft, 15m of water would be need to be added to the bottom of the leg section to compensate for the extra buoyancy provided by the tanks. The number and size of external buoyancy tanks required to allow the leg to float stably away from the CGB at a draft of 54m was calculated to be four tanks, each 20m long and 2.65m in diameter.

However, as stated above, the use of compressed air within the leg section would generate cracks in the concrete leading to loss of internal air pressure and the leg section sinking. Therefore this is not a viable option.

Ode also identified a number of practical challenges associated with the handling of the buoyancy tanks and their attachment to the leg section.

4. **Leg section flooded with seawater with external buoyancy tanks attached.**



To avoid the problems associated with the use of compressed air, an assessment was made of the size of external tanks required to float the leg section with the inside of the leg filled with water only. To achieve the floating draft of 54m, four external buoyancy tanks would be required, each 25m long and 6.25m in diameter, attached to the leg section.

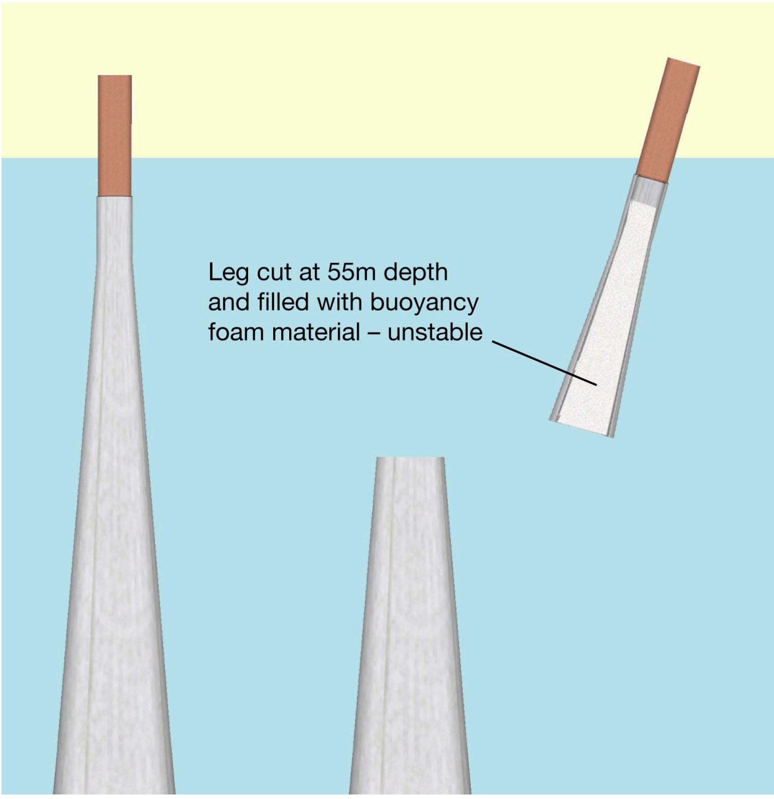
However, while flotation maybe possible in theory, given the scale of the tanks and the practical difficulties which would be associated with their handling and attachment, ode concluded:

Each buoyancy tank would displace 750 tonnes and would require a major offshore operation to attach it to the leg section. The large tanks would require a considerable time, measured in weeks, to attach to the leg, hence the work could not be achieved within a single weather window. A substantial offshore marine operation would be necessary, working within the splash zone above sea level and diving operations 15 to 20m below sea level, which would be complex and would present significant risks. The tanks, leg and the tank supports would have to be able to withstand loadings from a seasonal storm.

The magnitude of the environmental loads from wind, waves and current on the leg would be very large, making supporting the leg during the cutting operation impossible. The increase in wave and current loading would be so large that it would be beyond the capacity of a temporary bracing support (see Section 4.3) and may cause failure of the existing concrete leg.

For these reasons, this option is considered to be unviable.

5. Leg section filled with buoyant material.



To eliminate the provision of a water or air tight bulkhead to keep water out of the leg section, the possibility of filling the leg with foam to make it self-floating was investigated.

Ode concluded that filling or part filling the leg section with solid buoyancy would not provide the stable hydrostatic condition at the required draft. Furthermore, preformed buoyant material would have to be installed in the leg section, requiring removal of internal pipework and equipment. These operations would involve significant risks to personnel and would not be permitted by Fairfield Energy for health and safety reasons (see Section 3.5). It is therefore concluded that this method of floating the leg sections would not be viable.

4.5 Pressure retaining capacity of the leg

In relation to floating off the cut section of leg at 55m below sea level, Fairfield Energy commissioned Atkins to assess whether the cornet wall of the leg could withstand the internal pressure of compressed air added to provide leg buoyancy (Ref. 7). Atkins' technical note is included in Appendix F.

In summary, Atkins indicates that there would be significant vertical cracking in the concrete due to tensile hoop stress, probably around 20m below the top ring beam of the leg, and above this. At this level, the external water pressure would be around 30m, creating an outward pressure differential across the concrete wall of around 40m.

Previous analyses show that this magnitude of internal pressure would cause cracks of about 1.2mm in size on average, which would pass right through the thickness of the concrete wall. In Atkins' opinion, these cracks would probably be large enough to allow air to escape and therefore lose air pressure. Although it would be possible that air losses could be topped up with enough compressors on board, overall there would be considerable risk associated with a leg section floating-off operation. Furthermore, other possible leaks could occur through any existing penetrations in the legs.

5. Conclusions

By considering the findings of the technical reports commissioned from independent experts, Fairfield Energy has reached the conclusion that while removal of the steel columns at the tops of the concrete legs would be achievable, it would not be possible to cut the concrete legs into large sections for subsequent transportation to shore. For in situ deconstruction of the Dunlin CGB, the removal of the legs would be a necessary first step. As this first step could not be achieved, then it would also not be possible to remove the base of the CGB. This conclusion is based on:

- The successful completion of any operation to cut through a leg, including the simultaneous cutting of internal pipework and equipment, must be achievable within a favourable weather window of 72 hours duration, and with a very high degree of certainty. Failure to complete a planned cutting and removal operation within a summer weather window would leave a cut leg at risk of uncontrolled separation and descent to the seabed. The duration of cutting operations reported in this document do not offer the certainty of completing the work inside the required weather window.
- Diamond wire and other mechanical cutting technologies have been developed to cut through reinforced concrete and steel with varying degrees of success. Such technologies have not been applied on the scale required for deployment on the Dunlin CGB or in deepwater, harsh environment conditions.
- Diamond wire cutting equipment cannot cut through internal pipework and equipment inside the CGB legs with an acceptable degree of certainty, where the rigidity of such internal items cannot be guaranteed. Trapping of the diamond wire by unsecured internal items would result in wire breakage.
- The removal of all internal pipework and equipment within the leg sections prior to cutting, to prevent diamond wire entrapment and breakage, would expose personnel to unacceptably high levels of health and safety risk which would not be sanctioned by Fairfield Energy.
- With reference to the installation method adopted for the leg internal pipework and equipment, and the age of Dunlin facilities installed in the mid 1970s, it would not be practical to markedly improve or guarantee the stability of the internal leg equipment for the purposes of ensuring the successful completion of cutting operations. This is particularly so as all legs would be deliberately flooded before any cutting operations could commence to avoid seawater surging into a leg through the cut as the cutting operation began. Furthermore, the legs may have been flooded for a long period, perhaps years, before any decommissioning operations started as any loss of watertight integrity in the CGB at any time prior to cessation of production would require all legs to be flooded to preserve the structural integrity of the CGB. (Ref. 8).
- In the event of diamond wire breakage, or replacement due to wear, it is not clear how replacement diamond wires would be fitted given the uncertainties in maintaining the openness of the sawn gap. Diver intervention for wire replacement, particularly during the later stages of

cutting operations when the stability of the partly cut leg section could not be predicted, could not be sanctioned.

- It has been recommended by independent experts not to use a heavy lift vessel to support and remove leg sections throughout a 72 hour cutting operation (even assuming that the cutting operation could be successfully completed).
- Attempting to brace the leg section underwater while cutting proceeded in order to hold the cut leg section steady against environmental forces could not be achieved due to the scale and handling of the temporary support structures that would be required.
- Leg section removal methods based on the provision of buoyancy are not viable (even assuming that the cutting operation could be successfully completed).

As the concrete leg removal concepts have all been shown to be impractical when removing the top 55m of the concrete legs, further analysis addressing leg section removal from 110m below sea level has not been pursued. As the CGB cannot be removed by deconstruction at its current location, no consideration has been given to onshore recycling and disposal in regard to the CGB structure or sections thereof.

6. References

1. Fairfield Energy, Dunlin Alpha Decommissioning, Concrete Gravity Base Refloat Options, Study and Conclusions, July 2010. http://www.fairfield-energy.com/pages/view/dunlin-refloat-report

2. Intertek METOC, Dunlin Alpha Decommissioning, CGB Cells Contents Impact Assessment, June 2011. http://www.fairfield-energy.com/pages/view/dunlin-cells-contents-impact-assessment

3. Cutting Underwater Technologies, Review of Technologies and Conceptual Methods for Cutting of Dunlin A Concrete Legs, May 2011.

4. GL Noble Denton, Dunlin A Concrete Gravity Base Structure, Leg Section Removal Study, April 2011.

5. Atkins, Dunlin A Decommissioning, Assessment of Temporary Support Methods at -55m Cut Elevation, Technical Note 5073937-201-TN01, August 2011.

6. Offshore Design Engineering, Dunlin Decommissioning Study, Concrete Leg Section Hydrostatic Stability at Float Off, February 2011.

7. Atkins, Dunlin A Decommissioning, Leg Float-Off - Pressure Retaining Capacity, Technical Note 5091295.501 TN03, February 2011.

8. Shell, Dunlin Alpha Concrete Structure Emergency Procedures Manual, Document Number 1311-001, Re-issue 31 August 1999.

Any enquiries regarding this document should be addressed to:

Dunlin Alpha - Public Consultation
Fairfield Energy
Ash House
Fairfield Avenue
Staines
Middlesex
TW18 4AB
United Kingdom

T: +44 (0) 1224 300 500
E: info@fairfield-energy.com

Appendix A

Dunlin field and surrounding area

Appendix A

Dunlin field and surrounding area

Contents

A.1 Dunlin Cluster

A.2 Environmental aspects

A.3 Socio-economic aspects

A.4 Dunlin A platform

A.4.1 Introduction

A.4.2 Concrete gravity base structure

A.4.3 Platform lifecycle

A.4.3.1 Platform construction and installation

A.4.3.2 Concrete gravity base operational history

A.4.3.3 Drilling history

A.4.3.4 Drill cuttings

A.4.3.5 Cells 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).

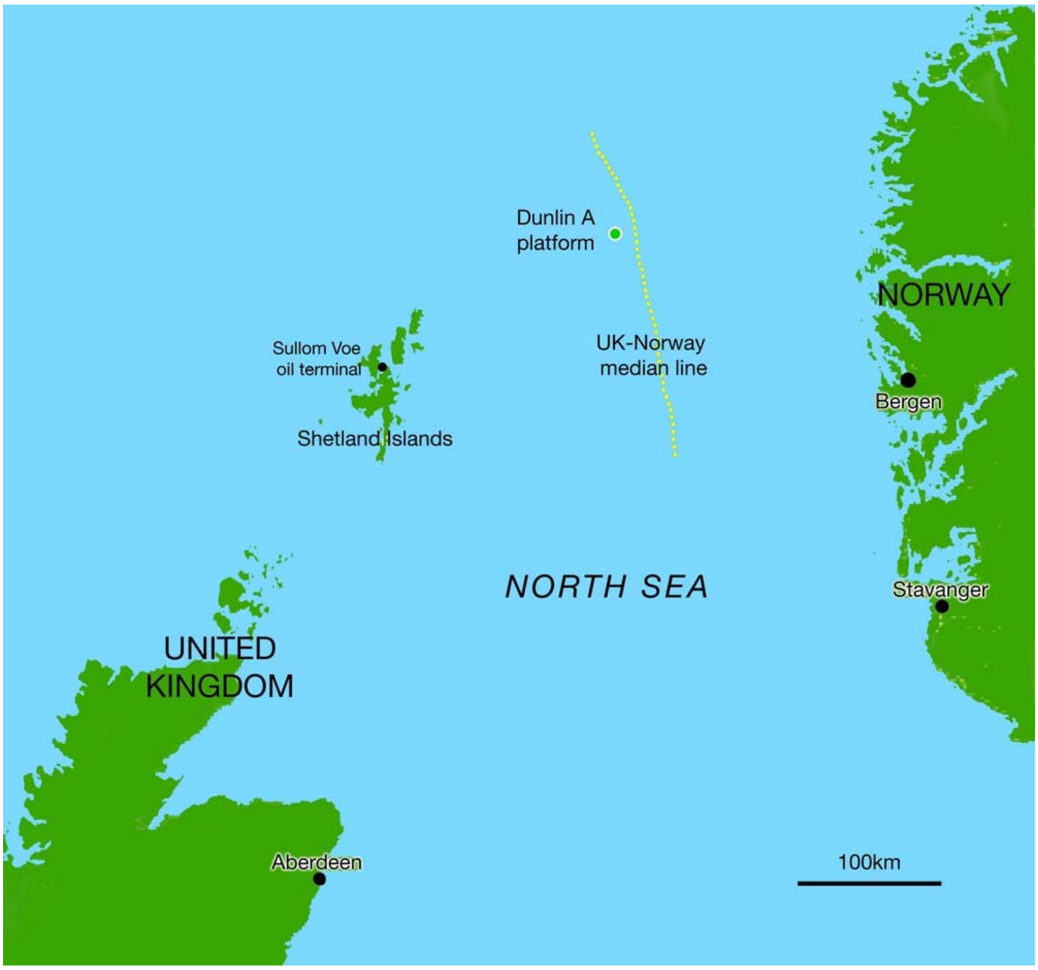


Figure A.1a Dunlin field location map

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.

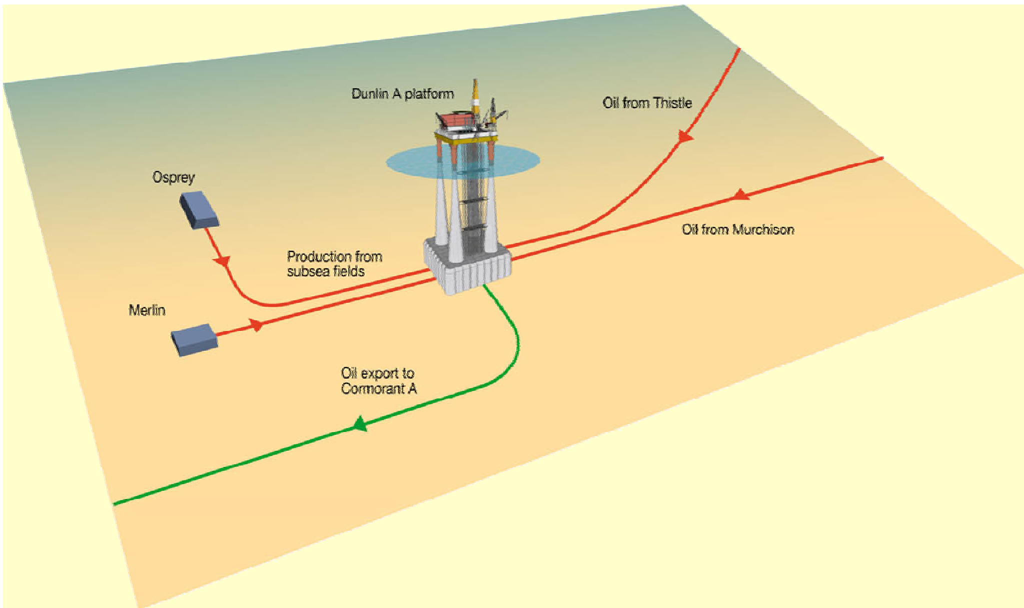


Figure A.1b Dunlin, Osprey and Merlin facilities

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.

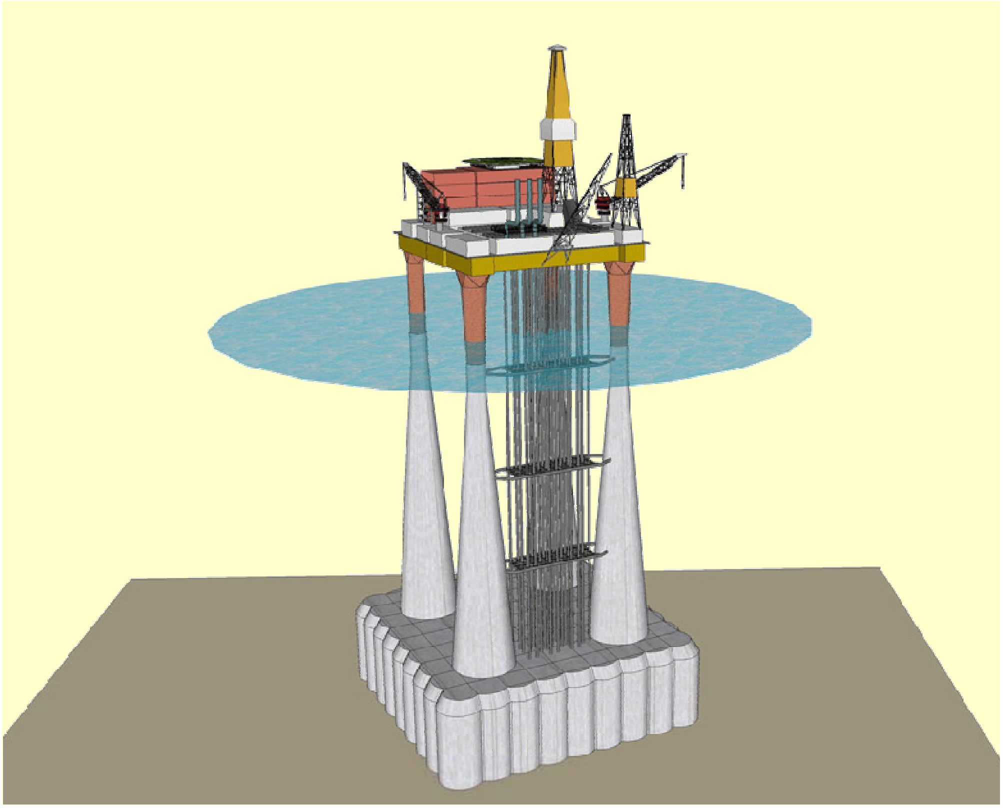


Figure A.1c Dunlin A platform

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.

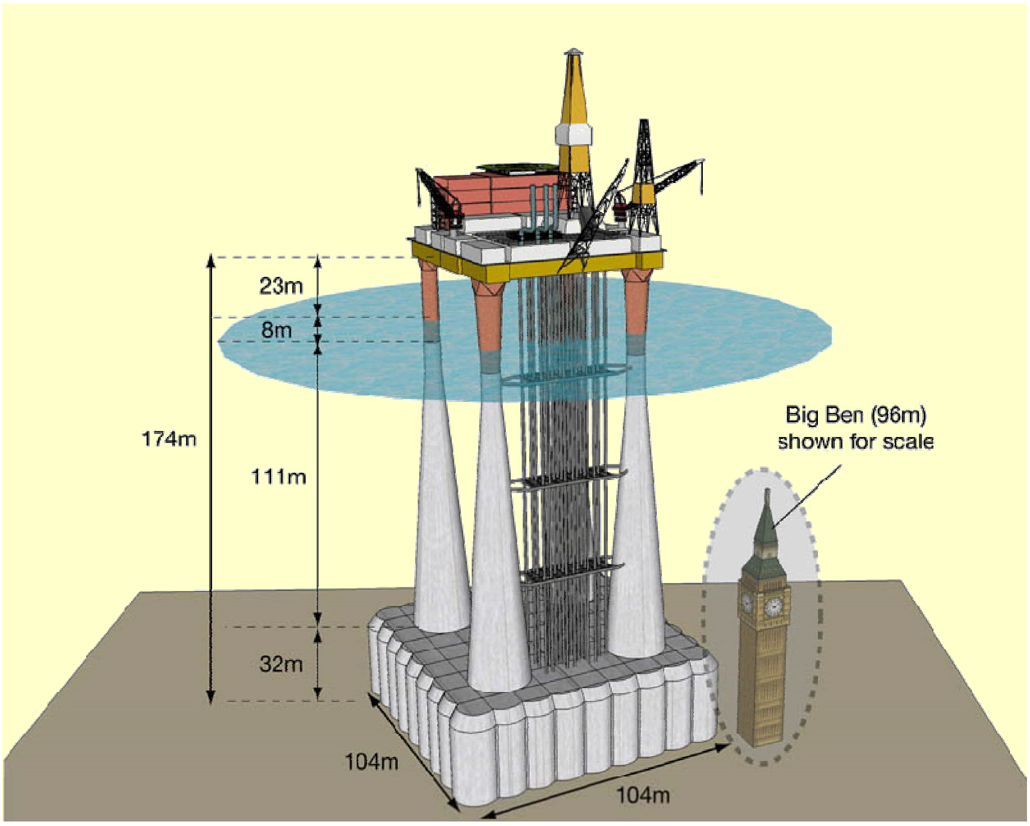


Figure A.4.1a Dunlin A compared with Big Ben for scale

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

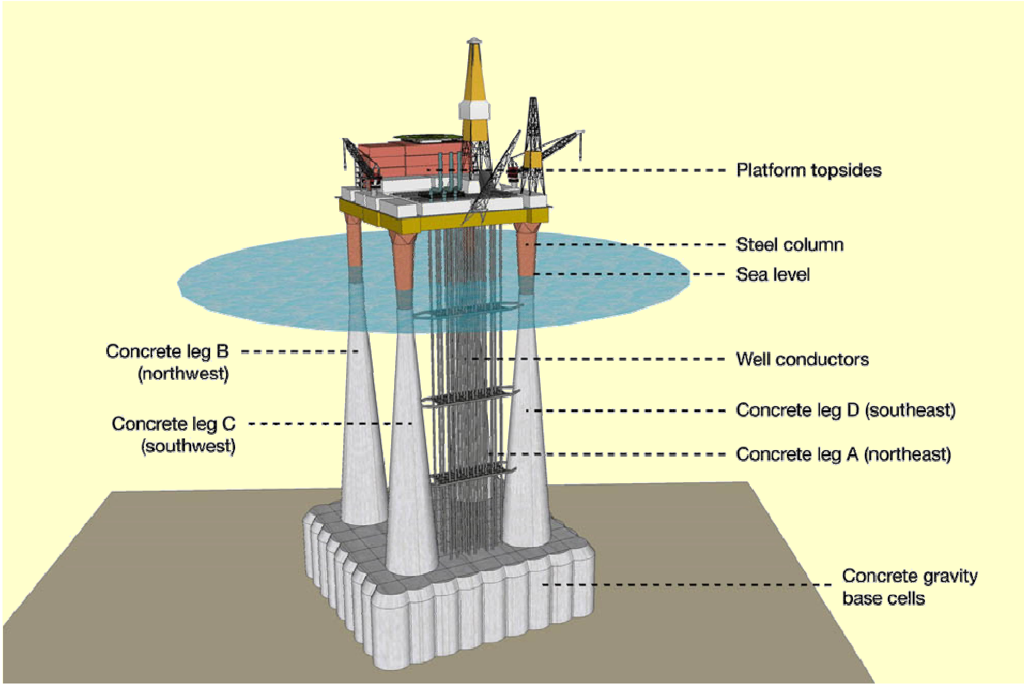


Figure A.4.1b Dunlin A platform main components

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.

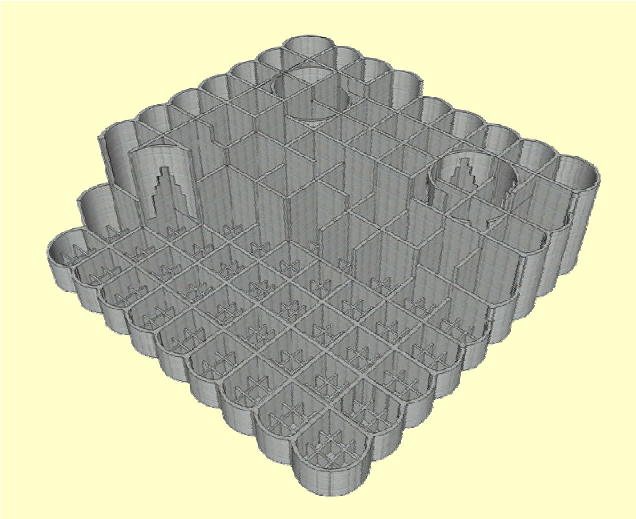


Figure 4.2a Cells in the CGB (cutaway view)

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.

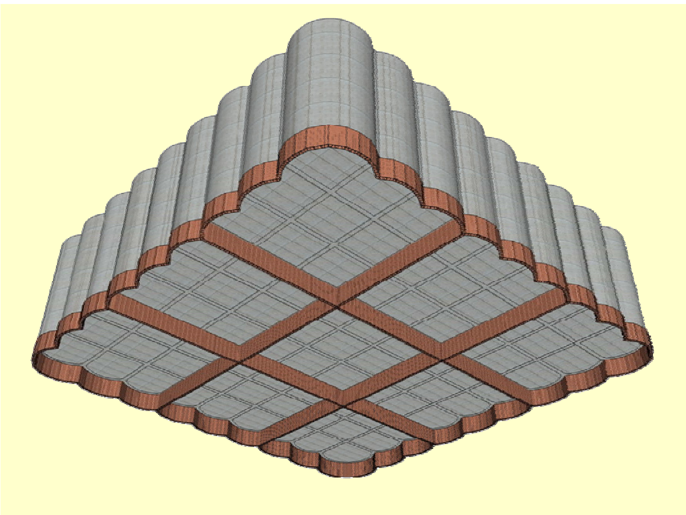


Figure 4.2b Steel skirt and walls

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.

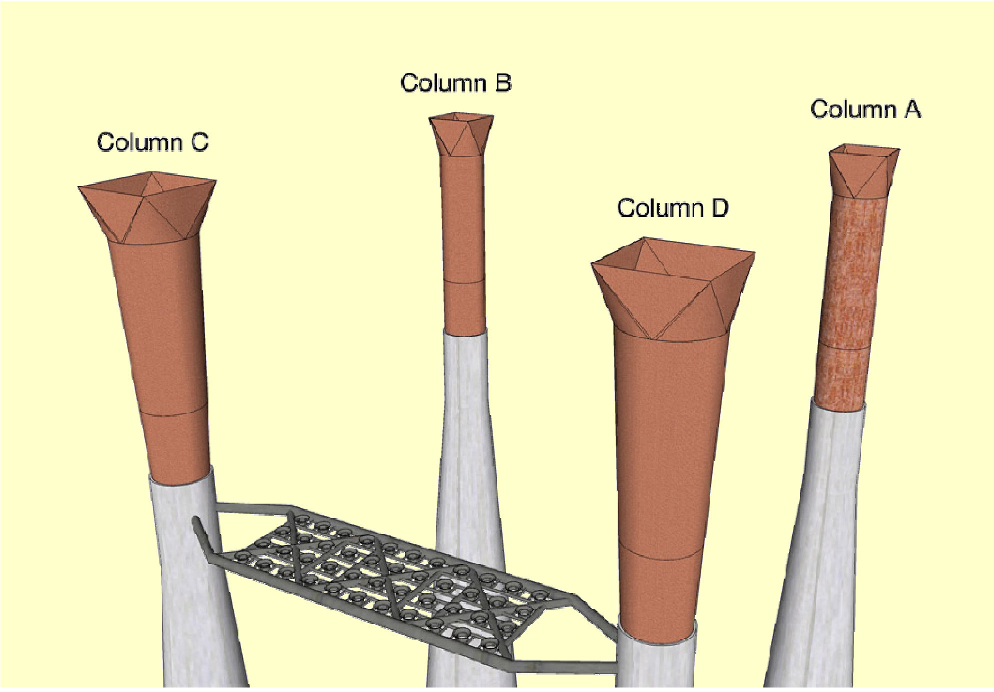


Figure 4.2c Steel columns at the tops of the concrete legs

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.

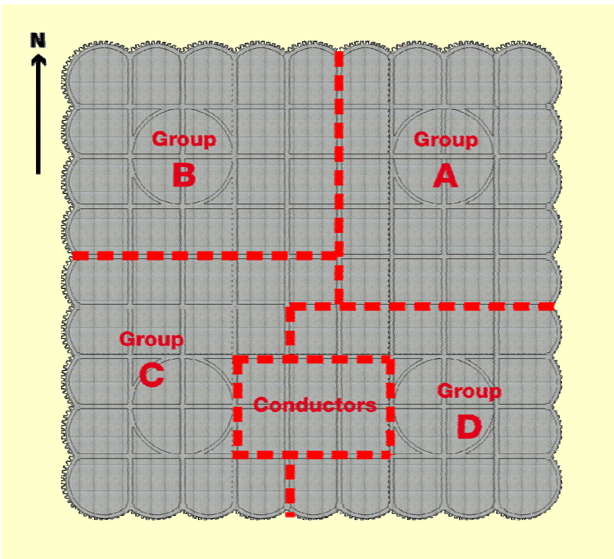


Figure A.4.3a Cells arranged in five groups

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.

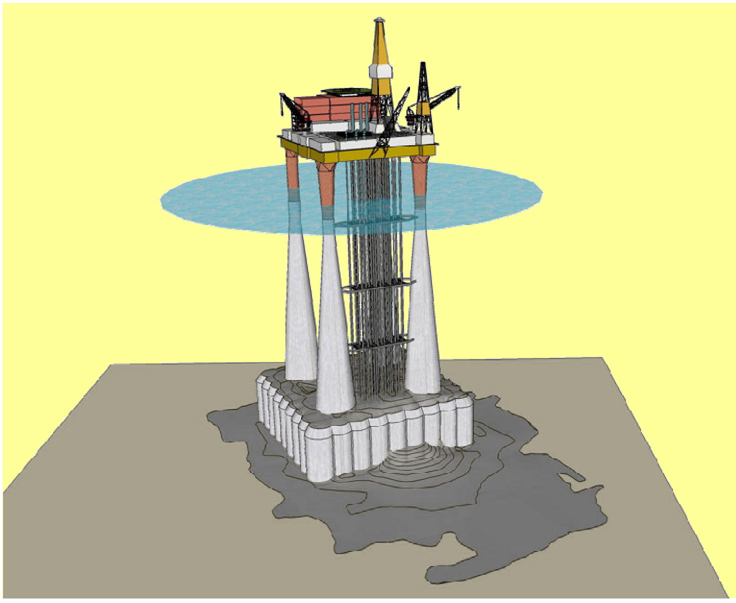


Figure A.4.3b Dunlin A showing a representation of the drill cuttings accumulation at the CGB base

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	4000m³	10,300m³
Maximum thickness	Approx 4m	Approx 11m
Surface area	3300m²	22,000m² (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
B.2	Re-use at current location
B.3	Refloat and tow for re-use at a new location
B.4	Refloat and tow inshore for deconstruction and disposal
B.5	In situ deconstruction
B.6	In situ decommissioning to 8m below sea level
B.7	In situ decommissioning to 55m below sea level
B.8	In situ decommissioning to 110m below sea level

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.

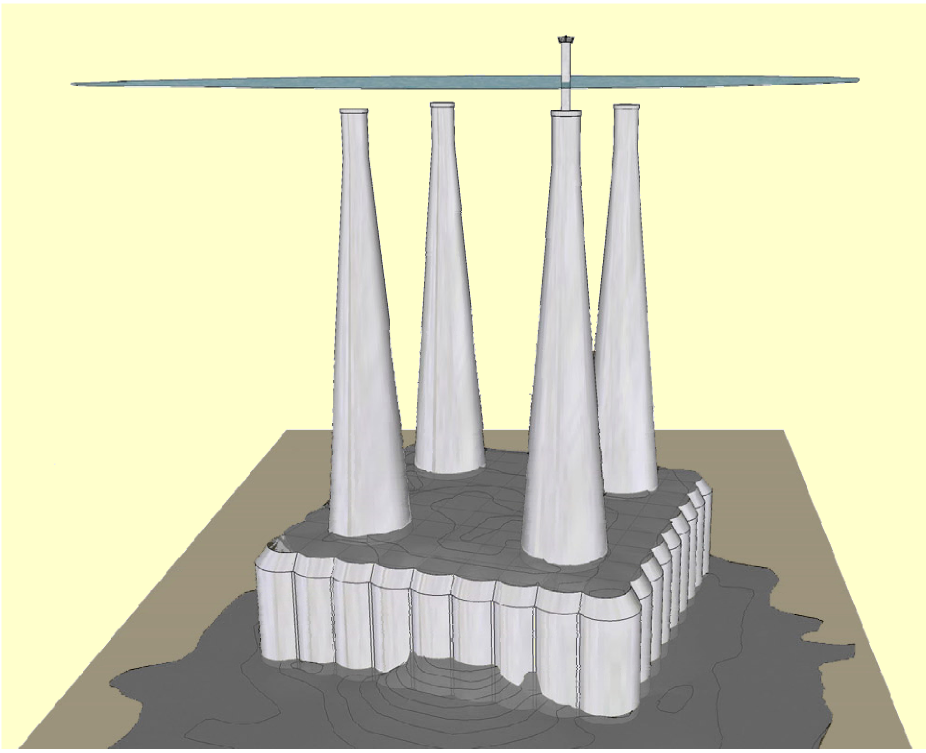


Figure B.6 In situ decommissioning to 8m below sea level

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.

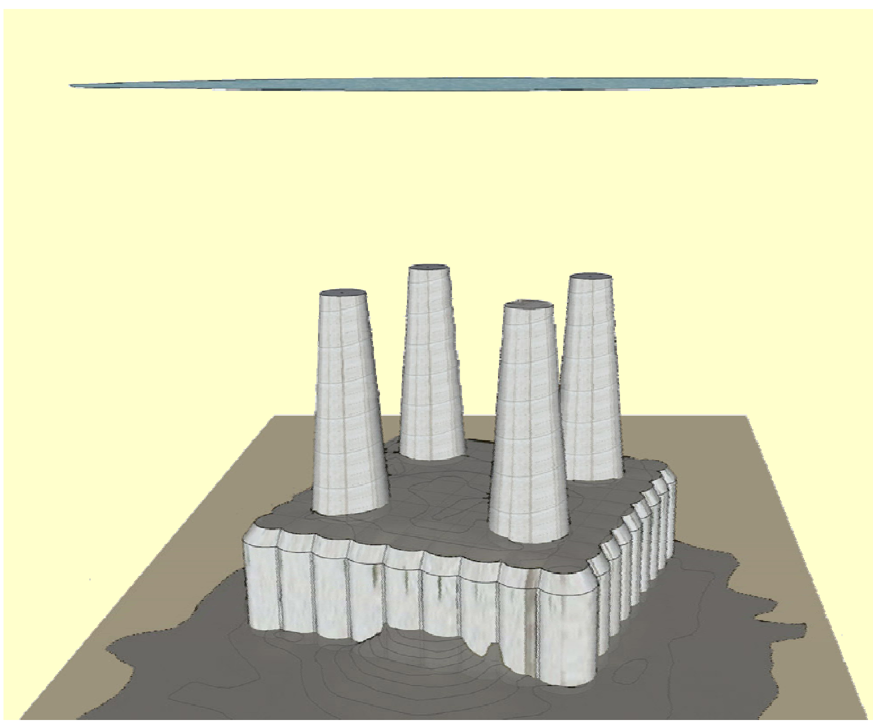


Figure B.7 In situ decommissioning to 55m below sea level

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.

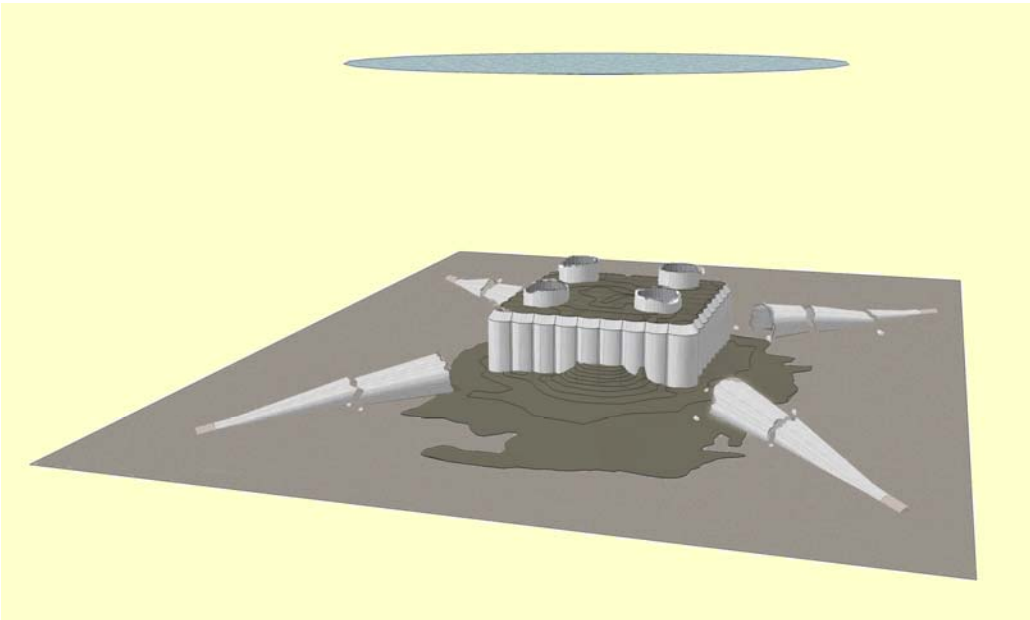


Figure B.8. In situ decommissioning to 110m below sea level

Appendix C

Review of cutting methods by

Cutting Underwater Technologies

REVIEW OF TECHNOLOGIES AND CONCEPTUAL METHODS FOR CUTTING OF DUNLIN A CONCRETE LEGS

CUT PRN: UK10060
Document No: UK10060_D1

Revision: 03
File Name: UK10060_D1_Rev03

Patent Information:

The information relevant to the Diamond Wire Cutting Technology developed by TS Tecnospamec Srl is covered by the Italy Patent no. 01253716, Norway Patent no. 180185, USA Patent no. 5.361.748, European Patent no. 0540834, Priority Date 06/11/91.

TECHNICAL AUTHOR

Prepared by	Reviewed by	Approved by
DAVE PATULLO	**MATTEO MOSCA**	**DINO VALLARINO**
Date: 22.07.2010	Date: 23.07.2010	Date: 23.07.2010

REVISION RECORD

Revision	Date	Description	Reviewed By
00	20.07.2010	Issued for Internal Review	MM / DV
01	23.07.2010	Issued for Comments	MM / DV
02	13.08.2010	Issued for Comments	MM / DV
03	05.09.2010	Issued for Approval	

CONTENTS

TECHNICAL AUTHOR *2*

ABBREVIATIONS *3*

1. EXECUTIVE SUMMARY *4*

2. SCOPE OF WORK & KEY OBJECTIVES *6*

3. CUTTING METHODS FOR CONCRETE LEGS REMOVAL *9*

3.1 SHAPED EXPLOSIVE CHARGES *9*

3.2 ABRASIVE WATER JET CUTTING *9*

3.3 TRACK SAW / CHAIN SAW CUTTING / DIAMOND STITCH DRILLING *13*

3.4 RECIPROCAL WIRE / CHAIN CUTTING *15*

3.5 DIAMOND WIRE CUTTING *18*

4. CONCLUSIONS *22*

ABBREVIATIONS

CGB	Concrete Gravity Base
DWCM	Diamond Wire Cutting Machine
LAT	Lowest Astronomical Tide
IMO	International Maritime Organisation
WROV	Work Class Remotely Operated Vehicle

1. EXECUTIVE SUMMARY

This report reviews different methods for cutting reinforced concrete underwater, and the possible application of those methods to the cutting of the Dunlin Alpha CGB at its current offshore location.

Five broad categories of cutting techniques have been considered, namely:

- Shaped explosive charges
- Abrasive water jets
- Track saw/chain saw/diamond stitch drilling
- Reciprocal wire/chain sawing
- Diamond wire cutting

Cutting operations for the legs of the CGB have been evaluated, as requested by Fairfield Energy, for three different depths below sea level: 8 m, 55 m and 110 m.

The feasibility of the cutting operations has been evaluated taking into consideration the following assumptions given by Fairfield Energy:

- The legs of the CGB would be irreversibly flooded before commencement of the cutting operations
- No diver access inside the legs would be allowed
- No preparatory work would be possible to remove or secure the equipment inside the legs
- There could be no guarantee of equipment stability inside the legs at -55 m and -110 m levels
- Removal of drill cuttings accumulations on the base of the CGB structure would be avoided as far as practical

Due consideration has been given to the procedures which would be necessary to perform the cutting operations, taking note of health and safety issues, environmental impact, the availability of effective cutting technology, and the operability of the technology for the particular task.

Given these considerations, CUT has concluded that cutting through a concrete leg at 8 m, 55 m and 110 m below sea level with most of the internal equipment still in place in the legs would be theoretically possible using diamond wire cutting, if the internals within the target areas were first removed or stabilised. However, the success of the technique would be severely compromised if the internals were not removed or stabilised because their unpredictable free movement could terminally damage the diamond wire during the cutting operation. This is a significant risk when considering the amount and complexity of equipment installed within the Dunlin A legs.

To prevent the sawn gap in the concrete from closing in an uncontrolled fashion onto the wire due to dynamic forces acting on the concrete leg section above the cut, shims would have to be inserted into the cut. While this procedure has been used successfully underwater on smaller steel structures, it has not been employed before for subsea cutting of a large concrete structure such as Dunlin A.

Although the use of shims would, in theory, allow part of the cutting process to be performed with the structure unsupported, control of the overall operation would also be dependent upon supporting the concrete leg section with a heavy lift crane vessel, or the installation of a substantial structural support frame, which would be required to stabilise the leg section above the cut level. It should be noted that CUT has not assessed the practicality of the associated marine operations and/or methods for adding structural support to the CGB. These aspects would require further consideration and could have a major bearing on the applicability of the cutting methods.

The other cutting techniques reviewed involve significant uncertainties about their effectiveness to achieve a cut at the stated depths, or would also require operations inside the legs, and have therefore been eliminated from further consideration.

2. SCOPE OF WORK & KEY OBJECTIVES

The Dunlin Alpha (Dunlin A) platform is located in 151m of water. The platform consists of a concrete gravity base (CGB) structure, supporting a module support frame and topsides. 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.

The CGB has a rectangular base, 104 m by 104 m in size, and 32 m deep. From the base, four circular concrete legs, 111 m high, rise up to 8 m below sea level. Each concrete leg weighs around 7,600 tonnes. Steel columns are attached to the top of the legs, rising up through the sea surface to support the topsides.

The purpose of this report is to review and analyse available or developing techniques for cutting concrete underwater which could be used to cut the CGB legs and internal equipment. Three target depths have been selected by Fairfield Energy for leg cutting (ref. Figure 1).

- 8 m below sea level (LAT) at the bolted / grouted concrete-to-steel interface (ref. Figure 2)
- 55 m below sea as defined by IMO Guidance for clear navigation above a submerged structure (ref. Figure 3)
- 110 m below sea level just above the roof of the CGB base (ref. Figure 4)

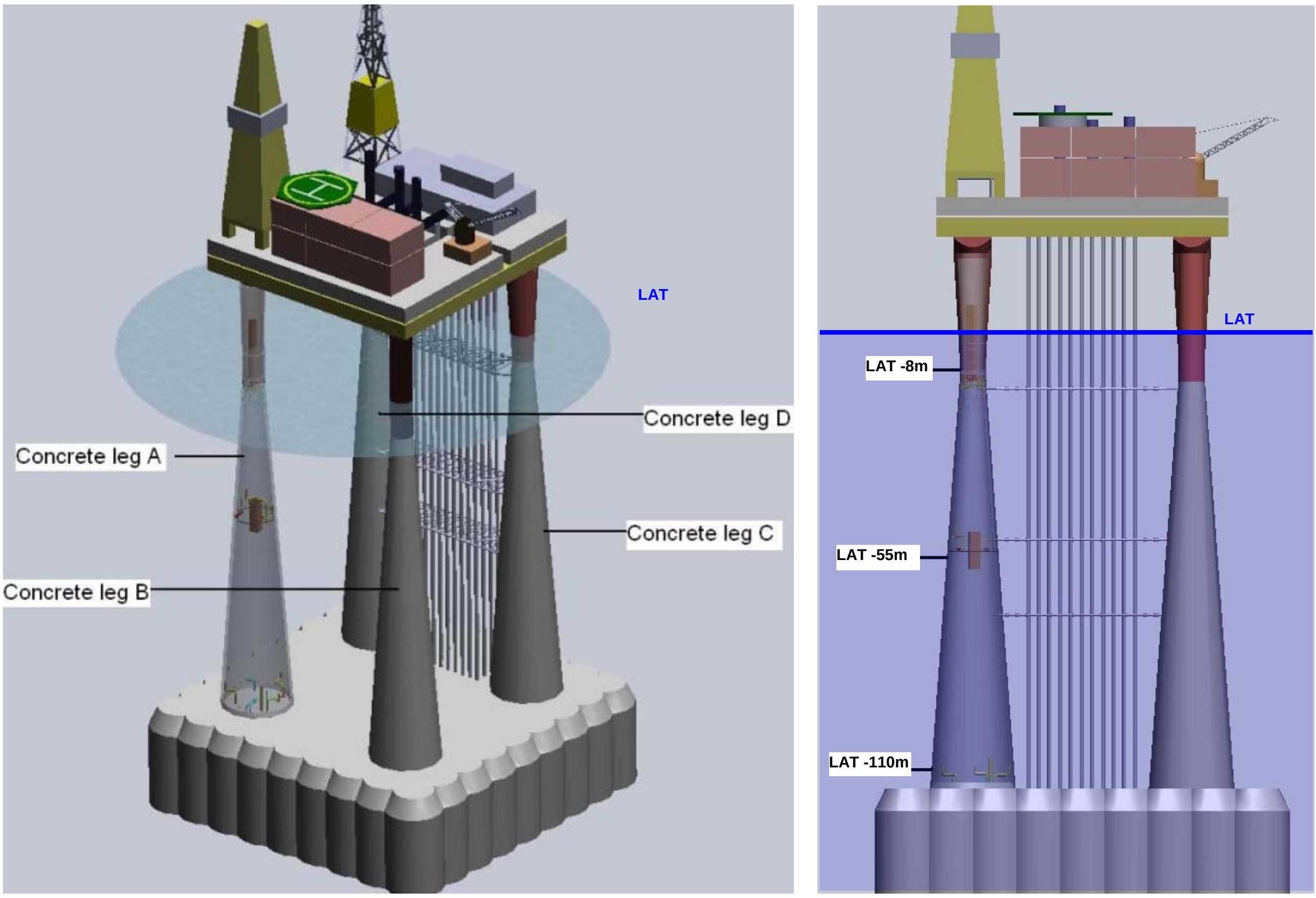


Figure 1: Dunlin A platform model and target cutting depths

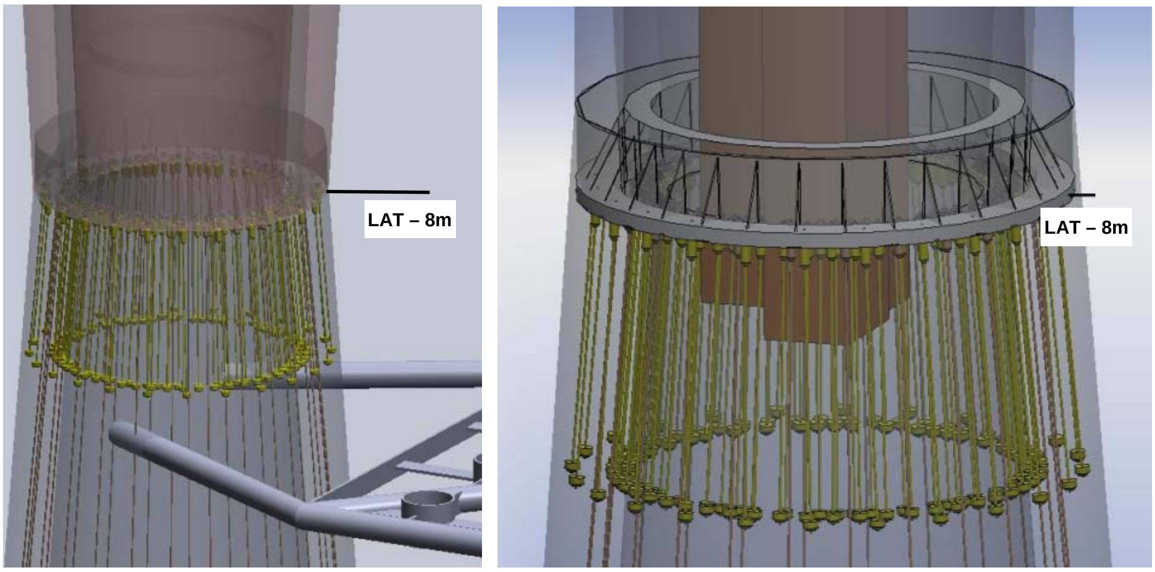


Figure 2: Target cutting depth at level -8 m LAT. (Steel reinforcement shown, but equipment inside legs not shown at this level)

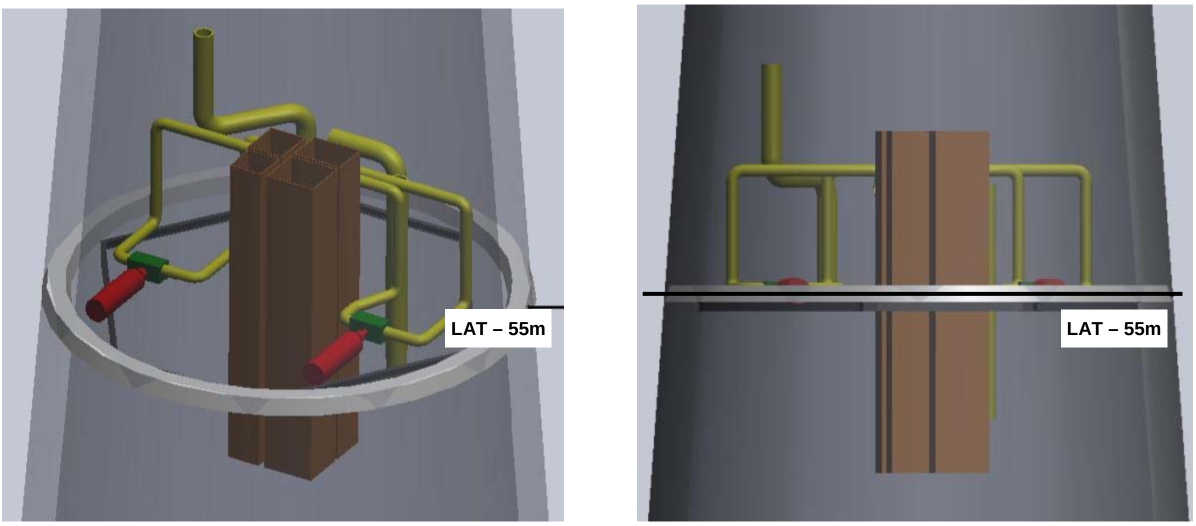


Figure 3: Target cutting depth at level -55 m LAT. (Equipment inside legs shown at this level)

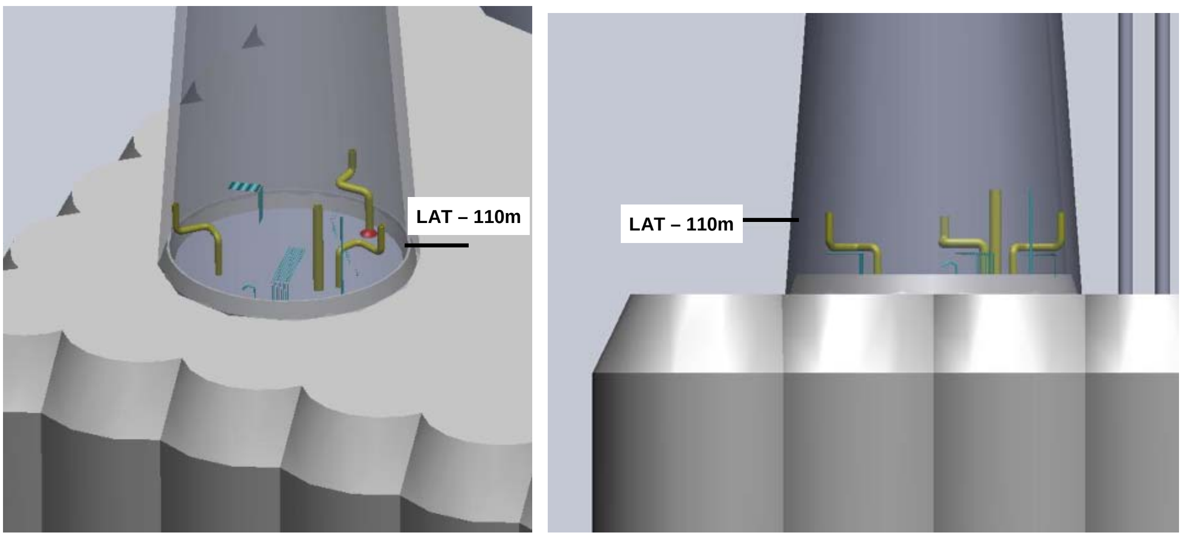


Figure 4: Target cutting depth at level -110 m LAT (Equipment inside legs shown at this level)

The concrete legs vary in diameter and thickness throughout their height. Details of the concrete leg sections at the target cutting depths are shown in Table 1 below.

	EL -110m		**EL -55m**		**EL -8m**	
	Legs A&B	**Legs C&D**	**Legs A&B**	**Legs C&D**	**Legs A&B**	**Legs C&D**
Leg						
Outer Diameter (m)	21.32	21.32	13.80	13.80	6.60	6.60
Inner Diameter (m)	19.77	19.77	12.45	12.45	4.80	4.80
Thickness (m)	0.77	0.77	0.68	0.68	0.90	0.90
Vertical reinforcement Number of bars Diameter	1536 Ø 20 mm	1088 Ø 25 mm	896 Ø 20 mm	1152 Ø 20 mm	576 Ø 20 mm	640 Ø 20 mm
No. of steel tendons	96	96	96	96	68	68

Table 1: Dunlin A concrete legs dimensions and structural characteristics at targeted cutting depths

This report considers the feasibility of making a cut at each of the target depths to sever a single concrete section. It does not consider the piecemeal reduction of the legs, section by section.

It is assumed, that prior to any leg cutting operations, that:

- The platform wells would have been plugged and abandoned and the conductors removed from a level around two metres below the mudline.
- The topsides would have been removed leaving the four steel columns projecting above sea level.
- All flowlines, pipelines and cables would have been disconnected at the seabed level.
- The legs would be completely flooded at the time of cutting and there would be no diving access within the legs.

3. CUTTING METHODS FOR CONCRETE LEGS REMOVAL

Five broad categories of cutting techniques have been considered, namely:

- Shaped explosive charges
- Abrasive water jets
- Track saw/chain saw/diamond stitch drilling
- Reciprocal wire/chain sawing
- Diamond wire cutting

The cutting techniques have been evaluated against key factors including health and safety, environmental impact, technological requirements and operability.

The ability to apply the technologies to Dunlin A has been reviewed conceptually. This review does not attempt to analyse the feasibility of other associated activities that would be required to control the overall operation to maintain stability of the structure, for example, supporting the concrete leg section with a heavy lift crane vessel, or the installation of a substantial structural support frame. These activities could have a major bearing on the applicability of the cutting methods described below.

3.1 Shaped explosive charges

Shaped explosive charges have previously been used to cut through parts of underwater steel offshore structures. However, their application to the legs of the Dunlin A platform could not be guaranteed to provide a controlled cut of a large diameter, reinforced concrete leg section - explosive charges are more suited to achieving demolition of a steel structure by destabilising it. Demolishing the legs would create a large volume of seabed debris, which would have to be removed piece by piece; it would disturb the drill cuttings around the base of the CGB; and it could create an impact on the base of the CGB, rupturing this and releasing the contents of the cells in the base.

Furthermore, the use of explosives would have a local environmental impact. The shockwave created by the detonation would disorientate, stun or kill marine life in the area.

The safety of the supporting vessels may also be compromised by any subsurface explosion.

For these reasons, shaped explosive charges have been eliminated as a method for cutting the legs of the CGB.

3.2 Abrasive water jet cutting

An abrasive water jet cutting system (ref. Figure 5) is a tool capable of slicing metallic or other materials using a jet of water or a mixture of water and an abrasive substance at high velocity and pressure. The process is essentially the same as water erosion found in nature but greatly accelerated and concentrated.

In theory, the technique could be applied to cut the concrete legs on Dunlin A by mounting the jet cutter on a rigid guide rail, attached to the leg by divers, as shown in Figure 6. The motion of the cutting nozzle on the rail is actuated by a hydraulic feeding system, powered and controlled either from the surface via an umbilical or from a WROV.

Cutting the concrete would require multiple passes to create sections of concrete which could then be removed by hydro-demolition, excavating them out with high pressure water to create a cavity in the leg (see Figure 7). To reach the inner sections of the leg inside the cavity, an extension nozzle would be required on the jet cutter. To maintain the stability of the leg and to ensure the excavated cavity remained open during the multistage operation, shims or jacks would be inserted between the upper and lower cut faces of the concrete. A heavy lift vessel would be required to help maintain the overall stability of the leg and section being cut.

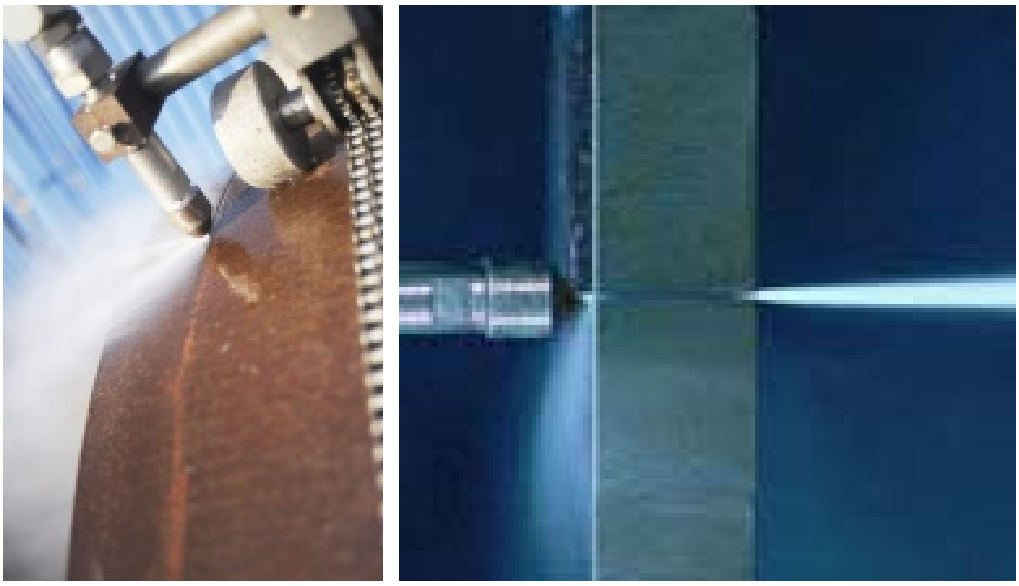


Figure 5: Abrasive water jet cutting system

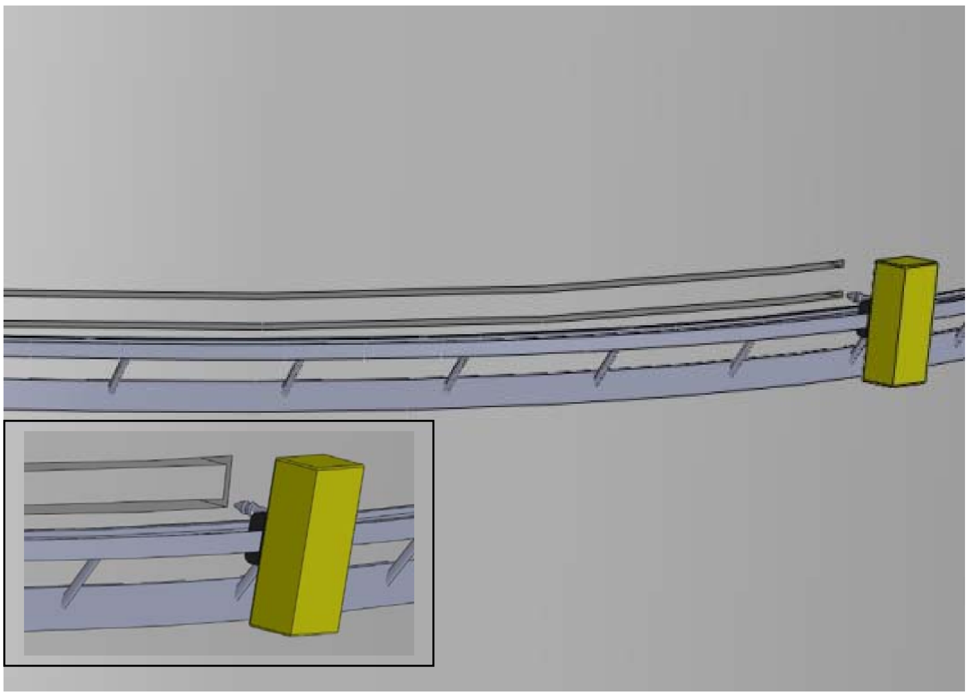


Figure 6: Water jet cutter mounted on a rail around a CGB leg

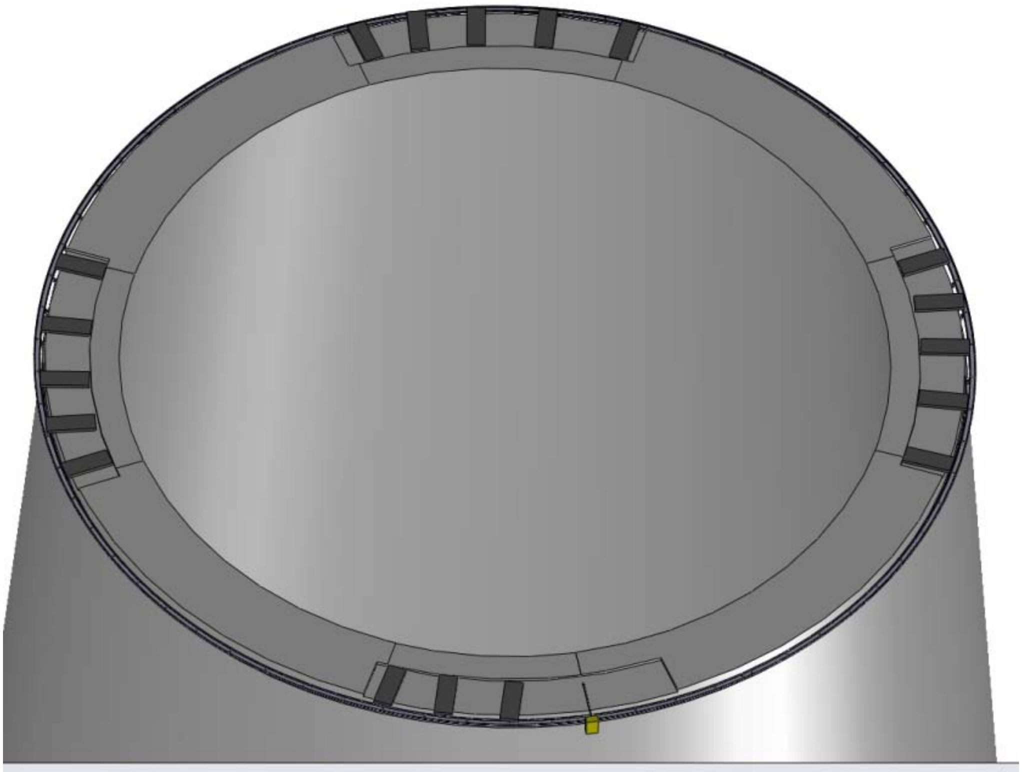


Figure 7: Cutting of the leg in progress, showing the excavated cavities (in section).

However, there would be several difficulties in applying this conceptual technique in practice to sever the concrete and the equipment inside the leg, including:

- The water jet rapidly loses velocity when operating subsea, placing a limit on the thickness of the concrete that can be cut. The 1200 mm thick concrete in the Dunlin A legs at the -8m and -110 m levels may prove to be beyond the limits of water jet cutting for single pass operation. There could be no guarantee that a cut was 100% completed with one cutting pass.

- Internal equipment could not be cut by abrasive jet cutting from outside the leg. Internal access would be required to do this. An impression of the equipment at the -55 m level inside Leg A is shown in Figure 8.

- The nozzle tips of the cutting head wear during use and would have to be replaced several times during the cutting process by divers.

- Underwater operations would be of long duration, and would create a large volume of solid waste which would remain on the seabed.

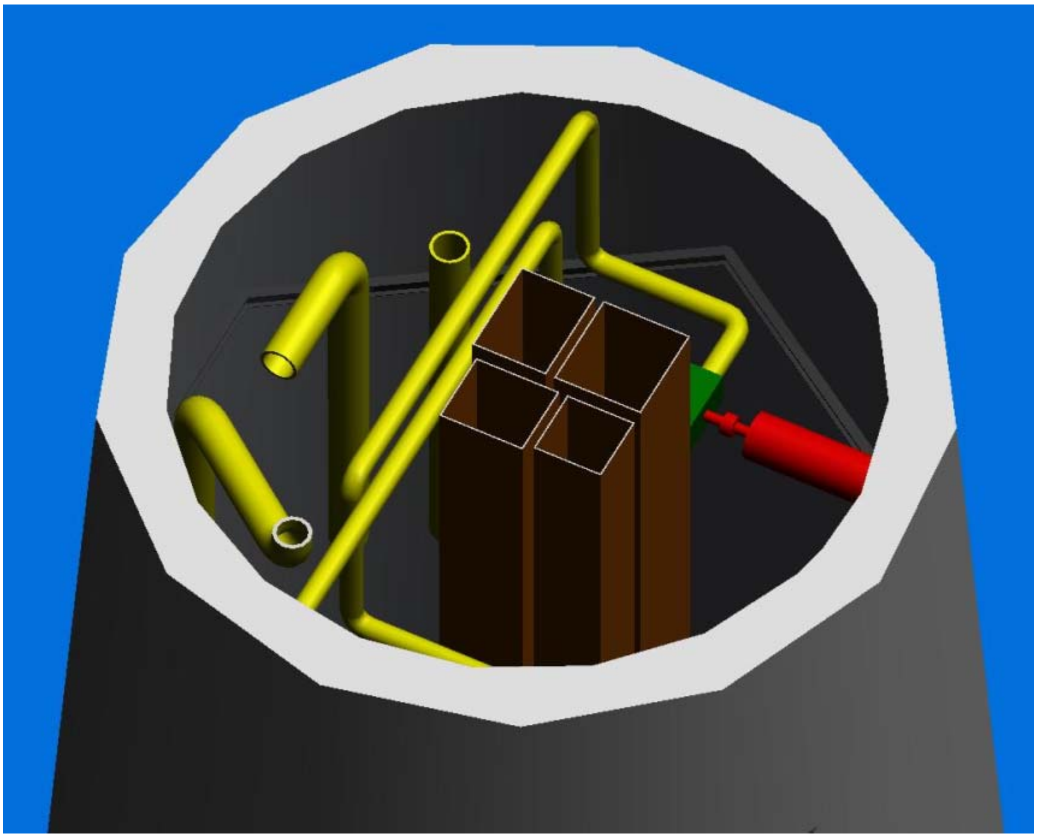


Figure 8: Illustration of equipment inside Leg A at -55 m level

3.3 Track saw / Chain saw cutting / Diamond stitch drilling

The track saw (ref. Figure 9), chain saw (ref. Figure 10) and diamond stitch drilling (ref. Figure 11) are commonly used in demolition and construction work in the onshore civil / building industries.

Figure 9: Track saw cutting system

Figure 10: Chain saw concrete cutting system

Figure 11: Concrete stitch drilling system

These systems have the ability to cut through concrete, reinforcing steel and tensioning tendons. The machines are commonly used onshore to cut holes in vertical slabs of concrete, primarily for door and window openings, as well as larger apertures. The machines would require significant adaptation for use in the subsea environment.

Although such machines could in theory deliver a precision cut through a given depth of concrete, applying them to cut the legs of Dunlin A would be extremely difficult, if not impossible, due to:

- It is not known if this style of cutting machine could be converted for subsea operations or if it is currently capable of cutting through highly reinforced concrete such as that in the CGB legs.

- The challenge of mounting such a machine underwater on a guide rail around the leg, similar to that described in Section 3.2. Due to the wall thickness of the leg, a diamond cutting (circular) saw would have to be approximately 3 m in diameter, the chain saw and drilling rig approximately 1.5 m in length. Powering and controlling such large cutting devices may be problematic, and they would require substantial underwater support structures.

- The internal equipment in the legs could not be cut in this way from outside the leg. Internal access would be required to do this.

- Maintaining leg stability would depend on the support of a heavy lift vessel, and insertion of shims to keep the cut line open. It would be imperative that the cut line not be allowed to close onto the saw blade as this would make recovering the saw exceptionally difficult or impossible.

3.4 Reciprocal wire / Chain cutting

Reciprocal wire cutting uses the strength of a high tensile cable along with carbide abrasive collars to abrade its way through the target to be cut by a reciprocating action. The wire is dragged back and forth underneath the target, using the weight of the target (normally a sunken vessel) to push against the wire. The wire is powered by submersible hydraulic power packs with electrical power and control umbilical lines connected to vessels on the surface.

The technique has been proven on a large scale in salvage operations, but has never been deployed for cutting reinforced concrete in the horizontal plane, as would be required to cut the Dunlin A legs.

Figure 12 shows a reciprocating wire in use underwater.

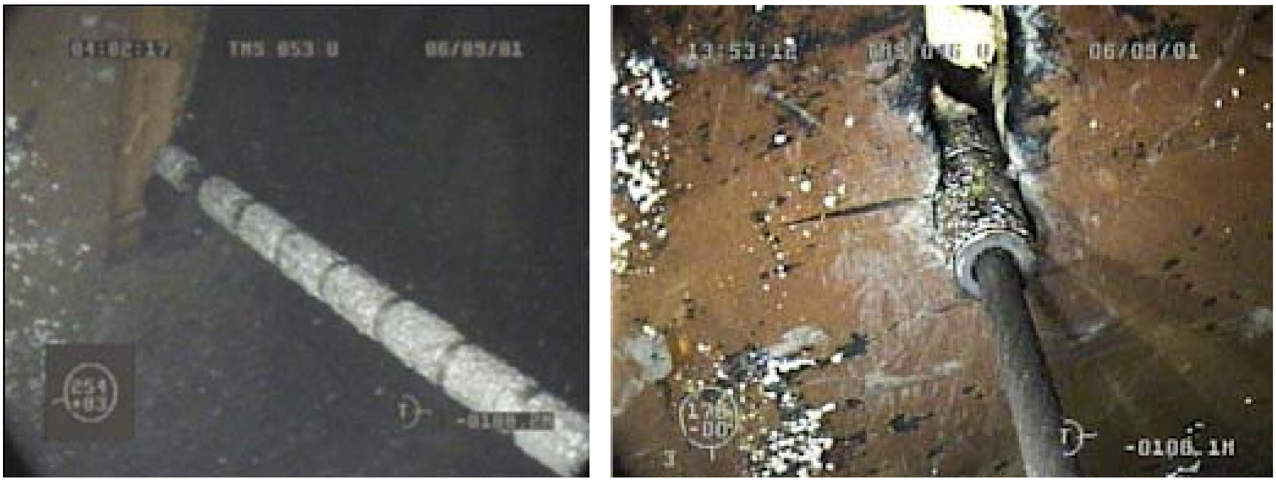


Figure 12: Reciprocal wire cutting

Figure 13 shows a section of salvaged ship hull, having been cut by reciprocal wire.

Figure 13: Ship hull cut by reciprocal wire saw

The cut through the vessels hull shown above was completed in an operation lasting approximately 55 hours.

Another system that has been traditionally used widely within the vessel salvage industry is the reciprocal chain cut. This system was the forerunner of the reciprocal wire cut described above. The chain cut system is normally used in the vertical position with the chain passing under the target. It should be noted that chain cutting would give a very uneven and jagged surface to the cut compared with wire cutting, making stability shimming during the operation very difficult.

In theory, reciprocating wire or chain could cut through the CGB concrete legs and the internal equipment in a single operation. However, there would be very significant challenges related to the size and weight of the cutting spread; the method of attaching this to a leg, particularly at levels above 110 m; and the force that would have to be put into the leg to provide cutting power.

Another issue relating to the use of reciprocal style cutting systems is the potential for shock loads and snatching of the cutting wire during the cutting process. As the cut progresses through the concrete towards the back wall (closest to the tool) there is a risk of a slab of concrete breaking off the leg due to forces being transferred to the back wall. If a large piece of leg were to break free, there would be a significant risk of the cutting tool or platform being damaged, potentially compromising the overall cutting operation. There is also the possibility that the heavy lift vessel could experience shock loading in the event of this type of failure.

A conceptual cutting device for either wire or chain cutting, that would allow large pieces of equipment to be hung off a leg with minimal fixings or bolting being necessary, is shown in Figures 14 and 15. This conceptual design uses the conical form of the leg for the initial positioning of the cutting device, supplemented with securing rods to prevent torsional rotation of the tool during the cutting process.

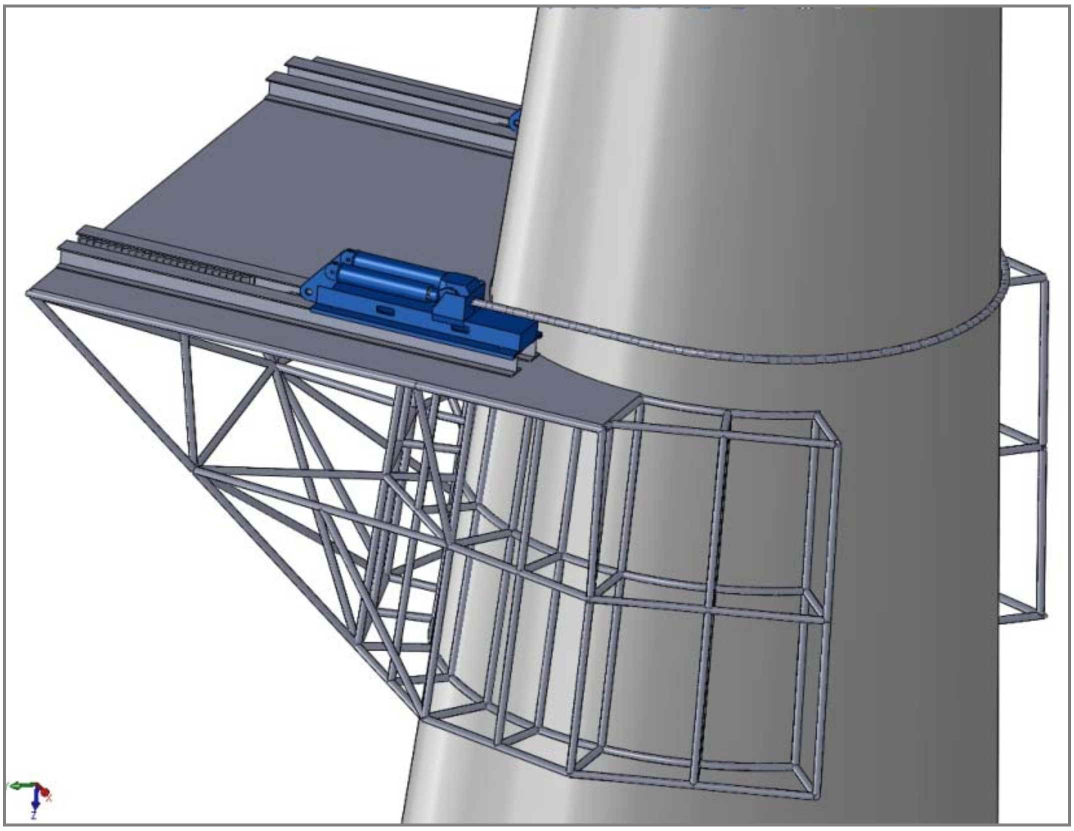


Figure 14: Conceptual reciprocal wire cutting system hung off a concrete leg.

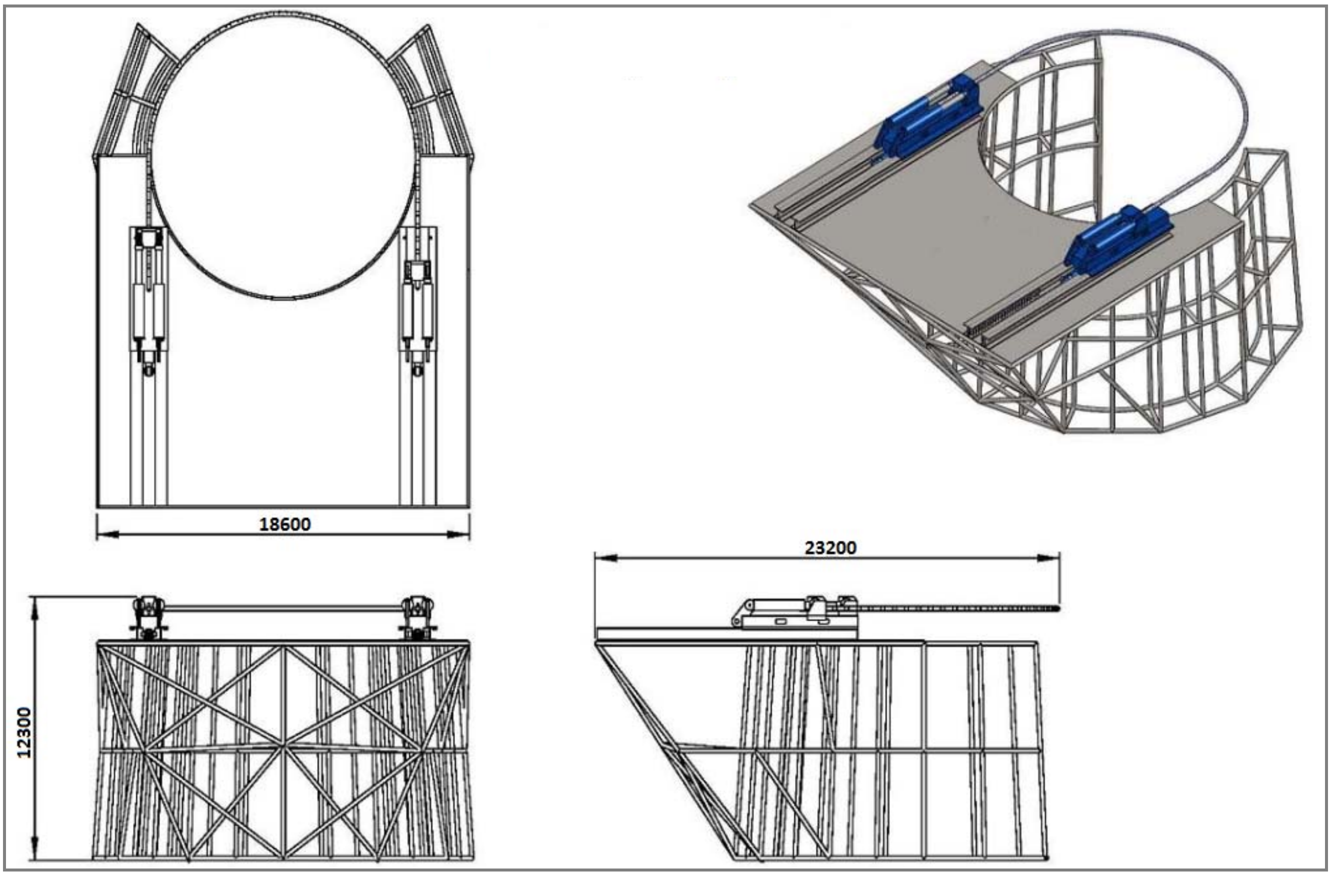


Figure 15: Indicative dimension (mm) of reciprocal wire cutting system for operation at -55 m level.

The estimated overall weight of the reciprocal wire cutting tool is approximately 35-50 tonnes. A more accurate appraisal of the overall weight cannot be completed without detailed design of the tool being undertaken.

While the reciprocating wire / chain cutting method offers an advantage in being able to cut through the concrete legs and the internals, the method would present a number of significant challenges that could compromise its chances of success, including:

- The structural stability of a leg may be compromised by the weight of the cutting tool and support frame, and the pulling force exerted by the cutting wire / chain, when operating at the -55 m and -8 m levels.

- Cutting operations may require shimming of the cut to prevent the wire or chain becoming trapped, and support of the cut section by a heavy lift crane vessel to maintain stability throughout the operations. The cut line would be rough, particularly so in the case of chain cutting and shimming in a way that would provide confidence in the cutting method may be very difficult to achieve.

- Fixing the support frames onto the legs will present many challenges due to their size and weight. Significant diving and WROV operations would be involved. At the -110 m level, drill cuttings would have to be removed to give clear access for the frame.

- Operations at the -8 m level could experience wave action within the splash zone, adding further challenges to setting or operating equipment in this area.

3.5 Diamond Wire Cutting

Diamond wire cutting has been used in a number of industries to carry out large scale cuts, including cutting subsea and topsides structures and pipelines in the offshore industry. Using cutting frames with different set-ups, this technique could be used to cut either through the wall of the concrete legs or through the legs and the internal equipment in a single operation.

The principle of a diamond wire cutting machine (DWCM) suitable for cutting through the leg wall is shown in Figure 16. This has been used on a variety of projects and structures up to 10m in diameter.

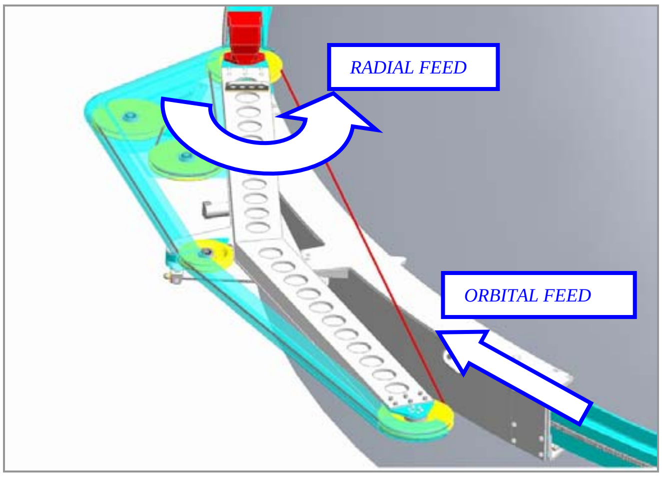


Figure 16: Orbital DWCM

A continuous diamond wire, typically 10 mm in diameter, is fed through the target material by a combined radial / orbital feed. The wire is tensioned within the orbital machine and driven against the target face. The machine is designed to allow the diamond wire to penetrate through the entire wall thickness. The cutting tool progresses around a pre-fabricated guide rail, attached to the side of the target.

A purpose-built DWCM could be used to cut the legs of the Dunlin A CGB. The guide rail could be installed either by divers using anchor bolts or expansion anchors, or by having the rail pre-assembled on a carrying frame that could be installed in one or two sections by WROV. With the rail installed on the leg at the target cutting elevation, one or more DWCMs could be deployed and installed onto the rail either by diver or WROV. Cutting of the concrete leg could then commence in a fully controlled way.

A conceptual machine and procedure for cutting through the legs and the internal equipment in a single operation is shown in Figures 17 to 20 below. The outline procedure described is for a cut at -110 m. The basic procedure would be the same at the -55 m and -8 m levels.

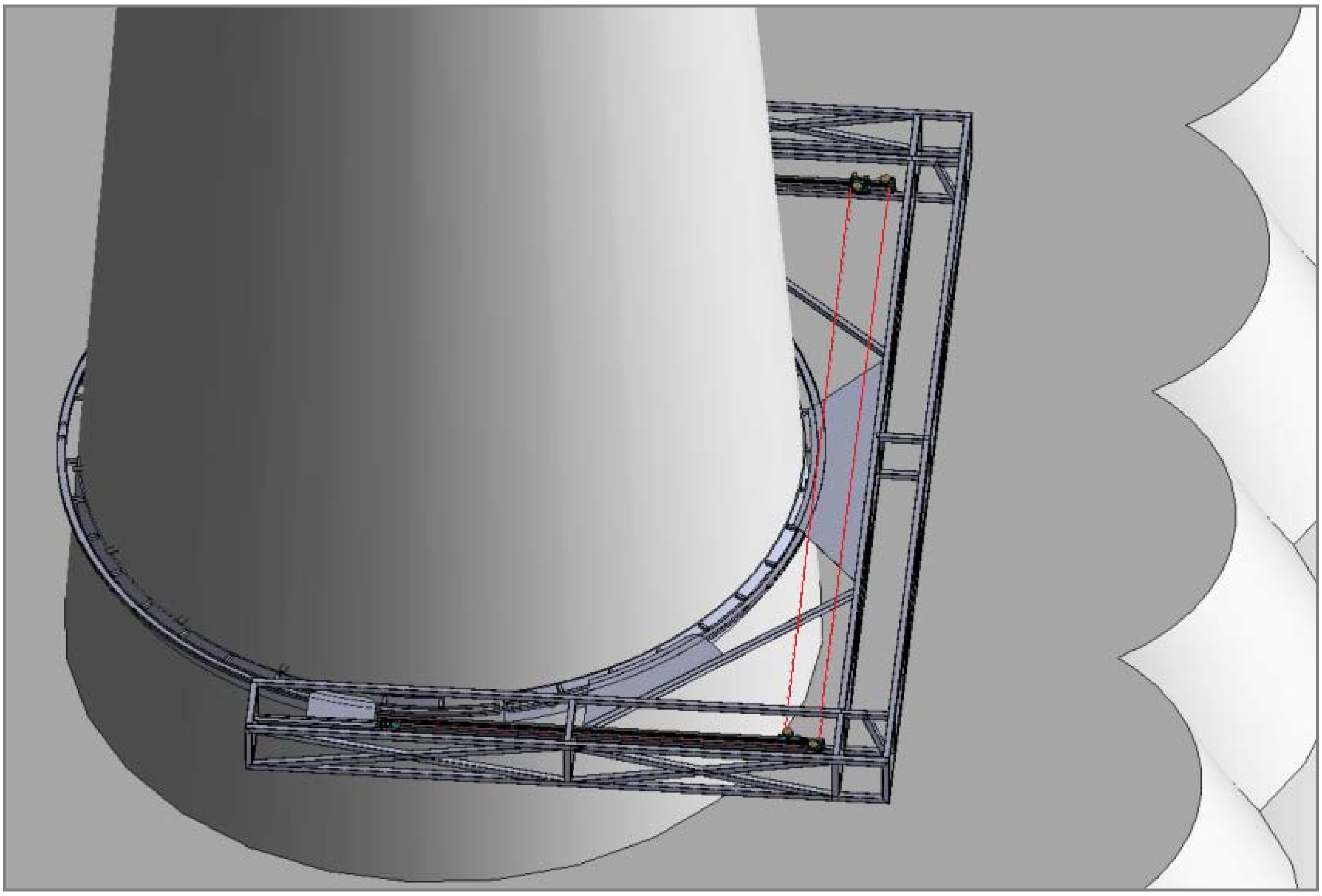


Figure 17: DWCM installed at the -110 m level with the diamond wire (shown in red) fully retracted prior to the start of the cutting operation.

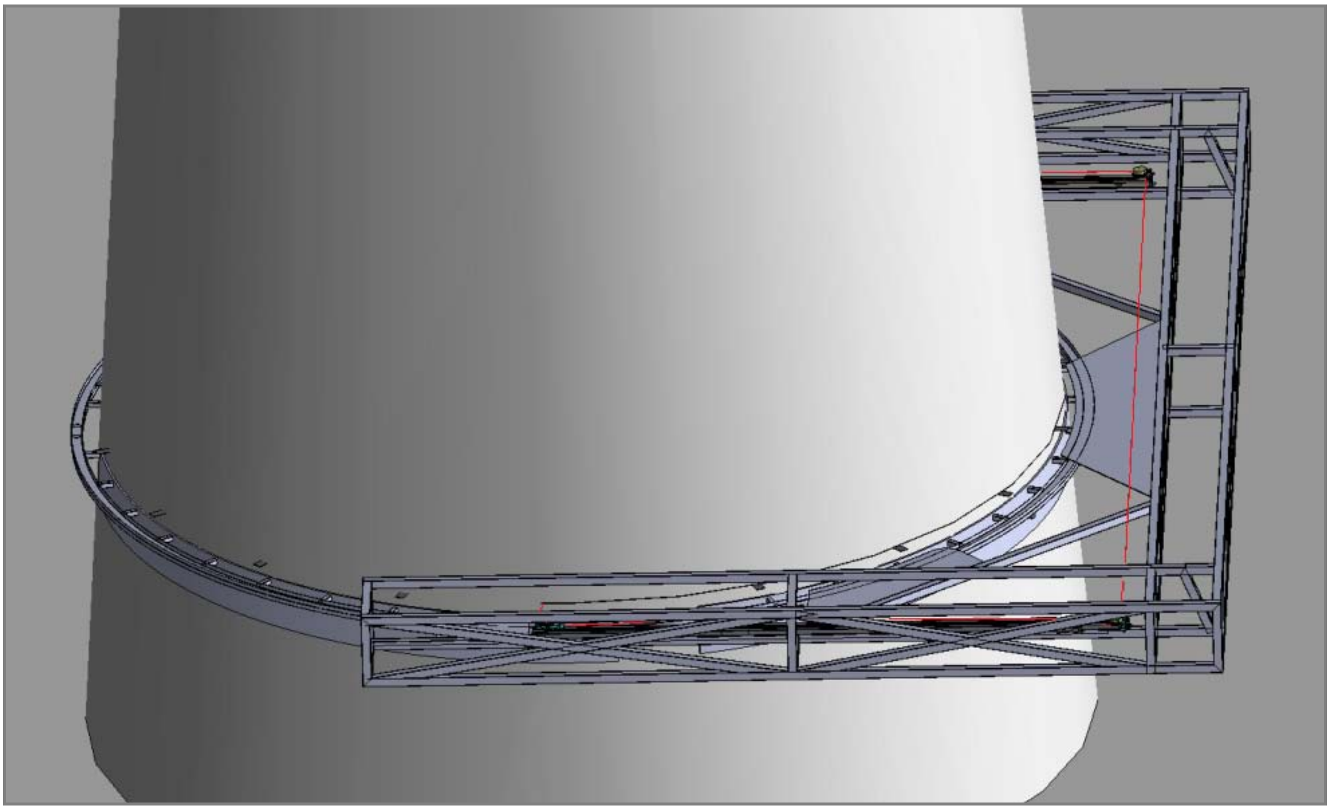


Figure 18: Wire at full travel having cut approximately 55% of the leg diameter.

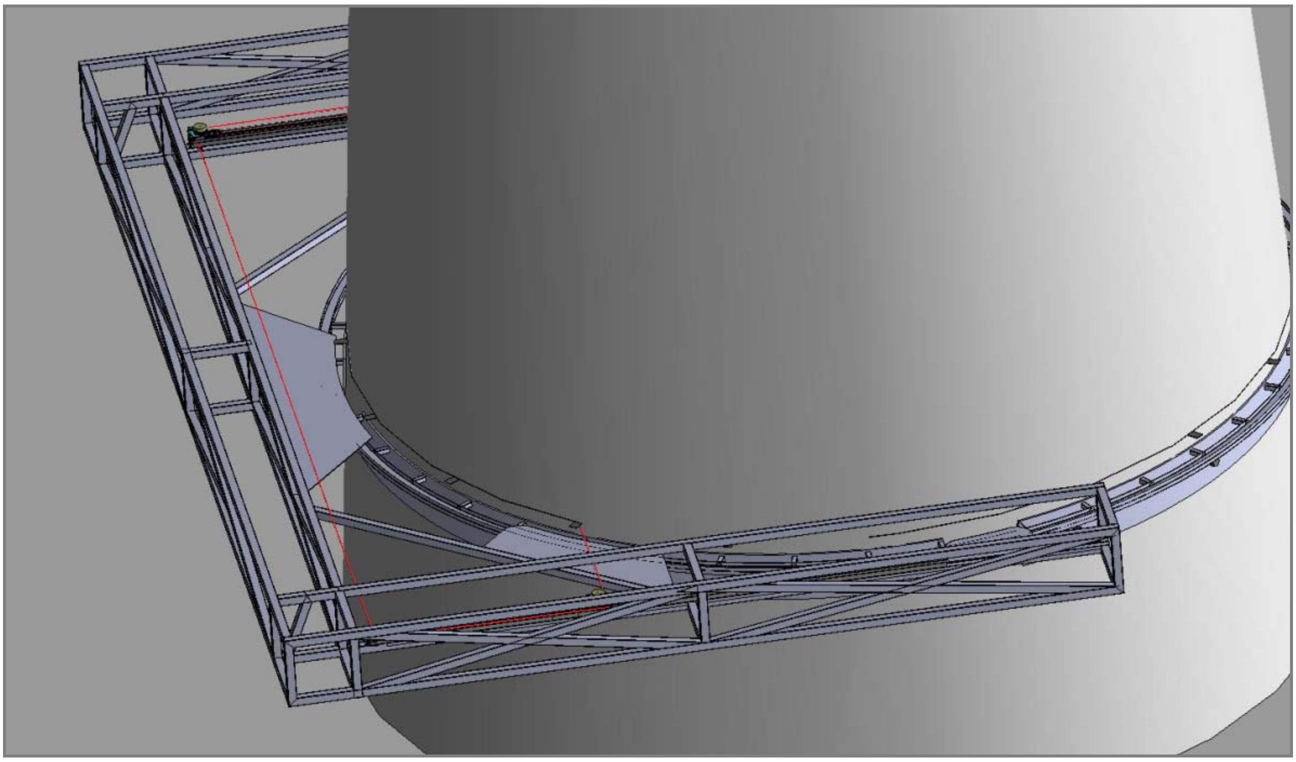


Figure 19: DWCM is repositioned to the opposite side of the leg and the cutting process starts again. This image shows the cut line left after the diamond wire has previously passed through the front face of the leg.

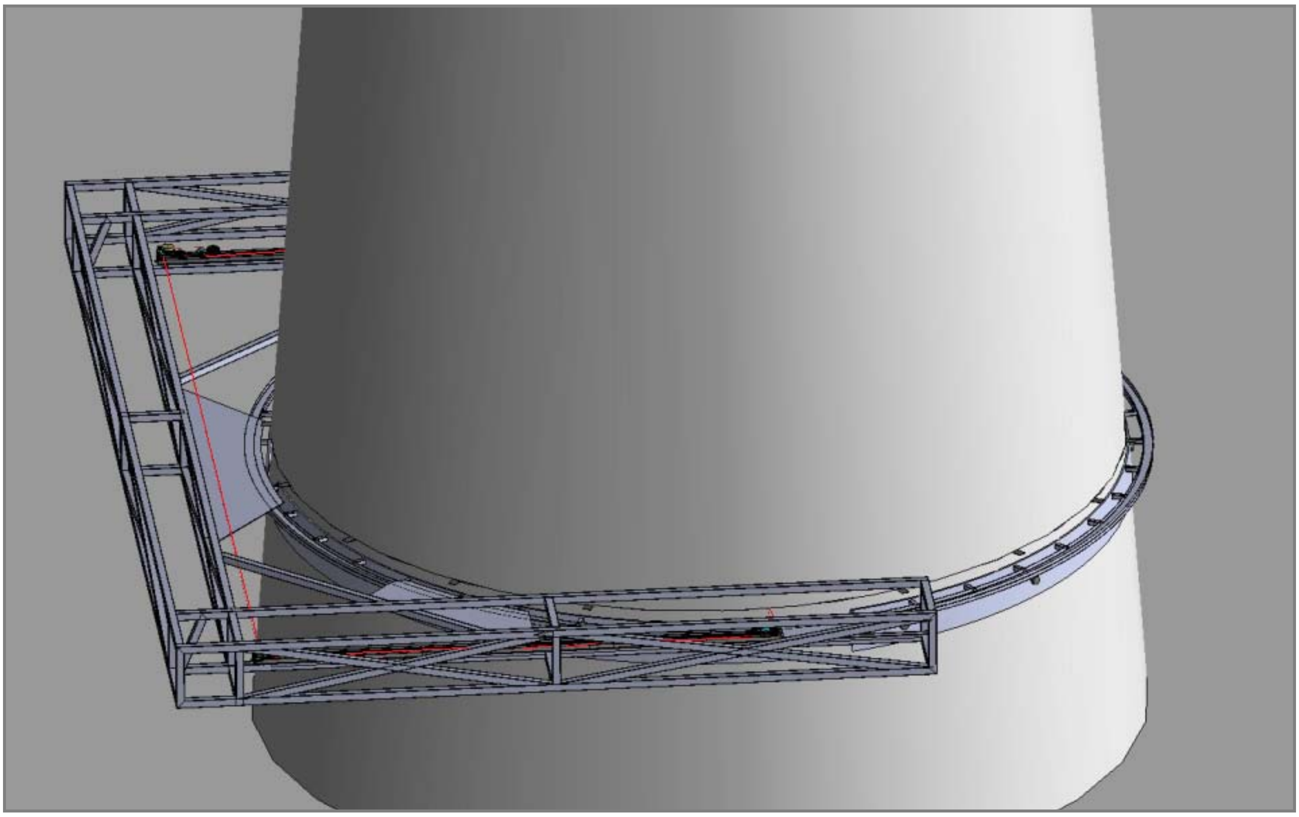


Figure 20: Wire progresses through the leg until it reaches the first cut line. On completion of the cut the DWCM and guide system would be transferred to the next cutting location.

Typically, a specially constructed diamond wire would be able to cut through heavily reinforced concrete at a rate between 0.4 m^2 and 1.2 m^2 per hour of operation. This would equate to an approximate cutting time of between 3 and 8 days for the largest section of a leg at the -110 m level, 2 to 3 days for the -55 m level, and 1 to 2 days for the -8 m level.

A heavy lift vessel would be required to provide overall structural stability, and shims would be inserted in the cut to help stabilise the cut section above and keep the cut line open.

Diamond wire cutting offers advantages over other cutting methods in that it can cut through concrete and steel and hence would be more likely to achieve complete severance of a leg section. The technique would be very effective in cutting through the concrete to steel interface at the -8m level. The cut line created by diamond wire in concrete would be relatively smooth and have a width varying by only 1mm, thereby, in theory, allowing the insertion of shims to transfer vertical loads. However, it must be noted that the diamond wires would start to wear during the cutting process, which could affect the smoothness and width of the cut. The method of inserting the shims, which would likely need diver intervention, would also need to be carefully assessed. In addition, a structural analysis that takes account of the shim properties, their number, location and size, plus the static and dynamic loads involved, would be required to assess the practical feasibility of this concept.

On this type of heavily reinforced concrete the typical cutting rate of the diamond wire would be between 0.4 and 0.5 square metres of concrete per linear metre of wire. With reference to the concrete thicknesses given in Table 1, this means that approximately 100m to 125m of wire would be required to cut at the -110m level, 55m to 70m of wire to cut at -55m, and 32m to 40m of wire to cut at -8m.

The diamond wire, which would be circulated around the DWCM to achieve a speed of approximately 20m/s at the cutting face, would wear during the cutting process. The wear progress could be monitored by measuring the friction between the wire and the target material. The wear of the wire would have a generally even distribution along the diamond bead surface with a consequent decrease in the bead diameter of less than 1mm.

It should be noted that the scale of a DWCM required to cut through an entire leg at the -110 m level would be very large, approximately six times the size of the current largest conventional (non orbital) machine.

In addition to the scale of the DWCM for the cut at the -110 m elevation, the use of diamond wire cutting to complete the removal of the Dunlin A legs would have other challenges to overcome to ensure a successful separation at any cutting elevation.

If internal equipment could be removed from the cut zones prior to cutting, the operation would have an increased chance of success. If this is not possible, there would be a requirement to stabilise the internals to ensure that the wire would not become pinched or jammed as a result of items moving or collapsing within the leg. In case of entrapment of the wire, the cutting operation would have to be resumed approaching the leg from a different direction or elevation, thus creating a new cut line to meet with the previous one. This would significantly increase the duration of the removal operation.

4. CONCLUSIONS

The two cutting techniques with the greatest chances of successfully performing the cutting operation of the Dunlin Alpha concrete legs are the diamond wire and the reciprocal wire methods.

Both of these techniques could feasibly cut through the concrete legs as well as the internal equipment, without the requirement to access the inside of the legs. It should be noted, however, that at their current stages of development, both methods have some technical limitations and associated operational challenges that become greater with water depth and dimension of the target leg section. Cutting operations such as those considered for Dunlin A have not been tried before in practice, therefore the operations described above are conceptual.

On balance, the diamond wire cutting method presents some key advantages over the reciprocating wire method, including:

- Diamond wire cutting is a relatively compact and light system, easier to install and requires significantly less power to drive the cutting string. The orbital DWCM system is especially compact when compared to reciprocal wire/chain – an approximate weight for the DWCM would be less than 15 tonnes including guide rails, compared to 35-50 tonnes for the reciprocating wire. Although cutting through concrete and internal equipment would require the building of a DWCM significantly larger than that currently existing, particularly so for the -110 m cut level, such a DWCM would be well below the size and weight required for a reciprocal wire cutter.

- The type of DWCM described is proven technology, since it has already successfully severed a target which was approximately 10m in diameter, and an increase in target diameter with this style of machine has no impact on operational feasibility. The application of the reciprocal wire cutting system may prove difficult or even impossible to realise in a horizontal plane due to the forces required to progress the cutting through the target.

- Diamond wire cutting could be more accurately controlled. The DWCM could be oriented at various angles around the leg and sever sections of the leg in an order which would ensure structural stability throughout the cutting operation.

- Diamond wire creates a thin clean cut line with relatively constant width, therefore shims could, in theory, be inserted between the cut edges to ensure the wire would not become trapped, and recreate continuity in the concrete to transfer vertical loads. In contrast, reciprocal wire cutting produces a wider and more irregular cut line when compared to diamond wire. While shimming of the cut line maybe possible, the shims would be larger and more difficult to install.

- Although the length of wire required for a DWCM would be longer than that required to encircle a concrete leg with a reciprocating wire, the DWCM could be engineered and built to store enough wire length to complete the cutting operation without wire replacement by divers. This would increase the overall tool weight and its complexity.

However, despite these apparent advantages for diamond wire, the orbital DWCM is not suitable to perform cutting through the internal equipment in the leg. If removal of the internal equipment is not achievable during the preparation phase, the DWCM would have to be designed to perform a linear cut through the entire leg and would therefore be required to accommodate enough diamond wire to cut through all internal items, as well as the reinforced concrete and tensioning cables, with a minimum number of wire replacements. The leg internals would also require stabilisation either during the preparation phase or during the cutting campaign. It should be noted that if stabilising grout was used to at the -110 m level, the material area to be cut would be increased significantly to approximately 350 m^2, with a correspondingly higher cutting time.

In summary, it is concluded that:

- Cutting the Dunlin Alpha legs could be achieved in theory by diamond wire cutting, or possibly reciprocating wire cutting, if specific preparation criteria have been implemented in advance. Lifting and deployment of large and heavy equipment would be required, with associated extensive diving time for positioning and securing the cutting machines, as well as for servicing the equipment and replacing the consumables during the cutting operation.

- Cutting the structure by any method at the -110 m level would be an extensive process involving many exceptional technical challenges.

- Cutting the structure at the -55 m and -8 m levels could be achieved with more certainty if the internal equipment in the leg was removed prior to the commencement of the cutting activities.

- Removal of internal equipment by WROVs would not be possible due to the complexity of gaining access through the walls of the legs and the nature of the items within the legs.

Appendix D

Review of marine operations by

GL Noble Denton

GL Noble Denton

No 1 The Exchange
62 Market Street
Aberdeen
AB11 5PJ UK

Phone +44 1224 289100
Fax +44 1224 289101
www.gl-nobledenton.com

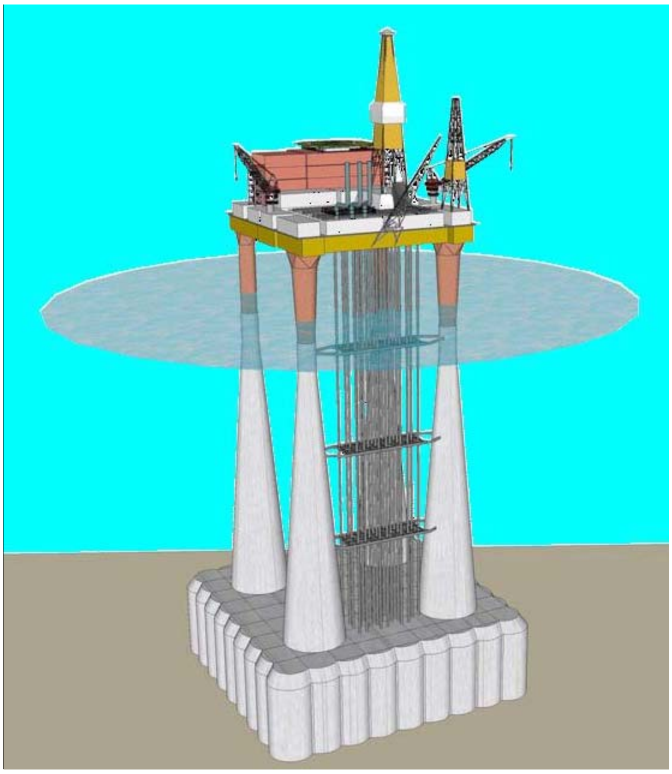
REPORT

FAIRFIELD ENERGY LIMITED

DUNLIN A CONCRETE GRAVITY BASE STRUCTURE

LEG SECTION REMOVAL STUDY

Report No: A7555/02, Rev 02, Dated 13/04/2011



Distribution:
Company: Fairfield Energy Limited Attn: Mr Terry Kimber

W/S No: 42/132016 CTR 00

REVISION DETAILS

Revision	Date	Description	Author	Checker	Approver
A	02/12/2010	Issued for Internal Distribution	RK	DWO	
O	26/01/2011	Issued to Client for Comment	RK	DWO	CMR
01	03/02/2011	Issued to Client	RK	DWO	CMR
02	13/04/2011	Issued to Client	RK	DWO	CMR

DESCRIPTION OF CHANGES

Revision	Section	Change
01	All	Minor changes in descriptive text.
02	All	Wave load calculations updated.
02	All	Minor changes in descriptive text.

INSERTED DOCUMENT/FILE REGISTER

Path and Filename	Details of File

CONTENTS

SECTION		PAGE
1	**EXECUTIVE SUMMARY**	**5**
2	**INTRODUCTION**	**6**
2.1	BACKGROUND	6
2.2	ANALYSIS	6
3	**DUNLIN ALPHA PLATFORM**	**8**
3.1	GENERAL DESCRIPTION	8
3.2	WEIGHT ESTIMATION OF LEG SECTION	10
4	**TYPICAL HEAVY LIFT VESSEL**	**12**
4.1	GENERAL PARTICULARS	12
4.2	HYDRODYNAMIC PROPERTIES	13
4.3	LIFTING ARRANGEMENT	17
5	**ANALYSIS METHODOLOGY**	**20**
5.1	GENERAL	20
5.2	SOFTWARE	21
5.3	MODELLING AND ANALYSIS	21
5.4	ENVIRONMENT	22
6	**ANALYSIS RESULTS**	**24**
6.1	ENVIRONMENTAL LOADS ON THE LEG SECTION	24
6.2	CALCULATION OF HOOK LOADS	26
6.3	EFFECT OF HOOK LOAD	28
7	**OPERATIONAL ASPECTS**	**29**
7.1	WEATHER RESTRICTED OPERATION	29
7.2	STRUCTURAL INTEGRITY	29
7.3	LIFT POINTS	30
8	**CONCLUSIONS AND RECOMMENDATIONS**	**31**
8.1	SSCV SUPPORT DURING CUTTING	31
8.2	ENVIRONMENTAL LOADS DURING REFLOAT	31
8.3	RECOMMENDATIONS	32
REFERENCES		**34**

FIGURES

Figure 3-1	Dunlin A Platform	8
Figure 3-2	Configuration of Dunlin A CGB	9
Figure 3-3	Leg geometry used in the analysis, Legs C & D	9
Figure 4-1	SSCV Thialf (Courtesy HMC)	12
Figure 4-2	Soft mooring lines representing the station keeping system	14
Figure 4-3	Hydrodynamic model of SSCV	15
Figure 4-4	Axis systems for SSCV Motion and Wave Incidence	16
Figure 4-5	Heave RAO – transfer function for vertical oscillation	16
Figure 4-6	Pitch RAO – transfer function for fore-aft rotation	17
Figure 4-7	Lifting arrangement	18
Figure 4-8	SSCV crane capacity chart	19
Figure 5-1	Forces and moments acting on the leg section	20
Figure 6-1	Leg section with buoyancy tanks attached	24
Figure 7-1	Bolted connection between steel and concrete	29

TABLES

Table 3-1	Weight estimate for leg section	10
Table 5-1	Metocean data for 10 year return seasonal storm design conditions	22
Table 6-1	Environmental loads on leg	24
Table 6-2	Environmental on leg with buoyancy tanks attached	25
Table 6-3	Factor of safety against overturning & sliding	25
Table 6-4	Factor of safety against overturning & sliding with buoyancy tanks attached	26
Table 6-5	Hook loads from analysis, 500 mT pretension	27
Table 6-6	Hook loads from analysis, 1000 mT pretension	27
Table 6-7	500 mT pretension on crane, without buoyancy tanks	28
Table 6-8	1000 mT pretension on crane, without buoyancy tanks	28

Abbreviations

CGB	Concrete Gravity Base
DP	Dynamic Positioning
HLV	Heavy Lift Vessel
HMC	Heerema Marine Contractors
IMO	International Maritime Organization
Kxx	Radius of gyration about X-axis
Kyy	Radius of gyration about Y-axis
Kzz	Radius of gyration about Z-axis
LCG	Longitudinal Centre of Gravity
mT	Metric tonne
RAO	Response Amplitude Operator
SSCV	Semi Submersible Crane Vessel
TCG	Transverse Centre of Gravity
VCG	Vertical Centre of Gravity
[ ]	Number of reference document (see page 34)

1 EXECUTIVE SUMMARY

This report has been compiled by GL Noble Denton to address the removal of the top sections of the Dunlin Alpha concrete legs in the circumstances of these being cut free from the platform legs using horizontal diamond wire cutting at 55m below sea level, and lifted or floated away.

The report concludes that:

- Trying to improve stability by supporting the leg section from the crane hook of a heavy lift vessel could introduce snatch loads on the crane rigging in moderate sea state conditions, or above moderate conditions. This introduction of large and unpredictable snatch loads would not be acceptable to the Marine Warranty Surveyor.

- Once cut free, there would be a risk that a 2800 tonne leg section could become unstable and overturned at sea states substantially below the design conditions (a 10 year return seasonal storm).

- Adding external buoyancy tanks to the leg section to float the cut section away from the lower leg would subject the section to increased environmental loads, and would make the cut section unstable at conditions substantially below the design sea state.

Further observations

- Conducting the cutting and lifting operations in weather conditions that limit this risk would need to be restricted to a reliable weather forecasting period of 72 hours. However, there is no certainty that the operations could be completed within this time.

- As the leg section could overturn or slide in moderate sea states (with or without buoyancy tanks attached), either the provision of additional restraint or the adoption of highly restrictive sea conditions would be required.

- It would be difficult to confirm the integrity of the leg section and lifting attachments. This fact would pose a serious threat to safety during any lifting operation.

2 INTRODUCTION

2.1 BACKGROUND

Fairfield Energy Limited (Fairfield hereafter) is engaged in evaluating various options regarding the decommissioning of the concrete gravity base (CGB) of the Dunlin Alpha platform. One of the options being reviewed is the in-situ decommissioning of the platform. This would involve removing the topsides, steel columns and concrete legs down to 55m below sea level to provide clear water for navigation to meet the guidelines of the International Maritime Organization (IMO).

It has been suggested that once the topsides is removed, cutting and removal of each of the four legs to 55m below sea level may require restraint of the partially cut legs while completing the cutting and lifting of the freed section. This restraint might be provided by connecting the crane hook of a heavy lift vessel (HLV) to the top of the individual leg section being removed.

Fairfield commissioned GL Noble Denton to analyse the marine operations issues related to crane hook support of the leg section throughout the subsea cutting operation in various weather conditions. The analysis:

- Considered a scenario where the CGB leg had been cut at an elevation 55m below sea level, creating a weight on the crane hook of the order of 3000 metric tonne (mT).
- Considered the use of a large semisubmersible crane vessel (SSCV) applying up to 1000 mT ‘stabilising’ uplift on the leg during the latter phases of the cut.
- Identified whether the SSCV would improve or worsen the leg stability during the cutting process.

This report presents an overview of the method, results and conclusions for the analysis.

2.2 ANALYSIS

To study the effect of hook load on the leg section, GL Noble Denton considered a large SSCV applying a specified hook load to the concrete leg sections during cutting. A SSCV of equivalent size to the vessels Thialf and S7000 was selected as being representative of a typical heavy lift vessel having suitable hook capacity for installation/decommissioning activities in the North Sea. The following cases were analysed and are presented in this report:

- SSCV applying 500 mT hook load
- SSCV applying 1000 mT hook load
- Concrete leg section exposed to weather without any restraint
- Concrete leg section with buoyancy tanks attached and exposed to weather without any restraint.

The analysis involved:

- Hydrodynamic modelling of the SSCV
- Estimation of leg section properties, weight and buoyancy
- Estimation of hook load created by vessel motion
- Estimation of environmental loads on the leg section and the buoyancy tanks

In carrying out the analysis, the following basic assumptions were made:

- For an operation of this type, a Marine Warranty Surveyor would require that a safety margin be built into the operational procedures in terms of the 'design sea conditions', such that these would exceed those anticipated during the operation.
- For an extended offshore operation there should be less than a 10% probability of the design conditions being exceeded.
- For the operations considered in this report, a typical design significant wave height would be slightly greater than 10m (see Section 5-4).

A general description of the Dunlin Alpha (Dunlin A) platform and estimation of the leg section weight and buoyancy are presented in Chapter 3. Details of the lifting configuration and hydrodynamic properties of a typical large SSCV are described in Chapter 4.

The analysis methodology is described in Chapter 5 and results from the study are given in Chapter 6. A high level overview of some of the operational issues is presented in Chapter 7.

Conclusions and recommendations are presented in Chapter 8.

3 DUNLIN ALPHA PLATFORM

3.1 GENERAL DESCRIPTION

The Dunlin A platform is a fixed installation, serving as a production facility for the Dunlin, Dunlin South West, Osprey and Merlin fields. It is a four-legged concrete gravity base substructure with topsides supported by a steel box girder frame. Figure 3-1 identifies main components of the platform.

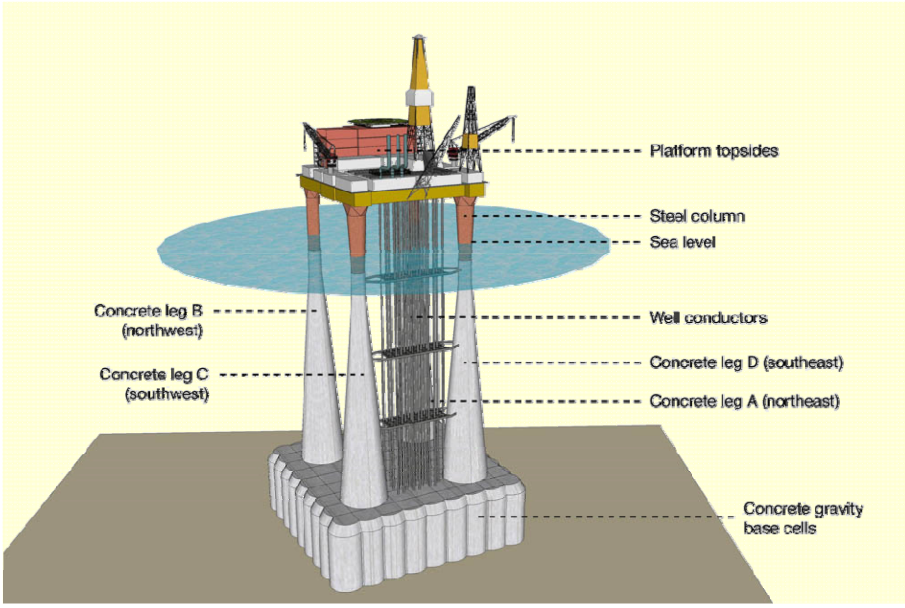


Figure 3-1 Dunlin A Platform

The concrete legs are joined to steel columns 8m below sea level (approximately 143m above the seabed), which support the box girder frame and the topsides. The steel columns for Legs C and D flare out from 5.46m diameter at this elevation to 8.14m diameter at elevation 167m, while the steel columns on Legs A and B are cylindrical with an external diameter of 5.46m.

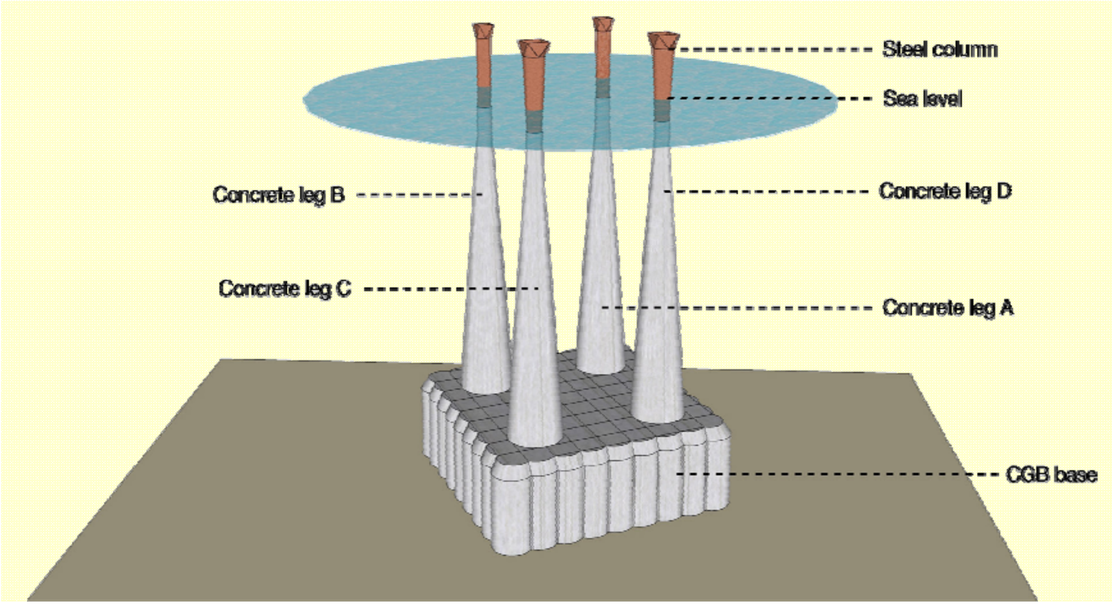


Figure 3-2 Configuration of Dunlin A CGB

Using detailed structural drawings of the platform, the geometry of the Legs C and D were modelled to estimate weight and buoyancy, as shown in Figure 3-3.

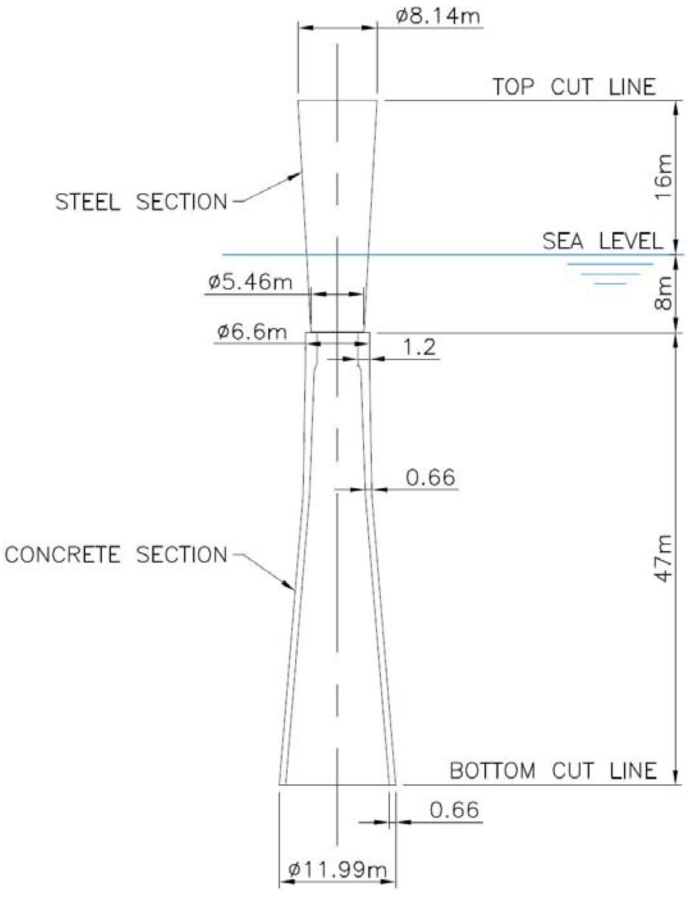


Figure 3-3 Leg geometry used in the analysis, Legs C & D

3.2 WEIGHT ESTIMATION OF LEG SECTION

The weight estimate of the leg section, including both the concrete and steel parts, is given below. The concrete volume was generated by the analysis model, with 4% steel reinforcement assumed for the purposes of weight estimation. A confirmatory check on the concrete volume was made using leg dimensions taken from as built drawings [8]. Steel weight was calculated from structural drawings [7].

Table 3-1 Weight estimate for leg section

1.0	***Geometry of the cut section***		
	Elevation at top cut level	+167	m
	Elevation at bottom cut level	+96	m
	Top of concrete section	+142.89	m
	Bottom of concrete section	+96.00	m
	Bottom of steel section	+143.00	m
	Top of steel section	+167.00	m
	Total length of steel section	24.00	m
	Total length of concrete section	46.89	m
	Water level	+151.00	m
2.0	***Weight of concrete section***		
2.1	***Weight of concrete***		
	Volume of concrete	817	m3
	Density of concrete	2400	kg/m3
	Weight	***1960.8***	***mT***
2.2	***Weight of steel reinforcement***		
	Assume 4% by volume reinforcement	32.68	m3
	Density of steel bars	7850	kg/m3
	Weight	***256.5***	***mT***
	Subtotal (2.1+2.2)	***2217.3***	***mT***
3.0	***Weight of steel section***		
3.1	***Shell plating***		
	Plating thickness	50	mm
	Height of steel section	24	m
	Bottom section radius	2.7	m
	Top section radius	4.1	m
	Surface area of the conical section	**513.4**	m2
	Weight of shell plating	***201.5***	***mT***
3.2	***Vertical stiffeners, 550 mm x 40 mm FB***		
	No of vertical stiffeners	40	
	Length of stiffeners	24.04	m
	Weight of stiffeners	***166.1***	mT
3.3	**Ring stiffners 650 mm x 16mm + 350 mmx 30 mm**		
	No of ring stiffeners	8	
	Average length of web	21.36	m
	Web plate weight	13.95	mT
	Average length of flange	17.28	m
	Flange plate weight	11.39	mT
	Total	***25.34***	***mT***

3.4	***Top flat @ 167m- 900mm x 60 mm + 350 mm x 40 mm***		
	Length of web	25.58	m
	Weight of web	10.84	mT
	Length of flange	19.92	m
	Weight of flange	2.189	mT
	Total	***13.031***	mT
3.5	***Bottom flat @ 143m - 60mm ring OD 6600, ID 4200***		
	Thickness	60	mm
	Plate weight	38.35	mT
	Brackets, approx 1200 mm x 600 mm	40	nos
	Approx thickness	40	mm
	Weight	4.52	mT
	Total	***42.88***	***mT***
	Subtotal (3.1 + 3.2 + 3.3 + 3.4 + 3.5)	***449***	***mT***
Total estimated weight		***2666***	***mT***
Estimated weight with 5% contingency		***2799***	***mT***

The weight estimate results in a total weight of the leg structure to be lifted of approximately 2800 mT.

Values presented in Table 3-1 reflect an adequately detailed approximation to leg weights for the purposes of this study. In the event that the leg removal project progressed into detailed design, further consideration would have to be given to the weight of internal structures in the legs, measured concrete densities and as-built variations in the wall profile. These are expected to comprise a relatively small fraction of the overall leg weight and are not explicitly represented in this estimate.

For calculating the safety factors against overturning moments created by environmental forces acting on the leg section, a value of 2666 mT (without contingency) was used in the analysis as this lower weight would give a more conservative result.

4 TYPICAL HEAVY LIFT VESSEL

4.1 GENERAL PARTICULARS

The basic geometry of SSCV Thialf was taken as typical of a large heavy lift crane vessel, having an appropriate crane lift capacity and motion characteristics for this type of operation.

Thialf is owned by Heerema Marine Contractors and is one of the largest offshore crane vessels. The vessel is equipped with two revolving stern mounted AmClyde cranes, each rated to a maximum of 7100 mT at the main hoist. The main particulars of the vessel are given below.

Length overall	201.6 m
Length	153.9 m
Breadth	88.4 m
Depth	49.5 m
Operating draft	13.1 to 31.7 m

Figure 4-1 SSCV Thialf (Courtesy HMC)

Both the Thialf and S7000 have dynamic positioning as well as spread mooring systems for station keeping. Heavy lift operations can be performed in either DP mode or with spread moorings.

4.2 HYDRODYNAMIC PROPERTIES

The hook load experienced during a heavy lift in a particular sea state would depend on the weight of the lifted structure and the motion characteristics of the heavy lift vessel. SSCVs have superior motion characteristics when compared with monohull vessels due to the smaller water plane area of the columns and the submerged pontoons.

In general, a floating crane vessel would exhibit the following dynamic behaviour:

- High frequency response (2 seconds (s) to 12s) which covers the normal wave frequency response
- Resonant response to swells and second order wave forces (12s to 30s) and
- Low frequency response (30s to 200s) mainly due to mooring and dynamic positioning operations.

In addition, the vessel would attract steady wind, current and wave drift loads. These steady mean loads would be counteracted by the mooring or DP station keeping systems. The energy associated with the wave frequency motion would be very high, hence station keeping systems are not normally designed to restrain the vessel against high frequency or resonant response in waves. Low frequency dynamic behaviour originates mainly from the properties of the station keeping system.

This analysis focuses solely on wave frequency motion characteristics of the heavy lift crane vessel. Steady (mean) loads on the vessel and effects from a low frequency response were eliminated since the corresponding accelerations were too low to have an impact on the lifting loads.

The mooring system is represented in the analysis by a soft mooring line at each corner of the vessel. This provides a light restraint against drift but does not affect the motion characteristics of the vessel. The mooring system is illustrated in Figure 4-2.

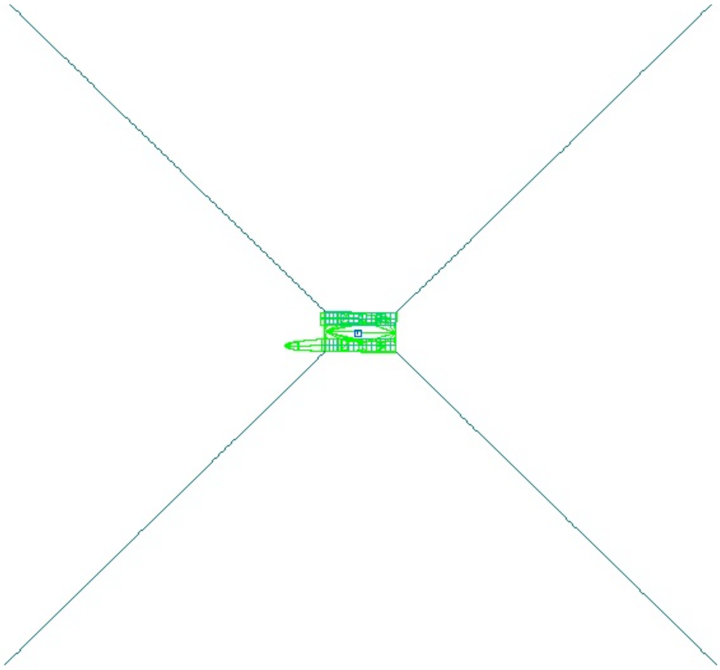


Figure 4-2 Soft mooring lines representing the station keeping system

In DP mode, an installation vessel typically operates within a position keeping accuracy of approximately 3.0m and ±1° in heading. Calculated vessel motions were compared with this.

The hydrodynamic properties of the vessel were estimated using a diffraction analysis of the hull form at the specified draft. The vessel hull form was generated from model data available to GL Noble Denton, and is considered to be representative of a large SSCV, appropriate for use in these analyses.

Once the vessel's hydrodynamic properties are established, motion characteristics of the vessel can be represented as Response Amplitude Operators (RAOs). RAOs indicate the vessel's motion characteristics in a sea state having a unit wave height. The RAOs can be linearly extrapolated to obtain motion response at other wave heights in combination with the sea spectrum using spectral methods.

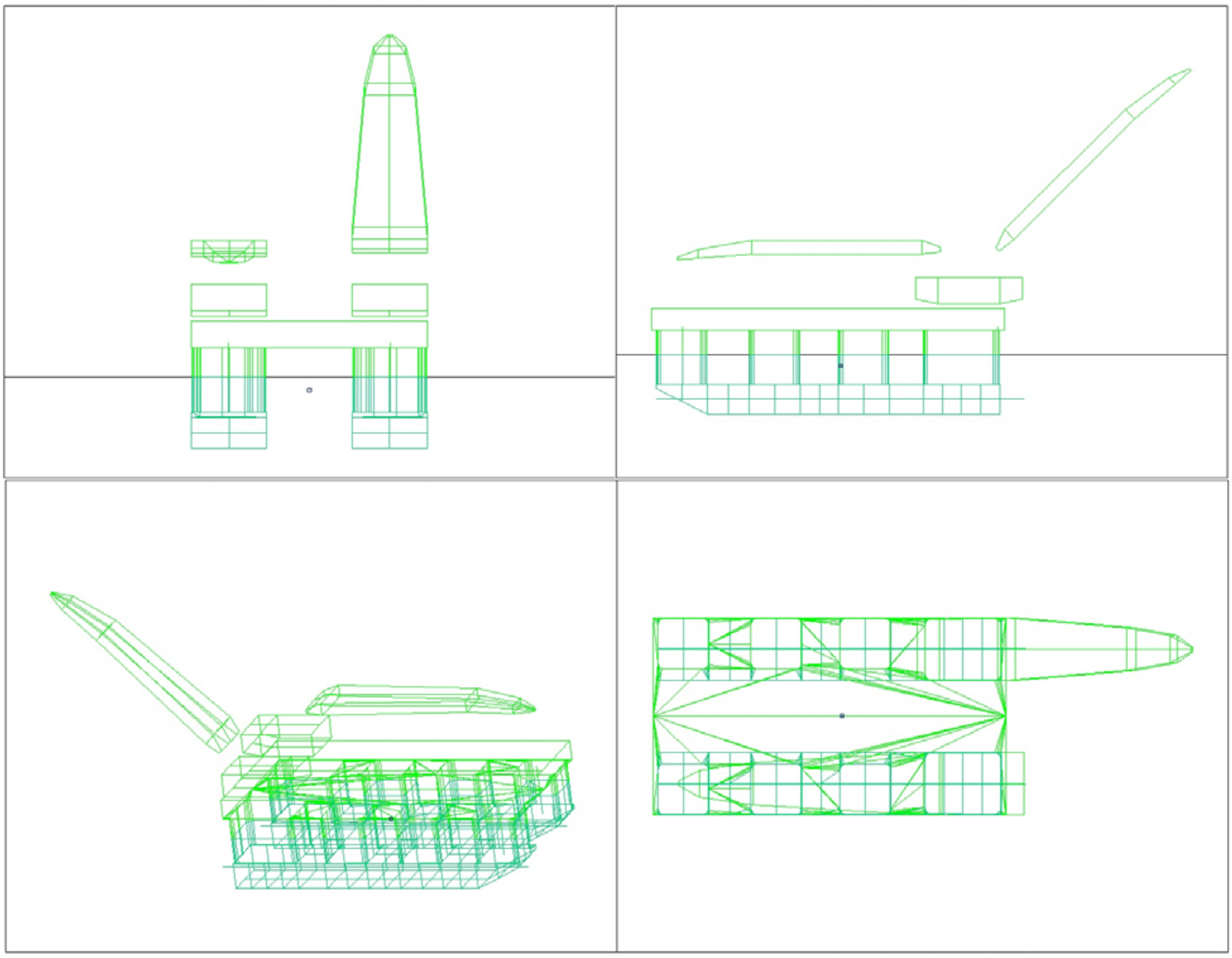


Figure 4-3 Hydrodynamic model of SSCV

To estimate the RAOs of the vessel the following mass properties were employed. The properties are considered to be representative of a vessel of this size and type under similar loading conditions.

Displacement	177 419 mT
LCG (Longitudinal Centre of Gravity)	82.58 m
TCG (Transverse Centre of Gravity)	0.0 m
VCG (Vertical Centre of Gravity)	22.0 m
Kxx (Radius of gyration about longitudinal axis)	34.70 m
Kyy (Radius of gyration about transverse axis)	40.90 m
Kzz (Radius of gyration about vertical axis)	47.00 m

Figure 4-4 shows the degrees of freedom of vessel motion, and the angle of incidence for waves impacting the vessel.

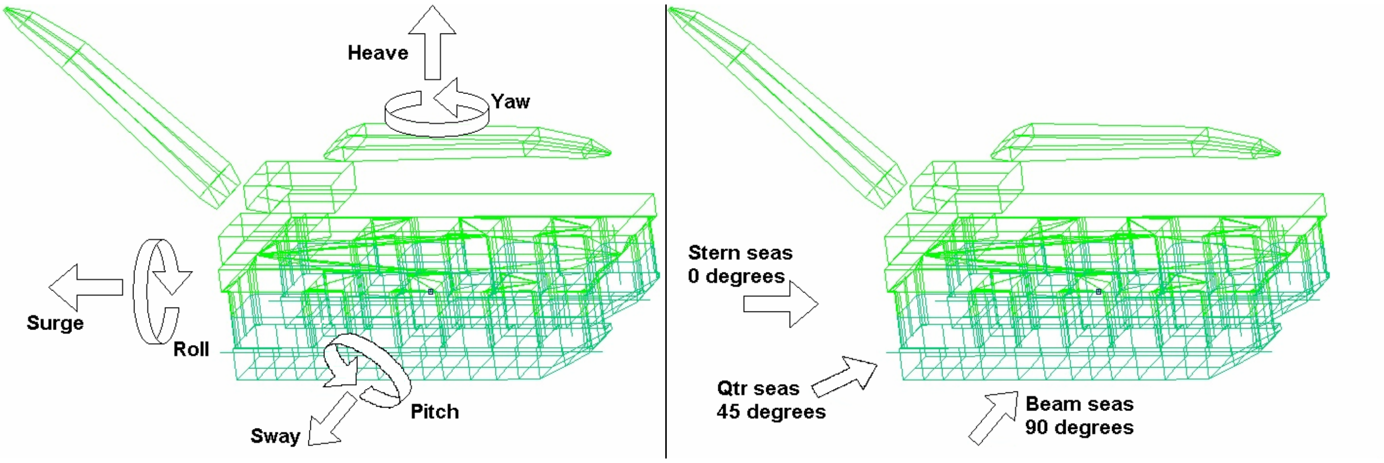


Figure 4-4 Axis systems for SSCV Motion and Wave Incidence

Motion RAOs were developed at the centre of gravity of the vessel. Graphs of the two most important degrees of freedom (heave and pitch) are shown in Figure 4-5 and Figure 4-6.

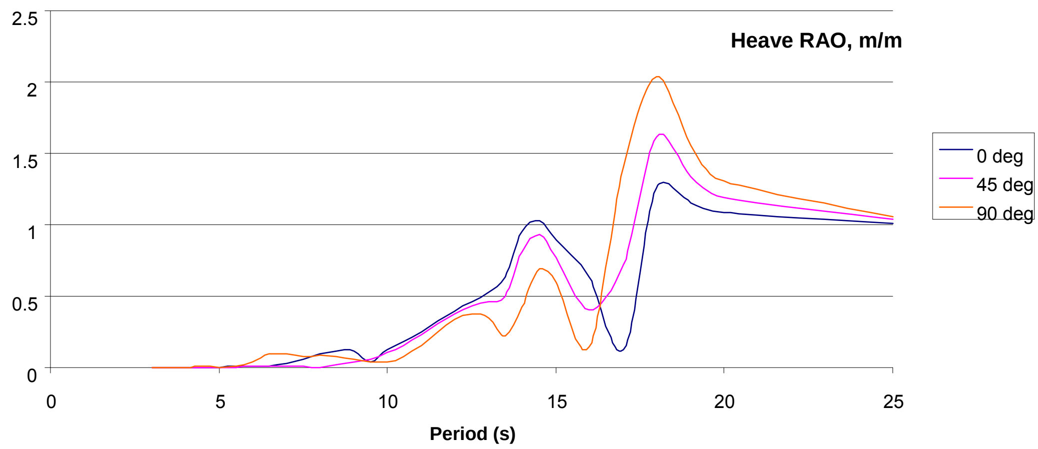


Figure 4-5 Heave RAO – transfer function for vertical oscillation

The heave RAO represents the amplitude of heave experienced by the vessel at 1m wave height for a range of wave periods. This may be combined with wave spectral data to develop the heave response of the vessel under a given sea state.

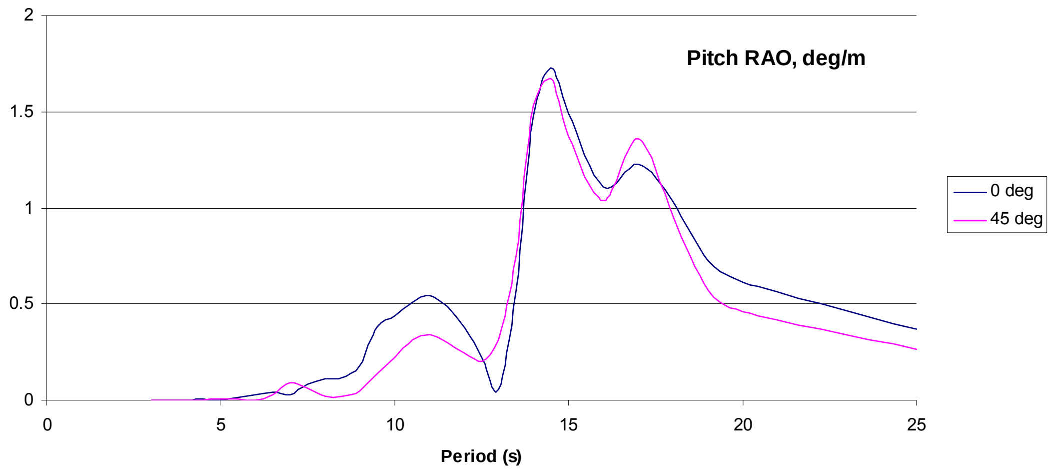


Figure 4-6 Pitch RAO – transfer function for fore-aft rotation

The pitch RAO represents the amplitude of pitch (in degrees) experienced by the vessel at 1m wave height for a range of wave periods. This may be combined with wave spectral data to develop the pitch response of the vessel under a given sea state.

4.3 LIFTING ARRANGEMENT

For the analysis, it was assumed that the vessel starboard crane would be used to hold the concrete leg section during the cutting operation, with a boom angle of 58 degrees at a lifting radius of 60m, as shown in Figure 4-7. The maximum hook height above sea level at this radius is approximately 105m.

It is assumed that slings would connect the crane hook to the top of the structure at +167m (16m above sea level).

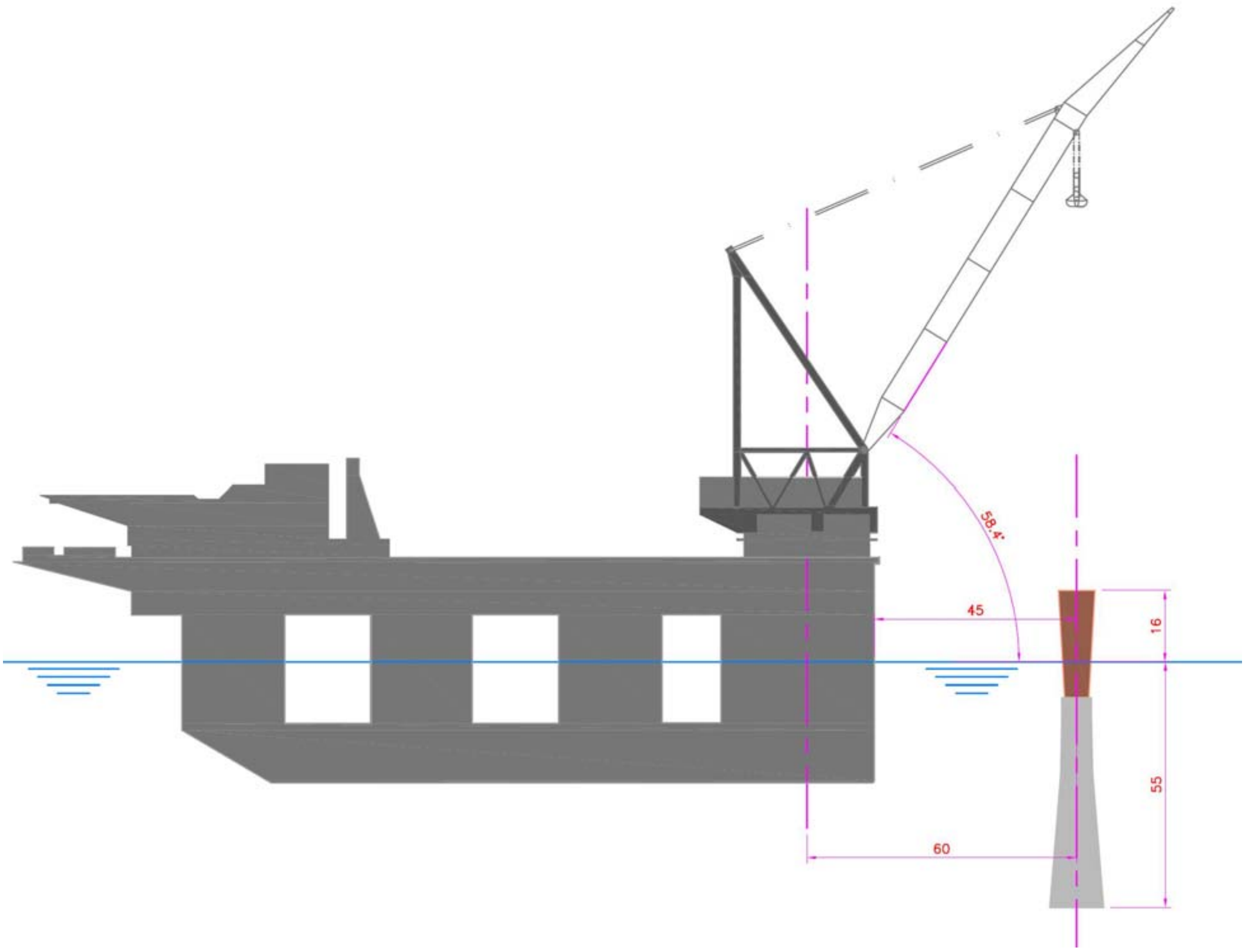


Figure 4-7 Lifting arrangement

The representative crane capacity chart for a large SSCV is shown in Figure 4-8.

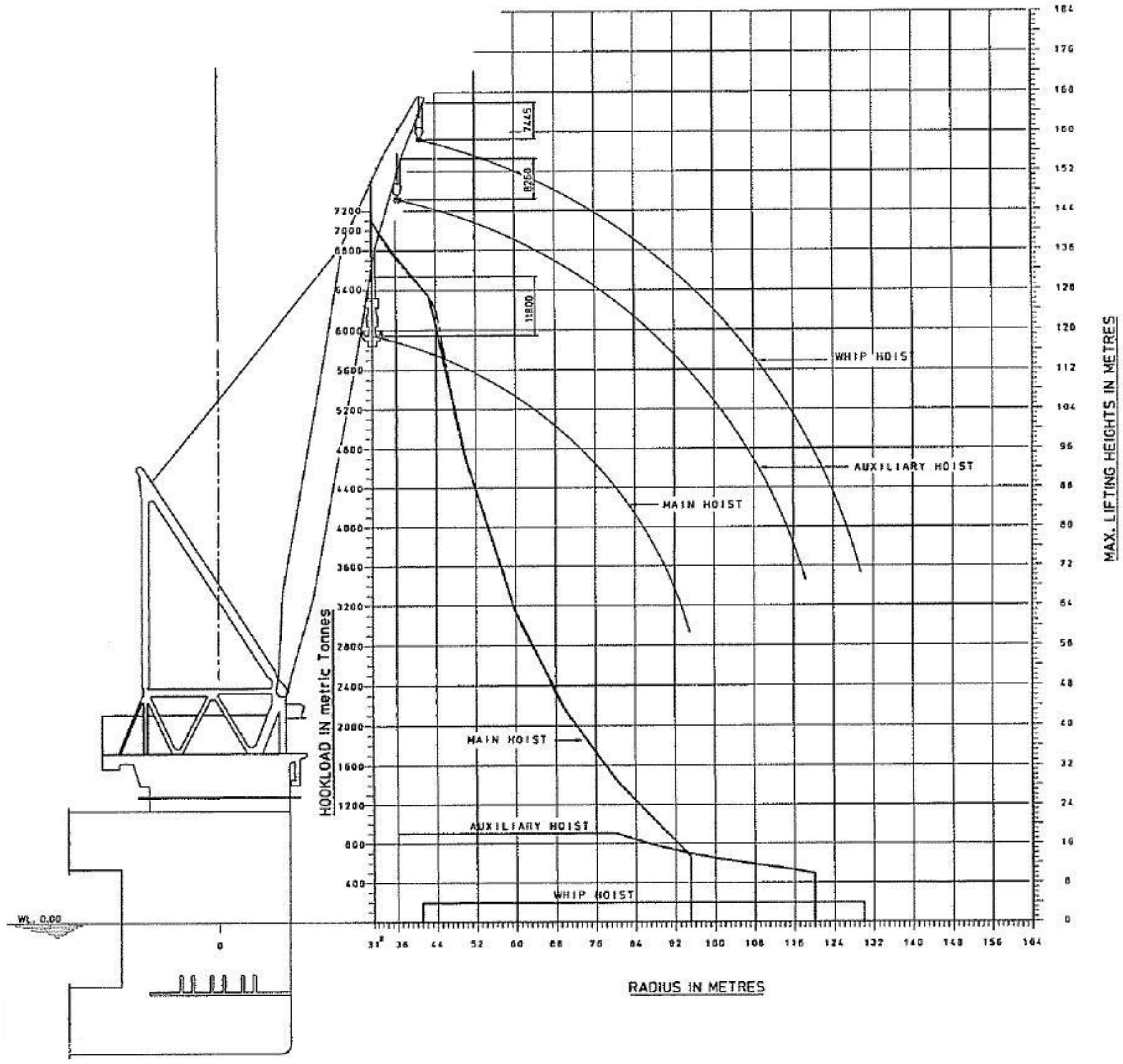


Figure 4-8 SSCV crane capacity chart

5 ANALYSIS METHODOLOGY

5.1 GENERAL

The stability of the leg section would depend on its weight and buoyancy, and the magnitude of the environmental loads acting on the section. A schematic of the forces and moments acting on the leg is shown in the figure below.

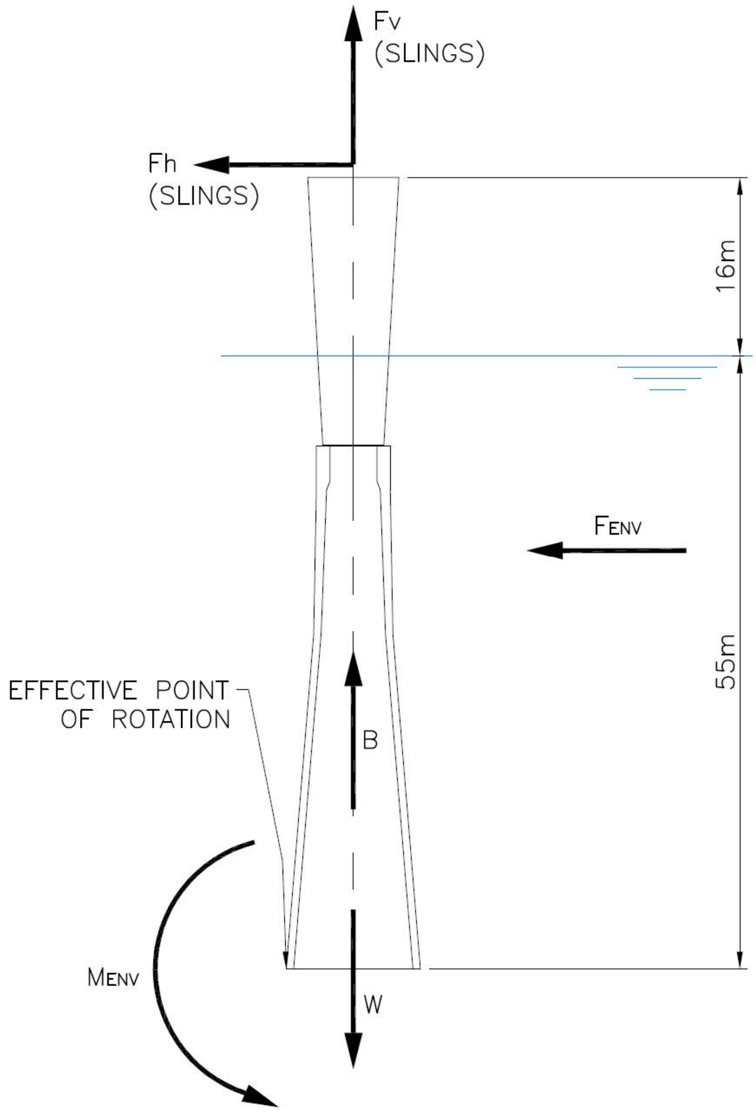


Figure 5-1 Forces and moments acting on the leg section

Where:

Fv and Fh are the vertical and horizontal hook loads

FENV is the environmental load (wind, wave and current) acting on the leg

MENV is the moment due to the environmental load acting about cut line

B is the buoyancy of the leg section

W is the weight of the leg section

With a crane hook connected to the leg section, the motion of the HLV would induce vertical and horizontal load components at the lifting point. The magnitude of these forces would be governed by the motion of the HLV vessel and the lift weight. In this particular case, the leg section would not be free to move until the cut was complete. In effect, the crane hook would be attached to a fixed point on the CGB and the HLV would be restrained by the slings attached to the lifting point.

The study was divided into two analyses:

- The environmental loads on the leg section created by waves, wind and current.
- Loads from the crane hook at the fixed attachment due to HLV motion, combined with environmental loads applied directly to the leg.

Environmental loads were derived from the wind, wave and current loads that would act on the geometry of the leg section. The moment about the cut line (MENV in Figure 5-1) represents the overturning moment caused by the environmental loads.

To generate the loads due to HLV motion, a motion analysis of the SSCV was required.

5.2 SOFTWARE

The analyses were carried out using Ultramarine software MOSES [3] (www.ultramarine.com).

MOSES (Multi Operational Structural Engineering Simulator) is a general purpose simulation programme used for the analysis of marine operations.

Environmental loading on the leg section was calculated using regular wave analysis in NDA Waveload [4]. Confirmatory irregular wave analyes were performed with MOSES (boundary element theory) and Orcaflex [5] (beam elements with the Morison Equation).

5.3 MODELLING AND ANALYSIS

As described in Sec 5.1, the analysis was carried out in two parts.

Environmental loads on the leg section were obtained using time domain simulations in NDA Waveload. Wave and current loads were estimated in the programme using the Morison Equation. The drag and added mass coefficients were estimated using industry standard techniques [9] & [10].

The load imposed by the crane vessel was estimated from motion analyses with a sling attached between the crane tip and a fixed point corresponding to the top of the CGB structure at +167m. A time domain analysis was carried out for stern, quartering and beam sea conditions. Analysis was carried out for two cases of vertical hook load being applied by the crane, namely 500 mT and 1000 mT.

5.4 ENVIRONMENT

Offshore lifting operations may be subject to a wide range of environmental conditions depending upon the season, duration of the operation, and sensitivity of the activity. Where an operation is of short duration (less than 72 hours) weather conditions can be forecast with sufficient accuracy to allow relatively low design wave heights to be adopted [11]. For a longer operation, the risk of deteriorating weather increases rapidly.

From the information currently available, the process of cutting and lifting the Dunlin A CGB leg section would be expected to extend beyond that of a reliable weather window forecast. On this basis, normal offshore practice is to require that a “safe” condition is attainable where the structure can resist design conditions with a 10% [2] [8] probability of exceedence (i.e. conditions that are unlikely to be experienced).

Environmental data for a location close to Dunlin A was extracted from the GL Noble Denton database.

Significant wave height (Hs) is a statistical parameter representing the wave height of an irregular sea state. This value corresponds to the mean of the highest one third of the wave components, and approximates the wave height perceived by an experienced seafarer. Peak period corresponds to the period with highest energy in a particular wave spectrum. All of these values are statistically generated from weather data collected from different sources by specialist agencies.

For the analogous condition of an unpiled jacket, GL Noble Denton guidelines also require consideration of the 10 year return seasonal storm [12]. Over the main offshore lifting period, April to September, this corresponds to a sea state with a significant wave height of 10.9m. If operations were restricted to a specific month a somewhat lower sea state could be applicable.

The 10 year return period environment has a 10% likelihood of being experienced in the field within a year. The selected design conditions for the analysis are shown in Table 5-1.

Table 5-1 Metocean data for 10 year return seasonal storm design conditions

Significant Wave height, m	10.9
Range of associated wave period (peak), seconds	13 to 17.5
Wind speed, knots	72.3
Surface current, knots	1.0

These environmental conditions were applied in the analysis of leg section stability without crane assistance.

In a separate analysis, sea states with significant wave heights of 1m, 2m and 3m were assessed in conjunction with crane hook loads and vessel movement. Current and wind loads on the vessel were not considered in this analysis since these loads would be offset by the mooring system/DP.

As the results of this study are intended for feasibility purposes only, a time domain analysis duration of 20 minutes was used. In the event that the leg removal project progressed into detailed design, a longer simulation period would be required in order to derive statistics representative of the behaviour of the system. Extrapolation of these results to a three hour duration indicates a potential variation of the extreme load of around 15%.

6 ANALYSIS RESULTS

6.1 ENVIRONMENTAL LOADS ON THE LEG SECTION

Forces acting on the leg section due to the action of waves, wind and current were estimated to ascertain the ability of the leg section to resist overturning and sliding once the cut had been completed.

Analyses were carried out for the leg section alone, and for the leg section with four buoyancy tanks attached. The buoyancy tank characteristics were taken from preliminary information provided by Fairfield [1]. They were modelled to be 25m long and 6.25m diameter, penetrating the water surface, as shown in Figure 6-1.

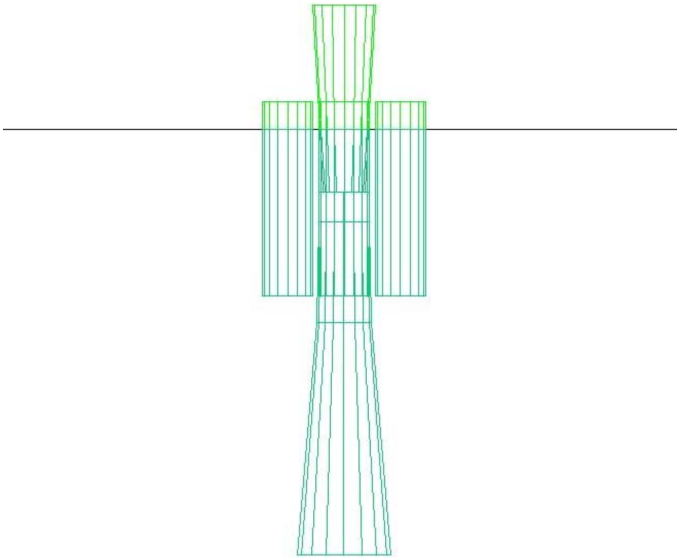


Figure 6-1 Leg section with buoyancy tanks attached

The average density of a buoyancy tank was extracted from the information provided [1], giving a value of 0.3 tonnes per cubic metre of displacement. Hence the dry weight of one buoyancy tank would be approximately 230 mT. The total weight of the leg assembly with buoyancy tanks would be 3586 mT.

Table 6-1 shows the environmental loads on the leg section for various sea states, acting concurrently with forces corresponding to the one year return current (velocity, Vc = 1 knot) and wind (velocity, Vw = 72 knots).

Table 6-1 Environmental loads on leg

Significant Wave Height, m	1.0	2.0	3.0	10.9
Vc = 1kn, Vw = 72 kn				
Force, mT	70.5	147	224	639
Moment about cut line, mT-m	3970	7070	9644	25834

Table 6-2 shows the environmental loads acting on the leg section under the same conditions, with buoyancy tanks attached to the leg section.

Table 6-2 Environmental on leg with buoyancy tanks attached

Significant Wave Height, m	1.0	2.0	3.0	10.9
Vc = 1kn, Vw = 72 kn				
Force, mT	151	381	536	1270
Moment about cut line, mT-m	8665	20325	27190	60620

The environmental loads and buoyancy would induce an overturning moment and would tend to tilt the leg section, while at the same time the weight of the structure would resist tilting. GL Noble Denton guidelines require a safety factor against uplift of the weather side (tilting) in excess of 1.2, and a safety factor against sliding in excess of 1.5. This safety factor represents the system capacity to resist tilting or sliding, with a larger safety factor indicating a lower likelihood of these events occurring.

The factor of safety against overturning was estimated from a combination of the submerged weight and the imposed moment for the environmental load cases considered above.

Sliding of the upper leg section in relation to the lower leg section could also occur under certain load conditions. The factor of safety against sliding for the upper leg section without buoyancy tanks was checked assuming a friction factor (μ) of 0.2.

Factors of safety for overturning and sliding are presented in Table 6-3. Although the 3m Hs condition produced only a marginal safety factor for overturning, lower sea state factors of safety against overturning and sliding were in excess of 1.2 and 1.5 respectively. All sea conditions equal to or greater than 3m Hs were found to be unacceptable.

Table 6-3 Factor of safety against overturning & sliding

Hs	1m	2m	3m	10.9m
Vc = 1kn, Vw = 72 kn				
Overturning	**1.79**	**1.33**	**1.10**	**0.52**
Sliding	**5.23**	**2.50**	**1.64**	**0.58**

The buoyancy tanks were considered to be installed in a partially flooded condition, and subsequently free-flooded. The flooded tanks would increase the overall weight of the structure. However, the combination of leg section and tanks would attract greater environmental loads. The factors of safety against overturning and sliding for the leg section with buoyancy tanks attached are given in Table 6-4.

Table 6-4 Factor of safety against overturning & sliding with buoyancy tanks attached

Hs	1m	2m	3m	10.9m
Vc = 1kn, Vw = 72 kn				
Overturning	**0.96**	**0.47**	**0.36**	**0.17**
Sliding	**3.66**	**1.45**	**1.03**	**0.43**

For the case of buoyancy tanks attached to the leg section, consideration was given to the leg being cut at -55m and the system free flooded with water. From this analysis, the structure would only be stable in very low sea conditions (Hs less than 1m).

The process of deballasting the tanks would reduce the submerged weight of the structure, resulting in an increasing tendency for the leg section both to topple and to slide off its foundations.

In the event that the leg was severed after deballasting of the buoyancy tanks, the above conclusions regarding overturning under environmental loads would not apply. Consideration would have to be given, however, to 'pop up' (the rapid ascent of the freed structure upwards) and to its transient hydrostatic stability.

6.2 CALCULATION OF HOOK LOADS

Hook loads in three directions were calculated and the maximum and minimum values are shown in Table 6-5. Fx and Fy indicate horizontal loads at the lift point attachment and Fz is the vertical load (see Figure 5-1). The maximum horizontal force (Fh) acting at the top of the structure is the resultant of Fx and Fy. Hs is the significant wave height.

Due to the motion at the crane boom tip, the applied load is generally amplified by a factor dependent on the acceleration of the lifted weight. In this case, the sling would be attached to a fixed point, hence variation in load would depend on the vessel displacement and sling stiffness. The vertical load experienced at the lift point would vary with sling tension.

It is to be noted that for 2m significant wave height the minimum hook load could become zero, indicating lines becoming slack. This would result in 'snatching' type loads at the lifting points. Snatching loads could displace the leg section or damage the crane, slings, lift points or attachments. The presence of snatch loads could also damage the underwater concrete cutting equipment.

For sea states with significant wave height of 3m, the maximum hook load could exceed the estimated 2800 mT weight of the leg section. Depending on the stiffness of the lifting slings, higher loads could also be present for lesser sea states. If the hook load exceeded the weight of the leg section, the leg section could lift off prematurely in an uncontrolled fashion.

Table 6-5 Hook loads from analysis, 500 mT pretension

Wave Incidence	Fx mT	Fy mT	Fz mT	Fx mT	Fy mT	Fz mT	Fx mT	Fy mT	Fz mT
	1m Hs			2m Hs			3m Hs		
	Maximum Force, mT								
0^o, Stern	0.7	1.2	530.5	4.0	5.4	1498.4	16.2	15.5	2820.5
45^o, Qtr	0.2	1.3	519.9	2.1	4.9	1051.3	16.9	30.3	2451.7
90^o, Beam	0.3	1.4	521.1	0.9	2.9	758.9	2.7	5.6	1224.2
MAX	0.7	1.4	530.5	4.0	5.4	1498.4	16.9	30.3	2820.5
	Minimum Force, mT								
0^o, Stern	-0.4	0.8	472.7	-2.5	-0.1	0.0	-17.2	-4.8	0.0
45^o, Qtr	-0.2	0.6	484.5	-1.1	-1.4	0.0	-12.7	-29.5	0.0
90^o, Beam	-0.4	0.5	483.8	-0.5	-0.4	249.9	-1.3	-2.3	0.0
MAX	0.4	0.8	484.5	2.5	1.4	249.9	17.2	29.5	0.0
MAX	0.7	1.4	530.5	4.0	5.4	1498.4	17.2	30.3	2820.5

Table 6-6 Hook loads from analysis, 1000 mT pretension

Wave Incidence	Fx mT	Fy mT	Fz mT	Fx mT	Fy mT	Fz mT	Fx mT	Fy mT	Fz mT
	1m Hs			2m Hs			3m Hs		
	Maximum Force, mT								
0^o, Stern	3.2	6.0	1030.9	10.8	13.4	2087.2	26.4	83.8	4566.8
45^o, Qtr	2.4	6.0	1018.9	6.4	12.6	1665.8	25.6	51.4	3539.0
90^o, Beam	2.5	6.4	1020.8	3.8	8.6	1308.0	6.5	12.0	1682.4
MAX	3.2	6.4	1030.9	10.8	13.4	2087.2	26.4	83.8	4566.8
	Minimum Force, mT								
0^o, Stern	0.9	4.6	971.1	-2.9	0.0	0.0	-43.8	-23.0	0.0
45^o, Qtr	1.4	4.3	983.3	-0.8	0.7	341.3	-26.1	-18.5	0.0
90^o, Beam	1.0	4.3	982.6	0.3	2.3	708.4	-0.5	0.6	356.7
MAX	1.4	4.6	983.3	2.9	2.3	708.4	43.8	23.0	356.7
MAX	3.2	6.4	1030.9	10.8	13.4	2087.2	43.8	83.8	4566.8

6.3 EFFECT OF HOOK LOAD

The application of moderate tension to the crane slings prior to lifting would reduce the effective weight of the structure, and hence would reduce the sea state at which tilt of the structure could occur. With an increase in tilt, the geometry of the applied loads would change and the crane slings would act to stabilize the load against toppling over. The resistance against initial tilting was analysed for the crane applying pretension of 500 mT and 1000 mT. The results are shown in Table 6-7 and Table 6-8.

Table 6-7 500 mT pretension on crane, without buoyancy tanks

Hs, m	1m	2m	3m
FENV, mT	70.5	147	224
MENV, mT-m	3970	7070	9644
Fh, mT	1.5	6.7	326.2
Fv, mT	530.5	1498.4	2820.5
Safety factor against tilt	1.31	0.74	0.29
Safety factor against sliding (μ = 0.2)	3.64	0.44	0.0

From the calculated safety factors, the results show that the structure would become sensitive to toppling for wave heights above 1.0m.

The figures are similar when the applied load is 1000 mT, as shown in Table 6-8.

Table 6-8 1000 mT pretension on crane, without buoyancy tanks

Hs, m	1m	2m	3m
FENV, mT	70.5	147	224
MENV, mT-m	3970	7070	9644
Fh, mT	7.1	17.2	1997.9
Fv, mT	1030.9	2087.2	4566.8
Safety factor against tilt	1.02	0.62	0.09
Safety factor against sliding (μ = 0.2)	2.09	0.00	0.00

These results demonstrate that it would be undesirable for the crane to remain connected to the leg with an applied load if the wave height exceeded 1.0m.

7 OPERATIONAL ASPECTS

7.1 WEATHER RESTRICTED OPERATION

The underwater cutting and removal operation would have to be carried out within a weather restricted period. Typically the accuracy of weather forecasting would require that the operation be completed within 72 hours to qualify as a weather restricted operation.

Cutting might then progress to a predetermined stage where design environmental loads became critical. From this 'point of no return', the entire operation would have to be completed within 72 hours, and the leg section removed and secured on top of a transportation barge or set down on the seabed. The later stages during leg section removal could not be exposed to severe weather without significant risk to the success of the operation and to the personnel involved.

The duration of the operation would depend on the reliability of the underwater cutting system. Unproven underwater cutting technology would increase the uncertainty in the duration of the operation and hence would put the operation at risk of exposure to severe weather.

7.2 STRUCTURAL INTEGRITY

The total estimated weight of the leg section is in excess of 2660 mT. The strength of the steel column and concrete leg, and the connection between the two, would have to be sufficient to allow lifting from the top of the column. The column structure may not be designed to withstand tensile loads arising out of self weight. In addition, the steel columns are connected to the concrete using a bolted connection 8m below sea level, as shown in Figure 7-1. The integrity of the bolted connection under tension loads would be critical to any lifting operations.

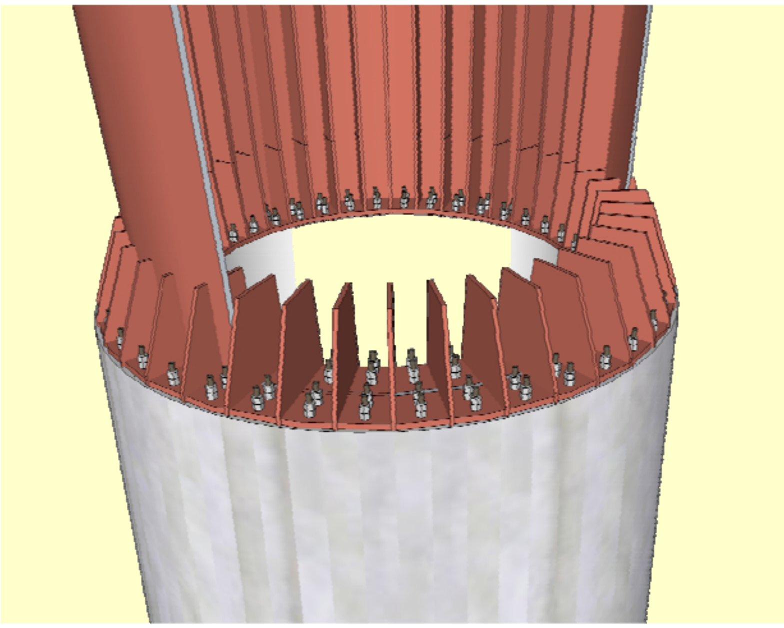


Figure 7-1 Bolted connection between steel and concrete

7.3 LIFT POINTS

There are currently no lift points on top of the steel column sections and lift points would have to be installed to attach the rigging. It is anticipated that this would involve substantial structural reinforcement of the steel column sections.

8 CONCLUSIONS AND RECOMMENDATIONS

8.1 SSCV SUPPORT DURING CUTTING

- Application of a crane hook load by the SSCV during underwater cutting of the leg could be detrimental to the operation. Calculations show that snatch loads could occur in relatively mild sea conditions, which could displace the leg section during the process of cutting, or damage the leg cutting mechanism, rigging, or lift points/attachments to the leg sections.

- It would not be advisable to impose a hook uplift load while cutting, except immediately prior to making the final lift.

- The factor of safety related to the risk of the cut leg section overturning is calculated to be 0.52 in the sea conditions of a 10 year return seasonal storm wave (Hs = 10.9m). This factor is considered to be unacceptable. GL Noble Denton guidelines [2] require a factor of safety of at least 1.2 against the 10 year return storm.

- Leg section stability is problematic even for a weather restricted operation. Since the reliability of weather forecasting beyond 72 hours is limited, a weather restricted operation should not exceed this. However, underwater cutting technology is unproven for diameters as large as the Dunlin legs and this would increase the uncertainty in the duration of the cutting process and hence the risk of exposure to severe weather.

- The potential for leg overturning and sliding in moderate sea states would require either the provision of additional restraint or the adoption of highly restrictive operational sea conditions.

- Installation of lift points would be required to lift the leg section, weighing approximately 2800 mT. This will require substantial structural reinforcement of the steel column at the lift point attachment.

- It would be difficult to confirm the integrity of the steel column, concrete section and the bolted attachment. This fact would pose a serious threat to safety during any lifting or set-down operation.

8.2 ENVIRONMENTAL LOADS DURING REFLOAT

- By attaching buoyancy tanks to the leg section, the risk of the leg section overturning due to environmental loads would be increased. Cutting the leg prior to deballasting the buoyancy tanks does not appear practical.

- If the leg cut were completed after deballasting the buoyancy tanks, the dynamics of the combined leg plus external tanks during ‘pop-up’ (rapid rise upwards through the water) would require further study.

8.3 RECOMMENDATIONS

- The use of an SSCV to support the upper leg section during cutting is not recommended.

- Reliability of the underwater concrete cutting technology would be vital to ensure that the removal of the leg section, by lifting or floating, could be achieved within a suitable weather window. Further development of cutting technology is required.

- Consideration should be given to restraint of the leg during cutting, either through segmental cutting or external means. It is accepted that segmental cutting would further increase the risk of diamond wire breakage due to the leg internal pipework and equipment; and the size of any additional restraint structure would likely be very substantial and therefore potentially impractical to handle.

- The provision of attachment points to the leg section would require further assessment. It is likely that substantial reinforcement of the leg section would be required.

This report is intended for the sole use of the person or organisation to whom it is addressed and no liability, of any nature whatsoever, shall be assumed to any other party in respect of its contents.

GL NOBLE DENTON

Signed: ______________Signed original on File_______________.

Renjeev Kurup
Principal Naval Architect

Countersigned: ________Signed original on File_______________.

Don Orr
Principal Naval Architect

Dated: Aberdeen, 13/04/2011

REFERENCES

[1] Offshore Design Engineering Ltd, Dunlin Decommissioning Study Refloat Report – Concrete Column Hydrostatic Stability at Float Off, 201501-AE-Q-0005, Dec 2010.

[2] GL Noble Denton, Guidelines for the Transportation and Installation of Steel Jackets, 0028/ND, March 2010

[3] Moses User Manual, rev 7.03, Ultramarine Inc.

[4] GL Noble Denton, NDA Waveload, Version 1R3.

[5] Orcina, Orcaflex, Version 9.3.

[6] Drawing, Dunlin A Platform, General Plan, 3551-C-301, rev Z

[7] Drawing, Dunlin A Platform, Leg C, 3551-S-360, rev Z

[8] Drawing, Dunlin A Platform, Substructure Dimensions Towers A, B, C and D (Slipform), 3551-C-1224, rev Z

[9] American Petroleum Institute, Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms – Working Stress Design, RP2a-WSD, 21st Edition

[10] Det Norske Veritas, Environmental Conditions and Environmental Loads, DNV-RP-C205, April 2007.

[11] Det Norske Veritas, Rules for Planning and Execution of Marine Operations, 1996 – 2000

[12] GL Noble Denton, Concrete Offshore Gravity Structures Guidelines for Approval of Construction, Towage and Installation, 0015/ND, Mar 2010.

Appendix E

Review of leg section external support by

Atkins

Technical Note 5073937-201-TN01

ATKINS

Project:	Dunlin A Decommissioning	**To:**	Terry Kimber, Fairfield Energy Ltd.
Subject:	Assessment of temporary support methods at -55m cut elevation	**From:**	Alan Marson
Date:	17/08/2011	**cc:**	Peter Meenan/Trevor Hodgson

1. Introduction

This technical note reviews the potential to provide temporary external systems capable of maintaining the structural stability of a leg on the Dunlin Alpha concrete gravity base (CGB) during a cut operation at -55m below sea level. The following assumptions have been made about the cutting operation:

- The topsides would be completely removed
- The steel column at the top of the concrete leg would be required to remain in place to enable lift points to be attached in air, and to avoid a further cut being necessary to remove the steel column.
- Diamond wire cutting would be used to sever the concrete
- The temporary support must have sufficient capacity to provide stability during summer storm conditions

A full description of the Dunlin Alpha platform and legs is provided elsewhere by Fairfield Energy.

2. Loads at Cut Elevation

The approximate weight of the concrete leg section above the cut elevation was calculated to be 2,600 tonnes with the steel column still in place. This compares to an estimate of 2,666 tonnes by GL Noble Denton (provided by Fairfield). Both of these figures involve assumptions on the density of concrete, proportion of reinforcement bars etc.

A simple two-dimensional beam element computer model of the leg section and steel column was generated and analysed using the ASASNL program, using transient dynamic analysis. A plot of this model is shown in Figure 1.

For the purpose of the support frame analysis, 10 year summer storm conditions were agreed to represent a realistic design case for the external support system. These conditions are listed below, as provided by Fairfield.

- Significant Wave Height: H_s = 10.9 m
- Maximum Wave Height: H_{max} = 20.3m
- Associated Wave Period: T_{ass} = 13 to 17.5s

In additional to this case, Atkins also considered further environmental conditions, including the largest wave that would be expected in 100 years, with a height of 28.7m. The effect of this more onerous condition is discussed in Section 4 below.

The seabed was artificially set at the top of the CGB base (151 – 32 = 119m below sea level) to allow for the effect of increased water velocities over the base.

The resulting analysis for the 10 year summer storm produced a maximum leg bending moment at the cut location of 220 MNm. (approximately 22500Te–metres). This would be the moment that must be resisted by the leg section as it was being cut, to retain stability.

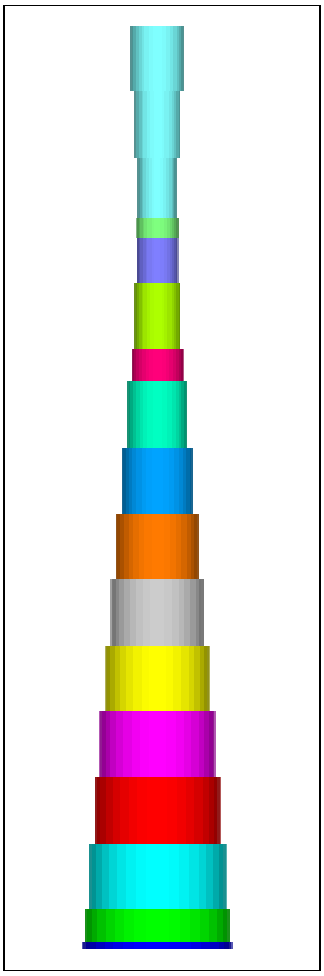


Figure 1 – ASASNL Model of leg section with steel column

3. Bracing Support Rig

The device envisaged to provide the temporary support for resisting the bending moments is termed a Bracing Support Rig (BSR), as illustrated in Figure 2. The device is intended to be reusable on all four CGB legs. The BSR would be attached to the leg by drilling and inserting pins into the concrete. It is estimated that each fully designed and fabricated structural steelwork BSR unit, fully equipped with a range of cutting tools and remote control instrumentation, would weigh about 100 tonnes and be approximately 5m in length. Around twelve units would be required.

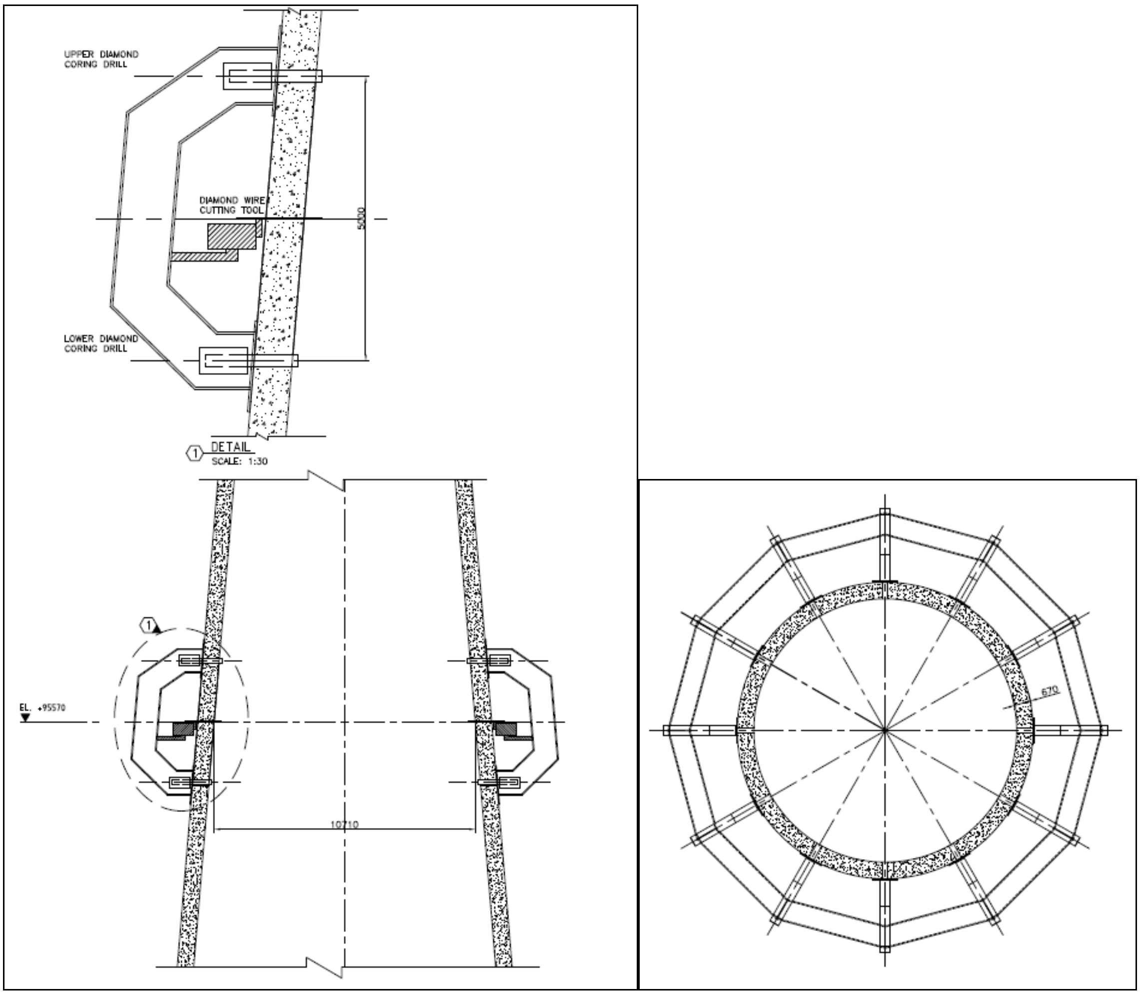


Figure 2 – Bracing support rig attached to leg

It is envisaged that the BSR would consist of the following principal components:

- 12 units mounted on a ring beam around the leg
- Assembled in halves around leg
- Fixed at top with temporary post-drilled bolts
- Upper & lower diamond coring drills
- Upper & lower hydraulically driven 200mm diameter steel pins.

The following theoretical procedure could be employed for removal of a single leg section using the BSR:

- Assemble BSR around leg
- Lower BSR to required cutting depth
- Locate BSR in place
- Drill 12 holes of 220 mm diameter using diamond coring drills
- Remove cores (or push through to drop inside)
- Insert 200mm diameter pins
- Cut through leg with diamond wire cutting tool
- Inspect and prove full through cut
- Rig leg top for heavy lift
- Withdraw lower pins
- Commence heavy lift
- Withdraw upper pins and remove BSR

4. Technical, Safety and Environmental Issues

The main issues related to removing leg sections would arise from the underwater cutting operation and the stability and handling of the leg sections.

Typically the leg section would be hooked up to a heavy lift vessel (HLV) with slack slings before the final critical cuts were performed. During cutting the leg sections would be exposed to wave action and would have to be held in place by the temporary clamps in the BSR.

The leg would be vulnerable to environmental forces from the start of final cutting until the lifting of the cut leg section. If most of the final cuts were completed and a summer storm arose unexpectedly, or if a cutting tool failed and caused delay, it would be necessary to disconnect and de-rig the slings to move the HLV away from the CGB. In such a condition the temporary supports for the cut leg must be designed and installed with the capacity to resist the appropriate hydrodynamic loading. Due to the thickness of the leg at the -55m elevation, it is unlikely any restraint frame would be able to provide the same strength as the uncut leg. In order to do so, the frame components would have to be impracticably large, causing difficulties in handling and installation.

Furthermore, it must be noted that the BSR described here would be designed according to the ten-year summer storm conditions listed in Section 2. Should the cutting operation fail and have to be suspended for a lengthy period, then the CGB leg could be exposed to more onerous winter environmental conditions. These conditions would include the largest wave expected in 100 years, being 28.7m high, which would subject the leg section at the cut elevation of -55m to an overturning moment of 360MNm (36,800Te-metres). Designing the BSR to be able to withstand forces of this magnitude would make handling and installation even more difficult and dangerous in the offshore environment.

5. Conclusions

In order to provide the same degree of reliability in the structural strength of the legs during the leg cutting operation, a substantial restraint system would be required. Due to the thickness of the concrete leg and its inherent strength, it is unlikely that a restraint system could achieve the same strength as the leg. While a frame system, such as that described above, could be designed to provide a restraint during cutting, the required sizes and weights of the frame system would present significant technical and marine operation challenges to the point of becoming impractical.

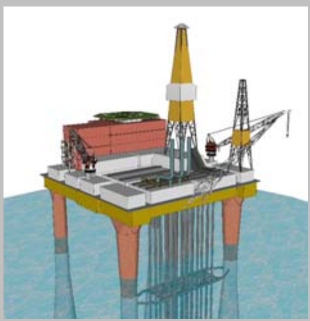
Appendix F

Review of leg section float off by

Offshore Design Engineering (ode)

ode

Offshore Design Engineering Limited



Dunlin Decommissioning Study

Concrete Leg Section Hydrostatic Stability at Float Off

PREPARED FOR:

Fairfield Energy Ltd

BY:

OFFSHORE DESIGN ENGINEERING LTD

S French

G Stenhouse

Document Number: **201501-AE-Q-0005**

Revision **1**

Issue Date: **17th February 2011**

DISCLAIMER

REVISION RECORD SHEET

Revision Number	Purpose	List of Updated/Modified Sections, if any
A	*Issued for IDC*	-
B	*General update and sections re-arranged*	*All*
0	*Issued for Information*	*Minor updates*
1	*Issued for Information*	*Minor updates*

1	17/02/2011	Issued for Information	SF	GS	SF
0	17/02/2011	Issued for Information	SF	GS	SF
B	18/12/2010	Issue for Comment	SF	GS	
A	06/12/2010	Issued for IDC	SF	GS	
Rev No	**Date**	**Status**	**Issued By**	**Checked By**	**Approved By**

Contents

1 EXECUTIVE SUMMARY 5
2 INTRODUCTION 6
3 FLOAT OFF OF CUT LEG SECTIONS 8
3.1 CALCULATION OF WEIGHT AND HYDROSTATIC STABILITY 9
3.2 LEG SECTION FILLED WITH AIR 10
3.3 LEG SECTION FILLED WITH AIR AND WATER 12
3.4 LEG SECTION FILLED WITH AIR AND WATER, WITH EXTERNAL BUOYANCY ATTACHED 15
3.5 LEG SECTION FLOODED WITH EXTERNAL BUOYANCY ATTACHED 18
3.6 LEG SECTION FILLED WITH BUOYANT MATERIAL 20
4 CONCLUSIONS 22

References

Reference	Title
Ref 1	1989 International Maritime Organization (IMO) Guidelines and Standards
Ref 2	GL Noble Denton. Dunlin Concrete Gravity Base Structure. Leg Section Removal Study. Report No. A&555/00. Rev 01
Ref 3	Atkins. Dunlin A Decommissioning. Float-Off. Pressure Retaining Capacity. Technical Note 5091295.501 TN03.

1 Executive Summary

This report assesses the practicality of floating the upper section of a leg of the Dunlin Alpha CGB away from the platform. The report assumes that the leg has been severed at 55m below sea level and that the temporary works required for float off have been installed prior to the cutting operation.

The cut leg section would weigh over 2600 tonnes. Five different methods for providing buoyancy to the leg section to enable it to float have been evaluated. As discussed below none of these options present a viable solution. The options reviewed are:

1. The leg section being filled entirely with air.
2. The leg section being air-filled and with ballast water added at the bottom of the section to make it float stably in a vertical position.
3. The leg being air-filled and with ballast water added at the bottom of the section, plus external buoyancy tanks attached.
4. The leg section flooded with seawater with external buoyancy tanks attached.
5. The leg section filled with buoyant material.

The installation of a gas tight bulkhead at the top of the leg section would be feasible in concept, thereby allowing compressed air to be injected into the section to displace water from its lower open end. However, the concrete leg would not be able to withstand the internal air pressure and would crack. This would allow air to escape and the section would not maintain its buoyancy. This fact makes the first three methods listed above non-viable.

Even if the concrete could withstand the internal air pressure, attempting to float off the leg section by using only the buoyancy that could be generated within the leg would not be feasible because the section of leg would not be hydrostatically stable until its floating draft was greater than the depth of the 55m cut. Therefore, the addition of external buoyancy would be required.

The third method listed above would require, at a minimum, four buoyancy tanks attached to the leg section, each 2.65m diameter and 20m long. However, this method is not viable due to the need for compressed air to be pumped into the leg section, which would cause the concrete to crack and allow the compressed air to escape. The leg would then sink.

The fourth method does not involve the use of compressed air. With the leg section flooded, four external buoyancy tanks, each 6.25m diameter and 25m long, would be required to float the section in a stable manner at the required draft. However, installation of the tanks would involve a major offshore operation requiring complex ballasting and heavy lifts, hazardous work in the splash zone at sea level, and diving operations 15m to 20m below sea level. In addition to these factors, the leg and the temporary support restraining the leg during the cutting operation would have to carry environmental loads imposed by wind, waves and current. Evaluation of the loading on the leg alone by others (Ref 2) shows that the provision of temporary support is uncertain. Each of the four buoyancy tanks would attract a loading similar to the steel column on top of the leg. The total force and bending moment to be restrained would be impossible to carry in a temporary support and may cause failure of the existing concrete leg. Hence this option is not viable.

Consideration was given to filling the leg with buoyant material, such as foam or granules, but this would not provide the stable hydrostatic condition at the draft required. This option is not viable.

2 Introduction

Fairfield Energy is currently assessing possible options for decommissioning the Dunlin Alpha Concrete Gravity Base (CGB). One of the options might be to remove the upper part of the CGB concrete legs to provide 55m clearance between the remaining lower leg section and sea level, as required by International Maritime Organisation guidelines (Ref 1).

In relation to this option, this report investigates whether it would be possible, once the cutting of the leg has been carried out, to make the upper section of the leg float in a stable manner in its current vertical orientation, to allow the subsequent towing of the section to a sheltered location where it could be either reused or recycled. This report addresses the floating drafts and hydrostatic stability that would be required, and the practicality of providing the necessary buoyancy.

This work is based on the assumption that the leg could be cut at 55m below sea level in a safe and practical manner, and that 'float off' of the free section of leg would follow completion of the cutting operation within the same weather window. Floating the large section of leg away from the CGB following completion of the cut would be a major marine operation and would require extensive planning, risk identification and risk mitigation measures.

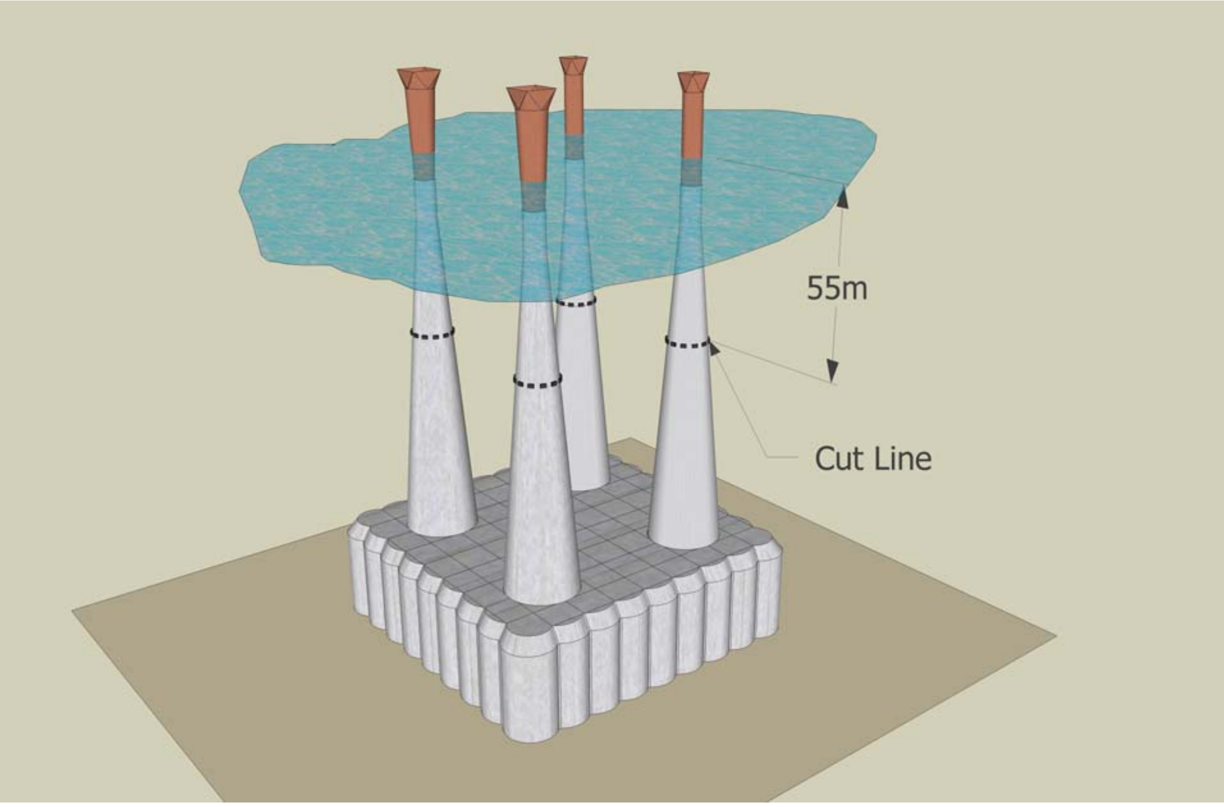


Figure 2.1 Dunlin Alpha CGB showing cut lines to release upper section of legs

For a float off operation to be possible the section of leg must have sufficient buoyancy to float and it must also be hydrostatically stable. This report addresses the stability of the upper section of the leg after it has been cut free from the CGB. Five possible methods for doing this are considered:

1. The leg section being filled entirely with air.
2. The leg section being air-filled and with ballast water added at the bottom of the section to make it float stably in a vertical position.
3. The leg being air-filled and with ballast water added at the bottom of the section, plus external buoyancy tanks attached.
4. The leg section flooded with seawater with external buoyancy tanks attached.
5. The leg section filled with buoyant material.

The floating stability for each case is considered and the practicality of providing the buoyancy is discussed.

It should be noted that float off options that require the leg to be filled with compressed air or additional buoyancy to be attached to the leg are considered without assessing the practicality of carrying out the pressurisation or attachment of the buoyancy. The consequences of making these preparations on the leg, prior to and during the cutting operation, are not addressed in this report.

3 Float off of cut leg sections

The criteria set for the float off of the sections of leg are that the leg section should float stably at a draft of 54m to provide a 1m clearance between the remaining portion of the CGB and the upper floating section.

When a floating body is heeled, the centre of buoyancy (B) moves laterally (see Figure 3.1). The point at which a vertical line through the heeled centre of buoyancy crosses the line through the original, vertical centre of buoyancy is the known as the metacentre (M). The metacentre remains directly above the centre of buoyancy regardless of the tilt of the floating body.

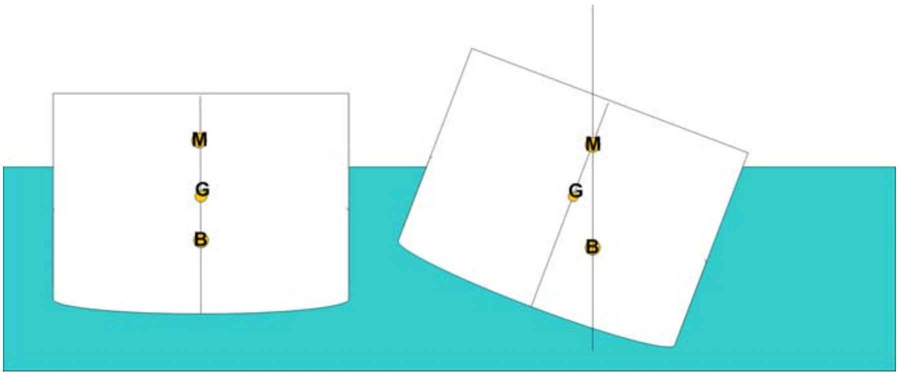


Figure 3.1 Floating body showing centres of gravity, buoyancy and the metacentre

The metacentre is considered to be fixed for small angles of heel. The metacentric height (GM) is the distance between the centre of gravity (G) and the metacentre. Metacentric height is the critical stability parameter for floating structures. A floating structure is stable when its GM is greater than zero. The minimum GM for a CGB structure required by a marine warranty surveyor in the offshore industry is normally set at 1m to retain stability for all operations. This criterion has been used to assess the feasibility of floating the leg sections.

The major contribution to the hydrostatic stability of a section of one of the Dunlin legs, comes from the relative positions of the centre of gravity and the centre of buoyancy. Lesser contributions to hydrostatic stability would come from ‘free surface’ effects. A stabilising free surface effect would be caused by the increase in displacement on the ‘down hill side’ as the leg section tilted and more of the structure went underwater, and the associated reduction in displacement on the ‘up hill side’ as the leg is tilted. However, ballast water flooding over to the lower side as the leg tilted would increase the overturning moment, leading to more tilt and creating a destabilising free surface effect. The free surface effects from the water surfaces outside the leg (the sea surface) and inside the leg (the ballast water surface) would be partially self cancelling but have been included within the calculations of hydrostatic stability for completeness.

For the float off, it has been assumed that the leg section would have been made water or air tight, where necessary, with no leakage occurring. For this report, it is assumed that the normal industry requirement for ‘single compartment stability’ - that is, where damage leading to flooding of any one separate compartment in a floating body should not cause loss of stability or sinking - is not required. This principal has been accepted previously for marine operations associated with decommissioning of oil and gas structures.

3.1 Calculation of weight and hydrostatic stability

Hydrostatic stability and weight calculations have been carried out for the upper section of leg above the proposed cut line 55m below sea level (sea level is referred to Lowest Astronomical Tide, or LAT).

The weight and geometry of the cut section of the CGB leg have been taken from the Noble Denton Report (Ref 2). The key parameters are listed below:

- Weight of steel column above concrete section = 449 tonnes
- Weight of cut concrete section = 2217.3 tonnes
- Steel section length = 24m
- Concrete section length = 46.89m
- Overall length = 70.89m
- Outside diameter at cut = 11.99m
- Inside diameter at cut = 10.67m
- Outside diameter at top of concrete = 6.6m
- Inside diameter at top of concrete = 4.3m (at thickened steel work connection)

The floating stability has been assessed by the calculation of the weight and centre of gravity of the concrete and equipment within the section of leg to be floated, the displacement and centre of displacement of the section of leg to be floated, and the weight and centre of gravity of water ballast within the cut section of leg. The changes in stability caused by the external free surface of the seawater and the internal free surface of the ballast water described in the previous section have been included.

In the cases where the addition of buoyancy tanks are assessed, the displacement, weight and, where appropriate, external free water surface effects have been included.

The following report sections discuss the five flotation cases outlined in Section 2.

3.2 Leg section filled with air

For the cut section of leg to float, the water within the leg would have to be removed. There are two primary options for dewatering the leg:

- Install a bulkhead near the bottom of the cut section with atmospheric air pressure in the leg above
- Install a bulkhead near the top of the leg section and use compressed air to force the air out of the leg and to prevent water flooding into the open end.

A bulkhead installed at the bottom of the section would have to be designed to resist the ambient hydrostatic pressure at the bulkhead. There are several significant reasons why this operation could not nor should not be attempted:

- The CGB legs would be flooded to above -55m level at the time of decommissioning making working within the legs impossible.
- Even if the CGB legs were dewatered to below the cut level to allow installation of the bulkhead, there would be a very significant work programme required within a confined space in the leg to first remove redundant pipework and equipment, and then constructing a water tight bulkhead approximately 10m across, capable of resisting at least 5.5 barg pressure. All material taken from and used in the leg would have to pass through the 4.3m internal diameter neck section of the leg. The HSE issues of providing safe access and egress, ventilation, and protection from overhead working, would prevent this work from being carried out.
- The pipework and risers that pass up the legs would have to be sealed before they were cut and removed to prevent flooding of the working space
- The bulkhead would have to be connected and sealed to the concrete inside the surface of the CGB leg.

These issues lead to the conclusion that installing a bulkhead at 55m below sea level inside the leg would be either impossible or so hazardous that it should not be attempted. Therefore, this option is not considered further in this report.

Installation of a bulkhead at the top of the leg section in the steel column could be achieved in less challenging circumstances as the section would be above water and much less internal and pipework would have to be removed. The attachment of the bulkhead with a gas tight seal could be possible, although the bulkhead would have to be constructed around the many steel stiffeners that exist in the steel column.

Once this bulkhead was in place the water below it could, in theory, be displaced by injecting compressed air below the bulkhead. The air pressure required would be around 5.5 barg. As the external water pressure would reduce linearly to zero at the sea surface, a pressure differential would exist across the walls of the pressurised leg section The upper sections of the concrete leg have insufficient capacity to carry the hoop tension generated by this pressure, and would crack, thereby creating potential leak paths for the compressed air to escape. (Ref 3). While additional compressed air could be added to balance the leakage losses, there would be a significant risk that a large crack could occur and cause the section of leg to sink if the volume of compressed air within the leg could not be maintained. However, for the purpose of conducting the hydrostatic stability calculations, it has been assumed that the leg section could be filled with compressed air, and that air leakage rates would be low.

With the whole of the leg section empty of water and filled with compressed air, the cut section of leg would be buoyant and would rise up to approximately 28m (see Figure 3.2). However, the section would not be stable in the vertical position and would capsize. This would not be an acceptable situation.

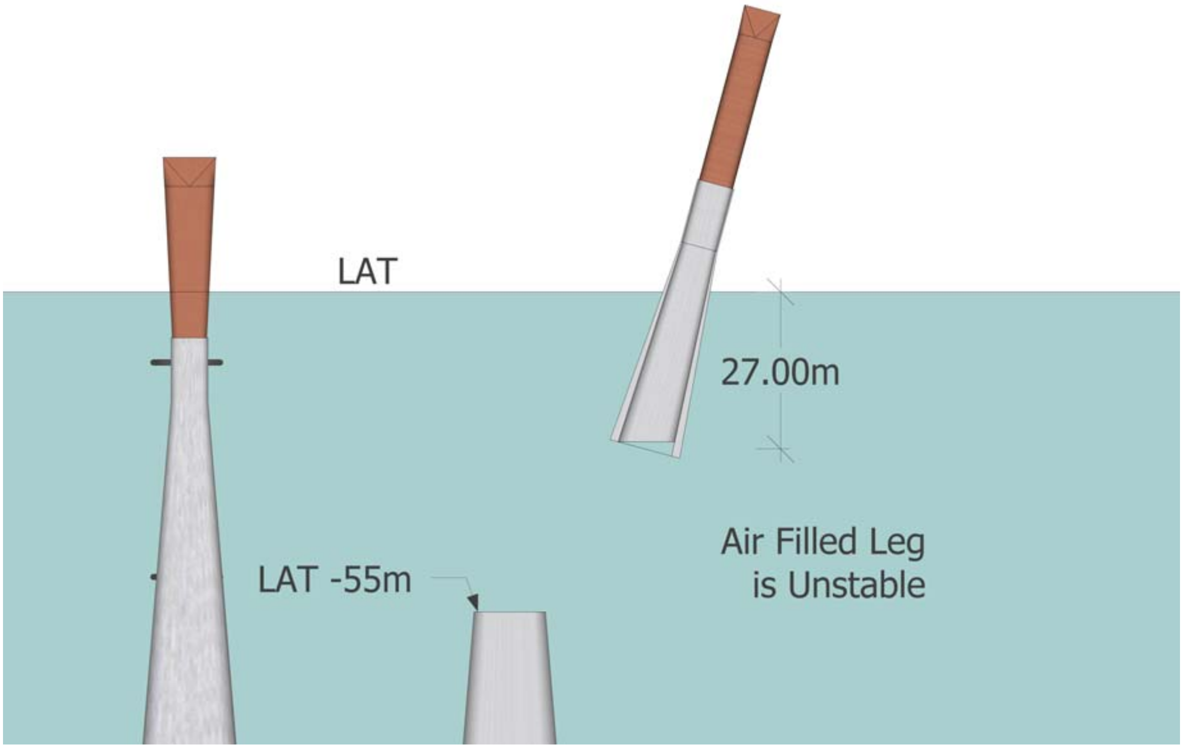


Figure 3.2 Cut section of leg rising and capsizing

3.3 Leg section filled with air and water

As stated in the previous section the air-filled leg section, with a top bulkhead, would be buoyant but would not be stable in the vertical position. By reducing the volume of compressed air to allow water into the bottom of the leg section, stability would increase, and the draft would increase, until floating stability in the vertical position was achieved.

For this case, the stability results are shown in Figure 3.3. It can be seen that if 15m depth of ballast water were to be added to the floating leg section the floating draft would be 57.8m with a metacentric height of 1.34m. By interpolation reducing the amount of ballast water to reduce the metacentic height to 1.0m corresponds to 57.7m draft. However, as the cut would be made at -55m, the leg section could not be floated off the lower leg section without external assistance to lift the leg clear of the CGB. Such assistance could only be provided by an external lifting method, such as a heavy lift crane or by attaching buoyancy tanks to the leg section.

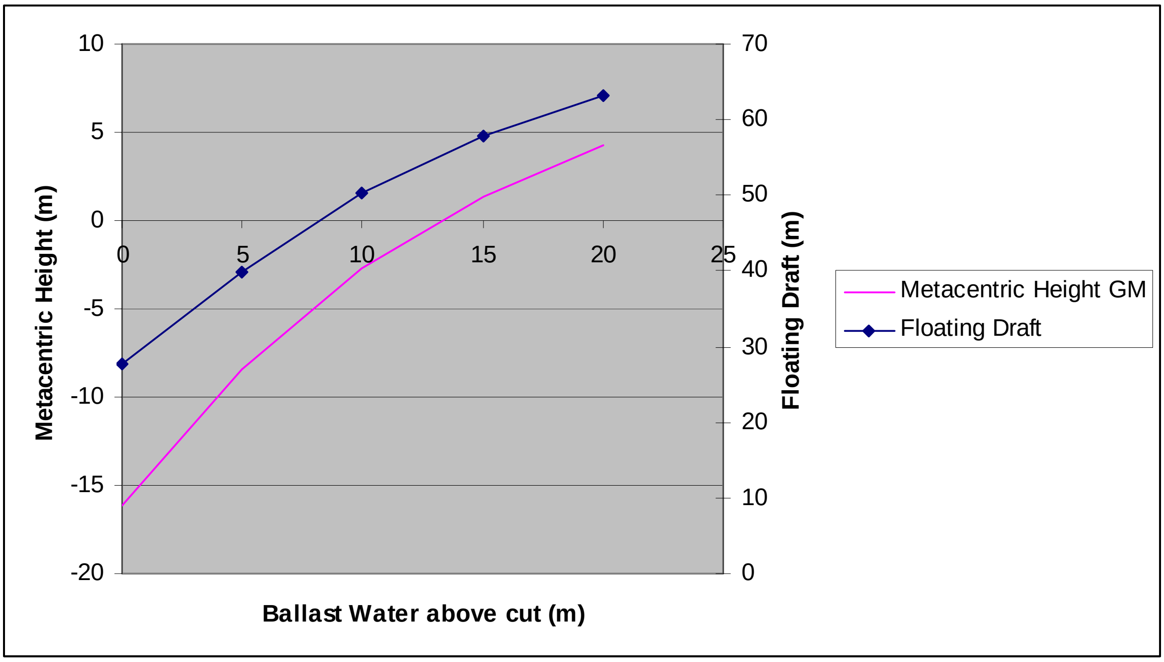


Figure 3.3 Graph of draft and metacentric height as ballast water is added to leg section

Figure 3.4 shows the cut leg section floating alongside the remaining CGB, if the leg were to be floated in this manner.

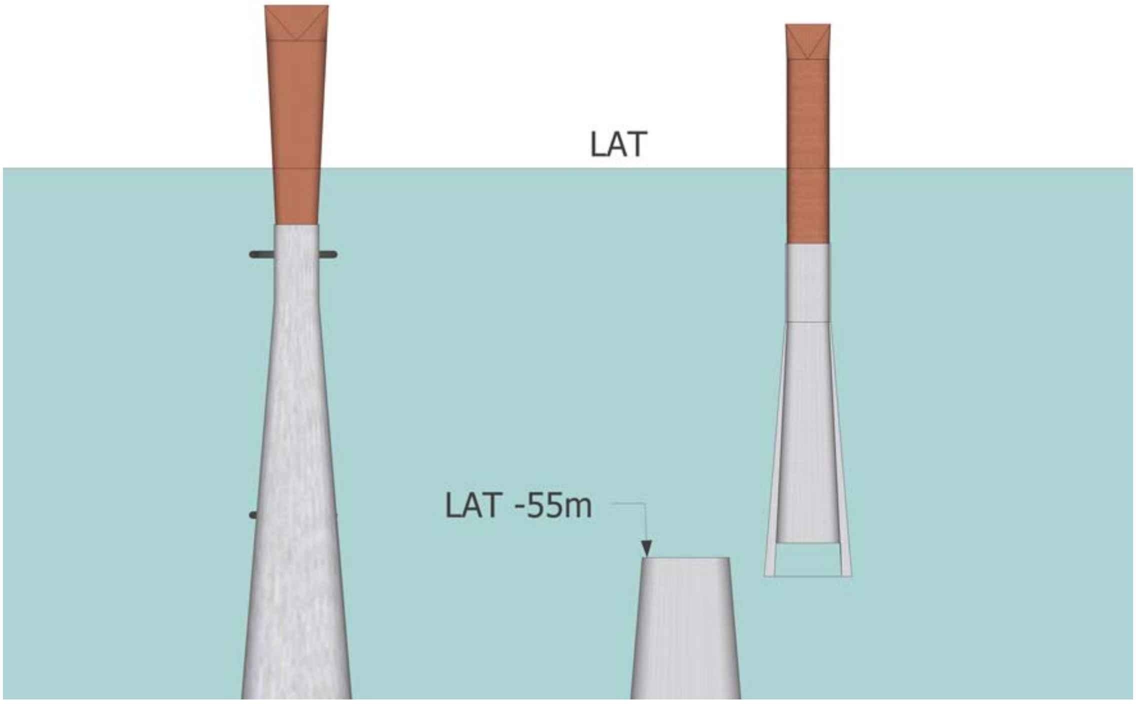


Figure 3.4 Cut section of leg floating adjacent to CGB

The buoyancy of the leg was calculated as the difference between the weight of the floating section and the water displaced by the floating section. When the weight and displacement are equal the floating section would be in equilibrium.

As is normal in naval architectural calculations the displacement of the leg was calculated using the external envelop of the floating body. In this case this is the outer surface of the column from the water surface down to the cut line and horizontally across the open bottom of the section of the leg (as if the bottom of the leg where closed off). The weight of all parts of the structure within the external envelop have to be included in the calculation, including the weight of the steel column, the concrete leg, piping and equipment within the leg, and ballast water within the leg.

The hydrostatic equilibrium position of the leg section was calculated in this manner and reported above. The total mass of compressed air required to achieve floating equilibrium was also allowed for.

It is also necessary to check that the floating leg section would respond to small dynamic motions in a safe manner. During any open sea towing operation long and short period waves impart loadings which move the towed item cyclically in both horizontal and vertical directions. The horizontal motion could be accommodated by use of sufficiently long mooring/towing lines and would not be of concern.

The use of compressed air to displace water and provide the buoyancy would be an effective option but does introduce an extra variable into the normal weight versus displacement equilibrium. A small vertical downward movement would generate an increase in displacement equal to the volume of the extra amount of leg submerged as the draft is increased. This would create additional buoyancy, which in turn would oppose the increase in draft.

In this case the increase in draft would also increase the pressure of the compressed air within the floating leg section. The overall quantity (mass) of compressed air would be constant so the increase in pressure would result in a reduction of volume (Boyle's gas law).

In this particular situation the water plane area of the leg is quite small and the volume of compressed air within the leg would be large. A small increase in draft would result in an increase in displacement due to submergence of more leg, which would be almost entirely negated by a reduction in the volume of the compressed air in the leg. In turn this would allow more ballast water to enter the bottom of the leg, increasing the overall weight of the floating section.

Hence the expected change in buoyancy that would normally maintain floating equilibrium would not be generated and large changes of draft for small changes in weight would be experienced. This would not be acceptable, hence it is concluded that attempting to float the leg with a diaphragm near the top of the section and compressed air displacing the water would not be a practicable option unless either the air tight bulkhead was positioned lower in the leg to reduce the total amount of compressed air, or the water plane area was increased to increase the rate of change in displacement as the draft was increased.

Using compressed air within the leg section would generate hoop tension in the concrete leg. The Atkins technical note (Ref 3) indicates that this is expected to generate cracks through the concrete which would make maintaining the air pressure within the leg impossible. Loss of internal air pressure would result in the leg section sinking. This is not therefore a viable option

In summary, float off of the section of leg using compressed air within the leg section would not be practical for two reasons related to floating stability and a third due to the internal air pressure cracking the concrete:

1. The floating draft required for the section to be hydrostatically stable would be greater than the depth of the cut, hence the section cut off the CGB would not float free.
2. If the floating section were to be separated from the CGB, the section would not maintain floating equilibrium or have the dynamic stability required because the volume of the compressed air would change with draft, thereby allowing the amount of ballast water to vary and negate the change to the displacement caused by the change in draft.
3. The air pressure within the leg required to keep the leg section afloat would crack the concrete, creating leakage paths. This would allow the compressed air to escape and cause the section to sink.

3.4 Leg section filled with air and water, with external buoyancy attached

As discussed in the previous section, floating the leg section off the CGB using only its own buoyancy would not be not feasible. This case considers the leg section being air and water filled as described above, with external buoyancy tanks being attached to the leg section. The buoyancy tanks would:

- allow the cut section of leg to float clear of the remaining CGB without assistance
- provide additional water plane area that would compensate for the change of buoyancy due to change in compressed air volume, caused by variation in draft due to wave action or any other external action.

External buoyancy attached around the leg could typically be provided by either steel buoyancy tanks or foam buoyancy elements, constructed onshore around a steel frame that would provide the required strength and strong attachment points. A maximum practical size for the fabrication of these units would be around 10m diameter and 50m long, and their attachment to the leg section would be a major offshore activity. For example, if foam buoyancy elements were used they would have to be winched down with a force equal to the buoyancy that they provide. This may be possible for smaller units but would be impracticable for large units over, say, 3m diameter and 20m long. Steel tanks do not present this problem as they can be ballasted to near neutral buoyancy for installation, and then subsequently de-ballasted to float off the leg section.

Specific problem areas with the provision of external buoyancy that have not been addressed in this report are:

- Supporting the leg section while the cut is being made to resist environmental loadings on the leg and the additional buoyancy.
- The physical handling and attachment of the buoyancy to the leg section and transfer of the buoyancy lift force to the leg. The upper connection point would be in the splash zone and the lower one subsea.
- Asymmetric loadings applied to the leg during sequential installation of the buoyancy.
- Disconnection of the supporting structure provided for the cutting operation prior to float off of the leg.

The size of external buoyancy tanks required to allow the leg to float stably away from the CGB at a draft of 54m has been calculated. The 54m floating draft selected would allow 1m clearance between the cut section and the remaining structure.

At least three buoyancy tanks would be required to distribute the additional displacement around the leg circumference; for this concept evaluation four tanks were provided to maintain symmetry. In a more detailed engineering study, different numbers of tanks could be considered but would not change the main conclusions relating to feasibility.

To maintain the 54m draft, additional water would be required to be added to the bottom of the leg section to compensate for the extra buoyancy provided by the tanks. The provision of extra buoyancy at the water surface, counterbalanced by additional water ballast at the bottom of the leg section, would create an increased restoring moment which would increase the hydrostatic stability at a particular draft.

Figure 3.5 shows the variation of metacentric height as the diameter of four 20m-long buoyancy tanks, attached to the leg section, is increased. In each case water ballast was added to maintain a floating draft of 54m.

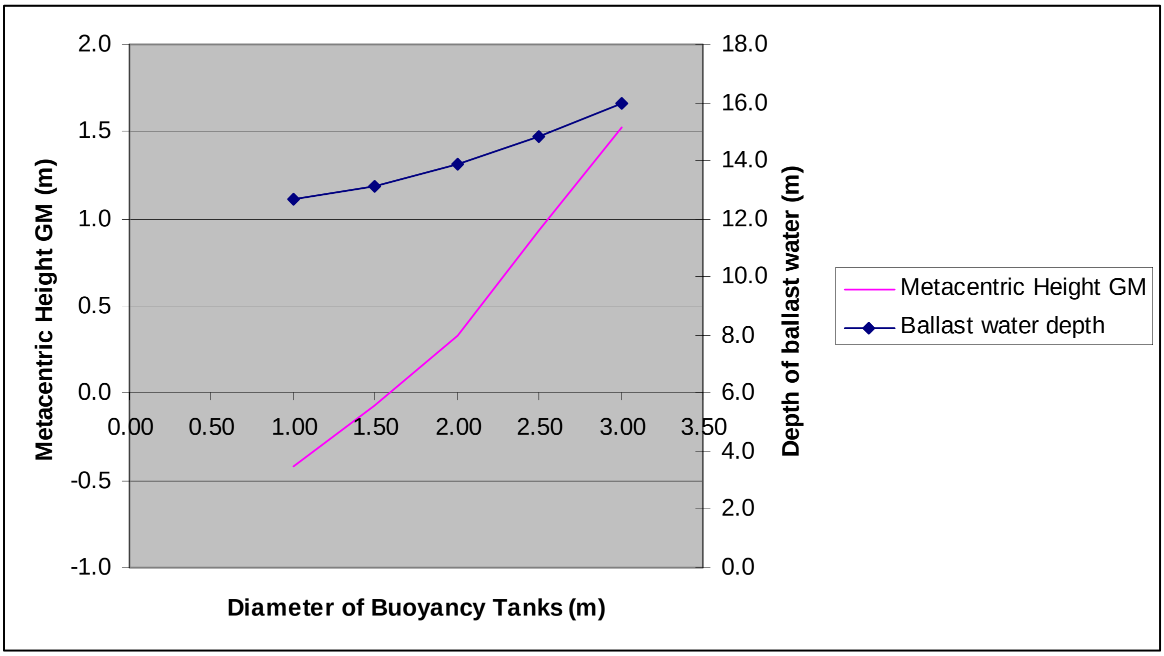


Figure 3.5 Graph of metacentric height and depth of ballast water required in leg section, as buoyancy tank diameter is increased

Reading from figure 3.5, a buoyancy tank diameter of 2.65m would be is required to provide 1m metacentric height. Figure 3.5 is only valid for buoyancy tanks 20m long and a floating draft of leg section of 54m. The depth of ballast water within the leg section would be 15m to achieve the 54m draft required for float off.

For this calculation, the tops of the buoyancy tanks were set 5m above LAT to allow the tanks' top connection to the leg to be made above water, and to benefit from the increased stability generated by increasing the combined area of the floating leg at water level. The concept is shown in Figure 3.6.

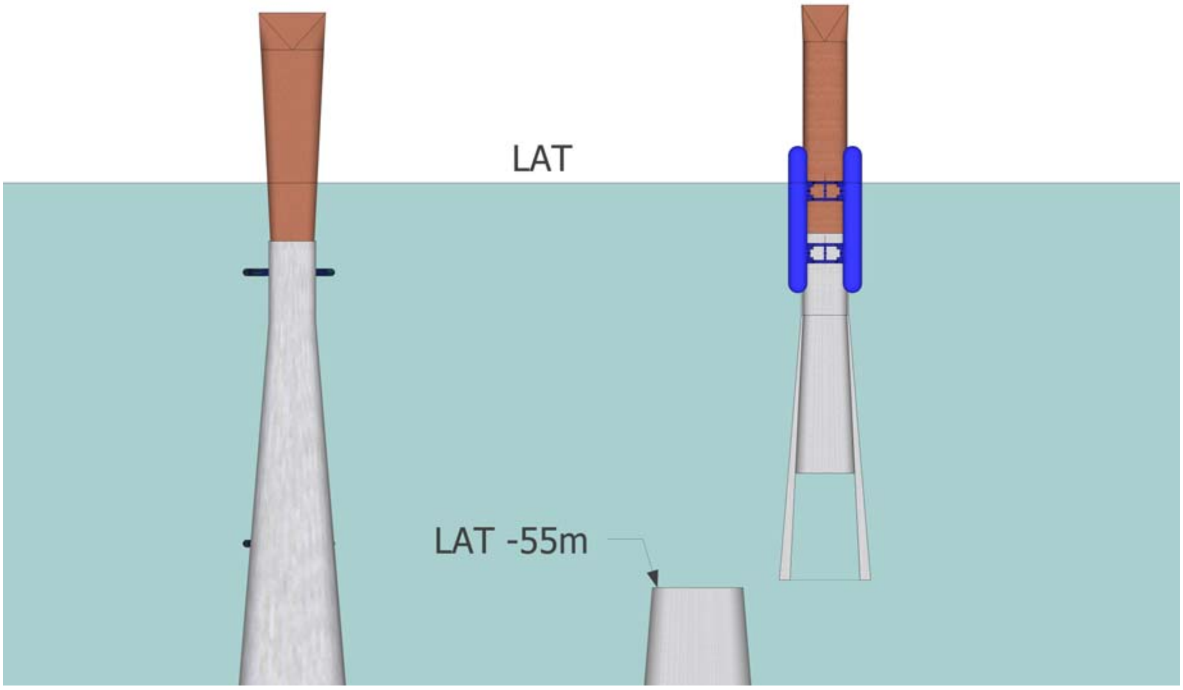


Figure 3.6 Cut section of leg filled with air and water, and with buoyancy tanks fitted, floating at 54m draft

It should be repeated that using compressed air within the leg section would generate hoop tension in the concrete leg. The Atkins technical note (Reference 3) indicates that this is expected to generate cracks through the concrete which would make maintaining the air pressure within the leg impossible. Loss of internal air pressure would result in the leg section sinking. Therefore this is not a viable option.

3.5 Leg section flooded with external buoyancy attached

To avoid the problems associated with the use of compressed air, an assessment has been made of the size of external tanks required to float the leg section with the inside of the leg filled with water only.

This has practical advantages in that the preparatory work inside the leg would be minimised and the potential for leakage or failure of the new bulkhead would be removed.

Figure 3.7 shows the variation of metacentric height as the diameter of four 25m-long tanks is increased. The leg section is water-filled and the floating draft required is 54m.

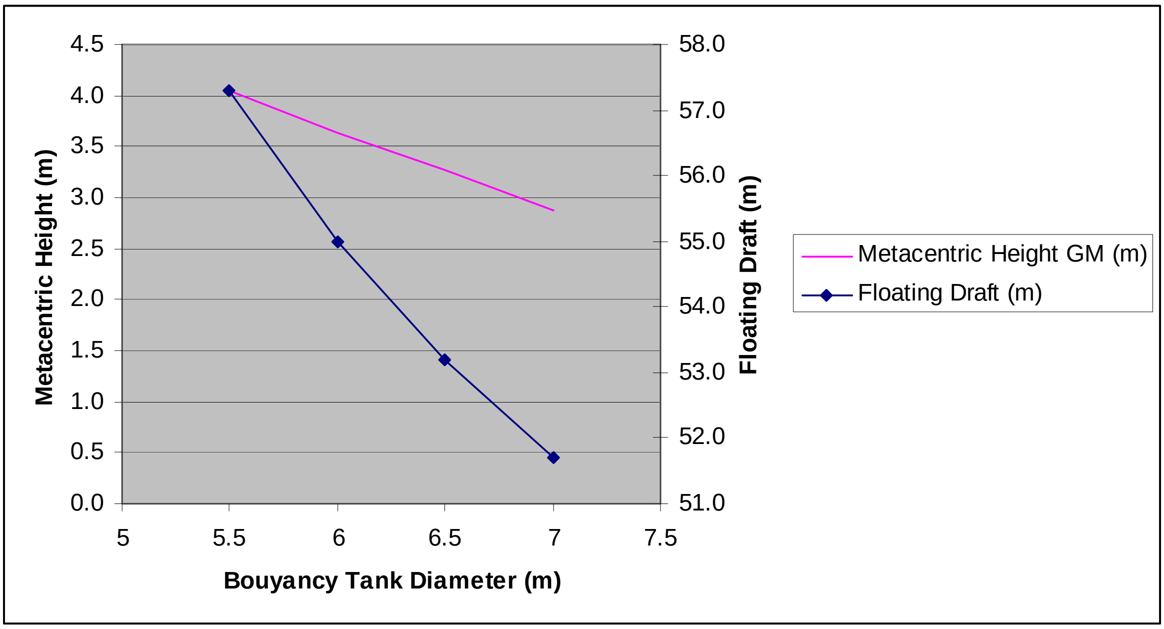


Figure 3.7 Graph of metacentric height and draft as buoyancy tank diameter is increased

Figure 3.8 shows the leg section floated off with the tanks attached.

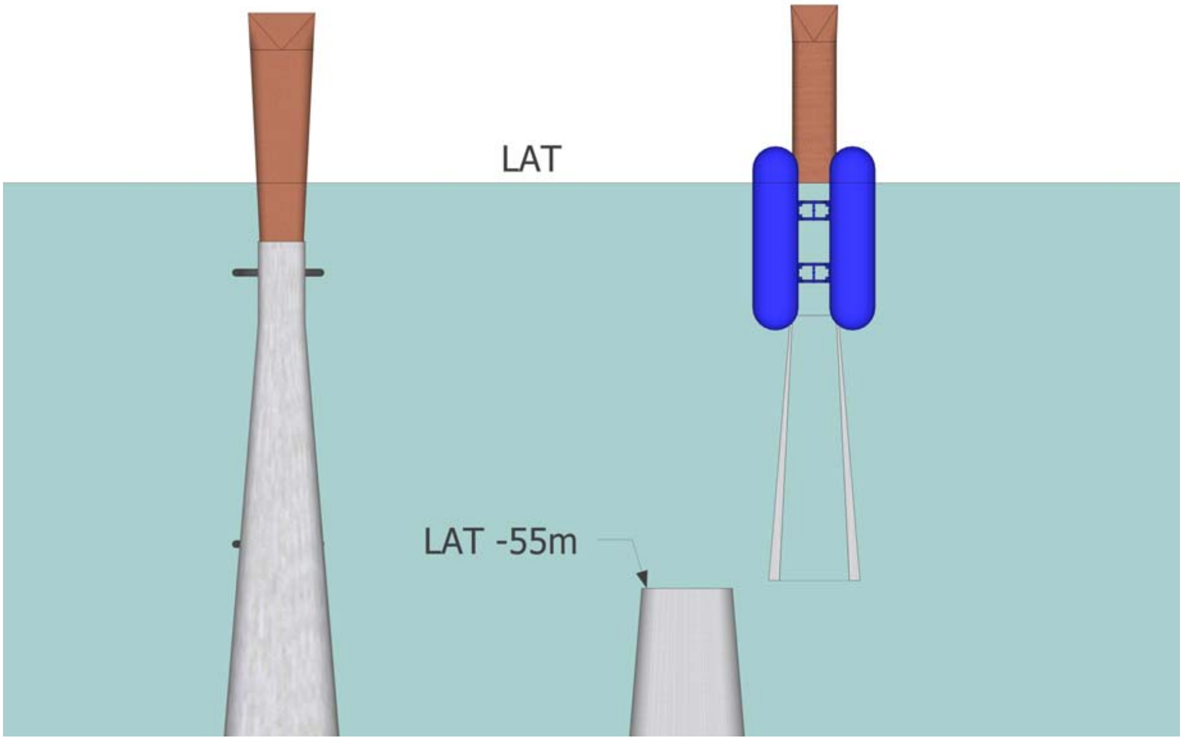


Figure 3.8 Flooded cut section of leg with buoyancy tanks attached

To achieve the floating draft of 54m, four external buoyancy tanks would be required, each 25m long and 6.25m in diameter, attached to the leg section.

Float off of the leg in this manner is only feasible if the issues below can be resolved:

- Supporting the leg section while the cut is being made to resist environmental loading on the leg and on the additional buoyancy. The large tanks would require a considerable time, measured in weeks, to attach to the leg, hence the work could not be achieved within a single weather window. The tanks, leg and the tank supports would have to be able to withstand loadings from a seasonal storm.
- The physical handling and attachment of the buoyancy to the leg section and transfer of the buoyancy lift force to the leg. The upper connection point would be in the splash zone and the lower one subsea. Each tank would have a displacement of 750 tonnes and if accidental impact with the leg occurs significant damage to both tank and leg would be anticipated.
- Asymmetric loadings applied to the leg during sequential installation of the buoyancy.
- Disconnection of the support structure provided for the cutting operation prior to float off of the leg.

Evaluation of the loading on the leg alone by others (Ref 2) shows that the provision of temporary support is uncertain. Each of the four buoyancy tanks would attract a loading similar to the steel section of the leg. The total force and bending moment to be restrained would be impossible to carry in a temporary support and may cause failure of the existing concrete leg. Hence this option is not viable.

3.6 Leg section filled with buoyant material

To eliminate the provision of a water or air tight bulkhead to keep water out of the leg section, the possibility of filling the leg with foam to make it self-floating has been investigated.

The based on a realistic foam density foam-filled leg section would have sufficient buoyancy to float but would not be hydrostatically stable and would capsize. Hence if this option were to be adopted assistance from a crane vessel would be required to initially move the section away from the CGB and then to lower it into a stable horizontal position.

However, installing the foam would present practical problems, as described below.

Lightweight, low density foams and materials such as polystyrene, are not suitable for this application because they do not possess the structural strength to prevent collapse when under pressure in the water and would not maintain their volume.

Self-foaming materials that could be expanded within the leg section are not an alternative as there is not a self-foaming material that could be injected into the leg that can act satisfactorily as foam buoyancy at 50m water depth.

Buoyancy elements suitable for deployment at this depth are normally manufactured from syntactic foam, the lightest syntactic foam being a composite material comprising glass microspheres and macrospheres held together within an epoxy resin system to create a homogenous matrix. Composite buoyancy systems are cast using dedicated mould tooling to provide repeatable consistent production.

If all of the internal pipework and equipment inside a leg section were to be removed, syntactic foam blocks could be cast and assembled inside the leg to create a large block of buoyancy. However, as the foam density quoted by manufacturers for this product is 346kg per cubic metre, this option would not provide sufficient buoyancy to float the leg section in a vertical orientation, and it would be impractical because of the difficulties involved with installation of the foam blocks and their subsequent removal and disposal onshore.

It is therefore concluded that this method of floating the leg sections would not be viable.

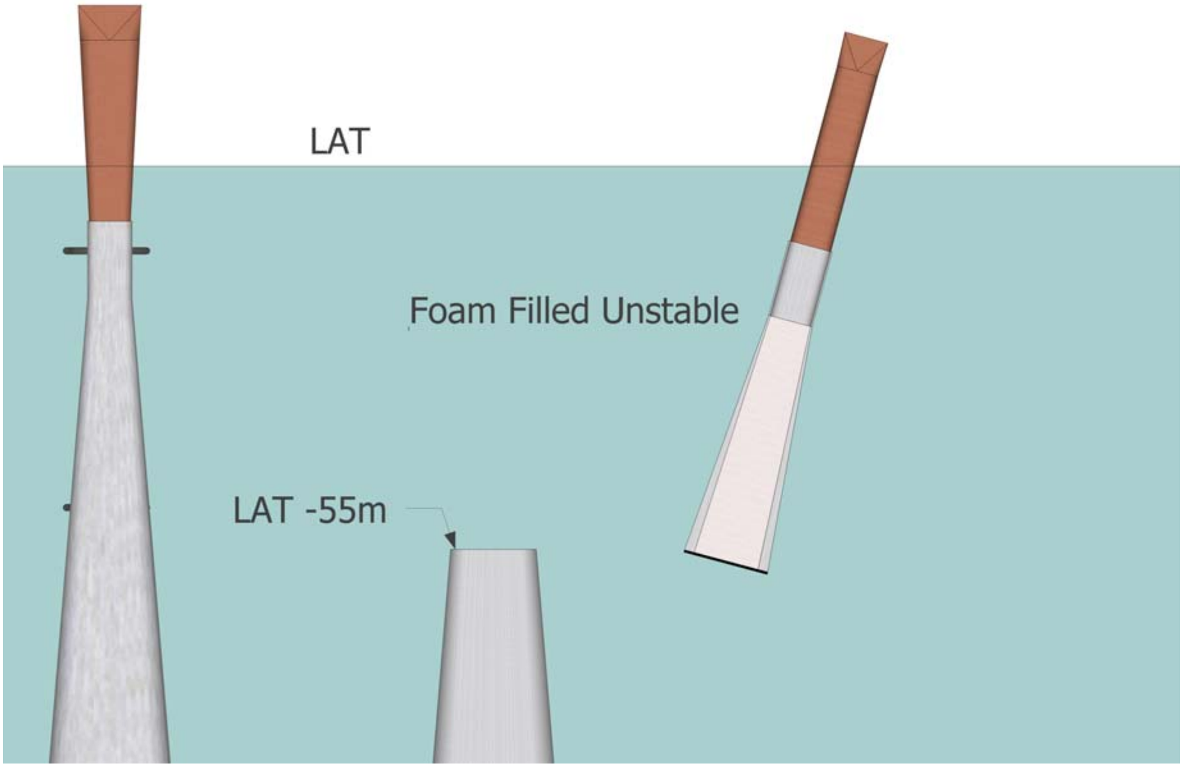


Figure 3.9 Foam-filled section of leg unstable

4 Conclusions

Five possible methods for floating off the section of a CGB leg above a cut line made 55m below sea level have been assessed. None of these options offers a viable solution to floating the upper section of the leg off the CGB.

The feasibility of each method is summarised below.

1. The leg air-filled.
    - Completely emptying the leg section by displacing the water with compressed air would make the section buoyant, but it would be unstable and the section would capsize.
    - Compressed air would be required to force water out of the leg. The air pressure required would crack the concrete of the leg section allowing the compressed air to escape. This in turn would cause the leg section to sink.
    - This option is not viable.
2. The leg section partially air-filled with ballast water at the bottom to make the section float in a stable manner in the vertical position.
    - For the leg section to be hydrostatically stable its draft would have to be greater than the depth of the cut, and this would prevent float off.
    - Compressed air would be required to force water out of the leg. The Atkins technical note (Ref 2) shows that the air pressure required would crack the concrete of the leg section allowing the compressed air to escape. This in turn would cause the leg section to sink.
    - The large volume of compressed air and the small area of leg at sea level would give the leg only very small reserve buoyancy.
    - This option is not viable.
3. The leg section partially air-filled with ballast water at the bottom, with external buoyancy tanks added to allow the section to float in a stable manner with a draft equal to the elevation of the cut.
    - This option was evaluated to select the minimum size of buoyancy tanks required. Four 2.65m diameter tanks each 20m long would provide sufficient buoyancy to allow the leg section to float in a stable manner and float off from the CGB.
    - Compressed air would be required to force water out of the leg. The Atkins technical note (Reference 2) shows that the air pressure required would crack the concrete of the leg section allowing the compressed air to escape. This in turn would cause the leg section to sink.
    - The buoyancy tanks at water line would increase the reserve buoyancy to an acceptable volume.
    - The attachment of the buoyancy to the upper steel section of leg above water line and the concrete leg at the bottom of the tanks has not been engineered but is conceptually feasible. Substantial offshore marine operations, working

within the splash zone above sea level and diving operations 10 to 15m below sea level, would be required.

- It would not be possible to upend the leg section to allow approach into shallow water without uncontrolled loss of the compressed air.
- This option is not viable.

4. The leg section flooded with external buoyancy tanks added.
    - This option was evaluated to avoid the need to dewater the leg section.
    - Four large buoyancy tanks each 25m long and 6.25m diameter would be required to allow stable float off.
    - Each buoyancy tank would displace 750 tonnes and would require a major offshore operation to attach it to the leg section. A substantial offshore marine operation would be necessary, working within the splash zone above sea level and diving operations 15 to 20m below sea level, which would be complex and would present significant risks.
    - The magnitude of the environmental loads from wind, waves and current on the leg would be very large, making supporting the leg during the cutting operation impossible. The CGB leg with tanks attached would attract significantly larger forces and moments from wave and current than the leg alone. The increase in wave and current loading would be so large that it would be beyond the capacity of a temporary support and may cause failure of the existing concrete leg.
    - This option is not viable.
5. The leg section filled with foam.
    - Filling or part filling the leg section with solid buoyancy would not provide the stable hydrostatic condition at the required draft.
    - Preformed buoyant material would have to be installed in the leg section, requiring removal if internal pipework and equipment. These operations would involve significant risks.
    - This option is not viable.

Appendix G

Review of leg section pressure containment by

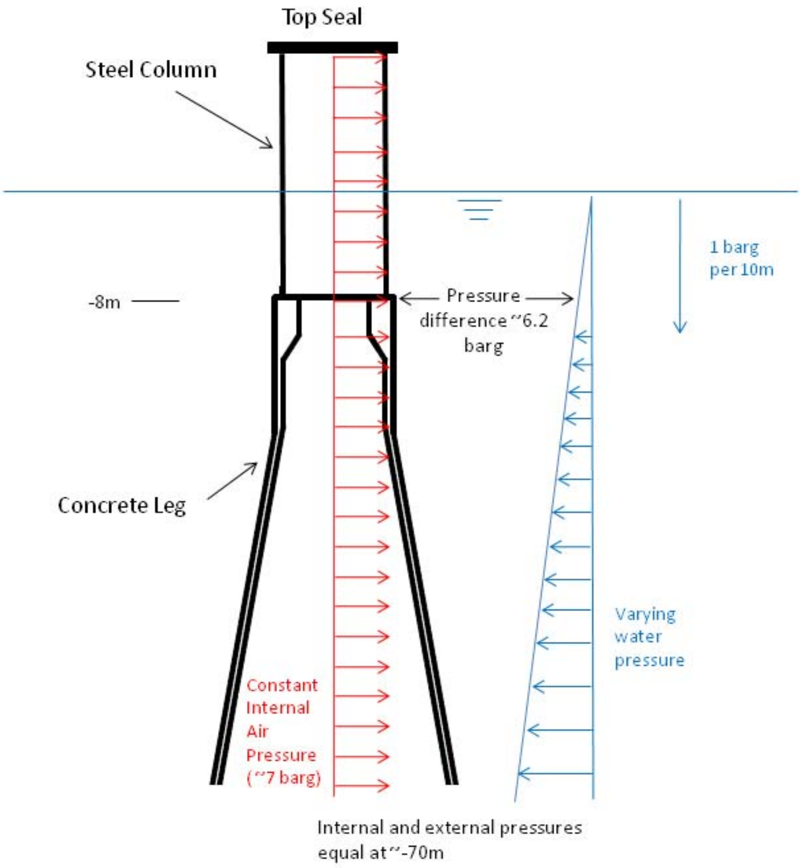
Atkins

Technical Note 5091295.501 TN03

Project:	Dunlin A Decommissioning	**To:**	Terry Kimber, Fairfield Energy Ltd.
Subject:	Float-Off - Pressure Retaining Capacity	**From:**	Peter A. Meenan
Date:	02/02/2011	**cc:**	Trevor Hodgson

1. Pressure Retaining Capacity

The concept of floating off the upper sections of the legs of the Dunlin Alpha CGB, cut at 55m below sea level, has been evaluated. One method might involve sealing the top of the section and then pressurising it internally with compressed air, to dispel the seawater inside and give the leg section buoyancy. For this to work, the concrete walls of the section would have to withstand the internal pressure of the air, allowing for the pressure differential caused by the external water pressure. This is shown below:



This technical note is a response to Fairfield Energy's question about the ability of the leg section to withstand these conditions. In concept, after the topsides was removed and before any cutting operation was undertaken, the leg would be capped at the top and air added to perform a pressure test. The internal air pressure would have to be at least 5.5 barg (equal to the hydrostatic water pressure if the leg was cut 55m below sea level). In addition, a safety factor of 1.25 would be applied for the pressure test, creating an internal air pressure of 5.5barg x 1.25.

1.1. Discussion

An internal pressure of 5.5 bar x 1.25 equates to approximately 70 m head of water.

The concrete ring beam at the top of the leg section is at -8m below sea level (LAT), meaning outward pressure at this level would be 70 - 8 = 62 m hydrostatic head. This pressure differential would decrease going down the leg, until it was balanced by the external water pressure at -70 m LAT. Therefore, a substantial proportion of the overall leg height would be subjected to tensile hoop stress.

Results from Atkins analysis of other similar CGB legs indicate that there would be significant vertical cracking in the concrete due to tensile hoop stress, probably around 20m below the top ring beam, and above this. At this level, the external water pressure would be around 30m, creating an outward pressure differential across the concrete wall of around 40m.

Previous analyses show that this magnitude of internal pressure would cause cracks of about 1.2 mm in size on average, which would pass right through the thickness of the concrete wall..

1.2. Opinion

To determine an accurate width and spacing of cracks, a calculation would be required based on specific data for the Dunlin Alpha legs and steel reinforcement. However, in Atkins' opinion, these cracks would probably be big enough to allow air to escape and therefore lose air pressure.

It is possible that air losses could be topped up with enough compressors on board, but overall there would be considerable risk associated with a leg section floating-off operation. Other possible leaks could occur through any existing penetrations in the legs.

Appendix H

Atkins

Decommissioning Capability Profile

Decommissioning

Atkins provides specialist skills and expertise in a number of fields which can support the decommissioning needs of both contractors and operators.

Investment Recovery, Re-Use & Re-Cycling

Atkins is possibly the best-in-class supplier of life-cycle risk assessment and risk management solutions to the UK offshore industry. This enables us to bring our knowledge and a pro-active approach to the achievement of Investment Recovery and Re-Use wherever practicably achievable in the decommissioning, removal & disposal stage of platforms or subsea facilities.

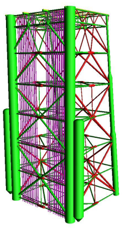
Brent Flare & SPAR Anchor Blocks

In August 2005 Shell recovered the Brent Flare and SPAR Anchor Block structures from the Brent Field. The contractor was Saipem using the HLV S7000. The methods used were derived from studies carried out by Atkins for Shell in 2003, 2004 and 2005.

Studies were also made to determine the possibilities for re-use of the structures.
The Anchor blocks were identified as having real residual civil engineering value and were taken to Norway where they are to be used in the construction of a new decommissioning quay.

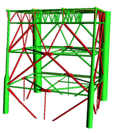
Jackets

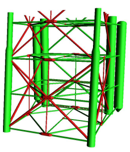
Atkins is a world-leader in the field of offshore dynamic structural analysis. We offer several specialist services in the design and analysis of fixed platforms and we have recently carried out studies for BP Amoco for the removal of NW Hutton, Thistle A and Miller platforms.



We are also retained by Excalibur to assist the design of the proposed HLV Pieter Schelte jacket lifting system.

We are familiar with existing and developing systems for Auxiliary Buoyancy for jackets e.g. Automarine, Seaflex and CVBS.





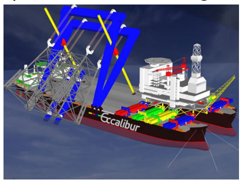
GBS Platforms

We have carried out many large complex structural analyses on Brent B, C and D for Shell; Dunlin A for Shell and then Fairfield and on Beryl A for Exxon-Mobil. Other studies in relation to utilities and ballast water systems have placed our staff with an in-depth and unique knowledge of these and other GBS units.

A major JIP for Shell, Exxon-Mobil, Kerr McGee and the UK HSE on the Decommissioning and Removal of the GBS platforms on the UKCS was completed in 2001 and has been reported and publicised by the HSE.

HLV Design

We have been retained, for several years, by Excalibur Engineering to undertake concept verification engineering for the Pieter Shelte decommissioning vessel. The vessel will have the capacity to remove and install topsides up to 48,000t and jackets up to 25,000t in a single lift operation for each.



As an integral part of the design team we have been required to work closely with the other disciplines to provide specialist advice on all structural engineering aspects of the design.

The work has involved structural assessments of the lifting and transportation of the majority of large North Sea jackets and topsides including barge launched and lift installed jackets and topside structures with module support frames and those with integrated deck constructions. The work also includes hydrodynamic analyses of the vessel for transportation and survival seastates.

Team Experience

We have a very experienced Decommissioning team which includes Engineers and Environmentalists with detailed knowledge of most of the GBS platforms in the UK sector and many of the major jackets, from the original construction phases, through the operational phase and into the late life/extended production phase. Atkins staff also has recent experience topside decommissioning studies for Brent and Maureen.

Atkins are actively supporting a number of re-use and investment recovery Interest Groups and our staff have provided chairmanship to several international conferences on Decommissioning and Re-Use.

Safety Management

Atkins has the in-house experience to support the complete requirements of any decommissioning project. This experience includes operation support, legislative requirements, Abandonment Safety Case assessment, management and HSE liaison. Our service includes HAZID, Dropped Object studies, EERA, QRA, Decommissioning Safety Case preparation and maintenance, HSE liaison, verification and assurance.

Environment

We provide lifecycle environmental support to decommissioning activities, including ENVID, environmental risk assessment, Environmental Impact Assessments, permits & consents, statutory consultations, drill cuttings & disposal options, BAT/BPEO, Comparative Assessments, authoring decommissioning programmes and undertaking audits.

Academic Liaison

Strong links with Academia are maintained in relation to Safety, Economics, Environmental Sciences, Naval Architecture and Engineering.

Our Senior and Chief Engineers are variously Visiting Professor at the University of Glasgow Department of Naval Architecture, Honorary Lecturer in the University of Aberdeen, Department of Engineering and Thesis Advisor to the Robert Gordon University, School of Mechanical & Offshore Engineering.

These links allow us to keep in touch with the latest research being done in the many highly intercalated disciplines which are needed to address the problems of decommissioning offshore assets in the best interests of all the stakeholders.

For further information contact:

Ramsay Fraser
(direct) +44 (0)1224 264342
(mobile) +44 0780 326 0300
ramsay.fraser@atkinsglobal.com

Appendix J

Cutting Underwater Technologies

Decommissioning Capability Profile

Cutting Underwater Technologies Ltd.

Representative of TS Tecnospamec Diamond Wire Cutting Technology

E-Brochure

Cutting Underwater Technologies Ltd
Representative of TS Tecnospamec
Diamond Wire Cutting Technology

COMPANY OVERVIEW & BACKGROUND

Group Profile

TS Tecnospamec was established in Genoa, Italy, in 1981. Its role, to perform advanced research and development projects leading to the deployment and operation of the new technologies for deep-water engineering projects offering support to the offshore and maritime industries.

Diamond Wire Cutting System

In 1991 Tecnospamec, developed the Diamond Wire Cutting System, a high efficiency, patented system, for the cutting of underwater structures using a specially designed Diamond Wire

Thereafter the CUT (Cutting Underwater Technologies) Group of companies, headquartered in Aberdeen, Scotland, was established by Tecnospamec in 1999. Their mission? To offer a range of services that utilised the advanced DWCS (Diamond Wire Cutting System(s)) developed by Tecnospamec. The primary focus for the new technologies was the platform and pipeline decommissioning markets, initially in the North Sea and later into other key oil producing regions around the world. Expansion has seen the diamond wire systems used on:

- Platform Topsides,
- Onshore Pipelines,
- Refining and other industrial applications
- The Nuclear Industry

The System has been extensively used in cutting jacket legs, thereby allowing offshore structures to be removed, subsea pipelines and conductors have also be severed with maximum efficiency and unsurpassed cost competitiveness.

Once positioned on to the structure that is to be cut, the DWCM uses its own hydraulic clamping system to lock itself in place. All operational functions of the DCWM can be controlled either from the surface using a stand alone Hydraulic Power Unit, Control Panel, Umbilical and Spooler or by utilising a WROV's own hydraulic supply. It can be seen therefore that the system is 100% safe for the operator who controls the wire speed, working pressures and flow rates required for maximum cutting efficiency remote from the actual cutting operation.

CUT now boast substantial experience in this key technology within the Offshore Structure Management & Abandonment sectors. Such has been the success of the patented DWC technology available through CUT that the group now has operational bases in Norway, Singapore, Brazil and the United States.

The Group markets and operate the Tecnospamec Diamond Wire Cutting System worldwide and is actively involved in major international decommissioning projects both on and offshore.

Mono-pile Cut
(Agip, Mediterranean)

Reinforced Concrete Slab
9.52m x 3.14m x 2.57m 2

DWC in Progress

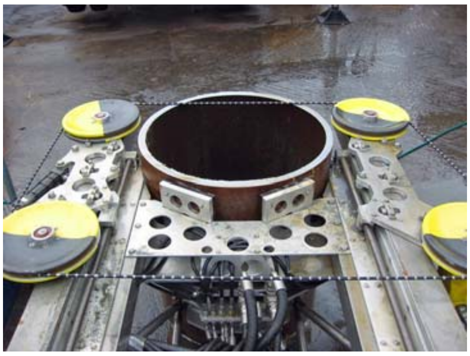
CUT HQ, Aberdeen Science and Energy Par, Claymore Drive, Bridge of Don, Aberdeen. AB23 8GD. UK
Tel: +44 (0)1224 222950; Fax: +44 (0)1224 826006; E-mail: info:cut-group.com; Web www.cut-group.com
VAT Reg No: 743 2799 09 Company No: 197961

TECHNICAL DETAILS

Diamond Wire Cutting Machines (DWCM)

A Diamond Wire Cutting Machine (DWCM) is a hydraulically activated machine used for cutting subsea and topside structures, pipelines and other industry plant or equipment of any size, shape or composition.

36" DWCM



To achieve the cutting action a continues loop of diamond wire is mounted on a number of pulleys, one or more being driven. Between two of the pulleys there is a large span of wire that performs the cutting as it comes into contact with the target material and remains so until the cut is complete. The basic DWCM hydraulic functions include the wire drive, wire feed, clamp and wire tensioners.

Control Methods Safety = Remotely

The DWCS is capable of carrying out its mission at a specific location under the given environmental conditions while positioning, installation and recovery, checking and wedging operations are possible either with diver or ROV assistance when used underwater. Alternatively when used either on the platform or on land a specially trained CUT operator would position (using a crane or other lifting assistance) the DWCM into position. All units are lightweight and easy to handle.

<u>DWCM's Modes of Operation</u>

Surface Powered Mode

Surface Powered DWCM is connected to the Hydraulic Power Unit using a multi-core umbilical in the region of 40 to 200 metres long. This then connects, on the surface, to the control panel through which the operator controls the wire speed, working pressures and flow rate for optimum cutting efficiency.

ROV Mode

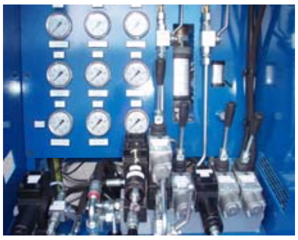
The ROV Controlled DWCM is connected either directly or indirectly through a short umbilical, with all the hydraulic functions being powered through the work class ROV's (WROV) onboard systems. Cutting functions are still controlled topside whilst a WROV or observation ROV can be used to monitor the cut progress.

Stand Alone

The Stand Alone system was developed for deep cutting operations where the WROV cannot provide enough hydraulic power. The DWCM & camera functions are controlled by a laptop computer via a purely electrical umbilical, Designed using proven ROV power and control technology. The Stand Alone system facilitates cutting at greater depths than previously achieved with the larger DWCM's.

HPU

Spooler & Umbilical



Hyd. Control Unit

Cutting Underwater Technologies Ltd
Representative of TS Tecnospamec
Diamond Wire Cutting Technology

CUT UK and our daughter companies have gained extensive experience around the globe on many different cutting applications. This expertise is detailed in the following "Track record" section. However, the following listing gives some understanding of our capabilities

Multistring Tubulars

Diamond wire is the only technology currently capable of cutting though a damaged non-grouted multistring with a cut cleans enough to allow for re-insertion.

The diamond wire is ideal for cutting straight, bent, twisted, grouted or non-grouted multistrings quickly and effectively with no doubt as to the final result.

Pipelines

Pipelines with any kind of external or internal protection, such as concrete, PVC, Epoxy, etc. can be cut in a single operation and at any depth.

Large Size Structure Cutting

The Diamond Wire Cutting System suits both offshore and onshore applications. By using standard machines, orbital cutters or custom-built DWCM's, virtually any structure can be cut to the exact requirements of the client either as a single piece or into sections for easier handling.

Platform Removal

Unlike other cutting systems, once the wire has passed through the leg, there is no doubt as to the completion of the cut. The client is always 100% guaranteed that upon lifting, the Jacket will be free.

This feature, together with a vast number of machines available, ranging from 10" to 150" cutting capacity, make Diamond Wire the ideal solution for decommissioning by minimizing the cost of vessels and equipment.

Other Materials

Diamond Wire Cutting is not just restricted to offshore activities and for cutting through steel. Solutions can be provided onshore as well and for other materials, for example:-

In 1996, at the Federal Tait Paper mill, Inveruire, Scotland, a reinforced concrete block of 9.52 by 3.14 by 2.57 meters was successfully cut.

In 2000, at an Onyx and Marble, quarry in France. Large section cutting and dressing with approximate dimensions of upper 7 by 7 meters; lower 8 X 8 meters; height 19.5 meters.

Singapore Orbital Cut

Jacket Leg

Test Cut Aberdeen

Mono-pile Cut

CUT HQ, Aberdeen Science and Energy Par, Claymore Drive, Bridge of Don, Aberdeen. AB23 8GD. UK
Tel: +44 (0)1224 222950; Fax: +44 (0)1224 826006; E-mail: info:cut-group.com; Web www.cut-group.com
VAT Reg No: 743 2799 09 Company No: 197961

Cutting Underwater Technologies Ltd
Representative of TS Tecnospamec
Diamond Wire Cutting Technology

New Headquarters - New Support Services - New Technology – New Markets

The building, and opening, of CUT's new, Aberdeen, HQ facility in 2009 consolidated all of CUT UK's operations under one roof. The additional space has also facilitated a significant growth in CUT's support services and manpower resources.

CUT's New Aberdeen Headquarters

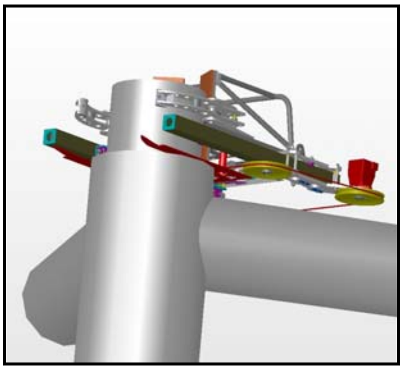
Recent major decommissioning projects in the North Sea:

- Frigg DP1 (Jacket piece small abandonment)
- Frigg DP2 (Piles & legs cut prior to re-float)
- Frigg DP2 (Jacket piece small reduction)
- N.W. Hutton (80+ Jacket cuts)
- MCP01 (20+ Topside cuts)
- Frigg QP (Jacket piece small reduction)
- Ekofisk (Numerous cuts on various infrastructure removals)

have demonstrated beyond doubt that CUT's integrated services approach offers the client full support during both the engineering and offshore phases of any project. Thus each cut can be pre-engineered prior to mobilisation allowing all parties to be fully aware of the workscope and thereby minimising "surprises" once offshore.

CAD Capability

CUT have the capability, in-house, to offer a full C.A.D. service which allows accessibility checks, configuration drawings, project storyboards and machine compatibility tests to be carried out as part of the engineering support services offered to the client.



Technological Developments

60 – 120 Modular DWCM

CUT's capability to engineer solutions to client requests has again been demonstrated during these projects which have seen the introduction of the 'Modular' DWCM concept and the unique capability to offer the innovative option of a 'Castellated Cut'. The cutting capacity of the Modular DWCM can be altered by changing the centre section of the machine thereby allowing a reduction in deck space requirements, greater, more flexible machine configuration and overall project cost savings

The Modular DWCM can cut 60-84 inches in one configuration and 85-121inches in the second. It is equipped for/with:

- Dual mode castellated or Z cut
- Active Wedging system
- Diamond Wire severing cutter
- Real time read-outs of feed and tension values
- Front and rear TV cameras
- Umbilical hot stab for ALL functions
- ROV docking interface
- Surface LCD monitor for TV and read-outs
- Deployment Basket

Cutting Underwater Technologies Ltd
Representative of TS Tecnospamec
Diamond Wire Cutting Technology

Castellated Cutting

Developed from CUT’s earlier innovation the ‘Z’ or ‘Step’ cut Castellated Cutting was developed to allow a severed target to retain a high degree of residual strength such that it will maintain stability during bad weather or delays in performing the actual lift.


Test Cut - Onshore


Severed Jacket Leg Onboard Crane Barge


Completed Cut - Offshore

Another advantage of the ‘Castellated Cutting’ technique may be that some, if not all of the major cuts can take place without the need to have a crane barge in attendance thus offering potential for large cost savings.

CUT Nuclear

A major milestone in CUT’s development was the formation, in 2009, of CUT Nuclear aimed, as the name suggests, squarely at the global nuclear decommissioning market.

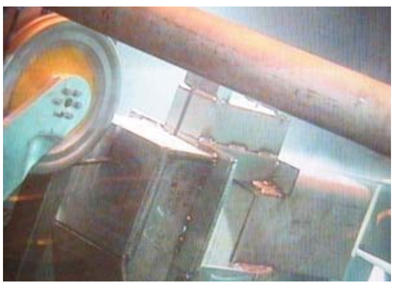
In 2008 Tecnospamec developed a new generation of 100% electrically driven and powered DWCM’s for cutting Steam Dryers structures (stainless steel) in contaminated pools. In May 2009 the first commercial cut of a Steam Dryer at an American BWR Nuclear Utility was completed using this technology.

As a follow on from this successful project, CUT Nuclear has been awarded the contract for removal of 1 (with 2 Optional) Dryer(s) in Sweden during 2010 and 2011

The new challenges that Tecnospamec and CUT will face will mean that new thinking, new designs and new techniques will be needed to develop the specialist technology and service capability required to succeed in this market.

It is a challenge that both will embrace with enthusiasm.


Electrical DWCM in position prior to commencement of cut


Cutting in Progress


Electrical Control Cabinets

CUT HQ, Aberdeen Science and Energy Par, Claymore Drive, Bridge of Don, Aberdeen. AB23 8GD. UK
Tel: +44 (0)1224 222950; Fax: +44 (0)1224 826006; E-mail: info:cut-group.com; Web www.cut-group.com
VAT Reg No: 743 2799 09 Company No: 197961

CERTIFICATE OF APPROVAL

This is to certify that the Quality Management System of:

Cutting Underwater Technologies Ltd
CUT HQ, Aberdeen Science and Energy Park,
Claymore Drive, Bridge of Don,
AB23 8GD, Aberdeen - Scotland
United Kingdom

has been approved by Lloyd's Register Quality Assurance to the following Quality Management System Standards:

ISO 9001:2008

The Quality Management System is applicable to:

Marketing and operation of TS Tecnospamec DWCS (diamond wire cutting system) to in-shore and off-shore sectors.

This certificate forms part of the approval identified by certificate number LRC 0151365/QMS.

Approval
Certificate No: LRC 0151365/QMS/001

Original Approval: 6th October 2005

Current Certificate: 16th February 2010

Certificate Expiry: 5th October 2011

Issued by: Lloyd's Register Quality Assurance Italy Srl
for and on behalf of Lloyd's Register Quality Assurance Limited

UKAS QUALITY MANAGEMENT
001

This document is subject to the provision on the reverse

Registered Office: Piazza della Vittoria 6-1 – 16121 Genova – Trib.Genova 189273/1996 – CCIAA Genova 356347

This approval is carried out in accordance with the LRQA assessment and certification procedures and monitored by LRQA.

The use of the UKAS Accreditation Mark indicates Accreditation in respect of those activities covered by the Accreditation Certificate Number 001

Macro Revision 13

DWCS RECORD

(December 2009)

Key data Summary

Projects	**508**
ROV assisted	189
Diver assisted	228
Platform removed	**79**
Platform Removals Back-up	6
Pipeline Removals	**175**
Pipeline Repairs	72
Contingency Projects	**26**
Number of Cuts	**2957**
Cuts of pipelines	842
Cuts of Multistring	356
Cuts of chains	30
Cuts of flexible and special pipelines	295
Cuts of drill strings	44
Cuts of risers/Guide posts/Pipes	408
Cuts of various items	140
Fat/Demo Tests	275
Cuts Offshore	**2682**
Cuts deeper than 1000m water depth	**212**
Cut surfaces and Time	
Steel (sqdm)	30700
Coating/Concrete (sqdm)	393096
Total cutting time (hours)	6897
Deepest EPRS Shell USA	**- 1,600m**
Deepest CUT Production Petrobras Brazil sealines	**- 1,568m**
Deepest CUT Exploration Chevron Texaco 8" Drill pipe Nigeria	**- 2,434 m**

DWCS RECORD
(December 2009)

Key data Summary

Projects	**508**
ROV assisted	189
Diver assisted	228
Platform removed	**79**
Platform Removals Back-up	6
Pipeline Removals	**175**
Pipeline Repairs	72
Contingency Projects	**26**
Number of Cuts	**2957**
Cuts of pipelines	842
Cuts of Multistring	356
Cuts of chains	30
Cuts of flexible and special pipelines	295
Cuts of drill strings	44
Cuts of risers/Guide posts/Pipes	408
Cuts of various items	140
Fat/Demo Tests	275
Cuts Offshore	**2682**
Cuts deeper than 1000m water depth	**212**
Cut surfaces and Time	
Steel (sqdm)	30700
Coating/Concrete (sqdm)	393096
Total cutting time (hours)	6897
Deepest EPRS Shell USA	**- 1,600m**
Deepest CUT Production Petrobras Brazil sealines	**- 1,568m**
Deepest CUT Exploration Chevron Texaco 8" Drill pipe Nigeria	**- 2,434 m**

DWCS RECORD

(December 2009)

Projects details

Year	Assisted by	Water Depth (m)	Customer Location	Project Details
2009	Diver	54	Superior Energy/South Timbalier 130/GoM/Normac Clough	Lift Boat Leg Cutting
2009	--	30	Subsea7/Shell/North Sea/Toisa Polaris	Indefadigable Pipelines Removal
2009	ROV	--	Allseas Engeneering BV/South Argentina/Highland Rover	Magellan Strait Pipe Contingency
2009	--	62	Fugro Rovtech/Fugro Saltire/North Sea	20" Pipe Cutting
2009	ROV	125	Subsea 7 Greenwell Base	Guide Post Cutting
2009	--	--	Stress Enginnering/DW Rupe Project/Waller Texas	Pipe Cutting
2009	Diver	23	Diamond Services/IRT/West W 331/D85/GoM	102" Monopole with Multistring Inside
2009	ROV	305	Canyon Offshore/MC194/Normand Commander/GoM	Pipeline Cutting Offshore
2009	--	28	Beryl/Crescent/ST 195 A/Arapaho/GoM	Platform Decomissioning
2009	ROV	1341	ATP/OCD 13198 #4/GoM/Iron Horse	Guide Base Cutting
2009	ROV	305	Canyon Offshore/Shell/MC194/Msv Normand Commander/GoM	Pipe Cutting
2009	--	--	Hallin Marine UK/Canyon/North Sea/Northern Canyon	30" Casing Cutting
2009	ROV	1400	SBM Services/Petrobras/Skandi Fluminense/Brazil	FPSO Capixaba Relocation
2009	--	99	Saipem UK Ltd (Sonsub Division)/Far Samson/S7000	Frigg "QP" Platform Removal
2009	--	--	Saipem UK Ltd (Sonsub Division)	Hire of Over-boarding Fairlead
2009	ROV	500	Doris Enginering/Total E & P/Congo/Polar Prince	Anchor Mooring Chain Cut
2009	ROV	27	Subsea 7/Conoco Phillips/Ekofisk 2/4 W/North Sea/normand Mjolne	Bracing Cut/VDM Removal
2009	--	380	Technip/Geoholm/North Sea/Norwegian Sector	Super Duplex Pipeline
2009	ROV	107	Statoil Hydro/Island Offshore/Island Vailant/Oseberg Field/Norvegian Sector	Cutting of Wellhead North Housing on Omega Field
2009	--	36	Apache Corporation/VR-284A/GoM/Kestrel	Jacket Leg and Conductor Cutting
2009	Diver	55	Jab Energy Solutions/Nippon Oil Exploration/WC 532/Spartan 208	Platform Removal
2009	Diver	27,5	Apache Corporation/EI GoM/Boaz	Multistring Cutting
2009	Diver	12	Energy XXI/GoM/WC238/Kylie	Caisson Cut
2009	--	30,5	Apache/Acergy Osprey/GoM/IOS 800	Vermillion Removal
2009	Diver	21	OSFI/William Gas Pipeline/Swing Thompson	Jacket Leg With Pile Cutting
2009	Diver	21,6	Helix Energy Solutions/GoM/Bob - Palmer	Multistring Conductor Cutting
2009	--	61	Jab Energy Solutions/Nippon Oil/Merit Energy/GoM EI 288/DB Cherokee	Multistring Conductor Cutting
2009	ROV	1021	Anadarko/Saipem/Galvestom/Hos Mystique	Jumper with Thermo Coating Cutting
2009	ROV	548	Deep Gulf Energy/Green Canyon/GoM/Q4000	Multistring Conductor Cutting
2009	--	--	Apache Corporation/GoM SS 291 B/Brave	Jacket Leg, Pile, Deck Leg, Multistring Cutting
2009	--	--	HSL Contructor/Shell/Palau Bukom/Singapore	Concrete Structure and Pump Basement
2009	Diver	6,7	Boh Bros Construction/Shaw Group/GoM	Concrete Pile Cutting
2009	--	8	Subsea 7/Curlew/North Sea	Chain Cutting Shell Curlew
2009	--	80	Technip/Conoco Philips/Ekofisk field/Seven Pelican/North Sea	Ekofisk Flowline
2009	--	80	Technip/Conoco Philips/Ekofisk field/Seven Pelican/North Sea	Ekofisk Flowline

DWCS RECORD
(December 2009)

Year	Assisted by	Water Depth (m)	Customer Location	Project Details
2009	Diver	55	Jab Energy/Nippon Exploration/WC532/Spartan 208/GoM	Platform Removal
2009	Diver	25	Conoco Phillips China/Technip SS7/Venturer/China	Mooring Chain Cutting
2009	--	--	Technip AS/ North Sea	North End Gate Protection
2009	--	60	Don/Stine Wellhead/Offshore Denmark/Acergy Osprey	Nini East Developement
2009	Diver	69	Saipem UK/North Sea/Saipem 7000	DP1 Jacket Removal
2009	ROV	26	Hereema Marine Contractors/Conoco Philips/Ekofisk/Thialf	Ekow/Ekor/Ekop Removal
2009	Diver	60	Jab Energy Solutions/nippon Oil Exploration/West Cameron/Cherokee	Caisson Cutting
2009	Diver	1,2	Chet Morris Construction/Palm Energy/West Delta 52/GoM/CM16	Conductor Cutting
2009	Diver	67	BP/Grand Isle 95 A/GoM/Gulmar Falcon	27" Pipeline Citting
2009	ROV	1250	Subsea7/BP/Angola/Bourbon101	Sleeper Cutting
2009	--	--	HSL/FW/Shell/Palau Bukom	Cutting of 4 Concrete Pillars
2009	ROV	24/98	Heerema Marine Contractors BV/BP/Hermod/North Sea	North West Hutton Platform Removal
2009	ROV	375	Subsea7/StatoilHydro/North Sea/Norwegian Sector/Seven Sisters	Receiver Cutting
2009	Diver	5	Aquanos Ltd/Maersk/Offshore Denmark/Finstaship MSV Nordica	Fender Removal
2009	Diver	80	Oceaneering/BP/GoM/SM205/Olympic Intervention IV	Jacket Leg and Brace Cutting
2009	Diver	23	Technip/Wintershall/DSV Skandi Achiever	30" Conductor Cutting
2009	Diver	15	Osiris Diving/Veolia Environmental/New Haven UK/On Shore	Barrette Cutting
2009	ROV	400	Statoil/Trandelag I Filed/North Sea/Island Vanguaro	Wellhead Cutting 36"+20"
2009	ROV	21	Heerema Marine Contractors BV/BP/Hermod/North Sea	North West Hutton Platform Removal
2009	Diver	18	Global Offshore/Exxon Mobil/Offshore Nigeria/Hercules Black Jack	24" Pipeline Cutting - Nigeria
2009	Diver	22	Saudi Aramco/J. MacDermott Saudi Arabia/Offshore Saudi Arabia/DB16	Cuting Of a Free Riser
2009	--	--	Anadarko/Saipem/Galvestom/HOS MYSTIQUE	Jumper with Thermo Coating Cutting
2009	ROV	0,5/80	Aker Solution/Total/Aker Storde/North Sea/Side Barge 19	DP2 Size Reduction
2009	Diver	27	Micoperi Marine Contractor s.r.l./Egypt Offshore/Adams Nomad	22" Pipeline Cut
2009	--	--	Heerema Marine Contractors BV/North Sea	North West Hutton Platform Removal
2008	--	--	Heerema Marine Contractors BV/North Sea	North West Hutton Platform Removal
2008	Diver	40	Dulam Internation/Statoil/Offshore Iran/Seamac Princess	Pipeline Cutting Offshore Iran
2008	ROV	35	OFSI/BP/West Delta Field/DB Swinging Thompson	Jacket Leg and Diagonal Member Cutting
2008	ROV	0,5/50	Aker Solution/Total/Aker Storde/North Sea/Side Barge 19	DP2 Size Reduction
2008	Diver	45	Acergy/Half Dan/Acergy Discovery	20" Pipeline cutting
2008	ROV	210	Technip Norge AS/Island Constructor/north Sea Norwegian Sector	30" Kvitebjorn Pipeline Repair Project

DWCS RECORD
(December 2009)

Year	Assisted by	Water Depth (m)	Customer Location	Project Details
2008	ROV	85	Deep Ocean/CTC/Kittawake Buoy/Volantis	Pile and Ancillary Cutting - Kittawake
2008	ROV	54	Total E&P Norge AS/Saipem/Saipem S7000/North Sea Norwegian Sector	Frigg - DP1 Jacket Removal
2008	ROV	690	Canyon/Allseas/Durgabai Field/Olympic Canyon/India	4"x241,25mm Pipeline Cutting
2008	Diver	3/17	S.R.P.T.M./Tangier Harbour/	Concrete Block Removal
2008	ROV	244	W&T Offshore/GoM/Q4000	Multistring Conductor Cutting
2008	Diver	36,5	Merit Energy/JAB Energy Solution/GoM/DSV Tiger	Multistring Conductor Cutting
2008	Diver	28,6	Tetra/Merit/GoM/East Cameron 254/Arapaho	Jacket Leg Cutting
2008	ROV	720	Allseas Engeneering BV/Durgabai Field/India Offshore/Highland Rover	Pipeline Cuts 4"x241.25mm coated
2008	ROV	165,5	Tetra Technologies/Apache/East Break 160/GoM/TigerFish	Multistring Well Conductor Cutting 30"
2008	Diver	36,5	Merit Energy/GoM/DSV Tiger	Multistrig Conductor Cutting (16"+10")
2008	Diver	2/5	Bluestream NL/Tyra Oil Field/North Sea/Denmark/Northern River	Tyra Field Fender Structures Cutting
2008	Diver	73,5	ConDive/Vermillion313/Gom/Ocean Commander	Jacket Leg and Conductor Cutting
2008	Diver	39,60	JAB Energy Solutions/OMP/SP 32/LB kaitlyn Eymard/GoM	Multistring Conductor Cutting
2008	Diver	--	JAB Energy Solutions/OMP/Main Pass 75 1/LB kaitlyn Eymard/GoM	48" Caisson with Multiple Well Strings
2008	Diver	7,6	LL&G Constructions/Golden Meadow/GoM	36" pile Cutting
2008	ROV	145	Subsea7/North Sea/Polar Prince	Vigdis Pup piece and Pipeline Cutting
2008	Diver	--	SBM/Hakodate Port/Geosea	Padeye Cut
2008	ROV	520	Transocean/Chevron/Offshore Angola/S701	Damaged Riser Cutting [with buoyancy 43"]
2008	--	25	Fugro Seacore/Pembroke - SW Wales/Deep Diver 1	E1200 milford Haven Piles Cutting 1300mmODx32mmWT
2008	Diver	2	Blestream NL/Maersk/Tyra West Field/Northen River	(32 and 18" Riser Guard) Tyra Field Strucures Cutting
2008	--	43	Saipem UK/Maersk/Denmark/DSV Bar Protector	20" OD 2" coating Pipeline Cutting (x4)
2008	Diver	18/34	ERT Energy Resource Technoligies/GoM/L/B Ram XII	Caisson Cutting - MI 604 [72" and 48" with 30" multistring]
2008	--	--	Technip/North Sea/Kvitebjorn	30" Export Pipeline
2008	ROV	145	Subsea7/North Sea/Polar Prince	Vigdis Pup piece and Pipeline Cutting
2008	Diver	--	SBM/Hakodate Port/Geosea	Padeye Cut
2008	ROV	520	Transocean/Chevron/Offshore Angola/S701	Damaged Riser Cutting [with buoyancy 43"]
2008	--	25	Fugro Seacore/Pembroke - SW Wales/Deep Diver 1	E1200 milford Haven Piles Cutting 1300mmODx32mmWT
2008	Diver	2	Blestream NL/Maersk/Tyra West Field/Northen River	(32 and 18" Riser Guard) Tyra Field Strucures Cutting
2008	--	43	Saipem UK/Maersk/Denmark/DSV Bar Protector	20" OD 2" coating Pipeline Cutting (x4)
2008	Diver	18/34	ERT Energy Resource Technoligies/GoM/L/B Ram XII	Caisson Cutting - MI 604 [72" and 48" with 30" multistring]
2008	--	--	Technip/North Sea/Kvitebjorn	30" Export Pipeline

DWCS RECORD
(December 2009)

Year	Assisted by	Water Depth (m)	Customer Location	Project Details
2008	--	--	Subsea7/North Sea/Vigdis	Vigdis WI Pipeline Cutting
2008	ROV	465	Subsea 7/North Sea/Subsea Viking	Foinaven Coated Pipeline Cut 10,75" OD
2008	Diver	145	Acergy UK Ltd/Acergy Osprey/Lyell Field	24"Pile and Follower Pile Cut Lyell Field
2008	--	surface	RGB/Total/North Sea/Dunbar Platform	Dunbar Fender Removal
2008	ROV	325	Acergy/Statoil/Asgard	60" Pile Cutting
2008	Diver	24	Saipem Asia SDN BHD/Offshore Taiwan/POE WB2	36" Pipeline Cutting
2008	ROV	130	Single Buoy Moorings/Equatorial Guinea/Normand Installer	4” Flexible Gas Lift Flowline Cut Equatorial Guinea
2008	Diver	10,36	Tetra technologies/Apache/LB Kayd/GoM	Well Intervention/Recovery 48”
2008	ROV	150	Sonsub/PTTEP/Myanmar	Cutting of Wellhead 30"x1"+20"x1"
2008	ROV	70	Apache Corporation/West Delta/Normand Clipper	24" Multistring Conductor Cutting
2007	--	Surface	Drafin Sub/Porto di Genova, Italy	Cutting of 900mmx115mm Pipeline
2007	Diver	125	Hydro Marine Services/Mc Dermott Australia/Angel project	Cutting of 14" and 30" coated Pipelines
2007	Diver	75	Meramid/CUEL/Thailandia	Cutting of a pipeline 10"x1/2"+1"coating OD 12"3/4
2007	Diver	80	Sonsub/Saipem/Thailandia	Cutting of 42"x1"+4" coating pipeline
2007	ROV	300	Bluewhale/CNOOC/China	Cutting 13,5" of risers (Coflexip)
2007	Diver	10,36	Tetra technologies/Apache/LB Kayd/GoM	Well Intervention/Recovery
2007	Diver	--	Besix Kier JV/Milford Haven/Jetty	Cutting of concrete pile 20"
2007	ROV	630	Canyon Offshore/Olympic Triton/Green Canyon	9,6" ROV Umbilical cutting
2007	ROV	1280	Trendsetter Engineering/Exxon Mobile/Ocean Intervention2/Mississippi Canyon	Mica Pig Tail Pipe Cutting
2007	Diver	115	Fugro/RovTech Limited/Transocean Prospect	13 3/8" Casing Cutting Transocean Cutting
2007	Diver	49	Con-Dive/LLC/GoM/Ocean Commander	Jacket Leg and Conductor Cutting
2007	Diver	24,3	Apache Corp./West Delta 75 H/DB "Cherokee"	Jacket Leg Cutting Job
2007	Diver	75	Subsea7/Conoco Phillips/Eldfisk Field/DSV Pelican	24" Pipeline Cutting
2007	Diver	1,2/3,9	Apache/GoM/DB "Arapaho"	Jacket Leg Cutting
2007	ROV	1478	Exxon Mobile/Trendsetter Engineering/Gom/NOR "Tigerfish"	Mica Pig Tail Pipe Cutting
2007	ROV	254/286	Technip/Statoil/Asgard field/CSO Constructor	Asgard J-101 repair
2007	Diver	18,3 / 78,6	Heerema/Conoco Phillips/North Sea/Hermod Crane Barge	Ekofisk CAT 1 Bridges, Flares and Tripod Removal 2007
2007	ROV	300	Subsea7/Statoil/Asgard Field Mid Norway/Skandi Bergen	Asgard Reeled Pipe Installation
2007	Diver	210	Tetra Technologies/Gulf of Mexico/M.V.Cherokee/	Jacket Leg and Conductor Cutting
2007	ROV	212	Apache/Global Divers/Grand Isle Block 82A/Sea Line	Cut Conductor
2007	Diver	13,1	Energy XXI/GoM/L-B "Kaitlyn Eymard"	Multistring conductor cutting
2007	Diver	55	Chevron/Global Divers&Marine/Gom/MSV Pioneer	Conductor Cutting
2007	ROV	610	Helix/Canyon Offshore/G0M/Intrepid	ROV Umbilical cutting
2007	Diver	28	Apache Corporation / GoM / DB Arapaho	20" Multistring well conductor cutting

Year	Assisted by	Water Depth (m)	Customer Location	Project Details
2007	Diver	33,5	Energy Resources Technology, Inc./ GoM / LB Ram 12	Multistring well conductor cutting
2007	Diver	23	NCG Services / Dragon Oil / Caspian Sea / Bogatir 3	Jacket Removal
2007	--	surface	Acergy SA / Globestar Nigeria Ltd / Mobile Nigeria/ Acergy Orion	16" OSO RD Pipeline Repair Project
2007	ROV	2000	Subsea 7 Brasil/Petrobras/Niteroi/	Flexible Pipe Contingency 6,5"x1,5" and 10"x2"
2007	Diver	26-87	Apache/Tetra Technologies/GoM/Tetra Arapaho	54.5" Jacket Leg and 20"- 24" Pile Cutting
2007	Diver	21,5	Chevron/GoM/Boa Deep C	39" Jacket Leg with 16" Pile Cutting
2007	ROV	60	Dong Energy AS/North Sea Danish Sector/Siem Danis	10"OD WI Pipeine Cutting
2007	ROV	100	Aker Marine Contractor/Total/North Sea	Frigg Cessation
2007	Diver	22,8	Apache/Tetra/GoM/Maersk Achiever	Well Conductor Cutting
2007	Diver	30	Apache Corporation/GoM/DSV Dancer	Conductor Cutting
2007	Diver	52 – 75	Wild Well/Apache Corporation/Gulf of Mexico/Normand Clipper	Multistring Well Cutting
2007	Diver	33	Energy Resources Technology, Inc.	Multistring Well Cutting
2007	ROV	640	Canyon Offshore/	Dropped 26" Tendon
2007	Diver	35,6	Chevron/Gulf of Mexico/Swing Thompson	39"Jacket Leg Cutting
2007	Diver	--	Chevron/Gulf of Mexico/DB1	39"1/2 Multistring Conductor Cutting
2007	ROV	125	Subsea 7/Norsk Hydro/Oseberg/Edda Fjord	36" riser cutting
2007	ROV	1829	BP/Mississippi Canyon 778/Thunderhorse/ GoM	Pipeline and Chain Cutting
2007	ROV	54,8	Pioneer Natural Resources/East Cameron 322/Rem Commander	Jacked Leg and Conductor Cutting
2007	ROV	54	BlueStream NL/Denmark/Ensco 71	Buestream 10"
2007	Diver	+2	RBG Ltd/Petrofac/North Sea/Northern Producer	36" OD Pipeline Cut
2007	Diver	40	Hydrodive Nigeria/Addax Petroleum/Nigeria/Barge Victory J316	Cutting of damaged 12" and 30" pipeline
2007	Diver	40	Gassco/Subsea 7/H7/Acergy Osprey/Toisa Polaris	36" Pipeline Cutting with 50" cutter
2007	Diver	80	Hyundai	Cutting of a 42"x1"+4" concrete coat. Pipeline
2007	ROV	682/831	Daewoo/Sonsub Pty Ltd/Myanmar	Cutting of a 13"3/8 x 13,1mm Riser
2007	ROV	60	Petronas/Swiber Marine/Kuantan Malaysia	6"Abu Cluster Pipeline Cutting For Repair
2007	ROV	127-153	PTTEP/Sonsub Pty Ltd/Zawtika1A/Doo Sung	Cutting of wellhead
2007	Diver	30,5	Apache Corporation/Tetra Technologies/Ship Shoal 193B	Apache Multistring Well Cutting
2007	Diver	37	Samson/Vermillion217A/Rem Commander	Jacket Leg Cutting
2007	Diver	41	Amerada Hess/Wild Well/Briton Sound	Multistring Conductor Cutting
2007	ROV	--	CNR International UK Ltd / North Sea	Cuttin Drill Pipe 5,5" Odx25mm wt
2007	Diver	30 – 60	BP / Saipem Mediterranean Services / Red Sea	16" to 20" Subsea Pipelines Cutting

Year	Assisted by	Water Depth (m)	Customer Location	Project Details
2007	ROV	2500	Shell / I Tech-Subsea 7 / Egypt	7,5" Drill String Cut
2007	Diver	85 / 150	Statoil / Sobsea 7 JV / North Sea	30" & 42" Pipe Cutting – Sleiper Tie in Subsea 7
2006	Diver	23	Energy XXI/L/B Audrey/GoM	30" Multistring conductor cutting
2006	Diver	9-36,5	Newfield/Toisa Proteus/GoM	39" (x10), 34" (x7), 33" (x2), 30" (x3), 26" (x10), 24" (x5) Multistring conductors cutting
2006	ROV	145	CNR International/Columbia E/Transocean Prospect	5,5" Drill string cutting (x2)
2006	Diver	5,4	Express Energy Service/Dominion WC 225 Well No. 6/Superior Freedom/GoM	48" Multistring conductors cutting (x5)
2006	--	surface	SRC Refinery/Singapore	72" (x2)+ 38"(x8) + 34" (x4) + 21" (x4) c/w refractory mesh Cyclones cutting
2006	ROV	63	Chevron/Wiggins Tide/Angola	16" Riser cutting (2)
2006	Diver	3-6	Herbosh-Kiere Marine Contractors/Kirkwall/MC Ails Orkney	Piles cutting OD 1020mm (x2) + side U channels (x2)
2006	ROV	340	Statoil/Technip Offshore Norge AS/Normand Progress/N.Sea - Norway	4,5" Drillstring cutting (x21)
2006	Diver	3-10	Statoil/Amundsen Diving AS/MS Scuba/N.Sea - Norway	1200 mm OD GRP Pipeline cutting (x31)
2006	ROV	500	BP/PGS Production AS/Foinaven West Shetland/M/V Olympic Hercules	111mm Dia Stud less Chain contingency
2006	Diver	82	Statoil/Subsea 7-Acergy JV/Sleipner - Langeled N.Sea Norway	Tie-Back Pipeline 30" to 44" OD(x10)
2006	--	--	BP/PGS Production As/Foinaven/CUT Aberdeen	111mm Dia Chain cutting trial (x1)
2006	Diver	30,5	Newfield Exploration Company/East Cameron 151C Well #C1/Superior Gale/ GoM	36" OD x 1" WT Piles cutting (x2)
2006	ROV	1829	BP/Mississippi Canyon 77, Chloe Candies/GoM	12" (x6) 10" (x1), 8" (x1) specially coated pipelines, 118mm stud less chain (x1)
2006	--	--	BP/Houston	12"(x1), 16"(x1), 18" (x1) Special coat pipelines trial cutting
2006	Diver	30,5	Tetra Technologies/Mustang Island A85/Tetra Arapaho/GoM	MU 85 Platform cutting (Toppling removal) 52" OD 2,250" WT leg piles (x9)
2006	Diver	15	W&T Offshore/L/B Myrtle/GoM	30" Multistring conductors cutting (x5)
2006	Diver	27	Tetra Technologies/MU A16 Platform/D/B Tetra Arapaho/GoM	Jacket legs 52 1/2" OD 1,250" WT 48" OD x 1" WT pile (x8), 30" Multistring conductor
2006	Diver	30,48	Tetra Technologies/Southern Hercules/GoM	30" and 26" Multistring conductors cutting (x15)
2006	Diver	4-18,5	Chevron Texaco /Superior Endeavour/GoM	36", 30", 26" Multistring conductors (x 8)
2006	Diver	9	Cal Dive Intl./Uncle John/CDI Fourchon/GoM	30" Multistring conductor
2006	--	--	TFE/Aker/Port Reval/MCP01/ N. Sea	Radio Tower 5800mmx3500mm steel grout, steel bots M56
2006	ROV	90	Conoco Phillips/Subsea 7/Viking Troll/ N. Sea - Norway	20" OD 0,5" WT pipeline (x2)
2006	Diver	135	Statoil/Subsea 7 Gulfax A Towhead, N. Sea Norway	Gulfax A HE 300B I Beams (x2)
2006	Diver	49-65	Pioneer Natural Resources/Tetra Technologies/DB1/GoM	48" OD x 1,5" WT Leg + 42" OD x 1,5" WT Pile (x2) Jacket

DWCS RECORD
(December 2009)

Year	Assisted by	Water Depth (m)	Customer Location	Project Details
2006	ROV	500	BP/Subsea 7/Foinaven West Shetland/MSV Nordica	10" Water injection Pipeline Repair (273mm x 15,9mm +2,5mm PE external +10mm chromium internal coat- pipeline (x2)
2006	ROV	135	Sonsub UK/ Skinfaks Rimfaks/Normand Cutter/ Offshore Norway	273mm x 15,9mm +50mm coat pipeline chromium 13% (x4)
2006	Diver	55	Phoenix International Inc./Min Pass 185/Kimberly Candles/GoM	30" OD Multistring conductors (x7)
2006	ROV	1824	BP E&P/Canyon/Northern Canyon/GoM	11" x 2"WT+ 7" Coat (x2) + 17" x 1/2" WT (x1) pipelines
2006	Diver	65	Exxon Mobil/Mc Dermott/Tidal Seligi A Field -West Malaysia	18" x 0,372 + 2" concrete coated pipeline (x4)
2006	Diver	120	Mariner Energy/South Marsh Island 66 GoM/S/S Uncle John	30" Multistring conductor
2006	Diver	27	Tetra Technologies/Vermillion 412/T. Arapaho/GoM	57" OD x 0,750" WT Leg + 54" OD x 1,250" WT Pile (x4) Platform
2006	Diver	65	Marmeid/CUEL/Mermaid Commander/Offshore Sagkhla- Thailand	16 3/4" x 3/4" + 1 3/8 concrete coated pipeline (x3)
2006	Diver	+5m	Besix Kier JV/Pembrokeshire/surface	Reinforced concrete pile 22" x 3 1/4 " (13)
2006	Diver	170	CNR International/Subsea 7/Lyell N. Sea/Borgsten Dolphin	20" Caisson cutting (x1)
2006	ROV	133	CNR International/Subsea 7/Lyell N. Sea/Borgsten Dolphin	5" Drillstring cutting (x1)
2006	Diver	30,5	Newfield Exploration Company/Superior Gale/ GoM	30" Multistring conductors cutting (x9)
2006	Diver	70	Mariner Energy/Eugene Island 314/ S/S Uncle John/GoM	24" Multistring Conductor (x2)
2006	--	--	Total/Technip/Technip yard Westhill Aberdeen	435,5mm OD, 310mm OD X60 c/w polyprop coating pipeline cut trial (x2)
2006	ROV	--	Statoil/Acergy CUT site Aberdeen	125mm chain link cutting test (x1) - Contingency contract
2006	ROV	--	Langeled - Statoil/Acergy site Aberdeen	44" x 1" +3" Reinforced Concrete Coat Langeled pipeline cutting trial (x1)
2006	--	--	Saipem/Sonsub/Houston Base	48" OD x 1/2" WT trial pipe cutting (x1)
2006	Diver	90	Subsea 7/ Rockwater 1- N. Sea	219,1 mm OD x 23,8 (x3), 219,1mm OD x 23,8mm WT + 55mm coat (x4), 168,3 OD x 11mm WT (x2) pipelines
2006	--	--	Sonsub UK/ CUT UK Base Aberdeen	10 3/4" OD pipe 13% chromium cut test (x1)
2006	ROV	640	Chevron/Saipem America/ M/V Normand Cutter- Green Canyon 237 GoM	26" OD x 0,880" WT Typhoon Tendon (x1)
2006	ROV	140	Subsea 7/N. Sea/ Sedco 704	Contingency 3" dia chain link
2006	Diver	+3m	Herbosh-Kiere Marine Contractors/Hail ken Point, Milford Haven- SW Wales/Skerchi/Samson	30" Reinforced concrete piles (x35), Steel Pile (x1)
2006	Diver	10-50	Horizon Offshore/Cal Dive Intl./Main Pass 289/Atlantic Horizon SAT XI	Platform Leg 39" OD 3" WT (x8) pipeline 24" x 1" + 2,5" Coat (x3)
2006	--	--	BP Exploration & production/Canyon Off./Canyon Base	OCGS 15607, GC 743 - 2 Sections wellhead guide base
2006	ROV	1000	Global Ind. Off./EEK/Green Canyon 298 GoM/D/B Emily Candies	4,5" + polyurethane +0,2" coat pipeline (x2)
2005	--	--	BP Exploration & production/Franks Yard/Lafayette, LA - USA	Multistring Conductor 36" x 1,5" + 24" x 0,625" + 18 5/8" x 0,5" + 14" x 0,75" Trial Cut

Year	Assisted by	Water Depth (m)	Customer Location	Project Details
2005	Diver	80	Apache/Tetra Applied Technologies Main Pass 296-A-Gom/DB Swing Thompson	Platform legs 46" x 1 1/4" + 42" x 5/8"(x8)
2005	ROV	1829	BP/Oeaneering Intl./M/V Edison Choust/Mississippi Canyon 777 GoM	Thunderhorse 7,6" Shackle (1 FAT + 1 Offshore)
2005	ROV	1064	Shell/Transocean/Oceaneering/Intl/Deepwater Nautilus/Green Canyon 434 GoM	21" Riser (x2); 6" ½" line (x10); 3 ½" line (2); 4 ½" line (x2)
2005	Diver	140	Shell Penguins/Subsea 7/Toisa Polaris/N. Sea	8" OD c/w plastic coat (x3); 10" OD c/w plastic coat (x6); 24" OD c/w plastic coat (x7) pipelines
2005	Diver	130	Total/All Seas/Stolt/Seaway Osprey/Block 3/15 – N.Sea	Pipe in pipe: 510mm OD + Ixoflex sleeve+477mm OD with PU resin + 381mm OD pipeline (x1); 444.5mm OD + Shrink Sleeve+381mm OD pipeline (x2)
2005	ROV	70	Murphy Oil/Oceaneering/Ocean Epoch Offshore Malaysia	30" Wellhead contingency
2005	Diver	--	Total/Stolt Offshore/MCP01 Truss Removal	FAT Tests of tailored machines on reinforced concrete sample
2005	Diver	50	Petronas Carigali Vietnam/Barabada Mc Dermott/DB30 Offshore Vietnam	10 ¾" ND + 65mm coated pipeline (x8)
2005	Diver	10	Gulf Oil/Seawind Diving/Wellard Barge/Petroplus Jetty 1 Milford haven S/W Wales	610mm OD + 245 or 250 mm OD + 140 mm OD grouted piles (x5); 705 to 765 mm OD piles steel piles (x7)
2005	Diver	70	Anglo-Suisse Offshore Partners LLC/West Delta 117D/Gom	36"+16"+13 3/8"+7" Multistring conductors (x5)
2005	ROV	2000	PGS/Fugro Survey/Schihallion/Olympic Hercules N. Sea	5 ½" OD Spiral Wire (x2)
2005	Diver	98	PGS/Subsea 7/MCP01/Pelican N. Sea	813mm OD pipeline (x4)
2005	Diver	61	St. Mary Land & Exploration Co./West Cameron 542/Rig Todco 253/GoM	Wellhead Recovery 36"+20"+13 3/8"+ 9 5/8 Multistring
2005	Diver	30	New Field Oil Co./Tiburun Divers/Eugene Island 182/M/V Joe G. Jr./GoM	30" +20"+13 3/8"+ 9 5/8" Multistring conductor (x5)
2005	Diver	3-10	BP/Fairweather Pacific Inc/PRC-421/Carpenteria CA USA	36" +24" Multistring (x2)
2005	Diver	77	Anadarko Petroleum/Eugene Island 296 A/Cal Diver II/GoM	45 ¾" jacket legs (3)
2005	Diver	33	Forrest Oil/Cal Dive Inc./Main Pass 98/GoM/L/B Myrtle	72" OD Caisson (2) + 30" Multistring Conductor (1)
2005	Diver	36	Brunei Shell Petroleum/Master Tech/Offshore Brunei/Imam Armada	8" OD x 9.5 mm WT pipeline (x2)
2005	RO V	100	Total/Aker M.C./Botnica/Frigg DP2 North Sea Norway	1422 mm OD Main + 1067 mm OD inner piles - corner leg (x1) onshore and offshore test cut
2005	--	--	Total/Aker M.C./Frigg DP2 Onshore FAT	1422 mm OD Main + 1067 mm OD inner piles - corner leg (x1) onshore 550 ton compression test cut
2005	Diver	3	Mærsk Oil and Gas AS/Stolt Offshore/Seaway Osprey N. Sea	813 mm OD Bumper Bar Support (x3)
2005	--	--	Shell Pulau Bukum (Refinery)/Singapore	48" OD Tower cutting
2005	ROV	14	MISC / Talisman/Subsea 7/DSV Rockwater 2/Malaysia	92mm chain link
2005	ROV	370	Statoil/Stolt Offshore/Seaway Eagle/Norway	Guide post 8,6" OD 2,36" WT + 20mm wire

DWCS RECORD
(December 2009)

Year	Assisted by	Water Depth (m)	Customer Location	Project Details
2005	ROV	1000	CNOC/Global Industries/Offshore Shenzen (PRC)	12" coated pipeline, 20" coated pipeline contingency
2005	Diver	23	Murphy Oil/Bisso Marine/Ship Shoal 167-GoM	Caisson 72" + 48"+ 30"+ 16" + 10 3/4 OD
2005	ROV	1664	Unocal/Oceaneering/Ocean Baroness/Hivaman 1	13 3/8" Casing
2005	Diver	40	Total/Skandi Patagonia/Tierra del Fuego	22" OD Pipeline cutting
2005	--	--	Rainbow Mechanical/Abu Dhabi	Haseloy C heat Exachanger pipes cutting (x3)
2005	Diver	18	Edison/Marine Consulting/M/B AD3/P.to San Giorgio M4 Adriatic Sea	26" (12), 24" (4) OD piles, 30" OD Multistring Conductors (4)
2005	ROV	--	Texaco/Oceaneering/ Offshore Nigeria	8" Drllstring contingency
2005	ROV	1173	Unocal/Oceaneering/Ocean Baroness/Indonesia	13 3/8" Casing
2005	ROV	1108	Unocal/Oceaneering/Ocean Baroness/Indonesia	13 3/8" Casing
2005	ROV	400	ENI/Oceaneering/DSV Island Frontier/Kristiansund Norway	21" Riser+ Choke and Kill Lines +Buoyancy = 39" OD
2005	--	--	CHIYODA/Shell Pulau Bukum (Refinery)/Singapore	10m OD Cracking Tower with refractory mesh
2004	Diver	190	ENI/Sonsub/Bar Protector-Normand Cutter/Bahr Essalam Libya	12" (1), 22" (5), 10" (3) OD Pipeline cutting
2004	Diver	10	ENI/Marine Consulting/MV Pigafetta-Palinuro 2/Gela- Italy	12" OD + polyethylene + expanded foam + concrete coating pipeline cutting (17)
2004	Diver	88	PMS/Subsea 7/N. Sea UK/Mayo/Tamasah NW	12"(3), 14"(2), 6" (3), 32" (2), 36" (1) OD Pipelines cutting
2004	Diver	126	Total/Subsea 7/Toisa Polaris/Frigg	32" NCP01 SPUR Line c/w f4,8mm fibreglass and 47,6 concrete coatings
2004	ROV	127	Statoil/Subsea 7/Toisa Polaris/Norway	6"x 7,5mm + 6mm coating (x12) Pipeline
2004	Diver	10-12	AGIP/Marine Consulting/Palinuro II/Gela	34" x 0,5" WT + 192mm Coating pipeline (x16)
2004	ROV	449	Unocal/Ocean Baroness/Sadewa 4 - Indonesia	13 3/8"X 0.75 Casing
2004	ROV	866	Oceaneering/Grand Canyon/Ocean Interventer/GoM	22" Multistring well 22"x3/4" + 5"x1" (x1)
2004	--	--	BSP Brunei/Kuala Belait	Multistring conductor Demo test 30"x1"+13"5/8x0,5"+9"5/8x0,5"+7"x0,5"
2004	--	--	Woodside/Clough Engineering/CUT Base Singapore	12"3/4x5/8" + 36 mm coating pipeline FAT (x1)
2004	--	--	BP/Sonsub US Workshop	4" OD x 1" pipeline FAT (x1)
2004	--	--	TS Base/Workshop Genova	Test trials for new generation wires and DWCM's (pipelines range 12" to 20" - 4 cuts)
2004	ROV	1448	Oceaneering/Ocean America/GoM	36"x1"1/8+20"x3"+5"1/8 x1" Multistring well
2004	Diver	78	Conoco Phillips/Subsea 7/Ekofisk - Growth/Seaway Osprey/N. Sea Norway	20"X 0.75" +60mm coat pipeline (x4)

Year	Assisted	Water	Customer	Project
	By	Depth m	Location	Details
2004	Diver	45	Talisman/Subsea7/Beatrice B/Pelican/N.Sea pipeline tie ins	6" x1" +1" coat pipeline tie-ins (x4)
2004	Diver	33	W&T Offshore/Eugene Island EI 384 E/GoM	Multistring conductor 30"+9"5/8+7" (x15)
2004	ROV	2434	Chevron Texaco/Oceaneering/DW Discovery	8" x 2,5" WT drill string
2004	ROV	330	Subsea 7/N. Sea Norway	16" Pipeline cutting (x2)
2004	Diver	92	Shell/Subsea 7/Toisa Polaris/N. Sea	Z spool cutting 219mm x 13.2mm (x3)
2004	Diver	71,5	Tetra S P 89 A/Caldiver II/GoM	Platform legs 91"x 2" + 84" x2",5 (x8)
2004	Diver	59	Chevron Texaco/American Constitution/GoM	WC 564 Severing Project 74,5" OD Leg with 5 x 16" Multistring conductors (x1)
2004	ROV	1642	Unocal/Oceaneering/Ocean Baroness/Rang Gas 7	16" OD casing (x1)
2004	ROV	74	BP/Oceaneering/N. Sea Global Artic IV	8" x 1" WT pipeline cutting (x2)
2004	--	--	Stazione Marittima Spa/Genova Harbour	Cutting of mooring bollard
2004	Diver	46	Marathon/Oceaneering/S. Pass 89 A/Ocean Project	Leg A2 53" (+48"+36"piles), Leg B1 51,25" (+48"+24"piles), 20" OD multistring
2004	Diver	26	Perenco/Cameroon KBC1/Gulf Fleet	30" OD Conductor (x1)
2004	ROV	1012	Shell/Stolt Offshore/Bonga field /Seaway Polaris	15.27" OD + 12,28" Pipe in Pipe with 4mm plastic coat
2004	ROV	1751	Unocal/Oceaneering/Ocean Baroness	16" OD casing (x1)
2004	--	--	BP/Oceaneering/Eugene Island 322/Onshore tests	48"OD (x1), 53" OD + 46" OD (x1) stepped cut
2004	ROV/Diver	27-35	BP/Oceaneering/Eugene Island 322/Ocean Service.- Intervention	Production and Drilling Jackets (2) toppling/Diagonals 24" OD (x17), Legs 51 1/4" + Piles 48" OD (x8, 4 stepped), Sump Caisson 36" OD
2004	ROV	1829	Unocal/Oceaneering/Ocean Baroness/Gula 3	16" OD casing (x1)
2004	ROV	137	Agip/Thales/Sea Explorer - Bredford Dolphin/Offshore Libya	30" OD WT 1" Piles (x3) - 36" OD x 1" WT (x15)
2004	ROV	579	Torch Offshore/GoM/Midnight Wrangler	4.5" OD Pipeline cutting (x3)
2004	--	--	Shell Pulau Bukum (Refinery)/Singapore	Cracking tower orbital cutting test (x2)
2004	ROV	1913	BHP/Oceaneering/GoM/Glomar Explorer	22" casing and 5" Drill pipe
2004	ROV	1005 -719	Japan Oil/Oceaneering/Atsumi-A1-Wjapan/Jobes Resolution	5" Drill string cutting (x2)
2004	Diver	17	Saipem/Sonsub/Offshore Sicily/Sentinel - Castoro 6	37,5" OD Pipeline cutting (x107)
2004	ROV	1338	Heerema/Oceaneering/GC 645/Bolder	6,5" mooring chain (x2))
2004	Diver	110	Hyundai/Hallin Marine/Ulsan/Hyundai 423	17.5" + 3"coat pipeline (x3)
2003	ROV	Tank	Heerema/Oceaneering/Morgan City	6.5" Chain cutting test
2003	ROV	1024	All Seas/Oceaneering/Pioneer/Gulf of Mexico	10.75" OD pipeline (x27)
2003	--	--	BP/Wood Group/Aberdeen - NW Hutton Top side decommissioning	Test trial on 36" OD pipe with wires, beams, square profiles etc.(x2)
2003	Diver	13	Frazer Diving/Pagerungan/Clementine	23" OD pipeline (x2)
2003	Diver	80	Walter O&G/Stolt/Am. Constitution/West Delta 111	84" OD WT 2,5" Caisson

DWCS RECORD
(December 2009)

Year	Assisted	Water	Customer	Project
	By	Depth m	Location	Details
2003	--	14	SBC Subottomcutter final Trial/Ulsteinvik Norway	36" OD WT 11mm pile cutting - 2,6m below seabed soil
2003	ROV	1846	BP/Transocean/Oceaneering/Discover Enterprise Mississippi Canyon 778 G.o.M.	6,5" (x17) + 3,5" (x6) +6" (x10)+ 21" (x5) Marine Riser recovery project
2003	Diver	121	Woodside/Technip/N. Mankin/Trunkline /Venturer	30" + 2" Coated Pipeline (x3)
2003	--	14	SBC Subottomcutter final Trial/Ulsteinvik Norway	36" OD WT 11mm pile cutting - 2,6m below seabed soil
2003	ROV	300	Torch Offshore/Garden Bank 240/GoM/Midnight Wrangle	3,5" coiled tubing (x5), 4,5" Coiled tubing (x9), 3,5" pipe (x4), 4" Umbilical twin armour, thermoplastic(x3)
2003	ROV	200	Shell UK/Draugen/Seaway Osprey	18" Inconel Bolt - Back up
2003	Diver	18	Shell Nigeria/Adamac/Kye/DB Dolphin Port Arcourt	41"+ 36"+ 30"+ 3" Legs (x3)
2003	Diver	109	Unocal/Stolt/Vermilion 410/Seaway Defender	60" Leg (x2), 48" Pile (x3), 30" multistring (x2)
2003	ROV	350	Amerada Hess/Stolt Offshore/Seaway Kestel GoM	8" + 2" plastic coated pipeline
2003	Diver	5	Army Corp of Eng. /Kokosing/Barge RST C/S 009	Reinforced concrete 26" jetty piles (x29)
2003	ROV	76	Phillips/Subsea 7/Ekofisk/Botnica	24" Coated pipeline (x4)
2003	ROV	350	N. Hydro/Technip-Coflexip/Fram West/Geobay	20" Pipeline (x6)
2003	Diver	110	Shell/Claymore/Rockwater 1	14,5" Coated pipeline (x4)
2003	Diver	85	BP/Subsea 7/Machar/Rockwater 1	30" multistring conductor
2003	Diver	65	TotalFinaElf/Stolt Offshore/DLB 801Eugene Island	259 A Eugene Island Platform removal Back-up
2003	--	--	TotalFinaElf/Stolt Offshore	TFE Platform removal FAT (x2) (42"+36" OD Pipes)
2003	Diver	24	Diamond Services/TS & B/ Huber/USA	72" and 48" OD Multistrings (x1)
2003	Diver	23	Unocal/Marsh Island/ RAM II/USA	30" OD (x1) and 24" OD (x1) Multistrings
2003	Diver	17	AGIP/RANA/ASSOSEI/Civitanova Marche	36"+20" casings (x1)
2003	ROV	1830	Unocal/Oceaneering/Ocean Baroness/Gehem 1	13 3/8" OD casing (x1)
2003	Diver	11	AMGA/CPL Concordia/Genova Harbour	Breakwaters wall reinforced concrete (x5)
2003	Diver	137	Statoil/Subsea 7/DSV Seway Osprey/Grane	30" OD (x2) + 20" OD (x5) pipelines
2003	Diver	137	Statoil/Subsea 7/Seway Osprey/Gulfaks Leak Site	12" ND + 55mm Coating pipeline
2003	ROV	300	Statoil/Stolt Offshore/DPV Viking Poseidon	14" ND+ 55mm coating pipeline (x7)
2003	Diver	103	Texaco/Technip/Captain UTM Orelia	5" OD x 1" wt Pipeline (x2)
2003	ROV	300	Unocal/Oceaneering/Ocean Baroness/Bangau	13 3/8" OD casing (x2)
2003	--	--	Shell valve demo cutting	Inconel Valve block -piping (x3)
2003	--	--	New d. wire & 30" DWCM Superlight demo CUT AS	24" OD wt. 22mm + 50mm concrete coated pipe (x2)
2003	ROV	16	Qatar Gasline/UAE/Seamec 1	16" OD pipeline (x2)
2003	ROV	99	Stolt Offshore/Sanha Field/Angola	30" OD + 20" Multistring Conductor

DWCS RECORD
(December 2009)

Year	Assisted By	Water Depth m	Customer Location	Project Details
2003	--	--	New concept diamond wire development project	No. 74 steel samples 100x120x10,2 mm
2003	ROV	900	All Seas/Gulf of Aqaba	36" OD X65 steel coated Pipeline contingency cutting
2003	ROV	1300-1500	Stolt Offshore/GOS Phase 2/Angola/Seaway Polaris	12 3/4" OD PP coated Pipeline contingency cutting
2002	ROV	--	KerrmcGee/J.Ray McDermott Inc.	400T Shackle onshore FAT/demo(x3)
2002	Diver	67	Exxon Mobil/McDermott/TAPIS A/EMPI Platf./DB26	6" ND Pipeline c/w coating (x3)
2002	ROV	240	Halliburton / Gaul Project	Custom DWCM - Removal of ships rudder(2)
2002	ROV	1100	BP/Svinoy well abandonment/Fareo-West Navion	36” Multistring conductor back-up/ Self powered DWCM Stand alone system
2002	ROV	250	Stolt Offshore USA/VIOSCA KNOLL /Seaway Falcon/ROV Sea King	6" Drill string
2002	ROV	224	Stolt Offshore/La Ceiba Field/Seaway Eagle	16" OD Bent Spool piece (x2)
2002	ROV	340	N. Hydro/Subsea 7/ MV BOTNICA	11" OD Pipeline (x31)
2002	ROV	350	N. Hydro/Subsea 7/Heidrum Platform	14" OD Pipeline
2002	Diver	140	Talisman/Subsea 7/Claymore South/Rockwater 1	12,5" ND Pipeline coating FBE 20 (x6)
2002	ROV	95	N. Hydro/Stolt Offshore / Far Saga	Tune Flowline 18"OD polypropylene/nylon coat (x26)
2002	ROV	95	N. Hydro/Subsea 7/ Oseberg Field/NORDICA	Tune Flowline 18"OD polypropylene/nylon coat
2002	ROV	1230	KerrmcGee/J.Ray McDermott/East Breaks/DB50	400T Shackle (x3)
2002	ROV	--	Halliburton / Gaul Project	Custom DWCM - Removal of ships rudder/onshore FAT/demo (3)
2002	ROV	300	Statoil/Stolt-Halliburton/Asgard/DSV Viking Poseidon	14"ND 2"wt c/w plastic coat (x4 subsea, x5 on board)
2002	Diver	146	Shell/Halliburton/Brent "C"/MV Toisa Polaris	26" ND 1"WT c/w 2" coating(x3)
2002	Diver	48	BP/Mc Dermott/West Java Arguira Field/Indonesia	12" ND c/w 1 1/2" coating (x2)
2002	ROV	230	Oceaneering /Platform Southern cross MARI B Template Offshore Israel	30" OD x 40mm WT Pile cutting (x2)
2002	ROV	120	N. Hydro TUNE/Halliburton/DSV Nordica	Thune flowline 12" ND(x6)
2002	Diver	22	Exxon Mobil USA/ J-up Carl Norberg/GoM MP74B	96" OD Caisson c/w no. 7x30" OD multistring conductors (x2)
2002	--	--	Exxon Mobil USA	30" OD Pipe cutting test
2002	--	--	Shell USA/Global Manatee	10" + 6" OD c/w foam pipe in pipe surface cutting (x2
2002	ROV	1728	Murphy/Oceaneering/Ocean Baroness/Bagang Field	5" Drill string cutting
2002	ROV	--	Stolt Offshore/Burullus Offshore Egypt	EPRS for emergency cutting of 4", 10", 20" lines
2002	ROV	--	N. Hydro TUNE/DSND	12" OD Pipeline cutting
2002	ROV	--	All Seas/Australia	EPRS for emergency cutting of 14" pipelaying
2002	ROV	1568	Petrobras/Campos Basin/SCS Seaway Harrier	6" ND Flexible lines (x2)
2002	ROV	300	Statoil/CSO AS/Skandi Inspector/Asgard K101	13" OD Pipeline cutting polypropylene coated (x4)

DWCS RECORD

(December 2009)

Year	Assisted By	Water Depth m	Customer Location	Project Details
2002	ROV	118	N. HydroTUNE/Halliburton/Geofjord	Thune flowline 12" ND (x2)
2001	Diver	80	Shell Baram 8 Miri, Malaysia	Wellhead removal, 32"x16"x10"x 7
2001	ROV	1350	BP Amoco/CSO USA - Nile project	EPRS Pipelines 12-16-&18" ND FBE coated
2001	ROV	560	Stolt Offshore/La Ceiba Field/Triton	19,75" c/w polyurethane 46mm thick coat pipeline (x4)
2001	Diver	10	Despe Porto Marghera Harbour	Reinforced concrete pillars T-Wall sections (x6)
2001	--	--	Hallin Marine/Singapore	Super duplex 6,65" OD pipeline demonstration cut
2001	--	--	NKK/Singapore	12" WT 12mm demonstration cut
2001	ROV	106	Ancana/Dominion/Burin -Thebaud S.	WDC Manifold D - 7 & 9" OD pipe special cutting (x3)
2001	ROV	116	N. Hydro/Stolt-Halliburton/MV Geobay	Thune flowline PL1 - PL2 12" ND(x4)
2001	Diver	30	Clyde/UWG/ENSCO 85 P12-C	Well Aband. Progr. - 30" OD Multistring conductor
2001	Diver	35	CPC/Touch/Giant CBK 11, CBK 12, CBK 13	Legs/plies 60"/54" (x4) - 54"/48" OD (x8) - 20"cond. (x4)
2001	Diver	5	TOTAL/KOMARITIM/N.Makam Delta/Awarna	24"OD (x5), 18" OD (x6), 16" OD (x5)
2001	Diver	65	Esso/TL Offshore/Terengganu/DB 26	16" OD pipeline (x3)
2001	Diver	40	BP PT KOMARITIM/N.W. Java Punai	15" OD WT 1/2" + Coat 2" (x4)
2001	ROV	298	Statoil/ Halliburton Subsea/Maxita	12,5" OD Ausgaard Pipeline (x2)
2001	--	3	DEVON/TWATCHMAN SNYDER & BIRD/USA	Devon Energy 72” Multistring jacket legs (x2)
2001	ROV	120	N. Hydro/Stolt-Rockwater/ DSND SUBSEA A/S	Vesterlled 32" OD riser + 32" OD coated pipeline (x8)
2001	--	--	N. Hydro/Stolt-Rockwater JV Vesterlled	Vesterlled Pipeline 33” OD Pipe FAT Test
2001	Diver	20	PERENCO/Offshore Cameroon	30" OD Multistring conductor
2001	Diver	13	Agip/Adriatica Sub	2500 mm OD c/w 30" Casing Monopile Flavia (x2)
2001	Diver	13	Agip/Adriatica Sub	1500 mm OD c/w 30" Casing Monopile Fulvia (x2)
2001	Diver	80	Talisman Claymore/Hall-S./Rockwater 1	30" pipeline (x10)
2001	ROV	105	N. Hydro TUNE/DSND/NORDICA	33" Riser (x2)
2001	Diver	25-30	BP "C" PT Komaritim Pgerungam Island	8" gas line cutting (x5)
2001	Diver	80	Statoil Tommeliten/Halliburton/SeawayOsprey	12" (x2), 9" (x3), 6" (x2) Duplex, 30" Ms. conductor
2001	--	--	Statoil Tommelitten/Halliburton Subsea	36,8" OD Pipe (x3) FAT
2001	Diver	18-42	Talisaman/Halliburton/ Rockwater 1	Beatrice16" pipeline cutting (x4)
2001	--	--	Statoil/Halliburton-Stolt Alliance	Tommelitten template 36" piles test
2001	--	--	BP Amoco/CSO USA - Nile project	Pipe in pipe 10,75" + 6,625 " OD, FAT (x2)
2001	Diver	80	Halliburton/Subsea/Beatrice/Semi2	16” Rubber coated pipeline (x4)
2001	ROV	120	Elf/CSO/ Lille Frigg 3 XMT	Bolts and sleeves (no 24)
2001	--	--	Elf/CSO Lille Frigg 3 XMT	Bolts and sleeves (no 24) + inn sleeve FAT
2001	Diver	120	Total /CSO/ CSO Apache	16” OD J Tube (x1)
2001	--	--	Total /CSO	Nugget 16" OD J tube cut test (x1)
2001	--	--	Maersk/Aquamarine Danish Sector	30" OD Multistring conductor back-up

DWCS RECORD
(December 2009)

2001	ROV	1450	Texaco/Ocean Deepw. Discovery Nigeria	7" OD drill string (x1)

Year	Assisted By	Water Depth m	Customer Location	Project Details
2001	ROV	--	Stolt Offshore	10", 12", 18" Girassol Project pipe-lay contingency
2001	ROV	1100	BP Amoco/CSO USA - Nile project	EPRS Pipe in pipe 10,75" + 6,625 "
2000	Diver	18	PT Komaritim/Indonesia/ISOL Challenger	6" OD Pgerungam pipeline repair cut
2000	Diver	30	Mc Dermott Mumbai High Platform	Risers 12" (x6), 12,75" (x13) 14" (x12,7 Monel)
2000	Diver	90	Texaco UK/CSO/Alliance	24"+16" Pipeline in pipe (x8)
2000	Diver	120	Talisman/CSO/Wellservicer	Water Injection project 8" OD pipe (x9)
2000	ROV	350	Elf NO/Halliburton Subsea/Far Sovereign	16" pipeline cutting (x7)
2000	Diver	30	BHP/DSND/Irish Sea Pioneer	12" pipe (x1)
2000	--	--	Onyx e Marbres Granules SA - S. Beat France	no. 9 Marbles wells
2000	Diver	120	Talisman/CSO/Orelia	8" OD pipe cutting (x3)
2000	Diver	110	Talisman/Halliburton/Toisa Polaris	32" pipeline cutting (x2)
2000	Diver	25	M. Dermott/W. Natuna/DB26	14" (x2) and 22" (x2) Pipelines cutting
2000	Diver	25	M. Dermott//W. Natuna/E Intermac	28" (x1) and 22" (x2) Pipelines cutting
2000	Diver	90	CSO/Durward & Duntless/Orelia	10" pipeline cutting (x4)
2000	Diver	--	CSO/Durward & Duntless/Orelia	8" pipeline cutting test (x1)
2000	ROV	350	Halliburton/SSOL/Shell Draugen/Maxita	16" pipeline cutting (x3)
2000	ROV	650-820	All Seas/Malampaya	Emergency pipeline cutting
2000	ROV	350	Norske Hydro/SCS/Troll	18 5/8" Casing (x6)
2000	ROV	5	Norske Hydro/SCS/Troll	18 5/8" Casing cutting test (x1)
2000	Diver	25	M. Dermott/Singapore/West Natuna	28" Pipeline cutting (x8)
2000	Diver	80	M Dermott/Oceaneering India	16" (x4), 12" 10"(x2) pipe/riser
2000	--	--	Halliburton/SSOL/Aberdeen	4" Pipe cutting test (x1)
2000	--	--	Halliburton/SSOL/Aberdeen	16" Pipeline cutting test (x1)
2000	--	--	Halliburton/SSOL/Aberdeen	INCONEL 725 S. Bolt 100mm cut test (x4)
2000	Diver	90	Texaco UK/CSO/ORELIA	24"+16" Pipeline in pipe (x2)
2000	--	--	Texaco UK/CSO/Aberdeen	24"+16" Pipeline in pipe (x1)
1999	Diver	125	Elf/ UK/CSO/Well 14/19-19	30" Multistring conductor (x3)
1999	Diver	20	S.Aramco/M.Dermott/DB27/Ar. Gulf	12" flowline cutting (x2)
1999	Diver	20	S.Aramco/M.Dermott/DB27/Ar. Gulf	6" flowline cutting (x6)
1999	Diver	20	S.Aramco/M.Dermott/DB27/Ar. Gulf	8" flowline cutting (x7)
1999	Diver	20	Kvaerner Cement. / Bharuch-India	48" Piles cutting (x9)
1999	--	--	Total Ind./PT Komaritim Balikpapan	16" pipeline surface cutting (x9)
1999	Diver	10	Total Ind./PT Komaritim Balikpapan	16" c/w c. coat pipeline cutting (x1)
1999	Diver	210	Shell USA - Offshore California	10 ¾" Pipeline cutting with u/w HPU
1999	--	--	Shell USA	10 ¾" Pipeline c. test with u/w HPU
1999	Diver	60	All Seas - Nova Scotia (Canada)	26" ND Pipeline cutting
1999	--	--	BP Foinaven/SCS/Barrow	Flange + studs 10.75" FTA cut test
1999	Diver	40	Walter Oil & Gas USA	30" Multistring Conductor cutting
1999	ROV	100	Phillips/Subsea NORGE	8" ND Coflexip lines (x4)
1999	ROV	250	SSSOL/ETAPS	8 5/8" Guide Post (x3)

DWCS RECORD
(December 2009)

Year	Assisted By	Water Depth m	Customer Location	Project Details
1999	Diver	--	OSMCS/USA – Long Beach	Cluster piles cutting (x6)
1999	--	--	OSMCS/USA – All Seas	16” OD Pipe c. test. Active wedge (x1)
1999	Diver	40	WINMAR/USA	48” OD Caisson Cutting (x1)
1999	Diver	40	WINMAR/USA	82” OD Caisson Cutting (x1)
1999	ROV	-	SSSOL/ETAPS - Aberdeen	8 5/8” Guide Post Cutting test (x3)
98/9	Diver	15	SAIPEM ASIA & EMC J.V. – China	14”OD Pipe Cutting (x10)
1998	--	--	SAIPEM ASIA & EMC J.V. – China	14”OD Pipe Cutting test (x1)
1998	--	--	WINMAR/MITCHEL/USA	36” OD Pipe Cutting test
1998	--	--	WINMAR/MITCHEL PTF/USA	81” OD Pipe cutting test (x2)
1998	Diver	2	BARRACUDA SUB/Viareggio	30” Reinforced Concrete piles (x4)
1998	--	--	WOODSIDE/TRITECH/Australia	8 5/8” Guide Post cutting test (x1)
1998	ROV	80	PPCon/SubSea Norge	30” OD Multistring J Tube cutting (x4)
1998	ROV	80	PPCon/SubSea No/Viking Troll	9.5” OD Coflexip line cutting
1998	Diver	15	ETPM/MC DERMOTT Nigeria	24” wt 1/2” Coated Pipeline (x15)
1997	--	--	All Seas Engineering BV/Rott.am	20” wt 1” Pipe Cutting test (PRT)
1997	--	--	Pemex/Oceanographia - USA	36” wt 1 1/4” Pipe cutting test
1997	--	--	Conoco/Coflexip Stena	6” Duplex Pipe cutting test
1997	Diver	40	ELF PETROLAND	30” Multistring conductor (Precision cut)
1997	Diver	40	NAM/EMC/Castoro 6 - Stephaniturm	10” + 2” Concrete Coated pipeline (x6)
1997	ROV	375	OCEANEERING A/S Norway	3” Chain cutting - Back up
1997	Diver	40	ARCO/IEV Indonesia	Tripod 48” conductor + 36”(+18”)+36” legs
1997	Diver	35	ETPM/MC DERMOTT	16” + 2” coating pipe cutting (x10)
1997	Div/ROV	75	GUPCO/I.N. W./Red Sea	30” Conductor string cutting
1997	--	--	AMOCO/AOC/LOMOND Platform	Pad-ear cutting (x1)
1997	--	--	Shell/All Seas/Gulf of Mexico	12” OD Cutting test - 20Lit/min flow
1997	--	--	BAKER O.T./CONOCO/Aberdeen	24” Conductor string cutting test
1997	--	--	BAKER O.T./TS Workshop Genoa	24” pipe (x1) cutting test
1996	--	--	BAKER O.T./CONOCO/N. Sea	13” and 9” casings cutting (x2)
1996	--	--	BAKER O.T./TS Workshop Genoa	24” pipe (x2) + steel plates (x4) c.test
1996	ROV	1.600	Shell/All Seas/Gulf of Mexico	Wet Buck. Cont.cy 6”-16” pipes
1996	--	--	Thomas T. & Sons Ltd/Inverurie	Reinforced concrete block (x3)
1996	ROV	30	Conoco/Seaway H.L./VIKING A Ptf	VIKING - 24” Conductor (x2)
1996	ROV	30	Conoco/Seaway H.L./VIKING Platform	VIKING - 36” Pile cutting (x8)
1996	--	--	Conoco/Seaway H.L./Aberdeen	VIKING - 30” Pile cutting test (x2)
1996	Diver	150	MSR/Coflexip Stena/Emerald	30” Wellhead /30” Conductor string
1996	Diver	150	MSR/Coflexip-Stena/Aberdeen	Emerald Platform Removal/Back-up
1996	Diver	140	MSR/Coflexip-Stena/Aberdeen	Esmond Platform Removal/Back-up
1996	Diver	25	Hamilton/Coflexip-Stena/Orelia	12” pipe (x8) - 30” conductor (x1)
1996	--	--	Thomas T. & Sons Ltd/Inverurie	Reinforced concrete block (x1)
1996	ROV	259	Statoil/Ocean. /SS Tr. Prospect	C /K lines (4), 30” Riser (1), hoses (2)
1996	ROV	--	Noble Drilling/BP Forties 40 Alpha	7 5/8” Casings - Back up
1996	--	--	MSR/Coflexip-Stena/Aberdeen	6” OD flexible pipe cutting test (1)
1996	ROV	191	MOBIL/Oceaneering/Equatorial Guinea	10” OD guide post cutting (x4)

DWCS RECORD
(December 2009)

1996	--	--	BP/Wood/SCS Aberdeen	16” OD pipe 25° angle cutting test

Year	Assisted By	Water Depth m	Customer Location	Project Details
1996	Div/ROV	75	GUPCO/I.N. W. /Red Sea	20” Conductor string (x2)
1995	--	--	Shell/Cameron/CSO	8,5” OD G. Post cutting test (x1)
1995	ROV	140	GLOBAL/OC./SEDCO FOREX	Drill strings cutting (x2)
1995	ROV	135	TEXACO/SEDCO EXPLORER	6 5/8” OD pipe cutting
1995	ROV	140	Shell/Stolt Comex Seaways	Choke kill lines cutting (x2)
1995	ROV	180	EMC/SSO/British VIKING/Troll	75mm c. frame (x4)+200mm pipe (x2)
1995	Diver	30	CONOCO VIKING/N. Sea	24” Conductor string
1995	ROV	335	SAGA/SONSUB/SNORRE TLP	Drilling strings cutting (x9)
1995	ROV	--	Shell /Oc./Stephaniturm/N. Sea	Corrosion Cup -Back up
1995	ROV	305	STATOIL/Bar Protector/N. Sea	Cup+Seal (J tube)
1995	ROV	80	Shell UK/SSO/Stadive/N. Sea	Brent/SPAR Chain (x2)
1995	ROV	--	Shell UK/SSO/ Stadive/N. Sea	Brent/SPAR Chain cut back-up
1995	--	--	Shell UK/SSO/Aberdeen	Brent/SPAR Chain c. test (x2)
1995	--	--	Gulf Circle/Abu Dhabi	R. Concrete blocks d. test (x3)
1995	--	--	Gulf Circle/Abu Dhabi	30” Conductors demo test (x2)
1995	--	--	STATOIL/CHTS/Aberdeen	Europipe pr. - 16” p. c. test
1995	--	--	All Seas/CHTS/Aberdeen	Troll project - 16” pipe c. test
1995	--	--	CHTS/Aberdeen	16” pipe c. test
1995	ROV	115	UGLANDS/SSO/Armada N.Sea	I beams (2000x600x25) (x2)
1994	--	--	UGLANDS/SSO/Aberdeen	I beam test (2000x600x25)
1994	--	--	HeereMac/Aberdeen	24” pipe, I beam, piston tests
1994	Diver	5	M/V Energy/Genoa Harbour	Propeller blade (bronze)
1994	--	--	Circle Hire T.S./Aberdeen	24” pipe c. test
1993	--	--	Circle Hire T.S./Aberdeen	24” pipe, I beam c. test
1993	Diver	106	Texaco/SOL/North Sea	30” conductor string
1993	Diver	0-70	Texaco/SOL/North Sea	48” caisson (x10)
1993	--	--	Texaco/SOL/Ravenna	48” caisson test
1993	Diver	0-12	Repsol/Tarragona	10 to 50” pipes (x26)
1993	--	--	Rockwater/Aberdeen	20” pipe, engine test
1993	Diver	60	Total/Makasar Straits	30” conductor string (x2)
1993	--	--	Total/Indonesia/Singapore	30” conductor test
1993	Div/ROV	104	Smit/Red Sea	SIDKI 12”+18” risers (x4)
1993	Div/ROV	104	Smit/Red Sea	SIDKI 30”+24” conductors (x10)
1992	Diver	22	Smit/North Sea	M/V Stora
1992	--	--	Smit/Ravenna/Rotterdam	M/V Stora tests
1992	ROV	600	NOS/Jonian Sea	20” pipe SAS
1992	--	--	NOS/Ravenna	20” pipe SAS test
1992	30	30	Seaway/Off. Nigeria	Albaz J/U legs
1992	Diver	15	Furlanis/Trieste	48” OD Sealines (x2)
1992	Diver	15	Furlanis/Trieste	60” OD Sealines (x2)
1992	Diver	25	Agip/Adriatic Sea	1800mm OD Monopile Ptf. (x3)
1991	--	--	Agip/Ravenna	1200mm OD pipe c. test
1991	Diver	45	Agip/Adriatic Sea	12 (x2), 10” OD risers (x2)

1991	Diver	35	Agip/Adriatic Sea	4 legs jacket (x3)

Year	Assisted By	Water Depth m	Customer Location	Project Details
1991	Diver	45	Agip/Adriatic Sea	8 legs jacket (x1)
1993	Div/ROV	104	Smit/Red Sea	SIDKI Platform legs (x4)
1990	--	--	TS/Ravenna	12, 16” pipes test (x6)

Appendix K

GL Noble Denton

Decommissioning Capability Profile

Oil & Gas

GL Noble Denton

Capability Profile

DECOMMISSIONING OF OFFSHORE PLATFORMS

GL Noble Denton

Overview

GL Noble Denton is one of the most experienced marine and engineering consultancies in the decommissioning and removal of offshore structures. Over the last ten years, in the Aberdeen area, GL Noble Denton has provided support to platform removal operations from desktop assessments through offshore supervision to the provision of staff for package receipt in onshore disposal yards. Decommissioning activities supported have ranged from entire platforms in the Northern North Sea to individual packages and isolated appraisal wells.

The decommissioning process phases supported by GL Noble Denton range from feasibility studies through ITT preparation and tender review to project execution.

Feasibility Studies, Costing Exercise and Planning

GL Noble Denton has supported early decommissioning planning activities on many North Sea platforms including :

- NW Hutton – concept studies on jacket removal, risk assessments for various removal options including derogation
- Brent steel jacket and concrete gravity base structures – refloat, leg removal and cell remediation appraisals
- Amethyst platforms – cost estimates for platform removal including comparison between Southern North Sea and Gulf of Mexico
- Miller platform – conventional and single piece removal feasibility studies and technology maturity appraisals
- Murchison and Ninian Northern – removal and onshore receipt of decks and jackets
- Wellhead Platform - support in development of heavy lifting strategy

This phase of the work forms a key component in the decision making process for selection of the preferred decommissioning option.

Engineering and Preparatory Work

The process of engineering and procedural review forms a key part of the warranty process. In addition to this, GL Noble Denton has provided substantial engineering and management services.

- Offshore condition and readiness surveys
- Technical and marine reviews of equipment and vessels
- Design checks on structural and marine aspects of operation
- Witness trials and function testing of new equipment
- Support in presentation of submissions to DECC and the HSE

Offshore Supervision

GL Noble Denton Aberdeen typically provides offshore supervision through both client representatives and marine warranty surveyors.

- On the platform before and during lifting operations
- On the lifting vessel from prior to field entry through to demob
- Including on site approval of marine operations
- May include a presence during towage for critical operations

Disposal Yard Activities

Receipt and process of packages removed from the platform is an important and highly visible stage in the decommissioning process.

- Yard procedures must be in place and must reflect Client requirements with regards safety and the environment
- In some cases yard modifications and / or additional equipment is required in order to receive and process platform waste
- Rapid turnaround of cargo barges may be critical in order to prevent delaying offshore removal activities
- Receipt of packages onshore may be challenging due to shape or condition

Key Benefits of Working with GL Noble Denton

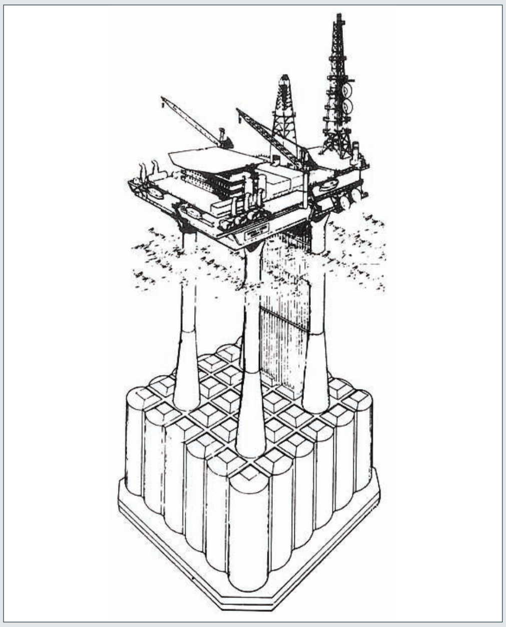
GL Noble Denton is uniquely positioned to provide platform removal guidance, support and supervision through.

- In depth experience with recent North Sea removal projects
- Involvement in all phases of the process from feasibility to onshore receipt
- Marine assurance, safety and security management
- Breadth of corporate expertise in platform removal operations including design, project management and execution
- The Aberdeen office incorporates multiple disciplines including Naval Architects, Structural, Marine, Electrical and Instrument Engineers

Highlighted Platform Removal Experience and Study Work

Brent Charlie

Brent Charlie was installed in 1978. The platform comprises a steel deck with a Seatank design concrete gravity base structure. Production is expected to continue until around 2014. GL Noble Denton has provided consultancy services in removal of the gravity base structure and in remediation of oil residues from the base cells.



Water depth	142 m
Deck weight	22 000 te
MSF weight	11 000 te
Number of well slots	40
Accommodation	200
Substructure weight	291 000 te
Number of legs	4
Drill cuttings mound	Yes

Indefatigable

The Shell operated section of Indefatigable field was brought onstream in 1971 and ceased production in 2004. GL Noble Denton is currently providing MWS for the removal of these six platforms.

Water depth	31 m
Deck weight (total)	4 661 te
Max module wgt	1 132 te
Well slots (total)	26
Accommodation	196
Jacket weight (total)	6 861 te
Max jacket weight	916 te
Piles (total)	38
Drill cuttings mound	no

GL Noble Denton

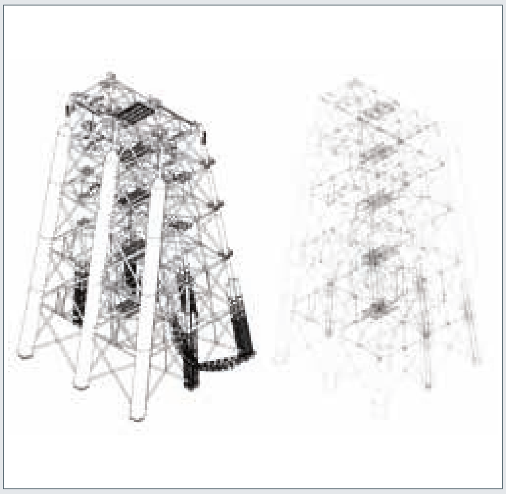
Miller

Miller platform was installed in 1991 and production continued until 2007. GL Noble Denton has provided consultancy services including appraisals and technical risk assessments of the various single piece and conventional removal concepts potentially applicable to removal of this platform.

Water depth	103 m
Deck weight	29 000 te
Number of well slots	40
Accommodation	196
Jacket weight (including footings)	18 000 te
Number of legs	8
Number of skirted piles	20
Drill cuttings mound	yes

Brent Alpha

Brent Alpha platform was installed in 1976 / 1977. Production is expected to continue until around 2014. GL Noble Denton has provided various consultancy services to the project including a refloat feasibility assessment for the jacket.



Water depth	140 m
Deck weight	16 600 te
Number of well slots	28
Accommodation	141
Jacket weight (including footings)	20 000 te
Number of legs	6
Number of piles	32
Drill cuttings mound	yes

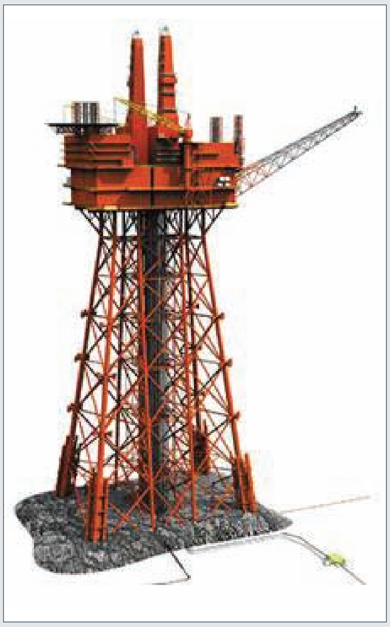
Murchison

Murchison platform was installed in 1979 and production is expected to continue until around 2014. GL Noble Denton is providing a range of consultancy services regarding removal of this platform.

Water depth	156 m
Deck weight	24 000 te
Number of well slots	40
Accommodation	198
Jacket weight (including footings)	26 700 te
Number of legs	8
Number of skirted piles	20
Drill cuttings mound	yes

Recently Completed North Sea Decommissioning Project

Project: NW Hutton Platform Removal
Client: BP Aberdeen
Location: Northern North Sea and Able Teeside



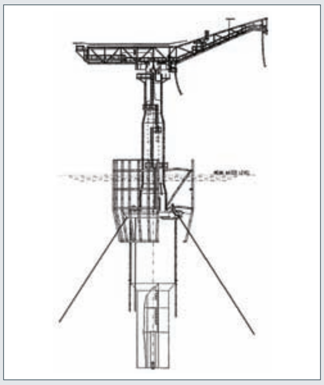
Challenge:
The N.W. Hutton platform was commissioned in 1983 and was in the hostile northern North Sea in 143m of water roughly half way between Shetland and Norway. The eight leg 17,500 tonne steel jacket supported a modular topsides with a combined dry weight of approximately 20,000 tonnes.

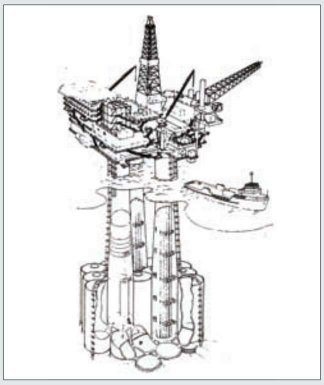
During the summers of 2008 and 2009 Heerema's semi-submersible crane vessel "Hermod" and a small fleet of flat top barges removed the topsides and approximately two thirds of the jacket structure of the North West Hutton platform. Overall the removal of N.W. Hutton represented one of the most challenging decommissioning projects tackled by the offshore industry to date.

Role:
GL Noble Denton acted as Marine and Engineering Consultant to BP during the preparatory phases of the project including assessing potential removal options and reviewing the pros and cons of derogation for the damaged jacket base section. During the removal GL Noble Denton provided Marine Warranty Surveyors both on the Hermod and at the dismantling yard at Able Teeside.

GL Noble Denton Decommissioning Project Experience (Aberdeen Office)

Year	Client	Project Title
2010	Fairfield Energy	Dunlin A Leg Removal Study
2010	CNR	Murchison and Ninian Northern Platform Removal Marine Services
2010	Perenco UK	Welland Platform Removal Heavy Lift Management
2010	Shell UK	Brent Alpha Jacket Refloat Feasibility Study
2010	Shell UK	Brent Charlie Attic Oil Removal Concept Study
2009	BP (Norge)	Valhall VRD Decommissioning
2009	BP (Aberdeen)	BP Miller Removal Technical Maturity Study
2009	Venture Production	Kittiwake Drilling Mast Removal Marine Assurance
2009	BP (Aberdeen)	Southern North Sea / Gulf of Mexico Platform Removal Comparison
2009	Venture Production	Kittiwake SAL Removal
2009	Talisman	Montrose A Rubicon Drilling Package Removal MWS
2009	BP (Aberdeen)	SNS Platform Decommissioning Study Removal of Amethyst Platforms
2009	Shell UK	Indefatigable Field Decommissioning Marine Assurance and Warranty
2008	Mobil North Sea	Linnhe Field Decommissioning Marine Warranty
2008	BP (Aberdeen)	North Everest TAD Skidbase Removal Marine Assurance and Warranty
2008	Venture Production	Kittiwake Loading Buoy Decommissioning Marine Warranty
2007	BP (Aberdeen)	Technology Review of Single Lifter Concepts for Removal of the Miller Platform
2007-2010	Shell UK	Shell Brent GBS Decommissioning
2006	BP (Aberdeen)	Magnus Flare Deck Removal Marine Assurance and Warranty
2005-2009	BP (Aberdeen)	NW Hutton Decommissioning Marine Assurance and Warranty
2005	TK Navion	Ardmore Field SALM Recovery
2005	BP (Aberdeen)	NW Hutton Decommissioning Support (FEED phase)
2005	BP (Aberdeen)	BP Miller Platform Removal Independent Comparative Assessment of Topsides and Jacket Removal Options
2005	BP (Aberdeen)	DB101 NW Hutton Lift Study
2005	Paladin Expro	Montrose A Drilling System Replacement Marine Warranty
2004	BP (Aberdeen)	Don Decommissioning Marine Assurance and Warranty
2002	BP (Aberdeen)	Schiehallion Blackstart Generator Removal Marine Assurance and Warranty
1999	BP (Aberdeen)	NW Hutton Independent Marine Review of Jacket and Topsides Removal by HLV
1998	Kerr McGee	Hutton TLP Removal Marine Warranty





Contact Details:

Don Orr
Principal Naval Architect
Direct: 01224 289177
Email: don.orr@nobledenton.com

Kevin Grant
Head of Engineering Execution
Direct: 01224 289120
Email: kevin.grant@nobledenton.com

GL Noble Denton
No.1 The Exchange
62 Market Street
Aberdeen
AB11 5PJ

Tel: 01224 289100
Fax: 01224 289101

The global independent
technical advisor

www.gl-nobledenton.com | Email glnobledenton@gl-group.com

16008_NS 22.02.2011

Appendix L

Offshore Design Engineering (ode)

Decommissioning Capability Profile

INTRODUCTION

ode has over 30 years of international experience providing comprehensive consulting, engineering, construction, project management and operations support services to the offshore oil & gas and wind energy industries. ode is structured with four operating divisions:

- Consulting
- FEED & Basic Engineering
- Projects
- Operations Support

ode's breadth of expertise delivers innovative, cost effective and robust technical solutions, with access to technical and project support from its two shareholders Saipem S.A and Doris Engineering S.A.

ode provides its Clients with a broad-based capability and support across the full project life-cycle from early conceptual and feasibility studies, through FEED and basic engineering to detailed engineering and design, procurement, construction and operations support, decommissioning and dis-investment. Project delivery is assured through ode's Project Management, SHEQ and risk management processes and capability.

DECOMMISSIONING CAPABILITY

ode has an extensive range of expertise and experience gained during successful participation in decommissioning projects. The projects have encompassed a wide range of decommissioning related activities, including:

- Due diligence cost review through to end of field life
- Planning and execution of marine operations for heavy lifting, refloat and towing activities.
- Detailed preparations prior to removal from the offshore location
- Planning and execution of afloat deconstruction of gravity base structures in deep water sheltered location
- Complete demanning and remote operation of platforms,
- Preparation for re-use or deconstruction and recycling of waste streams.

This depth of experience has been applied to both onshore and offshore facilities and particularly relates to the following areas:

- Legislative requirements
- Permits and consents
- Facility shutdown prior to decommissioning
- Decontamination and preparation for decommissioning
- Redeployment and re-use of facilities and equipment
- Offshore marine operations
- Deconstruction methods

- Recycling of materials
- Handling and disposal of hazardous waste

Given the complex legal framework and the high profile of decommissioning operations in the oil and gas sector, ode adds value to Clients' projects by the comprehensive planning of the process and the preparation of the requisite documentation and engineering. The range of services available comprises comprehensive technical and commercial expertise for the decommissioning of offshore and onshore facilities, including:

- Project management
- Planning and cost estimation
- Formal identification of BPEO
- Risk analysis & decommissioning options
- Drafting of abandonment programmes
- Writing decommissioning safety cases
- Environmental impact assessments:
- Environmental accounting
- Planning, engineering, and supervision of decommissioning marine operations
- Work-pack preparation
- Selection of removal and disposal contractors
- Construction/deconstruction supervision

DECOMMISSIONING PROJECT EXPERIENCE

ode has had involvement with approximately thirty decommissioning projects. A selection of completed decommissioning projects is included below. Further details can be provided if required.

ExxonMobil – Decommissioning of Camelot CB Platform

ode's scope included a review of the Camelot CB platform to determine the scope of work for the removal of all hydrocarbons and decommissioning of the platform for the HLV contractor to remove the topsides and jacket. The pipelines and wells had been previously disconnected.

The work consisted of the detailed review of all equipment on board, determining hydrocarbons remaining, and developing procedures for the removal of all hydrocarbons and the cleaning of the equipment.

Equipment had to be cleaned such that the platform could be brought onshore for disposal without presenting a hazard to the environment. In addition, ode produced a plan for the overall decommissioning project. A HAZID and HAZOP addressed the risks associated with the lifting and removal of equipment as well as the potential to produce explosive atmospheres.

ode was responsible for all offshore supervision of the decommissioning process and produced detailed work scopes and detailed job cards for offshore implementation, including:

- Removal of submersible pumps

- Cutting of caissons
- Isolation of process equipment
- Testing of padeyes
- Phased removal of control and telecommunications systems to allow remote surveillance during periods when platform was unmanned
- Phased removal of the electrical system, navigational aids and safety equipment, ensuring platform conformed to the safety case up until the point of removal
- The sea fastening of all remaining panels, generator exhausts and loose equipment

ode was responsible for closing out all of the offshore work-packs and producing completion certificates to demonstrate that all of the work had been undertaken correctly and completed satisfactorily.

A detailed inventory including types of material, weights and coatings of all steel, pipework, electrical and instrumentation equipment, cladding, insulation, etc, was produced to ensure that as much as possible would be recycled by the disposal contractor.

Although the jacket and topsides were transported to Teesside, ode prepared detail plans and located potential sites in the Great Yarmouth area where the jacket and topsides could have been landed and stored. This required discussions with local councils, port authority and environmental agencies.

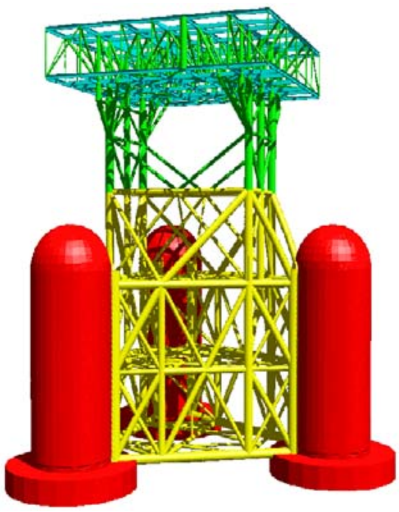
ConocoPhillips – Maureen Platform Refloat

ode undertook the study in two phases, with the first phase having two objectives:

- To develop a thorough understanding of all the factors involved in a successful refloat of the Maureen platform comprising the steel gravity substructure and topsides. In parallel with this, to identify the potential risks and determine the levels of danger which the platform might sustain during the refloating operation, and to formulate effective solutions to avoid or mitigate these risks
- To develop a refloating simulator which enabled a real-time visualisation of the refloating operation under various conditions, and which was suitable for quantitative risk assessment, equipment specification and training, and for publicity purposes.

These two objectives defined two major deliverables:

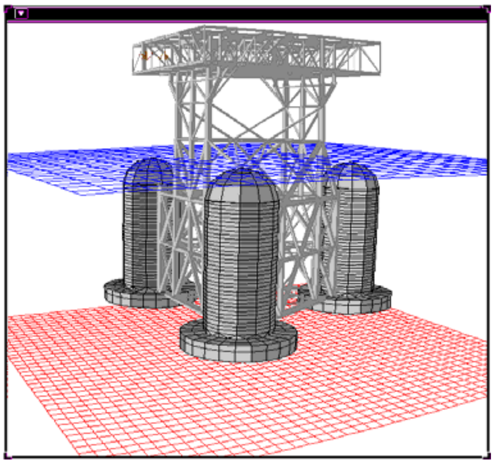
- An engineering analysis of the platform considering a number of refloat stages
- A refloating simulator.



The engineering analysis was performed with the help of two modules: a naval architectural module to determine the hydrostatic characteristics and the motions of the platform, and a structural module to determine the structural stresses resulting from hydrostatic and hydrodynamic loads, seabed constraints and platform accelerations. Both of these modules received their input data from a common data generation module in order to ensure full consistency and sharing of data.

The refloating simulator consisted of a fourth module which received information from the naval architectural and structural modules and displayed it in visual form on a screen.

The primary computer analysis was undertaken using the MOSES suite of programmes, with supplementary detailed finite element analysis of selected jacket nodes using ALGOR. Reference should be made to the attached computer diagrams.



Phase two of the work was intended to develop a practical refloat procedure taking into account all the potential risk scenarios. For this purpose the existing piping systems onboard the platform were reviewed for possible re-use and the following specific topics were examined:

- Foundation breakout (water injection/ deballasting)
- Platform hydrostatic stability
- Tank deballasting
- Ballast water volume control
- "What if" scenarios
- Pre-refloat systems and equipment checks.

Note: ode's parent company Howard Doris was involved with the original installation of Maureen in 1983

ConocoPhillips – Maureen Platform Decommissioning

ode provided engineering personnel to work within the Client project team to control and monitor the activities of the contractor selected to carry out the removal and dismantling of the Maureen Alpha Platform and associated peripheral equipment.

The project team provided assistance to the contractor on how the platform was to be removed, the sequencing of activities, and recovery of technical details relating to the platform for the Client's archives.

All contractor calculations and purchase orders were reviewed for technical and commercial acceptability. Key stages of the supply and operations were witnessed.

The approvals process was maintained with the various permits and consents being tracked and obtained in time to ensure that the project could progress to schedule.

The contractor's control of material and environmental accounting procedures were defined and reviewed to ensure compliance with the decommissioning plan.

The key operations covered during these phases of the project were:

- Detailed design, procurement and installation of pump, nitrogen and control systems required to refloat Maureen Alpha
- Extraction of Maureen Alpha from the seabed and float up to the surface
- Handling of potentially polluted ballast water and shipment to onshore terminal
- Tow of Maureen Alpha to deepwater inshore site
- Removal of Moira subsea template
- Removal of subsea flow lines

- Removal of Maureen subsea template
- Removal of ALC offloading column and abandonment of 24” pipeline in situ
- Mooring of Maureen Alpha and ALC in sheltered location
- Heavy lift of modules from Maureen deck and head of ALC
- Rotation of ALC to horizontal, removal of its base and preparation for re-use as a breakwater
- De-mating of the Maureen Alpha deck, and its skidding onto quayside for dismantling
- Staged deconstruction while floating and re-cycling of Maureen Alpha substructure
- Deconstruction and re-cycling of Maureen Alpha topsides
- Re-use of lower sections of storage tanks as foundation for quayside extension

Throughout these operations the technical, environmental and safety issues were monitored and controlled by the ode personnel integrated into the Client team.

International Oil Company – Decommissioning Study for Gulf of Suez Assets

A major international oil company with assets offshore Egypt required an assessment of the provision that should be made for the future decommissioning of its platforms, pipelines and terminals in the region.

ode carried out a review of the international, regional and local legislation controlling the decommissioning of these assets.

Work breakdown structures were developed for the decommissioning activities required for three ‘typical’ offshore structures, wells and associated pipelines.

Estimates were made of the expected cost and schedule to complete the decommissioning activities based on the use of North Sea practices for P&A of the wells, platform preparation for removal, diving operations, lifting operations and pipeline removal.

The same work breakdown structures were used by consultants with extensive experience of Gulf of Mexico practices to produce comparable estimates. The differences in working practices, contracting strategies, and the technical requirements for well abandonment were highlighted.

KEY ode TEAM MEMBERS

Stewart French

Stewart has 25-years experience in the design, construction and decommissioning of offshore steel and concrete structures, offshore wind farms, pipelines and tanker moorings. Duties have included field evaluation studies, conceptual and detailed design, and supervision of contractors during design and construction, marine operation engineering, decommissioning, contract administration and project management. Stewart is currently Head of ode Consulting Business Stream and responsible for the quality, applicability and level of innovation of work carried out. He is registered as mentor with engineering institutions and actively involved in the professional development of engineering staff.

Stewart has carried out project management of consultancy and design projects, and has been seconded to client teams for design verification, site management and bid evaluation, completed detailed structural analysis design and carried out marine operation planning and execution. He has extensive experience in all stages and aspects of project work from conceptual, FEED, detailed design, construction, transportation and installation, brownfield modifications and decommissioning, working for the contractor, the client and in verification roles.

Specific experience includes:

- Engineering and design of offshore oil and gas structures, both subsea manifolds and jackets
- Planning and execution of marine operations for offshore oil and gas structures (jacket, gravity base and suction anchor designs)
- Decommissioning of offshore facilities including a refloat project
- Selection and design of offshore wind turbine and transformer platform foundation structures
- Installation for offshore wind farm structures
- Preparation of decommissioning plans for presentation to the DTI, detailed steel design.
- Decommissioning cost estimation and planning.

Steve Palmer

Steve is responsible for ode's consultancy business in London and has been involved in the offshore industry, both overseas and in the UK, for over 25 years.

He is responsible for all aspects of ode's consultancy services including, conceptual engineering and strategic studies, FEED and basic engineering, project management services, cost estimating and economic analyses, decommissioning and health, safety, environmental and risk management services.

Steve's offshore experience includes:

- Provision of execution strategies and commercial support for various offshore wind farm developments including support for Round 3 submissions.
- Due diligence, facilities assessments, CAPEX/OPEX estimates and field development planning support for numerous onshore and offshore oil and gas developments in the UKCS, West Africa and Far Eastern regions.
- Decommissioning studies for offshore installations and advisory role to the Thailand government.
- Decommissioning studies for West Africa oil and gas field installations.
- Study Manager for the conceptual design of a large (c. $2 billion) oil and gas development in the Caspian Sea. The study required the technical definition and full field development CAPEX/OPEX estimates incorporating fixed platform and floating options, together with the drilling and onshore terminal facilities.

- Study Manager for the decommissioning of the PPCo Bacton onshore reception facilities. Study included all technical and HSE aspects for the decommissioning of the facilities to a green field site. This required a comprehensive review of all planning and consents, purging and decontamination, demolition and remediation activities, together with the preparation of partner liability assessments and a sanction grade cost estimate.

Mike Banning-Lover

Mike has thirty three years' experience of project & contract management, engineering, planning, cost estimating, construction and tendering for all types of facilities for the offshore oil & gas industry, in Europe, Canada, India, Southeast Asia and Australia. Recent experience has included project management, contracts and estimating assignments for subsea/floating production developments and major decommissioning projects. He is familiar with all aspects of offshore oil and gas development and decommissioning, from conceptual studies to direct management experience of offshore installation works. Mike published the paper "Load Adjustment and Weighing of Maureen Deck",, presented at Offshore Weight Engineering Conference, Aberdeen, December 1983.

Mike's experience includes the following projects:

- Project Manager for conceptual study for the afloat deconstruction of Shell Brent Delta concrete gravity base.

- Project Manager for EPC contract for the provision of a subsea piping and controls manifold to Total Forvie Field development.

- Deputy Project Manager for detail engineering and procurement services for the South Pars Phase 4 and 5 wellhead platforms for AGIP Iran.

- Project Services Manager in charge of management cost and progress reporting for detailed engineering, procurement of equipment and marine operations subcontract to Exmar on behalf of TotalFinaElf Libya for the FPSO to be operated in Field 137B offshore Libya.

- Senior Project Engineer for a major JIP study with Sonangol of FPSOs for deepwater applications offshore Angola on behalf of BP, Chevron, Esso and TotalFinaElf. Responsible for the identification of historical costs, cost reduction measures and typical project schedules.

- Principal Engineer responsible within Doris Engineering for the preparation of offshore testing requirements, turnkey cost estimates, risk assessments and schedules for alternative decommissioning options for the Frigg Field TP1 & CDP1 platforms for Elf Petroleum Norge a.s. (Phase 1 1999, Phase 2 2000).

- Senior Contracts Engineer for Fina Exploration Ltd. for the contract & tender document preparation and including tender evaluation, clarifications and negotiations with contractors for the Otter Field Development (subsea tie-back and FPSO).

- Principal Engineer for the preparation of tender documentation for the Maureen Field Decommissioning (Platform and ALC refloat and tow, Moira pipeline/umbilical removal, and drill cutting protection) for Phillips Petroleum Co. UK.

George Stenhouse

George is a Project / Construction Engineer and has been with ode since 2004. He has over 30 years' experience in gravity-based, piled, floating and subsea structures, pipelines, and multi-disciplined engineering of offshore oil, gas and wind farm projects.

George's decommissioning experience includes the following:

- Detailed decommissioning study for the Shell Indefatigable Field in the Southern North Sea.

- Decommissioning studies of all Talisman's forty three UK and North Sea Assets.

- Decommissioning study of BP's Chirag platform and pipelines offshore Baku in the Caspian Sea for project and commercial purposes.

John Daines

John has over 20 years experience in project engineering and co-ordination roles, the majority of which associated with offshore related projects in the Southern North sea. John's other experience includes working with site projects such as at the Bacton Gas Terminal. The roles have included construction management, client representation, project engineering/co-ordination and supervision.

Projects include:

- Construction Manager for the East Orovinyare Platform A project on behalf of GGPC GABON (EOV) Limited.
- Construction Manager for the brownfield modifications on the Exxon Mobil Thebaud gas platform in the Sable field, for acceptance of a new platform with compression facility.
- ExxonMobil Shutdown Coordinator responsible for platform shutdowns for the Thames & LAPS fields and Camelot A. Co-ordination, planning and supervision.

ode GENERAL RESOURCE

ode currently employs around 300 multidiscipline personnel, including a high proportion of principle and lead engineering staff. ode has a policy of maintaining a high proportion of staff employees and this is reflected in the approximate 45/65 split between staff and contract personnel. The high level of senior staff personnel reflects the objectives of ode's business, which is to assign quality, experienced resources that are reliable and competent, and generate value for our clients in whatever work environment they are in. In house resource includes the following categories:

Project Management Personnel

- Project managers
- Construction managers
- Project engineers

Engineering & Design Personnel

- Process
- Mechanical
- Plant Layout
- Pipeline (Onshore and Offshore)
- Structural
- Civil
- Electrical
- Control & Instrumentation
- Telecommunications
- Safety

All supported by 3D CAD modelling capability using PDMS and with access to PDS.

Project Services Personnel

- Procurement
- Contracts administration
- Planning & scheduling
- Cost control
- Cost estimating
- Document control