
TECHNICAL SESSION

The Process of Decommissioning and Removing Offshore and Associated Onshore Oil and Gas Facilities

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THE PLUGGING PROCESS: SECURING OLD GAS & OIL WELLS FOR THE PROTECTION OF THE ENVIRONMENT

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INTRODUCTION

The waters off the coast of California contain a total of 27 oil and gas platforms. Of the 27, four are located in state tidelands (within three miles of the coast) and 23 are located in the Federal Outer Continental Shelf (OCS). There are also six artificial islands located in state tidelands. As the end of service life approaches for these facilities, plans for their decommissioning need to be developed.

The decommissioning process begins long before the cessation of production. An effective pre-planning program should be established at least two years before decommissioning the structure. Planning is the key to ensuring that the work performed will be effective, efficient, environmentally sound, and within the financial resources of the owners.

The scope of decommissioning work is defined through the coordinated efforts of platform operators and regulatory agencies who oversee the specific field involved. In California, these agencies are the Minerals Management Services (MMS), the Department of Conservation, Division of Oil, Gas, and Geothermal Resources (DOC), and the California State Lands Commission (CSLC).

PRE-PLANNING

The key to optimizing asset value in a decommissioning project is allowing enough lead-time to properly create a strategy that allows an operator to choose the best disposal method for their property. The considerations to

be addressed when planning a decommissioning project are as follows:

Platform/Site Evaluation

Available information regarding the site and the structure (amount of debris in the site, drawings, inspection records, etc.) will facilitate the possible sale/reuse of the platform, thus decreasing the overall liability.

Environmental Considerations

An assessment of the environmental conditions surrounding the platform site needs to be performed, thereby informing the operator how the decommissioning operations might affect the surrounding marine ecosystem.

Financial Strategy

The owner needs to know the current costs of decommissioning a facility (including well plugging and abandonment [P & A] costs) in order to accurately accrue them as a liability.

Disposal Planning

Establishing a variety of potential disposal methods allows the company to derive the optimal value from the assets being removed.

Contracting Strategy

By formulating a contracting strategy, the owner will minimize the overall costs of contracted work that will be performed during decommissioning activities.

Regulatory Requirements

The regulatory requirements for well plugging and abandonment (P & A) in California are as follows:
Minerals Management Services (MMS)

The basic plugging requirements are found in 30 CFR 250.110 Subpart G.

Department of Conservation, Division of Oil, Gas, and Geothermal Resources (DOC)

The basic plugging requirements are found in the California Code of Regulations Title 14 Division 2, Chapter 4 beginning with Section 1745.

California State Lands Commission (CSLC)

The basic plugging requirements in the California Code of Regulations Title 2 Section 2128(q).

The plugging design must meet or exceed regulatory requirements. These requirements have been developed in cooperation with industry participants through years of experience. The basic plugging requirements for all three agencies are written to have general application to all wells. In that all wells are not the same, specific procedures may be approved to fulfill these requirements.

The plugging and abandonment of offshore wells is performed by the operators of the wells with guidance provided by these regulatory agencies. In state tidelands, the DOC and CSLC directly oversee all plugging and abandonment operations. In outer continental shelf (OCS) waters, the operations are conducted under the direction of the MMS. Operators and regulatory agencies work together as a team to successfully achieve the same goals.

Shutdown Planning

An early step in the process for decommissioning is to plan cessation of production and injection operations. The operator designs a shut down plan that will allow plugging and abandonment operations to proceed without the threat of pollution. This plan is designed to safely discontinue production and secure the platform and well until the actual P & A operations can commence.

PLUGGING AND ABANDONMENT PLANNING

Synthesize Information

The plugging and abandonment of wells is one of the primary stages of a facility abandonment program. An effective plugging and abandonment procedure is critical for the proper sealing of an oil and gas wellbore to safely secure it from future leakage. Techniques used to accomplish this process are based on industry experience, research, and conformance with applicable regulatory compliance standards and requirements. The synthesis of practical knowledge, current technology, and regulatory requirements results in the most effective wellbore plugging and abandonment possible. Only by planning ahead can this occur.

When an operator determines a need to plug and abandon wells on a given facility, they begin with a review of the existing well design along with records of past work, well past performance, and geological and reservoir conditions. The operator investigates all items that may relate to health and safety issues as well as regulatory requirements. The operator then designs a program based on reservoir and existing wellbore conditions. This will allow the operator to plan an abandonment program that will satisfy the goal of making the wells safe from future leakage and preserving the remaining natural resources.

Inspection and Testing

A preliminary wellbore / wellhead inspection and survey should be performed to document present conditions. All of the valves on the wellhead and tree are checked to ensure operability; if not, they will be hot-tapped.

A slickline unit is then installed to check for wellbore obstructions, to verify measured depths, and to gauge the internal diameter of tubing. The slickline unit is also used to pull safety valves as needed. A slickline unit is a machine with a hydraulically controlled spool of wire used for setting and retrieving safety valves, lugs, gas lift valves, and running bottom hole pressures. Slicklines are also used for a variety of other jobs such as recovering lost tools and swedging out tubing.

The slickline unit is then removed and a well service pump is installed to fill annuli and tubing with fluid to establish an injection rate into perforations and/or to pressure up tubing and casing to check for integrity. Casing annuli are also pressure tested to check for communication problems between casing strings and to record test pressures over a period of time.

Well Containment Plan

The operator must design a well containment plan. This plan includes determining the current reservoir condition and includes establishing contingency responses to events that may occur while working on the well.

Anytime work is performed on a well, there is a chance that something might go wrong. However, proper planning and use of appropriate safety equipment can reduce the potential for problems.

An important piece of equipment on the wellbore is the blowout prevention equipment (BOP). If the well head tree is to be removed, back-pressure valves are first installed, followed by removing the tree and then installing the BOP(s). The purpose of the BOP is to be able to close down and control the well in the event of a well flow. Prior to commencing downhole operations, the components of the BOP are function tested and then pressure tested to ensure that all components are in good working order. These tests are sometimes witnessed by representatives of the MMS (for federal waters) and/or the DOC (in state tidelands).

WELL ABANDONMENT

Basic Methods for P & A

The plugging and abandonment of offshore wells worldwide has been accomplished utilizing three different P & A methods: **Rig**, **Coil Tubing Unit**, and **Rigless**.

Rig

A rig is the derrick or mast, drawworks, and attendant surface equipment (circulation system, rotating equipment, hoisting system, well control equipment, power system, pipe and handling equipment, and any additional heavy equipment required) of a drilling or workover unit. The rig is powered by gas generators or diesel engines and has a basic crew of five to six men. This type of

equipment is either a small workover rig that is brought to the site or an existing drilling derrick that is already onsite. The rig must have the rated capacity to pull the downhole equipment out of the wellbore (including casing if necessary). Using a rig to P & A a well proceeds much like a normal workover on a well.

Before working on the well, fluid is either pumped into the wellbore or circulated to eliminate any pressures that might be present. Usually back pressure valves are usually installed in the well and the tree or wellhead is removed, after which the blowout prevention equipment is installed. After testing the BOP, the tubing is pulled and the pre-planned plugging procedure for the well is followed. Well plugging will usually require a minimum of three cement plugs to control migration of fluids (gas and oil) and protect fresh water sands. If necessary, rigs have the ability to pull tubing, cut and pull casing, recover scrap, set packers or retainers, and to drill out retainers in the well.

Coil Tubing Unit (CTU)

These are small units that carry tubing coiled around a large drum. In the mid-1980's, the coil tubing operations were limited to sand cleanouts and nitrogen jet services. However, recent advances have made CTU's useable in production and abandonment operations. The units are much like rigs in that they have pumps to circulate fluid and test BOP's (on a more limited scale). Coil tubing has been successfully used to P & A wells in the North Sea, the Gulf of Mexico, Southeast Asia, and the Middle East. Today's CTU's have the ability to perform almost any type of well P & A task that arises. Contemporary units operate with 10,000 psi and come in sizes up to 2.5 inches (ID) or larger. In addition, a 15,000 psi unit has been developed.

Offshore California plugging and abandonment operations using coil tubing has, to date, been limited to use on the Rincon Piers.

Rigless Abandonment

Rigless P & A involves several steps. First, a cementing unit mixes and pumps cement batches through the tubing placed in the wellbore. This results in the placement of the first and second (of at least three) cement plugs at different depths. Wireline and electric line units assist with the placement of the two

cement plugs. The P & A crew verifies the top of cement plugs by tagging it with the slick line units and pressure testing the top of the plugs. This method is used on both the initial and secondary plug. Afterwards, the platform crane, or a portable crane, is used to remove the very top portion of tubing from the hole. The crew then pumps the third cement plug. Well casings are cut below the sea floor with an electric line and/or an abrasive cutter, mechanical cutter, or other method. The casing is then pulled by casing jacks and/or a crane.

In the final examination of each plugged and abandoned well, there are no differences in the results of rig versus rigless methods (Figures 1-4). Step one shows two identical wells that will be plugged and abandoned with each method. Step two shows these wells after the bottom plugs have been set with the tubing having been pulled out of the well. Step three shows the balanced cement plug with the rigless method and the spotted cement plug with the rig method.

It is important to remember that with the rigless method the tree is still on, while the rig method uses BOP's which have to be tested. Figure 4 shows the rigless method having cut the production casing with a CIBP (cast iron bridge plug) set with 200+ feet of cement on top. The rig shows the same with a little more casing out of the hole.

Figure 1. Typical Wellbore Schematic.

**Well P&A -
Rig vs.
Rigless**

Step 1

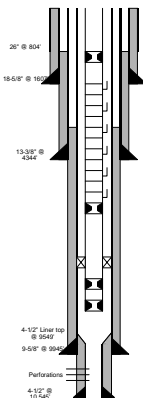


Figure 2. Bottom plugs set with tubing pulled out of hole.

**Well P&A -
Rig vs.
Rigless**

Step 2

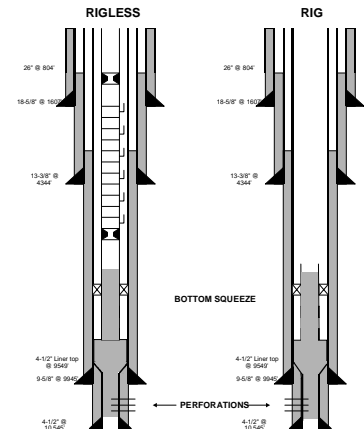


Figure 3. Balanced plug on rigless and stopped plug with the rig.

**Well P&A -
Rig vs.
Rigless**

Step 3

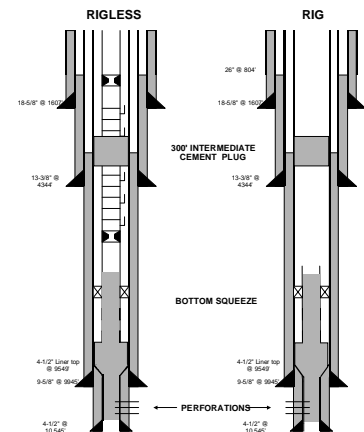
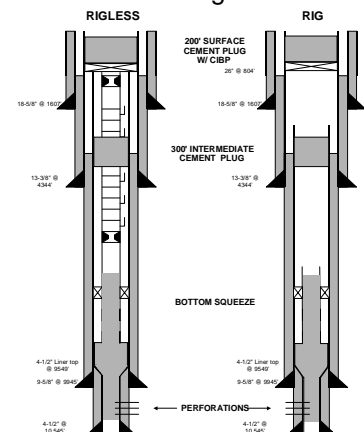


Figure 4. Rigless with cut casing and CIBP; Rig with same but with a little more casing out of hole.

**Well P&A -
Rig vs.
Rigless**

Step 4



At present, approximately five hundred wells per year are plugged and abandoned in the Gulf of Mexico (GOM) using the rigless method, as opposed to the 100-120 plugged and abandoned in the GOM using rigs. Acceptance of the rigless

method (the primary form of well P & A used in the Gulf of Mexico) has been expanded to North Sea operations to include both platform wells and subsea wells.

Although rigs have traditionally been used to plug and abandon subsea wells, several contractors in the North Sea region have experience using a diving support vessel and/or a dynamic positioning vessel for the procedure. Based on research regarding actual North Sea jobs, 3.6 days is the average time to plug and abandon non-problem subsea wells using the rigless method.

Basic Steps for Well P & A

Remove Downhole Equipment

In certain areas, like offshore California, the first step that is necessary for well P & A is the removal of the downhole equipment. This is accomplished by using a conventional workover or existing drilling rig that has the rated capacity to pull the downhole equipment from the wellbore. The operator is required to make a diligent effort to remove all downhole equipment. This includes items such as packers, production tubing, gas lift mandrels, and downhole pumps. Past work records on the well may be reviewed to determine if the effort has been made prior to commencing P & A operations. However, due to age and the conditions downhole, it is not always possible to retrieve all downhole equipment. Some of the equipment may be stuck in the wellbore due to scale, fill, or breakage. In any case, all downhole production or injection equipment that cannot be removed can be left in the well if approved by the appropriate agencies.

Wellbore Cleanout

After the downhole well equipment has been removed, a concerted effort must be made to remove the fill, scale, and other debris covering perforations that have not been previously plugged. The circulating fluid used to clean out the wellbore is required to have a sufficient density to control subsurface pressure and should have physical characteristics capable of removing the unwanted material. Additional tools or additives may be necessary to properly clean the wellbore.

Cement Plugging Methods

A cement plug is a volume of cement designed to fill a certain length of casing or open hole and

provide a seal against vertical migration of fluid or gas. There are various methods in which to place cement in the wellbore. The method used is dependent on wellbore conditions and regulatory requirements. Cement is pumped into the well (as a fluid) and placed in the desired location. Due to heat and pressure, through time (a number of hours) the cement hardens.

Plugging procedures throughout the world require a minimum of three (3) cement plugs. The first is usually the squeezing of the old producing zone to eliminate the influx into the wellbore of any fluid or gas. The second, middle plug, is usually placed near the middle of the wellbore or near a protective pipe shoe. Finally, the surface plug is installed within 200-300 feet below the mudline. Most plugs are 100 to 200 feet in length. Additional plugs are installed based on actual wellbore conditions.

Squeezing

Squeeze cementing is the most common method for plugging reservoirs. Squeeze cementing is also used in plugging and abandonment operations to place cement below "junk" that may be left in the wellbore or to get cement outside of previously uncemented (or poorly cemented) casing.

Common types of cement squeezes are the braidenhead method and the bullhead method. The braidenhead method is when cement is placed in a fashion similar to the balance plug method (see below), but then the well is shut-in and additional pressure is placed at the surface from the casing valve to force the cement further down the wellbore. The bullhead squeeze is cement pumped from the surface and forced down the wellbore by pump pressure from the surface.

Balance Plug/Displacement

This method is used for middle plug placement. The cement slurry is pumped down pipe, coiled tubing, workstring, or production tubing until the cement level outside the pipe is slightly below the top of cement (TOC) inside the pipe. The cement then falls out of the pipe, filling the void left as the pipe is slowly removed. Fluid spacers can be used both ahead and behind the cement slurry to aid in the proper placement of the cement.

Dump Bailer

The dump bailer is a tool that contains a measured quantity of cement that is lowered into the wellbore on a wireline. The bailer is opened on impact (i.e. striking a bridge plug or cement retainer, etc.) or by electronic activation. This method is limited by the volume of cement that can be placed and by the depth at which placement can occur. However, the dump bailer method does have the advantage of accurate placement of small quantities of cement (i.e., 10 to 60 feet). In state tidelands this method of placing may not meet regulatory requirements, while in federal waters no specific regulations prohibit this method of placing cement plugs (when placed in conjunction with cast iron bridge plugs).

Cement Grade and Quality

In state waters the grade and quality for the type of cement must meet standards defined by the American Petroleum Institute (API). API defines a competent cement plug as one that maintains a compressive strength of at least 1,000 pounds per square inch (psi) and a maximum liquid permeability of 0.1 millidarcy (md). The operator must have evidence that the proposed cement grade meets the minimum standards. All major cementing companies and P & A contractors use API cement. All cement grinds (batches of cement) are purchased with specification sheets showing the properties of the mixture. They also have the American Society for Testing and Materials (ASTM) C-150 Standard specifications for Portland cement explained on the same sheet (**Table 1**).

API cement comes in different classes which are based on the temperature downhole where the cement is to be placed. Cementing operations normally call for pumping in a fluid (which is the volume of the pipe depth plus 10 or more barrels) before the cement is started so that the cement will reach the desired location. After the desired amount of fluid has been pumped in, the cement is started. This procedure reduces the temperature near the wellbore (or wherever the cement is supposed to go), thereby causing a need for calculating the bottom hole temperature (BHT) when the cement arrives at the targeted depth. Some operators run lab tests on the cement before using it in the field to verify these calculations, but in doing so it is important to

remember to gather a sample of the mix water to be used (in the field) and include it in the lab test sample.

As there are many types of cements used in the plugging and abandonment of wells, the operator designs the cement slurry with three items in mind: 1) meeting the API definition for a competent cement plug; 2) meeting API recommended practices as detailed in API Spec 10; 3) creating a mixture that will perform the job in the most efficient manner.

Mud Program

All portions of the well not plugged with cement are to be filled with a fluid having a sufficient density to exert a hydrostatic pressure in excess of the greatest formation pressure in the intervals between plugs. The purpose of this fluid is to control any possible influx of formation fluids (water, oil, or gas) into the wellbore. State and federal regulations differ somewhat in the fluid that is to be placed in the intervals between plugs.

In state tidelands, the fluid must be inert, the density of the fluid must exert a hydrostatic pressure exceeding the greatest formation pressure in the intervals between plugs encountered during drilling, and the fluid must have the proper characteristics to suspend the weight material in the fluid. Excessive mud weight can be detrimental in produced or depleted wells. If produced zones are pressure-depleted or below normal pressure, excess mud density can cause a leak-off and result in the loss of well control fluid.

Federal regulations require that the fluid only have the proper density to exert a hydrostatic pressure exceeding the greatest formation pressure in the intervals between plugs at the time of abandonment.

The fluid that is used to fill all portions of the well not plugged with cement can either be mixed on-site or can be used drilling mud or completion fluid brought from drilling or completion operations (if said fluid is reconditioned). Old mud that has not been run through and cleaned is not usable for containment purposes in the wells being abandoned.

Table 1
BASIC CEMENTING MATERIALS

A basic cementing material is classified as one that, without special additives for weight control or setting properties, when mixed with the proper amount of water, will have cementitious properties. This may be a single ingredient or a combination of two or more ingredients, but they are always used in this combination of two or more ingredients, but they are always used in this combination even when special additives are used with them. The following are of this class:

Portland Cement	Pozmix Cement
High Early Cement	Pozmix 140
Retarded Cement	

API CLASSIFICATION FOR OIL WELL CEMENTS*

- Class A: Intended for use from surface to 6,000 feet (1830 m) depth* when special properties are not required. Available only in ordinary type (similar to ASTM C 150, Type I).**
- Class B: Intended for use from surface to 6,000 feet (1830 m) depth, when conditions require moderate to high sulfate-resistance. Available in both moderate (similar to ASTM C 150, Type II) and high sulfate-resistant types.
- Class C: Intended for use from surface to 6,000 feet (1830 m) depth, when conditions require high early strength. Available in ordinary and moderate (similar to ASTM C 150, Type III) and high sulfate-resistant types.
- Class D: Intended for use from 6,000 feet to 10,000 feet (1830 m to 3050 m) depth, under conditions of moderately high temperatures and pressures. Available in both moderate and high sulfate-resistant types.
- Class E: Intended for use from 10,000 feet to 14,000 feet (3050 m to 4270 m) depth, under conditions of high temperatures and pressures. Available in both moderate and high sulfate-resistant types.
- Class F: Intended for use from 10,000 feet to 16,000 feet (3050 m to 4880 m) depth, under conditions of extremely high temperatures and pressures. Available in both moderate and high sulfate-resistant types.
- Class G&H: Intended for use as a basic well cement from surface to 8,000 feet (2440 m) depth as manufactured or can be used with accelerators and retarders to cover a wide range of well depths and temperatures. No additions other than calcium sulfate or water or both, shall be interground or blended with the clinker during manufacture of Class G or H well cement. Available in moderate and high sulfate-resistant types.

* Reproduced by permission from API Spec. 10 "API Specification for Materials and Testing for Well Cements." Depth limits are based on the conditions imposed by the casing-cement specification tests (Schedules 1, 4, 5, 6, 8, 9) and should be considered as approximate values.

**ASTM C 150: Standard Specification for Portland Cement. Copies of this specification are available from American Society for Testing and Materials, 1916 Race Street, Philadelphia, PA 19103.

Verification and Pressure Testing of Plugs

Tagging TOC (Top of Cement)

All cement work is handled using calculated cement volumes to achieve the appropriate TOC.

The two methods most commonly used to ensure proper cement plug placement are: 1) use open-ended pipe to tag the plug (having previously measured the pipe and using that measurement as a point of reference); 2) use wireline tools to tag the plug and determining the TOC by looking at the counter on the wireline.

Pressure Testing Method

The pressure testing of the integrity of each cement plug by tagging it with open-ended pipe (as required by governmental regulations) has both positive and negative points:

- Pressure is exerted only on cross sections of the working pipe. This concentrates loads on the area where the pipe touches the cement;
- Reliance on the weight indicators may or may not be accurate at 15,000 psi;
- Shallow plugs might not have enough pipe weight to test;
- When using pipe weight, buoyancy factors and friction from the pipe against the casing must be taken into consideration.

Testing with pump pressure for integrity (as required) also has both positive and negative points:

- Pressure is exerted uniformly on the entire area of the plug;
- Pump pressure can be checked more accurately;
- A recorder can be installed, allowing the pressure to be recorded over time;
- Pressure is in addition to the hydrostatic pressure already on the plug;
- Individual portions of the plug cannot be tested.

Swab Testing Method

Swabbing is another method for pressure testing cement plugs. The wellbore fluid is swabbed down until the hydrostatic fluid above the plug is below the reservoir pressure gradient of the zone isolated by the plug. The fluid level is monitored for a reasonable time to ensure that the wellbore fluids have stabilized. If the fluid level has not changed, plug competency is considered verified. It should be noted that this method is used exclusively in California.

Certain particulars about the swabbing method should be reviewed. They are:

- There is the possibility of running coil tubing in the hole where displacement occurs using nitrogen. This has the same effect as swabbing;
- Swabbing requires more time than other methods;
- The cement plug could weaken when differentially tested, resulting in possible failure at a later date when fluid is reintroduced on top of the plug;
- Accurate measurements of bubble rise rates are difficult to determine when using the swabbing method.

CONCLUSIONS

By referring to past decommissioning projects and following guidelines set by regulatory agencies, a formal decommissioning plan can be developed which includes effective and efficient methodologies for plugging and abandoning wells. Although well P & A is generally considered one of the more sensitive portions of the decommissioning process, thorough pre-planning significantly reduces the number of associated uncertainties.

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Minimum Cased Hole Plugging Requirements

State (California)

1. A cement plug shall be placed opposite all perforations extending to a minimum of 100 feet above the perforated interval, liner top, cementing point, water shut-off holes or the zone, whichever is higher (1745.1[c]).
2. The location and hardness of the cement plugs must be verified by placing the total weight of the pipe string, or an open-end pipe weight of 10,000 pounds and by application of pump circulation. DOC to witness location and hardness (1745.6).
3. Inside cemented casing, a cement plug at least 100 feet long must be placed above each oil or gas zone whether or not the zone is perforated (1745.1[d]).
4. The location and hardness of the cement plugs must be verified by placing the total weight of the pipe string, or an open-end pipe weight of 10,000 pounds and by application of pump circulation. DOC to witness location and hardness (1745.6).
5. A 100-foot cement plug above the shoe of the immediate or second surface casing (1745.1 [d]).
6. The location and hardness of the cement plugs must be verified by placing the total weight of the pipe string, or an open-end pipe weight of 10,000 pounds and by application of pump circulation. DOC to witness location and hardness (1745.6).
7. A 100 foot plug across the freshwater/saltwater interface or opposite any impervious strata between fresh and saltwater zones (1745.1 [d]).
8. The location and hardness of the cement plugs must be verified by placing the total weight of the pipe string, or an open-end pipe weight of 10,000 pounds and by application of pump circulation. DOC to witness location and hardness (1745.6).
9. In the event that junk cannot be removed from the hole and the hole below the junk is not properly plugged, then cement plugs must be placed as follows (1745.2):
 - (a) Sufficient cement must be squeezed through the junk to isolate the lower oil, gas, or freshwater zones and a minimum of 100 feet must be placed on top of the junk (but no higher than the sea bed).
 - (b) If the top of the junk is opposite uncemented casing, then the casing annulus immediately above the junk must be cemented with sufficient cement to insure isolation of the lower zones.
10. Anytime casing is cut and recovered, other than for the surface plug, a cement plug must be placed from at least 100 feet below to at least 100 feet above the stub (1745.3).
11. The location and hardness of the cement plug must be verified by placing the total weight of the pipe string, or an open-end pipe weight of 10,000 pounds and by application of pump circulation. Division to witness location and hardness (1745.6).
12. No annular space that extends to the ocean floor must be left open to drilled hole below. A minimum of 200 feet of the annulus immediately above the shoe must be plugged (1745.4).
13. A cement plug at least 100 feet long must be placed in the well with the top between 50 and 150 feet below the ocean floor. All inside casing strings with uncemented annuli must be pulled from below the

surface plug. The casing must not be shot or cut in a manner that will damage outer casing strings and prevent re-entry into the well (1745.5).

14. The location and hardness of the cement plug must be verified by placing the total weight of the pipe string, or an open-end pipe weight of 10,000 pounds and by application of pump circulation. DOC to witness location and hardness (1745.6).
15. All portions of the hole not plugged with cement must be filled with a inert fluid of sufficient density to exert hydrostatic pressure exceeding the greatest formation pressure encountered while drilling such interval. DOC will test the mud to determine that it meets minimum requirements (1745.7).
16. All casing and anchor piling must be cut and removed from not more than 5 feet below the ocean floor, and the ocean floor clearing of cleared of obstruction (1745.8).

FEDERAL

30 CFR SUBPART G-- ABANDONMENT OF WELLS

250.110 General Requirements

The lessee shall abandon all wells in a manner to assure downhole isolation of hydrocarbon zones, protection of freshwater aquifers, clearance of sites so as to avoid conflict with other uses of the Outer Continental Shelf (OCS), and prevention of migration of formation fluids within the wellbore or to the seafloor. Any well which is no longer used or useful for lease operations shall be plugged and abandoned in accordance with the provisions of this subpart. However, no production well shall be abandoned until its lack of capacity for further profitable production of oil, gas, or sulphur has been demonstrated to the satisfaction of the District Supervisor. No well shall be plugged if the plugging operations would jeopardize safe and economic operations of nearby wells, unless the well poses a hazard to safety or the environment.

250.111 Approvals

The lessee shall not commence abandonment operations without prior approval of the District Supervisor. The lessee shall submit a request on Form MMS-124, Sundry Notice and reports on Wells, for approval to abandon a well and a subsequent report of abandonment within 30 days from completion of the work in accordance with the following:

- (a) **Notice of Intent to Abandon Well.** A request for approval to abandon a well shall contain the reason for abandonment including supportive well logs and test data, a description and schematic of proposed work including depths, type, location, length of plugs, the plans for mudding, cementing, shooting, testing, casing removal, and other pertinent information.
- (b) **Subsequent report of abandonment.** The subsequent report of abandonment shall include a description of the manner in which the abandonment or plugging work was accomplished, including the nature and quantities of materials used in the plugging, and all information listed in paragraph (a) of this section with a revised schematic. If an attempt was made to cut and pull any casing string, the subsequent report shall include a description of the methods used, size of casing removed, depth of the casing removal point, and the amount of the casing removed from the well.

250.112 Permanent Abandonment

- (a) **Isolation of zones in open hole.** In uncased portions of wells, cement plugs shall be set to extend from a minimum of 100 feet below the bottom to 100 feet above the top of any oil, gas, or freshwater zones to isolate fluids in the strata in which they are found and to prevent them from escaping into

other strata or to the seafloor. The placement of additional cement plugs to prevent the migration of formation fluids in the wellbore may be required by the District Supervisor.

- (b) **Isolation of open hole.** Where there is an open hole below the casing, a cement plug shall be placed in the deepest casing by the displacement method and shall extend a minimum of 100 feet above and 100 feet below the casing shoe. In lieu of setting a cement plug across the casing shoe, the following methods are acceptable:
- (1) A cement retainer and a cement plug shall be set. The cement retainer shall have effective back-pressure control and shall be set not less than 50 feet and not more than 100 feet above the casing shoe. The cement plug shall extend at least 100 feet below the casing shoe and at least 50 feet above the retainer.
 - (2) If lost circulation conditions have been experienced or are anticipated, a permanent-type bridge plug may be placed within the first 150 feet above the casing shoe with a minimum of 50 feet of cement on top of the bridge plug. This bridge plug shall be tested in accordance with paragraph (g) of this section.
- (c) **Plugging or isolating perforated intervals.** A cement plug shall be set by the displacement method opposite all perforations which have not been squeezed with cement. The cement plug shall extend a minimum of 100 feet above the perforated interval and either 100 feet below the perforated interval or down to a casing plug, whichever is the lesser. In lieu of setting a cement plug by the displacement method, the following methods are acceptable, provided the perforations are isolated from the hole below:
- (1) A cement retainer and a cement plug shall be set. The cement retainer shall have effective back-pressure control and shall be set not less than 50 feet and not more than 100 feet above the top of the perforated interval. The cement plug shall extend at least 100 feet below the bottom of the perforated interval with 50 feet placed above the retainer.
 - (2) A permanent-type bridge plug shall be set within the first 150 feet above the top of the perforated interval with at least 50 feet of cement on top of the bridge plug.
 - (3) A cement plug which is at least 200 feet long shall be set by the displacement method with the bottom of the plug within the first 100 feet above the top of the perforated interval.
- (d) **Plugging of casing stubs.** If casing is cut and recovered leaving a stub, the stub shall be plugged in accordance with one of the following methods:
- (1) A stub terminating inside a casing string shall be plugged with a cement plug extending at least 100 feet above and 100 feet below the stub. In lieu of setting a cement plug across the stub, the following methods are acceptable:
 - (i) A cement retainer or a permanent-type bridge plug shall be set not less than 50 feet above the stub and capped with at least 50 feet of cement, or
 - (ii) A cement plug which is at least 200 feet long shall be set with the bottom of the plug within 100 feet above the stub.
 - (2) If the stub is below the next larger string, plugging shall be accomplished as required to isolate zones or to isolate an open hole as described in paragraphs (a) and (b) of this section.
- (e) **Plugging of annular space.** Any annular space communicating with any open hole and extending to the mud line shall be plugged with at least 200 feet of cement.
- (f) **Surface plug.** A cement plug which is at least 150 feet in length shall be set with the top of the plug within the first 150 feet below the mud line. The plug shall be placed in the smallest string of casing which extends to the mud line.

- (g) **Testing of plugs.** The setting and location of the first plug below the surface plug shall be verified by one of the following methods:
 - (1) The lessee shall place a minimum pipe weight of 15,000 pounds on the cement plug, cement retainer, or bridge plug. The cement placed above the bridge plug or retainer is not required to be tested.
 - (2) The lessee shall test the plug with a minimum pump pressure of 1,000 pounds per square inch with a result of no more than a 10 percent pressure drop during a 15-minute period.
- (h) **Fluid left in hole.** Each of the respective intervals of the hole between the various plugs shall be filled with fluid of sufficient density to exert a hydrostatic pressure exceeding the greatest formation pressure in the intervals between the plugs at time of abandonment.
- (i) **Clearance of location.** All wellheads, casings, pilings, and other obstructions shall be removed to a depth of at least 15 feet below the mud line or to a depth approved by the District Supervisor. The lessee shall verify that the location has been cleared of all obstructions in accordance with 250.114 of this part. The requirement for removing subsea wellheads or other obstructions and for verifying location clearance may be reduced or eliminated when, in the opinion of the District Supervisor, the wellheads or other obstructions would not constitute a hazard to other users of the seafloor or other legitimate uses of the area.
- (j) **Requirements for permafrost areas.** The following requirements shall be implemented for permafrost:
 - (1) Fluid left in the hole adjacent to permafrost zones shall have a freezing point below the temperature of the permafrost and shall be treated to inhibit corrosion.
 - (2) The cement used for cement plugs placed across permafrost zones shall be designed to set before freezing and to have a low heat of hydration.

250.113 Temporary abandonment.

- (a) Any drilling well which is to be temporarily abandoned shall meet the requirements for permanent abandonment (except for the provisions in 250.112 (f) and (i), and 250.114) and the following:
 - (1) A bridge plug or a cement plug at least 100 feet in length shall be set at the base of the deepest casing string unless the casing string has been cemented and has not been drilled out. If a cement plug is set, it is not necessary for the cement plug to extend below the casing shoe into the open hole.
 - (2) A retrievable or a permanent-type bridge plug or a cement plug at least 100 feet in length, shall be set in the casing within the first 200 feet below the mud line.
- (b) Subsea wellheads, casing stubs, or other obstructions above the seafloor remaining after temporary abandonment will be protected in such a manner as to allow commercial fisheries gear to pass over the structure without damage to the structure or fishing gear. Depending on water depth, nature and height of obstruction above the seafloor, and the types and periods of fishing activity in the area. the District Supervisor may waive this requirement.
- (c) In order to maintain the temporarily abandoned status of a well, the lessee shall provide, within 1 year of the original temporary abandonment and at successive 1-year intervals thereafter, an annual report describing plans for reentry to complete or permanently abandon the well.
- (d) Identification and reporting of subsea wellheads, casing stubs, or other obstructions extending above the mud line will be accomplished in accordance with the requirements of the U.S. Coast Guard.

OFFSHORE PRODUCTION FACILITIES: DECOMMISSIONING OF TOPSIDE PRODUCTION EQUIPMENT

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EXECUTIVE SUMMARY

The removal and disposal of topside facilities is an integral part of the overall decommissioning activity for an offshore platform. Topsides can vary significantly in size, functionality and complexity, and hence, a range of decommissioning options has been identified in technical studies. The technologies to implement them are not all equally mature and, in general, removal is a more complex operation than installation. One feature common to all options is that the facilities will need to be cleaned and all prohibited substances removed in accordance with regulations.

The environmental impact of each option has generally been shown to be small. Other aspects to be considered are health and safety and cost. Opportunities for reuse are drawing increased attention, but are limited by the costs of refurbishment of the older facilities and the evolution of stricter technical standards. Further, particularly for the larger facilities, components were generally designed for a specific set of functional requirements that may not fit the operating and processing demands of a new facility.

The diversity and range of complexity of topside facilities suggest that no one option is likely to be the most appropriate in all cases, particularly when seen in the context of the decommissioning of the total installation.

INTRODUCTION

The purpose of this paper is to provide some background into the issues associated with the removal and disposal of the topside facilities of offshore platforms. It discusses the many aspects that have to be considered, and describes the complexities that must be taken into account in developing a plan for removal and disposal of topside facilities. Topside facilities refer to the deck supporting structure and the plant for drilling, processing and export

of oil and/or gas, and the utilities, accommodation and life support facilities.

The document addresses the key issues related to the technical state of the art, safety and environmental considerations, including energy usage, cost, and opportunities for reuse and recycling. Areas are identified where further technical or scientific studies are warranted. It is intended that discussion of these issues, the significance of which vary among different decommissioning options and different types of facilities, will lead to a better understanding of the framework within which a balance has to be achieved between the protection of the environment and safety, health, technological and economic considerations.

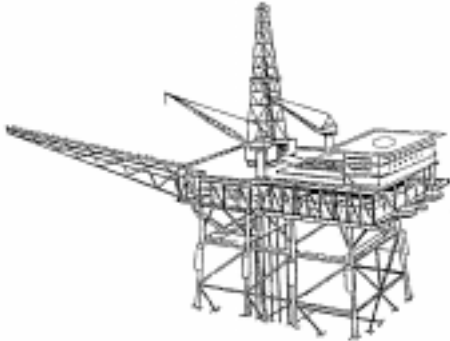
DESCRIPTION AND SPECIAL CONSIDERATIONS

"Topsides", "topside facilities", or "deck" is the terminology used, sometimes interchangeably, for the facilities which include the plant for processing oil/gas and accommodation. Also included, for the purpose of this report, is the steel supporting structure, either separate or integrated with the facilities, that supports the facilities on the substructure. The steel supporting structure is sometimes called "the deck" or "module support frame".

Topsides may vary greatly in functionality and complexity, from large integrated production, drilling and quarters platforms (PDQ) with accommodation for 200-300 workers, to processing only (manned or unmanned), drilling only, quarters only, gas compression or various combinations. Topside weights range from several hundred to a few thousand tonnes in the Gulf of Mexico and the southern North Sea to over 15 thousand tonnes offshore California, and to 10-40 thousand tonnes for very large PDQ structures such as those in the northern North Sea.

The configuration or arrangement of topsides is typically dictated by the capacity of available lift vessels used for installation. Topsides may be integrated, modular, or hybrid versions thereof, as illustrated in **Figures 1, 2 and 3**, respectively.

Figure 1. Integrated topsides / deck.



An integrated topsides refers to a system where the process facilities are installed in the deck structure in the fabrication yard and the facilities are hooked-up and commissioned onshore. The completed deck structure with the integrated facilities is then installed offshore onto the jacket or substructure. Integrated topsides are usually installed by a single offshore lift and are, therefore, limited to a weight of several thousand tonnes. A modular configuration is typically used for larger topsides where the deck structure is subdivided into modules or rectangular boxes that can be lifted by available crane vessels. The modules are supported on the jacket or substructure by a module support frame. Process facilities are yard-installed in the modules and then the interconnect and hook-up between the modules is performed offshore. Many of the very large topsides use a hybrid configuration where, in addition to the modules, process facilities are integrated into the module support frame.

Figure 2. Modular topsides / deck.

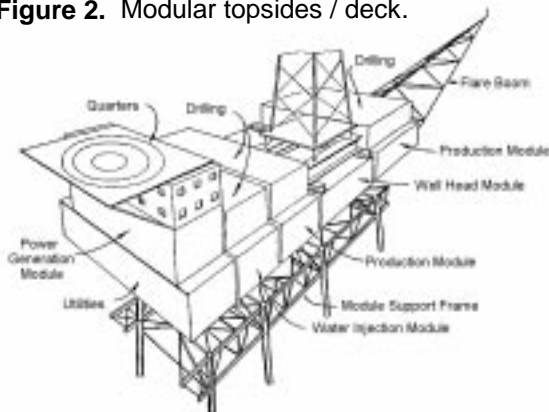
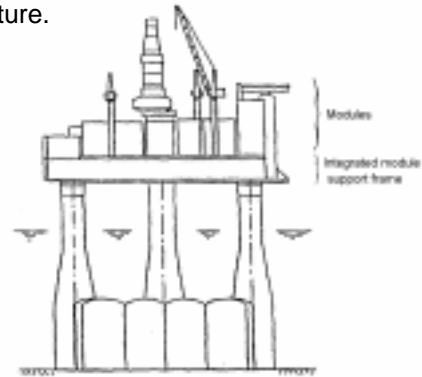


Figure 3. Hybrid topsides on concrete gravity-based structure.



OPTIONS FOR REMOVAL/DISPOSAL

The primary removal/disposal options are summarized in the chart in **Figure 4**. The decision as to removal options and the various disposal and reuse options will need to be made as part of the overall assessment for decommissioning of the installation. In any event, the platform will need to be cleaned and all prohibited substances removed in accordance with all regulations. Well established industry procedures are in place for this purpose (see Appendix A, p. 46).

REMOVAL

Removal consists of removing the integrated deck or the deck modules and the modular support frame (MSF). This may be achieved by any of the following:

- Remove in one piece;
- Remove groups of modules together;
- Remove in reverse order to installation;
- Piece-small removal.

REMOVAL IN ONE PIECE

The advantage of lifting off the topsides in one piece, as illustrated in **Figure 5**, is that it requires the least amount of work to be carried out offshore. The method requires a heavy lift crane vessel (HLV) with sufficient lifting capacity, or a large specialized decommissioning vessel. The current generation of HLV's would limit this method to topside weights in the 3 - 5000 tonne range (when safety factors and other constraints are taken into account) and no specialized decommissioning vessels have yet been fully developed or built.

Figure 4. Toppides Removal / Disposal Options

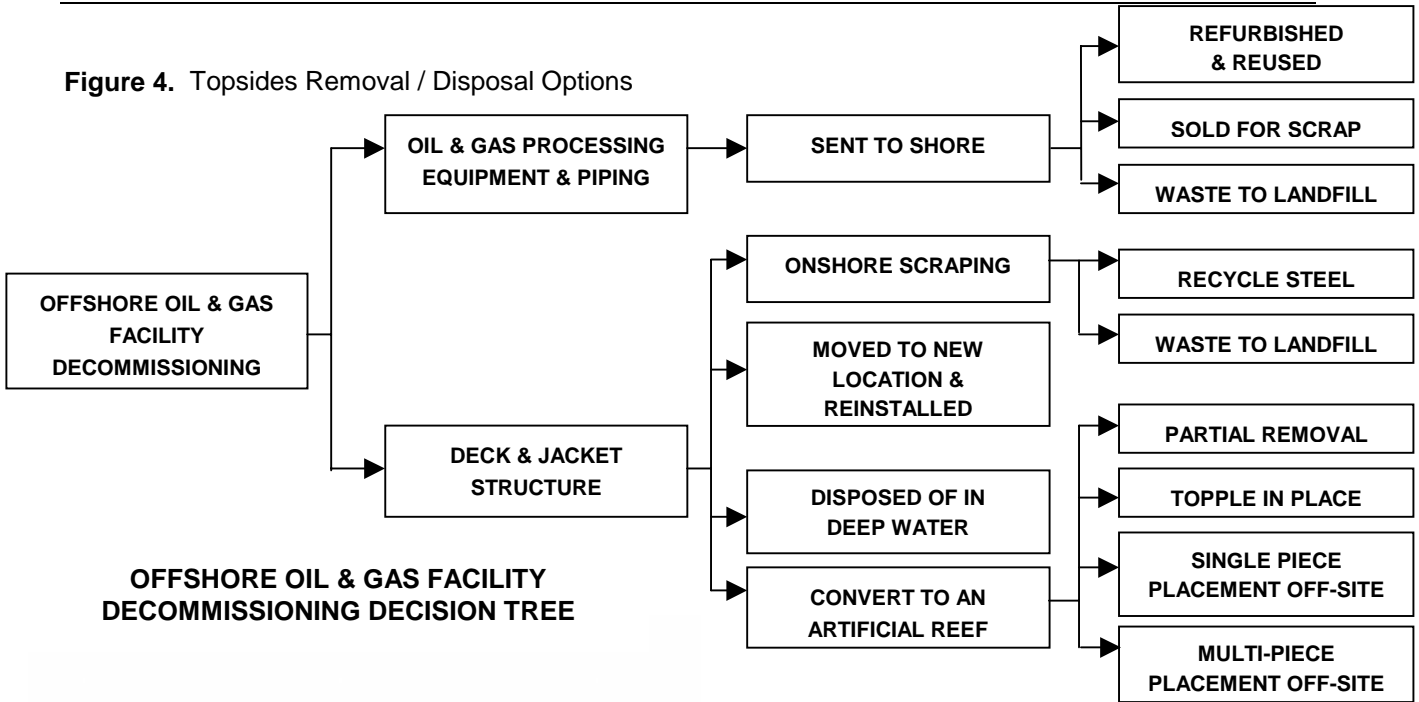
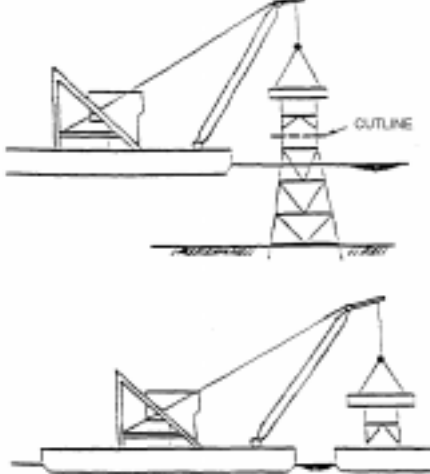


Figure 5. Removal in one piece.



One-piece removal of topsides is more practical for small platforms (e.g., the gas fields of the southern North Sea) which have topsides typically in the 1,000 to 2,000 tonne range. The larger platform decks (e.g., located offshore California in the northern sector of the North Sea) are too large to remove in one lift using a conventional HLV as the weight of some of the topsides facilities is in excess of 25,000 tonnes.

A major problem/drawback in the one-piece removal scenario is both how and where to offload the topsides onshore, particularly since onshore cranes do not have the capacity to lift large modules. Depending on the loading capacity of the quayside, it may be possible to

skid the topsides to the quayside. The other option would be to lift the topsides onto a cargo barge which could be moored alongside the quayside and the modules deconstructed on the barge itself.

LIFTING OF COMBINED MODULES

A recent study by an offshore contractor for the topsides of a large modular northern North Sea platform has shown that removing the topsides in groups of two to four modules at a time can be an effective option. This takes advantage of the increase in HLV capability that has occurred since the installation of the early large Northern North Sea platforms in the mid 70's. This option is illustrated in **Figure 6**. The advantage of this method is in reducing the time that heavy-lift vessels are required, since fewer lifts are necessary when compared to the reverse installation method, where modules are lifted individually.

This method, in addition to the preparations described below under Reverse Installation, needs sequencing, surveying and the fabricating and attaching of lift points as well as additional strengthening to allow for combined lifting. The position of the modules on the platform and their weight will dictate both whether or not combined removal is possible and which modules may be lifted at one time. Handling for onshore logistics will be difficult for the large units.

Figure 6. Lifting of combined modules.

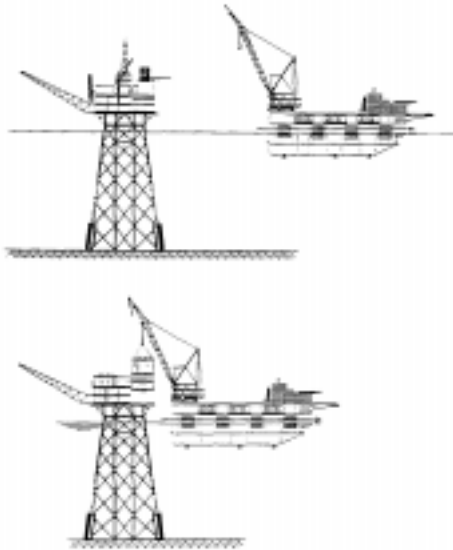
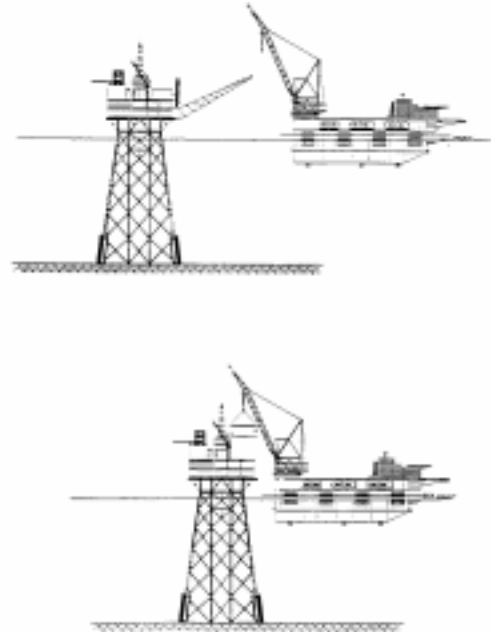


Figure 7. Reverse installation.



REVERSE INSTALLATION – INDIVIDUAL MODULES

This option, illustrated in **Figure 7**, involves dismantling the topsides and deck in the reverse order in which they were installed, i.e., removing the topsides modules and deck components one at a time. Reverse installation requires the chartering of moderate capacity crane barges and/or heavy-lift barges for the larger modules. Surveys of pipework, cabling, module structures, etc. will need to be made to establish the extent of the module preparation required prior to lifting. The following measures will be necessary:

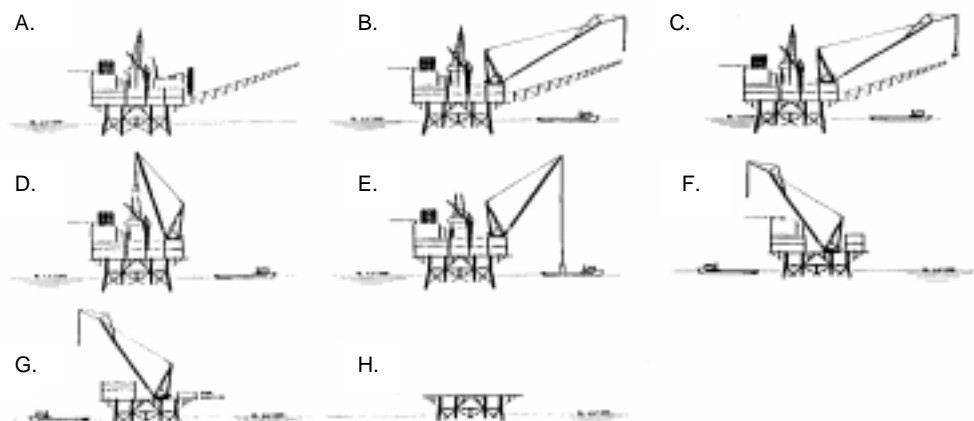
- The structural integrity of the modules would need to be checked, strengthening installed when deemed necessary, and centers of gravity of the loads established using jacking systems;
- Re-install lifting padeyes and slings or install lifting frames;
- All inter-module connections will need to be severed.

Preparation and lifting sequences will need to be planned in detail in order to maximize utilization of topside facilities such as accommodation and power and minimize the time the lifting vessel is on site.

Piece Small Removal

Another method to remove all or part of the topsides is to deconstruct them on the platform using mechanical and other cutting devices, along with the platform cranes, temporary deck mounted cranes and/or crawler cranes. The pieces can then be loaded into standard cargo containers which, when full, can be offloaded onto a supply vessel and transported to shore. When the platform cranes need to be removed, lifting operations would revert entirely to the temporary deck mounted cranes or crawler cranes. The advantage of this method is that neither an HLV or cargo barges are required, hence offshore spread costs are substantially eliminated. (A smaller crane vessel would be required at the end of the operation to remove the deck mounted cranes). On the other hand, however, this method is time and labor intensive and hence individual circumstances for a specific platform will determine whether it is more advantageous than the other methods. Piece small removal is illustrated in **Figure 8**.

Figure 8. Piece small removal.



DISPOSAL

There are three primary methods of disposal: refurbish and reuse, scrap and recycle, and dispose in designated landfills. In practice, a combination of those methods is likely to be employed, consistent with generally accepted waste disposal hierarchies. This means that to the extent that facilities or components of those facilities (such as pressure vessels and compressors, for example) can be refurbished and reused, and demand exists for this equipment, this will be the first method utilized. Whatever material or equipment cannot be refurbished or resold will then be sold for scrap and recycling, except for those elements that cannot be scrapped and recycled and hence need to be disposed in designated licensed landfills. While opportunities for reuse are drawing increased attention, there are inherent limitations in the cost of refurbishment, the evolution of stricter technical standards and the fact that, particularly for the larger facilities, many components were designed for a specific set of functional requirements that may not fit the operating and processing demands of a new facility.

In all cases, the facilities will have to be cleaned as necessary, and some materials, such as LSA, will require special handling and controlled disposal by specialized contractors. Additional information on cleaning is given in Appendix A (p. 46).

The steel support structure for the production facilities, sometimes referred to as module

support frame, may either be removed with the production facilities, or could alternatively be disposed with the jacket as an integral part of an artificial reef. This structure is purely a steel framework and does not contain any hydrocarbons or other equipment or materials.

CONSTRUCTION EQUIPMENT AND NEW TECHNOLOGY

To-date crane barges have essentially been the only means to remove topside facilities (and jackets). These barges can be traditional offshore construction barges with lift capacities in the hundreds of tons range, to ship shape vessels in the 2 - 3,000 ton range, to the very large semi-submersible dual crane heavy lift vessels with combined lift capacity in the order of 14,000 tons. Removed facilities are typically lowered onto a transport barge to be taken to a shore facility. In some cases it can be advantageous to put the removal facilities directly on the deck of the heavy lift vessel, then using the heavy lift vessel for transport to shore.

The realization that a growing number of larger installations will have to be decommissioned in the next few years has fostered the development of alternative concepts to the use of crane barges for deck removal. These range from a system using a truss structure in combination with standard transport barges, to the evolution of unique decommissioning vessels, such as catamaran type vessels that could act in "forklift" fashion to remove and transport a complete deck. Some of these concepts are only on the

drawing board, others have had various degrees of engineering studies performed, and some, like the truss and barge system will actually be tested on a real installation in the Gulf of Mexico this year.

EXPERIENCE TO DATE

The largest experience base with platform removal rests in the Gulf of Mexico, with some 1100 platforms decommissioned to date, although only 38 of those were in water depths over 200 feet, and none in water depths in excess of 400 feet. Topsides were typically in the 800 to 1000 ton range or less, with a maximum in the order of 3,000 tons, as compared to weights on the order of 8,000 to more than 16,000 tonnes offshore California. Of interest, however, is an established and growing market for reuse. One recent statistic claims that over the last three years, 25 percent of removed decks were stored for potential resale or reuse.

Probably the largest facility decommissioned to date is the Odin platform in 103 m (340 ft) of water in the Norwegian North Sea. The topsides consisted of 6 modules and a flare boom located on top of a module support frame. Total weight of those topsides was approximately 7600 tonnes, with three of those modules weighing over 1500 tonnes each, one just over 1000 tonnes, two in the 800 tonne range and the flare boom weighing just over 100 tonnes. The jacket weighs about 6200 tonnes. To date, the topsides have been removed and taken to shore for reuse and recycling, and part of the jacket has also been removed. The modules were removed individually (essentially reverse installation) by a heavy lift semi submersible crane barge with dual cranes, maximum lift capacity of 14,000 tonnes. They were placed on the deck of the heavy lift vessel and taken to the shore facility in two trips. Two other recently decommissioned North Sea platforms had topside facilities in the 4000 tonne range and were also taken to shore for reuse and recycling. In one case a final figure of 99.7 percent for reuse or recycling was achieved at the end of the project.

There is, however, experience also with the removal of larger individual modules in the North

Sea for platform refurbishment or upgrade projects.

KEY ISSUES

This section describes the key technical, safety, environmental and cost issues as they relate to the various structural configurations and methods of removal and disposal.

TECHNICAL ISSUES

In most cases, the removal of topsides is likely to be the reverse process of the installation. However, the removal process is inherently more complex than the installation process since it has to take into account modifications, both structural and through addition/deletion of equipment during the 20-30 year service life of the platform. This, together with an assessment of the structural integrity of the lifted parts, is essential to allow safe lifting operations when these topsides components (or modules) weighing several thousand tonnes are removed.

SAFETY ISSUES

Safety issues relate primarily to personnel safety during multiple heavy lift operations. Hydrocarbon and other residues must be removed to the extent that they do not impact hot work and other operations during cutting and lifting. Structural integrity is of utmost importance to ensure safety during heavy lifts. Further, these operations are inherently more complex than during installation, especially when the removed topsides elements may need to be placed and tied down onto barges moving under the effect of sea swells. A thorough safety assessment would be required for each platform and this would be a key factor in understanding the overall balance of options.

ENVIRONMENTAL ISSUES

These issues relate primarily to removal of hazardous material such as NORM/LSA scale, cleaning and disposal of hydrocarbon and other residues *in situ* and at the disposal site, potential for pollution at the final destination, and to the energy use (including CO₂ emissions) in various removal/ disposal options.

The technology for removal of hazardous material and cleaning of hydrocarbon and other residues is generally well proven (see detailed

description in Appendix A, p. 46). Technology and experience can be extrapolated and there is a good track record. Although, topsides will be taken to shore for recycling/reuse, some cleaning operations and removal of some equipment may be carried out offshore. Once onshore the potential pollutants will be disposed of in a controlled manner in licensed disposal facilities.

Energy consumption can be high for topsides removal, particularly where heavy lift vessels are required for an extended period of time.

COST ISSUES

The costs associated with removal and disposal onshore of the topside facilities are significant, accounting for 30-40 percent of the total removal costs of the installation, which in the North Sea can range from the upper tens of million US dollars to 200-300 million US dollars. This compares to removal / disposal costs in the Gulf of Mexico in the order of 1-2 million US dollars for the relatively small installations removed to date.

Costs are driven by complexities discussed earlier such as strengthening to ensure structural integrity, the costs of cleaning and preparing the deck for offshore disposal, and the high cost of large-crane vessels and supporting spread and equipment (especially if lengthy operations are involved). The difference in size and complexity, and particularly the larger offshore operations and weather constraints imposed by the severe North Sea environment accounts for the large difference in costs between North Sea and Gulf of Mexico removal.

Cost estimates for different removal/disposal options can be generated for the specifics of each individual topside facility, including such considerations as size, weight, modular vs. integrated, complexity, amount of cleaning required, etc and the availability and market rates for construction vessels and equipment at the time. This will be a significant factor to be weighed in the overall balance of different options.

CONCLUSIONS

The removal and disposal of topside facilities is an integral part of the overall decommissioning activity for an offshore platform. Topsides can vary significantly in size, functionality and complexity, and hence, a range of decommissioning options has been identified in technical studies. The technologies to implement them are not all equally mature and, in general, removal is a more complex operation than installation. One feature common to all options is that the facilities will need to be cleaned and all prohibited substances removed in accordance with regulations.

The environmental impact of each option has generally been shown to be small. Other aspects to be considered are health and safety and cost. Opportunities for reuse are drawing increased attention, but are limited by the costs of refurbishment of the older facilities and the evolution of stricter technical standards. Further, particularly for the larger facilities, components were generally designed for a specific set of functional requirements that may not fit the operating and processing demands of a new facility.

The diversity and range of complexity of topside facilities suggest that no one option is likely to be the most appropriate in all cases, particularly when seen in the context of the decommissioning of the total installation.

RECOMMENDED FUTURE STUDIES

Because of the uniqueness of each offshore installation, specific engineering studies will be required to determine the cost and technical feasibility in each individual case.

There are, however, some aspects that will benefit from further generic studies:

- Further investigation of technical and economic feasibility of the range of alternative removal methods, including the truss and barge method and specialized decommissioning vessels proposed by various contractors.
- Further evaluation of reuse potential and the applicability of various technical standards to extended life facilities.

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APPENDIX A:

CLEANING AND REMOVAL OF POTENTIALLY HARMFUL MATERIALS

A1. GENERAL DESCRIPTION

FLUSHING OF VESSELS AND PIPEWORK

Vessels, tanks and piping will be classified as to whether or not they have contained hydrocarbons. Those classified as having contained hydrocarbons would have to be flushed to remove residual hydrocarbons. Procedures for such cleaning have been developed which are regularly exercised in the preparation of pipework for cutting or other such work in potentially flammable atmospheres. Elements of these procedures are presented in Section A2.

The objectives for cleaning in these instances are to eliminate the explosion and fire risks associated with hydrocarbon residues and to remove the potential for release of any hydrocarbons or pollutants into the marine environment. Prior to the cutting up of structures for full or partial removal, it would be necessary to follow a procedure similar to that outlined in Section A2.

Each of the non-hydrocarbon systems will require separate consideration to determine the need for flushing and cleaning.

REMOVAL OF POTENTIALLY HARMFUL MATERIALS FROM TOPSIDE FACILITIES

A combination of the following activities may be found on individual platforms:

- | | |
|--|--|
| <ul style="list-style-type: none">• oil production/processing• condensate production/processing• gas production/processing• hydrocarbon pumping/loading | <ul style="list-style-type: none">• water injection• gas re-injection• power generation• drilling• accommodation and support |
|--|--|

Each of these facilities will have specific requirements for preparation for decommissioning.

As part of the disposal of the topsides, any material that cannot adequately be cleaned will be removed for onshore disposal. Among the materials to be considered on a particular platform are the following:

1. Hydrocarbons or potentially hazardous chemicals contained in the following vessels or equipment:

- | | |
|--|---|
| <ul style="list-style-type: none">• transformers• coolers• scrubbers• separators• heat exchangers• tanks for drilling consumables
inc. bulk storage of muds, etc.• biocide containers• diesel tanks
inc. bulk storage tanks | <ul style="list-style-type: none">• paint containers• batteries• fire extinguishing /
fighting equipment• pumps• engines• generators• oil sumps• tanks• hydraulic systems |
|--|---|

2. Quantities of heavy metals (e.g., lead, zinc, mercury, cadmium, etc.), if any, in biologically available form.

Where such elements are used on offshore installations they are predominantly in metallic form and thus not directly or easily available to the biological food chain. Bolts and other items made from alloys containing the above metals will not need to be removed before abandonment.

3. Other undesirable substances such as radiation sources.

4. Light bulky materials such as
→ life boats

- life jackets
- thermal insulation
- lightweight panels
- accommodation module fittings.

5. Chemicals used in drilling.

The principal use of chemicals on offshore installations is as additives in drilling muds employed in drilling the wells in the early phases of an oil or gas field development. It would be unlikely for there to be any such chemicals left on a platform at the time of removal. However, in the event of small quantities of chemicals remaining on the platform, e.g., corrosion inhibitors, such materials would be shipped back, preferably in their original containers, for disposal at appropriate reception facilities onshore.

EXISTING PROCEDURES

For each of the above, procedures will already be established for maintenance work requiring cleaning and dismantling of the various systems. In general, the procedures necessary to prepare a hydrocarbon system for “hot work” would satisfy the requirements of being substantially “hydrocarbon free” prior to disposal. Such procedures have been developed by each operator over a number of years and are in routine day-to-day use.

A2. ELEMENTS OF STANDARD INDUSTRY PROCEDURES FOR FLUSHING OF TANKS AND PIPEWORK

After the plant has been taken off stream, cooled down and pumped out, all items of equipment must then be depressured, drained and vented.

DEPRESSURING

Normal practice is to dispose of hydrocarbon gasses to fuel gas or flare systems.

As systems become depressured they should then be isolated by valving and subsequent blanking.

DRAINING

Prior to equipment being isolated, it is essential that it should be drained as far as is possible via fitted drain points.

Adequately sized drain lines should be installed at the lowest points and sized in accordance with operator's engineering practices.

VENTING

Where flammable or other harmful materials are to be vented, the point(s) for release must be located in order to preclude any possibility of vapors encroaching upon areas where personnel are working or where there is likelihood of ignition.

PURGING AND FLUSHING

Pipework can be flushed or purged using either steam, water or inert gas. For many applications, water is used as the primary cleaning method. However, steam cleaning is sometimes used but has a higher degree of safety implications.

Pipelines which carried wet oil or hydrocarbons will require flushing with sea water to obtain a satisfactory level of cleanliness, i.e., when the system is substantially hydrocarbon free. The pipeline will then be filled with sea water and sealed.

REMOVAL AND DISPOSAL OF DECK AND JACKET STRUCTURES

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INTRODUCTION

The removal of deck and jacket structures is the core of the decommissioning of an offshore oil and gas facility. This paper discusses the objectives of the decommissioning process along with the methodologies used to meet those objectives. There are many challenges to the decommissioning process created by water depth and the associated large mass of the platform structure. There are also limitations of equipment and techniques which must be analyzed in order to choose the best combination of resources and technologies to best fulfill the operational and environmental criteria established for the decommissioning site. The removal of offshore oil and gas facilities in California will include a wide range of structures from man made islands constructed of concrete and rock fill, to wooden piers with concrete caissons, to steel platforms in water depths ranging from 45 feet to 1200 feet.

Disposal issues are complex and are tied to the industrial capacity, environmental factors, and political climate of the decommissioning area. These variables narrow the available choices for disposal of the deck and jacket materials. A number of decommissioning project case histories on the U.S. West Coast are illustrated and discussed in this paper, along with descriptions of the methodologies and equipment used. These examples of past projects reveal some advances in technology, increased regulation by governing agencies, and an ongoing focus on safety.

This document reviews the state of the art technologies available to remove these marine structures, and reviews the rationale for the selection of resources and methodologies with given variables in structure location, size and design.

REMOVAL AND DISPOSAL GOALS

The removal of offshore oil facilities should be accomplished using methodologies which are efficient while offering the highest possible margin of safety for the workers and maintaining the smallest possible impact on the environment. Safety should always be the foremost consideration, with environmental impact and efficiency being weighed on a case by case basis.

Perhaps the most critical question is, how much of the structure should be removed? The presence of a structure over a number of years has created a marine ecosystem. This structure may be an obstacle to commercial fishing and a resource for sport fishing. Parts of the structure may be imbedded in the sea floor to the extent that total removal will create more disturbance to the environment than partial decommissioning in place. All of these factors must be considered in generating a removal plan (factors which dictate the limits of the removal).

The water depth may influence these options and impacts. A structure in shallow waters is likely to be easily accessible by the public, and public safety at the site following removal must be considered. A structure in deep waters may be partially decommissioned with all remaining materials far below the water surface. Further, the extreme mass of a deep water structure is a significant challenge, not only for the initial removal process, but for the disposal process as well. The scrapping and disposal capabilities on the U.S. West Coast are limited, and these limitations must be considered as a part of structure removal planning. The massive quantities of marine growth and the disposal of this material causes air quality issues at the disposal site due to the odor. Air emissions are also an important consideration in areas with air quality problems.

CASE HISTORIES IN SHALLOW WATER AND DEEP WATER

The following case histories will illustrate and discuss some of the major offshore decommissioning projects completed to date (**Figure 1**). It should be noted that the largest crane barge used for these projects in California has been rated at a 500 ton capacity. Future decommissioning projects on larger platforms in California may require a barge crane capacity ten times greater to remove these massive structures.

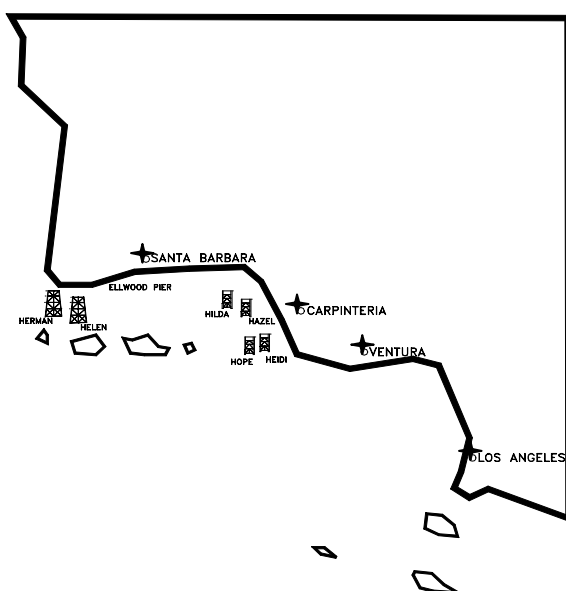


Figure 1. Facilities Decommissioned on the West Coast.

Aminoil Ellwood Pier

Ellwood Pier is located north of Goleta, California and is one of several oil production pier facilities still remaining in California. This pier is no longer a producing facility, and is now used for crew and material transfer. This facility had five concrete caissons with production wells positioned 700 feet beyond the terminus of the pier today. This section of pier and the caissons were decommissioned in 1979. The pier was made of steel H-pile columns supporting a timber deck, terminating at the five concrete caissons which were connected by steel trusses and covered with a continuous timber deck.

The timber deck was removed and the piles were cut off by divers below mudline. The concrete caissons were demolished using explosive shape charges. The 15 pound conical charges were positioned around the perimeter of the structures and detonated to reduce the caissons to pieces with maximum dimensions of approximately six feet. Reinforcing steel was cut by divers. The steel trusses were cut above water by rigging crews and below water by divers using arc-oxygen torches. The concrete rubble was reduced to a pile which did not extend above a water depth of -15 feet at low tide and was left in place. The steel was recovered and scrapped onshore. The use of explosives in open water, a common practice prior to 1980, has not been allowed in recent years for decommissioning work in California. Explosives continue to be used below mudline for pile and conductor severing.

Texaco Helen and Herman Platforms

Platforms Helen and Herman, originally installed in the late 1950's in State Waters, were decommissioned in 1988 following production shutdown and well plugging in 1973. These structures were located offshore Gaviota, California in 100 feet of water and 85 feet of water respectively and represented the early design of offshore oil platforms with simple tubular construction and anchor piles driven down through the annuli of the platform legs. Both structures had been moved to the site for installation on cargo barges and placed in position on the sea floor with a barge mounted crane. The decommissioning of these platforms was the first large scale offshore oil platform decommissioning project performed in California, and therefore there were many unanswered questions regarding disposal options. An artificial reef construction from the jacket materials was proposed during the project permitting and planning phase, however political opposition to the proposed reef site in Santa Monica Bay killed the plan. Deep water dumping was also considered and discarded. The only remaining disposal option was onshore scrapping, and this methodology was carried out to dispose of the materials.

Platform Helen was a 20 leg structure and Herman was a 4 leg structure. The marine growth accumulated on the structures was over 15 inches thick near the surface with up to 12 inches of hard growth. The structures were in poor condition after 15 years exposure without cathodic protection. Platform Helen had a number of 2 inch diameter pipelines running to subsea completions with a 6 inch and 8 inch production pipeline to shore. Platform Herman also had a 6 inch and 8 inch production pipeline to shore. The pipelines for both platforms were decommissioned in place with a section through the surf zone removed completely. All onshore facilities and pipelines were removed. The deck packages and jacket structures were removed in sections weighing from 100 to 400 tons. The cuts below the water line were made by divers using arc-oxygen torches. The jackets were attached to the sea floor by piles inside the legs. The piles on Helen were severed 1 foot below natural mudline using a mechanical casing cutter. This method proved to be less than reliable, as most of the cuts were incomplete and had to be completed by divers deployed down the inside of the 33 inch piles. The slope or "batter" of the outside legs proved to be a problem for the casing cutter, even though a centralizer was used. The piles on Herman were cut from the outside by divers after excavating a foot below the natural mudline because the interior of the pile had been grouted, leaving it inaccessible for cutting tools.

The Helen and Herman platforms together had a steel weight of approximately 3000 tons. The marine growth probably added 1000 tons to this figure. Disposal was performed onshore in Long Beach at a private yard with waterfront access. The size of the jacket structures, soaring about 80 feet above the deck of the barge, presented a significant problem for dismantling. The 500 ton derrick barge "Wotan" used to remove the structures was required to offload the materials at the dock. This process was feasible because all of the materials were brought in together on 3 barges. The onshore dismantling required two large crawler cranes to safely take down the tall tubular structures.

Chevron Hope, Heidi, Hilda and Hazel Platforms

The Chevron Hope, Heidi and Hilda platforms, located in State Waters off Carpinteria, California in water depths of 137', 126', 106', and 96' respectively, were decommissioned in 1996 immediately following well plugging (P & A) operations. The decommissioning project, sometimes called the 4-H Project, was postponed for one year due to air emission permitting delays, caused by strict limitations on air emissions imposed by the Environmental Protection Agency (EPA) on Santa Barbara County and the classification of decommissioning emissions by the Santa Barbara County Air Pollution Control District (APCD) as non-exempt. Emission offsets were required by the APCD to keep emission levels below target ceilings, and the time required to create those offsets resulted in the delay of the project. These platforms were installed between 1958 and 1965 and were in sound structural condition at the time of their decommissioning. Disposal options including onshore scrapping and artificial reef construction were weighed in the permitting and project planning phase. The artificial reef option was not selected because at the beginning of the permitting process in 1992, the State Lands Commission and the Coastal Commission were not favorably disposed toward this disposal method. Later, interest emerged in the artificial reef approach by the American Sport Fishing Association, and the concept was seriously analyzed for the 4-H Project; however, the late timing created permitting obstacles and there were questions as to the cost effectiveness of the method for this particular project. Therefore, onshore scrapping was used again as the disposal method of choice. Several potential sites in the Terminal Island area of the Port of Long Beach were selected for a dismantling and scrapping process similar to the one performed in 1988 for Platforms Helen and Herman. One of the lessons learned here was that future projects should include analysis of the artificial reef option for disposal from the outset of the permitting and planning phase.

Platforms Hope, Heidi and Hilda and Hazel were technically advanced designs at the time

of their installation (See **Figure 2**). The Hope, Heidi and Hilda jackets had two large diameter caisson legs which served as the flotation for the jackets during installation as they were towed to the site on their sides. This platform design concept was used as late as 1977 for the Thistle "A" platform installed in the North Sea. The Hope, Heidi and Hilda platforms were anchored to the sea floor by piles driven through sleeves in the large caisson legs and through sleeves in smaller caissons at the base of the opposing legs.

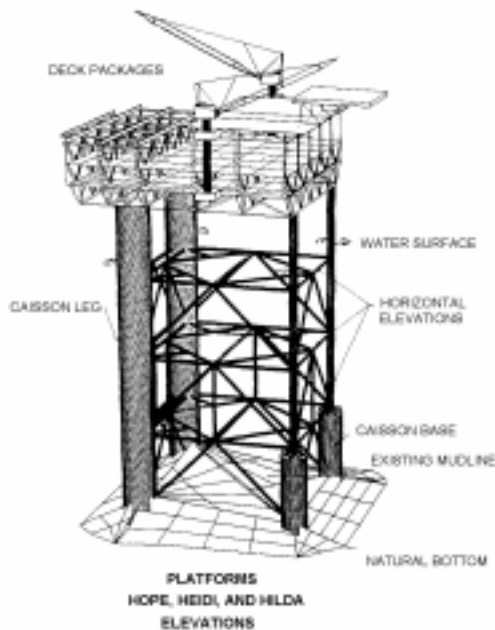


Figure 2. Platforms Hope, Heidi, and Hilda design. This illustration is typical of platform size in water depth ranges from 100 to 140 feet.

The Hazel jacket was a "gravity structure" design in which the platform was floated out on its buoyant caissons and ballasted on site by filling the caissons with sand and cement. A gravity structure by definition is secured to the sea floor by gravity alone and is not anchored by steel piles. Hazel was a typical tubular steel jacket structure sitting on large diameter caisson bases (See **Figure 3**). These caisson bases floated the structure to the site when empty, and became the anchor for the structure when jettied 18 feet into the sea floor and filled with ballast material. This gravity structure concept developed in the 1950's was later used for platform design in the treacherous Cook Inlet near Anchorage,

Alaska, and more recently has been used for concrete platform structures fabricated in Norwegian fjords and floated on the gravity bases which are later ballasted with sea water and/or crude oil storage.

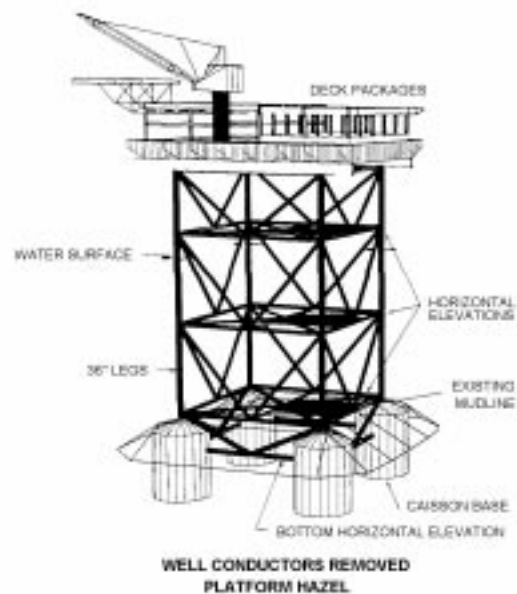


Figure 3. Platform Hazel design. This platform is a "gravity base" design and had no anchor piles.

The production well P&A process was completed during a two year period on the four platforms. The dismantling of production equipment followed, removing all production equipment and piping with hydrocarbon residue from the structure.

The removal of the 4-H platform structure decks was completed as the reverse of the installation process. This scenario is typical because the deck package lifts that were designed for installation are the safest and most practical configuration for removal. The marine equipment of the 1960's included derrick barges with capacities in the maximum range of 500 tons. Today we find derrick barges lifting more than 10 times that amount, but the package to be removed must be engineered for the lift, and many times, the package is removed in a configuration similar to its original installation. Equipment availability is also a factor to be considered. Construction barges are plentiful in California, but the largest barges, such as the D/B Wotan

used on this project, have a capacity of approximately 500 tons. If heavier equipment is needed, it must be imported from other areas at a significant cost. The 4-H decks were removed in sections weighing 100 to 350 tons and placed on cargo barges for transport and offloading at a dockside facility in Terminal Island. It must be noted that the air emission permit process was difficult due to the stringent requirements in Santa Barbara County. The option of importing larger equipment with significantly more capacity, greater horsepower, and higher fuel consumption would probably have been over the emission limitations imposed on the owner by the APCD.

The removal of the 4-H platform jackets offered many technical challenges in that the structures were designed to float on their own buoyant legs, and therefore there was no inherent design strength for lifting them. The large caisson legs, measuring up to 18 feet in diameter, had a mere ½ inch wall thickness and had been designed to withstand only the maximum pressures anticipated in the launch mode with partial flooding. Therefore dewatering the legs to lift the structure off bottom was risky at best with anticipated pressures meeting or exceeding design ratings, resulting in the requirement for another alternative to lift the structure. The answer for the recovery of the delicate but massive legs was the utilization of a pair of 250 ton capacity hydraulic gripping tools attached to 2 of the pile stubs on the legs. Further, it was necessary to cut the legs in up to 3 vertical sections to reduce the weight of the lifts to meet the capacity of the crane. The most effective cutting technique in depth ranges accessible to divers continues to be arc-oxygen torches, and this method was used for the majority of underwater structure cuts. This methodology is not as effective, however, when cutting through multiple well casing strings grouted together.

The severing of the legs in 3 sections as well as the pile and well conductor severing required below the bottom of the leg structure required methodology which would be efficient and reliable. The technology for abrasive water jet cutting has progressed to the point where it has been successfully used for many pile and conductor cutting operations on

decommissioning projects, however it has not yet achieved the reliability of explosive cutting.

The abrasive water jet methodology was used for intermediate cuts in the well casing strings inside the caisson legs for sectioning the legs in 3 parts; and it was also used for the removal of casing strings outside of the legs. However this methodology does not have guaranteed success and many cuts were repeated or completed by divers working inside the caisson legs after cuts proved to be incomplete. The piling and well casing cuts were performed far below the existing mudline to reach a depth below the bottom of the structure. It was crucial to the safety of the heavy lifts that these cuts be complete and reliable because they could not be examined for verification. Explosive cuts have been proven to be the most reliable cutting methodology in use, and 45 pound explosive charges were employed on each of the pile and well casing strings locations. These charges were effective in completely severing the piling and well conductors below mudline on 100% of the explosive cuts performed. A number of conductor cuts below mudline had to be made by divers due to access blockage of the casing annuli by grout. These cuts required divers to work inside the caisson legs, cutting the bottom of the structure clear as well as the conductors and casings.

The removal operation revealed another complication - the legs of Hope, Heidi, and Hilda were partially filled with grout or hardened drilling mud, increasing the leg weight beyond the capacity of the crane. Mud removal operations ensued, with divers pumping off the solid materials to storage tanks on the deck of a cargo barge. These tanks were offloaded in Terminal Island and the material was transported to an approved dump site.

The Hazel platform, a gravity structure, was partially decommissioned in place. The gravity base caissons were nearly covered with accumulated materials and shells in a mound under the structure. Because of the caissons' excessive weight and the disturbance to the sea floor which would be caused by their removal, this part of the structure was decommissioned in place.

The 4-H platforms had 20 intra field and field to shore pipelines and 9 power cables. Platform Hope was receiving and shipping production from platforms Grace and Gail, and these pipelines had to be rerouted around the Hope platform to facilitate the decommissioning of the structure (See **Figure 4**). Other pipelines were disconnected from the platforms, capped, and the ends were buried 3 feet below mudline. The pipeline and power cable decommissioning was performed by the 165 foot workboat M/V American Patriot. Most of these pipelines are buried where they reach shore, and those that sometimes become exposed are adjacent to pipelines still in production. Therefore, no landfall pipeline removals were performed; however, the decommissioned pipelines were grouted internally through the surf zone and decommissioned in place.

The steel mass of the 4-H platforms was in excess of 10,000 tons. The total weight of marine growth removed was in excess of 2700 tons. Disposal was performed onshore at a 20 acre dockside facility in Terminal Island. Steel scrap was reduced to marketable sizes and sold. The crane capacities onshore were very limited and it was necessary for the removal derrick barge to offload the structures at the dock. The package heights were designed to be limited to approximately 30 feet to avoid dismantling problems on the dock after offloading. The volume of the scrap required numerous trips to the dock to offload the cargo barges. Debris at the platform sites was removed by divers working aboard the 165 foot workboat M/V American Patriot and transported to Casitas Pier for land transport and disposal.

Exxon SALM

The Exxon SALM or Single Anchor Leg Mooring, was installed in 1980 in Federal OCS waters using a combination of a drill ship and derrick barges to complete the construction. It was decommissioned in 1994 using a derrick barge. The SALM was positioned in 500 foot waters off Goleta, California and had a 750 foot long Offshore Storage and Treatment Vessel (OS&T) permanently moored to the mooring structure.

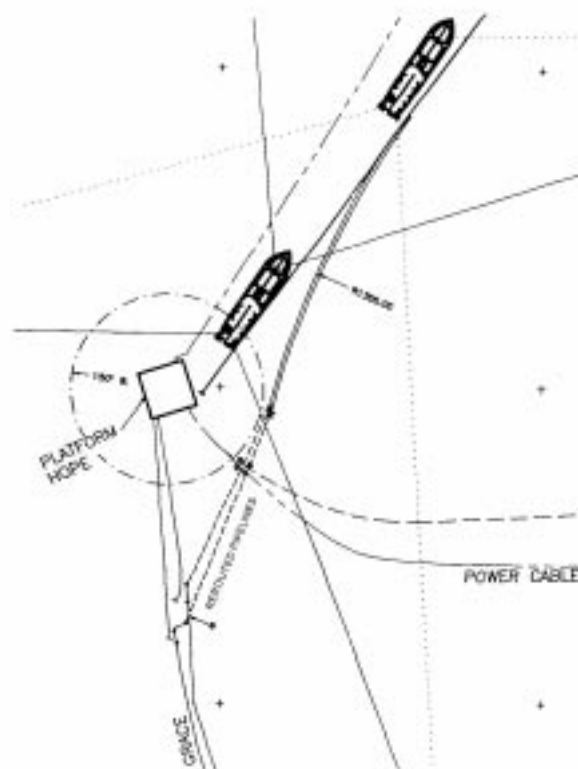


Figure 4. Pipeline Bypass at Platform Hope. The pipelines from Platform Grace originally terminated at Platform Hope, and production continued to shore in the Hope pipelines. A reroute of the pipelines around the platform kept the Hope pipelines in service for Platform Grace production.

The SALM was comprised of a base structure approximately 52 feet in diameter anchored by 6 piles. The riser and buoy structures connected by universal joints to each other and to the base plate resemble a large automotive drive shaft supporting a mooring yoke to the OS&T at the surface. Pipelines running from the Hondo platform sent crude oil and gas production up the riser and buoy structure, through swivel fittings at the universal joints and finally to the OS&T for treatment prior to offloading. The OS&T provided storage of the crude oil and deployed a mooring hawser to tankers for mooring during the offloading of produced oil emulsion. The OS&T facilities layout is shown in **Figure 5**.

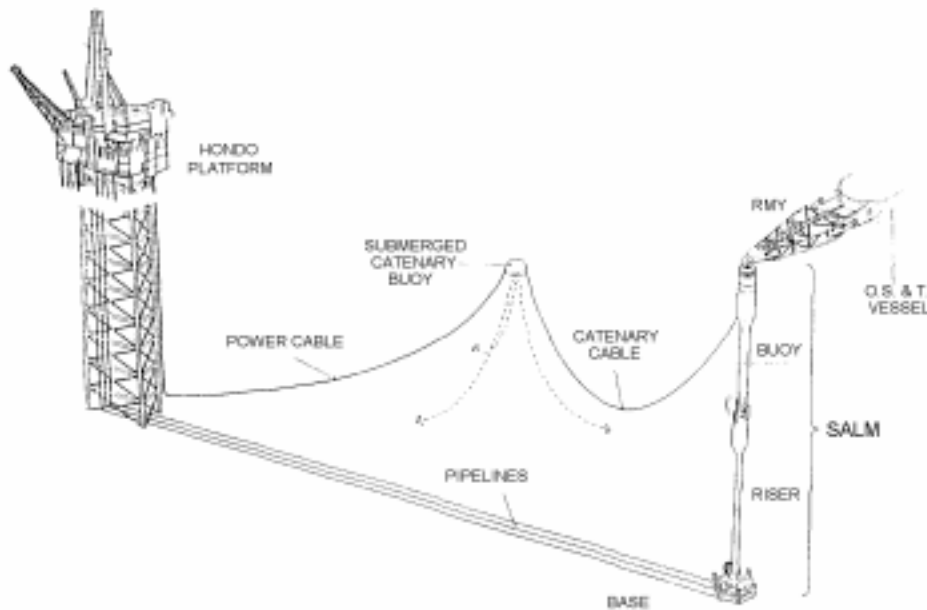


Figure 5. OS&T Abandonment Project Facilities Layout. Exxon OS&T Abandonment.

The removal of the SALM was the first deep water decommissioning project performed in California. The structure was 14 years old at the time of the removal operation, was in good condition and marketable for reuse in other areas. Therefore, the scrapping and artificial reef questions did not apply to this project.

The removal of the SALM system, like many decommissioning projects, was performed using many of the same techniques applied for the installation. In fact, the derrick barge used for the installation work, the D/B Long Beach (formerly D/B 300), was also used for the removal operation. The OS&T vessel was disconnected and towed to Ensenada, Mexico for temporary storage; however, in spite of established plans, the vessel was turned away by Mexican authorities, underscoring the potential uncertainties inherent in crossing international borders in the decommissioning process. The vessel was finally towed to a dock in the Port of Los Angeles for storage. The large yoke on the vessel's stern had to be supported by a large buoy which had been stored in the Port Hueneme area after the installation. The attachment of this buoy was accomplished by a delicate ballasting operation combined with the use of winches and a derrick barge.

The riser and buoy sections of the structure were removed using saturation divers. The hydraulically actuated pins which had secured the structure to the base during installation were found to be operational, replumbed and then retracted to disconnect the riser structure from the base structure. A ballasting operation on the buoyant riser and buoy structures (reducing the lift forces), combined with the attachment of a wire for controlled release at the base structure (reacting against the buoyancy), were used to recover the buoy and riser to the surface. The de-ballasting of the structure and attachment of transport buoyancy to the riser, further raised the SALM to a horizontal attitude for towing. The buoy was towed to the Port of Los Angeles for temporary storage.

The base structure was removed in a more typical fashion for decommissioning operations. Saturation divers disconnected the pipelines and capped and covered the ends with concrete mats to ensure the passage of trawl nets over the site in the future. The 6 anchor piles were severed 15 feet below the natural seafloor using abrasive water jet cutting technology operated remotely from the surface (see **Figure 6**). All of these cuts were successful. The base structure was cut into 7 sections by saturation divers using

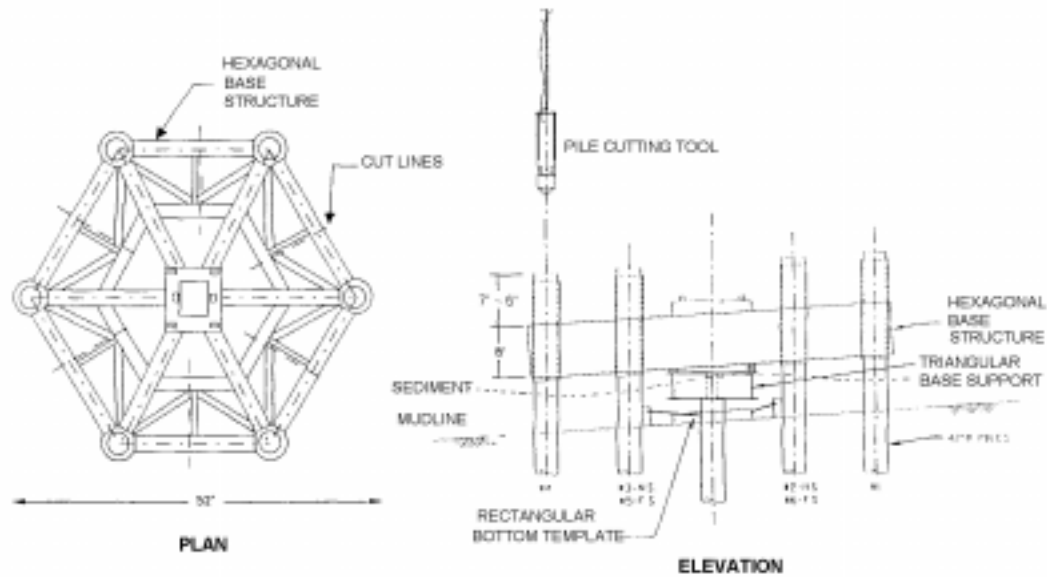


Figure 6. SALM Base Structure. Exxon OS&T Abandonment.

arc-oxygen torches and rigged for removal with the derrick barge.

The SALM and OS&T structure were resold and are now in operation overseas. The base structure was scrapped onshore.

Global Perspective

The number of platforms decommissioned each year exceeds 100 structures, most of which are located in the U.S. Gulf of Mexico. Most of the structures decommissioned to date have been located in relatively shallow water. The Exxon SALM described above and the Brent Spar removed from the North Sea are two deep water examples which did not have the tremendous mass of the majority of deep water structures which will be decommissioned in the future.

The challenges for the future will center around the removal and disposal of these massive structures. The environmental impacts of onshore disposal of these structures will be much greater than the impacts seen in the disposal of smaller structures, while the alternatives for decommissioning in place and artificial reefs may see an increase in potential benefits.

The removal of massive deep water structures may come first to California waters. These decommissioning projects will require larger capacity and more capable heavy lift equipment, support tugs, and transport barges, with an associated increase in air emissions. The removal of the deck packages of these newer structures may provide opportunities for reuse in other areas of the world, reducing the disposal dilemmas which must be faced. The total removal of the jackets for onshore scrapping would create many impacts including air emissions, marine growth disposal issues, and the quandary of insufficient sites for such activities.

The removal of the shallow water structures continues each year and we see similar scenarios to those recent decommissioning projects in California described above. Reuse of oil production platforms is quite common in the Gulf of Mexico. A reuse scenario could see an entire structure removed in one piece, transported and placed back on the sea floor. Another scenario on a larger structure could be the removal of the decks and jackets in separate lifts with reassembly at another location. In a different scenario, jackets and deck packages are removed from the field and reconditioned and upgraded onshore in a fabrication yard, followed by reinstalled at a

new offshore location. The obstacles to the installation of new offshore oil production facilities in California, makes these reuse scenarios much less likely to occur here.

ENGINEERING AND PLANNING

Organize Logistics

The planning of a decommissioning project begins with the identification of the equipment necessary and available to do the work. The choice of derrick barges, tug boats, and cargo barges along with the disposal plan will be the basis for an analysis of environmental impact using this equipment (See **Figure 7**). The most efficient means of removing the structure must be developed with all of the potential variables in mind. The owner must not only choose the most effective equipment spread, but ensure that it is available and can be successful in completing the work outside of any potential environmental windows such as the whale migration periods. Air emissions limitations have been an issue in the past; however, new legislation may have exempted oil production facility decommissioning work from these limitations.

Special Tool Design

The lifting of structures which have been in service for many years, and which may have been extensively modified since their installation, will probably require the design and fabrication of special tools and rigging to create lift points, and perhaps attachment tools to connect the rigging to those heavy lifts.

Engineer Heavy Lifts

The heavy lifts must be engineered to ensure that the lift is made safely and within the capacity of the crane used (See **Figure 8**). The dynamic loading conditions offshore add additional risk to the heavy lift, making the engineering effort a central issue. A weight take-off for the package to be lifted must be generated to accurately calculate the mass of the lift. The rigging of a lift bridle of at least 4 parts, as well as the use of special tools or spreader bars, add complexity to the lift. The center of gravity (CG) must be identified, and the rigging centered on this location (See **Figure 9**). A package which is not lifted around the CG may have three of its four load slings taking all of the load, creating excessive loading on those parts. A more significant miscalculation could result in an unstable load which has the potential of hitting the crane boom or dropping portions of the lift. The

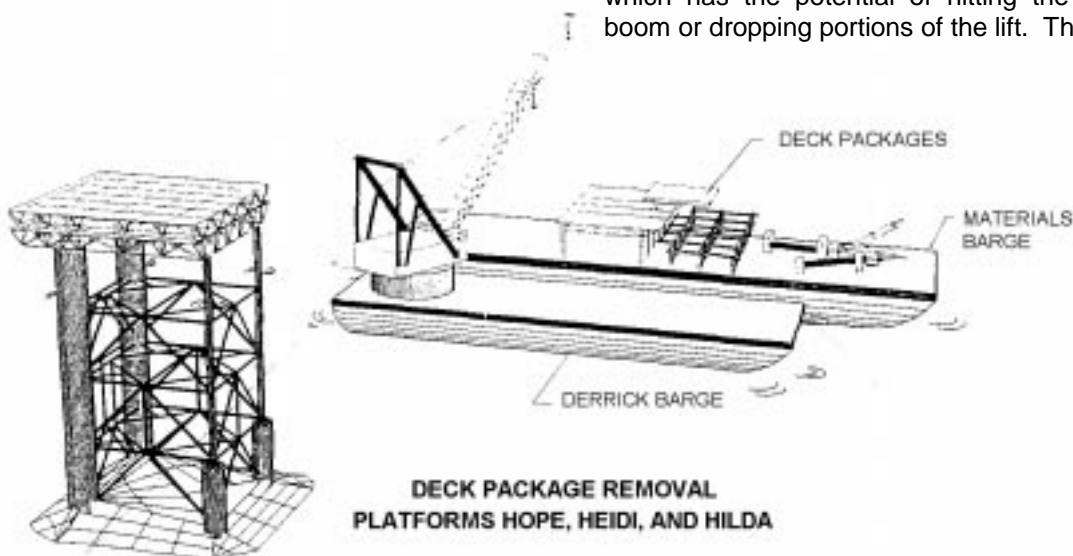


Figure 7. Equipment Spread – Shallow Water Decommissioning. This illustration compares the mass of the petroleum platform to the removal equipment. The platform is in 140 feet of water with a 500 ton crane barge (300 feet LOA) and cargo barge shown.

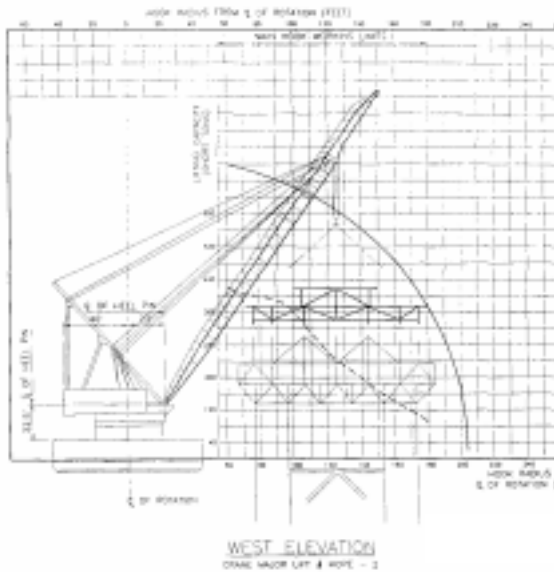


Figure 8. Lift Plan – Crane Chart. The heavy lifts are engineered with the load weight and dimensions, center of gravity, rigging, and crane capacity limits charted. This planning verifies that the crane can complete the lift without the boom touching the load, and that the working radius (capacity is sufficient to complete the lift).

engineered lift will specify specific rigging, crane radius to be used, weight take-offs for the lift which include the rigging weight, lift point location and type, plus a contingency factor.

Additional planning must be engineered to provide a means of aborting a lift after the load has been raised a few inches. A lift abort could be necessary due to mechanical malfunction on the crane, changing swell conditions, or a rigging failure. Tubular structures or any structure sitting on columns must have guides on the columns at the cut points which allow for approximately 1 foot of vertical travel before the load clears. This will enable the operator to lower the load within the guide if an abort is necessary.

Engineer Materials Transport

The heavy lift barge which has just rotated a lift package away from the platform under dynamic load conditions must have a place to set that load without delay. Therefore, it is imperative that planning include the cargo barge load. Each large lift may be placed in a

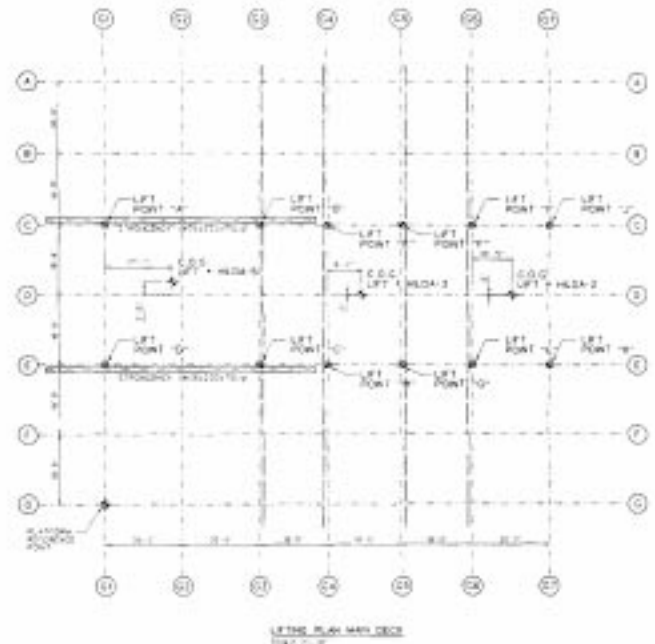


Figure 9. Lift Plan – Lift Points and CG Locations. The chart shows the center of gravity (CG) and lift points for the heavy lift preparations.

predesignated position on the barge, a position which has been verified relative to barge stability in the roughest seas anticipated (See **Figure 10**). Sea fastening is engineered to efficiently secure the load to the barge for transit.

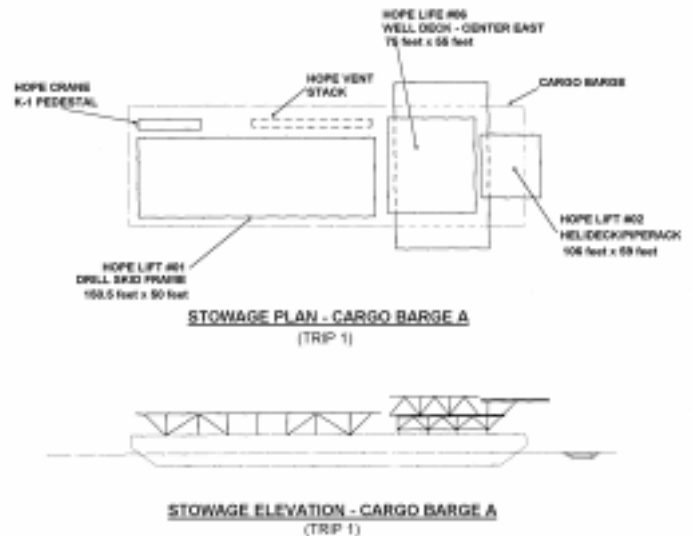


Figure 10. Materials Transport Planning. The sketch shows the plan for cargo barge loading. This planning also incorporates engineered sea fastening for each load and stability calculations.

Plan / Engineer Disposal

Every package that is placed on a barge must be eventually offloaded. The method of complete onshore disposal will require a crane equal to the barge crane for offloading, or the package may be reduced in size while at the dock. This may be impractical as the size reduction ties up high cost marine equipment for extended periods, and the new reduced lifts must be engineered and rigged as well. Alternative disposal means such as artificial reefs will require extensive engineering and planning which is combined with biological and environmental data.

PROJECT RESOURCES

Heavy Lift Equipment vs. Depth Ranges

Structures located in less than 200 foot water depths, and located in moderate environments such as the U.S. West Coast are typically of a size which can be dismantled by a 500 ton crane with 160 to 200 feet of boom. The structure age can also be a critical factor as platforms installed within the past 15 years may have been assembled with larger deck packages requiring larger lifts for a stable removal sequence. Jackets may be sectioned at will to suit the capacity of the equipment.

Support Vessels

Support vessels are the backbone of an offshore decommissioning project and the central vessel is the derrick barge. All derrick barges require tugs to maneuver them and sometimes place anchors. Some advanced derrick barges may be equipped with a dynamic positioning (DP) system which uses onboard computer controlled thrusters to accurately hold the vessel on station when integrated with a navigation system in lieu of anchors.

A 500 ton capacity derrick barge of approximately 300 foot length over all (LOA) and operating on the U.S. West Coast may require as much as a 3000 horsepower (hp) tug to provide towing and anchor handling. The anchors used may be 5 to 10 tons in weight

deployed on up to 2 inch wire rope anchor wires without chain, and can be expected to hold a tension of approximately 10 times their weight (Danforth Type) in sand. A 5000 ton capacity derrick barge of approximately 600 foot LOA may work with the assistance of up to a 25,000 hp tug set up to operate in more harsh environments such as the North Sea. Anchors used may be 15 tons or more in weight "piggybacked" with 2 anchors per mooring leg comprised of anchor chain.

Crew boats are commonly used in California because of the close proximity of the majority of platforms to land. Platforms which are in excess of 15 miles from a point of onshore crew transfer are typically out of practical range for daily shift changes by crewboat. Platforms which are out of range will require personnel accommodations during their operating life and the decommissioning equipment used to dismantle them will also need to accommodate the crews. Helicopter transport is an alternative to offshore accommodation, but is plagued in California by the coastal fog during the summer months and Santa Ana wind conditions in the winter months.

Tugs and cargo barges are needed to stage and transport removed materials and packages. Cargo barges which are available as a part of the typical marine transport market may range from 180 feet LOA to 400 feet LOA. These barges must be documented by the American Bureau of Shipping (ABS) with a Load Line Certificate to legally transport materials on the open sea in U.S. waters. Tugs in the range of 1500 hp for smaller barges and 3000 hp to 5000 hp for the larger barges are utilized for towing and maneuvering. The cargo barges must be moored on a remote mooring near the decommissioning site to receive multiple lifts from the derrick barge which may occur hours apart.

Special Tools

Special tools may be required for certain lift applications or perhaps robotic cutting applications. For example, the recent decommissioning of Platforms Hope, Heidi, Hilda, and Hazel required a number of special tools. Hydraulic grippers were adapted to special buoyant lift rigging for 500 ton lifts.

The buoyant rigging allowed another special tool, an A-frame with a 38 part lift block assembly, to stab onto the established gripper tools underwater. The A-frame was used for the removal of leg sections which had to be extracted through up to 20 feet of bottom material. The loads to be encountered on these lifts could not be entirely engineered, and the A-frame provided a great margin of safety without risk to the crane boom. These are just a few samples of special tools provided on one project.

Personnel

The platform decommissioning project will vary in personnel commitment by the size of the equipment used. The working window of opportunity due to equipment availability, or environmental restrictions may also affect the size of the decommissioning team. A small decommissioning project on a single platform in shallow waters may require only 40 to 50 personnel to operate the marine equipment spread. A moderately sized project with multiple platforms in shallow waters may require 75 to 100 personnel. A deep water decommissioning project with larger equipment may require in excess of 150 personnel.

DEMOLITION OF CONCRETE STRUCTURES

Concrete structures offshore include caissons with piers and concrete and rock islands. These facilities are typically located in water depths of 45 feet or less. The concrete structure's extreme weight creates some challenges to reduce the structure into sections for removal and there are a number of demolition techniques available:

Diamond Wire Sawing

A wire rope impregnated with industrial diamonds is fed through holes drilled into the concrete structure and the ends of the wire are connected together to form an endless loop. The loop is driven on the deck with a hydraulic powered sheave and pulling pressure is applied to force the wire loop to cut the concrete and reinforcing steel until the holes it has penetrated are connected by the

cut. This method typically requires access to both sides of the holes being drilled to facilitate feeding the wire through. The result is a clean and straight cut which is not limited by the thickness of the concrete.

Abrasive Water Jet

A high pressure water jet is directed at the concrete with an abrasive garnet or copper slag mixture. The water jet bombards the structure at pressures of 10,000 to 50,000 psi and the abrasive multiplies the cutting forces. This tool typically is directed with a robotic feed assembly which controls the rate of travel for the cut and will sever the reinforcing steel along with the concrete. The method can be employed to cut concrete thickness up to several feet.

Expansive Grout

A number of holes are drilled into the concrete structure and filled with an expansive grout. The grout expands as it hardens, cracking the surrounding concrete. This method reduces the concrete to rubble which must be hammered to expose reinforcing steel for final cuts with a torch.

Hydraulic Splitters

A number of holes are drilled into the concrete structure and a hydraulic splitting tool is inserted. The tool expands hydraulically and cracks the surrounding concrete. This method reduces the concrete to rubble which must be hammered to expose reinforcing steel for final cuts with a torch.

Explosives

Explosives may be used in small quantities in drilled holes through the concrete to reduce it to rubble.

Impact Demolition

The oldest and most familiar method for reducing concrete is direct impact to the structure. A wide range of tools may be used including hydraulic powered impact hammers operated from excavators or special support machines, and wrecking balls or tools manipulated from cranes. Reinforcing steel is manually cut when using this method.

REMOVAL PREPARATIONS TO DECK PACKAGES

Installation of Remote Moorings for Cargo Barges

The cargo barges required to receive materials should have a means to moor temporarily in the field. This serves to reduce fuel consumption, and allows tug crews to rest. As a lift is being prepared, the tug can take the barge under tow and maneuver alongside the derrick barge to receive the package. The barge and tug will depart the field for the disposal site when the barge is fully loaded.

Deck Package Lift Preparations

Deck package lifts will require lift point fabrication and installation prior to the arrival of the derrick barge. Crews will pre-rig as much as possible to reduce the duration of the derrick barge utilization. Preparatory cutting of decks may be performed in conjunction with engineering calculations for a modified structure analysis, to minimize the cutting time required to separate the packages for their lift (See **Figure 11**).

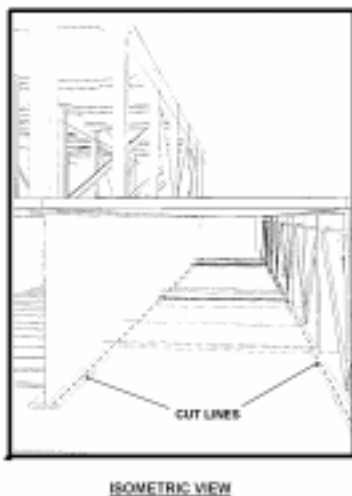


Figure 11. Preparations to Deck Packages. This isometric shows the cut lines for separation of two deck modules for lifting.

Preparations for Alternate Use

Any alternate use or disposal option may require specific preparations (relative to that option). The re-use of a structure may require

many protective measures to preserve the equipment on board during the transfer.

REMOVAL PREPARATIONS TO JACKETS

Marine Growth Removal

Marine growth will be removed at the underwater cut points to facilitate diver cuts using arc oxygen torches. The removal of all marine growth prior to removal of the structure has not been economically feasible. The removal of marine growth is accomplished by the use of a 10,000 psi hydroblaster which is operated by divers. The seawater jet removes the marine growth to within millimeters of bare metal.

Preliminary Cuts on Jackets

Preliminary cuts on a jacket in shallow waters may be made to prepare for removal, in conjunction with engineering calculations for a modified structure analysis. These may take place before or after deck package removals as dictated by engineering. Deeper water removals may also allow for preliminary cuts, as many of the members on the jacket were primarily for installation loads during a barge launch of the jacket.

Methodology for deep water cuts may include the use of saturation divers to depths of over 1000 feet; however saturation diving operations in excess of 600 - 700 feet are rare. The question of the use of divers for extreme depths depends on the projected safety of the operation and the cost of using divers versus remote intervention means. Cutting techniques using remote systems could include Atmospheric Diving Systems (ADS), a manned system which operates an abrasive water jet cutting tool or a mechanical equivalent. Other systems include heavy work Remotely Operated Vehicles (ROV) which carry similar tools in work packages on board. Remote applications have been cost effective in performing cuts in extreme depths, however heavy rigging is a tremendous challenge for remote intervention techniques. Therefore progressive lift methodology is a likely choice for the removal of jackets in deep water as discussed below. Deep water jacket removal

techniques have not been implemented to date, and specific methodologies must be developed and proven in the field.

REMOVAL OF DECK PACKAGES

The strategy for the removal of deck packages centers on several factors. First, the capacity of the derrick barge combined with the available space on the cargo barge will determine the maximum lift size. Second, the capacity of the offloading crane chosen must also be within the limits of this package size. Third, it must be determined if the package and the remaining portions of the deck packages will support themselves when the specified load is cut free and removed. Finally, the package itself must have the integrity to be lifted, or additional measures such as the use of spreader bars or strongback members may be taken to reduce the loads on the package. The choice of reuse of the package or scrapping may have some bearing on the size and configuration of the package chosen.

The deck package will be transported to the offloading location. A decommissioning project in Southern California is likely to offload in the Port of Los Angeles or Long Beach. The only likely alternative to scrapping the deck packages is reuse. Packages destined for reuse may remain on the cargo barges for shipment to another location for refurbishment and sale. Other alternatives such as artificial reefs are typically not applied to the deck packages. Deck package configurations are the easiest to scrap because they are comprised mainly of flat plate and beams. Conversely, the hydrocarbon residue which may be present on portions of the deck package would make the cleaning requirements excessive in order to incorporate the package into an artificial reef.

PILE AND CONDUCTOR SEVERING

The jacket is typically anchored to the sea floor by anchor piles. These piles may be driven over 200 feet into the sea floor and must be cut off at a specified distance below the mudline to remove the jacket. This distance has been 1 to 5 feet below mudline in

California state waters and 15 feet below mudline in Federal waters. Piles are grouted to the structure near the base, and may have well conductors inside. Most platforms do not have wells drilled through the anchor piles, but have a conductor bay in the center of the structure. Intermediate piling cuts may be required to separate the jacket into vertical sections, as the piling may extend well up into the jacket structure, particularly on the shallow water platforms.

Conductor severing and recovery will most likely be completed as a part of the well plugging process. The conductors may contain multiple strings of well casing, grouted together. Mechanical casing cutters are typically used in this application if a drill rig is available for deployment of the tools. Abrasive water jets may also be used to make these cuts at the designated elevation below mudline. The conductor may be lifted then with the drill rig through the structure and sectioned as it is lifted to facilitate offloading. The conductors, like the rest of the structure will be heavily fouled with marine growth. When the conductor is pulled up through the conductor guides located at each horizontal member elevation, the marine growth will be stripped as it passes through the guide. Jackets with excessive marine growth or jackets in poor condition may incur damage as the conductor is pulled up. Modification to the conductor guide or removal of the marine growth on the conductor may then be considered.

The mechanical casing cutter is perhaps the oldest method for cutting well conductors. The casing cutter is a drilling tool deployed on a drill pipe string. The cutting tool has 3 blades which fold up against the drill pipe. When hydraulic (drill water) pressure is applied to the tool, the blades are forced outward as the tool is rotated by the power swivel on the drill floor. The carbide tipped blades cut through the casing strings until penetration is complete through the outer conductor. Drillers can watch the back pressure on the drill water to determine when the cut is complete. The cut can be verified after the recovery of the tool, by the marks of penetration on the blades. This method is not 100% reliable, as the outer conductor will

deform significantly as the blade is forced through.

When final penetration is reached, the hydraulic back pressure will reduce, but the cut may not yet be complete. The final verification is the successful vertical movement of the conductor. The casing cutter methodology is problematic for conductor removals in which close tolerance conductor guides on the jacket are smaller than the deformed cut end of the conductor which must pass through the guide during recovery.

Abrasive water jet technology has been successfully used in recent years to cut multiple string well casings. The abrasive water jet leaves a clean, machine like cut in the casing strings. Several different systems are in use. The pressures range from 10,000 psi with a high volume output to 50,000 psi at a lower volume output. The abrasive is introduced at the cutting nozzle tip and may be sent down a hose dry by air pressure or in a water based solution. The abrasive is propelled by the water jet after being introduced into the cutting jet, and cuts the steel and grout as it hits the target. Casing strings with void areas rather than grouted annuli have been a problem for this methodology. The water gap between casing strings dampens the energy of the water jet and causes an incomplete cut. Inconsistent abrasive delivery can also be a problem. The systems which have an air delivery of the dry abrasive grit are limited to shallow water application. The systems using a fluid delivery of abrasive have been used in water depths exceeding 600 feet. The abrasives typically used are garnet and copper slag. Some operators have been reluctant to use copper slag because of the environmental implications of the copper content; however, the level of copper present in the slag material is relatively low, and there are no restrictions on its use. The most versatile aspect of this cutting technology is the relatively small tool size, and its potential and historic use by remote intervention systems such as ROV's and ADS to depths exceeding 1100 feet. The casing cuts which are completed below mudline cannot be verified visually. The tool operators have used microphones for audio

feedback and hydraulic back pressure readout to gauge whether the cut is being completed. The rotational cutting speed of the tool is set by the operator's "feel" for the cut and by the known capability of the tool. These methods are at best, only indications of cutting performance in progress, and there have been a significant percentage of incomplete cuts on previous decommissioning work in California and in the Gulf of Mexico. The abrasive water jet technology continues to develop and will be a popular technique for cutting applications in the future.

The use of explosives to cut conductors, well casings and piles has been the most reliable method in use for many years. The open water use of explosives has been restricted in recent times, but applications below mudline continue to be permitted with minimal impacts to marine life. The bottom cuts on anchor piles and conductors required for the removal of jacket structures must be clean to allow for a safe lift from the surface. A barge making such a lift in dynamic conditions at sea would certainly exceed its lift capacity if an incomplete cut left the load secured to the sea floor. This potentially dangerous condition dictates the use of the most reliable method for making these cuts, and explosives have proven to be nearly flawless in their reliability. An explosive cut is sized according to the diameter and wall thickness of the member to be cut, along with the number of strings. A typical charge for these cuts is a cylindrical explosive container which is lowered down the conductor or pile to the designated cut elevation and detonated from both ends to create a "collision charge". The force of the detonation at the ends moves toward the center of the cylinder and moves out horizontally when the two explosions collide. This horizontal force creates the directional cutting energy to sever the pile or conductor (See **Figure 12**). The methodology is extremely safe, as the explosive cannot be detonated without an explosive detonator. The detonator (blasting cap) is attached to a detonation cord which is secured to each end of the explosive. Modern blasting caps are detonated by high voltage and are not sensitive to radio waves as others have been in years past. Because the detonation cord may be several hundred feet long, the vessel

supporting the operation can move clear before a blasting cap is ever installed. The vessel continues to move away, paying out electrical wire to the blasting cap before detonation is applied to the wire with high voltage. The recent decommissioning of Platforms Hope, Heidi and Hilda employed the use of explosives for the majority of bottom cuts with a 100% success record. Spotting aircraft and boats were used to verify that there were no marine mammals in range of the blast area prior to each detonation. The charge size for the typical cuts on shallow water platforms is approximately 45 lbs.

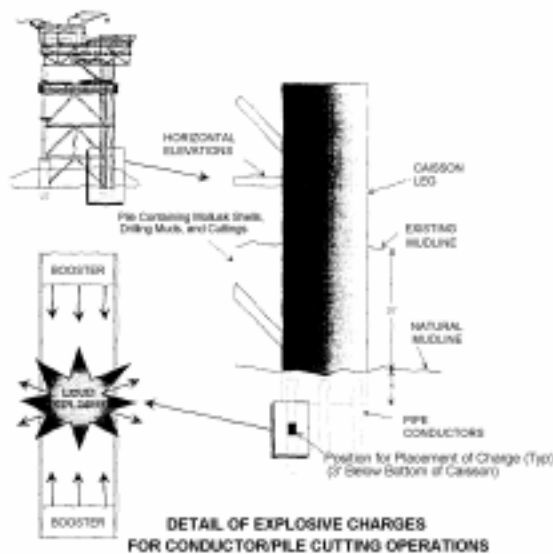


Figure 12. Pile and Conductor Severing Using Explosives. The used below mudline for conductor and pile cuts are typically bulk charge cylinders which are simultaneously detonated from top and bottom. The explosive force meets in the middle of the charge redirecting the cutting forces to the horizontal plane.

JACKET REMOVAL

Jacket removal can be accomplished in various degrees and using a number of methodologies. All jacket removal operations will take place following the completion of pipeline decommissioning. The most common removal scenario for shallow water jackets is complete removal of the jacket. This method will leave nothing on the sea floor except the mound that accumulates under

each jacket during its operating life. This mound is comprised of drill cuttings, shells and other organic material from marine life on the structure, and collected sediments for structures in depositional areas. The jacket removal is completed after bottom cuts have been completed below mudline on the anchor piles. The entire jacket is removed in sections or as a single lift if possible.

Deep water structures present much greater challenges for complete removal. The immense weight of the structures as well as their extreme depth, places a one step removal outside the limits of existing technology. A method known as “progressive transport” reduces the structure to packages for shipment in a cost effective manner. The structure is rigged between two barges and lifted after the pile severing operation is complete. The jacket is winched vertically off the bottom and the barges are moved into towards shallow water until the jacket touches bottom again. The upper portions of the jacket can now be removed above the water surface and the rigging is reattached underwater for another lift. The remaining structure is vertically lifted again and transported to shallow water where it is again reduced and rigged. This process can be repeated as needed to completely recover the jacket.

Jackets can be partially removed with a portion decommissioned in place. This method would involve the removal of the upper portions of the jacket such that the remaining structure was well below the surface, and clear of concerns about navigation hazard. The remaining structure would be in effect an artificial reef.

Another approach to decommissioning in place is jacket “toppling”. The jacket is pulled by winches on anchored barges after pile severing, and the structure is toppled on its side. The jacket structure on it’s side will be well below the water surface.

The deep water platforms in water depths of more than 400 feet are candidates for progressive transport, partial removal in place and decommissioning by toppling. Shallow water platforms are more likely candidates for

complete removal at the site. California platforms Helen, Herman, Hope, Heidi, and Hilda have all been completely removed at the site, and were located in water depths from 85 feet to 139 feet. Platform Hazel was decommissioned using partial removal in place due to her extremely heavy gravity structure caisson bases below the mudline.

DEBRIS REMOVAL

Debris removal is performed within a specified radius of the decommissioning site. The most recent California decommissioning projects have involved debris removal within a 1000 foot radius of the platform site. There are many ways to locate and remove debris; the choice may be affected by the equipment available in the area and the water depth. A preliminary survey of the site with side scan sonar can provide a target listing and location for existing debris.

A common method for debris removal in the U.S. Gulf of Mexico is the use of trawl nets to recover debris. Heavy nets called "gorilla nets" are used from trawl vessels to gather debris. Divers can assist in completing the debris recovery operation as required.

Diver recovery with ROV assistance is an effective technique when heavy trawl vessels and equipment are not available. This method has been successfully used on all California decommissioning projects to date. The ROV is deployed with color scanning sonar to locate debris items on the target list provided by the preliminary side scan data. Differential Global Positioning System (DGPS) satellite navigation is integrated with an acoustic tracking system to provide real time position data on the ROV during search and recovery operations. The ROV locates the debris and remains on location to guide the diver to the position with a recovery line. The support vessel recovers the debris and the diver as the ROV continues to the next debris target. This method is effective for debris recovery in less than 200 feet of water.

Deeper water recovery work may be more economically performed using remote intervention techniques. Well site clearance

has been performed in California in waters exceeding 300 foot depths using ROV's and manned submersibles for recovery of debris targets. The ROV recovery operations using light work ROV's are performed by attaching a recovery line from a spool on the ROV. The ROV is recovered with the line and the line is transferred to a winch for recovery of the debris target. Large work ROV's and manned submersibles have been used to attach recovery lines from the surface. The remote method is altered slightly with larger equipment in that the ROV or manned submersible remains on bottom during the debris target recovery and uses sonar to relocate the recovery wire for the next target.

MATERIAL TRANSPORT AND DISPOSAL

Material transport is most commonly achieved on cargo barges. These barges are available in the existing marine transport market up to a length of 400 feet. Larger barges, if required, would not be commonly available and would carry a significant cost.

Onshore scrapping has been the method of choice in California to date. The distance to the scrapping facility is critical due to the high cost of marine equipment. If barges are to be shuttled from the decommissioning work in the field for offloading, the shorter the duration, the fewer cargo barges and tugs are required. The existing scrap facilities in California are not set up for scrap reduction of large packages. These facilities are fed by numerous small scrap companies which reduce small volumes of scrap into marketable sizes of approximately 3 feet square and less. Because of this existing market condition, a steel scrap reduction and processing operation must be created to reduce these large packages to marketable dimensions. The scrap reduction process is costly and waste products must be hauled to a dump site. Most of the existing scrap processed in the Los Angeles area is shipped in bulk carriers to the Far East for sale there.

The debate over where to put artificial reefs, and who might be responsible has left the steel scrap yards with the business of

reducing these structures. Still there is a high level of interest in creating these reefs. The construction of an artificial reef would require environmental study, an engineering plan for the layout of the reef, and a significant commitment of marine equipment to place the materials.

Relocation and reuse of platform structures is common in the U.S. Gulf of Mexico, and structures are commonly lifted and relocated within a few miles to be set up for production again. This scenario is unlikely in California; however packages with enough value to warrant transport to other areas may be transported from California decommissioning projects. This was the case for the Exxon SALM and OS&T decommissioning project completed in 1993.

CONCLUSIONS

The removal and disposal of deck structures offers many options for reuse and recycling of materials. The deck structures may have viable equipment and components for use at another facility. A newer deck package may be transferred intact for installation on a new jacket. Older structures which are scrapped offer the type of configuration which is best for recycling (i.e., flat plate, beams, paint protected condition).

The removal and disposal of jacket structures presents many challenges. The extensive marine growth, deterioration of the materials, grouting of jacket piles and members, along with the size of the structure make offshore removal difficult. Reuse options are limited, especially on the U.S. West Coast. Onshore scrapping is very difficult with small structures, and may present tremendous challenges for larger structures. These obstacles make the search for alternatives worthwhile, and create a potential for the use of jacket structures as artificial reefs when relocated or partially decommissioned in place. These removal operations can be completed in an environmentally sound and safe manner with existing technology while creating jobs and increasing commerce. The disposal of the materials is a potential resource which can bring economic and/or environmental benefits.

REFERENCE

Exxon Company U.S.A. August 1994. *Exxon OS&T Abandonment Final Report.*

PIPELINE AND POWER CABLE DECOMMISSIONING

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INTRODUCTION

Offshore California oil and gas platforms are typically served by one to three pipelines. These pipelines range from 4 to 20 inches in diameter and move production fluids to other platforms or to onshore processing and distribution facilities. Some pipelines are used to return treated produced water to a platform for offshore disposal or injection. The specific properties of the fluids transported in a pipeline may change during its service life of 30 or more years.

In addition, to reduce air emissions, California production platforms are designed for, or have been converted to, electrical power. This power is provided by the regional onshore electrical distribution network and reaches the offshore facility via power cables traversing the sea floor like oversized extension cords.

To a casual onshore observer, the ultimate consequence of terminating production from offshore oil and gas fields is the removal of associated offshore and onshore facilities. The presence or absence of pipelines and power cables related to these facilities is a less obvious, but still important, factor to consider in decommissioning.

DETERMINING OBJECTIVES

It is difficult, if not impossible, to develop an adequate engineering plan for decommissioning pipelines or power cables until specific determinations are made regarding their disposition. Without question, decisions whether, or not, to remove or decommission in-place are a basic element in determining the scope of work. Federal regulations allow

decommissioned OCS pipelines to be left in-place when they do not constitute a hazard to navigation, commercial fishing, or unduly interfere with other uses of the OCS. California regulations are similar in allowing pipelines to be left in-place when they are not considered a hazard or obstruction, although California State Lands Commission policy requires removal, when feasible, of pipeline segments in the surf zone to a depth of -15 feet MLLW (mean low low water). There are few examples where total removal or decommissioning in-place is the only preferred option because pipeline and power cable alignments typically traverse a range of environmental settings that require different solutions to address a variety of decommissioning objectives that are, at times, conflicting.

From an operator's perspective, highest priority is usually given to assuring worker safety in the context of pursuing regulatory compliance and minimizing the risk of future liability, at minimum expense. Regulatory agencies with primary oversight responsibility for pipeline and power cable decommissioning also tend to place emphasis on assuring worker safety, but cost is of less concern than the need to fulfill regulatory mandates to minimize adverse environmental impacts and user conflicts, such as preclusion of commercial trawling. The interests of other stakeholders usually focus on one or more of the issues already mentioned to the exclusion of all others.

One of the keys to optimizing decisions regarding pipeline and power cable disposition options is to find an acceptable balance between conflicting interests that is sufficiently flexible to address the variety of conditions that might be present along the alignment. The

other key is to have a clear and accurate understanding of existing conditions based on a pre-decommissioning survey of pipeline and power cable alignments.

Useful preliminary information regarding conditions along pipeline and power cable alignments can be obtained from a number of sources. Reviews of historical records, such as pre-installation surveys, as-built documentation, external pipeline surveys and records of fishing conflicts provide background information applicable to the design of an adequate pre-decommissioning survey.

Pre-decommissioning surveys are used to characterize conditions along pipeline and power cable alignments. Surveys on recent California projects have employed side-scan sonar to provide reconnaissance-level overviews and are usually supplemented with detailed video and sonar documentation, using an ROV (Remotely Operated Vehicle), in areas where significant conditions are suspected. The results of pre-decommissioning surveys should be evaluated in the context of available historical documentation to aid in determining whether specific segments of an alignment are subject to major changes over time. Burial conditions may change seasonally in shallow water, high energy environments and spans may migrate.

Careful documentation provides a basis for determining preferred disposition options by identifying conditions, like high spans, that have potential to interfere with other uses such as commercial trawling. Documentation can also provide insight into whether or not preclusion is even an issue because other factors, like high relief seafloor features, may preclude trawling. Pre-decommissioning surveys are also used to identify environmental and engineering conditions that might require special safety or environmental protection measures during the conduct of a decommissioning project.

ENGINEERING, PLANNING AND EXECUTION

The majority of pipelines on the U.S. West Coast have been installed with a "bottom tow" technique, meaning that the pipes were welded

together at a staging area at the onshore landfall position and, with temporary buoyancy attached, were pulled offshore by an anchored barge. Many pipelines were pulled in bundles of two to three pipelines to an offshore facility. Upon completion of the tow, the buoyancy was Removed by divers, remotely operated vehicles (ROV's), or boats dragging sweep wires. The bottom tow method is significant for the decommissioning process because pull sleds were used on the leading end of the pipeline and are typically left in place near the platform. Connecting spools were installed by divers to complete the installation. The removal process must consider the disposition of these pull sleds and any remaining rigging left after the temporary flotation was removed from the pipeline. Most pipelines on the U.S. west coast have not been buried by the installation contractor. Some pipelines in depositional areas of sand transport have naturally become buried, and others remain uncovered for the majority of their length.

Engineering and Planning for Power Cable Removal

The power cables which run from shore to the offshore facility are armored with one or two layers of steel armor wire, with internal high voltage wires which were typically designed to carry in excess of 30,000 volts. These cables are four to six inches in diameter and are quite heavy. Sub-sea power cables, when buried or lying flat on the sea floor, are not a hazard to trawl fishing and have typically been decommissioned and abandoned in place with the ends buried below mudline. The weight of the cables creates a challenge for recovery, because if they are to be recovered in one piece, a large powered reel as large as 35 feet in diameter would be needed along with linear cable engines (a hydraulic powered, rubber coated steel track assembly which captures the cable and pushes the cable through the tool). The potential reuse of these cables is questionable and therefore the cable may more simply be cut into pieces as it is recovered; however, the disposal of the cables is difficult because of the complexity of separating the armor, the insulation and the copper wire. It is most likely that an onshore dump site is the ultimate destination of a recovered power cable. All decommissioned power cables to-

date have been abandoned in place with the exception of the Hondo SALM described in **CASE HISTORIES.**

the planning for power cable removal would include the set up of a retrieval system and a rigging and cutting methodology to quickly sever the power cable. Burial issues are generally not critical, as the power cable can be recovered in spite of a burial condition due to the high strength and relatively small diameter. A disposal plan would be required if a power cable is removed.

Power Cable Removal

Power cables are more typically abandoned in place than removed. The removal process would involve attaching the cable to a recovery winch by divers. The cable end can then be retrieved so that a linear cable engine can be set up to drive the cable up onto the recovery vessel and a hydraulic shear can be used to section the cable for stowage and transport.

Engineering and Planning for Pipeline Removal

Pipeline removal operations require engineering pre-planning to determine the methodology for removal and the size and capacity of removal equipment. Historic documentation of the pipeline operation and conditions prior to final shutdown are necessary to identify residual fluids and gases in the pipeline. Shutdown documentation should reveal the methodology used for final cleaning and flushing of the pipeline, which will provide data for an estimate of the extent of additional cleaning required for decommissioning.

Determining the most appropriate removal techniques will require data from recent pipeline surveys or a dedicated pre-decommissioning survey. Data requirements include: pipeline burial locations, burial depth, water depth along the route, nearby pipeline or structure locations and environmental information such as the position of kelp beds and hard bottom habitats.

In addition, engineering planning requires knowledge of pipeline characteristics such as diameter, wall thickness, density and locations

of weight coat (if present), flanges, pull sleds, and pipeline crossings.

Assembled data are analyzed to determine how much of the pipeline will be removed. Survey data from the removal locations are used to determine the type of excavation equipment required as well as any environmental precautions which must be taken. For example, anchor plans must be developed around the kelp beds and hard bottom habitats.

The barge capacity, both for recovering the pipe and storing the pipe, must be evaluated along with auxiliary equipment such as cargo barges and tug boats. The methodology for cutting the pipe may be critical, especially if a long length of pipeline is to be recovered. The protective coatings and weight coat typical of most pipeline sections to be removed make pipeline severing difficult, because these coatings must be removed in order to cut the pipe with a torch.

Disposal is a critical issue for pipeline removal because reuse of the steel is not feasible due to the coatings on the pipeline. Typically, pipelines must be cut into lengths as short as 6 feet and hauled to an approved dump site on land. This process is costly and the methodology chosen to process the material for dumping is important, in order to achieve a cost effective result.

Pipeline Removal Preparations

Survey

The pipelines will be surveyed or existing data will be studied to determine the location of flanges, crossings, kelp, and hard bottom habitats.

Cleaning

Pipelines are cleaned using a process called "progressive pigging". This process involves sending a series of polyethylene (poly) foam "pigs" and cleaning pigs through the pipeline with chemical agents and flush water to remove all hydrocarbons. The pig is a foam bullet shaped plug which is slightly larger in diameter than the inside diameter of the pipeline. The pig is introduced into the pipeline through a "pig launcher" (a pressure vessel connected to the end of the pipeline). The pig launcher has a diameter larger than the

pipeline to allow insertions of the pig by hand, and a hatch or flange which is closed behind. The pig is pushed from the launcher into the pipeline by pumping air, nitrogen, water or chemicals into the launcher behind the pig. A measured amount of fluid or gas is pumped before a second pig is inserted into the launcher. The progression continues until the required number of pigs with the corresponding amount of driving chemicals or flush water is sent through the line, removing all remaining hydrocarbons. The pigs are received in a "pig catcher". The pig catcher is similar to the pig launcher. The pig catcher, located at the opposite end of the pipeline, is plumbed to allow fluids or gas to flow through, pushing the pigs to the end of the catcher.

The types of pigs available that may be used is based upon the condition of the pipeline, previous cleaning history, and the expected buildup of wax, corrosion, or other residue from hydrocarbon production, as listed below:

1. *Low Density Poly Pig* - A low density pig can pass through partially blocked pipelines because it can radically deform as it is pushed through. This pig seals the push fluid or gas to ensure that all liquid in the pipeline is displaced by the fluid or gas behind the pig.
2. *Medium Density Poly Pig* - A medium density pig can pass through blockages with moderate force applied and can move some material collected on pipeline walls.
3. *High Density Poly Pig* - A high density pig passes through blockages with higher force applied and will move material collected on pipeline walls.
4. *Brush Pig* - This pig has wire brushes or other types of brushes to remove material residue left by previous pigs.
5. *Scraper Pig* - This pig has a number of hard scrapers built in to scrape the more resistant residue off pipeline walls.
6. *Poly Pig* - Final flushing is completed using a poly pig.

Progressive pigging is necessary to ensure that the pigs do not get stuck in the pipeline. The

use of a high density or scraper pig on the first run could scrape enough material to stop the pig and block the pipe. Pushing the first one or two pigs with several barrels of de-greaser or surfactant will soften and dissolve hydrocarbon residue in the pipeline, allowing the denser poly pigs to remove the majority of material before using a scraper pig. It should be noted that a pipeline which has been kept clean or was cleaned at the time of shutdown, may only require low density poly pigs and flush water for final cleaning. Verification of the pipeline cleaning is based upon flush water quality checks which may rely on visual verification that there is no hydrocarbon "sheen" or measurements by instrumentation.

Flush water is typically pumped down disposal wells, processed for disposal, or trucked to an approved dump site.

Pipeline Removal Operations

Pipelines will generally be removed offshore through the surf zone and capped. The removal may be completed by an anchored barge or work boat with adequate winch and crane capacity to pull the pipe aboard and lift sections to a cargo barge or boat for transport to shore. The onshore pipeline may be removed completely, or some sections may be abandoned in place due to their transition through a sensitive environment such as a fragile beach bluff. The pipeline end seaward of the surf zone, typically in water depths exceeding 15 feet MLLW (mean lower low water), is capped with a steel cap and jetted down 3 feet below mudline by divers.

Divers will cut the pipeline with an arc oxygen torch at the platform and install a cap on the end. A tent may be used over the cut point to catch any residual hydrocarbons, however, the progressive pigging operation will usually clean the pipeline well enough to avoid any hydrocarbon releases. The pipeline end is buried below the mudline, typically by diver operated jetting. The pipeline end may alternatively be covered by a concrete mat as shown in **Figure 1**. The mat provides a cover for the pipeline end that will not hinder a trawl net. A pipeline pull sled at the platform may create an obstacle for fishing. The sled would need to be removed or buried with the pipeline

end to eliminate the potential snagging hazard for trawl nets.

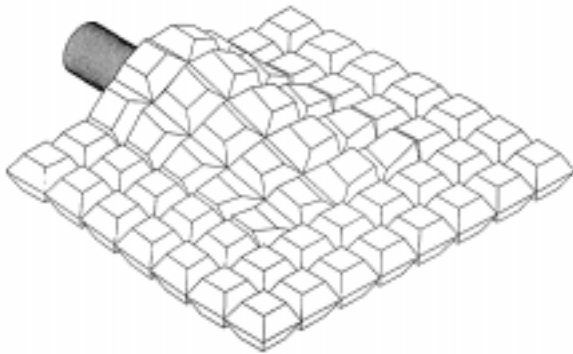


Figure 1. Flexible Concrete Mat Pipeline End Treatment. Exxon OS&T Abandonment Plan.

The recovery of removed pipeline sections is accomplished by rigging a winch wire to the pipeline and lifting it to the barge. A crane may be used in conjunction with the winch to hoist the pipeline onto the recovery vessel. The pipeline removal operation will typically create forces on the pipeline which result in buckling and bending. These structural failures have no impact on the removal process and allow for lower cost removal operations. Excavation may be required to remove the pipeline, or it may be recovered without excavation if enough lifting force can be applied.

Pipeline crossings may be an obstacle to decommissioning, particularly if the pipeline to be decommissioned crosses under a live production pipeline. A pipeline crossing is the intersection of two or more pipelines, generally at some location away from the platform site. The crossing of the newest pipeline is usually built up 1.5 to 2 feet above the older existing pipe with a steel frame bridge and/or cement bags. This crossing creates a mound which may be a trawling obstacle. The removal of one of the pipelines at a crossing creates an element of risk, and if the pipeline is to be removed entirely, the abandonment in place of several hundred feet of the pipe at the crossing may be advisable to avoid any possible disturbance of the pipeline in service.

Pipeline Disposal

Pipeline materials must be transported by truck or barge to an approved dump site. The scrap

value of the steel in the pipelines is exceeded by the cost of removing the pipeline coatings; and therefore a scrapping disposal option is not viable. The pipeline materials must be reduced in length in accordance with the dimensions dictated by the selected dump site, and may be as short as 6 feet. A hydraulic shear may be used effectively to section the pipeline materials to meet these requirements.

CASE HISTORIES

Exxon, Hondo-to-SALM Pipelines and Power Cable

The first deep water (approximately 500 feet) pipeline and power cable decommissioning project off California was associated with the removal of Exxon's Single Anchor Leg Mooring (SALM) and Offshore Storage and Treatment vessel (OS&T) in 1994. The SALM/OS&T facility was installed in 1980 to transfer, process and store production from platform Hondo until the onshore Las Flores Canyon Processing Facility became fully operational.

This project included decommissioning three short (approximately 1.6 miles) pipelines and a power cable that connected the SALM to platform Hondo (**Figure 2**). A number of factors were considered in determining the scope of work to be performed. The critical factors that influenced the decision process in this case were:

- (1) The work area was situated adjacent to active, high volume pipelines, requiring careful planning and execution when establishing the derrick barge mooring.
- (2) Operations requiring saturation diving needed to be minimized to enhance safety.
- (3) The area was considered a productive trawling area by commercial fishing operators.

The condition of the pipelines and power cables were well documented along their alignments in a number of recent surveys. The most recent of these surveys showed 75% of the length of the two smaller (6 inch and 8 inch) and 56% of the larger (12 inch) pipelines were buried. After considering the options, it was determined that they could be abandoned

in place if adequate measures were taken to assure the severed ends would not significantly interfere with trawling.

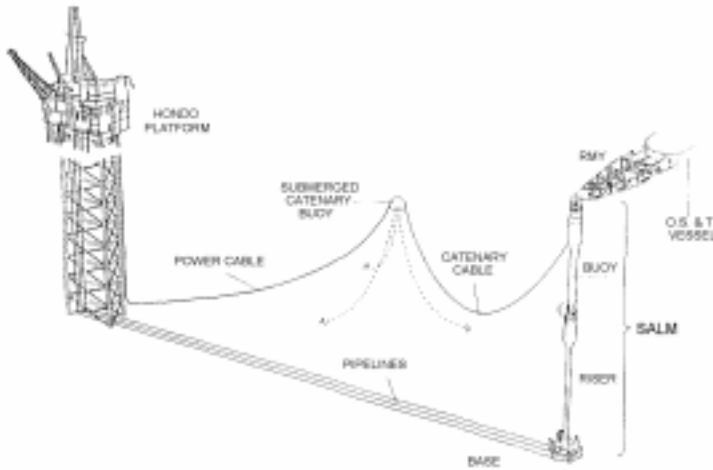


Figure 2. OS&T Abandonment Project Facilities Layout. Exxon OS&T Abandonment.

A total of eight primary work vessels were employed during the course of decommissioning the SALM/OS&T and associated pipelines and power cable. The project required that a four leg mooring system be established for the derrick barge. Precision mooring techniques were used to install and remove the four anchors without incident in spite of their close proximity to active pipelines in deep water (up to 650 feet).

Prior to disconnecting, the pipelines were progressively “pigged” using standard maintenance procedures and sequentially flushed with sea water to remove hydrocarbons. Each line was flushed until water samples passed static sheen tests on two consecutive flush cycles. The flushed pipelines were severed by divers about 100 feet from the SALM base and the spool pieces retrieved for onshore disposal. During pipeline cutting operations, underwater containment tents were used to collect any traces of residual oil that may have been trapped. The cut ends were sealed with mechanical plugs and each cut end was covered with an articulated concrete mattress (**Figure 1**), because it was not practical to bury the ends to the required three foot depth using divers.

The power cable system serving the SALM/OS&T facility was somewhat unusual

because the dynamic nature of the SALM system required a portion of the cable to be suspended above the sea floor using a three-point mooring buoy (**Figure 2**). Except for the suspended catenary portion, the 5 inch diameter power cable was buried along its alignment. The cable was cut by divers where the catenary contacted the sea floor and the severed end of the cable was buried to a depth of 3 feet. The balance of the cable and associated mooring system were retrieved for onshore disposal.

Subsequent trawl testing over the abandoned pipelines and power cable, especially over the severed ends, verified that the area could be trawled with conventional fishing gear. The lease is still an active component of the Santa Ynez production unit and, if it is later determined that the pipelines or power cable impede commercial trawling operations, appropriate remediation would be relatively easy to implement during platform decommissioning.

Texaco, Helen and Herman

Platforms Helen and Herman were installed in the late 1950’s in water depths of 100 feet and 85 feet, respectively, offshore Gaviota, California. They were decommissioned in 1988 after a 15 year shut down period. The pipelines’ cathodic protection was not maintained during the long shut down.

Platform Helen had a 6 inch and 8 inch diameter production pipeline which came ashore under a train trestle. Platform Herman had a 6 inch and 8 inch diameter production pipeline which came ashore further north on the Hollister ranch. Both of these areas were environmentally sensitive and at each location the pipelines were visible on the beach. The Herman pipelines passed through a delicate beach bluff. The decommissioning plan required the removal of a minimum of 800 linear feet of pipeline through the surf zone, and the removal of all of the onshore pipe. The ends of the pipeline were to be capped and buried below mudline at the nearshore cut point and the offshore terminus.

A progressive pigging operation was initiated from a crane barge at the platform sites to

ensure that the pipelines were clean. The operation was started after the pipelines were disconnected from the platform. The pigging operation revealed leaks in the dormant pipelines, and repairs were made to provide the pipeline integrity necessary to run the pigs.

Following the installation of several Plidco clamps, the pigging operation was completed. A pig launcher was installed underwater at the platform site and the flush water was collected onshore in vacuum trucks and discharged at an approved dump site. A pig receiver installed at a valve box onshore collected the pigs at the end of the cleaning run.

The pipelines were then capped and buried below mudline at the platform sites and the crane barge was relocated to the landfall locations of the pipelines. The pipelines were cut on the beach by a rigging crew and approximately 1000 feet offshore by a diving crew. The crane barge pulled the cut segments offshore, through the surf zone, and recovered them for transfer to a cargo barge. The severed ends were capped and buried below the mudline and the remainder of the pipeline, outside the surf zone, was abandoned in place.

The rigging crew on the beach used a bull dozer, an excavator and a rubber tired loader to remove the onshore portion of the pipeline and valve boxes. The excavations were backfilled and shaped to natural contours.

Chevron Platforms Hope, Heidi, Hilda, and Hazel

Platforms Hope, Heidi, Hilda and Hazel were installed from the late 1950's to the early 1960's in water depths of up to 139 feet offshore Carpinteria, California. These platforms had a total of 14 pipelines ranging from 6 inches to 12 inches in diameter. Each of the pipelines was thoroughly cleaned and flushed using progressive pigging techniques prior to severing.

The pipelines from Hope to shore were also used for Platform Grace and Gail production. A 10 inch and 12 inch pipeline from Grace terminated at Platform Hope where production was transferred to the Hope to shore pipelines. Therefore the decommissioning of Platform

Hope required a reroute of the pipelines so that the Hope to shore lines could continue in production. The reroute added two bypass sections of pipeline to the existing lines, rerouting the Grace pipelines around Hope and connecting to two of the Hope to shore pipelines. Platform Heidi also had production pipelines terminating at Hope to share the pipelines to shore.

The landfall of the Hope to shore pipelines at Casitas Pier is typically buried. This burial condition, combined with the continued use of two of the three Hope to shore pipelines, made a surf zone abandonment of the unused pipeline unwise. Removal activities in close proximity to active pipelines would have created unnecessary hazards.

Similarly, the Hazel to shore pipelines are buried at a landfall near Casitas pier. Hilda production pipelines terminated at Platform Hazel to share the Hazel to shore pipelines. These pipelines were abandoned in place in the surf zone.

All of the pipelines abandoned in place in the surf zone were grouted out to a water depth of -15 feet at MLLW. The grouting operation serves to keep the pipeline weighted down to discourage any exposure in the future through the surf zone area.

Offshore at the platform sites, the cleaned pipelines were cut free of the platform risers, capped and buried three feet below mudline.

These platforms had approximately 8 power cables, although some of them were out of service. The power cables were approximately 4 inches in diameter with an armor jacket. These cables were abandoned in place by cutting the end free from the structure and burying the end three feet below mudline.

Ventura Tanker Berth Pipelines

The Ventura Tanker Berth was installed in the late 1940's before the construction of the Ventura Harbor breakwater, and consisted of eight moorings surrounding a pipeline terminus with loading hoses to connect to tanker vessels. The tanker berth had one 20 inch diameter crude oil emulsion pipeline and one 8

inch diameter gasoline pipeline. Maintenance dredging of Ventura Harbor was eventually compromised by the presence of these pipelines, although the burial depth was significant.

The plan for decommissioning was designed around the removal of approximately 1500 feet of each pipeline where they crossed the harbor channel entrance and became a potential hazard to maintenance dredging operations. The entire pipeline was grouted internally prior to removal.

The grouting operation was preceded by a “hot tap” of the pipelines onshore, meaning that an access hole was drilled with a hot tap tool assembly, designed to contain any internal gases under pressure. Although the idle pipeline was depressurized when it was originally shutdown, a pressure buildup due to external heat or chemical reaction was possible during the period it was inactive. This precaution was taken due to the potential presence of explosive or poisonous gases remaining from the crude oil emulsion residue in the pipeline.

The hot tap gas samples from the 20 inch pipeline verified that there were no hazardous gases present. The pipeline was cold cut with a hydraulic powered reciprocating saw and terminated with a welded flange where a pig receiver was installed. A pig launcher was installed on the offshore end of the pipe by divers. Several pigs were introduced into the oil pipeline and the pipeline was cleaned and flushed. The flush water was processed from the pipe termination onshore through the remaining pipeline to the existing tank farm nearby. The water was transferred from the tank farm to a processing facility via connecting pipelines. The 8 inch pipeline had been severed by dredging and was not cleaned.

Grouting operations filled the 20 inch pipeline from the onshore access point to the offshore terminus. The 20 inch and 8 inch pipelines were then removed in the specified area near the breakwater. Divers cut the pipelines into sections and rigged them for recovery onto a work boat. This removal operation required extensive excavation to uncover the pipelines. Airlifting techniques were used by the divers to

uncover the pipe at burial coverage exceeding 15 feet.

CONCLUSIONS

A clear and balanced understanding of decommissioning goals and accurate knowledge of conditions that characterize pipeline and power cable alignments are the necessary prerequisites for making reasonable decisions whether or not to remove or abandon in-place. Experience to-date indicates that removal will be the preferred disposition option for pipeline and power cable segments when:

- they have characteristics that might interfere with commercial trawling or other activities.
- they are located in water depths less than –15 feet (MLLW) or onshore (pipelines only) and not deeply buried.
- they are located in areas subject to maintenance dredging (navigation channels and designated anchorages).

Mitigation might also be considered as an alternative to removal when it can be demonstrated that it would be effective (e.g., shrouding severed ends or flanges with articulated concrete mattresses).

SITE CLEARANCE AND VERIFICATION

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INTRODUCTION

The last stage in decommissioning offshore facilities is site clearance. Site clearance is the process of eliminating or otherwise addressing potentially adverse impacts from debris and seafloor disturbances due to offshore oil and gas operations.

Though infrequent, the cumulative sum of materials lost overboard in the vicinity of an offshore facility can become significant over a time frame that may exceed 30 years. It should be understood that the debris associated with an offshore site is rarely a result of intentional dumping. Virtually all of it can be attributed to accidental losses associated with routine activities, some of which may not be directly related to activities on the facility. Vessels service platforms on a frequent basis to transfer supplies and personnel to and from shore bases. Tires, commonly used as fenders on service vessels and platforms, are occasionally lost during the inevitable contacts that occur. Less frequently, a load of supplies may be dropped overboard during transfer. Materials are also lost during construction and routine maintenance. Moorings for service vessels fail periodically, leaving anchors and associated ground tackle (i.e., chain, cable) on the seafloor.

Except for the unusual case where a loss is considered an operational or environmental risk, immediate recovery is not considered a practical or necessary option. Piecemeal salvage is not cost effective and usually addresses no functional objective as long as the structure remains on location and the lost material poses no risk. Some debris may even enhance the value of the artificial habitat associated with the structure. However, once the structure is removed, regulations and lease terms require that the location be left in a state that will not preclude or unduly interfere with other uses. Site clearance tends

to focus on eliminating debris that has potential to interfere with other activities.

Site clearance also attempts to address such issues as seafloor disturbances around the facility. Mounds of shell debris from repeated maintenance cleaning of biofouling from the structure can accumulate around its base. Such accumulations, combined with mud, cuttings and cement discharged during drilling operations, have been observed to reach a thickness of more than 20 feet above the original seafloor at shallow water locations where dispersion was minimal. At some sites, anchors from large construction vessels may scar the seafloor with deep furrows and mud mounds. Mitigation may be a more effective and environmentally preferable solution than "restoration" when dealing with fishing preclusion issues related to these types of site conditions.

The level of effort required to locate, assess and resolve potential problems associated with debris and seafloor disturbances depends on potential uses of the area, environmental setting, platform age and the frequency of certain activities associated with the operation of the facility being removed. Clearing the location around a typical offshore California production platform with 20 to 40, or more, wells and an operational history that may exceed 30 years, can be a major part of the total decommissioning effort.

GOALS AND PLANNING

The primary goal of site clearance is to clear the location impacted by the facility and associated activities by removing all potentially hazardous materials and eliminating, or mitigating, conditions that might interfere with other uses. For all practical purposes, "other uses" tends to mean commercial trawling operations, as navigation or military use are usually not significant factors associated with offshore California facility sites. Secondary

goals include clearing the site cost effectively with minimum adverse impacts.

Clearing an offshore industrial site may appear to be a simple task but experience has shown it is not one to be taken lightly if a high standard is to be achieved. The strategy for clearing an offshore location must address conditions that tend to be very site-specific. An adequate strategy for one location may prove ineffective or unnecessary at another. The following factors should be considered when planning site clearance.

Determine Disposition Option

To date, all site clearance operations off California have occurred at sites where total removal of facilities, except for pipelines and power cables, was the only disposition option approved. This may not always be the case, as consideration is being given to disposition alternatives that might include leaving part of a structure on location, especially in deep water. Obviously, the scope of site clearance work will be determined by the disposition option chosen.

Determine Alternative Uses

As previously noted, one of the primary goals of site clearance is to condition a location so that it is available to commercial trawling operators; assuming, of course, the facility is to be completely removed. Consultation with representatives of the trawling industry and fisheries regulators should be the basis for determining a site's suitability for any contemplated use. Information from representatives of other fisheries (commercial and recreational) and fisheries researchers should also be considered. The environmental setting of the area to be cleared also needs to be considered. Some facilities may not be located in an environment suitable for trawling or any other use that requires special site conditioning. The effort and expense of site clearance, beyond removal of potentially hazardous materials, may not be beneficial in such cases.

Review Operational History

Regulatory agencies and operators maintain records that are useful in estimating the scope of site clearance effort that may be required.

Examples include "lost item" and mooring maintenance records, surveys that document seafloor debris and documented user conflicts, such as Fisherman's Contingency Fund claims.

Usually, the lead regulatory agency for reviewing the decommissioning project is in the best position to comprehensively assess such records. The lead agency also reviews the operational history of the lease if it is being relinquished. These reviews determine, in part, the size of the area that may have been impacted by all oil and gas activities, from exploration through decommissioning. On some leases, there may be unresolved site clearance issues related to early exploration drilling in the 1950s and 1960s, that would not be addressed if the focus is only on the immediate area surrounding the facility being decommissioned. In such cases, site clearance may only clear a small area in a field of obstructions and the site may not be trawlable unless there is a plan to address conditions present in the surrounding area.

Conduct Pre-clearance Surveys

The two most recent decommissioning projects off California employed "pre-clearance surveys to estimate the extent of the debris field (see **CASE HISTORIES**). The most effective pre-clearance surveys employ very high-resolution side scan sonar technique to efficiently and accurately locate potential debris and other features of interest over relatively large areas. Earlier California decommissioning projects relied more on diver observations and ROVs (Remotely Operated Vehicles) equipped with video cameras and sector scan sonar. These techniques are more suitable for locating, assessing and assisting in removal and remediation near a work site or at previously surveyed locations. They are less effective than side scan sonar as a primary tool for systematically searching and locating debris over large areas and should not be depended on for that purpose unless the area is smaller than a few hundred feet in diameter.

There are a number of advantages in conducting a pre-clearance survey using side scan sonar. The technique is effective for providing a comprehensive overview of the

distribution of debris over a large area, thus providing some degree of assurance that far-field debris are not missed. Side scan surveys also provide information useful in assessing the potential for alternative uses of the site because it can document seafloor conditions, such as high relief rocky habitat, that preclude trawling. Although pre-clearance side scan surveys have, until recently, been considered to be an extra decommissioning expense, experience indicates the information gained can result in significantly lower ROV and dive costs by allowing more efficient use of those more expensive and time consuming techniques. Information from surveys completed prior to beginning removal work on a facility can also be used as a planning tool for minimizing adverse impacts on any sensitive habitat that may be located near the work area. However, one should be aware that the quality of the side scan sonar surveys can vary. The effectiveness of side scan sonar surveys for site clearance applications is improved by optimizing target detection rather than seafloor mapping capability. Pre-clearance surveys conducted primarily to document sensitive habitat prior to facility removal may need to be followed by a second survey, optimized for target detection, after the structure is removed (see **CASE HISTORIES**).

CLEARANCE AND VERIFICATION STRATEGIES

Equipped with a comprehensive understanding of the site, with an emphasis on applying the results of a thorough evaluation of a pre-clearance survey, one should have a clear idea of the distribution and types of conditions that will require attention to prepare the site for alternative uses. As previously noted, most of the effort spent actually clearing the site involves removing debris. However, there may be other conditions at a site that require alternative methods of remediation.

Debris Removal

Debris removal within a fixed radius of an offshore structure is usually an element of the facility removal contract. Debris density is usually highest near the structure, thus much, if not most, of the debris associated with a

facility is salvaged during its removal using the same equipment.

The salvage methods used during the removal of a facility depend primarily on using the divers and ROVs already on location while they are working near the base of the structure. This is an ideal arrangement for removing large or awkward items, as heavy lift equipment is already on location. However, once the structure has been dismantled and removed, the use of divers to locate and remove relatively small items scattered over an extended area is not cost effective. Good planning, based on a high quality pre-clearance survey, assures that all items requiring large capacity lift capability will be removed before demobilizing the derrick barge. Usually, any heavy items that remain on the seafloor are within the capacity of a suitably rigged anchor handling vessel, although most debris are actually salvaged using the dive/ROV support vessel.

Following removal of the facility and associated near-field debris, the most common method in the Gulf of Mexico for removing items that might remain is to trawl the area with nets. Site clearance trawling in the Gulf has resulted in the development of specialized, heavy-duty trawling gear with reinforced mesh, commonly known as "Gorilla Nets". These nets are dragged across the seafloor, often using a saturation pattern of traverses designed to provide 100% coverage of the clearance area in four directions (i.e., headings at 90° intervals). This may be one of the most efficient and cost effective methods to assure significant debris is removed over large areas. However, to date, such methods have not been used to clear a west coast site because suitable vessels are not generally available and the need to clear sites has been too infrequent to justify mobilizing and maintaining such a capability locally. It should also be noted that most west coast platform sites are located in water depths greater than the 300 foot cut-off depth for site clearance in the Gulf of Mexico. Deploying this type of gear in water depths greater than 500 feet would require significantly larger winch capacity and greater horsepower. Either factor might make this method a less viable alternative to removal techniques currently in use off California.

Local trawling vessels, with few exceptions, employ very small nets for deep water trawling and most of their available power is used to handle the very long cables required. Local vessels also tend to be efficiently sized and, thus, would be difficult to retrofit with the significantly larger power plants and winches needed to operate larger, heavier gear suitable for removing debris. The narrow margin of reserve power available in the local trawl fleet is part of the reason seemingly minor seafloor debris can cause them major problems.

Recent site clearance operations off California have relied primarily on ROV and diver methods for debris removal, although some local trawlermen have unintentionally participated in such work. An ROV equipped with sector scan sonar, video camera and using acoustic tracking, integrated with the primary surface navigation system, is the principal method employed to relocate and assess sonar targets from pre-clearance surveys. The advantages of an ROV vs. a diver are safety, ability to function for extended periods at great water depth, and the ability of sonar to locate targets beyond the range of visibility. The principal disadvantage of an ROV is the limited range of manipulative functions it can perform compared to human hands, which is why divers are still used for salvage operations at water depths less than a few hundred feet. Even in shallow water, ROVs are used to minimize diver time during search and assessment operations.

At water depths beyond a few hundred feet, salvage contractors rely almost solely on ROV methods. The most common strategy is to fit an ROV manipulator arm with a tool, suitably customized so that it is capable of attaching a line to the object. The line is then run to a surface vessel equipped with an adequately sized winch and the item retrieved. This is a tedious but effective method for the majority of debris encountered, although other methods may be needed for unusually awkward or heavy items. In such cases a separate, dedicated salvage operation may be required.

The heaviest item that might be routinely encountered are abandoned work boat moorings. Salvage of existing and known abandoned moorings is usually part of the

facility removal operation. However, it would not be unusual for a platform to have 10 or more mooring failures during a functional life of 30 years. Records may be inadequate for assuring all lost moorings were recovered, which is a reason to conduct a careful search around all known mooring locations for evidence of orphaned moorings. Sonar will usually detect any orphan moorings capable of causing problems for trawlers.

Other Remedial Methods

Some potential obstructions may be abandoned in place if adequate measures are taken to remediate the problem. Typical examples are the severed ends of pipelines and power cables. Regulatory requirements require cut ends to be buried or otherwise conditioned so that they will not interfere with trawling. Burial is usually accomplished by divers using hydraulic jetting equipment. However, bottom type, pipe diameter or water depth may preclude burial. In such cases, some other form of end treatment, like articulated concrete mats or shrouds, may suffice to assure trawlability. Similar treatments may also be suitable for remediating other potential snags, like pipeline flanges.

Another class of features that can cause problems to trawlers are major seafloor alterations such as deep scars and mud mounds caused by mooring large work vessels such as the derrick barges used for removing structures. The seafloor perturbations caused by anchoring usually heal with time, due to natural processes, but it might require years. Past attempts at remediating such features have shown mixed results and some alternative mitigation that is advantageous to the affected user may be a more practical and immediate solution.

A more difficult seafloor alteration to remediate are the mounds of shell debris, mixed with drill cuttings and cement, that can accumulate under shallow water facilities where dispersion is minimal. The recent platforms decommissioned by Chevron (see **CASE HISTORIES**) were characterized by 20+ foot high mounds that are untrawlable and some form of alternative mitigation for permanent preclusion may be the only

practical option. In deep water, such accumulations tend to be dispersed over a larger area, although cement accumulations around well risers may have potential for damaging trawl gear. If relief is not excessive, articulated concrete mats may be a possible solution for remediating some of these conditions.

Verification

The best method to test the adequacy of site clearance operations, when conditioning for trawling is the objective, is to trawl the area with the type of gear that will be used. Trawling tests were used to verify the two most recent California decommissioning projects (see **CASE HISTORIES**). In both cases, local fishermen were contracted, but the projects were quite different in execution.

In the shallow water Chevron project, a very dense pattern of trawl passes was scheduled, covering an area within a 1000 feet radius of each platform site. GPS navigation was used to accurately locate the position of each snag encountered and documented snags were systematically remediated and retrawled. The shell mound features that remained after the structures were removed were found to be untrawable with conventional gear. The mounds were also trawled with roller gear but some snags were still experienced. Other snags were encountered outside the clearance area, while making turns to line up for the next traverse. Some of these snags were caused by obstructions remaining from early exploration drilling.

In the Exxon project, the clearance area was relatively large, about 2 square miles, and in water depths that ranged from 300 to 700 feet. Although thorough, the clearance effort was considered an interim measure as the lease is still active and may need to be cleared again when it is relinquished. In this instance, trawl testing objectives focused only on areas with potential to cause problems. Because of the deep water and the difficulty in positioning the small (approximately 40 foot opening) net, acoustic tracking was installed on the net to assure precise knowledge of its position relative to the targeted test areas. The only snag encountered during test trawling was attributed to natural features.

When a site is not being conditioned for trawling, the most appropriate verification method is to conduct a post-clearance side scan sonar survey with methods similar to those used in the pre-clearance survey. A comparison of data from both surveys provides a comprehensive picture of what was accomplished during clearance operations and is an excellent method for documenting the final condition of the site.

Off-the-shelf software/hardware systems are now available that facilitate the construction of mosaics from sonar data, making such projects less labor intensive and more precise for use in before and after comparisons. Some software allows side scan sonar data to be interfaced with sector scan sonar used in ROV operations. The data can also be manipulated to help locate and classify potential debris targets that are hidden in background clutter on conventional facsimile displays of sonar data. The use of these data enhancement and analysis techniques will allow more definitive verification of future offshore site clearance projects.

CASE HISTORIES

Exxon, Santa Ynez Unit, SALM and OS&T Site

The first and only major site clearance project related to decommissioning a federal oil and gas facility off California occurred in 1994 following the removal of Exxon's Single Anchor Leg Mooring (SALM) and Offshore Storage and Treatment Vessel (OS&T). The SALM/OS&T facility was situated in approximately 500 ft of water, about 3.5 miles south of Gaviota, CA and was used to transfer, process and store production from platform Hondo between 1980 and 1994. With the addition of output from two new oil and gas platforms, all Santa Ynez Unit production was pipelined onshore to the new Las Flores Canyon processing facility, making the SALM/OS&T facility redundant.

There were a number of precedent setting aspects to the SALM/OS&T site clearance project which made it a challenging exercise, including:

- Deepest water site cleared on the federal OCS (possibly the world?)
- Motion of the OS&T around its mooring had potential to distribute debris over a large area
- Trawlers wanted access to the area although it was still under lease and site clearance, arguably, could be delayed until production ceased, 10 to 20 years later.

Exxon had already arranged for a site clearance program as part of the removal contract for the SALM/OS&T facility. The area proposed for clearance included areas around the SALM base, derrick barge moorings used for decommissioning, and at a number of other specified locations with suspected potential to impede trawling. Exxon's initial proposal met or even exceeded precedent, given the water depth. However, the MMS determined that a much larger area needed to be documented and cleared, if necessary, to be confident that the area being reopened would be trawlable.

The principal factors considered in reviewing Exxon's site clearance program included:

- dispersed debris field
- potential for debris from other activities in the vicinity, especially pipeline construction
- presence of natural obstructions in the area had been documented on prior surveys (high relief rocks)
- three partially exposed pipelines and a power cable decommissioned in-place, including the articulated concrete mats used to cover severed ends of pipelines
- Seafloor scars caused by derrick barge moorings, power cable moorings, pipelay operations and removal of SALM base pilings
- Documented loss of a large anchor from a tanker

After re-evaluating all these factors, Exxon agreed to significantly expand the scope of site clearance. Site clearance was conducted in two phases. The removal contractor would still perform phase 1 - "Facility Removal Area Clearance" and the additional area specified would be included in phase 2 - "Outer

Operational Area Clearance." Both phases used a three stage approach to site clearance: (1) pre-clearance sonar search, (2) target evaluation and remediation, (3) trawl testing for verification.

Phase 1 - Exxon's facility removal contractor surveyed a 1500 ft radius area around the center of the SALM base using a 500 kHz side scan sonar. Side scan sonar was also used to relocate the lost tanker anchor. An ROV mounted sector scan sonar was used to survey a 200 ft radius around each of the four derrick barge moorings to document anchor impacts.

All unidentified sonar targets were assessed using ROV video and potential obstructions were salvaged using the removal equipment on site. The cleared areas were then test trawled by a licensed commercial trawler using standard trawling gear. No obstructions were reported.

Phase 2 - Following SALM/OS&T removal operations, a second side scan sonar reconnaissance was conducted over approximately 2 square miles of seafloor, between Platform Hondo and the OS&T site. The water depth ranged between 300 and 760 feet and the survey included the area cleared by the removal contractor in Phase 1. The 500 kHz side scan sonar system was equipped with acoustic tracking integrated with surface navigation to facilitate accurate sonar target location. Sonar range and transect spacing provided better than 200% coverage of the survey area.

The Phase 2 side scan sonar survey located 270 sonar targets (including seafloor features). All sonar targets were cataloged, mapped and their sonar images classified for follow-up evaluation using an ROV.

The second stage of phase 2 clearance operations included ROV target identification and salvage. Approximately 60% of the sonar targets were selected for evaluation with an ROV because they had sonar signatures that suggested potential debris or obstructions. The ROV was equipped with sector scanning sonar and acoustic tracking to relocate targets, and video for evaluation and documentation. Targets considered to be

potential trawling hazards, were salvaged using the ROV. This required equipping the ROV with an appropriately designed tool to enable a cable to be attached to the item for recovery. A total of 36 items of debris were ultimately recovered in phase 2. Tires were the most common type of debris recovered (50% of total). A number of items were recovered from the area cleared in phase 1. We assume this was a consequence of the phase 1 contractor knowing a more comprehensive, site clearance effort would follow.

The final stage in phase 2 site clearance was verification using conventional trawl gear. Trawl verification efforts focused on specific areas where residual conditions might pose some risk of "snags" or net damage. The size of area, water depth and small size of deep water trawl nets used in the local fisheries made a typical 200% to 400% trawl verification strategy impractical, and probably unnecessary, given the thorough clearance effort already implemented. Intensive trawl verification was also considered premature in this case because the area could be subject to additional clearance efforts when production ceased on the active lease at some, undetermined, future date. Although trawl verification concentrated on the highest risk areas, and employed acoustic tracking to assure the net passed over potential hazards, no obstructions were encountered. Net damage did occur on one pass; however, the trawl operator believed the damage was caused because he strayed into high relief rocks outside the designated test areas.

The clearance effort following removal of the SALM/OS&T facility appears to have been successful as there have been no reported gear damage or losses during the year it has been accessible to trawlers. At the time this is being written, the three step approach to site clearance used by Exxon (i.e., pre-clearance sonar reconnaissance, evaluation/remediation, verification) serves as a working model for evaluating future California OCS site clearance proposals.

Chevron, "4-H" Platform Sites

The most recent offshore site clearance operations conducted off California occurred

in 1996 following Chevron's decommissioning and removal of four platforms on California state leases seaward of Santa Barbara County, between Carpinteria and Summerland. Platforms Hilda, Hazel, Hope and Heidi, commonly referred to as the "4-H" platforms, were installed between 1958 and 1965. A total of 134 wells were drilled from these four relatively shallow water facilities (depths ranged from 98 to 141 feet). The primary objective of site clearance operations at the "4-H" platforms was to condition the areas impacted by the facilities so that they could be trawled. The effort expended by Chevron and their contractors in trying to accomplish that objective may be one of the most intensive site clearance exercises related to offshore oil and gas decommissioning, to date.

Factors considered in developing a site clearance strategy included:

- older, debris potential uncertain
- shallow water, debris probably concentrated close to platform
- significant accumulations of shell debris, mixed with, cement and drill cuttings at the base of the platforms.

Prior to commencing removal of the structures, a side scan sonar and bathymetry survey of the seafloor within a 1400 foot radius of each platform was conducted. A 500 kHz sidescan sonar system was used with range and transect spacing adequate to achieve a theoretical 400% coverage of the seafloor around each platform structure. The pre-decommissioning survey was used to locate debris and confirm the locations of active pipelines, power cables and sensitive habitat that would need to be avoided during decommissioning operations.

During the course of structure removal operations, debris located in the pre-decommissioning side scan sonar survey was removed by divers with ROV assistance. Facility elements abandoned in-place, such as pipelines, were buried by divers using hydraulic jetting technique.

Following removal of the "4-H" platforms and debris, a second, post-decommissioning, side scan sonar survey was conducted over an area that encompassed a 1000 foot radius

around each platform site and the area around the two temporary moorings used during removal operations. The post-removal survey was used to verify debris removal by comparing results to the earlier survey and to locate any new or residual features that might be a potential problem for trawl verification. Swath bathymetry studies were also conducted to document the mounds of shell debris that characterized all four sites.

A licensed commercial fisherman, using conventional trawling gear, was contracted to determine if the sites were adequately conditioned to allow snag-free, trawling operations. Trawl testing was conducted on a very dense, saturation grid employing 102, 2000 ft long traverses at each platform location (i.e., the area covered by the second side scan sonar survey). Trawl passes were spaced 40 ft apart with one half the traverses oriented N-S and the other half, E-W. The initial trawling trials occurred over a four month period in late 1996 (total of 46 working days) and a total of 25 snags were documented. More than half (14 of 25) were believed to be associated with pipelines or power cables; another 5 were located on the shell mounds at the old platform sites. Actually, more snags would have been recorded if attempts to trawl across the mounds had not been suspended early in the trawl testing program. The remaining 6 snags that were documented were associated with undetermined or natural features, or were encountered adjacent to, but outside, the designated clearance areas. By the time trawling trials with conventional gear were suspended (12/96), about 80% of the planned trawling was complete.

Chevron responded to the results of the initial trawl testing with additional efforts focused on eliminating snags, including two associated with an old drilling site outside the designated clearance zone. Later, in mid-1997, further trawl testing was attempted over the shell mounds using roller gear of the type Chevron had previously supplied to Santa Barbara Channel trawl operators as mitigation for problems alleged to be associated with one of their OCS pipelines. Preliminary reports indicate the roller trawls were significantly more successful in traversing the mounds but snags were still experienced.

As this case history is being written (9/97), the shell mound issue remains unresolved. Commercial trawl fishermen want the mounds removed to clear the area for their activities. However, others consider these relief features to be potential habitat that may enhance hook and line fisheries (commercial and recreational) and diving opportunities.

SLC project conditions require Chevron to conduct a follow-up seafloor survey one year after project completion, if warranted. In the meantime, it is clear that the shell mounds are not trawlable. However, this may be a classic example of a site condition that cannot, or should not, be directly mitigated. The mounds are about 200 to 220 feet in diameter and their relief above the original seafloor ranges from 22 to 26 feet. The average volume of material contained in each mound is estimated to be in excess of 8,000 cubic yards. The environmental impacts, that would result from removing, transporting and disposing of more than 30,000 cubic yards of material, would be significant. In such instances, alternative mitigation that addresses the needs of the affected users should be considered.

CONCLUSIONS

Site clearance activities associated with the most recent offshore California oil and gas decommissioning projects are among the most thorough and sophisticated ever performed by the industry. Sonar search and mapping technology is being used effectively to document site conditions and the industry has shown considerable diligence in addressing potential user problems. In spite of these unprecedented efforts, some of the effects of production activities may not be easy or practical, or even reasonable, to remediate. High relief shell mounds that remained at the sites of four recently removed shallow water platforms will locally preclude some activities of one user group, although they may well enhance opportunities for others. Experience, to date, does not provide much precedent for dealing with the conflicting interests in such cases but they are an opportunity for alternative mitigation which could be more advantageous than eliminating certain types of obstructions when all interests are taken into account.

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DECOMMISSIONING OF ONSHORE FACILITIES: TECHNICAL ISSUES

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Decommissioning and removal of offshore facilities in most cases have onshore components that need to be considered at the same time that any offshore project is considered. Although the goals of decommissioning projects, whether offshore or onshore, are substantially the same, decommissioning of onshore facilities presents a different set of technical challenges from those of offshore facilities. Decommissioning is also affected by the different types of existing oil and gas facilities that are auxiliary to offshore development. Those facilities may include oil and gas processing facilities, marine terminals, pipelines, and storage facilities among others. Generally, the goal of decommissioning is to restore the site to its original, prior to oil and gas development state, or for some other predetermined and approved land use. Onshore facilities are generally decommissioned by removing aboveground facilities, testing for contamination, remediating if necessary, recontouring, and revegetating the site.

REMOVAL

Removal is defined as the proper decommissioning, dismantling and disposal of all above ground facilities, appurtenances and any other obstruction or structure constructed for the operation of the oil and gas facility. In addition, removal also refers to the proper unearthing and disposal of underground facilities such as underground tanks and pipelines if deemed environmentally preferred.

Removal is typically done as a series of steps that include draining, cleaning and flushing all vessels; removal of all vessels, above ground piping, and appurtenances; removal of all buildings and foundations; removal of underground sumps, cables and piping; and loading and transporting of materials or equipment by truck to be recycled, sold, sold for scrap or disposed at an appropriate landfill.

During the draining and cleaning of all vessels care is taken to ensure no materials are spilled. In the cleanup of tanks, tank bottoms and residuals are removed using vacuum trucks or sump pumps. Tank walls are washed to bare metal with diesel and water. Tank bottoms, residuals and cleaning wastes are treated and recycled where possible by utilizing a mobile treatment unit or at an approved treatment and recycling facility.

The removal of all vessels and above ground piping entails unbolting equipment and cutting equipment into sections (if the equipment is not reusable) that can be easily transported to an appropriate recycling or salvaging facility, or for disposal.

Underground components include sumps, foundations, piping, underground tanks, electrical cables and conduits, and cathodic protection cables. Underground components are removed using trenching equipment and then are cut into transportable pieces. Decommissioning of pipelines used to ship oil, gas, and sometimes produced water generally entails inspection of the pipelines concurrent with survey and preparation of the site, followed by purging and capping of the pipelines. Pipelines are left in place or removed depending on burial depth and location. Pipelines that are buried less than 3 feet in depth are usually excavated and removed. Typically, pipelines are removed in creek crossings and other exposed areas to prevent future erosion. In some cases, pipelines are slurried with cement to ensure that their integrity is preserved through time.

CONTAMINATION TESTING

Prior to facilities being removed, a preliminary inventory of existing equipment and hazardous materials should be collected. In addition, historical information can be used to ascertain potential sources of contaminants and types of

contaminants that may be encountered within the facility to be decommissioned. Historical information is also useful for documentation of previous spills or other incidents. The next step would be to conduct a preliminary surface and subsurface investigation. Typically, the sampling program at this stage should include a soil gas survey, shallow soil borings, chemical analysis and the preparation of a preliminary assessment report.

The initial sampling should take place in areas suspected of having the greatest probability of subsurface contamination. Sampling locations can be determined based on visual inspections, review of the site history and site surveys and evaluation by a qualified contractor. Trenches are usually excavated and earth materials examined, specially in former treatment, storage and processing areas of the facility.

The results of the preliminary investigation are used to determine if significant contamination has occurred. If it has, then an Environmental Assessment may be necessary to define the extent of the contamination. The Environmental Assessment will consist of more extensive testing including: soil testing, soil vapor testing (if applicable), groundwater testing (if applicable), health risk and ecological risk assessments as needed or required.

There are a number of sources of contamination associated with onshore oil and gas facilities. **Table 1** provides a list of potential contaminants associated with different types of oil and gas operations. Existing governmental regulations require remediation or containment of oil spills as they occur; additionally, regulations specify measures to protect vulnerable areas such as creeks from spills. However, accidental releases occur irrespective of, or before such regulations were effective and enforced. In addition, other sources of contamination are minor spills of crude oil from aging infrastructure, and spills of imported products that may contain hazardous substances. The types and causes of contamination vary widely, depending on operating procedures and processes used in a specific activity and historic period. For example, some processing operations active during the 1960s used fluids as a heat transfer

medium that contained PCBs before they were classified as suspected human carcinogens. Spills of these fluids during handling, processing, and storage left soils contaminated. In most cases, chronic leaks from tanks and pipelines usually result in remedial efforts during decommissioning .

Regulatory agencies typically base characterization of crude oil releases and level of remedial action on concentrations of total petroleum hydrocarbons and, in some instances, concentrations of individual soluble constituents such as benzene, toluene, ethylbenzene, and xylenes (collectively referred to as BTEX) and certain polynuclear aromatic hydrocarbons that are toxic in certain dosages.

If hazardous wastes are discovered in groundwater, the Regional Water Quality Control Board (RWQCB) can require remediation, depending upon type(s) and extent of hazards. If hazardous wastes are discovered in soil, RWQCB will investigate type and potential to leach through to groundwater, and propose remedial actions based on their findings.

REMEDICATION OF CONTAMINATED SITES

Remediation is defined as the removal and proper disposition of unauthorized or accidental releases and/or contamination pertinent to the oil and gas process or related operation. Remediation must include areas affected by the unauthorized disposition or accidental release when contamination occurs off the site, but where the contamination is generated by the facilities operations.

The primary goals of remediating contaminated soils are to protect public health, to protect groundwater in rural areas necessary to support the state's agricultural industry and to protect sensitive environmental resources. Basic issues that take shape around remediation of soils and groundwater generally focus on type of contaminant, extent, cleanup level, cleanup methods, and timing of remediation. The type of contamination also weighs heavily in defining potential issues.

Table 1¹
Listing of Potential Contaminants Associated with Oil & Gas Operations

Process-Specific Equipment, or Type of Area	Possible Contaminants
Contaminated Soil around Oil Field Facilities and Equipment	The soil may contain one or more of the following: asphalt, BTEX (benzene, toluene, ethyl benzene, xylene), chemical residues, paraffin, salt, tar, and/or weathered oil. BTEX will only be associated with light oil fields (i.e., high gravity oil production).
Drilling Muds	Elevated concentrations of chromium may be found in drilling mud pits which contain ferrochromelignosulfonates in the disposed drilling mud.
Cut-Labs	Cut-labs may have associated solvent waste disposal into a pit/sump, or into a dry well located near the lab.
Electric Distribution Centers	Some distribution centers may have PCB contamination from leaking transformers and other oil-filled equipment.
Filters	Some diatomaceous earth filters contained a precoat of asbestos fiber, or cellulose fiber. Old installations will have a disposal pit that probably contains asbestos fibers mixed with diatomaceous earth, and the solids filtered from the water.
Flares	Ash from burning crude will contain heavy metals. Area around flare may be contaminated with heavy metal salts.
Storage Yards	PCBs, other chemicals.
Hydrogen Sulfide Gas Scrubbers	Iron sponge units would leave a residue of metallic iron, iron sulfide and iron oxide (rust). Spent iron sponge can be pyrophoric. Scrubbers that use the amine reaction unit may have elemental sulfur as an end product, and probably have sulfur storage areas or potential for sulfur spills.
Loading Areas	Likely areas where hydrocarbon spills, leaks or drainage can occur.
Oil and Gas Wells	Must be properly abandoned to prevent flow of oil, gas, or water to surface and to prevent communication between salt water and fresh water zones. Early produced water spills from vintage 1950s fields may contain arsenic due to use of sodium arsenite in producing oil wells for corrosion inhibition.
Pipelines	Any hazard associated with pipelines will be due to either contained fluids, or to areas where leaks have occurred and contaminated the soil.
Pump Stations	Hazards at pump stations would be due to associated sumps or contaminated soil. Besides hydrocarbon spills, spills or leakage of thinners or diluents may be a concern. Old pump stations may have used mercury-containing flow meters. Some mercury leakage or disposal may have occurred on-site.
Steam Lines	Some of the early thermal lines may have been wrapped with an asbestos-containing insulation.
Sumps/Pits	Materials contained in sumps can include asphalt, chemical wastes, drilling mud, formation solids, salts, tar, trash, waste lubricating oil, waste water, water, and weathered oil.
Tanks	Potential problems with tank farms include: contained solids, contained fluids, contaminated soil around or underneath the tanks, and associated pits or sumps. The following materials may be found inside old oil field tanks: asphalt, chemicals, chemical residues, corrosion products, crude oil, crude oil diluent, diesel oil, drilling mud, filter sand and gravel, foaming agents for fire control, gas oils in gas storage tanks, gasoline, glycol and/or glycol residues, green sand, ion exchange resins, iron sponge, lubricating oil, road oil, salt, sand, solidified oil, tar, water, and waste water.
Water Treating Facilities	Chemicals used include emulsion breakers, coagulants, polymers, biocides, scale inhibitors and corrosion inhibitors.

¹Scott, J. 1994. Santa Barbara County Oil and Gas Facilities Inventory.

When oil and gas sites are discovered to be contaminated with well-known toxins such as polychlorinated biphenals (PCBs) or with hydrocarbon, levels of remediation are determined based on assumptions about the potential to reach groundwater sources, the potential for damage to environmentally sensitive areas, and the future use of the land.

Uses such as residences, education, and recreation dictate a higher level of remediation due to higher potential exposure of humans to health risks. Certain jurisdictions require cleanup levels that are protective of environmental resources in addition to being protective of human health.

Table 2 shows the different types of contaminants and the potential hazards of hydrocarbon compounds associated with crude oil, drilling muds, solvents and metals. The potential paths of exposure include inhalation (of fugitive dust or vapors emitted from soils and waters), ingestion (of groundwater, surface water, and soils; or of produce, fruits, poultry, and livestock raised in area; or of seafood harvested nearshore if contaminants runoff into ocean; or from infant exposure through breast milk), and dermal contact with soil or water.

Crude oil contains hydrocarbon compounds which can be divided into four major structural forms: (1) alkanes, more commonly called paraffins, (2) cycloalkanes, more commonly called naphthenes or cycloparaffins, (3) alkenes, more commonly called olefins, and (4) arenes, more commonly called aromatics. Soluble and potentially toxic constituents of crude oil are usually limited to benzene, toluene, ethylbenzene, and xylenes (BTEX) along with certain types of polynuclear aromatic hydrocarbons. Aromatics contain BTEX. Monoaromatics (single 6-member carbon ring with three double bonds) are very water soluble compared to their alkane and alkene counterparts, and move easily into groundwater; in comparison, polynuclear aromatics (multiple 6-member carbon rings with three double bonds) range from moderately water soluble to relatively insoluble. Moreover, crude oil found in contaminated soils may have already degraded through evaporation, dilution with surface or groundwater, and chemical and biological oxidation (although generally aromatics will take longer to biodegrade).

Remediation Methods

Recently, there have been positive results in remediating sites contaminated with crude oil by methods other than the typical treatment methods of excavation and disposal offsite. As an example, there is much promise in new applications of specially bred microbes to safely and effectively bioremediate hydrocarbon contamination. Bioremediation occurs naturally in soils, whereupon carbon-bearing molecules such as hydrocarbons from petroleum provide a source of nutrients to microflora. The microorganisms create a biofilm around the hydrocarbon molecule and digest it, or decompose it into simpler compounds of carbon and oxygen. Bioremediation can be accomplished *in situ*, which is the least expensive method when conditions are optimal, or *ex situ* (land farming and biopiles) which requires excavation and transport of the contaminated soils (*ex situ* can occur onsite or offsite).

Limiting factors to bioremediation appear to be soil and weather conditions as well as the acreage of contamination that can be effectively remediated. On the positive side, bioremediation appears to work, at least in some cases, on contaminated soils under and around operating equipment and tanks. Consequently, some bioremediation may occur in advance of full decommissioning activities.

Basic issues with various potential methods revolve around the adequacy for cleanup level, timing, environmental impact, and cost of one method versus another. Options should be considered and their feasibility should be analyzed during the planning of decommissioning. Table 3 provides with a description of some of the most common methods of soil and groundwater remediation.

Table 2²
Potential Hazards of Hydrocarbons

HAZARDS IDENTIFICATION		
CATEGORY	SUBCATEGORY	HAZARD
ALIPHATICS	n-hexane	Peripheral neuropathy in humans
	branched chained alkanes	Hydrocarbon neuropathy in male rats only
AROMATICS	benzene	Group A carcinogen - leukemia in humans
	toluene	Solvent neurotoxicity; Prop 65 reproductive toxicant
	xylene	Solvent neurotoxicity
	ethylbenzene	Solvent neurotoxicity
METALS	barium	Relatively non-toxic as sulfate; soluble salts are toxic
	lead	Impairs neurodevelopment (Prop 65 listed); B2 carcinogen
	cadmiun	Group A inhalant carcinogen
	chromiun	Group A carcinogen by inhalation; B2 oral
	nickel	Some exposures (by inhalation) are carcinogenic
POLYCYCLIC AROMATIC HYDROCARB	non-carcinogenic PAHs (naphthalene, etc)	Systemic toxicity
	carcinogenic PAHs (benzoapryine, chryzene, etc.)	Group B2 dermal, inhalant, oral carcinogen
SOLVENTS	carbon tetrachloride	Group B2 carcinogen
	tetrachloroethane	Group B2 carcinogen
	trichloroethane	Group D carcinogen
	trychloroehylene	Group B2 carcinogen
	methylene chloride	Group B2 carcinogen
	Mainly liver tumors and hepatotoxicity	

EPA Carcinogen Classification:

Group A: Human Carcinogen

Group B: Probable Human Carcinogen

Group C: Possible Human Carcinogen

Group D: Not Classifiable

Group E: Negative Evidence

²USEPA. 1989. United States Environmental Protection Agency. Health Effects Assessments Summary Tables and Users Guide. USEPA Office of Emergency and Remedial Response, USEPA, Washington, D.C.

Table 3³
Remediation Techniques

TECHNIQUE	DESCRIPTION
Physical Barrier - Membrane Barriers and Sheetpile	<p>A synthetic membrane barrier such as High Density Polyethylene (HDPE) walls can be used as a short term measure to contain the lateral movement of separate-phase contaminants that float on the water table. Ground water does not penetrate the membrane barrier, but it does continue to flow under and around the barrier. A ground water extraction system may be installed on the upgradient side of the barrier to reduce hydraulic pressures and improve hydraulic control. The HDPE material is resistant to penetration by plant roots and burrowing animals, and inspection/maintenance related requirements should not be required.</p> <p>Due to the strength of the steel piles, sheetpiling can be used to retain soils during excavation and minimize the disturbed area. With this process option, interlocking steel sheets are vibrated or pounded through the soil to the required depth. The sheetpiling retards the lateral movement of separate-phase hydrocarbon, but less than the synthetic membrane option. This is an alternative to installation of HDPE barriers using excavation and trenching.</p>
Vacuum Enhanced Drop Tube	<p>Vacuum-enhanced drop tube recovery removes separate-phase contaminants from the subsurface, which reduces chemical volume. This technique consists of a small diameter drop tube placed at or below the liquid level in a vertical extraction well. A high vacuum would be applied to the drop tube which would quickly draw soil vapor through the drop tube. The vacuum also aids in oxygenation of the soil column above the water table (the vadose zone) which in turn aids in the biodegradation process. Ground water and separate-phase contaminant would also be drawn out of the well and mixed in the turbulent flow in the drop tube. The vapor would be separated from the mixed liquids and each would be disposed of using other options.</p>
Dual Pump Recovery	<p>Dual-pump recovery provides both containment of the separate-phase contaminant, which reduces mobility, and contaminant removal, which reduces chemical volume. This technique involves installing vertical extraction wells and pumping ground water with a submersible pump set at the bottom of the well and pumping separate-phase contaminants with a skimming pump set at the top of the liquid in the well. The extracted ground water and the separate-phase contaminant would be handled using other techniques. Wells should be installed along the downstream edge of the separate phase plumes with overlapping "cones of depression" to ensure that separate-phase contaminant would be captured along the entire edge of the plume.</p>
Excavation	<p>This technique consists of removing separate-phase contaminant from selected areas using a track-mounted excavator or other conventional excavation equipment. Once excavated, separate-phase contaminants and contaminated soil needs to be treated. It can be hauled to a bioremediation site for treatment. Clean overburden soil should be stockpiled and redistributed over the excavated area after the pit is backfilled with treated soils.</p>
Vertical or Horizontal Biosparging	<p>With this process, air is introduced to the subsurface below the water table to promote the growth of aerobic microorganisms which could degrade dissolved-phase contaminants. Biosparging can be accomplished continuously or in a pulsed fashion through vertical or horizontal wells. As the injected air sweeps upward through the contaminant-affected ground water and soil, it may also transfer volatile compounds from a liquid to a vapor phase.</p>
Ground Water Extraction	<p>This process consists of pumping dissolved-phase contaminant from ground water extraction wells. Ground water extraction can provide both hydraulic containment, which can prevent chemical migration, and dissolved-phase contaminant removal, which can reduce chemical volume. The extracted ground water would then be treated and discharged using other technologies.</p>

³Arthur D. Little. 1997. Guadalupe Oil Field Environmental Impact Report, Public Draft.

Extracted Material Treatment

TECHNIQUE	DESCRIPTION
Oil/Water Separation	With this process option, extracted ground water with entrained separate-phase contaminant would be pumped into a large holding tank where gravity would separate the immiscible hydrocarbon from the water. Baffles and separation plates are used to prevent short-circuiting and increase separation efficiency.
Liquid-Phase Carbon Adsorption	This process would treat extracted ground water, removing dissolved-phase contaminant from extracted ground water by pumping it through two or more vessels containing granular activated carbon (GAC) connected in series. As the water is passed through the carbon beds, the petroleum hydrocarbons would become adsorbed onto the GAC. After the GAC becomes saturated with hydrocarbons, it would be replaced with fresh GAC. The used GAC would be transported to an off-site facility for regeneration. This technology is proposed as a process to treat extracted dissolved-phase ground water or water taken from a separate-phase treatment technology.
Recycling	With this process option, recovered hydrocarbon would be transported to A nearby Refinery and reprocessed into other products.
Deep Well Injection	Under this disposal option, untreated or partially treated water generated by remediation activities would be pumped down unused oil wells into the oil-bearing formation thousands of feet underground. Liquids generated by pumping in the beach area and by various pilot tests have been injected under permit as Class I fluids in this manner.
Landfarm Bioremediation	Landfarm bioremediation utilizes naturally occurring micro-organisms for the degradation of the hydrocarbons. Exposing the affected soils to the air and adding moisture and other nutrients enhances the activity of the microorganism, resulting in increased rates of hydrocarbon degradation. During operations, soil will be periodically wetted down with water pumped from existing on-site wells to maintain an optimum moisture content for biodegradation. Nutrients may also be sprayed over the excavated soil, or nutrients could be introduced by tilling the affected soil with compost and other amendments. On a periodic basis, (e.g., every few weeks) soil should be tilled or disked with conventional earthworking equipment.
Air-Phase Carbon Adsorption	This process would treat extracted air from the vacuum drop tube systems, removing contaminant from the extracted air by routing it through vessels connected in series and containing GAC. As the air is passed through the carbon beds, the petroleum hydrocarbons would become adsorbed onto the GAC. After the GAC becomes saturated with hydrocarbons, it would be replaced with fresh GAC. The used GAC would be transported to an off-site facility for regeneration.

Restoration

Restoration and recontouring is defined as the process by which the land is returned to its original state. General procedures for restoration include minor recontouring and grading, including backfilling and ground leveling; preparing topsoil; drainage control; and installing slope stabilization measures, and other erosion control and soil stabilization measures as needed.

Recontouring and regrading may be necessary in areas where large pieces of equipment or foundations are excavated and removed. In general, sites should be returned to more natural contours depending on the subsequent land use. Backfilling and soil importation may be necessary in some areas, specially where facilities are excavated or where remediation measures require transport of soils offsite. Imported topsoil

must be fertile, friable topsoil of character and texture similar to the project site soil. In addition, the soil should be without a mixture of subsoil materials, obtained from a well drained arable site, reasonably free from clays, lumps, coarse sands, stones, plants, and other foreign materials. Finish grading should include provision of positive surface drainage of planted areas. Existing drainage flowlines should be utilized as much as possible. Erosion control measures include straw bails, silt fences, jute netting, water bars, diversion channels, etc., and should be used as needed depending on the site topography and final contours.

Revegetation

Revegetation is the replanting and re-establishment, where appropriate, of native

species previously removed during the construction of the facility or known to exist in the surrounding area of the facility to be decommissioned. Revegetation of a decommissioned site requires a number of steps that include site and seedbed preparation, seeding, mulching, fencing and irrigating.

Site preparation includes breaking up compacted soils by disking or other methods, and mixing imported soils with the existing material. Chiseling also restores soil permeability. Mulching with finely chipped vegetation or straw may be needed to improve the seedbed.

Only species and species varieties adaptable to local soil and climatic conditions should be used for seeding. Seeding techniques may include broadcasting, drilling, hydromulching or other appropriate techniques or combinations thereof. Fertilizers and soil amendments should be used as needed, to optimize revegetation success. Seeding should occur at a time of the year when seeds are most likely to receive moisture and germinate, generally in late fall.

Mulches are applied to seedbeds to retard soil erosion, moderate surface temperatures, retain moisture and provide shade for seedlings. Mulches are recommended for steep slopes and on rocky, shallow soils or exposed windy slopes. One of the most effective and universally available mulches is grain straw.

Trees and other planted vegetation may require irrigation after planting and then periodically thereafter to ensure revegetative success. In some areas fencing may be necessary to keep livestock from trampling new seedlings or predators from eating the seeds.

Inspection and monitoring of the revegetation effort should be conducted by a landscape contractor or revegetation expert to ensure that the prescribed maintenance procedures are being carried out and to determine that the revegetation is effective. Additional maintenance activities may include herbicide treatments and reseeding where necessary.